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 December 23, 2016

Book 2 of 4

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 *PSIP Update Report: December 2016*.

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.

Agricultural A–E Land Classification

The Land Study Bureau (LSB) of the University of Hawai‘i, together with the United States Department of Agricultural soil survey, developed an overall master productivity rating for Hawai‘i’s agricultural land. The productivity rating of land is based on a productivity formula that multiplies the following five percentage indexes:

a = percentage rating for the general character of the soil profile
b = percentage rating for the texture of the surface horizon
c = percentage rating for the slope of the land
x = percentage rating for salinity, soil reaction, damaging winds, erosion, etc.
y = percentage rating for rainfall

This overall productivity rating ranged from “A”, very good, to “E”, not suitable. Only A, B, and C classified land is deemed suitable for agriculture. The classifications are essentially based on soil quality. Higher percentage ratings means more highly favorable agricultural land. Thus, the range of ratings for agricultural A through E land is :

A = 85–100
B = 70–84
C = 55–69
D = 30–54
E = 0–29

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

Those services that are necessary to support the transmission of capacity and energy from resources to loads while maintaining reliable operation of the electric system in accordance with good utility practice.

As-Available Renewable Energy

See Variable Renewable Energy on page A-38.

Automatic Generation Control (AGC)

A process for adjusting demand and resources from a central location 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-20.)

Baseload Capacity

See Capacity, Generating on page A-4.

Baseload Generation

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

Battery Energy Storage Systems (BESS)

Any battery storage system used for contingency or regulating reserves, load shifting, ancillary services, or other utility or customer functions. (See also Energy Storage on page A-12.)

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

The MW rating of the unit. Capacity must be assured for at least four hours and controllable during the 24-hour day.

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-20.

Contingency Reserves

The reserves deployed to meet contingency disturbance requirements, typically based upon the largest single contingency on each island. Contingency reserves are comprised of fast frequency responses (FFR1 and FFR2) and primary frequency response. In the Hawaiian Electric Companies' system, contingency reserves are automatically initiated.

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 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 = 1,000 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-20.)

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.

Ancillary Services: Demand response programs and responses that provide the ancillary services required to continually meet demand or to maintain system stability.

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 and Droop Response

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. Droop response is the time it takes for online generators to pick up load following a contingency event. Electrical systems with faster droop response times can better withstand contingency events.

Dual-Train Combined Cycle (DTCC)

See Combined Cycle on page A-5.

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 1,000 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 (FFR1 and FFR2)

FFR reduces the rate of change of frequency (RoCoF) with a response proportional to the generation contingency, and quickly restores the balance between supply and demand following a loss of load reducing operational down reserves from synchronous generation. FFR1 reduces the Rate of Change of Frequency (RoCoF) caused by the loss of generation; FFR1 is a proportional response. FFR2 reduces the RoCoF caused by the loss of generation. FFR2 is considered fixed because, once committed, it cannot be altered; however, the amount available can be variable because the FFR2 capacity depends on customer load.

Fast Frequency Response (FFR) Program

A DR fast frequency response grid service capable of responding to a contingency event (the maximum FFR requirement depending on the total available MW). A customer who enrolls in this DR program must be able to meet the requirements specified by FFR1 or FFR2.

Federal Energy Regulatory Commission (FERC)

FERC is the United States federal agency that regulates the transmission and wholesale sale of electricity and natural gas in interstate commerce, regulates the transportation of oil by pipeline in interstate commerce, and licenses non-federal hydropower projects. FERC also reviews proposals to build interstate natural gas pipelines, natural gas storage projects, and liquefied natural gas (LNG) terminals.

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

Firm Capacity
See Capacity, Generating on page A-4.

Feed-In Tariff (FIT) Program
A FIT program specific to the Hawaiian Electric Companies, under guidelines issued by the Hawaiʻi 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.

Floating Storage and Regasification Unit (FSRU)
An FSRU is an LNG vessel, either near-shore or off-shore, that enables LNG to be transferred from an LNG transit carrier ship. The transferred LNG can then be stored and regasified before ultimately being distributed onshore as natural gas.

Flywheel
See Energy Storage on page A-12.

Forced Outage
See Outage on page A-26.

Forced Outage Rate
See Outage on page A-26.

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-26.

G

Gas Turbine World

Gas Turbine World is a privately-published, bi-monthly journal for gas turbine buyers and users, and is designed to address their practical information needs with technical depth and real-world context. Gas Turbine World annually publishes its industry-benchmark GTW Handbook and its new production year GTW Performance Specs.

Generating Capacity

See Capacity, Generating on page A-4.

Generation (Electricity)

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

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

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

Generator (Electric)

A machine that transforms mechanical, chemical, or thermal energy into electric energy. Includes wind generators, solar PV generators, and other systems that convert energy of one form into electric energy. (See also Capacity, Generating on page A-4.)

Geographic Information System (GIS)

A computer system designed to capture, store, manipulate, analyze, manage, and present all types of geographical data.

Gigawatt (GW)

A unit of power, capacity, or demand equal to one billion watts, one million kilowatts, or one thousand megawatts.

Gigawatt-Hour (GWh)

A unit of electric energy equal to one billion watt-hours, one million kilowatt-hours, or one thousand megawatt-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.

Grid Export

The total amount of DG-PV generation exported to the grid. Grid export through both the Customer Grid Supply or Customer Self Supply program is compensated at the same amount as grid-scale PV levelized cost of energy.

Grid-Scale Generation

A term coined for this PSIP that describes the same type of facility as utility-scale generation, however, makes clearer that such generation is not necessarily utility owned, but rather is owner agnostic. (See also Utility-Scale Generation on page A-37.)

Gross Generation

See Generation (Electricity) on page A-15.

H

Hawaiʻi Public Utilities Commission (PUC or Commission)

A state agency that regulates all franchised or certificated public service companies operating in Hawaiʻi. The Commission 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.

Hawaiʻi Revised Statute (HRS)

The codified laws of the State of Hawaiʻi. The entire body of state laws is referred to the Hawaiʻi 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.

I

IHS Energy

IHS Energy provides information, analytics, and insight about world energy markets. They publish and continually update energy-related forecasts and outlooks, analytical platforms and datasets, and an exploration and production database. IHS Energy provides detailed data that, among many other benefits, enables better capital investments as well as capital and operating costs analysis and optimization.

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.

Independent System Operator (ISO)

An ISO is an independent, nonprofit organization comprised of member utilities. In general, an ISO oversees the operation of a bulk electric power system, its transmission lines, and the electricity market generated and transmitted by its member utilities. The goal of an ISO is to operate the grid reliably and efficiently, provide fair and open transmission access, promote environmental stewardship, and facilitate effective markets and promote infrastructure development.

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).

Inertia

Inertia is the response of generators from the kinetic energy in the rotating masses that remain online as frequency starts to drop following a contingency event. Inertia provides ride-through of momentary system disruptions to avoid a system contingency inertia reduces the rate of change of frequency (RoCoF), allowing slower governor actions to catch up and contribute to frequency stabilization. Electrical systems with high inertia are more robust can better withstand contingency events.

Installed Capacity

See Capacity, Generating on page A-4.

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. We also filed an IDRPP Update on March 31, 2015; a supplemental report on November 6, 2015; and a revised supplemental report on Nov. 20, 2015.

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-4.

Intermittent Renewable Energy

See Variable Renewable Energy on page A-38.

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 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 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. Also references as Demand Response (DR).

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-26.

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 or one thousand kilowatts. 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 or one thousand kilowatt-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-15.

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-4.

Net Energy Metering (NEM)

A financial arrangement between a customer with a renewable distributed generator and the utility, where the customer only pays for the net amount of electricity taken from the grid, regardless of the time periods when the customer imported from or exported to the grid. Under a NEM arrangement, the customer is allowed to remain connected to the power grid, so that the customer can take advantage of the grid's reliability infrastructure (such as ancillary services provided by generators, energy storage devices, and demand response programs), use the grid as a "bank" for power generated by the customer in excess of the customer's needs, and use the grid as a backup resource for times when the power generated by the customer is less than the customer's needs.

Net Generation

See Generation (Electricity) on page A-15.

New Source Review (NSR)

A permitting process created by Congress in 1977 as an amendment to the Clean Air Act requiring pre-construction review for environmental controls for the construction of new facilities or modifications to existing facilities (not routine scheduled maintenance) that would significantly increase a regulated pollutant. NSR was designed to eventually force the modernization of existing generation assets to comply with air emission regulations.

New Source Performance Standards (NSPS)

Created as part of the Clean Air Act in 1970 to establish limits for certain air pollution emissions and water pollution discharges for how much certain categories of new facilities or modified existing facilities (such as boilers) can emit.

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 Replacement Reserves (RR). Replacement Reserves may be used for restoring regulation or contingency reserves. 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-35.)

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-32.)

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-26.

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-4.

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. PVC is expected to offer circuit-level value in helping to address back-feeding risks as well as power quality and voltage issues. The Demand Response team will collaborate on the development of DER

Phase 2 program design to help identify opportunities to incorporate specific PVC options.

Planned Outage

See Outage on page A-26.

Planning Reserve

See Reserve on page A-32.

Power

The rate at which energy is supplied to a load (consumed), usually measured in watts (W), kilowatts (kW), megawatts (MW), gigawatts (GW), and terawatts (TW).

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.

Primary Frequency Response (PFR)

Primary frequency response are reserves are the reserve capacity from online synchronous generation that provides both regulating reserves and contingency reserves. PFR is available to handle the sudden loss of a generator or major transmission line with a response proportional to the changes in frequency. In general, the largest online unit tends to determine the amount of PFR available to the system following a contingency

event. If this largest unit trips offline, then the generators already online (and "spinning") can quickly pick up load within a defined time period to keep the system running.

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-12.

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. The most operationally and cost-efficient way to deliver Residential RTP programs is with an AMI infrastructure in place.

Reciprocating Internal Combustion Engines (RICE)

A reciprocating internal combustion engine uses the reciprocating movement of pistons to create pressure that is converted into electricity.

Regulation Reserves (RR) Program

A DR grid service capable of providing up and down reserves to balance system variability. A customer who enrolls in this program must be able to provide a load resource that could initiate a response within two seconds. The Companies examined RegDown as an additional program option, and while there are sufficient resources projected of being able to deliver such a service, the modeling efforts undertaken did not demonstrate a significant value of this service based on the current resource mix expected to deliver that RegDown service.

Regulating Reserves (RegUp & RegDown)

The service used to maintain system frequency in response to supply and demand imbalances over short time frames, typically on the order of one to several seconds. RegUp and RegDown resources adjust their generation or load levels in response to automatic generation control (AGC) signals provided by the system operator.

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-34.)

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 Standards (RPS)

A goal for the percentage of electricity sales in Hawai‘i to be derived from renewable energy sources. The RPS is set by state law. Savings from energy efficiency and displacement or offset technologies 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.

Replacement Reserves (RR)

Off-line, quick-start resources that can be used as a replacement reserve provided they can be started and synchronized to the grid by a 10-minute or 30-minute timeframe depending upon system needs. These resources may be used for restoring load, regulation or supporting and replacing contingency reserves.

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-26.)

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.

RSMeans Construction Index

RSMeans is the world's leading provider of construction cost data, software, and services for all phases of the construction lifecycle, providing accurate and up-to-date cost information to help project and control the cost of both new building construction and renovation projects. RSMeans annually updates and publishes a collection of cost data books.

S

Scheduled Outage

See Outage on page A-26.

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-5.

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.

Special Use Permit

A permit required for the construction of solar and wind facilities on Agricultural rated B or C land that represents 10% of the entire parcel or 20 acres, whichever is less. Such a facility must also meet the criteria set forth in Act 55 (Session Laws of Hawaiʻi, 2014) pertaining to making the project site available for compatible agricultural uses at discounted rates, project decommissioning, and site restoration. All special use permit applications are review by one or more state agencies and are difficult to obtain.

Spinning Reserves

See Primary Frequency Response on page A-28.

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 (SOx)

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.

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-26.)

T

Tariff
A published volume of rate schedules and general terms and conditions under which a product or service will be supplied.

Terawatt (TW)
A unit of power, capacity, or demand equal to one trillion watts, one billion kilowatts, one million megawatts, or one thousand gigawatts. The total power used by humans worldwide is commonly measured in terawatts.

Terawatt Hour (TWh)
A unit of electric energy equal to one trillion watt-hours, one billion kilowatt-hours, one million megawatt-hours, or one thousand gigawatt-hours.

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 transition to 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 Hawaiʻi 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.

Utility-Scale Generation

The designation for any small- or large-scale generation facility, usually a variable renewable resource such as solar PV or wind. These facilities can be either owned by the utility, or owned by an Independent Power Producer (IPP) under a Power Purchase Agreement (PPA). While generally not defined by output, their generation capabilities can range from as small as 1 MW to much larger (such as 100 MW or more). (See also Grid-Scale Generation on page A-16.)

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. Party Commentary and Input

The Hawaiian Electric Companies have actively sought input from the Participants and Intervenors (collectively referred to as the "Parties") to the PSIP proceeding to assist us in updating, supplementing, and amending our initial 2014 PSIPs[1] as directed in Order No. 33320.[2] Our solicitations started with our *Proposed PSIP Revision Plan*[3] that presented a schedule of conferences for just this purpose and included a table itemizing the input we needed for our modeling analyses. Continuing with our *Power Supply Improvement Plan Update Interim Status Report*,[4] we made it clear that we were proactively soliciting input from the Parties, even inviting the Intervenors to our internal planning meetings and engaging in one-on-one dialogue with most of the Parties. We initially held a stakeholder conference, and proposed another, to engage in direct discourse with the Parties; and participated in two technical conferences held by the Commission to further engage the Parties.

---

[1] Docket 2011-0206: *Hawaiian Electric Power Supply Improvement Plan*; Docket 2011-0092: *Maui Electric Power Supply Improvement Plan*; Docket 2012-0212: *Hawai'i Electric Light Power Supply Improvement Plan*; all instituted on August 26, 2014; and subsequent filing in Docket 2014-0183: *Hawaiian Electric Companies Power Supply Improvement Plan Errata*.

[2] Docket No. 2014-0183, Order No. 33320: *Admitting Intervenors and Participants, Identifying Observations and Concerns, Specifying Initial Statement of Issues, and Establishing Schedule of Proceedings*, issued November 4, 2015.

[3] Docket No. 2014-0183, *Hawaiian Electric Companies' Proposed PSIP Revision Plan*, filed November 25, 2015.

[4] Docket No. 2014-0183, *Power Supply Improvement Plan Update Interim Status Report*, filed February 16, 2016.

After filing our *PSIP Update Report: April 2016*,[5] we continued to engage the Parties and solicit input through two more stakeholder conferences, more personal invitations for Intervenors to attend our internal planning meetings, numerous impromptu meetings, two technical conferences, four structured stakeholder meetings, and myriad email exchanges. We received commentary and input from the Parties and general public in response to Order No. 33740.[6] Except for certain confidential information covered by the Commission's protective order, we shared *all* information with the Parties through a web interface. We have considered *all* input and commentary, incorporating all relevant, credible, and timely input into the development of our updated PSIP. We remain open to and expect input from stakeholders in future planning cycles.

This appendix:

- Reviews the background of the PSIP docket.
- Highlights and explores relevant Party input and commentary, and their impact on our modeling analyses.
- Details the communication surrounding our three stakeholder conferences and the last two technical conferences as well as the four stakeholder meetings, providing an overview of the proceedings and the input received.
- Compiles the Party comments filed in response to Order No. 33320, and explains how we responded to it and included it in our analyses.
- Summarizes the Party and general public submissions in response to Order No. 33740, then compiles this input into topics and explains how we responded to it.
- Concludes by including the presentation slides from the stakeholder conferences.

[5] Docket No. 2014-0183, *Power Supply Improvement Plan Update Report: April 2016*, filed April 1, 2016.

[6] Docket No. 2014-0183, Order No. 33740: *Inviting Comments on the HECO Companies' Power Supply Improvement Plan Update*, issued June 3, 2016.

THE UPDATED PSIP PROCEEDING

The updated PSIP proceeding has included:

- Six Commission Orders (together with a Protective Order and a Company Motion for Clarification).[7]
- Seven opportunities for comments and input from the Parties.
- Three sets of information request (IR) letters and responses.
- Four Commission technical conferences.
- Three Company stakeholder conferences.
- Four organized stakeholder meetings.
- Five Company PSIP report-related filings culminating in this *PSIP Update Report: December 2016*.

The overall PSIP proceeding began with Order No. 32257[8] that instituted Docket 2014-0183 to review the PSIPs that we were directed to file by August 28, 2014. The intent of this proceeding was to "review the HECO Companies' Power Supply Improvement Plans". The Order named the Consumer Advocate and our three operating utilities—Hawaiian Electric, Maui Electric, and Hawai'i Electric Light—as parties to the docket.

A little more than two weeks after we filed our 2014 PSIPs, the Commission issued Order No. 32294 inviting public comments on our plans. While not intending to limit comments, the Order did specifically request "commenters to address whether the plans provide clear, actionable strategies to:

- lower and stabilize customer bills;
- integrate a diverse portfolio of cost-effective renewable energy projects;
- operate each island grid reliably and cost-effectively with substantial quantities of variable renewable energy resources; and
- contain appropriate strategies and timely action plans, supported by well-reasoned and compelling analyses, to achieve these goals on each island."[9]

Figure B-1. on the following two pages depicts a visual representation of the milestones and deadlines that comprise this PSIP update proceeding.

---

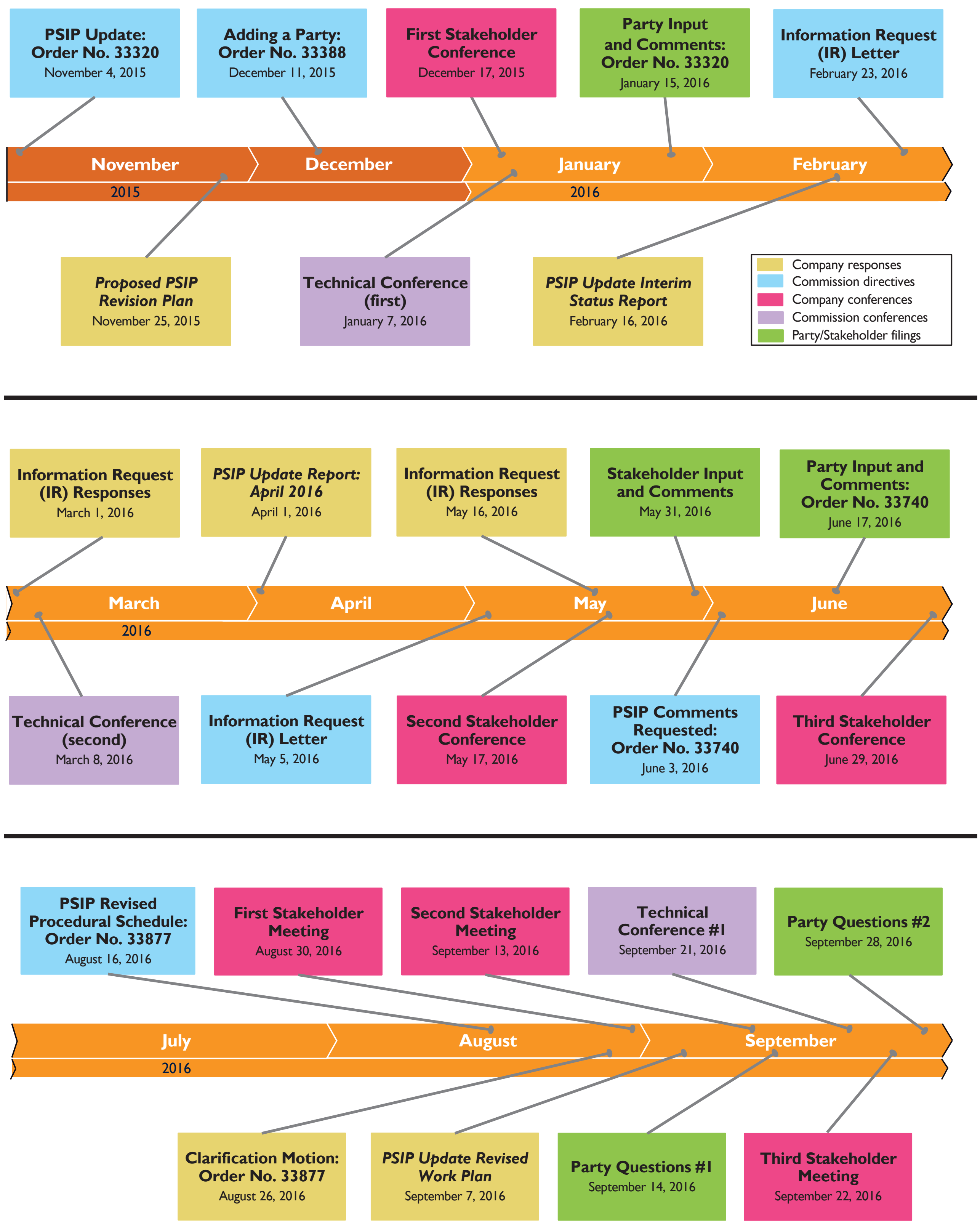
[7] Docket 2014-0183, Order No. 33877: *Hawaiian Electric Companies' Motion for Clarification of Order No. 33877*, filed August 26, 2016.

[8] Docket 2014-0183, Order No. 32257: *Instituting a Proceeding to Review the HECO Companies' Power Supply Improvement Plans*, issued August 7, 2014.

[9] Docket 2014-0183, Order No. 32294: *Inviting Public Comments on the HECO Companies' Power Supply Improvement Plans*, issued September 12, 2014, at 4.

B. Party Commentary and Input

The Updated PSIP Proceeding



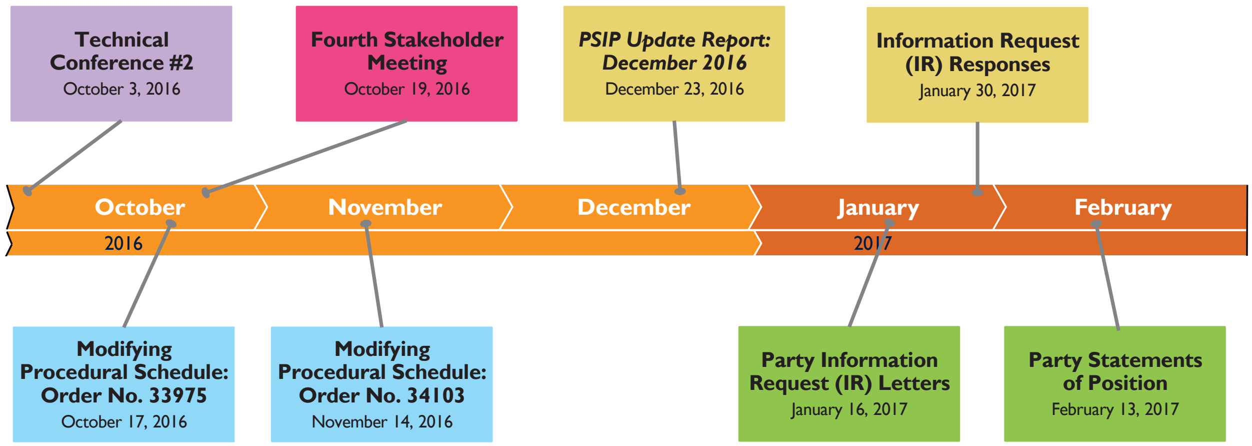


Figure B-1. PSIP Update Report Timeline

Responding to Commission Orders

The Hawai‘i Public Utilities Commission, by its Order No. 32257,[10] instituted a proceeding for reviewing the Power Supply Improvement Plans (PSIPs) that were subsequently filed by the Hawaiian Electric Companies. Six additional Commission Orders (not including a protective order) directly affected this updated PSIP.

Order No. 33320.[11] Issued on November 4, 2015, this Order instituted the process for updating our 2014 PSIPs filed on August 28, 2014. The Order:

- Reiterated the Commission’s guidance from their Inclinations[12] document, and detailed their eight Observations and Concerns, an Initial Statement of Issues, itemized seven component plans, and stated the purpose of the PSIP.
- Admitted 21 Intervenors and Participants — the “Parties” — to the PSIP proceeding (the Commission subsequently added two more by separate order).
- Directed the Companies to file a *Proposed PSIP Revision Plan* by November 25, 2015, an interim PSIP update by February 15, 2016, and a “supplemented, amended, and updated” PSIP by April 1, 2016. We filed these reports on their deadlines.
- Directed the Parties to respond, by January 15, 2016, to our *Proposed PSIP Revision Plan*, comment on the eight Observations and Concerns and the Initial Statement of Issues, and submit input and recommendations concerning the creation of the updated PSIP. Nineteen of the twenty-three Parties filed comments.

---

[10] Order No. 32257; *op. cit.*

[11] Order No. 33320; *op. cit.*

[12] Docket 2012-0036, Order 32052, *Exhibit A: Commission's Inclinations on the Future of Hawai‘i’s Electric Utilities*, issued April 28, 2014.

In our *PSIP Update Report: April 1*, we committed to filing an addendum by August 1, 2016 or within two months after the Energy Information Administration (EIA) published updated fuel prices. We revised our initial self-imposed filing date, setting it for September 30, 2016. The Commission, on its own motion, moved the filing to December 1, 2016,[13] then again to December 23, 2016.[14]

The Parties admitted into the PSIP proceeding included the following participants:[15]

- AES (AES Hawai‘i, Inc.)
- Blue Planet (Blue Planet Foundation)
- Eurus (Eurus Energy America Corporation)
- First Wind (First Wind Holdings, LLC)
- Hawai‘i Gas (The Gas Company, LLC, dba Hawai‘i Gas)
- HPVC (The Hawai‘i PV Coalition)
- HREA (Hawai‘i Renewable Energy Alliance)
- HSEA (Hawai‘i Solar Energy Association)
- LOL (Life of the Land)
- NextEra (NextEra Energy Hawai‘i, LLC)
- Paniolo Power (Paniolo Power Company, LLC)
- Puna Pono (Puna Pono Alliance)
- REACH (Renewable Energy Action Coalition of Hawai‘i, Inc)
- Sierra Club
- SunPower (SunPower Corporation)
- TASC (The Alliance for Solar Choice)
- Tawhiri (Tawhiri Power LLC)
- Ulupono (Ulupono Initiative)

Order No. 33320[16] also admitted the following governmental organizations as intervenors:

- CoH (County of Hawai‘i)
- CoM (County of Maui)
- DBEDT (The Department of Business, Economic Development, and Tourism)

Order No. 32257[17] had previously admitted the Division of Consumer Advocacy (DCA) as an intervenor.

---

[13] Docket 2014-0183, Order No. 33877: *Establishing a Procedural Schedule to Address the Hawaiian Electric Companies' Power Supply Improvement Plan Update*, at 33.

[14] Docket 2014-0183, Order No. 33975: *Modifying the Procedural Schedule*, issued October 17, 2016; at 5.

[15] Order No. 33320; *op. cit.*, at 163.

[16] *Ibid*.

[17] Order No. 32257; *op. cit.*, at 5.

Order No. 33320 stated these conditions to intervention and participation:

> [T]he commission reminds all Parties that it is imperative that their involvement in this docket reflect a high standard of quality, relevance, and timeliness.
>
> Insofar as the matters in this docket "require[d] specialized knowledge," the commission's decision to allow [each party] to intervene [or participate] is based, to a significant extent, on [each party's] assurances that it will provide meaningful assistance to the commission.
>
> To that end, each party's respective intervener or participant status is conditioned on the requirement that each party "possess expertise with respect to [PSIP] issues" or "retain consultants that have" "engineering, economic, and policy expertise commensurate with the highly complex and technical nature of these interrelated issues[,]" so that the matters concerning PSIPs "can be addressed in both a comprehensive and timely fashion." Furthermore, the commission encourages parties to submit alternative analyses and analytical methods into the record that will support development of final PSIPs.[18]

Order No. 33388.[19] This Order admitted the newly formed Distributed Energy Resources Council of Hawai'i (DERC) as a participant.

At this point, the Commission had admitted 23 Parties to the PSIP proceeding.

After being admitted to the proceeding, First Wind was purchased by SunEdison which subsequently filed for bankruptcy protection on April 21, 2016, effectively removing themselves from being a Party to the PSIP docket (although they have yet to file a formal withdrawal motion).

In Docket No. 2015-0022,[20] NextEra and the Hawaiian Electric Companies sought Commission approval for a proposed change of control. On July 15, 2016, the Commission issued Order No. 33795 dismissing the application without prejudice and closing the docket. On July 18, 2016, NextEra issued a press release announcing the termination of their plans to acquire the Hawaiian Electric Companies. On July 20, 2016, NextEra filed a motion to withdraw from the PSIP proceeding, Docket No. 2014-0183; the following day, the Consumer Advocate filed a response to not take a position on NextEra's withdrawal. The Commission subsequently granted NextEra's motion to withdraw.[21]

Thus, while FirstWind/SunEdison has not officially withdrawn, there effectively remains 21 Parties to the PSIP docket.

---

18 Order No. 33320; *op. cit.*, at 171–172.

19 Docket No. 2014-1083, Order No. 33388: *Order Granting Motion for Enlargement of Time to Intervene or Participate, Denying Motion to Intervene, and Granting Motion to Participate*, at 14.

20 Docket No. 2015-0022: *Application for Approval of the Proposed Change of Control and Related Matters*, instituted January 29, 2015.

21 Order No. 33877; *op. cit.*, at 12.

Order No. 33740.[22] This Order invited comments and input from the Parties and general public about our *PSIP Update Report: April 2016*, establishing a deadline of June 17, 2016. Twenty of the twenty-three Parties filed comments, as did 174 members of the general public.

Order No. 33877.[23] This Order:

- Reiterated the PSIP-related directives from previous Orders.
- Specified Commission guidance on six additional topics.
- Directed the Companies to file a work plan for completing the updated PSIP by September 8, 2016.
- Scheduled two technical conferences: Technical Conference #1 for September 21, 2016 and Technical Conference #2 for October 3, 2016.
- Directed the Parties to file questions for each conference. The Order established a September 14, 2016 due date for the first round of questions, and a September 28, 2016 due date for the second round of questions.
- Changed the procedural schedule to incorporate these new directives, which also included moving our self-imposed deadline for filing a revision to our updated PSIP from September 30, 2016 to December 1, 2016.
- Added milestones for Information Request (IR) issuance by the Parties and response by the Companies, as well as Statements of Position by the Parties and Companies.

The Companies filed a Motion for Clarification with respect to Order No. 33877[24] to align our understanding with that of the Commission. The Commission has not issued an order on our motion.

Order No. 33975.[25] This Order modified the procedural schedule established in Order No. 33877. It moved the deadline to December 23, 2016 for filing our revision to the updated PSIP, pushed the remaining milestones out to January and February 2017, and removed the Companies' requirement for filing a Statement of Position.

Order No. 34103.[26] This Order modified the procedural schedule set in Order No. 33975 by requiring the Companies to file work papers on December 23, 2016 together with our updated PSIP, moved the IR issuance and response dates out by 10 days, and moved the Statement of Position date out one week.

---

22 Order No. 33740; *op. cit.*

23 Order No. 33877; *op. cit.*

24 *Hawaiian Electric Companies' Motion for Clarification of Order No. 33877*; *op. cit.*

25 Order No. 33975; *op. cit.*

26 Docket 2014-0183, Order No. 34103: *Modifying the Procedural Schedule*; issued November 14, 2016.

Stakeholder and Technical Conferences

A total of seven conferences (an eighth proposed) and four stakeholder meetings have been held by both the Hawaiian Electric Companies and the Commission. In every conference, the Parties were encouraged to submit comments, suggestions, and their input to the Companies to use in our modeling and analyses. At each of our stakeholder conferences and through subsequent emails, we requested input and comments from the Parties that we could incorporate into our analyses. In February 2016, we invited individuals who represented the intervenors, either in person or through a conference bridge, to attend our internal planning meetings.

First Stakeholder Conference: December 17, 2015. We held this conference for four main reasons—to accept comments and respond to questions about our *Proposed PSIP Revision Plan*; to seek input from the Parties on future pricing for resource options; to seek input from the Parties on developable levels of various renewable resource options; and to discuss any other pertinent issues raised by the stakeholders. This input and feedback affected how we developed our *PSIP Update Report: April 2016*.

Colton Ching, Hawaiian Electric Vice President of Energy Delivery, began the conference by outlining its purpose. Mark Glick, DBEDT, moderated. The Parties gave presentations. (See "First Stakeholder Conference: December 17, 2015" on page B-47 for details.)

First Technical Conference: January 7, 2016. The Commission organized a three-hour technical conference on January 7, 2016. The Commission invited representative from all Parties.

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.[27]

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

The Commission also directed the Companies to give a presentation on these topics to begin the conference. Mr. Ching 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 Stakeholder Conference: February 22, 2016. We proposed a stakeholder conference for this date to discuss the filing of our *PSIP Update Interim Status Report*. In it, we 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. The Commission did not rule on our proposal, so the conference was not held.

Planning Meeting Attendance. After our February 22, 2016 conference, we invited intervenors to the docket to attend and participate in our planning 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, the County of Hawaiʻi, and the County of Maui attended numerous meetings, either in person or through a phone conference bridge.

Second 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 Companies' responses to information requests[.]"[28]

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 Hawaiʻi, Hawaiʻi 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 complete information so that we could include it in our PSIP analysis. In early 2016, this information was only partially provided by Paniolo Power in response to our written request, but was subsequently submitted to us on October 26, 2016.

Once again, we requested all Parties to submit any input to our modeling and analysis for creating the 2016 updated PSIPs.

[28] Commission letter dated March 2, 2016, signed by David C. Parsons, Supervising Economist.

Second Stakeholder Conference: May 17, 2016. After filing our *PSIP Update Report: April 2016*, we held this Second Stakeholder Conference on May 17, 2016 (originally scheduled for April 15, 2016) to present the findings and results of our updated PSIPs. During the conference, we introduced our consultant, Energy + Environmental Economics (E3) and their work on its capacity expansion model, responded to questions and comments, and solicited additional input.

Fourteen of the Parties submitted input as a result of our request during this stakeholder conference, virtually all of which they subsequently filed in their responses to Order No. 33740 together with additional comments. (See “Second Stakeholder Conference: May 17, 2016” on page B-61 for more information.)

Third Stakeholder Conference: June 29, 2016. We held this conference at the behest of the Parties. This third conference was held to enable the Parties to make formal presentations about their input as it pertains to our continued research, modeling, and analyses for supplementing our updated PSIP scheduled originally scheduled for September 2016. As a result, four Parties made presentations. In addition, E3 presented their progress using the RESOLVE modeling tool. (See “Third Stakeholder Conference: June 29, 2016” on page B-110 for details.)

First Stakeholder Meeting: August 30, 2016. DBEDT representatives started the process for a series of meetings between the Companies and certain Parties. This first meeting essentially discussed two main topics: a suggested capacity expansion model methodology and a review of additional input assumptions. (See “First Stakeholder Meeting: August 30, 2016” on page B-123 for details.)

Second Stakeholder Meeting: September 13, 2016. This meeting explored our modeling analysis process of using RESOLVE, PowerSimm Planner, and PLEXOS to develop a resource plan and near-term action plan; speculated on the potential topics for proposed workgroups; and analyzed the regulatory process and how it might be altered. (See “Second Stakeholder Meeting: September 13, 2016” on page B-124 for details.)

Technical Conference #1: September 21, 2016. The Commission scheduled this conference in Order No. 33877 so that they could interact directly with the Companies' planning team and consultants to facilitate the finalizing of the PSIP. The Commission solicited questions, inputs, assumptions, methods, and analytical approaches from the Parties to conduct constructive conversations during the conference. (See “Technical Conference #1 and #2” on page B-120 for more information.)

Third Stakeholder Meeting: September 22, 2016. After Technical Conference #1, the Companies continued the meetings with the Parties, resuming the discussion from previous meetings and from Technical Conference #1. The meeting focused on modeling analysis, input assumptions, operational and customer-related risks, and ancillary service requirements. (See "Third Stakeholder Meeting: September 22, 2016" on page B-125 for details.)

Technical Conference #2: October 3, 2016. Order No. 33877 also included the scheduling for this technical conference as a follow-up to Technical Conference #1 held 12 days earlier. The Commission again solicited the same type of information from the Parties, based on the outcomes from the previous conference. The Commission's intent for this conference was the same as the previous one: to facilitate the finalizing of the PSIP. (See "Technical Conference #2: October 3, 2016" on page B-121 for more information.)

Fourth Stakeholder Meeting: October 19, 2016. At this fourth meeting, the Parties validated and confirmed the input assumptions that we garnered from Technical Conference #1 and #2, and from the previous stakeholder meetings. These input assumptions included on-island wind and PV for O'ahu, wind and pumped storage hydro input, LNG, plus a number inputs for various sensitivities (such as the hedge value of renewable generation and lowest cost plan regardless of RPS). We then directed E3 to run sensitivity analyses on each of these input assumptions. (See "Fourth Stakeholder Meeting: October 19, 2016" on page B-127 for details.) A week later, the Parties submitted additional detailed information about much of this input. E3 analyzed the findings from the sensitivity analyses to assess their impact on the near-term action plan.

INPUT INCORPORATED INTO OUR PSIP UPDATE REPORT

Since the advent of this PSIP Update proceeding, we have actively sought input from the Parties during our three stakeholder conferences and four stakeholder meetings. To direct this input, we have provided data to the Parties on several occasions.

- On February 2, 2016, we voluntarily provided new resource input assumptions, posting this information on a WebDAV site accessible by the Parties.
- On February 16, 2016, in our interim status report, we included proposed methods of analysis, input assumptions, and other information.
- On February 29, 2016, we responded to a lengthy and comprehensive set of Commission-issued Information Requests, covering virtually all of the areas previously questioned by the Parties.
- On April 1, 2016, we filed our *PSIP Update Report: April 2016*.
- On June 24, 2016, we voluntarily provided updated new resource input assumptions.
- On September 7, 2016, we filed our work plan for completing the updated PSIP, which detailed our modeling analysis process.

We have considered and incorporated *all* pertinent input and related comments, as well as comments the Parties filed in response to four Commission Orders.

For our *PSIP Update Report: April 2016*, we considered and incorporated Party input and comments received as a result of our First Stakeholder Conference and Party filings in response to Order No. 33320, which also included perspectives gained from the January 7, 2016 Technical Conference.

For our *PSIP Update Report: December 2016*, we considered and incorporated Party input and comments received as a result of two additional stakeholder conferences and four stakeholder meetings as well as Party filings in response to Order No. 33740 and Order No. 33877 (for Technical Conferences #1 and #2).

Much of the information we received, considered, and incorporated from Party filings in this proceeding was procedural. How we responded to this procedural input is detailed in "Order No. 33320: Party Input and Our Response" starting on page B-51, and in "Order No. 33740: Party Input and Our Response" on page B-91.

Party Responses to Commission Orders and Company Requests

We received five iterations of comments and input from the Parties: from Order No. 33320, in response to our solicitation during the Second Stakeholder Conference, in response to Order No. 33740, in preparation for Technical Conference #1, and in preparation for Technical Conference #2.

Order No. 33320. Nineteen of the twenty-three Parties filed "initial responses" to our Revision Plan as encouraged in Order No. 33320. Appendix B. Input from the Parties in our *PSIP Update Report: April 2016* explains how we engaged the Parties; details the comments, suggestions, and input submitted by the Parties; and how we considered and incorporated this input into our research, modeling, and analysis. Most of that information is repeated here in "First Stakeholder Conference: December 17, 2015" on page B-47 and in "Order No. 33320: Party Input and Our Response" on page B-51.

Second Stakeholder Conference, May 17, 2016. After filing our *PSIP Update Report: April 2016*, we held a Second Stakeholder Conference to review the results of our PSIP. At the conference, we solicited additional comments and input from the Parties that we could incorporate into our modeling analysis for our subsequent *PSIP Update Report: December 2016*.

Order No. 33740. In addition, the Commission issued Order No. 33740 inviting the Parties and "interested persons who are not Parties to this docket" to submit comments on our *PSIP Update Report: April 2016*. The Commission stated that submitters "are free to comment upon any aspect of the PSIPs; however, the Commission is particularly interested in comments that address the Initial Statement of Issues. In addition, the Parties are encouraged to address what specific procedural steps the Commission should consider to ensure constructive further progress in this docket." The Order outlined these Initial Statement of Issues with a reference to Order No. 33320 that describes these issues in detail. The Commission set a June 17, 2016 deadline for submissions. "Order No. 33740: Summaries of Filed Responses" (page B-67) summaries those comments; "Order No. 33740: Party Input and Our Response" (page B-91) categorizes those comments and our responses.

Technical Conference #1. For this conference, 19 of the Parties submitted questions, inputs, assumptions, methods, and analytical approaches for us to consider and incorporate into our modeling analyses and resource planning.

Technical Conference #2. Nineteen of the Parties again submitted questions, inputs, assumptions, methods, and analytical approaches based on the discussions from Technical Conference #1.

Table B-1. outlines the Party input from these sources.

Stakeholder	Order No. 33320	Second Stakeholder Conference	Order No. 33740	Technical Conference #1	Technical Conference #2
Intervenor					
County of Hawai'i	√	√	√	√	√
County of Maui	√	√	√	√	√
Department of Business, Economic Development, and Tourism	√	–	√	√	√
Division of Consumer Advocacy	√	–	√	√	√
Party					
AES Hawai'i		√	√	√	
Blue Planet Foundation	√	√	√	√	√
Distributed Energy Resources Council of Hawai'i	√	√	√	√	√
Eurus Energy America	√			√	√
First Wind Holdings (acquired by SunEdison)	√				
The Gas Company (dba Hawai'i Gas)	√	√	√	√	√
The Hawai'i PV Coalition	√		√	√	
Hawai'i Renewable Energy Alliance		√	√	√	√
Hawai'i Solar Energy Association	√	√	√	√	√
Life of the Land	√		√	√	√
NextEra Energy Hawai'i				n/a	n/a
Paniolo Power Company	√	√	√	√	√
Puna Pono Alliance			√	√	√
Renewable Energy Action Coalition of Hawai'i	√	√	√		
Sierra Club	√	√	√	√	√
SunPower Corporation	√	√	√	√	√
The Alliance for Solar Choice	√	√	√	√	√
Tawhiri Power	√		√		√
Ulupono Initiative	√	√	√	√	√

Legend: √ = submitted input; – = no input submitted

Table B-1. Outline of Party Comments and Input by Source

Cases and Sensitivities

In detailed discussions and collaborations with the Parties at Technical Conference #1 and Technical Conference #2, the four stakeholder meetings, and subsequent conference calls, together we agreed on a list of sensitivities for our modeling analyses.

Core Cases

These are the core cases that we modeled in PLEXOS. The post-April PSIP plans are a result of our actions as specified in Chapter 7: Next Steps of the December 2016 PSIP update;[29] all of E3's plans are a result of their analysis as described in our PSIP Work Plan.[30] All core cases were modeled with the high DG-PV forecast with DR.[31]

The core cases vary by island:

O'ahu

We are modeling five core cases for O'ahu:

1. Post-April PSIP Plans
2. E3 Plan
3. E3 Plan with LNG
4. E3 Plan with Generation Modernization
5. E3 Plan with LNG and Generation Modernization

Maui and Hawai'i Island

We are modeling the first three core cases as run for O'ahu:

1. Post-April PSIP Plan
2. E3 Plan
3. E3 Plan with LNG

Lana'i and Moloka'i

We are modeling two different core cases for Lana'i and Moloka'i:

1. 100% Renewables by 2020
2. 100% Renewables by 2030

[29] *Op. cit.*; *Power Supply Improvement Plan Update Report: April 2016.*

[30] Docket 2014-0183; *PSIP Update Revised Analytical Approach and Work Plan*, filed September 7, 2016.

[31] These core cases are described in greater detail in Chapters 3: Analytical Approach. Chapter 4: Analytical Results discusses the results for each island.

Interisland Transmission

Interisland transmission was modeled between Oʻahu, Maui, and Hawaiʻi Island by E3 as a "copper-plate" configuration (that is, all three islands are bus-bar connected).

Sensitivities

All Party input culminated into input assumptions analyzed as sensitivities to the E3 Plan. The Companies' consultant, E3, ran these sensitivities on each of the above cases in an order that, when possible, builds on or adds a different dimension to the results of the previous sensitivity.

1. Hedge value of renewables (using various fuel price forecasts including biomass, fossil fuels, and LNG) on Oʻahu, Maui, and Hawaiʻi Island.
2. Higher grid-scale solar and wind resource potential only on Oʻahu based on Ulupono's (Dr. Fripp's) assumptions.
3. LNG pricing only on Oʻahu based on Hawaiʻi Gas's pricing.
4. Pumped storage hydro and wind profiles only on Hawaiʻi Island based on Paniolo Power's proposed project assumptions.
5. Least-cost plan regardless of RPS attainment on Oʻahu, Maui, and Hawaiʻi Island based on the Consumer Advocate's suggestion.
6. Generation modernization on Oʻahu.
7. Department of Defense projects on Oʻahu where RESOLVE determines which resources are selected and which are not.

Party Modeling Input and Suggestions: A Summary

Over the course of the PSIP proceeding, we have received and considered all Party input and commentary, and incorporated pertinent information in our PSIP modeling process. Here, we discuss the input and process suggestions we've incorporated. Some of this information came to us in the middle of 2016, while much of it came in the fall and as late as the end of October—less than two month before the filing deadline. We have done our best to incorporate this information into our modeling process given the time constraints.

Several parties—notably Hawaiʻi Gas, SunPower, Ulupono, and Paniolo Power—engaged in fact-based discussions with us regarding input assumptions for our modeling analyses. As a result, we considered and analyzed their input on resources central to our analyses: LNG, PV potential, Oʻahu renewable resource potentials, and pumped storage hydro. Summary descriptions of our discussion appear below; detailed descriptions of our collaborations surrounding this Party input (including their specific data) follows

these summaries (starting with the "Hawai'i Gas Input: Liquefied Natural Gas" section on page B-25.

Virtually all of the Parties, through their filings and through our technical and stakeholder conferences, commented on our input assumptions and analytical process, and about regulatory procedures. We thoughtfully considered all of their commentary and incorporated all comments directly connected with our development of the PSIP. DBEDT, Ulupono, and Paniolo submitted specific modeling suggestions. Summary descriptions of these suggestions and how they affected our modeling appear below (see "Party Modeling Suggestions" on page B-22).

Ultimately, through these discussion and a series of meetings with these parties, together we agreed that the Companies seriously considered and addressed their input and concerns, and collaboratively arrived at mutually agreed upon input assumptions. After these many deliberations, while we ran a number of sensitivities using Party input, virtually all of our foundational input assumptions remained unchanged.

Hawai'i Gas: LNG. Hawai'i Gas formally provided information about their LNG proposal in their response to Order No. 33740 on June 20, 2016 (and reiterated that information in their response to Order No. 33877). We compared their LNG fuel price forecasts with the LNG forecasted input assumptions that we employed when developing our *PSIP Update Report: April 2016*. The average difference between the two was approximately $0.11 per MMBtu. On June 27, 2016, we sent an email to Hawai'i Gas that detailed 29 questions regarding their response to Order No. 33740; they did not respond to our questions.

On October 28, 2016, Hawai'i Gas provided more detailed information following our solicitation for input at our Second Stakeholder Conference and our Fourth Stakeholder Meeting. This information detailed their contract pricing for various levels of metric tons per annum (mtpa), and added observations on the basis of their forecast, infrastructure costs, volume effects, multiple index options, and hedging and volatility. In the end, Hawai'i Gas acknowledged that their costs were very similar to ours; thus, using our data as input would not materially affect the results of our modeling analysis as opposed to using their data. We also agreed on one main point: when compared to oil, LNG is cleaner burning and lower priced.

Hawai'i subsequently requested that we use a higher LNG volume of 0.9 mtpa . This value represents the sum of our projected volume (0.6 mtpa) and Hawai'i Gas's projected volume (0.3 mtpa), which Hawai'i Gas confirmed does not include volume for the KPLP power plant.

SunPower: PV Potential. Following our Second Stakeholder Conferences and in response to Order No. 33740, SunPower submitted a U.S. Department of Energy *SunShot Vision Study* (dated February 2012) about the potential of PV in the greater United States together with PV system costs and forecasts from GTM Research. The Companies sent SunPower a series of questions about this input, to which SunPower diligently responded. SunPower and the Companies engaged in a number of very constructive conversations about this information and about energy storage capital costs. Ultimately, we could not justify using the lower capital cost projections for solar PV in Hawaiʻi suggested by SunPower. Further, our energy storage costs were similar to those recommended by SunPower. In the end, we agreed that our cost estimates, while not exactly the same as theirs although similar, would be used in our modeling analysis.

SunPower did suggest separating residential from commercial DG-PV pricing in future analysis. In Chapter 7: Next Step, we have noted our intention to follow their suggestion in subsequent updates to our PSIP.

Paniolo Power: Pumped Storage Hydro and Grid-Scale Wind. At our Second Stakeholder Conference, Paniolo Power indicated they had assembled information regarding pumped storage hydro. Paniolo also provided commentary and suggestions in their response to Order No. 33740, and three Siemens reports in their response to Order No. 33877: *Hawaiʻi Island Generation Supply Transformation Plan* (redacted, dated May 14, 2105; filed over a year later on September 14, 2016), *Study of Electric Supply Options for the Island of Hawaiʻi* (dated July 2015; filed over a year later on September 28, 2016), and *Study of Pumped Storage Hydroelectric for the Island of Hawaiʻi* (dated February 11, 2016; filed September 28, 2016). All three reports presented discussion and results of analyzing wind energy in combination with pumped storage hydro (PSH). Eurus also provided a paper summarizing a proposed PSH project on Oʻahu.

From first notice, we engaged in a number of discussions with Paniolo, requesting details regarding their studies. Their response was not immediately forthcoming, then partially submitted, which forestalled our evaluation of their studies. Eventually, on October 26, 2106, Paniolo did provide detailed data, however, *some of it was outdated and almost all of it was virtually identical to the input we were using in our modeling analyses*. One main difference was their 85% turnaround efficiency rating versus our 80%. In a subsequent email, Paniolo acknowledged that 80% was the more prudent percent to model.

During our Fourth Stakeholder Meeting, Dr. Fripp interestingly noted that his SWITCH optimization model for Oʻahu chose battery energy storage systems (BESS)—because of their declining costs—over PSH and its relatively flat cost. Nonetheless, in the end, we used our 2016 PSH cost assumptions (which were lower than Paniolo's) for our modeling analyses.

In early November 2016, Paniolo informed us they were developing wind data that would be available in about a month, but that estimated wind data for use in our modeling analyses could be available in "a day or two". We told them that a month out for wind data is too late to include in our modeling, but we might be able to incorporate the estimated wind data. Paniolo did provide us with the foresaid estimated wind data about a week later on November 11, 2016. We forwarded this information to E3, and E3 was able to incorporate this into their analysis. Paniolo subsequently provided site specific data analyzed by AWS Truepower on December 5, 2016. (This eight-page redacted report and companion one-page summary is reproduced in "Paniolo Power Wind Resource and Energy Production Assessment" on page B-130.) We informed Paniolo Power that E3 was nearly complete with its analytical work and would not be able to incorporate this information.

Ulupono: O'ahu Grid-Scale PV and Grid-Scale Wind Potentials. Dr. Matthias Fripp, a professor at the University of Hawai'i and representing Ulupono (and at one point, Blue Planet), suggested changes to the NREL study being conducted to determine the on-island renewable resource potential for O'ahu. Those suggestions includes expanding the land slope of grid-scale PV installations from 5% to 10%, and to expand land selection to include Agricultural grade "B" and grade "C" designations.

As a result, we instructed NREL to rerun their study; Appendix F: NREL Reports contains their updated report and our related assessment of its results. In the end, we agreed to use this suggested expanded basis in our modeling analysis to determine the maximum *theoretical* potential of grid-scale PV and grid-scale wind on O'ahu. We also asked NREL to review the assumptions suggested by Dr. Fripp. NREL concluded that the primary difference in assumptions relates to land-use; NREL states that a more accurate resource potential estimate would require a site-by-site assessment across the entire island of O'ahu.

In addition, Dr. Fripp provided research about rooftop potential for DG-PV, wind potential, and grid-scale solar PV capacities on O'ahu. This research showed a theoretical potential total of 3,022 MW of direct-current PV from residential rooftops, a theoretical potential total of 2,680 MW of grid-scale wind, and (based on a 20% land slope) a theoretical potential total of 9,168 MW of grid-scale fixed PV potential or 8,010 MW of grid-scale tracking PV.

See "Grid-Scale PV and Grid-Scale Wind Potential" in Appendix H: Renewable Resource Options for O'ahu for a more detailed discussion of the realities surrounding the potential of these on-island resources.

Finally, after our Fourth Stakeholder Meeting, Ulupono, together with Dr. Fripp suggested a number of changes to our modeling process. One was to modify their solar supply curve data by segregating larger and smaller curves, and by estimating the cost of

a small scale (approximately 2 MW) solar project, which creates correct economic, dispatch, and weather correlations. A second was to modify the modeling algorithm to incorporate the risks of cost hedging. A third was to reorder the sequence of running various cases and sensitivities. This suggestion was spawned because DBEDT expressed a need to directly compare action plans identified by the analysis on similar footings. DBEDT identified a number of common factors for comparing action plans to better identify the conditions under which a particular best performs. And a fourth was to use multiple blocks with different capacity factors for each resource.

Together with E3, we worked with Ulupono and their consultant Dr. Fripp to incorporate these suggestions into the sensitivity analyses work.

DBEDT: Near-Term Action Plan Sensitivities. DBEDT requested that E3 use RESOLVE to test the robustness of our findings based on their proposed five-step methodology. DBEDT felt the proposed near-term action plan (and anything that might change in it) was highly sensitive to long-term forecasts of uncertain variables: fuel price, renewable price, and storage price forecasts as well as the impact of the interisland transmission. After some discussions, together we eliminated the three forecasts as problematic because the near-term action plan did not include LNG nor recommend new thermal resources. In a subsequent phone call, E3 confirmed that the “copper-plate” interisland analysis only increased the amount of renewable generation that RESOLVE selects for the near-term action plan.

We also tested a sensitivity of not including the MCBH and JBPHH microgrid projects, as DBEDT requested. The results of the analysis chose not to build these microgrids, but included the building of new biodiesel projects in 2045.

TASC: Load Banks. The Alliance for Solar Choice (TASC), at our Third Stakeholder Conference, suggested employing dispatchable load banks to consume otherwise curtailed renewable energy, or “spinning renewable energy”. TASC cited a very small project as way of an example. Load banks may have value to mitigate contingency curtailments. Without understanding how load banks could improve on our analysis and potentially reduce costs, we did not consider load banks in our resource assumptions.

LOL: Hydrokinetic Energy Technologies. After our Third Stakeholder Conference, Life of the Land suggested that all of O‘ahu’s generation could be provided by ocean (hydrokinetic) energy technologies. We reviewed this and several other related reports. All of these reports not only failed to demonstrate the possibility of viable installations or of imminent technological breakthroughs, but also pointed to the extreme cost of this immature technology. Our research could not find any evidence of commercially available hydrokinetic technologies that would be appropriate for Hawai‘i. As a result, we did not consider ocean energy technologies in our analyses. (See Appendix H:

Renewable Resource Options for O'ahu for an in-depth analysis of this latent technology.)

HREA: Biomass Fixed O&M and Fuel Costs. In September 2016, HREA, acting on behalf of Hu Honua who is not a Party to the PSIP docket, submitted biomass assumptions. Specifically, Hu Honua stated that our biomass fixed O&M and fuel cost assumptions were too low compared to theirs. Hu Honua appears to be attempting to influence the PSIP results to reflect its higher costs. HREA, itself, asserted that our PSIP assumptions should not be used as a baseline against which to compare actual projects.

We concur that our biomass assumptions differ from those submitted by Hu Honua. In June 2016, independent of Party input, we had already revised our biomass projections for greater accuracy. Despite Hu Honua's and HREA's belated attempts, we used our revised assumptions in our modeling analysis.

Party Modeling Suggestions

DBEDT, Ulupono, and Paniolo Power each suggested analytical methodologies for us to model as sensitivities.

DBEDT: Additional Modeling Framework. In their response to Order No. 33877 requesting questions in preparation for Technical Conference #1, DBEDT suggested an additional methodology for modeling our action plans. In an October 27, 2016 email following our Fourth Stakeholder Meeting, DBEDT reiterated this suggestion and included an explanation of its rationale. DBEDT's suggested analytical methodology is reproduced here (formatted for clarity).

> DBEDT envisions that the five-year action plan optimization would be the result of the following, or a substantially similar, multi-step process:
> (1) the capacity expansion models will be run under a variety of scenarios with the optimization period being 30 years;
> (2) the capacity expansion model would be provided choices of options and/or constraints;
> (3) the resulting five-year action plans from each scenario that was optimized over 30 years would be compared to identify a discrete number of candidate five-year action plans that warrant further assessment;
> (4) the candidate five-year action plans would be fixed in the capacity expansion model and runs would be made again under the same scenarios in step 1 to identify which five-year action plan is most resilient under an uncertain future; and
> (5) the five-year action plan that is deemed to be most resilient would be subject to detailed analysis to assess for system security among other things.[32]

[32] *Pre-Technical Conference Comments of the Department of Business, Economic Development, and Tourism*, filed in Docket No. 2014-0183 on September 14, 2016; at 8.

DBEDT presented examples of options and constraints:

- With and without interisland transmission.
- With and without offshore wind.
- Varying levels of available geothermal, wind, solar, biofuels, and other generation types per island.
- Accelerated renewable targets.

DBEDT suggested that resiliency could be assessed by identifying a variety of metrics, such as system average rates, standard deviation of the system average rates under various fuel price and load scenarios, and system reliability; and that this analysis would result in either a preferred plan or a limited set of candidate plans. DBEDT stressed the critical nature for following their suggested methodology.

DBEDT explained that the purpose of this methodology was to be able to directly compare—on an "apples to apples" basis—Company action plans that resulted from our modeling of various cases and sensitivities, including a focus on financial investments. Absent this process, the only debatable differentiator among the action plans would be a prediction of the expected future state of the energy sector.

Their methodology stated that E3, through their RESOLVE model, would need "to fix the five-year action plans as inputs and perform a series of runs for each (fixed) action plan under the scenarios and sensitivities that resulted in the candidate five-year action plans." Performing this methodology would give us "a better position to analyze the merits of individual actions and investments."

Ulupono: Suggested PSIP Methodology. For our First Stakeholder Meeting on August 30, 2016, Ulupono proposed a PSIP methodology comprised of these four steps:

1. *Policy Scenarios.* Define major large-scale infrastructure on policy choices that would significantly impact the electric grid (such as siting interisland cable, geothermal, LNG, offshore wind projects, and accelerated EV and DER penetration). Develop a matrix to optimize possible scenarios of these options, then systematically remove choices to assess results.

2. *Major Assumptions.* Develop the following assumptions, then vet and modify them through Party working groups: 1. Inputs and model formulations being used in the E3 RESOLVE model; 2. Add all resource inputs excluded from the E3 model; 3. Capital costs over time; 4. Criteria and algorithms used to define MW and their supply curves for major renewable resources; 5. Hourly profiles used to define projected output; 6. Costs related to operating or deactivating utility-owned and IPP plants; 7. LNG, coal, and oil fuel assumptions; and 8. Hourly loads and demand response potential.

3. *Capacity Expansion Model.* Run RESOLVE (or SWITCH) to select least-cost resources through iterations with system reliability models, DER models, and risk and volatility algorithms. The DER models should inform DER uptake and possible shifts in load shape, and allow for grid support services. The risk and volatility algorithms can be used to develop hedged fuel prices to assess risk tolerance, or employ a Monte Carlo approach to "project" a large number of fuel price trajectories.

4. *Five-Year Action Plans.* Assess the resultant action plans to determine near-term actions necessary to reach the 100% renewable target with the least difficulty and to increase the longer-term opportunity for other resources as they become available.

Figure B-2 depicts Ulupono's representation of their suggested PSIP methodology.

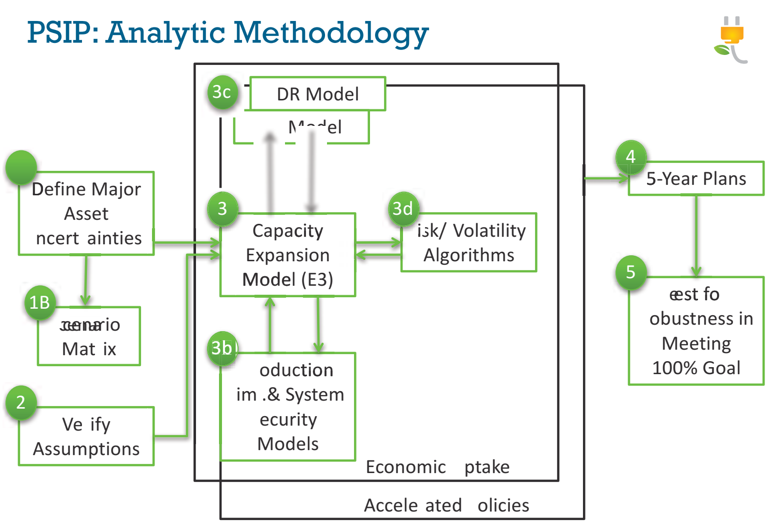


Figure B-2. Alternative PSIP Analytical Methodology

Ulupono suggests running the SWITCH model with a framework called the Progressive Hedging Algorithm (PHA) to address the best near-term actions that consider how to adapt to changing conditions. The recommended process involves generating a million fossil fuel price trajectories for the next 35 years, assess groups of 100–200 trajectories to choose up to 200 least-cost candidate plans, optimize the plans for longer-term conditions, plot the average and range of long-term costs, then employ a stakeholder process to manually select a preferred plan. Repeat the assessing, optimizing, and selecting steps for each policy scenario (from step 1 above) to create a preferred plan for each scenario, then again employ a stakeholder process to manually identify the most plausible policy scenario or important questions to settle before choosing the final preferred plan.

Ulupono offered a timeline for implementing their methodology. Subsequent meetings and discussions successfully resulted in narrowing Ulupono's input into a sensitivity analysis. (See "Sensitivities" on page B-17.)

Paniolo Power: Hawai‘i Island Capacity Expansion Planning. At our First Stakeholder Meeting (August 30, 2016), Paniolo Power recommended that Siemens (together with a third-party independent observer) use their AURORAXMP model to perform the capacity expansion modeling for Hawai‘i Island. Paniolo contended that the modeling being performed by the Companies and our consultants does “not work well on the neighbor islands”. Paniolo listed five reasons for their recommendation.

Paniolo suggested that three policy issues be addressed: 1. LNG as a bridge tool compare with an immediate transformation to all renewable resources; 2. Interisland transmission between O‘ahu and Hawai‘i Island if O‘ahu cannot achieve 100% renewable generation with on-island resources; and 3. Costs and benefits of grid resiliency through varying sizes of integrated energy districts (essentially, microgrids).

Paniolo suggested the planning to attain 100% renewable generation should first be applied solely to Hawai‘i Island. This planning should replace the annual fuel cost input with the equivalent annual unamortized renewable energy capital investment; and should examine large wind or solar PV facilities coupled with energy storage, and if these facilities can coexist with integrated energy districts. Then the energy bill impact of the benefits and costs of resiliency versus customer benefit could be explored.

Resource planning assumptions would include: a focus on wind and solar PV, BESS or PSH for storage, small CTs or ICEs replacing less efficient generation, PPAs not extended, no assumption of HEP ownership, and a unit retirement plan coupled to the timing of constructing energy storage resources. Paniolo concluded with a timeline that parallels current Company modeling and planning.

Subsequent meetings and discussions successfully resulted in narrowing Paniolo Power’s input into a sensitivity analysis. (See “Sensitivities” on page B-17.)

Hawai‘i Gas Input: Liquefied Natural Gas

When developing our *PSIP Update Report: April 2016*, we compared Hawai‘i Gas’s LNG fuel price forecasts (Table B-2) with our LNG forecasted input assumptions (Table B-5) and found the average difference between the two was approximately $0.11 per MMBtu. Because of that small difference, we used our LNG input assumptions in our modeling analyses.

Hawai‘i Gas LNG Proposal

On May 31, 2016, Hawai‘i Gas formally provided information about their LNG proposal in response to our solicitation for input at our Second Stakeholder Conference. On June 20, 2016, Hawai‘i Gas again provided detailed information about their LNG proposal in response to Order No. 33740.

After reviewing this more detailed input, we emailed Hawai‘i Gas (on June 27, 2016, copying all Parties) requesting more information so that we could better compare their LNG fuel price forecasts and assumptions with ours. That email contained 29 questions—reproduced here—distributed among four areas: volume and pricing assumptions, timing, contract structure, and supply chain.

1. Volume and Pricing Assumptions

a. What are the minimum and maximum LNG take obligations for Hawai‘i Gas (HG) to offer the pricing in Table A of your May 31 Comment Letter? What are the penalties, if any, for not meeting the minimum take obligation as it may exist? Are volume commitments adjustable over the 15-year term without penalties?

b. Please elaborate on the correlation between HG’s pricing and volume commitments. In your June 20 Hawai‘i Public Utilities Commission (HPUC) Letter, the values in Table 10 do not seem to match Tables 2 or 4. Please clarify. What portion of the “Other Costs” makes up the FSRU?

c. What are the fixed and variable cost components associated with the HG LNG pricing proposal? What percentage of the total delivered price is associated with the underlying commodity? Is the pricing provided by HG contingent upon other off-takers, in addition to Hawaiian Electric and HG, contracting with the LNG supplier? Does the pricing in Table A represent the same price for all users of the HG supply chain? What would the delivered price be if Hawaiian Electric was the only off-taker? What price would Independent Power Producers pay for LNG and what would be their contract structure?

d. Excluding commodity prices, are the prices provided subject to change? If so, please explain why and how they may change.

e. The Hawaiian Electric Companies’ updated PSIP lays out road maps for achieving 100% renewable energy with LNG as a transitional fuel and does not contemplate electricity users transitioning to self-supply generation using fossil fuels, which are currently not subject to the RPS. Does HG intend to offer gas from its intended LNG supply chain to self-generators? Please provide HG’s views on this potential issue.

f. Please provide the calculation to convert from capital cost dollars to a $/MMBtu price and indicate what assumptions were made.

- **g.** The HG "Facts About LNG for Hawai'i" report includes neighbor island utility volumes, but does not identify a means to deliver LNG to the neighbor islands. Are the HG pricing calculations contingent upon volume off-takes at any neighbor island utilities (such as Maui Electric or Hawai'i Electric Light), and if so, in what volumes?
- **h.** What toll would Hawaiian Electric pay for using the new pipeline (s)? Is the total a fixed $/MMBtu number or variable based on volume?
- **i.** The prices supplied in Table A do not represent the latest EIA data for 2016. Will the tables be updated accordingly?
- **j.** Please provide the per MMBtu cost that HG anticipates charging Hawaiian Electric for deliveries of LNG to Kahe, and to Maui and Hawai'i Island. Please confirm if the indicative per MMBtu cost is fixed or variable based on volume.
- **k.** Is a 100% indexation to North American gas available? If so, please provide one.

2. Timing

- **a.** Who will bear the schedule risk if this in-service date is not met?
- **b.** Is the LNG supplier willing to hold its price relationship to Brent or Henry Hub for a potential lengthy regulatory approval window?

3. Contract Structure

- **a.** Please explain the commercial structure of the supply chain described in your May 31 Comment Letter.
- **b.** What is the "firmness" of the LNG supply delivered to Hawaiian Electric's facilities? Will there be liquidated damages available to Hawaiian Electric in the event of non-delivery to cover the incremental cost of Hawaiian Electric sourcing an alternate fuel?
- **c.** Can the contract be extended beyond 15 years to address the gap between contract termination and 100% renewables, and if so, what is the incremental cost to extend?
- **d.** HG states that it has a "binding RFP". In what specific respects is the RFP binding on the bidders? For how long? What form of contract has HG signed with the bidders to make the RFP binding? Is HG negotiating a contract for all potential off-takers in Hawai'i?
- **e.** Which entity would be contracting with the LNG supplier? What, if any, credit requirements would be required of Hawaiian Electric to support HG's 15 year contract?

- **f.** On page 2 of your June 20 HPUC Letter, HG asserts that the FSRU will be owned and operated by a third-party and that the LNG supply vessel will be owned and operated by a third-party. Are these the same third-party and, if not, how many contracts will Hawaiian Electric be required to negotiate? Who will bear the cost risk if one party fails to perform?
- **g.** Which entity will fund the FERC process discussed in your June 20 HPUC Letter and which entity will be financially responsible if the process is delayed? What "similar" projects have completed the FERC process in 30–36 months as stated by HG?
- **h.** On page 5 of your June 20 HPUC Letter, HG states that the contract can be terminated early. Is there an early termination fee or other negative contractual consequences? If so, please describe them.

4. Supply Chain

- **a.** What is the ratability of the HG supply chain? Are there additional costs to cover periods that LNG cannot be offloaded to the FSRU because of weather conditions or insufficient storage availability in the FSRU?
- **b.** What are the logistics planned to serve the neighbor islands with LNG from the FSRU and what are the associated costs?
- **c.** Under which easement would a gas pipeline to Kahe Power Plant be built? If HG intends to use Hawaiian Electric's existing oil pipeline easement, is there room for a new gas pipeline alongside the existing oil pipeline which may need to remain intact for contingent liquid fuel supply?
- **d.** What gas pressure would be supplied to Kahe Power Plant?
- **e.** For Maui and Hawai‘i Island, does HG propose to supply LNG or natural gas? If natural gas, what is the supply gas pressure?
- **f.** Where will the natural gas for HG's LNG supply chain be sourced from and what is the supply risk?
- **g.** On page 2 of your June 20 HPUC Letter, HG states that the pipeline infrastructure will be five to ten miles. What length of pipeline and what route was assumed to generate the estimates in Table 1?
- **h.** On page 3 of your June 20 HPUC Letter, HG states that the FSRU is already in service. When will the FSRU will be available for service in Hawai‘i, what will be the cost to refurbish and deliver the FSRU to Hawai‘i, and is the FSRU design suited for Hawai‘i's needs?

Hawaiʻi Gas did not respond to these questions.

In an email sent on October 28, 2016, Hawaiʻi Gas provided more detailed information following our solicitation for input at our Second Stakeholder Conference and our Fourth Stakeholder Meeting. This information detailed their contract pricing for various levels of metric tons per annum: 0.3 mtpa, 0.4 mtpa, 0.5 mtpa, 0.6 mtpa, 0.7 mtpa, 0.8 mtpa, 0.9 mtpa, and 1.0 mtpa pricing. Each mtpa volume listed prices in both 2015 and nominal dollar amounts for LNG-only delivery, infrastructure cost, and the "all-in" cost of delivery plus infrastructure. The email contained five sections, outlining their additional observations on the forecast basis, fixed versus constant infrastructure costs, aggregating volume effects, multiple LNG price index options, and hedging and volatility.

In the subsequent email exchanges, the Companies and Hawaiʻi Gas acknowledged that economies of scale affect pricing (the larger the volume, the lower the per unit cost) and that the need for LNG would decline as our RPS attainment increased.

Hawaiʻi Gas confirmed that they expect to deliver 0.3 mtpa of LNG annually (without decline over time and does not include volumes for the KPLP power plant). Our projections set our annual delivery expectations at 0.6 mtpa of LNG. Thus, we used a combined total of 0.9 mtpa of LNG in our modeling analysis. Over the years, we gradually reduced that volume as increasing amounts of renewable generation replaced LNG-fired generation.

Subsequent meetings and discussions successfully resulted in narrowing Hawaiʻi Gas's input into a sensitivity analysis. (See "Sensitivities" on page B-17.)

LNG Cost Comparisons

Table B-2 through Table B-6 details Hawai‘i Gas forecasted costs and Hawaiian Electric forecasted costs, and compares the two.

Table B-2 itemizes the Hawai‘i Gas forecasted costs for LNG for 0.6 mtpa, the associated capital expenditures (CapEx), and the combination of these two costs (“all-in”) for both 2015 and nominal dollars.

$/MMBtu	Hawai‘i Gas LNG 0.6 MTPA Price Forecasts					
	LNG 0.6 mtpa: 100% Henry Hub		CapEx Infrastructure: LNG 0.6 mtpa		All-In Cost: LNG 0.6 mtpa + CapEx Infrastructure	
Year	*2015 Dollars*	*Nominal Dollars*	*2015 Dollars*	*Nominal Dollars*	*2015 Dollars*	*Nominal Dollars*
2016	n/a	n/a	n/a	n/a	n/a	n/a
2017	n/a	n/a	n/a	n/a	n/a	n/a
2018	n/a	n/a	n/a	n/a	n/a	n/a
2019	n/a	n/a	n/a	n/a	n/a	n/a
2020	$10.98	$12.13	$1.83	$2.03	$12.81	$14.16
2021	$10.85	$12.27	$1.80	$2.04	$12.65	$14.31
2022	$10.87	$12.57	$1.77	$2.05	$12.64	$14.62
2023	$11.35	$13.38	$1.75	$2.06	$13.10	$15.44
2024	$11.67	$14.02	$1.72	$2.07	$13.39	$16.08
2025	$11.82	$14.47	$1.70	$2.08	$13.52	$16.54
2026	$11.65	$14.54	$1.67	$2.09	$13.32	$16.63
2027	$11.61	$14.78	$1.65	$2.10	$13.26	$16.88
2028	$11.67	$15.15	$1.63	$2.11	$13.30	$17.26
2029	$11.73	$15.54	$1.60	$2.12	$13.33	$17.66
2030	$11.74	$15.88	$1.58	$2.13	$13.32	$18.02
2031	$11.68	$16.15	$1.55	$2.15	$13.23	$18.29
2032	$11.71	$16.55	$1.53	$2.16	$13.24	$18.71
2033	$11.64	$16.81	$1.50	$2.17	$13.14	$18.99
2034	$11.62	$17.16	$1.48	$2.19	$13.10	$19.35
2035	$11.56	$17.46	$1.46	$2.20	$13.02	$19.66
2036	$11.55	$17.83	$1.44	$2.22	$12.99	$20.05
2037	$11.47	$18.10	$1.41	$2.23	$12.88	$20.33
2038	$11.40	$18.38	$1.39	$2.25	$12.79	$20.62
2039	$11.48	$18.91	$1.37	$2.26	$12.85	$21.18
2040	$11.49	$19.34	$1.35	$2.28	$12.85	$21.62
2041	$11.49	$19.73	$1.34	$2.29	$12.83	$22.02

Table B-2. Hawai‘i Gas LNG 0.6 MTPA Price Forecasts

Like Table B-2, Table B-3 itemizes the Hawai'i Gas forecasted costs for LNG, except for 0.3 mtpa, the associated capital expenditures (CapEx), and the combination of these two costs ("all-in") for both 2015 and nominal dollars.

$/MMBtu	Hawai'i Gas LNG 0.3 MTPA Price Forecasts					
	LNG 0.3 mtpa: 100% Henry Hub		CapEx Infrastructure: LNG 0.3 mtpa		All-In Cost: LNG 0.3 mtpa + CapEx Infrastructure	
Year	*2015 Dollars*	*Nominal Dollars*	*2015 Dollars*	*Nominal Dollars*	*2015 Dollars*	*Nominal Dollars*
2016	n/a	n/a	n/a	n/a	n/a	n/a
2017	n/a	n/a	n/a	n/a	n/a	n/a
2018	n/a	n/a	n/a	n/a	n/a	n/a
2019	n/a	n/a	n/a	n/a	n/a	n/a
2020	$10.98	$12.13	$3.66	$4.04	$14.64	$16.17
2021	$10.85	$12.27	$3.59	$4.06	$14.44	$16.33
2022	$10.87	$12.57	$3.53	$4.09	$14.40	$16.65
2023	$11.35	$13.38	$3.48	$4.11	$14.83	$17.49
2024	$11.67	$14.02	$3.43	$4.12	$15.10	$18.14
2025	$11.82	$14.47	$3.39	$4.14	$15.21	$18.61
2026	$11.65	$14.54	$3.34	$4.17	$14.99	$18.71
2027	$11.61	$14.78	$3.29	$4.19	$14.90	$18.96
2028	$11.67	$15.15	$3.24	$4.21	$14.91	$19.36
2029	$11.73	$15.54	$3.19	$4.23	$14.92	$19.77
2030	$11.74	$15.88	$3.15	$4.26	$14.89	$20.14
2031	$11.68	$16.15	$3.10	$4.28	$14.78	$20.43
2032	$11.71	$16.55	$3.05	$4.31	$14.76	$20.86
2033	$11.64	$16.81	$3.00	$4.34	$14.64	$21.15
2034	$11.62	$17.16	$2.96	$4.36	$14.58	$21.53
2035	$11.56	$17.46	$2.91	$4.39	$14.47	$21.85
2036	$11.55	$17.83	$2.86	$4.42	$14.41	$22.25
2037	$11.47	$18.10	$2.82	$4.45	$14.29	$22.55
2038	$11.40	$18.38	$2.78	$4.48	$14.18	$22.86
2039	$11.48	$18.91	$2.74	$4.51	$14.22	$23.43
2040	$11.49	$19.34	$2.70	$4.54	$14.19	$23.88
2041	$11.49	$19.73	$2.66	$4.57	$14.16	$24.30

Table B-3. Hawai'i Gas LNG 0.3 MTPA Price Forecasts

Table B-4 itemizes the same information as Table B-2 and Table B-3, except for 0.9 mtpa. These four LNG-related tables all employ a 21-year planning horizon: 2020 to 2041.

$/MMBtu	Hawai'i Gas LNG 0.9 MTPA Price Forecasts					
	LNG 0.9 mtpa: 100% Henry Hub		CapEx Infrastructure: LNG 0.9 mtpa		All-In Cost: LNG 0.9 mtpa + CapEx Infrastructure	
Year	*2015 Dollars*	*Nominal Dollars*	*2015 Dollars*	*Nominal Dollars*	*2015 Dollars*	*Nominal Dollars*
2016	n/a	n/a	n/a	n/a	n/a	n/a
2017	n/a	n/a	n/a	n/a	n/a	n/a
2018	n/a	n/a	n/a	n/a	n/a	n/a
2019	n/a	n/a	n/a	n/a	n/a	n/a
2020	$10.98	$12.13	$1.22	$1.35	$12.20	$13.48
2021	$10.85	$12.27	$1.20	$1.36	$12.05	$13.63
2022	$10.87	$12.57	$1.18	$1.37	$12.05	$13.93
2023	$11.35	$13.38	$1.16	$1.37	$12.51	$14.75
2024	$11.67	$14.02	$1.15	$1.38	$12.82	$15.39
2025	$11.82	$14.47	$1.13	$1.39	$12.95	$15.85
2026	$11.65	$14.54	$1.12	$1.39	$12.77	$15.93
2027	$11.61	$14.78	$1.10	$1.40	$12.71	$16.18
2028	$11.67	$15.15	$1.08	$1.41	$12.75	$16.56
2029	$11.73	$15.54	$1.07	$1.41	$12.80	$16.96
2030	$11.74	$15.88	$1.05	$1.42	$12.79	$17.30
2031	$11.68	$16.15	$1.04	$1.43	$12.72	$17.58
2032	$11.71	$16.55	$1.02	$1.44	$12.73	$17.99
2033	$11.64	$16.81	$1.00	$1.45	$12.64	$18.26
2034	$11.62	$17.16	$0.99	$1.46	$12.61	$18.62
2035	$11.56	$17.46	$0.97	$1.47	$12.53	$18.93
2036	$11.55	$17.83	$0.96	$1.48	$12.51	$19.31
2037	$11.47	$18.10	$0.94	$1.49	$12.41	$19.58
2038	$11.40	$18.38	$0.93	$1.50	$12.33	$19.88
2039	$11.48	$18.91	$0.92	$1.51	$12.40	$20.42
2040	$11.49	$19.34	$0.90	$1.52	$12.40	$20.86
2041	$11.49	$19.73	$0.89	$1.53	$12.38	$21.26

Table B-4. Hawai'i Gas LNG 0.9 MTPA Price Forecasts

Table B-5 itemizes the Hawaiian Electric forecasted costs for LNG and associated CapEx for nominal dollars, then compares the 0.6 mtpa all-in costs for Hawai‘i Gas and Hawaiian Electric. Note that Hawaiian Electric's forecasted all-in costs begin to become the lower-cost option beginning in 2029.

$/MMBtu	Hawaiian Electric LNG Price Forecasts and Differentials				
	LNG: 2016 EIA Early Release	LNG: Total Cost Henry Hub	CapEx for New Infrastructure	All-In Cost: LNG + Infrastructure CapEx	All-In 0.6 mtpa Cost Differential: Hawai‘i Gas – Hawaiian Electric
Year	*Nominal Dollars*	*Nominal Dollars*	*Nominal Dollars*	*Nominal Dollars*	*Nominal Dollars*
2016	n/a	n/a	n/a	n/a	n/a
2017	n/a	n/a	n/a	n/a	n/a
2018	n/a	n/a	n/a	n/a	n/a
2019	n/a	n/a	n/a	n/a	n/a
2020	n/a	n/a	n/a	n/a	n/a
2021	$7.61	$14.76	$0.90	$15.66	($1.35)
2022	$7.77	$15.01	$0.90	$15.91	($1.29)
2023	$8.03	$15.35	$0.90	$16.25	($0.81)
2024	$8.43	$15.83	$0.90	$16.73	($0.65)
2025	$8.71	$16.20	$0.90	$17.10	($0.56)
2026	$8.31	$15.88	$0.90	$16.78	($0.15)
2027	$8.43	$16.09	$0.90	$16.99	($0.11)
2028	$8.64	$16.39	$0.90	$17.29	($0.03)
2029	$8.85	$16.70	$0.90	$17.60	$0.06
2030	$9.03	$16.96	$0.90	$17.86	$0.16
2031	$9.15	$17.18	$0.90	$18.08	$0.21
2032	$9.36	$17.49	$0.90	$18.39	$0.32
2033	$9.48	$17.71	$0.90	$18.61	$0.38
2034	$9.64	$17.97	$0.90	$18.87	$0.48
2035	$9.78	$18.22	$0.90	$19.12	$0.54
2036	$9.96	$18.50	$0.90	$19.40	$0.65
2037	$10.07	$18.72	$0.90	$19.62	$0.71
2038	$10.19	$18.95	$0.90	$19.85	$0.77
2039	$10.49	$19.36	$0.90	$20.26	$0.92
2040	$10.71	$19.69	$0.90	$20.59	$1.03
2041	$10.94	$20.05	$0.90	$20.95	$1.07

Table B-5. Hawaiian Electric LNG Price Forecasts and Differentials

For the sake of comparison, Table B-6 itemizes the 2015 and nominal dollar costs for low sulfur fuel oil (LSFO), ultra-low sulfur diesel (ULSD), and a blend of 40% LSFO / 60% ULSD (for NAAQS compliance).

$/MMBtu	Hawaiian Electric Fuel Oil Price Forecasts					
	Low Sulfur Fuel Oil (LSFO)		Ultra-Low Sulfur Diesel (ULSD)		40% LSFO / 60% ULSD	
Year	*Pacific Power (EIA) 2015 Dollars*	*Pacific Power (EIA) Nominal Dollars*	*2015 Dollars*	*Nominal Dollars*	*2015 Dollars*	*Nominal Dollars*
2016	$9.14	$9.31	$11.95	$12.17	$10.26	$10.45
2017	$10.59	$11.01	$13.52	$14.06	$11.76	$12.23
2018	$11.90	$12.62	$15.36	$16.28	$13.28	$14.09
2019	$13.74	$14.86	$17.72	$19.16	$15.33	$16.58
2020	$14.70	$16.24	$18.92	$20.90	$16.39	$18.10
2021	$15.40	$17.42	$19.80	$22.39	$17.16	$19.41
2022	$15.96	$18.45	$20.43	$23.63	$17.75	$20.52
2023	$16.34	$19.26	$20.83	$24.55	$18.13	$21.38
2024	$16.65	$20.00	$21.18	$25.44	$18.47	$22.18
2025	$17.02	$20.83	$21.68	$26.53	$18.88	$23.11
2026	$17.48	$21.81	$22.23	$27.74	$19.38	$24.19
2027	$17.85	$22.72	$22.69	$28.88	$19.79	$25.18
2028	$18.12	$23.53	$23.05	$29.93	$20.09	$26.09
2029	$18.52	$24.54	$23.56	$31.21	$20.53	$27.21
2030	$18.79	$25.42	$23.90	$32.34	$20.83	$28.19
2031	$19.25	$26.62	$24.49	$33.86	$21.35	$29.51
2032	$19.73	$27.89	$25.12	$35.50	$21.89	$30.93
2033	$20.23	$29.22	$25.74	$37.18	$22.43	$32.40
2034	$20.77	$30.68	$26.44	$39.05	$23.04	$34.03
2035	$21.07	$31.82	$26.88	$40.60	$23.40	$35.33
2036	$21.58	$33.31	$27.54	$42.51	$23.96	$36.99
2037	$21.89	$34.53	$27.93	$44.06	$24.30	$38.34
2038	$22.42	$36.15	$28.61	$46.14	$24.90	$40.15
2039	$22.90	$37.73	$29.23	$48.16	$25.43	$41.90
2040	$23.45	$39.46	$29.95	$50.41	$26.05	$43.84
2041	$23.45	$40.25	$29.95	$51.42	$26.05	$44.71

Table B-6. Hawaiian Electric Fuel Price Forecasts

In the end, Hawai‘i Gas acknowledged that their costs were very similar to ours; thus, using our data as input would not materially affect the results of our modeling analysis. We also agreed on one main point: when compared to oil, LNG is cleaner burning and lower priced.

SunPower Input: Solar PV Potential

SunPower sent us a letter in response to our solicitation for input at our Second Stakeholder Conference. They also submitted a U.S. Department of Energy *SunShot Vision Study* (dated February 2012) that described the potential of PV in the greater United States together with PV system costs and forecasts (up to 2020) developed by GTM Research, a third-party industry research and analysis firm.

Among other topics, SunPower asserted that our resource assumptions for the costs and amounts of energy storage and PV were too high.

On May 31, 2016, we sent SunPower an email (copying all Parties) containing a series of questions about this input to garner more information. In that email, we stated that new resource cost assumptions are extremely important inputs to the PSIP analysis as they are major drivers for resource choices in our candidate resource plans. That email also contained seven questions requesting more information, to which they answered. SunPower responded on July 8, 2016.

Our emailed questions and SunPower's responses are reproduced here.

1. Are the GTM values expressed in real or nominal dollars? If expressed in real dollars, what is the reference year? If expressed in nominal dollars, what is the underlying rate of inflation assumed?

   SunPower Response: For the PSIP, we applied a 1.8% rate of inflation. These figures are all in 2016 dollars and do not account for inflation.

2. For the solar PV costs, we are assuming that the GTM costs are presented in dollars per DC watt. Please confirm. The High grid-scale solar and wind resource potential on O‘ahu PV costs presented in the PSIP are expressed in dollars per AC watt and assume fixed tilt systems with a 1.5 DC-to-AC inverter ratio. Thus, to get equivalent dollars per DC watt for High grid-scale solar and wind resource potential on O‘ahu solar, divide the PSIP numbers in Appendix J: Modeling Assumptions Data by 1.5. Please provide the MW AC size and DC-to-AC ratio assumed for the grid-scale solar. Please provide the DC-to-AC ratio assumed for the residential solar.

   SunPower Response: These figures are dollars per watt DC. For grid-scale solar, we assume a 1.3 DC-to-AC ratio and for residential we assume a 1.15 DC-to-AC ratio.

3. If you were designing a solar PV project for Hawai‘i, would you install fixed tilt or a tracking system? What inverter loading ratio would you use? (We understand that in actual application, this depends on the site and other factors, but we are interested in understanding what assumptions others believe we should be using in this regard in the PSIP projections).

SunPower Response: The answer to this question is site-specific. However, in our opinion, tracking systems provide increased solar production, which, in general, offsets the additional cost of the tracking system. Therefore, tracking systems typically provide a greater value than fixed tilt systems over the life of the PPA.

4. Have the GTM numbers been adjusted to reflect Hawai‘i costs? The PSIP solar PV numbers reflect premiums for Hawai‘i cost utilizing the RS Means Construction Index. The Hawai‘i location factors were applied to data obtained from IHS Energy. We also added 4% to the cost of the PV and wind systems to reflect Hawai‘i General Excise Taxes. The solar PV costs also reflect a land premium for Hawai‘i. The details of these cost factors as utilized in the PSIP numbers and how they were applied to adjust for just Hawai‘i were provided in response to PUC-HECO-IR-44.

SunPower Response: SunPower utilizes a variety of competitive intelligence firms in our internal analysis, which include GTM as well as IHS and others. While the GTM numbers are not specific to Hawai‘i, we recommend the Companies utilize the GTM numbers (and associated forecast) as a baseline from which to extrapolate a Hawai‘i PV cost forecast, utilizing the Companies’ detailed cost information from recent PUC-approved PV PPAs. From our perspective, it is important work from the GTM numbers utilizing a broad base of recent PV PPAs in Hawai‘i in order to reflect forecasted “real world” PV costs.

5. Similarly, have the storage numbers been adjusted for just Hawai‘i? They do say “Hawai‘i” so we assume so. Please confirm.

SunPower Response: Yes, the storage numbers we provided are adjusted for just Hawai‘i. We also encourage the Companies to obtain access to the Bloomberg New Energy Finance New Energy Outlook 2016 as an additional resource. The report includes storage cost forecasts (which, for reference, are lower than the storage numbers we provided) from 2015–2040.

6. Can you provide the numbers that are in the storage cost graphs in a tabular format (preferably in Microsoft Excel or similar?)

SunPower Response: The graph represents SunPower’s internal analysis for storage costs for Hawai‘i, utilizing a variety of sources, some of which are proprietary or confidential. SunPower felt comfortable with sharing the results of our internal analysis in the spirit of collaboration. However, we are not comfortable providing associated spreadsheets.

7. What cost trend (in real terms if possible) would you recommend using for solar PV after 2020?

SunPower Response: It is rare to find a cost trend for PV post-2020. However, given recent history, it is certainly expected that costs will continue to decline. The most

> recent cost trend information we have access to is the Bloomberg New Energy Finance New Energy Outlook 2016, which includes cost trend assumptions for PV out to 2040. As you may know, access to that report requires a subscription and we encourage the Companies to obtain access to it. We also suggest that the Companies reach out to GTM and the Department of Energy SunShot Initiative to seek their guidance.

Before responding to our questions, SunPower asked if we both could meet to discuss the assumptions related to grid-scale solar PV and energy storage capital costs, and other forecasts. Over the subsequent months, together we engaged in a number of very constructive conversations about this information. Topics centered around the capital costs of grid-scale PV (both fixed tilt and single-axis tracking), commercial and residential PV, and energy storage projections and forecasts.

Because of their specific and objective information, we reinvestigated our solar PV and energy storage capital costs assumptions. SunPower's PV and storage capital cost assumptions were only forecasted through 2020 for the greater United States, without any cost adjustments or extrapolations being made for the state of Hawai'i. SunPower's projections (actually, those of GTM Research) were quite a bit lower than our PSIP assumptions.

Nonetheless, we compared SunPower's grid-scale and residential PV and battery energy storage system (BESS) forecasts to the PSIP assumptions, with adjustments made to ensure that the assumptions were being compared on a consistent basis. We found their cost assumptions to be relatively close to ours: SunPower's grid-scale PV costs were marginally lower, with their residential PV and BESS marginally higher.

Thus, we determined there is no objective nor defensible basis for changing our solar PV capital cost assumptions. To initially develop our assumptions, we informally vetted them with a project developer and found them to be generally consistent with the market price (that is, approximately $4 per DC watt installed). In fact, the many data points we investigated suggested that, if anything, our solar PV capital cost forecasts were too low. We informed SunPower of our conclusions, and pointed out that their indicative EPC-only price for West Loch was about the same as our projection.

SunPower suggested that we should use a single-axis tracker in our assumptions rather than fixed tilt, even though existing grid-scale PV projects are about evenly split between the two systems.

SunPower considered our energy storage cost assumptions to be too low, yet on further examination, they exhibit only minor differences. SunPower did point out that a two-hour residential BESS—not the four-hour residential BESS in our assumptions—is typical in today's market. SunPower also pointed out our BESS assumptions are not set

for economies of scale—in other words, the prices for a 1 MW BESS models are the same as a 10 MW BESS. We have made these adjustments to our assumptions. SunPower suggested that we model multiple capabilities—load shifting, renewable firming, reactive power, frequency response, and black start capabilities—for longer-duration batteries. They also consider a grid-scale PV plus BESS worthy of analysis.

SunPower recommended that we should delineate between residential and commercial PV systems by developing separate forecasts. Our cost assumption uses one price for both residential and commercial PV, which we consider reasonable for our long-term modeling analysis. Still, in the future, we will develop separate price forecasts: one for commercial PV and one for residential PV (which we've noted in Chapter 7: Next Steps).

Finally, SunPower indicated that limiting development of grid-scale PV on land slopes less than 5% was conservative and 10% was more aggressive, but was not able to comment if there would be an added cost for such development. Our analysis, as a result of input from Ulupono and Blue Planet representative Dr. Matthias Fripp, considers grid-scale PV development on land slopes up to 10%.

During our wide ranging and lengthy discussions, we both have jointly identified and discussed the factors that may explain the differences between GTM Research's numbers and our PSIP assumptions. In the end, however, these discussions have not resulted in us changing our grid-scale PV and storage capital cost assumptions. Discussions with SunPower made clear that we developed these PSIP assumptions as fairly and as objectively as possible, to which they concurred.

Paniolo Power Input: Pumped Storage Hydro and Grid-Scale Wind

Over the course of 2016, the Companies have repeatedly and earnestly tried to engage and work with Paniolo Power regarding input assumptions related to pumped storage hydroelectricity and grid-scale wind. While Paniolo Power provided their data to us (some was protected under a development agreement, was thus proprietary, and could not be divulged), some of it was outdated, some was only slightly different than ours, and some was identical to ours. As a result, we were unable to use their data in our modeling analyses.

In February 2016, Paniolo Power submitted a 25-page report, *Study of Pumped Storage Hydroelectric for the Island of Hawai'i* (published with a February 11, 2016 date), prepared by Siemens. In a February 18, 2016 email to Paniolo, the Companies acknowledged receipt of that report. On that same day, HD Baker & Company emailed Paniolo requesting information about the report, citing specific capital costs for pumped storage hydro obtained informally from Eurus at the First Technical Conference on January 7, 2016.

On March 7, 2016, the Companies sent a detailed "informal data request" to Paniolo Power requesting information for modeling Parker Ranch's suggested pumped storage hydro project. On March 22, 2016, Paniolo Power sent its responses, and also filed its responses in Docket No. 2014-0183. Their response, however, did not include detailed information requested for modeling in PSS/E (a Siemens software product) that would allow us to evaluate the resource for transmission planning and system security modeling. Further, Paniolo's response did not provide certain information regarding ramp rates in MW per minute (as requested) so that we could evaluate the Paniolo-suggested wind project on a sub-hourly basis.

In addition, Paniolo did not provide prices, instead only providing indicative costs. (In production simulations, costs cannot be substituted for prices, as prices include gross profit and more accurately represent the total capital investment assumptions.) Neither did Paniolo provide detailed annual dispatch simulation results nor a summary of the input assumptions used in the Siemens report. Paniolo asserted that pumped storage hydro could provide ancillary services and contribute to system reliability, yet they provided no information to support that assertion. Paniolo didn't provide all the information needed to evaluate PSH.

We contacted Paniolo with follow-up questions to obtain the additional necessary information. Paniolo stated that such information could not be provided because they risked disclosing proprietary and competitive information. As a result, we could not incorporate this incomplete Paniolo Power information in our modeling analyses.

On September 14, 2016, Paniolo Power filed its first set of questions in response to Order No. 33877 together with a 106–page slide deck report entitled *Hawai'i Island Generation Supply Transformation Plan*, submitted by Siemens 16 months earlier on May 14, 2015—even though, in that interim period, both the Commission (through Order No. 33320 and Order No. 33740) and the Companies (through filed plans and three stakeholder conferences) repeatedly requested input from the Parties. Five days later at Technical Conference #1, Commission consultant Carl Freedman asked if we had reviewed the report (which he termed "well done") or attempted to "replicate" the results.

We subsequently were able to review Paniolo's filed report. We discovered that the report's results were based on 2014 PSIP assumptions, making it virtually impossible to benchmark and compare these results to our 2016 PSIP analysis. (At the Fourth Stakeholder Meeting, Party members, including Paniolo, acknowledged that such a benchmarking effort was unproductive.) The report neglected to provide a complete set of input assumptions or detailed results of its system dispatch modeling, making it impossible to scrutinize the results.

On September 28, 2016, again in response to Order No. 33740, Paniolo filed its second set of questions, plus two additional Siemens reports: *Study of Electric Supply Options for the*

Island of Hawai'i (published with a July 2015 date, 16 pages, and essentially a narrative summary of the 106-page slide deck report) and *Study of Pumped Storage Hydroelectric for the Island of Hawai'i* (previously given to us).

Within days of that filing, we assembled a spreadsheet comparing our input assumptions for our current modeling analysis, comparing them to the same information provided by Paniolo (specifically, the *Hawai'i Island Generation Supply Transformation Plan* report and their responses to our February informal data request). The spreadsheet revealed a number of gaps in Paniolo's data. At the Fourth Stakeholder Meeting, Paniolo reviewed this spreadsheet, finally providing the missing information. In an October 22, 2016 email, Paniolo changed some of this information and added more details.

Here is our summary evaluation of their information:

1. Paniolo based their reports on outdated 2014 EIA AEO prices, where oil prices were double today's prices. Their use of the 2014 PSIP assumptions attempted to benchmark their analysis with the 2014 PSIP Preferred Plan for Hawai'i Island. Paniolo acknowledged the difficulty in making a side-by-side comparison between of the 2016 PSIP analyses and the 2014-based Siemens analysis.
2. Paniolo did not consider ramp rates (they didn't conduct any sub-hourly analysis). However, they confirmed that our 20% per minute ramp rate was consistent with the technology.
3. Paniolo's assumptions were only slightly different for factors such as forced and planned outage rates, fixed O&M costs, and other factors (see Table B-7).

Pumped Storage Hydro Factor and Rate Assumptions		
Factor and Rate	*Hawaiian Electric*	*Paniolo Power*
AFUDC Factor	16.36%	Presumably accounted for in annual fixed charge
Levelized Cost Factor	11.43%	Presumably accounted for in annual fixed charge
Fixed Charge Per Year	$44.16 per kW month (2020 calculated)	$43.99 per kW month
Duration Hours	6.0 hours	6.0 hours
Turnaround Efficiency (net)	80%	85%
Discharge Cycles Per Year	365	Up to 365, drawn when needed
Depth of Discharge	100%	Up to 100%, no limit
Plant Life	40 years	40 years
Construction Years	6 years	5 years
Spin Ramp Rate	20% per second	20% (equivalent to HELCO unit ramp rates)
Quick Start Ramp Rate	20% per second	20% (equivalent to HELCO unit ramp rates)
Fixed O&M	$30 per kW year	$28 per kW year
Forced Outage Rate	3.00%	2.00%
Planned Outage Rate	3.80%	5.00%

Table B-7. Pumped Storage Hydro Factor and Rate Assumptions

4. We assume a turnaround efficiency rate for pumped storage hydro of 80%; Paniolo's uses an efficiency rate of 85% (see Table B-7). At the Fourth Stakeholder Meeting, Paniolo could not verify that their assumed 85% turnaround efficiency was net round-trip or it was the technology efficiency before accounting for auxiliary station loads and losses. A Ternary pumped storage hydro design (mentioned in the Siemens report), which switches between pumping and generation in less than a minute, might be able to achieve net efficiency rates greater than 80%. However, this is untested.

In response to our query about the difference in efficiency ratings, Paniolo acknowledged (in an email sent November 3, 2016) that, based on head, flow, technology, and design, an 85% turnaround efficiency could be achieved. However, because Siemens did not indicate a specific design for the pumped storage hydro "project" discussed in their report, Paniolo acknowledged that we should use an 80% turnaround efficiency in our 2016 PSIP modeling.

Nominal $/kW	Pumped Storage Hydro Overnight Capital Cost Assumptions	
Year	*Hawaiian Electric*	*Paniolo Power*
2016	$3,500	Mauna Kea Sites: $4,000 to $4,500 per kW Kohala Sites: $5,000 to $6,000 per kW Reference year 2013, escalator not specified
2017	$3,563	
2018	$3,627	
2019	$3,692	
2020	$3,759	
2021	$3,827	
2022	$3,895	
2023	$3,966	
2024	$4,037	
2025	$4,110	
2026	$4,184	
2027	$4,259	
2028	$4,336	
2029	$4,414	
2030	$4,493	
2031	$4,574	
2032	$4,656	
2033	$4,740	
2034	$4,825	
2035	$4,912	
2036	$5,001	
2037	$5,091	
2038	$5,182	
2039	$5,276	
2040	$5,370	
2041	$5,467	
2042	$5,566	
2043	$5,666	
2044	$5,768	
2045	$5,872	

Table B-8. Pumped Storage Hydro Overnight Capital Cost Assumptions

5. Paniolo's capital cost assumptions for pumped storage hydro were higher than our 2016 PSIP assumptions (see Table B-8). At the Fourth Stakeholder Meeting, Paniolo asked that we not use their site-specific pumped storage capital costs, but rather use our lower non-site-specific capital cost estimate.

6. Paniolo's stated grid-scale wind factors and rate assumptions, with some caveats, are identical to our 2016 PSIP assumptions (Table B-9).

Grid Scale Wind Factor and Rate Assumptions		
Factor and Rate	*Hawaiian Electric*	*Paniolo Power*
Wind Plant Size	30 MW	20, 40, 60, & 80 MW
Wind Plant Capital Cost	$2,465 per kW	$2,338 per kW*
Total Development and Construction Time	2 years	2 years
Fixed O&M	$33.79 per kW year	$33.79 per kW year†
Annual Capacity Factor	54%	54%
Unitized 8,760 Annual Hour Wind Profile	Based on Tawhiri historical data	Based on Tawhiri historical data

* Assumes wind development in 2019; cost assumption from Table B-10.
† Based on 2014 PSIP assumptions. Fixed operations and maintenance costs would be closer to the Hawaiian Electric 2016 PSIP assumption.

7. In the same November 3, 2016 email (mentioned above), Paniolo told us that they had retained AWS Truepower to analyze Paniolo's wind data. This analyzed wind data, however, would not be available until approximately December 1, 2016, but stated that Paniolo would attempt to get the results sooner. Paniolo did offer to provide us with the AWS Truepower modeled wind as an estimate for site-specific wind in "a day or two". In our response, we stated that December 1, 2016 was much too late for us to consider their wind analysis results in our modeling, but that the estimated wind data would "work for us". Paniolo provided these site-specific wind estimates on November 11, 2016, which we passed along to E3. We told Paniolo that, if there was time after modeling the current queue of work, we would use these wind estimates in our analysis, but it was unlikely. Fortunately, E3 was able to incorporate the November 11, 2016 information into the sensitivity analysis.

Paniolo subsequently emailed us the completed AWS Truepower report on December 5, 2016. The report summarized a 55.9% net capacity factor for wind sited on Parker Ranch. Paniolo stated that they would analyze three years of actual wind data using smaller and fewer wind turbines sited in the most optimal locations; as a result, they expected the net capacity factor to increase. The report redacted the proposed site layout and location pending community knowledge and acceptance. We informed Paniolo that E3 was nearly complete with their analytical work and would not be able to incorporate this information.

Table B-10 compares the wind plant cost assumptions—declining in real dollars over time—for Paniolo Power and the Companies. Paniolo sourced their cost assumptions from Berkeley Lab, Electricity Markets & Policy Group Summary Brief of October

2016; our cost assumptions were developed for us by NextEra Energy. Paniolo Power referenced our wind capital cost assumptions when applying Berkeley Lab's declining cost assumptions. (Note that Paniolo Power has cited NextEra Energy Resources as a current development partner.)

2016 Real $/kW	Wind Plant Capital Cost Assumption Comparison		
Year	*Hawaiian Electric Companies*	*Paniolo Power*	*% Difference*
2014	n/a	$2,550	n/a
2015	n/a	$2,508	n/a
2016	$2,465	$2,465	0.00%
2017	$2,459	$2,423	+1.49%
2018	$2,357	$2,380	–1.00%
2019	$2,301	$2,338	–1.61%
2020	$2,309	$2,295	+0.61%
2021	$2,305	$2,259	+2.04%
2022	$2,324	$2,224	+4.50%
2023	$2,334	$2,188	+6.67%
2024	$2,333	$2,152	+8.41%
2025	$2,318	$2,117	+9.49%
2026	$2,303	$2,081	+10.67%
2027	$2,279	$2,045	+11.44%
2028	$2,264	$2,009	+12.69%
2029	$2,244	$1,974	+13.68%
2030	$2,234	$1,938	+15.27%
2031	$2,212	$1,924	+14.97%
2032	$2,199	$1,910	+15.13%
2033	$2,178	$1,896	+14.87%
2034	$2,165	$1,882	+15.04%
2035	$2,144	$1,868	+14.78%
2036	$2,131	$1,854	+14.94%
2037	$2,112	$1,840	+14.78%
2038	$2,099	$1,826	+14.95%
2039	$2,079	$1,812	+14.74%
2040	$2,067	$1,798	+14.96%
2041	$2,048	$1,784	+14.80%
2042	$2,035	$1,770	+14.97%
2043	$2,017	$1,756	+14.86%
2044	$2,005	$1,742	+15.10%
2045	$1,986	$1,728	+14.93%

Table B-10. Wind Plant Overnight Capital Cost Assumptions

8. While Paniolo states that "[a]ccelerating bulk LNG delivery by 3 years and lowering LNG prices can produce significant cost savings in the near to medium term when LNG consumption is the highest,"[33] they fail to provide any supporting evidence for this claim.

9. Paniolo's plan states "Lower Rooftop Solar Penetration Results in Reduced Curtailment"[34] as a heading to a slide. It's unclear from this headline if they are recommending less rooftop PV or attempting to justify that curtailment. Paniolo states "PV penetration rates for HI are based on HELCO PSIP forecasts"[35] and assume no curtailment of DG-PV.

10. It's unclear if Paniolo's plan addresses regulation or system security requirements.

As an interesting note to analyzing pumped storage hydro as a viable energy storage method, during our Fourth Stakeholder Meeting, Dr. Fripp stated that his SWITCH optimization model for O'ahu chose BESS over pumped storage hydro because BESS costs decline over time whereas pumped storage hydro cost remain relatively flat.

The bottom line: For pumped storage hydro, Paniolo ultimately provided outdated, materially similar, and mostly identical information as our PSIP assumptions. In the end, we used our 2016 PSH cost assumptions (which were also lower than Paniolo's) for our modeling analyses. In addition, their estimated wind data was provided too late for us to use as inputs to our modeling process. We can, however, incorporate such input submitted on a timely bases in future updated.

Additional Party Input

Two other technologies were raised by the Parties: load banks during our Third Stakeholder Conference, and ocean energy technologies outside of the official proceeding.

Load Banks

The Alliance for Solar Choice (TASC), at the Third Stakeholder Conference, suggested that the Companies begin analyzing distributed load banks and modeling potential locations (beginning with Moloka'i because of its small size) as a means to consume otherwise curtailed renewable energy. TASC cited a similar installation employing two 1.5 MW systems on Tasmania by way of example. TASC did not provide costs for load banks, nor did they provide a functioning grid-scale example.

[33] Docket No. 2014-0183, *Paniolo Power Company, LLC's First Round of Questions Pursuant to Order No. 33877*, filed September 14, 2016, at 21 (page 10 of Attachment 1).

[34] *Ibid.*, at 38 (page 27 of Attachment 1).

[35] *Ibid.*, at 66 (page 55 of Attachment 1).

E3's analysis currently uses varying methods for handling curtailed renewable energy (such as energy storage and demand response) and identifies the most economical resource mix. Although load banks may have value to mitigate contingency events, absent additional information about how load banks could improve on our analysis and potentially reduce costs, we did not consider load banks in our resource assumptions.

Ocean Energy Technologies

After our Third Stakeholder Conference, Life of the Land referenced a U.S. Department of Energy study asserting that O'ahu could be fully powered with ocean energy technologies. The study was actually published by EPRI in 2011 with a companion report published in 2004.[36] The 2011 report, *Mapping and Assessment of the United States ocean Wave Energy Resource*[37] maps ocean areas that are potential sites for ocean energy technology and theoretically asserts the ocean energy potential of coastline United States, Hawai'i of course being at the forefront. It doesn't, however, discuss the current potential or related costs of such technology.

For that, we referred to the Technology Readiness Level (TRL) and Commercial Readiness Index (CRI) for hydrokinetic energy: ocean wave, tidal generation, and ocean thermal energy conversion (OTEC). According to our 2014 PSIPs, the CRI for ocean wave and tidal generation is 3-commercial scale-up: implementation by specific policy because financing is not available; the CRI for OTEC is 2-commercial trial, meaning a commercial trial whose funding is 100% at risk. According to Dr. Luis Vega, University of Hawai'i, in a 2014 presentation,[38] ocean wave and tidal generation is premature and whose devices will not be available for one to two decades; OTEC needs approximately five to ten years to build a commercially viable 10 MW unit where the cost would be about 50¢ per kWh.

For more information about ocean (hydrokinetic) energy technologies, see "Hydrokinetic Energy" in Appendix H: Renewable Resource Options for O'ahu. Our modeling analysis did not consider ocean energy technologies because of its latent nature, uncertain viability, and exorbitant costs.

Sensitivities Input

In our stakeholder meetings and subsequent conference calls, certain Parties (most notably Ulupono, Paniolo Power, the Consumer Advocate, DBEDT, Hawai'i Gas) and the Companies discussed and developed a series of sensitivities to run. These sensitivities included the hedge premium for fossil fuels, fuel price risk, and O'ahu-based DOD projects. The results of these sensitivities are described in Chapter 3: Analytical Approach.

[36] Available at http://www.energy.ca.gov/oceanenergy/E2I_EPRI_REPORT_WAVE_ENERGY.PDF.

[37] Available at http://www1.eere.energy.gov/water/pdfs/mappingandassessment.pdf.

[38] Ocean Thermal Energy Conversion (OTEC) & Wave Energy Conversion (WEC) for Pacific Island Nations & Asian Developing Nations (http://www.boem.gov/NREL-OTEC-WEC/), July 30, 2014; p 27–28.

FIRST 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 representatives 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 grid 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 grid scale wind, grid 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 grid-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 grid-scale

wind, grid-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

Conference Proceedings: First Stakeholder Conference

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.

Colton Ching opened the meeting, discussed the purpose of the conference, and outlined the four milestones for the April 2016 PSIP update. Mark Glick used a presentation format to organize and conduct the conference (see page B-130 for the slides). During the presentation, Mr. Glick focused on garnering input regarding the Commission's eight Observations and Concerns. He also explained that the Companies were seeking comments regarding the inputs, assumptions, analysis, and results for the updated PSIPs.

The conference featured three presentations from the Parties. Mr. Yunker presented DBEDT's planning methodology to achieve an energy future that meets or exceeds the state's energy goals (see page B-150 for the slides). Erik Kvam of REACH presented its recommendations for a process to develop a mix of resource options for attaining 100% renewable generation (see page B-154 for the slides). Matthias Fripp, professor at the University of Hawaiʻi and a consultant to Blue Planet Foundation and Ulupono, presented how a SWITCH Optimization Model can be employed to develop the resource option necessary for achieving 100% renewable power on Oʻahu (see page B-159 for the slides).

Following the presentation, Mr. Glick and Mr. Ching opened the floor for input and questions from the Parties. A lively discussion ensued regarding the many aspects that comprise the development of the updated PSIPs.

ORDER NO. 33320: PARTY INPUT AND OUR RESPONSE

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."[39]) 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.[40]

To assist the Parties, our *Proposed PSIP Revision Plan* contained a table[41] describing, in detail, the high priority inputs to the Commission's eight Observations and Concerns that we require for our analysis.

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 April 2016 updated PSIP 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.")[42]
- Addressed or incorporated in the *PSIP Update Interim Status Report*.
- Addressed or incorporated in our April 2016 updated PSIP.

[39] Order No. 33320; *op. cit.* at 171.

[40] Docket 2014-0183, *Hawaiian Electric Companies' Proposed PSIP Revision Plan*, *op. cit.* at 28–29.

[41] Docket 2014-0183, *Hawaiian Electric Companies' Proposed PSIP Revision Plan*, *op. cit.*, Table 1. High Priority Input Required for our Analysis, at 29–31.

[42] Order No. 33320; *op. cit.* at 171.

- Addressed in our resource planning that continued after the April 2016 updated PSIP was filed.

To date, we have incorporated several key points of feedback from the Parties in our 2016 updated PSIP. 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 the Parties to access 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 grid-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.
- Invited Party representatives to participate in working meetings with the Hawaiian Electric Companies' planning team on the remainder of analysis and modeling for the April 2016 updated PSIP. This creates greater transparency of the planning, analysis, process, and decisions made during the iterative process.

Receiving Party Input

In their January 15, 2016 filing and again during the March 8, 2016 technical 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 did, however, consider and address 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 whose data and independent technical analyses could help address issues of concern for the April 2016 updated PSIP. These stakeholders include the Hawai'i Natural Energy Institute (HNEI), Electric Power Research Institute (EPRI), U.S. Department of Energy, University of Hawai'i Economic Research Organization (UHERO), National Renewable Energy Laboratory (NREL), and Hawai'i Energy.

NREL has performed an independent review of our new resource assumptions and an independent analysis of the wind and solar PV "developable" potential for each island. EPRI provided access to their database for developing resource costs. 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.

Hawai'i Energy provided us with energy efficiency projections by reducing energy intensities on current square footage, assisting us in developing long-term forecasts that would support the PSIP.

In addition, we contacted Pulama Lana'i 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 Lana'i stated they are continuing to investigate multiple energy options, but that they were not at a point to contribute any input.

Responding to Order No. 33320 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 PSIP. To streamline our response, we organized the input comments into 15 topics. Table B-11 contains a cross reference between a Party filing and the 15 topics. A checkmark indicates that a Party commented on that topic; a dash means that they did not comment on the topic. The remainder of this section explains each topic and our response.

Party	1. Business Model	2. Value of Solar	3. Decision Framework	4. Transparency	5. Resource Inputs	6. Cases and Sensitivities	7. System Security	8. DER & DR Optimization	9. Risks	10. Customer Bill Impacts	11. LNG	12. Fossil Generation	13. Party Input	14. EE and EV	15. Interisland Transmission
CoH	√	–	–	√	√	–	–	–	–	√	–	–	–	–	–
CoM	√	–	√	√	√	√	–	√	√	√	–	–	–	–	√
DBEDT	–	–	√	√	√	√	–	√	√	√	–	√	√	√	–
DCA	–	–	–	√	√	√	√	√	√	√	√	√	√	√	√
AES	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
Blue Planet	√	–	√	√	√	√	–	–	√	–	√	–	–	√	–
DERC	√	√	√	√	√	–	√	√	√	–	–	–	–	–	–
Eurus	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
Hawai‘i Gas	–	–	–	√	√	√	–	–	√	–	√	√	–	–	–
HPVC*	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
HREA	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
HSEA*	√	–	–	–	√	√	–	√	√	–	√	–	√	√	–
LOL	√	–	–	√	√	–	√	√	–	√	–	–	√	–	–
NextEra	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
Paniolo Power	√	–	√	√	√	√	–	–	√	√	√	√	–	–	√
Puna Pono	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
REACH	–	–	√	√	√	√	√	–	√	–	–	–	–	√	–
Sierra Club	√	–	–	–	√	–	–	√	–	–	√	√	–	–	–
SunEdison	–	√	–	–	–	–	–	√	–	√	–	√	–	–	–
SunPower	–	√	√	√	–	–	–	√	–	√	√	√	–	–	–
TASC	√	√	√	√	√	–	√	√	–	–	–	–	–	–	–
Tawhiri	–	–	–	–	–	–	–	√	–	√	–	√	√	–	–
Ulupono	√	–	–	√	–	–	–	√	√	√	√	–	–	–	√

* = Joinder to Sierra Club’s submission

Table B-11. Party to Order No. 33320 Input Topic Cross Reference

1. Utility Business Model

Some 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 action plans will answer a significant part of this question.
- What is the optimal role of the Companies in this future?
- How are the Companies situated to carry out this role?

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 action 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 several owners and operators of grid-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

For our April 2016 PSIP update, we were 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.

We directly addressed this for our December 2016 PSIP update. E3's work compares the total resource costs of available resources and determines the most the economical resource plan. The total resource cost of DG-PV (specific amounts are listed in Appendix J: Modeling Assumptions Data) is significantly higher than that of grid-scale PV. To account for the value and actual cost of energy produced by DG-PV, E3 performed analyses incorporating both the High-DER and the Market-DER forecasts as assumed inputs.

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

For our December 2016 PSIP update, we modified our analytical approach, relying on an automated process involving an analytical flow of three modeling tools: RESOLVE, PowerSimm Planner, and PLEXOS (fully explained in Chapter 3: Analytical Approach).

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 input assumptions and process in Chapter 3: Analytical Approach; all input assumptions in Appendix J: Modeling Assumptions Data; and descriptions of all modeling tools in Appendix C: Analysis Methods and Models.

We established an FTP (WebDAV) 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 Intervenors to attend our planning and decision-making meetings; three organizations responded: the Consumer Advocate, DBEDT, the County of Maui, and the County of Hawai‘i. These representatives attended many of our weekly planning 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: Modeling Assumptions Data documents how we arrived at the assumptions used in our analyses. We have uploaded all resource assumptions to the FTP (WebDAV) server. We also requested additional information from Paniolo Power about the initial resource inputs they provided. For our December 2016 updated PSIP, we engaged with SunPower in productive discussions regarding solar PV and BESS costs, and have completed the sensitivity analyses using input assumptions from the Parties.

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 addition to developing our post-April PSIP plans, E3 developed multiple core cases and sensitivities using input from the Parties.

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 are using 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 O: System Security Analysis documents the process and results from our system security analysis.

8. DER and DR Optimization

The Parties want assurance that the PSIP is 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: Analysis Methods and Models.) We also considered the benefits of incorporating the High-DER forecast, which is a non-market based approach that attempts to estimate the potential of DG-PV.

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

The objective was to determine "least-regrets" near-term action plans. Results from the analyses and sensitivities were considered in determining the "least-regrets" near-term action plans.

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

Chapter 5: Financial Impacts compares the impact on customer bills in both nominal and real dollars.

11. Liquefied Natural Gas (LNG)

The Parties want us to specify our plan to import and exit from LNG use, to minimize or eliminate stranded costs that impact customers; and 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

As indicated in our Motion for Clarification[43] and our PSIP Work Plan,[44] LNG is not included in the near-term action plan. We have, however, analyzed and included these analyses with LNG over the long-term in the December 2016 PSIP update to determine LNG's impact in stabilizing and lowering costs for customers and in lowering emissions while aiding in the effective integration of more renewable energy.

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

As indicated in our Motion for Clarification and our PSIP Work Plan, the 3x1 Kahe combined cycle project has been removed from the near-term action plan. The post-April PSIP plan and cases evaluated by E3 compare different resource plans with and without generation modernization. Ascend Analytics also analyzed the benefits of replacing dispatchable generation with flexible generation.

13. Party Input

The Parties want assurance that their input will be considered and integrated in candidate plans and in the Preferred Plans.

---

[43] *Hawaiian Electric Companies' Motion for Clarification of Order No. 33877*; *op. cit.*

[44] *PSIP Update Revised Analytical Approach and Work Plan*; *op. cit.*

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 Vehicles

Some Parties want to know how energy efficiency help grid issues. 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. Interisland Transmission

The Parties want us to address the impact of interisland transmission on the reliability of the O‘ahu, Maui, and Hawai‘i Island power grids, specifically how a forced cable outage affects reserve requirements and reliability.

Our Action Regarding this Topic

E3 has completed the "copper-plate" analysis which assumes O‘ahu, Maui, and Hawai‘i are grid-connected in 2020 to understand whether interisland transmission is cost-effective under the most optimistic conditions. Further analyses is needed to understand the impacts of a forced cable outage.

SECOND STAKEHOLDER CONFERENCE: MAY 17, 2016

In our *PSIP Update Report: April 2016*, we proposed to convene a Second Stakeholder Conference on April 15, 2016. During that conference, we were 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.[45]

To better prepare for that meeting, and to ensure E3's involvement, we decided to postpone the conference until a date uncertain. To wit, we sent the following email to the Parties, other stakeholders, and the Commission.

> Sent: Friday, April 08, 2016 8:43 AM
>
> Subject: Hawaiian Electric Companies' PSIP Stakeholder Conference
>
> Aloha,
>
> We would like to inform you that the Hawaiian Electric Companies' proposed April 15, 2016 Technical Conference will be rescheduled to a later date as a Stakeholder Conference. We are currently working on the logistics for the Stakeholder Conference and will advise you of the date, time, and location once the details have been worked out. Thank you for your patience.
>
> Mahalo,
> Todd Kanja
>
> PSIP Project Lead

After deciding on a place, date, and time, we sent the following email to the Parties, other stakeholders, and the Commission.

> Sent: Wednesday, May 04, 2016 5:47 PM
>
> Subject: Hawaiian Electric Companies' PSIP Stakeholder Conference
>
> Aloha,
>
> Please be advised that the Hawaiian Electric Companies will hold a PSIP Update Stakeholder Conference on Tuesday, May 17, 2016 from 9 am–11:30 am, at the American Savings Bank tower, 1101 Bishop St, 8th Floor, Honolulu, Hawai'i, 96813. Additional details, along with a meeting agenda, for the conference will follow.
>
> Mahalo
> Todd Kanja
> PSIP Project Lead

[45] *PSIP Update Report: April 2016*, at B-6.

A week later, we emailed the Parties, other stakeholders, and the Commission to officially invite them, and to present the format and structure of the conference.

Sent: Wednesday, May 11, 2016 4:14 PM

Subject: Hawaiian Electric Companies' PSIP Stakeholder Conference - May 17, 2016

Aloha,

We would like to invite you to attend Hawaiian Electric's second Power Supply Improvement Plan (PSIP) Stakeholder Conference.

This Conference is intended to be an open discussion of the Next Steps and forward-going PSIP planning work. In particular input on the scenarios and analytical structure/process to assess unfinished planning work will be timely. The Conference will consist of a series of moderated discussions around the following topics:

A. PSIP Update Highlights and Next Steps

B. Presentation by EThree Consulting on Capacity Expansion Modeling

C. Comments and Questions & Answers

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 Tuesday, May 17, from 9:00 AM to 11:30 AM, on the 8th Floor of the American Savings Bank Tower located at 1001 Bishop St., Honolulu, HI 96813 in downtown Honolulu. Parking validation will not be provided for this event.

We would appreciate it if you could select one person to represent your organization at this Conference. A limited number of conference lines will be available for remote access to the meeting. If your organization wishes to attend or participate via conference call, please RSVP no later than noon, Friday, May 13, 2016 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
heather.villamil@hawaiianelectric.com

We look forward to seeing you at this meeting.

Mahalo,
Colton Ching

To better ensure the greatest participation from the Parties and other stakeholders, we emailed them again with this reminder about accepting our invitation.

> Sent: Monday, May 16, 2016 9:17 AM
>
> Subject: Hawaiian Electric Companies' PSIP Stakeholder Conference - May 17, 2016
>
> Good morning,
>
> Thank you to those of you that have already sent in your RSVPs for tomorrow's Stakeholder Conference. For those that have not submitted your RSVP yet, we would appreciate it if you could do so by noon today to Heather Villamil:
>
> Heather Villamil
> (808) 543-5820
> heather.villamil@hawaiianelectric.com
>
> We look forward to seeing you at this meeting.
>
> Aloha,
> Todd

On May 17, 2016, we convened the Second Stakeholder Conference. Although the meeting was scheduled for two-and-a-half-hours, the actual meeting ran three hours. See "Conference Proceedings: Second Stakeholder Conference" on page B-64 for a summary.

On the day following the conference, we sent the following email to summarize the conference and to solicit additional input from the stakeholders.

> Sent: Wednesday, May 18, 2016 7:14 AM
>
> Subject: PSIP Stakeholder Conference - Thank You
>
> Good morning,
>
> Thank you for participating in yesterday's Stakeholder Conference! We sincerely value each opportunity we have to engage in thoughtful discussion with all of you, along with the sharing of ideas and inputs for further consideration in the PSIP update process. We would especially like to thank Mark Glick for facilitating the group's discussion once again and Ren Orans and Ana Mileva from E3 for their detailed presentation on their use of the RESOLVE model. For your information and reference, attached are copies of the slides that were presented.
>
> We continue to welcome any additional ideas, inputs or comments that you may have. Please don't hesitate to send them to Todd Kanja, Hawaiian Electric's Project Lead for the PSIP Update. Todd can be reached at: todd.kanja@hawaiianelectric.com and (808) 543-4329. To allow adequate time for assessment as part of our current analyses, we would appreciate receiving your information by Wednesday, May 31, 2016.
>
> Mahalo!
> Colton Ching

As of Friday, May 27, 2016, we had received input from only two of the Parties, so we sent the following reminder email.

> Sent: Friday, May 27, 2016 4:56 PM
>
> Subject: PSIP Stakeholder Conference - Thank You
>
> Aloha,
>
> Just sending a friendly reminder that we would appreciate any additional ideas, inputs or comments that you may have by Tuesday, May 31, 2016. Hope you all have an enjoyable Memorial Day weekend!
>
> Mahalo,
> Todd

Conference Proceedings: Second Stakeholder Conference

Alan Oshima, President of the Hawaiian Electric Companies, opened the conference by saying that the PSIP is a 30-year journey to attain our 100% renewable energy goal; that the Companies cannot do it alone; that public policy must align; and that while we are all aligned on this goal, we are here in collaboration to determine how best to reach that goal.

Colton Ching, Vice President of Energy Delivery at the Hawaiian Electric Companies, introduced the meeting, explained its guidelines, and discussed how the Companies' analysis must keep up with new inputs, assumptions, and changes in public policy. Mr. Ching then highlighted the contents of the *PSIP Update Report: April 2016*, and explained our efforts for greater transparency. Topics included resource assumptions, the decision framework, themes and cases, renewable energy on O'ahu, interisland transmission, DER, DR, 100% renewable energy versus 100% RPS, and LNG combined with generation modernization.

Next steps include investigating further offshore wind, optimizing DR and DER, update our production simulations, conducting a risk premium analysis of oil and LNG, integrating the updated EIA fuel price forecasts, investigating interisland transmission for bring benefits and renewable generation to connected islands, and further analysis around system security.

Mr. Glick introduced Ren Orans and Ana Mileva from E3 who presented their RESOLVE capacity expansion model (see page B-166 for the slides). E3's is an independent planning effort using a different methodology and approach to determine how their conclusions compare with those of the Companies' analysis. Mr. Orans and Ms. Mileva explained how a diverse renewable portfolio enables them to be able to adjust as certain technologies emerge or change in their 'potency' and cost. They explained three options:

overbuild renewables, pursue integration solutions to avoid overbuilding, or determine the optimal mix of solutions and overbuilding. For their continued work, they requested input around the scope, costs, and benefits of interisland transmission beyond the analysis already underway; concepts of how interisland transmission fits into the five island resource plans; and also input for offshore wind—all as elements of attaining 100% renewable generation on O‘ahu.

Mr. Glick encouraged attendees to focus their questions around the Next Steps in the *PSIP Update Report: April 2016*. Colton clarified that comments should focus on creating an updated plan, and that near-term steps will not be taken until approved by the PUC and after long-term direction is clarified. Most questions centered on assumptions and constraints incorporated into the plans, and that they be re-evaluated, especially the assumption that O‘ahu cannot produce all its energy needs from renewables.

Input Received: Second Stakeholder Conference

By our stated deadline of May 31, 2016, we received input from nine sources, two of which were letters signed by a group of the Parties. Here is an overview of the submitted input, almost all of which the Parties also submitted in response to Order No. 33740.

Ulupono, et al. A group letter signed by Ulupono, Blue Planet, Sierra Club, Hawai‘i Gas, County of Maui, HREA, and DERC of Hawai‘i. Ulupono submitted this exact letter in its response to Order No. 33740. For a summary of this Ulupono filing Order No. 33740, see “Ulupono et al Joint Recommendations—Multiple Signers” on page B-68 and “Ulupono Initiative Comments” on page B-70.

Hawai‘i Gas. An email requesting that the Companies use in future modeling, the LNG price forecasts from the Hawai‘i Gas binding RFP and contract negotiations. The email listed Hawai‘i Gas’s price forecasts using EIA AEO and STEO price forecast and escalation methods to enable a comparison on an “apples to apples” basis. Hawai‘i Gas essentially filed this same information (although using slightly different wording) in its response to Order No. 33740. For a summary of this Hawai‘i Gas Order No. 33740 filing, see “Hawai‘i Gas Comments” on page B-73.)

County of Hawai‘i. A letter stating the lack of meaningful stakeholder engagement, the dearth of opportunities for stakeholder participation, and the lack of transparency in model assumptions and data input during the Companies’ process of developing the PSIP Update. The County of Hawai‘i also called for a second conference “to allow for greater collaboration and increased dialog between” the Companies and stakeholders. The County of Hawai‘i filed their letter in Docket No. 2014-0183 on June 1, 2016, and also filed additional comments in response to Order No. 33740. For a summary of the County of Hawai‘i Order No. 33740 filing, see “County of Hawai‘i Comments” on page B-82.

TASC. Sunrun sent an email on behalf of The Alliance for Solar Choice. This email appears as Exhibit A in the joint Hawai'i PV Coalition and TASC filing in response to Order No. 33740. For a summary of the joint HPVC and TASC Order No. 33740 filing, see "Hawai'i PV Coalition (HPVC) and The Alliance for Solar Choice (TASC) Comments" on page B-79.

AES Hawai'i. An emailed letter discussing the future of the AES Kapolei facility as outlined in the PSIP Update. AES included and expanded on this discussion in its response to Order No. 33740. For a summary of the AES Order No. 33740 filing, see "AES Hawai'i Comments" on page B-85.

SunPower. An email stating that the energy storage and PV cost assumptions in the PSIP Update are significantly higher that current market conditions, and proposing lower energy storage costs for subsequent analysis. SunPower filed these same comments and data in its response to Order No. 33740. For a summary of the SunPower Order No. 33740 filing, see "SunPower Comments" on page B-76.

REACH. An email with an attached 23-page report entitled *Creating the Electric Utility We Want…in Hawai'i or Anywhere*. REACH filed this same report in its response to Order No. 33740. For a summary of the REACH Order No. 33740 filing, see "Renewable Action Coalition of Hawai'i (REACH) Comments" on page B-81.

Blue Planet, et al. A group-emailed letter signed by Blue Planet, Sierra Club, Paniolo Power, DERC of Hawai'i, HREA, HSEA, and the County of Maui. The signers stated their support of the Ulupono et al. letter. The signers questioned whether or not the collaboration between the Companies and stakeholders was meaningful as evidenced by the Companies' recent LNG filings which "is prematurely seeking to implement the centerpiece of its proposed PSIP and…its proposed merger with NextEra Energy". The signers called for an immediate withdrawal of the applications filed in Docket No. 2016-0135: LNG Application, Docket No. 2016-0136: Kahe Combined Cycle Waiver from Competitive Bidding, and Docket No. 2016-0137: Kahe Combined Cycle 3x1 Generating Unit. (*Note:* The Companies withdrew all three applications following the Commission's dismissal without prejudice of Docket No. 2015-0022: Change of Control.)

Blue Planet did not file this letter in Docket No. 2014-0183 in response to Order No. 33740; its three pages are reproduced starting on page B-163.

Blue Planet also filed wholly different comments in response to Order No. 33740. For a summary of the Blue Planet Order No. 33740 filing, see "Blue Planet Foundation Comments" on page B-72.

ORDER NO. 33740: SUMMARIES OF FILED RESPONSES

On June 3, 2016, the Commission issued Order No. 33740 inviting comments from the Parties and from the general public on the *PSIP Update Report: April 2016*, Docket No. 2014-0183, and Order No. 33320. Specifically, the Commission requested comments on its Initial Statement of Issues "for the review, supplement, amendment, and updating of the PSIPs for each of the Companies.

1. Whether the PSIPs, as amended and updated in this proceeding, provide useful context and meaningful analysis to inform major resource acquisition and system operation decisions and identify well-reasoned and adequately-supported plans and actions that will result in reliable energy services, meeting State clean energy requirements, while ensuring that costs and rates will be reasonable.
2. Whether the PSIP for each of the HECO Companies, as amended and updated in this proceeding, includes reasonable plan components as required for HECO in Order No. 32053, including:
   a. A Fossil Generation Retirement Plan;
   b. A Generation Flexibility Plan;
   c. A Must-Run Generation Reduction Plan;
   d. An Environmental Compliance Plan;
   e. A Key Generator Utilization Plan;
   f. An Optimal Renewable Energy Portfolio Plan; and
   g. A Generation Commitment and Economic Dispatch Review.
3. Whether the PSIPs, as amended and updated, adequately address the Observations and Concerns addressed in this Order."[46]
   1. The PSIP cost impacts and risks have not been demonstrated to be reasonable.
   2. The PSIPs do not appear to aggressively seek lower-cost, new grid-scale renewable resources.
   3. The PSIPs utilization do not adequately address and integration of distributed energy resources.
   4. The proposed plans for fossil-fueled power plants are not sufficiently justified.

[46] Order No. 33320; *op. cit.* at 138–139.

5. System security requirements appear costly and are not sufficiently justified.
6. The proposed plan for provision of ancillary services lacks transparency and may not be most cost-effective option.
7. The PSIP analysis on interisland transmission lacks sufficient detail.
8. Customer and implementation risks are not adequately addressed.[47]

Twenty of the 23 Parties (NextEra, Eurus, and First Wind did not file responses), the Companies, and 174 members of the general public filed responses to the Order.

This section contains summaries of each Party response, a summary of the general public responses, and a summary of the Companies' response. This section begins with the Ulupono et all summary, as it was signed by eleven of the Parties, is followed by the responses of these signers (as they are all somewhat related), continues with the remaining Party responses (in the order in which they were filed) and a summary of the general public comments, and concludes with the Companies' response.

To focus on the most pertinent information, comments related to the proceeding's background have been omitted. All pertinent comments are numbered to better itemize and refer to them, cross referenced to specific pages within each filing.

Summaries of the Ulupono et al Filing and Its Party Signers

Ulupono et al Joint Recommendations—Multiple Signers

Eleven of the Parties submitted a Joint Recommendations filing on June 17, 2016. The filing contained two sections:

- Joint Recommendations signed by Ulupono, Blue Planet, Hawai'i Gas, County of Maui, HREA, Sierra Club, DERC of Hawai'i, HSEA, SunPower, TASC, and HPVC. These signers feel that the PSIP Update raises numerous concerns and needs further work, which were articulated in the letter attached as Annex A.
- An Annex A that contained the jointly-signed letter sent to the Companies on May 31, 2016 as solicited input following the Second Stakeholder Conference. This letter was signed by Ulupono, Blue Planet, Hawai'i Gas, County of Maui, HREA, Sierra Club, DERC of Hawai'i, and Paniolo Power.

All signers of the joint recommendations and the Annex A letter (except HREA and HSEA) filed additional comments highlighting specific concerns in response to Order No. 33740.

[47] Order No. 33320; *op. cit.* at 3–7.

Ulupono et al Joint Recommendations. Here is a summary of the joint recommendations of the near-term steps that the Commission should consider "to ensure constructive further progress in this docket" (p 1). (As a matter of clarity, the numbers and letters of this summary coincide with the same numbers and letters in the Ulupono et al Joint Recommendations filing.) The Commission should:

1. Convene a second stakeholder session as soon as possible to focus on specific concerns and feedback from the Parties (p 2).
2. Clarify and reaffirms the PSIP objectives, and provide guidance as to how the PSIP must address elements required by Order No. 33320 (p 2).
3. Convene one or more technical sessions to review modeling and assumptions used by RESOLVE, indicate how SWITCH can supplement and improve RESOLVE, and ensure that RESOLVE is used transparently (p 3). RESOLVE should identify:
   - **a.** Three to five alternative generation resource mixes to attain 100% clean energy by 2045 and an action plan for each alternative for the next 5 years (p 3).

b. Identify key decisions the Commission must make to implement each alternative action plan (p 3).

c. Identify key factors that the Commission should use to evaluate each plan to ultimately select the desired action plan (p 3).

Invite the Parties to submit limited numbers of information requests (as part of the docket record) before a technical sessions to be answered by the Companies at the technical session or after to be answered within two weeks (p 4).

4. Appoint an Independent Entity to oversee the work of finalizing the PSIP (p 4).
5. Ensure the Companies finalize the PSIP based on all Party input and comments in a manner that ensures transparency (p 4).
6. Direct the Companies to present a draft PSIP to all Parties for review and comments to be submitted within four weeks (p 5).
7. Direct the Companies to incorporate Party comments and file the PSIP in the docket (p 5).
8. Request the Parties to submit a brief recommending a PSIP preferred plan and its near term action steps (p 5).
9. Decide which PSIP preferred plan to accept for each operating utility (p 5).
10. Establish dates for formal review of the status and progress made by each operating utility on its preferred plan (p 5).

Ulupono el al Annex A Letter. The Ulupono et al Annex A Letter begins with a request to convene another stakeholder conference (which the Companies held on June 29, 2016). The remainder of the Annex A letter is summarized here.

1. While the E3 RESOLVE model is focused, transparent, objective, and understandable, it should be adjusted to:
   a. Be free of artificial constraints or biases and its assumptions corrected or supplemented, such as assuming that Oʻahu cannot achieve 100% renewable generation on its own (Annex A, pp 1–2).
   b. Include a more comprehensive analysis of the volatility of oil and LNG prices using market-based prices and relying on Monte Carlo, block bootstrap methods, and other probabilistic analytic approaches (Annex A, p 2).
   c. Include a "base" or "reference" plan for comparing cases (Annex A, pp 1–2).
   d. Use the aforementioned adjustments to create cases for the underlying modeling and analysis in developing the PSIP (Annex A, p 2).
2. The PSIP analysis should be expanded to integrate more DG-PV and microgrids, and to consider the implications of customer retention economics (Annex A, pp 2–3).
3. The PSIP should be expanded to include updated battery storage information and emerging and expanded DER approaches, methodologies, and devices (Annex A, p 2).
4. The PSIP should analyze a statewide grid through a comprehensive or selective interisland two-way cable system with various site-specific offshore and onshore resource options (Annex A, p 2).
5. The PSIP analysis should be expanded so that its conclusions more fully embrace the Commission's *Inclinations*, and the RESOLVE model enhanced as previously discussed to produce results that would help to identify, frame, and provide realistic policy choices and embody real and substantial stakeholder participation and input (Annex A, p 3).
6. The Companies should collaborate more closely with stakeholders, especially considering independent their studies and analyses (Annex A, p 4).

Ulupono Initiative Comments

Ulupono Initiative also filed individual comments in response to Order No. 33740. Ulupono's filing contained three sections: their own comments, the complete Joint Recommendations filing, and an Annex B that contained three slides from a presentation that was to be given by Matthias Fripp at the stakeholder conference yet to be held on

June 29, 2016. This summary focuses only on the first section of Ulupono's own comments.

1. The essential need of the PSIP process—unbiased, objective analysis and information—has not been met and that the tremendous amount of information and insight generated by the Companies has not been correctly integrated into the evolving PSIP (p 2).
2. The PSIP Update introduced new systemic biases and failed to correct methodological errors. Ulupono previously highlighted such that the full set of viable resource options, nor the tradeoffs between them, have been fully disclosed beyond nominal direct cost comparisons (p 3).
3. The analytical process employed to develop the PSIP Update (defining and evaluating three themes) not only is inferior to the capacity expansion planning approach, but also produced artificially constrained choices (point 1, pp 3–4).
4. The PSIP Update, in a flawed and deceptive manner, uses the EIA's short-term (13–24 month) energy outlook (STEO) price forecast in a long-term price scenario, with artificially low future price escalations that are entirely the construct of the Companies (point 2, p 4).
5. The PSIP Update ignores the impacts of fossil fuel price volatility and its incumbent risks, which should be evaluated, explicitly quantified, and assessed with the real asset hedge offered by renewable energy resources. There are three viable, quantitative approaches to incorporating the costs of volatility: 1. Actual market quotes regarding hedging costs from qualified companies; 2. Mathematical algorithms for estimating hedging costs; and 3. Use a Monte Carlo approach to evaluate choices over a long timeframe (point 3, pp 4–6).
6. Near-term resource choice is not based on objective and unbiased analysis, as evidenced by eliminating the SunEdison and Hu Honua projects, including Department of Defense resource projects, and refusing to consider sourcing LNG through a collaboration with Hawai‘i Gas (point 4, pp 6–7).
7. The PSIP Update is entirely utility ownership centric, relying heavily in a misguided and unsubstantiated attempt to create value in NextEra's acquisition of the Companies as necessary to achieve the preferred plans. The Companies, as stand-alone entities, are completely capable of securing long-term LNG contracts and of building combined cycle units (point 5, p 7).
8. While demonstrating considerable work, the PSIP Update does not adequately address the underlying purpose and ultimate function (p 8), only partially follows

the guidance and mandates required by the Commission (p 9), and does not provide what the Initial Statement of Issues requires in at least three specific areas:

a. The PSIP Update and its concomitant five-year action plans, like the 2014 PSIPs before, are predicated on a predefined end state and incomplete analysis; then substantiated through faulty, inadequate, and otherwise incomplete and misleading "choices" (point 1, pp 9–10)

b. The rationale for developing customer bill impacts is not explained or justified, especially when comparing the 23% reduction in monthly bills for full service residential customers (declared in the 2014 PSIPs) with the slight increase stated in the PSIP Update, despite using STEO energy price forecasts which are artificially low (point 2, p 10).

c. The means for financing, nor the total financial implications on customers, of the substantial projected capital expenditures required for each theme is not fully and realistically examined (point 3, pp 10–11).

9. The most constructive approach to developing a PSIP that meets its intended use—to provide unbiased, objective information regarding the tradeoffs to ratepayers of alternative resource portfolios—is for the Commission, the Consumer Advocate, the Parties, and the Companies to jointly undertake this task (pp 11–12).

Blue Planet Foundation Comments

In addition to signing and supporting both the "Ulupono et al Joint Recommendations" (page B-69) and the "Ulupono et al Annex A Letter" (page B-70), Blue Planet filed the following comments in response to Order No. 33740. Those comments, summarized here, are in additional to the input Blue Planet supplied in response to the Companies' solicitation following the Second Stakeholder Conference.

1. The PSIP Update suffers systemic deficiencies, some likely related to biased assumptions of utility ownership, energy asset ownership, and an evolving business model that are either a reflection of or the cause of planning biases (pp 1–2).

2. Distributed energy resources are treated as exogenous factors (that is, forecast) instead of a resource to be maximized, discounting the fact that customer update of DER can be greatly influenced (both positively and negatively) by utility action strategies (p 2).

3. Planned quantified risk analysis should not only include LNG versus oil, but also on new fossil fuel and renewable generation and DER to properly assess and value all generation options, as well as to understand how grid reliability and security risks affect this same range of generation options (p 3).

4. Any new investments in fossil fuel infrastructure should be limited to system needs only after optimizing the foundational elements of a 100% renewable system (pp 3–4).
5. Certain energy storage options—pumped storage hydro, hydrogen storage, distributed energy storage systems, and thermal distributed storage—must be more thoroughly considered with a certain level of vision, even if that vision includes a measure of uncertainty (pp 4–5).
6. The disparity between installing offshore wind resources until after 2030 must be reconciled with the Bureau of Ocean Energy Management's (BOEM) having already started the process for leasing offshore wind sites (p 5).
7. The different conclusions derived from the SWITCH and RESOLVE capacity expansion models must be studied to determine the cause of their divergent results (pp 5–6).

Hawaiʻi Gas Comments

In addition to signing and supporting both the "Ulupono et al Joint Recommendations" (page B-69) and the "Ulupono et al Annex A Letter" (page B-70), Hawaiʻi Gas filed comments in response to Order No. 33740. Those comments, summarized here, include the input Hawaiʻi Gas supplied in response to the Companies' solicitation following the Second Stakeholder Conference.

1. The Companies chose not to incorporate Hawaiʻi Gas's lower-cost LNG pricing in either its PSIP Update nor in its LNG application, even though that pricing would have saved customers an additional $3.5 billion over 20 years (p 1).
2. Provided in its comments, Hawaiʻi Gas included:
   - An overview of the infrastructure costs associated with the Hawaiʻi Gas logistics model which included the floating storage regasification unit (FSRU) submerged turret loading (STL) system, undersea pipeline, and onshore facilities (pp 2–3).
   - A description of the Hawaiʻi Gas LNG logistics model for receiving, regasifying, and distributing LNG on Oʻahu (pp 3–5).
   - An explanation of the permitting and scheduling process (pp 5–6).
   - A detailed summary of the total delivered LNG Brent prices levels resulting from their RFP process (and its negotiated option to purchase LNG based on a hybrid formula that combines Brent and Henry Hub components) that guarantees delivered LNG will always be priced below crude—and therefore, below Hawaiʻi's oil-based fuel alternatives (pp 6–7).
   - A table recasting Hawaiʻi Gas's LNG pricing in real and nominal dollars that correlates with the EIA AEO (and updated STEO) price forecasts used in the PSIP

Update, with a request for the Companies to use these "alternative" prices in future models (pp 7–8).

- An explanation of how Hawai'i Gas's LNG supply contract was structured to stabilize and lock in prices over the longer term (p 9).
- Two graphs depicting the enormous dollar amount that LNG use could have saved over the last ten years and is projected to save over the next twenty years (pp 9–10).
- A discussion demonstrating the assumed decline of LNG use over the contract's 15-year lifecycle (compared to the constant LNG use over the 20-year lifecycle in the Companies' plan) and its flexible scaling allowing for the increased penetration of renewable generation alternatives and decreased cost per kilowatt hour (pp 11–14).
- An analysis of the savings that can be realized by the Companies implementing the Hawai'i Gas plan—$3.5 billion over 20 years at constant 800,000 metric tons per annum (mtpa), a bulleted list assessment of the benefits for using the Hawai'i Gas model in the PSIP analysis, and its advantages in supporting State energy objectives (pp 14–18).

County of Maui Comments

In addition to signing and supporting both the "Ulupono et al Joint Recommendations" (page B-69) and the "Ulupono et al Annex A Letter" (page B-70), the County of Maui filed comments in response to Order No. 33740. On July 8, 2016, the County of Maui sent an email to the Companies to clarify and expand on their field comments. Both sets of comments are summarized here.

1. While supporting the complete set of Joint Recommendations, the County of Maui particularly supports recommendations #3, which called for one or more technical conferences to review modeling and assumptions, and #4 (both on page B-69), which calls for the appointment of an Independent Entity (p 2).
2. The Companies cannot be realistically expected to restructure and adopt a new sustainable business model—especially in the face of the disruptive nature of DER services and technologies—and create unbiased resource plans that reflect the best interests of the customers (pp 2–3). Instead, an Independent Entity should direct the preparation of a customer-funded, public interest, resource plan in addition to a PSIP created by the Companies to provide the Commission with a more complete assessment of resource alternatives and proposed capital improvements (p 4).
3. Maui's preferred plan based on Theme 2 triples the island's wind capacity without identifying their general locations and assessing their attendant cultural, environmental, and social impacts (p 5).

4. The flat growth projection through 2045 of DG-PV (in Maui's Theme 2) is not credible, and instead should be replaced with the assumption of a high DG-PV and DER forecast (developed through a collaborative process with the stakeholders), hardwired for 2045, as a starting point, then reverse engineered to the present to better uncover issues that would not have otherwise been raised (p 6).

5. Hardwire a near-term market disruption from distributed energy storage systems (similar to the Morgan Stanley report for Australia's solar plus storage market referenced by TASC's presentation at the Third Stakeholder Conference), then perform an iteration by modeling TASC's dynamic resistive frequency control approach (email).

6. A high DER future in 2045 should be modeled as a starting point, and be defined these five factors: 1. Customer costs from a DER microgrid are less than or equal to the cost of grid services; 2. The DER microgrid performance is greater than or equal to that of grid services; 3. New developments generate their own power and reduce grid growth; 4. Most homes and businesses use onsite energy storage for reliability and security; and 5. All new vehicles are EVs (pp 6–7).

7. The silo approach used to create the PSIP Update resulted in a rigid plan of inflexibility with its inclusion of LNG and a combined cycle plant, relying on a low, limited DG-PV adoption, which only portends to burden ratepayers now and again in the future when investments are made to handle greater distribution-level impacts (pp 8–9).

8. An adjusted value approach should be considered to capture the true value (on a MW basis) and flexibility of energy storage when compared to current fossil-fueled assets (coupled with their laggard deactivation schedule) and when compared to an interisland cable connection (pp 9–10).

9. The inclusion of merged scenarios conditioned upon the approval of the NextEra acquisition reflects bias and intrudes upon the associated deliberations, demonstrating further the need for an Independent Entity who can oversee objectively developed plans (p 10).

Sierra Club Comments

In addition to signing and supporting both the "Ulupono et al Joint Recommendations" (page B-69) and the "Ulupono et al Annex A Letter" page B-70), Sierra Club filed comments in response to Order No. 33740. Those comments are summarized here.

1. The PSIP Update fails to satisfy any of the Commission's Initial Statement of Issues (pp 1–2).

2. The PSIP Update is tainted by its linkage to the proposed NextEra acquisition being approved, and as such is not ownership agnostic nor resource agnostic (pp 4–6).

3. The PSIP Update fails to address the Commission's direction to pursue a new utility and market structure that better serve the interests of its customers and the public, and instead focuses on promoting their traditional business model based on utility capital spending (pp 6–10).

4. The PSIP Update does not include any nearer-term actions aimed at obtaining specific efficiencies and improvements in current generation operations (pp 10–11).

5. The Commission must clarify whether or not the PSIP proceeding has replaced the IRP Framework with its various attendant processes and safeguards (such as an Advisory Group and Independent Entity); and revisit, renew, and reconcile any and all differences (p 12).

6. The PSIP Update continues a bias for switching to LNG with no clear exit plan, prolonging its fossil fuel generation at the expense of pursuing a clean energy portfolio (pp 13–17).

7. The PSIP Update continues a persistent failure to recognize the benefits of DER to the grid and the general public, and to fully integrate and utilize customer DER (pp 18–20).

8. The Commission, at a bare minimum, should ensure an objective and productive planning process by delegating the energy system planning function entirely to an Independent Entity who has the authority to require the Companies to conduct necessary additional planning modeling and analysis (pp 20–22).

SunPower Comments

In addition to signing and supporting the "Ulupono et al Joint Recommendations" (page B-69), SunPower Corporation filed comments in response to Order No. 33740. Those comments, summarized here, include the input SunPower supplied in response to the Companies' solicitation following the Second Stakeholder Conference.

1. SunPower commends the Companies for clearly stating the mix of renewable resources anticipated to meet the 100% renewable energy goal, and for creating a workable plan for attaining that goal (p 2).

2. The expectation of significant savings from the use of LNG as a transition fuel is far from clear, and the transition's substantial capital costs would preclude investments in other more economical technologies (pp 2–3).

3. The use of biomass, its source and infrastructure costs for Maui Electric and Hawai'i Electric require further analysis (p 3).

4. The Companies' and E3's analysis of the costs and amounts of energy storage (Figure B-3.) and PV (Figure B-4)—and their wide range of possibilities—are outdated, insufficient, and inaccurately high; and should instead use the current market assumptions in the GTM Research *PV Systems and Pricing Forecast* or the U.S. Department of Energy *SunShot Vision Study* (both of which we have provided to the Companies) as baseline in further analysis (pp 4–8).

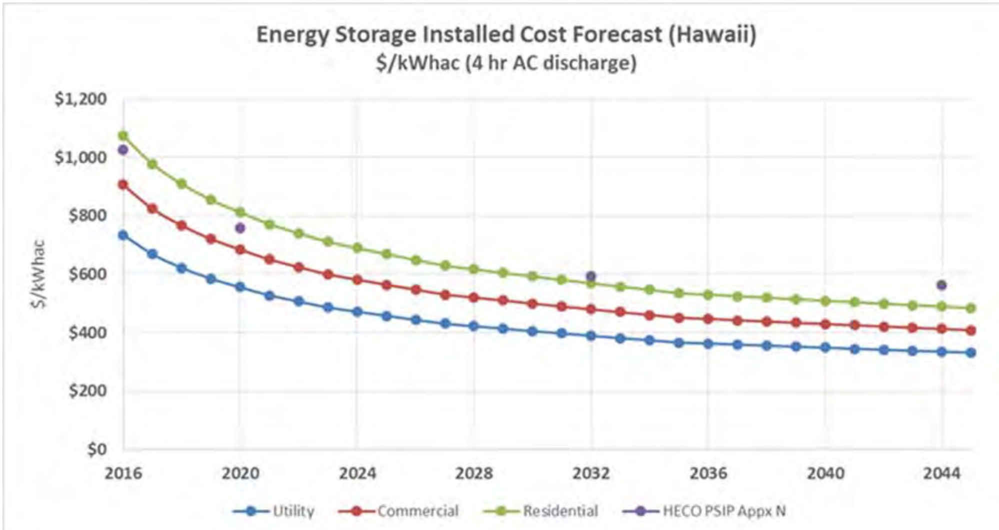


Figure B-3. Comparison of Installed Cost Forecasts for Energy Storage ($/kWh AC)

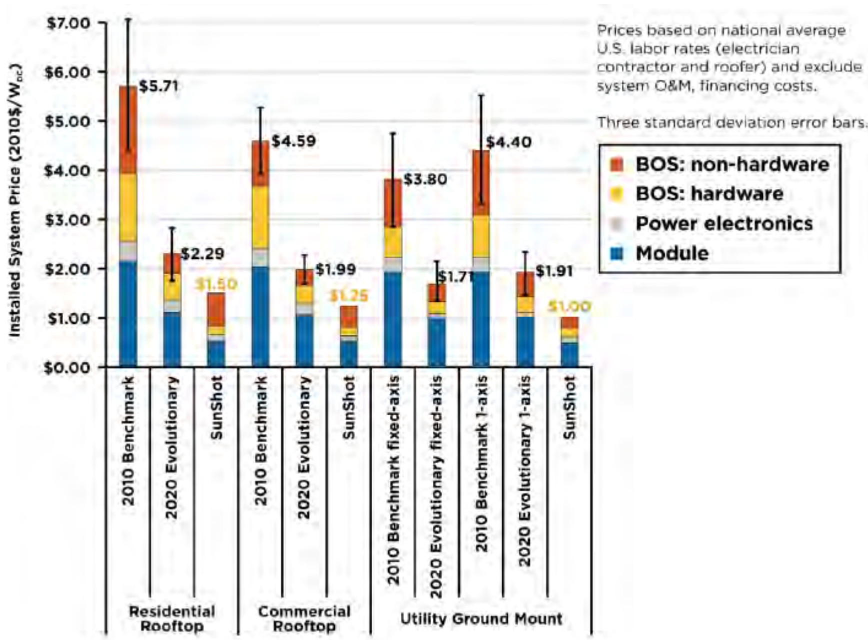


Figure B-4. Installed PV System Price Comparison[48]

[48] U.S. Department of Energy *SunShot Vision Study*, February 2012 (http://energy.gov/sites/prod/files/2014/01/f7/47927.pdf); p. 89.

5. The PSIP Update's assertion of its Theme 2 only being possible in a merged scenario needs closer scrutiny; and its reliance on utility-owned generation and continued operation under a traditional regulatory model are contrary to Commission directives (pp 9–10).

Distributed Energy Resources Council (DERC) of Hawai'i Comments

In addition to signing and supporting both the "Ulupono et al Joint Recommendations" (page B-69) and the "Ulupono et al Annex A Letter" (page B-70), the Distributed Energy Resources Council (DERC) of Hawai'i filed comments in response to Order No. 33740. Those comments are summarized here.

1. The PSIP Update adopts, but fails to integrate distributed energy resources (DER) in its ongoing planning process in a meaningful way, even though DERs can provide a tremendous number of cost competitive benefits to customers, the electrical grid, and all utility customers (pp 5–7).

2. The PSIP Update appear to completely exclude distributed energy storage from its evolving plan, even while acknowledging its value to ancillary services, over-generation, circuit-level issues, and operational flexibility (pp 7–9).

3. The Companies should conduct pilot programs that determine the efficacy of residential distributed energy storage and smart-supply DERs (to function as a hybrid between self-supply and grid-supply systems) to better determine how they can export on the shoulders of the load curve, capture excess energy, and shift peak load (pp 10–12).

4. The PSIP Update fails to consider the positive financial impact of both customer-invested and utility-invested distributed energy storage (pp 12–14).

5. DERC opposes the proposed investment in LNG, preferring to understand what the $1.3 billion investment slated for LNG development could achieve if invested directly into infrastructure that support renewables (p 14).

6. The PSIP Update, while recognizing the value of keeping customers connected to the grid, fails to offer any substantial plan to encourage connected nor analyze the economic potential for customer exit (p 15).

7. DERC recommends (p 16):
   - The appointment of an Independent Entity to monitor future proceedings.
   - An upgraded and revamped analytical strategy to include dynamic and stochastic models that incorporate all potential DER attributes.
   - Parallel investments in rigorous pilot projects to investigate DER impacts and contributions.

Hawai‘i PV Coalition (HPVC) and The Alliance for Solar Choice (TASC) Comments

In addition to signing and supporting the "Ulupono et al Joint Recommendations" (page B-69), the Hawai‘i PV Coalition (HPVC) and The Alliance for Solar Choice (TASC) jointly filed comments in response to Order No. 33740. Those comments, summarized here, also include the input TASC supplied in response to the Companies' solicitation following the Second Stakeholder Conference and an email TASC sent to the Companies on July 13, 2016.

1. The PSIP Update provides no insight or analysis of alternative DER configurations that could address system constraints and avoid distribution and transmission system upgrades (p 4).
2. The PSIP Update lacks analysis of non-capital alternatives that address DER integrations and interconnections costs (p 5).
3. The PSIP Update does not identify or examine the benefits of DER in providing ancillary services, nor explain its absence from the preferred plans (pp 5–6).
4. The DER forecast of a steep decline for DG-PV and distributed energy storage installations over the next ten years defy common sense and are, on first impression, unreasonable. TASC, using the model input data, intends to conduct its own analysis and devise its own outputs and conclusions (p 6).
5. The PSIP Update reveals a continued dedication to preserving a traditional utility-centric business model rather than embracing a customer-focused one (pp 7–8).
6. The Commission should appoint an Independent Entity to oversee the work of finalizing the PSIP, and be granted authority to (pp 8–11):
   - Access all models and underlying data, inputs, and assumptions.
   - Revise operational parameters within the models.
   - Direct the compilation of three to five alternate scenarios in the public interest.
7. Continued analysis should include a safety valve (load bank) to control excess energy risks, reduce down reserves, and reduce curtailment of renewable resources (email).

Summaries of Remaining Party Responses

Paniolo Power Comments

In addition to signing and supporting the "Ulupono et al Annex A Letter" (page B-70), Paniolo Power filed comments in response to Order No. 33740. Those comments are summarized here.

1. The PSIP Update suffers from many material shortcomings that do not support the Commission's Initial Statement of Issues because of bias toward the Companies' self-interest and a dependency on NextEra's acquisition of the Companies (p 4).

2. The Hawai'i Electric Light preferred plan is unclear why more long-duration storage, wind, and PV resources are not included; geothermal was selected as the next generating unit given its uncertainty; and the resultant financial analysis was optimized (pp 6–8).

3. The basis for unit deactivation, resource addition, must-run generation reduction for Hawai'i Electric Light is unclear (pp 9–11).

4. The selection and addition of renewable resources for Maui Electric is more aggressive than that for Hawai'i Electric Light despite the similarity of our grids (pp 11–14).

5. Hawai'i Island projects should be given higher priority because of it higher rates and lower rate of return when compared to O'ahu and Maui (p 15).

6. The PSIP Update should contain more resource diversification obtained in a competitive bidding process, and not based on using LNG (acquired only after a NextEra acquisition) or using biofuels in existing fossil-fueled generation (pp 15–18).

7. Integrated energy districts—microgrids—should be required for communities with health facilities for life, safety, and security; and not just for military installations (p 18).

8. Paniolo Power suggests the Commission consider these procedural steps (pp 23–24):
   - Schedule another informal PSIP stakeholder meeting.
   - Allow the Parties to submit written questions to the Companies.
   - Direct the Companies to respond to these questions in writing.
   - Hold technical sessions to discuss and elaborate on these and other questions and responses (retaining a court report to document the sessions).
   - Direct the Companies to provide supplemental responses as needed.
   - Allow the Parties make specific recommendations to any part of the PSIP preferred plans, including their own analysis and modeling.
   - Direct the Companies to revise and resubmit the PSIP.
   - Allow the Parties to write final statements of position and recommendations regarding the revised and resubmitted PSIP.
   - Decide whether to accept, reject, or modify the PSIPs, and determine the effect of its decision on future applications and proposals.

Life of the Land and Puna Pono Alliance Comments

Life of the Land and Puno Pono Alliance jointly filed comments in response to Order No. 33740. Those comments, related through metaphor and anecdotes without citation, are summarized here.

The PSIP, as an evolving plan, still needs more work in a number of areas. Many key assumptions—such as load and demand shifting, energy storage, microgrids, geothermal, DER, and identification of sources—and their basis should be transparently detailed.

Renewable Action Coalition of Hawai‘i (REACH) Comments

The Renewable Action Coalition of Hawai‘i (REACH) filed comments in response to Order No. 33740. That filing included a twenty-three-page publication entitled *Creating the Electric Utility We Want in Hawai‘i or Anywhere* (originally submitted in response to the Companies' solicitation following the Second Stakeholder Conference) and comments regarding the *PSIP Update Report: April 2016*.

The REACH publication, informational by its own admission, presents a five-step process for building consensus to successfully achieve 100% renewable energy. REACH's additional comments specifically filed in response to Order No. 33740 are summarized here.

1. The PSIP Update (although with some amount of ambivalence) fails to elucidate plans that can inform Commission decisions, in general, because the Companies have not reached consensus of a clear renewable planning process, and its attendant generation resources (most notably LNG), associated risks, and benefits (pp 33–47).
2. The PSIP Update does not comply with the Commission's stated component plans mainly because the Companies have not arrived at consensus as to the fundamental components of each plan (pp 47–51).
3. The PSIP Update has not either arrived at consensus, adequately addressed, or sufficiently justified the Commission's Observations and Concerns (pp 52–57).
4. The Commission might consider suspending the docket until the Companies reach consensus on a renewable planning process to systematically evaluate renewable energy options (pp 57–58).

County of Hawai‘i Comments

The County of Hawai‘i filed comments in response to Order No. 33740. Those comments, summarized here, include the input the County of Hawai‘i supplied in response to the Companies' solicitation following the Second Stakeholder Conference. The County of Hawai‘i:

1. Supports the joint recommendations of the Ulupono Initiative et al filing, certain comments by Paniolo Power, and the County of Maui's call for an Independent Entity to direct the preparation of a ratepayer-funded public interest resource plan to counter the Companies' shareholder-funded resource plan (pp 1–2).
2. Increase the overall transparency and provide access to data necessary to collaboratively conduct independent analyses and modeling for developing alternative strategies (p 3).
3. Submits that the Hawai‘i Electric Light Preferred Plan does not provide useful analyses to inform major resource acquisitions, nor does it appear to be well-reasoned from a ratepayer's standpoint (p 3).
4. Considers the Component Plans to be inadequate, not sufficiently analyzed, not good enough, questionable, non-existent content, and botched (p 4).
5. States that the *PSIP Update Report: April 2016* does not, insufficiently, or inadequately address all eight Observations and Concerns (p 5).
6. For Hawai‘i Electric Light, asserts that Hawai‘i Island projects be prioritized, that a diversified portfolio of renewable generation displace oil-fired plants (not converted to LNG), that Hawai‘i Gas supplied LNG should be analyzed, and all new generation be competitively bid, a process that the Commission should revisit (p 6).
7. Further asserts that the Hawai‘i Electric Light preferred plan (pp 7–8):
   - Is uncertain and risky (p 7).
   - Is not a diversified renewable energy portfolio (even though Hawai‘i Island has more Class 7 (on public display) onshore wind resources, Maui installs four to five times more new wind resources) (p 7).
   - Doesn't include long-duration storage (p 7).
   - Doesn't fully address ancillary services (p 7).
   - Doesn't sufficiently include integrated energy districts or microgrids which should be considered for communities with health facilities for life safety (p 8).
   - Fails to deactivate fossil generation at the expense of burning biofuels which impedes transformation planning (p 8).

8. Considers the Maui Electric preferred plan more diversified; and finds the lack of pumped storage hydro coupled with cost-effective wind resources developed at North Point, South Point, Lalamilo, and Parker Ranch concerning (p 9).

9. Has retained the services of some of the nation's leading power systems engineers and energy economists—their modeling team based at Arizona State university—to develop an independent, objective, third-party integrated resource plan for Hawai'i Island, consistent with the 100% renewable energy target, that could potentially be extrapolated to other Hawaiian Islands, and further petitions the Commission to require the Companies to provide (through protective agreements or non-disclosure agreements) the information necessary for their modeling team to perform their work (pp 9–12).

Tawhiri Power Comments

Tawhiri Power filed comments in response to Order No. 33740. Those comments are summarized here.

1. Discussion on the PSIP Update should be delayed until future technical conferences can establish "best practices" to pave a concerted path for all involved (p 3).

2. A vertically-integrated utility model should not be relied upon for planning a transition from fossil-fueled generation to 100% renewable generation, as this is, at best, a first step. The process for creating the PSIP Update is largely a utility-based approach borrowed largely from mainland experiences that do not reflect the dynamics of Hawai'i's IPP and DER markets nor local county economics (p 3).

3. The next steps must assure the integration of non-utility generation alternatives that provide the least cost and most benefit for local economies (p 3).

Department of Business, Economic Development, and Tourism (DBEDT) Comments

The Department of Business, Economic Development, and Tourism (DBEDT) filed comments in response to Order No. 33740. DBEDT's comments are summarized here.

1. The PSIP should be a clear plan for delivering electricity and energy services, be approved by the Commission, and focus on a five-year action plan that also forms the basis for a long-term plan (p 5).

2. The Companies should continue to engage stakeholders and incorporate their input (forecasts, resource options, constraints, and framework) into your analyses (p 7).

3. The five-year plan must include an implementation timeline overlaid with other dependent dockets; clearly present all alternatives; await direction on interisland

transmission and LNG; base resources costs on agnostic ownership; include replacement renewable energy generation that is technology agnostic and ranked on such factors as dispatch time, delivery time, and energy cost; and be fulfilled through expeditiously issued RFPs. Their view of the five-year plan appears in a five-tiered table outlining RFPs for procuring renewables, grid-scale storage, general, and LNG overlaid with concurrent efforts (pp 7–12).

4. Individual case runs should not substitute for capacity expansion modeling by E3, which can be used to validate case run conclusions (p 12).

5. The PSIPs can be tested using the capacity expansion models to determine if there is a benefit to increased renewable adoption (p 15).

6. The Companies' approach to iteratively look at DER and DR based on costs resulting from proposed resources is positive (p 15).

7. The PSIP should include a comprehensive analytical framework of detailed and independent unbiased scenario analysis, as well as include a broad range of resource options, their costs, and their benefits (pp 12–13).

8. DBEDT cannot comment on the Component Plans (Appendix M: Consultant Reports of the *PSIP Update Report: April 2016*) nor on six of the eight Observations and Concerns (#1 and #4–#8) because they are contingent upon interisland transmission and LNG, two issues that remain unresolved (pp 14–15).

9. Observations and Concerns #2 and #3 can both be tested using capacity expansion models for increasing the pace of adopting renewables (pp 15–16).

10. While concurring with the need to modernize O‘ahu's generation fleet, DBEDT questions whether the proposed Kahe 3x1 CC power plant represents the best benefit to cost ratio, and recommends further analysis employing capacity expansion models be completed within 21 days—in other words, by July 8, 2016 (pp 16–17).

11. DBEDT questions the validity of several purported benefits of the Kahe 3x1 CC plant—reduced customer costs; avoided environmental compliance costs; improved fuel savings and efficiencies; avoided O&M costs; and lowered results from the calculations that determined fuels and heat rate savings, and capital recovery costs—and recommends more detailed analysis using more relevant cases that enable better comparison among options be completed within 21 days—in other words, by July 8, 2016 (pp 16–27).

12. How all available portfolio options were compared is unclear despite the analysis of over a hundred cases. For example, is the Kahe 3x1 CC a better option to a smaller build-out with fewer deactivations; or to using biofuels versus becoming a stranded asset in the face of alternative renewable options (p 18)?

13. DBEDT identified five procedural "next steps" that the Commission should consider:

- Continuing collaborate planning (p 27).
- Updating and improving "scenario analyses", including new resources, constraints, forecasts, and list of resources, when modeling especially with the RESOLVE O'ahu case runs (p 28).
- Developing an analytical framework within which all future analysis is performed, especially for capacity expansion modeling conducted by E3 with RESOLVE (pp 28–29).
- Conducting specific analyses for multiple interisland transmission options, including procurement, installation, interconnection, and grid update costs (pp 29–30).
- Developing specific work products and activities (such as a list of resources and a resource description template), and holding another conference to solicit stakeholders feedback on this process (pp 30–31).

14. DBEDT believes that the Companies should be required to (pp 31–32):

- File a comprehensive, complete, and final PSIP within 120 days—by October 15, 2016.
- Complete the interisland transmission analysis, and present its findings and recommendations within 120 day—by October 15, 2016.
- Provide further detail and analysis of a more granular Theme 3 (renewables without LNG) within 75 days—by August 31, 2016.
- Provide further detail and analysis about the Kahe 3x1 CC plant incorporating DBEDT's comments within 21 days—by July 8, 2016.

15. DBEDT recommends the Commission appoint an independent facilitator to monitor and provide specific guidance to the Companies in the completion of its PSIP (p 32).

AES Hawai'i Comments

AES Hawai'i filed comments in response to Order No. 33740, which also contain the substance of their letter to the Companies on May 31, 2016 following the Second Stakeholder Conference. AES's comments are summarized here.

1. The 2014 PSIP Preferred Plan sought to renegotiate the AES PPA and convert the plant to a 50/50 biomass and coal fuel mix, while the *PSIP Update Report: April 2016* cancels the PPA when it expires on September 1, 2022 (p 2).

2. Any phase out of the AES plant or premature PPA cancellation should not jeopardize electricity reliability (pp 4–5).

3. The methodology for retiring units and adding replacement generation is not transparent; the plans for LNG retrofits is not sufficiently justified and is at the expense of not seeking lower-cost grid-scale renewable resources (p 5).
4. The plan continues to grow Company-owned generation assets (Kahe 3x1 CC plant, Maui generation, and the HEP purchase). The Companies should not be allowed to avoid the competitive bidding framework without seeking lower-cost options (p 6).
5. Cancelling the AES PPA while proposing a transition to LNG should the Companies merge with NextEra shows plan bias (p 6).
6. Deactivating units, rather than retiring them, keeps them in the rate base, unnecessarily raising customer rates; because it is unclear that these units will be used for capacity planning (pp 7–8).
7. The filing of three applications on May 18, 2016 portend the Companies' implementation of the unapproved PSIP (p 8).

Division of Consumer Advocacy Comments

The Division of Consumer Advocacy (DCA) filed comments in response to Order No. 33740. Those comments are summarized here. The Consumer Advocate:

1. Strongly urges the Commission to consider an integrated, consolidated review of various resources (generation, DR, storage, and others) in lieu of the current fragmented approach (p 6).
2. Urges the Commission to focus on the five-year horizon that comprises the action plan and de-emphasize the need for a long-term plan (that is, years 6 through 30) because no one is capable of providing accurate and reliable forecasts for the next 30 years. The rationale: short-term actions are more salient and are more readily implemented, while long-term actions can and will be reviewed—and likely changed—in future iterations of the resource plans. The Commission should require all Parties to apply the same focus to develop an orderly and timely resource plan (pp 7–10).
3. Illustrates in Attachment A (pp 29–30) how the action plan can identify key decision points to determine how to proceed (p 11).
4. Recommends that the PSIP be viewed as the development of a decision tree that can be used as a tool within which to evaluate the reasonableness of any particular course of action (p 12).

5. Suggests procedural steps for the remainder of this proceeding as follows (p 13):

Procedural Step:	Date:
Stakeholder Conference	June 29, 2016
Technical Meeting 1	July 2016: second week
Technical Meeting 2	July 2016: fourth week
Simultaneous IRs	August 2016: first week
IR responses	August 2016: third week
Hawaiian Electric's Addendum Filing	August 1, 2016
Simultaneous IRs	September 2016: first week
IR responses	October 2016: third week
Final Statements of Position	November 2016: second week
Proposed Decision and Order	December 2016: second week
Hawaiian Electric response, if necessary	January 2017: second week
Final Decision and Order	January 2017: fourth week

6. Recommends comparing the results from different models (RESOLVE, SWITCH, and P-Month) using *the same set of inputs* (emphasis theirs) to establish consistency and optimized planning (p 17).

7. Recommends that stakeholders be given another opportunity (a two-week window) to review the modeling assumptions and provide proposed assumptions with supporting documentation (pp 18–19).

8. Contends that a "least cost" reference case where system costs are minimized irrespective of RPS and EEPS targets would provide a useful benchmark to compare against other plans (p. 19).

9. Recommends additional steps focusing on quantitative (and not qualitative) metrics should be taken to verify that the PSIP results are consistent with an optimized resource plan (p 21):
   - Analyze the optimal mix versus renewable penetration levels to minimize costs.
   - Analyze sensitivities on varying levels of resources (such as DR and energy storage).
   - Explain in detail the rationale for determining the optimum mix of generation build-out and deactivation.
   - Document how resource availability was determined.
   - Compare the Companies' results to those of its consultants.

10. Recommends the following actions be taken to minimize the cost of a generation build-out and deactivation (pp 23–24):
    - Evaluate how system security and reliability criteria affect costs.
    - Describe the methods used to minimize the cost of a build-out.
    - Review the sub-hourly and system hosting capacity analyses.
11. Recommends that plans including LNG must include a thorough assessment of the risks and costs of converting the Companies' current generators to burn natural gas (pp 24–25):
    - Describe how existing units will be converted, and what physical upgrades and changes are required.
    - Describe what equipment will be required to process LNG.
    - Identify conversion costs for each unit and costs associated with purchasing and building costs associated with the LNG facilities.
12. Contends that the role of resource ownership in the planning process must be revisited (pp 25–26).
13. Suggests that more work is necessary to identify grid monitoring and control challenges (pp 27–28); and recommends the following actions:
    - Clearly identify what problems are anticipated for an electrical grid with a large amount of renewable energy from a system security standpoint.
    - Identify what solutions are proposed to address these problems.
    - Provide a detailed description of the methods used to address the costs of solutions.

Hawaiian Electric Companies Comments

The Companies filed comments in response to Order No. 33740. Those comments are summarized here.

1. The *PSIP Update Report: April 2016* represents the Companies' best efforts to develop a plan to achieve 100% renewable energy by 2045 (pp 1–2).
2. The *PSIP Update Report: April 2016* outlines a five-year action plan that incorporated a complete grid transformation, considered numerous planning consideration (chief among them, changing our planning horizon from 15 years to 30 years), and that should be implemented in the short term to start on the road toward achieving 100% renewable generation (pp 2–5).

3. The Companies are working on a supplement to the *PSIP Update Report: April 2016* (as outlined in Chapter 9: Next Steps of that report) and moving to implement the five-year action plan (p 5).

4. The Companies plan to regularly update our resource plan to provide optimal pathways toward achieving the 100% renewable energy goal (p 6).

General Public Comments

There were 174 total responses from the general public to Order No. 33740 (two of which were submitted after the deadline). All but three of these 174 responses from the general public commented mostly on hierarchical issues surrounding the *PSIP Update Report: April 2016*. Table B-12 summarizes these comments.

Comment	Number
Against LNG transition	135
Greater environmental consideration (also against LNG for the same reason)	1
Supports LNG transition	3
Against smart meters (one is also against 100% renewables)	32
Supports pumped storage hydro (PSH) projects on O‘ahu and Maui	2
Commented on the initial statement of issues and the Observations and Concerns as they relate to Lana‘i (detailed in the narrative)	1
Total	*174*

Table B-12. Summary of General Public Responses to Order No. 33740

Two general public comments support pumped storage hydro (PSH) projects. One (by the Vice President of a company that develops "sustainable energy projects for Hawai‘i") supports PSH on Maui and O‘ahu; and one supports a complete transition of the Maui grid to two PSH systems (proposed by a company who also proposes to develop and build these systems).

One filing was submitted by Sally Kaye (as a personal statement), selectively commenting on the Commission's initial statement of issues and Observations and Concerns, on the Lana‘i preferred resource plan, and some general observations.

1. The Companies continue to signal their intent on ownership of power supply and generation instead of exploring alternative business models.

2. The Update does not adequately address the speculative nature of geothermal on Maui island.

3. The Update does not adequately explain the termination of the AES PPA, nor compare that decision with the cost of converting the plant to biomass, nor identify the renewable energy sources to replace the AES load.

4. The deactivation plan appears to unreasonably shift all risk to customers, and does not identify any customer benefit for the proposed nonbypassable recovery fee. In addition, it's unclear if the proposed consolidated rates would fairly assign deactivation costs to only those customers affected or borne by all customers.

5. The proposed Construction Work in Progress (CWIP) recovery mechanism (which is contrary to traditional regulatory "used and useful" and "placed-in-service" policies) is not subject to prudency reviews, time-limited collections, return of funds collected if construction is not completed, nor true-up measures.

6. At least for Maui island, the Update has not fully analyzed the most economical means for providing ancillary services as required by Observation and Concern #6.

7. The contention that O'ahu cannot provide for its own [renewable] energy needs is based on pure speculation and is not factually supported, and thus does not substantiate the need for analyzing interisland transmission.

8. The Lana'i preferred resource plan fails to adequately analyze or substantiate the details around installed wind energy in 2020, 2030, and 2045; acknowledges that the plan is not based on a complete financial model; fails to deactivate any generation assets; acknowledges uncertainty with the majority landowner plans; fails to fully analyze the DG-PV potential.

9. The PSIP Update contains a number of questionable actions: the implementation of more renewables at the expense of a long-term LNG commitment, a questionable financial position that has unadvisedly deferred capital expenditures, undervaluing energy efficiency, and incomplete consideration of customer preferences especially around siting replacement generation.

ORDER NO. 33740: PARTY INPUT AND OUR RESPONSE

The Commission issued Order No. 33740 inviting the Parties and "interested persons who are not Parties to this docket" to submit comments on our *PSIP Update Report: April 2016*, asking responders to focus mainly on the Initial Statement of Issues outlined in Order No. 33320.

As with Party responses to Order No. 33320, we organized their comments into 15 topics and responded to these topics in essentially the same way (as outlined in "How We Considered and Incorporated Input from the Parties" on page B-51).

Responding to Order No. 33740 Party Input

Table B-13 contains a cross reference between a Party filing and the 15 topics. A checkmark indicates that a Party commented on that topic; a dash means that they did not comment on the topic. The remainder of this section explains each topic and our response.

Party	1. PSIP Process	2. Independent Entity	3. Conferences	4. PSIP Input & Analysis	5. PSIP Generation	6. Capacity Expansion Models	7. Interisland Transmission	8. Fuels & Forecasts	9. DER & DG-PV	10. LNG	11. Renewable Energy on O'ahu	12. Microgrids	13. Energy Storage	14. Utility Ownership	15. Customer Retention Economics
CoH	√	√	√	√	√	–	–	–	–	–	–	√	–	–	–
CoM	√	√	√	–	√	√	√	–	√	√	√	√	√	√	√
DBEDT	√	√	–	√	√	√	–	–	√	–	–	–	–	–	–
DCA	√	–	–	√	–	√	–	–	–	√	–	–	–	√	–
AES	–	–	–	√	√	√	–	–	–	√	–	–	–	√	–
Blue Planet	√	√	√	–	√	√	√	–	√	√	√	√	√	√	√
DERC	√	√	√	–	√	√	√	–	√	√	√	√	√	√	√
Eurus	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
Hawai'i Gas	√	√	√	–	√	√	√	√	√	√	√	√	√	–	√
HPVC*	√	√	√	–	√	√	–	–	√	–	–	–	–	√	–
HREA†	√	√	√	–	√	√	√	–	√	√	√	√	√	√	√
HSEA†	√	√	√	–	√	√	–	–	–	√	–	–	–	√	–
LOL‡	–	–	–	√	–	–	–	–	–	–	√	–	–	–	–
NextEra	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
Paniolo Power	√	–	√	√	√	√	√	–	√	√	√	√	√	√	√
Puna Pono‡	–	–	–	√	–	–	–	–	–	–	√	–	–	–	–
REACH	√	–	–	√	–	–	–	–	–	–	–	–	–	–	–
Sierra Club	√	√	√	–	√	√	√	–	√	√	√	√	√	√	√
SunEdison	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
SunPower	√	√	√	–	√	√	–	–	–	–	–	–	–	√	–
TASC*	√	√	√	–	√	√	–	–	√	–	–	–	–	√	–
Tawhiri	–	–	√	√	√	–	–	–	–	–	–	–	–	√	–
Ulupono	√	√	√	√	√	√	√	√	√	√	√	√	√	√	√

* = HPVC and TASC jointly filed a response.
† = HREA and HSEA did not file individual responses, only signing onto the 'Ulupono et al' response.
‡ = Life of the Land and Puna Pono jointly filed a response.

Table B-13. Party to Order No. 33740 Input Topic Cross Reference

1. PSIP Process

Party Comments

All responding Parties but one request that the process for creating the PSIP be expanded and formalized to include their direct involvement to better enable a collaborative approach for creating the PSIP. This approach includes the Commission, the Parties, and the Companies working together to develop the PSIP. Toward that end, these Parties request that the Companies:

- Provide information to the Parties necessary for them to conduct their own independent modeling and analysis for developing independent resource plans, and to review, comment, and present specific alternatives to all input and modeling assumptions.
- Allow the Parties to submit questions that the Companies respond to in writing. If necessary, hold technical conferences to discuss and elaborate on these and other questions and responses.
- Incorporate the Parties' independent studies and analyses, as well as their alternative input and modeling assumptions, into the PSIP process.
- Incorporate impartial generation resource technologies and ownership.
- Present a draft PSIP to all Parties for review and comments, and transparently finalize the PSIP based on Party comments.
- File a PSIP focused on preferred resource plans and concomitant five-year action plans for each island served (identifying key decision points) whose steps are concurrent with all other relevant dockets. These action plans must form the basis for long-term (thirty-year) decisions.

Using this filed PSIP, the Parties recommend preferred resource plans and its five-year action plans. The Commission rules on all submissions, modifies them as they see necessary, and chooses preferred resource plans for the operating utilities. The Commission establishes dates to formally review the status and progress that each operating utility is making on its preferred resource plan.

Parties Issuing These Comments

County of Hawai'i, County of Maui, DBEDT, Consumer Advocate, Blue Planet, DERC, Hawai'i Gas, HPVC, HREA, HSEA, Paniolo Power, REACH, Sierra Club, SunPower, TASC, and Ulupono.

Our Action Regarding this Topic

Input assumptions are critical to sound modeling and analysis. Toward that end, we invested significant time, energy, and expertise to develop our resource cost assumptions

and all other input assumptions. To ensure the reasonableness of these estimates, we engaged NREL to conduct a third-party review.

Throughout, we have shared these modeling assumptions (including resource cost and fuel price forecast information) and posted it on our FTP (WebDAV) site so that all the Parties could access it. The Parties were free to use this information to conduct their own independent modeling and analysis (for instance, by running the SWITCH modeling tool) to develop independent resource plans.

Since the outset of this proceeding, we actively sought, on numerous occasions, the assistance of the Parties to provide input about resource cost assumptions and resource potentials that could be properly vetted and incorporated into the PSIP analyses. During that time, we have considered and incorporated input from several Parties: renewable energy cost assumptions from SunPower, LNG fuel price forecasts from Hawaiʻi Gas, PV and wind resource potentials for Oʻahu from Ulupono (Dr. Fripp), and wind and pumped storage hydro information from Paniolo Power. Other Parties have submitted input to us, which we have incorporated into our sensitivity analyses. (We thoroughly examine this information in "Input Incorporated into Our PSIP Update Report" starting on page B-13.)

The Parties have had numerous opportunities to submit comments and input to us for use in creating the PSIP. Since December 2015 and continuing through the end of October 2016, the Parties benefitted from the many opportunities to engage with us about all aspects of modeling, analyzing, and developing our PSIP. We have hosted three stakeholder conferences, four organized stakeholder meetings, a handful of scheduled conference calls, and dozens of extemporaneous and planned meetings with the Parties; and participated in four Commission-sponsored technical conferences. We invited the Parties to present at two of our stakeholder conferences: eight Parties did. We distributed the contact information of our PSIP Project Lead, inviting the Parties to email and call him. After filing our *PSIP Update Report: April 2016*, we also invited the Parties to submit comments and input about that PSIP after we discussed that report during our Second Stakeholder Conference.

Ulupono Initiative, through its work with Dr. Fripp, has presented findings from analyses produced using the SWITCH modeling tool. In discussions with Dr. Fripp, we learned this modeling developed a lowest cost, technically feasible result, however, the model didn't consider land-use, community, social, environmental, nor commercial issues. As a result, we re-evaluated the screening criteria for grid-scale PV, requested NREL to update and expand the inputs to its resource potential studies.

NREL subsequently revised their report (included in Appendix F: NREL Reports), adding a brief appendix, that explains the differences in results related to land-use assumptions.

In our modeling, we have worked to optimize DR, DER, and grid-scale resources while meeting the RPS requirements necessary to achieve 100% renewable generation by 2045. Cost and reliability are significant drivers in this optimization. For the April PSIP, we applied the Decision Matrix (outlined in Appendix C: Analysis Methods and Models) in meetings attended by three intervenors: Consumer Advocate, DBEDT, and County of Hawaiʻi to identify the Preferred Plans. (We posted all analyses output files on the FTP (WebDAV) site for Party access.) For the December 2016 PSIP, we are employing a process involving the RESOLVE and PowerSimm modeling tools, with interactions with the PLEXOS modeling tool, to evaluate and select final action plans.

Both the *PSIP Update Report: April 2016* and the subsequent *PSIP Update Report: December 2016* represents our concerted efforts to develop five action plans. These action plans consider and incorporate numerous planning options, including a complete grid transformation, to draw a roadmap for achieving 100% renewable generation by 2045 while stabilizing rates, and maintaining a secure and reliable grid. These action plans can be implemented in the near-term, and form the foundation for long-term planning.

Today's electric industry has become increasing dynamic; change, sometimes seemingly overnight, has become the norm. As such, we plan to regularly update the resource cost and other input assumptions necessary to adjust our PSIP to keep pace with these volatile circumstances.

2. Independent Entity

Party Comments

The responding Parties recommend the Commission appoint an Independent Entity to perform two fundamental functions:

- To direct the preparation of a customer-funded, public interest, resource plan.
- To monitor the PSIP proceeding, include the Parties as necessary, assess all inputs and models, revise operational parameters, and guide the completion of the PSIP.

The purpose of this dual path is to ensure an objective and productive planning process and to provide the Commission with a more complete assessment of resource alternatives and proposed capital improvements.

The Commission must also clarify the current process of creating the PSIP, and whether that process should be replaced with the IRP Framework, an Independent Entity, and an Advisory Group with its attendant safeguards.

Parties Issuing These Comments

County of Hawaiʻi, County of Maui, DBEDT, Blue Planet, DERC, Hawaiʻi Gas, HPVC, HREA, HSEA, Sierra Club, SunPower, TASC, and Ulupono.

Our Action Regarding this Topic

To develop the *PSIP Update Report: April 2016*, we created a Decision Matrix (see Appendix C: Analysis Methodologies of that PSIP report) that enabled us to define objectives, set requirements, and consider the various inputs and assumptions that feed into the PSIP planning and modeling, and best determine the quantity and timing of DER, DR, and grid-scale resources.

Using this Decision Matrix, we defined a number of hierarchical themes; defined an array of resource costs, input variables, and assumptions; and developed hundreds of candidate resources plans incorporating these input assumptions and numerous sensitivities. We performed this analysis using various models and cross-checked results to compare and contrast output, to better ensure the accuracy of our analysis and process. We then conducted a rigorous down-selection process (in the presence of the Intervenors) to methodically hone in on our preferred resource plans—all of which maintain system security with reasonable rates, and attain the renewable generation levels mandated by statute.

This decision-making process prioritized regulations and requirements, cost, reliability, renewable generation levels, and other decision priorities as directed.

We followed a different process for our *PSIP Update Report: December 2016*. Based on developments since April 1, 2016, many of the resource costs, inputs, and assumptions changed, as has our foundational themes (especially since NextEra's proposal to acquire the Companies was not approved by the Commission).

Throughout this entire process of over a year, we continually solicited input from the Parties, yet received little actionable input in return. We did receive input from a few Parties—Hawai‘i Gas, SunPower, Ulupono, and Paniolo Power of particular note—that, after some modification, was usable in our modeling analysis. The remaining bulk of Party input consisted of suggestions, comments, and concerns.

We are employing multiple industry-leading modeling tools—RESOLVE, PowerSimm Planner, and PLEXOS—to conduct the analyses necessary to develop our December 2016 PSIP. Two of our consultants, E3 and Ascend Analytics together with our resource planning team, are running these models. Our foundational set of input and resource cost assumptions, combined with the Party input (mentioned above), was then fed into these models to be analyzed. The models then chose the elements that comprise our five near-term action plans. (See Chapter 3: Analysis Approach for a detailed discussion of the process.)

Given this, unless relying on substantially different input assumptions, modeling tools, and decision priorities, it is unclear how a planning process directed and overseen by an Independent Entity would arrive at substantially different results and resource plans.

3. Stakeholder and Technical Conferences

Party Comments

Most of the responding Parties requested that the Companies hold another stakeholder conference. The purpose of the conference is to enable greater collaboration and increase dialog.

The Parties also requested one or more technical conferences to discuss the RESOLVE and SWITCH capacity expansion modeling tools, their inputs and assumptions, and how they can identify alternative generation resource mixes for attaining a 100% clean energy future; to review modeling input and assumptions; and to establish "best practices" to pave a concerted path for all involved

Parties Issuing These Comments

County of Hawai'i, County of Maui, Blue Planet, DERC, Hawai'i Gas, HPVC, HREA, HSEA, Paniolo Power, Sierra Club, SunPower, TASC, Tawhiri Power, and Ulupono.

Our Action Regarding this Topic

In response to requests from the Parties, we held a Third Stakeholder Conference on June 29, 2016. (We previously held stakeholder conferences on December 17, 2015 and on May 17, 2016.) At this third conference, four Parties gave presentations: Blue Planet, TASC, DBEDT, and Ulupono. Our consultant, E3, presented their RESOLVE modeling tool and the Companies mapped out next steps. The conference also enabled the Parties to engage in a discussion with us about topics of their choosing. (See "Third Stakeholder Conference: June 29, 2016" on page B-110 for details.)

We also held a series of stakeholder meetings from August through October 2016 to discuss Party input. (See "Stakeholder Meetings" on page B-123 for details.)

4. PSIP Input, Assumptions, and Analysis

Party Comments

About half the responding Parties submit that the *PSIP Update Report: April 2016*:

- Does not fully address the Initial Statement of Issues: 1.) Is not well-reasoned nor diversified enough, is predicted on attaining a predefined "end state", and does not provide useful nor complete analyses to inform major resource acquisitions; 2.) Insufficiently and inadequately addresses the seven Component Plans; and 3.) Does not adequately or sufficiently address all eight Observations and Concerns.
- Does not fully explain the means for financing capital expenditures nor the total financial implications for customers.
- Is largely utility-based and not in the interest of customers.

- Lacks a thorough analysis of Theme 3 (renewable generation without LNG).
- Does not adequately explain the AES PPA termination.
- In its deactivation plans, appears to unreasonably shift all risk to customers, does not identify any customer benefit for the proposed nonbypassable recovery fee, and appears to unfairly assign deactivation costs to all customers

These Parties submit that the PSIP should:

- Be a comprehensive analytical framework of detailed and independent unbiased scenario analysis, as well as include a broad range of resource options, their costs, and their benefits.
- Explain clear plan for delivering electricity and energy services.
- Include a benchmark "least cost" reference case (regardless of generation type) to be used for comparing other potential plans.
- Update the costs, quantities, and timing of LNG to those provided by Hawai'i Gas; as well as for energy storage and PV values provided by SunPower.
- Adjust many input assumptions—build-out and deactivation costs; system security and reliability criteria costs; sub-hourly and system hosting capacity inputs; system impacts of large amounts of renewable energy integration; load and demand shifting, energy storage, microgrids, geothermal, DER, and identification of sources input—and transparently detail their basis.

Parties Issuing These Comments

County of Hawai'i, DBEDT, Consumer Advocate, AES Hawai'i, Life of the Land, Paniolo Power, Puna Pono, REACH, Sally Kaye (personal statement), Tawhiri Power, and Ulupono.

Our Action Regarding this Topic

Addressing some of these comments would entail a significant amount of work and cost, and are nonetheless outside of the purview of Commission Orders. Absent Commission directives, we do not plan to address them. We have, however, addressed the remaining issues through our revised modeling analysis process (which is detailed in Chapter 3: Analysis Approach).

5. PSIP Generation Resources

Party Comments

Almost all responding Parties submit that low-cost, grid-scale, and customer generated renewable energy should first be pursued aggressively and optimized as foundational elements of a 100% renewable future. This renewable energy includes PV, DER

(including "smart" DERs), wind, geothermal, and hydro as well as energy storage, energy efficiencies, DR, and fuels such as biomass (including biofuels). In other words, a diversified portfolio of renewable generation that precludes and displaces fossil-fuel fired generation.

All other current and proposed fossil generation and generating units should be limited by the incorporation of this renewable energy into the PSIP resource plans. Unit deactivation plans, PPA terminations, and replacement fossil generation additions and retrofits (such as for LNG and the proposed Kahe 3x1 combined cycle plant) must all be considered against this aggressive renewable energy future. Analysis should include a safety valve (load bank) to control excess energy risks, reduce down reserves, and reduce curtailment of renewable resources.

The methodology for creating this energy future must be fully transparent and impartial, properly assess and value all generation options, defer and minimize capital expenditures, be competitively bid, fully identify the locations for siting all replacement generation and fully consider the cultural, environmental, and social impacts, assess the impacts on grid reliability and system security and implement appropriate measures to adequately address both, fully identify and address all financial implications and customer bill impacts, evaluate and address the tradeoffs between fossil and renewable generation, and consider customer preferences.

Parties Issuing These Comments

County of Hawai‘i, County of Maui, DBEDT, AES Hawai‘i, Blue Planet, DERC, Hawai‘i Gas, HPVC, HREA, HSEA, Paniolo Power, Sally Kaye (personal statement), Sierra Club, SunPower, TASC, Tawhiri Power, and Ulupono.

Our Action Regarding this Topic

Our directive is to develop a PSIP that provides "useful context and meaningful analysis to inform major resource acquisition and system operation decisions, and identify well-reasoned and adequately-supported plans and actions that will result in reliable energy services, meeting State clean energy requirements, while ensuring that costs and rates will be reasonable."[49] Our modeling tools select the resources and timing to achieve this directive. Renewable generation will be foundational to that plan, and will be implemented in a manner that best achieves our directive.

[49] Order No. 33877; *op. cit.*, at 7.

6. Capacity Expansion Modeling Tools

Party Comments

The comments for responding Parties are summarized as follows.

The RESOLVE and SWITCH capacity expansion models should be run simultaneously to model the costs and benefits of an increased pace for adopting renewable generation. The results of these models should then be compared, divergent results assessed, and a consistency established for creating an optimized resource plan. As an alternative, review the modeling and assumptions used by RESOLVE, indicate how SWITCH can supplement and improve RESOLVE, and ensure that RESOLVE is used transparently.

RESOLVE inputs should be free of artificial constraints, have its assumptions corrected or supplemented (such as the current unit deactivation schedule), include a more comprehensive analysis of the volatility of oil and LNG prices, and include a reference case for comparison's sake.

The process should embody real and substantial stakeholder participation and input. The Parties should be allowed to submit a limited number of information requests (IRs).

The results from the RESOLVE and SWITCH modeling and analysis should enable the Commission to evaluate each alternative resource plan, identify key factors, and make informed decisions for implementing each plan, especially over the next five years.

Parties Issuing These Comments

County of Maui, DBEDT, Consumer Advocate, AES Hawai‘i, Blue Planet, DERC, Hawai‘i Gas, HPVC, HREA, HSEA, Paniolo Power, Sierra Club, SunPower, TASC, and Ulupono.

Our Action Regarding this Topic

E3's analysis using RESOLVE was developed independently without input from the Companies. RESOLVE used only the resource cost and fuel price forecast assumptions that we posted to our FTP (WebDAV) site. An E3-written report describing how the RESOLVE modeling tool was employed in developing the December 2016 PSIP can be found in Appendix P: Consultant Reports. The FTP (WebDAV) site contains all the inputs necessary for the Parties to fulfill their own request: using the SWITCH model to conduct their own independent modeling and analysis to develop independent resource plans.

7. Interisland Transmission

Party Comments

The comments for the responding Parties are summarized as follows.

Any interisland transmission analysis must be considered against pertinent renewable alternatives for O‘ahu, including distributed energy storage systems (DESS) and battery energy storage systems (BESS)—using an adjusted value approach— as well as offshore wind. Interisland transmission should also be analyzed as creating a potential statewide grid through a comprehensive or selective two-way cable system among various islands. One general public commenter contends that O‘ahu can generate all of its energy needs from renewable resources, thus making moot the need for interisland transmission.

Parties Issuing These Comments

County of Maui, Blue Planet, DERC, Hawai‘i Gas, HREA, Paniolo Power, Sally Kaye (personal statement), Sierra Club, and Ulupono.

Our Action Regarding this Topic

Before analyzing interisland transmission, we requested NREL to update their studies on O‘ahu's renewable resource potential, and quantify the amount of offshore wind resources needed to potentially achieve 100% renewable generation on-island. (These reports are presented in Appendix F: NREL Reports.) In addition, E3 has run sensitivity analysis using the significantly higher resource potentials provided by Dr. Fripp. Our analysis incorporates our High-DER forecast, which assumes that all single family residential and 20 to 25% of commercial customers are net-zero where DG-PV production is equivalent to consumption. We are also in discussions with Google and Mapdwell to refine the technical potential of DG-PV using their high resolution satellite imagery and 3D modelling work.

With this information at hand, E3 analyzed available alternatives including interisland transmission. The results of this analysis can be found in "Interisland Transmission Copper-plate Plans" in Chapter 3: Analytical Approach.

8. Fuels and Forecasts

Party Comments

Hawai‘i Gas provided "alternative LNG prices"—correlating with the EIA AEO and STEO fuel forecasts used in the *PSIP Update Report: April 2016*—requesting their use in further PSIP analysis. Ulupono contends that the EIA AEO and STEO fuel forecasts are artificially low and highly volatile. As such, they should only be used in short-term (up to two years) analysis and evaluated, explicitly quantified, and assessed against the hedge offered by renewable resources to garner their true impact on planning.

Parties Issuing These Comments

Hawai‘i Gas and Ulupono.

Our Action Regarding this Topic

We fully understand that fuel prices and fuel price forecasts are volatile, and change over time. For our April PSIP, we relied on fuel price forecasts developed using the STEO forecast. We were attempting to demonstrate the impact of lower fuel prices on the resource plans to better understand whether LNG would still be cost effective with lower petroleum prices. We did this because EIA had yet to publish its 2016 Annual Energy Outlook (AEO) containing fuel price forecasts, and we didn't want to rely on the 2015 AEO forecast because those prices were significantly higher the 2016 actual pricing, and would have painted an inaccurate picture.

For our December 2016 PSIP, we updated our fuel price forecasts to incorporate the forecasts from the 2016 EIA Annual Energy Outlook. In addition, E3 has completed sensitivity analyses evaluating the hedge value of renewable energy (as requested by Ulupono) and the LNG fuel price forecast provided by Hawai‘i Gas.

9. DER and DG-PV

Party Comments

A majority of the responding Parties state that DER and DG-PV can provide a number of cost competitive benefits to customers and the electric grid. The PSIP analysis should:

- Integrate more DG-PV.
- Include emerging and expanded DER approaches, methodologies, and devices.
- Include smart-supply DERs.
- Consider both as increasing resources.
- Be quantified against other renewable and fossil-fuel investments.
- Examine the benefits of DER in providing ancillary services.
- Consider alternative and non-capital DER configurations to address integration and interconnection costs and to relieve system constraints.

Essentially, the PSIP analysis should treat DER and DG-PV as resources to be maximized.

Parties Issuing These Comments

County of Maui, DBEDT, Blue Planet, DERC, Hawai‘i Gas, HPVC, HREA, Paniolo Power, Sierra Club, TASC, and Ulupono.

Our Action Regarding this Topic

Our analysis does consider both the Market DG-PV and High DG-PV forecasts: for O‘ahu approximately 1,300 MW of market level DG-PV and approximately 2,100 MW of high forecast DG-PV. Market DG-PV is based on expected customer response to market pricing; High DG-PV includes all single-family residential customers and 20–25% of total commercial sales (assuming rooftop space constraints and challenges arising from property ownership). Our analysis has also considered increasing levels of DR and ultimately incorporated the High DER forecast into the resource plans. (See "DG-PV Energy Sales Forecasts" in Appendix J: Modeling Assumptions Data for DG-PV forecasts for all islands we serve.)

In addition, our analysis accounts for all interconnection and integration costs (which we fully describe in Appendix N: Integrating DG-PV on Our Circuits). Although we believe that our high DER assumptions provide a good high DG-PV penetration boundary for analysis of future situations, we are in discussions with Google and Mapdwell to better understand the technical potential of DG-PV using their high resolution satellite imagery and 3-D modeling work.

At the Technical Conferences and Stakeholder Conferences, we received input that another method is to estimate high forecast DG-PV based on available rooftop space. Performing a detailed investigation and analysis on this input would take some time to arrive at a reasonably accurate forecast. As such, we have taken this input as an action item to be performed for the next iteration of the PSIP.

While Party input hasn't stated a maximize level of market DG-PV, one Party (Ulupono, the only Party submitting input related to DER) has stated the expected high DG-PV forecast to be approximately 3,000 MW.

10. Liquefied Natural Gas (LNG)

Party Comments

About half the responding Parties feel that the Companies should immediately withdraw its three LNG-related applications, abandoning their plan to source LNG directly and, instead, collaborate with Hawai‘i Gas to import the fuel. Hawai‘i Gas, in its Order No. 33740 filing, presented a comprehensive plan (including adjusting its pricing structure to conform with those of the Companies) for such a collaboration.

Any resultant resource plan must thoroughly assess the risks and costs associated with importing and distributing LNG, including converting current generation units to burn LNG. In addition, the Parties request an assessment of what could be achieved by investing this sum entirely in a renewable generation infrastructure.

Parties Issuing These Comments

County of Maui, Consumer Advocate, AES Hawai‘i, Blue Planet, DERC, Hawai‘i Gas, HREA, HSEA, Paniolo Power, Sierra Club, Ulupono, and general public comments.

Our Action Regarding this Topic

As a direct result of the Commission’s dismissal of NextEra Energy’s application to acquire the Hawaiian Electric Companies and NextEra’s subsequent withdrawal from the PSIP docket, we have withdrawn our three LNG-related applications. All of these applications were predicated on NextEra’s direct involvement.

As indicated in our Motion for Clarification and our PSIP Work Plan, LNG is not included in the near-term action plan, but we have analyzed and included these analyses over the long-term with LNG in the December 2016 PSIP update to determine LNG’s impact in stabilizing and lowering costs for customers and in lowering emissions while aiding in the effective integration of more renewable energy.

11. Renewable Energy on O‘ahu

Party Comments

Several of the responding Parties commented on the various renewable resources included in the *PSIP Update Report: April 2016* for attaining 100% renewable generation on O‘ahu. These Parties stated that offshore wind must be reconciled with the Bureau of Ocean Energy Management’s (BOEM) efforts to lease offshore wind sites. The benefits and costs of onshore and offshore renewable generation options should be compared and contrasted with those of interisland transmission.

A general public commenter questioned the assumption that O‘ahu could not generate 100% of its energy needs from current renewable resources. Life of the Land, citing two EPRI studies, suggested that O‘ahu could obtain all of its renewable generation needs through current ocean wave energy technology.

Parties Issuing These Comments

County of Maui, Blue Planet, DERC, Hawai‘i Gas, HREA, Life of the Land, Paniolo Power, Puno Pono, Sally Kaye (personal statement), Sierra Club, and Ulupono.

Our Action Regarding this Topic

We have incorporated the revised resource potential provided by NREL into our analysis. To be feasible, all renewable technologies must exhibit fundamental attributes (further discussed in Appendix E: New Resource Options):

- Sound engineering design concepts.
- Commercial availability from a reputable vendor who can fully support the performance and servicing of the technology (including all balance of plant items) over its useful life.
- Demonstrated financial feasibility of a project employing the technology, including its benefits to customers, system needs, and integration costs—all of which would be stated in a competitive bidding process or waiver from same approved by the Commission.
- Ability of the project sponsor to demonstrate the financial wherewithal and technical capabilities to successfully finance, construct, and operate the project employing the technology.

Renewable generation options for O‘ahu is thoroughly discussed in Appendix H: Renewable Resource Options for O‘ahu. Additional information on these resources can be found in the following sections:

Grid-Scale Wind and Grid-Scale PV. Appendix F: NREL Reports fully discussed the possibilities, potential, and realities of on-island grid-scale PV and grid-scale wind on O‘ahu. Bottom line: while a theoretical maximum potential exists, the feasibility of realizing this maximum is much less certain.

Offshore Floating Platform Wind. Appendix H: Renewable Resource Options for O‘ahu fully discusses the potential and realities of this promising renewable resource. We remain engaged in BOEM’s leasing process and continue to monitor the overall viability of offshore wind for O‘ahu.

Interisland Transmission. See “Interisland Transmission” in Chapter 2: Commission Directives for a discussion about the analysis of interisland transmission among O‘ahu, Maui, and Hawai‘i Island. See “Interisland Transmission Copper-plate Plans” in Chapter 3: Analytical Approach for a discussion of the resources and results of E3’s interisland transmission analysis.

Hydrokinetic Energy. Ocean energy technologies are currently not feasible, nor do they appear to be in the near-future. See “Ocean Energy Technologies” on page B-46 for a rational discussion of these emerging technologies.

The combined results of our analysis appears in our near-term action plans, which detail how we plan to attain 100% renewable energy on O‘ahu.

E3 has also analyzed the higher onshore resource potentials provided by Dr. Fripp. Our long-range plans are completely flexible and open to multiple pathways for achieving 100% renewable energy; our near-term action plan does not preclude any future pathway, including new emerging technologies.

12. Microgrids

Party Comments

Half of the responding Parties state that the PSIP analysis should give greater consideration to microgrids, especially comparing their performance to the cost of grid services. Two Parties feel that integrated energy districts (microgrids)—should also be required for communities with health facilities for life, safety, and security.

Parties Issuing These Comments

County of Hawai‘i, County of Maui, Blue Planet, DERC, Hawai‘i Gas, HREA, Paniolo Power, Sierra Club, and Ulupono.

Our Action Regarding this Topic

A microgrid can be considered as a non-transmission alternative (NTA) to conventional transmission and distribution. There is a growing and important role for distributed sites to enhance energy resiliency and security—which we fully intend to exploit. Microgrids, including those on military sites interconnected and complementing the electric grid, can:

- 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, labor force, and housing necessary for major humanitarian response missions.
- Help ensure our ability to support core military missions, which are a key sector of our economy.

Three microgrids are currently in the plans for O‘ahu’s electric grid. The Schofield Barracks Generating Station, which broke ground on August 22, 2016, will contribute 50 MW to the grid and enhance our ability to integrate more renewable generation. We plan to design, permit, finance, build, own, operate, and lease at little to no cost, a new 54 MW generating station located on the Marine Corps Base Hawai‘i site in Kaneohe. We are also considering two concepts at Joint Base Pearl Harbor-Hickam: a 90 MW microgrid on base or a 100 MW power barge at the Waiau Generating Station that could be interconnected to the base from that site or temporarily relocated to the base under emergency conditions. The Airport Dispatchable Standby Generation (DSG) unit,

scheduled for completion in early 2017, offers 8 MW of emergency generation for the airport and limited duty dispatchable generation for the O‘ahu grid. (See Appendix D: Current Generation Portfolios for descriptions of these projects.)

The Queens Medical Center, with the only Level 2 Trauma Center in the Pacific, is also equipped with sufficient distributed generation to operate its Punchbowl campus as a microgrid. The Companies strongly supported this microgrid project.

13. Energy Storage

Party Comments

The Parties who signed the Annex A letter (see page B-70) expressed concern about a number of issues around battery energy storage and related information used in future analysis. Their concerns include:

- Adjusting forecasts for an increase (rather than a decrease) in distributed energy storage systems and accounting for their use in localized reliability and security.
- Thoroughly considering a wider array of energy storage options (such as hydrogen storage and thermal distributed storage), including its financial impact.
- Assessing energy storage’s value to ancillary services, over-generation, circuit-level issues, and operational flexibility (such as flexing the load curve, capturing excess energy, and shifting peak load).
- Updating the outdated, insufficient, and inaccurately high costs and amounts of energy storage.
- Comparing and contrasting the value of energy storage against interisland transmission.

The County of Maui suggested a specific situation to analyze: hardwiring a near-term market disruption from distributed energy storage systems, then iterate by modeling TASC’s dynamic resistive frequency control approach.

Parties Issuing These Comments

County of Maui, Blue Planet, DERC, Hawai‘i Gas, HREA, Paniolo Power, Sierra Club, and Ulupono.

Our Action Regarding this Topic

As we stated in our response to "11. Renewable Energy on O'ahu" (page B-104), we are only including currently viable technologies in our modeling analysis, which includes their current operational capabilities. As yet, this does not include technologies such as hydrogen storage and thermal distributed storage. Our "least regrets" near-term action plan is one where our long-range plans are completely flexible, so should this technology become cost-effective in the future, we can incorporate this—or any new technology—when appropriate.

14. Utility Ownership

Party Comments

Most of the responding Parties contend that the *PSIP Update Report: April 2016* suffers systemic deficiencies because of its main focus on preserving a traditional utility-centric business model, continued utility-owned new generation and utility capital spending, and a dependence on the NextEra acquisition. These Parties, instead, prefer a PSIP that embraces a customer-focused model, opening the possibilities to other types of resource ownership. All new generation options must be owner agnostic, cost-effective, and competitively bid. As such, planning and analysis should be separated from ownership issues.

Parties Issuing These Comments

County of Maui, Consumer Advocate, AES Hawai'i, Blue Planet, DERC, HPVC, HREA, HSEA, Paniolo Power, Sally Kaye (personal statement), Sierra Club, SunPower, TASC, Tawhiri Power, and Ulupono.

Our Action Regarding this Topic

The December 2016 PSIP update relies on owner agnostic generation options for its near-term action plans, except in special circumstances such as with the Department of Defense. Even in those special circumstances, construction for any utility-owned generation would, of course, be competitively bid and sources.

15. Customer Retention Economics

Party Comments

Several of the responding Parties state that the PSIP should recognize the value of keeping customers connected to the grid, and therefore should include an analysis for the potential and implications of customer retention economics, and present a substantial plan to encourage customers staying connected.

Parties Issuing These Comments

County of Maui, Blue Planet, DERC, Hawai‘i Gas, HREA, Paniolo Power, Sierra Club, and Ulupono.

Our Action Regarding this Topic

We fully understand and appreciate the importance of keeping customers connected to the electric grid. Customer exit results in reduced DG-PV capacity adversely affecting renewable generation on the grid, and ultimately raises prices to remaining customers. In addition, self-generating customers are not required to comply with state renewable generation goals. See Appendix Q: Customer Retention Economics for a discussion of this topic.

THIRD STAKEHOLDER CONFERENCE: JUNE 29, 2016

In response to comments received from our May 17, 2016 conference, we convened a Third Stakeholder Conference on June 29, 2016. We sent the following email to the Parties and other stakeholders informing them about this upcoming conference.

> Sent: Wednesday, June 01, 2016 5:48 PM
>
> Subject: PSIP Stakeholder Conference
>
> Aloha,
>
> Thank you for providing us your input to our forward-going PSIP work. We have reviewed input and feedback provided by several parties and would like to schedule a follow-up Stakeholder Conference. We are currently working on the logistics for the Stakeholder Conference and will provide a follow up email next week providing the date, time, and location once the details have been worked out. Thank you for your patience.
>
> Mahalo,
> Todd Kanja
> PSIP Lead

A little over a week later, we confirmed the date and time with this email.

> Sent: Friday, June 10, 2016 at 01:39
>
> Subject: PSIP Stakeholder Conference
>
> Aloha,
>
> Please be advised that the Hawaiian Electric Companies will hold a PSIP Update Stakeholder Conference on **Wednesday, June 29, 2016 from 10 am–3 pm.** Additional details, along with the meeting location and agenda for the conference, will follow.
>
> Mahalo,
> Todd Kanja
> PSIP Project Lead

Five days hence, we emailed the Parties, and other stakeholders, and the Commission about the format of the conference and inviting them to present their input in a formal presentation.

> Sent: Wednesday, June 15, 2016 at 15:15
>
> Subject: PSIP Stakeholder Conference
>
> Sending on behalf of Colton Ching, Vice President of Energy Delivery
>
> Aloha,
>
> Thank you for your continued participation in our Power Supply Improvement Plan (PSIP) planning process. Based on comments received from our May 17, 2016 Stakeholder Conference and May

> 31, 2016 request for Stakeholder input, we have scheduled a follow-up Stakeholder Conference on Wednesday, June 29, 2016, from 10:00 am to 3:00 pm. We are reaching out to you with some additional details for this conference, whose emphasis will be to provide Stakeholders an opportunity to provide input in the form of a formal presentation.
>
> As noted in our June 9, 2016 email, we are planning to start the meeting at 10:00 am and end it at 3:00 pm. We are planning to have a morning session (10:00 am–12:00 pm) and afternoon session (1:00 pm–3:00 pm) with a 1 hour break for lunch (on your own). In order to allow everyone an opportunity to participate in the meeting, we ask that presentations be kept to a maximum of 15 minutes and related to our forward-going work as described in Chapter 9 "Next Steps" of the PSIP Update Report: April 2016. We will adjust the agenda according to the amount of presentations we receive.
>
> If you plan to use slides or other visuals for your presentation, please send the electronic files by 12:00 pm, MONDAY, JUNE 27, 2016 to us at the email address provided below. Please note that this opportunity to present is optional and that there is no requirement that you prepare a presentation. If you wish to distribute hard copies to the stakeholders, please bring at least 30 copies.
>
> Although space remains limited, we will do our best to accommodate two representatives per organization to attend in person. In addition, we will also allow for participation via telephone conference. Unfortunately, the conference bridge does have limits, and for that reason, we will need to prioritize those who do not have a representative attending in person. We thank you for your understanding.
>
> If your organization wishes to attend this meeting, please RSVP no later than 12:00 pm, MONDAY, JUNE 27, 2016 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 individual who will be calling in.
>
> RSVP to:
> Heather Villamil
> (808) 543-5820
> heather.villamil@hawaiianelectric.com
>
> We are still working to secure a Hawaiian Electric meeting room in Downtown Honolulu for the conference and will let you know as soon as we have one. We look forward to seeing you at this meeting.
>
> Mahalo,
> Colton Ching

On June 25, 2016, we sent an email to the Parties, stakeholders, and the Commission detailing the specifics for the conference. Attached was an Excel file containing the revised new generation assumptions.

> Sent: Saturday, June 25, 2016 at 00:35
>
> Subject: Hawaiian Electric PSIP Stakeholder Conference
>
> Sending on behalf of Colton Ching, Vice President of Energy Delivery
>
> Aloha, Parties to Docket No. 2014-0183,

As a follow-up to our June 15, 2016 email, we would like to provide additional details about our upcoming PSIP Stakeholder Conference.

- Date, Time, Location: The Conference will be held on Wednesday, June 29, 2016, from 10:00 am to 3:00 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. Our building that houses the auditorium is a secured facility and a government issued ID is required for entry. Please arrive early to allow time for check in with the security guard (once you present your ID, you will receive a visitor badge).
- Purpose, Format: The purpose of this Conference is to provide Docket Parties with an opportunity to offer input in the form of a formal presentation. Like prior conferences, the Department of Business, Economic Development, and Tourism has agreed to moderate these discussions to facilitate open and constructive dialogue. To that end, the conversations that take place at this Conference are intended to be informal and not part of the official record in this docket.
- Ground Rules: As with the previous Conferences, we ask that no recording devices of any kind (video or audio) be used. Other ground rules are:
  - Listen and be open to all ideas
  - Always engage assuming no malicious intent, process is intended to be collaborative among the parties
  - Try to provide supporting facts/data whenever possible when making comments
  - Please silence all cell phones to avoid disrupting others
  - All dialogue should be directed through the facilitator
  - Leave preconceptions outside of the Conference
  - Avoid sidebar conversations so the stakeholders can remain engaged
  - Honor time limits so everyone has an opportunity to voice their thoughts

  Your acceptance of this invitation indicates your acceptance of these conditions.
- Presentations and Inputs: The Conference will consist of presentations by interested Parties, followed by a brief presentation by E3 describing our planned work on continued analysis of interisland transmission. We are planning to have a morning session (10:00 am–12:00 pm) and an afternoon session (1:00 pm–3:00 pm) with a 1-hour break for lunch (on your own). In order to allow everyone an opportunity to participate in the meeting, we ask that presentations be kept to a maximum of 15 minutes and related to our forward-going work as described in Chapter 9 "Next Steps" of the PSIP Update Report: April 2016. If you wish to provide resource information, we ask that the information be provided in the same format as our updated resource information, which is attached for your reference. We will adjust the agenda according to the amount of presentations we receive.

  As a friendly reminder, if you plan to provide a presentation at this Conference, please send the electronic files by 12:00 pm, MONDAY, JUNE 27, 2016 to us at the email address of Heather Villamil provided below. Please note that this opportunity to present is optional and that there is no requirement that you prepare a presentation. If you wish to distribute hard copies to the attendees, please bring at least 30 copies.

- Participation In Person and via Teleconference: Although space remains limited, we will do our best to accommodate two representatives per organization to attend in person. In addition, we will also allow for participation via telephone conference. Unfortunately, the conference bridge does have limits, and for that reason, we will need to prioritize those who do not have a representative attending in person. We thank you for your understanding.
- RSVP: If your organization wishes to attend this Conference, please RSVP no later than 12:00 pm, MONDAY, JUNE 27, 2016 to Heather Villamil. Her contact information is below. Please indicate who will be representing your organization, as only those who RSVP and are on the guest list will be allowed to check in. If you are unable to attend in person, please inform us if you will be participating via telephone conference and the name of the individual who will be calling in.

  RSVP to:
  Heather Villamil
  (808) 543-5820
  heather.villamil@hawaiianelectric.com

We look forward to seeing you at this Conference.

Mahalo,
Colton Ching

Two days later, we again emailed the Parties, stakeholders, and Commission with the conference agenda, and attached the PSIP fuel price forecasts for our three operating utilities that we were using in our current analysis.

Sent: Tuesday, June 27, 2016 at 01:41

Subject: Hawaiian Electric PSIP Stakeholder Conference

Sending on behalf of Colton Ching, Vice President of Energy Delivery

Aloha, Parties to Docket No. 2014-0183,

Based on the responses we have received to present as of 4:00 PM today, we have set the agenda for Wednesday's PSIP Stakeholder Conference.

Agenda

Introduction – 10:00 AM to 10:15 AM

Morning Session – 10:15 AM to 11:45 AM
1. E3 – Interisland Transmission Scope Presentation
2. DBEDT Presentation

Lunch (On your own) Break – 11:45 AM to 12:45 PM

Afternoon Session – 12:45 PM to 3:00 PM
1. Recap of Morning Session (DBEDT)
2. Ulupono Initiative Presentation
3. TASC Presentation
4. Hawaiian Electric Presentation

Reminders

The Conference will be held on Wednesday, June 29, 2016, from 10:00 am to 3:00 pm (Lunch on

your own from 11:45 AM-12:45 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. Our building that houses the auditorium is a secured facility and a government issued ID is required for entry. Please arrive early to allow time for check in with the security guard (once you present your ID, you will receive a visitor badge). The security guard will allow entry to those parties who RSVP'd and are on the guest list.

Ground Rules: As with the previous Conferences, we ask that no recording devices of any kind (video or audio) be used. Other ground rules are:

- Chatham House Rules apply (participants are free to use the information received, but neither the identity nor the affiliation of the speaker (s), nor that of any other participant, may be revealed)
- Listen and be open to all ideas
- Always engage assuming no malicious intent, process is intended to be collaborative among the parties
- Try to provide supporting facts/data whenever possible when making comments
- Please silence all cell phones to avoid disrupting others
- All dialogue should be directed through the facilitator
- Leave preconceptions outside of the Conference
- Avoid sidebar conversations so the stakeholders can remain engaged
- Honor time limits so everyone has an opportunity to voice their thoughts

Your acceptance of this invitation indicates your acceptance of these conditions.

- Updated Fuel Price Forecasts utilizing the EIA Annual Energy Outlook 2016 Early Release (Reference) are attached for your reference. Please note that these forecasts have been posted to the PSIP WebDAV site.

We look forward to seeing you at this Conference.

Mahalo,
Colton Ching

The day before the conference, we emailed a revised agenda.

Sent: Tuesday, June 28, 2016 at 23:13

Subject: Hawaiian Electric PSIP Stakeholder Conference

Aloha,

Please note that tomorrow's agenda has been revised as noted below.

Revised Agenda

Introduction – 10:00 AM to 10:15 AM

Morning Session - 10:15 AM to 11:45 AM
1. Blue Planet Presentation
2. TASC Presentation
3. DBEDT Presentation

> Lunch (On your own) Break - 11:45 AM to 12:45 PM
>
> Afternoon Session – 12:45 PM to 3:00 PM
> 1. Recap of Morning Session
> 2. Ulupono Initiative Presentation
> 3. E3 – Interisland Transmission Scope Presentation
> 4. Hawaiian Electric Presentation
>
> Thank you,
> Todd

In response to a Party member request, we emailed all invited stakeholders with attachments of the presentations listed on the agenda.

The evening after the meeting concluded, we emailed conference participants with a summary of the proceedings, a call for additional input, all the presentations attached (again), and an Excel file attached (again) containing our new generation assumptions to be used as a format for subsequent input from the Parties.

> Sent: Wednesday, June 29, 2016 7:25 PM
>
> Subject: Hawaiian Electric PSIP Stakeholder Conference
>
> Sent on behalf of Colton Ching, Vice President of Energy Delivery
>
> Aloha, Parties to Docket No. 2014-0183,
>
> Thank you for your participation in yesterday's (sic-today's) stakeholder conference! We are especially grateful to Dr. Matthias Fripp, Steven Rymsha, Chris Yunker, Kyle Datta, Jerry Sumida, and Jeremy Hargreaves for taking the time to develop and share their presentations, and to Mark Glick once again for his leadership in facilitating the group's discussion. Since the presentations were sent out over multiple emails leading up to the stakeholder conference, we are attaching all of them here once more for your convenience.
>
> As stated during my presentation, we welcome additional inputs for our analyses by Wednesday, July 6, 2016. If you wish to offer resource information, please provide it in the same format as our updated resource information, which is attached for your reference (see Excel file), and send it to Todd Kanja, Hawaiian Electric's Project Lead for the PSIP Update. Todd can be reached at: todd.kanja@hawaiianelectric.com and (808) 543-4329.
>
> Mahalo!
> Colton Ching

Two days later, we emailed the Parties the revised NREL report included in our *PSIP Update Report: April 2016*, pointing out the pages and maps that were being revised.

> Sent: Friday, July 1, 2016 at 13:31
>
> Subject: Hawaiian Electric PSIP Stakeholder Conference
>
> Aloha,
>
> As a follow-up to discussion regarding the NREL resource potentials during yesterday's Stakeholder Conference, we wanted to clarify that the grid-scale onshore wind potential and grid-scale solar PV

> potentials for the islands of Hawai'i, Maui, and O'ahu can be found in Appendix F, pages F-24 and F-25. These are the resource potentials used in the preferred plans. We would also like to note that the Utility Scale PV Development Potential Maps on pages F-39 through F-46 are not correct and will be updated. We will ask NREL to update these Development Potential Maps to match with data provided on pages F-24 and F-25.
>
> Mahalo,
> Todd

On July 5, 2016, we sent our final email to the Parties concerning the conference. In it, we attached our notes from the conference's proceedings and the revised NREL report.

> Sent: Tuesday, July 5, 2016 at 15:47
>
> Subject: Hawaiian Electric PSIP Stakeholder Conference - Flip Chart Notes and Corrected NREL report
>
> Aloha,
>
> Hope you all had a safe and enjoyable 4th of July weekend! As a follow-up to last week's PSIP Stakeholder Conference and June 30 (sic), 2016 email, please find attached 1) Flip Chart Notes from the conference and 2) updated NREL resource potential report with corrected pages F-39 through F-46. As a friendly reminder, if you would like to submit resource cost information, please do so by July 6, 2016. We ask that the information be provided in the same format as the resource cost information spreadsheets provided in our June 24, 2016 and June 27, 2016 emails.
>
> Mahalo,
> Todd

Conference Proceedings: Third Stakeholder Conference

Colton Ching, Vice President of Energy Delivery at the Hawaiian Electric Companies, introduced Mark Glick from DBEDT who would be moderating the conference. Mr. Ching that the Companies would be assessing cost information received from SunPower and Hawai'i Gas, as well as all the comments and input received as a result of our May 17, 2016 conference and Order No. 33740.

Mr. Glick began by stating his appreciation for this conference so that the Parties could comment and provide feedback to any outstanding issues. We expect to come up with an optimized analysis that creates the lowest cost plan that explores DER and storage. Mr. Glick then introduced the people and organizations giving presentations.

After the lunch break, Mr. Glick summarized the proceedings from the morning, reviewing each of the three presentations and providing some overall comments about the task of creating a Power Supply Improvement Plan.

Presentations: Third Stakeholder Conference

This section summarizes the main point from the presentations given at the Third Stakeholder Conference.

Blue Planet

Dr. Matthias Fripp, University of Hawaiʻi Manoa, presented on behalf of Blue Planet (see page B-188 for the slides). He made these points during his presentation:

- The iterative process for creating and validating the assumptions used for analysis needs greater transparency, such as a technical committee to vet the data.
- Multiple models (such as SWITCH and RESOLVE) should be run to provide different perspectives and allow for richer results.
- The risk and uncertainty of customer rates needs more analysis, especially when comparing long- and short-term costs, the resultant savings from both, and their relative stability.
- NREL's assumption of 500–600 MW potential for grid-scale solar on Oʻahu pales in comparison to our estimates.
- Agreement among the Companies and the Parties is needed to effectively handle uncertainty and cost projections.

TASC

Steve Rymsha presented on behalf of TASC (see page B-192 for the slides). He made these points during his presentation:

- Incorporate renewable spinning reserve, smart homes, and flywheels or bulk energy storage to the modeling analysis.
- Model distributed load banks and their locations as a means to not change current generation resources or grid infrastructure.
- Pilot the strategy being employed on Tasmania (two 1.5 MW systems) using load banks by starting with Molokaʻi and determining how it can be expanded to other islands.
- Rather than curtailing, allow energy to flow onto the grid by employing substations with resistive response capabilities.

DBEDT

Chris Yunker presented on behalf of DBEDT (see page B-196 for the slides). He made these points during his presentation:

- Consider cost, reliability, social impacts, and island-specific resources in the interisland transmission analysis at a high level first to better avoid excess analysis

paralysis; analyze further the impact and cost of cable configurations and redundancy that are critical to reliability; and analyze the impact on terminus grids.

- Compare and contrast the viability, desirability, timing, capabilities, and cost of our interisland transmission with those of the much larger mainland examples by engaging the companies involved in their planning and implementation.
- Analyze the baseline system requirements for the 3x1 combined cycle Kahe unit as well as the cost recovery timeframe (including $50 million for early deactivation).
- Initiate the procurement process for renewable generation, together with DER and DR as all need long-term planning to be fully realized. Use models to analyze the potential for various renewable options.
- Consider the future prospects for energy storage (see the related Navigant study).

Ulupono

Kyle Datta presented on behalf of Ulupono (see page B-202 for the slides). He made these points during his presentation:

- Model battery energy storage earlier in the preferred plans, especially when planning to attain the 30% and 40% RPS scenarios.
- Review the plan's costs (especially transmission costs) which appear too low compared to other's analysis, and do not include customer service costs.
- Model the impact of integrating 100% renewables earlier in the planning period.
- Analyze the risk of the stranded costs of grid-scale solar versus DG-PV.
- The costs for installing and operating grid-scale solar must be closely monitored to ensure their lower costs when compared to continued DER installations.

E3 (Energy and Environmental Economics)

Ren Orans and Ana Mileva presented on behalf of E3 (see page B-205 for the slides). They made these points during their presentation:

- Interisland transmission analysis includes cost, redundancy decisions, individual island reserve constraints, and resultant benefits from different configurations. Other issues to analyze include the maximum benefits and their related costs, depth and path of the cable, available resources on Maui and Hawai'i Island including siting locations and grid connections, and grid upgrades necessary for a cable interconnection (especially Hawai'i Island). A thorough market and development feasibility study must be conducted.
- Curtailed renewables should offer reserves, and could be eliminated with storage or with better control (although that must be assessed).

- NREL's resource potential for O'ahu needs further analysis to better understand their outcomes and benefits across all islands.
- Advanced storage, including hydrogen, can be modeled. Hydrogen, however, has an extremely large draw on renewable generation, must be optimized in wind and seasonally, and can affect spinning reserves.
- Renewable resources for each island must be identified and located using potential resource studies and NREL studies that include high-level maps, including detailed community work necessary to site resources.

Hawaiian Electric

Colton Ching presented on behalf of the Companies (see page B-218 for the slides). He began by reviewing the timeline for the PSIP Update beginning with November 2015 and carrying through September 2016. Mr. Ching:

- Summarized the energy storage and PV cost information received from SunPower and the LNG forecast and supplier from Hawai'i Gas.
- Displayed graphs that compared the PSIP Update cost assumptions for PV and energy storage with those provided by SunPower, and discussed how these differences would be analyzed.
- Presented the next steps for the Companies in continuing to update our PSIP, focusing on an updated analysis with new fuel price forecasts and resource cost assumptions, additional system security analyses, interisland transmission, and offshore wind, plus additional risk premium stochastic analysis and sub-hourly analysis.
- Stated September 30, 2016 as the revised filing date.

Action items: Third Stakeholder Conference

The following action items were identified at the Third Stakeholder Conference:

- E3 will distribute its assumptions and inputs, including how their model operates (through the FTP site currently being used to distribute information to the Parties) so long as it doesn't contain proprietary information.
- The Companies will cite the NREL reference in the upcoming PSIP filing, and will conduct a sensitivity analysis to compare our PV costs assumptions against those presented by SunPower.
- The Parties will submit any addition input (with source documentation) by July 6, 2016.

TECHNICAL CONFERENCE #1 AND #2

The Commission scheduled two additional conferences, called Technical Conference #1 and Technical Conference #2.

Technical Conference #1: September 21, 2016

In Order No. 33877, the Commission established an updated procedural schedule that included, among a number of directives, the convening of two technical conferences. The purpose of these conferences, chaired by Commission staff, was "to enable the commission to interact directly with the HECO Companies' planning team, and to facilitate the finalizing of the PSIPs."[50] The Commission also invited the Parties to propose questions and suggest alternative modeling inputs, assumptions, methods, and analytical approaches." The Parties responded with over 200 questions and other suggestions for the Commission.

At the conference, the Companies were prepared to respond to each of these questions.

David Parsons, Chief of Policy and Research for the Commission, moderated the meeting. Carl Freedman conducted the meeting. Colton Ching was the main representative for the Company. As directed, all Company consultants and members of the resource planning team attended the conference, either in person or through the conference telephone bridge.

Commission staff and representatives asked all of the questions during the conference, few of which touched on the 200+ Party questions. Mr. Freedman and Mr. Parsons asked the vast majority, with Jay Griffin and Matthew McDonnell contributing a few; little additional guidance was offered. Mr. Ching responded to many questions, with Company staff and outside consultants responding to questions specific to their areas of expertise.

The conference focused on four areas: optimization and overall modeling approach; resource options; ancillary services and system security; and inputs, assumptions, uncertainty, and risk. The conference lasted all day. There were no presentations.

Various representatives of the Companies, including consultants, responded to questions. They:

- Described the modeling process that we published in our Work Plan, and the input assumptions and sensitivities we plan to run in the modeling analysis. They stated

[50] Order No. 33877; *op. cit.* at 32.

that the process for developing the five near-term action plans (one for each island we serve) is integral to the modeling process.

- Reiterated that LNG will not be part of the near-term action plans, but we are modeling its inclusion for long-term planning. As a result, no unit modifications will be undertaken in the near-term.
- Stated that the RESOLVE optimization model is being used for our analysis, and discussed in detail many input assumptions, resources, and other variables being used in the model, and the results that they produce—all of which are being used to develop the updated PSIP.
- Described how the least-cost plan is being developed.
- Explained how DR and DER is being used as inputs to the RESOLVE model to run detailed production simulations to develop retail rates.
- Discussed the roles that DG-PV, curtailment, legacy programs (such as NEM, SIA, and FIT), current programs (CSS and CGS), fuel forecasts (including LNG), energy storage (including pumped storage hydro), grid-scale PV, grid-scale wind, Federal and state energy tax credits, O‘ahu renewable resource potentials, electric vehicles, unit deactivations, IPPs and PPAs, ancillary services, and system security have in our modeling analysis.
- Explained how the PowerSimm Planner modeling tool complements RESOLVE, and is being use to run multiple models for a richer mosaic of potential results.
- Described in detail our system security analysis, its models, its complexity, its depth of analysis, and its consideration of risks and trade-offs.
- Delineated how risk and uncertainty are being addressed and being incorporated systematically, and how a risk premium is being developed for use in our modeling.
- Listed the various stakeholder input that was considered for our analysis, especially input from SunPower, Ulupono and Dr. Fripp, Paniolo Power, and Hawai‘i Gas.
- Explained how we are analyzing customer retention conomics using, in part, the customer update model to determine how it drives behavior

The overall impression was that of a productive meeting.

Technical Conference #2: October 3, 2016

In many respects, this second technical conference mirrored the first. The Parties again submitted about 200 questions, some the same questions because Commission representatives and staff didn’t address them at Technical Conference #1.

As in the previous technical conference, Mr. Parsons moderated, Mr. Freedman ran the conference, and Mr. Ching represented the Company. Commission staff again asked

virtually all of the questions; Mr. Ching, Company staff, and outside consultants responded to questions in their areas of expertise.

The meeting began with this prescient announcement from Caroline Ishida, the Commission's Chief Counsel: "…the Commission is considering deferring action on pending G.O. 7 dockets before the Commission pending the outcome of this meeting providing clarity on the PSIP process."

Mr. Parsons began by acknowledging that "long-term resource planning is a challenging and complex process", and that the Companies have integrated "a significant amount of change and best practices" and are continuously improving its modeling and analysis process. He continued by stating a fundamental principle of which we at the Companies are fully cognizant: resource planning is a fundamental responsibility, an essential function of business, and one that must be continuously fulfilled; an ongoing process.

Mr. Parsons continued by expounding and expanding on Commission guidance that the Companies must follow:

- Review and comply with directives in previous Orders.
- Transparently and credibly develop the PSIP and resultant action plans.
- Address Party input and other factors (such as DER, DR, fuel price volatility and risk, and others) with sensitivity analysis.
- Demonstrate how the Companies will stabilize and lower costs to customers, more aggressively seek lower cost renewables, improve the modeling of distributed resources and ancillary services, improve the analysis of fossil fuel generation resources, evaluate the costs of achieving different reliability and system security standards, and squarely address customer implementation risks.
- Develop near-term action plans (potentially updated annually) that map a path forward and form a foundation for longer-term analysis and planning.

As with Technical Conference #1, various representatives of the Companies, including consultants, responded to questions. They:

- Discussed the sensitivities being included in our modeling analysis, adjustments made for smaller sized grids on Lana'i and Moloka'i, optimization choices, and how long modeling takes.
- Explained how some system security analysis can be performed simultaneously with the modeling analysis (and hopefully not repeated), but that much must wait for a plan to be complete. Fully conducting system security analysis is a time-consuming process; for instance, it takes at least two weeks to analyze just frequency for each plan.

- Enumerated many of the factors being analyzed in our modeling: interisland transmission, solar and wind resource potential and profiles, DER update, ancillary services, LNG and other fuels, pumped storage hydro, DG-PV, CSS and CGS, transmission and distribution, demand response, as well as many others.
- Explained that, because of Paniolo's outdated input assumptions and forecasts as well as missing information from their Siemens reports, we used other available information to analyze pumped storage hydro.
- Discussed conversations with various Party members about their input.

Commission representatives closed by reiterating some Commission directives. The conference ended early.

STAKEHOLDER MEETINGS

From August through October 2016, we held four meetings with the certain Parties essentially to discuss input assumptions and our modeling analyses process. These meetings were open to all Parties to attend.

First Stakeholder Meeting: August 30, 2016

On August 23, 2016, DBEDT contacted us to schedule a meeting with the Parties in the upcoming weeks. We readily accepted. A two-hour meeting was then scheduled for August 30, 2016.

In an email, Ulupono suggested the following agenda:

1. Purpose of the meeting
2. Understanding the PUC Order
3. How methodology builds on Appendix C
4. How assumptions verification process differs from work to date
5. Hawai'i Island approach
6. Specific workgroups (DER/renewable/fossil/methodology)

There were three attachments to the email: a suggested PSIP methodology, an accompanying flowchart, and an application of the suggested methodology for Hawai'i Island.

The suggested PSIP methodology consisted of four steps. 1. Define the major large-scale infrastructure and policy choices that significantly impact the electrical systems, then develop a matrix to define various possibilities. 2. Convene specific workgroups to develop input assumptions (such as resources, fuels, loads, and capital costs). 3. Iterate a

capacity expansion model with system reliability models, DER models, and risk and volatility algorithms to select a least-cost resource plan. 4. Determine the actions that must be implemented over the near-term that best enables the 100% renewable generation goal to be attained.

Representatives from Blue Planet, DBEDT, Hawai‘i Gas, Paniolo Power, Sierra Club, and Ulupono, plus Hu Honua, together with representatives from the Companies, attended the meeting. Discussion during the meeting followed the suggested agenda.

The Parties wanted to meet to discuss the work plan we would file on September 7, 2016, and to provide input to our modeling analyses. During the meeting, we discussed the purpose of the PSIP, the potential for the planning process to be collaborative, the purpose of the PSIP proceeding, and the intent of the near-term action plans that are central to the PSIP. We also discussed how capacity expansion modeling builds on the analysis methodologies (described in Appendix C: Analysis Methodologies of our *PSIP Update Report: April 2016*), its advantages, and its shortcomings. Paniolo Power described how the suggested PSIP methodology can be applied to the modeling analysis for Hawai‘i Island. A final discussion involved establishing workgroups.

All attendees agreed to schedule another meeting to continue the discussion, especially on the remaining agenda topics.

Second Stakeholder Meeting: September 13, 2016

The influence of hurricanes Madeline and Lester delayed the scheduling of this Second Stakeholder Meeting. The meeting was ultimately scheduled the day before the Parties were required to submit questions in preparation for Technical Conference #1.

The Companies made clear that only representatives attend subsequent stakeholder meetings. We took exception to a representative from Hu Honua being invited and then attending the First Stakeholder Meeting, as well as our not being notified of their attendance. Hu Honua is not an approved participant in PSIP Docket No. 2014-0183, and thus is not beholden to nor required to execute a Protective Agreement as directed in Protective Order No 33588. Hu Honua’s attendance hindered an open and candid discussion, and cast a shadow on a collaborative process. The Parties agreed “to err on the side of respect and process” and limit attendance at subsequent meetings to “participants and intervenors”.

Attendees at this Second Stakeholder Meeting included representatives from Blue Planet, County of Hawai‘i, DBEDT, Paniolo Power, Sierra Club, and Ulupono together with representatives from the Companies. We continued discussing the previous meeting’s agenda items.

The meeting focused on the clarity of and a discussion about the modeling analysis process and its input assumptions. The discussion featured representatives from the Companies' consultants E3, Ascend Analytics, and Black & Veatch. The discussion also began scrutinizing various input assumptions, including LNG, DER, DG-PV, energy storage, offshore wind, and electric vehicles. Operational and customer-related risks as well as meeting ancillary service requirements were also discussed.

The discussion began ascertaining that the key points for the Hawai'i Island suggested methodology had been fully covered. Next, we explained how Ascend Analytics would quantify risk by developing a risk premium to iterate in subsequent analysis. The concept of working groups was further explored. The Parties felt that working groups should be formed to develop analysis scenarios, input assumptions, technologies, and specific modeling methodologies for the special issues facing Hawai'i Island and Maui island.

The discourse turned to analyzing the regulatory process, how topics from these meetings could be communicated to the Commission, and how the schedule could potentially be altered. Other topics inquired as to whether we were analyzing load shifting batteries, DER and DR optimization, and interisland transmission; we did.

Everyone agreed that E3, Ascend, Black & Veatch, and Dr. Fripp should attend a Third Stakeholder Meeting to discuss, in greater depth, the modeling analysis.

Third Stakeholder Meeting: September 22, 2016

The day after Technical Conference #1, the Companies and Parties held their third meeting to review the conference proceedings and to continue the discussion from previous meetings. The following agenda was created and adhered to during the meeting.

Agenda for Joint Parties Discussion	
9:00–9:45	Clarity on Process ▪ Can methodology by modified. ▪ Can changes in the input assumptions be incorporated into the models. ▪ If not, explain how proposed changes would be incorporated into "scenarios"? ▪ Do your responses change if PUC added more time to the schedule. If so, how much time would be needed?
9:45–12:30	Methodology Discussion Explicit inclusion of fuel risk into optimization: ▪ Treatment of risk by Ascend: Explain methodology for calculating the risk premium and quantify your answer. ▪ Explain precisely how this is added to the NPV revenue requirements. ▪ Explain what the short term risk premium is based on?

	▪ Explain how these will be (or already have been): • Incorporated into E3 Resolve. • Built into PowerSimm. Discussion of alternative approaches to incorporating risk. Selection of 5 year plans in the context of long term direction. Integration and iteration between models: ▪ Funnel approach vs. integration/iteration approach. ▪ Integration of simplified risk, PV/storage/EV adoption, DR into the power optimization model. Identification of Ancillary Services Requirements: ▪ Analysis in model. ▪ Calculation and validation of reserve requirements for wind and solar forecast errors. ▪ How shortfalls are used to revise capacity models. ▪ How requirements are translated into near term actions. Scenarios.
12:30–1:30	Lunch Break.
1:30–3:00	Critical Inputs Assumptions: ▪ LNG ▪ Solar PV ▪ Storage ▪ Offshore Wind ▪ DER ▪ EV
3:00–3:30	Summary and Next Steps.

In-person and conference call bridge attendees at this Third Stakeholder Meeting included representatives from Blue Planet, DBEDT, Consumer Advocate, Hawai‘i Gas, Life of the Land, Paniolo Power, Sierra Club, and Ulupono together with staff and Company consultants: HD Baker, Solari Communication, Ascend Analytics, Black & Veatch, and E3. Almost the entire agenda was covered during the meeting, the only exceptions being the last four items of the Critical Inputs Assumptions which were covered in the Fourth Stakeholder Meeting.

We verified that our modeling analysis—hourly and sub-hourly—considers all aspects raised by the Parties: DG-PV uptake, DER and DR uptake, energy storage, load profiles, PV production profiles, tariffs, export rates, future grid programs, PV cost curves, storage cost curves, tax credits, fuel options, addressable populations, customer rates, inflation rates, cost of capital, numerous risk factors, integration costs, DR program benefits, EV projections and adoption, PV plus storage, economics and customer uptake relationships,

avoided costs, alternative technologies, sales forecasts—nothing that could bias the results is being omitted.

Most of the meeting's discussion focused on dissecting our input assumptions; the modeling process of RESOLVE, PowerSimm Planner, and PLEXOS; the DR analysis, and how our analyses results in a near-term action plan and a foundation for long-term planning.

Despite Party protestations to the contrary, we explained how we have been fully transparent in our planning and modeling analysis. We have considered and incorporated all usable input and comments received from the Parties, clarified our approach to modeling analyses described in our Work Plan, and have posted for consumption by the Parties all input assumptions and other information employed in our process to develop an update to the PSIP.

We concluded the meeting by discussing our rationale for IPP modeling and our input assumptions for LNG and solar PV, including how we had considered and incorporated input from Hawai'i Gas and SunPower.

Everyone agreed to schedule a final meeting to finish discussing the agenda.

Fourth Stakeholder Meeting: October 19, 2016

A fourth, and final, stakeholder meeting was convened to conclude our discussions on analysis methodologies, input assumptions, and other related topics. Colton Ching, Hawaiian Electric Vice President of Energy Delivery, sent the following email to schedule this meeting.

> Hi everyone,
>
> As a follow up to our September 22nd meeting, I would like to propose a meeting on October 19th, 8:30-10:30am. Per Kyle's proposal at the conclusion of the September 22nd meeting, the idea for this next meeting is for parties to come to the meeting with a "sheet" of data on the assumptions and inputs that were discussed at the meeting. Information provided in the meeting will then be used for sensitivity analysis planned for our December 1 PSIP Update.
>
> In advance of the 10/19 meeting we will send tables of what we have thus far for those input assumptions discussed at our last meeting: on-island grid-scale solar sensitivity analysis, on-island grid-scale wind sensitivity analysis, Paniolo Power's wind and pumped storage hydro sensitivity analysis, and Hawai'i Gas' LNG sensitivity analysis. These tables will denote specific data fields provided by parties. The tables will also note where we are using our own data for fields in which specific data has not been provided by parties. This would be consistent with what was discussed at PUC's 10/3 technical conference.
>
> The intent of providing these tables is to transparently provide the detailed inputs we have

received to date for the sensitivity analyses and where we are using our own data. We are hopeful that these tables will facilitate parties' efforts to provide additional data and input on assumptions that they would like to be included. I would like to encourage meeting participants to review these tables beforehand and come prepared to provide a "redline" of the tables with the additional or alternative data and inputs they would like to be included in our sensitivity analyses. If there are parties calling in and using WebEx, we would appreciate an email of the redline version before the meeting so that we can set it up and make the tables available for all participants.

Additionally, given the interest that the PUC staff has shown in the sensitivity analyses we will be performing as part of the PSIP Update and the data and inputs to them, in addition to the parties, we will be inviting the PUC to attend and observe this October 19th meeting as well.

Thanks, and stay tuned for a follow up email providing the meeting room, call in bridge, and aforementioned tables.

Colton

Todd Kanja, Hawaiian Electric PSIP Project Lead, included the following text in the meeting invitation sent to the Parties and key Company staff and consultants.

This is a follow-up to the September 22nd Stakeholder Meeting. The intent of this meeting is to validate input assumptions for sensitivity analyses that was discussed at the September 21st Technical Conference and September 22nd Stakeholder Meeting. In particular, we'd like to reach agreement on the input assumptions for O'ahu on-island PV, O'ahu on-island wind, Paniolo Power's wind and pump storage hydro, and Hawai'i Gas LNG proposal. Depending on E3's ability to provide documentation on their approach to determining a hedge value of renewables and availability, we may include that as an agenda item as well. We are planning on a 2 hour meeting and will try to keep the discussion focused and concise. Our approach will be to prepare tables of the input assumptions from the parties and assumptions that we intend on making where data was not provided. We intend on distributing these tables by the end of the week so that the Parties have a couple of days to review and decide if our assumptions are appropriate or provide us with different assumptions. Our goal is to get agreement on the input assumptions so that E3 can run sensitivity analyses for each set of input assumptions.

Attached is an email that Colton sent to the Parties earlier today notifying them of this follow-up session.

I will send an update with the Webex information once it's available.

Thanks,
Todd

In-person and conference call bridge attendees at this final stakeholder meeting included representatives from the Commission, Blue Planet, DBEDT, Division of Consumer Advocacy, Hawai‘i Gas, Life of the Land, Paniolo Power, REACH, Sierra Club, SunPower, and Ulupono; a representative from Siemens; all together with staff and Company consultants: HD Baker, Solari Communication, Ascend Analytics, Black & Veatch, and E3.

Mr. Ching opened the meeting by restating the purpose of the meeting: validating the input assumptions specified in the (above) meeting notice, specifically the O‘ahu’s on-island grid-scale wind and PV, Paniolo Power’s wind and pumped storage hydro, and Hawai‘i Gas’s LNG proposal assumptions.

Participants first discussed Paniolo Power’s input assumptions. Ulupono-representative Dr. Fripp then outlined the grid-scale wind, grid-scale PV, and rooftop solar assumptions used as input assumptions in the SWITCH model. Finally, we discussed the Hawai‘i Gas assumptions in their LNG proposal.

In the week following this stakeholder meeting, we held a series of conference calls to further delve into the various suggested input assumptions and to discuss additional sensitivities to run.

In the end, we arrived at an agreement as to the assumptions that we would use as input for sensitivities to be run by E3 in RESOLVE in their modeling analysis. We ended by discussing the possibility of scheduling a meeting with E3 to review these input assumptions and the sensitivities to be run.

STAKEHOLDER CONFERENCE COMMENTS AND PRESENTATIONS

Paniolo Power Wind Resource and Energy Production Assessment

AWS Truepower®

PREPARED FOR
PARKER RANCH, INC.

ENERGY PRODUCTION SUMMARY

Assessment of the Wind Resource and Energy Production

DECEMBER 5, 2016

FOR THE PROPOSED PARKER RANCH WIND PROJECT

ISLAND OF HAWAII

CLASSIFICATION
CONFIDENTIAL

463 NEW KARNER ROAD | ALBANY, NY 12205
awstruepower.com | info@awstruepower.com

DISCLAIMER

Acceptance of this document by the client is on the basis that AWS Truepower is not in any way to be held responsible for the application or use made of the findings and that such responsibility remains with the client.

KEY TO DOCUMENT CLASSIFICATION

STRICTLY CONFIDENTIAL	For recipients only
CONFIDENTIAL	May be shared within client's organization
AWS TRUEPOWER ONLY	Not to be distributed outside AWS Truepower
CLIENT'S DISCRETION	Distribution at the client's discretion
FOR PUBLIC RELEASE	No restriction

DOCUMENT CONTRIBUTORS

AUTHOR	SUPPORTING AUTHOR	REVIEWER
Mike Markus Chief Meteorologist	**Bonnie Vehlies** Senior Renewable Energy Analyst	**Dave DeLuca** Director of Client Services

DOCUMENT HISTORY

ISSUE	DATE	SUMMARY
A	5 December 2016	Initial Report

TABLE OF CONTENTS

1. INTRODUCTION

AWS Truepower, LLC, was retained by Parker Ranch, Inc. (Parker Ranch) to evaluate the long-term wind resource and energy production potential of the proposed Parker Ranch Wind Project, located in Hawaii, about 9 km to the south-southeast of Kapaau, and 19 km northwest of Waimea. This report presents the results of our analysis and summarizes the methods used to develop the wind resource and energy estimates.

2. WIND MEASUREMENTS

Wind monitoring at the Parker Ranch project began in August 2013 with the installation of two Triton sodar units, designated Sites 298 and 302. A sodar instrument is a mobile device that uses sound waves to remotely measure the wind speed and direction at heights that are well above typical mast heights. Table 1 presents basic information about the sodars including their geographic coordinates, elevations, periods of record and monitoring heights. The sodar units remain in operation. Parker Ranch provided the data to AWS Truepower via ftp. Each data file contained 10-minute average wind speed and direction records.

The sodar data were screened by AWS Truepower and found to be of good quality. The observed mean wind speeds at a height of 80 m, the proposed turbine hub height, are 8.08 m/s at Site 298 and 9.20 m/s at Site 302. The annualized mean wind speeds, which take into account repeated months in the data record and weight each calendar month by its number of days, are 8.05 m/s at Site 298 and 9.15 m/s at Site 302.

3. ESTIMATION OF LONG-TERM MEAN WIND SPEED

We obtained historical wind speed data from several regional potential reference stations operated by the National Weather Service (NWS), as well as a MERRA-2 dataset[1], and assessed them for suitability as long-term references.

Linear regression equations were established using concurrent daily mean wind speeds at Site 298 and each potential reference source. The strength of the correlation between the sodar measured wind speeds and the reference source observations varied widely among the different references. The same was true for the long-term wind speed estimates. We also consulted another long-term regional sodar dataset and, based on the evidence, ultimately concluded that the wind speeds during the sodar period of record were likely slightly below normal. Given the uncertainty with regard to the adjustment of the onsite data record to the climatological conditions, we elected to use the observed annualized 80 m mean wind speed of 8.05 m/s at Site 298 as our best estimate of the long-term mean wind speed.

The long-term wind speed at Site 302 was estimated using Site 298 as the reference. The regression was performed using concurrent daily wind speeds. Substitution of the estimated long-term speed at Site 298 into the regression equation yields a long-term mean wind speed of 9.12 m/s at Site 302. A summary of the estimated long-term wind speeds is presented in Table 2.

1 MERRA-2, which was developed by the National Aeronautics and Space Administration (NASA), utilizes a variety of observing systems which have been assimilated into a global three-dimensional grid by numerical atmospheric models at a horizontal resolution of 1/2° latitude and 2/3° longitude.

The sodar long-term 80 m wind speeds were compared to the existing AWS Truepower wind map of the region and were found to be somewhat higher than suggested by the map. We elected to adjust the wind map speeds upward by 3% to bring them more in line with the sodar observations. It should be noted that the wind speed discrepancy was larger than 3%, but since the map suggests much stronger speeds to the west and southwest of Site 302, we decided to employ a more conservative upward adjustment.

4. ESTIMATION OF LONG-TERM ENERGY PRODUCTION

The energy production of the proposed Parker Ranch Wind Project was estimated for two turbine layouts, one consisting of 20 turbines and the other containing 40 turbines, designed by AWS Truepower. The turbine layouts are presented in Figure 1 and Figure 2. The turbine model considered in this assessment is the Vestas V116-2.0 MW turbine with a 116 m rotor diameter and a hub height of 80 m. The 80 m wind speed data collected at Site 302 served as the input data to the energy estimates. Specifically, a wind speed frequency distribution was created from the 3-year dataset and scaled to match the array-average wind speeds of 9.61 m/s (20-turbine layout) and 9.43 m/s (40-turbine layout), respectively. The number of observations in each wind speed bin was then multiplied by the power output for the Vestas turbine at each speed bin at an estimated site air density of 1.109 kg/m^3 and then summed over all speed bins to produce a gross energy estimate. The gross energy production for each project scenario was then reduced by the estimated project losses. AWS Truepower assumed preliminary project losses of 18.3% for the 20-turbine layout and 20.1% for the 40-turbine layout. These loss estimates will be further refined upon a more detailed analysis. Table 3 provides the estimated gross and net energy estimates for the two layouts. The preliminary estimated net energy production for the 20-turbine layout is 205.5 GWh (58.6% net capacity factor), while the corresponding values for the 40-turbine layout are 497.5 GWh (56.7% net capacity factor).

WindLogics independently estimated the energy production potential of the Parker Ranch project, but assumed project losses of only 13.8%. Applying this loss value to the AWS Truepower estimated gross energy production would result in net capacity factors of 61.8% and 61.2% for the 20-turbine and 40-turbine layouts, respectively.

5. SUMMARY

The long-term wind resource at the proposed Parker Ranch Wind Project was estimated using data from two sodar sites. The energy production was simulated using an existing wind resource map of the project area that was adjusted to the sodar observations, a wind speed frequency distribution based on three years of data collected at Site 302, and the Vestas V116-2.0 MW turbine model at an 80 m hub height. Preliminary project losses were estimated by AWS Truepower to adjust the gross energy production to net production values. The preliminary net energy estimate for the 20-turbine layout is 205.5 GWH and 58.6% net capacity factor. The corresponding values for the 40-turbine layout are 397.7 GWH and 56.7%.

[redacted]

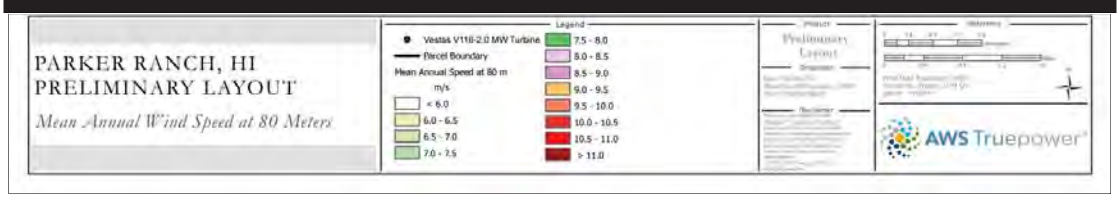


Figure 1. Proposed Parker Ranch 20-Turbine Layout

[redacted]

Figure 2. Proposed Parker Ranch 40-Turbine Layout

Table 1. Sodar Summary

Sodar	Site UTM Coordinates (WGS84, Zone 5)		Elevation (m)	Period of Record	Wind Speed and Direction Monitoring Heights (m)
	Easting	Northing			
298	[redacted]	[redacted]	799	8/30/2013 – 11/21/2016	200, 180, 160, 140, 120, 100, 80, 60, 40
302	[redacted]	[redacted]	642	8/30/2013 – 11/21/2016	

Table 2. Sodar Long-Term Wind Speed Projection Summary

Sodar	Monitoring Height (m)	Reference	Regression Equation	r^2	Long-Term 80 m Wind Speed (m/s)
298	80	-	-	-	8.05
302	80	Sodar 298	y = 1.013x + 0.963	0.97	9.12

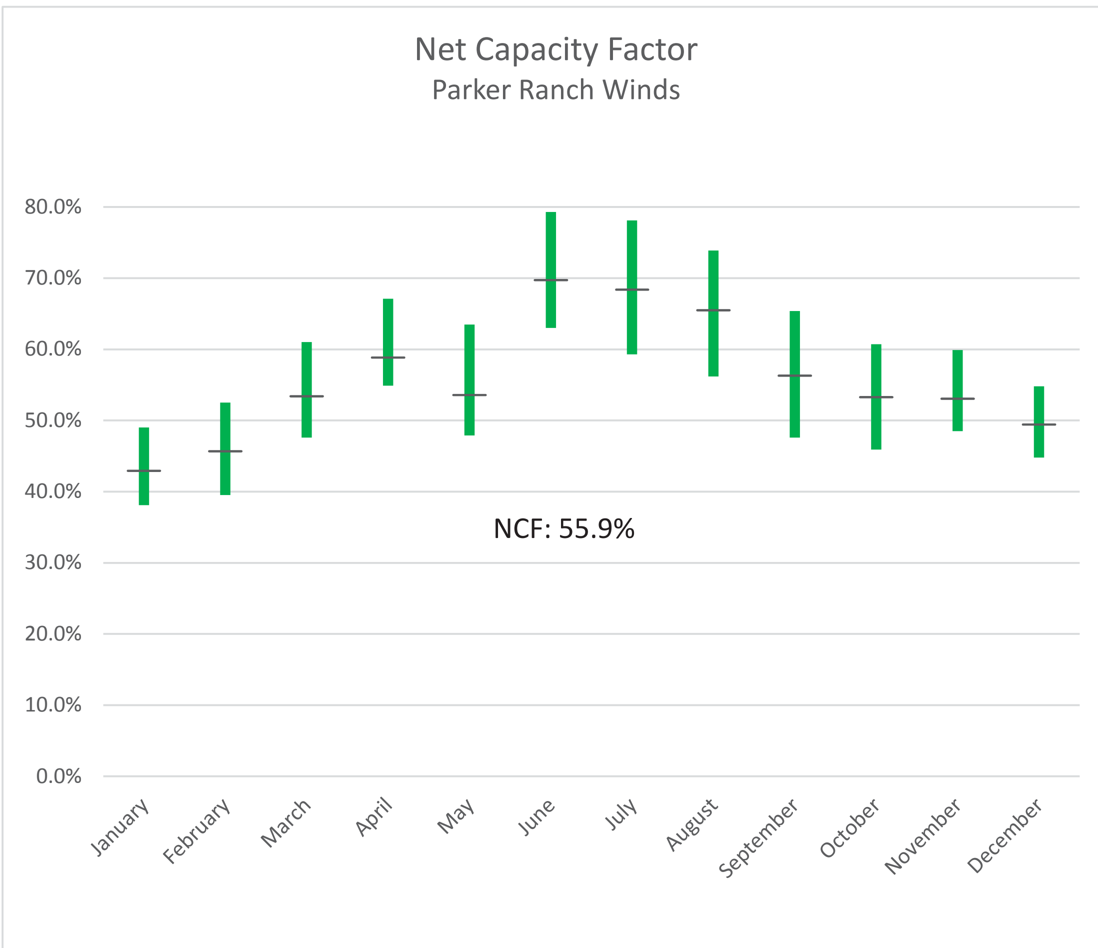
Table 3. Parker Ranch Preliminary Energy Production Estimates

Project Scenario	Gross Energy Output (GWh)	Net Energy Output (GWh)	Net Capacity Factor (%)
20-Turbine Layout	251.4	205.5	58.6
40-Turbine Layout	497.5	397.7	56.7

Parker Ranch Summary Wind Information, November 9, 2016

Actual wind data: September 1, 2013 to June 30, 2015 (1 year, 9 months)

Gross Capacity Factor (%)		**65.1%**
	Wake Effect	9.0%
	Availability	2.9%
	Electrical	2.5%
	Weather	0.0%
Total Project Losses (%)		**13.8%**
Net Capacity Factor (%)		**55.9%**



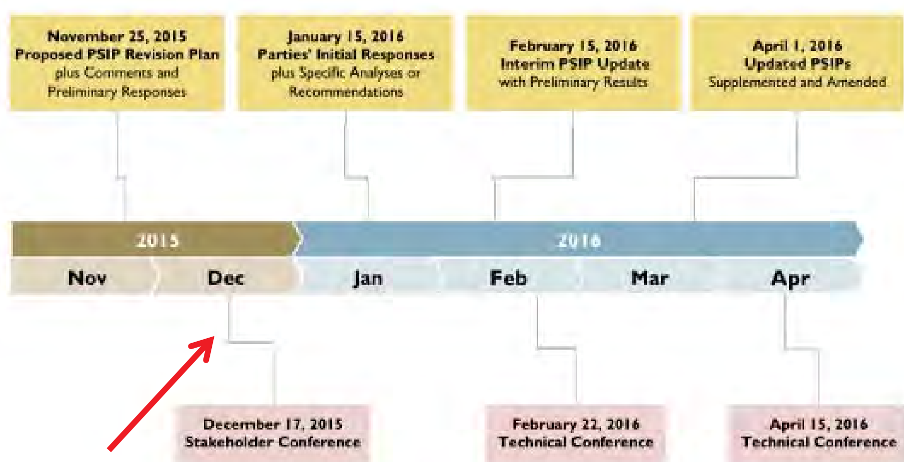
Next steps: AWS TruePower will review all actual wind data (spanning three years from 9/1/2013 to present) and use fewer and smaller turbines placed at the most optimal highest producing wind locations. We expect net capacity factor to exceed 55.9%.

Hawaiian Electric Presentation: First Stakeholder Conference

Hawaiian Electric
Power Supply Improvement Plan (PSIP)
Stakeholder Conference

December 17, 2015

Proposed PSIP Update Schedule



PSIP Stakeholder Conference 2

PSIP Stakeholder Conference Agenda

- Participant Presentations (30 min total)
  - DBEDT
  - REACH
  - Blue Planet
- Stakeholder Input and Discussion (2 hours)
  - 8 Observations and Concerns
  - Additional Pertinent Circumstances
- Concluding Remarks

PSIP Stakeholder Conference 3

Ground Rules

- Listen and be open to all ideas
- All dialogue is in confidence and off record. Please NO recording of this session.
- Always engage assuming no malicious intent, process is intended to be collaborative among the parties
- Try to provide supporting facts / data whenever possible when making comments
- Document issues requiring a deeper dive on the flip chart to there is adequate time to get through all critical topics
- Please silence cell phones to avoid disrupting others
- All dialogue should be directed through facilitator
- Leave preconceptions outside of conference
- Please avoid side bar conversations so the stakeholders can remain engaged
- Honor time limits so everyone has an opportunity to voice their thoughts

PSIP Stakeholder Conference 4

DBEDT

PSIP Stakeholder Conference 5

REACH

PSIP Stakeholder Conference 6

BLUE PLANET

PSIP Stakeholder Conference 7

Questions to Consider

- What Do You Want Analyzed?
- What Inputs Should be Considered?
- How Should the Information be Presented in the PSIP?

PSIP Stakeholder Conference 8

Stakeholder Input and Discussion: PUC's 8 Observations and Concerns

1. Customer Rate and Bill Impact:

PSIP Cost Impacts and Risk Have Not Been Demonstrated to Be Reasonable

2. Technical Cost and Resources Availability:

PSIPs Do Not Appear to Aggressively Seek Lower-Cost, New Utility-Scale Renewable Resources

PSIP Stakeholder Conference 11

3. DER Integration:

PSIPs do not Adequately Address Utilization and Integration of Distributed Energy Resources

PSIP Stakeholder Conference 12

4. Fossil-Fuel Plant Dispatch and Retirements:

Proposed Plans for Fossil-Fueled Power Plants are not Sufficiently Justified

PSIP Stakeholder Conference 13

5. System Security Requirements:

System Security Requirements Appear Costly and Are Not Sufficiently Justified

PSIP Stakeholder Conference 14

6. Ancillary Services:

Proposed Plan for Provision of Ancillary Services Lack Transparency and May Not be Most Cost-Effective Option

7. Inter-Island Transmission:

PSIP Analysis on Inter-Island Transmission Lacks Sufficient Detail

8. Implementation Risks & Contingencies:

Customer and Implementation Risks Are Not Adequately Addressed

Stakeholder Input and Discussion: Additional Pertinent Circumstances

Additional Pertinent Circumstances

- Increased RPS requirements established by Act 97 of the 2015 Hawaiʻi Legislature
- Substantial decrease in petroleum prices
- Limits the use of LNG as a cost-effective transitional bridge fuel that does not impede the utilization of renewable energy sources as established by Act 38 of the 2015 Hawaiʻi Legislature
- Changes in the estimated timing for implementation of major near-term projects in the 2014 Preferred Plans, including LNG utilization and BESS projects
- Potential significant changes in Federal energy policies that may affect Hawaiʻi's utilities, including the July 29, 2015 U.S. Supreme Court decision regarding Mercury and Air Toxics Standards (MATS) regulations and promulgation of the Clean Power Plan Final Rule.
- An announcement by the Governor of the State of Hawaiʻi regarding administration policy regarding utilization of LNG fuels for electric utility power production

PSIP Stakeholder Conference 19

Stakeholder Input and Discussion: Resource Options

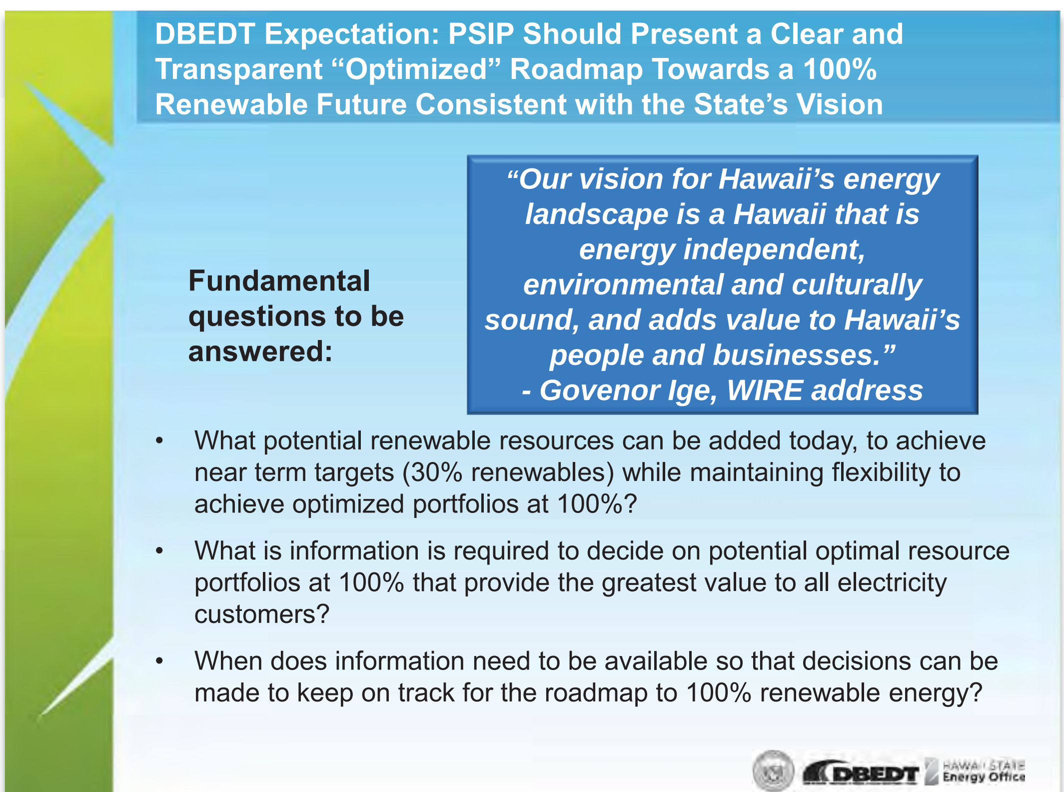
PSIP Stakeholder Conference 20

Resource Option(s) That Will Assist in Development of Portfolios

- Future Pricing
- Developable Levels
- Issues

PSIP Stakeholder Conference 21

DBEDT Presentation: First Stakeholder Conference



The States Comments Today Address a Subset of Identified PUC Issues

The fundamental questions discussed here address the following PUC identified issues:

1. PSIP Cost Impacts and Risk Have Not Been Demonstrated to Be Reasonable
2. PSIPs do Not Appear to Aggressively Seek Lower-Cost, New Utility-Scale Renewable Resources
3. PSIPs do not Adequately Address Utilization and Integration of Distributed Energy Resources

….

7. PSIP Analysis on Inter-Island Transmission Lacks Sufficient Detail

HSEO will comment more comprehensively on these and additional issues, expectations and recommendations within the proceeding

DBEDT HAWAII STATE Energy Office

Near Term Planning Considerations for 30% Renewables

The State expects the PSIP to address near term decision points in the planning process including:

1. PSIP Cost Impacts and Risk Have Not Been Demonstrated to Be Reasonable

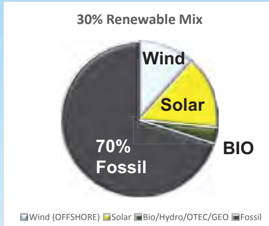
1. Near term targets are met
   - Planning should not result in delays in implementation
2. Long term portfolio options remain viable
   - Current additions should be made cost effectively while preserving future options
3. Plans are regularly refreshed to allow for continued refinement of renewable portfolio
   - The interim resource targets need to be regularly updated to achieve progressive interim renewable penetration targets
4. Interim resource targets are subject to an identified RFP formula by which to evaluate resource combinations
   - To ensure low cost resource procurement targets are guides subject to market pricing
   - Individual resource targets could be exceeded if they prove lower cost when combined with normalizing mitigation factors (e.g. solar with storage relative to dispatchable bio fuels)

DBEDT HAWAII STATE Energy Office

What potential renewable resources can be added today, to achieve near term targets (30% renewables) while maintaining flexibility to achieve optimized portfolios at 100%?

ALL VALUES ARE ILLUSTRATIVE

Near Term Target

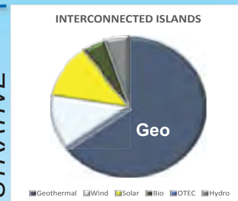


Total MW	Interim Target	Renew %
Wind	300	12%
Solar	650	15%
Bio	30	3%
Total		30%

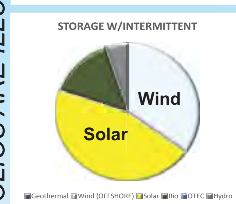
2. PSIPs do not Appear to Aggressively Seek Lower-Cost, New Utility-Scale Renewable Resources

Fits Within

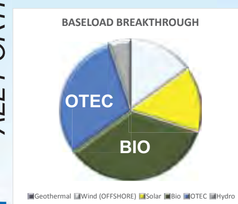
ALL PORTFOLIOS ARE ILLUSTRATIVE



Total MW	Flat Load	30% Growth
Geothermal	800	1,100
Wind	300	400
Solar	700	950
Bio	60	80
OTEC	0	0
Hydro	100	150



Total MW	Flat Load	30% Growth
Geothermal	0	0
Wind	700	900
Solar	1,900	2,500
Bio	150	200
OTEC	0	0
Hydro	80	110



Total MW	Flat Load	30% Growth
Geothermal	0	0
Wind	350	500
Solar	650	850
Bio	300	450
OTEC	300	400
Hydro	80	110

Resource mix can include distributed and utility scale resources

DBEDT HAWAII STATE Energy Office

The State feels the following information would be required to decide on optimal 100% renewable resource portfolios

- How do grid costs vary by portfolio?
  - How does the location of renewables and location of integration measures impact total costs and benefits (Utility Scale, DG/DER)
- How do renewable integration costs vary by portfolio?
  - What is the cost impact of the renewable mix on ancillary service requirements?
- What is the renewable potential by island and resource?
  - What is the technical potential?
  - What are the cultural impacts?
- What is the potential benefit of customer energy management
  - If loads can be modified by customers (usage or technology) what impact would it have on portfolio costs at 100%?
  - What is the costliest component of the load to serve?
  - Does the plan provide customers the opportunity to modify use to avoid creating costly loads prior to the utility being forced to make an investment to serve it?
- What is the economic impact of electricity to Hawaii?
  - What is the impact of price volatility?
  - What is the impact of long run average costs?

1. PSIP Cost Impacts and Risk Have Not Been Demonstrated to Be Reasonable

2. PSIPs do Not Appear to Aggressively Seek Lower-Cost, New Utility-Scale Renewable Resources

3. PSIPs do not Adequately Address Utilization and Integration of Distributed Energy Resources

7. PSIP Analysis on Inter-Island Transmission Lacks Sufficient Detail

DBEDT HAWAII STATE Energy Office

When does information need to be available so that decisions can be made to keep on track for the roadmap to 100% renewable energy?

TIMELINE IS ILLUSTRATIVE

	2015 - 2020	2020 - 2025	2025 – 2030	2030 - 2035	2035 - 2040	2040 - 2045
Illustrative RPS Timeline	• Procure and build resources for 30% • IRP/PSIP for 40%	• RFP and begin development for 40% • IRP for 50%- 60% Resources	• Complete development of 40% • RFP for 50% - 60% • IRP for 70% Resources	• Development of 50% - 60% • RFP for 60% - 70% • IRP for 80% - 90% Resources	• Develop 60% - 70% Resources • RFP for 80% - 90% Resources • IRP for 100%	• RFP and development of 100% RPS
Illustrative Transmission Decision Timeline	Gather necessary info. including resource potential by island	Decision on inter-island cable arguably can occur no later than 2025 if not earlier to keep on track with targets beyond 40%		Transmission line available (if optimal path)		
Pricing reform	Timeline including rate design, AMI deployment, customer response and incorporation		Reasonably paced action today will allow for customer response to be incorporated into load forecasts in the mid 2020 timeframe			

- The State expects that the PSIP will address critical path items in a comprehensive timeline to show timely decisions can be made
- Given the compact timeline, the State expects any critical issue that is not directly incorporate into the current analysis will be identified in a timeline such that there is certainty in the timeframe in which it will be addressed

DBEDT Hawaii State Energy Office

REACH Presentation: First Stakeholder Conference

Renewable Energy Action Coalition of Hawaii

RESOURCE OPTIONS FOR GETTING TO 100% RENEWABLE ENERGY

Hawaiian Electric
Power Supply Improvement Plan (PSIP)
Stakeholder Conference

December 17, 2015

PSIP Stakeholder Conference 1

Participant Input to Observations and Concerns Identified by the PUC

1. PSIP Cost Impacts and Risk Have Not Been Demonstrated to Be Reasonable
2. PSIPs do Not Appear to Aggressively Seek Lower-Cost, New Utility-Scale Renewable Resources
3. PSIPs do not Adequately Address Utilization and Integration of Distributed Energy Resources
4. Proposed Plans for Fossil-Fueled Power Plants are not Sufficiently Justified
5. System Security Requirements Appear Costly and Are Not Sufficiently Justified
6. Proposed Plan for Provision of Ancillary Services Lack Transparency and May Not be Most Cost-Effective Option
7. PSIP Analysis on Inter-Island Transmission Lacks Sufficient Detail
8. Customer and Implementation Risks Are Not Adequately Addressed

PSIP Stakeholder Conference 2

If one asks,
"What *mix* of options would get us to 40% renewable energy at *lowest aggregate cost*?

PSIP Stakeholder Conference 3

One gets a planning process that looks like this:

Figure L-2. Illustration of the Process for Developing the Hawaiian Electric Preferred Plan

PSIP Stakeholder Conference 4

And one gets a plan that looks like this:

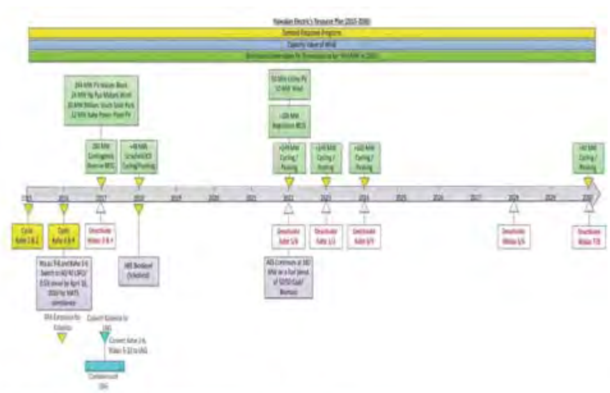


Figure ES-5. Hawaiian Electric Preferred Plan 2015-2030

PSIP Stakeholder Conference 5

If one asks "What *options* in what *amounts* in what *order* would get us to 100% renewable energy at *greatest benefit* and *lowest cost*?"

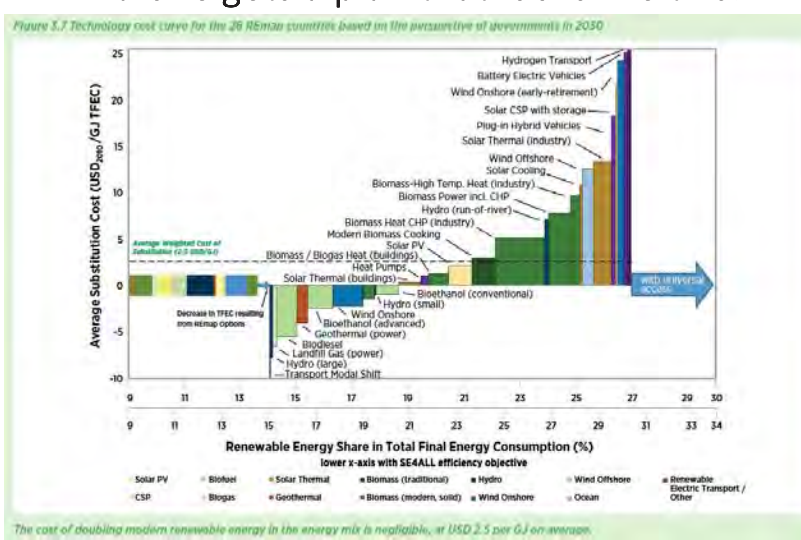
PSIP Stakeholder Conference 6

One gets a planning process that looks like this:

1) Identify plausible renewable energy options (renewable generation, T&D including mitigation, storage, demand management)
2) Evaluate options one-by-one for system performance impacts and cost & benefit
3) Compose plan prioritizing options evaluated to provide greatest benefit and lowest cost
4) Implement first step of plan
5) Use knowledge gained during first step of plan to re-evaluate options

PSIP Stakeholder Conference 7

And one gets a plan that looks like this:



PSIP Stakeholder Conference 8

Renewable Energy Action Coalition of Hawaii

RESOURCE OPTIONS FOR GETTING TO 100% RENEWABLE ENERGY

Hawaiian Electric
Power Supply Improvement Plan (PSIP)
Stakeholder Conference

December 17, 2015

Blue Planet Presentation: First Stakeholder Conference

Resource Combinations to Achieve 100% Renewable Po

Matthias Fripp

University of Haw a

- Asst. Prof. of Ele ineering
- U.H. Energy Resea anization (U)
- Renewable Energy nd Sustainab

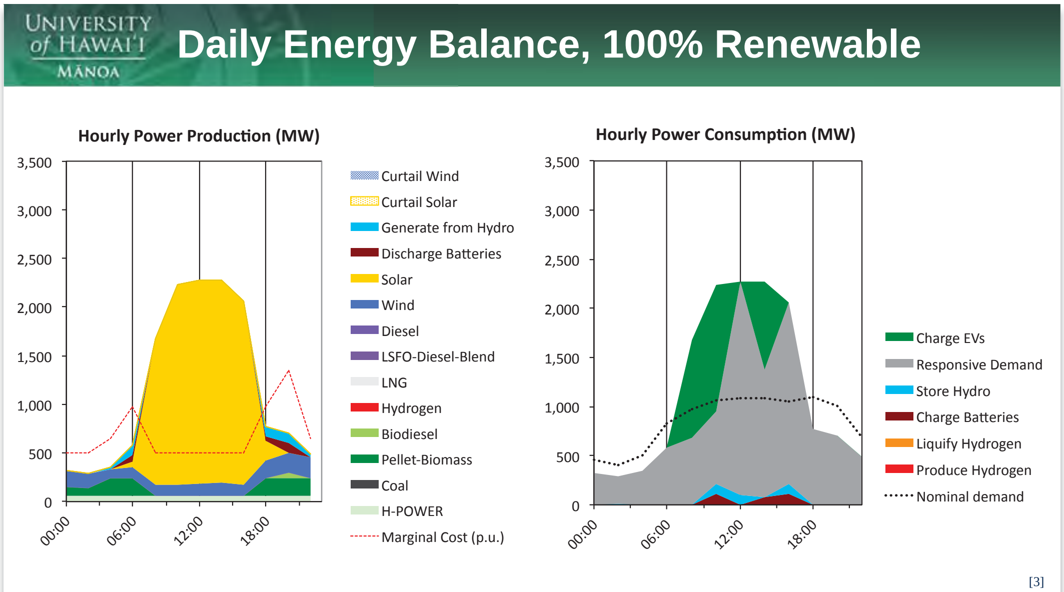
Blue Planet Found

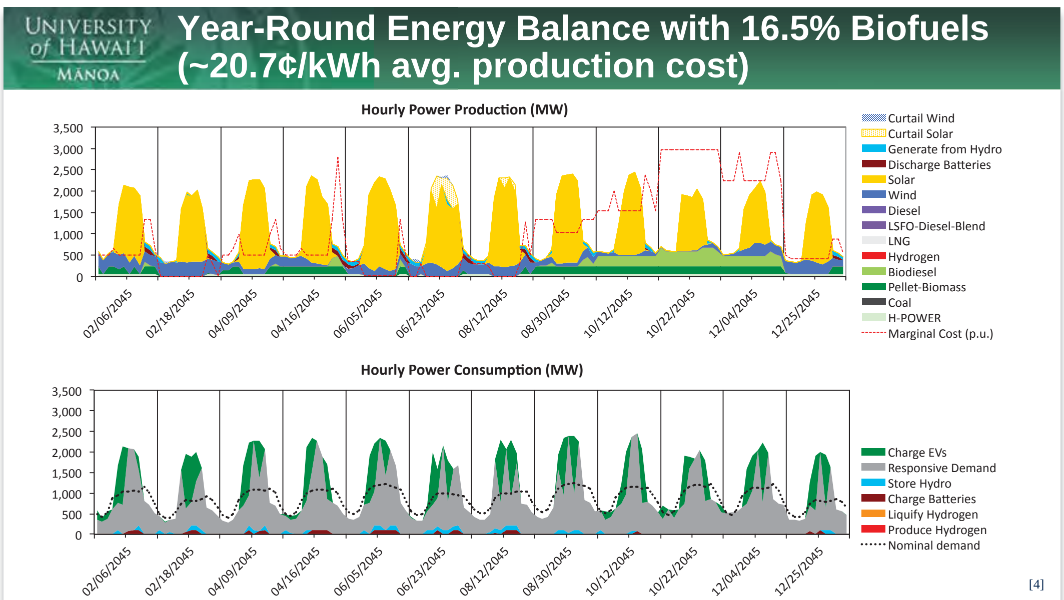
- Consultant

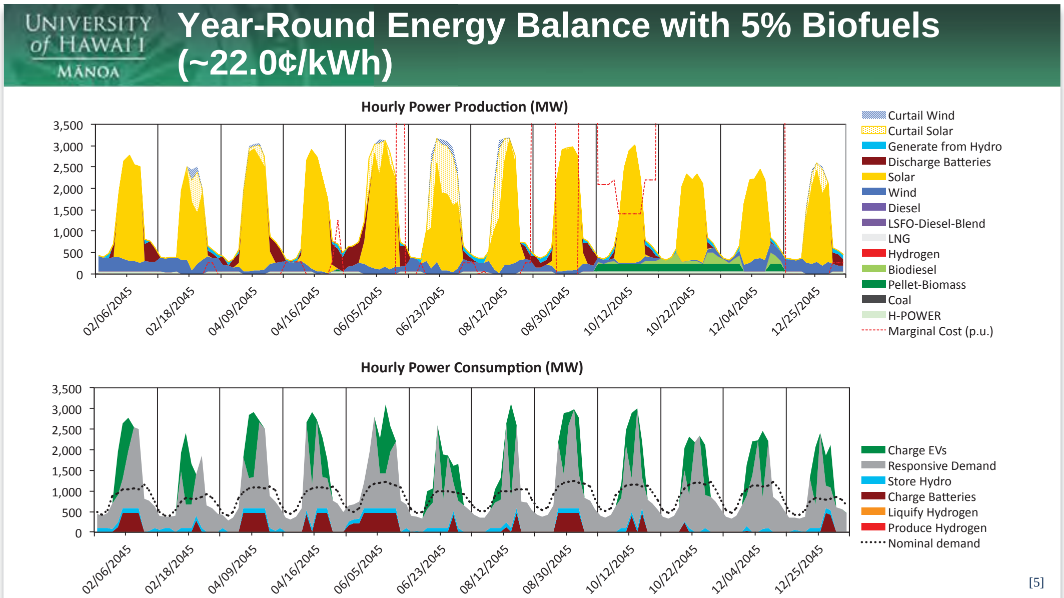
UNIVERSITY of HAWAI'I MĀNOA

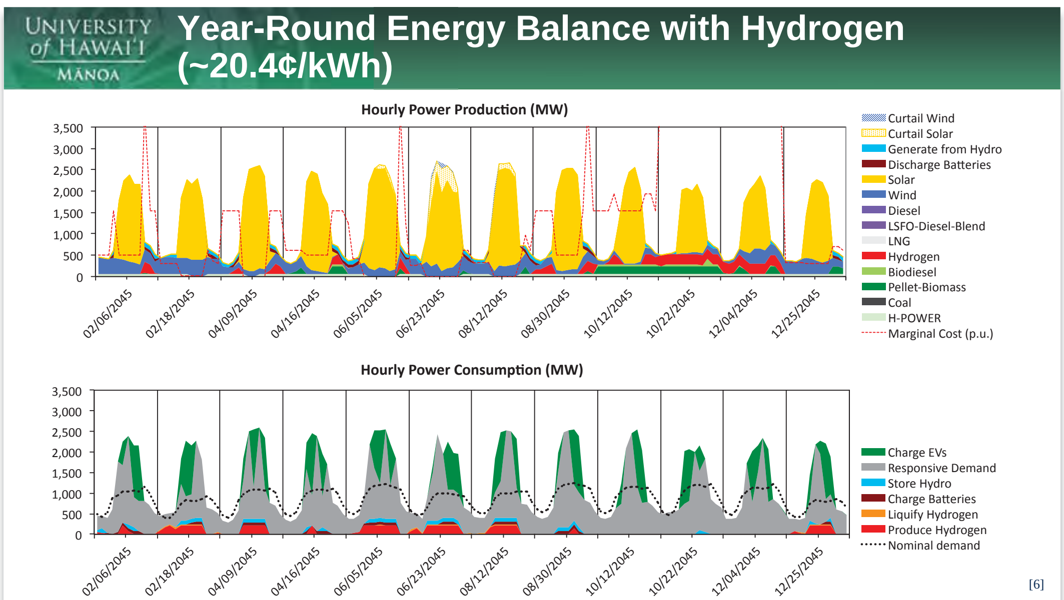
- Meet overall energy requirements
  - Build wind projects where appropriate/suitable (up to ~300 MW on Oahu)
  - Build a lot of solar power (2,000–3,000 MW)
  - Use biofuels as needed/appropriate (0-16% of energy)
- Meet hourly energy requirements
  - Harness demand response via real-time electricity pricing (300 MW?)
    - Same loads can also provide "spinning" reserves
  - Build pumped hydroelectric storage if cost-effective (150 MW+)
  - Build as much battery capacity as needed (100–400 MW)
  - Fill in with biofuel or hydrogen when needed (400-600 MW)
- Meet seasonal energy requirements
  - Use biofuel or hydrogen on low-sun days
    - Produce hydrogen on high-sun / high-wind days

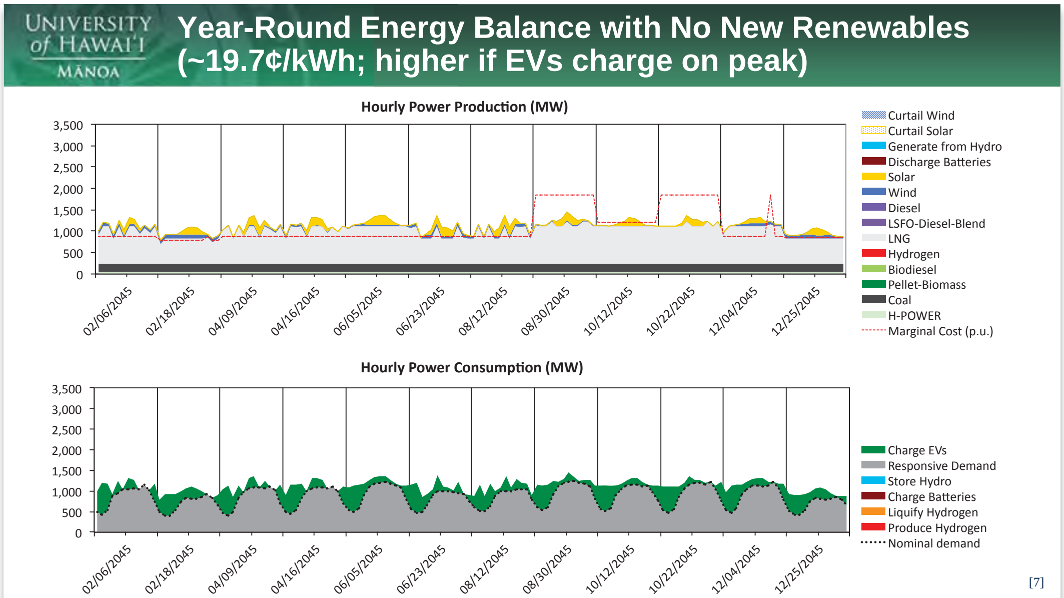
[2]


UNIVERSITY of HAWAI'I MĀNOA
Daily Energy Balance, 100% Renewable
Hourly Power Production (MW)
Hourly Power Consumption (MW)
3,500
3,000
2,500
2,000
1,500
1,000
500
0
00:00
06:00
12:00
18:00
Curtail Wind
Curtail Solar
Generate from Hydro
Discharge Batteries
Solar
Wind
Diesel
LSFO-Diesel-Blend
LNG
Hydrogen
Biodiesel
Pellet-Biomass
Coal
H-POWER
Marginal Cost (p.u.)
Charge EVs
Responsive Demand
Store Hydro
Charge Batteries
Liquify Hydrogen
Produce Hydrogen
Nominal demand
[3]


UNIVERSITY of HAWAI'I MĀNOA
Year-Round Energy Balance with 16.5% Biofuels
(~20.7¢/kWh avg. production cost)
Hourly Power Production (MW)
Hourly Power Consumption (MW)
3,500
3,000
2,500
2,000
1,500
1,000
500
0
02/06/2045
02/18/2045
04/09/2045
04/16/2045
06/05/2045
06/23/2045
08/12/2045
08/30/2045
10/12/2045
10/22/2045
12/04/2045
12/25/2045
Curtail Wind
Curtail Solar
Generate from Hydro
Discharge Batteries
Solar
Wind
Diesel
LSFO-Diesel-Blend
LNG
Hydrogen
Biodiesel
Pellet-Biomass
Coal
H-POWER
Marginal Cost (p.u.)
Charge EVs
Responsive Demand
Store Hydro
Charge Batteries
Liquify Hydrogen
Produce Hydrogen
Nominal demand
[4]


UNIVERSITY of HAWAI'I MĀNOA
Year-Round Energy Balance with 5% Biofuels (~22.0¢/kWh)
Hourly Power Production (MW)
3,500
3,000
2,500
2,000
1,500
1,000
500
0
02/06/2045
02/18/2045
04/09/2045
04/16/2045
06/05/2045
06/23/2045
08/12/2045
08/30/2045
10/12/2045
10/22/2045
12/04/2045
12/25/2045
Curtail Wind
Curtail Solar
Generate from Hydro
Discharge Batteries
Solar
Wind
Diesel
LSFO-Diesel-Blend
LNG
Hydrogen
Biodiesel
Pellet-Biomass
Coal
H-POWER
Marginal Cost (p.u.)
Hourly Power Consumption (MW)
Charge EVs
Responsive Demand
Store Hydro
Charge Batteries
Liquify Hydrogen
Produce Hydrogen
Nominal demand
[5]


UNIVERSITY of HAWAI'I MĀNOA
Year-Round Energy Balance with Hydrogen (~20.4¢/kWh)
Hourly Power Production (MW)
3,500
3,000
2,500
2,000
1,500
1,000
500
0
02/06/2045
02/18/2045
04/09/2045
04/16/2045
06/05/2045
06/23/2045
08/12/2045
08/30/2045
10/12/2045
10/22/2045
12/04/2045
12/25/2045
Curtail Wind
Curtail Solar
Generate from Hydro
Discharge Batteries
Solar
Wind
Diesel
LSFO-Diesel-Blend
LNG
Hydrogen
Biodiesel
Pellet-Biomass
Coal
H-POWER
Marginal Cost (p.u.)
Hourly Power Consumption (MW)
Charge EVs
Responsive Demand
Store Hydro
Charge Batteries
Liquify Hydrogen
Produce Hydrogen
Nominal demand
[6]


UNIVERSITY of HAWAI'I MĀNOA
Year-Round Energy Balance with No New Renewables (~19.7¢/kWh; higher if EVs charge on peak)
Hourly Power Production (MW)
3,500
3,000
2,500
2,000
1,500
1,000
500
0
02/06/2045
02/18/2045
04/09/2045
04/16/2045
06/05/2045
06/23/2045
08/12/2045
08/30/2045
10/12/2045
10/22/2045
12/04/2045
12/25/2045
Curtail Wind
Curtail Solar
Generate from Hydro
Discharge Batteries
Solar
Wind
Diesel
LSFO-Diesel-Blend
LNG
Hydrogen
Biodiesel
Pellet-Biomass
Coal
H-POWER
Marginal Cost (p.u.)
Hourly Power Consumption (MW)
Charge EVs
Responsive Demand
Store Hydro
Charge Batteries
Liquify Hydrogen
Produce Hydrogen
Nominal demand
[7]

Blue Planet Input: Second Stakeholder Conference

May 31, 2016

(*Via e-mail*)
Mr. Colton K. Ching
Hawaiian Electric
P.O. Box 2750
Honolulu, HI 96840
colton.ching@hawaiianelectric.com

Re: ***PSIP Update - Comments on Further Work on PSIP***

Dear Colton:

This letter is in response to the request of the Hawaiian Electric Companies ("Hawaiian Electric") for informal comments by May 31, 2016, on the presentations made at the "Stakeholder Conference" convened on May 17, 2016.

Blue Planet Foundation, Earthjustice on behalf of Sierra Club, Paniolo Power Company, LLC, Distributed Energy Resources Council of Hawaii, Hawaii Renewable Energy Alliance, Hawaii Solar Energy Association, and County of Maui support the comments provided by Ulupono Initiative and other parties dated May 31, 2016, which recommends necessary fundamental improvements in Hawaiian Electric's PSIP analysis. However, we raise an equally important concern regarding the *process* of any collaboration between Hawaiian Electric and stakeholders, which *must* be a meaningful exercise in order to produce reliable results and inspire public confidence in Hawaiian Electric's proposed plans and projects.

In particular, the recent LNG applications[1] by Hawaiian Electric severely undercut the effectiveness and legitimacy of any such collaboration. By filing the LNG applications, Hawaiian Electric is prematurely seeking to implement the centerpiece of its proposed PSIP (and apparently also the centerpiece of its proposed merger with NextEra Energy). Such implementation is premature because the Commission has not yet issued comment, approval, or rejection for the latest iteration of Hawaiian Electric's proposed PSIP. At this stage, Hawaiian Electric's preferred plan is simply a proposal awaiting instruction from the Commission on next steps, and awaiting formal submission of analysis, testimony, statements of position, and other input from intervenors and participants. Unlike some other potential capital expenditures, the LNG applications are not broadly consistent with many potential outcomes of the PSIP process; the LNG applications are narrowly tailored to Hawaiian Electric's preferred PSIP outcome.

We hope that the PSIP process can be repaired without Commission intervention. To that end, further PSIP work should include the following steps:

[1] Applications filed in Docket Nos. 2016-0135, -0136, and -0137.

(i) Hawaiian Electric should immediately withdraw the LNG applications, not to be re-filed unless the Commission approves a PSIP plan that is wholly consistent with such applications.

(ii) Any further planning and analysis should divorce itself from issues of ownership, and thus from the forthcoming decision on the proposed merger with NextEra Energy. If Hawaiian Electric believes that subsequent large applications to implement the proposed PSIP need to incorporate merged/unmerged scenarios, then the LNG applications, and other contested core action steps, should be held until the merger is resolved.

(iii) Hawaiian Electric should welcome formal procedural mechanisms for PSIP intervenors and participants to provide further input (e.g. analysis, testimony, and statements of position) on the proposed PSIP for the Commission's record. The informal comments submitted here, narrowed to the select issues raised at the Stakeholder Conference, are not sufficient for stakeholders to fully contribute to the PSIP process and to the Commission's review of the proposed PSIP.

As Hawaiian Electric recently pointed out in a letter to Mr. Henry Curtis, further direction from the Commission regarding the PSIP process is anticipated:

> **Participants <u>will be allowed</u>—and are encouraged—to present analysis, testimony, statements of position, and reply statements of position as may be specifically allowed or required in further orders in this docket**. Participants shall not be permitted to file motions or responses concerning procedural and legal matters (such as those pertaining to scheduling, further changes in the scope of the proceedings, or other matters pertaining to the conduct of the proceeding), except as specifically allowed by the commission. **In addition, the scope and form of allowed discovery for Parties, Intervenors and Participants <u>will be governed</u> by further order of the commission**.

Order No. 33320 at 168 (emphasis added) (quoted in letter from Hawaiian Electric to Henry Curtis, Life of the Land, filed May 23, 2016 in Docket No. 2014-0183).

In the meanwhile, we are hopeful that Hawaiian Electric can take affirmative steps to improve both the PSIP analysis as outlined by Ulupono, and the PSIP process as outlined above, in order to facilitate effective energy planning and collaboration going forward.

The undersigned parties appreciate this opportunity to informally provide comments related to the presentations provided at the Stakeholder Conference. However, this is not intended to be—nor can it be—a comprehensive review, comment and response to Hawaiian Electric's updated proposed PSIP filed on April 1, 2016.

None of the informal comments submitted should be construed as such. The Commission has not yet established subsequent procedural steps for the parties and Hawaiian Electric to provide and address comprehensive responses to the updated proposed PSIP. Accordingly, the undersigned parties reserve the right to provide comments, responses, testimony, and statements of position etc. on the updated proposed PSIP to the Commission in the docketed proceeding when appropriate.

Respectfully,

/s/ Richard Wallsgrove
Policy Director
Blue Planet Foundation

/s/ Isaac Moriwake
Earthjustice
Attorneys for Sierra Club

/s/ Jose Dizon
General Manager
Paniolo Power Company, LLC

/s/ Leslie Cole-Brooks
Executive Director
Distributed Energy Resources Council of Hawaii

/s/ Warren Bollmeier
President
Hawaii Renewable Energy Alliance

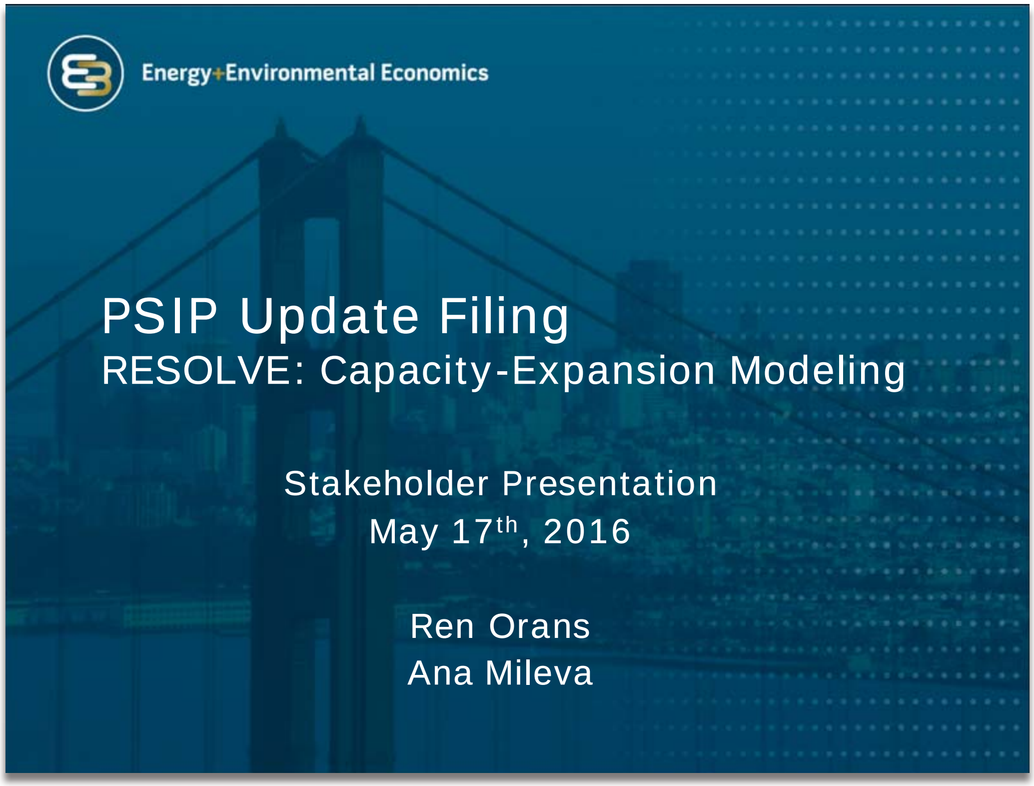
/s/ Rick Reed
Director
Hawaii Solar Energy Association

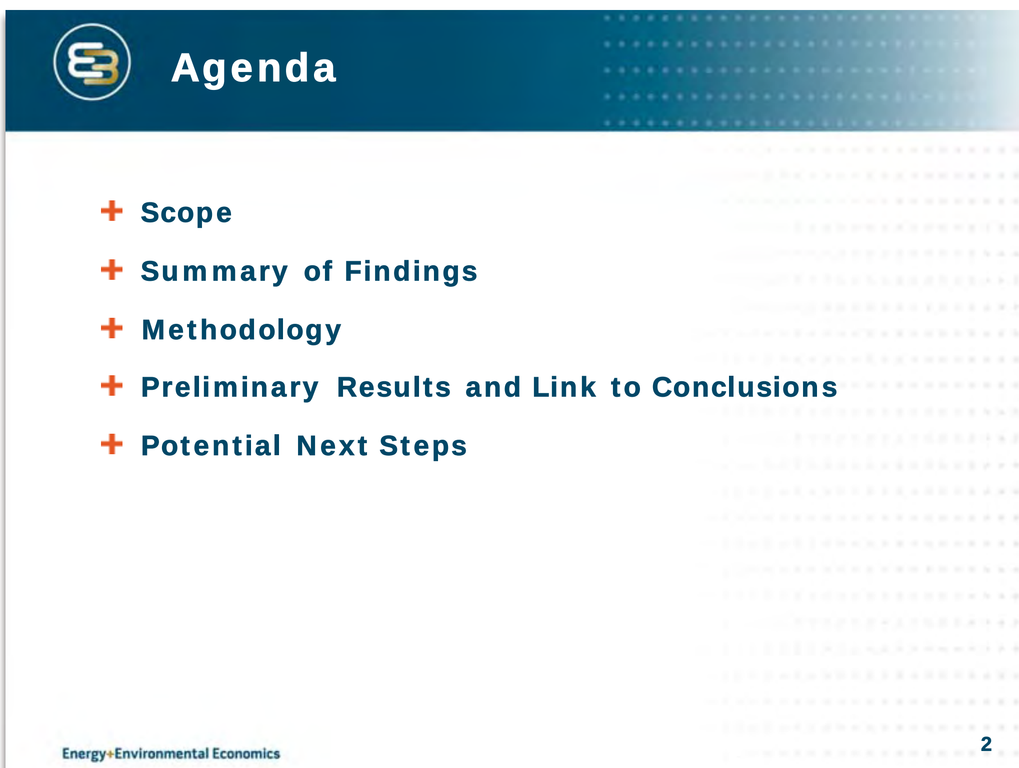
/s/ Frederick Redell, PE
Energy Commissioner
County of Maui Office of Economic Development

/s/ Kalvin Kobayashi
Energy Coordinator
County of Maui Department of Management

Cc:
Public Utilities Commission, Consumer Advocate, Participants and Intervenors in Docket No. 2014-0183 (via Stakeholder Conference e-mail distribution list)

E3 Presentation: Second Stakeholder Conference





Scope

- **Address some of the previous filings' shortcomings identified by the Commission**
  - Leverage E3's extensive modeling experience in long-term planning from California and New York to inform HECO planning decisions
- **Identify short-term and long-term decision points for HECO on the path to 100% RPS on O'ahu**
- **Test robustness of HECO's proposed short-term decisions with regard to a plausible range of long-term scenarios**

Energy+Environmental Economics

3

Summary of Findings

- **The LNG investment decision is critically dependent on the spread in fuel prices**
  - Lower future oil prices would reduce the savings provided by LNG
  - Faster ramp-up in RPS would limit the ability to recover the cost of the LNG infrastructure
- **The capital cost of renewable resources and supporting infrastructure – including transmission and balancing solutions – becomes increasingly important relative to fuel costs over time as the RPS target increases**
  - Shifts focus from fuel cost savings to integration solutions and optimal capacity-expansion planning
  - Major decision points are on large capital investments independent of fuel price projections
- **Limited renewable potential on O'ahu requires deployment of off-island renewable resources and transmission infrastructure**

Energy+Environmental Economics

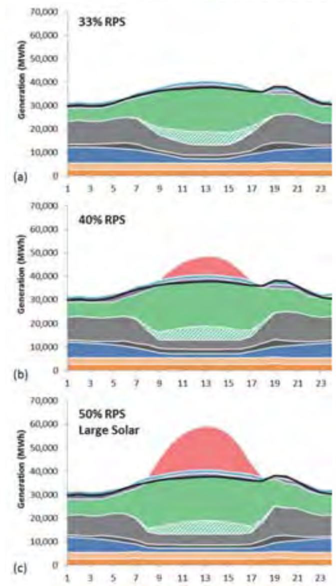
4


Energy+Environmental Economics
Economic Framework and Methodology for Selection of Optimal Resource Portfolios


Methodology
+ Question: How to align the planning process with the Commission's vision for the future grid?
+ E3 RESOLVE is an optimal investment planning model
• Selects least-cost resource portfolio and integration solutions to meet RPS targets
• Considers all resource options on level playing field
• Evaluates long-term benefits of investments as renewable portfolio evolves over time
• Allows investigation of new policy and regulatory reforms
+ Suited to addressing many of the challenges in the Commission's Inclinations document
+ Complementary approach to detailed production simulation modeling
Energy+Environmental Economics
6

The renewable integration challenge

+ **Primary drivers of renewable integration challenges at high penetrations:**
  - Renewable oversupply during low load periods
  - Inflexible conventional generation
    - Must-run resources
    - Self-scheduled resources/contract limitations
    - Technical constraints on ramping, minimum stable levels, minimum up and down times
    - High costs associated with cycling
  - Small balancing areas where diversity of renewables is limited, and generator fleets are constrained



Energy+Environmental Economics

7

Renewable integration solutions

+ **Various solutions have been proposed, with different performance characteristics and costs**
  - Energy storage (batteries, compressed air, etc)
  - Flexible loads or advanced DR
  - Flexible resources (new flexible CCGTs, Aero CTs, Reciprocating Engines or retrofits to existing plants)
  - Tariff design, regulatory and market changes

http://www.theiet.org/membership/member-news/31a/ev-charging-course.cfm

http://allthingsd.com/files/2012/10/Nest-Cooling-2.jpg

Wartsila.com

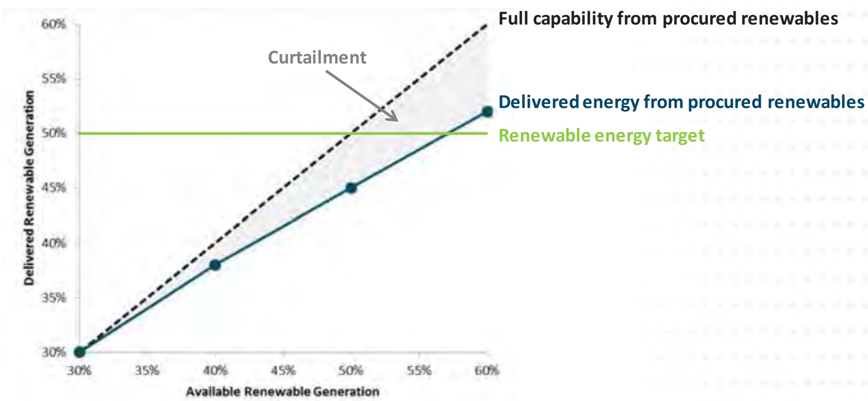
http://renews.biz/67193/vattenfall-pumps-new-life-into-80mw

Teslamotors.com

8

Economics of renewable integration

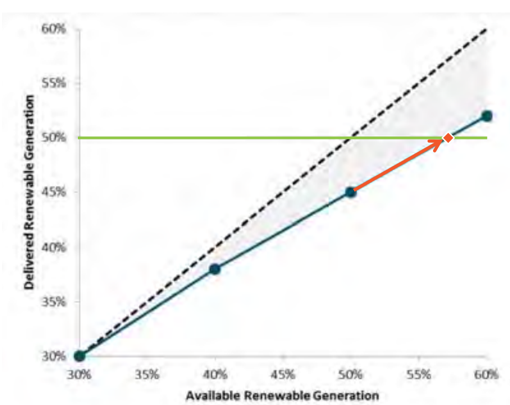
+ **The consequence of failing to supply enough flexibility to integrate renewables is renewable curtailment, or reliability issues**



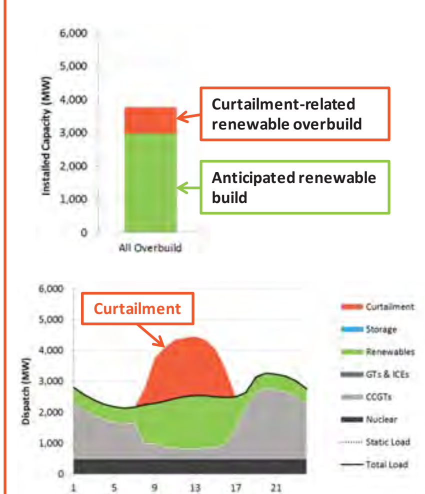
Energy+Environmental Economics 9

Option 1. Overbuild renewables

+ **Overbuilding the renewable fleet allows for policy goal to be met with some allowance for curtailment**



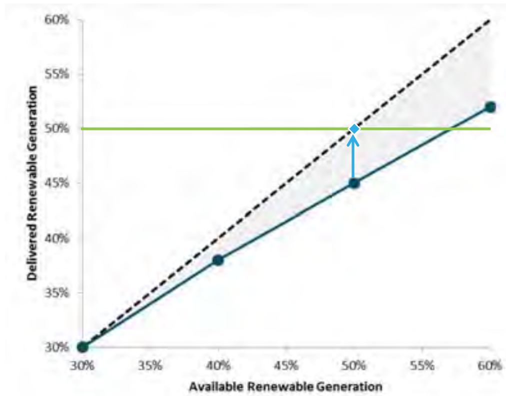
Option 1. Overbuild the renewable fleet



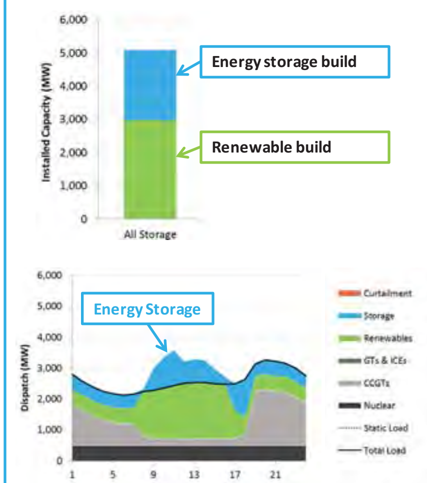
Energy+Environmental Economics 10

Option 2. Pursue integration solutions to avoid overbuild

+ Integration solutions (eg. storage, balancing area consolidation) permit more effective delivery of existing renewable fleet



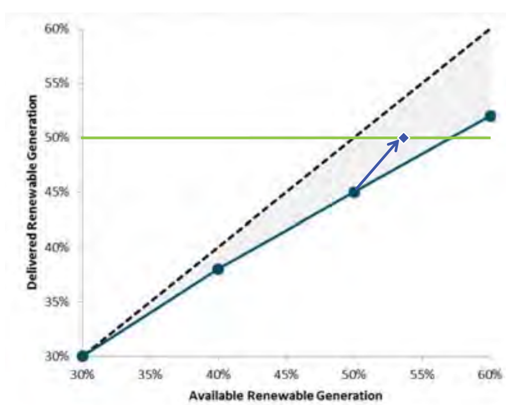
Option 2. Pursue integration solutions



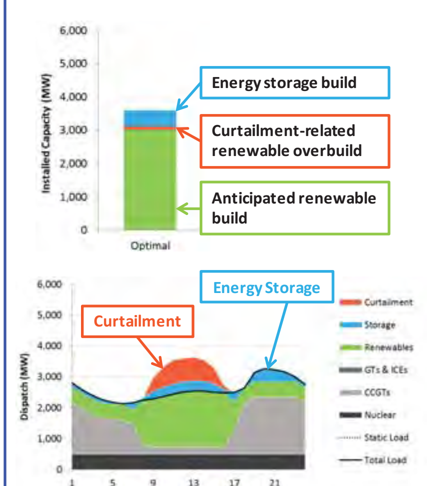
Energy+Environmental Economics 11

Option 3. Determine optimal mix of solutions and overbuild

+ Optimal solution combines multiple strategies based on costs and benefits

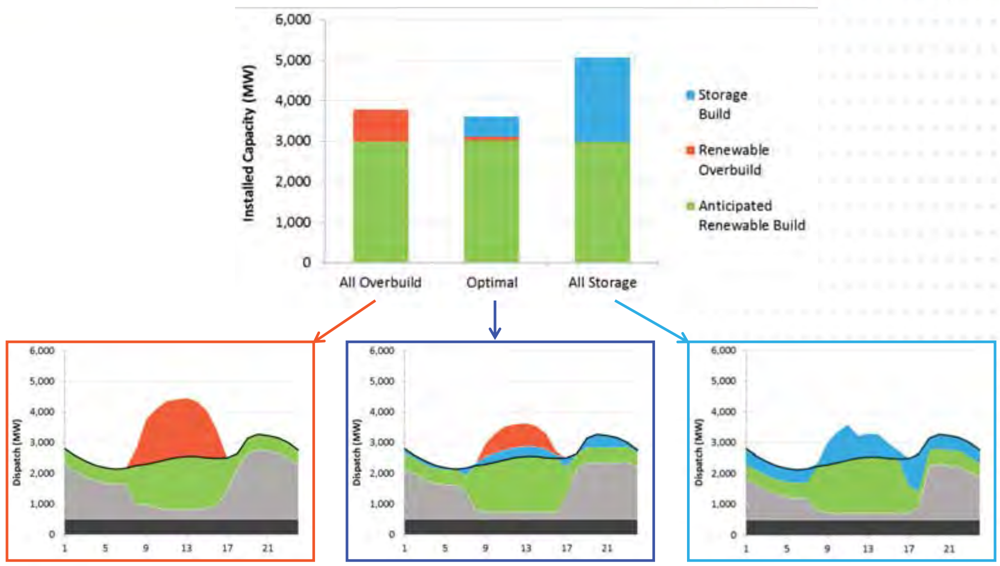


Option 3. Find optimal solution



Energy+Environmental Economics 12

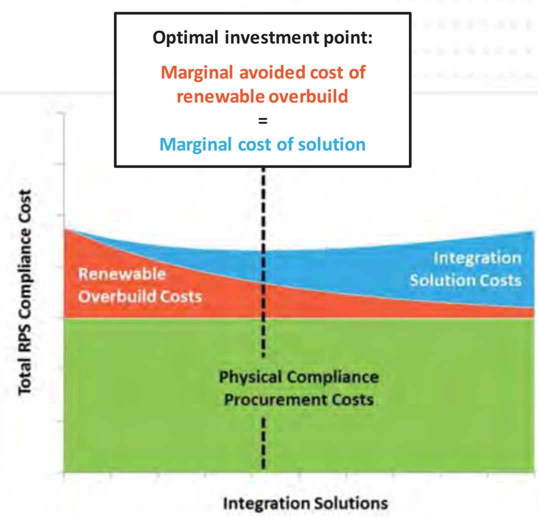
Optimal solution balances non-renewable solutions with overbuild



Energy+Environmental Economics 13

Identifying optimal investment in solutions

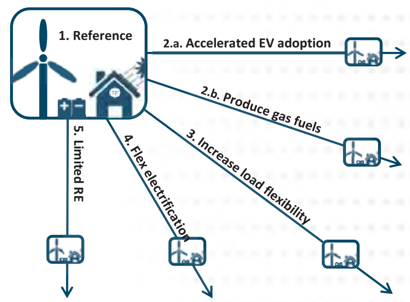
- **Single solution case:**
  - The cost of the solution can be weighed against the avoided cost of overbuilding renewables for RPS compliance
- **Multiple solution case:**
  - Multidimensional optimization
  - Complex interactive effects
  - **Requires models that treat both operations and investment costs**
    - SWITCH and RESOLVE are examples of such models



Energy+Environmental Economics 14

Optimal Expansion Planning

- Optimal expansion planning models can be used to investigate some of the questions the HPUC asked HECO to address in the PSIP update
- Parties can vet model assumptions and models can provide results for a range of curated scenarios
- Such models can be used to begin a constructive discussion about forming a well-balanced, robust portfolio of resources that meets Hawaii's needs



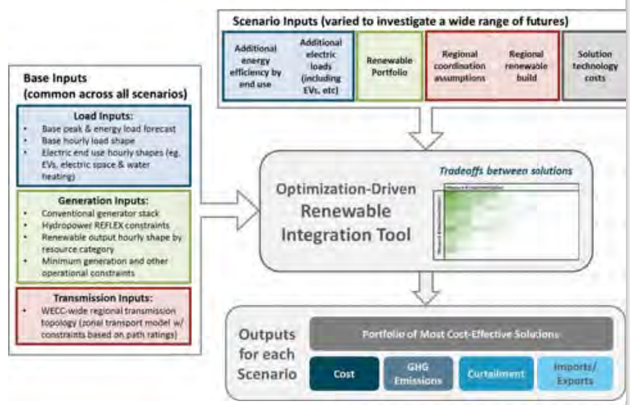
Energy+Environmental Economics

Energy+Environmental Economics

RESOLVE Model

RESOLVE Modeling Framework

+ **Co-optimizes investment and operational decisions over multiple years**
  - Can solve for optimal investments in renewable resources, energy storage, conventional generators
  - Can test value of solutions with unknown or uncertain supply curves, like flexible loads & time-of-use rates



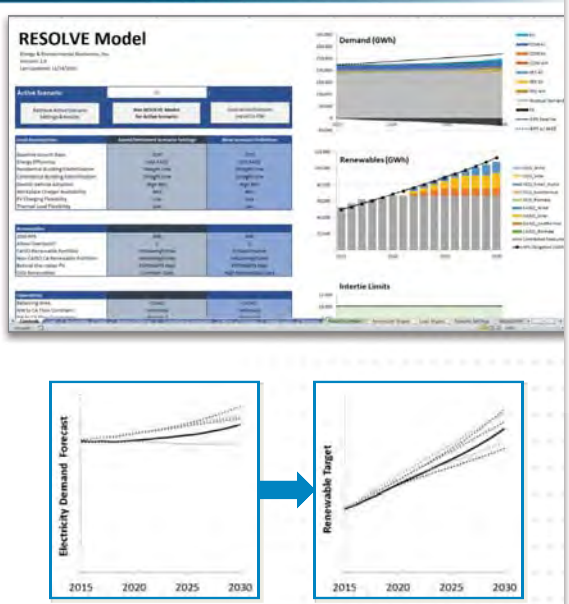
+ **Operational detail focuses on primary drivers of renewable integration challenges**
  - Hourly dispatch with reserve and operating constraints
  - Zonal treatment of interconnection to model flows with increased granularity in primary zone of study

Energy+Environmental Economics 17

Scenario-based analysis produces more robust conclusions

Scenarios determined by:

- Loads by subsector, including residential and commercial thermal loads, electric vehicle adoption, & energy efficiency
  - Dynamically-updated hourly load shapes
- Renewable policies
  - RPS targets and behind-the-meter PV adoption
- Renewable resource costs and potentials
- Costs
  - Renewable, conventional, and storage technology costs, transmission costs
  - Fuel prices



Energy+Environmental Economics 18

Detailed hourly model brings operational challenges into investment decisions

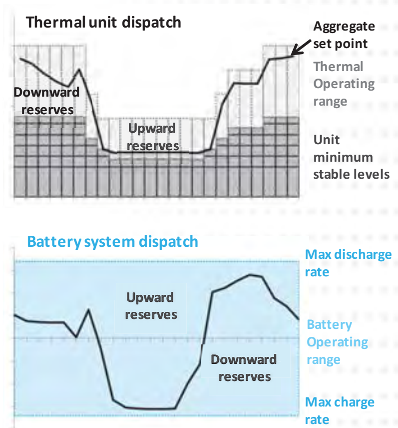
For each year in the simulation, a subset of days are selected and weighted to reflect long-run distributions of:

- Daily load, wind, and solar
- Monthly hydro availability (in CA)

Operations modeled using linear dispatch formulation

- MIP possible for small systems or when runtime is not a constraint; linear approximations for large systems
- Upward and downward operating reserve constraints

Simulates economic dispatch on each day subject to technical operating constraints



Detailed hourly model brings operational challenges into investment decisions

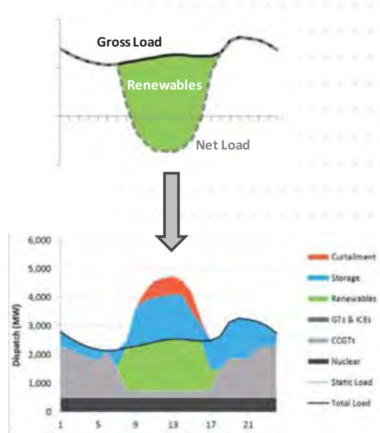
For each year in the simulation, a subset of days are selected and weighted to reflect long-run distributions of:

- Daily load, wind, and solar
- Monthly hydro availability (in CA)

Operations modeled using linear dispatch formulation

- MIP possible for small systems or when runtime is not a constraint; linear approximations for large systems
- Upward and downward operating reserve constraints

Captures operational impacts of renewable integration challenges



Energy+Environmental Economics

RESOLVE
Exploratory Results for O’ahu

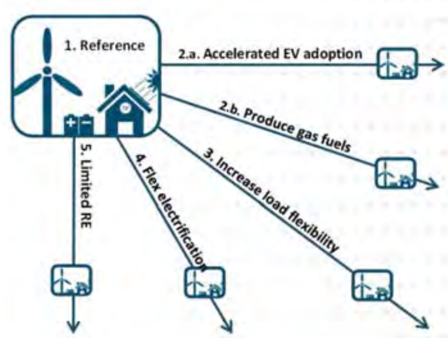
Scenarios

E3 developed several high-level scenarios to represent different policy directions for Hawaii

Cases include:

- Reference
- Flexible Loads
- Direct Electrification
- Flexible Electrification
- Produced Fuels
- Limited Renewable Potential

Fuel price, technology cost, and technology availability sensitivities explored within each high-level scenario



Energy+Environmental Economics

Key Assumptions

+ **Loads**
  - HECO's 2014 load used as basis to begin forecast
  - 1.15% annual load growth assumed through 2045; peak load reaches 1,667 MW in 2045 from 1,170 MW in 2014
  - Transportation load added separately and varies depending on case

Annual Transportation Load (GWh)	2020	2025	2030	2035	2040	2045
Reference	73	239	494	705	847	933
Direct Electrification	110	385	816	1,238	1,521	1,631
Produced Fuels	258	898	1,897	2,960	3,717	4,011

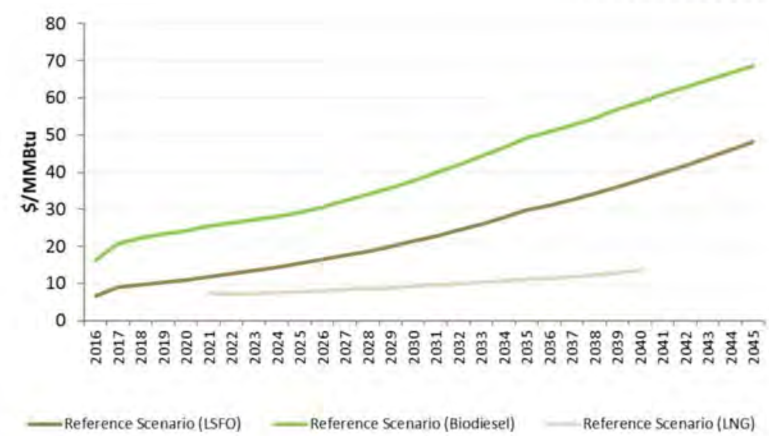
+ **RPS targets: 40% in 2030, 70% in 2040, and 100% in 2045**
+ **O'ahu Resource Potential**
  - 779 MW of rooftop PV assumed built by 2045
  - 154 MW of onshore wind
  - 3,452 MW of utility PV
    - Updated O'ahu resource potential is considerably lower (600 MW), but E3 tested only as a sensitivity

Energy+Environmental Economics

Key Assumptions

Fuel prices

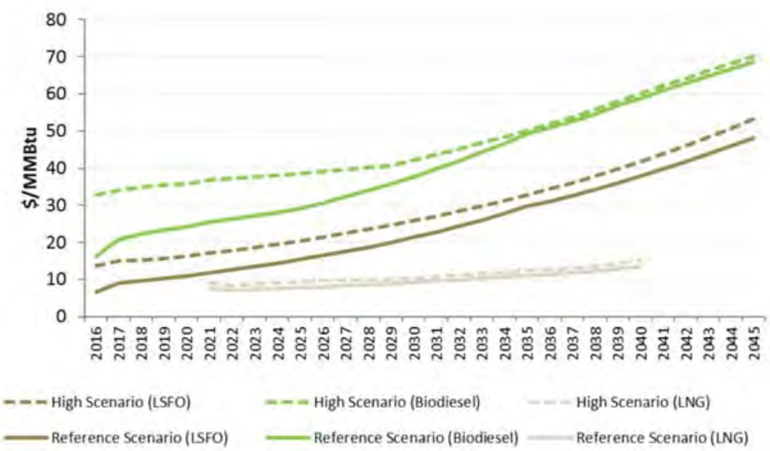
- Reference, Low, and High fuel price scenarios for LSFO, Biodiesel and LNG



Energy+Environmental Economics

Key Assumptions

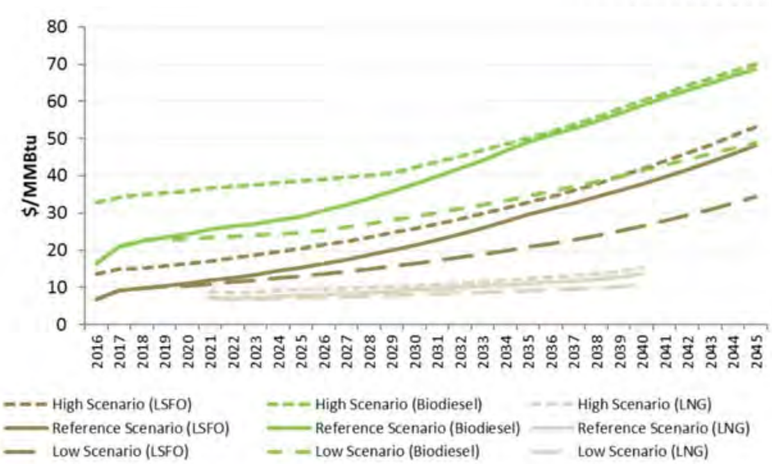
+ **Fuel prices**
  - Reference, Low, and High fuel price scenarios for LSFO, Biodiesel and LNG



Energy+Environmental Economics

Key Assumptions

Fuel prices
- Reference, Low, and High fuel price scenarios for LSFO, Biodiesel and LNG



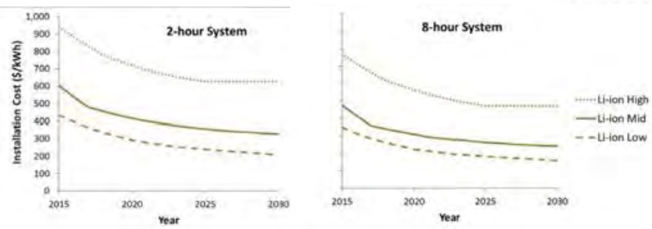
Energy+Environmental Economics

Key Assumptions

+ Generation Technology Costs

$ / kW (AC) Year	Onshore Wind	Offshore Wind	Utility-Scale Solar PV
2016	2405	4971	2719
2020	2253	4115	2201
2025	2263	3356	1890
2030	2181	3112	1689
2035	2095	2940	1524
2040	2020	2818	1376
2045	1942	2703	1242

+ Storage Technology Costs



Energy+Environmental Economics

The LNG Decision

+ **E3 used RESOLVE to find the annualized operating cost and incremental investment cost for a range of policy cases and the HECO fuel price forecasts**
  - Not including cost of LNG storage
+ **Benefits depend on the spread between LNG and fuel oil prices**
  - Strongly tied to the fuel forecast assumptions
+ **Depending on fuel price trajectory, $293-$383 million benefit per year in 2030 in the Reference Case**
+ **Benefits decrease over time as system uses less fuel due to renewable additions**

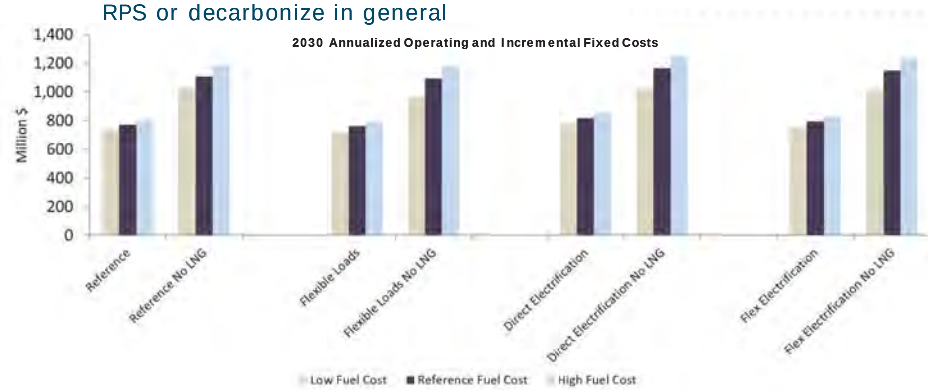
Energy+Environmental Economics

*Cost of LNG storage containers or contracting fixed costs and inter-island cable to access solar from outside O'ahu not included

28

The LNG Decision

- **LNG looks like a short term "least regrets" decision**
  - If the required capital investments in storage, piping, and delivery terminal are less than the estimated benefits
  - If the updated fuel price forecasts developed by HECO are accurate
  - Decision not critically dependent on later decisions to meet 100% RPS or decarbonize in general



Energy+Environmental Economics

*Cost of LNG storage containers or contracting fixed costs and inter-island cable to access solar from outside O'ahu not included

Meeting 100% RPS

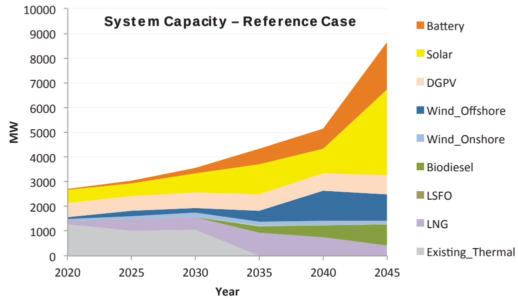
- **O'ahu renewable resource potential is limited**
- **Off-island renewable options are needed to meet the 100% RPS target**
- **Options include:**
  - Offshore wind
  - Inter-island cable – high-solar case?
  - Biofuels
- **Preliminary work shows different integration solutions may be needed depending on option chosen**

Energy+Environmental Economics

30

Meeting 100% RPS, Reference Case

- Meeting the 100% RPS is dominated by capital investments
- Resources with high fixed costs but low variable costs such as photovoltaics (3,452 MW), wind (154 MW onshore wind; 1060 MW offshore wind), and batteries (1938 MW) need to be procured in Reference Case

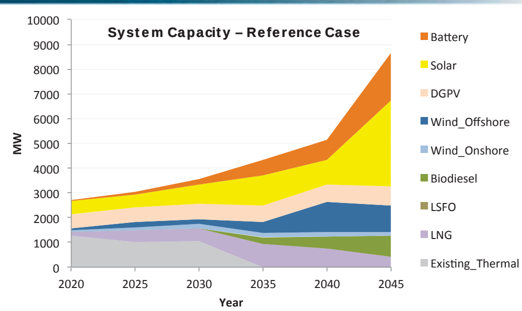


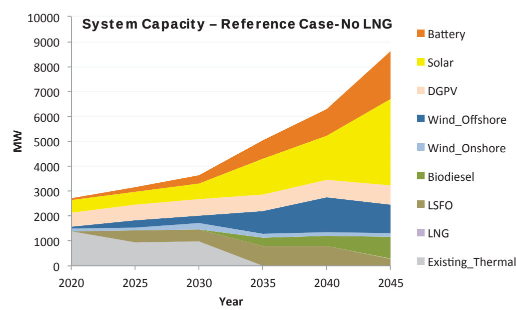
Energy+Environmental Economics

31

Meeting 100% RPS, Reference vs No LNG

- Meeting the 100% RPS is dominated by capital investments
- Resources with high fixed costs but low variable costs such as photovoltaics (3,452 MW), wind (154 MW onshore wind; 1060 MW offshore wind), and batteries (1938 MW) need to be procured in Reference Case
- This is the case with or without LNG, as at 100% RPS, biodiesel is the only available renewable fuel



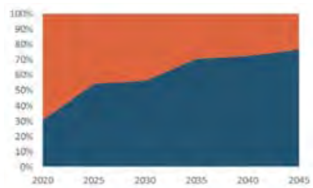


Energy+Environmental Economics

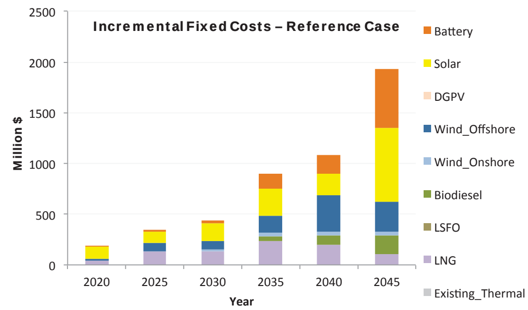
32

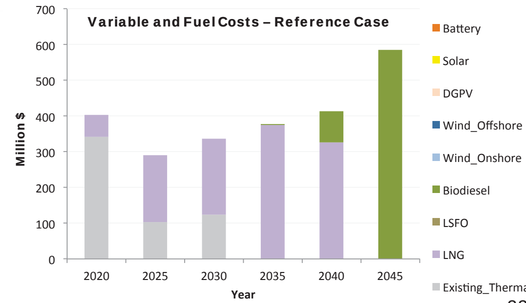
The Cost of Meeting 100% RPS

- Fuel prices are important for determining if LNG conversion and new plant investment is cost-effective, but they become increasingly less important as O'ahu approaches 100% RPS
- Focus shifts to optimal expansion planning for renewables portfolio, transmission, and integration solutions



*Cost of LNG storage containers or contracting fixed costs and inter-island cable to access solar from outside O'ahu not included



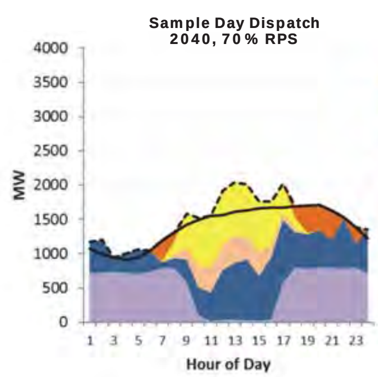


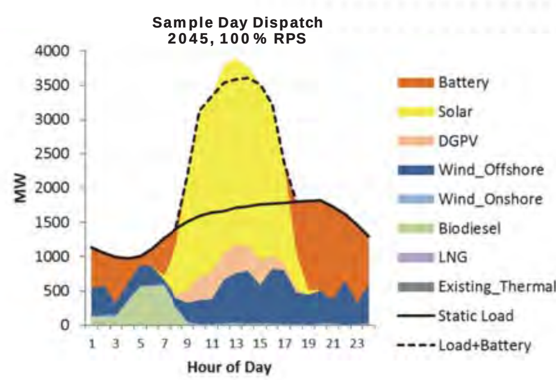
Energy+Environmental Economics

33

Renewable Integration Solutions are Needed

- Batteries are used to store solar energy during the day and dispatch that energy to help meet load when the sun is not shining
- Stored solar energy complemented by offshore wind and biofuels



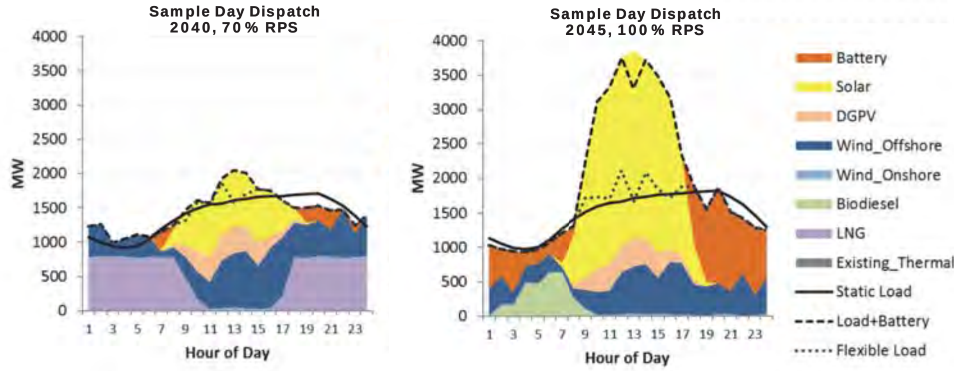


Energy+Environmental Economics

34

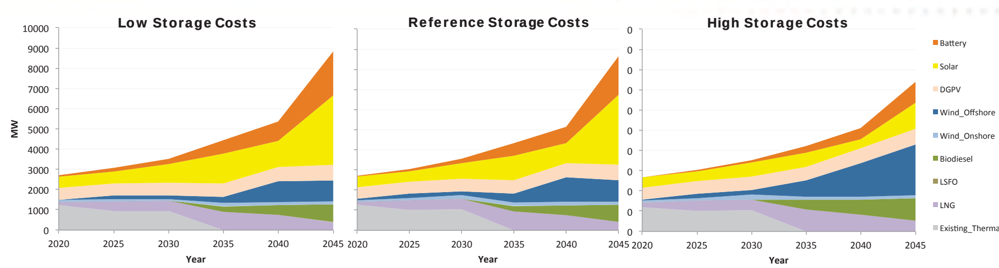
Renewable Integration Solutions: Flexible Loads

- **Flexibility from load and electric vehicles can reduce the cost of meeting the 100% RPS target and should be explored in more detail**
  - Battery procurement is lower in the flexible load cases, providing savings: 1,938 MW of battery storage in the Reference Case becomes 1,698 MW in the Flexible Loads Case



Energy+Environmental Economics 35

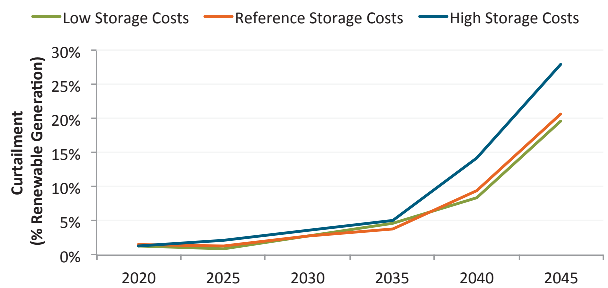
Renewable Integration Solutions: the Role of Storage



- **Given high costs, RESOLVE defers battery investment as long as possible.**
- **Through 2030, storage costs have little impact on the optimal build**
  - Less than 300 MW of batteries installed in all cases
- **Beyond 2030, the effect of storage costs on the optimal portfolio of renewables can be dramatic**
  - If battery costs decline substantially, RESOLVE will select more solar PV over offshore wind and biofuels.

Energy+Environmental Economics 36

Renewable Integration Solutions: the Role of Storage



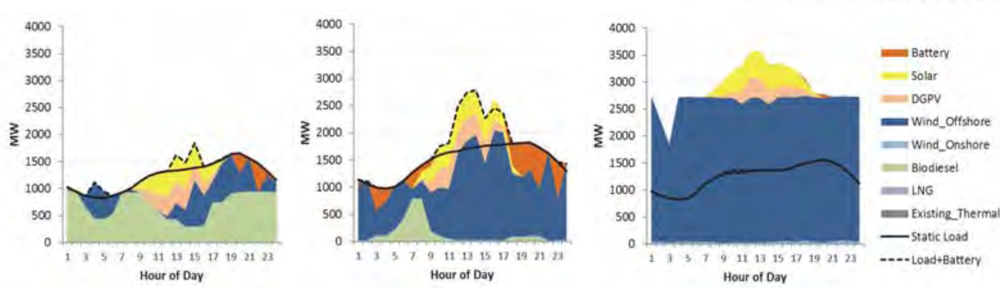
- The expected curtailment over time mirrors the renewable build out schedule.
- Through 2030, storage costs have little impact on the optimal build
  - Less than 300 MW of batteries installed in all cases
- Beyond 2030, higher storage costs will lead to both less solar and higher expected curtailment

Energy+Environmental Economics 37

Integrating Wind

- Unlike solar, which exhibits a diurnal generation pattern, wind does not follow a cyclical pattern
- Daily and seasonal variations in wind output can be large, posing balancing challenges

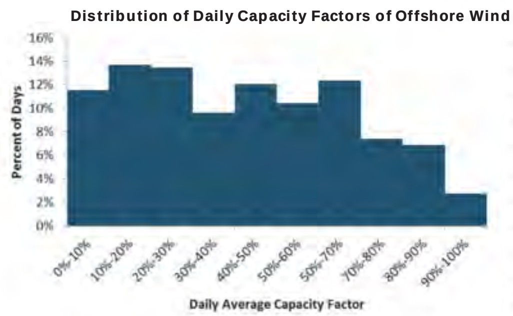
Dispatch on Three Sample Days
Limited Solar Scenario
2045



Energy+Environmental Economics 38

Integrating Wind

- **Solar curtailment can be readily addressed with batteries and flexible loads, which can provide daily balancing**
- **Providing balancing for wind probably requires integration solutions beyond batteries**
  - High-wind case is often paired with a produced decarbonized fuel like hydrogen

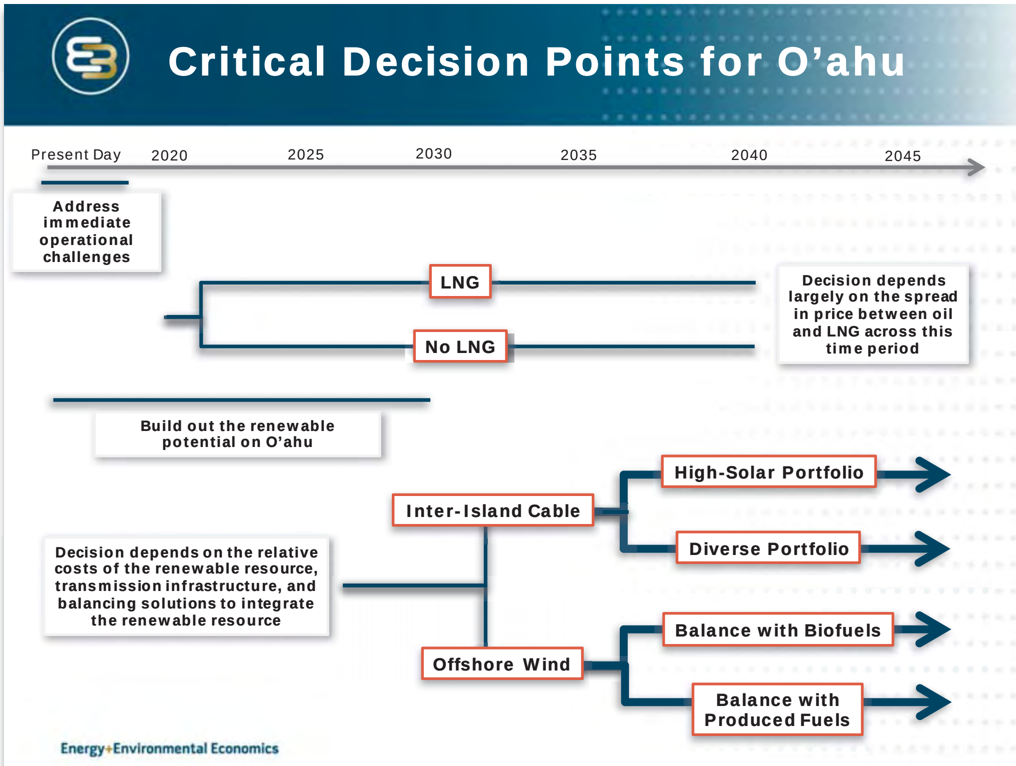


Energy+Environmental Economics

39

Energy+Environmental Economics

Conclusions and Next Steps



Potential Next Steps

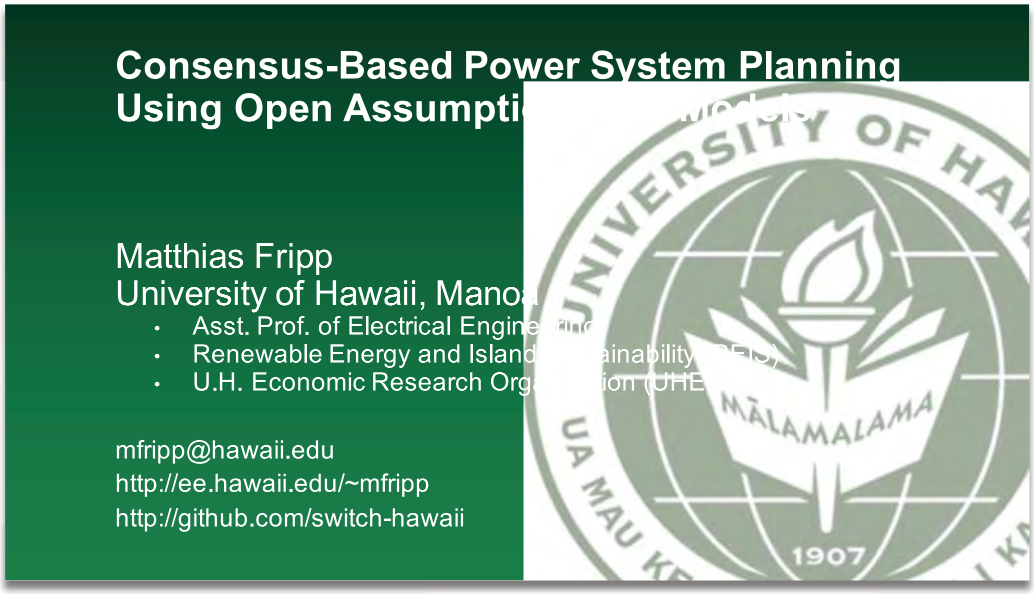
+ Fully align E3's assumptions with HECO's and create process for validating assumptions
+ Use RESOLVE to calculate a breakeven fuel price spread to help commission decide about robustness of LNG decision
+ Develop an Inter-Island Cable case
+ Use RESOLVE to develop a least-cost plan that is not constrained to be compliant with the 100% RPS goal

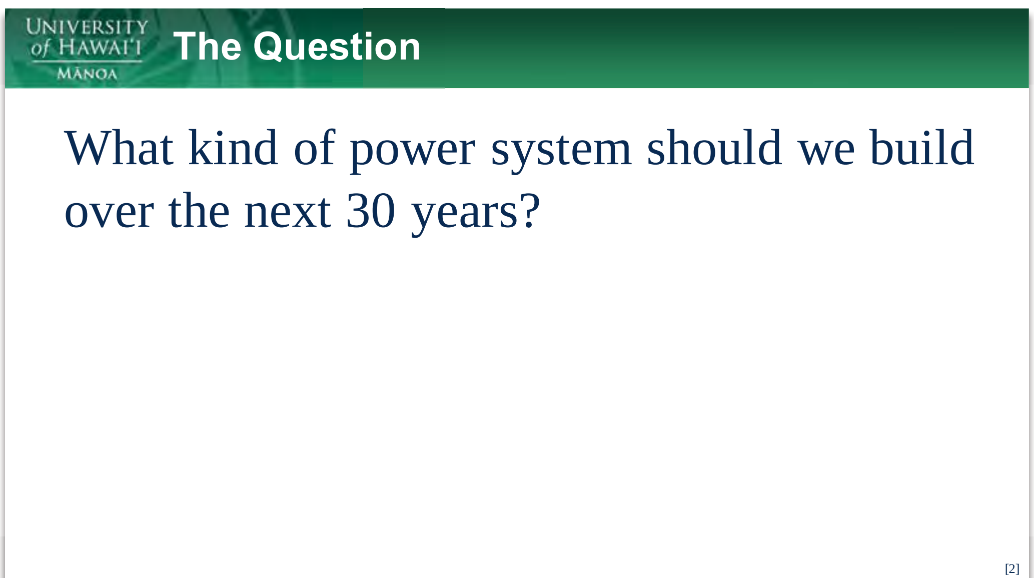
Energy+Environmental Economics

42


Energy+Environmental Economics
Thank You!
Energy and Environmental Economics, Inc. (E3)
101 Montgomery Street, Suite 1600
San Francisco, CA 94104
Tel 415-391-5100
www.ethree.com

Blue Planet Presentation: Third Stakeholder Conference





The Process We've Been Using

- HECO makes investment plans inside a "black box"
- Community and PUC try to judge their merit
- Does not lead to consensus(!)
  - Plans are monolithic, and different options are hard to compare

[3]

A Consensus-Based Approach

- HECO and stakeholders **agree on assumptions about the future**
  - Cost of renewable energy projects, fossil fuels and biofuels; screening rules for renewable energy projects; future renewable energy targets; possible range for these values; willingness to pay higher near-term costs to lower long-term risks
  - If stakeholders disagree on some assumptions, they can be used as sensitivity cases
- HECO and stakeholders **agree on optimization techniques** to choose the least-cost investment plan
- If we can agree on these smaller, more concrete questions, then **we get an overall plan we can agree on**

[4]

UNIVERSITY of HAWAI'I MĀNOA

Proposal

- HECO works with stakeholders to agree on assumptions and questions *before* producing a plan
  - Have already made amazing progress with PSIPs
- HECO works with stakeholders to agree on modeling methods
  - E3 RESOLVE is a great step in this direction
- HECO produces optimal plans using these assumptions and methods
- Iterative process
  - Start with early data and preliminary results, then improve
  - If an "optimal" plan is implausible or unattractive, it's a starting point for constructive discussion and further analysis
    - Do we really want 30% biofuels? What would we build instead if we could only use 5%? How much would that cost?
  - Eventually, this framework can also be used for selecting RFP bids, judging prudency of investments, or even running a full-fledged capacity market

[5]

UNIVERSITY of HAWAI'I MĀNOA

Data Recommendations

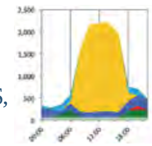
- More realistic screens for solar projects
  - No existing or proposed Oahu projects would meet the screens from 4/1/16 PSIP
  - 20%+ slope is possible at reasonable cost
  - Small parcels can be used and can be joined together (maybe 500 kW for smallest flat sub-parcel?)
- Consider using bulk electricity storage
  - Batteries, pumped storage hydro, hydrogen could all be cost-effective, depending on cost of other resources
  - Solar+storage option is especially important with high biodiesel prices

[6]

UNIVERSITY of HAWAI'I MANOA

Use a State-of-the-Art Optimization Model as the Heart of Portfolio Selection

- SWITCH power system planning model
  - Written by Matthias Fripp in 2008
  - Now open-source, used and maintained by multiple contributors
  - Oahu version is now running with resource data based on PSIP, OWITS, HSIS, NREL NSRDB
  - All data and code are available from http://github.com/switch-hawaii
- Energy+Environmental Economics (E3) RESOLVE
  - Developed by E3 based on SWITCH
  - Strong team for framing analysis, preparing datasets and running the model
- No other capacity planning models can do this job
  - optimize multi-decade power system investments based on chronological, hourly behavior of renewables, storage and demand response



[7]

UNIVERSITY of HAWAI'I MANOA

SWITCH Model Design

Objective

- minimize total cost of electricity production in 2021–2052 (net present value)

Constraints

- policy constraints (RPS, MATS)
- provide enough electricity and reserves every hour
- physical limits of equipment and project sites

Decision variables (co-optimized)

- **Investments**: How much capacity to add of each technology
  - Wind, solar, fossil-fueled and hydro power plants; batteries and hydrogen storage; transmission
  - Investments occur in 2021, 2029, 2037 and 2045
- **Operation:** Power production or consumption by each project and responsive demand, each hour
  - 12-24 days of hourly behavior are modeled during each investment period
  - Follow-up production-cost model can test and plans using 8760+ hours

Open-source model and data available at http://www.switch-model.org

[8]

TASC Presentation: Third Stakeholder Conference

PSIP Chapter 9 "Next Steps"?

Addressing System Security with Renewable Spinning Reserves

THE ALLIANCE FOR SOLAR CHOICE

Overview

- Excess Energy
- Curtailment
- System Contingency Batteries
- Leveraging Solar Spinning Reserves

THE ALLIANCE FOR SOLAR CHOICE

Excess Energy

- Excess energy is an opportunity.
- Excess energy is a problem if you are not looking to leverage renewable resources to achieve 100% penetration.
- Renewable spinning reserves in significant quantity allows must run conventional generation to be shutdown.
- The only must run generation is renewable.

THE ALLIANCE FOR SOLAR CHOICE

Curtailment of DERs and utility scale renewables

- Utilizing curtailment as a utility tool ensures investments in utility scale system security batteries.
- Curtailment and ramp rate limits increase cost of renewables, increases consumption of fossil fuels, and decreases system reliability.

THE ALLIANCE FOR SOLAR CHOICE

Systems Contingency Batteries

- Large quantities of utility scale system security batteries are only needed at low renewable penetrations levels, <u>*if*</u> utility curtailment is a practice, and customer resources are not leveraged.
- Smart homes and businesses in conjunction with utility scale resistive frequency controls can provide the same services as a long term solution.

THE ALLIANCE FOR SOLAR CHOICE

Addressing System Security with Renewable Spinning Reserves

- Resources to unlock renewable spinning reserves
  - Resistive frequency control
  - Synchronous condensers
  - Flywheels and/or bulk energy storage
  - Smart homes and businesses
  - Significant investments in renewable resources

THE ALLIANCE FOR SOLAR CHOICE

Dynamic Resistive Frequency Control Unleashes Renewable Spinning Reserves

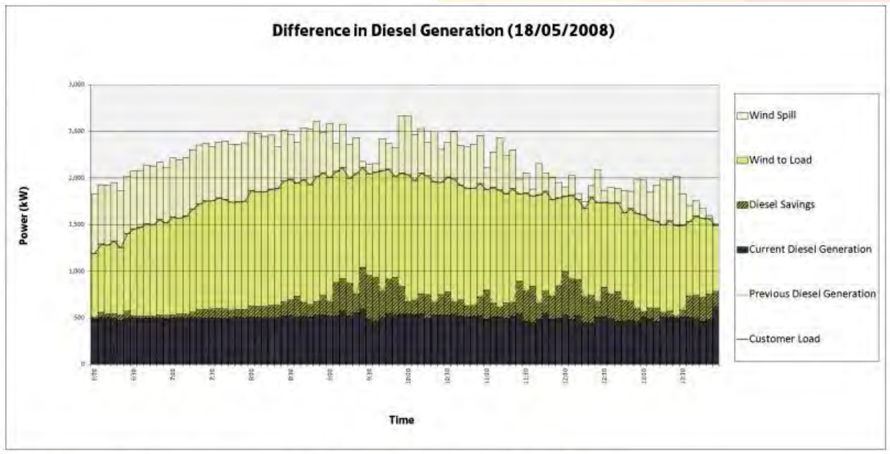


Figure 1: Comparison between current control method and new resistor control method

THE ALLIANCE FOR SOLAR CHOICE

Hydro Tasmania
The power of natural thinking

Morgan Stanley: Australian utilities underestimate disruptive power of solar+storage

- Australian utilities are underestimating the disruptive potential of solar-plus-storage technology, according to a new report from investment bank Morgan Stanley.
- The report estimates that solar and storage technology will be adopted four times more quickly in Australia than the country's utilities expect.
- Morgan Stanley estimates battery storage will grow from about 2,000 Australian homes now to one million by 2020 or as high as two million homes by 2020 in its most optimistic estimate.
- http://www.utilitydive.com/news/morgan-stanley-australian-utilities-underestimate-disruptive-power-of-sola/421237/

THE ALLIANCE FOR SOLAR CHOICE

DBEDT Presentation: Third Stakeholder Conference

PSIP Comments and Next Steps

Chris Yunker

Energy Systems & Planning Branch Manager
Hawaii State Energy Office
Department of Business Economic Development and Tourism

PSIP Stakeholder Conference

Jun 28, 2016

HAWAII STATE Energy Office

PSIP Analytical Requirement

Questions to be answered for a PSIP Decision:

What are the **actions that need to be taken in the next 5 years** for Hawaii to achieve our objective of 100% renewables in 2045?

- Establishes prudency of the path forward

How much analysis, and **how detailed** does the analysis need to be, for the Commission **to reach a decision on elements within the 5 year plan**?

- Enough analysis and detail to reach a decision point on whether key elements that drive the 5 year action plan are prudent

What should the 5 year action plan provide?

- Guidance on the sequence of resource decision points such that the utility can solicit and acquire the resources over the next 5 years

It is not necessary to adopt the outer year portion of a roadmap to 100% renewables

What is important is to adopt a 5 year plan that can effectively accommodate multiple pathways to 100% renewables

HAWAII STATE Energy Office

PSIP Remaining Scope

Gain a common understanding on the resource potentials, forecasts and constraints for each island to be analyzed

- Provide comprehensive list of resources the HECO Companies will include in the RESOLVE runs, which should be provided to stakeholders.
- Provide a template for collecting the information required to add a new resources, constraints, or forecasts in the RESOLVE model.

Develop a select number of scenarios for a capacity expansion model to run for each island and interconnected grid combinations

- Calibrate HECO's capacity expansion model with stakeholders who choose to run a capacity expansion model independently
- Establish breakeven cable costs to screen for viable scenarios, if any, to do further analysis on

DBEDT HAWAII STATE Energy Office

PSIP Remaining Scope (Cont.)

Establish what, if any, procurement actions within the 5 year action plan are impacted by a viable interconnected grid scenario

Establish what, if any, interconnected grid options are viable long run economic options to conduct further analysis on
(not required for a PSIP ruling, part of a PSIP ruling)

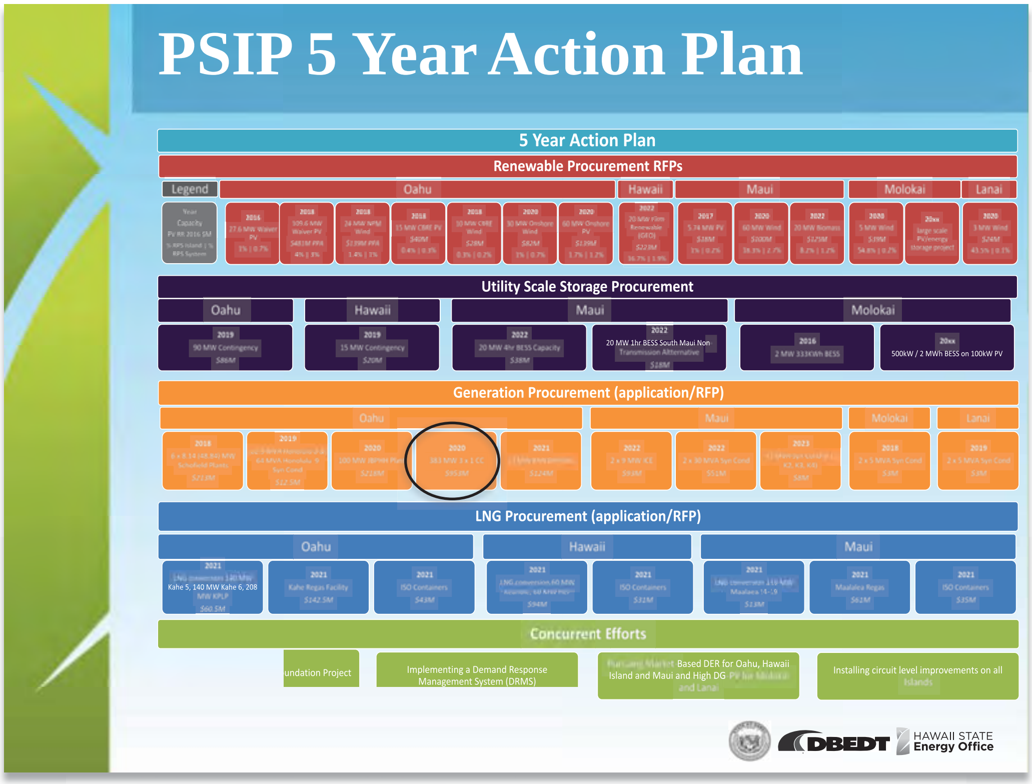
- Develop costs estimate for viable options that include the procurement, installation and interconnection of the undersea cable, as well as related grid upgrades.

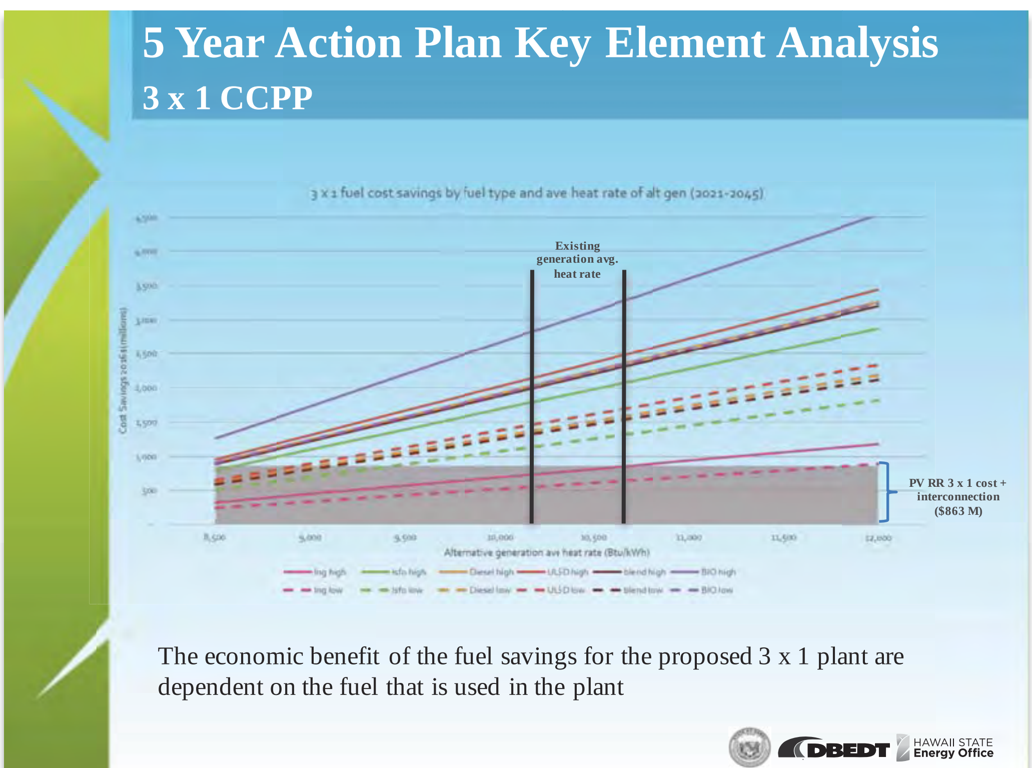
If warranted **run capacity expansion model which includes interisland cable as a resource option**

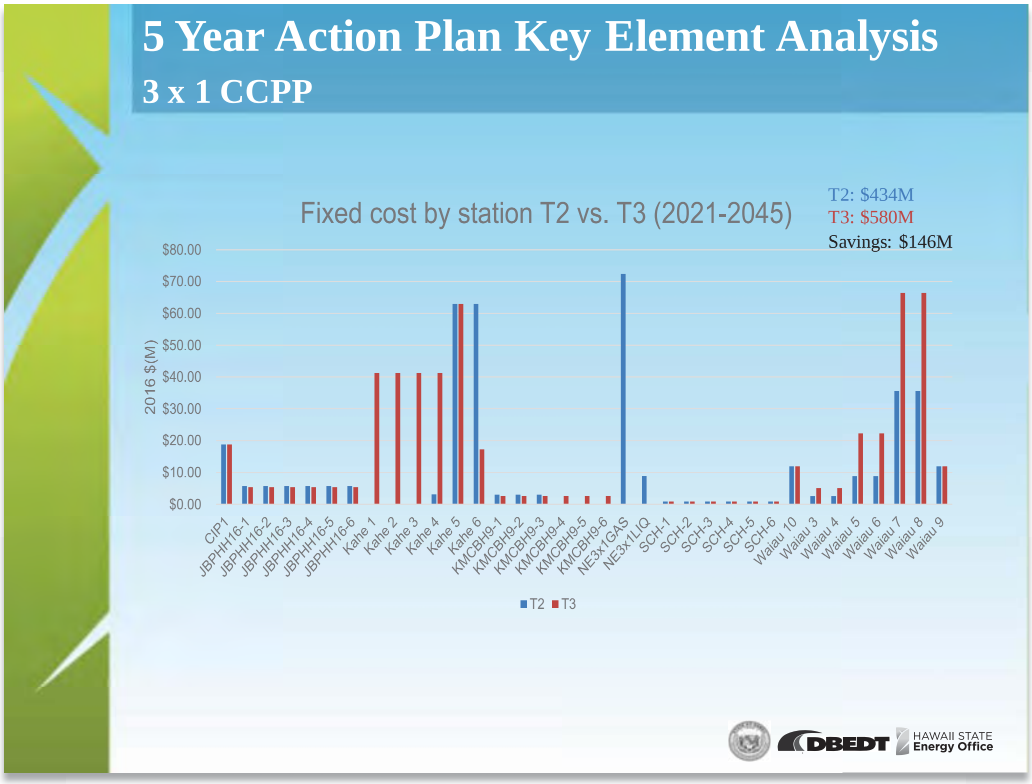
- Identify candidate portfolios and key investments within the resulting 5 year plans

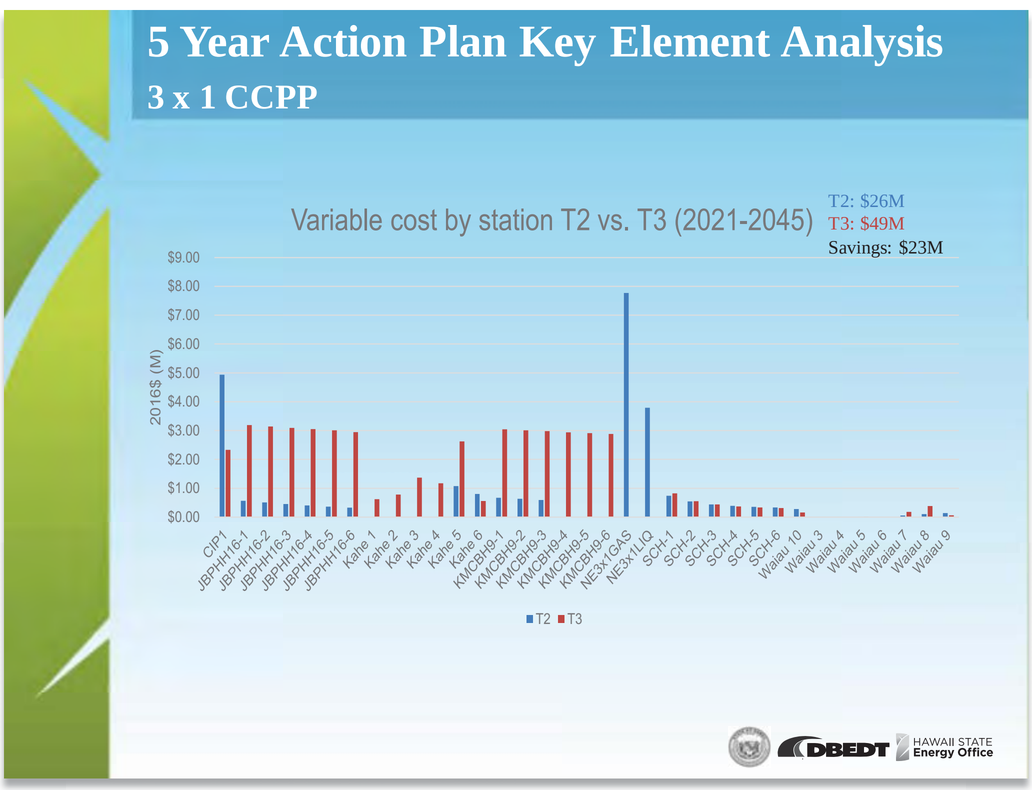
For candidate portfolios **construct case runs to analyze the discrete benefits and the drivers of those benefits for key investments** to support a Commission ruling of prudency

DBEDT HAWAII STATE Energy Office


PSIP 5 Year Action Plan
5 Year Action Plan
Renewable Procurement RFPs
Legend
Oahu
Hawaii
Maui
Molokai
Lanai
Utility Scale Storage Procurement
Oahu
Hawaii
Maui
Molokai
20 MW 1hr BESS South Maui Non Transmission Alternative
500kW / 2 MWh BESS on 100kW PV
Generation Procurement (application/RFP)
LNG Procurement (application/RFP)
Oahu
Hawaii
Maui
Kahe 5, 140 MW Kahe 6, 208 MW KPLP
Concurrent Efforts
undation Project
Implementing a Demand Response Management System (DRMS)
Based DER for Oahu, Hawaii Island and Maui and High DG
Installing circuit level improvements on all
DBEDT
HAWAII STATE Energy Office

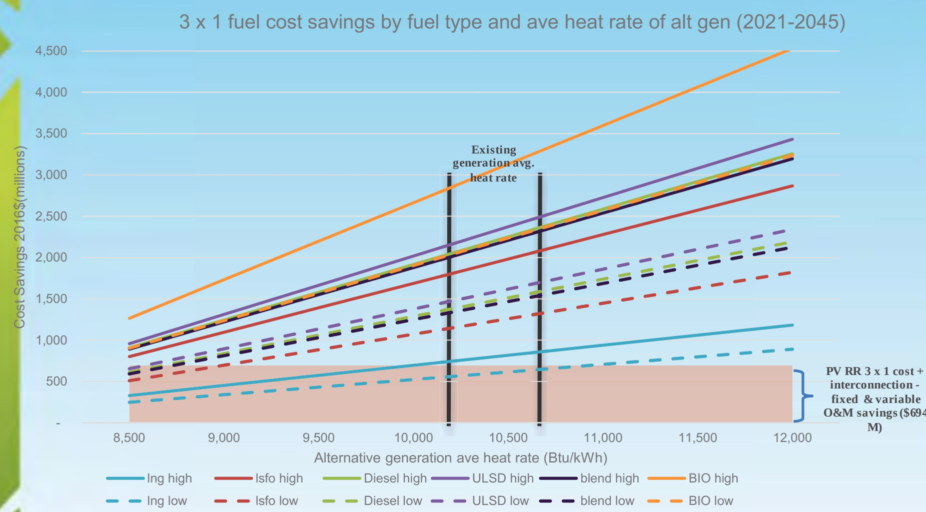

5 Year Action Plan Key Element Analysis
3 x 1 CCPP
3 x 1 fuel cost savings by fuel type and ave heat rate of alt gen (2021-2045)
Existing generation avg. heat rate
PV RR 3 x 1 cost + interconnection ($863 M)
Alternative generation ave heat rate (Btu/kWh)
The economic benefit of the fuel savings for the proposed 3 x 1 plant are dependent on the fuel that is used in the plant
DBEDT
HAWAII STATE Energy Office


5 Year Action Plan Key Element Analysis
3 x 1 CCPP
Fixed cost by station T2 vs. T3 (2021-2045)
T2: $434M
T3: $580M
Savings: $146M
2016 $(M)
$80.00
$70.00
$60.00
$50.00
$40.00
$30.00
$20.00
$10.00
$0.00
CIP1
JBPHH16-1
JBPHH16-2
JBPHH16-3
JBPHH16-4
JBPHH16-5
JBPHH16-6
Kahe 1
Kahe 2
Kahe 3
Kahe 4
Kahe 5
Kahe 6
KMCBH9-1
KMCBH9-2
KMCBH9-3
KMCBH9-4
KMCBH9-5
KMCBH9-6
NE3x1GAS
NE3x1LIQ
SCH-1
SCH-2
SCH-3
SCH-4
SCH-5
SCH-6
Waiau 10
Waiau 3
Waiau 4
Waiau 5
Waiau 6
Waiau 7
Waiau 8
Waiau 9
T2
T3
DBEDT
HAWAII STATE Energy Office


5 Year Action Plan Key Element Analysis
3 x 1 CCPP
Variable cost by station T2 vs. T3 (2021-2045)
T2: $26M
T3: $49M
Savings: $23M
2016$ (M)
$9.00
$8.00
$7.00
$6.00
$5.00
$4.00
$3.00
$2.00
$1.00
$0.00
CIP1
JBPHH16-1
JBPHH16-2
JBPHH16-3
JBPHH16-4
JBPHH16-5
JBPHH16-6
Kahe 1
Kahe 2
Kahe 3
Kahe 4
Kahe 5
Kahe 6
KMCBH9-1
KMCBH9-2
KMCBH9-3
KMCBH9-4
KMCBH9-5
KMCBH9-6
NE3x1GAS
NE3x1LIQ
SCH-1
SCH-2
SCH-3
SCH-4
SCH-5
SCH-6
Waiau 10
Waiau 3
Waiau 4
Waiau 5
Waiau 6
Waiau 7
Waiau 8
Waiau 9
T2
T3
DBEDT
HAWAII STATE Energy Office

5 Year Action Plan Key Element Analysis

3 x 1 CCPP



There are other additional benefits, alternative fuel price forecasts and potential alternative resources which will have an impact on whether or not a 3 x 1 CCPP is prudent

DBEDT HAWAII STATE Energy Office

In Summary

The 5 year action plan and the guidance it provides is what should be adopted in a PSIP ruling

- The remaining pathway to 100% is simply to show the 5 year action plan is prudent

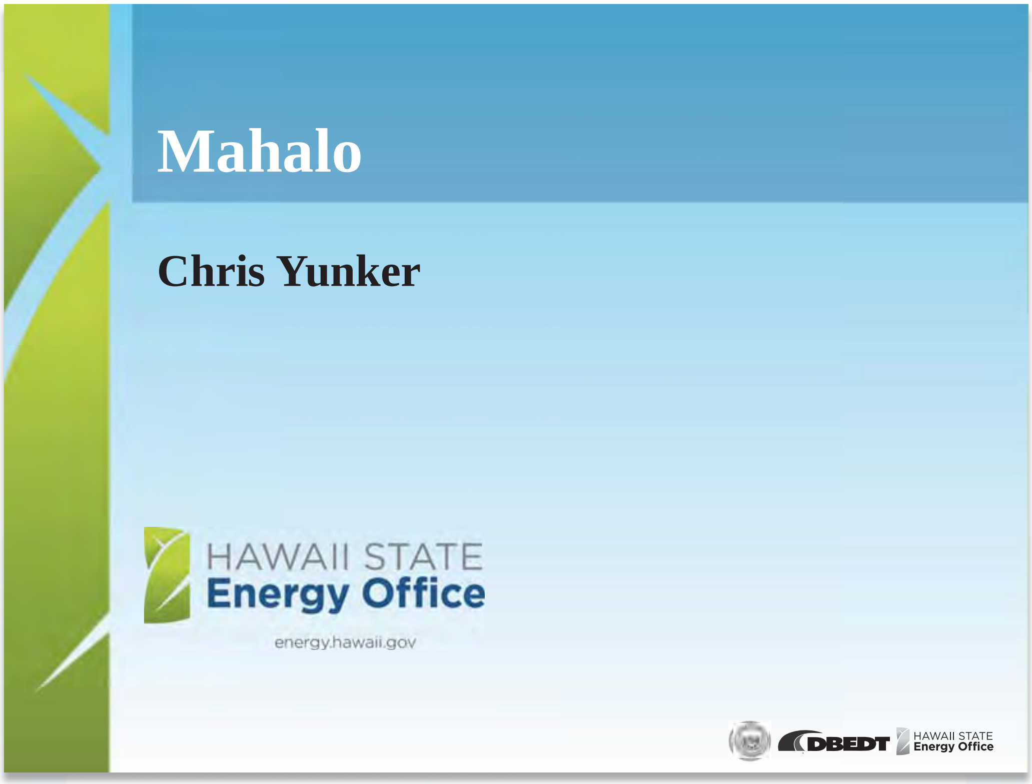
There needs to be a clearly agreed upon analytical scope, analytical process and supporting procedural timeline that allows for the completion of the PSIP

- Expansion model to assure relevant candidate portfolios are identified
- Case runs to understand the drivers of costs and benefits for alternative candidate 5 year action plans

There needs to be a detailed breakdown of costs and benefits presented for key elements in the 5 year action plan so that a decision point to move forward can be reached

- Detailed costs for specific resources would be part of an application

DBEDT HAWAII STATE Energy Office


Mahalo
Chris Yunker
HAWAII STATE
Energy Office
energy.hawaii.gov
DBEDT
HAWAII STATE
Energy Office

Ulupono Initiative Presentation: Third Stakeholder Conference

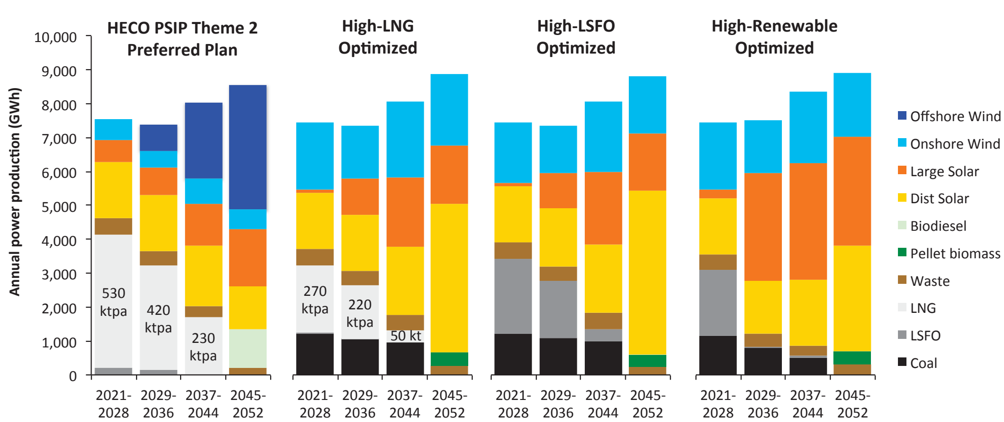
Valuing Risk Matters

- Renewable Power are a hedge against fossil fuel risk
- Quantitatively incorporating risk can lead to new conclusions regarding the optimal resource mix
- We are presenting two approaches:
  - Monte Carlo
  - Market Based Hedge

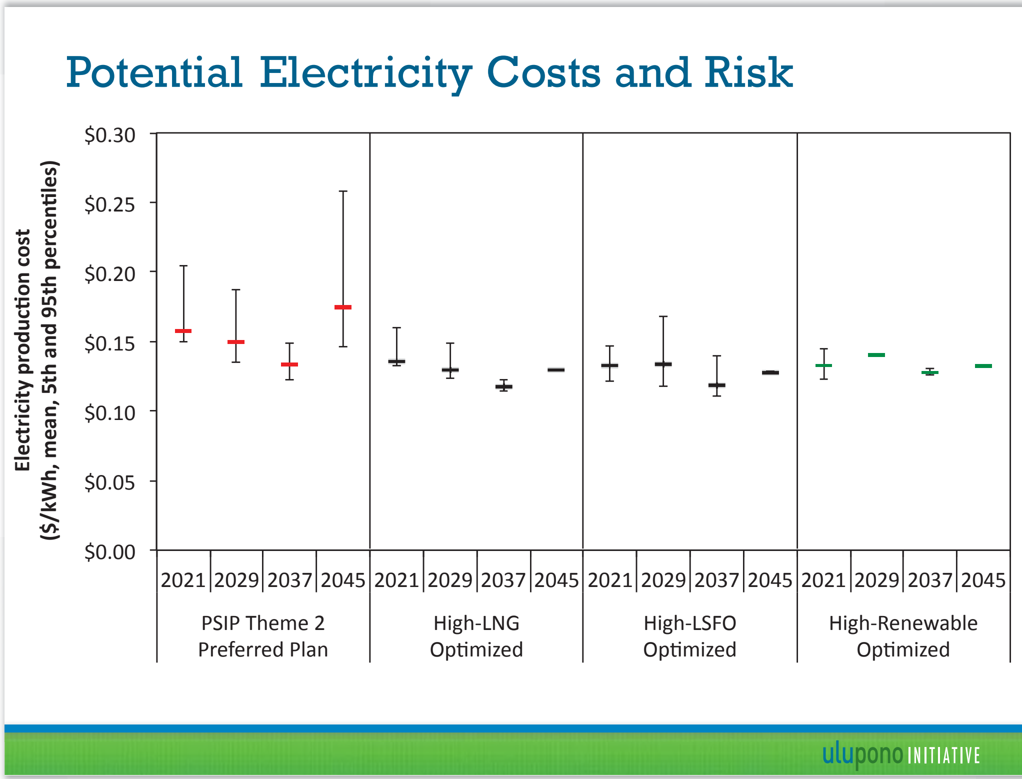
We propose a path forward to understand of our situation and the tradeoffs of our choices

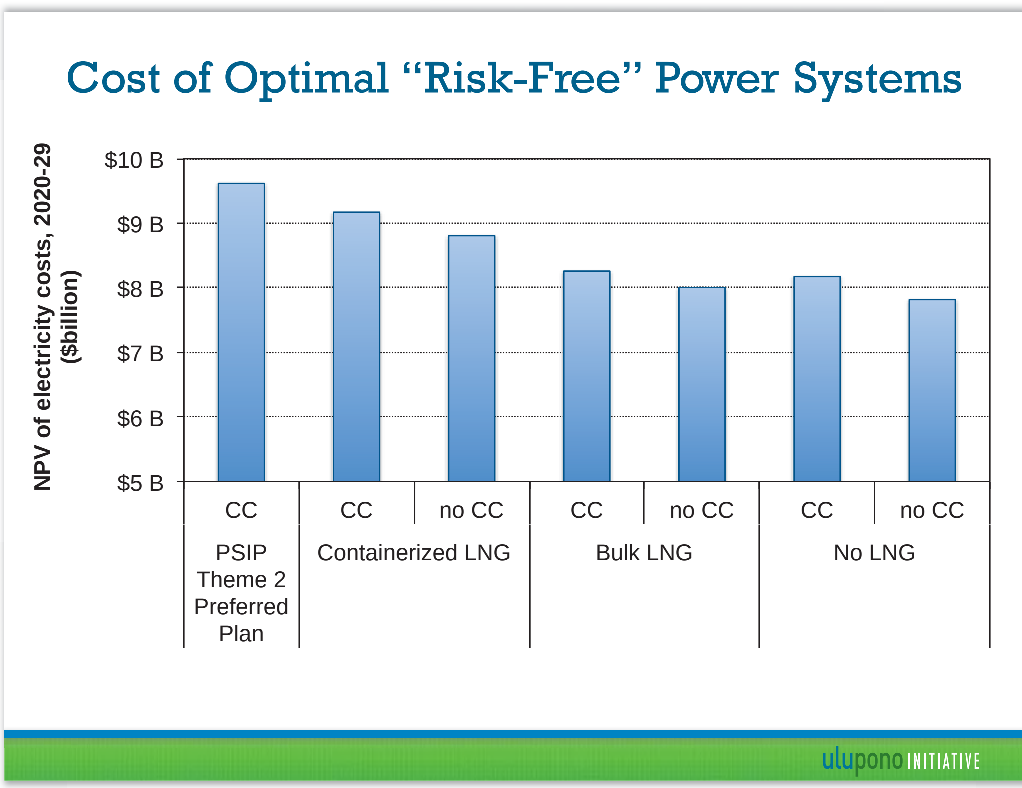
ulupono INITIATIVE

Selected Power System Designs - Energy

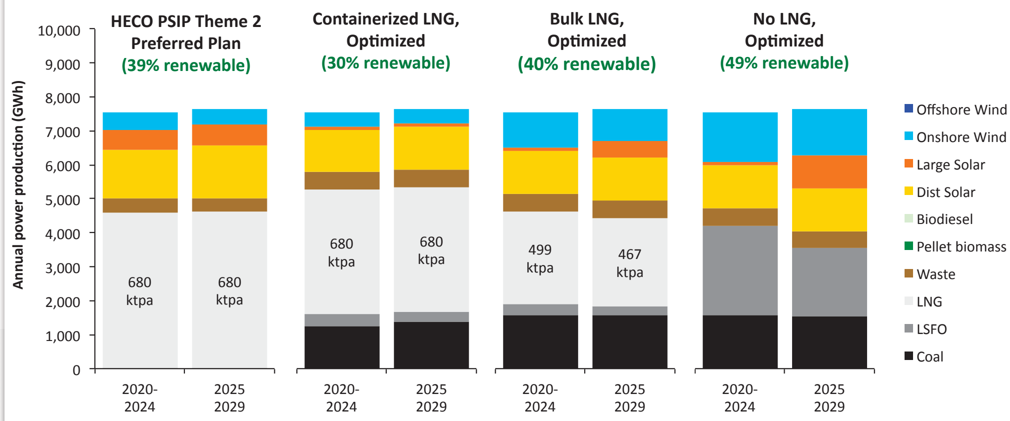


ulupono INITIATIVE


Potential Electricity Costs and Risk
Electricity production cost ($/kWh, mean, 5th and 95th percentiles)
$0.30
$0.25
$0.20
$0.15
$0.10
$0.05
$0.00
2021 2029 2037 2045 2021 2029 2037 2045 2021 2029 2037 2045 2021 2029 2037 2045
PSIP Theme 2 Preferred Plan
High-LNG Optimized
High-LSFO Optimized
High-Renewable Optimized
ulupono INITIATIVE


Cost of Optimal "Risk-Free" Power Systems
NPV of electricity costs, 2020-29 ($billion)
$10 B
$9 B
$8 B
$7 B
$6 B
$5 B
CC
CC
no CC
CC
no CC
CC
no CC
PSIP Theme 2 Preferred Plan
Containerized LNG
Bulk LNG
No LNG
ulupono INITIATIVE

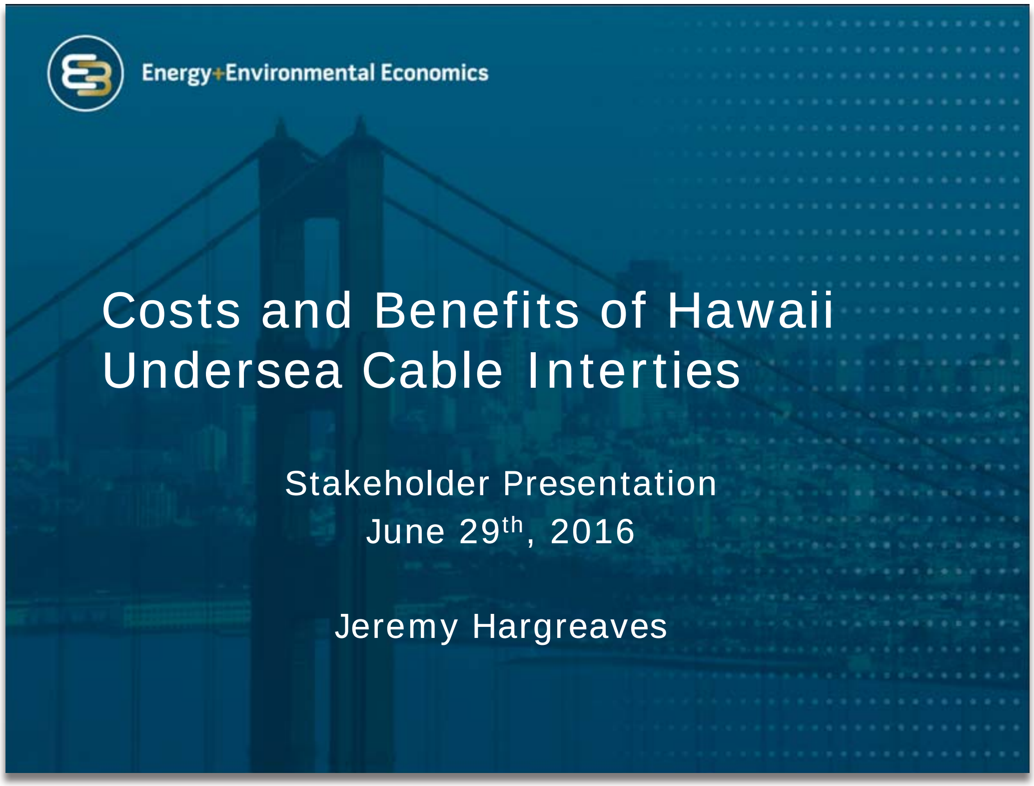
Optimal Power System Operation, Without New Combined Cycle Plant



Recommended Next Steps

- To extent not addressed in PUC Order 33320, Commission provides detailed guidance for revised PSIPs
- Commission Technical Session re:
  - Modeling, data parameters and assumptions, nature and extent of data used by RESOLVE model
  - Agreement on using modified RESOLVE model, on a transparent basis, to:
    - identify 3-5 alternative generation resource mixes to achieve 100% clean energy by 2045. with 5-year action plan
    - identify key decision Commission must make to implement each plan, with major tradeoffs, costs, risks benefits, minimization of foreclosure of future options
  - Information requests (limited number, scope) before and after Technical Session
- Commission appoints Independent Entity to oversee finalizing PSIPs
- HECO Companies finalize PSIPs, based on results of modified RESOLVE models, participation by parties, submit same to Commission
- Commission asks parties to provide short brief recommending which proposed PSIP plan should be the preferred plan and action plan
- Commission decides whether to accept the PSIPs and alternative plan
- Commission sets future formal review dates, process for input from the parties and the public

E3 Presentation: Third Stakeholder Conference



Scope

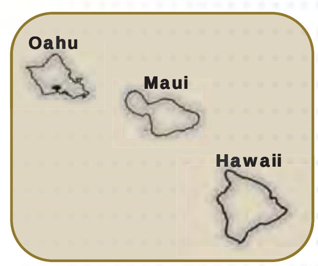
- **Determine cost effectiveness of undersea interties between the Hawaiian islands**
  - Relative to other policy options for reaching RPS targets
  - Subject to sensitivities on fuel and technology pricing
- **Two phases of the study**
  1. Compare the cost of a copper plate transmission case between O'ahu, Maui and the Big Island with the cost of each island going it alone
  2. If the potential savings from phase 1 justify further study, determine cable costs and refine the benefits with greater detail around cable capabilities

Energy+Environmental Economics 3

Phase 1 Methodology

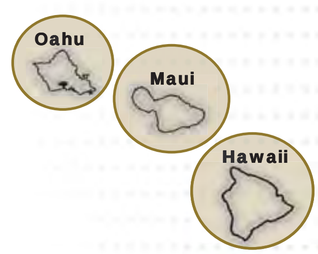
1. 'Copper Plate' case

- Determine the least cost resource plan to meet RPS targets with unlimited transmission between islands
- Model Islands as a single zone



2. 'Go it Alone' case

- Analyze the islands separately. Supplement the O'ahu plan from the PSIP with Maui and Big Island studies
- Calculate a total cost of meeting the RPS without interconnection



Energy+Environmental Economics 4

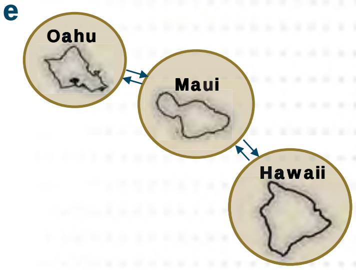
Phase 1 Methodology

- **Determine the breakeven costs of the copper plate**
  - Savings of case 1 over case 2 represent the cost of cables at which Hawaii would breakeven
  - Theoretical maximum benefits from cable interconnections given unlimited transmission modeled
- **Are savings high enough to justify further study?**
  - If breakeven costs are higher than rough estimates of cable costs, we will proceed to Phase 2
- **Impacts of the cable case on resource selection**
  - How does the cable affect the value of LNG and other resources selected in 'Go it Alone' case?

Energy+Environmental Economics 5

Phase 2 Methodology

- **Develop cost estimates for the cable interties**
  - Work with HECO and engineers to develop intertie alternatives and pricing
- **Modeling refinement**
  - Model the transmission constraints of each of the intertie options
  - Find the benefits of each intertie option
  - Determine the least cost option and how it compares against other policy alternatives
  - Test robustness against sensitivities on key inputs



Energy+Environmental Economics 6

Energy+Environmental Economics

Economic framework to select optimal resource portfolios for cable intertie comparison

E3 RESOLVE

Question: How to navigate the many policy and resource options available to meet RPS goals?

+ **E3 RESOLVE is an optimal investment planning model**
  - Selects least-cost resource portfolio and integration solutions to meet RPS targets
  - Considers all resource options on level playing field
  - Evaluates long-term benefits of investments as renewable portfolio evolves over time
  - Allows investigation of new policy and regulatory reforms
+ **Complementary approach to detailed production simulation modeling**
+ **Helps make sense of the growing state space of options in high renewable systems, including cable interties**

Energy+Environmental Economics 8

Renewable integration solutions

- **Various solutions have been proposed, with different performance characteristics and costs**
  - Energy storage (batteries, etc.)
  - Flexible loads or advanced DR
  - Flexible resources (new flexible CCGTs, Aero CTs, Reciprocating Engines or retrofits to existing plants)
  - Tariff design, regulatory and market changes
  - Renewable resource diversity
  - Increased transmission


Wartsila.com


http://renews.biz/67193/vattenfall-pumps-new-life-into-80mw


http://www.theiet.org/membership/member-news/31a/ev-charging-course.cfm

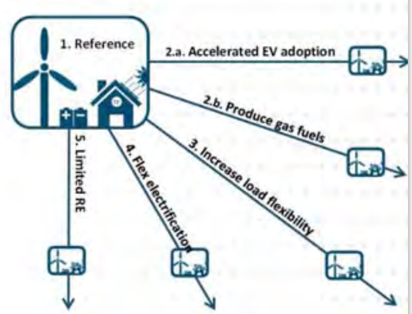
http://allthingsd.com/files/2012/10/Nest-Cooling-2.jpg


Teslamotors.com

9

Establish potential future scenarios

- **Optimal expansion planning models can be used to investigate how system planners should respond in different policy or price driven scenarios**
  - Determines optimal investments within the constraints of a defined potential future policy world
- **Building cables is one potential policy for Hawai'i**

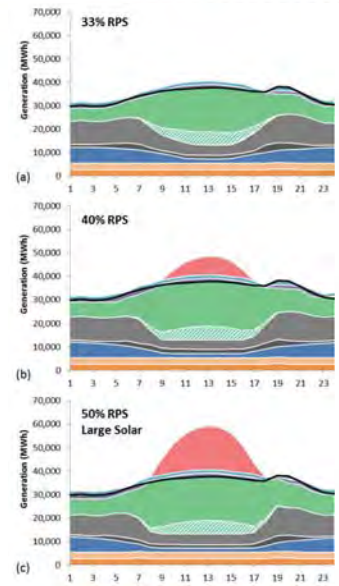


- **Establish a set of plausible policy scenarios for Hawai'i**
  - Includes 'Copper Plate' and 'Go it Alone' cases in Phase 1
- **Determine the optimal resource investments in each policy case, subject to sensitivities around fuel and technology costs**

Energy+Environmental Economics

The renewable integration challenge

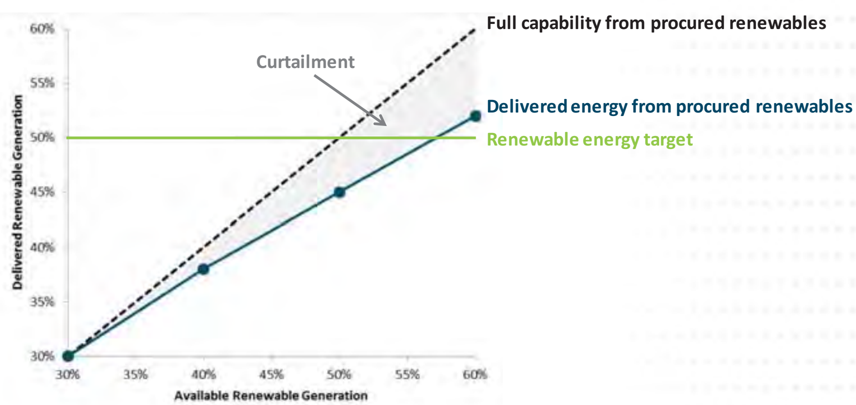
+ **Primary drivers of renewable integration challenges at high penetrations:**
  - Renewable oversupply during low load periods
  - Inflexible conventional generation
    - Must-run resources
    - Self-scheduled resources/contract limitations
    - Technical constraints on ramping, minimum stable levels, minimum up and down times
    - High costs associated with cycling
  - Small balancing areas where diversity of renewables is limited, and generator fleets are constrained



Energy+Environmental Economics 11

Economics of renewable integration

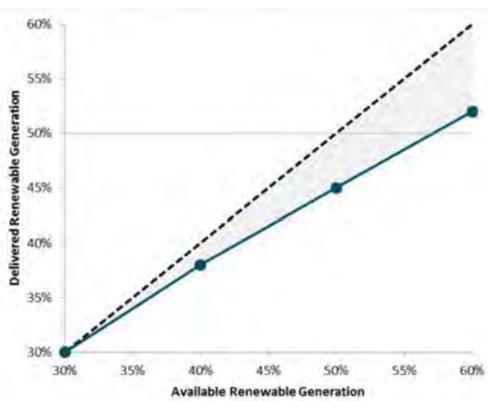
+ **The consequence of failing to supply enough flexibility to integrate renewables is renewable curtailment, or reliability issues**

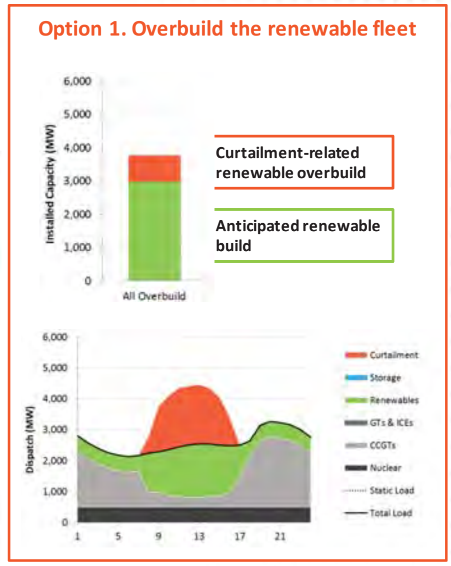


Energy+Environmental Economics 12

Option 1. Overbuild renewabl

+ **Overbuilding the renewable fleet allows for policy goal to be met with some allowance for curtailment**



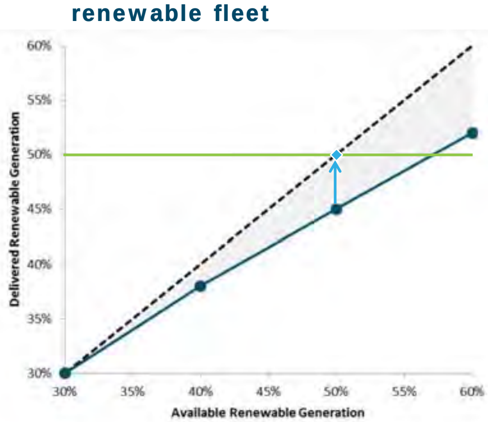


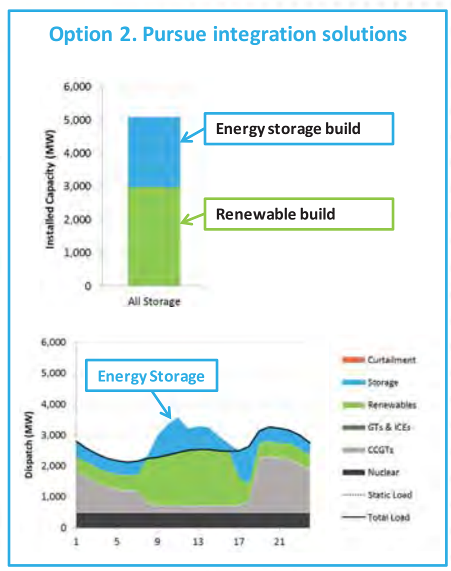
Energy+Environmental Economics

13

Option 2. Pursue integration solutions to avoid overbuild

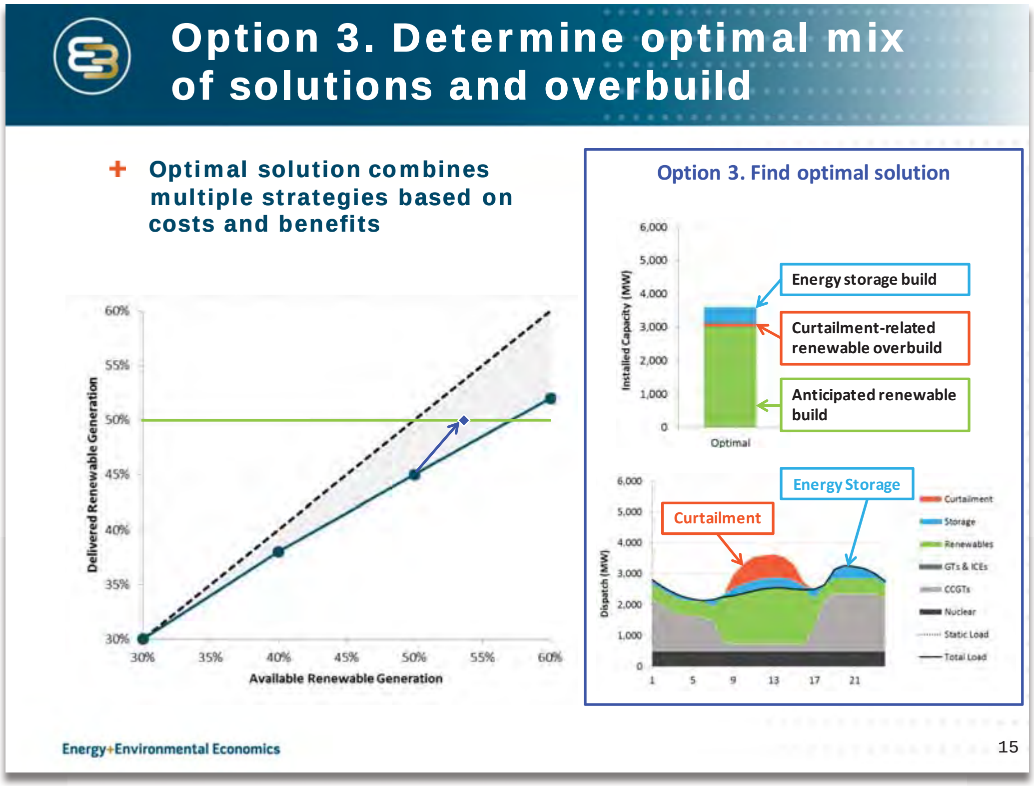
+ **Integration solutions (eg. storage, balancing area consolidation) permit more effective delivery of existing renewable fleet**

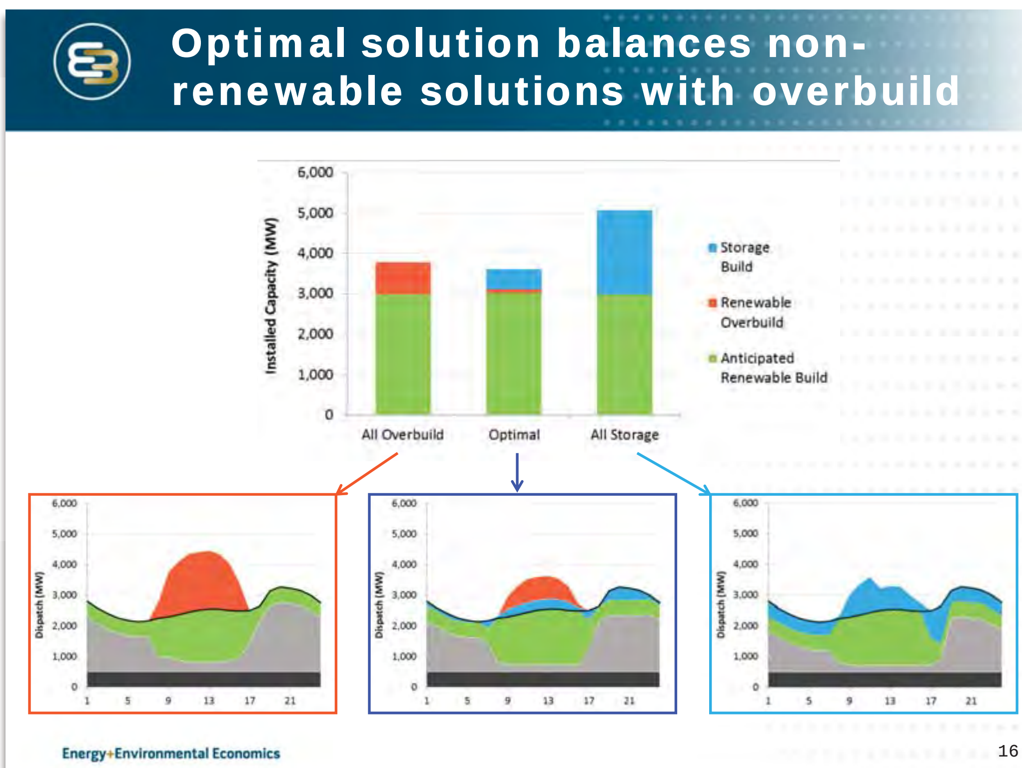




Energy+Environmental Economics

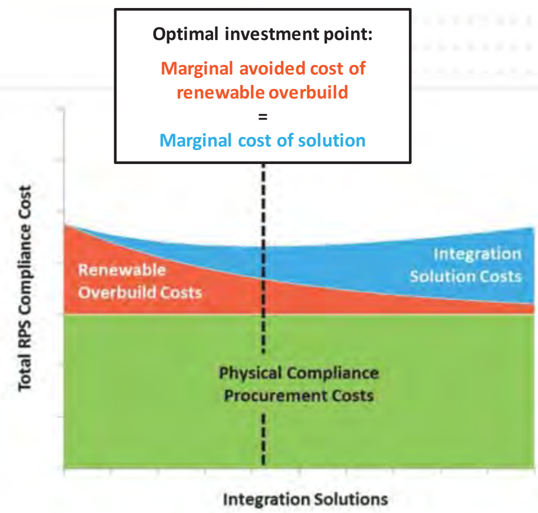
14


Option 3. Determine optimal mix of solutions and overbuild
Optimal solution combines multiple strategies based on costs and benefits
Delivered Renewable Generation
Available Renewable Generation
Option 3. Find optimal solution
Installed Capacity (MW)
Energy storage build
Curtailment-related renewable overbuild
Anticipated renewable build
Optimal
Dispatch (MW)
Energy Storage
Curtailment
Energy+Environmental Economics
15


Optimal solution balances non-renewable solutions with overbuild
Installed Capacity (MW)
Storage Build
Renewable Overbuild
Anticipated Renewable Build
All Overbuild
Optimal
All Storage
Energy+Environmental Economics
16

Identifying optimal investment in solutions

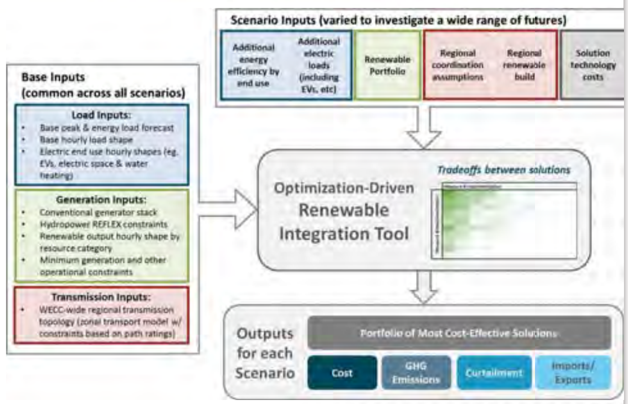
+ **Single solution case:**
  - The cost of the solution can be weighed against the avoided cost of overbuilding renewables for RPS compliance
+ **Multiple solution case:**
  - Multidimensional optimization
  - Complex interactive effects
  - **Requires models that treat both operations and investment costs**
    - SWITCH and RESOLVE are examples of such models



Energy+Environmental Economics 17

RESOLVE Modeling Framework

- **Co-optimizes investment and operational decisions over multiple years**
  - Can solve for optimal investments in renewable resources, energy storage, conventional generators
  - Can test value of solutions with unknown or uncertain supply curves, like flexible loads & time-of-use rates

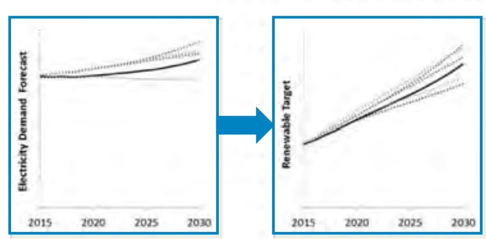


- **Operational detail focuses on primary drivers of renewable integration challenges**
  - Hourly dispatch with reserve and operating constraints
  - Zonal treatment of interconnection to model flows with increased granularity in primary zone of study

Energy+Environmental Economics 19

Scenario-based analysis produces more robust conclusions

- **Scenarios determined by:**
  - Loads by subsector, including residential and commercial thermal loads, electric vehicle adoption, & energy efficiency
    - Dynamically-updated hourly load shapes
  - Renewable policies
    - RPS targets and behind-the-meter PV adoption
  - Renewable resource costs and potentials
  - Costs
    - Renewable, conventional, and storage technology costs, transmission costs
    - Fuel prices

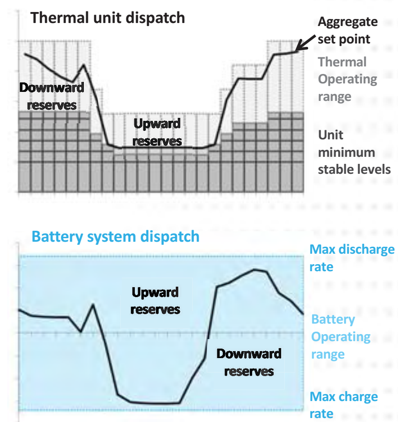


Energy+Environmental Economics 20

Detailed hourly model brings operational challenges into investment decisions

- **For each year in the simulation, a subset of days are selected and weighted to reflect long-run distributions of:**
  - Daily load, wind, and solar
  - Monthly hydro availability (in CA)
- **Operations modeled using linear dispatch formulation**
  - MIP possible for small systems or when runtime is not a constraint; linear approximations for large systems
  - Upward and downward operating reserve constraints

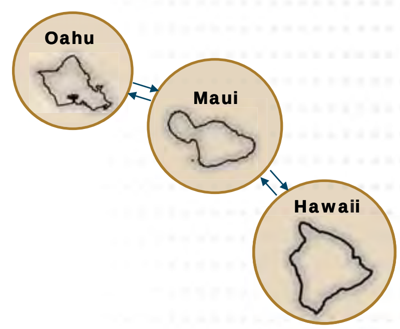
Simulates economic dispatch on each day subject to technical operating constraints



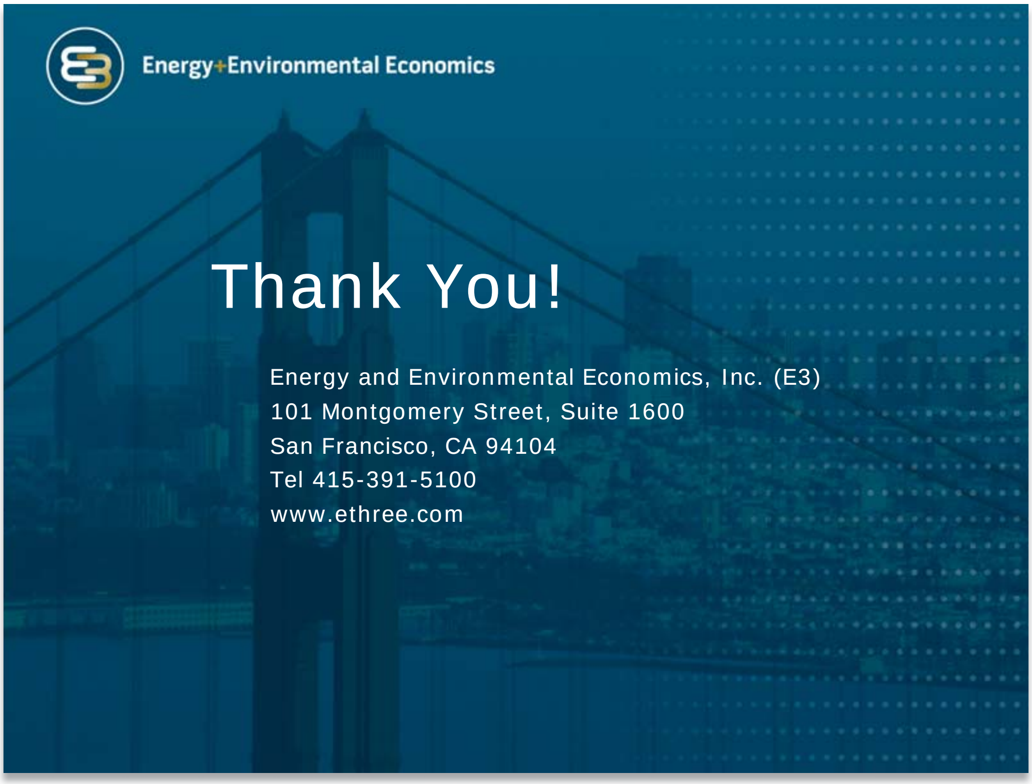
Energy+Environmental Economics 21

Zonal dispatch treatment enables study of flow constraints between islands

- **Each zone:**
  - Optimal investment decisions
  - Detailed treatment of operating reserves, depending on cable option modeled
- **Detailed representation of flow constraints**
- **Flows may be impacted by:**
  - Min and max intertie flow constraints
  - Min and max simultaneous flow constraints for groups of interties
  - Ramping constraints on interties
  - Hurdle rates



Energy+Environmental Economics 22


Energy+Environmental Economics
Thank You!
Energy and Environmental Economics, Inc. (E3)
101 Montgomery Street, Suite 1600
San Francisco, CA 94104
Tel 415-391-5100
www.ethree.com


Energy+Environmental Economics
Back-up Slides

Potential Next Steps

+ **Phase 1 underway - aligning E3's assumptions for each island with HECO's**
+ **Next steps:**
  - Produce 'Copper Plate' and 'Go it Alone' cases for assessment of cable breakeven cost
  - Assess the viability of cable interconnection and need for Phase 2
  - Establish the process and timing for stakeholder comments

Energy+Environmental Economics

26

Hawaiian Electric Presentation: Third Stakeholder Conference

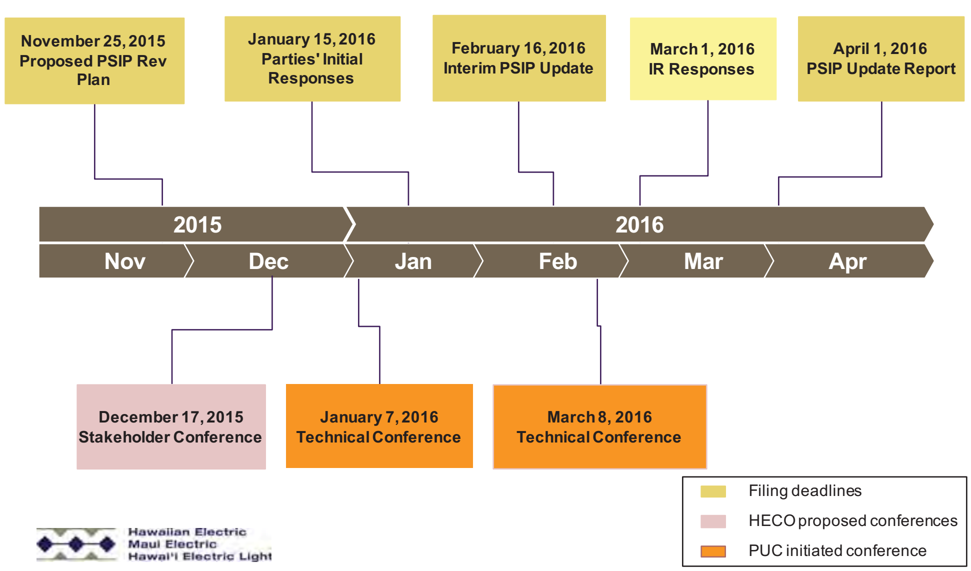
Hawaiian Electric
Maui Electric
Hawai'i Electric Light

PSIP Update

Stakeholder Conference

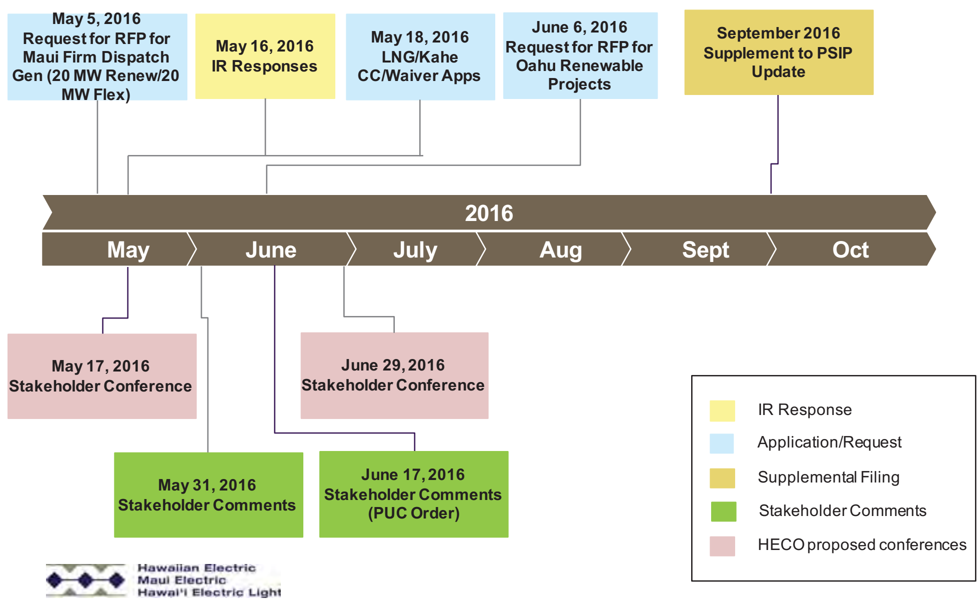
June 29, 2016

Recap of PSIP Update timeline



Hawaiian Electric
Maui Electric
Hawai'i Electric Light

Recap of PSIP Update timeline



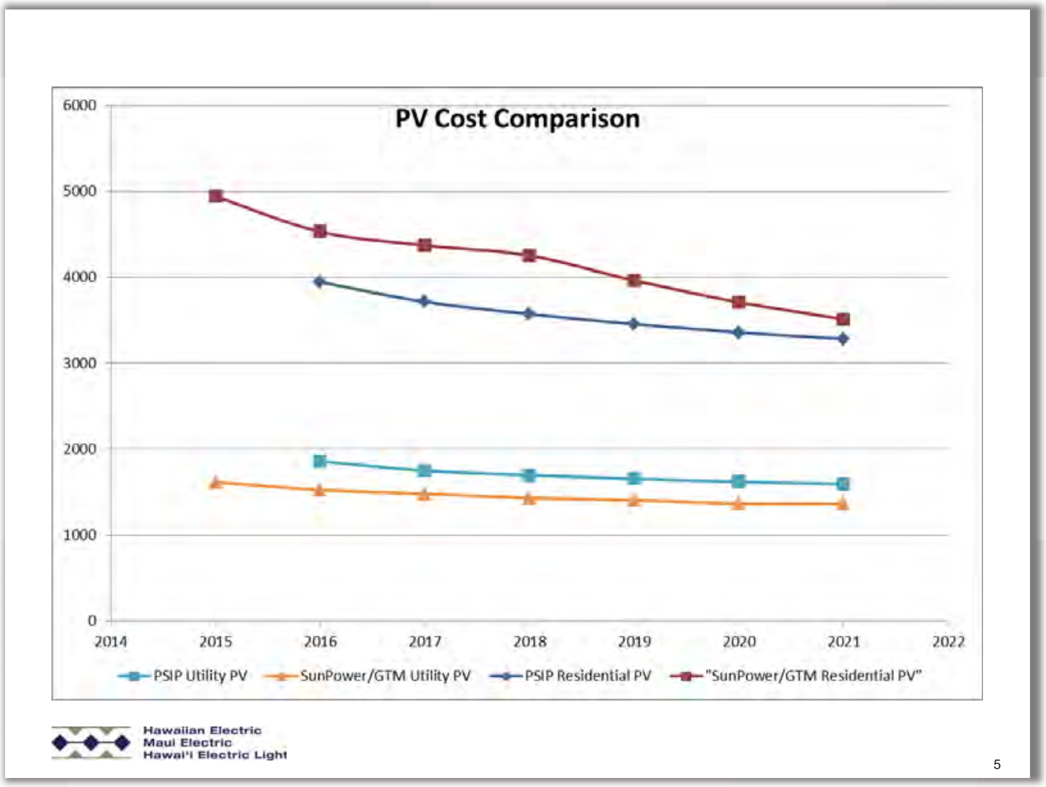
Hawaiian Electric
Maui Electric
Hawai'i Electric Light

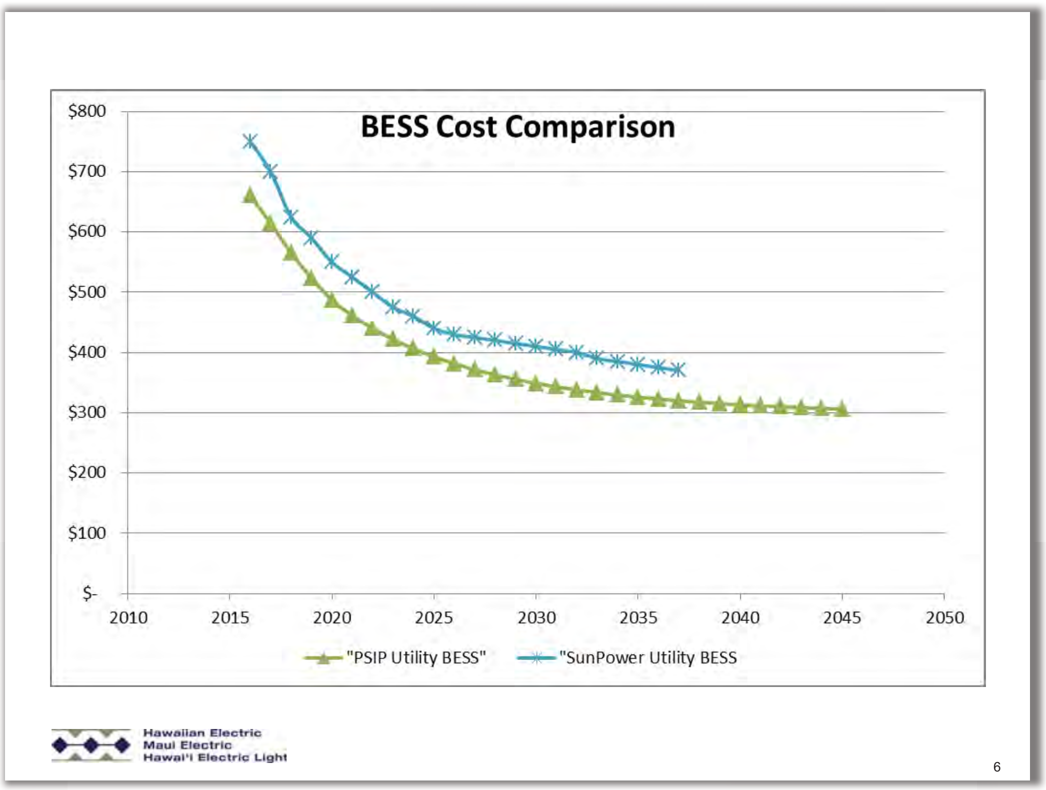
Participant Cost Information

- SunPower
  - Utility and Residential PV Costs
  - Utility and Residential BESS Costs
  - Adjusted for comparative analysis
    - Costs relatively close
    - Residential BESS costs comparable
- Hawaii Gas
  - Provided 2 fuel price forecasts
    - 100% Brent basis
    - 50% Brent / 50% Henry Hub basis
  - Commodity forecast different than PSIP
  - Requested clarifications to perform comparative analysis

Hawaiian Electric
Maui Electric
Hawai'i Electric Light

4


PV Cost Comparison
6000
5000
4000
3000
2000
1000
0
2014
2015
2016
2017
2018
2019
2020
2021
2022
PSIP Utility PV
SunPower/GTM Utility PV
PSIP Residential PV
"SunPower/GTM Residential PV"
Hawaiian Electric
Maui Electric
Hawai'i Electric Light
5


BESS Cost Comparison
$800
$700
$600
$500
$400
$300
$200
$100
$-
2010
2015
2020
2025
2030
2035
2040
2045
2050
"PSIP Utility BESS"
"SunPower Utility BESS
Hawaiian Electric
Maui Electric
Hawai'i Electric Light
6

Next Steps

- Update Analysis
  - New EIA AEO Fuel Price Forecast (Early Release May 17, 2016; AEO 2016 July 7, 2016)
  - Updated Resource Costs (ITC, Biomass)
  - Further Refinements if possible
  - Update Production Simulations and Cost Analyses
  - Sensitivity Analyses using Alternative Pricing Provided by Parties (input no later than 7/6/16)
- Perform Additional System Security Analyses
  - Perform analysis for contingency BESS (FFR1) for Oahu, Maui, and Hawaii Island
- Identify Alternatives and Analyze Inter-Island Transmission
  - E3 Break-even analysis

Hawaiian Electric
Maui Electric
Hawai'i Electric Light

7

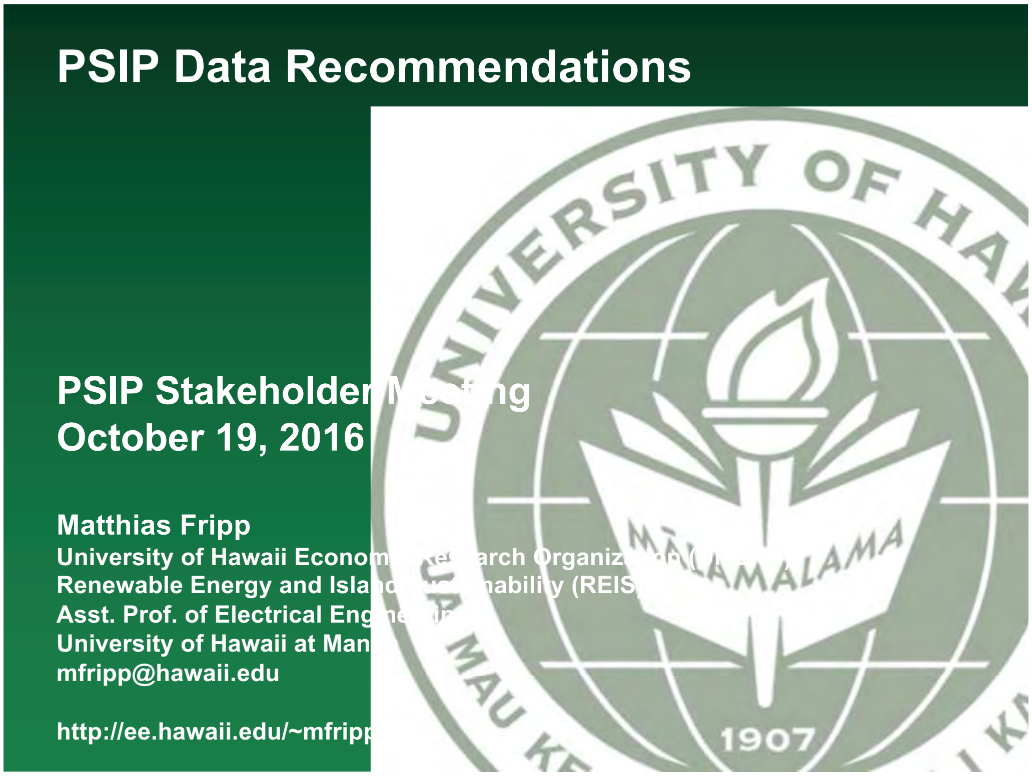
Next Steps

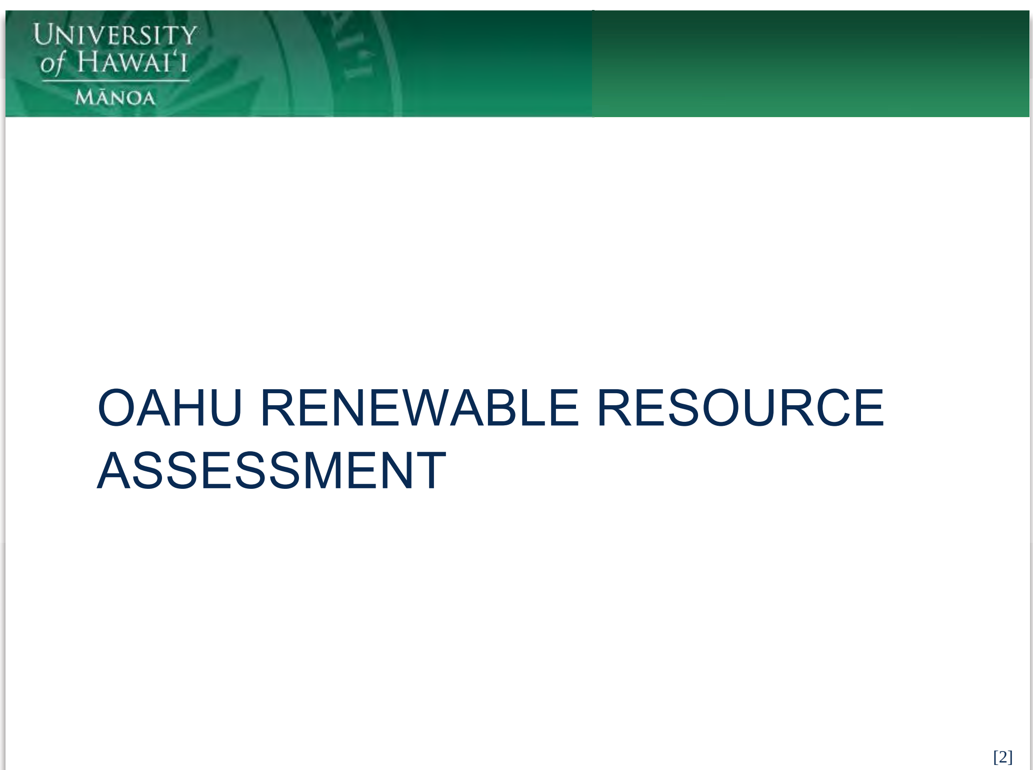
- Evaluating Feasibility of Offshore Wind Resources with consideration of Bureau of Ocean Energy Management (BOEM) process
- Complete LNG Risk Premium Analysis
  - Ascend Analytics (stochastic analysis)
- Complete Sub-hourly Analysis
  - Refine storage analysis
- Update System-level Hosting Capacity Analyses
- **Revised Estimated Completion: September 30, 2016**

Hawaiian Electric
Maui Electric
Hawai'i Electric Light

8

Ulupono Presentation: Fourth Stakeholder Meeting



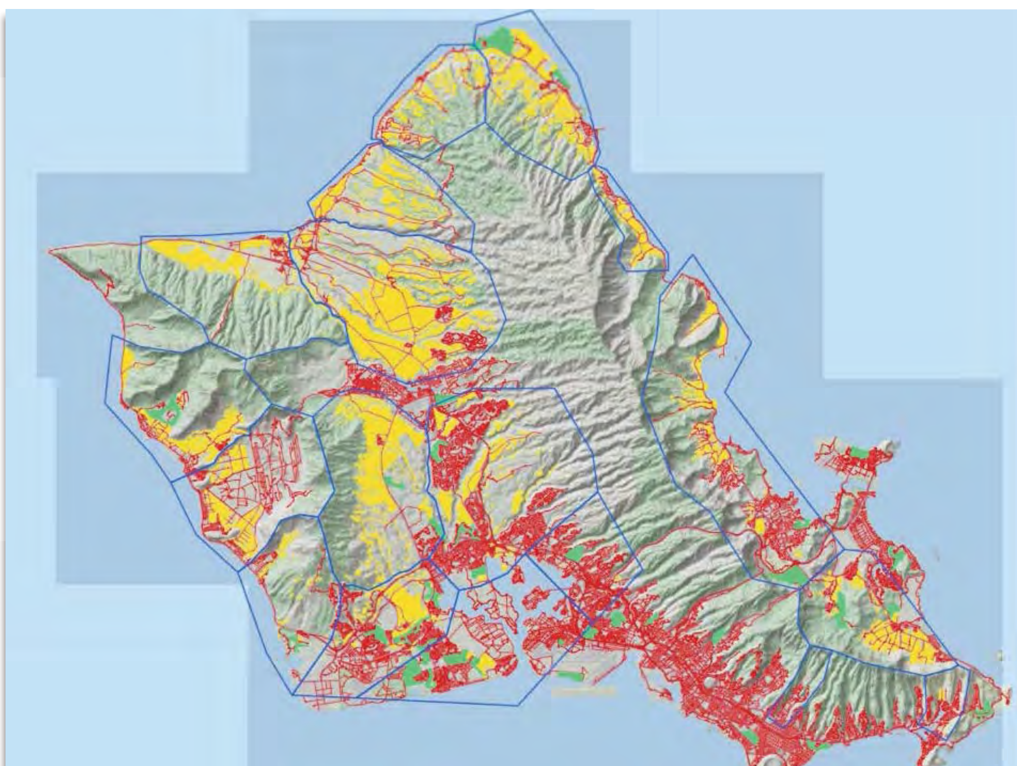


UNIVERSITY of HAWAIʻI MĀNOA

Utility-Scale Solar Resources

- only zoned for agriculture or country
  - this may exclude significant military land
- no Class A agricultural land
- no golf courses
- not within 50 meters of street centerlines
  - this also filters out rural businesses and neighborhoods
- not steeper than 10% slope
  - Waianae Solar built on slopes up to 15%
- patch is at least 60 meters across in all directions
- assume fixed PV uses 6 acres per MW(AC) and tracking PV uses 7.5 acres per MW(AC).
  - These are roughly the lower quartile of the national statistics given on p. 11 of http://www.nrel.gov/docs/fy13osti/56290.pdf
  - Waianae Solar uses 7.2 acres per MW(AC) for tracking PV systems
- assume fixed PV has a ground cover ratio of 0.68 and tracking PV has ground cover ratio of 0.45
  - these affect capacity factor when the sun is low; these values are the upper quartile from p. 13 of http://www.nrel.gov/docs/fy13osti/56290.pdf
- use NREL's PVWatts tool to calculate hourly output for each 4 km cell, using irradiance data from the National Solar Radiation Database (NSRDB)

[3]



UNIVERSITY of HAWAI'I MĀNOA

Rooftop Solar

- Total roof area from Google Map images
  - double-checked with visual review and comparison to population and housing data from U.S. Census
- 40% coverage of roofs, based on assuming
  - 15% of roofs are flat, with 70% coverage
  - 85% are sloped, with 35% coverage
- Estimate total capacity based on 12% efficiency with 1,000 W/m^2 irradiance (capacity=120 W/m^2)
- Hourly behavior can be modeled based on existing solar, or using NSRDB and PVWatts, with more assumptions about roof orientation

[5]

UNIVERSITY of HAWAI'I MĀNOA

Rooftop Solar

[6]

UNIVERSITY of HAWAI'I MĀNOA

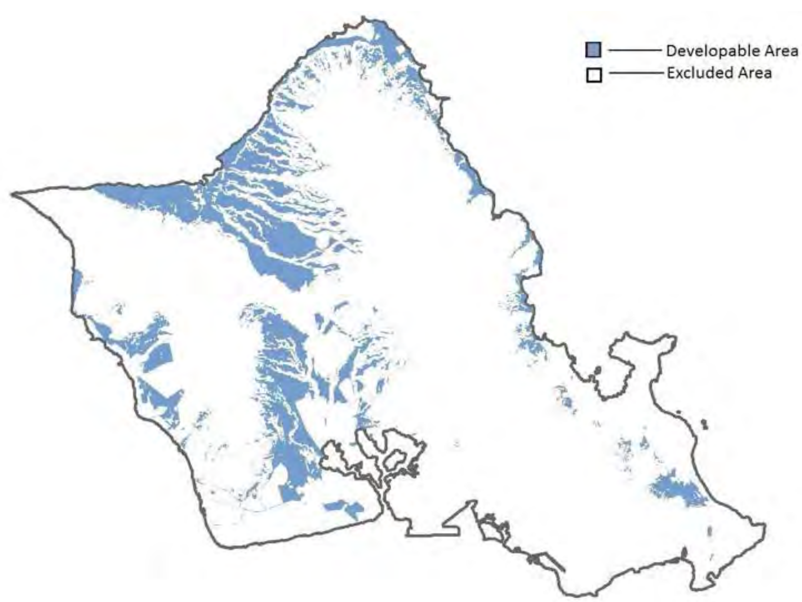
Onshore Wind

- only zoned for agriculture or country
  - also not within 300 meters of other zones
- not steeper than 20% slope
  - also not within 30 meters of steep slopes (eliminates narrow ridgetops and valleys)
- density of 8.8 MW per km^2 (spacing approx. 6x6 turbine diameters)
  - less dense than Kahuku wind farm (12.9 MW/km^2)
  - on high end of the 5-8 MW/km^2 range given by an NREL report at http://www.nrel.gov/docs/fy09osti/45834.pdf
- no advance screens for resource quality
  - let the optimization model decide what is cost-effective
- turbines are clustered by region and resource quality
- hourly behavior of each project is calculated from OWITS data

[7]

UNIVERSITY of HAWAI'I MĀNOA

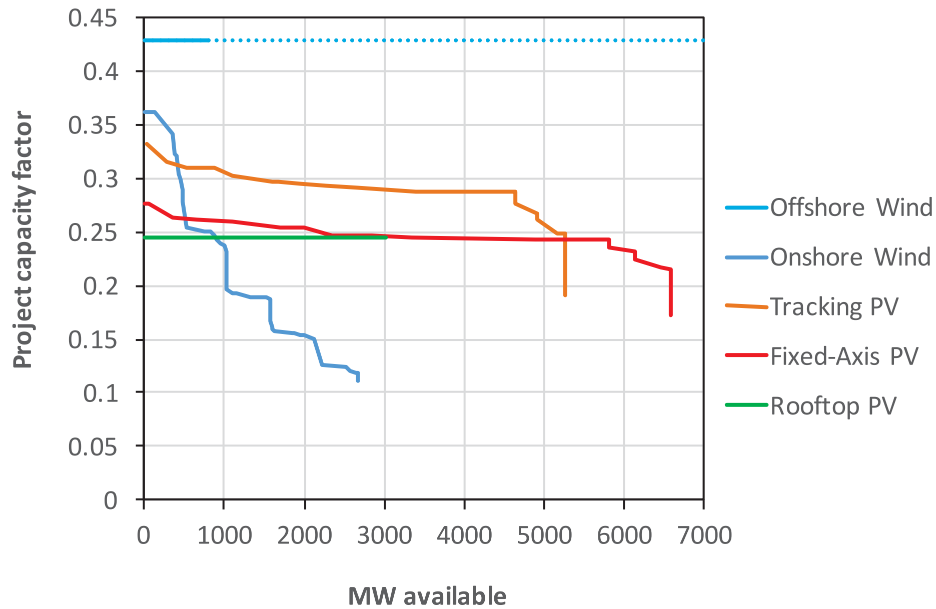
Potential Wind Farm Locations



[8]

UNIVERSITY of HAWAIʻI MĀNOA

Oahu Renewable Resource Supply Curves



UNIVERSITY of HAWAIʻI MĀNOA

Tracking Solar Should be Included

- produces 18% more than fixed-axis solar
- produces more morning and evening power than fixed-axis
- costs ~10.7% more than fixed-axis solar
  - avg. ratio for 2010-15 from p. 40 of https://emp.lbl.gov/sites/all/files/lbnl-188238_2.pdf
  - could be lower, e.g., IdeemaTec safeTrack Horizon costs $0.15-0.25/W for the entire rack and tracking system, replacing similarly-priced fixed-axis rack
- requires 25% more land than fixed-axis solar
- note: you can’t use land simultaneously for tracking and non-tracking solar

[10]

University of Hawai'i Mānoa

Renewable Time Series

- Renewable energy time series should be
  - site specific
    - reflects spatial diversification
    - reflects mix of resource qualities that are available
  - synchronized with loads
    - reflects correlation/anticorrelation between wind, solar and loads
- Suitable data are available from the SWITCH-Hawaii dataset

[11]

University of Hawai'i Mānoa

OTHER NOTES

[12]

UNIVERSITY of HAWAI'I MĀNOA

Solid Biomass

- should be considered as a fuel for AES, Kahe and Waiau
- can provide extra energy on low-wind, low-sun days (plants may run all day during certain times of year)
- much cheaper than biodiesel
- pellet biomass available from Zilkha at ~$14/MMBtu
  - lower than LSFO or LNG
  - See "Public comment" [letter from Zilkha], PUC docket 2014-0183, 10/6/14, 4 pgs; http://dms.puc.hawaii.gov/dms/OpenDocServlet?RT=&document_id=91+3+ICM4+LSDB15+PC_DocketReport59+26+A1001001A14J07B00959H7225418+A14J07B45304A025041+14+1960
- may be available locally

[13]

UNIVERSITY of HAWAI'I MĀNOA

Biofuel Limits

- There should be scenarios with and without limits on use of biomass and biofuel
  - biofuels have undesirable environmental and land-use impacts
  - biofuels may continue import-dependence and exposure to price volatility
- I recommend a limit around 5%
  - the right limit depends on policy preferences and price uncertainty

[14]

UNIVERSITY of HAWAI'I MĀNOA

Hydrogen Option Should be Included

- Can provide inter-seasonal storage for low-sun, low-wind days
- Important alternative to biofuels or overbuild-and-curtail
  - cost-competitive
  - reduces environmental impacts and land requirements
  - especially important in low-biofuel cases
- Simplified model available in SWITCH-Hawaii
  - Produce hydrogen and then either use it the same day or liquefy it
  - Storage tank capacity is equal to total amount of hydrogen liquefied during the year (conservative; allows any usage pattern)

[15]

UNIVERSITY of HAWAI'I MĀNOA

Hydrogen Cost and Performance Data Sources

- electrolyzer
  - http://www.hydrogen.energy.gov/h2a_prod_studies.html
- liquifier and tank
  - http://www.nrel.gov/docs/fy99osti/25106.pdf
- fuel cell
  - http://www.nrel.gov/docs/fy10osti/46719.pdf
- Values based on current technology are available from SWITCH-Hawaii dataset (next page)
  - also recommend considering future technology/prices

[16]

UNIVERSITY of HAWAI'I MĀNOA

Cost and Performance Data for Current Hydrogen Technologies

- hydrogen_liquifier_variable_cost_per_kg := 0.0
- hydrogen_liquifier_fixed_cost_per_kg_hour_year := 0.0
- hydrogen_electrolyzer_kg_per_mwh := 18.4
- hydrogen_liquifier_capital_cost_per_kg_per_hour := 41949
- hydrogen_electrolyzer_variable_cost_per_kg := 0.0
- hydrogen_electrolyzer_capital_cost_per_mw := 1557850
- hydrogen_fuel_cell_mwh_per_kg := 0.0176976
- liquid_hydrogen_tank_life_years := 40
- hydrogen_electrolyzer_life_years := 40
- liquid_hydrogen_tank_capital_cost_per_kg := 29.50
- hydrogen_fuel_cell_capital_cost_per_mw := 966402
- hydrogen_liquifier_mwh_per_kg := 0.01
- hydrogen_electrolyzer_fixed_cost_per_mw_year := 76842
- hydrogen_liquifier_life_years := 30
- hydrogen_fuel_cell_fixed_cost_per_mw_year := 32095
- hydrogen_fuel_cell_variable_cost_per_mwh := 0.0
- hydrogen_fuel_cell_life_years := 15

[17]

UNIVERSITY of HAWAI'I MĀNOA

Fuel Price Forecasts

- Current PSIP oil and biodiesel price forecasts seem to be consistent with historical relationship between Brent Crude and Hawaii prices
- Risk adder or Monte Carlo treatment should be applied to benchmarks (Brent Crude and Henry Hub) and then propagated from there to the forecasts for individual fuels
- Constant components of fossil fuel price formulas should probably include inflation
  - PSIP currently seems to use constant-nominal-dollar adders for delivery cost, which may understate future costs
  - e.g., if
    diesel = 1.1331×[Brent Crude ($/MMBtu)] + 1.92,
    the $1.92 may need to be inflated over time

[18]

C. Analytical Methods and Models

Planning for electric power systems utilizing 100% renewable energy is a complex undertaking. The Companies have developed comprehensive methods and modeling tools to tackle this challenge.

This appendix describes the basis of our planning, the revised optimization process, and the full capabilities of all models. Chapter 3: Analytical Approach describes the revised and refined analytical process for this December 2016 PSIP, and details how we employed this process to develop our near-term action plans.

PLANNING REQUIREMENTS AND PRINCIPLES

Our planning process incorporated various planning requirements and principles into our modeling analysis.

Planning Requirements

Planning requirements are fixed parameters that do not vary between cases or sensitivities. Planning 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, ultimately attaining 100% RPS by 2045.

Regulatory and Environmental 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, to ensure public safety, and to keep the power on.

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 primary and 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 consume energy, use our electricity services, and provide services back to us. 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.

Planning Objectives

Planning objectives are the specific results the planning process aims to achieve. Planning objectives of the PSIP are consistent with Commission directives: to advance achievement of the State's 100% renewable energy goal, to stabilize and reduce customer rates, and to maintain safe and reliable service.

Achieve the State's 100% Renewable Energy Goal. Our objective is to achieve 100% renewable energy by or before 2045 to comply with Hawai'i state law. We strive to exceed the interim RPS targets integrating additional renewable energy that can help reduce customer rates.

Stabilize and Reduce Customer Rates. Stabilizing and reducing customer rates is a primary objective of the planning process. The analysis methodologies utilized in the December 2016 updated PSIP are designed to minimize total system costs. Total system costs consider the total costs to the electric system, including generation, transmission

and distribution, interconnection, revenue requirements, capital expenditures, and integration costs. Mitigating customer and implementation risk are factors to stabilizing and reducing customer rates.

Maintain Safe and Reliable Service. Safe and reliable service is the foundational element of our electric power grid. An integrated, robust plan for first avoiding, then handling contingencies is necessary, and an increasingly difficult task as more and more variable renewable generation is added to the system.

OPTIMIZED ANALYTICAL PROCESS

Our planning engineers, working closely with consultants, developed an innovative and transparent process to optimize all resources including DER, DR, and grid-scale resources, and build on our DR work completed to date. This iterative process builds on the process employed in our April 2016 PSIP update, and incorporates all of the updated input assumptions. Figure C-1 depicts the flow of the modeling tools and the optimization of DER, DR, and grid-scale renewables.

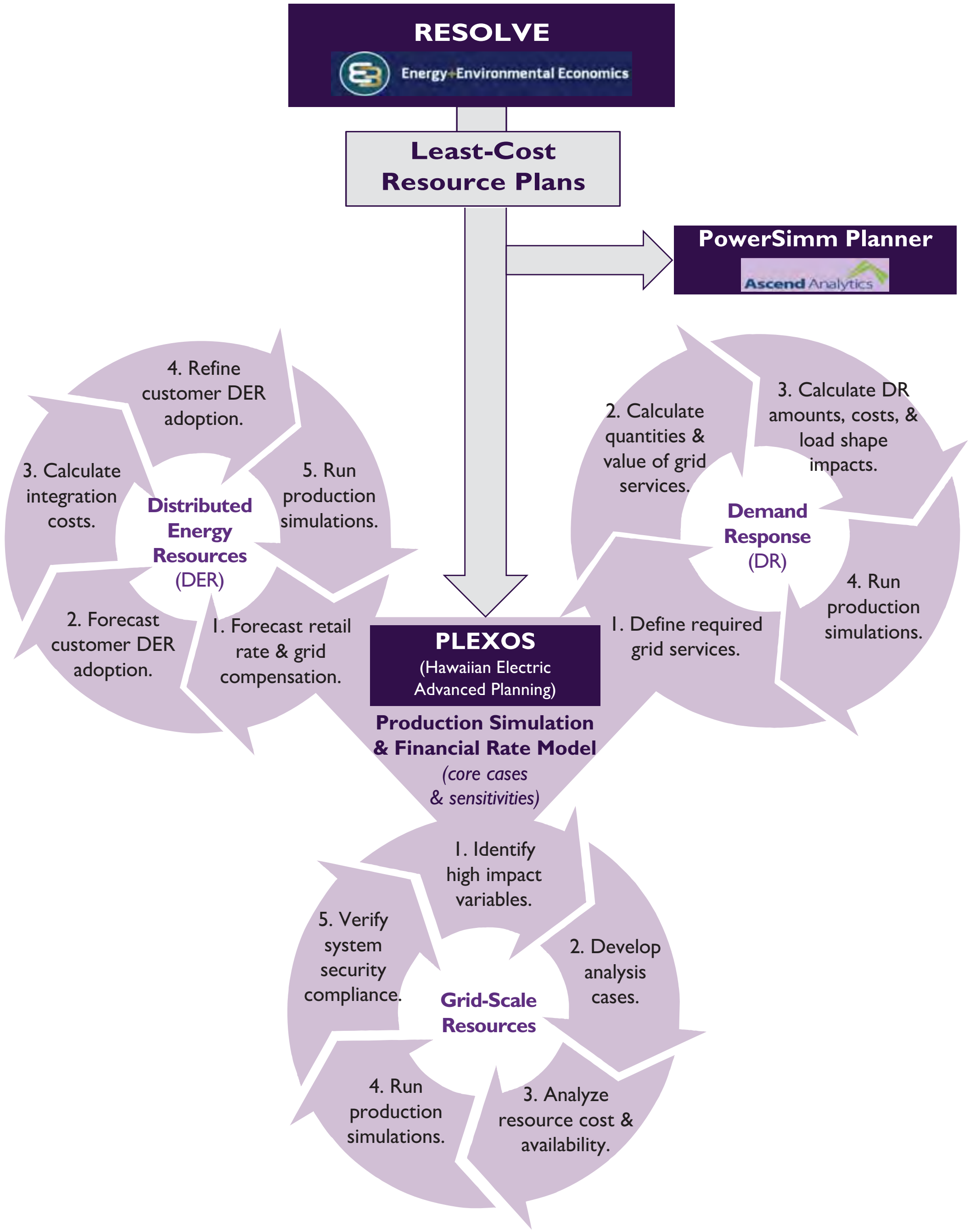


Figure C-1. Revised PSIP Optimization Process

The following sections explain the DER, DR, and Grid-Scale Resources 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 developed forecasts for market DG-PV (based on expected customer response to market pricing) and high DG-PV (all single-family residential customers and 20–25% of total commercial customers are net zero). We assume that existing DER programs, including legacy NEM, Standard Interconnection Agreement (SIA), Customer Grid Supply to cap, and Customer 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—for planning purposes only.

Forecasting assumptions include historical hourly customer load profiles by island and rate schedule from the Company's class load studies, optimum system size, tariffs, export rate, retail electricity prices, storage value, income tax credits, system costs, eligible customers, inflation rate, and weighted average cost of capital.

We have refined these economic adoption assumptions, and developed models to forecast adoption rate.

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 can benefit customers by offsetting their retail electricity purchases with compensation for providing grid services.

Forecast Payback Time for DG-PV Compensation. Order No. 33258[2] specified the 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 a Planning 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).

[1] Appendix J: Modeling Assumptions Data contains forecasts for the cost of DG-PV, grid-scale PV, and residential energy storage. These cost forecasts were developed in conjunction with the grid-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.

- Enabled full utilization of DG-PV. 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.

We compared grid-scale PV with DG-PV. We also assumed the future DG-PV export rate to mirror the respective levelized cost of energy (LCOE) of grid-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. This updated PSIP assumes 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 DERMS 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.
- This updated PSIP assume policies and programs (including pricing programs) that stipulate DER control by 2019. The details of these policies and programs are expected to be captured outside of the updated PSIP and jointly between current DR program filings and the anticipated DER Phase II proceedings.
- Ability 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 install near-term communications sufficient for the preliminary stage of DER control and the associated feedback loop.

2. Forecast Customer DER Adoption Levels

If the customer's payback time on their initial investment 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 on circuits over the hosting capacity. That methodology allocates DG-PV forecast pro-rata across circuits, identifies integration solutions and their respective costs, then applies these integration costs to adjust the economics and the expected adoption rate from both a system and a customer perspective. Integrating variable renewable energy (including DG-PV, grid-scale PV, and grid-scale wind) might require regulating reserves, energy storage, and investments in system operations. Based on these changed economics, the DG-PV is reforecast.

Figure C-2 depicts a high-level overview of the circuit-level integration cost methodology.

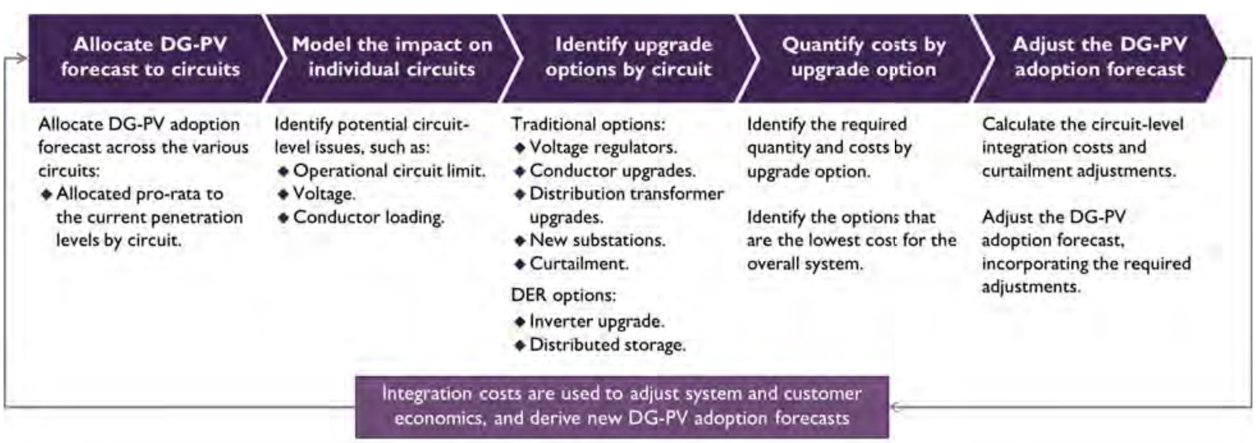


Figure C-2. Circuit-Level Integration Cost Methodology

4. Refine Customer DER Adoption Levels

Integration costs 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 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 instance.

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: one, customer uptake of DER based on the economics from the customer's perspective, and two, 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.

The DR evaluation was conducted using the post-April 2016 PSIP plan for each island, and the results were used in the production simulation and capacity planning models for the December 2016 PSIP update evaluation period. Grid service valuation was initially performed on a single plan per island; this guided the evaluation of DR amounts, costs, and the impact of system load shapes. Those initial plans per island were:

- *O'ahu, Hawai'i Island, and Maui:* Renewables without LNG
- *Lana'i and Moloka'i:* 100% renewable energy achieved in 2030

DR amounts, costs, and the impact on system load shapes were then evaluated on all post-April PSIP plans. In addition to those listed above, this included:

O'ahu and Maui:

- Accelerated renewables without LNG
- Renewables without LNG and without new generation
- Renewables with LNG

Hawai'i Island:

- Accelerated renewables without LNG
- Renewables with LNG

Later analyses involving both grid services valuing as well as defining DR amounts, costs, and the impact on system load shape are to be performed on the E3 plan:

- *O'ahu:* E3 Plan and E3 Plan with generation modernization
- *Hawai'i Island and Maui:* E3 Plan

Results of grid services valuing, updated for any differences developed following the post-April PSIP plan evaluations, will be documented in the February 10, 2017 DR Application.

1. Define Required Grid Services

Our portfolio of DR programs delivers grid services that help meet system security and other requirements that displace the need for resources. 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 December 2016 PSIP update, some of the service definitions and their associated requirements were modified, although more will be addressed in the DR Application Tariff, Rules, and Rider modifications.

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 forecasts for EVs and storage based on new fuel and resource forecasts and modified assumptions; 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 this DR optimization.

Costs will not always be aligned with quantity. For example, without DR, a firm unit may be required to remain online during the mid-day solar peak in order to provide

regulating reserve. With some portion of the regulating reserve requirement provided by DR, the unit may be shut down during the mid-day solar peak. This may require a startup to meet the evening demand. While DR results in a lower daily cost, the unit startup will result in an hour with higher cost.

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 contingency reserve service may be linked to the primary frequency response (governor response) combined with the regulating 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. A DR portfolio that provide multiple services will have greater value.

The value of each grid service is calculated to determine how they are best to applied to all potential grid-scale resources. Grid service values are calculated by comparing system production costs between model runs for adjusted service levels. More precisely, augmenting the system with a free resource that can provide the specific grid service 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 all resources. Generators can be simulated as must-runs for reliability. If a service can meet the reliability need, the must-run requirements can be 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. 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 comprise this iterative process.

Preliminary Inputs. These inputs are required for analyzing DR fit:

- The refined DR potential calculated during DR optimization Step 1.
- The quantity and value of the services derived from DR optimization Step 2.

Identify DR Portfolio Fit. DR can provide a portion of the required grid services by displacing grid services otherwise provided 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 the timing of deactivation, 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. These sensitivities include changes such as the availability, size, and cost of storage and the role of DR products given modified security constraints.[3]

Derive Value Associated with Customer Storage. Customer owned storage can provide value to the grid system – and can provide additional value as the utility influences the timing of use of the customer storage. The Adaptive Planning model develops annual values ($/kw of installed customer storage) 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. This value is calculated and provided to inform customer storage adoption models that predict the build-out of DG-PV plus energy storage systems and storage only systems.

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. Forecasted customer adoption for DESS and DG-PV plus storage is provided to 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 programs. 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

[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.

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 hour by year for the entire planning period. As DR is intended to manipulate demand to deliver grid services, an optimized portfolio ultimately impacts system load shapes.
- Ability of the DR portfolio to provide regulating reserve, by hour by year for the entire planning period. The regulating reserve profile ensures that DR information is available so that DR can substitute for firm generation in meeting regulating reserve requirements.
- Contribution of DR portfolio towards meeting Fast Frequency Reserve requirements.
- Avoided annual costs of the portfolio for the planning period.
- Material adjustments made to the resource plans resulting from the DR optimization. Changes include resizing resources, shifting retirement schedules, deferring capital investments, and shifts in procurement timing.

4. Run production simulations and economic evaluations with DR 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.

Grid-Scale Resources Iterative Cycles

The grid-scale resource iterative cycle is similar to those for DER and DR.

1. Identify High Impact Variables

Variables that have a high impact on the Planning 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 Planning 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 Planning 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) 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 Planning 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 an existing resource, 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 Planning 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 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.

ANALYTICAL MODELS

We are employing a number of analytical models to develop our December 2016 PSIP. Our Advanced Planning team, our Transmission and Distribution Planning team, Forecasting team, Demand Response team, Finance 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 the near-term action plan 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:

- *RESOLVE Optimization Model and Long-Term Case Development*: Energy and Environmental Economics (E3)
- *PowerSimm Planner*: Ascend Analytics
- *PLEXOS® for Power Systems*: Hawaiian Electric Advanced Planning Department
- *Adaptive Planning for Production Simulation*: Black and Veatch
- *DG-PV Adoption Model*: Hawaiian Electric Forecasting Division
- *Customer Energy Storage System Adoption Model*: Hawaiian Electric Demand Response Department
- *PSS®E for System Security Analysis*: Hawaiian Electric Transmission and Distribution Planning Department
- *Financial Forecast and Rate Impact Model*: Hawaiian Electric Budgets and Financial Analysis Department

How Models Were Run for Our Analysis

No single model has the ability to produce completely optimized plans incorporating DR, DER, grid-scale resources, and system security resources. Instead, we utilized a number of models to conduct the analysis necessary for developing our December 2016 PSIP. These models were RESOLVE, PowerSimm Planner, PLEXOS for Power Systems, Adaptive Planning for Production Simulation, DG-PV Adoption, Customer Energy Storage System Adoption, PSS/E for System Security analysis, and the Financial Forecast and Rate Impact Model.

An explanation of each model follows: how it was used in our analysis, its inputs and outputs, and its limitations.

To support the PSIP, historical data and econometric models predict DR together with DG-PV and energy storage (DER) adoption; RESOLVE drives optimal asset portfolio design; PowerSimm Planner supports the analysis with stochastic modeling to account for risk and to validate results; Adaptive Planning for Production Simulation optimizes the use of DR and DER; PLEXOS provides detailed production simulation and cost data for the generation system; PSS/E examines system security requirements; and financial rate models determine the ultimate cost to the customer.

RESOLVE Optimization Model

E3 assessed long-term plans for O'ahu, Hawai'i Island, and Maui by running the RESOLVE optimization model on the core cases and on many sensitivities.

The E3 analysis determined what set of incremental system capacity investments and dispatch decisions for each island would be least cost to meet their RPS goals under the assumptions defined for the core cases and sensitivity cases.

The E3 analysis focused on developing theoretical, least-cost resource plans to achieve the RPS goals and investigating the impact of large scale decisions (such as LNG, the interisland cable, and other sensitivities), and how they might influence near-term actions. The result is a quantitative evaluation of available resources and sensitivities to determine least-regrets near-term actions.

Input Assumptions and How They Are Used in RESOLVE

E3 ran RESOLVE, an optimal capacity expansion model which considers the total cost of new resources being built on the system, to conduct its analysis. RESOLVE minimizes total costs over the planning period (out to 2045) where years in the future are being discounted at the utility cost of capital. Important inputs include sales and peak forecasts, load shape and flexible loads, hourly renewable resource shapes, resource performance characteristics, and new and existing resource costs.

Load shape and flexible loads. RESOLVE took as input the Hawaiian Electric hourly load forecast out to 2045, which includes the effects of efficiency and vehicles, but is not net of DG-PV. RESOLVE also takes an hourly flexible load potential (provided by Black & Veatch). This flexible load potential is combined with the Hawaiian Electric load forecast to create two hourly forecasts: 1. a "base" case forecast, which is the unmovable portion of load that must be met in each hour, and 2. a flexible load that can be shifted during the course of the day, provided it follows the constraints of the hourly flexible load potential given by the Black & Veatch hourly forecast. Flexible load energy over the sum of the day is the same—that is, flexible loads are assumed to have a net zero impact on total energy. Thus, over the course of the day, the "base" plus "flexible" loads must have the same amount of energy as the Hawaiian Electric hourly load forecast. In this way, we aim to

capture increased DR and other programs that allow for more flexible, demand-side load management.

Hourly renewable resource shapes. These resource shapes include DG-PV, grid-scale solar PV, onshore wind, and offshore wind. The model combines the hourly resource unitized shape with the capacity of that resource to create an hourly energy created by each renewable resource. Some of these resources are curtailable, and some are not (that is, all DG-PV online before 2020 is uncurtailable). Resources that are curtailable can also offer upward and downward reserves.

New resource and existing resource costs. Hawaiian Electric provided levelized capital costs for new units on a $/kW year basis. The RESOLVE model allows each island to buy the relevant new resources at their levelized costs. For example, if RESOLVE decides to buy a 10 MW wind plant in 2020, the cost for that plant will be 10 MW times the $/kW year for 2020; the levelized capital cost is valid throughout the lifetime of the plant. This levelized capital cost includes any fixed O&M cost as well as interconnection costs that the facilities are charged. Similarly, existing generation resources have an annual fixed O&M cost. Both existing and new resources must pay the variable O&M costs and fuel costs which stem from every MWh of energy produced. (This is relevant only for thermal resources, as renewable sources such as solar and wind do not have a variable O&M cost.)

The resulting plans from RESOLVE were evaluated by Hawaiian Electric using the hourly production simulation model PLEXOS. Our Advanced Planning team integrates DER and DR in that process. The results are used in the financial analysis and the plans are evaluated for system security.

RESOLVE Model Limitations

The nature of the capacity expansion modeling means RESOLVE has some limitations.

To ensure reasonable model solve time, RESOLVE represents a year using a representative sample of weighted days. The subset of days is selected to cover the full range of potential conditions encountered over the provided 8,760-hour shape that would influence the planning decisions in the future. Days are weighted to reflect the long-run distributions of key metrics including hourly load, hourly renewables for each island (including solar, onshore wind, and offshore wind and hydroelectric when appropriate), and hourly net load. Instead of simulating every single year, we model 2020, 2022 (the LNG decision year), 2025, and every fifth year afterwards.

The model ensures that reserve requirements are held in both upwards and downwards directions. These reserves account for contingencies and increased variability over an hour from renewables, but do not include the short-term reserves over short timeframes. This is particularly important in later years of the model when thermal generation

providing system inertia is potentially taken offline. Other resources are left for short-term system balancing. Currently our reserve requirements and generator characteristics do not ensure this capability is met.

Planning Reserve Margin Methodology Used in RESOLVE

E3 used a reserve margin methodology as part of their planning and modeling to create their resultant plans.

Planning reserve margin (PRM) is designed to ensure that enough dependable generation capacity is available to meet expected demand in the planning horizon. It is defined as the differences between the resources available and the expected peak period loads. Under conventional conditions, a system planner can calculate expected peak load and ensure there are enough reliable dispatchable resources available to meet the expected peak load plus some margin for reserves, contingencies, planned maintenance, and unplanned events. Typically this process involves choosing a reliability standard based on an expected loss of load probability (LOLP; for example, one day in ten years), and a corresponding PRM designed to maintain that LOLP over the planning horizon in each plan. However, Some jurisdictions, however, are increasing their dependence on renewable or variable energy resources (VER) to meet their RPS requirements. For them, this simple PRM calculation based on LOLP needs to account for the specific VER's contributions to PRM at each stage in the plan.

Because VERs produce energy that is stochastic by nature, it is unreasonable to count their entire nameplate capacity in calculating the amount of resources available to meet PRM (for example, a 20 MW wind plant should not contribute 20 MW to the PRM). Conversely, completely ignoring renewable resources in the PRM calculation would result in an excessive thermal build unused for large amounts of time because of expensive fuel costs or RPS constraints. The RESOLVE methodology creates a simple metric representing the amount of capacity a planner can rely on to attribute to renewable resources in maintaining "dependable capacity".

Unlike a traditional PRM calculation (which is focused on maintaining sufficient capacity to serve the expected peak load), the PRM methodology E3 used (outlined below) is calculated for every hour in the planning horizon. While only one of these hours is binding, that binding hour cannot be identified because it is determined by an interplay of energy demand, demand response, DG-PV, and the "dependable capacity" produced for each renewable resource. For example, the binding hour for PRM in a system with only solar renewable resources will likely occur in the evening, while the binding hour for a system with a combination of wind and solar resources could occur earlier in the day.

PRM Methodology Calculation Steps

These steps describe the methodology used to value the PRM contribution of renewable resources in this planning study that incorporates the interplay described above. The process begins with normalized hourly generation shapes for each renewable resource. The normalized hourly generation shapes used in the PSIP analysis, produced by the National Renewable Energy Laboratory, are hourly forecasted generation for 2045.

1. Calculate the distribution of the hourly renewable output for each renewable resource for each season-hour (for example, summer hours 1–24).
2. Calculate the tenth percentile of each distribution above (the tenth percentile represents the energy a planner can rely on for the identified renewable resource to provide with a 90% confidence level).
3. Use the identified tenth percentile calculated for each renewable resource in each season-hour and map it to the entire year (for example, apply the tenth percentile value for summer hour 12 to the twelfth hour of all summer days in the year in question in the plan on each island).
4. For each renewable resource, multiply these hourly tenth percentile values (calculated in the previous set) by the installed nameplate capacity of the renewable resource to calculate the hourly "dependable capacity" MW contribution of that renewable resource to the PRM.

   For example, assume the tenth percentile for solar summer hour 12 was 0.10 and the system had 110 MW of nameplate solar installed. The solar contribution to PRM during each summer hour 12 would be 0.10 multiplied by 110 MW which would equal 11 MW.
5. For each hour, add together the PRM contributions from renewable resources, thermal resources, and batteries (described in "Thermal and Battery Contribution to PRM" below) to calculate the hourly PRM generation available.
6. Compare the available PRM generation with the PRM requirement, specified as a multiplier (greater than 1) of the hourly load.
7. If the generation side of the PRM constraint is greater than the load side for all hours, the PRM requirement has been met for the year in question. If there are one or more hours in which the PRM load requirement is greater than the generation resources available to meet PRM, the model must procure additional generation resources at least cost.

In this way, RESOLVE can rely on some level of renewable output for capacity instead of relying solely on an increasingly lower capacity factor thermal fleet in a high RPS world.

Thermal and Battery Contribution to PRM

Thermal resources contribute their maximum rated power output towards the PRM constraint.

In this planning study, we find that batteries are built more for energy purposes (that is, absorbing high renewable output hours and shifting the energy to lower output hours) than for providing capacity. Nevertheless, we allow batteries to contribute to PRM. A battery's contribution to the PRM constraint is the power output a battery could discharge for four hours. For example, if a battery held 4 kWh of energy, then its contribution to PRM would be 1 kW as that is the power output the battery could maintain for four hours (1 kW for each hour). This four-hour cutoff is consistent with planning methodology used in the California market, which is one of the few markets with explicit formulations for how to evaluate the planning and capacity contributions of batteries.

Suitability for Using a Simple, Single-Hour and Fixed PRM Number

This relatively simple PRM methodology is designed to determine the economic comparison of costs and benefits of a large number of cases over a relatively short period. It is largely unbiased towards different resources and is therefore suitable for comparing the costs of each PSIP plan.

Although the proposed process accounts for a VER's contribution to meeting a simple, single PRM calculation for a single hour, the approach is too simple to assure that the reliability between each PSIP plan or over the course of each PSIP plan is maintained. For this reason, the Companies have proposed using a number of other models to test the reliability of each of the studied PSIP plans. However, even that analysis is probably insufficient and limited by time, data, and analytical tools. In particular, the simple, single-hour contribution of each VER and the fixed PRM percentage over the course of the expansion plan are simplifications that need to be tested.

In California, as part of their long term planning process, E3 is currently building a version of RESOLVE that incorporates information from our RECAP model that determines the specific LOLP and PRM needed for each plan over time and the equivalent load carrying capability (ELCC) of each VER over time in each plan as a more accurate way to count VERs in their contribution to dependable capacity.[4]

[4] A description of how RESOLVE is being adapted to incorporate a more detailed check on reliability in California can be found here: http://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=6442451565.

PowerSimm Planner

Ascend's PowerSimm modeling tool evaluated 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 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, PowerSimm is able to measure dumped energy in every renewable expansion plan. These results determine the amount of load-shifting battery storage required, and calculate the cost of this storage. PowerSimm models 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.

System Flexibility Software, a module of PowerSimm Planner, has the ability to estimate one-hour ramps and regulation for a variety of fixed scenarios for daytime and nighttime requirements. PowerSimm's System Flexibility Software runs a large number of scenarios scaling historical minutely data to forecasted load wind and solar capacities. The regulation tool enables interactive queries into the output of these runs. The queries enable a choice of a base or high DG-PV forecast, the year, solar adders for 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 base case; a historic window allows scrolling through time, showing two consecutive days of load, grid-scale solar, grid-scale 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 before. The maximum ramp for each year is reported for the daytime and nighttime. Regulation is calculated as the difference between net load and load-following, where net load is load minus solar and wind, and load-following is a linear interpolation of net load through minute zero of each hour. Regulation is then separated into regulation-up (regulation greater than zero) and regulation-down (regulation less than zero) to remove bias from zero regulation calculated at minute zero 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.

PLEXOS for Power Systems

The Hawaiian Electric Advanced Planning Department conducted production simulations and modeling analysis with the PLEXOS for Power Systems modeling tool, to perform hourly and sub-hourly analysis (fully incorporating the DER and DR portfolios) and provide hourly dispatches that are then analyzed in PSS/E for system security. The outputs are also used in the Financial Forecast and Rate Impact Model.

PLEXOS for Power Systems models many features of the power systems on O‘ahu, Maui, Hawai‘i Island, Lana‘i, and Moloka‘i. PLEXOS simulates 30-years of hourly system operation, 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 possible restrictions. PLEXOS optimized 30-year expansion plans for Moloka‘i and Lana‘i.

Input Assumptions and How They Are Used in PLEXOS

PLEXOS used the same set of input assumptions as RESOLVE and PowerSimm Planner to model various long-range plans. This allows for an economic analysis of the various plans 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.

The model uses certain profiles as inputs directly, including hourly load, wind generation, solar generation, distributed energy resources, and demand response profiles covering a 30-year period. PLEXOS uses these profiles as inputs to optimize for the rest of the generation to fill in the net load differences. The renewable resources have a mixture of curtailable and non-curtailable resources (such as, firm renewable generators like HPOWER on O‘ahu and PGV on Hawai‘i Island, and NEM on all islands). Power Purchase Agreements (PPAs) are modeled according to their contract requirements. Existing renewable resources have a specified merit order to curtailment; new variable renewable energy resources are modeled to maximize flexibility. Resource costs are based on capacity, thus PLEXOS models new variable renewables as flexible resources that can be curtailed as necessary before curtailing existing renewable resources.

PLEXOS also models the generation fleet in great detail by using input assumptions that provide the generator attributes: capacity, minimum stable level, heat rates, fuels, variable O&M costs, outages rates, start and stop time, minimum up and down time, minimum and maximum capacity factor restrictions, in-service and retirement dates, and

other operating restrictions. Generation build and retirement costs are another input for any potential capacity additions or subtractions, necessary if using the long-term planning feature to optimize resource additions and retirements.

PLEXOS is also able to handle multiple fuels, costs, and contracts allowing their usage to be optimized throughout the year. The PLEXOS model makes use of fuel price forecasts for the different fuels available, as well as any usage requirements and supply limits.

Regulating reserve requirements are another input to the model. PLEXOS will dispatch the generators to provide the required reserves.

Energy storage properties are also inputs into the model. PLEXOS is able to model batteries, pumped storage hydro, and other types of energy storage. The power and capacity requirements are inputs along with any cycle limits, usage costs, efficiencies, and other constraints. PLEXOS will optimize the use of the storage to provide energy and reserves.

PLEXOS is able to output a wide variety of information. Results are available on hourly intervals as well as aggregated on a monthly and yearly basis. PLEXOS can output:

- Overall system production costs, as well as any unserved energy and dumped energy. The outputs provide not only aggregate level costs, but also the individual generator production costs.
- Standard measurements (such as capacity factors) for each generator: fuel usage, costs, energy produced, outages, and generator attributes on an hourly basis as well as monthly and yearly summaries.
- Fuel usage and costs on a per fuel basis or by generator on an hourly basis as well as monthly and yearly summaries.

PLEXOS Model Limitations

A model performs only as well as its realistic and accurate input assumptions, which in turn, directly affects the possibility of attaining quality results.

PLEXOS's primary limitation is its balancing speed with detailed modeling, particularly with various system operating constraints and energy storage. Constraints must be linear, but may not match actual constraints. Complicated fuel constraints requiring a minimum use of some fuels and maximum use of others are one of the largest issues affecting performance. In general, though, the fuel constraints are modeled in PLEXOS but because of this complexity, run times in PLEXOS can vary extensively. For example, introducing energy storage into resource plans caused run times to range between 10 to 48 hours per single run.

PLEXOS is also limited when modeling complicated combined cycle modes while trying to balance speed and performance. While PLEXOS is able to model combined-cycle

plants in great detail and in a number of different ways, there are certain configurations for combined cycle operation that require significant modeling intensity and would lead to long run times. In general, simplifications of combine cycle modeling to boost performance are conservative, in that more detailed runs can be performed if the results raise concerns or problems.

Transmission modeling is another limitation. PLEXOS uses a DC load flow model while the Hawai'i databases were built to exclude transmission. PLEXOS can still model known constraints related to transmission and could still model transmission in the future if necessary. If transmission data were added, PLEXOS would not perform the modeling of voltage or transient stability necessary for detailed transmission reliability studies. PLEXOS is fully capable of using limitations and operating procedures learned from those studies to be consistent.

Adaptive Planning for Production Simulation

Black & Veatch is running the Adaptive Planning for Production Simulation (AP) model to evaluate the capability and benefits associated with customer-owned assets: traditional Demand Response (DR) devices, customer-owned batteries installed with or without PV systems (DER), and electric vehicles (EV). Our analysis ensures that DR and DER assets are optimized as a portfolio fully considering the flexibility and limitations associated with these assets.

Inputs to the AP Model

AP takes as inputs all data required to characterize utility-owned assets, customer-owned assets, demand, and system security requirements—and evaluates them in sub-hourly and hourly increments. Expanded AP inputs and methodology explicitly address customer-owned assets, criteria associated with their use, and the technology-agnostic value of system security services they may provide. Those inputs critical to the evaluation of DR, DER, and EVs include the following for allocating customer resources to meet system security requirements.

Utility asset expansion and retirement plan. The expansion plan identifies the utility resources available in each year.

Wind and solar variability profiles. Hourly profiles define wind, grid-scale PV, and DG-PV variability. These profiles define the ability of the appropriate resources to generate power in each hour of the evaluation. Sub-hourly profiles are developed by Black & Veatch by applying historical sub-hourly variability to the hourly forecasts. When applying historical sub-hourly data to hourly forecasts, we look for a match between output level and time of day.

Demand forecast. Hourly gross and net demand profiles are used to establish commitment and dispatch requirements and when optimizing load shift provided by customer-owned assets.

System security requirements. Our analysis focuses on those system requirements that can be partially met by customer assets. These include the need for capacity, inertial response/fast frequency response, contingency, wind/solar variability regulation, demand regulation, ramping, and regulating reserve. Recognizing that the islands' need for system security is also under evaluation, we analyze against those system security requirements that defined at the time of our analysis.

Customer resource potential. Traditional DR resource and EV potential is provided by Navigant. Customer battery potential is provided by uptake models based on avoided cost value of storage provided by Black & Veatch. The potential defines the maximum amount of customer resources that are available in each year to shape demand and provide system security.

Customer resource criteria. Certain criteria limit the ability of customer resources to provide multiple services at the same time. Typically, a customer resource (such as a water heater) is limited to simultaneously providing one service that increases load (e.g., load shift to the middle of the day) and one service that decreases load (fast frequency response). In addition, there are limits on the frequency and duration of customer resource calls. These limits are considered in determining the most cost-effective use of limited DR, DER, and EV resources.

Outputs

The AP model creates a comprehensive set of outputs that support a number of subsequent evaluations in the overall PSIP and DR evaluation processes. 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. These outputs include quantifying and valuing grid services as well as the following results provided to other models

Avoided cost value of storage. The value that customer-owned batteries deliver to the generation system provides an estimate of the incentives that the Companies can use to encourage customer battery build-out. This value—specifically the ability to load shift and provide regulation—is determined by modeling the generation system without directly competing resources (DR, DER, or load shift batteries), then evaluating the same generating system configuration with an incremental amount of load shift and associated regulation capability. The results feed storage uptake models.

Optimized DR and DER profiles. DR and DER uptake between the best use of various utility and customer assets is optimized through full simulation of each hour of each year of the evaluation period. The optimization considers the customer resource criteria—limits in the ability of customer resources to provide multiple system security services at the same time—and the optimal use of customer assets. The optimization results are translated into 8,760 profiles for each year in the evaluation period for each service provided by DR and DER. The model provides yearly peak use (in MW) by the DR and DER programs. These results are transmitted to other production simulation models and used to determine the cost of the DR programs.

Value of Services

The value of service analysis attempts to segregate, to the best degree possible, the value of each independent grid service to the generating system. This is done by evaluating top down, bottom up, and by service bundles. Service bundles recognize that certain technologies provide a suite of services that cannot be easily decomposed. For example, an ICE unit can provide inertia, regulation, and energy while online; it can provide replacement reserves when offline and also provides capacity. A service bundle, in this example, allows a top down comparison to the bottom up aggregation of the individual services.

In general, grid services are valued by removing some portion of assets that provide the service as their primary function, then adding a "service proxy asset" that provides the specific service into the system in incremental steps. The service proxy asset is provided at a level quantity for all hours and at zero cost to the system (no capital or operating cost are associated with the service proxy asset). The difference in generating cost between a run that includes the service proxy and one that does not can be used to calculate the technology-agnostic value attributed to that service. By adding in the service proxy in steps, we can see how the value of the service tracks against the quantity of service added and, as such, at what point the incremental service substantially declines in value.

Value of services methodology will be described in greater detail in the February 2017 DR Application.

DR and DER Optimization

A customer participating in DR (for example, with their water heater or battery) has options—called DR products—on how their DR asset (the water heater or battery) can be used. AP evaluates available DR products, both individually and in combination, to identify the optimum DR portfolio mix. AP fits the products together either to substitute for physical assets that would otherwise need to be added or to address system security needs in a more economical manner.

Combining individual DR product potential into a portfolio is limited in the ability of its end devices to provide multiple services simultaneously.

Typically, an end device can simultaneously provide one load-building and one load-reducing service. For example, a water heater (participating in a pricing program) that uses midday solar generation to build load can also provide fast frequency response (FFR-a reduction in load after the sudden loss of a generating asset). During evening hours when the water heater is reducing load under the pricing program, however, it cannot also provide the load reducing FFR service.

Similarly, a water heater cannot simultaneously provide both FFR and regulating reserve (reducing electricity use because other customers suddenly need more) because FFR causes the end device to shut down thus making it unavailable to provide any other service. As such, the DR potential for each product must be managed to prevent over allocation of end-use devices.

The value of individual DR products will change over time. This is because the generating system is in a state of continual change with the adding and subtracting of grid-scale resources, changing resource mixes, the continuous adding of consumer resources, and evolving loads (electric vehicle loads for example)—all contributing to make each year's DR and DER value proposition unique. Thus, how the DR and DER portfolio is utilized can be expected to vary over time.

AP bases how customer-owned assets are used hour to hour on the best value derived from the asset. Since both the DR and DER 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, AP allocates DR and DER potential 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 and DER potential, the optimal allocation must be evaluated for each hour.

Generation Adequacy Modeling

In addition to evaluating DR, Black & Veatch performed Loss of Load Probability (LOLP) modeling for certain O'ahu cases to help confirm reliability measures associated with those cases. Black & Veatch uses a proprietary LOLP model (AP for LOLP) to calculate reliability measures for generation-demand systems. The LOLP model is a component of the Black & Veatch Adaptive Planning suite. The model uses the same input format as the Adaptive Planning for Production Simulation model.

AP for LOLP considers the ability of firm generation, variable renewable generation, demand response, and utility load shifting batteries to meet capacity needs. It uses a

Monte Carlo simulation solution methodology. For this analysis, the Monte Carlo model evaluates the ability to meet load each hour of each year with many (5,000) simulations evaluated for each year. For each of the 5,000 simulations, key variables that affect LOLP – demand, capacity of variable renewable generating assets, DR load shift potential, and asset forced outages – are allowed to vary.

AP Model Limitations, Shortcuts, and Simplifications

AP incorporates a detailed understanding of energy demand, wind resources, solar resources, system security requirements, operating constraints, and more. On an hourly basis, it allocates the complex array of utility-owned and customer-owned assets to meet energy and system security needs. To reduce the complexity of factors not directly related to DR and DER, AP has been configured to assume that the data used to characterize grid-scale assets and system security needs is completely accurate—in other words, our knowledge of the future is perfect.

Grid-scale assets sometimes break down unexpectedly. Black & Veatch uses a probabilistic model to assign when forced outages due to breakdowns will occur. Forced outages are assigned and fed into AP at the beginning of each study —forced outage timing is not modified within AP while assigning forced outages external, AP ensures consistency across model runs, it limits the ability of AP to consider changes in system security needs for the full range of unexpected system upset conditions.

When identifying system security needs, AP considers the system at a high level. Power flow, system transients, and locational limitations are beyond its capability. Additional modeling of various system states using specialized tools is required to identify system security needs related to transients and location.

DG-PV and Customer Energy Storage System Adoption Models

The DG-PV Adoption Model was used to address DER integration. The model forecasted market DG-PV and DG-PV paired with battery customer adoption amounts for self-supply, SIA, and potential future DG-PV products while also considering related integration costs. The model forecasted DG-PV customer adoption amounts based on historical market behavior and future projections of costs, electricity prices and incentives. 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.

The Customer Energy Storage System Adoption Model forecasted customer adoption of distributed storage when compensated at avoided cost for providing grid services through the proposed DR programs. 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.

Input Assumptions and How They Are Used in the DG-PV and Storage Update Models

Both models use a common set of input assumptions to determine the results provided for creating our action plans.

The DG-PV and the Customer Energy Storage System Adoption model takes into account the following:

- Addressable populations to determine the market size in terms of number of customers in each rate class that could potentially adopt DER.
- Hourly customer load profiles by island and rate schedule to determine the optimal DER system size and the energy flows (when DER is used and exported; when a battery is charging or discharging).
- Unitized hourly DG-PV production profiles by island to determine the optimal DER system size and the energy flows (when DER is used and exported; when a battery is charging or discharging).
- Tariffs and retail electricity price projections to determine the avoided cost resulting from customer DER use (customer economics analysis).
- Export energy compensation rate to determine the compensation for energy exported to the grid in a future grid-export program (customer economics analysis).
- The value of storage (for providing grid services) to determine the revenue stream received by DER systems with storage (customer economics analysis).
- Investment tax credit assumptions to determine the state and federal income tax credits that reduce the effective DER system cost (customer economics analysis).
- System cost assumptions to calculate the effective cost of DER system (customer economics analysis).
- The weighted average cost of capital to determine the net present value of the DER system (customer economics analysis).
- Integration costs to determine the new installations that are projected to be above the circuit hosting capacity that incur an additional one-time dollars per watt integration cost (customer economics analysis).
- The rate of inflation because all adoption modeling relationships and results are calculated in real dollars, so inflation is used to convert nominal inputs to real dollars as necessary.
- The uptake relationship to determine future uptake as a percent of the addressable population (derived from customer economics and uptake relationship regression equation).

DG-PV and Storage Update Model Outputs

Both models generate a common set of outputs and use them for similar purposes. The DG-PV and the Customer Energy Storage System Adoption models output:

- The number of customers electing to install a DER system in each year by island and rate class to scale up hourly energy flow profiles for the production simulations and DR modeling, and to define the addressable populations for stand-alone storage uptake (DR).
- The optimum system size for the average customer in each island, rate class, and program.
- The DG-PV installed capacity, and battery storage installed capacity for each year by island, rate class, and program. (The customer uptake and optimum system size combine to result in the installed capacity for all three results.) These results are then provided as input to the production simulations and DR modeling.
- The number of participating and non-participating customers in each DER program. These results are then provided as input to the DR modeling.
- Hourly profiles for energy flows (when customer energy is used or exported; when a battery is charging or discharging). These results are then provided as input to the production simulations and DR modeling.

DG-PV and Storage Update Model Abilities and Limitations

Both models can account for:

- Future customer economics.
- Rational customer technology adoption behavior based on past behavior in Hawai‘i and future customer economics.
- Future DER programs as defined in the assumptions (for example, future grid export).

The models are limited in their ability to:

- Forecast undefined future programs and tariffs. Assumptions must be made to define specific program attributes that impact customer economics (for example, future grid export).
- Manage complex and numerous future program options. While capable of handling one or two options, but numbers of options beyond that require other methods.
- Forecast rate classes with limited historical data because there is not enough data to regress historical relationships (for example, Schedule P on Maui, Lana‘i, Moloka‘i, or Hawai‘i Island). Forecasters, however, can make adjustments outside of the model (such as including future Schedule P uptake) to lessen impact of model limitations.

DG-PV and Storage Update Model Process

The financial model (retail electricity rates from production simulations), the AP model (value of DR and storage), and other assumptions (such as system costs, DER attributes, and investment tax credits) act as inputs.

The DG-PV and Customer Energy Storage System Adoption models then:

1. Update these assumptions:
   - Validate and compare these new assumptions against prior assumptions.
   - Input the validated assumptions into the model analyses.
   - Conduct test runs and ensure the results are reasonable.
   - Add the sources of the assumptions data as necessary to ensure validate results.
2. Determine the optimum system size by conducting system size optimization hear map runs for each island, rate schedule, and DER program.
3. Execute and iterate the uptake models by rate schedule and by DER program, with and without integration costs, for each island (generally 12–16 iterations).
4. Summarize and validate the capacity forecast results by comparing the current results with prior forecasts to ensure they are reasonable, then conduct additional model runs if necessary.
5. Prepare the forecast package—summary files of capacity, energy, counts, hourly profiles, and customer participation details—for distribution.
6. Distribute the forecast package to the production simulations and the DR model.

PSS/E Software for System Security Analysis

PSS/E performs simulations for a specific set of conditions (such as unit dispatch and system load). Load flow simulations are performed to determine potential overload and voltage problems under steady-state conditions for various system configurations (normal, N-1, or N-1-1). Dynamic simulations are performed to evaluate frequency, voltage, and rotor angle stability of the transmission system and its components.

We perform multiple simulations using Python, a programming language used with PSS/E to automate functions in PSS/E simulations. We developed (internally) a tool to screen the hourly dispatch from the production simulations to select "typical" and "boundary" hours in a particular year based on frequency response profiles for loss of generation contingency events. The screening tool runs a PSS/E transmission system model that has been condensed to an equivalent single-bus system model. The screening tool analyzes the largest loss of generation contingency for every hour of the year and calculates the frequency nadir; along with the FFR1 and FFR2 capacities required to meet TPL-001. Data from the screening tool is used to select typical and boundary hours for

evaluation and to create histograms and duration curves of the frequency nadirs for the entire year.

In our system security process, we run a number of steps—and iterate them—to analyze various system conditions. We run all these analytical processes for each resource plan for a single year. We perform analyses for selected years (5–6 years) to account for the significant changes in a resource plan (such as resource additions, resource retirements, load, and increasing amounts of renewable generation).

Frequency Stability Analyses for Loss of Generation (under frequency)

1. Screen production simulation hourly data to select a "typical" and "boundary" hour for select years for each resource plan core case. Create a histogram and duration curve for the final report.
2. Setup the dispatch case in PSS/E and the associated PSS/E dynamic file for each hour. If the resource modeling needs to be modified or new resources need to be added, this setup time might be extended. A dispatch table is created as needed.
3. Run the dynamic simulation for each dispatch case by tripping the largest generator. Analyze the results and estimate the FFR1 capacity to meet TPL-001. If there is UFLS, add FFR1 capacity to the PSS/E case and rerun the simulation. Continue adding FFR1 capacity until there is no UFLS for Oahu (or one block of UFLS for Maui and Hawai'i Island). This can require several iterations. Plot the results for the final report.
4. Repeat step 3 with FFR2 capacity to determine the FFR2 requirement for each dispatch case, depending on the resource plan.
5. Repeat step 3 with PFR capacity to determine the PFR requirement for each dispatch case.
6. For O'ahu, run a sensitivity analysis to determine FFR1, FFR2, and PFR requirements with AES curtailed to the full capacity of Kahe Unit 5 for the typical and boundary hours. Plot the results for a final report.
7. Compile all simulation results, tables, and graphs for the final report.

Frequency Stability Analyses for Electrical Fault (over frequency)

1. Screen production simulation hourly data to select an hour with high DG-PV. This step may not be required if the hours selected for the loss of generation analysis has a high capacity of legacy DG-PV.
2. Set up the dispatch case in PSS/E and the associated PSS/E dynamic file for each hour. Create a dispatch table for the final report.

3. Run dynamic simulation for a normally cleared fault on every transmission circuit in the system. Analyze and plot the results for the final report. Develop a summary table of all normally cleared faults for the final report.
4. Determine potential mitigation options such as addition of PFR or running units in VPO. Select a line fault that results in the worst frequency response or system collapse and run a dynamic simulation to determine the PFR capacity. Increase or decrease PFR capacities to meet TPL-001 requirements.
5. With the mitigation options added to the dispatch, run dynamic simulations for a normally cleared fault on all transmission circuits. Plot the results for the final report. Develop a summary table for all transmission circuits.
6. Repeat steps 3 and 5 for delayed clearing faults, if applicable.
7. Compile all the simulation results, tables, and graphs for the final report.

Voltage Stability Analysis (QV)

1. Screen production simulation hourly data to select an hour with high load. The QV analysis was performed from 2019 through 2021.
2. Set up the dispatch case in PSS/E.
3. Run QV analysis for N-2 contingencies for Oahu (N-1 contingencies for Maui and Hawai'i Island) to determine reactive power requirements for each critical bus to meet bus voltage set points ranging from 1.0 PU to 0.90 PU. Analyze data, develop summary table and plot QV curves for final report.
4. Perform sensitivity analysis for dispatch cases that do not meet reactive power requirements. Add synchronous condensers and repeat steps 2 and 3. Analyze data and repeat if necessary. Note that in some cases, additional load flow analysis is required to determine mitigation.
5. Compile all simulation results, tables, and graphs for the final report.

Minimum Fault Current Screening

1. Screen production simulation hourly data from 2019 through 2021 to determine if minimum fault current requirements are met.
2. Add synchronous condensers when resource plans violate minimum fault current criteria.

Financial Forecast and Rate Impact Model

The financial model takes inputs from the Production Simulation system cost files, as well as other general planning and forecasting assumptions in order to calculate revenue requirements and associated bill impacts for each theme.

Table C-1 details the major financial model inputs required and the sources of the input.

Inputs	Source
Capital expenditures	Planning System Cost files
Plant addition dates	Planning System Cost files
Sales	Planning System Cost files
Fuel costs	Planning System Cost files
Purchase power costs	Planning System Cost files
Operating costs	Planning System Cost files; Historical actuals
Removal costs	Property Accounting
Depreciation rates	Approved depreciation rates; Management forecast
Inflation rates	Blue Chip GDPPI forecast
Interest rates	Management forecast
Tax rates	Federal and state tax codes
Equity ratio	Management analysis
Allowed ROE	Approved rate cases
Historical Financial Statements	General Ledger
Weighted average cost of capital	Management analysis

Table C-1. Financial Model Inputs

The inputs are entered into the financial model calculate its results. See Financial Forecast and Rate Impact Model (page H-80) for an explanation of how the financial model calculates bills, profit and loss, cash flow, revenue and rates, debt and equity, balance sheet assets and debts, and capital expenditures.

Table C-2 details the major outputs of the financial model.

Outputs	Description
Revenue requirements	Total revenue requirements based on all the cost inputs from above.
Average residential rates	Average rates based on the cost inputs from the revenue requirements divided by the sales forecast.
Typical residential bill impact	Typical bill based on 500 kWh monthly usage.

Table C-2. Financial Model Outputs

The financial model takes input from various other sources, primarily from the production simulations.

The financial model—and the PSIP process as a whole—accounts for but does not reflect detailed planning and forecasting for balance of business capital expenditures. There may be situations where balance of business capital expenditures are a higher priority than PSIP capital expenditures, or vice versa and that some re-prioritization is needed.

RESOLVE OPTIMIZATION MODEL AND LONG-TERM PLAN DEVELOPMENT

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 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 our April 2016 updated PSIP to explore 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 C-3. illustrates how these trends might manifest themselves in a 100% renewable generation case.

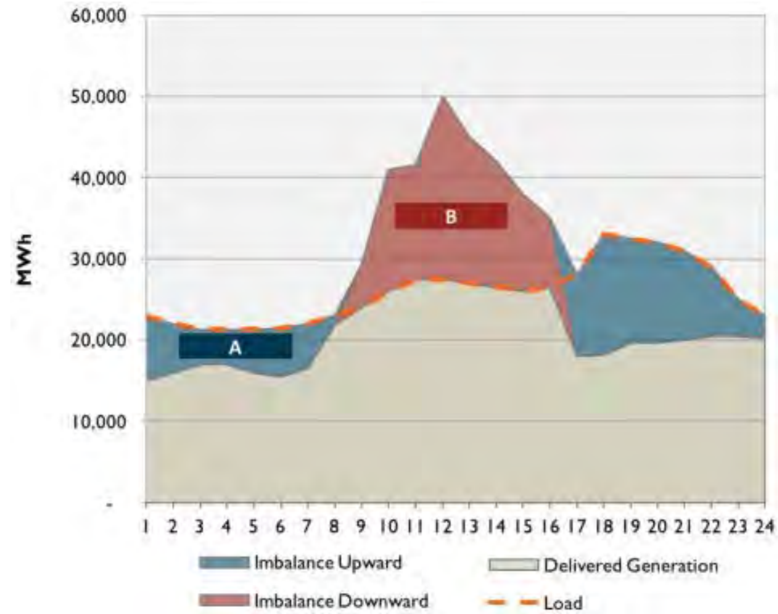


Figure C-3. Example Dispatch at 100% Renewables

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 C-4. 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.

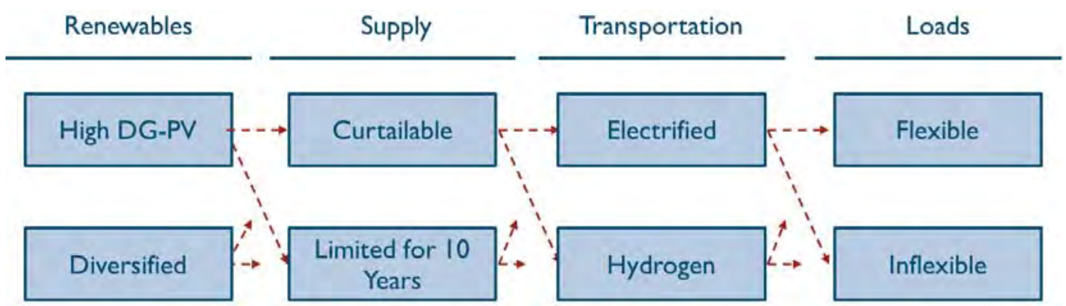


Figure C-4. Case Drivers of Potential Hawaiian Electric Futures

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 C-4) 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[5] and the United States[6] to develop multiple paths and a strategic vision for transforming Hawai'i's energy future. Combinations of the case drivers shown in Figure C-4 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

---

[5] https://ethree.com/public_projects/energy_principals_study.php.

[6] http://unsdsn.org/wp-content/uploads/2014/09/US_DDPP_Report_Final.pdf.

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 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 C-5 shows the conceptual effects of uncertain storage pricing.

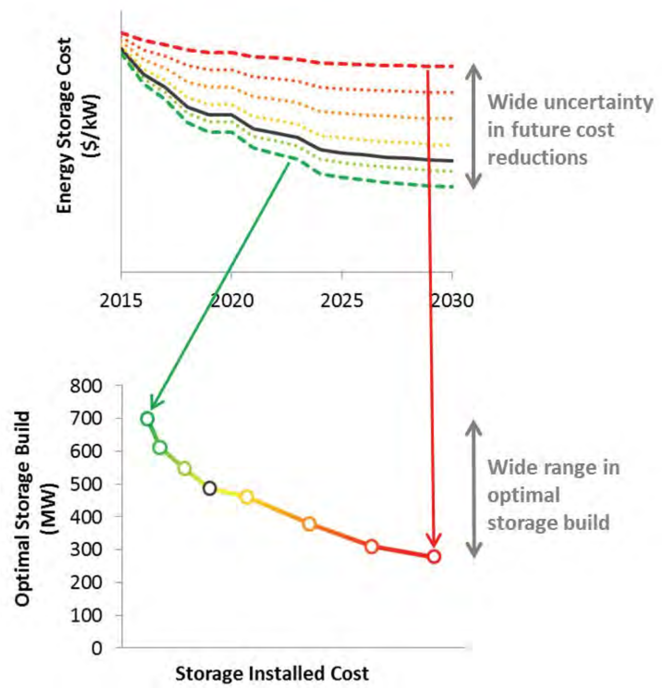


Figure C-5. Conceptual Effect of Storage Price Sensitivity

Beyond energy storage, a broad suite of integration solutions was employed to meet the RPS targets (Table C-3). 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.
Interisland transmission	Both	Seconds to hours	Balancing benefits depend on the complementarity of load and renewables being connected.

Table C-3. 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 C-6). 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.

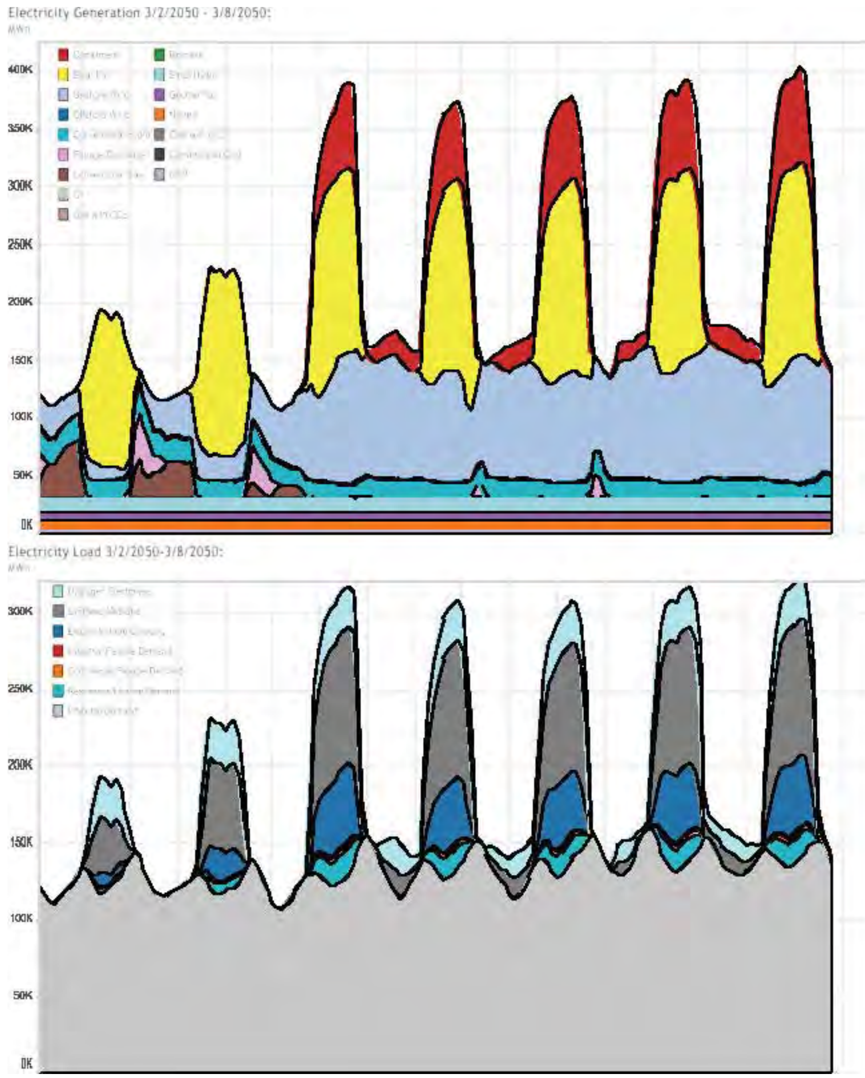


Figure C-6. Dispatch at 100% Renewables: Supply (top) and Demand (bottom)

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 C-7 shows a hypothetical day when generating resources must operate to meet the following constraints:

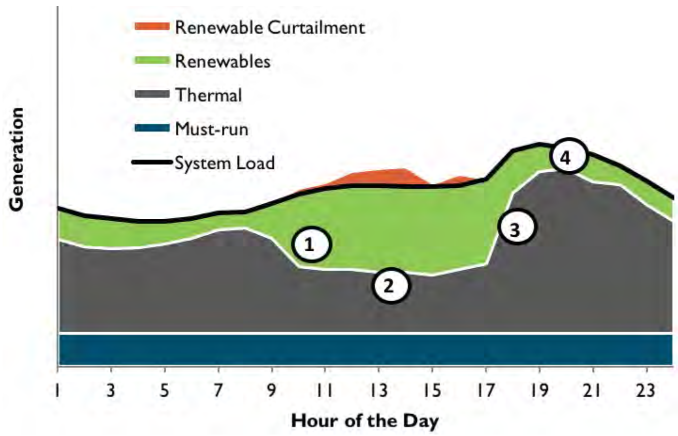


Figure C-7. Renewable Integration Challenges

Key to Figure C-7 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 C-8 shows the resource mix under three hypothetical renewable integration strategies.

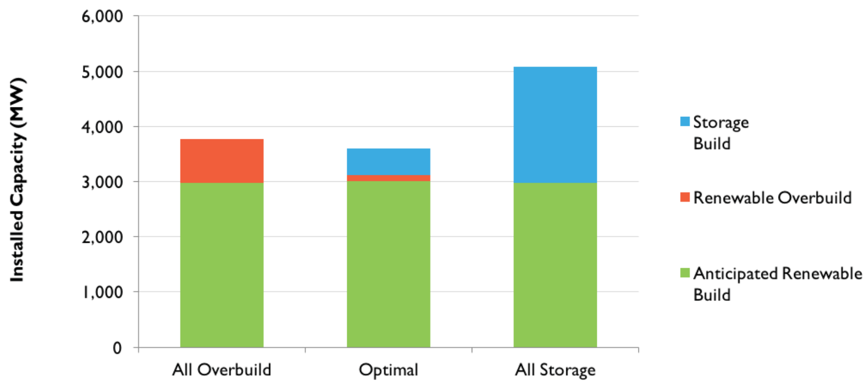


Figure C-8. Hypothetical Renewable Integration Strategies

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 C-9 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.

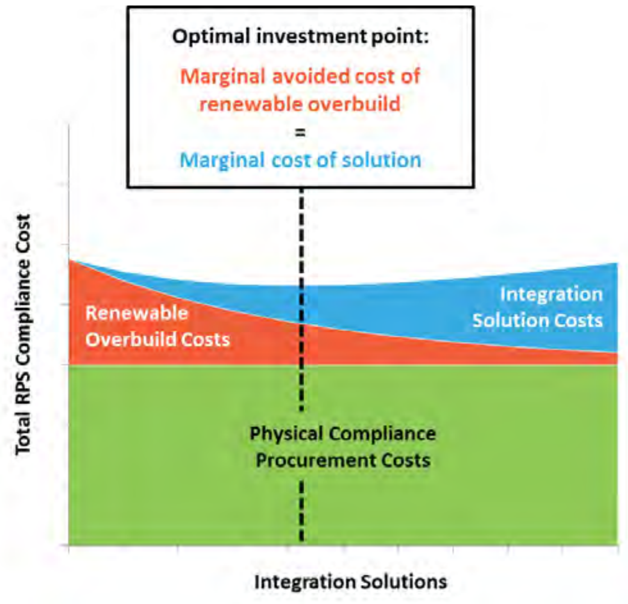


Figure C-9. Tradeoff Curve Between Integration Strategies

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.

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.

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 value and need of flexible thermal generation, under conditions of perfect and imperfect foresight, in meeting future load in O‘ahu.
- Determines the change in costs and risks in costs for meeting PSIP portfolio emission constraints with and 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 and sub-hourly cycles using sub-hourly modeling.
- 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 detail 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 leverages 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 expands 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 the Companies' 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. Furthermore, simulating future conditions with "meaningful uncertainty" better articulates some dimensions of risks for each of the proposed portfolios.

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.

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.

Stochastic Dynamic Programming for Resource Selection

Ascend defines the value function as:

$$V_t(1_{it}, \dots 1_{Nt}) = \mathrm{E}[\textstyle\sum_{j=t}^{T}\sum_{i=1}^{N} \beta t * \ Total\ Costs_{jt} \ * 1(optimal)_{ji}]$$

$1(optimal)$ are the optimal asset choices (build or don't build) for time j, j = t, …, T so the value function is the expected minimum cost for the expansion planning problem.

Dynamic programming turns the multi-period problem into a two-period problem via an equivalent, recursive definition of the value function:

$$V_t(1_{i,t}, \dots 1_{N,t}) = \min\left\{\sum_{i=1}^{N} Total\ Costs_{i,t+1} 1_{i,t+1}\right\} + \beta E\left[V_{t+1}(1_{i,t+1}, \dots 1_{N,t+1})\right]$$

Where the minimization is over $1_{i,+1}$, … $1_{N,\ +1}$, the portfolio of assets that will be online in period t+1. State vector is ($1_{,}$, … $1_{N,}$).

To handle (1), the value function is iteratively solved for using a backwards recursion:

- Find all the asset mixes that satisfy the constraints as of month "T": for each of these, calculate the NPV of costs associated with the asset mix.
- Find all the asset mixes that satisfy the constraints as of the previous period (month T–1).
- Find all the asset construction plans that get you from a feasible asset mix in month T–1 to a feasible asset mixes from month T:
  - For each of these construction plans, calculate the NPV of the costs (that is, the cost associated with each construction opportunity plus the NPV for the asset mix from the month-N asset mix that the construction will result in).
  - Note that for each feasible asset mix in month N-1, you need only track the construction opportunity that has the lowest NPV
- Repeat, stepping from T–1 back to T–2, then back to T–3, and so on until arriving at month 0.
- The end of this backwards recursion results in the expression for V ($1_{i,}$, … $1_{N,}$) for all t, thus easily solving for the minimum cost portfolio given an arbitrary initial state for any t in (1, …, T).

We can use to calculate the expectation part of the second component in Bellman's equation: [($1_{i,+1}$, … $1_{N,\ +1}$)].

Using simulations when no closed form exists for the transition probabilities is one of the major advances in the field of Approximate Dynamic Programming.

For the Policy functions used in stochastic dynamic programming we have:

$$V_t(1_{i,t}, \dots 1_{N,t}) = \min\left\{\sum_{i=1}^{N} Total\ Costs_{i,t+1} 1_{i,t+1}\right\} + \beta E\left[V_{t+1}(1_{i,t+1}, \dots 1_{N,t+1})\right]$$

Where the minimization is over $1_{i,+1}$, … $1_{N,\ +1}$, the portfolio of assets that will be online in period t+1. State vector is ($1_{,}$ … $1_{N,}$).

Policy functions are the solutions to the previous minimization as functions of the state.

$$1^*_{i,t+1} = f_{i,t+1}(1_{i,t}, \dots 1_{N,t})$$

$$1^*_{N,t+1} = f_{N,t+1}(1_{i,t}, \dots 1_{N,t})$$

Optimized expansion paths are simulated by the policy function markov chain.

Stated in less technical terms:

The Minimum Expected Value of Total Cost:

$$\text{E[NPV of Total Costs]} = \text{E}\left[\sum_{t=1}^{T}\sum_{i=1}^{N} \beta t * \ Total\ Costs_{it}\ * 1_{it}\right]$$

Fixed Costs follow revenue requirements: depreciation, amortization, current taxes, deferred taxes, insurance, property taxes, on-going capital improvements, and return on equity and debt.

Variable Operating Costs come from hourly dispatch aggregated up to monthly totals including: start-up costs, minimum uptime and minimum downtime constraints, emissions and variable heat rates.

Subject To:

Reserve Margin Constraints:

$$\sum_{i=1}^{N} Capacity_{it} \geq \gamma PeakLoad_t\ for\ t = 1\ to\ T$$

where γ is the required reserve margin.

Energy Constraint:

$$\sum_{i=1}^{N} Energy_{it} \geq Load_t \; for \; t = 1 \; to \; T$$

Renewable Constraint:

$$\sum_{i=1}^{N} Renewables_{it} \geq RPS_t \;\; for \; t = 1 \; to \; T$$

Ancillary Service Requirements:

$$\sum_{i=1}^{N} Regulation_{it} \geq \grave{}Reg\ Limitt \;\; for \; t = 1 \; to \; T$$

$$\sum_{i=1}^{N} Spin\ Res_{it} \geq Spin\ Limit_t$$

$$\sum_{i=1}^{N} NonSpin\ Res_{it} \geq NonSpin\ Req$$

$$\sum_{i=1}^{N} Flex\ Ramp_{it} \geq Flex\ Ramp\ Req$$

PowerSimm System Flexibility Software

The objective of the PowerSimm module, System Flexibility Software, is to determine the amount of flexible generation capacity required when planning to integrate intermittent renewable energy sources into an energy system. Flexibility requirements are estimated in terms of (1) regulation requirements necessary to maintain CPS2 scores at 95 and 99.9, (2) ramping requirements at both 15-minute and 1-hour time steps, 3) changes in ramping direction of net load, and 4) dump energy.

Because of the large proportion of solar generation, these requirements are estimated by daytime and nighttime requirements. The analysis determines flexible generation requirements by estimating the variability of historical minutely data for load and renewable generation.

The methodology of the PowerSimm System Flexibility Software is defined below.

Regulation

Regulation is the intra-hourly deviations from the linear interpolation through minute zero of net load. It is a zero-sum system balancing metric that represents the system's requirement for flexible generation capacity at the 1-minute level.

$$Regulation_t = NetLoad_t - NetLoadFollowing_t$$

$$NetLoad_t = Load_t - UtilityPV_t - CustomerPV_t - OnshoreWind_t - OffshoreWind_t$$

- Load and renewable data is assigned peak period labels for Day-Time and Night-Time. The daytime peak period is defined as the minutes of the day in Honolulu as recorded by the following website: http://www.timeanddate.com/sun/usa/honolulu.
- Net Load is calculated as load minus renewables.
- Net Load following is calculated as the linear interpolation of net load from the first minute to the last minute of each hour.
- Regulation is then calculated as the difference between net load and net load following (not counting minute zero).
- The regulation requirement is then calculated as the average of the absolute values of the upper and lower confidence bounds of regulation calculated separately for Day-Time and Night-Time as defined above.

Ramps

$$Ramp_{t,p} = Net\_Load_t - Net{-}Load_{t-p}$$

The 1-hour and 15-minute ramp statistics are calculated as the difference between the net-load at a given time (time t) and the net-load exactly 15 minutes and 1 hour prior to that time respectively (time t–p, where p is the time interval of 15 or 60 minutes). Physical ramps assume that load minus renewables can never be less than zero, since generators cannot ramp down less than zero. Physical and absolute ramps are calculated for each minutely data point at time t, where we have data for time t–p. The maximum 15-minute and 1-hour ramps up and ramps down for each year are reported both for the day-time and night-time.

Scaling

Historical minutely data is multiplicatively scaled to forecasted capacities by dividing by the historical max and multiplying by the forecasted capacity.

- Overlapping historical data for grid-scale solar PV, DG-PV, onshore wind, offshore wind, and load are each separately scaled so that the average is 1 MW.
- Load is scaled to the forecasted average MW, and renewables are scaled to their assumed capacity times the historical capacity factors by theme and year.

Forecasts for the selected theme can be viewed in the 'Selected Forecast' tab. Then adders for onshore wind, offshore wind, and grid-scale solar PV are applied to forecasts, and the same process is done to scale the renewable resource's generation to its new capacity.

Dump Energy

Dump energy is the must-take energy in excess of load, that is, the energy that should be curtailed or utilized for charging batteries.

$$Dump_t = Max\{0, MustRunThermal_t + RenewableGen_t - Load_t\}$$

- Minutely dump energy is summed by day.
- Daily dump energy is averaged by year.
- Average daily dump energy is converted from MWm to MWh.
- Dump-hours are calculated from minutely data as the average number of hours per day where the system is dumping more than 10% of load.

Minimum Thermal Generation Levels (labeled as 'mingen' in the software) are calculated as the minimum generation output from thermal generators that are considered must-run for the selected theme and year. For additional flexibility, dump energy is also calculated using minimum generation adders from 0–100 MW by 10 MW. Minimum Thermal Generation can be viewed by Year and Theme in the 'mingen' tab.

Dump Energy was also calculated similarly using hourly data (minute zero of each hour) to illustrate the difference in minutely and hourly calculations of dump energy.

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 C-10 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.

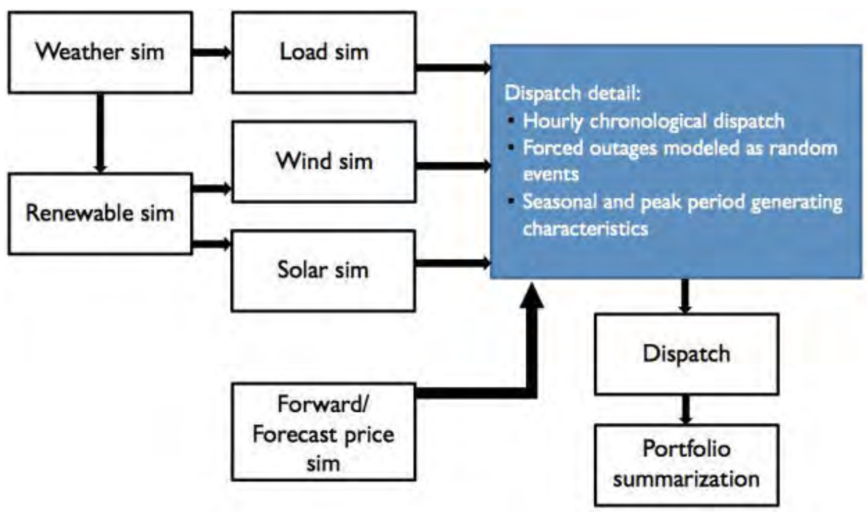


Figure C-10. PowerSimm Process Flow Diagram

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.

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. PLEXOS provides output from the island data sets for benchmarking with existing models used by the Companies.

PLEXOS 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 core cases.

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.

Energy Exemplar developed PLEXOS datasets to model generation resources for O‘ahu, Hawai‘i Island, and Maui for our April 2016 updated PSIP. We developed PLEXOS datasets to model generation resources on Moloka‘i and Lana‘i.

Unit commitment and economic dispatch to evaluate the economics of the generation system was modeling for all five islands. Capacity expansion modeling for portfolio optimization and RPS modeling was run for Moloka‘i and Lana‘i.

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.

ADAPTIVE PLANNING FOR PRODUCTION SIMULATION

Black & Veatch is applying its Adaptive Planning for Production Simulation (AP) model to support the 2016 updated PSIP analysis. AP 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 model incorporates Demand Response (DR), Distributed Energy Resources (DER), and grid-scale renewable integration into its production runs.

AP 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 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 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 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 Hawai'i 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 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 grid-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 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'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 energy, down regulation via curtailment and up regulation while being curtailed. 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

Grid-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 in a method very similar to the treatment of grid-scale storage and grid-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 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 DR products can be 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 grid-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

Given the interest in identifying if and when DR products could substitute for physical resources to help meet primary frequency response (for example, fast frequency response-FFR), the ability to understand implications of the security protocols on service requirements is a key issue. To this end, Black & Veatch incorporated, as an option, a regression model based on inertia and kinetic energy from electric generators to better relate needs to optional portfolio and service combinations into AP. The resulting regression becomes 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

At the heart of AP 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, 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.

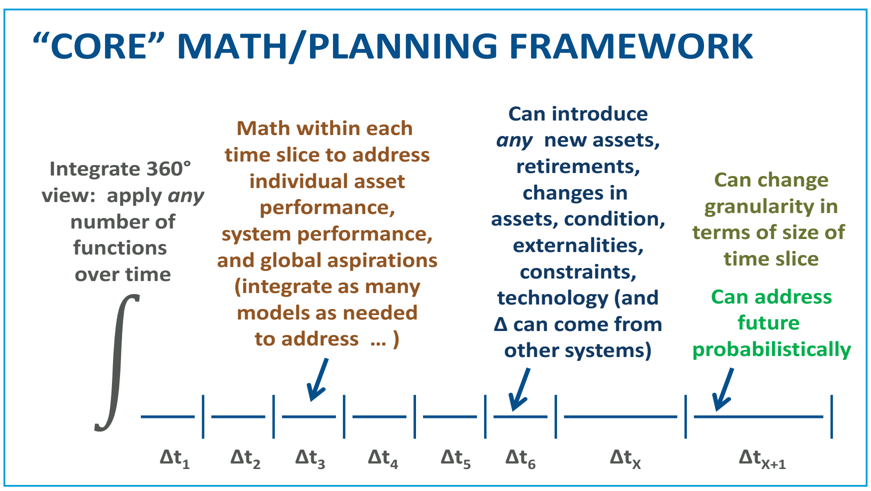


Figure C-11. Adaptive Planning Core Math and Planning Framework

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 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.

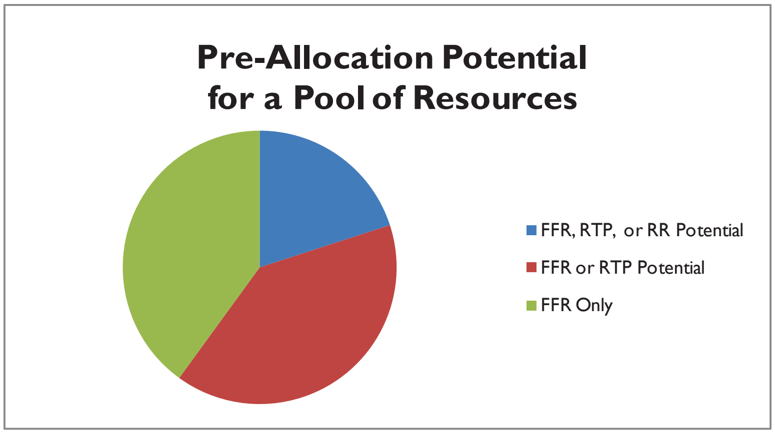
When determining commitment (units that are online), the model endeavors to meet both demand (incorporating load-shift demand response) and grid security requirements. It starts up or shuts down generating resources as needed to meet these requirements. It prioritizes the resources online to include 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.



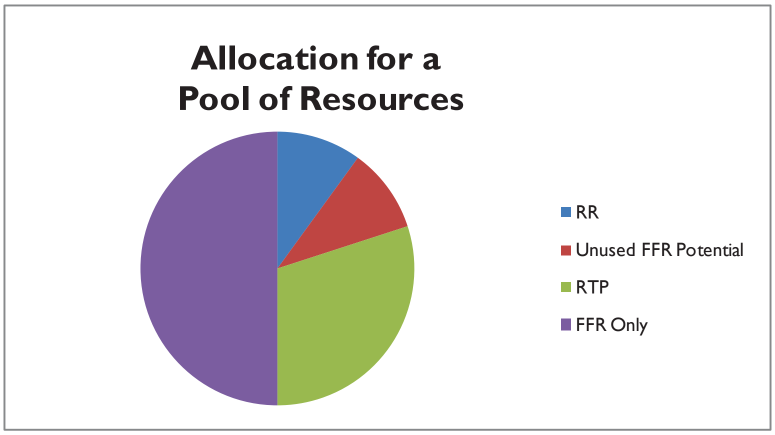


Figure C-12. Sample Resource Allocation

AP maps end-use devices to DR products to ensure the 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. An end device cannot provide FFR at the same time as RR.
3. End devices participating in pricing programs can provide FFR or RR while building load.
4. End devices participating in pricing programs cannot provide FFR 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.
3. Regulating reserve meets up-regulation.
4. Aggregated DR calls are checked against aggregated limits (number of calls per year, length of call) to ensure usage is within limits.
5. 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 and RR.

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).

Loss of Load Probability (LOLP) Modeling

Black & Veatch uses a proprietary LOLP model (AP for LOLP) to calculate reliability measures for generation-demand systems. The LOLP model is a component of the Black & Veatch Adaptive Planning suite and is based on a Monte Carlo simulation approach. The model uses the same input format as the Adaptive Planning for Production Simulation model.

The reliability measures that AP for LOLP calculates are:

- Loss of load probability (LOLP)
- Loss of load expectation (LOLE)
- Unserved energy

LOLP is the probability that capacity cannot meet load and as such LOLP is a probabilistic measure. LOLP is stated in days per year. The LOLP does not measure the duration of the inability to serve load. It only measures the number of times (number of days) that load cannot be served. For instance, from an LOLP standpoint, not being able to serve load for four consecutive hours is no worse than not being able to serve load for one. LOLE is the hour by hour accumulation of the probability that hourly demand exceeds system capacity. Unserved energy is the hour by hour accumulations of the probability that hourly demand exceeds system capacity multiplied by the capacity shortfall. These reliability measures can be calculated for multiple years, taking into account maintenance scheduling, forced outages, and generation unit commissioning and retirements.

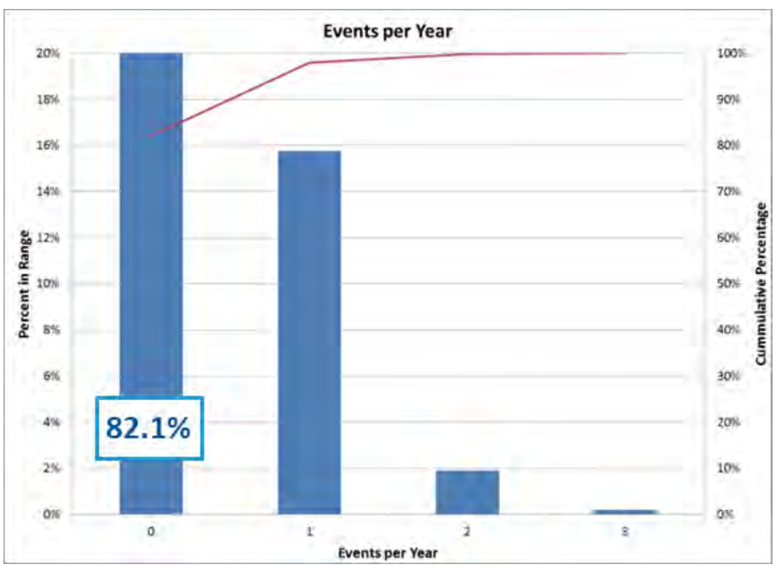


Figure C-13. AP for LOLP Predicts One Failure Event in Five Years

AP for LOLP considers the ability of firm generation, non-firm generation, demand response, and utility load shifting batteries to meet capacity needs. It uses a Monte Carlo

simulation solution methodology. For this analysis, the Monte Carlo model evaluates the ability to meet load each hour of each year with many (currently 5,000) simulations evaluated for each year. For each of the 5,000 simulations, key variables that affect LOLP are allowed to vary.

These are:

- Demand
- Capacity of non-firm assets
- DR load shift potential
- Asset forced outages

Demand, capacity of non-firm assets, and DR load shift potential are randomized using the same methodology. LOLP begins with a profile that defines demand (or capacity or DR potential) for each hour of each year. For each simulation, the demand (or capacity or DR potential) in each hour is randomized by selecting a value for that same hour that occurs within the window of 21 days before and 21 days after the day in question. An example depicting the capacity of non-firm assets is provided in Figures 3 and 4. In hour 12, non-firm resources (wind, central solar, and distributed solar) are predicted to generate 1,110 MW (Figure 3). However, within the +/- 21 day window, the generation could be as high as 1,150 MW or as low as 375 MW (Figure C-18).

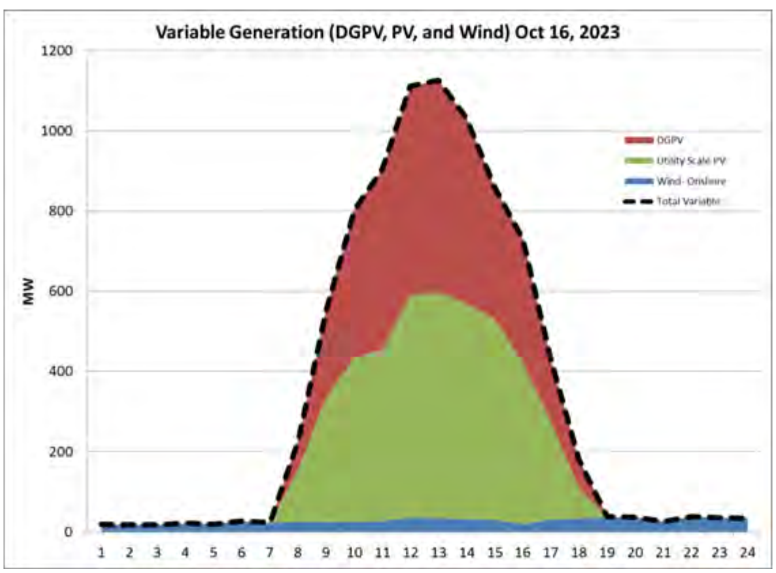


Figure C-14. Variable Renewable Generation Projection for October 16, 2023

Hawaiian Electric
Maui Electric
Hawaiʻi Electric Light

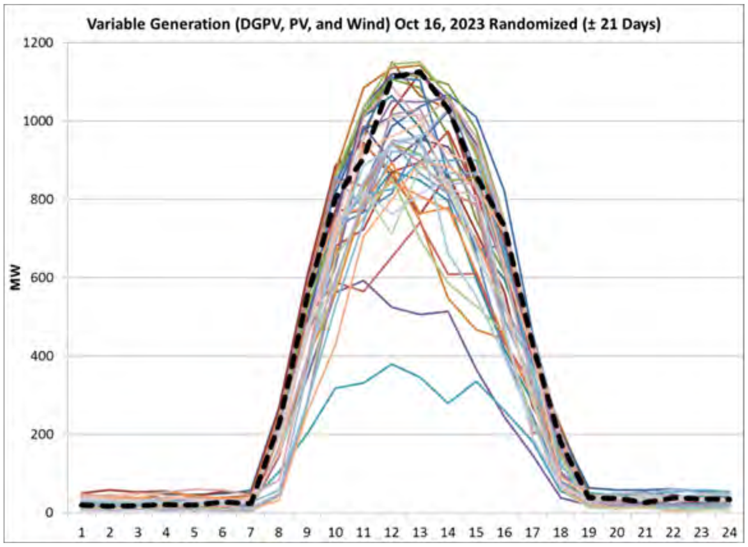


Figure C-15. Randomized Generation Projections for October 16, 2023

Asset forced outages are randomly assigned based on the forced outage rate data provided.

Model Outputs and Visualization Tools

AP 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.

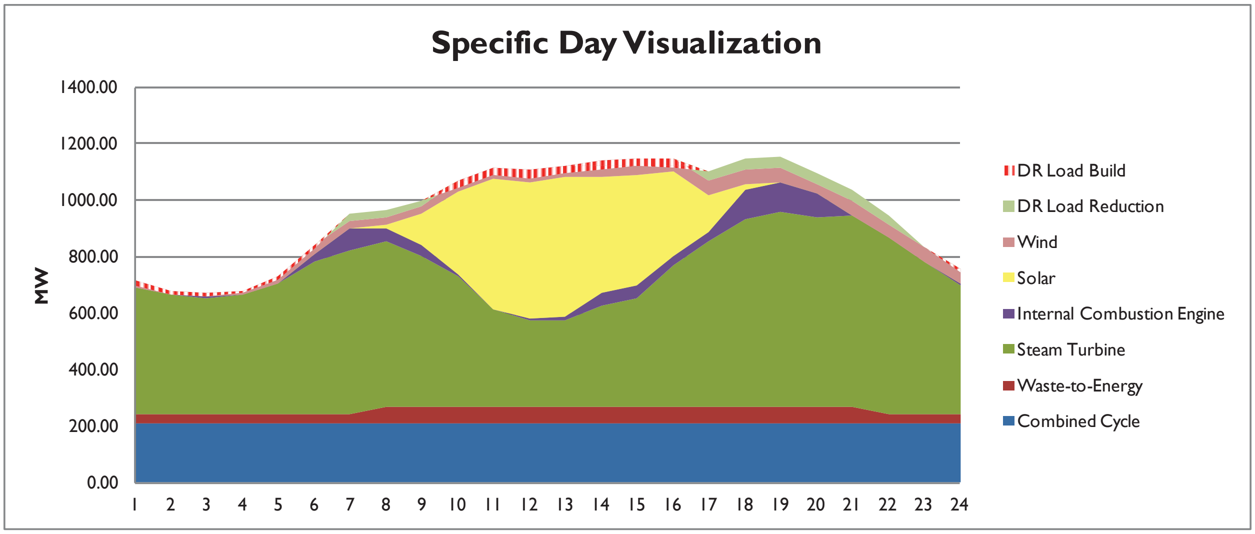


Figure C-16. Specific Day Results Example

- *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.
- *Value of Service:* Value of Service views are Avoided cost views where the savings are divided by the amount of service provided. Value of service views describe how the value of a service changes with the amount and timing of service being examined.

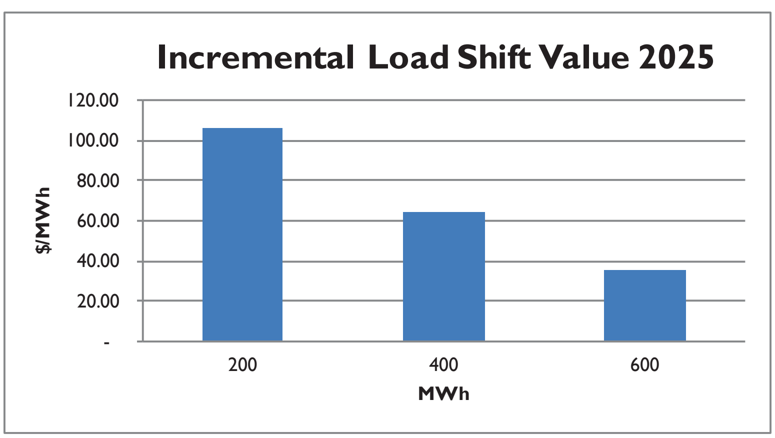


Figure C-17. Value of Service Results Example

DG-PV ADOPTION MODEL

The proprietary DG-PV Adoption Model (developed by the Boston Consulting Group) forecasts the adoption of customer-sited energy resources. The model primarily determines the quantity and installed capacity of DG-PV (with and without storage), together with the given retail or export rate when this adoption would occur. This model has been applied 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 self-supply, and potential future DG-PV combined with the possibility of the adoption of customer-sited storage.

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 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 capacity installed. 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 resource. The model can also integrate explicit integration costs to fine-tune the customer adoption levels as necessary.

The following assumptions were used in DG-PV forecasts for use in our December 2016 PSIP analysis:

- 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 Hawai‘i, by island, between payback time and levels of customer adoption for DG-PV.
- PV irradiance profiles for each island served.
- Company class load study 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 installed capacity through 2045 based on NPV and payback periods.

CUSTOMER ENERGY STORAGE SYSTEM ADOPTION MODEL

The proprietary Customer Energy Storage System Adoption Model (also developed by the Boston Consulting Group) 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.

PSS/E FOR SYSTEM SECURITY ANALYSIS

Our Transmission and Distribution Planning Division uses the Siemens PTI (Power Technology International) PSS®E (Version 33.7) Power-Flow and Transient Stability software application for transmission grid modeling and for system security analysis. This application is one of three most commonly used grid simulation programs for United States utilities. The application supports the IEEE (Institute of Electric and Electronic Engineer) generic models for generators and inverters. When available, custom models can preclude generic models.

PSS/E 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 PSS/E provide transmission planning and operations engineers a broad range of methodologies for use in the design and operation of reliable networks. PSS/E is used for power system transmission analysis in over 115 countries worldwide.

PSS/E analyzes the steady state and dynamic performance of transmission networks. It is an integrated, interactive application for simulating, analyzing, and optimizing power system performance and provides probabilistic and dynamic modeling features.

The application has two distinct 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 PSS/E to verify the system events as well as to verify the modeling assumptions.

Input to PSS/E 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).

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.

Several Modules Comprise the Modeling Tool

Our Budgets and Financial Analysis Department updated and refined this model that was specifically created to perform financial analysis for the December 2016 PSIP.

The Financial Forecast and Rate Impact Model is comprised of several modules (Figure C-18). The model also includes a discussion that contains the inputs feeding into the calculation modules, and a dashboard that captures all the major outputs from the various modules.

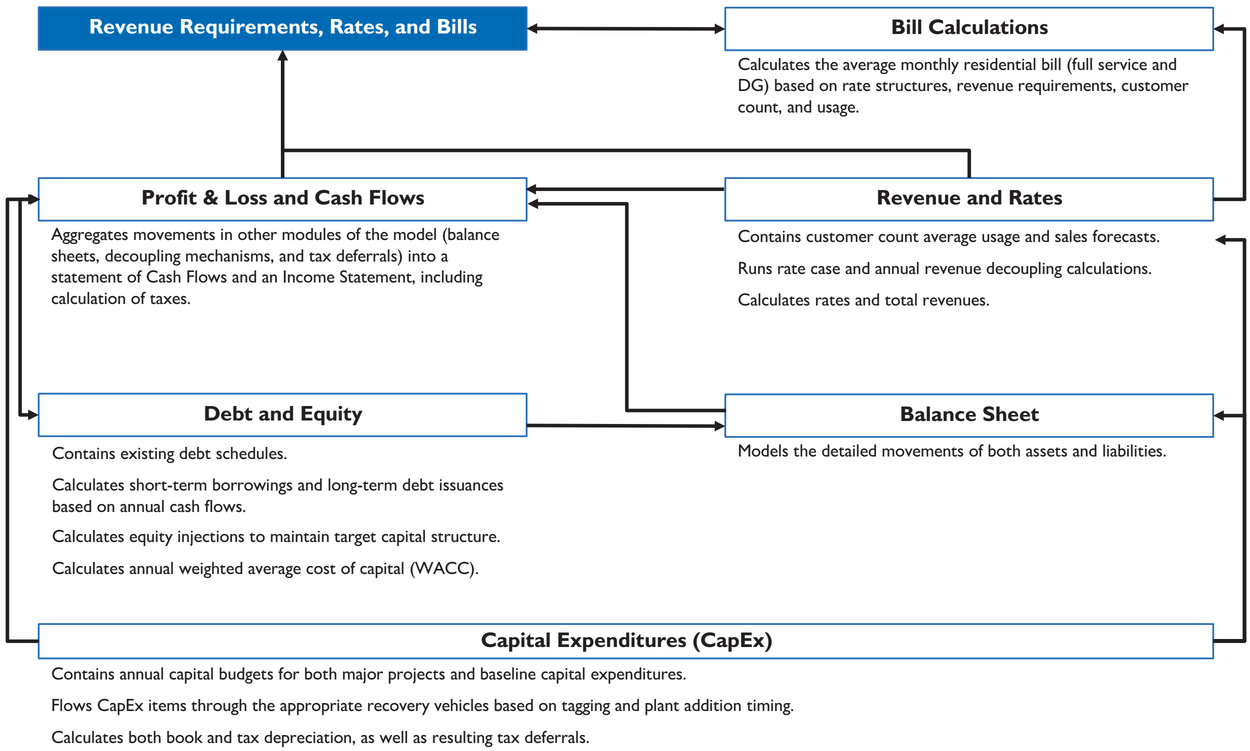


Figure C-18. High-Level Module Structure of the Financial Forecast and Rate Impact Model

Bill Calculations

This module calculates the average monthly bill for full service and DG-PV residential customers. It:

- Calculates average bills under both current rate structures and the proposed DG-PV framework, with fixed rates calculated for both cases.
- Bases the bill calculations on forecasts of annual number of DG-PV customers and usage, production, and export for an average DG-PV customer.

Profit & Loss and Cash Flow

This module primarily aggregates movements from other modules of the model (for example, balance sheet, decoupling mechanisms, and tax deferrals) into a statement of Cash Flows and an Income Statement.

For the statement of Cash Flows:

- Produces detailed schedules of operating, investment, and financing cash flows.
- For operating cash flow, key inputs from other modules include depreciation, change in tax deferrals, change in regulatory assets, and change in accounts receivable and accounts payable.
- Investment cash flow is driven by capital expenditures, which are calculated and picked up from the CapEx module.
- Financing cash flow is driven by the base dividend payments calculated from Net Income in the Income Statement, combined with the debt and equity issuances, and additional dividend payments calculated in the Debt and Equity module.

For the Income Statement:

- Key movements picked up from other modules include Total Revenues, Revenue Balancing Adjustment (RBA), depreciation, and interest expenses.
- Fuel, PPA, and variable and fixed production O&M costs come directly from the PSIP production simulation input, while the remaining O&M items are escalated annually by inflation, adjusted for any specific project-related savings or cost increases.
- Income and revenue taxes are calculated directly, with tax deferrals added from the CapEx module.

Revenue and Rates

This module contains various calculations that add up to a total annual revenue requirement:

- Periodic rate case calculations, with both a calculation of allowed return in order to adjust rates, and a calculation of net allowed revenue for RBA adjustments.
- Detailed RAM and RBA calculations, which reflect the most recent adjustments to the RAM.
- Mark-up of fuel and PPA costs by the revenue tax adjustment factor, to allow pass-through in rates.
- Calculation of total effective rates, by summarizing and adding up the different rate components contributed by RAM, RBA, other surcharges, rate case adjustments, and fuel and PPA pass-through.

- Calculation of total annual revenues, by multiplying the total effective rate with the total forecasted sales provided by (and used in) the PSIP production simulation.

Debt and Equity

This module calculates short-term borrowing, long-term debt issuance, equity injections, and additional dividend payouts:

- Based on an objective to maintain a minimum ending cash balance, short-term borrowing, and long-term debt are used to cover any shortfalls from the net cash flow before financing. Short-term borrowing is exhausted first, with any remaining shortfall covered by long-term debt.
- Upon issuance of debt, equity injections are calculated (if necessary) to maintain the target capital structure.
- Interest expense on new debt is calculated, with short-term borrowings carrying full interest expense in the year of issuance, and long-term debt carrying half a year's interest expenses in the year of issuance, and a full year of interest expense starting in the year following issuance.
- In years with equity over the target ratio, the model calculates additional dividend payments to achieve target capital structure.
- The weighted average cost of capital by year is calculated based on currently-authorized equity returns and forecasted debt rates using the target capital structure.

Balance Sheet

The module presents detailed annual assets movements, including:

- Utility Plant in Service, Accumulated Depreciation, and Construction Work in Progress, driven by annual changes of these items in the CapEx module.
- Annual change in Customer Accounts Receivables are based on annual relative change in Total Revenues.

Also presents detailed annual liabilities movements, including:

- Common Stock and debt balances are driven by calculations in the Debt and Equity module
- Any increase in Retained Earnings is net of any additional dividends paid out as part of the optimization of the capital structure.
- Accounts Payable adjusted annually based on average relative annual change in capital expenditures, fuel, and PPA costs.

For both assets and liabilities, all items that are not explicitly driven by calculations in other parts of the model are kept constant.

Capital Expenditures (CapEx)

This module contains detailed annual capital budgets, and calculations of surcharges, securitization (if applicable), and depreciation (book and tax). The module:

- Details capital expenditures and plant additions by year for baseline and major projects (RAM definition).
- Summarizes plant additions by asset category for depreciation purposes and allows for the inclusion and exclusion of specific projects depending on the cases modeled.
- Summarizes plant additions by surcharge category (Preapproved Baseline, Major Project, or REIP) for decoupling calculations in the Revenue and Rates module.
- Calculates average baseline capital investments for use in the RAM adjustment.
- Calculates accumulated depreciation and depreciation expense by asset (production plant) and by asset category (transmission, distribution, and general).
- Calculates tax depreciation and subsequent deferred tax impact on book and tax depreciation differences.
- Calculates the annual securitization payments associated with the retirement and removal of individual generating units (if applicable).

D. Current Generation Portfolios

HAWAIIAN ELECTRIC SYSTEM

Hawaiian Electric's generation capacity has a mix of utility-owned generation as well as generation from independent power producers (IPPs).

Utility-Owned Generation

Kahe Generating Station. The Kahe generation station has six steam units, all baseload generation, with a combined nameplate capacity of 651 MW, with 620 MW net generation. These are Hawaiian Electric's most efficient units. The station has black start capability.

Waiau Generating Station. The Waiau generating station has eight units: six are steam units and two are diesel. Two are baseload units; four are cycling units; and two are quick-start combustion turbines. Their combined nameplate capacity is 499 MW, with 481 MW net generation. The station has black start capability.

Campbell Industrial Park (CIP). The CIP generating station has one combustion turbine, CT-1, which runs on biodiesel. It provides 113 MW net firm generation. The unit is both quick-start capable and black start capable. This peaking unit runs approximately 10% of the time to address peak load times.

Honolulu Generating Station. The Honolulu generating station, located in the downtown load center, has two steam units with a combined nameplate capacity of 113 MW, with 107 MW net generation. Both are cycling units. These units were deactivated in January 2014.

Our utility-owned generation fleet (summarized in Table D-1) has served our customers for many decades.

Unit	Type	Fuel	Capability (MW)		Age (years)
			Gross	Net	
Baseload (Load Following)					
Kahe 1	Reheat Steam	LSFO	86.0	82.2	54
Kahe 2	Reheat Steam	LSFO	86.0	82.2	53
Kahe 3	Reheat Steam	LSFO	90.0	86.2	47
Kahe 4	Reheat Steam	LSFO	89.0	85.3	45
Kahe 5	Reheat Steam	LSFO	142.0	134.6	43
Kahe 6	Reheat Steam	LSFO	142.0	133.8	36
Waiau 7	Reheat Steam	LSFO	87.0	83.3	51
Waiau 8	Reheat Steam	LSFO	90.0	86.2	49
Baseload: Total Capability/Average Age			*812.0*	*773.8*	*47.3*
Cycling					
Waiau 3	Non-Reheat Steam	LSFO	49.0	47.0	70
Waiau 4	Non-Reheat Steam	LSFO	49.0	46.5	67
Waiau 5	Non-Reheat Steam	LSFO	57.0	54.5	58
Waiau 6	Non-Reheat Steam	LSFO	56.0	53.7	56
Cycling: Total Capability/Average Age			*211.0*	*201.7*	*62.8*
Peaking					
Waiau 9	Simple Cycle CT	LSFO	53.0	52.9	44
Waiau 10	Simple Cycle CT	LSFO	50.0	49.9	44
CIP CT-1	Simple Cycle CT	Biodiesel	113.0	112.2	8
Peaking: Total Capability/Average Age			*216.0*	*215.0*	*32.0*

Table D-1. Hawaiian Electric Generating Units

Hawaiian Electric's baseload units average 47 years of age, while the cycling units average 63 years. The combined average age of all steam units is 52 years. While our existing generation fleet does well in serving stable, predictable, consistent loads, they are not as capable as modernized generation in effectively managing system stability with higher levels of variable generation.

As the roles of firm generation assets evolve, the technical and operational capabilities of these units must match their new use pattern. To meet the future requirements, many existing generators must be modified or replaced in order to cost-effectively supply supplemental energy, fast balancing services, and other requirements identified for reliable and secure power delivery in the future. Among other attributes, new assets need to have operational flexibility: the ability to start quickly, ramp up and down at high rates, and must be designed to regularly start and stop multiple times daily even after

long periods of being offline. The baseload steam units in Hawaiian Electric's fleet do not fully possess these characteristics and will need replacement with modern units that do.

Until such time that replacements generating assets come into service, our existing steam generating fleet will serve our customers in an increasingly dynamic way for many years. Our peaking and cycling units will continue to fulfill their existing 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 may need to cycle offline while others will be at new lower minimum loads. We will continue to maximize the flexibility of these units to support our transition to the 100% RPS while considering potentially more cost-effective and beneficial solutions.

Independent Power Producer (IPP) Generation

H-POWER. The Honolulu Program of Waste Energy Recovery (H-POWER) is a municipal solid waste refuse to energy plant that generates 68.5 MW of baseload, firm generation.

AES Hawai'i. The AES unit is a coal fired plant that generates 180 MW of baseload generation.

Kalaeloa. The Kalaeloa cogeneration (combined-cycle) plant burns LSFO to generate 208 MW of baseload generation.

Kahuku Wind. The Kahuku Wind facility generates up to 30 MW of variable generation.

Kawailoa Wind. The Kawailoa Wind facility generates up to 69 MW of variable generation.

Kapolei Sustainable Energy Park. The Kapolei Sustainable Energy Park features over 4,000 solar panels that generate 1 MW of variable generation.

Kalaeloa Renewable Energy Park and Kalaeloa Two. Together, these two solar photovoltaic installations generate 10 MW of variable renewable generation.

Waihonu Solar PV. The Waihonu Solar PV facility near Mililani provides 6.5 MW of variable renewable generation through the Tier 3 Feed-In Tariff (FIT) program.

Unit	Fuel	Net MW	Delivery Type
H-Power	Refuse	68.5	Baseload
AES	Coal	180.0	Baseload
Kalaeloa	LSFO	208.0	Baseload
Kahuku Wind	Wind	30.0	Variable
Kawailoa	Wind	69.0	Variable
Kapolei Sustainable Energy Park	PV	1.0	Variable
Kalaeloa Renewable Energy Park	PV	5.0	Variable
Kalaeloa Two	PV	5.0	Variable
Waihonu Solar PV	PV	6.5	Variable
Total	—	*573.0*	—

Table D-2. O‘ahu IPP Generation Units

Waianae Solar. The 27.6 MW Waianae Solar project is nearing completion and is scheduled for commercial operation in early 2017.

Planned Near-Term Changes to Current Hawaiian Electric Generation

The PSIP analysis assumes removing from service of much of the current thermal generation by 2045. The timing considers several factors: the overall cost to customers for different resource options, maintaining adequacy of reliable service and adequacy of supply (AOS), the need for increased flexibility, and the successful implementation of new resources to replace the current thermal generation. The “Fossil Generation Retirement Plan” in Appendix M: Component Plans discusses and provides the long-term plan.

Waiau 3 and Waiau 4

Our PSIP analysis assumes that Waiau 3 and Waiau 4 are removed from service between 2020 to 2023, depending on the resource plan. E3’s analysis determined the earliest possible removal from service to be 2020 based solely on economic decisions and threshold planning reserve margin (PRM) planning criteria. E3 also analyzed an alternative removal schedule (provided by us) that factors in additional adequacy of supply parameters.

The 2014 PSIPs targeted these units for deactivation at the end of this year, 2016, based on the assumption they would no longer be needed for adequacy of supply. However, based on updated Loss of Load Probability (LOLP) analysis done in conjunction with Hawaiian Electric’s 2015 AOS report using a guideline of 4½ years per day, removal of Waiau 3 and Waiau 4 will result in a 2017 reserve capacity shortfall of 50 MW. The AOS report stated that reserve capacity shortfalls could be mitigated “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 keeping Waiau 3 and Waiau 4 available for service until the end of 2017 as the preferred mitigation option to avoid a capacity shortfall in 2017. However, shortfalls are still projected after 2017, even when the Schofield Generating Station is in service in 2018. Retaining Waiau 3 and Waiau 4 beyond 2017 virtually eliminated reserve capacity shortfalls. Therefore, Waiau 3 and Waiau 4 will remain in service until other resources are added to the system that allow for their removal without resulting in adequacy of supply shortfalls.

Dates when Waiau 3 and Waiau 4 can be removed from service will be determined as specified in "Fossil Generation Retirement Plan" in Appendix M: Component Plans.

Honolulu 8 and Honolulu 9

The PSIP analysis assumes that Honolulu 8 and Honolulu 9, which are currently deactivated, are retired and converted to synchronous condensers in 2021 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 will not need to return these unit to service if Waiau 3 and Waiau 4 remain in service until the end of 2020, and the Schofield Generating Station comes online in 2018 as planned, unless other generating units suffered catastrophic problems.

Should actual peak demand exceed forecast, adequacy of supply could require returning Honolulu 8 and Honolulu 9 to service. The decision will consider other mitigating measures (such as running new DR programs, acquiring additional firm capacity, deferring other unit deactivations, and refining generating unit planned outage schedules). Returning Honolulu 8 and Honolulu 9 to service would take about three months.

Status of Existing Firm Generation PPAs

Since we filed our April 2016 PSIPs, we have changed the assumptions for some of our Independent Power Producers on Oʻahu: AES Hawaiʻi; and Kalaeloa Energy Partners (KPLP)

AES Hawaiʻi

The 2016 PSIP analysis assumes that our power purchase agreement (PPA) with AES Hawaiʻi on Oʻahu 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. 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. The unit provides relatively little ancillary services.

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 Hawaiʻi. 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. While this could be called upon as needed, we are not required to use it. Because AES provides the lowest cost energy, 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 Oʻahu-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.

Hawaiʻi Electric Light: Hamakua Energy Partners (HEP)

HEP is a reliable, flexible firm capacity resource on Hawaiʻi 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 Hawaiʻi Electric Light submitted an application (Docket No. 2016-0033) requesting the Commission issue an order 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.

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 remove the single-start-per-day restriction. The purchase will remove the fixed contractual capacity charge. The PSIP assumes utility ownership of HEP, reflecting the actual heat-rate, variable costs under utility ownership, and capability for more than one start per day.

Hawaiʻi Electric Light: Hu Honua

The PSIP analysis does not assume Hu Honua is available.

Hawaiʻi Electric Light: Puna Geothermal Venture (PGV)

PGV experienced capacity reductions following tropical storm Iselle. The facility has completed well work and has increased its production. The PSIP analysis assumed PGV at 38 MW from January 2016. Though at present it remains at 34.5 MW capacity, it is expected to achieve a 38 MW capacity within the next few months after controls work and testing.

Hawaiʻi Electric Light: Geothermal Request for Proposal (RFP)

Hawaiʻi 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 determined that developing the proposed geothermal project would not be economically and financially viable and therefore a near-term geothermal project resulting from this RFP is not a base assumption in the analysis.

Hawaiʻi Electric Light remains committed to the development of geothermal on the island of Hawaiʻi if it is in the best interest of its customers. While Hawaiʻi Electric Light is disappointed that the Geothermal RFP did not result in a viable geothermal project, we remain hopeful that geothermal generation can be a viable option on Hawaiʻi Island in the future. This means it can help Hawaiʻi meet its 100% renewable energy goal while lowering customer bills, reducing Hawaiʻi's dependence on imported oil, allowing for continued integration and management of variable renewable resources, and maintaining reliability of service. Geothermal resource additions were considered as potential future options in the development of the PSIP.

Maui Electric: Hawaiian Commercial & Sugar (HC&S) Closure

Maui Electric's PPA with HC&S allows us to schedule up to 4 MW of firm capacity during certain months of the year. The PPA term originally 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 contributes no generation in 2017 and beyond.

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.

Generation Modernization On O'ahu

Hawaiian Electric will seek to replace firm generating capacity for the island of O'ahu as existing power plants age and as new flexible (and efficient) generation technology becomes necessary to integrate large amounts of variable renewable energy resources on the island grid. This modernization process has already begun as the Schofield Generating Station (SGS) and the Airport Dispatchable Standby Generation (DSG) projects are currently under construction. Other near-term planned additions include a microgrid concept at Marine Corps Based Hawai'i (similar to the SGS project) and a power barge located in Pearl Harbor.

Schofield Generating Station

The Schofield Generation Station is currently under construction on 8.13 leased acres at the Schofield Barracks Army facility in central O'ahu. The power plant will generate 50 MW (6-unit x 8.4 MW) of firm, fast-start, dispatchable energy. The plant, with its installed reciprocating engines, will be able to quickly start up, shut down, or change its output in response to sudden changes in solar and wind generation. The Schofield facility, once online, can reach synchronous level in less than one minute, and attain full load in six minutes. As a result, the generating station enables the addition of more variable renewable generation to the grid.

Hawaiian Electric will develop, own, and operate the facility, and its generation will serve the O'ahu electric grid. The power plant will also add a measure of energy security to the Army installation. In an emergency, the Army will be able to isolate the power plant to provide reliable generation to the Schofield, Wheeler, and Kunia bases so the Army and National Guard can carry out their missions of national defense and emergency response.

The Schofield Generation Station will provide a number of benefits for the Oʻahu grid. The plant:

- Will improve the reliability and resiliency of the Oʻahu grid.
- Will enable adding increased amounts of variable renewable energy.
- Help alleviate a portion of the projected shortfall in reserve capacity in 2018 and succeeding years.
- Will increase system reliability and, as a result, minimize the potential for future generation shortfall.
- Will provide additional energy security to Oʻahu because of its siting at high elevation away from sea level.

The plant will run on a mix of fossil fuel and biofuel and is targeted for operation in spring 2018.

Airport DSG

The Airport Dispatchable Standby Generation (DSG) unit—originally scheduled for completion in 2013, but delayed until early 2017 because of design changes—offers emergency generation for the airport and limited duty dispatchable generation for the Oʻahu grid. The DSG installation will consist of four 2.0 MW internal combustion engines (ICEs) that burn biofuel, for a total capacity of 8 MW.

The DSG will be owned by the Airport division of the State of Hawaiʻi's Department of Transportation. The DSG is a prioritized power facility; it's primary purpose is to provide all 8 MW of power to the Honolulu Airport within five minutes of an outage. When not providing emergency power to the airport, Hawaiian Electric can dispatch individual or all of the 2 MW units to provide additional capacity to the Oʻahu power grid, for up to 1,500 hours per year per unit.

The Companies are providing the funding to build the DSG. We will monitor the DSG's operability and status, manage and pay for routine maintenance and operating costs, and pay for the fuel. The ICEs that power the DSG will enable us to better manage and integrated increasing amounts variable renewable generation.

Marine Corps Base Hawaiʻi (MCBH) Microgrid Concept

The Marine Corps and the Navy are seeking enhanced energy security for their bases, similar to what is being done with the Army and the Schofield Generating Station. They are interested in partnering with Hawaiian Electric in this venture, so long as it doesn't require a significant capital investment by the Department of Defense (DoD). There are potential synergies between the goals of the DoD and Hawaiian Electric that could be aligned to develop mutually beneficial solutions to the benefit of all Oʻahu customers.

The Air Force has similar goals and requirements as the Marine Corps and Navy. The Hickam Air Force Base and Naval Base Pearl Harbor were consolidated into the Joint Base Pearl Harbor–Hickam (JBPHH), administered by the Navy. Because of this, 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.
- 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.

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.

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) have sufficient capacity and grid controls to safely and reliably serve the base's load.

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 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.

Site Characteristics, Restrictions, and Needs

The Marine Corps previously identified a suitable site on MCBH (Figure D-1) 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-1. 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 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-3 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-3. Number versus Size of Proposed MCBH Generating Units

Table D-3 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.

Waiau Power Barge

Independent of any military considerations, the Company has identified that the waters of Pearl Harbor immediately adjacent to our Waiau Power Plant are ideal for a floating power plant—power barge—and that this concept could result in a very cost-effective method to provide replacement capacity for O‘ahu. Hawaiian Electric is currently working with the Navy to determine the approvals necessary to use the waters of Pearl Harbor for this purpose.

Figure D-2 shows a three-dimensional rendering of one possible configuration at the proposed site.

Figure D-2. 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. First, the installed costs of a power barge are lower than any land based construction in Hawai'i, since the entire station would be built in a shipyard and shipped as a single unit. The on-site construction would be limited to the mooring system and the interconnections for utilities and power. Second, a power barge at the proposed location could utilize existing infrastructure at Waiau Power Plant. Third, the delivery schedule for a completed power barge is less than that 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 fully 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 Kaua'i 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-4. 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-4. 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 by the Navy to meet their 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 and not anticipated for use as a civil defense or Navy energy security asset, 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 is anticipated to serve as a state-wide emergency and resiliency asset serving a government need, a waiver from the Framework may be justified. Furthermore, if the Navy determines the power barge would meet their energy security needs, the project would

meet several criteria under which a waiver would justifiable. In that case, the implementation would likely be similar to that described for the MCBH microgrid project.

Joint Base Pearl Harbor–Hickam (JBPHH) Microgrid

The Navy is currently studying options for supplying the energy security they desire. While use of the Waiau Power Barge is one of the options they are exploring, they are also considering locations on base at JBPHH for location of a microgrid concept similar to the Schofield Generating Station and MCBH microgrid concepts.

If the Navy determines that a land-based project at JBPHH is viable and preferred, Hawaiian Electric will work closely with the Navy to help bring a land-based project to fruition. In this case, the power barge would still be installed (with the Navy's approval to use the harbor), but not designed to meet Navy energy security needs. The implementation of the land-based project would likely be similar to that described for the MCBH microgrid project. The size of a Navy land-based facility is expected to be in the 60MW to 100MW range. Because it has not been determined yet whether a land-based JBPHH microgrid project will be pursued, it was not included in the PSIP analyses. However, the maturation of this concept could result in it being a specific option in future plans and correspondingly has the potential to accelerate the removal from service of one or more existing generating units.

West Loch Solar Facility

The Company, together with the Navy, have requested Commission approval of a 20 MW solar facility sited at JBPHH, West Loch Annex, on O'ahu. The Company plans to build, own, and operate the facility. The renewable energy generated by the solar plant will feed the island's electric grid and serve all customers, including the Navy base. In reciprocation of the land needed for the project, we will perform electrical infrastructure upgrades to Navy-owned facilities.

The solar facility, if approved, will generate the lowest cost energy in the state, projected to save customers $109 million during its expected 25-year lifespan when compared with the cost of generating power from an oil-fired plant.

MAUI ELECTRIC EXISTING GENERATION

Maui Electric owns and operates three island electric grids on the islands of Maui, Molokaʻi, and Lanaʻi. Each island has its own unique physical grid design based on system load, demand, and customer needs. Maui Electric's generation portfolio is composed of a mix of renewable and firm resources. Our current generation mix allows us to integrate significant amounts of renewable energy when available, while ensuring reliability for our customers.

Maui Electric generates the majority of its power from combined-cycle and internal combustion engine units, as well as a growing portfolio of renewable energy. Maui's total firm capacity is 251.7 MW (gross). Lanaʻi's total firm capacity is 9.40 MW (gross). Molokaʻi's total firm capacity is 15.18 MW (gross).

Maui Island Firm Generation Assets

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

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

Maui Electric's existing dispatchable generation fleet comprises two main power plants at Kahului and Maʻalaea. 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 one- to two-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 environmental permitting.

Table D-5 lists the Maui island dispatchable generating fleet.

Unit	Type	Fuel*	Capability (MW net)	Age (years)	Type of Operation
Baseload					
Kahului 3	Combustion Engineering	IFO	11.5	62	Baseload (Load Following)
Kahului 4	Babcock and Wilcox	IFO	12.5	50	Baseload (Load Following)
Ma'alaea 14	GM LM2500 CT	LSD	21.0	24	Baseload (Load Following)
Ma'alaea 15	ABB Steam Turbine	n/a	16.0	23	Baseload (Load Following)
Ma'alaea 16	GM LM2500 CT	LSD	21.0	23	Baseload (Load Following)
Combined-Cycle: Total Capability/Average Age			*82.0*	*36.4*	
Cycling					
Ma'alaea 10–11	Mitsubishi /MAN 18V52/55A	LSD	12.5 each	36	Cycling
Ma'alaea 12–13	Mitsubishi /MAN 18V52/55A	LSD	12.5 each	28	Cycling
Ma'alaea 17	GM LM2500 CT	LSD	21.0	18	Cycling (Load Following)
Ma'alaea 18	Mitsubishi Steam Turbine	n/a	16.0	10	Cycling (Load Following)
Ma'alaea 19	GM LM2500 CT	LSD	21.0	16	Cycling (Load Following)
Cycling: Total Capability/Average Age			*108.0*	*24.6*	
Peaking					
Kahului 1	Combustion Engineering	IFO	5.00	68	Peaking
Kahului 2	Combustion Engineering	IFO	5.00	67	Peaking
Ma'alaea 1	GM EMD 20-645 ICE	ULSD	2.05	45	Peaking
Ma'alaea 2–3	GM EMD 20-645 ICE	ULSD	2.50 each	44	Peaking
Ma'alaea X1–X2	GM EMD 20-645 ICE	ULSD	2.50 each	29	Peaking
Ma'alaea 4–6	Cooper PC2-16	LSD	5.60 each	43	Peaking
Ma'alaea 7–9	Colt PC2-16	LSD	5.60 each	38	Peaking
Hana 1–2	Cummins ICE	ULSD	0.97 each	27/32	Peaking/Emergency
Peaking: Total Capability/Average Age			*58.04*	*41.9*	

* LSD = low sulfur diesel; ULSD = ultra low sulfur diesel; IFO = intermediate sulfur fuel oil; n/a = steam turbines powered by waste heat and do not directly use fuel

Table D-5. Maui Island 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

Maʻalaea M14–16 consist of two 21 MW GM LM2500 combustion turbines, two natural circulation HRSGs, and one 16 MW ABB steam turbine. Maʻalaea M17–19 consist of two 21 MW GM 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. Additional improvements might allow full cycling capability, but further investigation is necessary. The combustion turbines can be online in 25 minutes following startup. M17–19 can be cycled offline as necessary, with a one- to two-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 minimize 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 data. 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 GM'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 Motors (GM) 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 GM 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 does not provide load flexibility and therefore does not support all type of system stability needs. The GM 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 peaking 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 Firm 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 late 2017. As with the Maui units, the EMDs are expected to be serviceable well into the future. In addition the La Ola photovoltaic installation, owned by Lana'i Sustainability Research, contributes 1.2 MW.

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

Unit	Type	Fuel*	Capability (MW net)	Age (years)	Type of Operation
Miki Basin LL1–LL6	EMD diesel engines	ULSD	1.0 each	60	Peaking
Miki Basin LL7–LL8	Caterpillar 3608 diesel engines	ULSD	2.2 each	20	Baseload
Manele Bay CHP	Caterpillar C32-1100	ULSD	0.8	0	Not in Service
All Generation: Total Capability/Average Age			*11.2*	*40*	

Table D-6. Lana'i Utility-Owned Generation Units

Moloka'i Firm Generation Assets

The Moloka'i system is also small. Moloka'i has capacity to generate 12 MW (gross) of power at the Pala'au Power Plant. The Moloka'i grid includes a centralized generating station with nine diesel internal combustion units and one diesel combustion turbine.

Pala'au 7, 8, and 9 (three 2.2 MW Caterpillar 3608 diesel engines) operate in baseload service (often just two concurrently). Pala'au 1 and 2 (two 1.25 MW Caterpillar 3516 diesel engines), and Pala'au 3, 4, 5, and 6 (four 0.97 MW Cummins KTA50 diesel engines) and Pala'au 10 (2.0 MW Solar Centaur T4001 combustion turbine) operate in peaking service. Because of the age and operating history of these units, Maui Electric includes one Caterpillar unit and two Cummins units (1.25 + 0.97 + 0.97 = 3.19 MW) toward firm capacity for the Moloka'i system. Pala'au also has one 2.22 MW Solar Centaur T4001 combustion turbine. The Moloka'i engines have a large user base and are 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.

The Moloka'i system includes an overhead transmission line from Pala'au Generation Plant to Pu'unana Substation. Moloka'i's transmission and distribution systems are operated at 34.5 kV, 12.47 kV, 4.16 kV, and 2.4 kV respectively.

Unit	Type	Fuel*	Capability (MW gross)	Age (years)	Type of Operation
Pala'au 7–9	Caterpillar 3608 diesel engines	ULSD	2.20 each	20	Baseload
Pala'au 10	Solar Centaur T4001 CT	ULSD	2.22	34	Peaking
Pala'au 1–2	Caterpillar 3516 diesel engines	ULSD	1.25 each	31	Peaking
Pala'au 3–6	Cummins KTA50 diesel engines	ULSD	0.97 each	31/25	Peaking
All Generation: Total Capability/Average Age			*15.18 MW*	*27*	

Table D-7. Moloka'i Existing Generation Units

Maui Electric Variable Resources

Maui Electric's grid includes up to 115.4 MW of generation from renewable sources on Maui, Lanaʻi, and Molokaʻi through a series of power purchase agreements (PPAs) and other interconnection agreements.

Maui Electric's system incorporates wind energy from three wind sites totaling 72 MW of variable renewable generation on Maui island via power purchase agreements. Kaheawa I consists of 20 wind turbines that provide us with 30 MW of variable generation. Kaheawa II consists of 14 wind turbines that provide us with 21 MW of variable generation. Auwahi currently consists of 7 wind turbines that provide us with 21 MW of variable generation.

Makila hydroelectric unit provides Maui Electric with 0.5 MW of variable generation. The La Ola photovoltaic site, owned by Lanaʻi Sustainability Research, contributes 1.2 MW of variable generation. PPAs for two 2.87 MW solar facilities—Kuʻia Solar and South Maui Renewable Resources—have also been approved by the PUC. Both projects are expected to be placed in-service in 2017.

Unit	Energy	Rating MW	Type
Kaheawa I (Maui)	Wind	30.0	Variable
Kaheawa II (Maui)	Wind	21.0	Variable
Auwahi (Maui)	Wind	21.0	Variable
Makila Hydro (Maui)	Hydro	0.5	Variable
La Ola Solar (Lanaʻi)	Solar PV	1.2	Variable
Distributed Generation (Maui, Lanaʻi, Molokaʻi)	Mostly Solar PV	92.0	Variable
Total	—	*165.7*	—

Table D-8. Renewable Generation on Maui, Lanaʻi, and Molokaʻi

Planned Near-Term Changes to Current Maui Electric Generation

Maui Electric Kahului Power Plant

Our Kahului Power Plant (KPP) has four steam units totaling 35.92 MW (net) firm capacity. Maui Electric deactivated two units (Kahului 1 and Kahului 2) to conform to our System Improvement and Curtailment Reduction Plan (SICRP),[1] however they were reactivated in 2016 due to system needs. All four units were previously scheduled for retirement by 2019; however, their retirement would have resulted in a reserve capacity shortfall of approximately 40 MW. To ensure enough capacity to meet demand, we

[1] The permit includes various conditions, including a compliance plan which identifies interim milestones to cease water discharge by 2024.

obtained a National Pollutant Discharge Elimination System (NPDES) permit[2] from the State of Hawai'i Department of Health (DOH) with a compliance plan that will allow KPP to continue operating provided we retire the units before November 30, 2024. We currently plan to retire the entire facility in 2022 assuming sufficient replacement resources (including DR and generation) are in operation by then.

Maui Electric Ma'alaea Units

Our Ma'alaea Power Plant has 15 diesel units and 4 gas turbines totaling 208.42 MW (net) of firm capacity. The gas turbines can be configured into two separate combined-cycle systems supplying two steam turbines. We are in the process of modifying the baseloaded combined-cycle system, allowing it to operate at lower levels so that the grid can accommodate more renewable generation. 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.

Maui Electric Moloka'i and Lana'i

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 completed 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 9.4 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 is expected to return to service in 2017.

---

2 *Ibid.*

HAWAI'I ELECTRIC LIGHT SYSTEM

Hawai'i Electric Light currently owns and operates 23 firm generating units, totaling about 181.6 MW (net, maximum capacity), at five generating stations and four distributed generation sites. Three steam units (fueled with No. 6 fuel oil–MSFO) are located at the Hill, and Puna generating stations. Ten diesel engine generators (fueled with diesel) are located at the Waimea, Kanoelehua, and Keahole generating stations. Our five combustion turbines (CTs–fueled with diesel) are located at the Kanoelehua, Keahole, and Puna generating stations. Two of the Keahole CTs are configured to operate in combined cycle with a heat recovery steam turbine. Four distributed generation diesel engines fueled with diesel fuel are located individually at the Panaewa, Ouli, Punalu'u, and Kapua substations (the Panaewa and Kapua units are temporarily located at Kapoho as part of a lava mitigation plan to serve customers potentially isolated by the flow, and will be restored for grid operation).

Two independent power producers (IPPs) provide firm capacity power to our grid. One is a combined-cycle power plant owned and operated by Hamakua Energy Partners LP (HEP); the other is a geothermal power plant owned and operated by Puna Geothermal Venture (PGV).

Our generation fleet has the following capabilities:

- 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.

Table D-9 lists the dispatchable generating fleet of Hawai'i Electric Light.

Unit	Type	Fuel*	Capability (MW net)	Age (years)	Type of Operation
Combined-Cycle					
Keahole	2 - GM LM2500 CT with ST	LSD	56.3	12/6	Frequency Regulation, Load Following, Cycling
Combined-Cycle: Total Capability/Average Age			*56.3*	*10*	
Steam					
Hill 5	Non-Reheat Steam	IFO	13.5	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
Steam: Total Capability/Average Age			*49.4*	*46.3*	
Emergency/ Peaking					
Kanoelehua CT1	GM 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	GM LM2500 SCCT	LSD	21.0	24	Peaking, Black start
Kanoelehua	Fairbanks Morse ICE	ULSD	2.0	54	Peaking, Emergency
Kanoelehua	3 - GM EMD 20-645 ICE	ULSD	7.5	41–44	Peaking, Emergency
Keahole	3 - GM EMD 20-645 ICE	ULSD	7.5	28–32	Peaking, Emergency
Waimea	3 - GM EMD 20-645 ICE	ULSD	7.5	44–46	Peaking, Emergency
Mobile	4 - Cummins ICE†	ULSD	5.0	17–18	Peaking, Emergency
Peaking: Total Capability/Average Age			*76.2*	*43.4*	
Major Independent Power Producers (IPPs)					
Hamakua Energy Partners	2 - GM LM2500 CT with ST	Naphtha	60.0	16	Frequency Regulation, Black Start, Load Following, Cycling
Puna Geothermal Venture	Geothermal	n/a	38.0	24	Baseload
Major IPPs: Total Capability/Average Age			*90.0*	*18.7*	
Hydroelectric					
Puueo No. 1	Hydroelectric	n/a	2.6	11	Non-Firm
Puueo No. 2	Hydroelectric	n/a	0.75	98	Non-Firm
Waiau No. 1‡	Hydroelectric	n/a	0.75	95	Non-Firm
Waiau No. 2‡	Hydroelectric	n/a	0.35	88	Non-Firm
Hydroelectric: Total Capability/Average Age			*4.35*	*73*	

* LSD = low sulfur diesel; IFO = intermediate sulfur fuel oil; ULSD = ultra-low sulfur diesel.
† Panaewa and Kapua located at Kapoho for lava flow emergency use only.
‡ An application has been submitted to repower Waiau increasing total capacity to slightly over 2.5 MW.

Table D-9. Hawai'i Electric Light Fossil Generating Units

Over 85.5 MW of utility-scale renewable energy capacity is available on Hawai'i Island: 38 MW is firm generation from the IPP Puna Geothermal Venture: 30.1 from IPP wind, and 16.6 run of river hydro (utility-owned and IPP). In addition there is over 2.5 MW of Feed-in Tariff generation, primarily solar and a growing amount of distributed generation (also primarily solar PV).

Unit	Energy	Net MW	Delivery Type
Puna Geothermal Venture*	Geothermal	38*	Firm
Puueo No. 1	Hydro	2.6	Variable
Puueo No. 2	Hydro	0.75	Variable
Waiau No. 1†	Hydro	0.75**	Variable
Waiau No. 2†	Hydro	0.35**	Variable
Tawhiri Power LLC	Wind	20.5	Variable
Hawi Renewable Development	Wind	10.5	Variable
Wailuku River Hydroelectric LP	Hydro	12.1	Variable
Consolidated Installed Residential and Commercial PV	Solar	79.3	Variable
Total	—	*164.9*	—

* PGV is presently at 34.5 but expected to achieve 38 MW considered in the PPA in the near term.
† An application has been submitted to repower Waiau increasing total capacity to slightly over 2.5 MW.

Table D-10. Hawai'i Electric Light Renewable Energy Resources.

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. 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 have 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 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 might 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 load requirements from the 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 GM 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 combustion 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 GM 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 GM Frame 5 SCCT has 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 GM 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 Ma'alaea, Keahole, and HEP.

The ABB CT35 SCCT is 27 years old and has much smaller user base. Maintaining this combustion turbine may prove more difficult in the next 20 to 30 years. The assumption is that it will be maintained until 2045.

All the simple cycle combustion turbines have the capability to operate in isochronous control (zero-droop or swing unit) for frequency control and stability during major system disturbances and can support system restoration from black start. CT2 is located in Keahole, which allows it to support the minimum generation requirement for the west side of Hawai'i Island for voltage and transmission system constraints and is the only black-start resource available in West Hawai'i

Conventional Steam Generating Assets

The conventional steam generating assets provide many benefits. Hill 5 and Hill 6 cycle to provide steam generated electricity. Puna was placed on seasonal cycling, operating during low generating capacity margins but due to a change in fuel costs, is now operated on a routine peaking cycle 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 of 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 three hour start time for warm start. With present equipment and controls, these units require extensive manual operation during startup and the startup time may be shortened if equipment is modified. The units have a lower minimum dispatch limit than combined cycle units.

These conventional steam units provide firm capacity and have a sustained ramp rate of 2–3 MW per minute. While presently satisfactory, this ramp rate may not be sufficient for future higher penetrations of variable solar and wind, requiring supplement from other ramping resources. The inertial contribution is relatively high.

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. 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 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 and 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.

Planned Near-Term Changes to Current Hawai‘i Electric Light Generation

The assumptions for generating units are generally consistent with those used in the April 2016 filing. This includes the retirement of Shipman 3 and 4 in December 2015. The dispersed diesel units have increased capacity to 1.25 MW. Two of the units were temporarily relocated to a site in Puna to provide emergency service to customers at risk of being disconnected from the grid by lava flow, and will be returned to the original locations. The units are assumed returned to service. An application to repower Waiau Hydro has been submitted. If this project is approved, the Waiau capacity would increase to over 2.5 MW. The PSIP analysis assumes the repowered turbine is in service.

CONSOLIDATED RENEWABLE GENERATION

Installed Residential and Commercial PV

Over the last ten plus years, we have witnessed an explosion in PV generation, comprised of individual distributed generation and from IPPs. Since 2011, the amount of PV has grown steadily by an average of nearly 100 MW annually. About two-thirds of this capacity is from uncontrollable, must-take residential DG-PV. The remaining one-third is from the combined generation of commercial installations and IPP sites.

Utility	Number of PV Systems			PV Capacity (MW)		
	Residential	*Commercial*	*Total*	*Residential*	*Commercial*	*Total*
Hawaiian Electric	44,267	1522	45,789	243.4	148.6	392.0
Maui Electric	10,148	782	10,930	56.7	30.7	87.4
Hawai'i Electric Light	10,263	647	10,910	52.4	26.9	79.3
Totals	*64,678*	*2,951*	*67,629*	*352.5*	*206.2*	*558.7*

Table D-11. Consolidated Installed Residential and Commercial PV (September 30, 2016)

Figure D-3 depicts the annual growth of combined DG-PV and commercial (IPP) PV generation on the electric power grids of all five islands we serve: O'ahu, Maui, Moloka'i, Lana'i, and Hawai'i Island.

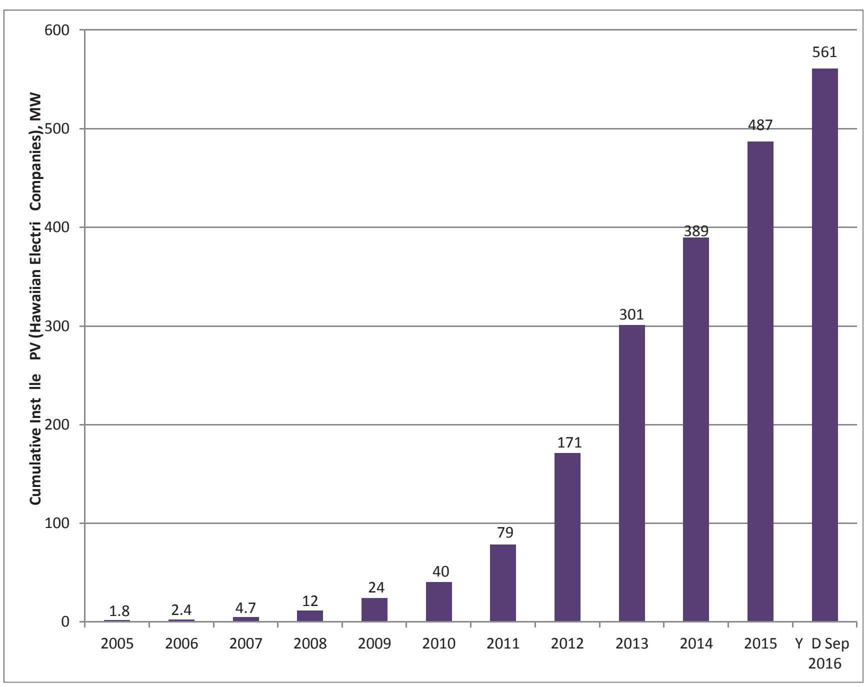


Figure D-3. PV Generation Growth: 2005–2016

Renewable Generation Resources

A number of resources comprise the renewable generation at all three operating utilities. This consolidated total tracks to the RPS milestones that we must meet over the next 30 years. The current milestone is 30% by the end of 2020; the next milestone is 40% by the end of 2030.

Table D-12 breaks out, by operating utility, the generation amount from various renewable resources applied toward meeting RPS.

Electric Energy Generated from Renewable Resources (net MW hours)				
Renewable Resource	**Hawaiian Electric**	**Maui Electric**	**Hawai'i Electric Light**	**Total**
Customer-Sited, Grid-Connected Renewables	464,412	88,956	89,691	643,060
Biomass (including municipal solid waste)	385,846	30,870	0	416,716
Geothermal	0	0	230,495	230,495
Grid-Scale Photovoltaic and Solar Thermal	40,750	7,904	2,557	51,212
Hydroelectric	0	9,823	63,275	73,098
Wind	216,197	264,291	132,293	612,782
Biofuels	52,424	988	0	53,412
Total Renewable Generation	1,159,630	402,833	518,311	2,080,775
Total Company-Wide Sales	6,754,083	1,137,630	1,064,785	8,956,498
RPS Percentage	17.2%	35.4%	48.7%	23.2%

Table D-12. Electric Energy Generated from Renewable Resources (Year 2015)

Notes:

- *Customer-Sited, Grid-Connected Renewables* represent generation from photovoltaic, wind, and hydro systems based on known system installations for 2015 including Net Energy Metering (NEM) installations, non-NEM systems, and Smart Power for Schools (formally Sun Power for Schools) installations. Recorded generation data was used whenever available; otherwise, estimates were made based on reasonable performance assumptions for typical photovoltaic systems.
- Renewable electrical energy generated from *Utility-Scale Photovoltaic and Solar Thermal, Hydroelectric, and Wind* is based on recorded data from Feed-In Tariff (FIT) contracts and Independent Power Producers with PPAs.
- Starting on January 1, 2015, energy efficiency and solar water heating amounts cannot be applied toward meeting the RPS, thus these amounts are not included.

Figure D-4 depicts the various renewable resources on our five electric power grids, and their combined RPS attainment, as of December 31, 2015.

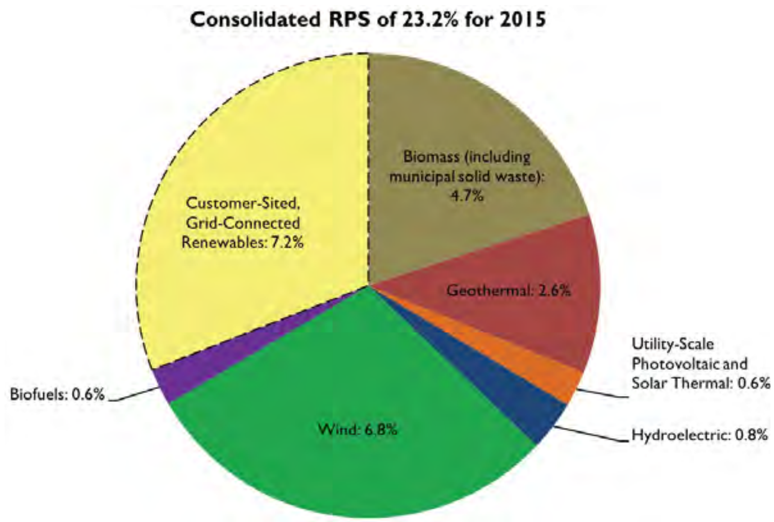


Figure D-4. Consolidated RPS of 23.2% for 2015

Note: Adding the individual percentages derives a total of 23.3% which is accounted for through rounding of the single digit decimals.

For the sake of comparison, our consolidated RPS in 2013 without energy efficiency measures was 18.2%; in 2014, our consolidated RPS climbed to 21.3% — an increase of about 17%. At the end of 2015, our consolidated RPS is 23.2% — an increase of 9% over 2014.

IMPACTS OF VARIABLE GENERATION AND DER ON OUR GENERATION FLEET

The operation of our power systems has become increasingly complex and challenging due to the impacts of variable wind and a rapid increase in distributed generation, most of which is variable solar photovoltaic (PV). Current levels of variable generation have already led to changes in how existing generation assets are used. Continued additions of variable generation will lead to further changes.

There is increased offline and deep cycling, requiring a greater number of unit commitment decisions. In general, there are fewer conventional plants online to provide frequency and voltage regulation, ramping, short circuit current for fault detection, and system inertia. This results in less stable frequency and system security issues.

As distributed PV generation increases, the minimum daytime load demand continues to decrease. Now that the PV generation levels are causing the minimum demand to approach the minimum load capability of the baseload units typically online, the use of fossil generation must change to accommodate this increased DG-PV. The conventional plants increasing serve a role of supplementing the production of variable renewable resources (wind and solar) to meet demand.

The Effects of DG-PV on Demand

The impact of increased distributed solar has been to change the net demand served by our generators. The evening peak still is the largest peak and remains at sunset. However, the daytime demand is highly variable due to the impact of distributed solar. During high PV production, the daytime demand approaches and in some cases is lower than the nighttime minimum and will decrease further with additional solar PV.

Figure D-5 (created four years ago) depicts this demand evolution using average demand curves over a year period for Hawaiian Electric. Starting in 2011, noticeable changes began to appear to the typical daily demand curve shape (frequently referred to in the industry as the "duck" curve) because of the proliferation of rooftop PV systems. Two years ago, we anticipated the typical demand curve to match the dotted blue line (labeled "2015"). Today, however, we are experiencing a demand curve that more closely matches that of the dotted light blue line (labeled "2017"). In other words, the evolving demand curve is moving faster than we initially projected. This quickening pace has stretched the daily responsibilities of our system operators, making their efforts to maintain a stable, reliable grid much more challenging.

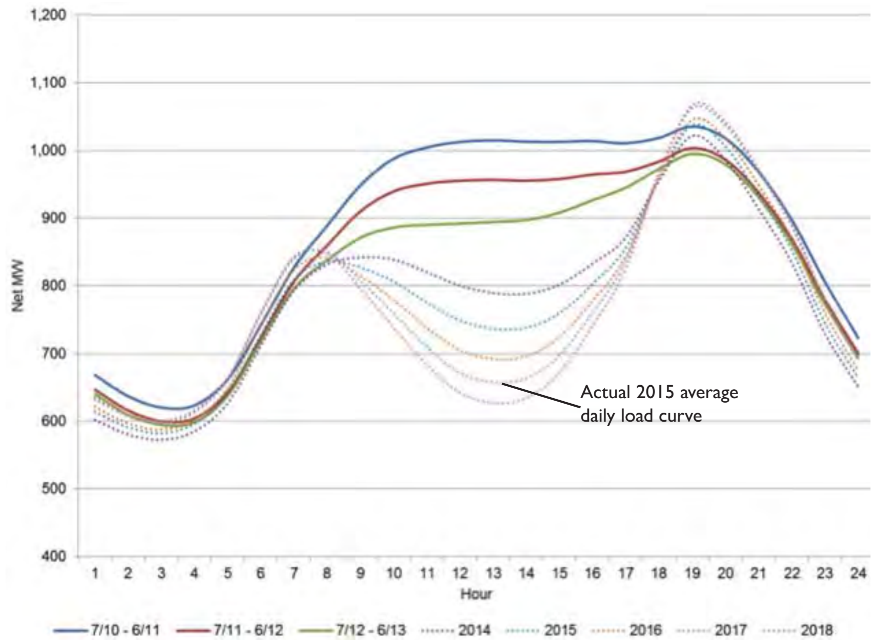


Figure D-5. Evolving Demand Profile from DG-PV Growth

These demand curves represent annual averages. In actuality, demand during the middle of the day is unpredictable. Some days demand is low because DG-PV generation is higher; other days demand is high because DG-PV generation is low. The chart below shows recorded data for Hawai‘i Electric Light showing this variability for a week period comparing 2011 through 2016.

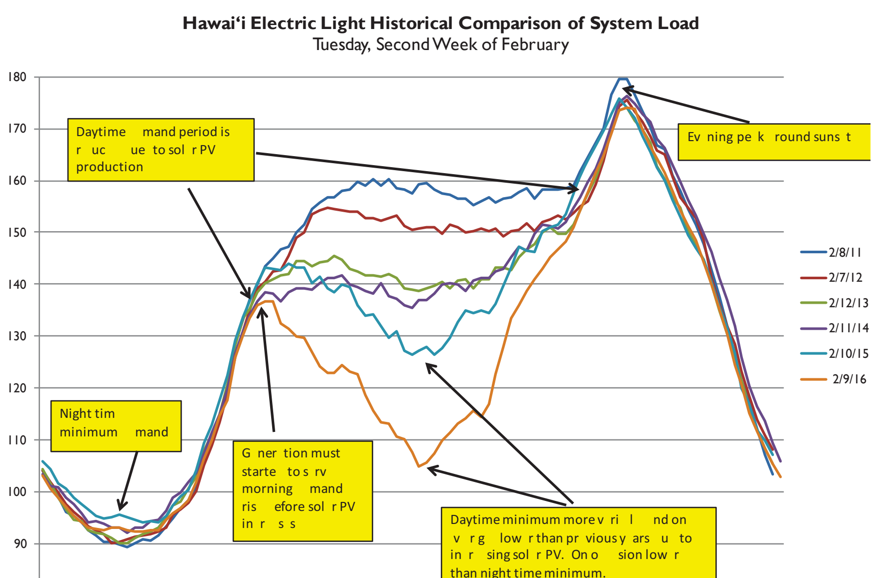


Figure D-6. Hawai‘i Electric Light Weekday System Load Comparison

The vast majority of the existing PV systems are installed through the Net Energy Metering (NEM) program, a Standard Interconnection Agreement (SIA), as well as

through the Customer Self Supply (CSS) and Customer Grid Supply (CGS) programs. These behind-the-meter systems offset the customer's energy use. Most residential loads are low during the day when DG-PV generation is at its highest, thus much of this generation is exported to the electric grid where it must be accommodated by reducing other generator output. At present, the operator can neither directly monitor nor control nearly all of these systems.

The existing variable distributed solar creates challenges with maintaining system frequency. In the future, as distributed generation increases, it will be necessary for distributed resources to contribute to balancing supply and demand to preserve system operability and reliability. This will include provisions for system control and local response to frequency. For the present, the other generation sources on the system, including controllable utility scale renewable energy, must be reduced to accommodate the distributed solar.

Impact of Variable Generation on System Balancing and Generator Use

To ensure a functional and reliable grid, a balance between supply and demand must be maintained. The balance is measured by the electric frequency—the system is balanced when very close to 60 Hz (cycles per second).

The impact of higher levels of variable generation has affected our systems in the following ways:

- Variable energy displaces output from conventional plants. This has led to increased operation at low output for generators. It has also led to offline cycling of some units previously operated continuously.
- The net demand to be served by generation is more difficult to predict. The existing fossil generation resources provide energy to meet the remaining demand after the solar PV and wind production. Even with state-of-the art forecasting, a great deal of uncertainty exists about the amount of variable energy available over the next several hours.
- There is an increasing need for frequency response and ramping. The variable output of wind and solar PV creates a frequency imbalance that must be offset by other generation. With existing conventional units displaced to accommodate variable renewable energy, there are fewer generators online to respond to changes in variable solar and wind. Because of these combined actions, faster response for frequency control (fast primary frequency response and ramp rate) is required.

On afternoons with high DG-PV generation, demand could fall below the minimum output that the system can support—that is, below the minimum demand of the generators that must remain online to keep the system operable. This potential can only

be mitigated by adding new resources, and may include a combination of variable generation controls and frequency response, new resources to increase demand on the system (such as storage), or adding resources that allow reliable operation with reduced or no minimum online generation.

Generator Modifications and Characteristics

To manage the changes to the system due to variable generation, the following are areas of change to existing plants and desired characteristics for new generators:

Increased ramping capability. With increasing variable generation, the required ramp rates may exceed the capability of existing units. Many of the available options for replacement generation have superior ramping capabilities and would provide more flexibility to react to variable energy ramps in output.

Increased dispatch range, reduced minimum dispatch limit. With increasing minute-to-minute balancing and fast ramping requirements, the ability of generators to operate a lower minimum dispatch levels is desired.

Capable of routine offline cycling. As renewable energy facilities displace conventional plants, offline cycling may be required to avoid excess energy. Some plants historically operated continuously are cycled offline daily or operated only for peaking periods. Other facilities have been removed from service. Measures must be taken to preserve the generator and enable its return to service in a reasonable time if needed.

Faster startup times. Fast startup times help manage the uncertainty in net demand forecasts by being able to adjust the online generation for changes in variable generation and supplementing resources for unexpected reductions in variable generation output. To offset from potential down ramp events, offline generation will ideally have quick start times (less than 10 minutes to start and reach full load) and low startup costs. Conversely, sometimes the variation from variable generation may be upward. In these cases, it is ideal that online generation can be shut down quickly and later quickly restarted if necessary. This flexibility to start and stop quickly many times daily at low cost is not a characteristic typical of our existing firm generation fleet.

Increased capabilities from variable generation. The variability of wind and solar energy sources increases the burden on other generation to provide frequency response and ramping. Modern wind and solar facilities have the capability to lessen these impacts if properly designed. Newer wind and inverter-based generation resources, if properly designed, can provide some frequency response and limit potential ramp rates. By utilizing these capabilities, variable resources place less of a demand on other resources on the system. The capability to control resources is also a critical factor as distributed generation provides a significant amount of the total energy on the systems.

There are significant challenges in managing the system with existing generation resources under the changing use requirements. 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.

Reducing minimum load requirements:

- 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.

Compared to on-off cycling, low-load operation allows for quicker return to full load capability and lower long-term maintenance costs.

A disadvantage is that at some loads, the units have limited ramping capability until at or above its normal operating range. Figure D-7 shows the ability of a Hawaiian Electric unit to reach full load from its old minimum compared to the 5 MW minimum.

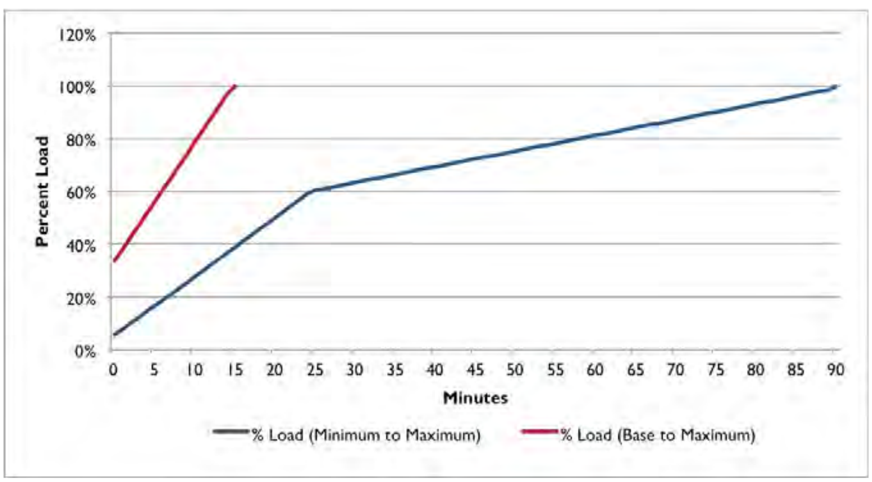


Figure D-7. Ramp Time from Minimum and Base Loads to Full Load: Hawaiian Electric

Increasing renewable energy can also require cycling units off and on. However, many of the larger, lower-cost conventional units are designed for continuous operation, not cycling. This option, therefore, creates much concern about reliably, especially when combined with running the units at low load levels. Startup problems can delay the time a unit is brought on and thus cause generation shortfalls. Any time a unit not designed to cycle is frequently cycled offline and online, these startup risks become inherent. Cycling

these units also increases wear and tear; over time, they require more maintenance. Offline cycling on a routine basis is not feasible for all existing generators. When units are taken offline for extended periods, preservation measures are required, including routine inspection of the preservation equipment, to ensure the generators remain in good condition and ready to return to service when needed.

Evolving Dispatch of Our Cycling Units

The effect of changing use of our generating units has already been very noticeable. Utility-owned generation has experienced increased offline cycling, lower capacity factors, and reduced average operating load. Generators have been removed from service for periods of time which required measures to preserve the units and return them to service in a reasonable time when need to serve demand or when cost changes made these units economical.

Long-Term Reliability Issues

Long-term reliability issues include starting units to operating levels, safely, quickly, and securely, to meet demand. The more we push these units beyond their intended design, the more problems are likely to surface. This might already have been the case with Waiau 3.

Only time will tell how the effects of our changes affect reliability.

Changing Use of Existing Generation

Hawaiian Electric, Hawai‘i Electric Light, and Maui Electric have expanded the capabilities of the existing generating units to support the changing electric system. These modifications, however, required tradeoffs.

Low loads and increased cycling of these units, while successful, 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, which based much of its results on Equivalent Demand Forced Outage Rates (EFORd). The EFORd is a measure of the probability that a firm generating unit will not be available due to forced outages or deratings during a demand period. That report demonstrated higher forced outage rates that result from cycling operation (Figure D-8), and concluded that costs associated with cycling and increased load-following events would drive future maintenance costs higher.

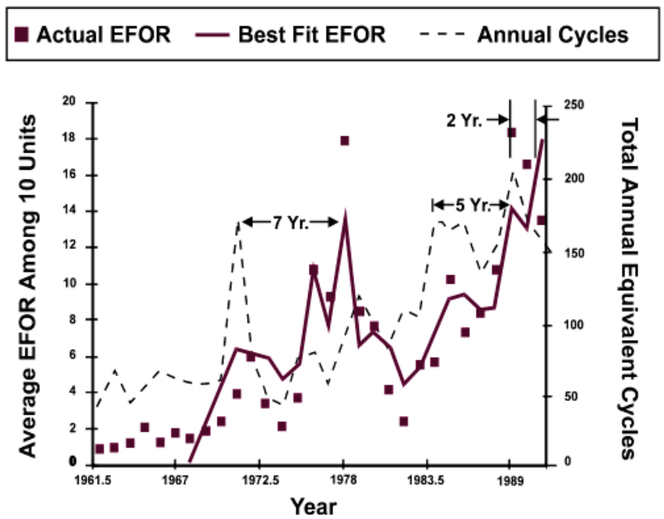


Figure D-8. Forced Outage Rates from Cycling: U.S. Averages

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.

E. New Resource Options

To develop our December 2016 updated PSIP, the Companies carefully considered a set of new resource options in our analysis. These options and related assumptions provide planners with a set of consistent new resource options from which to choose when selecting a future optimal portfolio of generation resource additions. In other words, this information is a planning tool. These new resource assumptions, however, are not intended to provide rigid baselines for new project developers to obtain Power Purchase Agreements (PPAs).

We developed these assumptions from the best publically available information, independently reviewed by the National Renewable Energy Laboratory (NREL), shared with the parties to Docket 2014-0183 beginning in February 2016, and continuously vetted against new information available (including input from the Parties). In the end, we reviewed all input assumptions, retaining some and adjusting others as appropriate.

We made every attempt to ensure these assumptions reflect "real world" conditions. Proposals for specific projects, however, might result in different values for any of the PSIP assumptions; these variances would be based on specific site conditions, technology vendors utilized, developer profit requirements, and many other variables. Competitive procurement of resources will ensure the cost effectiveness of the resource addition and selection of the best available resources.

To avoid speculation, our December 2016 PSIP analysis required that resource options considered be either commercially available today or reasonably available within the study period. Our near-term Action Plans commit only to resources that are fully commercial today. We believe the best interests of our customers are served by not expecting them to underwrite the risks associated with technologies that are not commercially available today.

In the longer term, however, this PSIP can consider certain resource options (for example, offshore floating platform wind) that appear poised to become commercially available within the next ten to fifteen years. Other emerging options (for example, hydrokinetic energy) appear to be at least a decade or more away from commercialization. As our Action Plans include flexibility to incorporate technology change, we fully expect that future long-term resource planning efforts will consider resource options that are not commercially available today.

In turn, all Parties must consider the types of renewable resources, their cost, and current and future availability that can play an integral role in achieving our 100% renewable energy goal. We are and will always be open to new technologies as they are developed into commercial products. In the meantime, our near-term Action Plans maximize the resource potential currently available from commercially available renewable resources: solar PV, wind, DER, and "firm" renewables.

AVAILABLE GENERATION OPTIONS

For the December 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]

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

[1] Order No. 33320, at 80.
[2] *Ibid.*, at 84–85.
[3] *Ibid.*, at 83.

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 2014 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 Grid-Scale Resource Assumptions

For the December 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 dollars per kW. The data underlie the nominal dollar assumptions used in the PSIP analysis. The constant dollar projection is a useful way to portray the expected future cost trends of various electric power generation technologies.

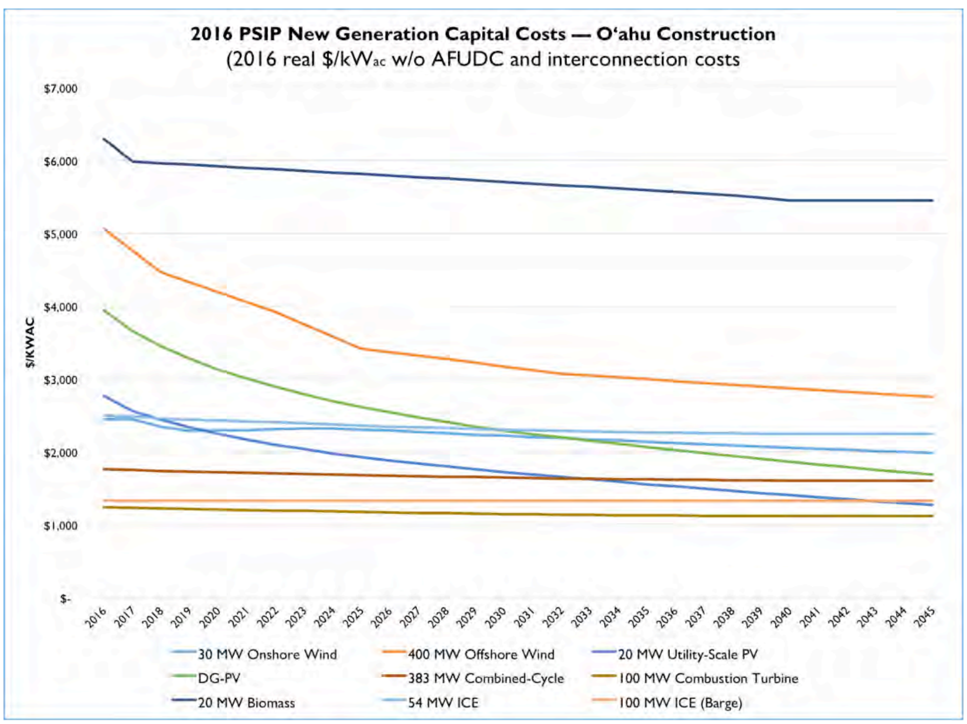


Figure E-1. December 2016 Updated PSIP New Generation Resource Capital Costs—O'ahu

[4] Power Supply Improvement Plan, filed August 26, 2104, at H-1.

Data Sources

In our analyses for this December 2016 PSIP, we have completely reworked the resource technologies and cost assumptions, starting 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.
- 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.
- 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.

In our response to Information Request PUC-HECO-IR-44,[9] we discussed our development of new resource assumptions in greater detail. As a public document, this information was readily available to the Parties; nonetheless, we posted our response on our collaborative WebDAV ftp site and emailed it to Parties who sent requests.

---

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.

9 Docket 2014-0183, PUC-HECO-44, filed on March 1, 2016.

New Resource Input from the Parties

As directed, beginning in November 2015, we continually solicited input from the Parties regarding new resource assumptions and costs. Several Parties provided input.

Paniolo Power replied first with partial information regarding the costs and operating characteristics of grid-scale wind and pumped storage hydroelectric (PSH), then provided a more complete set of information. Their PSH data, as jointly agreed, was essentially the same as ours, and site-specific information for wind was provided under protective order.

Hawaiʻi Gas provided information about LNG. After adjusting their data to the same format as our LNG data, together we found that both sets were essentially similar. Hawaiʻi Gas commented that their expected volume in 2020 will be 300,000 tonnes per annum (TPA), excluding the volumes of the Kalaeloa Partners LP power plant. Given Hawaiian Electric's estimated volume of 600,000 for Oʻahu, Hawaiʻi Gas requested that LNG pricing at the 900,000 TPA volume be evaluated.

Ulupono representative Dr. Matthias Fripp provided information about the theoretical maximum potential for grid-scale solar PV and grid-scale wind resources on Oʻahu. These potentials expanded on the results from a similar NREL study.

SunPower provided grid-scale solar PV capital costs from a third-party source, however these costs did not readily adjust for Hawaiʻi installation. After a series of productive interactions, together we determined that both sets of data were essentially similar.

In September 2016, HREA submitted biomass fixed O&M and fuel cost assumptions (on behalf of Hu Honua who is not a Party) that were higher than our assumptions. We had already adjusted our biomass assumptions in June 2016, which we used in our modeling analysis.

See "Input Incorporated into Our PSIP Update" in Appendix B: Party Commentary and Input for detailed discussion of our interactions with these Party members, the results of these discussions, and how they affected the input assumptions in our modeling analysis.

Several Parties suggested nascent technologies as resource options (specifically ocean wave power and hydrogen storage). No Party, however, proffered specific capital costs, operating costs, performance specifications, or specific justification that such options were commercially available or could be reasonably expected to be commercially available. Indeed, our own research concluded such technologies are not viable resource options, and thus were not considered in our planning.

Developing the Resource Cost Assumptions

We pursued several avenues to develop and then synthesize resource costs into a common set of assumptions for the December 2016 PSIP update analysis. These avenues included data sources, NextEra Energy, and NREL.

We researched and reviewed the most current data sources possible—one such source is the NREL ATB database. The NREL ATB data source provides a publicly available source of the forward curves for capital costs, and operations and maintenance expenses for several different power generation technologies. We combined this data with the EIA's 2013 *Updated Capital Cost Estimates for Utility-Scale Electricity Generating Plants* Honolulu-specific information regarding locational adjustments (by technology) to adjust the NREL ATB data for Hawai‘i. We adjusted the cost data using 2016 dollars as the base year by converting all cost information from real dollars to nominal dollars using a 1.8% inflation and escalation rate (because nominal dollars are used to evaluate various cases in our economic analysis).

We worked with NextEra Energy to develop some resource assumptions that have been used in both our April and December 2016 updated PSIP. 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 used IHS Energy's proprietary research reports to develop initial cost assumptions for certain resources, including solar PV and energy storage. 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. We collaborated with NREL to derive the new resource assumptions based on independent data sources. In addition, we contracted with an outside consultant, HD Baker and Company, to compile these resource assumptions to assure their consistency and objectivity. 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 Tax to the base price.

New grid-scale solar PV and grid-scale wind projects are eligible for federal and state investment tax credits (ITC) for residential (mostly rooftop) and commercial installations. (The commercial business that installs, develops, or finances the project claims the tax credit). In 2016, the tax credit is highest; the ITC slowly dwindles over the next five to seven years.

Federal tax credits directly reduce the installer's federal taxes; state tax credits directly reduce the installer's state taxes. Until the end of 2018, installers also benefit from an accelerated depreciation schedule. For example, a project installed in 2016 can depreciate 50% of the project cost (after the tax credit) in the first year of a five-year depreciation schedule. Table E-1 compiles the various federal and state tax credits used as input assumptions for the December 2016 PSIP analysis.

PSIP Investment Tax Credits Assumed in December 2016 PSIP Update				
	Grid-Scale Solar PV and DG-PV		*Grid-Scale Wind*	
Year End	Federal ITC	Hawai'i State ITC	Federal ITC	Hawai'i State ITC
2016	30% + 50% Bonus Depreciation	35%	30% + 50% Bonus Depreciation	35%
2017	30% + 40% Bonus Depreciation	35%	30% + 50% Bonus Depreciation	35%
2018	30% + 30% Bonus Depreciation	30%	24% + 40% Bonus Depreciation	24%
2019	30%	30%	18% + 30% Bonus Depreciation	18%
2020	26%	26%	12%	12%
2021	22%	22%	0%	0%
2022 and after	10%	10%	0%	0%

Notes: Federal investment tax credits are pursuant to an extension included in the 2015 Omnibus Appropriations Act (P.L. 114-113). Hawai'i State investment tax credits are assumptions based on the Federal ITC and are assumed to phase out in-line with any Federal phase out.

Table E-1. Solar PV and Wind Investment Tax Credits

We retained NREL to independently and objectively review the assumptions synthesized through this processes. NREL filed two reports on their analysis. NREL found our assumptions to be consistent with their own database and other third-party sources. We discuss specifics of their conclusions Grid-Scale Resource Assumptions on page E-18. (Appendix F contains the actual NREL reports.)

Generation Technologies Considered

For our December 2016 PSIP update, our near-term action plans rely only on technologies that are commercially available today. Those technologies include grid-scale solar photovoltaic, distributed solar photovoltaic, onshore wind, combustions turbines, combined-cycle plants, internal combustion engines, geothermal, waste-to-energy, microgrids, solar photovoltaics plus storage combination, and biomass as a fuel. We consider this to be in the best interest of our customers.

For the longer-term, we also considered floating platform offshore wind, which appears likely to achieve commercialization within the next decade. Several promising

hydrokinetic energy technologies, while intriguing, were not considered because they are not currently commercial available. These technologies require substantial amounts of subsidies and investment in research, development, and engineering. They are, at least, two decades or more away from commercialization. We will continuously monitor developments with these technologies, and as new resource options become commercially available, we will likely consider such technologies in future resource plans.

We developed our December 2016 updated PSIP 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 developed our December 2016 updated PSIP to be flexible over the long-term to accommodate technology and cost improvements in existing technologies, and to accommodate the commercialization of transformational technologies that might become available. It is our best understanding that this prudent and reasonable philosophy benefits our customers, and best achieves our state's renewable energy goals.

Our choice of technologies for the December 2016 updated PSIP is a planning assumption, and in no way is intended to limit or discourage proposals for other technologies. Such proposals, however, must exhibit the following attributes:

- Sound engineering design concepts.
- Commercial availability of the technology from a reputable vendor who stands 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 customers, taking into account system needs and integration costs.
- 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 December 2016 updated PSIP, we limited new resource analysis choices to these technologies.

Grid-Scale Solar Photovoltaic

Solar PV technology is mature. Current forecasts are characterized by continuing modest declines in capital costs and incremental improvements to the technology. Multiple grid-scale solar PV projects have been placed in service in Hawai‘i, and more are on the way. We have significant experience with solar PV technology in the Hawai‘i market, as do many IPP project developers and capital providers.

The PSIP assumptions reference fixed-tilt (versus single-axis and multi-axis tracking) systems. The December 2016 PSIP update utilizes capacity factors and output profiles for grid-scale solar based on historical experience with existing grid-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 (DC) power. The ratios of DC output to (usable) AC output in grid-scale solar PV projects typically ranges from 1.1–1 to 1.5–1. Both the reference plant capital cost and the NREL resource analysis assume 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.

In response to stakeholder input, the December 2016 PSIP update utilized different sizes of PV projects, with corresponding capital cost adjustments for smaller projects (that is, smaller PV projects have a higher per unit cost).

Distributed Solar Photovoltaic

The PSIP cost assumptions and future cost trends for DG-PV are based on the same source data as the grid-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 dollars) over the study period. The net capacity factor for DG-PV is assumed to be 18.4% for O‘ahu, 16.9% for Hawai‘i island, 17.8% for Maui, 16.3% for Lana‘i, and 19.8% for Moloka‘i.

Onshore Wind Power

Onshore wind projects employ a 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 (IPPs). We have significant experience with onshore wind technology in the Hawai‘i market, as do many IPP project developers and capital providers.

Wind projects on O‘ahu, Maui, and Hawai‘i Island all 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 December 2016 updated PSIP reflect these economies of scale.

Because of the limited harbor facilities on Moloka‘i and Lana‘i, the cost of mobilization to install what would likely be a single larger scale wind turbine (that is, the current market sizes are in excess of 2 MW) would be prohibitive. Instead, wind project assumptions

were developed for 100 kW turbines that could be installed without large cranes and the resulting high mobilization costs.

The net capacity factor modeled in the reference plant was 22.7% for Oʻahu, 54.4% for Hawaiʻi Island, and 51% for Maui, Lanaʻi, and Molokaʻi.

Floating Platform Offshore Wind

The April 2016 updated PSIP plans for Oʻahu incorporated a substantial amount of floating platform offshore wind. Recent activities by the Bureau of Ocean Energy Management (BOEM) towards developing leases for offshore wind blocks in Hawaiʻi, and interest from at least three different developers, led the Companies to commission an assessment of offshore wind. See "Offshore Floating Platform Wind Energy" in Appendix H: Renewable Resource Options for Oʻahu for a discussion of the commercial and technical status, development risks, and costs of this renewable resource.

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 installation lead times. Smaller CTs typically are less efficient than larger machines (heat rates as high as 18,000 Btu per kWh for small microturbines). CTs are a mature technology with projected flat capital costs (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 (when 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 when variable renewable generation wanes.

Several very large, well-capitalized international vendors 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. The Companies, as well as most utilities, have a vast amount of experience with CTs, as do many IPP project developers and capital providers.

Combined-Cycle

Combined-cycle power plants employ CTs that add a heat recovery steam generator (HRSG). HRSGs take the exhaust heat from one or more CTs, "recover" the thermal

energy that otherwise would go to waste, and produce steam. The steam is then used to turn a turbine coupled to a generator. Combined-cycle plants typically exhibit the greatest efficiency technically possible with thermal generation. Heat rates for modern combined-cycle plants operating at high capacity factor as low as 7,000 Btu per kWh. The reliability of combined-cycle plants is high; as such, they tend to be used as baseload and cycling generation.

Combined-cycle power plants are a mature technology, with flat projected capital costs, and incremental performance improvements over time. Like CTs, combined-cycle power plants are used by utilities and IPPs around the world. Combined-cycle plants are procured and serviced through a well-established and mature supply chain. Financing for combined-cycle plants is readily available in the capital markets.

There are various configurations of combined-cycle plants; chief among them are a single-train combined-cycle (STCC), a dual-train combined-cycle (DTCC), and a 3x1 combined-cycle (3x1 CC). 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 (which the Companies filed an application in Docket 2016-0033 to acquire) is also a DTCC plant utilizing the same make and model of combustion turbines installed at both Keahole and Maʻalaea.

The 383 MW 3x1 CC proposed in our April 2016 PSIP update has been replaced with a proposed 152 MW STCC configuration for this December 2016 PSIP update.

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 grid-scale applications as well.

ICE generation has relatively high efficiencies (heat rates of approximately 10,000 Btu per 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.

We are currently building a 50 MW ICE generation station at the Schofield Barracks Army Base on Oʻahu. (See "Schofield Generating Station" in Appendix D: Current Generation Portfolios for more information.) The Schofield Generating Station will provide additional operating flexibility to help manage increasing penetrations of variable renewable resources, including DG-PV. It is also designed to allow Schofield Barracks to operate as a microgrid (that is, in an "islanded" mode) providing energy security for the base.

Geothermal

Geothermal power generation relies on underground heat sources. Typically, water is injected into a well drilled into an underground high temperature pocket to create steam that is channeled to the earth's surface and used to turn a steam turbine-generator set to generate electricity.

There are two types of geothermal power plants. Flash steam geothermal plants directly utilize high temperature hot water extracted from wells to produce steam that turns a steam turbine-generator. Binary cycle geothermal plants take the hot water from wells, and pass it through a heat exchanger with a working fluid with a much lower boiling point than water, and then that fluid is used as steam to turn the turbine-generator set. Hawai'i Electric Light currently purchases electrical capacity and energy from the Puna Geothermal Venture (PGV) 38 MW geothermal power plant. PGV utilizes a binary cycle design.

A variation of the binary plant design is driving a growing sector of the geothermal development industry. Because the binary design uses a working fluid with low boiling points, it is becoming feasible to tap into much lower temperature geothermal resources that occur naturally in certain locations that are not necessarily associated with volcanic activity. Technological advancements in directional drilling allow access to deeper and "cooler" geothermal resources, while improved working fluids and innovative cooling technologies allow lower temperature thermal resources to be used in power production applications. The potential for this type of geothermal technology to be employed in Hawai'i is unknown. If that potential is proven, it could conceivably unlock geothermal energy on islands beyond just Maui and Hawai'i Island.

Because geothermal is a proven technology, it has been considered a new resource option for the December 2016 updated PSIP for Maui and Hawai'i Island. Developing new geothermal generation in Hawai'i will require extensive resource assessment through additional field research (that is, test wells), development of clear regulatory and institutional frameworks, and ultimately, permitting and construction. Because of the extensive activities necessary to develop new geothermal resources, the December 2016 updated PSIP considers geothermal potential resources only available beyond the near-term planning period.

Biomass Plants

Biomass plants can generate power in several ways. Biomass feedstock can 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). Biomass feedstock can also be burned directly to provide heat to create steam, which in turn powers a steam turbine-

generator to produce electricity. The PSIP assumption for a 20 MW biomass plant is based on this latter 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. In addition, grown crops as well as process water waste can create biogas (a biomass fuel commercially proven in installations around the world) through anaerobic digestion.

Biofuels (another form of biomass) can be easily transported via truck containers and barges to generation sites, and substituted for liquid fuel in many of our existing units. Both biogas and biomass for power generation are economically feasible only when the feedstock is close to the power generation facility. Cellulosic crops and crop waste can serve as feedstock for anaerobic digesters to produce biogas. 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 April updated PSIP filing. For the December 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 $60 per bone dry ton (BDT) with a heat content of 7,500 Btu per pound. This results in a fuel price of $4.453 per MMBtu.[10] 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 $0.26 per kWh.

---

[10] http://www.hawaiicleanenergyinitiative.org/storage/pdfs/6_SpecificEconomicModeling_ScottTurn.pdf.

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.

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, 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.[11] 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.[12] 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.

---

11 http://www.covanta.com/facilities/facility-by-location/honolulu.aspx.

12 http://bigislandnow.com/2014/04/22/big-island-rubbish-enough-to-go-around/.

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 more 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.

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."[13]

Microgrids can be developed for a number of different purposes across a spectrum of uses. At one end, a military installation or data center would require an extremely high level of reliability, thus connecting the microgrid to the surrounding power grid, while retaining the option of operating the microgrid isolated ("islanded") from the grid. An example is the Schofield Generation Station currently being constructed.

At the other end, an owner might want to become completely self-sufficient by supplying all of their power from the microgrid, disconnected from the surrounding power grid. The cost to operate this isolated microgrid on par with current utility rate depends on the level of reliability desired by the owner (for example, no generation while the microgrid is out for an unplanned or maintenance outage), installation and maintenance, storage, and control systems.

A microgrid can consists of something as simple as distributed generation (for example, internal combustion engines, combined heat and power systems, solar PV, or distributed wind), energy storage systems, demand-side management systems, and a control system that, in effect, creates a balancing area within a defined set of loads. Microgrids can also incorporate energy storage and demand side management systems. Microgrids can operate interconnected with the larger utility system, or they can operate in an islanded mode.

Combined with utility time-based rate programs (such as time-of-use rates, dynamic pricing, and critical peak pricing) and demand response programs, sophisticated microgrid control systems allow microgrids to "call" power from the grid when it is economically advantageous to do so, and "put" power to the grid in response to DR program price signals.

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

[13] https://building-microgrid.lbl.gov/microgrid-definitions.

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 December 2016 updated PSIP. We will evaluate microgrid proposals case by case.

Solar PV Plus Storage Combination

A combination of grid-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.

In 2015, Kauai Island Utility Cooperative (KIUC) 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.

Concentrated Solar Thermal Power

Concentrated solar thermal power (CSP) is a rapidly advancing commercially available technology; the installed base of global CSP capacity, however, is still only about 1,200 MW.[15]

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.

---

[14] http://cleantechnica.com/2015/09/22/now-solar-power-meet-evening-peak-load-hawaii/.

[15] http://www.energy.gov/articles/year-concentrating-solar-power-five-new-plants-power-america-clean-energy.

We currently have no CSP plants on our grids. Hawai'i 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 over 365 days and, after the project lost the land rights required for continued operations.

Hydrokinetic (Ocean) Energy

The several technologies of hydrokinetic energy capture the energy from flowing water that occurs in rivers and mostly in ocean currents. These technologies include tidal range, tidal stream, ocean current energy (including river in-stream energy), ocean wave energy, ocean thermal energy conversion (OTEC), and salinity gradient.

Three technologies—tidal range, tidal stream, and salinity gradient—have little potential for Hawai'i because of the methods employed to harness and generate energy. The other three technologies— ocean current energy (absent river in-stream energy), ocean wave energy, and ocean thermal energy conversion—all demonstrate future promise for generating energy in Hawai'i.

The world's first OTEC facility was developed in Hawai'i during the 1970s. An OTEC facility is currently generating 100 kW on Hawai'i Island with a 1 MW facility in the planning stages. Two small scale, pilot ocean wave projects have recently begun operating in Kaneohe Bay in O'ahu; one generates 18 kW and the other generates 4 kW of electricity.

Both technologies are clearly still firmly in the development stage. 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.

For more information, see "Hydrokinetic Energy" in Appendix H: Renewable Resource Options on O'ahu for explanations of each technology and their commercial readiness.

GRID-SCALE RESOURCE ASSUMPTIONS

For the December 2016 PSIP update, the Companies have undertaken a more detailed analysis of the renewable resource potential on all of the islands, with particular emphasis on O‘ahu given its significantly higher energy needs and limited resource potential. If the renewable constraints on O‘ahu are significant, because of land use or community issues, the strategic need for off-island options becomes greater.

One constraint was the theoretical maximum potential for grid-scale PV and grid-scale wind on O‘ahu, Maui, and Hawai‘i Island. NREL initially developed estimates that we employed in the April 2016 PSIP. For this December 2016 PSIP, we requested that NREL revise its analysis by relaxing these estimates using factors suggested by the Parties (mainly Dr. Matthias Fripp of the University of Hawai‘i on behalf of the Ulupono Initiative). Dr. Fripp also conducted his own research to arrive at theoretical maximum potentials for grid-scale PV and grid-scale wind.

Table E-2 shows the differences in the results of the analyses by NREL, by Dr. Fripp, and a separate analysis performed by AWS Truepower[16] in 2014 regarding the grid-scale wind potential on O‘ahu.

Source	O‘ahu Grid Scale Solar PV Potential		O‘ahu Grid Scale Wind Potential	
	MW	*Description*	*MW*	*Description*
NREL	2,756	Sites outside excluded areas with annual capacity factors greater than 10%.	162	Sites outside excluded areas with mean wind speeds greater than 6.5 meters per second.
Ulupono (Dr. Fripp)	9,168	Fixed tilt PV; 20% land slope; 16%–26%. annual capacity factors.	2,680	12%–36% annual capacity factors.
	6,583	Fixed tilt PV; 10% land slope.		
AWS Truepower	n/a	n/a	189	Results of detailed study of available and developable wind sites by AWS Truepower for Castle & Cooke.

Table E-2. Comparison of Results of O‘ahu Resource Potential Analyses

For a more detailed discussion of this topic, see “Grid-Scale PV and Grid-Scale Wind Potential” in Appendix H: Renewable Resource Option on O‘ahu.

[16] AWS Truepower, *Potential Build-Out of Wind Energy Projects on Maui and O‘ahu – Site Screening and Preliminary Layout Development*, January 27, 2014; filed in Docket 2013-0169 on January 28, 2014.

Grid-Scale Resources by Island

Table E-3 summarizes the PSIP grid-scale resource options currently available for developing longer-term 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	1, 5, 10, 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	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

* 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 December 2016 PSIP update analysis.

Table E-3. Preliminary New Grid-Scale Resource Options Available

Note: Properly evaluating the waste-to-energy facilities listed in Table E-3 depends, in large part, on acquiring reliable data regarding Hawai'i-specific cost and performance characteristics.

DISTRIBUTED ENERGY RESOURCES COST ASSUMPTIONS

We developed DER resource capital cost assumptions using the same sources and methodology as for grid-scale resources. We concentrated on DG-PV, residential lithium-ion BESS, and behind-the-meter commercial customer class BESS. We used IHS Energy's projections of distributed solar and energy storage costs, applied Hawai'i locational adjustments using RSMeans data, and added 4% for the Hawai'i General Excise Tax.

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.

INTERISLAND TRANSMISSION ASSUMPTIONS

Our December 2016 updated PSIP analysis is based on interisland transmission cables using high voltage direct current (HVDC) technology, including converter stations on either end of a submarine cable. Without assurance that an interisland project has a high likelihood of development, potential vendors are unlikely to develop accurate costs for a specific interisland cable configuration.

So, rather than developing an accurate capital cost, we decided to first analyze the *benefits* of interisland transmission to determine if the sum total of such benefits could reasonably exceed this approximated cost. This break-even analysis assumes various "copper-plate" configurations: assume one or more cables transfers power between two or more points, without consideration of reliability; comparing the benefits against $600 million (the lowest known capital cost estimate); [17] and if benefits exceed cost, then conduct further analysis. E3 has analyzed the benefits of interisland transmission are part of developing this December 2016 PSIP.

Our goal is to determine, as quickly as possible, whether or not interisland transmission represents a viable resource option for Hawai'i that demands further research. We

[17] NextEra Energy developed and filed the $600 million estimate in Docket No. 2014-0169. (NextEra has since withdrawn from that proceeding.) This amount is at the low end of the $553–$969 million estimated range filed in our 2013 Integrated Resource Plan Report.

believe this two-step process—first evaluating the benefits, then, if warranted, evaluating the cost—is the most prudent, cost effective, and timely way to determine if interisland transmission demand further consideration as an option to pursue to help achieve our State's renewable energy goals.

For more information about interisland transmission, see "Interisland Transmission" in Appendix H: Renewable Resource Option on O'ahu.

NEW RESOURCE RISKS AND UNCERTAINTIES

Developing grid-scale energy infrastructure, whether by a utility or an IPP, involves managing a number of implementation risks and uncertainties. Improperly managing these risks and uncertainties can adversely impact the State's ability to achieve its 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 stands behind contractual assurances that the project will be completed within 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, and ocean tidal and wave 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 consulting with dozens of state and federal agencies, preparing and disseminating notices, preparing numerous impact reports and studies, and navigating a maze of state and federal agency permitting processes. Many of the permits are subject to contested hearing processes; 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, issued permits have been revoked because of procedural errors, after developers have spent significant time, effort, and money working in good faith with the

communities and agencies to obtain those permits.[18] 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 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.

[18] "Hawai‘i 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.

F. NREL Reports

The Companies retained the National Renewable Energy Laboratory (NREL) to prepare and submit four study reports to support our *PSIP Update Report: December 2016*. These reports assessed resource potentials, wind and solar power profiles, and resource costs on three of the islands we serve: O‘ahu, Maui, and Hawai‘i Island. The Companies used the data from these reports in our modeling analysis to develop the December 2016 updated PSIP.

These studies are:

- *Utility-Scale Onshore Wind, Utility-Scale PV, and CSP Potential Resource* (page F-2) assessed these three resource potentials. Since these utility-scale resources are owner agnostic, they are better characterized by the term "grid-scale". Based on Party input, we requested NREL to update the O‘ahu grid-scale PV potential of this study to include 100% of agricultural B and C class land with slopes less than or equal to 10%.
- *Aggregated Wind Power Profile Time Series* (page F-37) used two scenarios to calculate hourly onshore wind power profiles.
- *Aggregated Solar Power Profile Time Series* (page F-43) used solar radiation data from 1998 through 2014 to calculate solar power profiles.
- *Electricity Generation Capital, Fixed, and Variable O&M Costs* (page F-61) independently assessed our resource data assumptions.

Each report with an attendant summary is presented here.

UTILITY-SCALE ONSHORE WIND, UTILITY-SCALE PV, AND CSP POTENTIAL RESOURCE

This NREL report describes their studies that estimated the onshore grid-scale wind and grid-scale PV potential for each of the three main islands we serve: Oʻahu, Maui, and Hawaiʻi Island. The report estimated the maximum grid-scale wind potential for each of the three islands to be as follows:

Island	Potential MWac
Oʻahu	183
Maui	840
Hawaiʻi	3,532

Table F-1. Maximum Grid-Scale Wind Potential for Oʻahu, Maui, and Hawaiʻi Island

The report estimated the maximum grid-scale PV potential for each of the three islands to be as follows:

Island	Potential MWac (<3% slope)	Potential MWac (<5% slope)	Potential MWac (<10% slope; Ag A)	Potential MWac (<10% slope; Ag A,B,C)
Oʻahu	583	796	1,434	2,970
Maui	272	783	n/a	n/a
Hawaiʻi	11,514	30,484	n/a	n/a

Table F-2. Maximum Grid-Scale PV Potential for Oʻahu, Maui, and Hawaiʻi Island

The initial study (included in our *PSIP Update Report: April 2016*) excluded lands with a greater than 3% and 5% slope, urban areas, wetlands, park lands, mountainous areas, ravines, and certain agricultural areas (100% of A class lands are excluded and 90% of B and C class lands are excluded[1]) for grid-scale PV development. The study thus, assumed that the remaining land was available to be developed for grid-scale PV. The capacity-weighted average land use for PV was assumed to be 8.7 acres per MWac. Wind excluded lands with slopes greater than 20%, minimum threshold wind speed of 6.5 meters per second, and assumed power density of 3 MW per kilometer.

At our request, NREL reanalyzed the PV potential for Oʻahu based on Party input. The updated PV resource potential analysis for Oʻahu increased the slope exclusion criteria to 10%, and included all agricultural B and C land.

1 Please refer to Appendix A: Glossary and Acronyms for an explanation of agricultural land classifications and how they are developed.

NREL has also directly reviewed assumptions of resource potentials for O‘ahu provided by Dr. Mathias Fripp on behalf of Ulupono Initiative. NREL states that the differences in resource potential are driven by differences in land use assumptions. NREL states that a better estimate of resource potential could be obtained from a site by site analysis.

The maximum potential for grid-scale wind suggested by this NREL report (183 MW) aligns with the results found by AWS Truepower in 2012,[2].which was a site by site analysis of the wind potential on O‘ahu. That report concluded the maximum potential wind generation to be 189 MW, but because of a number of exogenous factors, concluded the remaining actual potential to be about 40–50 MW.[3]

Maui and Hawai‘i Island has more than adequate renewable resource potential (for both grid-scale PV and grid-scale wind) to meet their native electrical loads and, as a result, can be met by on-island resources.

[2] Docket 2013-0169; *Potential Build-Out of Wind Energy projects on Maui and O‘ahu, Site Screening and Preliminary Layout Development*, prepared by AWS Truepower for Castle & Cooke, dated January 27, 2014; filed as a public comment on January 28, 2014.

[3] Docket 2013-0169, *Public Comments of Castle & Cooke*, January 28, 2014: pp 17–18.

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

This report was prepared by the National Renewable Energy Laboratory and submitted to the Hawaiian Electric Companies via email on December 9, 2016.

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 Oʻahu, Maui, and Hawaiʻi Island. 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 F-1 to F-6 show the utility-scale onshore wind and utility-scale solar PV resource potentials (in MWac terms) for Hawaiʻi Island, Maui, and Oʻahu 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 F-1 to F-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 F-4 to F-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 is 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.

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 F-3. Grid-Scale Onshore Wind Potential for Hawai'i (MWac)

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 F-4. Grid-Scale Onshore Wind Potential for Maui (MWac)

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 F-5. Grid-Scale Onshore Wind Potential for O'ahu (MWac)

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 F-6. Grid-Scale Solar PV Potential for Hawai‘i (MWac)

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 F-7. Grid-Scale Solar PV Potential for Maui (MWac)

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%	Slope 10%	Slope 10%*
>= 10	0	1,338	67	2,155	1,527	2,301	583	796	1,434	2,970
>= 12	0	1,338	67	2,155	1,527	2,301	583	796	1,434	2,970
>= 14	0	1,338	67	2,155	1,527	2,301	583	796	1,434	2,970
>= 16	0	1,338	67	2,155	1,527	2,301	583	796	1,428	2,923
>= 18	0	1,338	67	2,134	1,527	2,277	583	793	1,368	2,756
>= 20	0	414	67	895	692	968	329	397	664	1,053

*“B” and “C” agricultural lands are not excluded (see ection 4.2 for details).

Table F-8. Grid-Scale Solar PV Potential for O‘ahu (MWac)

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 F-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, that is, whether the data is traversed in the latitude or longitude dimension.

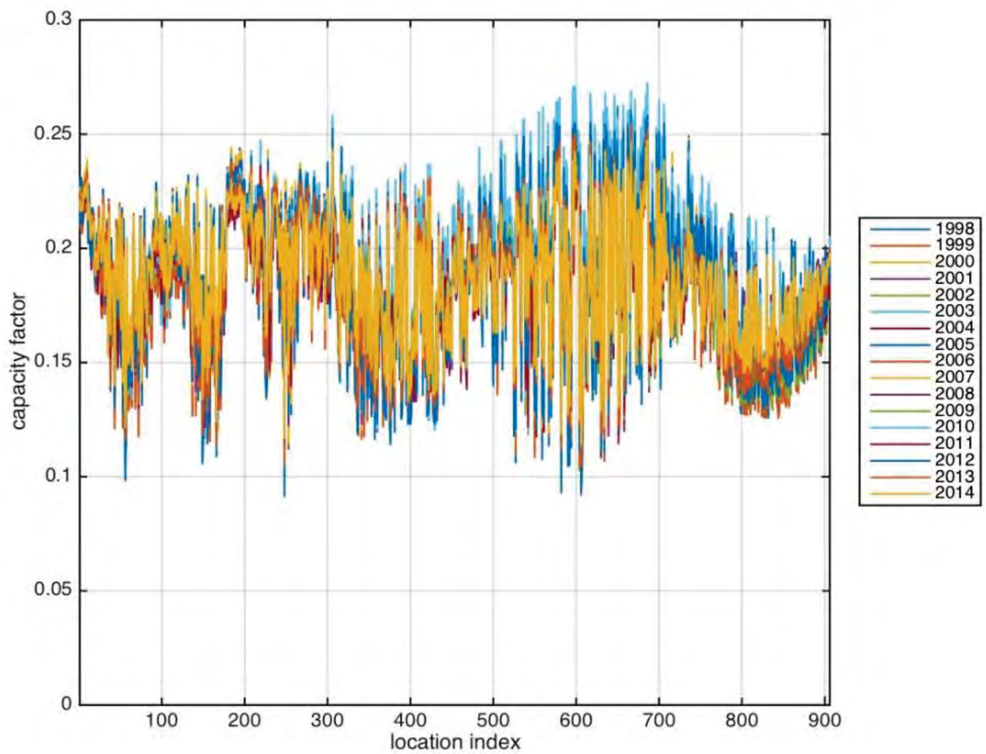


Figure F-1. Annual Variability of Solar Capacity Factors

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 F-2 shows the percentage of half hour intervals for all the years to give some visual indication of the variability in this statistic.

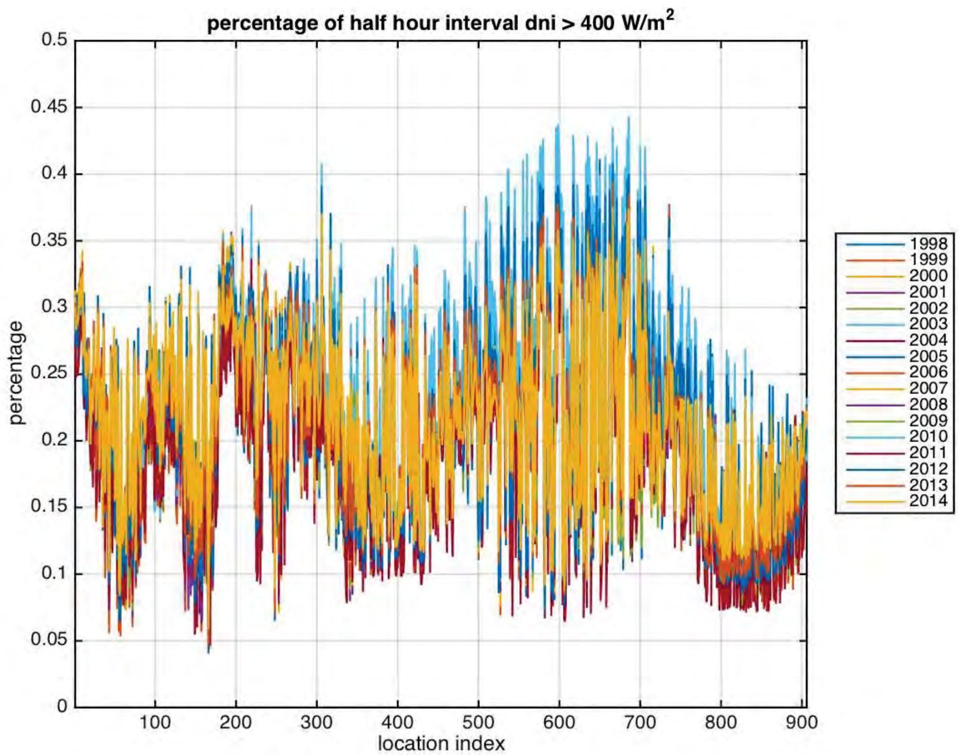


Figure F-2. Percentage of Half-Hour Interval DNI > 400 W/m^2

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 F-3 shows a typical agricultural parcel on the island of O'ahu.

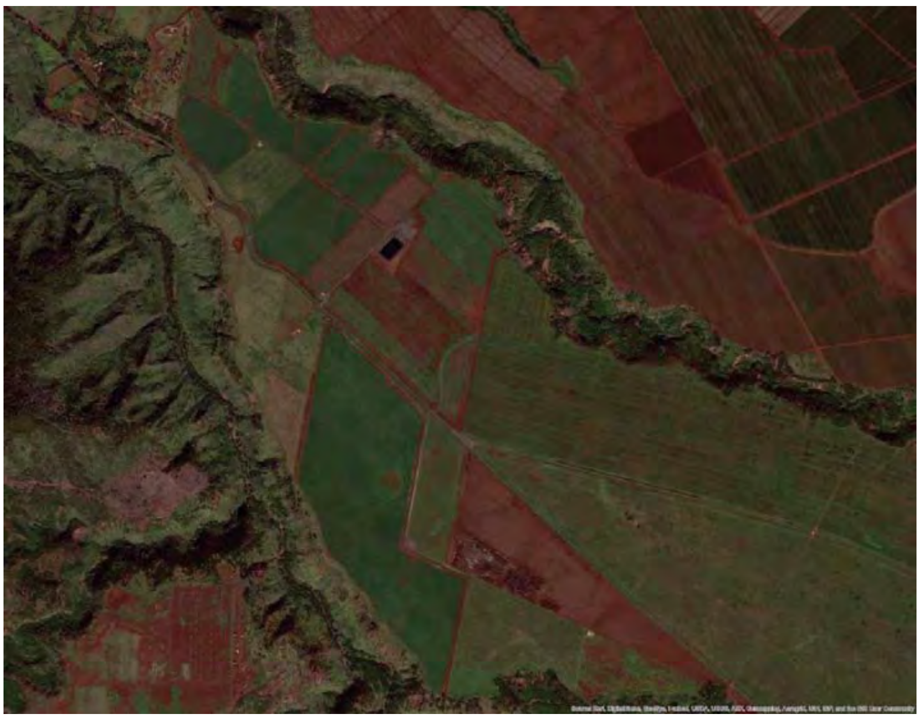


Figure F-3. Typical Agricultural Parcel on O'ahu

Figure F-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%.

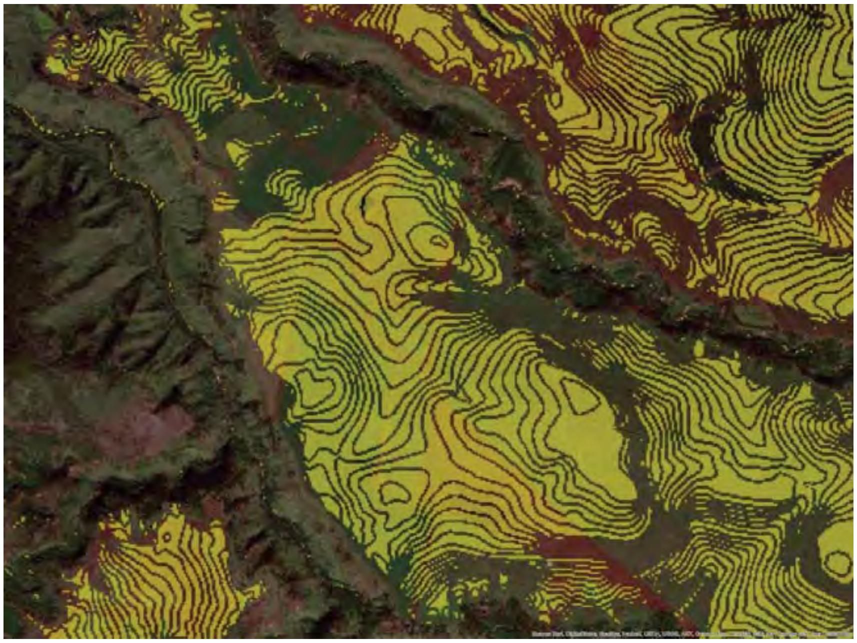


Figure F-4. Typical Agricultural Parcel on O'ahu after 3% Slope Analysis

It is evident from aerial photographs that the terracing effect seen in Figure F-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 F-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 F-4.

The expansion/shrinking was run twice, and the results are shown in Figure F-5. Large areas of land were unified, and tiny scattered areas were largely eliminated.

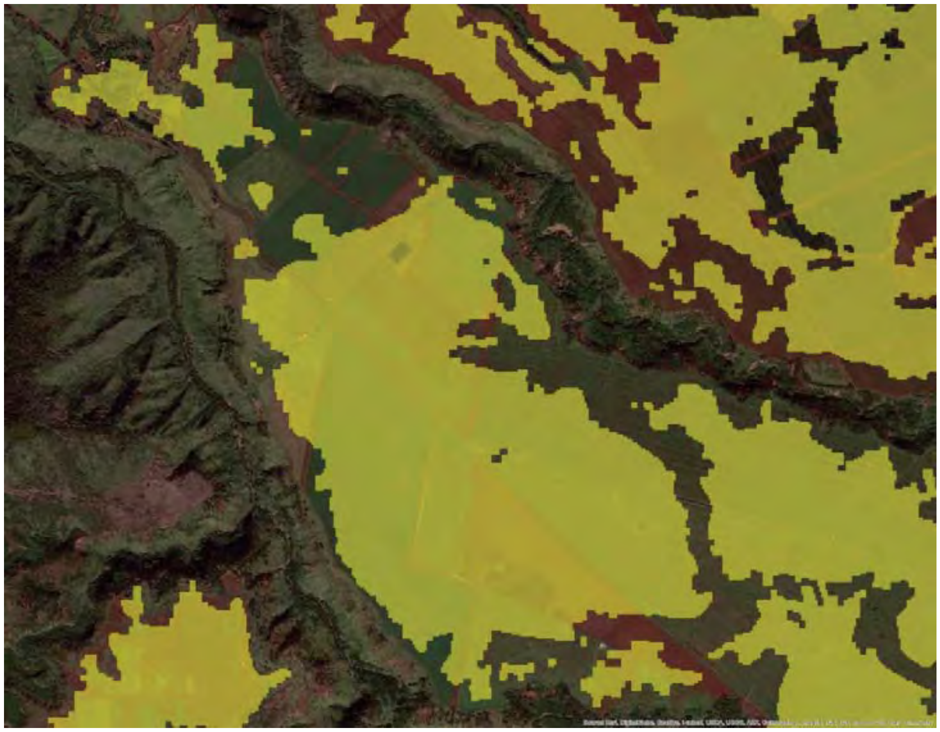


Figure F-5. Typical Agricultural Parcel on O'ahu after the Boundary Clean Tool Analysis

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[*] 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

[*] http://www.cap tol.hawaii. ov/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 PV

Concentrated Solar Power

[*] “B” and “C” agricultural lands are highlighted in the ap.
[†] “B” and “C” agricultural ands are not excluded (see section 4.2 for details).

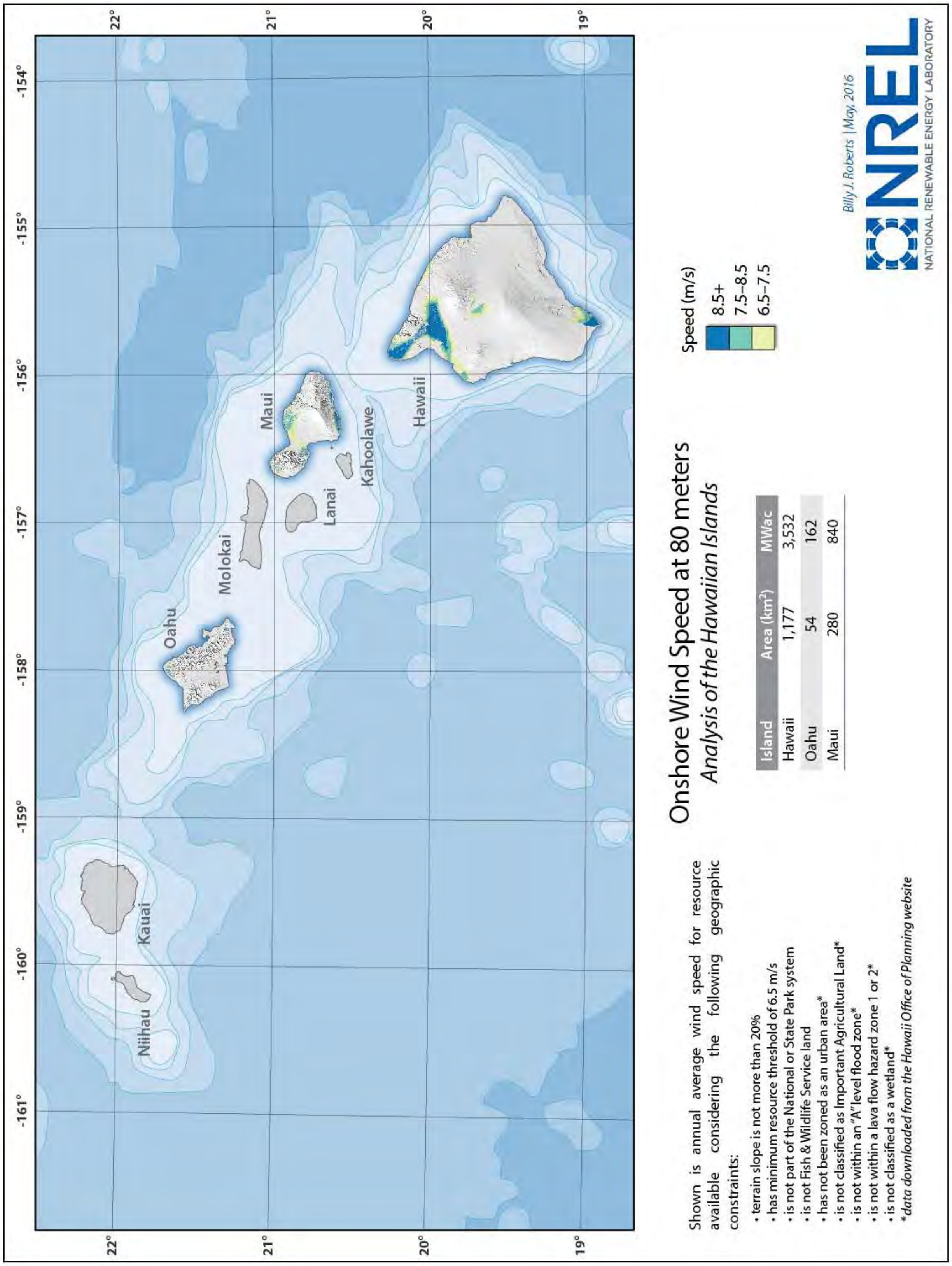


Figure F-6. Grid-Scale Onshore Wind Development Potential for All Hawaiian Islands

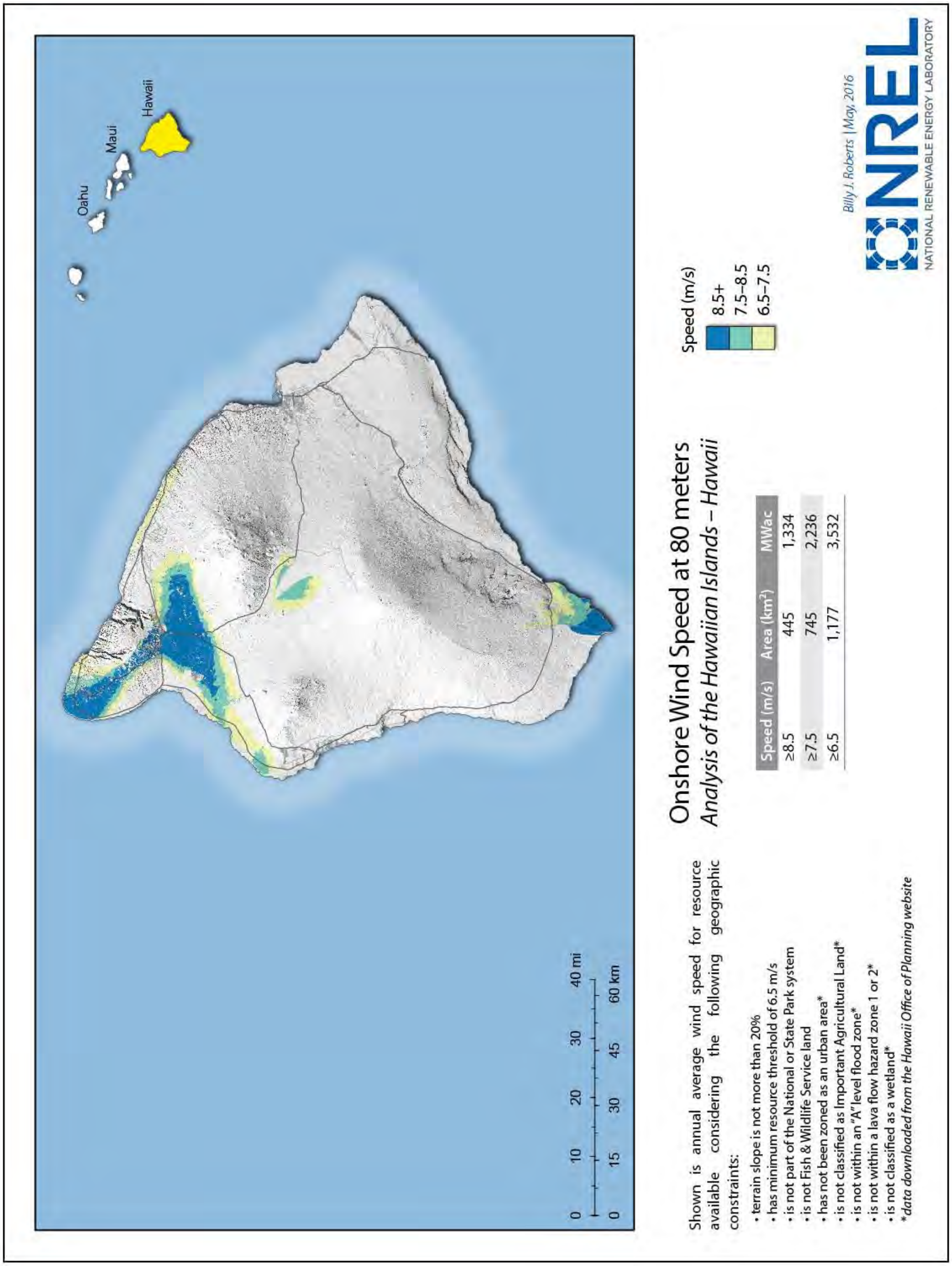


Figure F-7. Grid-Scale Onshore Wind Development Potential for Hawai'i Island

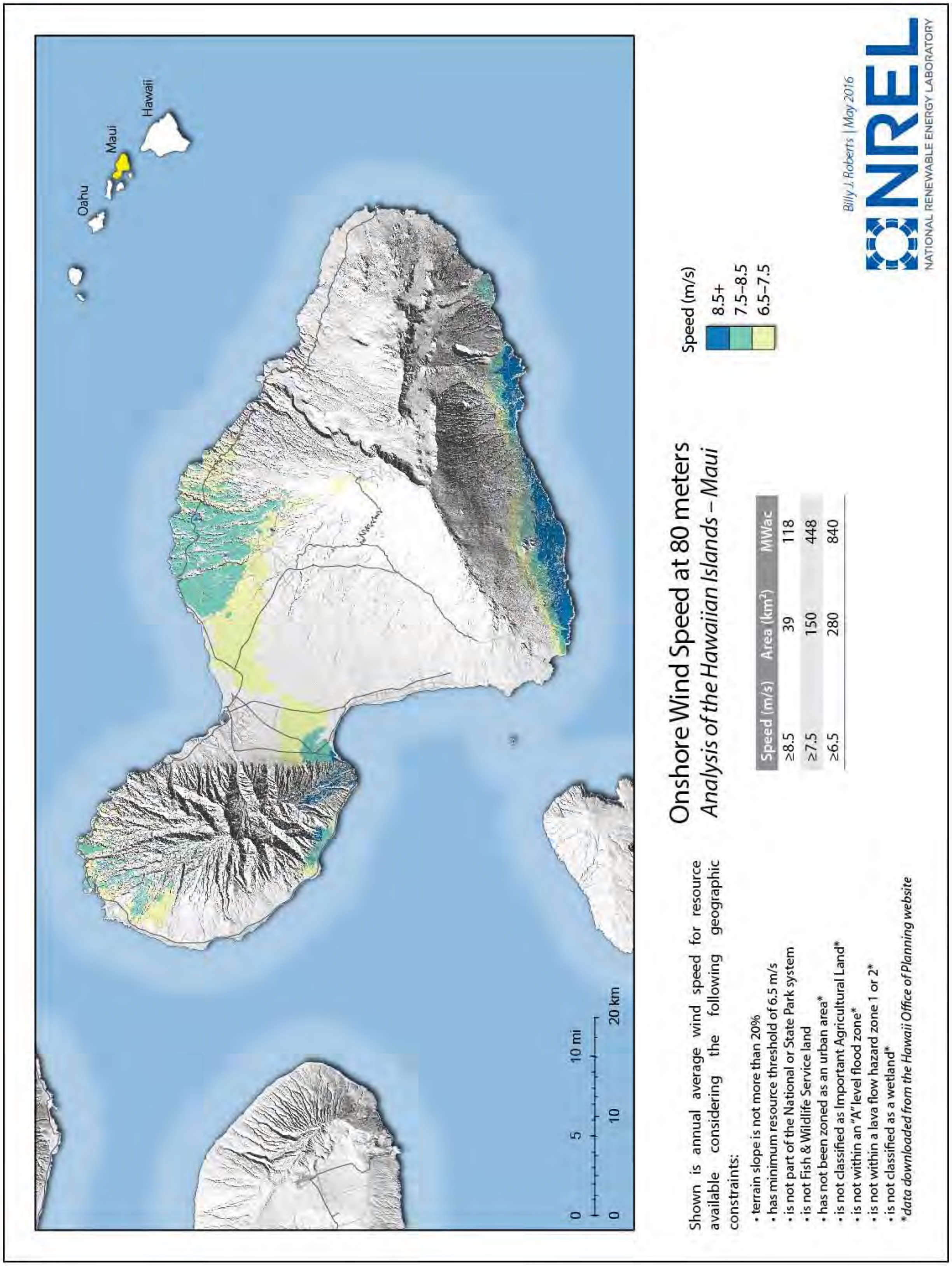


Figure F-8. Grid-Scale Onshore Wind Development Potential for Maui

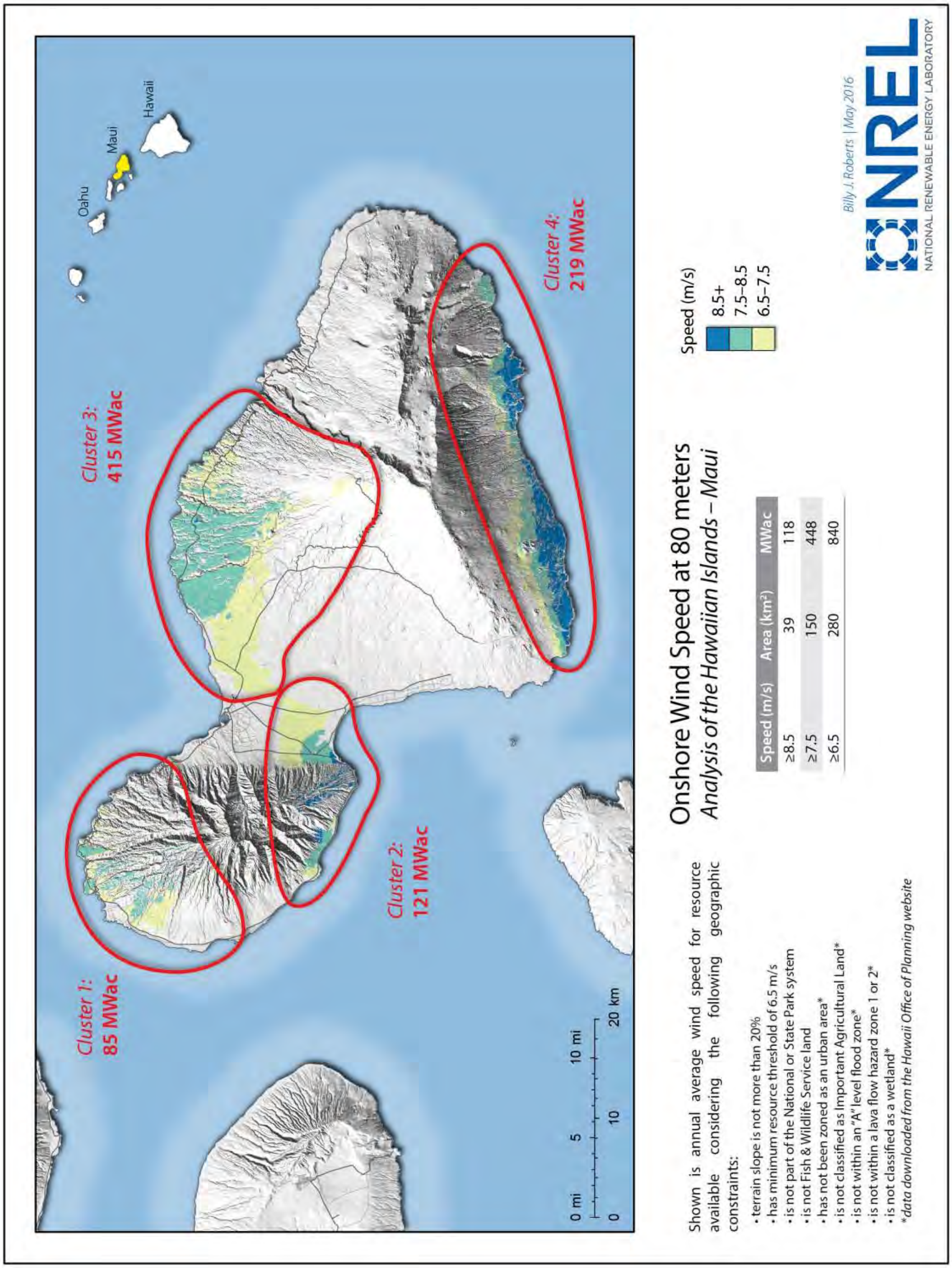


Figure F-9. Grid-Scale Onshore Wind Development Potential for Maui with Clusters

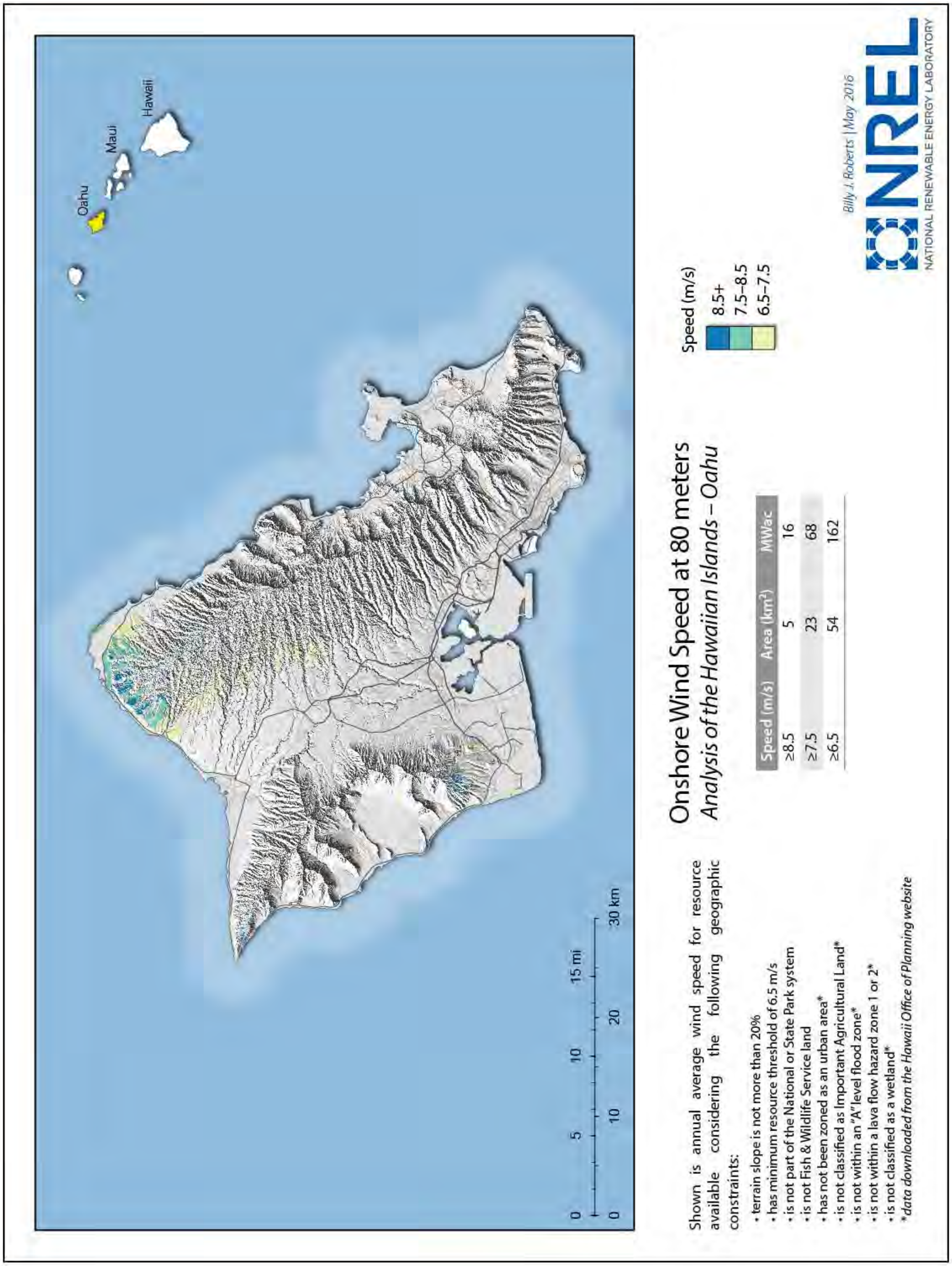


Figure F-10. Grid-Scale Onshore Wind Development Potential for O'ahu

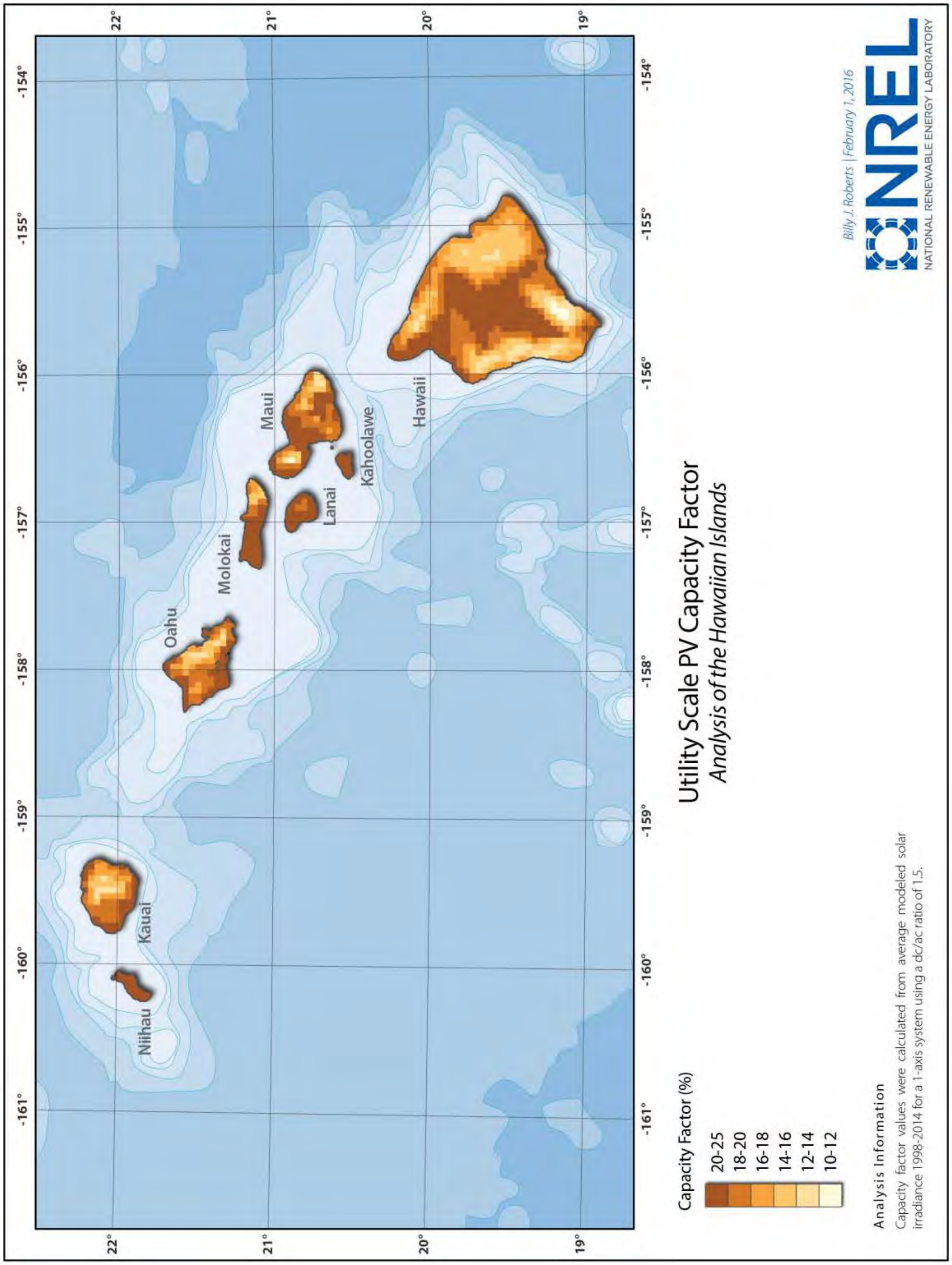


Figure F-11. Capacity Factor for All Hawaiian Islands

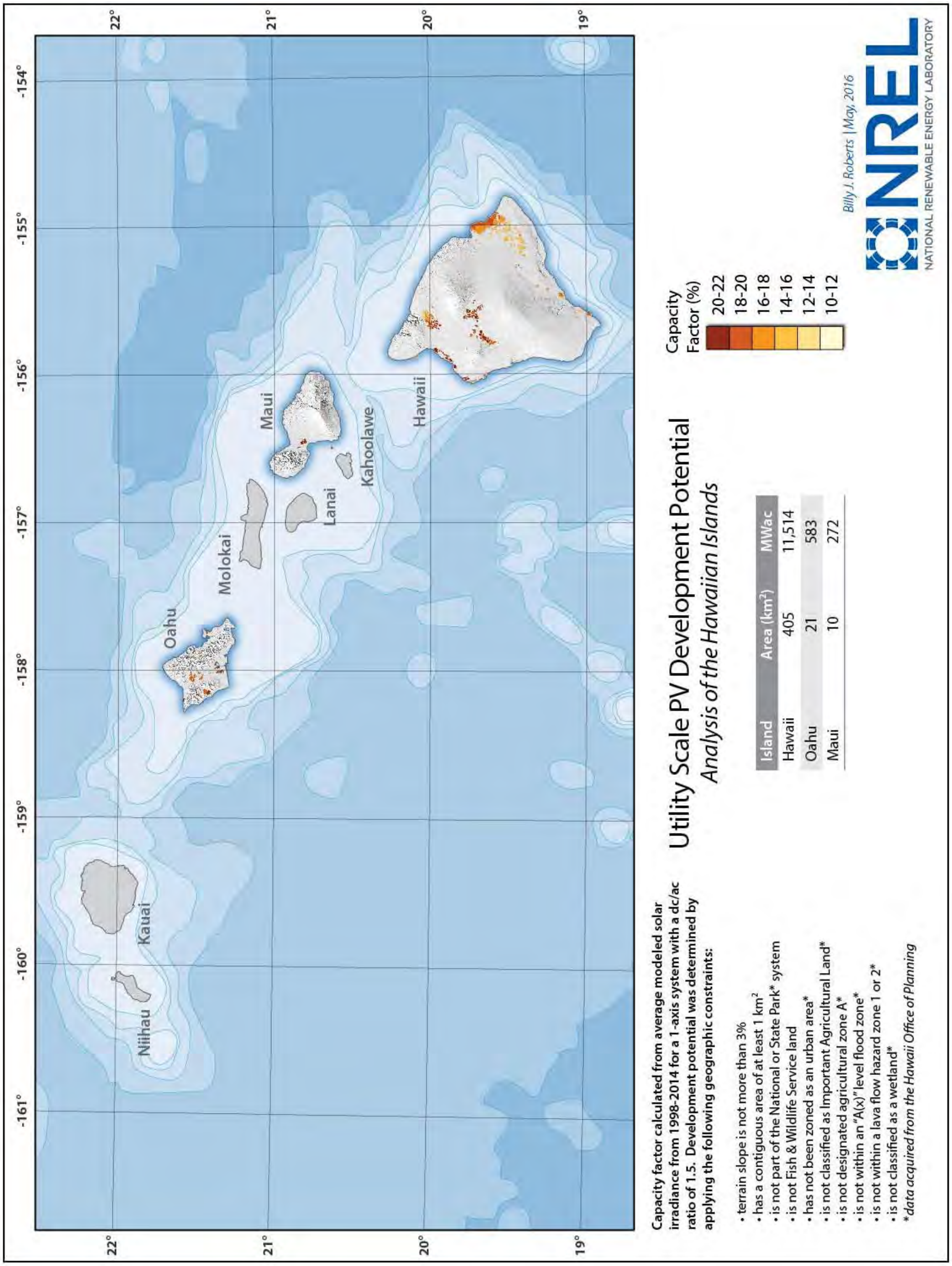


Figure F-12. Grid-Scale PV Development Potential for All Hawaiian Islands (3% slope exclusion)

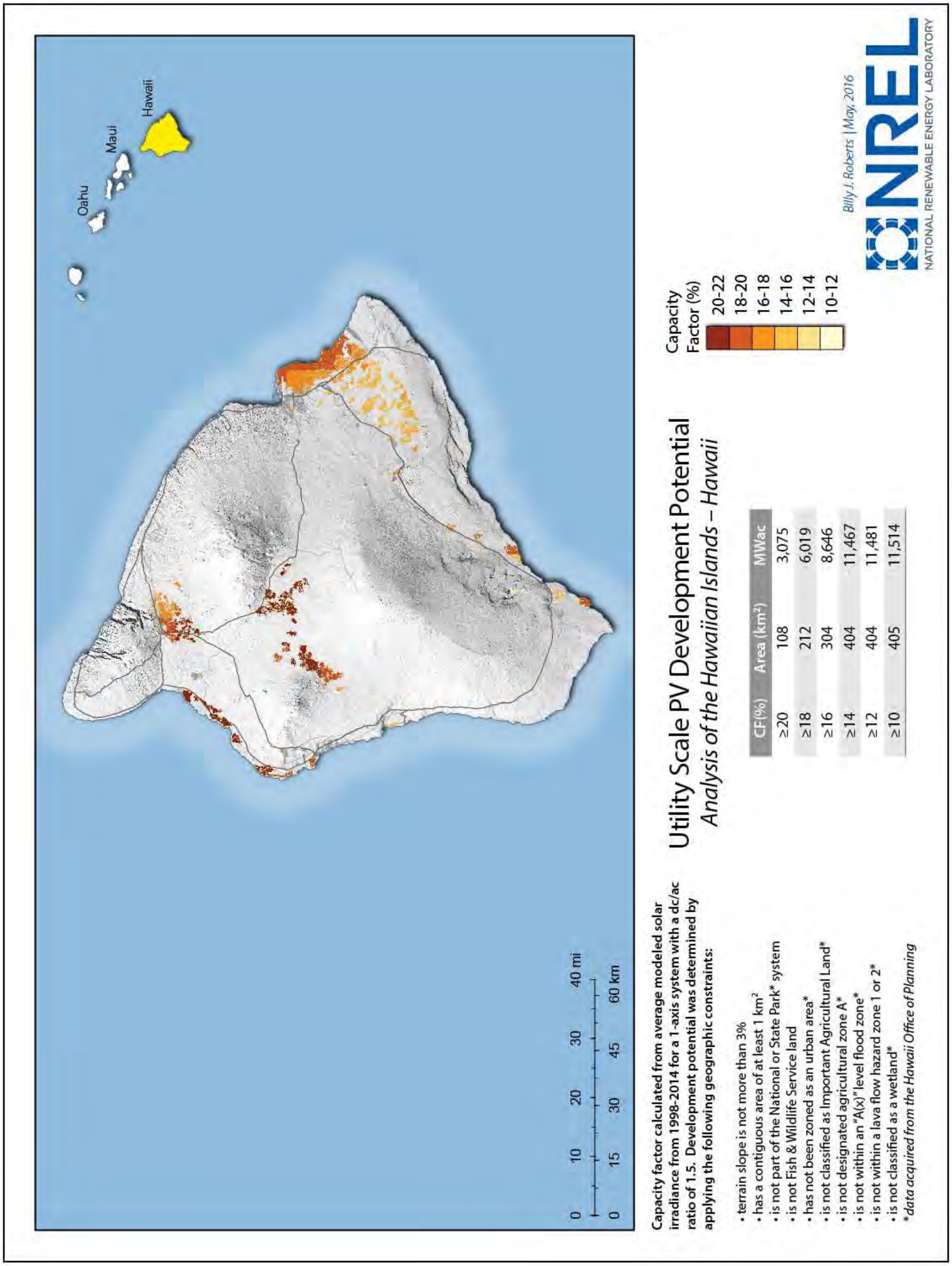


Figure F-13. Grid-Scale PV Development Potential for Hawai'i Island (3% slope exclusion)

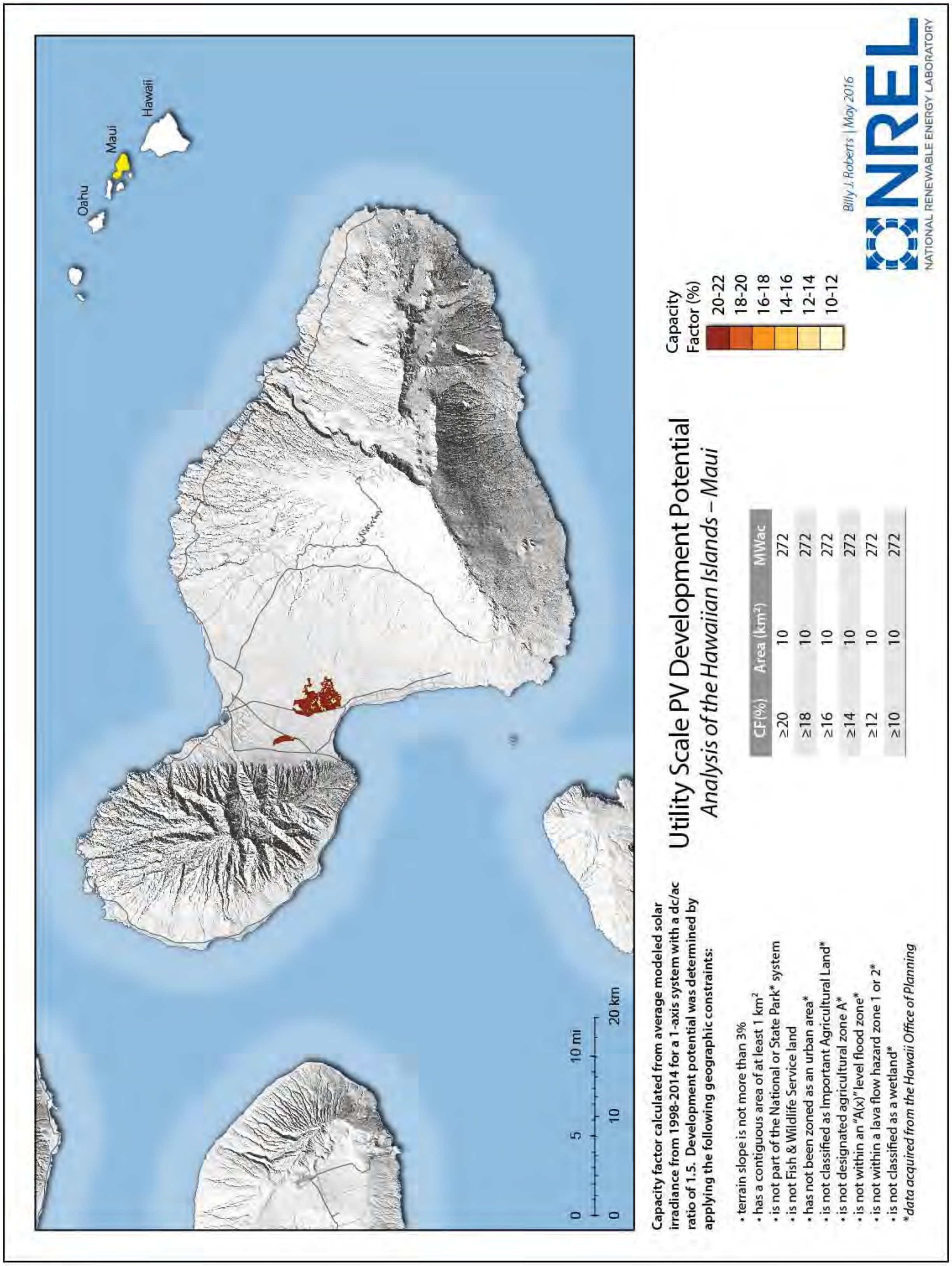


Figure F-14. Grid-Scale PV Development Potential for Maui (3% slope exclusion)

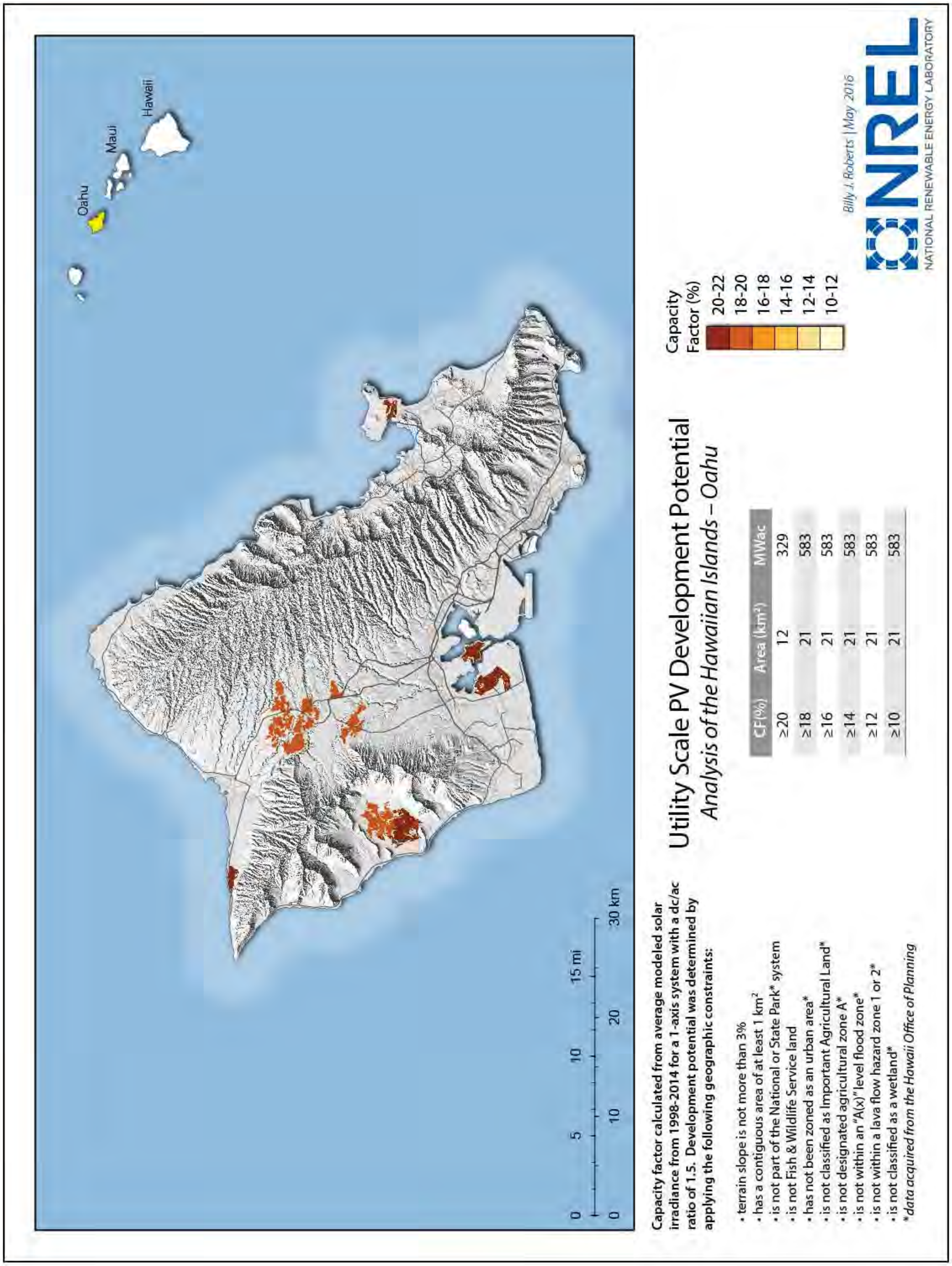


Figure F-15. Grid-Scale PV Development Potential for O'ahu (3% slope exclusion)

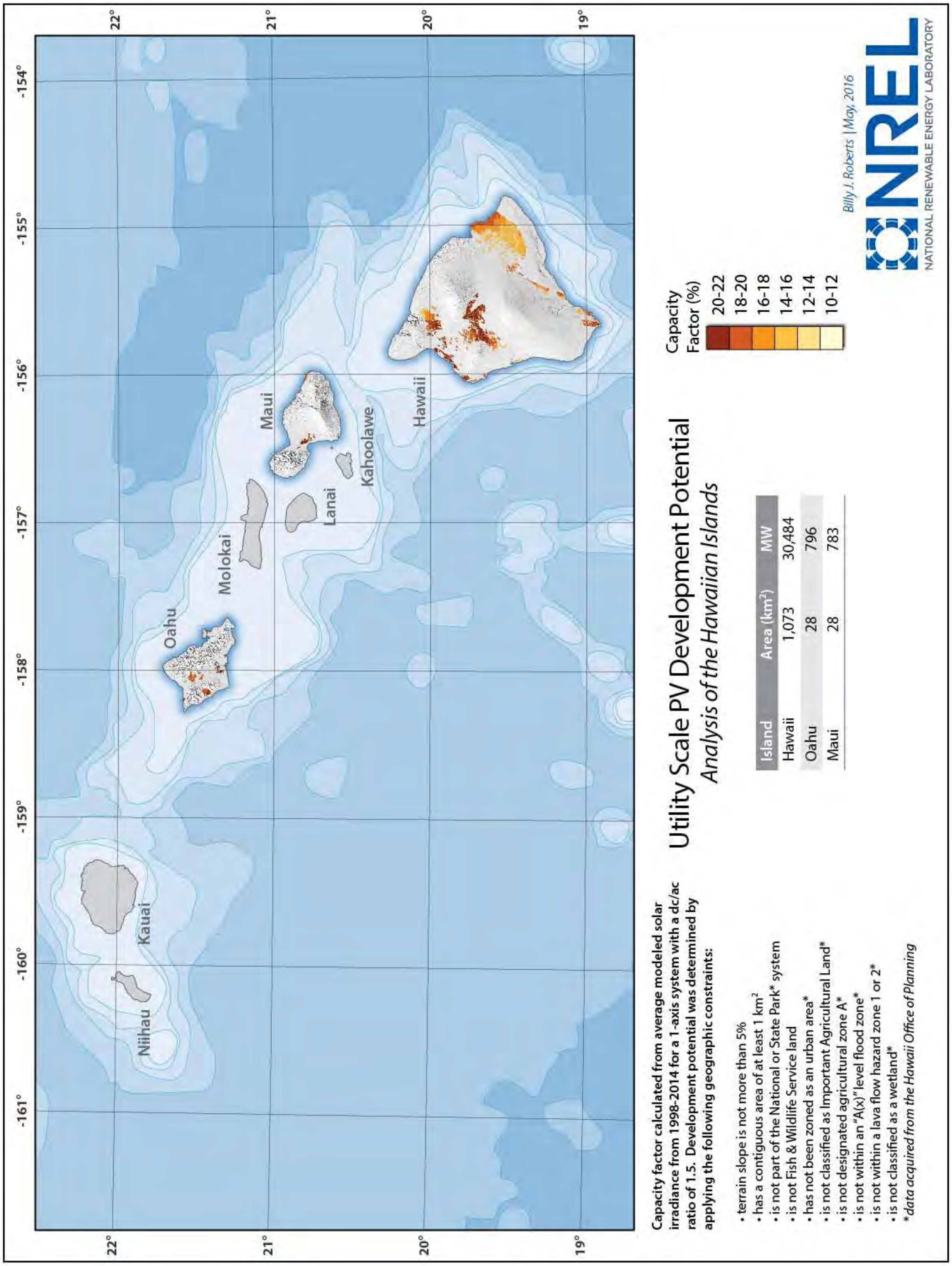


Figure F-16. Grid-Scale PV Development Potential for All Hawaiian Islands (5% slope exclusion)

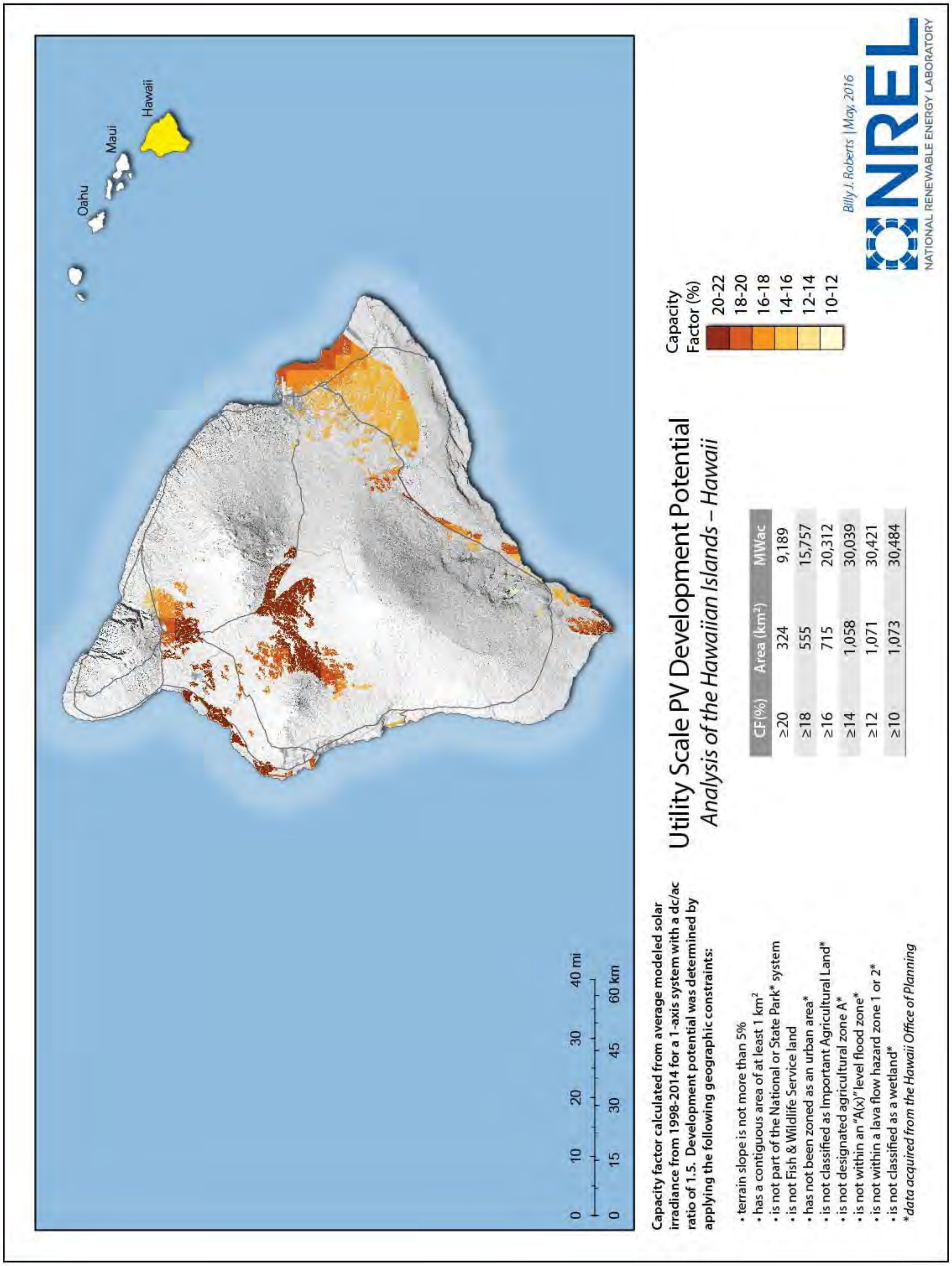


Figure F-17. Grid-Scale PV Development Potential for Hawai'i Island (5% slope exclusion)

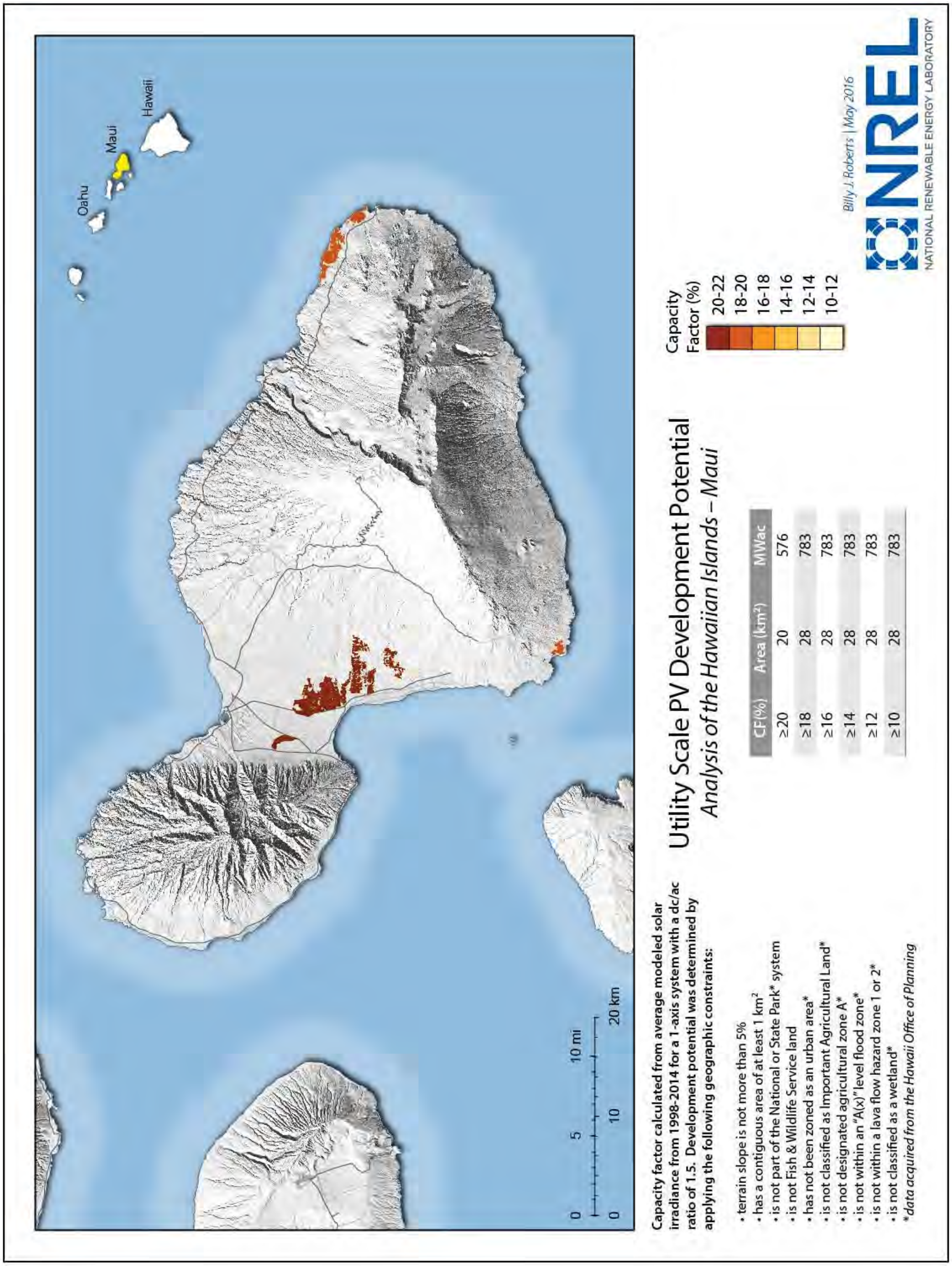


Figure F-18. Grid-Scale PV Development Potential for Maui (5% slope exclusion)

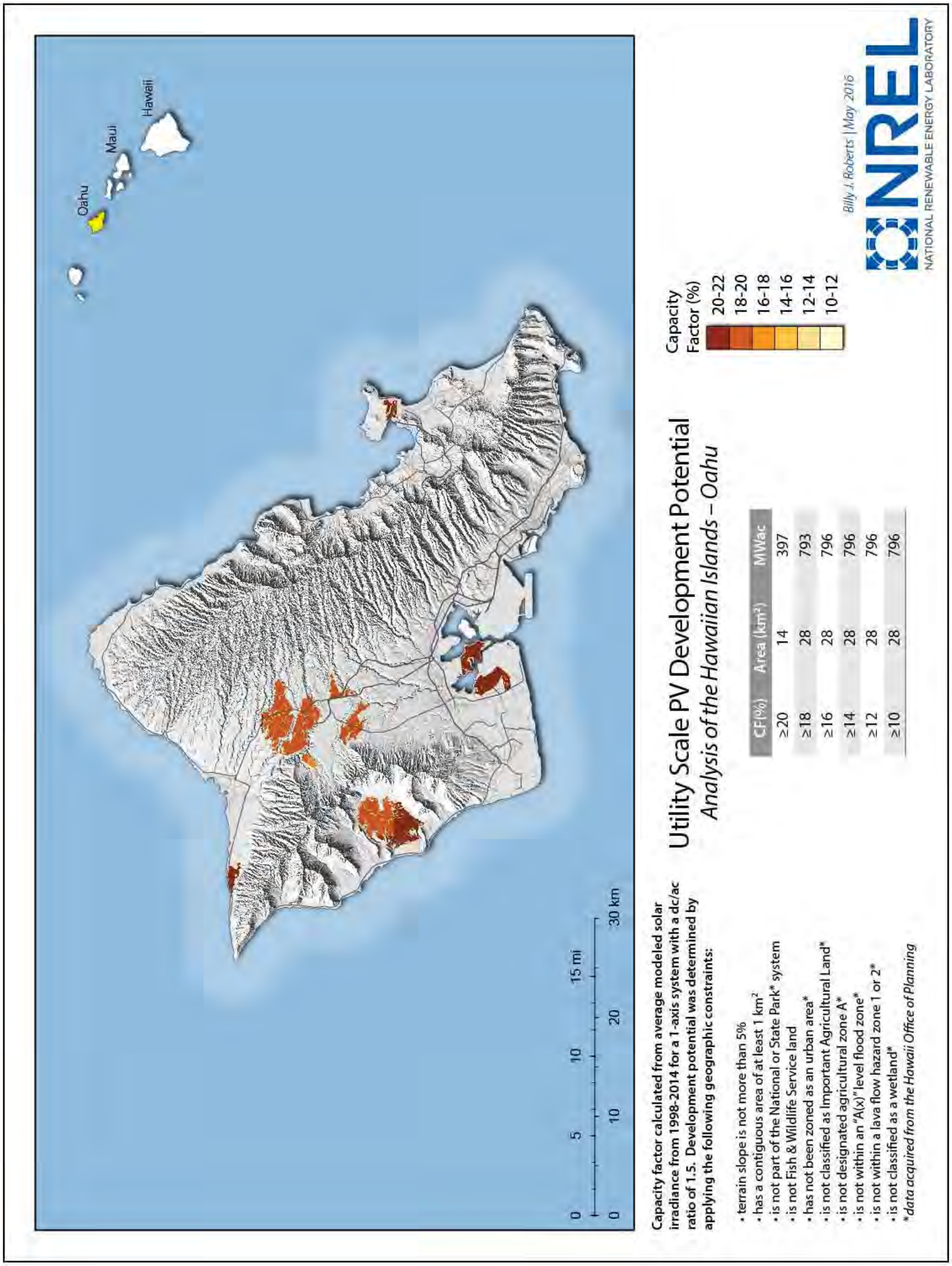


Figure F-19. Grid-Scale PV Development Potential for O'ahu (5% slope exclusion)

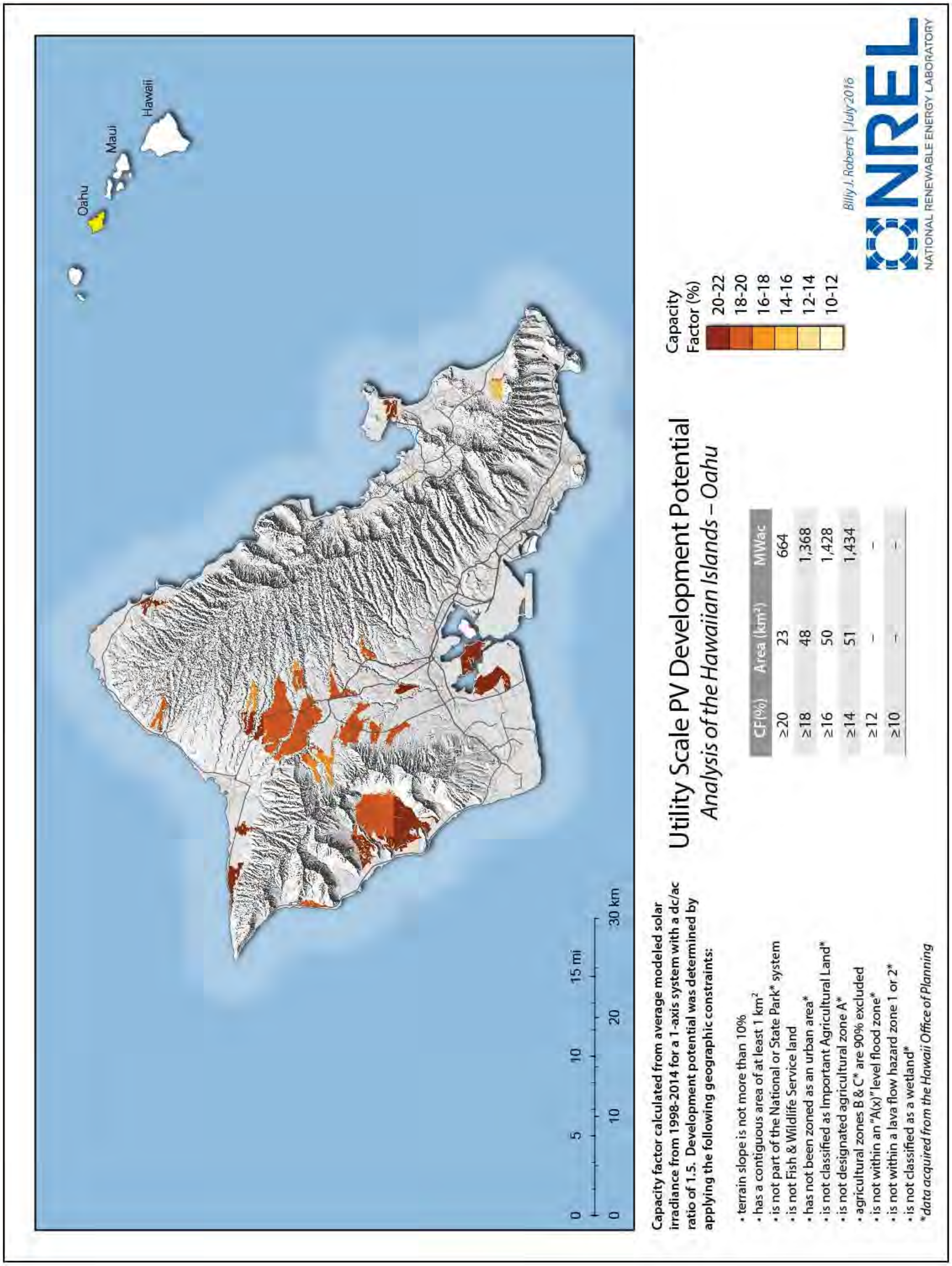


Figure F-20. Grid-Scale PV Development Potential for O'ahu (10% slope exclusion; Ag B and C class land 90% excluded)

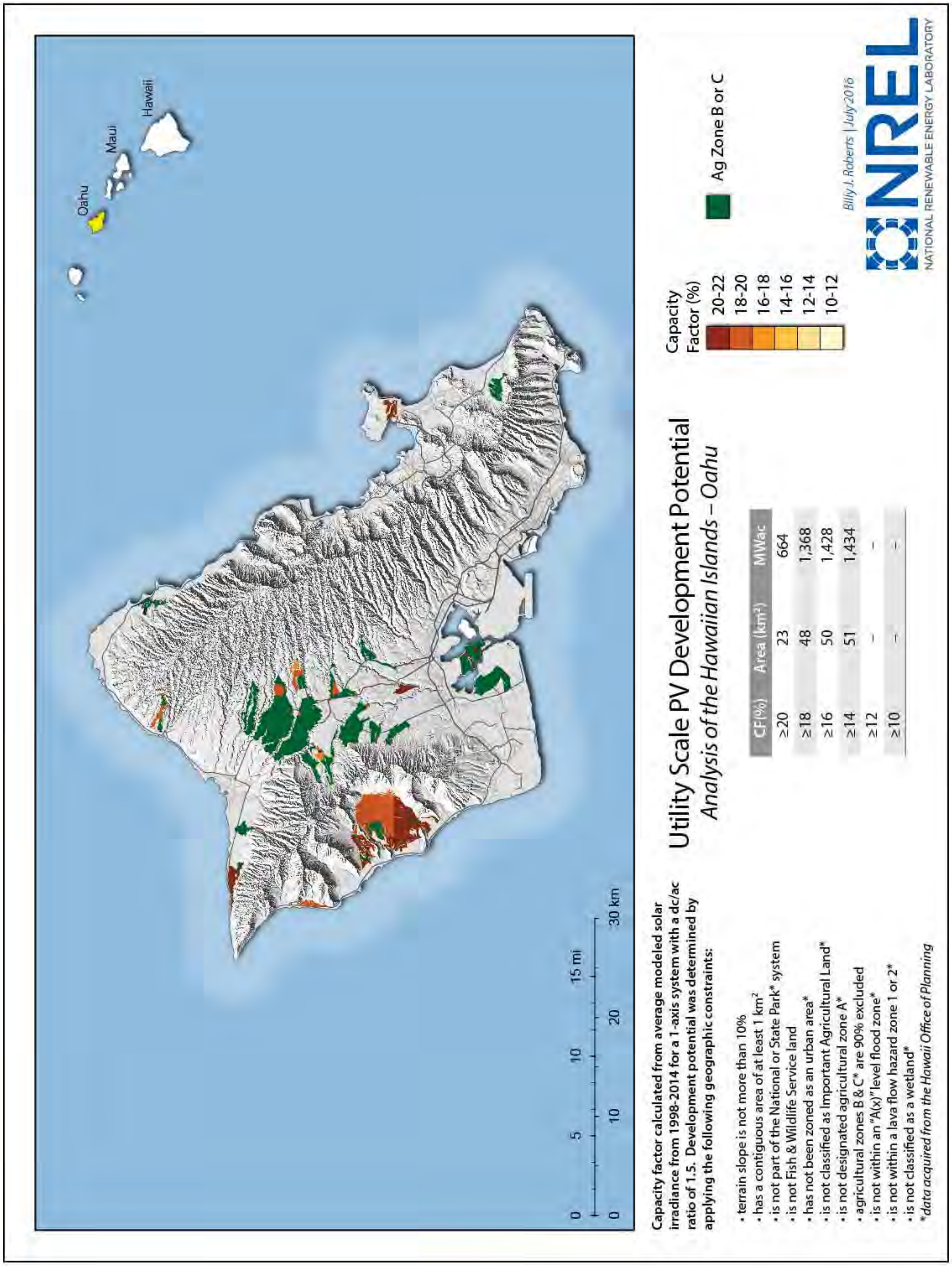


Figure F-21. Grid-Scale PV Development Potential for O‘ahu (10% slope exclusion; Ag B and C class land highlighted)

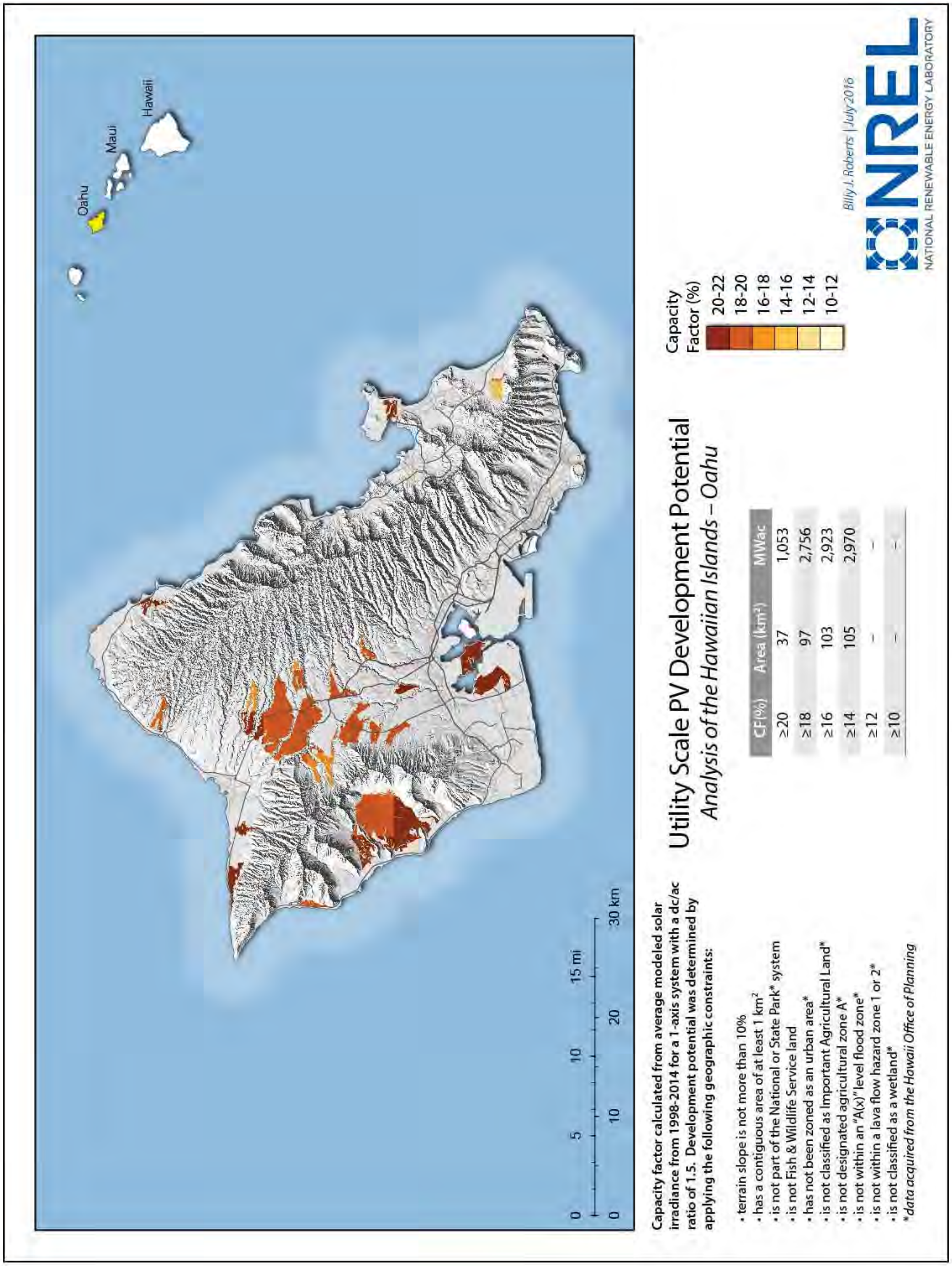


Figure F-22. Grid-Scale PV Development Potential for O'ahu (10% slope exclusion; Ag B and C class land included)

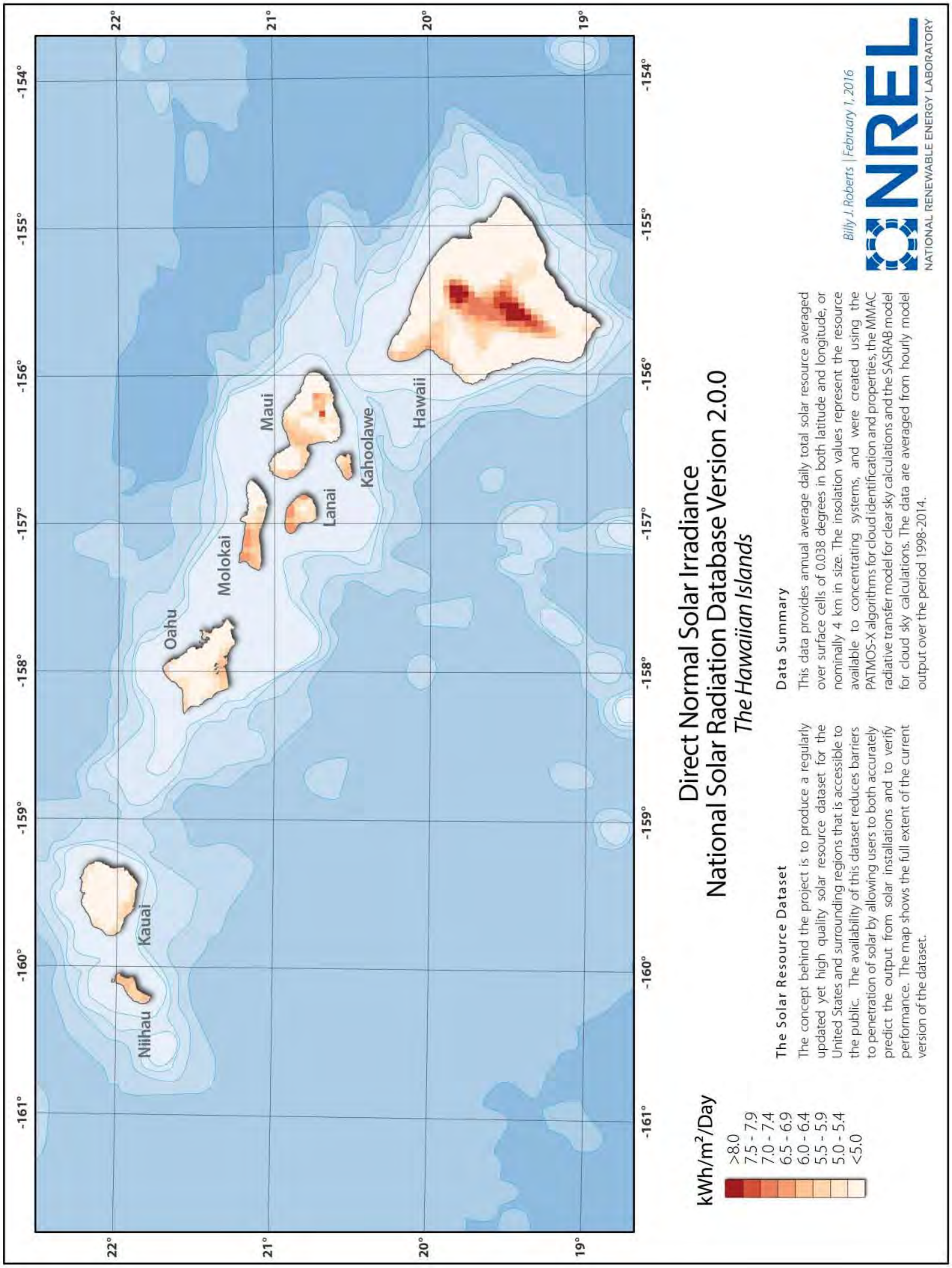


Figure F-23. Direct Normal Irradiance for All Hawaiian Islands

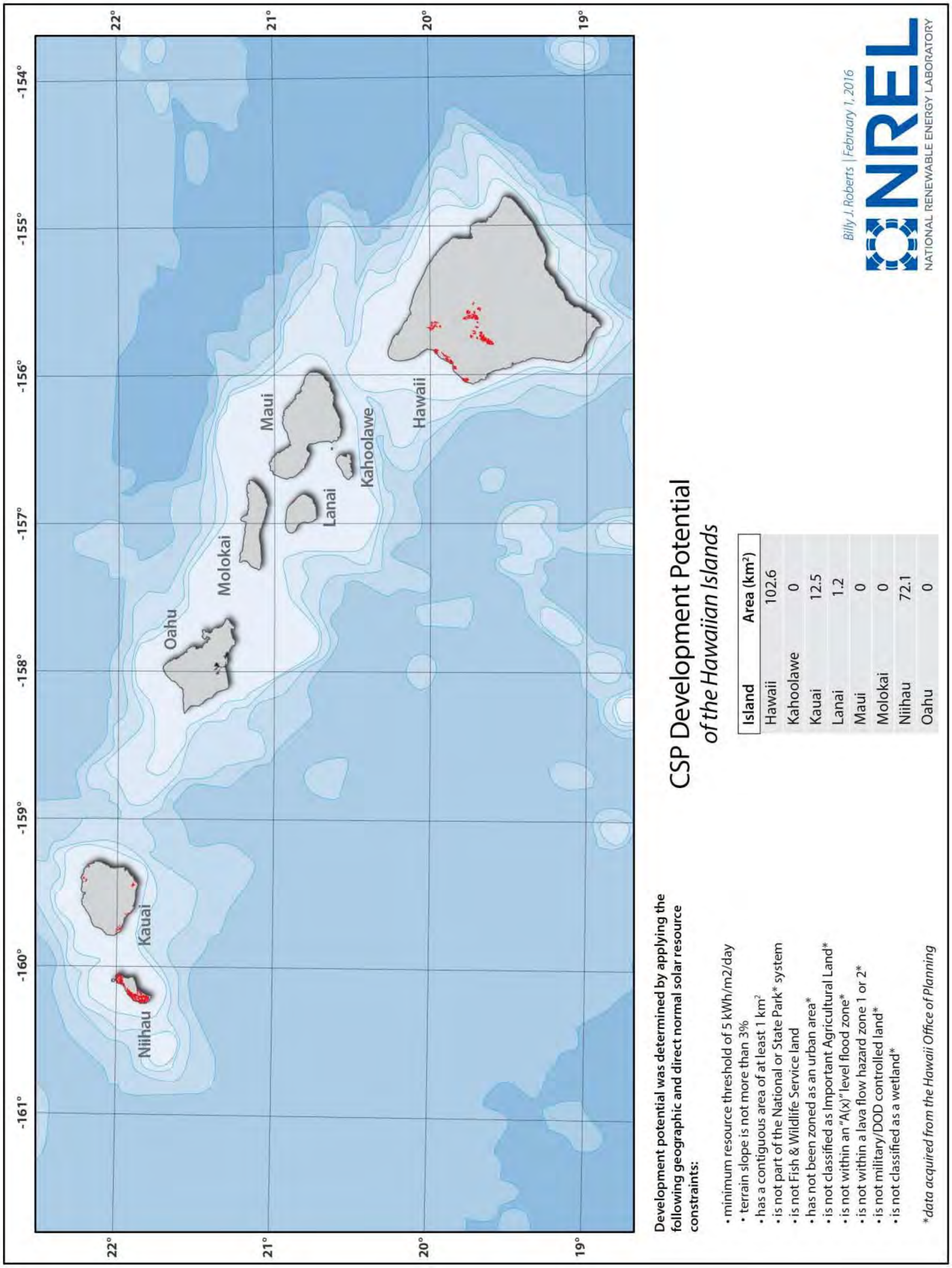


Figure F-24. Concentrated Solar Power Development Potential for All Hawaiian Islands

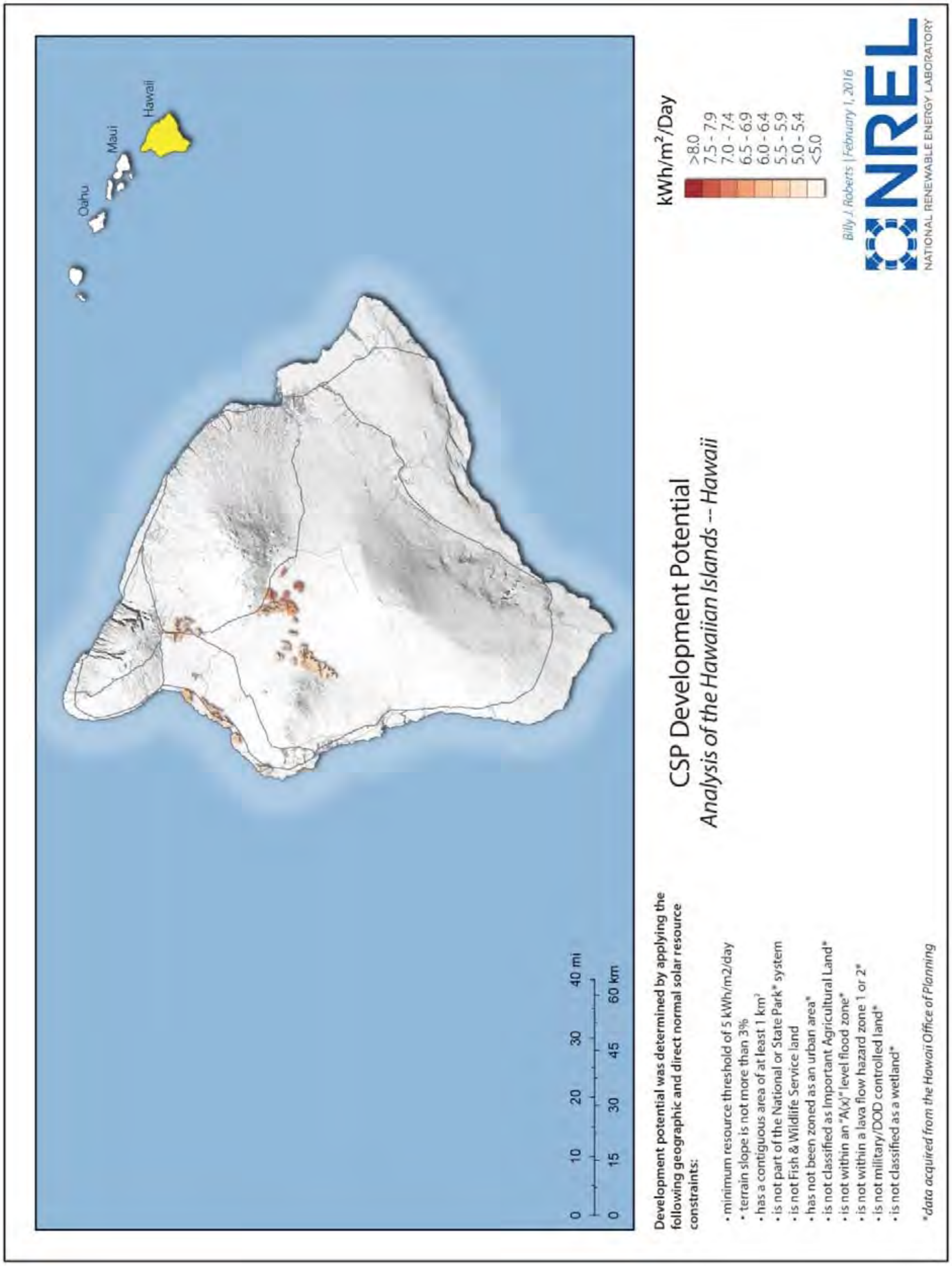


Figure F-25. Concentrated Solar Power Development Potential for Hawai'i Island

Appendix A: System Advisor Model (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 F-9. System Advisor Model (SAM) Parameters

Appendix B: Potential Updates & Differences with other Resource Potential Assessments

The assessment of utility-scale onshore wind, utility-scale PV, and CSP potential resources for Hawai‘i Island, Maui, and O‘ahu presented in this document is dependent on the data and assumption considered in the analysis. As mention in Dr. Hodge’s email of 10/26/2016, the differences between NREL’s analysis and the resource potential assessment performed by Dr. Fripp at the University of Hawaii are mainly due to the different land use availability assumptions.

The utility-scale onshore wind, utility-scale PV, and CSP resource potential assessment presented in this document could be further improved by analyzing every individual potential available site. This would require more detailed local information, such as current land use, ownership details, and potential social opposition.

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.

AGGREGATED WIND POWER PROFILE TIME SERIES

This NREL study produced aggregated hourly, onshore wind power profiles for the Hawaiian Islands. The profiles were calculated at 80-meter and 100-meter hub heights based on wind speeds simulations using the Weather Research and Forecasting (WRF) model. The two simulations used a spatial resolution of 1.5 km square grid, a temporal resolution of one hour, and four 1.94 MW turbines in each grid. The use of two hub heights in the simulations enable a better direct comparison between two onshore wind scenarios. NREL based the wind hourly time series on 2014 data to coincide with the historical load shape used.

The wind power profiles take into account the Agricultural B and C class land exclusions discussed in Analysis 4 of the *Utility-Scale Onshore Wind, Utility-Scale PV, and CSP Potential Resource* study (see page F-13).

While existing renewable energy wind projects use historical recorded data for modeling, future offshore wind projects will use these wind power profiles. Future onshore wind projects will use hourly profiles based on existing wind farms in the specific location that the resource could be added.

The original intent of this study was to develop an improved power profile time series that accounts for the diversity of sites included in the resource potential analysis. However, the analysis averaged all sites (that is, 6.5 meters per second, 7.5 meters per second, and 8.5 meters per second), resulting in capacity factors for Maui and Hawai‘i Island that were significantly lower than existing resources, and capacity factors for O‘ahu that were significantly higher than existing resources. To avoid inaccurately modeling the wind power profile time series for these three islands, we did not use these aggregated wind power profile time series in the December 2016 PSIP update for onshore wind. We did, however, use the aggregated wind power profile time series for O‘ahu for O‘ahu offshore wind.

Aggregated Wind Power Profile Time Series

Caroline Draxl
Ignacio Losada Carreno
Andrew Clifton
Carlo Brancucci Martinez-Anido

This report was prepared by the National Renewable Energy Laboratory and submitted to the Hawaiian Electric Companies via email on July 21, 2016.

Aggregated Wind Power Profile Time Series

Aggregated hourly onshore wind power profile time series are provided for 2 different scenarios for three Hawaiian Islands (Hawaii, Maui, and Oahu) for year 2014:

- 80-meter hub-height
- 100-meter hub-height

The onshore wind power profile time series are calculated from wind speeds (at 80- and 100-meter hub-heights) based on meteorological simulations using the Weather Research and Forecasting (WRF) model with a spatial resolution of 1.5 km x 1.5 km and a temporal resolution of 1 hour.

The two scenarios use the same reference 1.94 MW turbine (NREL, 2014) but at different hub heights. This will allow a better direct comparison between the two onshore wind scenarios. In order to assume a similar wind power density as in the resource assessment report (3 MW/km^2), it is assumed that only a maximum of four 1.94 MW turbines can fit in each grid point (1.5x1.5km), which corresponds to a power density of 3.45 MW/km^2. This number is also closer to the power density assumed in the WIND Toolkit (up to eight 2-MW turbines in a 2x2km cell). In other words, the maximum available land in a 1.5x1.5 km cell is 2.25 km^2 and up to four 1.94 MW wind turbines are allowed. If the available land is less than 2.25 km^2, zero, one, two, or three wind turbines are allowed depending on the available land.

The aggregated and normalized onshore wind power profile time series take into account the land exclusions of Analysis 4 (see NREL's resource assessment conducted during the first phase of this study, "Utility-Scale Onshore Wind, Utility-Scale PV, and CSP Potential Resource"). Only sites with an average wind speed at 80-meter height equal or higher than 6.5 m/s in the REEDS data set (AWS Truepower, 2014) are considered. The sites that form the aggregated and

normalized time series are shown in the onshore wind resource potential maps for Hawaii, Maui, and Oahu in NREL's resource assessment mentioned above.

WRF Modeling

We used the Weather Research and Forecasting (WRF; Skamarock et al., 2008, www.wrf-model.org.) model to simulate wind speeds for Hawaii for the whole year of 2014. The WRF model is a community NWP model maintained by the National Center for Atmospheric Research (NCAR) in the United States. The advantage of a community model is that many users contribute with code updates and experiences, which makes it a well updated tool. It has been successfully applied to wind-energy-related studies and wind resource assessments (e.g., Draxl et al., 2014, Draxl et al., 2012; Draxl et al., 2013; Storm and Basu, 2010; Phadke et al., 2011; Dvorak et al., 2012; Carvalho et al., 2013; Carvalho et al., 2014; Santos-Alamillos et al., 2013; Garcia-Diez et al., 2012; Ji-Hang et al., 2014; Lundquist et al., 2014). The WRF model allows for accurate simulations of winds near the surface and at heights that are important for wind energy purposes. WRF's ability to downscale to required resolutions allows for modelling small-scale features, such as fronts, sea breezes, or winds influenced by orography, which are all important factors in describing the wind characteristics over Hawaii.

For this project, data were simulated over Hawai'i at multiple heights at a hourly temporal resolution. To achieve a high resolution of 1.5 km, data were downscaled from the Climate Forecast System Re-analyses from the National Center for Environmental Predictions (NCEP), using three modeling domains. The outermost domain has a grid spacing of 37.5 km, and the two inner domains have a 7.5 km and 1.5 km grid spacing (Figure F-26). Sea Surface Temperatures from NCEP were also used as boundary conditions to improve the simulations. The model was restarted every day at 12 UTC, and the first 12 hours were discarded due to model spin up. Data were linearly interpolated to hub heights of 80 and 100m.

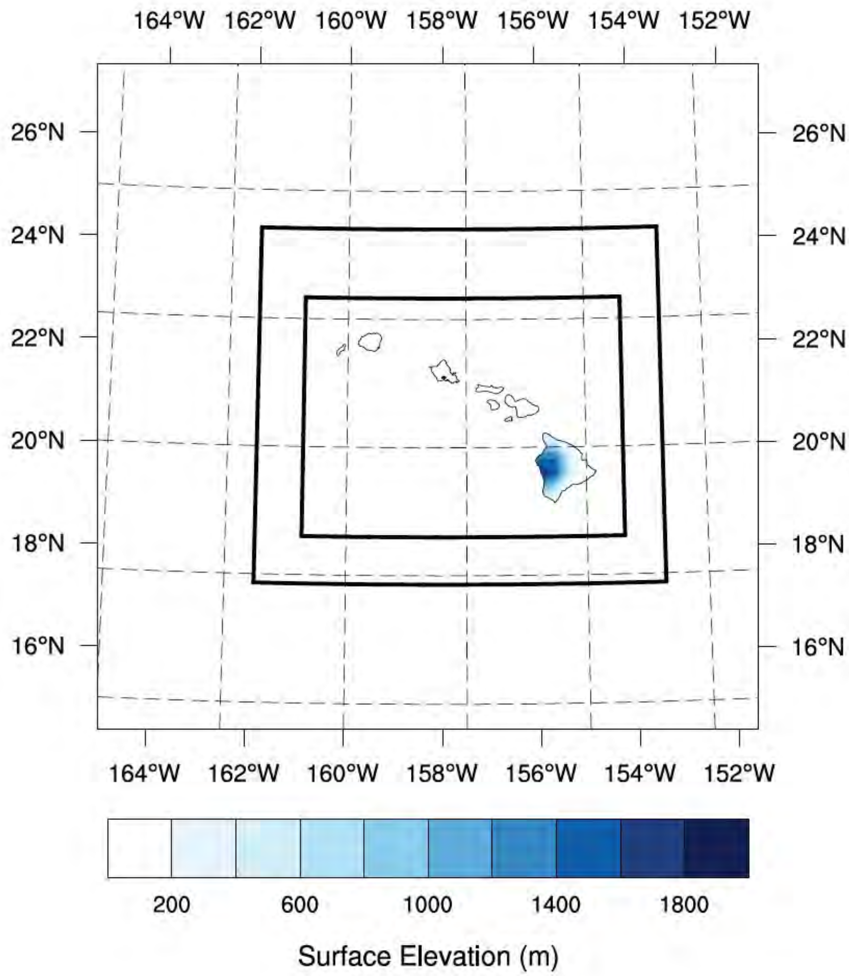


Figure F-26. Weather Research and Forecasting Modeling Domains Over Hawai'i

Hawai'i being a chain of islands in the middle of the Pacific, it is exposed to occasionally high winds in excess of 30 m/s, especially on or near mountain tops or mountain passes. Because of the variations in the terrain, wind speeds can vary from one location to the next. Specifically, in the year 2014, the Hawaiian Islands were hit by two hurricanes, one in August and one in October. Figure F-27 shows snapshots of the U and V wind components during the October hurricane on October 19 as an example of how the WRF model is able to simulate extreme weather. Figure F-28 shows precipitation during the same time.

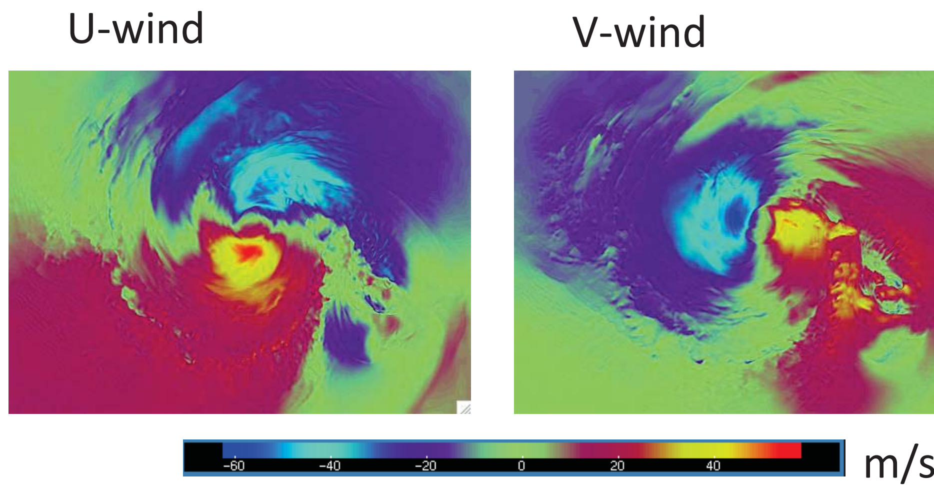


Figure F-27. U and V Wind Component from WRF Simulations on October 19, 2014 at 90 Meters Over the Hawaiian Islands

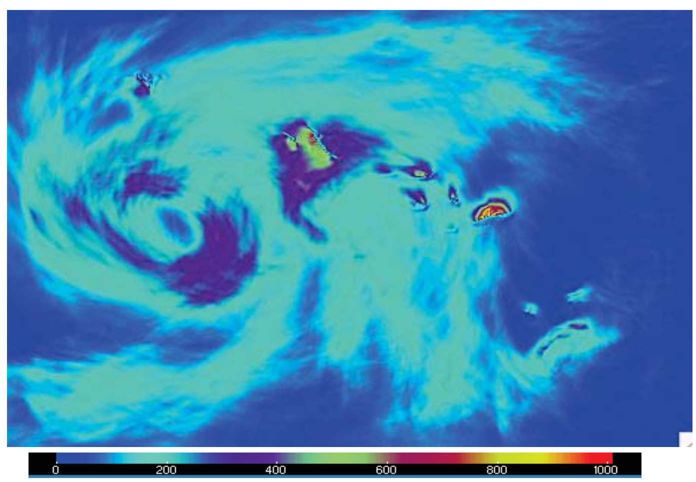


Figure F-28. Precipitation Over the Hawaiian Islands at a Specific Time on October 19, 2014 (mm of precipitation)

References

AWS Truepower, LLC, NREL REEDS LICENSED DATASETS AND USER'S GUIDE, November 5, 2014.

Carvalho, D.; Rocha, A.; Gómez-Gesteira, M.; Silva Santos, C. (2014). WRF wind simulation and wind energy production estimates forced by different reanalyses: Comparison with observed data for Portugal. *Applied Energy*, 01/2014, 117, 116–126.

Carvalho, D.; Rocha, A.; Silva Santos, C.; Pereira, R. (2013). Wind resource modelling in complex terrain using different mesoscale–microscale coupling techniques. *Applied Energy*, 2013, vol. 108, issue C, pages 493–504.

Dvorak, M.J.; Corcoran, B. A.; Hoeve, J.E.T.; McIntyre, N.G.; Jacobson, M.Z. (2012). US East Coast offshore wind energy resources and their relationship to peak-time electricity demand. *Wind Energy*, 16, 977–997. doi: 10.1002/we.1524.

Delle Monache, L.; Eckel, T.; Rife, D.; Nagarajan, B. (2013). Probabilistic weather prediction with an analog ensemble. *Monthly Weather Review*, 141, 3498–3516.

Draxl,C; Purkayastha, A; Parker, Z. (2014). *Wind Resource Assessment of Gujarat (India).* National Renewable Energy Laboratory, Golden, CO. USA. NREL/TP-5000-61741.

Draxl, C.; Hodge, B.M.; Orwig, K.; Jones, W.; Searight, K.; Getman, D.; Harrold, S.; McCaa, J.; Cline, J.; Clark, C. (2013). *Advancements in Wind Integration Study Data Modeling: The Wind Integration National Dataset (WIND) Toolkit*. National Renewable Energy Laboratory, Golden, CO. USA. NREL/CP-5D00-60269.

Draxl, C.; Hahmann, A.N.; Peña, A.; Giebel, G. (2012). Evaluating winds and vertical wind shear from Weather Research and Forecasting model forecasts using seven planetary boundary layer schemes. *Wind Energy*. doi: 10.1002/we.1555.

Garcia-Diez, M.; Fernandez, J.; Fita, L.; Menendez, M.; Mendez, F.J.; Gutierrez, J.M. (2012). Using WRF to generate high resolution offshore wind climatologies. *8º Congreso Internacional AEC*, Salamanca, Spain, Sep. 2012. Proceedings.

LI Ji-Hang; GUO Zhen-Hai; WANG Hui-Jun (2014). Analysis of wind power assessment based on the WRF model. *Atmospheric and Oceanic Science Letters*, 7(2): 126–131.

Lundquist et al (2014). Estimating the wind resource in Uttarakhand: comparison of dynamic downscaling with Doppler lidar wind measurements. NREL Technical report NREL/TP-5000-61103.

NREL, 2014 Cost of Wind Energy Review, October 2015. http://www.nrel.gov/docs/fy16osti/64281.pdf

Santos-Alamillos, F. J.; Pozo-Vázquez, D.; Ruiz-Arias, J. A.; Lara-Fanego, V.; Tovar-Pescador, J. (2013). Analysis of WRF model wind estimate sensitivity to physics parameterization choice and terrain representation in Andalusia (Southern Spain). *J. Appl. Meteor. Climatol.*, 52, 1592–1609. doi: http://dx.doi.org/10.1175/JAMC-D-12-0204.1.

Skamarock, W.C.; Klemp, J.B.; Dudhia, J.; Gill, D.O.; Barker, D.M.; Duda, M.G.; Huang, X.Y.; Wang, W.; Powers, J.G. (2008). *A description of the Advanced Research WRF Version 3*. NCAR Tech Notes-475+STR. Boulder, CO: National Center for Atmospheric Research.

Storm, B.; Basu, S. (2010). The WRF Model forecast-derived low-level wind shear climatology over the United States Great Plains. *Energies*, 3, 258–276. doi:10.3390/en3020258.

AGGREGATED SOLAR POWER PROFILE TIME SERIES

This NREL study produced aggregated hourly solar power time series profiles for the Hawaiian Islands. The next page lists the eight different axis-tracking scenarios analyzed—four for all available sites and four for selected sites based on our request—for O‘ahu, Maui, and Hawai‘i Island.

NREL derived these time series profiles using NREL’s mean solar radiation data compiled from 1998 to 2014. The solar radiation data used a spatial resolution of a four-kilometer square grid (four km x four km) with temporal resolution of 30 minutes. NREL based the solar hourly time series on 2014 data to coincide with the historical load shape used.

While existing renewable energy solar projects use historical recorded data for modeling, all future grid-scale solar projects will use these NREL power profile time series.

The December PSIP Update modeling, to the extent feasible, used this NREL data in our analysis to best analyze potential resource options.

Aggregated Solar Power Profile Time Series

Aron Habte
Ignacio Losada Carreno
Billy Roberts
Carlo Brancucci Martinez-Anido

This report was prepared by the National Renewable Energy Laboratory and submitted to the Hawaiian Electric Companies via email on July 12, 2016.

Aggregated Solar Power Profile Time Series

Aggregated normalized hourly solar power profile time series values are provided in ac-energy/ac-capacity terms as requested by HECO) are provided for 8 different scenarios for three Hawaiian Islands Hawaii, Maui, and Oahu) for year 2014 as well as for 16 different years (1998-2013):

- All available sites
  - Fixed tilt (20°), DC/AC   1.2
  - Fixed tilt (20°), DC/AC   1.5
  - Single-axis tracking, DC/AC = 1.2
  - Single-axis tracking, DC/AC = 1.5
- Selected available sites based on HECO's requests
  - Fixed tilt (20°), DC/AC   1.2
  - Fixed tilt (20°), DC/AC   1.5
  - Single-axis tracking, DC/AC = 1.2
  - Single-axis tracking, DC/AC = 1.5

The aggregated time series for each scenario for each of the three islands are provided in the file "Solar_Power_Time_Series.zip". The file also includes the coordinates of all the available for each island as well as the selected ones based on HECO's requests.

Mean solar radiation data over the years 1998 to 2014 was taken from the latest National Solar Radiation Database (NSRDB) [1-3] which has a spatial resolution of 4 km x 4 km and a temporal resolution of 30 minutes. 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. The System Advisor Model (SAM) [4] was used to attain solar power profile time series. SAM is a performance and

financial model which makes performance predictions for grid-connected power projects based on parameters specified by the user [5].

The aggregated solar power profile time series take into account the land exclusions of Analysis 4 (see NREL's resource assessment conducted during the first phase of this study, "Utility-Scale Onshore Wind, Utility-Scale PV, and CSP Potential Resource") with a maximum slope of 5%. The capacity-weighted average land use for a fixed tilt small PV plant was taken to be 7.6 acres/MWac, while for a 1-axis small PV plant was taken to be 8.7 acres/MWac [6].

Solar Resource Inter-Annual Variability Analysis

The inter-annual solar resource variability analysis for each island differs depending on the scenario. The next three sections provide tables and figures comparing the solar resource variability between 17 years (1998-2014) for each island for different scenarios.

For all figures (Figure F-29 through Figure F-52) all use a DC/AC= 1.2 conversion factor.

3.1 Hawai'i Island

Year	All sites				Selected sites			
	1-axis tracking		Fixed tilt (20°)		1-axis tracking		Fixed tilt (20°)	
	DC/AC = 1.2	DC/AC = 1.5	DC/AC = 1.2	DC/AC = 1.5	DC/AC = 1.2	DC/AC = 1.5	DC/AC = 1.2	DC/AC = 1.5
1998	0.219	0.267	0.183	0.226	0.257	0.311	0.208	0.256
1999	0.221	0.268	0.183	0.226	0.261	0.315	0.211	0.259
2000	0.229	0.279	0.191	0.236	0.265	0.323	0.217	0.267
2001	0.228	0.278	0.190	0.235	0.261	0.317	0.212	0.262
2002	0.224	0.275	0.188	0.233	0.255	0.312	0.210	0.259
2003	0.234	0.287	0.194	0.240	0.265	0.322	0.214	0.264
2004	0.227	0.278	0.187	0.232	0.251	0.307	0.204	0.253
2005	0.230	0.281	0.191	0.236	0.261	0.317	0.211	0.261
2006	0.215	0.264	0.180	0.223	0.249	0.304	0.203	0.251
2007	0.225	0.274	0.185	0.229	0.255	0.309	0.205	0.253
2008	0.224	0.274	0.186	0.230	0.246	0.299	0.200	0.247
2009	0.215	0.265	0.181	0.224	0.248	0.304	0.203	0.251
2010	0.233	0.284	0.193	0.238	0.265	0.320	0.213	0.262
2011	0.217	0.266	0.182	0.225	0.245	0.300	0.201	0.249
2012	0.219	0.268	0.183	0.226	0.253	0.307	0.205	0.252
2013	0.222	0.271	0.183	0.227	0.250	0.304	0.202	0.250
2014	0.224	0.275	0.185	0.230	0.246	0.300	0.200	0.248
Average (1998-2014	0.224	0.274	0.186	0.230	0.255	0.310	0.207	0.256

Table F-10. Capacity Factor for Each Scenario and Each Year: Hawai'i Island

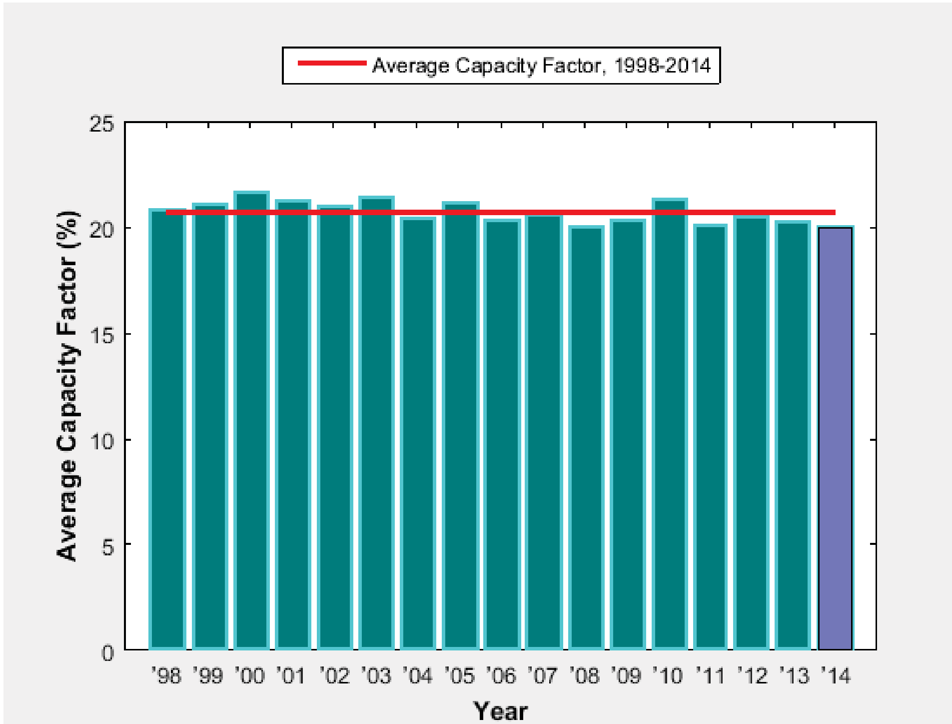


Figure F-29. Average Capacity Factor (selected sites, fixed tilt): Hawai‘i Island

Figure F-30. Average Capacity Factor (selected sites, one-axis tracking): Hawai‘i Island

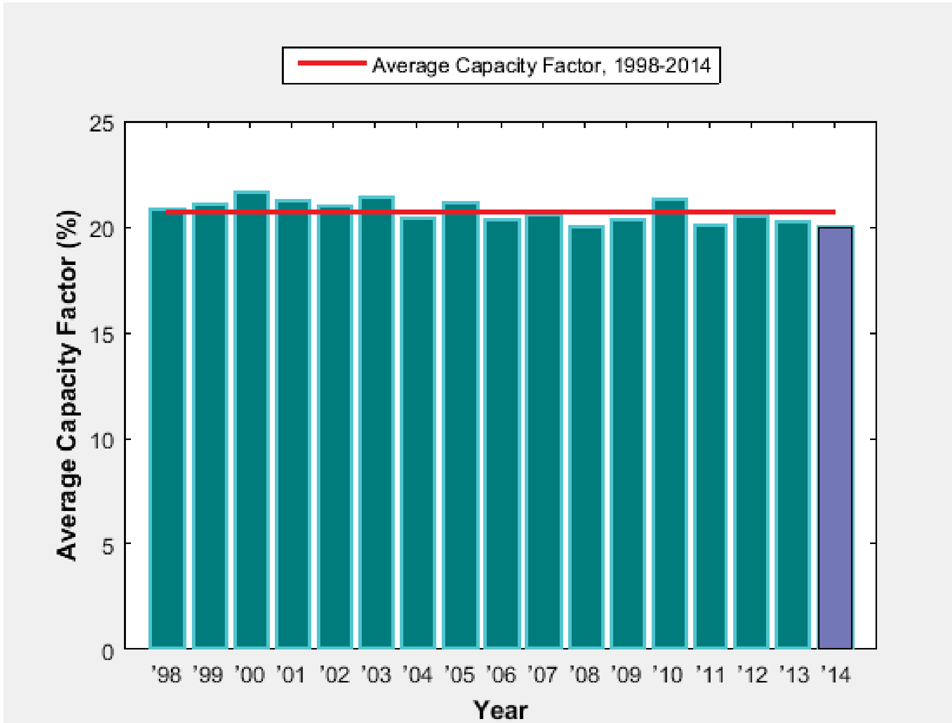


Figure F-31. Average Capacity Factor (all sites, fixed tilt): Hawai'i Island

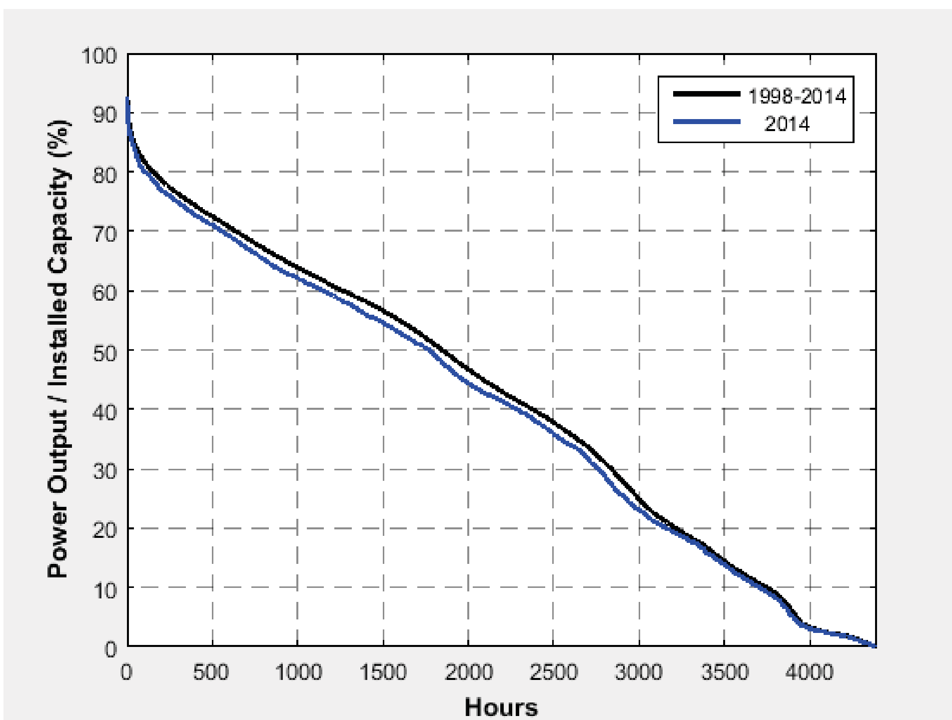


Figure F-32. Load Duration Curve—Power Output/Installed Capacity (selected sites, fixed-tilt): Hawai'i Island

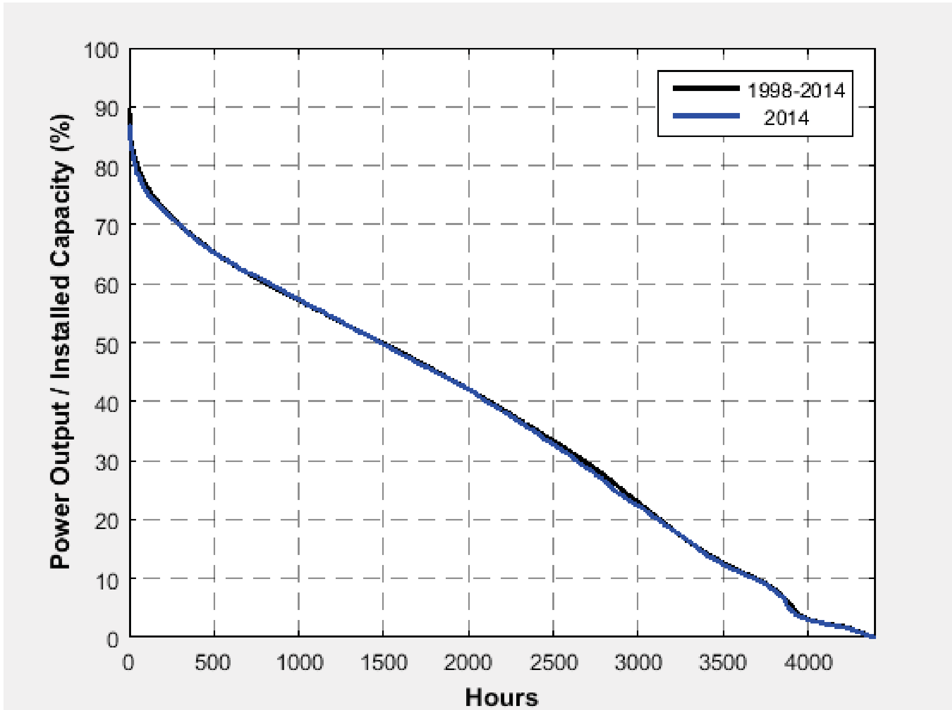


Figure F-33. Load Duration Curve—Power Output/Installed Capacity (all sites, fixed-tilt): Hawai‘i Island

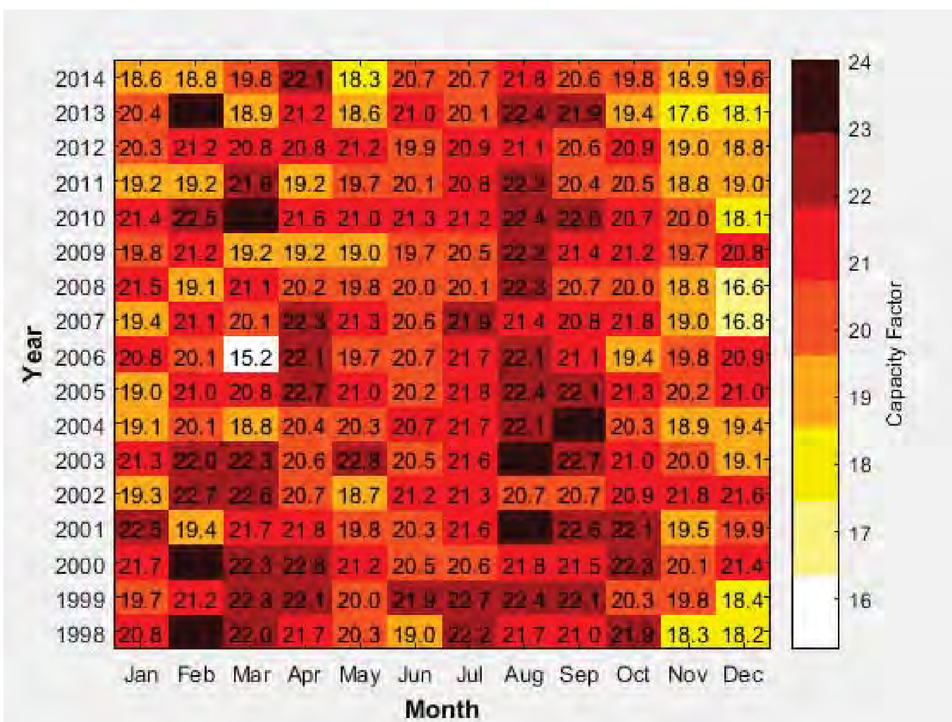


Figure F-34. Heat Map of Average Capacity Factor (selected sites, fixed tilt): Hawai‘i Island

Hawaiian Electric
Maui Electric
Hawai‘i Electric Light

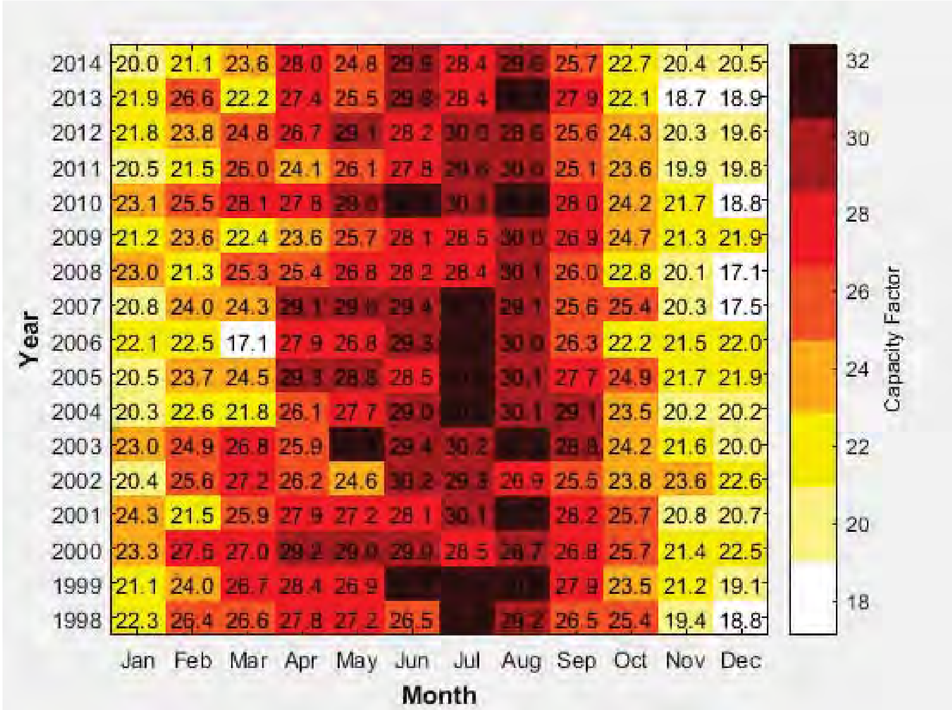


Figure F-35. Heat Map of Average Capacity Factor (selected sites, one-axis tracking): Hawai'i Island

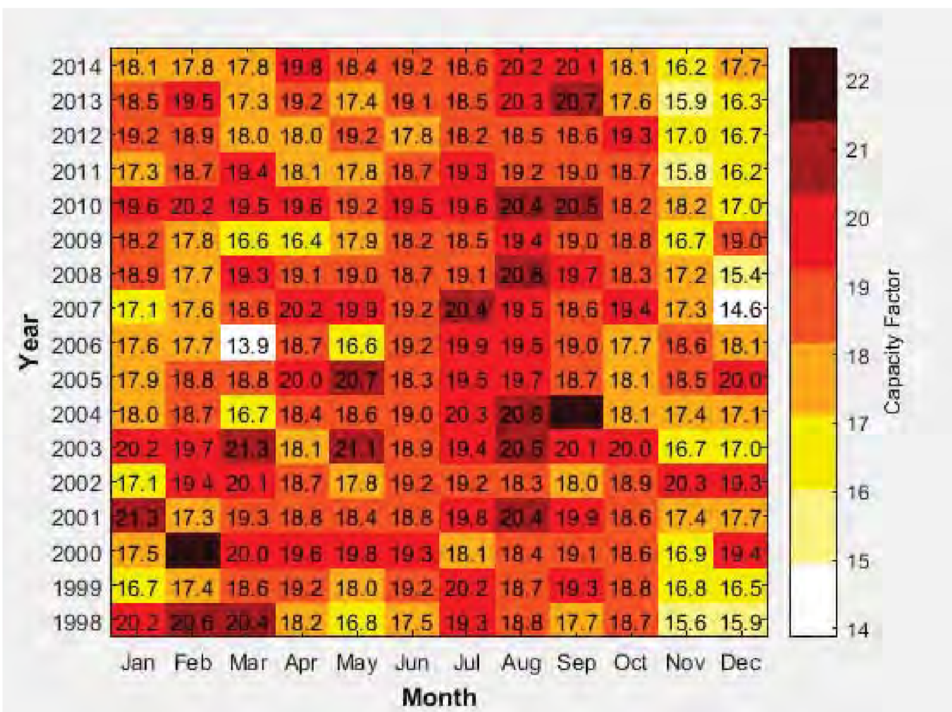


Figure F-36. Heat Map of Average Capacity Factor (all sites, fixed tilt): Hawai'i Island

3.2 Maui

Year	All sites				Selected sites			
	1-axis tracking		Fixed tilt (20°)		1-axis tracking		Fixed tilt (20°)	
	DC/AC = 1.2	DC/AC = 1.5	DC/AC = 1.2	DC/AC = 1.5	DC/AC = 1.2	DC/AC = 1.5	DC/AC = 1.2	DC/AC = 1.5
1998	0.260	0.317	0.211	0.261	0.279	0.340	0.224	0.276
1999	0.272	0.330	0.219	0.270	0.284	0.345	0.226	0.279
2000	0.273	0.334	0.222	0.274	0.286	0.349	0.229	0.283
2001	0.267	0.327	0.218	0.269	0.281	0.343	0.226	0.280
2002	0.259	0.319	0.213	0.264	0.270	0.332	0.220	0.272
2003	0.271	0.331	0.219	0.270	0.283	0.345	0.226	0.279
2004	0.263	0.321	0.211	0.262	0.271	0.332	0.217	0.269
2005	0.270	0.329	0.218	0.269	0.280	0.342	0.224	0.277
2006	0.257	0.314	0.209	0.259	0.273	0.333	0.219	0.271
2007	0.258	0.316	0.209	0.258	0.275	0.336	0.219	0.271
2008	0.259	0.317	0.209	0.259	0.272	0.332	0.217	0.269
2009	0.257	0.316	0.210	0.260	0.273	0.335	0.220	0.273
2010	0.268	0.326	0.215	0.266	0.285	0.347	0.226	0.279
2011	0.253	0.310	0.208	0.257	0.268	0.328	0.217	0.269
2012	0.266	0.324	0.214	0.264	0.281	0.342	0.224	0.277
2013	0.263	0.321	0.213	0.263	0.275	0.337	0.221	0.273
2014	0.260	0.318	0.209	0.260	0.268	0.328	0.215	0.267
Average (1998-2014	0.263	0.322	0.213	0.264	0.277	0.338	0.222	0.274

Table F-11. Capacity Factor for Each Scenario and Each Year: Maui

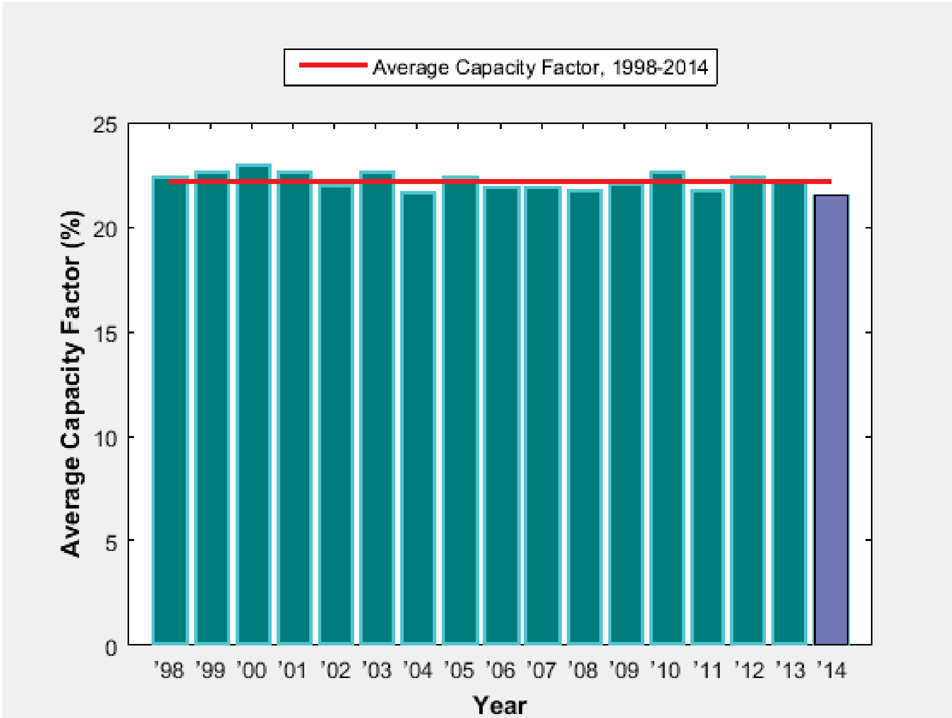


Figure F-37. Average Capacity Factor (selected sites, fixed tilt): Maui

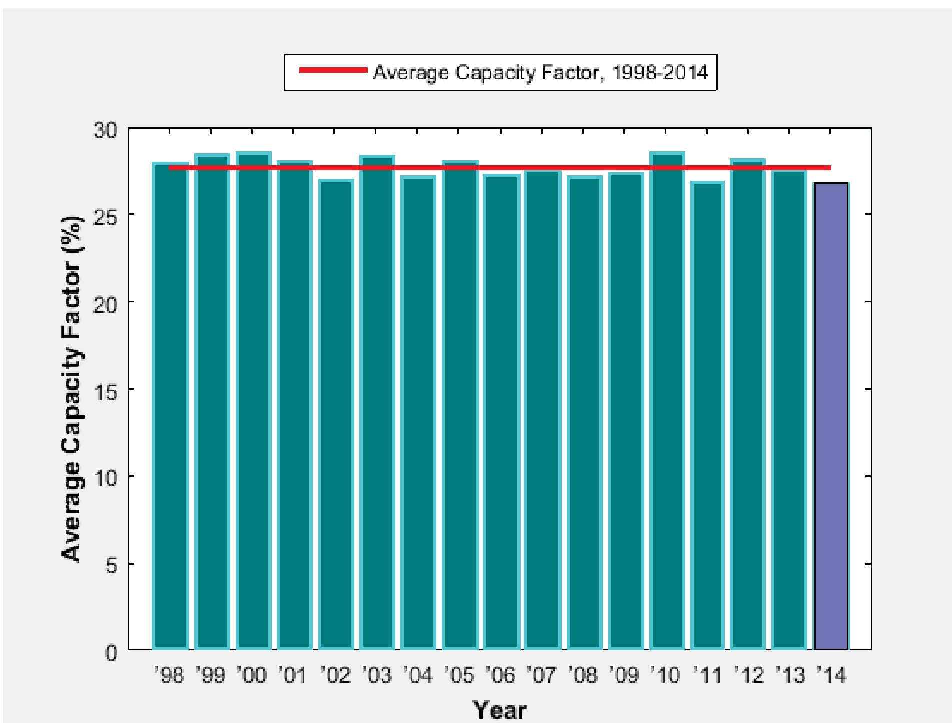


Figure F-38. Average Capacity Factor (selected sites, one-axis tracking): Maui

Figure F-39. Average Capacity Factor (all sites, fixed tilt): Maui

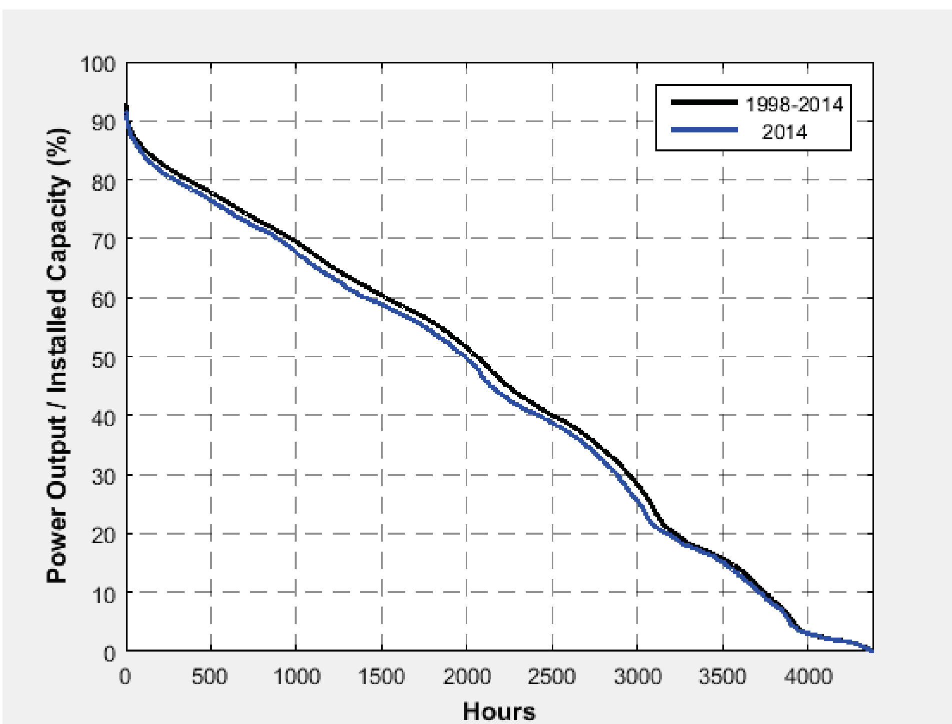


Figure F-40. Load Duration Curve—Power Output/Installed Capacity (selected sites, fixed-tilt): Maui

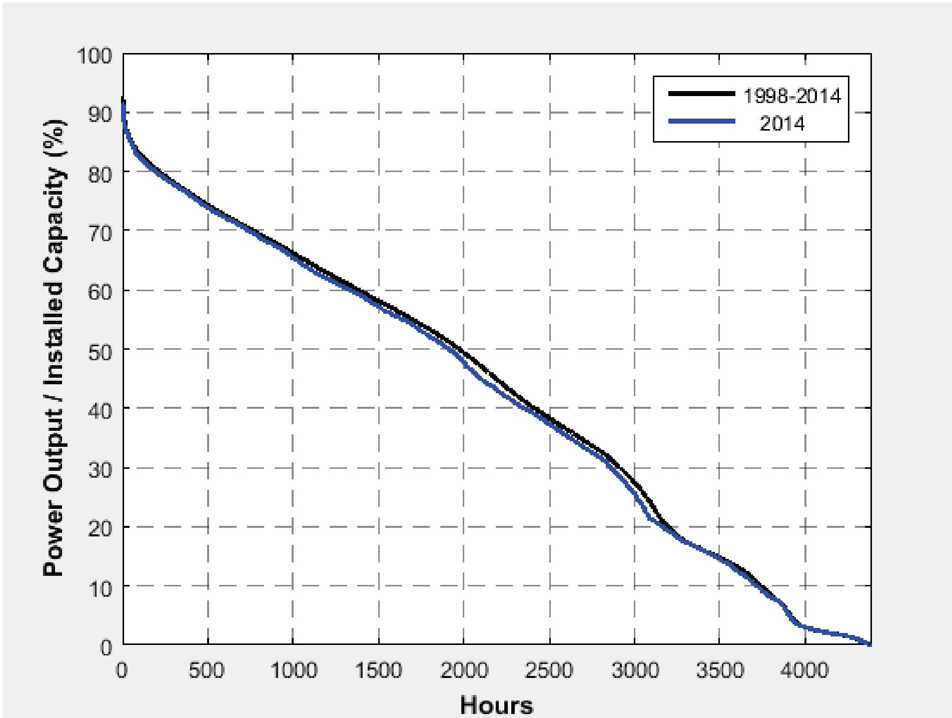


Figure F-41. Load Duration Curve—Power Output/Installed Capacity (all sites, fixed-tilt): Maui

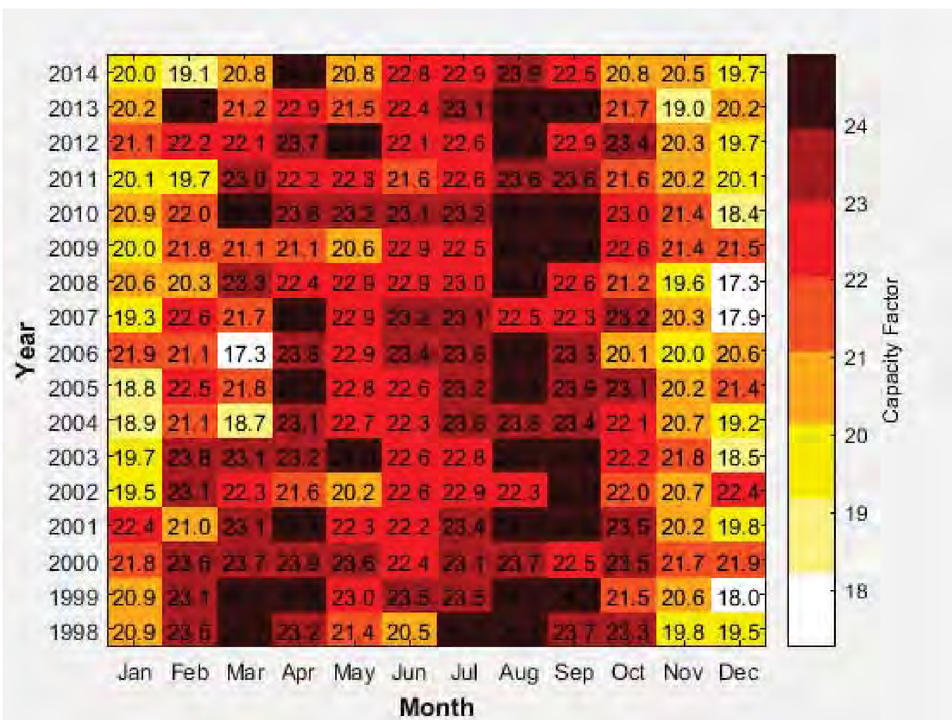


Figure F-42. Heat Map of Average Capacity Factor (selected sites, fixed tilt): Maui

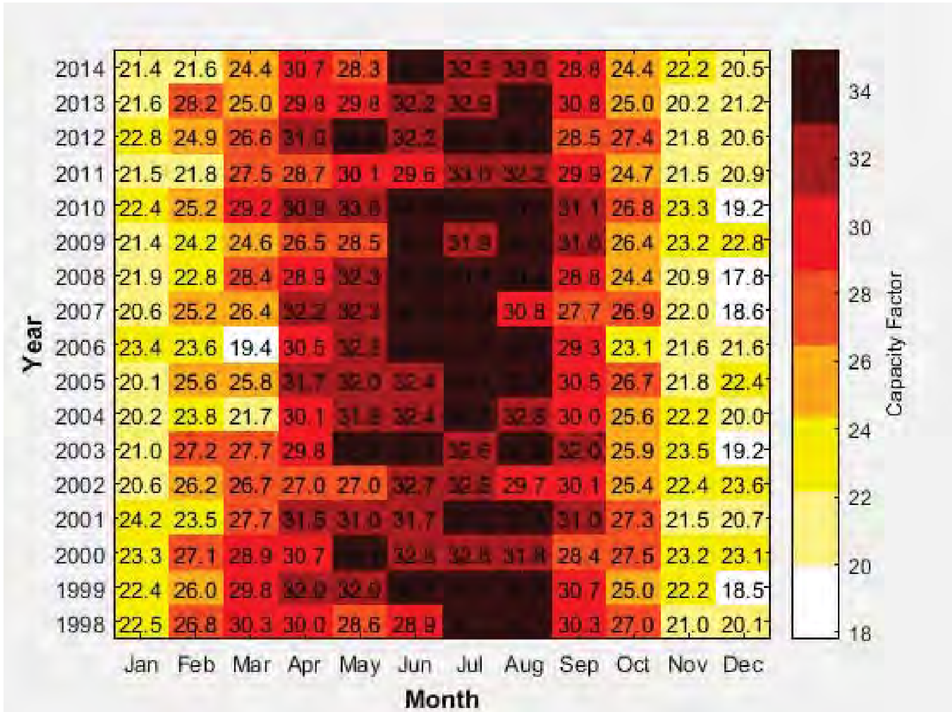


Figure F-43. Heat Map of Average Capacity Factor (selected sites, one-axis tracking): Maui

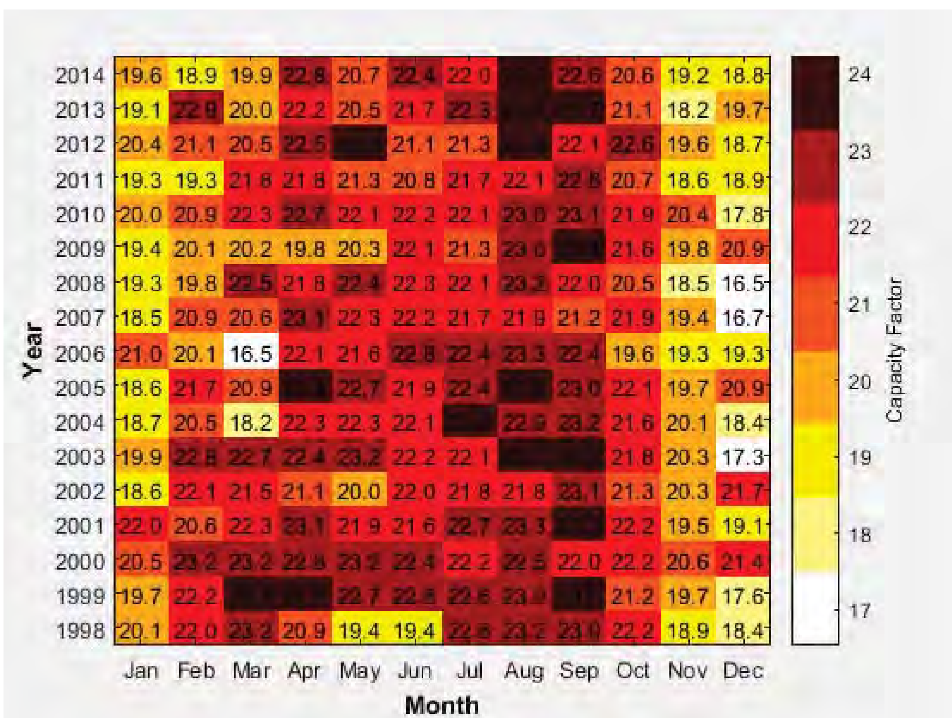


Figure F-44. Heat Map of Average Capacity Factor (all sites, fixed tilt): Maui

Hawaiian Electric
Maui Electric
Hawai'i Electric Light

3.3 O‘ahu

Year	All sites				Selected sites			
	1-axis tracking		Fixed tilt (20°)		1-axis tracking		Fixed tilt (20°)	
	DC/AC = 1.2	DC/AC = 1.5	DC/AC = 1.2	DC/AC = 1.5	DC/AC = 1.2	DC/AC = 1.5	DC/AC = 1.2	DC/AC = 1.5
1998	0.233	0.286	0.190	0.236	0.233	0.286	0.190	0.236
1999	0.234	0.286	0.191	0.236	0.234	0.286	0.191	0.236
2000	0.246	0.301	0.200	0.247	0.246	0.301	0.200	0.247
2001	0.241	0.296	0.197	0.244	0.241	0.296	0.197	0.244
2002	0.242	0.298	0.199	0.247	0.242	0.298	0.199	0.247
2003	0.246	0.302	0.199	0.247	0.246	0.302	0.199	0.247
2004	0.242	0.297	0.196	0.243	0.242	0.297	0.196	0.243
2005	0.250	0.306	0.202	0.251	0.250	0.306	0.202	0.251
2006	0.237	0.290	0.193	0.239	0.237	0.290	0.193	0.239
2007	0.252	0.309	0.203	0.252	0.252	0.309	0.203	0.252
2008	0.244	0.299	0.197	0.245	0.244	0.299	0.197	0.245
2009	0.251	0.308	0.204	0.254	0.251	0.308	0.204	0.254
2010	0.246	0.301	0.200	0.247	0.246	0.301	0.200	0.247
2011	0.245	0.301	0.201	0.249	0.245	0.301	0.201	0.249
2012	0.240	0.294	0.195	0.242	0.240	0.294	0.195	0.242
2013	0.242	0.297	0.197	0.243	0.242	0.297	0.197	0.243
2014	0.245	0.300	0.198	0.246	0.245	0.300	0.198	0.246
Average (1998-2014	0.243	0.298	0.198	0.245	0.243	0.298	0.198	0.245

Table F-12. Capacity Factor for Each Scenario and Each Year: O‘ahu

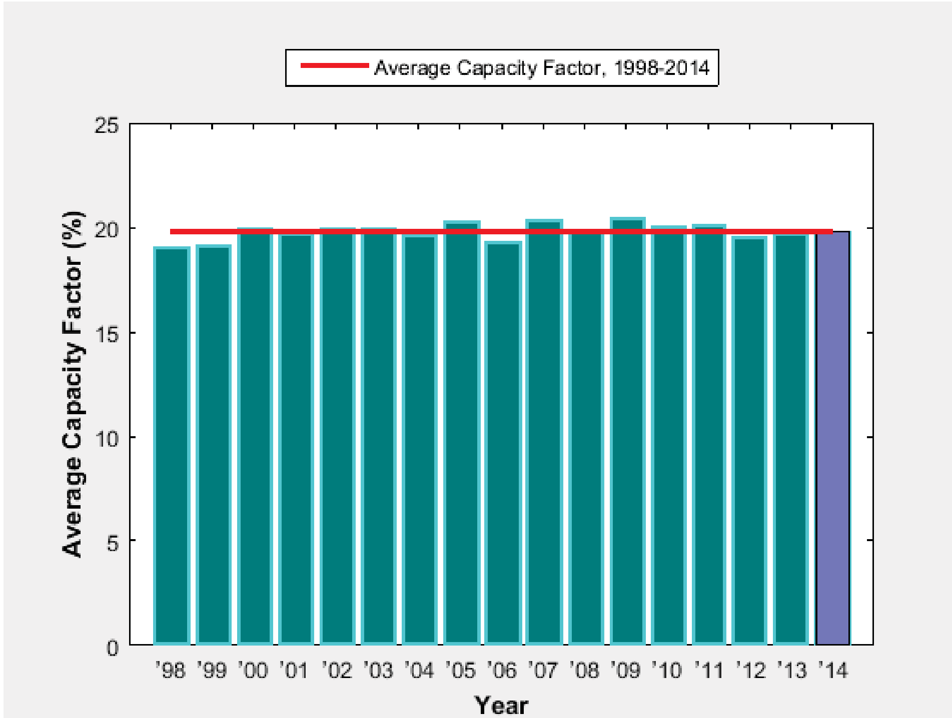


Figure F-45. Average Capacity Factor (selected sites, fixed tilt): O'ahu

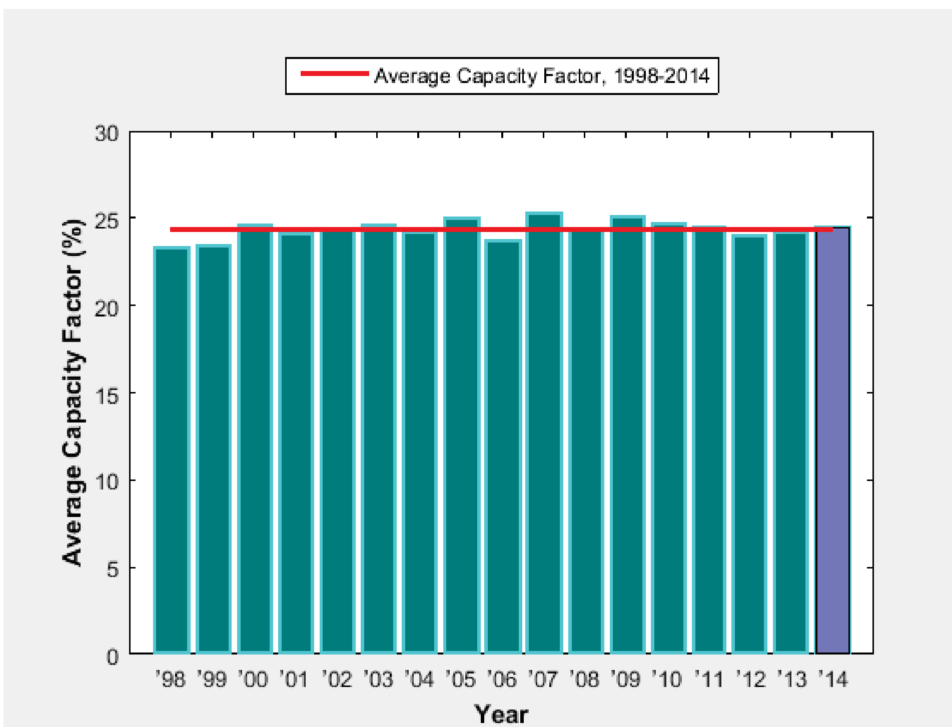


Figure F-46. Average Capacity Factor (selected sites, one-axis tracking): O'ahu

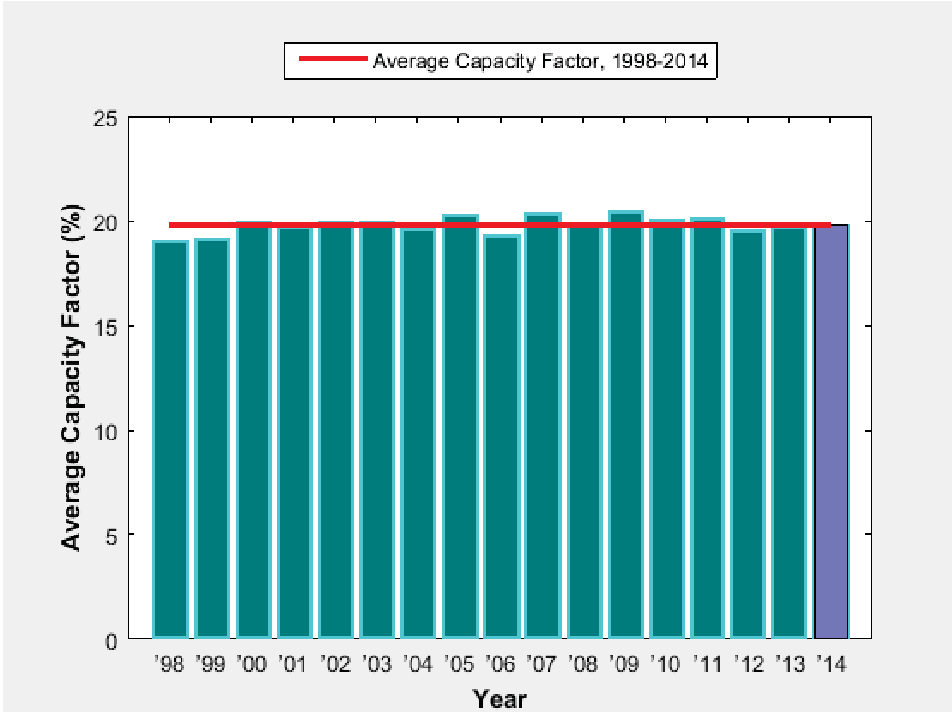


Figure F-47. Average Capacity Factor (all sites, fixed tilt): O'ahu

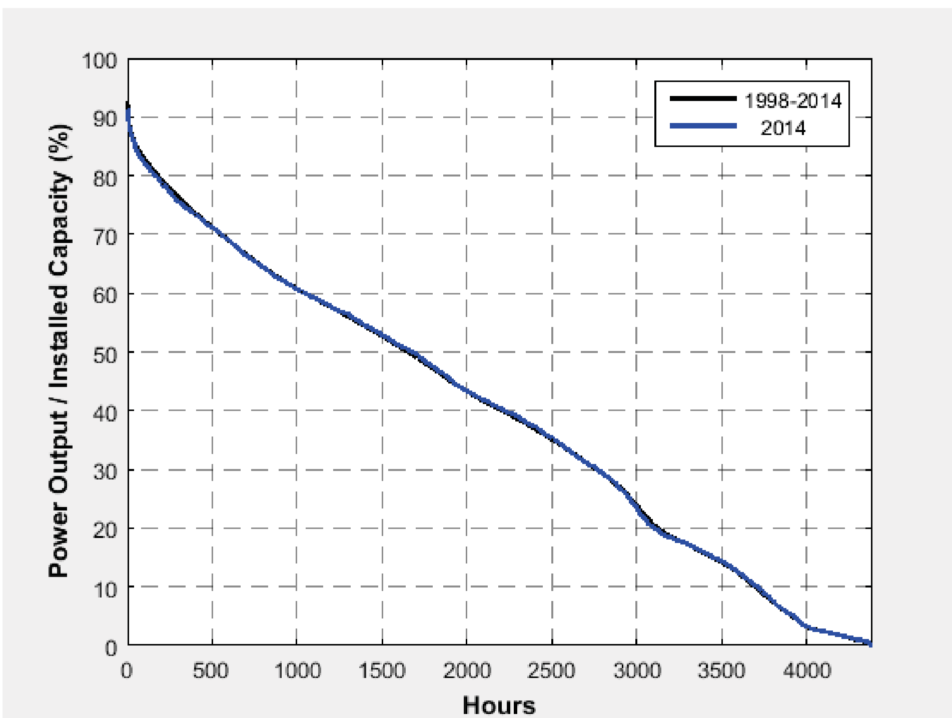


Figure F-48. Load Duration Curve—Power Output/Installed Capacity (selected sites, fixed-tilt): O'ahu

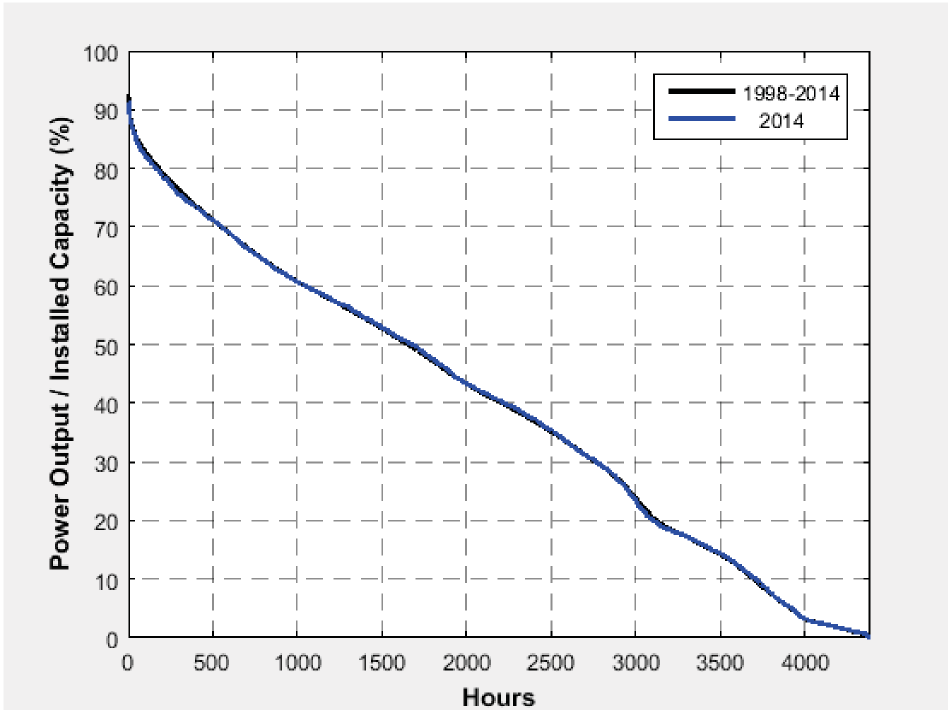


Figure F-49. Load Duration Curve—Power Output/Installed Capacity (all sites, fixed-tilt): O‘ahu

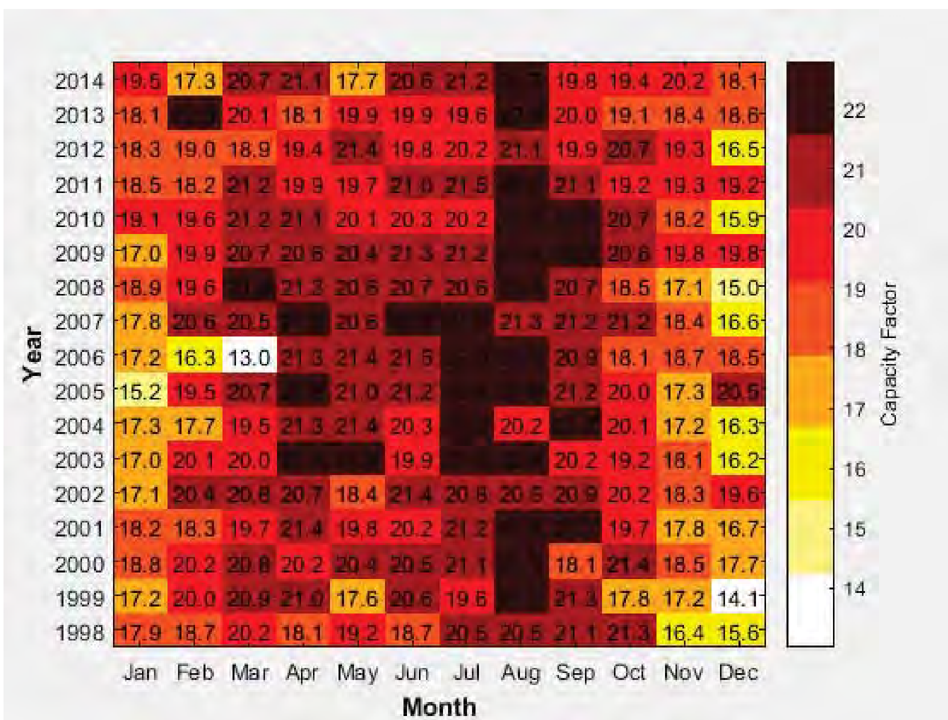


Figure F-50. Heat Map of Average Capacity Factor (selected sites, fixed tilt): O‘ahu

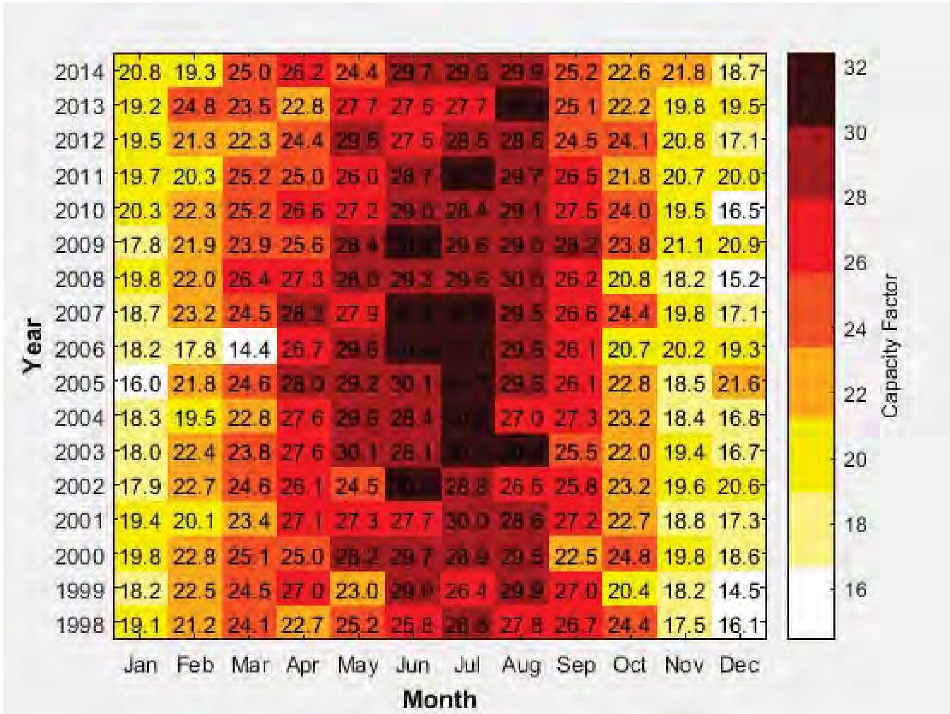


Figure F-51. Heat Map of Average Capacity Factor (selected sites, one-axis tracking): O'ahu

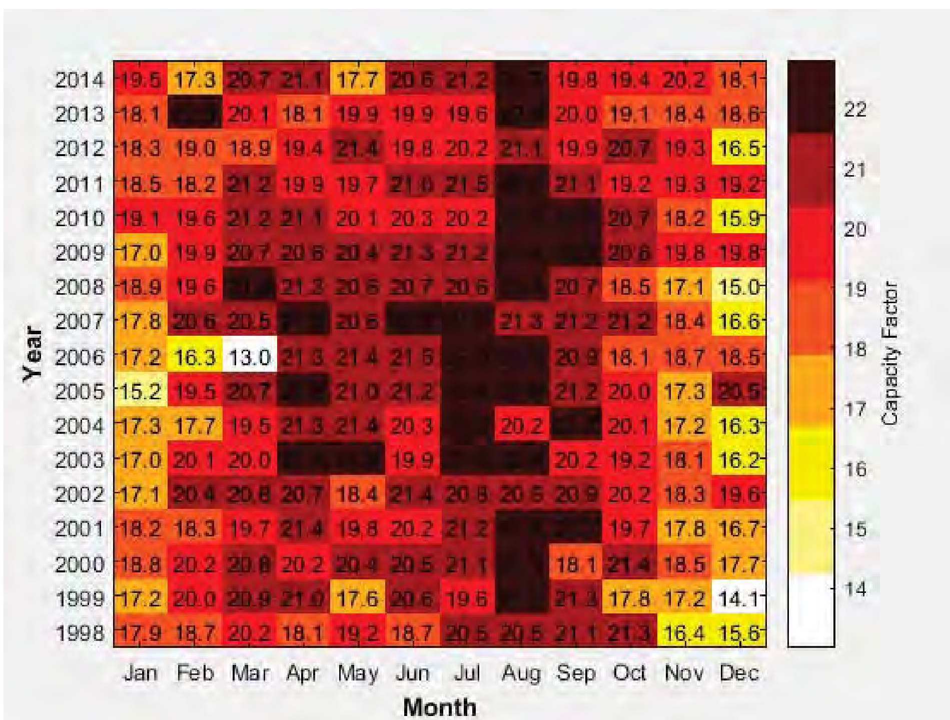


Figure F-52. Heat Map of Average Capacity Factor (all sites, fixed tilt): O'ahu

References

[1] National Solar Radiation Database (NSRDB), https://nsrdb.nrel.gov

[2] Sengupta, .; Habte, A.; Gotseff, P.; Weekley, A.; opez, A.; Anderberg, .; olling, C.; Heidinger, A. (2014). "Physics-Based GOES Product for Use in NREL's National Solar Radiation Database: Preprint." 6 pp. NREL/CP-5D00-62776.

[3] Sengupta, .; Habte, A.; Gotseff, P.; Weekley, A.; opez, A.; Mol ing, C.; Heidinger, A. (2014). "Physics-Based GOES Satellite Product for Use in NRE 's National Solar Radiation Database: Preprint." 9 pp.; NREL/CP-5D00-62237

[4] System Advisor odel, SAM 2014.1.14: General Description, National Renewable Energy Laboratory, Technical Report No. NREL/TP-6A20-61019.

[5] PVWatts Version 5 Manual, National Renewable Energy Laboratory, September 4, 2014.

[6] Land-Use Requirements for Solar Power Plants in the United States, National Renewable Energy Laboratory, Technical Report No. NRE /TP-6A20-56290, June 2013.

[7] 2014 Cost of Wind Energy Review, National Renewable Energy Laboratory, October 2015. http://www.nrel.gov/docs/fy16osti/64281.pdf

[8] AWS Truepower, C, NREL REEDS CEN SED DATASETS AND USER'S GUIDE, November 5, 2014.

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 also reviewed onshore wind, offshore wind, grid-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, Hawai'i. These same values were used by HECO in their 2014 PSIPs for their cost input assumptions and they are presented in Table F-13. These multipliers, which pertain to projects in Honolulu, have been applied to the raw data from the ATB and Lazard in order to create Hawai'i-specific values.

Cost Multiplier Comparison

Technology	EIA/ AIC
Land-based wind	30.1%
Off-shore wind	13.8%
CS	36.7%
Utili y V	40.5%
Biomass steam	53.6%
Geo hermal	27.2%
Hydropower	0.0%
Combined cycle	53.1%
Combus ion urbine	51.5%

Table F-13. Cost Multipliers

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."

Year Installed	Hawaii Specific N minal Capital Costs ($/kW)			Hawaii Specific N minal Fixed & M Costs ($/kW)			Hawaii Specific N minal Variable & M Costs ($/kW)		
2014 PSIPs - HECO, MECO, HELC									
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 - ahu									
	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									
	w		High	w		High	w		High
2015	$1,658.28		$2,255.27	$35.69		$40.79	$0.00		$0.00
ATB									
	w	id- int	High	w	id- int	High	w	id- int	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

Table F-14. Wind, Onshore

The cost estimates for land-based wind are presented in Table F-14. The capital costs for wind with a cable running from Maui to O‘ahu (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 PSIP’s capital cost estimates for smaller wind projects on Maui and Hawai‘i Island (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 PSIP shows a reduction in O&M costs compared to the 2014 PSIPs for the 30 MW 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.

Year Installed	Hawaii Specific N minal Capital Costs ($/kW)			Hawaii Specific N minal Fixed O&M Costs ($/kW)			Hawaii Specific N minal Variable & M Costs ($/kW)		
2014 PSIPs - HECO, MECO, HELC									
2015	t 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 - ahu									
	Fl ating Platf rm, 400MW			Fl ating Platf rm, 400MW			Fl ating Platf rm, 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									
	w		High	w		High	w		High
2015	$3,597.29	0	$6,382.29	$61.18	0	$101.97	$13.26	0	$18.35
ATB									
	w	id- int	High	w	id- int	High	w	id- int	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

Table F-15. Wind, Offshore

The cost estimates for offshore wind are presented in Table F-15. Note that there are no values for Maui and Hawaiʻi Island 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 Hawaiʻi Island.

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.

Year Installed	Hawaii Specific N minal Capital Costs ($/kW)			Hawaii Specific N minal Fixed O&M Costs ($/kW)			Hawaii Specific N minal Variable & M Costs ($/kW)		
2014 PSIPs - HECO, MECO, HELC									
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 - ahu									
	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									
	w		High	w		High	w		High
2015	$2,292.28	0	$2,149.01	$13.26	0	$10.20	$0.00	0	$0.00
ATB (100MW Single Axis Tracking)									
	w	id- int	High	w	id- int	High	w	id- int	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

Table F-16. Grid-Scale Photovoltaics

The cost estimates for utility-scale PV are presented in Table F-16[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 154 GW 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 20 MW case in Maui and Hawai‘i Island) 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 (that is, 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.

Year	Hawaii Specific Nominal Capi al Costs ($/kW)	Hawaii Specific Nominal Fixed O&M Costs ($/kW-year)	Hawaii Specific Nominal Variable O&M Costs ($/kW)
2014 P IPs - HECO, MECO, HELC			
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 P IPs - ahu			
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 P IPs - 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

Table F-17. Residential Photovoltaics

The cost estimates for utility-scale PV are presented in Table F-17. 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.

Year	Hawaii Specific Nominal Capital Costs ($/kW)			Hawaii Specific Nominal Fixed O&M Costs ($/kW-year)			Hawaii Specific Nominal Variable O& Costs ($/kW)		
2016 P IPs - ahu									
	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	id	High	Low	id	High	Low	id	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

Table F-18. Concentrated Solar Power (CSP)

The cost estimates for utility-scale PV are presented in Table F-18. Note that there are no estimates for CSP for either the 2014 PSIPs or Maui and Hawaiʻi Island 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 Oʻahu 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.

Year Installed	Hawaii Specific N minal Capital Costs ($/kW)			Hawaii Specific N minal Fixed O&M Costs ($/kW)			Hawaii Specific N minal Variable O& Costs ($/kW)		
2014 PSIPs - HECO, MECO, HELC									
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 - ahu									
	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									
	w		High	w		High	w		High
2015	$4,072.27	0	$5,481.90	$96.87	0	$96.87	$15.30	0	$15.30
ATB									
	w	id- int	High	w	id- int	High	w	id- int	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

Table F-19. Biomass Steam

The cost estimates for biomass steam are presented in Table F-19. 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.

Year Installed	Hawaii Specific Nominal Capital Costs ($/kW)			Hawaii Specific Nominal Fixed O&M Costs ($/kW)			Hawaii Specific Nominal Variable O& Costs ($/kW)		
2014 PSIPs - HECO, MECO, HELC									
	on-Dispatchable		Fully Dispatchable	on-Dispatchable		Fully Dispatchable	on-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 - ahu									
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	id-Poi t	High	Low	id-Poi t	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

Table F-20. Geothermal

The cost estimates for geothermal are presented in Table F-20. Note that HECO only considered geothermal projects on Maui and Hawai‘i Island. 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.

Year Installed	Hawaii Specific N minal Capital Costs ($/kW)			Hawaii Specific N minal Fixed O&M Costs ($/kW)			Hawaii Specific N minal Variable O& Costs ($/kW)		
2014 PSIPs - HECO, MECO, HELC									
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 - ahu									
	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									
	w		High	w		High	w		High
2015	$1,405.04	0	$1,873.39	$6.32	0	$5.61	$3.57	0	$2.04
ATB									
	w	id- int	High	w	id- int	High	w	id- int	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

Table F-21. Combined Cycle Turbine

The cost estimates for combined cycle turbines are presented in Table F-21. Note that no cost estimates for the 2016 PSIPs were included for Maui and Hawai‘i Island. 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.

Year Installed	Hawaii Specific Nominal Capital Costs ($/kW)			Hawaii Specific Nominal Fixed O&M Costs ($/kW)			Hawaii Specific Nominal Variable O& Costs ($/kW)		
				2014 PSIPs - HECO, MECO, HELC					
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 - ahu					
	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 / il aui		20.5MW Gas / il Hawaii	20.5MW Gas / il aui		20.5MW Gas / il 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

Table F-22. Simple Cycle Combustion Turbine

The cost estimates for simple cycle combustion turbines are presented in Table F-22. The 2016 PSIPs have cost estimates for a 100 MW plant on O‘ahu and a 20.5 MW plant on Maui and Hawai‘i Island; 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