BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF HAWAI‘I

------ In The Matter Of -----	)	
	)	
PUBLIC UTILITIES COMMISSION	)	DOCKET NO. 2014-0183
	)	
Instituting a Proceeding to Review the Power Supply Improvement Plans for Hawaiian Electric Company, Inc., Hawaii Electric Light Company, Inc., and Maui Electric Company, Limited.	)	

Hawaiian Electric Companies' PSIPs Update Report

Filed April 1, 2016

Book 1 of 2

FILED

2016 APR -1 P 3:39

PUBLIC UTILITIES COMMISSION

JOSEPH P. VIOLA
Vice President
Regulatory Affairs

April 1, 2016

The Honorable Chair and Members of the
Hawai'i Public Utilities Commission
465 South King Street, First Floor
Kekuanaoa Building
Honolulu, Hawai'i 96813

Dear Commissioners:

Docket No. 2014-0183 – Instituting a Proceeding to Review the Hawaiian Electric Companies' Power Supply Improvement Plans ("PSIPs")
Order No. 33320 Compliance Filing

Pursuant to Order No. 33320, filed November 4, 2015 in the subject proceeding, the Hawaiian Electric Companies[1] hereby respectfully submit their PSIPs Update Report.[2]

Sincerely,

Enclosure

c: Service List

[1] The Hawaiian Electric Companies are Hawaiian Electric Company, Inc., Maui Electric Company, Limited, and Hawai'i Electric Light Company, Inc.
[2] Order No. 33320 provides that in accordance with the Schedule of Proceedings, by April 1, 2016, the Companies shall file supplemented, amended and updated PSIPs.

SERVICE LIST
(Docket No. 2014-0183)

JEFFREY T. ONO EXECUTIVE DIRECTOR DEPARTMENT OF COMMERCE AND CONSUMER AFFAIRS DIVISION OF CONSUMER ADVOCACY P.O. Box 541 Honolulu, Hawaiʻi 96809	2 Copies Via Hand Delivery
DOUGLAS S. CHIN ATTORNEY GENERAL OF HAWAII DEBORAH DAY EMERSON GREGG J. KINKLEY, ESQ DEPUTY ATTORNEY GENERALS DEPARTMENT OF THE ATTORNEY GENERAL STATE OF HAWAII 425 Queen Street Honolulu, Hawaiʻi 96813 Counsel for DEPARTMENT OF BUSINESS, ECONOMIC DEVELOPMENT, AND TOURISM	1 Copy Electronic Transmission
MOLLY A. STEBBINS CORPORATION COUNSEL WILLIAM V. BRILHANTE, JR. DEPUTY CORPORATION COUNSEL COUNTY OF HAWAIʻI 101 Apuni Street, Suite 325 Hilo, Hawaiʻi 96720 Counsel for the COUNTY OF HAWAIʻI	1 Copy Electronic Transmission
PATRICK K. WONG CORPORATION COUNSEL MICHAEL J. HOPPER DEPUTY CORPORATION COUNSEL DEPARTMENT OF THE CORPORATION COUNSEL COUNTY OF MAUI 200 S. High Street Wailuku, Maui, Hawaiʻi 96793 Counsel for the COUNTY OF MAUI	1 Copy Electronic Transmission
RICK REED DIRECTOR HAWAII SOLAR ENERGY ASSOCIATION 761 Ahua Street Honolulu, Hawaiʻi 96819	1 Copy Electronic Transmission

ERIK KVAM
PRESIDENT
RENEWABLE ENERGY ACTION COALITION
OF HAWAII, INC.
1110 University Avenue, Suite 402
Honolulu, Hawai‘i 96826

1 Copy
Electronic Transmission

WARREN S. BOLLMEIER II
PRESIDENT
HAWAII RENEWABLE ENERGY ALLIANCE
46-040 Konane Place, #3816
Kaneohe, Hawai‘i 96744

1 Copy
Electronic Transmission

RICHARD WALLSGROVE
PROGRAM DIRECTOR
BLUE PLANET FOUNDATION
55 Merchant Street, 17th Floor
Honolulu, Hawai‘i 96813

1 Copy
Electronic Transmission

DOUGLAS A. CODIGA, ESQ.
MATTHEW M. MATSUNAGA, ESQ.
SCHLACK ITO LLLC
Topa Financial Center
745 Fort Street, Suite 1500
Honolulu, Hawai‘i 96813
Counsel to NEXTERA ENERGY HAWAII, LLC

1 Copy
Electronic Transmission

MARK J. BENNETT, ESQ.
DUANE R. FISHER, ESQ.
STARN O’TOOLE MARCUS & FISHER
733 Bishop Street, Suite 1900
Honolulu, Hawai‘i 96813
Counsel to NEXTERA ENERGY HAWAII, LLC

1 Copy
Electronic Transmission

COLIN A. YOST, ESQ
1003 Bishop Street
Pauahi Tower, Suite 2020
Honolulu, Hawai‘i 96813
Counsel for HAWAII PV COALITION

1 Copy
Electronic Transmission

TIM LINDL
KEYES, FOX & WIEDMAN LLP
436 14th Street, Suite 1305
Oakland, CA 94612
Counsel to THE ALLIANCE FOR SOLAR CHOICE

1 Copy
Electronic Transmission

SANDRA–ANN Y.H. WONG
ATTORNEY AT LAW, A LAW CORPORATION
1050 Bishop Street, #514
Honolulu, Hawaiʻi 96813
Counsel for TAWHIRI POWER LLC
Counsel for SUNPOWER CORPORATION

1 Copy
Electronic Transmission

HENRY Q CURTIS
VICE PRESIDENT FOR CONSUMER AFFAIRS
LIFE OF THE LAND
P.O. Box 37158
Honolulu, Hawaiʻi 96837

1 Copy
Electronic Transmission

THOMAS L. TRAVIS
VICE PRESIDENT
PUNA PONO ALLIANCE
RR 2 Box 3317
Pahoa, Hawaiʻi 96778

1 Copy
Electronic Transmission

TOM KOBASHIGAWA
DIRECTOR, REGULATORY AFFAIRS
HAWAI'I GAS
745 Fort Street, Suite 1800
Honolulu, Hawaiʻi 96813

1 Copy
Electronic Transmission

DEAN T. YAMAMOTO
CARLITO P. CALIBOSO
TYLER P. MCNISH
YAMAMOTO CALIBOSO LLLC
1099 Alakea Street, Suite 2100
Honolulu, Hawaiʻi 96813
Counsel for AES HAWAII, INC.
Counsel for PANIOLO POWER COMPANY, LLC
Counsel for EURUS ENERGY AMERICA CORPORATION

1 Copy
Electronic Transmission

GERALD A. SUMIDA
TIM LUI-KWAN
ARSIMA A. MULLER
CARLSMITH BALL LLP
ASB Tower, Suite 2100
1001 Bishop Street
Honolulu, Hawaiʻi 96813
Counsel for ULUPONO INITIATIVE LLC

1 Copy
Electronic Transmission

ISAAC H. MORIWAKE EARTHJUSTICE 850 Richards Street, Suite 400 Honolulu, Hawai‘i 96813-4501 Counsel for SIERRA CLUB	1 Copy Electronic Transmission
FIRST WIND HOLDINGS, LLC 1099 Alakea Street, Suite 2440 Honolulu, Hawai‘i 96813	1 Copy Electronic Transmission
CHRIS DEBONE ACTING PRESIDENT DISTRIBUTED ENERGY RESOURCES COUNCIL OF HAWAII 99-1350 Koaha Place Aiea, Hawai‘i 96701	1 Copy Electronic Transmission

Power Supply Improvement Plans Update Report

Power Supply Improvement Plans: Supplemented, Amended, and Updated

1 April 2016

Hawaiian Electric
Maui Electric
Hawai'i Electric Light

Preface

The Hawaiian Electric Companies respectfully submit this supplemented, amended, and updated Power Supply Improvement Plan (PSIP) to comply with Order No. 33320 issued by the Hawai'i Public Utilities Commission on November 4, 2015 in Docket No. 2014-0183.

Table of Contents

FIGURES

TABLES

Executive Summary

SHARED COMMITMENT TO A CLEAN ENERGY FUTURE

With an unprecedented 100% Renewable Portfolio Standard, Hawai‘i's clean energy leadership is clear and indisputable. Achieving this critical goal will require a comprehensive transformation of our island power grids. A multidimensional planning process that requires near-term actions to set the foundation for the plan and a recognition that flexibility is critical as the specifics for the long-term continue to change as technology and costs continue to evolve. While there are many views on the best path to achieve our 100% RPS goal, there is notable unity in Hawai‘i in recognizing the critical importance of addressing the negative economic, environmental and energy security impacts of our state's dependence on imported petroleum oil. Most of all, that shared mindset will be required for our entire community – government, business, developers, community and environmental groups, utilities, and customers – to come together to address the issues that must be resolved to achieve this goal for our island home.

A Dynamic Energy Environment

Changes that took place in the 18 months since we filed our Power Supply Improvement Plans in 2014 demonstrate how dynamic our Hawai‘i energy environment is. Consider just a few of the changes:

- Passage of Act 97, which extended a 40% RPS requirement in 2030 to a 100% RPS in 2045.
- Dramatic decline in the price of fuel oil by more than 75%, creating significant changes and uncertainty in forecasted costs, and much lower bills.
- Hawai‘i Public Utilities Commission (Commission) Decision & Order No. 33258 ending the Net Energy Metering (NEM) program for new solar customers and

concurrently creating two new replacement programs: Customer Grid-Supply and Customer Self-Supply.

- Valuable ongoing experience with increasing levels of distributed generation (DG), including the testing and installation of advanced inverters to allow greater amounts of DG and reduce the need for distribution upgrades.
- In addition, NextEra Energy and the Hawaiian Electric Companies have proposed a merger which is pending before the Commission.

Energy technology and policy is constantly evolving and customer needs and expectations are changing.

Therefore, our planning in this context of change must include:

Actions to be taken in the immediate future to take advantage of available resources and achieve near-term energy goals, satisfy customer preferences, and provide a hedge against uncertainty in future oil prices.

Near-term steps that help us further understand, explore, and develop longer-term resources.

Long-term energy planning using the best information available today but recognizing the limitations on insights into the future. The actions identified in the 2025–2045 time period are less certain, and are expected to be further optimized and adjusted based on changing circumstances in future planning updates to reach our 100% renewable energy goal in other ways.

Preservation of a reliable and resilient power grid. Hawai'i's small and islanded power grids make this especially challenging and even more critical to achieve. The resiliency of our grid and reliability of service is vital for our economy, for our military partners, and for critical infrastructure. Our customers expect and deserve it.

Key Results—What Are the Takeaways?

There are several notable high level results from this Power Supply Improvement Plan Update:

1. **Our companies' project we can exceed the RPS requirements** as defined under the current law and can also chart a path to achieve true 100 percent renewable energy for electricity by 2045. The *Additional Insights* section (below) highlights some considerations and challenges to meeting these bold goals.

2. Customer participation through the use of market-based distributed energy resources (DER) plays a critical role. We project that the capacity of installed **DER, largely private rooftop solar, can grow by about 370 percent** compared to our 2014 PSIPs.

3. We can essentially re-invent our power system—by modernizing generation to be more flexible and efficient, transforming our transmission and distribution system to be smarter and better integrate distributed private and larger scale renewables, and obtain the energy security and environmental benefits from a 100% renewable future—all while **keeping electric rates stable and relatively flat** on a real dollar basis.

4. **Liquefied Natural Gas (LNG) as a transitional fuel**, combined with more efficient and flexible modern generation, provides the best path with the lowest cost and lowest carbon footprint to reach Hawaiʻi's 100%renewable energy goal.

Additional Insights

Despite future uncertainties, long-term planning should be viewed as providing useful directional insights. Some of these insights include:

a. Our long term portfolios must include a diverse set of resources. With greater use of renewable energy, a diverse mix of renewable resources provides greater assurance of self-sufficiency and energy resiliency as weather patterns vary and other unforeseen events occur.

b. Dispatchable, firm renewable energy (currently biomass and geothermal) on Maui and Hawaiʻi Island are key to achieving high levels of renewable energy at reasonable costs.

   This suggests that policymakers, government agencies, and private organizations with interests in energy, agriculture, water use and land use, need to be involved in developing clear policies and rules that will determine the feasibility of these options for the future.

c. With their more abundant open spaces, the neighbor islands will lead the way and in fact, Molokaʻi and Lānaʻi are projected to reach a 100% RPS by 2030, while Maui and Hawaiʻi Island could achieve a 100% RPS by 2040. This will help Oʻahu, with its larger population and energy needs challenged with limited land and on-island renewable resources, meet the 2030 70% RPS goal.

   To reach 100% RPS in 2045, Oʻahu appears to need additional resources beyond those available on island (e.g., currently, offshore wind, biofuels, neighbor island renewables transmitted via interisland cable). These alternatives need to be studied further to better understand their respective risks and relative costs. Such endeavors require the efforts and input of our entire state, not just the utility. Policies, environmental permits, community and cultural issues and concerns must be addressed. Changes in state policies, statutes, and regulations governing resource development may also be needed. And as circumstances change in the years ahead, the alternatives for O‘ahu may be revised.

In the context of the potential need for resources to be shared amongst the islands to cost-effectively achieve 100% renewable energy, the concept of consolidated rates for the Hawaiian Electric Companies should be evaluated.

d. Planning must be looked at as a continuous process—a process in which analysis is updated for changing circumstances, new technologies, changing economics, and new policies. Action plans and long-term directions should be reviewed continuously, especially given the rapid change in the clean energy sector.

KEY RESULTS: THE PATH TO 100% RENEWABLE ENERGY

Each Preferred Plan considered a number of factors.

Electricity Rate and Bill Impacts. Recognizing the importance of affordability to our customers, limiting overall costs and annual rate increases was a high priority.

Customer Choice. To meet the diverse needs of our customers, all plans must facilitate customer choice and aim to be fair to all customers.

Future Fuel Prices. Because of changing fuel markets, each plan must be evaluated for different oil, biofuel, and LNG price scenarios.

Infrastructure Investments. To ensure electric grid resiliency and meet our state's clean energy goals, all approaches require investment in new infrastructure by customers, developers, and the utility.

Service Reliability and Resiliency. To meet the needs of our customers and our state's economy, the modernized grid must be reliable and resilient to ensure all resources remain connected, even during severe or abnormal weather conditions.

Flexibility. Recognizing our dynamic energy environment and the benefits for our customers, plans must adapt to accommodate future technology and pricing breakthroughs.

Minimizing Risks. Our Preferred Plans minimize the risks—financial, implementation, and technology among them—inherent in any plan of this magnitude.

Under the current Preferred Plans, our tri-company consolidated renewable energy mix in 2045 could be the amounts listed in Table ES-1.

Renewable Resource	MW
Total DG-PV	1,220
FIT*	40
Utility-scale PV	870
Onshore Wind	530
Offshore Wind	800
Hydro	20
Geothermal	120
Waste/Biomass	130

* = all solar

Table ES-1. 2045 Renewable Energy Resources

Figure ES-1 shows the total capacity of renewable energy included in the Preferred Plans on a consolidated basis. By 2045, the total capacity of renewable energy on the systems is more than double the total of the system peaks to be served.

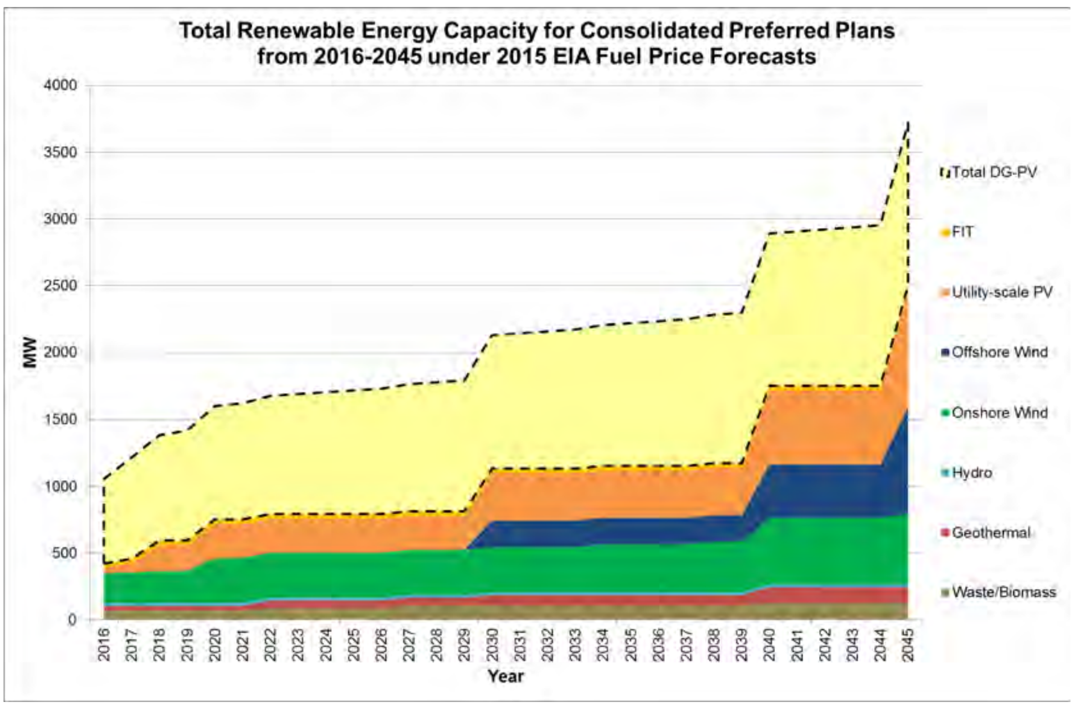


Figure ES-1. Total Renewable Energy Capacity for Consolidated Preferred Plans from 2016-2045 under 2015 EIA Fuel Price Forecasts

Again, while instructive for directional planning, this prediction of a renewable resource mix 30 years into the future is certain to evolve as we adapt to take advantage of rapidly evolving technology, policies, and energy options.

Achieving the RPS

Under the current Preferred Plans, RPS will exceed requirements as our companies move toward 100% renewable energy by 2045 (Figure ES-2).

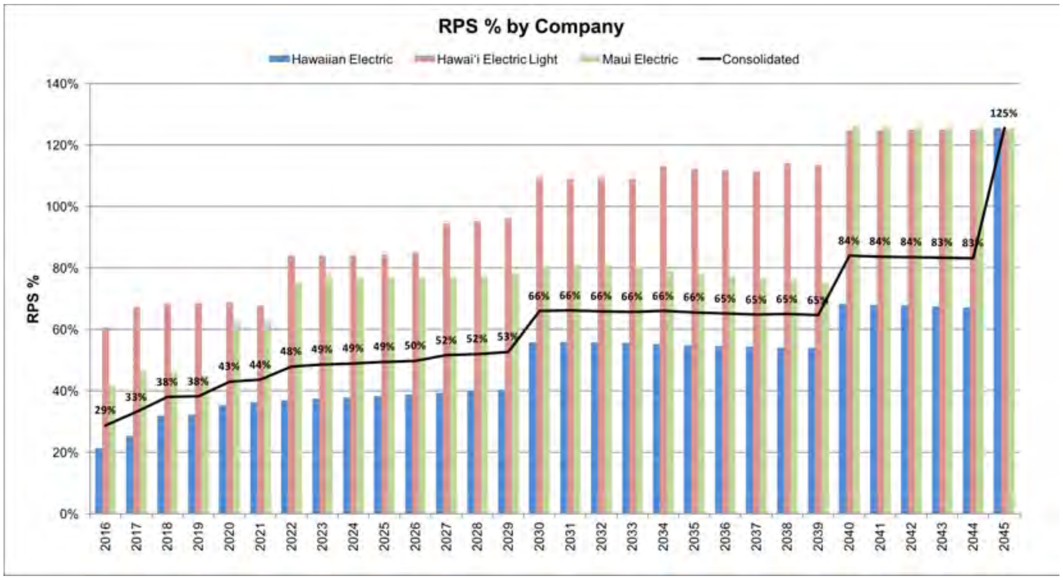


Figure ES-2. Renewable Portfolio Standards Compliance of Preferred Plans

The calculation of the RPS per the law does result in values over 100%. To emphasize that we are committed to achieving 100% renewable energy in 2045, Figure ES-3 shows the renewable energy as a percent of total energy including customer-sited generation.

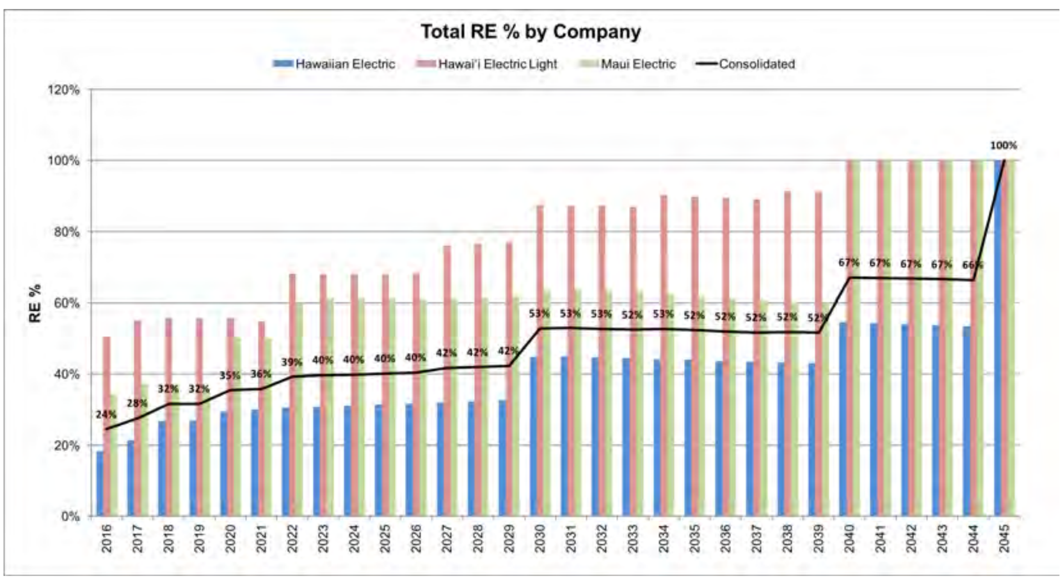


Figure ES-3. Total Renewable Energy Percent of Preferred Plans

Figure ES-4 provides a long-term view of a path towards 100% renewable in 2045. Under the current Preferred Plans, the possible path as our tri-companies move toward 100% renewable energy by 2045 is as follows:

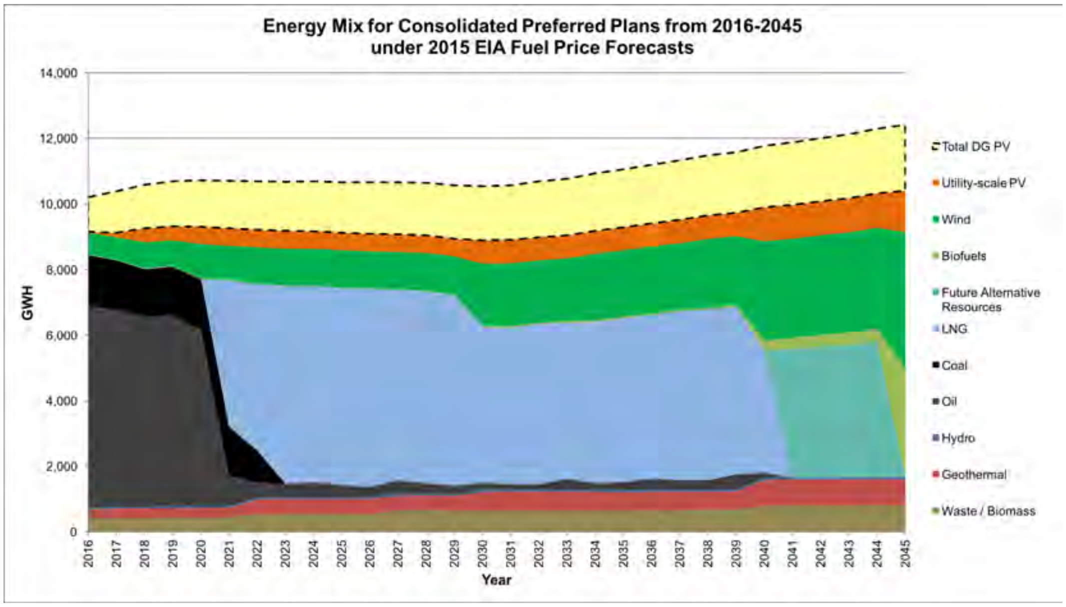


Figure ES-4. Energy Mix for Theme 2 on O'ahu from 2016-2045 under 2015 EIA Fuel Price Forecasts

Future Alternative Fuels: During the last intervening years in the transition to 100% renewable energy, potential fuels at this time could include biofuels, LNG, oil, other renewable options or a mix of options. Given rapidly evolving energy options and technology, the exact fuel mix is difficult to predict today.

Multiple Benefits Provided from Demand Response Programs

Demand Response (DR) programs—market-based programs that incentivize customers for change in electricity usage patterns—play a key role in integrating variable renewables. In addition to providing capacity and load shifting, DR can also provide other ancillary services, such as regulating reserves. Load shifting DR programs to encourage more usage at times when solar generation is most abundant appears to provide the most value.

Distributed Energy Resources Plays a Critical Role

Economic, market-based DER contributes a significant portion of the resource mix, resulting in a 250% increase over current levels and a 370% increase over the starting point level in our 2014 PSIP. The current PSIP Update assumes market-based levels of DER for O'ahu, Hawai'i Island and Maui and higher levels of DG-PV for Moloka'i and Lāna'i, as those smaller islands are leading the rest of the state in developing new solutions for DG integration challenges. However, because the market-based DER is expected to largely be variable solar PV, the energy contribution of market- based DER, while still significant, is smaller than the megawatt capacity suggests. This is the assumption for now, but as we continue to analyze the long-term options for addressing the challenge of closing the gap to 100% renewable energy on O'ahu and as technologies and their prices change, the option of pursuing a higher DG-PV strategy on O'ahu in later years should be kept open.

Community-Based Renewable Energy (CBRE) Enables Broader Customer Benefits

Community-Based Renewable Energy (CBRE) could also provide a significant contribution to the attainment of 100% renewable energy, and allow many other customers to participate and benefit from renewable energy options like solar PV who otherwise cannot or would not.

Liquefied Natural Gas (LNG) as a Bridge Fuel Provides the Most Affordable Pathway to 100% Renewables

There appears to be alignment among most stakeholders that Hawai'i must achieve the 100% RPS goal in a cost-effective manner. Our PSIP Update confirms that LNG and generation modernization (as described below) offer the best path forward in the transition to 100% RPS.

LNG is a prudent choice because it will displace 80 percent of our imported oil use between 2021-2040, keep electric rates lower than they were 18 months ago, lessen price volatility, and significantly reduce our carbon footprint. This is true across the range of fuel prices evaluated in this PSIP for O'ahu, Maui and Hawai'i Island combined.

The Governor has stated his concern that using LNG will divert focus away from a 100%renewable energy future. We understand our responsibility in working with others throughout the state not to let that happen. We believe we can move aggressively towards 100% renewables with LNG as a transitional bridge fuel through 2040, limiting permanent infrastructure while allowing for variable demand and lessening the cost burden on customers as we make the transition to renewables.

Although, as noted below, the current LNG option and the significant benefits it can provide customers is available only under the merged scenario, we would still be interested in pursuing LNG in an unmerged scenario if an option is developed and provides meaningful cost savings, reliability and environmental benefits for our customers. However, the merged scenario below provides a clearer and more immediate path for delivery and earlier benefits for customers.

Furthermore, the case utilizing LNG and the advanced combined cycle generator produces fewer carbon dioxide emissions than the accelerated renewable generation planning scenario by over 4 million tons during the 30-year planning period. These results demonstrate the value of efficient and flexible generation utilizing clean burning natural gas along with renewable generation additions while meeting the 100% RPS targets by 2045. Not only will customers realize the lowest overall cost, but they will also receive the long-term benefits of a cleaner environment.

The Need for Flexible and Efficient Generation Is Needed

As the Commission has recognized in its Inclinations paper, "the Hawaiian Electric Companies should continue to evaluate opportunities to retire and replace older, high cost plants with new resources with valuable characteristics that provide required support services cost-effectively to maintain a reliable electricity grid with high levels of renewable resources."[1] One example of a flexible and efficient generator is an advanced combined cycle unit planned for O'ahu. Such generators have many benefits -- fast starting, cycling, fast ramping, fuel efficiency, low emissions, and improved reliability—all of which lower operating costs for customers. The flexibility of these units supports the variable nature of renewable generation and the transition to 100% RPS, as well as reduces the size of costly energy storage systems. When sited at existing generating stations, they can take advantage of existing infrastructure, minimizing the impact to the local community. On Maui and Hawai'i Island, existing dispatchable combined cycle generators already provide a considerable amount of flexible generation, allowing higher levels of renewable generation on those islands. Use of LNG in these generators can enhance their flexibility while lowering costs and reducing emissions. LNG was not found to be cost-effective for use on Moloka'i and Lāna'i.

The PSIP Update results indicate that for Oahu, the lowest overall cost and lowest emissions are achieved in the case that includes a large-scale advanced combined cycle facility to replace older steam generators at the Kahe power plant combined with the use of LNG. Updated generation facilities will also make our overall system more resilient as

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

a result of siting the new facilities outside of recently revised tsunami inundation zones. More specifically, with input from NextEra Energy, we have identified a 383 MW 3x1 combined cycle facility to replace Kahe Units 1–4 which could use LNG as a substitute for oil. This scenario—only possible as a merged entity—results in lower costs to customers over the planning period of cases evaluated, supports an increasing amount of renewables, reduces environmental emissions, and improves grid reliability and security. Furthermore, this advanced 3x1 combined cycle option appears to be advantageous with or without LNG, but is clearly better when using LNG as a transitional fuel source to get to a 100% RPS. In fact, when utilizing both LNG and the advanced combined cycle option on O‘ahu, carbon dioxide emissions would be reduced by over 4.1 million tons by 2023. This is the equivalent of removing over 110,000 passenger vehicles from the road each year.

Again, such a scenario combined with other projects and programs envisioned for this same timeframe (such as Smart Grid, Schofield Generating Station projects, and others) would require the financial backing and development capacity of the merged organization.

Grid-Connected Microgrids on Military Installations Enhance Statewide Resiliency

In Hawai‘i, there is a growing and important role for distributed generation at military sites to enhance energy resiliency and security.

Microgrids on military sites that operate in complementary fashion interconnected to the utility grid:

- Provide resiliency and energy security for all our customers by using diversified locations for firm generation.
- Provide enhanced energy resiliency and security on military bases that are key to national defense and emergency or disaster response. These bases house airfields, ports, logistics, manpower, and housing necessary for major humanitarian response missions.
- Help ensure our state is capable of supporting military core missions and therefore remains a key sector of our economy.

In addition to the Schofield Barracks Generating Station previously approved by the Commission and well into the development process, this PSIP Update also includes plans for similar distributed generation on Marine Corps Base Hawai‘i and Joint Base Pearl Harbor-Hickam.

FIVE-YEAR ACTION PLANS: SETTING A COURSE FOR OUR RENEWABLE FUTURE

Hawaiʻi is well on its way to meeting its energy goals as the Hawaiian Electric Companies exceeded a 23% RPS in 2015, substantial progress from 9% achieved in 2008, the year Hawaiʻi broke new ground with bold new renewable energy goals under the Hawaiʻi Clean Energy Initiative. The five year Action Plans will keep up the momentum.

Again, given the uncertainty and the future changes inherent in planning for a 30-year horizon, it's most important to focus on five-year action plans that keep up our progress, support the integration of increasing amounts of variable energy and reduce risk. The Action Plans are designed not to foreclose any future resource option.

Key Steps In Our Five-Year Action Plans

Implementing a Smart Grid Foundation Project to install the modern wireless network, smart meters and other enhanced technology to modernize and improve the efficiency of our existing power grids.

Implementing a Demand Response Management System (DRMS) to enable greater use of evolving DR programs.

Pursuing Market-Based DER for Oʻahu, Hawaiʻi Island and Maui and High DG-PV for Molokaʻi and Lānaʻi. High DG-PV will be considered for Oʻahu in later years as an option to help close the gap to get to 100% renewable energy. In the near-term Action Plan period, market-based and High DG-PV levels are similar. DER programs by their nature can be adjusted to meeting changes in market interest, technology, pricing, value, and system needs.

Installing Circuit Level Improvements on All Islands. Enabling monitoring and controls to DER systems, upgraded conductors, voltage regulators, transformer replacements, reconfiguring circuits, distributed energy storage while leveraging existing and future advanced inverter functionality.

Pursuing Energy Storage Options:

- Installing 90 MW of utility-scale battery storage on Oʻahu to provide contingency reserve power to help maintain reliability in an emergency situation, ensure energy resiliency under low inertia operating conditions, and to help meet fluctuating energy needs due to variable wind and solar resources.
- Install energy storage on Maui and Hawaiʻi Island to provide contingency reserves.
- Participating in many energy storage pilot projects with technologies that may provide grid services. Some of these pilots include (not an exhaustive list)

partnerships with innovative start-ups, such as Stem[2] and Shifted Energy[3]. Based on what we learn, we can pursue "front-of-the-meter" storage options and demand response programs, both directly and indirectly.

- Implementing several Molokaʻi projects including:
  - A battery storage research project in partnership with Hawaii Natural Energy Institute to determine applications for batteries in high solar PV penetration scenarios.
  - A pilot program in partnership with E-Gear LLC, installing their specialized Energy Management Controller and storage technology to allow at least 10 rooftop PV systems in the queue to move forward. The program will test the equipment monitoring capability and controllability of such systems by Molokai system operators and the impact of such advanced PV systems on the grid.
- Evaluation of other storage options, including for load shifting, as technologies improve and costs reduce.

Implementing Community-Based Renewable Energy using a phased approach to help ensure a sustainable program, in line with the market demand, while respecting the technical limitations of the electric grid. Community-bases renewable energy programs are intended to provide affordable renewable energy options for our many customers who are renters or live in multi-unit buildings. The first phase is envisioned to last two years, to commence upon Commission approval. Learnings from the first phase will inform the planning process for the second phase.

Issuing Requests for Proposals to seek over 351 MW of additional renewable energy by 2022 via a competitive processes.

- 225 MW of utility- scale wind and solar for Oʻahu. This includes 25MW under a proposed CBRE program.
- 20 MW of firm dispatchable renewable capacity for Hawaiʻi Island in 2022.
- 60 MW of variable renewable and 38 MW of firm dispatchable renewable or renewable-capable generation capacity for Maui to address the anticipated retirement of the Kahului Power Plant in 2022, growth in customer demand, constrained South Maui transmission capability, and Hawaiian Commercial & Sugar (HC&S) ceasing operations.
- 5 MW of wind energy for Molokaʻi and 3 MW of wind energy for Lanaʻi for 2020

[2] Stem is an energy storage provider that has deployed a pilot project aimed at demonstrating how distributed storage can help the utility affordably integrate more renewable energy onto the system.

[3] Hawaiian Electric is working with a company called Shifted Energy to deploy 499 grid interactive water heaters at the Kapolei Lofts development project (housing in Kapolei developed by Forest City) for the demand response program. See http://www.greentechmedia.com/articles/read/hawaii-to-test-smart-water-heaters-as-grid-resources.

Researching alternative curtailment policies to help ensure cost-effectiveness and flexibility in contracting renewable resources and supporting the reliable operation of the grid.

Deactivating generation not well suited to support the integration of renewables. For O'ahu, under the plan using LNG, Kahe Units 1 to 3 and Waiau Units 3 and 4 will be deactivated. On Maui, Kahului Units 1 to 4; and on Hawai'i Island, the plan assumes the Puna Steam Unit will be deactivated.

Taking the next steps to pursue the benefits of LNG. Given the environmental, cost saving, price stability and price hedging benefits of LNG, we plan to submit an application to the Commission for approval of an LNG fuel supply agreement and related regulatory applications for the modernization of generation at O'ahu's Kahe Generating Station described in the Need for Flexible and Efficient Generation section above.

Improving flexibility of existing generation to help facilitate the integration of variable renewable generation (lower operating levels, ramp improvements).

Investments for Hawai'i's Renewable Future

Achieving 100 percent renewable energy takes substantial capital investment. All options, whether the Preferred Plans or other candidate plans, require substantial amounts of capital, compensated for by customer savings over time. The total capital investment over the next 30 years for Hawai'i is estimated to be $25.8 billion (in nominal dollars), of which the utility may invest 53%, or $13.6 billion. The balance may be made by project developers, customers, and the State (via tax incentives).

However, with this investment, we are able to modernize generation to be more flexible and efficient, transform our transmission and distribution system to better integrate both distributed and larger utility-scale renewables, and obtain the energy security and environmental benefits by achieving a 100% renewable future, all while keeping electric rates stable and relatively flat on a real dollar basis. Figure ES-5 through Figure ES-8 depicts the average monthly residential bill for O'ahu over the planning period.

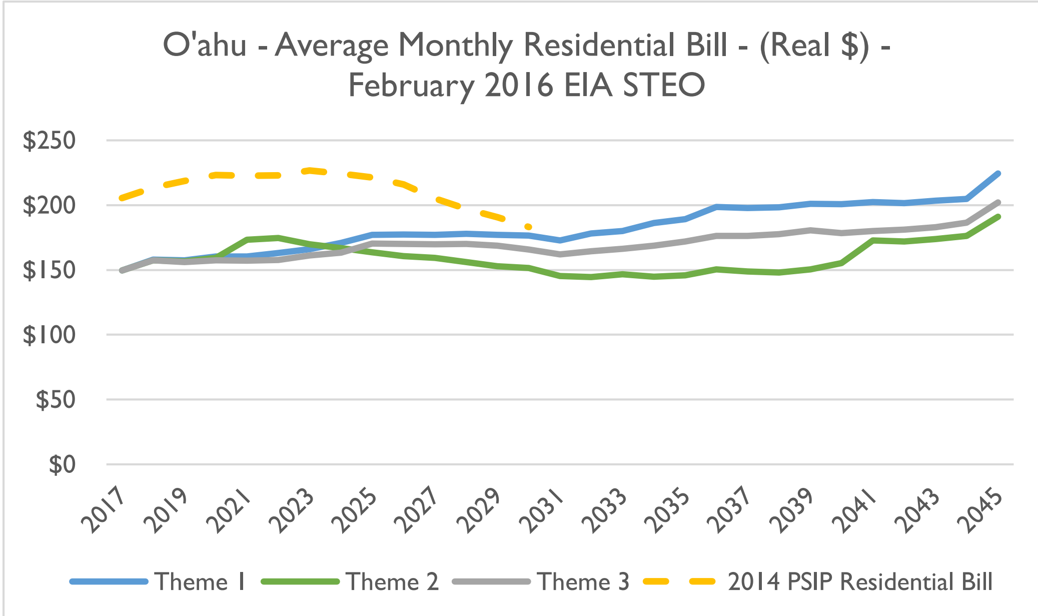


Figure ES-5. Residential Bill (Real 2016 $): February 2016 EIA STEO

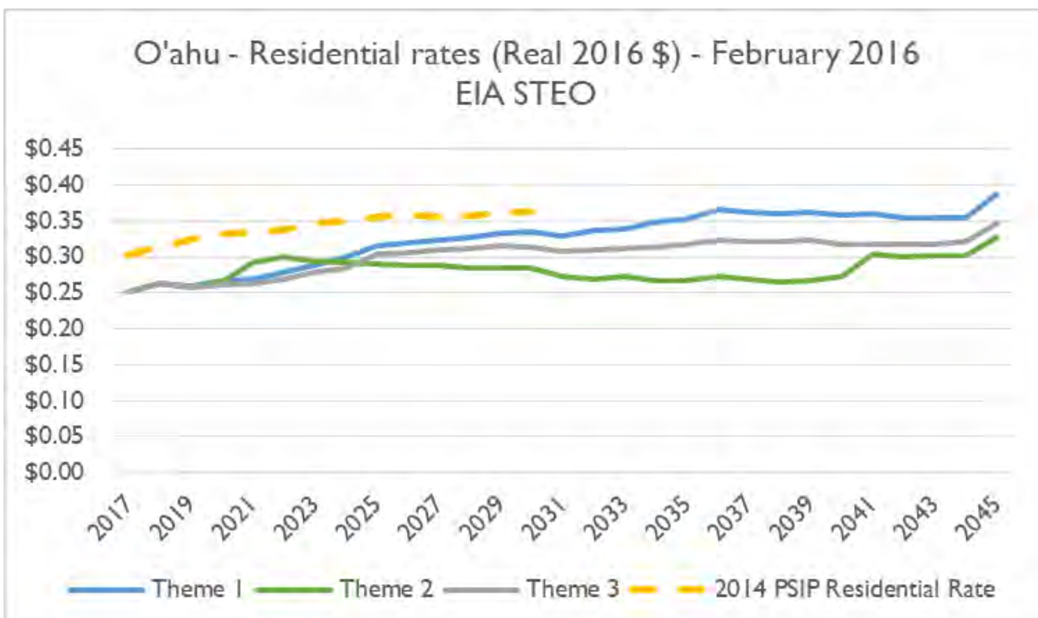


Figure ES-6. Residential Rates (Real 2016 $): February 2016 EIA STEO

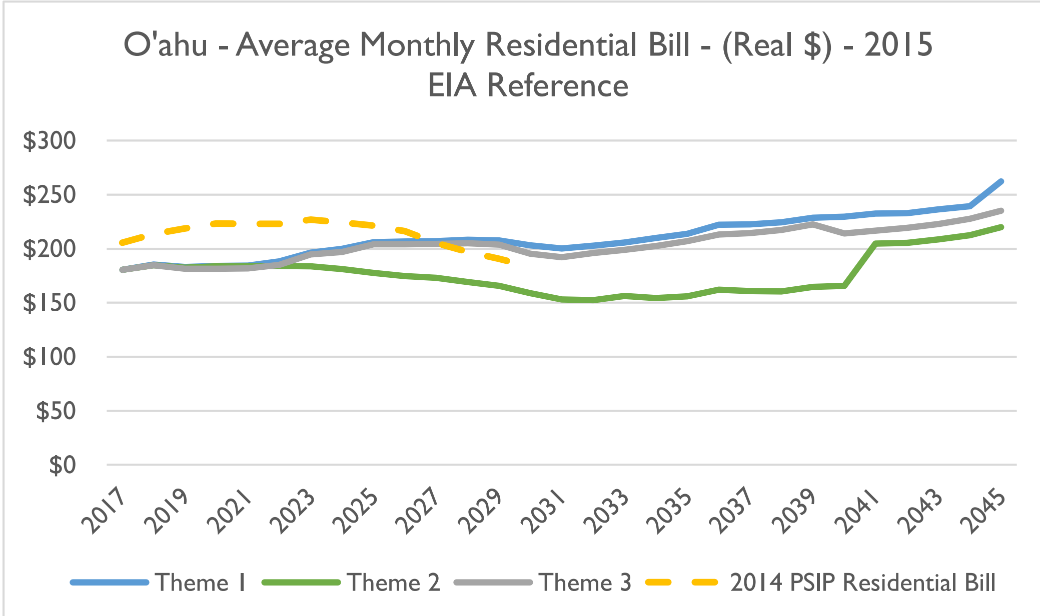


Figure ES-7. Residential Bill (Real 2016 $): 2015 EIA Reference

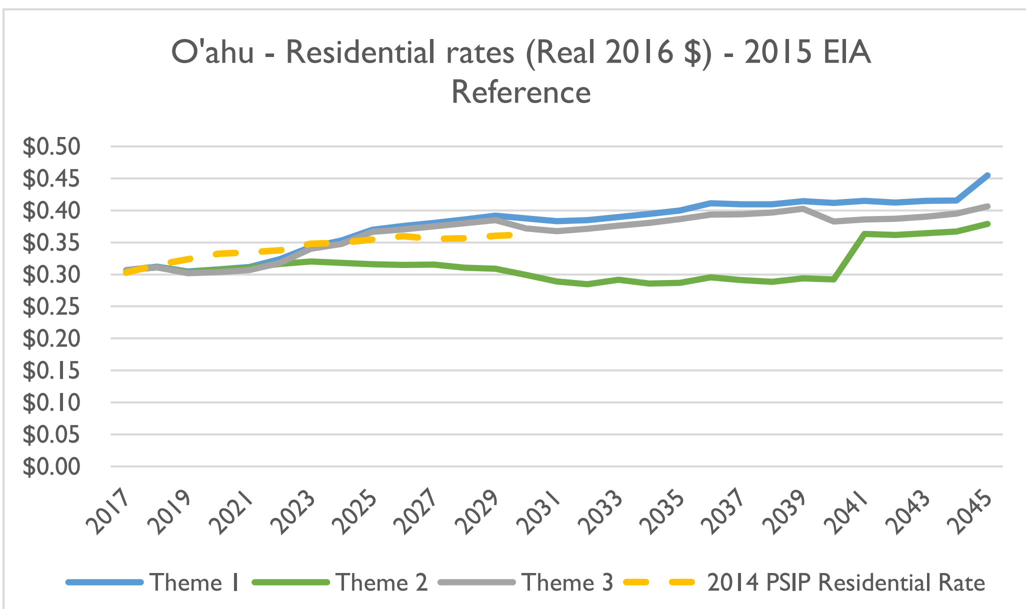


Figure ES-8. Residential Rates (Real 2016 $): 2015 EIA Reference

Stakeholder Input

Consistent with the Commission's directive, on January 15, 2016, most of the Parties in this docket filed reports providing input into the process outlined in Order 33320. In addition, we held a stakeholder conference on December 17, 2015 and participated in an

Executive Summary Planning Status of Our PSIP Update Interim Status Report technical conference on January 7, 2016. The Commission also held another Technical Conference on March 8, 2016. We've also proposed another Technical Conference to be held on April 15, 2016.

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

We invited Parties in the docket to attend and participate in our working meetings where we reviewed analysis, made decisions on further refinements, and discussed the modeling analysis for completing the 2016 updated PSIPs. Representatives from DBEDT, the Consumer Advocate, and the County of Hawaiʻi participated in about 10 meetings.

As indicated in our Proposed PSIP Revision Plan, additional organizations provided independent technical analyses to help address issues of concern. These stakeholders include the Hawaii Natural Energy Institute, Electric Power Research Institute, U.S. Department of Energy, University of Hawaiʻi Economic Research Organization, National Renewable Energy Laboratory, and Hawaiʻi Energy.

Unprecedented Process

The 2016 updated PSIP is a first of a kind planning analysis that aims to optimize resources across those owned by customers, other third parties, and utilities, to include behind-the-meter DER, distribution resources, transmission, and centralized power plants. Though this massive planning process we are completely transforming our power grids.

To create our 2016 updated PSIPs, we developed new tools, new processes, and new methods to plan for the utility of the future and used a team of industry-leading consultants. Because of schedule constraints, we have not been able to fully utilize some of these new tools, processes, and methods, nor fully realize their benefits. After the April 1 filing, we plan to continue using these newly developed methodologies as we continue our work in this docket and in other related (such as DER and DR) dockets.

NEXT STEPS

Given the scope of that directive and the timeframe in which to complete it, we have completed a thorough analysis to develop PSIP updates that include five-year action plans that can be implemented in the short-term. We will continue to evaluate the potential long-term renewable resource options especially for the period of time after 2030.

Updated Fuel Price Forecasts

One of the foundations of our analysis is the fuel price forecasts for LNG and petroleum-based fuels. The U.S. Energy Information Administration issues updated fuel price forecasts generally mid-year. After we receive these forecasts, we can update our analysis based on these updated prices. We expect to file an addendum to our 2016 updated PSIPs within two months after these fuel price forecasts are published.

Analyze Inter-Island Transmission

Given the findings of the PSIP Update that O'ahu will likely need a substantial amount of off–island renewable resources in order to meet a 100% renewable energy goal in 2045, we plan to reassess the scope and requirements for an interisland cable. As a follow-up action, we plan to (a) identify viable resource alternatives, such as wind and geothermal, and resource availability and location; (b) develop capital cost estimates for the alternatives, including cost to integrate the resources; and (c) complete the analyses comparing the alternatives and mixes of alternatives.

Perform Further Research on Offshore Wind

Although our current plan projects the use of significant amounts of offshore wind energy, we plan to perform further evaluation of the viability of these resources. This would include assessing the resource potential, evaluating possible onshore interconnection configurations, identifying risks factors (for example, permitting, community acceptance, natural hazards and hazards from human activity), and refining resource development and installation costs. These evaluations will be performed in conjunction with our planned analysis of an interisland cable system.

Perform Additional System Security Analysis for the Preferred Plans

While system security analyses were performed as part of the PSIP Update, additional analysis will be completed, including a protection coordination study, reactive power requirements and voltage stability analysis.

WORKING TOGETHER FOR HAWAI'I'S RENEWABLE ENERGY FUTURE

Although our energy environment is changing more rapidly than ever, what is clear is that Hawai'i's 100% RPS goal is achievable, technology and pricing will continue to change to make this possible, and foundational investments in more flexible generation and use of cleaner fuels in the transition can be an important step as increasing amounts of variable renewable energy resources are added on our path to 100% renewable energy. Most importantly, achieving the groundbreaking 100 percent renewable energy goal for our state will take *our entire community working together* to make the difficult decisions needed to achieve this clean energy future for our state.

1. Introduction

The Companies fully embrace attaining Hawai‘i's 100% Renewable Portfolio Standard (RPS) goal. For our 2016 supplemented, amended, and updated PSIP, we have developed a set of Preferred Plans and their attendant Five-Year Action Plans that explain how we intend to deliver affordable, reliable, clean energy. Each plan not only meets the intermediate milestone RPS targets, but also attains 100% renewable energy generation by 2045.

A COMPREHENSIVE GRID TRANSFORMATION

The Companies face an unprecedented situation: a comprehensive transformation of our five electric power grids. Attaining our state's renewable energy goals represents uncharted territory for both short-term and long-term resource planning. Performing the analyses necessary to attain this goal is a complicated resource planning process, requiring new tools and new processes: modeling across generation, transmission, distribution, infrastructure, and behind-the-meter resources options.

Several high-level objectives drive our planning process, chief among them attaining 100% renewable energy, establishing reasonable customer bills in light of the state's bold renewable goal, and maintaining reliability. During our planning, we considered numerous variables: customer rate and bill impacts, customer choice, resource costs and availability, distributed energy resources (DER), demand response (DR) as a component of DER, energy storage, new technologies, generation modernization, existing generating assets, transmission and distribution infrastructure modernization and upgrade, fuel selections, environmental considerations, system security, ancillary services, capital cost considerations, and risks.

Many entities are involved in this process: expert teams from our three operating utilities together with several knowledgeable and experienced consulting firms, each running different modeling tools to analyze various paths toward developing a reasonable Preferred Plan for each island we serve. In addition, we incorporated input from several of the Parties and from most of the intervenors to the docket.

Goals of the PSIP

Our 2016 updated PSIP attains these goals:

- Offer customer choices in generating and saving energy.
- Systematically integrate cost-effective renewable energy over the next 30 years.
- Meet or exceed all RPS milestone targets.
- Exceed the 100% RPS by attaining 100% of generation from renewable resources by 2045.
- Implement a revised suite of DR programs.
- Reduce customers exposure to fuel price risk and volatility.
- Modernize the generation fleet to cost effectively integrate higher levels of variable renewable energy resources.
- Systematically retire older, less-efficient and less flexible fossil generation.
- Reduce must-run fossil generation.
- Increase generation operational flexibility.
- Utilize new technologies for grid services.
- Meet and exceed environmental requirements.
- Maintain the level of system reliability our state relies on.

Developing Meaningful, Well-Reasoned Plans

Planning for this intensive resource and grid transformation requires critical inputs and forecasts as well as modeling tools that simulate future configuration of a power grid—which is how we proceeded for these updated PSIP. Our planners must then evaluate resultant configurations, and arrive at decisions that are virtually unprecedented in energy resource planning. The decisions facing our resource planners, and ultimately the state of Hawaiʻi, cannot be overstated. These decisions are monumental.

In addition, we must arrive at these decisions without the benefit of being able to compare and contrast them with similar decisions by other utilities. We are on our own.

We updated resource assumption inputs and engaged stakeholders for input, then developed and analyzed nearly 200 candidate plans—or cases—from which we chose our final Preferred Plans. Throughout, we followed a Decision Framework to make critical assessments and decisions along the way in a transparent manner and included intervenors in the process to observe, ask questions, and provide comments. That process led us to this 2016 updated PSIP.

We created the 2016 updated PSIP based on the current state of our power grid, forecast conditions; reasonable assumptions regarding technology readiness, availability, performance, applicability, and costs; and on the ability to maintain system security requirements. As a result, these plans present an actionable, cost-effective path to transforming our power systems into the ultimate model of sustainability. We have attempted to fully document and be transparent about the assumptions and processes utilized to develop the plans.

This supplemented, amended, and updated PSIP:

- Includes long-term analysis of the integrated grid systems to better evaluate specific, prudent near-term capital investments and other near-term decisions.
- Provides context and sound analysis to inform well-considered choices and illuminate trade-offs between major interrelated or mutually exclusive resource strategies and choices.
- Provides assurance that the overall operational cost and rate impacts and proposed resource acquisitions are reasonable and economically affordable to benefit all customers.
- Identifies risks and uncertainties that inform the issues and trade-offs associated with resource acquisition and system operation decisions.

As circumstances change, we will continue to evaluate the impacts of any changes to our material assumptions, seek to improve the planning methodologies, and evaluate and revise this PSIP to best meet the needs of our customers.

ATTAINING 100% RPS

Our 2016 updated PSIP meets, and exceeds, each of the RPS milestones set by law in 2020, 2030, 2040, and 2045. In addition, the 2016 updated PSIP attains 100% renewable generation by 2045.

Our Renewable Generation Goal

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

Subject to Commission approval of the proposed merger, NextEra Energy stated their intent to “undertake good faith efforts to achieve a consolidated RPS” more aggressively than the statutory requirements.

Table 1-2 lists the statutory milestones together with these more aggressive RPS percentages.

Milestone Date	Renewable Electrical Energy Generation as a Percentage of Sales	Merged Commitment for Renewable Energy
December 31, 2020	30%	35%
December 31, 2030	40%	50%
December 31, 2040	70%	70%
December 31, 2045	100%	100%

Table 1-2. Commitments for Attaining State RPS Law

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

Regardless of whether or not pending legislation is enacted, we are today committed to attaining 100% renewable generation by 2045. All of our planning, modeling, analyses, and evaluations are based on this goal.

COMPONENTS FOR ACHIEVING THE 100% RPS TARGET

Hawaiʻi has set a bold target for achieving a 100% RPS by 2045. For the state to meet these targets, we undertook a thorough evaluation of the options to attain that goal. We believe that this can be best understood with a methodical analysis of the building blocks needed to achieve a 100% renewable energy solution and a reasonable path to get there, with a particular focus on the near-term steps needed to enable the reasonable path.

As a whole, the combination of market-level cost-effective distributed energy resources with firm, dispatchable renewable biomass and geothermal plus utility-scale wind are key renewable resources needed to achieve a 100% renewable energy goal. These renewables need to be integrated with demand response and optimized amounts of energy storage and biofuels. Liquefied natural gas as a transitional fuel and generation modernization affords a significant opportunity to reduce customers bill as the transition is made to higher levels of renewable energy.

The Role of Distributed Energy Resources

Distributed energy resources (DER) provide a core component of the potential renewable additions to the islands. DER can take many forms and encompass several approaches, including demand response, energy efficiency, electric vehicles, customer-owned generation, and customer-owned storage technologies.

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

The adoption of DER is also driven by customer economics, which is then driven by two factors: the benefits of the DER system to the customer (for example, avoided electricity purchases from the utility and compensation received for exports to the grid) and the capital and operating cost of the DER system. We forecasted DER adoption in two ways. First, we assumed that compensation to DER customers for exports is based on the cost of a utility-scale solar plant ("market DG-PV"). Second, we forecasted a high DG-PV case based on enhanced compensation for DER exports ("high DG-PV").

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

Milestone Date	Market DG-PV Forecast	High DG-PV Forecast
December 31, 2015	487 MW	487 MW
December 31, 2020	848 MW	853 MW
December 31, 2030	991 MW	1,466 MW
December 31, 2040	1,129 MW	2,161 MW
December 31, 2045	1,204 MW	2,508 MW
Growth (2015–2045)	717 MW	2,023 MW
Growth Percent	247%	515%

Table 1-3. DG-PV Forecasts Under Market and High Scenarios (total for all islands)

In developing the 2016 updated PSIP, we have sought to estimate the likely rate of DG-PV adoption, ensuring any plan is robust enough to encompass higher or lower adoption rates while maintaining a path towards a 100% RPS. Our PSIP takes these sensitivities into account. We are committed to continuing to evaluate and optimize DER under various adoption rates. DER alone, though. cannot meet the 100% RPS target for Hawai‘i.

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

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

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

Demand Response

Demand response (DR) is an important and integral component of our resource mix. In addition to providing capacity and load shifting, DR can also provide ancillary services, such as regulating reserves.

We developed a portfolio of DR programs and described those programs for O‘ahu in the DR Dockets.[4] In the PSIP analyses, we optimized the use of these DR programs for the five islands we serve through iterations of the PSIP modeling results. The DR programs developed align with the grid services needed by each of our systems, and with program design and costs aligned with market studies developed in the DR Docket. The DR programs enable our customers to better manage their energy use and cost. We continue to aggressively pursue DR programs that best meet these goals.

We intend to implement DR programs that appeal to residential and commercial customers, and that provide cost-efficient services most beneficial to the grid. It is absolutely essential that DER and DR remain connected to the grid to provide their contributions to the system. A highly reliable grid is necessary for DER and DR resources to function properly; as such, system security becomes ever more important.

Cost-Effective Utility-Scale Renewable Generation

After fully utilizing economical levels of DER and DR, the 2016 updated PSIP analyzed and optimized the use of cost-effective, utility scale renewable solutions. The candidate renewable resources include solar PV; onshore wind for all islands; offshore wind for O‘ahu; geothermal for Hawai‘i Island and Maui; and biomass for Hawai‘i Island, Maui, Lana‘i, and Moloka‘i. While these resources were specifically analyzed in this PSIP update, we fully recognize that other, new renewable resources will become portfolio options in the future. We will consider inter-island transmission, as well as other renewable resources, for further optimization of renewables in future analyses.

The Hawaiian Islands have abundant renewable resource potential, but face many challenges due to the nature of each island’s unique physical and societal characteristics. The approach utilized in the development of the PSIP methodically evaluates the feasibility of adding available utility scale renewable wind and solar to each island. With assistance from third-party organizations, we undertook several supporting efforts to better understand the reasonable wind and solar resource potential of each island.

For O‘ahu, it is clear that the aggregate potential of variable renewables such as utility-scale solar, onshore wind, and distributed-solar, while significant, is not sufficient to reach the 100% RPS goal without additional renewable resources. As such, we

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

considered offshore wind resources in addition to inter-island transmission as competitive alternatives to biofuels.

Our analysis for all of our utilities, therefore, sought resource mixes that considered variable renewables, in addition to the following:

- The addition of energy storage systems.
- Strategic use of curtailment. (We evaluated the economics of curtailing variable renewable resources assuming the curtailed energy is paid for under a "take or pay" arrangement and the regulation benefit of the unused energy versus energy storage systems.)
- Liquefied natural gas (LNG) as a cost-effective transitional bridge fuel toward attaining 100% RPS.
- Renewable liquid biofuels burned in existing or modernized generation facilities.
- Offshore wind resources that would be constructed on floating platforms.
- Geothermal as a firm, dispatchable renewable resource.
- Biomass as a firm, dispatchable renewable resource.

The addition of an inter-island cable, which could function as a grid-tie between O'ahu and Maui and Hawai'i Island, might unlock the development of additional renewable resources on those islands where renewable resource potential exceeds what could reasonably be consumed locally.

Waste-to-energy (WTE) plants fulfill a broader societal role. The timing of their implementation, however, is not under our control. WTE projects depend on a steady and predictable flow of municipal solid waste, tipping fees paid to the owner of the WTE plant, and the value of the electricity produced by the WTE plant based on alternative sources of generation. Each of these factors contribute to a WTE plant's economic viability. Local county governments typically instigate the development of WTE projects on their own or in conjunction with a private developer. Analysis of a WTE resource option requires specific information regarding the size, operating profile, fixed costs, and energy costs for WTE on any particular island. Therefore, WTE projects were not explicitly considered in this PSIP update. Specific proposals will be modeled as they are received.

Energy Storage

Energy storage is a set of rapidly advancing technologies. We believe that continued transformative shifts in energy storage technologies could further enable the integration of renewables onto the system, in a cost-effective manner. As we developed our updated PSIP analyses, we evaluated the use of energy storage technologies. Specifically, we considered battery energy storage systems (BESS) and pumped storage hydro (PSH). A flywheel option was also developed, but does not specifically appear in any of our plans, and would be considered at the time when the storage resources are procured.

Energy storage can be utility-scale or distributed at the customer level, both providing load-shifting capabilities. As DR can also provide that capability, we assessed energy storage potential considering the contribution from market-priced, cost-effective DR also providing load shifting and have defined the system security requirements in technology neutral terms so that DR resources can be evaluated.

Energy storage can also provide ancillary services, such as fast frequency reserves, primary frequency reserves, regulation reserves, and replacement reserves. Using storage to provide these functions provides an alternative to obtaining these services from online generation and can increase the ability of the system to accept more renewable energy.

While energy storage prices (particularly BESS technologies) are forecasted to decline in cost and improve in performance, they still come at a cost. Therefore, in our analyses we evaluated the tradeoffs between curtailment of variable renewable resources (that is, wind and solar PV), the installation of energy storage, and use of biofuels. Our final and preferred plans reflect an optimized balance between curtailment of variable renewable resources, the costs of BESS systems, and biofuels.

LNG as a Cost-Effective Transitional Bridge Fuel

There appears to be alignment among most stakeholders that Hawaiʻi must achieve the 100% RPS goal in a cost-effective manner. LNG is a prudent choice because it will allow us to significantly lower emissions, reduce fuel costs and customer bills, and reduce customer exposure to fuel price volatility as we transition our system to achieving our energy goals.

Our findings show that LNG plans offer the best long-term economics for our customers while we transition to 100% renewable energy. Without LNG, a substantial amount of oil will be burned during the transition to renewables under any transition scenario, with continued significant exposure to higher oil prices and volatility risk for some time to come.

For Oʻahu, the remaining solar and onshore wind potential only partially attains the amount needed to reach 100% renewables. This means that offshore resources will be required to meet the RPS goals: inter-island cable, offshore wind, or liquid biofuels. These alternatives still need to be fully evaluated, as all three present substantial risks:

Offshore Wind. There has never been an offshore wind project sited in waters as deep as those in Hawaiʻi, and integrating large quantities of offshore variable renewables injected into the Oʻahu system at only a few points presents substantial interconnection and operational challenges.

Inter-Island Transmission. Undersea transmission systems are in service around the world and are a proven commercial technology. The current plans, paths, and projected costs for inter-island transmission require further evaluation to ensure the impact to the existing transmission system is addressed.

Biofuels. Sufficient quantities of biofuels, in the short term, appear to be questionable.

While initial steps need to be taken now to make such off-island resources viable options for the long–term, accelerating these projects into the near term rather than waiting until they perhaps might be more fully developed is risky and very likely to be more expensive.

Given the foregoing, LNG provides a hedge against oil price volatility and development risk inherent in offshore resources such as deep-water offshore wind and inter-island cables while reducing emissions. Even with LNG, these resources will be needed, but LNG allows time for these options to mature, their risks to diminish, and their prices to decline.

Renewable Biofuels

Renewable biofuels, particularly liquid or gaseous biofuels, play an important role in achieving the 100% RPS. Utilizing biofuels as a complement to DER, wind, solar and energy storage has the benefit of using a portion of the dispatchable thermal generation mix as part of the overall generation solution. This can help avoid the commitment of new capital for other renewable generation or additional resources to provide ancillary services that can be provided by existing and modernized replacement thermal generation. The flexibility of the dispatchable thermal generators will need to be a critical component in compensating for the variable nature of the wind and solar resources, providing energy during low renewable generation periods or seasons, thereby helping to ensure that our customers can continue to receive electricity from a safe and reliable system.

Offshore Wind

Offshore wind has been considered as a resource option for O‘ahu in the PSIP updates. Two developers have announced their intentions to pursue the installation of offshore wind to serve O‘ahu:

- Alpha Wind Energy proposes to develop a 408 MW offshore wind project in federal waters off O‘ahu's northwest and southern coasts. The announced capital cost of the project is $1.6 billion (approximately $3,925 per kilowatt).[5]

[5] http://www.hawaiicleanenergyinitiative.org/wind-in-oahus-waves/.

- Progression Energy Hawai'i Offshore Wind Inc. proposes to develop a 400 MW offshore wind project off Barbers Point in O'ahu. The announced capital cost of the project is also $1.6 billion (approximately $4,000 per kilowatt).[6]

We do not have agreements with either of these developers to purchase their power; we would likely further the vetting and evaluation of these projects though an RFP process.

Both developers propose using floating platforms, each supporting an 8 MW wind turbine, with undersea cables connecting the platforms to points on land. Floating offshore platforms in the proposed water depths (approximately 1,000 meters) have never been developed. Integrating such large quantities of a variable renewable resource, tied into the O'ahu system at a few interconnection points, poses significant technical challenges, and costs for upgrades in the O'ahu transmission system and will need to be studied. Notwithstanding these challenges, off-island resources will be required, so we must seriously investigate the offshore wind option.

Inter-Island Transmission

Inter-island transmission interconnections present another possible tool for achieving our 100% renewable energy goal. Undersea transmission systems are in service around the world and are a proven technology.

In Hawai'i, inter-island interconnections could allow the sharing of renewable resources across the islands and possibly provide other operating and economic benefits. For O'ahu in particular, inter-island transmission presents a potential alternative (or complement) to offshore wind systems, for bringing renewable energy to O'ahu from other islands.

Like offshore wind, inter-island interconnections with injections of relatively large amounts of power through a few interconnection points pose integration challenges and will need to be studied. Again however, because of Hawai'i's aggressive renewable energy goals, the inter-island option must be on the table and fully investigated.

Our analysis ultimately showed that we would require more capacity than was being included in our 2014 assumptions for inter-island transmission. Because of this, we plan to further analyze an array of inter-island transmission options after April 1, 2016.

Geothermal

Our findings indicate that firm renewable resources may be cost effective on the neighbor islands. Geothermal is one such option. Geothermal potential is proven on the east side

---

[6] http://www.utilitydive.com/news/developers-propose-competing-16b-400-mw-offshore-wind-projects-in-hawaii/406957/.

of Hawai‘i Island. Additional explorations of geothermal potential on the west side of Hawai‘i Island have been considered.

Maui may also have geothermal potential, but this requires additional explorations to prove its viability.

Development of geothermal will require community support and to date there has been significant community opposition to this development. One significant impediment to the development of future geothermal that was identified by the developers who participated in the recent Hawai‘i Island Geothermal RFP was the current County of Hawai‘i nighttime drilling ban ordinance. Policy makers and private organizations with interest in energy, land use, and water, should carefully consider the implications of geothermal energy development and develop the appropriate permitting and approval guidelines.

Biomass

Biomass is another firm renewable resource option.

HC&S's January 2016 announcement of ceasing sugar production and power sales, and the planned retirement of Maui Electric's Kahului Power Plant, present unique opportunities for the island of Maui. Given the most recent electricity forecasts, Maui expects to have a need for new generation or firm capacity to meet a reserve capacity shortfall in the 2017–2022 timeframe. We are evaluating several measures including demand response, energy storage, time-of-use rates and distributed and centralized generation to meet the needs of the island.

Biomass is one renewable resource that can meet the demands required of a firm power provider without the use of fossil fuel. Typically one hurdle for a biomass facility is to produce or identify enough feedstock. However the HC&S land previously held in sugarcane may be suitable for feedstock production. Using the land to produce biomass ensures this land will stay in agricultural use and help Maui to preserve our open spaces, while at the same time contribute to energy security by lessening our dependence on imported fuel. For the purposes of this PSIP update, the agricultural feedstock for a Maui biomass plant was assumed to be burned in a biomass steam unit.

On Hawai‘i Island, there appears to be substantial potential for biomass power. Policy makers and private organizations with an interest in agriculture, land use and water use, should investigate the potential and the policy implications of the use of agricultural land for energy crops.

Taking Advantage of Our Natural Resources

Hawai'i enjoys an abundance of natural energy resources that can be obtained from the sun, the wind, the ocean, biofuels, and geothermal. The technologies to extract energy and convert it to electricity are commercially available today for solar, wind, biofuels, and geothermal. New technologies will undoubtedly emerge over the next 30 years—technologies that will tap the ocean's energy potential for generating electricity and that will make current renewable generation more efficient.

We cannot, however, afford to wait for these technological improvements to emerge. We must start on a path to 100% clean renewable energy today, and continue to review and adjust our plans as circumstances change.

We are on the cusp of a revolution in energy storage technologies that will allow us to take greater advantage of variable solar and wind resources to reliably meet the needs of our customers. The realities of achieving 100% renewable energy requires cooperation and collaboration with the communities we serve, our government, and other stakeholders. We cannot do it alone.

DEVELOPING THE PREFERRED PLANS AND FIVE-YEAR ACTION PLANS

In developing our 2016 updated PSIP, we focused on a path for attaining 100% of generation from renewable resources in 2045 at a reasonable cost while maintaining system security. We were not married to any solution or resource, but rather focused on resources and solutions that attained our goal. The Action Plans identified the near term steps we need to undertake to attain 100% renewables.

Our modeling, analysis, and decision-making centered on a foundation of reasonable cost and risk while maintaining reliability as a means for attaining 100% renewable generation by 2045.

Foundational Elements of the PSIP

Decision Framework for Developing the Updated PSIP

We developed and employed a Decision Framework to develop the 2016 updated PSIP. The Decision Framework is based on four factors that form the foundation of our analysis, and a three-step iterative process employed to help us arrive at our chosen Preferred Plans.

Four factors comprise our Decision Framework.

Objectives. The specific results that the planning process aims to achieve. We defined these as lowest cost to the system, minimizing risks, and other considerations (such as renewable content).

Requirements. Fixed parameters around which a plan must be built and that do not vary between plans or plan sensitivities. We defined these as meeting RPS milestone dates, attaining 100% renewable generation, environmental compliance, planning criteria (including system security), and customer choice.

Input Parameters. Elements that can be varied to deal with uncertainty and to understand the sensitivity of a plan to a change in assumptions. Examples include demand, energy efficiency, DR potential, and DER potential, and their integration costs.

Decision Variables. Variables that can be varied toward achieving the Objectives. Our decision variables were based on the quantity and timing of DER, DR, and utility-scale resources.

The objectives, requirements, and input parameters all feed into the planning, modeling, and plan development by adjusting Decision Variables.

These four factors formed the basis for the planning, modeling, analysis, and decision-making we employed to arrive at our Preferred Plans. We performed several iterative cycles around DER, DR, and utility-scale resources and their costs to attain results that served as inputs to production simulation models. Results from the models help planners garner insights on how inputs drive the outputs and on how successive rounds of iteration should be performed. These new insights serve as inputs to continue the iterative cycles until reasonably optimal results are achieved.

Appendix C: Analysis Methodologies explains the Decision Framework in detail.

Modeling Methods and Analysis

In our analysis, we employed a number of modeling tools and worked with several experienced consultants to develop our 2016 updated PSIP. These consultants included Black & Veatch, Boston Consulting Group, Energy Exemplar, Ascend Analytics, Energy and Environmental Economics (E3), and PA Consulting. Almost all employed a modeling tool to generate results that were used to evaluate and develop various aspects of our plans.

Black & Veatch used their Adaptive Planning for Production Simulation tool in our DR forecasts. Their tool evaluates resource plans on a sub-hourly basis considering supply side and demand side resources, and security ancillary services and operational protocols.

The Boston Consulting Group DG-PV Adoption Model forecasts customer adoption of DG–PV (with and without storage) considering the economics of DG-PV from the customer's perspective. The BCG Customer Energy Storage Adoption Model forecasts customer adoption of energy storage systems considering customer economics. Both models helped us forecast DER levels.

Ascend's PowerSimm uses stochastic modeling to provide a unified framework of physical and financial risk factors impacting resource planning including ancillary services, operations, fuel price risk, carbon prices, and meteorology.

E3's RESOLVE evaluates investment decisions as well as operations to find a least cost portfolio solution over the planning time horizon.

Energy Exemplar ran PLEXOS, a sub-hourly simulation model, to optimize the portfolio of available resources considering system demand, fuel, reserves, installed capacity, green energy, water, and emissions.

All three of these models supported our development of the candidate plans, and ultimately our Preferred Plans. Appendix H: Analytical Models and Methods describes each of these modeling tools.

Assumptions

We accessed a number of outside organizations for data to use as assumptions in our planning and analysis. These organizations included the National Renewable Energy Laboratories (NREL), Lazard, Energy Information Administration (EIA), Electric Power Research Institute (EPRI), IHS Energy, NextEra Energy, Gas Turbine World, and RSMeans. We also included input from two of the Parties, our internal data and estimates for the cost of internal combustion engines (ICE), and system interconnection costs.

Input from the Parties

Our Revision Plan stated that we "intend to engage the parties and participants in this docket (collectively the 'Parties') as well as other stakeholders to solicit valuable input that can be incorporated into our own analysis and planning."[7] In addition, it stated that we "intend to incorporate stakeholder input to the greatest extent possible, within the time frames established, to inform the assumptions, methods, and evaluation metrics to arrive at a recommended course of action."[8]

We have followed through on each of these statements. Appendix B: Input from the Parties details the stakeholder and technical conferences we held and attended, our

---

[7] Order No. 33320 Compliance Filing, filed November 25, 2015 in Docket No. 2014-0183, at 1.

[8] *Ibid.*, at 28.

efforts to engage the Parties, and how we incorporated their input into our analyses. To further the transparency of our process, we invited intervenors to attend our internal planning meetings; three accepted and participated in the process on several occasions.

Eight Observations and Concerns

The Commission noted eight Observations and Concerns,[9] each of which encompasses a wide swath of areas under analysis in developing our 2016 updated PSIP. None of these eight Observations and Concerns can be considered as isolated issues in developing our PSIP. As such, we have integrated seven of these eight Observations and Concerns throughout our planning, modeling, analyses, and decision-making. Our analysis surrounding Observations and Concerns #7 regarding an inter-island cable will continue after filing our PSIP. For our 2016 updated PSIP, we concentrated on fully analyzing O‘ahu’s on-island resource potential and quantifying needed resource requirements

Chapter 2: Eight Observations and Concerns explains how we integrated these issues into our work.

Reasonable Plan Components

The Commission also noted a number of component plans[10] for us to consider. As with the eight Observations and Concerns, these component plans are not isolated issues, but integral to the overall development of our PSIP. As such, we included the content required from each of these plans in our planning, modeling, analysis, and decision-making.

Appendix M: Component Plans describes our work for each of these plans.

Arriving at the Preferred Plans

Our planning and analysis in developing the 2016 updated PSIP began with a number of cases being initially developed, transformed into three foundational themes (which spawned about two hundred candidate plans) and ultimately evolving into our Preferred Plans and attendant five-year Action Plans.

Themes

After our interim report, we began to develop the full array of plans reflective not only of issues that we feel are important, but also to address the different visions that different stakeholders have regarding the best way forward to achieve 100% RPS or renewable energy.

---

9 Order No. 33320, Docket No. 2014-0183, at 44–45.

10 *Ibid.*, at 138–139.

The result was to develop plans around three "themes" summarized as follows:

Theme 1: Accelerate Renewables. This theme assumes that accelerated pursuit of deployment of renewable resources, perhaps achieving interim and final RPS and renewable energy goals ahead of schedule.

Theme 2: Renewables With LNG. This theme utilizes LNG as a bridge fuel to more immediately reduce the use of oil as a fuel, while we progress towards our goal of 100% renewable energy. It also includes modernization of the existing thermal generation fleet with an efficient, flexible combined–cycle plant selected to support the growing renewable fleet. Theme 2 has the lowest emissions of the three themes

Theme 3: Renewables Without LNG. This theme does not use LNG, and continues our progress towards 100% renewable energy based on the existing RPS interim milestones.

These themes are more fully explained in Chapter 3.

Key Policy Decisions and Development of Candidate Plans

Finding the "right" resource plan going forward hinges on a relatively small number of crucial policy and technical decisions. To do this we identified key Decision Variables:

- Distributed Energy Resources
- Demand Response
- Utility-Scale Renewables
- Energy Storage Technologies
- Thermal Generation and Fuel Choices
- Renewable Energy Milestones

The Decision Variables guided the development of approximately 200 candidate plans that we tested, analyzed, and selected for additional analysis. We cycled through an analysis of the plans, using the outputs from one iteration as inputs to subsequent iterations. This process, coupled with analytic review, inexorably dwindled the field of candidate plans that complied with our objectives.

System Security

Integrating renewables into our system needs to be accomplished safely and reliably. Improving the flexibility of the generating fleet and limiting the magnitude of contingencies are important pieces to integrating larger amounts of variable resources. Failure to maintain the security of the grid impedes its ability to withstand sudden disturbances. System security and resilience are maintained by operating the system with sufficient inertia, fast frequency response, or primary frequency response. To accomplish this, the system operator, at times, must sacrifice efficiency for reliability and run dispatchable generators at higher minimum levels to maintain adequate reserves.

In this update, we defined and determined the amount of technology-neutral ancillary services required to meet reliability criteria, rather than solely relying on must-run generating units. This philosophy highlights the opportunity for distributed resources and demand response technologies to provide the ancillary services needed for a resilient, secure grid. For instance, if abundant PV resources along with emerging storage technologies are able to support the system with fast frequency response and regulating reserves, then these distributed resources can further displace traditional oil fired firm generation. Finally, the grid is wholly secured by re-purposing the retired firm generators as synchronous condensers or installing new ones to ensure sufficient system fault current is available to operate protective relays, an ancillary service not currently available from inverter-based generators, which historically was provided by running fossil fueled generating units.

Preferred Plans

After multiple iterations and careful analysis and decision-making, we arrived at optimum resource plans for each Theme, for each island.

These plans were then taken and applied to the financial model to determine financial impacts of each plan. The financial model provides a projection of financial metrics that include: capital expenditures, rates, and average customer bills. From these final candidate plans, we developed a set of Preferred Plans, taking into account costs and risks.

Five-Year Action Plans

We constructed optimal, long-term, renewable resource plans—our Preferred Plans—focusing on the near–term decisions that must be made within the next five years. From this, we developed detailed five-year Action Plans coupled with each Preferred Plan.

Near-term decisions can be made in the next five years. Many of the resources in our plans are projected to be placed into service well beyond the five–year near-term planning period. Because of the potential long lead times for feasibility determinations, procurement, permitting, and construction, and with the need for consensus among our communities and government entities, we believe it prudent to start working on the long-term decisions during these five years. Policy makers, private organizations, and our communities must begin now to discuss and develop clear policies, market mechanisms, and commercial arrangements necessary to implement the renewable generation necessary to achieve our 100% RPS goal by 2045.

Next Steps

We have endeavored to file an updated PSIP as directed by the Commission. We have completed a considerable amount of analyses and are reporting herein on a number of actionable findings. Given the scope of the Commission's directives and the limited amount of time to accomplish the considerable amount of analyses, there are still tasks to be completed. The five-year action plan in Chapter 9 provides details regarding our next steps.

OTHER CONSIDERATIONS

Various Risks Impact Each Theme

We assessed our Preferred Plans through the lens of several risks.

Planning Flexibility Risk. All plans must maintain a level of flexibility and optionality to incorporate technological advancements or to adjust should future expectations fall short.

Technology Risk. Renewable technologies have various levels of commercial readiness and availability. We must not base our Preferred Plans on technologies that are unproven or have unknown feasibility.

Fuel Price Risk. One of the most important risk variables is the projected cost of fuels such as oil, coal, LNG, and biofuels. High fossil fuel prices make variable renewables more attractive because the "fuel" for those resources is essentially free. Low fuel prices make fossil fuels more attractive from a customer bill impact standpoint. This is an important sensitivity in our PSIP analysis.

Financing Risk. The large amounts of capital required to transform our energy system will require that the Companies, IPPs, and customers raise capital. The ability to raise capital, and the cost of that capital, are a function of overall risk, including regulatory and political risks, as well as the risks mentioned above.

Implementation Risk. Development of large infrastructure projects is complex under the best of circumstances. Unique factors in Hawai'i add complexity. This is an external risk that is outside our control. We cannot base our Preferred Plans on projects that have little chance of being constructed.

Stranded Costs. Consideration must be given to minimize or eliminate the prospect of stranded costs in any capital invested in pursuit of implementing a plan.

Customer Adoption Risk. How much customers participate in energy generation must be considered in light of their financial investment. How lifestyle considerations affect their energy management and participation in grid services must be assessed.

Demand Forecast Risks. There are also risks associated with future demand forecasts. These forecasts assume that the state's aggressive energy efficiency portfolio standard (EEPS) is met, and that the uptake of DER by customers as forecasted is actually realized. Finally our future need for capacity and ancillary services from generating resources is impacted by whether or not our forecasted demand response quantities come about.

Strategies for Developing the PSIP

In its Inclinations, the Commission articulated a number of strategies[11] related to the generation system, which it suggested would lower and stabilize the costs of generation. We respond to those strategies here.

Seek high penetrations of lower-cost, new utility-scale resources

Utility-scale renewable resources were evaluated as part of this PSIP update. In general utility scale resources were found to be cost effective and are included in our Preferred Plans.

Modernize the generation system to achieve a future with high penetrations of renewable resources

As part of the analysis for this 2016 updated PSIP, we evaluated modernizing the generation system running with and without LNG. Modernization, in general, is only less expensive in the short term if the savings from using a lower cost fuel (such as LNG) offsets the increased costs from the capital expenditure.

Exhaust all opportunities to achieve operational efficiencies in existing plants.

Operational efficiencies come in the form of lower heat rates. Operational efficiency gains require capital investments. To be effective, the cost savings realized from efficiencies must outstrip their cost. As such, we have not exhausted all opportunities; however, we have evaluated and continue to evaluate all reasonable opportunities, and implement them when they are cost effective as a normal course of our operations as we monitor heat rate of our units continuously. We have implemented capital projects when necessary to restore efficiencies or maintain reliability. In most cases, projects have had both reliability and efficiency benefits.

[11] *Ibid.*, at 42.

Pursue opportunities to lower fuel costs in existing power plants

Through comprehensive source testing and analysis, we have been able to minimize fuel costs for the MATS compliance plan for Hawaiian Electric and expect to comply with the MATS limits using 100% LSFO in all Hawaiian Electric steam units. Initially, we planned to switch to an LSFO and diesel-fuel blend in our steam generating units. Through the testing program, we have developed a cost effective MATS compliance plan based on optimized operating parameters (such as excess O_2, fuel firing temperatures, and soot blowing frequency), boiler and air heater washes, Opacitrol fuel additive (combustion catalyst) on select units, and steam atomization to improve combustion.

In addition, our analysis continues to indicate that LNG is a prudent choice that allows us to significantly lower emissions, reduce fuel costs and customer bills, and reduce customers' exposure to fuel price volatility as we transition our system to achieving 100% renewable energy.

CHANGES AFFECTING OUR RESOURCE PLANNING FOR THE UPDATED PSIP

Over the course of the nineteen months since we filed our 2014 PSIPs, a substantial number of circumstances have changed that dramatically affected the underlying assumptions and condition for planning our 2016 updated PSIP. The Commission noted a number changed circumstances;[12] we identified several additional developments. We respond to these as directed.

All of these changes affect our planning over the next five years—essentially the time period for developing a short-term plan—as well as for our planning over the next 30 years. In effect, then, we are not creating a supplemented, amended, and updated PSIP—we are creating an entirely new PSIP. This is the basis from which we have proceeded in our modeling, analyses, and assessments, all ultimately affecting how we plan to meet both the immediate and long-term energy needs for Hawai'i.

[12] Order No. 33320 at 133.

Integrating Sixteen Changed Circumstances into Our Updated PSIP

Here are the major changed circumstances that have transpired over the relatively short period of time of nineteen months—changes that we integrated into our modeling and analysis for creating our Preferred Plans. The Commission identified the first five changed circumstances.

1. Passage of Act 97 (2015), which changed a 40% RPS target in 2030 to attaining a 100% RPS in 2045. This change alone affected the fundamental underpinnings of our resource planning: our planning horizon, originally set for 15 years, has now been extended to 30 years.
2. Substantial decreases in the prices of fuel oil, affecting both our current supply as well as our forecasted costs.
3. The delay in LNG implementation from 2017 (as projected in our 2014 PSIPs) until 2021, and an announcement by the Governor of the State of Hawai‘i regarding the administration’s view regarding utilization of LNG fuels for electric utility power production.
4. Rescheduling of the O‘ahu battery energy storage system (BESS) project from 2016 until 2019.
5. The issuance, and subsequent stay (by the U.S. Supreme Court on February 9, 2016), of the Clean Power Plan Final Rule that portends further tightening of emission standards for greenhouse gases from existing fossil-fuel electric generation.
6. The pending proposed merger between NextEra Energy and the Hawaiian Electric Companies.
7. A good faith commitment by NextEra Energy (if the merger is approved) to exceed the RPS requirements: 35% by 2020 (instead of the statutory 30%) and 50% by 2030 (instead of the statutory 40%).
8. The closing of the Net Energy Metering (NEM) program by the Commission and its concurrent replacement with two new DER programs: customer grid-supply and customer self-supply.
9. The enactment of advanced inverter standards to mitigate DG-PV impacts (attained through the DER docket).
10. Filed tariffs for new DR programs (awaiting Commission decision) and the development of ancillary services requirements (in the DR docket).

11. The termination of the Hu Honua Bioenergy power purchase agreement due to Hu Honua's default and continued failure to meet critical construction milestones guaranteed under the PPA.
12. Ormat's withdrawal from contract negotiations to provide additional geothermal generation on Hawai'i Island.
13. A pending asset purchase agreement with Hamakua Energy Partners (HEP).
14. Deferral of the retirement date of the Kahului Power Plant from 2019 to 2022.
15. Termination of three PPAs for solar facilities on O'ahu totaling 109 MW due to the project companies' failures to meet guaranteed project milestones and substantial commitment milestones in their PPAs.
16. HC&S notified Maui Electric that it was ceasing sugar operations and terminating the PPA effective January 6, 2017.

Taken all together, these changes have created a vastly different environment for energy planning. The near future may also present comparable changes. Because of this continued dynamic environment, we strive to build flexibility into our resource planning.

Continually Evolving Energy Environment

Renewable generation clearly is burgeoning. As with virtually all other emerging, maturing, and evolving technologies, we expect breakthrough developments, decreasing prices, increasing implementation, and growing community acceptance.

Consider the profound impact on the environment, on culture, and on energy demand, should electric vehicles replace gas-fueled cars in large numbers and the impact they will have on the electric grid. Consider the profound impact on renewable generation should the cost of energy storage decrease by 70% over the next 15 years (as was predicted in January 2016). Consider the rapid shift in generation toward renewables as other jurisdictions demonstrate the same forward-thinking mind set of the Hawai'i Legislature and adopt more progressive goals for transitioning to renewable generation.

We, as electric companies and as a state, must adequately prepare and plan for such a future. These are the challenges that we face, and continually work toward solving, in our resource planning.

Accomplishments Since the 2014 PSIP Filing

Much has transpired since we filed our original PSIPs. We have:

- Applied for and obtained approval for the 50 MW Schofield Generating Station.
- Retired two oil–fired generating units on Hawai'i Island.
- Applied for and received approval for two utility-scale PV projects on Maui.
- Increased DG-PV on all five islands from 328 MW to 487 MW at the end of 2015.
- Progressed LNG plans from concept to finalizing LNG contract negotiations and preparation of an LNG application.
- Attained a consolidated RPS of 23.2% by the end of 2015.
- Filed an application for the Smart Grid Foundation Project.

This is just a sampling of our accomplishments. We will continue making progress after filing our 2016 updated PSIP.

OUR VISION AND STRATEGIC OBJECTIVES

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. We intend to continue innovating, exploring, and evaluating new technologies for a cleaner generation system with affordable costs for our customers.

To reach our vision, we focus on three overarching goals, while attaining increased customer satisfaction overall.

<table>
<tr><th>Goals</th><th>Description</th><th>Company-Wide</th><th>Hawaiian Electric</th><th>Maui Electric</th><th>Hawai‘i Electric Light</th></tr>
<tr><td>Cost-Effective Clean Energy Portfolio</td><td>- Ensure cost-effective, transparent, and less volatile prices for customers.
- Eliminate potential market inefficiencies.
- Reduce environmental footprint by reducing emissions.
- Reduce dependence on imported fossil fuels through existing resources.</td><td>- Generation operations flexibility program
- Leverage ancillary services capabilities of renewable resources, DER, and DR
- LNG application
- Inter-Island transmission analysis
- RFP for additional renewables
- DR programs</td><td>- Generation modernization
- Replacement projects for terminated waiver project PPAs.
- Defer deactivation of Waiau 3 & 4</td><td>- Two utility-scale solar PV PPAs.
- RFP for replacement generation
- Reserve capacity shortfall mitigation</td><td>- Hamakua Energy Partners (HEP) purchase
- RFP for firm, dispatchable renewable generation to displace fossil-fired capacity and energy.
- Cost effective utilization of existing resources.</td></tr>
<tr><td>Modern Grid & Technology Platform</td><td>- Continue to ensure a safe and reliable power grid.
- Develop a platform to enable more renewables, more efficient delivery, and greater resiliency.
- Contribute to Hawai‘i’s economic growth and environment.</td><td colspan="4">- Smart Grid
- Storage applications
- Further integration of wind and solar forecasting into System Operations
- Expanded monitoring and data capture from real–time systems through PMU data for post-disturbance review and model updates
- Adaptive underfrequency load-shed
- Monitoring and control of DER and variable resources
- Transmission and distribution upgrades.</td></tr>
<tr><td>Quality Customer Experience & Innovative Energy Solutions</td><td>- Enable and support changing customer needs and preferences in light of energy alternatives.
- Ensure fair treatment to all customers.
- Be a front-runner in clean innovations.
- Enable third parties to provide innovative solutions in Hawai‘i.</td><td colspan="4">- DER policies
- Community-Based Renewable Energy (CBRE)
- Demand Response Management System (DRMS)
- Demand response portfolio tariff structure</td></tr>
</table>

Table 1-4. Overview on Related Proceedings and Corporate Actions to the PSIP Update

Addressing Near-Term Filings

The updated PSIP lays the foundation for other near-term filings, some of which are detailed in our five-year action plans.

Company-Wide

DER Policies (Docket No. 2014-0192). The updated PSIP incorporates the decisions of last year's DER Phase 1 proceeding and work on selected non-policy related DER issues to prepare for the upcoming DER Phase II proceeding.

- *Circuit-Level Hosting Capacity.* In the updated PSIP, we have expanded on the circuit-level hosting capacity methodology by identifying several DG-PV integration options and estimating costs of these integration options for various amounts of DG-PV. In this PSIP, we explicitly consider DG-PV integration costs in the resource plan optimization. Results of this integration cost analysis can inform and help the DER Phase II proceeding identify appropriate policies for DER integration.
- *System-Level Hosting Capacity.* System-level hosting capacity analysis was performed on a filtered set of cases ensuring those are fulfilling all reliability related planning criteria.
- *New DER Products (Self-Supply, Grid-Supply).* In line with decisions of the DER Phase 1 proceeding, we have developed DG-PV adoption forecasts for the new customer Self-Supply and Grid-Supply products absent program caps. In addition, we explored the implications of adding additional amounts of DG-PV to the system. DER policies related to achieving these DG-PV projections in a safe, reliable, cost-effective way will need to be discussed during the DER Phase II proceeding.
- *Advanced Inverters.* In the updated PSIP, we assumed that are technologies are advancing such that control of customer DG–PV will be feasible by mid-2018.
- *Time-of-Use Rates.* The updated PSIP's production simulation results provide some of the necessary data to develop adjusted Time-of-Use rates during the DER Phase II proceeding.

Demand Response Portfolio Tariff Structure (Docket No. 2015-0412). A major building block of the PSIP update decision-making process has been the DR iterative cycle, calculating avoided costs by individual themes and cases, and developing forecasts for DR portfolios for the individual islands for the PSIP planning horizon. The technology neutral system security requirements defined in this PSIP will be used to inform DR products in our planned June 2016 DR product filing.

Demand Response Management System (DRMS) (Docket No. 2015-0411). DRMS is a key enabler to integrate high amounts of DER and to leverage DR resources. The updated PSIP assumes the DRMS is implemented by mid-2017. The DRMS application filed on December 30, 2015 incorporates not only traditional DRMS functionality, but a full suite of distributed energy management capabilities that will be required to fully leverage the value of various DER. Hawaiian Electric is targeting initiation of the DRMS project by late 2016 to early 2017, depending on Commission approval timing.

Smart Grid. Smart grid initiatives are key to our achieving all three overarching goals. An Advanced Metering Infrastructure (AMI) and Meter Data Management Systems (MDMS) can enable more cost-effective and transparent prices for customers. Conservation voltage reduction (CVR) controls voltage and enhances power quality and conservation. Direct load control (DLC) enables two-way communication and control. Both can enable more renewables (including DER), more efficient delivery, and greater resiliency. AMI and technologies that provide customers with a seamless integrated mobile and web energy platform can help address customer expectations of a modern utility.

The updated PSIP assumes significant amounts of DER and DR are achieved, and Smart Grid is implemented. Smart grid initiatives like AMI, MDMS, CVR, and DLR enable higher levels of DG-PV and robust DR programs. We filed an application for approval of the Smart Grid Foundation Project on March 31, 2016, and plan to implement Smart Grid upon approval.

Generation Operational Flexibility Projects. In the updated PSIP, we analyzed operational flexibility pilots and projects designed to accommodate greater quantities of low cost, renewable energy resources. This analysis deepened our understanding of how generation operational flexibility projects impact the overall system and the implications for resources and cost. PSIP results will be considered in the Generation Operational Flexibility Projects proceeding.

Community-Based Renewable Energy (Docket No. 2015-0389). Various resources are required to achieve 100% RPS, including DER, utility-scale resources, and potentially, community-based renewable energy (CBRE). For planning purposes, the 2016 updated PSIP assumed some CBRE. Upon Commission review and approval of the CBRE program, these resources can be solidified in future refinements of the plans.

RFP for Additional Renewables. Various new, cost-effective renewable resources are required to achieve 100% renewable energy. The updated PSIP Preferred Plans identified a set of renewable projects by island system that will require the launch of new, competitive procurement processes.

LNG Application. The updated PSIP performed a rigorous assessment on the economic feasibility of LNG that would enable us to procure a lower cost and cleaner fuel for Hawai‘i. As a result of these analyses, we plan to submit an application for an LNG fuel supply agreement, and a General Order No. 7 application for to make capital expenditures related to LNG-related dual fuel unit conversions and related infrastructure. Commission approval of these applications will allow us to procure International Organization for Standardization compliant intermodal cryogenic containers (ISO Containers) for the transport of the LNG, and to receive, store, and regasify LNG, and utilize natural gas at the designated generation facilities. These applications will be filed shortly after the filing of this PSIP update.

Storage Applications. Consistent with the Preferred Plans, the Companies will be evaluating the potential procurement of energy storage resources.

Capital Budget. We have recently filed our interim budget. The budget will need to be updated once the updated PSIP have been established.

Inter-Island Transmission (Docket No. 2013-0169). The Commission directed us to develop economic analysis on the cost-effectiveness of inter-island transmission options. Inter-island transmission is a unique resource with unique costs and operational benefits that require detailed calculation in order to be characterized correctly. The development of an optimized interisland transmission system is in process, but was not completed in time to be included in this filing. Insights developed through this PSIP update (i.e. estimates of off-island energy needed to achieve 100% renewable energy on Oʻahu) will be used to scope a more informed inter-island transmission analysis after April 1, 2016.

Merger (Docket No. 2015-0022). In the updated PSIP, the cases including LNG assume the proposed merger of NextEra Energy and Hawaiian Electric Companies is approved. Combined with other projects and programs envisioned for this same timeframe (such as Smart Grid, Schofield Generating Station, and other projects), the cases that include LNG will require the financial backing and development capacity of the merged organization.

Hawaiian Electric

Kahe Combined Cycle Generation Modernization Application (Replacement Generation). The 2016 updated PSIP analyzed the benefits of generation modernization, which includes a flexible 383 MW, 3x1 advanced combined cycle generation unit in Oʻahu, located at the existing Kahe Generating Station site. The analyses in this PSIP update demonstrates that this generation unit replacement is beneficial for the customers and helps achieve the state goals in a cost-effective way. Therefore, we are planning to file an application for the 3x1 CC unit. This application will be conditioned on approval of the merger.

Power Barge at JBPHH and ICE Units at MCBH. Hawaiian Electric plans to pursue the installation of distributed generation at Joint Base Pearl Harbor–Hickam (JBPHH) and at Marine Corps Base Hawaiʻi (Kaneohe) (MCBH). These generation additions will support the retirement of existing Kahe and Waiau units and the expiration of the PPA for AES Hawaiʻi's coal unit by the end of 2022.

Potential New RFP for Replacement Capacity for Waiver Projects. Three of the four approved PPAs for the waiver projects were terminated due to developer non-performance. We desire to procure low-cost renewables and are considering all options to replace these projects including issuing a new RFP to replace the capacity represented by the terminated waiver project PPAs. For planning purposes, the 2016 updated PSIP assumes the terminated waiver projects will be replaced by similar resources.

Defer Deactivation of Waiau 3 and 4. We reviewed and evaluated retirement options for generation capacities on O‘ahu ensuring cost-effectiveness to all customers. We have summarized our findings in Appendix M: Component Plans.

Hawai‘i Electric Light

Hamakua Energy Partners (HEP) Purchase (Docket No. 2016-0033). For the updated PSIP modeling and financial analysis, HEP is modeled as an IPP plant. On February 12, 2016, we filed an application for Commission approval of our proposed purchase of the 60 MW dual-fuel combined-cycle HEP plant. The application describes the purchase terms and the significant cost benefits to our customers that would result from this purchase.

Hu Honua PPA Termination. On March 1, 2016, we terminated the PPA with Hu Honua Bioenergy based on Hu Honua's default and failure to meet critical PPA milestones. The 2016 updated PSIP analysis therefore assumes Hu Honua as being not available.

Hawai‘i Geothermal RFP. While the recent geothermal RFP did not result in a project, we remain hopeful that geothermal generation can be a viable option on Hawai‘i Island in the future and can help Hawai‘i meet its 100% renewable energy goal while lowering customer bills. The updated PSIP therefore assessed several cases with new geothermal capacities available on Hawai‘i Island, including West Hawai‘i geothermal resources. The development of additional geothermal resources will require the support of communities and government agencies.

Maui Electric

South Maui Renewable Resources (Docket No. 2015-0225) and Kuia Solar (Docket No. 2015-0224) PPA Applications. In February 2016, the Commission approved, with conditions, the power purchase agreements for these two utility–scale solar PV projects. These resources contribute to the cost-effective pursuit of RPS milestones. For planning purposes, we assumed these solar resources are available and included them in the updated PSIP analysis.

Potential RFP for Replacement Generation. The 2016 updated PSIP analyzed several retirement scenarios. A potential full retirement of Kahului Power Plant during the planning horizon would require procurement of replacement generation to fulfill system demand.

Central Maui Transmission Upgrades. Retirement of KPP will require upgrades to the 23 kV transmission system in Central Maui in order to maintain system reliability.

RFP of Emergency Generator for Reserve Capacity Shortfalls. Given the most recent load forecasts, Maui expects to have a need for new generation or firm capacity to meet reserve capacity shortfalls in the 2017–2022 timeframe. We are evaluating several measures, including DR, energy storage, time–of–use rates and distributed and centralized generation to meet the needs of Maui Electric's customers.

Our Role: To Create and Implement a Strategic PSIP

Our role is to create and implement a Preferred Plan for each operating utility that fulfills the state's policy goals of 100% RPS by 2045, meets the diverse service requirements of our customers at reasonable and more stable rates, and maintains reliable energy service. Our PSIP, created in a rapidly changing environment, can then serve as a strategic basis and provide context to inform future investments, programs, and operational decisions until they are updated again.

2. Eight Observations and Concerns

The Commission noted eight Observations and Concerns,[13] each of which encompasses a wide swath of areas under analysis in developing our 2016 updated PSIP. None of these eight Observations and Concerns can be considered in isolation. As such, we have integrated them throughout our planning, modeling, analyses, and decision-making.

#1. CUSTOMER RATE AND BILL IMPACTS

Chapter 3 fully describes the overall planning process, plan development, and iterative optimization process from the 1st iteration, which was included in the PSIP Interim Status Report filed February 16, 2016, through the development of the Final Plans and selection of the Preferred Plans. Financial analysis and "all-in" results are presented in Chapter 4. The Net Present Value of cumulative revenue requirements, under both 2015 EIA Annual Energy Outlook Reference and February 2016 EIA Short Term Energy Outlook fuel price forecasts, have been calculated for the best evaluated resource plan for each theme. Residential customer rates and monthly bill impacts, in nominal and real (2016) $/kWh, are provided for both fuel price forecasts. It should be noted that all finalist and Preferred Plans meet or exceed all statutory RPS requirements.

To maximize the accuracy of our analyses, we updated all input assumptions, including resource costs, fuel costs, and resource availability assumptions. We also shared all relevant assumptions with the Parties to solicit feedback. In addition, we engaged NREL to independently assess resource cost assumptions and provide an analysis of wind and PV availability. NREL's reports can be found in Appendix F.

[13] Order No. 33320, Docket No. 2014-0183, at 44–45.

Theme 2, which uses the LNG fuel price forecasts included in Appendix J, produced significant cost savings and has the largest beneficial impact to customer bills. To address the uncertainty in future fuel prices, sensitivity analyses were completed for both the 2015 EIA Annual Energy Outlook Reference fuel price forecast and February 2016 EIA Short Term Energy Outlook fuel price forecast for each case. While there is no way to accurately predict future fuel prices, results from Ascend Analytics' stochastic modeling of all-in delivered LNG and oil indicate that oil prices are characterized by "higher levels of volatility and slower rates of mean reversion as compared to natural gas. Higher volatility in oil prices translates to more uncertainty in future oil prices and a wider 90-percent confidence band in comparison to LNG." Figure 2-1 depicts these results.

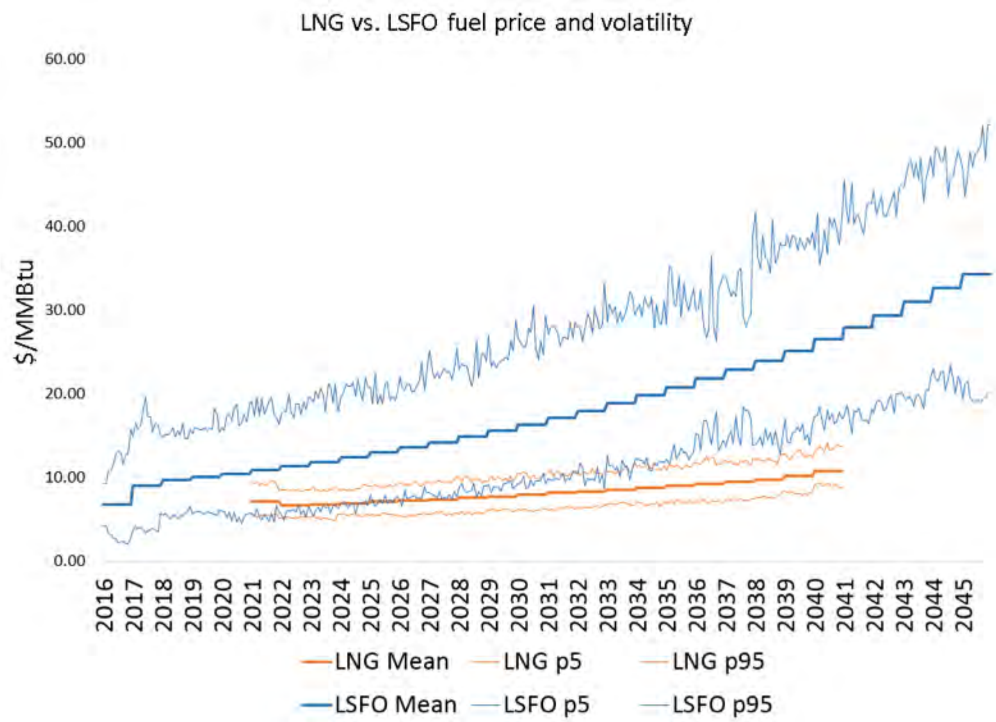


Figure 2-1. Stochastic Fuel Price Forecast, Ascend Analytics

To address the capital expenditure constraints, revenue requirement projections which included capital expenditure projections for power supply, smart grid, ERP, and all other utility capital expenditures (referred to as "balance of utility business capital expenditures") were considered. As described in detail in Appendix I, the balance of utility business capital expenditures have been calculated using a top down approach for the high fuel price scenario. Chapter 4 summarizes the capital expenditures by category for each Theme.

#2. TECHNICAL COSTS AND RESOURCE AVAILABILITY

Utility-scale resources are a key decision variable in the Decision Framework, which assesses the cost-effectiveness of various resource types.

We started by updating all resource costs, including capital costs, interconnection costs, fuel costs, O&M costs, and resource availability assumptions. Virtually all deployable technologies were considered. Though found not to be cost-effective at this time, new concepts such as accelerating alternative fuel vehicle adoptions (electric vehicles and hydrogen vehicles) and flexible electrification where electric vehicles could be used for load balancing were evaluated by E3. We retained NREL to independently assess our new resource cost assumptions and made appropriate adjustments to our assumptions as a result. We also commissioned NREL to develop independent assessments of the utility–scale solar PV and wind levels that could be developed on each island based on topographic, land-use restrictions, proximity to urban areas, and renewable energy production potentials in specific locations. NREL's reports can be found in Appendix F.

Although adjustments were made to O'ahu for utility scale PV and onshore wind to be consistent with NREL's resource potential estimates, cases including high levels of PV were developed and analyzed. We compared case results of varying levels of energy storage and biofuels, and developed an optimized-mix of these dispatchable resources. In addition, we included community-based renewable energy (CBRE), DER and DR resources, utility scale PV, geothermal, onshore and offshore wind, biomass, biofuels, pumped storage hydro, and battery energy storage systems. (After this filing, we will complete our analysis of an inter-island transmission system, including estimated costs and benefits relative to offshore renewable energy serving O'ahu and benefits of combined grid operations.)

Chapter 3 fully describes the planning process and Appendix K provides all of the cases considered. Both high DG-PV and market DG-PV cases were evaluated. Integration requirements for DG-PV are discussed in detail in Appendix N. Identification and consideration of integration costs for DG-PV was included in all of the analyses. In addition, accelerating renewables (Theme 1) which achieves 100% RE on the neighbor islands (including Lana'i and Moloka'i) by 2030 were developed and optimized for cost. As noted in Chapter 3 and Appendix C, the overarching objective of the planning process was to optimize and find the lowest cost mix of resources and plan to achieve the statutory RPS requirements. The resulting near-term actions to acquire cost-effective RE projects are described in Chapter 8.

#3. DISTRIBUTED ENERGY RESOURCES INTEGRATION

DER is one of three key resource-types that were optimized as part of the Decision Framework, and we evaluated the full spectrum of DER. Energy efficiency attainment and electric vehicle adoption were forecast and incorporated in system net load for all PSIP cases. Demand response, distributed storage, and DG-PV were optimized through iterative cycles to achieve lowest system cost while enabling customers to provide cost-effective and reliable grid services. Self-consumption economics were based on retail rates; grid export economics were based on the value the DER provides the system (utility-scale PV LCOE for DG-PV, value of storage to the system for distributed storage, value to the system for DR).

Multiple options were developed to integrate DG-PV on over-hosting capacity circuits and the lowest cost integration option was selected for explicit consideration in the economics for those DG-PV systems forecast to be installed on an over-hosting capacity circuit. The DG-PV integration strategies and costs are more fully described in Appendix N.

We determined high-value system-level use cases for DER in 2016 - 2020 as follows. Robust DG-PV adoption compensated at utility-scale PV LCOE reduces the need to procure utility-scale PV and helps meet near-term RPS targets cost-effectively. Storage was analyzed as a decision variable in the various PSIP cases, and was found to be cost effective for selected use cases in DR programs.

We sought cost effective solutions by weighing the costs and benefits of (full or partial) inverter retrofit against alternative ones when addressing either circuit or system-level interconnection barriers. For instance, we are currently considering the cost and benefits of legacy inverters without ride-through capabilities in our contingency battery analysis. We considered retrofit of inverters to ones that have reactive power capabilities for voltage mitigation in the DG-PV integration analysis (see, Appendix N).

A cornerstone of the DR program portfolio is the aggregation of DR resources. All of the proposed DR services utilize various DER technologies to achieve this aggregation philosophy. Furthermore, the demand response management system that will be used to deliver the DR services through the intelligent management and optimization of groups of DERs has been specified to allow for the attribution, selection and dispatch of these resources across various zones. These zones map to the physical topography of the various islands' systems and span from the system level at the highest level down to the individual circuit at the lowest level. As such, the current architecture and system design of the DR portfolio implementation allows for targeted deployment of DERs, which is suitable and appropriate as a tool for helping to address distribution or transmission level constraints such as those being considered by non-transmission alternatives in South Maui.

We varied RPS attainment in the analysis cases and, through iterative cycles, optimized DER amounts across islands and across cases to determine the role and contribution of DER in high-RPS attainment scenarios. In addition to the DG-PV adoption forecast optimized for the system, we analyzed a "high DG-PV" forecast to further characterize the role and contribution of DER in aggressive RPS attainment scenarios. DER plays a significant role in the preferred plans. Further work on how to achieve the sustainable DER adoption as envisioned by the preferred plans will be covered in the DER 2.0 proceedings.

#4. FOSSIL-FUEL PLANT DISPATCH AND RETIREMENTS

Chapter 3 outlines the breadth of cases considered in the three iterations completed, around three Themes: Theme 1–Accelerate Renewables, Theme 2–Renewables With LNG, and Theme 3–Renewables Without LNG. Cases considered various mixes and amounts of resources. The multiple cases were specifically designed to iterate towards a low-cost objective, and address risks associated with changes in fuel price by analyzing both LNG and oil, and analyzing various fuel price forecasts. We refined those cases to incorporate results from preceding runs of DER, DR, and utility-scale resources iterations to determine low cost potential with minimized risks, and analyzed grid modernization to characterize the tradeoffs and risks of modernizing our generating fleet versus other resource options. We identified potential dates for displacement of fossil generation, then updated our Fossil Generation Retirement Plans. Additional details for the Fossil Generation Retirement Plan can be found in Chapter 8 and the Component Plans included in Appendix M.

Theme 2 included LNG as a transitional fuel on Oʻahu, Maui, and Hawaiʻi Island and modernization of the generation fleet on Oʻahu with efficient, flexible replacement generation selected to support the growing renewable fleet on Oʻahu. Additional details of LNG as a transitional fuel are described below. For all cases, both high and low fuel price forecasts were evaluated to understand the respective cost impact. The analyses suggest that the most significant savings can be achieved with LNG and modernization of the generation fleet with market DG-PV. Details of the Preferred Plan are provided in Chapters, 5, 6, and 7, and the financial results are provided in Chapter 4. It should be noted that all cases comply with statutory RPS requirements.

As part of our analysis, we reviewed and clarified our environmental compliance strategies, and updated our Environmental Compliance Plan and Key Generator Utilization Plan. Finally, we updated our Generation Commitment and Economic Dispatch Review. All of these plans are included in Appendix M, Component Plans.

LNG as a Transitional Fuel

We have highlighted the need for modernized and flexible generation resources in order to minimize costs, reduce emissions and facilitate the increased integration of variable renewable resources. Even with these new resources in place, the Companies' current fuel source for its dispatchable generation during the transition period to a 100% RE will be petroleum-based fuels.

As a result, customers will be exposed to a petroleum-based fuel which is:

- Forecasted to cost more than LNG.
- Significantly more volatile in price than LNG.
- Subject to increasing restrictions under tightening federal environmental standards.

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

Overview of the LNG Delivery System

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

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

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

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

Flexibility with Minimal Permanent Infrastructure: To be consistent with achieving the RPS goals, the Companies required any fuel supply to have flexibility to accommodate a dynamic energy environment and generation from renewable resources. The fuel supply system should have minimal permanent infrastructure that could limit flexibility and increase the risk of stranded assets.

Neighbor Island Coverage: The Companies required a cost-effective solution that could supply fuel to Maui and Hawai'i Island just as easily as to O'ahu without making substantial modifications to the overall supply chain.

Minimal Permitting: To expedite adoption of cheaper natural gas in the fuel portfolio, the Companies required non-permanent infrastructure for the LNG supply system to avoid extensive and time-consuming permitting processes associated with developing an LNG terminal.

Security of Supply: To mitigate geo-political risk and ensure continuity of supply, the Companies sought a fuel supply from a North America as opposed to gas sourced from politically sensitive global locations.

Lower Price Volatility to Customers-Gas vs. Oil Indexed Pricing: Globally, LNG is typically priced off a formula which is indexed to oil prices. To reduce dependence on oil-linked, fuel pricing (current fuel portfolio) and minimize commodity pricing volatility, the Companies required LNG to be indexed off of North American natural gas prices.

Ability to Serve Other Customers in Hawai'i: The Companies wanted the LNG seller to have the ability to sell excess volumes to third party off-takers and/or for the Companies to take additional spot volumes if available.

Unit Conversions

Under a merged scenario between the Hawaiian Electric Companies and NextEra Energy, the Companies intend to enter into an agreement to acquire approximately 800,000 metric tons of LNG annually from the Fortis LNG facility in Vancouver, BC. Deliveries could start in 2021 and coincide with the commencement of commercial operations of modernized combined cycle units at Kahe. In addition to the modernized units, the Companies would convert five of their existing generation units (six including HEP if its purchase by the Companies is approved by the Commission) to allow them to use LNG in addition to petroleum-based fuels. This involves installation of new equipment to receive, store and regasify the LNG, and conversion of the existing generating units to allow for gas utilization (with total estimated cost of the conversions at approximately $340 million). Although not yet negotiated, it is assumed that the two combustion turbines at the Kalaeloa Partners LP Generating Station would also be modified to use LNG. After the completion of the modernization and conversions, the Companies would have approximately 1,100 MW of generation capacity capable of using LNG-based fuel during the transition period to 100% RPS (as outlined in Table 2-1).

Unit Name	Status	Unit Capacity (MW)	Unit Ownership
Kahe 5	Existing	140	Hawaiian Electric
Kahe 6	Existing	140	Hawaiian Electric
Kalaeloa	Existing	208	IPP
Kahe Combined Cycle	New	383	Hawaiian Electric
Ma‘alaea 14/15/16	Existing	58	Maui Electric
Ma‘alaea 17/18/19	Existing	58	Maui Electric
Keahole 4/5/7	Existing	60	Hawai‘i Electric Light
HEP CT1/CT1	Existing	60	Hawai‘i Electric Light or IPP

Table 2-1. Unit Conversions to Dual Fuel

#5. SYSTEM SECURITY REQUIREMENTS

Selected resource cases from each of the three Themes for each island grid were screened for system security with a focus on loss of generator and electrical transmission fault disturbances. These selected resource plans formed the basis for performing a limited system security analyses that defined in a technology neutral manner the fast frequency response (FFR) and primary frequency response (PFR) requirements for selected years of a plan. The results of the security analysis are presented in Appendix O.

Since filing our 2014 PSIPs, we have updated and revised our system security requirements and focused this analysis on single contingency loss of generation events to determine acceptable under frequency load shedding (UFLS)[14] capacities. Loss of generation contingencies have a greater impact on resource plans because it dictates on-line reserve requirements which in turn, establish FFR and PFR requirements. A full system security analysis that includes voltage stability, rotor angle stability and fault current protection coordination on for all islands will be performed for the preferred plans.

For Oʻahu, HI-TPL-001 was revised to allow no UFLS for single generator contingency events (previous criteria allowed 12% customer loss) while Maui and Hawaiʻi Island allow 15% loss of system load (previous criteria allowed 15% customer loss). The Molokaʻi and Lanaʻi systems were removed from HI-TPL-001 since these systems are unique island distribution systems that do not qualify as transmission systems. Further revisions to HI-TPL-001 are required for multiple contingency events, both loss of generation and/or loss of transmission elements.

The more stringent HI-TPL-001 criteria for Oʻahu is designed to minimize the risk of deep load shed events, and potential island-wide blackouts with an appropriately sized FFR resource such as a BESS which become more likely in the future with even more distributed PV. Under high levels of distributed PV penetration, the residential load net of PV is reduced so UFLS schemes are less effective, compromising system security. UFLS is designed to shed low impact loads and avoid critical load like hospitals, emergency responders, military bases, schools, etc. The proliferation of distributed PV is primarily on residential distribution circuits so the daytime UFLS capacities continue to degrade and it is becoming more difficult to find sufficient load to shed during a single contingency event. Additionally, the more stringent criterion support the use of distributed resources to supply fast frequency response. Load shedding of the

[14] Under-frequency load shedding (UFLS) is a means to restore system frequency to operating equilibrium for various loss of generation contingency events. Ultimately, it is the last line of defense of system security to prevent system blackouts but it has shortcomings for future conditions in Hawaiʻi.

distribution system, as allowed under the previous criteria, would be counterproductive since it would disconnect demand response resources from the system.

The limited system security analysis for Hawaiʻi Island was expanded to simulate the impacts of transmission faults that cause loss of generation contingency events for selected resource plans. Hawaiʻi Island's transmission infrastructure covers a very large territory that increases its exposure to electrical faults that can cause large capacities of DG-PV to disconnect from the system. Additional analyses were performed to determine FFR and PFR requirements to ensure system security for Hawaiʻi Island and should be indicative findings when these analyses are conducted for the preferred plan.

Fundamentally, distributed generation (primarily PV) poses one of the biggest challenges to system security because it imposes conflicting requirements on the electrical system: 1) the reduction of system load displaces synchronous generators and 2) distributed resources increases regulating and frequency response reserve requirements that are traditionally provided by synchronous generators. More specifically, transformation of the electrical system must address the following system security issues:

- DG-PV displaces synchronous generators that provide essential grid services like inertia, regulating reserves, and system fault current.
- DG-PV reduces the capacity of the system's under frequency load shed scheme (UFLS).
- Legacy DG-PV and their less flexible frequency ride through ability increases the magnitude of a loss of generation or fault contingency.
- DG-PV is currently not controllable by and is invisible to the system operator.

The process of identifying needs and designing solutions follows a several-step process that we believe addresses the Commission's concerns regarding the prior PSIP filing. (Note that this process was outlined as six steps in the Companies' February 2016 filing. The revised process is equivalent, but reorganized to complement the rest of the PSIP more clearly.) The five steps are:

1. Establish operational reliability criteria.
2. Define technology-neutral ancillary services for meeting reliability criteria.
3. Determine the amount of ancillary services needed to support the resource plan.
4. Find the lowest reasonable cost solution, considering all types of qualified resources.
5. Identify flexible planning and future analyses to optimize over time.

The amounts of each type of ancillary service needed to meet system security vary by island, resource plan, and time period. That is because Frequency Response needs are driven by the size of the largest contingency event, which is generally the loss of the largest unit online at the time (combined with potential sympathetic loss of legacy DG-PV). Regulation needs are driven by the variability of net load (that is, load minus variable generation output), which depends especially on the amount of PV and wind, and Replacement Reserve needs are driven by the amounts of Frequency Response and Regulation needed after an event.

The Companies defined fast frequency response and primary frequency response requirements in technology-neutral terms so any qualified resource can meet them, whether traditional generation, advanced features of inverter-interfaced generation and storage, or demand response. Our objective is to identify the lowest reasonable cost combination that ensures system security for a given resource plan and in subsequent iterations, let the market and specific resource applications determine available resources. To do so, we break the analysis into three steps:

1. Construct an initial pre-DR solution that meets system security needs;
2. Substitute DR to the full extent it is cost-effective, producing a revised resource strategy;
3. Consider whether the solution would affect system conditions (especially unit commitment and dispatch, affecting inertia and the amount of Primary Frequency Reserves available) to warrant another iteration of analysis.

There was not sufficient time to complete these three steps for the preferred plans. These steps will be done in conjunction with development of the Demand Response Programs.

#6. ANCILLARY SERVICES

As part of this filing, the Companies' analyses began with the establishment of operational reliability criteria and the refinement of grid service definitions sufficient to meet these reliability criteria. This refinement of ancillary services was grounded in the definitions of grid services found in the Supplemental Report filed under Docket No. 2007-0341, filed November 30, 2015.

In particular, Fast Frequency Response (FFR) was refined into several sub-categories of FFR, including: Instantaneous Inertia (II), Primary Frequency Reserves (PFR), Fast Frequency Reserves 1 Up (FFR1Up) and 2 Up (FFR2Up), and Fast Frequency Reserves Down (FFRDown). Further, Supplemental Reserves was recast to Replacement Reserves (RR) and Regulating Reserves was refined to Regulation Reserves Up (RegUp) and Regulating Reserves Down (RegDown). The Companies then revised these ancillary services needs for the O‘ahu cases.

These revised ancillary service needs for O‘ahu were coupled with the existing needs defined for the other island systems and a set of resources that are capable of cost-effectively meeting the ancillary service needs were identified. Included in this resource pool was utility-scale, centralized energy storage resource options as well as a DR portfolio that included the use of distributed, behind-the-meter storage options. As part of the DR optimization effort, the Companies developed respective optimal and most cost-effective implementation of the combination of these resources. The final optimized potential of distributed storage will be iterated and refined prior to filing the Final DR Program Portfolio application.

Consistent with the previous methodology applied during the development of the Interim DR Program Portfolio application (Docket No. 2015-0412), the Companies assessed the quantities of these service needs over a 30-year horizon and developed the value of these services by virtue of the costs associated with delivering them. With these values defined, the Companies were then positioned to assess substitution opportunities for delivering these services via the most cost-effective means possible.

The DR portfolio, utilizing a growing population of DERs, was considered as a cost effective substitution option for delivering these ancillary services. The Companies refined the DR portfolio based on previous feedback in an attempt to find the lowest reasonable cost solution considering all types of qualified resources for all islands. The Companies then identified flexible planning and future analyses to optimize the DR portfolio over time. This process is not complete, but will continue until the Final DR Program Portfolio application is filed in mid-2016.

Finally, the Companies updated our Must-Run Generation Reduction Plans and Generation Flexibility Plans to include these ancillary service refinements.

#7. INTER-ISLAND TRANSMISSION

Our PSIP analyses show that, for O‘ahu to achieve 100% renewable energy in 2045, significantly greater off–island renewable resources will be required (if found to be more cost effective than biofuels).

Analysis performed in this updated PSIP has shown that O‘ahu would require more offshore capacity than was included in our 2014 PSIP assumptions. Because of this, we plan to further analyze an array of inter-island transmission options after April 1, 2016. A plan for addressing the interisland transmission analysis is discussed in Chapter 9: Next Steps. In conjunction with the analysis, we also plan to further investigate offshore wind.

#8. IMPLEMENTATION RISKS AND CONTINGENCIES

Our Decision Framework contains nine risks and uncertainties that we used as part of our assessment to develop our 2016 updated PSIP. The risks identified in the Decision Framework were used as parameters in the selection of representative resource plans for each Theme on each island and ultimately to select each island's Preferred Plan.

Chapter 3 describes the multiple initial cases, which were specifically designed to iterate toward a low-cost objective. The impact of accelerating the implementation of renewable energy resources, LNG and generation modernization, while accounting for risks attributed to changes in fuel prices for both LNG and oil, were evaluated. We refined these cases to incorporate results from preceding runs of DER, DR, and utility-scale resource iterative cycles, iterated to achieve low-cost and minimized risk objectives, and analyzed grid modernization to characterize tradeoffs and risks of capital investments.

We ran production simulation using different modeling software (via consultants) for comparative purposes, conducted stochastic analysis to characterize risks associated with fuel price forecasts (through Ascend Analytics as described above), and ran sensitivity analyses using high and low fuel price forecasts.

We calculated present values of revenue requirements, and the relative difference in revenue requirements between cases for initial cases. Capital expenditure constraints were considered as described above. Using the Decision Framework, the Preferred Plans were selected and five-year action plans to implement the Preferred Plans were developed. It should be noted that with the exception of Theme 2 which requires LNG, generation modernization, and unit conversions, the near term actions for all final plans are very similar.

3. Planning Themes and Candidate Plans

The overall plan development and selection process was iterative in nature. The general process was:

First iteration consisted of the development of initial cases that were discussed in the PSIP Update Interim Status Report filed February 16, 2016.

Second iteration expanded the number of cases from the first iteration to evaluate numerous other alternative cases as candidate plans under three themes.

- Theme 1 is a path to accelerate pursuing 100% renewable energy with minimal imported liquid biofuels.
- Theme 2 is a path to achieve 100% renewable energy with LNG as a transitional fuel.
- Theme 3 is a path to achieve 100% renewable energy without LNG as a transitional fuel.

Third iteration refined a smaller set of candidate plans under each theme using knowledge gained from the analysis through the second iteration.

Final plans, one under each theme, were selected based on the results from the third iteration.

Figure 3-1 illustrates the general overview of the process.

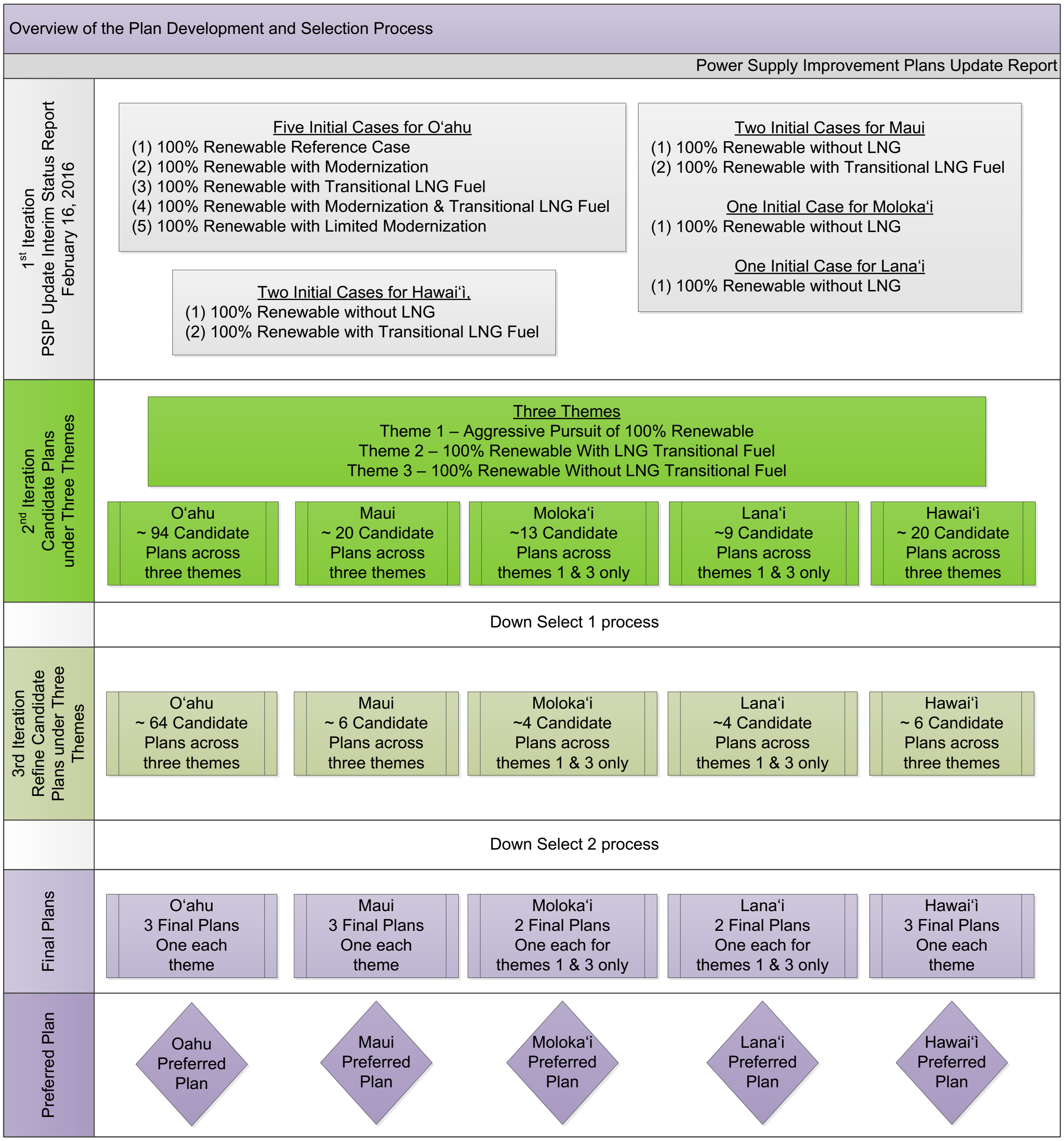


Figure 3-1. Overview of the Plan Development and Selection Process

DEVELOPMENT OF CANDIDATE PLANS

Numerous unique 30-year resource plans ("cases") across the five islands served by the Hawaiian Electric Companies were developed by specifically considering the following:

- Three major paths—themes—for achieving 100% renewable energy by 2045.
- Decision variables based on the Commission's Observations and Concerns, and input from stakeholders.
- System specific considerations (for example, island specific levels of resource availability, current levels of RPS attainment, resource availability on a specific island).

The cases were evaluated, screened to select plans for further consideration, and then further screened to select an optimal resource plan for each of the three Themes. This chapter explains the process for building the candidate plans, the criteria and processes used to evaluate the plans, the major findings as we evaluated and screened the plans, and the resulting final plans – one plan for each theme.

As noted earlier, the themes and decision variables applied in the second and third iterations.

Because of the large volume of analytical work performed in the second and third iterations and it is impractical to explain each step and every decision made in each iteration, the following sections should be considered a narrative of the process as it applied primarily to the third iteration. Some of the same steps were used in the second iteration and it would be redundant to repeat them below. The third iteration is the most relevant since it is the basis from which the final decisions were made.

The Three Themes

The Companies recognize that there are different visions for attaining 100% renewable energy. Accordingly, we developed different resource plans around three major themes.

- Theme 1 accelerates renewable energy (RE) deployment across the Hawaiian Electric territories and achieves 100% RE in 2030 for Maui, Moloka‘i, Lana‘i, and Hawai‘i Island and in 2045 for O‘ahu, uses imported liquid biofuels sparingly for firming purposes, does not use LNG, and maximizes use of non-fuel burning RE resources like PV, wind, and geothermal. Theme 1 could be implemented under a merged or an unmerged scenario.
- Theme 2 meets interim RPS mandates across the Hawaiian Electric territories on-time and achieves 100% RE in 2040 for Maui, Moloka‘i, Lana‘i, and Hawai‘i Island and in 2045 for O‘ahu , balances the use of both fuel and non-fuel burning RE, and uses LNG.

Because NextEra Energy's financial backing is required to implement Theme 2, this Theme can be considered a "merged" scenario where the proposed merger of the Companies and NextEra Energy is completed.

- Theme 3 meets interim RPS mandates across the Hawaiian Electric territories on-time and achieves 100% RE in 2040 for Maui, Molokaʻi, Lanaʻi, and Hawaiʻi Island and in 2045 for Oʻahu, balances the use of both fuel and non-fuel burning RE, and for planning analysis, presumes that LNG is not available. Theme 3 could be implemented under a merged or an unmerged scenario.

Error! Reference source not found. summarizes the three major themes.

Theme Element	Theme 1	Theme 2	Theme 3
Short Description	Accelerate Renewables	Renewables With LNG	Renewables Without LNG
Theme Description	Accelerate renewables using DER, variable renewable resources, energy storage (if necessary) and minimal liquid biofuels on Oʻahu. Accelerate renewables using firm renewable energy resources, variable renewable energy resources, energy storage (if necessary) and minimal imported liquid biofuels on the neighbor islands. 100% renewable energy generation by 2030 on neighbor islands and 2045 on Oʻahu.	Meet the RPS milestones (as presently defined) on a state-wide basis using DER, LNG, firm (if available) and variable renewable resources, energy storage (if necessary). 100% renewable energy generation by 2040 on Maui and Hawaiʻi island and 2045 on Oʻahu.	Meet the RPS milestones (as presently defined) on a state-wide basis using DER, firm (if available) and variable renewable resources, energy storage (if necessary). 100% renewable energy generation by 2040 on Maui, Molokaʻi, Lanaʻi, and Hawaiʻi island and 2045 on Oʻahu.
LNG	No LNG	LNG 2021–2040	No LNG
Merger	Unmerged.	Requires merger.	Unmerged.
100% Renewable Energy Achievement	2030 RE on Maui, Hawaiʻi Island 2030 RE on Molokaʻi, Lanaʻi 2045 RE on Oʻahu	2040 RE on Maui, Hawaiʻi Island 2045 RE on Oʻahu (Not applicable to Molokaʻi & Lanaʻi)	2040 RE on Maui, Hawaiʻi Island 2040 RE on Molokaʻi, Lanaʻi 2045 RE on Oʻahu
Renewables	Maximize use of variable, non-fuel burning renewable resources, including DER. Use firm renewables (for example, biomass, geothermal) when cost effective vs. variable renewables.	Balance of non-fuel burning renewable resources and firm renewable resources.	Balance of non-fuel burning renewable resources and firm renewable resources.
DG-PV	High	High and Market evaluated	High and Market evaluated
Demand Response	All cases in all themes employ demand response to provide grid services. Quantities and pricing based on DR market potential study and avoided cost iterations.		

Table 3-1. Summary of the Three Themes

Selection of Decision Variables

Decision variables can be varied to test the suitability of different combinations of supply side resources and fuel, energy storage, and demand-side resources for achieving the Objectives. Decision variables include resources and programs that can be leveraged by the utility in a given plan to achieve the Objectives. Decision variables were developed by specifically considering the Commission's Eight Observations & Concerns, and high impact variables.

Table 3-2 summarizes the decision variables selected, how they address the eight Observations and Concerns, and how they were applied in the analyses of the various cases.

Decision Variable	Eight Observations & Concerns	Context and Application of the Decision Variable
Primary Fossil Fuel	O&C #4: Proposed plans for fossil-fueled power plants not sufficiently justified.	Fossil generation plans were evaluated by considering alternate fuel price scenarios, cost-effective fossil generation replacement plan consistent with high renewable strategy, and a long-term fuel supply strategy to minimize fuel cost and price volatility risk. Plans were evaluated under February 2016 EIA STEO and 2015 EIA Reference fuel price scenarios.
Energy Storage	O&C #2: PSIPs do not appear to aggressively seek lower-cost, new utility-scale renewable resources (requests to identify and consider key enabling technologies to support renewable strategy e.g. bulk energy storage). O&C #6: Proposed plan for provision of ancillary services lacks transparency and may not be most cost-effective option (requests to review proposed energy storage resources to determine and demonstrate optimal, cost-effective sizing and utilization strategies).	Updated resource capital cost forecasts suggest battery-based storage technology costs are forecast to decrease dramatically (in real terms), which may lead to storage playing a critical role in attaining 100% RPS. Pumped storage hydro (PSH) was evaluated as a storage resource option. Resource capital cost forecasts show flat capital costs for PSH (in real terms). Based on these and other factors, energy storage was considered as an option in a number of plans and compared to other options for renewable resource management (e.g. renewable resource curtailment, use of firm renewables that do not require storage) varied across islands in the cases. PSH was evaluated as a resource on applicable islands. Plans were evaluated without must-run fossil fueled generation after a particular date (2022 for O'ahu for Theme 2 and 2025 in Themes 1 and 3; 2022 for Maui; 2016 for Moloka'i and Lana'i; and 2019 for Hawai'i island). This enabled other resources, such as demand response and energy storage (batteries, PSH or flywheels) to have a fair opportunity to provide cost-effective ancillary services (frequency response and frequency regulation), and other options, such as synchronous condensers, to provide voltage regulation in lieu of a thermal generation in order to accept more renewable energy. After the resource plans were constructed, system security requirements were reassessed and if other resources such as demand response and energy storage were not of sufficient capacity to cover all of the system needs, minimal thermal generation was added to serve those needs.

Decision Variable	Eight Observations & Concerns	Context and Application of the Decision Variable
Utility-Scale Renewables	O&C #2: PSIPs do not appear to aggressively seek lower-cost, new utility-scale renewable resources (requests to optimize renewable resource portfolio alternatives considering full potential of available renewable resource options without unsubstantiated constraints; identify actions to support acquisition of near-term cost-effective RE projects to meet 2020 RPS; and develop strategic direction and decision rules for cost-effective high renewable strategy).	The updated resource cost forecasts show variable renewable resource capital costs are expected to decline modestly (in real terms) through the study period. The updated resource availability potential study performed by NREL shows variable renewable resource (i.e. wind and solar-PV) potential is high on neighbor islands, but constrained on O‘ahu. Several developers are proposing offshore wind projects to serve O‘ahu. Inter-island cable(s) may provide a means of delivering renewable energy to O‘ahu from resources located on the neighbor islands. Based on these and other factors including RPS attainment, amount and type of renewable resource was varied by island in the cases. While inter-island cable scenarios will be examined further beyond the date of this filing, offshore wind was considered in the O‘ahu cases; these cases serve as a proxy for non- O‘ahu sited renewable resources that could serve O‘ahu through an inter-island cable.
Renewable Energy Percent Timing	O&C #2: PSIPs do not appear to aggressively seek lower-cost, new utility-scale renewable resources (requests to optimize renewable resource portfolio alternatives considering full potential of available renewable resource options without unsubstantiated constraints; develop and implement Lana‘i and Moloka‘i High RE plans; and develop strategic direction and decision rules for cost-effective high renewable strategy).	The following 100% RPS and 100% renewable energy (RE) generation attainment schedules were considered: ▪ Accelerate RE reaching 100% RE by 2030 on the neighbor islands. (Theme 1) ▪ 100% RE achievement by 2040 or 2045 on Maui and Hawai‘i Island and 2040 on Moloka‘i and Lana‘i. (Themes 2 and 3). ▪ 100% RE achievement by 2045 on O‘ahu.
DG-PV Amount	O&C #3: PSIPs do not adequately address utilization and integration of DER (requests to include DER in overall system optimization instead of "treating DG-PV as an end state", to explicitly consider integration costs, and to consider the role and potential contribution of DER in high-RPS attainment scenarios).	Market DG Scenario: DG PV adoption was forecast with DG export compensation based on utility-scale PV equivalent. This allows DG-PV customers to provide cost-effective grid services, while also optimizing system costs. High DG Scenario: DG-PV adoption was forecast assuming compensation meaningfully higher than utility-scale PV equivalent, driving higher DG-PV adoption at an incrementally higher cost than other similar resources. Both DG-PV adoption scenarios account for integration costs. In the market DG-PV" forecast, adoption was re-calculated under the system upgrade costs attributable to DG-PV customers and was allocated to those DG-PV customers. DG-PV integration costs presume advanced inverter functionality to provide a level of voltage response and the ability to allow for remote monitoring and control.

Decision Variable	Eight Observations & Concerns	Context and Application of the Decision Variable
Demand Response	O&C #3: PSIPs do not adequately address utilization and integration of DER (requests evaluation of full spectrum of DER in analysis, including distributed energy storage). O&C #6: Proposed plan for provision of ancillary services lacks transparency and may not be the most cost-effective option (requests evaluation and consideration of potential contributions from all potential sources of grid services including DER and DR).	All cases analyzed for the PSIP assume that demand response programs will be in place to leverage DESS and DR resources to provide ancillary services based on the potential study and avoided cost methodology.

Table 3-2. Application of Decision Variables on the Eight Observations and Concerns

O‘ahu Decision Variables

In addition to the general application of the decision variables across all islands, Table 3-3 summarizes specific considerations for applying the decision variables to O‘ahu cases.

Decision Variable	O‘ahu Drivers	Context and Application of the Decision Variables Specific to O‘ahu
Primary Fossil Fuel	O‘ahu's energy requirements allow volumes of alternative, low-cost, clean fuels (for example, LNG) to be feasible.	Analyze LNG (with new 3x1 Kahe combined-cycle) under Theme 2 and plans without LNG under Themes 1 and 3. Analyze plans under February 2016 EIA STEO and 2015 EIA Reference fuel price scenarios.
Energy Storage	O‘ahu may require energy storage in order to integrate large quantities of variable renewables required late in the planning period.	Analyze cases with and without storage. Consider economics of storage to avoid over-generation of renewable energy vs. economics of using curtailed (dispatched) variable energy as an operational resource.
Utility-Scale Renewables	O‘ahu is constrained in its ability to site on-island variable renewable resources (based on NREL resource potential study).	Maximize the remaining potential on O‘ahu. Evaluate off-island resources (offshore wind or inter-island cable(s)).
Renewable Energy Percent Timing	O‘ahu is constrained in its ability to site on-island variable renewable resources (based on NREL resource potential study). There may be a desire by some to limit the use of liquid biofuels on O‘ahu.	Consider strategies for achieving RPS and RE goals by accelerating achievement of RPS milestones on the neighbor islands, and appropriate compensation mechanisms to those customers, allowing time to develop solutions for O‘ahu that will be required late in the study period (that is, 2040–2045). Consider strategies for utilizing biofuels in a more strategic manner (that is, backup for variable renewables).
DG-PV Amount	In all cases, DG-PV plays an important role in achieving 100% RE on O‘ahu.	Analyze the cost effectiveness of DG-PV under a market based DG-PV scenario (whereby DG-PV is compensated based on the value of utility-scale PV) versus a high DG-PV scenario (whereby a premium is paid for DG-PV output relative to utility-scale PV).
Demand Response	In all cases, DR can play a role in providing grid services on O‘ahu.	Analyze and optimize the uptake of DR programs based on its potential and its value, based on an avoided cost analysis.

Table 3-3. Decision Variable Applications for O‘ahu Cases

Hawai'i Island Decision Variables

Table 3-4 summarizes specific considerations for applying the decision variables to Hawai'i Island cases.

Decision Variable	Hawai'i Island Drivers	Context and Application of the Decision Variable Specific to Hawai'i Island
Primary Fossil Fuel	Use of LNG on Hawai'i Island will require transport of LNG and conversion of units to burn LNG.	Evaluate feasibility of use of LNG on Hawai'i Island, taking into account that volumes not used on Hawai'i island will need to be used on O'ahu to maintain LNG pricing. Analyze plans under February 2016 EIA STEO and 2015 EIA Reference fuel price scenarios.
Energy Storage	Hawai'i Island already has a high penetration of variable renewable resources. However, Hawai'i Island has virtually unlimited variable resource potential (according to the NREL resource potential study).	Evaluate firm renewables versus controllable variable renewables and energy storage.
Utility-Scale Renewables	Hawai'i Island can support variable renewables (wind and solar PV) and firm renewables (biomass, geothermal). However, wind available on Hawai'i Island has a much higher capacity factor than utility-scale solar PV.	Evaluate firm renewables versus controllable variable renewables and energy storage.
Renewable Energy Percent Timing	Hawai'i Island is already close to 50% RE (48.7% in 2015), achieved with geothermal and variable renewables.	Evaluate firm renewables versus controllable variable renewables and energy storage.
DG-PV Amount	In all cases, DG-PV plays an important role in achieving 100% RE on Hawai'i Island.	Analyze the cost effectiveness of DG-PV under a market based DG-PV scenario (whereby DG-PV is compensated based on the value of utility-scale PV) versus a high DG-PV scenario (whereby a premium is paid for DG-PV output relative to utility-scale PV).
Demand Response	In all cases, DR can play a role in providing grid services on Hawai'i island.	Analyze and optimize the uptake of DR programs based on its potential and its value, based on an avoided cost analysis.

Table 3-4. Decision Variable Applications for Hawai'i Island Cases

Maui Decision Variables

Table 3-5 summarizes specific considerations for applying the decision variables to Maui cases.

Decision Variable	Maui Drivers	Context and Application of the Decision Variable Specific to Maui
Primary Fossil Fuel	Use of LNG on Maui will require transport of LNG and conversion of units to burn LNG.	Evaluate feasibility of use of LNG on Maui, taking into account that volumes not used on Maui will need to be used on O'ahu to maintain LNG pricing. Analyze plans under February 2016 EIA STEO and 2015 EIA Reference fuel price scenarios.
Energy Storage	Maui already has a high penetration of variable renewable resources (and some energy storage associated with renewable resources). However, Maui has substantial variable resource potential (according to the NREL resource potential study).	Evaluate firm renewables versus variable renewables and energy storage.
Utility-Scale Renewables	Maui faces a capacity shortfall beginning in 2016. with the retirement of HC&S generation and increasing capacity shortfall with the retirement of the Kahului station in 2022.	Evaluate suitability of variable renewable resources versus firm renewable resources Evaluate capacity need to determine size and type of new firm resources Evaluate potential benefits to Maui from a grid-tie with O'ahu.
Renewable Energy Percent Timing	Maui (including Moloka'i and Lana'i) achieved 35.4% RPS in 2015, achieved mostly with variable renewables.	Evaluate firm renewables versus variable renewables and energy storage.
DG-PV Amount	In all cases, DG-PV plays an important role in achieving 100% RE on Maui.	Analyze the cost effectiveness of DG-PV under a market based DG-PV scenario (whereby DG-PV is compensated based on the value of utility-scale PV) versus a high DG-PV scenario (whereby a premium is paid for DG-PV output relative to utility-scale PV).
Demand Response	In all cases, DR can play a role in providing grid services on Maui.	Analyze and optimize the uptake of DR programs based on its potential and its value, based on an avoided cost analysis.

Table 3-5. Decision Variable Applications for Maui Cases

Lana'i and Moloka'i Decision Variables

Table 3-6 summarizes specific considerations for applying the decision variables to Lana'i and Moloka'i cases.

Decision Variable	Lana'i and Moloka'i Drivers	Context and Application of the Decision Variable Specific to Lana'i and Moloka'i
Primary Fossil Fuel	Lana'i and Moloka'i loads are too small to justify shipments of LNG. Lana'i operates a CHP plant for one of its largest customers.	Evaluate feasibility of small ICE units fired with diesel fuel versus variable renewables. Analyze plans under February 2016 and 2015 EIA Reference fuel price scenarios.
Energy Storage	High variable renewable penetrations will require energy storage to meet the energy needs.	Evaluate energy storage in conjunction with variable renewables.
Utility-Scale Renewables	There is adequate wind and solar PV potential on Moloka'i and Lana'i.	Large scale wind turbines (greater than 1 MW class turbines) will be expensive to build due to mobilization costs. Consider utility-grade small wind turbines (100 KW class turbines) that can be erected without heavy cranes, and solar PV.
Renewable Energy Percent Timing	There is an opportunity to accelerate attainment of 100% RE by 2030.	Build Moloka'i and Lana'i cases to achieve 100% RE by 2030 and 2040.
DG-PV Amount	Moloka'i has significant penetrations of DG-PV.	Consider integration costs for higher penetrations of DG-PV on Moloka'i.
Demand Response	DR may be possible on Moloka'i and Lana'i but may be limited by small scale.	Analyze and optimize the uptake of DR programs based on its potential and its value, based on an avoided cost analysis.

Table 3-6. Decision Variable Applications for Lana'i and Moloka'i Cases

Development of Cases for Evaluation

The decision variables described in the previous sections were combined to develop unique cases for modeling and analysis. In general, the cases were designed around various combinations of the decision variables in order to create an array of possible plans or cases. In addition, each case was tested against fuel price inputs representing a February 2016 EIA STEO fuel price projection and a 2015 EIA Reference fuel price projection.

- For O'ahu, a total of 168 cases were developed.
- For Hawai'i Island, a total of 30 cases were developed.
- For Maui, a total of 31 cases were developed.
- For Lana'i, a total of 13 cases were developed.
- For Moloka'i, a total of 17 cases were developed.

Resource Plan Development Process

For each case, a resource plan was developed. In order to determine near-optimal resource sizing, types and timing, a spreadsheet tool was developed. The tool identifies what new resource is cost-effective when, and how much that new resource can be curtailed while remaining cost-effective. This tool compares the cost of new resources to that of existing resources, and the amount of curtailment up to which that new resource is still lower cost than existing resources. It indicates when new cost-effective resources should be introduced into a plan. Figure 3-2. compares forecasted resource rates on Maui in 2030.

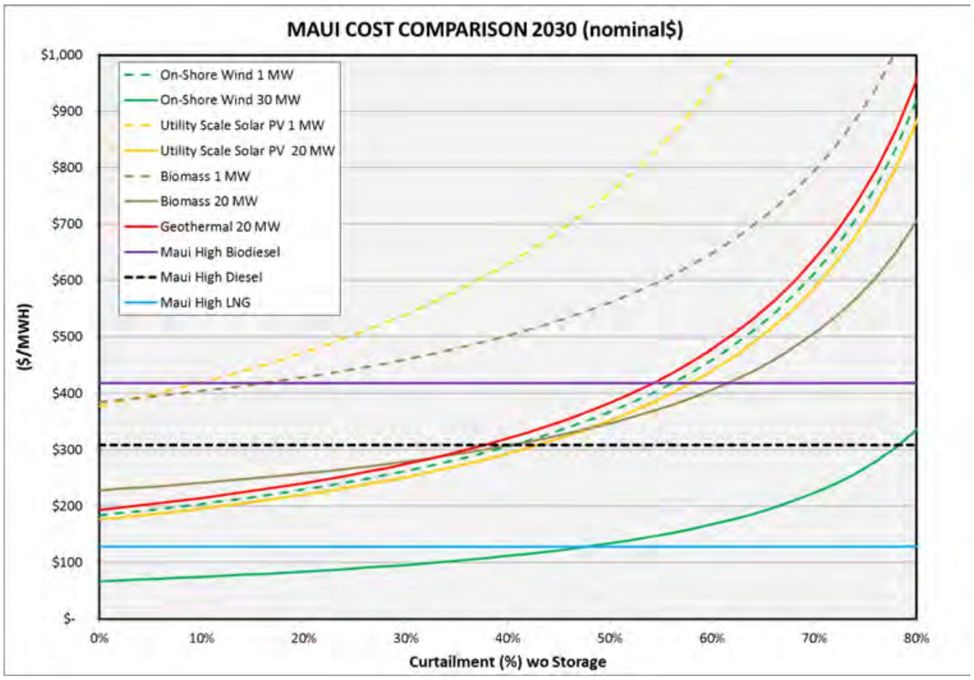


Figure 3-2. Forecasted Resource Cost Comparison: Maui

The y-axis represents the levelized cost per MWh of a resource, and the x-axis represents an approximation of the resource cost under increasing levels of over-generation from variable resources. It was assumed that if less energy is accepted by the system, the cost per MWh would be greater, which is shown by the up sloped lines. The horizontal lines represent the approximate operational cost of an existing generating asset in a future year (2030 in this example) under various fuel prices. Therefore, resources that fall below horizontal lines suggest cost effect resources when compared to an existing generating unit under a forecasted fuel price.

Long-term resource plans out to 2045 were developed with the help of this tool.

The list of all cases and the resulting resource plans developed for each case are included as Appendix K.

EVALUATION PROCESS

Evaluation Criteria

The criteria for evaluating the various plans are based on the Objectives. The primary objectives are:

- Achieve the lowest cost for our customers.
- Minimize risk to our customers.

In general, if a plan does not meet the primary objectives it is dropped from further consideration.

Important, but secondary, objectives include:

- Types of resources to meet state renewable energy goals.
- Reduce emissions.

Plans that remain after meeting the primary objectives were evaluated against these additional objectives.

Table 3-7 summarizes the objectives and evaluation criteria that were used to evaluate the cases.

Objectives		Evaluation Criteria	Description	Metric
Primary Objectives	Achieve Lowest Cost for Customers	Plan NPV Revenue Requirement	Net present value of revenue requirements associated with each resource plan. At the first level filter, this includes only incremental resource plan costs and total fuel costs.	Resource plan NPV
		Retail Rate Impact	This is a comparison across plans of the total retail rate to full-service customers.	Full-service customer retail rate.
		Average Customer Bill	This is a comparison across plans of the average monthly customer bill for a 500 KWH/month customer.	Full-service customer average monthly bill.
		Capital Investment Requirements	This is the total capital requirement associated with a plan, including utility capital, IPP capital and customer capital.	Total capital and total capital by year.
		Fuel Cost Exposure	This is the total fuel cost associated with a given resource plan. This is an indicator of the relative exposure to fuel cost among candidate plans.	Total NPV fuel cost.
	Minimize Risk to Customers	Plan Flexibility	This considers the ability of the plan to accommodate disruptive changes during the planning period.	Inspection of plans

Objectives		Evaluation Criteria	Description	Metric
		Plan Implementation Risk	This considers the risk in implementing a given plan. Does the plan include technologies that may be difficult to permit and finance? Does the plan overly rely on a certain type of resource? Are the risks inherent in the plan near-term or long-term risks?	Inspection of plans.
		Stranded Cost Risk	This considers the risk that a major capital project will become economically obsolete during its life.	Inspection of plans.
		Fuel Price Volatility	This considers the resilience of the plan to different fuel price scenarios.	Evaluate the plans under a range of fuel prices.
Secondary Objectives	Meet State Energy Policy Goals	Renewable Portfolio Standard	Does the plan meet the RPS statute as it currently exists?	% RPS attainment (current definition)
		Renewable Energy Generation	Does the plan attain a 100% renewable energy generation portfolio?	% of total energy generated with renewable energy resources.
		DER Utilization	Does the plan accommodate customer choice? Does the plan cost effectively utilize DER?	Market DG-PV levels High DG-PV levels Demand response utilization
	Reduce Emissions	Estimate emissions	What are the estimated CO_2 emissions of the plan?	Tons of CO_2 emissions

Table 3-7. Planning Objectives and Evaluation Criteria

Screening Process

Candidate Plans. As described above, candidate plans were created based on the themes, decision variables, and fuel scenarios.

First Iteration

The first iteration involved the development and analysis of plans for the Companies' PSIP Update Interim Status Report, which was filed on February 16, 2016. The case runs, logic and considerations in developing the cases, and comparative results of the cases runs were all presented in the Interim Status Report.

As stated in the report, in this first iteration, optimized demand response programs were included in the analysis of the plans for O'ahu. For the neighbor islands, demand response program information was not yet available so they were not included in the neighbor island analyses at that point.

In addition, the fuel price forecasts used in the first iteration were based on the 2015 EIA Reference, 2015 FAPRI Reference, and 2015 EIA Average Henry Hub Spot Prices for

Natural Gas fuel price forecasts, and the February 2016 Forward/Hybrid Curve, 2015 FAPRI Low, and Chicago Mercantile Exchange Henry Hub Natural Gas Futures (Escalated) fuel price forecasts.

In this first iteration, plans were developed for all islands to achieve 100% renewable energy by 2045 and biofuels were used liberally to help meet the 100% renewable energy requirement.

Second Iteration

The second iteration constructed candidate plans under the three themes discussed previously for various sizes, types and timing of renewable energy and energy storage additions. This is discussed in more detail below.

In addition, an updated February 2016 EIA STEO Price Forecast for oil and LNG was developed and used. This February 2016 EIA STEO Price Forecast was based on the EIA's Short-Term Energy Outlook (STEO). This was used in lieu of the February 2016 Forward/Hybrid Curve and the Chicago Mercantile Exchange Henry Hub Natural Gas Futures (Escalated) fuel price forecasts. The biofuel forecast was also revised to correct an anomaly in the later years of the forecast.

In contrast with the first iteration, options for the neighbor islands to achieve 100% renewable energy sooner than 2045 were evaluated. This is because O‘ahu's demand is much higher than that of the neighbor islands (in fact, O‘ahu's peak demand is over twice as high as the peak demand of all of the neighbor islands combined) while O‘ahu's on-island renewable energy potential is lower than that of the neighbor islands. Therefore, the neighbor islands may need to accelerate their renewable energy integration in order for the RPS requirements to be cost-effectively met across the Hawaiian Electric territories.

For the neighbor islands in this second iteration, alternative renewable energy resources to biofuels were used to help meet the 100% renewable energy requirement.

NPV Screen. The revenue requirements for each candidate plan were determined based on the resource plan, the production simulations for the given resource plan (which provides fuel cost, O&M costs, renewable curtailment, and reliability indicators), and the fixed revenue requirements associated with the resource plan.

Down Select 1. The first set of candidate plans was selected based on the net present value of revenue requirements associated with each case. Plans were selected under both 2015 EIA Reference and February 2016 EIA STEO fuel price forecasts, which bracketed the plans within future fuel price scenarios. Representatives from the Consumer

Advocate, DBEDT, and County of Hawai‘i were present in the room and via a web meeting link during this process.

Refine Remaining Cases 1. The remaining cases were analyzed and discussed using the evaluation criteria. Refinements to the cases were identified. Representatives from the Consumer Advocate, DBEDT, and County of Hawai‘i were present in the room and via a web meeting link during this process. Based on the identified refinements, the planning teams then processed new runs of the production simulations and revenue requirements for the remaining cases.

Third Iteration

As a result of the insights provided by the second iteration, the candidate plans were adjusted. In addition, new information was integrated into the analysis.

For the neighbor islands, plans were optimized to lower plan costs by reducing biofuel usage and increasing renewable energy and energy storage resources.

In this iteration, circuit-level integration costs were developed and used in the plan analyses. These circuit-level integration costs included items such as service transformer upgrades, conductor upgrades, distributed energy storage and communication and controls for advanced inverters. In addition, in order to achieve a high level of DG-PV, it was assumed that customers would need to be incentivized with higher credits for exporting their energy to the grid. This was captured in the analysis.

Within this iteration, a re-optimized demand response package was analyzed on a limited basis to determine its impact on the overall costs. The impacts appeared minimal. Furthermore, tests were conducted to determine if distributed energy storage could be a cost-effective substitute for bulk load-shifting energy storage. This did not appear to be the case due to the economy of scale provided by bulk energy storage.

In addition, because it was assumed the fixed costs for LNG would be allocated among the islands proportionately by volume consumed, cost allocations were recalculated based on the results of the case runs. These reallocated costs were folded into the overall financial analysis.

Also within this phase, adjustments were made in the neighbor island analyses to remove all must-run constraints in order to better determine how ancillary services could be most cost-effectively provided, whether by operating a generating unit or by some other resource, such as demand response, energy storage or synchronous condensers.

Review and Assess First Set of Refined Cases. The next set of case analyses and results were presented by the planning teams for each island. Each case was analyzed by comparing NPV revenue requirements, customer bill impacts, DER feasibility and renewable energy attainment. Each case was discussed in the context of risk factors and other decision variables. Representatives from the Consumer Advocate and DBEDT were present in the room and via a web meeting link during this process. The County of Hawai'i representative was not available for this process.

Down Select 2. During the review and assessment of the first set of refined cases, a number of issues were identified for further investigation and analysis. Certain adjustments to various cases were identified for additional analysis.

Refine Remaining Cases 2. Based on these issues and refinements, the planning teams then processed additional runs of the production simulations and revenue requirements for the cases.

The primary goal of this process was to select one final plan under each theme.

The three fundamental decisions to be made were:

- LNG or No LNG
- High DG-PV or Market DG-PV
- 100% RE in 2040 or 2045 for the neighbor islands.

Plans were developed for different possible futures – 2015 EIA Reference / February 2016 EIA STEO Fuel Prices and High/Market DG-PV.

Review and Assess Second Set of Refined Cases. The second refinement of the cases were presented to the Hawaiian Electric Companies' executive team. Minor changes and additional analyses to address executive questions and comments were identified.

Select Plans. The final plans for each Theme were selected.

Final Review. The final plans for each Theme were reviewed.

Final Theme Plans. Final plans for each theme were documented for determination of the Preferred Plan.

EVALUATION PROCESS AND RESULTS

O'ahu Results

Down Select 1 – O'ahu

The primary purpose of the Down Select 1 was to apply a revenue requirements filter to the various candidate plans to select the lowest cost plans under 2015 EIA Reference and February 2016 EIA STEO fuel scenarios.

In one of the group meetings (noted as "Down Select 1" above), the group compared the plan costs and other attributes (e.g., RPS, energy mix). The primary findings for O'ahu were:

- Theme 2 (with LNG) was lowest cost compared to Themes 1 and 3 in both the 2015 EIA Reference Fuel Price case and the February 2016 EIA STEO Fuel Price case.
- More analyses needed to be done to determine if plans with High DG-PV or Market DG-PV were lower cost. The analyses at that point were inconclusive.

Table 3-8 presents the O'ahu results from the Down Select 1 process after screening on a NPV revenue requirements basis. These plans represented the best plans under February 2016 EIA STEO and 2015 EIA Reference fuel forecasts and were therefore selected for additional analysis.

Candidate Plans – Down Select 1 – O'ahu			
	Theme 1	Theme 2	Theme 3
NPV RR $ millions February 2016 EIA STEO Fuel	$17,751	$15,097	$15,521
NPV RR $ millions 2015 EIA Reference Fuel	$20,774	$17,354	$19,701
Spread 2015 EIA Reference to February 2016 EIA STEO Fuel	17%	15%	27%
DER Forecast	High	Market	Market
100% RPS / RE	100% RE and RPS in 2045	100% RE and RPS in 2045	100% RE and RPS in 2045
Deactivations	Honolulu 8/9 converted to synchronous condensers 1/2019 AES contract terminated 9/2022 Waiau 3 & 4 deactivated 1/2023 and converted to synchronous condensers Kahe 6 deactivated 1/2025 and converted to synchronous condensers Waiau 5/6 deactivated 1/2030	Honolulu 8/9 converted to synchronous condensers 1/2019 Kahe 1, 2, and 3 deactivated 12/2020 and converted to synchronous condensers AES contract terminated 9/2022 Waiau 3 & 4 deactivated 1/2022 Kahe 4 deactivated 1/2022 Waiau 5/6 deactivated 1/2024 Waiau 7/8 deactivated 1/2030	Honolulu 8/9 converted to synchronous condensers 1/2019 AES contract terminated 9/2022 Waiau 3 & 4 deactivated 1/2023 and converted to synchronous condensers Kahe 6 deactivated 1/2025 and converted to synchronous condensers Waiau 5/6 deactivated 1/2030

Candidate Plans – Down Select 1 – O'ahu			
Variable Renewable Additions	27.6 MW Waiver PV 2016 15 MW onshore solar 2018 (CBRE) 10 MW onshore wind 2018 (CBRE) 24 MW NPM Wind 2018 109.6 MW Waiver PV 2018 360 MW onshore solar PV 2020 20 MW onshore wind 2020 1600 MW offshore wind 2025	27.6 MW Waiver PV 2016 15 MW onshore solar 2018 (CBRE) 10 MW onshore wind 2018 (CBRE) 24 MW NPM Wind 2018 109.6 MW Waiver PV 2018 30 MW onshore wind 2020 60 MW onshore solar PV 2020 400 MW offshore wind 2025 520 MW onshore solar PV 2040 1200 MW offshore wind 2045	27.6 MW Waiver PV 2016 15 MW onshore solar 2018 (CBRE) 10 MW onshore wind 2018 (CBRE) 24 MW NPM Wind 2018 109.6 MW Waiver PV in 2018 30 MW onshore wind 2020 400 MW offshore wind 2025 420 MW of solar PV 2045 800 MW offshore wind 2045
Firm Renewable Additions	None	None	None
Thermal Generation Additions	50 MW Schofield ICE 2018 100 MW JBPHH Plant 2022 54 MW KMCBH Plan 2023	50 MW Schofield ICE 2018 100 MW JBPHH Plant 2020 27 MW KMCBH Plant 6/2021 3x1 CC in 6/2021	50 MW Schofield ICE 2018 100 MW JBPHH Plant 2022 54 MW KMCBH Plan 2023
Energy Storage Additions	90 MW Contingency BESS 2019	90 MW Contingency BESS 2019	90 MW Contingency BESS 2019

Table 3-8. Candidate Plans from Down Select 1

After Down Select 1, these plans became the basis for further analysis across the three themes.

Note: Net Present Value Revenue Requirements. At this stage, these represent only the incremental fixed revenue requirements associated with the resource plan i.e. revenue requirements associated with new resources, DER integration costs, fixed and variable O&M, and fuel. These NPV revenue requirements do *not* include the revenue requirements associated with a) embedded costs of existing generation, transmission, distribution and general plant b) non-power supply related capital expenditures, c) and base capital expenditures. These are accounted for in the financial model and in the results presented in Chapters 4, 5, 6, 7 and 8.

Initial Findings and Observations for O'ahu

In the review of the results of the first down select process, the following initial findings were made for O'ahu:

- Theme 2 offers the best economics for O'ahu when viewed over the entire study period.
- Because of the constraints on the development of renewable resources on O'ahu (i.e., no geothermal, very limited on-island biomass resources, constrained land area for additional solar and onshore wind), achieving 100% renewables on O'ahu will require either (i) extensive use of liquid biofuels and/or (ii) extensive access to offshore

resources (e.g. offshore wind, renewable resources located on neighbor islands interconnected to O‘ahu via inter-island cable).

- The renewable constraints on O‘ahu and the timeframes for development of off-island resources to serve O‘ahu, mean that continued use of imported fossil fuels is required well into the study period for all three themes.
- Theme 1 will require substantial amounts of renewable energy resources (modeled in at this stage as offshore wind) relative early in the study period (2025). For Theme 1, this concentrates a great deal of implementation risk early in the study period, since the scenario is reliant on very large quantities of very deep water offshore wind (with uncertain capital costs and unproven feasibility).
- A possible strategy should be tested whereby 100% RPS achievement on Maui and Hawai‘i Island is accelerated (ensuring 70% consolidated RPS is achieved by 2040), and allowing for additional options to materialize for O‘ahu late in the study period.
- Even with a high penetration of variable renewables in the resource mix, curtailment strategies (assuming the provider is compensated for curtailed energy) or strategic use of biofuels in thermal generation are both economically more advantageous than use of large quantities of energy storage that would be required to take all of the variable renewable energy.
- Theme 1 is substantially more expensive than either Theme 2 or Theme 3.
- The analyses were inconclusive in determining if plans with the Market based penetrations of DG-PV are more economical than the high DG-PV scenario.

Down Select 2 – O‘ahu

In the next group meeting (noted as Down Select 2 above), the updated results were reviewed.

The findings for O‘ahu were similar to those of the first meeting.

Plan risks, in terms of fuel price risk, technological risk, resource cost and availability risk, and stranded cost risk were also discussed at the meeting. Plans with LNG would have risks associated with locking in a long-term contract. Plans without LNG would have higher oil price volatility risk. Plans with geothermal would have development risks.

Following the conference call, there was additional discussion on how the final plan for each island should be selected. It was decided that each Theme should have a final plan and that the selected final plan for each theme could be one of the following: (1) the plan derived in the 2015 EIA Reference Fuel Price case; or (2) the plan derived in the February 2016 EIA STEO Fuel Price case; or (3) a hybrid constructed from knowledge gained from (1) and (2).

O'ahu used Method (3) and created a hybrid plan based on the insights learned from the numerous cases evaluated up to that point.

- Plans with Market DG-PV were the lowest cost in most cases.
- With the neighbor islands achieving 100% RE by 2030 in Theme 1 and 2040 in Themes 2 and 3, the O'ahu plans added a mix of onshore solar and offshore wind to meet the intermediate RPS goals.

Further refinements were made before the final plans were passed on to the Financial Model.

The results of modified runs and evaluation of the results of several sensitivities around 2015 EIA Reference and February 2016 EIA STEO fuel, as shown in Table 3-9.

Final Plans – Down Select 2 – O'ahu			
	Theme 1	Theme 2	Theme 3
NPV RR $ millions February 2016 EIA STEO Fuel	$16,299	$14,782	$15,765
NPV RR $ millions 2015 EIA Reference Fuel	$20,303	$17,413	$20,441
Spread 2015 EIA Reference to February 2016 EIA STEO Fuel	25%	18%	30%
DER Forecast	High	Market	Market
100% RPS / RE	100% RE and RPS in 2045	100% RE and RPS in 2045	100% RE and RPS in 2045
Deactivations	AES in 2022 Waiau 3 & 4 in 2023 Kahe 6 in 2025 Waiau 5 & 6 in 2030	Kahe 1,2,3 in 2020 AES in 2022 Waiau 3 & 4 in 2022 Kahe 4 in 2022 Waiau in 2024 Waiau 7 & 8 in 2030	AES in 2022 Waiau 3 & 4 in 2023 Kahe 6 in 2025 Waiau 5 & 6 in 2030
Variable Renewable Additions	27.6 MW Waiver PV 2016 15 MW CBRE solar2018 10 MW onshore wind 2018 (CBRE) 24 MW NPM Wind 2018 109.6 MW Waiver PV 2018 30 MW onshore wind 2020 200 MW solar PV 2020 200 MW solar PV 2022200 MW solar PV 2024 200 MW offshore wind 2030 200 MW offshore wind 2032 200 MW offshore wind 2034 200 MW offshore wind 2036	27.6 MW wavier PV 2016 15 MW CBRE solar 2018 10 MW onshore wind 2018 (CBRE) 24 MW NPM Wind 2018 109.6 MW Waiver PV 2018 30 MW onshore wind 2020 60 MW solar PV 2020 100 MW solar PV 2030 200 MW offshore wind 2030 200 MW solar PV 2040 200 MW offshore wind 2040 300 MW solar PV 2045 400 MW offshore wind 2045	27.6 MW wavier PV 2016 15 MW CBRE solar 2018 10 MW onshore wind 2018 (CBRE) 24 MW NPM Wind 2018 109.6 MW Waiver PV 2018 30 MW onshore wind 2020 60 MW solar PV 2020 100 MW solar PV 2030 200 MW offshore wind 2030 200 MW solar PV 2040 200 MW offshore wind 2040 300 MW solar PV 2045 400 MW offshore wind 2045

Final Plans – Down Select 2 – O'ahu			
Firm Renewable Additions	None	None	None
Thermal Generation Additions	50 MW Schofield ICE 2018 100 MW JBPHH Plant 2022 54 MW KMCBH Plan 2023	50 MW Schofield ICE 2018 100 MW JBPHH Plant 2020 27 MW KMCBH Plant 6/2021 3x1 CC 2021	50 MW Schofield ICE 2018 100 MW JBPHH Plant 2022 54 MW KMCBH Plan 2023
Energy Storage Additions	90 MW Contingency BESS 2019	90 MW Contingency BESS 2019	90 MW Contingency BESS 2019

Table 3-9. Final Plans from Down Select 2

Hawai'i Island Results

Down Select 1 – Hawai'i Island

The primary purpose of the Down Select 1 was to apply a revenue requirements filter to the various candidate plans to select the lowest cost plans under 2015 EIA Reference and February 2016 EIA STEO fuel scenarios.

The primary findings for Hawai'i Island were:

- Plans with Market DG-PV were the lowest cost in all scenarios.
- Theme 2 (with LNG) was lowest cost compared to Themes 1 and 3 in the 2015 EIA Reference Fuel Price case but Theme 3 (No LNG) was lowest cost compared to Themes 1 and 2 in the February 2016 EIA STEO Fuel Price case.

Overall, it was found that Plans with 100% RE in 2040 on the neighbor islands appeared to aid in meeting the 70% RPS in 2040 across the Hawaiian Electric territories since O'ahu appeared to have a more difficult time meeting that level.

The decision was made to freeze the Maui and Hawai'i island RE assumption at meeting 100% RE in 2040 and only those cases from Themes 2 and 3, as well as all cases from Theme 1, were carried forward to the next phase of plan selection.

Table 3-10 presents the Hawaiʻi Island results from the Down Select 1 process after screening on a NPV revenue requirements basis. These plans represented the best plans under February 2016 EIA STEO and 2015 EIA Reference fuel forecasts and were therefore selected for additional analysis.

Candidate Plans – Down Select 1 – Hawaiʻi Island			
	Theme 1	Theme 2	Theme 3
NPV RR $ millions February 2016 EIA STEO Fuel	2561	2461	2465
NPV RR $ millions 2015 EIA Reference Fuel	2906	2762	2922
Spread 2015 EIA Reference to February 2016 EIA STEO Fuel	13 %	12 %	19 %
DER Forecast	High DG PV Forecast	Market DG-PV	Market DG-PV
100% RPS / RE	2030	2040	2040
Deactivations	Puna Steam 2022 Hill 5 2024 Hill 6 2026	Puna Steam 2022 Hill 5 2024 Hill 6 2026	Puna Steam 2022 Hill 5 2024 Hill 6 2026
Variable Renewable Additions	30 MW Wind 2028	20 MW Wind 2034 20 MW Wind 2038	20 MW Wind 2034 20 MW Wind 2038
Firm Renewable Additions	20 MW Geothermal 2022 20 MW Biomass 2024 20 MW Geothermal 2026	20 MW Geothermal 2022 20 MW Biomass 2027 20 MW Geothermal 2030	20 MW Geothermal 2022 20 MW Biomass 2027 20 MW Geothermal 2030
Thermal Generation Additions	None	None	None
Energy Storage Additions	30 MW Pump Storage 2030 30 MW Load shifting BESS 2030	Contingency Reserve Storage only. None for load-shifting	Contingency Reserve Storage only. None for load-shifting

Table 3-10. Candidate Plans from Down Select 1: Hawaiʻi Island

After Down Select 1, these plans became the basis for further analysis across the three themes.

Initial Findings and Observations for Hawaiʻi Island

In the review of the results of the first down select process, the following initial findings were made for Hawaiʻi Island:

- Themes 2 and 3 offer the best economics for Hawaiʻi Island when viewed over the entire study period.
- Firm renewable resources provide the most value (e.g., displacement of fossil fuel consumption, contribution to renewable energy %, and provision of grid services) to Hawaiʻi Island compared to variable renewables which will require either curtailment

or energy storage to manage in a system already heavy with variable renewables (wind, DG-PV).

- Hawai'i Island has available feedstock such as eucalyptus that can be used to fuel biomass generation. However, additional detailed analysis will be required to determine the feedstock requirements for a biomass plant and favorable pricing as biomass fuel.
- Geothermal resources can continue to play a role in providing renewable energy to Hawai'i Island. However, community concerns will need to be addressed in order for energy users on Hawai'i island to expand the use of this resource. Additional exploration of available geothermal resources on Hawai'i Island, in particular in West Hawai'i, should be a priority of state agencies and private organizations involved in energy, land and water issues
- There is substantial potential for wind energy on Hawai'i Island, many times greater than the energy requirements of the island. The relatively high capacity factors of the available wind make additional wind resources attractive. However, strategies for managing the variability of the wind, such as energy storage combined with dispatchable wind resources will be required as renewable energy levels grow, factoring in the economics of the multitude of options.
- Energy storage will be required to support additional variable renewable resources on Hawai'i Island. This will presents opportunities to explore in detail, through procurement strategies, market-based solutions for energy storage including BESS and pumped storage hydroelectric.
- Theme 1 is generally more expensive than either Theme 2 or Theme 3.
- Market based penetrations of DG-PV are more economical than the high DG-PV scenario.

Down Select 2 – Hawai'i Island

The findings for Hawai'i Island were:

- Plans with Market DG-PV were still the lowest cost in all scenarios.
- Theme 2 (with LNG) was lowest cost compared to Themes 1 and 3 in the 2015 EIA Reference Fuel Price case but Theme 3 (No LNG) was lowest cost compared to Themes 1 and 2 in the February 2016 EIA STEO Fuel Price case. These results were consistent with the results from the previous meeting.

Plan risks, in terms of fuel price risk, technological risk, resource cost and availability risk, and stranded cost risk were also discussed at the meeting. Plans with LNG would have risks associated with locking in a long-term contract. Plans without LNG would have higher oil price volatility risk. Plans with geothermal would have development risks.

The results at this point were then viewed in totality. Based on the analytical results for Maui and Hawai‘i Island, the decision was made that the final plan for these islands would assume Market DG-PV. Therefore, two of the three decisions were made (i.e., 100% RE by 2040 and Market DG-PV).

Following the conference call, there was additional discussion on how the final plan for each island should be selected. It was decided that each Theme should have a final plan and that the selected final plan for each theme could be one of the following: (1) the plan derived in the 2015 EIA Reference Fuel Price case; or (2) the plan derived in the February 2016 EIA STEO Fuel Price case; or (3) a hybrid constructed from knowledge gained from (1) and (2).

It was decided that for Hawai‘i Island, it would be the plan based on the 2015 EIA Reference Fuel Price case. Further refinements were made before the final plans were passed on to the Financial Model.

The results of modified runs and evaluation of the results of several sensitivities around 2015 EIA Reference and February 2016 EIA STEO fuel, for Hawai‘i Island are presented in Table 3-11.

Final Plans – Down Select 1 – Hawai‘i Island			
	Theme 1	Theme 2	Theme 3
NPV RR $ millions February 2016 EIA STEO Fuel	$2,563	$2,464	$2,467
NPV RR $ millions 2015 EIA Reference Fuel	$2,908	$2,765	$2,924
Spread 2015 EIA Reference to February 2016 EIA STEO Fuel	13%	12%	19%
DER Forecast	High DG-PV Forecast	Market DG-PV	Market DG-PV
100% RPS / RE	2030	2040	2040
Deactivations	Puna Steam 2022 Hill 5 2024 Hill 6 2026	Puna Steam 2022 Hill 5 2024 Hill 6 2026	Puna Steam 2022 Hill 5 2024 Hill 6 2026
Variable Renewable Additions	30 MW Wind 2028	20 MW Wind 2034 20 MW Wind 2038	20 MW Wind 2034 20 MW Wind 2038
Firm Renewable Additions	20 MW Geothermal 2022 20 MW Biomass 2024 20 MW Geothermal 2026	20 MW Geothermal 2022 20 MW Biomass 2027 20 MW Geothermal 2030	20 MW Geothermal 2022 20 MW Biomass 2027 20 MW Geothermal 2030
Thermal Generation Additions	None	None	None
Energy Storage Additions	30 MW Pump Storage 2030 30 MW Load shifting BESS 2030	Contingency Reserve Storage only. None for load-shifting	Contingency Reserve Storage only. None for load-shifting

Table 3-11. Final Plans from Down Select 2: Hawai'i Island

Additional Findings and Observations for Hawai‘i Island

- Due to limited renewable resource potential on O‘ahu, the neighbor islands, having the renewable resource potential to meet 100% renewable energy in 2040, can contribute to attain consolidated corporate RPS goals.
- Adding new firm renewable and variable generation renewable resources in lieu of biofuel in conventional generating units in 2040 is a more cost effective way to attain 100% RPS and 100% renewable energy.
- Higher costs result when 100% renewable energy is accelerated from 2045 to 2040.
- Additional refinements included the adjustment of storage and the timing of future resources to attain 100% renewable energy.
- LNG use in Theme 2 ends following December 31, 2039, based on attainment of 100% RE in 2040.
- Increased costs for Hawai‘i Island in order to reach corporate goal of 70% RPS in 2040.

- Additional resource costs, such as for synchronous condensers, must be included if must-run requirement for fossil fuel generation is removed in advance of the addition of new dispatchable resources.

Based on these additional findings and observations, the final plans for each Theme were developed for Hawai‘i Island.

Maui Results

Down Select 1 – Maui

The primary purpose of the Down Select 1 was to apply a revenue requirements filter to the various candidate plans to select the lowest cost plans under 2015 EIA Reference and February 2016 EIA STEO fuel scenarios.

The primary findings for Maui were:

- Plans with Market DG-PV were the lowest cost in all scenarios.
- Theme 2 (with LNG) was lowest cost compared to Themes 1 and 3 in the February 2016 EIA STEO Fuel Price case but Theme 3 (No LNG) was lowest cost compared to Themes 1 and 2 in the 2015 EIA Reference Fuel Price case.

Complete results for Lana‘i and Moloka‘i were not available at this point.

Overall, it was found that Plans with 100% RE in 2040 on the neighbor islands appeared to aid in meeting the 70% RPS in 2040 across the Hawaiian Electric territories since O‘ahu appeared to have a more difficult time meeting that level.

The decision was made to freeze the Maui and Hawai‘i island RE assumption at meeting 100% RE in 2040 and only those cases from Themes 2 and 3, as well as all cases from Theme 1, were carried forward to the next phase of plan selection.

Refinements to the remaining plans were made after this meeting.

Table 3-12 presents the Maui results from the Down Select 1 process after screening on a NPV revenue requirements basis. These plans represented the best plans under February 2016 EIA STEO and 2015 EIA Reference fuel forecasts and were therefore selected for additional analysis.

Candidate Plans – Down Select 1 – Maui			
	Theme 1	Theme 2	Theme 3
NPV RR $ millions February 2016 EIA STEO Fuel	$3,533	$3,387	$3,416
NPV RR $ millions 2015 EIA Reference Fuel	$3,981	$3,937	$3,928
Spread 2015 EIA Reference to February 2016 EIA STEO Fuel	13%	16%	15%
DER Forecast	High	Base	Base
100% RPS / RE	2030	2040	2040
Deactivations			
Variable Renewable Additions	■ 30 MW Wind 2020 ■ 30 MW Wind 2040 ■ 30 MW Wind 2045	■ 60 MW Wind 2020 ■ 30 MW Wind 2040 ■ 60 MW PV 2045 ■ 120 MW Wind 2045	■ 60 MW Wind 2020 ■ 30 MW Wind 2022 ■ 30 MW Wind 2025 ■ 30 MW Wind 2040 ■ 60 MW PV 2045 ■ 60 MW Wind 2045
Firm Renewable Additions	■ 20 MW Biomass 2022 ■ 40 MW Geothermal 2030	■ 20 MW Biomass 2022 ■ 20 MW Biomass 2040	■ 20 MW Biomass 2022 ■ 20 MW Biomass 2040
Thermal Generation Additions	■ Remove must-run for fossil fuel generation	■ 2x9 MW ICE 2022 ■ Remove must-run for fossil fuel generation	■ 2x9 MW ICE 2022 ■ Remove must-run for fossil fuel generation
Energy Storage Additions	■ 30 MW PSH 2022 ■ 30 MW, 6hr LS BESS 2030	■ 20 MW LS BESS 2022 ■ 30 MW LS BESS 2037 (Replacement)	■ 20 MW LS BESS 2022 ■ 30 MW LS BESS 2037 (Replacement)

Table 3-12. Candidate Plans from Down Select 1 – Maui

After Down Select 1, these plans became the basis for further analysis across the three themes.

Initial Findings and Observations for Maui

In the review of the results of the first down select process, the following initial findings were made for Maui:

- Theme 2 offers the best economics for Maui when viewed over the entire study period.
- Given the most recent electricity forecasts, Maui expects to have a need for new generation or firm capacity to meet a reserve capacity shortfall in the 2017-2022 timeframe. We are evaluating several measures including demand response, energy storage, time-of-use rates and distributed and centralized generation to meet the needs of the island, however it is likely that combination of some, if not all, of these resources will be required.

- Firm renewable resources (i.e. biomass, geothermal) provide the most value to Maui compared to variable renewables, which will require either curtailment or energy storage to manage in a system already heavy with variable renewables (wind, DG-PV).
- Biomass is a firm renewable resource that can meet energy demands without the use of fossil fuel. Typically one hurdle for a biomass facility is to produce or identify enough feedstock. HC&S' January 2016 announcement that it is ceasing sugar production present unique opportunities for the island of Maui. HC&S land previously held in sugarcane may be suitable for feedstock production. Using the land to produce biomass ensures this land will stay in agricultural use and help Maui to preserve our open spaces, while at the same time contribute to energy security by lessening our dependence on imported fuel. Again, this suggests updated research on biomass feedstock should be a priority of State agencies and private organizations involved in energy, agriculture, land, and water issues. Although we modeled and evaluated an energy crop opportunity on Maui as a biomass resource, an alternative form of biofuel (liquid or gaseous) grown, processed and used for energy production on Maui could have similar benefits to Maui's energy system and Maui Electric's customers if the alternative forms of biofuels combined with the generating resource are similar in costs to biomass resource evaluated for this PSIP.
- Geothermal could potentially play a role in providing a source of firm renewable power for Maui. Additional exploration of available geothermal resources on Maui should be a priority of state agencies and private organizations involved in energy, land and water issues.
- Theme 1 is substantially more expensive than either Theme 2 or Theme 3.
- Market based penetrations of DG-PV are more economical than the high DG-PV scenario.

Down Select 2 – Maui

The findings for the Maui were:

- Plans with Market DG-PV were still the lowest cost in all scenarios.
- Theme 2 (with LNG) was lowest cost compared to Themes 1 and 3 in the February 2016 EIA STEO Fuel Price case but Theme 3 (No LNG) was lowest cost compared to Themes 1 and 3 in the 2015 EIA Reference Fuel Price case. These results were consistent with the results from the previous meeting.

Plan risks, in terms of fuel price risk, technological risk, resource cost and availability risk, and stranded cost risk were also discussed at the meeting. Plans with LNG would have risks associated with locking in a long-term contract. Plans without LNG would have higher oil price volatility risk. Plans with geothermal would have development risks.

The results at this point were then viewed in totality. Based on the analytical results for Maui and Hawai‘i island, the decision was made that the final plan for these islands should have Market DG-PV. Therefore, two of the three decisions were made (i.e., 100% RE by 2040 and Market DG-PV).

Following the conference call, there was additional discussion on how the final plan for each island should be selected. It was decided that each Theme should have a final plan and that the selected final plan for each theme could be one of the following: (1) the plan derived in the 2015 EIA Reference Fuel Price case; or (2) the plan derived in the February 2016 EIA STEO Fuel Price case; or (3) a hybrid constructed from knowledge gained from (1) and (2).

- Plans with Market DG-PV were the lowest cost in all scenarios.
- With the neighbor islands achieving 100% RE by 2030 in Theme 1 and 2040 in Themes 2 and 3, the O‘ahu plans added a mix of onshore solar and offshore wind to meet the intermediate RPS goals.

It was decided that for Maui, it would be the plan based on the 2015 EIA Reference Fuel Price case.

Further refinements were made before the final plans were passed on to the Financial Model.

Further details on the down selection process are provided below.

The results of modified runs and evaluation of the results of several sensitivities around 2015 EIA Reference and February 2016 EIA STEO fuel, are shown in Table 3-13.

Final Plans – Down Select 2 – Maui			
	Theme 1	Theme 2	Theme 3
NPV RR $ millions February 2016 EIA STEO Fuel	$3,769	$3,207	$3,079
NPV RR $ millions 2015 EIA Reference Fuel	$4,351	$3,635	$3,651
Spread 2015 EIA Reference to February 2016 EIA STEO Fuel	15%	13%	19%
DER Forecast	High	Base	Base
100% RPS / RE	2030	2040	2040
Deactivations			
Variable Renewable Additions	■ 30MW Wind 2020 ■ 30 MW Wind 2040 ■ 30 MW Wind 2045	■ 60MW Wind 2020 ■ 120 MW Wind 2040 ■ 40 MW Utility PV 2045 ■ 30 MW Wind 2045	■ 60MW Wind 2020 ■ 30 MW Wind 2022 ■ 30 MW Wind 2025 ■ 60 MW Wind 2040 ■ 40 MW Utility PV 2045 ■ 30 MW Wind 2045
Firm Renewable Additions	■ 20 MW Biomass 2022 ■ 40 MW Biomass 2030 ■ 40 MW Geothermal 2030	■ 20 MW Biomass 2022 ■ 20 MW Biomass 2040 ■ 40 MW Geothermal 2040	■ 20 MW Biomass 2022 ■ 20 MW Biomass 2040 ■ 40 MW Geothermal 2040
Thermal Generation Additions	■ Remove must-run for fossil fuel generation	■ 2x9 MW ICE 2022 ■ Remove must-run for fossil fuel generation	■ 2x9 MW ICE 2022 ■ Remove must-run for fossil fuel generation
Energy Storage Additions	■ 30 MW PSH 2022 ■ 30 MW, 6hr LS BESS 2030	■ 20 MW LS BESS 2022 ■ 30 MW LS BESS 2037 (Replacement)	■ 20 MW LS BESS 2022 ■ 30 MW LS BESS 2037 (Replacement)

Table 3-13. Final Results and Expansion Plans from Down Select 2 – Maui

Additional Findings and Observations for Maui

- Due to limited renewable resource potential on O‘ahu, the neighbor islands, having the renewable resource potential to meet 100% renewable energy in 2040, can contribute to attain consolidated corporate RPS goals.
- Adding new firm renewable and variable generation renewable resources in lieu of biofuel in conventional generating units in 2040 is a more cost effective way to attain 100% RPS and 100% renewable energy.
- Higher costs when 100% renewable energy is accelerated from 2045 to 2040.
- Additional refinements included the additions of geothermal, biomass, and wind in 2040 to attain 100% renewable energy.
- LNG use in Theme 2 ends following December 31, 2039, based on attainment of 100% RE in 2040.
- Increased costs for Maui in order to reach corporate goal of 70% RPS in 2040.
- Addition of synchronous condensers is needed on the Maui system for system security and assist in reduction of the must-run requirement for fossil fuel generation.

Based on these additional findings and observations, the final plans for each Theme were developed for Maui.

Lana‘i Results

Down Select 1 – Lana‘i

The primary purpose of the Down Select 1 was to apply a revenue requirements filter to the various candidate plans to select the lowest cost plans under 2015 EIA Reference and February 2016 EIA STEO fuel scenarios.

Table 3-14 presents the Lana‘i results from the Down Select 1 process after screening on a NPV revenue requirements basis. These plans represented the best plans under February 2016 EIA STEO and 2015 EIA Reference fuel forecasts and were therefore selected for additional analysis. (Note: Theme 2 was not applicable to Lana‘i)

Candidate Plans – Down Select 1 – Lana'i		
	Theme 1	Theme 3
NPV RR $ millions February 2016 EIA STEO Fuel	$132	$138
NPV RR $ millions 2015 EIA Reference Fuel	$150	$161
Spread 2015 EIA Reference to February 2016 EIA STEO Fuel	14%	17%
DER Forecast	High	Base
100% RPS / RE	2030	2030
Deactivations		
Variable Renewable Additions	■ 3 MW Wind 2020 ■ 1 MW Wind 2030 ■ 1 MW Wind 2045	■ 2 MW Wind 2020 ■ 1 MW Wind 2030 ■ 1 MW Wind 2045
Firm Renewable Additions	None	None
Thermal Generation Additions	Remove must-run for CAT 1 & 2.	
Energy Storage Additions	1 MW LS BESS 2040	

Table 3-14. Candidate Results and Expansion Plans from Down Select 1 – Lana'i

After Down Select 1, these plans became the basis for further analysis across the three themes.

Findings and Observations for Lana'i

In the review of the results of the down select process, the following findings were made for Lana'i:

- Theme 1 offers the best strategy for Moloka'i when viewed over the entire study period.
- Firm renewable generation is limited and at a higher cost than existing generating resources.
- New wind resources are cost effective, including reduction in energy taken due to curtailment.
- Lower cost liquid fuel would be beneficial on Lana'i .
- Reduction in must-run fossil fuel generation provides opportunities to accept more lower cost variable renewable generation.
- Large scale battery energy storage is not cost effective
- Due to compensation cost of future DER resources and the limited number of existing non-controllable DER systems, there are opportunities for controllable DER resources on Lana'i .

- For the final plans, removing 1 MW load shifting battery energy storage forecasted to be added late in the plan reduces costs.
- Synchronous condensers are needed on the Lana‘i system for system security and to assist in reduction of must-run fossil fuel generation.
- Removed the must-run requirement for fossil fuel generation.
- The finding for Lana‘i was that Theme 1 was lower cost than Theme 3 in both the February 2016 EIA STEO Fuel Price case and the 2015 EIA Reference Fuel Price case.

Based on these additional findings and observations, the final plans for Theme 1 and Theme 3 were developed for Lana‘i.

Final Plans – Down Select 2 – Lana‘i		
	Theme 1	Theme 3
NPV RR $ millions February 2016 EIA STEO Fuel	$126	$130
NPV RR $ millions 2015 EIA Reference Fuel	$149	$153
Spread 2015 EIA Reference to February 2016 EIA STEO Fuel	19%	18%
DER Forecast	High	Base
100% RPS / RE	2030	2030
Deactivations		
Variable Renewable Additions	■ 3 MW Wind 2020 ■ 1 MW Wind 2030 ■ 1 MW Wind 2045	■ 3 MW Wind 2020 ■ 1 MW Wind 2030 ■ 1 MW Wind 2040
Firm Renewable Additions	None	None
Thermal Generation Additions	Remove must-run for CAT 1 & 2.	Remove must-run for CAT 1 & 2.
Energy Storage Additions		

Table 3-15. Final Plans from Down Select 2 – Lana‘i

Moloka‘i Results

Down Select 1 – Moloka‘i

The primary purpose of the Down Select 1 was to apply a revenue requirements filter to the various candidate plans to select the lowest cost plans under 2015 EIA Reference and February 2016 EIA STEO fuel scenarios.

Table 3-16 presents the Moloka‘i results from the Down Select 1 process after screening on a NPV revenue requirements basis. These plans represented the best plans under February 2016 EIA STEO and 2015 EIA Reference fuel forecasts and were therefore selected for additional analysis.

Candidate Plans – Down Select 1 – Moloka'i		
	Theme 1	Theme 3
NPV RR $ millions February 2016 EIA STEO Fuel	$87	$91
NPV RR $ millions 2015 EIA Reference Fuel	$100	$106
Spread 2015 EIA Reference to February 2016 EIA STEO Fuel	15%	18%
DER Forecast	High	Base
100% RPS / RE	2030	2030
Deactivations		
Variable Renewable Additions	■ 3 MW Wind 2020 ■ 1 MW Wind 2030 ■ 1 MW Wind 2045	■ 4 MW Wind 2020 ■ 1 MW Wind 2040
Firm Renewable Additions	None	None
Thermal Generation Additions	Remove must-run conditions for CAT 1 & 2	
Energy Storage Additions	1 MW Load Shifting BESS 2040	

Table 3-16. Candidate Plans from Down Select 1 – Moloka'i

After Down Select 1, these plans became the basis for further analysis across the three themes.

Findings and Observations for Moloka'i

In the review of the results of the down select process, the following findings were made for Moloka'i:

- Firm renewable generation is limited and at a higher cost than existing generating resources.
- New wind resources are cost effective, including reduction in energy taken due to curtailment.
- Lower cost liquid fuel would be beneficial on Moloka'i .
- Reduction in must-run fossil fuel generation provides opportunities to accept more lower cost variable renewable generation.
- Large scale battery energy storage is not cost effective.
- Due to compensation cost of future DER resources, there are opportunities for controllable DER resources on Moloka'i. However, the opportunities are limited due to the number of existing uncontrollable DER.
- For the final plans, removing 1 MW load shifting battery energy storage forecasted to be added late in the plan reduces costs.

- Synchronous condensers are needed on the Moloka'i system for system security and to assist in reduction of must-run fossil fuel generation.
- Removed the must-run requirement for fossil fuel generation.
- The finding for Lana'i was that Theme 1 was lower cost than Theme 3 in both the February 2016 EIA STEO Fuel Price case and the 2015 EIA Reference Fuel Price case.
- The finding for Moloka'i was that Theme 1 was lower cost than Theme 3 in the February 2016 EIA STEO Fuel Price case but Theme 3 was lower cost than Theme 1 in the 2015 EIA Reference Fuel Price case.
- Theme 1 offers the best economics for Moloka'i when viewed over the entire study period.

Based on these additional findings and observations, the final plans for Theme 1 and Theme 3 were developed for Moloka'i.

Final Plans – Down Select 2 – Moloka'i		
	Theme 1	Theme 3
NPV RR $ millions February 2016 EIA STEO Fuel	$107	$103
NPV RR $ millions 2015 EIA Reference Fuel	$125	$121
Spread 2015 EIA Reference to February 2016 EIA STEO Fuel	17%	18%
DER Forecast	High	Base
100% RPS / RE	2030	2030
Deactivations		
Variable Renewable Additions	▪ 5 MW Wind 2020 ▪	▪ 5 MW Wind 2020 ▪ 1 MW Wind 2045
Firm Renewable Additions	None	None
Thermal Generation Additions	Remove must-run conditions for CAT 1 & 2	Remove must-run conditions for CAT 1 & 2
Energy Storage Additions		

Table 3-17. Final Plans from Down Select 2 – Moloka'i

4. Financial Impacts

This chapter provides the financial analyses of the Final Plan for each Theme. It presents the total revenue requirement over the period for each Company and the residential customer electricity rate and bill impacts for each of the three Themes. Results are presented under both fuel forecasts and in both real (2016) and nominal dollars[15]. For each of the customer rate and bill impact analyses, a comparison with the analogous results from the 2014 PSIP is also provided.

These analyses should not be used as precise long-term projections of customer rates. The value of these projections is not in the precise values but in the relative results of the planning Themes and scenarios to inform a preferred plan. Actual values could vary significantly with changes in assumptions including resource costs, new renewable technologies, fuel prices, energy efficiency, etc.

O‘AHU FINANCIAL IMPACTS

For O’ahu, Theme 2 (100% Renewable Energy with LNG) results in the lowest net present value of annual revenue requirements[16] over the 2017 to 2045 planning period, under both fuel price forecasts.

---

15 Throughout this Chapter, results presented in nominal dollars have been escalated by a 1.8% inflation rate.

16 Net Present Value of annual revenue requirements is the present value, in 2016 $, of the 29 year stream of annual revenue requirements from 2017 through 2045.

Revenue Requirement Analysis

Total utility company revenue requirements, under both fuel forecasts, have been calculated for the Final Plan for each Theme. Table 4-1 shows the Net Present Value of the annual revenue requirements for each Theme and Figure 4-1 through Figure 4-4 compare each Theme's annual revenue requirement under the 2015 EIA Reference and February 2016 EIA STEO fuel forecasts respectively, in real (2016 $) and nominal dollars.

Net Present Value of Revenue Requirement ($000)	2015 EIA Reference	February 2016 EIA STEO
NPV of Theme 1 Revenue Requirement	$28,481,004	$24,601,630
NPV of Theme 2 Revenue Requirement	$25,826,376	$23,325,106
NPV of Theme 3 Revenue Requirement	$29,044,299	$24,357,219

Table 4-1. Net Present Value of Revenue Requirement

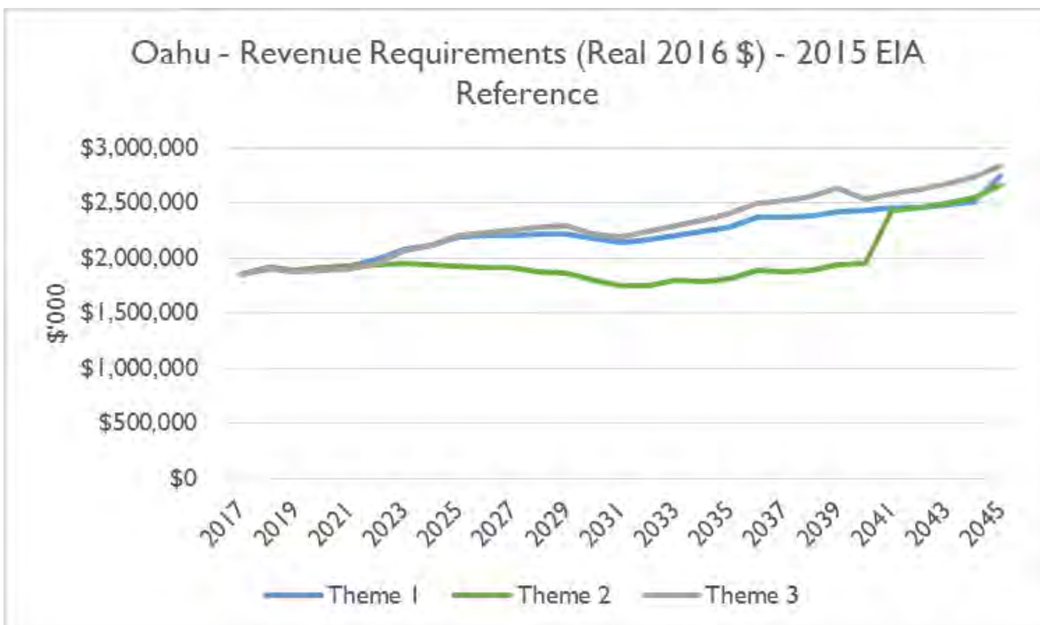


Figure 4-1. Comparison of Revenue Requirement (Real 2016 $) – 2015 EIA Reference

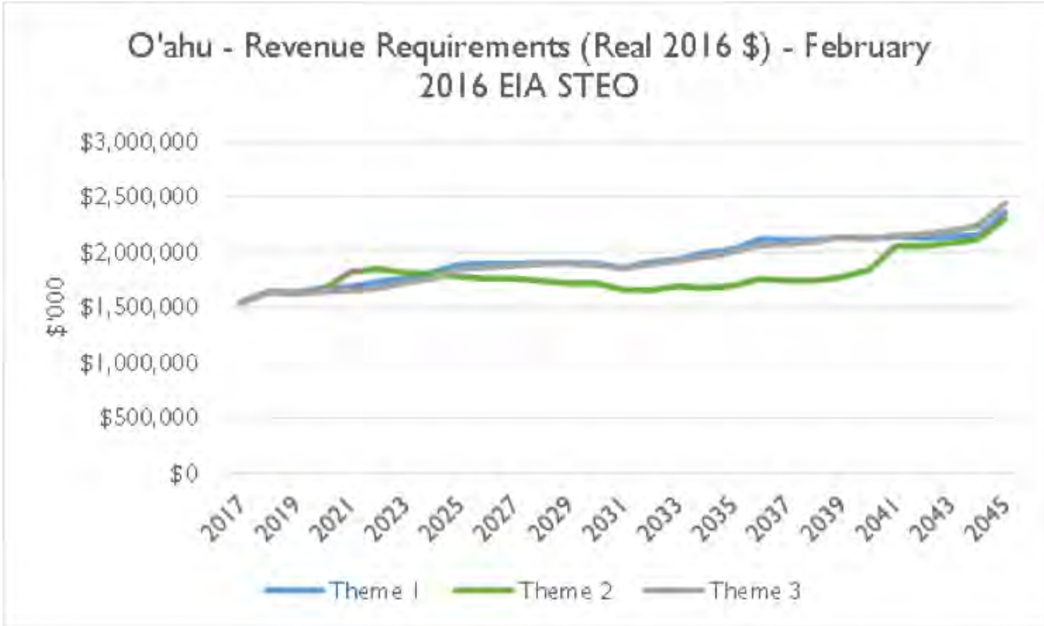


Figure 4-2. Comparison of Revenue Requirement (Real 2016 $) – February 2016 EIA STEO

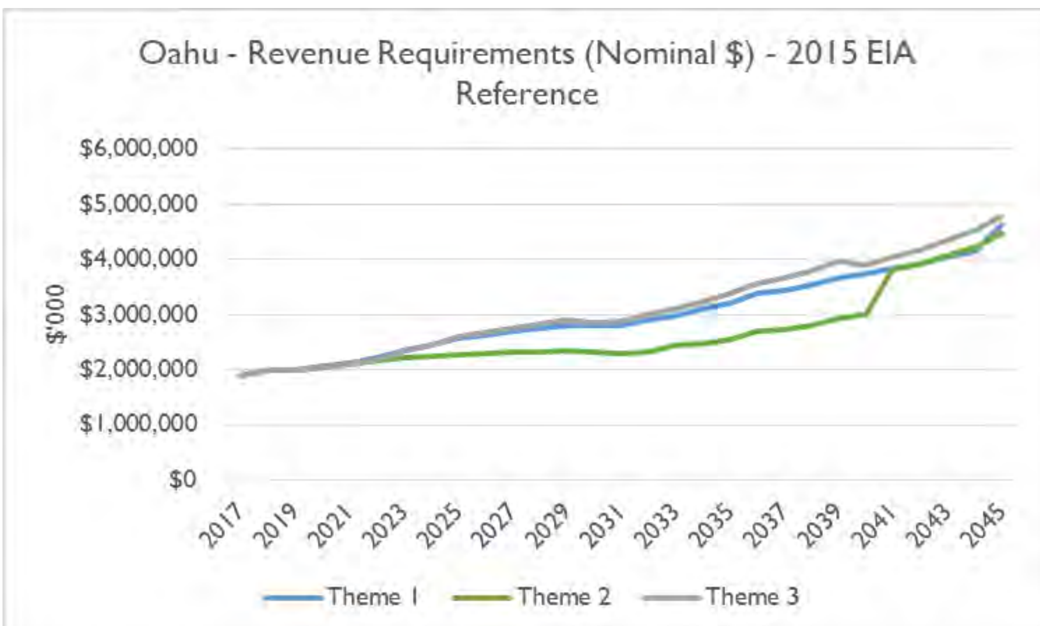


Figure 4-3. Comparison of Revenue Requirement (Nominal $) – 2015 EIA Reference

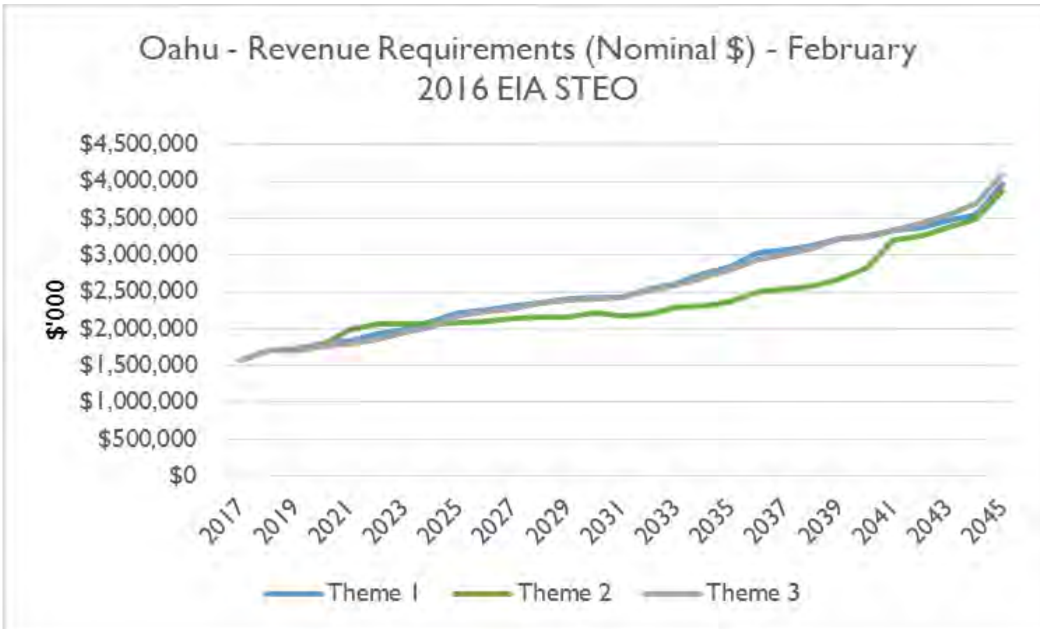


Figure 4-4. Comparison of Revenue Requirement (Nominal $) – February 2016 EIA STEO

Customer Rate Impact Analysis

Customer rates are generally a function of the revenue requirement allocated across projected kWh sales. Thus, declining kWh sales will increase rates and increasing kWh sales will decrease rates. Over the planning period, kWh sales are generally projected to decline consistent with our state's energy efficiency goals and the assumed load reduction from distributed generation. As a result of an increasing revenue requirement in combination with declining sales, residential customer rates, in real 2016 $, consistently rise over the planning period for Themes 1 and 3 under both fuel price forecasts. For Theme 2, customer rates hold relatively steady through 2040 under both fuel price forecasts.

Compared to the 2014 PSIP results, Theme 2 customer rates in real terms are projected to be consistently lower for either fuel price forecast. Themes 1 and 3 are projected to be lower than 2014 PSIP results for the February 2016 EIA STEO fuel price forecast, while under the 2015 EIA Reference fuel price forecast customer rates would be somewhat higher than the 2014 projections from the mid-2020s through 2030.

Customer rates in nominal terms show consistent increases as inflation, even at the historically low levels used in this analysis, dramatically impacts the value of a dollar over the almost 30 year planning period.

The residential customer rate for the three Themes, under the 2015 EIA Reference fuel price forecast, is presented in real 2016 $ in Figure 4-5 and and in nominal $ in Figure 4-6. 2014 PSIP results are also shown for comparison purposes.

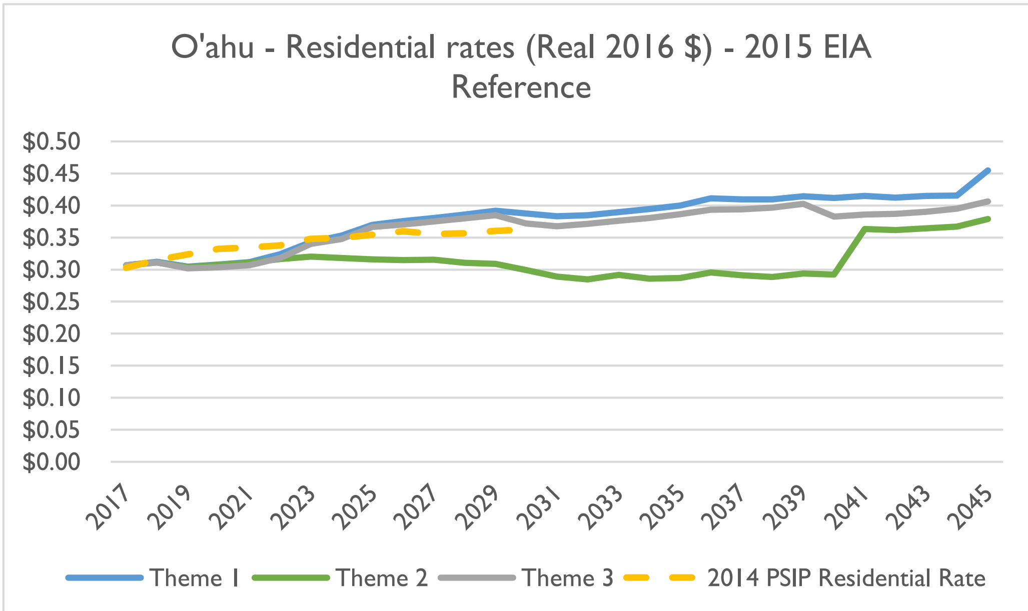


Figure 4-5. Residential Rates (Real 2016 $): 2015 EIA Reference

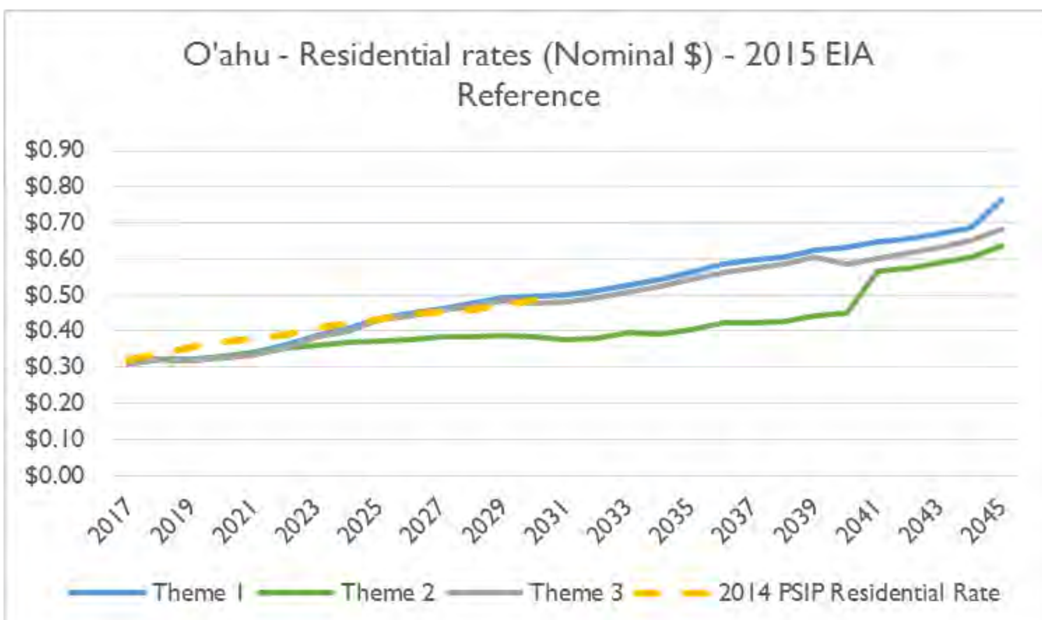


Figure 4-6. Residential Rates (Nominal $): 2015 EIA Reference

The residential customer rate for the three Themes, under the February 2016 EIA STEO fuel price forecast, is presented in real 2016 $ in Figure 4-7 and in nominal $ in Figure 4-8. 2014 PSIP results are also shown for comparison purposes.

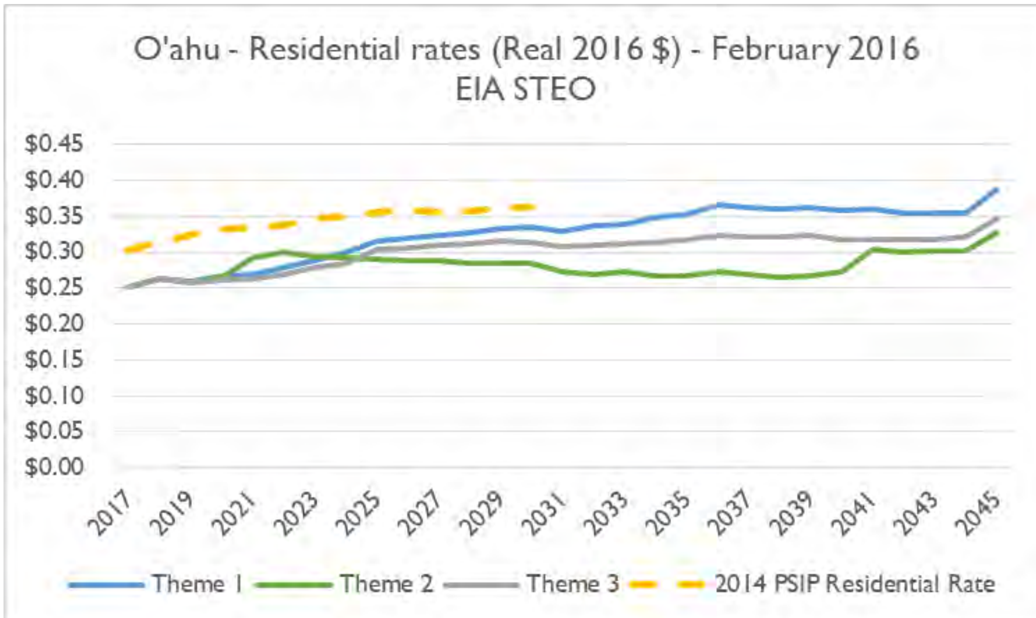


Figure 4-7. Residential Rates (Real 2016 $): February 2016 EIA STEO

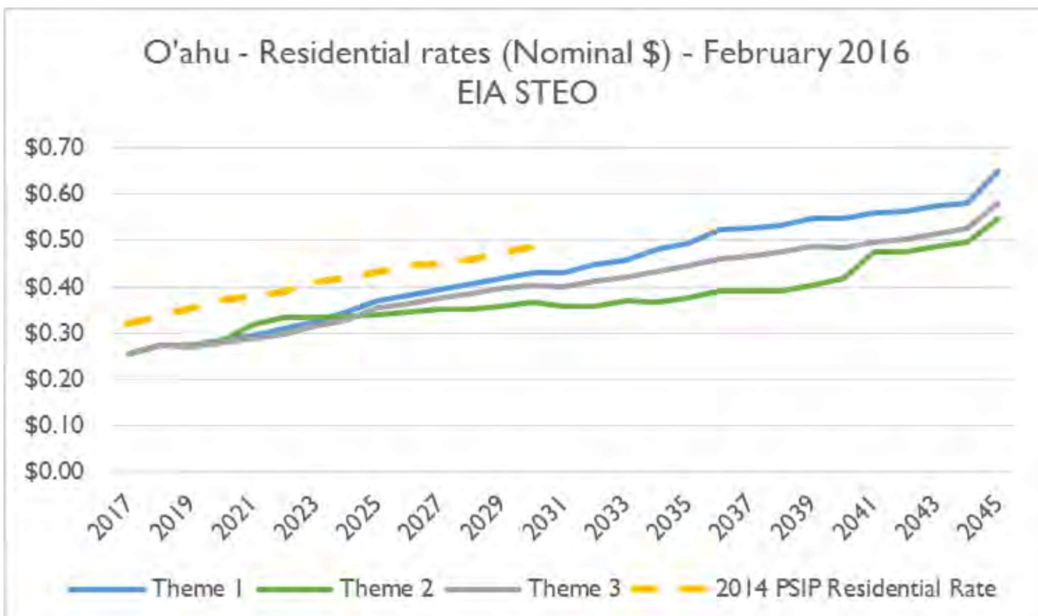


Figure 4-8. Residential Rates (Nominal $): February 2016 EIA STEO

Residential Customer Bill Impact Analysis

The overall impact on a customer's bill is the combination of usage and rates. Over the planning period, usage per customer is expected to decline, consistent with the Energy Efficiency Portfolio Standard goals.[17] The residential customer bill analyses below present each Theme's projected residential bill impact for the average non-DG-PV customer.

The residential customer bill impact for the three Themes, under the 2015 EIA Reference fuel price forecast, is presented in real 2016 $ in Figure 4-9 and in nominal $ in Figure 4-10. 2014 PSIP results are also shown for comparison purposes. The increase seen in Theme 2 between the years of 2041 and 2045 is attributed to transition from LNG to future alternative resources.

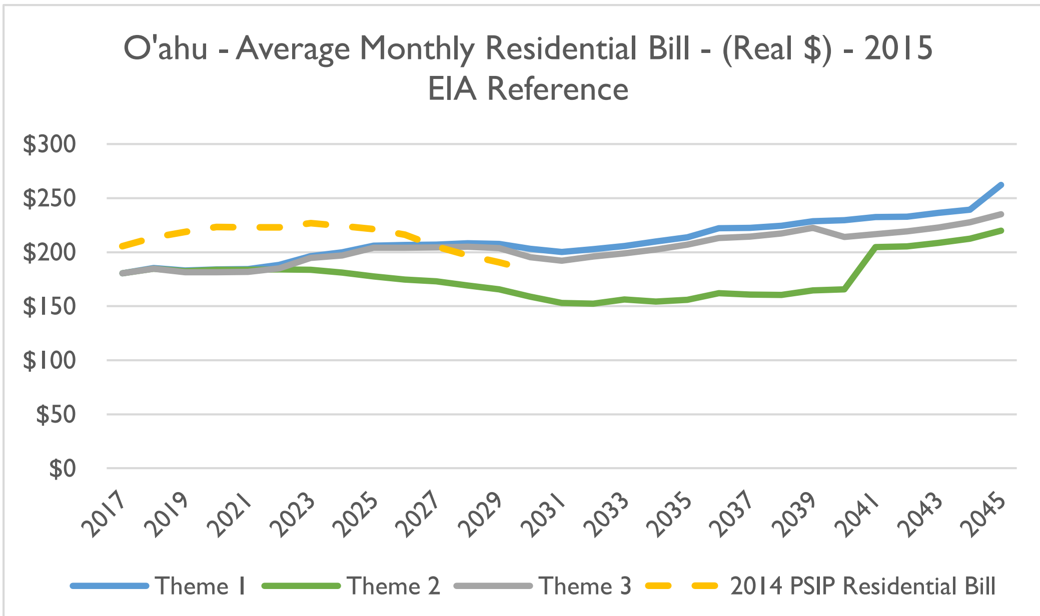


Figure 4-9. Residential Bill (Real 2016 $): 2015 EIA Reference

[17] Please see Appendix I for further discussion of the impact of the Energy Efficiency Portfolio Standard on customer rate and bill impact analyses.

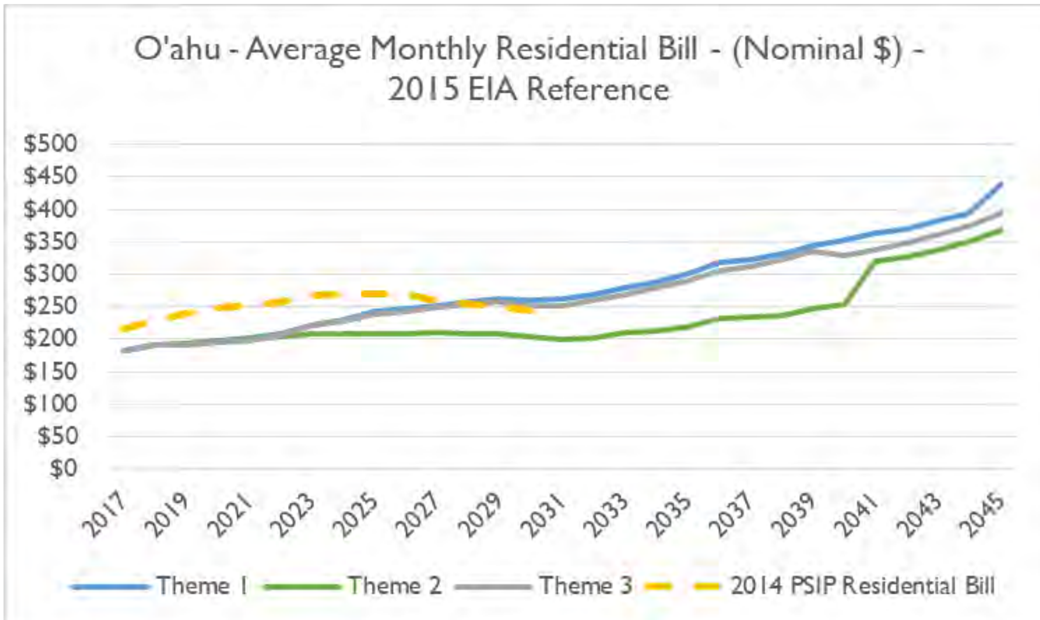


Figure 4-10. Residential Bill (Nominal $): 2015 EIA Reference

The residential customer bill impact for the three Themes, under the February 2016 EIA STEO fuel price forecast, is presented in real 2016 $ in Figure 4-11 and in nominal $ in Figure 4-12 below. 2014 PSIP results are also shown for comparison purposes.

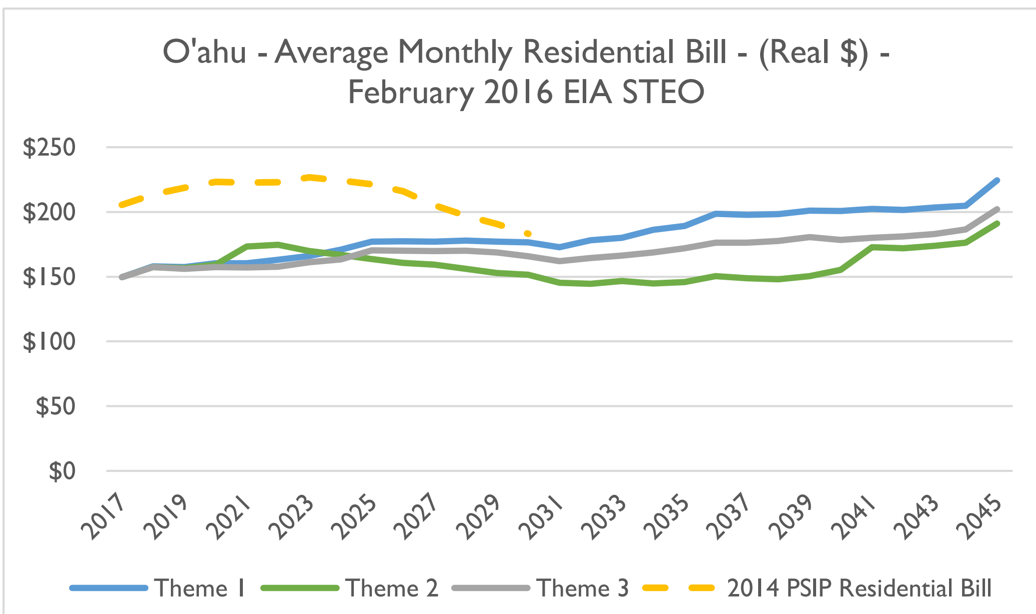


Figure 4-11. Residential Bill (Real 2016 $): February 2016 EIA STEO

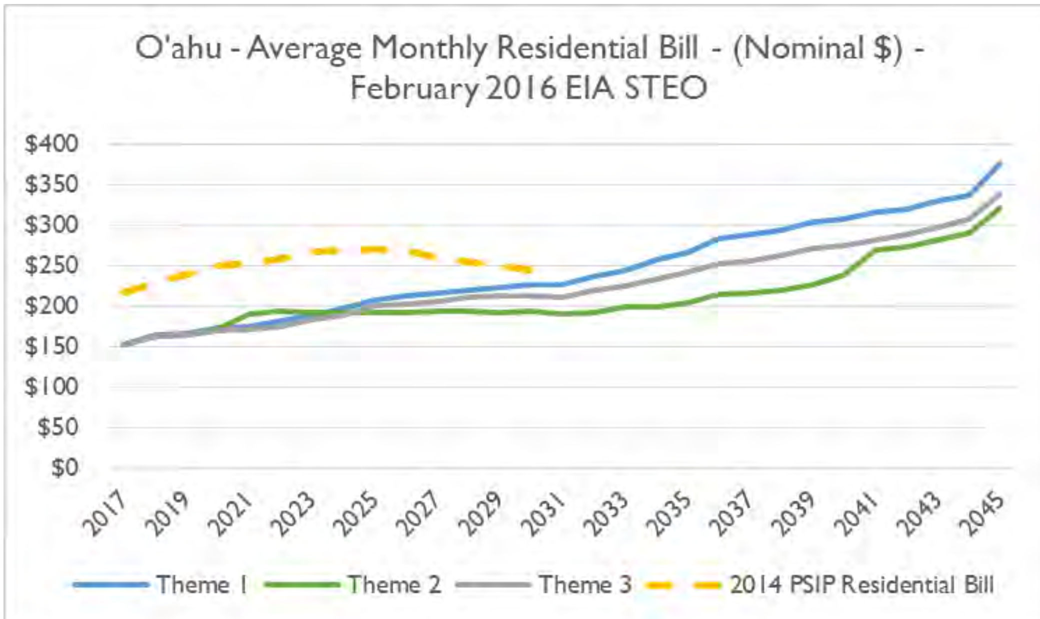


Figure 4-12. Residential Bill (Nominal $): February 2016 EIA STEO

Capital Expenditure Projections

The revenue requirement projections for each Theme include capital expenditure projections for power supply, smart grid, ERP, and all other utility capital expenditures (referred to as "balance-of-utility business capital expenditures"). The Power Supply capital expenditures range from $1.8B ($1.0B in the first 9 years) for Theme 3 to $2.4B ($1.8B in the first 9 years) for Theme 2, consistent with the mix and timing of resource additions and retirements.

Smart Grid and ERP are treated separately, as these proposed capital projects have different costs under a merged and an unmerged future. As Theme 2 is only possible in a merged future, the analysis uses the merged capital costs for both of these projects for Theme 2 capital expenditures. While Themes 1 and 3 can occur in either a merged or an unmerged future, in order to clearly focus on the differences in revenue requirements and bills caused solely by differences in Power Supply costs we need to use a uniform value for these costs in each Theme. For this reason, in this analysis we have used the capital expenditures for these projects that would be appropriate if the Next Era merger is consummated.

As described in detail in Appendix I, the balance-of-utility business capital expenditures have been calculated using a top down manner for the 2015 EIA Reference fuel price scenario and have been consistently applied across all three Themes for both fuel cases. The tables below summarize the capital expenditures by category for each Theme.

Theme 1

Under the Theme 1 resource plan, $2.1B (nominal) of capital will be invested by the utility in Power Supply assets over the 29 year planning period, with $1.2B (nominal) of this investment occurring in the first 9 years of the period.

Theme 1 ('000)	2017-2020	2021-2025	2026-2030	2031-2035	2036-2040	2041-2045	Total
Power Supply	$421,744	$746,744	$313,854	$455,006	$90,381	$87,688	$2,115,417
Smart Grid	$171,507	$24,277	$23,374	$25,081	$2,663	$0	$246,904
ERP	$36,993	$0	$0	$0	$0	$0	$36,993
Balance-of-utility business	$655,000	$1,055,314	$1,153,773	$1,261,419	$1,379,108	$1,507,777	$7,012,390
Total	1,285,244	$1,826,334	$1,491,001	$1,741,508	$1,472,152	$1,595,465	$9,411,705

Table 4-2. Theme 1 Capital Expenditures (Nominal $)

Theme 2

Under the Theme 2 resource plan, $2.4B (nominal) of capital will be invested by the utility in Power Supply assets over the 29 year planning period, with $1.8B (nominal) of this investment occurring in the first 9 years of the period.

Theme 2 ('000)	2017-2020	2021-2025	2026-2030	2031-2035	2036-2040	2041-2045	Total
Power Supply	$1,511,957	$288,327	$96,185	$245,008	$206,296	$96,754	$2,444,527
Smart Grid	$171,507	$24,277	$23,374	$25,081	$2,663	$0	$246,904
ERP	$36,993	$0	$0	$0	$0	$0	$36.993
Balance-of-utility business	$655,000	$1,055,314	$1,153,773	$1,261,419	$1,379,108	$1,507,777	$7,012,390
Total	$2,375,457	$1,367,918	$1,273,332	$1,531,510	$1,588,067	$1,604,531	$9,740,814

Table 4-3. Theme 2 Capital Expenditures (Nominal $)

Theme 3

Under the Theme 3 resource plan, $1.8B (nominal) of capital will be invested by the utility in Power Supply assets over the 29 year planning period, with $1.0B (nominal) of this investment occurring in the first 9 years of the period.

Theme 3 - ('000)	2017-2020	2021-2025	2026-2030	2031-2035	2036-2040	2041-2045	Total
Power Supply	$378,874	$655,004	$255,271	$408,219	$36,137	$35,250	$1,768,756
Smart Grid	$171,507	$24,277	$23,374	$25,081	$2,663	$0	$246,904
ERP	$36,993	$0	$0	$0	$0	$0	$36.993
Balance-of-utility business	$655,000	$1,055,314	$1,153,773	$1,261,419	$1,379,108	$1,507,777	$7,012,390
Total	$1,242,374	$1,734,595	$1,432,419	$1,694,721	$1,417,909	$1,543,027	$9,065,043

Table 4-4. Theme 3 Capital Expenditures (Nominal $)

Risk Analysis

Planning to achieve an affordable and resilient electricity supply that meets Hawaii's clean energy policy goals is a complex and challenging effort for all stakeholders. There are important future uncertainties to consider, including fuel prices and technology developments, and the investment decisions made today by customers, third parties, the State, and Hawaiian Electric will impact customers for decades to come. These uncertainties impact the risks facing our customers and Hawaiian Electric, including:

- Electricity price risk, in terms of absolute level
- Electricity price risk, in terms of volatility
- "Buyer's Remorse" risk for capital investments made in long term assets
- Ability to afford the investments necessary to ensure the reliability and security of the electricity grid

These risks are somewhat different under each of the three Themes. Table 4-5 provides a qualitative assessment of each of these risks under each of the Themes. An up arrow indicates a better, less risky result, relative to the other Themes.

Risk	Theme 1	Theme 2	Theme 3
Price level	↓	↑	↓
Price volatility	↑	↑	↓
Capital investment	↔	↓	↑
Grid reliability & security	↓	↑	↓

Table 4-5. Risk Assessment

TOTAL SOCIETAL COSTS FOR ENERGY: HAWAIIAN ELECTRIC

As Hawai'i selects the best path to achieve its renewable energy future, the total societal cost of electricity is an important consideration. For this analysis, the total societal cost of electricity is the sum of the costs for independent generation, investments in distributed generation and storage, federal and state tax incentives, fuel, and all other utility operating costs. The chart below provides, by Theme, the Net Present Value of this cost stream over the period 2017 through 2045.

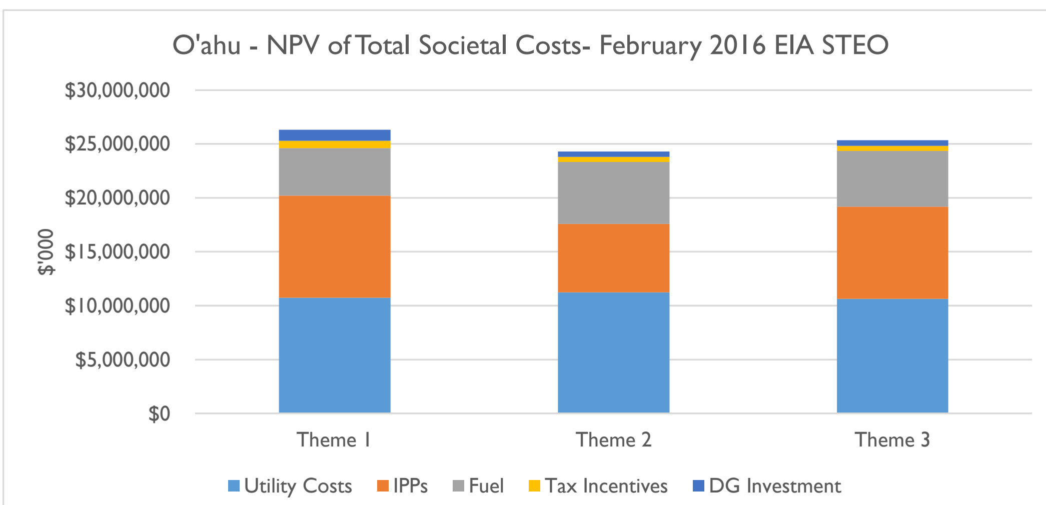


Figure 4-13. Total Societal Costs of the Plans 2017 through 2045

TOTAL SOCIETAL INVESTMENT: HAWAIIAN ELECTRIC

Significant investments by home and business owners across the State, project developers and independent power producers, Federal and State government, and the Company are all required to achieve Hawaii's goal of 100% renewable energy. The capital expenditures required to achieve Hawaii's energy policy goals on Oahu range from $16.4B in Theme 3 to $18B in Theme 1. Hawaiian Electric Company investments represent only a fraction of that total, ranging from $8.9B to $9.7B across the Themes. Table 4-6 through Table 4-8 provide the Company's projections of this total investment, by stakeholder, for each Theme.

Investor	2017 -20	2021-25	2026-30	2031-35	2036-40	2041-45	Total
Distributed Generation & Storage Owners	$302,900	$407,400	$564,600	$551,200	$544,500	$537,900	$2,908,500
Utility Scale Renewable Generation	$697,738	$831,155	$884,820	$1,793,562	$922,853	$0	$5,130,128
Federal Tax Incentives	$468,791	$230,432	$56,068	$54,595	$53,564	$52,114	$915,564
Hawaii Tax Incentives	$131,723	$21,360	$500	$1,000	$500	$0	$155,083
Hawaiian Electric	$1,582,453	$1,396,284	$1,582,385	$1,676,665	$1,342,615	$1,337,688	$8,918,090
Theme 1 Total	**$3,183,605**	**$2,886,631**	**$3,088,373**	**$4,077,022**	**$2,864,032**	**$1,927,702**	**$18,027,365**

Table 4-6. Total Societal Energy Investment – Theme 1

Investor	2017 -20	2021-25	2026-30	2031-35	2036-40	2041-45	Total
Distributed Generation & Storage Owners	$302,900	$161,200	$154,300	$149,600	$150,000	$158,600	$1,076,600
Utility Scale Renewable Generation	$451,725	$0	$1,092,238	$0	$1,361,910	$2,607,669	$5,513,542
Federal Tax Incentives	$468,791	$24,441	$33,533	$9,968	$54,620	$76,425	$667,778
Hawaii Tax Incentives	$131,723	$10,860	$3,000	$0	$5,500	$8,000	$159,083
Hawaiian Electric	$2,375,457	$1,367,918	$1,273,332	$1,531,510	$1,588,067	$1,604,531	$9,740,815
Theme 2 Total	**$3,730,596**	**$1,564,419**	**$2,556,403**	**$1,691,078**	**$3,160,097**	**$4,455,225**	**$17,157,818**

Table 4-7. Total Societal Energy Investment – Theme 2

4. Financial Impacts

Total Societal Investment: Hawaiian Electric

Investor	2017 -20	2021-25	2026-30	2031-35	2036-40	2041-45	Total
Distributed Generation & Storage Owners	$309,200	$163,400	$154,300	$149,600	$150,000	$158,600	$1,085,100
Utility Scale Renewable Generation	$451,725	$0	$1,092,238	$0	$1,361,910	$2,607,669	$5,513,542
Federal Tax Incentives	$363,357	$24,441	$33,533	$9,968	$54,620	$76,425	$562,344
Hawaii Tax Incentives	$128,223	$10,860	$2,500	$500	$5,500	$8,000	$155,583
Hawaiian Electric	$1,242,374	$1,734,595	$1,432,419	$1,694,721	$1,417,909	$1,543,027	$9,065,045
Theme 3 Total	**$2,494,879**	**$1,933,296**	**$2,714,990**	**$1,854,789**	**$2,989,939**	**$4,393,721**	**$16,381,614**

Table 4-8. Total Societal Energy Investment – Theme 3

The above investment totals do not include energy efficiency investments made by customers or demand response investments made by DR providers or customers.

MAUI FINANCIAL IMPACTS

The data and analyses presented in this section cover all of Maui Electric's service territory and customers, unless clearly noted. Moloka'i and Lana'i are included in the Maui results, and there is a section below that addresses each of those islands individually.

For Maui, Themes 2 and 3 have virtually the same net present value of revenue requirements over the 2017 to 2045 planning period, under both fuel price forecasts. Theme 1 is clearly a higher cost solution, as compared either Theme 2 or Theme 3, for Maui. The Lana'i and Moloka'i results included in these county-wide analyses are for Theme 1 only.

Revenue Requirement Analysis

Total Maui Electric revenue requirements, under both fuel forecasts, have been calculated for the Final Plan for each Theme. Table 4-9 shows the Net Present Value of the annual revenue requirements for each Theme and Figure 4-14 through Figure 4-17 compare each Theme's annual revenue requirement under the 2015 EIA Reference and February 2016 EIA STEO fuel forecasts respectively, in both real (2016$) and nominal dollars.

Net Present Value of Revenue Requirement ($000)	2015 EIA Reference	February 2016 EIA STEO
NPV of Theme 1 Revenue Requirement	$6,156,969	$5,551,132
NPV of Theme 2 Revenue Requirement	$5,413,969	$4,978,143
NPV of Theme 3 Revenue Requirement	$5,435,341	$4,840,345

Table 4-9. Net Present Value of Revenue Requirement

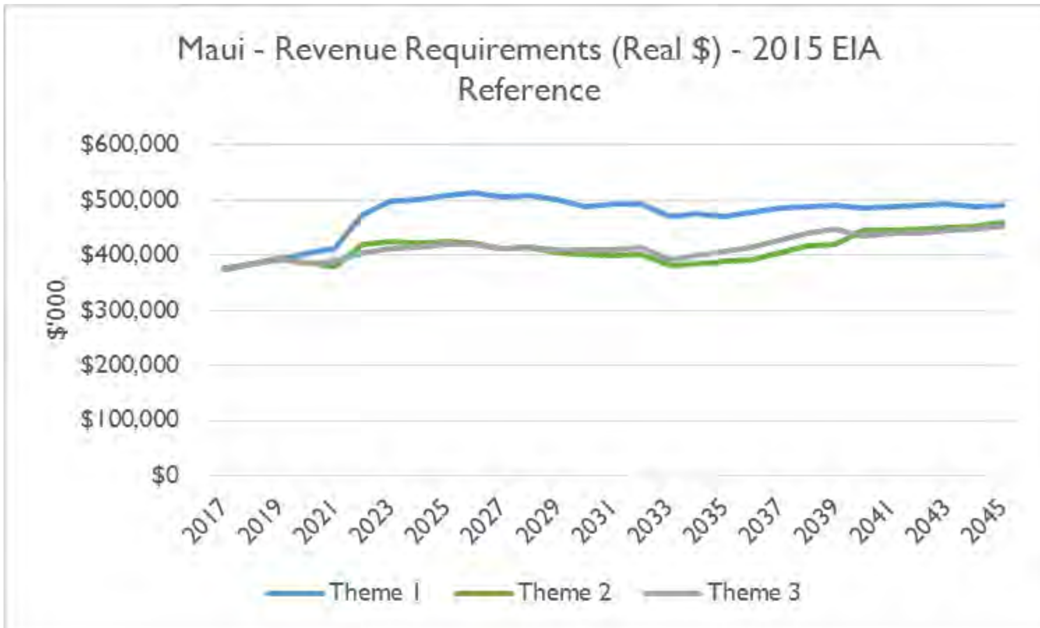


Figure 4-14. Comparison of Revenue Requirement (Real 2016 $) – 2015 EIA Reference

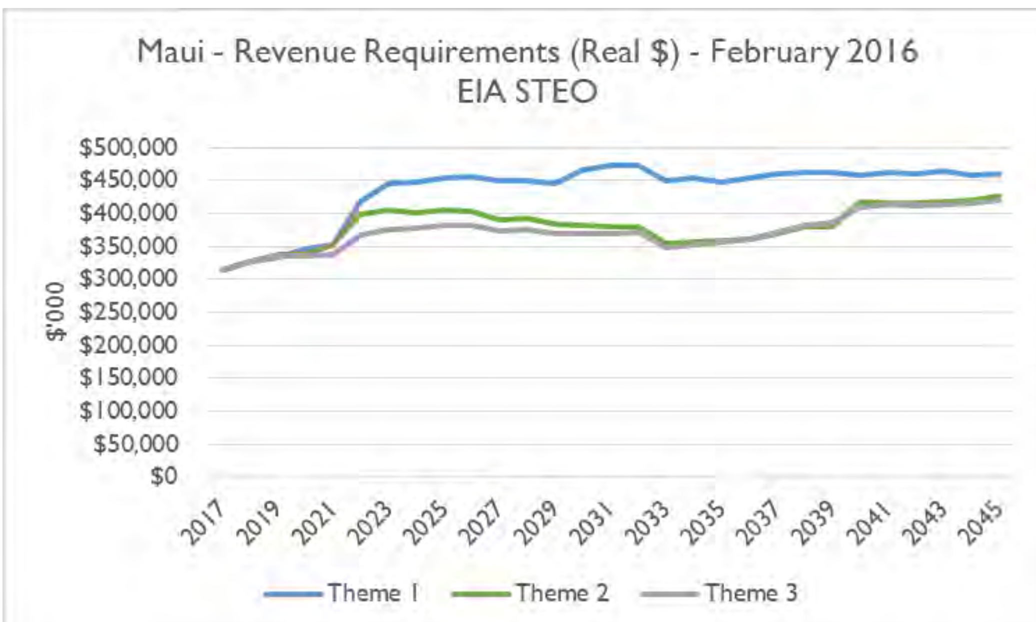


Figure 4-15. Comparison of Revenue Requirement (Real 2016 $)– February 2016 EIA STEO

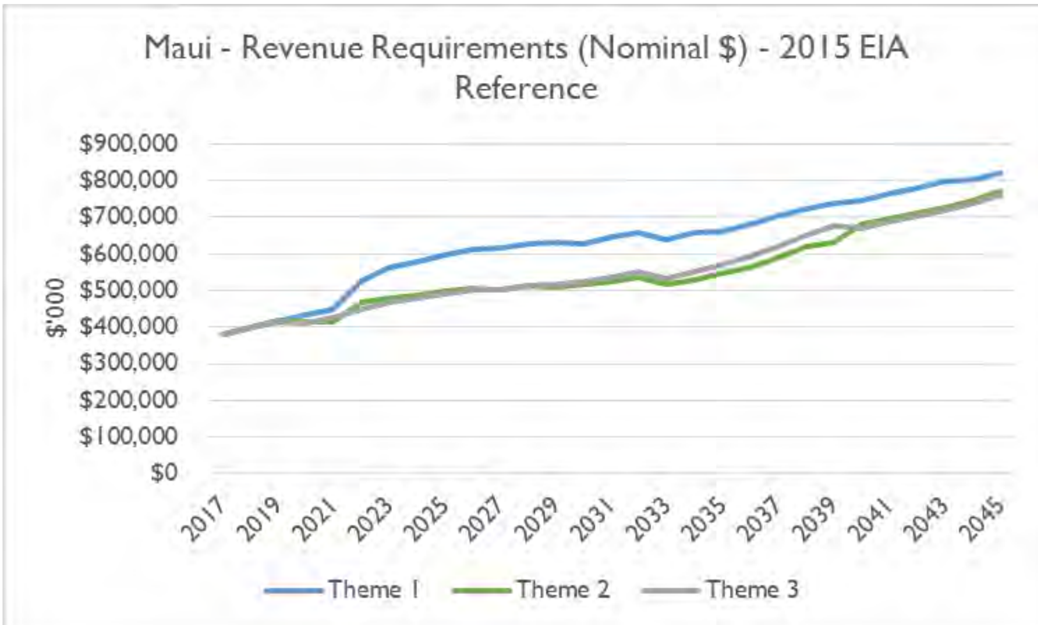


Figure 4-16. Comparison of Revenue Requirement (Nominal $) – 2015 EIA Reference

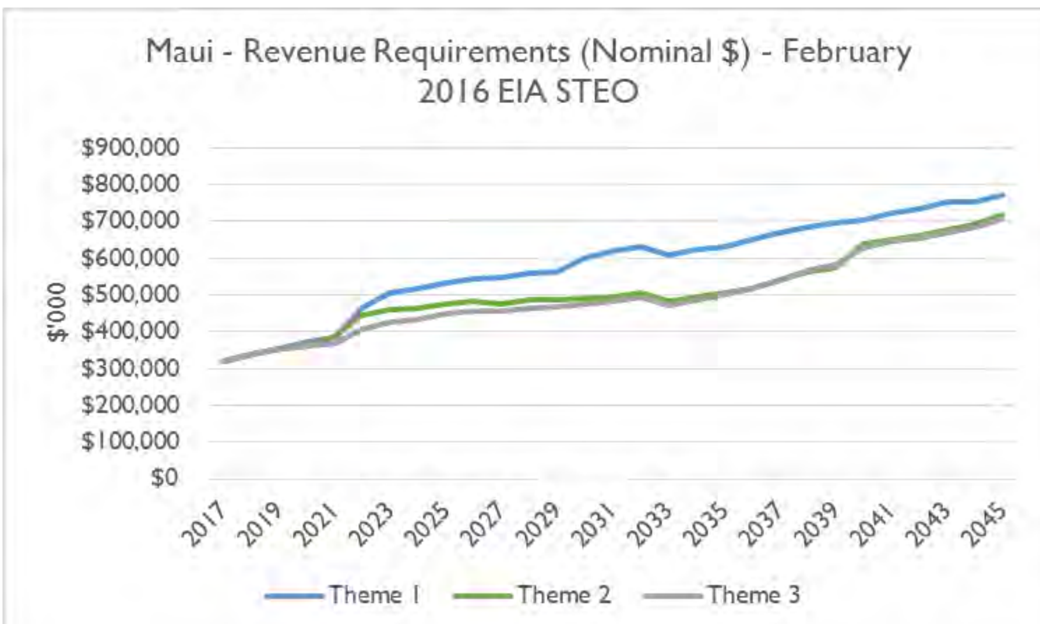


Figure 4-17. Comparison of Revenue Requirement (Nominal $) – February 2016 EIA STEO

Customer Rate Impact Analysis

Residential customer rates, in real 2016 $, fall over the planning period for Themes 2 and 3 under the 2015 EIA Reference fuel price forecast and stay roughly flat under the February 2016 EIA STEO fuel price forecast. In contrast, customer rates in real 2016 $, increase for Theme 1, under both the 2015 EIA Reference and February 2016 EIA STEO price fuel forecasts.

Compared to the 2014 PSIP results, customer rates in real terms are projected to be consistently lower under Themes 2 and 3, under either fuel price forecast. Theme 1 results in rates higher than the 2014 PSIP results, in real terms.

Customer rates in nominal terms show consistent increases as inflation, even at the historically low levels used in this analysis, dramatically impacts the value of a dollar over the almost 30 year planning period.

The residential customer rate for the three Themes, under the 2015 EIA Reference fuel price forecast, is presented in real 2016 $ in Figure 4-18 and in nominal $ in Figure 4-19. 2014 PSIP results are also shown for comparison purposes.

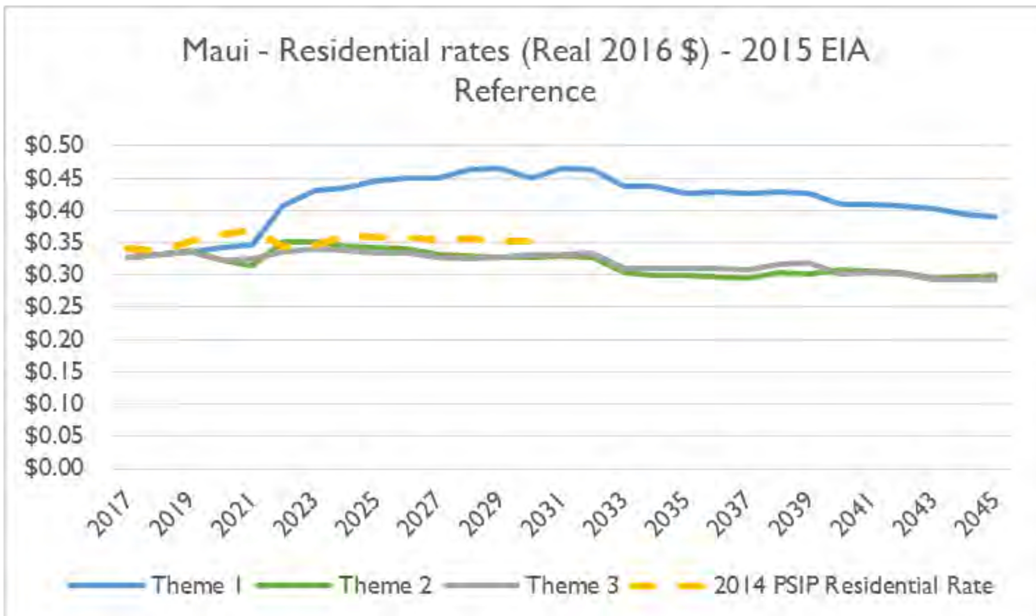


Figure 4-18. Residential Rates (Real 2016 $): 2015 EIA Reference

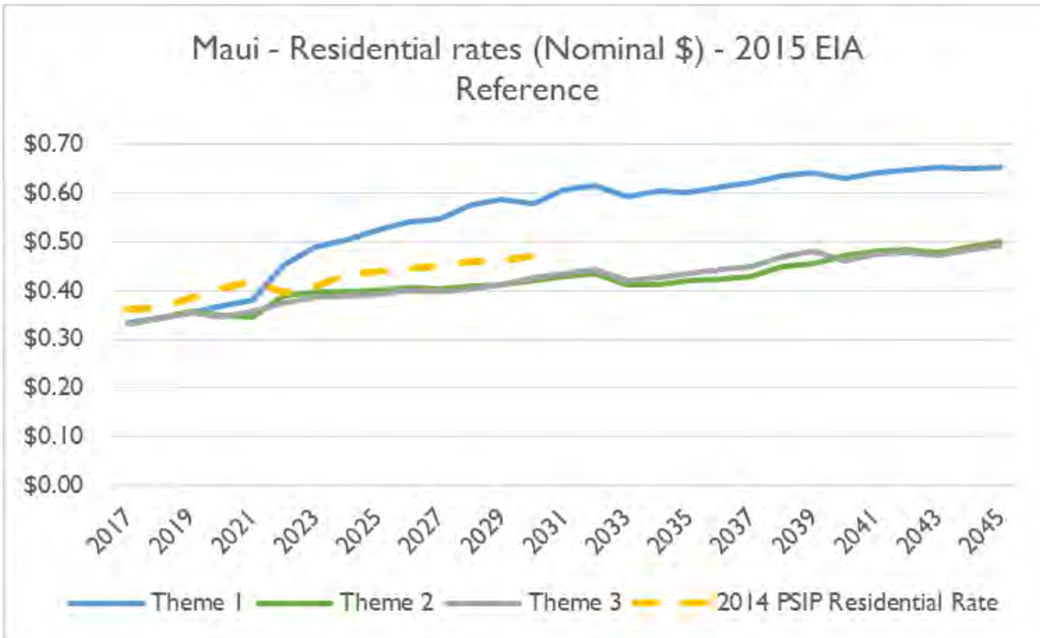


Figure 4-19. Residential Rates (Nominal $): 2015 EIA Reference

The residential customer rate for the three Themes, under the February 2016 EIA STEO fuel price forecast, is presented in real 2016 $ in Figure 4-20 and in nominal $ in Figure 4-21 below. 2014 PSIP results are also shown for comparison purposes.

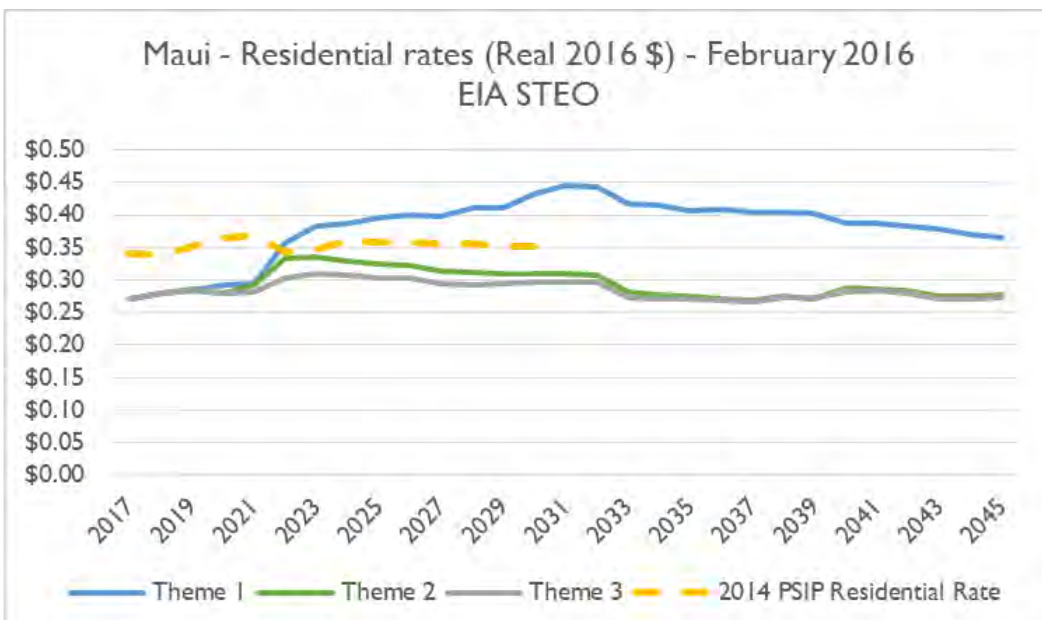


Figure 4-20. Residential Rates (Real 2016 $): February 2016 EIA STEO

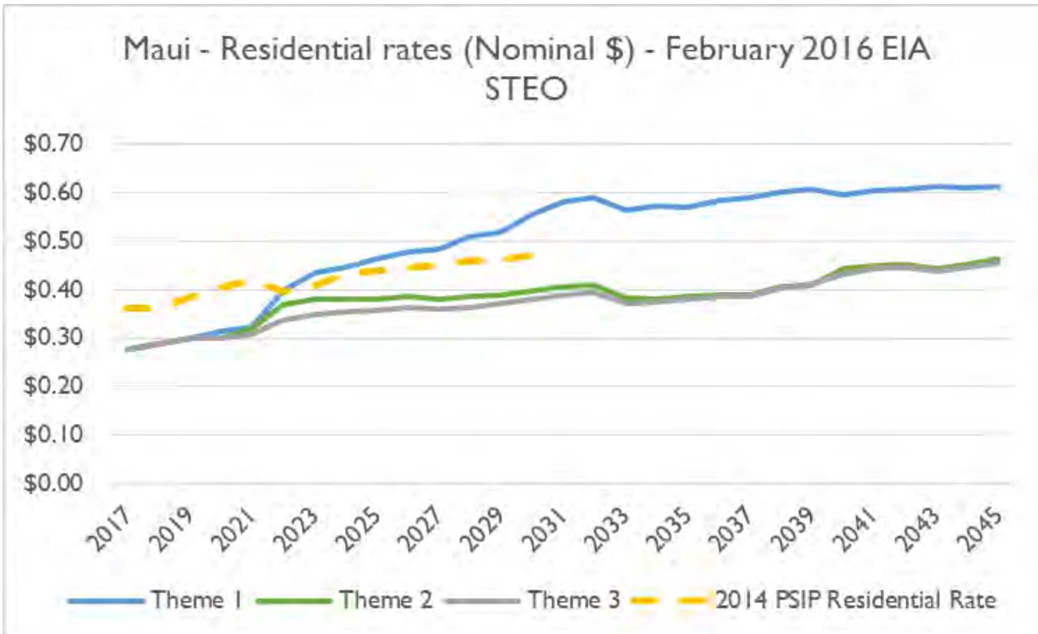


Figure 4-21. Customer Rates (Nominal $): February 2016 EIA STEO

Residential Customer Bill Impact Analysis

The overall impact on a customer's bill is the combination of usage and rates. Over the planning period, usage per customer is expected to decline, consistent with the Energy Efficiency Portfolio Standard goals. The residential customer bill analyses below present each Theme's projected residential bill impact for the average non-DG-PV customer.

The residential customer bill impact for the three Themes, under the 2015 EIA Reference fuel price forecast, is presented in real 2016 $ in Figure 4-22 and in nominal $ in Figure 4-23. 2014 PSIP results are shown for comparison purposes.

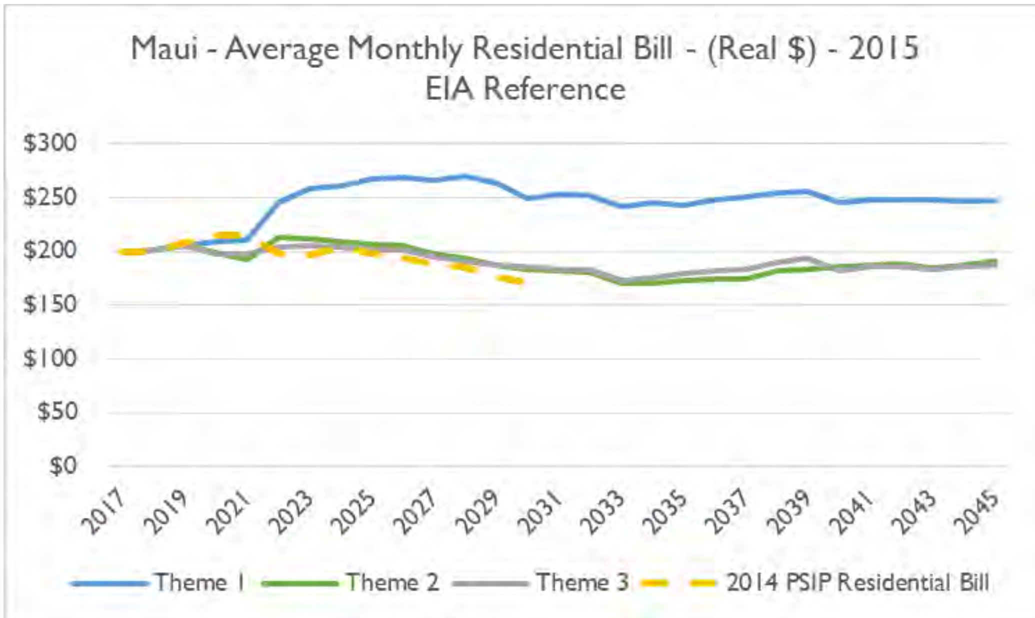


Figure 4-22. Residential Bill (Real 2016 $): 2015 EIA Reference

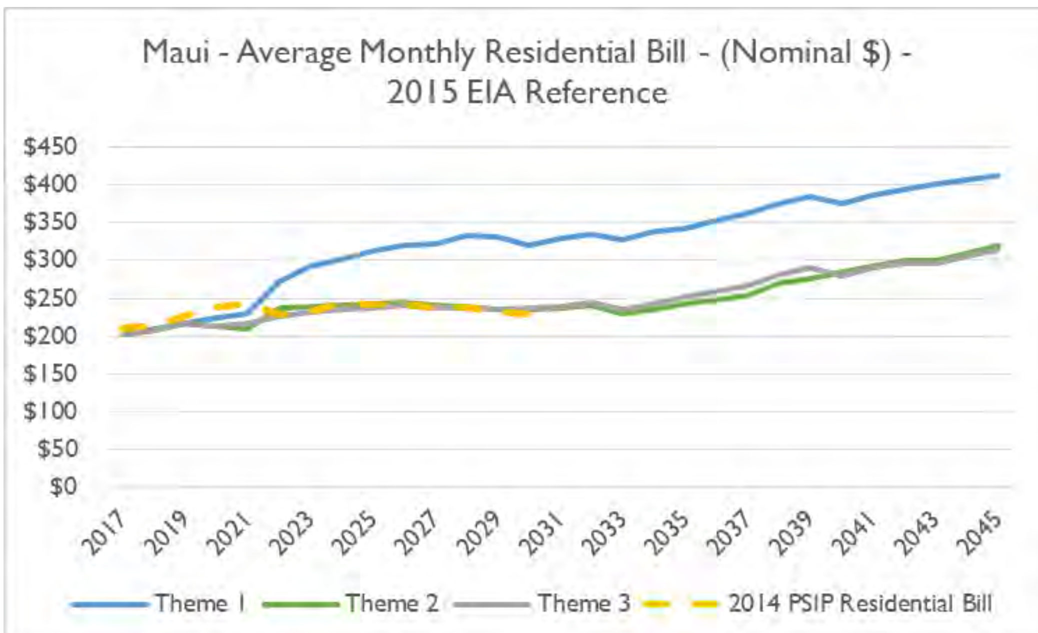


Figure 4-23. Residential Bill (Nominal $): 2015 EIA Reference

The residential customer bill impact for the three Themes, under the February 2016 EIA STEO fuel price forecast, is presented in real 2016 $ in Figure 4-24 and in nominal $ in Figure 4-25. 2014 PSIP results are shown for comparison purposes.

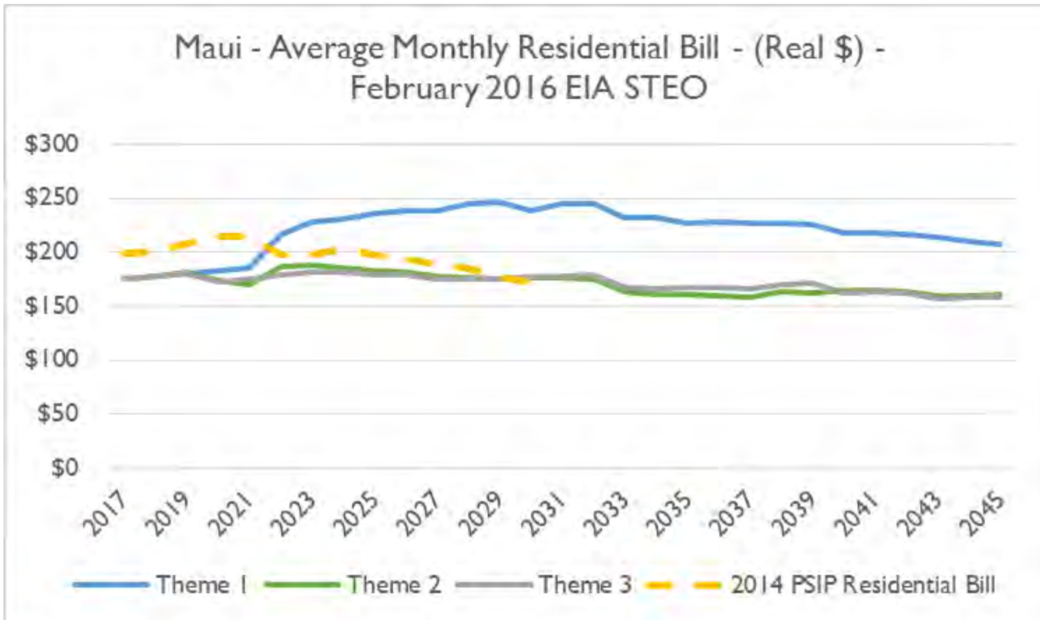


Figure 4-24. Residential Bill (Real 2016 $): February 2016 EIA STEO

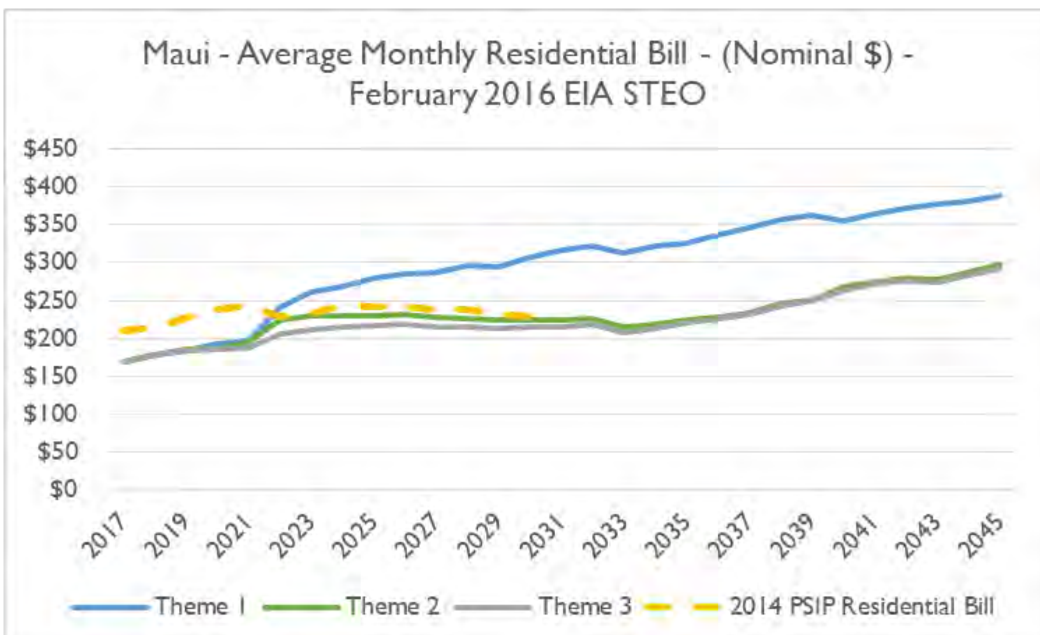


Figure 4-25. Residential Bill (Nominal $): February 2016 EIA STEO

Moloka'i and Lana'i

Moloka'i and Lana'i Theme 1 results have been included in all of the Maui Electric analyses presented above, as they were in the 2014 PSIP. Due to scale and logistic limitations, LNG was not evaluated on Moloka'i or Lana'i and thus only Theme 1 and

Theme 3 plans were developed and analyzed. Figure 4-26 through Figure 4-33 compare the annual real and nominal revenue requirement for Theme 1 and Theme 3 for each island under both fuel forecasts.

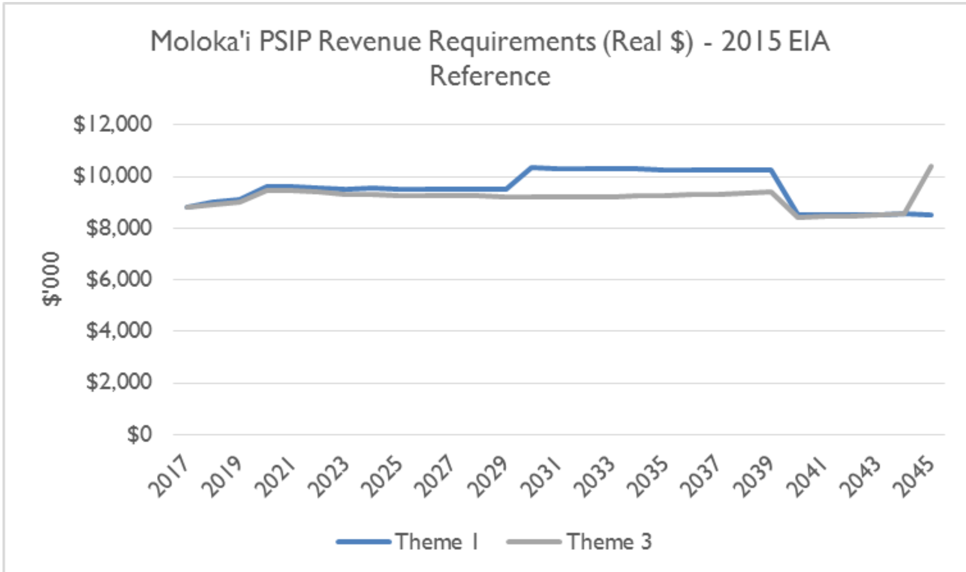


Figure 4-26. Comparison of Revenue Requirement (Real 2016 $) – 2015 EIA Reference

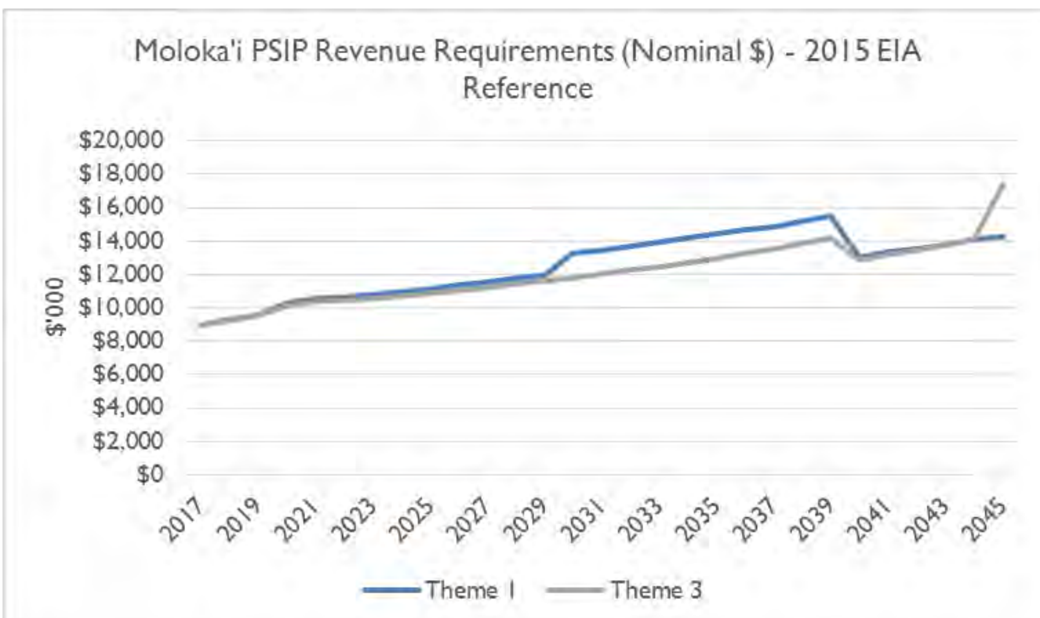


Figure 4-27. Comparison of Revenue Requirement (Nominal $) – 2015 EIA Reference

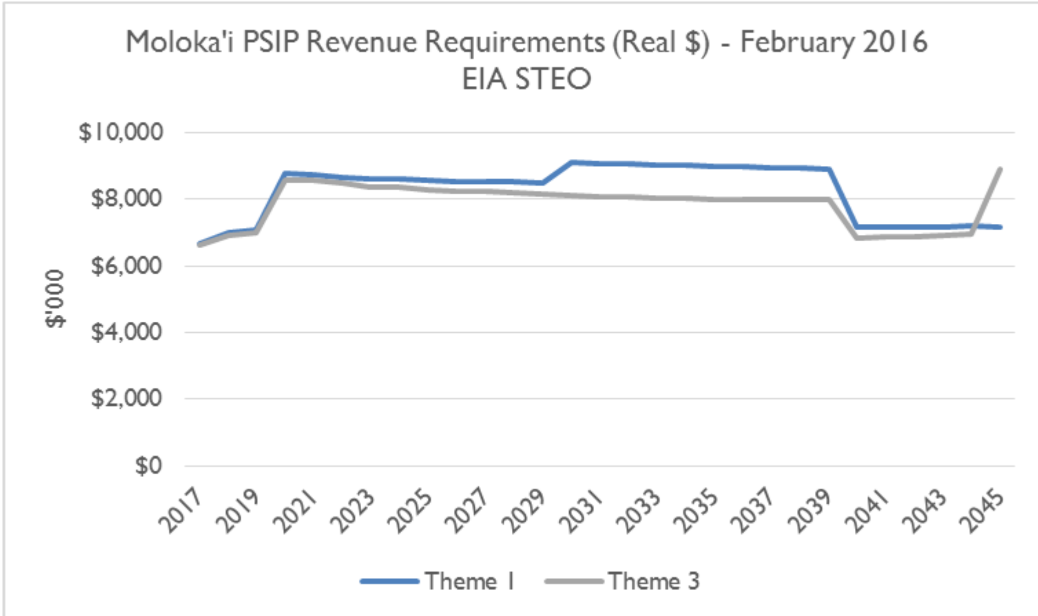


Figure 4-28. Comparison of Revenue Requirement (Real 2016 $)– February 2016 EIA STEO

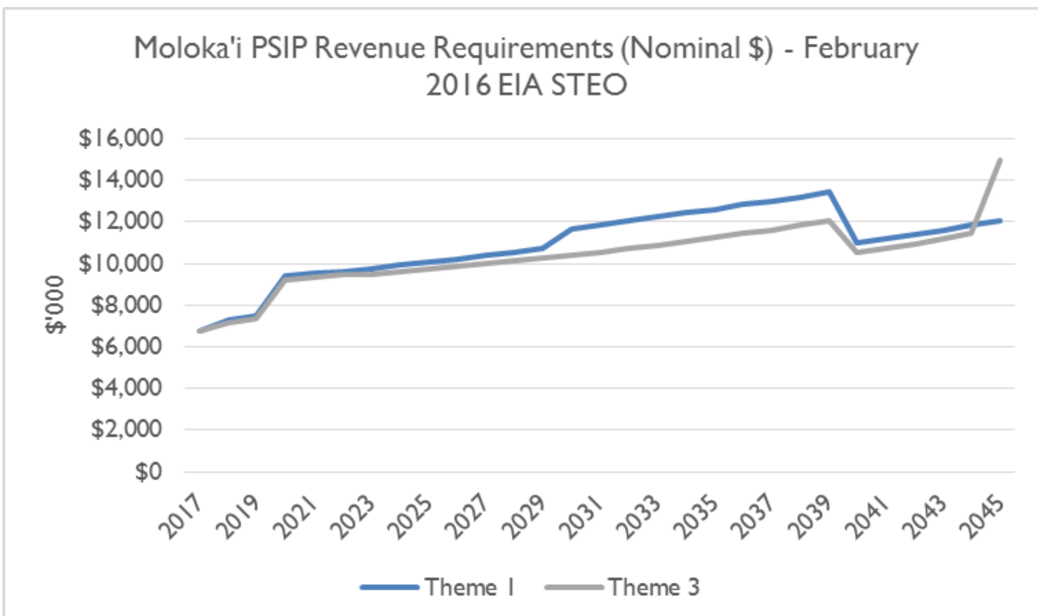


Figure 4-29. Comparison of Revenue Requirement (Nominal $) – February 2016 EIA STEO

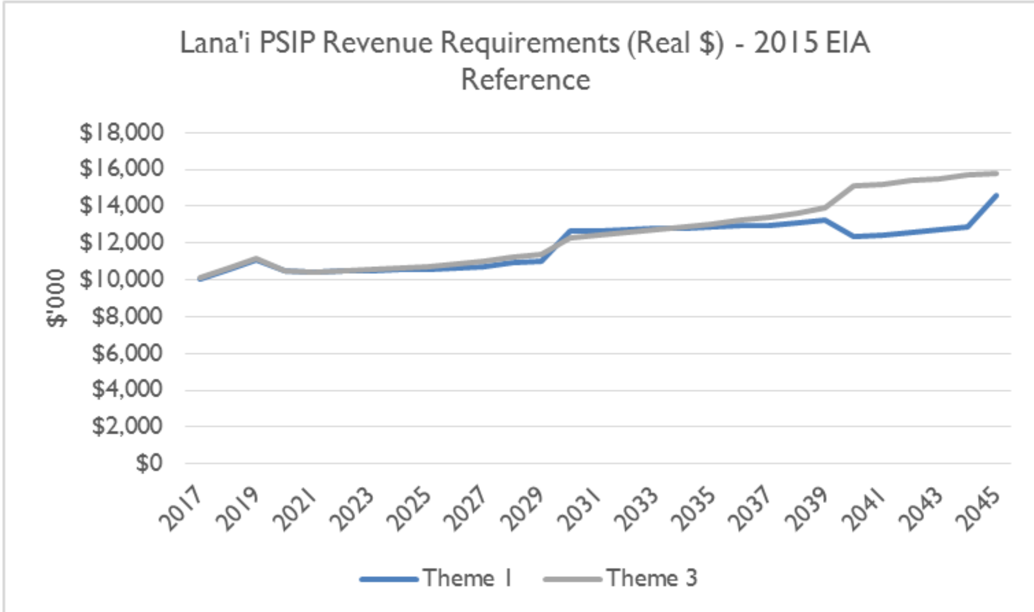


Figure 4-30. Comparison of Revenue Requirement (Real 2016 $) – 2015 EIA Reference

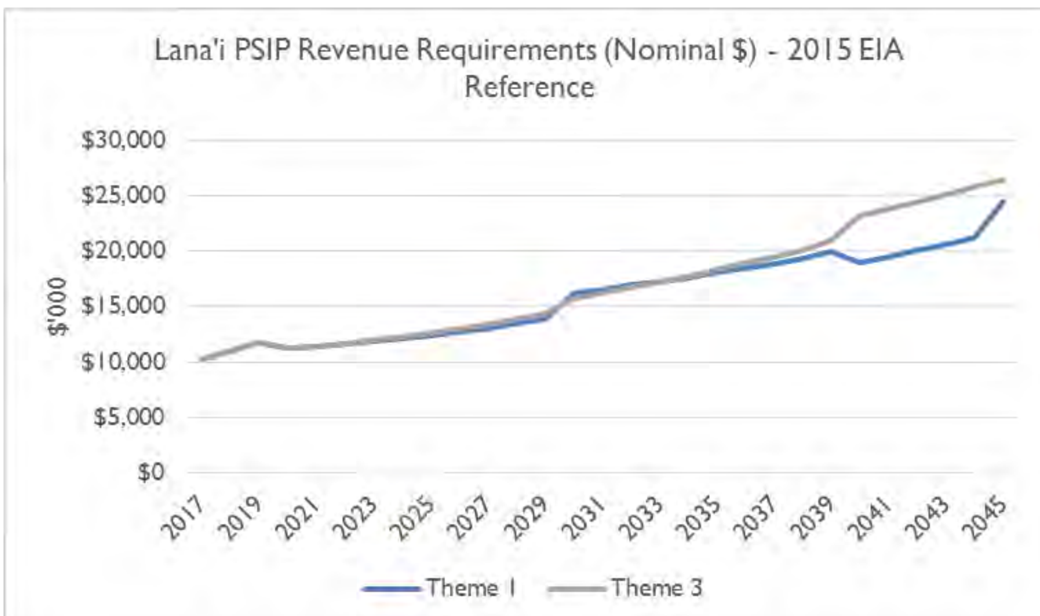


Figure 4-31. Comparison of Revenue Requirement (Nominal $) – 2015 EIA Reference

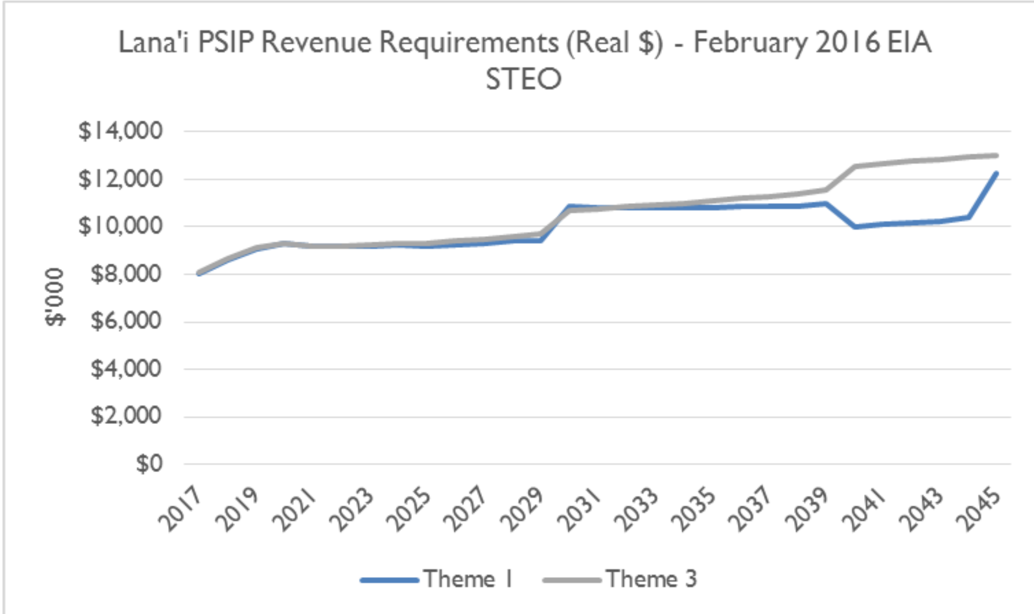


Figure 4-32. Comparison of Revenue Requirement (Real 2016$)– February 2016 EIA STEO

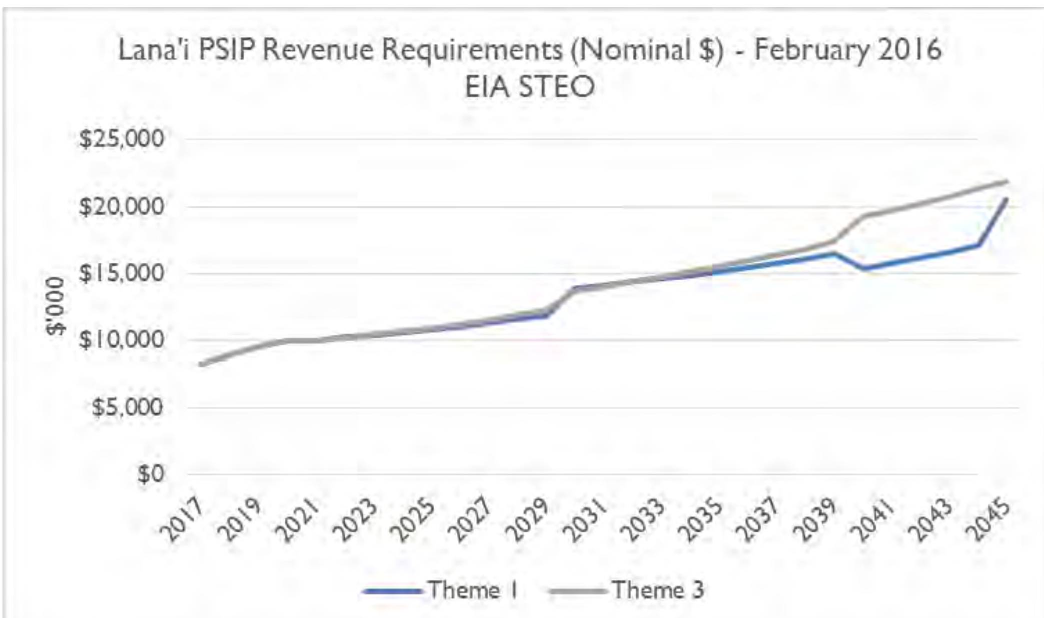


Figure 4-33. Comparison of Revenue Requirement (Nominal $) – February 2016 EIA STEO

The Company has not built a complete financial model for Moloka'i and Lana'i and so is not able to produce residential rate and bill impact analyses that are fully comparable to those presented in this report for the other islands. The available analysis tools do provide an understanding of the system average rate and this is presented in real and nominal dollars in Figure 4-34 through Figure 4-41.

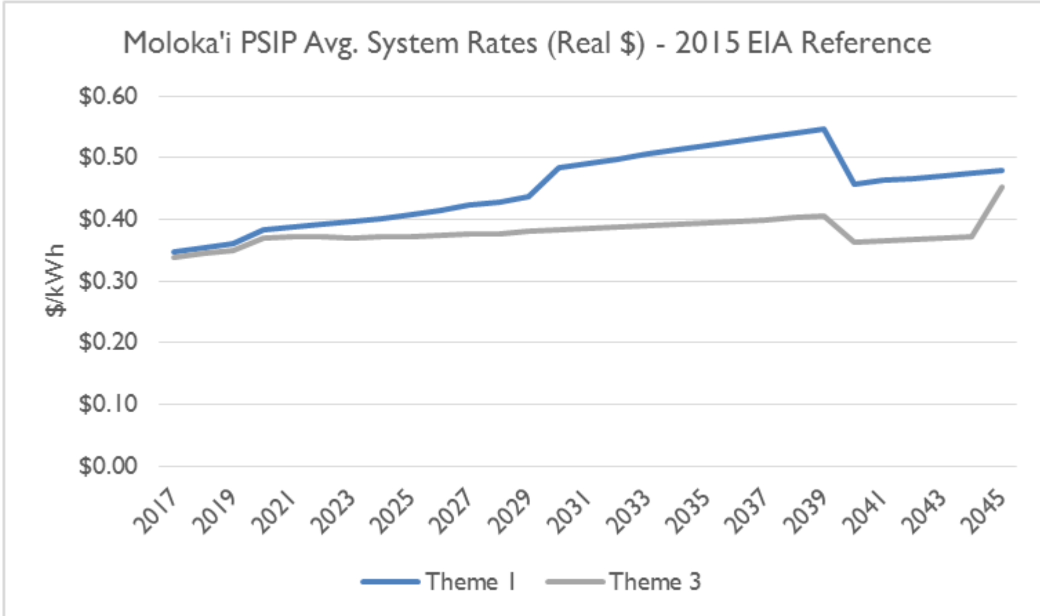


Figure 4-34. Comparison of Moloka'i System Average Rates (Real 2016 $) – 2015 EIA Reference

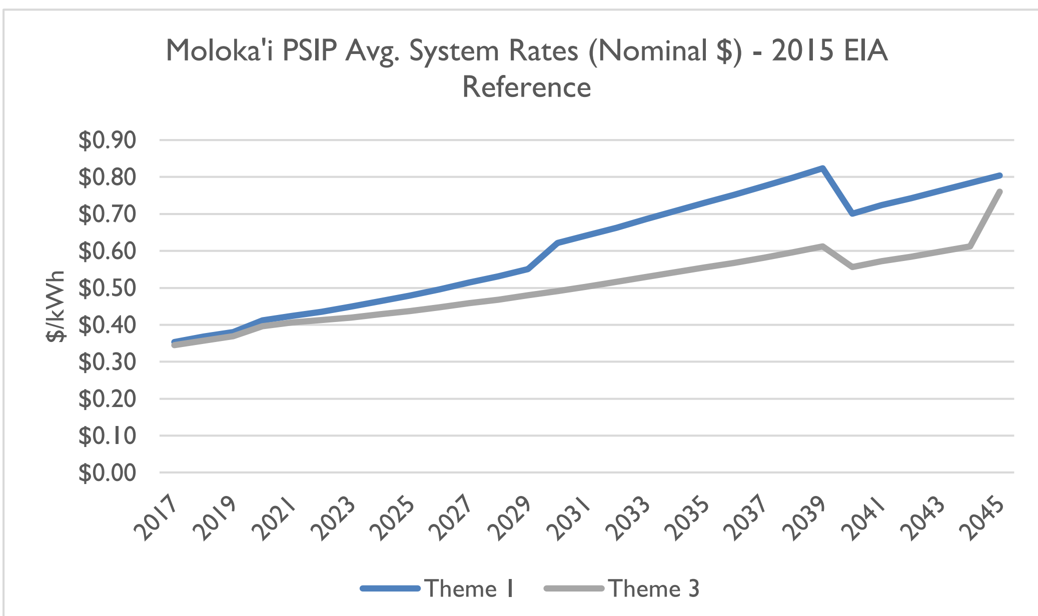


Figure 4-35. Comparison of Moloka'i System Average Rates (Nominal $) – 2015 EIA Reference

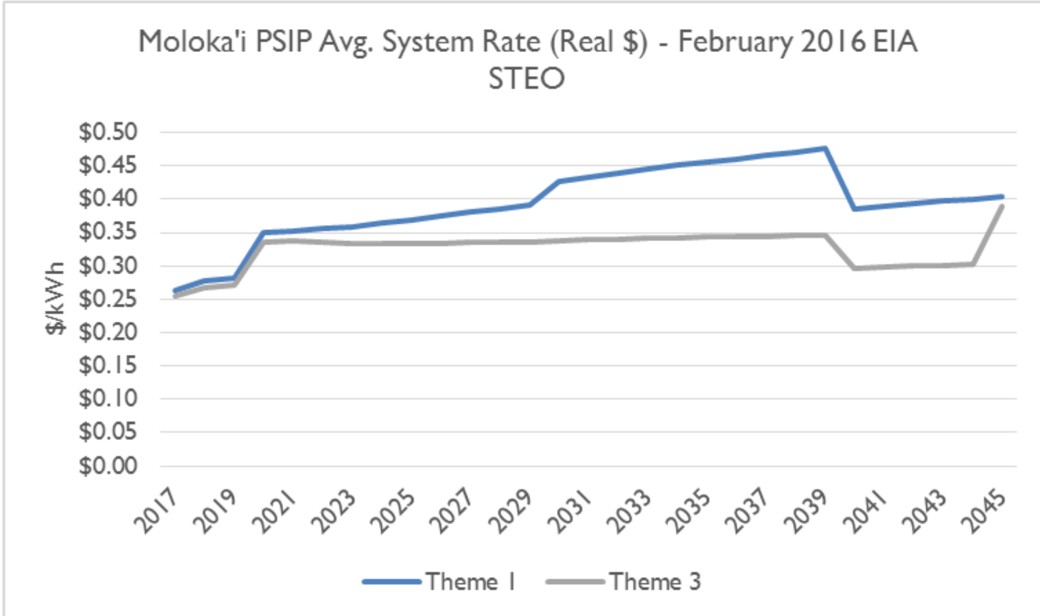


Figure 4-36. Comparison of Moloka'i System Average Rate (Real 2016 $) – February 2016 EIA STEO

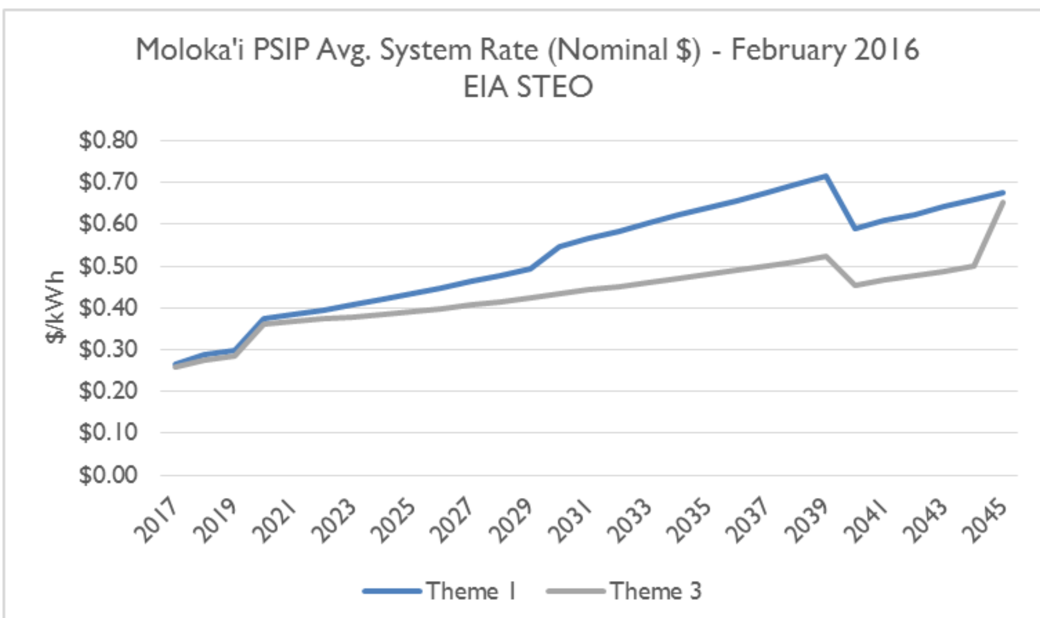


Figure 4-37. Comparison of Moloka'i System Average Rate (Nominal $) – February 2016 EIA STEO

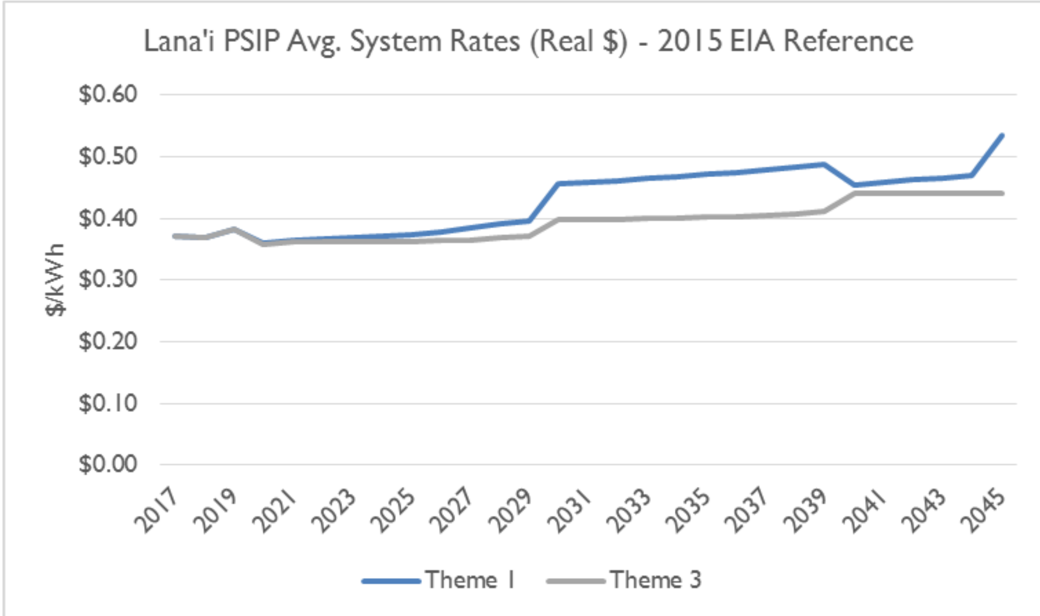


Figure 4-38. Comparison of Lana'i System Average Rates (Real 2016 $) – 2015 EIA Reference

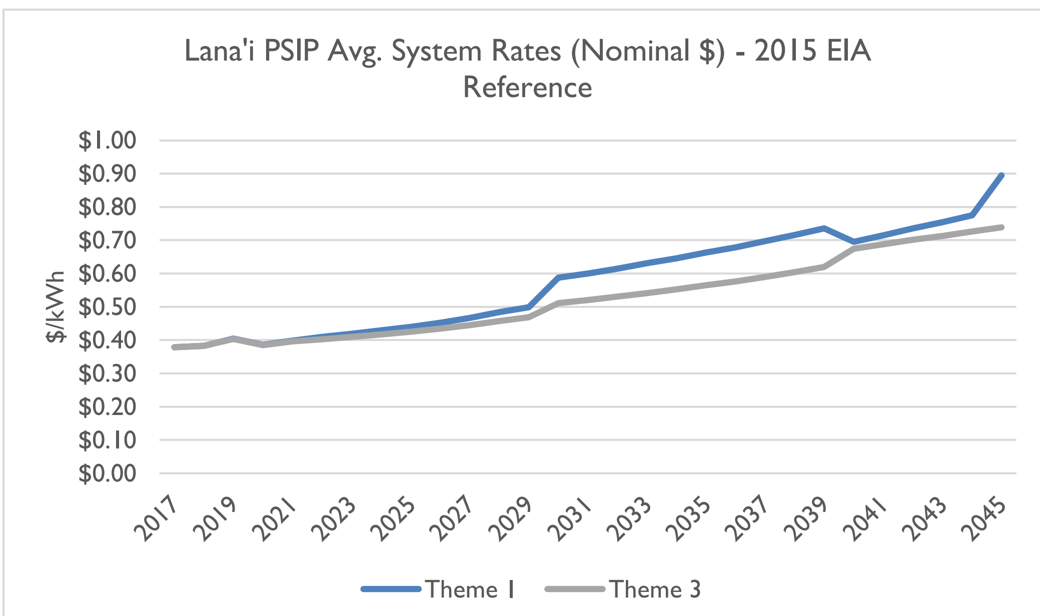


Figure 4-39. Comparison of Lana'i System Average Rates (Nominal $) – 2015 EIA Reference

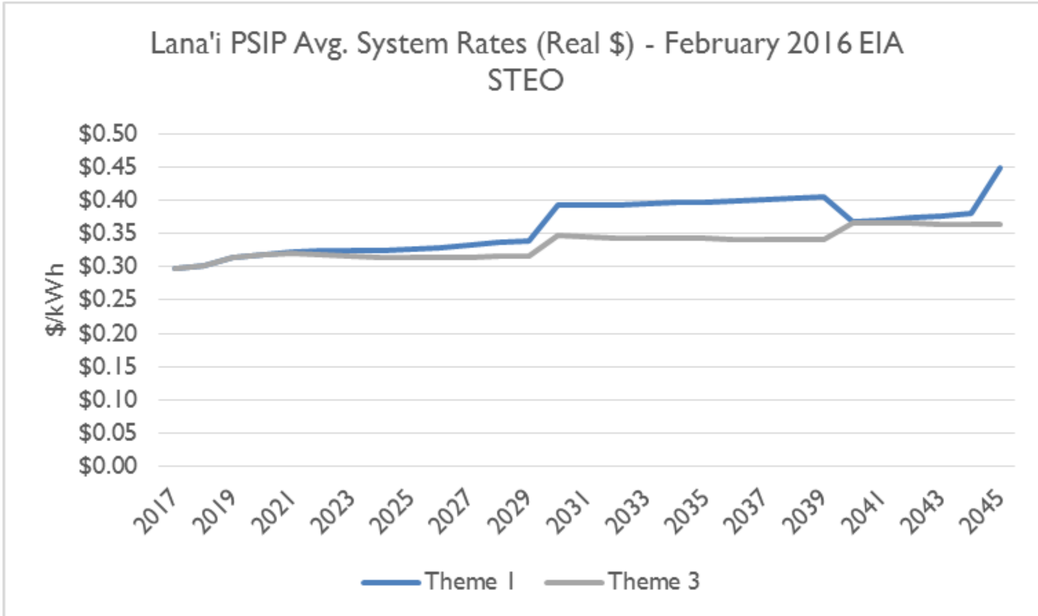


Figure 4-40. Comparison of Lana'i System Average Rates (Real 2016 $) – February 2016 EIA STEO

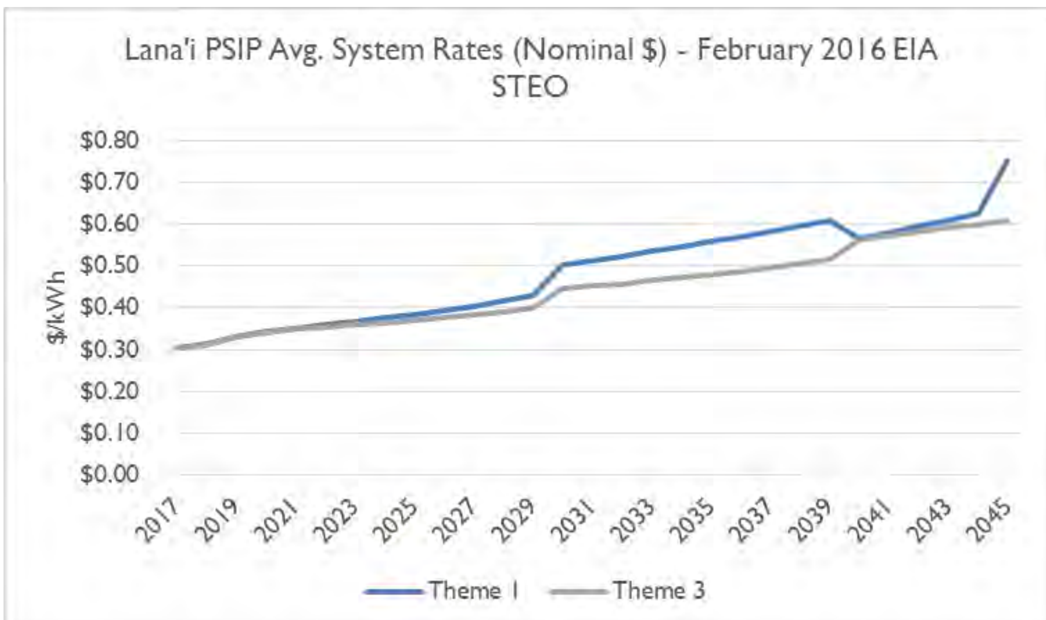


Figure 4-41. Comparison of Lana'i System Average Rates (Nominal $) – February 2016 EIA STEO

Capital Expenditure Projections

The revenue requirement projections for each Theme include capital expenditure projections for power supply, smart grid, ERP, and all other utility capital expenditures (referred to as "balance-of-utility business capital expenditures"). The Power Supply capital expenditures range from $0.5B ($0.25B in the first 9 years) for Theme 3 to $1.0B

($0.4B in the first 9 years) for Theme 1, consistent with the mix and timing of resource additions and retirements.

Smart Grid and ERP are treated separately, as these proposed capital projects have different costs under a merged and an unmerged future. As Theme 2 is only possible in a merged future, the analysis uses the merged capital costs for both of these projects for Theme 2 capital expenditures. While Themes 1 and 3 can be occur in either a merged or an unmerged future, we have used the merged capital expenditures for these projects in this analysis, in order to ease the comparability of results between Themes.

As described in detail in Appendix I, the balance-of-utility business capital expenditures have been calculated using a top down manner for the 2015 EIA Reference fuel price scenario and have been consistently applied across all three Themes for both fuel cases. The tables below summarize Maui Electric's capital expenditures by category for each Theme for all three islands.

Theme 1

Under the Theme 1 resource plan, $1.0B (nominal) of capital will be invested by the utility in Power Supply assets over the 29 year planning period, with $0.4B (nominal) of this investment occurring in the first 9 years of the period.

Theme 1 ('000)	2017-2020	2021-2025	2026-2030	2031-2035	2036-2040	2041-2045	Total
Power Supply	$122,192	$285,023	$172,041	$159,038	$146,173	$100,082	$984,549
Smart Grid	$34,487	$2,288	$3,176	$4,299	$523	$0	$44,773
ERP	$7,132	$0	$0	$0	$0	$0	$7,132
Balance-of-utility business	$99,393	$128,219	$140,181	$153,260	$167,559	$183,192	$871,804
Total	$263,203	$415,530	$315,398	$316,597	$ 314,256	$283,274	$1,908,258

Table 4-10. Theme 1 Capital Expenditures (Nominal $)

Theme 2

Under the Theme 2 resource plan, $0.6B (nominal) of capital will be invested by the utility in Power Supply assets over the 29 year planning period, with $0.37B (nominal) of this investment occurring in the first 9 years of the period.

Theme 2 ('000)	2017-2020	2021-2025	2026-2030	2031-2035	2036-2040	2041-2045	Total
Power Supply	$204,966	$168,298	$53,688	$43,101	$131,432	$26,043	$627,528
Smart Grid	$34,487	$2,288	$3,176	$4,299	$523	$0	$44,773
ERP	$7,132	$0	$0	$0	$0	$0	$7,132
Balance-of-utility business	$99,393	$128,219	$140,181	$153,260	$167,559	$183,192	$871,804

Total	$345,978	$298,805	$197,045	$200,660	$299,514	$209,235	$1,551,238

Table 4-11. Theme 2 Capital Expenditures (Nominal $)

Theme 3

Under the Theme 3 resource plan, $0.5B (nominal) of capital will be invested by the utility in Power Supply assets over the 29 year planning period, with $0.25B (nominal) of this investment occurring in the first 9 years of the period.

Theme 3 - ('000)	2017-2020	2021-2025	2026-2030	2031-2035	2036-2040	2041-2045	Total
Power Supply	$124,909	$134,635	$53,688	$43,101	$131,432	$26,043	$513,807
Smart Grid	$34,487	$2,288	$3,176	$4,299	$523	$0	$44,773
ERP	$7,132	$0	$0	$0	$0	$0	$7,132
Balance-of-utility business	$99,393	$128,219	$140,181	$153,260	$167,559	$183,192	$871,804
Total	$265,920	$265,141	$197,045	$200,660	$299,514	$209,235	$1,437,516

Table 4-12. Theme 3 Capital Expenditures (Nominal $)

Risk Analysis

Planning to achieve an affordable, reliable, and secure electricity supply that meets Hawaii's clean energy policy goals is a complex and challenging effort for all stakeholders. There are important future uncertainties to consider, including fuel prices and technology developments, and the investment decisions made today by customers, third parties, the State, and Maui Electric will impact customers for decades to come. These uncertainties impact the risks facing our customers and Maui Electric, including:

- Electricity price risk, in terms of absolute level
- Electricity price risk, in terms of volatility
- "Buyer's Remorse" risk for capital investments made in long term assets
- Ability to afford the investments necessary to ensure the reliability and security of the electricity grid

These risks are somewhat different under each of the three Themes. Table 4-13 provides a qualitative assessment of each of these risks under each of the Themes. An up arrow indicates a better, less risky result, relative to the other Themes.

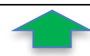
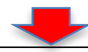
Risk	Theme 1	Theme 2	Theme 3
Price level			
Price volatility			
Capital investment			
Grid reliability & security			

Table 4-13. Risk Assessment

TOTAL SOCIETAL COSTS FOR ENERGY: MAUI ELECTRIC

As Hawai'i selects the best path to achieve its renewable energy future, the total societal cost of electricity is an important consideration. For this analysis, the total societal cost of electricity is the sum of the costs for independent generation, investments in distributed generation and storage, federal and state tax incentives, fuel, and all other utility operating costs. The chart below provides, by Theme, the Net Present Value of this cost stream over the period 2017 through 2045.

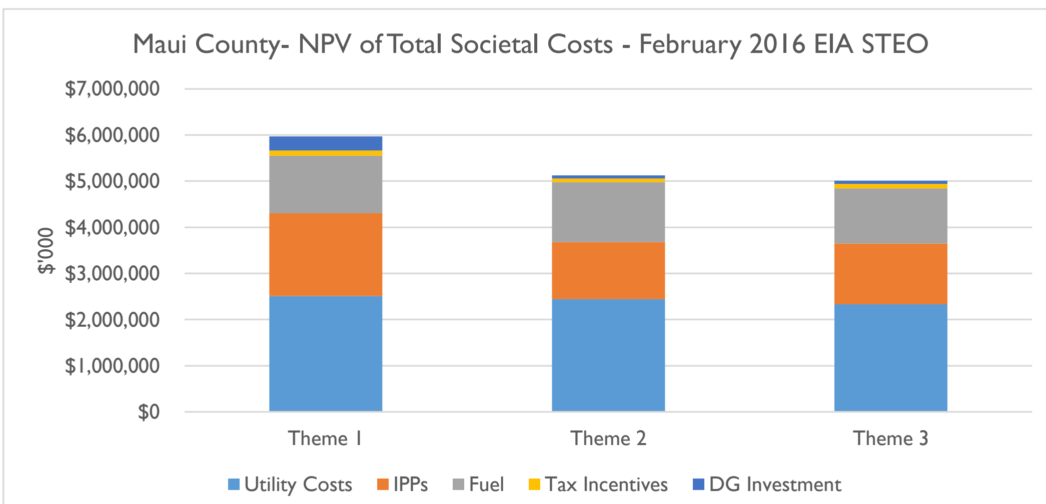


Figure 4-42. Total Societal Costs of the Plans 2017 through 2045

TOTAL SOCIETAL INVESTMENT: MAUI ELECTRIC

Significant investments by home and business owners across the State, project developers and independent power producers, Federal and State government, and the Company are all required to achieve Hawai'i's goal of 100% renewable energy. The capital expenditures required to achieve Hawai'i's energy policy goals for Maui, Moloka'i, and Lana'i range from $4.4B in Theme 3 to $6.3B in Theme 1. Maui Electric investments represent only a fraction of that total, ranging from $1.4B to $1.9B across the Themes. Table 4-14 through Table 4-16 provides the Company's projections of this total investment, by stakeholder, for each Theme.

Investor	**2017 -20**	**2021-25**	**2026-30**	**2031-35**	**2036-40**	**2041-45**	**Total**
Distributed Generation & Storage Owners	$302,900	$407,400	$564,600	$551,200	$544,500	$537,900	$2,908,500
Utility Scale Renewable Generation	$100,062	$144,943	$808,112	$0	$117,773	$131,282	$1,302,172
Federal Tax Incentives	$47,314	$18,592	$19,027	$18,424	$17,970	$17,493	$138,820
Hawaii Tax Incentives	$28,535	$4,378	$500	$0	$1,000	$1,500	$35,913
Maui Electric	$263,203	$415,530	$315,398	$316,597	$314,256	$283,274	$1,908,258
Theme 1 Total	**$742,014**	**$990,843**	**$1,707,637**	**$886,221**	**$995,499**	**$971,449**	**$6,293,663**

Table 4-14. Total Societal Energy Investment – Theme 1

Investor	**2017 -20**	**2021-25**	**2026-30**	**2031-35**	**2036-40**	**2041-45**	**Total**
Distributed Generation & Storage Owners	$302,900	$161,200	$154,300	$149,600	$150,000	$158,600	$1,076,600
Utility Scale Renewable Generation	$280,400	$0	$0	$0	$1,226,956	$197,291	$1,704,647
Federal Tax Incentives	$72,466	$2,392	$689	$694	$714	$799	$77,754
Hawaii Tax Incentives	$20,887	$1,187	$0	$0	$3,000	$0	$25,074
Maui Electric	$345,978	$298,805	$197,045	$200,660	$299,514	$209,235	$1,551,238
Theme 2 Total	**$1,022,631**	**$463,584**	**$352,034**	**$350,954**	**$1,680,184**	**$565,925**	**$4,435,313**

Table 4-15. Total Societal Energy Investment – Theme 2

Investor	2017 -20	2021-25	2026-30	2031-35	2036-40	2041-45	Total
Distributed Generation & Storage Owners	$309,200	$163,400	$154,300	$149,600	$150,000	$158,600	$1,085,100
Utility Scale Renewable Generation	$162,299	$330,326	$6,205	$0	$998,450	$204,786	$1,702,066
Federal Tax Incentives	$83,286	$13,966	$689	$694	$714	$9,840	$109,189
Hawaii Tax Incentives	$24,887	$3,187	$500	$0	$2,000	$3,500	$34,074
Maui Electric	$265,920	$265,141	$197,045	$200,660	$299,514	$209,235	$1,437,516
Theme 3 Total	**$845,592**	**$776,020**	**$358,739**	**$350,954**	**$1,450,678**	**$585,961**	**$4,367,945**

Table 4-16. Total Societal Energy Investment – Theme 3

The above investment totals do not include energy efficiency investments made by customers or demand response investments made by DR providers or customers.

HAWAI'I ISLAND FINANCIAL IMPACTS

For Hawai'i Island, the selection between Themes, based on financial metrics, is somewhat more nuanced than it is for the other islands. Theme 1 results in the lowest net present value of revenue requirements over the 2017 to 2045 planning period, under both fuel price forecasts. And Theme 2 results in the lowest residential rates and customer bills over the planning period. This divergence is driven by the higher level of Grid Export DG-PV under Theme 1 and the bill credits associated with it. So, while the absolute revenue requirement is lower under Theme 1, the rate and bill impact of a residential customer without DG-PV is lower under Theme 2.

Revenue Requirement Analysis

Total company revenue requirements, under both fuel forecasts, have been calculated for the best evaluated resource plan for each Theme. Table 4-17 shows the Net Present Value of the annual revenue requirements for each Theme and Figure 4-43 through Figure 4-46 compare each Theme's annual revenue requirement under the 2015 EIA Reference and February 2016 EIA STEO fuel forecasts respectively, in real (2016 $) and nominal dollars.

Net Present Value of Revenue Requirement ($000)	2015 EIA Reference	February 2016 EIA STEO
NPV of Theme 1 Revenue Requirement	$4,676,993	$4,372,196
NPV of Theme 2 Revenue Requirement	$4,750,970	$4,491,804
NPV of Theme 3 Revenue Requirement	$4,879,952	$4,455,761

Table 4-17. Net Present Value of Revenue Requirement

Hawaiian Electric
Maui Electric
Hawai'i Electric Light

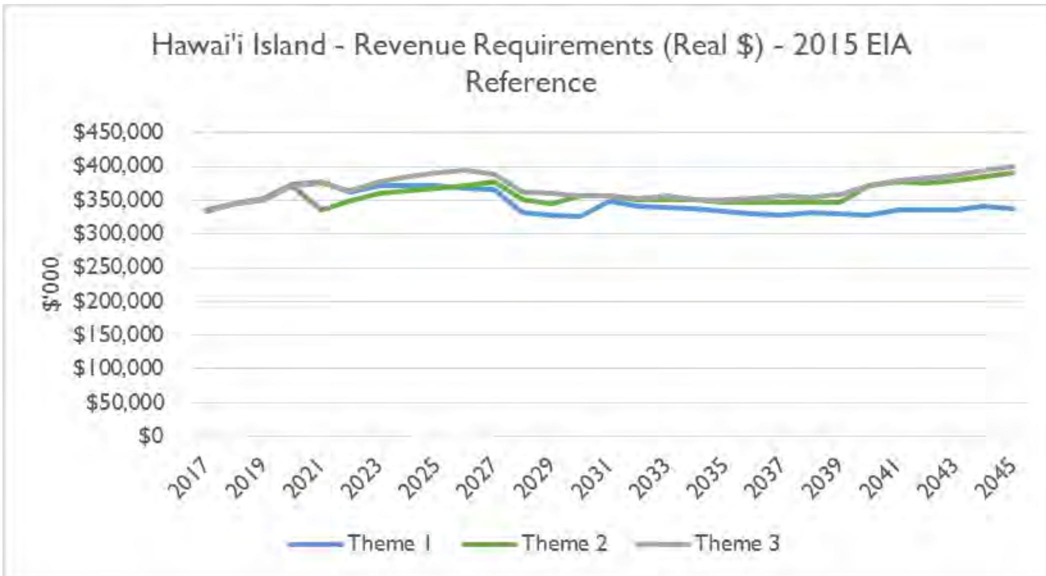


Figure 4-43. Comparison of Revenue Requirement (Real 2016 $) –2015 EIA Reference

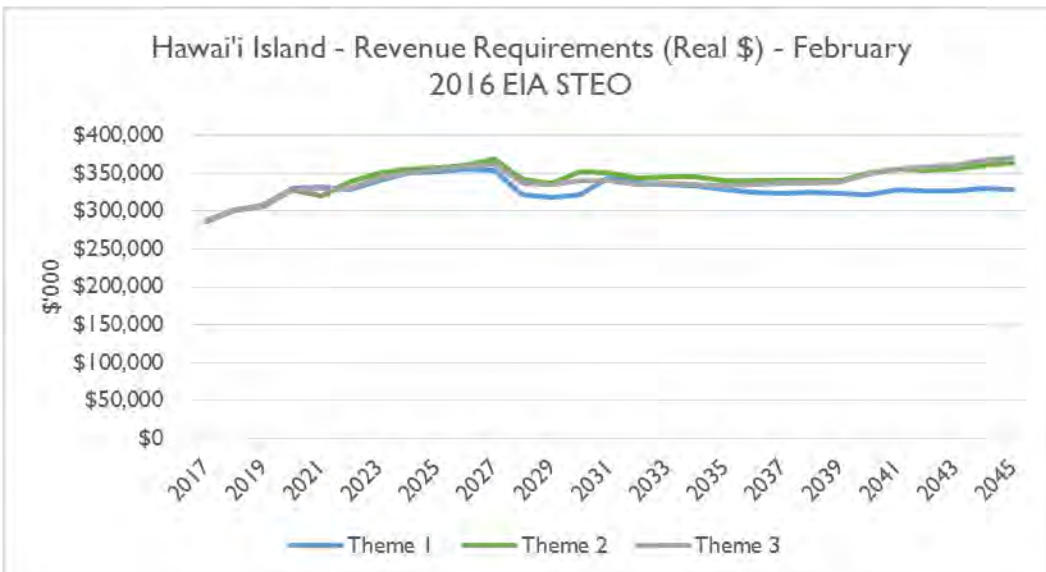


Figure 4-44. Comparison of Revenue Requirement (Real 2016$) – February 2016 EIA STEO

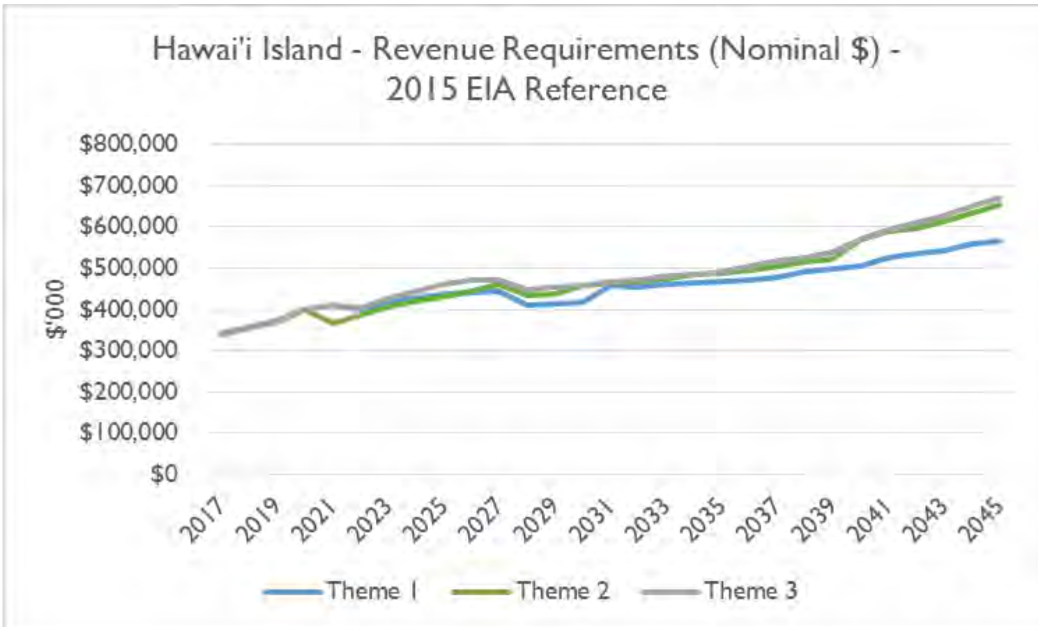


Figure 4-45. Comparison of Revenue Requirement (Nominal $) – 2015 EIA Reference

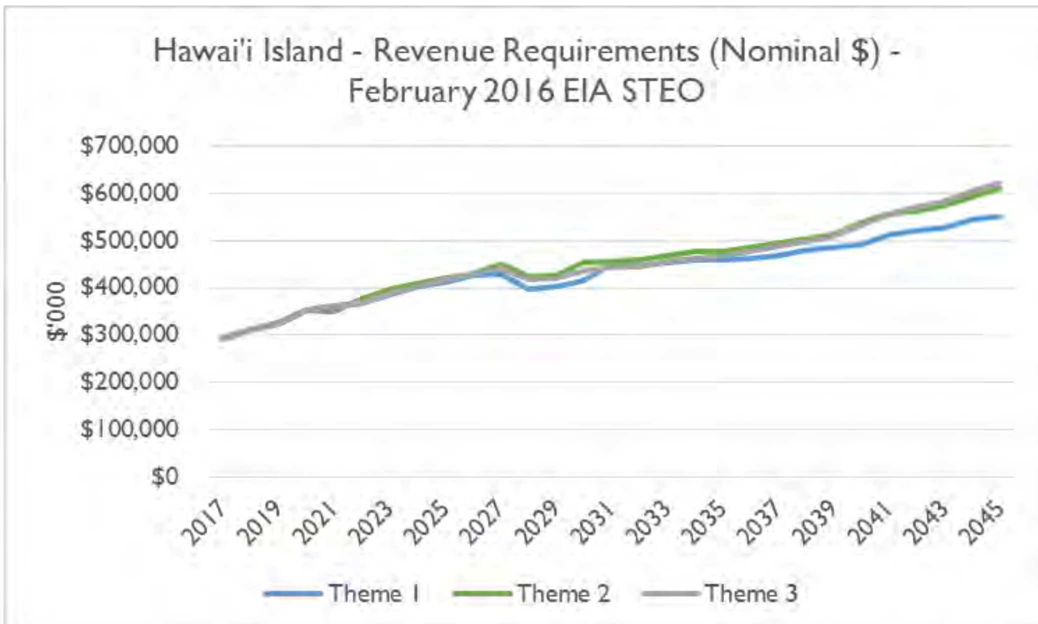


Figure 4-46. Comparison of Revenue Requirement (Nominal $) – February 2016 EIA STEO

Customer Rate Impact Analysis

Residential customer rates, in real 2016 $, trend flat to slightly lower over the planning period for Themes 1 and 2 under the 2015 EIA Reference fuel price forecast. Both of these Themes show a slight increase in real terms over the first 10 years of the planning period, before declining back to the starting level under the February 2016 EIA STEO fuel price forecast. Rates for Theme 3 are consistently higher than Themes 1 and 2 under both forecasts.

Compared to the 2014 PSIP results, customer rates for Themes 1 and 2 are projected to be consistent lower through 2030 under both fuel forecasts.

Customer rates in nominal terms show consistently increases as inflation, even at the historically low levels used in this analysis, dramatically impacts the value of a dollar over the almost 30 year planning period.

The residential customer rate for the three Themes, under the 2015 EIA Reference fuel price forecast, is presented in real 2016 $ in Figure 4-47 and in nominal $ in Figure 4-48. 2014 PSIP results are also shown for comparison purposes.

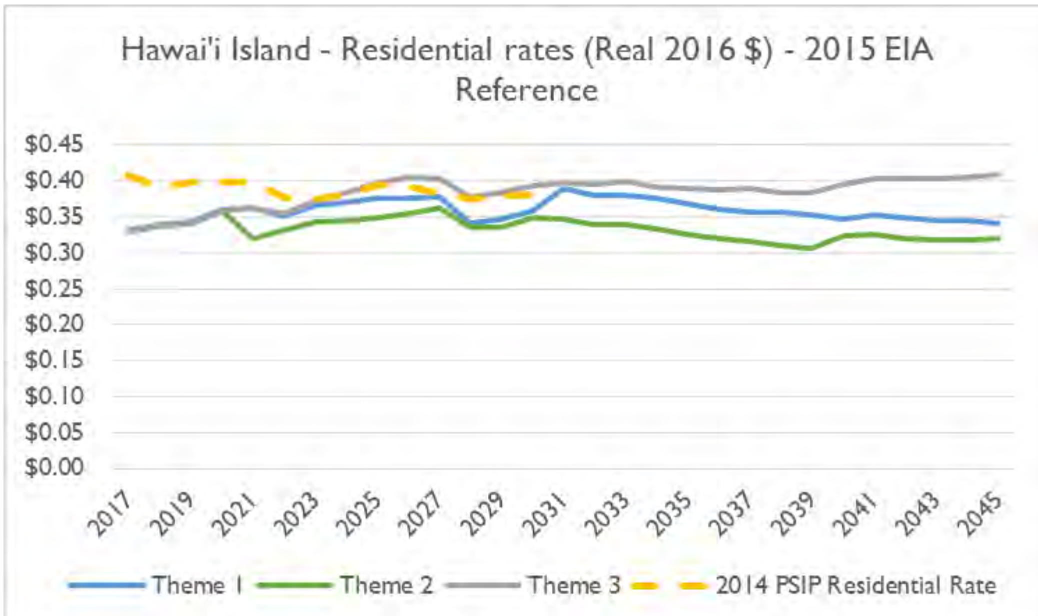


Figure 4-47. Residential Rates (Real 2016 $): 2015 EIA Reference

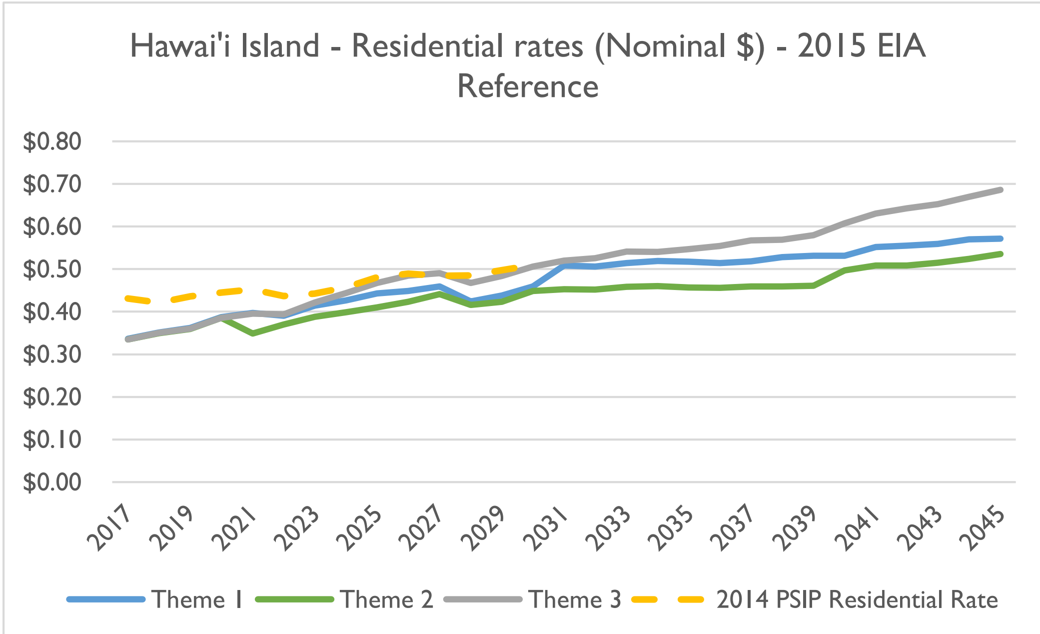


Figure 4-48. Residential Rates (Nominal $): 2015 EIA Reference

The residential customer rate for the three Themes, under the February 2016 EIA STEO fuel price forecast, is presented in real 2016 $ in Figure 4-49 and in nominal $ in Figure 4-50. 2014 PSIP results are also shown for comparison purposes.

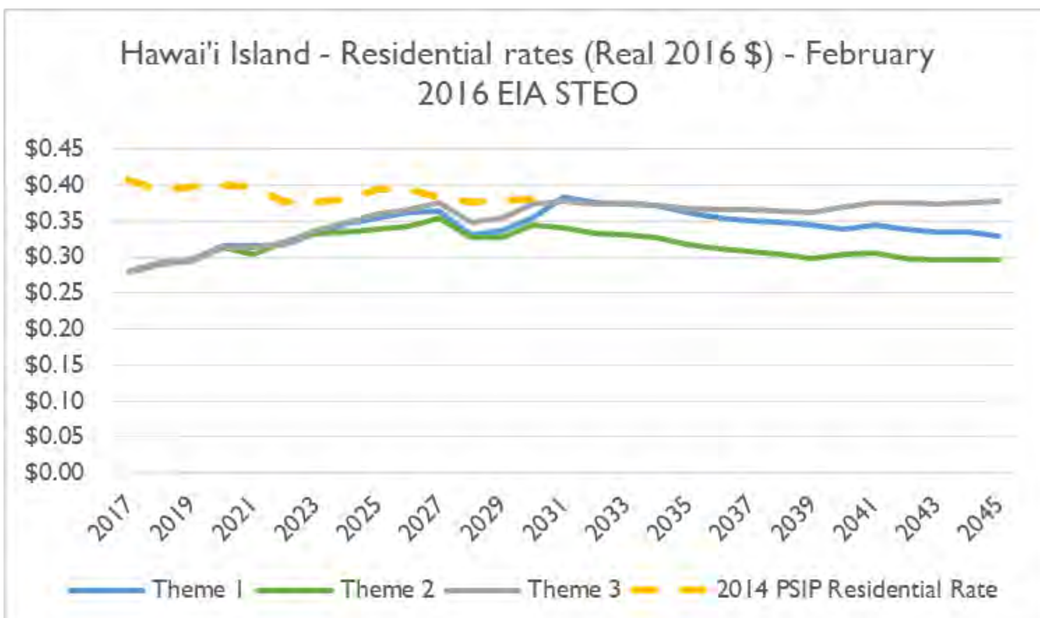


Figure 4-49. Residential Rates (Real 2016 $): February 2016 EIA STEO

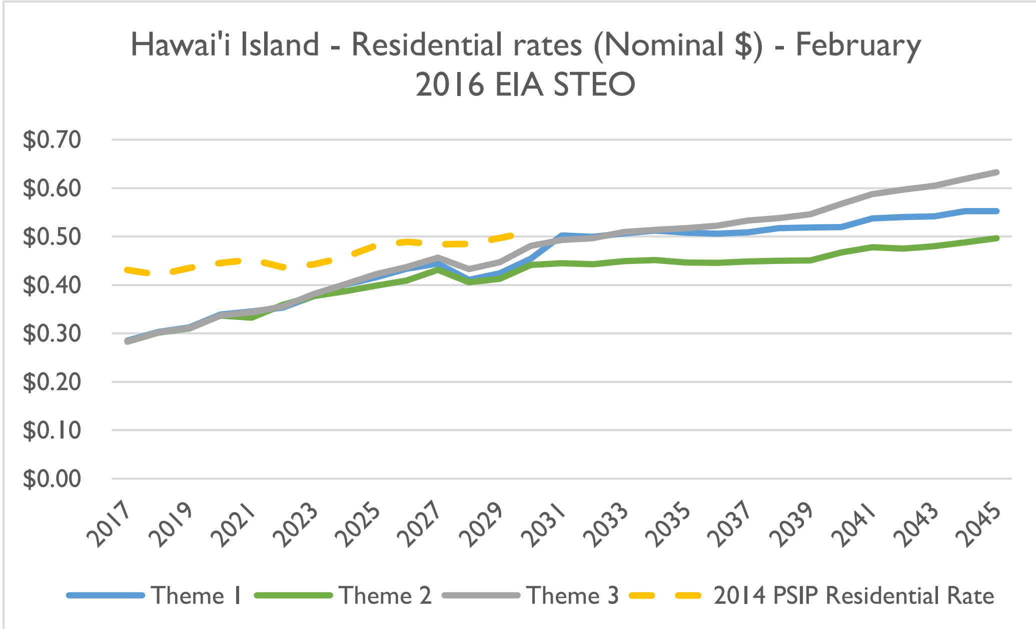


Figure 4-50. Residential Rates (Nominal $): February 2016 EIA STEO

Residential Customer Bill Impact Analysis

The overall impact on a customer's bill is the combination of usage and rates. Over the planning period, usage per customer is expected to decline, consistent with the Energy Efficiency Portfolio Standard goals. The residential customer bill analyses below present each Theme's projected residential bill impact for the average non-DGPV customer.

The residential customer bill impact for the three Themes, under the 2015 EIA Reference fuel price forecast, is presented in real 2016 $ in Figure 4-51 and in nominal $ in Figure 4-52. 2014 PSIP results are also shown for comparison purposes.

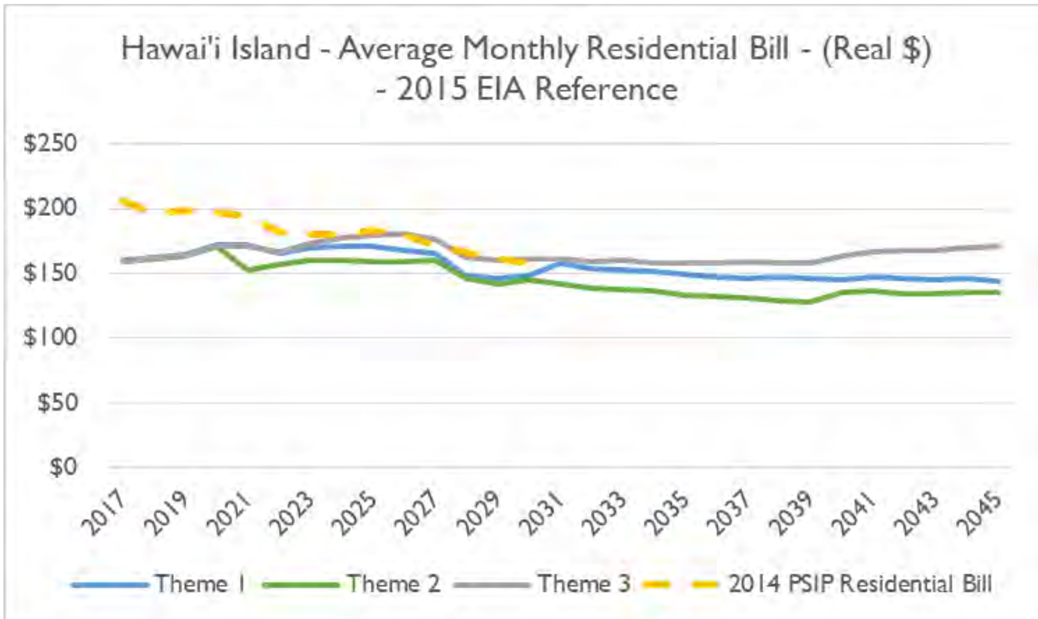


Figure 4-51. Residential Bill (Real 2016 $): 2015 EIA Reference

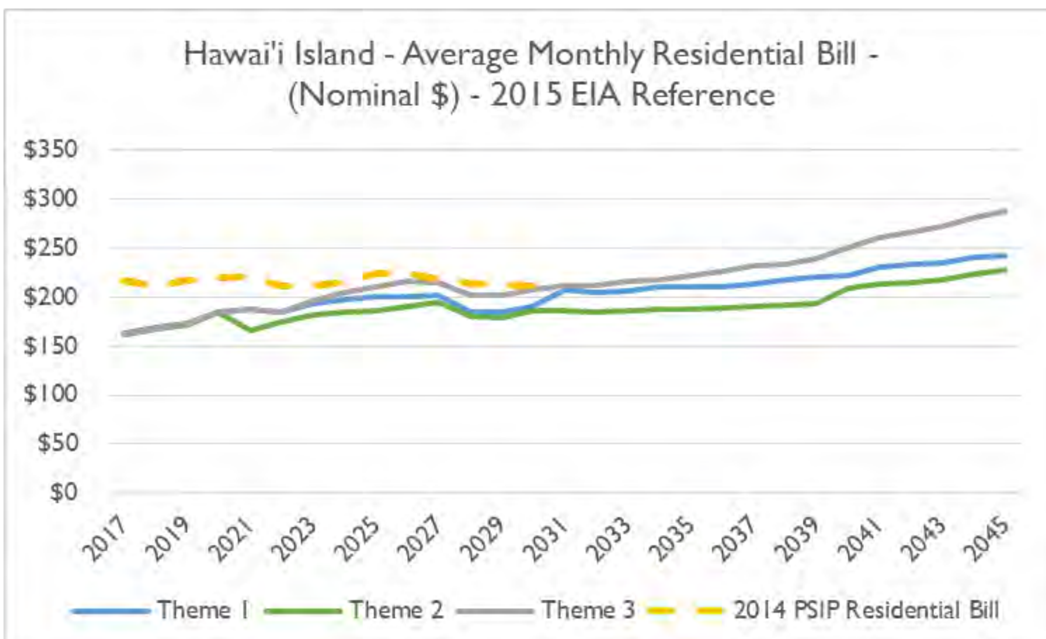


Figure 4-52. Residential Bill (Nominal $): 2015 EIA Reference

The residential customer bill impact for the three Themes, under the February 2016 EIA STEO fuel price forecast, is presented in real 2016 $ in Figure 4-53 and in nominal $ in Figure 4-54. 2014 PSIP results are also shown for comparison purposes.

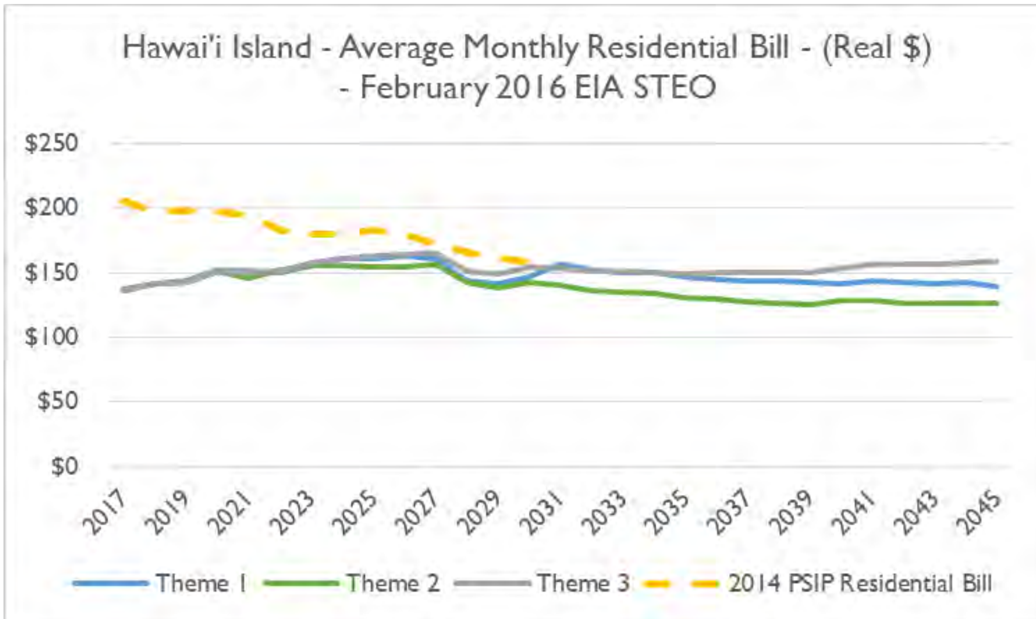


Figure 4-53. Residential Bill (Real 2016 $): February 2016 EIA STEO

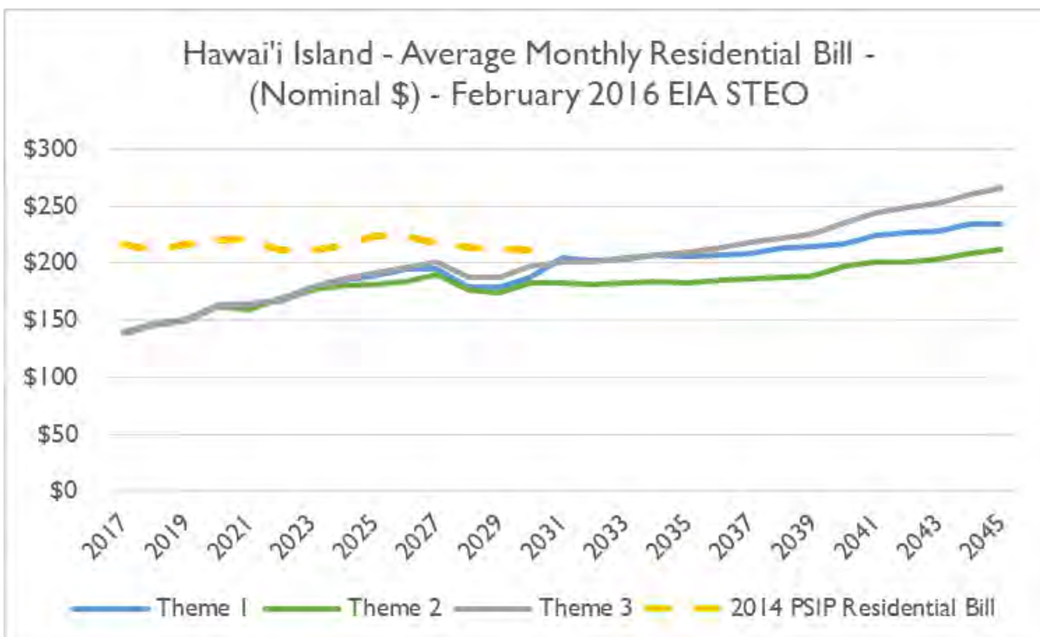


Figure 4-54. Residential Bill (Nominal $): February 2016 EIA STEO

Capital Expenditure Projections

The revenue requirement projections for each Theme include capital expenditure projections for power supply, smart grid, ERP, and all other utility capital expenditures (referred to as "balance-of-utility business capital expenditures"). The Power Supply capital expenditures range from $0.6B ($0.3B in the first 9 years) for Theme 3 to $1.0B ($0.3B in the first 9 years) for Theme 1, consistent with the mix and timing of resource additions and retirements.

Smart Grid and ERP are treated separately, as these proposed capital projects have different costs under a merged and an unmerged future. As Theme 2 is only possible in a merged future, the analysis uses the merged capital costs for both of these projects for Theme 2 capital expenditures. While Themes 1 and 3 can occur in either a merged or an unmerged future, in order to clearly focus on the differences in revenue requirements and bills caused solely by differences in Power Supply costs we need to use a uniform value for these costs in each Theme. For this reason, in this analysis we have used the capital expenditures for these projects that would be appropriate if the Next Era merger is consummated.

As described in detail in Appendix I, the balance-of-utility business capital expenditures have been calculated using a top down manner for the 2015 EIA Reference fuel price scenario and have been consistently applied across all three Themes for both fuel cases. The tables below summarize the capital expenditures by category for each Theme.

Theme 1

Under the Theme 1 resource plan, $1.0B (nominal) of capital will be invested by the utility in Power Supply assets over the 29 year planning period, with $0.3B (nominal) of this investment occurring in the first 9 years of the period.

Theme 1 ('000)	2017-2020	2021-2025	2026-2030	2031-2035	2036-2040	2041-2045	Total
Power Supply	$139,206	$142,509	$338,181	$110,095	$93,913	$140,101	$964,006
Smart Grid	$42,587	$2,348	$3,984	$4,554	$596	$0	$54,069
ERP	$8,275	$0	$0	$0	$0	$0	$8,275
Balance-of-utility business	$169,538	$212,476	$232,300	$253,973	$ 277,668	$ 303,574	$ 1,449,529
Total	$359,607	$357,333	$574,464	$368,622	$372,177	$443,676	$2,475,879

Table 4-18. Theme 1 Capital Expenditures (Nominal $)

Hawaiian Electric
Maui Electric
Hawai'i Electric Light

Theme 2

Under the Theme 2 resource plan, $0.8B (nominal) of capital will be invested by the utility in Power Supply assets over the 29 year planning period, with $0.4B (nominal) of this investment occurring in the first 9 years of the period.

Theme 2 ('000)	2017-2020	2021-2025	2026-2030	2031-2035	2036-2040	2041-2045	Total
Power Supply	$255,715	$156,226	$100,648	$105,891	$80,828	$81,075	$780,384
Smart Grid	$42,587	$2,348	$3,984	$4,554	$596	$0	$54,069
ERP	$8,275	$0	$0	$0	$0	$0	$8,275
Balance-of-utility business	$169,538	$212,476	$232,300	$253,973	$ 277,668	$ 303,574	$ 1,449,529
Total	$476,116	$371,050	$336,931	$364,418	$359,092	$384,650	$2,292,257

Table 4-19. Theme 2 Capital Expenditures (Nominal $)

Theme 3

Under the Theme 3 resource plan, $0.6B (nominal) of capital will be invested by the utility in Power Supply assets over the 29 year planning period, with $0.3B (nominal) of this investment occurring in the first 9 years of the period.

Theme 3 - ('000)	2017-2020	2021-2025	2026-2030	2031-2035	2036-2040	2041-2045	Total
Power Supply	$135,362	$134,908	$105,685	$99,120	$80,828	$81,075	$636,978
Smart Grid	$42,587	$2,348	$3,984	$4,554	$596	$0	$54,069
ERP	$8,275	$0	$0	$0	$0	$0	$8,275
Balance-of-utility business	$169,538	$212,476	$232,300	$253,973	$ 277,668	$ 303,574	$ 1,449,529
Total	$355,762	$349,732	$341,969	$357,646	$359,092	$ 384,560	$ 2,148,851

Table 4-20. Theme 3 Capital Expenditures (Nominal $)

Risk Analysis

Planning to achieve an affordable, reliable, and secure electricity supply that meets Hawai'i's clean energy policy goals is a complex and challenging effort for all stakeholders. There are important future uncertainties to consider, including fuel prices and technology developments, and the investment decisions made today by customers, third parties, the State, and Hawaiian Electric will impact customers for decades to come. These uncertainties impact the risks facing our customers and Hawaiian Electric, including:

- Electricity price risk, in terms of absolute level
- Electricity price risk, in terms of volatility

- "Buyer's Remorse" risk for capital investments made in long term assets
- Ability to afford the investments necessary to ensure the reliability and security of the electricity grid

These risks are somewhat different under each of the three Themes. Table 4-21 provides a qualitative assessment of each of these risks under each of the Themes. An up arrow indicates a better, less risky result, relative to the other Themes.

Risk	Theme 1	Theme 2	Theme 3
Price level	↓	↑	↓
Price volatility	↑	↑	↓
Capital investment	↓	↔	↑
Grid reliability & security	↓	↑	↑

Table 4-21. Risk Assessment

TOTAL SOCIETAL COSTS FOR ENERGY: HAWAI'I ELECTRIC LIGHT

As Hawai'i selects the best path to achieve its renewable energy future, the total societal cost of electricity is an important consideration. For this analysis, the total societal cost of electricity is the sum of the costs for independent generation, investments in distributed generation and storage, federal and state tax incentives, fuel, and all other utility operating costs. The chart below provides, by Theme, the Net Present Value of this cost stream over the period 2017 through 2045.

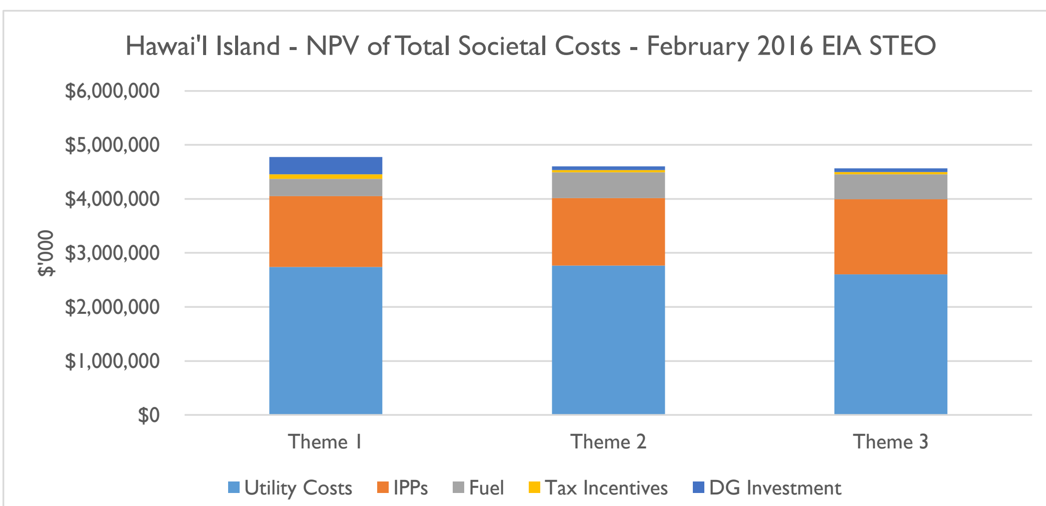


Figure 4-55. Total Societal Costs of the Plans

TOTAL SOCIETAL INVESTMENT: HAWAI'I ELECTRIC LIGHT

Significant investments by home and business owners across the State, project developers and independent power producers, Federal and State government, and the Company are all required to achieve Hawai'i's goal of 100% renewable energy. The capital expenditures required to achieve Hawai'i's energy policy goals for Hawai'i Island range from $4.0B in Theme 3 to $6.2B in Theme 1. Hawai'i Electric Light investments represent only a fraction of that total, ranging from $2.1B to $2.5B across the Themes. Table 4-22 through Table 4-24 provide the Company's projections of this total investment, by stakeholder, for each Theme.

Investor	2017 -20	2021-25	2026-30	2031-35	2036-40	2041-45	Total
Distributed Generation & Storage Owners	$302,900	$407,400	$564,600	$551,200	$544,500	$537,900	$2,908,500
Utility Scale Renewable Generation	$0	$355,946	$326,346	$0	$0	$0	$682,292
Federal Tax Incentives	$32,851	$19,455	$20,055	$19,490	$19,147	$18,800	$129,798
Hawaii Tax Incentives	$22,551	$4,511	$1,000	$0	$0	$0	$28,062
Hawaii Electric Light	$359,607	$357,333	$574,464	$368,622	$372,177	$443,676	$2,475,879
Theme 1 Total	**$717,909**	**$1,144,645**	**$1,486,465**	**$939,312**	**$935,824**	**$1,000,376**	**$6,224,531**

Table 4-22. Total Societal Energy Investment – Theme 1

Investor	2017 -20	2021-25	2026-30	2031-35	2036-40	2041-45	Total
Distributed Generation & Storage Owners	$302,900	$161,200	$154,300	$149,600	$150,000	$158,600	$1,076,600
Utility Scale Renewable Generation	$0	$206,939	$394,202	$73,700	$76,762	$0	$751,603
Federal Tax Incentives	$24,871	$3,228	$1,105	$1,122	$1,193	$1,361	$32,880
Hawaii Tax Incentives	$17,230	$1,570	$0	$500	$500	$0	$19,800
Hawaii Electric Light	$476,116	$371,050	$336,931	$364,418	$359,092	$384,650	$2,292,257
Theme 2 Total	**$821,117**	**$743,987**	**$886,538**	**$589,340**	**$587,547**	**$544,611**	**$4,173,140**

Table 4-23. Total Societal Energy Investment – Theme 2

Investor	2017 -20	2021-25	2026-30	2031-35	2036-40	2041-45	Total
Distributed Generation & Storage Owners	$309,200	$163,400	$154,300	$149,600	$150,000	$158,600	$1,085,100
Utility Scale Renewable Generation	$0	$206,939	$394,202	$73,700	$76,762	$0	$751,603
Federal Tax Incentives	$24,871	$3,228	$1,105	$1,122	$1,193	$1,361	$32,880
Hawaii Tax Incentives	$17,230	$1,570	$0	$500	$500	$0	$19,800
Hawaii Electric Light	$355,762	$349,732	$341,969	$357,646	$359,092	$384,650	$2,148,851
Theme 3 Total	**$707,063**	**$724,869**	**$891,576**	**$582,568**	**$587,547**	**$544,611**	**$4,038,234**

Table 4-24. Total Societal Energy Investment – Theme 3

The above investment totals do not include energy efficiency investments made by customers or demand response investments made by DR providers or customers.

ADDITIONAL FINANCIAL CONSIDERATIONS

The above analysis was performed and presented on a Company and island specific basis. However, with the potential need to resources amongst the islands to cost effectively achieve 100% renewable energy, the prospects and value of consolidated state-wide rates for Hawaiian Electric Company should be further evaluated.

5. Hawaiian Electric Preferred Plan

Hawaiian Electric performed comprehensive analyses of different paths to achieving 100% renewable energy by 2045. This chapter will provide key results of the analysis for the Final Plans leading to the selection of the Preferred Plan.

ENERGY MIX OF FINAL PLANS FOR O‘AHU

As discussed in Chapter 3, different paths to achieving 100% renewable energy in 2045 were analyzed. Figure 5-1 summarizes the annual RPS[18] for each year. Theme 1 accelerates RPS targets while Themes 2 and 3 strategically achieve the same RPS targets.

[18] Per the RPS law (HRS § 269-91), RPS is not the same as all grid-based electricity coming from renewable energy resources, which in the calculation of RPS can result in values greater than 100%.

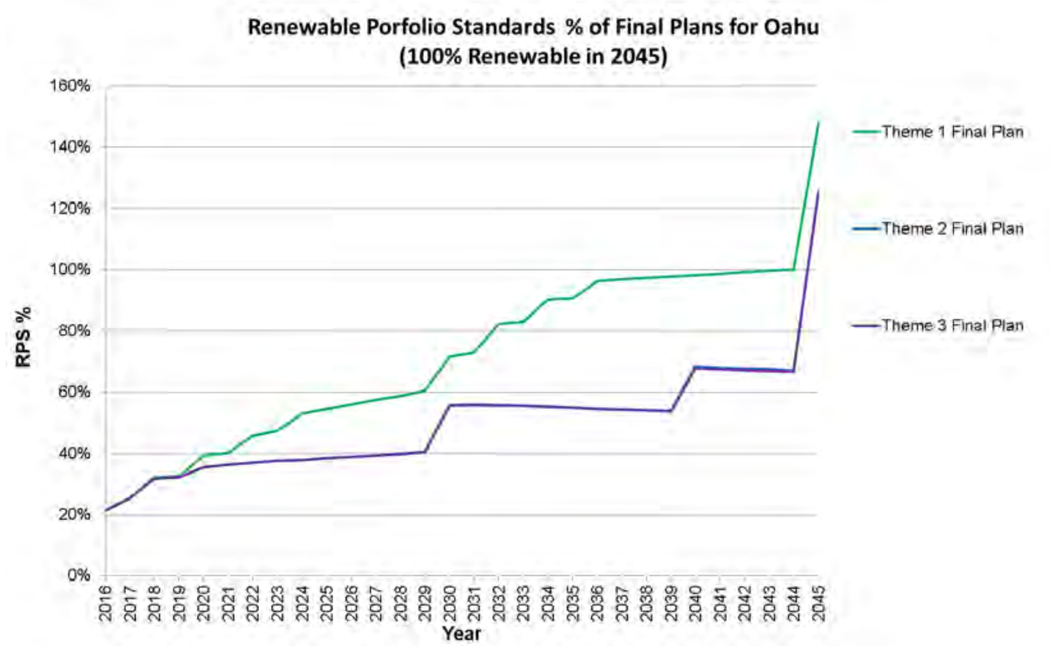


Figure 5-1. Renewable Portfolio Standards Percent of Final Plans for O'ahu (100% Renewable in 2045)

The resource mix for the final plans changes over time as it reaches 100% renewable in 2045. The figures below reveal how the energy mix in the final plan under each theme grow to 100% renewable energy.

The annual energy served by resource type is shown in Figure 5-2 for the Theme 1 final plan under the 2015 EIA Reference Fuel Price Forecasts. The accelerated transition to renewable wind and solar can be easily seen as the fossil fuel (oil and coal) significantly decreases over time.

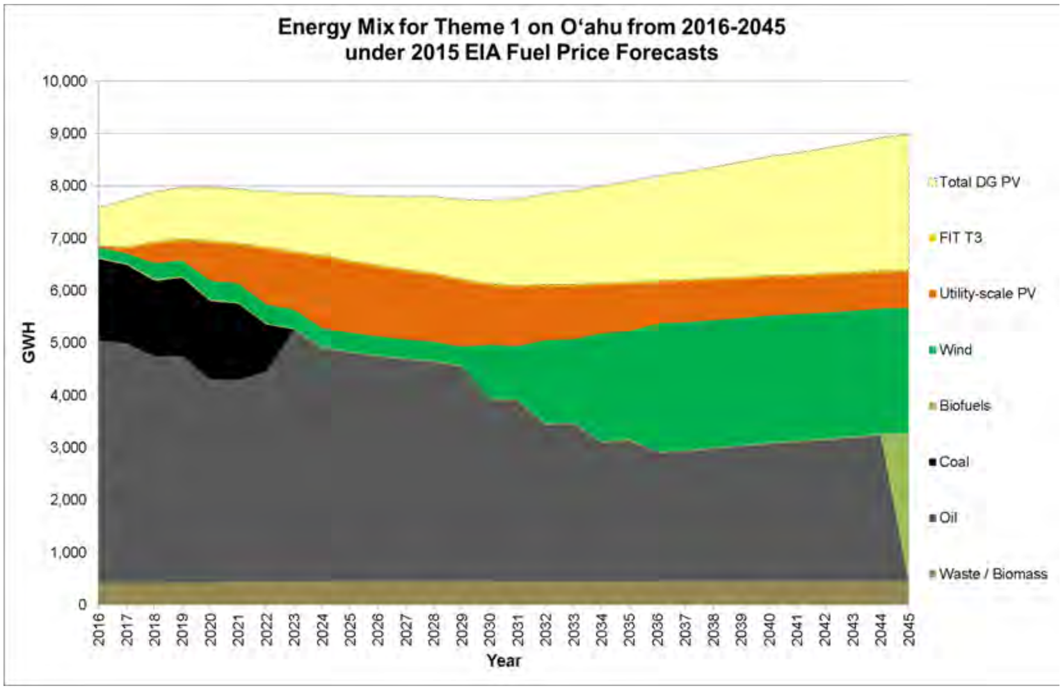


Figure 5-2. Energy Mix for Theme 1 on O'ahu from 2016-2045 under 2015 EIA Fuel Price Forecasts

Each final plan was evaluated under a range of fuel prices and Figure 5-3 shows the energy mix of Theme 1 under the February 2016 EIA STEO Fuel Price Forecasts. The lower fuel prices did not noticeably change the energy mix.

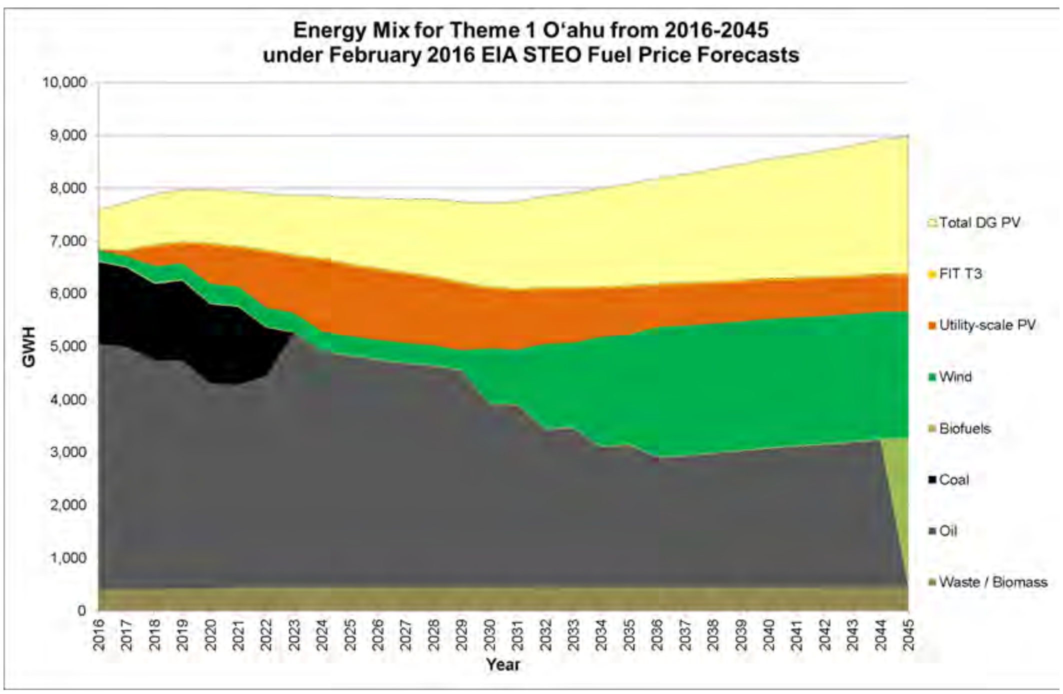


Figure 5-3. Energy Mix for Theme 1 on O'ahu from 2016–2045 under February 2016 EIA STEO Fuel Price Forecasts

The Theme 2 final plan adds new flexible generation to replace existing thermal generation and uses LNG as a transitional fuel from oil to assist with the integration of renewable energy. Renewable energy is added strategically meet intermediate RPS targets and ultimately 100% renewable energy in 2045. The energy mix for Theme 2 under the 2015 EIA Reference Fuel Price Forecasts is shown in Figure 5-4. The transition to LNG occurs during the planned contract period of 2021-2040. At the conclusion of the 20-year LNG contract, alternative fuels to provide the remaining power to the island during this 70% RPS period were considered. Potential fuels include to provide this energy include LNG, oil, biofuels, or a mix of all three. Under the current fuel prices forecasts, oil is cheaper than biofuels so it was selected as the fuel until the use of biofuels was necessary in 2045 to meet the 100% renewable energy.

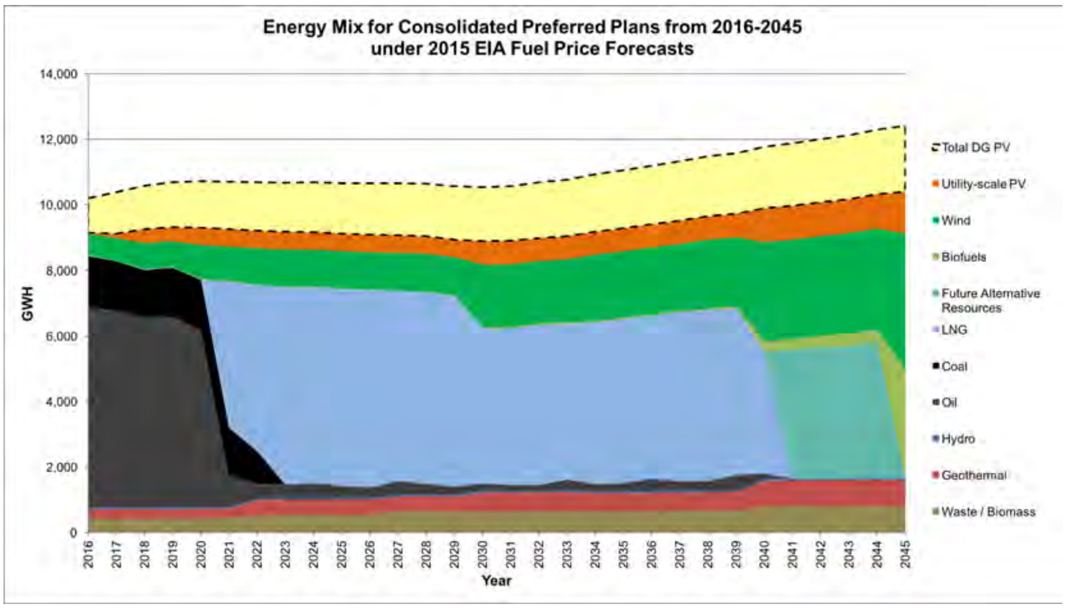


Figure 5-4. Energy Mix for Theme 2 on O'ahu from 2016-2045 under 2015 EIA Fuel Price Forecasts

Future Alternative Fuels: During the last intervening years in the transition to 100% renewable energy, potential fuels at this time could include biofuels, LNG, oil, other renewable options or a mix of options. Given rapidly evolving energy options and technology, the exact fuel mix is difficult to predict today.

The energy mix of Theme 2 under the February 2016 EIA STEO Fuel Price Forecasts did not noticeably change under the lower fuel prices as shown in Figure 5-5.

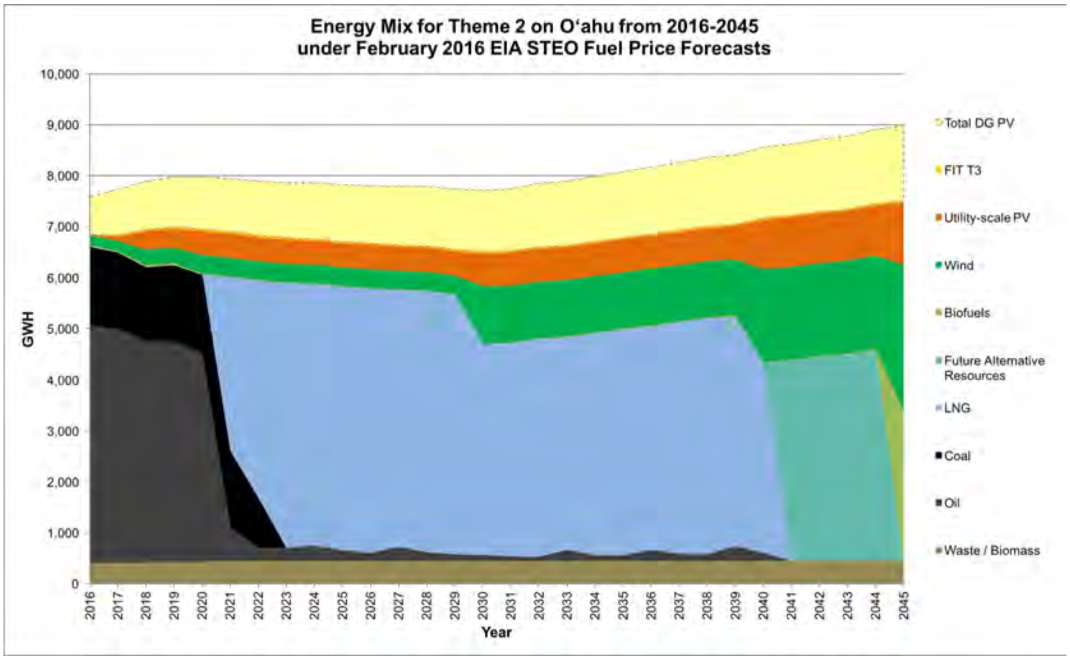


Figure 5-5. Energy Mix for Theme 2 on O'ahu from 2016-2045 under February 2016 EIA STEO Fuel Price Forecasts

Future Alternative Fuels: During the last intervening years in the transition to 100% renewable energy, potential fuels at this time could include biofuels, LNG, oil, other renewable options or a mix of options. Given rapidly evolving energy options and technology, the exact fuel mix is difficult to predict today.

The final plan for Theme 3 makes the planning assumption that LNG is not an available fuel and strategically increases renewable energy to meet the intermediate RPS targets as in Theme 2. Figure 5-6 illustrates the energy mix under the 2015 EIA Reference Fuel Price Forecasts.

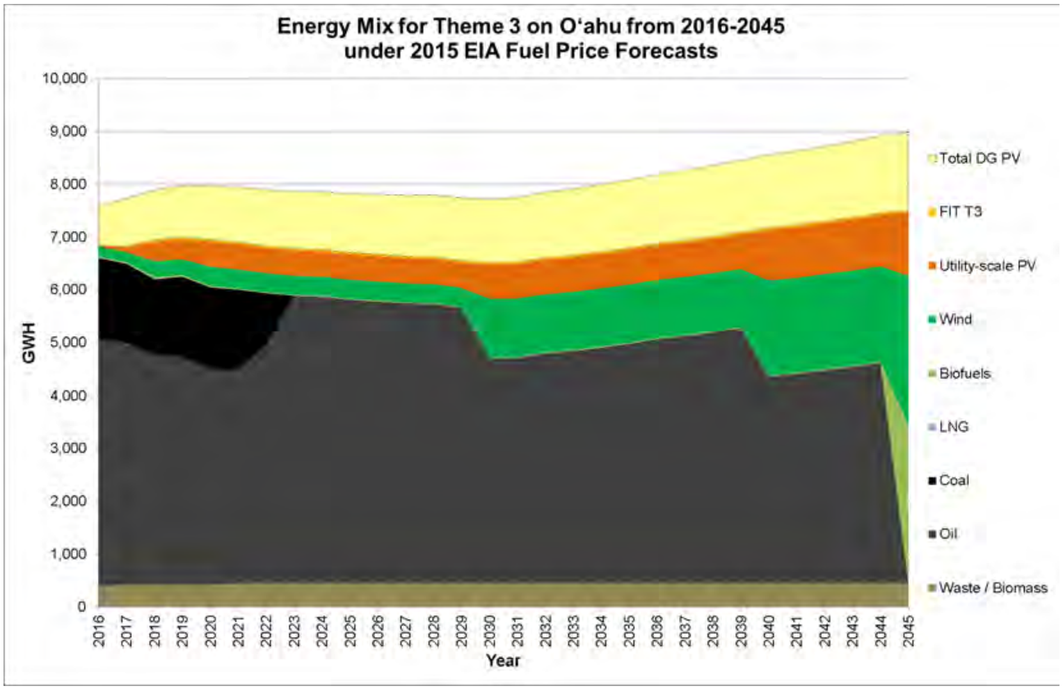


Figure 5-6. Energy Mix for Theme 3 on O'ahu from 2016-2045 under 2015 EIA Fuel Price Forecasts

Similar to the final plans in Themes 1 and 2, the energy mix of Theme 3 under the February 2016 EIA STEO Fuel Price Forecasts did not noticeably change under the lower fuel prices as shown in Figure 5-7.

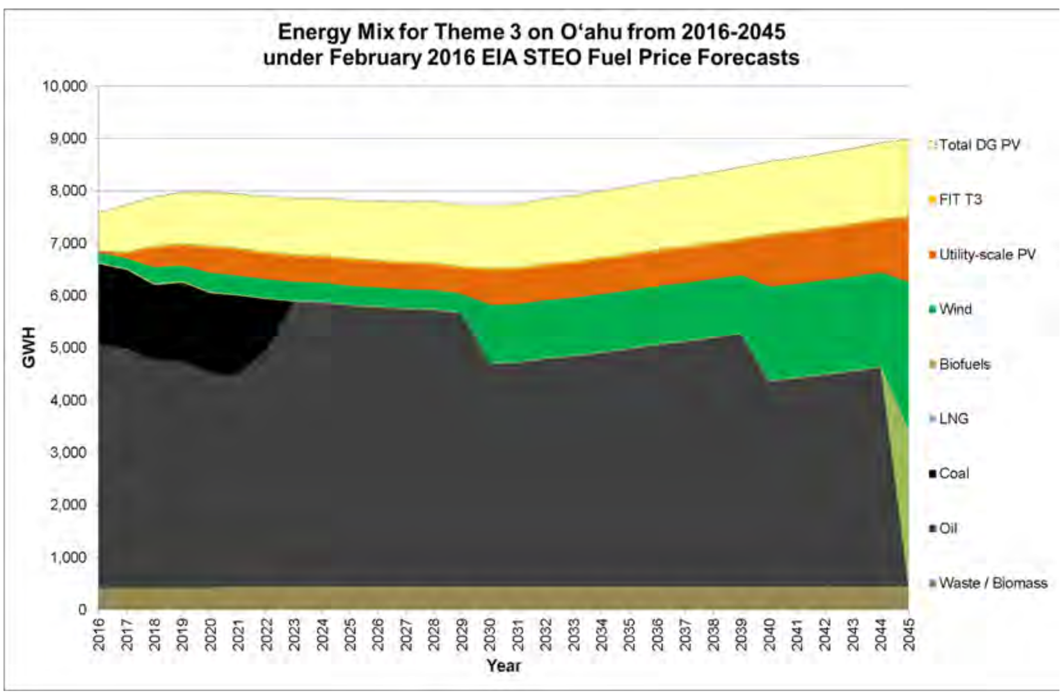


Figure 5-7. Energy Mix for Theme 3 on O'ahu from 2016-2045 under February 2016 EIA STEO Fuel Price Forecasts

The different paths of Themes 1, 2, and 3 to achieving the 100% renewable energy are clearly displayed in Figure 5-2 through Figure 5-7. Although Theme 1 reduces dependency on fossil fuels faster than Themes 2 and 3, the higher levels of DG-PV and accelerated pursuit of renewable energy increases costs as discussed in Chapter 4. Theme 2 reduces costs compared to Themes 1 and 3, as it switches a portion of fossil generation from oil to cleaner, lower cost LNG while strategically adding renewable resources.

PERCENT OVER-GENERATION OF TOTAL SYSTEM OF FINAL PLANS FOR O'AHU

Hawaiian Electric has been actively increasing the flexibility of the existing generating units to integrate increasing levels of variable generation. All the final plans include the capability to operate existing generating units at lower minimum load levels, minimizing baseload operation of the existing generators, and adding new firm flexible generation along with increasing wind and solar generation. Even with more flexible firm generating units, there may still be instances of over-generation of variable resources during low demand periods (which may occur during daytime hours due to influence of DG-PV, as well as during typical night time low load hours).

As increasingly more renewable energy is added to the system, over-generation occurrences will become inevitable. Figure 5-8 provides estimates of the percent over-generation of the total system annual energy for the final plans under the 2015 EIA Reference Fuel Price Forecasts. Since Theme 1 integrates greater amounts of variable renewable energy (utility scale and High DG-PV) than Themes 2 and 3, the percent over-generation increases significantly and much earlier than in Themes 2 and 3. Adding storage to accept the over-generation would be an option but is dependent on the cost of the storage technologies. However, situations of over-generation provide opportunities, coupled with appropriate controls systems, to use wind and solar generation as regulation resources in addition to use as a reserve resource. This provides additional value compared to a resource providing energy only. In combination, wind and solar used for energy and some level of regulation and reserve appears to be cheaper than the alternative of additional storage, at least at moderate over-generation levels. For the purposes of this PSIP Update, we include the full cost of the utility-scale wind and solar resources in cost calculations, regardless of over-generation levels and provide a simplified accounting for other services from these resources.

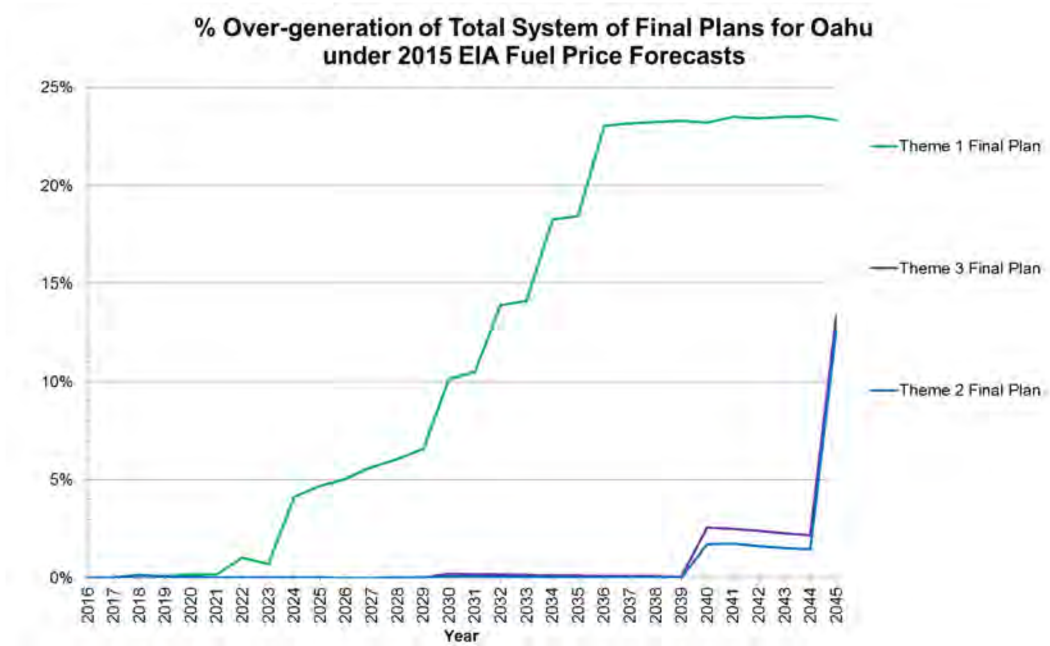


Figure 5-8. Percent Over-generation of Total System of Final Plans for O'ahu under the 2015 EIA Reference Fuel Price Forecasts

Similar estimates of the percent over-generation for the final plans under the February 2016 EIA STEO Fuel Price Forecasts is in Figure 5-9. Again, there isn't a visible difference between the two fuel price forecasts.

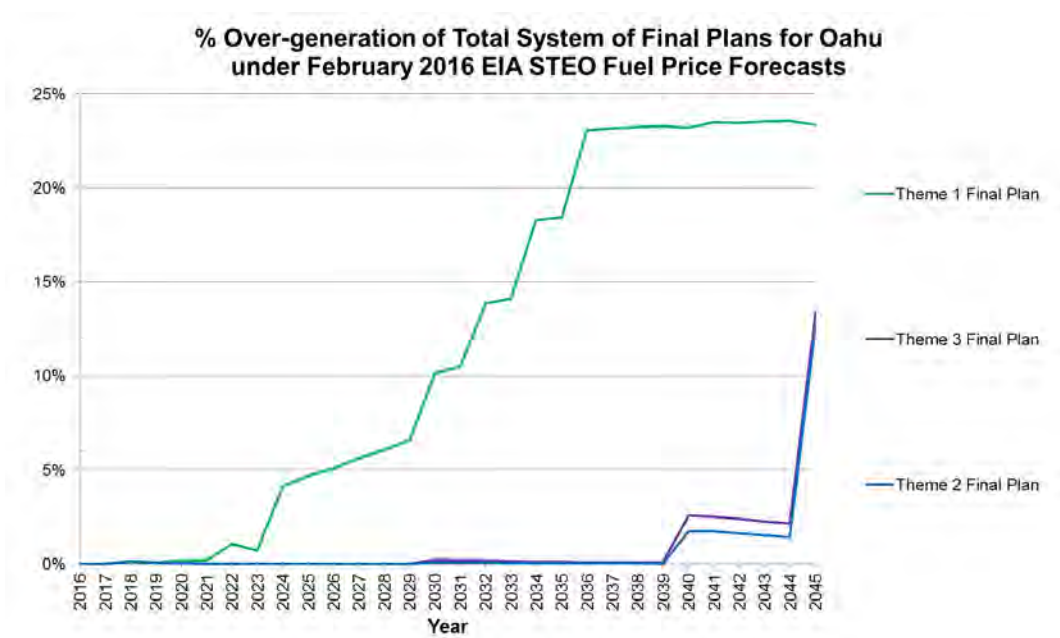


Figure 5-9. Percentage of Over-generation of Total System of Final Plans for O'ahu under the February 2016 EIA STEO Fuel Price Forecasts

TOTAL SYSTEM RENEWABLE ENERGY UTILIZED OF FINAL PLANS FOR O‘AHU

The previous section discussed over-generation of energy provided by resources, but another view is to assess how much renewable energy is being utilized by the system. The year-by-year amount of renewable energy being utilized for Theme 1 is shown in Figure 5-10. Theme 1 is utilizing 100% of the renewable energy in the near term and slowly decreases to about 91% in 2030. The lowest amount utilized is about 78% in the later years (2036-2044) and the average over the entire 30 year period is about 85.5%. The results shown in Figure 5-10 is the same under both fuel price forecasts.

Total System Renewable Energy Utilized for Theme 1 on O‘ahu

% RE Utilized	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2016-2045
	100%	100%	100%	100%	100%	100%	99%	99%	96%	96%	96%	95%	95%	94%	91%	91%	87%	87%	83%	83%	78%	78%	78%	78%	78%	78%	78%	78%	78%	84%	85.5%

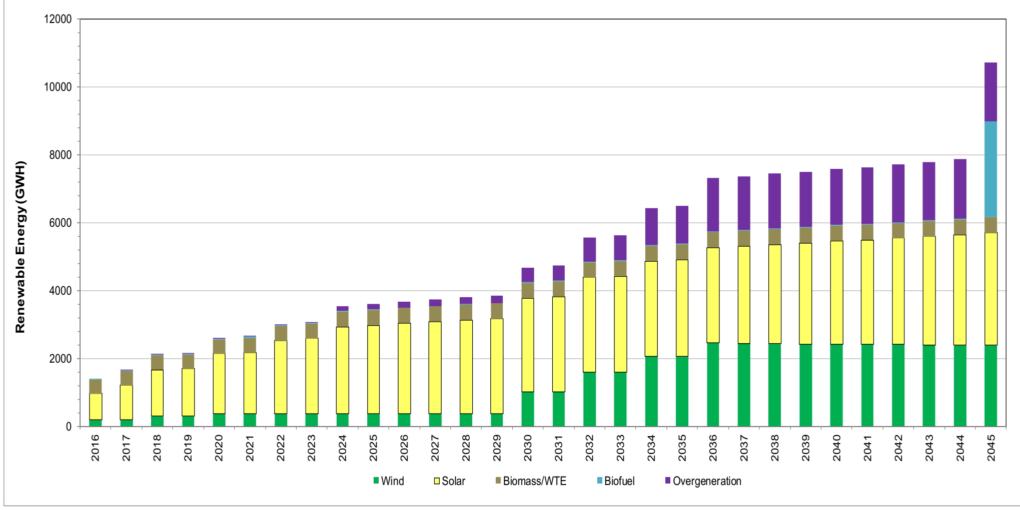
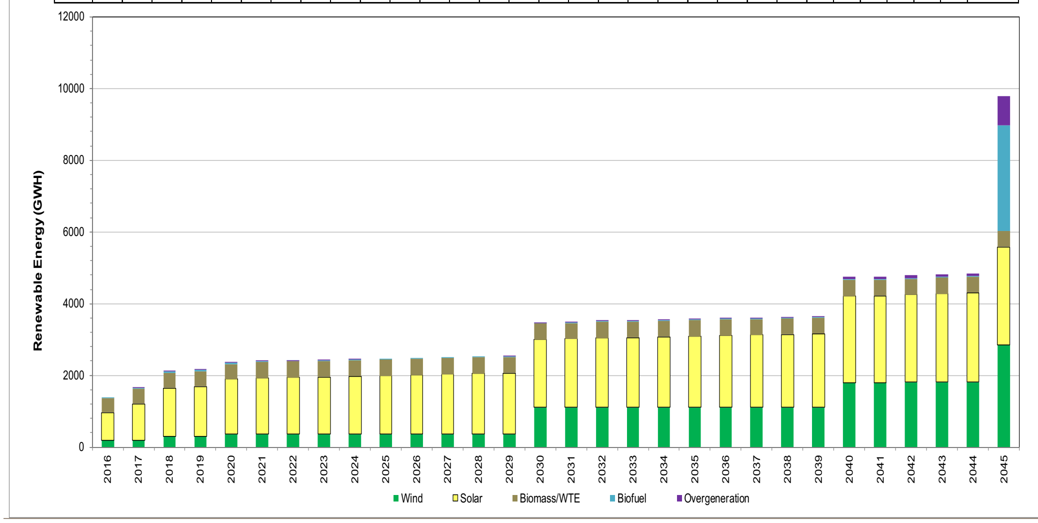


Figure 5-10. Total System Renewable Energy Utilized for Theme 1 on O‘ahu

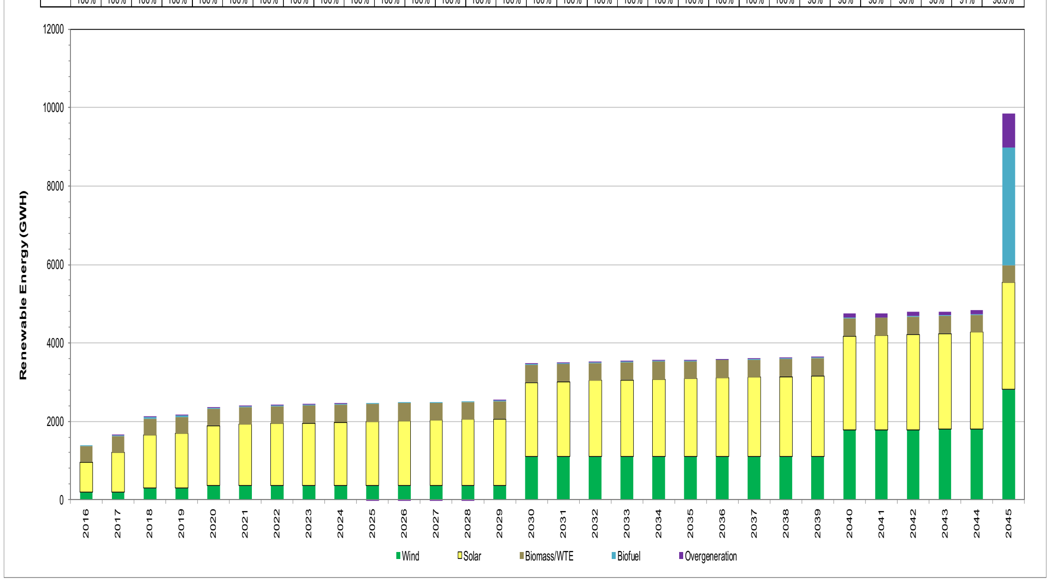
As shown in Figure 5-11, Theme 2 is utilizing 100% of the renewable energy available until about 2040. The lowest amount utilized is about 92% in 2045 and the average over the entire 30 year period is about 98.8%. The results shown in Figure 5-11 are the same under both fuel price forecasts.



% RE Utilized	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2016-2045
	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	98%	98%	99%	99%	99%	92%	98.8%

Figure 5-11. Total System Renewable Energy Utilized for Theme 2 on O‘ahu

Theme 3 has the same levels of renewable energy as Theme 2 and has very similar utilization of the energy. Figure 5-12 indicates that Theme 3 is utilizing 100% of the renewable energy available until about 2040. The lowest amount utilized is about 91% in 2045 and the average over the entire 30 year period is about 98.6%. The results shown in Figure 5-12 is the same under both fuel price forecasts.



% RE Utilized	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2016-2045
	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	98%	98%	98%	98%	98%	91%	98.6%

Figure 5-12. Total System Renewable Energy Utilized for Theme 3 on O‘ahu

DAILY ENERGY CHARTS OF FINAL PLANS FOR O'AHU

The charts in the previous sections displayed annual views of how renewable energy is being integrated into the final plans. This section will convey a more granular view by providing the energy mix for select days of some years of the final plans that were modeled.

All the final plans have the same starting point. Based on the modeling assumptions, the day with the highest penetration of solar energy is September 12, 2016 and

Figure 5-13. Modeled Energy Profile for September 12, 2016 of the Final Plans

provides a view of how much solar is being accepted on the system.

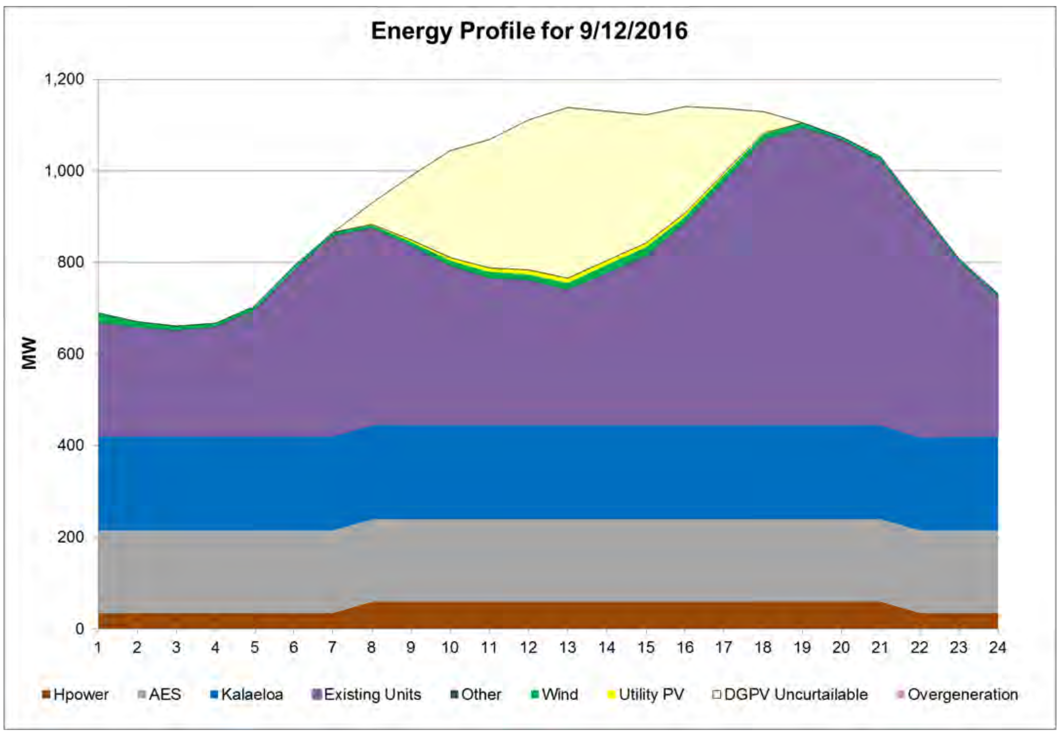


Figure 5-13. Modeled Energy Profile for September 12, 2016 of the Final Plans

Based on the modeling assumptions, the day with the highest penetration of wind energy is August 6, 2016. Figure 5-14 provides a view of how much wind is being accepted on the system.

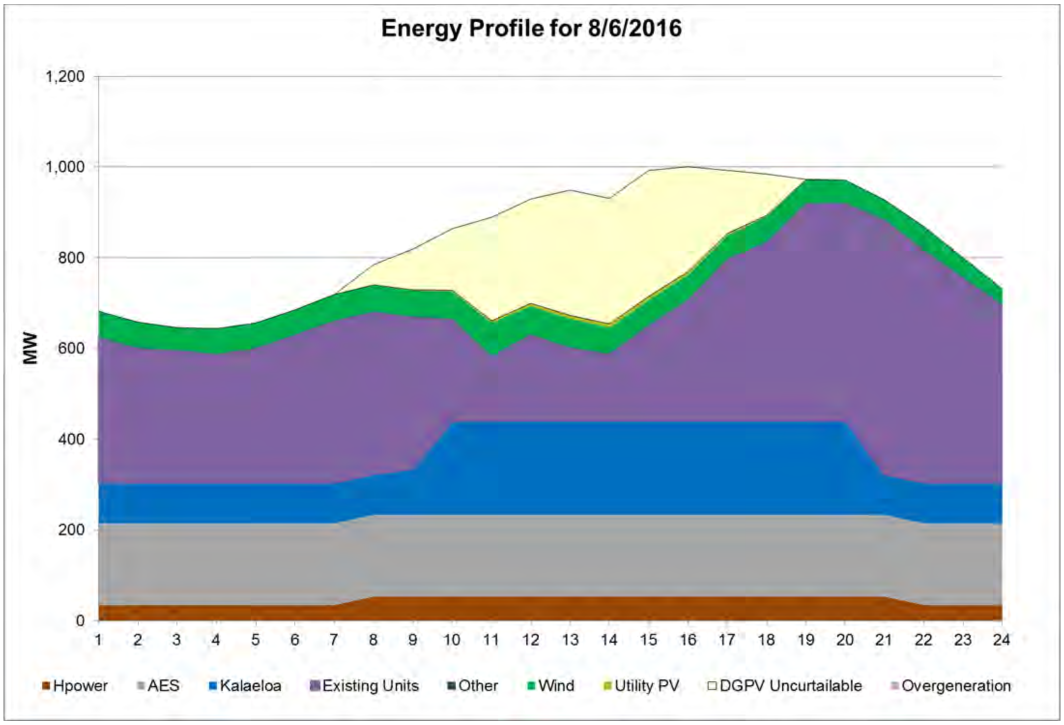


Figure 5-14. Modeled Energy Profile for August 6, 2016 of the Final Plans

In Theme 2, LNG becomes available from 2021. Based on the modeling assumptions, the day with the highest penetration of solar energy is June 6, 2021. Theme 1 includes the higher level of DG-PV; Figure 5-15 shows that there is over-generation in the middle of the day. Theme 2, shown in Figure 5-16, and Theme 3, shown in Figure 5-17, include the Market DG-PV forecast and does not have over-generation on this particular day. It can also be seen that Theme 2 has the 3x1 CC unit and LNG so the economic dispatch of the thermal generators are slightly different when compared to Theme 3.

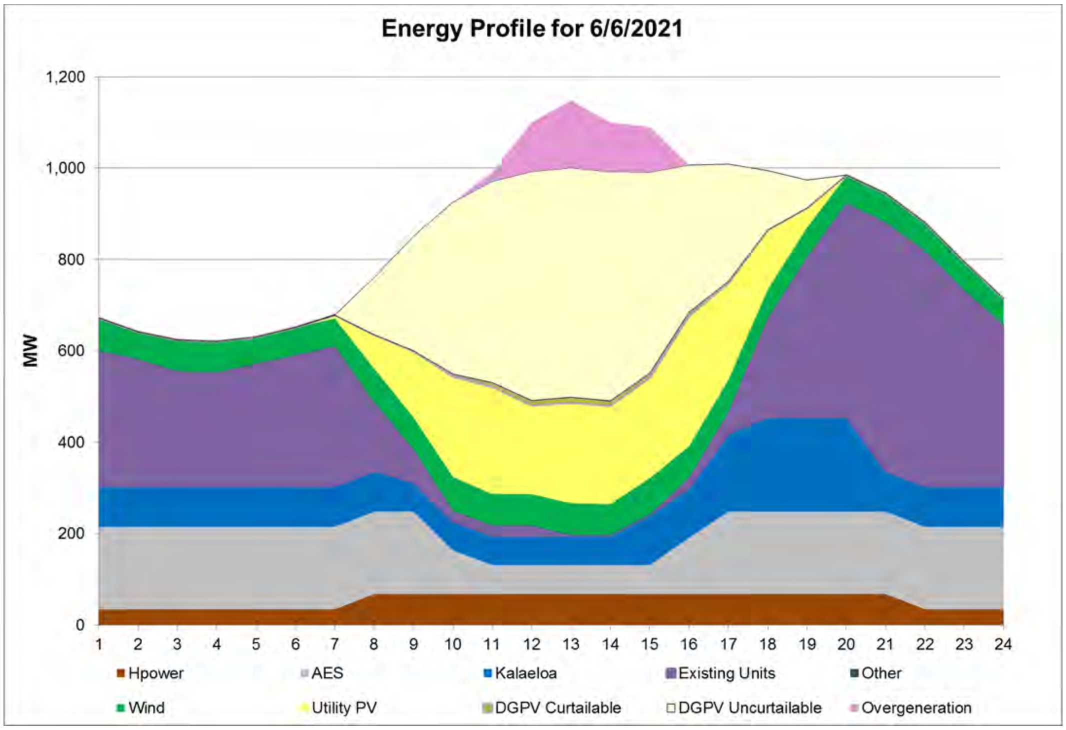


Figure 5-15. Modeled Energy Profile for June 6, 2021 of Theme 1

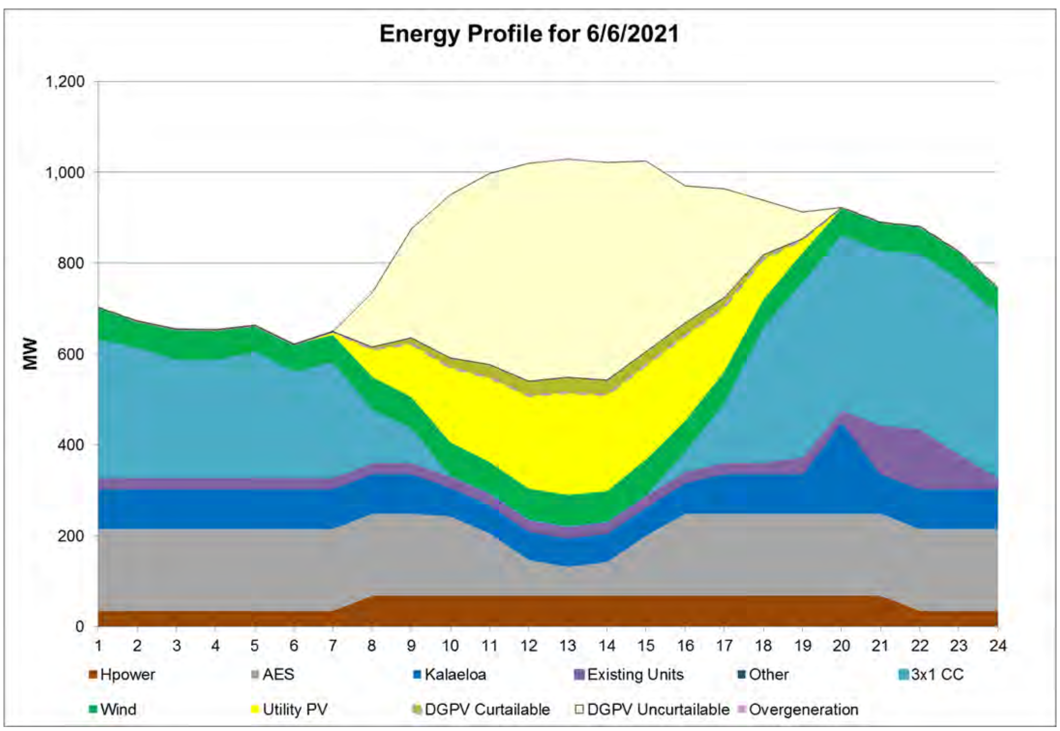


Figure 5-16. Modeled Energy Profile for June 6, 2021 of Theme 2

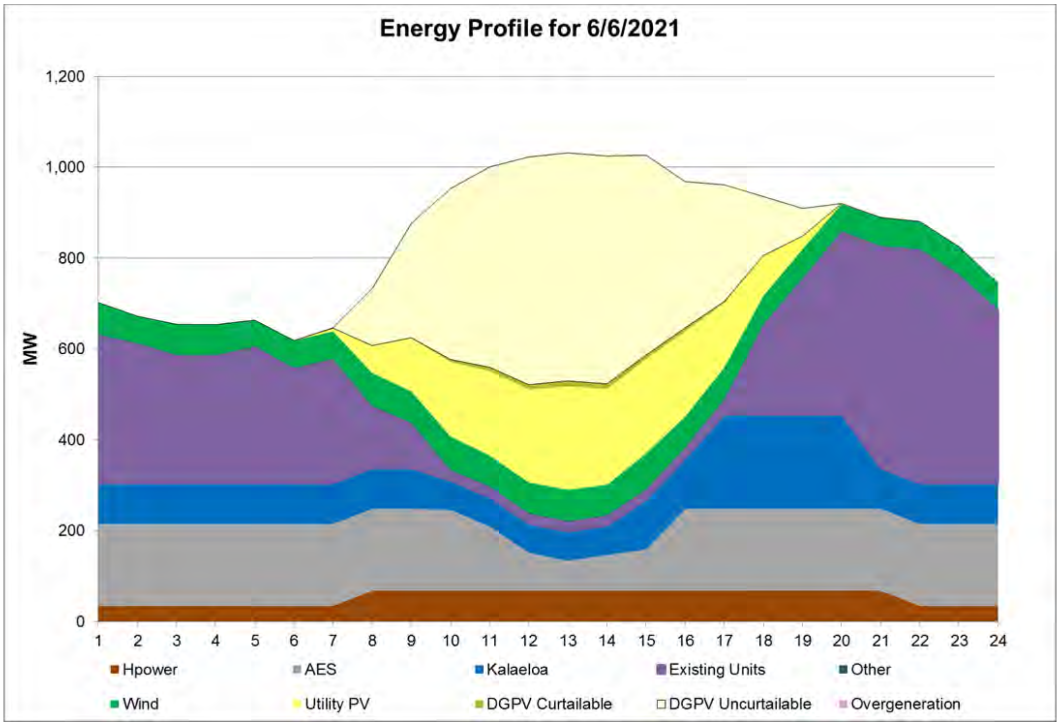


Figure 5-17. Modeled Energy Profile for June 6, 2021 of Theme 3

As indicated by the % over-generation and % renewable energy utilized presented earlier, higher levels of variable renewable generation will result in more instances where over-generation will occur. Looking out further in the planning period to 2030, the day with the highest penetration of solar energy is August 17, 2030 for Theme 1 as shown in Figure 5-18. There is over-generation of solar in the middle of the day under Theme 1.

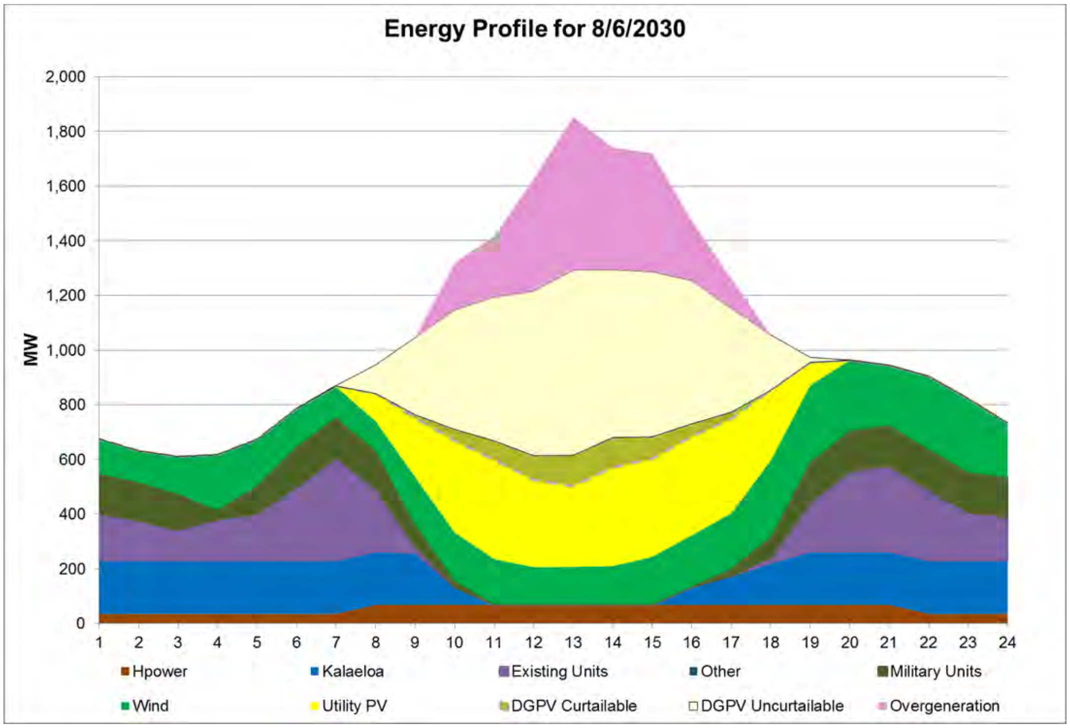


Figure 5-18. Modeled Energy Profile for August 6, 2030 of Theme 1

With the Market DG-PV, there is no visible over-generation in the middle of the day for Theme 2, shown in Figure 5-19, and small amounts of over-generation shown for Theme 3, in Figure 5-20.

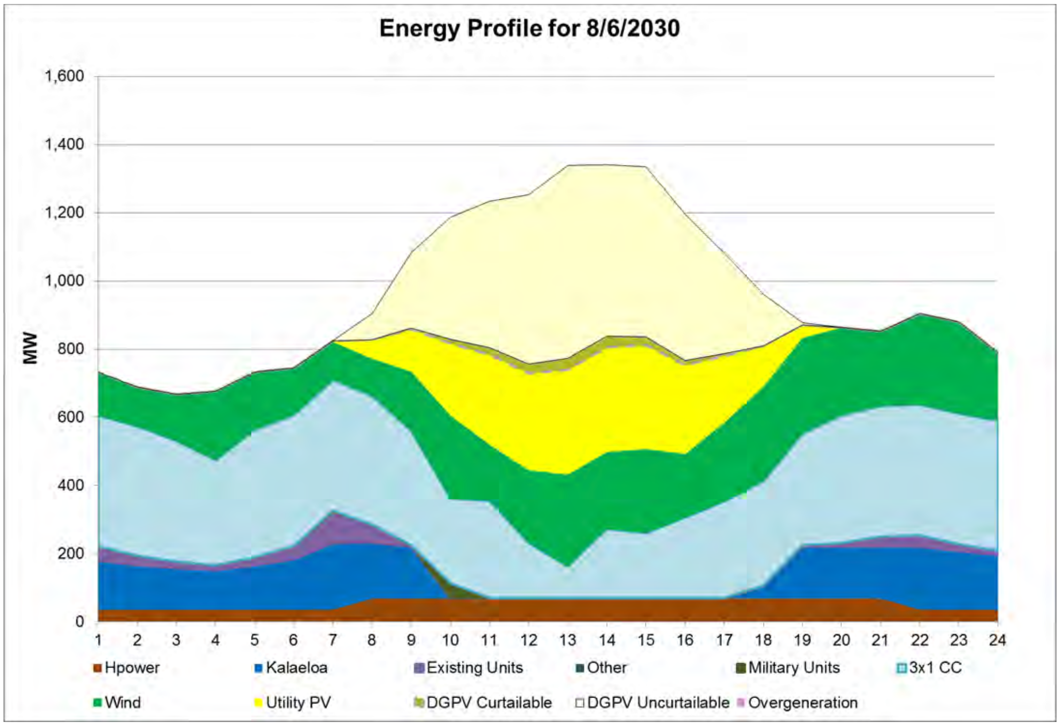


Figure 5-19. Modeled Energy Profile for August 6, 2030 of Theme 2

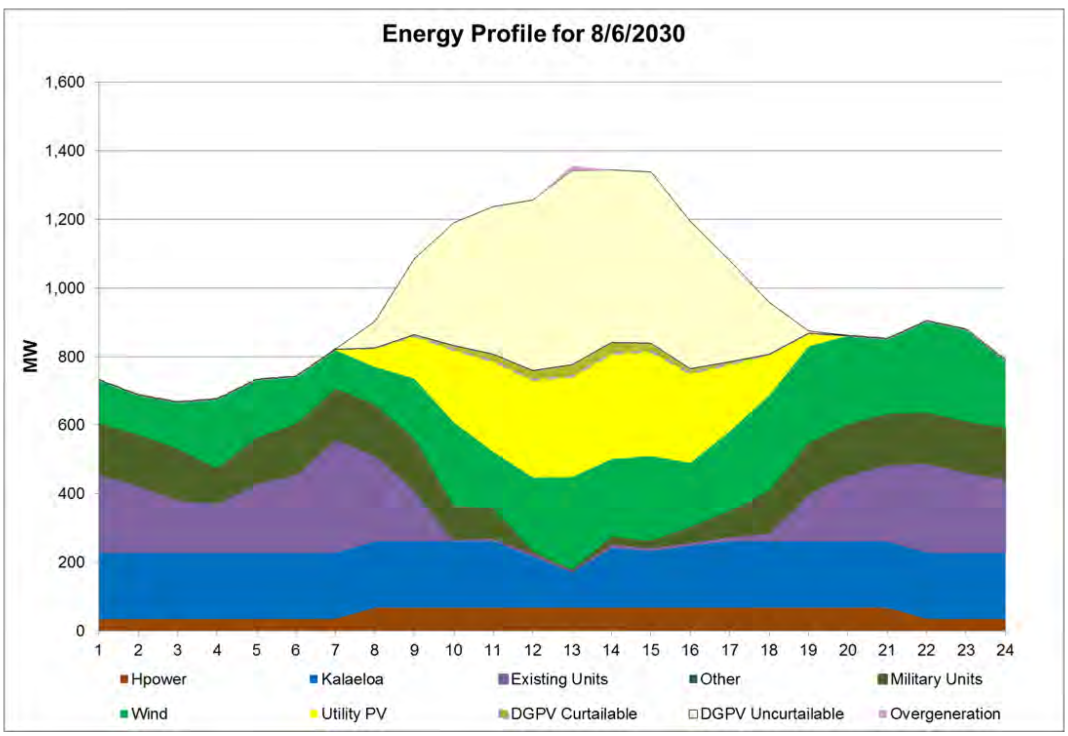


Figure 5-20. Modeled Energy Profile for August 6, 2030 of Theme 3

Moving towards 100% renewable in 2045, Figure 5-21 illustrates how most of the demand is being served by variable renewable energy but that there is a significant amount of over-generation for Theme 1 on the highest solar penetration day, August 19, 2045.

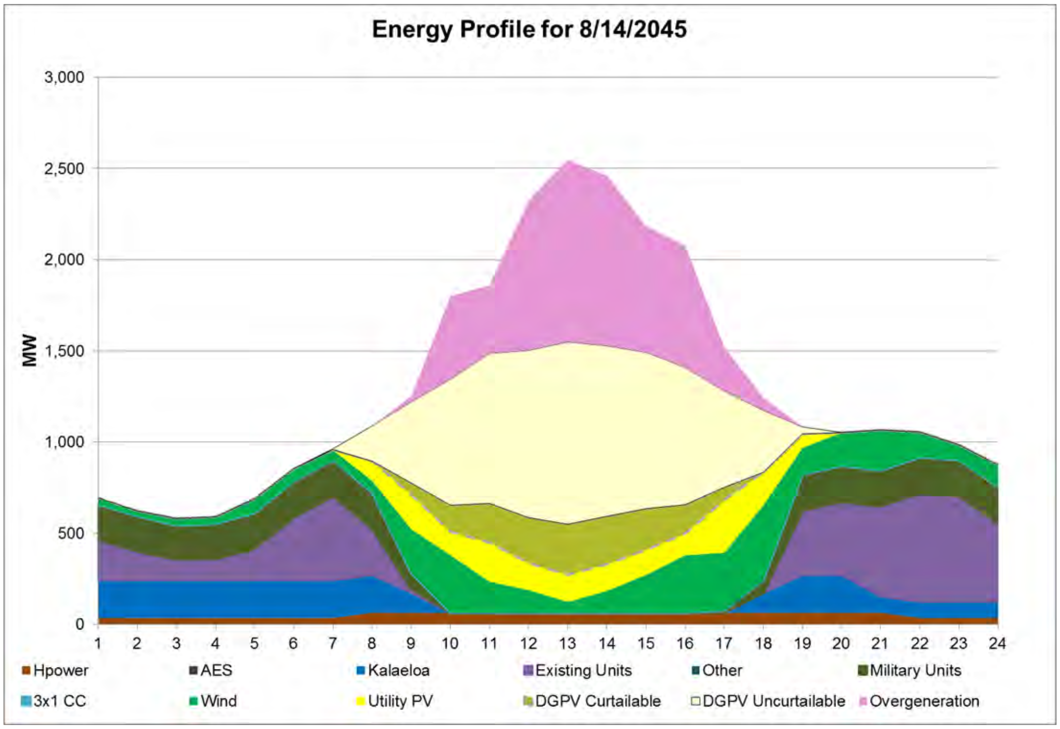


Figure 5-21. Modeled Energy Profile for August 14, 2045 of Theme 1

Although Theme 2 in Figure 5-22 and Theme 3 in Figure 5-23 have Market DG-PV, there is still significant over-generation in the middle of the day on this high solar day in 2045.

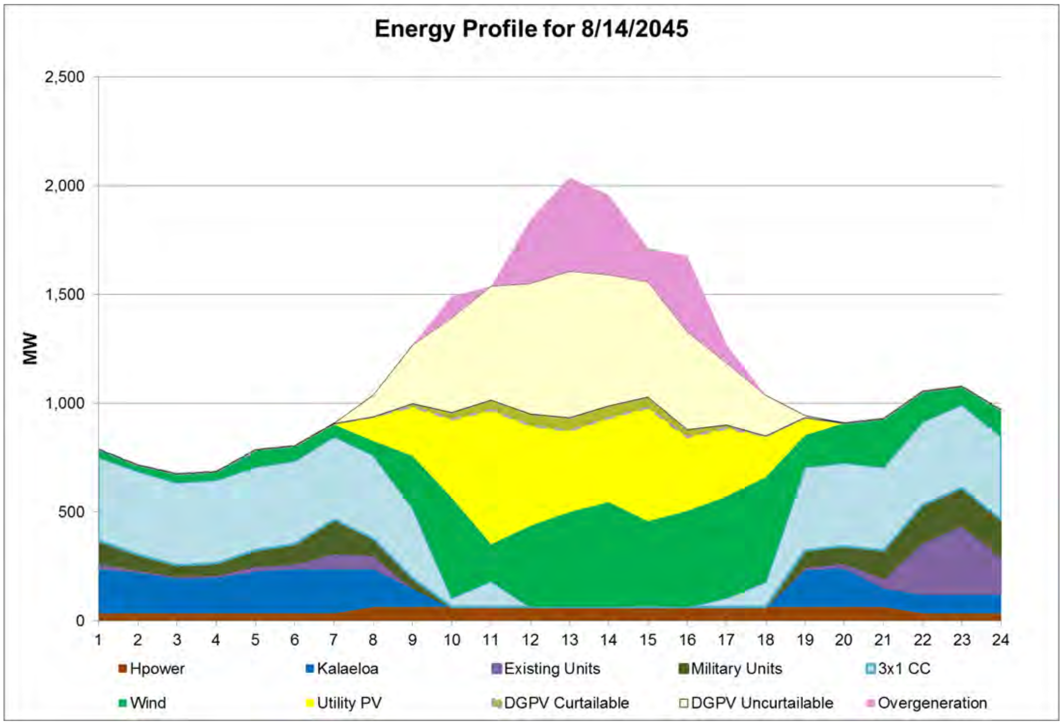


Figure 5-22. Modeled Energy Profile for August 14, 2045 of Theme 2

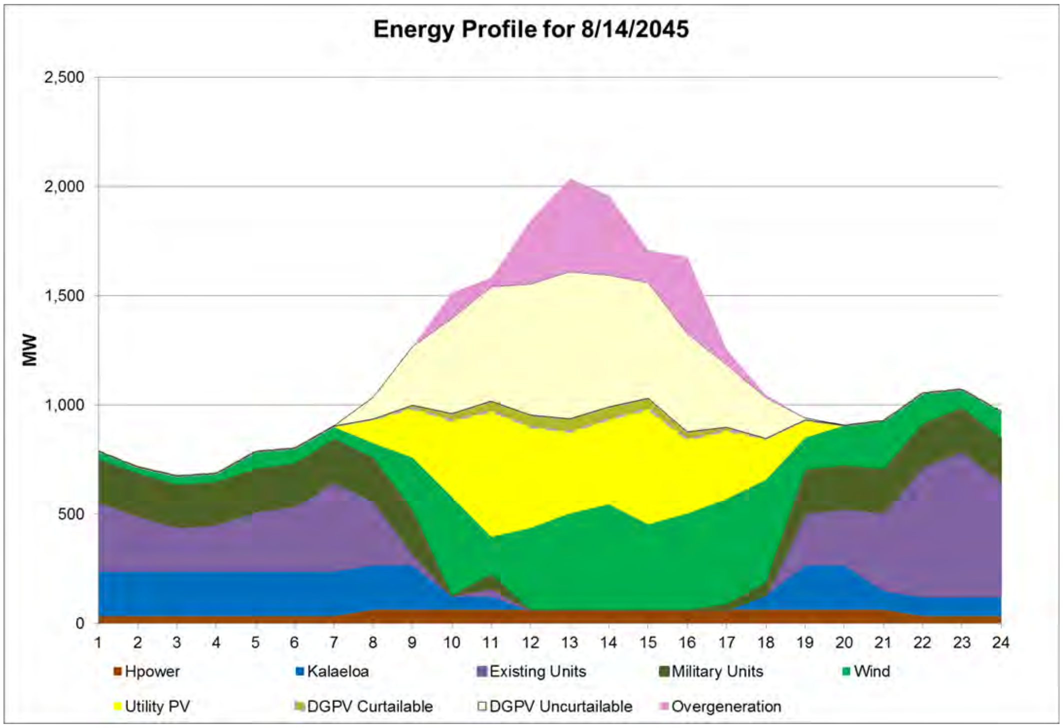


Figure 5-23. Modeled Energy Profile for August 14, 2045 of Theme 3

While it may appear in the charts that the amount of over-generation, if stored, could be used to displace a significant portion of the thermal generation using biofuels in 2045, the charts are not representative of all days in the year. The following charts are based on a day in 2045 that has the least amount of available generation from solar and wind. Figure 5-24 has minimal over-generation for Theme 1 and there is no over-generation for Themes 2 (Figure 5-25) and 3 (Figure 5-26) to store so thermal generation would be required to serve the demand.

The daily energy charts are a simple means to illustrate the complex and challenging issue of determining the "right size" of storage that makes economic sense. In the iterative process described in Chapter 3, there were cases analyzed that added varying amounts of storage and all cases with storage, based on the current cost assumptions, increased the total costs of the plan which is why all the final plans do not include load shifting storage.

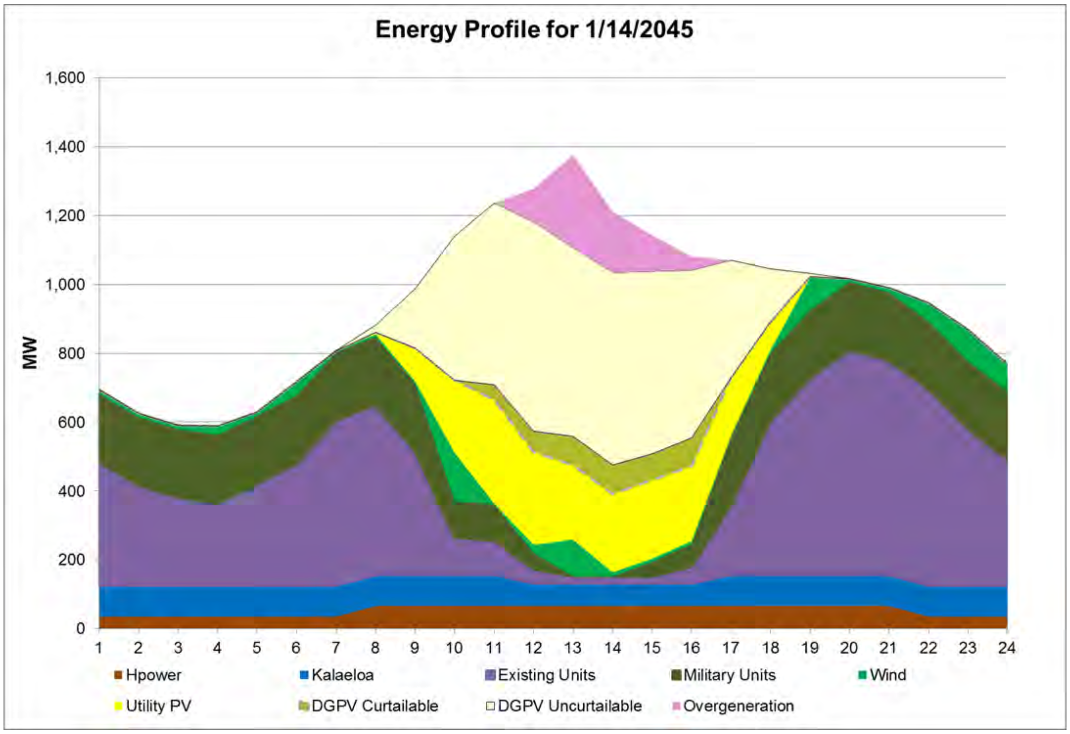


Figure 5-24. Modeled Energy Profile for January 14, 2045 of Theme 1

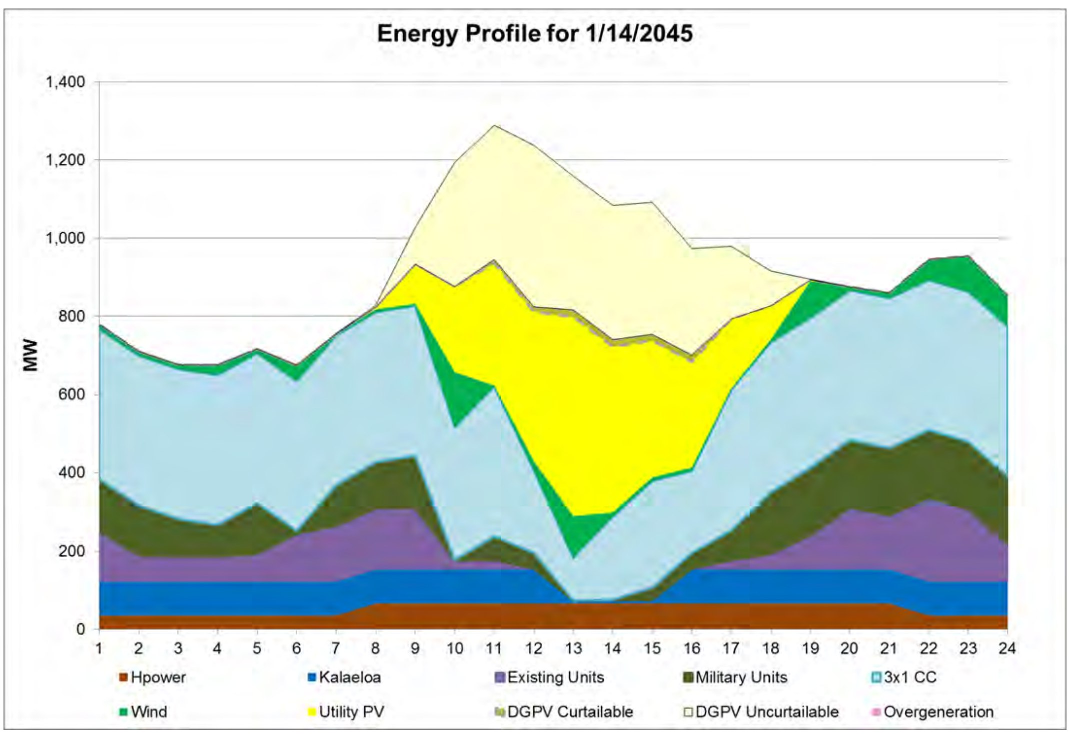


Figure 5-25. Modeled Energy Profile for January 14, 2045 of Theme 2

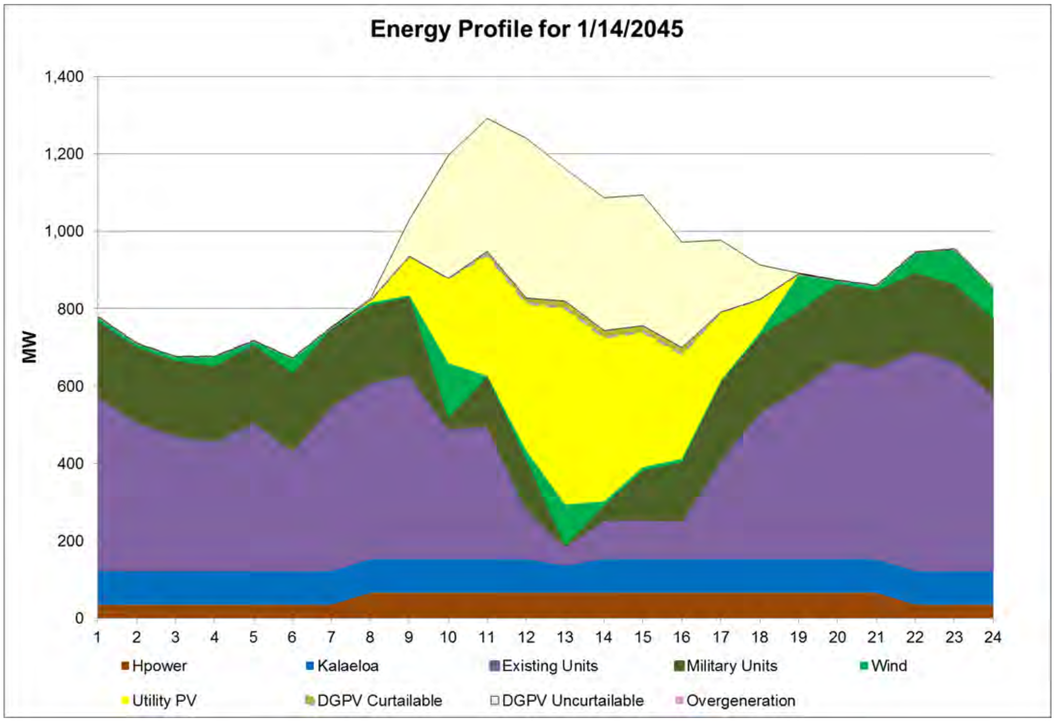


Figure 5-26. Modeled Energy Profile for January 14, 2045 of Theme 3

EMISSIONS OF FINAL PLANS FOR O'AHU

The CO_2 emissions of the final plans were estimated and are shown in Figure 5-27. Theme 3 has the highest projected emissions among the three final plans since a bulk of the thermal generation remains on oil until 2045. Theme 1 has lower projected emissions than Theme 3 due to the increasing levels of renewables displacing oil. Theme 2 has the lowest projected emissions of all three themes as a result of a combination of modernized generation and switch to LNG. Although Theme 1 accelerates renewable resources earlier than in Theme 2, the offset of emissions is greater by switching from oil to LNG and by replacing existing thermal generation with an efficient combined cycle unit.

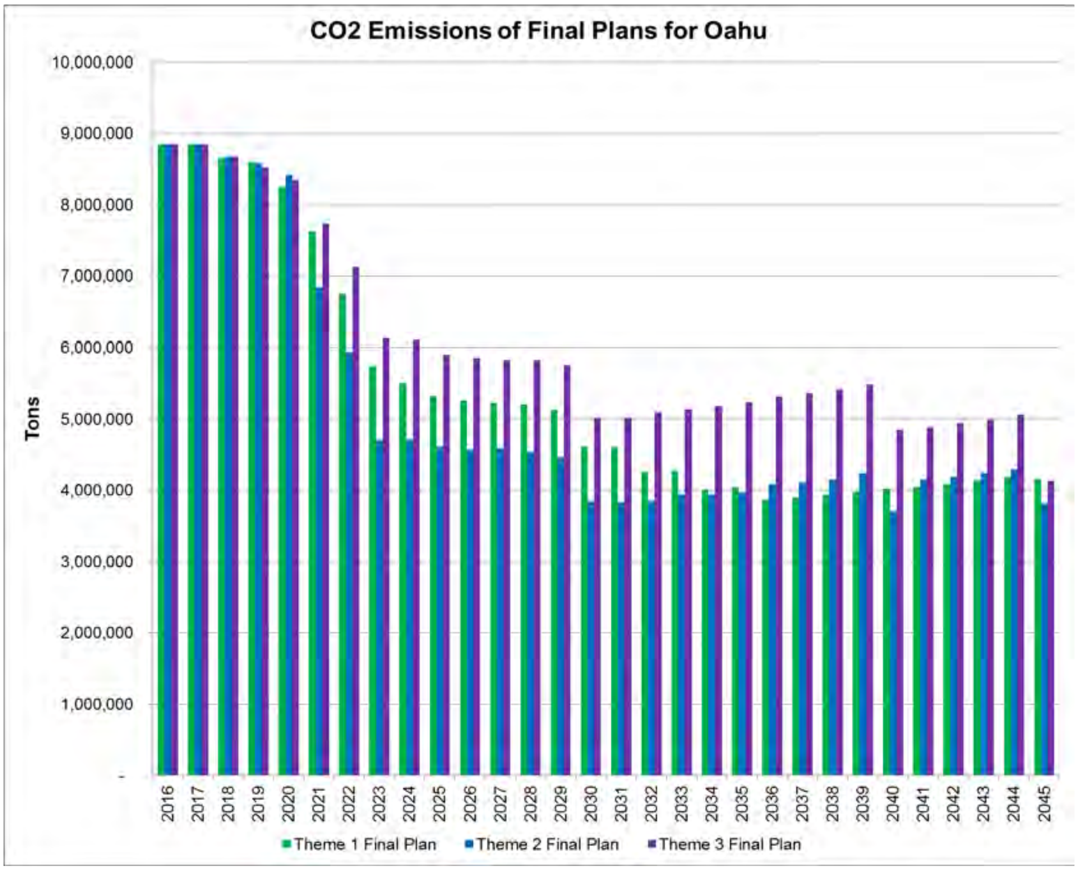


Figure 5-27. Estimated CO_2 Emissions of the Final Plans for O'ahu

O'AHU SELECTION OF THEME 2

The rigorous long-term analyses of the three themes provided insights on the different strategies for achieving 100% renewable energy by 2045. They provide directional guidance to inform the risks and the level of "no regrets" in short- term actions, particularly as you compare long-term resources across multiple themes. Although the steps along the paths to 2045 are different among the final plans, the starting point is the same. The purpose of the Preferred Plan is to inform the evaluation of specific near-term actions that are implementable based on the direction that the longer-term view of the plan provides. The Preferred Plan will balance technical, economic, environmental, and cultural considerations.

Based on the results of the analyses, Theme 2 will add a substantial amount of flexible, firm generation that will allow for the retirement of older generating units, incorporate significant amounts of variable renewable generation, and stabilizes customer bills by using lower cost fuel in the transition to 100% renewable.

Year	Preferred Plan (Final Plan from Theme 2)
2016	27.6 MW Waiver PV Project added 12/31/2016
2017	
2018	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6 MW Waiver PV Projects added 1/1/2018 Install 15MW Onshore Solar PV (CBRE) Install 10 MW Onshore Wind (CBRE)
2019	90 MW Contingency BESS Convert Honolulu 8 & 9 to Synchronous Condensers
2020	Install 100MW JBPHH Plant, 12/2020 Kahe 1, 2, 3 Deactivated, 12/2020 Install 30MW of Onshore Wind Install 60MW of Onshore Solar PV
2021	Install 27 MW KMCBH Plant, 6/2021 Install 3x1 CC, 6/2021 LNG Units: K5-6, KPLP, 3x1CC
2022	AES Deactivated 9/2022 Waiau 3 & 4 Deactivated, 1/2022 Kahe 4 Deactivated, 1/2022
2023	
2024	Waiau 5 & 6 Deactivated, 1/2024
2025	
2030	Waiau 7 & 8 Deactivated, 1/2030 Install 100MW of Onshore Solar PV Install 200MW of Offshore Wind
2040	Install 200MW of Onshore Solar PV Install 200MW of Offshore Wind
2045	Install 300MW of Onshore Solar PV Install 400MW of Offshore Wind

Table 5-1. Hawaiian Electric Preferred Plan

6. Maui Electric Preferred Plan

Maui Electric developed this Preferred Plan for transforming the system from current state to a future vision of the utility in 2045 that is consistent with the Commission's Observations and Concerns.

Implementation of Maui Electric's Preferred Plan would safely transform the electric systems of Maui, Lanaʻi, and Molokaʻi, and achieve unprecedented levels of renewable energy production. The electric systems of the future would integrate a balanced portfolio of renewable energy resources, thermal generation, energy storage, and demand response.

The Preferred Plan for the island of Maui increases variable renewable energy, and uses firm renewable sources to assist with the operation of the grid. Existing fossil-fuel steam generating units will be replaced with more flexible, fast-starting, cycling thermal generating units, and renewable firm generation is scheduled to displace existing fossil fuel generating units. The generators from retired steam generating units will be repurposed as synchronous condenser units to maintain fault current requirements and provide a level of rotating inertia. Demand response will also be used to further reduce fossil fuel utilization by providing ancillary services. The Preferred Plans for Lanaʻi and Molokaʻi strive for accelerated energy independence with minimal reliance on imported liquid fuels.

Our vision will advance our systems towards our goal of decreasing fossil fuels, integrating more renewable energy, and maintaining system reliability. Our commitment to reshaping our systems will result in achieving 100% renewable generation by 2040.

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. While specific resources are included in the Preferred Plan, we will continually seek more cost-effective, renewable resources to meet the needs of the system through a competitive process.

Maintaining flexibility in the resource options positions us to provide many alternatives to increase renewable energy while ensuring reliability to our customers. As we execute the Maui Preferred Plan we will incorporate more firm, cost-effective renewable resources, such as biomass and geothermal, and more variable renewable resources, such as wind and solar PV. We will take advantage of technology that can produce larger, centralized projects that can benefit the entire community, and also distributed energy resources (DER) 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 proposed for South Maui to support the electrical system instead of new overhead transmission infrastructure. Initially, our plan includes internal combustion engines to meet the firm generation need. The internal combustion engines proposed for South Maui may be candidates for relocation to Central Maui when the firm capacity renewable generation in South Maui is commercialized. Other non-transmission alternative such as combined PV/battery systems or wind/battery systems that are able to provide firm power on command in the South Maui area are also candidates.

Our plan selectively chose cost effective renewable resources using a relative comparison based on capital, O&M costs, and energy utilization. This provided a plan that considered both cost and risk while meeting (and exceeding) renewable energy goals. Evaluation of curtailment with respect to cost savings was also incorporated in the plan development. Curtailed variable renewable resources were still found to be cost effective when compared to storage options and the curtailed energy provides regulation and other ancillary services beneficial to grid operations.

The following resources were identified as low cost options, as shown in Figure 6-1:

- Wind is the lowest cost resource
- Biomass, Geothermal and Utility scale PV were the next lowest cost resources. These three resources were cost competitive against one another.
- Biomass and Geothermal provides firm, dispatchable power, more valuable to the grid at costs comparable to PV.

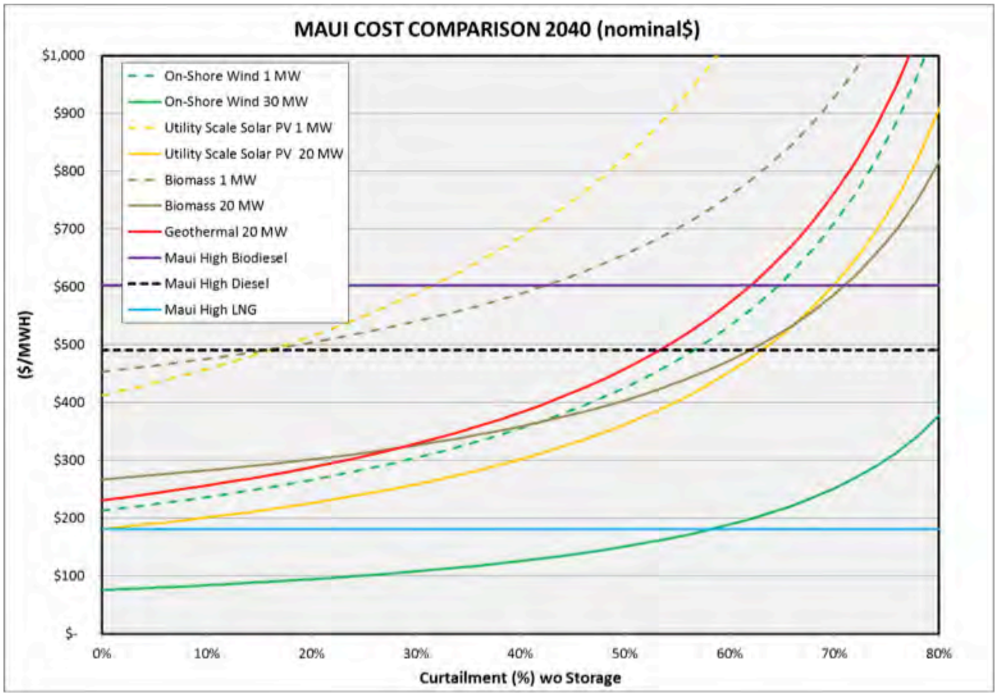


Figure 6-1. Forecasted Resource Cost Comparison: Maui 2040

Maui Preferred Plan

Maui Electric's Maui Division Preferred Plan is referred to as Theme 2 in Chapter 3, which meets interim RPS mandates across the Hawaiian Electric service areas and achieves 100% RE in 2040 on Maui while balancing the use of both fuel and non-fuel burning RE, and uses LNG. Because NextEra Energy's financial backing is required to implement Theme 2, this Theme can be considered a "merged" scenario where the proposed merger of the Companies and NextEra Energy is completed.

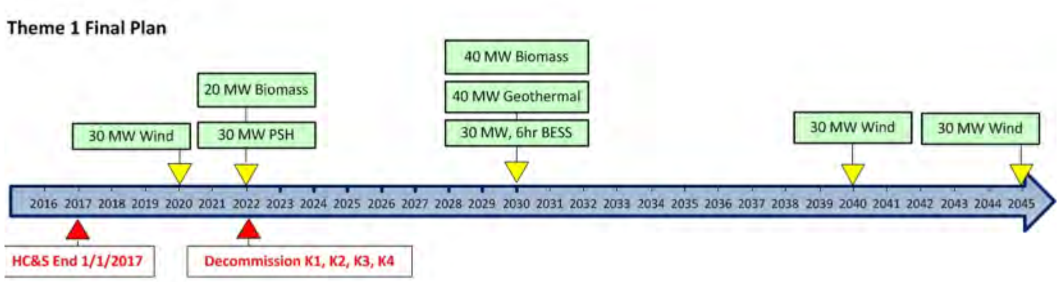


Figure 6-2. Maui Final Plans - Schedule of Resources: Theme 1

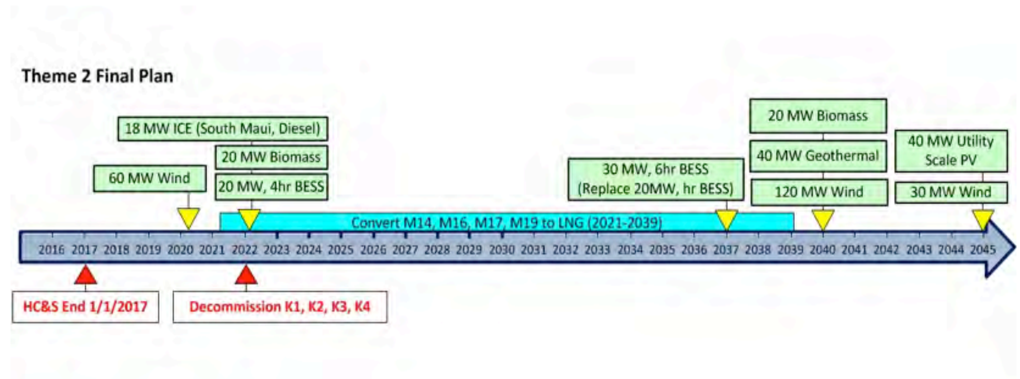


Figure 6-3. Maui Final Plans - Schedule of Resources: Theme 2

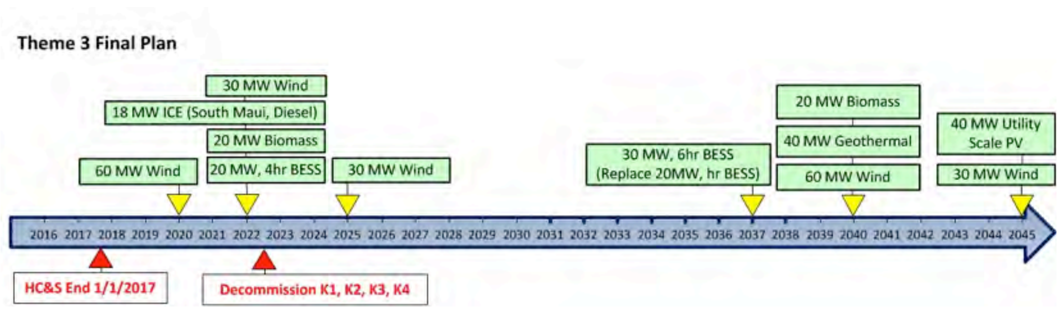


Figure 6-4. Maui Final Plans - Schedule of Resources: Theme 3

EMISSIONS OF FINAL PLANS FOR MAUI

The CO_2 emissions of the final plans were estimated and are shown in Figure 6-3 below. Theme 3 has the highest projected emissions among the three final plans since a bulk of the thermal generation remains on fossil fuel until 2039. Theme 2 has lower emissions with the switch to LNG. Theme 1 has the lowest projected emissions due to the increasing levels of renewables displacing fossil fuels.

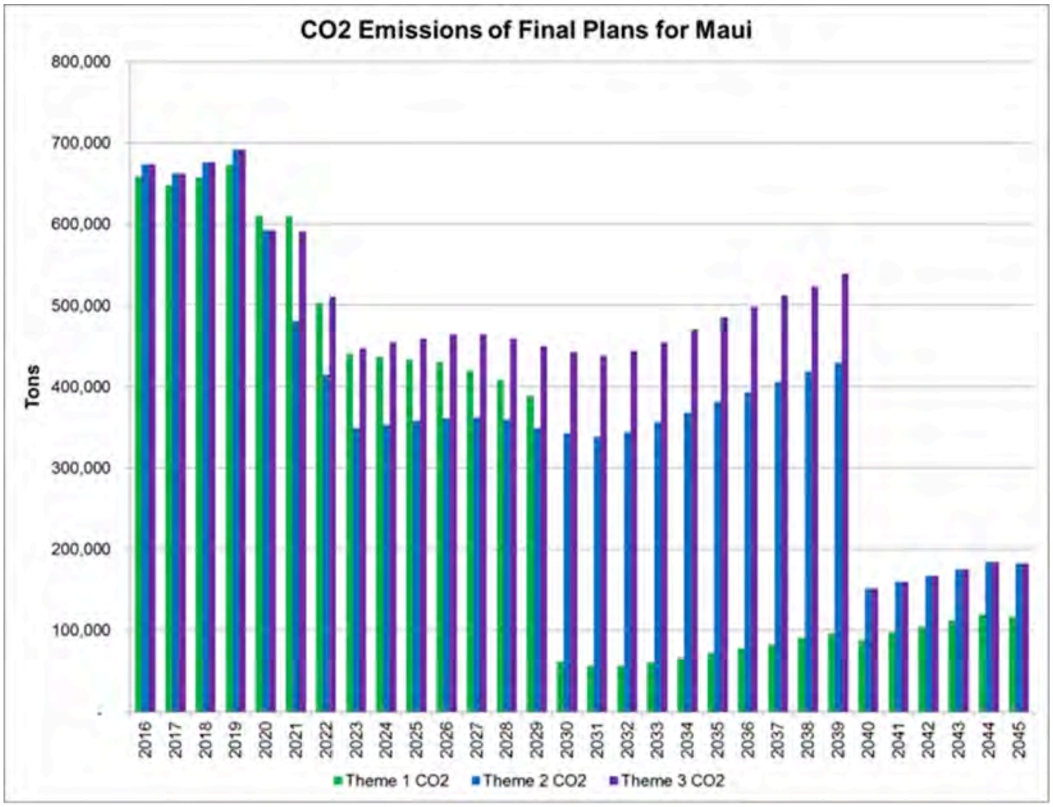


Figure 6-5. CO2 Emissions of Final Plans for Maui

ENERGY MIX OF FINAL PLANS FOR MAUI

Our commitment to reshaping our systems will result in Renewable Portfolio Standards (RPS) meeting or exceeding the requirement of 70% by 2040, and a vision of energy independence from fossil fuel by 2045 and possibly as early as 2040.

All of Maui Electric's Final Plans will add significantly more renewable energy to meet or exceed the mandated Consolidated RPS targets in 2020, 2030, and 2040. Our Consolidated RPS is planned to meet or exceed the 70% RPS by 2040 before transitioning to fully renewable energy electrical system by 2045.

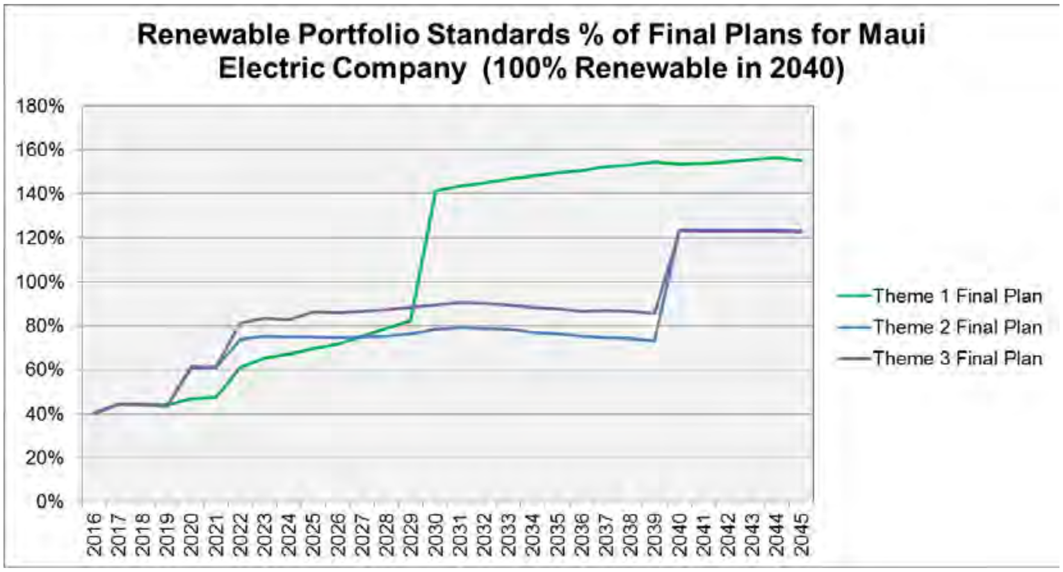


Figure 6-6. Renewable Portfolio Standards Percent of Final Plans for Maui (100% Renewable in 2040)

The Maui Preferred Plan will change over time to convert thermal units to LNG and incorporate greater amounts of renewable energy out to 2045. The figures that follow shows how the resource mix of the three Maui themes vary in generation and transforms over time. The accelerated transition to renewable resources of Theme 1 final plan can be seen in Figure 6-2 for the plan under the 2015 EIA Reference Fuel Price Forecasts and Figure 6-3 for the plan under the February 2016 EIA STEO Fuel Price Forecasts. The plan adds pumped storage hydro, biomass and geothermal resources to compliment increasing amounts of wind and High DG-PV resources. Theme 1 achieves 100% renewable energy on Maui by 2030 with the addition of geothermal and biomass resources along with biodiesel switching for conventional generation. Under both the 2015 EIA and February 2016 STEO Fuel Price Forecasts, the system resource energy mix are identical.

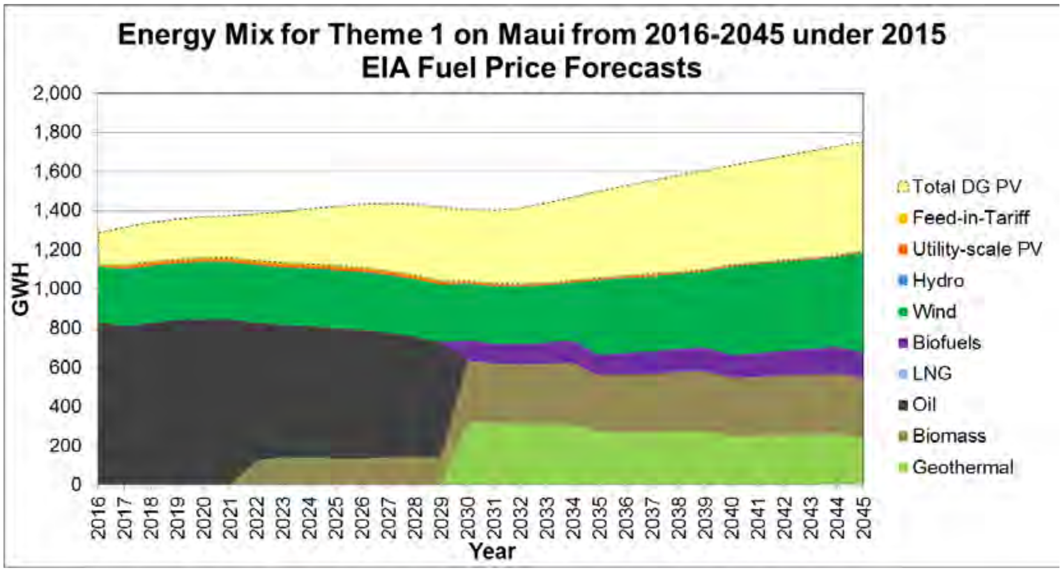


Figure 6-7. Energy Mix for Theme 1 on Maui from 2016-2045 under 2015 EIA Fuel Price Forecasts

Theme 2 final plan incorporates LNG as a transitional fuel as shown in Figure 6-4 for the plan under the 2015 EIA Reference Fuel Price Forecasts and Figure 6-5 for the plan under the February 2016 EIA STEO Fuel Price Forecasts. LNG fueling of the combined-cycle units at Maʻalaea allows for the reduction of oil use from 2021 to 2039 on Maui. The addition of biomass, wind, and geothermal resources along with biodiesel switching for conventional generation achieves 100% renewable energy on Maui in 2040. Under both the 2015 EIA and February 2016 STEO Fuel Price Forecasts, the system resource energy mix are identical.

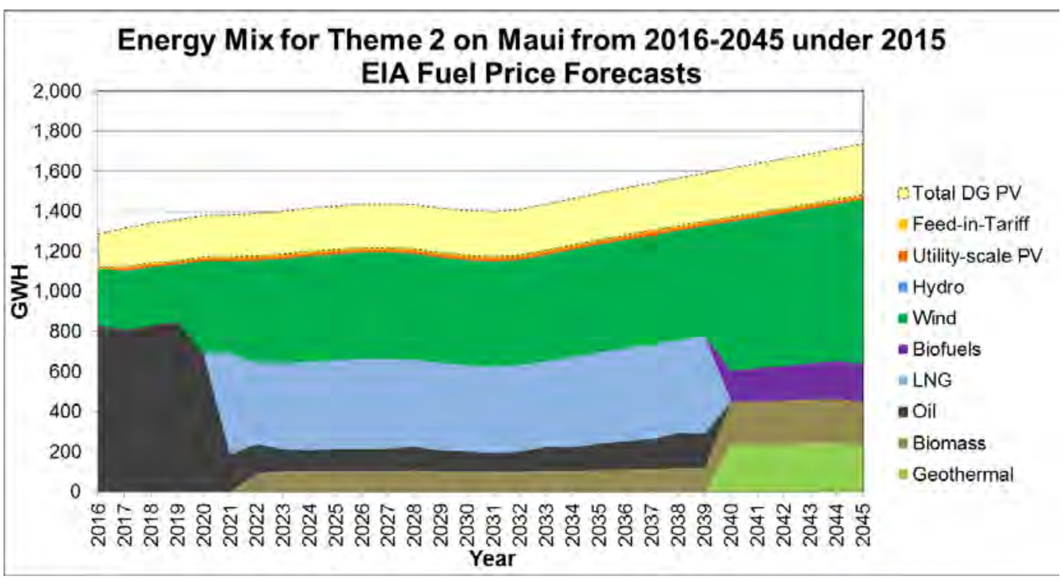


Figure 6-8. Energy Mix for Theme 2 on Maui from 2016-2045 under 2015 EIA Fuel Price Forecasts

Theme 3 final plan economically incorporates renewable resources and continues to use oil instead of LNG as shown in Figure 6-6 for the plan under the 2015 EIA Reference Fuel Price Forecasts and Figure 6-7 for the plan under the February 2016 EIA STEO Fuel Price Forecasts. The addition of wind resources in 2022 and 2025 results in oil use reduction from 2020 to 2039 on Maui. The addition of geothermal, biomass and wind resources along with biodiesel switching for conventional generation achieves 100% renewable energy on Maui in 2040. Under both the 2015 EIA and February 2016 STEO Fuel Price Forecasts, the system resource energy mix are identical.

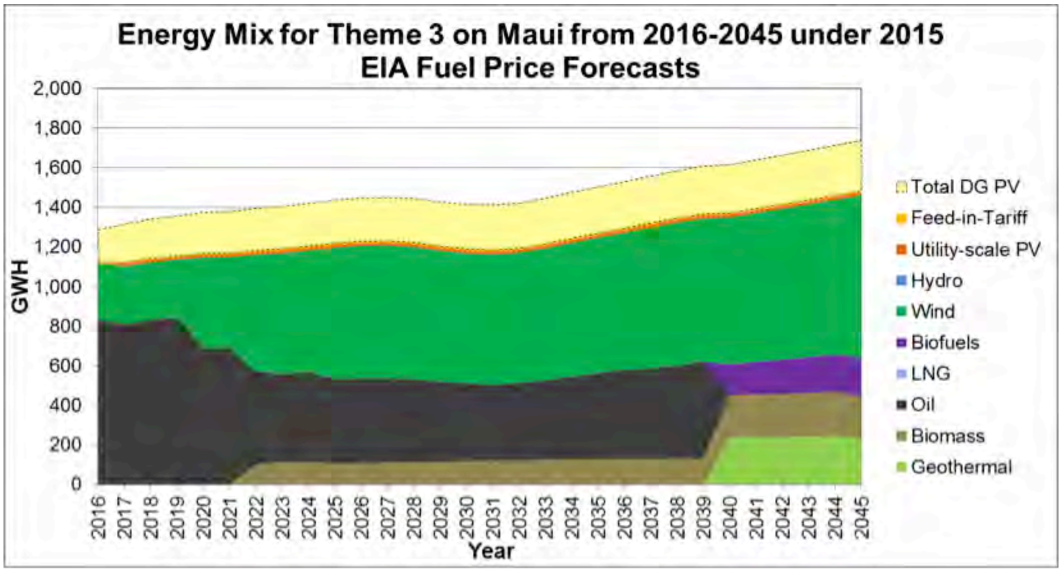


Figure 6-9. Energy Mix for Theme 3 on Maui from 2016-2045 under 2015 EIA Fuel Price Forecasts

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

TOTAL SYSTEM RENEWABLE ENERGY UTILIZED OF FINAL PLANS FOR MAUI

The extent to which renewable energy can be utilized on Maui will depend on factors such as the total system load or energy demand, the amount of downward regulation that must be carried on the system to counteract an unexpected loss of load, the total output from variable generation resources, and the position of the variable generation resource in the curtailment sequence. In all Themes Maui Electric strives for high utilization of renewable energy on the system to achieve 100% RE. Under both the 2015 EIA and February 2016 STEO Fuel Price Forecasts, the total system renewable energy utilization are identical.

Renewable Energy Utilization

% RE	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2016-2045
Utilized	97%	98%	99%	98%	92%	93%	99%	99%	98%	98%	97%	97%	95%	94%	93%	92%	92%	92%	92%	91%	91%	91%	91%	91%	87%	86%	86%	86%	86%	82%	91%

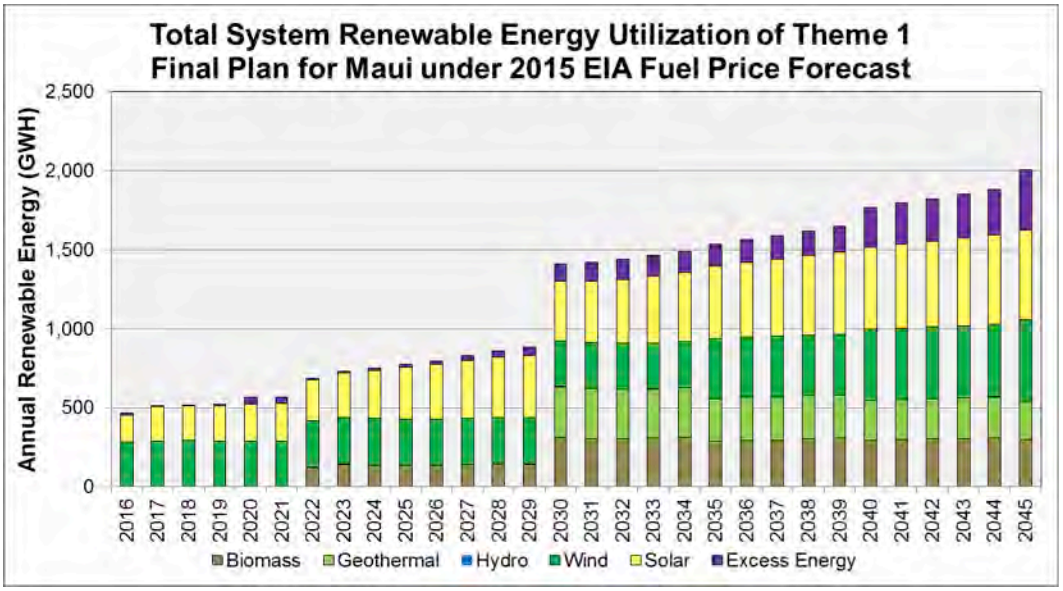


Figure 6-10. Total System Renewable Energy Utilization of Theme 1 Final Plan for Maui Under 2015 EIA Fuel Price Forecast

Renewable Energy Utilization

% RE	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2016-2045
Utilized	98%	99%	99%	97%	87%	87%	94%	96%	96%	97%	97%	97%	96%	96%	96%	96%	96%	97%	97%	98%	98%	98%	99%	99%	82%	83%	84%	84%	85%	82%	91%

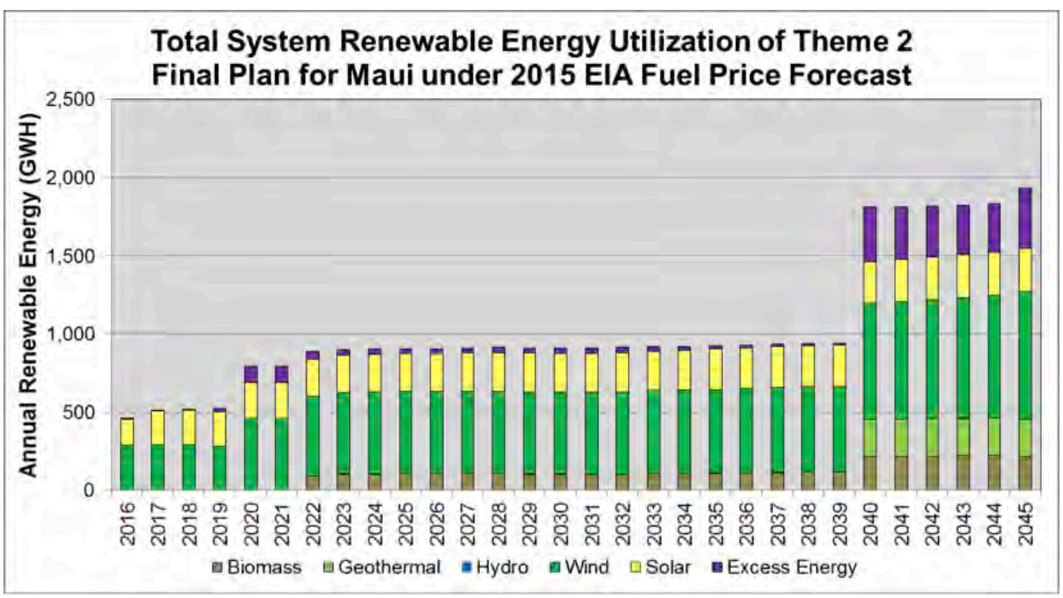


Figure 6-11. Total System Renewable Energy Utilization of Theme 2 Final Plan for Maui Under 2015 EIA Fuel Price Forecast

Renewable Energy Utilization

% RE	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Utilized	98%	99%	99%	98%	86%	87%	90%	92%	92%	86%	87%	87%	86%	86%	86%

% RE	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2016-2045
Utilized	86%	86%	87%	88%	88%	89%	90%	91%	92%	82%	83%	83%	84%	84%	83%	87%

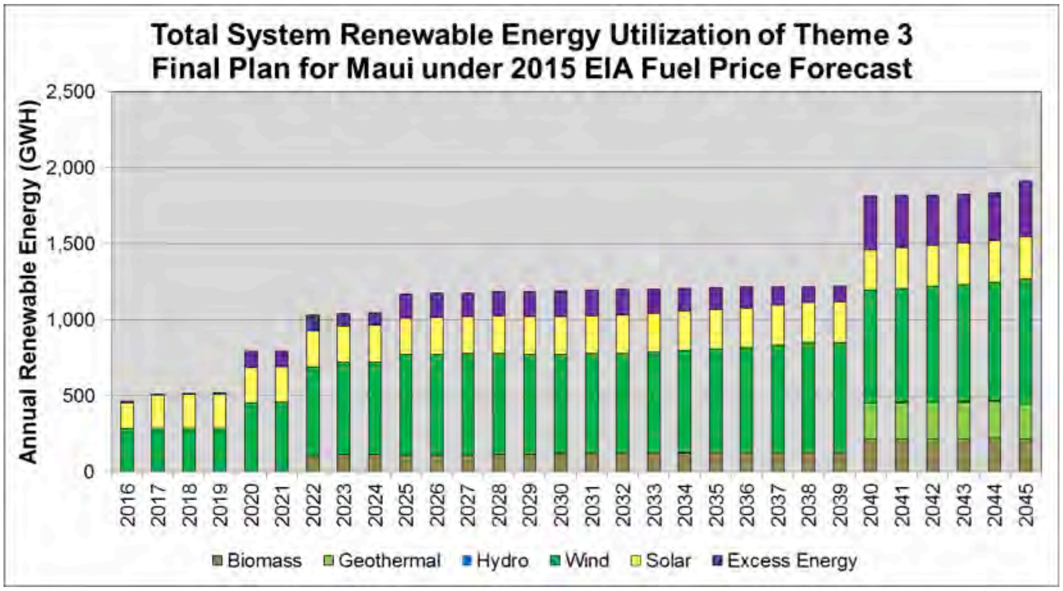


Figure 6-12. Total System Renewable Energy Utilization of Theme 3 Final Plan for Maui Under 2015 EIA Fuel Price Forecast

PERCENT OVER-GENERATION OF TOTAL SYSTEM OF FINAL PLANS FOR MAUI

The Maui Electric system has greatly increased the amounts of variable generation that can be utilized. By acquiring additional new flexible firm renewable generation along with increasing wind generation, lower levels of curtailment are achieved during low demand periods (which may occur during daytime hours due to influence of DG-PV, as well as during typical night time low load hours). However, even with these improvements, non-firm renewable generation such as wind is occasionally available in quantities that cannot be effectively utilized by the system. A combination of reducing must-run generation and adding load shifting energy storage in 2022 significantly reduced curtailment.

However, situations of over-generation are not fully eliminated and provide opportunities, coupled with appropriate controls systems, to use wind and solar generation as regulation resources in addition to use as a reserve resource. This provides more value than a resource providing energy only. In combination, wind and solar used for energy and some level of regulation and reserve appear to be cheaper than the alternative of additional storage, at least at moderate over-generation levels. For the purposes of this PSIP update, we include the full cost of the utility scale variable generation resources in cost calculations, regardless of over-generation levels and provides a simplified accounting for other services from these resources.

Figure 6-13 shows the annual levels of curtailment on the Maui system for each Theme. Under both the 2015 EIA and February 2016 STEO Fuel Price Forecasts, the total system renewable energy utilization are identical.

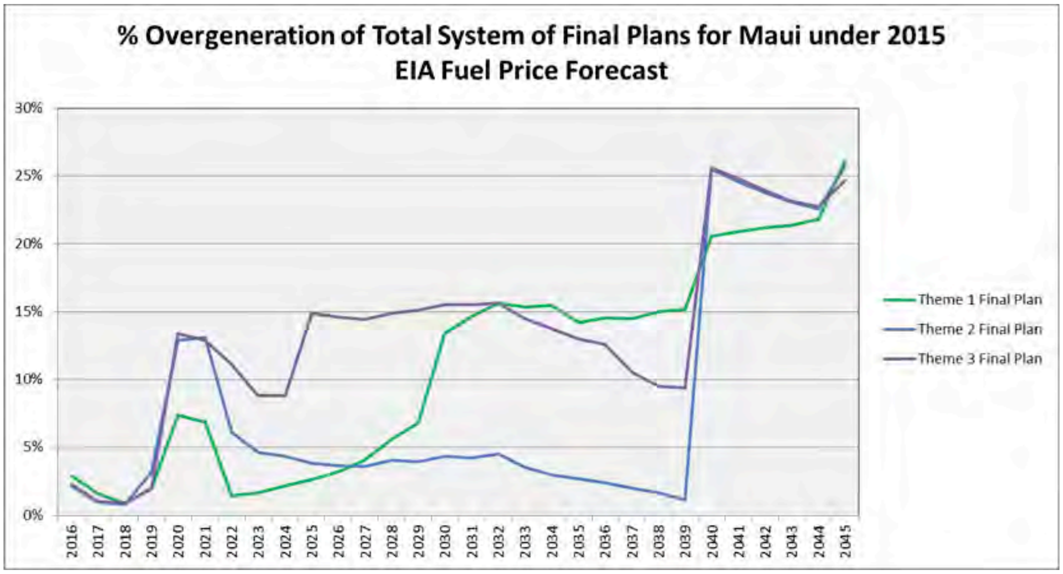


Figure 6-13. Percent Over-Generation of Total System of Final Plans for Maui under 2015 EIA Fuel Price Forecast

DAILY ENERGY CHARTS OF FINAL PLANS FOR MAUI

The utilization of renewable energy is mostly dependent on the system load, amount of available renewable generation, and must-run generation. For example, the greater the system load, the more opportunity exists to utilize renewable energy. Conversely, a lower system load would restrict the utilization of renewable energy. In addition, when renewable generation is not available, then other resources, such as liquid fuel generation, will be required to meet the system load.

Historically, wind and solar have seasonal tendencies with respect to the amount of available generation produced. As shown in the following figure, the Maui wind and solar resources tend to have more generation in the months of March to October. Therefore, as wind and solar resources are added to the Maui system, then a lower percentage of renewable energy is utilized. In the months of November to February, without significant quantities of wind and solar, the system load will not be able to be met by variable renewable energy alone.

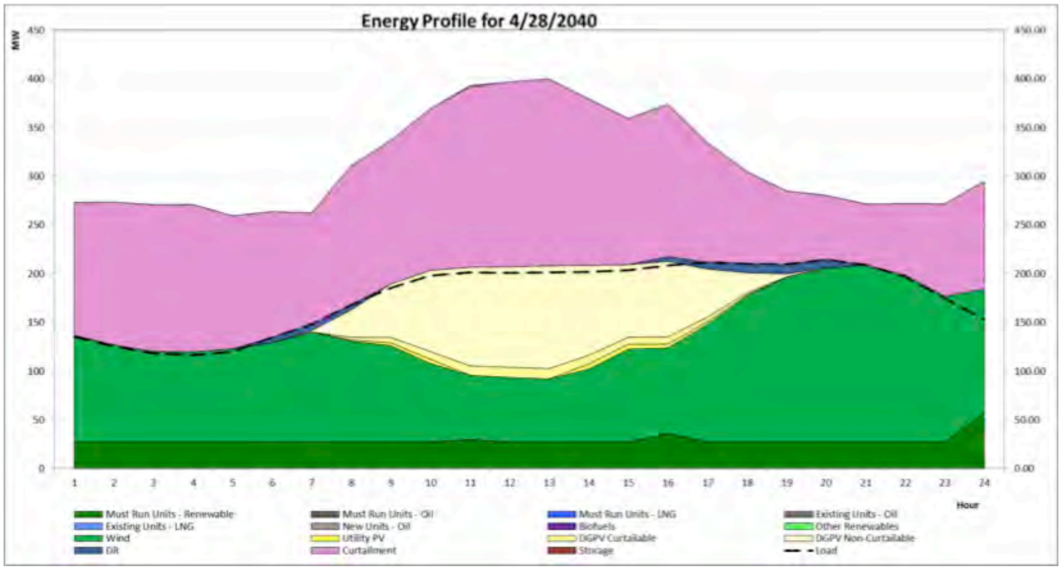


Figure 6-14. Seasonal Potential Renewable Energy Profile

Conceptually, if the amount of wind and solar energy generated in a year is equal to the total annual system load, then there would be enough renewable energy to serve the load on an annual basis. However, due to the seasonal tendency of wind and solar, there would be an imbalance from month to month. A storage component would be required to shift the load over seasons in order to utilize all the renewable energy. This is "seasonal energy shifting". In the figure below, the dashed line represents the seasonal monthly load. Periods where the potential renewable resource energy falls under the load, indicates periods where there is an insufficient amount of renewable generation to serve the load. Periods where the potential renewable resource energy is above the load, indicates periods where there is excess renewable generation.

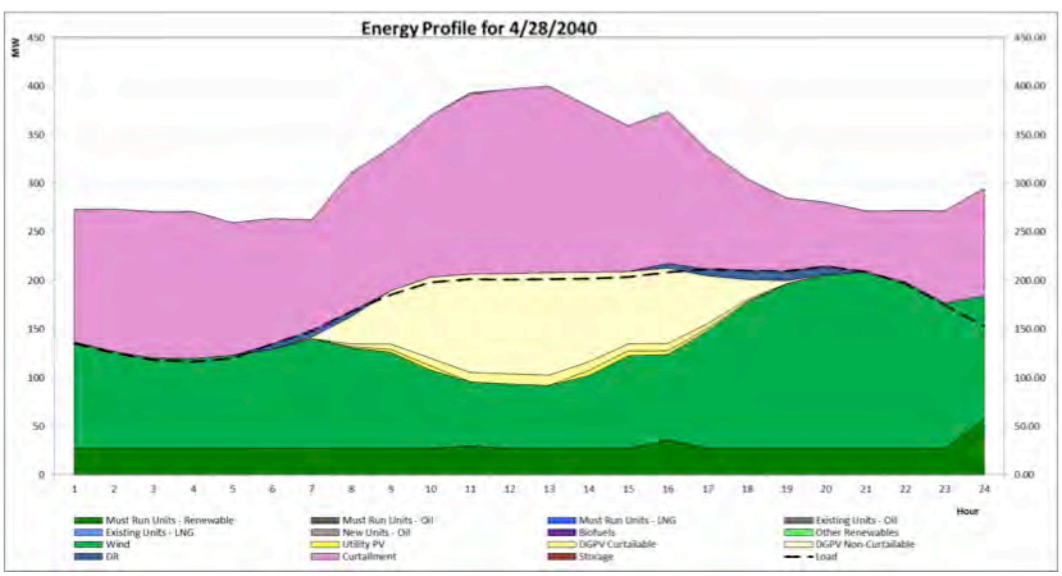


Figure 6-15. Seasonal Potential Renewable Energy Profile and System Load

Load shifting resources that have the ability to charge over the March to October period, store the energy over an extended period of time, and then discharge in the months of November to February could conceivably provide a solution. For example, if there is 170 GWh of annual curtailed energy, then storage technology of approximately 230 units at 30 MW with operation duration of 24 hours would be required for the seasons that have insufficient renewable energy to serve the load. This would essentially eliminate curtailment for the entire year and potentially eliminate the need to operate conventional generation. However, the larger the storage requirement, the greater the cost will be. An approximate cost of the battery energy storage system would be $40 billion based on a cost of $246/kWh in 2045. This example shows that energy storage for seasonal load shifting with the purpose of eliminating curtailment is unrealistic.

Another use for energy storage could be for day to day purposes to reduce curtailment and the use of conventional generation. Day to day operation would require far less energy storage than a seasonal load shifting battery. For example, if 180 MWh of load shifting was appropriate on a day to day basis, then a single 30 MW/180MWh energy storage resource could be utilized on the system. The approximate cost of this battery energy storage system would be $44 million. However, with this limited operational size and duration, when exhausted, other resources would have to be called upon to satisfy the system load (i.e. conventional generation). Daily load shifting energy storage, such as pumped storage hydro and load shifting batteries were considered in the plans. These storage resources were also credited with firm capacity benefit by reducing peak load. Limited amounts of energy storage are economical when storage can be installed for peaking capacity needs in lieu of new firm conventional generating resources. The figure below shows the comparative capital and Fixed O&M costs of peaking generating resources. Peaking resources would be needed to provide generation during the daily priority peak period of 5 pm to 9 pm.

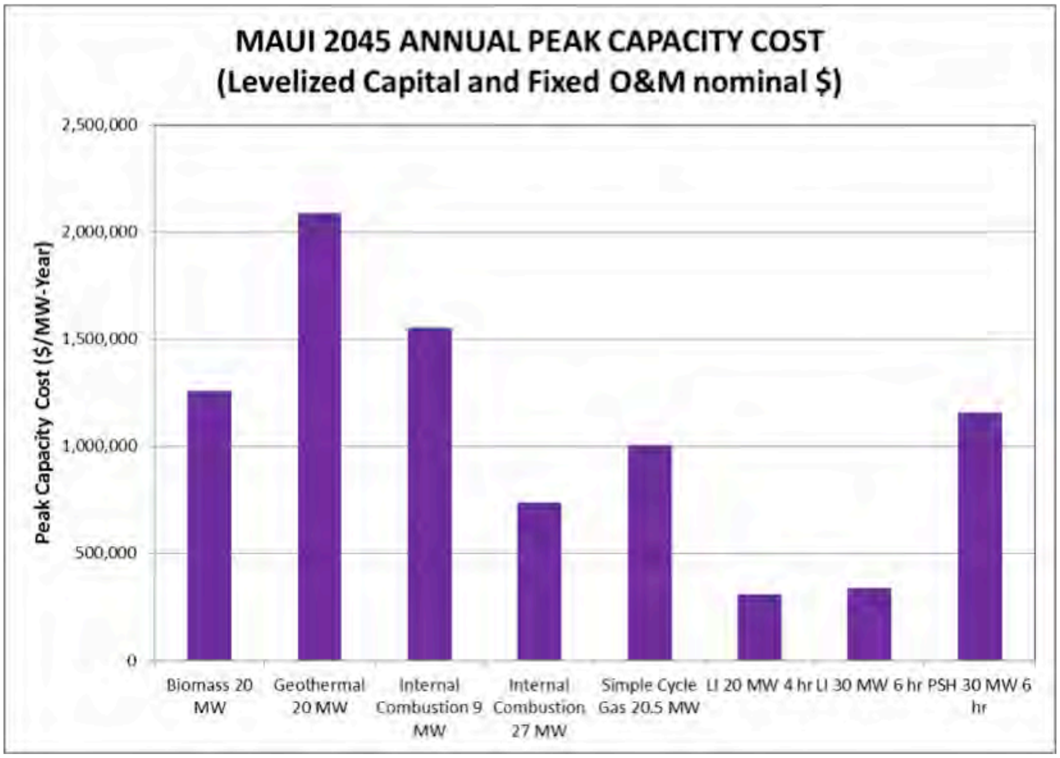


Figure 6-16. Maui 2045 Annual Peak Capacity Cost

The following figure shows the advantage of a diversified portfolio of resources such as, firm dispatchable, variable generation, demand response, and load shifting storage to serve our customer's energy needs.

The resources and components of the figure are:

- The dashed black line is the system load prior to load shifting (i.e. time of use, storage, and demand response) and without the effects of DG-PV.
- The blue area represents the peak shaving effects of demand response.
- The red area represents the peak shaving effects of load shifting storage.
- The pink area represents the curtailed energy.
- The 3 shades of yellow represent PV.
- The light green area represents wind.
- The dark green area represents the firm renewable resources.
- The purple area represents conventional generation on biodiesel.

Results from the production simulation show that on May 12, 2040, of the Theme 2 final plan, several dynamic interactions of different resources are shown:

- Periods where the conventional generation is providing energy shows times where the either the wind energy decreased or when conventional generation was required to meet the system load when other renewables (i.e. PV and wind) were insufficient.
- The area under the curtailed energy profile and above the dashed black line is amount of load that has been shifted to the daytime period as a result of charging the energy storage resource and executing the load contribution portion of the demand response programs. It is implicit that load shifting occurred as increased levels of PV were utilized during the daytime periods. Thereby increasing renewable energy taken that would have been otherwise been curtailed without demand response and energy storage.

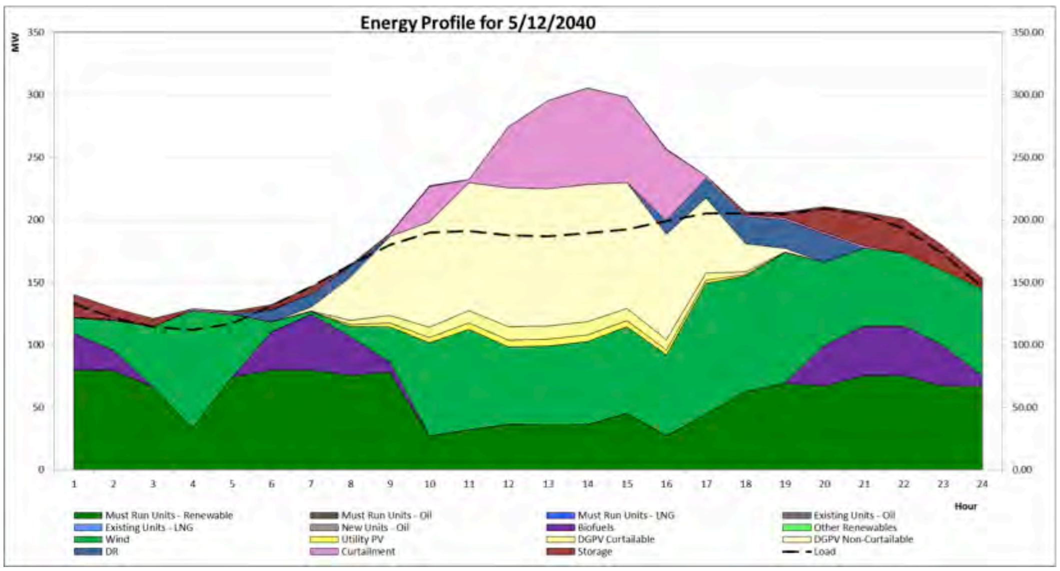


Figure 6-17. Theme 2 Maui 2040 Daily Energy Chart – Dynamic Mix of Generation

The following figure shows a day in a high renewable energy season where there is an overabundance of variable generation (i.e. wind and PV). An artifact of the desire to increase the levels of variable renewable generation is increasing amounts of curtailment when the renewable energy production is greater than the system demand over the entire day. Therefore, there are essentially no opportunities to shift load to reduce curtailment.

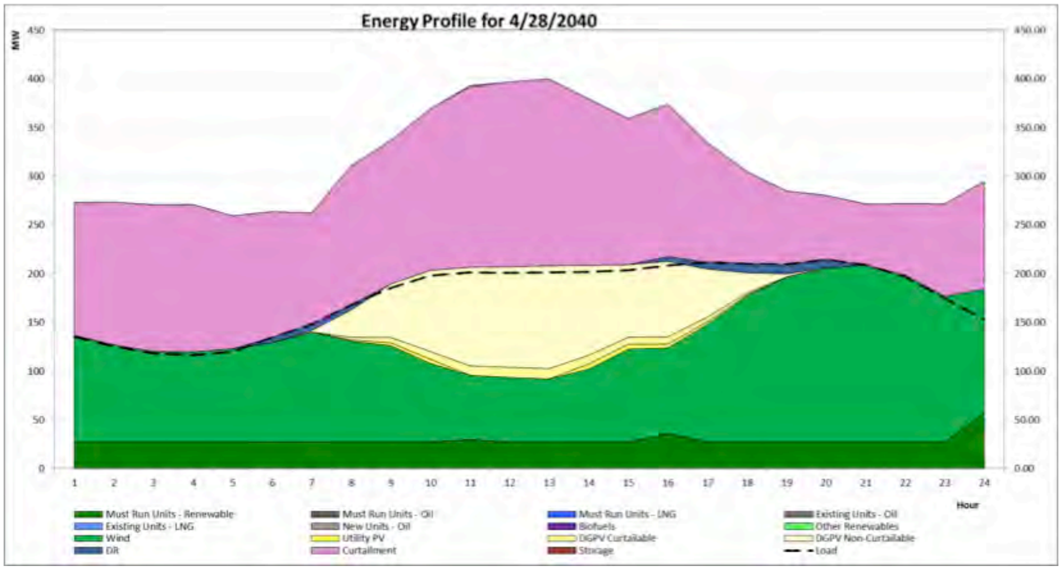


Figure 6-18. Theme 2 Maui 2040 Daily Energy Chart – High Wind and PV

Conversely, the following figure shows a day where greater reliance on firm generation (including renewable and conventional generation) is required due to the absence of sufficient variable renewable energy to serve the system load. It shows that biomass and geothermal are operating at or near normal top load throughout the day, requiring less biodiesel conventional generation. Therefore, incorporation of additional firm renewable generation is desirable to achieve greater levels of total renewable generation without necessitating the curtailment of seasonal variable generating resources.

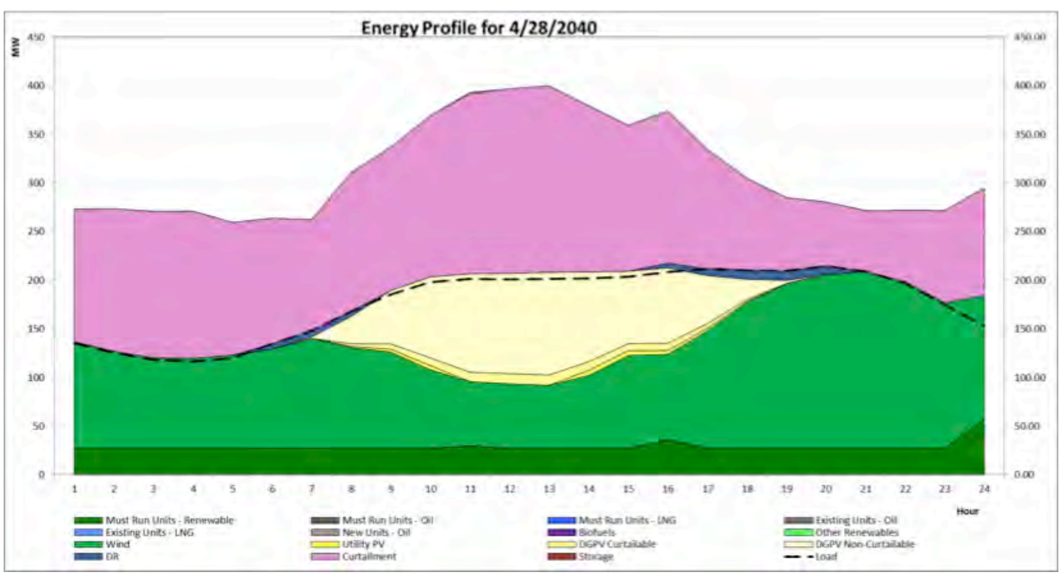


Figure 6-19. Theme 2 Maui 2040 Daily Energy Chart – Low Wind and PV

The following charts show various levels of renewable energy resources at different times for each Theme. The charts depict periods of:

- Abundance of wind and PV generation.
- Absence of wind and PV generation.

Theme 1

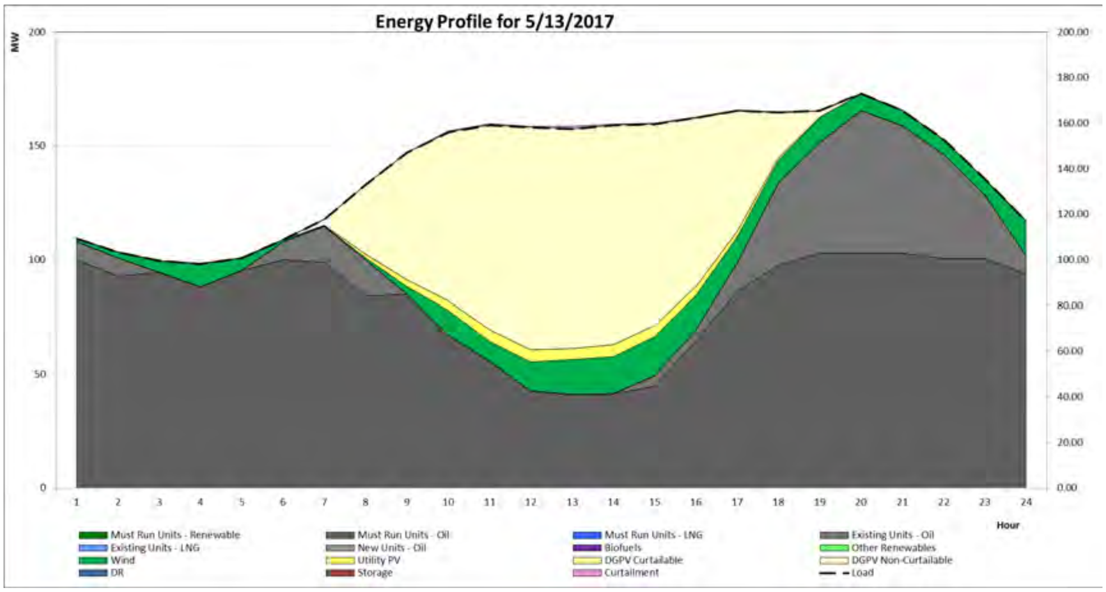


Figure 6-20. Theme 1 Max PV Day 5/13/2017

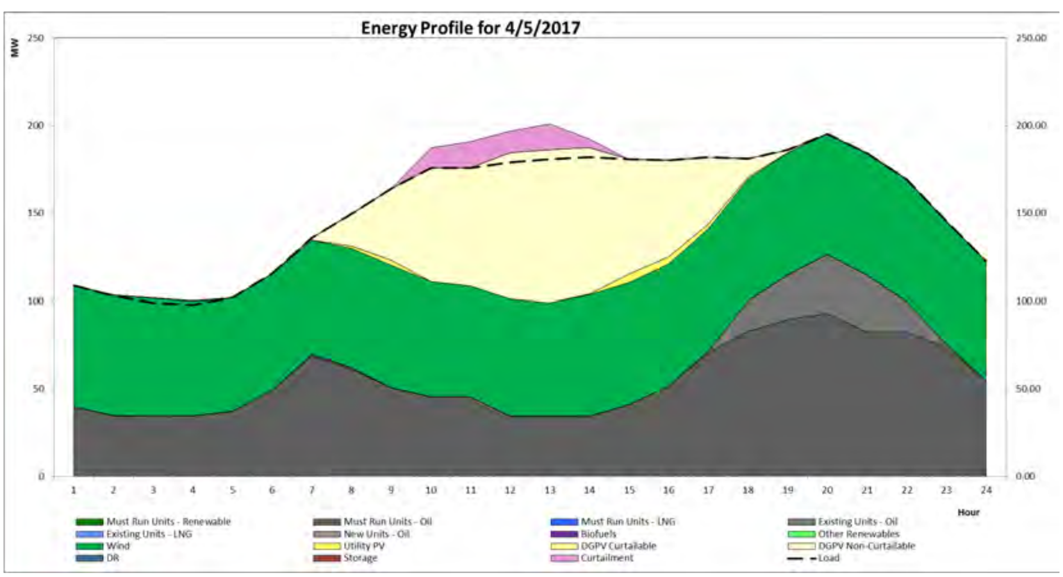


Figure 6-21. Theme 1 Max Wind Day 4/5/17

6. Maui Electric Preferred Plan

Daily Energy Charts of Final Plans for Maui

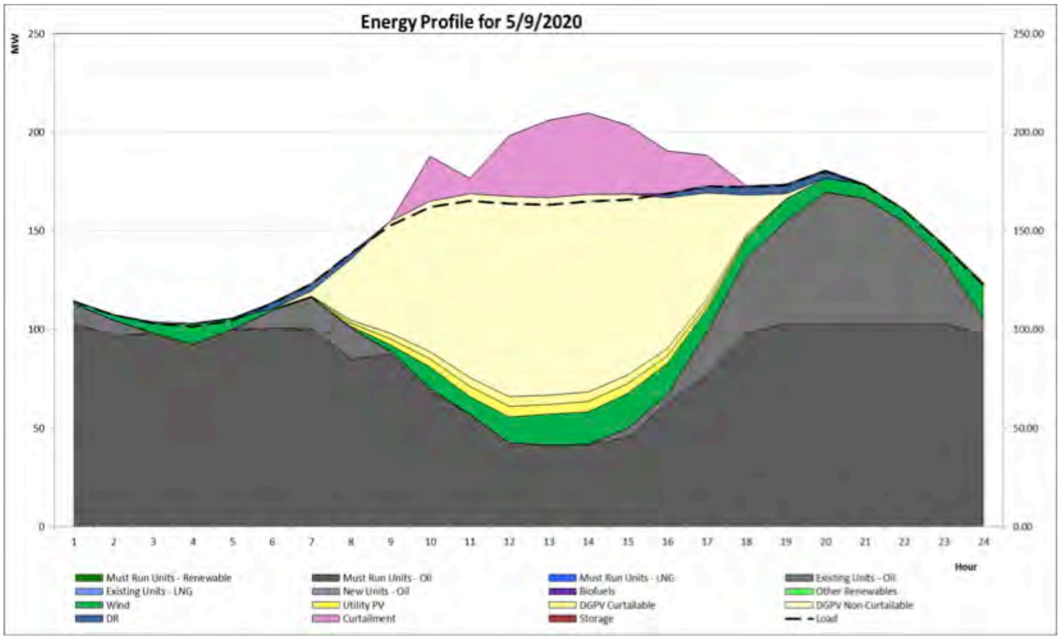


Figure 6-22. Theme 1 Max PV Day 5/9/20

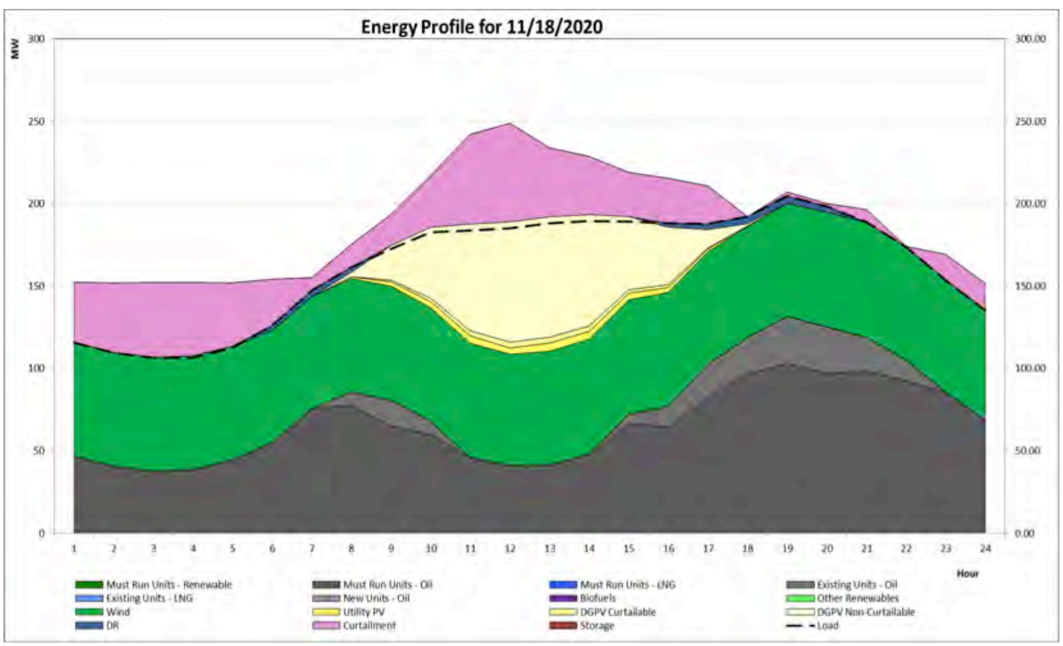


Figure 6-23. Theme 1 Max Wind Day 11/18/20

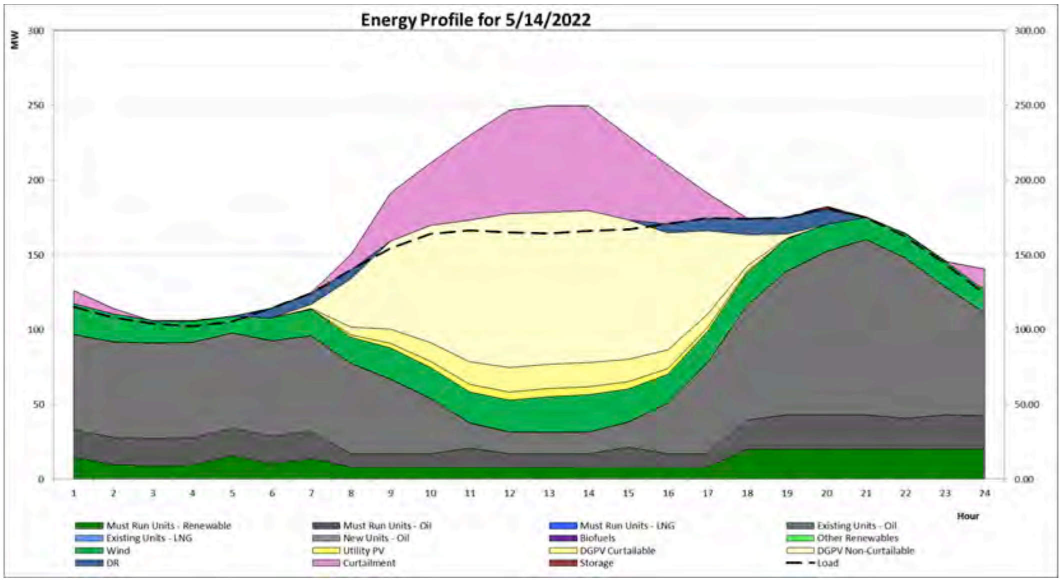


Figure 6-24. Theme 1 Max PV Day for 5/14/21

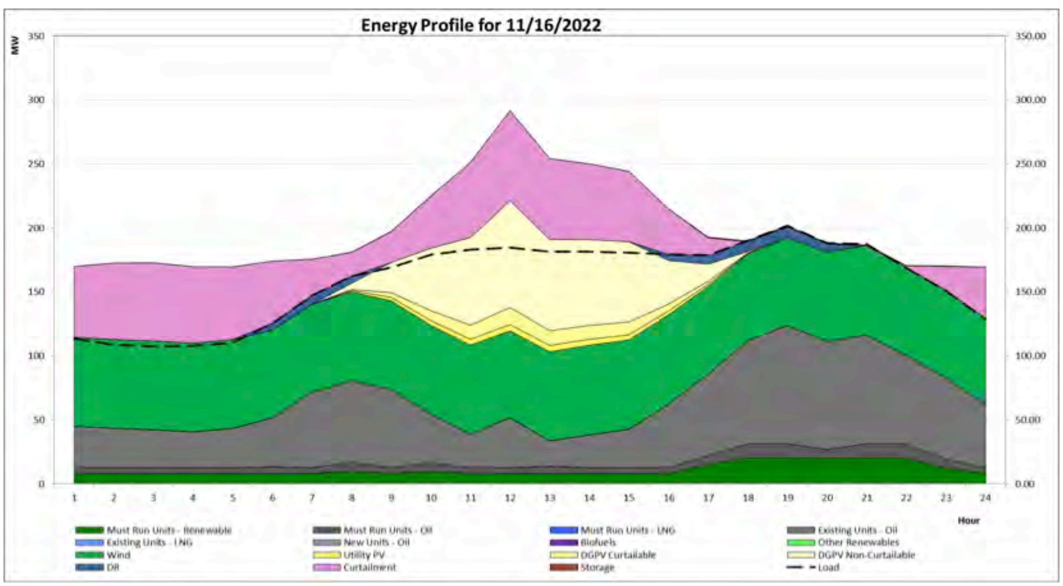


Figure 6-25. Theme 1 Max Wind Day for 11/16/22

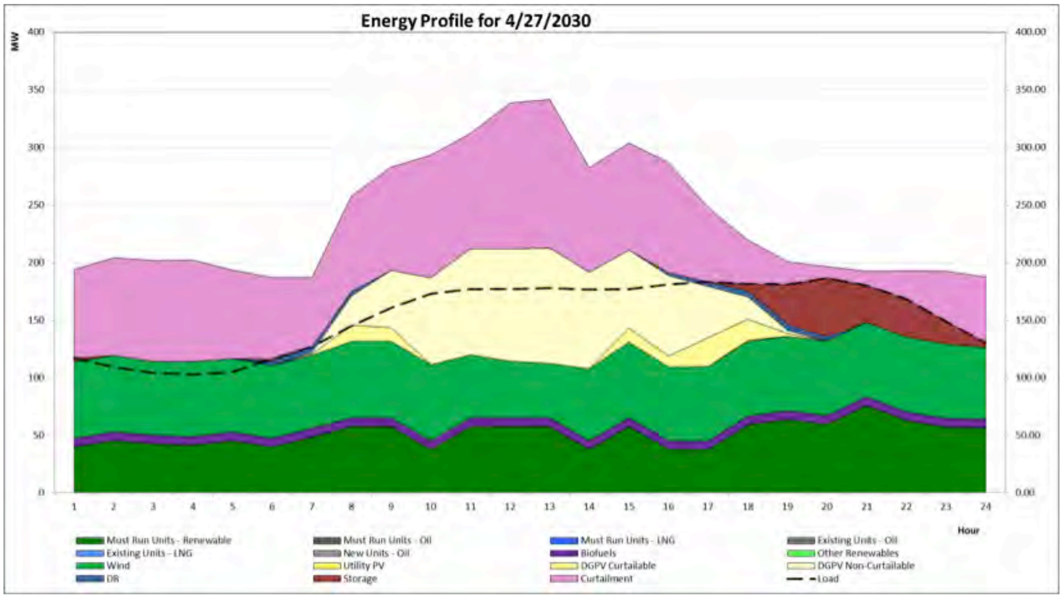


Figure 6-26. Theme 1 Max PV and Wind Day 4/27/30

Theme 2

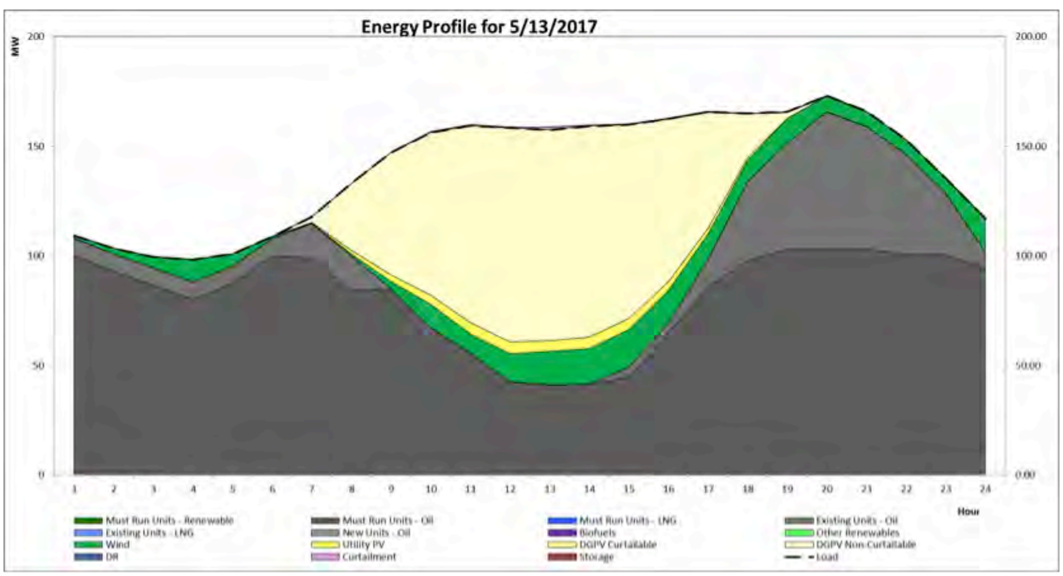


Figure 6-27. Theme 2 Max PV Day 5/13/17

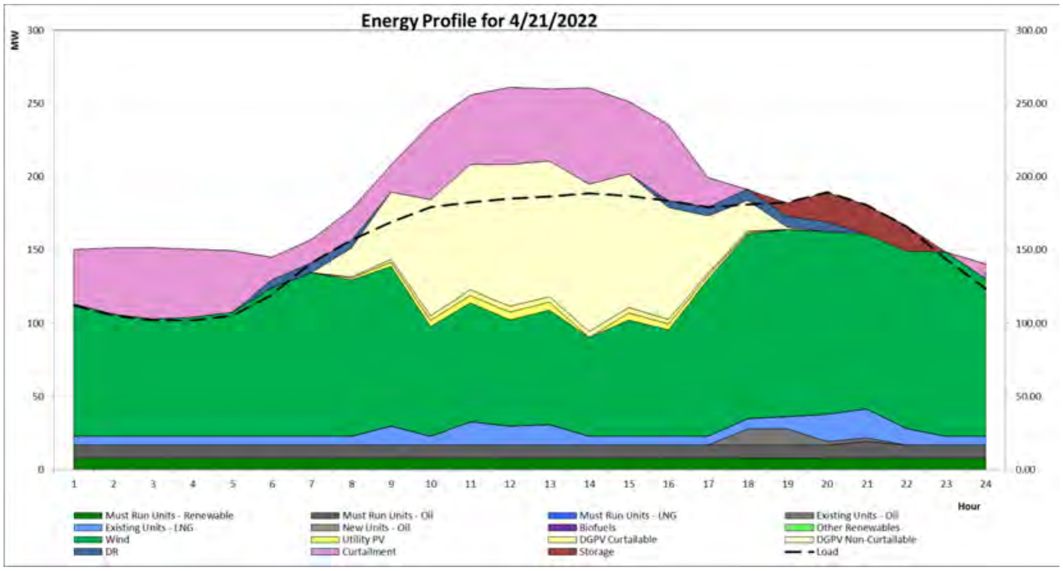


Figure 6-28. Theme 2 Max Wind Day 4/21/22

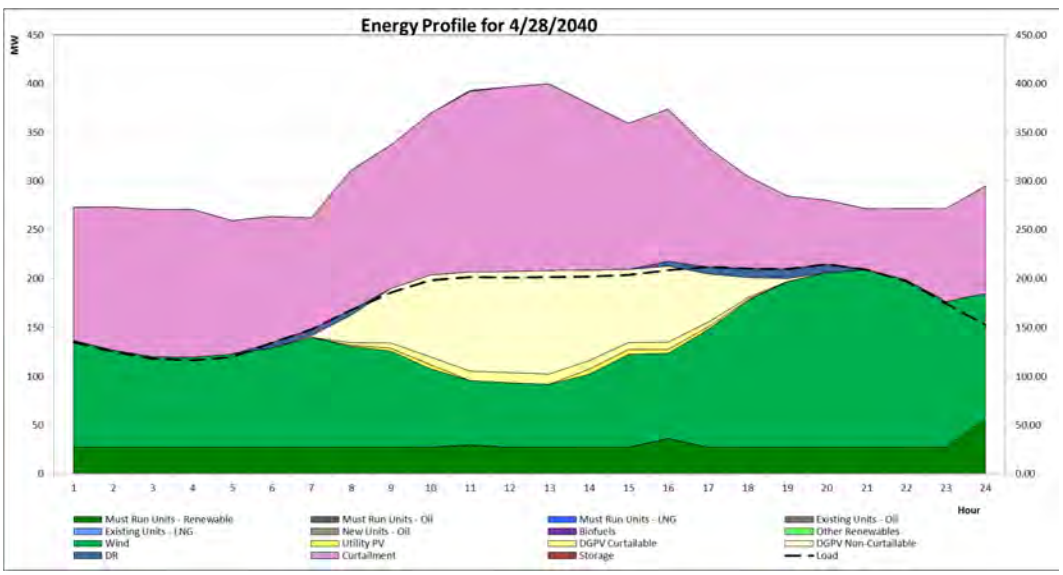


Figure 6-29. Theme 2 Max PV and Wind Day 4/28/40

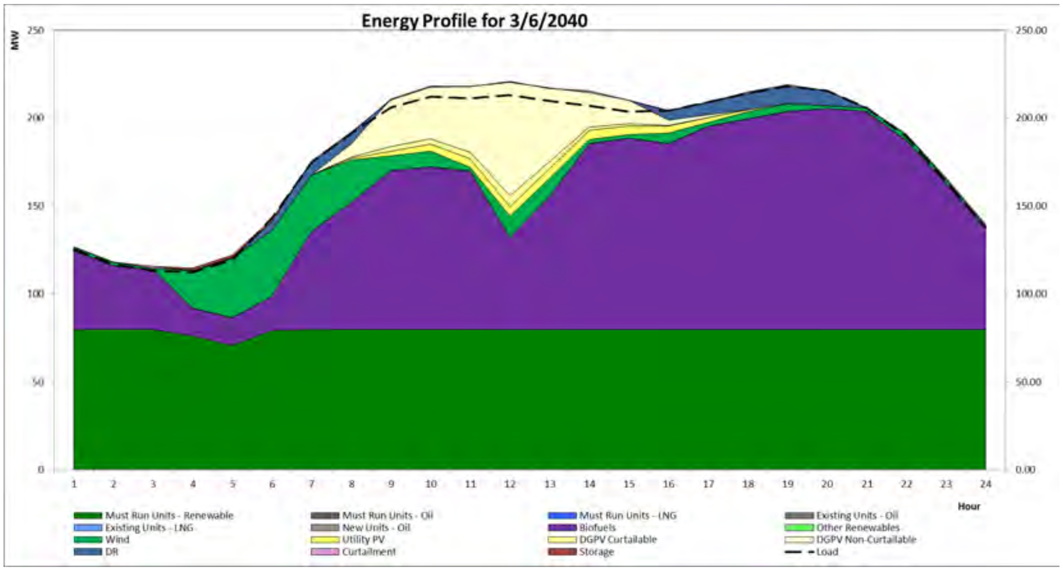


Figure 6-30. Theme 2 Least PV and Wind Day 3/6/40

Theme 3

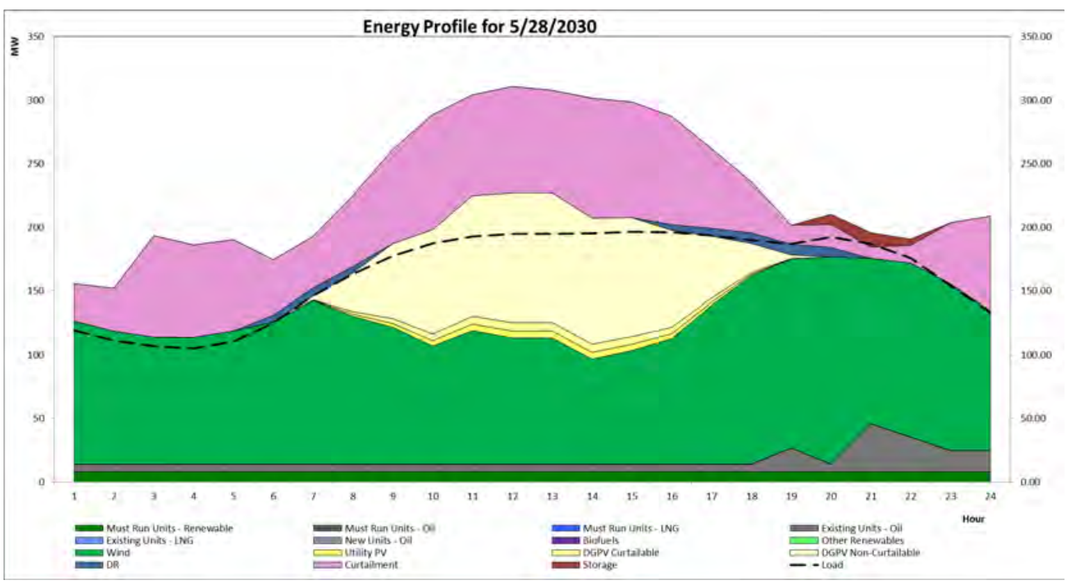


Figure 6-31. Theme 3 Max Wind and PV Day 5/28/30

Least Wind and PV Day 3/5/30

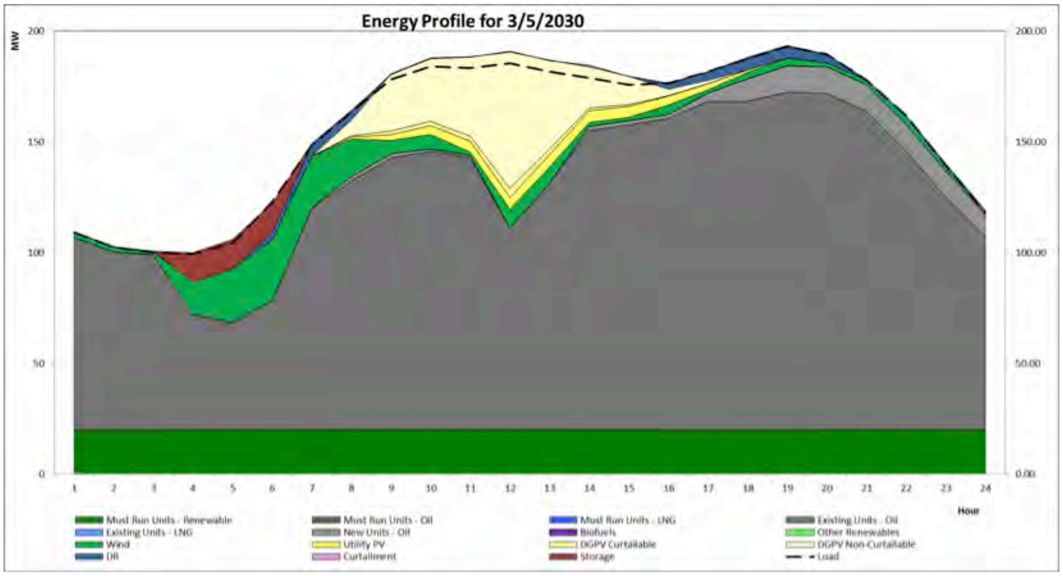


Figure 6-32. Theme 3 Least Wind and PV Day 3/5/30

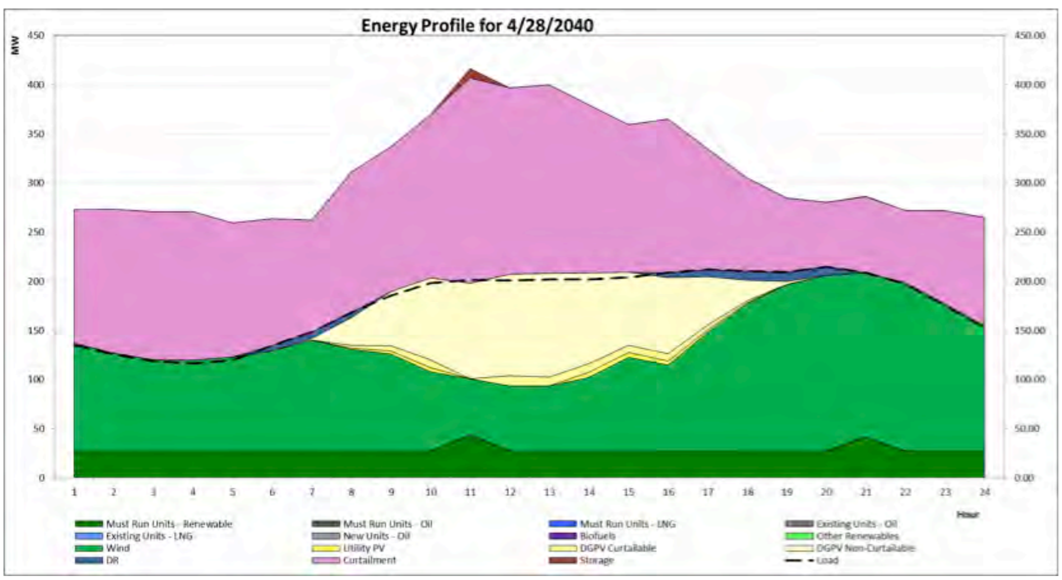


Figure 6-33. Theme 3 Max Wind and PV Day 4/28/40

MAUI SELECTION OF THEME 2

The rigorous long-term analyses of the three themes provided insights on the different strategies for achieving 100% renewable energy by 2040. They provide directional guidance to inform the risks and the level of “no regrets” in short- term actions, particularly as you compare long-term resources across multiple themes. Although the steps along the paths to 2045 are different among the final plans, the starting point is the same. The purpose of the Preferred Plan is to inform the evaluation of specific near-term actions that are implementable based on the direction that the longer-term view of the plan provides. The Preferred Plan will balance technical, economic, environmental, and cultural considerations.

Based on the results of the analyses, Theme 2 will add a diverse mix of renewables resources - with a considerable contribution from firm renewables - coupled with flexible, firm generation and energy storage. In the modernization of Maui’s generation system, Kahului Power Plant will be retired. The net result of this is a lower-cost resource plan with less exposure to volatile oil prices and lower rates compared with alternatives in the transition to 100% renewable.

Case Name	Preferred Plan
Case Label	MHB40
DER Forecast	Market DG-PV
Fuel Price	2015 EIA Reference
2016	
2017	5.74 MW of PV Projects
2018	
2019	
2020	Install Two - 30 MW Future Wind (60 MW Total Wind)
2021	
2022	Install Two - 9 MW ICE (18 MW Total ICE) Install 20 MW Biomass Install 20 MW 4 hour BESS for Capacity Install 20 MW 1hr BESS for South Maui Non-Transmission Alternative Install Two - 30 MVA Synchronous Condenser (Ma'alaea) (60 MVA Total) Install Two - 9 MW ICE
2023	Convert K1, K2, K3, K4 to Synchronous Condensers – 41 MVA
2024–2036	*No additions 2024–2036*
2037	Replace 20 MW 4hr BESS with a 30 MW 6 hour BESS for Capacity
2038	
2039	
2040	Install 20 MW Biomass Install Two - 20 MW Geothermal Install Four - 30 MW Future Wind Install Two - 20 MW 1hr BESS for Regulation
2041	
2042	
2043	
2044	
2045	Install 30 MW Future Wind Install Two - 20 MW Future PV

Table 6-1. Maui Preferred Plan

LANA‘I AND MOLOKA‘I

We conducted analysis for the islands of Lana‘i and Moloka‘i for two of the three Themes described in Chapter 3 to develop final plans to reach 100% renewable options in 2030 in Theme 1 and 2040 in Theme 3. 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.

Maui Electric developed this Preferred Plan for transforming the system from current state to a future vision of the utility in 2030 that is consistent with the Commissions Observations and Concerns.

The Preferred Plans for Lana‘i and Moloka‘i strive for accelerated energy independence with minimal reliance on imported liquid fuels. The Preferred Plans for the islands of Lana‘i and Moloka‘i reduces “must-run” generation, increases variable renewable energy, and uses firm renewable sources to help stabilize the grid. Demand response will also be used to further reduce fossil fuel utilization.

Our vision will advance our systems towards our goal of decreasing fossil fuels, integrating more renewable energy, and maintaining system reliability. Our commitment to reshaping our systems will result in Renewable Portfolio Standards (RPS) meeting or exceeding the consolidated company requirement of 70% by 2040, and a vision of energy independence from fossil fuel by 2045 and possibly as early as 2040.

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.

Moloka‘i and Lana‘i Preferred Plans

Maui Electric’s Moloka‘i and Lana‘i Divisions Preferred Plans are referred to as Theme 1 in Chapter 3, which meets interim RPS mandates across the Hawaiian Electric service areas and achieves 100% RE in 2030, while balancing the use of both fuel and non-fuel burning RE.

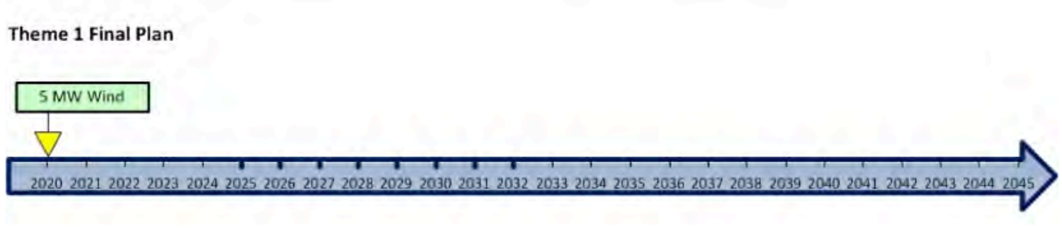


Figure 6-34. Moloka‘i Final Plans - Schedule of Resources Theme 1

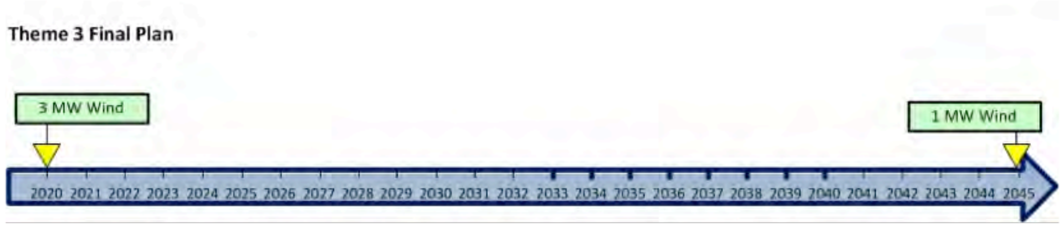


Figure 6-35. Moloka'i Final Plans - Schedule of Resources Theme 3

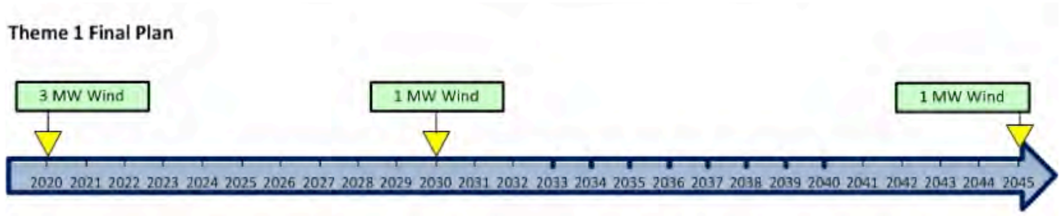


Figure 6-36. Lana'i Final Plans - Schedule of Resources – Theme 1

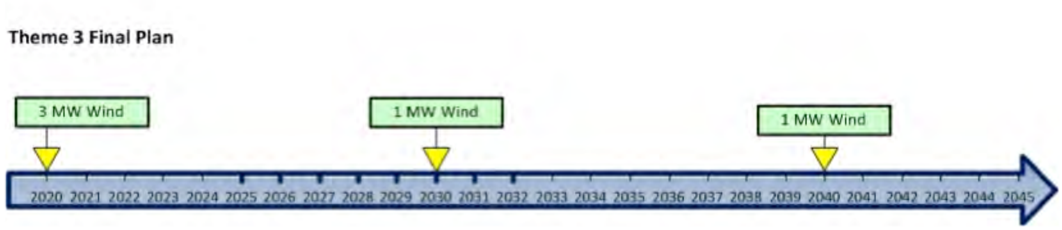


Figure 6-37. Lana'i Final Plans - Schedule of Resources – Theme 3

ENERGY MIX OF FINAL PLANS FOR MOLOKA'I

Our commitment to reshaping our systems will result in Renewable Portfolio Standards (RPS) meeting or exceeding the requirement of 70% by 2040, and a vision of energy independence from fossil fuel by 2045 and possibly as early as 2040.

All of Maui Electric's Final Plans will add significantly more renewable energy to meet or exceed the mandated Consolidated RPS targets in 2020, 2030, and 2040. Our Consolidated RPS is planned to meet or exceed the 70% RPS by 2040 before transitioning to fully renewable energy electrical system by 2045. On Moloka'i, Theme 1 attains 100% renewable generation by 2030 and Theme 3 attains 100% renewable generation by 2040.

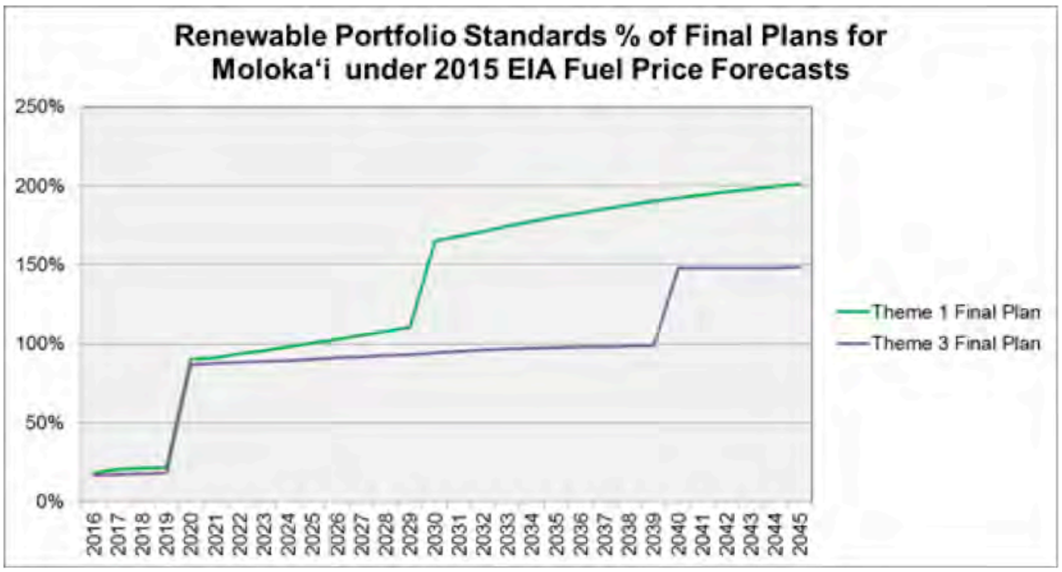


Figure 6-38. Renewable Portfolio Standards Percent of Final Plans for Moloka'i

The Moloka'i Preferred Plan will change over time to reduce and eventually eliminate must-run fuel burning thermal units and incorporate greater amounts of renewable energy out to 2045. The figures that follow shows how the resource mix of the two Moloka'i themes vary in generation and transforms over time. Under both the 2015 EIA and February 2016 STEO Fuel Price Forecasts, the system resource energy mix are identical.

Theme 1

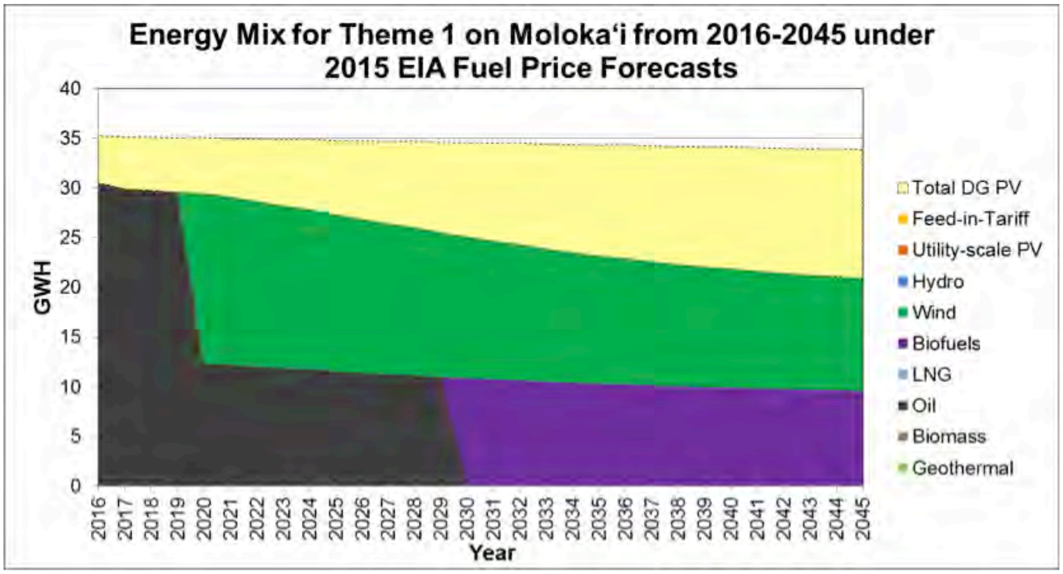


Figure 6-39. Energy Mix for Theme 1 on Moloka'i from 2016-2045 under 2015 EIA Fuel Price Forecasts

Theme 3

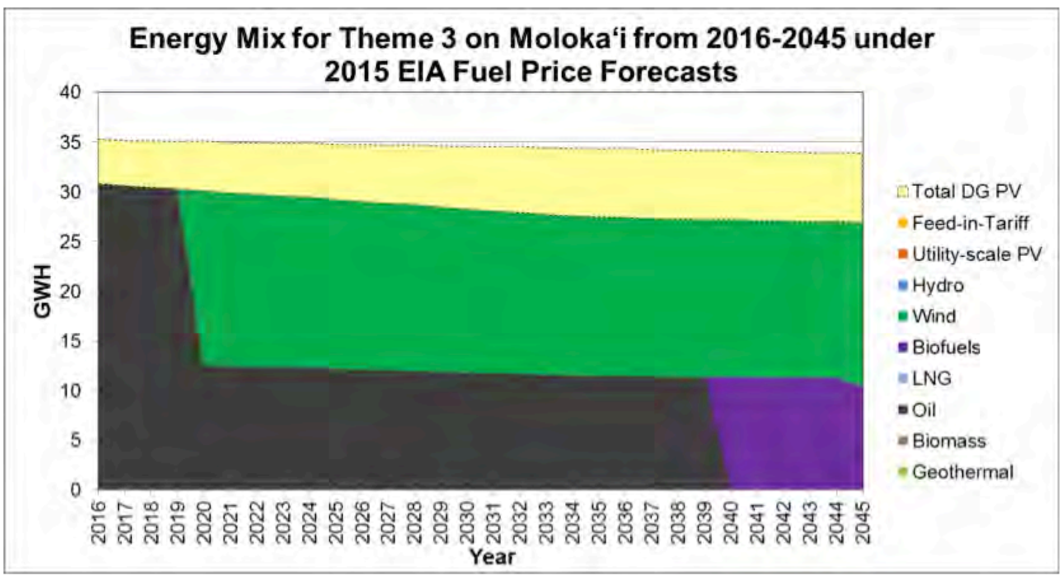


Figure 6-40. Energy Mix for Theme 1 on Moloka'i from 2016-2045 under 2015 EIA Fuel Price Forecasts

The generation mix in all themes has increasing levels of renewable energy replacing fossil generation. Renewable energy from distributed PV continues to grow over time and new wind resources are also added to the system. As firm generating units are removed from must-run operation, system security measures will be required. The theme 1 plan provides the most integration of DER over the term of the planning horizon.

PERCENT OVER-GENERATION OF TOTAL SYSTEM OF FINAL PLANS FOR Moloka'i

The Moloka'i electric system will greatly increase the amounts of variable generation that can be utilized. By eliminating must-run fossil fuel generation along with increasing wind generation and DER, lower levels of curtailment will be achieved during low demand periods (which may occur during daytime hours due to influence of DG-PV, as well as during typical night time low load hours). However, even with these improvements, non-firm renewable generation such as wind is occasionally available in quantities that cannot be effectively utilized by the system. Under both the 2015 EIA and February 2016 STEO Fuel Price Forecasts, the total system renewable energy utilization are identical.

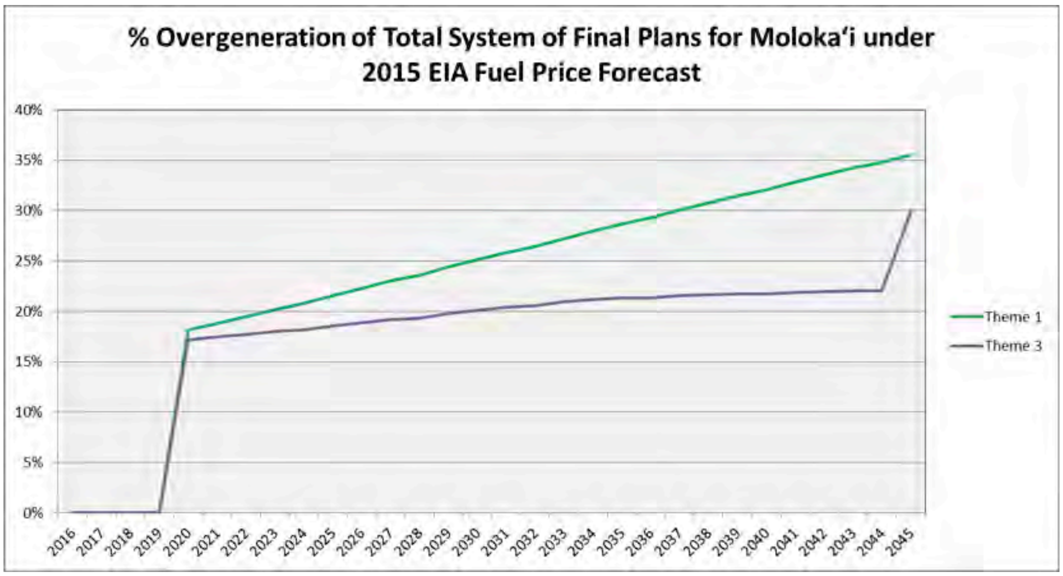


Figure 6-41. Percent Over-Generation of Total System of Final Plans for Moloka'i under 2015 EIA Fuel Price Forecast

TOTAL SYSTEM RENEWABLE ENERGY UTILIZED OF FINAL PLANS FOR MOLOKA'I

The extent to which renewable energy can be utilized on Moloka'i will depend on factors such as the total system load or energy demand, the amount of downward regulation that must be carried on the system to counteract an unexpected loss of load, the total output from variable generation resources, and the position of the variable generation resource in the curtailment sequence. Under both the 2015 EIA and February 2016 STEO Fuel Price Forecasts, the total system renewable energy utilization are identical.

Theme 1

Renewable Energy Utilization

% RE	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2016-2045
Utilized	100%	100%	100%	100%	82%	81%	81%	80%	79%	78%	78%	77%	76%	76%	81%	81%	80%	79%	79%	78%	78%	77%	76%	75%	75%	74%	74%	73%	72%	72%	78%

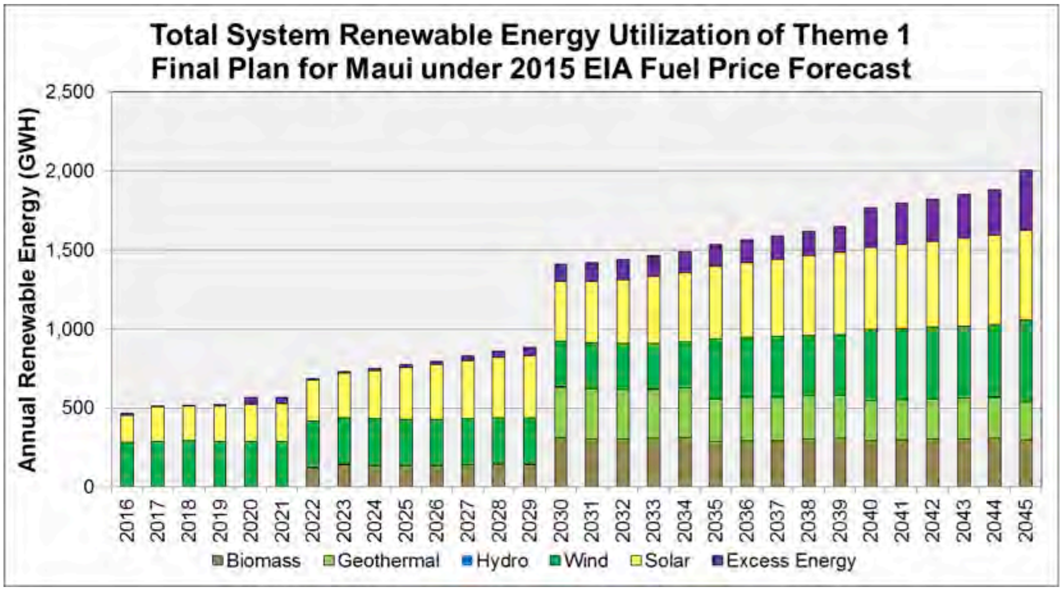


Figure 6-42. Total System Renewable Energy Utilization of Theme 1 Final Plan for Moloka‘i Under 2015 EIA Fuel Price Forecast

Theme 3

Renewable Energy Utilization

% RE	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2016-2045
Utilized	82%	82%	82%	82%	81%	81%	81%	81%	80%	80%	80%	79%	79%	79%	79%	79%	78%	78%	78%	84%	84%	84%	84%	84%	77%	0%	0%	0%	0%	0%	81%

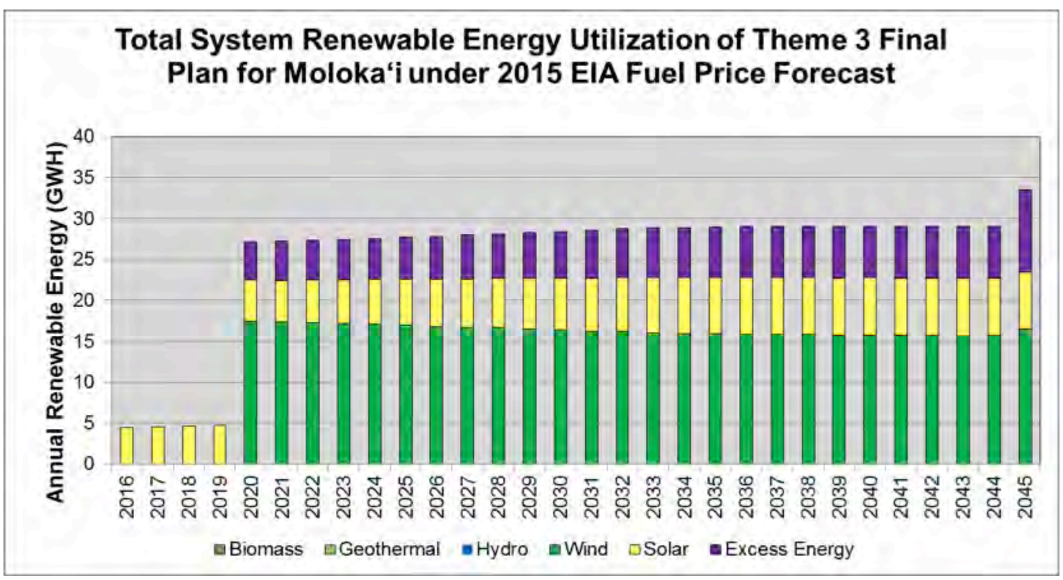


Figure 6-43. Total System Renewable Energy Utilization of Theme 3 Final Plan for Moloka‘i Under 2015 EIA Fuel Price Forecast

DAILY ENERGY CHARTS OF FINAL PLANS FOR MOLOKAʻI

The following charts illustrate representative study days on Molokaʻi with increasing renewable energy contributions that displace fossil fueled generation over time. These charts show the advantage of a diversified portfolio of resources such, firm dispatchable, variable generation, and demand response to serve our customer's energy needs.

A noticeable occurrence in each chart is the large contribution of PV energy during daylight hours, and in some instances, an excess of PV generation during daylight hours. During non-daylight hours, customer needs will need to be met by the portfolio of resources other than PV, such as load shifting storage, wind, and firm dispatchable generation.

Theme 1

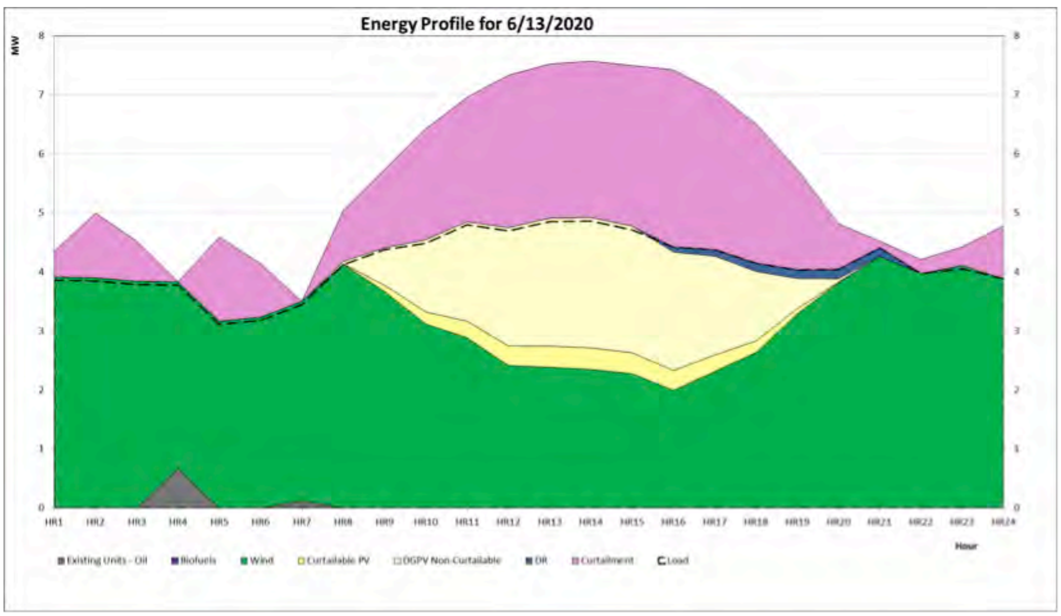


Figure 6-44. Theme 1 Max PV Day 6/13/20

Hawaiian Electric
Maui Electric
Hawaiʻi Electric Light

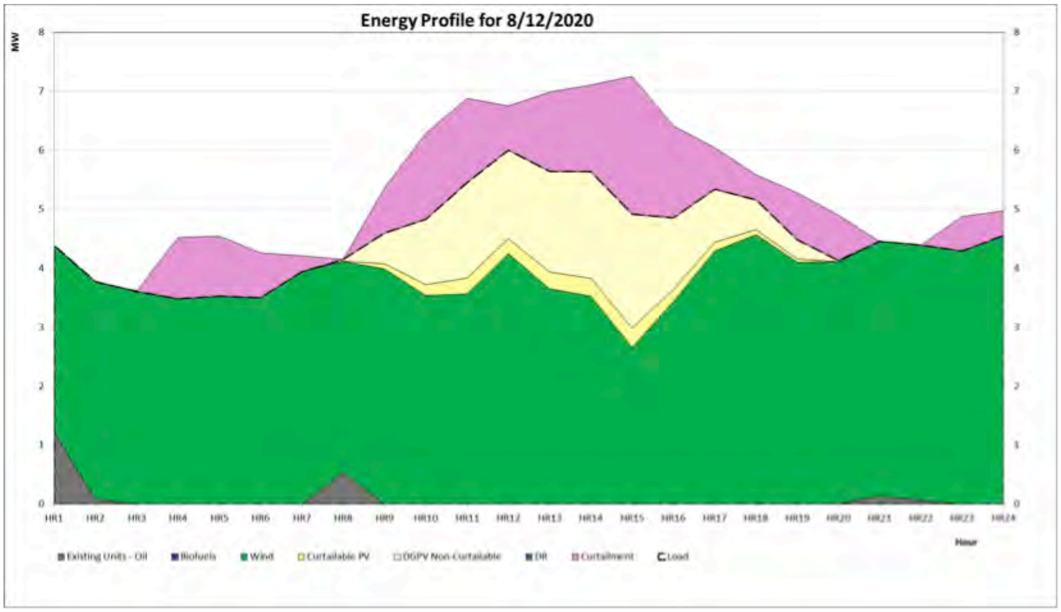


Figure 6-45. Theme 1 Max Wind and PV Day 8/12/20

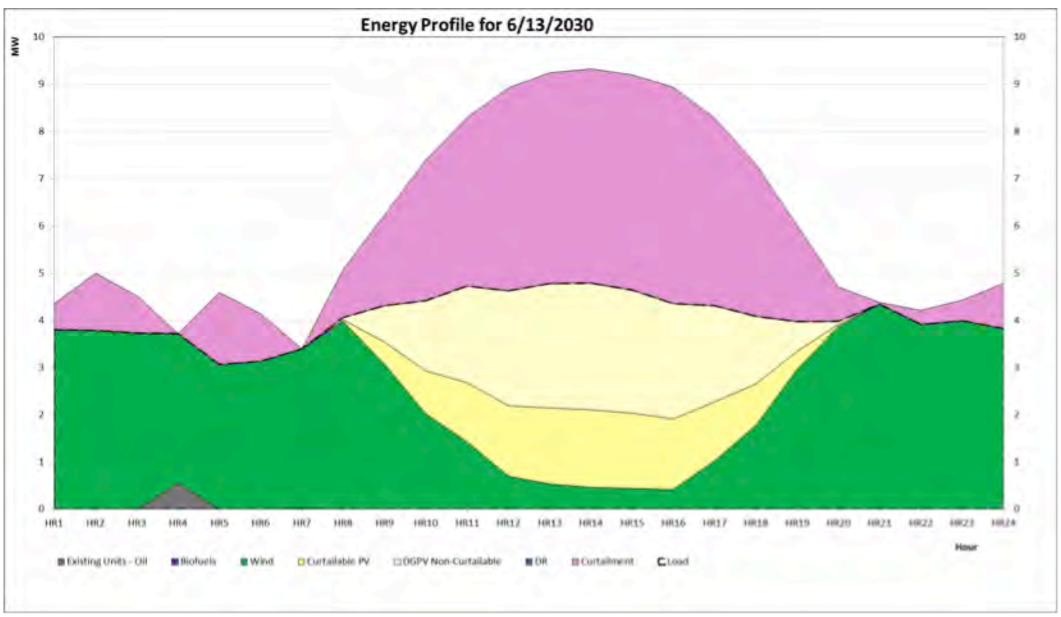


Figure 6-46. Theme 1 Max PV Day 6/13/30

6. Maui Electric Preferred Plan

Daily Energy Charts of Final Plans for Moloka'i

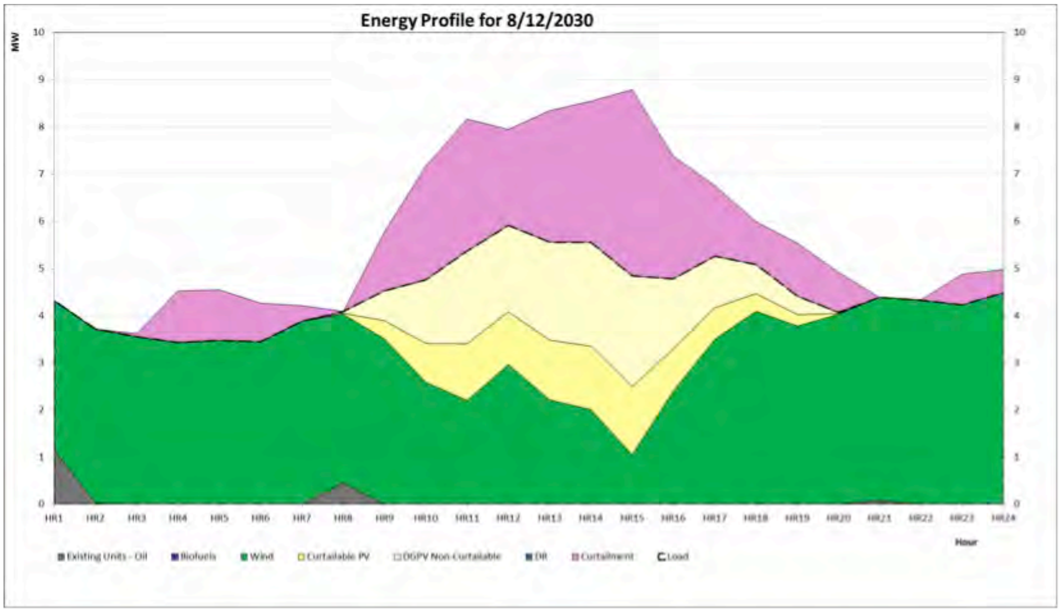


Figure 6-47. Theme 1 Max Wind and PV Day 8/12/30

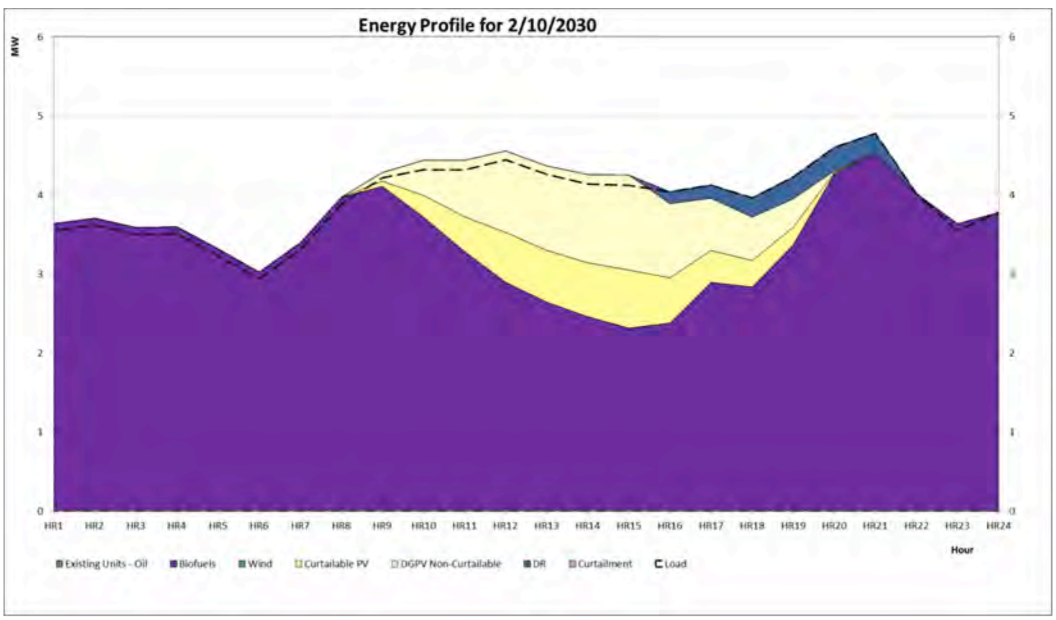


Figure 6-48. Theme 1 Least PV and Wind Day 2/10/30

Theme 3

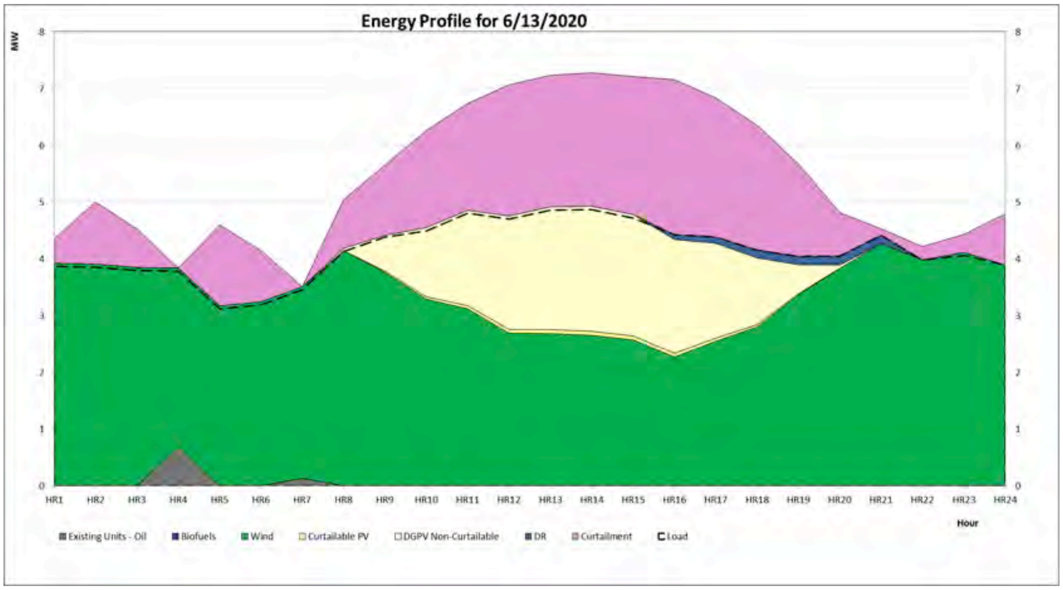


Figure 6-49. Theme 3 Max PV Day 6/13/20

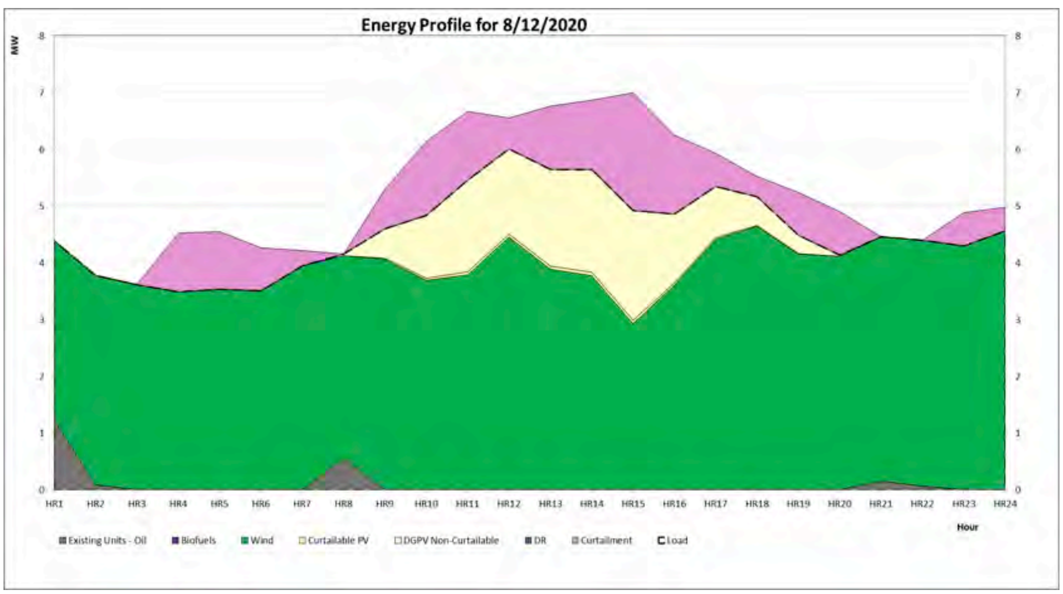


Figure 6-50. Max Wind and PV Day 8/12/20

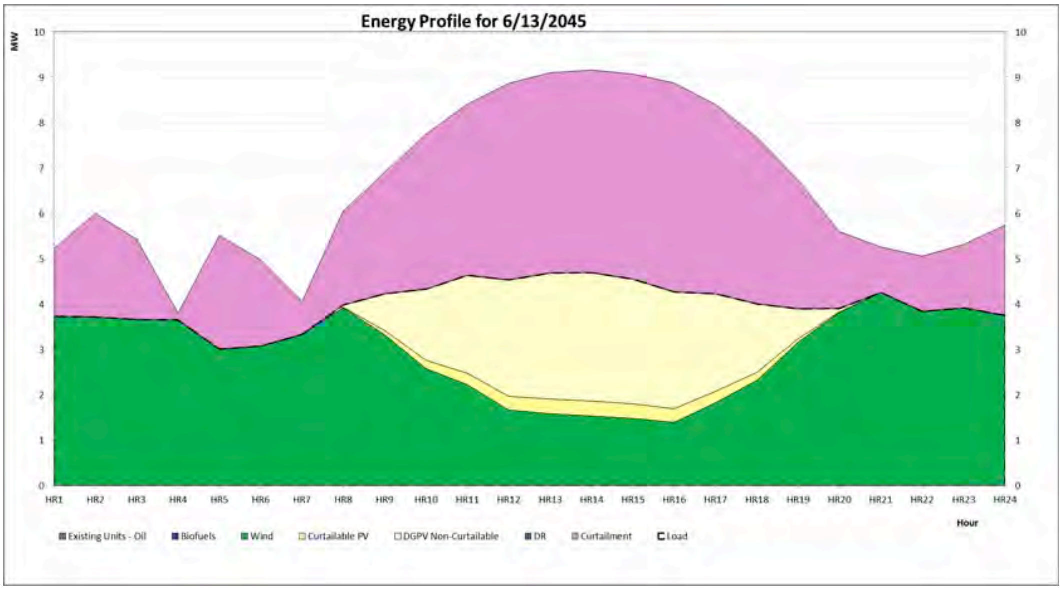


Figure 6-51. Theme 3 Max PV Day 6/13/45

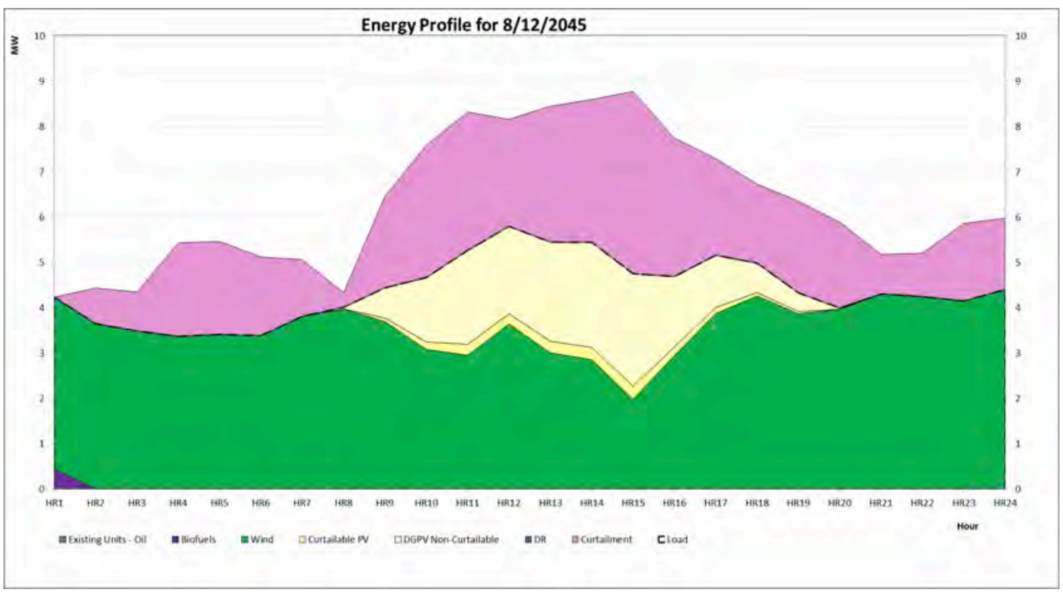


Figure 6-52. Theme 3 Max PV and Wind Day 8/12/45

MOLOKA‘I SELECTION OF THEME 1

Theme 1 will add significant amounts of variable renewable generation in conjunction with the removal of "must-run" conventional generation upon installation of system security measures. Moloka‘i will achieve 100% renewable energy by 2030.

Case Name	Preferred Plan
Case Label	
DER Forecast	High DG-PV
Fuel Price	2015 EIA Reference
2016	
2017	
2018	Install two - 5 MVA Synchronous Condenser (10 MVA Total)
2019	
2020	5 MW Wind
2021–2045	*No additions after 2020*

Table 6-2. Moloka‘i Preferred Plan

ENERGY MIX OF FINAL PLANS FOR LANA‘I

Our commitment to reshaping our systems will result in Renewable Portfolio Standards (RPS) meeting or exceeding the requirement of 70% by 2040, and a vision of energy independence from fossil fuel by 2045 and possibly as early as 2040.

All of Maui Electric's Final Plans will add significantly more renewable energy to meet or exceed the mandated Consolidated RPS targets in 2020, 2030, and 2040. Our Consolidated RPS is planned to meet or exceed the 70% RPS by 2040 before transitioning to fully renewable energy electrical system by 2045. On Lana‘i, Theme 1 attains 100% renewable generation by 2030 and Theme 3 attains 100% renewable generation by 2040.

Lana‘i ownership could have an impact on the ability of Maui Electric meeting its stated goals going forward. Maui Electric continues to work in conjunction with the Lana‘i ownership on the development of the Lana‘i system and customer needs.

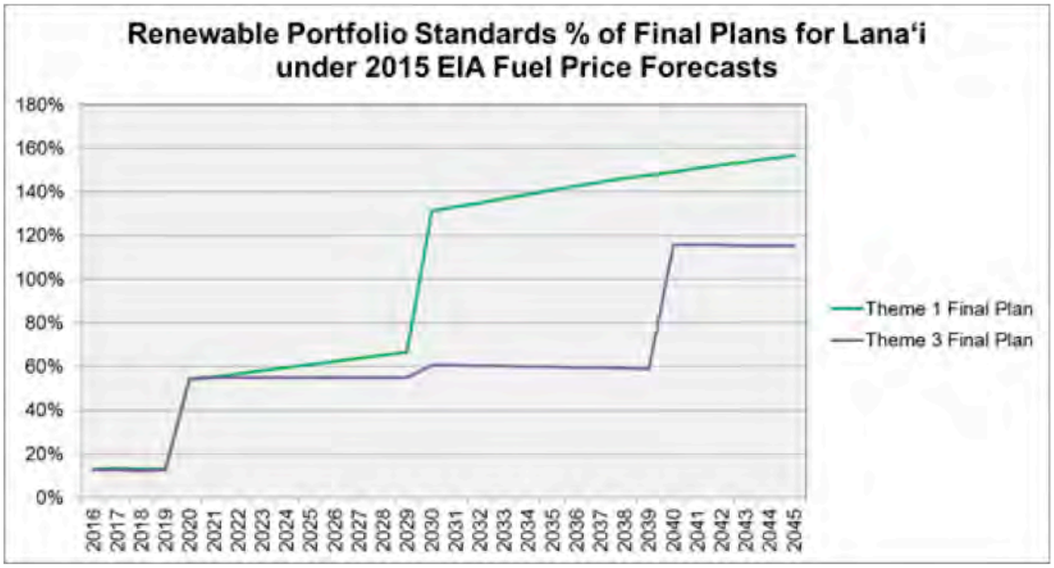


Figure 6-53. Renewable Portfolio Standards Percent of Final Plans for Lana'i (100% Renewable in 2040)

The Lana'i Preferred Plan will reduce and eventually eliminate must-run fossil fuel burning thermal units and incorporate greater amounts of renewable energy out to 2045. The figures that follow shows how the resource mix of the two Lana'i themes vary in generation and transforms over time. Under both the 2015 EIA and February 2016 STEO Fuel Price Forecasts, the system resource energy mix are identical.

Theme 1

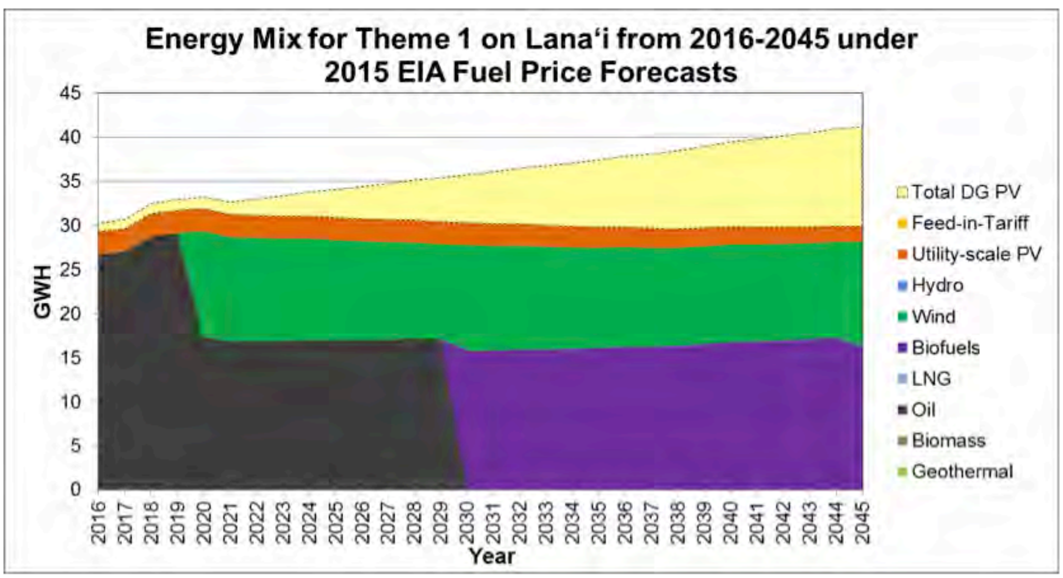


Figure 6-54. Energy Mix for Theme 1 on Lana'i from 2016-2045 under 2015 EIA Fuel Price Forecasts

Theme 3

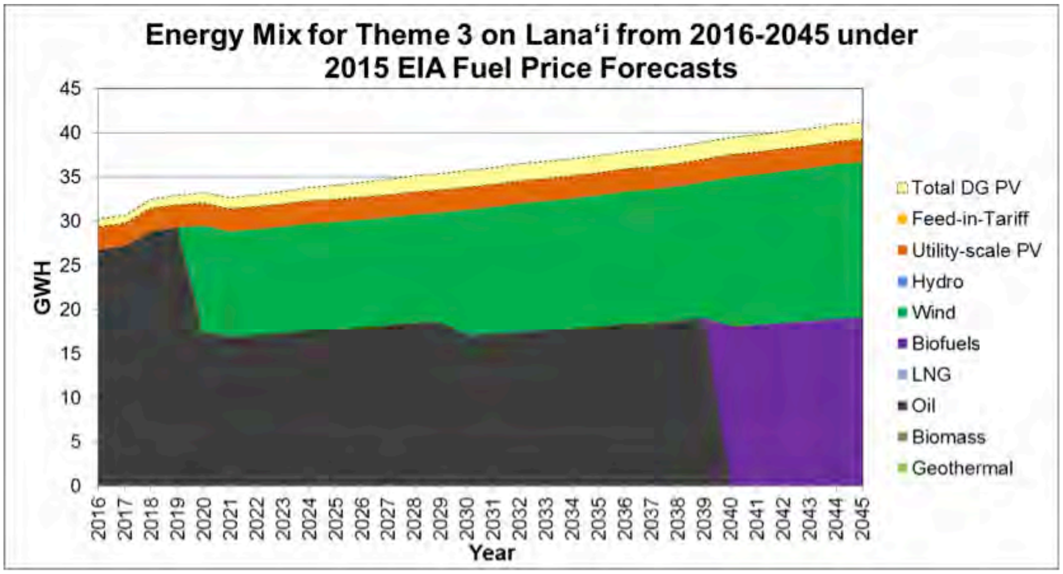


Figure 6-55. Energy Mix for Theme 3 on Lana'i from 2016-2045 under 2015 EIA Fuel Price Forecasts

The generation mix in all themes has increasing levels of renewable energy replacing fossil generation. Renewable energy from distributed PV continues to grow over time and new wind resources are also added to the system. As firm generating units are removed from must-run operation, system security measures will be required. The theme 1 plan provides the most integration of DER over the term of the planning horizon.

PERCENT OVER-GENERATION OF TOTAL SYSTEM OF FINAL PLANS FOR LANA'I

The Lana'i electric system has greatly increased the amounts of variable generation that can be utilized. By eliminating must-run fossil fuel generation along with increasing wind generation and DER, lower levels of curtailment are achieved during low demand periods (which may occur during daytime hours due to influence of DG-PV, as well as during typical night time low load hours). However, even with these improvements, non-firm renewable generation such as wind is occasionally available in quantities that cannot be effectively utilized by the system. Under both the 2015 EIA and February 2016 STEO Fuel Price Forecasts, the total system renewable energy utilization are identical

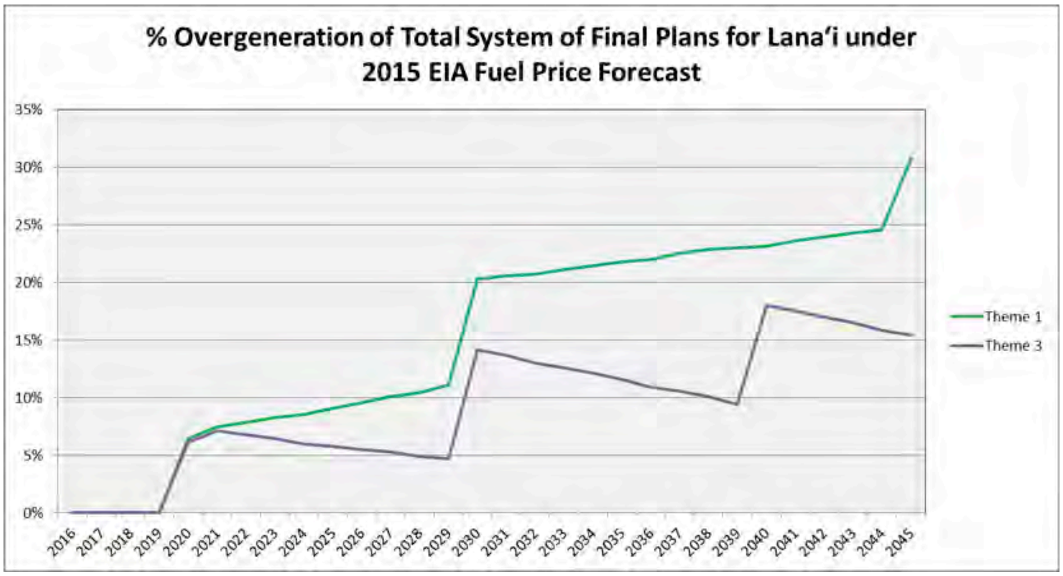


Figure 6-56. Percent Over-Generation of Total System of Final Plans for Lana'i under 2015 EIA Fuel Price Forecast

TOTAL SYSTEM RENEWABLE ENERGY UTILIZED OF FINAL PLANS FOR LANA‘I

The extent to which renewable energy can be utilized on Lana‘i will depend on factors such as the total system load or energy demand, the amount of downward regulation that must be carried on the system to counteract an unexpected loss of load, the total output from variable generation resources, and the position of the variable generation resource in the curtailment sequence. In all Themes Maui Electric anticipates high utilization of renewable energy on the system to achieve 100% RE. . Under both the 2015 EIA and February 2016 STEO Fuel Price Forecasts, the total system renewable energy utilization are identical.

Theme 1

Renewable Energy Utilization

% RE	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Utilized	100%	100%	100%	100%	93%	91%	91%	91%	90%	90%	89%	89%	88%	88%	86%

% RE	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2016-2045
Utilized	86%	86%	86%	85%	85%	85%	85%	84%	84%	84%	84%	84%	83%	83%	78%	85%

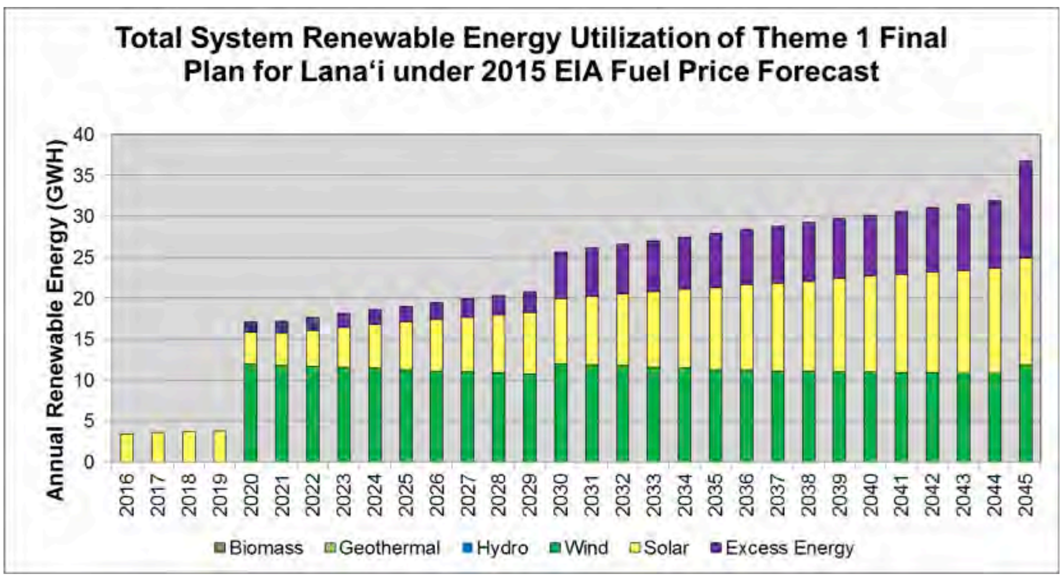


Figure 6-57. Total System Renewable Energy Utilization of Theme 1 Final Plan for Lana‘i Under 2015 EIA Fuel Price Forecast

Theme 3

Renewable Energy Utilization

% RE Utilized	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2016-2045
	100%	100%	100%	100%	93%	92%	92%	93%	93%	93%	94%	94%	94%	95%	84%	85%	86%	86%	87%	87%	88%	88%	89%	90%	88%	89%	89%	89%	90%	90%	90%

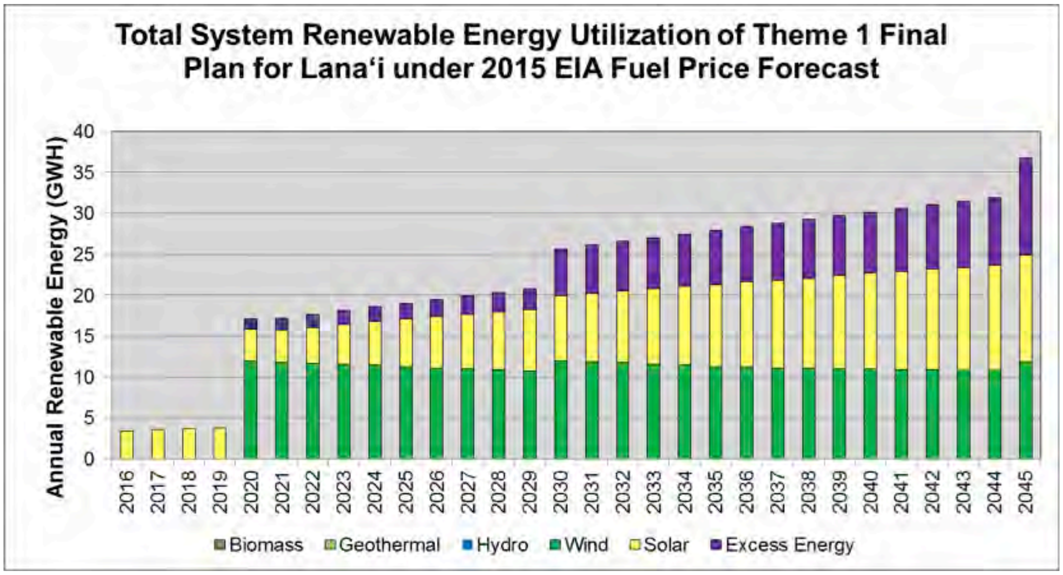


Figure 6-58. Total System Renewable Energy Utilization of Theme 3 Final Plan for Lana'i Under 2015 EIA Fuel Price Forecast

DAILY ENERGY CHARTS OF FINAL PLANS FOR LANA'I

The following charts illustrate representative study days on Lana'i with increasing renewable energy contributions that displace fossil fueled generation over time. These charts show the advantage of a diversified portfolio of resources such, firm dispatchable, variable generation, and demand response to serve our customer's energy needs.

A noticeable occurrence in each chart is the large contribution of PV energy during daylight hours, and in some instances, an excess of PV generation during daylight hours. During non-daylight hours, customer needs will need to be met by the portfolio of resources other than PV, such as load shifting storage, wind, and firm dispatchable generation.

Theme 1

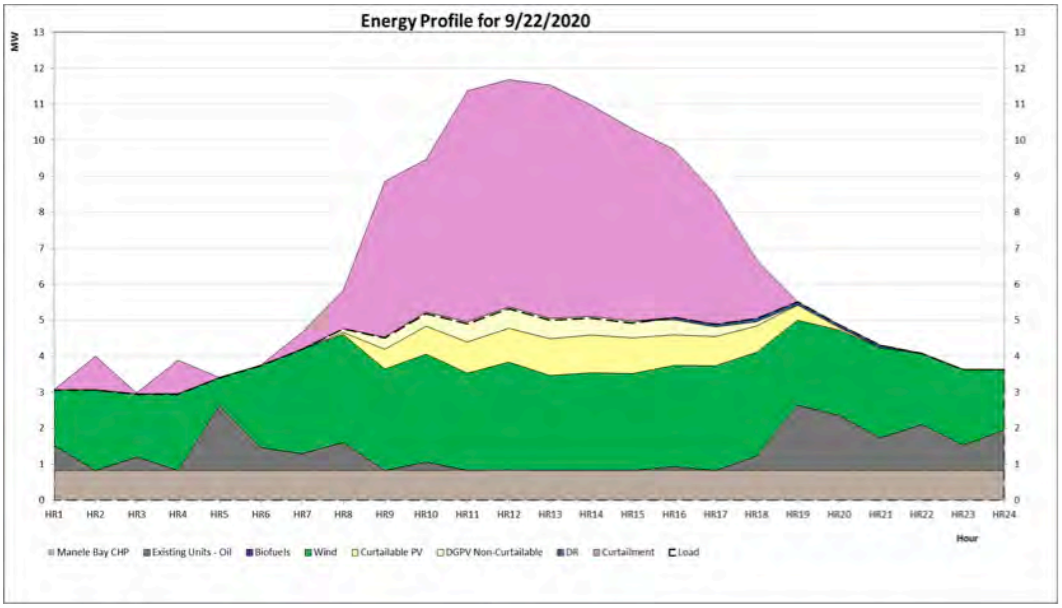


Figure 6-59. Theme 1 Max PV Day 9/22/20

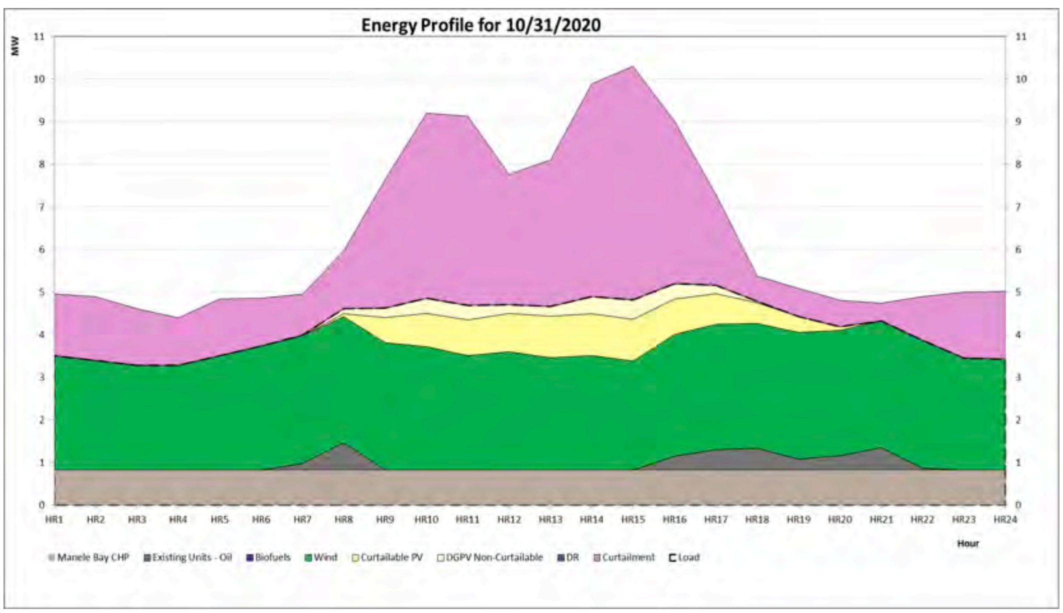


Figure 6-60. Theme 1 Max Wind and PV Day 10/31/20

6. Maui Electric Preferred Plan

Daily Energy Charts of Final Plans for Lana‘i

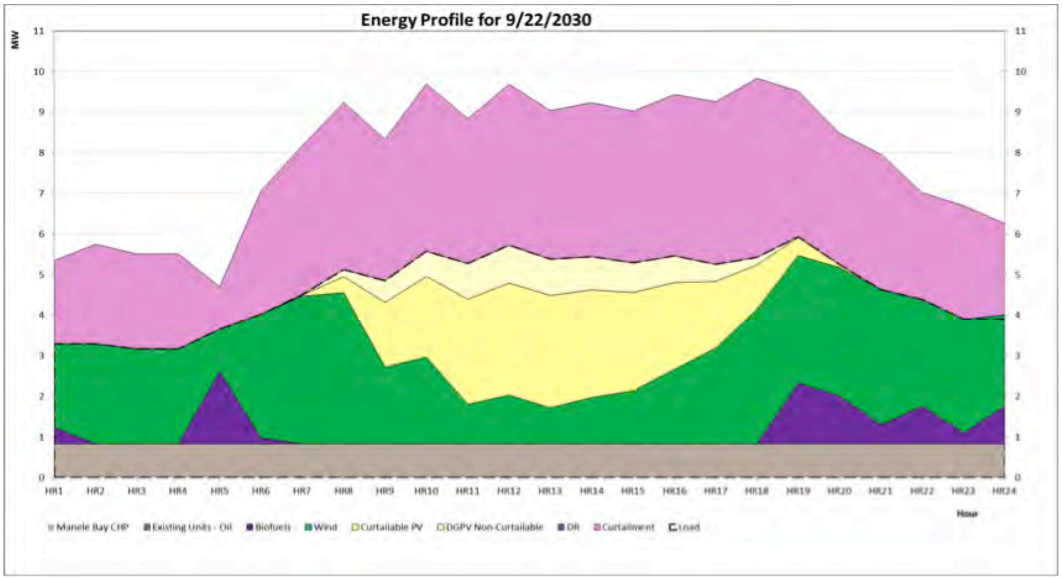


Figure 6-61. Theme 1 Max PV Day 9/22/30

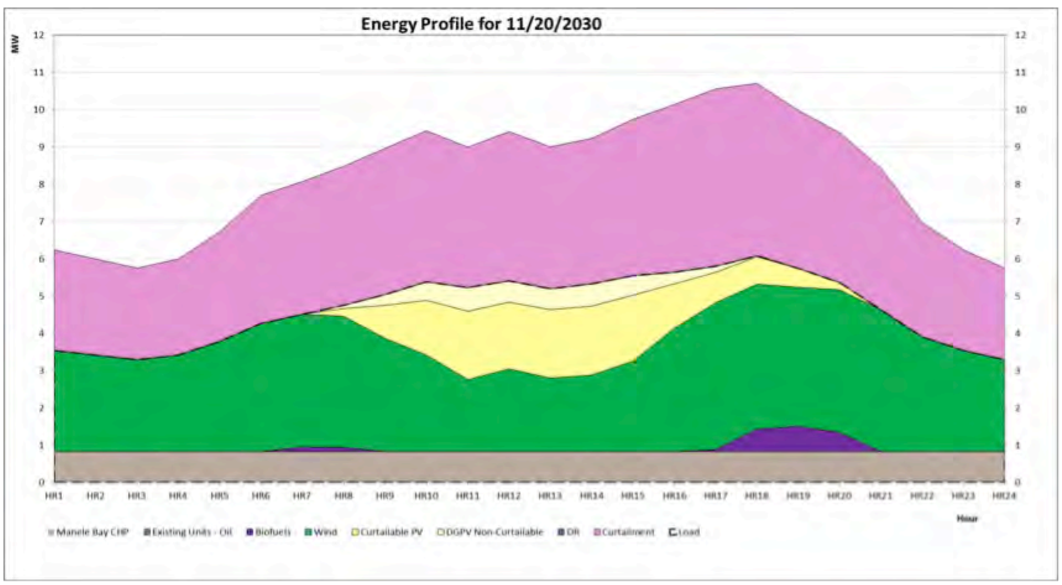


Figure 6-62. Theme 1 Max Wind and PV Day 11/20/30

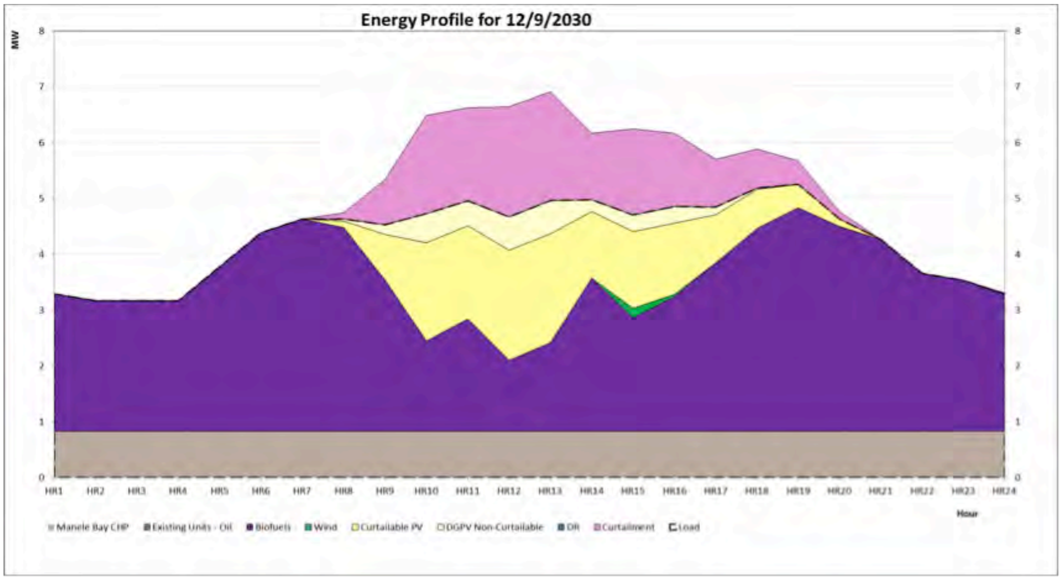


Figure 6-63. Theme 1 Least PV and Wind Day 12/9/30

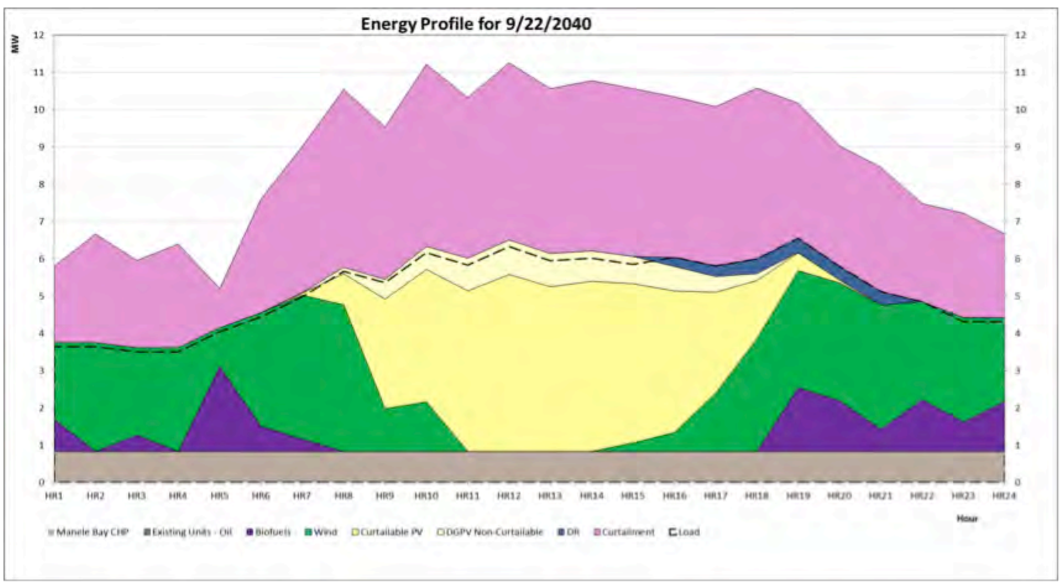


Figure 6-64. Theme 1 Max PV Day 9/22/40

Theme 3

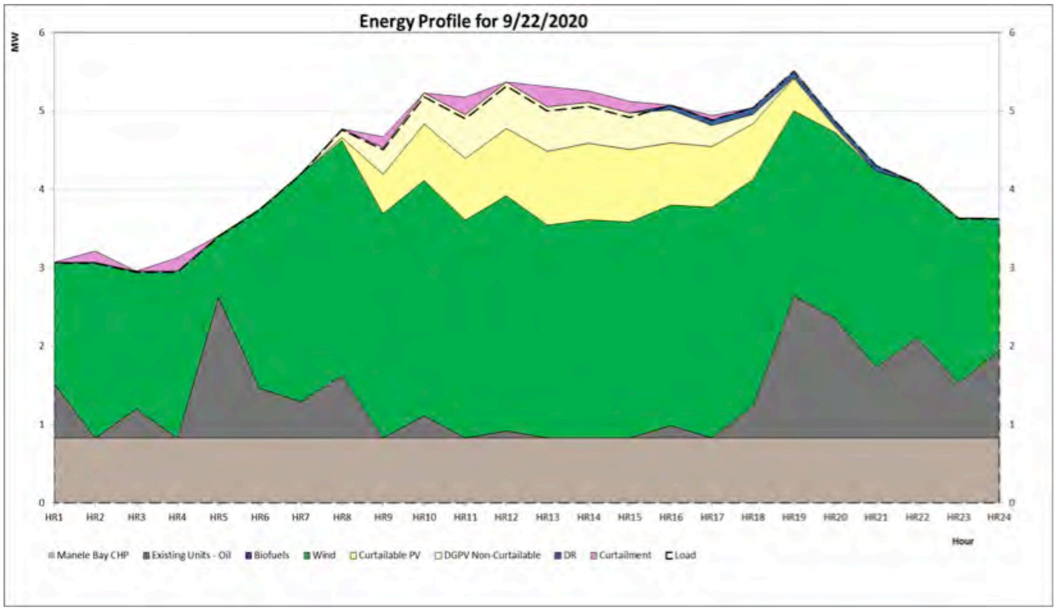


Figure 6-65. Theme 3 Max PV Day 9/22/20

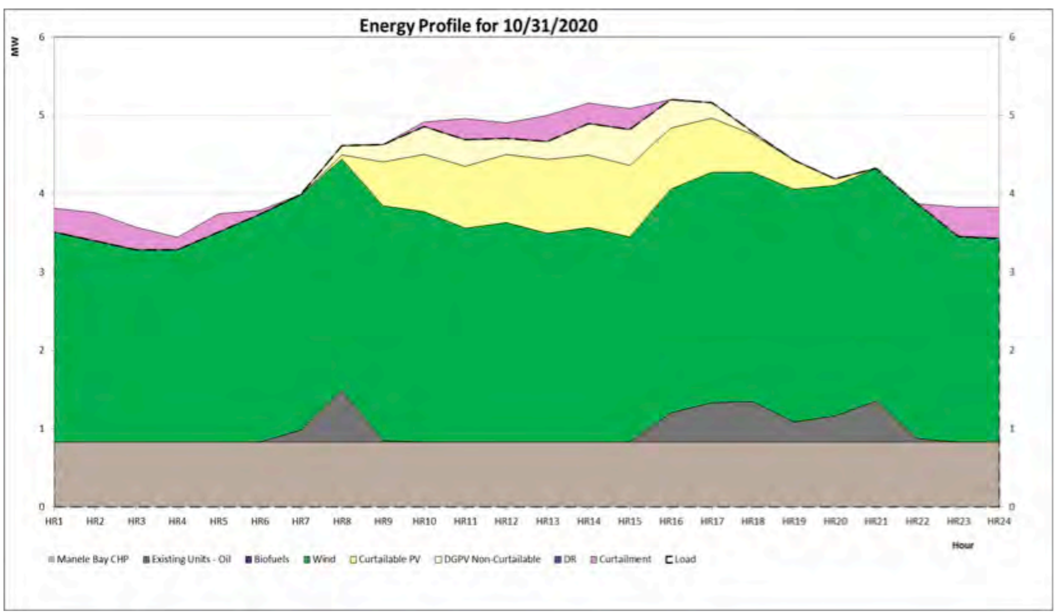


Figure 6-66. Theme 3 Max Wind and PV Day 10/31/20

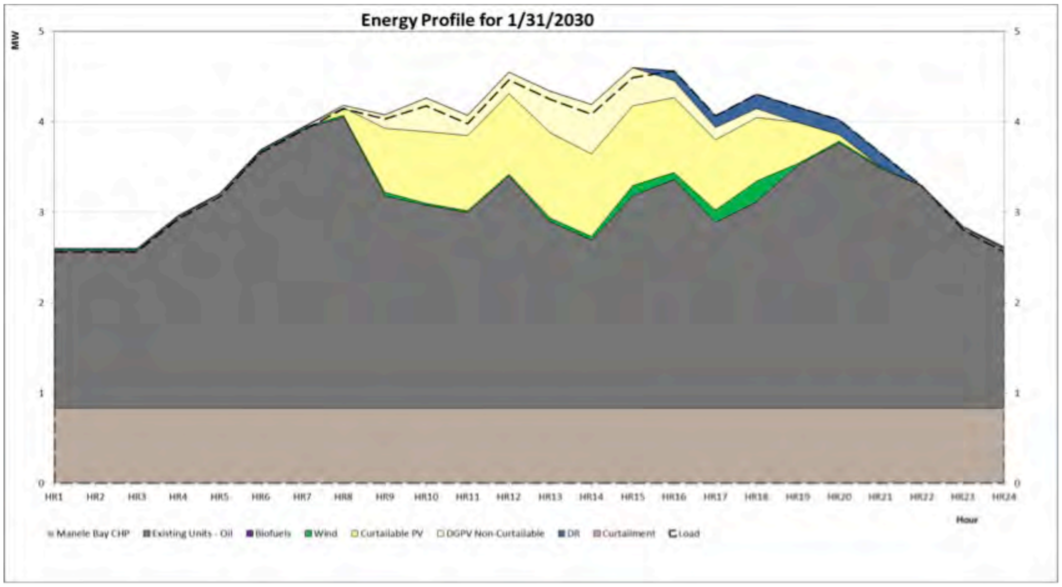


Figure 6-67. Theme 3 Max PV Day 1/31/30

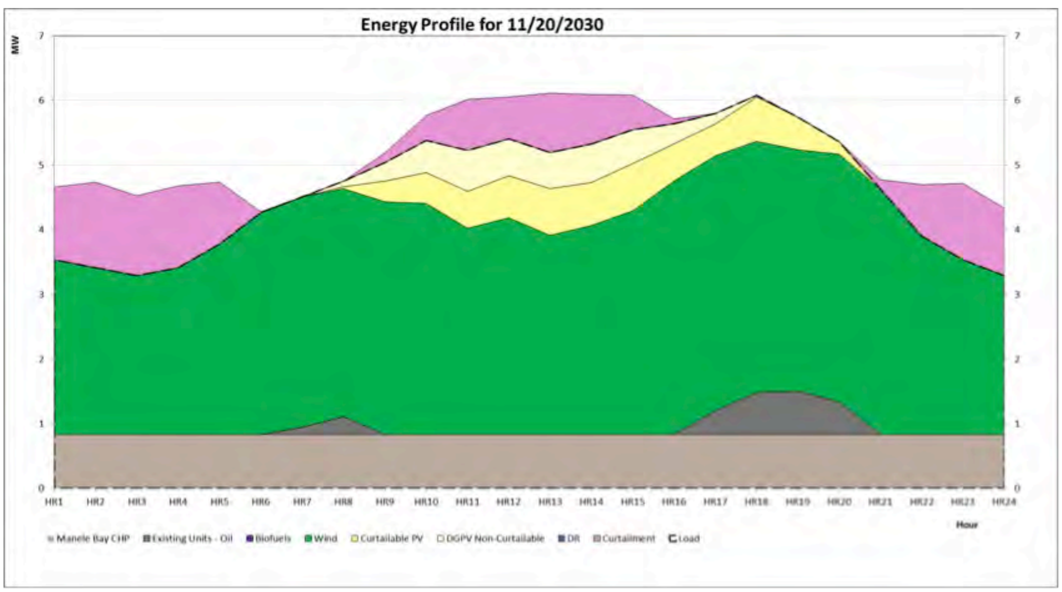


Figure 6-68. Theme 3 Max PV and Wind Day 11/20/30

6. Maui Electric Preferred Plan

Daily Energy Charts of Final Plans for Lana'i

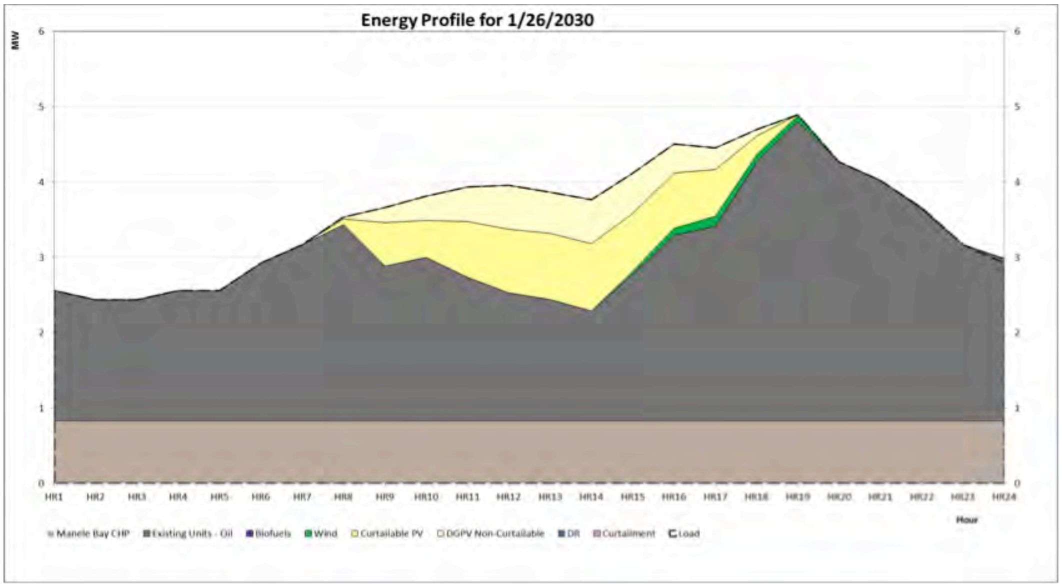


Figure 6-69. Theme 3 Least PV and Wind Day 1/26/30

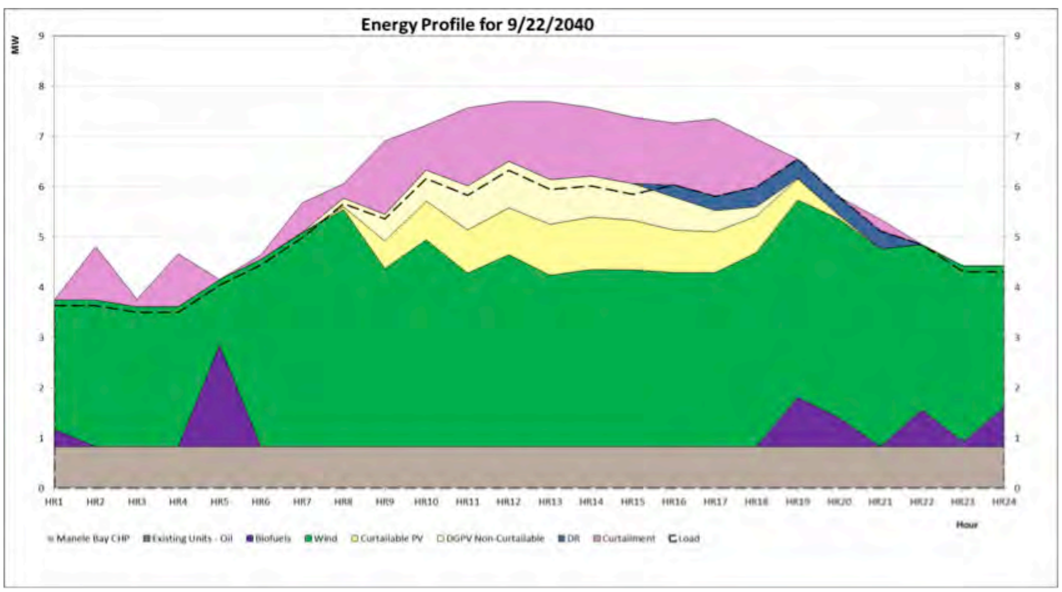


Figure 6-70. Theme 3 Max PV Day 9/22/40

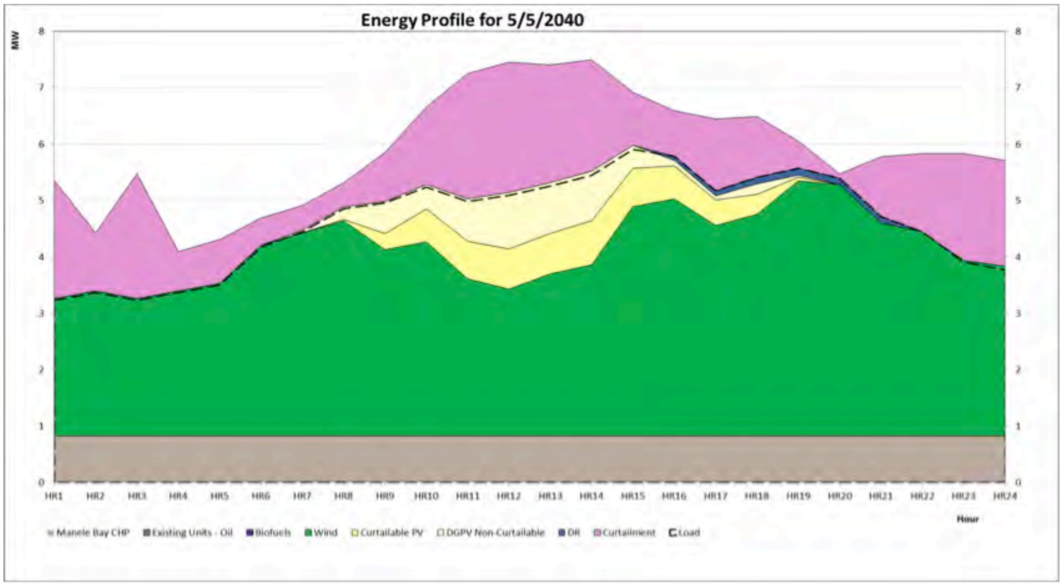


Figure 6-71. Theme 3 Max PV and Wind Day 5/5/40

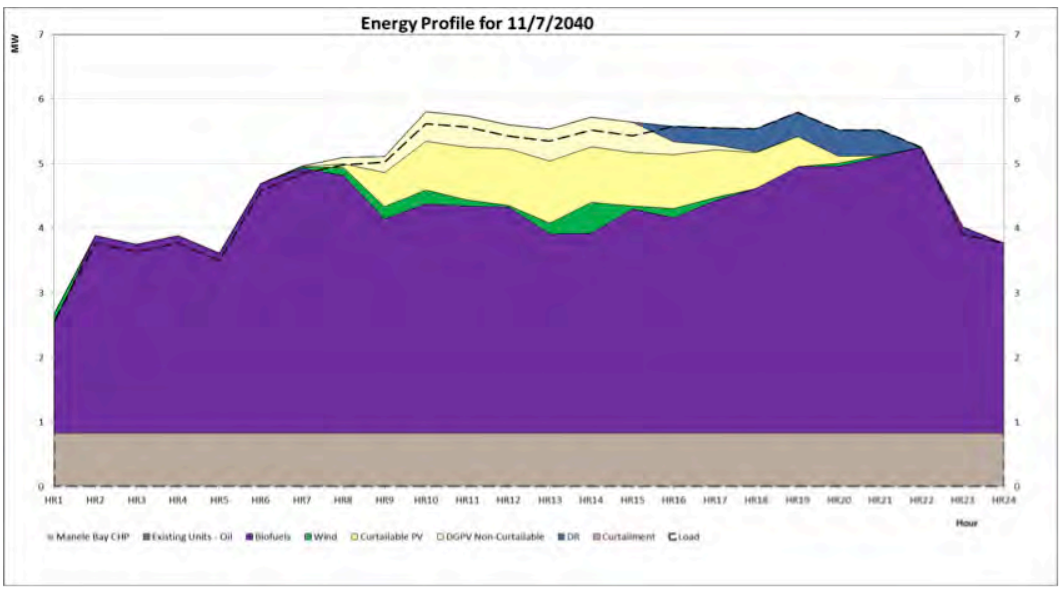


Figure 6-72. Theme 3 Least PV and Wind Day 11/7/40

LANA'I SELECTION OF THEME 1

Theme 1 will add significant amounts of variable renewable generation in conjunction with the removal of "must-run" conventional generation upon installation of system security measures. Lana'i will achieve 100% renewable energy by 2030.

Case Name	Preferred Plan
Case Label	
DER Forecast	High DG-PV
Fuel Price	2015 EIA Reference
2016	
2017	
2018	
2019	Install two - 5 MVA Synchronous Condenser (10 MVA Total)
2020	3 MW Wind
2021–2029	*No additions 2021–2029*
2030	1 MW Wind
2031–2034	*No additions 2031–2034*
2045	1 MW Wind

Table 6-3. Lana'i Preferred Plan

7. Hawai‘i Electric Light Preferred Plan

Hawai‘i Electric Light developed this Preferred Plan for transforming the system from current state to a future vision of the utility in 2045 that is consistent with the Commissions Observations and Concerns.

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

This Preferred Plan transforms the electric system to provide the appropriate characteristics to accommodate high levels of both variable and dispatchable renewable technologies. This transformation includes the addition of new renewable dispatchable generating units and energy storage for cost effective and reliable operations. The plans also incorporate systematic retirement of existing steam generating units as their value to the system has diminished. This transformation allows for the incorporation of unprecedented amounts of renewable generation on the electric system, above levels that are already the highest in the nation.

Through adding the identified resources to the electric system, the Hawai‘i Electric Light Preferred Plan exceeds the mandated RPS at every interim year by a substantial margin, decreases reliance on imported fossil fuels, improves costs, and preserves system operability.

ENERGY MIX OF FINAL PLANS

As discussed in Chapter 3, different paths to achieving 100% renewable energy in 2045 were analyzed. Figure 7-1 summarizes the annual RPS for each year. Theme 1 accelerates the RPS targets while Themes 2 and 3 strategically achieves the RPS targets.

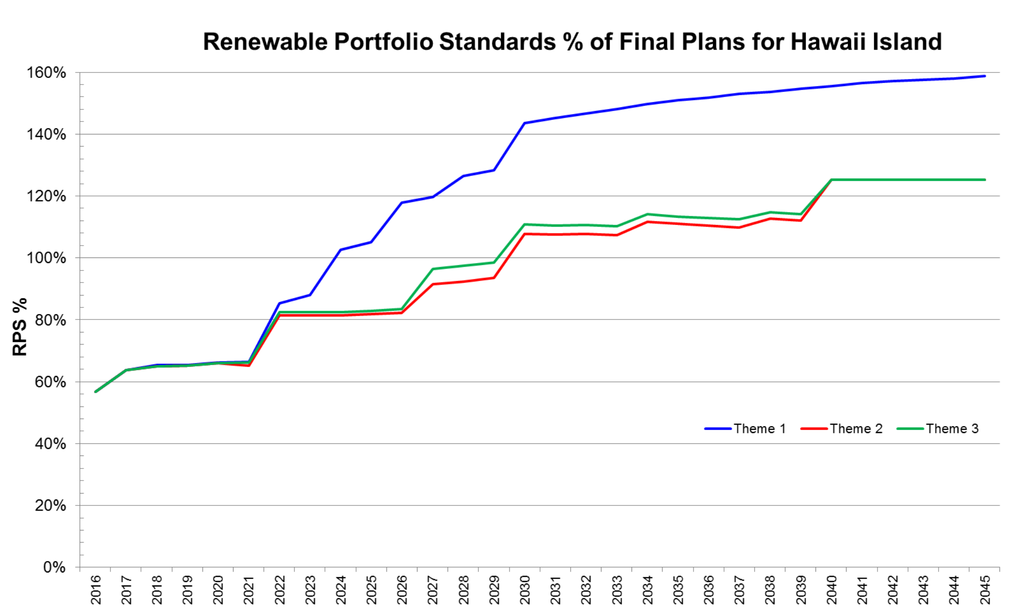


Figure 7-1. Renewable Portfolio Standards of Final Plans for Hawai'i Island

The Hawai'i Electric Light Preferred Plan includes the conversion of the islands two combined cycle units to LNG and incorporate greater amounts of renewable energy out to 2045. The figures that follow show how the resource mix of the three Hawai'i Island themes vary in generation and transform over time.

The annual energy served by resource type is shown in Figure 7-2 for the Theme 1 final plan under the 2015 EIA Reference Fuel Price Forecasts. The transition to renewable wind, biomass, and geothermal can be easily seen as the fossil fuel (oil and diesel) significantly decreases over time.

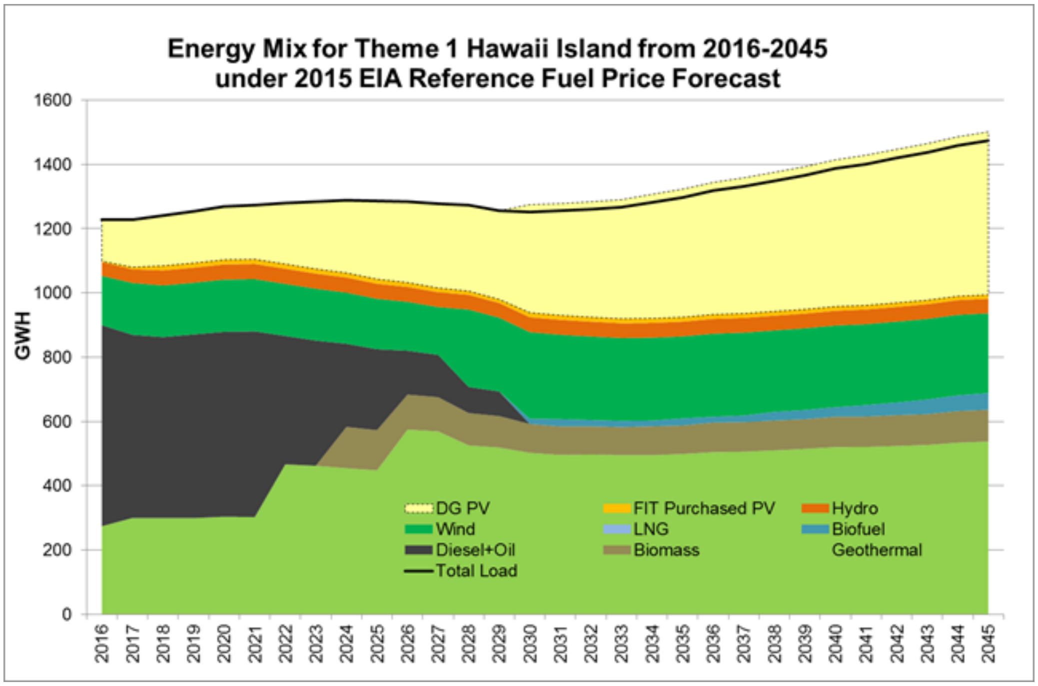


Figure 7-2. Energy Mix for Theme 1 on Hawai'i Island from 2016-2045 under 2015 EIA Fuel Price Forecast

Each final plan was evaluated under a range of fuel prices and Figure 7-3 shows the energy mix of Theme 1 under the February 2016 EIA STEO Fuel Price Forecasts. The lower fuel prices did not noticeably change the energy mix

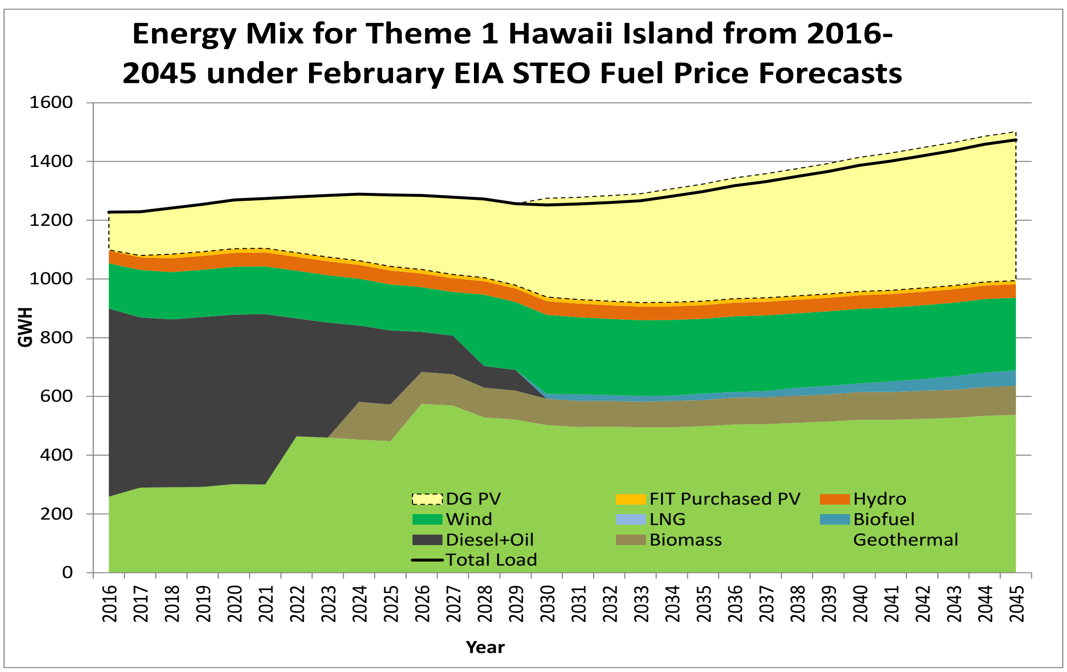


Figure 7-3. Energy Mix for Theme 1 on Hawai'i Island from 2016-2045 under February 2016 EIA STEO Fuel Price Forecast

The Theme 2 final plan uses LNG as a transitional fuel from oil to increasing levels of renewable energy. Renewable energy is added to meet intermediate RPS targets as it moves towards 100% renewable in 2040. The energy mix for Theme 2 under the 2015 EIA Reference Fuel Price Forecasts is shown in Figure 7-4.

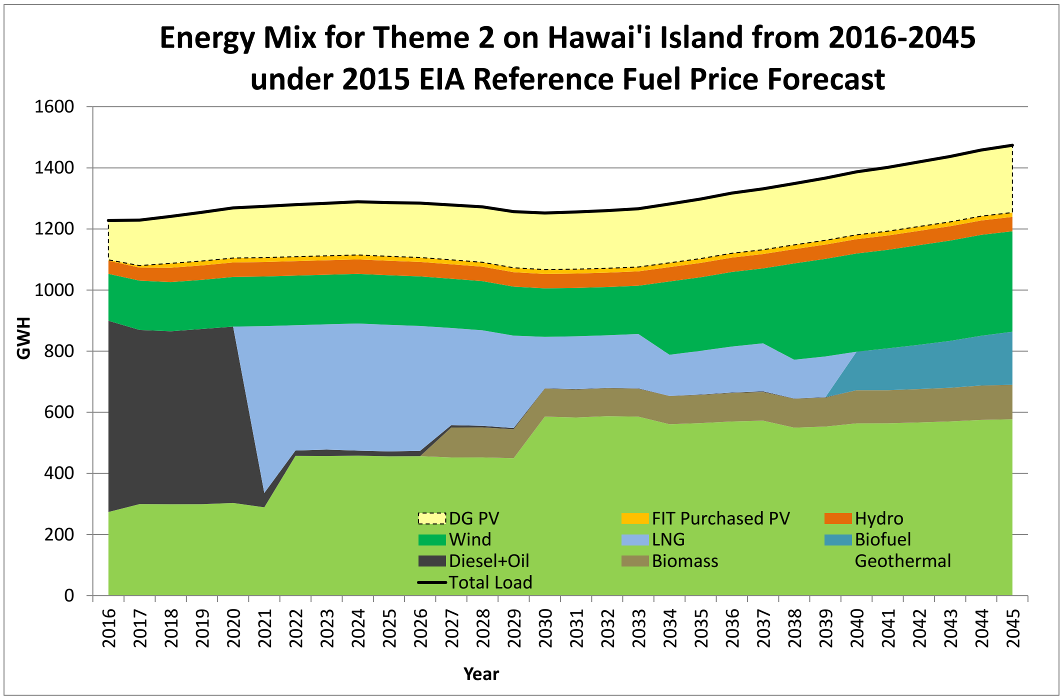


Figure 7-4. Energy Mix for Theme 2 on Hawai'i Island from 2016-2045 under 2015 EIA Reference Fuel Price Forecast

The energy mix of Theme 2 under the February 2016 EIA STEO Fuel Price Forecasts did not noticeably change under the lower fuel prices as shown in Figure 7-5.

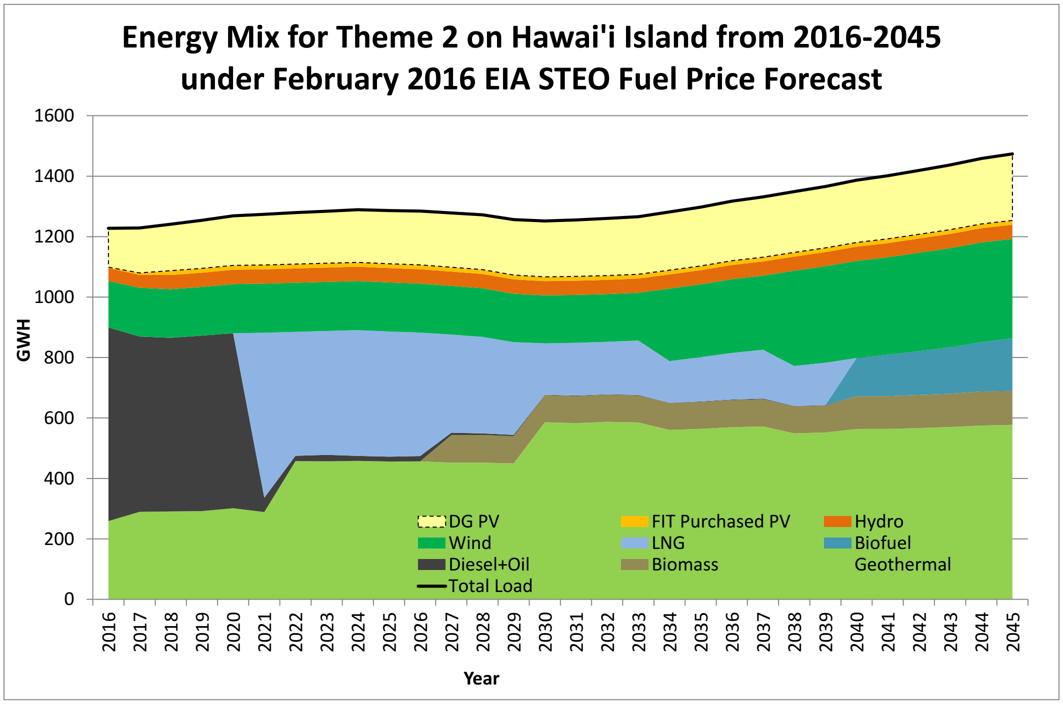


Figure 7-5. Energy Mix for Theme 2 on Hawai'i Island from 2016-2045 under February 2016 EIA STEO Fuel Price Forecasts

The final plan for Theme 3 does not include the use of LNG and strategically increases renewable energy to meet the intermediate RPS targets as in Theme 2. Figure 7-6 illustrates the energy mix under the 2015 EIA Reference Fuel Price Forecasts.

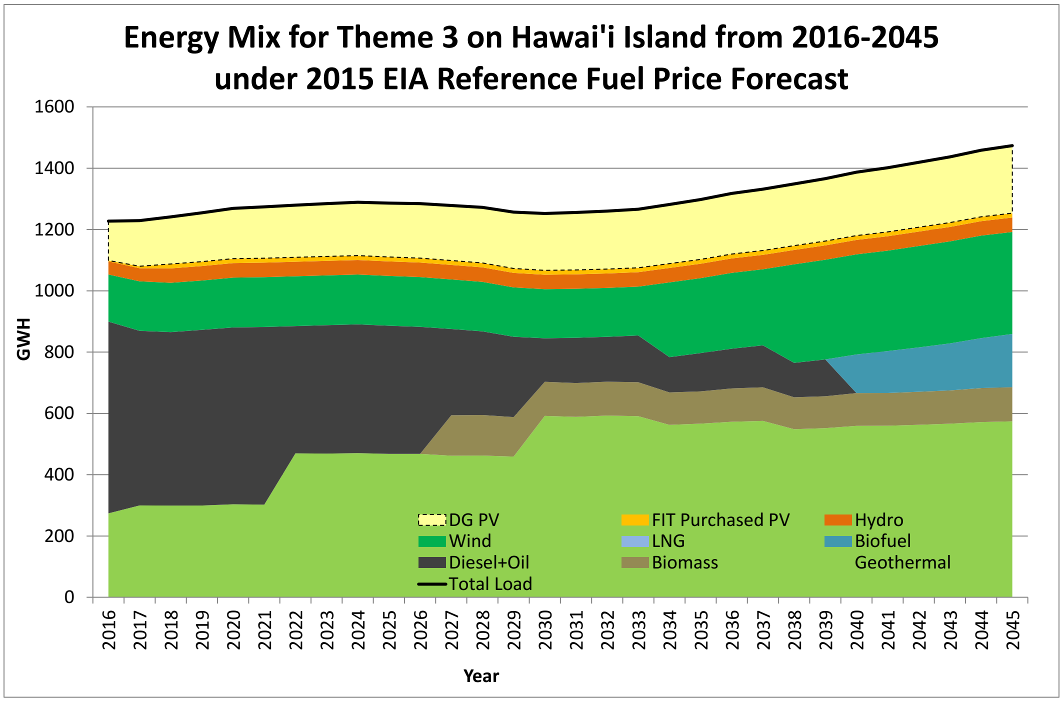


Figure 7-6. Energy Mix for Theme 3 on Hawai'i Island from 2016-2045 under 2015 EIA Fuel Price Forecasts

Similar to the final plans in Themes 1 and 2, the energy mix of Theme 3 under the February 2016 EIA STEO Fuel Price Forecasts did not noticeably change under the lower fuel prices as shown in Figure 7-7.

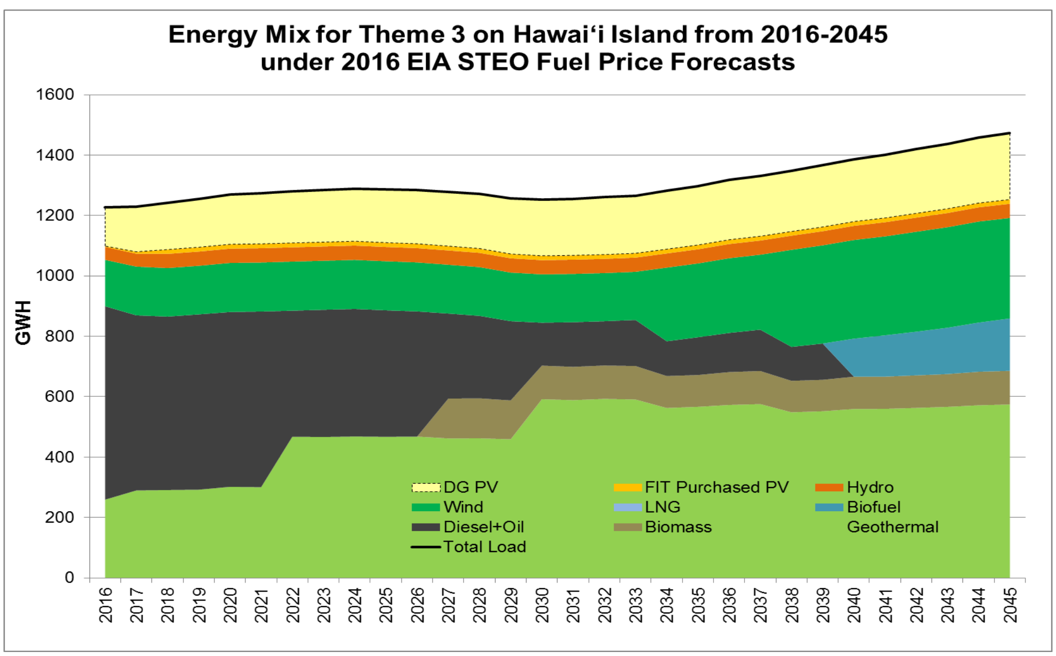


Figure 7-7. Energy Mix for Theme 3 on Hawai'i Island from 2016-2045 under February 2016 EIA STEO Fuel Price Forecasts

The generation mix in all themes 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 new flexible firm generation is added to the system, firm fossil-fuel generating units are displaced. The different paths of Themes 1, 2, and 3 to achieving 100% renewable energy is clearly displayed in the figures above.

OVER-GENERATION OF TOTAL SYSTEM OF FINAL PLANS

The Hawai‘i Island electric system currently has a large share of energy generated by renewable resources. The addition of new flexible firm renewable generation along with increasing wind generation, provide the path to 100% renewable energy generation. There must be available renewable energy in excess of demand to ensure adequacy of supply (from renewable resources) under a 100% renewable energy case. Further, with nearly all resources being renewable, both variable and renewable resources must adjust output to balance with demand – which at lower renewable penetration was borne primarily by dispatchable fossil generation. As a result, variable renewable generation such as wind and PV will occasionally be available in quantities that cannot be fully utilized by the system.

However, situations of over-generation provide opportunities, coupled with appropriate controls systems, to use wind and solar generation as regulation resources in addition to use as a reserve resource. This provides more value than a resource providing energy only. In combination, wind and solar used for energy and some level of regulation and reserve appear to be cheaper than the alternative of additional storage, at least at moderate over-generation levels. For the purposes of this PSIP update, we include the full cost of the utility scale variable generation resources in cost calculations, regardless of over-generation levels and provides a simplified accounting for other services from these resources.

As the islands evolve to ever increasing levels of renewable energy, grid management capabilities, such as dispatch control to balance demand, frequency response, and voltage regulation, will be increasingly required from both variable and firm renewable resources as the systems are transformed to economically and reliably serve the energy needs of the future with 100% renewable energy. This increasing contribution to grid management will require changes to both procurement terms and technical and operational capabilities of all renewable resources, including distributed and variable energy resources.

Figure 7-8 provides estimates of the percent oversupply from variable resources over-generation of the total system annual energy for the final plans under the 2015 EIA Reference Fuel Price Forecasts. Since Theme 1 integrates greater amounts of variable renewable energy than Themes 2 and 3, the percent over-generation increases significantly and much earlier than in Themes 2 and 3. The charts do not show available capacity from dispatchable renewable resources that are not utilized to follow demand and/or accommodate variable energy resources. In 100% renewable energy systems, variable and firm dispatchable resources will compete to serve demand. The actual allocation of energy between variable and dispatchable should be done in a manner to decrease overall system costs and manage system security, considering the relative costs and capabilities of all resources to provide energy and grid services.

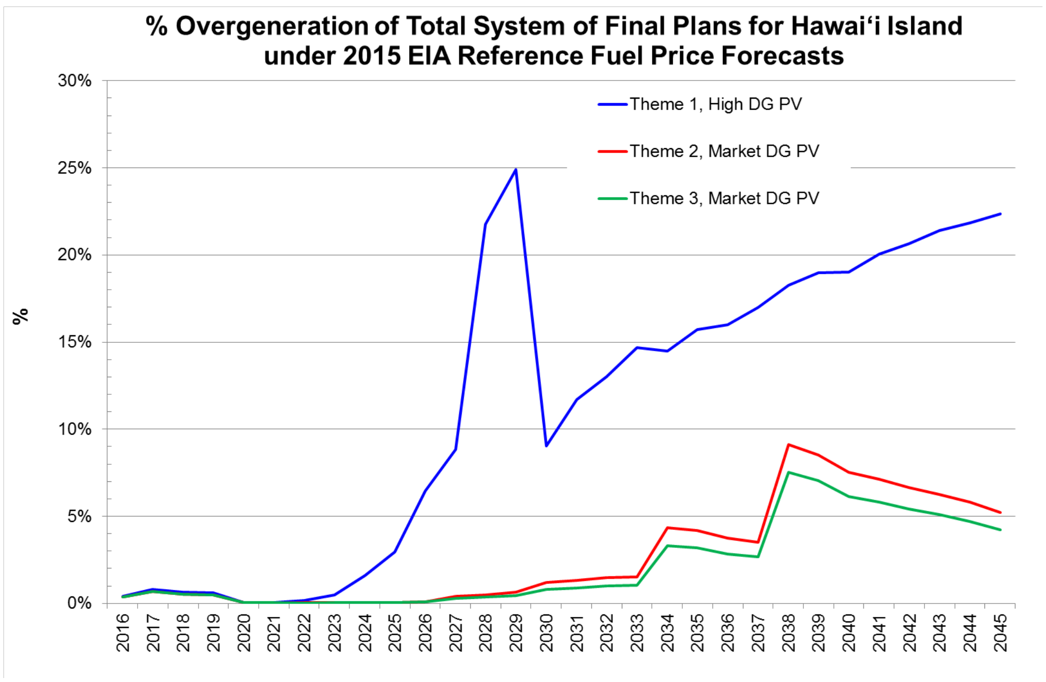


Figure 7-8. Percent Over-Generation of Total System of Final Plans for Hawai'i Island under 2015 EIA Reference Fuel Price Forecasts

Similar estimates of the percent over-generation for the final plans under the February 2016 EIA STEO Fuel Price Forecasts is in Figure 7-9. Again, there isn't a visible difference between the two fuel price forecasts.

Hawaiian Electric
Maui Electric
Hawai'i Electric Light

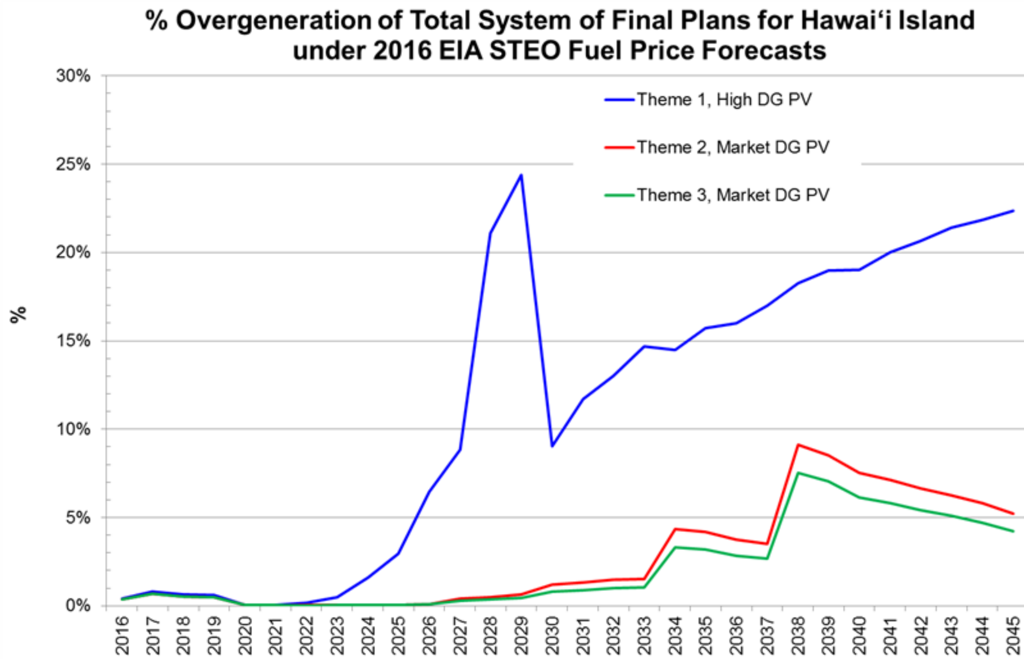


Figure 7-9. Percent Over-Generation of Total System of Final Plans for Hawai‘i Island under February 2016 EIA STEO Fuel Price Forecasts

TOTAL SYSTEM RENEWABLE ENERGY OF FINAL PLANS

The extent to which renewable energy can be utilized on Hawai‘i Island will depend on factors such as the total system load or energy demand, the amount of downward regulation that must be carried on the system to counteract an unexpected loss of load or increase in variable generation, and the total output from variable generation resources. In all Themes, Hawai‘i Electric Light anticipates there is increasingly more renewable energy than can be utilized, as resources are added to ensure cost-effective adequacy of supply using 100% renewable energy.

Theme 1 is utilizing nearly 100% of the variable renewable energy in the near-term and slowly decreases to about 90% after 2040. The results shown in Figure 7-10 is the same under both fuel price forecasts.

Theme 1 2015 EIA Reference Fuel Price Forecast

% RE	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Utilized	99.8%	99.6%	99.6%	99.7%	100.0%	100.0%	99.9%	99.8%	99.3%	98.7%	97.3%	96.2%	91.2%	89.7%	96.1%

% RE	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2016-2045
Utilized	94.8%	94.1%	93.3%	93.3%	92.6%	92.4%	91.8%	91.1%	90.7%	90.6%	90.0%	89.6%	89.1%	88.9%	88.6%	93.5%

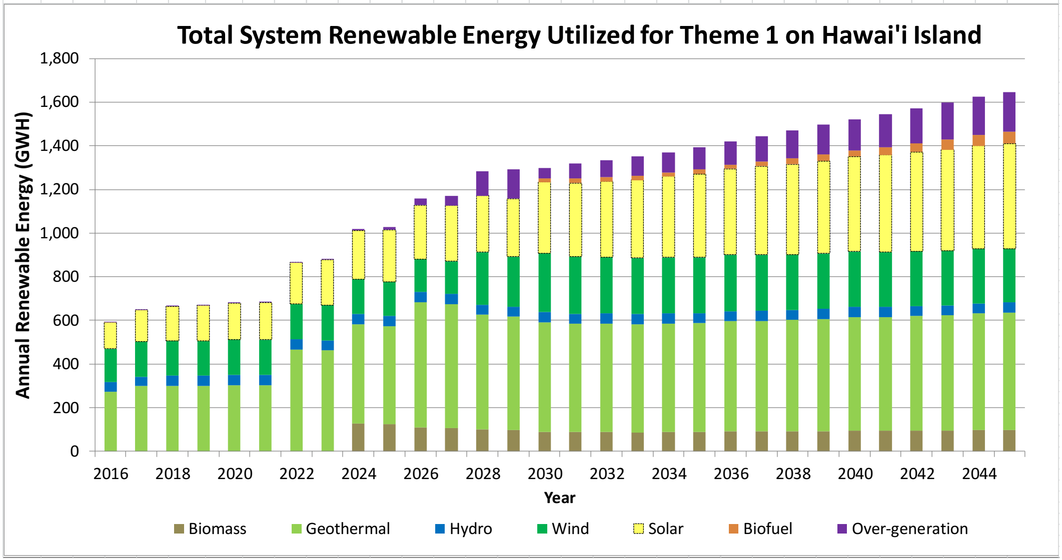


Figure 7-10. Total System Renewable Energy Utilized for Theme 1 on Hawai‘i Island

As revealed in Figure 7-11, Theme 2 is utilizing 100% of the variable renewable energy available until about 2030. The lowest amount utilized is about 97%. The results shown in Figure 7-11 is the same under both fuel price forecasts.

% RE	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Utilized	99.8%	99.6%	99.7%	99.7%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	99.8%	99.8%	99.7%	99.5%

% RE	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2016-2045
Utilized	99.5%	99.4%	99.4%	98.3%	98.4%	98.6%	98.7%	96.7%	96.9%	97.4%	97.5%	97.7%	97.8%	98.0%	98.2%	98.8%

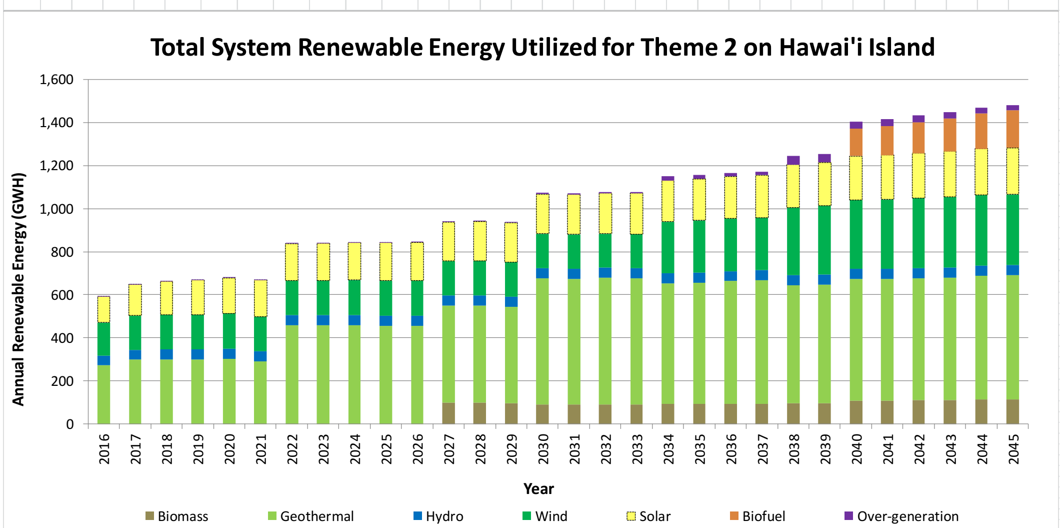


Figure 7-11. Total System Renewable Energy Utilized for Theme 2 on Hawai‘i Island

Theme 3 has the same levels of renewable energy as Theme 2 and has very similar utilization of the energy. Figure 7-12 indicates that Theme 3 is utilizing 100% of the renewable energy available until about 2030. The lowest amount utilized is about 97%. The results shown in Figure 7-12 is the same under both fuel price forecasts.

% RE	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Utilized	99.8%	99.6%	99.7%	99.7%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	99.9%	99.8%	99.8%	99.7%

% RE	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2016-2045
Utilized	99.6%	99.6%	99.6%	98.7%	98.8%	98.9%	99.0%	97.3%	97.5%	97.8%	97.9%	98.1%	98.2%	98.3%	98.5%	99.0%

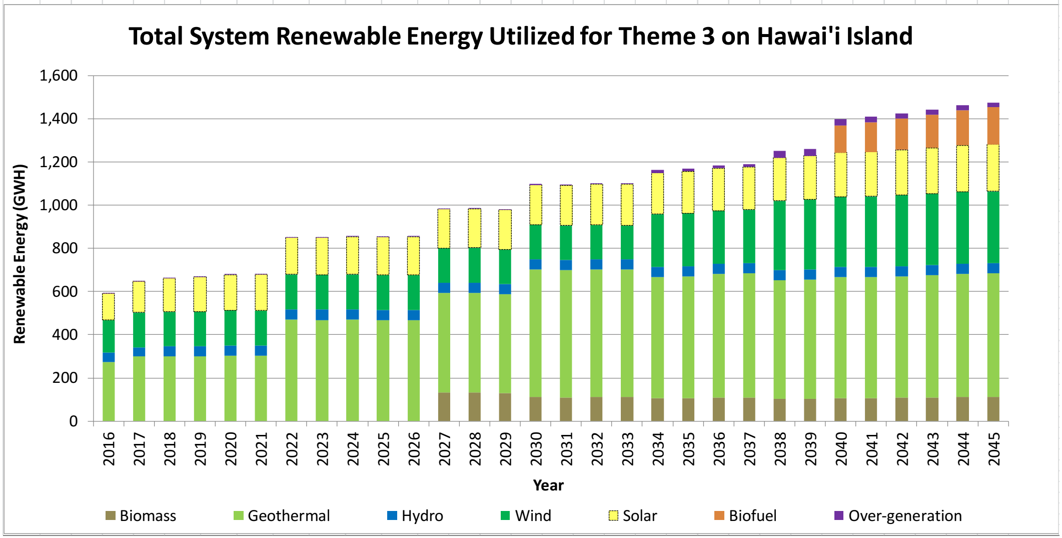


Figure 7-12. Total System Renewable Energy Utilized for Theme 3 on Hawaiʻi Island

DAILY ENERGY CHARTS OF FINAL PLANS

The following charts illustrate representative study days on Hawaiʻi Island with increasing renewable energy contributions that displace fossil fueled generation over time. These charts show the advantage of a diversified portfolio of resources such as, firm dispatchable, variable generation, demand response, and load shifting storage to serve our customer's energy needs.

A noticeable occurrence in each chart is the large contribution of PV energy during daylight hours, resulting in potential oversupply of PV generation. During hours without PV production, beyond daylight or cloudy/low irradiance days, customer needs will need to be met by the portfolio of resources other than PV, including storage, wind, and firm dispatchable generation.

Theme 1

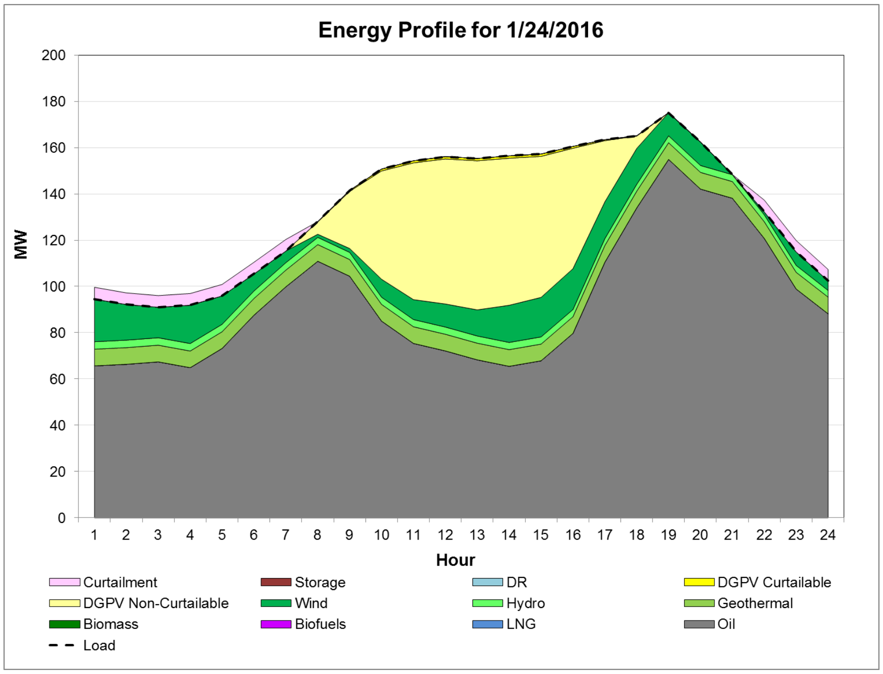


Figure 7-13. Modeled Energy Profile for January 24, 2016 of the Final Plans

Based on the modeling assumptions, the day with the highest penetration of PV energy is January 24, 2016. Figure 7-13 provides the view of the PV energy being accepted together with other renewable and non-renewable resources for Theme 1. Since the assumptions between Theme 1 – 3 are the same in 2016, this chart is representative of all the three themes.

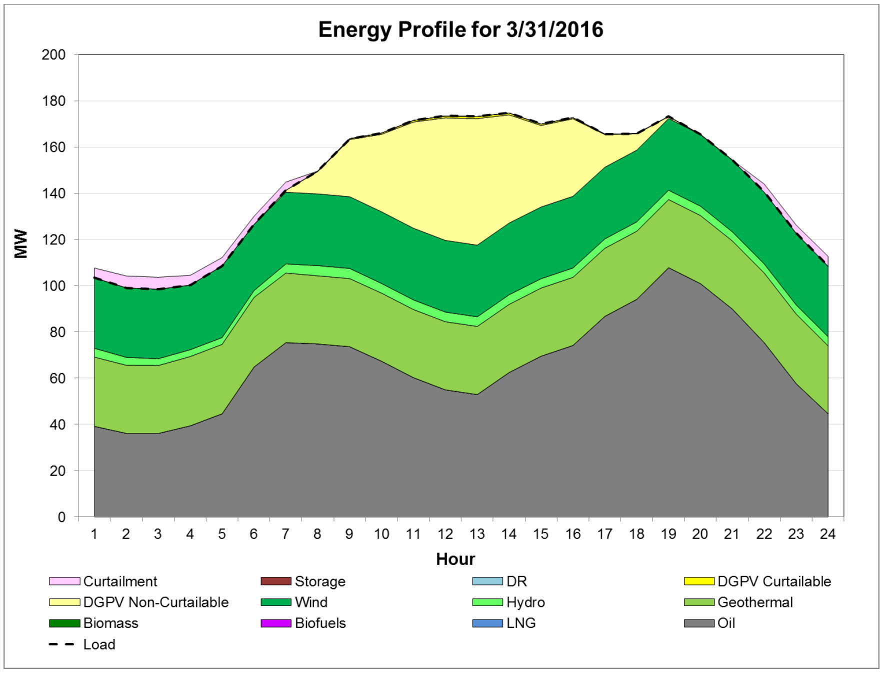


Figure 7-14. Modeled Energy Profile for March 31, 2016 of the Final Plans

Based on the modeling assumptions, the day with the highest penetration of wind energy is March 31, 2016. Figure 7-14 provides the view of the wind energy being accepted together with other renewable and non-renewable resources. Since the assumptions between Theme 1–3 are the same in 2016, this chart is representative of all the three themes.

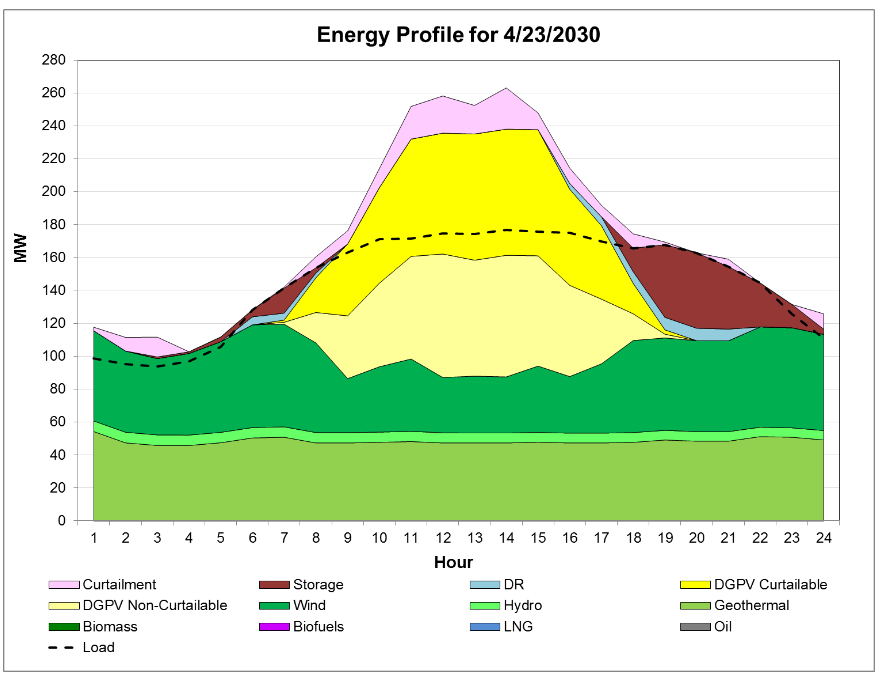


Figure 7-15. Modeled Energy Profile for April 23, 2030 of the Final Plans

Figure 7-15 above illustrates the day with highest available energy from PV and wind in 2030 for Theme 1. As can been seen from the graph, in 2030 the system is 100% renewable as only renewable generating resources serve the daily load. The chart also illustrates the excess generation from wind and PV during day and night hours due to high levels of energy from wind and PV resources. Furthermore, the figure illustrates the use of DR and storage resources.

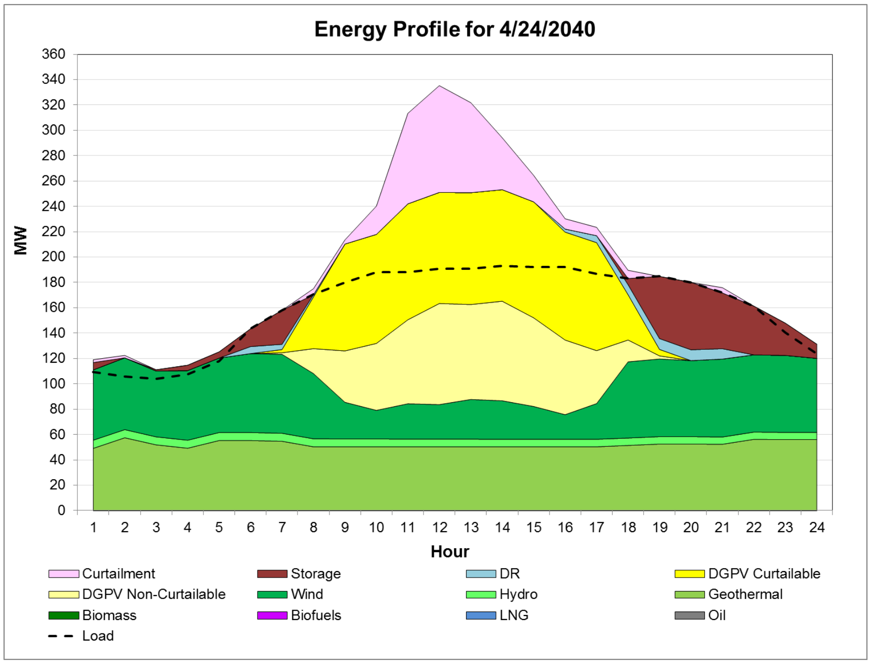


Figure 7-16. Modeled Energy Profile for April 24, 2040 of the Final Plans

Figure 7-16 above illustrates the day with the highest available energy from PV and wind in 2040 for Theme 1. The system is 100% renewable.

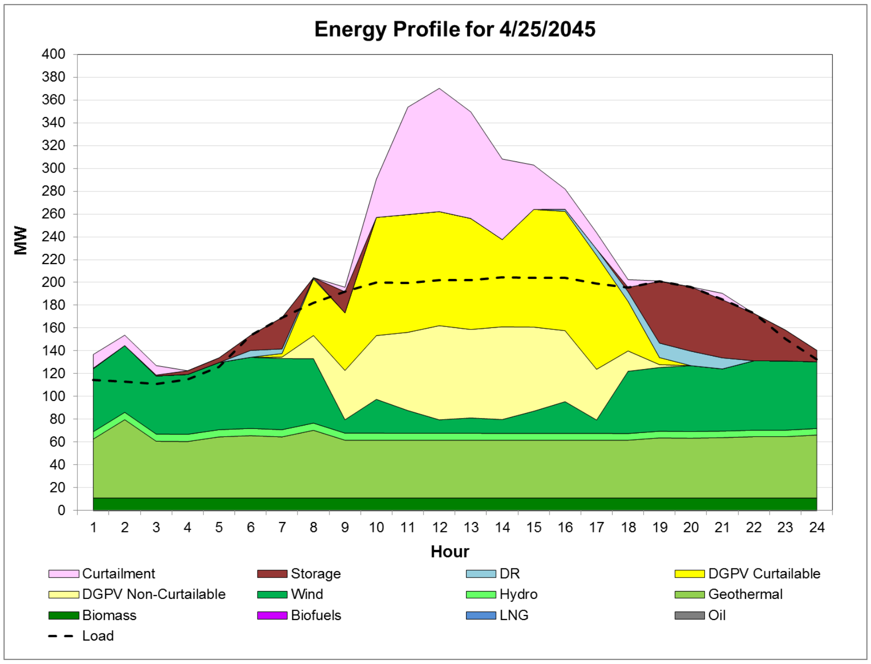


Figure 7-17. Modeled Energy Profile for April 25, 2045 of the Final Plans

Similar to the figure before, Figure 7-17 illustrates the day with highest available energy from PV and wind in 2045 for Theme 1. The system is 100% renewable.

Theme 2

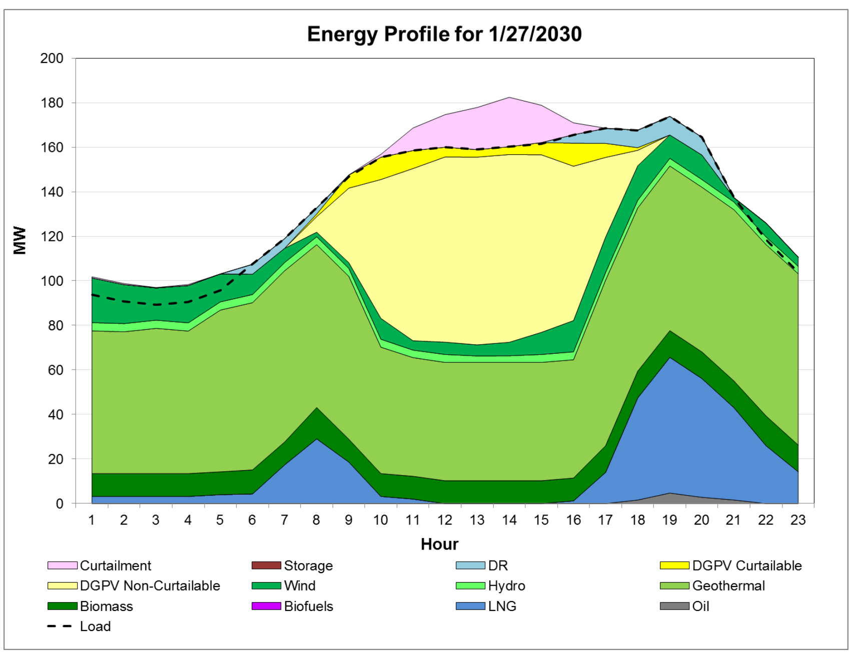


Figure 7-18. Modeled Energy Profile for January 27, 2030 of the Final Plans

Figure 7-18 above illustrates the day with the highest penetration of PV in 2030. There is some excess energy during the day for Theme 2. Most oil generation has been replaced by LNG fuel. A small amount of generation is produced by oil resources to serve the energy during the peak hours.

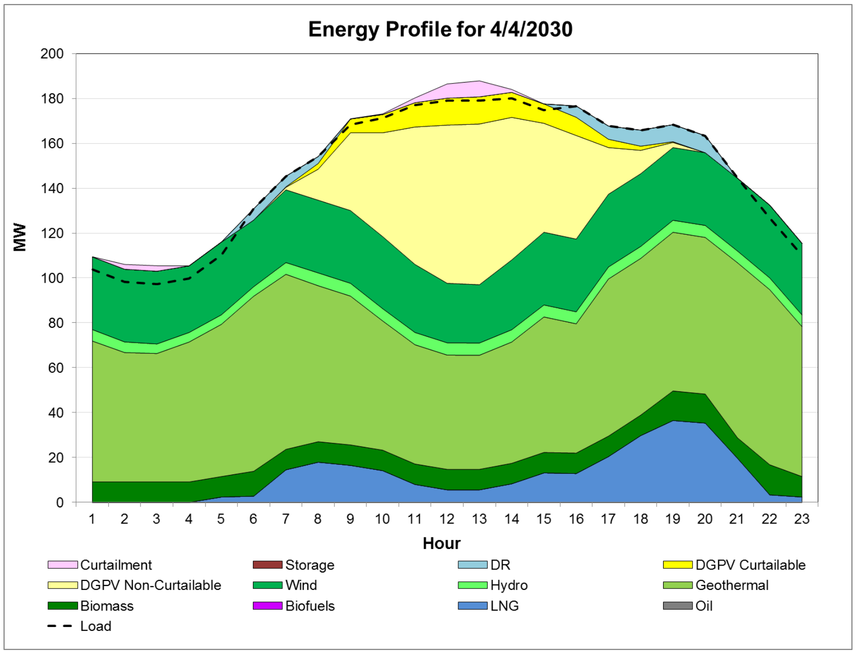


Figure 7-19. Modeled Energy Profile for April 4, 2030 of the Final Plans

Figure 7-19 illustrates the day with the highest penetration of wind in 2030. All of the oil generation is replaced by LNG. High availability of wind and PV resource reduces the use of LNG and oil generation.

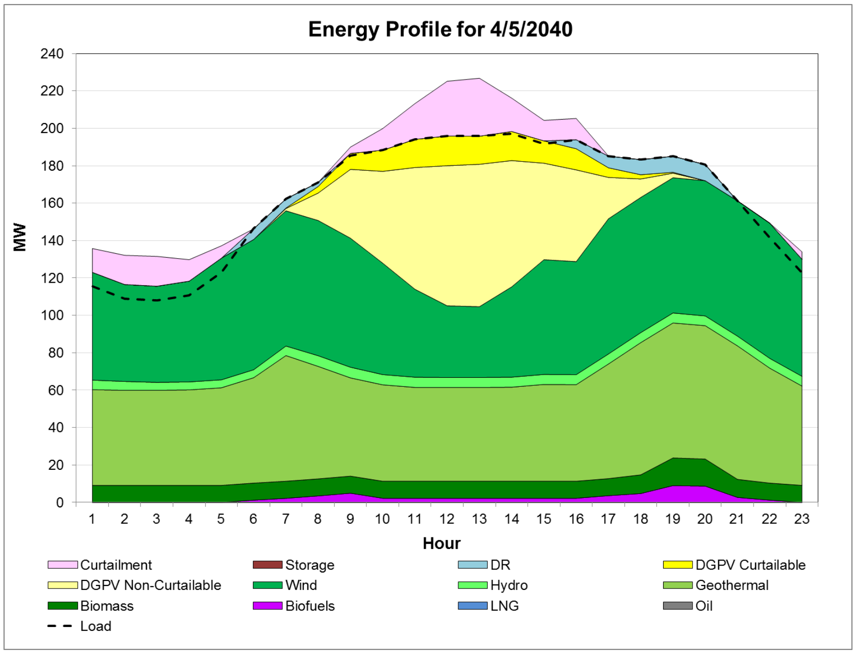


Figure 7-20. Modeled Energy Profile for April 5, 2040 of the Final Plans

Figure 7-20 above illustrates a day in 2040 with high PV and wind generation for Theme 2. The system is 100% renewable. The majority of renewable energy is provided by firm and variable generation renewable resources. A small portion of generation is provided by biofuels. Over-generation occurs during the day and night hours due to high availability of wind and PV resources.

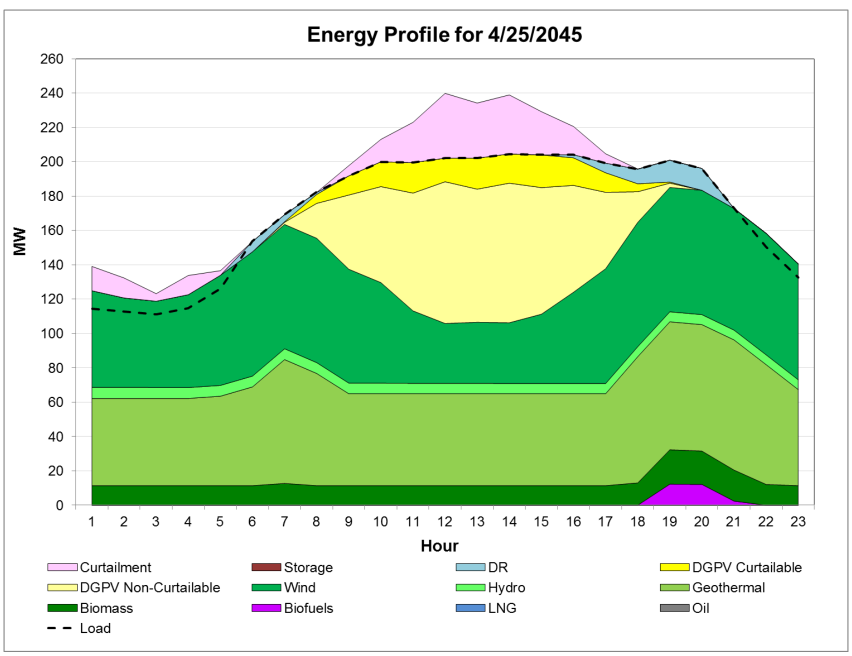


Figure 7-21. Modeled Energy Profile for April 25, 2045 of the Final Plans

Figure 7-21 above illustrates a day in 2045 with high PV and wind generation.

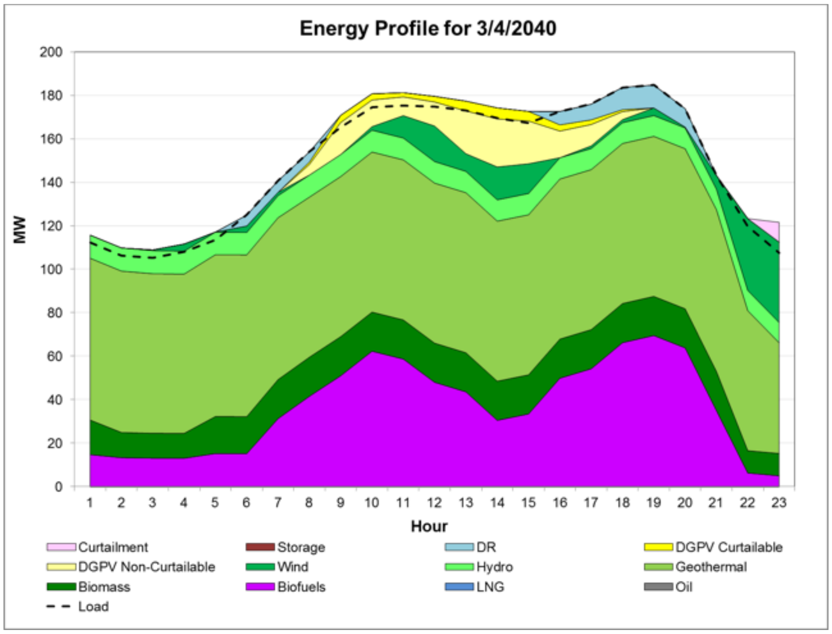


Figure 7-22. Modeled Energy Profile for March 4, 2040 of the Final Plans

Figure 7-22 above illustrates daily generation with minimum availability of both wind and PV. In this case, there is minimum excess generation during this day. However, for the system to reliability meet the daily load, it relies heavily on firm dispatchable renewable resources and thermal generators using biofuels. This situation will occur during the days when PV and wind energy resources are unavailable or minimally available.

Theme 3

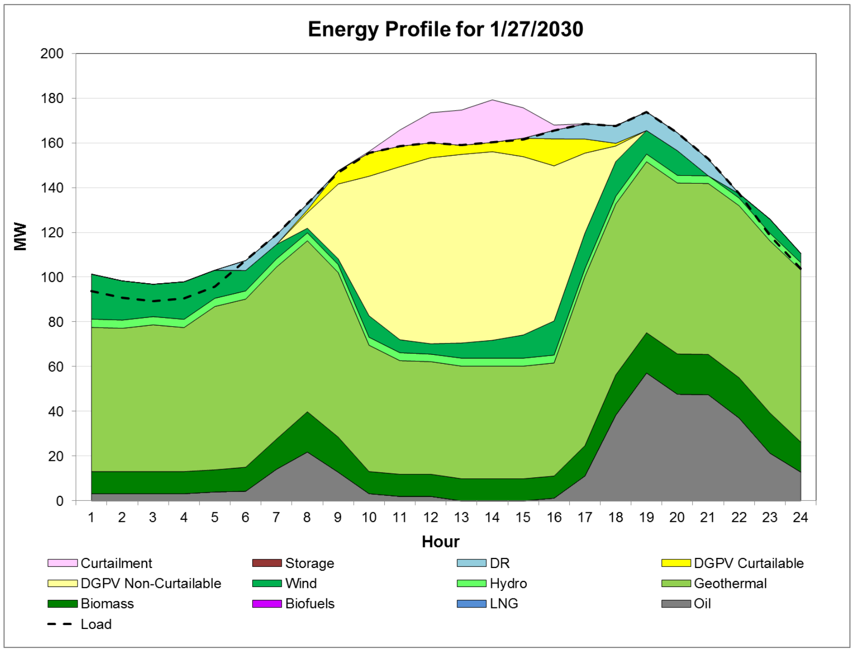


Figure 7-23. Modeled Energy Profile for January 27, 2030 of the Final Plans

Similarly to Theme 2, Figure 7-23 above illustrates the daily generation with high penetration of PV. Unlike Theme 2, the system does not switch to LNG.

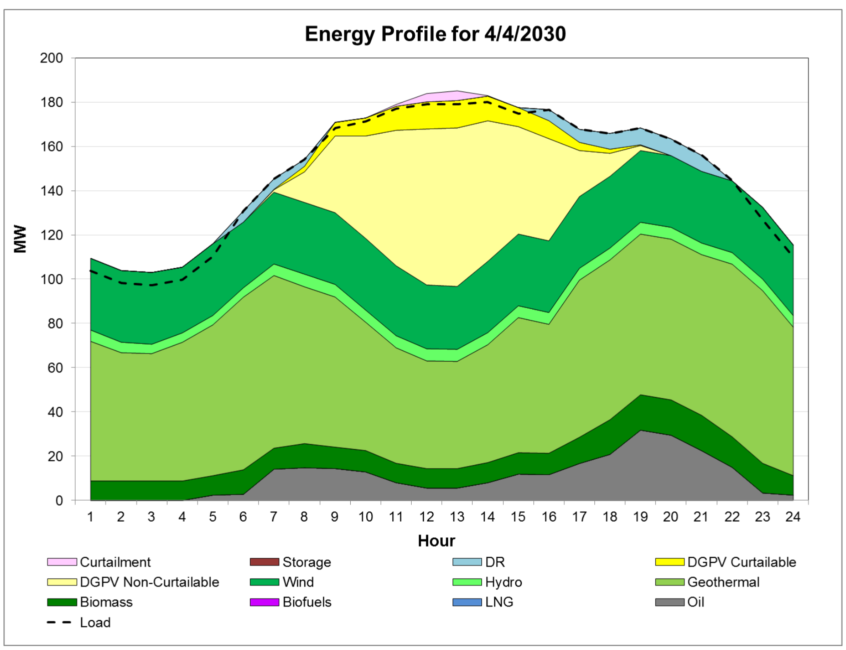


Figure 7-24. Modeled Energy Profile for April 4, 2030 of the Final Plans

Figure 7-24 above illustrates a day with high wind generation. Unlike Theme 2, the system does not switch to LNG.

Emissions of Final Plans for Hawai'i Island

The CO2 emissions of the final plans were estimated and are shown in the figure below. Theme 3 has the highest projected emissions among the three final plans since some generating units remain on fossil fuel until 2039. Theme 2 has lower emissions with the switch to LNG. Theme 1 has the lowest projected emissions due to the increasing levels of renewables displacing fossil fuels.

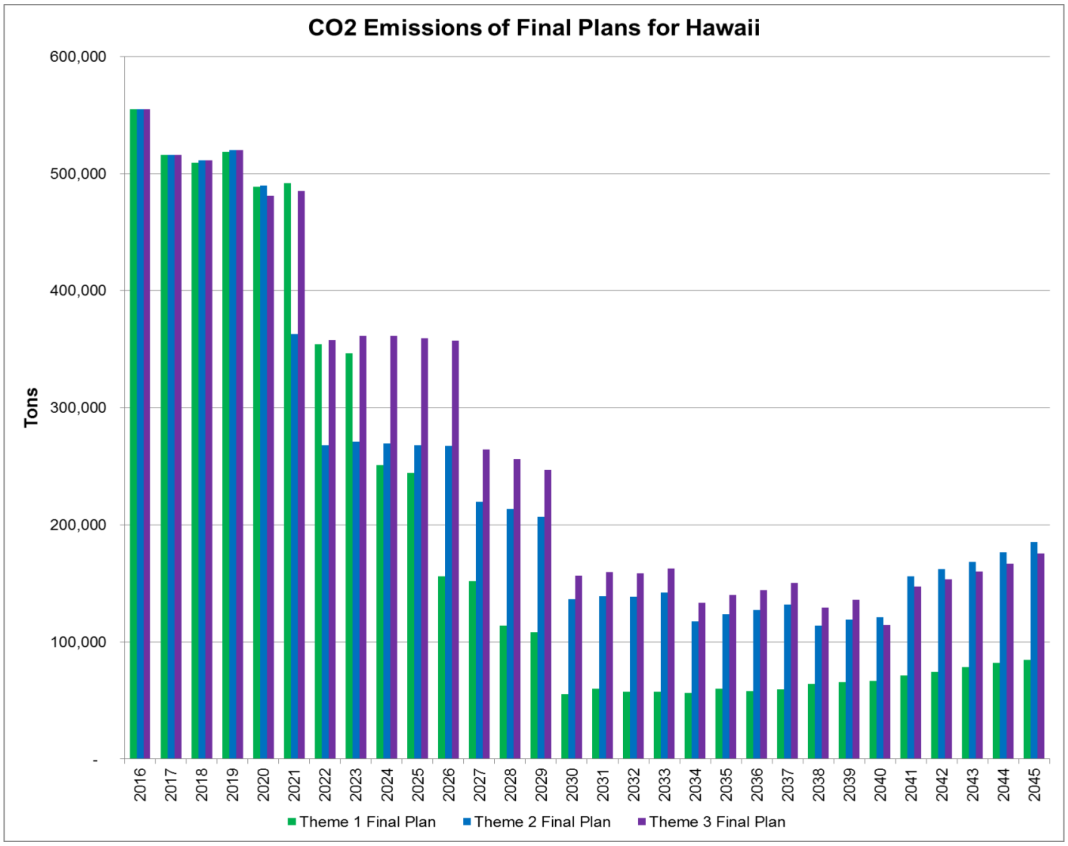


Figure 7-25. CO2 Emissions of Final Plans for Hawai'i

HAWAI‘I ISLAND SELECTION OF THEME 2

The rigorous long-term analyses of the three themes provided insights on the different strategies for achieving 100% renewable energy by 2040. They provide directional guidance to inform the risks and the level of "no regrets" in short- term actions, particularly as you compare long-term resources across multiple themes. Although the steps along the paths to 2045 are different among the final plans, the starting point is the same. The purpose of the Preferred Plan is to inform the evaluation of specific near-term actions that are implementable based on the direction that the longer-term view of the plan provides. The Preferred Plan will balance technical, economic, environmental, and cultural considerations.

Based on the results of the analyses, Theme 2 will add a substantial amount of flexible, firm generation that will allow for the retirement of older generating units, incorporate significant amounts of variable renewable generation, and lower and stabilize customer bills by using lower cost fuel in the transition to 100% renewable.

7. Hawai'i Electric Light Preferred Plan

Hawai'i Island Selection of Theme 2

Case Name	Preferred Plan
DER Forecast	Baseline
Fuel Price	Feb 2016 EIA STEO or 2015 EIA Reference
2016	
2017	
2018	
2019	15 MW Contingency battery
2020	
2021	
2022	20 MW Geothermal Puna Steam Deactivated
2023	
2024	
2025	
2026	
2027	20 MW Biomass Hill 5 Deactivated
2028	
2029	
2030	20 MW Geothermal Hill 6 Deactivated
2031	
2032	
2033	
2034	20 MW Wind
2035	
2036	
2037	
2038	20 MW Wind
2039	
2040	Biofuels
2041	
2042	
2043	
2044	
2045	

Table 7-1. Hawai'i Island Preferred Plan

8. Five-Year Action Plans

This Five-Year Action Plan details a set of actions that must be taken to continue the transformation of our electric systems, and to continue on the path of reaching our 100% renewable energy goal. This Action Plan focuses on the near-term 2016 to 2020 period and includes those activities that must be done within this period to accomplish goals that are beyond that period. For example, acquiring new, firm capacity resources may take anywhere from five years to ten years or more, depending on the type of resource. Actions, such as initiating a competitive procurement process, will need to be taken within the Action Plan period in order to have the resource in service by the date needed.

COMPANY-WIDE

Achieving the RPS

The Preferred Plans across our territories exceed the requirements of the RPS law as shown in Figure 8-1.

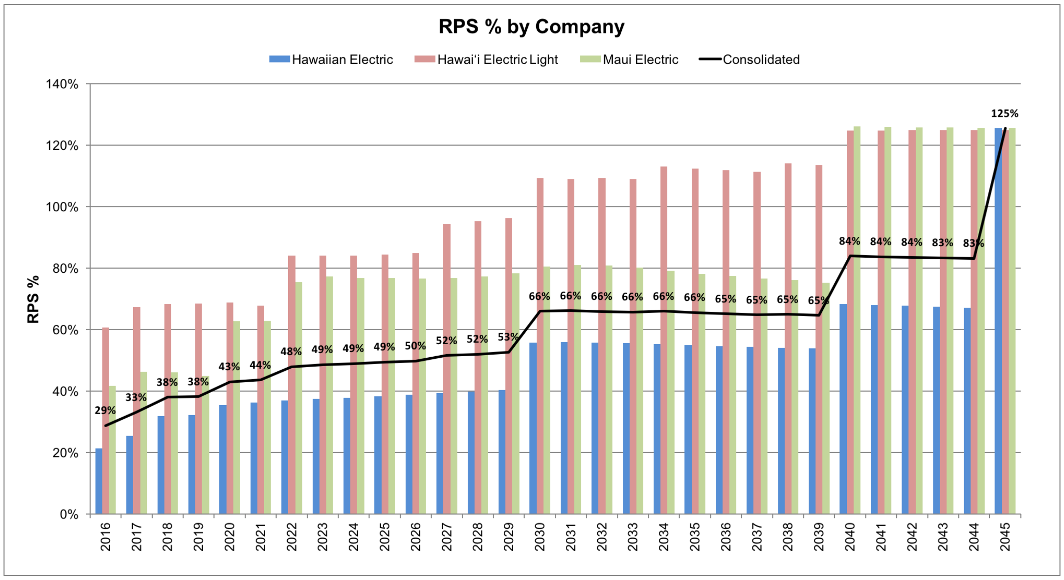


Figure 8-1. Renewable Portfolio Standards Compliance of Preferred Plans

The calculation of the RPS per the law does result in values over 100%. To emphasize that we are committed to achieving 100% renewable energy in 2045, Figure 8-2 shows the renewable energy as a percent of total energy including customer-sited generation.

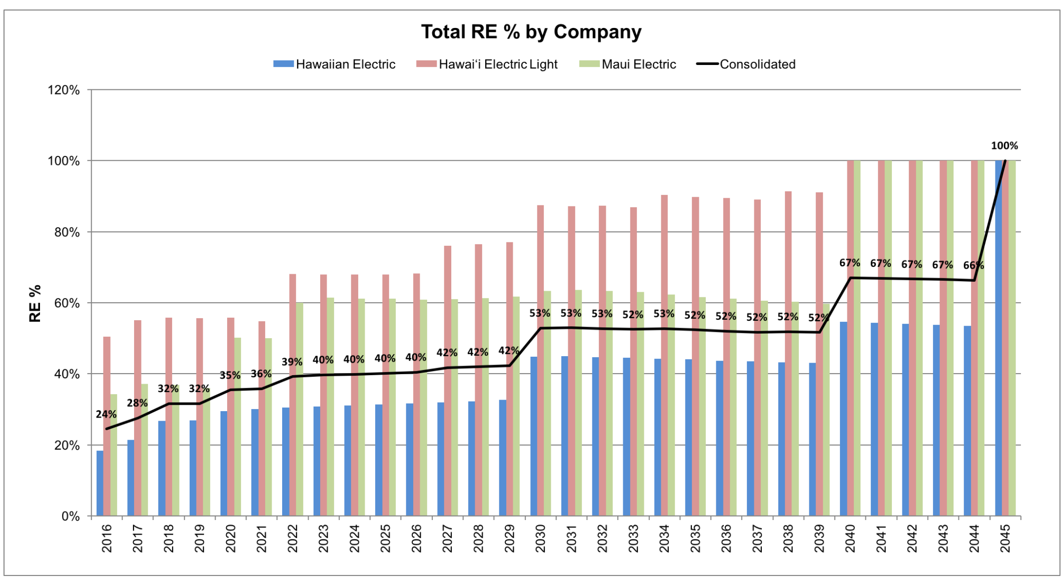


Figure 8-2. Total Renewable Energy Percent of Preferred Plans

Figure 8-1 and Figure 8-2 provides a long-term view of a path towards 100% renewable in 2045. Figure 8-3 shows the total capacity of renewable energy included in the Preferred Plans on a consolidated basis. By 2045, the total capacity of renewable energy on the systems is more than double the total of the system peaks to be served.

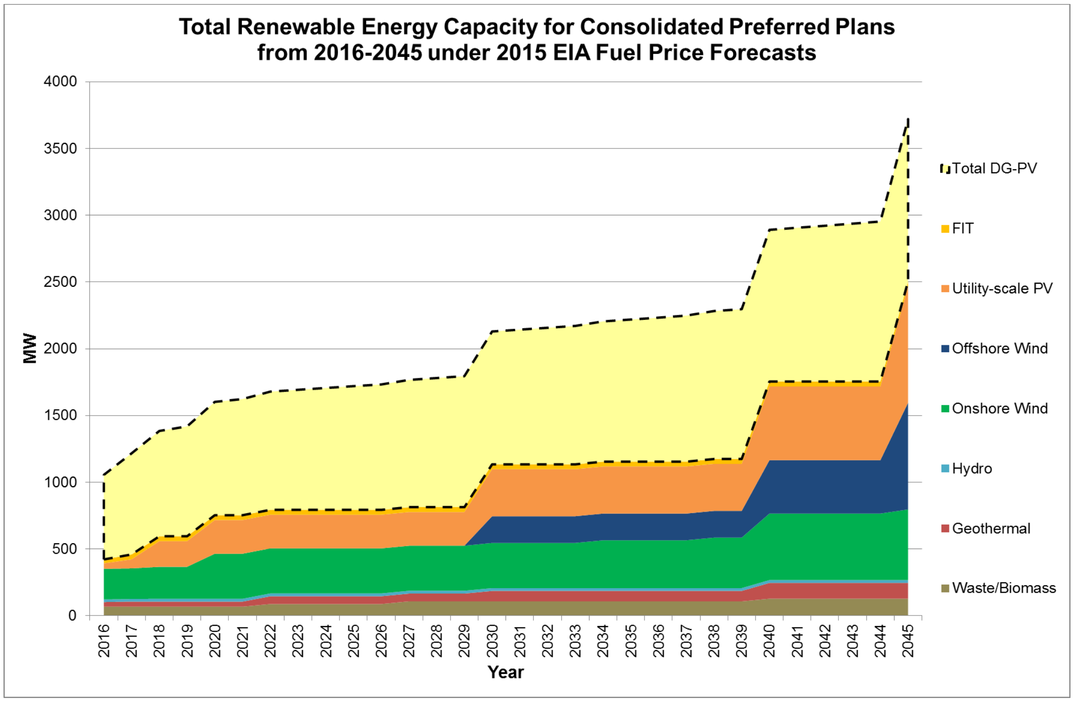


Figure 8-3. Total Renewable Energy Capacity for Consolidated Preferred Plans from 2016-2045 under 2015 EIA Fuel Price Forecasts

The energy mix for the Preferred Plans on a consolidated basis, including the all the renewable energy capacity shown in Figure 8-4.

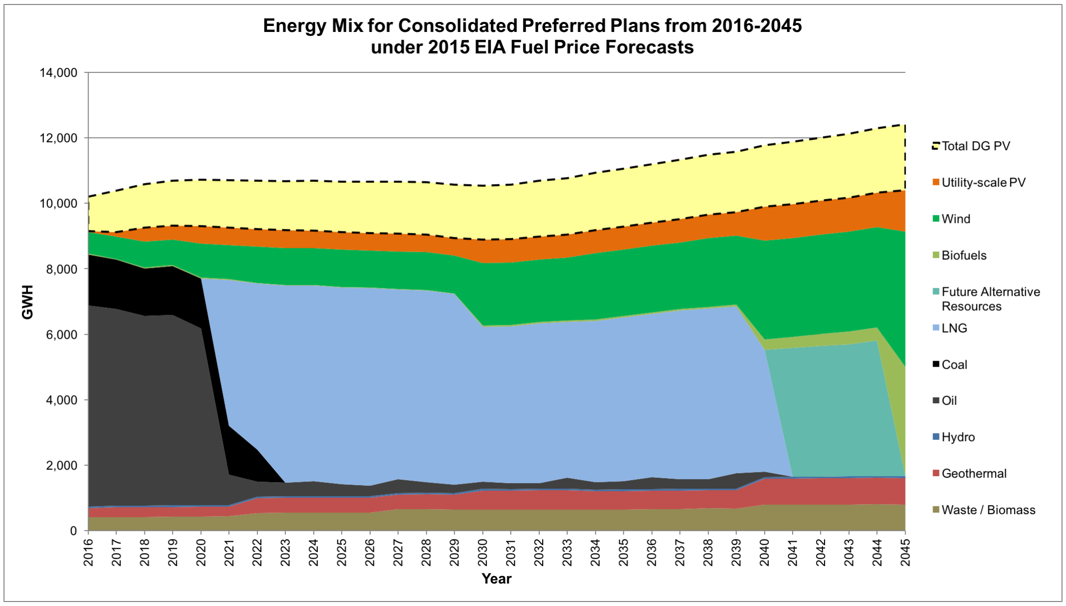


Figure 8-4. Energy Mix for Consolidated Preferred Plans from 2016-2045 under 2015 EIA Fuel Price Forecasts

Future Alternative Fuels: During the last intervening years in the transition to 100% renewable energy, potential fuels at this time could include biofuels, LNG, oil, other renewable options or a mix of options. Given rapidly evolving energy options and technology, the exact fuel mix is difficult to predict today.

The near-term action plan items will strategically grow the level of renewable energy on our systems to allow for the flexibility to transition to even greater levels on the course to 100% renewable. The longer-term perspective provided by the Preferred Plans will help guide actions and decisions in the near-term to achieve our commitment to 100% renewable energy.

Demand Response

Distributed Energy Resources (DER) is a major component to achieving the state's goal of a 100% RPS by 2045. The Companies fully support and promote next generation DER programs that can provide grid benefits that can be realized by all of Hawai'i. Following Commission Order No. 33258 on October 12, 2015 resolving Phase I issues in Docket No. 2014-0192, the net energy metering program was closed to new participants. Pursuant to Order No. 33258, two new DER programs, Customer Grid-Supply and Customer Self-Supply were launched.

In the meantime, the Companies have successfully met all of their commitments to clear the 2,749 customers within the queue of existing net energy metering (NEM) projects as described in the Companies' Plan to "Clear the Queue," filed on October 31, 2014.

In Phase II of Docket 2014-0192, the Companies will continue to collaborate with the customer and industry stakeholders, including solar contractors, inverter manufacturers, and external organizations such as NREL to develop innovative technical solutions and program policies that ensure fair and safe interconnection to the grid, while providing the same reliability that all customers have come to expect.

Building a "Smart Export" DER environment of the future that is fully integrated, able to contribute when needed, and supportive of the grid, will require visibility, controllability, and the extensive use of advanced inverters for all DER systems and programs.

As we increase our understanding of both the circuit and system limits for each island grid it is important that we establish annual Hosting Capacity limits as a methodology to manage future interconnections. This will allow us to plan, communicate, and coordinate the integration of DER in a way that benefits all customers. Integrating annual Hosting Capacity limits into an automated end-to-end tool that screens and processes DER applications will greatly facilitate interconnection and positively impact customer experience. This integration is expected to be completed in the 4th quarter of 2016.

DR Programs/DR Tariffs

The Interim DR Program Application was filed with the Commission on December 30, 2015 in Docket No. 2015-0412. The two major requests in the application are for approval of the Tariff Structure and the cost recovery methodology. A final DR Program Application will be filed after filing of this PSIP Update. The final DR Application will present the cost effective DR programs that will be pursued specific to each of the island based on the updated analyses. Hawaiian Electric is targeting initiation of the DR programs by early 2017, depending on the timing of Commission approval. The Companies will also investigate whether location-specific DR programs can be developed to mitigate circuit level issues to integrate DER resources.

One of the envisioned DR Programs, Real-Time Pricing, requires the approval of the Smart Grid project, and therefore is expected to start in 2020 in the unmerged scenario of the Smart Grid project but could start as early as 2018 in the merged Smart Grid scenario.

The Preferred Plans for each island includes DR in the early years consistent with the DR Programs/DR Tariffs contained in the Action Plan.

Demand Response Management System (DRMS)

The DRMS Application was filed with the Commission on December 30, 2015 in Docket No. 2015-0411. Currently, contract negotiations with the selected vendor, Omnetric, are in progress. We plan to file a signed contract with Omnetric at the Commission by mid-year 2016.

While awaiting Commission approval of the Companies' cost recovery proposal for the DRMS project, Hawaiian Electric will continue to develop integration requirements for the DRMS. The Hawaiian Electric team will also work with projects, such as Sustainable and Holistic Integration of Energy Storage and Solar PV (SHINES), to develop state-of-the-art capability that could potentially be incorporated directly into the DRMS if approved by the Commission. Hawaiian Electric is targeting initiation of the DRMS project by late 2016 to early 2017, depending on the timing of Commission approval.

The DRMS is required to enable the DR resources that are included in the Preferred Plans.

Time–of–Use (TOU) Rates

The Companies proposed revised residential TOU rates in the Distributed Energy Resources Docket No. 2014-0192 and they are before the Commission for consideration and approval. The Companies indicated in that docket that they plan to propose revised commercial TOU rate options as part of Phase 2 of the proceeding. The Companies noted that Phase 2 would offer an avenue for collaboration with other parties in the docket and allow for a better analysis of the appropriate price signals that would be beneficial to the grid while enhancing customer choices and giving consideration to the appropriate form of recovery of fixed generation, transmission, and distribution costs.

Community-Based Renewable Energy (CBRE)

A phased approach will help to implement the CBRE Program in a sustainable manner, in-line with the market demand, while respecting the technical limitations of the electric grid. The first phase ("Phase One") is envisioned to last two years commencing upon Commission approval. Findings from the Phase One will inform the planning process for Phase Two. The planning process for Phase Two of CBRE will begin 18 months after Commission approval of Phase One.

Below is a chart outlining by island, technology, and size of project, the capacity allocation for Phase One CBRE (Tier 1 projects are less than or equal to 250 kW_{AC}, Tier 2 projects are 250kW_{AC} to less than or equal to 1MW_{AC}, and Tier 3 projects are greater than 1MW_{AC}):

	Solar (MW_{AC})		Wind (MW_{AC})	
	Tier 1 and 2	Tier 3	Tier 1 and 2	Tier 3
O'ahu	5	10	0	10
Hawai'i Island	1	0	0	2
Maui	1	0	0	2
Moloka'i	0	0	0.5	0
Lana'i	0	0	0.5	0
Total	7	10	1	14
Phase 1 Total	32			

Table 8-1. CBRE Island Technology

Distributed Energy Storage

As the Companies increase the amount of renewable energy production, energy storage will play a role in distributing that energy throughout the day to coincide with demand, and to provide grid services such as fast-frequency response or contingency reserves. The Companies are supportive of energy storage as a customer option and have prepared the following guiding principles to assist in enacting policies that benefit all customers:

- Energy storage policies should promote or enable renewable energy production to help Hawai'i achieve the state's goal of 100% RPS by 2045.
- Energy storage policies should provide overall cost effective grid benefits to all customers, including those who do not choose to install batteries on their property.
- Should the state choose to enact policy to promote energy storage through investment tax credits (ITC) or rebates to customers who install energy storage, these customers should remain connected to the electric system for the life of the storage system to support the societal benefit for which these ITCs or rebates are intended i.e. integrating more cost-effective renewable energy that contributes to the state's renewable energy goals.

The Companies have a number of pilot projects that are evaluating various energy storage technologies that could potentially provide grid services. These pilot projects include, but are not limited to, partnerships with innovative start-ups such as Stem[19] and Shifted Energy[20]. Our findings from these pilot projects may help us develop additional distributed energy programs that leverage distributed energy storage resources.

---

[19] Stem is an energy storage provider that has deployed a pilot project aimed at demonstrating how distributed storage can help the utility affordably integrate more renewable energy onto the system.

[20] Hawaiian Electric is working with a company called Shifted Energy to deploy 499 grid interactive water heaters at the Kapolei Lofts development project (housing in Kapolei developed by Forest City) for the demand response program. See http://www.greentechmedia.com/articles/read/hawaii-to-test-smart-water-heaters-as-grid-resources.

Curtailment Policy Review

The Companies are researching new curtailment policies that will provide flexibility in contracting renewable resources and support the reliable operation of the grid as an alternative to the current practice of allocating curtailments in reverse chronological order. New contract terms will be included as part of RFPs for future resources and adopted as new power purchase agreements are negotiated.

Smart Grid

On March 31, 2016, the Companies filed an application for approval of the Smart Grid Foundation Project. Pending a favorable Commission decision, the Companies plan to implement the following from 2017-2021.

- Advanced Metering Infrastructure (AMI) across all islands that the Companies serve, which automates meter reading and provides a communication network to control service end points.
- Meter Data Management System to automate billing by 15–minute increments.
- Conservation Voltage Reduction which controls voltage from substations to service endpoints for enhanced power quality and conservation.
- Customer Facing Solution that provides customers with a seamless integrated mobile and web energy portal.
- Direct Load Control to replace existing 1-way load control switches on O'ahu with switches that have 2-way communication and control.
- Outage Management System expansion that improves reliability and customer outage information.
- Enterprise Service Bus for efficient data interchange.
- Enterprise Data Warehouse to promote data collection, sharing and analytics.
- As part of the smart grid project application, the Companies have filed an update to the Smart Grid Roadmap describing additional activities planned for the Smart Grid expansion, including leveraging the Advanced Metering Infrastructure for Distribution Automation (DA) and endpoint control.

Environmental Compliance

Mercury and Air Toxics Standards (MATS)

Hawaiian Electric's Waiau units 5 to 8 and Kahe units 1 to 6 will demonstrate compliance with MATS by meeting emission limits for filterable particulate matter (fPM) and fuel moisture content. Hawaiian Electric received a one-year extension of the MATS Rule compliance date to April 16, 2016. The compliance strategy must be in place by this date and initial compliance must be demonstrated within 180 days, or no later than October 13, 2016. Kahe and Waiau will each demonstrate compliance using a site-wide emissions average of all units to calculate a 30-day rolling average value that will be reported to the EPA. Results from periodic monitoring of stack emissions from the steam units at Kahe and Waiau will be used as input into the facility-wide emissions average calculation.

Hawaiian Electric has determined through extensive emissions testing that careful control of boiler operation and fuel specifications are sufficient to achieve compliance with the MATS 0.03 pound per MMBtu fPM emission standard when using 100% LSFO fuel in all units. Hawaiian Electric's fuel supplier has also certified that the fuel will satisfy the moisture limit.

Waiau units 3 and 4 have annual capacity factors of less than 8% and will be classified in the limited-use subcategory. These units will not be subject to MATS emissions standards, but must comply with work practice standards. Honolulu units 8 and 9 are currently deactivated. MATS requirements will not apply to them until they are reactivated.

The boilers operated by Maui Electric and Hawai'i Electric Light are not subject to MATS because they generate less than 25 MW.

National Ambient Air Quality Standards (NAAQS)

The NAAQS requirements may require reductions in SO2 emissions at Kahe and Waiau by the use of lower sulfur fuels. Compliance with the SO2 NAAQS requires that facilities demonstrate through either modeling or monitoring that offsite impacts are below the standard and will be in attainment with the standard. Hawaiian Electric plans to monitor ambient SO2 concentrations in the area of Kahe and Waiau for at least three years beginning no later than January 1, 2017 through December 31, 2019. Following the collection of ambient SO2 monitoring data, the EPA, by December 31, 2020, will issue its final attainment or nonattainment designation for Kahe and Waiau. If reductions in SO2 emissions at Kahe and Waiau are required, the Companies currently believe the worst-case scenario would be blending 40% LSFO with 60% ultra–low sulfur diesel no later than December 31, 2024 to achieve the December 31, 2025 attainment deadline.

Greenhouse Gases (GHG)

To meet new Hawai'i Department of Health (DOH) requirements that took effect in mid-2014, the Hawaiian Electric Companies submitted a GHG Emissions Reduction Plan (EmRP) to DOH on June 30, 2015. This EmRP commits the Hawaiian Electric Companies to reducing aggregate GHG emissions from their eleven (11) affected facilities by 16% from 2010 levels by January 1, 2020. That reduction will be accomplished by replacing fossil-fueled power generation with more power from renewable sources. Importantly, it will not require expensive emissions controls or fuel switches. Adherence to this PSIP will be enough to assure that the GHG reduction targets are met.

As part of a negotiated amendment to the Power Purchase Agreement (PPA Amendment No. 3) between AES Hawai'i and Hawaiian Electric, Hawaiian Electric has agreed to include the AES Hawai'i coal-fired power plant as a partner in the Companies' EmRP. Similarly, with the planned acquisition of the Hamakua Energy Partners (HEP) facility by Hawai'i Electric Light, the GHG emissions from the HEP facility will also be addressed in the Companies' EmRP. Both the AES PPA amendment and the HEP acquisition are subject to Commission approval, so the inclusion of these facilities in the Companies' EmRP is also subject to Commission approval. Hawaiian Electric is working closely with the DOH on the timing of the EmRP modifications to address these changes in the partnership.

The EPA's Clean Power Plan (CPP) rule was published on August 3, 2015 to govern emissions of GHG from existing steam electrical generating units (EGUs). The CPP did not establish GHG emissions limits for Hawai'i, but left that to be worked out later because the state's circumstances are so much different from the mainland. The U.S. Supreme Court on February 6, 2016 stayed the CPP pending further action by EPA and federal courts. The timing for establishing federal GHG emission reduction requirements that could affect the Companies' EGUs power plants is uncertain.

Clean Water Act / National Pollution Discharge Elimination System (NPDES)

2016 -2018: Renew Hawaiian Electric NPDES Permits

The NPDES permits for Honolulu, Waiau and Kahe all expire in 2017. Permit renewal applications must be submitted to the DOH at least six months prior to the expiration dates. The permit expiration dates and renewal application due dates are shown in the Table 8-2.

Facility	Permit Expiration Date	Application Due Date
Honolulu Plant	May 31, 2017	November 30, 2016
Waiau Plant	June 28, 2017	December 28, 2016
Kahe Plant	October 24, 2017	April 24, 2017

Table 8-2. Hawaiian Electric NPDES Permit Dates

Although the Honolulu Power Plant is currently deactivated, its NPDES is being renewed to allow the plant to be reactivated if necessary in the future.

Negotiate §316(b) compliance with DOH during renewal process (Hawaiian Electric only).

The NPDES permit renewal applications will include cooling water intake fish protection reports for each plant, as required by the Clean Water Act (CWA) Section 316(b). The fish protection reports will be submitted with the permit renewal applications. We plan to negotiate 316(b) best technology available (BTA) options with the DOH, and the outcome of negotiations could include a requirement for affected facilities to install fish protection technology on the cooling water intake systems within the next five years. The specific requirements and compliance dates will be determined during permit negotiations with the DOH.

Obtain new NPDES permits for Honolulu, Kahe and Waiau

New permits will include 316(b) requirements and are also likely to include additional water quality standards.

2019 – 2022

Possible installation of fish protection technology at Waiau and Kahe

If required, fish protection technology (e.g., fish friendly traveling screens, barrier nets, or closed cycle cooling) will be installed at Waiau and Kahe. The specific compliance dates will be determined during permit negotiations with the DOH.

Renew Maui Electric NPDES Permits

Maui Electric's NPDES permits for Ma'alaea and Kahului expire in December 2019 and May 2020, respectively. Permit renewal applications must be submitted at least six months prior to the expiration dates. The 316(b) requirements are not applicable to Maui Electric's facilities. The permit expiration dates and renewal application due dates are shown in Table 8-3.

Facility	Permit Expiration Date	Application Due Date
Ma'alaea	December 15, 2019	June 14, 2019
Kahului	May 13, 2020	November 13, 2019

Table 8-3. Maui Electric NPDES Permit Dates

Kahului Plant Retirement/NPDES Compliance Plan

The Kahului NPDES permit that was effective on June 1, 2015 contains a compliance schedule that includes cessation of operations at the Kahului Plant no later than November 30, 2024. Maui Electric's current plans include the scheduled retirement of the Kahului Plant on December 31, 2022.

Advanced Inverter Functionality

The Hawaiian Electric Companies are working with leading equipment manufacturers from the Advanced Inverter Technical Working Group (AITWG) and the U.S. Department of Energy's National Renewable Energy Laboratory (NREL) to test selected capabilities of advanced inverter functionality that would accelerate the implementation of solar PV and distributed energy storage systems (collectively referred to as DER Systems) that can provide grid-supportive benefits to the Companies' grids. On December 15, 2015, the Hawaiian Electric Companies filed a proposed Advanced Inverter Test Plan and have since been aggressively pursuing the execution of the Commission's directives to test advanced inverters.[21] The results of this initial phase of testing are expected to be available by the beginning of the third-quarter and will be used by the Companies to propose the activation of new advanced inverter functions.

The near-term goal for the Advanced Inverter Test Team, which comprises engineers and research scientists from the inverter manufacturing industry, NREL and the Hawaiian Electric Companies, is to implement the highest priority Advanced Inverter functions that can be implemented as soon as the national certification standards from Underwriter Laboratories, Inc. (UL) are issued. In Hawaiʻi, as well as in California, the utilities are requiring that advanced inverters be capable of meeting UL 1741 Supplement A standards within 12-months after UL's final publication of the new standard, now expected to be issued in the May-June 2016 timeframe.

The Hawaiian Electric Companies are proactively working with the inverter manufacturers to test advanced inverter functions ahead of the formal adoption of UL 1741 Supplement A so that the manufacturing industry can implement DER Systems that better support Hawaiʻi's new Customer Self-Supply, Customer Grid-Supply, and other DER programs.

The Companies are currently working with the Advanced Inverter Test Team to collaboratively develop an implementation plan, including the timeline for activation of voltage regulation advanced inverter functions. The intent of the Hawaiian Electric Companies' advanced inverter implementation plan will be to require the mandatory activation of the selected voltage regulation functions sooner than required on the mainland. The staged implementation of multiple advanced inverter voltage regulation functions to actively manage the impact of high-level of PV penetration is needed in order for Hawaiʻi to continue to aggressively pursue the interconnection of DER Systems and to mitigate the negative impacts of existing PV-Systems ("Legacy PV") that do not provide grid support capabilities.

[21] Docket No. 2014-0192, Decision and Order No. 33258, Compliance Filing – Advanced Inverter Test Plan.

As noted in the Companies' February 11, 2016 response to the Commission's supplemental information request regarding the Technical Conference on the Companies' Advanced Inverter Test Plan held January 28, 2016, the Companies' strategy for implementing advanced inverters is a multi-facet approach that extends beyond the hardware testing of advanced inverter equipment. The Companies are also working with other industry partners to form a consortium to fund a broader research and development program to address the system-level functions and capabilities of DER Systems. The Hawaiian Electric Companies are members of the Grid Modernization Lab Call (GMLC) Hawaiʻi Regional Partnership, which recently received a $1 million grant from the U.S. Department of Energy to address the research, development and testing of grid frequency support advanced inverter functions.

This GMLC Project 15 – Grid Frequency Support for Distributed Inverter-Based Resources in Hawaiʻi – will comprehensively evaluate the merits of various Fast Frequency Service control methods, including the Frequency-Watt Advanced Inverter function. This comprehensive approach for addressing the bulk-power system level issues, with the ability to leverage the fast response capabilities of power electronics from PV inverters and battery energy storage systems, requires innovation to develop advanced inverter capabilities that are not yet adopted on a widespread basis across the industry.

The GMLC Project 15 will take a holistic approach to go beyond the scope of what is currently being pursed in the Advanced Inverter Test Plan by developing new bulk-power system models, time domain modeling, simulation and controls development, and field testing and demonstration that is not within the limited budget and schedule afforded to the Advanced Inverter Test Plan. When attempting to address the resiliency of the grid with high levels of non-firm, non-dispatchable, DER Systems, a more sophisticated and comprehensive approach is needed. The Companies recognize the need to pursue this parallel track of research, development and demonstration and will be pursuing the Advanced Inverter testing of the selected system-level advanced inverter functions to complement the GMLC Project 15 statement of work

Circuit-Level Improvements on All Islands

The growth levels of DG-PV studied in this PSIP will require distribution circuit level improvements to further integrate these systems onto the grid. At the present time, more than 46%of the circuits on Oʻahu have DG-PV penetration levels that exceed 100% of the daytime minimum load, and on Maui 38% of the circuits exceed 100% of the daytime minimum load. To support the continued integration of DG-PV, even with the continued development of functionality from advanced inverters, the Companies will need to make improvements to its distribution circuits to accommodate the changes to the load flow on circuits due to Customer Self Supply, Customer Grid Supply, grandfathered NEM, SIA, Community Based Renewable Energy, and any future DER programs.

In the near-term, the circuit level improvements will include the following:

- Overhead and underground conductor upgrades to address power flow conditions where energy may overload conductors past 100% of their thermal rating. This can be resolved by upgrading the conductor size to create additional capacity.
- Voltage regulator installations or other voltage adjusting or correcting devices to address voltage quality issues, where analyses show that neighborhoods or sections of circuits may experience high and/or low voltage caused by the reverse power flow generated from PV systems.
- Distribution (service or secondary) transformer replacements or transformer modification when the transformers are overloaded if the aggregate PV connected to a transformer divided by the transformer rating exceeds 200%. In other cases, secondary high voltage will necessitate an upgrade of secondary conductors in addition to the replacement of the distribution transformer.
- Reconfiguring circuits to resolve the loss of operational flexibility when it has been determined that the PV or DER penetration exceeds the operational limit of the circuit.
- Substation upgrades if operational flexibility is lost where the reverse power generated by DG-PV systems loads the substation transformer to more than 50% of its highest transformer rating, or with advanced inverter control of DG-PV resources reverse power flow loads the substation transformer to more than 100% of its highest transformer rating.
- Distributed Battery Energy Storage Systems will be deployed behind or in front of the meter to relieve distribution system congestion and maintain operational flexibility. Strategically located storage can avoid conductor overloads, while simultaneously maintaining operational flexibility at the circuit or system level.
- VAR compensation devices will be considered and used when available and found to be cost effective in mitigating voltage issues. These devices leverage modern power electronics to provide fast acting reactive power to reduce voltage fluctuations, and regulate circuit voltages to avoid the high voltage effects of high DG-PV penetration. These devices come in many different forms: advanced inverters, low voltage static VAR compensators, fast switching capacitors, and inline power regulators. These types of devices, located on the secondary part of the distribution system, can potentially provide more cost-effective and efficient regulation to mitigate voltage quality impacts and displace traditional, slower acting equipment such as capacitor banks and voltage regulators. This distributed voltage regulation technique represents a departure from traditional industry methods of voltage regulation. While we have started to demonstrate and assess these innovative devices, the technology is a

relatively recent development and has yet to achieve widespread adoption across the industry.

Controlling PV / Advanced Inverters

The Companies' ability to control customer-sited DG-PV with advanced inverter capabilities will depend on the implementation of foundational infrastructure such as an advanced distribution management system, a distributed energy resource management system, and advanced metering infrastructure. The Companies recently revised interconnection Rule 14H to include functional requirements for remote configurability and controllability features however no single industry standard or protocol has been identified for implementation).

The Companies' plan to implement Advanced Inverter requirements for remote configurability and controllability will depend in most part on the hardware and software standards that are under development in California's Smart Inverter Working Group Phase 2 proceedings. There are several emerging open protocol communications standards that show great promise for the DER industry stakeholders to align new product capabilities that will allow the utilities to interconnect through non-proprietary control systems. In the interim, the Companies plan to request Commission approval to activate other autonomous Advanced Inverter functions that do not depend on proprietary control systems to implement remote communications and controls as the newer open standards are further developed.

In addition, policies and programs, including pricing programs that stipulate the parameters within which control of a distributed energy resource may be administered, will need to be in place. These policies and programs are expected to be captured jointly between current DR program filings and the anticipated efforts within the DER Phase II proceedings.

Ideally, to lower the cost of communications functionality, the Companies will explore the use of a single, secure Company-owned communications network to exercise DER control along with other grid modernization devices, DA devices, and AMI. However, the Companies' Advanced Meter Infrastructure is not currently expected to be deployed until after 2018. Based on discussions with aggregators and providers of distributed energy resources, the Companies expect that these aggregators will provide near-term communications sufficient for the preliminary stage of DG control and the associated feedback loop.

Currently, only a limited number of inverter manufacturers are able to provide aggregation services for their legacy PV inverters and many do not provide any form of communications hardware or software capability at all. All of the inverter manufacturers that provide communications to their legacy PV inverters today are reliant on the public internet services provided by their customers' internet service providers to maintain the reliable connection to perform remote communications services for software system upgrades and activation of new functionality. There may be cybersecurity issues associated with internet service platforms that will need to be addressed. The ability of the customer to disconnect their internet service to the DER Systems has hampered the ability of the Companies to remotely configure, upgrade and active new functions in the existing fleet of legacy inverters. These are the real-life examples that inverter manufacturers and the Companies will have to jointly solve in order to achieve the stringent communications infrastructure requirements for "always-on" connectivity that will ensure the necessary high-level reliability control functions that are envisioned by the Companies' DER systems operational model in the future.

Renewable Acquisition

The Preferred Plans for each island identify various types and sizes of renewable energy resources that should be added at various times in order to achieve long-term objectives, including reaching 100% renewable energy by 2045. The Hawaiian Electric Companies plan to procure these new renewable resources through a competitive procurement process to ensure the best value for the customers. There may be exceptions as allowed in the Commission's Competitive Bidding Framework that will need to be evaluated and justified.

From time to time, the Companies may receive unsolicited proposals for renewable energy projects outside of a competitive procurement cycle. In such cases, the Companies will review the merits of those proposals in accordance with established rules and practices.[22]

Legacy PV

Much work has already been done to improve the performance of existing PV systems. For example, in December 2014, Enphase remotely reprogrammed many of the existing Enphase inverters to upgrade the inverters' ability to ride through voltage and frequency upset conditions to prevent disconnections that could exacerbate the effects of system disturbances. This was done no cost to the Companies or to their customers.

A substantial number of existing inverters cannot be remotely reprogrammed. Reprogramming these inverters would require that a person visit each site to either upgrade the inverter software or replace the inverter. Performing this work on all remaining legacy inverters would result in a very high cost. Rather than replacing

[22] For example, see Docket No. 2015-0224 (PPA with Ku'ia Solar, LLC) and 2015-0225 (PPA with South Maui Renewable Resources LLC) for the evaluation methodologies used.

inverters or reprogramming them on-site at a high cost, the Companies' plan is to upgrade the distribution circuits and equipment on the system to account for the potential effects of legacy PV remaining in place for the next 15 to 20 years.

LNG Procurement

Given the cost-effectiveness of LNG, the Companies plan to submit an application for approval of an LNG fuel supply agreement and General Order No. 7 requests for LNG-related dual fuel unit conversions to receive, store, and regasify LNG and utilize natural gas at the designated generation facilities and procurement of International Standard Organization intermodal cryogenic containers for the transport of the LNG, which will enable the Companies to procure a lower cost and cleaner fuel.

As noted earlier, LNG is included in plans under a scenario where the Hawaiian Electric Companies merge with NextEra Energy. In the event the merger is not approved by the Commission, the Companies will explore pursuing LNG under a different contract.

Research, Development and Demonstration Activities

The Hawaiian Electric Companies are engaged in numerous RD&D and pilot projects, including technology testing, to address numerous technical needs, operational applications, and customer engagement options that will help facilitate the increasing integration of renewable energy. These RD&D and pilot projects include those in the area of Grid Management (voltage and frequency), Visualization and Operation Tool Development, Distributed Energy Resources (DER) functionality, and control, Customer Solutions and Options, Demand Response, and Electrification of Transportation. The Hawaiian Electric Companies will continue its RD&D efforts to find innovative ways to integrate more renewable energy.

Interisland Cable

Analysis of the economic attractiveness of an interisland cable from O'ahu to one or more of the neighbor islands will continue. Analyses could not be completed in time for this filing. Please see Chapter 9 for the next steps for this analysis.

O'AHU ACTION PLAN

Utility-Scale Energy Storage for Contingency Reserve

Recognizing the need to secure the grid with contingency reserves that meet the requirements of our changing power system, Hawaiian Electric issued a technology neutral energy storage system request for proposal in April 2014 that would provide 60-200 MW of power for a duration of 30 minutes. The request for proposal intended to procure an energy storage system(s) to meet the following technical objectives:

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

Hawaiian Electric received over sixty (60) proposals that included one or more of the following technologies: battery energy storage, demand side management, flywheel energy storage, flywheel-battery hybrid storage systems, pumped storage hydro, pumped thermal with compressed air storage, and ice storage combined with demand side management. After a thorough evaluation of all proposals, battery energy storage emerged as the preferred technology to suit the Company's requirements.

The 2014 PSIP identified a 200 MW contingency battery energy storage system. We expect to reduce the previous capital requirement by seizing upon lower resource costs and by optimizing the size of the battery to the 90 MW size range after more detailed sizing analyses are conducted. To meet the full contingency reserve requirement, the utility-scale battery will be supplemented by demand response programs.

As part of the updated sizing analyses, Hawaiian Electric will identify Fast Frequency Response 1 (FFR1)[23], FFR2[24], and Primary Frequency Response (PFR) requirements. FFR1 can be satisfied by utility scale energy storage, curtailed energy from central station PV, or curtailed energy from wind plants. FFR2 can be satisfied by demand response

[23] Technologies that are responsive within 12 cycles.
[24] Technologies that are responsive within 30 cycles.

programs. The acquisition of technically qualified FFR resources can further reduce the utility-scale size requirement.

The optimized battery size will make this investment resistant to changing contingency requirements. The battery energy storage system will help to meet near-term contingency requirements (a trip of AES and legacy PV), remain flexible to meet future contingency requirements as in the case of the Preferred Plan (e.g., the trip of a Kahe Combined Cycle Unit, or a trip of a cable that interconnects offshore wind), and maximize the value of this investment by also functioning as a frequency regulating resource.

The Company intends to submit an application for approval to commit funds towards the procurement of the final optimally sized contingency battery energy storage system later this year.

System-Level Improvements

Fossil Generation Retirement Plan

Hawaiian Electric's Preferred Plans identify generating units that are planned to be deactivated or decommissioned. Its Preferred Plan for Theme 2 (merged scenario) shows that Kahe Units 1 to 4 and Waiau Units 3 to 8 will be deactivated or decommissioned over time as the generating system is modernized. The final Theme 3 (no LNG scenario) shows that Waiau Unit 3 to 6 and Kahe Unit 6 will be deactivated over time as the generating system is modernized.

Generation Flexibility Plan / Must-Run Generation Reduction Plan

Hawaiian Electric is improving the operational flexibility of its steam units to help facilitate the integration of variable renewable generation. Much has been accomplished but more will be done.

- Modify procedures and test operations to achieve minimum loads of 5 MW-gross (near zero net-to-system).
- Review and improve procedures to facilitate cycling of units that previously have not typically been cycled, while minimizing deleterious long-term effects on the units.
- Develop processes to enable units to ramp at higher ramp rates.

Testing has already been conducted on most of the 90 MW reheat units and three of the six units are already available for low load operation. All of the 90 MW reheat units will be ready for low load operation by the third quarter of 2016.

It has already become necessary to operate at very low outputs on the steam units. On multiple occasions one or more units has been dispatched to the new, lower outputs.

The ability of the steam units to achieve lower operating levels is reflected in the PSIP modeling effort.

It is expected that ramp rate improvements will be completed by the third quarter of 2016. Ramp rate improvements will result from improved control system logic. Hawaiian Electric control engineers and its controls consultants have identified effective solutions for improving ramp rates. Testing is in progress.

A number of projects have been identified to help improve and support low load operation and/or cycling of the steam units.

- Steam Atomization Projects: K1-4 and W7-8 have or will have their mechanical atomization systems replaced with steam atomization. The main purpose of these projects was for improvements in emissions associated with MATS compliance. However, a secondary benefit is significantly improved turndown capability on the burners resulting in improved flexible operations and better startup processes.
- Pilot variable speed drives on K1 Boiler Feed Pumps: Project supports more efficient low load and cycling operations. Project is being evaluated and benefits to cost are being considered.
- Automated Air Ejector/Gland Seal Steam: This is currently a manual process that does not change during normal operation. During low load operation, this requires moderate operator attention. Projects will improve the reliability of low load operation.
- Turbine Hood Spray: Hood spray keeps the low pressure turbine hood at proper temperatures. At low load and during startup, there is risk of overheating the turbine hood. Units that cycle and operate at low load should have turbine hood sprays for safe operations.
- Other Projects such as turbine bypass systems and cross feeding systems will be considered based on the cycling and retirement plans. These projects are not necessary to begin cycling but will provide increased reliability if the units will cycle often and for many years.

Generation Commitment and Economic Dispatch

Hawaiian Electric is in the process of determining the appropriate timeframe to transition to new operating reserve policies, such as the General Electric / Hawai'i Natural Energy Institute regulating reserve formula for generation commitment purposes.[25] It is anticipated that as significant levels of utility-scale and/or distributed variable renewable generation are added to the O'ahu grid, operating with regulating reserves as

[25] See page 4-21 of the Companies Power Supply Improvement Plan Update Interim Status Report for a description of the GE-HNEI formula.

an explicit component of the system reserve requirements will be needed to maintain system stability and reliability.

Hawaiian Electric also presently requires frequency response controls on any new utility-scale renewable generation and will likely require such controls on future distributed generation, when such capabilities become available. Frequency response controls will allow these future renewable resources to supply downward reserves (for overfrequency mitigation) in lieu of carrying such reserves on conventional generators and storage devices. This will allow the conventional generation to operate at lower minimum levels and the O'ahu grid to host higher levels of renewable generation sooner and/or reduce the amount of energy storage needed.

Dependable demand response resources with the proper operating characteristics as discussed in the Companies' Integrated demand response Portfolio Plan (IDRPP)[26] also have the potential to reduce the reserve requirements that has to be carried by the system's online generation resources and storage devices.

Hawaiian Electric continues to refine and improve the approach to determining its reserve requirements. In particular, Hawaiian Electric is currently engaged with the Electric Power Research Institute (EPRI) in a study exploring the use of stochastic methods for determining operating reserve requirements. Stochastic methods with modern forecast techniques could help to optimize the regulating reserve requirements and potentially, also optimize the total reserve requirements. A final report is anticipated to be completed in December 2016.

Within the constraints of meeting the system reserve requirements and other operating consideration, and fulfilling the regulatory and contractual obligations, Hawaiian Electric will continue to economically commit and dispatch the dispatchable generation.

Renewable Acquisition

Replacement of Waiver Projects

Hawaiian Electric is reviewing all of its options and is considering pursuing a transparent and competitive effort to procure resources that may provide viable alternatives to replace the terminated waiver project PPAs, to provide similar benefits to its customers at the earliest timeframe possible. Hawaiian Electric has been considering various options for a competitive procurement process in compliance with the Commission's Framework for Competitive Bidding.

[26] See the Companies filings, dated September 23, 2015 and November 6, 2015, in Docket No. 2007-0341.

Offshore Wind

Hawaiian Electric is aware of two unsolicited offshore wind energy lease requests received by the US Department of the Interior's Bureau of Ocean Energy Management (BOEM). The proposed projects are approximately 400 MW each in size and include plans for floating offshore wind turbines with undersea cables to various points on O'ahu. Hawaiian Electric will monitor the BOEM lease process for these projects and any other offshore wind project development activities that occur, as Hawaiian Electric will openly consider all energy technologies in order to meet Hawai'i's RPS requirements.

Generation Modernization

Hawaiian Electric plans to install, own and operate the following new and replacement generation assets: a 3x1 combined cycle unit at the Kahe generating station (only under a merged scenario); a reciprocating engine station at Marine Corps Base Hawai'i (both merged and unmerged scenarios); and a reciprocating engine station at Joint Base Pearl Harbor Hickam or a power barge at the Waiau Generating Station (both merged and unmerged scenarios). Approval from the Commission for each of these options is envisioned to be completed via separate competitive bidding waiver requests and General Order No. 7 applications.

As noted earlier, the 3x1 combined cycle unit is part of Theme 2, where the Hawaiian Electric Companies are merged with NextEra Energy. In the event the merger is not approved by the Commission, Hawaiian Electric does not plan to pursue the installation of the 3x1 combined cycle unit.

Underfrequency Load Shed Scheme

Under frequency load shed (UFLS) schemes are designed to stabilize system frequency for severe contingency events and ultimately prevent a system collapse for a cascading contingency. The UFLS scheme is used as a last resort safety net. The schemes are coordinated such that increasing capacities of load are shed in blocks depending on the severity of the event. Typically, the initial blocks (e.g., UFLS blocks 1 – 3) are shed at the 12 kV distribution circuit level to target non-critical residential loads while Blocks 4 & 5 are at the sub-transmission level to shed a large capacity of load to prevent system collapse. Distributed PV will reduce the UFLS capacities of Blocks 1-3 during the day while demand response could reduce UFLS capacities of all blocks at any given hour. Coordination of demand response programs with UFLS will be challenging because over shedding can be more problematic than under shedding. Hawaiian Electric will be conducting a long term UFLS study to specify how its current UFLS scheme should be redesigned to accommodate the changes to the system due to DER resources, DR programs, and projects to automate the distribution system. This study is expected to be completed in mid-2017.

On O'ahu, we have already seen a deterioration of load during the day that affects the current load shed scheme due to DG–PV on our circuits. In 2016, we will be revising the UFLS scheme by rearranging and adding circuits that are part of the UFLS scheme to replace the approximately 10 MW of load lost during the day from Blocks 1 and 2.

MAUI ACTION PLAN

Utility-Scale Energy Storage

The Company will complete a BESS sizing study by the end of 2016 to support submittal of an application for approval to expend funds for a BESS system that will provide Fast Frequency Reserves 1 to make up any shortfall in Fast Frequency Reserves or Primary Frequency Reserves that demand response programs cannot provide to meet the system security requirements identified in the PSIP and subsequent system security studies. The size of this resource is expected to be in the 3 MW to 11 MW size range, a significant reduction in size from the 60 MW BESS that was contemplated in the 2014 PSIP. Further analysis is needed to determine the optimal size needed. The BESS will supplement DR-provided Fast Frequency Response 2 resources to arrest frequency decay caused by events such as the sudden loss of a large generating unit. The Company will conduct an RFP for development of the BESS.

System-Level Improvements

Fossil Generation Retirement Plan

Maui Electric plans to retire Kahului Power Plant (KPP) in 2022 to comply with stringent NPDES requirements. A reserve capacity shortfall of at least 40 MW will result from the retirement of KPP if no new firm capacity is added. In addition, as previously described in Maui Electric's 2014 PSIP, not only does KPP supply power to meet demand, it also provides voltage support for the central Maui area 23 kV system. Upgrades to the Central Maui transmission line must be in place before KPP is retired.

Non–transmission alternatives were considered as options to the transmission upgrades. Options such as utilization of internal combustion engine distributed generation (ICE DG), PV, BESS, DR, synchronous condensers, and capacitor banks were evaluated as options to address the transmission line need.

Additionally, due to the anticipated 40 MW reserve capacity shortfall following the retirement of KPP, Maui Electric does not anticipate retiring any additional generating assets over the planning period of this PSIP. As variations in load occur over the years, units may be deactivated and reactivated, as needed to serve the capacity need.

Over the long term and in future PSIP updates, the need for conventional generation to serve as backup to 100% renewable energy generation needs to be assessed.

Generation Flexibility Plan

Maui Electric has implemented many changes in our generation fleet to increase flexibility and renewable acceptance. These have previously been described in our System Improvement and Curtailment Reduction Plan (SICRP) and subsequent annual updates and included:

- Implementation of the Maui Operational Measures
- Reduction in the number of base loaded units
- Deactivation of KPP units 1 and 2
- Lowering of the minimums on KPP units 3 and 4
- Study and implementation of new regulating reserve requirements
- Automation of curtailment though our Automatic Generation Control (AGC) system

In addition to the above actions that were already completed, Maui Electric will seek Commission approval as necessary to make modifications to our Dual Train Combined Cycle #1 (DTCC1) that will allow operation at lower minimum loads. Going forward, Maui Electric will seek to procure replacement generation for KPP that will have flexible attributes more likely to allow increased renewable resource penetration over a wide variety of potential futures.

Must-Run Generation Reduction Plan

The major actions summarized above to reduce the online megawatts associated with must-run generation and described in the SICRP are listed in more detail below.

The PSIP modeling assumed no fossil-fueled must-run units on Maui after 2022.

Task	Description	Current Target Implementation Date	Actual Implementation Date	Current Status
1	HSIS[27] Regulating Reserve Policy Implementation	10/16/13	10/16/13	Completed
2	K1and K2 Deactivation	2/1/14	2/1/14	Completed
3	DTCC2 Operational Changes – Simple Cycle Operation Enabled	5/1/14	5/24/14	Completed
4	DTCC1 Low Load Modifications – File Capital Project Application with Commission	1/1/2017	NA	In Progress

Table 8-4. SICRP Milestone Metrics Status Update

Additionally, after the retirement of KPP in 2022, it is anticipated that fossil-fueled replacement generation will not be base loaded, thereby further reducing must-run generation.

Generation Commitment and Economic Dispatch

Our current unit commitment and dispatch decisions are based upon wind resource availability, maintenance schedules, costs, system security, and generator operating characteristics which determine contribution to security and adequacy of supply, as constrained by contractual requirements. The system, which utilizes an Automatic Generation Control (AGC) system to improve efficiency in managing firm and variable renewable resources, is already designed to accept variable renewable resources as a priority. The System Generation Operator uses information from the Energy Management System and AGC, operational plans, resource forecasts, planning studies, and relative resource costs to facilitate secure and cost-effective operation of the power system. Throughout the day, the system regulating reserves are monitored for quick response to system load changes. The amount of online reserves carried is currently based on the Hawaiʻi Solar Integration Study (HSIS) reserve policy as described in the SICRP.

To build upon the steps that were taken to prepare the system to accommodate more renewable resources, Maui Electric commits to the following actions:

- Continue Modernizing our Generation Fleet – Maui Electric will continue modernizing our generation fleet to minimize base loaded generation so that more renewable energy can be accommodated on our system. Maui Electric will seek Commission approval as necessary to make modifications to our Dual Train

27 Hawaiʻi Solar Integration Study.

Combined Cycle units to allow operation at lower minimum loads to reduce base loaded generation and allow the system to utilize more renewable energy.

- Further evaluation of Wind, Solar, and Load Forecasts into Dispatch – Maui Electric will continue to evaluate the process of incorporating wind, solar, and load forecasts into our generation commitment and economic dispatch process and will continue to explore improvement opportunities. The Hawaiian Electric Companies are currently working with AWS Truepower to help us develop forecasting tools that can be integrated with our EMS. As we implement our action plan, we will continue to refine and adapt our process to reflect changes in daily dispatch and commitment requirements from new resources, changes in operational modes of existing resources, and changes in demand and distributed generation.
- Further Evaluation of Regulating Reserve Requirements – With the current renewable resources on the system the HSIS assumptions are presently at their study limits and, as such, new regulating reserve criteria may need to be studied.
- Maui Electric will continue to refine and improve the approach to determining its reserve requirements. As stated above, Hawaiian Electric is currently engaged with EPRI in a study exploring the use of stochastic methods for determining operating reserve requirements. Based on the study results, Maui Electric may adopt similar reserve requirements
- Using Curtailed Energy for Reserve – Maui Electric is exploring whether curtailed energy can serve as regulating reserve in order to further minimize our thermal generation. The curtailment and un-curtailment of power from as-available generation resources will allow these resources to act in the same manner as conventional thermal units and facilitate the integration of other generating assets. If curtailed energy can be used as regulating reserve, it would potentially reduce the minimum thermal generating levels, allowing the system to accept additional generation from as-available renewable resources.
- Integrating Demand Response Resources into Operations – The proposed DR portfolio is focused on technology agnostic solutions to provide system reliability. When DR resources are obtained, we will work to safely integrate DR resources into the operations on each island, where available, to contribute to system reliability.

Transmission and Distribution System Upgrades

The Central Maui Transmission Line Upgrade Project is being driven by the retirement of the Kahului Power Plant.

The Central Maui Transmission Line Upgrade Project will consist of the following:

- Maʻalaea – Puʻunene Substation reconductoring
- Maʻalaea to Waiʻinu Substation 69 kV reconductoring

- Wai‘inu to Kanaha 23 kV to 69 kV upgrade

Non–transmission alternatives were considered as options to the transmission upgrades. Options such as utilization of ICE DG, PV, BESS, DR synchronous condensers, and capacitor banks were evaluated as options to address the transmission line need.

Additionally, transmission line upgrades in South Maui are required to accommodate the projected growth in the South Maui area as well as to maintain the required voltage should something interfere with the transmission of energy from the Ma‘alaea Power Plant. A portfolio of non-transmission alternatives was considered as an option to offset the need for this transmission line work. Being responsive to community feedback opposing the transmission line upgrades, Maui Electric plans to solicit proposals for generation in the South Maui area in conjunction with a competitive procurement process to replace the generating capacity of KPP by 2022.

Maui Electric will explore opportunities for aggregated DR to provide location-specific benefits, particularly in the case of non-transmission alternatives. A cornerstone of the DR program portfolio is the effective aggregation of DR resources. All of the proposed DR services utilize various DER technologies to achieve this aggregation philosophy. Furthermore, the DERMS that will be sued to deliver the DR services through the intelligent management and optimization of groups of DERs has been specified to allow for the attribution, selection and dispatch of these resources across various zones. These zones map to the physical topography of the various islands’ systems and span from the system level at the highest level down to the individual circuit at the lowest level. As such, the current architecture and system design of the DR portfolio implementation allows for targeted deployment of DERs, which is suitable and appropriate as a tool for helping to address distribution or transmission level constraints such as those being considered by non-transmission alternatives in South Maui.

Replacement Capacity in 2022

Maui Electric is actively working to procure additional firm dispatchable capacity consistent with the PSIP for the island of Maui utilizing the Commission’s Framework for Competitive Bidding. Additional generation capacity is needed on the island of Maui to address anticipated retirement of the generating units at KPP at the end 2022, load growth, constrained South Maui transmission capability, and Hawaiian Commercial & Sugar (HC&S) ceasing operations.

Underfrequency Load Shed Scheme

In 2016, Maui Electric will be conducting an UFLS study to verify the performance of the current system under typical underfrequency events and to propose mitigation measures in the event that the current system performance does not meet planning and operating criteria. Due to the increasing amount of renewable generation being added to the Maui Electric system, the dynamic performance of Maui's current system under generation loss contingencies has changed. These changes could potentially impact the reliability of the Maui system. Based on the results of the study, changes to the Maui underfrequency load shedding scheme may be required.

MOLOKA'I ACTION PLAN

Energy Storage

Distributed Energy Storage

To address the near-term challenges resulting from the high level of DG–PV currently interconnected and waiting to interconnect to the Molokaʻi grid, the minimal impact system is a viable option. A minimal impact system would utilize the energy generated by the PV system solely to charge a storage system during the PV producing hours. The energy stored in the battery would be used to meet the customers nighttime energy needs. Maui Electric will offer customers the option to interconnect minimal impact systems subject to Commission approval.

Utility-Scale Energy Storage

An Altairnano/HNEI 2MW/333KWh Lithium-Ion BESS will be installed second quarter 2016. This BESS is a research project with the Companies partnering with Hawaiʻi Natural Energy Institute to determine applications for batteries in high solar PV penetration scenarios.

Maui Electric is in discussions with Molokaʻi Island Energy (MIE) for a large scale PV and energy storage project. Maui Electric will continue discussion with MIE and will perform more detailed analyses based on the specific parameters proposed.

Maui Electric submitted a High Energy Cost Grant application to the USDA, Rural Utilities Service, in December 2015 to install a proposed utility-owned 100 kW photovoltaic (PV) system with a 500 kW/2 MWh battery energy storage system. To avoid contributing to the excess energy situation on Molokaʻi, the PV system will not export energy to the grid directly. The PV energy would charge the batteries and only the batteries would be connected to the grid and provide energy at peak times or as needed.

System-Level Improvements

Fossil Generation Retirement Plan

Maui Electric does not anticipate retiring any Molokaʻi generating assets over the planning period of this PSIP. As variations in load occur over the years, units may be deactivated (and reactivated) as needed.

Generation Flexibility Plan

Molokaʻi has a centralized generating station with nine (9) diesel internal combustion units and one (1) diesel combustion turbine with capacity to generate 12.0 MW (gross) of power. Maui Electric applied for and received approval from the Department of Health (DOH) for modifications to the air permit that would allow lower minimum operating levels on the base loaded units to accommodate the addition of more renewables to the system. Additionally, generator control upgrades are planned to enable remote monitoring and operation of the generating units.

Must-Run Generation Reduction Plan

Maui Electric currently runs with a minimum number of base loaded units on Molokaʻi – typically two. Maui Electric applied for and received approval from the DOH for modifications to the Palaʻau power plant's air permit that allow lower minimum operating levels on the base loaded units.

Generation Commitment and Economic Dispatch

Maui Electric currently operates with two base loaded units on Molokaʻi because this is the lowest number of base loaded units that satisfy our single contingency criteria. When additional units are needed, they are committed in the most economical order given operational constraints. The Molokaʻi system does not have AGC and therefore the demand for electricity is shared equally between the online units in an isochronous mode of operation.

E-Gear Energy Management Control (EMC) and Storage Technology Pilot Project

In partnership with E-Gear LLC, the Hawaiian Electric Companies will launch a pilot program designed to allow more customers to interconnect rooftop PV systems on Molokaʻi.

E-Gear will install their specialized EMC and storage technology, which will be paid for by the utility, alongside 10 existing rooftop PV systems that have been waiting to be connected to the grid. This equipment can be monitored and controlled by utility system operators, potentially improving the interaction of rooftop PV systems with the grid and reducing the chance these systems will undermine reliable service and power quality for all Molokaʻi customers. The Hawaiian Electric Companies will evaluate the performance of these systems and determine whether similar systems can be used to integrate more solar power in areas with high concentrations of rooftop PV systems.

E-Gear is currently evaluating their EMC-equipped PV systems—designed to minimize the grid impact of rooftop PV systems on a small, highly saturated grid like Molokaʻi's—in partnership with the EPRI.

Renewable Acquisition

Molokaʻi Island Energy Proposal

Maui Electric is actively investigating and considering adoption of an alternative curtailment mechanism and intends to submit its report to the Commission on May 18, 2016 as required by the Commission's Decisions and Orders in Docket Nos. 2015-0224 and 2015-0225.[28] Since Maui Electric anticipates that the results of the investigation will fundamentally modify the structure of all future as-available PPAs, it is deferring the negotiations on a PPA with MIE until after the report has been filed and the Commission and Consumer Advocate have had the opportunity to comment. Maui Electric does not anticipate that the results of the report will adversely affect the ongoing MIE Interconnection Requirements Study.

LANAʻI ACTION PLAN

Utility-Scale Energy Storage

Maui Electric will continue to explore the merits of utility-scale variable generation coupled with utility-scale energy storage to increase the renewable energy percentage on Lanaʻi.

System-Level Improvements

Fossil Generation Retirement Plan

Maui Electric does not anticipate retiring any Lanaʻi generating assets over the planning period of this PSIP. As variations in load occur over the years, units may be deactivated (and reactivated) as needed.

[28] Docket No. 2015-0224, For Approval of PPA for Renewable As-Available Energy with Kuʻia Solar, LLC, Decision and Order No. 33541, dated February 22, 2016, pages 68-69. Docket No. 2015-0225, For Approval of PPA for Renewable As-Available Energy with South Maui Renewable Resources LLC, Decision and Order No. 33537, dated February 18, 2016, pages 67-68.

Generation Flexibility Plan

The Lanaʻi grid includes a centralized generating station with nine (9) diesel units with 10.4 MW of firm capacity. Generator control upgrades were completed in 2015 to enable remote monitoring and operation of the generating units. Maui Electric also has an agreement to operate a Combined Heat and Power (CHP) unit that is expected to return to service in 2017. The CHP unit will replace one (1) of the two (2) diesel units that provide base load power for the system at Miki basin.

Maui Electric applied for, and is awaiting, approval from DOH for modifications to our air permit that allow lower minimum operating levels on the base loaded units to accommodate the addition of more renewables to the system.

Must-Run Generation Reduction Plan

Maui Electric currently runs with a minimum number of base loaded units on Lanaʻi – typically two. Maui Electric applied for, and is awaiting approval from DOH for modifications to the Miki Basin power plant's air permit that allow lower minimum operating levels on the base loaded units to accommodate the addition of more renewables to the system.

Generation Commitment and Economic Dispatch

Maui Electric currently operates with two base loaded units on Lanaʻi because this is the lowest number of base loaded units that satisfy our single contingency criteria. The CHP base load non-regulating operation is required to fulfill the contractual heat requirement of the customer. When additional units are needed, they are committed in the most economical order given operational constraints. The Lanaʻi system does not have AGC and therefore the demand for electricity is shared equally between the online units in an isochronous mode of operation (excluding the CHP).

HAWAI'I ISLAND ACTION PLAN

Utility-Scale Energy Storage

The Company will provide a BESS sizing study to support submittal of an application for approval to expend funds on a BESS system in 2016. The storage will be designed to provide acceptable system reliability. The sizing of the resource will consider other available cost–effective resources, including demand response. The size of this storage is expected to be 16 MW, with the predominant factor in size being the amount of DER systems that trip at 60.5 Hz. The Company will conduct an RFP for development of the BESS.

Circuit-Level Improvements

Service Transformer Upgrades

Transformer upgrades and new installations are necessary to maintain reliable service with increasing amounts of DER integrated onto the grid. Hawai'i Electric Light will continue to upgrade service transformers as the transformers become overloaded and will also install new transformers to mitigate voltage issues.

Circuit Improvements

Hawai'i Electric Light will use Synergi models, analysis, and field measurements to identify other circuit improvements needed with DER installations. This may include reconductoring, load tap changer setting adjustments, voltage regulator installations, and other equipment upgrades and installations.

System-Level Improvements

Fossil Generation Retirement Plan

While there are no fossil-fueled generating units scheduled to be retired within the five-year Action Plan Period, Hawai'i Electric Light's Preferred Plan shows future dates when certain resources could be removed from service based upon the identified new firm renewable energy additions. Such dates may be adjusted based on further optimization, including actual fuel costs and resource availability at the time of the decision, and on the timing of proposed renewable energy additions which provide capacity and operational benefits similar to the potentially displaced resources.

Units are considered for retirement when all of the below are true:

- They cannot economically serve bulk demand;
- They are not required for adequacy of supply;
- They are not required for system security and reliability reasons, such as offline reserves, fast-start, system restoration, or other critical function, or are not the most economic means of meeting system security and reliability (where other resources may compete).

If retirement is enabled through addition of a new resource, a period of time for the new resource to become reliable and proven will be accommodated before retirement. Typically, a resource would be used for replacement capacity for a period of time before retirement.

As new, firm capacity renewable resources are added to the system, as shown in Hawai'i Electric Light's Preferred Plan, Hawai'i Electric Light will retire existing fossil-fueled generating units when the above conditions are met.

Must-Run Generation Reduction Plan

In the PSIP plans, the value of dispatchable renewable energy resources has been identified as providing value by displacing maximum amount of fossil fuels through the high capacity factor. The acquisition of these resources will include design and operational requirements to leverage the ability for renewable resources to provide grid services similar to displaced fossil generation. This will enable renewable energy to provide all the reliability that fossil-fueled must-run units provide, with a minimum of supplemental resource additions.

Additional analyses based on planning criteria will be performed to identify additional system security constraints beyond the PSIP, which may identify additional cost-effective resource options to address operational constraints.

Prior to altering operational requirements based on system security, the system operators will be provided with resources and operating criteria to ensure acceptable system security based on the through planning analysis.

Generation Commitment and Economic Dispatch

To facilitate operation, state-of-the art forecasting tools have been integrated into the control room. There remains, however, a great deal of uncertainty in the forecast, which can lead to under or over committing the generation. Under committing occurs when production is lower or a down-ramp occurs, and may lead to a generation shortfall and need for supplemental or emergency generation.

For supplemental and emergency purposes, Hawai'i Electric Light will increasingly rely on fast-start resources for start-failure of cycled units and short-term generation needs caused by forecast error. The availability of these units allows the operator to adjust generation quickly in response to changes in net demand. They are also used to restore under frequency load-shed. Further work is being done to improve controls for reliable startup, and allow for stable low-load operation at the steam units.

Hawai'i Electric Light has integrated its state-of-the art wind and PV forecasting into the control room, which is used for the daily unit commitment decisions. Additional projects are in progress to further integrate the forecasting services into the Energy Management System and provide additional visibility and control of DER. This includes EMS cyber security enhancement for migration to the MPLS communications to enable smart-grid technologies and additional integration of distributed networks and transmission components into the EMS control room. This path is in accordance with the telecommunications migration plan. The first stage will be completed in 2016.

Transmission and Distribution System Upgrades

6800 Line Reconductor, Phases 2 to 4

This project pertains to the 69 kV transmission line that runs from Keamuku switching station to Keahole switching station. This project is needed to replace 21 miles of aged and deteriorated transmission poles, insulators and hardware along Mamalahoa highway to improve the reliability of the aging infrastructure. The reconductoring work is targeted for the period 2016 to 2017. Phases 2-4 have been approved by the Commission.

Kilauea 3400, Phases 1 and 2

This project pertains to the 34 kV transmission line that runs from Puna Power Plant to Kilauea switching station. This project is needed to replaced aged and deteriorated sub-transmission poles, insulators and hardware along Hawai'i Belt road to improve the reliability of the aging infrastructure. The replacement work is targeted for the period 2016 to 2017.

New 9400 Transmission Line, Phases 1 and 2

This project pertains to a new 69 kV transmission line that will run from Waimea/Ouli area to North Kohala. It will help facilitate the eventual rebuild of the 3300 line which is presently a radial line. The new transmission line reconductoring work is targeted for the period 2019 to 2020. An application seeking Commission approval to commit funds to this project is planned to be will be submitted in 2017.

6200 Transmission Line Rebuild

This project pertains to the 69 kV transmission line that runs along the saddle road from Kaumana Switching station to Keamuku Switching station. This project is needed to improve reliability of critical cross-island transmission line, as well as to potentially support additional East Hawai'i generation. The reconductoring work is targeted for 2018. An application seeking Commission approval to commit funds to this project will be submitted in 2016.

Underfrequency Load Shed Scheme

Hawai'i Electric Light is implementing a Dynamic UFLS project that is scheduled to be completed by the end of 2016. The scheme adaptively assigns circuits to each stage of the underfrequency load-shed scheme to ensure adequate system protection for loss of generation contingencies under varying net demand levels and levels of distributed generation. The project includes an application on the EMS system, which will calculate the required load shed for each stage based on net demand, and a communication to circuit relaying to assign circuits to a particular under frequency stage.

The project includes upgrades and installations of equipment at 41 substations. These upgrades include installing Real Time Automation Controllers (RTAC), upgrading Supervisory Control and Data Acquisition (SCADA) equipment and electromechanical feeder relays at some locations, and SCADA master station upgrade. With the increasing amounts of uncontrolled and unmonitored rooftop PV, the daily net loading of feeders can change dramatically throughout the day and is no longer predictable. In order to maintain the proper load in each stage of UFLS to meet the system protection targets, the UFLS system must now monitor feeder loads in real-time and adjust the amount of load in each stage of the UFLS according to the actual measured load on that feeder at that time. The dynamic UFLS scheme will allow for automated allocation of feeders to UFLS settings based on actual system load and feeder loads at the time. This allows the UFLS scheme to adapt to changing system and feeder conditions dynamically and continue to provide the necessary protection for the utility grid.

In addition to adding dynamic functionality to the UFLS scheme, frequency rate of change relaying (df/dt) on feeder breakers will be used to speed up sensing time for the first stage of load shedding. The df/dt functionality reduces the possibility of over shedding thereby stabilizing frequency faster, which is necessary to accommodate existing distributed resources connected with the original IEEE 1547 fast-trip requirements during off-normal voltages and frequencies. Reducing over shedding: (a) reduces the chances of "legacy PV" tripping (PV that trips at 59.3 Hz) reducing the overall amount of load that must be shed for stability; and (b) reduces the chances of the frequency rebounding to higher than 60.5 Hz which can cause a large amount of PV to trip, causing the frequency to drop again, triggering additional load shedding and effecting many more customers than necessary.

Renewable Energy Restoration – Waiau Hydro Repowering and Rehabilitation

Hawai'i Electric Light plans to rehabilitate Unit 1 and repower Unit 2 at its Waiau Hydroelectric Power Plant, which is about 96 years old. Rehabilitation and repowering of the aging equipment is expected to increase renewable energy production from the facility. Hawai'i Electric Light plans to submit an application for approval from the Commission to commit funds to this project once project details have been worked out.

9. Next Steps

Given the scope of the Commission's directives and its accompanying limited timeframe, we have completed a thorough analysis, and produced an actionable PSIP that includes Preferred Plans and their attendant Five-Year Action Plans that can be implemented in the short-term.

Over the following months, we will be continuing our analysis to widen the scope and assess additional considerations and constraints to refine our Preferred Plans and make clearer the subsequent 25 years until 2045.

Update Analyses for New EIA AEO Fuel Price Forecast

Two of the foundations of our analysis is the fuel price forecast for both LNG and petroleum-based fuels. The U.S. Energy Information Administration (EIA) issues updated fuel price forecasts generally mid-year. After we receive these new fuel price forecasts, we will perform additional analysis based on those updated forecasts.

Because of this reliance, we will file an addendum to our 2016 updated PSIP either by August 1, 2016 or within two months after these fuel price forecasts are published.

Analyze Inter-Island Transmission

Given the findings of this updated PSIP that O'ahu will likely need a substantial amount of off–island renewable resources to meet a 100% renewable energy goal in 2045, Hawaiian Electric plans to reassess the scope and requirements for inter-island transmission. As a follow-up action, Hawaiian Electric plans to assess inter-island transmission configurations that might benefit the furthering of our renewable energy goals; assess the costs, integration challenges, and operational considerations inherent in the configurations; and identify the benefits of inter-island transmission relative to alternatives and mixes of alternatives.

Perform Further Research on Offshore Wind

Hawaiian Electric plans to further evaluate the viability of offshore wind resources. This will include assessing, in greater depth, the resource's potential, possible onshore interconnection configurations, risks factors (such as permitting, community acceptance, natural hazards, and hazards from human activity), resource development and installation costs, and the feasibility of acquiring and implementing offshore wind projects. These evaluations will be performed in conjunction with our planned analysis of an inter-island cable system.

Perform Additional System Security Analysis for the Preferred Plans

The system security analysis focused on N-1 loss of generation contingency events that affect frequency stability. Further analysis is required to ensure system security. These analyses include:

- A protection coordination study to determine the fault current requirements at the sub-transmission system level to ensure distribution protection schemes can operate. Simulations will be performed to maintain system MVA requirements for fault current.
- System MVAR requirements and voltage stability.
- Rotor angle stability.
- Load flow analysis, distribution to transmission.
- Low inertia system analysis.
- Under frequency load shed, an islanding scheme, or both.

Re-Optimize the DR Portfolio for the Preferred Plans

As of the ongoing iterations, we will rerun the Adaptive Planning model to identify the optimal DR portfolio for the final resource plans. This effort will subsume additional iterations between the DR portfolio valuing and the econometric model that optimizes the addition of more distributed storage resources. Once the iterations converge on the value and amounts of distributed storage resources, we will then optimize the final DR model run by incorporating the updated potential study with new storage uptake amounts and new assumptions, optimized DR services by highest benefit cost ratio of each program; and all rules for DR service prioritization.

When the modeling has been completed, we will develop the avoided cost from the optimized DR portfolio. The portfolio costs will also be developed based on the maximum MW in the optimized portfolio (in accordance with the bottom-up methodology described in Appendix J). With avoided costs and costs finalized, we will then perform tests to determine the final cost effective portfolio by island.

The resulting portfolio will be filed in the final DR Program portfolio application in the summer of 2016.

Update Production Simulations and Cost Analyses

Reflect Findings from System Security Analyses

The system security analyses performed in the PSIP defined the system requirements to maintain system reliability for providing frequency and voltage regulation and satisfying the our planning criteria TPL-001. The next step in the process (which could not be completed in time for this filing) is to determine the most economical means to satisfy the requirements.

For example, for the Maui analyses, production simulations were performed and plans were evaluated without must-run fossil-fueled generation after 2022. This assumes that other resources (such as demand response and energy storage: batteries, PSH, or flywheels) will provide cost-effective ancillary services (frequency response and frequency regulation) and other options (such as synchronous condensers) could provide voltage regulation, in lieu of a must-run unit, to accept more renewable energy. Analyses will need to be performed to determine the most economical means to provide the required ancillary services.

Reflect Updated Demand Response Impacts and Costs

The DR program impacts will be re–optimized. This information will be integrated into our updated analyses.

Complete LNG Risk Premium Analysis

We plan to complete risk premium analyses—the monetized value of resource cost volatility—using Ascend Analytics' modeling tools and techniques to define the risk associated with LNG and oil prices for the Preferred Plans.

Complete Sub-Hourly Analysis

We plan to perform additional analysis to optimize the operation of energy storage, including sub-hourly analyses to provide additional insights into the operation of energy storage resources.

Update System–Level Hosting Capacity Analysis

The analysis will determine the extent the system–level hosting capacity will change as a result of updates to the PSIP.

A. Glossary and Acronyms

To aid in understanding and comprehension, the glossary and acronym entries in this appendix clarify the meaning of terms and concepts used throughout the 2016 updated Power Supply Improvement Plans (PSIPs).

A

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

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

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

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

As-Available Renewable Energy

See Variable Renewable Energy on page A-34.

Automatic Generation Control (AGC)

A process for adjusting demand and resources from a central location in order to help maintain frequency. AGC helps balance supply and demand.

Avoided Costs

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

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

B

Baseload

The minimum electric or thermal load that is supplied continuously over a period of time. (See also Load, Electric on page A-18.)

Baseload Capacity

See Capacity, Generating on page A-3.

Baseload Generation

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

Battery Energy Storage Systems (BESS)

Any battery storage system used for contingency or regulating reserves, load shifting, ancillary services, or other utility or customer functions. (See also Energy Storage on page A-11.)

Black Start Resource

A generating unit and its associated set of equipment that can be started without system support or can remain energized without connection to the remainder of the system, and that has the ability to energize a bus, thus meeting a restoration plan's needs for real and reactive power capability, frequency and voltage control, and is included in the restoration plan.

British Thermal Unit (Btu)

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

C

Capacitor

A device used to correct AC voltage so that the voltage is in phase with the AC current. Capacitors are typically installed in substations and on distribution system poles, at locations where local voltage correction can reduce system current flow, reducing losses and improves efficiency.

Capacity Factor (cf)

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

Capacity, Generating

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

Baseload Capacity: Those generating facilities within a utility system that are operated to the greatest extent possible to maximize system mechanical and thermal efficiency and minimize system operating costs. Baseload capacity typically operates at high annual capacity factors, for example greater than 60%. Island systems experience lower capacity factors because output is often reduced to accommodate lower demand periods and variable energy production.

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

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

Intermediate Capacity: Flexible generators able to efficiently vary their output across a wide band of loading conditions. Also known as Cycling Capacity. Typically annual capacity factors for intermediate duty generating units range from 20% to 60%. Island systems experience lower capacity factors because output is often reduced to accommodate lower demand periods and variable energy production.

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

Peaking and Emergency Capacity: Generators typically called on for short periods of time during system peak load conditions or as replacement resources following contingencies. Annual capacity factors for peaking generation are typically less than 20%.

Capital Expenditures

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

Carbon Dioxide (CO_2)

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

Combined Cycle (CC)

A combination of combustion turbine- and steam turbine-driven electrical generators, where the combustion turbine exhaust is passed through a heat recovery waste heat boiler which, in turn, produces steam which drives the steam turbine. There are a number of possible configurations for combined cycle units.

3x1 Combined-Cycle: A configuration in which there are three combustion turbines, three heat recovery waste heat boilers, and one steam turbine. Each combustion turbine produces heat for a single waste heat boiler, which in turn produces steam that is directed to the single steam turbine.

Dual-Train Combined-Cycle (DTCC): A configuration in which there are two combustion turbines, two heat recovery waste heat boilers, and one steam turbine. Each combustion turbine and waste heat boiler combination produces steam that is directed to the single steam turbine. Sometimes referred to as a 2x1 combined-cycle.

Single-Train Combined-Cycle (STCC): A configuration in which there is one combustion turbine, one heat recovery waste heat boiler, and one steam turbine. Sometimes referred to as a 1x1 combined-cycle.

Combined Heat and Power (CHP)

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

Combustion Turbine (CT)

Any of several types of high-speed generators using principles and designs of jet engines to produce low cost, high efficiency power; also commonly referred to as a gas turbine (GT). Combustion turbines typically use natural gas or liquid petroleum fuels to operate.

Concentrated Solar Thermal Power (CSP)

A technology that uses mirrors to concentrate solar energy to drive traditional steam turbines or engines that create electricity. A CSP plant can store this energy until needed to meet demand.

Conductor Sag

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

Connected Load

See Load, Electric on page A-18.

Contingency Reserve

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

Critical Peak Incentive (CPI) Program

A DR capacity grid service capable of providing peak load reduction during emergency situations when insufficient generation resources are available. The current Commercial Direct Load Control program could be re-classified under this program as part of the initial migration to a redeveloped DR portfolio.

Customer Grid Supply (CGS)

A program where customers receive a Commission-approved credit for electricity sent to the grid and are billed at the retail rate for electricity they use from the grid. Customer Grid Supply is one of two programs (the other being Customer Self Supply) that replaced the Net Energy Metering (NEM) program.

Customer Self Supply (CSS)

A program intended only for solar PV installations that are designed to not export any electricity to the grid. Customers are not compensated for any export of energy. Customer Self Supply is one of two programs (the other being Customer Grid Supply) that replaced the Net Energy Metering (NEM) program.

Curtailment

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

Cycling

The operation of generating units at varying load levels (including on/off and low load variations), in response to changes in system load requirements. Cycling causes a power plant's boiler, steam lines, turbine, and auxiliary components to go through unavoidably large thermal and pressure stresses.

D

Day-Ahead Load Shift (DALS) Program

A DR capacity grid service capable of providing a static period pricing rate delivered to commercial customers six hours before the starting day of an event for on-peak, off-peak, and mid-day times. Through the price differential, customers are encouraged to shift their energy usage from the peak time to the middle of the day when solar PV is at its peak, or at night when demand is low

Daytime Minimum Load (DML)

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

Demand

The rate at which electricity is used at any one given time (or averaged over any designated interval of time). Demand differs from energy use, which reflects the total amount of electricity consumed over a period of time. Demand is often measured in kilowatts (kW = 1 kilowatt = 1000 watts), while energy use is usually measured in kilowatt-hours (kWh = kilowatts x hours of use = kilowatt-hours). Load is considered synonymous with demand. (See also Load, Electric on page A-18.)

Demand Charge

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

Demand Response (DR)

Changes in electric usage by end-use customers from their normal consumption patterns in response to incentives caused by changes in the state of the electric grid or changes in the price of electricity. The underlying objective of demand response is to actively engage customers in modifying the demand for electricity to address system needs, in lieu of relying on utility-scale generating assets to address system needs.

Load Control: Includes direct control by the utility or other authorized third party of customer end-uses such as air conditioners, lighting, water heaters, distributed storage, electric vehicles, and motors. Load control can entail partial load reductions or complete load interruptions as well as load increase as needed. Customers usually receive financial consideration for participation in load control programs.

Price Response: Refers to programs that provide pricing incentives to encourage customers to change their electricity usage profile. Price response programs include real-time pricing, day-ahead load shift, time-of-use (TOU), and critical peak pricing (CPP) incentives.

Demand-Side Management (DSM)

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

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

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

Department of Land and Natural Resources (DLNR)

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

DG 2.0

A generic term used in the 2014 PSIPs 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.

DG-PV (Distributed Generation-Photovoltaics)

An initialism describing the entirety of distributed photovoltaic generation (sometimes referred to as rooftop solar) on the power grid.

Direct Current (DC)

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

Direct Load Control (DLC)

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

Direct Transfer Trip (DTT)

A protection mechanism that originates from station relays in response to a specific system event. Remote events, such as generator trips, can cause load shed through DTT.

Dispatchable Generation

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

Distributed Energy Resources (DER)

Non-centralized generating and storage systems that are co-located with energy load. Also known as Distributed Generation (see Distributed Generation two entries below).

Distributed Energy Storage System (DESS)

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

Distributed Generation (DG)

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

Distribution Circuit Monitoring Program (DCMP)

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

Distribution Circuit

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

Distribution Transformer

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

Disturbance Ride-Through

The capability of resources to remain connected to the grid during transient off-normal voltage and frequency conditions that occur for typical system disturbances.

Droop

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

Dual-Train Combined Cycle (DTCC)

See Combined Cycle on page A-4.

E

Economic Dispatch

The allocation of load to online dispatchable generating units based on their costs, to effect the most economical production of electricity for customers.

Electric Power Research Institute (EPRI)

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

Electric Vehicle (EV)

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

Electricity

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

Emissions

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

Energy

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

Energy Efficiency DSM

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

Energy Efficiency Portfolio Standard (EEPS)

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

Energy Information Administration (EIA)

A principal agency of the United States Federal Statistical System (within the U.S. Department of Energy) responsible for collecting, analyzing, and disseminating energy information. One of its major roles is to provide publically available fuel price projections for the power generation industry.

Energy Management System (EMS)

A centralized system of computer-aided tools used to monitor, control, and optimize the performance of the utility power system and interconnected resources.

Energy Storage

A system or a device capable of storing electrical energy. Three major types of energy storage are relevant for consideration in Hawai‘i.

Battery: An energy storage device composed of one or more electrolyte cells that stores chemical energy. A large-scale battery can provide a number of ancillary services, including frequency regulation, voltage support (dynamic reactive power supply), load following, and black start as well as providing energy services such as peak shaving, valley filling, and potentially energy arbitrage. Also referred to as a Battery Energy Storage System (BESS).

Flywheel: A cylinder that spins at very high speeds, storing rotational kinetic energy. A flywheel can be combined with a device that operates either as an electric motor that accelerates the flywheel to store energy or as a generator that produces electricity from the energy stored in the flywheel. The faster the flywheel spins, the more energy it retains. Energy can be drawn off as needed by slowing the flywheel. A large flywheel plant can provide a number of ancillary services including frequency regulation, voltage support (dynamic reactive power supply), and potentially spinning reserve.

Pumped Storage Hydroelectric: Pumped storage hydro facilities typically use off-peak electricity to pump water from a lower reservoir into one at a higher elevation storing potential energy. When the water stored in the upper reservoir is released, it is passed through hydraulic turbines to generate electricity. The off-peak electrical energy used to pump the water uphill can be stored indefinitely as gravitational energy in the upper reservoir. Thus, two reservoirs in combination can be used to store electrical energy for a long period of time, and in large quantities. A modern pumped-storage facility can provide a number of ancillary services, such as frequency regulation, voltage support (dynamic reactive power), spinning and non-spinning reserve, load following and black start as well as energy services such as peak shaving and energy arbitrage.

Expense

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

F

Fast Frequency Response (FFR) Program

A DR fast frequency response grid service capable of responding to contingency events within 30 cycles (the maximum FFR requirement depending on the total available MW) or less. A customer who enrolls in this DR program must be able to offer load resources that could respond to a local discrete response in 30 cycles or less.

Feeder

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

Firm Capacity

See Capacity, Generating on page A-3.

Feed-In Tariff (FIT) Program

A FIT program specific to the Hawaiian Electric Companies, under guidelines issued by the Hawai'i Public Utilities Commission, which allows customers to sell the renewable electric energy produced by a qualifying system to the electric utility.

Feed-In Tariff (FIT)

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

Five-Five-Five (5-5-5)

A grant initiative started in 2012 by the Joint Center for Energy Storage Research (JCESR) whose goal is to provide a grid-enabled battery that is capable of providing five times the energy density at one-fifth the cost of commercial batteries within five years.

Flywheel

See Energy Storage on page A-11.

Forced Outage

See Outage on page A-24.

Forced Outage Rate

See Outage on page A-24.

Fossil Fuel

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

Frequency

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

Frequency Regulation

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

Full-Forced Outage

See Outage on page A-24.

G

Generating Capacity

See Capacity, Generating on page A-3.

Generation (Electricity)

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

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

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

Generator (Electric)

A machine that transforms mechanical, chemical, or thermal energy into electric energy. Includes wind generators, solar PV generators, and other systems that convert energy of one form into electric energy. (See also Capacity, Generating on page A-3.)

Geographic Information System (GIS)

A computer system designed to capture, store, manipulate, analyze, manage, and present all types of geographical data.

Gigawatt (GW)

A unit of power, capacity, or demand equal to one billion watts.

Gigawatt-Hour (GWh)

A unit of electric energy equal to one billion watt-hours.

Greenhouse Gases (GHG)

Any gas whose absorption of solar radiation is responsible for the greenhouse effect, including carbon dioxide, methane, ozone, and the fluorocarbons.

Grid (Electric)

An interconnected network of electric transmission lines and related facilities.

Gross Generation

See Generation (Electricity) on page A-14.

H

Hawai‘i Public Utilities Commission (PUC)

A state agency that regulates all franchised or certificated public service companies operating in Hawai‘i. The PUC prescribes rates, tariffs, charges and fees; determines the allowable rate of earnings in establishing rates; issues guidelines concerning the general management of franchised or certificated utility businesses; and acts on requests for the acquisition, sale, disposition or other exchange of utility properties, including mergers and consolidations.

Hawai‘i Revised Statute (HRS)

The codified laws of the State of Hawai‘i. The entire body of state laws is referred to the Hawai‘i Revised Statutes; the abbreviation HRS is normally used when citing a particular law.

Heat Rate

A measure of generating station thermal efficiency, generally expressed in Btu per net kilowatt-hour. It is computed by dividing the total Btu content of fuel burned for electric generation by the resulting net kilowatt-hour generation.

Heat Recovery Steam Generator (HRSG)

An energy recovery heat exchanger that recovers heat from a hot exhaust gas stream, and produces steam that can be used in a process (cogeneration) or used to drive a steam turbine in a combined-cycle plant.

Impacts

The positive or negative consequences of an activity. For example, there may be negative consequences associated with the operation of power plants from the emission discharge or release of a material to the environment (for example, health effects). There may also be positive consequences resulting from the construction and siting of power plants which could affect society and culture.

Impedance

A measure of the opposition to the flow of power in an AC circuit.

Independent Power Producer (IPP)

Any entity that owns or operates an electricity generating facility that is not included in an electric utility's rate base. This term includes, but is not limited to, co-generators (or combined heat and power generators) and small power producers (including net metered and feed-in tariff systems) and all other non-utility electricity producers, such as exempt wholesale generators, who sell electricity or exchange electricity with the utility. IPPs are sometimes referred to as non-utility generators.

Industrial Fuel Oil (IFO)

A fuel oil that contains less than 20,000 parts per million of sulfur, or 2% sulfur content. Also referred to as medium sulfur fuel oil (MSFO).

Installed Capacity

See Capacity, Generating on page A-3.

Integrated Demand Response Portfolio Plan (IDRPP)

A comprehensive demand response portfolio proposal filed by the Companies with the Hawai‘i Public Utilities Commission on July 28, 2014.

Integrated Resource Plan (IRP)

The plan by which electric utilities identify the resources or the mix of resources for meeting near- and long-term consumer energy needs. An IRP conveys the results from a planning, analysis, and decision-making process that examines and determines how a utility will meet future demands. Developed in the 1980s, the IRP process integrates efficiency and load management programs, considered on par with supply resources; broadly framed societal concerns, considered in addition to direct dollar costs to the utility and its customers; and public participation into the utility planning process.

Interconnection Charge

A one-off charge to DG customers reflecting costs of studies and any potential upgrades (such as transformer upgrades) associated with distributed generation.

Intermediate Capacity

See Capacity, Generating on page A-3.

Intermittent Renewable Energy

See Variable Renewable Energy on page A-34.

Internal Combustion Engines (ICE)

A heat engine that combines fuel with an oxidizer (usually air) in a combustion chamber that creates pressure and mechanical force to generate electricity.

Inverter

A device that converts direct current (DC) electricity to alternating current (AC) either for stand-alone systems or to supply power to an electricity grid. An appropriately designed inverter can provide dynamic reactive power as well as real power and disturbance ride-through capability. A solar PV system uses inverters to convert DC electricity to AC electricity for use in the grid, or directly by a customer.

Islanding

A condition in which a circuit remains powered by non-utility generation (that is, distributed generation resources) even when the circuit has been disconnected from the wider utility power network.

K

Kilowatt (kW)

A unit of power, capacity, or demand equal to one thousand watts. The demand for an individual electric customer, or the capacity of a distributed generator, is sometimes expressed in kilowatts. The standard billing unit for electric tariffs with a demand charge component is the kilowatt.

Kilowatt-Hour (kWh)

A unit of electric energy equal to one thousand watt-hours. The standard billing unit for electric energy sold to retail consumers is the kilowatt-hour.

L

Levelized Cost of Energy (LCOE)

The price per kilowatt-hour in order for an energy project to break even; it does not include risk or return on investment.

Life-Cycle Costs

The total cost impact over the life of a program or the life of an asset. Life-cycle costs include Capital Expenditures, operation, maintenance and administrative expenses, and the costs of decommissioning.

Liquefied Natural Gas (LNG)

Natural gas that has been cooled until it turns liquid, in order to make storage and transport easier. LNG must be regasified before it can be burned as fuel.

Load, Electric

The term load is considered synonymous with demand. Load may also be defined as an end-use device or an end-use customer that consumes power. Using this definition of load, demand is the measure of power that a load receives or requires.

Baseload: The constant generation of electric power load to meet demand.

Connected Load: The sum of the capacities or ratings of the electric power consuming apparatus connected to a supplying system, or any part of the system under consideration.

Load Balancing

The efforts of the system operator to ensure that the load is equal to the generation. During normal operating conditions the system operator utilizes load following and frequency regulation for load balancing.

Load Control Program

A program in which the utility company offers some form of compensation (for example, a bill credit) in return for having permission to remotely control a customer's energy use (such as controlling an air conditioner or water heater) for defined periods of time.

Load Forecast

An estimate of the level of future energy needs of customers in an electric system. Bottom-up forecasting uses utility revenue meters to develop system-wide loads; used often in projecting loads of specific customer classes. Top-down forecasting uses utility meters at generation and transmission sites to develop aggregate control area loads;

useful in determining reliability planning requirements, especially where retail choice programs are not in effect.

Load Management DSM

Electric utility or third party marketing programs designed to encourage the utility's customers to adjust the timing of their energy consumption. By coordinating the timing of its customers' consumption, the utility can achieve a variety of goals, including reducing the utility's peak system load, increasing the utility's minimum system load, and meeting unusual, transient, or critical system operating conditions.

Load Profile

Measurements of a customer's electricity usage over a period of time which shows how much and when a customer uses electricity. Load profiles can be used by suppliers and transmission system operators to forecast electricity supply requirements and to determine the cost of serving a customer.

Load Shedding

A purposeful, immediate response to curtail electric service. Load shedding is typically used to curtail large blocks of customer load (for example, particular distribution feeders) during an under frequency event (when frequency drops below a certain level) when demand for electricity exceeds supply (for example, during the sudden loss of a generating unit).

Load Tap Changer (LTC)

A substation controller used to regulate the voltage output of a transformer.

Loss-of-Load Probability (LOLP)

The probability that a generation shortfall (loss of load) would occur. This probability can be used as a consideration in generation adequacy requirements. The generation adequacy planning criteria for O‘ahu requires the LOLP not to exceed one outage day every 4½ years. The other four islands we serve do not define a minimum LOLP, but rather plan for generation adequacy of supply through reserve margin calculations.

Low Sulfur Diesel (LSD)

A diesel fuel that contains a maximum of 500 parts per million of sulfur.

Low Sulfur Fuel Oil (LSFO)

A fuel oil that contains less than 500 parts per million of sulfur; about 0.5% sulfur content.

Low Sulfur Industrial Fuel Oil (LSIFO)

A fuel oil that contains up to 7,500 parts per million of sulfur; about 0.75% sulfur content. LSIFO is used if a fuel with lower sulfur content than medium sulfur fuel oil is needed.

Low Voltages

Voltages above 0.9 per unit that are of concern because these voltages can become an under voltage violation in the future.

M

Maintenance Outage

See Outage on page A-24.

MBtu

A thousand Btu. (See also British Thermal Unit on page A-3.)

Medium Sulfur Fuel Oil (MSFO)

A fuel oil that contains between 1,000 and 5,000 parts per million of sulfur; between 1% and 3.5% sulfur content.

Megawatt (MW)

A unit of power, capacity, or demand equal to one million watts. Generating capacities of power plants and system demand are typically expressed in megawatts.

Megawatt-Hour (MWh)

A unit of electric energy equal to one million watt-hours. The energy output of generators or the amount of energy purchased from Independent Power Producers is oftentimes specified in megawatt-hours.

Mercury and Air Toxics Standard (MATS)

A federal standard that requires coal- and oil-fired power plants to limit the emissions of toxic air pollutants: particular matter (such as arsenic), heavy metals (such as mercury) and acid gases (such as carbon dioxide).

Minimum Load (ML) Program

A DR capacity grid service that provides incentives to customers to shift their usage to the middle of the day to increase demand during that period when DG-PV generation is high. This program was not included in any DR portfolio analysis because load shifting programs such as time-of-use (TOU), day-ahead load shift (DALS), and real-time pricing (RTP) were already fulfilling this load flattening benefits.

MMBtu

One million Btu. (See also British Thermal Unit on page A-3.)

Must-Run Unit

A generation facility that must run continually due to operational constraints or system requirements to maintain system reliability; typically a large thermal power plant.

N

N-1 Contingency

The unexpected failure or outage of a single system component (such as a generator, transmission line, circuit breaker, switch, or other electrical element); and can include multiple electrical elements if they are linked so that failures occur simultaneously at the loss of the single component. Also known as an N-1 condition.

Nameplate Generation

See Generation (Electricity) on page A-14.

National Ambient Air Quality Standards (NAAQS)

A Federal standard, set by the Environmental Protection Agency (EPA), to limit the emission of six "criteria" pollutants: carbon monoxide (CO), lead, nitrogen dioxide (NO_2), ozone, particulate matter, and sulfur dioxide (SO_2). These regulations apply to all fuel-fired power plants.

National Pollutant Discharge Elimination System (NPDES)

NPDES permits, administers, and enforces a program that regulates pollutants discharged into water sources.

National Renewable Energy Laboratory (NREL)

The Federal laboratory dedicated to researching, developing, commercializing, and using renewable energy and energy efficiency technologies. NREL creates a wealth of well researched studies that utilities across the country rely on for planning to integrate renewable generation.

Net Capacity

See Capacity, Generating on page A-3.

Net Energy Metering (NEM)

A financial arrangement between a customer with a renewable distributed generator and the utility, where the customer only pays for the net amount of electricity taken from the grid, regardless of the time periods when the customer imported from or exported to the grid. Under a NEM arrangement, the customer is allowed to remain connected to the power grid, so that the customer can take advantage of the grid's reliability infrastructure (such as ancillary services provided by generators, energy storage devices, and demand response programs), use the grid as a "bank" for power generated by the customer in excess of the customer's needs, and use the grid as a backup resource for times when the power generated by the customer is less than the customer's needs.

Net Generation

See Generation (Electricity) on page A-14.

Nitrogen Oxide (NOx)

A pollutant and strong greenhouse gas emitted by combusting fuels.

Nominal Dollars

At its most basic, nominal dollars are based on a measure of money over a period of time that *has not been* adjusted for inflation. Nominal value represents a cost usually in the current year. As such, nominal dollars can also be referred to as current dollars; in other words, what it costs to buy something today. Nominal dollars are often contrasted with real dollars.

Non-Spin Auto Response (NSAR) Program

A 10-minute DR resource capable of replacing other resources that are used for spinning reserves. When paired with an FFR program, NSAR can also replace a contingency battery. A customer enrolled in this NSAR program would have 10 minutes to respond and reduce their enrolled load resource.

Non-Transmission Alternative (NTA)

Programs and technologies that complement and improve operation of existing transmission systems that individually or in combination defer or eliminate the need for upgrades to the transmission system.

North American Electric Reliability Corporation (NERC)

An international regulatory authority whose mission is to ensure the reliability of the bulk power system in North America.

O

Ocean Thermal Energy Conversion (OTEC)

A process that can produce electricity by using the temperature difference between deep cold ocean water and warm tropical surface waters.

Off-Peak Energy

Electric energy supplied during periods of relatively low system demands as specified by the supplier. In general, this term is associated with electric water heating and pertains to the use of electricity during that period when the overall demand for electricity from our system is below normal.

Once-Through Steam Generator (OTSG)

A specialized type of HRSG without boiler drums that enables the inlet feedwater to follow a continuous path (without segmented sections for economizers, evaporators, and superheaters) allowing it to grow or contract based on the heat load being received from the gas turbine exhaust. OTSGs can be run dry, meaning the hot exhaust gases can pass over the tubes with no water flowing inside the tubes.

On-Peak Energy

Electric energy supplied during periods of relatively high system demand as specified by the supplier.

Operation and Maintenance (O&M) Expense

The recurring costs of operating, supporting, and maintaining authorized programs, including costs for labor, fuel, materials, and supplies, and other current expenses.

Operating Reliability

The ability of the electric system to withstand sudden disturbances such as electric short circuits or unanticipated loss of system components. Operating reliability is synonymous with system security. (See also System Security on page A-31.)

Operating Reserves

That capability above firm system demand required to provide for regulation, load forecasting error, equipment forced and scheduled outages, and local area protection. It consists of spinning and non-spinning reserve. (See also Reserve on page A-29.)

Spinning Reserve: The portion of operating reserve consisting of generation synchronized to the system and fully available to serve load within a defined time period following a contingency event; or load fully removable from the system within a defined time period following a contingency event.

Supplemental Reserve: Generation (synchronized or capable of being synchronized to the system) that is fully available to serve load within a defined recovery period following the contingency event; or load fully removable from the system within the defined recovery following the contingency event.

Outage

The period during which a generating unit, transmission line, or other facility is out of service. The following are types of outages or outage-related terms.

Forced Outage: The removal from service availability of a generating unit, transmission line, or other facility for emergency reasons or a condition in which the equipment is unavailable due to unanticipated failure.

Forced Outage Rate: The hours a generating unit, transmission line, or other facility is removed from service, divided by the sum of the hours it is removed from service, plus the total number of hours the facility was connected to the electricity system expressed as a percent.

Full-Forced Outage: The net capability of main generating units that is unavailable for load for emergency reasons.

Maintenance Outage: The removal of equipment from service availability to perform work on specific components that can be deferred beyond the end of the next weekend, but requires the equipment be removed from service before the next planned outage. Typically, a Maintenance Outage may occur anytime during the year, have a flexible start date, and may or may not have a predetermined duration.

Partial Outage: The outage of a unit or plant auxiliary equipment that reduces the capability of the unit or plant without causing a complete shutdown. It may also include the outage of boilers in common header installations.

Planned (or Scheduled) Outage: The shutdown of a generating unit, transmission line, or other facility, for inspection or maintenance, in accordance with an advance schedule.

P

Partial Outage

See Outage on page A-24.

Particulate Matter (PM)

A complex mixture of extremely small particles and liquid droplets made up of a number of components, including acids (such as nitrates and sulfates), organic chemicals, metals, and soil or dust particles.

Peak Demand

The maximum amount of power necessary to supply customers; in other words, the highest electric requirement occurring in a given period (for example, an hour, a day, month, season, or year). For an electric system, it is equal to the sum of the metered net outputs of all generators within a system and the metered line flows into the system, less the metered line flows out of the system. From a customer's perspective, peak demand is the maximum power used during a specific period of time.

Peaker

A generation resource that generally runs to meet peak demand, usually during the late afternoon and early evening when the demand for electricity during the day is highest. It is also referred to as a peaker plant or a peaking power plant. These resources are often used for supplemental reserves.

Peaking Capacity

See Capacity, Generating on page A-3.

Photovoltaic (PV)

Electricity from solar radiation typically produced with photovoltaic cells (also called solar cells): semiconductors that absorb photons and then emit electrons.

Photovoltaic Curtailment (PVC) Program

A DR capacity grid service capable of curtailing a customer's PV generation when minimum must-run generators are within a specified threshold limit that requires more system load to prevent the sudden loss of an online generator.

Planned Outage

See Outage on page A-24.

Planning Reserve

See Reserve on page A-29.

Power

The rate at which energy is supplied to a load (consumed), usually measured in watts (W), kilowatts (kW), or megawatts (MW).

Power Factor

A dimensionless quantity that measures the extent to which the current and voltage sine waves in an AC power system are synchronized. If the voltage and current sine waves perfectly match, the power factor is 1.0. Power factors not equal to 1.0 result in dissipation of electric energy into losses.

Power Purchase Agreement (PPA)

A contract for an electric utility to purchase energy and or capacity from a commercial source (for example, an Independent Power Producer) at a predetermined price or based on pre-determined pricing formulas.

Present Value

The value of an asset, taking into account the time value of money—a future dollar is worth less today. Present value dollars are expressed in a constant year dollars (usually the current year). Future dollars are converted to present dollars using a discount rate. For example, if someone borrows money from you today and agrees to pay you back $1.00 in one year at a discount rate of 10%, you would be only be willing to loan the other person $0.90 today. Utility planners use present value as a way to directly compare the economic value of multi-year plans with different future expenditure profiles. Net present value (NPV) is the difference between the present value of all future benefits, less the present value of all future costs.

Public Benefits Fee Administrator (PBFA)

A third-party agent that handles energy efficiency rebates and incentives within the service territories of the Hawaiian Electric Companies.

Pumped Storage Hydroelectric

See Energy Storage on page A-11.

Q

Qualitative

Consideration of externalities which assigns relative values or rankings to the costs and benefits. This approach allows expert assessments to be derived when actual data from conclusive scientific investigation of impacts are not available.

Quantitative

Consideration of externalities which provides value based on available information on impacts. This approach allows for the quantification of impacts without assigning a monetary value to those impacts (for example, tons of crop loss).

R

Ramp Rate

A measure of the speed at which a generating unit can increase or decrease output, generally specified as MW per minute.

Rate Base

The value of property upon which a utility is permitted to earn a specified rate of return as established by a regulatory authority. The rate base generally represents the book value of property used by the utility in providing service and may be calculated by any one or a combination of the following accounting methods: fair value, prudent investment, reproduction cost, or original cost. Depending on which method is used, the rate base includes net cost of plant in service, working cash, materials and supplies, and deductions for accumulated provisions for depreciation, contributions in aid of construction, customer advances for construction, accumulated deferred income taxes, and accumulated deferred investment tax credits.

Reactive Power

The portion of electricity that establishes and sustains the electric and magnetic fields of alternating-current equipment. Reactive power is provided by generators, synchronous condensers, or electrostatic equipment (such as capacitors) and directly influences electric system voltage.

Real Dollars

At its most basic, real dollars are a measure of money over a period of time that *has been* adjusted for inflation. Real dollars represents the true cost of goods and services sold because the effects of inflation are stripped out of the cost. Over time, real dollars are a measure of purchasing power. As such, real dollars can also be referred to as constant dollars; in other words, if the price of something goes up over time at the same rate as inflation, the cost is the same in real dollars. Real dollars are often contrasted with nominal dollars.

Real-Time Pricing (RTP) Program

A DR capacity grid service capable of providing hourly retail rate prices to customers up to six hours before the event day starts. Retail rates are based on weather, system resource availability, and forecasted load profile. A residential RTP program requires an AMI infrastructure where customers are able to change their electric usage pattern based on the different hourly retail rates.

Reciprocating Internal Combustion Engines (RICE)

A reciprocating internal combustion engine uses the reciprocating movement of pistons to create pressure that is converted into electricity.

Regulating Reserves (RR) Program

A DR grid service capable of providing up and down reserves to balance system variability when renewable penetration is high. A customer who enrolls in this program must be able to provide a load resource that could respond within two seconds.

Regulating Reserves

An amount of reserve capacity responsive to automatic generation control (AGC) that is sufficient to provide normal regulating margin to maintain system frequency.

Reliability

The degree of performance of the elements of the bulk electric system that results in electricity being delivered to customers within accepted standards and in the amount desired. Reliability may be measured by the frequency, duration, and magnitude of adverse effects on the electric supply. Electric system reliability can be addressed by considering two basic and functional aspects of the electric system, adequacy of supply and system security. (See also System Reliability on page A-31.)

Renewable Energy Resources

Energy resources that are naturally replenished, but limited in their constant availability (or flow). They are virtually inexhaustible but are limited in the amount of energy that is available over a given period of time. The amount of some renewable resources (such as geothermal and biomass) might be limited over the short term as stocks are depleted by use, but on a time scale of decades or perhaps centuries, they can likely be replenished.

Renewable energy resources currently in widespread use include photovoltaics, biomass, hydroelectric, geothermal, solar, and wind. Other renewables resources still under development include ocean thermal, wave, and tidal action technologies. Utility renewable resource applications include bulk electricity generation, on-site electricity generation, distributed electricity generation, non-grid-connected generation, and demand-reduction (energy efficiency) technologies.

Unlike fossil fuel generation plants (which can be sited where most convenient because the fuel is transported to the plant), most renewable energy generation plants must be sited where the energy is available; that is, a wind farm must be sited where a sufficient and relatively constant supply of wind is available. In other words, fossil fuels can be brought to their generation plants whereas most renewable energy generating plants must be brought to the renewable energy source. Some renewable resources are exceptions; their fuels (such as biomass and biofuels), like fossil generation, can be brought to the generation plant.

Renewable Portfolio Standard (RPS)

A goal for the percentage of electricity sales in Hawaiʻi to be derived from renewable energy sources. The RPS is set by state law. Savings from energy efficiency and displacement or offset technologies were part of the RPS until January 2015, after which they were counted toward the new Energy Efficiency Portfolio Standard (EEPS).

The current RPS statute calls for 10% of net electricity sales by December 31, 2010; 15% of net electricity sales by December 31, 2015; 25% of net electricity sales by December 31, 2020; and 40% of net electricity sales by December 31, 2030; 70% of net electricity sales by December 31, 2040; and 100% of net electricity sales by December 31, 2045.

Reserve

There are two types of reserves.

Operating Reserve: That capability above firm system demand required to provide for regulation, load forecasting error, equipment forced and scheduled outages, and local area protection. (See also Operating Reserves on page A-23.)

Planning Reserve: The difference between a control area's expected annual peak capability and its expected annual peak demand expressed as a percentage of the annual peak demand.

Reserve Margin (Planning)

The amount of unused available capability of an electric power system at peak load for a utility system as a percentage of total capability. Planning reserve margin is designed to measure the amount of generation capacity available to meet expected demand in a planning horizon. Coupled with probabilistic analysis, calculated planning reserve margins have been an industry standard used by planners for decades as a relative indication of adequacy of supply (AOS).

Resiliency

The ability to quickly locate faults and automatically restore service after a fault, using FLISR (Fault Location, Isolation, and Service Restoration).

Retail Rate

The rate at which specific classes of customers compensate the utility for grid electricity.

Reverse Flow

The flow of electricity from the customer site onto the distribution circuit or from the distribution circuit through the substation to higher voltage lines. Also called backfeed.

S

Scheduled Outage

See Outage on page A-24.

Service Charge

A fixed customer charge intended to allocate the cost of servicing the grid to all customers, regardless of capacity needs.

Simple-Cycle Combustion Turbine (SCCT)

A generating unit in which the combustion turbine operates in a stand-alone mode, without waste heat recovery.

Single-Train Combined Cycle (STCC)

See Combined Cycle on page A-4.

Smart Grid

A platform connecting grid hardware devices to smart grid applications, including Advanced Metering Infrastructure (AMI), Volt/VAR Optimization (VVO), Direct Load Control (DLC), and electric vehicle charging.

Spinning Reserve

See Operating Reserves on page A-23.

Steam Turbine (ST)

A turbine that is powered by pressurized steam and provides rotary power for an electrical generator.

Stochastic Modeling

Modeling analysis using as input a random collection of variables that represent the uncertainties associated with those variables (as opposed to deterministic modeling that analyzes a single state). Stochastic modeling analyzes multiple states and the range of their uncertainty, then captures the probabilities of those uncertainties.

Sulfur Oxide (SO_x)

A precursor to sulfates and acidic depositions formed when fuel (oil or coal) containing sulfur is combusted. It is a regulated pollutant.

Substation

A small building or fenced in yard containing switches, transformers, and other equipment and structures for the purpose of stepping up or stepping down voltage, switching and monitoring transmission and distribution circuits, and other service functions. As electricity gets closer to where it is to be used, it goes through a substation where the voltage is lowered so it can be used by customers such as homes, schools, and factories.

Supervisory Control and Data Acquisition (SCADA)

A system used for monitoring and control of remote equipment using communications networks.

Supplemental Reserve Service

See Operating Reserves on page A-23.

Supply-Side Management

Actions taken to ensure the generation, transmission, and distribution of energy are conducted efficiently. Supply-side generation includes generating plants that supply power into the electric grid.

Switching Station

An electrical substation, with a single voltage level, whose only functions are switching actions.

System

The utility power grid: a combination of generation, transmission, and distribution components.

System Average Interruption Duration Index (SAIDI)

The average outage duration for each customer served. SAIDI is a reliability indicator.

System Average Interruption Frequency Index (SAIFI)

The average number of interruptions that a utility customer would experience. SAIFI is a reliability indicator.

System Reliability

Broadly defined as the ability of the utility system to meet the demand of its customers while maintaining system stability. Reliability can be measured in terms of the number of hours that the system demand is met.

System Security

The ability of the electric system to withstand sudden disturbances such as electric short circuits or unanticipated loss of system elements. (See also Operating Reliability on page A-23.)

T

Tariff

A published volume of rate schedules and general terms and conditions under which a product or service will be supplied.

Time-of-Use (TOU) Program

A DR capacity grid service capable of providing a static period pricing rate for on-peak, off-peak, and mid-day times to residential customers. Through a price differential, customers are encouraged to shift their energy usage from the peak to the middle of the day when solar PV is at its peak, or at night when demand is low. When the time-of-use (TOU) program ends, participants will be able to enroll in the RTP program.

Time-of-Use (TOU) Rates

The pricing of electricity based on the estimated cost of electricity during a particular time block. Time-of-use rates are usually divided into three or four time blocks per twenty-four hour period (on-peak, mid-peak, off-peak and sometimes super off-peak) and by seasons of the year (summer and winter).

Total Resource Cost (TRC)

A method for measuring the net costs of a conservation, load management, or fuel substitution program as a resource option, based on the total costs of the program, including both the participants' and the utility's costs.

Transformer

A device used to change voltage levels to facilitate the transfer of power from the generating plant to the customer. A step-up transformer increases the voltage (power) of electricity while a step-down transformer decreases it.

Transmission and Distribution (T&D)

Transmission lines are used for the bulk transfer of electric power across the power system, typically from generators to load centers. Distribution lines are used for transfer of electric power from the bulk power level to end-users and from distributed generators into the bulk power system. Hawaiian Electric standard transmission voltages are 138,000 volts; and 69,000 volts (for Maui Electric and Hawai'i Electric Light). Distribution voltage is 23,000 volts (Maui Electric) and 13,200 volts (all systems).

Two-Way Communications

The platform and capabilities that are required to allow bi-directional communication between the utility and elements of the grid (including customer-sited advanced inverters), and control over key functions of those elements. The platform must contain monitor and control functions, be TCP/IP addressable, be compliant with IEC 61850, and provide cyber security at the transport and application layers as well as user and device authentication.

U

Ultra Low Sulfur Diesel (ULSD)

A diesel fuel that contains less 15 parts per million of sulfur.

Under Frequency Load Shedding (UFLS)

A system protection scheme used during transient adverse conditions to balance load and generation. The term essentially explains the process: when frequency drops below a certain point, this scheme sheds load to keep from completely losing the system.

Under Voltage Load Shedding (UVLS)

A system protection scheme used during low voltage conditions to avoid a voltage collapse.

United States Department of Defense (DOD)

An executive department of the U.S. government responsible for coordinating and supervising all agencies and functions of the Federal government that are concerned directly with national security and the armed forces.

United States Department of Energy (DOE)

An executive department of the U.S. government that is concerned with the United States' policies regarding energy, environmental, and nuclear challenges.

United States Energy Information Administration (EIA)

The principal agency responsible for collecting, analyzing, and disseminating energy information to promote sound policymaking, efficient markets, and public understanding of energy. The EIA conducts independent comprehensive data collection of energy sources, end uses, and energy flows; generates short- and long-term domestic and international energy projections; and performs informative energy analyses. EIA programs cover data on coal, petroleum, natural gas, electric, renewable, and nuclear energy.

United States Environmental Protection Agency (EPA)

An executive department of the U.S. government whose mission is to protect human health and the environment.

University of Hawai‘i Economic Research Organization (UHERO)

The economic research organization at the University of Hawai‘i, which is a source for information about the people, environment, and Hawai‘i and the Asia-Pacific economies, including energy issues.

V

Variable Renewable Energy

A generator whose output varies with the availability of it primary energy resource, such as wind, the sun, and flowing water. The primary energy source cannot be controlled in the same manner as firm, conventional, fossil-fuel generators. Specifically, while a variable generator (without storage) can be dispatched to operate below the available energy, it cannot be increased above what can be produced by the available resource energy. Variable energy can be coupled with storage, or the primary energy source can be stored for future use (such as with solar thermal storage, or when converted into electricity via storage technologies). Also referred to as intermittent and as-available renewable energy.

Voltage

Voltage is a measure of the electromotive force or electric pressure for moving electricity.

Voltage Regulation

The control of voltage to keep the value within a specified target or range.

W

Waste-to-Energy (WTE)

A process of generating electricity from the primary treatment (usually burning) of waste. WTE is a form of energy recovery.

Watt

The basic unit of measure of electric power, capacity, or demand from the International System of Units (SI); named after the Scottish engineer James Watt (1736–1819).

Wave and Tidal Power

A process that captures the power of waves and tides and converts it into electricity. While the arrival of waves at a power facility is somewhat predictable (mainly because waves travel across the ocean), tides are extremely predictable because they are driven by the gravitational pull of the moon and sun.

B. Input from the Parties

Throughout the process of creating our 2016 updated PSIPs, we have actively sought input from the Parties by thoroughly assessing their January 2016 submissions to the Commission and by engaging the Parties in a series of conferences, meetings, and one-on-one dialogs.

STAKEHOLDER AND TECHNICAL CONFERENCES

Beginning with our *Proposed PSIP Revision Plan* and continuing with our *Power Supply Improvement Plan Update Interim Status Report*, we have made it clear that we are proactively soliciting input from the Parties. In our *Proposed PSIP Revision Plan*, we proposed a schedule of conferences for just this purpose:

- Stakeholder Conference: held on December 17, 2015
- Technical Conference: proposed to be held on February 22, 2016 (but not approved by the Commission)
- Technical Conference: proposed to be held on April 15, 2016

The Commission also scheduled a Technical Conference held on January 7, 2016, and then scheduled another Technical Conference held on March 8, 2016.

Stakeholder Conference: December 17, 2015

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

Our goals for the stakeholder conference were two-fold:

- **Overall Objective:** To obtain a clearer understanding of potential input from the Parties and how it might affect how we develop the 2016 updated PSIPs.
- **Process Considerations:** Discuss the objectives of the process set forth by the Commission in Order No. 33320, answer specific questions regarding the PSIP analysis process, and discuss any other pertinent issues raised by the stakeholders.

We invited over 40 people, including representative from all Parties and the Commission, to attend the conference and to give a presentation about their input. Here is the first of two email messages we sent to invitees.

Sent: Wednesday, December 09, 2015 9:54 AM

Subject: PSIP Stakeholder Conference - December 17, 1pm-4pm

Aloha,

We would like to invite you to attend Hawaiian Electric's Power Supply Improvement Plan (PSIP) Stakeholder Conference.

This Conference is intended to be an open discussion of the PSIP update process. The Conference will consist of a series of moderated open discussions around the following objectives:

A. Respond to questions and accept comments that parties may have about the Companies' November 25th filing, providing its plan for updating the PSIP.

B. Seek input from meeting participants on future pricing for resource options, including but not limited to utility scale generation (renewable and fossil), DER, DR, and grid modernization components. Input to include pricing and ability of these options to provide grid or ancillary services.

C. Seek input from meeting participants on developable levels of various renewable resource options, including but not limited to utility scale wind, utility scale solar, distributed solar, geothermal, etc.

In order to maintain a neutral position, the Department of Business, Economic Development and Tourism has agreed to moderate these discussions. The conversations that take place at this Conference are intended to be informal and not part of the official record in this docket. This is to encourage open and constructive dialogue. Accordingly, we ask that no recording devices of any kind (video or audio) be used. Your acceptance of this invitation indicates your acceptance of these conditions. We thank you for your cooperation.

The Conference will take place on Thursday, December 17, from 1:00 PM until 4:00 PM, in the King Street Auditorium at the Hawaiian Electric Company headquarters building located at 900 Richards Street in downtown Honolulu. Parking validation will not be provided for this event. A government issued ID is required for entry into this building. Please arrive early to allow time for check in (present your ID and receive a Visitor badge).

Due to space limitations, we would appreciate it if you could select one person to represent your organization at this Conference. While we strongly encourage in-person participation, a limited number of conference lines will be available for remote access to the meeting.

If your organization wishes to attend this meeting, please RSVP no later than noon, Tuesday, December 15, 2015 and indicate who will be representing your organization at this meeting. If you plan to call into this meeting, please also indicate that in your RSVP response.

RSVP to:
Heather Villamil
(808) 543-5820

We look forward to seeing you at this meeting.

Mahalo,
Colton Ching

Two days later, we sent the following email to provide more details about the conference.

Sent: Friday, December 11, 2015 8:50 PM

Subject: Additional Info: PSIP Stakeholder Conference - December 17, 1pm-4pm

Aloha,

We are reaching out to you with some additional logistics on the Hawaiian Electric's Power Supply Improvement Plan (PSIP) Stakeholder Conference scheduled for December 17, 2015.

If you wish to provide input in the form of a formal presentation at this meeting, that opportunity will be offered to you. In order to allow everyone an opportunity to participate in the meeting, we would ask that you keep your formal presentation brief (7-10 minutes) and that you adhere to the agenda topics outlined below:

• Resource options, including but not limited to utility scale generation (renewable and fossil), DER, DR, and grid modernization components. Input to include pricing and ability of these options to provide grid or ancillary services.

• Developable levels of various renewable resource options, including but not limited to utility scale wind, utility scale solar, distributed solar, geothermal, etc.

We are particularly interested in your thoughts regarding the resource options we should consider in the PSIP updates. This includes technologies, cost trends, their utilization as a grid resource and constraints by island, if any. If you plan to use slides or other visuals for your presentation, please send the electronic version BY NOON, TUESDAY, DECEMBER 15, 2015 to the email address below. By Monday, we will send a presentation template for your convenience. This opportunity to present is optional, i.e. there is no requirement that you prepare a presentation. The number of presentations will be limited to the time allotted for this meeting and presentation requests will be honored in the order that we receive the presentations via email. If you wish to distribute hard copies to the stakeholders, please bring at least 30 copies.

REMINDER: The Conference will take place on Thursday, December 17, from 1:00 PM to 4:00 PM, in the King Street Auditorium at the Hawaiian Electric Company headquarters building located at 900 Richards Street in downtown Honolulu.

We have received several requests for permission to allow more than one representative to attend the stakeholder conference. After reconsideration, although space remains limited, we will do our best to accommodate two representatives per organization to attend in person. In addition, as stated previously, we will also allow for participation via telephone conference. Unfortunately, the conference bridge also has limits, and for that reason, we will need to reserve remote access for only those who do not have a representative attending in person. We thank you for your understanding. AS A REMINDER: If your organization wishes to attend this meeting, please RSVP no later than NOON, TUESDAY, DECEMBER 15, 2015 to Heather Villamil. Her contact information is below. PLEASE INDICATE WHO WILL BE REPRESENTING YOUR ORGANIZATION. IF YOU ARE UNABLE TO ATTEND IN PERSON, PLEASE INFORM US IF YOU WILL BE PARTICIPATING VIA TELEPHONE CONFERENCE AND THE NAME OF THE INDIVIDUALWHO WILL BE CALLING IN

RSVP to:
Heather Villamil
(808) 543-5820
heather.villamil@hawaiianelectric.com

We look forward to seeing you at this meeting.

Mahalo,
Colton Ching

About 40 people (excluding company personnel) attended either in person or through a phone-in bridge. As we recommended, the meeting was fairly informal to better solicit candid remarks.

The conference featured four presentations. Mr. Glick's focused on garnering input regarding the Commission's eight Observations and Concerns. Mr. Yunker presented DBEDT's planning methodology to achieve an energy future that meets or exceeds the state's energy goals.

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

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

Technical Conference: January 7, 2016

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

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

> The purpose and scope of the technical conference is to further examine and understand the Revision Plan submitted by the HECO Companies on November 25, 2015, and obtain a status report on plans and progress towards the supplementation and amendment of the Companies' PSIPs. In particular, the commission seeks to ascertain (1) the resources that have been or will be obtained or retained by the Companies to perform necessary analyses, including the nature and identification of analysis models, work teams, and consultants; (2) identification of analysis approaches that have been determined; (3) identification of analyses input assumptions and sources for input assumptions that have been determined; and (4) any preliminary results.[1]

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

Proposed Technical Conference: February 22, 2016

The Commission did not render a decision on our proposed technical conference, so we did not hold it. In it, we had proposed to review our *Power Supply Improvement Plan Update Interim Status Report* and to solicit constructive feedback, the results of any substantiated analyses from the Parties, and well-considered recommendations that we could include in our ongoing analyses.

Technical Conference: March 8, 2016

The Commission called this 2½-hour technical conference "to provide an opportunity for the Companies to benefit from feedback from the Parties and the Commission, and assist the Commission in its review of the our responses to information requests."[2]

---

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

[2] Commission letter dated March 2, 2016, signed by David C. Parsons, Supervising Economist.

During the meeting, the Commission provided feedback on our interim status report, guidance on topics and planning elements, and asked a series of questions organized around the eight Observations and Concerns. Life of the Land, REACH, Distributed Energy Resources Council of Hawai‘i, Hawai‘i Renewable Energy Alliance, and Paniolo Power also asked questions. Paniolo Power indicated that they had detailed information on a pumped-storage hydro unit located at Parker Ranch. We asked them to provide that information so that we could include it in our PSIP analysis. This information, however, was not forthcoming. Once again, we requested all Parties to submit any input to our modeling and analysis for creating the 2016 updated PSIPs.

Proposed Technical Conference: April 15, 2016

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

We are awaiting Commission decision regarding our proposal for this meeting.

Planning Meeting Attendance

We invited intervenors to the docket to attend and participate in our working meetings where we review analysis, make decisions on further refinements, and discuss the modeling analysis for completing the 2016 updated PSIPs. Representatives from DBEDT, the Consumer Advocate, and the County of Hawai‘i attended, either in person or through a phone conference bridge. These representatives participated in about 10 meetings.

CONSIDERING AND INCORPORATING INPUT FROM THE PARTIES

Order No. 33320 directed the Parties in the docket to file a report on January 15, 2016 that included, among other topics, input to our process for creating the 2016 updated PSIPs. (The Order stated that the term "Parties" in this docket refers "collectively to the Parties, Intervenors, and Participants in this proceeding."[3]) Our *Proposed PSIP Revision Plan* stated that:

> The Companies welcome and actively seek to obtain input from the Parties and other stakeholders regarding the assumptions, methods, and evaluation metrics. … (T)he Companies encourage the Parties to provide constructive inputs related to the Commission's Observations and Concerns, supplemented with appropriate quantitative justification, methodology, assumptions, and information sources that can apply to the creation of actionable updated PSIPs. This input can be particularly impactful to our analyses. The Companies will incorporate input submitted by the Parties to the extent that time allows.[4]

To assist the Parties, our *Proposed PSIP Revision Plan*[5] contained a table[6] describing, in detail, the high priority inputs to the Commission's eight Observations and Concerns that we require for our analysis.

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

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

[3] Order No. 33320 at 171.

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

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

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

Two Parties (HSEA and HPVC) joined the Sierra Club's submission. Four Parties did not file a response: AES Hawai'i, Hawai'i Renewable Energy Alliance (HREA), NextEra Energy Hawai'i, and Puna Pono Alliance.

How We Considered and Incorporated Input from the Parties

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

- Out of scope. We recognize the Commission's specific instructions to limit issues in the 2016 updated PSIPs to the issues established by the Commission. (Order No. 33320 specifically states that the Parties' "participation will be limited to the issues as established by the commission in this docket.")[7]
- Addressed or incorporated in the *PSIP Update Interim Status Report*.
- Addressed or incorporated in our 2016 updated PSIPs (to be filed on or before April 1, 2016).
- To be addressed in our resource planning that will continue after the April 1, 2016 updated PSIPs filing.

To date, we have incorporated several key points of feedback from the Parties in our 2016 updated PSIPs. We:

- Distributed resource cost assumptions to the Parties on February 2, 2016 to provide transparency of input variable assumptions and provide an opportunity for Parties comments on these input variables.
- Established an FTP site where input information and data developed thus far in the PSIP updated process is posted. This allows Parties to access the information and post feedback. We established this communication platform to provide transparency and a greater understanding of the input variables to be used for the PSIP Update analysis.
- Used a "decision framework" to establish a clear basis for how plan objectives will be prioritized and to clarify how Preferred Plans are selected among the candidate plans.
- Introduced the PSIP optimization processes consisting of DER, DR, and utility-scale iterative cycles to capture analytical steps in achieving our 100% RPS goals which ensure planning iterations are performed to meet the optimization objectives across these resource options.

---

[7] Order No. 33320 at 171.

- Invited Party representatives to participate in working meetings with the Hawaiian Electric Companies planning team on the remainder of analysis and modeling for the 2016 updated PSIPs. This creates greater transparency of the planning, analysis, process, and decisions made during the iterative process.

Receiving Party Input

We actively solicited input from the Parties regarding new resource options, costs, and constraints: in our compliance filing (November 25, 2015), before and during our stakeholder conference (December 17, 2015), and during the Commission-organized Technical Conferences (January 7, 2016 and March 8, 2016).

In their January 15, 2016 filing and again during the March 8, 2016 conference, many Parties offered opinions and suggestions regarding resource types to consider. We were unable to find any specific numerical or objective data in Party input that could be used in our 2016 PSIP modeling efforts. We are, however, considering and addressing the resource types suggested by the Parties. In addition, two Parties included in their filings specific cost information regarding projects they are sponsoring. We compared and validated this cost input to other independent data sources, resulting in certain resource capital cost assumptions reflecting Party input.

Input Incorporated from Other Organizations

Our *Proposed PSIP Revision Plan* listed six additional organizations who agreed to provide independent technical analyses to help address issues of concern for the 2016 updated PSIPs. These stakeholders include the Hawaiʻi Natural Energy Institute (HNEI), Electric Power Research Institute (EPRI), U.S. Department of Energy, University of Hawaiʻi Economic Research Organization (UHERO), National Renewable Energy Laboratory (NREL), and Hawaiʻi Energy.

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

In addition, we also contacted Pulama Lanaʻi about their plans related to projected energy use and possible self-generation for us to include in our analysis. In their February 9, 2016 response letter, Pulama Lanaʻi stated they are continuing to investigate multiple energy options, but that they were not at a point to contribute any input.

Finally, Hawai‘i Energy will be providing us with energy efficiency projections by reducing energy intensities on current square footage, assisting us in developing long-term forecasts that would support the PSIPs.

RESPONDING TO PARTY INPUT

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

To streamline how we responded to input from the Parties for the 2016 updated PSIPs, we organized the input comments into 15 topics. These 15 topics are:

#	Topic	#	Topic	#	Topic
1	Utility Business Model	2	Value of Solar	3	Decision Framework
4	Transparency	5	Resource Input	6	Cases & Sensitivities
7	System Security Criteria	8	DER & DR Optimization	9	Risks
10	Customer Bill Impacts & Relevant Metrics	11	LNG	12	Fossil Generation Upgrades
13	Stakeholder Input	14	Energy Efficiency & Electric Transport	15	Inter-Island Transmission

Table B-1. Party Input Topics

Table B-2 contains a cross reference between the Party submitting a filing and the 15 topics that summarize the various comments. A Party needs only to read across the table to see the input topics they commented on, and refer to the remainder of this appendix to read how we considered and incorporated their input. A checkmark indicates that a Party commented on that topic; a blank means that they did not comment on the topic.

Party	1. Business Model	2. Value of Solar	3. Decision Framework	4. Transparency	5. Resource Inputs	6. Cases & Sensitivities	7. System Security	8. DER & DR	9. Risks	10. Customer Bill Impacts	11. LNG	12. Fossil Generation	13. Party Input	14. EE and EV	15. Inter-Island Cable
CA				√	√	√	√	√	√	√	√	√	√	√	√
CoH	√			√	√					√					
CoM	√		√	√	√	√		√	√	√					√
DBEDT			√	√	√	√		√	√	√		√	√	√	
AES															
Blue Planet	√		√	√	√	√			√		√			√	
DERC	√	√	√	√	√		√	√	√						
Eurus															
Hawaiʻi Gas				√	√	√			√		√	√			
HPVC*															
HREA															
HSEA*	√				√	√		√	√		√		√	√	
LOL	√			√	√		√	√		√			√		
NextEra															
Paniolo Power	√		√	√	√	√			√	√	√	√			√
Puna Pono															
REACH			√	√	√	√	√		√					√	
Sierra Club	√				√			√			√	√			
SunEdison		√						√		√		√			
SunPower		√	√	√				√		√	√	√			
TASC	√	√	√	√	√		√	√							
Tawhiri								√		√		√	√		
Ulupono	√			√				√	√	√	√				√

* = Joiner to Sierra Club's submission

Table B-2. Party to Input Topic Cross Reference

1. Utility Business Model

The Parties assert that the Companies need to transform their business model to move forward and enable the new Hawai'i energy landscape. The Commission stated this topic in its Inclinations, but not in Order No. 33320.

Our Action Regarding this Topic

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

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

NextEra and the Companies have responded to the question of a sustainable business model in the merger docket (Applicants Exhibit 42, Docket 2015-0022). While we concur that our business model is an important issue to discuss, as directed by the Commission, continued discussion is beyond the scope of this docket.

We developed our Preferred Plans within the framework of a sustainable business model that enables us to transform our power grid to meet the 100% renewable energy goal. Incorporated in that business model is our intent to remain one of the power producers of utility-scale generation.

2. Value of Solar

The Parties assert that our avoided cost methodology does not fully capture the value of solar, and recommend a comprehensive study to develop a different methodology.

Our Action Regarding this Topic

We are confident that our avoided cost methodology and the development of integration solutions and costs and characteristics of operation is a sufficient proxy given the time constraints. Nonetheless, we plan to cover this topic in more detail in Phase 2 of the DER docket.

3. Optimization Decision Framework

The Parties stated that our process for choosing the Preferred Plans in our 2014 PSIPs was not well articulated and was flawed; that the optimization steps were unclear; and that our discrete uncoordinated analysis resulted in suboptimal resource allocation. Some Parties concluded that the process needs an optimization framework detailing an overarching logic; and that this framework guide development paths and portfolios for specific goals (for example, rate reduction, low cost, and 100% RPS), and help select Preferred Plans that best accomplish those goals.

Our Action Regarding this Topic

We have developed a detailed decision framework (see Appendix C), and discussed how we used this framework to analyze and optimize the various cases to select our Preferred Plans (see Chapter 3).

4. Transparency

The Parties want to understand and be informed about:

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

Our Action Regarding this Topic

We documented our decision framework in Appendix C, the actual iterative implementation of that decision framework in Chapter 3; all assumptions in Appendix J; and all modeling tools in Appendix H. We established an FTP server site where we post content from our PSIP work; the server enables the Parties not only to read this content, but also to post additional content and to comment. To further our desire to make our process transparent, we invited representatives from the Parties to attend our planning and decision-making meetings; three organizations responded: the Consumer Advocate, DBEDT, and County of Hawai‘i. These representative attended about 10 of our meetings, both in person and through a phone bridge.

5. Resource Inputs

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

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

Our Action Regarding this Topic

Appendix J documents how we arrived at the assumptions used in our analyses. We have uploaded all resource assumptions to the FTP server. We also requested additional information from Paniolo Power about the initial resource inputs they provided.

6. Cases and Sensitivities

The Parties want various cases and sensitivities explored, such as:

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

Our Action Regarding this Topic

In our 2016 updated PSIP analysis, we developed three themes and applied multiple sensitivities to each theme, creating numerous cases to analyze for each operating utility. We evaluated all of these cases, under a merged and unmerged scenario, to be considered for our Preferred Plans. These cases and the process for selecting the Preferred Plans are described in Chapter 3.

We did not run a case that does not attain 100% RPS by 2045; we only ran cases that, at a minimum, complied with statute.

7. System Security Criteria

The Parties contend that the system security methodology and results published in our 2014 PSIPs are overly conservative and limit DER adoption; and that system-level constraints should emphasize safety, reliability, and power quality rather than economics.

Our Action Regarding this Topic

We leveraged the analyses from the Integrated Demand Response Portfolio Plan (IDRPP) supplemental filing to determine technology-neutral system security requirements for each resource plan. This included removing any system must run requirements for each island's grid as a starting point for system security analysis. If the technical requirements are met, DR and DER can be used to support, impact, and provide system security. Appendix P documents the process and results from our system security analysis.

8. DER and DR Optimization

The Parties want assurance that the PSIPs are coordinated with the DER and DR dockets; that we treat DER as a resource to be optimized (and not an end state); and that appropriate consideration be given to motivate customer adoption. The Parties want us to view DER as customer-centric solutions and recommend our conducting an in-depth study to better achieve the Commission's overarching goals for reducing rates and ensuring a clean energy future while providing customer choice.

Our Action Regarding this Topic

We documented our current DER and DR optimization process, and have explained the potential services that DER and DR can provide to the grid and how we plan to fully utilize them. (Refer to Appendix C.) As directed by the Commission, we considered customer choice as important, but not necessarily the primary criteria for evaluating any resource portfolio.

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

9. Risks

The Parties want assurance that all risks are properly documented and explored through the various portfolios and options. They are concerned that customers will bear the impact of stranded costs because of the chosen resource mix, and want information on when and how customer savings are realized under the various plans.

Our Action Regarding this Topic

We developed a thorough set of risk criteria to evaluate each alternative plan on an equal basis with similar objectives. We explained this risk criteria and evaluation process and posted it on our FTP server. We have included sensitivities that test key risk factors in our 2016 updated PSIPs.

Our Decision Framework lists a number of risks that must be minimized. We discuss the risks associated with the three themes in Chapter 1: Introduction; Appendix E: New Resource Options discusses the risks associated with implementing new resources into our generation mix.

10. Customer Bill Impacts and Relevant Metrics

Some of the Parties want assurance that the impact on customer bills will be evaluated for all plans, that nominal impacts will be stated for all plans, and that comparisons with alternative portfolios will be provided. Some Parties want the Companies to develop bill impact estimates for various residential segments (such as customers who do and do not participate in distributed generation programs).

Our Action Regarding this Topic

Our 2016 updated PSIPs compare the impact that each Preferred Plan has on customer bills. We show these impacts in both nominal and real dollars. Whenever possible, we described the main drivers that impact bills.

11. Liquefied Natural Gas (LNG)

The Parties want us to specify our plan to import and exit from LNG use, and to minimize or eliminate stranded costs that impact customers; and want to see the savings demonstrated for using LNG as a bridge fuel as compared to investing in only renewable generation. Some parties do not consider LNG a feasible option because it's not a renewable resource.

Our Action Regarding this Topic

We developed cases that achieve 100% RPS both with and without LNG under market DG PV forecast and higher DG adoption for both high and low fuel price projection. All cases with LNG assume that LNG will end in 2040, and that all applicable costs are depreciated over the time period of LNG usage to avoid stranded costs. Our theme plans also show the cost differential from investing in LNG as opposed to investing in only renewable resources.

12. Fossil Generation Upgrades

The Parties want to better understand the final cost and performance characteristics of fossil generation upgrades (such as, how the units previously performed, what the modified units are now capable of, and how the performance and savings of the modified generators might compare to new and existing generating units).

Our Action Regarding this Topic

We documented the cost for modernizing our fleet with the installation of a 3x1 combined-cycle unit on O'ahu's Kahe site, and describe the benefits of such a unit. We also quantified the value of such a unit compared to other selected alternatives.

13. Party Input

The Parties want assurance that their input will be considered and integrated in candidate plans and in the Preferred Plans.

Our Action Regarding this Topic

This appendix describes, in detail, how we considered and incorporated party input into our analyses. Virtually all input dealt with process; we received virtually no data that directly contributed to our analyses.

14. Energy Efficiency and Electric Transport

The Parties want to know how energy efficiency will help with grid issues. In addition, the CA wants us to incorporate measures from recently published energy efficiency studies into our analyses. The Parties want us to encourage further adoption of electric transportation.

Our Action Regarding this Topic

We incorporated energy efficiency measures that meet EEPS into our analyses.

We offer TOU incentives to EV owners to shift charging to overnight, and are piloting a charging infrastructure that can align with DR programs and pricing. We have filed a revised TOU structure to shift charging to midday when solar production is at its peak.

To minimize "range anxiety", we are installing and operating publicly available, direct current fast charging stations that can charge an EV battery to 80% capacity in 30 minutes. We are also demonstrating the capability to limit and curtail the maximum demand of a 50 kW DC fast charging station to 25 kW, and investigating opportunities to encourage daytime public and workplace charging.

Hawaiian Electric participates in the Honolulu Department of Transportation Services (DTS) 2016 Transportation Investment Generating Economic Recovery (TIGER) grant application for a Honolulu Urban Bus Circulator System. The TIGER grant is a cost-effective solution to significantly advance mobility in the most congested areas of the city. The current proposal includes up to 24 high frequency and high capacity electric buses that will be incorporated within the circulator system; Hawaiian Electric plans to partner with DTS on the electric bus charging infrastructure.

15. Inter-Island Transmission

The Parties want us to address the impact of inter-island transmission on the reliability of the Oʻahu, Maui, and Hawaiʻi Island power grids, specifically how a forced cable outage affects reserve requirements and reliability.

Our Action Regarding this Topic

We are analyzing a grid-tie between Oʻahu and Maui and between Oʻahu and Hawaiʻi Island, and how an outage would affect reserve requirements and reliability. The 2016 updated PSIPs describe our progress on this analysis, which we expect to only be able to complete after the filing deadline. We are committed to completing this analysis, including updated analysis that incorporates the 2016 EIA AEO fuel price forecast[8] and submitting that updated analysis on or before August 31, 2016.

8 The Energy Information Administration 2016 Annual Energy Outlook is expected to be published in June 2016.

C. Analysis Methodologies

The issues related to planning the future of Hawai‘i’s power systems are complex. These issues represent uncharted territory for any utility performing long-range resource planning.

Hawai‘i faces a unique situation: a comprehensive electric grid transformation to attain a 100% Renewable Portfolio Standard (RPS) by 2045. To aid in this endeavor, we developed a Decision Framework and PSIP Planning and Modeling process creating a structure that incorporates planning, modeling, and optimizing potential resources to attain our energy goals. Through this process, we expect to enable careful, thoughtful, well-rounded, and well-considered decisions.

In our 30-year planning period for these updated PSIPs, we are considering the optimization of a number of resource options, including commercial and emerging DER options, DR, and a number of commercial and emerging utility-scale resources. This optimization must take into account the system reliability issues of our independent island systems. In addition, we must consider customer behavior, global energy market conditions and expectations, state energy policy objectives, and competing agendas of various stakeholders.

The methods and techniques used by the utility industry in the past are simply not sufficient to accomplish the analysis required to address these many factors. A key objective is to make this planning process clear and transparent despite its complexity. Our Decision Framework describes our approach for considering the various input options, and our PSIP Planning and Modeling process explains our approach for developing the most optimal resource plans.

DECISION FRAMEWORK

Four factors comprise our Decision Framework.

Objectives. The specific results that the planning process aims to achieve. It's important that these objectives be precise.

Requirements. Fixed parameters around which a plan must be built and that do not vary between plans or plan sensitivities.

Input Parameters. Parameters that are not fixed like a Requirement, but are also not a variable that can be controlled to optimize toward achieving the Objectives. Input Parameters can be varied to deal with the uncertainty and to understand the sensitivity of a plan to a change in assumptions.

Decision Variables. Variables that can be varied toward achieving the Objectives. Decision Variables include resources and programs that can be leveraged by the utility in a given plan to achieve the Objectives.

The objectives, requirements, and input parameters all feed into the decision variables. Figure C-1 depicts the quantities and timing of resources (including DER, DR programs, and utility-scale resources) on the electric system that are varied to achieve the objectives, while meeting fixed requirements, and considering the input parameters as assumptions. These are the primary objectives, requirements, and input parameters.

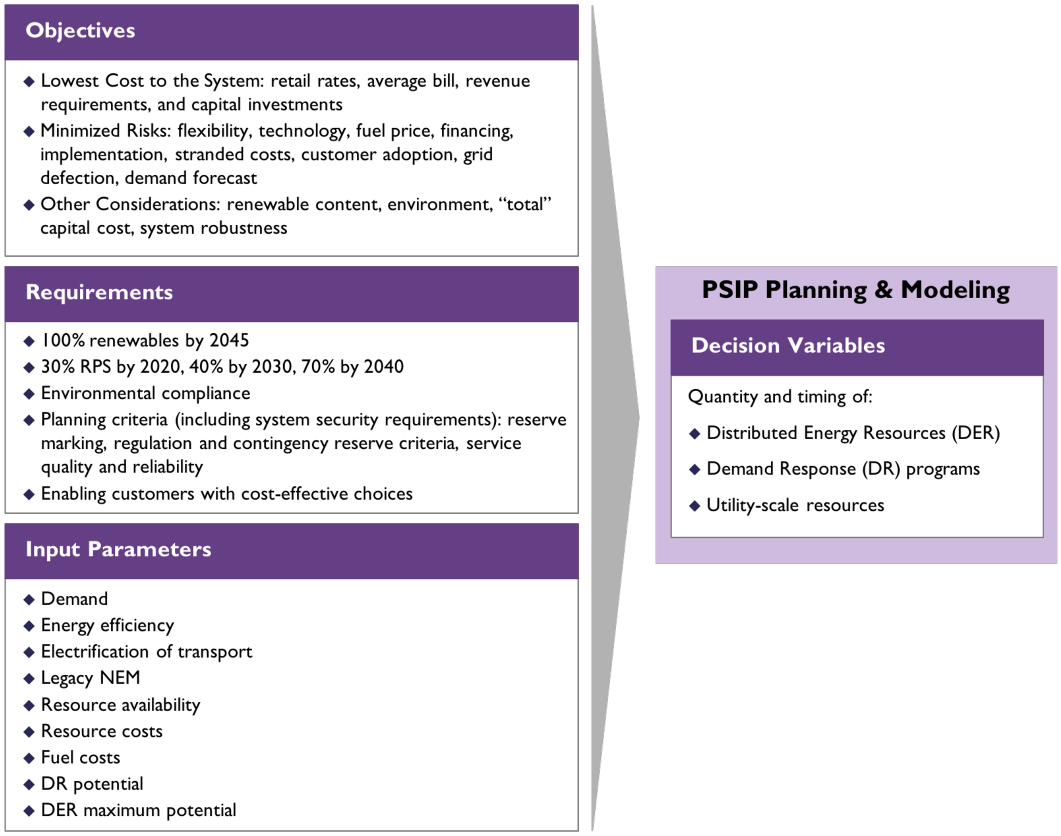


Figure C-1. Overview of the Decision Framework

Objectives

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

Lowest Cost to the System. Minimizing customer cost is a primary objective of the planning process, including the retail rates and a customer's average bill. Total system costs consider the total costs to the electric system, including generation, transmission and distribution, interconnection, revenue requirements, capital expenditures, and integration costs.

Minimized Risks. Any forecast has uncertainty, which in turn introduces risk to a plan that is carried out based on that forecast. Examples of risks for a given plan include planning flexibility; technologies chosen and their related costs; fuel costs that are higher or lower than forecasted; project implementation risks including permitting and siting issues, and community acceptance; financing risks associated with availability and cost of capital investments and expenditures; risks associated with stranded costs, and the rate at which customers adopt renewable generation and provide grid services; the risk of customers leaving the grid and spreading fixed costs over the remaining customers; and the risk of not achieving energy efficiency goals to the point of affecting demand forecasts.

Other Considerations. We must consider many other factors besides the primary objectives of minimizing customer cost and minimizing risks. For example, a plan that is more costly than another, but achieves greater levels of renewable energy and lower fossil fuel use might be preferred by some stakeholders. Another plan with lowest utility revenue requirements, and thus has the most favorable impact on customer bills, might require large subsidies (for example, tax credits and subsidies) and customer investments that results in a higher total cost. While every plan meets system security requirements, some plans might have qualitative considerations related to system robustness (such as the amount of inertia and the size of the transmission balancing area). We must also consider the environmental impact of current and future generation.

Requirements

Requirements are fixed parameters around which plans are built. Requirements do not vary between plans or plan sensitivities. Requirements include RPS mandates, other regulatory compliance, planning criteria, and enabling customers the choice of providing cost-effective and reliable grid services.

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

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

Planning Criteria (including system security requirements). Planning criteria are standards for safe, reliable power supply for customers. Planning criteria are developed considering system security requirements, system reliability, loss of load probability, service quality, and adequacy of supply necessary to maintain an acceptable level of reliability.

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

System security requirements are necessary to provide an adequate level of reliability. Currently, generators provide the majority of the necessary system security attributes. At some point, DR and energy storage resources might be available in sufficient capacities to augment or replace these generators. Updated system security analyses identified fast frequency response requirements for each island system. Continued analysis based on planning criteria might identify additional resource needs and operational constraints.

Enabling Customers with Cost-Effective Choices. With more DER options, customers have choices that we will continue to enable. Customers can effectively be a "prosumer", that is one who both consumes energy, uses utility services, and provides services to the utility. Customers also have the choice to provide grid services to the electric system; the price for such grid services, however, must reflect their economic value relative to other resources.

Input Parameters

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

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

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

DR and DER Potential. DR and DER programs might provide multiple grid services. We must determine the total potential that these programs could contribute to the candidate plans. DR includes programs that leverage a variety of flexible customer-sited resources to provide grid services. Self-supply and grid supply programs and DER compensation levels, effectively set, affects customer adoption.

Decision Variables

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

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

PSIP PLANNING AND MODELING

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

Figure C-2 illustrates the PSIP Planning and Modeling process. These processes involve multiple internal resources and modeling efforts. Throughput of a single iteration takes time, with multiple reviews and validations at various points during each iteration.

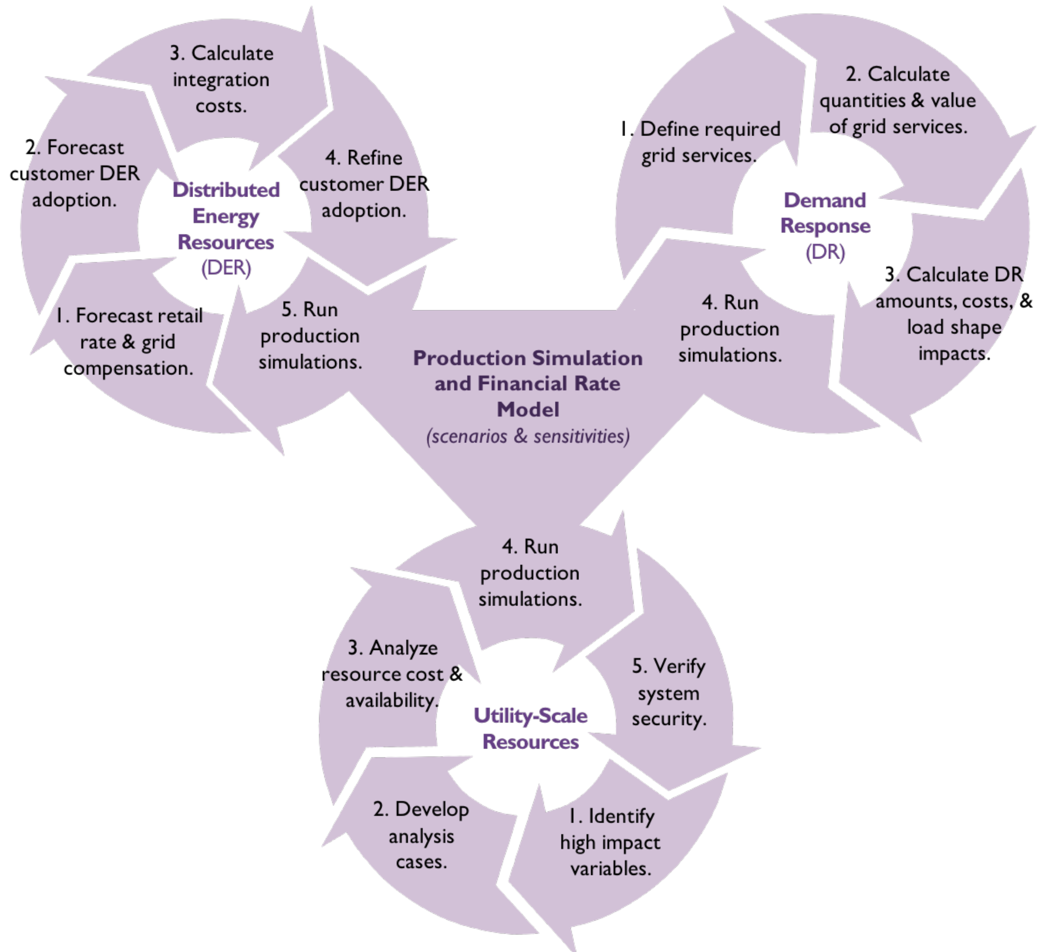


Figure C-2. PSIP Optimization Process for DER, DR, and Utility-Scale Resources

The following sections explain each of these three iterative cycles.

DISTRIBUTED ENERGY RESOURCES ITERATIVE CYCLES

DER includes assets such as DG-PV and distributed energy storage systems (DESS) that play a critical and growing role in the future electric system. Customers decide to install these assets based on a number of factors, including cost savings on electricity consumption and compensation from providing grid services through DR programs. We plan to integrate and optimize DER into the generation resource mix on a system level based on customer decisions to install these assets.

To begin, we forecast the potential DER that customers would be willing to adopt based on preliminary assumptions on customer economics related to DER. We plan to integrate the new DER exports into the resource mix that is below the avoided cost for alternative generation assets with similar attributes. We assume that existing DER programs, including legacy NEM, Standard Interconnection Agreement (SIA), Grid Supply to cap, and Self Supply run through their current program life at current compensation levels. In addition, we assume a new program for grid export of DG-PV will be instituted—similar to today's Grid Supply program but with an updated compensation rate. (This assumption is only for planning; we will discuss a detailed program structure in the DER 2.0 proceedings.) Forecasting assumptions included the 2013–2014 historical hourly customer load profiles by island and rate schedule, optimum system size, tariffs, export rate, storage value, income tax credits, system costs, eligible customers, inflation rate, and weighted average cost of capital.

Since the interim filing, we have refined these economic adoption assumptions, and developed programs to enhance this adoption rate—programs that optimize and provide the most benefits for our customers and grid services in conjunction with other renewable resources in our future portfolio.

1. Forecast Retail Rate and Grid Compensation

The payback time of a customer-sited DER system is determined by customer benefits received over time versus customer cost for the DER system.[1] The DER system may benefit customers by offsetting their retail electricity purchases by being compensated for providing grid services.

- **Forecast Payback Time for DG-PV Compensation.** Order No. 33258[2] specified compensation rate and cap by island for a new grid-supply product. As a preliminary assumption for the compensation of the export of future DG-PV not covered under the existing programs and aligned with an Objective to achieve lowest cost, we:
- Considered resources with similar variable generation attributes, to avoid inequitable comparisons to firm generation resources.
- Considered resources with comparable time-of-day production (for example, those resources producing during solar generation hours).
- Enabled full utilization of DG-PV on the system. To achieve an objective at lowest cost, this implies compensating DG-PV at the same level as alternative energy resources with similar attributes (renewable, variable, producing during solar generation hours).
- Modeled the DG-PV resource as controllable and curtailable, similar to other variable generation resources.

---

1 Appendix J: Modeling Assumptions Data contains forecasts for the cost of DG-PV, utility-scale PV, and residential energy storage. These cost forecasts were developed in conjunction with the utility-scale cost assumptions utilizing the same base data sources and assumptions.

2 Issued on October 13, 2015 in Docket No. 2014-0192: Proceeding to Investigate Distributed Energy Resource Policies.

We compared utility-scale PV with DG-PV. We also assumed the future DG-PV export rate to mirror the respective levelized cost of energy (LCOE) of utility-scale PV for every year of the 30-year planning horizon. This assumption ensures optimal amounts of DG-PV are fully utilized by the system under economic dispatch principles. (This is simply a modeling assumption, and not a policy decision.) Continued analysis could further refine these assumptions.

Forecast Payback Time for Other DER Compensation. Retail electricity price and the value of grid services are a function of the overall electric system. Retail electricity price forecasts are derived from the production simulation and financial rate model. The value of grid services is derived from the production simulation and DR modeling.

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

DER Controllability. The 2016 updated PSIPs assume system operator control of DG-PV will be feasible before or by mid-2018, based upon the following:

- Commission approval of our proposals in the DR docket by the end of 2016 and of our proposals in the DER docket by the end of 2017.
- A Distributed Energy Resource Management System (DERMS) implemented by mid-2017. A DERM incorporates traditional Demand Response Management System (DRMS) functionality and a full suite of distributed energy management capabilities currently in production and under development by Omnetric. The DERMS is assumed to control a wide array of distributed energy resources, regardless as to whether they are enrolled specifically in a DR program.
- The 2016 updated PSIPs assume policies and programs (including pricing programs) that stipulate distributed energy resource control in place by mid-2018. The details of these policies and programs are expected to be captured outside of the updated PSIPs and jointly between current DR program filings and the anticipated DER Phase II proceedings.
- Implementation of a Company-owned A*dvanced* Metering Infrastructure (AMI) communications network to exercise DER control. Our AMI infrastructure is not currently expected to be implemented until after 2018. We expect that aggregators and DER providers will provide near-term communications sufficient for the preliminary stage of DER control and the associated feedback loop.

2. Forecast Customer DER Adoption Levels

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

3. Calculate Integration Costs and Curtailment Amounts

When DG-PV installations exceed the circuit hosting capacity limit, circuit upgrades are required while some curtailment might also be required. Integration costs and curtailment amounts to accommodate DG-PV over the circuit hosting capacity limit are calculated by circuit.

We developed a methodology to quantify integration costs and curtailment amounts on circuits over the hosting capacity. That methodology allocates DG-PV forecast pro-rata across circuits, identifies integration solutions and their respective costs, calculates curtailment amounts, then applies these integration costs and curtailment amounts to adjust the economics and the expected adoption rate from both a system and a customer perspective. Integrating variable renewable energy (including DG-PV, utility-scale PV, and utility-scale wind) might require regulating reserves, energy storage, investments in system operations, and curtailment. Based on these changed economics, the DG-PV is re-forecast.

Figure C-3 depicts a high-level overview of the circuit-level integration cost methodology.

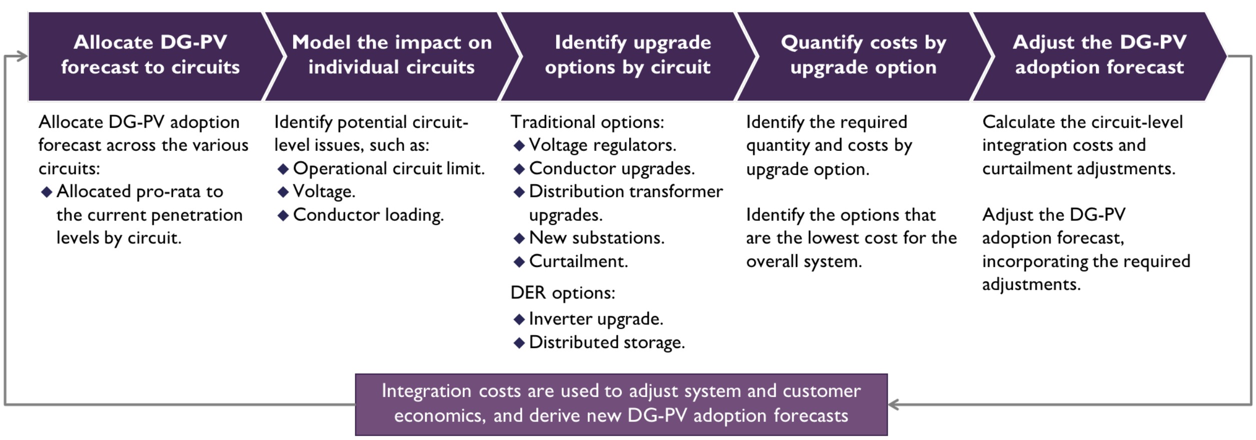


Figure C-3. Circuit-Level Integration Cost Methodology

4. Refine Customer DER Adoption Levels

Integration costs and curtailment amounts adversely impact the value of DG-PV for customers adopting DG-PV above the circuit or system hosting capacity limits. As a result, integration costs and curtailment amounts can result in a refined payback time and associated customer adoption rates. To determine preliminary assumptions for our 2016 PSIP analysis, integration costs are allocated only to those customers who install a

DG-PV system above circuit and system hosting capacity limits (and not assumed for other customers), or integration costs are allocated to all customers. DG-PV adoption forecasts and costs to customer are provided for each scenario.

We continue to refine the economic adoption assumptions and are developing programs to enhance this adoption rate. These programs optimize and provide the most benefits for our customers and grid services in conjunction with other renewable resources in our future portfolio.

5. Run Production Simulation with DER Adoption Levels

The previous four steps result in a forecast of DER adoption levels based on two factors: 1.) customer uptake of DER based on the economics from the customer's perspective, and 2.) provision of power supply and grid services from the customer that is cost effective for the overall system.

These DER adoption levels are then included in a subsequent production simulation and financial model iterations and as potential in the DR iterative cycles. The DER adoption levels impact net sales and peak forecasts. If the retail electricity price and the value of DER substantially change in the production simulation and financial model, and in the DR modeling, then the five DER steps are iterated again. Successive iterations optimize the quantities of DER.

DEMAND RESPONSE (DR) ITERATIVE CYCLES

Demand Response requires a separate iterative cycle for resource planning.

1. Define Required Grid Services

Our portfolio of DR programs delivers grid services that help meet system security requirements. These grid services serve as the basis of all programs. Grid service definitions are cross-referenced with DR program attributes and rules to ensure an effective delivery of the grid services by DR resources. As part of the PSIP update, these service definitions and their associated equations are being modified.

The first step in DR optimization is to assess the degree to which these modifications impact the DR potential, and thus the overall DR portfolio. In parallel, we are adjusting, as necessary, the market potential of the various DR programs.

The DR potential study model is re-run with these modified and refined inputs: updated load forecasts based on new resource plans; adjusted ability to control a DR resource based on revised program attributes; refined end-use load shapes and associated ability to shed load; and modified percentage of customers willing to enroll in a particular program.

2. Calculate Quantities and the Value of Grid Services

To identify the potential for DR resources to deliver grid services, DR optimization must first understand the quantities and value of the various grid services for each time interval, for each island power grid. To the extent feasible, DR opportunities for providing each grid service is evaluated independent from each other based on the results of step 1 of DR optimization.

Costs will not always be aligned with quantity. For example, it may be necessary to provide a minimum amount of a particular grid service during a particular time interval in order to alleviate a must-run requirement and therefore realize value from a DR resource.

The value of a given grid service might depend on that grid service being provided concurrently and in conjunction with other grid services. For example, the inertia grid service may be linked to the primary frequency response (governor response) combined with the spinning contingency reserve to alleviate a must-run requirement. This means that a DR resource that provides only a single grid service would have limited value on a stand-alone basis. DR resources that provide multiple services will have greater value.

The value of each grid service is calculated to determine how best to apply DR resources. Grid service values are calculated by comparing system production costs between model runs for adjusted service levels. More precisely, altering appropriate service requirements or constraints relative to a reference case results in differences in system costs that can be used to calculate the incremental costs of delivering that service. Understanding the relationship to quantity and value of services over time helps determine substitution opportunities for DR products. Generators can be simulated as must-runs for reliability. If a service can meet the reliability need, the must-run requirements are adjusted to allow generation to be dispatched economically. The change in costs from relaxing must-run constraints helps infer the value of a service (such as inertia).

3. Calculate DR Amounts, Costs, and System Load Shape Impacts

Once the quantities and values of grid services have been derived, an optimal DR portfolio is developed as input. An iterative process derives both the population of end-use devices and the resulting DR fit for delivering grid services cost-effectively. Several sub-tasks represent this iterative process.

Preliminary Inputs. These inputs are required for analyzing DR fit:

- The refined DR potential calculated during DR step 1.
- The quantity and value of the services derived from DR step 2.

Identify DR Portfolio Fit. DR can provide a portion of the required grid services by displacing grid services by generating assets within an analysis case. The projected fit and value of DR products to meet some or all of each of the grid service needs, for each time step, is determined for each island power grid. Using the adaptive planning model (developed by Black & Veatch), the provision of grid services from conventional resources and DR products are optimized to meet the power system reliability requirements at minimal overall cost (producing cost savings). Cost savings result from changes in the timing of the expansion plan or size of an added resource, changes in retirement timing, or changes in operation. These cost savings can be capital deferment, avoided fixed costs, or avoided variable costs.

DR programs can be reshaped daily to address changes in demand, wind and solar profiles, and the availability of assets.

The adaptive planning model can then calculate the "stack" of DR resource utilization and allocate them to maximize their value to the DR portfolio. This capability allows us to assess the fit of the model's results against system security needs and the underlying asset portfolio characteristics.

A sensitivity analysis is then conducted to expose areas where changes in the electric system can substantially impact the value of DR services. These sensitivities include the availability, size and cost of storage and the role of DR products given modified security constraints.[3]

Because the adaptive planning model directly calculates value in moving underlying end uses between DR programs, the resulting fit is generally optimized against security and system asset characteristics. Further investigation might be necessary to validate results or to identify gaps where additional DR products could help meet system response requirements or reduce curtailment of variable renewables.

Derive Value. Value can be derived of bundled services for storage only, or for real time pricing (RTP) only (that is, for DG-PV plus energy storage systems). The model develops annual values associated with bundles of grid services that can be delivered by a stand-alone storage device. This then serves as a proxy for the annual economic value earned with stand-alone DESS. In addition, the model develops an annual value of the

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

time-of-use (TOU) and RTP programs, which serves as a proxy for economic value for DG-PV plus energy storage system. Values are for the 2017–2045 timeframe.

Load shifting can be accomplished with pricing, storage, and behavioral tools (for example, DR) in addition to utility-scale and grid solutions.

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

Refine Populations and Potential. The model inserts the forecasted customer adoption for DESS and DG-PV plus storage into the potential study model. A revised DR potential is then calculated based on the updated customer groups.

Rerun DR Portfolio Fit. This revised DR portfolio potential is then used to determine the DR fit and corresponding value of the DR services. The DESS and DG-PV plus storage values are compared to the values previously calculated. If these values are essentially consistent with the previous iteration, forecasting is complete because the convergence reflects an optimal population of the end uses and the DR portfolio as a whole, for that particular case—in other words, the best fit. If the values are meaningfully different, then customer adoption is re-forecasted.

Iterate until Values Converge. If the economic value of DR, DESS, and PV plus storage converge, the iterative process is complete because the economic value of the populations and the DR portfolio are sufficiently optimized, for that particular case. If these economic values vary, iterations continue until the set of economic values converge.

Finalize the DR Portfolio. A DR portfolio is optimized when the fit and economic values converge. This optimized DR portfolio is then finalized and used in production simulations. For each case, these results are a combination of the:

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

4. Run production simulations with DR amount and load shape adjustments

The optimized DR portfolio is then used as an input to the production simulation model. Portfolio costs and any cost impacts related to resource plan adjustments are added to the economic evaluation of each resource plan case.

UTILITY-SCALE RESOURCES ITERATIVE CYCLES

The utility-scale resource iterative cycle is similar to the cycles for DER and DR.

1. Identify High Impact Variables

Variables that have a high impact on the Objectives are first identified. Initial examples include fuel type, extent of generation modernization, and amount of DER adoption. In subsequent iterations, additional high impact variables are identified and varied between cases to understand their impact on the Objectives.

2. Develop and Refine Analysis Cases

Cases to be analyzed are developed based on the high impact variables and the results of the DER and DR iterative cycles to better understand their impact on the Objectives. For example, the fuel type used in one case might assume a low LNG price forecast whereas another case might assume a low oil price forecast (without LNG) for as a transition fuel toward attaining the 100% RPS goal.

DR amounts, costs, and system load shape impacts from the DR iterative cycles are also incorporated into the cases run in the production simulation.

3. Analyze Forecasted Resource Costs and Availability

This step determines near-optimal resource quantity and timing. The production simulation and financial rate model determines, at a very detailed level, generation output and the associated rate impacts for a given case. Multiple cases are compared, revised, and successively iterated until a plan is identified that best meets the Objectives.

To make this iterative process more efficient, resource cost forecasts are analyzed outside of the production simulation to identify likely near-optimal resource quantity and timing for the various analysis cases. Two models outside of the production simulation identify likely near-optimal resource quantity and timing.

Resource Cost Competitiveness and Economic Curtailment Amount. This model identifies how much of a new resource can remain cost effective when curtailed, and when such a resource should be introduced into the plan. The model calculates when a new resource costs less than existing resources, and how much can be curtailed while still remaining less costly.

System Need and Cost-Effective New Resource Implementation Amount. This model, accounting for system needs and economic curtailment, determines how much of a new resource can be added to the system by calculating the net non-curtailable resources from load. The model then adds the cost-effective resources up to the economic curtailment amount to determine the annual amount (in MWs) that the new resource can be added.

The two models output an annual schedule as to when a new resource can cost-effectively be implemented, and when existing resources can be retired. This schedule is then used in the production simulations.

4. Run Production Simulations

This step analyzes cases to test the incorporated high impact variables and near-optimal resource quantity and timing. Production simulations calculate each resource's generation through hourly and sub-hourly unit commitment and economic dispatch algorithms. Outputs are then used to determine the total system costs and the impact on customer rates that consider capital costs, fuel costs, and fixed and variable O&M costs over the planning period. These results are analyzed, and then iterated until a plan is unveiled that best meets the Objectives.

5. Verify System Security Compliance

Each case is analyzed to ensure it meets system security requirements for simulated commitment schedules and dispatch levels when subjected to various contingency conditions. If system security requirements are not met, technology-neutral system requirements are determined and adjustments are made to the resource plans. Sometimes, generating units must be committed or dispatched outside of ideal economic dispatch levels until technology-neutral alternatives are added to the grid or until the driving contingency event can be eliminated to maintain system security.

When sufficient capacities of DER and DR resources are available, ancillary services provided by thermal units will not constrain resource plans.

D. Current Generation Portfolios

PLANNED CHANGES TO CURRENT GENERATION

Our assumptions include changes to current generating units and to existing PPAs.

Current Generating Units

Hawaiian Electric plans to retire most of its current thermal generation during the planning period, however the exact timing of these retirements is uncertain as it depends on a number of factors. Chief among these factors is maintaining adequacy of supply, but these factors also include the timing of the implementation of replacement generation, fuel costs, outcomes from DR programs, and peak demand.

Waiau 3 and Waiau 4

Our PSIP analysis assumes that Waiau 3 and Waiau 4 will be deactivated in 2022 to 2023, depending on the theme. For Theme 1 and Theme 3, Waiau 3 and Waiau 4 are assumed deactivated in 2023; for Theme 2, they are assumed deactivated in 2022. We made these judicious assumptions based on our assessments of capacity needs and the input variables in this 2016 updated PSIPs.

The 2014 PSIPs targeted these units for deactivation at the end of this year, 2016. Based on a Loss of Load Probability (LOLP) guideline of 4½ years per day, Hawaiian Electric's 2015 AOS reported a reserve capacity shortfall of 50 MW, beginning in 2017 if these units were deactivated in 2016. The AOS report stated that reserve capacity shortfalls could be mitigated by "by deferring future deactivation of units, increasing Demand Response Programs, reactivating units that are currently deactivated, or acquiring additional firm capacity through a competitive bidding process."

Hawaiian Electric's 2016 AOS report assumed the deactivation of Waiau 3 and Waiau 4 at the end of 2017 to avoid a capacity shortfall in 2017. Shortfalls are still projected for 2018 and 2019, even if the Schofield Generating Station is in service in 2018. Delaying the deactivation of Waiau 3 and Waiau 4 beyond 2017 virtually eliminated reserve capacity shortfalls. A small reserve capacity shortfall is still anticipated in 2018.

We will continue to monitor factors that determine the best timing for deactivating Waiau 3 and Waiau 4. These factors include system demand, net of customer-sited distributed generation and demand response, availability of new generating capacity (from the Schofield Generation Station), and the unavailability of capacity from scheduled or unscheduled maintenance.

Honolulu 8 and Honolulu 9

The PSIP analysis assumes that Honolulu 8 and Honolulu 9 remain deactivated, and are converted to synchronous condensers to enhance power line voltage regulation.

Hawaiian Electric's 2016 AOS report assumed Honolulu 8 and Honolulu 9 remained deactivated until 2020 and beyond. We would not need to reactivate these units if the deactivation of Waiau 3 and Waiau 4 were deferred until the end of 2020, and the Schofield Generating Station came online in 2018.

Higher than forecasted peak demand might cause reserve capacity shortfalls.[1] We would need to reconsider reactivating Honolulu 8 and Honolulu 9 if significant reserve capacity shortfalls are projected, but only after implementing other mitigating measures (such as running new DR programs, acquiring additional firm capacity, deferring other unit deactivations, and refining generating unit planned outage schedules). Reactivating Honolulu 8 and Honolulu 9 would take about three months.

Maui Electric

On Maui, Kahului 1 and Kahului 2 are currently deactivated. However, these units are counted towards firm capacity because they can be, and are, reactivated when needed to maintain system reliability.

Maui Island has two generating stations and one distributed site. Our Kahului Power Plant has four steam units totaling 35.92 MW (net) firm capacity. Maui Electric deactivated two units to conform with our System Improvement and Curtailment Reduction Plan,[2] but we can reactivate them in the event of a shortfall. The other two

[1] Our 2016 AOS report noted that the peak demand recorded in 2015 and adjusted for standby load was 1,232 MW-net. This was 37 MW higher than the 1,195 MW-net peak demand forecasted for 2015. The report attributed this higher peak demand to higher than normal temperatures and humidity. The adjusted 2015 recorded peak is 69 MW higher than the 1,163 MW-net peak demand forecast for 2016.

[2] *System Improvement and Curtailment Reduction Plan* filed in Docket No. 2011-0092, September 3, 2013.

units were previously scheduled for retirement in 2019, however their retirement would have resulted in a reserve capacity shortfall of approximately 40 MW per year. To ensure enough capacity to meet demand, we obtained a National Pollutant Discharge Elimination System (NPDES) permit[3] from the State of Hawai'i Department of Health (DOH) to allow Kahului Power Plant to continue operating provided we retire the units by November 13, 2024. We currently plan to retire the entire facility in 2022 assuming sufficient replacement resources (including DR and generation) are in operation by then.

Our Ma'alaea Power Plant has 15 diesel units and 4 gas turbines. They can be configured into two separate combined-cycle systems supplying two steam turbines totaling 208.42 MW (net) of firm capacity. In 2014, we upgraded the generator controls on four of the diesel units so that they could be monitored and operated remotely. These upgrades enable us to better respond to system disturbances and system demands because of increased variable renewable resources on the system. We plan to modify one of the combined-cycle systems, allowing it to operate at lower levels so that the grid can accommodate more renewable generation.

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

Our analysis assumes that all units on Moloka'i and Lana'i are active and operating. Moloka'i has a centralized generating station with nine diesel internal combustion engines (ICEs) and one diesel combustion turbine with combined capacity to generate 12.0 MW (gross) firm capacity. We recently received approval from the DOH to allow for lower minimum operating levels on the two baseload units to accommodate more renewable generation. We also scheduled generator control upgrades for 2016 to improve operation and troubleshooting of the generating units.

Lana'i includes a centralized generating station with nine diesel units with 10.4 MW (gross) firm capacity. We have applied to the DOH to allow for lower minimum operating levels on the two baseload units to accommodate more renewable generation We plan to implement the same generator control upgrades as on Moloka'i. We also plan to operate a Combined Heat and Power (CHP) unit to provide baseload power; it's expected to return to service in 2017.

Hawai'i Electric Light

Hawai'i Electric Light placed Shipman 3 and Shipman 4 on dry layup (inactive) on November 21, 2013, and retired them on December 31, 2015. The production and maintenance costs for the units were not cost effective compared with other generating

[3] The permit includes various conditions, including a compliance plan which identifies interim milestones to cease water discharge by 2024.

units. Even without these units, the utility has sufficient generating capacity to provide adequacy of supply.

Status of Existing PPAs

Since we filed our 2014 PSIPs, we have experienced changes in assumptions for some of our Independent Power Producers: AES Hawai'i, Kalaeloa Energy Partners (KPLP), Hamakua Energy Partners (HEP), Hu Honua, and Hawaiian Commercial & Sugar (HC&S). We have also updated our plans for modifying existing units to burn gas, and changed operations to comply with environmental requirements.

AES Hawai'i Generating Unit

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

However, in the near term, to address potential generation reserve shortfalls, AES can provide additional capacity to help ensure reliable service until additional firm generation is available. On January 22, 2016, we filed an application with the Commission seeking approval of Amendment No. 3 to our existing PPA with AES Hawai'i. If this amendment is approved by the Commission, AES would provide an additional 9 MW of firm, dispatchable capacity and associated energy from the existing power plant. This could be called upon as needed but we are not required to use it. Because AES provides the lowest cost energy to the system, this addition helps lower customer bills in the near term. The amendment will not extend the term of the PPA.

Kalaeloa Energy Partners (KPLP)

The O'ahu-based Kalaeloa Plant's combined-cycle design has the operational flexibility required to support the needs of a renewable generation fleet. The existing PPA for the Kalaeloa Plant, however, is restrictive in not allowing us to operate the plant with the flexibility that will be required in the future. Operating restrictions include limitations on startup times, ramp rates, and minimum load. In addition, the unit's fuel source is inflexible; we would like to have more fuel sources available to minimize costs to the customer.

The ability to operate KPLP more closely aligned with its design would enable the facility to better support our future renewable fleet. Options to remove these restrictions are ongoing and could consider several alternatives. Should the PPA expire and KPLP cease to provide firm capacity, we might seek additional capacity by deferring future deactivation of units, increasing DR programs, optimizing maintenance schedules, reactivating currently deactivated units, or acquiring additional firm capacity.

The 2016 PSIP analysis assumes the same operational flexibility of the KPLP plant (described herein) after the end of the existing PPA.

Hamakua Energy Partners (HEP)

HEP is a reliable, flexible firm capacity resource on Hawai'i Island that continues to be critical in meeting adequacy of supply and system security needs with reasonable energy costs.

On February 12, 2016, Hawaiian Electric and Hawai'i Electric Light submitted an application requesting the Commission issue an order no later than November 1, 2016 approving the purchase of the 60 MW dual-fuel combined-cycle HEP plant and its related assets. The application describes the purchase terms and the benefits to our customers.

Acquiring and continuing to operate HEP provides Hawai'i Electric Light customers an efficient and reliable source of electric power. Company ownership enables us to improve customer benefits. The PPA's Covered Source Permit constrains unit commitment to one start per unit per day. Under the PPA, a started unit cannot be taken offline unless it will not be needed later in the day. The economic dispatch is based upon the contractual heat rate, which results in a higher energy rate than the equipment heat rate.

Company acquisition would allow economic dispatch of the plant based on the true heat rate, which results in lower costs than the contractual heat rate and to take action to reduce the startup restrictions. The purchase would remove the fixed contractual capacity charge, thereby saving customers money. In addition, we anticipate economic and system reliability improvements by adding a steam bypass system (which HEP was unwilling to install at their expense). This addition will permit faster startup time in simple cycle, improving system benefits associated with increasing variable renewable energy, and reducing startup costs.

The HEP plant can be converted to burn clean, cheaper LNG, supporting the transition to 100% renewables. Ownership enables the Company to have direct control on the potential for this fuel conversion and equipment maintenance to better meet future needs of our system and our customers.

Adding the HEP combined-cycle plant to our fleet also provides valuable operational and maintenance synergies. For example, the Keahole unit on Hawai‘i Island and the two Ma‘alaea units in Maui also run the same GE LM2500s in a combined-cycle plant configuration.

Hu Honua

On March 1, 2016, Hawai‘i Electric Light terminated the PPA with Hu Honua Bioenergy for firm capacity and energy (biomass) due to Hu Honua's failure to meet critical construction milestones that were guaranteed under the PPA. The PSIP analysis does not assume Hu Honua is available.

Hawai‘i Island Geothermal Request for Proposal (RFP)

Hawai‘i Electric Light issued an RFP for additional geothermal generation. The only project bidder that met the minimum threshold requirements for selection to the Final Award Group in the Geothermal RFP has determined that developing the proposed geothermal project would not be economically and financially viable. All received bids were for projects located in East Hawai‘i. Given this, a geothermal project resulting from this RFP is not a base assumption in the analysis.

Hawai‘i Electric Light remains committed to the development of geothermal on the island of Hawai‘i if it is in the best interest of its customers. While Hawai‘i Electric Light is disappointed that the Geothermal RFP did not result in viable geothermal project, we remain hopeful that geothermal generation can be a viable option on Hawai‘i Island in the future and can help Hawai‘i meet its 100% renewable energy goal while lowering customer bills, reducing Hawai‘i's dependence on imported oil, allowing for continued integration and management of variable renewable resources, and maintaining reliability of service.

Hawaiian Commercial & Sugar (HC&S) Closure

Maui Electric's current PPA with HC&S allows us to schedule up to 4 MW of firm capacity during certain months of the year. The PPA terms continued through December 31, 2017. On January 6, 2016, HC&S issued a Notice of Termination of Power Purchase Agreement, which specified that HC&S's contribution to the Maui Electric power grid would end on January 6, 2017.

The Maui Electric analysis assumes HC&S contributing 4 MW of firm capacity in 2016, and no generation in 2017 and beyond.

Maui Electric will explore other grid-related impacts associated with the PPA's termination. Maui Electric will continue discussions with HC&S about potential energy partnership opportunities that can result from future HC&S operations, including a locally-sourced biofuel supply.

EXISTING GENERATION FLEET

Hawaiian Electric Existing Generation

Hawaiian Electric recognizes certain challenges with integrating high levels of variable renewable energy into the current generation fleet, because of certain disadvantages:

- Slower ramp rates
- Longer start-up times
- Higher maintenance cost associated with cycling and turndown
- Less efficiency

Our generation fleet has served our customers for many decades. Unit characteristics are shown in Table D-1.

Unit	Type	Fuel	Capability (MW) Gross	Net	Age
Baseload (Load Following)					
Kahe 1	Reheat Steam	LSFO	86.0	82.2	53
Kahe 2	Reheat Steam	LSFO	86.0	82.2	52
Kahe 3	Reheat Steam	LSFO	90.0	86.2	46
Kahe 4	Reheat Steam	LSFO	89.0	85.3	44
Kahe 5	Reheat Steam	LSFO	142.0	134.6	42
Kahe 6	Reheat Steam	LSFO	142.0	133.8	35
Waiau 7	Reheat Steam	LSFO	87.0	83.3	50
Waiau 8	Reheat Steam	LSFO	90.0	86.2	48
	Totals/Average		*812.0*	*773.8*	*46.1 years*
Cycling					
Waiau 3	Non-Reheat Steam	LSFO	49.0	47.0	69
Waiau 4	Non-Reheat Steam	LSFO	49.0	46.5	66
Waiau 5	Non-Reheat Steam	LSFO	57.0	54.5	61
Waiau 6	Non-Reheat Steam	LSFO	56.0	53.7	55
	Totals/Average		*211.0*	*201.7*	*62.8 years*
Peaking					
Waiau 9	Simple Cycle CT	LSFO	53.0	52.9	43
Waiau 10	Simple Cycle CT	LSFO	50.0	49.9	43
CIP CT-1	Simple Cycle CT	Biodiesel	113.0	112.2	7
	Totals/Average		*216.0*	*215.0*	*31 years*

Table D-1. Hawaiian Electric Generating Unit Characteristics

The baseload units average 46 years of age, while the cycling units average 63 years. The combined average age of all steam units is 52 years. The existing generation fleet does well in serving stable consistent loads that are predictable.

Our existing fleet is not as efficient as modernized generation in effectively managing system stability with higher levels of variable generation. The fleet does have the advantage of limiting or reducing the cost of developing replacement generation because of the modifications made to its operation to enhance its flexibility.

To better integrate increasing amounts of variable renewable generation, the existing generation fleet ramp rate, turndown and on-off cycling capability must be expanded.

Ramp Rate

Wind and solar generation's variable nature requires generating units to react to output changes. Existing baseload units could provide a total ramping capability of 20.2 MW per minute. Our steam and cycling units together provide a total ramp rate of 33.6 MW per minute. We have been working to improve the ramp rates of the existing units.

Unit	Current Normal Ramp Rate (MW/min)	Proposed "Future" Normal Ramp Rate (MW/min)
Kahe 1	2.3	4.0
Kahe 2	2.3	4.0
Kahe 3	2.3	5.0
Kahe 4	2.3	5.0
Kahe 5	2.5	4.0
Kahe 6	2.5	4.0
Waiau 7	3.0	4.0
Waiau 8	3.0	4.0
Total Baseload Ramp Rate	*20.2*	*34.0*
Waiau 3	0.9	0.9
Waiau 4	0.5	0.5
Waiau 5	3.0	3.0
Waiau 6	3.0	3.0
Total Cycling Ramp Rate	*27.6*	*41.4*

Table D-2. Hawaiian Electric Generation Ramp Rates

The improved ramp rates have been tested over the years at all our units. The implementation issues revolve primarily around adjusting control system functions to allow for automatic operation at higher ramp rates.

Turndown and On-Off Cycling

The existing units have traditional minimum loads based on being able to respond to system disturbances and achieve full load anytime necessary. As renewable penetration increases, it will be advantageous for existing steam units to improve turndown (reduce minimum load) or cycle online and offline.

Reducing minimum load has some advantages over on-off cycling. When online and at minimum loads, the units still provide necessary services to the system: inertia, voltage regulation, frequency regulation, short-circuit current, some ramping capability, and some ability to respond to system disturbance. Compared to on-off cycling, low-load operation allows for quicker return to full load capability and lower long-term maintenance costs.

We have tested and confirmed that the low-load and cycling goals set forth in our 2014 PSIPs are achievable. Currently, system load dispatchers can reduce three units to the new 5 MW load when necessary to integrate additional renewable energy. The other units are expected to be ready for low-load operations by third quarter 2016.

Unit	Traditional Minimum Load (MWg)	New Minimum Load (MWn)	Restoration Time (hours)*	Cycling Time (hours)†
Kahe 1	25	5	1.5	3.5
Kahe 2	25	5	1.5	3.5
Kahe 3	25	5	1.5	3.5
Kahe 4	25	5	1.5	3.5
Kahe 5	45	25	1.5	3.5
Kahe 6	45	n/a	1.5	3.5
Waiau 7	25	5	1.5	3.5
Waiau 8	25	5	1.5	3.5

* Restoration time is from the new minimum load to full load capable.
† Cycling time is from a hot shutdown to full load capable.

Table D-3. Hawaiian Electric Generation Low Load and Cycling Targets

Minimum load reductions are accomplished by implementing hybrid variable pressure control operations. To maintain critical operating parameters, the units' throttle pressure is reduced when generating load drops below 30 MW. The pressure is reduced linearly from 1,800 psig at 30 MW to 900 psig at 10 MW. When load is below 10 MW, pressure remains at 900 psig.

Reducing minimum load requirements offers certain advantages over cycling units offline. It:

- Reduces thermal stress to the turbine rotor and casing.
- Reduces generation to a minimum to integrate more renewable energy.
- Provides system inertia.
- Provides short circuit current in the event of a system fault.
- Provides MVAR (reactive power) capacity and voltage support.
- Enables a unit to load to full capability faster than a unit startup.

A disadvantage is that the unit will have limited ramping capability until the throttle pressure increases to its normal operating range. DER and DR resources can mitigate this lack of reserve capacity.

Figure D-1 shows the ability of a unit to reach full load from its old minimum compared to the 5 MW minimum.

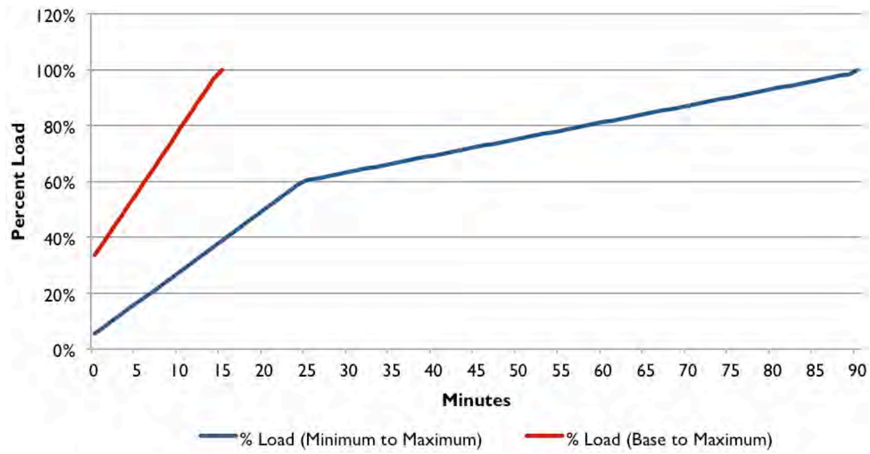


Figure D-1. Ramp Time from Minimum and Base Loads to Full Load: Hawaiian Electric

Unit Retirement Order Methodology

The current initial criteria for determining order of retirements includes cost, capacity factors, operational flexibility (including the constraints imposed by environmental permits), age, unit efficiency, and site staffing efficiencies.

Under Theme 2, the order of retirement assumed is as follows:

1. Honolulu 8 and Honolulu 9 units are already deactivated.
2. Kahe 1–3 together with the commercial operation of the Kahe replacement generation. (The intake cooling water systems are required for replacement generation.) Retirement Date: January 1, 2021.
3. Waiau 3 and Waiau 4, because of age, a low efficiency non-reheat plant design, and limited operational flexibility. Deactivation Date: January 1, 2022.
4. Kahe 4, because of staffing efficiencies and operational impact. This unit shared a control room and multiple systems with Kahe 3 and, because of the shared systems and stack structure, Kahe 1–3 cannot be demolished until Kahe 4 is retired. Deactivation Date: January 1, 2022.
5. Waiau 5 and Waiau 6, because of age, a low efficiency non-reheat plant design, and limited operational flexibility. Deactivation Date: January 1, 2024.
6. Waiau 7 and Waiau 8, because of age and its improved efficiency reheat design over other Waiau units. Deactivation Date: January 1, 2030.
7. Kahe 5 and Kahe 6 last, because they are the newest, largest, and most efficient units in the fleet (although there are no current plans to deactivate these units).

Under Theme 1 and Theme 3, the order of retirement assumed is as follows:

1. Honolulu 8 and Honolulu 9 units are already deactivated.
2. Waiau 3 and Waiau 4, because of age, a low efficiency non-reheat plant design. Deactivation Date: January 1, 2023.
3. Kahe 6, if not burning LNG, has limited operational flexibility because of covered source permit requirements. Deactivation Date: January 1, 2025.
4. Waiau 5 and Waiau 6, because of age, a low efficiency non-reheat plant design. Deactivation Date: January 1, 2030.
5. Waiau 7 and Waiau 8, because of age, its improved efficiency reheat design over other Waiau units, and improved staffing efficiencies by retiring the last Waiau steam unit.
6. Kahe 1 and Kahe 2, because of age, and their improved efficiency over Waiau units.
7. Kahe 3 and Kahe 4, because of age, and their improved efficiency over Waiau units.
8. Kahe 5 last, because it is one the newest, largest, and most efficient units in the fleet.

Generation Fleet Summary

Hawaiian Electric has expanded the capabilities of the existing generating units to support the changing electric system. These modifications, however, required tradeoffs.

Reducing unit minimum loads allows for increased renewable integration, but also reduces ramp rates. Many unit components are designed to last a specific number of cycles. At the average age of 52, the units have already experienced many thermal cycles. Low loads and increased cycling of these units, while successful, also increases maintenance costs, increases the potential for unplanned outages, and decreases their normal operational efficiency.

In 2012, the National Renewable Energy Laboratory (NREL) published its report, *Power Plant Cycling Costs*. That report demonstrated higher forced outage rates that result from cycling operation (Figure D-2), and concluded that costs associated with cycling and increased load following events would drive future maintenance cost higher.

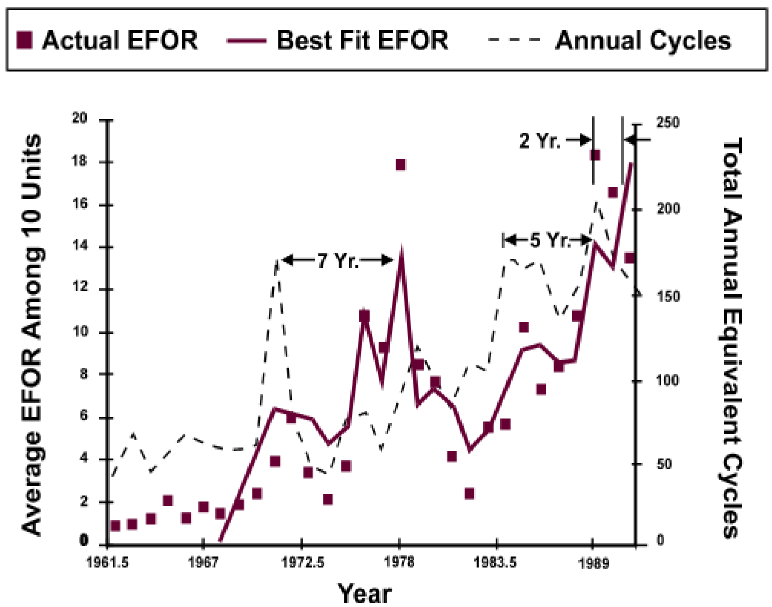


Figure D-2. Forced Outage Rates from Cycling: U.S. Averages

We understand the impact on units from low loads and increased thermal cycles. As a result, we are optimizing procedures and reviewing practices and options to minimize cost and maximize reliability. We expect to review options to reduce or minimize cycling-related damage.

To continue to provide reliable service, our aging steam units require continued capital investment. NextEra Energy analyzed the investment necessary to run the existing units out to 2045. This analysis projects a capital investment of $935 million. Investments would include replacing:

- The major boiler pressure components
- The major turbine components
- Controls
- Excitation
- Old motors and pumps
- Critical valves
- Critical balance of plant components

NextEra based its analysis on an assessment of unit condition assessment, component maintenance history, and industry experiences, and based its costs on the review of similar projects and industry standards.

Our existing steam generating fleet will serve our customers in an increasing dynamic way for years to come. Our peaking and cycling units will continue to fulfill those roles in the upcoming years. Our baseload (load following) units, however, will be assuming new roles in supporting the system. When renewable generation is high (such as high solar days), some of our reheat units will need to be cycled offline while others will be at new low loads. We will maximize the flexibility of these units to support our transition to the 100% RPS while considering potentially more cost-effective and beneficial solutions.

Maui Electric Existing Generation

Maui Electric's existing dispatchable generation fleet comprises two main power plants at Kahului and Ma'alaea. These plants include:

- Quick-start internal combustion engines (ICEs) that provide emergency replacement power and peaking generation.
- Combined-cycle units, comprised of two combustion turbines (CTs), two heat recovery steam generators (HRSGs) or once-through steam generators (OTSGs), and one steam turbine (ST) that provide high efficiency and relatively low cost cycling capability with a 1–2 hour start time, and fast ramping response. These combined-cycle units support the integration of variable renewables resources needed to achieve the 100% RPS goal by 2045.
- Older conventional steam units with limited cycling and load ramping capability that are scheduled for retirement by 2024 because of permitting.

Table D-4 lists the Maui dispatchable generating fleet.

Unit	Type	Fuel*	Capability (MW net)	Age	Type of Operation
Maʻalaea 14	GE LM2500 CT	LSD (future LNG)	21.0	24	Baseload (Load Following)
Maʻalaea 15	ABB Steam Turbine	n/a	16.0	23	Baseload (Load Following)
Maʻalaea 16	GE LM2500 CT	LSD (future LNG)	21.0	23	Baseload (Load Following)
Maʻalaea 17	GE LM2500 CT	LSD (future LNG)	21.0	18	Cycling (Load Following)
Maʻalaea 18	Mitsubishi Steam Turbine	n/a	16.0	10	Cycling (Load Following)
Maʻalaea 19	GE LM2500 CT	LSD (future LNG)	21.0	16	Cycling (Load Following)
Total Combined-Cycle Capability (MW)/Average Age			*116.0*	*19*	
Kahului 1	Combustion Engineering	IFO	5.0	68	Reserve Shutdown
Kahului 2	Combustion Engineering	IFO	5.0	67	Reserve Shutdown
Kahului 3	Combustion Engineering	IFO	11.5	62	Baseload (Load Following)
Kahului 4	Babcock and Wilcox	IFO	12.5	50	Baseload (Load Following)
Total Cycling Capability (MW)/Average Age			*34.0*	*62*	
Maʻalaea 1	GE EMD 20-645 ICE	LSD	2.5	45	Peaking
Maʻalaea 2–3	GE EMD 20-645 ICE	LSD	2.5 each	44	Peaking
Maʻalaea X1–X2	GE EMD 20-645 ICE	LSD	2.5 each	29	Peaking
Maʻalaea 4–6	Cooper PC2-16	LSD	5.6 each	43	Peaking
Maʻalaea 7–9	Colt PC2-16	LSD	5.6 each	38	Peaking
Maʻalaea 10–11	Mitsubishi /MAN 18V52/55A	LSD	12.5 each	36	Peaking
Maʻalaea 12–13	Mitsubishi /MAN 18V52/55A	LSD	12.5 each	28	Peaking
Total Peaking Capability (MW)/Average Age			*96.0*	*38*	

* LSD = low sulfur diesel; IFO = intermediate sulfur fuel oil; n/a = steam turbines powered by waste heat and do not directly use fuel

Table D-4. Maui Electric Generating Units

The existing generation, combined with DR and DER, provide operational flexibility to support the integration of more variable renewable energy resources. These assets have low minimum operating loads, cycling capability, quick-start capability, load following and ramping capability, and black start capability.

Combined Cycle Generation Assets

M14–16 consist of two 21 MW GE LM2500 combustion turbines, two natural circulation HRSGs, and one 16 MW ABB steam turbine. Maʻalaea M17–19 consist of two 21 MW GE LM2500 combustion turbines, two OTSGs, and one 16 MW Mitsubishi steam turbine. These units support the system in several ways.

Support of Renewables. They provide flexible generation and economic bulk supply of energy demand. M17–19 are designed for cycling and supporting the ramping needs. The units are limited by permit constraints to two starts per day. The combustion turbines can be online in 25 minutes following startup. M14–16 are being modified to better support low-load operation. The combustion turbines can be online in 25 minutes following startup. M17–19 can be cycled offline as necessary, with a 1 to 2 hour startup and three-hour minimum down time.

The units are capable of relatively fast ramping (2 MW per minute on AGC) and a minimum dispatch limit of 25%, driven by the covered source permit and 60% based on minimum steam flow through the once-through steam generator.

Support of High-Run-Hour Generation. With a heat rate between 8,330 Btu/kWh and 8,525 Btu/kWh, the combined cycle units provide generation at high efficiencies making them well suited for bulk customer service needs until the required variable and firm renewables are built. Because of this high efficiency, they are well suited to consume biodiesel after 2045 to support the 100% RPS target and minimizing the impact on customer bills.

Cycling and Startup Costs. While the LM2500 combustion turbines do not incur a startup cost, the heat recovery steam generator and the steam turbine are impacted by cycling. This cost is included in the production cost modeling. The LM2500 combustion turbines in the Maʻalaea CC units have bypass systems that allows for faster starts with minimal startup cost impact.

Long Term Reliability and Maintenance. The CC units were evaluated for continued operation to 2045. An estimated capital expenditure of $113.5 million was deemed necessary to support long term operations. The capital expenditures represent capital investment over what is normally included in scheduled overhaul cycles. The expenditures were calculated based on units running to 2045 and were based on a review of condition assessment, component maintenance history, and review of industry experiences. The budgetary costs were created based on reviewing similar projects and using industry standards. The identified investment generally include:

- Replacing heat recovery steam generator pressure components.
- Refurbishing generators stators and rotors.
- Upgrading excitation systems.
- Upgrading the transformer and electrical systems.
- Replacing major pumps and motors.
- Upgrading obsolete control systems.

Quick/Fast Start Peaking Generation Assets

The quick/fast-start peaking generation units support the increased variable renewables resources needed to achieve the 100% RPS goal by 2045.

M1–3 and X1–2 are 20-EMD-645 ICE units built in the 1970s and 1980s (manufactured by GE's Electro-Motor Division, thus the EMD designation) with individual maximum loads of 2.5 MW. M4–7 are Cooper PC2-16 ICE units constructed in the mid-1970s, and M8–9 are Colt-PC2-16 diesel engines constructed in the late 1970s, with individual maximum loads of 5.6 MW. M10–M13 are Mitsubishi Heavy Industry (MHI) ICE units manufactured by MAN of Germany, model 18V52/55A, constructed between 1979 and 1989, with individual maximum loads of 12.5 MW. The ICEs provide 96 MW of quick/fast start capability.

These units support the system in several ways.

Support of Renewables and Load Loss. The various types of ICE units support the variable renewable generation differently.

The General Electric (GE) Electro-Motive Diesel (EMD) ICE units (2.5 MW units) are quick start and can be at full load in less than 10 minutes. These units support renewable generation because they are offline reserve generation that can be deployed in response to cloud cover or wind events resulting in un-forecasted losses of variable generation.

The Cooper PC2-16 units (5.6 MW units) can come online 15 minutes after start, and take an additional 50 minutes to reach full load. Current constraints dictate that the units need to be started sequentially rather than simultaneously. They serve the system best when used for compensating for forecasted loss of variable generation and recovery following an event to supplement other sources generation.

The MHI 18V52/55A ICE units (12.5 MW units) can come online 17 minutes after a start command is given and be at full load in 117 minutes. They serve the system best being available for forecasted lack of variable generation and supporting peak loads.

Cycling and Start-Up Costs. The ICE units have very low startup costs. They can be used to provide generation when only a small increment is needed, in lieu of starting a larger unit and operating them at an inefficient load-point. The ICE units are well suited for quick starting and numerous starts.

Long Term Reliability and Maintenance. Though some of these units are older, their modular design allows for continuous repair and overhaul extending their life through 2045. These types of units normally do not require any additional capital expenditures to extend their life to 2045.

The GE EMD ICE and Cooper PC2-16 ICE units have a large user base resulting in long term availability of parts. The MHI ICE units are expected to be serviceable with replacement parts for many years to come as both Mitsubishi Heavy Companies and MAN continue to produce engines (different model) and maintain the engineering and facilities to produce parts for these engines.

Support of System Stability. While they supply load replacement very quickly, the ICE do not provide load flexibility and therefore do not support all type of system stability needs. The GE EMD ICE units (2.5 MW units) cannot be incrementally controlled through the SCADA/EMS system and are not used for regulation.

Conventional Steam Generation Assets

Kahului Power Plant has four steam units. Kahului 1 and Kahului 2 are currently in a reserve shutdown status. Kahului 3 and Kahului 4 are baseload units currently operating at low loads while also providing a significant amount of online system regulating reserve. All steam units at Kahului will be retired by 2024 for environmental reasons.

When the Kahului plant is fully retired, replacement generation is needed to continue to support the variable renewable resources and the system demand.

Lana‘i Generation Assets

The Lana‘i system is small—its generation needs are met by six 1.0 MW EMD diesel engines and two 2.2 MW Caterpillar 3608 diesel engines. A Caterpillar C32-1100 combined heat and power unit (CHP) will provide 800 kW of power and heat to support Manele Bay hotel loads starting in 2017. As with the Maui units, the EMDs are expected to be serviceable well into the future.

The EMD units (Miki Basin 1–6) are capable of starting in less than 10 minutes, and are well suited for responding to un-forecasted changes in variable generation. The Caterpillar engines are more efficient than the EMDs; they are well suited for meeting system peaks and forecasted changes in variable generation. The Caterpillar 3608 engines can start and be online in 17 minutes and at full load in 22 minutes.

The size of the Lana‘i system, with the flexibility of the current generation mix, help support the transition to 100% renewables. The units can compensate for changes in generation as well as supplement energy storage use.

Moloka'i Generation Assets

The Moloka'i system is also small. The generation fleet comprises two 1.25 MW Caterpillar 3516 diesel engines, four 1.0 MW Cummings KTA50 diesel engines, three 2.2 MW Caterpillar 3608 diesel engines, and one 2.0 MW Solar Centaur T4001 combustion turbine. The Moloka'i engines have a large user base and expected to be serviceable with parts for well into the future.

The Caterpillar 3608 engines are more efficient than the other engines and are well suited for meeting system peaks and forecasted changes in variable generation. The Caterpillar engines can start and be online in 17 minutes and at full load in 22 minutes. This makes them ideal for efficiently supporting forecasted needs.

The flexibility of the generation fleet supports the transition to 100% RPS by providing quick starting and quick ramping capabilities to compensate for losses of forecasted and un-forecasted variable generation as well as supporting peak loads. The units are well equipped to support the transition to 100% RPS by providing grid services such as frequency and voltage control, meeting changes in generation need, and supplementing energy storage as necessary.

Hawai'i Electric Light Generation Assets

Hawai'i Electric Light dispatchable generation fleet has included both utility-owned and independent power producer assets. These units include:

- Quick/fast start generation including simple cycle combustion turbines (SCCT) and ICEs that provide emergency replacement power and peaking generation, but at a higher cost than the larger resources. The simple cycle combustion turbines can be used as black start resources.
- Combined-cycle units, comprised of two CTs, two HRSGs, and one ST with high efficiency and relatively low cost. These assets provide cycling capability with a 1–2 hour start time, and have fast ramping capability.
- Older conventional steam units have offline cycling capability, but longer start-up times and less ramping capability when compared to the combined-cycle units.
- Geothermal IPP provides firm energy.

These generating assets, combined with DR resources and DER, provide the flexibility necessary to integrate more variable renewable resources to meet 100% RPS requirements.

The Hawai‘i Electric Light dispatchable generating fleet comprises:

Unit	Type	Fuel*	Capability (MW net)	Age	Type of Operation
Keahole	2 – GE LM2500 CT with ST	LSD (future LNG)	56.3	12/6	Frequency Regulation, Load Following, Cycling
HEP	2 – GE LM2500 CT with ST	LSD (future LNG)	60.0	15	Frequency Regulation, Load Following, Cycling
Total Combined-Cycle Capability (MW)/Average Age			*116.3*	*10*	
Hill 5	Non-Reheat Steam	IFO	14.1	51	Frequency Regulation, Load Following, Cycling
Hill 6	Non-Reheat Steam	IFO	20.2	42	Frequency Regulation, Load Following, Cycling
Puna 1	Non-Reheat Steam	IFO	15.7	46	Frequency Regulation, Load Following, Cycling
Total Steam Capability (MW)/Average Age			*50.0*	*62*	
Kanoelehua CT1	GE Frame 5 SCCT	LSD	11.5	54	Peaking, Emergency, Black start
Keahole CT2	ABB GT-35 SCCT	LSD	13.8	27	Peaking, Emergency, Black start
Puna CT3	GE LM2500 SCCT	LSD	21.0	24	Peaking, Black start
Kanoelehua	Fairbanks Morse ICE	ULSD	2.0	54	Peaking, Emergency
Kanoelehua	3 - GE EMD 20-645 ICE	ULSD	7.5	43	Peaking, Emergency
Keahole	3- GE EMD 20-645 ICE	ULSD	7.5	44	Peaking, Emergency
Waimea	3- GE EMD 20-645 ICE	ULSD	7.4	45	Peaking, Emergency
Mobile	4 - Cummins ICE	ULSD	5.0	30	Peaking, Emergency
Total Peaking Capability (MW)/Average Age			*75.7*	*40*	

* LSD = low sulfur diesel; IFO = intermediate sulfur fuel oil; ULSD = ultra-low sulfur diesel (15 ppm s)

Table D-5. Hawai‘i Electric Light Fossil Generating Units

Requirements for the Existing Dispatchable Generation

The existing generation on Hawai‘i Island provides operational flexibility to support the integration of more variable renewable energy resources to meet the 100% RPS requirement. These assets have low minimum operating loads, cycling capability, quick-start capability, load following and ramping capability, and black start capability. In addition, Hawai‘i Electric Light has potential firm renewable energy resources (biomass, geothermal) to help meet 100% RPS requirements.

Combined-Cycle Generation Assets

The combined-cycle (CC) units support increasing variable renewables resources incorporated to achieve the 100% RPS goal by 2045.

Support of Renewables. They provide flexible generation and economic bulk supply of energy demand. The units can be cycled offline as necessary, with a 1 to 2 hour startup and three hour minimum down time. The units are capable of relatively fast ramping (4 MW per minute) and a minimum dispatch limit of 30%–40%, driven by the covered source permit and minimum steam flow through the heat recovery steam turbine. Potential may exist to increase these ramp rates.

Support of High Run Hour Generation. The combined-cycle units are the most efficient conventional plants on the system, well suited for cost effective service of the bulk customer energy needs that will continue to be required until dependable replacement renewable resources are available to serve these needs. Because of this high efficiency, they are the most cost-effective resources for future fuel-switching to biodiesel to support the 2045 100% RPS target and minimizing the impact on customer bills.

Cycling and Startup Costs. While the LM2500 combustion turbines do not incur a startup cost, the heat recovery steam generator and the steam turbine may increase costs because of offline cycling.

The LM2500 combustion turbines that are part of the Keahole CC unit have steam bypass systems which allows for faster starts than would be possible without the bypass. It also allows for faster startup in simple-cycle mode for emergency replacement power (22 minutes).

The LM2500 combustion turbines that are part of the HEP CC unit do not presently have steam bypass systems but this will be pursued to add flexibility to increase the support of future renewables as well as lower total cost and faster available replacement power.

Long Term Reliability and Maintenance. The CC units were evaluated for continued operation to 2045. An estimated capital expenditure of $113.5 million was deemed necessary to support long term operations. The capital expenditures represent capital investment over what is normally included in scheduled overhaul cycles. The expenditures were calculated based on units running to 2045 and were based on a review of condition assessment, component maintenance history, and review of industry experiences. The budgetary costs were created based on reviewing similar projects and using industry standards. The identified investment generally include:

- Replacing heat recovery steam generator pressure components.
- Refurbishing generators stators and rotors.
- Upgrading excitation systems.
- Upgrading the transformer and electrical systems.
- Replacing major pumps and motors.
- Upgrading obsolete control systems.

Quick/Fast Start Peaking Generation Assets

The quick/fast start peaking generation units support the renewable resources needed to achieve the 100% RPS goal by 2045. The ICEs provides 29.5 MW of quick start capability all available in less than three minutes. These units support the system in several ways.

Support of Renewables and Load Loss. These smaller resources quickly allow the system to meet lead requirements from loss of generating units or transmission lines, variability in wind and solar resources because of changes in weather, and emergency peaking needs.

Costs. The ICE units have very low startup costs. They can be used to provide generation when only a small increment is needed, in lieu of starting a larger unit and operating them at an inefficient load-point. The ICE units are well suited for quick starting and numerous starts.

Long Term Reliability and Maintenance. Though some of these units are older, their modular design allows for continuous repair and overhaul extending their life through 2045. These types of units normally do not require any additional capital expenditures to extend their life to 2045.

The GE EMD ICE units have a large user base resulting in long term availability of parts to maintain the engines. The Fairbanks Morse ICE unit has a similar large user base.

The simple cycle combustion turbines (SCCT) provide 46.3 MW of peaking capability, and are used for emergency replacement reserves and peaking energy.

Support of Renewables and Loss of Load. The simple cycle combustion turbines have fast start capability (5–22 minutes) which is not as quick as the ICE units but faster than combined cycle and steam unit startup.

Costs. The cost varies between the different types of SCCT units.

The GT-35 and Frame 5 have a high heat rate, and accordingly, high production costs. These units have the shortest startup times of the gas turbines: less than 10 minutes. They do incur a maintenance cost for each start, but because of the high production costs, do not incur many starts per year. They are operated primarily for emergency replacement power and short-term energy needs.

The GE LM2500 does not incur a significant maintenance cost for starts. These can be started as needed to support the system needs. These units are relatively efficient, second only to the combined-cycle operation. These units are used for short-term energy needs, in addition to emergency replacement power.

Long Term Reliability and Maintenance. These combustion turbine units are 24 to 54 years old. Their modular design allows for continuous repair and overhaul extending their life through 2045. With limited operation hours, these types of units normally do not require any additional capital expenditures to extend their life to 2045.

Though 54 years old, the GE Frame 5 SCCT have a large user base resulting in long term availability of parts. This type of turbine is still being manufactured today which allows for potential upgrades. The GE LM2500 SCCT is 24 years old. It also has a large user base and is still being manufactured today. This type of combustion turbine is shared with the combined-cycle unit at Maʻalaea, Keahole, and HEP.

The ABB CT35 SCCT is 27 years old and has much smaller user base. Maintaining this combustion turbine may prove more difficult in the next 20 to 30 years. The assumption is that it will be maintained until 2045. All the simple cycle combustion turbines have the capability to operate in isochronous control (zero-droop or swing unit) for frequency control and stability during major system disturbances and restoration. CT2 is located in Keahole, which allows it to support the minimum generation requirement for the west side of Hawaiʻi Island for voltage and transmission system constraints.

Conventional Steam Generating Assets

The conventional steam generating assets provide many benefits. Hill 5 and Hill 6 cycle to provide steam generated electricity. Puna has been operating for seasonal cycling during low generating capacity margins. It may shortly operate to a greater extent to serve demand, as the present availability of low-cost fuel has made the unit cost-competitive for operation compared with combined cycle assets.

Support of Renewables. Because the small size of these steam units, they provide greater dispatch flexibility than larger steam units. The units can be cycled offline with a minimum 3 hour start time for warm start. With present equipment and controls, these units require extensive manual operation during startup and startup time may be shortened if equipment is modified. The units have a lower minimum dispatch limit than combined cycle units, but a smaller dispatch range.

These conventional steam units provide firm capacity and have a sustained ramp rate of 2–3 MW per minute. While presently satisfactory, this may not be sufficient for future higher penetrations of variable solar and wind, requiring supplement from other ramping resources.

The steam units are significantly less efficient than the combined-cycle units. Because of this low efficiency, they would not be cost-effective for higher cost fuels (such as biodiesel) after 2045 to support the 100% RPS target.

Cycling and Startup Costs. The equipment of the entire conventional steam plant is impacted by cycling. This cost is included in the production cost modeling.

Long Term Reliability and Maintenance. NextEra calculated the capital investments necessary for the three steam units to support the Hawaiʻi Electric Light system until 2045. Analysis showed that an investment of $49 million will be necessary to maintain reliable operation. The expenditures were calculated based on units running to 2045 and were based on a review of condition assessment, component maintenance history, and review of industry experiences. The budgetary costs were created based on reviewing similar projects and using industry standards. Generally the capital investments include work over and beyond what is normally done during the overhaul cycle and includes:

- Replacing major boiler pressure components.
- Replacing major turbine components.
- Refurbishing generator stators and rotors.
- Replacing excitation systems.
- Replacing transformer and electrical systems
- Replacing major pumps and motors.
- Replacing critical piping and valves.
- Upgrading obsolete control systems.

Operations of the Conventional Steam Generation Assets

Selecting which large units will operate to serve the majority of demand is based on providing system security at the lowest cost of meeting the minimum system security requirements, considering the available resources capable of meeting those requirements, and the overall production cost.

System security analysis has identified that, at present, the system can generally operate with acceptable reliability with a minimum of four of the existing larger units online. These units can be any combination of three steam units with or without the LM2500 units, in simple or combined cycle (a plant operating in combined cycle counts as two units to the minimum four unit requirement), with at least one of the units located at Keahole because of voltage and transmission security constraints.

GENERATION MODERNIZATION

Because of its age, we are considering modernizing the existing O‘ahu generation fleet as one option for the 2016 updated PSIP.

Dispatchable Generation Selected for Modernization

Hawai‘i requires flexible dispatchable resources to meet foreseeable demand as the generation fleet transitions to a 100% RPS portfolio. One of our tasks is to design an optimized fleet that ensures the lowest possible impact to the customer bill while maintaining reliability.

Customer electric demand must be met while we expand our renewable generation fleet to achieve 100% RPS. The amount of utility scale renewables, storage, and dispatchable generation must be cost effective. And we must maintain reliability.

The generation fleet of the future must support a variable renewable fleet. A modernized fleet must support the delivery of electricity, ensure grid stability, and long-term operations of all types of variable renewables; minimize the total impact to customer bills; ensure fuel flexibility for burning natural gas and biodiesel to maximize efficiency; and reduce emissions and its impact on the environment.

We have considered all of the necessary components of a cost-effective renewable plan; our Decision Framework outlines how we are developing a portfolio that meets them. The proposed generation modernization would ensure reliability, facilitate renewable integration, and reduce costs to the customer. Modernized units must include high capacity generation as well as fast-start, low capacity generation.

Together with NextEra, we first evaluated potential high capacity generation using the following criteria:

- Lowest total (capital and operational) cost
- High efficiency to minimize fuel cost
- Fast start and load ramp to support renewables
- Low emissions

Next, we evaluated the two basic combined-cycle technologies: advanced combined-cycle units and aeroderivative combined-cycle units. We determined that advanced combined-cycle units had the needed characteristics: they have the lowest total cost combined with the highest efficiency while supporting fast-start and ramp rates and low emissions. (Aeroderivatives have higher total costs and lower efficiencies.)

We next screened various combined-cycle configurations, discovering that a 300 to 350 MW unit had best overall savings for customers. We compared a configuration of three combined-cycle units, each with one combustion turbine and one heat recovery steam generator, that supply steam to one steam turbine (that is, three 1x1 CC units), against one combined cycle unit with three combustion turbines, three heat recovery steam generators, and a single steam turbine (that is, a 3x1 CC unit)

Evaluating the total cost of these two configurations revealed the 3x1 CC would save $136 million over the cost of three 1x1 CC units. Due to its efficient heat rate, that savings from the 3x1 CC would be $48 million in capital construction costs, $21 million in maintenance costs, and $67 million in fuel cost over the unit's life.

The combined cycle unit can burn biodiesel, which helps toward attaining 100% RPS. The unit's higher efficiency lowers the cost of energy generated from biodiesel by 30% compared to burning biofuels in existing conventional steam units.

The combined cycle unit is flexible. It can provide the quick-start on short notification to respond to the loss of a variable resource. This quick-starting capability enables the size of a battery energy storage system (BESS) providing contingency reserve to be minimized. The unit can also supplement an optimized BESS to ensure load demand is met in times of extended low resource.

An advanced 3x1 combined cycle unit is capable of starting and ramping quickly in several modes. For a hot start, the first combustion turbine takes 15 minutes to ramp to full load (versus 42 minutes for a 1x1 SCCT configuration). A second combustion turbine, started one minute after the first, reaches full load in 16 minutes (versus 43 minutes for a 2x1 configuration). The third combustion turbine, started one minute after the second, reaches full load in 17 minutes. All told, the 3x1 combined-cycle unit reaches full load in 44 minutes with a ramp rate of 35 MW per minute. These startup times and ramp rates are significantly faster than our existing thermal fleet, which require many hours for a hot startup and ramp at rate of 3–5 MW per minute.

An advanced 3x1 combined cycle unit is capable of starting and ramping quickly in several modes. Single simple cycle combustion turbines (SCCT) take 15 minutes to ramp to full load and 43 minutes; a double SCCT (1x2) ramps in 16 minutes and 43 minutes; and a triple SCCT (1x3) ramps in 17 minutes and 44 minutes. The ramp rate of a 3x1 from minimum load to full load operation is 35 MW per minute. These startup times and ramp rates are significantly faster than our existing thermal fleet, which require many hours for a hot startup and ramp at rate of 3–5 MW per minute.

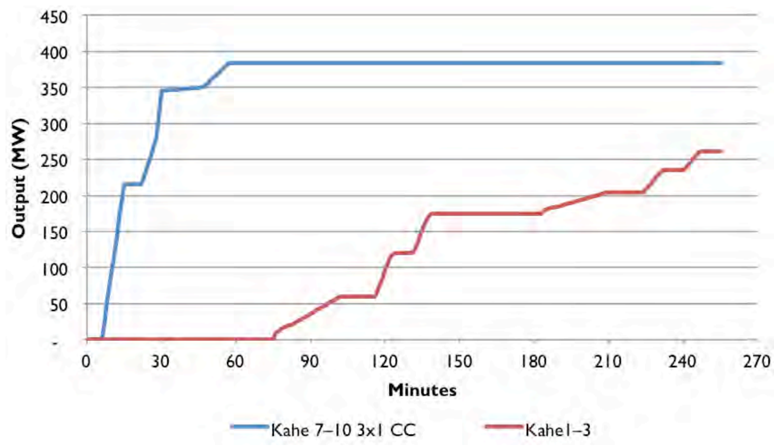


Figure D-3. Hot Start of a 3x1 CC versus Kahe 1–3

This capability responds to drops in renewable resources, minimizes the size and cost of the BESS, and eliminates online reserve units to support system load transients. This fast-starting unit together with a cost-effective storage system could stay offline when not needed to serve load, resulting in significant fuel cost savings over less flexible generating alternatives.

We next evaluated the optimal location for siting the unit, one that also minimizes costs. Our evaluations found Kahe to be optimal. Constructing on the Kahe site gave us the opportunity to replace Kahe 1–3 (as they are already planned to be retired), to keep existing units running for most of the construction period (critical to maintaining LOLP criteria until renewables back by storage can be brought online), to build above the tsunami plain, and to cost-effectively integrate the new unit into the O‘ahu grid.

The 3x1 CC encompasses some unique design features that prevent losing the entire unit at one time. The 3x1 CC's design ensures that any one combustion turbine failure only results in the loss of 127 MWs, one-third of the unit's capacity (similar to the largest existing Kahe unit). The loss of the steam turbine generator results in a maximum loss of approximately 145 MW as the combustion turbines can continue operating. This design feature also lowers the largest contingency risk currently present with AES at 180 MW.

To accomplish this flexibility, a dump condenser is added to the steam turbine condenser enabling the 3x1 CC plant to operate in simple cycle mode for extended periods of time if the main condenser trips. The dump condenser also allows the three combustion turbine trains to operate during a steam turbine outage. This allows the 3x1 combined-cycle unit to continue at reduced capacity during failures and outages.

We propose replacing Kahe 1–3 with this state of the art, highly fuel efficient, operationally flexible, 383 MW, 3x1 combined-cycle unit—Kahe 7–10. The Kahe 7–10 CC unit would encompass approximately 15 acres on the Kahe property (in an unused area north of the existing units) and with a potential in-service date of January 2021.

Kahe 7–10 could operate using LNG, fuel oil, a mix of the fuels, or biofuels. Kahe 1–3 would be retired in 2020, shortly before Kahe 7–10 CC comes online.

Figure D-4. Possible Kahe 3x1 CC with Removal of Kahe 1–4 (Artist Rendering)

The proposed Kahe 7–10 combined-cycle unit would consist of three nominal 80 MW General Electric 6FA.03 combustion turbines (CTs) and three heat recovery steam generators (HRSG), which would use the waste heat from the CTs to produce steam for the new steam turbine generator. Kahe 7–10's base capacity would be 358 MW. For additional power production, the facility could be capable of utilizing wet compression technology during peak demand periods to add about 25 MW of capacity to the unit, totaling 383 MW. The unit's base heat rate would be 6,965 Btu/kWh at an average ambient temperature of 86º F. The unit would have an estimated average forced outage factor of approximately 1.6%, a planned outage factor of 5.0%, and an equivalent availability factor of 92.2%. The ramp rate would be 35 MW per minute.

To limit a single contingency event to less than 145 MW, Kahe 7–10 would be designed with the capability of bypassing the steam turbine. This same design feature would allow for fast startup and for the three combustion turbines to reach full load in 17 minutes while the steam turbine is brought online more slowly, reaching full load in 44 minutes. In addition, a dump condenser would allow for the steam turbine and its main condenser to be taken offline for maintenance while still allowing for full operation of the three combustion turbines.

Locating on the existing Kahe site would lower construction and connection costs, improve the permitting schedule and lowering permitting risks, and reduce land improvement before construction. The unit could also take advantage of existing infrastructure, including:

- Cooling water intake and discharge
- Liquid fuel tanks and pipelines
- Demineralized water
- 138 kV substation
- Transmission infrastructure

The existing Kahe units can remain in service during the initial construction period. At some point, however, the existing units would be shut down and certain critical services (such as the transmission and cooling water systems) would be integrated into the new CC unit. Contracting with a third-party company to build the unit would extend the construction schedule (and add cost) to the finished project.

A modernized Kahe 7–10 could provide 383 MW at a capital cost of $716 million (without AFUDC or interconnection costs), or $1,870 per kW, and be online in 2021. Table D-6 summarizes the unit's costs and key operating characteristics.

Kahe 7–10 3x1 CC	Characteristic
Unit model	GE 6F.03 3x1 CC
Total cost (without AFUDC)	$716,200,000
Cost per kilowatt	$1,870/kW
Net sum capability Heat rate at base	358 MW 6,965 Btu/kWh
Net sum capability with wet compression Heat rate at base with wet compression	383 MW 7,028 Btu/kWh
Minimum load, CT only	36 MW
Minimum load, combined cycle 1x1	64 MW
Time for CT to baseload 221 MW	17 minutes
Fuel types	Gas, oil, biofuels

Table D-6. Kahe Advanced Combined Cycle Unit Characteristics

Benefits of the 3x1 Advanced Combined Cycle Units

Advanced combined cycle units have the operational characteristics required to support the variable nature of renewable generation and support the transition to 100% RPS.

Efficiency

A 3x1 unit utilizing advanced combined-cycle technology would be more efficient and utilize significantly less fuel than the existing Kahe units. As the Figure D-5 demonstrates, the 3x1 combined cycle units would be 31% more fuel efficient at full load and 42% more efficient at minimum load compared to the existing Kahe units.

Figure D-5. Heat Rate Comparison of Kahe 1–3 and Kahe 7–10 CC

Improved Reliability

A 3x1 advanced combined cycle units would also be more reliable (Figure D-6).

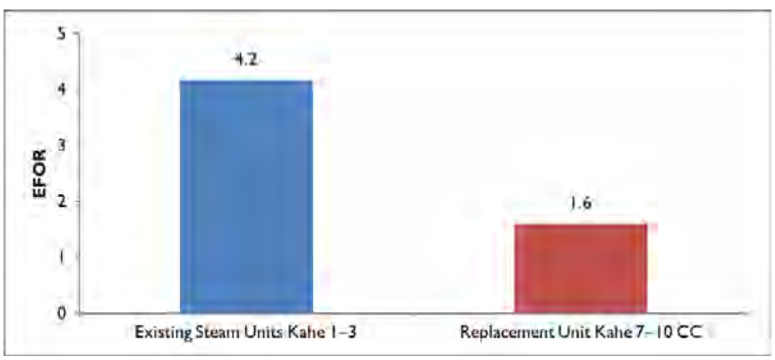


Figure D-6. EFOR of Kahe 1–3 and Projected EFOR of Kahe 7–10 3x1 Combined Cycle

Faster Cold Start Ramp Rates

Advanced combined cycle units have fast start and load ramping capabilities even in cold conditions. This characteristic is vital for reliability to support a system with high renewable penetration and allows for a more rapid and increased level of renewable integration. Table D-7 compares the cold condition ramp rates of Kahe 1–3 and Kahe 7–10.

Ramp Time (hours)	2	4	6	8	10	12	14	16	18	20	22	24
Kahe 1–3 Steam (MW)	0	0	0	0	0	5	40	70	100	100	125	132
Kahe 7–10 3x1 CC (MW)	321	358	358	358	358	358	358	358	358	358	358	358

Table D-7. Cold Start Ramp Rates: Kahe 1–3 and Kahe 7–10 3x1 Combined Cycle

Reduced Emissions

Attaining a 100% RPS would coincidently reduce environmental emissions from our generating units. Modernizing the existing fleet with an advanced combined cycle unit would further enhance those environmental benefits. Table D-8 shows how adding an advanced combined cycle unit significantly reduces emissions compared to our current generation mix, even when both are fueled by liquid fossil fuels.

Fleet Portfolio	SO_2	NOx	PM	CO_2
Existing Generation	14.1 K	24.6 K	5.1 K	4.7 M
Modernization	8.5 K	14.8 K	2.1 K	4.4 M
Percent Reduction	39.1%	39.8%	58.8%	8.3%

Table D-8. 2023 Emission Rates of Existing Fleet versus Replacement Generation

The reductions of CO_2, SO_2, NOx and PM through the modernization result in several environmental benefits. CO_2 reductions support the state's goal to reduce greenhouse gas emissions that contribute to climate change impacts (such as increased temperatures and sea level rise). Combining the lower emission profile of advanced combined cycle units with the use of natural gas compounds this environmental benefit. CO_2 content in natural gas is approximately 33% less than in the low sulfur fuel oil currently used in the generating units. Using natural gas also reduces SO_2 emissions, assisting the state to attain the 2010 one-hour SO_2 National Ambient Air Quality Standards (NAAQS) requirement. SO_2 emissions are attributed to respiratory illnesses and acid rain formation. NOx emissions are the primary contributor to the formation of ozone (smog) that can cause respiratory illness. Particulate Matter (PM) results in visible emissions (smoke) observable by local residents and business near the plant. PM emissions also include the Hazardous Air Pollutant metals that may increase the risk of cancer and respiratory illness.

Modernizing our fleet and adding advanced combined-cycle units burning natural gas would reduce other hazardous air pollutants emissions: metals, including mercury, arsenic, chromium, and nickel; and acid gases, including hydrogen chloride and hydrogen fluoride

Online Reserve Requirement for O'ahu Renewable Fleet Support

Inherent in the nature of renewable generation is the significant volatility in its contribution to daily generation needs. The existing O'ahu dispatchable fleet is not currently equipped to respond quickly enough for the increased variability associated with increasing amounts of variable renewable energy generation.

One option of responding to this increasing volatility would be to add large, utility-scale batteries to the system. The amount of support needed from the batteries, however, is significant and does not appear to be an optimal use of capital resources for these purposes. A second option would be to keep the existing thermal units on at minimum load as online reserve generation. While reducing the amount and cost of required batteries, any savings would be offset by the costs associated with running units at load low. Another option would be to replace existing units with a dispatchable fleet that can start and ramp up quickly.

Together with NextEra, we compared the existing fleet to a modernized fleet, and their respective abilities to respond to the complete loss of variable renewable generation. A study by Wind Logics evaluated the projected 2045 renewable resources to better understand the largest generation swings that could be expected. Figure D-7 depicts the largest expected drop over one year. We used the study's results to analyze the system response to a "large cloud cover event": a drop of 630 MW within a 30-minute time period.

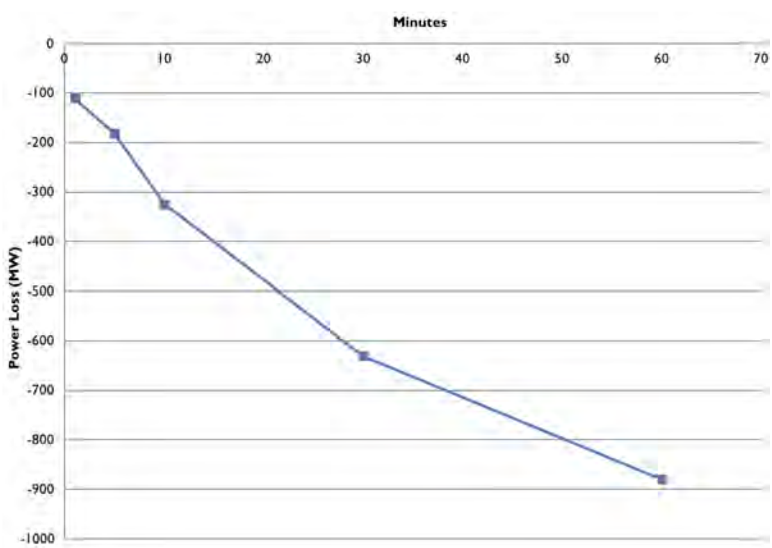


Figure D-7. Largest Drop in MW as a Function of Time

We considered the units that were available to respond to such an event. A battery energy storage system (BESS) would need to be sized to handle the initial load response. As the BESS is called on to supply larger and larger generation amounts for longer and longer time periods, the cost increases exponentially. A more cost effective solution would be to replace the lost potential generation with fully dispatchable resources.

According to our studies, Kahe 7–10 would be able respond to large cloud cover events without having to be online like the slower base loaded units. Table D-9 reflects the start time, in minutes, for the various units.

After factoring in the starting time, ramp rates, and minimum operating loads, we determined that the combination of six peaking units, the Kalaeloa IPP unit, and the baseload units at Kahe 4–6, all together, would be required to adequately respond at the same rate as the Kahe 7–10 proposed unit (depicted in the Current Unit Mix column of Table D-9). Because of their four to six hour startup times, the Kahe units would need to already be online to respond quickly.

Minutes	Individual Unit Response (MW)					Individual Unit Response (MW)	
	Kahe 3	Kahe 4	Kahe 5	Kahe 6	Kahe 7–10	Current Unit Mix*	Modernized Unit Mix†
0	5	5	25	45	0	0.0	65.0
15	35	35	55	105	215	361.0	426.0
30	57	57	91	142	345	685.5	763.5
45	65	65	103	142	349	751.0	805.0
60	73	73	116	142	383	817.5	876.5
75	81	81	130	142	383	878.0	907.0
90	90	89	142	142	383	907.0	907.0

* Current Unit Mix includes Kahe 3–6, Waiau 9–10, CIP CT-1, KPLP, Schofield, and DoD generating units.
† Modernized Unit Mix contains the same units as the Current Unit Mix, except it replaces Kahe 3–6 with the Kahe 7–10 CC unit.

Table D-9. Current and Modernized Unit Response to Loss of Renewable Generation Event

The Modernized Unit Mix column of Table D-9 shows how much more quickly the combined baseload generation that included the advanced Kahe 7–10 unit, ramped to respond to large cloud cover events. Table D-9 also demonstrates that at least four of the currently utilized baseload steam units would be required to be online at their minimum output (plus a downward regulating margin) to adequately respond to large cloud cover events.

The fuel cost for keeping the online reserve at minimum load during all daylight hours can be significant. The calculated cost of this extra fuel is demonstrated in Figure D-8.

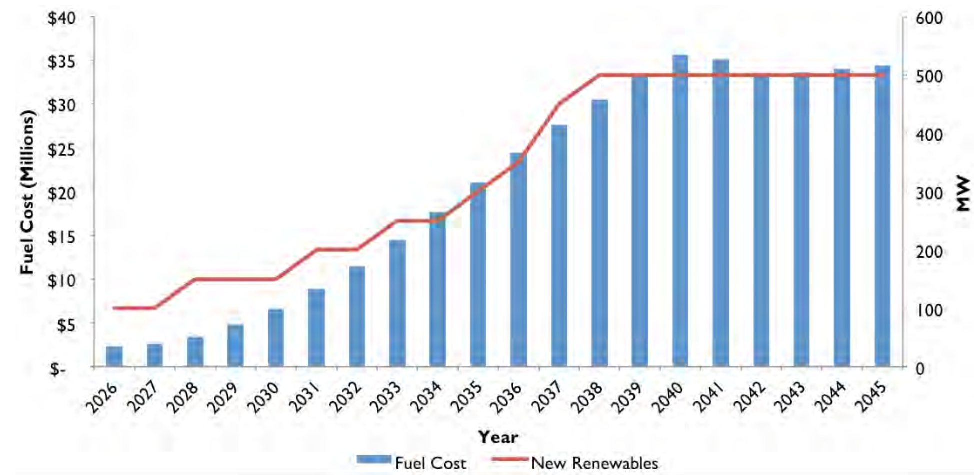


Figure D-8. Extra Fuel Cost

As our renewable fleet grows, the need for the steam units would decrease, and the economic dispatch model would lower their capacity factors to zero. If they were not needed to respond to these large cloud cover events, they could be left in cold standby (using no fuel) or possibly even retired.

Military Base Microgrids

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

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

Hawaiian Electric's goals include:

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

Hawaiian Electric understands the DoD's goals to include:

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

Marine Corps Base Hawai'i (MCBH) Microgrid Concept

To provide the services desired by the Marine Corps, it is only practical that generation be located on Marine Corps Base Hawai'i. In addition to meeting the needs of the Marines, adding generation on the windward side of the island can provide resiliency benefits to customers in that area. Therefore, this is the only concept contemplated for this branch of service.

The addition of generation would create a microgrid for the military base where the new generation and existing base resources (such as rooftop PV) has sufficient capacity and grid controls to safely and reliably serve the base's load.

Site Characteristics, Restrictions and Needs

The Marine Corps previously identified a suitable site on MCBH (Figure D-9) for a replacement generating station near the existing Hawaiian Electric substation that feeds the base. The size of the potential generating station site is approximately 4.8 acres.

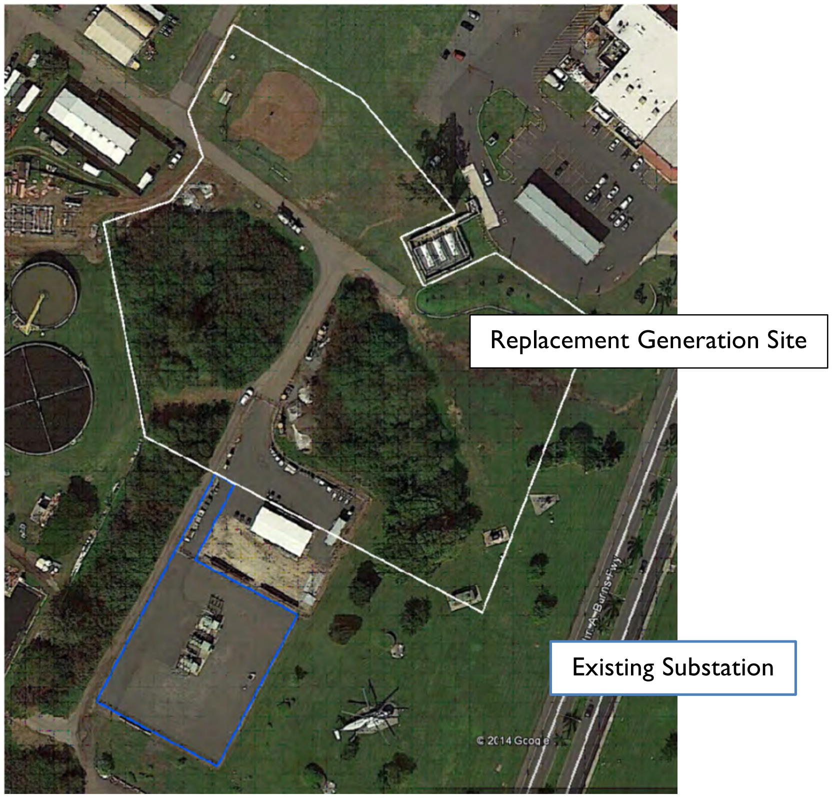


Figure D-9. MCBH Site for Possible Replacement Generation

Based on thermal limitations of the existing 46 kV sub-transmission system feeding the base as well as the need to keep exhaust stacks less than 100 feet above ground level (because of air space restriction associated with nearby helicopter operations), it appears that 54 MW is the maximum size generating station this site could practically accommodate. Furthermore, each of the two 46 kV sub-transmission feeds is individually limited to 30 MW. Therefore, 30 MW would be the maximum size for any individual unit at this site.

No interconnection requirement study has been completed for interconnection at this location and could result in further restriction of project size. The peak load of MCBH is approximately 16 MW and the intent of a project on this site is to be able to serve the entire peak with one generating unit out of service for maintenance (N-1 design criteria). A preliminary air permit analysis indicates that 54 MW of reciprocating engines with 100 feet tall stacks (3 into 1) can be installed in compliance with all air regulations.

Generating Unit Selection and Project Size

Based on the N-1 criteria, Table D-10 shows the relationship between the number of units and the minimum size of each generating unit for a 60 MW peak load with N-1 criteria.

Generating Units	Minimum Size per Generating Unit (MW)	Total System Capacity (MW)
2	16.0	32.0
3	8.0	24.0
4	5.3	21.3
5	4.0	20.0

Table D-10. Number versus Size of Proposed MCBH Generating Units

Table D-10 indicates the site cannot only accommodate enough capacity to meet the N-1 criteria, but that additional units could be placed at this site to satisfy a more robust criteria or to provide additional energy resiliency for off-base customers.

Previous analysis done for Maui Electric indicated that medium speed reciprocating engines for a station of this size are more cost-effective than using combustion turbines. However, the analysis is dependent on expected capacity usage of the project. Therefore, a specific analysis for O‘ahu should be conducted to determine the most cost-effective technology for this site.

Of the two engine sizes that Wärtsilä offers (9 MW and 17 MW), either could satisfy the design criteria. However, for this size of a project, the 9 MW engine is expected to be more cost-effective and to provide better resiliency and power restoration capability. Thus, if Wärtsilä engines are chosen for this site, the project would use either the 20V32 (liquid-only) or the 20V34DF engine (liquid and gas). Either case would result in a minimum project size of 27 MW.

Proposed Project Strategy

Based on Hawaiian Electric’s unique and sole capability to deliver energy security to MCBH through integrated generating station and grid operations, the Marine Corps would select Hawaiian Electric as its sole partner for an energy security project on the selected site. Hawaiian Electric, with the support of the Marine Corps, would request from the Public Utilities Commission a waiver from its Framework for Competitive Bidding, based on the Marine Corps’ stated requirement to work with the utility to meet military needs.

Hawaiian Electric would lease the project site for in-kind consideration in lieu of monetary rent for the life of the project and design, permit, finance, construct, own, and operate a new, up to 54 MW firm generating station located on the site. The generating station would normally be dispatched to meet grid-wide demands from all Hawaiian Electric customers.

Under conditions identified in the lease, Hawaiian Electric would provide energy security guarantees such that the Marine Corps would gain significantly enhanced energy security for MCBH. These guarantees by Hawaiian Electric would provide the Marine Corps in-kind consideration in lieu of monetary rent payments for the life of the project.

In return for the enhanced energy security, the Marine Corps would contribute to the project with land and other contributions as deemed appropriate for the value of the energy security guarantees provided. The value of the land and other contributions to the project would reduce project costs, thereby saving our customers money compared to siting a similar project at a non-military location.

Joint Base Pearl Harbor–Hickam (JBPHH) Microgrid Concept

To provide the services desired by the Navy, two concepts are being considered: 1) locating a microgrid on base at JBPHH; or 2) installing a power barge at the Waiau Generating Station that could either be interconnected to JBPHH or temporarily relocated to JBPHH under emergency conditions.

The addition of generation would create a microgrid for the military base where the new generation and existing base resources (such as rooftop PV) has sufficient capacity and grid controls to safely and reliably serve the Base's load.

Site Characteristics, Restrictions and Needs

The Navy has not identified a desired and suitable site at JBPHH for installation of a new generating station. Hawaiian Electric, however, proposed the site shown in gray in Figure D-10.

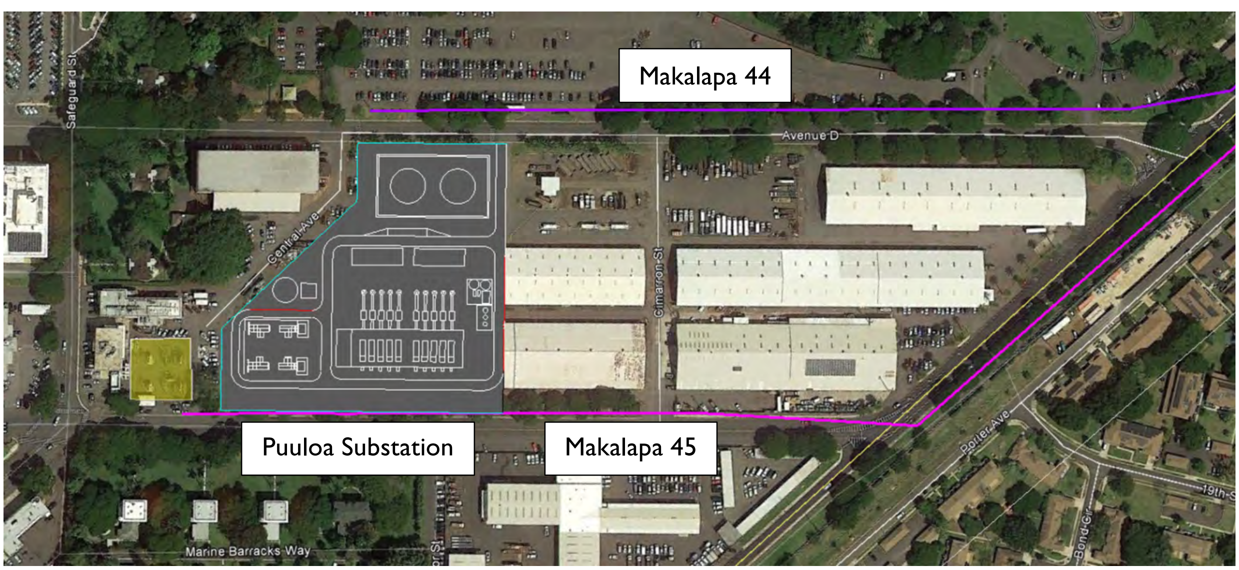


Figure D-10. JBPHH Site for Possible Replacement Generation

Based on thermal limitations of the existing 46 kV sub-transmission system feeding the base, it appears that 96 MW is the maximum size generating station this site could practically accommodate. Furthermore, each of the two 46 kV sub-transmission feeds is individually limited to 48 MW. Therefore, 48 MW would be the maximum size for any individual unit at this site.

No air permit analysis has been done yet for this site and could result in further restriction of project size. No interconnection requirement study has been completed for interconnection at this location and could result in further restriction of project size. The peak load of JBPHH is approximately 60 MW and the intent of a project on this site is to be able to serve the entire peak with one generating unit out of service for maintenance (N-1 design criteria).

Generating Unit Selection and Project Size

Based on the N-1 criteria, Table D-11 shows the relationship between the number of units and the minimum size of each generating unit for a 60 MW peak load with N-1 criteria.

Generating Units	Minimum Size per Generating Unit (MW)	Total System Capacity (MW)
4	20.0	80.0
5	15.0	75.0
6	12.0	72.0
7	10.0	70.0
8	8.6	68.6
9	7.5	67.5

Table D-11. Number versus Size of the Proposed JBPHH Generating Units

Table D-11 indicates the site cannot only accommodate enough capacity to meet the N-1 criteria, but that additional units could be placed at this site to satisfy a more robust criteria, or to provide additional energy resiliency for off-base customers.

We have not analyzed the most cost-effective technology to site on at JBPHH (RICE units or combustion turbines). Based on our analysis for Maui Electric, we expect that medium speed reciprocating engines would be the lowest overall cost choice.

Of the two engine sizes that Wärtsilä offers (9 MW and 17 MW), either could satisfy the design criteria. However, for this size of a project, the 9 MW engine is expected to be more cost-effective. Thus, if Wärtsilä engines are chosen for this site, the project would use either the 20V32 (liquid-only) or the 20V34DF engine (liquid and gas). Either case would result in a minimum project size of 72 MW.

Proposed Project Strategy

Based on Hawaiian Electric's unique and sole capability to deliver energy security to JBPHH through integrated generating station and grid operations, the Navy would select Hawaiian Electric as its sole partner for an energy security project on the selected site. Hawaiian Electric, with the support of the Navy, would request from the Public Utilities Commission a waiver from its Framework for Competitive Bidding, based on the Navy's stated requirement to work with the utility to meet military needs.

Hawaiian Electric would lease the project site for the life of the project and design, permit, finance, construct, own, and operate a new, up to 96 MW firm generating station located on the site. The generating station would normally be dispatched to meet grid-wide demands from all Hawaiian Electric customers.

Under conditions identified in the lease, Hawaiian Electric would provide energy security guarantees such that the Navy would gain significantly enhanced energy security for JBPHH. These guarantees by Hawaiian Electric would provide the Navy in-kind consideration in lieu of monetary rent payments for the life of the project.

In return for the enhanced energy security, the Navy would contribute to the project with land and other contributions as deemed appropriate for the value of the energy security guarantees provided. The value of the land and other contributions to the project would reduce project costs, thereby saving our customers money compared to siting a similar project at a non-military location.

Waiau Power Barge Concept

Independent of any military considerations, Hawaiian Electric has identified that the waters of Pearl Harbor immediately adjacent to Hawaiian Electric's Waiau Power Plant are ideal for a floating power plant ("power barge"), and that this concept could result in a very cost-effective method to provide replacement capacity for Oʻahu.

Figure D-11 shows a three dimensional rendering of one possible configuration at the proposed site.

Figure D-11. Possible Power Barge at the Waiau Generation Station (Artist Rendering)

The power barge concept presents three areas of potential savings compared to land based generating stations at other sites (including JBPHH). First, the installed costs of a power barge are lower than any land based construction in Hawaiʻi, since the entire station would be built in a shipyard and shipped as a single unit. The on-site construction would be limited to the mooring system and the interconnections for utilities and power. Second, a power barge at the proposed location could utilize existing infrastructure at Waiau Power Plant. Third, the delivery schedule for a completed power barge is less than for a comparable facility built on site, reducing project costs.

Another potential advantage of a power barge is that it could be designed to be capable of moving between islands to provide emergency power and increase state-wide resiliency. This concept has not been studied, but could prove worthy of consideration if it broadens stakeholder support for the project. Such a capability would require additional systems and capabilities onboard the barge, and additional infrastructure on each island where the barge could be deployed. It would also have company and state policy considerations, which would require the support of state and county governments, and possibly Kauaʻi Island Utility Cooperative (KIUC). Project cost allocations associated with these additional capabilities would also have to be determined.

Two types of power barge have been studied, reciprocating internal combustion engine (RICE) units and simple-cycle combustion turbines (CT). For the purposes of the study, 100 MW nominal capacity barges were assumed, although the barge could be larger or smaller based on the outcome of air permitting and interconnection analyses. Barge comparison results are summarized in Table D-12. Based on the analysis, the RICE barge appears to be the better solution for Hawaiian Electric than the turbine barge.

Type	Total Cost	Net Heat Rate (Btu/kWh HHV)
RICE	$160 Million	8,507
CT	$180 Million	8,951

Table D-12. Waiau Power Barge Comparison

Although the Waiau Power Barge concept was initiated to meet Hawaiian Electric needs, because of the close proximity of Waiau Power Plant to JBPHH, Hawaiian Electric is discussing with the Navy the possibility of using the power barge concept to fulfill the Navy's energy security needs as well. In a situation in which the Navy requires a direct feed of electrical power, this concept could take one of two forms:

- The barge could be re-located to a temporary mooring at JBPHH, and connected directly to the base electrical infrastructure.
- The barge could remain in place, but divert power to JBPHH via a direct connection using overhead or underwater cabling.

The peak load of JBPHH is approximately 60 MW. Since the overall capacity of the barge would be determined by Hawaiian Electric's capacity needs and not the Navy's needs alone, a minimum barge capacity of 100 MW is likely to be required. If the Waiau Power Barge concept were selected to meet the Navy's energy security needs, the project would also need to be able to serve the entire JBPHH peak with one generating unit out of service for maintenance (N-1 design criteria). The 100 MW RICE barge would incorporate six 17 MW units, which would satisfy this criteria. The 100 MW CT barge, as analyzed, has a single 100 MW CT, which would not satisfy the criteria. Other combinations of smaller CT units could be considered, but in general this would increase the cost and the heat rate of the CT barge option, thereby making it even less competitive versus the RICE barge. Therefore, the RICE barge would be a better choice than the CT barge to meet the Navy's energy security needs.

Proposed Project Strategy

If the Waiau Power Barge is only considered as a Hawaiian Electric project for replacement capacity, it could be included as a competitive proposal to an open RFP for new generation, as outlined in the Framework for Competitive Bidding. If the barge serves as a state-wide emergency and resiliency asset serving a government need, a waiver from the Framework may be justified. Furthermore, if the Navy agreed that the power barge would meet their energy security needs, the project would meet several criteria under which a waiver would justifiable. The remainder of this strategy assumes this case.

Based on Hawaiian Electric's unique and sole capability to deliver energy security to JBPHH through integrated generating station and grid operations, and Hawaiian Electric's existing Waiau Power Plant located on Pearl Harbor, the Navy would select Hawaiian Electric as its sole partner for an energy security project. Hawaiian Electric, with the support of the Navy, would request from the Public Utilities Commission a waiver from its Framework for Competitive Bidding, based on the Navy's stated requirement to work with the utility to meet military needs (and also potentially on the project's unique capability to move inter-island as a "power supply needed to respond to an emergency situation").

Hawaiian Electric would lease the project site for the life of the project and design, permit, finance, construct, own, and operate a new, 100 MW or more RICE power barge. (The requirements for, and cost of, a lease of Pearl Harbor waters are not developed, but a preliminary estimate is $150,000 per year.)

The Navy would fund project costs that solely support the project's ability to meet the Navy's specific energy security requirements. If the barge will be deployable to other islands, cost sharing arrangements for project costs that are required for this capability would be negotiated by stakeholders. The power barge would normally be dispatched to meet grid-wide demands from all Hawaiian Electric customers.

Under conditions identified in the lease, Hawaiian Electric would provide energy security guarantees such that the Navy would gain significantly enhanced energy security for JBPHH. These guarantees by Hawaiian Electric would provide the Navy in-kind consideration in lieu of monetary rent payments for the life of the project. If deployable to other islands, the barge would only do so after Hawaiian Electric ensured that JBPHH's demand is being served by the grid.

In return for the enhanced energy security, the Navy would contribute to the project with land and water lease rights, and other contributions as deemed appropriate for the value of the energy security guarantees provided. The value of the Navy contributions to the project would reduce project costs, thereby saving our customers money compared to siting a similar project at a non-military location.

E. New Resource Options

This appendix discusses the new resource options that were considered in our analysis for the 2016 updated PSIPs.

AVAILABLE GENERATION OPTIONS

For the 2016 updated PSIP analyses, we have taken a "clean sheet" approach in developing new resource options. In developing this new set of assumptions, we are mindful of the Commission's concerns expressed in Order No. 33320 about the results from our 2014 PSIPs:

> …appears to rely on the utilization of renewable resources with relatively high costs and unproven resources with uncertain feasibility.[1]
>
> …the technology cost assumptions utilized by the Hawaiian Electric Companies in the PSIPs also appear conservative" and "…do not appear to accurately reflect current cost trends…[2]
>
> …the amounts and types of renewable resources that are considered in the PSIP analyses appear to be inappropriately limited. Generally, the Hawaiian Electric Companies' criteria for exclusion of resource technologies from consideration in the economic analyses based on the state of commercial readiness appear over-restrictive. The Companies have categorically excluded generation technologies with a Commercial Readiness Index ("CRI") lower than five. This excludes technologies with a CRI of four, which are technologies in full-scale commercial use and have "publicly verifiable data on technical and financial performance."[3]

---

1 Order No. 33320, at 80.

2 *Ibid.*, at 84–85.

3 *Ibid.*, at 83.

While technologies with a CRI Level 4 are in full-scale commercial use and have "publicly verifiable data on technical and financial performance", the full description of CRI Level 4 also included criteria related to the ability of these technologies to be financed. In particular, CRI Level 4 technologies "…may still require subsidies" and that there is "…interest from debt and equity sources" that "…still [require] government support." We chose to consider technologies in the 2014 PSIPs based on the ability of the technology to receive financing without the need for subsidies, and to avoid relying heavily on technologies that have "high costs and uncertain feasibility". The 2014 PSIPs also stated that "…this planning assumption is for the PSIP analyses only, and does not affect our intent to thoughtfully consider specific projects that include emerging technologies. In other words, we welcome generating technologies not considered in the PSIPs that are proposed in responses to future request for proposals (RFP) for any of our power systems."[4] We reiterate that intent here.

New Utility-Scale Resource Assumptions

For the 2016 PSIP analysis, we use multiple sources of forward curves for the capital cost of new generating technologies and new energy storage technologies. Figure E-1. shows the projections of per unit capital costs expressed in 2016 real $/kW. The data portrayed underlie the nominal dollar assumptions used in the 2016 PSIP analysis. The constant dollar projection is a useful way to portray the expected future cost trends of various electric power generation technologies.

[4] Power Supply Improvement Plan, filed August 26, 2104, at H-1.

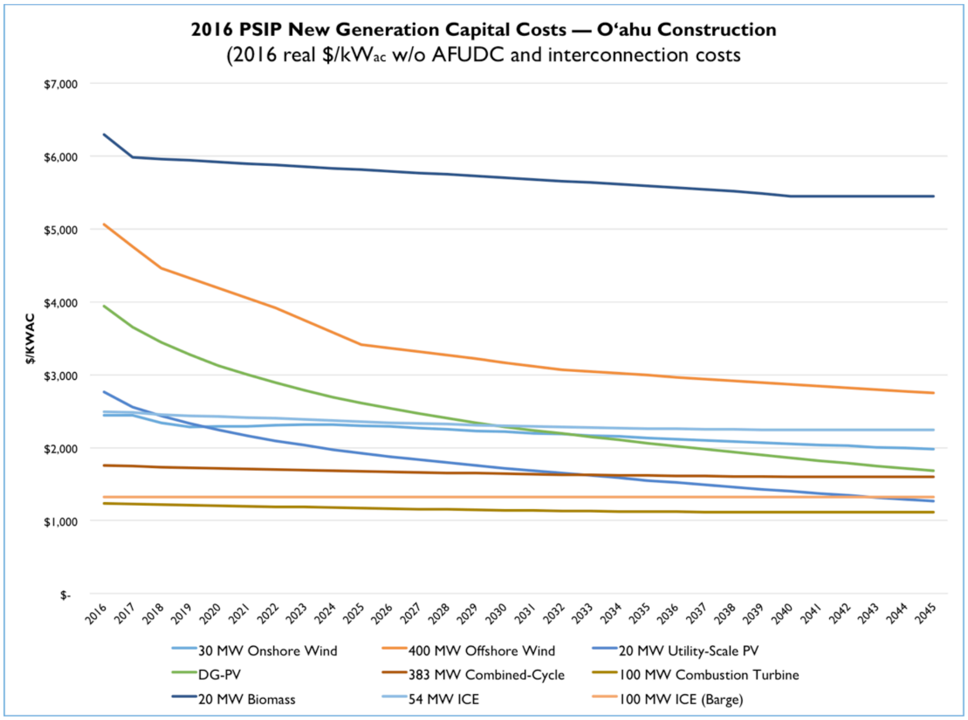


Figure E-1. 2016 Updated PSIP New Generation Resource Capital Costs—O'ahu

Data Sources

In our analyses for these 2016 PSIPs, we have completely reworked the resource technologies and cost assumptions. The re-working of the new resource assumptions started with a review of current literature and data sources including:

- National Renewable Energy Laboratories' (NREL) *2015 Annual Technology Baseline (ATB)* spreadsheet (July 2015).[5]
- *Lazard Levelized Cost of Energy Analysis – Version 9.0* (November 2015).[6]
- Energy Information Administration's (EIA) *Updated Capital Cost Estimates for Utility-Scale Electricity Generating Plants* (April 2013),[7] used primarily as guidance for regional cost adjustments.
- Electric Power Research Institute (EPRI) *Technology Assessment Guide* (2013-2015 data sets), a proprietary[8] database of power technology costs and performance.

---

5 The NREL ATB spreadsheet is available at: http://www.nrel.gov/analysis/data_tech_baseline.html.

6 The Lazard analysis is available at: https://www.lazard.com/media/2390/lazards-levelized-cost-of-energy-analysis-90.pdf.

7 The EIA report is available at: http://www.eia.gov/forecasts/capitalcost/.

8 "Proprietary" means that the materials, analysis, and data are trademarked, privately-owned, private, patented, or otherwise exclusive to the party producing the information. Generally, any party willing to pay for a license can obtain the information. We are bound by the terms of the license or right agreement when we use these resources. This is a common commercial practice.

- Various proprietary reports published by IHS Energy in 2015 regarding cost trends related to solar PV, wind, and energy storage technologies.
- *Gas Turbine World 2014–15 Handbook*, a publication that provides power plant prices, price trends, and performance data for combustion turbines and combined-cycle plants.
- RSMeans data, which publishes proprietary indices regarding materials, labor, and productivity for more than 900 cities in the United States and Canada, including Honolulu and Hilo.
- NextEra Energy, *NextGrid Hawai'i* study submitted to the Commission in September 2013.
- Our internal data and estimates for the cost of internal combustion engines (ICE), including the actual budgeted costs for the Schofield Generating Station (as proposed in Docket 2014-0113 and reduced to reflect favorable movement in foreign exchange rates) and a vendor quote for the 100 MW ICE "power barge" proposed for O'ahu.
- Our internal estimates of system interconnection costs for resources of various sizes (including the cost of connecting to the grid). These estimates exclude costs associated with system upgrades that might be required to accommodate a specific project.
- Certain resource capital cost assumptions received as input from two of the Parties.

Development Process

The process of developing resource assumptions involved several different efforts that were synthesized into a common set of assumptions for the 2016 PSIP update analysis.

We researched and reviewed the most current data sources possible. The NREL ATB database was one such current source. A significant advantage of the NREL ATB data source is that it provides a publicly available source of the forward curves for capital costs, and operations and maintenance expenses for several different power generation technologies. This data was combined with the EIA's 2013 *Updated Capital Cost Estimates for Utility-Scale Electricity Generating Plants* information regarding locational adjustments (by technology), specifically for Honolulu, to adjust the NREL ATB data for Hawai'i. We adjusted the cost data using 2016 dollars as the base year for the 2016 updated PSIPs by converting all cost information from real dollars to nominal dollars using a 1.8% inflation and escalation rate. We use nominal dollars to evaluate various cases in our economic analysis. Our analyses and conclusions also incorporate input from certain Parties.

NextEra Energy consulted with us to develop the new resource assumptions. NextEra Energy has extensive experience as a developer, owner, and operator of wind power, solar PV projects, concentrated solar power (CSP) projects, gas-fired generation stations, and bulk energy storage projects. NextEra Energy also uses IHS Energy's proprietary research reports to develop initial cost assumptions for certain resources. IHS reported information for developing renewable resources and energy storage for California, and also provided forward curves for various resources. The California reference was adjusted to a Hawai‘i value based on the RSMeans' city indices for materials, labor, and productivity. NextEra Energy then compared the results of the Hawai‘i-adjusted data to its own experience in developing and operating some of the technologies considered, including projects in Hawai‘i .[9] The result is a set of cost values for the various technologies that reflect independent evaluations *and* actual experience. All prices were adjusted for Hawai‘i by applying a 4% adder for Hawai‘i General Excise Taxes.

We retained NREL to independently and objectively review the assumptions synthesized through this processes. NREL filed two reports on their analysis. Generally, NREL found our assumptions to be in line with their own database and other third-party sources. We discuss specifics of their conclusions Utility-Scale Resource Assumptions on page E-17. (Appendix F contains the actual NREL reports.)

Generation Technologies Considered

Order No. 33320 recognized that actionable plans cannot be built on "unproven" resources that might be technically and economically feasible in the future, while also stating that the choice of technologies cannot be "overly restrictive". We do not believe that the best interests of our customers are served by expecting them to underwrite the risks associated with technologies that are not commercially available today.

To clarify our intent, our 2016 updated PSIPs should "… address the need for applications for approval of individual capital projects, programs, contracts, and RFPs to be considered with the benefit of the context provided by well-vetted, sufficiently analyzed comprehensive system plans."[10]

Thus, we are developing our 2016 updated PSIPs to serve as the basis for actionable, near-term decisions regarding approvals for RFPs to solicit resources to meet capacity needs, applications for capital expenditures related to power supply and energy storage projects, and applications for PPA approvals.

In addition, we are developing our 2016 updated PSIPs to be flexible over the long-term to accommodate technology and cost improvements in existing technologies, and to

---

[9] On February 4, 2014, *Pacific Business News* published an article entitled "NextEra Provides Cost Estimates for Hawaiian Electric's New Energy Plans." The author did not contact us prior to publication. We believe the article misleads the reader by suggesting that NextEra-provided estimates were not vetted or subject to independent review. In reality, we collaborated with NextEra Energy and NREL to derive the new resource assumptions based on independent data sources. In addition, we contracted with an outside consultant to compile these resource assumptions to assure their consistency and objectivity.

[10] *Op. cit.*, at 39.

accommodate the commercialization of transformational technologies that might become available. We strongly believe this is a prudent and reasonable philosophy that is not only in the best interest of our customers, but also in the best interest of achieving the state's renewable energy policy goals.

To reiterate: the choice of technologies in these 2016 updated PSIPs is a planning assumption, which in no way is intended to limit or discourage proposals for other technologies. Such proposals, however, must have the following attributes:

- Sound engineering design concepts.
- Commercial availability of the technology from a reputable vendor who will stand behind the performance and servicing of the technology (including all balance of plant items) over its useful life.
- Demonstrated financial feasibility of the project employing the technology, including its benefits to ratepayers, taking into account the system needs (as stated in a competitive bidding process approved by the Commission, or as stated in a waiver from the competitive bidding framework approved by the Commission) and the costs of integration.
- The ability of the project sponsor to demonstrate the financial wherewithal and technical capabilities to successfully finance, construct, and operate the project employing the technology.

To meet our goals for the 2016 updated PSIPs, we limited new resource analysis choices to these technologies.

Utility-Scale Solar Photovoltaic

Solar PV technology is mature. Current forecasts are characterized by continuing modest decline in capital costs and incremental improvements to the technology. Multiple utility-scale solar PV projects are installed in Hawai'i. There is significant experience in the Hawai'i market with solar PV technology by us, multiple project developers, and capital providers.

The PSIP assumptions reference fixed-tilt systems (as opposed to single-axis and multi-axis tracking systems). The PSIPs utilize capacity factors and output profiles for utility-scale solar based on historical experience with existing utility-scale solar PV systems. Costs for solar PV systems are typically expressed in dollars per watt of the total output of the PV system panels (direct current power). The ratios of DC output to (usable) AC output in utility-scale solar PV projects typically ranges from 1.1–1 to 1.5–1. The reference plant capital cost assumes a 1.5–1 DC to AC ratio. The NREL resource analysis also assumes a 1.5 to 1 DC to AC ratio. This higher ratio typically allows projects to achieve higher capacity factors since more PV panels boosts output over the shoulder periods around the time of peak irradiance. We did not however have profile data for plants incorporating a 1.5 DC to AC ratio. The capacity factor modeled for utility-scale solar PV was 20.4% for O‘ahu, 20.41% for Hawai‘i Island, 20.4% for Maui, 20.6% for Lana‘I, and 21.1% for Moloka‘i. We believe that fixed tilt solar PV systems with the 1.5 DC to AC ratio may achieve capacity factors as high as 25%. We are investigating load profile information for 1.5 DC to AC ratios that will be incorporated into future analyses.

Distributed Solar Photovoltaic

The PSIP assumptions for the cost of DG-PV are based on the same source data, including future cost trends, as used for utility-scale solar PV. These solar PV costs were adjusted for Hawai‘i and compared to actual costs for residential PV systems based on contact with vendors. The cost of DG-PV is expected to decline (in real terms) slightly over the study period. The net capacity factor for DG-PV is assumed to be 18.4% for O‘ahu, 16% for Hawai‘i island, 18% for Maui, 16% for Lana‘i and 20% for Moloka‘i.

Onshore Wind Power

Onshore wind projects employ mature technology. Wind power trends are characterized by modest decreases in per unit capital cost (in real dollars), modest performance increases, and substantial improvements in the size of commercially available single wind turbines. Over 200 MW of wind capacity are operating in our service areas, almost all of it owned by independent power producers. There is significant experience in the Hawai‘i market with onshore wind technology by the Companies, multiple project developers, and capital providers. The net capacity factor modeled in the reference plant was 22.7% for O‘ahu, 54.4% for Hawai‘i Island, and 51% for Maui, Lana‘i, and Moloka‘i.

Wind projects exhibit significant economies of scale because of the intensive mobilization effort (for example, heavy cranes, equipment to move towers, and turbines from port to the site location). The cost assumptions used in the 2016 updated PSIPs reflect these economies of scale.

Combustion Turbines

Modern combustion turbines (CTs) are the “workhorse” of electric utility systems around the world. Essentially jet engines coupled to a generator, CTs can be designed to burn a variety of fuels including fuel oil, naphtha, and natural gas. CTs are characterized by relatively low capital costs, modest efficiency (heat rates of 10,500 BTU per kWh), high reliability, and relatively short lead times for installation. Smaller CTs typically are less efficient than larger machines (heat rates as high as 18,000 Btu/kWh for small “microturbines”). CTs are a mature technology with projected flat capital cost (in real dollars) and continued small incremental performance improvements over time.

CTs have significant operating flexibility with fast-start capability, fast ramping, and a high level of variability when spinning. CTs are typically used as peakers (where capacity is required to meet short duration peak demands). Typical annual capacity factors for CTs are less than 20%, sometimes significantly less. CTs can play an important role in integrating variable renewables by providing capacity and energy at times when the variable renewable resources may be limited.

There are several very large, well-capitalized international vendors who provide CTs in a variety of sizes. Each of these vendors has extensive supply chains for parts and service. Their capabilities are supplemented by numerous specialized O&M service firms and after-market parts suppliers. There is a vast amount of experience with CTs on the part of utilities (including the Hawaiian Electric Companies and NextEra Energy), IPP project developers, and providers of capital.

Combined Cycle

Combined-cycle power plants are a mature technology that employ CTs, but add a heat recovery steam generator (HRSG) that takes the exhaust heat from one or more CTs "recover" the thermal energy that that would otherwise go to waste, and produce steam. The steam is then used to turn a turbine coupled to a generator. There are various configurations of combined-cycle plants. A single CT, coupled to a HRSG and steam turbine-generator set, is referred to as a single-train combined-cycle (STCC) plant.

Similarly, two CTs, coupled with two HRSGs and a steam turbine-generator is referred to as a dual-train combined-cycle (DTCC) plant. We own and operate three DTCC plants: one at the Keahole plant on Hawaiʻi Island and two at the Maʻalaea plant on Maui. The Hamakua Energy Partners (HEP) plant on Hawaiʻi Island is also a DTCC plant utilizing the same make and model of combustion turbines installed at both Keahole and Maʻalaea.

Combined-cycle plants typically exhibit the greatest efficiency technically possible with thermal generation. Heat rates for modern combined-cycle plants operating at a high capacity factor can be as low as 7,000 Btu/kWh. The reliability of combined-cycle plants is high. They tend to be used as baseload and cycling generation. This too is considered to be a mature technology, with flat projected capital cost, and incremental performance improvements over time. Like CTs, combined-cycle power plants are utilized by utilities and IPPs around the world. Combined-cycle plants are procured and serviced through a well-established and mature supply chain. Financing is readily available in the capital markets for combined-cycle plants owned by utilities or by IPPs.

The 2016 updated PSIPs propose combined-cycle options for Oʻahu in a 152 MW STCC configuration and a 383 MW 3x1 configuration (three combustion turbines, three heat recovery waste heat boilers, and one steam turbine), the latter for modernization at the Kahe power plant.

Internal Combustion Engine

Internal combustion engine (ICE) generation couples an internal combustion engine with a generator. Modern ICE generators are in widespread use throughout the world. They are the dominant technology employed in DG applications; however, they are routinely found in utility-scale applications as well. We are currently building a 6-unit x 8.4 MW (for a total of 50 MW) ICE generation station at the Schofield Barracks Army Base on O‘ahu. That project is scheduled to enter commercial operation in 2017. The Schofield Generating Station will provide additional operating flexibility to help manage increasing penetrations of variable renewable resources, including DG-PV. It is also being designed to allow Schofield Barracks to operate as a microgrid (that is, in an "islanded" mode) providing energy security for the base.

ICE generation has relatively high efficiencies (heat rates of approximately 10,000 Btu/kWh) across a wide operating range (25% to 100% of full load), and rapid start-up and shutdown capabilities. ICE generation is a mature technology. Cost and performance trends into the future are relatively flat. There is a robust and competitive market for ICE consisting of several major global vendors and a handful of other players.

Biomass

Biomass can be used to generate power in several ways. Biomass feedstock can be burned directly to provide heat to create steam, which in turn powers a steam turbine-generator to produce electricity. Biomass feedstock can also be processed through gasifiers to produce a gas or liquid fuel that is then burned in thermal generating technologies (such as ICE, CTs, and combined-cycle plants). The PSIP assumptions for the 20 MW biomass plant are based on a direct combustion process.

We continue to explore opportunities to use locally produced energy crops for their possible contribution to renewable power generation. Various parties in Hawai‘i continue to research and develop the commercial potential of test crops: cellulosic feedstock (such as bana grass); energy cane and oil seed crops (such as jatropha, sunflower, and pongamia); and eucalyptus from farms on Hawai‘i Island.

Crops for biofuel that could substitute for fossil fuels in thermal power generation include cellulosic crops or crop waste for biomass-to-gas-to liquid technologies and oil seed crops for feedstock. Alexander & Baldwin (A&B) has expressed interest in pongamia trees that produce oil seed for biodiesel and can grow on less-than-optimal lands while serving as shade for other interspersed crops.

Biofuels can be easily substituted for liquid fuel in a number of existing generating units and easily transported via truck containers and barges. Typically, both biogas and biomass for power generation are economically feasible only when the feedstock is in close proximity to the power generation facility. Cellulosic crops and crop waste can serve as feedstock for anaerobic digesters to produce biogas, which are commercially proven in installations around the world. Our use of biogas for power would require conversion of existing generation to fire gas or new gas-fired generation. Biomass derived from energy crops, crop waste, or tree waste can be dried and pelletized to use in generating units that can otherwise burn coal. Cost-effective biomass or biogas generation using purpose-grown crops remains to be proven, but holds promise.

The January 7, 2016 announcement by A&B to cease production of sugar by Hawaiian Commercial Sugar & Company (HC&S) on Maui and transfer to a diversified agricultural model presents opportunities for further exploration of energy crops on portions of their 36,000 acres. The economics and bioenergy technologies must still be proven.

Our analysis assumed biomass fuel is obtained from on-island biomass resources. For Maui, this is based on the fact that at one point the HC&S power plant produced 40 MW of power from organic waste (bagasse) that is a by-product of the sugar cane operation. With the closure of the HC&S sugar operation, we assumed that a portion of HC&S's property could be dedicated energy crops. Other land outside of HC&S may also be available for growing biomass crops. On Hawai'i Island, we assumed that there is available land to support biomass plants.

We have re-examined and updated our biomass assumptions since our interim filing. For the 2016 updated PSIPs, the capital costs for biomass plants was derived from the NREL ATB (with adjustment factors for Hawai'i) and from an assumption that biomass fuel would cost $80 per bone dry ton (BDT) with a heat content of 7,500 Btu per pound. This results in a fuel price of $5.34 per MMBtu.[11] We also assumed a plant heat rate of 13,500 Btu per kWh. These assumptions result in an all-in cost of electricity at a 50% capacity factor of approximately $0.28 per kWh (which is generally consistent with Hu Honua contract that we recently terminated due to their non-performance.[12])

Geothermal

Geothermal power generation relies on underground heat sources. Typically, water is injected into a well drilled into an underground pocket with high temperatures to create steam that is channeled to the earth's surface and used to turn a steam turbine-generator

[11] http://www.hawaiicleanenergyinitiative.org/storage/pdfs/6_SpecificEconomicModeling_ScottTurn.pdf.

[12] The Hu Honua plant intended to utilize the federal Production Tax Credit, which has since expired. Therefore, the actual PPA rate for the Hu Honua plant was somewhat less than the prices derived from our current assumptions.

set to generate electricity. Hawai‘i Electric Light currently purchases electrical capacity and energy from the Puna Geothermal Venture 38 MW geothermal power plant.

Geothermal is a proven technology and has been considered a new resource option for the 2016 updated PSIPs for Maui and Hawai‘i Island. Developing new geothermal generation in Hawai‘i will require extensive resource assessment and permitting. New geothermal resources on both islands require additional field research (that is, test wells) to prove its potential as an energy source. Because of this extensive research, the 2016 updated PSIPs consider geothermal potential resources only in the later years of the 30-year planning period.

Offshore Wind

There are currently two proposed offshore wind projects being proposed for O‘ahu. The first consists of 400 MW on the northwest side of the island and the second is for 400 MW on the south-southeast side. Because of the significant water depths at the proposed Hawai‘i sites (±1000 meters), offshore wind installations in Hawai‘i will most likely employ large wind turbines installed on floating platforms and sited in deep water (±1000 meters).

Floating wind turbine technology is less mature than fixed-bottom technology; the first floating turbine was installed in 2009 and four additional machines have been installed in subsequent years. Because these projects are single turbine, proof-of-concept installations, they have been more expensive than fixed-bottom projects (on a $/kW basis). These projects are not able to achieve economies of scale and have elevated budgets for research and development. According to at least one source, floating technologies are becoming increasingly mature; the first commercial applications are expected to occur by 2020 (Smith et al. 2015).

The economics of floating technologies are different from fixed-bottom technologies. Some elements (such as electric infrastructure) will be more expensive because undersea power cables must be able to withstand dynamic loading within the water column, whereas power cables for fixed turbines can be laid out directly on the seabed. Further, in the Hawaiian Electric system, interconnection of a 400 MW offshore wind project and its effect on system security needs must be carefully evaluated. The design of this interconnection cable system will be extremely important since a failure of the cable system will severely impact system security, as the loss of 400 MW of wind generation is considerably larger than the size of the current largest land-based contingency.

There is the potential for capital costs to be lower than a fixed platform structure because the entire turbine-substructure unit can be assembled in port and towed to the project site. These cost reductions will be possible in Hawai‘i only if appropriate facilities (for example, ship-building type facilities) and heavy construction equipment are available.

Because the weight of floating platforms is relatively insensitive to turbine size, the economics generally are substantially improved for projects that use large (for example, more than 8 MW) wind turbines. Currently, no existing installations of floating platforms utilize 8 MW turbines.

Considerable uncertainty surrounds the future cost of floating technology given its pre-commercial status and its installation in the Hawaiʻi environment. A preliminary analysis conducted by NREL and the U.S. Department of Energy suggests that a reference floating offshore wind facility installed in 2020 could have an installed capital cost of approximately $4,500 per kW. This cost, however, is uncertain.

The NREL ATB shows that $4,500 per KW is the lowest capital cost ever achieved for shallow and mid-depth offshore wind projects, and that almost $8,000 per kW (*before* adjusting for a Hawaiʻi location) is the capital cost for deep water offshore wind projects. Development risk factors could affect the cost of offshore wind projects in Hawaiʻi. The two known developers of proposed offshore wind projects have released figures suggesting that the capital cost of offshore wind, installed in Hawaiʻi, would be approximately $4,000 per kW. Absent other reliable data, we have used the new preliminary NREL figure of $4,500 per kW in our assumptions, however, the margin of error might be large. We assumed that offshore wind projects near Oʻahu have an annual net capacity factor of 42.4%.

Because it is clear that reaching the State's renewable energy goals will require resources that are not located on Oʻahu, the resource plans developed for Oʻahu include floating offshore platforms incorporating 8 MW wind turbines. However, these projects do not appear in plans prior to 2030; additional due diligence will need to be undertaken to fully vet the viability of this resource option.

Because floating platform offshore wind requires the installation of undersea cables, we plan to further evaluate this emerging technology together with the inter-island cable analyses to be performed in the next phase of our planning analyses (see Chapter 9: Next Steps). Both technologies offer potentially competing solutions for helping Oʻahu reach 100% renewable energy generation. .

Concentrated Solar Thermal Power

Concentrated solar thermal power (CSP) is a rapidly advancing commercially available technology; however, the installed base of global CSP capacity is still only about 1,200 MW.[13] (Hawaiʻi Electric Light terminated the contract for the CSP-based Keahole Solar Power contract on September 9, 2014 after the facility failed to delivery energy for

[13] http://www.energy.gov/articles/year-concentrating-solar-power-five-new-plants-power-america-clean-energy.

over 365 days and, after the project, lost the land rights required for continued operations.)

CSP utilizes thermal radiation from the sun. The thermal solar energy is typically transferred to a working fluid; the resultant heat is used to make steam. That steam is used in a steam turbine coupled to an electric generator. In some CSP applications, the thermal energy can be stored, spreading the output of the CSP facility over a longer period of time, resulting in capacity factors higher than those achieved with solar PV technology. CSP requires direct sunlight to function efficiently; cloud cover significantly degrades performance (in contrast to solar PV which does not exhibit as much performance degradation on cloudy days relative to CSP). As a result, most of the operating CSP plants are located in deserts in California, Spain, and the Middle East.

CSP has a relatively expensive capital cost. With the maturity of solar PV and the rapidly improving performance and steep forecasted capital cost price declines of battery energy storage systems (BESS), the technical and economic viability of CSP relative to a solar plus BESS applications may be relatively limited to areas with consistent solar thermal radiation.

Solar PV Plus Storage Combination

A combination of utility-scale solar PV and BESS can create a "dispatchable" renewable resource. With the performance and cost improvements of BESS technologies, this combination could become a useful tool for achieving our RPS goals.

Kauai Island Utility Cooperative (KIUC) has recently announced its intent to develop a project with 17 MW of solar PV combined with a 13 MW/52 MWh (four-hour duration) BESS system.[14] This project will allow KIUC to store solar energy during the DG-PV "valley" of the daily demand curve, and then provide that energy later in the day and evening to serve the daily peak demand. We have met with the developer of the Kauai project and discussed potential applications for the technology in our service areas. We anticipate that future solicitations for new resources might result in proposals for this combination of technologies.

Waste-to-Energy

Like biomass plants, waste-to-energy (WTE) systems are dominated by two basic technologies: systems that involve direct combustion of the waste, with the resulting heat being used in a boiler to generate steam that drives a steam turbine-generator set; and gasification systems where the waste is broken down into a low-BTU gas that typically fuels an ICE generator.

[14] http://cleantechnica.com/2015/09/22/now-solar-power-meet-evening-peak-load-hawaii/.

WTE facilities tend to have very site-specific designs because the plant must be sized for the volume of the waste stream and must use the technology most appropriate for the makeup of the waste stream. For this reason, reliable capital cost and operating data for WTE plants has been difficult to find. None of the data sources we reviewed cover or routinely provide analysis for a "typical" WTE plant.

Given the volume of our waste stream, WTE plants on Maui, Lanaʻi, Molokaʻi, and Hawaiʻi Island would have relatively smaller sizes. Reliable cost data on these smaller plants is difficult to obtain. A literature search of smaller WTE plants reveals potential capital costs ranging from $4,000 to $11,000 per kW.

WTE plants exhibit economies of scale: very small plants will likely have a high per unit capital cost compared to larger plants. Considerations include the sales of electricity; the "tipping fees" received from the source of the waste; and, in some cases, from the value of recycled materials pulled from the waste stream before it enters the WTE plant. Even with a given capital cost, there is the potential for a great deal of variability in determining a projected price for electricity from a WTE plant. Because of the relatively constant stream of waste, a typical WTE system is not able to substantially vary its output because of the relative narrow efficient operating range (especially direct combustion WTE plants).

The H-POWER steam plant, a 68.5 MW WTE facility in the Campbell Industrial Park owned by the City and County of Honolulu, processes up to 3,000 tons per day of municipal solid waste.[15] H-POWER is a steam plant.

In recent years, the County of Hawaiʻi and the County of Maui have proposed several waste-to-energy plants. The last two mayoral administrations in the County of Hawaiʻi both proposed waste-to-energy facilities, but both plans were abandoned. In the County of Hawaiʻi, questions arise regarding whether the waste stream is adequate to support a WTE plant.[16] Several private developers have also proposed WTE facilities on Hawaiʻi Island. There is a pending proposal from the County of Maui and a private developer to provide gas derived from municipal waste landfills to fuel existing Maui Electric power plants.

We will continue to work with the communities and stakeholders on WTE proposals that can help with municipal solid waste disposal issues and provide benefits to electricity customers. Should this technology become commercially viable and demonstrate the ability to be financed without substantial subsidies, we will reconsider including WTE generation as an option in future resource plans.

---

[15] http://www.covanta.com/facilities/facility-by-location/honolulu.aspx.

[16] http://bigislandnow.com/2014/04/22/big-island-rubbish-enough-to-go-around/.

Ocean Thermal Energy Conversion

Hawai'i is a pioneer in ocean thermal energy conversion (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. OTEC International (OTECI), which had proposed a 100 MW OTEC project to serve O'ahu, announced that it was withdrawing from the Hawai'i market.[17]

As a point of reference, in August 2015, Makai Ocean Engineering completed the world's largest operational OTEC plant at its facility in Kona that generates 100 kW. In addition, a 1 MW OTEC plant is planned for the Hawai'i Ocean Science and Technology Park in Kailua-Kona on Hawai'i Island.

Should this technology become commercially viable—offered by a vendor willing to financially back the development and performance of a full-scale plant—and demonstrate the ability to be financed without substantial subsidies, we will consider including OTEC as an option in future resource plans.

Wave and Tidal Power

Successful demonstration tidal and wave power projects have been implemented in several locations, including Hawai'i. We currently partner with the U.S. Navy (and others) in a small-scale pilot.

Small utility-scale wave power projects have been installed in Europe.

Figure E-2. Pelamix Wave Energy Converter at the European Marine Energy Test Centre, 2008

[17] http://www.utilitydive.com/news/heco-developer-shelve-100-mw-ocean-thermal-energy-project-off-hawaii/401000/.

Ocean Renewable Power Company (ORPC) installed their tidal generator turbine (TidGen) in Cobscook Bay in Eastport, Maine, and their river generator turbine (RivGen) in the Kvichak River (Igiugig, Alaska). TidGen is expected to increase the size of the generator to 5 MW gross, maintain that for the length of their 20-year PPA.

Figure E-3. ORPC TidGen Tidal Generator

Implementing large-scale tidal and wave installations has thus far been hampered by a lack of understanding of the associated siting and permitting challenges in multiple jurisdictions. Wave and tidal power projects may face similar interconnection challenges as offshore wind.

Should this technology become commercially viable in a large scale and demonstrate the ability to be financed without substantial subsidies, we will reconsider including wave and tidal power as a resource option in future resource plans.

Microgrids

The U.S. Department of Energy defines a microgrid as "… a group of interconnected loads and distributed energy resources (DER) with clearly defined electrical boundaries that acts as a single controllable entity with respect to the grid (and can) connect and disconnect from the grid to enable it to operate in both grid connected or island mode."[18]

A typical microgrid consists of DG (for example, internal combustion engines, combined heat and power systems, solar PV, distributed wind), energy storage systems, and demand management systems that, in effect, create a balancing area within a defined set of loads. Microgrids can operate interconnected with the larger utility system, or they can operate in an islanded mode. Islanded operation is particularly of interest to customers who require a very high level of reliability and energy security. The Schofield Generating Station is designed to allow islanded operation of the Schofield Barracks Army Base.

Combined with utility time-based rate programs (such as time-of-use rates, dynamic pricing, and critical peak pricing) and demand-response programs, sophisticated

[18] https://building-microgrid.lbl.gov/microgrid-definitions.

microgrid control systems allow microgrids to "call" power from the grid when it is economically advantageous to do so, and "put" power to the grid in response to DR program price signals.

We believe that microgrids can provide additional flexibility to our power grid, especially from customers with critical loads who can justify the costs of providing higher reliability. Proposals for microgrids that aggregate multiple customer loads raise numerous issues (such as cost allocation, rate design, and stranded costs) that are beyond the scope of the 2016 updated PSIPs. We will evaluate microgrid proposals case by case.

UTILITY-SCALE RESOURCE ASSUMPTIONS

An accurate and realistic estimate of the incremental renewable resource potential, particularly on O'ahu, is very important. If the renewable constraints on O'ahu are significant, the strategic need for off-island options becomes greater. As such, we retained NREL to perform an analysis of the "developable" potential on O'ahu, Maui, and Hawai'i Island.

The NREL analysis employs four-kilometer resolution solar insolation and wind resource potential maps for each island to first determine total developable land. The analysis then applies exclusion factors (that is, areas where development of wind or solar is not possible).

For utility-scale solar PV, these exclusion factors include:

- Terrain not conducive to development, including sloped areas. Two exclusion cases were analyzed: slopes greater than 3% and slopes greater than 5%. The slope exclusions are based on the much higher construction costs for building solar PV on steep slopes.
- Heavily populated urban areas.
- National and state park lands.
- Wetlands.
- Agricultural lands including Important Agricultural Land (IAL)[19], 100% of land designated as Agricultural Class A, 90% of land designated as Agricultural Class B, and 90% of land designated as Agricultural Class C.[20]

Similar exclusions were applied for wind, except that agricultural lands were not excluded.

[19] See Act 183, SLH 2005: http://hdoa.hawaii.gov/wp-content/uploads/2013/02/Act-183.pdf.

[20] See HRS §205-2: http://www.capitol.hawaii.gov/hrscurrent/vol04_Ch0201-0257/HRS0205/HRS_0205-0002.htm.

Table E-1 shows the preliminary results of the NREL analysis for O‘ahu, Maui, and Hawai‘i Island. The NREL study assumes development potentials of 28.4 MW_{AC} per square kilometer for solar PV and 3.0 MW_{AC} per square kilometer for wind. These results indicate that while Maui and Hawai‘i Island have substantial “developable” resource potential, O‘ahu is reaching the limits of additional developable wind resource potential. If it is possible to develop solar PV on lands with slopes greater than 3%, then there is still adequate resource potential for utility-scale solar PV. Setting a siting slope of more than 3% limits the remaining utility-scale solar PV potential on O‘ahu to zero.

Results of NREL’s Island Utility-Scale Resource Potential Study (MWac)				
Resource	*Exclusion Criteria*	*O‘ahu*	*Hawai‘i*	*Maui*
Utility-Scale PV	Excludes capacity factor potential less than 18%, and all areas with slope greater than 5%	793	15,757	783
	Excludes capacity factor potential less than 18%, and all areas with slope greater than 3%	583	6,019	272
Utility-Scale Wind	Excludes all areas with wind speeds less than 6.5 meters per second at 80 meters high	162	3,532	840

Table E-1. Results of NREL’s Island Utility-Scale Resource Potential Study

The results in Table E-1 vary significantly from the initial results reported in our interim filing. After more careful review of the NREL reports, we found that their initial analysis did not consider the limitations on agricultural lands set forth in HRS §205-2. Further, we found that the results for solar PV were presented DC megawatts (and not in AC megawatts) and thus had to be converted. These adjustments are reflected in the data presented here.

The NREL study is not site specific. Therefore, it’s crucial that the figures in Table E-1. be construed as indicative, but not the absolute, potential.

Utility-Scale Resources by Island

Table E-2 summarizes the PSIP utility-scale resource options currently available to the planning teams for development of long-term power resource plans.

Resource Type	PSIP Assumed Project Block Sizes by Technology (MW)			
	O'ahu	*Maui*	*Moloka'i and Lana'i*	*Hawai'i Island*
Solar PV	20	1, 5, 10, 20	1	1, 5, 10, 20
Onshore Wind	30	10, 20, 30	10 x 100 kW	10, 20, 30
Combustion Turbines	100	20.5	n/a*	20.5
Combined-Cycle	152 1x1 383 3x1	n/a	n/a	n/a
Internal Combustion Engines	27 (3 x 9 MW) 54 (6 x 9 MW) 100 (6 x 16.8 MW)	9	1	9
Geothermal	n/a	20†	n/a	20
Biomass	20	20	1	20
Waste-to-Energy	n/a	10	1	10
Offshore Wind	400	n/a	n/a	n/a
Off-Island Wind + Cable	200, 400	n/a	n/a	n/a
Solar CSP w/10 hours storage	100	n/a	n/a	n/a

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

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

Table E-2. Preliminary New Utility-Scale Resource Options Available in the 2016 PSIP Analyses

The ability to properly evaluate waste-to-energy facilities in the 2016 PSIP update is contingent upon the ability to acquire reliable data regarding Hawai'i-specific cost and performance characteristics of a WTE plant at or close the sizes shown above. We welcome input from the parties in the development of the assumptions for WTE.

DISTRIBUTED ENERGY RESOURCES COST ASSUMPTIONS

We developed DER resource capital cost assumptions using the same sources and methodology as for utility-scale resources. We concentrated on DG-PV, residential lithium-ion BESS, and behind-the-meter commercial customer class BESS. We utilized IHS Energy's projections of distributed solar and energy storage costs, applied Hawai'i locational adjustments using RSMeans data, and added 4% for Hawai'i General Excise Taxes.

The available data for residential systems from IHS included only the storage medium, and not the balance-of-plant components (for example, inverters, enclosures, and switchgear) under the assumption that the distributed storage would be installed in conjunction with a solar PV system that incorporates the inverter and other balance-of-plant items. We believe that there are opportunities for stand-alone distributed energy storage under time based pricing and demand response programs, so we added balance-of-plant cost estimates to develop stand-alone storage costs.

INTER-ISLAND TRANSMISSION ASSUMPTIONS

Our 2016 updated PSIP analyzed the feasibility of inter-island cables. Because of the distances, interconnections between the islands will be accomplished by using high voltage direct current (HVDC) technology, including converter stations on either end of a submarine cable. Submarine HVDC systems have been successfully deployed around the world; the market for HVDC systems is expected to dramatically increase in the future.[21]

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

NextEra Energy developed capital cost assumptions for a 200 MW and 400 MW cable system for a grid tie between Maui and Oʻahu in consultation with HVDC vendors. HVDC projects are typically developed with the vendor providing turnkey engineering procurement construction (EPC) with guaranteed prices (subject to sliding cost categories related to commodity prices), guaranteed schedules, and guaranteed performance. (A cable between Hawaiʻi Island and Oʻahu was not considered at this time, but will be considered in future analyses.) HVDC projects are typically developed with the vendor providing turnkey engineering procurement construction (EPC) with guaranteed prices (subject to sliding cost categories related to commodity prices), guaranteed schedules, and guaranteed performance.

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

NEW RESOURCE RISKS AND UNCERTAINTIES

In general, developing utility-scale energy infrastructure, whether by the utility, an independent power producer, or otherwise, involves managing a number of implementation risks and uncertainties. Improper management of these risks and uncertainties can have an adverse impact on the ability of the State to achieve the 100% RPS goal.

Technology Risks. Chosen technologies must be commercially proven, particularly if the project provides a significant portion of the grid's power. Commercially proven technologies are characterized by a well capitalized and experienced vendor who can offer a performance warranty. Large projects also require an experienced and well capitalized construction firm who will stand behind contractual assurances that the project will be completed within the budget, on time, and guarantee performance. The technology must be backed by a supply chain of parts and services necessary to operate the plant.

Solar PV, onshore wind, internal combustion engines, combustion turbines, combined-cycle units, geothermal, biomass technologies and undersea cables generally meet these commercial requirements. Deep water offshore wind using floating platforms, OTEC, ocean tidal and waver power are examples of technologies that have yet to meet these commercial requirements.

Permitting and Siting Risks. Depending on the project type and location, a typical project might involve consultation with dozens of state and federal agencies, preparation and dissemination of notices, preparation of numerous impact reports and studies, and navigation through a maze of state and federal agency permitting processes. Many of the permits are subject to contested hearing processes, and all permits are subject to appeals by those who oppose a particular project. This permitting complexity requires extremely well qualified vendors with experience developing new infrastructure, and who understand the unique social and cultural dynamic of Hawai'i. Hawai'i's recent history with large infrastructure projects has been one characterized by community opposition and legal challenges.

In some cases, permits that have been issued have been revoked because of procedural errors, after developers have spent significant time, effort, and money working in good faith with the communities and permitting agencies to obtain those permits.[22] This atmosphere of uncertainty leads to less competition for new projects from highly qualified vendors (with resulting higher costs for the projects and greater risk on non-completion) and a higher cost of capital. This is a significant risk for achieving

[22] "Hawaii Supreme Court Revokes Construction Permit For Thirty Meter Telescope On Mauna Kea." *Forbes.* December 3, 2015. http://www.forbes.com/sites/alexknapp/2015/12/03/hawaii-supreme-court-revokes-construction-permit-for-thirty-meter-telescope-on-mauna-kea/#550cc2223094.

Hawai‘i’s 100% RPS goals. Achieving 100% RPS requires significant new infrastructure, significant amounts of capital to be raised in capital markets, and highly qualified developers with experience in completing complex projects on time and within budget.

Construction Risks. Construction risks are typically managed by the project developer, but such risks can be significant. Unforeseen site conditions, discovery of endangered species and or previously unknown archeological finds, labor strikes and lockouts, and material and labor shortages all can affect the cost and schedule of construction. Extended delays in construction can result in cost uncertainty as commodity prices and interest rates fluctuate. These risks are manageable, but again, large infrastructure construction risks require sophisticated construction project management skills and experience.

Financing Risks. Large infrastructure projects require significant amounts of capital. The incremental capital to develop these projects must be raised in capital markets. Most projects combine equity with debt. The willingness of both debt and equity providers to supply the capital to build new infrastructure projects, and the price of the capital (that is, equity returns required and debt interest rates) depends on a number of factors. First, capital providers assess the merits of the project itself. Second, they assess the regulatory and political risks associated with the project, the relative certainty (or uncertainty) of the regulatory and political environment, and whether that environment is conducive to a return of, and a return on, capital. Third, in the case of major energy infrastructure, they assess the financial strength of the local utility. Finally, they assess the ability of the project developer to manage the extensive risks outlined herein.

When substantial risks are present in the project’s environment, fewer capital providers will be available to compete for providing this capital. As a result, the cost of capital, borne by customers, will be higher.

F. National Renewable Energy Laboratory (NREL) Reports

The Companies commissioned the National Renewable Energy Laboratory (NREL) to conduct two studies in support of our 2016 updated PSIPs. One report, entitled *Electricity Generation Capital, Fixed, and Variable O&M Costs*, independently assessed our resource data assumptions. A second report, entitled *Utility-Scale Onshore Wind, Utility-Scale PV, and CSP Potential Resource*, assessed variable resource potential on three of the islands we serve: O'ahu, Maui, and Hawai'i Island.

Each report with an attendant summary is presented here.

ELECTRICITY GENERATION CAPITAL, FIXED, AND VARIABLE O&M COSTS

NREL independently reviewed the 2016 updated PSIP resource assumptions (described in Appendix J: Modeling Assumptions Data), including their capital cost, and their fixed and variable operating and maintenance (O&M) costs. NREL reviewed onshore wind, offshore wind, utility-scale PV, residential PV (DG-PV), concentrated solar power (CSP), biomass steam, geothermal, combined-cycle combustion turbines, and simple-cycle combustion turbines.

NREL compared our resource assumptions to their Annual Technology Baseline (ATB) database and resource assumptions from Lazard, an investment bank active in the power industry. The ATB database provides forward curves of these costs, while the Lazard data is only for a single point in time.

In general, the NREL findings support our resource assumptions; any differences are explained throughout the report.

Electricity Generation Capital, Fixed and Variable O&M Costs

Erol Chartan
David Bielen
Carlo Brancucci Martinez-Anido
Wesley Cole
Bri-Mathias Hodge

Report prepared by the National Renewable Energy Laboratory and submitted to the HECO companies via email on 2/12/2016.

I. Introduction

The HECO companies (HECO, MECO, and HELCO) submitted Power Supply Improvement Plans (PSIPs) in 2014 to help inform pending and future resource acquisition and system operation decisions. The Public Utilities Commission (PUC) reviewed the PSIPs and made recommendations to improve these plans. The PUC recommended that the HECO companies (hereafter, HECO) update and improve their technology cost and performance assumptions. In response, HECO have done so for their 2016 PSIPs. HECO has contracted the National Renewable Energy Laboratory (NREL) to provide input on these assumptions used in its analysis of future electricity supply options.

In this report, we compare HECO's 2014 and 2016 PSIP technology cost assumptions to those used in the NREL Annual Technology Baseline (ATB); we also compare the cost multipliers for converting continental U.S. technology costs to the Hawaiian system. The technology cost and performance assumptions within HECO's 2014 PSIPs have been updated to reflect values more in line with those that we have observed in the ATB and other literature. In general, HECO's assumptions for their draft 2016 PSIPs are now much more in line with ATB assumptions. For utility-scale photovoltaics (PV), concentrated solar power (CSP), and land-based and onshore wind, HECO's assumed capital costs for the 2016 PSIPs match well with those in the ATB, with differences mostly due to comparing different MW sizes of each technology. The most significant differences between HECO's 2016 PSIP assumptions and NREL's assumptions for these four technology types lie in the operations and maintenance (O&M) costs. For thermal generation technologies (geothermal, biomass steam, combined cycle turbine, and simple cycle combustion turbine) the most significant differences reside in the O&M costs for geothermal and both capital and O&M costs for biomass steam.

II. Overview of the Cost Resources

This report reviews the capital costs, fixed O&M costs, and variable O&M costs for Hawaii from their 2014 and draft 2016 PSIPs for a range of technologies. Capital costs reflect an overnight cost of building a power plant. The costs include only the plant envelope, and therefore do not include costs such as potential distribution-level upgrades or spur-line costs. Technology cost assumptions for the 2014 PSIPs were created from a cost report created by Black & Veatch in February 2012 for NREL using 2009 data (Black & Veatch, 2012). In line with PUC's request to use more recent data, HECO's 2016 PSIPs have been developed using cost assumption data from, but not limited to, NREL's ATB, the Energy Information Administration (EIA), Lazard, the Electric Power Research Institute (EPRI), and customized cost assumptions developed by NextEra. Relative to the 2014 PSIPs cost assumptions, the 2016 PSIPs renewable energy cost assumptions are generally lower. This report uses two up-to-date cost data sources to compare to HECO's data, namely the NREL ATB and Lazard-v9.0, which we describe below (National Renewable Energy Laboratory, 2015; Lazard, 2015).

1. *ATB* – Costs were reported in 2013$ and have been converted to nominal dollars to match HECO's data by using a constant 1.8% annual inflation rate. The ATB contains a range of cost assumptions for technologies coming online each year from 2014 through 2050. The range and mid-case for each technology was reported for 2016 to represent current costs, while projections for the same future years HECO reported were also reported. Each mid-case observation reflects NREL's best cost estimate of a given technology in a given year.[1]
2. *Lazard-v9.0* – Costs were reported in 2015$ and have been converted to nominal dollars by using a constant 1.8% annual inflation rate. For each technology, Lazard provides a range for capital costs and fixed and variable O&M. We assume that Lazard costs are for plants that would begin construction in 2015. Unlike the ATB, Lazard does not provide cost projections for future years.

In addition to current cost estimates for 2016, HECO PSIPs report cost projections through 2045. The ATB includes projections over this range, but the estimates in the latter years are subject to considerable uncertainty.

The ATB and Lazard-v9.0 data reported here have been adjusted to represent capital costs in Hawaii (HECO's PSIPs cost data is only for Hawaii). The cost multipliers for NREL's data were taken from the appendix of the U.S. EIA report "Updated Capital Cost Estimates for Utility Scale

[1] ATB Disclaimer: It is recognized that disclosure of these Data is provided under the following conditions and warnings: (1) these Data have been prepared for reference purposes only; (2) these Data consist of forecasts, estimates or assumptions made on a best-efforts basis, based upon present expectations; and (3) these Data were prepared with existing information and are subject to change without notice.

Electricity Generating Plants," which was prepared for EIA by the Science Applications International Corporation (SAIC) (Science Applications International Corporation, 2013). The technology-specific multipliers in the report represent adjustments for economic conditions in Honolulu, Hawaii. These same values were used by HECO in their 2014 PSIPs for their cost input assumptions and they are presented in Table 1. These multipliers, which pertain to projects in Honolulu, have been applied to the raw data from the ATB and Lazard in order to create Hawaii-specific values.

Cost Multiplier Comparison

Table 1: Multipliers

Technology	EIA/SAIC
Land-based wind	30.1%
Off-shore wind	13.8%
CSP	36.7%
Utility PV	40.5%
Biomass steam	53.6%
Geothermal	27.2%
Hydropower	0.0%
Combined cycle	53.1%
Combustion turbine	51.5%

III. Technology Cost Assumptions Comparison

This section presents the technology costs assumptions by technology. The tables summarize the values that were included in HECO's 2014 PSIPs, HECO's 2016 PSIPs, Lazard-v9.0, and the NREL ATB.

Notes: the year column corresponds to the installation year of the facility. Values in the tables below shaded with darker backgrounds represent "not available in this year."

Table 2: Wind, Onshore

Year Installed	Hawaii Specific Nominal Capital Costs ($/kW)			Hawaii Specific Nominal Fixed O&M Costs ($/kW)			Hawaii Specific Nominal Variable O&M Costs ($/kW)		
2014 PSIPs - HECO, MECO, HELCO									
2015	$2,867.01			$66.78			$0.00		
2020	$3,134.50			$73.01			$0.00		
2025	$3,426.94			$79.82			$0.00		
2030	$3,746.67			$87.27			$0.00		
2016 PSIPs - Oahu									
	30MW	200MW + Cable	400MW + Cable	30MW	200MW + Cable	400MW + Cable	30MW	200MW + Cable	400MW + Cable
2016	$2,465.00	N/A	N/A	$27.40	$27.40	$27.40	-	-	-
2020	$2,480.00	$5,097.00	$4,572.00	$29.43	$29.43	$29.43	-	-	-
2025	$2,722.00	$5,664.00	$5,085.00	$32.17	$32.17	$32.17	-	-	-
2030	$2,867.00	$6,154.00	$5,514.00	$35.17	$35.17	$35.17	-	-	-
2035	$3,010.00	$6,688.00	$5,981.00	$38.46	$38.46	$38.46	-	-	-
2040	$3,171.00	$7,270.00	$6,490.00	$42.04	$42.04	$42.04	-	-	-
2045	$3,333.00	$7,907.00	$7,046.00	$45.97	$45.97	$45.97	-	-	-
2016 PSIPs - Maui & Hawaii									
	10MW	20MW	30MW	10MW	20MW	30MW	10MW	20MW	30MW
2016	$4,171.00	$2,968.00	$2,465.00	$65.07	$41.61	$33.79	-	-	-
2020	$4,198.00	$2,987.00	$2,480.00	$69.88	$44.69	$36.29	-	-	-
2025	$4,606.00	$3,277.00	$2,722.00	$76.40	$48.86	$39.68	-	-	-
2030	$4,853.00	$3,453.00	$2,867.00	$83.53	$53.42	$43.38	-	-	-
2035	$5,093.00	$3,624.00	$3,010.00	$91.32	$58.40	$47.42	-	-	-
2040	$5,367.00	$3,819.00	$3,171.00	$99.85	$63.85	$51.85	-	-	-
2045	$5,640.00	$4,013.00	$3,333.00	$109.16	$69.80	$56.69	-	-	-
Lazard-v9.0									
	Low		High	Low		High	Low		High
2015	$1,658.28		$2,255.27	$35.69		$40.79	$0.00		$0.00
ATB									
	Low	Mid-Point	High	Low	Mid-Point	High	Low	Mid-Point	High
2016	$2,021.73	$2,348.39	$2,412.90	$51.69	$52.75	$53.80	$0.00	$0.00	$0.00
2020	$2,045.98	$2,467.56	$2,591.38	$53.25	$55.52	$57.78	$0.00	$0.00	$0.00
2025	$2,124.06	$2,647.82	$2,833.15	$55.74	$59.46	$63.17	$0.00	$0.00	$0.00
2030	$2,257.04	$2,871.95	$3,097.48	$58.23	$63.65	$69.07	$0.00	$0.00	$0.00
2035	$2,442.57	$3,130.27	$3,386.47	$60.71	$69.59	$75.51	$0.00	$0.00	$0.00
2040	$2,670.46	$3,422.32	$3,702.42	$64.75	$74.46	$82.56	$0.00	$0.00	$0.00
2045	$2,919.61	$3,741.62	$4,047.86	$69.02	$81.41	$90.26	$0.00	$0.00	$0.00

The cost estimates for land-based wind are presented in Table 2. The capital costs for wind with a cable running from Maui to Oahu (provided by HECO in their 2016 PSIPs) are much larger than those for non-cable projects according to all three data sources. HECO's 2016 PSIPs assume the technology to be available from 2020 onward; for that year and beyond the 30 MW figures are between the low- and high-cases provided by the ATB. In contrast, the HECO 2016 PSIPs' capital cost estimates for smaller wind projects on Maui and Hawaii (10 MW and 20 MW) are generally above the ATB high-case. For 20 MW projects, the difference between the HECO costs and the ATB high case is relatively small, particularly in the later years. For 10 MW projects, the same difference is quite large.

The assumptions for the 2016 PSIPs show a reduction in O&M costs compared to the 2014 PSIPs for the 30MW case and are generally close to or below the bounds provided by Lazard-v9.0. They are also significantly below the ATB low-case in all years for projects larger than 10 MW.

Table 3: Wind, Offshore

Year Installed	Hawaii Specific Nominal Capital Costs ($/kW)			Hawaii Specific Nominal Fixed O&M Costs ($/kW)			Hawaii Specific Nominal Variable O&M Costs ($/kW)		
2014 PSIPs - HECO, MECO, HELCO									
2015	Not Commercial			$0.00			$0.00		
2020	$5,815.90			$158.19			$0.00		
2025	$6,191.99			$172.94			$0.00		
2030	$6,604.17			$189.08			$0.00		
2016 PSIPs - Oahu									
	Floating Platform, 400MW			Floating Platform, 400MW			Floating Platform, 400MW		
2016	$5,062.00			$96.71			-		
2020	$4,500.00			$103.86			-		
2025	$4,013.00			$113.55			-		
2030	$4,067.00			$124.15			-		
2035	$4,202.00			$135.73			-		
2040	$4,403.00			$148.39			-		
2045	$4,617.00			$162.24			-		
2016 PSIPs - Maui & Hawaii									
	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
2016	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
2020	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
2025	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
2030	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
2035	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
2040	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
2045	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Lazard-v9.0									
	Low		High	Low		High	Low		High
2015	$3,597.29	0	$6,382.29	$61.18	0	$101.97	$13.26	0	$18.35
ATB									
	Low	Mid-Point	High	Low	Mid-Point	High	Low	Mid-Point	High
2016	$5,622.24	$6,738.77	$8,562.43	$127.65	$136.09	$170.91	$0.00	$0.00	$0.00
2020	$5,300.59	$6,442.97	$8,495.64	$125.76	$130.30	$168.82	$0.00	$0.00	$0.00
2025	$4,915.50	$6,163.05	$8,622.91	$128.83	$130.07	$180.85	$0.00	$0.00	$0.00
2030	$4,973.40	$6,548.49	$9,427.42	$134.07	$138.14	$197.73	$0.00	$0.00	$0.00
2035	$5,218.37	$7,063.41	$10,306.99	$143.62	$149.55	$216.17	$0.00	$0.00	$0.00
2040	$5,465.75	$7,615.58	$11,268.62	$153.78	$161.88	$236.34	$0.00	$0.00	$0.00
2045	$5,740.05	$8,195.19	$12,319.97	$166.36	$176.98	$258.39	$0.00	$0.00	$0.00

The cost estimates for offshore wind are presented in Table 3. Note that there are no values for Maui and Hawaii within the 2016 PSIPs because HECO believes that the on-shore wind resource potential for each of these islands exceeds the total maximum electrical demand for each of these islands, and therefore the more expensive off-shore wind option would never be utilized for Maui or Hawaii.

The values from the ATB represent fixed platform turbines, and the ranges reflect designs for shallow and deep water. In comparison the values from the HECO companies represent floating offshore wind turbines, which have several differences relative to the fixed-bottom wind turbine that comprise the vast majority (~99%) of global installations to date. Floating wind turbine technology is less mature than fixed-bottom technology; the first floating turbine was installed in 2009 and four additional machines have been installed in the subsequent years. Because these projects are single turbine, proof-of-concept installations, they historically have been more expensive than fixed-bottom projects ($/kW basis). These projects are not able to achieve economies of scale and have elevated budgets for research and development. Floating technologies are, however, becoming increasingly mature and the first commercial applications are expected to occur by 2020 (Smith et al. 2015).

The economics of floating technologies are different from fixed-bottom technologies. Some elements, such as electric infrastructure, will be more expensive because cables must be able to withstand dynamic loading within the water column, whereas cables for fixed turbines can be laid out directly on the seabed. Other elements, such as installation and O&M costs, will be considerably lower because the entire turbine-substructure unit can be assembled in port and towed to the project site. The tow-out method reduces cost and risk by eliminating the need to conduct lifting operations in the offshore environment. Further, unlike fixed substructures, the weight of floating platforms is relatively insensitive to turbine size. As a result, the economics improve markedly for projects that use industry-leading 8+ MW wind turbines. While there is considerable uncertainty about the future cost of floating technology given its pre-commercial status, it is reasonable to expect that floating projects will be more competitive than fixed-bottom technology in deep water. Further, floating offshore wind in Deep Water could become more competitive than fixed-bottom offshore wind in Shallow Water by the mid- to late-2020s (Musial and Smith 2015).

Preliminary analysis conducted by NREL and the U.S. Department of Energy and presented at the 2015 National Offshore Wind Strategy Meeting held in Washington, DC on December 10th, suggests that a reference floating offshore wind facility installed in 2020 is expected to have an installed capital cost of approximately $4,500/kW, fixed O&M costs of approximately $80/kW-year, and no variable O&M costs. This capital cost estimate is reflected in the 2016 PSIP values. The 2016 PSIP values for capital cost are consistently lower than ATB's fixed turbine range. Moreover, the fixed O&M estimates for the 2016 PSIPs are also much lower than the ATB range.

Table 4: Utility-Scale Photovoltaics

Year Installed	Hawaii Specific Nominal Capital Costs ($/kW)			Hawaii Specific Nominal Fixed O&M Costs ($/kW)			Hawaii Specific Nominal Variable O&M Costs ($/kW)		
2014 PSIPs - HECO, MECO, HELCO									
2015	$3,987.52			$53.42			$0.00		
2020	$4,120.21			$54.76			$0.00		
2025	$4,261.63			$57.20			$0.00		
2030	$4,454.88			$59.63			$0.00		
2016 PSIPs - Oahu									
	20MW			20MW			20MW		
2016	$2,793.00			$22.97			-		
2020	$2,432.00			$24.67			-		
2025	$2,284.00			$26.97			-		
2030	$2,232.00			$29.49			-		
2035	$2,203.00			$32.24			-		
2040	$2,174.00			$35.25			-		
2045	$2,146.00			$38.53			-		
2016 PSIPs - Maui & Hawaii									
	5MW	10MW	20MW	5MW	10MW	20MW	5MW	10MW	20MW
2016	$3,262.00	$2,849.00	$2,574.00	$29.87	$28.20	$24.77	-	-	-
2020	$2,841.00	$2,481.00	$2,241.00	$32.08	$30.29	$26.60	-	-	-
2025	$2,669.00	$2,331.00	$2,105.00	$35.07	$33.11	$29.08	-	-	-
2030	$2,608.00	$2,278.00	$2,057.00	$38.34	$36.20	$31.80	-	-	-
2035	$2,574.00	$2,248.00	$2,031.00	$41.92	$39.58	$34.76	-	-	-
2040	$2,540.00	$2,218.00	$2,004.00	$45.83	$43.27	$38.01	-	-	-
2045	$2,507.00	$2,189.00	$1,978.00	$50.11	$47.31	$41.55	-	-	-
Lazard-v9.0									
	Low		High	Low		High	Low		High
2015	$2,292.28	0	$2,149.01	$13.26	0	$10.20	$0.00	0	$0.00
ATB (100MW Single Axis Tracking)									
	Low	Mid-Point	High	Low	Mid-Point	High	Low	Mid-Point	High
2016	$2,776.69	$3,066.91	$3,293.55	$17.41	$17.41	$17.41	$0.00	$0.00	$0.00
2020	$1,871.89	$2,808.72	$3,537.16	$9.97	$9.97	$9.97	$0.00	$0.00	$0.00
2025	$2,046.54	$2,559.61	$3,867.17	$10.90	$10.90	$10.90	$0.00	$0.00	$0.00
2030	$2,237.48	$2,237.48	$4,227.98	$11.92	$11.92	$11.92	$0.00	$0.00	$0.00
2035	$2,446.23	$2,446.23	$4,622.44	$13.03	$13.03	$13.03	$0.00	$0.00	$0.00
2040	$2,674.46	$2,674.46	$5,053.71	$14.25	$14.25	$14.25	$0.00	$0.00	$0.00
2045	$2,923.99	$2,923.99	$5,525.22	$15.57	$15.57	$15.57	$0.00	$0.00	$0.00

The cost estimates for utility-scale PV are presented in Table 4.[2] The low and high values from Lazard-v9.0 correspond to different types of solar technology. The lower capital cost is associated with fixed-tilt systems, which have a lower capacity factor. The higher capital cost is associated with 1-axis tracking systems, which have a higher capacity factor. Thus, the lower capital cost system actually has a higher levelized cost of electricity (LCOE) than the higher capital cost system. The ATB values reflect cost estimates for single axis tracking solar at 100 MW in size; over 154GW of available capacity has been summarized into this data.

The capital and O&M costs decreased significantly from the 2014 to 2016 PSIPs. Whereas all costs within the 2014 PSIPs are higher than the ranges in Lazard or ATB, the costs from the 2016 PSIPs are much more comparable. The 2016 PSIPs show the utility scale PV coming online in 2020 when the capital costs are slightly higher than the range of costs given by Lazard-v9.0 (except for the 20MW case in Maui and Hawaii) and within the range from the ATB. The future capital cost projections from the 2016 PSIPs are within the ATB range until 2030, at which point they drop below the ATB low-case. This occurs because the PSIP assumed values continue to decline while the ATB capital costs begin to flat-line in real dollars (i.e., they increase nominally). The fixed O&M costs from the 2016 PSIPs are higher than those provided by Lazard-v9.0 and the ATB, both currently and in future years. This is at least partly expected given the ATB values are for a 100 MW solar farm as opposed to HECO, who considered 5 MW, 10 MW and 20 MW projects.

[2] All costs in the above table are in AC. The ATB figures had a DC – AC cost multiplier of 1.1 applied.

Table 5: Residential Photovoltaics

Year	Hawaii Specific Nominal Capital Costs ($/kW)	Hawaii Specific Nominal Fixed O&M Costs ($/kW-year)	Hawaii Specific Nominal Variable O&M Costs ($/kW)
2014 PSIPs - HECO, MECO, HELCO			
2015	$4,830.33	$53.42	$0.00
2020	$4,563.07	$54.76	$0.00
2025	$4,603.00	$57.20	$0.00
2030	$4,785.19	$59.63	$0.00
2016 PSIPs - Oahu			
2016	$3,945.00	n/a	n/a
2020	$3,360.00	n/a	n/a
2025	$3,068.00	n/a	n/a
2030	$2,933.00	n/a	n/a
2035	$2,894.00	n/a	n/a
2040	$2,856.00	n/a	n/a
2045	$2,819.00	n/a	n/a
2016 PSIPs - Maui & Hawaii			
2016	$3,985.00	n/a	n/a
2020	$3,394.00	n/a	n/a
2025	$3,100.00	n/a	n/a
2030	$2,962.00	n/a	n/a
2035	$2,924.00	n/a	n/a
2040	$2,885.00	n/a	n/a
2045	$2,848.00	n/a	n/a

The cost estimates for utility-scale PV are presented in Table 5. There is no cost data for residential photovoltaics provided for the 2016 PSIPs, or within ATB or Lazard-v9.0. However, as exhibited in the 2014 PSIP numbers, there is a substantial cost advantage to utility-scale PV over residential PV due to significant economies of scale.

Table 6: CSP (Concentrated Solar Power)

Year	Hawaii Specific Nominal Capital Costs ($/kW)			Hawaii Specific Nominal Fixed O&M Costs ($/kW-year)			Hawaii Specific Nominal Variable O&M Costs ($/kW)		
2016 PSIPs - Oahu									
	100MW Solar CSP + 10hrs storage			100MW Solar CSP + 10hrs storage			100MW Solar CSP + 10hrs storage		
2016	$12,304.00			$92.38			n/a		
2020	$9,848.00			$99.21			n/a		
2025	$7,694.00			$108.47			n/a		
2030	$7,309.00			$118.59			n/a		
2035	$7,508.00			$129.65			n/a		
2040	$8,209.00			$141.75			n/a		
2045	$8,975.00			$154.98			n/a		
Lazard-v9.0									
	Low	High		Low	High		Low	High	
2015	$12,196.86	$12,545.34		$10.20	$13.26		$0.00	$0.00	
ATB									
	Low	Mid	High	Low	Mid	High	Low	Mid	High
2016	$6,806.97	$11,271.88	$14,219.65	$68.57	$68.57	$68.57	$3.16	$3.16	$3.16
2020	$4,775.03	$7,590.80	$9,567.11	$57.78	$57.78	$57.78	$3.40	$3.40	$3.40
2025	$5,220.54	$7,289.79	$10,459.71	$63.17	$63.17	$63.17	$3.72	$3.72	$3.72
2030	$5,707.61	$6,868.39	$11,435.58	$69.07	$69.07	$69.07	$4.06	$4.06	$4.06
2035	$6,240.12	$7,509.20	$12,502.51	$75.51	$75.51	$75.51	$4.44	$4.44	$4.44
2040	$6,822.32	$8,209.80	$13,668.98	$82.56	$82.56	$82.56	$4.86	$4.86	$4.86
2045	$7,458.83	$8,975.76	$14,944.28	$90.26	$90.26	$90.26	$5.31	$5.31	$5.31

The cost estimates for utility-scale PV are presented in Table 6. Note that there are no estimates for CSP for either the 2014 PSIPs or Maui and Hawaii in the 2016 PSIPs. The data for the 2016 PSIPs assume 10 hours of Thermal Energy Storage (TES), while the data from the ATB includes cases of 6 hours and 12 hours of TES. The 2016 PSIP current capital cost estimates for Oahu are within the bounds provided by Lazard-v9.0 and the ATB. In future years, the 2016 PSIP costs are generally within the bounds provided by the ATB (the lone exception occurs in 2020). However, the HECO fixed O&M estimates are much higher than the Lazard-v9.0 values, and higher than the values from the ATB high-case. The variable O&M values from the ATB are non-zero due to the storage component of CSP, whereas the 2016 PSIP and Lazard-v9.0 values assume no variable O&M costs.

Table 7: Biomass Steam

Year Installed	Hawaii Specific Nominal Capital Costs ($/kW)			Hawaii Specific Nominal Fixed O&M Costs ($/kW)			Hawaii Specific Nominal Variable O&M Costs ($/kW)		
2014 PSIPs - HECO, MECO, HELCO									
2015	$6,547.52			$105.73			$16.69		
2020	$7,158.39			$115.60			$18.25		
2025	$7,826.26			$126.38			$19.96		
2030	$8,556.44			$138.17			$21.82		
2016 PSIPs - Oahu									
	20MW			20MW			20MW		
2016	$5,251.00			$79.05			$12.98		
2020	$5,299.00			$84.90			$13.94		
2025	$5,692.00			$92.82			$15.24		
2030	$6,107.00			$101.48			$16.66		
2035	$6,546.00			$110.95			$18.22		
2040	$6,973.00			$121.30			$19.92		
2045	$7,624.00			$132.61			$21.78		
2016 PSIPs - Maui & Hawaii									
	20MW			20MW			20MW		
2016	$5,251.00			$79.05			$13.00		
2020	$5,299.00			$84.90			$13.96		
2025	$5,692.00			$92.82			$15.26		
2030	$6,107.00			$101.48			$16.69		
2035	$6,546.00			$110.95			$18.25		
2040	$6,973.00			$121.30			$19.95		
2045	$7,624.00			$132.61			$21.81		
Lazard-v9.0									
	Low		High	Low		High	Low		High
2015	$4,072.27	0	$5,481.90	$96.87	0	$96.87	$15.30	0	$15.30
ATB									
	Low	Mid-Point	High	Low	Mid-Point	High	Low	Mid-Point	High
2016	$6,295.43	$6,295.43	$6,295.43	$112.88	$112.88	$112.88	$5.27	$5.27	$5.27
2020	$6,353.86	$6,353.86	$6,353.86	$121.23	$121.23	$121.23	$5.67	$5.67	$5.67
2025	$6,824.89	$6,824.89	$6,824.89	$132.54	$132.54	$132.54	$6.19	$6.19	$6.19
2030	$7,322.28	$7,322.28	$7,322.28	$144.91	$144.91	$144.91	$6.77	$6.77	$6.77
2035	$7,848.51	$7,848.51	$7,848.51	$158.43	$158.43	$158.43	$7.40	$7.40	$7.40
2040	$8,361.96	$8,361.96	$8,361.96	$173.21	$173.21	$173.21	$8.09	$8.09	$8.09
2045	$9,142.12	$9,142.12	$9,142.12	$189.37	$189.37	$189.37	$8.85	$8.85	$8.85

The cost estimates for biomass steam are presented in Table 7. The data from the 2016 PSIPs represent a stand-alone biomass plant (50 MW Net); both capital costs and fixed O&M costs are much lower compared to the 2014 PSIPs. The capital cost used in the 2016 PSIPs for 2020 is within the range provided by Lazard-v9.0. Capital costs from the 2016 PSIPs are also significantly lower than the single values from the ATB in both the current year and the future projections. Fixed O&M costs from the 2016 PSIPs for 2020 are significantly below values from Lazard-v9.0, and for all years they are significantly below the ATB values. Variable O&M costs from the 2016 draft PSIPs in 2020 are similar to values from Lazard-v9.0, while for all years they are higher than the ATB values.

Table 8: Geothermal

Year Installed	Hawaii Specific Nominal Capital Costs ($/kW)			Hawaii Specific Nominal Fixed O&M Costs ($/kW)			Hawaii Specific Nominal Variable O&M Costs ($/kW)		
2014 PSIPs - HECO, MECO, HELCO									
	Non-Dispatchable		Fully Dispatchable	Non-Dispatchable		Fully Dispatchable	Non-Dispatchable		Fully Dispatchable
2015	$8,409.31		$8,586.27	$40.07		$40.07	$34.50		$34.50
2020	$9,193.89		$9,387.36	$43.81		$43.81	$37.72		$37.72
2025	$10,051.66		$10,263.19	$47.89		$47.89	$41.24		$41.24
2030	$10,989.47		$11,220.73	$52.36		$52.36	$45.09		$45.09
2016 PSIPs - Oahu									
2016		n/a			n/a			n/a	
2020		n/a			n/a			n/a	
2025		n/a			n/a			n/a	
2030		n/a			n/a			n/a	
2035		n/a			n/a			n/a	
2040		n/a			n/a			n/a	
2045		n/a			n/a			n/a	
2016 PSIPs - Maui & Hawaii									
		20MW, Fuel Type Lava			20MW, Fuel Type Lava			20MW, Fuel Type Lava	
2016		$8,804.00			$158.11			$2.58	
2020		$9,456.00			$169.81			$2.77	
2025		$10,338.00			$185.65			$3.03	
2030		$11,302.00			$202.97			$3.31	
2035		$12,357.00			$221.91			$3.62	
2040		$13,510.00			$242.62			$3.96	
2045		$14,770.00			$265.25			$4.33	
Lazard-v9.0									
	Low		High	Low		High	Low		High
2015	$5,058.52	0	$7,263.51	$0.00	0	$0.00	$30.59	0	$40.79
ATB									
	Low	Mid-Point	High	Low	Mid-Point	High	Low	Mid-Point	High
2016	$8,040.86	$9,382.79	$14,382.83	$121.32	$121.32	$121.32	$0.00	$0.00	$0.00
2020	$8,635.62	$10,076.81	$15,446.69	$130.30	$130.30	$130.30	$0.00	$0.00	$0.00
2025	$9,441.31	$11,016.96	$16,887.84	$142.45	$142.45	$142.45	$0.00	$0.00	$0.00
2030	$10,322.17	$12,044.83	$18,463.46	$155.74	$155.74	$155.74	$0.00	$0.00	$0.00
2035	$11,285.22	$13,168.60	$20,186.08	$170.27	$170.27	$170.27	$0.00	$0.00	$0.00
2040	$12,338.12	$14,397.22	$22,069.42	$186.16	$186.16	$186.16	$0.00	$0.00	$0.00
2045	$13,489.25	$15,740.46	$24,128.47	$203.53	$203.53	$203.53	$0.00	$0.00	$0.00

The cost estimates for geothermal are presented in Table 8. Note that HECO only considered geothermal projects on Maui and Hawaii. The numbers from ATB are site-specific, which is why the capital cost ranges are large.

The 2016 PSIPs include slightly higher capital cost assumptions and much higher O&M costs compared to the values from the 2014 PSIPs. The capital cost values within the 2016 PSIPs are always within the ATB ranges (near the low-case) but much higher than values from Lazard-v9.0. The 2016 PSIP fixed O&M costs are significantly higher than the ATB estimates throughout the entire horizon.

Table 9: Combined Cycle Turbine

Year Installed	Hawaii Specific Nominal Capital Costs ($/kW)			Hawaii Specific Nominal Fixed O&M Costs ($/kW)			Hawaii Specific Nominal Variable O&M Costs ($/kW)		
2014 PSIPs - HECO, MECO, HELCO									
2015	$2,095.88			$7.02			$4.08		
2020	$2,291.43			$7.68			$4.47		
2025	$2,505.21			$8.39			$4.88		
2030	$2,738.95			$9.18			$5.34		
2016 PSIPs - Oahu									
	152MW (1 x 1)		383MW (3 x 1)	152MW (1 x 1)		383MW (3 x 1)	152MW (1 x 1)		383MW (3 x 1)
2016	$1,660.00		$1,758.00	$17.29		n/a	$4.49		n/a
2020	$1,742.00		$1,845.00	$18.57		n/a	$4.82		n/a
2025	$1,859.00		$1,969.00	$20.30		n/a	$5.27		n/a
2030	$1,991.00		$2,108.00	$22.20		n/a	$5.76		n/a
2035	$2,143.00		$2,270.00	$24.27		n/a	$6.30		n/a
2040	$2,318.00		$2,455.00	$26.53		n/a	$6.89		n/a
2045	$2,535.00		$2,684.00	$29.01		n/a	$7.53		n/a
2016 PSIPs - Maui & Hawaii									
2016	n/a			n/a			n/a		
2020	n/a			n/a			n/a		
2025	n/a			n/a			n/a		
2030	n/a			n/a			n/a		
2035	n/a			n/a			n/a		
2040	n/a			n/a			n/a		
2045	n/a			n/a			n/a		
Lazard-v9.0									
	Low		High	Low		High	Low		High
2015	$1,405.04	0	$1,873.39	$6.32	0	$5.61	$3.57	0	$2.04
ATB									
	Low	Mid-Point	High	Low	Mid-Point	High	Low	Mid-Point	High
2016	$1,578.02	$1,578.02	$1,578.02	$14.77	$14.77	$14.77	$3.16	$3.16	$3.16
2020	$1,654.85	$1,654.85	$1,654.85	$15.86	$15.86	$15.86	$3.40	$3.40	$3.40
2025	$1,767.52	$1,767.52	$1,767.52	$17.34	$17.34	$17.34	$3.72	$3.72	$3.72
2030	$1,890.96	$1,890.96	$1,890.96	$18.96	$18.96	$18.96	$4.06	$4.06	$4.06
2035	$2,037.91	$2,037.91	$2,037.91	$20.73	$20.73	$20.73	$4.44	$4.44	$4.44
2040	$2,203.27	$2,203.27	$2,203.27	$22.66	$22.66	$22.66	$4.86	$4.86	$4.86
2045	$2,408.83	$2,408.83	$2,408.83	$24.78	$24.78	$24.78	$5.31	$5.31	$5.31

The cost estimates for combined cycle turbines are presented in Table 9. Note that no cost estimates for the 2016 PSIPs were included for Maui and Hawaii. The values for the 2016 PSIPs represent either a single-unit 152 MW plant or a three-unit 383 MW plant, both without carbon capture and sequestration (CCS). The low and high values for the Lazard-v9.0 data correspond to different types of configurations of Combined Cycle Turbines. The current capital costs for the 2016 PSIPs are within the bounds from Lazard-v9.0, while the fixed and variable O&M costs are higher. For the current year and all future projections, the 2016 PSIP capital and O&M costs are slightly higher than those from the ATB.

Table 10: Simple Cycle Combustion Turbine

Year Installed	Hawaii Specific Nominal Capital Costs ($/kW)			Hawaii Specific Nominal Fixed O&M Costs ($/kW)			Hawaii Specific Nominal Variable O&M Costs ($/kW)		
2014 PSIPs - HECO, MECO, HELCO									
2015	$1,097.69			$5.85			$33.28		
2020	$1,200.10			$6.40			$36.38		
2025	$1,312.07			$7.00			$39.78		
2030	$1,434.49			$7.65			$43.49		
2016 PSIPs - Oahu									
	100MW Gas / Oil			100MW Gas / Oil			100MW Gas / Oil		
2016	$1,237.00			$9.01			$12.99		
2020	$1,292.00			$9.68			$13.95		
2025	$1,373.00			$10.58			$15.25		
2030	$1,466.00			$11.57			$16.68		
2035	$1,577.00			$12.65			$18.23		
2040	$1,706.00			$13.83			$19.93		
2045	$1,865.00			$15.12			$21.79		
2016 PSIPs - Maui & Hawaii									
	20.5MW Gas / Oil			20.5MW Gas / Oil Maui		20.5MW Gas / Oil Hawaii	20.5MW Gas / Oil Maui		20.5MW Gas / Oil Hawaii
2016	$3,586.00			$140.00		$140.00	$1.26		$1.75
2020	$3,747.00			$150.36		$150.36	$1.35		$1.88
2025	$3,981.00			$164.38		$164.38	$1.48		$2.05
2030	$4,251.00			$179.72		$179.72	$1.62		$2.25
2035	$4,571.00			$196.49		$196.49	$1.77		$2.46
2040	$4,947.00			$214.82		$214.82	$1.93		$2.69
2045	$5,408.00			$234.86		$234.86	$2.11		$2.94
Lazard-v9.0									
	Low		High	Low		High	Low		High
2015	$1,235.87	0	$1,544.84	$5.10	0	$25.49	$4.79	0	$7.65
ATB									
	Low	Mid-Point	High	Low	Mid-Point	High	Low	Mid-Point	High
2016	$1,324.98	$1,324.98	$1,324.98	$7.38	$7.38	$7.38	$13.71	$13.71	$13.71
2020	$1,385.23	$1,385.23	$1,385.23	$7.93	$7.93	$7.93	$14.73	$14.73	$14.73
2025	$1,471.30	$1,471.30	$1,471.30	$8.67	$8.67	$8.67	$16.10	$16.10	$16.10
2030	$1,571.64	$1,571.64	$1,571.64	$9.48	$9.48	$9.48	$17.61	$17.61	$17.61
2035	$1,689.11	$1,689.11	$1,689.11	$10.36	$10.36	$10.36	$19.25	$19.25	$19.25
2040	$1,829.54	$1,829.54	$1,829.54	$11.33	$11.33	$11.33	$21.04	$21.04	$21.04
2045	$2,000.23	$2,000.23	$2,000.23	$12.39	$12.39	$12.39	$23.01	$23.01	$23.01

The cost estimates for simple cycle combustion turbines are presented in Table 10. The 2016 PSIPs have cost estimates for a 100 MW plant on Oahu and a 20.5 MW plant on Maui and Hawaii; the capital and fixed O&M cost estimates are much greater for the 20.5 MW plant versus the 100 MW plant. The 100 MW plant has slightly higher capital and fixed O&M costs compared to the 2014 PSIPs and much lower variable O&M costs. The current capital costs for the 100 MW plant in the 2016 PSIPs are within the bounds from Lazard-v9.0. For both the current year and future projections, the capital costs for the 100 MW plant in the 2016 PSIP are slightly lower to those from the ATB, the fixed O&M costs are slightly higher and the variable O&M costs are slightly lower.

IV. Conclusion

In general, HECO’s assumptions for their draft 2016 PSIPs are now much more in line with ATB assumptions. The most significant differences reside in the O&M costs for geothermal and both capital and O&M costs for biomass steam.

References

Black & Veatch (2012). *Cost and Performance Data for Power Generation Technologies*. Golden, CO: National Renewable Energy Laboratory. http://bv.com/docs/reports-studies/nrel-cost-report.pdf%E2%80%8E.

Lazard (2015). *Lazard's Levelized Cost of Energy Analysis—Version 9.0*. https://www.lazard.com/media/2390/lazards-levelized-cost-of-energy-analysis-90.pdf.

National Renewable Energy Laboratory (2015, July). *Annual Technology Baseline and Standard Scenarios*. http://www.nrel.gov/analysis/data_tech_baseline.html.

Science Applications International Corporation. (2013). *Updated Capital Cost Estimates for Utility Scale Electricity Generating Plants*. Washington, DC: U.S. Energy Information Administration. http://www.eia.gov/forecasts/capitalcost/pdf/updated_capcost.pdf.

Musial, W.; Smith, A. (2015). *Building a Business Case for Offshore Wind*. 2016 National Offshore Wind Strategy Workshop. Hotel Palomar, Washington, DC 20037. December 10th 2016. US Department of Energy and US Department of Interior.

Smith, A.; Musial, W., Stehly, T. (2015*) 2014-2015 Offshore Wind Market Technologies Report*. National Renewable Energy Laboratory. NREL/TP-5000-64283. http://energy.gov/sites/prod/files/2015/09/f26/2014-2015-offshore-wind-technologies-market-report-FINAL_1.pdf

UTILITY-SCALE ONSHORE WIND, UTILITY-SCALE PV, AND CSP POTENTIAL RESOURCE

An NREL report estimated the onshore utility-scale PV and utility-scale wind potential for each of the three main islands we serve: O‘ahu, Maui, and Hawai‘i Island. NREL used a square (four kilometer by four kilometer) grid database that they developed and refined over several years. The grid details solar irradiance at the earth’s surface and wind speeds 80 meters above the earth’s surface. Their study assumed a “typical” year. Based on this database, their study identified areas with high solar or wind potential.

The study excluded areas where the ability to develop utility-scale wind and utility-scale PV was highly unlikely. Exclusions included urban areas, wetlands, park lands, mountainous areas, ravines, and certain agricultural areas. The study then assumed that the remaining land was available to be developed for utility-scale wind, utility-scale PV, or for the dual purpose of both wind and PV together.

The results of the NREL resource potential study are indicative as they do not represent the actual developable land. Some of this “available” land, for instance, might be privately held and not for sale. In reality, the amount of land available for development is likely less than the potential shown in the NREL assessment, perhaps significantly.

The results do suggest renewable resource potential on Maui and Hawai‘i Island that exceeds each island’s native electrical loads. The results for O’ahu, however, suggest that additional utility-scale wind development is less than 100 MW, and that while the resource potential for utility-scale PV is becoming constrained, the addition of a few hundred megawatts is possible. Appendix E: New Resource Options discusses the implications of this NREL study.

Utility-Scale Onshore Wind, Utility-Scale PV, and CSP Potential Resource

Billy Roberts
Erol Chartan
Andrew Weekley
Anthony Lopez
Carlo Brancucci Martinez-Anido
Bri-Mathias Hodge

Report prepared by the National Renewable Energy Laboratory and submitted to the HECO companies via email on 3/17/2016.

I. Executive Summary

This report by the National Renewable Energy Laboratory NREL presents estimates for the total amount of developable utility-scale wind, utility-scale solar photovoltaic (PV) and concentrated solar power (CSP) potential for the Hawaiian islands of Oahu, Maui, and Hawaii. These estimates of technical potential do not take into account existing or committed wind and solar plants. Existing solar and wind resource data and the use of standard exclusion factors were utilized by NREL to provide independent estimates. Sites where both solar PV and wind could be deployed were examined together as possible dual use sites.

Tables 1 to 6 show the utility-scale onshore wind and utility-scale solar PV resource potentials (in MWac terms) for the islands of Hawaii, Maui, and Oahu for the following four analyses that differ in terms of land exclusions:

1. Default slope analysis
2. Default slope analysis without DOD exclusions
3. Improved slope analysis without DOD exclusions
4. Improved slope analysis without DOD exclusions with updated agricultural land exclusions.

Tables 1 to 3 show the wind potential with an additional exclusion for each row excluding any site whose mean wind speed at 80m height is lower than the figures stated. Tables 4 to 6 show the utility-scale PV potential organized by two main exclusions, capacity factor and slope. The slope exclusions exclude all land with a slope steeper than the figure stated as potential for PV and the capacity factor exclusions exclude all PV whose capacity factor are lower than the figures stated. The difference between the default and improved slope analyses and the updated agricultural land exclusions are described in sections 4.1 and 4.2.

No technical potential values are provided for CSP. When considering the direct normal irradiance potential and the GIS exclusion factors in the three islands, very limited CSP potential exists.

Table 1 - Utility-Scale Onshore Wind Potential (MWac) for Hawaii

Mean Wind Speed (m/s) at 80m	Analysis 1 (MW)	Analysis 2 (MW)	Analysis 3 (MW)	Analysis 4 (MW)
>= 6.5	3,276	3,276	3,303	3,532
>= 7.5	2,107	2,107	2,123	2,236
>= 8.5	1,290	1,290	1,299	1,334

Table 2 - Utility-Scale Onshore Wind Potential (MWac) for Maui

Mean Wind Speed (m/s) at 80m	Analysis 1 (MW)	Analysis 2 (MW)	Analysis 3 (MW)	Analysis 4 (MW)
>= 6.5	698	698	700	840
>= 7.5	412	412	417	448
>= 8.5	117	117	121	118

Table 3 - Utility-Scale Onshore Wind Potential (MWac) for Oahu

Mean Wind Speed (m/s) at 80m	Analysis 1 (MW)	Analysis 2 (MW)	Analysis 3 (MW)	Analysis 4 (MW)
>= 6.5	174	183	154	162
>= 7.5	81	81	69	68
>= 8.5	19	19	16	16

Table 4 - Utility-Scale Solar PV Potential (MWac) for Hawaii

Capacity Factor (%)	Analysis 1 (MW)		Analysis 2 (MW)		Analysis 3 (MW)		Analysis 4 (MW)	
	Slope 3%	Slope 5%	Slope 3%	Slope 3%	Slope 3%	Slope 5%	Slope 3%	Slope 5%
>= 10	10,868	30,634	10,868	30,703	12,557	33,012	11,514	30,484
>= 12	10,833	30,573	10,833	30,643	12,523	32,949	11,481	30,421
>= 14	10,703	30,036	10,703	30,105	12,385	32,405	11,467	30,039
>= 16	8,339	20,204	8,339	20,273	9,448	21,873	8,646	20,312
>= 18	5,481	14,841	5,481	14,911	6,322	16,338	6,019	15,757
>= 20	2,469	8,315	2,469	8,385	3,075	9,193	3,075	9,189

Table 5 - Utility-Scale Solar PV Potential (MWac) for Maui

Capacity Factor (%)	Analysis 1 (MW)		Analysis 2 (MW)		Analysis 3 (MW)		Analysis 4 (MW)	
	Slope 3%	Slope 5%	Slope 3%	Slope 5%	Slope 3%	Slope 5%	Slope 3%	Slope 5%
>= 10	0	1,321	0	1,321	697	1,443	272	783
>= 12	0	1,321	0	1,321	697	1,443	272	783
>= 14	0	1,321	0	1,321	697	1,443	272	783
>= 16	0	1,321	0	1,321	697	1,443	272	783
>= 18	0	1,321	0	1,321	697	1,443	272	783
>= 20	0	1,110	0	1,110	697	1,230	272	576

Table 6 - Utility-Scale Solar PV Potential (MWac) for Oahu

Capacity Factor (%)	Analysis 1 (MW)		Analysis 2 (MW)		Analysis 3 (MW)		Analysis 4 (MW)	
	Slope 3%	Slope 5%	Slope 3%	Slope 5%	Slope 3%	Slope 5%	Slope 3%	Slope 5%
>= 10	0	1,338	67	2,155	1,527	2,301	583	796
>= 12	0	1,338	67	2,155	1,527	2,301	583	796
>= 14	0	1,338	67	2,155	1,527	2,301	583	796
>= 16	0	1,338	67	2,155	1,527	2,301	583	796
>= 18	0	1,338	67	2,134	1,527	2,277	583	793
>= 20	0	414	67	895	692	968	329	397

II. Report Structure

This report is split into four main sections: introduction, overview of data and modeling assumptions, GIS exclusions, and the resource potential maps (for Analysis 1) for each technology type: utility-scale onshore wind, utility-scale PV, and concentrated solar power.

III. Overview of Data & Modeling Assumptions

a. Utility-Scale Onshore Wind

The REEDS data set containing utility-scale wind speed data was supplied from AWS [1]. A typical meteorological year (TMY) method was used with 20 km summary resolution where simulated hourly wind resource data and statistics were generated for each 3% gross capacity factor interval calculated from the 200 m spatial map. The mean wind speed data at 200 m spatial resolution were attained for 80 m height. The power density assumed was 3 MW/km as used in the Wind Vision report and seen in the Wind Vision Appendices [2].

b. Utility-Scale PV

Mean solar radiation data over the years 1998 to 2014 was taken from the latest National Solar Radiation Database (NSRDB) [3-5] which has 4 km x 4 km and 30 minute resolution. NSRDB is a serially complete collection of meteorological and solar irradiance data sets. The database is managed and updated using the latest methods of research by a specialized team of forecasters at the National Renewable Energy Laboratory (NREL). The data spans 1998 – 2014 and the latest version now uses satellite retrievals. Cloud properties, aerosol depth, and precipitable water vapor are used to calculate Global Horizontal Irradiance (GHI) values at each point in the mesh.

The System Advisor Model (SAM) [6] with parameters DC – AC ratio = 1.5 was used to attain capacity factors for 1-axis tracking panels with tilt fixed at zero. Please refer to Appendix A for an extended list of the SAM parameters used in this analysis. SAM is a performance and financial model which makes performance predictions for grid-connected power projects based on parameters that you specify as inputs to the model. It is distributed for free by NREL. SAM's user interface allows the user to input variables and simulation controls and displays tables and graphs of results. Information on the code can be found in the PVWatts Version 5 Manual [7].

The capacity-weighted average land use for a 1-axis small PV plant was taken to be 8.7acres/MWac [8].

Figure 1 illustrates the inter-annual variability of capacity factors as a function of location index. It highlights the value of having a wide temporal range of data. In this plot the two-dimensional geospatial dataset is displayed as a sequence rather than a map and each point in the sequence corresponds to a latitude and longitude in a geospatial grid. Neighbors in the sequence are either neighbors in latitude or longitude depending on how the data is converted from the geospatial grid, i.e. whether the data is traversed in the latitude or longitude dimension.

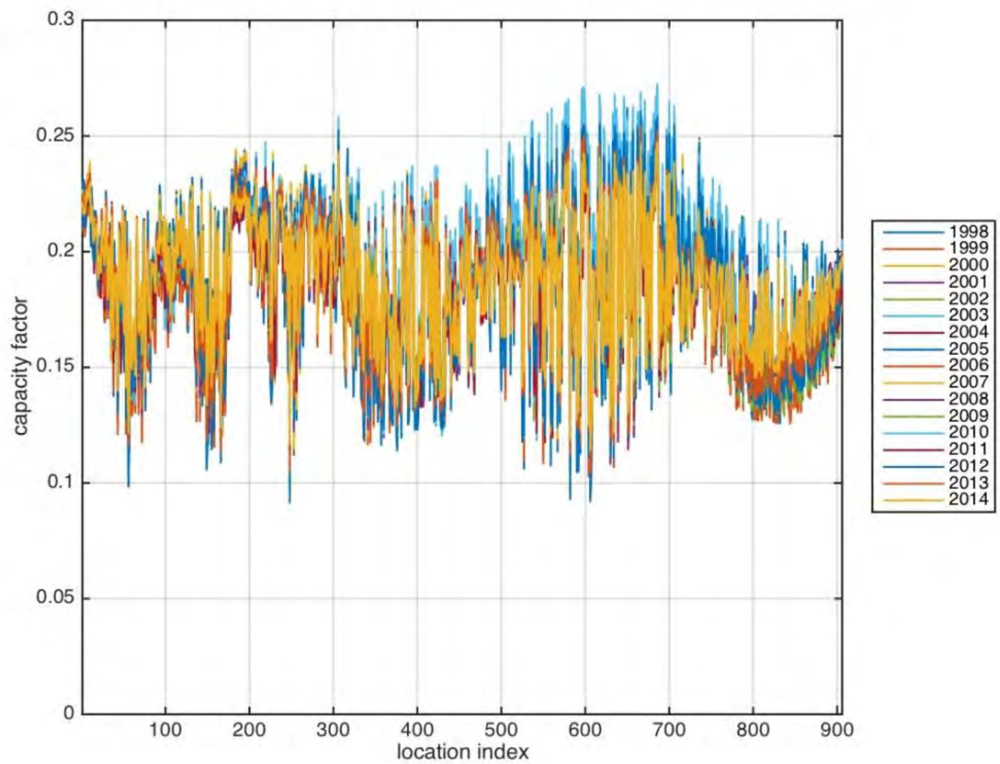


Figure 1: Annual Variability of Solar Capacity Factors

c. Concentrated Solar Power (CSP)

In order to assess the CSP potential for the three islands, a Direct Normal Irradiance (DNI) map has been created using mean values from the NSRDB. In order to assess the CSP potential for the three islands, a Direct Normal Irradiance (DNI) map has been created using mean values from the NSRDB as per the description above. DNI > 400 W/m^2 was calculated by finding the number of half hour intervals in a year where DNI > 400 W/m^2, dividing by the number of half hour intervals in the year and averaging across 1998 – 2014. The value 400 is chosen as a suitable benchmark given the current CSP technology. Figure 2 shows the percentage of half hour intervals for all the years to give some visual indication of the variability in this statistic.

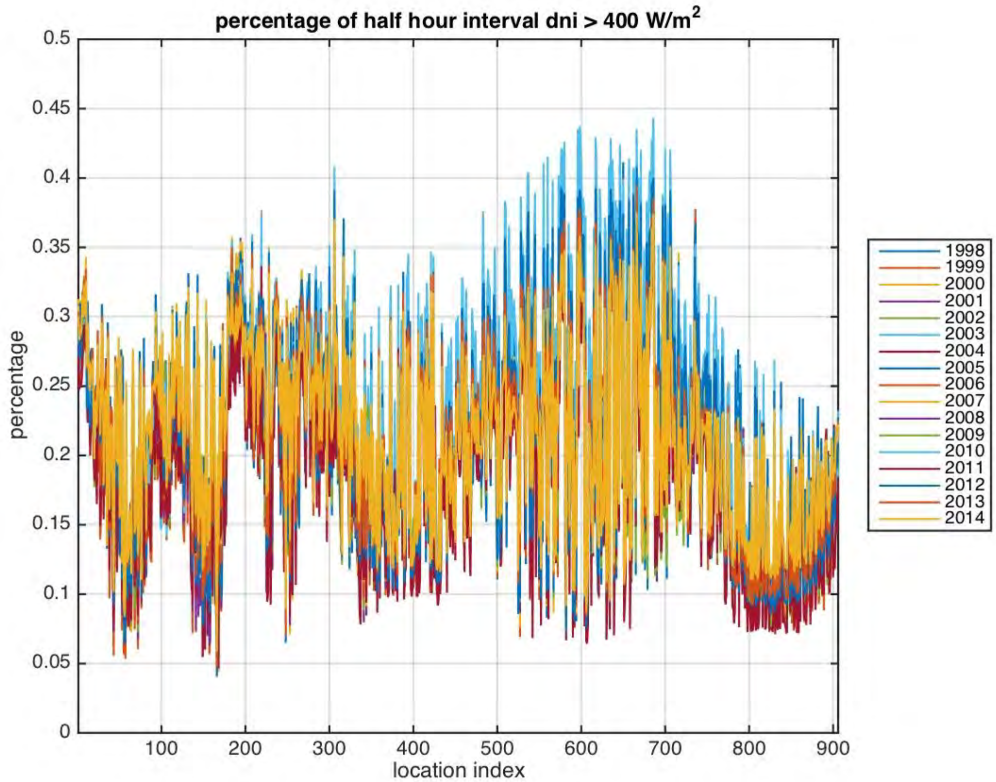


Figure 2: Percentage of Half Hour Interval DNI > 400 W/m^2

IV. GIS Exclusions

Geospatial analysis and mapping of the wind and solar resources was accomplished through the use of Geographic Information Systems (GIS) technology. Using relevant and available geographic data, areas likely to be impediments to development were excluded from consideration. Standard exclusions applied to all technologies were National and State Parks, US Fish & Wildlife Service (FWS) lands, areas zoned as urban, areas classified as Important Agricultural Land, areas within any “A” level flood zone, areas classified as lava flow hazard zones 1 and 2, all military or Department of Defense (DOD) lands, and wetlands. All of these datasets, except for National and State Parks and FWS lands were acquired from the state through the Hawaii Office of Planning website (planning.hawaii.gov). Additional resource-specific exclusions were applied as well. The photovoltaic analysis included exclusions for terrain slopes greater than either 3% or 5%, as well as a minimum contiguous area requirement of 1 km^2. Concentrating solar included a slope exclusion of greater than 3% as well as the minimum contiguous area requirement of 1 square kilometer, plus a minimum resource threshold of 5/kWh/m2/day irradiance. Wind included an exclusion of slopes greater than 20% [9] and a minimum wind speed resource threshold of 6.5 m/s, 7.5 m/s, or 8.5 m/s.

4.1 Improved Slope Analysis

A percent slope analysis was performed in the default analysis in order to create slope constraints of 3% and 5% for PV and 20% for wind. The elevation data used for this analysis was 1/3 arc-second (approx. 10 meter) digital elevation models (DEMs) from the National Elevation Dataset (NED) available through the US Geological Survey's nationalmap.gov. These DEMs are currently the best available, but do contain known artifacts and artificial anomalies due to data sources, processing methods, etc. One of these anomalies is terracing effect, and can be thought of as appearing like artificial terraces in the data. Figure 3 shows a typical agricultural parcel on the island of Oahu.

Figure 3

Figure 4 shows the same area after the results of a 3% slope analysis has been applied. Areas highlighted in yellow are where slope is not more than 3%. All other areas are greater than 3%.

Figure 4

It is evident from aerial photographs that the terracing effect seen in Figure 4 is not a genuine geographic feature, but a result of artifacts in the data. This terracing caused a large number of parcels to be divided incorrectly into strips of land rather than being shown as contiguous areas. This posed no significant problem for the wind analysis, which did not have a minimum contiguous area requirement, but it significantly reduced potential land area for PV, which for the purposes of this study included a minimum contiguous area requirement of 1 km^2. Upon applying that constraint, much potential land such as those areas shown in Figure 2 were eliminated.

In order to compensate for the artifacts in the data and attempt to recover the artificially segmented areas, the Boundary Clean tool was applied using ArcGIS. Boundary Clean is a process by which zones in a raster are expanded and shrunk programmatically over large areas in an attempt to fill in narrow bands or tiny gaps of missing data as well as eliminate tiny stray islands such as those that run along ridges seen in Figure 4.

The expansion/shrinking was run twice, and the results are shown in Figure 5. Large areas of land were unified, and tiny scattered areas were largely eliminated.

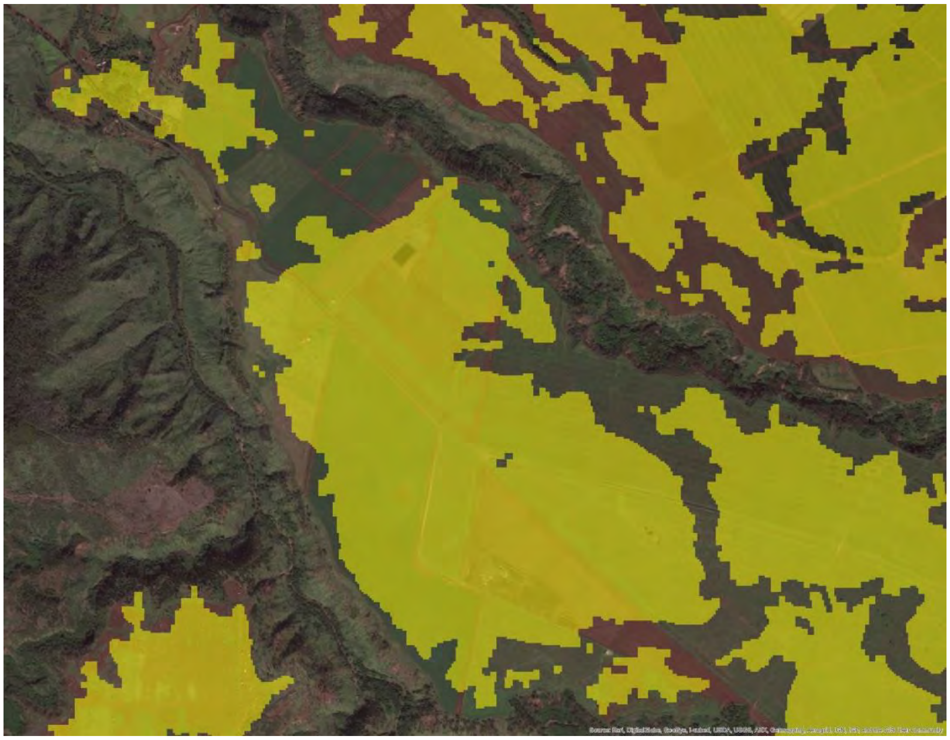


Figure 5

This process was repeated on the 5% and 20% slope analyses, and the resulting “clean” slope areas were used to run the final technical potential analysis.

After applying the minimum contiguous area constraint, available land area for PV development increased significantly. Small land areas were still dropped out, but the larger, now-intact areas remained. For the wind analysis, however, the impact was minimal, and in some cases the clean slope decreased available land area. As previously stated, cleaning the slope analysis filled in gaps, but it also eliminated numerous scattered, tiny, disconnected areas. As the wind analysis did not consider a minimum contiguous area, these tiny areas in the slope data that was not cleaned were left in the original analysis. The net result for wind was the loss of small scattered areas but the gain of areas within filled gaps. By chance, some islands had a net gain and others had a net loss, but in all cases the differences were relatively minor.

Post-processing the calculated slope data by cleaning the boundaries appears to have yielded a more realistic representation of the slope of the terrain, and thus a more realistic estimate of the resource potential in the state. As with any analysis, a site-specific analysis combined with proper ground-truthing should be implemented to verify site suitability, as the methods employed here are suitable only for a broad sweep of the state to understand general scale and distribution of development potential.

4.2 Updated Agricultural Land Exclusions

For Analyses 1, 2, and 3, agricultural land exclusions include lands classified as "Important Agricultural Land" (IAL) in the Hawaii Office of Planning website (planning.hawaii.gov) for both utility-scale onshore wind and utility-scale solar PV.

For Analysis 4, no agricultural land exclusions are considered for utility-scale onshore wind. For utility-scale solar PV, a different agricultural land classification from the Hawaii Office of Planning is used in addition to the IAL exclusions. This alternative agricultural land classification divides agricultural lands in five zoning designations: A, B, C, D, and E. Taking into consideration the statute[1] that details the agricultural land zoning designations, the following exclusions (in addition to IAL exclusions) are applied to the utility-scale solar PV resource assessment for Analysis 4:

- 100% of "A" lands are excluded
- 90% of "B" and "C" lands are excluded

It is important to note that a utility-scale PV resource area was removed if it was made too small to meet the minimum contiguous area requirement (1 km^2) due to an intersection with an "A" land. However, resource areas that fell partially or fully within "B" or "C" lands were not removed based on the minimum continuous area requirement; the total resource area within the "B" or "C" agricultural zone was reduced by 90%.

In summary, Analysis 4 includes the following agricultural land exclusions:

- Utility-scale onshore wind:
    - No agricultural land exclusion is applied

- Utility-scale solar PV:
    - "IAL" lands excluded
    - 100% of "A" agricultural lands excluded
    - 90% of "B" and "C" agricultural lands excluded

[1] http://www.capitol.hawaii.gov/hrscurrent/vol04_Ch0201-0257/HRS0205/HRS_0205-0002.htm

V. Resource Potential Maps

The following self-explanatory maps refer to Analysis 1 and are included herein after in the following order:

Utility-Scale Onshore Wind

- Utility-scale onshore wind development potential for all Hawaiian islands
- Utility-scale onshore wind development potential for Hawaii
- Utility-scale onshore wind development potential for Maui
- Utility-scale onshore wind development potential for Oahu

Utility-Scale PV

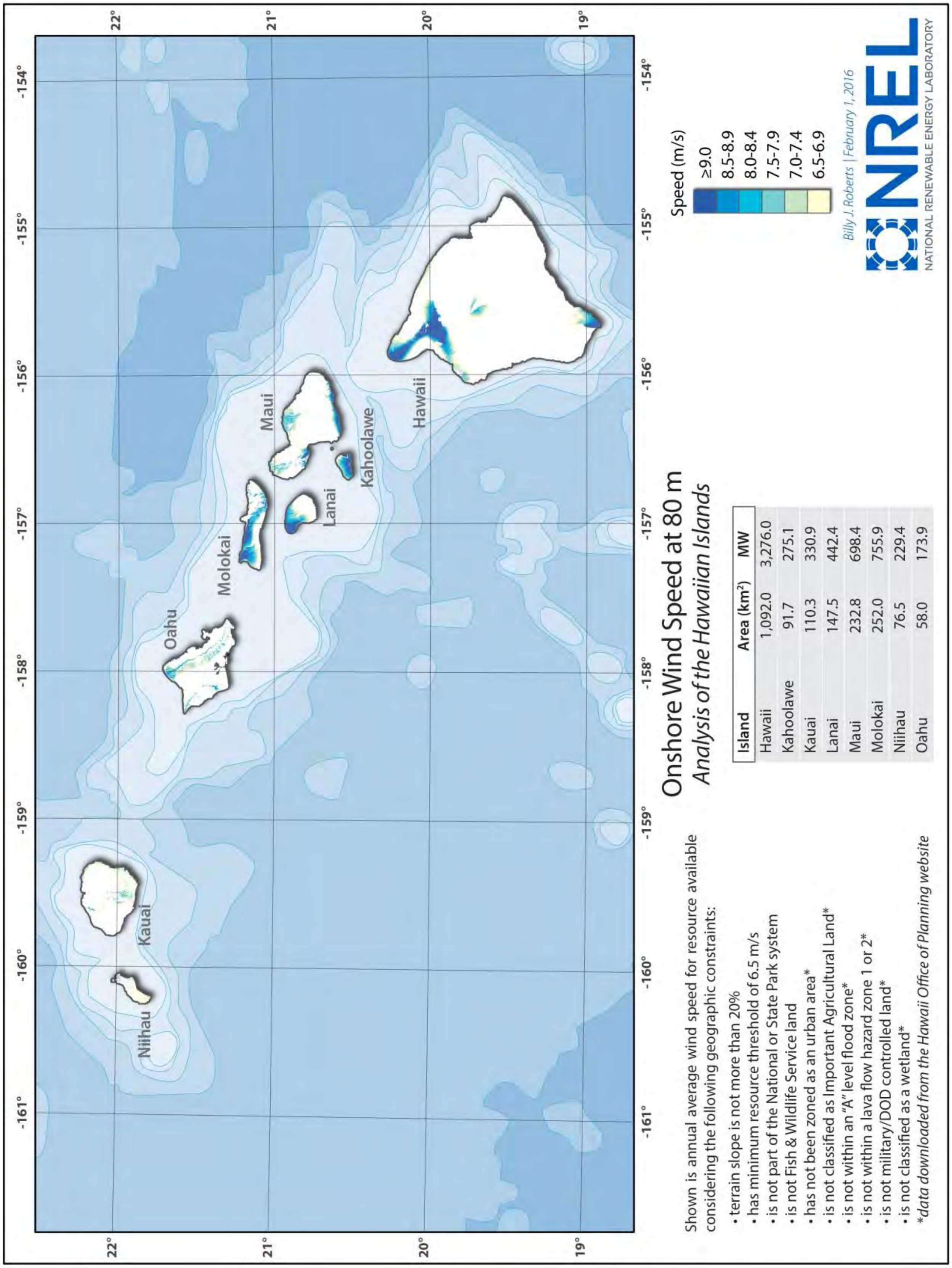
- Capacity factor for all Hawaiian islands
- Utility-scale PV development potential for all Hawaiian islands (3% slope exclusion)
- Utility-scale PV development potential for Hawaii (3% slope exclusion)
- Utility-scale PV development potential for Maui (3% slope exclusion)
- Utility-scale PV development potential for Oahu (3% slope exclusion)
- Utility-scale PV development potential for all Hawaiian islands (5% slope exclusion)
- Utility-scale PV development potential for Hawaii (5% slope exclusion)
- Utility-scale PV development potential for Maui (5% slope exclusion)
- Utility-scale PV development potential for Oahu (5% slope exclusion)

Concentrated Solar Power

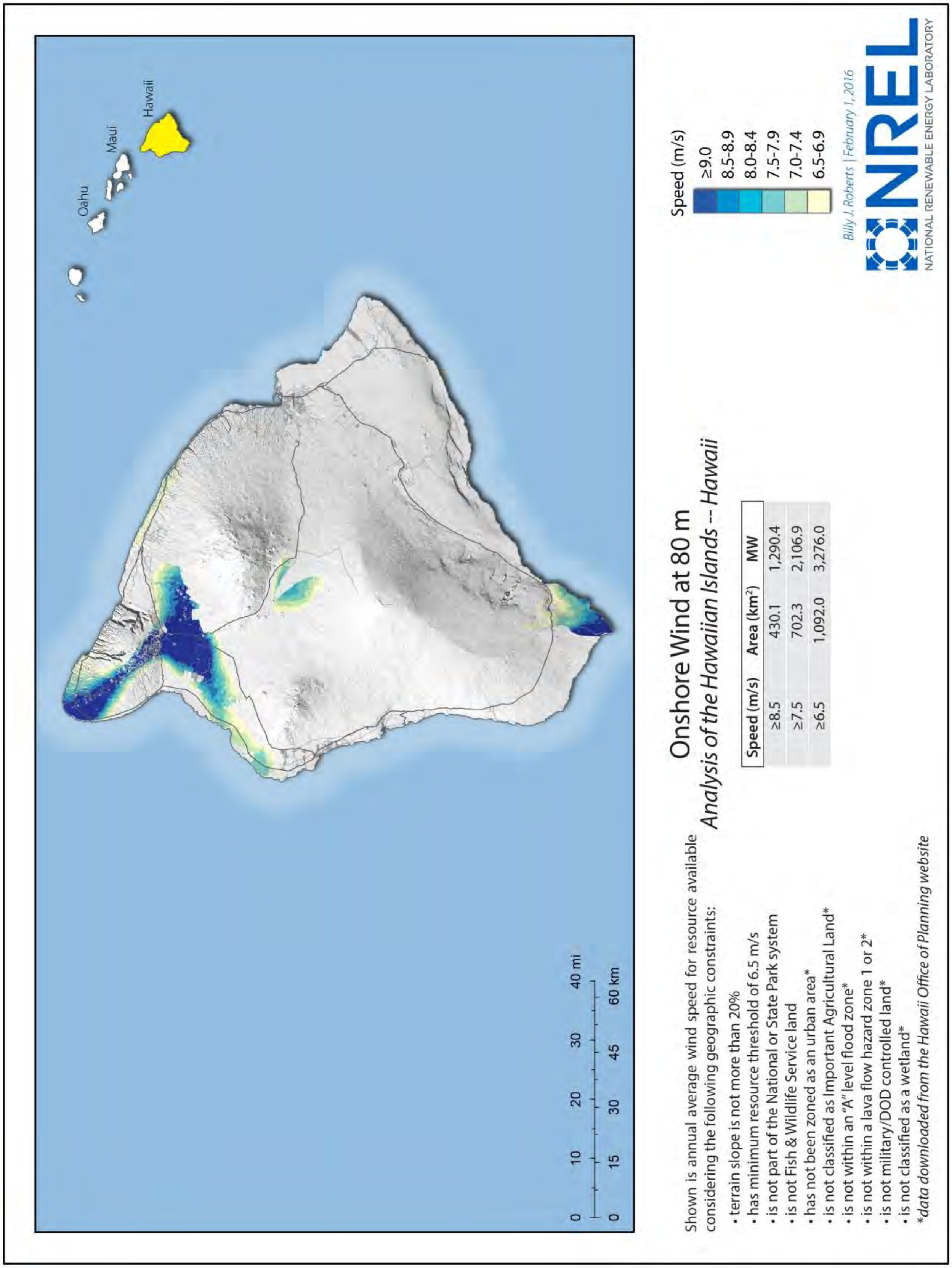
- Direct normal irradiance for all Hawaiian islands
- Concentrated solar power development potential for all Hawaiian islands
- Concentrated solar power development potential for Hawaii

F. National Renewable Energy Laboratory (NREL) Reports

Utility-Scale Onshore Wind, Utility-Scale PV, and CSP Potential Resource

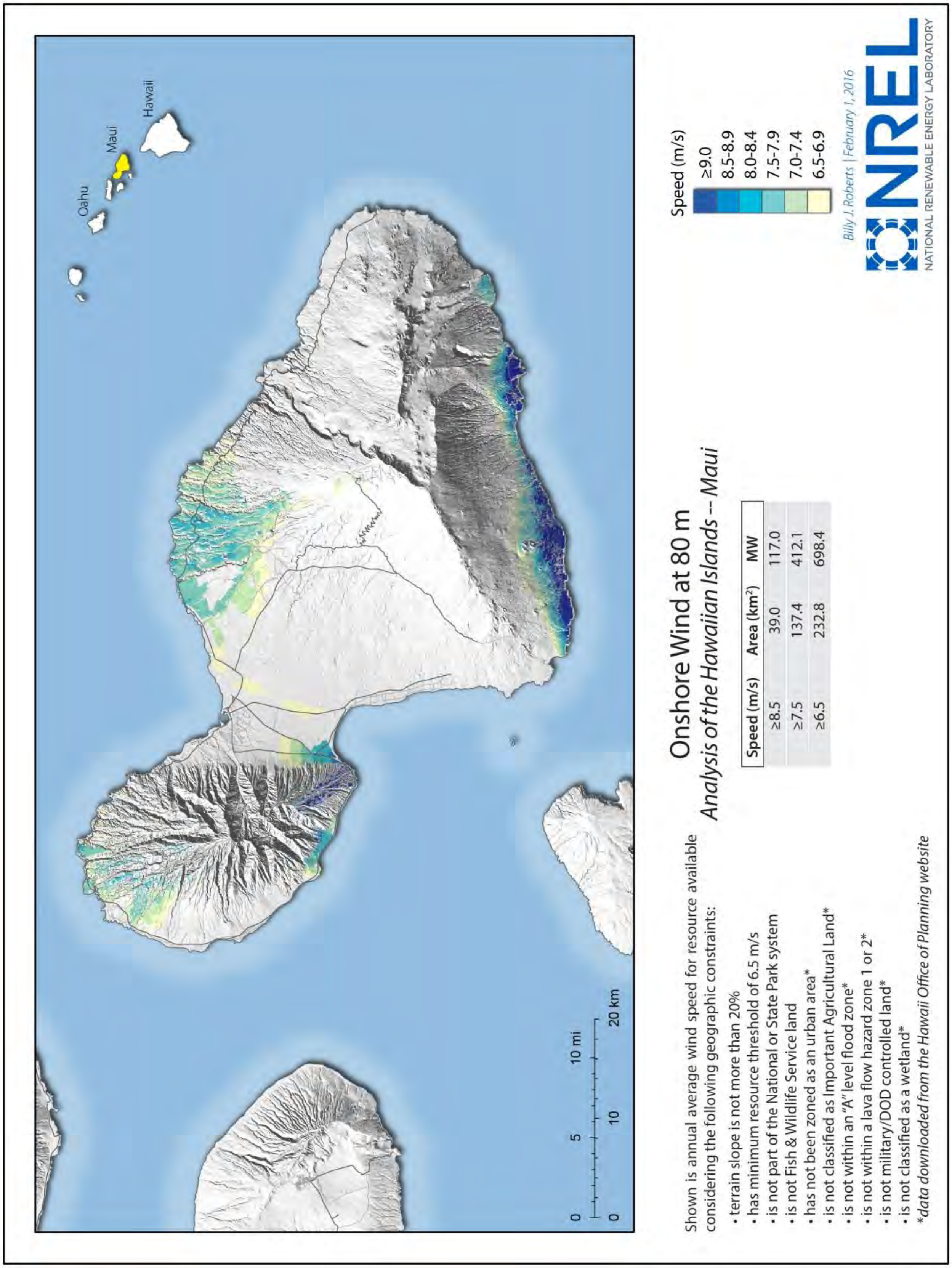


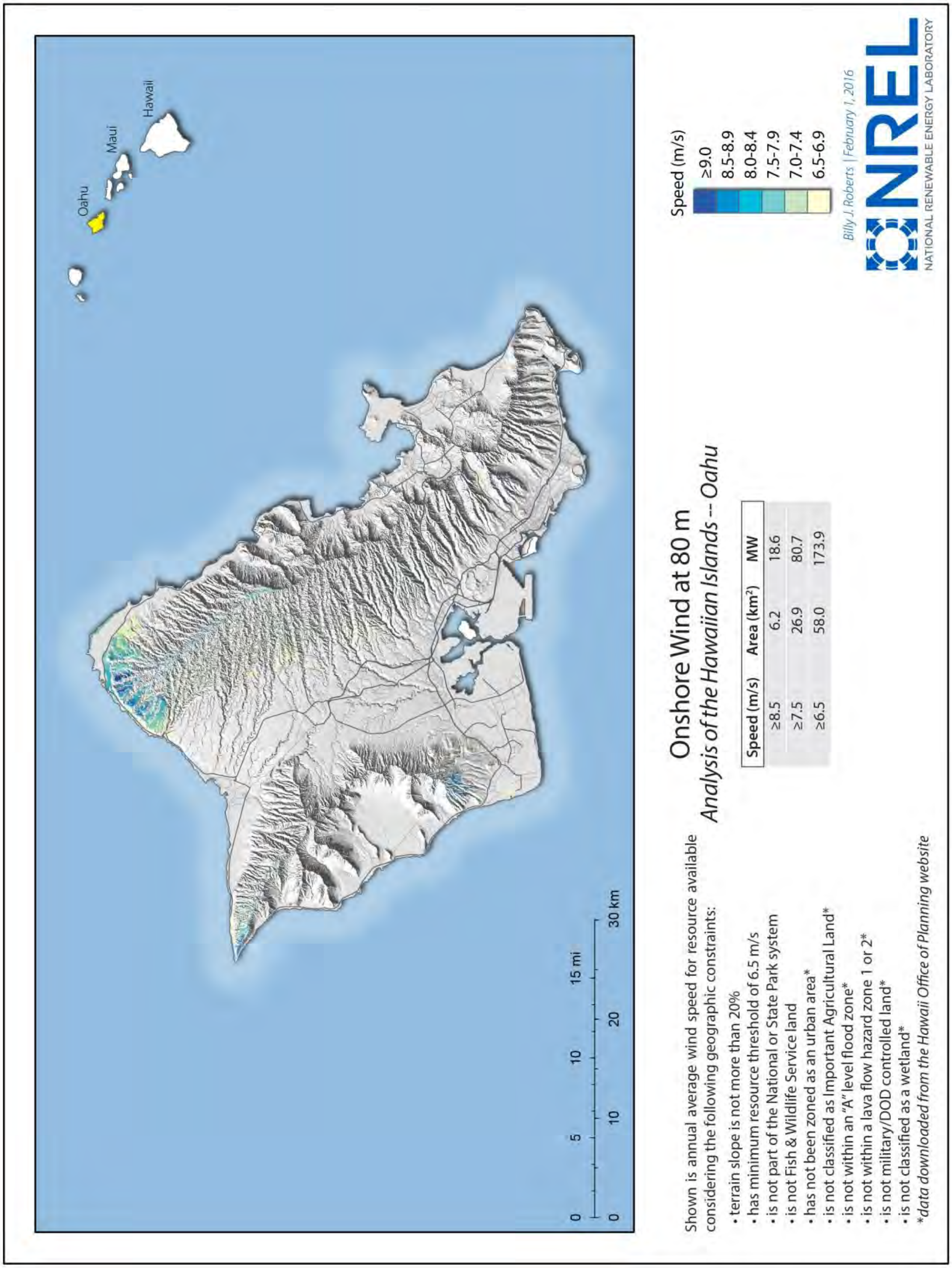
Island	Area (km²)	MW
Hawaii	1,092.0	3,276.0
Kahoolawe	91.7	275.1
Kauai	110.3	330.9
Lanai	147.5	442.4
Maui	232.8	698.4
Molokai	252.0	755.9
Niihau	76.5	229.4
Oahu	58.0	173.9


Onshore Wind at 80 m
Analysis of the Hawaiian Islands -- Hawaii
Speed (m/s) | Area (km²) | MW
≥8.5 | 430.1 | 1,290.4
≥7.5 | 702.3 | 2,106.9
≥6.5 | 1,092.0 | 3,276.0
Speed (m/s)
≥9.0
8.5-8.9
8.0-8.4
7.5-7.9
7.0-7.4
6.5-6.9
Oahu
Maui
Hawaii
0 10 20 30 40 mi
0 15 30 45 60 km
Shown is annual average wind speed for resource available considering the following geographic constraints:
• terrain slope is not more than 20%
• has minimum resource threshold of 6.5 m/s
• is not part of the National or State Park system
• is not Fish & Wildlife Service land
• has not been zoned as an urban area*
• is not classified as Important Agricultural Land*
• is not within an "A" level flood zone*
• is not within a lava flow hazard zone 1 or 2*
• is not military/DOD controlled land*
• is not classified as a wetland*
*data downloaded from the Hawaii Office of Planning website
Billy J. Roberts | February 1, 2016
NREL
NATIONAL RENEWABLE ENERGY LABORATORY

F. National Renewable Energy Laboratory (NREL) Reports

Utility-Scale Onshore Wind, Utility-Scale PV, and CSP Potential Resource

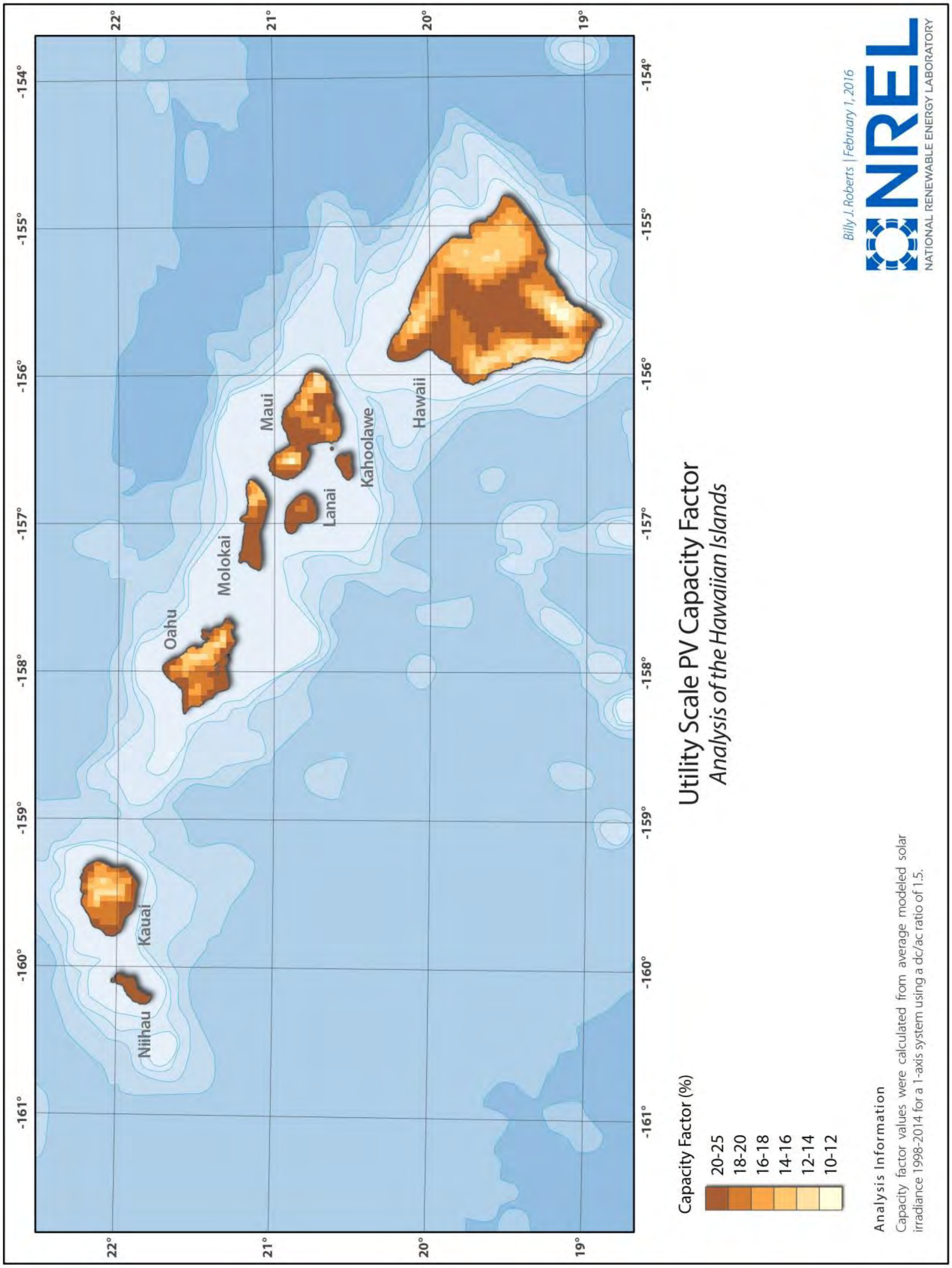


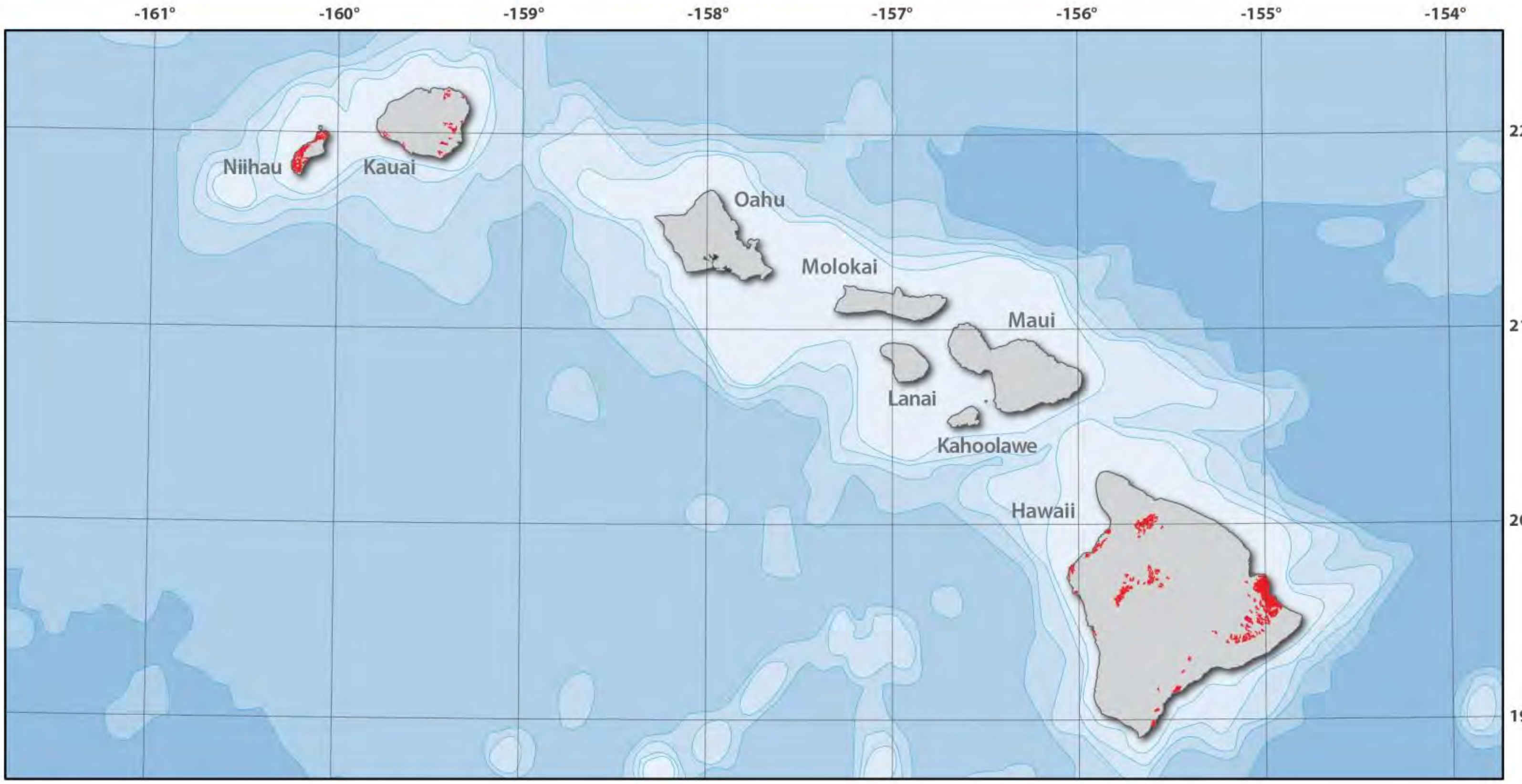


Speed (m/s)	Area (km²)	MW
≥8.5	6.2	18.6
≥7.5	26.9	80.7
≥6.5	58.0	173.9

F. National Renewable Energy Laboratory (NREL) Reports

Utility-Scale Onshore Wind, Utility-Scale PV, and CSP Potential Resource





Capacity factor calculated from average modeled solar irradiance from 1998-2014 for a 1-axis system with a dc/ac ratio of 1.5. Development potential was determined by applying the following geographic constraints:

- terrain slope is not more than 3%
- has a contiguous area of at least 1 km²
- is not part of the National or State Park* system
- is not Fish & Wildlife Service land
- has not been zoned as an urban area*
- is not classified as Important Agricultural Land*
- is not within an "A(x)" level flood zone*
- is not within a lava flow hazard zone 1 or 2*
- is not military/DOD controlled land*
- is not classified as a wetland*

**data acquired from the Hawaii Office of Planning*

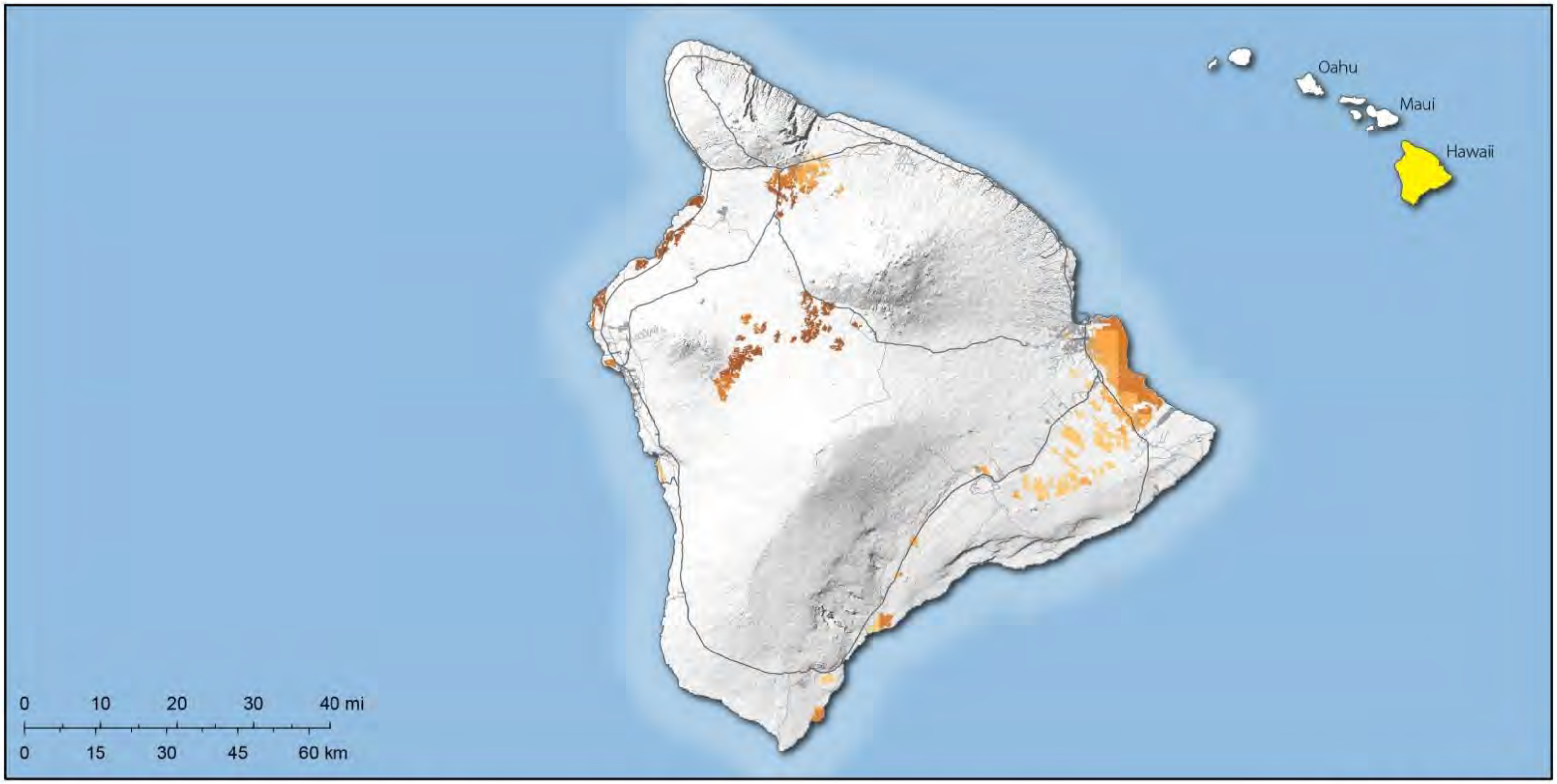
Utility Scale PV Development Potential

Analysis of the Hawaiian Islands

Island	Area (km^2)	MW	MWh	GW	GWh
Hawaii	382.7	16,302.3	25,947,687.7	16.3	25,947.7
Kahoolawe	0	0	0	0	0
Kauai	32.8	1,398.3	2,318,290.7	1.4	2,318.3
Lanai	1.2	51.0	95,393.7	0.1	95.4
Maui	0	0	0	0	0
Molokai	0	0	0	0	0
Niihau	72.1	3,069.4	5,931,000.5	3.1	5,931.0
Oahu	0	0	0	0	0

Billy J. Roberts | February 1, 2016

NATIONAL RENEWABLE ENERGY LABORATORY



Capacity factor calculated from average modeled solar irradiance from 1998-2014 for a 1-axis system with a dc/ac ratio of 1.5. Development potential was determined by applying the following geographic constraints:

- terrain slope is not more than 3%
- has a contiguous area of at least 1 km²
- is not part of the National or State Park* system
- is not Fish & Wildlife Service land
- has not been zoned as an urban area*
- is not classified as Important Agricultural Land*
- is not within an "A(x)" level flood zone*
- is not within a lava flow hazard zone 1 or 2*
- is not military/DOD controlled land*
- is not classified as a wetland*

**data acquired from the Hawaii Office of Planning*

Utility Scale PV Development Potential
Analysis of the Hawaiian Islands -- Hawaii

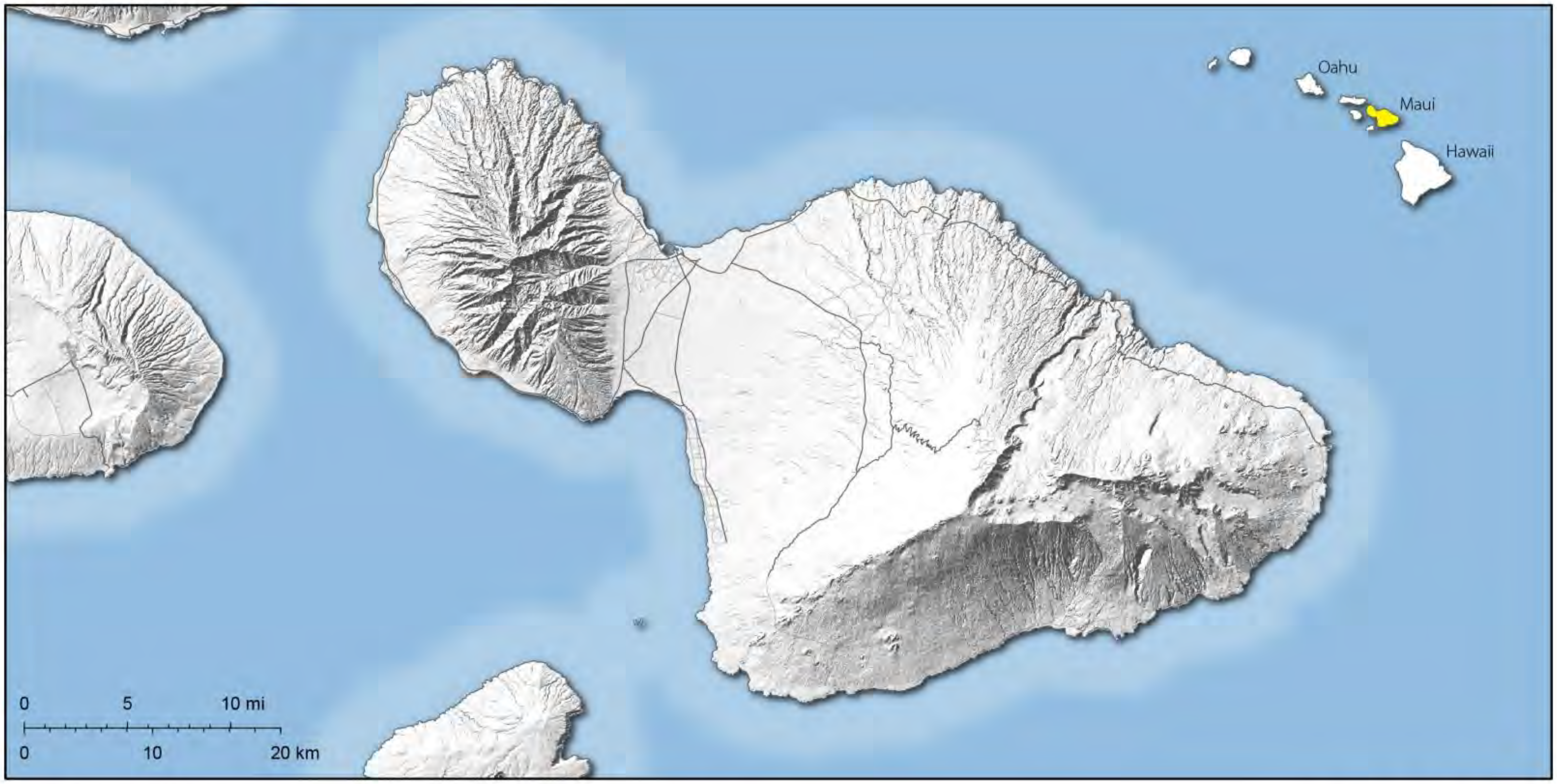
CF Range (%)	Area (km²)	MW	MWh	GW	GWh
≥20	86.9	3,704.0	7,039,667.6	3.7	7,039.7
≥18	193.0	8,220.9	14,441,481.3	8.2	14,441.5
≥16	293.6	12,507.7	20,934,700.7	12.5	20,934.7
≥14	376.9	16,055.4	25,663,262.6	16.1	25,663.3
≥12	381.5	16,250.1	25,898,220.5	16.3	25,898.2
≥10	382.7	16,302.3	25,947,687.7	16.3	25,947.7

Capacity Factor (%)

- 20-25
- 18-20
- 16-18
- 14-16
- 12-14
- 10-12

Billy J. Roberts | February 1, 2016

NATIONAL RENEWABLE ENERGY LABORATORY



Capacity factor calculated from average modeled solar irradiance from 1998-2014 for a 1-axis system with a dc/ac ratio of 1.5. Development potential was determined by applying the following geographic constraints:

- terrain slope is not more than 3%
- has a contiguous area of at least 1 km²
- is not part of the National or State Park* system
- is not Fish & Wildlife Service land
- has not been zoned as an urban area*
- is not classified as Important Agricultural Land*
- is not within an "A(x)" level flood zone*
- is not within a lava flow hazard zone 1 or 2*
- is not military/DOD controlled land*
- is not classified as a wetland*

**data acquired from the Hawaii Office of Planning*

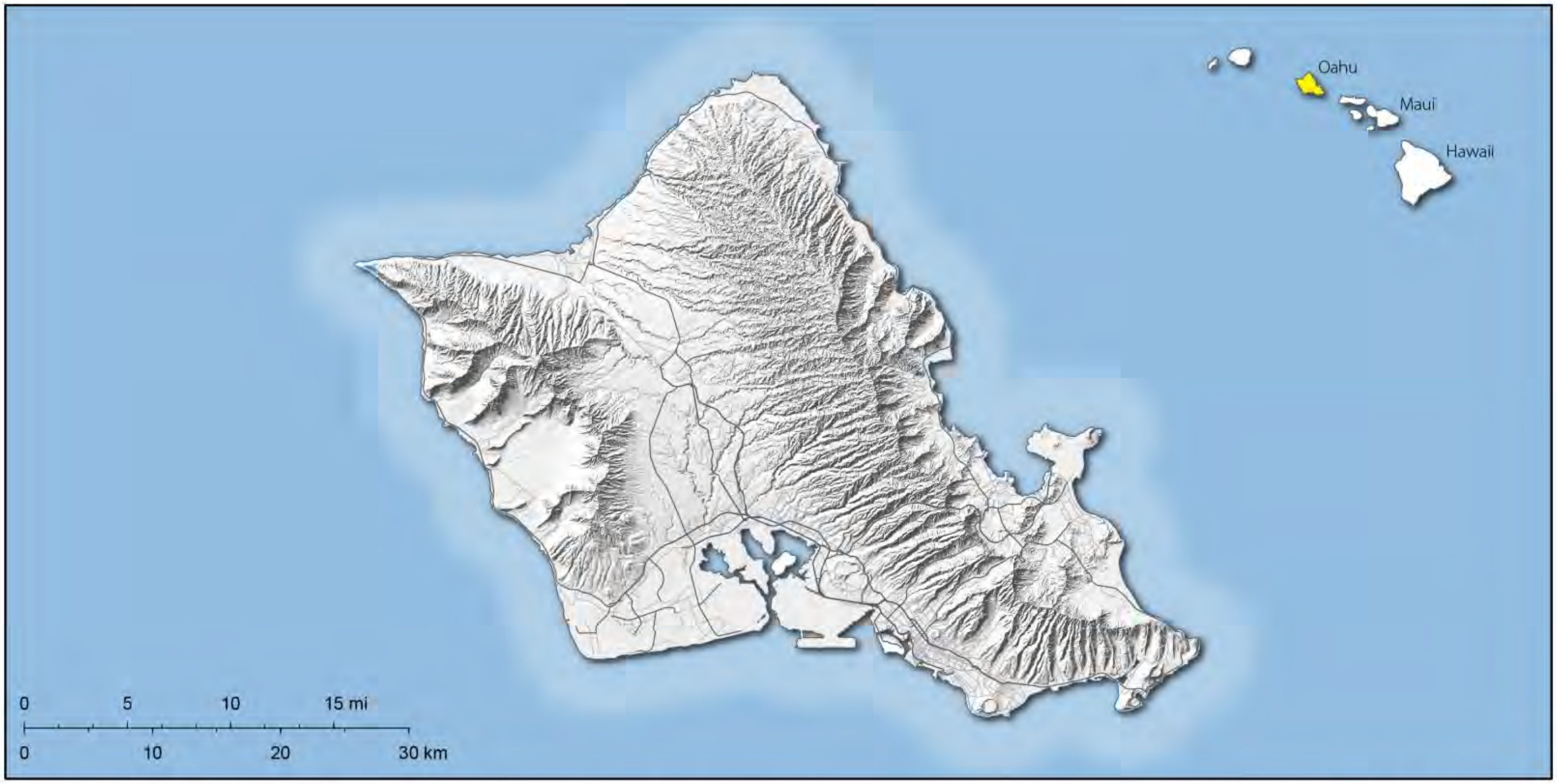
Utility Scale PV Development Potential
Analysis of the Hawaiian Islands -- Maui

CF Range (%)	Area (km²)	MW	MWh	GW	GWh
≥20	0	0	0	0	0
≥18	0	0	0	0	0
≥16	0	0	0	0	0
≥14	0	0	0	0	0
≥12	0	0	0	0	0
≥10	0	0	0	0	0

Capacity Factor (%)
- 20-25
- 18-20
- 16-18
- 14-16
- 12-14
- 10-12

Billy J. Roberts | February 1, 2016

NREL
NATIONAL RENEWABLE ENERGY LABORATORY



Capacity factor calculated from average modeled solar irradiance from 1998-2014 for a 1-axis system with a dc/ac ratio of 1.5. Development potential was determined by applying the following geographic constraints:

- terrain slope is not more than 3%
- has a contiguous area of at least 1 km^2
- is not part of the National or State Park* system
- is not Fish & Wildlife Service land
- has not been zoned as an urban area*
- is not classified as Important Agricultural Land*
- is not within an "A(x)" level flood zone*
- is not within a lava flow hazard zone 1 or 2*
- is not military/DOD controlled land*
- is not classified as a wetland*

*data acquired from the Hawaii Office of Planning

Utility Scale PV Development Potential

Analysis of the Hawaiian Islands -- Oahu

CF Range (%)	Area (km^2)	MW	MWh	GW	GWh
≥20	0	0	0	0	0
≥18	0	0	0	0	0
≥16	0	0	0	0	0
≥14	0	0	0	0	0
≥12	0	0	0	0	0
≥10	0	0	0	0	0

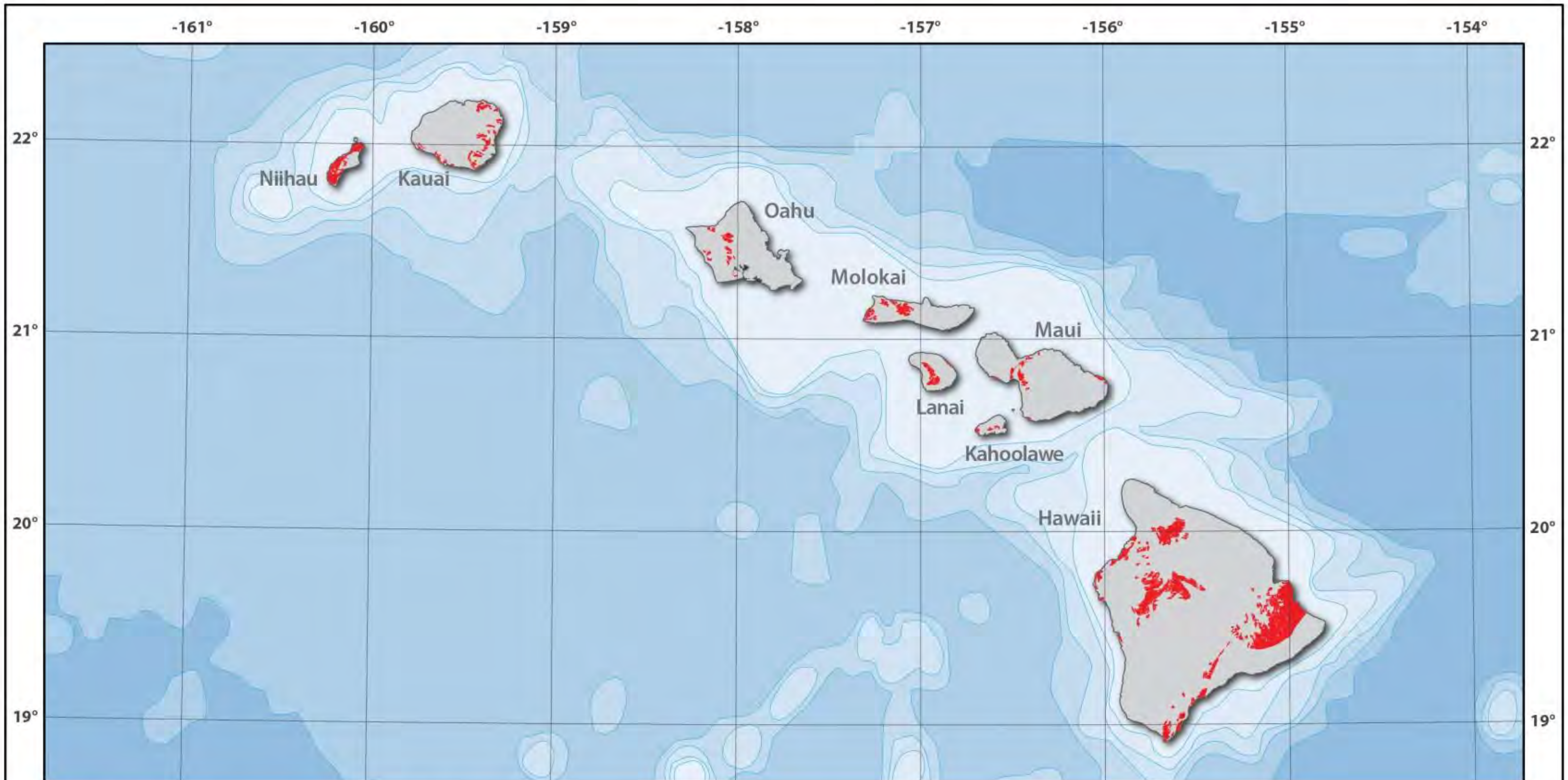
Capacity Factor (%)

20-25
18-20
16-18
14-16
12-14
10-12

Billy J. Roberts | February 1, 2016

NREL
NATIONAL RENEWABLE ENERGY LABORATORY

Hawaiian Electric
Maui Electric
Hawai'i Electric Light



Capacity factor calculated from average modeled solar irradiance from 1998-2014 for a 1-axis system with a dc/ac ratio of 1.5. Development potential was determined by applying the following geographic constraints:

- terrain slope is not more than 5%
- has a contiguous area of at least 1 km²
- is not part of the National or State Park* system
- is not Fish & Wildlife Service land
- has not been zoned as an urban area*
- is not classified as Important Agricultural Land*
- is not within an "A(x)" level flood zone*
- is not within a lava flow hazard zone 1 or 2*
- is not military/DOD controlled land*
- is not classified as a wetland*

**data acquired from the Hawaii Office of Planning*

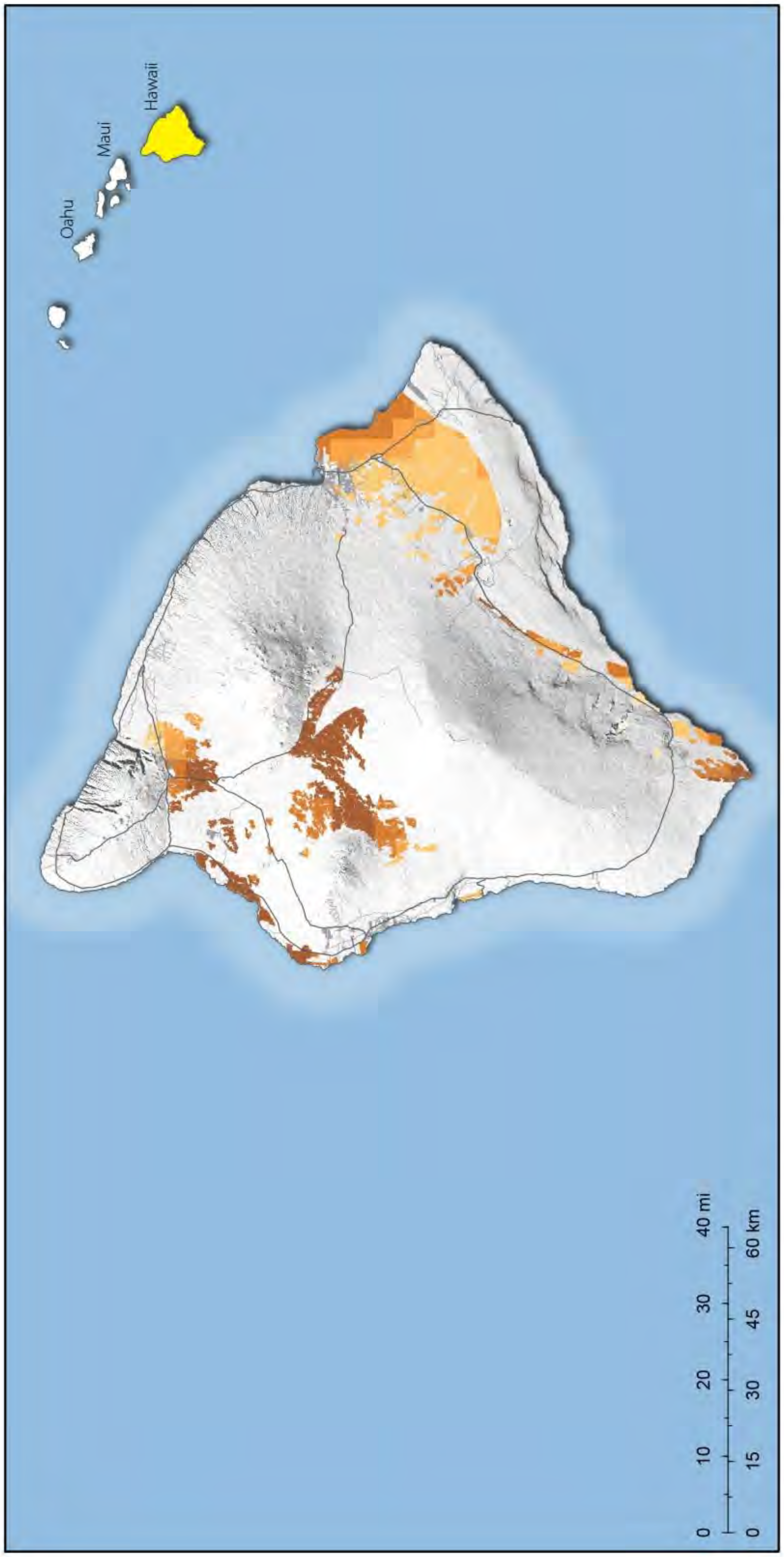
Utility Scale PV Development Potential

Analysis of the Hawaiian Islands

Island	Area (km^2)	MW	MWh	GW	GWh
Hawaii	1,078.7	45,951.4	72,608,871.7	46.0	72,608.9
Kahoolawe	8.1	346.6	675,289.3	0.3	675.3
Kauai	85.8	3,656.8	6,054,802.7	3.7	6,054.8
Lanai	41.8	1,781.2	3,227,898.6	1.8	3,227.9
Maui	46.5	1,980.9	3,743,976.3	2.0	3,744.0
Molokai	61.9	2,635.6	5,253,430.0	2.6	5,253.4
Niihau	92.6	3,946.4	7,631,634.0	3.9	7,631.6
Oahu	47.1	2,007.2	3,434,495.9	2.0	3,434.5

Billy J. Roberts | February 1, 2016

NREL
NATIONAL RENEWABLE ENERGY LABORATORY



Capacity Factor (%)

20-25
18-20
16-18
14-16
12-14
10-12

Billy J. Roberts | February 1, 2016

NREL NATIONAL RENEWABLE ENERGY LABORATORY

Utility Scale PV Development Potential

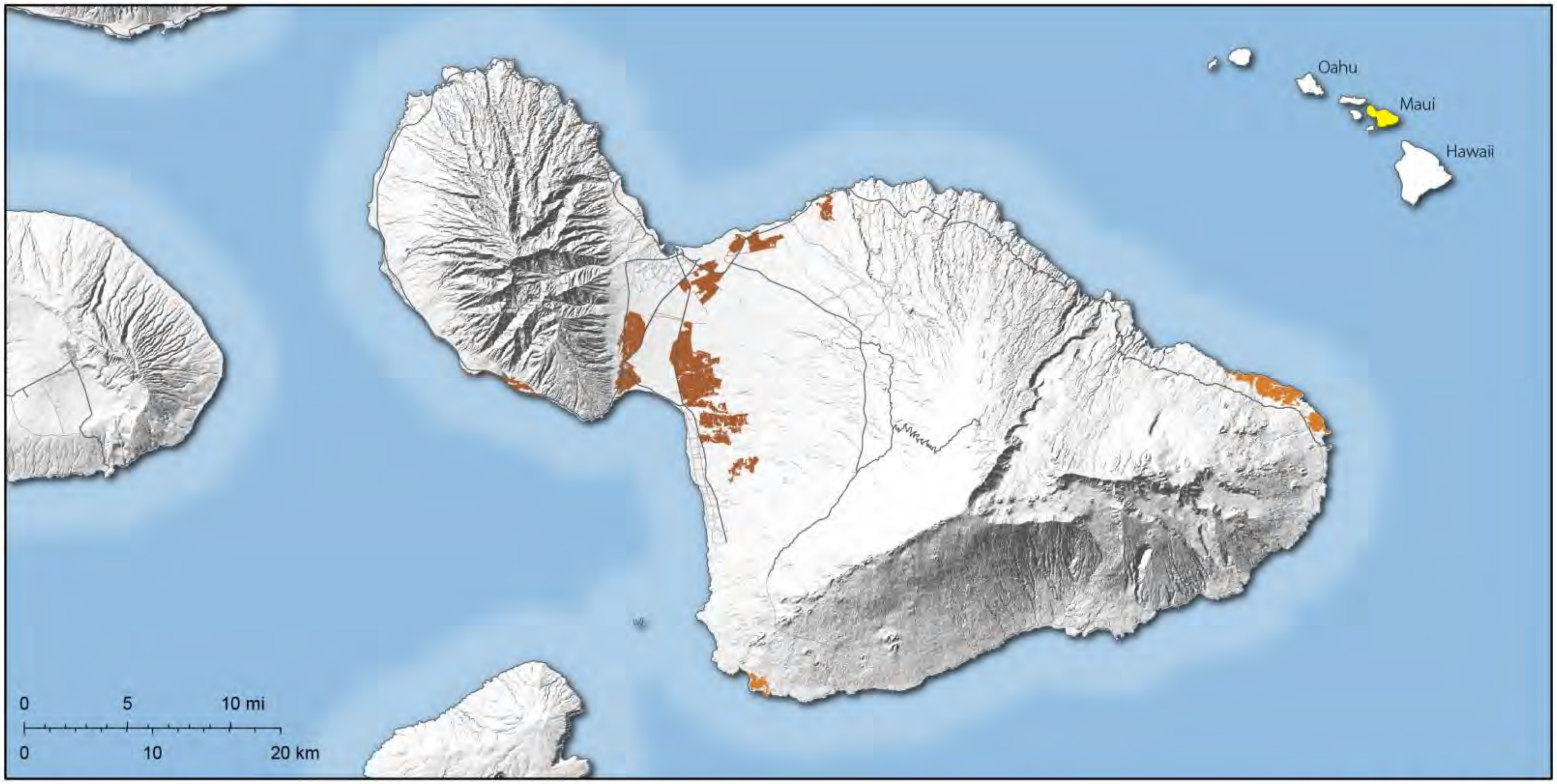
Analysis of the Hawaiian Islands -- Hawaii

CF Range (%)	Area (km²)	MW	MWh	GW	GWh
≥20	292.8	12,472.9	23,708,896.8	12.5	23,708.9
≥18	522.6	22,262.4	39,916,124.8	22.3	39,916.1
≥16	711.4	30,306.2	52,014,707.0	30.3	52,014.7
≥14	1,057.6	45,054.3	71,551,672.7	45.1	71,551.7
≥12	1,076.5	45,860.1	72,521,769.5	45.9	72,521.8
≥10	1,078.7	45,951.4	72,608,871.7	46.0	72,608.9

Capacity factor calculated from average modeled solar irradiance from 1998-2014 for a 1-axis system with a dc/ac ratio of 1.5. Development potential was determined by applying the following geographic constraints:

- terrain slope is not more than 5%
- has a contiguous area of at least 1 km²
- is not part of the National or State Park* system
- is not Fish & Wildlife Service land
- has not been zoned as an urban area*
- is not classified as Important Agricultural Land*
- is not within an "A(x)" level flood zone*
- is not within a lava flow hazard zone 1 or 2*
- is not military/DOD controlled land*
- is not classified as a wetland*

**data acquired from the Hawaii Office of Planning*



Capacity factor calculated from average modeled solar irradiance from 1998-2014 for a 1-axis system with a dc/ac ratio of 1.5. Development potential was determined by applying the following geographic constraints:

- terrain slope is not more than 5%
- has a contiguous area of at least 1 km²
- is not part of the National or State Park* system
- is not Fish & Wildlife Service land
- has not been zoned as an urban area*
- is not classified as Important Agricultural Land*
- is not within an "A(x)" level flood zone*
- is not within a lava flow hazard zone 1 or 2*
- is not military/DOD controlled land*
- is not classified as a wetland*

**data acquired from the Hawaii Office of Planning*

Utility Scale PV Development Potential
Analysis of the Hawaiian Islands -- Maui

CF Range (%)	Area (km²)	MW	MWh	GW	GWh
≥20	39.1	1,665.5	3,236,991.4	1.7	3,237.0
≥18	46.5	1,980.9	3,743,976.3	2.0	3,744.0
≥16	-	-	-	-	-
≥14	-	-	-	-	-
≥12	-	-	-	-	-
≥10	-	-	-	-	-

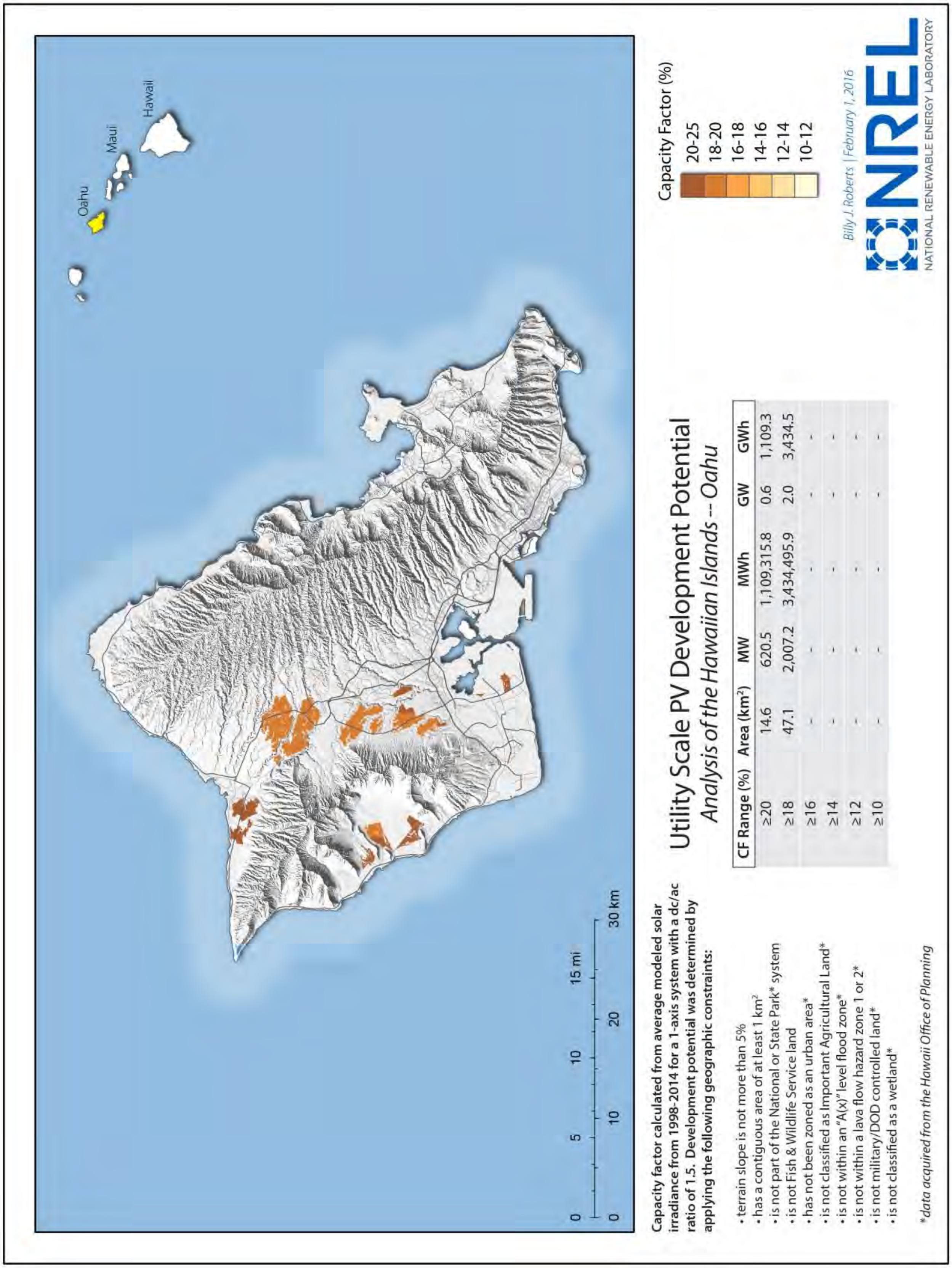
Capacity Factor (%)
- 20-25
- 18-20
- 16-18
- 14-16
- 12-14
- 10-12

Billy J. Roberts | February 1, 2016

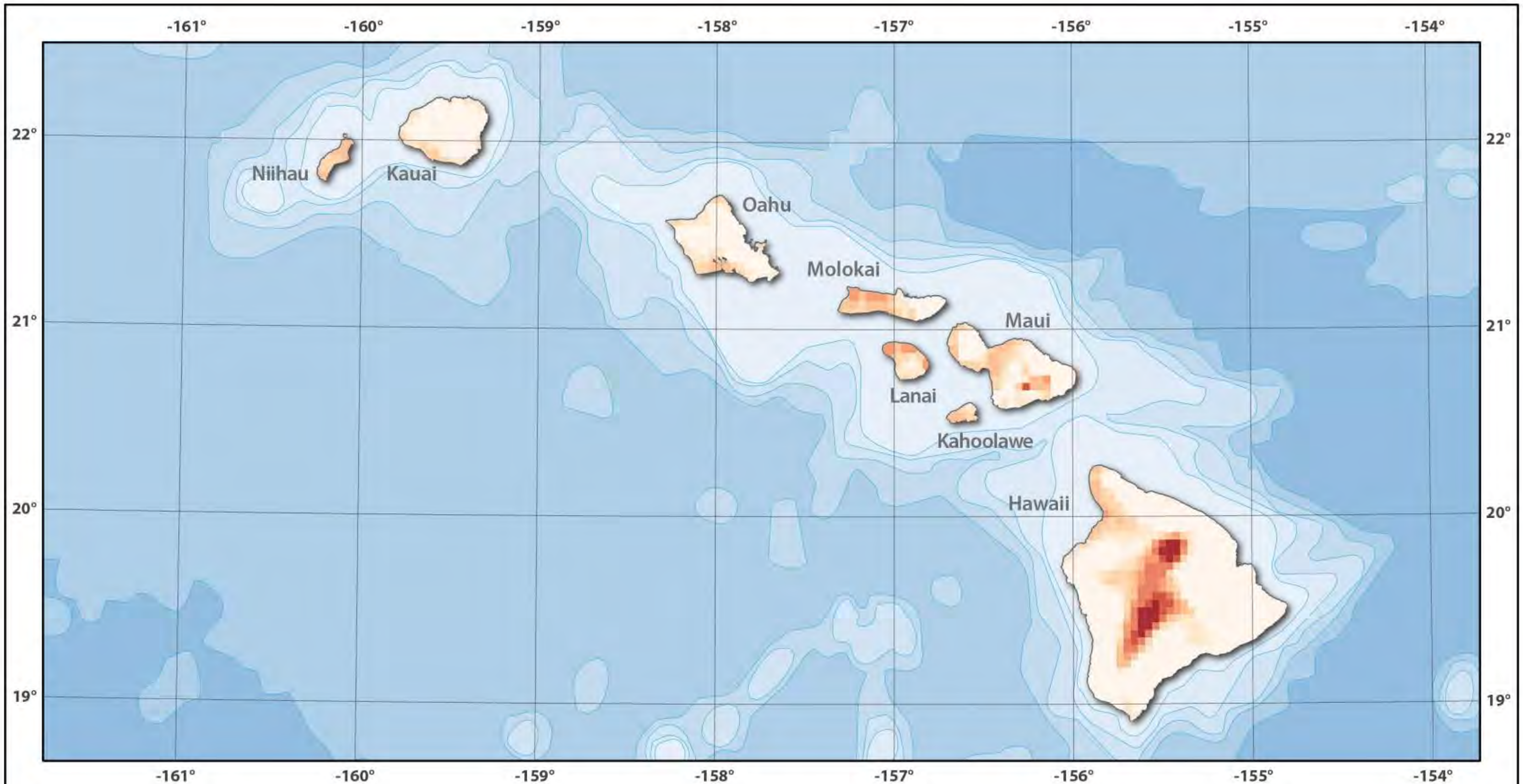
NATIONAL RENEWABLE ENERGY LABORATORY

F. National Renewable Energy Laboratory (NREL) Reports

Utility-Scale Onshore Wind, Utility-Scale PV, and CSP Potential Resource



CF Range (%)	Area (km²)	MW	MWh	GW	GWh
≥20	14.6	620.5	1,109,315.8	0.6	1,109.3
≥18	47.1	2,007.2	3,434,495.9	2.0	3,434.5
≥16	-	-	-	-	-
≥14	-	-	-	-	-
≥12	-	-	-	-	-
≥10	-	-	-	-	-



Direct Normal Solar Irradiance
National Solar Radiation Database Version 2.0.0
The Hawaiian Islands

kWh/m²/Day

- >8.0
- 7.5 - 7.9
- 7.0 - 7.4
- 6.5 - 6.9
- 6.0 - 6.4
- 5.5 - 5.9
- 5.0 - 5.4
- <5.0

The Solar Resource Dataset

The concept behind the project is to produce a regularly updated yet high quality solar resource dataset for the United States and surrounding regions that is accessible to the public. The availability of this dataset reduces barriers to penetration of solar by allowing users to both accurately predict the output from solar installations and to verify performance. The map shows the full extent of the current version of the dataset.

Data Summary

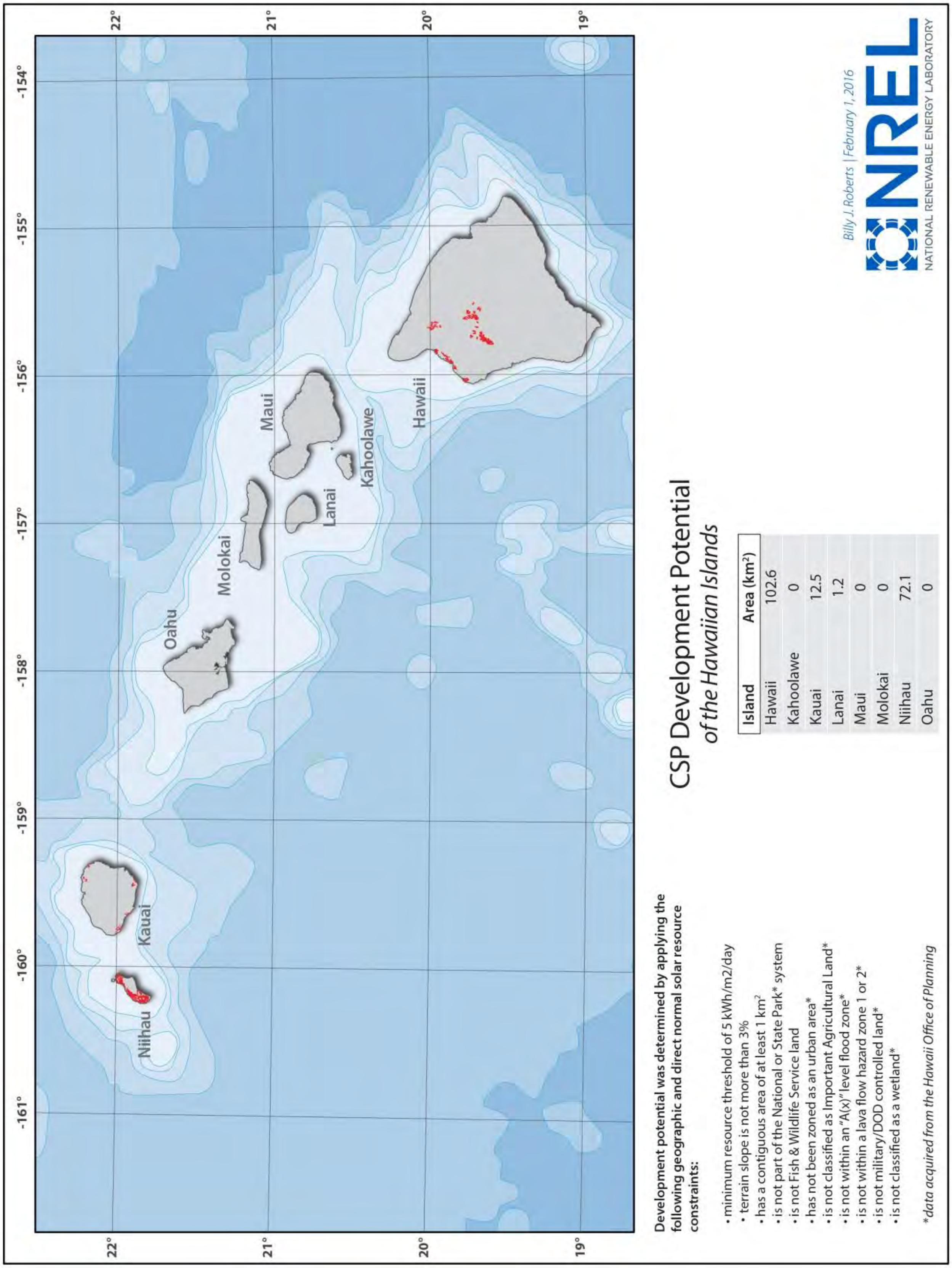
This data provides annual average daily total solar resource averaged over surface cells of 0.038 degrees in both latitude and longitude, or nominally 4 km in size. The insolation values represent the resource available to concentrating systems, and were created using the PATMOS-X algorithms for cloud identification and properties, the MMAC radiative transfer model for clear sky calculations and the SASRAB model for cloud sky calculations. The data are averaged from hourly model output over the period 1998-2014.

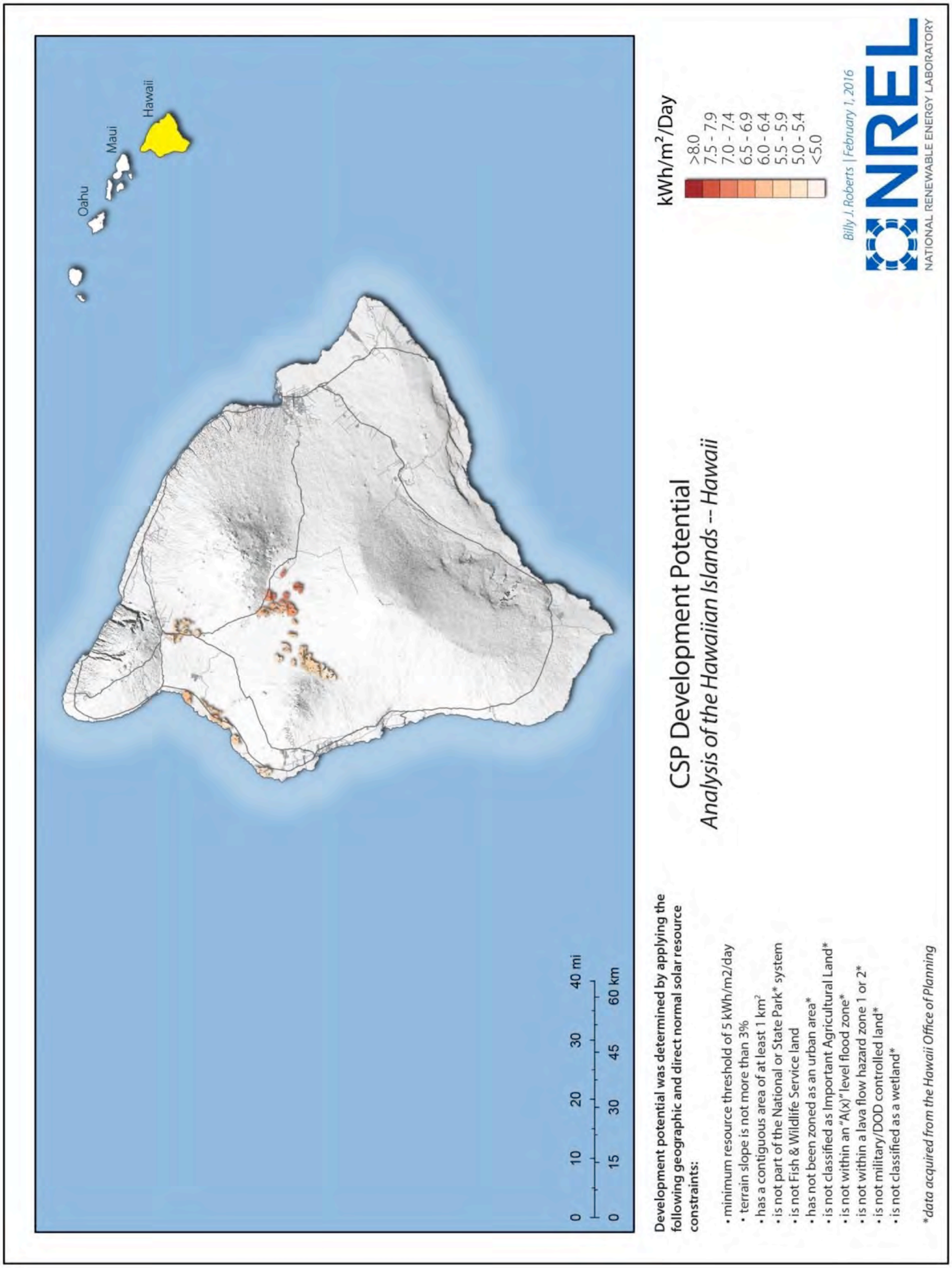
Billy J. Roberts | February 1, 2016

NATIONAL RENEWABLE ENERGY LABORATORY

F. National Renewable Energy Laboratory (NREL) Reports

Utility-Scale Onshore Wind, Utility-Scale PV, and CSP Potential Resource




Oahu
Maui
Hawaii
0 10 20 30 40 mi
0 15 30 45 60 km
CSP Development Potential
Analysis of the Hawaiian Islands -- Hawaii
kWh/m²/Day
>8.0
7.5 - 7.9
7.0 - 7.4
6.5 - 6.9
6.0 - 6.4
5.5 - 5.9
5.0 - 5.4
<5.0
Billy J. Roberts | February 1, 2016
NREL
NATIONAL RENEWABLE ENERGY LABORATORY
Development potential was determined by applying the following geographic and direct normal solar resource constraints:
• minimum resource threshold of 5 kWh/m2/day
• terrain slope is not more than 3%
• has a contiguous area of at least 1 km²
• is not part of the National or State Park* system
• is not Fish & Wildlife Service land
• has not been zoned as an urban area*
• is not classified as Important Agricultural Land*
• is not within an "A(x)" level flood zone*
• is not within a lava flow hazard zone 1 or 2*
• is not military/DOD controlled land*
• is not classified as a wetland*
*data acquired from the Hawaii Office of Planning

Appendix A: SAM Parameters

System parameters	Value
self.system_capacity	10000
self.dc_ac_ratio	1.5
self.tilt	0
self.azimuth	180
self.inv_eff	96
self.losses	14.0757
self.array_type	2
self.gcr	0.4
self.adjust_constant	0

Table 7: SAM Parameters

References

[1] AWS Truepower, LLC, NREL REEDS LICENSED DATASETS AND USER’S GUIDE, November 5, 2014.

[2] Wind Vision: A New Era for Wind Power in the United States, U.S. Department of Energy, April 2015.

[3] National Solar Radiation Database (NSRDB), https://nsrdb.nrel.gov

[4] Sengupta, M.; Habte, A.; Gotseff, P.; Weekley, A.; Lopez, A.; Anderberg, M.; Molling, C.; Heidinger, A. (2014). "Physics-Based GOES Product for Use in NREL's National Solar Radiation Database: Preprint." 6 pp. NREL/CP-5D00-62776.

[5] Sengupta, M.; Habte, A.; Gotseff, P.; Weekley, A.; Lopez, A.; Molling, C.; Heidinger, A. (2014). "Physics-Based GOES Satellite Product for Use in NREL's National Solar Radiation Database: Preprint." 9 pp.; NREL/CP-5D00-62237.

[6] System Advisor Model, SAM 2014.1.14: General Description, National Renewable Energy Laboratory, Technical Report No. NREL/TP-6A20-61019.

[7] PVWatts Version 5 Manual, National Renewable Energy Laboratory, September 4, 2014.

[8] Land-Use Requirements for Solar Power Plants in the United States, National Renewable Energy Laboratory, Technical Report No. NREL/TP-6A20-56290, June 2013.

[9] Lopez, Anthony, et al. US renewable energy technical potentials: A GIS-based analysis. National Renewable Energy Laboratory, Technical Report No. NREL/TP-6A20-51946, 2012.

G. Energy Storage Systems

Energy storage—be it Battery Energy Storage Systems (BESS) or Distributed Energy Storage Systems (DESS)—play in integral role in our renewable energy future.

ENERGY STORAGE TECHNOLOGIES

Various sizes of energy storage systems are commercially available ranging from one to two kilowatts of output to hundreds of megawatts, and in output durations of as much as six hours or longer.

For our analyses in developing the 2016 updated PSIPs, we considered a number of commercially-available energy storage technologies: flywheels and pumped storage hydroelectric (PSH); and lithium-ion battery energy storage systems (BESS) and distributed energy storage systems (DESS). We also evaluated hydrogen energy storage, as it is a promising technology.

Flywheels

Flywheels are rotating mechanical devices that store energy in the angular momentum of its rotating mass. A flywheel consists of a rotor (its rotating mass) attached to a motor (mounted on a very low friction bearing) and generator that spins at high speeds. To maintain the angular momentum of its rotating mass, a flywheel's motor acts like load and draws power from the grid, which enables the flywheel to absorb energy.

Flywheels can provide inertia to a power system. During a grid event (such as a sudden loss of load), the inertia from the flywheel's motor drives its generator, creating replacement electricity that is injected back into the grid. Flywheels can thus help avoid a system contingency. On an island power grid, a contingency can result in significant frequency decay extremely quickly, faster than spinning reserve can respond. Flywheels can provide the inertial response necessary to slow the rate of frequency decay, giving spinning reserve enough time to respond.

Flywheels can provide fast-response, short-term "ride-through" capability that allows seamless transfer of load from the grid to a longer-term backup system (such as an emergency generator). Besides providing inertial response, flywheels can be designed to provide energy for fast frequency response.

Flywheels have a minimum and maximum speed. The flywheel's actual speed indicates its "state of charge". The minimum speed represents a fully discharged state; the maximum speed represents a fully charged state.

While flywheels are expensive (high capital costs), they can charge and discharge hundreds of thousands of times over their useful life. Flywheel energy storage can be developed in two years or less (omitting regulatory approval lead-times). The round trip efficiency of a flywheel storage system is approximately 85%. Flywheels have very little environmental impact. Modern metallurgy has produced flywheel technologies that are safe during operation. Flywheels can also be placed underground for additional safety.

The more than 400 flywheels currently placed in utility-scale situations have been operating for more than seven million hours.[1]

Beacon Power is the major flywheel manufacturer providing commercial utility-scale systems operating in the United States. Other flywheel manufacturers (such as Amber Kinetics) are working towards bringing their systems to market.

The rotor of a Beacon Power Smart Energy 25 flywheel spins between 8,000 rpm and 16,000 rpm. At 16,000 rpm, a single flywheel can deliver 30 kWh of extractable energy at a power level up to 265 kW for five minutes or as low as 170 kW for ten minutes (Figure G-1).

[1] http://beaconpower.com/operating-plants/.

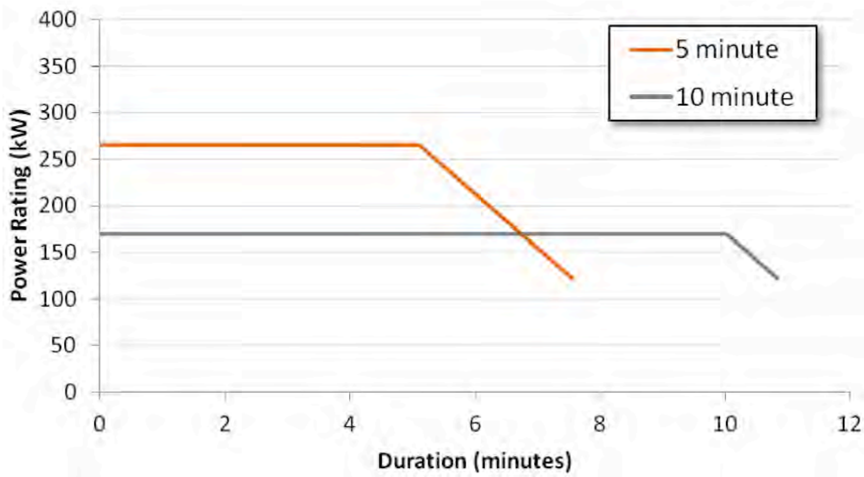


Figure G-1. Flywheel Extractable Energy Rates and Duration

The cyclic life capability of energy storage-based systems is of critical importance for performing frequency regulation. Beacon's flywheel is designed for a minimum 20-year life, with virtually no maintenance required for the mechanical portion of the flywheel system over its lifetime.

Beacon's experience to date in ISO New England involves 6,000 or more effective full charge and discharge cycles per year. The flywheel system is capable of over 175,000 full charge and discharge cycles at a constant full power charge and discharge rate, with no degradation in energy storage capacity over time.

A flywheel's mechanical efficiency for frequency response is over 97 percent; total system round-trip charge and discharge efficiency is 85 percent. Figure G-2 depicts a flywheel's superior capacity when compared with a lithium-ion battery.

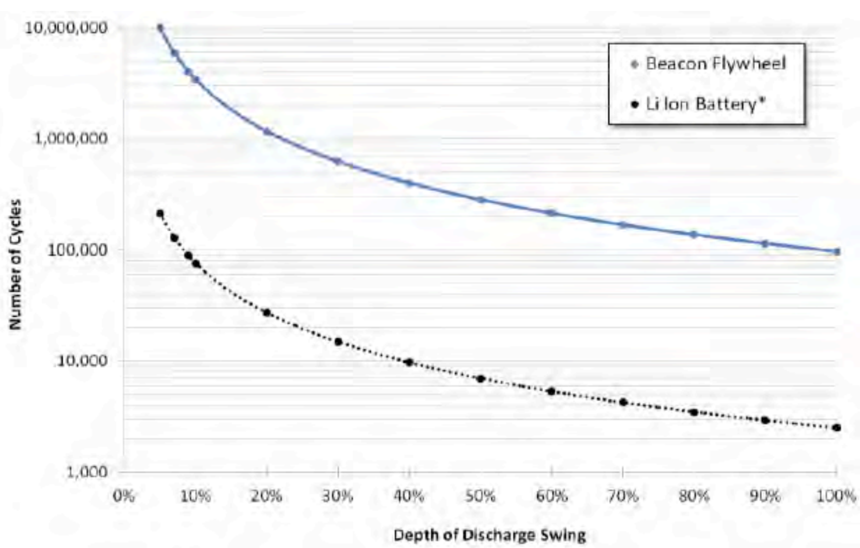


Figure G-2. Flywheel Cycle Life versus Lithium-Ion Battery

Pumped Storage Hydroelectricity (PSH)

Pumped storage hydroelectric (PSH) energy storage is a mature technology that has been successfully implemented around the world in grid applications.

PSH stores energy as gravitational potential energy of water, pumped from a lower elevation reservoir to a higher elevation reservoir. When demand is low or renewable energy production is high, a reversible turbine-generator pumps water from the lower reservoir to the higher one. When energy is needed for the grid, water is released down into the lower reservoir through the turbine-generator, generating electricity. The distance between these two reservoirs—be they natural bodies of water or artificial reservoirs—must be high enough to generate power.

While PSH has a relatively high capital cost, its useful life is 50 years or more. Pumped storage is very efficient, with round trip efficiencies approaching 80%. Figure G-3 shows the typical layout of a PSH project.

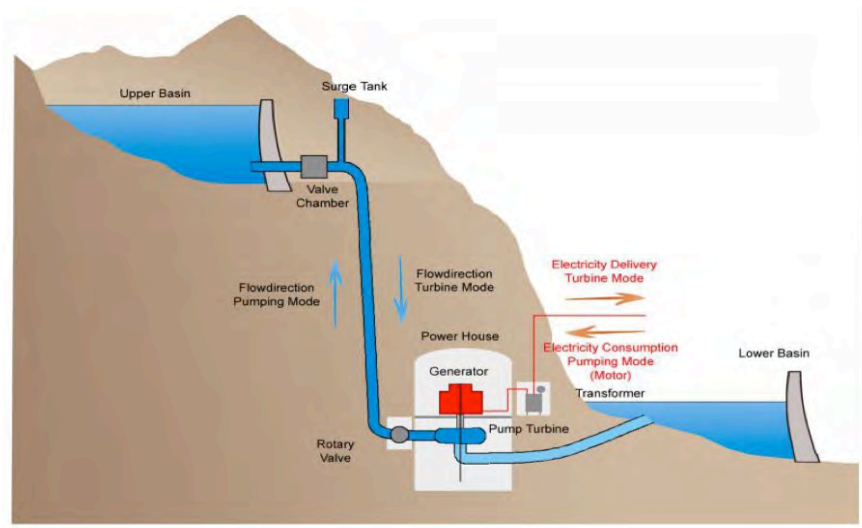


Figure G-3. Typical Pumped Storage Plant Arrangement[2]

PSH can provide peaking capacity and load shifting capabilities. While considered a quick-start resource, PSH takes a brief amount of time (about seven seconds) to start moving the water or to change direction through the turbine to produce electricity (its water column constant). These brief delays are limiting factors for single penstock systems.

[2] Source: Alstom Power.

An adjustable speed pump turbine provides more precise control, thus providing operating flexibility, which in turn allows PSH to provide ancillary services (such as frequency regulation, spinning reserve, and load following) while generating and pumping. This can increase operating efficiencies, improve dynamic behavior, and lower operating costs.

Unlike a battery (which already has charge) or a flywheel (that has angular momentum), starting a PSH charging cycle requires high levels of electric current to start the motors necessary to pump water to the higher elevation. To put this in perspective, a 30 MW PSH system on the Hawai'i Electric Light grid would require starting 37.5 MW of motor load (assuming an 80% round trip efficiency). Because the typical daily peak demand is about 150 MW, starting the PSH motor represents an instantaneous 25% increase in load. This could cause currents to exceed the short circuit limits of the transmission system, which, without mitigation, would result in a significant frequency disturbance.

Pumped storage is the most widely used form of storage for large electrical grids. More than 120,000 MW of PSH has been installed around the world,[3] most of which exceed 1,000 MW per installation.[4] PSH installations are very site dependent, relatively expensive, and have long lead times for permitting and construction. According to the U.S. Department of Energy:

> Pumped storage is a long-proven storage technology, however, the facilities are very expensive to build, may have controversial environmental impacts, have extensive permitting procedures, and require sites with specific topologic and/or geologic characteristics. As estimated in a report commissioned by EIA, the overnight cost to construct a pumped hydroelectric plant is about $5,600/kW…[5]

Over the years, a number of PSH projects have been studied and proposed in Hawai'i. Table G-1 through Table G-4 show the results of numerous PSH studies in our service areas. These studies shows a wide distribution of the per unit capital cost data, reflecting the site specific nature of PSH.

---

[3] "Packing Some Power," The *Economist.* May 3, 2012, http://www.economist.com/node/21548495?frsc=dg%7Ca (citing EPRI as their source).

[4] https://en.wikipedia.org/wiki/List_of_pumped-storage_hydroelectric_power_stations. (This list is not complete. We are aware of projects not included in this list, and some smaller than the ones listed by this source).

[5] http://www.eia.gov/todayinenergy/detail.cfm?id=6910.

O‘ahu

Table G-1 summarizes the historical PSH projects studied on O‘ahu. All costs are nominal dollars.

Site Designation	Study Year	Size (MW)	Hours of Storage	Estimated Capital Cost ($M)	Estimated Capital Cost per kW
Kapa‘a Quarry	No data	No data	No data	No data	No data
Ku Tree Reservoir	No data	No data	No data	No data	No data
Nu‘uanu Reservoir	No data	No data	No data	No data	No data
Koko Crater	1994	160.0	7.5	$161	$1,006
Ka‘au Crater	1994	250.0	8.0	$256	$1,024
Kunia	2004	150.0	8.0	$189	$1,260
Mokuleia	2007	50.0	12.0	$197	$3,940
Hawaiian Cement	2008	7.0–74.0	8.0	No data	No data
Palehua	2014	200.0	6.0	$650	$3,250

Table G-1. Historical Studies of Pumped Storage Hydroelectric Projects on O‘ahu

Hawai‘i Island

Table G-2 summarizes the historical PSH projects studied on Hawai‘i Island. All costs are nominal dollars.

Site Designation	Study Year	Size (MW)	Hours of Storage	Estimated Capital Cost ($M)	Estimated Capital Cost per kW
Pu‘u Wa‘awa‘a	1995	30.0	6.0	$71	$2.367
Pu‘u Anahulu	1995	30.0	6.0	$71	$2,367
Pu‘u Enuhe	1995	30.0	6.0	$61	$2,033
Hawi	2004	10.0	5.0	$39	$3,900
Waimea	2004	2.3	12.0	$17	$7,391
Kaupulehu / Kukio	2006	50.0	5.0	$239	$4,780
Mauna Kea 15a	2016	56.4	5.0	$228	$4,046
Mauna Kea 5	2016	22.9	5.0	$105	$4,583
Mauna Kea 15a + 8c	2016	97.0	5.0	$422	$4,352
Kohala 12	2016	18.1	5.0	$89	$5,426
Kohala 8	2016	39.6	5.0	$239	$6,036

Table G-2. Historical Studies of Pumped Storage Hydroelectric Projects on Hawai‘i Island

Maui

Table G-3 summarizes the historical PSH projects studied on Maui. All costs are nominal dollars.

Site Designation	Study Year	Size (MW)	Hours of Storage	Estimated Capital Cost ($M)	Estimated Capital Cost per kW
Ma'alaea	1995	30.0	6.0	$83	$2,767
Honokowai	1995	30.0	6.0	$77	$2,567
Kahoma	1995	30.0	6.0	$104	$3,467
Pu'u Makua	2006	50.0	12.0	$169	$3,380
Lahaina West	2007	14.7	5.0	$62	$4,218
Lahaina West	2007	6.9	3.6	$39	$5,652
Makawao	2007	31.2	5.0	$220	$7,051
Kihei	2008	50.0	9.0	$315	$6,300

Table G-3. Historical Studies of Pumped Storage Hydroelectric Projects on Maui

Moloka'i

Table G-4 summarizes the historical PSH projects studied on Moloka'i. All costs are nominal dollars.

Site Designation	Study Year	Size (MW)	Hours of Storage	Estimated Capital Cost ($M)	Estimated Capital Cost per kW
East Moloka'i # 1	2007	3.0	5.0	$15	$5,000
East Moloka'i # 2	2007	1.0	5.0	$7	$7,000
West Moloka'i	2007	8.6	5.0	$57	$6,628

Table G-4. Historical Studies of Pumped Storage Hydroelectric Projects on Moloka'i

The vast majority of these studies are for PSH project less than 100 MW. Because the typical PSH installation in the United States is about 1,000 MW, there is limited data on the capital cost and performance for 100 MW PSH projects. Our research uncovered only a few instances of proposed (not constructed) comparably-sized PSH projects.

Based on limited data, we are using a capital cost estimate of $3,500 per kW in 2016 dollars for a 30–50 MW utility-scale PSH project, evaluating it against other storage options. This is optimistic; the average capital cost of all past studies itemized in the above tables is $4,050 per kW (not adjusted for inflation). The forecasted trend for PSH capital cost is flat in real terms, reflecting a mature technology.[6] These uncertain costs are in addition to the substantial permitting challenges any PSH project would face in Hawai'i.

[6] *E-storage: Shifting From Cost to Value Wind and Solar Applications.* World Energy Council. 2016. Table 6a: "Assumptions underpinning development of specific cumulated investment costs to 2030".

We will consider solicitations for PSH projects from experienced developers who can manage project risks, meet our specific power grid needs, and provide customer benefits that exceed those of other storage technology providers.

Lithium-Ion Energy Storage Systems

Lithium-ion refers to a wide range of chemistries all involving the transfer of lithium-ions between electrodes during charge and discharge cycles of the battery.[7] Lithium-ion batteries are very flexible storage devices with high energy density, a fast charge rate, a fast discharge rate, and a low self-discharge rate, making lithium-ion batteries ideal for grid applications.[8]

Lithium-ion energy storage technologies have rapidly advanced to the point that they are commercially available for utility-scale and distributed energy applications. These advances have been led by the development of advanced lithium-ion batteries for use in consumer electronics and automotive applications. According to a recent report from the Electric Power Research Institute (EPRI), battery energy storage "…is emerging as a potential technology solution for the utility industry because of a confluence of industry drivers related to both energy storage technology advancement as well as transformations in the electric power enterprise."[9]

The EPRI report identifies several trends within the energy storage industry:

- Technological advances in energy storage with active cycling capabilities, combined with longer useful asset lives.
- Declining costs and performance improvements in lithium-ion battery technologies.
- A pipeline of innovative research and development related to more advanced storage technologies, which could lead to lower costs and longer durations of energy storage.

Capital costs for lithium-ion batteries are declining,[10] particularly as the use of lithium-ion for electric vehicle batteries rises. Even with their current commercial status, the expectations are for lithium-ion battery performance to improve, and for costs to continue to drop.

---

7 Energy Storage Association. http://energystorage.org/energy-storage/technologies/lithium-ion-li-ion-batteries.

8 *Lithium Ion Technical Handbook*. Gold Peak Industries (Taiwan), Ltd. http://web.archive.org/web/20071007175038/http://www.gpbatteries.com/html/pdf/Li-ion_handbook.pdf.

9 Electric Power Research Institute Inc. *Energy Storage Valuation Analysis: 2015: Objectives, Methodologies, Summary Results, and Research Directions*, Technical Update 3002006068, January 2016.

10 See for example: http://rameznaam.com/2013/09/25/energy-storage-gets-exponentially-cheaper-too/.

Utility-scale lithium-ion batteries installations can be easily scaled in size; have relatively short lead times for procurement, engineering, and installation; and have ultimate flexibility for permitting and siting them at available real estate or existing utility plant sites. Lithium-ion energy storage systems can be configured for a number of different applications at various voltage levels. This flexibility makes lithium-ion energy storage systems an excellent candidate for providing non-transmission alternatives in constrained areas.

Lithium-ion batteries themselves have a useful life through 4,000 to 5,000 normal charge-discharge cycles. More frequent use of the full charge-discharge capabilities of lithium-ion would shorten the life. Lithium-ion battery energy storage can be developed in two years or less, not counting regulatory approval lead-times. The typical efficiency of lithium-ion batteries is 80%–90%, depending on the application.

The use of lithium-ion batteries is largely being driven today by automotive and consumer electronic applications. Disposal of these kinds of lithium-ion batteries presents a challenge. A great deal of effort is being put into developing proper disposal and recycling methods for lithium-ion batteries.[11] Lithium-ion batteries, however, do not contain metallic lithium, nor do they contain lead, cadmium, or mercury. At the end of their useful life, lithium-ion batteries can be dismantled and the parts reused.[12]

In its comments filed on January 15, 2016 in Docket 2014-0183, Paniolo Power states: "…while larger battery systems are starting to be built, batteries used for long duration, utility-scale applications must still be considered in the development phase… Battery technologies for long duration storage should be considered still under development as they are simultaneously attempting to improve the chemical compositions, storage capacity, operating life, disposal issues, and costs of batteries."[13] Based on current conditions, however, we find that Paniolo Power's characterization of long duration BESS to be off the mark. Lithium-ion battery technology has made substantial advances in cost and performance. Several vendors have reached a level of maturity and capitalization that they can offer performance guarantees on utility-scale lithium-ion battery systems. Kauai Island Utility Cooperative (KIUC) has contracted to purchase power from a solar PV project that incorporates a four-hour lithium-ion energy storage system. We find this indicative of the maturity of lithium-ion as a long-duration energy storage option.

11 See for example: http://energy.gov/sites/prod/files/2015/06/f23/es229_gaines_2015_o.pdf.

12 See for example: http://auto.howstuffworks.com/fuel-efficiency/vehicles/how-green-are-automotive-lithium-ion-batteries.htm.

13 Docket 2014-0183, Comments of Paniolo Power, January 15, 2016, pp 23–24.

Distributed Energy Storage Systems (DESS)

A distributed energy storage system (DESS) is essentially a lithium-ion battery located on a customer's property that helps control DG-PV generation. High penetrations of DG-PV create many challenges: uncertain amounts and low reliability of generation, inadequate dispatching or scheduling control, and safety concerns with energy feedback. Optimally located DESS batteries can mitigate many of the challenges. DESS can also provide backup power, voltage correction, and demand response.

Long-term benefits include improved system control and reliability of essentially uncontrolled DG-PV, and improved system reliability. DESS can also help reduce peak loads, help regulate voltage and frequency, and allow more time for service restoration during scheduled or accidental power interruptions.

DESS typically last for 15 years or more, are capable of over 3,000 charge-discharge cycles, have a round trip efficiency greater than 95%, and generally cost between 15¢–25¢ per kWh.

Hydrogen Energy Storage

According to NREL: "… hydrogen can play an important role in transforming our energy future if hydrogen storage technologies are improved."[14]

Hydrogen is a versatile energy storage carrier, with high energy density, that holds significant promise for stationary, portable, and transport applications. Hydrogen could be used to "de-carbonize" applications that rely on natural gas. In electricity applications, hydrogen can be produced through electrolysis with "excess" variable renewable energy (for example, energy available for production by wind and solar resources at times when the net system demand for electricity is low). Hydrogen can be stored under pressure in storage vessels or underground caverns. The stored hydrogen is then used in fuel cells or to produce electricity, thus providing a means of load shifting in grids with high penetrations of variable renewable resources.[15]

While Europe has a relatively robust commercial supply chain for hydrogen production and storage for industrial uses,[16] hydrogen storage technology for electricity is still in the research and development phase. In the United States, demonstration projects have been constructed that integrate wind turbines and solar PV with electrolyzer systems to

[14] http://www.nrel.gov/hydrogen/proj_storage.html.

[15] *Program on Technology Innovation: Hydrogen Energy Systems Development in Europe*, Technical Update 3002007274. Electric Power Research Institute, January 2016.

[16] *Ibid.*

produce hydrogen. A significant challenge towards commercialization is the ability to scale the hydrogen systems to larger sizes.[17]

We believe that hydrogen energy storage systems hold great promise. The availability of commercial hydrogen energy storage systems, however, is limited at this time. We will continue to monitor developments in this technology, and as appropriate, include hydrogen energy storage in future power supply plan updates.

ENERGY STORAGE APPLICATIONS

For these updated PSIPs, we developed detailed assumptions for several applications, using several technologies. These applications included:

Inertia: provides ride-through of momentary system disruptions to avoid a system contingency.

Contingency: instantaneously (less than seven cycles, for faster for Lana‘i and Moloka‘i) provides inertial response, slowing the change in frequency, and provides fast frequency response and energy following the loss of generation contingencies.

Regulation: provides frequency response and frequency regulation under automatic generation control (AGC).

Variable renewable smoothing: responds to changes in a variable resources output when coupled with that variable resource or group of resources. Thus, the net impact of the storage and variable resource is smoothed and has less impact on system frequency. This reduces the need for primary frequency response and regulation reserves from other system resources.

Load Shifting: stores energy for use at a later time to serve demand. As an alternative to installing new equipment or modifying circuits, the storage may be installed so the energy can be used to reduce circuit or transmission constraints in lieu of providing non-transmission alternatives.

[17] http://www.renewableenergyworld.com/articles/2014/07/hydrogen-energy-storage-a-new-solution-to-the-renewable-energy-intermittency-problem.html.

Table G-5 summaries the applications, uses, duty cycles, technologies, and sizes of energy storage systems.

Application	Duration	Storage Duty Cycles	Depth of Discharge	Energy Storage	Sizes Available to Planners (MW)
Inertia	Seconds	5,000 per year	Deep: up to100%	Flywheels	10
Contingency	Up to 30 minutes	~10 per year	Deep: up to100%	Lithium-Ion BESS	1, 5, 10, 20, 50, 100
Regulation	Up to 30 minutes	~15,000 per year	Shallow: 20% to 50%	Lithium-Ion BESS	1, 5, 10, 20, 50, 100
				PSH	30, 50
Load Shifting	1–8 hours	Daily	Deep: up to100%	Lithium-Ion BESS	1, 5, 10, 20, 50, 100; 2 for grid support
				PSH	30, 50
				CSP with Storage	100

Table G-5. Updated PSIP Energy Storage Applications, Sizes, Technologies

In practice, a single energy storage installation can be used for more than its primary purpose. For instance, a load shifting battery can also provide regulation service if required. A contingency battery could, in theory, provide some load shifting. A 20 MW, 30-minute hour battery (that is, 10 MWh) could provide 10 hours of load shifting storage if the output of the battery system is limited to 1 MW (1 MW x 10 hours = 10 MWh). The key is to closely manage the battery's charge and discharge cycling to maintain its useful life based on its designed application.

While being able to provide grid services other than load shifting (such as regulation reserve), the cost of PSH solely to provide these other grid services would not be justified.

Cost Assumptions Related to Energy Storage

Figure G-4 depicts the underlying constant 2016 dollar assumptions for the capital costs associated with selected sizes, technologies, and applications for energy storage systems assumed in the 2016 updated PSIP. (Refer to Appendix J: Modeling Assumptions Data for the specific capital cost assumptions for energy storage resources.)

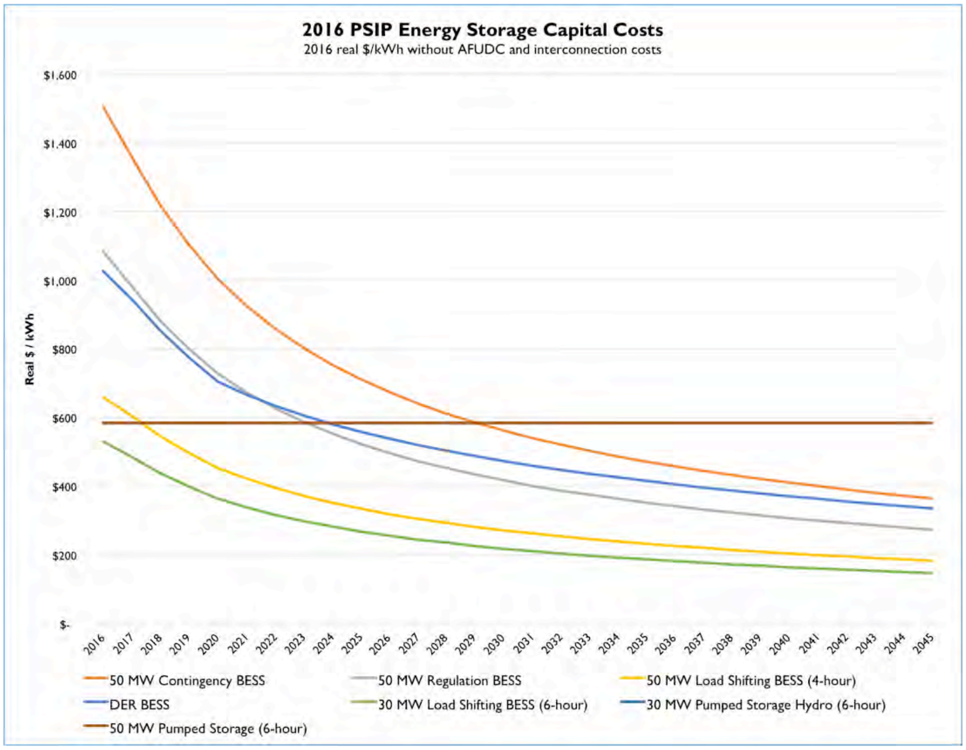


Figure G-4. 2016 Updated PSIP Energy Storage Capital Costs

The method for determining the capital and operating costs assumptions for energy storage systems was largely the same as for new utility-scale generating facilities. The primary source of data for current prices and forward curves was IHS Energy consultants. Prices were adjusted for Hawai‘i using RSMeans city indices. Prices were adjusted upwards by 4% to account for Hawai‘i general excise taxes.

Adjustments to BESS prices and costs were made based on the different applications. The application affects the “duty cycle” of the BESS, which in turn drives certain design parameters including the spacing of cells to better dissipate heat (longer duration storages requires more spacing, resulting in larger footprints) and air conditioning requirements. More frequent and deeper discharge of BESS requires replacement of battery cells more often in order to maintain output.[18]

5-5-5 Battery Initiative

Advances in battery storage technologies have drawn significant attention, such as the 5-5-5 battery initiative.

[18] Some vendors oversize the battery from the start, so that as the batteries degrade over time and the project’s output declines to the customer’s specified output requirements. Others provide warranty wraps where they replace cells as they degrade so that the desire output is maintained.

In 2013, the United States Department of Energy awarded the Joint Center for Energy Storage Research (JCESR), led by Argonne National Laboratory, with a $120 million grant to address "the scientific and engineering research needed to advance the next generation of electrochemical energy storage for both transportation and the grid."[19]

In a written statement before the Subcommittee on Energy Committee on Science, Space, and Technology of the United States House of Representatives, Director George Crabtree explained the vision and mission of JCESR through this grant:

> JCESR's vision addresses the two largest energy sectors in the U.S.: transportation and the electricity grid, which together account for two-thirds of our energy use. Our vision is aggressively transformative: to enable widespread penetration of electric vehicles that replace foreign oil with domestic electricity, reduce carbon emissions, and lower energy use; and to modernize the electricity grid by breaking the century-old constraint of matching instantaneous demand with instantaneous generation, enabling widespread deployment of clean and sustainable but variable wind and solar electricity while increasing reliability, flexibility and resilience. Both transformations can be achieved with a single disruptive breakthrough: high-performance, low-cost electricity storage, beyond today's commercial lithium-ion technology. JCESR's vision is to transform transportation and the grid with the next generation beyond lithium-ion electricity storage.
>
> JCESR's mission goals are to provide two prototypes, one for transportation and one for the grid, which, when scaled to manufacturing, are capable of providing five times the energy density at one-fifth the cost of commercial batteries in January 2012 when our proposal was prepared, summarized by the shorthand expression "5-5-5".[20]

JCESR implemented and continuously refines a new paradigm for battery research and development that integrated discovery science, battery design, research prototyping, and manufacturing collaboration in a single, highly interactive organization. JCESR expects this new paradigm to accelerate the pace of discovery and innovation and shorten the time from conceptualization to commercialization.

At the date of this statement, JCESR research has resulted in 26 invention disclosures with a dozen patent applications, and has selected and begun to converge four next-generation prototype concepts. In addition, JCESR is testing several candidate materials and batteries in half-cell and full cell prototypes.

[19] *Grid Energy Storage*, published by the U.S. Department of Energy, December 2013. p 42.

[20] Written Statement of George Crabtree, Director, Joint Center for Energy Storage Research (JCESR), Argonne National Laboratory, University of Illinois at Chicago. Before the Subcommittee on Energy Committee on Science, Space, and Technology United States House of Representatives; Hearing on: Department of Energy (DOE) Innovation Hubs, June 17, 2015. pp 1–2.

H. Analytical Models and Methods

We are employing a number of analytical models to develop our 2016 updated PSIPs. Our System Planning team, our Transmission and Distribution Planning team, and several consultants process numerous individual and overlapping model runs using these tools. Together, we are performing a thorough, exhaustive analysis to develop a series of alternative plans. Then, from those plans, we are developing Preferred Plans for each operating utility to provide reasonable cost, reliable energy to our customers while reaching our 100% RPS goal.

These modeling tools and the team running the tool include:

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

SIEMENS PTI PSSE FOR SYSTEM SECURITY ANALYSIS

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

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

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

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

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

P-MONTH MODELING ANALYSIS METHODS

Our System Planning Department uses the P-Month hourly production simulation model to perform analyses for developing alternative plans for the 2016 updated PSIPs.

The P-Month modeling tool includes these characteristics:

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

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

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

We use computer models for the 2016 updated PSIP analyses. Production costs of the operating the system is simulated using the P-Month hourly production simulation model. The model is populated with unit data to characterize the resources operating on the system at all hours so that the performance and cost of the system can be evaluated for various future cases. The data from the hourly production simulation model is processed using other internally developed tools to evaluate the results of the simulations.

P-Month Hourly Production Simulation Model

Thermal Generation Modeling

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

Variable Generation Modeling

The model for energy produced by renewable resources and other variables uses a 8,760 hourly profile (365 days at 24 hours a day). This profile is constructed based on historical observed output from in service variable generation or from solar irradiance profiles and measured wind potential for future variable generation. Generation that is produced according to this hourly profile that cannot be accommodated on the system, in any one hour is curtailed per the established curtailment order for resources modeled as controllable. The curtailment order follows a last in, first out rule whereby the last installed variable renewable resource is curtailed first, that is, reverse chronological order for resources designated as being able to be controlled.

Unit Forced Outage Modeling

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

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

Using the Monte Carlo, or deterministic, technique, forced outages for generating units are treated as random, discrete outages in one week increments. The model randomly takes a generating unit out of service (during periods when it is available) up to a total forced outage time of 5%. By this methodology, the unit can operate at normal top load for 95% of the time when it is not on overhaul but is not able to operate (that is, has a zero output) for 5% of the time when it is not on overhaul. For the 2016 updated PSIPs, the modeling uses the Monte Carlo methodology to capture the forced outages of all thermal units.

Demand Response Modeling

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

Energy Storage Modeling

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

System Security Requirements

The system security requirements are included through regulating and contingency reserve requirements. The requirements are met using contribution of services from demand response, energy storage, and thermal generation in the modeling. The system security requirements depend on the levels of PV and wind on the system. The regulating reserve requirements were changed hourly in the model to reflect the dynamic changes in levels of PV and wind throughout the day. Curtailed energy from controllable

PV and future wind resources contributed to meeting the regulating reserve requirement. The contingency reserve requirements for O‘ahu were changed annually to reflect the largest unit contingency on the system.

Sub-Hourly Model

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

Key Model Inputs

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

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

Methodology for Post-Processing of Production Simulation Results

Key Outputs

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

- Generation produced by each firm generation unit
- Generation accepted into the system by non-firm generating units
- Excess energy not accepted into the system (curtailed energy)
- Fuel consumption and fuel costs

- Variable and fixed O&M costs
- Start-up costs

Post-Processing

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

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

All costs are post-processed into annual and total dollars to be used in the financial model. All annual, total, and present value (2016 dollar) revenue requirements are also post-processed for use in evaluating the different plans but are not meant to be the "all-in costs" that the financial model considers. Revenue requirements are characterized as utility and IPP. Utility revenue requirements are categorized into fuel, fixed O&M, variable O&M, and capital. IPP revenue requirements are categorized into capacity and energy payments. Using the revenue requirements from post-processing, plans can be analyzed according to several key metrics.

Key Metrics

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

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

Lana‘i & Moloka‘i Modeling

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

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

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

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

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

ADAPTIVE PLANNING FOR PRODUCTION SIMULATION

Black & Veatch is applying its Adaptive Planning (AP) for Production Simulation to support the 2016 updated PSIP analysis. AP for Production Simulation provides a framework for modeling complex systems, exploring options (impacts of constraints), and comparing such options across varying metrics. Key metrics or outcomes associated with this analysis include costs, degree of renewable penetration (both capacity and energy served), utilization of demand response and distributed energy resources, avoided costs associated with demand response, and metrics associated with generation-related grid security.

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

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

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

Black & Veatch possesses deep domain expertise in the technologies deployed—from design, operations, and reliability perspectives—as well as deep domain expertise in complex simulation. This combination provides critical thinking and credibility needed in addressing very complex and costly investment decisions across PSIP areas of interest.

Given the desire and need for massive transformation, the underlying model must be very technically robust to assure that all transformative steps are both rational and fully understood. Key aspects that can be specifically addressed include technology selection and implementation, plant refurbish and upgrades, retirements, DER build out, and participation and structure of DR programs.

Black & Veatch capabilities and reputation are critical for both credibility of the process and model as well as credibility of the results, given that the interactions between conventional power production, renewable resources, storage, and customers are very complex, and given that Hawaiʻi is clearly on the cutting edge of such strategy development. Black & Veatch possesses the ability to leverage proven analytics framework within the context of the 2016 updated PSIPs, to provide high-level of modeling expertise to build and refine PSIP cases, and the ability to help define and manage complex processes needed to align asset portfolio, security requirements, DER uptake assumptions, and DR portfolio implementation and utilization. These capabilities are complementary to the larger PSIP team and are foundational to PSIP team's ability to deliver critical thinking and key results.

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

Configuration Methodology

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

Thermal Generation

Firm thermal generation resources are modeled as having the ability to meet demand, up and down regulation, contingency, and frequency response (modeled as system inertia requirements based on system state). Assets are committed based on the combined minimum load operating, minimum load fuel, startup time, and associated startup costs.

These assets are dispatched by AP for Production Simulation's optimizer to achieve the lowest possible fuel and variable operating costs based on a given set of constraints.

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

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

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

Variable Generation

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

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

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

Central Energy Storage

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

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

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

Distributed Energy Resources

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

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

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

Demand Response

Demand response can be evaluated in two ways.

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

- Hourly load modification projections by product.
- Hourly ancillary services projections.

- Program fixed and incentive costs.

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

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

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

System Security

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

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

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

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

Time Slice Model within AP for Production Simulation

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

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

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

- Status (available, scheduled outage, forced outage, retired).

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

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

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

Commitment and Dispatch Methodology

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

When determining commitment (units that are online), the model endeavors to meet both demand (incorporating load-shift demand response) and grid security requirements. It starts up or shuts down generating resources as needed to meet these requirements. It prioritizes the resources online to include units required to support system security, to meet goals such as maximizing renewable resource use, and to meet the requirements of power purchase agreements. The load shifting battery charge and discharge cycle is optimized for each day based on load net of wind and solar generation and DR load shift.

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

Demand Response Methodology

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

When combining the potential of individual DR products into a portfolio, it must be recognized that each end-use device is limited in its ability to provide multiple services at a time. Typically, an end device can provide one load building and one load reduction service simultaneously. For example, a water heater participating in a pricing program that builds load during midday to take advantage of solar generation can at the same time provide FFR—a reduction in load in response to a sudden loss of a generating asset. It cannot provide FFR during evening hours when the water heater is reducing load under the pricing program, as this would constitute providing two load reducing services simultaneously. Similarly, a water heater cannot simultaneously provide both FFR and regulating reserve because, once turned off to provide one service, there is no potential available to provide the other service. As such, the DR potential for each product must be managed to prevent over allocation of end-use devices.

AP for Production Simulation maps end-use devices to DR products to ensure full range of services are evaluated while ensuring no double allocation of services. These mapping rules are:

1. Pricing Programs (TOU, DALS, and RTP) are mutually exclusive: a single end device can only participate in one Pricing Program.
2. FFR and NSAR[1] cannot be called at the same time for a single end device; however an end device may be called under FFR and then immediately be called to participate in NSAR.
3. An end device cannot provide FFR and NSAR at the same time as RR.

[1] NSAR program is a 10-minute supplemental reserve resource capable of replacing other resources that are used for spinning reserves. When paired with an FFR program, it can also be used to replace a contingency grid battery.

4. End devices participating in pricing programs can provide FFR, NSAR, or RR while building load.

5. End devices participating in pricing programs cannot provide FFR, NSAR, or RR while decreasing load.

The DR end-use allocation is based on the best value derived from the end-use device. Since both the DR potential (air conditioner load is higher in the summer and peaks during midday) and the needs of the generation and transmission system are dynamic by hour, DR potential is allocated for each hour. The allocation is complex as some system constraints are dynamic. For example, the system security requirement that sets the FFR need is based on the unit commitment, which is determined by the allocation of DR end-use devices for regulating reserves and load shifting. Given the finite DR potential, the optimal allocation often requires the layering of the constraints such that all constraints are satisfied and the DR potential is not over allocated.

Order and priority between underlying resources are managed as follows:

1. Pricing products shift load to desirable times and thus support capacity needs.

2. FFR is given next priority for potential. It meets both FFR and can also be used to provide an equivalent to contingency in combination with non-spin auto response (NSAR).

3. NSAR back-stops FFR so that, combined, the two products can provide an equivalent to contingency. Dedicated NSAR can reduce contingency battery size when paired with FFR.

4. Regulating reserve meets up-regulation.

5. Aggregated DR calls are checked against aggregated limits (number of calls per year, length of call) to ensure usage is within limits.

6. Products that meet specific needs other than those listed above, such as PV curtailment and minimum load, were not shown, in prior evaluations, to be cost-effective. Thus, these products are evaluated external to the simulation process to quantify their contribution to the generation system and can be incorporated into the simulation process when cost-effective.

The load shift (described in priority and order 1) is evaluated as an outer loop to the simulation model to optimize between pricing and incentive products. Potential associated with pricing products is allocated in a manner consistent with the anticipated price signal flexibility. Potential associated with products under a tiered rate schedule is allocated approximately as required by the generation system, but is constant for each hour within a tier. Potential associated with pricing products set via a forward-looking, hourly pricing scheme is tailored hour-by-hour and therefore more closely matches the requirement of the generation system. The load shift is MWh neutral on a daily basis; the increase and decrease each day does not change the overall demand associated with that day.

Tradeoffs between pricing products and incentive programs are evaluated for distinct levels of pricing products taken (0%, 50%, 100%). When less than 100% of the pricing product is used for load shift, the remainder of the end product's potential is made available (where there is overlap) for FFR, NSAR, and so on.

Each level of participation is compared for each day; the case with the lowest generation cost defines the percent of pricing product taken for that day.

The pricing products may reduce or postpone new generation as pricing programs shift loads and thereby reduce the annual peak. This reduces the need for new units to meet the reserve margin requirements.

Sub-Hourly Model

Traditional hourly modeling does not expose the operational transients that must be managed during real-time operation of the electric grid. Traditional hourly modeling also does not expose potential value (economic and risk mitigation value, for example) that one set of resources may have over another set of resources, as all transients are softened. Sub-hourly modeling exposes some of this value to support the optimum resource selection that does not violate policy considerations (risk tolerance, renewable goals, budget constraints, fuel diversity)

Similar to an hourly modeling approach, the sub-hourly model calculates both commitment (which units are generating power) and dispatch (MW contributed by each asset to achieve the target demand), but now at a sub-hourly time step. Maximum daily rate of change is greater and ramp rate constraints are hit more often, thereby potentially changing the economic outcome of the simulation as compared to the hourly model.

The sub-hourly model (five-minute time step) performs a constrained optimization for asset dispatch against a sub-hourly desired load. The resources considered include generation (dispatchable and non-dispatchable), demand response, and energy storage. Each asset has two primary states: available or unavailable. Each unavailable state may have sub-states (for example, scheduled versus unscheduled outages). There are also system constraints that must be met. These include:

- Spinning reserve requirements (incorporating energy storage and demand response options).
- Grid stability requirements, either must-run units or verification that adequate inertia is present on the system given system conditions.

- Policy constraints (power quality, reliability targets, risk tolerance).

The sub-hourly model changes the state of each asset to optimize the economics within the bounds of the model constraints. Accounting routines keep track of asset performance ($, MWh, number of starts) and system performance (unserved load, curtailed generation, $, MWh).

This modeling approach is ideally suited to evaluating, comparing, and contrasting differing strategies regarding the mix of fossil generation, utility renewables versus energy storage, distributed generation versus energy storage, and demand response options. Based on the supply options provided, the model determines the low-cost means for meeting the required load within constraints. These constraints can be modified to evaluate other policy considerations (such as greater renewable penetration).

Model Outputs and Visualization Tools

AP for Production Simulation output is generally organized into views of differing granularity according to the following:

- *Periodic Values:* This can be period to period (five-minute, hourly, daily, or annual) and consists of period inputs (assets available, state, demand), production factors (individual asset production or utilization in support of grid services), consumables (fuel, chemicals), and other variable O&M costs.
- *Average Day:* This view aggregates and averages all period values into a single day "view" by year, showing system behavior, unit participation and ramping, and provision of services during peak and off-peak periods.
- *Specific Day:* Similar to Average Day, this view provides the same outputs but for a specific day or range of days, showing the variability of system resources from day-to-day and year-to-year. This view is particularly valuable in understanding the variability in the value of grid services and optimizing DR portfolio.
- *Aggregations by Resource Type:* All views are available either by individual asset, DR program, or aggregated by type of asset. This shows how different asset classes are utilized in matching demand or providing grid services.
- *Comparisons:* Comparison views are applied against two cases to identify differences in outcomes, year-to-year or period-to-period.
- *Avoided Costs:* Avoided cost views are generated by mathematically "subtracting" an underlying base or reference case from the subject case. In particular, grid service values (or value of DR program) are based on mathematically assessing differential system costs against differential resources available to provide the grid services.

DG-PV ADOPTION MODEL

BCG developed the proprietary DG-PV Adoption Model to forecast and optimize the adoption of customer-sited energy resources. The model primarily determines the quantity and total power supply of DG-PV (with and without storage), together with the given retail or export rate when this adoption would occur. BCG has applied this model throughout the United States, Europe, and Australia with high levels of success. The model helps develop perspectives from a customer-centric approach regarding compensation levels, and resulting amounts and timing of customer-sited energy resources.

The model was used to forecast future quantities of grid-supply up to the cap, self-supply quantities, and potential future DG-PV combined with the possibility of the adoption of customer-sited storage. The model was also used to evaluate the potential impact of grid defection.

The DG-PV Adoption Model examines the relationship between customer economics and technology adoption—net present value (NPV), internal rate of return (IRR), and payback time for adopting DG-PV with or without a storage system. The model optimizes the distributed energy resource system configuration to yield the highest NPV given technology costs, appropriate investment tax credits, and retail or time-of-use (TOU) and export rates. The model then applies optimum results to a regression-based relationship of previous DG-PV adoption to determine the number of future installs and the total sum of energy provided. This approach allows for distributed energy values to be optimized and forecasted based on customer logic and economics, then integrated into the system resource mix as an optimized resource. The model can also integrate explicit integration costs to fine-tune the customer adoption levels as necessary.

BCG is a global consultancy with 84 offices across 46 countries of the world with over 50 years of experience in the energy sector. BCG has successfully completed over 3,400 engagements across the energy value chain including over 1,400 engagements involving renewable and distributed energy resources.

BCG has been involved in the PSIP process since 2014 and is intimately familiar with the exceptional complexities surrounding Hawai'i's energy markets. For the 2016 updated PSIPs, BCG performed customer economic and adoption modeling of DG-PV and energy storage systems to determine how to best forecast and optimize these components. This wealth of experience, coupled with local understanding, positions BCG as being uniquely suited to support the Companies craft a solution that optimizes DERs in Hawai'i's energy future.

BCG worked with the Companies as well as Black &Veatch to develop the following assumptions that were used to develop DG-PV forecasts:

- Progression of technology costs for DG-PV technology from 2016–2045.
- Progression of technology costs for customer storage technology from 2016–2045.
- Future value of storage based on the Black & Veatch Adaptive Planning for Production Simulation model.
- Historical relationships for Hawaiʻi, by island, between NPV, IRR, and payback time and levels of customer adoption for DG-PV.
- PV irradiance profiles for each island served.
- Current load and consumption profiles for each rate schedule.
- Current and addressable populations for DG-PV and customer storage.

The model then outputs the:

- Optimum NPV, IRR, and payback period for a given load profile, system configuration, rate schedule, and build year.
- Overall number of installed DG-PV systems and energy capacity through 2045 based on NPV and payback periods.

CUSTOMER ENERGY STORAGE SYSTEM ADOPTION MODEL

BCG's proprietary Customer Energy Storage System Adoption Model forecasts customer installations of storage. The model first calculates economics (including payback time) of customer-sited storage installed in a given year based on the total value of storage that it provides. Based on this payback, the model forecasts the percent of eligible customers that adopt storage systems. Eligible customers are assumed to be those who have yet to install a storage system. The correlation of payback to percent of eligible customers is based on the historical correlation of payback time for a DG-PV system and the percent of eligible customers that adopted DG-PV. Given a similar economic profile, a similar percent of customers adopt a storage system as have adopted historical DG-PV, mainly because the two investments are similar.

The model uses the following as inputs:

- Customer storage technology cost forecasts through 2045, including lithium-ion battery, balance-of-system, installation, and annual O&M costs.
- Customer storage technology performance forecasts through 2045, including energy capacity, power capacity, round-trip efficiency, and equipment life expectancy.
- The value of storage forecasts through 2045 based on Black & Veatch's model, including the value of various grid services that can be fulfilled by storage systems (including day-ahead load shift and time of use, FFR, and regulating reserve), while ensuring no double counting. The value is based on the avoided cost to the electric system for the grid services that the storage systems provide (as calculated by the Adaptive Planning for Production Simulation model).
- Historical payback time of DG-PV.

Using these inputs, the storage system adoption model first calculates customer economics for installing storage systems in a given year, and then forecasts customer adoption of storage systems based on the customer economics. The model then outputs the customer storage system adoption forecasts through 2045 (based on system-optimized compensation at avoided cost).

This modeling tool is suitable to calculate the system-optimal level of standalone storage systems to include in the PSIP planning process for two key reasons:

- It forecasts the amount of cost-effective standalone storage systems that could provide grid services.
- It forecasts customers adopting distributed energy resources by using actual historical correlations between customer payback time and adoption rate.

These forecasts are then used as input to the DR potential forecast and DR avoided cost modeling, which in turn generates DR amounts and load shapes that are included in overall system planning.

POWERSIMM PLANNER MODELING TOOL

The electric supply system with increasing amounts of variable generation has broad needs for flexible generation to manage increased daily ramps, greater regulation requirements, substantial amounts of energy storage—all of which require closer analysis. Uncertainties also include the physical dynamics of weather-driven renewable generation and load, uncertainty in adoption rate of DER, storage system capabilities and costs, and market prices of fuel and emissions.

Ascend Analytics uses its PowerSimm software to simulate future conditions to capture system operations at a more detailed level necessary to properly plan for a 100% renewable supply portfolio. Ascend's software models at the minute level, and employs stochastic programming to select the most robust resource plan to meet future needs.

Ascend analyzed converting the current generation fleet to firing LNG. Our analysis determines the optimal power supply resource mix. Ascend's PowerSimm software:

- Determines optimal expansion plan with consideration of costs, system reliability and flexibility, resource adequacy, and uncertainty of fuel prices, carbon, and meteorology impacting renewable generation and load.
- Provides a robust evaluation of the economic merits of combined-cycle (CC) units and internal combustion engines (ICEs) versus flexible storage for O'ahu that captures the extrinsic value of each asset to provide flexible energy and ancillary services.
- Determines the change in costs and risks in costs for meeting PSIP portfolio emission constraints without LNG.
- Develops optimal unit retirements with consideration of costs, resource adequacy, and system flexibility needs.
- Develops a detailed economic evaluation of energy storage system relative to alternative supply from either fossil fuel or biomass resources.
- Evaluates the cost effectiveness of energy storage for regulating reserve using sub-hourly modeling.
- Determines the relative value of customer demand response.
- Determines regulation and contingent reserve requirements for each island served as a function of solar and wind.
- Determines the cost tradeoff between renewable curtailment and alternative actions of either cycling thermal generation or utilizing storage.

Ascend Analytics is a leading energy analytics software company that serves as the analytic infrastructure supporting portfolio management and planning decisions for a host of national utilities. Ascend provides analytic solutions that systematically capture and incorporate uncertainty into the decision making process. In addition, Ascend models physical system operations in greater details than other production cost modeling and planning software. In 2014, Ascend supported the nearly $1 billion acquisition of renewable hydro generation in a resource plan for NorthWestern Energy in Montana. The resource plan proceedings were conducted in the Montana Supreme Court Chambers with Ascend testifying and receiving the distinction of modeling "fully consistent with industry best practices" by the independent experts retained by the Commission to review Ascend's modeling.

PowerSimm Planner

Ascend Analytics completed analysis in 2015 that valued for Hawaiian Electric the conversion of its oil based generation fleet to LNG. Through this PowerSimm modeling analysis, Ascend proved the value of a structured framework that models uncertainty in key risk drivers including: weather, load, renewable generation, renewable penetration rates, and market fuel prices and carbon. Ascend plans to leverage these modeling capabilities of uncertainty combined with a more granular physical representation of Hawaiian Electric's power supply system at the minutely level. In addition, Ascend plans to expand upon the detailed modeling of minutely level system operations to determine the optimal power supply resource mix inclusive of uncertainty. The use of minutely dispatch operations also supports evaluation of system capabilities to meet dynamic ramps and maintain system frequency.

Ascend brings the unique capability to model system operations in greater physical detail over a broad spectrum of future operating conditions at a granular level of minutely dispatch. In addition, Ascend's capacity expansion logic integrates the more granular system modeling and uncertainty to pick the most robust supply plan to meet Hawaiian Electric's future needs over a broad spectrum of future simulated meteorological conditions and market prices.

Ascend has found that while deterministic runs with sensitivities provide insight into portfolio management decisions, the limited set of information of deterministic runs compared to probabilistically enveloping future states through Monte Carlo simulations can bias results. Furthermore, simulating future conditions with "meaningful uncertainty" can better articulate dimensions of risks for each of the future supply portfolios.

PowerSimm Planner's capacity expansion module determines optimal future supply portfolios by selecting the best supply portfolio over all simulated future conditions. This is a substantial improvement over other solutions that are limited to picking the best portfolio over a single deterministic run (and often with only load duration curve granularity). By determining the best portfolio over all future states, PowerSimm provides a more robust future supply portfolio.

Description of PowerSimm Planner

PowerSimm Planner provides optimal resource planning analysis that combines detailed system operations, including minutely level dispatch modeling, with simulations of the principal risk factors determining physical and financial uncertainty. PowerSimm Planner directly incorporates risk into to the resource selection process by finding the optimal expansion plan over a broad set of future simulated conditions to jointly minimize costs and risks. The selected optimal resource expansion plans provide distributions of costs where risk can be monetized as a direct cost; thus, enabling uncertainty to be valued in direct comparison of alternative expansion plans.

Underlying the risk based decision analysis framework of PowerSimm Planner are simulations of future conditions that rigorously realize the standard of “meaningful uncertainty”. The realization of physical uncertainty begins with weather and then the resultant load and renewable generation levels. Financial uncertainty extends to commodity prices for fuel following market expectations of future prices uncertainty including episodic high and low price events. Carbon is also simulated based on ranges in forecast expectations of carbon prices.

System operations are measured down to minutely level generation and load with determination of ancillary service components of regulating reserves and contingent reserves as a function of renewable generation levels. The more granular dispatch conditions enable the physical system modeling to reflect actual system operations chronologically through time.

Recognizing the computational burden of the simulations, dispatch, and summary of results, Ascend utilizes a parallel distributed computing system: “The Ascend Cloud”. This bank of computers supports resource planning analysis without compromising the modeling. The model inputs and outputs can be readily accessed through the Ascend Cloud.

PowerSimm Resource Selection

PowerSimm Planner performs optimal capacity expansion planning to determine the least cost and least risk resource options to meet future load. The optimal expansion plan analysis determines the least cost resource mix to meet a target reserve margin to maintain system reliability. Because utility planning involves a trade-off between long-term capital investment decisions and variable operating costs, the optimal expansion plan seeks to minimize the net present value (NPV) of future variable and fixed costs. To account for capital investment decisions not fully amortized over the 30 year planning horizon, the levelized cost for future resource options are used.

The expansion planning problem can be more formally stated as:

Minimize:	Portfolio costs = net PV power cost + fixed PV cost
Subject to:	Resource adequacy requirements
	RPS standards
	Regulation and contingent reserve requirements
	Thermal generation operating characteristics
	Battery storage operating characteristics and life cycles
Where:	Costs = net power costs + fixed costs
	Net power costs = fuel + variable O&M + emissions
	Fixed costs = fixed revenue requirement of portfolio in each year calculated from the financial model

The addition of new generation resources follows from both the requirement to ensure reliable generation supply and the economics of new generation.

While using deterministic runs with sensitivities provides insight into portfolio management decisions, this limited set of information biases results. This bias is not observed when realized through probabilistically enveloping future states through Monte Carlo simulations. Figure H-1 illustrates this effect by taking the expected value of Monte Carlo simulations shown in the solid black line that removes the bias of the orange line by depending on a limited set of future conditions. Furthermore, simulating future conditions with "meaningful uncertainty" better articulates some dimensions of risks for each of the proposed portfolios.

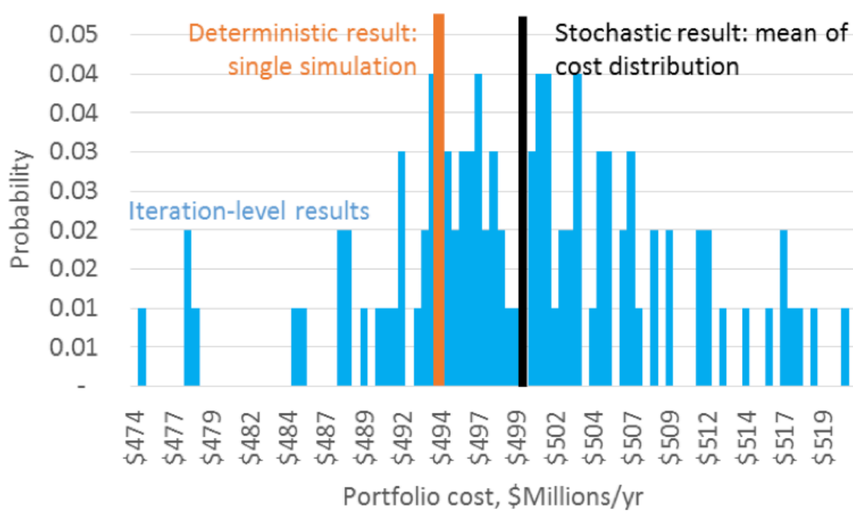


Figure H-1. Deterministic versus Stochastic Simulation Based Results

The use of Monte Carlo simulations can be combined with the Resource Selection module of PowerSimm Planner to systematize the resource selection process. PowerSimm's Resource Selection module automates the resource selection process of determining the optimal future supply portfolios. The methodology provides the best supply portfolio overall based on simulated future conditions. The ability to select the optimal portfolio over a broad spectrum of future conditions without loss of generation modeling details provides substantial advantages over picking the best portfolio from a single deterministic run. The optimization of future supply portfolio utilizes a stochastic dynamic program to minimize the net present value of costs over all simulations subject to a series of constraints, most notably, capacity. By determining the best portfolio overall future states, PowerSimm provides a more robust future supply portfolio.

For purposes of illustration, Ascend draws a sporting analogy for resource selection under uncertainty. Selection of an optimal resource portfolio over the first deterministic run is equivalent to finding the best swimmer (Michael Phelps) and the second run may be akin to the best cyclist (Chris Froom), and the third would be the best runner (Ryan Hall). In resource planning, we're not interested in the best athlete for any individual event, but the best athlete over all three events (Figure H-2). We want the best triathlete, the best resource portfolio over a broad set of future states. The portfolio may not be the best for any individual future run, however, the portfolio performs the best overall future states.

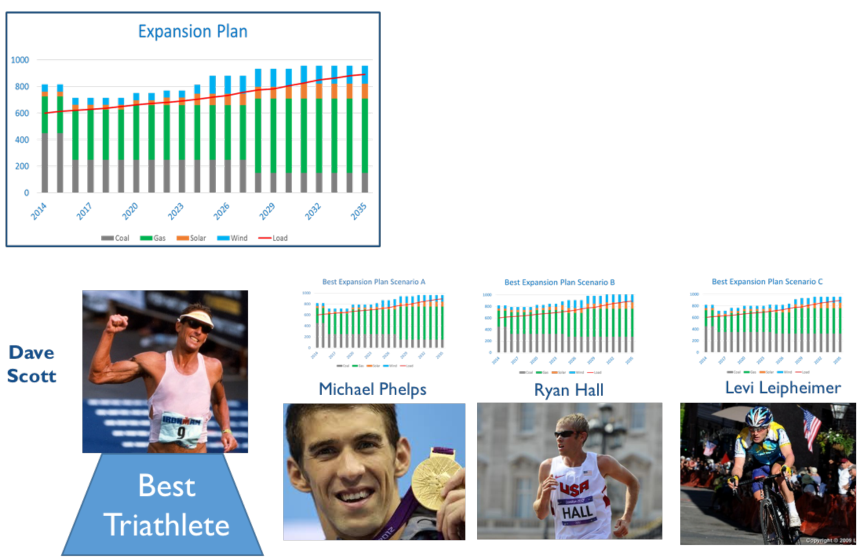


Figure H-2. Triathlete Analogy to Expansion Planning

By incorporating uncertainty into the expansion planning process, this analysis builds upon the concept of risk and simulations that produce "meaningful uncertainty". The challenge of incorporating uncertainty into capacity expansion planning is further met by the need to address the value of resource flexibility. The modeling requirements to account for resource flexibility require hourly simulations and modeling asset start-up and shut down costs and times and generation ramp rates. More flexible resources can quickly and cost effectively cycle—a core asset attribute to support the addition of more renewable generation. The addition of uncertainty and detailed hourly generation characteristics distinguishes the rigor of capacity expansion planning used in this analysis.

Comparison with Traditional Capacity Expansion Models

PowerSimm Planner includes many features unavailable or limited in traditional capacity expansion models for a number of modeling areas.

Physical generation asset operating characteristics (such as heat rate curves, ramp rates, min-up, min-down, and others. Traditional capacity expansion models have no ability to capture asset operating characteristics other than plant capacity. Integrated models dispatch generation consistent with the full set of plant operating constraints. By overlooking the physical constraints of asset operations, these models introduce potential biases and inconsistencies when selecting intermediate and peaking resources by not modeling asset flexibility.

Chronological relationship of load. Traditional capacity expansion models use load duration curves, which removes the hourly and daily pattern of load.

Chronological relationship to market prices. Traditional capacity expansion models use of price duration curves removes the hourly and daily pattern of market prices. Moreover, the structural relationship between system load and market prices are not maintained.

Imports and exports. Both models account for imports and exports, but the inability of traditional capacity expansion models to capture physical asset details introduces resource selection biases and inconsistencies. For example, a peaking unit may be designated as having the ability to provide exports when the start-up and shut-down costs or minimum run-times may make an off-system sale uneconomic.

Ancillary services. Traditional capacity expansion models do not have the ability to model ancillary services.

Simulation Framework

PowerSimm develops realistic simulations of future conditions to probabilistically envelope the expected value and range of potential future cases. Figure H-3 depicts the framework to simulate physical and financial uncertainty. The simulation of future conditions is initiated with before-delivery simulations of forward/forecast prices, which then evolve to the final monthly price expiration. Weather simulations then drive renewable generation and load. Spot prices are simulated as a function of load, renewable generation, and other potential variables of supply.

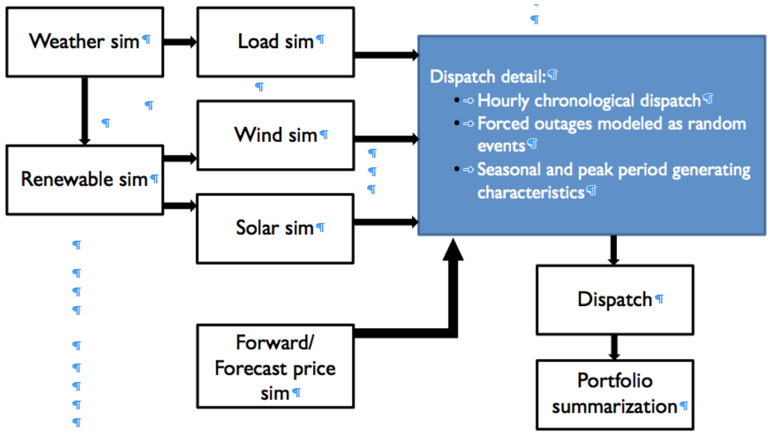


Figure H-3. PowerSimm Process Flow Diagram

The simulation framework of PowerSimm addresses uncertainty as viewed through today's market expectations (forward/forecast prices) and the future realized delivery conditions for load, spot prices, and generation.

Simulation of Commodity Prices and Physical Components

Simulation of electric system and customer loads follows from a common analytical structure that seeks to preserve the fundamental relationship between demand and price. The simulation process is divided into two separate components: before delivery and during delivery. The before-delivery simulation of forward/forecast prices evolves current expectations through time from the start date to the end of the simulation horizon. The simulations during delivery capture the relationship of physical system conditions (that is, weather, load, wind, solar, unit outages, and when applicable transmission). The inter-relationship between before-delivery and during-delivery simulations is central to linking expectations to realized observations.

For forward/forecast prices representing before-delivery simulations, monthly prices are evolved into the future from the current forward/forecast prices through expiration of each contract or forecast month. This process of evolving forward/forecast prices into the future draws on the observed behavior of forward contract variability and covariate relationships to create future monthly price projections. Within each before-delivery simulation, observed commodity prices behavior, volatility, rate of reversion, and covariate relationships across commodities drive price movements to ultimately arrive at a final evolved price at delivery. The average of these final evolved prices across all simulations for each monthly price equals the current forecast expectation of the price at delivery. Similarly, the average of the simulated electric spot prices for a given month equals the current forecast price for that month. Seasonal hydro conditions are also correlated with the simulated forward/forecast prices.

The during-delivery simulation process begins with simulation of weather. PowerSimm simulates weather using a cascading vector auto-regression approach across multiple locations. This approach maintains both the temporal and spatial correlations of weather patterns for the region. Ascend applies a cascading vector auto-regression approach to maintain inter-month temperature correlations consistent with the historical data. For example, if a hot July day is likely to be followed by another hot July day, the cascading vector auto-regression method captures this effect. The application of weather simulations supports the analysis of uncertainty through hundreds of weather cases without the limitation of the pure historical record where extreme weather events beyond observed conditions may occur (but with a low probability). The second step of the process combines these weather simulations with other factors in the load simulation process.

Load and Price Simulation

PowerSimm uses the weather simulations as well as forecasted input load values, scaling and shaping the simulated load shapes to match forecasted monthly demand and peak demand values. The simulations of electric load use a state-space modeling framework to estimate seasonal patterns, daily and hourly time series patterns, and the impact of weather. The state-space framework of PowerSimm produces results that reflect the explained effects of weather and time-series patterns and the unexplained components of uncertainty.

The during-delivery simulation of prices addresses the more intuitive simulations of system conditions and spot prices. System conditions of unit outages, supply stack composition, system imports and exports, and transmission outages are separated independent of weather but can also serve as determinants to the spot price of electricity.

LONG-TERM CASE DEVELOPMENT AND RESOLVE

Achieving a 100% RPS in 2045 would require dramatic changes in how energy is generated and used. Traditional resource planning has focused on matching the peak load and reliability needs of the system with thermal generating resources to maintain the quality of service. Planning with increasing levels of energy from variable renewable resources shifts the planning paradigm away from maintaining sufficient peak capacity towards determining the quantity and type of measures needed to integrate those resources at least cost. This requires both new planning tools and a broad perspective on how energy is produced and consumed, with the potential addition of transportation as a substantial new end-use to the electric sector.

Given the multi-decade lifetime of infrastructure built today, the decisions made now and in the near future have a potentially significant impact on the ability to meet the 100% RPS target in 2045 as well as the ultimate total cost of achieving this goal. However, the long timeline also means significant uncertainty exists about future technology costs and capabilities, fuel prices, and other factors that may have a major impact on the cost of the transition. The Hawaiian Electric Companies and Hawaiʻi have no control over such factors; these are the future conditions that are essentially inevitable on the islands. Understanding these factors and how they affect the cost effectiveness of investments made today is critical. Near-term decisions should be both consistent with the islands' long-term goals and robust against a range a future uncertainties. Another necessary step is therefore to identify the controllable decision levers available in formulating a robust, least regrets plan to best handle what happens in the future.

The difference between planning elements that happen to the islands served versus those that are decision levers is dependent on many complex and interacting factors. Global market prices for fuels and technologies, as well as technological innovation, fall into the first category. Others (such as battery procurement) can be directly decided by the Companies. But what about customer behavior, renewable resource portfolio diversity, or transportation infrastructure? These typically fall outside of the traditional Company planning cases, but can be influenced by tariff design and policy development. Identifying these factors early in the planning process, engaging stakeholders in a discourse around the policy issues, and arriving at a consensus about the policy directives is critical to create long-term policy certainty and thus enable effective planning.

Energy and Environmental Economics (E3) was retained to address these key questions. E3 has multiple contracts with the California State Agencies to support their long-term planning efforts to meet both RPS and greenhouse gas (GHG) reduction targets and were responsible for developing the four United States deep decarbonization cases used in the COP 21 process to help reach climate agreements in Paris, December of 2015. E3 also has a long history working with both the Hawai'i Public Utilities Commission and the Companies on energy issues in Hawai'i.

In this analysis, E3 first investigated what the least cost planning decisions for the Companies should be given current policy and economic trends on the islands to create a business-as-usual case. E3 then developed cases that satisfy potential policy directives to adapt to higher renewables. The cases account for the value of creating a portfolio with more diversity, more control of variable renewable resources, the evolution of the transportation sector to electric vehicles powered by hydrogen or synthetic natural gas, and flexible loads capable of responding to supply-side needs. E3 compared the costs of each of these cases and the decisions that need to be made to achieve them, forming the basis for discussion in a state policy decision process.

Case Development

Based on E3's prior work for the Companies exploring the operational impacts and integration requirements of higher renewable penetration levels on the islands, E3 also identified and included in their analysis several current trends with significant implications for the Companies' planning processes. These trends include:

- Low renewable portfolio diversity: high levels of customer adoption of DG-PV.
- Non-dispatchable renewable supply: limited utility control (via curtailment) over renewable generation.
- Load inflexibility: limited ability of loads to respond to supply conditions.

Figure H-4 illustrates how these trends might manifest themselves in a 100% renewable generation case.

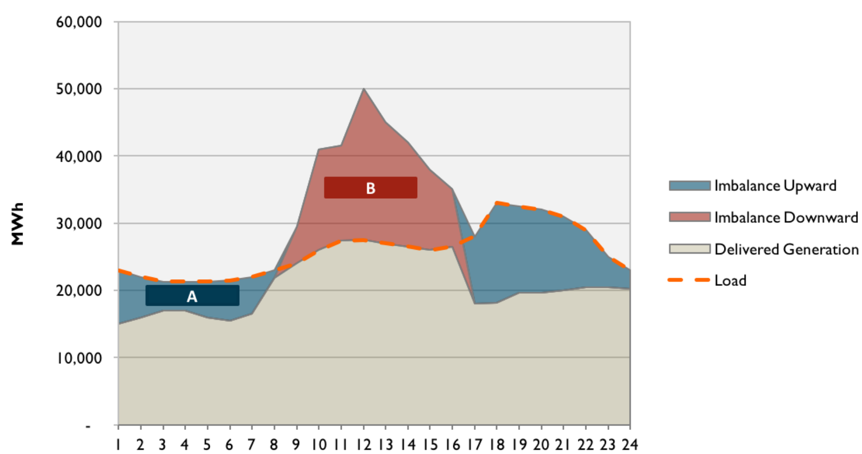


Figure H-4. Example Dispatch at 100% Renewables

In this case, the renewable portfolio consists of largely solar energy, so energy production is concentrated during the daylight hours. The load is assumed to be inflexible. The combination of these factors results in oversupply in the middle of the day (imbalance downward, B) and undersupply at night (imbalance upward, A). If the renewable generation were not curtailable, the consequence of the daytime oversupply would be an over-generation reliability event. The nighttime undersupply results in a traditional loss-of-load reliability event. Building storage to meet such imbalances is the approach that is often considered, but such storage requires substantial capital investment and is potentially unsuited to imbalances that may persist over a number of days, or even weeks or months. Renewable portfolio diversity to reduce the oversupply levels or the deployment of load controllability equipment may be more cost-effective integration alternatives. Incorporating the available alternatives into a single modeling framework is necessary to identify trade-offs and synergies among them, and optimally combine them.

E3 investigated a series of cases exploring potential futures in Hawai‘i to determine the planning solutions needed in each one. These cases are defined by the factors on the system described by the categories in Figure H-5. Within each of these categories, E3 investigated two or more different potential futures. Each case is defined by a set of assumptions describing customer behavior, renewable diversity, and transportation infrastructure, reflecting the decisions the Companies may have limited control over but may be impacted by state-level policy developments.

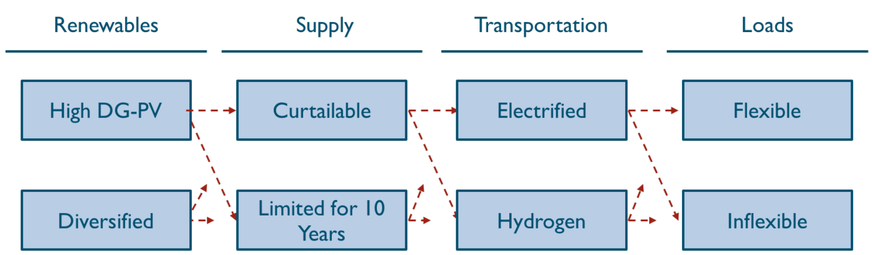


Figure H-5. Case Drivers of Potential Hawaiian Electric Futures

These cases explore the impact of the following policy decision points for Hawai‘i that depend on price and political drivers:

High consumer PV adoption versus diverse resource portfolio: E3 analyzed the differences among integration solution needs when consumer adoption of DG-PV is allowed to grow to high levels compared to a more diverse portfolio of resources.

Curtailment of supply: E3 explored the impact on resource plans of whether the Companies have full control over curtailing new generation resources, compared to a case where contracts or technological constraints limit the curtailment capability for some time.

Low-carbon economy transition: To decarbonize the entire economy of Hawai‘i, either fossil-fueled services (such as transportation) must be electrified and served by clean electric generation, or a transition must be made to using gas (such as hydrogen or synthetic methane) as an energy carrier. E3 considered both load electrification and gas (hydrogen or synthetic natural gas) transition cases. Under the gas transition case, gas is produced on the island and functions as a controllable load with a daily consumption requirement. Conversely, in the base electrification case, E3 used electric loads (including EVs) to balance renewable generation. Previous work has shown that electrification does not provide the same flexibility as the gas generation path but could ultimately be a less expensive path for decarbonizing Hawai‘i.

Load participation: Increasing levels of efficiency and substantial growth in flexible loads are a cornerstone of most long-term high RPS cases E3 has studied so far. The levels of flexible loads are partially dependent on tariff design, market development, technological capabilities and pricing for distributed generation technologies. The cases explore the amounts and types of flexible loads needed to substantially mitigate integration challenges.

The simple matrix (shown in Figure H-5) leads to eight Cases that E3 described, provided input data for, and modeled. The matrix is not meant to be an exhaustive list of all key drivers or decarbonization paths, but is an attempt to develop a workable number of cases suitable to explore initial analysis and stakeholder discussion. The number of cases can be expanded to include other critical elements or additional sensitivities based on initial results as well as feedback from either the Commission or key stakeholders. For each case, E3 also explored sensitivities to the uncertainty around market fuel and technology pricing.

Modeling Approach

Developing Case Data

Variable renewable energy poses challenges to traditional electricity sector planning and procurement as well as day-to-day reliable operations of the grid. Analyses of these challenges generally focus on near-term issues related to supply-side flexibility. These challenges can often be solved within traditional paradigms of supply-side dispatch. However, such a focus may ignore the broader context and longer-term challenges and opportunities presented by transitioning away from imported energy, not just of the electric sector, but for the energy system more broadly. For instance, a large transformation in transportation away from internal combustion engines has major implications for the electricity sector that need to be factored into long-term energy planning. E3 has drawn on its work in developing deep decarbonization paths for both California[2] and the United States[3] to develop multiple paths and a strategic vision for transforming Hawai‘i's energy future. Combinations of the case drivers shown in Figure H-5 form each of the cases investigated. Case development consisted of the following three tasks.

Task 1. Demand Case Development. As the first step in developing the vision for the electric sector under a 100% renewable penetration, E3 focused on the potential for other energy system choices to impact the electricity sector. This focused on new electric loads from:

- Direct transportation electrification (that is, electric vehicles)
- Building electrification
- Electric fuel production: hydrogen electrolysis and power-to-gas synthetic natural gas

These new loads affect the load shapes of the electric sector, the overall demand for electricity, and the potential supply portfolios that can meet their demand. This is a very important context for the electricity sector, not just for the challenges that these new loads pose, but for the opportunities they present. This is a first-cut, case analysis to assess the scale of these potential impacts. E3 developed energy transformation case demand forecasts based on previous work developing deep decarbonization paths for California and the U.S. These focused on key choices in the transportation sector and buildings:

- Light duty vehicles
- Heavy-duty vehicles
- Buses
- Thermal end-uses (water and space heating)

E3 utilized all available data for Hawai‘i to develop a realistic assessment of future electricity demand from activities in these sectors.

Task 2. Renewable Portfolio Development. In this task, E3 developed prospective renewable portfolios for supplying levels of overall electricity demand developed in Task 1. The first portfolio is composed of reference renewable supply assumptions, with high levels of DG-PV. Additional portfolios are based on existing renewable energy potential data and reflect policy direction to procure the best prospective portfolios to minimize supply and demand imbalances (that is, 100% solar would exacerbate supply and demand imbalances) versus cost and development potential constraints. The level that a

2 https://ethree.com/public_projects/energy_principals_study.php.
3 http://unsdsn.org/wp-content/uploads/2014/09/US_DDPP_Report_Final.pdf.

resource can be curtailed is also factored into the portfolios to reflect potential transition times to the Companies' full control of the renewable fleet, including DG-PV systems.

Task 3. Load Development. E3 first assessed the flexibility from the new loads detailed in Task 1. Many of these loads come associated with storage, which allows them to mitigate their demands on the electricity sector. For example, a car battery connected to the grid offers the ability to delay or advance its charging needs based on its inherent chemical storage capacity. End-uses in buildings offer thermal storage to perform activities like pre-cooling and pre-heating to manage loads with regards to supply conditions. Electric fuel production may be the most flexible of all, taking advantage of existing gas infrastructure or hydrogen storage to flexibly operate plants during periods of over generation.

E3 also examined permanent load shaping. Here, targeted energy efficiency can reduce loads during times of the day where consistent supply deficits occur. For example, aggressive lighting efficiency can reduce nighttime load in a high-solar case, increasing the coincidence of demand and supply. Permanent load shifting could provide pre-cooling opportunities at mid-day to reduce nighttime cooling loads.

Developing Optimal Resource Portfolios for Each Case

For each case and selected fuel price and capital cost sensitivities, E3 used its investment model RESOLVE to develop optimal resource portfolios for meeting the RPS targets. (RESOLVE is an optimization tool that selects a least cost portfolio of renewable resources and integration solutions over a chosen time horizon. E3 built it for the California State Agencies to study cost-effective integration solutions including demand response and a range of storage technologies, and to determine the value of regional integration in mitigating renewable integration costs.)

Price sensitivities are developed under each of the cases to include plausible future market price trajectories for both fuel and capital investments.

A number of factors influence the cost effectiveness of a conversion of oil-fueled generation to LNG, including capital expenditures necessary for the conversion, oil and LNG price trends and spreads, and quantity of energy generated by the converted plants. The payback of thermal capital investments also depends on the expected energy demand, which is influenced by renewable energy production and energy use patterns.

The optimal resource mix depends in part on the price trajectory of energy storage technologies. E3 does not have confidence that an accurate prediction of energy storage technology price can be made out to 2045. Therefore, E3 considered several price trajectories to evaluate the expected price impact on the resource mix.

Figure H-6 shows the conceptual effects of uncertain storage pricing.

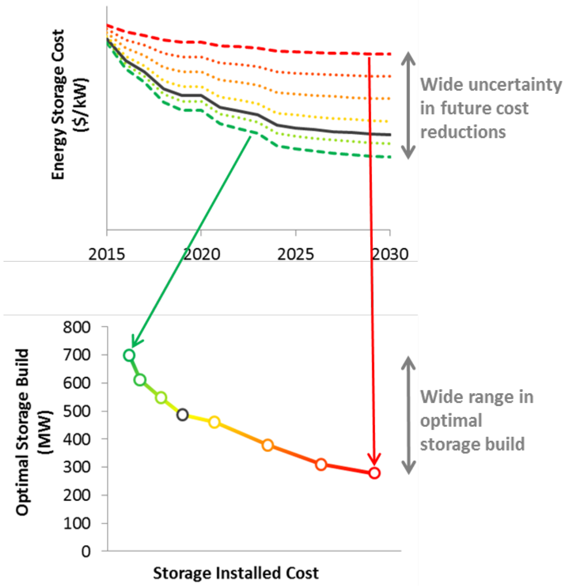


Figure H-6. Conceptual Effect of Storage Price Sensitivity

Beyond energy storage, a broad suite of integration solutions was employed to meet the RPS targets (Table H-1). The applicability of many of these strategies relies on decisions made outside the electricity sector itself (for example, EV penetration determines the availability of EV load to manage imbalances).

Resource	Balancing Direction	Balancing Timeframe	Resource Potential
Flexible building thermal loads	Both	Seconds to hours	Depends on electrified thermal end-uses, controllable equipment, and customer participation.
EV charging management	Both	Seconds to hours	Depends on available public and private infrastructure as well as overall electric vehicle penetration.
Hydrogen electrolysis	Both	Seconds to weeks	Depends on demand for hydrogen in other sectors (primarily transportation).
Power-to-gas synthetic natural gas	Both	Seconds to months	Depends on demand for gas and available gas storage facilities.
Targeted energy efficiency	Upward	Hours	Depends on end-use electricity demands .
Permanent load shaping	Both	Hours	Depends on building loads and customer incentives.
Battery storage	Both	Seconds to days	Effective balancing, but at high capital cost and efficiency penalty.
Pumped storage hydro	Both	Seconds to months	Depends on site availability.
Flexible renewable generation	Upward	Minutes to days	Depends on available renewable fuels (geothermal).
Flexible thermal generation	Both	Seconds to hours	Depends on price of available fossil fuels.
Curtailment	Downward	—	Depends on controllability of renewable resources.
Inter-island transmission	Both	Seconds to hours	Balancing benefits depend on the complementarity of load and renewables being connected.

Table H-1. System Balancing Options

How these balancing solutions are implemented in the context of a low-carbon electricity grid is shown in an example from the U.S. deep decarbonization paths analysis (Figure H-7). This chart shows the Western Interconnection in a high renewables case during a week in March. In this case, high penetrations of renewable generation necessitate the dispatch of flexible fuel production, battery storage, flexible building loads, and EV charging in order to effectively manage periods of over- and under-supply. Those loads are available for dispatch because of the electrification of transportation under this case. As control over energy supply is reduced, participation from other resources-like loads are a critical element for maintaining a low-cost, reliable electricity grid.

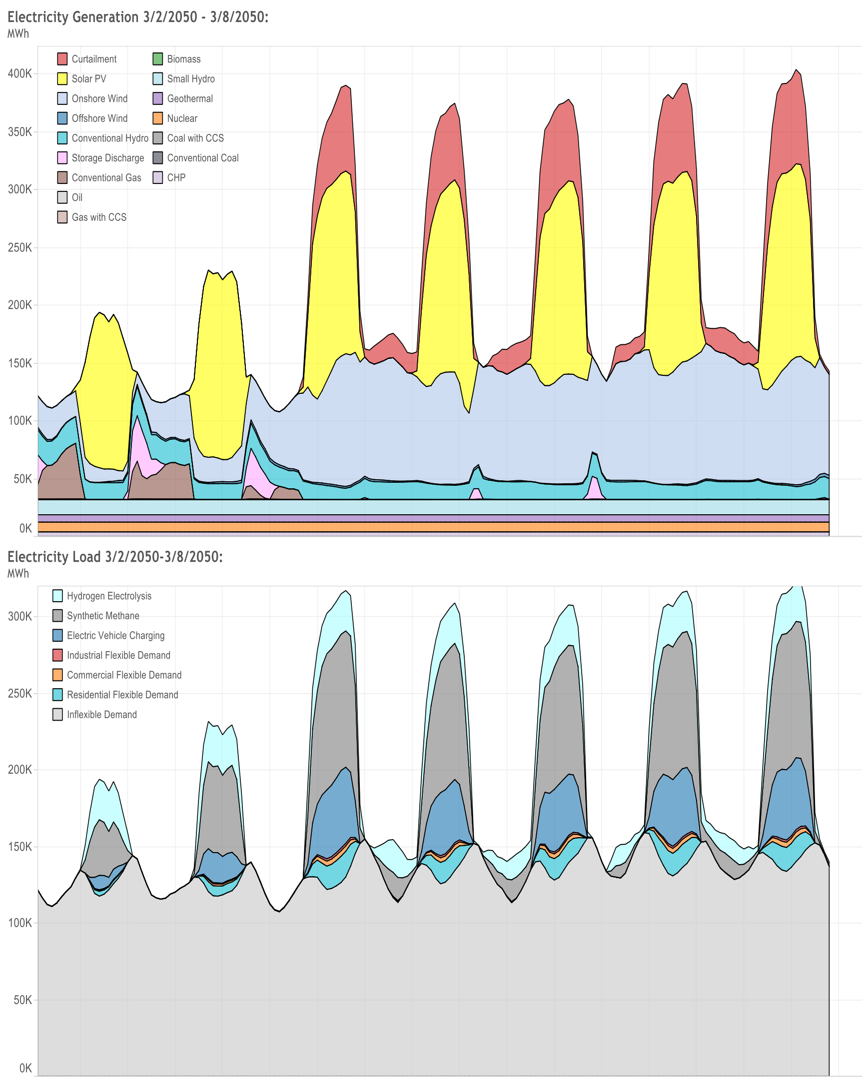


Figure H-7. Dispatch at 100% Renewables: Supply (top) and Demand (bottom)

Economic Selection of Optimal Renewable Integration Solutions using RESOLVE

Planning the development of a 100% RPS compliant electric energy system presents a number of challenges. The plan must choose a portfolio of varied resources that work in concert to reliably meet consumer electricity demand while accommodating the variability of renewable energy resources. Every hour of the planning horizon, the system must satisfy several operational constraints including reliability needs, for example generator minimum generating levels, ramping constraints, contractual obligations, and reserve requirements. Figure H-8 shows a hypothetical day when generating resources must operate to meet the following constraints:

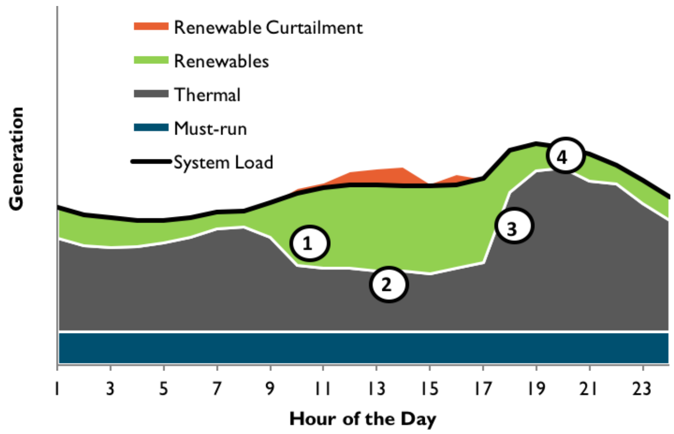


Figure H-8. Renewable Integration Challenges

Key to Figure H-8 numbers:

1. Downward ramping capability: ramp capability must be available to meet morning ramps as solar production increases and the net load drops.
2. Minimum generation: resources must be capable of lowering their output sufficiently, either by turning off generation, or ramping down output, such that low midday net loads are balanced while reliability requirements are still met.
3. Upward ramping capability: ramp capability must be available to meet capacity needs as solar production falls in the evening.
4. Peaking capability: peak loads must be met, often after solar generation has dropped off.

There are many different combinations of resources that can be included in the resource portfolio to meet reliability needs, so determining the least cost portfolio must be done through an optimization framework. Figure H-9 shows the resource mix under three hypothetical renewable integration strategies.

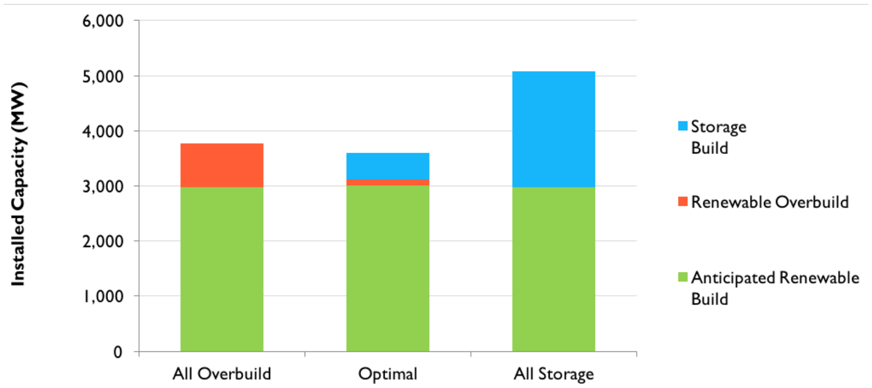


Figure H-9. Hypothetical Renewable Integration Strategies

The lowest cost portfolio of renewables and integration solutions at any point in time is a mix of resources that minimizes both operating costs and capacity expenditures over the planning horizon. The value of each integration solution changes over time depending on the evolving needs of the system. Those selected in an optimal resource portfolio offer the greatest net value over their lifetime in combination with the other resources selected. Some technologies may be stepping stones to longer term portfolios. In addition, a robust analysis incorporates the costs of the enabling technologies on the grid (for example, interconnection, control systems).

Figure H-10 depicts an optimal tradeoff between renewable overbuilding and other integration solutions. The optimal point for each resource is where the benefit of the marginal unit of any resource to the system is equal to its marginal cost. In reality, each type of resource adds a dimension to the optimization; each combination of resources has complex operational interactions. Finding the least cost solution requires a sophisticated optimization model that treats operational and investment costs while satisfying operational and reliability constraints.

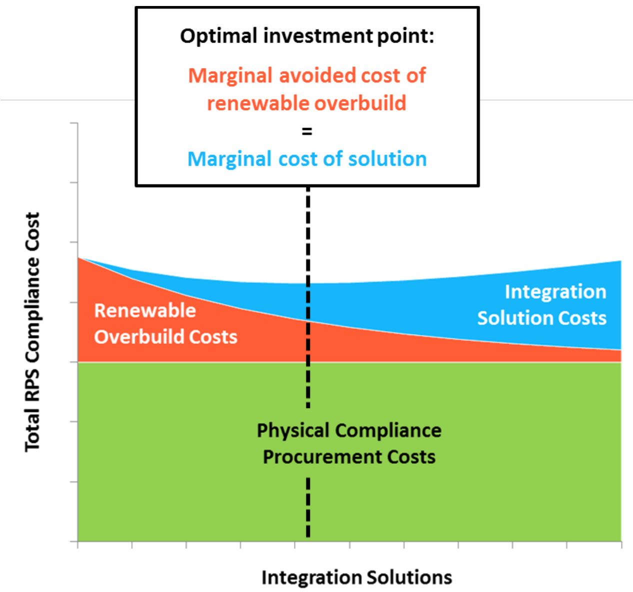


Figure H-10. Tradeoff Curve Between Integration Strategies

The optimal resource mix depends on a number of assumptions about the future state of the world. An optimal resource plan should be robust to uncertain future trajectories of fuel prices, technology costs, and consumer adoption of DER.

For each case investigated in the analysis, E3 used its RESOLVE model to optimize resource portfolios over a planning horizon out to 2045. RESOLVE builds on the REFLEX advanced production simulation model to optimize investment decisions subject to detailed hourly operational constraints including reserve requirements, ramping limitations, and unit-commitment constraints. Using its demonstrated methodology, Ascend Analytics is determining the electric power system's operating and contingency reserve requirements on an annual basis. These reserve requirements serve as input data for RESOLVE, which then determines an optimal resource plan that adjusts the portfolio of resources on an annual basis. RESOLVE selects the optimal portfolio of resources to be installed in each year, choosing from generation retrofits, battery energy storage, demand management, thermal generation, and renewable generation. The solution found by RESOLVE co-optimizes investment and operational costs.

E3 is developing long-term strategic options for the electric sector under high penetrations of renewable energy. Over the full planning horizon and considering the uncertainties involved, E3 is identifying near-term least regrets planning decisions.

PLEXOS FOR POWER SYSTEMS

PLEXOS® provides a platform for economic analyses of energy systems that co-optimizes the contributions from energy, ancillary services, fuels, emissions, water resources, and transmission systems from sub-hourly chronological scheduling to analyze long-term planning. The model datasets for the islands are developed from reference case assumptions provided by the Companies. PLEXOS provides detailed modeling of the generation resources, including thermal, wind, solar PV, battery storage, demand response, distributed energy resources, hydroelectric, and pumped-storage hydro in these data sets. Energy Exemplar provides output from the island data sets for benchmarking with existing models used by the Companies.

Energy Exemplar contributes data in capacity expansion plans for all five islands served combined with economic analyses of those expansion plans. The expansion plans are produced under several cases.

The Energy Exemplar project team are highly trained and experienced in implementing PLEXOS models and the economic analysis of power systems. The PLEXOS modeling approach implements its models as physical systems with economic and financial impacts. The model uses engineering inputs for generation resources, resulting in operational and financial outputs that depend on forecasts of market conditions (such as fuel prices and contract positions for the scarce resources that power the various assets). PLEXOS is reliable simulation software using state-of-the-art mathematical optimization combined with the latest data handling. Combined with visualization and distributed computing methods, the model provides a high-performance, robust simulation system for electric power that is leading edge, open, and transparent. PLEXOS meets the demands of energy market participants, system planners, investors, regulators, consultants, and analysts with a comprehensive range of features seamlessly integrating electric, water, gas, and heat production, transportation and demand over simulated timeframes from minutes to decades. PLEXOS is one of the fastest, most sophisticated, most cost-effective software available for performing the analyses required to develop the 2016 updated PSIPs.

PLEXOS is reliable simulation software that uses state-of-the-art mathematical optimization, combined with the latest data handling, visualization, and distributed computing methods, to provide a high-performance, robust simulation system for electric power, water and gas. Its processing is open and transparent. PLEXOS meets the demands of energy market participants, system planners, investors, regulators, consultants, and analysts with a comprehensive range of features. The model seamlessly integrates electric, water, gas, and heat production; transportation; and demand over simulated timeframes from minutes to decades—all delivered through a common simulation engine with easy-to-use interface and integrated data platform. PLEXOS is one of the fastest and most sophisticated software available today for the task at hand, and also the most cost-effective.

Energy Exemplar developed PLEXOS datasets to model generation resources for O‘ahu, Hawai‘i Island, Maui, Lana‘i, and Moloka‘i. Each island model implements two modeling approaches:

- Unit commitment and economic dispatch to evaluate the economics of the generation system (including energy and ancillary services).
- Capacity expansion modeling for portfolio optimization and RPS modeling.

The analysis includes evaluating DR programs, existing economic fleet retirement, expansion to satisfy RPS targets (including renewable and traditional resources), expansion, and economic modeling of battery storage devices. This tool also develops sub-hourly models to capture the benefits conveyed by flexible resources, especially in a resource mix that includes high variable renewable penetration.

HOW MODELS WERE USED IN OUR ANALYSIS

The AP for Production Simulation, DG-PV Adoption, Customer Energy Storage System, PowerSimm Planner, RESOLVE, and PLEXOS for Power System models were all used to support our analysis for the 2016 updated PSIPs. An explanation of how each was used follows.

AP for Production Simulation

Black & Veatch provided DR portfolio evaluations to support the current PSIP effort. Our analyses supported three interrelated aspects of the PSIP by providing:

- System avoided cost value to support customer battery resource build-out analysis.
- Ability of the DR portfolio to meet the needs of the generating and transmission system.
- Maximum MW by year, by program for determining DR program costs.

These analyses required full production simulation modeling of the generating system including gross demand, centralized firm and variable generation assets, PPA contract obligations, security requirements, DER volumes, and DR products.

System avoided cost value for customer battery resource build-out focused on the value that customer batteries could provide by better utilizing non-firm renewable generation resources (that is, reducing wind or solar curtailment) and provided value by ensuring that the build-out assumptions were rooted in the needs of the generating system. The value was determined by taking the difference between the system cost with and without an estimated battery build-out. The analysis considered the ability of the customer battery to load shift to best avoid curtailment and provide spin equivalent.

The ability of the DR portfolio to meet system needs was determined by modeling the system with the DR portfolio and associated customer batteries. The available DR portfolio, excluding customer batteries, was defined in a separate Potential Study that characterized the end uses available on each island by their ability to provide the various DR products (FFR, RR, RTP, and so on). The build-out of customer batteries was defined subsequent to the step described above. The DR and customer batteries were allowed to respond to system energy and security needs in conjunction with the central assets available for each case evaluated.

The following results were compiled and provided to other modeling teams:

- Material adjustments to the resource plan.
- Effective impact on the system load shape, by hour.
- Ability to provide effective spin, by hour.

Using this method ensured that the PSIP DR evaluation was consistent with the analysis performed to support the 2015 DR filing. It also ensured that all modeling teams utilized the same DR profiles.

Based on the above analysis, the maximum MW by year associated with each DR product and customer class was provided to the Companies to support the development of a bottoms-up estimate of the cost to implement DR.

DG-PV Adoption Model

The DG-PV Adoption Model was used to address Observation and Concern #3, and focused on DER Integration.

The model was a key tool in the DER iterative cycle as part of the PSIP Decision Framework. The model forecasted market DG-PV customer adoption amounts for self-supply, grid-supply up to a cap, and potential future DG-PV products while also considering related integration costs. The model forecasted DG-PV customer adoption amounts optimized for the electric system.

In the future, the model can be used to fine-tune the DG PV forecasts as technology costs, tax credits, grid service compensation rates, retail rates or other underlying assumptions change.

Customer Energy Storage System Model

The Customer Energy Storage System Adoption Model was used to address Observation and Concern #6; it focused on ancillary services, in particular the services that can be provided by distributed storage systems through the proposed DR programs.

The model was a key tool in the DER and DR iterative cycles as part of the PSIP Decision Framework. The model forecasted customer adoption of distributed storage when compensated at avoided cost for providing grid services through the proposed DR programs.

In the future the model can be used to fine-tune distributed storage forecasts as technology costs, tax credits, value of storage figures, or other underlying assumptions change.

PowerSimm Planner

Ascend's PowerSimm modeling tool was used to evaluate costs associated with renewable expansion plans. By optimizing dispatch according to unit characteristics, forecasted fuel prices, load, and renewables; the expected costs associated to each plan can be measured and accounted for. In addition, by introducing stochastic simulations into the modeling framework, PowerSimm is able to output a realistic range of possible future costs for each portfolio. By summarizing the range of costs through a risk premium, the Companies can directly compare the merits of trading off expected costs for higher risk.

In addition to cost and risk, Ascend's PowerSimm software is also able to measure dumped energy in every renewable expansion plan. These results are used to determine the amount of load-shifting battery storage required, and to calculate the cost of this storage. PowerSimm is able to model the effect of adding this storage to the portfolio, so this process of measuring dump energy and calculating storage costs can be repeated. By running multiple studies for a given expansion plan with varying levels of battery storage, we are able to hone in on a level of battery storage that strikes the right balance between minimizing costs and minimizing dump energy.

The Ascend regulation tool is an interactive modelling tool that can be used to estimate one-hour ramps and regulation for a variety of fixed scenarios for daytime and nighttime requirements. Behind the scenes, an analysis script runs a large number of scenarios where it scales historical minutely data to forecasted load wind and solar capacities. The regulation tool allows you to query the output of these runs interactively. Users are given the option to choose a base or high DG-PV forecast, the year, solar adders, that adds capacity to utility solar baseline forecasts, and wind adders, similar to solar adders. Regulation and ramp statistics are also shown for the strategic and aggressive strategies for the selected year, and are partitioned by daytime and nighttime. Graphs of regulation and ramps are also included for each of the three themes, and a historic window allows scrolling through time, showing two consecutive days of load, utility solar, wind, DG-PV, net load, load-following, regulation, and regulation requirements.

The one-hour ramp statistic is calculated as the difference between the net load at a given time and the net load exactly one hour prior to that time. The maximum ramp for each year is reported both for the daytime and nighttime. Regulation is calculated as the difference between net load and load-following, where net load is load (solar and wind) and load-following is a linear interpolation of net load through minute 0 of each hour. Regulation is then separated into regulation-up (regulation > 0) and regulation-down (regulation < 0) to remove bias from 0 regulation calculated at minute 0 of each hour. The 95th percentile of regulation-up and the negative of the 5th percentile of regulation-down are then averaged together to form the regulation requirement. These one-sided confidence bounds combine to form a 95% confidence interval for regulation, without including the zero regulation calculated at minute zero of each hour.

RESOLVE

E3 assessed the long term plan for Oahu.

The E3 analysis determined how the decisions to build out the system might change depending on the policy direction Hawai‘i takes in the future to meet their RPS goals, and how the uncertainty surrounding pricing of fuels and technology affect those decisions.

The long term focus of the E3 scope emphasizes investigation of the large scale changes in Hawai‘i energy policy over the time horizon to 2045 rather than the near term detailed modeling of system operations. The result is an evaluation of several different policy ‘futures’ under uncertain cost trajectories for technologies and fuels. This framework is the basis for evaluating long-term policy pathways in Hawai‘i that may be expanded in the future to include greater detail on the input assumptions and definition of additional cases to be investigated.

The core of the analysis is several cases that represent different policy directions in Hawai‘i. Each of these cases is a potential set of future system conditions that can be targeted by development of policy in Hawai‘i. These represent controllable decision levers available to Hawai‘i in formulating a robust, least regrets plan to best handle what happens in the future. A least regrets plan has to be robust against aspects that Hawai‘i has no control over. These include external forces such as global commodity prices and future technology pricing.

PLEXOS for Power System

PLEXOS for Power Systems models many features of the power systems on O‘ahu, Maui, Hawai‘i, Lana‘i, and Moloka‘i. PLEXOS optimizes the 30-year expansion plan for these islands subject to RPS. PLEXOS also simulates 30-years of hourly system operation, including the co-optimization of energy and ancillary services subject to fuel limits, renewable portfolio standards, the availability of storage devices, the curtailment (or not) of renewable resources, the typical operation of existing resources, and many other limitations.

PLEXOS models the variety of expansion themes that are addressed in the PSIP analysis plan. This allows for an economic analysis of the various approaches and also a view of how each island’s power system would operate in the context of several expansion strategies. PLEXOS provides the ability to model both the long-term operation of these systems and the very detailed operations of the system to a degree that is unique amongst simulation models in this area.

PLEXOS is also used for the development of optimal storage capacity sizing. In this situation, the sub-hourly capabilities of PLEXOS are particularly important to understanding the economic value of storage capability.

FINANCIAL FORECAST AND RATE IMPACT MODEL

PA Consulting Energy and Utilities team developed the Financial Forecast and Rate Impact Model specifically for modeling the impacts of key metrics (such as revenue requirements, rates, and average customer bills) for the Updated PSIPs. The model's design reflects important and unique characteristics of the Companies' business: timing and frequency of rate cases, revenue adjustment mechanisms (RAM), maintenance of the target capital structure, and customer usage and bill composition. PA Consulting initially developed this financial model for the 2014 PSIPs. Since then, the model has been refined and updated to reflect the most current conditions, including recent regulatory changes to the RAM.

The model comprises a comprehensive and interconnected set of detailed modules, each representing a key aspect of the company's financial framework. These modules calculate average customer bills, income statements, cash flow statement, and balance sheets. Additional modules, in turn, calculate detailed schedules of annual capital expenditures, and annual debt and equity issuances.

The model's foundation uses the PSIP case variables to build a range of company financial data, including:

- Annual reports (income statements, cash flow statements, and balance sheets)
- Schedules of existing debt
- Operation and maintenance (O&M) expenses not covered by the PSIPs
- Annual capital expenditures not directly covered by the PSIP cases (transmission, distribution, and other general expenditures)
- Rate structures
- Projections of customer count and average usage
- Sales forecasts
- Most recent net plant values for all generation units

The Financial Forecast & Rate Impact Model requires two key inputs for each PSIP case—production costs (such as fuel prices, power purchase agreements (PPAs), variable and fixed O&M expenses) and incremental capital expenditures. From this input, the model automatically updates all modules to reflect the resultant financial impact on each PSIP case. These financial impacts—pass-through of fuel and PPA costs, application of the appropriate RAM and surcharges for the capital expenditures, updated rate case calculations, and revised debt and equity issuances—lead to updated revenue requirements, rates, and average bill values.

PA Consulting Group's Energy and Utilities team is uniquely qualified to create and implement this financial model. The team has extensive experience in utility accounting, complex financial modeling, and support of rate cases and other regulatory filings.

Several Modules Comprise the Modeling Tool

PA Consulting Group's Energy and Utilities team updated and refined this model that was specifically created to perform financial analysis for the Companies' PSIPs.

The Financial Forecast and Rate Impact Model is comprised of several modules (Figure H-11). The model also includes a discussion that contains the inputs feeding into the calculation modules, and a dashboard that captures all the major outputs from the various modules.

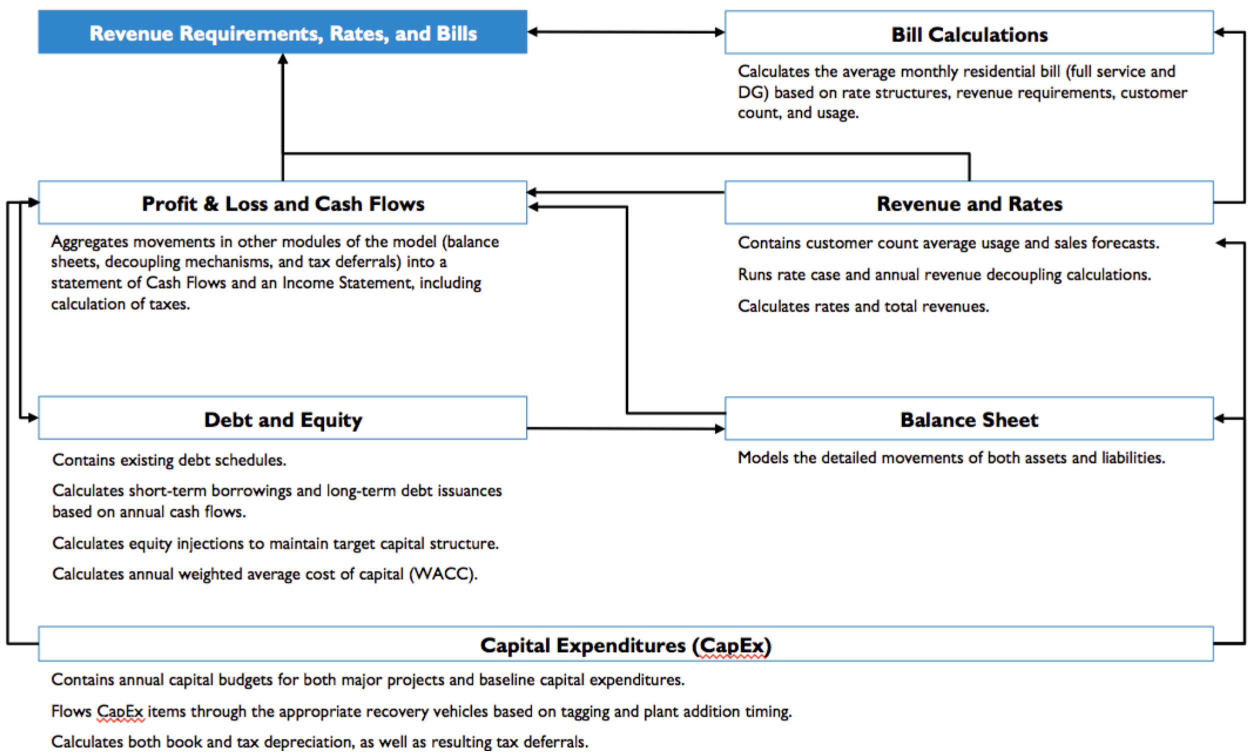


Figure H-11. High-Level Module Structure of the Financial Forecast and Rate Impact Model

Bill Calculations

This module calculates the average monthly bill for full service and DG residential customers. It:

- Calculates average bills under both current rate structures and the proposed DG 2.0 framework, with fixed rates calculated for both cases.

- Bases the bill calculations on forecasts of annual number of DG customers and usage, production, and export for an average DG customer.

Profit & Loss and Cash Flow

This module primarily aggregates movements from other modules of the model (for example, balance sheet, decoupling mechanisms, and tax deferrals) into a statement of Cash Flows and an Income Statement.

For the statement of Cash Flows:

- Produces detailed schedules of operating, investment, and financing cash flows.
- For operating cash flow, key inputs from other modules include depreciation, change in tax deferrals, change in regulatory assets, and change in accounts receivable and accounts payable.
- Investment cash flow is driven by capital expenditures, which are calculated and picked up from the CapEx module.
- Financing cash flow is driven by the base dividend payments calculated from Net Income in the Income Statement, combined with the debt and equity issuances, and additional dividend payments calculated in the Debt and Equity module.

For the Income Statement:

- Key movements picked up from other modules include Total Revenues, Revenue Balancing Adjustment (RBA), depreciation, and interest expenses.
- Fuel, PPA, and variable and fixed production O&M costs come directly from the PSIP production simulation input, while the remaining O&M items are escalated annually by inflation, adjusted for any specific project-related savings or cost increases.
- Income and revenue taxes are calculated directly, with tax deferrals added from the CapEx module.

Revenue and Rates

This module contains various calculations that add up to a total annual revenue requirement:

- Periodic rate case calculations, with both a calculation of allowed return in order to adjust rates, and a calculation of net allowed revenue for RBA adjustments.
- Detailed RAM and RBA calculations, which reflect the most recent adjustments to the RAM.
- Mark-up of fuel and PPA costs by the revenue tax adjustment factor, to allow pass-through in rates.

- Calculation of total effective rates, by summarizing and adding up the different rate components contributed by RAM, RBA, other surcharges, rate case adjustments, and fuel and PPA pass-through.
- Calculation of total annual revenues, by multiplying the total effective rate with the total forecasted sales provided by (and used in) the PSIP production simulation.

Debt and Equity

This module calculates short-term borrowing, long-term debt issuance, equity injections, and additional dividend payouts:

- Based on an objective to maintain a minimum ending cash balance, short-term borrowing, and long-term debt are used to cover any shortfalls from the net cash flow before financing. Short-term borrowing is exhausted first, with any remaining shortfall covered by long-term debt.
- Upon issuance of debt, equity injections are calculated (if necessary) to maintain the target capital structure.
- Interest expense on new debt is calculated, with short-term borrowings carrying full interest expense in the year of issuance, and long-term debt carrying half a year's interest expenses in the year of issuance, and a full year of interest expense starting in the year following issuance.
- In years with equity over the target ratio, the model calculates additional dividend payments to achieve target capital structure.
- The weighted average cost of capital by year is calculated based on currently-authorized equity returns and forecasted debt rates using the target capital structure.

Balance Sheet

The module presents detailed annual assets movements, including:

- Utility Plant in Service, Accumulated Depreciation, and Construction Work in Progress, driven by annual changes of these items in the CapEx module.
- Annual change in Customer Accounts Receivables are based on annual relative change in Total Revenues.

Also presents detailed annual liabilities movements, including:

- Common Stock and debt balances are driven by calculations in the Debt and Equity module
- Any increase in Retained Earnings is net of any additional dividends paid out as part of the optimization of the capital structure.

- Accounts Payable adjusted annually based on average relative annual change in capital expenditures, fuel, and PPA costs.

For both assets and liabilities, all items that are not explicitly driven by calculations in other parts of the model are kept constant.

Capital Expenditures (CapEx)

This module contains detailed annual capital budgets, and calculations of surcharges, securitization (if applicable), and depreciation (book and tax). The module:

- Details capital expenditures and plant additions by year for baseline and major projects (RAM definition).
- Summarizes plant additions by asset category for depreciation purposes and allows for the inclusion and exclusion of specific projects depending on the cases modeled.
- Summarizes plant additions by surcharge category (Preapproved Baseline, Major Project, or REIP) for decoupling calculations in the Revenue and Rates module.
- Calculates average baseline capital investments for use in the RAM adjustment.
- Calculates accumulated depreciation and depreciation expense by asset (production plant) and by asset category (transmission, distribution, and general).
- Calculates tax depreciation and subsequent deferred tax impact on book and tax depreciation differences.
- Calculates the annual securitization payments associated with the retirement and removal of individual generating units (if applicable).

I. Financial Analyses and Bill Impact Calculations

In our Preferred Plans, the Companies developed alternative approaches to achieve 100% RPS, analyzed the differentials between cases, and prepared comprehensive total customer bill impact and rate analyses. These results are described in Chapter 4: Financial Impacts.

Preparing comprehensive bill impact and rate analyses for a nearly 30-year planning period is an unusual level of financial planning and projections in the industry. While the Preferred Plans provide the expected fuel cost, operating costs, and capital investments for critical resources given our resource cost assumptions and fuel price forecasts, the capital investments and operating expenses for the balance of our utility business needs to be projected and incorporated into the comprehensive bill impact and rate analyses; in other words, our non-power supply costs.

To meet this challenge, we developed a top-down methodology to project this "balance-of-utility business" capital and expense requirements.

ITERATIVE TOP-DOWN METHODOLOGY

Our non-power supply cost structure—and correspondingly its revenue requirement and customer bills in total—comprise four primary elements.

- Operating & maintenance costs.
- Taxes other than income and public benefits fund.
- Return on and of existing utility asset investments.
- Return on and of future utility asset investments, net of productivity savings.

We projected each of these major elements individually, and then apply a financing capacity test and a rate change test.

Financing Capacity Test

We currently have a limit to the amount of new capital expenditures we can finance on terms acceptable to both customers and shareholders. As the financing constraint is assumed to not be binding if the NextEra Energy merger is consummated, it is not applied to Theme 2. However, as Themes 1 and 3 may occur under either a merged or a stand-alone future, there's a ceiling on the total capital expenditures of the consolidate plan in a given year or period of years.

For the unmerged future, the annual capital expenditures of the Preferred Plans and the future annual capital expenditures for the balance of the business are summed by year to determine if the total capital expenditures are within the Company's financing capacity. Projected capital expenditures for the balance of the utility business are evaluated for operational needs along with the need to stay within the Company's financing capacity. The adjusted balance of business capital expenditure plan is then used for the customer bill and rate impact analyses.

Rate Change Test

There are also economic and policy limitations to levels of future changes in customer bills and rates. While the science of these limits maybe somewhat less precise than the financing capacity limits discussed above, these limits are real and constraining.

To determine an annual rate change test limitation for each operating utility against which to test the plans, three different approaches to project annual rate changes were considered. These are:

- Rates adjust at the rate of inflation.
- Rates adjust at a blended rate, reflecting fuel price forecasts[1] and general inflation for "business as usual"[2] operations, for both 2015 U.S Energy Information Administration's (EIA) Reference and February 2016 EIA Short-Term Energy Outlook (STEO) fuel price forecasts.
- Rates adjust at the rate of price change over the prior decade.

[1] The fuel price component of these rate trajectories have been adjusted to reflect fuel blending required to meet environmental regulations.

[2] "Business as usual" in this context means continued use of the existing generating portfolio and fuel types, consistent with environmental regulations.

These approaches, when applied to each operating utility, result in the following annual rate change ceilings (shown in Figure I-1 through Figure I-3).

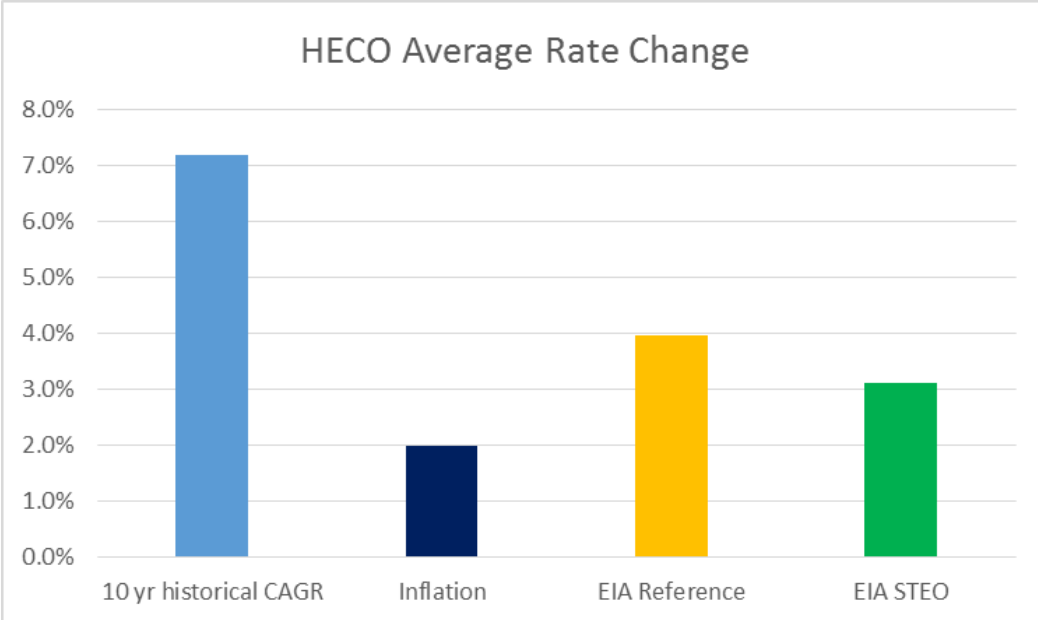


Figure I-1. Hawaiian Electric Average Rate Change

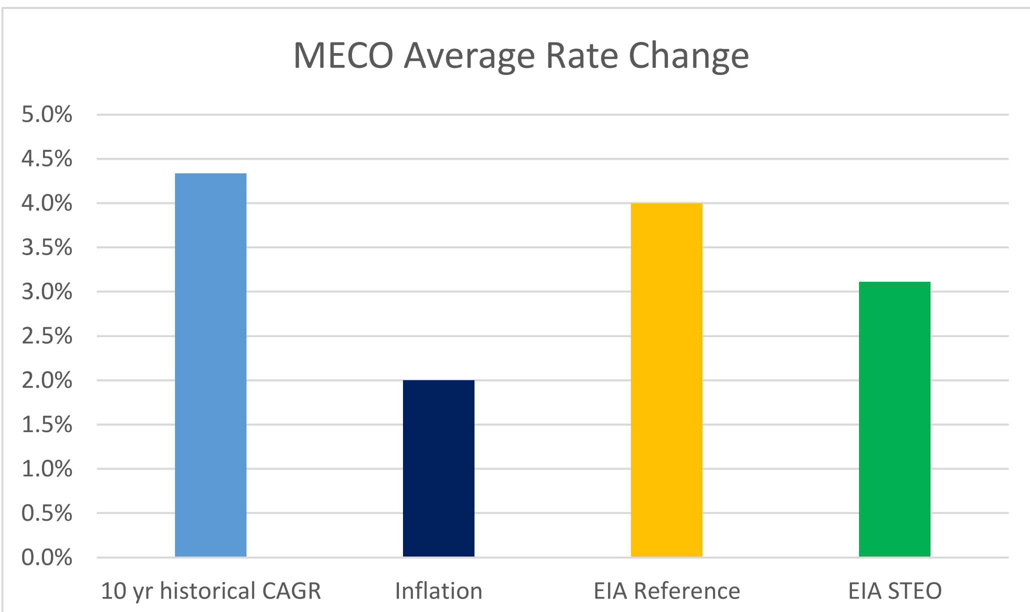


Figure I-2. Maui Electric Average Rate Change

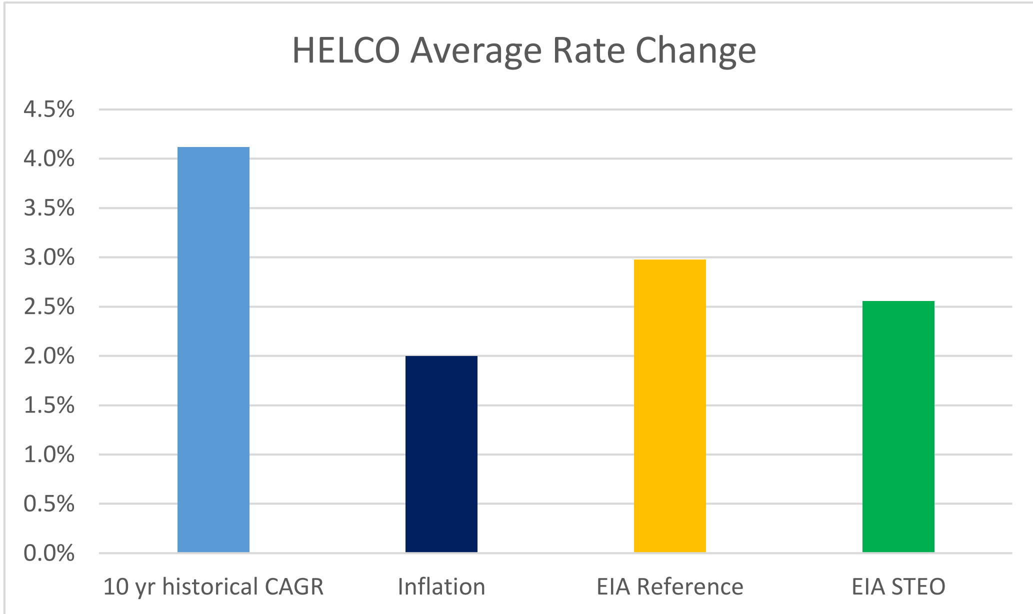


Figure I-3. Hawai'i Electric Light Average Rate Change

In addition to these annual rate change data points, we understand that there is a price point beyond which customers have economically feasible alternatives to grid supply. While there are many quantitative and qualitative factors that go into such a decision, we know that we must deliver to our customers an attractive total value proposition of affordability, reliability, and convenience. Based on these analyses, we targeted an annual rate change ceiling of 4%, while giving consideration to the operational needs for balance of the utility business capital expenditures.

The lumpy rate increases inherent with tradition rate base treatment of major capital projects are a challenge in this context. One approach that could be used to smooth out the rate impact of major capital investments is to allow for the inclusion of the Construction Work in Progress (CWIP) associated with major projects to be included in rate base. This approach would also benefit customers through a lower total cost for each project, as AFUDC financing charges would not be added to a project's cost. This treatment for major capital investments is one that a number of other jurisdictions have adopted; while we have not included that treatment in our rate and bill impact calculations, we believe it is a concept that should be considered, perhaps for all new major projects greater than $50M, as these plans move from proposals to projects.

It is important to note that annual rate change is a more constraining constraint as compared to total bill impact because of the anticipated sales volume reduction impact of energy efficiency measures.

Impact of Energy Efficiency Portfolio Standard on Rates and Customer Bills

Hawai‘i’s Energy Efficiency Portfolio Standard (EEPS) is guiding significant improvements in energy efficiency across all customers and is a primary driver of the decline in kWh sales through 2030. These usage declines are incorporated into the sales forecasts used for the PSIP analyses. Figure I-5 provides a perspective on the significance of this impact on projected sales volume for O‘ahu. While these net sales figures include the impact of both EEPS and the standard DER penetration assumptions, the DER impact is generally constant year to year, so the shape of the curve is driven by the EEPS impact.

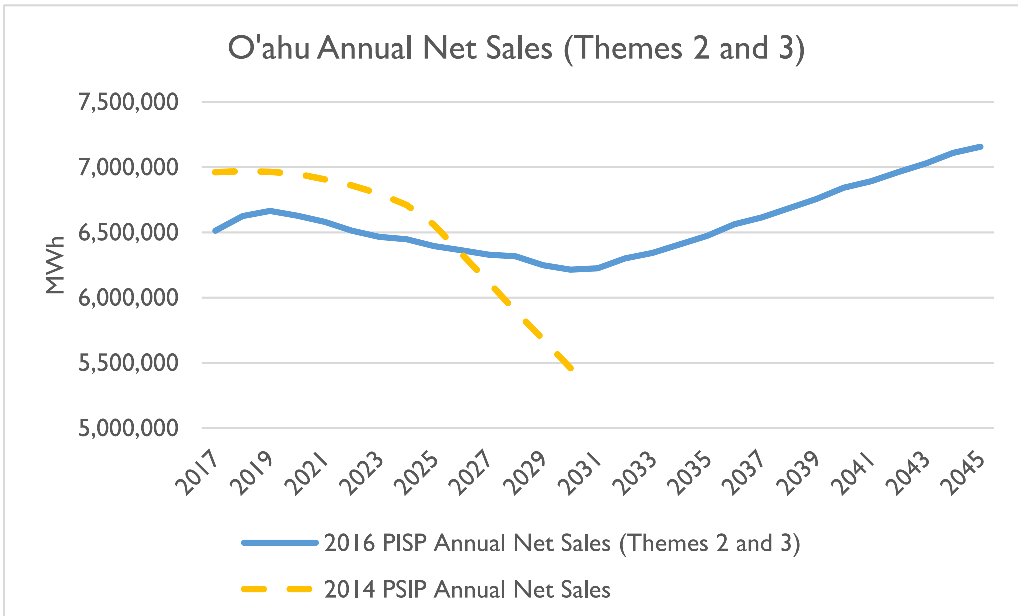


Figure I-5. Impact of Energy Efficiency Portfolio Standard on Sales

These sales volume changes are allocated across all customer classes in the PSIP analyses and do impact both the residential rate and residential customer bill impact analyses. While factors, including the applicable level of DG-PV penetration, do impact the specific calculations by theme for each island, the calculated usage per non-DG-PV residential customer varies with the EEPS driven net sales decline, as shown in Figure I-6.

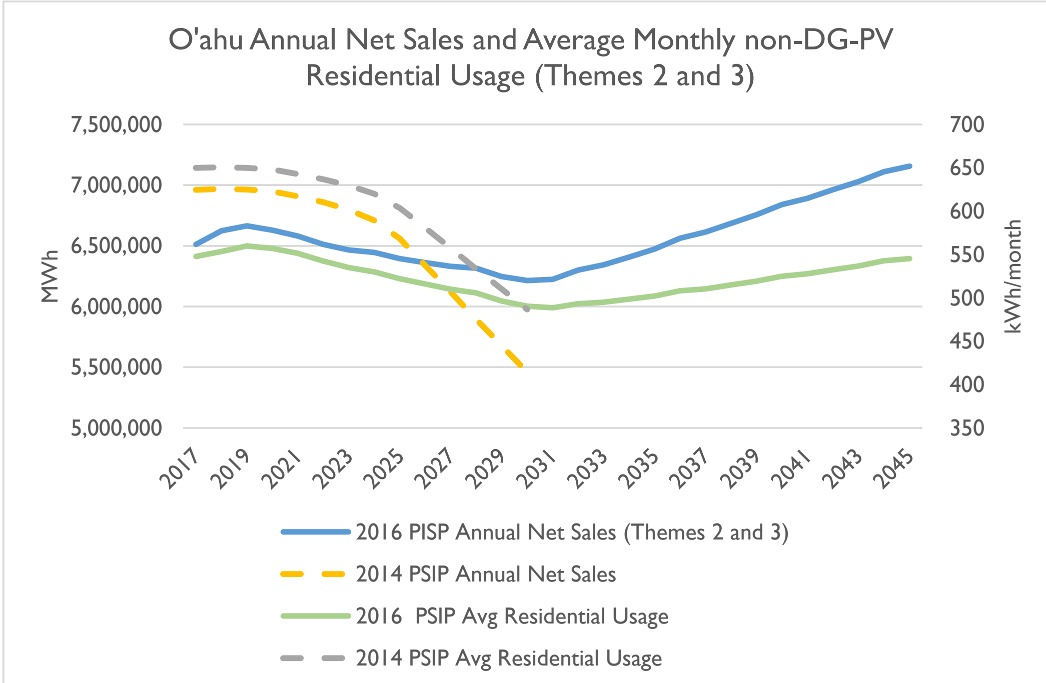


Figure I-6. Impact of Energy Efficiency Portfolio Standard on Sales & Residential Usage

Applying the Rate Change Test Iteratively

To test each merged and unmerged scenario against this initial rate change limit, we have combined the annual capital expenditures, fuel, and operating costs associated with the PSIP Preferred Plans with the annual capital expenditure and operating cost projections for the balance of the utility business to calculate an initial rate impact for each. We use the twelve month average 2015 residential rate level for each island as the starting point for this analysis. The use of a twelve month average rate provides some degree of smoothing to the very volatile monthly rates customers have experienced, due to the dramatic swings in oil prices.

For any year in which an operating utility plan results in a rate change greater than the annual ceiling, we review and adjust the timing and magnitude of the capital expenditures associated with the balance of the utility business.

Through iteration we calculate a balance-of-utility business capital expenditure profile that results in annual rate changes less than or equal to the ceiling in all years of the planning period and is consistent across all themes, so as to ease direct comparison of revenue requirements and customer bill impacts between themes.

Alignment with Existing Capital Plans and Ability to Meet Customer Requirements Test

This top-down, balance-of-utility business constrained capital expenditure plan will be reviewed to ensure that it reflects investment levels that will continually meet customer requirements for new service, maintain or enhance service reliability, and enable timely modernization of the grid to enable the distributed energy resources called for in the PSIP Preferred Plans. Management judgment will be applied to the timing and magnitude of the total capital expenditure plan to adjust as appropriate so as to ensure these critical customer requirements will be met. This may result in specific years where the resulting rate change is higher than the initially targeted ceiling.

This judgment will be applied consistent with the capital allocation process that is now being utilized. This process allocates available capital funds to types of work through a prioritization process at the type of work level, rather than to specific projects. This is a higher level prioritization than was used in the 2014 PSIPs. (Further information on the Companies' prioritization process will be provided as part of the Capital Budget Workbook update to be filed following this PSIP.)

Resource Usage Test

Lastly, final balance-of-utility business capital expenditure plan will be reviewed from a resource management perspective. Cost effective execution of capital work requires effective use of existing and future company resources, especially in transmission and distribution. A degree of consistency in the level of investment is highly desirable given the availability and mobilization costs of contract resources in Hawaiʻi and the required investment and timeline for training and development of Company resources. Here again, management judgment will be applied to determine if adjustments to the magnitude and timing of the final balance-of-utility business capital expenditure plan is required.

OPERATIONS AND MAINTENANCE EXPENSES

Operating and maintenance (O&M) expenses are a broad category of expense, which we have projected in three distinct ways. First, PSIP-related O&M is projected for each resource plan as modeled, based on the resource cost, retirement, and transition costs associated with each resource plan. Second, for Smart Grid and ERP, specific O&M cost adjustments are used, consistent with the respective General Order 7 applications.[3] The remaining operating and maintenance costs are projected to increase at the rate of

[3] Applications to the Commission for approval to commit funds in excess of $2.5 million.

inflation over the 30 year forecast period. The starting point for projected these future costs are 2015 actual expenses.

This assumption represents an intense pressure on operating costs, as labor costs comprise a significant percentage of these operating costs and skilled labor costs have consistently risen at rates above inflation in recent years. When this relationship is extended out over 30 years, it implies either a reversal of this labor cost relationship or very significant productivity gains must be achieved in order to meet this operating cost projection. If such gains are not achieved, future operating costs will be higher than the costs incorporated into the customer bill impact and rate analyses.

TAXES OTHER THAN INCOME AND PUBLIC BENEFITS FUND

A material component of a customer’s total electric bill is comprised of various taxes the Companies pay, as well as the public benefit fund charge the Companies collect to fund Hawaiʻi Energy’s energy efficiency programs. The laws and regulations that govern these taxes and fees are assumed to remain constant throughout the forecast period. Taxes on fuel that are assessed volumetrically are projected consistent with the plan’s expected fuel consumption. Other fees are assumed to increase at the rate of inflation.

The current public benefit fund charge of 2% of electric revenues, including revenue taxes, has been applied throughout the planning period.

RETURN ON AND OF EXISTING UTILITY ASSETS

The Companies have $4.1 billion of net utility assets, as of December 31, 2015, including $1.0 billion of generating property, plant, and equipment assets. These existing assets are currently used and useful for utility service, are being depreciated, and the net balance is in rate base earning a return, based on the authorized capital structure and return on equity. The customer bill impact and rate impact analysis assumes the currently authorized capital structure, return on equity, and interim rate adjustment mechanisms are constant over the forecast period. Similarly, the analyses assume that depreciation rates for existing plant remain the same. Lastly, the analyses assume that upon retirement, undepreciated plant balances are transferred to a regulatory asset amortized over 20 years and that removal costs in excess of removal costs already recovered from customers, if any, are given the same regulatory treatment.

CAPITAL INVESTMENTS IN POWER SUPPLY ASSETS

For each theme's resource plan, all of the capital investments associated with the plan are summed by year to reflect the total annual capital expenditure for the new resources envisioned in the plan. In addition, each plan also includes the capital expenditures required for the major reliability investments for each existing generating unit that is expected to operate well into the 2030s or beyond. Lastly, routine generation capital expenditures already planned for 2017 through 2020 are included, and a provision of $1 million per year per unit for capital expenditures associated with break or fix activities is included for each existing generating unit that remains operational beyond 2020.

These capital expenditures have all been modeled using the traditional rate base approaches for determining revenue requirements and customer rates. This approach assigns the capital cost recovery risk for these investments to customers and to the extent certain customers disconnect from the grid or significantly reduce their grid consumption, capital cost recovery would be shifted to the remaining customers. While the Company is not yet in a position to make a specific proposal, we believe it is likely that capital cost recovery for certain of these power supply investments would be appropriately treated as a cost that cannot be bypassed. To the extent that we determine this is the case, we would anticipate including such a recommendation as part of any filing seeking approval of such a capital project.

BALANCE-OF-UTILITY BUSINESS CAPITAL INVESTMENTS

The iterative top down methodology uses capital investments, excluding power supply, also referred to as "balance-of-utility business" capital expenditures, as the adjustable input to achieve an acceptable rate trajectory. The balance of utility business capital expenditures are divided into two specific categories:

Very large projects, requiring GO7 approval, specifically Smart Grid and ERP/EAM, are shown with the total cost assuming the Next Era merger is consummated. Total capital expenditures and deferred software costs for these projects[4] are projected as follows:

- Smart Grid: $346 million
- ERP/EAM: $52 million
- All other utility capital expenditures.

[4] These are the cost estimates available at the time of this analysis. For the most complete and current cost estimates for these projects, please refer to the most recent filings applicable to each.

It should be noted that capital expenditures for new office or yard facilities are not included in the customer bill impact and rate impact analyses. If, as the Company continues to evaluate our facility requirements in the normal course of business, new facility investments can be justified, those would be evaluated on a stand-alone business case basis.

To frame the level of balance-of-utility business capital expenditures required over the forecast period, we considered several sources and perspectives. These include:

- Balance-of-utility business capital expenditure benchmark data for US utilities indicate that for utilities with aging T&D assets, capital expenditures in the $400 to $600 per customer per year range are typical. This would suggest the following ranges for each Hawaiian Electric Company:
  - Hawaiian Electric: $120 million to $180 million
  - Maui Electric: $30 million to $45 million
  - Hawai‘i Electric Light: $30 million to $45 million
- Hawaiian Electric’s most recent five years have averaged approximately $190 million
- Engineering assessments across the Hawaiian Electric grids indicate significant reliability and capability issues that need to be addressed to ensure reliable service, particularly so given Hawaii’s exposure to hurricanes and other major storms.
- Historical averages for a panel of US utilities indicate that approximately $7.5 billion in balance of business utility capital expenditures are required for each 1% growth in GDP. Using DBEDT’s forecasted growth rate of 2.33%, the projected balance-of-utility business capital expenditures are:
  - Hawaiian Electric: $178 million
  - Maui Electric: $44 million
  - Hawai‘i Electric Light: $43 million

Given these data, it is expected that the combination of the PSIP Preferred Plan capital expenditures and rate change limits will constrain balance-of-utility business capital expenditures for at least the first 10 to 15 years of the planning period in both merged and unmerged scenarios.

RETIREMENT AND REMOVAL COSTS

All of the Preferred Plans call for the deactivation and subsequent retirement of existing fossil generation units. For financial modeling, each unit is considered to be retired two years after it is deactivated, unless reactivation is explicitly planned in the resource plan. Further, we have assumed that each unit is removed in the year following retirement.

The net book value at retirement and the removal costs represent prudent expenditures that have served customers for many years and thus will need to be recovered from customers. We expect to seek Commission approval for recording these costs as a regulatory asset, to be amortized and recovered from customers over the 20 years following unit retirement. The financial results presented in this report are based on this approach.

Table I-1 presents the net book value of the units to be retired, annual depreciation expense, as well as the estimated removal costs for each.

Millions / Unit	Net Book Value: December 31, 2015	Annual Depreciation Expense	Estimated Removal Costs
Honolulu 8 & 9	$49.4	$1.6	$20.0
Waiau 3 & 4	$22.7	$0.9	$20.0
Waiau 5 & 6	$39.8	$1.2	$20.0
Kahe 1–3	$76.7	$2.4	$30.0
Kahe 4	$24.9	$1.0	$10.0
Kahului 1–4	$5.4	$1.4	$10.9
Puna Steam	$11.4	$0.4	$4.0
Hill 5 & 6	$14.5	$1.0	$9.0

Table I-1. Financial Data of Units to Be Retired

With the shift to renewable energy sources, several of the resource plans call for converting the generator of retired generating units for use as a synchronous condenser. In those cases, we have assumed that the generator assets and common plant that continue to be used for synchronous condenser operations will have a net book value of $2 million per unit that will remain in service and $1 million of removal costs will be avoided.

The net book value at retirement and the removal costs incurred represent prudent expenditures that have served customers for many years and thus will need to be recovered from customers. The financial results represent recovery of these costs from customers over a 20-year period following unit retirement.

In prior PSIPs, we modeled the recovery of retirement and removal costs through a securitization mechanism. While this approach could be used, it may not prove to be cost effective because these costs are somewhat smaller than previously anticipated and are spread out over a number of years. This makes the administrative costs of establishing and using a securitization mechanism appear impractical.

We expect to seek Commission approval for recording these costs as a regulatory asset, to be amortized and recovered from customers over the 20-years following unit retirement.

There is one aspect of a standard utility securitization that does seem to be appropriate for these costs. Recovery of these costs on a non-bypassable basis from all current and future customers would be appropriate, as all current customers have benefited from the use of these assets. While this rate design topic is beyond the scope of this 2016 updated PSIP, we suggest that this concept be considered in future rate design discussions relating to retirement and removal costs.

J. Modeling Assumptions Data

The Hawaiian Electric Companies created this PSIP based, in parts, on a realization of the current state of the electric systems in 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.

This appendix summarizes the assumptions utilized to perform the PSIP analyses. It includes:

- Reliability criteria
- Utility cost of capital
- Fuel price forecasts and availability
- Energy sales and peak demand forecasts
- Resource capital costs
- Demand response data inputs

RELIABILITY CRITERIA

Adequacy of Supply

Every year, we file an Adequacy of Supply (AOS) report. This report indicates how the generation capacity on each island's power grid is able to meet all reasonably expected demand as well as provide a reasonable reserve to meet emergencies. The AOS incorporates a Loss-of-Load Probability (LOLP) of, at most, one outage day every 4½ years in its overall capacity planning criteria.

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.

Required Regulating Reserve

General Electric (GE), working under a contract with the Hawai‘i Natural Energy Institute (HNEI)[1], developed a formula for determining the amount of regulating reserve necessary to maintain the minute-to-minute balance between supply and demand on the O‘ahu grid. The formula is:

Required regulating reserve amount equals the sum of:

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

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

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

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

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

Required regulating reserve amount equals the sum of:

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

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

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

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

The greater of 6 MW, or

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

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

UTILITY COST OF CAPITAL AND FINANCIAL ASSUMPTIONS

The Hawaiian Electric Companies finance their investments through two main sources of capital: debt (borrowed money) or equity (invested money). In both cases, we pay a certain rate of return for the use of this money. This rate of return is our *Cost of Capital*.

Table J-1 lists the various sources of capital, their weight (percent of the entire capital portfolio), and their individual rates of return. Composite percentages for costs of capital are presented under the table.

Capital Source	Weight	Rate
Short Term Debt	3.0%	4.0%
Long Term Debt (Taxable Debt)	39.0%	7.0%
Hybrids	0.0%	6.5%
Preferred Stock	1.0%	6.5%
Common Stock	57.0%	11.0%

Composite Weighted Average 9.185%
After-Tax Composite Weighted Average 8.076%

Table J-1. Utility Cost of Capital

FUEL PRICE FORECASTS AND AVAILABILITY

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.

This appendix summarizes the assumptions utilized to perform the PSIP analyses.

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

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

Petroleum-Based Fuels

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

When the 2015 AEO was published in April 2015 Brent crude oil was approximately $60 a barrel. Over the remainder of 2015 Brent crude oil continued to drop to below $40 per barrel at the end of 2015, which is below the 2015 AEO low economic growth case which estimated 2016 Brent crude oil at over $50 per barrel. Because the 2016 Annual Energy Outlook (2016 AEO) update from the EIA is not expected until June 2016, alternative Forward/Hybrid pricing forecasts were initially presented in the Interim PSIP to account for the Companies' expectation that 2016 AEO forecasts would be lower than the 2015 AEO. However, since the time the Interim PSIP was filed, the Companies developed an alternative fuel price forecast which relies on the more recent February 2016 EIA Short Term Energy Outlook (STEO), which is published by the EIA on a monthly basis and accounts for current market prices. This newly developed forecast (STEO Adjusted Forecast) utilizes the 2016 and 2017 Brent crude oil forecasts from the February 2016 STEO and is escalated using similar escalation factors as those for the EIA 2015 AEO Brent crude oil forecast. It is the Companies' view that this pricing curve under the STEO Adjusted Forecast is a more conservative (lower prices) estimate than what the EIA 2016 AEO Reference forecast may be when released in June, 2016. To capture the potential for higher future prices and objectively assess the competitiveness of competing resources that reduces the risk of high commodity prices, the 2015 AEO fuel price forecast remains unchanged from the Interim PSIP.

Biodiesel forecasts are generally derived by comparing commodity forecasts with recent biofuel contracts and RFP bids to determine adjustments needed to derive each company's respective biodiesel price forecast from forecasted commodities. EIA provides low, reference, and high petroleum forecasts, which are used to project low, reference, and high petroleum-based fuel price forecasts. A similar commodity forecast has not been found for biodiesel, although EIA might provide one in the future. In lieu of such a source, the biodiesel forecast is based on the Food and Agricultural Policy Institute at the University of Missouri (FAPRI) forecast of biodiesel prices in the United States.

While the EIA forecast provides petroleum prices through 2040, FAPRI provides biodiesel pricing through 2024 and then that trend is extrapolated by Hawaiian Electric out to 2045. The EIA forecast trend is also extrapolated from 2040-2045. In the Interim PSIP Report, it was noted that as a result of extending both forecasts beyond their provided period, the extrapolated forecast resulted in an unlikely case in which biodiesel prices falling below oil prices in later years. Since the Interim PSIP Report, the biodiesel forecasts have been adjusted to correct this issue and better correlate with the respective 2015 AEO and February 2016 STEO fuel price forecasts for petroleum-based fuels.

LNG Fuel Price Forecasts

Fuel price forecasts for this PSIP Update report were developed using commodity price forecasts published by the EIA: 2015 Annual Energy Outlook (AEO) and February 2016 Short Term Energy Outlook (STEO). The 2015 EIA fuel price forecast used average Henry Hub spot prices for natural gas (2013 dollars per million Btu), adjusted from 2013 dollars to nominal dollars.

As described in the Interim PSIP, since the time the EIA 2015 Annual Energy Outlook (AEO) was published in April 2015, Brent crude oil has dropped from $60 a barrel to less than $40 a barrel, and natural gas prices dropped from $3/MMBtu to less than $2/MMBtu. Because the 2016 Annual Energy Outlook (2016 AEO) update from the EIA is not expected until June 2016, alternative Forward/Hybrid pricing forecasts were initially presented in the Interim PSIP to account for the Companies' expectation that 2016 AEO forecasts would be lower than the 2015 AEO. However, since the time the Interim PSIP was filed, the Companies developed an alternative fuel price forecast which relies on the more recent February 2016 EIA Short Term Energy Outlook (STEO), which is published by the EIA on a monthly basis and accounts for current market prices. This newly developed forecast (STEO Adjusted Forecast) utilizes the 2016 and 2017 natural gas forecasts from the February 2016 STEO and is escalated using the same escalation factors from the EIA 2015 AEO natural gas forecast. It is the Companies' view that this pricing curve under the STEO Adjusted Forecast is a more conservative (lower prices) estimate than what the EIA 2016 AEO Reference forecast may be when released in June, 2016. To capture the potential for higher future prices and objectively assess the competitiveness of competing resources that reduces the risk of high commodity prices, the 2015 AEO fuel price forecast remains unchanged from the Interim PSIP.

To develop the delivered LNG fuel price forecasts (2015 AEO and STEO Adjusted), the Companies used cost information for the pipeline transport, LNG liquefaction, transportation of the LNG, and transportation logistics from the Companies' Containerized LNG Supply to Hawaiʻi RFP and added the natural gas prices from the EIA 2015 AEO and EIA February 2016 STEO, adjusted to the Station 2 gathering point pricing in British Columbia. The EIA forecasts are based on Henry Hub pricing. Henry Hub, a Louisiana natural gas distribution hub and pricing point for natural gas futures contracts traded on the New York Mercantile Exchange (NYMEX), is currently at a 15-year price low. The price is expected to increase gradually over the next decade as the shale gas market rebalances. The LNG price forecasts used in the PSIP attempts to account for natural gas that is sourced from British Columbia. Historically, and based on the future's market pricing, gas sourced from Alberta (AECO market) and British Columbia (Station 2 gathering point) has traded at a discount to the United States Henry Hub pricing.

For Oahu's LNG pricing curves, a negative 26.5% basis was applied to create a Station 2 equivalent Henry Hub price. For example, a $2.00/MMBtu Henry Hub price would equate to a $1.47/MMBtu Station 2 price. A 4.5% adder was applied to the derived Station 2 price to account for shrinkage on the pipelines from the Station 2 gathering point to the liquefaction plant.

The Companies contemplates that the natural gas for its LNG will be procured under a daily or monthly index, gathered at Station 2 and transported on the Spectra Energy Westcoast Transmission T-South pipeline. T-South is a looped (multiple pipeline) system that moves gas from Station 2 to the Huntingdon/Sumas (Sumas) trading pool. T-South firm capacity can be procured at a rolled-in tariff rate, meaning that if capital improvements are required to increase pipeline capacity, expansion costs are borne by all users on the pipeline. Charges to use the pipeline will be at a fixed tariff CAD/GJ rate, converted to $/MMBtu. As a mature depreciating pipeline system, the general trend is towards stable long-term rates. The current rate is approximately $0.32/MMBtu.

From the Sumas hub, gas will be distributed on the Fortis regulated Coastal Transmission System (CTS) to the existing FortisBC Energy Inc. (FEI) LNG facility on Tilsbury Island in Delta, British Columbia, Canada on the Fraser River. The CTS pipeline rate is regulated under the Rate Schedule 50 (RS50) tariff in units of CAD/GJ and converted to $/MMBtu for the Hawaiian Electric contract. The FEI CTS system is designed to meet high winter peaking demand and is therefore under-utilized for a majority of the year. Therefore, if more flat non-peaking load is added, by Hawaiian Electric or other industrial demand, the general trend would be for rates to reduce. This is reflected in the RS50 rate floor which decreases as demand increases. The current tariff rate under RS50 is approximately $0.42/ MMBtu.

The LNG fuel price forecast included in Table J-2 through Table J-7 represent the total variable costs of the LNG, which includes the gas commodity, taxes, port fees, wharfage, stevedoring, and other ancillary delivery service charges. Table J-8 and Table J-9 are the total nominal LNG costs, inclusive of fixed and variable costs. Fixed costs include liquefaction, pipeline tolls (for tariff service), and shipping charges.

Hawaiian Electric Fuel Forecasted Fuel Prices—Nominal Dollars

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

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

Hawaiian Electric Fuel Forecasted Fuel Prices—Nominal Dollars

$/MMBtu	Hawaiian Electric Fuel Price Forecasts					
	Feb 2016 EIA STEOe					*2015 FAPRI Low*
Year	LSFO	Diesel	ULSD	40% LSFO/ 60% ULSD	LNG	Biodiesel
2016	$6.77	$9.28	$10.22	$8.78	n/a	$16.37
2017	$9.07	$11.67	$12.67	$11.16	n/a	$20.82
2018	$9.69	$12.34	$13.38	$11.83	n/a	$22.90
2019	$10.10	$12.80	$13.86	$12.28	n/a	$22.78
2020	$10.48	$13.24	$14.32	$12.71	n/a	$23.00
2021	$10.87	$13.67	$14.78	$13.14	$7.19	$23.47
2022	$11.36	$14.22	$15.35	$13.68	$6.67	$23.71
2023	$11.88	$14.79	$15.95	$14.25	$6.82	$23.97
2024	$12.43	$15.40	$16.58	$14.84	$6.97	$24.30
2025	$13.00	$16.03	$17.24	$15.46	$7.12	$24.61
2026	$13.60	$16.68	$17.92	$16.11	$7.28	$25.39
2027	$14.24	$17.38	$18.66	$16.81	$7.45	$26.24
2028	$14.92	$18.12	$19.43	$17.54	$7.62	$27.13
2029	$15.63	$18.90	$20.24	$18.31	$7.80	$28.05
2030	$16.38	$19.72	$21.09	$19.12	$7.98	$29.01
2031	$17.18	$20.58	$21.99	$19.98	$8.17	$30.02
2032	$18.02	$21.51	$22.96	$20.89	$8.37	$31.09
2033	$18.91	$22.47	$23.96	$21.85	$8.58	$32.21
2034	$19.85	$23.48	$25.01	$22.85	$8.79	$33.37
2035	$20.79	$24.50	$26.08	$23.86	$9.00	$34.51
2036	$21.80	$25.60	$27.21	$24.95	$9.27	$35.73
2037	$22.87	$26.75	$28.41	$26.09	$9.51	$37.02
2038	$23.96	$27.93	$29.64	$27.26	$9.80	$38.30
2039	$25.16	$29.22	$30.98	$28.54	$10.25	$39.71
2040	$26.50	$30.66	$32.48	$29.97	$10.84	$41.30
2041	$27.91	$32.06	$33.90	$31.39	n/a	$42.88
2042	$29.39	$33.62	$35.51	$32.95	n/a	$44.43
2043	$30.96	$35.27	$37.21	$34.59	n/a	$45.96
2044	$32.60	$37.00	$38.99	$36.31	n/a	$47.47
2045	$34.34	$38.81	$40.86	$38.13	n/a	$48.95

Table J-3. Hawaiian Electric Fuel Price Forecasts (2 of 2)

Maui Electric Fuel Forecasted Fuel Prices—Nominal Dollars

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

Table J-4. Maui Electric Fuel Price Forecasts (1 of 2)

Maui Electric Fuel Forecasted Fuel Prices—Nominal Dollars

$/MMBtu	Maui Electric Fuel Price Forecasts						
	Feb 2016 EIA STEO						*2015 FAPRI Low*
Year	MSFO	Diesel	ULSD (Maui)	ULSD (Moloka'i)	ULSD (Lana'i)	LNG	Biodiesel
2016	$5.54	$9.43	$9.99	$11.07	$14.08	n/a	$16.70
2017	$7.51	$12.09	$12.73	$13.78	$16.80	n/a	$21.23
2018	$8.04	$12.83	$13.49	$14.55	$17.62	n/a	$23.36
2019	$8.38	$13.33	$14.00	$15.08	$18.20	n/a	$23.23
2020	$8.71	$13.80	$14.49	$15.59	$18.76	n/a	$23.46
2021	$9.04	$14.27	$14.98	$16.09	$19.31	$9.58	$23.94
2022	$9.45	$14.87	$15.60	$16.71	$19.98	$9.12	$24.19
2023	$9.90	$15.50	$16.25	$17.38	$20.69	$9.30	$24.45
2024	$10.37	$16.16	$16.93	$18.07	$21.43	$9.50	$24.79
2025	–	$16.84	$17.64	$18.79	$22.20	$9.69	$25.10
2026	–	$17.56	$18.38	$19.54	$23.00	$9.89	$25.93
2027	–	$18.33	$19.17	$20.35	$23.86	$10.10	$26.83
2028	–	$19.14	$20.01	$21.20	$24.76	$10.32	$27.77
2029	–	$20.00	$20.89	$22.09	$25.70	$10.55	$28.74
2030	–	$20.89	$21.82	$23.03	$26.70	$10.78	$29.76
2031	–	$21.84	$22.80	$24.02	$27.75	$11.02	$30.83
2032	–	$22.86	$23.84	$25.08	$28.86	$11.27	$31.96
2033	–	$23.92	$24.94	$26.18	$30.03	$11.52	$33.14
2034	–	$25.03	$26.08	$27.34	$31.25	$11.79	$34.37
2035	–	$26.15	$27.24	$28.51	$32.48	$12.05	$35.58
2036	–	$27.36	$28.48	$29.76	$33.79	$12.37	$36.88
2037	–	$28.63	$29.79	$31.08	$35.17	$12.66	$38.24
2038	–	$29.92	$31.12	$32.43	$36.59	$13.01	$39.59
2039	–	$31.35	$32.59	$33.91	$38.14	$13.51	$41.09
2040	–	$32.94	$34.23	$35.55	$39.86	$14.16	$42.78
2041	–	$34.53	$35.85	$37.13	$41.35	n/a	$44.44
2042	–	$36.27	$37.63	$38.91	$43.17	n/a	$46.08
2043	–	$38.10	$39.51	$40.78	$45.07	n/a	$47.70
2044	–	$40.02	$41.48	$42.75	$47.07	n/a	$49.29
2045	–	$42.04	$43.56	$44.81	$49.17	n/a	$50.86

Table J-5. Maui Electric Fuel Price Forecasts (2 of 2)

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

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

Table J-6. Hawai'i Electric Light Fuel Price Forecasts (1 of 2)

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

$/MMBtu	Hawai'i Electric Light Fuel Price Forecasts					
	Feb 2016 EIA STEO					*2015 FAPRI Reference*
Year	MSFO	Diesel	ULSD	Naptha	LNG	Biodiesel
2016	$5.84	$9.88	$10.24	$11.40	n/a	$16.86
2017	$7.83	$12.46	$12.88	$13.84	n/a	$21.44
2018	$8.37	$13.19	$13.62	$14.56	n/a	$23.59
2019	$8.72	$13.68	$14.13	$15.06	n/a	$23.46
2020	$9.05	$14.15	$14.61	$15.54	n/a	$23.69
2021	$9.39	$14.62	$15.10	$16.01	$9.81	$24.18
2022	$9.81	$15.21	$15.70	$16.60	$9.34	$24.42
2023	$10.27	$15.83	$16.33	$17.22	$9.53	$24.69
2024	$10.74	$16.48	$17.00	$17.86	$9.73	$25.03
2025	$11.24	$17.16	$17.70	$18.53	$9.93	$25.35
2026	$11.75	$17.86	$18.42	$19.23	$10.14	$26.16
2027	$12.31	$18.62	$19.20	$19.98	$10.35	$27.04
2028	$12.90	$19.42	$20.02	$20.77	$10.58	$27.95
2029	$13.52	$20.26	$20.88	$21.60	$10.81	$28.91
2030	$14.17	$21.14	$21.78	$22.47	$11.04	$29.90
2031	$14.86	$22.07	$22.74	$23.39	$11.29	$30.95
2032	$15.59	$23.06	$23.76	$24.37	$11.54	$32.06
2033	$16.36	$24.11	$24.83	$25.39	$11.80	$33.22
2034	$17.17	$25.20	$25.95	$26.46	$12.07	$34.42
2035	$17.99	$26.30	$27.07	$27.54	$12.34	$35.61
2036	$18.87	$27.48	$28.28	$28.69	$12.67	$36.87
2037	$19.79	$28.72	$29.56	$29.91	$12.96	$38.21
2038	$20.74	$29.99	$30.86	$31.15	$13.32	$39.53
2039	$21.78	$31.39	$32.29	$32.52	$13.83	$40.99
2040	$22.94	$32.94	$33.89	$34.03	$14.48	$42.65
2041	$24.16	$34.46	$35.44	$35.41	n/a	$44.28
2042	$25.45	$36.15	$37.17	$37.03	n/a	$45.89
2043	$26.81	$37.92	$38.98	$38.73	n/a	$47.47
2044	$28.24	$39.79	$40.90	$40.51	n/a	$49.03
2045	$29.74	$41.75	$42.91	$42.39	n/a	$50.57

Table J-7. Hawai'i Electric Light Fuel Price Forecasts (2 of 2)

LNG Total Price Forecasts

February 2016 EIA STEO Henry Hub Spot Prices for Natural Gas–Nominal Dollars

Nominal $/MMBtu	February 2016 EIA STEO Henry Hub Natural Gas Futures		
Year	*O'ahu Total Cost*	*Maui Total Cost*	*Hawai'i Island Total Cost*
2021	$13.45	$15.82	$16.04
2022	$12.99	$15.40	$15.62
2023	$13.18	$15.63	$15.86
2024	$13.38	$15.87	$16.11
2025	$13.59	$16.12	$16.36
2026	$13.80	$16.37	$16.62
2027	$14.02	$16.64	$16.89
2028	$14.24	$16.91	$17.16
2029	$14.47	$17.19	$17.45
2030	$14.71	$17.47	$17.74
2031	$14.96	$17.77	$18.04
2032	$15.22	$18.08	$18.35
2033	$15.49	$18.39	$18.67
2034	$15.76	$18.71	$19.00
2035	$16.03	$19.04	$19.33
2036	$16.36	$19.42	$19.72
2037	$16.66	$19.77	$20.08
2038	$17.02	$20.19	$20.50
2039	$17.53	$20.76	$21.07
2040	$18.20	$21.48	$21.80

Table J-8. February 2016 STEO Henry Hub Spot Prices for Natural Gas

2015 EIA Henry Hub Spot Prices for Natural Gas (Reference Case)–Nominal Dollars

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

Table J-9. 2015 EIA Henry Hub Spot Prices for Natural Gas (Reference)

Hawaiian Electric Fuel Price Forecasts (Nominal Dollars)

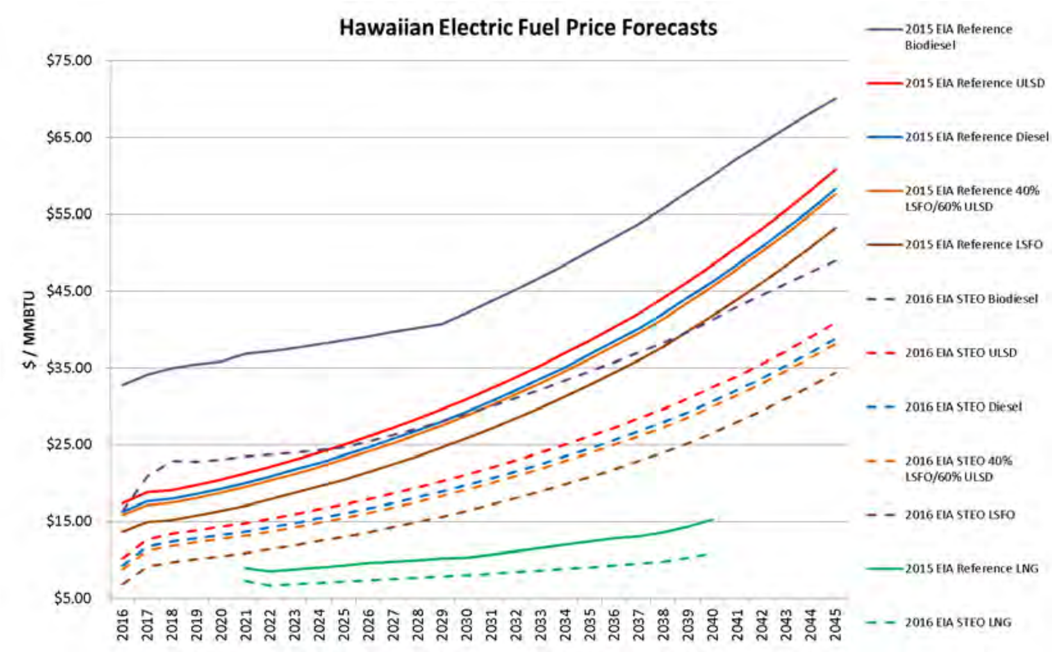


Figure J-1. Hawaiian Electric Fuel Price Forecasts

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

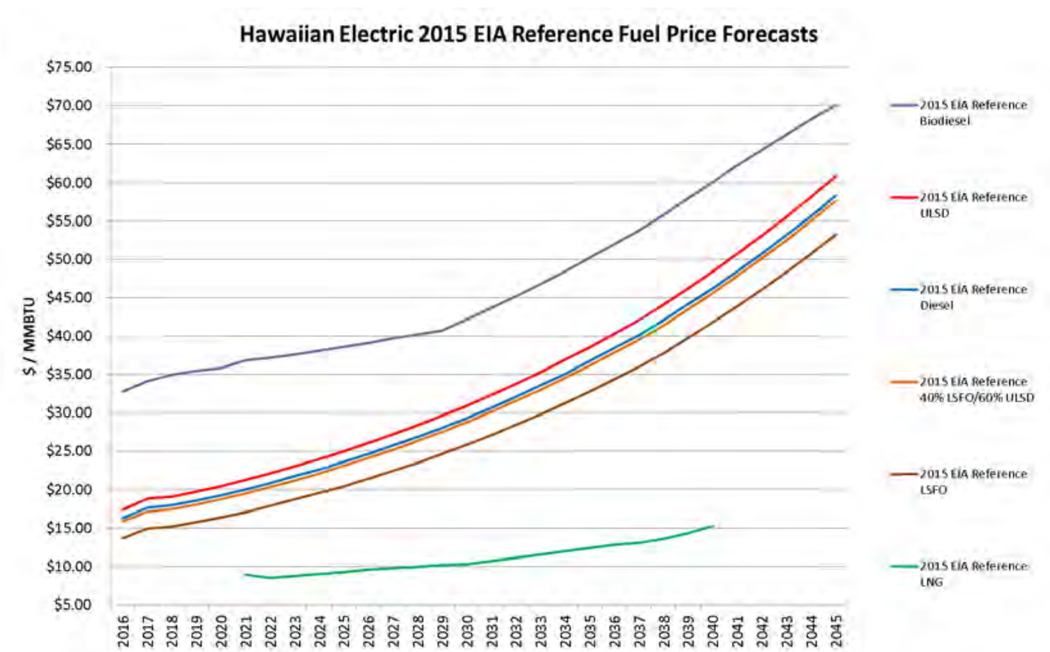


Figure J-2. Hawaiian Electric 2015 EIA Reference Fuel Price Forecasts

Hawaiian Electric February 2016 EIA STEO Fuel Price Forecasts (Nominal Dollars)

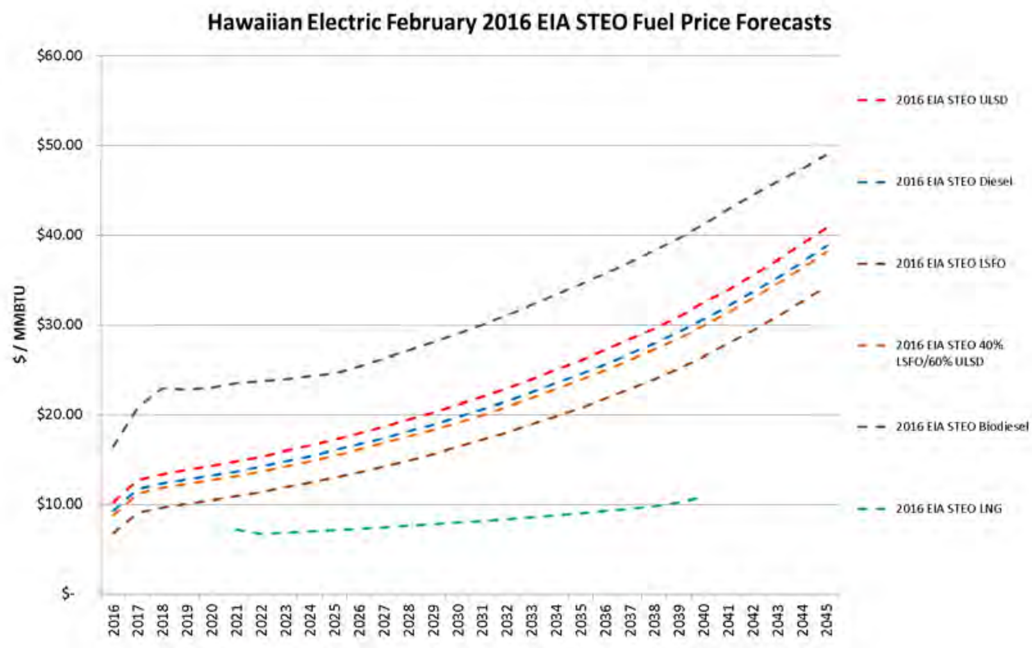


Figure J-3. Hawaiian Electric February 2016 EIA STEO Fuel Price Forecasts

Maui Electric Fuel Price Forecasts (Nominal Dollars)

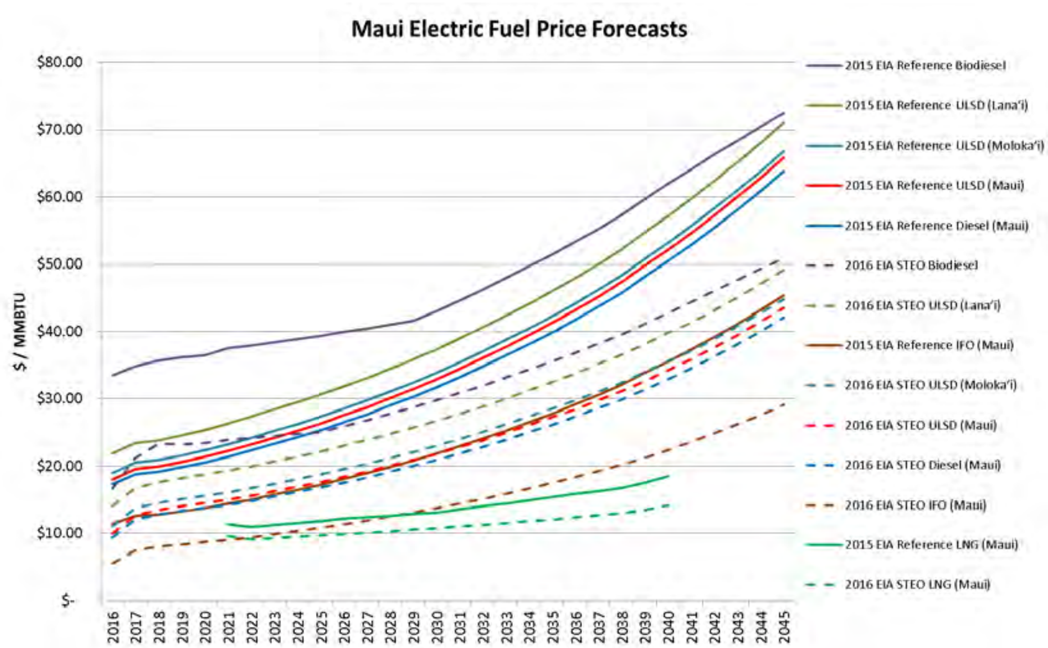


Figure J-4. Maui Electric Fuel Price Forecasts

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

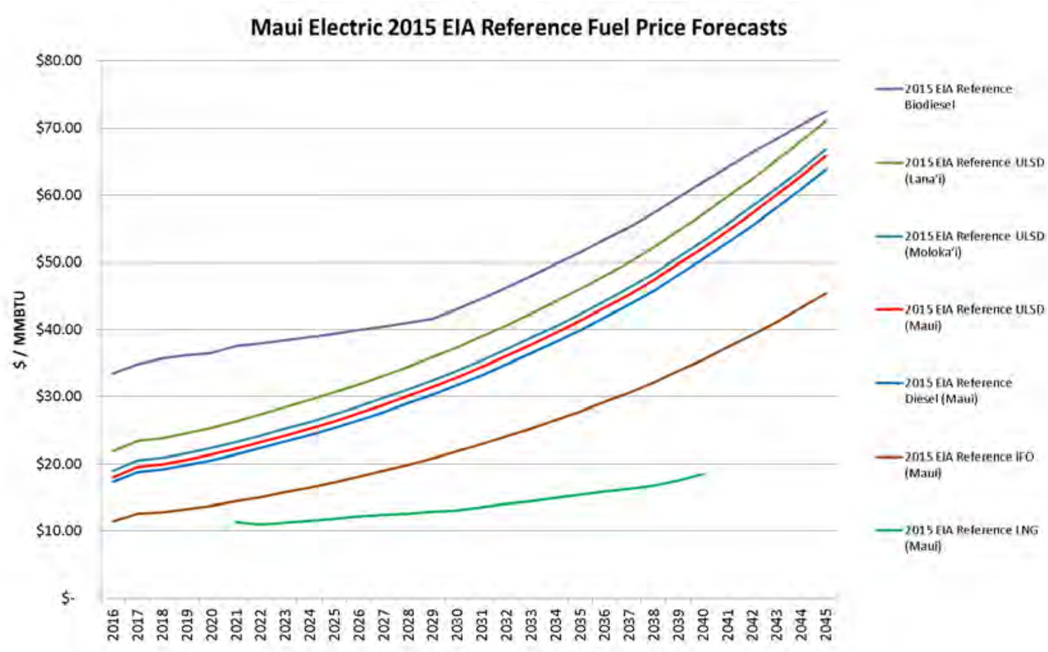


Figure J-5. Maui Electric 2015 EIA Reference Fuel Price Forecasts

Maui Electric February 2016 EIA STEO Fuel Price Forecasts (Nominal Dollars)

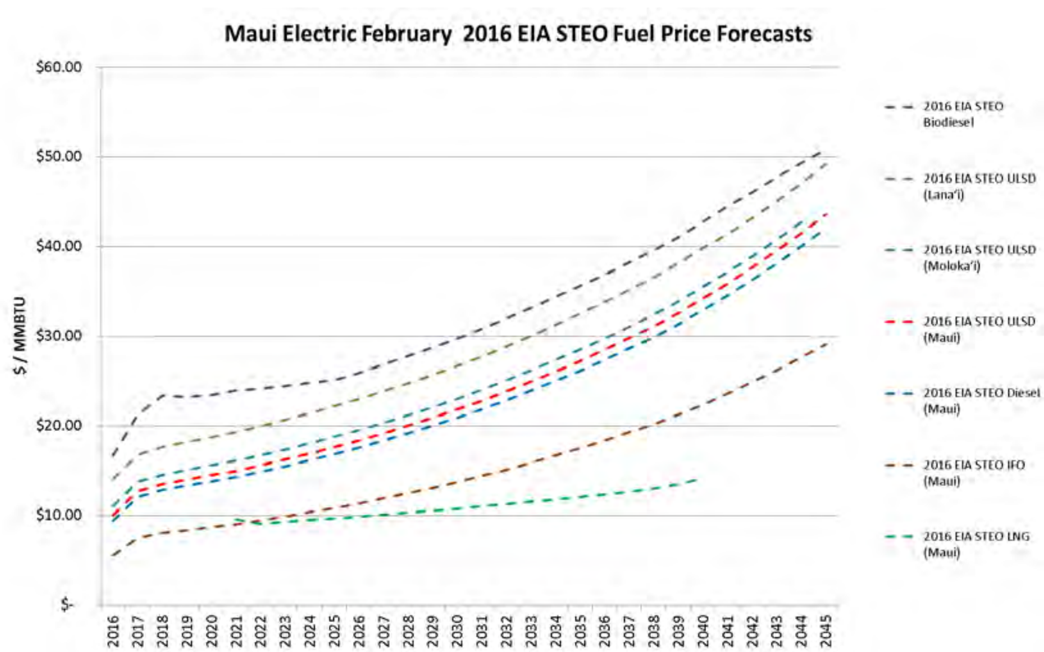


Figure J-6. Maui Electric February 2016 EIA STEO Fuel Price Forecasts

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

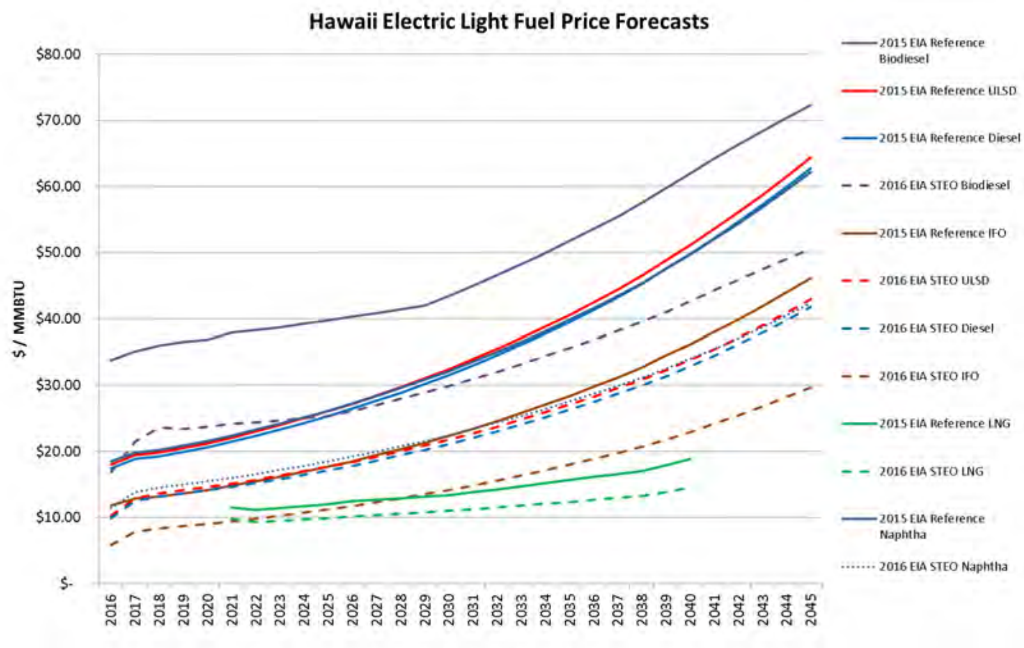


Figure J-7. Hawai'i Electric Light Fuel Price Forecasts

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

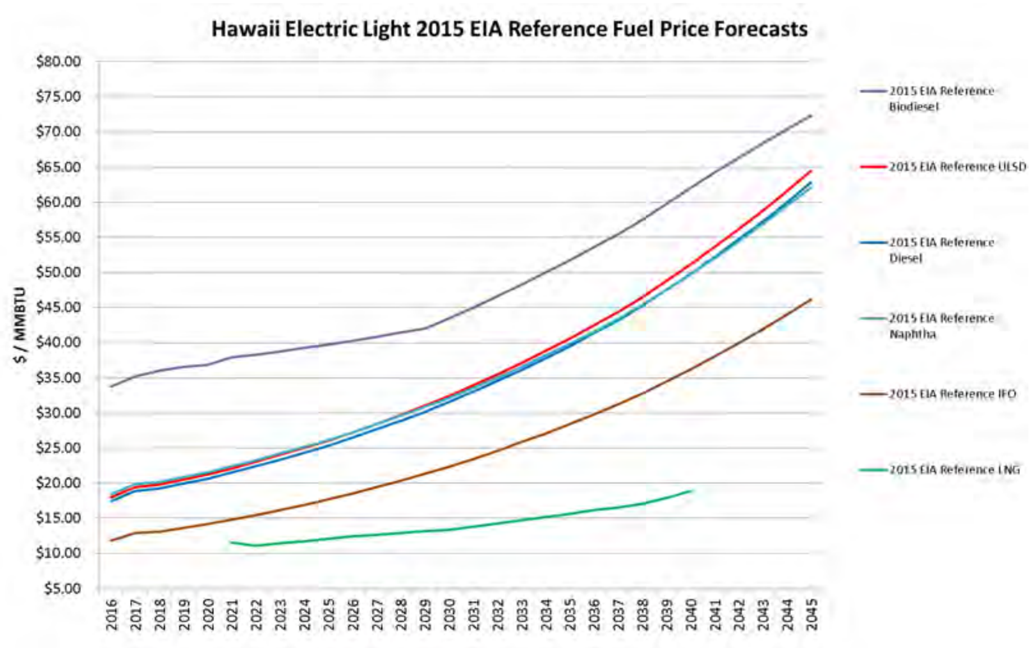


Figure J-8. Hawai'i Electric Light 2015 EIA Reference Fuel Price Forecasts

Hawai‘i Electric Light February 2016 EIA STEO Fuel Price Forecasts (Nominal Dollars)

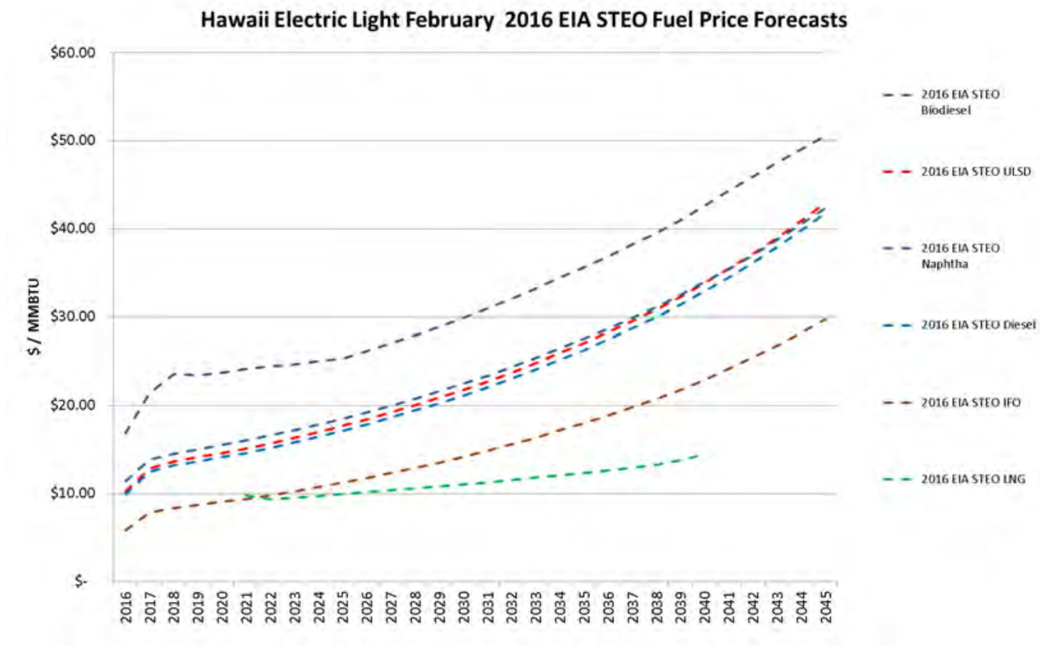


Figure J-9. Hawai‘i Electric Light February 2016 EIA STEO Fuel Price Forecasts

ENERGY SALES AND PEAK DEMAND FORECAST

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

The forecast developed for the February 2016 interim filing was one of the key assumptions that fed into the beginning of an iterative process used to determine varying levels of customer adoption of DER and participation in DR programs to achieve system optimization. As described in Appendix C: Analysis Methodologies, the PSIP optimization process involves iterative cycles that analyze DER, DR and utility-scale resources in production simulation and financial rate models toward selecting a preferred plan. Forecast sensitivities were developed as a result of varying the levels of DER and DESS adoption.

Sales and Peak Demand Projections Methodology

The Company develops sales and peak demand forecasts on an annual basis and utilizes the latest information available at the time the forecast is prepared. The sales and peak forecasts adopted in May 2015 for all islands were used as the starting point for the sales and peak demand analyses, as they were the most currently available forecasts. As part of the first iteration in the PSIP optimization process the DG projections in the May 2015 forecast were updated to reflect modifications to the existing Company tariffs identified in Decision and Order No. 33258 in Docket No. 2014-0192 received in October 2015 for use in the February 2016 interim filing. This order approved revised interconnection standards, the closing of the Net Energy Metering program and new options for customers aimed at continuing the growth of rooftop solar while ensuring safe and reliable service.

The methodology for deriving net peak demand and energy requirements to be served by the Company begins with the identification of key factors that affect load growth. These factors include the economic outlook, analysis of existing and proposed large customer loads, and impacts of customer-sited technologies such as energy efficiency measures and customer-sited distributed generation (DG-PV). Impacts from emerging technologies such as electric vehicles (EV) and storage are also evaluated given their significant potential impact on future demand for energy.

Following the February 2016 interim filing the forecasts (one per island) were updated as sensitivities associated with the DER projections were developed. Two iterations of developing DER forecasts were performed which fed into the PSIP optimization cycle.

Forecast sensitivities focused around varying the levels of DG-PV and DESS adoption as key planning assumptions were adjusted such as the inclusion of integration costs associated with DG-PV penetration and system costs as the adoption of these technologies are sensitive to energy prices among other things.

The Company reached out to Hawaii Energy to assist with the development of alternative energy efficiency forecasts to better address potential uncertainties. At this time, it is a work in progress that is not be available to support the April 2016 PSIP analyses, however, as part of a larger iterative cycle, the PSIP analyses could be incorporated into the ongoing Energy Efficiency Technical Working Group process.

Energy Sales Forecast

In general, the underlying economy driven sales forecast ("underlying forecast") is first derived by using econometric methods and historical sales data, excluding impacts from energy efficiency measures and DG. This methodology captures the impact of economic growth, which are typically the most influential factor when forecasting long-term changes in sales and peak demand. Estimates of impacts from energy efficiency measures, DG installed through the Company's tariffed programs and electric vehicles (referred to as "layers") are then incorporated to adjust the underlying forecast to arrive at a preliminary sales forecast. This methodology is illustrated below in the following chart (Figure J-10). The forecast is then used to drive the DER optimization routine.

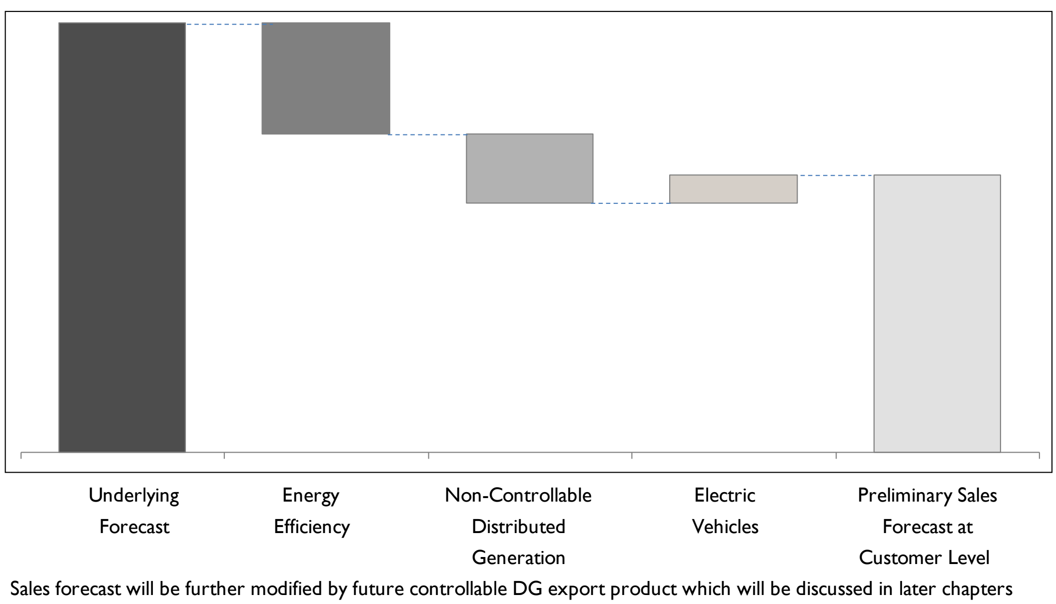


Figure J-10. Illustrative Waterfall Methodology for Developing the Sales Forecast

The forecasted sales used to be served by each operating company through the study period expressed at the customer level is shown in Figure J-11 through Figure J-15. This forecast depicts the starting point of the iterative cycle used in the February 2016 interim filing analyses. Data for the sales forecast projections are detailed in Table J-10 through Table J-14.

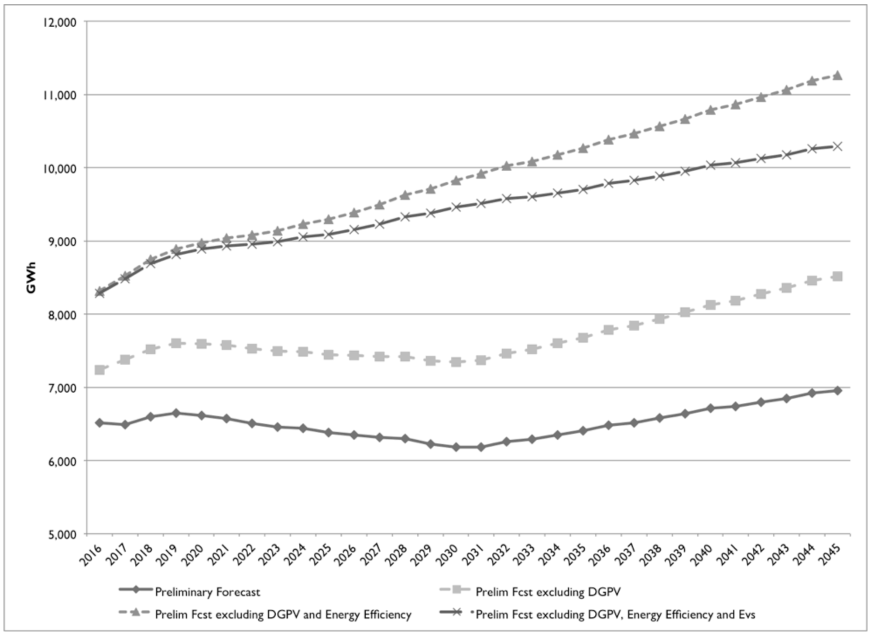


Figure J-11. O'ahu Customer Level Sales Forecast

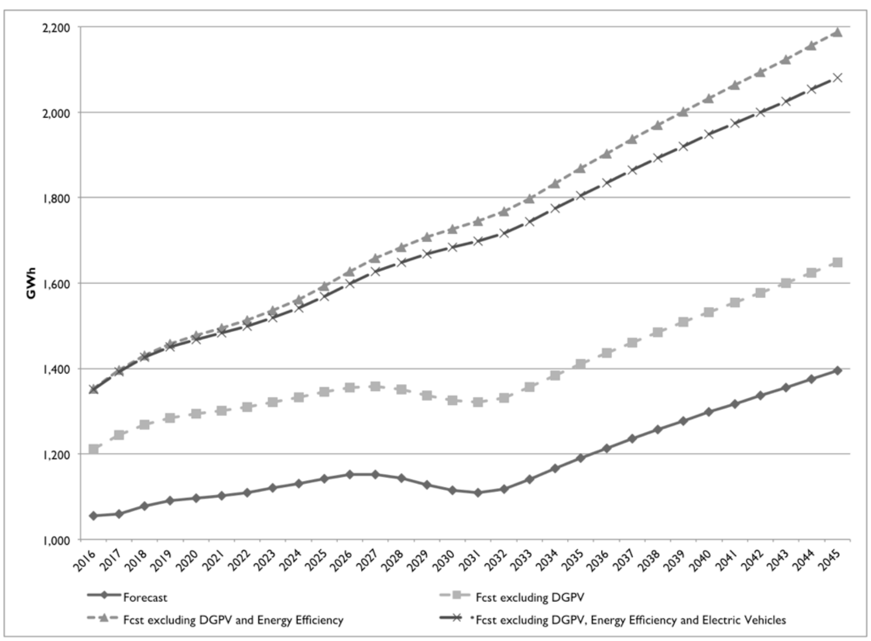


Figure J-12. Maui Island Customer Level Sales Forecast

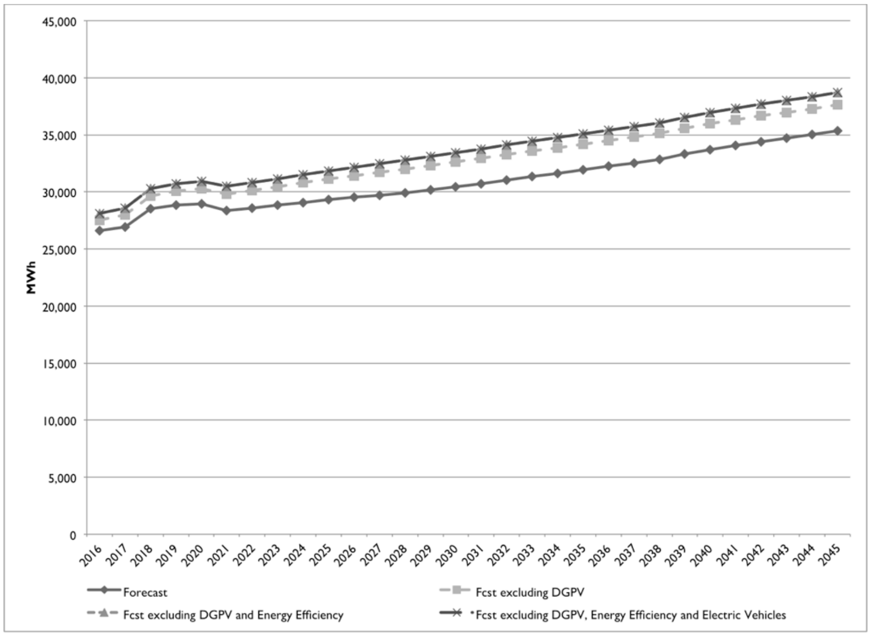


Figure J-13. Lana‘i Customer Level Sales Forecast

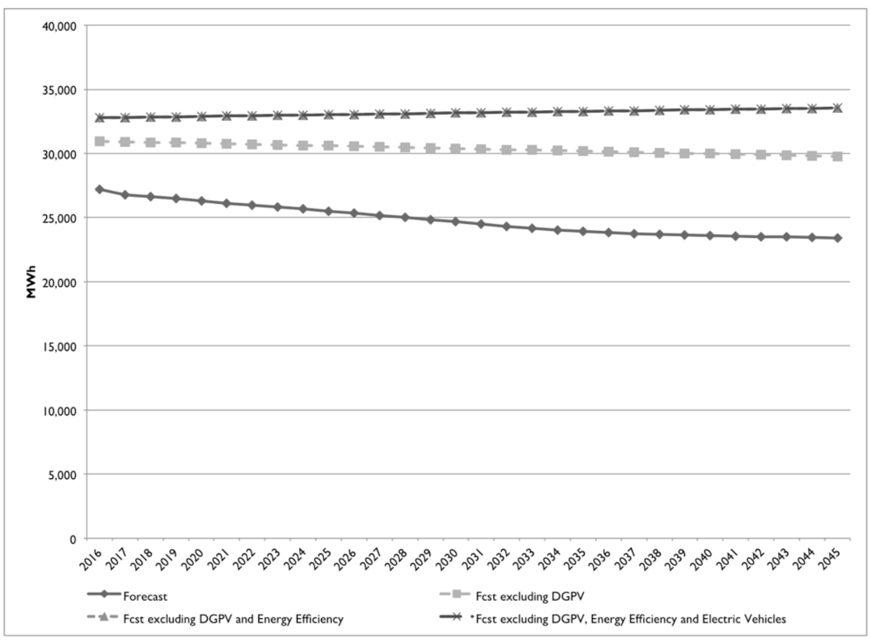


Figure J-14. Moloka‘i Customer Level Sales Forecast

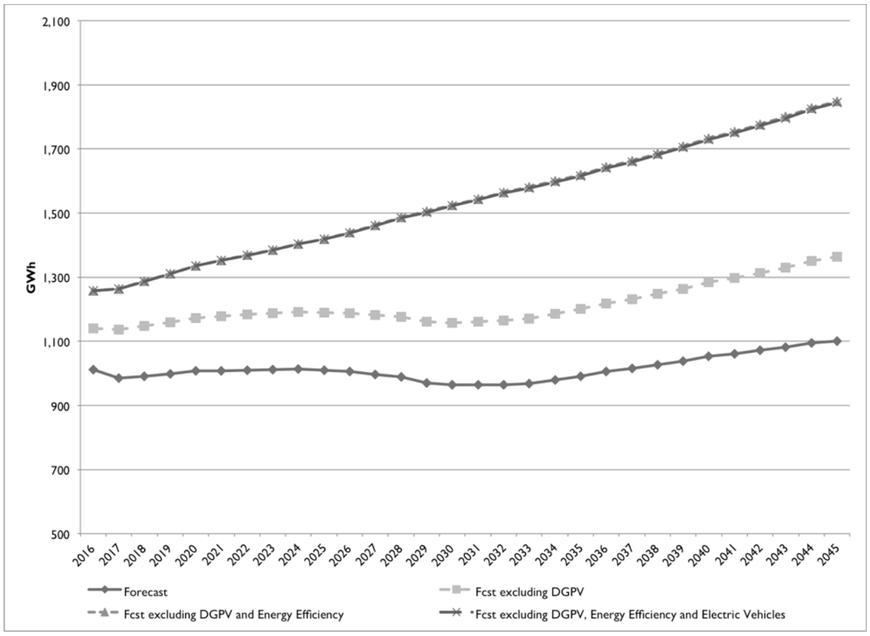


Figure J-15. Hawai'i Island Customer Level Sales Forecast

Following the February 2016 interim filing two additional DER forecasts were developed as part of the second iteration in the optimization cycle.

Underlying Forecast. The underlying forecast incorporates projections for key drivers of the economy prepared by the University of Hawai'i Economic Research Organization (UHERO) in April 2015 such as job counts, personal income and resident population. Electricity price and weather variables are also included in the models.

Energy Efficiency. The preliminary projections for impacts associated with energy efficiency measures over the next five to ten years were assumed to be consistent with historical average annual impacts achieved by the Public Benefits Fund Administrator, Hawai'i Energy. In addition to the impacts from Hawai'i Energy's programs, changes to building and manufacturing codes and standards would be integrated into the marketplace over time contributing to market transformation. Collectively, these changes would support energy efficiency impacts growing at a faster pace in order to meet the longer term energy efficiency goal in 2030 (expressed in GWh). This pace is identified in the framework that governs the achievement of Energy Efficiency Portfolio Standards (EEPS) in the State of Hawai'i as prescribed in Hawai'i Revised Statutes § 269-96, and set by the Commission in Decision and Order No. 30089 in Docket No. 2010-0037. It was assumed the 30% sales reduction goal would continue beyond 2030. The preliminary projections did not consider participation in DR programs.

To determine the peak demand savings from energy efficiency, an average annual ratio between historical efficiency sales and peak impacts was applied to the projected annual energy impacts.

There is a significant uncertainty regarding the degree customers will engage in the adoption of energy efficiency measures, building practices and participation in DR programs. This will have a direct impact on projected sales and peak demand levels. If customer adoption is lower than projected, then demand for energy could exceed the forecasted levels and conversely, higher than projected would lower customer demand for energy. Over the 30-year planning period, participation may be higher or lower than the forecast depending on factors such as customer preferences, general economic conditions and availability of affordable technology. Although all future unknowns cannot be identified, the Company will work together with Hawaiʻi Energy to develop alternative energy efficiency forecasts to better understand and address potential uncertainties.

Distributed Generation. The projections for impacts associated with distributed generation photovoltaic (DG-PV) systems installed under the Company's tariffed programs (legacy NEM, SIA, grid-supply to cap, self-supply and potential future grid-supply) were developed separately by program for residential and commercial customers and aggregated into an overall forecast for DG-PV systems. As part of the iteration process three DG-PV forecasts were developed.

Iteration 1 – February 2016 interim filing

In the near term (through 2017) assumptions based on recent historical activity were made regarding the timing of system installations associated with the remaining applications in the legacy NEM queue. Near term SIA projections (through 2017) were based on known projects with anticipated installation dates in the two year window. Beyond 2017 the Company used a customer adoption model developed by Boston Consulting Group which forecasted future quantities of grid-supply up to the cap, self-supply, SIA and potential future grid-supply DG-PV systems. The model examines the relationship between economics and DG-PV adoption based on payback time, net present value (NPV) and internal rate of return (IRR) from the customer's perspective. For the potential future grid-supply program, it was assumed that exported to the grid would be compensated at utility-scale PV LCOE. A methodology was developed to calculate integration costs, but not yet incorporated in the DG PV adoption forecast.

Figure J-16 through Figure J-18 depicts the preliminary DG-PV forecasts for Oʻahu, Hawaiʻi Island, and Maui developed in iteration 1 to support the February 2016 interim report.

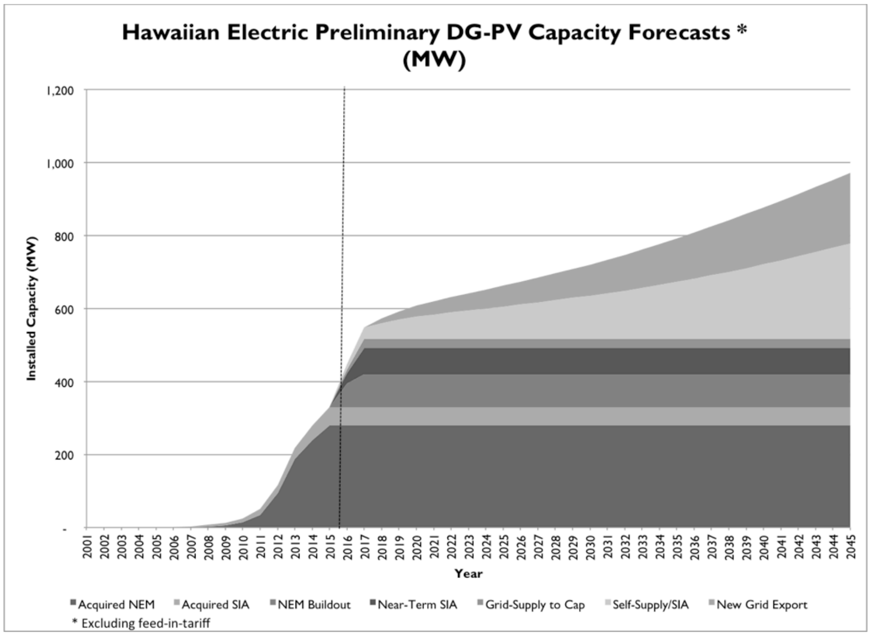


Figure J-16. O‘ahu Preliminary DG-PV Capacity Forecasts

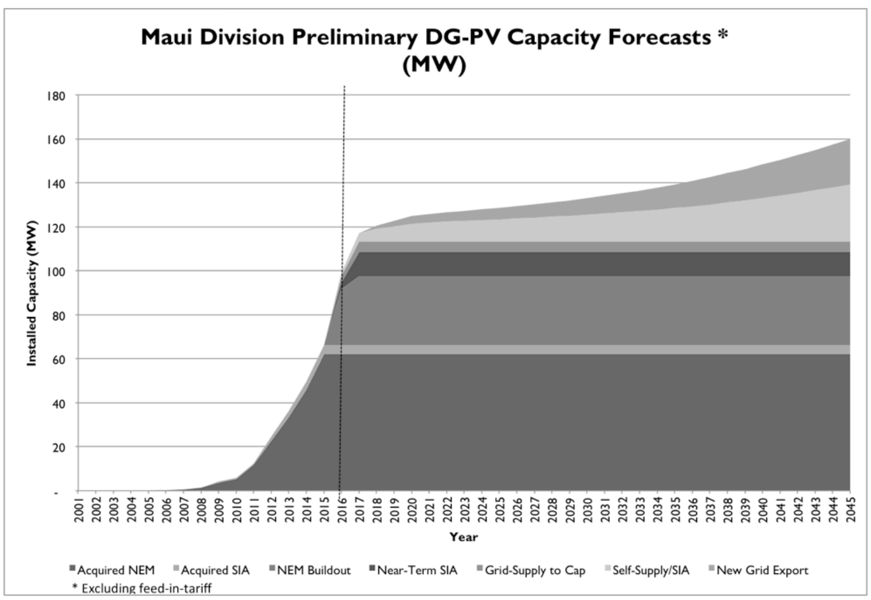


Figure J-17. Maui Island Preliminary DG-PV Capacity Forecasts

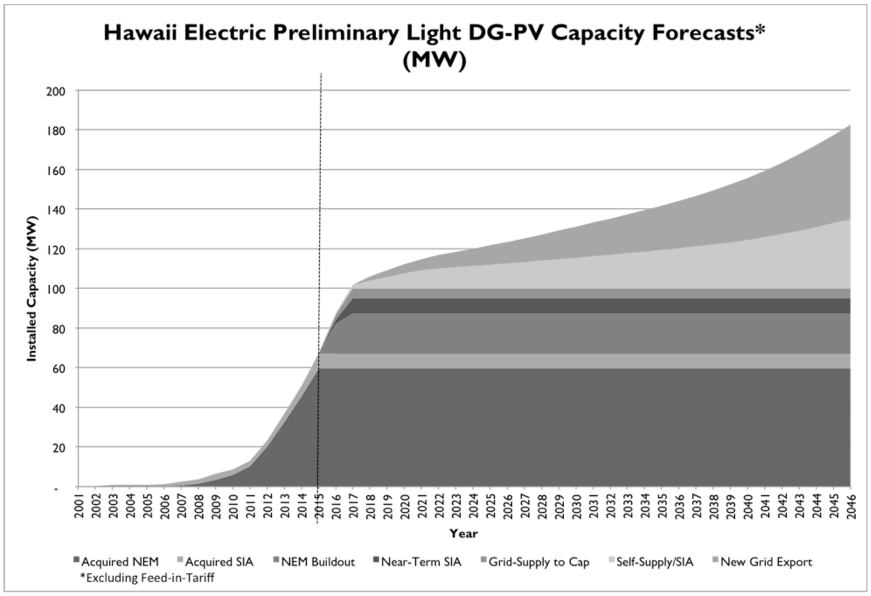


Figure J-18. Hawai'i Island Preliminary DG-PV Capacity Forecasts

Iteration 2 – Inclusion of integration costs

Following the February 2016 interim filing the DG-PV forecast was updated to include integration costs to refine the forecast.

Iteration 2 – Higher DG Market Potential

A higher DG market potential forecast scenario was also developed. For the residential customers the Company assumed that 100% of the single-family residential electricity sales would be offset by DG-PV by 2045. The Company assumed that it was unlikely to offset 100% of the commercial customers' load given the amount of rooftop space required and therefore focused on business sectors that currently participate or are likely to participate in a Company program. Roughly 20-25% of the total commercial sales would be offset by DG-PV in 2045 for all islands with the exception of Lanai (7%) which has fairly low participation to date.

The forecast was not done from a maximum rooftop potential perspective and did not consider whether it was cost effective from a customer or system level perspective. To achieve this higher level of DG-PV will likely require mandates or significant additional customer incentives.

See Figure J-19 through Figure J-23 for a comparison between the three DG-PV forecasts. Data corresponding to the DG-PV forecast figures are detailed in Table J-25 through Table J-29.

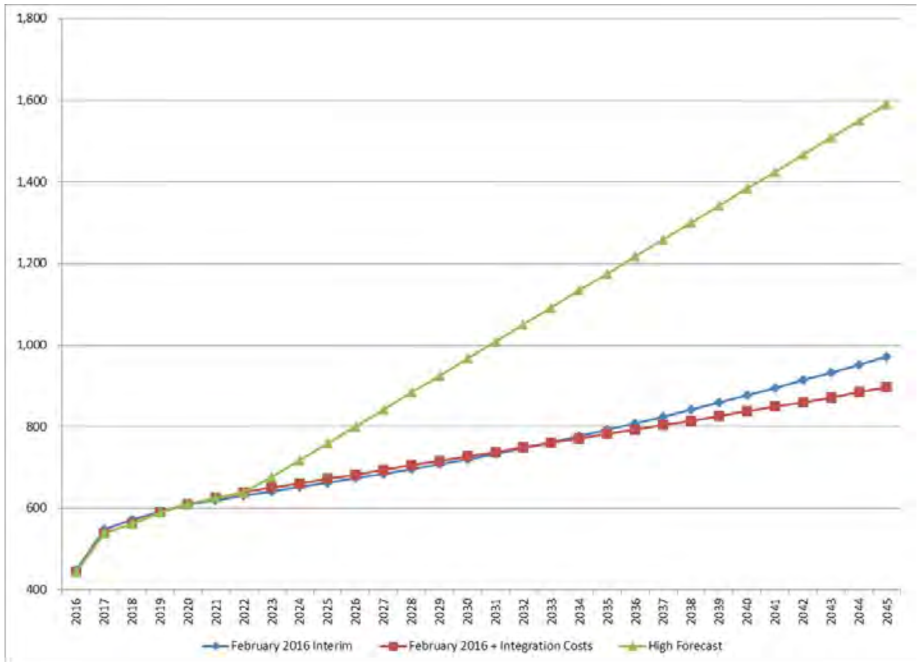


Figure J-19. O‘ahu DG-PV Capacity Forecast Comparison

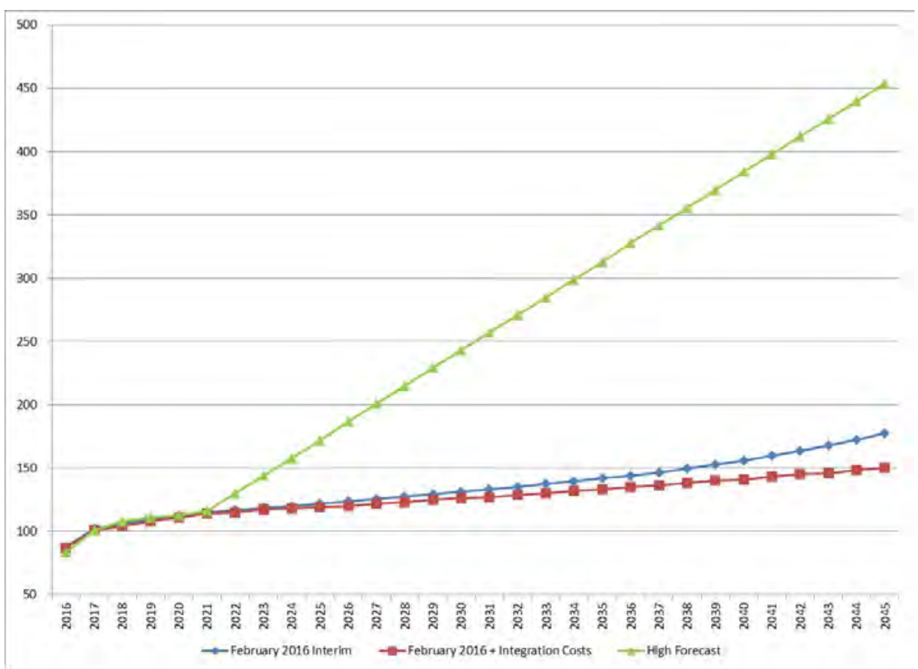


Figure J-20. Maui Island DG-PV Capacity Forecast Comparison

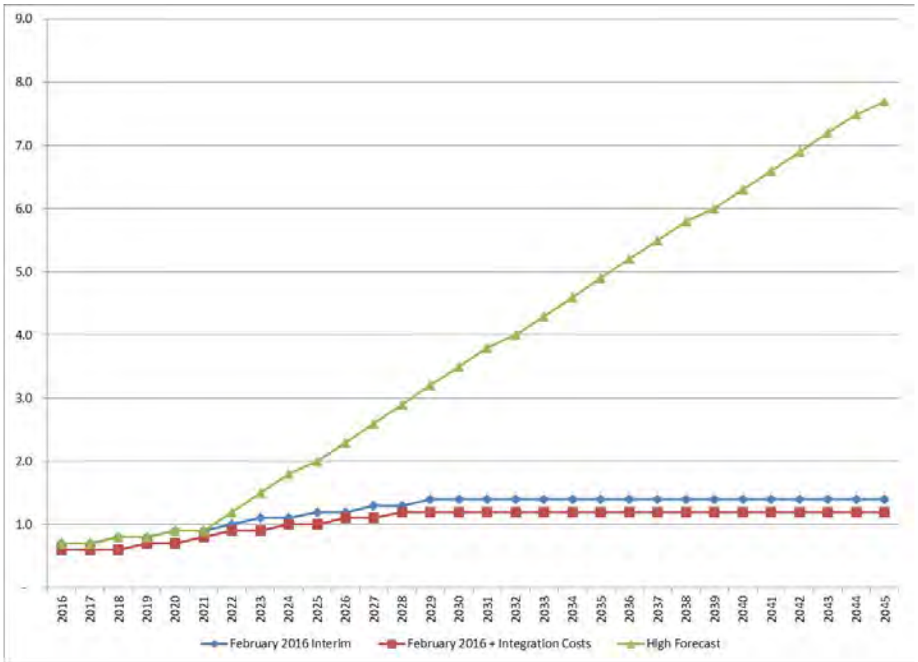


Figure J-21. Lana'i Island DG-PV Capacity Forecast Comparison

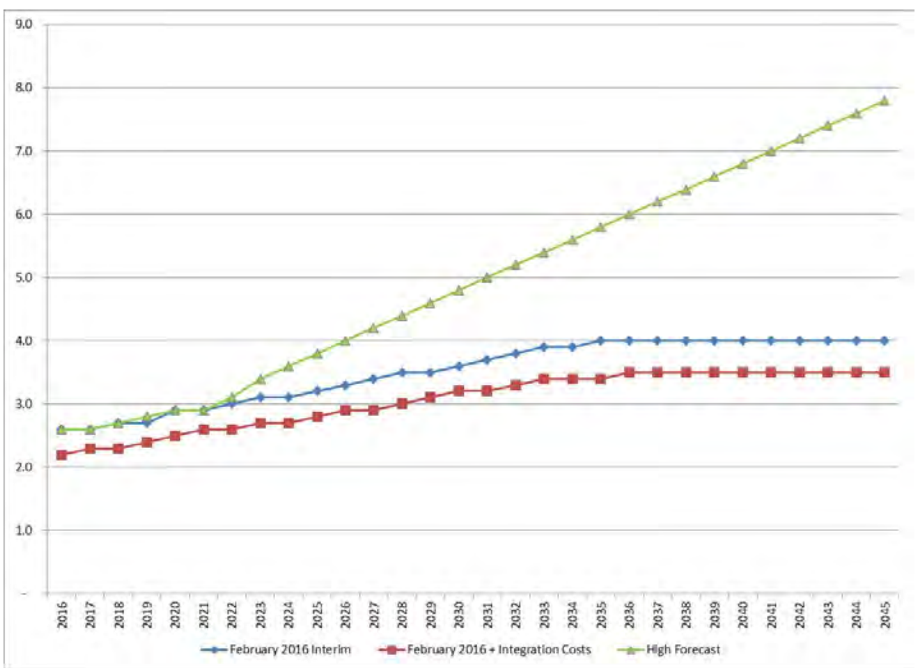


Figure J-22. Moloka'i Island DG-PV Capacity Forecast Comparison

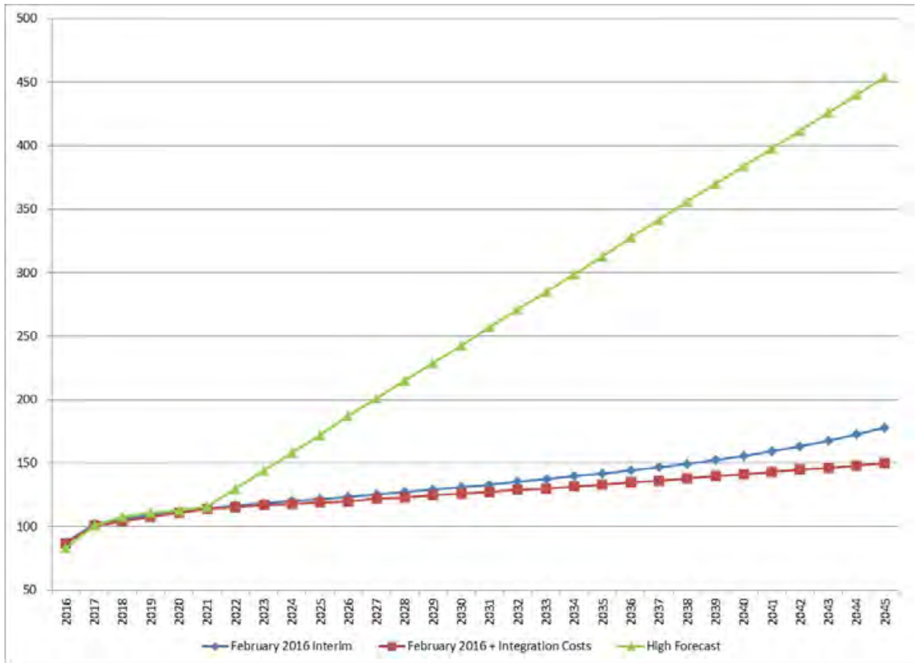


Figure J-23. Hawai'i Island DG-PV Capacity Forecast Comparison

Electric Vehicles. The development of the electric vehicles forecast was based on estimating the number of electric vehicles purchased per year using a historical average annual growth rate then multiplying by an estimate of the annual energy used per vehicle. The annual energy used per vehicle was based on the average miles driven per year as stated in the Hawaiʻi Data Book multiplied by the energy required per mile averaged over a 2015 Nissan Leaf, Chevy Volt, Chevy Spark and Tesla Model S.

Peak Demand Forecast

The peak demand forecast was derived using Itron's proprietary modeling software, MetrixLT. The software utilizes load profiles by rate schedule from class load studies conducted by the Company and the underlying sales forecast derived by rate schedule. The rate schedule load profiles adjusted for forecasted sales are aggregated to produce system profiles. The Company employed the highest system demands to calculate the underlying annual system. After determining the underlying peak forecast, the Company made adjustments that were outside of the underlying forecasts, for example impacts from energy efficiency measures. No adjustments were made to the underlying system peak forecast for DG-PV or electric vehicles as forecasted system peaks are expected to occur during the evening.

The underlying peak forecast for Lana'i and Moloka'i Divisions were derived by employing a sales load factor method which compares the annual sales in MWh against the peak load in MW multiplied by the number of hours during the year.

The peak demands of each operating company forecasted through the study period expressed at the net generation level are in Figure J-24 through Figure J-28 and do not include the impacts of customers' distributed storage systems or the effects of DR programs on the peaks. Data for the peak forecast projections are detailed in Table J-15 through Table J-19.

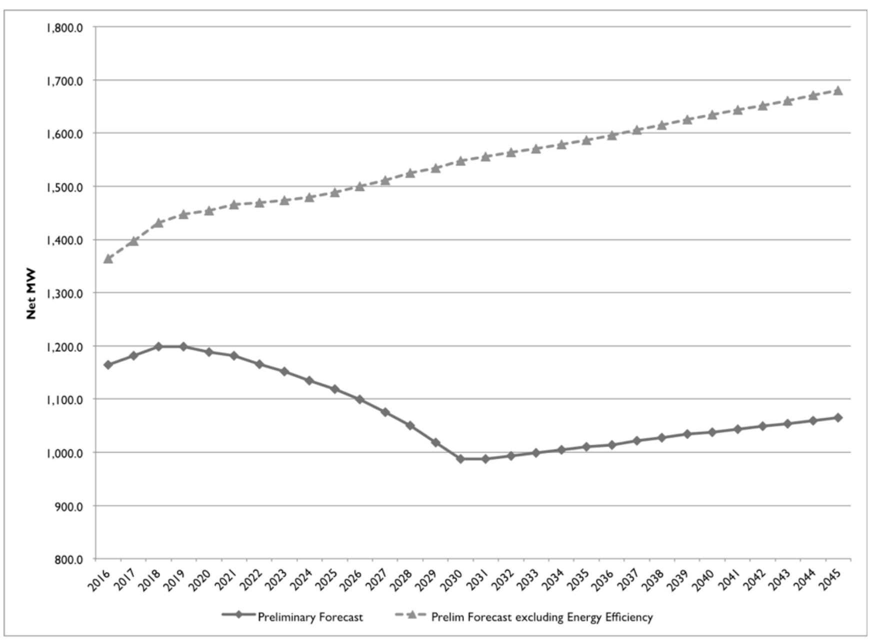


Figure J-24. O'ahu Generation Level Peak Demand

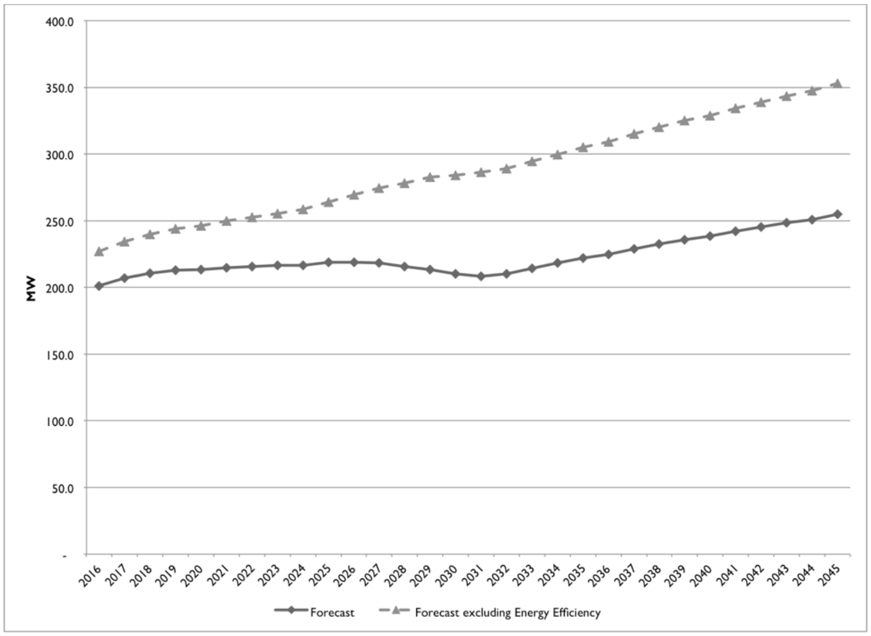


Figure J-25. Maui Island Generation Level Peak Demand

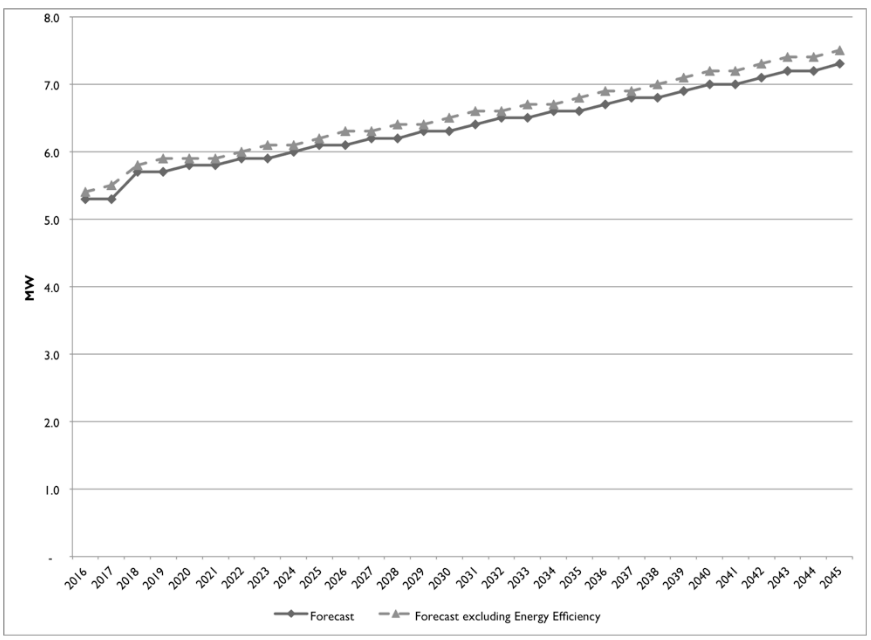


Figure J-26. Lana'i Generation Level Peak Demand

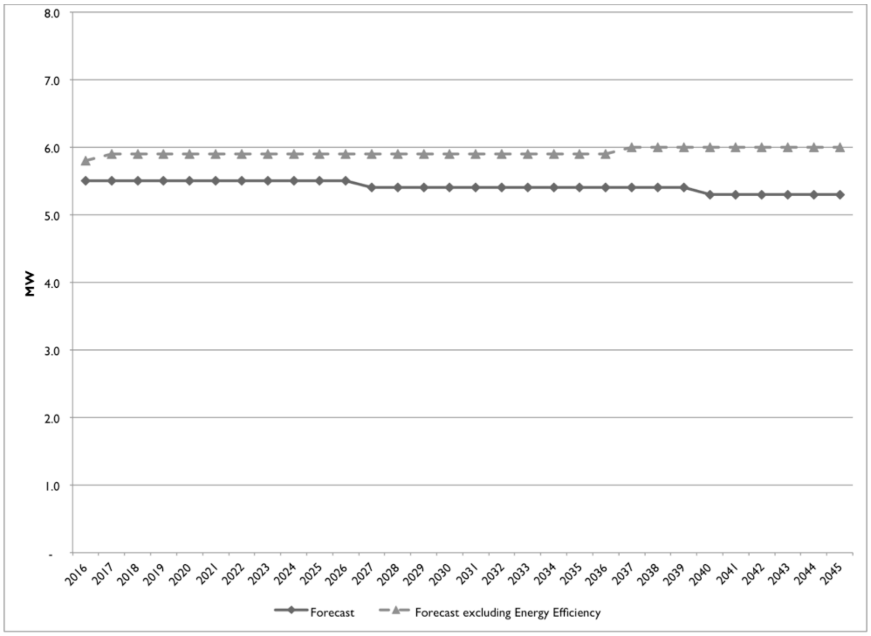


Figure J-27. Moloka'i Generation Level Peak Demand

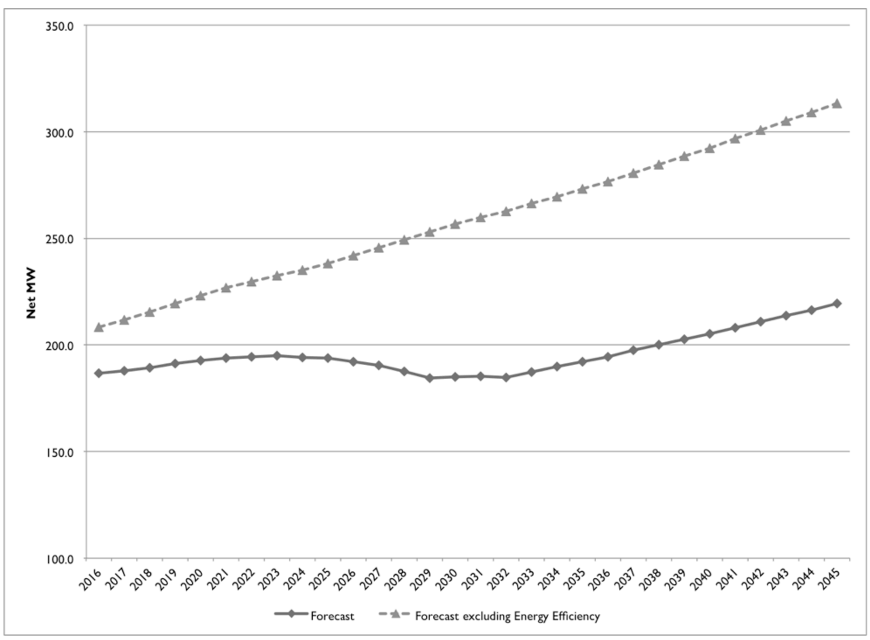


Figure J-28. Hawai'i Island Generation Level Peak Demand

Comparison to the August 2014 PSIP Forecast

The forecasts used in this filing are generally lower than the forecast used in the August 2014 PSIP filing for Hawaiian Electric and Hawaiʻi Electric Light for most of the PSIP planning range (Table J-20 and Table J-24). The primary factors contributing to the lower sales forecast in this filing are: 1) slower economic growth projection used to derive the underlying sales forecast and 2) the higher preliminary DG-PV potential. Although the national and local economy has been recovering since the great recession ended, UHERO lowered their economic outlook forecast to reflect the recovery taking longer and being less resilient than previously expected.

The forecast for Maui Electric used in this filing is similar to, but slightly lower than the forecast used in the August 2014 PSIP filing for the first several years of the PSIP planning range, then generally higher in the longer term (Table J-21 through Table J-23). While the twin effects of a weaker economic outlook and higher preliminary DG-PV potential affects underlying sales for Maui; this is partially mitigated by lower electricity prices in the near-term driving consumption and offsetting downward sales pressure.

A more optimistic real personal income per capita outlook for Maui specifically in 2025 and beyond, contributes to a higher underlying sales forecast in the long-term.

The forecast for Lanaʻi Division used in this filing is higher than the previous forecast used in the PSIP filing as newer information associated with the land owner's plans were incorporated (Table J-22). The near term forecast reflects anticipated changes to the resort operations, and the long term impacts includes assumptions around an increase in the number of people on the island related to the expansion plans.

The forecast for Molokaʻi Division used in this filing is lower than the forecast used in the PSIP filing (Table J-23). The primary factor driving the lower sales forecast is impact associated with the higher preliminary DG-PV potential.

The DG-PV forecasts for all companies reflect continued customer interest in the near term including a faster pace of releasing the legacy NEM queue, the changes made to the Federal Investment Tax Credit beyond 2016, and interest in the new programs such as grid-supply and self-supply. The lower sales were partially offset by the effects of lower electricity prices driven by lower fuel oil prices and new construction projects identified between forecasts. The energy efficiency forecasts were also refreshed with additional historical years of performance by Hawaiʻi Energy and the assumption of achieving a 30% sales reduction in 2030 were applied to different sales forecast resulting in achieving different impact levels. The impacts from the energy efficiency refresh had varying results for each company. Hawaiian Electric's energy impacts were lower in the near term and higher in the long term when compared against the PSIP forecast. Hawaiʻi Electric Light's were higher in the near term and lower in the long term and Maui Division was lower for the entire planning range.

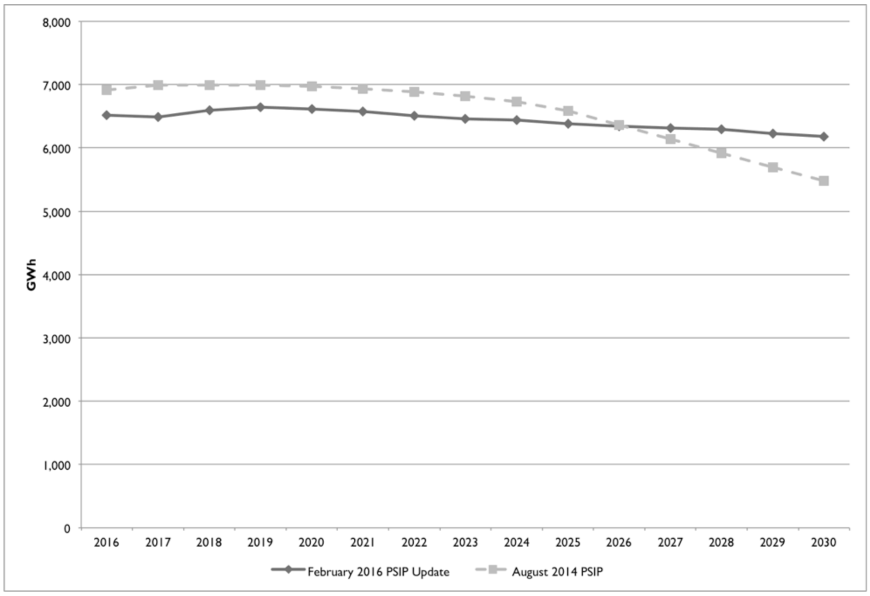


Figure J-29. O‘ahu Sales Forecast Comparison

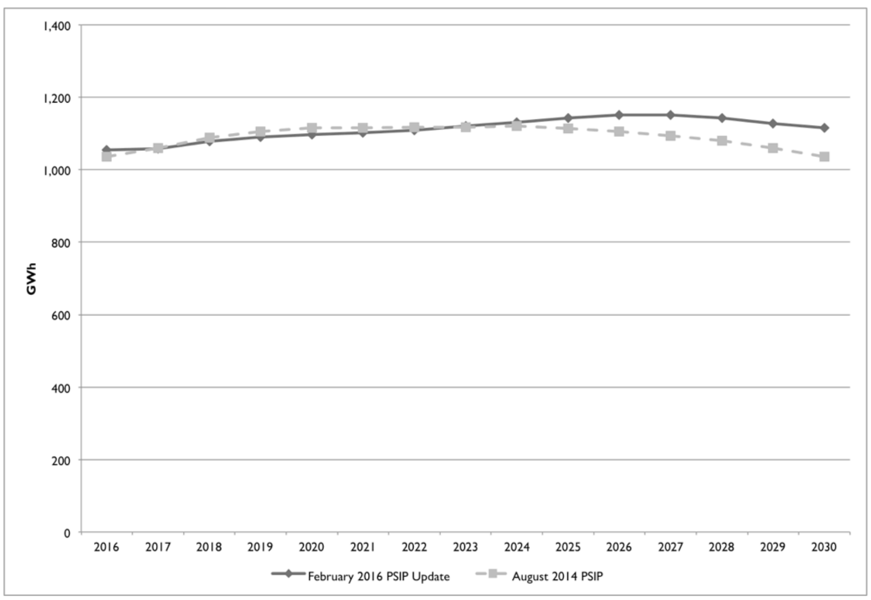


Figure J-30. Maui Island Sales Forecast Comparison

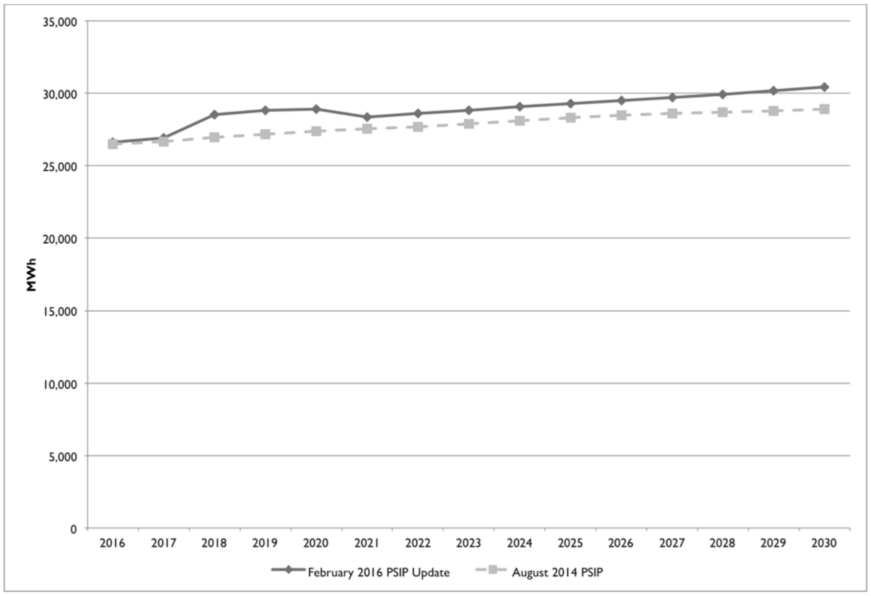


Figure J-31. Lana'i Sales Forecast Comparison

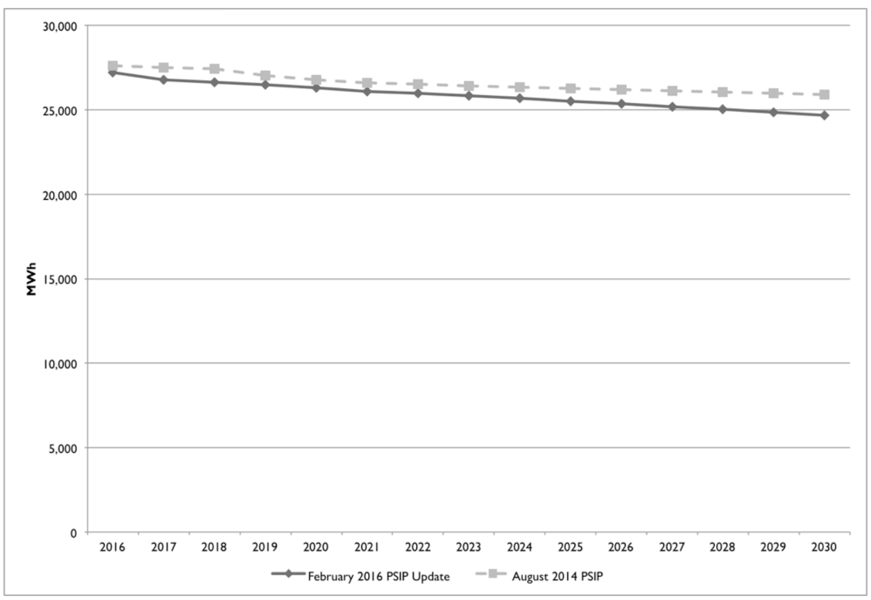


Figure J-32. Moloka'i Sales Forecast Comparison

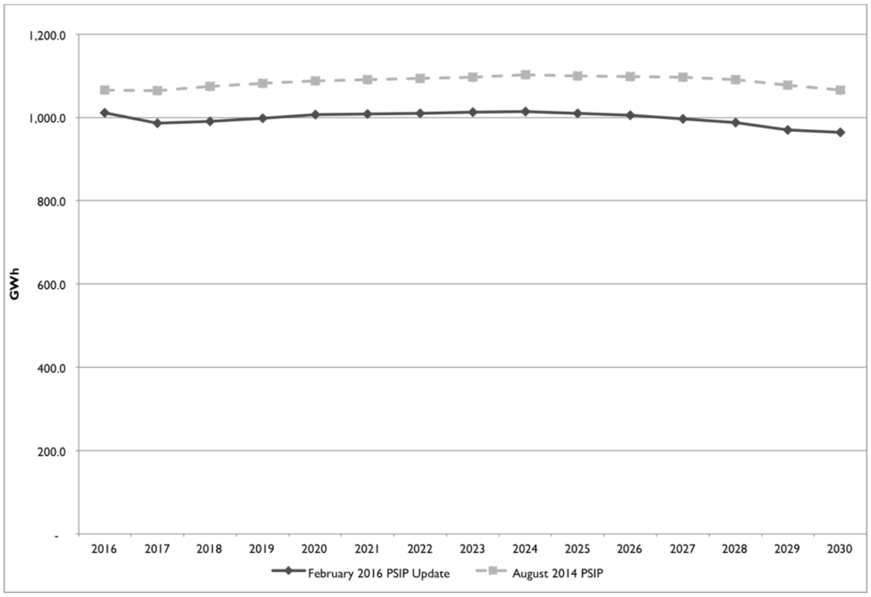


Figure J-33. Hawai'i Island Sales Forecast Comparison

See Table J-20 through Table J-24 for the detailed sales comparison between the preliminary sales forecast and PSIP sales forecast.

Note that the peak forecasts were developed using the method described in the prior page and the differences between the current preliminary forecasts and the PSIP forecast are a result of the differences in the sales forecasts.

UHERO's Economic Forecasts

UHERO's forecasts for non-farm jobs, personal income, and visitor arrivals were used in developing the sales forecasts. Figure J-34 through Figure J-367 compare the economic forecasts developed by UHERO in 2015 against the forecast developed in 2014, illustrating the less optimistic outlook between the two forecasts. See also Table J-30 through Table J-32 for a comparison between UHERO's April 2014 and April 2015 economic forecasts.

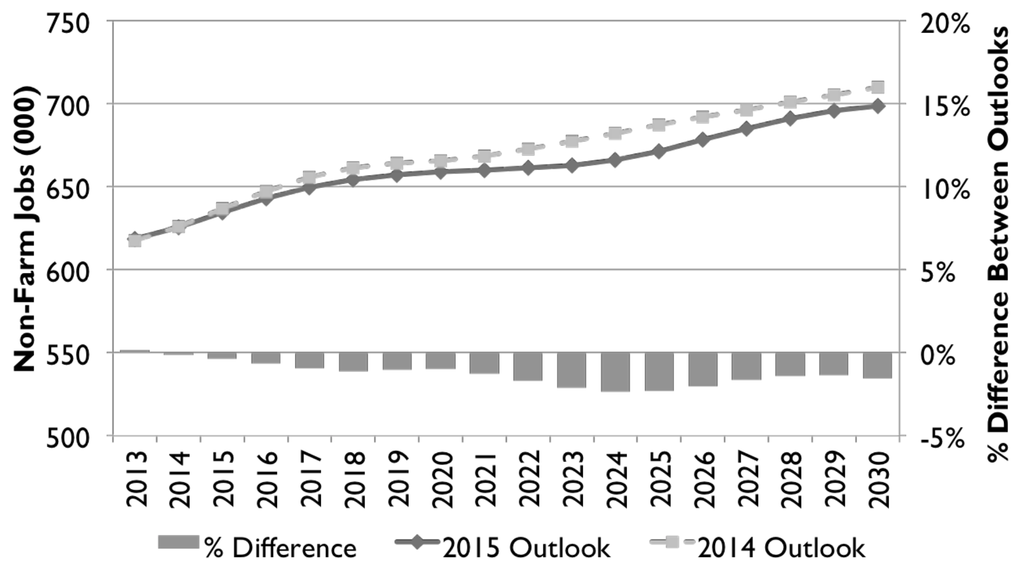


Figure J-34. Hawai'i Non-Farm Job Count Forecast Comparison

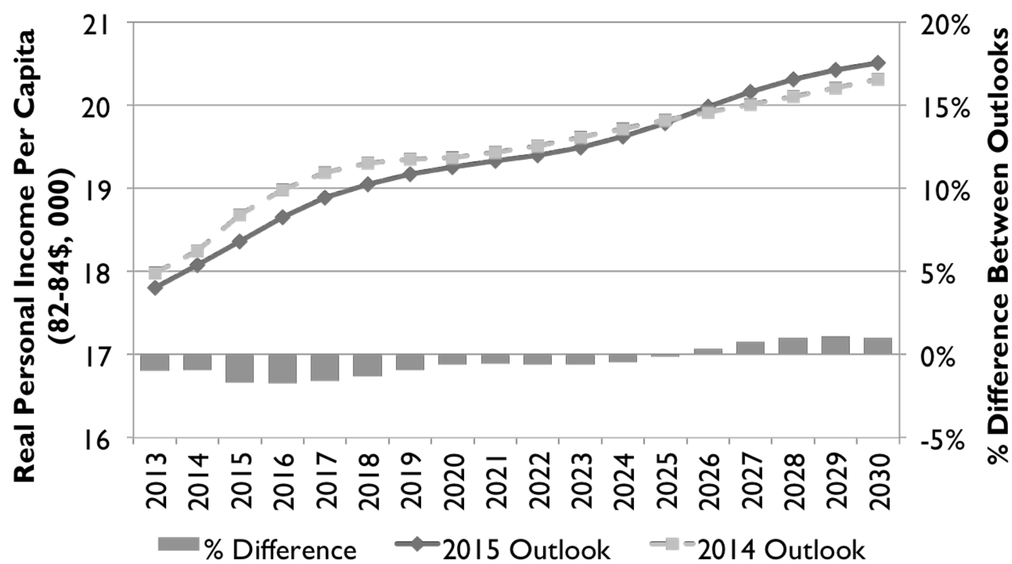


Figure J-35. Hawai'i Real Personal Income per Capita Forecast Comparison

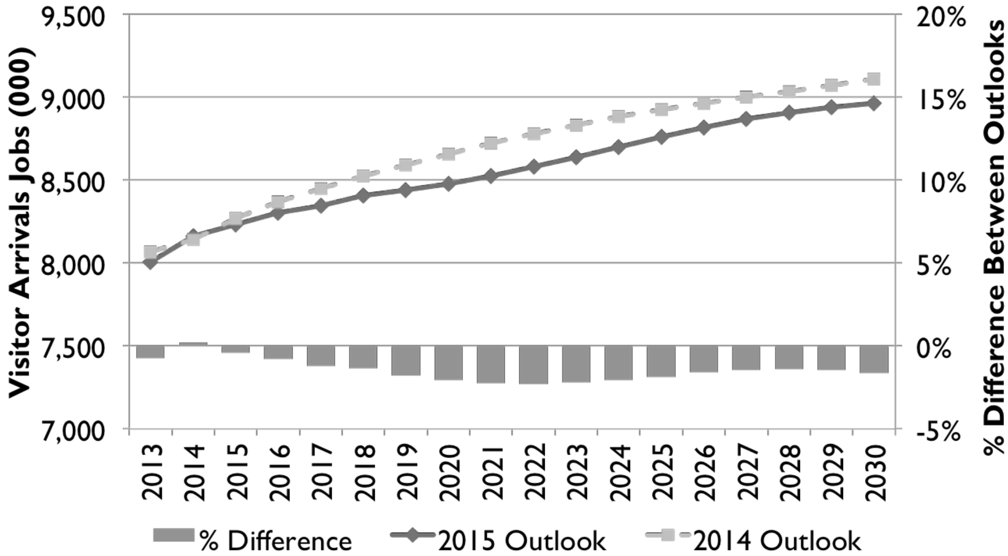


Figure J-36. Hawai'i Visitor Arrival Forecast Comparison

Load Profiles

Available generating resources must be able to meet a demand profile over a period of time that doesn't include customer-sited distributed generation. Our analysis used a demand profile in two ways:

- An annual hourly load profile (8,760 data points: 365 days at 24 hours a day).
- A sub-hourly load profile data, which model intra-hour issues associated with ramping of generating resources and energy storage in response to variable renewable generation.

Because of the proliferation of customer-sited distributed generation, the net load profile has changed dramatically over the past few years. Our analysis assumed a system gross load profile. The model includes the profile of customer-sited distributed generation, which results in the net load to be served.

Sub-Hourly Profile

Black & Veatch has developed sub-hourly profiles for variable generation that includes rooftop solar panels, and utility-scale solar and wind. These profiles form the backbone for evaluating the impacts of variable generation and the fleet's ability to meet demand.

Black & Veatch's model is based on historical changes in minute-to-minute generation by asset type and island. Using historical data, the model creates a probability distribution function based on time of day and current generation levels. The probability, then, is a distribution of all the possible changes in demand for an asset type. Combining this probability with random number generation results in the change in output for the next time step for that asset.

The model "fills in" the sub-hourly generation of each asset in between the hourly generation profiles provided by the Hawaiian Electric planning group. Black & Veatch's model ensures that energy production over each day with the sub-hourly profiles matches the production from the hourly model. This daily energy matching aligns total production with models that employ only hourly data.

The difference between the modeling data for sub-hourly versus hourly is dramatic. Figure J-37 depicts an example day of an hourly profile on the Hawaiian Electric grid and the output profile from the Black & Veatch model.

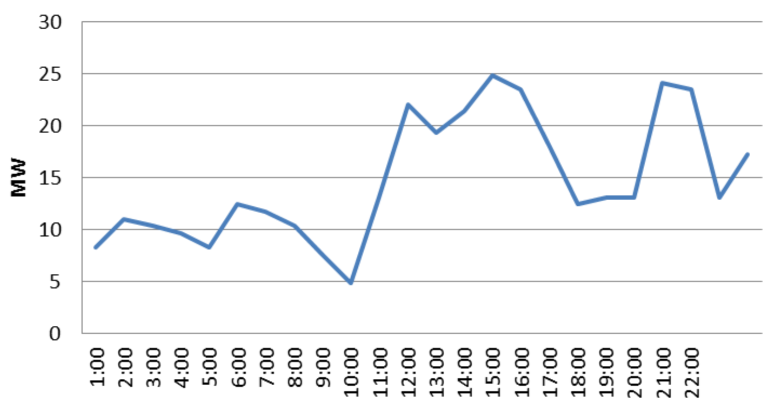


Figure J-37. Wind Unit Day Hourly Profile Example

Figure J-38 depicts an example day of an hourly profile on the Hawaiian Electric grid and the output profile from the Black & Veatch model.

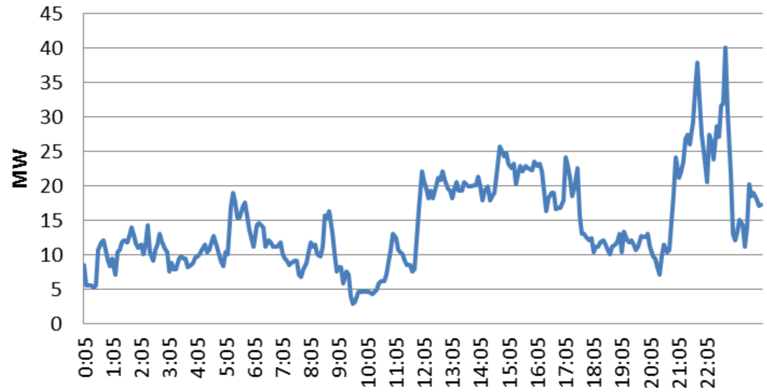


Figure J-38. Wind Unit Day Sub-Hourly Profile Example

SALES FORECASTS

O'ahu Customer Level Sales Forecast – February 2016 Interim

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

Table J-10. O'ahu Customer Level Sales Forecast (GWh)

Maui Island Customer Level Sales Forecast – February 2016 Interim

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

Table J-11. Maui Island Customer Level Sales Forecast (GWh)

Lana'i Customer Level Sales Forecast – February 2016 Interim

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

Table J-12. Lana'i Customer Level Sales Forecast (MWh)

Moloka'i Customer Level Sales Forecast - February 2016 Interim

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

Table J-13. Moloka'i Customer Level Sales Forecast (MWh)

Hawai'i Island Customer Level Sales Forecast - February 2016 Interim

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

Table J-14. Hawai'i Island Customer Level Sales Forecast (GWh)

PEAK DEMAND FORECASTS

O'ahu Generation Level Peak Demand Forecast

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

* System peak occurs in the evening.

Table J-15. O'ahu Generation Level Peak Demand Forecast (MW)

Maui Island Generation Level Peak Demand Forecast

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

* System peak occurs in the evening.

Table J-16. Maui Island Generation Level Peak Demand Forecast (MW)

Lana‘i Generation Level Peak Demand Forecast

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

* System peak occurs in the evening.

Table J-17. Lana‘i Generation Level Peak Demand Forecast (MW)

Moloka'i Generation Level Peak Demand Forecast

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

* System peak occurs in the evening.

Table J-18. Moloka'i Generation Level Peak Demand Forecast (MW)

Hawai'i Island Generation Level Peak Demand Forecast

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

* System peak occurs in the evening.

Table J-19. Hawai'i Island Generation Level Peak Demand Forecast (MW)

SALES FORECAST COMPARISONS

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

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

Table J-20. O'ahu Interim 2016 PSIP versus 2014 PSIP Sales Forecast Comparisons (GWh)

Maui Island Interim 2016 PSIP versus 2014 PSIP Sales Forecast Comparisons

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

* Includes off-grid and leap year impacts.

Table J-21. Maui Island Interim 2016 PSIP versus 2014 PSIP Sales Forecast Comparisons (GWh)

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

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

* Includes off-grid and leap year impacts.

Table J-22. Lana'i Interim 2016 PSIP versus 2014 PSIP Sales Forecast Comparisons (MWh)

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

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

* Includes off-grid and leap year impacts.

Table J-23. Moloka'i Interim 2016 PSIP versus 2014 PSIP Sales Forecast Comparisons (MWh)

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

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

Table J-24. Hawai'i Island Interim 2016 PSIP versus 2014 PSIP Sales Forecast Comparisons (GWh)

O'ahu DG-PV Forecast Cumulative Installed Capacity

	February 2016 Interim Filing	February 2016+ Integrations Costs	High DG-PV
Year	*MW*	*MW*	*MW*
2016	447	445	445
2017	548	538	538
2018	572	563	563
2019	591	589	589
2020	608	610	610
2021	620	626	626
2022	631	639	639
2023	642	650	676
2024	652	661	717
2025	663	672	759
2026	674	683	800
2027	685	694	842
2028	696	705	884
2029	708	716	925
2030	720	727	967
2031	733	738	1,009
2032	747	749	1,050
2033	761	760	1,092
2034	776	771	1,134
2035	791	782	1,175
2036	808	793	1,217
2037	824	804	1,259
2038	841	815	1,300
2039	859	826	1,342
2040	877	837	1,384
2041	895	849	1,425
2042	914	860	1,467
2043	933	872	1,508
2044	952	884	1,550
2045	971	897	1,592

Table J-25. O'ahu DG-PV Forecast Cumulative Installed Capacity

Maui DG-PV Forecast Cumulative Installed Capacity

	February 2016 Interim Filing	February 2016+ Integrations Costs	High DG-PV
Year	*MW*	*MW*	*MW*
2016	99	98	99
2017	117	115	117
2018	120	118	120
2019	123	122	123
2020	125	124	126
2021	126	126	129
2022	127	127	142
2023	127	128	156
2024	128	129	169
2025	129	130	182
2026	129	130	195
2027	130	131	208
2028	131	132	222
2029	132	133	235
2030	133	134	248
2031	134	135	261
2032	135	136	275
2033	136	137	288
2034	138	138	301
2035	139	139	314
2036	141	140	327
2037	143	142	341
2038	144	143	354
2039	146	144	367
2040	148	145	380
2041	150	147	394
2042	153	148	407
2043	155	150	420
2044	157	151	433
2045	160	153	446

Table J-26. Maui DG-PV Forecast Cumulative Installed Capacity

Lana'i DG-PV Forecast Cumulative Installed Capacity

	February 2016 Interim Filing	February 2016+ Integrations Costs	High DG-PV
Year	*MW*	*MW*	*MW*
2016	0.7	0.6	0.7
2017	0.7	0.6	0.7
2018	0.8	0.6	0.8
2019	0.8	0.7	0.8
2020	0.9	0.7	0.9
2021	0.9	0.8	0.9
2022	1.0	0.9	1.2
2023	1.1	0.9	1.5
2024	1.1	1.0	1.8
2025	1.2	1.0	2.0
2026	1.2	1.1	2.3
2027	1.3	1.1	2.6
2028	1.3	1.2	2.9
2029	1.4	1.2	3.2
2030	1.4	1.2	3.5
2031	1.4	1.2	3.8
2032	1.4	1.2	4.0
2033	1.4	1.2	4.3
2034	1.4	1.2	4.6
2035	1.4	1.2	4.9
2036	1.4	1.2	5.2
2037	1.4	1.2	5.5
2038	1.4	1.2	5.8
2039	1.4	1.2	6.0
2040	1.4	1.2	6.3
2041	1.4	1.2	6.6
2042	1.4	1.2	6.9
2043	1.4	1.2	7.2
2044	1.4	1.2	7.5
2045	1.4	1.2	7.7

Table J-27. Lana'i DG-PV Forecast Cumulative Installed Capacity

Moloka'i DG-PV Forecast Cumulative Installed Capacity

	February 2016 Interim Filing	February 2016+ Integrations Costs	High DG-PV
Year	*MW*	*MW*	*MW*
2016	2.6	2.2	2.6
2017	2.6	2.3	2.6
2018	2.7	2.3	2.7
2019	2.7	2.4	2.8
2020	2.9	2.5	2.9
2021	2.9	2.6	2.9
2022	3.0	2.6	3.1
2023	3.1	2.7	3.4
2024	3.1	2.7	3.6
2025	3.2	2.8	3.8
2026	3.3	2.9	4.0
2027	3.4	2.9	4.2
2028	3.5	3.0	4.4
2029	3.5	3.1	4.6
2030	3.6	3.2	4.8
2031	3.7	3.2	5.0
2032	3.8	3.3	5.2
2033	3.9	3.4	5.4
2034	3.9	3.4	5.6
2035	4.0	3.4	5.8
2036	4.0	3.5	6.0
2037	4.0	3.5	6.2
2038	4.0	3.5	6.4
2039	4.0	3.5	6.6
2040	4.0	3.5	6.8
2041	4.0	3.5	7.0
2042	4.0	3.5	7.2
2043	4.0	3.5	7.4
2044	4.0	3.5	7.6
2045	4.0	3.5	7.8

Table J-28. Moloka'i DG-PV Forecast Cumulative Installed Capacity

Hawai‘i Island DG-PV Forecast Cumulative Installed Capacity

	February 2016 Interim Filing	February 2016+ Integrations Costs	High DG-PV
Year	*MW*	*MW*	*MW*
2016	88	87	83
2017	102	101	101
2018	106	104	108
2019	109	108	111
2020	112	111	113
2021	115	114	116
2022	117	115	130
2023	118	117	144
2024	120	118	158
2025	122	119	172
2026	124	120	187
2027	125	122	201
2028	127	123	215
2029	129	125	229
2030	131	126	243
2031	133	127	257
2032	135	129	271
2033	137	130	285
2034	140	132	299
2035	142	133	313
2036	144	135	328
2037	147	136	342
2038	149	138	356
2039	152	140	370
2040	156	141	384
2041	159	143	398
2042	163	145	412
2043	168	146	426
2044	172	148	440
2045	178	150	454

Table J-29. Hawai‘i Island DG-PV Forecast Cumulative Installed Capacity

UHERO STATE OF HAWAI'I FORECASTS

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

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

Table J-30. State of Hawai'i 2014 and 2015 Non-Agricultural Job Forecasts

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

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

Table J-31. State of Hawai'i 2014 and 2015 Real Personal Income per Capita Forecasts ($000)

State of Hawai'i 2014 and 2015 Visitor Arrivals Forecasts

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

Table J-32. State of Hawai'i 2014 and 2015 Visitor Arrivals Forecasts

RESOURCE CAPITAL COSTS

New Resource Cost Assumptions: O‘ahu (1 of 4)

Hawai‘i specific nominal overnight capital cost $/kW$_{AC}$,[2] without AFUDC

Nominal $/kW	Replacement Resource Capital Cost Assumptions: O‘ahu						
Technology	Onshore Wind*	Offshore Wind Floating Platform*	Onshore Wind + Cable*	Onshore Wind + Cable*	Utility-Scale Solar PV*	Solar DG-PV	CSP w/ 10 Hours Storage
Size (MW)	30	400	200	400	20	DG-PV	100
Fuel	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Source	IHS Energy RSMeans	NREL	IHS Energy RSMeans Vendor Quotes	IHS Energy RSMeans Vendor Quotes	IHS Energy RSMeans	IHS Energy RSMeans	NREL
Island	O‘ahu	O‘ahu	Maui to O‘ahu	Maui to O‘ahu	O‘ahu	O‘ahu	O‘ahu
2016	$2,448	$5,061	NA	NA	$2,768	$3,945	$12,304
2017	$2,487	$4,848	NA	NA	$2,602	$3,716	$12,525
2018	$2,426	$4,625	NA	NA	$2,522	$3,573	$11,681
2019	$2,411	$4,564	NA	NA	$2,459	$3,457	$10,781
2020	$2,464	$4,499	$5,095	$4,571	$2,407	$3,360	$9,848
2021	$2,504	$4,430	$5,205	$4,671	$2,367	$3,285	$8,874
2022	$2,570	$4,357	$5,322	$4,777	$2,332	$3,218	$7,867
2023	$2,627	$4,247	$5,454	$4,898	$2,303	$3,160	$7,813
2024	$2,674	$4,132	$5,557	$4,990	$2,279	$3,111	$7,756
2025	$2,705	$4,012	$5,662	$5,083	$2,259	$3,068	$7,694
2026	$2,736	$4,024	$5,755	$5,165	$2,245	$3,034	$7,627
2027	$2,756	$4,036	$5,848	$5,247	$2,232	$3,004	$7,555
2028	$2,788	$4,047	$5,945	$5,332	$2,222	$2,976	$7,478
2029	$2,813	$4,057	$6,047	$5,420	$2,213	$2,952	$7,396
2030	$2,851	$4,066	$6,151	$5,513	$2,207	$2,933	$7,309

* = Amounts have been reduced by the $500,000 state tax credit cap

Table J-33. Replacement Resource Capital Cost Assumptions w/o AFUDC: O‘ahu 2016–2030 (1 of 4)

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

New Resource Cost Assumptions: O‘ahu (2 of 4)

Hawai‘i specific nominal overnight capital cost $/kW$_{AC}$, without AFUDC

Nominal $/kW	Replacement Resource Capital Cost Assumptions: O‘ahu						
Technology	Onshore Wind*	Offshore Wind Floating Platform*	Onshore Wind + Cable*	Onshore Wind + Cable*	Utility-Scale Solar PV*	Solar DG-PV	CSP w/ 10 Hours Storage
Size (MW)	30	400	200	400	20	< 10 kW	100
Fuel	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Source	IHS Energy RSMeans	NREL	IHS Energy RSMeans Vendor Quotes	IHS Energy RSMeans Vendor Quotes	IHS Energy RSMeans	IHS Energy RSMeans	NREL
Island	O‘ahu	O‘ahu	Maui to O‘ahu	Maui to O‘ahu	O‘ahu	O‘ahu	O‘ahu
2031	$2,874	$4,074	$6,254	$5,603	$2,201	$2,925	$7,216
2032	$2,908	$4,081	$6,359	$5,695	$2,196	$2,917	$7,117
2033	$2,933	$4,121	$6,466	$5,788	$2,190	$2,910	$7,245
2034	$2,968	$4,161	$6,575	$5,883	$2,184	$2,902	$7,375
2035	$2,993	$4,201	$6,685	$5,980	$2,178	$2,894	$7,508
2036	$3,028	$4,241	$6,798	$6,078	$2,172	$2,887	$7,643
2037	$3,055	$4,281	$6,912	$6,178	$2,167	$2,879	$7,781
2038	$3,091	$4,321	$7,029	$6,280	$2,161	$2,872	$7,921
2039	$3,118	$4,361	$7,147	$6,384	$2,155	$2,864	$8,064
2040	$3,155	$4,402	$7,268	$6,489	$2,149	$2,856	$8,209
2041	$3,182	$4,442	$7,391	$6,596	$2,144	$2,849	$8,356
2042	$3,220	$4,482	$7,516	$6,705	$2,138	$2,841	$8,507
2043	$3,248	$4,527	$7,643	$6,816	$2,132	$2,834	$8,660
2044	$3,287	$4,571	$7,773	$6,929	$2,126	$2,827	$8,816
2045	$3,316	$4,616	$7,904	$7,044	$2,121	$2,819	$8,975

* = Amounts have been reduced by the $500,000 state tax credit cap

Table J-34. Replacement Resource Capital Cost Assumptions w/o AFUDC: O‘ahu 2031–2045 (2 of 4)

New Resource Cost Assumptions: O‘ahu (3 of 4)

Hawai‘i specific nominal overnight capital cost $/kW$_{AC}$, without AFUDC

Nominal $/kW	Replacement Resource Capital Cost Assumptions: O‘ahu						
Technology	Combined Cycle Gas	Combined Cycle Gas	Simple Cycle Gas	Biomass	Internal Combustion	Internal Combustion	Internal Combustion
Size (MW)	383 (3 x 1)	152 (1 x 1)	100	20	27 (3 x 9 MW)	54 (6 x 9 MW)	100 (6 x 16.8 MW) Power Barge
Fuel	Gas / Oil	Gas / Oil	Gas / Oil	Biomass	Gas / Oil	Gas / Oil	Gas / Oil
Source	NextEra	NextEra	Gas Turbine World RSMeans	NREL	Hawaiian Electric	Hawaiian Electric Schofield Application	Hawaiian Electric
Island	O‘ahu	O‘ahu	O‘ahu	O‘ahu, Maui, Hawai‘i Island	O‘ahu, Maui, Hawai‘i Island	O‘ahu, Maui, Hawai‘i Island	O‘ahu
2016	$1,758	$1,660	$1,237	$6,296	$3,177	$2,493	$1,758
2017	$1,783	$1,683	$1,253	$6,092	$3,219	$2,526	$1,783
2018	$1,797	$1,697	$1,261	$6,178	$3,238	$2,541	$1,797
2019	$1,822	$1,720	$1,277	$6,269	$3,280	$2,574	$1,822
2020	$1,845	$1,742	$1,292	$6,354	$3,319	$2,604	$1,845
2021	$1,870	$1,766	$1,309	$6,446	$3,362	$2,638	$1,870
2022	$1,896	$1,790	$1,326	$6,541	$3,406	$2,672	$1,896
2023	$1,921	$1,813	$1,342	$6,633	$3,448	$2,705	$1,921
2024	$1,944	$1,836	$1,358	$6,725	$3,487	$2,736	$1,944
2025	$1,969	$1,859	$1,373	$6,826	$3,527	$2,768	$1,969
2026	$1,992	$1,881	$1,388	$6,918	$3,564	$2,797	$1,992
2027	$2,021	$1,909	$1,408	$7,019	$3,617	$2,838	$2,021
2028	$2,051	$1,937	$1,428	$7,121	$3,668	$2,878	$2,051
2029	$2,079	$1,963	$1,447	$7,222	$3,716	$2,916	$2,079
2030	$2,108	$1,991	$1,466	$7,323	$3,766	$2,955	$2,108

Table J-35. Replacement Resource Capital Cost Assumptions w/o AFUDC: O‘ahu 2016–2030 (3 of 4)

New Resource Cost Assumptions: O‘ahu (4 of 4)

Hawai‘i specific nominal overnight capital cost $/kW$_{AC}$, without AFUDC

Nominal $/kW	Replacement Resource Capital Cost Assumptions: O‘ahu						
Technology	Combined Cycle Gas	Combined Cycle Gas	Simple Cycle Gas	Biomass	Internal Combustion	Internal Combustion	Internal Combustion
Size (MW)	383 (3 x 1)	152 (1 x 1)	100	20	27 (3 x 9 MW)	54 (6 x 9 MW)	100 (6 x 16.8 MW) Power Barge
Fuel	Gas / Oil	Gas / Oil	Gas / Oil	Biomass	Gas / Oil	Gas / Oil	Gas / Oil
Source	NextEra	NextEra	Gas Turbine World RSMeans	NREL	Hawaiian Electric	Hawaiian Electric Schofield Application	Hawaiian Electric
Island	O‘ahu	O‘ahu	O‘ahu	O‘ahu, Maui, Hawai‘i Island	O‘ahu, Maui, Hawai‘i Island	O‘ahu, Maui, Hawai‘i Island	O‘ahu
2031	$2,139	$2,019	$1,487	$7,425	$3,819	$2,997	$1,729
2032	$2,169	$2,048	$1,507	$7,528	$3,872	$3,038	$1,761
2033	$2,202	$2,079	$1,530	$7,638	$3,930	$3,083	$1,792
2034	$2,234	$2,110	$1,552	$7,743	$3,986	$3,127	$1,825
2035	$2,270	$2,143	$1,577	$7,850	$4,050	$3,178	$1,857
2036	$2,304	$2,176	$1,601	$7,952	$4,112	$3,226	$1,891
2037	$2,342	$2,211	$1,627	$8,062	$4,179	$3,279	$1,925
2038	$2,379	$2,246	$1,653	$8,166	$4,246	$3,331	$1,959
2039	$2,419	$2,284	$1,681	$8,267	$4,317	$3,387	$1,995
2040	$2,455	$2,318	$1,706	$8,361	$4,382	$3,439	$2,031
2041	$2,499	$2,360	$1,737	$8,512	$4,461	$3,501	$2,067
2042	$2,544	$2,403	$1,768	$8,665	$4,542	$3,564	$2,104
2043	$2,590	$2,446	$1,800	$8,821	$4,623	$3,628	$2,142
2044	$2,637	$2,490	$1,832	$8,979	$4,707	$3,693	$2,181
2045	$2,684	$2,535	$1,865	$9,141	$4,791	$3,760	$2,220

Table J-36. Replacement Resource Capital Cost Assumptions w/o AFUDC: O‘ahu 2031–2045 (4 of 4)

New Resource Cost Assumptions: Maui, Lana‘i, Moloka‘i, Hawai‘i Island (1 of 4)

Hawai‘i specific nominal overnight capital cost $/kW$_{AC}$ (without AFUDC)

Nominal $/kW	Replacement Resource Capital Cost Assumptions: Maui, Lana‘i, Moloka‘i, Hawai‘i Island							
Technology	Onshore Wind*	Onshore Wind*	Onshore Wind*	Onshore Wind*	Utility-Scale Solar PV*	Utility-Scale Solar PV*	Utility-Scale Solar PV*	Utility-Scale Solar PV*
Size (MW)	10	20	30	1 (10 x 100 kW)	1	5	10	20
Fuel	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Source	IHS, RSMeans	IHS, RSMeans	IHS, RSMeans	Indicative quote from NPS + install estimate	IHS, RSMeans	IHS, RSMeans	IHS, RSMeans	IHS, RSMeans
Island	Hawai‘i Maui	Hawai‘i Maui	Hawai‘i Maui	Lana‘i Moloka‘i	Lana‘i Moloka‘i	Hawai‘i Maui	Hawai‘i Maui	Hawai‘i Maui
2016	$4,121	$2,943	$2,448	$4,900	$3,523	$3,162	$2,799	$2,549
2017	$4,187	$2,990	$2,487	$5,044	$3,283	$2,968	$2,630	$2,396
2018	$4,084	$2,916	$2,426	$4,909	$3,169	$2,876	$2,549	$2,323
2019	$4,058	$2,898	$2,411	$4,842	$3,077	$2,801	$2,484	$2,264
2020	$4,148	$2,962	$2,464	$4,958	$3,003	$2,741	$2,431	$2,216
2021	$4,216	$3,010	$2,504	$5,088	$2,946	$2,695	$2,391	$2,180
2022	$4,327	$3,089	$2,570	$5,234	$2,896	$2,654	$2,355	$2,148
2023	$4,425	$3,159	$2,627	$5,416	$2,853	$2,620	$2,325	$2,121
2024	$4,503	$3,215	$2,674	$5,520	$2,819	$2,591	$2,301	$2,098
2025	$4,556	$3,252	$2,705	$5,622	$2,790	$2,569	$2,281	$2,080
2026	$4,609	$3,290	$2,736	$5,692	$2,770	$2,552	$2,266	$2,067
2027	$4,643	$3,314	$2,756	$5,758	$2,751	$2,537	$2,253	$2,055
2028	$4,697	$3,352	$2,788	$5,830	$2,736	$2,525	$2,242	$2,046
2029	$4,739	$3,382	$2,813	$5,910	$2,724	$2,515	$2,234	$2,038
2030	$4,803	$3,428	$2,851	$5,995	$2,716	$2,508	$2,228	$2,032

* = Amounts have been reduced by the $500,000 state tax credit cap

Table J-37. Replacement Resource Capital Cost Assumptions w/o AFUDC: Maui, Lana‘i, Moloka‘i, Hawai‘i Island 2016–2030 (1 of 4)

New Resource Cost Assumptions: Maui, Lana‘i, Moloka‘i, Hawai‘i Island (2 of 4)

Hawai‘i specific nominal overnight capital cost $/kW$_{AC}$ (without AFUDC)

Nominal $/kW	Replacement Resource Capital Cost Assumptions: Maui, Lana‘i, Moloka‘i, Hawai‘i Island							
Technology	Onshore Wind*	Onshore Wind*	Onshore Wind*	Onshore Wind*	Utility-Scale Solar PV*	Utility-Scale Solar PV*	Utility-Scale Solar PV*	Utility-Scale Solar PV*
Size (MW)	10	20	30	1 (10 x 100 kW)	1	5	10	20
Fuel	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Source	IHS, RSMeans	IHS, RSMeans	IHS, RSMeans	Indicative quote from NPS + install estimate	IHS, RSMeans	IHS, RSMeans	IHS, RSMeans	IHS, RSMeans
Island	Hawai‘i Maui	Hawai‘i Maui	Hawai‘i Maui	Lana‘i Moloka‘i	Lana‘i Moloka‘i	Hawai‘i Maui	Hawai‘i Maui	Hawai‘i Maui
2031	$4,842	$3,456	$2,874	$6,071	$2,707	$2,501	$2,222	$2,027
2032	$4,900	$3,497	$2,908	$6,149	$2,699	$2,494	$2,216	$2,022
2033	$4,942	$3,527	$2,933	$6,227	$2,690	$2,487	$2,210	$2,016
2034	$5,001	$3,569	$2,968	$6,307	$2,682	$2,480	$2,204	$2,011
2035	$5,043	$3,599	$2,993	$6,387	$2,673	$2,474	$2,198	$2,006
2036	$5,104	$3,642	$3,028	$6,468	$2,665	$2,467	$2,192	$2,000
2037	$5,148	$3,673	$3,055	$6,551	$2,657	$2,460	$2,186	$1,995
2038	$5,209	$3,717	$3,091	$6,634	$2,648	$2,453	$2,180	$1,990
2039	$5,254	$3,749	$3,118	$6,718	$2,640	$2,447	$2,174	$1,984
2040	$5,317	$3,794	$3,155	$6,803	$2,632	$2,440	$2,168	$1,979
2041	$5,364	$3,827	$3,182	$6,889	$2,624	$2,433	$2,163	$1,974
2042	$5,428	$3,872	$3,220	$6,977	$2,615	$2,427	$2,157	$1,968
2043	$5,475	$3,906	$3,248	$7,065	$2,607	$2,420	$2,151	$1,963
2044	$5,541	$3,953	$3,287	$7,154	$2,599	$2,413	$2,145	$1,958
2045	$5,590	$3,988	$3,316	$7,244	$2,591	$2,407	$2,139	$1,953

* = Amounts have been reduced by the $500,000 state tax credit cap

Table J-38. Replacement Resource Capital Cost Assumptions w/o AFUDC: Maui, Lana‘i, Moloka‘i, Hawai‘i Island 2031–2045 (2 of 4)

New Resource Cost Assumptions: Maui, Lana'i, Moloka'i, Hawai'i Island (3 of 4)

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

Nominal $/kW	Replacement Resource Capital Cost Assumptions: Maui, Lana'i, Moloka'i, Hawai'i Island						
Technology	DG Solar PV	Simple Cycle Gas	Biomass	Biomass	Geothermal	Internal Combustion	Internal Combustion
Size (MW)	DG-PV	20.5	1	20	20	1	9
Fuel	n/a	Gas / Oil	Biomass	Biomass	n/a	Oil	Gas / Oil
Source	IHS, RSMeans	NextEra	HECO Research of Comparable Plants	NREL	NREL	NextEra	NextEra
Island	Hawai'i, Maui, Lana'i, Moloka'i	Hawai'i Maui	Lana'i, Moloka'i	Hawai'i Maui	Hawai'i Maui	Lana'i, Moloka'i	Hawai'i Maui
2016	$3,985	$3,586	$8,334	$6,296	$8,804	$10,394	$5,407
2017	$3,753	$3,634	$8,064	$6,092	$8,963	$10,532	$5,479
2018	$3,609	$3,655	$8,179	$6,178	$9,124	$10,593	$5,510
2019	$3,492	$3,702	$8,298	$6,269	$9,289	$10,731	$5,582
2020	$3,394	$3,747	$8,411	$6,354	$9,456	$10,859	$5,649
2021	$3,318	$3,795	$8,533	$6,446	$9,626	$11,000	$5,722
2022	$3,251	$3,844	$8,659	$6,541	$9,799	$11,142	$5,796
2023	$3,192	$3,892	$8,781	$6,633	$9,976	$11,280	$5,868
2024	$3,142	$3,936	$8,902	$6,725	$10,155	$11,408	$5,935
2025	$3,100	$3,981	$9,036	$6,826	$10,338	$11,540	$6,003
2026	$3,065	$4,023	$9,158	$6,918	$10,524	$11,661	$6,066
2027	$3,034	$4,082	$9,291	$7,019	$10,713	$11,832	$6,155
2028	$3,007	$4,140	$9,427	$7,121	$10,906	$12,000	$6,243
2029	$2,982	$4,194	$9,560	$7,222	$11,103	$12,157	$6,324
2030	$2,962	$4,251	$9,694	$7,323	$11,302	$12,322	$6,410

Table J-39. Replacement Resource Capital Cost Assumptions w/o AFUDC: Maui, Lana'i, Moloka'i, Hawai'i Island 2016–2030 (3 of 4)

New Resource Cost Assumptions: Maui, Lana‘i, Moloka‘i, Hawai‘i Island (4 of 4)

Hawai‘i specific nominal overnight capital cost $/kW$_{AC}$ (without AFUDC)

Nominal $/kW	Replacement Resource Capital Cost Assumptions: Maui, Lana‘i, Moloka‘i, Hawai‘i Island						
Technology	DG Solar PV	Simple Cycle Gas	Biomass	Biomass	Geothermal	Internal Combustion	Internal Combustion
Size (MW)	DG-PV	20.5	1	20	20	1	9
Fuel	n/a	Gas / Oil	Biomass	Biomass	n/a	Oil	Gas / Oil
Source	IHS, RSMeans	NextEra	HECO Research of Comparable Plants	NREL	NREL	NextEra	NextEra
Island	Hawai‘i, Maui, Lana‘i, Moloka‘i	Hawai‘i Maui	Lana‘i, Moloka‘i	Hawai‘i Maui	Hawai‘i Maui	Lana‘i, Moloka‘i	Hawai‘i Maui
2031	$2,955	$4,311	$9,829	$7,425	$11,506	$12,494	$6,500
2032	$2,947	$4,371	$9,966	$7,528	$11,713	$12,668	$6,590
2033	$2,939	$4,436	$10,111	$7,638	$11,924	$12,856	$6,688
2034	$2,931	$4,499	$10,250	$7,743	$12,138	$13,040	$6,783
2035	$2,924	$4,571	$10,391	$7,850	$12,357	$13,250	$6,893
2036	$2,916	$4,641	$10,527	$7,952	$12,579	$13,453	$6,998
2037	$2,908	$4,717	$10,673	$8,062	$12,806	$13,672	$7,112
2038	$2,901	$4,792	$10,810	$8,166	$13,036	$13,890	$7,226
2039	$2,893	$4,873	$10,944	$8,267	$13,271	$14,123	$7,347
2040	$2,885	$4,947	$11,068	$8,361	$13,510	$14,338	$7,459
2041	$2,878	$5,036	$11,267	$8,512	$13,753	$14,596	$7,593
2042	$2,870	$5,126	$11,470	$8,665	$14,001	$14,859	$7,730
2043	$2,863	$5,219	$11,677	$8,821	$14,253	$15,126	$7,869
2044	$2,855	$5,313	$11,887	$8,979	$14,509	$15,398	$8,010
2045	$2,848	$5,408	$12,101	$9,141	$14,770	$15,676	$8,154

Table J-40. Replacement Resource Capital Cost Assumptions w/o AFUDC: Maui, Lana‘i, Moloka‘i, Hawai‘i Island 2031–2045 (4 of 4)

Replacement Resource Construction Expenditure Profiles: O'ahu

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

Table J-41. Replacement Resource Construction Expenditure Profiles: O'ahu (1 of 2)

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

Table J-42. Replacement Resource Construction Expenditure Profiles: O'ahu (2 of 2)

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

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

Table J-43. Replacement Resource Construction Expenditure Profiles: Maui, Lana‘i, Moloka‘i, Hawai‘i Island (1 of 2)

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

Table J-44. Replacement Resource Construction Expenditure Profiles: Maui, Lana‘i, Moloka‘i, Hawai‘i Island (2 of 2)

Energy Storage Cost Assumptions: Inertia and Contingency Applications (1 of 2)

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

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

Table J-45. Energy Storage Cost Assumptions: Inertia and Contingency Applications 2016–2030 (1 of 2)

Energy Storage Cost Assumptions: Inertia and Contingency Applications (2 of 2)

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

Nominal $/kWh	Energy Storage Cost Assumptions: Inertia and Contingency Applications					
Application	Inertia	Contingency				
Size (MW)	10	1	5	20	50	100
Technology	Flywheel	Lithium-Ion				
Duration Hours	0.25	0.5				
Turnaround Efficiency	85%	81%				
Discharge Cycles Per Year	15,000	Up to 10				
Depth of Discharge	100%	Up to 100%				
Plant Life Years	15%	15				
2031	$4,409	$706	$706	$706	$706	$706
2032	$4,327	$693	$693	$693	$693	$693
2033	$4,255	$682	$682	$682	$682	$682
2034	$4,190	$671	$671	$671	$671	$671
2035	$4,133	$662	$662	$662	$662	$662
2036	$4,083	$654	$654	$654	$654	$654
2037	$4,038	$647	$647	$647	$647	$647
2038	$3,998	$641	$641	$641	$641	$641
2039	$3,962	$635	$635	$635	$635	$635
2040	$3,930	$630	$630	$630	$630	$630
2041	$3,902	$625	$625	$625	$625	$625
2042	$3,876	$621	$621	$621	$621	$621
2043	$3,854	$617	$617	$617	$617	$617
2044	$3,833	$614	$614	$614	$614	$614
2045	$3,815	$611	$611	$611	$611	$611

Table J-46. Energy Storage Cost Assumptions: Inertia and Contingency Applications 2031–2045 (2 of 2)

Energy Storage Cost Assumptions: Regulation / Renewable Smoothing Applications (1 of 2)

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

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

Table J-47. Energy Storage Cost Assumptions: Regulation / Renewable Smoothing 2016–2030 (1 of 2)

Energy Storage Cost Assumptions: Regulation / Renewable Smoothing Applications (2 of 2)

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

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

Table J-48. Energy Storage Cost Assumptions: Regulation / Renewable Smoothing Applications 2031–2045 (2 of 2)

Energy Storage Cost Assumptions: Load Shifting and Grid Support Applications (1 of 2)

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

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

Table J-49. Energy Storage Cost Assumptions: Load Shifting and Grid Support Applications 2016–2030 (1 of 2)

Energy Storage Cost Assumptions: Load Shifting and Grid Support Applications (2 of 2)

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

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

Table J-50. Energy Storage Cost Assumptions: Load Shifting and Grid Support Applications 2031–2045 (2 of 2)

Energy Storage Cost Assumptions: Residential, Commercial, and Long Duration Load Shifting Applications (1 of 2)

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

Nominal $/kWh	Energy Storage Cost Assumptions: Residential, Commercial, and Long Duration Load Shifting Applications						
Application	Residential		Commercial		Long Duration Load Shifting		
Size (MW)	0.002		0.050	1.000	30.000	30.000	50.000
Technology	Lithium-Ion w/o inverter	Lithium-Ion w/ inverter & Balance of Plant	Lithium-Ion		Lithium-Ion	Pumped-Storage Hydro	
Duration Hours	4.0		2.0		6.0		
Turnaround Efficiency	88%		88%		80%		
Discharge Cycles Per Year	Up to 365		Up to 365		Up to 365		
Depth of Discharge	Up to 100%		Up to 100%		Up to 100%		
Plant Life Years	10		10		15	40	
2016	$506	$1,026	$553	$553	$530	$583	$583
2017	$465	$961	$511	$511	$493	$594	$594
2018	$416	$884	$461	$461	$454	$605	$605
2019	$373	$817	$417	$417	$421	$615	$615
2020	$335	$757	$378	$378	$391	$626	$626
2021	$317	$729	$359	$359	$371	$638	$638
2022	$303	$706	$342	$342	$353	$649	$649
2023	$290	$687	$328	$328	$339	$661	$661
2024	$280	$670	$316	$316	$326	$673	$673
2025	$270	$655	$305	$305	$316	$685	$685
2026	$262	$643	$296	$296	$306	$697	$697
2027	$256	$632	$289	$289	$298	$710	$710
2028	$250	$623	$282	$282	$291	$723	$723
2029	$245	$615	$276	$276	$285	$736	$736
2030	$240	$608	$271	$271	$280	$749	$749

Table J-51. Energy Storage Cost Assumptions: Residential, Commercial, and Long Duration Load Shifting Applications 2016–2030 (1 of 2)

Energy Storage Cost Assumptions: Residential, Commercial, and Long Duration Load Shifting Applications (2 of 2)

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

Nominal $/kWh	Energy Storage Cost Assumptions: Residential, Commercial, and Long Duration Load Shifting Applications						
Application	Residential		Commercial		Long Duration Load Shifting		
Size (MW)	0.002		0.050	1.000	30.000	30.000	50.000
Technology	Lithium-Ion w/o inverter	Lithium-Ion w/ inverter & Balance of Plant	Lithium-Ion		Lithium-Ion	Pumped-Storage Hydro	
Duration Hours	4.0		2.0		6.0		
Turnaround Efficiency	88%		88%		80%		
Discharge Cycles Per Year	Up to 365		Up to 365		Up to 365		
Depth of Discharge	Up to 100%		Up to 100%		Up to 100%		
Plant Life Years	10		10		15	40	
2016	$236	$601	$267	$267	$275	$762	$762
2017	$232	$596	$263	$263	$271	$776	$776
2018	$229	$591	$259	$259	$268	$790	$790
2019	$227	$587	$256	$256	$264	$804	$804
2020	$224	$583	$253	$253	$262	$819	$819
2021	$222	$579	$251	$251	$259	$833	$833
2022	$220	$576	$249	$249	$257	$848	$848
2023	$218	$574	$247	$247	$255	$864	$864
2024	$217	$571	$245	$245	$253	$879	$879
2025	$216	$569	$243	$243	$252	$895	$895
2026	$214	$567	$242	$242	$250	$911	$911
2027	$213	$565	$241	$241	$249	$928	$928
2028	$212	$564	$240	$240	$248	$944	$944
2029	$211	$563	$239	$239	$247	$961	$961
2030	$211	$561	$238	$238	$246	$979	$979

Table J-52. Energy Storage Cost Assumptions: Residential, Commercial, and Long Duration Load Shifting Applications 2030–2045 (2 of 2)

Energy Storage Construction Expenditure Profiles: Inertia and Contingency Applications

All costs are for lithium-ion batteries.

	Energy Storage Construction Expenditure Profiles: Inertia and Contingency Applications					
Application	Inertia	Contingency				
Years Before Commercial Operation Date	10 MW	1 MW	5 MW	20 MW	50 MW	100 MW
–6	00%	00%	00%	00%	00%	00%
–5	00%	00%	00%	00%	00%	00%
–4	00%	00%	00%	00%	00%	00%
–3	00%	00%	00%	00%	00%	00%
–2	20%	00%	00%	20%	20%	20%
–1	80%	100%	100%	80%	80%	80%
Total COD	100%	100%	100%	100%	100%	100%

Table J-53. Energy Storage Construction Expenditure Profiles: Inertia and Contingency Applications

Energy Storage Construction Expenditure Profiles: Regulation/Renewable Smoothing Applications

All costs are for lithium-ion batteries.

	Energy Storage Construction Expenditure Profiles: Inertia and Contingency Applications				
Application	Regulation/Renewable Smoothing				
Years Before Commercial Operation Date	1 MW	5 MW	20 MW	50 MW	100 MW
–6	00%	00%	00%	00%	00%
–5	0%	00%	00%	00%	00%
–4	00%	00%	00%	00%	00%
–3	00%	00%	00%	00%	00%
–2	00%	00%	20%	20%	20%
–1	100%	100%	80%	80%	80%
Total COD	100%	100%	100%	100%	100%

Table J-54. Energy Storage Construction Expenditure Profiles: Regulation/Renewable Smoothing Applications

Energy Storage Construction Expenditure Profiles: Load Shifting and Grid Support Applications

All costs are for lithium-ion batteries.

	Energy Storage Construction Expenditure Profiles: Load Shifting and Grid Support Applications					
Application	Load Shifting					*Grid Support*
Years Before Commercial Operation Date	1 MW	5 MW	20 MW	50 MW	100 MW	*5 MW*
–6	00%	00%	00%	00%	00%	00%
–5	00%	00%	00%	00%	00%	00%
–4	00%	00%	00%	00%	00%	00%
–3	00%	00%	00%	00%	00%	00%
–2	00%	00%	20%	20%	30%	00%
–1	100%	100%	80%	80%	70%	100%
Total COD	100%	100%	100%	100%	100%	100%

Table J-55. Energy Storage Construction Expenditure Profiles: Load Shifting and Grid Support Applications

Energy Storage Construction Expenditure Profiles: Residential, Commercial, and Long Duration Load Shifting Applications

	Energy Storage Construction Expenditure Profiles: Residential, Commercial, and Long Duration Load Shifting Applications						
Application	Residential		Commercial		Long Duration Load Shifting		
Technology	Lithium-Ion w/o inverter	Lithium-Ion w/ inverter & Balance of Plant	Lithium-Ion		Lithium-Ion	Pumped-Storage Hydro	
Years Before Commercial Operation Date	0.002 MW		0.050 MW		30.000 MW		50.000 MW
–6	n/a	n/a	n/a	n/a	00%	5%	5%
–5	n/a	n/a	n/a	n/a	00%	10%	10%
–4	n/a	n/a	n/a	n/a	00%	10%	10%
–3	n/a	n/a	n/a	n/a	00%	20%	20%
–2	n/a	n/a	n/a	n/a	30%	30%	30%
–1	n/a	n/a	n/a	n/a	70%	25%	25%
Total COD	n/a	n/a	n/a	n/a	100%	100%	100%

Table J-56. Energy Storage Construction Expenditure Profiles: Residential, Commercial, and Long Duration Load Shifting Applications

DEMAND RESPONSE DATA INPUTS

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

The primary modeling data assumptions originated from the Navigant Potential Study. The study forecasted the quantity of MW by customer class and end use device that the Companies can target in each DR program.

The end uses are identified in the following tables. Table J-57 lists the DR end uses for residential customers; Table J-58 lists the DR end uses for commercial, industrial, and small business customers.

Building Type	End Uses
Electric Vehicles	EV
Photovoltaics	PV
Residential	Cooling, water heating, and other

Table J-57. DR End Uses for Residential Customers

Customer Storage is a End Use for Residential customers, as well as other building types. Storage was not forecasted in the gross load profile. In the interim DR filing, the gross load profile did include customer storage, but the PSIP modeling assumed no customer storage as the base case, the case to build on. BCG has created a econometrics model to better forecast customer uptake of customer storage based on the customers payback period, provided DR incentives or reduced price and other state and federal incentives. The forecasted number for customer storage is added into each DR portfolio case, but because each case is different, we were not able to consistently settle on one case for DR or storage. Once all inputs for the Preferred Case are accepted, the forecasted Customer Storage potential will be locked in with the entire DR portfolio potential.

Building Type	End Uses
Education	Cooling, lighting, ventilation, water heating, and other
Electric Vehicles	EV
Grocery	Cooling, lighting, ventilation, water heating, and other
Health	Cooling, lighting, ventilation, water heating, and other
Hotel	Cooling, lighting, ventilation, water heating, and other
Industrial	Whole facility
Large Multi-Family	Cooling, lighting, water heating, and other
Military	Cooling, heating, lighting, ventilation, water heating, and other
Office	Cooling, heating, lighting, ventilation, water heating, and other
Photovoltaics	PV
Restaurant	Cooling, lighting, ventilation, water heating, and other
Retail	Cooling, heating, lighting, ventilation, water heating, and other
Warehouse	Whole facility
Water Pumping	Whole facility

Table J-58. DR End Uses for Commercial, Industrial, and Small Business Customers

The Navigant Potential Study determined the maximum achievable potential of end-use devices to provide specific services (fast frequency response, non-spin auto response, regulating reserves, load building, and load reduction) through specific DR programs (time of use, day ahead load shift, real-time pricing, critical peak incentive, minimum load building, fast frequency response, non-spin auto response, and regulating reserves). AP for Production Simulation uses annual weekday and weekend potential data by DR program, customer class, building type, and end use. Figure J-39 shows the potential, under available programs, to decrease load using the cooling end use available from military buildings on O'ahu. It is a snapshot based on a weekday during September 2030.

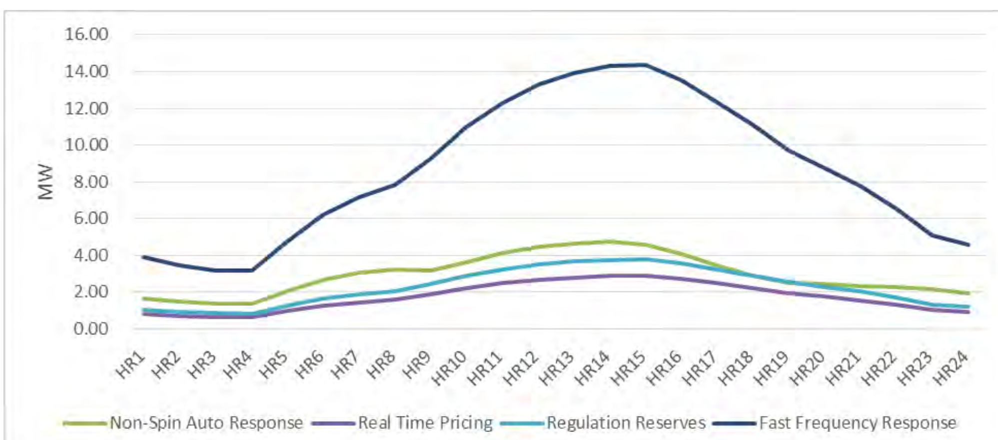


Figure J-39. Example Load Decrease Potential Supporting DR Programs

In general, DR programs grow over time. Figure J-40 shows how Regulation Reserves potential considering all customer classes and all end uses on O'ahu is expected to increase between 2018 (the first year available) and 2045. This data also represents a September weekday snapshot.

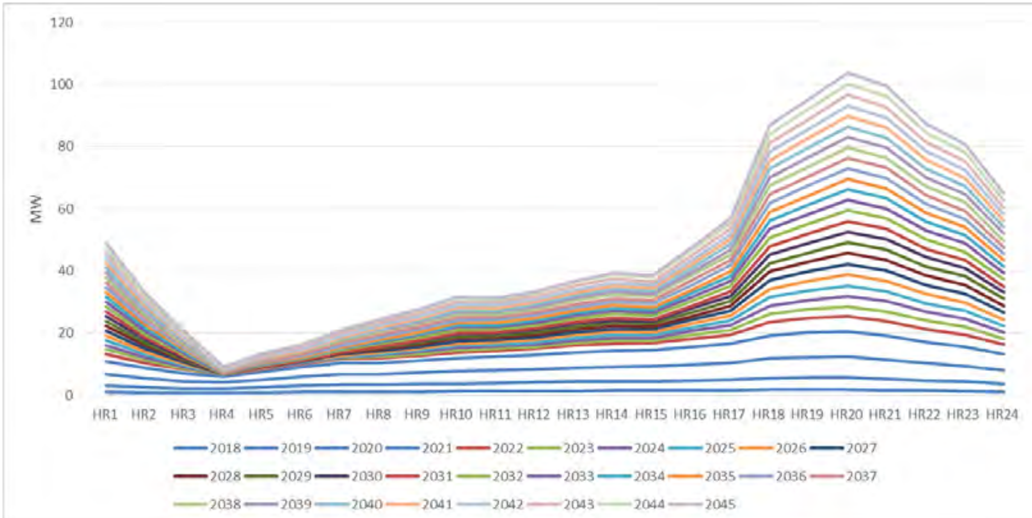


Figure J-40. O'ahu Regulating Reserve DR Program Growth Over Time

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

AP for Production Simulation also includes system security constraints (provided by the Companies) for DR to improve grid stability specifically for O'ahu. These constraints focus on eliminating under-frequency load shedding (UFLS) after a contingency event such as a unit trip. The constraints include data on net system load, kinetic energy, and the largest contingency. This data enables AP for Production Simulation to determine the amount of Fast Frequency Response and segregated customer end-use devices necessary to handle a contingency. Kinetic energy by unit is included in Table J-59. O'ahu's largest contingency unit is, prior to retirement, AES, Kahe 5, then Kahe 6.

Unit	Kinetic Energy (MW)	Unit	Kinetic Energy (MW)
AES	614	KMCBH-1	25
CIP C-1	765	KMCBH-2	25
H-Power Off Peak	209	KMCBH-3	25
H-Power On Peak	209	KMCBH-4	25
JBPHH-1	46.6	KMCBH-5	25
JBPHH-2	46.6	KMCBH-6	25
JBPHH-3	46.6	Schofield 1 (SCH-1)	22.6
JBPHH-4	46.6	Schofield 2 (SCH-2)	22.6
JBPHH-5	46.6	Schofield 3 (SCH-3)	22.6
JBPHH-6	46.6	Schofield 4 (SCH-4)	22.6
Kahe 1	426	Schofield 5 (SCH-5)	22.6
Kahe 2	426	Schofield 6 (SCH-6)	22.6
Kahe 3	357	Waiau 3	225
Kahe 4	357	Waiau 4	222
Kahe 5	692	Waiau 5	261
Kahe 6	692	Waiau 6	256
Kahe 7–10 3x1 CC	1,074.5	Waiau 7	426
Kalaeloa-1 (CT+ST)	878	Waiau 8	426
Kalaeloa-2 (CT+ST)	591	Waiau 9	447
		Waiau 10	447

Table J-59. Kinetic Energy by Unit for O‘ahu

Demand Response Portfolio

A portfolio of DR programs is under development. While a preliminary, interim program portfolio application was filed on December 30, 2015, that portfolio is currently being revised, an updated application will be filed in mid-2016, following the filing of a PSIP Preferred Plan and any subsequent iterations thereof. The information below reflects both the current state of the DR portfolio, pending final refinements prior to the final DR program portfolio application. The sections that follow describe each proposed DR program, the methodology for calculating program costs, the methodology for determining the avoided costs associated with the portfolio (the means of reducing system costs if replaced with DR), and the targeted MWs to be utilized by the Companies given the deployment of the Preferred Plan.

Demand Response Programs

The DR program portfolio application presented a suite of DR programs that are candidates for the portfolio. Each of the nine DR programs was designed to deliver a specific grid service. The figure below has been updated since the interim DR application,[3] to reflect the new grid service naming convention (FFR2 and Replacement Reserves).

DR Program	Grid Service Delivered
Real-Time Pricing (RTP)	Capacity
Time-of-Use (TOU)	
Day-Ahead Load Shift (DALS)	
Minimum Load (ML)	
PV Curtailment (PVC)	
Critical Peak Incentive (CPI)	
Fast Frequency Response (FRR)	Fast Frequency Response 2
Regulating Reserve (RR)	Regulating Reserve
Non-Spin Auto Response (NSAR)	Replacement Reserve (10-Minute)

Table J-60. DR Program to Grid Service Mapping

Descriptions of these programs follow.

Real-Time Pricing. RTP is a capacity grid service resource capable of providing hourly retail rate prices to customers up to six hours before the event day starts. Retail rates will be based on weather, system resource availability, and forecasted load profile. As mentioned earlier, Residential RTP requires an AMI infrastructure to be in place where the customers are able to change their electric usage pattern based on the different hourly retail rates provided by the Companies.

Time-of-Use. TOU is a capacity grid service resource capable of providing a static period pricing rate for on-peak, off-peak, and mid-day times of the day to residential customers only. Customers are encouraged, through the price differential, to shift their energy usage from the peak time of day to the night or middle of the day, when solar PV is at its peak. Once RTP becomes available, TOU programs are expected to end and the participants will have an opportunity to enroll into RTP.

Day-Ahead Load Shift. DALS is a capacity grid service resource capable of providing a static period pricing rate are delivered six hours before the event start day for on-peak, off-peak, and mid-day times of the day to commercial customers only. Customers are encouraged, through the price differential, to shift their energy usage from the peak time of day to the night or middle of the day, when solar PV is at its peak."

Minimum Load. ML is a capacity grid service resource capable of providing increased load in the middle of the day by incentivizing customers to shift their usage to the middle of the day. While identified as an option, this program was not used in any of the

3 See Docket No. 2015-0412, Interim DR Program Portfolio Application filing, filed December 30, 2015.

portfolios' analysis because the benefits of load shifting programs, such as TOU, DALS, or RTP, were already fulfilling the load flattening benefits.

PV Curtailment. PVC is a capacity grid service resource capable of issuing curtailment of customer's PV during times when minimum must run generators are within a specified threshold limit that requires more load on the system in order to prevent sudden shut down of an online generator.

Critical Peak Pricing. CPI is a capacity grid service resource capable of providing peak load reduction during emergency situations when not enough generation resources are available. The current existing Commercial DLC program could be re-classified under this program as part of the initial migration.

Fast Frequency Response. FFR program is a FFR grid service resource capable of responding to contingency events within 30 cycles or less.[4] A customer who enrolls in this program would have to be able to offer load resources that could respond to a local discrete response in 30 cycles or less.

Regulating Reserve. RR is a grid service resource capable of providing up and down reserves to balance the variability of the system given high renewable penetration. A customer who enrolls in this program must be able to provide a load resource that could respond within two seconds.

Non-Spin Auto Response. NSAR is a 10-minute spinning reserve capable of replacing other resources that are used for Spinning Reserves. It may also be used for the replacement of a contingency grid battery when paired with an FFR program. A customer who is enrolled in this NSAR program would have 10-minutes to respond and reduce their enrolled load resource.

Methodology for Determining Cost of DR Programs

For this PSIP Update, and subsequently for the updated DR program portfolio application, program costs have been developed using a bottom-up approach. This represents a change from the levelized, top-down approach taken during the DR interim application. These costs are embedded into the production cost models when performing optimization of resource plans. The Companies will continue to refine cost assumptions in advance of the final DR application is submitted to provide the best possible 2-year proposed budget and the 15-year avoided cost analysis to be provided as part of the final DR application.

[4] 30 cycles is the maximum FFR response requirement dependent on total MW available. The requirement may be less than 30 cycles after further analysis.

Finally, an inflation rate of 1.8% and annual replacement rate of 5% was used to calculate costs. The following is an excerpt from the Companies response to PSIP IR-40[5] regarding the method of calculating costs:

> In the DR Interim Application, costs were determined using the levelized costs as part of the Potential Study (See Exhibit A of the DR Interim Application). In order to estimate and assess the cost effectiveness of the programs in its current status, a top down approach of levelized cost was used for the DR Interim Application. For the April PSIP Update and final DR Program Portfolio Application filing to be filed in Docket No. 2015-0412 later this year, a bottom-up approach will be used for a more accurate representation of the cost of each of the programs. Key to the bottom-up approach will be estimating the enabling cost of each customer, quantifying their material, incentive, and installation costs. The cost will then be multiplied by the number of customers expected to be enrolled in each program. Followed by additional costs such as labor, marketing, evaluation, and general outside services will then be added to complete the overall cost of the DR program portfolio. The MWs determined through the avoided cost analysis supports the number of customer appliances that are needed on each program. The number of expected customers will be derived and supported from the potential study and the avoided cost analysis update. These updates will be filed as exhibits in the upcoming final DR Program Portfolio Application to be filed in Docket No. 2015-0412 later this year.
>
> Foundationally, historical DR costs incurred by the Companies have been used to calculate the necessary program costs for programs similar to those in the Companies' current portfolio. For program costs associated with proposed programs that are new to the Companies, such as RR, responses to the Companies' Grid Services request for proposals, as well as data derived from mainland markets have been used to derive cost estimates."
>
> The key to an accurate program cost projection is the DR Potential Study, which will continue to be updated during the process. While certain costs remain uncertain, such as incentive structures, the Companies have derived incentives from the avoided costs of the programs, less the anticipated administrative and operational costs. The Companies will continue to modify costs over time as programs are implemented and actual costs are tracked.

The approach described above has already been undertaken, and the new program costs resulting from that process are as follows:

[5] ?How is this referenced

Island	NPV Cost
O'ahu	$323,087,299
Maui	$19,411,699
Hawai'i Island	$20,112,813
Moloka'i	$666,532
Lana'i	$750,911
DRMS	$13,414,991

Table J-61. DR Program Net Present Value Costs

Methodology for Determining Avoided Costs of DR Programs

Avoided cost analysis for DR programs allows the Companies to compare the system costs of a resource plan with DR programs against the system costs of a resource plan without DR programs.

The following is an excerpt from the Demand Response Interim application:

> Each program will be designed to provide resources that can either directly or in combination with other programs, replace a more costly resource. An iteration analyzing which combination presented the best cost-effective DR programs was performed in the Avoided Cost Analysis. The Avoided Cost analysis resulted in advancing programs that were beneficial for each island in terms of their relative benefit and ultimately their contribution to a cost beneficial portfolio… The cost-effectiveness analysis determined which islands were capable of implementing a cost-effective DR Portfolio, although further analysis is required before finalizing the entire portfolio of programs for each island.

The Companies, in tandem with Black & Veatch modelers, have developed specific modeling techniques to evaluate the range of services provided by DR based on the characteristics of each service combined with the performance characteristics of the individual end uses. The methodology for calculating the avoided cost, as well as the specific modeling techniques is described in Appendix H, under the Adaptive Planning for Production Simulation description.

The avoided cost for a grid service is the cost of an alternative resource (energy storage or a generator) to provide the equivalent service. Avoided costs are based on several factors, including installed capacity costs, fuel costs, and cost of alternatives, each of which depends on the current state of the system. Additionally, alterations to a baseline resource capital plan promote meaningful avoided costs opportunities. In the context of the PSIP Update, the following represent examples of potential avoided cost values of DR across the different systems:

O'ahu: The DR portfolio enables the deferral of units at the KMBCH station and/or JBPHH station. Other avoided costs include improved heat rate performance and reduced fuel costs.

Maui: The DR portfolio enables the deferral of two ICE. Other avoided costs include improved heat rate performance and reduced fuel costs.

Moloka'i: The DR portfolio enables improved heat rate performance and reduced fuel costs.

Lana'i: The DR portfolio enables improved heat rate performance and reduced fuel costs.

Hawai'i Island: The DR portfolio enables the reduction of the contingency battery by 1 MW through the combination of FFR and NSAR demand response products. Other avoided costs include improved heat rate performance and reduced fuel costs.

During the PSIP modeling process, multiple plans were created, generating multiple DR portfolios. The DR portfolios include varying amounts of end device potentials, including customer storage, by year and island. Customer storage uptake forecasting is synergistic with DR portfolio optimization, and the resource is considered as a DR end use capable of providing multiple grid services.

The DR portfolio development started with the resource stack for each plan, then created the DR portfolio from that plan, but did not add that new portfolio into the plan, unless that case would proceed towards the Preferred Plan. The Preferred Plans incorporated the DR portfolios shown below, but the iterative step of optimizing the Preferred Plan with DR is not yet complete. Optimization of the DR portfolio will be performed in the next iteration. The final cost, avoided cost and cost effectiveness analysis will utilize the optimized DR portfolio and include it within the Final DR Application, anticipated for filing in mid-2016.

DR Grid Service Portfolio: O‘ahu (1 of 2)

Customer	Commercial			
Program	*Regulating Reserves*	*Pricing*	*Fast Frequency Response*	*Non-Spin Auto Response*
Grid Service	RR	Capacity	FFR	Replacement Reserves
Frequency	Continuous	Daily	Contingency Event	Contingency Event
Event Length	30 minutes	24 hours	10 minutes	1 hour
Year	MW	MW	MW	MW
2016	–	–	–	–
2017	–	1.5	1.9	2.6
2018	–	4.7	5.8	4.4
2019	–	8.2	9.1	9.5
2020	–	11.6	11.6	13.2
2021	–	17.4	18.6	14.8
2022	–	19.4	18.0	14.8
2023	–	19.1	15.0	14.7
2024	–	19.3	15.9	14.8
2025	–	19.4	16.1	14.6
2026	–	19.6	16.4	14.9
2027	–	19.7	16.7	15.1
2028	–	20.3	18.5	15.4
2029	–	20.2	18.0	15.8
2030	–	20.3	19.0	16.4
2031	–	20.7	18.9	17.1
2032	–	21.4	19.4	18.0
2033	–	22.0	20.7	18.8
2034	–	22.7	20.6	19.6
2035	–	24.2	20.5	19.8
2036	–	25.5	20.6	20.3
2037	–	26.8	21.5	22.1
2038	–	28.1	22.2	23.0
2039	–	29.5	23.4	24.1
2040	–	31.0	23.7	24.4
2041	–	32.4	24.0	24.9
2042	0.7	33.9	24.1	25.2
2043	1.7	35.7	24.3	25.5
2044	2.7	37.2	24.6	26.0
2045	2.3	38.7	25.0	26.4

Table J-62. O‘ahu DR Program Grid Service Portfolio: MW (1 of 2)

DR Grid Service Portfolio: O‘ahu (2 of 2)

Customer	Residential				Small Business		
Program	*RR*	*Pricing*	*FFR*	*NSAR*	*Pricing*	*FFR*	*NSAR*
Grid Service	RR	Capacity	FFR	Replacement Reserves	Capacity	FFR	Replacement Reserves
Frequency	Continuous	Daily	Contingency	Contingency	Daily	Contingency	Contingency
Event Length	30 minutes	24 hours	10 minutes	1 hour	24 hours	10 minutes	1 hour
Year	MW	MW	MW	MW	MW	MW	MW
2016	–	–	–	–	–	–	–
2017	–	2.6	3.6	1.9	1.5	0.8	1.4
2018	0.3	7.9	14.9	4.1	4.5	2.7	2.8
2019	0.8	13.3	19.3	8.3	7.6	3.4	5.6
2020	1.4	11.5	27.5	12.7	5.3	5.5	8.3
2021	2.1	18.2	31.4	14.6	8.0	10.4	9.3
2022	2.8	21.9	40.4	16.0	8.9	10.6	9.3
2023	3.3	24.5	32.4	18.1	8.9	7.0	9.4
2024	3.7	26.7	33.1	20.3	9.0	7.3	9.5
2025	4.2	29.0	33.6	22.3	9.2	7.6	9.3
2026	4.3	28.6	34.1	24.1	9.5	8.0	9.4
2027	4.2	29.8	34.5	25.8	9.8	8.5	9.6
2028	4.5	30.7	38.8	27.3	10.3	9.2	9.8
2029	4.9	30.8	38.2	28.5	10.5	9.9	9.9
2030	5.1	31.0	40.2	29.5	10.7	10.8	10.1
2031	5.3	31.1	40.2	30.4	11.5	11.9	10.9
2032	5.3	31.5	38.2	31.4	12.8	12.8	11.8
2033	5.7	31.7	42.9	31.5	14.4	14.0	12.9
2034	5.8	31.8	40.4	31.8	15.8	15.3	14.1
2035	5.9	32.4	39.7	32.0	17.2	16.3	15.1
2036	6.4	32.6	40.1	31.2	18.6	17.4	16.2
2037	8.9	32.6	47.6	33.4	20.0	19.5	18.0
2038	10.8	32.6	41.8	33.4	21.4	20.5	19.1
2039	11.9	32.8	48.8	33.1	23.0	21.8	20.4
2040	13.5	33.1	48.8	33.0	24.8	22.4	21.1
2041	14.4	33.4	43.4	32.2	26.2	23.1	22.2
2042	15.2	33.5	43.8	31.4	27.6	23.9	22.9
2043	16.4	33.5	44.4	30.6	29.3	24.3	23.3
2044	17.3	33.8	43.7	29.8	30.8	24.7	23.7
2045	17.3	33.9	42.3	29.1	32.2	25.0	24.1

Table J-63. O‘ahu DR Program Grid Service Portfolio: MW (2 of 2)

DR Grid Service Portfolio: Maui

Customer	Commercial		Residential		Small Business	
Program	*RR*	*Pricing*	*RR*	*Pricing*	*RR*	*Pricing*
Grid Service	RR	Capacity	RR	Capacity	RR	Capacity
Frequency	Continuous	Daily	Continuous	Daily	Continuous	Daily
Event Length	30 minutes	24 hours	30 minutes	24 hours	30 minutes	24 hours
Year	MW	MW	MW	MW	MW	MW
2016	–	–	–	–	–	–
2017	–	0.2	–	0.6	–	0.3
2018	0.0	0.5	0.3	1.8	0.1	0.8
2019	0.0	1.0	0.8	3.1	0.2	1.4
2020	0.1	0.2	1.8	0.4	0.4	0.2
2021	0.1	0.5	2.9	1.2	0.6	0.5
2022	0.1	1.1	3.7	2.6	0.7	0.9
2023	0.2	1.8	4.0	4.0	0.7	1.5
2024	0.2	1.9	4.3	4.4	0.7	1.6
2025	0.4	2.1	4.6	4.7	0.8	1.7
2026	0.4	2.1	5.0	4.9	0.8	1.8
2027	0.4	1.9	5.5	4.8	0.9	1.7
2028	0.4	1.9	5.9	4.7	0.9	1.7
2029	0.5	1.9	6.2	5.1	1.0	1.7
2030	0.5	1.9	6.5	4.9	1.1	1.7
2031	0.5	1.9	6.9	4.8	1.1	1.8
2032	0.6	2.0	7.3	5.3	1.2	1.9
2033	0.6	1.9	7.8	5.1	1.3	1.8
2034	0.6	2.0	8.4	5.3	1.3	1.9
2035	0.7	2.0	8.8	5.5	1.4	2.0
2036	0.7	2.2	9.3	6.0	1.5	2.1
2037	0.7	2.1	9.7	5.8	1.5	2.1
2038	0.7	2.2	10.1	6.2	1.6	2.3
2039	0.8	2.3	10.6	6.4	1.7	2.3
2040	0.8	2.3	10.8	6.5	1.7	2.4
2041	0.8	2.2	11.6	6.6	1.8	2.3
2042	0.8	2.2	12.0	6.4	1.8	2.3
2043	0.9	2.3	12.3	6.9	1.9	2.5
2044	0.9	2.4	12.8	7.0	1.9	2.6
2045	0.9	2.4	13.1	7.2	2.0	2.6

Table J-64. Maui DR Program Grid Service Portfolio: MW

DR Grid Service Portfolio: Lana'i

Customer	Commercial		Residential		Small Business	
Program	*RR*	*Pricing*	*RR*	*Pricing*	*RR*	*Pricing*
Grid Service	RR	Capacity	RR	Capacity	RR	Capacity
Frequency	Continuous	Daily	Continuous	Daily	Continuous	Daily
Event Length	30 minutes	24 hours	30 minutes	24 hours	30 minutes	24 hours
Year	MW	MW	MW	MW	MW	MW
2016	0.00	0.00	0.00	0.00	0.00	0.00
2017	0.00	0.00	0.00	0.02	0.00	0.01
2018	0.00	0.00	0.01	0.05	0.00	0.02
2019	0.00	0.00	0.02	0.08	0.00	0.04
2020	0.00	0.04	0.05	0.07	0.01	0.03
2021	0.00	0.06	0.07	0.10	0.01	0.04
2022	0.00	0.07	0.09	0.11	0.01	0.04
2023	0.00	0.08	0.10	0.12	0.01	0.04
2024	0.01	0.08	0.12	0.12	0.02	0.04
2025	0.01	0.08	0.12	0.12	0.02	0.05
2026	0.01	0.08	0.14	0.12	0.02	0.05
2027	0.01	0.08	0.15	0.14	0.02	0.05
2028	0.01	0.09	0.16	0.13	0.02	0.05
2029	0.01	0.09	0.18	0.14	0.03	0.05
2030	0.02	0.09	0.19	0.14	0.03	0.05
2031	0.02	0.09	0.21	0.14	0.03	0.05
2032	0.02	0.09	0.22	0.14	0.03	0.05
2033	0.02	0.09	0.23	0.15	0.03	0.06
2034	0.02	0.09	0.24	0.15	0.04	0.05
2035	0.02	0.09	0.27	0.15	0.04	0.06
2036	0.02	0.09	0.28	0.15	0.04	0.06
2037	0.02	0.10	0.29	0.16	0.04	0.06
2038	0.02	0.10	0.29	0.16	0.04	0.06
2039	0.02	0.10	0.30	0.18	0.04	0.06
2040	0.02	0.10	0.31	0.17	0.05	0.06
2041	0.02	0.10	0.32	0.16	0.05	0.06
2042	0.03	0.10	0.34	0.17	0.05	0.07
2043	0.03	0.11	0.35	0.16	0.05	0.06
2044	0.03	0.11	0.37	0.17	0.05	0.06
2045	0.03	0.11	0.37	0.18	0.05	0.07

Table J-65. Lana'i DR Program Grid Service Portfolio: MW

DR Grid Service Portfolio: Moloka‘i

Customer	Commercial		Residential		Small Business	
Program	*RR*	*Pricing*	*RR*	*Pricing*	*RR*	*Pricing*
Grid Service	RR	Capacity	RR	Capacity	RR	Capacity
Frequency	Continuous	Daily	Continuous	Daily	Continuous	Daily
Event Length	30 minutes	24 hours	30 minutes	24 hours	30 minutes	24 hours
Year	MW	MW	MW	MW	MW	MW
2016	0.00	0.00	0.00	0.00	0.00	0.00
2017	0.00	0.00	0.00	0.02	0.00	0.01
2018	0.00	0.01	0.01	0.06	0.00	0.03
2019	0.00	0.02	0.02	0.10	0.00	0.04
2020	0.00	0.02	0.05	0.07	0.01	0.03
2021	0.00	0.04	0.08	0.10	0.01	0.04
2022	0.00	0.04	0.10	0.12	0.02	0.05
2023	0.00	0.04	0.11	0.11	0.02	0.05
2024	0.00	0.04	0.12	0.12	0.02	0.05
2025	0.01	0.04	0.12	0.14	0.02	0.05
2026	0.01	0.04	0.13	0.12	0.02	0.05
2027	0.01	0.04	0.14	0.12	0.02	0.05
2028	0.01	0.04	0.15	0.13	0.02	0.05
2029	0.01	0.04	0.16	0.13	0.02	0.05
2030	0.01	0.03	0.17	0.13	0.02	0.05
2031	0.01	0.03	0.18	0.15	0.03	0.05
2032	0.01	0.03	0.19	0.15	0.03	0.05
2033	0.01	0.03	0.19	0.15	0.03	0.04
2034	0.01	0.03	0.20	0.16	0.03	0.05
2035	0.01	0.03	0.21	0.16	0.03	0.05
2036	0.02	0.03	0.21	0.16	0.03	0.05
2037	0.02	0.03	0.21	0.15	0.03	0.05
2038	0.02	0.03	0.22	0.15	0.03	0.05
2039	0.02	0.03	0.23	0.15	0.03	0.05
2040	0.02	0.03	0.23	0.15	0.03	0.05
2041	0.02	0.03	0.24	0.15	0.04	0.05
2042	0.02	0.03	0.24	0.16	0.04	0.05
2043	0.02	0.03	0.24	0.15	0.03	0.05
2044	0.02	0.03	0.25	0.15	0.03	0.05
2045	0.02	0.03	0.26	0.15	0.04	0.05

Table J-66. Moloka‘i DR Program Grid Service Portfolio: MW

DR Grid Service Portfolio: Hawai'i Island (1 of 2)

Customer	Commercial			
Program	*Regulating Reserves*	*Pricing*	*Fast Frequency Response*	*Non-Spin Auto Response*
Grid Service	RR	Capacity	FFR	Replacement Reserves
Frequency	Continuous	Daily	Contingency Event	Contingency Event
Event Length	30 minutes	24 hours	10 minutes	1 hour
Year	MW	MW	MW	MW
2016	RR	Capacity	FFR	Replacement Reserves
2017	Continuous	Daily	Contingency Event	Contingency Event
2018	30 minute	24 hours	10 minutes	1 hour
2019	MW	MW	MW	MW
2020	0.00	–	0.0	–
2021	0.00	0.15	0.0	–
2022	0.00	0.44	0.0	–
2023	0.00	0.74	0.11	0.51
2024	0.01	0.78	0.09	0.51
2025	0.02	1.17	0.09	0.51
2026	0.02	1.28	0.09	0.51
2027	0.02	1.27	0.09	0.50
2028	0.02	1.25	0.09	0.50
2029	0.02	1.22	0.09	0.50
2030	0.02	1.20	0.09	0.50
2031	0.02	1.17	0.09	0.49
2032	0.02	1.12	0.09	0.49
2033	0.02	1.12	0.09	0.49
2034	0.02	1.13	0.09	0.48
2035	0.02	1.16	0.09	0.48
2036	0.02	1.17	0.09	0.48
2037	0.02	1.19	0.09	0.48
2038	0.02	1.21	0.09	0.48
2039	0.02	1.22	0.09	0.47
2040	0.02	1.22	0.09	0.47
2041	0.02	1.23	0.08	0.47
2042	0.02	1.24	0.08	0.47
2043	0.02	1.25	0.08	0.46
2044	0.02	1.26	0.08	0.46
2045	0.02	1.26	0.08	0.46

Table J-67. Hawai'i Island DR Program Grid Service Portfolio: MW (1 of 2)

DR Grid Service Portfolio: Hawai'i Island (2 of 2)

Customer	Residential				Small Business			
Program	RR	Pricing	FFR	NSAR	RR	Pricing	FFR	NSAR
Grid Services	RR	Capacity	FFR	Repl.	RR	Capacity	FFR	Repl.
Frequency	Continuous	Daily	Contingency	Contingency	Continuous	Daily	Contingency	Contingency
Event Length	30 minute	24 hours	10 minutes	1 hour	30 minutes	24 hours	10 minutes	1 hour
Year	MW	MW	MW	MW	MW	MW	MW	MW
2016	–	–	–	–	–	–	–	–
2017	–	0.65	–	–	–	0.31	–	–
2018	0.19	1.95	–	–	0.01	0.94	–	–
2019	0.57	3.29	1.0	0.57	0.00	1.58	0.24	0.40
2020	1.17	2.51	1.0	0.57	0.00	1.05	0.24	0.40
2021	1.80	3.77	1.0	0.58	0.02	1.59	0.24	0.40
2022	2.02	4.19	1.0	0.58	0.02	1.75	0.24	0.40
2023	2.02	4.22	1.0	0.58	0.02	1.75	0.24	0.40
2024	2.04	4.32	1.0	0.58	0.02	1.74	0.24	0.40
2025	2.06	4.55	1.0	0.58	0.02	1.74	0.24	0.40
2026	2.10	4.77	1.0	0.59	0.02	1.73	0.24	0.40
2027	2.10	4.98	1.0	0.59	0.02	1.71	0.24	0.41
2028	2.10	5.16	1.0	0.59	0.02	1.66	0.24	0.41
2029	2.07	5.29	1.0	0.59	0.02	1.64	0.25	0.41
2030	2.06	5.27	1.0	0.59	0.02	1.64	0.25	0.41
2031	2.08	5.34	1.0	0.59	0.02	1.62	0.25	0.41
2032	2.11	5.39	1.0	0.60	0.02	1.60	0.25	0.42
2033	2.14	5.41	1.0	0.60	0.03	1.59	0.25	0.41
2034	2.17	5.46	1.0	0.60	0.03	1.61	0.25	0.41
2035	2.22	5.58	1.0	0.60	0.03	1.61	0.25	0.41
2036	2.26	5.69	1.0	0.61	0.04	1.63	0.25	0.41
2037	2.34	5.82	1.0	0.61	0.04	1.63	0.25	0.41
2038	2.43	5.96	1.0	0.61	0.05	1.64	0.25	0.41
2039	2.69	6.07	1.0	0.62	0.05	1.65	0.24	0.41
2040	2.96	6.21	1.0	0.62	0.05	1.67	0.24	0.40
2041	3.22	6.31	1.0	0.63	0.06	1.69	0.24	0.40
2042	3.50	6.43	1.0	0.63	0.06	1.70	0.24	0.40
2043	3.77	6.53	1.0	0.63	0.07	1.70	0.24	0.40
2044	4.06	6.67	1.0	0.64	0.07	1.70	0.24	0.40
2045	4.34	6.81	1.0	0.64	0.07	1.73	0.23	0.40

Table J-68. Hawai'i Island DR Program Grid Service Portfolio: MW (2 of 2)