A. Glossary and Acronyms

To aid in understanding and comprehension, the glossary and acronym entries in this appendix clarify the meaning of terms and concepts used throughout the 2016 updated Power Supply Improvement Plans (PSIPs).

A

Adequacy of Supply (AOS)

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

Advanced Inverter

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

Alternating Current (AC)

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

Ancillary Services

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

As-Available Renewable Energy

See Variable Renewable Energy on page A-34.

Automatic Generation Control (AGC)

A process for adjusting demand and resources from a central location in order to help maintain frequency. AGC helps balance supply and demand.

Avoided Costs

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

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

B

Baseload

The minimum electric or thermal load that is supplied continuously over a period of time. (See also Load, Electric on page A-18.)

Baseload Capacity

See Capacity, Generating on page A-3.

Baseload Generation

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

Battery Energy Storage Systems (BESS)

Any battery storage system used for contingency or regulating reserves, load shifting, ancillary services, or other utility or customer functions. (See also Energy Storage on page A-11.)

Black Start Resource

A generating unit and its associated set of equipment that can be started without system support or can remain energized without connection to the remainder of the system, and that has the ability to energize a bus, thus meeting a restoration plan's needs for real and reactive power capability, frequency and voltage control, and is included in the restoration plan.

British Thermal Unit (Btu)

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

C

Capacitor

A device used to correct AC voltage so that the voltage is in phase with the AC current. Capacitors are typically installed in substations and on distribution system poles, at locations where local voltage correction can reduce system current flow, reducing losses and improves efficiency.

Capacity Factor (cf)

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

Capacity, Generating

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

Baseload Capacity: Those generating facilities within a utility system that are operated to the greatest extent possible to maximize system mechanical and thermal efficiency and minimize system operating costs. Baseload capacity typically operates at high annual capacity factors, for example greater than 60%. Island systems experience lower capacity factors because output is often reduced to accommodate lower demand periods and variable energy production.

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

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

Intermediate Capacity: Flexible generators able to efficiently vary their output across a wide band of loading conditions. Also known as Cycling Capacity. Typically annual capacity factors for intermediate duty generating units range from 20% to 60%. Island systems experience lower capacity factors because output is often reduced to accommodate lower demand periods and variable energy production.

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

Peaking and Emergency Capacity: Generators typically called on for short periods of time during system peak load conditions or as replacement resources following contingencies. Annual capacity factors for peaking generation are typically less than 20%.

Capital Expenditures

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

Carbon Dioxide (CO_2)

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

Combined Cycle (CC)

A combination of combustion turbine- and steam turbine-driven electrical generators, where the combustion turbine exhaust is passed through a heat recovery waste heat boiler which, in turn, produces steam which drives the steam turbine. There are a number of possible configurations for combined cycle units.

3x1 Combined-Cycle: A configuration in which there are three combustion turbines, three heat recovery waste heat boilers, and one steam turbine. Each combustion turbine produces heat for a single waste heat boiler, which in turn produces steam that is directed to the single steam turbine.

Dual-Train Combined-Cycle (DTCC): A configuration in which there are two combustion turbines, two heat recovery waste heat boilers, and one steam turbine. Each combustion turbine and waste heat boiler combination produces steam that is directed to the single steam turbine. Sometimes referred to as a 2x1 combined-cycle.

Single-Train Combined-Cycle (STCC): A configuration in which there is one combustion turbine, one heat recovery waste heat boiler, and one steam turbine. Sometimes referred to as a 1x1 combined-cycle.

Combined Heat and Power (CHP)

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

Combustion Turbine (CT)

Any of several types of high-speed generators using principles and designs of jet engines to produce low cost, high efficiency power; also commonly referred to as a gas turbine (GT). Combustion turbines typically use natural gas or liquid petroleum fuels to operate.

Concentrated Solar Thermal Power (CSP)

A technology that uses mirrors to concentrate solar energy to drive traditional steam turbines or engines that create electricity. A CSP plant can store this energy until needed to meet demand.

Conductor Sag

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

Connected Load

See Load, Electric on page A-18.

Contingency Reserve

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

Critical Peak Incentive (CPI) Program

A DR capacity grid service capable of providing peak load reduction during emergency situations when insufficient generation resources are available. The current Commercial Direct Load Control program could be re-classified under this program as part of the initial migration to a redeveloped DR portfolio.

Customer Grid Supply (CGS)

A program where customers receive a Commission-approved credit for electricity sent to the grid and are billed at the retail rate for electricity they use from the grid. Customer Grid Supply is one of two programs (the other being Customer Self Supply) that replaced the Net Energy Metering (NEM) program.

Customer Self Supply (CSS)

A program intended only for solar PV installations that are designed to not export any electricity to the grid. Customers are not compensated for any export of energy. Customer Self Supply is one of two programs (the other being Customer Grid Supply) that replaced the Net Energy Metering (NEM) program.

Curtailment

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

Cycling

The operation of generating units at varying load levels (including on/off and low load variations), in response to changes in system load requirements. Cycling causes a power plant's boiler, steam lines, turbine, and auxiliary components to go through unavoidably large thermal and pressure stresses.

D

Day-Ahead Load Shift (DALS) Program

A DR capacity grid service capable of providing a static period pricing rate delivered to commercial customers six hours before the starting day of an event for on-peak, off-peak, and mid-day times. Through the price differential, customers are encouraged to shift their energy usage from the peak time to the middle of the day when solar PV is at its peak, or at night when demand is low

Daytime Minimum Load (DML)

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

Demand

The rate at which electricity is used at any one given time (or averaged over any designated interval of time). Demand differs from energy use, which reflects the total amount of electricity consumed over a period of time. Demand is often measured in kilowatts (kW = 1 kilowatt = 1000 watts), while energy use is usually measured in kilowatt-hours (kWh = kilowatts x hours of use = kilowatt-hours). Load is considered synonymous with demand. (See also Load, Electric on page A-18.)

Demand Charge

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

Demand Response (DR)

Changes in electric usage by end-use customers from their normal consumption patterns in response to incentives caused by changes in the state of the electric grid or changes in the price of electricity. The underlying objective of demand response is to actively engage customers in modifying the demand for electricity to address system needs, in lieu of relying on utility-scale generating assets to address system needs.

Load Control: Includes direct control by the utility or other authorized third party of customer end-uses such as air conditioners, lighting, water heaters, distributed storage, electric vehicles, and motors. Load control can entail partial load reductions or complete load interruptions as well as load increase as needed. Customers usually receive financial consideration for participation in load control programs.

Price Response: Refers to programs that provide pricing incentives to encourage customers to change their electricity usage profile. Price response programs include real-time pricing, day-ahead load shift, time-of-use (TOU), and critical peak pricing (CPP) incentives.

Demand-Side Management (DSM)

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

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

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

Department of Land and Natural Resources (DLNR)

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

DG 2.0

A generic term used in the 2014 PSIPs to describe revised tariff structures governing export and non-export models, based on fair allocation of costs among distributed generation (DG) customers and traditional retail customers, and fair compensation of DG customers for energy provided to the grid.

DG-PV (Distributed Generation-Photovoltaics)

An initialism describing the entirety of distributed photovoltaic generation (sometimes referred to as rooftop solar) on the power grid.

Direct Current (DC)

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

Direct Load Control (DLC)

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

Direct Transfer Trip (DTT)

A protection mechanism that originates from station relays in response to a specific system event. Remote events, such as generator trips, can cause load shed through DTT.

Dispatchable Generation

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

Distributed Energy Resources (DER)

Non-centralized generating and storage systems that are co-located with energy load. Also known as Distributed Generation (see Distributed Generation two entries below).

Distributed Energy Storage System (DESS)

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

Distributed Generation (DG)

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

Distribution Circuit Monitoring Program (DCMP)

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

Distribution Circuit

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

Distribution Transformer

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

Disturbance Ride-Through

The capability of resources to remain connected to the grid during transient off-normal voltage and frequency conditions that occur for typical system disturbances.

Droop

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

Dual-Train Combined Cycle (DTCC)

See Combined Cycle on page A-4.

E

Economic Dispatch

The allocation of load to online dispatchable generating units based on their costs, to effect the most economical production of electricity for customers.

Electric Power Research Institute (EPRI)

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

Electric Vehicle (EV)

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

Electricity

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

Emissions

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

Energy

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

Energy Efficiency DSM

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

Energy Efficiency Portfolio Standard (EEPS)

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

Energy Information Administration (EIA)

A principal agency of the United States Federal Statistical System (within the U.S. Department of Energy) responsible for collecting, analyzing, and disseminating energy information. One of its major roles is to provide publically available fuel price projections for the power generation industry.

Energy Management System (EMS)

A centralized system of computer-aided tools used to monitor, control, and optimize the performance of the utility power system and interconnected resources.

Energy Storage

A system or a device capable of storing electrical energy. Three major types of energy storage are relevant for consideration in Hawai‘i.

Battery: An energy storage device composed of one or more electrolyte cells that stores chemical energy. A large-scale battery can provide a number of ancillary services, including frequency regulation, voltage support (dynamic reactive power supply), load following, and black start as well as providing energy services such as peak shaving, valley filling, and potentially energy arbitrage. Also referred to as a Battery Energy Storage System (BESS).

Flywheel: A cylinder that spins at very high speeds, storing rotational kinetic energy. A flywheel can be combined with a device that operates either as an electric motor that accelerates the flywheel to store energy or as a generator that produces electricity from the energy stored in the flywheel. The faster the flywheel spins, the more energy it retains. Energy can be drawn off as needed by slowing the flywheel. A large flywheel plant can provide a number of ancillary services including frequency regulation, voltage support (dynamic reactive power supply), and potentially spinning reserve.

Pumped Storage Hydroelectric: Pumped storage hydro facilities typically use off-peak electricity to pump water from a lower reservoir into one at a higher elevation storing potential energy. When the water stored in the upper reservoir is released, it is passed through hydraulic turbines to generate electricity. The off-peak electrical energy used to pump the water uphill can be stored indefinitely as gravitational energy in the upper reservoir. Thus, two reservoirs in combination can be used to store electrical energy for a long period of time, and in large quantities. A modern pumped-storage facility can provide a number of ancillary services, such as frequency regulation, voltage support (dynamic reactive power), spinning and non-spinning reserve, load following and black start as well as energy services such as peak shaving and energy arbitrage.

Expense

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

F

Fast Frequency Response (FFR) Program

A DR fast frequency response grid service capable of responding to contingency events within 30 cycles (the maximum FFR requirement depending on the total available MW) or less. A customer who enrolls in this DR program must be able to offer load resources that could respond to a local discrete response in 30 cycles or less.

Feeder

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

Firm Capacity

See Capacity, Generating on page A-3.

Feed-In Tariff (FIT) Program

A FIT program specific to the Hawaiian Electric Companies, under guidelines issued by the 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.

Flywheel

See Energy Storage on page A-11.

Forced Outage

See Outage on page A-24.

Forced Outage Rate

See Outage on page A-24.

Fossil Fuel

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

Frequency

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

Frequency Regulation

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

Full-Forced Outage

See Outage on page A-24.

G

Generating Capacity

See Capacity, Generating on page A-3.

Generation (Electricity)

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

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

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

Generator (Electric)

A machine that transforms mechanical, chemical, or thermal energy into electric energy. Includes wind generators, solar PV generators, and other systems that convert energy of one form into electric energy. (See also Capacity, Generating on page A-3.)

Geographic Information System (GIS)

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

Gigawatt (GW)

A unit of power, capacity, or demand equal to one billion watts.

Gigawatt-Hour (GWh)

A unit of electric energy equal to one billion watt-hours.

Greenhouse Gases (GHG)

Any gas whose absorption of solar radiation is responsible for the greenhouse effect, including carbon dioxide, methane, ozone, and the fluorocarbons.

Grid (Electric)

An interconnected network of electric transmission lines and related facilities.

Gross Generation

See Generation (Electricity) on page A-14.

H

Hawai'i Public Utilities Commission (PUC)

A state agency that regulates all franchised or certificated public service companies operating in Hawai'i. The PUC prescribes rates, tariffs, charges and fees; determines the allowable rate of earnings in establishing rates; issues guidelines concerning the general management of franchised or certificated utility businesses; and acts on requests for the acquisition, sale, disposition or other exchange of utility properties, including mergers and consolidations.

Hawai'i Revised Statute (HRS)

The codified laws of the State of Hawai'i. The entire body of state laws is referred to the Hawai'i Revised Statutes; the abbreviation HRS is normally used when citing a particular law.

Heat Rate

A measure of generating station thermal efficiency, generally expressed in Btu per net kilowatt-hour. It is computed by dividing the total Btu content of fuel burned for electric generation by the resulting net kilowatt-hour generation.

Heat Recovery Steam Generator (HRSG)

An energy recovery heat exchanger that recovers heat from a hot exhaust gas stream, and produces steam that can be used in a process (cogeneration) or used to drive a steam turbine in a combined-cycle plant.

Impacts

The positive or negative consequences of an activity. For example, there may be negative consequences associated with the operation of power plants from the emission discharge or release of a material to the environment (for example, health effects). There may also be positive consequences resulting from the construction and siting of power plants which could affect society and culture.

Impedance

A measure of the opposition to the flow of power in an AC circuit.

Independent Power Producer (IPP)

Any entity that owns or operates an electricity generating facility that is not included in an electric utility's rate base. This term includes, but is not limited to, co-generators (or combined heat and power generators) and small power producers (including net metered and feed-in tariff systems) and all other non-utility electricity producers, such as exempt wholesale generators, who sell electricity or exchange electricity with the utility. IPPs are sometimes referred to as non-utility generators.

Industrial Fuel Oil (IFO)

A fuel oil that contains less than 20,000 parts per million of sulfur, or 2% sulfur content. Also referred to as medium sulfur fuel oil (MSFO).

Installed Capacity

See Capacity, Generating on page A-3.

Integrated Demand Response Portfolio Plan (IDRPP)

A comprehensive demand response portfolio proposal filed by the Companies with the Hawaiʻi Public Utilities Commission on July 28, 2014.

Integrated Resource Plan (IRP)

The plan by which electric utilities identify the resources or the mix of resources for meeting near- and long-term consumer energy needs. An IRP conveys the results from a planning, analysis, and decision-making process that examines and determines how a utility will meet future demands. Developed in the 1980s, the IRP process integrates efficiency and load management programs, considered on par with supply resources; broadly framed societal concerns, considered in addition to direct dollar costs to the utility and its customers; and public participation into the utility planning process.

Interconnection Charge

A one-off charge to DG customers reflecting costs of studies and any potential upgrades (such as transformer upgrades) associated with distributed generation.

Intermediate Capacity

See Capacity, Generating on page A-3.

Intermittent Renewable Energy

See Variable Renewable Energy on page A-34.

Internal Combustion Engines (ICE)

A heat engine that combines fuel with an oxidizer (usually air) in a combustion chamber that creates pressure and mechanical force to generate electricity.

Inverter

A device that converts direct current (DC) electricity to alternating current (AC) either for stand-alone systems or to supply power to an electricity grid. An appropriately designed inverter can provide dynamic reactive power as well as real power and disturbance ride-through capability. A solar PV system uses inverters to convert DC electricity to AC electricity for use in the grid, or directly by a customer.

Islanding

A condition in which a circuit remains powered by non-utility generation (that is, distributed generation resources) even when the circuit has been disconnected from the wider utility power network.

K

Kilowatt (kW)

A unit of power, capacity, or demand equal to one thousand watts. The demand for an individual electric customer, or the capacity of a distributed generator, is sometimes expressed in kilowatts. The standard billing unit for electric tariffs with a demand charge component is the kilowatt.

Kilowatt-Hour (kWh)

A unit of electric energy equal to one thousand watt-hours. The standard billing unit for electric energy sold to retail consumers is the kilowatt-hour.

L

Levelized Cost of Energy (LCOE)

The price per kilowatt-hour in order for an energy project to break even; it does not include risk or return on investment.

Life-Cycle Costs

The total cost impact over the life of a program or the life of an asset. Life-cycle costs include Capital Expenditures, operation, maintenance and administrative expenses, and the costs of decommissioning.

Liquefied Natural Gas (LNG)

Natural gas that has been cooled until it turns liquid, in order to make storage and transport easier. LNG must be regasified before it can be burned as fuel.

Load, Electric

The term load is considered synonymous with demand. Load may also be defined as an end-use device or an end-use customer that consumes power. Using this definition of load, demand is the measure of power that a load receives or requires.

Baseload: The constant generation of electric power load to meet demand.

Connected Load: The sum of the capacities or ratings of the electric power consuming apparatus connected to a supplying system, or any part of the system under consideration.

Load Balancing

The efforts of the system operator to ensure that the load is equal to the generation. During normal operating conditions the system operator utilizes load following and frequency regulation for load balancing.

Load Control Program

A program in which the utility company offers some form of compensation (for example, a bill credit) in return for having permission to remotely control a customer's energy use (such as controlling an air conditioner or water heater) for defined periods of time.

Load Forecast

An estimate of the level of future energy needs of customers in an electric system. Bottom-up forecasting uses utility revenue meters to develop system-wide loads; used often in projecting loads of specific customer classes. Top-down forecasting uses utility meters at generation and transmission sites to develop aggregate control area loads;

useful in determining reliability planning requirements, especially where retail choice programs are not in effect.

Load Management DSM

Electric utility or third party marketing programs designed to encourage the utility's customers to adjust the timing of their energy consumption. By coordinating the timing of its customers' consumption, the utility can achieve a variety of goals, including reducing the utility's peak system load, increasing the utility's minimum system load, and meeting unusual, transient, or critical system operating conditions.

Load Profile

Measurements of a customer's electricity usage over a period of time which shows how much and when a customer uses electricity. Load profiles can be used by suppliers and transmission system operators to forecast electricity supply requirements and to determine the cost of serving a customer.

Load Shedding

A purposeful, immediate response to curtail electric service. Load shedding is typically used to curtail large blocks of customer load (for example, particular distribution feeders) during an under frequency event (when frequency drops below a certain level) when demand for electricity exceeds supply (for example, during the sudden loss of a generating unit).

Load Tap Changer (LTC)

A substation controller used to regulate the voltage output of a transformer.

Loss-of-Load Probability (LOLP)

The probability that a generation shortfall (loss of load) would occur. This probability can be used as a consideration in generation adequacy requirements. The generation adequacy planning criteria for O'ahu requires the LOLP not to exceed one outage day every 4½ years. The other four islands we serve do not define a minimum LOLP, but rather plan for generation adequacy of supply through reserve margin calculations.

Low Sulfur Diesel (LSD)

A diesel fuel that contains a maximum of 500 parts per million of sulfur.

Low Sulfur Fuel Oil (LSFO)

A fuel oil that contains less than 500 parts per million of sulfur; about 0.5% sulfur content.

Low Sulfur Industrial Fuel Oil (LSIFO)

A fuel oil that contains up to 7,500 parts per million of sulfur; about 0.75% sulfur content. LSIFO is used if a fuel with lower sulfur content than medium sulfur fuel oil is needed.

Low Voltages

Voltages above 0.9 per unit that are of concern because these voltages can become an under voltage violation in the future.

M

Maintenance Outage

See Outage on page A-24.

MBtu

A thousand Btu. (See also British Thermal Unit on page A-3.)

Medium Sulfur Fuel Oil (MSFO)

A fuel oil that contains between 1,000 and 5,000 parts per million of sulfur; between 1% and 3.5% sulfur content.

Megawatt (MW)

A unit of power, capacity, or demand equal to one million watts. Generating capacities of power plants and system demand are typically expressed in megawatts.

Megawatt-Hour (MWh)

A unit of electric energy equal to one million watt-hours. The energy output of generators or the amount of energy purchased from Independent Power Producers is oftentimes specified in megawatt-hours.

Mercury and Air Toxics Standard (MATS)

A federal standard that requires coal- and oil-fired power plants to limit the emissions of toxic air pollutants: particular matter (such as arsenic), heavy metals (such as mercury) and acid gases (such as carbon dioxide).

Minimum Load (ML) Program

A DR capacity grid service that provides incentives to customers to shift their usage to the middle of the day to increase demand during that period when DG-PV generation is high. This program was not included in any DR portfolio analysis because load shifting programs such as time-of-use (TOU), day-ahead load shift (DALS), and real-time pricing (RTP) were already fulfilling this load flattening benefits.

MMBtu

One million Btu. (See also British Thermal Unit on page A-3.)

Must-Run Unit

A generation facility that must run continually due to operational constraints or system requirements to maintain system reliability; typically a large thermal power plant.

N

N-1 Contingency

The unexpected failure or outage of a single system component (such as a generator, transmission line, circuit breaker, switch, or other electrical element); and can include multiple electrical elements if they are linked so that failures occur simultaneously at the loss of the single component. Also known as an N-1 condition.

Nameplate Generation

See Generation (Electricity) on page A-14.

National Ambient Air Quality Standards (NAAQS)

A Federal standard, set by the Environmental Protection Agency (EPA), to limit the emission of six "criteria" pollutants: carbon monoxide (CO), lead, nitrogen dioxide (NO_2), ozone, particulate matter, and sulfur dioxide (SO_2). These regulations apply to all fuel-fired power plants.

National Pollutant Discharge Elimination System (NPDES)

NPDES permits, administers, and enforces a program that regulates pollutants discharged into water sources.

National Renewable Energy Laboratory (NREL)

The Federal laboratory dedicated to researching, developing, commercializing, and using renewable energy and energy efficiency technologies. NREL creates a wealth of well researched studies that utilities across the country rely on for planning to integrate renewable generation.

Net Capacity

See Capacity, Generating on page A-3.

Net Energy Metering (NEM)

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

Net Generation

See Generation (Electricity) on page A-14.

Nitrogen Oxide (NOx)

A pollutant and strong greenhouse gas emitted by combusting fuels.

Nominal Dollars

At its most basic, nominal dollars are based on a measure of money over a period of time that *has not been* adjusted for inflation. Nominal value represents a cost usually in the current year. As such, nominal dollars can also be referred to as current dollars; in other words, what it costs to buy something today. Nominal dollars are often contrasted with real dollars.

Non-Spin Auto Response (NSAR) Program

A 10-minute DR resource capable of replacing other resources that are used for spinning reserves. When paired with an FFR program, NSAR can also replace a contingency battery. A customer enrolled in this NSAR program would have 10 minutes to respond and reduce their enrolled load resource.

Non-Transmission Alternative (NTA)

Programs and technologies that complement and improve operation of existing transmission systems that individually or in combination defer or eliminate the need for upgrades to the transmission system.

North American Electric Reliability Corporation (NERC)

An international regulatory authority whose mission is to ensure the reliability of the bulk power system in North America.

O

Ocean Thermal Energy Conversion (OTEC)

A process that can produce electricity by using the temperature difference between deep cold ocean water and warm tropical surface waters.

Off-Peak Energy

Electric energy supplied during periods of relatively low system demands as specified by the supplier. In general, this term is associated with electric water heating and pertains to the use of electricity during that period when the overall demand for electricity from our system is below normal.

Once-Through Steam Generator (OTSG)

A specialized type of HRSG without boiler drums that enables the inlet feedwater to follow a continuous path (without segmented sections for economizers, evaporators, and superheaters) allowing it to grow or contract based on the heat load being received from the gas turbine exhaust. OTSGs can be run dry, meaning the hot exhaust gases can pass over the tubes with no water flowing inside the tubes.

On-Peak Energy

Electric energy supplied during periods of relatively high system demand as specified by the supplier.

Operation and Maintenance (O&M) Expense

The recurring costs of operating, supporting, and maintaining authorized programs, including costs for labor, fuel, materials, and supplies, and other current expenses.

Operating Reliability

The ability of the electric system to withstand sudden disturbances such as electric short circuits or unanticipated loss of system components. Operating reliability is synonymous with system security. (See also System Security on page A-31.)

Operating Reserves

That capability above firm system demand required to provide for regulation, load forecasting error, equipment forced and scheduled outages, and local area protection. It consists of spinning and non-spinning reserve. (See also Reserve on page A-29.)

Spinning Reserve: The portion of operating reserve consisting of generation synchronized to the system and fully available to serve load within a defined time period following a contingency event; or load fully removable from the system within a defined time period following a contingency event.

Supplemental Reserve: Generation (synchronized or capable of being synchronized to the system) that is fully available to serve load within a defined recovery period following the contingency event; or load fully removable from the system within the defined recovery following the contingency event.

Outage

The period during which a generating unit, transmission line, or other facility is out of service. The following are types of outages or outage-related terms.

Forced Outage: The removal from service availability of a generating unit, transmission line, or other facility for emergency reasons or a condition in which the equipment is unavailable due to unanticipated failure.

Forced Outage Rate: The hours a generating unit, transmission line, or other facility is removed from service, divided by the sum of the hours it is removed from service, plus the total number of hours the facility was connected to the electricity system expressed as a percent.

Full-Forced Outage: The net capability of main generating units that is unavailable for load for emergency reasons.

Maintenance Outage: The removal of equipment from service availability to perform work on specific components that can be deferred beyond the end of the next weekend, but requires the equipment be removed from service before the next planned outage. Typically, a Maintenance Outage may occur anytime during the year, have a flexible start date, and may or may not have a predetermined duration.

Partial Outage: The outage of a unit or plant auxiliary equipment that reduces the capability of the unit or plant without causing a complete shutdown. It may also include the outage of boilers in common header installations.

Planned (or Scheduled) Outage: The shutdown of a generating unit, transmission line, or other facility, for inspection or maintenance, in accordance with an advance schedule.

P

Partial Outage

See Outage on page A-24.

Particulate Matter (PM)

A complex mixture of extremely small particles and liquid droplets made up of a number of components, including acids (such as nitrates and sulfates), organic chemicals, metals, and soil or dust particles.

Peak Demand

The maximum amount of power necessary to supply customers; in other words, the highest electric requirement occurring in a given period (for example, an hour, a day, month, season, or year). For an electric system, it is equal to the sum of the metered net outputs of all generators within a system and the metered line flows into the system, less the metered line flows out of the system. From a customer's perspective, peak demand is the maximum power used during a specific period of time.

Peaker

A generation resource that generally runs to meet peak demand, usually during the late afternoon and early evening when the demand for electricity during the day is highest. It is also referred to as a peaker plant or a peaking power plant. These resources are often used for supplemental reserves.

Peaking Capacity

See Capacity, Generating on page A-3.

Photovoltaic (PV)

Electricity from solar radiation typically produced with photovoltaic cells (also called solar cells): semiconductors that absorb photons and then emit electrons.

Photovoltaic Curtailment (PVC) Program

A DR capacity grid service capable of curtailing a customer's PV generation when minimum must-run generators are within a specified threshold limit that requires more system load to prevent the sudden loss of an online generator.

Planned Outage

See Outage on page A-24.

Planning Reserve

See Reserve on page A-29.

Power

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

Power Factor

A dimensionless quantity that measures the extent to which the current and voltage sine waves in an AC power system are synchronized. If the voltage and current sine waves perfectly match, the power factor is 1.0. Power factors not equal to 1.0 result in dissipation of electric energy into losses.

Power Purchase Agreement (PPA)

A contract for an electric utility to purchase energy and or capacity from a commercial source (for example, an Independent Power Producer) at a predetermined price or based on pre-determined pricing formulas.

Present Value

The value of an asset, taking into account the time value of money—a future dollar is worth less today. Present value dollars are expressed in a constant year dollars (usually the current year). Future dollars are converted to present dollars using a discount rate. For example, if someone borrows money from you today and agrees to pay you back $1.00 in one year at a discount rate of 10%, you would be only be willing to loan the other person $0.90 today. Utility planners use present value as a way to directly compare the economic value of multi-year plans with different future expenditure profiles. Net present value (NPV) is the difference between the present value of all future benefits, less the present value of all future costs.

Public Benefits Fee Administrator (PBFA)

A third-party agent that handles energy efficiency rebates and incentives within the service territories of the Hawaiian Electric Companies.

Pumped Storage Hydroelectric

See Energy Storage on page A-11.

Q

Qualitative

Consideration of externalities which assigns relative values or rankings to the costs and benefits. This approach allows expert assessments to be derived when actual data from conclusive scientific investigation of impacts are not available.

Quantitative

Consideration of externalities which provides value based on available information on impacts. This approach allows for the quantification of impacts without assigning a monetary value to those impacts (for example, tons of crop loss).

R

Ramp Rate

A measure of the speed at which a generating unit can increase or decrease output, generally specified as MW per minute.

Rate Base

The value of property upon which a utility is permitted to earn a specified rate of return as established by a regulatory authority. The rate base generally represents the book value of property used by the utility in providing service and may be calculated by any one or a combination of the following accounting methods: fair value, prudent investment, reproduction cost, or original cost. Depending on which method is used, the rate base includes net cost of plant in service, working cash, materials and supplies, and deductions for accumulated provisions for depreciation, contributions in aid of construction, customer advances for construction, accumulated deferred income taxes, and accumulated deferred investment tax credits.

Reactive Power

The portion of electricity that establishes and sustains the electric and magnetic fields of alternating-current equipment. Reactive power is provided by generators, synchronous condensers, or electrostatic equipment (such as capacitors) and directly influences electric system voltage.

Real Dollars

At its most basic, real dollars are a measure of money over a period of time that *has been* adjusted for inflation. Real dollars represents the true cost of goods and services sold because the effects of inflation are stripped out of the cost. Over time, real dollars are a measure of purchasing power. As such, real dollars can also be referred to as constant dollars; in other words, if the price of something goes up over time at the same rate as inflation, the cost is the same in real dollars. Real dollars are often contrasted with nominal dollars.

Real-Time Pricing (RTP) Program

A DR capacity grid service capable of providing hourly retail rate prices to customers up to six hours before the event day starts. Retail rates are based on weather, system resource availability, and forecasted load profile. A residential RTP program requires an AMI infrastructure where customers are able to change their electric usage pattern based on the different hourly retail rates.

Reciprocating Internal Combustion Engines (RICE)

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

Regulating Reserves (RR) Program

A DR grid service capable of providing up and down reserves to balance system variability when renewable penetration is high. A customer who enrolls in this program must be able to provide a load resource that could respond within two seconds.

Regulating Reserves

An amount of reserve capacity responsive to automatic generation control (AGC) that is sufficient to provide normal regulating margin to maintain system frequency.

Reliability

The degree of performance of the elements of the bulk electric system that results in electricity being delivered to customers within accepted standards and in the amount desired. Reliability may be measured by the frequency, duration, and magnitude of adverse effects on the electric supply. Electric system reliability can be addressed by considering two basic and functional aspects of the electric system, adequacy of supply and system security. (See also System Reliability on page A-31.)

Renewable Energy Resources

Energy resources that are naturally replenished, but limited in their constant availability (or flow). They are virtually inexhaustible but are limited in the amount of energy that is available over a given period of time. The amount of some renewable resources (such as geothermal and biomass) might be limited over the short term as stocks are depleted by use, but on a time scale of decades or perhaps centuries, they can likely be replenished.

Renewable energy resources currently in widespread use include photovoltaics, biomass, hydroelectric, geothermal, solar, and wind. Other renewables resources still under development include ocean thermal, wave, and tidal action technologies. Utility renewable resource applications include bulk electricity generation, on-site electricity generation, distributed electricity generation, non-grid-connected generation, and demand-reduction (energy efficiency) technologies.

Unlike fossil fuel generation plants (which can be sited where most convenient because the fuel is transported to the plant), most renewable energy generation plants must be sited where the energy is available; that is, a wind farm must be sited where a sufficient and relatively constant supply of wind is available. In other words, fossil fuels can be brought to their generation plants whereas most renewable energy generating plants must be brought to the renewable energy source. Some renewable resources are exceptions; their fuels (such as biomass and biofuels), like fossil generation, can be brought to the generation plant.

Renewable Portfolio Standard (RPS)

A goal for the percentage of electricity sales in Hawaiʻi to be derived from renewable energy sources. The RPS is set by state law. Savings from energy efficiency and displacement or offset technologies were part of the RPS until January 2015, after which they were counted toward the new Energy Efficiency Portfolio Standard (EEPS).

The current RPS statute calls for 10% of net electricity sales by December 31, 2010; 15% of net electricity sales by December 31, 2015; 25% of net electricity sales by December 31, 2020; and 40% of net electricity sales by December 31, 2030; 70% of net electricity sales by December 31, 2040; and 100% of net electricity sales by December 31, 2045.

Reserve

There are two types of reserves.

Operating Reserve: That capability above firm system demand required to provide for regulation, load forecasting error, equipment forced and scheduled outages, and local area protection. (See also Operating Reserves on page A-23.)

Planning Reserve: The difference between a control area's expected annual peak capability and its expected annual peak demand expressed as a percentage of the annual peak demand.

Reserve Margin (Planning)

The amount of unused available capability of an electric power system at peak load for a utility system as a percentage of total capability. Planning reserve margin is designed to measure the amount of generation capacity available to meet expected demand in a planning horizon. Coupled with probabilistic analysis, calculated planning reserve margins have been an industry standard used by planners for decades as a relative indication of adequacy of supply (AOS).

Resiliency

The ability to quickly locate faults and automatically restore service after a fault, using FLISR (Fault Location, Isolation, and Service Restoration).

Retail Rate

The rate at which specific classes of customers compensate the utility for grid electricity.

Reverse Flow

The flow of electricity from the customer site onto the distribution circuit or from the distribution circuit through the substation to higher voltage lines. Also called backfeed.

S

Scheduled Outage

See Outage on page A-24.

Service Charge

A fixed customer charge intended to allocate the cost of servicing the grid to all customers, regardless of capacity needs.

Simple-Cycle Combustion Turbine (SCCT)

A generating unit in which the combustion turbine operates in a stand-alone mode, without waste heat recovery.

Single-Train Combined Cycle (STCC)

See Combined Cycle on page A-4.

Smart Grid

A platform connecting grid hardware devices to smart grid applications, including Advanced Metering Infrastructure (AMI), Volt/VAR Optimization (VVO), Direct Load Control (DLC), and electric vehicle charging.

Spinning Reserve

See Operating Reserves on page A-23.

Steam Turbine (ST)

A turbine that is powered by pressurized steam and provides rotary power for an electrical generator.

Stochastic Modeling

Modeling analysis using as input a random collection of variables that represent the uncertainties associated with those variables (as opposed to deterministic modeling that analyzes a single state). Stochastic modeling analyzes multiple states and the range of their uncertainty, then captures the probabilities of those uncertainties.

Sulfur Oxide (SO_x)

A precursor to sulfates and acidic depositions formed when fuel (oil or coal) containing sulfur is combusted. It is a regulated pollutant.

Substation

A small building or fenced in yard containing switches, transformers, and other equipment and structures for the purpose of stepping up or stepping down voltage, switching and monitoring transmission and distribution circuits, and other service functions. As electricity gets closer to where it is to be used, it goes through a substation where the voltage is lowered so it can be used by customers such as homes, schools, and factories.

Supervisory Control and Data Acquisition (SCADA)

A system used for monitoring and control of remote equipment using communications networks.

Supplemental Reserve Service

See Operating Reserves on page A-23.

Supply-Side Management

Actions taken to ensure the generation, transmission, and distribution of energy are conducted efficiently. Supply-side generation includes generating plants that supply power into the electric grid.

Switching Station

An electrical substation, with a single voltage level, whose only functions are switching actions.

System

The utility power grid: a combination of generation, transmission, and distribution components.

System Average Interruption Duration Index (SAIDI)

The average outage duration for each customer served. SAIDI is a reliability indicator.

System Average Interruption Frequency Index (SAIFI)

The average number of interruptions that a utility customer would experience. SAIFI is a reliability indicator.

System Reliability

Broadly defined as the ability of the utility system to meet the demand of its customers while maintaining system stability. Reliability can be measured in terms of the number of hours that the system demand is met.

System Security

The ability of the electric system to withstand sudden disturbances such as electric short circuits or unanticipated loss of system elements. (See also Operating Reliability on page A-23.)

T

Tariff

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

Time-of-Use (TOU) Program

A DR capacity grid service capable of providing a static period pricing rate for on-peak, off-peak, and mid-day times to residential customers. Through a price differential, customers are encouraged to shift their energy usage from the peak to the middle of the day when solar PV is at its peak, or at night when demand is low. When the time-of-use (TOU) program ends, participants will be able to enroll in the RTP program.

Time-of-Use (TOU) Rates

The pricing of electricity based on the estimated cost of electricity during a particular time block. Time-of-use rates are usually divided into three or four time blocks per twenty-four hour period (on-peak, mid-peak, off-peak and sometimes super off-peak) and by seasons of the year (summer and winter).

Total Resource Cost (TRC)

A method for measuring the net costs of a conservation, load management, or fuel substitution program as a resource option, based on the total costs of the program, including both the participants' and the utility's costs.

Transformer

A device used to change voltage levels to facilitate the transfer of power from the generating plant to the customer. A step-up transformer increases the voltage (power) of electricity while a step-down transformer decreases it.

Transmission and Distribution (T&D)

Transmission lines are used for the bulk transfer of electric power across the power system, typically from generators to load centers. Distribution lines are used for transfer of electric power from the bulk power level to end-users and from distributed generators into the bulk power system. Hawaiian Electric standard transmission voltages are 138,000 volts; and 69,000 volts (for Maui Electric and Hawai'i Electric Light). Distribution voltage is 23,000 volts (Maui Electric) and 13,200 volts (all systems).

Two-Way Communications

The platform and capabilities that are required to allow bi-directional communication between the utility and elements of the grid (including customer-sited advanced inverters), and control over key functions of those elements. The platform must contain monitor and control functions, be TCP/IP addressable, be compliant with IEC 61850, and provide cyber security at the transport and application layers as well as user and device authentication.

U

Ultra Low Sulfur Diesel (ULSD)

A diesel fuel that contains less 15 parts per million of sulfur.

Under Frequency Load Shedding (UFLS)

A system protection scheme used during transient adverse conditions to balance load and generation. The term essentially explains the process: when frequency drops below a certain point, this scheme sheds load to keep from completely losing the system.

Under Voltage Load Shedding (UVLS)

A system protection scheme used during low voltage conditions to avoid a voltage collapse.

United States Department of Defense (DOD)

An executive department of the U.S. government responsible for coordinating and supervising all agencies and functions of the Federal government that are concerned directly with national security and the armed forces.

United States Department of Energy (DOE)

An executive department of the U.S. government that is concerned with the United States' policies regarding energy, environmental, and nuclear challenges.

United States Energy Information Administration (EIA)

The principal agency responsible for collecting, analyzing, and disseminating energy information to promote sound policymaking, efficient markets, and public understanding of energy. The EIA conducts independent comprehensive data collection of energy sources, end uses, and energy flows; generates short- and long-term domestic and international energy projections; and performs informative energy analyses. EIA programs cover data on coal, petroleum, natural gas, electric, renewable, and nuclear energy.

United States Environmental Protection Agency (EPA)

An executive department of the U.S. government whose mission is to protect human health and the environment.

University of Hawai‘i Economic Research Organization (UHERO)

The economic research organization at the University of Hawai‘i, which is a source for information about the people, environment, and Hawai‘i and the Asia-Pacific economies, including energy issues.

V

Variable Renewable Energy

A generator whose output varies with the availability of it primary energy resource, such as wind, the sun, and flowing water. The primary energy source cannot be controlled in the same manner as firm, conventional, fossil-fuel generators. Specifically, while a variable generator (without storage) can be dispatched to operate below the available energy, it cannot be increased above what can be produced by the available resource energy. Variable energy can be coupled with storage, or the primary energy source can be stored for future use (such as with solar thermal storage, or when converted into electricity via storage technologies). Also referred to as intermittent and as-available renewable energy.

Voltage

Voltage is a measure of the electromotive force or electric pressure for moving electricity.

Voltage Regulation

The control of voltage to keep the value within a specified target or range.

W

Waste-to-Energy (WTE)

A process of generating electricity from the primary treatment (usually burning) of waste. WTE is a form of energy recovery.

Watt

The basic unit of measure of electric power, capacity, or demand from the International System of Units (SI); named after the Scottish engineer James Watt (1736–1819).

Wave and Tidal Power

A process that captures the power of waves and tides and converts it into electricity. While the arrival of waves at a power facility is somewhat predictable (mainly because waves travel across the ocean), tides are extremely predictable because they are driven by the gravitational pull of the moon and sun.

B. Input from the Parties

Throughout the process of creating our 2016 updated PSIPs, we have actively sought input from the Parties by thoroughly assessing their January 2016 submissions to the Commission and by engaging the Parties in a series of conferences, meetings, and one-on-one dialogs.

STAKEHOLDER AND TECHNICAL CONFERENCES

Beginning with our *Proposed PSIP Revision Plan* and continuing with our *Power Supply Improvement Plan Update Interim Status Report*, we have made it clear that we are proactively soliciting input from the Parties. In our *Proposed PSIP Revision Plan*, we proposed a schedule of conferences for just this purpose:

- Stakeholder Conference: held on December 17, 2015
- Technical Conference: proposed to be held on February 22, 2016 (but not approved by the Commission)
- Technical Conference: proposed to be held on April 15, 2016

The Commission also scheduled a Technical Conference held on January 7, 2016, and then scheduled another Technical Conference held on March 8, 2016.

Stakeholder Conference: December 17, 2015

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

Our goals for the stakeholder conference were two-fold:

- **Overall Objective:** To obtain a clearer understanding of potential input from the Parties and how it might affect how we develop the 2016 updated PSIPs.
- **Process Considerations:** Discuss the objectives of the process set forth by the Commission in Order No. 33320, answer specific questions regarding the PSIP analysis process, and discuss any other pertinent issues raised by the stakeholders.

We invited over 40 people, including representative from all Parties and the Commission, to attend the conference and to give a presentation about their input. Here is the first of two email messages we sent to invitees.

Sent: Wednesday, December 09, 2015 9:54 AM

Subject: PSIP Stakeholder Conference - December 17, 1pm-4pm

Aloha,

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

This Conference is intended to be an open discussion of the PSIP update process. The Conference will consist of a series of moderated open discussions around the following objectives:

A. Respond to questions and accept comments that parties may have about the Companies' November 25th filing, providing its plan for updating the PSIP.

B. Seek input from meeting participants on future pricing for resource options, including but not limited to utility scale generation (renewable and fossil), DER, DR, and grid modernization components. Input to include pricing and ability of these options to provide grid or ancillary services.

C. Seek input from meeting participants on developable levels of various renewable resource options, including but not limited to utility scale wind, utility scale solar, distributed solar, geothermal, etc.

In order to maintain a neutral position, the Department of Business, Economic Development and Tourism has agreed to moderate these discussions. The conversations that take place at this Conference are intended to be informal and not part of the official record in this docket. This is to encourage open and constructive dialogue. Accordingly, we ask that no recording devices of any kind (video or audio) be used. Your acceptance of this invitation indicates your acceptance of these conditions. We thank you for your cooperation.

The Conference will take place on Thursday, December 17, from 1:00 PM until 4:00 PM, in the King Street Auditorium at the Hawaiian Electric Company headquarters building located at 900 Richards Street in downtown Honolulu. Parking validation will not be provided for this event. A government issued ID is required for entry into this building. Please arrive early to allow time for check in (present your ID and receive a Visitor badge).

Due to space limitations, we would appreciate it if you could select one person to represent your organization at this Conference. While we strongly encourage in-person participation, a limited number of conference lines will be available for remote access to the meeting.

If your organization wishes to attend this meeting, please RSVP no later than noon, Tuesday, December 15, 2015 and indicate who will be representing your organization at this meeting. If you plan to call into this meeting, please also indicate that in your RSVP response.

RSVP to:
Heather Villamil
(808) 543-5820

We look forward to seeing you at this meeting.

Mahalo,
Colton Ching

Two days later, we sent the following email to provide more details about the conference.

Sent: Friday, December 11, 2015 8:50 PM

Subject: Additional Info: PSIP Stakeholder Conference - December 17, 1pm-4pm

Aloha,

We are reaching out to you with some additional logistics on the Hawaiian Electric's Power Supply Improvement Plan (PSIP) Stakeholder Conference scheduled for December 17, 2015.

If you wish to provide input in the form of a formal presentation at this meeting, that opportunity will be offered to you. In order to allow everyone an opportunity to participate in the meeting, we would ask that you keep your formal presentation brief (7-10 minutes) and that you adhere to the agenda topics outlined below:

• Resource options, including but not limited to utility scale generation (renewable and fossil), DER, DR, and grid modernization components. Input to include pricing and ability of these options to provide grid or ancillary services.

• Developable levels of various renewable resource options, including but not limited to utility scale wind, utility scale solar, distributed solar, geothermal, etc.

We are particularly interested in your thoughts regarding the resource options we should consider in the PSIP updates. This includes technologies, cost trends, their utilization as a grid resource and constraints by island, if any. If you plan to use slides or other visuals for your presentation, please send the electronic version BY NOON, TUESDAY, DECEMBER 15, 2015 to the email address below. By Monday, we will send a presentation template for your convenience. This opportunity to present is optional, i.e. there is no requirement that you prepare a presentation. The number of presentations will be limited to the time allotted for this meeting and presentation requests will be honored in the order that we receive the presentations via email. If you wish to distribute hard copies to the stakeholders, please bring at least 30 copies.

REMINDER: The Conference will take place on Thursday, December 17, from 1:00 PM to 4:00 PM, in the King Street Auditorium at the Hawaiian Electric Company headquarters building located at 900 Richards Street in downtown Honolulu.

We have received several requests for permission to allow more than one representative to attend the stakeholder conference. After reconsideration, although space remains limited, we will do our best to accommodate two representatives per organization to attend in person. In addition, as stated previously, we will also allow for participation via telephone conference. Unfortunately, the conference bridge also has limits, and for that reason, we will need to reserve remote access for only those who do not have a representative attending in person. We thank you for your understanding. AS A REMINDER: If your organization wishes to attend this meeting, please RSVP no later than NOON, TUESDAY, DECEMBER 15, 2015 to Heather Villamil. Her contact information is below. PLEASE INDICATE WHO WILL BE REPRESENTING YOUR ORGANIZATION. IF YOU ARE UNABLE TO ATTEND IN PERSON, PLEASE INFORM US IF YOU WILL BE PARTICIPATING VIA TELEPHONE CONFERENCE AND THE NAME OF THE INDIVIDUALWHO WILL BE CALLING IN

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

We look forward to seeing you at this meeting.

Mahalo,
Colton Ching

About 40 people (excluding company personnel) attended either in person or through a phone-in bridge. As we recommended, the meeting was fairly informal to better solicit candid remarks.

The conference featured four presentations. Mr. Glick’s focused on garnering input regarding the Commission’s eight Observations and Concerns. Mr. Yunker presented DBEDT’s planning methodology to achieve an energy future that meets or exceeds the state’s energy goals.

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

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

Technical Conference: January 7, 2016

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

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

> The purpose and scope of the technical conference is to further examine and understand the Revision Plan submitted by the HECO Companies on November 25, 2015, and obtain a status report on plans and progress towards the supplementation and amendment of the Companies' PSIPs. In particular, the commission seeks to ascertain (1) the resources that have been or will be obtained or retained by the Companies to perform necessary analyses, including the nature and identification of analysis models, work teams, and consultants; (2) identification of analysis approaches that have been determined; (3) identification of analyses input assumptions and sources for input assumptions that have been determined; and (4) any preliminary results.[1]

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

Proposed Technical Conference: February 22, 2016

The Commission did not render a decision on our proposed technical conference, so we did not hold it. In it, we had proposed to review our *Power Supply Improvement Plan Update Interim Status Report* and to solicit constructive feedback, the results of any substantiated analyses from the Parties, and well-considered recommendations that we could include in our ongoing analyses.

Technical Conference: March 8, 2016

The Commission called this 2½-hour technical conference "to provide an opportunity for the Companies to benefit from feedback from the Parties and the Commission, and assist the Commission in its review of the our responses to information requests."[2]

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

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

During the meeting, the Commission provided feedback on our interim status report, guidance on topics and planning elements, and asked a series of questions organized around the eight Observations and Concerns. Life of the Land, REACH, Distributed Energy Resources Council of Hawai‘i, Hawai‘i Renewable Energy Alliance, and Paniolo Power also asked questions. Paniolo Power indicated that they had detailed information on a pumped-storage hydro unit located at Parker Ranch. We asked them to provide that information so that we could include it in our PSIP analysis. This information, however, was not forthcoming. Once again, we requested all Parties to submit any input to our modeling and analysis for creating the 2016 updated PSIPs.

Proposed Technical Conference: April 15, 2016

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

We are awaiting Commission decision regarding our proposal for this meeting.

Planning Meeting Attendance

We invited intervenors to the docket to attend and participate in our working meetings where we review analysis, make decisions on further refinements, and discuss the modeling analysis for completing the 2016 updated PSIPs. Representatives from DBEDT, the Consumer Advocate, and the County of Hawai‘i attended, either in person or through a phone conference bridge. These representatives participated in about 10 meetings.

CONSIDERING AND INCORPORATING INPUT FROM THE PARTIES

Order No. 33320 directed the Parties in the docket to file a report on January 15, 2016 that included, among other topics, input to our process for creating the 2016 updated PSIPs. (The Order stated that the term "Parties" in this docket refers "collectively to the Parties, Intervenors, and Participants in this proceeding."[3]) Our *Proposed PSIP Revision Plan* stated that:

> The Companies welcome and actively seek to obtain input from the Parties and other stakeholders regarding the assumptions, methods, and evaluation metrics. … (T)he Companies encourage the Parties to provide constructive inputs related to the Commission's Observations and Concerns, supplemented with appropriate quantitative justification, methodology, assumptions, and information sources that can apply to the creation of actionable updated PSIPs. This input can be particularly impactful to our analyses. The Companies will incorporate input submitted by the Parties to the extent that time allows.[4]

To assist the Parties, our *Proposed PSIP Revision Plan*[5] contained a table[6] describing, in detail, the high priority inputs to the Commission's eight Observations and Concerns that we require for our analysis.

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

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

[3] Order No. 33320 at 171.

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

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

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

Two Parties (HSEA and HPVC) joined the Sierra Club's submission. Four Parties did not file a response: AES Hawaiʻi, Hawaiʻi Renewable Energy Alliance (HREA), NextEra Energy Hawaiʻi, and Puna Pono Alliance.

How We Considered and Incorporated Input from the Parties

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

- Out of scope. We recognize the Commission's specific instructions to limit issues in the 2016 updated PSIPs to the issues established by the Commission. (Order No. 33320 specifically states that the Parties' "participation will be limited to the issues as established by the commission in this docket.")[7]
- Addressed or incorporated in the *PSIP Update Interim Status Report*.
- Addressed or incorporated in our 2016 updated PSIPs (to be filed on or before April 1, 2016).
- To be addressed in our resource planning that will continue after the April 1, 2016 updated PSIPs filing.

To date, we have incorporated several key points of feedback from the Parties in our 2016 updated PSIPs. We:

- Distributed resource cost assumptions to the Parties on February 2, 2016 to provide transparency of input variable assumptions and provide an opportunity for Parties comments on these input variables.
- Established an FTP site where input information and data developed thus far in the PSIP updated process is posted. This allows Parties to access the information and post feedback. We established this communication platform to provide transparency and a greater understanding of the input variables to be used for the PSIP Update analysis.
- Used a "decision framework" to establish a clear basis for how plan objectives will be prioritized and to clarify how Preferred Plans are selected among the candidate plans.
- Introduced the PSIP optimization processes consisting of DER, DR, and utility-scale iterative cycles to capture analytical steps in achieving our 100% RPS goals which ensure planning iterations are performed to meet the optimization objectives across these resource options.

[7] Order No. 33320 at 171.

- Invited Party representatives to participate in working meetings with the Hawaiian Electric Companies planning team on the remainder of analysis and modeling for the 2016 updated PSIPs. This creates greater transparency of the planning, analysis, process, and decisions made during the iterative process.

Receiving Party Input

We actively solicited input from the Parties regarding new resource options, costs, and constraints: in our compliance filing (November 25, 2015), before and during our stakeholder conference (December 17, 2015), and during the Commission-organized Technical Conferences (January 7, 2016 and March 8, 2016).

In their January 15, 2016 filing and again during the March 8, 2016 conference, many Parties offered opinions and suggestions regarding resource types to consider. We were unable to find any specific numerical or objective data in Party input that could be used in our 2016 PSIP modeling efforts. We are, however, considering and addressing the resource types suggested by the Parties. In addition, two Parties included in their filings specific cost information regarding projects they are sponsoring. We compared and validated this cost input to other independent data sources, resulting in certain resource capital cost assumptions reflecting Party input.

Input Incorporated from Other Organizations

Our *Proposed PSIP Revision Plan* listed six additional organizations who agreed to provide independent technical analyses to help address issues of concern for the 2016 updated PSIPs. These stakeholders include the 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.

In addition, we also 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.

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

RESPONDING TO PARTY INPUT

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

To streamline how we responded to input from the Parties for the 2016 updated PSIPs, we organized the input comments into 15 topics. These 15 topics are:

#	Topic	#	Topic	#	Topic
1	Utility Business Model	2	Value of Solar	3	Decision Framework
4	Transparency	5	Resource Input	6	Cases & Sensitivities
7	System Security Criteria	8	DER & DR Optimization	9	Risks
10	Customer Bill Impacts & Relevant Metrics	11	LNG	12	Fossil Generation Upgrades
13	Stakeholder Input	14	Energy Efficiency & Electric Transport	15	Inter-Island Transmission

Table B-1. Party Input Topics

Table B-2 contains a cross reference between the Party submitting a filing and the 15 topics that summarize the various comments. A Party needs only to read across the table to see the input topics they commented on, and refer to the remainder of this appendix to read how we considered and incorporated their input. A checkmark indicates that a Party commented on that topic; a blank means that they did not comment on the topic.

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

* = Joiner to Sierra Club's submission

Table B-2. Party to Input Topic Cross Reference

1. Utility Business Model

The Parties assert that the Companies need to transform their business model to move forward and enable the new Hawai'i energy landscape. The Commission stated this topic in its Inclinations, but not in Order No. 33320.

Our Action Regarding this Topic

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

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

NextEra and the Companies have responded to the question of a sustainable business model in the merger docket (Applicants Exhibit 42, Docket 2015-0022). While we concur that our business model is an important issue to discuss, as directed by the Commission, continued discussion is beyond the scope of this docket.

We developed our Preferred Plans within the framework of a sustainable business model that enables us to transform our power grid to meet the 100% renewable energy goal. Incorporated in that business model is our intent to remain one of the power producers of utility-scale generation.

2. Value of Solar

The Parties assert that our avoided cost methodology does not fully capture the value of solar, and recommend a comprehensive study to develop a different methodology.

Our Action Regarding this Topic

We are confident that our avoided cost methodology and the development of integration solutions and costs and characteristics of operation is a sufficient proxy given the time constraints. Nonetheless, we plan to cover this topic in more detail in Phase 2 of the DER docket.

3. Optimization Decision Framework

The Parties stated that our process for choosing the Preferred Plans in our 2014 PSIPs was not well articulated and was flawed; that the optimization steps were unclear; and that our discrete uncoordinated analysis resulted in suboptimal resource allocation. Some Parties concluded that the process needs an optimization framework detailing an overarching logic; and that this framework guide development paths and portfolios for specific goals (for example, rate reduction, low cost, and 100% RPS), and help select Preferred Plans that best accomplish those goals.

Our Action Regarding this Topic

We have developed a detailed decision framework (see Appendix C), and discussed how we used this framework to analyze and optimize the various cases to select our Preferred Plans (see Chapter 3).

4. Transparency

The Parties want to understand and be informed about:

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

Our Action Regarding this Topic

We documented our decision framework in Appendix C, the actual iterative implementation of that decision framework in Chapter 3; all assumptions in Appendix J; and all modeling tools in Appendix H. We established an FTP server site where we post content from our PSIP work; the server enables the Parties not only to read this content, but also to post additional content and to comment. To further our desire to make our process transparent, we invited representatives from the Parties to attend our planning and decision-making meetings; three organizations responded: the Consumer Advocate, DBEDT, and County of Hawai‘i. These representative attended about 10 of our meetings, both in person and through a phone bridge.

5. Resource Inputs

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

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

Our Action Regarding this Topic

Appendix J documents how we arrived at the assumptions used in our analyses. We have uploaded all resource assumptions to the FTP server. We also requested additional information from Paniolo Power about the initial resource inputs they provided.

6. Cases and Sensitivities

The Parties want various cases and sensitivities explored, such as:

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

Our Action Regarding this Topic

In our 2016 updated PSIP analysis, we developed three themes and applied multiple sensitivities to each theme, creating numerous cases to analyze for each operating utility. We evaluated all of these cases, under a merged and unmerged scenario, to be considered for our Preferred Plans. These cases and the process for selecting the Preferred Plans are described in Chapter 3.

We did not run a case that does not attain 100% RPS by 2045; we only ran cases that, at a minimum, complied with statute.

7. System Security Criteria

The Parties contend that the system security methodology and results published in our 2014 PSIPs are overly conservative and limit DER adoption; and that system-level constraints should emphasize safety, reliability, and power quality rather than economics.

Our Action Regarding this Topic

We leveraged the analyses from the Integrated Demand Response Portfolio Plan (IDRPP) supplemental filing to determine technology-neutral system security requirements for each resource plan. This included removing any system must run requirements for each island's grid as a starting point for system security analysis. If the technical requirements are met, DR and DER can be used to support, impact, and provide system security. Appendix P documents the process and results from our system security analysis.

8. DER and DR Optimization

The Parties want assurance that the PSIPs are coordinated with the DER and DR dockets; that we treat DER as a resource to be optimized (and not an end state); and that appropriate consideration be given to motivate customer adoption. The Parties want us to view DER as customer-centric solutions and recommend our conducting an in-depth study to better achieve the Commission's overarching goals for reducing rates and ensuring a clean energy future while providing customer choice.

Our Action Regarding this Topic

We documented our current DER and DR optimization process, and have explained the potential services that DER and DR can provide to the grid and how we plan to fully utilize them. (Refer to Appendix C.) As directed by the Commission, we considered customer choice as important, but not necessarily the primary criteria for evaluating any resource portfolio.

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

9. Risks

The Parties want assurance that all risks are properly documented and explored through the various portfolios and options. They are concerned that customers will bear the impact of stranded costs because of the chosen resource mix, and want information on when and how customer savings are realized under the various plans.

Our Action Regarding this Topic

We developed a thorough set of risk criteria to evaluate each alternative plan on an equal basis with similar objectives. We explained this risk criteria and evaluation process and posted it on our FTP server. We have included sensitivities that test key risk factors in our 2016 updated PSIPs.

Our Decision Framework lists a number of risks that must be minimized. We discuss the risks associated with the three themes in Chapter 1: Introduction; Appendix E: New Resource Options discusses the risks associated with implementing new resources into our generation mix.

10. Customer Bill Impacts and Relevant Metrics

Some of the Parties want assurance that the impact on customer bills will be evaluated for all plans, that nominal impacts will be stated for all plans, and that comparisons with alternative portfolios will be provided. Some Parties want the Companies to develop bill impact estimates for various residential segments (such as customers who do and do not participate in distributed generation programs).

Our Action Regarding this Topic

Our 2016 updated PSIPs compare the impact that each Preferred Plan has on customer bills. We show these impacts in both nominal and real dollars. Whenever possible, we described the main drivers that impact bills.

11. Liquefied Natural Gas (LNG)

The Parties want us to specify our plan to import and exit from LNG use, and to minimize or eliminate stranded costs that impact customers; and want to see the savings demonstrated for using LNG as a bridge fuel as compared to investing in only renewable generation. Some parties do not consider LNG a feasible option because it's not a renewable resource.

Our Action Regarding this Topic

We developed cases that achieve 100% RPS both with and without LNG under market DG PV forecast and higher DG adoption for both high and low fuel price projection. All cases with LNG assume that LNG will end in 2040, and that all applicable costs are depreciated over the time period of LNG usage to avoid stranded costs. Our theme plans also show the cost differential from investing in LNG as opposed to investing in only renewable resources.

12. Fossil Generation Upgrades

The Parties want to better understand the final cost and performance characteristics of fossil generation upgrades (such as, how the units previously performed, what the modified units are now capable of, and how the performance and savings of the modified generators might compare to new and existing generating units).

Our Action Regarding this Topic

We documented the cost for modernizing our fleet with the installation of a 3x1 combined-cycle unit on O‘ahu's Kahe site, and describe the benefits of such a unit. We also quantified the value of such a unit compared to other selected alternatives.

13. Party Input

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

Our Action Regarding this Topic

This appendix describes, in detail, how we considered and incorporated party input into our analyses. Virtually all input dealt with process; we received virtually no data that directly contributed to our analyses.

14. Energy Efficiency and Electric Transport

The Parties want to know how energy efficiency will help with grid issues. In addition, the CA wants us to incorporate measures from recently published energy efficiency studies into our analyses. The Parties want us to encourage further adoption of electric transportation.

Our Action Regarding this Topic

We incorporated energy efficiency measures that meet EEPS into our analyses.

We offer TOU incentives to EV owners to shift charging to overnight, and are piloting a charging infrastructure that can align with DR programs and pricing. We have filed a revised TOU structure to shift charging to midday when solar production is at its peak.

To minimize "range anxiety", we are installing and operating publicly available, direct current fast charging stations that can charge an EV battery to 80% capacity in 30 minutes. We are also demonstrating the capability to limit and curtail the maximum demand of a 50 kW DC fast charging station to 25 kW, and investigating opportunities to encourage daytime public and workplace charging.

Hawaiian Electric participates in the Honolulu Department of Transportation Services (DTS) 2016 Transportation Investment Generating Economic Recovery (TIGER) grant application for a Honolulu Urban Bus Circulator System. The TIGER grant is a cost-effective solution to significantly advance mobility in the most congested areas of the city. The current proposal includes up to 24 high frequency and high capacity electric buses that will be incorporated within the circulator system; Hawaiian Electric plans to partner with DTS on the electric bus charging infrastructure.

15. Inter-Island Transmission

The Parties want us to address the impact of inter-island transmission on the reliability of the Oʻahu, Maui, and Hawaiʻi Island power grids, specifically how a forced cable outage affects reserve requirements and reliability.

Our Action Regarding this Topic

We are analyzing a grid-tie between Oʻahu and Maui and between Oʻahu and Hawaiʻi Island, and how an outage would affect reserve requirements and reliability. The 2016 updated PSIPs describe our progress on this analysis, which we expect to only be able to complete after the filing deadline. We are committed to completing this analysis, including updated analysis that incorporates the 2016 EIA AEO fuel price forecast[8] and submitting that updated analysis on or before August 31, 2016.

[8] The Energy Information Administration 2016 Annual Energy Outlook is expected to be published in June 2016.

C. Analysis Methodologies

The issues related to planning the future of Hawai'i's power systems are complex. These issues represent uncharted territory for any utility performing long-range resource planning.

Hawai'i faces a unique situation: a comprehensive electric grid transformation to attain a 100% Renewable Portfolio Standard (RPS) by 2045. To aid in this endeavor, we developed a Decision Framework and PSIP Planning and Modeling process creating a structure that incorporates planning, modeling, and optimizing potential resources to attain our energy goals. Through this process, we expect to enable careful, thoughtful, well-rounded, and well-considered decisions.

In our 30-year planning period for these updated PSIPs, we are considering the optimization of a number of resource options, including commercial and emerging DER options, DR, and a number of commercial and emerging utility-scale resources. This optimization must take into account the system reliability issues of our independent island systems. In addition, we must consider customer behavior, global energy market conditions and expectations, state energy policy objectives, and competing agendas of various stakeholders.

The methods and techniques used by the utility industry in the past are simply not sufficient to accomplish the analysis required to address these many factors. A key objective is to make this planning process clear and transparent despite its complexity. Our Decision Framework describes our approach for considering the various input options, and our PSIP Planning and Modeling process explains our approach for developing the most optimal resource plans.

DECISION FRAMEWORK

Four factors comprise our Decision Framework.

Objectives. The specific results that the planning process aims to achieve. It's important that these objectives be precise.

Requirements. Fixed parameters around which a plan must be built and that do not vary between plans or plan sensitivities.

Input Parameters. Parameters that are not fixed like a Requirement, but are also not a variable that can be controlled to optimize toward achieving the Objectives. Input Parameters can be varied to deal with the uncertainty and to understand the sensitivity of a plan to a change in assumptions.

Decision Variables. Variables that can be varied toward achieving the Objectives. Decision Variables include resources and programs that can be leveraged by the utility in a given plan to achieve the Objectives.

The objectives, requirements, and input parameters all feed into the decision variables. Figure C-1 depicts the quantities and timing of resources (including DER, DR programs, and utility-scale resources) on the electric system that are varied to achieve the objectives, while meeting fixed requirements, and considering the input parameters as assumptions. These are the primary objectives, requirements, and input parameters.

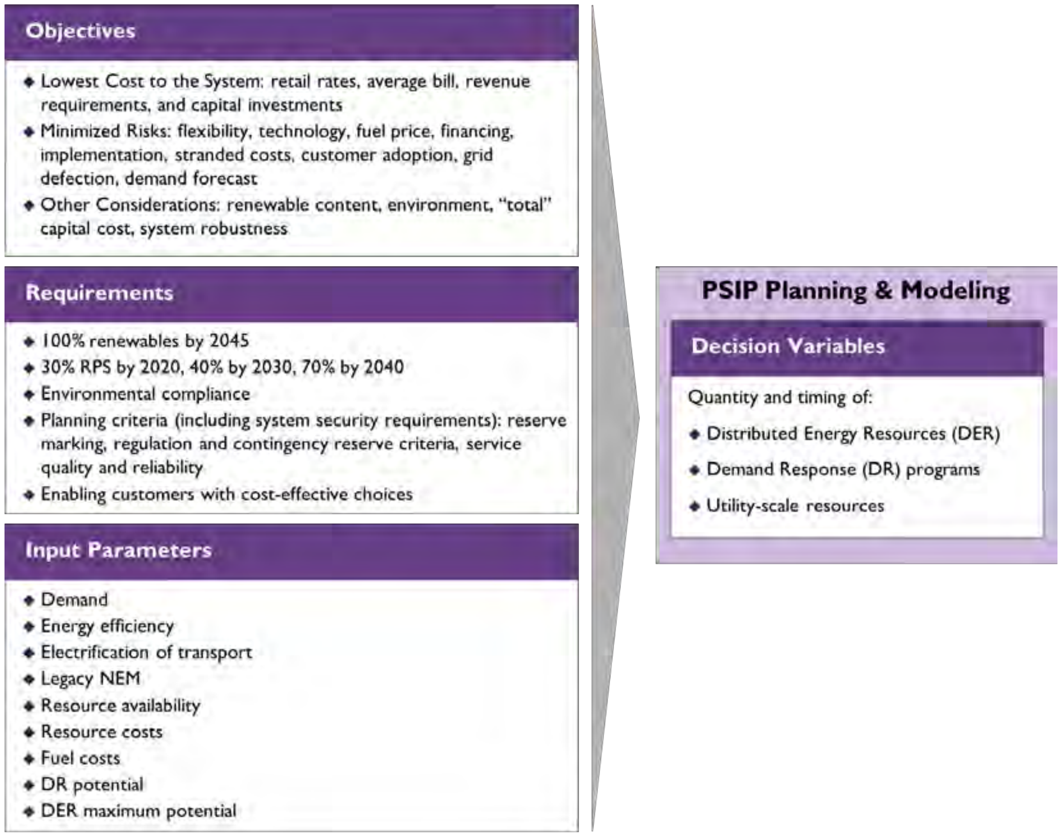

Figure C-1. Overview of the Decision Framework

Objectives

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

Lowest Cost to the System. Minimizing customer cost is a primary objective of the planning process, including the retail rates and a customer's average bill. Total system costs consider the total costs to the electric system, including generation, transmission and distribution, interconnection, revenue requirements, capital expenditures, and integration costs.

Minimized Risks. Any forecast has uncertainty, which in turn introduces risk to a plan that is carried out based on that forecast. Examples of risks for a given plan include planning flexibility; technologies chosen and their related costs; fuel costs that are higher or lower than forecasted; project implementation risks including permitting and siting issues, and community acceptance; financing risks associated with availability and cost of capital investments and expenditures; risks associated with stranded costs, and the rate at which customers adopt renewable generation and provide grid services; the risk of customers leaving the grid and spreading fixed costs over the remaining customers; and the risk of not achieving energy efficiency goals to the point of affecting demand forecasts.

Other Considerations. We must consider many other factors besides the primary objectives of minimizing customer cost and minimizing risks. For example, a plan that is more costly than another, but achieves greater levels of renewable energy and lower fossil fuel use might be preferred by some stakeholders. Another plan with lowest utility revenue requirements, and thus has the most favorable impact on customer bills, might require large subsidies (for example, tax credits and subsidies) and customer investments that results in a higher total cost. While every plan meets system security requirements, some plans might have qualitative considerations related to system robustness (such as the amount of inertia and the size of the transmission balancing area). We must also consider the environmental impact of current and future generation.

Requirements

Requirements are fixed parameters around which plans are built. Requirements do not vary between plans or plan sensitivities. Requirements include RPS mandates, other regulatory compliance, planning criteria, and enabling customers the choice of providing cost-effective and reliable grid services.

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

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

Planning Criteria (including system security requirements). Planning criteria are standards for safe, reliable power supply for customers. Planning criteria are developed considering system security requirements, system reliability, loss of load probability, service quality, and adequacy of supply necessary to maintain an acceptable level of reliability.

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

System security requirements are necessary to provide an adequate level of reliability. Currently, generators provide the majority of the necessary system security attributes. At some point, DR and energy storage resources might be available in sufficient capacities to augment or replace these generators. Updated system security analyses identified fast frequency response requirements for each island system. Continued analysis based on planning criteria might identify additional resource needs and operational constraints.

Enabling Customers with Cost-Effective Choices. With more DER options, customers have choices that we will continue to enable. Customers can effectively be a "prosumer", that is one who both consumes energy, uses utility services, and provides services to the utility. Customers also have the choice to provide grid services to the electric system; the price for such grid services, however, must reflect their economic value relative to other resources.

Input Parameters

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

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

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

DR and DER Potential. DR and DER programs might provide multiple grid services. We must determine the total potential that these programs could contribute to the candidate plans. DR includes programs that leverage a variety of flexible customer-sited resources to provide grid services. Self-supply and grid supply programs and DER compensation levels, effectively set, affects customer adoption.

Decision Variables

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

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

PSIP PLANNING AND MODELING

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

Figure C-2 illustrates the PSIP Planning and Modeling process. These processes involve multiple internal resources and modeling efforts. Throughput of a single iteration takes time, with multiple reviews and validations at various points during each iteration.

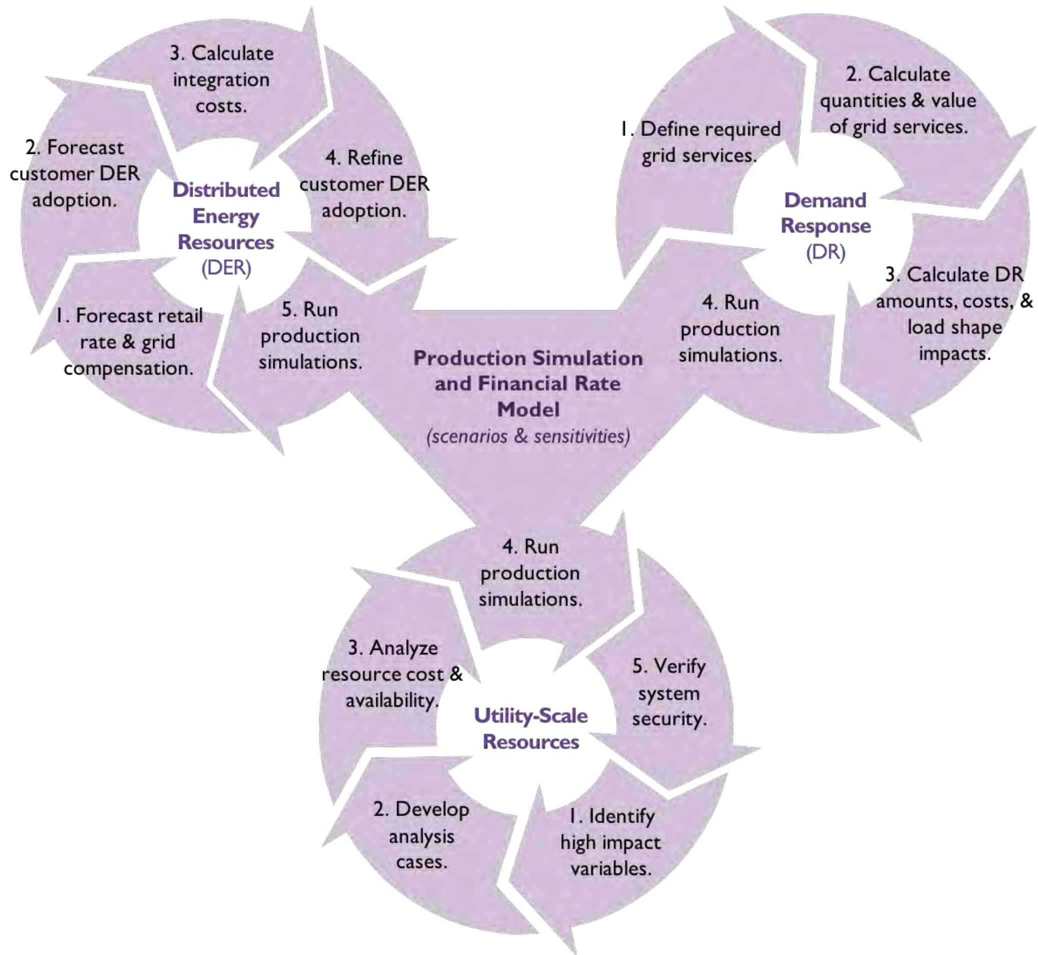

Figure C-2. PSIP Optimization Process for DER, DR, and Utility-Scale Resources

The following sections explain each of these three iterative cycles.

DISTRIBUTED ENERGY RESOURCES ITERATIVE CYCLES

DER includes assets such as DG-PV and distributed energy storage systems (DESS) that play a critical and growing role in the future electric system. Customers decide to install these assets based on a number of factors, including cost savings on electricity consumption and compensation from providing grid services through DR programs. We plan to integrate and optimize DER into the generation resource mix on a system level based on customer decisions to install these assets.

To begin, we forecast the potential DER that customers would be willing to adopt based on preliminary assumptions on customer economics related to DER. We plan to integrate the new DER exports into the resource mix that is below the avoided cost for alternative generation assets with similar attributes. We assume that existing DER programs, including legacy NEM, Standard Interconnection Agreement (SIA), Grid Supply to cap, and Self Supply run through their current program life at current compensation levels. In addition, we assume a new program for grid export of DG-PV will be instituted—similar to today's Grid Supply program but with an updated compensation rate. (This assumption is only for planning; we will discuss a detailed program structure in the DER 2.0 proceedings.) Forecasting assumptions included the 2013–2014 historical hourly customer load profiles by island and rate schedule, optimum system size, tariffs, export rate, storage value, income tax credits, system costs, eligible customers, inflation rate, and weighted average cost of capital.

Since the interim filing, we have refined these economic adoption assumptions, and developed programs to enhance this adoption rate—programs that optimize and provide the most benefits for our customers and grid services in conjunction with other renewable resources in our future portfolio.

1. Forecast Retail Rate and Grid Compensation

The payback time of a customer-sited DER system is determined by customer benefits received over time versus customer cost for the DER system.[1] The DER system may benefit customers by offsetting their retail electricity purchases by being compensated for providing grid services.

- **Forecast Payback Time for DG-PV Compensation.** Order No. 33258[2] specified compensation rate and cap by island for a new grid-supply product. As a preliminary assumption for the compensation of the export of future DG-PV not covered under the existing programs and aligned with an Objective to achieve lowest cost, we:
- Considered resources with similar variable generation attributes, to avoid inequitable comparisons to firm generation resources.
- Considered resources with comparable time-of-day production (for example, those resources producing during solar generation hours).
- Enabled full utilization of DG-PV on the system. To achieve an objective at lowest cost, this implies compensating DG-PV at the same level as alternative energy resources with similar attributes (renewable, variable, producing during solar generation hours).
- Modeled the DG-PV resource as controllable and curtailable, similar to other variable generation resources.

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1 Appendix J: Modeling Assumptions Data contains forecasts for the cost of DG-PV, utility-scale PV, and residential energy storage. These cost forecasts were developed in conjunction with the utility-scale cost assumptions utilizing the same base data sources and assumptions.

2 Issued on October 13, 2015 in Docket No. 2014-0192: Proceeding to Investigate Distributed Energy Resource Policies.

We compared utility-scale PV with DG-PV. We also assumed the future DG-PV export rate to mirror the respective levelized cost of energy (LCOE) of utility-scale PV for every year of the 30-year planning horizon. This assumption ensures optimal amounts of DG-PV are fully utilized by the system under economic dispatch principles. (This is simply a modeling assumption, and not a policy decision.) Continued analysis could further refine these assumptions.

Forecast Payback Time for Other DER Compensation. Retail electricity price and the value of grid services are a function of the overall electric system. Retail electricity price forecasts are derived from the production simulation and financial rate model. The value of grid services is derived from the production simulation and DR modeling.

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

DER Controllability. The 2016 updated PSIPs assume system operator control of DG-PV will be feasible before or by mid-2018, based upon the following:

- Commission approval of our proposals in the DR docket by the end of 2016 and of our proposals in the DER docket by the end of 2017.
- A Distributed Energy Resource Management System (DERMS) implemented by mid-2017. A DERM incorporates traditional Demand Response Management System (DRMS) functionality and a full suite of distributed energy management capabilities currently in production and under development by Omnetric. The DERMS is assumed to control a wide array of distributed energy resources, regardless as to whether they are enrolled specifically in a DR program.
- The 2016 updated PSIPs assume policies and programs (including pricing programs) that stipulate distributed energy resource control in place by mid-2018. The details of these policies and programs are expected to be captured outside of the updated PSIPs and jointly between current DR program filings and the anticipated DER Phase II proceedings.
- Implementation of a Company-owned A*dvanced* Metering Infrastructure (AMI) communications network to exercise DER control. Our AMI infrastructure is not currently expected to be implemented until after 2018. We expect that aggregators and DER providers will provide near-term communications sufficient for the preliminary stage of DER control and the associated feedback loop.

2. Forecast Customer DER Adoption Levels

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

3. Calculate Integration Costs and Curtailment Amounts

When DG-PV installations exceed the circuit hosting capacity limit, circuit upgrades are required while some curtailment might also be required. Integration costs and curtailment amounts to accommodate DG-PV over the circuit hosting capacity limit are calculated by circuit.

We developed a methodology to quantify integration costs and curtailment amounts on circuits over the hosting capacity. That methodology allocates DG-PV forecast pro-rata across circuits, identifies integration solutions and their respective costs, calculates curtailment amounts, then applies these integration costs and curtailment amounts to adjust the economics and the expected adoption rate from both a system and a customer perspective. Integrating variable renewable energy (including DG-PV, utility-scale PV, and utility-scale wind) might require regulating reserves, energy storage, investments in system operations, and curtailment. Based on these changed economics, the DG-PV is re-forecast.

Figure C-3 depicts a high-level overview of the circuit-level integration cost methodology.

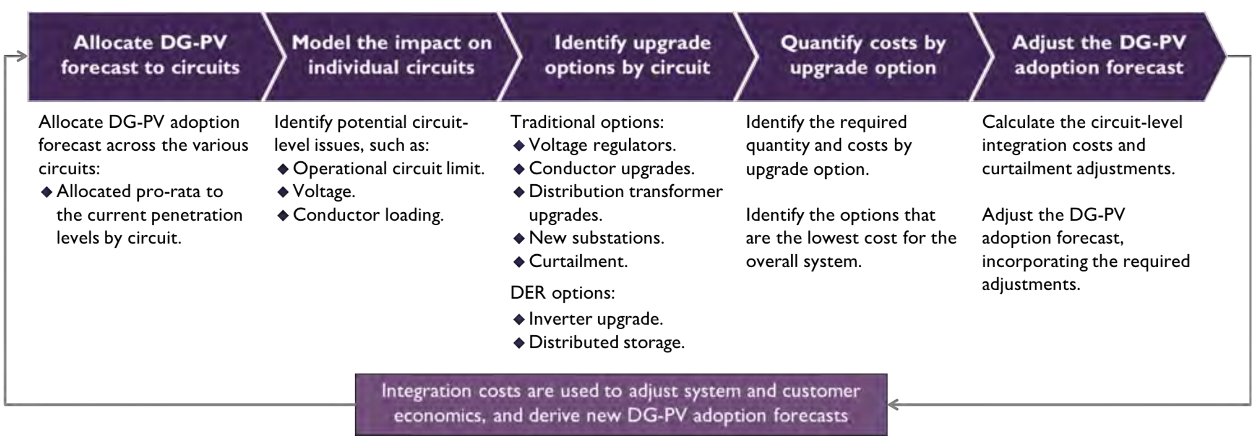

Figure C-3. Circuit-Level Integration Cost Methodology

4. Refine Customer DER Adoption Levels

Integration costs and curtailment amounts adversely impact the value of DG-PV for customers adopting DG-PV above the circuit or system hosting capacity limits. As a result, integration costs and curtailment amounts can result in a refined payback time and associated customer adoption rates. To determine preliminary assumptions for our 2016 PSIP analysis, integration costs are allocated only to those customers who install a

DG-PV system above circuit and system hosting capacity limits (and not assumed for other customers), or integration costs are allocated to all customers. DG-PV adoption forecasts and costs to customer are provided for each scenario.

We continue to refine the economic adoption assumptions and are developing programs to enhance this adoption rate. These programs optimize and provide the most benefits for our customers and grid services in conjunction with other renewable resources in our future portfolio.

5. Run Production Simulation with DER Adoption Levels

The previous four steps result in a forecast of DER adoption levels based on two factors: 1.) customer uptake of DER based on the economics from the customer's perspective, and 2.) provision of power supply and grid services from the customer that is cost effective for the overall system.

These DER adoption levels are then included in a subsequent production simulation and financial model iterations and as potential in the DR iterative cycles. The DER adoption levels impact net sales and peak forecasts. If the retail electricity price and the value of DER substantially change in the production simulation and financial model, and in the DR modeling, then the five DER steps are iterated again. Successive iterations optimize the quantities of DER.

DEMAND RESPONSE (DR) ITERATIVE CYCLES

Demand Response requires a separate iterative cycle for resource planning.

1. Define Required Grid Services

Our portfolio of DR programs delivers grid services that help meet system security requirements. These grid services serve as the basis of all programs. Grid service definitions are cross-referenced with DR program attributes and rules to ensure an effective delivery of the grid services by DR resources. As part of the PSIP update, these service definitions and their associated equations are being modified.

The first step in DR optimization is to assess the degree to which these modifications impact the DR potential, and thus the overall DR portfolio. In parallel, we are adjusting, as necessary, the market potential of the various DR programs.

The DR potential study model is re-run with these modified and refined inputs: updated load forecasts based on new resource plans; adjusted ability to control a DR resource based on revised program attributes; refined end-use load shapes and associated ability to shed load; and modified percentage of customers willing to enroll in a particular program.

2. Calculate Quantities and the Value of Grid Services

To identify the potential for DR resources to deliver grid services, DR optimization must first understand the quantities and value of the various grid services for each time interval, for each island power grid. To the extent feasible, DR opportunities for providing each grid service is evaluated independent from each other based on the results of step 1 of DR optimization.

Costs will not always be aligned with quantity. For example, it may be necessary to provide a minimum amount of a particular grid service during a particular time interval in order to alleviate a must-run requirement and therefore realize value from a DR resource.

The value of a given grid service might depend on that grid service being provided concurrently and in conjunction with other grid services. For example, the inertia grid service may be linked to the primary frequency response (governor response) combined with the spinning contingency reserve to alleviate a must-run requirement. This means that a DR resource that provides only a single grid service would have limited value on a stand-alone basis. DR resources that provide multiple services will have greater value.

The value of each grid service is calculated to determine how best to apply DR resources. Grid service values are calculated by comparing system production costs between model runs for adjusted service levels. More precisely, altering appropriate service requirements or constraints relative to a reference case results in differences in system costs that can be used to calculate the incremental costs of delivering that service. Understanding the relationship to quantity and value of services over time helps determine substitution opportunities for DR products. Generators can be simulated as must-runs for reliability. If a service can meet the reliability need, the must-run requirements are adjusted to allow generation to be dispatched economically. The change in costs from relaxing must-run constraints helps infer the value of a service (such as inertia).

3. Calculate DR Amounts, Costs, and System Load Shape Impacts

Once the quantities and values of grid services have been derived, an optimal DR portfolio is developed as input. An iterative process derives both the population of end-use devices and the resulting DR fit for delivering grid services cost-effectively. Several sub-tasks represent this iterative process.

Preliminary Inputs. These inputs are required for analyzing DR fit:

- The refined DR potential calculated during DR step 1.
- The quantity and value of the services derived from DR step 2.

Identify DR Portfolio Fit. DR can provide a portion of the required grid services by displacing grid services by generating assets within an analysis case. The projected fit and value of DR products to meet some or all of each of the grid service needs, for each time step, is determined for each island power grid. Using the adaptive planning model (developed by Black & Veatch), the provision of grid services from conventional resources and DR products are optimized to meet the power system reliability requirements at minimal overall cost (producing cost savings). Cost savings result from changes in the timing of the expansion plan or size of an added resource, changes in retirement timing, or changes in operation. These cost savings can be capital deferment, avoided fixed costs, or avoided variable costs.

DR programs can be reshaped daily to address changes in demand, wind and solar profiles, and the availability of assets.

The adaptive planning model can then calculate the "stack" of DR resource utilization and allocate them to maximize their value to the DR portfolio. This capability allows us to assess the fit of the model's results against system security needs and the underlying asset portfolio characteristics.

A sensitivity analysis is then conducted to expose areas where changes in the electric system can substantially impact the value of DR services. These sensitivities include the availability, size and cost of storage and the role of DR products given modified security constraints.[3]

Because the adaptive planning model directly calculates value in moving underlying end uses between DR programs, the resulting fit is generally optimized against security and system asset characteristics. Further investigation might be necessary to validate results or to identify gaps where additional DR products could help meet system response requirements or reduce curtailment of variable renewables.

Derive Value. Value can be derived of bundled services for storage only, or for real time pricing (RTP) only (that is, for DG-PV plus energy storage systems). The model develops annual values associated with bundles of grid services that can be delivered by a stand-alone storage device. This then serves as a proxy for the annual economic value earned with stand-alone DESS. In addition, the model develops an annual value of the

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

time-of-use (TOU) and RTP programs, which serves as a proxy for economic value for DG-PV plus energy storage system. Values are for the 2017–2045 timeframe.

Load shifting can be accomplished with pricing, storage, and behavioral tools (for example, DR) in addition to utility-scale and grid solutions.

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

Refine Populations and Potential. The model inserts the forecasted customer adoption for DESS and DG-PV plus storage into the potential study model. A revised DR potential is then calculated based on the updated customer groups.

Rerun DR Portfolio Fit. This revised DR portfolio potential is then used to determine the DR fit and corresponding value of the DR services. The DESS and DG-PV plus storage values are compared to the values previously calculated. If these values are essentially consistent with the previous iteration, forecasting is complete because the convergence reflects an optimal population of the end uses and the DR portfolio as a whole, for that particular case—in other words, the best fit. If the values are meaningfully different, then customer adoption is re-forecasted.

Iterate until Values Converge. If the economic value of DR, DESS, and PV plus storage converge, the iterative process is complete because the economic value of the populations and the DR portfolio are sufficiently optimized, for that particular case. If these economic values vary, iterations continue until the set of economic values converge.

Finalize the DR Portfolio. A DR portfolio is optimized when the fit and economic values converge. This optimized DR portfolio is then finalized and used in production simulations. For each case, these results are a combination of the:

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

4. Run production simulations with DR amount and load shape adjustments

The optimized DR portfolio is then used as an input to the production simulation model. Portfolio costs and any cost impacts related to resource plan adjustments are added to the economic evaluation of each resource plan case.

UTILITY-SCALE RESOURCES ITERATIVE CYCLES

The utility-scale resource iterative cycle is similar to the cycles for DER and DR.

1. Identify High Impact Variables

Variables that have a high impact on the Objectives are first identified. Initial examples include fuel type, extent of generation modernization, and amount of DER adoption. In subsequent iterations, additional high impact variables are identified and varied between cases to understand their impact on the Objectives.

2. Develop and Refine Analysis Cases

Cases to be analyzed are developed based on the high impact variables and the results of the DER and DR iterative cycles to better understand their impact on the Objectives. For example, the fuel type used in one case might assume a low LNG price forecast whereas another case might assume a low oil price forecast (without LNG) for as a transition fuel toward attaining the 100% RPS goal.

DR amounts, costs, and system load shape impacts from the DR iterative cycles are also incorporated into the cases run in the production simulation.

3. Analyze Forecasted Resource Costs and Availability

This step determines near-optimal resource quantity and timing. The production simulation and financial rate model determines, at a very detailed level, generation output and the associated rate impacts for a given case. Multiple cases are compared, revised, and successively iterated until a plan is identified that best meets the Objectives.

To make this iterative process more efficient, resource cost forecasts are analyzed outside of the production simulation to identify likely near-optimal resource quantity and timing for the various analysis cases. Two models outside of the production simulation identify likely near-optimal resource quantity and timing.

Resource Cost Competitiveness and Economic Curtailment Amount. This model identifies how much of a new resource can remain cost effective when curtailed, and when such a resource should be introduced into the plan. The model calculates when a new resource costs less than existing resources, and how much can be curtailed while still remaining less costly.

System Need and Cost-Effective New Resource Implementation Amount. This model, accounting for system needs and economic curtailment, determines how much of a new resource can be added to the system by calculating the net non-curtailable resources from load. The model then adds the cost-effective resources up to the economic curtailment amount to determine the annual amount (in MWs) that the new resource can be added.

The two models output an annual schedule as to when a new resource can cost-effectively be implemented, and when existing resources can be retired. This schedule is then used in the production simulations.

4. Run Production Simulations

This step analyzes cases to test the incorporated high impact variables and near-optimal resource quantity and timing. Production simulations calculate each resource's generation through hourly and sub-hourly unit commitment and economic dispatch algorithms. Outputs are then used to determine the total system costs and the impact on customer rates that consider capital costs, fuel costs, and fixed and variable O&M costs over the planning period. These results are analyzed, and then iterated until a plan is unveiled that best meets the Objectives.

5. Verify System Security Compliance

Each case is analyzed to ensure it meets system security requirements for simulated commitment schedules and dispatch levels when subjected to various contingency conditions. If system security requirements are not met, technology-neutral system requirements are determined and adjustments are made to the resource plans. Sometimes, generating units must be committed or dispatched outside of ideal economic dispatch levels until technology-neutral alternatives are added to the grid or until the driving contingency event can be eliminated to maintain system security.

When sufficient capacities of DER and DR resources are available, ancillary services provided by thermal units will not constrain resource plans.

D. Current Generation Portfolios

PLANNED CHANGES TO CURRENT GENERATION

Our assumptions include changes to current generating units and to existing PPAs.

Current Generating Units

Hawaiian Electric plans to retire most of its current thermal generation during the planning period, however the exact timing of these retirements is uncertain as it depends on a number of factors. Chief among these factors is maintaining adequacy of supply, but these factors also include the timing of the implementation of replacement generation, fuel costs, outcomes from DR programs, and peak demand.

Waiau 3 and Waiau 4

Our PSIP analysis assumes that Waiau 3 and Waiau 4 will be deactivated in 2022 to 2023, depending on the theme. For Theme 1 and Theme 3, Waiau 3 and Waiau 4 are assumed deactivated in 2023; for Theme 2, they are assumed deactivated in 2022. We made these judicious assumptions based on our assessments of capacity needs and the input variables in this 2016 updated PSIPs.

The 2014 PSIPs targeted these units for deactivation at the end of this year, 2016. Based on a Loss of Load Probability (LOLP) guideline of 4½ years per day, Hawaiian Electric's 2015 AOS reported a reserve capacity shortfall of 50 MW, beginning in 2017 if these units were deactivated in 2016. The AOS report stated that reserve capacity shortfalls could be mitigated by "by deferring future deactivation of units, increasing Demand Response Programs, reactivating units that are currently deactivated, or acquiring additional firm capacity through a competitive bidding process."

Hawaiian Electric's 2016 AOS report assumed the deactivation of Waiau 3 and Waiau 4 at the end of 2017 to avoid a capacity shortfall in 2017. Shortfalls are still projected for 2018 and 2019, even if the Schofield Generating Station is in service in 2018. Delaying the deactivation of Waiau 3 and Waiau 4 beyond 2017 virtually eliminated reserve capacity shortfalls. A small reserve capacity shortfall is still anticipated in 2018.

We will continue to monitor factors that determine the best timing for deactivating Waiau 3 and Waiau 4. These factors include system demand, net of customer-sited distributed generation and demand response, availability of new generating capacity (from the Schofield Generation Station), and the unavailability of capacity from scheduled or unscheduled maintenance.

Honolulu 8 and Honolulu 9

The PSIP analysis assumes that Honolulu 8 and Honolulu 9 remain deactivated, and are converted to synchronous condensers to enhance power line voltage regulation.

Hawaiian Electric's 2016 AOS report assumed Honolulu 8 and Honolulu 9 remained deactivated until 2020 and beyond. We would not need to reactivate these units if the deactivation of Waiau 3 and Waiau 4 were deferred until the end of 2020, and the Schofield Generating Station came online in 2018.

Higher than forecasted peak demand might cause reserve capacity shortfalls.[1] We would need to reconsider reactivating Honolulu 8 and Honolulu 9 if significant reserve capacity shortfalls are projected, but only after implementing other mitigating measures (such as running new DR programs, acquiring additional firm capacity, deferring other unit deactivations, and refining generating unit planned outage schedules). Reactivating Honolulu 8 and Honolulu 9 would take about three months.

Maui Electric

On Maui, Kahului 1 and Kahului 2 are currently deactivated. However, these units are counted towards firm capacity because they can be, and are, reactivated when needed to maintain system reliability.

Maui Island has two generating stations and one distributed site. Our Kahului Power Plant has four steam units totaling 35.92 MW (net) firm capacity. Maui Electric deactivated two units to conform with our System Improvement and Curtailment Reduction Plan,[2] but we can reactivate them in the event of a shortfall. The other two

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[1] Our 2016 AOS report noted that the peak demand recorded in 2015 and adjusted for standby load was 1,232 MW-net. This was 37 MW higher than the 1,195 MW-net peak demand forecasted for 2015. The report attributed this higher peak demand to higher than normal temperatures and humidity. The adjusted 2015 recorded peak is 69 MW higher than the 1,163 MW-net peak demand forecast for 2016.

[2] *System Improvement and Curtailment Reduction Plan* filed in Docket No. 2011-0092, September 3, 2013.

units were previously scheduled for retirement in 2019, however their retirement would have resulted in a reserve capacity shortfall of approximately 40 MW per year. To ensure enough capacity to meet demand, we obtained a National Pollutant Discharge Elimination System (NPDES) permit[3] from the State of Hawai'i Department of Health (DOH) to allow Kahului Power Plant to continue operating provided we retire the units by November 13, 2024. We currently plan to retire the entire facility in 2022 assuming sufficient replacement resources (including DR and generation) are in operation by then.

Our Ma'alaea Power Plant has 15 diesel units and 4 gas turbines. They can be configured into two separate combined-cycle systems supplying two steam turbines totaling 208.42 MW (net) of firm capacity. In 2014, we upgraded the generator controls on four of the diesel units so that they could be monitored and operated remotely. These upgrades enable us to better respond to system disturbances and system demands because of increased variable renewable resources on the system. We plan to modify one of the combined-cycle systems, allowing it to operate at lower levels so that the grid can accommodate more renewable generation.

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

Our analysis assumes that all units on Moloka'i and Lana'i are active and operating. Moloka'i has a centralized generating station with nine diesel internal combustion engines (ICEs) and one diesel combustion turbine with combined capacity to generate 12.0 MW (gross) firm capacity. We recently received approval from the DOH to allow for lower minimum operating levels on the two baseload units to accommodate more renewable generation. We also scheduled generator control upgrades for 2016 to improve operation and troubleshooting of the generating units.

Lana'i includes a centralized generating station with nine diesel units with 10.4 MW (gross) firm capacity. We have applied to the DOH to allow for lower minimum operating levels on the two baseload units to accommodate more renewable generation We plan to implement the same generator control upgrades as on Moloka'i. We also plan to operate a Combined Heat and Power (CHP) unit to provide baseload power; it's expected to return to service in 2017.

Hawai'i Electric Light

Hawai'i Electric Light placed Shipman 3 and Shipman 4 on dry layup (inactive) on November 21, 2013, and retired them on December 31, 2015. The production and maintenance costs for the units were not cost effective compared with other generating

3 The permit includes various conditions, including a compliance plan which identifies interim milestones to cease water discharge by 2024.

units. Even without these units, the utility has sufficient generating capacity to provide adequacy of supply.

Status of Existing PPAs

Since we filed our 2014 PSIPs, we have experienced changes in assumptions for some of our Independent Power Producers: AES Hawai'i, Kalaeloa Energy Partners (KPLP), Hamakua Energy Partners (HEP), Hu Honua, and Hawaiian Commercial & Sugar (HC&S). We have also updated our plans for modifying existing units to burn gas, and changed operations to comply with environmental requirements.

AES Hawai'i Generating Unit

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

However, in the near term, to address potential generation reserve shortfalls, AES can provide additional capacity to help ensure reliable service until additional firm generation is available. On January 22, 2016, we filed an application with the Commission seeking approval of Amendment No. 3 to our existing PPA with AES Hawai'i. If this amendment is approved by the Commission, AES would provide an additional 9 MW of firm, dispatchable capacity and associated energy from the existing power plant. This could be called upon as needed but we are not required to use it. Because AES provides the lowest cost energy to the system, this addition helps lower customer bills in the near term. The amendment will not extend the term of the PPA.

Kalaeloa Energy Partners (KPLP)

The O'ahu-based Kalaeloa Plant's combined-cycle design has the operational flexibility required to support the needs of a renewable generation fleet. The existing PPA for the Kalaeloa Plant, however, is restrictive in not allowing us to operate the plant with the flexibility that will be required in the future. Operating restrictions include limitations on startup times, ramp rates, and minimum load. In addition, the unit's fuel source is inflexible; we would like to have more fuel sources available to minimize costs to the customer.

The ability to operate KPLP more closely aligned with its design would enable the facility to better support our future renewable fleet. Options to remove these restrictions are ongoing and could consider several alternatives. Should the PPA expire and KPLP cease to provide firm capacity, we might seek additional capacity by deferring future deactivation of units, increasing DR programs, optimizing maintenance schedules, reactivating currently deactivated units, or acquiring additional firm capacity.

The 2016 PSIP analysis assumes the same operational flexibility of the KPLP plant (described herein) after the end of the existing PPA.

Hamakua Energy Partners (HEP)

HEP is a reliable, flexible firm capacity resource on Hawai‘i Island that continues to be critical in meeting adequacy of supply and system security needs with reasonable energy costs.

On February 12, 2016, Hawaiian Electric and Hawai‘i Electric Light submitted an application requesting the Commission issue an order no later than November 1, 2016 approving the purchase of the 60 MW dual-fuel combined-cycle HEP plant and its related assets. The application describes the purchase terms and the benefits to our customers.

Acquiring and continuing to operate HEP provides Hawai‘i Electric Light customers an efficient and reliable source of electric power. Company ownership enables us to improve customer benefits. The PPA’s Covered Source Permit constrains unit commitment to one start per unit per day. Under the PPA, a started unit cannot be taken offline unless it will not be needed later in the day. The economic dispatch is based upon the contractual heat rate, which results in a higher energy rate than the equipment heat rate.

Company acquisition would allow economic dispatch of the plant based on the true heat rate, which results in lower costs than the contractual heat rate and to take action to reduce the startup restrictions. The purchase would remove the fixed contractual capacity charge, thereby saving customers money. In addition, we anticipate economic and system reliability improvements by adding a steam bypass system (which HEP was unwilling to install at their expense). This addition will permit faster startup time in simple cycle, improving system benefits associated with increasing variable renewable energy, and reducing startup costs.

The HEP plant can be converted to burn clean, cheaper LNG, supporting the transition to 100% renewables. Ownership enables the Company to have direct control on the potential for this fuel conversion and equipment maintenance to better meet future needs of our system and our customers.

Adding the HEP combined-cycle plant to our fleet also provides valuable operational and maintenance synergies. For example, the Keahole unit on Hawai'i Island and the two Ma'alaea units in Maui also run the same GE LM2500s in a combined-cycle plant configuration.

Hu Honua

On March 1, 2016, Hawai'i Electric Light terminated the PPA with Hu Honua Bioenergy for firm capacity and energy (biomass) due to Hu Honua's failure to meet critical construction milestones that were guaranteed under the PPA. The PSIP analysis does not assume Hu Honua is available.

Hawai'i Island Geothermal Request for Proposal (RFP)

Hawai'i Electric Light issued an RFP for additional geothermal generation. The only project bidder that met the minimum threshold requirements for selection to the Final Award Group in the Geothermal RFP has determined that developing the proposed geothermal project would not be economically and financially viable. All received bids were for projects located in East Hawai'i. Given this, a geothermal project resulting from this RFP is not a base assumption in the analysis.

Hawai'i Electric Light remains committed to the development of geothermal on the island of Hawai'i if it is in the best interest of its customers. While Hawai'i Electric Light is disappointed that the Geothermal RFP did not result in viable geothermal project, we remain hopeful that geothermal generation can be a viable option on Hawai'i Island in the future and can help Hawai'i meet its 100% renewable energy goal while lowering customer bills, reducing Hawai'i's dependence on imported oil, allowing for continued integration and management of variable renewable resources, and maintaining reliability of service.

Hawaiian Commercial & Sugar (HC&S) Closure

Maui Electric's current PPA with HC&S allows us to schedule up to 4 MW of firm capacity during certain months of the year. The PPA terms continued through December 31, 2017. On January 6, 2016, HC&S issued a Notice of Termination of Power Purchase Agreement, which specified that HC&S's contribution to the Maui Electric power grid would end on January 6, 2017.

The Maui Electric analysis assumes HC&S contributing 4 MW of firm capacity in 2016, and no generation in 2017 and beyond.

Maui Electric will explore other grid-related impacts associated with the PPA's termination. Maui Electric will continue discussions with HC&S about potential energy partnership opportunities that can result from future HC&S operations, including a locally-sourced biofuel supply.

EXISTING GENERATION FLEET

Hawaiian Electric Existing Generation

Hawaiian Electric recognizes certain challenges with integrating high levels of variable renewable energy into the current generation fleet, because of certain disadvantages:

- Slower ramp rates
- Longer start-up times
- Higher maintenance cost associated with cycling and turndown
- Less efficiency

Our generation fleet has served our customers for many decades. Unit characteristics are shown in Table D-1.

Unit	Type	Fuel	Capability (MW) Gross	Net	Age
Baseload (Load Following)					
Kahe 1	Reheat Steam	LSFO	86.0	82.2	53
Kahe 2	Reheat Steam	LSFO	86.0	82.2	52
Kahe 3	Reheat Steam	LSFO	90.0	86.2	46
Kahe 4	Reheat Steam	LSFO	89.0	85.3	44
Kahe 5	Reheat Steam	LSFO	142.0	134.6	42
Kahe 6	Reheat Steam	LSFO	142.0	133.8	35
Waiau 7	Reheat Steam	LSFO	87.0	83.3	50
Waiau 8	Reheat Steam	LSFO	90.0	86.2	48
	Totals/Average		*812.0*	*773.8*	*46.1 years*
Cycling					
Waiau 3	Non-Reheat Steam	LSFO	49.0	47.0	69
Waiau 4	Non-Reheat Steam	LSFO	49.0	46.5	66
Waiau 5	Non-Reheat Steam	LSFO	57.0	54.5	61
Waiau 6	Non-Reheat Steam	LSFO	56.0	53.7	55
	Totals/Average		*211.0*	*201.7*	*62.8 years*
Peaking					
Waiau 9	Simple Cycle CT	LSFO	53.0	52.9	43
Waiau 10	Simple Cycle CT	LSFO	50.0	49.9	43
CIP CT-1	Simple Cycle CT	Biodiesel	113.0	112.2	7
	Totals/Average		*216.0*	*215.0*	*31 years*

Table D-1. Hawaiian Electric Generating Unit Characteristics

The baseload units average 46 years of age, while the cycling units average 63 years. The combined average age of all steam units is 52 years. The existing generation fleet does well in serving stable consistent loads that are predictable.

Our existing fleet is not as efficient as modernized generation in effectively managing system stability with higher levels of variable generation. The fleet does have the advantage of limiting or reducing the cost of developing replacement generation because of the modifications made to its operation to enhance its flexibility.

To better integrate increasing amounts of variable renewable generation, the existing generation fleet ramp rate, turndown and on-off cycling capability must be expanded.

Ramp Rate

Wind and solar generation's variable nature requires generating units to react to output changes. Existing baseload units could provide a total ramping capability of 20.2 MW per minute. Our steam and cycling units together provide a total ramp rate of 33.6 MW per minute. We have been working to improve the ramp rates of the existing units.

Unit	Current Normal Ramp Rate (MW/min)	Proposed "Future" Normal Ramp Rate (MW/min)
Kahe 1	2.3	4.0
Kahe 2	2.3	4.0
Kahe 3	2.3	5.0
Kahe 4	2.3	5.0
Kahe 5	2.5	4.0
Kahe 6	2.5	4.0
Waiau 7	3.0	4.0
Waiau 8	3.0	4.0
Total Baseload Ramp Rate	*20.2*	*34.0*
Waiau 3	0.9	0.9
Waiau 4	0.5	0.5
Waiau 5	3.0	3.0
Waiau 6	3.0	3.0
Total Cycling Ramp Rate	*27.6*	*41.4*

Table D-2. Hawaiian Electric Generation Ramp Rates

The improved ramp rates have been tested over the years at all our units. The implementation issues revolve primarily around adjusting control system functions to allow for automatic operation at higher ramp rates.

Turndown and On-Off Cycling

The existing units have traditional minimum loads based on being able to respond to system disturbances and achieve full load anytime necessary. As renewable penetration increases, it will be advantageous for existing steam units to improve turndown (reduce minimum load) or cycle online and offline.

Reducing minimum load has some advantages over on-off cycling. When online and at minimum loads, the units still provide necessary services to the system: inertia, voltage regulation, frequency regulation, short-circuit current, some ramping capability, and some ability to respond to system disturbance. Compared to on-off cycling, low-load operation allows for quicker return to full load capability and lower long-term maintenance costs.

We have tested and confirmed that the low-load and cycling goals set forth in our 2014 PSIPs are achievable. Currently, system load dispatchers can reduce three units to the new 5 MW load when necessary to integrate additional renewable energy. The other units are expected to be ready for low-load operations by third quarter 2016.

Unit	Traditional Minimum Load (MWg)	New Minimum Load (MWn)	Restoration Time (hours)*	Cycling Time (hours)†
Kahe 1	25	5	1.5	3.5
Kahe 2	25	5	1.5	3.5
Kahe 3	25	5	1.5	3.5
Kahe 4	25	5	1.5	3.5
Kahe 5	45	25	1.5	3.5
Kahe 6	45	n/a	1.5	3.5
Waiau 7	25	5	1.5	3.5
Waiau 8	25	5	1.5	3.5

* Restoration time is from the new minimum load to full load capable.
† Cycling time is from a hot shutdown to full load capable.

Table D-3. Hawaiian Electric Generation Low Load and Cycling Targets

Minimum load reductions are accomplished by implementing hybrid variable pressure control operations. To maintain critical operating parameters, the units' throttle pressure is reduced when generating load drops below 30 MW. The pressure is reduced linearly from 1,800 psig at 30 MW to 900 psig at 10 MW. When load is below 10 MW, pressure remains at 900 psig.

Reducing minimum load requirements offers certain advantages over cycling units offline. It:

- Reduces thermal stress to the turbine rotor and casing.
- Reduces generation to a minimum to integrate more renewable energy.
- Provides system inertia.
- Provides short circuit current in the event of a system fault.
- Provides MVAR (reactive power) capacity and voltage support.
- Enables a unit to load to full capability faster than a unit startup.

A disadvantage is that the unit will have limited ramping capability until the throttle pressure increases to its normal operating range. DER and DR resources can mitigate this lack of reserve capacity.

Figure D-1 shows the ability of a unit to reach full load from its old minimum compared to the 5 MW minimum.

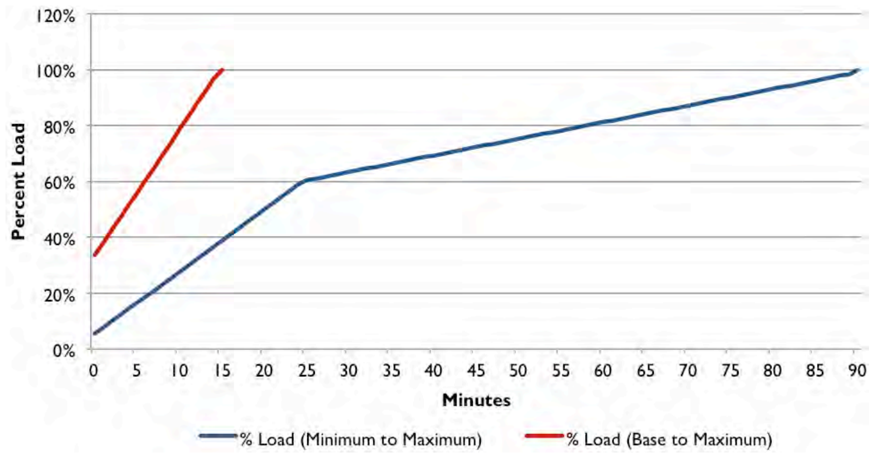

Figure D-1. Ramp Time from Minimum and Base Loads to Full Load: Hawaiian Electric

Unit Retirement Order Methodology

The current initial criteria for determining order of retirements includes cost, capacity factors, operational flexibility (including the constraints imposed by environmental permits), age, unit efficiency, and site staffing efficiencies.

Under Theme 2, the order of retirement assumed is as follows:

1. Honolulu 8 and Honolulu 9 units are already deactivated.
2. Kahe 1–3 together with the commercial operation of the Kahe replacement generation. (The intake cooling water systems are required for replacement generation.) Retirement Date: January 1, 2021.
3. Waiau 3 and Waiau 4, because of age, a low efficiency non-reheat plant design, and limited operational flexibility. Deactivation Date: January 1, 2022.
4. Kahe 4, because of staffing efficiencies and operational impact. This unit shared a control room and multiple systems with Kahe 3 and, because of the shared systems and stack structure, Kahe 1–3 cannot be demolished until Kahe 4 is retired. Deactivation Date: January 1, 2022.
5. Waiau 5 and Waiau 6, because of age, a low efficiency non-reheat plant design, and limited operational flexibility. Deactivation Date: January 1, 2024.
6. Waiau 7 and Waiau 8, because of age and its improved efficiency reheat design over other Waiau units. Deactivation Date: January 1, 2030.
7. Kahe 5 and Kahe 6 last, because they are the newest, largest, and most efficient units in the fleet (although there are no current plans to deactivate these units).

Under Theme 1 and Theme 3, the order of retirement assumed is as follows:

1. Honolulu 8 and Honolulu 9 units are already deactivated.
2. Waiau 3 and Waiau 4, because of age, a low efficiency non-reheat plant design. Deactivation Date: January 1, 2023.
3. Kahe 6, if not burning LNG, has limited operational flexibility because of covered source permit requirements. Deactivation Date: January 1, 2025.
4. Waiau 5 and Waiau 6, because of age, a low efficiency non-reheat plant design. Deactivation Date: January 1, 2030.
5. Waiau 7 and Waiau 8, because of age, its improved efficiency reheat design over other Waiau units, and improved staffing efficiencies by retiring the last Waiau steam unit.
6. Kahe 1 and Kahe 2, because of age, and their improved efficiency over Waiau units.
7. Kahe 3 and Kahe 4, because of age, and their improved efficiency over Waiau units.
8. Kahe 5 last, because it is one the newest, largest, and most efficient units in the fleet.

Generation Fleet Summary

Hawaiian Electric has expanded the capabilities of the existing generating units to support the changing electric system. These modifications, however, required tradeoffs.

Reducing unit minimum loads allows for increased renewable integration, but also reduces ramp rates. Many unit components are designed to last a specific number of cycles. At the average age of 52, the units have already experienced many thermal cycles. Low loads and increased cycling of these units, while successful, also increases maintenance costs, increases the potential for unplanned outages, and decreases their normal operational efficiency.

In 2012, the National Renewable Energy Laboratory (NREL) published its report, *Power Plant Cycling Costs*. That report demonstrated higher forced outage rates that result from cycling operation (Figure D-2), and concluded that costs associated with cycling and increased load following events would drive future maintenance cost higher.

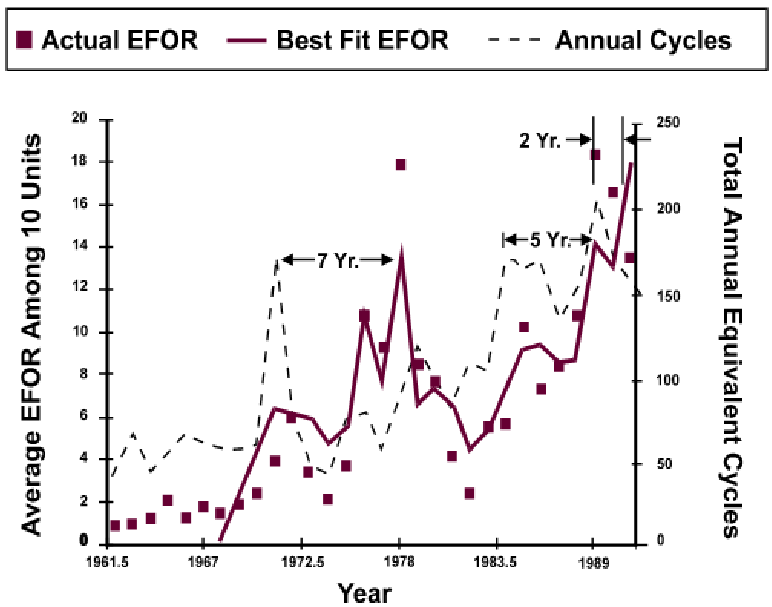

Figure D-2. Forced Outage Rates from Cycling: U.S. Averages

We understand the impact on units from low loads and increased thermal cycles. As a result, we are optimizing procedures and reviewing practices and options to minimize cost and maximize reliability. We expect to review options to reduce or minimize cycling-related damage.

To continue to provide reliable service, our aging steam units require continued capital investment. NextEra Energy analyzed the investment necessary to run the existing units out to 2045. This analysis projects a capital investment of $935 million. Investments would include replacing:

- The major boiler pressure components
- The major turbine components
- Controls
- Excitation
- Old motors and pumps
- Critical valves
- Critical balance of plant components

NextEra based its analysis on an assessment of unit condition assessment, component maintenance history, and industry experiences, and based its costs on the review of similar projects and industry standards.

Our existing steam generating fleet will serve our customers in an increasing dynamic way for years to come. Our peaking and cycling units will continue to fulfill those roles in the upcoming years. Our baseload (load following) units, however, will be assuming new roles in supporting the system. When renewable generation is high (such as high solar days), some of our reheat units will need to be cycled offline while others will be at new low loads. We will maximize the flexibility of these units to support our transition to the 100% RPS while considering potentially more cost-effective and beneficial solutions.

Maui Electric Existing Generation

Maui Electric's existing dispatchable generation fleet comprises two main power plants at Kahului and Ma'alaea. These plants include:

- Quick-start internal combustion engines (ICEs) that provide emergency replacement power and peaking generation.
- Combined-cycle units, comprised of two combustion turbines (CTs), two heat recovery steam generators (HRSGs) or once-through steam generators (OTSGs), and one steam turbine (ST) that provide high efficiency and relatively low cost cycling capability with a 1–2 hour start time, and fast ramping response. These combined-cycle units support the integration of variable renewables resources needed to achieve the 100% RPS goal by 2045.
- Older conventional steam units with limited cycling and load ramping capability that are scheduled for retirement by 2024 because of permitting.

Table D-4 lists the Maui dispatchable generating fleet.

Unit	Type	Fuel*	Capability (MW net)	Age	Type of Operation
Maʻalaea 14	GE LM2500 CT	LSD (future LNG)	21.0	24	Baseload (Load Following)
Maʻalaea 15	ABB Steam Turbine	n/a	16.0	23	Baseload (Load Following)
Maʻalaea 16	GE LM2500 CT	LSD (future LNG)	21.0	23	Baseload (Load Following)
Maʻalaea 17	GE LM2500 CT	LSD (future LNG)	21.0	18	Cycling (Load Following)
Maʻalaea 18	Mitsubishi Steam Turbine	n/a	16.0	10	Cycling (Load Following)
Maʻalaea 19	GE LM2500 CT	LSD (future LNG)	21.0	16	Cycling (Load Following)
Total Combined-Cycle Capability (MW)/Average Age			*116.0*	*19*	
Kahului 1	Combustion Engineering	IFO	5.0	68	Reserve Shutdown
Kahului 2	Combustion Engineering	IFO	5.0	67	Reserve Shutdown
Kahului 3	Combustion Engineering	IFO	11.5	62	Baseload (Load Following)
Kahului 4	Babcock and Wilcox	IFO	12.5	50	Baseload (Load Following)
Total Cycling Capability (MW)/Average Age			*34.0*	*62*	
Maʻalaea 1	GE EMD 20-645 ICE	LSD	2.5	45	Peaking
Maʻalaea 2–3	GE EMD 20-645 ICE	LSD	2.5 each	44	Peaking
Maʻalaea X1–X2	GE EMD 20-645 ICE	LSD	2.5 each	29	Peaking
Maʻalaea 4–6	Cooper PC2-16	LSD	5.6 each	43	Peaking
Maʻalaea 7–9	Colt PC2-16	LSD	5.6 each	38	Peaking
Maʻalaea 10–11	Mitsubishi /MAN 18V52/55A	LSD	12.5 each	36	Peaking
Maʻalaea 12–13	Mitsubishi /MAN 18V52/55A	LSD	12.5 each	28	Peaking
Total Peaking Capability (MW)/Average Age			*96.0*	*38*	

* LSD = low sulfur diesel; IFO = intermediate sulfur fuel oil; n/a = steam turbines powered by waste heat and do not directly use fuel

Table D-4. Maui Electric Generating Units

The existing generation, combined with DR and DER, provide operational flexibility to support the integration of more variable renewable energy resources. These assets have low minimum operating loads, cycling capability, quick-start capability, load following and ramping capability, and black start capability.

Combined Cycle Generation Assets

M14–16 consist of two 21 MW GE LM2500 combustion turbines, two natural circulation HRSGs, and one 16 MW ABB steam turbine. Maʻalaea M17–19 consist of two 21 MW GE LM2500 combustion turbines, two OTSGs, and one 16 MW Mitsubishi steam turbine. These units support the system in several ways.

Support of Renewables. They provide flexible generation and economic bulk supply of energy demand. M17–19 are designed for cycling and supporting the ramping needs. The units are limited by permit constraints to two starts per day. The combustion turbines can be online in 25 minutes following startup. M14–16 are being modified to better support low-load operation. The combustion turbines can be online in 25 minutes following startup. M17–19 can be cycled offline as necessary, with a 1 to 2 hour startup and three-hour minimum down time.

The units are capable of relatively fast ramping (2 MW per minute on AGC) and a minimum dispatch limit of 25%, driven by the covered source permit and 60% based on minimum steam flow through the once-through steam generator.

Support of High-Run-Hour Generation. With a heat rate between 8,330 Btu/kWh and 8,525 Btu/kWh, the combined cycle units provide generation at high efficiencies making them well suited for bulk customer service needs until the required variable and firm renewables are built. Because of this high efficiency, they are well suited to consume biodiesel after 2045 to support the 100% RPS target and minimizing the impact on customer bills.

Cycling and Startup Costs. While the LM2500 combustion turbines do not incur a startup cost, the heat recovery steam generator and the steam turbine are impacted by cycling. This cost is included in the production cost modeling. The LM2500 combustion turbines in the Maʻalaea CC units have bypass systems that allows for faster starts with minimal startup cost impact.

Long Term Reliability and Maintenance. The CC units were evaluated for continued operation to 2045. An estimated capital expenditure of $113.5 million was deemed necessary to support long term operations. The capital expenditures represent capital investment over what is normally included in scheduled overhaul cycles. The expenditures were calculated based on units running to 2045 and were based on a review of condition assessment, component maintenance history, and review of industry experiences. The budgetary costs were created based on reviewing similar projects and using industry standards. The identified investment generally include:

- Replacing heat recovery steam generator pressure components.
- Refurbishing generators stators and rotors.
- Upgrading excitation systems.
- Upgrading the transformer and electrical systems.
- Replacing major pumps and motors.
- Upgrading obsolete control systems.

Quick/Fast Start Peaking Generation Assets

The quick/fast-start peaking generation units support the increased variable renewables resources needed to achieve the 100% RPS goal by 2045.

M1–3 and X1–2 are 20-EMD-645 ICE units built in the 1970s and 1980s (manufactured by GE's Electro-Motor Division, thus the EMD designation) with individual maximum loads of 2.5 MW. M4–7 are Cooper PC2-16 ICE units constructed in the mid-1970s, and M8–9 are Colt-PC2-16 diesel engines constructed in the late 1970s, with individual maximum loads of 5.6 MW. M10–M13 are Mitsubishi Heavy Industry (MHI) ICE units manufactured by MAN of Germany, model 18V52/55A, constructed between 1979 and 1989, with individual maximum loads of 12.5 MW. The ICEs provide 96 MW of quick/fast start capability.

These units support the system in several ways.

Support of Renewables and Load Loss. The various types of ICE units support the variable renewable generation differently.

The General Electric (GE) Electro-Motive Diesel (EMD) ICE units (2.5 MW units) are quick start and can be at full load in less than 10 minutes. These units support renewable generation because they are offline reserve generation that can be deployed in response to cloud cover or wind events resulting in un-forecasted losses of variable generation.

The Cooper PC2-16 units (5.6 MW units) can come online 15 minutes after start, and take an additional 50 minutes to reach full load. Current constraints dictate that the units need to be started sequentially rather than simultaneously. They serve the system best when used for compensating for forecasted loss of variable generation and recovery following an event to supplement other sources generation.

The MHI 18V52/55A ICE units (12.5 MW units) can come online 17 minutes after a start command is given and be at full load in 117 minutes. They serve the system best being available for forecasted lack of variable generation and supporting peak loads.

Cycling and Start-Up Costs. The ICE units have very low startup costs. They can be used to provide generation when only a small increment is needed, in lieu of starting a larger unit and operating them at an inefficient load-point. The ICE units are well suited for quick starting and numerous starts.

Long Term Reliability and Maintenance. Though some of these units are older, their modular design allows for continuous repair and overhaul extending their life through 2045. These types of units normally do not require any additional capital expenditures to extend their life to 2045.

The GE EMD ICE and Cooper PC2-16 ICE units have a large user base resulting in long term availability of parts. The MHI ICE units are expected to be serviceable with replacement parts for many years to come as both Mitsubishi Heavy Companies and MAN continue to produce engines (different model) and maintain the engineering and facilities to produce parts for these engines.

Support of System Stability. While they supply load replacement very quickly, the ICE do not provide load flexibility and therefore do not support all type of system stability needs. The GE EMD ICE units (2.5 MW units) cannot be incrementally controlled through the SCADA/EMS system and are not used for regulation.

Conventional Steam Generation Assets

Kahului Power Plant has four steam units. Kahului 1 and Kahului 2 are currently in a reserve shutdown status. Kahului 3 and Kahului 4 are baseload units currently operating at low loads while also providing a significant amount of online system regulating reserve. All steam units at Kahului will be retired by 2024 for environmental reasons.

When the Kahului plant is fully retired, replacement generation is needed to continue to support the variable renewable resources and the system demand.

Lana‘i Generation Assets

The Lana‘i system is small—its generation needs are met by six 1.0 MW EMD diesel engines and two 2.2 MW Caterpillar 3608 diesel engines. A Caterpillar C32-1100 combined heat and power unit (CHP) will provide 800 kW of power and heat to support Manele Bay hotel loads starting in 2017. As with the Maui units, the EMDs are expected to be serviceable well into the future.

The EMD units (Miki Basin 1–6) are capable of starting in less than 10 minutes, and are well suited for responding to un-forecasted changes in variable generation. The Caterpillar engines are more efficient than the EMDs; they are well suited for meeting system peaks and forecasted changes in variable generation. The Caterpillar 3608 engines can start and be online in 17 minutes and at full load in 22 minutes.

The size of the Lana‘i system, with the flexibility of the current generation mix, help support the transition to 100% renewables. The units can compensate for changes in generation as well as supplement energy storage use.

Moloka‘i Generation Assets

The Moloka‘i system is also small. The generation fleet comprises two 1.25 MW Caterpillar 3516 diesel engines, four 1.0 MW Cummings KTA50 diesel engines, three 2.2 MW Caterpillar 3608 diesel engines, and one 2.0 MW Solar Centaur T4001 combustion turbine. The Moloka‘i engines have a large user base and expected to be serviceable with parts for well into the future.

The Caterpillar 3608 engines are more efficient than the other engines and are well suited for meeting system peaks and forecasted changes in variable generation. The Caterpillar engines can start and be online in 17 minutes and at full load in 22 minutes. This makes them ideal for efficiently supporting forecasted needs.

The flexibility of the generation fleet supports the transition to 100% RPS by providing quick starting and quick ramping capabilities to compensate for losses of forecasted and un-forecasted variable generation as well as supporting peak loads. The units are well equipped to support the transition to 100% RPS by providing grid services such as frequency and voltage control, meeting changes in generation need, and supplementing energy storage as necessary.

Hawai‘i Electric Light Generation Assets

Hawai‘i Electric Light dispatchable generation fleet has included both utility-owned and independent power producer assets. These units include:

- Quick/fast start generation including simple cycle combustion turbines (SCCT) and ICEs that provide emergency replacement power and peaking generation, but at a higher cost than the larger resources. The simple cycle combustion turbines can be used as black start resources.
- Combined-cycle units, comprised of two CTs, two HRSGs, and one ST with high efficiency and relatively low cost. These assets provide cycling capability with a 1–2 hour start time, and have fast ramping capability.
- Older conventional steam units have offline cycling capability, but longer start-up times and less ramping capability when compared to the combined-cycle units.
- Geothermal IPP provides firm energy.

These generating assets, combined with DR resources and DER, provide the flexibility necessary to integrate more variable renewable resources to meet 100% RPS requirements.

The Hawai‘i Electric Light dispatchable generating fleet comprises:

Unit	Type	Fuel*	Capability (MW net)	Age	Type of Operation
Keahole	2 – GE LM2500 CT with ST	LSD (future LNG)	56.3	12/6	Frequency Regulation, Load Following, Cycling
HEP	2 – GE LM2500 CT with ST	LSD (future LNG)	60.0	15	Frequency Regulation, Load Following, Cycling
Total Combined-Cycle Capability (MW)/Average Age			*116.3*	*10*	
Hill 5	Non-Reheat Steam	IFO	14.1	51	Frequency Regulation, Load Following, Cycling
Hill 6	Non-Reheat Steam	IFO	20.2	42	Frequency Regulation, Load Following, Cycling
Puna 1	Non-Reheat Steam	IFO	15.7	46	Frequency Regulation, Load Following, Cycling
Total Steam Capability (MW)/Average Age			*50.0*	*62*	
Kanoelehua CT1	GE Frame 5 SCCT	LSD	11.5	54	Peaking, Emergency, Black start
Keahole CT2	ABB GT-35 SCCT	LSD	13.8	27	Peaking, Emergency, Black start
Puna CT3	GE LM2500 SCCT	LSD	21.0	24	Peaking, Black start
Kanoelehua	Fairbanks Morse ICE	ULSD	2.0	54	Peaking, Emergency
Kanoelehua	3 - GE EMD 20-645 ICE	ULSD	7.5	43	Peaking, Emergency
Keahole	3- GE EMD 20-645 ICE	ULSD	7.5	44	Peaking, Emergency
Waimea	3- GE EMD 20-645 ICE	ULSD	7.4	45	Peaking, Emergency
Mobile	4 - Cummins ICE	ULSD	5.0	30	Peaking, Emergency
Total Peaking Capability (MW)/Average Age			*75.7*	*40*	

* LSD = low sulfur diesel; IFO = intermediate sulfur fuel oil; ULSD = ultra-low sulfur diesel (15 ppm s)

Table D-5. Hawai‘i Electric Light Fossil Generating Units

Requirements for the Existing Dispatchable Generation

The existing generation on Hawai‘i Island provides operational flexibility to support the integration of more variable renewable energy resources to meet the 100% RPS requirement. These assets have low minimum operating loads, cycling capability, quick-start capability, load following and ramping capability, and black start capability. In addition, Hawai‘i Electric Light has potential firm renewable energy resources (biomass, geothermal) to help meet 100% RPS requirements.

Combined-Cycle Generation Assets

The combined-cycle (CC) units support increasing variable renewables resources incorporated to achieve the 100% RPS goal by 2045.

Support of Renewables. They provide flexible generation and economic bulk supply of energy demand. The units can be cycled offline as necessary, with a 1 to 2 hour startup and three hour minimum down time. The units are capable of relatively fast ramping (4 MW per minute) and a minimum dispatch limit of 30%–40%, driven by the covered source permit and minimum steam flow through the heat recovery steam turbine. Potential may exist to increase these ramp rates.

Support of High Run Hour Generation. The combined-cycle units are the most efficient conventional plants on the system, well suited for cost effective service of the bulk customer energy needs that will continue to be required until dependable replacement renewable resources are available to serve these needs. Because of this high efficiency, they are the most cost-effective resources for future fuel-switching to biodiesel to support the 2045 100% RPS target and minimizing the impact on customer bills.

Cycling and Startup Costs. While the LM2500 combustion turbines do not incur a startup cost, the heat recovery steam generator and the steam turbine may increase costs because of offline cycling.

The LM2500 combustion turbines that are part of the Keahole CC unit have steam bypass systems which allows for faster starts than would be possible without the bypass. It also allows for faster startup in simple-cycle mode for emergency replacement power (22 minutes).

The LM2500 combustion turbines that are part of the HEP CC unit do not presently have steam bypass systems but this will be pursued to add flexibility to increase the support of future renewables as well as lower total cost and faster available replacement power.

Long Term Reliability and Maintenance. The CC units were evaluated for continued operation to 2045. An estimated capital expenditure of $113.5 million was deemed necessary to support long term operations. The capital expenditures represent capital investment over what is normally included in scheduled overhaul cycles. The expenditures were calculated based on units running to 2045 and were based on a review of condition assessment, component maintenance history, and review of industry experiences. The budgetary costs were created based on reviewing similar projects and using industry standards. The identified investment generally include:

- Replacing heat recovery steam generator pressure components.
- Refurbishing generators stators and rotors.
- Upgrading excitation systems.
- Upgrading the transformer and electrical systems.
- Replacing major pumps and motors.
- Upgrading obsolete control systems.

Quick/Fast Start Peaking Generation Assets

The quick/fast start peaking generation units support the renewable resources needed to achieve the 100% RPS goal by 2045. The ICEs provides 29.5 MW of quick start capability all available in less than three minutes. These units support the system in several ways.

Support of Renewables and Load Loss. These smaller resources quickly allow the system to meet lead requirements from loss of generating units or transmission lines, variability in wind and solar resources because of changes in weather, and emergency peaking needs.

Costs. The ICE units have very low startup costs. They can be used to provide generation when only a small increment is needed, in lieu of starting a larger unit and operating them at an inefficient load-point. The ICE units are well suited for quick starting and numerous starts.

Long Term Reliability and Maintenance. Though some of these units are older, their modular design allows for continuous repair and overhaul extending their life through 2045. These types of units normally do not require any additional capital expenditures to extend their life to 2045.

The GE EMD ICE units have a large user base resulting in long term availability of parts to maintain the engines. The Fairbanks Morse ICE unit has a similar large user base.

The simple cycle combustion turbines (SCCT) provide 46.3 MW of peaking capability, and are used for emergency replacement reserves and peaking energy.

Support of Renewables and Loss of Load. The simple cycle combustion turbines have fast start capability (5–22 minutes) which is not as quick as the ICE units but faster than combined cycle and steam unit startup.

Costs. The cost varies between the different types of SCCT units.

The GT-35 and Frame 5 have a high heat rate, and accordingly, high production costs. These units have the shortest startup times of the gas turbines: less than 10 minutes. They do incur a maintenance cost for each start, but because of the high production costs, do not incur many starts per year. They are operated primarily for emergency replacement power and short-term energy needs.

The GE LM2500 does not incur a significant maintenance cost for starts. These can be started as needed to support the system needs. These units are relatively efficient, second only to the combined-cycle operation. These units are used for short-term energy needs, in addition to emergency replacement power.

Long Term Reliability and Maintenance. These combustion turbine units are 24 to 54 years old. Their modular design allows for continuous repair and overhaul extending their life through 2045. With limited operation hours, these types of units normally do not require any additional capital expenditures to extend their life to 2045.

Though 54 years old, the GE Frame 5 SCCT have a large user base resulting in long term availability of parts. This type of turbine is still being manufactured today which allows for potential upgrades. The GE LM2500 SCCT is 24 years old. It also has a large user base and is still being manufactured today. This type of combustion turbine is shared with the combined-cycle unit at Maʻalaea, Keahole, and HEP.

The ABB CT35 SCCT is 27 years old and has much smaller user base. Maintaining this combustion turbine may prove more difficult in the next 20 to 30 years. The assumption is that it will be maintained until 2045. All the simple cycle combustion turbines have the capability to operate in isochronous control (zero-droop or swing unit) for frequency control and stability during major system disturbances and restoration. CT2 is located in Keahole, which allows it to support the minimum generation requirement for the west side of Hawaiʻi Island for voltage and transmission system constraints.

Conventional Steam Generating Assets

The conventional steam generating assets provide many benefits. Hill 5 and Hill 6 cycle to provide steam generated electricity. Puna has been operating for seasonal cycling during low generating capacity margins. It may shortly operate to a greater extent to serve demand, as the present availability of low-cost fuel has made the unit cost-competitive for operation compared with combined cycle assets.

Support of Renewables. Because the small size of these steam units, they provide greater dispatch flexibility than larger steam units. The units can be cycled offline with a minimum 3 hour start time for warm start. With present equipment and controls, these units require extensive manual operation during startup and startup time may be shortened if equipment is modified. The units have a lower minimum dispatch limit than combined cycle units, but a smaller dispatch range.

These conventional steam units provide firm capacity and have a sustained ramp rate of 2–3 MW per minute. While presently satisfactory, this may not be sufficient for future higher penetrations of variable solar and wind, requiring supplement from other ramping resources.

The steam units are significantly less efficient than the combined-cycle units. Because of this low efficiency, they would not be cost-effective for higher cost fuels (such as biodiesel) after 2045 to support the 100% RPS target.

Cycling and Startup Costs. The equipment of the entire conventional steam plant is impacted by cycling. This cost is included in the production cost modeling.

Long Term Reliability and Maintenance. NextEra calculated the capital investments necessary for the three steam units to support the Hawai'i Electric Light system until 2045. Analysis showed that an investment of $49 million will be necessary to maintain reliable operation. The expenditures were calculated based on units running to 2045 and were based on a review of condition assessment, component maintenance history, and review of industry experiences. The budgetary costs were created based on reviewing similar projects and using industry standards. Generally the capital investments include work over and beyond what is normally done during the overhaul cycle and includes:

- Replacing major boiler pressure components.
- Replacing major turbine components.
- Refurbishing generator stators and rotors.
- Replacing excitation systems.
- Replacing transformer and electrical systems
- Replacing major pumps and motors.
- Replacing critical piping and valves.
- Upgrading obsolete control systems.

Operations of the Conventional Steam Generation Assets

Selecting which large units will operate to serve the majority of demand is based on providing system security at the lowest cost of meeting the minimum system security requirements, considering the available resources capable of meeting those requirements, and the overall production cost.

System security analysis has identified that, at present, the system can generally operate with acceptable reliability with a minimum of four of the existing larger units online. These units can be any combination of three steam units with or without the LM2500 units, in simple or combined cycle (a plant operating in combined cycle counts as two units to the minimum four unit requirement), with at least one of the units located at Keahole because of voltage and transmission security constraints.

GENERATION MODERNIZATION

Because of its age, we are considering modernizing the existing O'ahu generation fleet as one option for the 2016 updated PSIP.

Dispatchable Generation Selected for Modernization

Hawai'i requires flexible dispatchable resources to meet foreseeable demand as the generation fleet transitions to a 100% RPS portfolio. One of our tasks is to design an optimized fleet that ensures the lowest possible impact to the customer bill while maintaining reliability.

Customer electric demand must be met while we expand our renewable generation fleet to achieve 100% RPS. The amount of utility scale renewables, storage, and dispatchable generation must be cost effective. And we must maintain reliability.

The generation fleet of the future must support a variable renewable fleet. A modernized fleet must support the delivery of electricity, ensure grid stability, and long-term operations of all types of variable renewables; minimize the total impact to customer bills; ensure fuel flexibility for burning natural gas and biodiesel to maximize efficiency; and reduce emissions and its impact on the environment.

We have considered all of the necessary components of a cost-effective renewable plan; our Decision Framework outlines how we are developing a portfolio that meets them. The proposed generation modernization would ensure reliability, facilitate renewable integration, and reduce costs to the customer. Modernized units must include high capacity generation as well as fast-start, low capacity generation.

Together with NextEra, we first evaluated potential high capacity generation using the following criteria:

- Lowest total (capital and operational) cost
- High efficiency to minimize fuel cost
- Fast start and load ramp to support renewables
- Low emissions

Next, we evaluated the two basic combined-cycle technologies: advanced combined-cycle units and aeroderivative combined-cycle units. We determined that advanced combined-cycle units had the needed characteristics: they have the lowest total cost combined with the highest efficiency while supporting fast-start and ramp rates and low emissions. (Aeroderivatives have higher total costs and lower efficiencies.)

We next screened various combined-cycle configurations, discovering that a 300 to 350 MW unit had best overall savings for customers. We compared a configuration of three combined-cycle units, each with one combustion turbine and one heat recovery steam generator, that supply steam to one steam turbine (that is, three 1x1 CC units), against one combined cycle unit with three combustion turbines, three heat recovery steam generators, and a single steam turbine (that is, a 3x1 CC unit)

Evaluating the total cost of these two configurations revealed the 3x1 CC would save $136 million over the cost of three 1x1 CC units. Due to its efficient heat rate, that savings from the 3x1 CC would be $48 million in capital construction costs, $21 million in maintenance costs, and $67 million in fuel cost over the unit's life.

The combined cycle unit can burn biodiesel, which helps toward attaining 100% RPS. The unit's higher efficiency lowers the cost of energy generated from biodiesel by 30% compared to burning biofuels in existing conventional steam units.

The combined cycle unit is flexible. It can provide the quick-start on short notification to respond to the loss of a variable resource. This quick-starting capability enables the size of a battery energy storage system (BESS) providing contingency reserve to be minimized. The unit can also supplement an optimized BESS to ensure load demand is met in times of extended low resource.

An advanced 3x1 combined cycle unit is capable of starting and ramping quickly in several modes. For a hot start, the first combustion turbine takes 15 minutes to ramp to full load (versus 42 minutes for a 1x1 SCCT configuration). A second combustion turbine, started one minute after the first, reaches full load in 16 minutes (versus 43 minutes for a 2x1 configuration). The third combustion turbine, started one minute after the second, reaches full load in 17 minutes. All told, the 3x1 combined-cycle unit reaches full load in 44 minutes with a ramp rate of 35 MW per minute. These startup times and ramp rates are significantly faster than our existing thermal fleet, which require many hours for a hot startup and ramp at rate of 3–5 MW per minute.

An advanced 3x1 combined cycle unit is capable of starting and ramping quickly in several modes. Single simple cycle combustion turbines (SCCT) take 15 minutes to ramp to full load and 43 minutes; a double SCCT (1x2) ramps in 16 minutes and 43 minutes; and a triple SCCT (1x3) ramps in 17 minutes and 44 minutes. The ramp rate of a 3x1 from minimum load to full load operation is 35 MW per minute. These startup times and ramp rates are significantly faster than our existing thermal fleet, which require many hours for a hot startup and ramp at rate of 3–5 MW per minute.

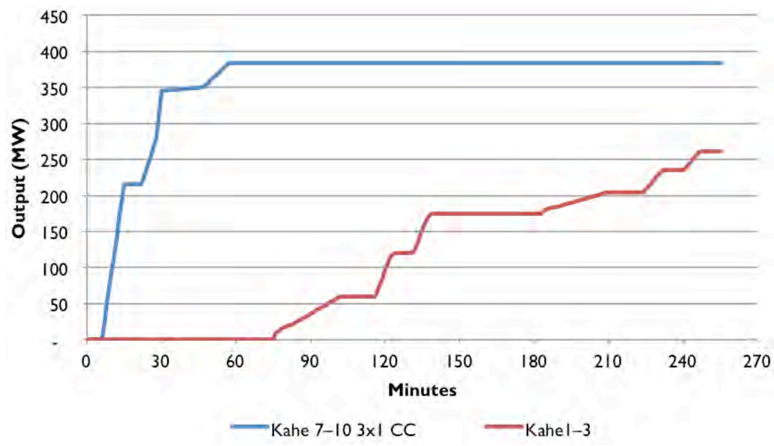

Figure D-3. Hot Start of a 3x1 CC versus Kahe 1–3

This capability responds to drops in renewable resources, minimizes the size and cost of the BESS, and eliminates online reserve units to support system load transients. This fast-starting unit together with a cost-effective storage system could stay offline when not needed to serve load, resulting in significant fuel cost savings over less flexible generating alternatives.

We next evaluated the optimal location for siting the unit, one that also minimizes costs. Our evaluations found Kahe to be optimal. Constructing on the Kahe site gave us the opportunity to replace Kahe 1–3 (as they are already planned to be retired), to keep existing units running for most of the construction period (critical to maintaining LOLP criteria until renewables back by storage can be brought online), to build above the tsunami plain, and to cost-effectively integrate the new unit into the O'ahu grid.

The 3x1 CC encompasses some unique design features that prevent losing the entire unit at one time. The 3x1 CC's design ensures that any one combustion turbine failure only results in the loss of 127 MWs, one-third of the unit's capacity (similar to the largest existing Kahe unit). The loss of the steam turbine generator results in a maximum loss of approximately 145 MW as the combustion turbines can continue operating. This design feature also lowers the largest contingency risk currently present with AES at 180 MW.

To accomplish this flexibility, a dump condenser is added to the steam turbine condenser enabling the 3x1 CC plant to operate in simple cycle mode for extended periods of time if the main condenser trips. The dump condenser also allows the three combustion turbine trains to operate during a steam turbine outage. This allows the 3x1 combined-cycle unit to continue at reduced capacity during failures and outages.

We propose replacing Kahe 1–3 with this state of the art, highly fuel efficient, operationally flexible, 383 MW, 3x1 combined-cycle unit—Kahe 7–10. The Kahe 7–10 CC unit would encompass approximately 15 acres on the Kahe property (in an unused area north of the existing units) and with a potential in-service date of January 2021.

Kahe 7–10 could operate using LNG, fuel oil, a mix of the fuels, or biofuels. Kahe 1–3 would be retired in 2020, shortly before Kahe 7–10 CC comes online.

Figure D-4. Possible Kahe 3x1 CC with Removal of Kahe 1–4 (Artist Rendering)

The proposed Kahe 7–10 combined-cycle unit would consist of three nominal 80 MW General Electric 6FA.03 combustion turbines (CTs) and three heat recovery steam generators (HRSG), which would use the waste heat from the CTs to produce steam for the new steam turbine generator. Kahe 7–10's base capacity would be 358 MW. For additional power production, the facility could be capable of utilizing wet compression technology during peak demand periods to add about 25 MW of capacity to the unit, totaling 383 MW. The unit's base heat rate would be 6,965 Btu/kWh at an average ambient temperature of 86° F. The unit would have an estimated average forced outage factor of approximately 1.6%, a planned outage factor of 5.0%, and an equivalent availability factor of 92.2%. The ramp rate would be 35 MW per minute.

To limit a single contingency event to less than 145 MW, Kahe 7–10 would be designed with the capability of bypassing the steam turbine. This same design feature would allow for fast startup and for the three combustion turbines to reach full load in 17 minutes while the steam turbine is brought online more slowly, reaching full load in 44 minutes. In addition, a dump condenser would allow for the steam turbine and its main condenser to be taken offline for maintenance while still allowing for full operation of the three combustion turbines.

Locating on the existing Kahe site would lower construction and connection costs, improve the permitting schedule and lowering permitting risks, and reduce land improvement before construction. The unit could also take advantage of existing infrastructure, including:

- Cooling water intake and discharge
- Liquid fuel tanks and pipelines
- Demineralized water
- 138 kV substation
- Transmission infrastructure

The existing Kahe units can remain in service during the initial construction period. At some point, however, the existing units would be shut down and certain critical services (such as the transmission and cooling water systems) would be integrated into the new CC unit. Contracting with a third-party company to build the unit would extend the construction schedule (and add cost) to the finished project.

A modernized Kahe 7–10 could provide 383 MW at a capital cost of $716 million (without AFUDC or interconnection costs), or $1,870 per kW, and be online in 2021. Table D-6 summarizes the unit's costs and key operating characteristics.

Kahe 7–10 3x1 CC	Characteristic
Unit model	GE 6F.03 3x1 CC
Total cost (without AFUDC)	$716,200,000
Cost per kilowatt	$1,870/kW
Net sum capability Heat rate at base	358 MW 6,965 Btu/kWh
Net sum capability with wet compression Heat rate at base with wet compression	383 MW 7,028 Btu/kWh
Minimum load, CT only	36 MW
Minimum load, combined cycle 1x1	64 MW
Time for CT to baseload 221 MW	17 minutes
Fuel types	Gas, oil, biofuels

Table D-6. Kahe Advanced Combined Cycle Unit Characteristics

Benefits of the 3x1 Advanced Combined Cycle Units

Advanced combined cycle units have the operational characteristics required to support the variable nature of renewable generation and support the transition to 100% RPS.

Efficiency

A 3x1 unit utilizing advanced combined-cycle technology would be more efficient and utilize significantly less fuel than the existing Kahe units. As the Figure D-5 demonstrates, the 3x1 combined cycle units would be 31% more fuel efficient at full load and 42% more efficient at minimum load compared to the existing Kahe units.

Figure D-5. Heat Rate Comparison of Kahe 1–3 and Kahe 7–10 CC

Improved Reliability

A 3x1 advanced combined cycle units would also be more reliable (Figure D-6).

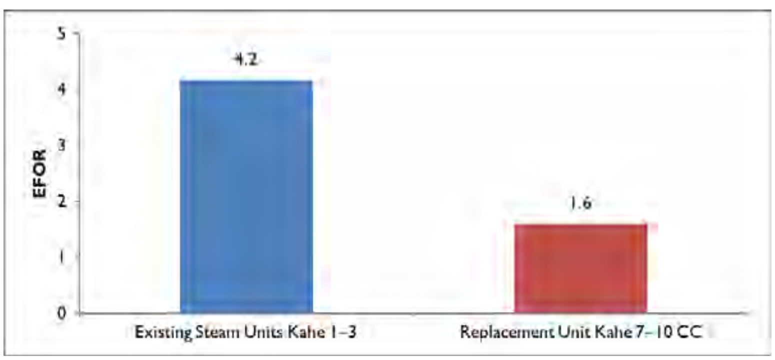

Figure D-6. EFOR of Kahe 1–3 and Projected EFOR of Kahe 7–10 3x1 Combined Cycle

Faster Cold Start Ramp Rates

Advanced combined cycle units have fast start and load ramping capabilities even in cold conditions. This characteristic is vital for reliability to support a system with high renewable penetration and allows for a more rapid and increased level of renewable integration. Table D-7 compares the cold condition ramp rates of Kahe 1–3 and Kahe 7–10.

Ramp Time (hours)	2	4	6	8	10	12	14	16	18	20	22	24
Kahe 1–3 Steam (MW)	0	0	0	0	0	5	40	70	100	100	125	132
Kahe 7–10 3x1 CC (MW)	321	358	358	358	358	358	358	358	358	358	358	358

Table D-7. Cold Start Ramp Rates: Kahe 1–3 and Kahe 7–10 3x1 Combined Cycle

Reduced Emissions

Attaining a 100% RPS would coincidently reduce environmental emissions from our generating units. Modernizing the existing fleet with an advanced combined cycle unit would further enhance those environmental benefits. Table D-8 shows how adding an advanced combined cycle unit significantly reduces emissions compared to our current generation mix, even when both are fueled by liquid fossil fuels.

Fleet Portfolio	SO_2	NOx	PM	CO_2
Existing Generation	14.1 K	24.6 K	5.1 K	4.7 M
Modernization	8.5 K	14.8 K	2.1 K	4.4 M
Percent Reduction	39.1%	39.8%	58.8%	8.3%

Table D-8. 2023 Emission Rates of Existing Fleet versus Replacement Generation

The reductions of CO_2, SO_2, NOx and PM through the modernization result in several environmental benefits. CO_2 reductions support the state's goal to reduce greenhouse gas emissions that contribute to climate change impacts (such as increased temperatures and sea level rise). Combining the lower emission profile of advanced combined cycle units with the use of natural gas compounds this environmental benefit. CO_2 content in natural gas is approximately 33% less than in the low sulfur fuel oil currently used in the generating units. Using natural gas also reduces SO_2 emissions, assisting the state to attain the 2010 one-hour SO_2 National Ambient Air Quality Standards (NAAQS) requirement. SO_2 emissions are attributed to respiratory illnesses and acid rain formation. NOx emissions are the primary contributor to the formation of ozone (smog) that can cause respiratory illness. Particulate Matter (PM) results in visible emissions (smoke) observable by local residents and business near the plant. PM emissions also include the Hazardous Air Pollutant metals that may increase the risk of cancer and respiratory illness.

Modernizing our fleet and adding advanced combined-cycle units burning natural gas would reduce other hazardous air pollutants emissions: metals, including mercury, arsenic, chromium, and nickel; and acid gases, including hydrogen chloride and hydrogen fluoride

Online Reserve Requirement for Oʻahu Renewable Fleet Support

Inherent in the nature of renewable generation is the significant volatility in its contribution to daily generation needs. The existing Oʻahu dispatchable fleet is not currently equipped to respond quickly enough for the increased variability associated with increasing amounts of variable renewable energy generation.

One option of responding to this increasing volatility would be to add large, utility-scale batteries to the system. The amount of support needed from the batteries, however, is significant and does not appear to be an optimal use of capital resources for these purposes. A second option would be to keep the existing thermal units on at minimum load as online reserve generation. While reducing the amount and cost of required batteries, any savings would be offset by the costs associated with running units at load low. Another option would be to replace existing units with a dispatchable fleet that can start and ramp up quickly.

Together with NextEra, we compared the existing fleet to a modernized fleet, and their respective abilities to respond to the complete loss of variable renewable generation. A study by Wind Logics evaluated the projected 2045 renewable resources to better understand the largest generation swings that could be expected. Figure D-7 depicts the largest expected drop over one year. We used the study's results to analyze the system response to a "large cloud cover event": a drop of 630 MW within a 30-minute time period.

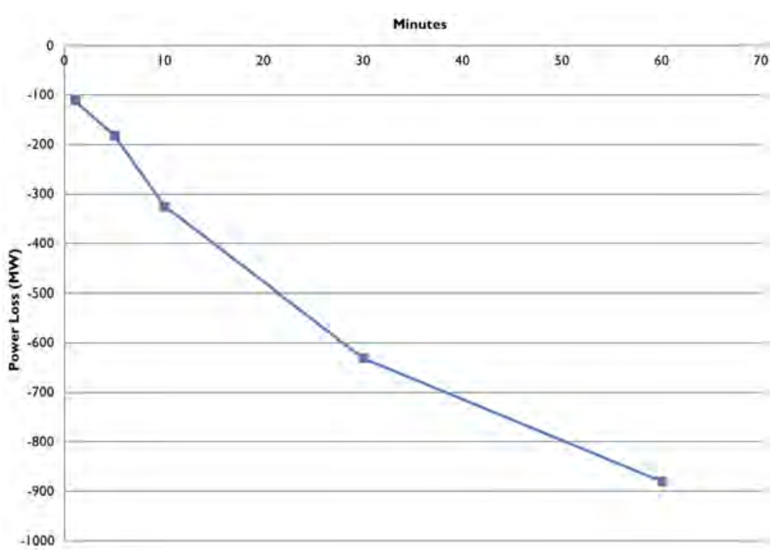

Figure D-7. Largest Drop in MW as a Function of Time

We considered the units that were available to respond to such an event. A battery energy storage system (BESS) would need to be sized to handle the initial load response. As the BESS is called on to supply larger and larger generation amounts for longer and longer time periods, the cost increases exponentially. A more cost effective solution would be to replace the lost potential generation with fully dispatchable resources.

According to our studies, Kahe 7–10 would be able respond to large cloud cover events without having to be online like the slower base loaded units. Table D-9 reflects the start time, in minutes, for the various units.

After factoring in the starting time, ramp rates, and minimum operating loads, we determined that the combination of six peaking units, the Kalaeloa IPP unit, and the baseload units at Kahe 4–6, all together, would be required to adequately respond at the same rate as the Kahe 7–10 proposed unit (depicted in the Current Unit Mix column of Table D-9). Because of their four to six hour startup times, the Kahe units would need to already be online to respond quickly.

Minutes	Individual Unit Response (MW)					Individual Unit Response (MW)	
	Kahe 3	Kahe 4	Kahe 5	Kahe 6	Kahe 7–10	Current Unit Mix*	Modernized Unit Mix†
0	5	5	25	45	0	0.0	65.0
15	35	35	55	105	215	361.0	426.0
30	57	57	91	142	345	685.5	763.5
45	65	65	103	142	349	751.0	805.0
60	73	73	116	142	383	817.5	876.5
75	81	81	130	142	383	878.0	907.0
90	90	89	142	142	383	907.0	907.0

* Current Unit Mix includes Kahe 3–6, Waiau 9–10, CIP CT-1, KPLP, Schofield, and DoD generating units.
† Modernized Unit Mix contains the same units as the Current Unit Mix, except it replaces Kahe 3–6 with the Kahe 7–10 CC unit.

Table D-9. Current and Modernized Unit Response to Loss of Renewable Generation Event

The Modernized Unit Mix column of Table D-9 shows how much more quickly the combined baseload generation that included the advanced Kahe 7–10 unit, ramped to respond to large cloud cover events. Table D-9 also demonstrates that at least four of the currently utilized baseload steam units would be required to be online at their minimum output (plus a downward regulating margin) to adequately respond to large cloud cover events.

The fuel cost for keeping the online reserve at minimum load during all daylight hours can be significant. The calculated cost of this extra fuel is demonstrated in Figure D-8.

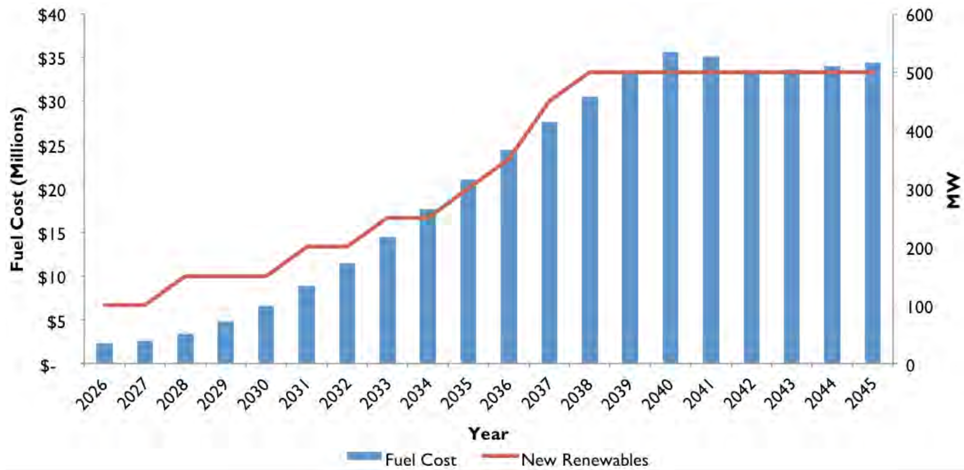

Figure D-8. Extra Fuel Cost

As our renewable fleet grows, the need for the steam units would decrease, and the economic dispatch model would lower their capacity factors to zero. If they were not needed to respond to these large cloud cover events, they could be left in cold standby (using no fuel) or possibly even retired.

Military Base Microgrids

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

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

Hawaiian Electric's goals include:

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

Hawaiian Electric understands the DoD's goals to include:

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

Marine Corps Base Hawaiʻi (MCBH) Microgrid Concept

To provide the services desired by the Marine Corps, it is only practical that generation be located on Marine Corps Base Hawaiʻi. In addition to meeting the needs of the Marines, adding generation on the windward side of the island can provide resiliency benefits to customers in that area. Therefore, this is the only concept contemplated for this branch of service.

The addition of generation would create a microgrid for the military base where the new generation and existing base resources (such as rooftop PV) has sufficient capacity and grid controls to safely and reliably serve the base's load.

Site Characteristics, Restrictions and Needs

The Marine Corps previously identified a suitable site on MCBH (Figure D-9) for a replacement generating station near the existing Hawaiian Electric substation that feeds the base. The size of the potential generating station site is approximately 4.8 acres.

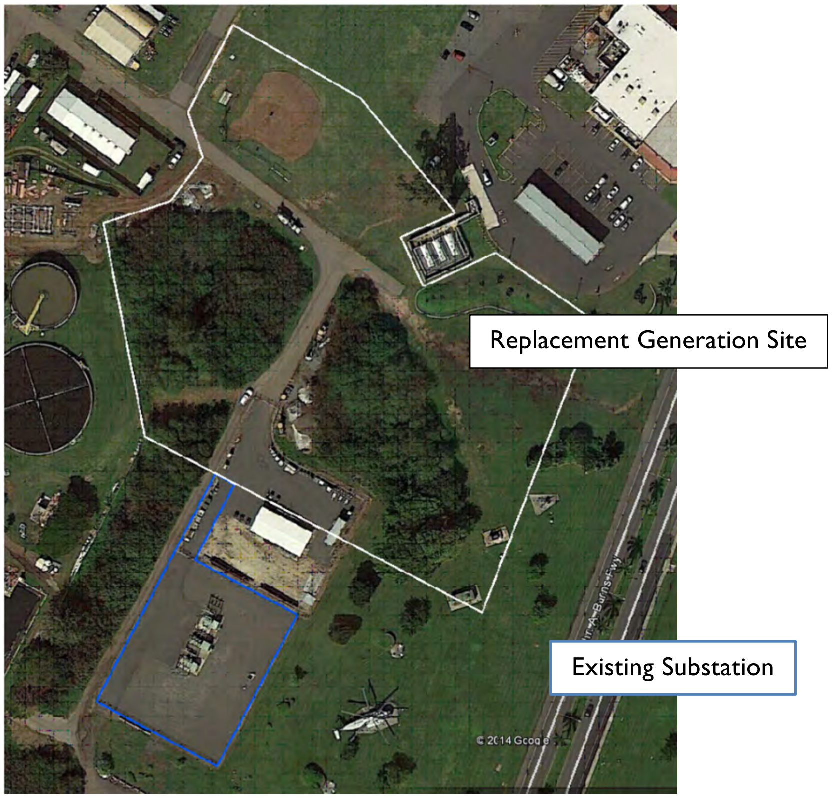

Figure D-9. MCBH Site for Possible Replacement Generation

Based on thermal limitations of the existing 46 kV sub-transmission system feeding the base as well as the need to keep exhaust stacks less than 100 feet above ground level (because of air space restriction associated with nearby helicopter operations), it appears that 54 MW is the maximum size generating station this site could practically accommodate. Furthermore, each of the two 46 kV sub-transmission feeds is individually limited to 30 MW. Therefore, 30 MW would be the maximum size for any individual unit at this site.

No interconnection requirement study has been completed for interconnection at this location and could result in further restriction of project size. The peak load of MCBH is approximately 16 MW and the intent of a project on this site is to be able to serve the entire peak with one generating unit out of service for maintenance (N-1 design criteria). A preliminary air permit analysis indicates that 54 MW of reciprocating engines with 100 feet tall stacks (3 into 1) can be installed in compliance with all air regulations.

Generating Unit Selection and Project Size

Based on the N-1 criteria, Table D-10 shows the relationship between the number of units and the minimum size of each generating unit for a 60 MW peak load with N-1 criteria.

Generating Units	Minimum Size per Generating Unit (MW)	Total System Capacity (MW)
2	16.0	32.0
3	8.0	24.0
4	5.3	21.3
5	4.0	20.0

Table D-10. Number versus Size of Proposed MCBH Generating Units

Table D-10 indicates the site cannot only accommodate enough capacity to meet the N-1 criteria, but that additional units could be placed at this site to satisfy a more robust criteria or to provide additional energy resiliency for off-base customers.

Previous analysis done for Maui Electric indicated that medium speed reciprocating engines for a station of this size are more cost-effective than using combustion turbines. However, the analysis is dependent on expected capacity usage of the project. Therefore, a specific analysis for O‘ahu should be conducted to determine the most cost-effective technology for this site.

Of the two engine sizes that Wärtsilä offers (9 MW and 17 MW), either could satisfy the design criteria. However, for this size of a project, the 9 MW engine is expected to be more cost-effective and to provide better resiliency and power restoration capability. Thus, if Wärtsilä engines are chosen for this site, the project would use either the 20V32 (liquid-only) or the 20V34DF engine (liquid and gas). Either case would result in a minimum project size of 27 MW.

Proposed Project Strategy

Based on Hawaiian Electric’s unique and sole capability to deliver energy security to MCBH through integrated generating station and grid operations, the Marine Corps would select Hawaiian Electric as its sole partner for an energy security project on the selected site. Hawaiian Electric, with the support of the Marine Corps, would request from the Public Utilities Commission a waiver from its Framework for Competitive Bidding, based on the Marine Corps’ stated requirement to work with the utility to meet military needs.

Hawaiian Electric would lease the project site for in-kind consideration in lieu of monetary rent for the life of the project and design, permit, finance, construct, own, and operate a new, up to 54 MW firm generating station located on the site. The generating station would normally be dispatched to meet grid-wide demands from all Hawaiian Electric customers.

Under conditions identified in the lease, Hawaiian Electric would provide energy security guarantees such that the Marine Corps would gain significantly enhanced energy security for MCBH. These guarantees by Hawaiian Electric would provide the Marine Corps in-kind consideration in lieu of monetary rent payments for the life of the project.

In return for the enhanced energy security, the Marine Corps would contribute to the project with land and other contributions as deemed appropriate for the value of the energy security guarantees provided. The value of the land and other contributions to the project would reduce project costs, thereby saving our customers money compared to siting a similar project at a non-military location.

Joint Base Pearl Harbor–Hickam (JBPHH) Microgrid Concept

To provide the services desired by the Navy, two concepts are being considered: 1) locating a microgrid on base at JBPHH; or 2) installing a power barge at the Waiau Generating Station that could either be interconnected to JBPHH or temporarily relocated to JBPHH under emergency conditions.

The addition of generation would create a microgrid for the military base where the new generation and existing base resources (such as rooftop PV) has sufficient capacity and grid controls to safely and reliably serve the Base's load.

Site Characteristics, Restrictions and Needs

The Navy has not identified a desired and suitable site at JBPHH for installation of a new generating station. Hawaiian Electric, however, proposed the site shown in gray in Figure D-10.

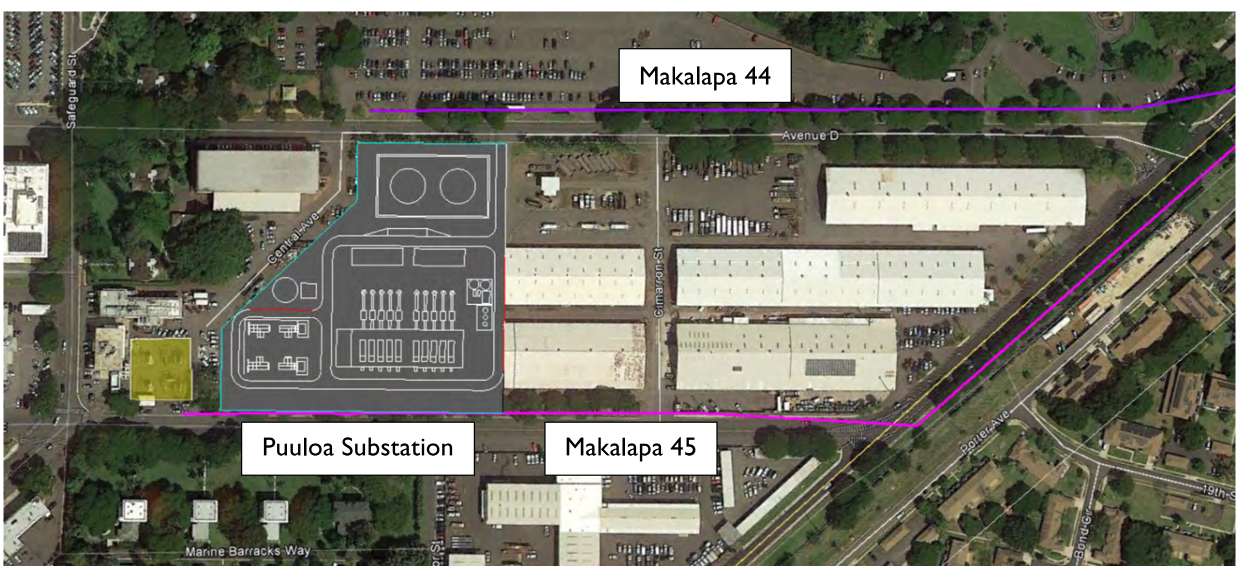

Figure D-10. JBPHH Site for Possible Replacement Generation

Based on thermal limitations of the existing 46 kV sub-transmission system feeding the base, it appears that 96 MW is the maximum size generating station this site could practically accommodate. Furthermore, each of the two 46 kV sub-transmission feeds is individually limited to 48 MW. Therefore, 48 MW would be the maximum size for any individual unit at this site.

No air permit analysis has been done yet for this site and could result in further restriction of project size. No interconnection requirement study has been completed for interconnection at this location and could result in further restriction of project size. The peak load of JBPHH is approximately 60 MW and the intent of a project on this site is to be able to serve the entire peak with one generating unit out of service for maintenance (N-1 design criteria).

Generating Unit Selection and Project Size

Based on the N-1 criteria, Table D-11 shows the relationship between the number of units and the minimum size of each generating unit for a 60 MW peak load with N-1 criteria.

Generating Units	Minimum Size per Generating Unit (MW)	Total System Capacity (MW)
4	20.0	80.0
5	15.0	75.0
6	12.0	72.0
7	10.0	70.0
8	8.6	68.6
9	7.5	67.5

Table D-11. Number versus Size of the Proposed JBPHH Generating Units

Table D-11 indicates the site cannot only accommodate enough capacity to meet the N-1 criteria, but that additional units could be placed at this site to satisfy a more robust criteria, or to provide additional energy resiliency for off-base customers.

We have not analyzed the most cost-effective technology to site on at JBPHH (RICE units or combustion turbines). Based on our analysis for Maui Electric, we expect that medium speed reciprocating engines would be the lowest overall cost choice.

Of the two engine sizes that Wärtsilä offers (9 MW and 17 MW), either could satisfy the design criteria. However, for this size of a project, the 9 MW engine is expected to be more cost-effective. Thus, if Wärtsilä engines are chosen for this site, the project would use either the 20V32 (liquid-only) or the 20V34DF engine (liquid and gas). Either case would result in a minimum project size of 72 MW.

Proposed Project Strategy

Based on Hawaiian Electric's unique and sole capability to deliver energy security to JBPHH through integrated generating station and grid operations, the Navy would select Hawaiian Electric as its sole partner for an energy security project on the selected site. Hawaiian Electric, with the support of the Navy, would request from the Public Utilities Commission a waiver from its Framework for Competitive Bidding, based on the Navy's stated requirement to work with the utility to meet military needs.

Hawaiian Electric would lease the project site for the life of the project and design, permit, finance, construct, own, and operate a new, up to 96 MW firm generating station located on the site. The generating station would normally be dispatched to meet grid-wide demands from all Hawaiian Electric customers.

Under conditions identified in the lease, Hawaiian Electric would provide energy security guarantees such that the Navy would gain significantly enhanced energy security for JBPHH. These guarantees by Hawaiian Electric would provide the Navy in-kind consideration in lieu of monetary rent payments for the life of the project.

In return for the enhanced energy security, the Navy would contribute to the project with land and other contributions as deemed appropriate for the value of the energy security guarantees provided. The value of the land and other contributions to the project would reduce project costs, thereby saving our customers money compared to siting a similar project at a non-military location.

Waiau Power Barge Concept

Independent of any military considerations, Hawaiian Electric has identified that the waters of Pearl Harbor immediately adjacent to Hawaiian Electric's Waiau Power Plant are ideal for a floating power plant ("power barge"), and that this concept could result in a very cost-effective method to provide replacement capacity for O'ahu.

Figure D-11 shows a three dimensional rendering of one possible configuration at the proposed site.

Figure D-11. Possible Power Barge at the Waiau Generation Station (Artist Rendering)

The power barge concept presents three areas of potential savings compared to land based generating stations at other sites (including JBPHH). First, the installed costs of a power barge are lower than any land based construction in Hawai'i, since the entire station would be built in a shipyard and shipped as a single unit. The on-site construction would be limited to the mooring system and the interconnections for utilities and power. Second, a power barge at the proposed location could utilize existing infrastructure at Waiau Power Plant. Third, the delivery schedule for a completed power barge is less than for a comparable facility built on site, reducing project costs.

Another potential advantage of a power barge is that it could be designed to be capable of moving between islands to provide emergency power and increase state-wide resiliency. This concept has not been studied, but could prove worthy of consideration if it broadens stakeholder support for the project. Such a capability would require additional systems and capabilities onboard the barge, and additional infrastructure on each island where the barge could be deployed. It would also have company and state policy considerations, which would require the support of state and county governments, and possibly 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-12. Based on the analysis, the RICE barge appears to be the better solution for Hawaiian Electric than the turbine barge.

Type	Total Cost	Net Heat Rate (Btu/kWh HHV)
RICE	$160 Million	8,507
CT	$180 Million	8,951

Table D-12. Waiau Power Barge Comparison

Although the Waiau Power Barge concept was initiated to meet Hawaiian Electric needs, because of the close proximity of Waiau Power Plant to JBPHH, Hawaiian Electric is discussing with the Navy the possibility of using the power barge concept to fulfill the Navy's energy security needs as well. In a situation in which the Navy requires a direct feed of electrical power, this concept could take one of two forms:

- The barge could be re-located to a temporary mooring at JBPHH, and connected directly to the base electrical infrastructure.
- The barge could remain in place, but divert power to JBPHH via a direct connection using overhead or underwater cabling.

The peak load of JBPHH is approximately 60 MW. Since the overall capacity of the barge would be determined by Hawaiian Electric's capacity needs and not the Navy's needs alone, a minimum barge capacity of 100 MW is likely to be required. If the Waiau Power Barge concept were selected to meet the Navy's energy security needs, the project would also need to be able to serve the entire JBPHH peak with one generating unit out of service for maintenance (N-1 design criteria). The 100 MW RICE barge would incorporate six 17 MW units, which would satisfy this criteria. The 100 MW CT barge, as analyzed, has a single 100 MW CT, which would not satisfy the criteria. Other combinations of smaller CT units could be considered, but in general this would increase the cost and the heat rate of the CT barge option, thereby making it even less competitive versus the RICE barge. Therefore, the RICE barge would be a better choice than the CT barge to meet the Navy's energy security needs.

Proposed Project Strategy

If the Waiau Power Barge is only considered as a Hawaiian Electric project for replacement capacity, it could be included as a competitive proposal to an open RFP for new generation, as outlined in the Framework for Competitive Bidding. If the barge serves as a state-wide emergency and resiliency asset serving a government need, a waiver from the Framework may be justified. Furthermore, if the Navy agreed that the power barge would meet their energy security needs, the project would meet several criteria under which a waiver would justifiable. The remainder of this strategy assumes this case.

Based on Hawaiian Electric's unique and sole capability to deliver energy security to JBPHH through integrated generating station and grid operations, and Hawaiian Electric's existing Waiau Power Plant located on Pearl Harbor, the Navy would select Hawaiian Electric as its sole partner for an energy security project. Hawaiian Electric, with the support of the Navy, would request from the Public Utilities Commission a waiver from its Framework for Competitive Bidding, based on the Navy's stated requirement to work with the utility to meet military needs (and also potentially on the project's unique capability to move inter-island as a "power supply needed to respond to an emergency situation").

Hawaiian Electric would lease the project site for the life of the project and design, permit, finance, construct, own, and operate a new, 100 MW or more RICE power barge. (The requirements for, and cost of, a lease of Pearl Harbor waters are not developed, but a preliminary estimate is $150,000 per year.)

The Navy would fund project costs that solely support the project's ability to meet the Navy's specific energy security requirements. If the barge will be deployable to other islands, cost sharing arrangements for project costs that are required for this capability would be negotiated by stakeholders. The power barge would normally be dispatched to meet grid-wide demands from all Hawaiian Electric customers.

Under conditions identified in the lease, Hawaiian Electric would provide energy security guarantees such that the Navy would gain significantly enhanced energy security for JBPHH. These guarantees by Hawaiian Electric would provide the Navy in-kind consideration in lieu of monetary rent payments for the life of the project. If deployable to other islands, the barge would only do so after Hawaiian Electric ensured that JBPHH's demand is being served by the grid.

In return for the enhanced energy security, the Navy would contribute to the project with land and water lease rights, and other contributions as deemed appropriate for the value of the energy security guarantees provided. The value of the Navy contributions to the project would reduce project costs, thereby saving our customers money compared to siting a similar project at a non-military location.

E. New Resource Options

This appendix discusses the new resource options that were considered in our analysis for the 2016 updated PSIPs.

AVAILABLE GENERATION OPTIONS

For the 2016 updated PSIP analyses, we have taken a "clean sheet" approach in developing new resource options. In developing this new set of assumptions, we are mindful of the Commission's concerns expressed in Order No. 33320 about the results from our 2014 PSIPs:

> …appears to rely on the utilization of renewable resources with relatively high costs and unproven resources with uncertain feasibility.[1]
>
> …the technology cost assumptions utilized by the Hawaiian Electric Companies in the PSIPs also appear conservative" and "…do not appear to accurately reflect current cost trends…[2]
>
> …the amounts and types of renewable resources that are considered in the PSIP analyses appear to be inappropriately limited. Generally, the Hawaiian Electric Companies' criteria for exclusion of resource technologies from consideration in the economic analyses based on the state of commercial readiness appear over-restrictive. The Companies have categorically excluded generation technologies with a Commercial Readiness Index ("CRI") lower than five. This excludes technologies with a CRI of four, which are technologies in full-scale commercial use and have "publicly verifiable data on technical and financial performance."[3]

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1 Order No. 33320, at 80.

2 *Ibid.*, at 84–85.

3 *Ibid.*, at 83.

While technologies with a CRI Level 4 are in full-scale commercial use and have "publicly verifiable data on technical and financial performance", the full description of CRI Level 4 also included criteria related to the ability of these technologies to be financed. In particular, CRI Level 4 technologies "…may still require subsidies" and that there is "…interest from debt and equity sources" that "…still [require] government support." We chose to consider technologies in the 2014 PSIPs based on the ability of the technology to receive financing without the need for subsidies, and to avoid relying heavily on technologies that have "high costs and uncertain feasibility". The 2014 PSIPs also stated that "…this planning assumption is for the PSIP analyses only, and does not affect our intent to thoughtfully consider specific projects that include emerging technologies. In other words, we welcome generating technologies not considered in the PSIPs that are proposed in responses to future request for proposals (RFP) for any of our power systems."[4] We reiterate that intent here.

New Utility-Scale Resource Assumptions

For the 2016 PSIP analysis, we use multiple sources of forward curves for the capital cost of new generating technologies and new energy storage technologies. Figure E-1. shows the projections of per unit capital costs expressed in 2016 real $/kW. The data portrayed underlie the nominal dollar assumptions used in the 2016 PSIP analysis. The constant dollar projection is a useful way to portray the expected future cost trends of various electric power generation technologies.

[4] Power Supply Improvement Plan, filed August 26, 2104, at H-1.

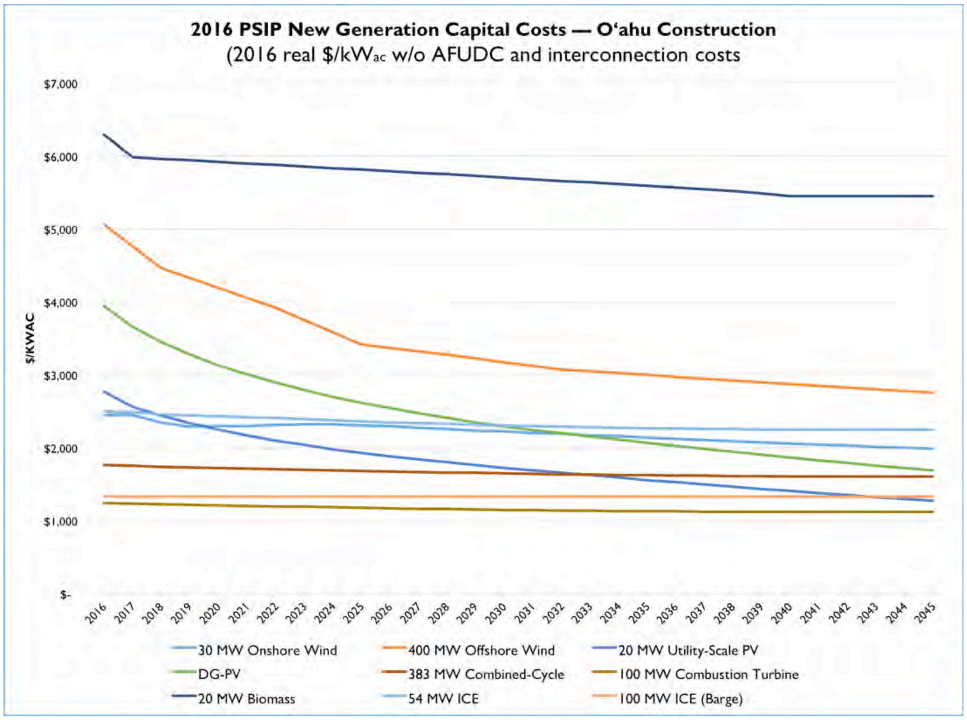

Figure E-1. 2016 Updated PSIP New Generation Resource Capital Costs—O'ahu

Data Sources

In our analyses for these 2016 PSIPs, we have completely reworked the resource technologies and cost assumptions. The re-working of the new resource assumptions started with a review of current literature and data sources including:

- National Renewable Energy Laboratories' (NREL) *2015 Annual Technology Baseline (ATB)* spreadsheet (July 2015).[5]
- *Lazard Levelized Cost of Energy Analysis – Version 9.0* (November 2015).[6]
- Energy Information Administration's (EIA) *Updated Capital Cost Estimates for Utility-Scale Electricity Generating Plants* (April 2013),[7] used primarily as guidance for regional cost adjustments.
- Electric Power Research Institute (EPRI) *Technology Assessment Guide* (2013-2015 data sets), a proprietary[8] database of power technology costs and performance.

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5 The NREL ATB spreadsheet is available at: http://www.nrel.gov/analysis/data_tech_baseline.html.

6 The Lazard analysis is available at: https://www.lazard.com/media/2390/lazards-levelized-cost-of-energy-analysis-90.pdf.

7 The EIA report is available at: http://www.eia.gov/forecasts/capitalcost/.

8 "Proprietary" means that the materials, analysis, and data are trademarked, privately-owned, private, patented, or otherwise exclusive to the party producing the information. Generally, any party willing to pay for a license can obtain the information. We are bound by the terms of the license or right agreement when we use these resources. This is a common commercial practice.

- Various proprietary reports published by IHS Energy in 2015 regarding cost trends related to solar PV, wind, and energy storage technologies.
- *Gas Turbine World 2014–15 Handbook*, a publication that provides power plant prices, price trends, and performance data for combustion turbines and combined-cycle plants.
- RSMeans data, which publishes proprietary indices regarding materials, labor, and productivity for more than 900 cities in the United States and Canada, including Honolulu and Hilo.
- NextEra Energy, *NextGrid Hawai'i* study submitted to the Commission in September 2013.
- Our internal data and estimates for the cost of internal combustion engines (ICE), including the actual budgeted costs for the Schofield Generating Station (as proposed in Docket 2014-0113 and reduced to reflect favorable movement in foreign exchange rates) and a vendor quote for the 100 MW ICE "power barge" proposed for O'ahu.
- Our internal estimates of system interconnection costs for resources of various sizes (including the cost of connecting to the grid). These estimates exclude costs associated with system upgrades that might be required to accommodate a specific project.
- Certain resource capital cost assumptions received as input from two of the Parties.

Development Process

The process of developing resource assumptions involved several different efforts that were synthesized into a common set of assumptions for the 2016 PSIP update analysis.

We researched and reviewed the most current data sources possible. The NREL ATB database was one such current source. A significant advantage of the NREL ATB data source is that it provides a publicly available source of the forward curves for capital costs, and operations and maintenance expenses for several different power generation technologies. This data was combined with the EIA's 2013 *Updated Capital Cost Estimates for Utility-Scale Electricity Generating Plants* information regarding locational adjustments (by technology), specifically for Honolulu, to adjust the NREL ATB data for Hawai'i. We adjusted the cost data using 2016 dollars as the base year for the 2016 updated PSIPs by converting all cost information from real dollars to nominal dollars using a 1.8% inflation and escalation rate. We use nominal dollars to evaluate various cases in our economic analysis. Our analyses and conclusions also incorporate input from certain Parties.

NextEra Energy consulted with us to develop the new resource assumptions. NextEra Energy has extensive experience as a developer, owner, and operator of wind power, solar PV projects, concentrated solar power (CSP) projects, gas-fired generation stations, and bulk energy storage projects. NextEra Energy also uses IHS Energy's proprietary research reports to develop initial cost assumptions for certain resources. IHS reported information for developing renewable resources and energy storage for California, and also provided forward curves for various resources. The California reference was adjusted to a Hawai'i value based on the RSMeans' city indices for materials, labor, and productivity. NextEra Energy then compared the results of the Hawai'i-adjusted data to its own experience in developing and operating some of the technologies considered, including projects in Hawai'i .[9] The result is a set of cost values for the various technologies that reflect independent evaluations *and* actual experience. All prices were adjusted for Hawai'i by applying a 4% adder for Hawai'i General Excise Taxes.

We retained NREL to independently and objectively review the assumptions synthesized through this processes. NREL filed two reports on their analysis. Generally, NREL found our assumptions to be in line with their own database and other third-party sources. We discuss specifics of their conclusions Utility-Scale Resource Assumptions on page E-17. (Appendix F contains the actual NREL reports.)

Generation Technologies Considered

Order No. 33320 recognized that actionable plans cannot be built on "unproven" resources that might be technically and economically feasible in the future, while also stating that the choice of technologies cannot be "overly restrictive". We do not believe that the best interests of our customers are served by expecting them to underwrite the risks associated with technologies that are not commercially available today.

To clarify our intent, our 2016 updated PSIPs should "… address the need for applications for approval of individual capital projects, programs, contracts, and RFPs to be considered with the benefit of the context provided by well-vetted, sufficiently analyzed comprehensive system plans."[10]

Thus, we are developing our 2016 updated PSIPs to serve as the basis for actionable, near-term decisions regarding approvals for RFPs to solicit resources to meet capacity needs, applications for capital expenditures related to power supply and energy storage projects, and applications for PPA approvals.

In addition, we are developing our 2016 updated PSIPs to be flexible over the long-term to accommodate technology and cost improvements in existing technologies, and to

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[9] On February 4, 2014, *Pacific Business News* published an article entitled "NextEra Provides Cost Estimates for Hawaiian Electric's New Energy Plans." The author did not contact us prior to publication. We believe the article misleads the reader by suggesting that NextEra-provided estimates were not vetted or subject to independent review. In reality, we collaborated with NextEra Energy and NREL to derive the new resource assumptions based on independent data sources. In addition, we contracted with an outside consultant to compile these resource assumptions to assure their consistency and objectivity.

[10] *Op. cit.*, at 39.

accommodate the commercialization of transformational technologies that might become available. We strongly believe this is a prudent and reasonable philosophy that is not only in the best interest of our customers, but also in the best interest of achieving the state's renewable energy policy goals.

To reiterate: the choice of technologies in these 2016 updated PSIPs is a planning assumption, which in no way is intended to limit or discourage proposals for other technologies. Such proposals, however, must have the following attributes:

- Sound engineering design concepts.
- Commercial availability of the technology from a reputable vendor who will stand behind the performance and servicing of the technology (including all balance of plant items) over its useful life.
- Demonstrated financial feasibility of the project employing the technology, including its benefits to ratepayers, taking into account the system needs (as stated in a competitive bidding process approved by the Commission, or as stated in a waiver from the competitive bidding framework approved by the Commission) and the costs of integration.
- The ability of the project sponsor to demonstrate the financial wherewithal and technical capabilities to successfully finance, construct, and operate the project employing the technology.

To meet our goals for the 2016 updated PSIPs, we limited new resource analysis choices to these technologies.

Utility-Scale Solar Photovoltaic

Solar PV technology is mature. Current forecasts are characterized by continuing modest decline in capital costs and incremental improvements to the technology. Multiple utility-scale solar PV projects are installed in Hawaiʻi. There is significant experience in the Hawaiʻi market with solar PV technology by us, multiple project developers, and capital providers.

The PSIP assumptions reference fixed-tilt systems (as opposed to single-axis and multi-axis tracking systems). The PSIPs utilize capacity factors and output profiles for utility-scale solar based on historical experience with existing utility-scale solar PV systems. Costs for solar PV systems are typically expressed in dollars per watt of the total output of the PV system panels (direct current power). The ratios of DC output to (usable) AC output in utility-scale solar PV projects typically ranges from 1.1–1 to 1.5–1. The reference plant capital cost assumes a 1.5–1 DC to AC ratio. The NREL resource analysis also assumes a 1.5 to 1 DC to AC ratio. This higher ratio typically allows projects to achieve higher capacity factors since more PV panels boosts output over the shoulder periods around the time of peak irradiance. We did not however have profile data for plants incorporating a 1.5 DC to AC ratio. The capacity factor modeled for utility-scale solar PV was 20.4% for O‘ahu, 20.41% for Hawai‘i Island, 20.4% for Maui, 20.6% for Lana‘I, and 21.1% for Moloka‘i. We believe that fixed tilt solar PV systems with the 1.5 DC to AC ratio may achieve capacity factors as high as 25%. We are investigating load profile information for 1.5 DC to AC ratios that will be incorporated into future analyses.

Distributed Solar Photovoltaic

The PSIP assumptions for the cost of DG-PV are based on the same source data, including future cost trends, as used for utility-scale solar PV. These solar PV costs were adjusted for Hawai‘i and compared to actual costs for residential PV systems based on contact with vendors. The cost of DG-PV is expected to decline (in real terms) slightly over the study period. The net capacity factor for DG-PV is assumed to be 18.4% for O‘ahu, 16% for Hawai‘i island, 18% for Maui, 16% for Lana‘i and 20% for Moloka‘i.

Onshore Wind Power

Onshore wind projects employ mature technology. Wind power trends are characterized by modest decreases in per unit capital cost (in real dollars), modest performance increases, and substantial improvements in the size of commercially available single wind turbines. Over 200 MW of wind capacity are operating in our service areas, almost all of it owned by independent power producers. There is significant experience in the Hawai‘i market with onshore wind technology by the Companies, multiple project developers, and capital providers. The net capacity factor modeled in the reference plant was 22.7% for O‘ahu, 54.4% for Hawai‘i Island, and 51% for Maui, Lana‘i, and Moloka‘i.

Wind projects exhibit significant economies of scale because of the intensive mobilization effort (for example, heavy cranes, equipment to move towers, and turbines from port to the site location). The cost assumptions used in the 2016 updated PSIPs reflect these economies of scale.

Combustion Turbines

Modern combustion turbines (CTs) are the “workhorse” of electric utility systems around the world. Essentially jet engines coupled to a generator, CTs can be designed to burn a variety of fuels including fuel oil, naphtha, and natural gas. CTs are characterized by relatively low capital costs, modest efficiency (heat rates of 10,500 BTU per kWh), high reliability, and relatively short lead times for installation. Smaller CTs typically are less efficient than larger machines (heat rates as high as 18,000 Btu/kWh for small “microturbines”). CTs are a mature technology with projected flat capital cost (in real dollars) and continued small incremental performance improvements over time.

CTs have significant operating flexibility with fast-start capability, fast ramping, and a high level of variability when spinning. CTs are typically used as peakers (where capacity is required to meet short duration peak demands). Typical annual capacity factors for CTs are less than 20%, sometimes significantly less. CTs can play an important role in integrating variable renewables by providing capacity and energy at times when the variable renewable resources may be limited.

There are several very large, well-capitalized international vendors who provide CTs in a variety of sizes. Each of these vendors has extensive supply chains for parts and service. Their capabilities are supplemented by numerous specialized O&M service firms and after-market parts suppliers. There is a vast amount of experience with CTs on the part of utilities (including the Hawaiian Electric Companies and NextEra Energy), IPP project developers, and providers of capital.

Combined Cycle

Combined-cycle power plants are a mature technology that employ CTs, but add a heat recovery steam generator (HRSG) that takes the exhaust heat from one or more CTs "recover" the thermal energy that that would otherwise go to waste, and produce steam. The steam is then used to turn a turbine coupled to a generator. There are various configurations of combined-cycle plants. A single CT, coupled to a HRSG and steam turbine-generator set, is referred to as a single-train combined-cycle (STCC) plant.

Similarly, two CTs, coupled with two HRSGs and a steam turbine-generator is referred to as a dual-train combined-cycle (DTCC) plant. We own and operate three DTCC plants: one at the Keahole plant on Hawaiʻi Island and two at the Maʻalaea plant on Maui. The Hamakua Energy Partners (HEP) plant on Hawaiʻi Island is also a DTCC plant utilizing the same make and model of combustion turbines installed at both Keahole and Maʻalaea.

Combined-cycle plants typically exhibit the greatest efficiency technically possible with thermal generation. Heat rates for modern combined-cycle plants operating at a high capacity factor can be as low as 7,000 Btu/kWh. The reliability of combined-cycle plants is high. They tend to be used as baseload and cycling generation. This too is considered to be a mature technology, with flat projected capital cost, and incremental performance improvements over time. Like CTs, combined-cycle power plants are utilized by utilities and IPPs around the world. Combined-cycle plants are procured and serviced through a well-established and mature supply chain. Financing is readily available in the capital markets for combined-cycle plants owned by utilities or by IPPs.

The 2016 updated PSIPs propose combined-cycle options for Oʻahu in a 152 MW STCC configuration and a 383 MW 3x1 configuration (three combustion turbines, three heat recovery waste heat boilers, and one steam turbine), the latter for modernization at the Kahe power plant.

Internal Combustion Engine

Internal combustion engine (ICE) generation couples an internal combustion engine with a generator. Modern ICE generators are in widespread use throughout the world. They are the dominant technology employed in DG applications; however, they are routinely found in utility-scale applications as well. We are currently building a 6-unit x 8.4 MW (for a total of 50 MW) ICE generation station at the Schofield Barracks Army Base on O‘ahu. That project is scheduled to enter commercial operation in 2017. The Schofield Generating Station will provide additional operating flexibility to help manage increasing penetrations of variable renewable resources, including DG-PV. It is also being designed to allow Schofield Barracks to operate as a microgrid (that is, in an "islanded" mode) providing energy security for the base.

ICE generation has relatively high efficiencies (heat rates of approximately 10,000 Btu/kWh) across a wide operating range (25% to 100% of full load), and rapid start-up and shutdown capabilities. ICE generation is a mature technology. Cost and performance trends into the future are relatively flat. There is a robust and competitive market for ICE consisting of several major global vendors and a handful of other players.

Biomass

Biomass can be used to generate power in several ways. Biomass feedstock can be burned directly to provide heat to create steam, which in turn powers a steam turbine-generator to produce electricity. Biomass feedstock can also be processed through gasifiers to produce a gas or liquid fuel that is then burned in thermal generating technologies (such as ICE, CTs, and combined-cycle plants). The PSIP assumptions for the 20 MW biomass plant are based on a direct combustion process.

We continue to explore opportunities to use locally produced energy crops for their possible contribution to renewable power generation. Various parties in Hawai‘i continue to research and develop the commercial potential of test crops: cellulosic feedstock (such as bana grass); energy cane and oil seed crops (such as jatropha, sunflower, and pongamia); and eucalyptus from farms on Hawai‘i Island.

Crops for biofuel that could substitute for fossil fuels in thermal power generation include cellulosic crops or crop waste for biomass-to-gas-to liquid technologies and oil seed crops for feedstock. Alexander & Baldwin (A&B) has expressed interest in pongamia trees that produce oil seed for biodiesel and can grow on less-than-optimal lands while serving as shade for other interspersed crops.

Biofuels can be easily substituted for liquid fuel in a number of existing generating units and easily transported via truck containers and barges. Typically, both biogas and biomass for power generation are economically feasible only when the feedstock is in close proximity to the power generation facility. Cellulosic crops and crop waste can serve as feedstock for anaerobic digesters to produce biogas, which are commercially proven in installations around the world. Our use of biogas for power would require conversion of existing generation to fire gas or new gas-fired generation. Biomass derived from energy crops, crop waste, or tree waste can be dried and pelletized to use in generating units that can otherwise burn coal. Cost-effective biomass or biogas generation using purpose-grown crops remains to be proven, but holds promise.

The January 7, 2016 announcement by A&B to cease production of sugar by Hawaiian Commercial Sugar & Company (HC&S) on Maui and transfer to a diversified agricultural model presents opportunities for further exploration of energy crops on portions of their 36,000 acres. The economics and bioenergy technologies must still be proven.

Our analysis assumed biomass fuel is obtained from on-island biomass resources. For Maui, this is based on the fact that at one point the HC&S power plant produced 40 MW of power from organic waste (bagasse) that is a by-product of the sugar cane operation. With the closure of the HC&S sugar operation, we assumed that a portion of HC&S's property could be dedicated energy crops. Other land outside of HC&S may also be available for growing biomass crops. On Hawai'i Island, we assumed that there is available land to support biomass plants.

We have re-examined and updated our biomass assumptions since our interim filing. For the 2016 updated PSIPs, the capital costs for biomass plants was derived from the NREL ATB (with adjustment factors for Hawai'i) and from an assumption that biomass fuel would cost $80 per bone dry ton (BDT) with a heat content of 7,500 Btu per pound. This results in a fuel price of $5.34 per MMBtu.[11] We also assumed a plant heat rate of 13,500 Btu per kWh. These assumptions result in an all-in cost of electricity at a 50% capacity factor of approximately $0.28 per kWh (which is generally consistent with Hu Honua contract that we recently terminated due to their non-performance.[12])

Geothermal

Geothermal power generation relies on underground heat sources. Typically, water is injected into a well drilled into an underground pocket with high temperatures to create steam that is channeled to the earth's surface and used to turn a steam turbine-generator

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[11] http://www.hawaiicleanenergyinitiative.org/storage/pdfs/6_SpecificEconomicModeling_ScottTurn.pdf.

[12] The Hu Honua plant intended to utilize the federal Production Tax Credit, which has since expired. Therefore, the actual PPA rate for the Hu Honua plant was somewhat less than the prices derived from our current assumptions.

set to generate electricity. Hawai‘i Electric Light currently purchases electrical capacity and energy from the Puna Geothermal Venture 38 MW geothermal power plant.

Geothermal is a proven technology and has been considered a new resource option for the 2016 updated PSIPs for Maui and Hawai‘i Island. Developing new geothermal generation in Hawai‘i will require extensive resource assessment and permitting. New geothermal resources on both islands require additional field research (that is, test wells) to prove its potential as an energy source. Because of this extensive research, the 2016 updated PSIPs consider geothermal potential resources only in the later years of the 30-year planning period.

Offshore Wind

There are currently two proposed offshore wind projects being proposed for O‘ahu. The first consists of 400 MW on the northwest side of the island and the second is for 400 MW on the south-southeast side. Because of the significant water depths at the proposed Hawai‘i sites (±1000 meters), offshore wind installations in Hawai‘i will most likely employ large wind turbines installed on floating platforms and sited in deep water (±1000 meters).

Floating wind turbine technology is less mature than fixed-bottom technology; the first floating turbine was installed in 2009 and four additional machines have been installed in subsequent years. Because these projects are single turbine, proof-of-concept installations, they have been more expensive than fixed-bottom projects (on a $/kW basis). These projects are not able to achieve economies of scale and have elevated budgets for research and development. According to at least one source, floating technologies are becoming increasingly mature; the first commercial applications are expected to occur by 2020 (Smith et al. 2015).

The economics of floating technologies are different from fixed-bottom technologies. Some elements (such as electric infrastructure) will be more expensive because undersea power cables must be able to withstand dynamic loading within the water column, whereas power cables for fixed turbines can be laid out directly on the seabed. Further, in the Hawaiian Electric system, interconnection of a 400 MW offshore wind project and its effect on system security needs must be carefully evaluated. The design of this interconnection cable system will be extremely important since a failure of the cable system will severely impact system security, as the loss of 400 MW of wind generation is considerably larger than the size of the current largest land-based contingency.

There is the potential for capital costs to be lower than a fixed platform structure because the entire turbine-substructure unit can be assembled in port and towed to the project site. These cost reductions will be possible in Hawai‘i only if appropriate facilities (for example, ship-building type facilities) and heavy construction equipment are available.

Because the weight of floating platforms is relatively insensitive to turbine size, the economics generally are substantially improved for projects that use large (for example, more than 8 MW) wind turbines. Currently, no existing installations of floating platforms utilize 8 MW turbines.

Considerable uncertainty surrounds the future cost of floating technology given its pre-commercial status and its installation in the Hawai'i environment. A preliminary analysis conducted by NREL and the U.S. Department of Energy suggests that a reference floating offshore wind facility installed in 2020 could have an installed capital cost of approximately $4,500 per kW. This cost, however, is uncertain.

The NREL ATB shows that $4,500 per KW is the lowest capital cost ever achieved for shallow and mid-depth offshore wind projects, and that almost $8,000 per kW (*before* adjusting for a Hawai'i location) is the capital cost for deep water offshore wind projects. Development risk factors could affect the cost of offshore wind projects in Hawai'i. The two known developers of proposed offshore wind projects have released figures suggesting that the capital cost of offshore wind, installed in Hawai'i, would be approximately $4,000 per kW. Absent other reliable data, we have used the new preliminary NREL figure of $4,500 per kW in our assumptions, however, the margin of error might be large. We assumed that offshore wind projects near O'ahu have an annual net capacity factor of 42.4%.

Because it is clear that reaching the State's renewable energy goals will require resources that are not located on O'ahu, the resource plans developed for O'ahu include floating offshore platforms incorporating 8 MW wind turbines. However, these projects do not appear in plans prior to 2030; additional due diligence will need to be undertaken to fully vet the viability of this resource option.

Because floating platform offshore wind requires the installation of undersea cables, we plan to further evaluate this emerging technology together with the inter-island cable analyses to be performed in the next phase of our planning analyses (see Chapter 9: Next Steps). Both technologies offer potentially competing solutions for helping O'ahu reach 100% renewable energy generation. .

Concentrated Solar Thermal Power

Concentrated solar thermal power (CSP) is a rapidly advancing commercially available technology; however, the installed base of global CSP capacity is still only about 1,200 MW.[13] (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

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[13] http://www.energy.gov/articles/year-concentrating-solar-power-five-new-plants-power-america-clean-energy.

over 365 days and, after the project, lost the land rights required for continued operations.)

CSP utilizes thermal radiation from the sun. The thermal solar energy is typically transferred to a working fluid; the resultant heat is used to make steam. That steam is used in a steam turbine coupled to an electric generator. In some CSP applications, the thermal energy can be stored, spreading the output of the CSP facility over a longer period of time, resulting in capacity factors higher than those achieved with solar PV technology. CSP requires direct sunlight to function efficiently; cloud cover significantly degrades performance (in contrast to solar PV which does not exhibit as much performance degradation on cloudy days relative to CSP). As a result, most of the operating CSP plants are located in deserts in California, Spain, and the Middle East.

CSP has a relatively expensive capital cost. With the maturity of solar PV and the rapidly improving performance and steep forecasted capital cost price declines of battery energy storage systems (BESS), the technical and economic viability of CSP relative to a solar plus BESS applications may be relatively limited to areas with consistent solar thermal radiation.

Solar PV Plus Storage Combination

A combination of utility-scale solar PV and BESS can create a "dispatchable" renewable resource. With the performance and cost improvements of BESS technologies, this combination could become a useful tool for achieving our RPS goals.

Kauai Island Utility Cooperative (KIUC) has recently announced its intent to develop a project with 17 MW of solar PV combined with a 13 MW/52 MWh (four-hour duration) BESS system.[14] This project will allow KIUC to store solar energy during the DG-PV "valley" of the daily demand curve, and then provide that energy later in the day and evening to serve the daily peak demand. We have met with the developer of the Kauai project and discussed potential applications for the technology in our service areas. We anticipate that future solicitations for new resources might result in proposals for this combination of technologies.

Waste-to-Energy

Like biomass plants, waste-to-energy (WTE) systems are dominated by two basic technologies: systems that involve direct combustion of the waste, with the resulting heat being used in a boiler to generate steam that drives a steam turbine-generator set; and gasification systems where the waste is broken down into a low-BTU gas that typically fuels an ICE generator.

[14] http://cleantechnica.com/2015/09/22/now-solar-power-meet-evening-peak-load-hawaii/.

WTE facilities tend to have very site-specific designs because the plant must be sized for the volume of the waste stream and must use the technology most appropriate for the makeup of the waste stream. For this reason, reliable capital cost and operating data for WTE plants has been difficult to find. None of the data sources we reviewed cover or routinely provide analysis for a "typical" WTE plant.

Given the volume of our waste stream, WTE plants on Maui, Lanaʻi, Molokaʻi, and Hawaiʻi Island would have relatively smaller sizes. Reliable cost data on these smaller plants is difficult to obtain. A literature search of smaller WTE plants reveals potential capital costs ranging from $4,000 to $11,000 per kW.

WTE plants exhibit economies of scale: very small plants will likely have a high per unit capital cost compared to larger plants. Considerations include the sales of electricity; the "tipping fees" received from the source of the waste; and, in some cases, from the value of recycled materials pulled from the waste stream before it enters the WTE plant. Even with a given capital cost, there is the potential for a great deal of variability in determining a projected price for electricity from a WTE plant. Because of the relatively constant stream of waste, a typical WTE system is not able to substantially vary its output because of the relative narrow efficient operating range (especially direct combustion WTE plants).

The H-POWER steam plant, a 68.5 MW WTE facility in the Campbell Industrial Park owned by the City and County of Honolulu, processes up to 3,000 tons per day of municipal solid waste.[15] H-POWER is a steam plant.

In recent years, the County of Hawaiʻi and the County of Maui have proposed several waste-to-energy plants. The last two mayoral administrations in the County of Hawaiʻi both proposed waste-to-energy facilities, but both plans were abandoned. In the County of Hawaiʻi, questions arise regarding whether the waste stream is adequate to support a WTE plant.[16] Several private developers have also proposed WTE facilities on Hawaiʻi Island. There is a pending proposal from the County of Maui and a private developer to provide gas derived from municipal waste landfills to fuel existing Maui Electric power plants.

We will continue to work with the communities and stakeholders on WTE proposals that can help with municipal solid waste disposal issues and provide benefits to electricity customers. Should this technology become commercially viable and demonstrate the ability to be financed without substantial subsidies, we will reconsider including WTE generation as an option in future resource plans.

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[15] http://www.covanta.com/facilities/facility-by-location/honolulu.aspx.

[16] http://bigislandnow.com/2014/04/22/big-island-rubbish-enough-to-go-around/.

Ocean Thermal Energy Conversion

Hawai‘i is a pioneer in ocean thermal energy conversion (OTEC) research, having demonstrated the first successful OTEC project on Hawai‘i Island in the 1970s. Despite the technological promise of OTEC for large-scale electricity generation, no full-scale OTEC plant has yet to be built anywhere in the world. OTEC International (OTECI), which had proposed a 100 MW OTEC project to serve O‘ahu, announced that it was withdrawing from the Hawai‘i market.[17]

As a point of reference, in August 2015, Makai Ocean Engineering completed the world's largest operational OTEC plant at its facility in Kona that generates 100 kW. In addition, a 1 MW OTEC plant is planned for the Hawai‘i Ocean Science and Technology Park in Kailua-Kona on Hawai‘i Island.

Should this technology become commercially viable—offered by a vendor willing to financially back the development and performance of a full-scale plant—and demonstrate the ability to be financed without substantial subsidies, we will consider including OTEC as an option in future resource plans.

Wave and Tidal Power

Successful demonstration tidal and wave power projects have been implemented in several locations, including Hawai‘i. We currently partner with the U.S. Navy (and others) in a small-scale pilot.

Small utility-scale wave power projects have been installed in Europe.

Figure E-2. Pelamix Wave Energy Converter at the European Marine Energy Test Centre, 2008

[17] http://www.utilitydive.com/news/heco-developer-shelve-100-mw-ocean-thermal-energy-project-off-hawaii/401000/.

Ocean Renewable Power Company (ORPC) installed their tidal generator turbine (TidGen) in Cobscook Bay in Eastport, Maine, and their river generator turbine (RivGen) in the Kvichak River (Igiugig, Alaska). TidGen is expected to increase the size of the generator to 5 MW gross, maintain that for the length of their 20-year PPA.

Figure E-3. ORPC TidGen Tidal Generator

Implementing large-scale tidal and wave installations has thus far been hampered by a lack of understanding of the associated siting and permitting challenges in multiple jurisdictions. Wave and tidal power projects may face similar interconnection challenges as offshore wind.

Should this technology become commercially viable in a large scale and demonstrate the ability to be financed without substantial subsidies, we will reconsider including wave and tidal power as a resource option in future resource plans.

Microgrids

The U.S. Department of Energy defines a microgrid as "… a group of interconnected loads and distributed energy resources (DER) with clearly defined electrical boundaries that acts as a single controllable entity with respect to the grid (and can) connect and disconnect from the grid to enable it to operate in both grid connected or island mode."[18]

A typical microgrid consists of DG (for example, internal combustion engines, combined heat and power systems, solar PV, distributed wind), energy storage systems, and demand management systems that, in effect, create a balancing area within a defined set of loads. Microgrids can operate interconnected with the larger utility system, or they can operate in an islanded mode. Islanded operation is particularly of interest to customers who require a very high level of reliability and energy security. The Schofield Generating Station is designed to allow islanded operation of the Schofield Barracks Army Base.

Combined with utility time-based rate programs (such as time-of-use rates, dynamic pricing, and critical peak pricing) and demand-response programs, sophisticated

[18] https://building-microgrid.lbl.gov/microgrid-definitions.

microgrid control systems allow microgrids to "call" power from the grid when it is economically advantageous to do so, and "put" power to the grid in response to DR program price signals.

We believe that microgrids can provide additional flexibility to our power grid, especially from customers with critical loads who can justify the costs of providing higher reliability. Proposals for microgrids that aggregate multiple customer loads raise numerous issues (such as cost allocation, rate design, and stranded costs) that are beyond the scope of the 2016 updated PSIPs. We will evaluate microgrid proposals case by case.

UTILITY-SCALE RESOURCE ASSUMPTIONS

An accurate and realistic estimate of the incremental renewable resource potential, particularly on O'ahu, is very important. If the renewable constraints on O'ahu are significant, the strategic need for off-island options becomes greater. As such, we retained NREL to perform an analysis of the "developable" potential on O'ahu, Maui, and Hawai'i Island.

The NREL analysis employs four-kilometer resolution solar insolation and wind resource potential maps for each island to first determine total developable land. The analysis then applies exclusion factors (that is, areas where development of wind or solar is not possible).

For utility-scale solar PV, these exclusion factors include:

- Terrain not conducive to development, including sloped areas. Two exclusion cases were analyzed: slopes greater than 3% and slopes greater than 5%. The slope exclusions are based on the much higher construction costs for building solar PV on steep slopes.
- Heavily populated urban areas.
- National and state park lands.
- Wetlands.
- Agricultural lands including Important Agricultural Land (IAL)[19], 100% of land designated as Agricultural Class A, 90% of land designated as Agricultural Class B, and 90% of land designated as Agricultural Class C.[20]

Similar exclusions were applied for wind, except that agricultural lands were not excluded.

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[19] See Act 183, SLH 2005: http://hdoa.hawaii.gov/wp-content/uploads/2013/02/Act-183.pdf.

[20] See HRS §205-2: http://www.capitol.hawaii.gov/hrscurrent/vol04_Ch0201-0257/HRS0205/HRS_0205-0002.htm.

Table E-1 shows the preliminary results of the NREL analysis for O'ahu, Maui, and Hawai'i Island. The NREL study assumes development potentials of 28.4 MW_{AC} per square kilometer for solar PV and 3.0 MW_{AC} per square kilometer for wind. These results indicate that while Maui and Hawai'i Island have substantial "developable" resource potential, O'ahu is reaching the limits of additional developable wind resource potential. If it is possible to develop solar PV on lands with slopes greater than 3%, then there is still adequate resource potential for utility-scale solar PV. Setting a siting slope of more than 3% limits the remaining utility-scale solar PV potential on O'ahu to zero.

Results of NREL's Island Utility-Scale Resource Potential Study (MWac)				
Resource	*Exclusion Criteria*	*O'ahu*	*Hawai'i*	*Maui*
Utility-Scale PV	Excludes capacity factor potential less than 18%, and all areas with slope greater than 5%	793	15,757	783
	Excludes capacity factor potential less than 18%, and all areas with slope greater than 3%	583	6,019	272
Utility-Scale Wind	Excludes all areas with wind speeds less than 6.5 meters per second at 80 meters high	162	3,532	840

Table E-1. Results of NREL's Island Utility-Scale Resource Potential Study

The results in Table E-1 vary significantly from the initial results reported in our interim filing. After more careful review of the NREL reports, we found that their initial analysis did not consider the limitations on agricultural lands set forth in HRS §205-2. Further, we found that the results for solar PV were presented DC megawatts (and not in AC megawatts) and thus had to be converted. These adjustments are reflected in the data presented here.

The NREL study is not site specific. Therefore, it's crucial that the figures in Table E-1. be construed as indicative, but not the absolute, potential.

Utility-Scale Resources by Island

Table E-2 summarizes the PSIP utility-scale resource options currently available to the planning teams for development of long-term power resource plans.

Resource Type	PSIP Assumed Project Block Sizes by Technology (MW)			
	O'ahu	*Maui*	*Moloka'i and Lana'i*	*Hawai'i Island*
Solar PV	20	1, 5, 10, 20	1	1, 5, 10, 20
Onshore Wind	30	10, 20, 30	10 x 100 kW	10, 20, 30
Combustion Turbines	100	20.5	n/a*	20.5
Combined-Cycle	152 1x1 383 3x1	n/a	n/a	n/a
Internal Combustion Engines	27 (3 x 9 MW) 54 (6 x 9 MW) 100 (6 x 16.8 MW)	9	1	9
Geothermal	n/a	20†	n/a	20
Biomass	20	20	1	20
Waste-to-Energy	n/a	10	1	10
Offshore Wind	400	n/a	n/a	n/a
Off-Island Wind + Cable	200, 400	n/a	n/a	n/a
Solar CSP w/10 hours storage	100	n/a	n/a	n/a

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

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

Table E-2. Preliminary New Utility-Scale Resource Options Available in the 2016 PSIP Analyses

The ability to properly evaluate waste-to-energy facilities in the 2016 PSIP update is contingent upon the ability to acquire reliable data regarding Hawai'i-specific cost and performance characteristics of a WTE plant at or close the sizes shown above. We welcome input from the parties in the development of the assumptions for WTE.

DISTRIBUTED ENERGY RESOURCES COST ASSUMPTIONS

We developed DER resource capital cost assumptions using the same sources and methodology as for utility-scale resources. We concentrated on DG-PV, residential lithium-ion BESS, and behind-the-meter commercial customer class BESS. We utilized IHS Energy's projections of distributed solar and energy storage costs, applied Hawai'i locational adjustments using RSMeans data, and added 4% for Hawai'i General Excise Taxes.

The available data for residential systems from IHS included only the storage medium, and not the balance-of-plant components (for example, inverters, enclosures, and switchgear) under the assumption that the distributed storage would be installed in conjunction with a solar PV system that incorporates the inverter and other balance-of-plant items. We believe that there are opportunities for stand-alone distributed energy storage under time based pricing and demand response programs, so we added balance-of-plant cost estimates to develop stand-alone storage costs.

INTER-ISLAND TRANSMISSION ASSUMPTIONS

Our 2016 updated PSIP analyzed the feasibility of inter-island cables. Because of the distances, interconnections between the islands will be accomplished by using high voltage direct current (HVDC) technology, including converter stations on either end of a submarine cable. Submarine HVDC systems have been successfully deployed around the world; the market for HVDC systems is expected to dramatically increase in the future.[21]

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

NextEra Energy developed capital cost assumptions for a 200 MW and 400 MW cable system for a grid tie between Maui and Oʻahu in consultation with HVDC vendors. HVDC projects are typically developed with the vendor providing turnkey engineering procurement construction (EPC) with guaranteed prices (subject to sliding cost categories related to commodity prices), guaranteed schedules, and guaranteed performance. (A cable between Hawaiʻi Island and Oʻahu was not considered at this time, but will be considered in future analyses.) HVDC projects are typically developed with the vendor providing turnkey engineering procurement construction (EPC) with guaranteed prices (subject to sliding cost categories related to commodity prices), guaranteed schedules, and guaranteed performance.

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

NEW RESOURCE RISKS AND UNCERTAINTIES

In general, developing utility-scale energy infrastructure, whether by the utility, an independent power producer, or otherwise, involves managing a number of implementation risks and uncertainties. Improper management of these risks and uncertainties can have an adverse impact on the ability of the State to achieve the 100% RPS goal.

Technology Risks. Chosen technologies must be commercially proven, particularly if the project provides a significant portion of the grid's power. Commercially proven technologies are characterized by a well capitalized and experienced vendor who can offer a performance warranty. Large projects also require an experienced and well capitalized construction firm who will stand behind contractual assurances that the project will be completed within the budget, on time, and guarantee performance. The technology must be backed by a supply chain of parts and services necessary to operate the plant.

Solar PV, onshore wind, internal combustion engines, combustion turbines, combined-cycle units, geothermal, biomass technologies and undersea cables generally meet these commercial requirements. Deep water offshore wind using floating platforms, OTEC, ocean tidal and waver power are examples of technologies that have yet to meet these commercial requirements.

Permitting and Siting Risks. Depending on the project type and location, a typical project might involve consultation with dozens of state and federal agencies, preparation and dissemination of notices, preparation of numerous impact reports and studies, and navigation through a maze of state and federal agency permitting processes. Many of the permits are subject to contested hearing processes, and all permits are subject to appeals by those who oppose a particular project. This permitting complexity requires extremely well qualified vendors with experience developing new infrastructure, and who understand the unique social and cultural dynamic of Hawai‘i. Hawai‘i's recent history with large infrastructure projects has been one characterized by community opposition and legal challenges.

In some cases, permits that have been issued have been revoked because of procedural errors, after developers have spent significant time, effort, and money working in good faith with the communities and permitting agencies to obtain those permits.[22] This atmosphere of uncertainty leads to less competition for new projects from highly qualified vendors (with resulting higher costs for the projects and greater risk on non-completion) and a higher cost of capital. This is a significant risk for achieving

[22] "Hawaii Supreme Court Revokes Construction Permit For Thirty Meter Telescope On Mauna Kea." *Forbes.* December 3, 2015. http://www.forbes.com/sites/alexknapp/2015/12/03/hawaii-supreme-court-revokes-construction-permit-for-thirty-meter-telescope-on-mauna-kea/#550cc2223094.

Hawai'i's 100% RPS goals. Achieving 100% RPS requires significant new infrastructure, significant amounts of capital to be raised in capital markets, and highly qualified developers with experience in completing complex projects on time and within budget.

Construction Risks. Construction risks are typically managed by the project developer, but such risks can be significant. Unforeseen site conditions, discovery of endangered species and or previously unknown archeological finds, labor strikes and lockouts, and material and labor shortages all can affect the cost and schedule of construction. Extended delays in construction can result in cost uncertainty as commodity prices and interest rates fluctuate. These risks are manageable, but again, large infrastructure construction risks require sophisticated construction project management skills and experience.

Financing Risks. Large infrastructure projects require significant amounts of capital. The incremental capital to develop these projects must be raised in capital markets. Most projects combine equity with debt. The willingness of both debt and equity providers to supply the capital to build new infrastructure projects, and the price of the capital (that is, equity returns required and debt interest rates) depends on a number of factors. First, capital providers assess the merits of the project itself. Second, they assess the regulatory and political risks associated with the project, the relative certainty (or uncertainty) of the regulatory and political environment, and whether that environment is conducive to a return of, and a return on, capital. Third, in the case of major energy infrastructure, they assess the financial strength of the local utility. Finally, they assess the ability of the project developer to manage the extensive risks outlined herein.

When substantial risks are present in the project's environment, fewer capital providers will be available to compete for providing this capital. As a result, the cost of capital, borne by customers, will be higher.

F. National Renewable Energy Laboratory (NREL) Reports

The Companies commissioned the National Renewable Energy Laboratory (NREL) to conduct two studies in support of our 2016 updated PSIPs. One report, entitled *Electricity Generation Capital, Fixed, and Variable O&M Costs*, independently assessed our resource data assumptions. A second report, entitled *Utility-Scale Onshore Wind, Utility-Scale PV, and CSP Potential Resource*, assessed variable resource potential on three of the islands we serve: O‘ahu, Maui, and Hawai‘i Island.

Each report with an attendant summary is presented here.

ELECTRICITY GENERATION CAPITAL, FIXED, AND VARIABLE O&M COSTS

NREL independently reviewed the 2016 updated PSIP resource assumptions (described in Appendix J: Modeling Assumptions Data), including their capital cost, and their fixed and variable operating and maintenance (O&M) costs. NREL reviewed onshore wind, offshore wind, utility-scale PV, residential PV (DG-PV), concentrated solar power (CSP), biomass steam, geothermal, combined-cycle combustion turbines, and simple-cycle combustion turbines.

NREL compared our resource assumptions to their Annual Technology Baseline (ATB) database and resource assumptions from Lazard, an investment bank active in the power industry. The ATB database provides forward curves of these costs, while the Lazard data is only for a single point in time.

In general, the NREL findings support our resource assumptions; any differences are explained throughout the report.

Electricity Generation Capital, Fixed and Variable O&M Costs

Erol Chartan
David Bielen
Carlo Brancucci Martinez-Anido
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Report prepared by the National Renewable Energy Laboratory and submitted to the HECO companies via email on 2/12/2016.

I. Introduction

The HECO companies (HECO, MECO, and HELCO) submitted Power Supply Improvement Plans (PSIPs) in 2014 to help inform pending and future resource acquisition and system operation decisions. The Public Utilities Commission (PUC) reviewed the PSIPs and made recommendations to improve these plans. The PUC recommended that the HECO companies (hereafter, HECO) update and improve their technology cost and performance assumptions. In response, HECO have done so for their 2016 PSIPs. HECO has contracted the National Renewable Energy Laboratory (NREL) to provide input on these assumptions used in its analysis of future electricity supply options.

In this report, we compare HECO's 2014 and 2016 PSIP technology cost assumptions to those used in the NREL Annual Technology Baseline (ATB); we also compare the cost multipliers for converting continental U.S. technology costs to the Hawaiian system. The technology cost and performance assumptions within HECO's 2014 PSIPs have been updated to reflect values more in line with those that we have observed in the ATB and other literature. In general, HECO's assumptions for their draft 2016 PSIPs are now much more in line with ATB assumptions. For utility-scale photovoltaics (PV), concentrated solar power (CSP), and land-based and onshore wind, HECO's assumed capital costs for the 2016 PSIPs match well with those in the ATB, with differences mostly due to comparing different MW sizes of each technology. The most significant differences between HECO's 2016 PSIP assumptions and NREL's assumptions for these four technology types lie in the operations and maintenance (O&M) costs. For thermal generation technologies (geothermal, biomass steam, combined cycle turbine, and simple cycle combustion turbine) the most significant differences reside in the O&M costs for geothermal and both capital and O&M costs for biomass steam.

II. Overview of the Cost Resources

This report reviews the capital costs, fixed O&M costs, and variable O&M costs for Hawaii from their 2014 and draft 2016 PSIPs for a range of technologies. Capital costs reflect an overnight cost of building a power plant. The costs include only the plant envelope, and therefore do not include costs such as potential distribution-level upgrades or spur-line costs. Technology cost assumptions for the 2014 PSIPs were created from a cost report created by Black & Veatch in February 2012 for NREL using 2009 data (Black & Veatch, 2012). In line with PUC's request to use more recent data, HECO's 2016 PSIPs have been developed using cost assumption data from, but not limited to, NREL's ATB, the Energy Information Administration (EIA), Lazard, the Electric Power Research Institute (EPRI), and customized cost assumptions developed by NextEra. Relative to the 2014 PSIPs cost assumptions, the 2016 PSIPs renewable energy cost assumptions are generally lower. This report uses two up-to-date cost data sources to compare to HECO's data, namely the NREL ATB and Lazard-v9.0, which we describe below (National Renewable Energy Laboratory, 2015; Lazard, 2015).

1. *ATB* – Costs were reported in 2013$ and have been converted to nominal dollars to match HECO's data by using a constant 1.8% annual inflation rate. The ATB contains a range of cost assumptions for technologies coming online each year from 2014 through 2050. The range and mid-case for each technology was reported for 2016 to represent current costs, while projections for the same future years HECO reported were also reported. Each mid-case observation reflects NREL's best cost estimate of a given technology in a given year.[1]
2. *Lazard-v9.0* – Costs were reported in 2015$ and have been converted to nominal dollars by using a constant 1.8% annual inflation rate. For each technology, Lazard provides a range for capital costs and fixed and variable O&M. We assume that Lazard costs are for plants that would begin construction in 2015. Unlike the ATB, Lazard does not provide cost projections for future years.

In addition to current cost estimates for 2016, HECO PSIPs report cost projections through 2045. The ATB includes projections over this range, but the estimates in the latter years are subject to considerable uncertainty.

The ATB and Lazard-v9.0 data reported here have been adjusted to represent capital costs in Hawaii (HECO's PSIPs cost data is only for Hawaii). The cost multipliers for NREL's data were taken from the appendix of the U.S. EIA report "Updated Capital Cost Estimates for Utility Scale

[1] ATB Disclaimer: It is recognized that disclosure of these Data is provided under the following conditions and warnings: (1) these Data have been prepared for reference purposes only; (2) these Data consist of forecasts, estimates or assumptions made on a best-efforts basis, based upon present expectations; and (3) these Data were prepared with existing information and are subject to change without notice.

Electricity Generating Plants," which was prepared for EIA by the Science Applications International Corporation (SAIC) (Science Applications International Corporation, 2013). The technology-specific multipliers in the report represent adjustments for economic conditions in Honolulu, Hawaii. These same values were used by HECO in their 2014 PSIPs for their cost input assumptions and they are presented in Table 1. These multipliers, which pertain to projects in Honolulu, have been applied to the raw data from the ATB and Lazard in order to create Hawaii-specific values.

Cost Multiplier Comparison

Table 1: Multipliers

Technology	EIA/SAIC
Land-based wind	30.1%
Off-shore wind	13.8%
CSP	36.7%
Utility PV	40.5%
Biomass steam	53.6%
Geothermal	27.2%
Hydropower	0.0%
Combined cycle	53.1%
Combustion turbine	51.5%

III. Technology Cost Assumptions Comparison

This section presents the technology costs assumptions by technology. The tables summarize the values that were included in HECO's 2014 PSIPs, HECO's 2016 PSIPs, Lazard-v9.0, and the NREL ATB.

Notes: the year column corresponds to the installation year of the facility. Values in the tables below shaded with darker backgrounds represent "not available in this year."

Table 2: Wind, Onshore

Year Installed	Hawaii Specific Nominal Capital Costs ($/kW)			Hawaii Specific Nominal Fixed O&M Costs ($/kW)			Hawaii Specific Nominal Variable O&M Costs ($/kW)		
2014 PSIPs - HECO, MECO, HELCO									
2015	$2,867.01			$66.78			$0.00		
2020	$3,134.50			$73.01			$0.00		
2025	$3,426.94			$79.82			$0.00		
2030	$3,746.67			$87.27			$0.00		
2016 PSIPs - Oahu									
	30MW	200MW + Cable	400MW + Cable	30MW	200MW + Cable	400MW + Cable	30MW	200MW + Cable	400MW + Cable
2016	$2,465.00	N/A	N/A	$27.40	$27.40	$27.40	-	-	-
2020	$2,480.00	$5,097.00	$4,572.00	$29.43	$29.43	$29.43	-	-	-
2025	$2,722.00	$5,664.00	$5,085.00	$32.17	$32.17	$32.17	-	-	-
2030	$2,867.00	$6,154.00	$5,514.00	$35.17	$35.17	$35.17	-	-	-
2035	$3,010.00	$6,688.00	$5,981.00	$38.46	$38.46	$38.46	-	-	-
2040	$3,171.00	$7,270.00	$6,490.00	$42.04	$42.04	$42.04	-	-	-
2045	$3,333.00	$7,907.00	$7,046.00	$45.97	$45.97	$45.97	-	-	-
2016 PSIPs - Maui & Hawaii									
	10MW	20MW	30MW	10MW	20MW	30MW	10MW	20MW	30MW
2016	$4,171.00	$2,968.00	$2,465.00	$65.07	$41.61	$33.79	-	-	-
2020	$4,198.00	$2,987.00	$2,480.00	$69.88	$44.69	$36.29	-	-	-
2025	$4,606.00	$3,277.00	$2,722.00	$76.40	$48.86	$39.68	-	-	-
2030	$4,853.00	$3,453.00	$2,867.00	$83.53	$53.42	$43.38	-	-	-
2035	$5,093.00	$3,624.00	$3,010.00	$91.32	$58.40	$47.42	-	-	-
2040	$5,367.00	$3,819.00	$3,171.00	$99.85	$63.85	$51.85	-	-	-
2045	$5,640.00	$4,013.00	$3,333.00	$109.16	$69.80	$56.69	-	-	-
Lazard-v9.0									
	Low		High	Low		High	Low		High
2015	$1,658.28		$2,255.27	$35.69		$40.79	$0.00		$0.00
ATB									
	Low	Mid-Point	High	Low	Mid-Point	High	Low	Mid-Point	High
2016	$2,021.73	$2,348.39	$2,412.90	$51.69	$52.75	$53.80	$0.00	$0.00	$0.00
2020	$2,045.98	$2,467.56	$2,591.38	$53.25	$55.52	$57.78	$0.00	$0.00	$0.00
2025	$2,124.06	$2,647.82	$2,833.15	$55.74	$59.46	$63.17	$0.00	$0.00	$0.00
2030	$2,257.04	$2,871.95	$3,097.48	$58.23	$63.65	$69.07	$0.00	$0.00	$0.00
2035	$2,442.57	$3,130.27	$3,386.47	$60.71	$69.59	$75.51	$0.00	$0.00	$0.00
2040	$2,670.46	$3,422.32	$3,702.42	$64.75	$74.46	$82.56	$0.00	$0.00	$0.00
2045	$2,919.61	$3,741.62	$4,047.86	$69.02	$81.41	$90.26	$0.00	$0.00	$0.00

The cost estimates for land-based wind are presented in Table 2. The capital costs for wind with a cable running from Maui to Oahu (provided by HECO in their 2016 PSIPs) are much larger than those for non-cable projects according to all three data sources. HECO's 2016 PSIPs assume the technology to be available from 2020 onward; for that year and beyond the 30 MW figures are between the low- and high-cases provided by the ATB. In contrast, the HECO 2016 PSIPs' capital cost estimates for smaller wind projects on Maui and Hawaii (10 MW and 20 MW) are generally above the ATB high-case. For 20 MW projects, the difference between the HECO costs and the ATB high case is relatively small, particularly in the later years. For 10 MW projects, the same difference is quite large.

The assumptions for the 2016 PSIPs show a reduction in O&M costs compared to the 2014 PSIPs for the 30MW case and are generally close to or below the bounds provided by Lazard-v9.0. They are also significantly below the ATB low-case in all years for projects larger than 10 MW.

Table 3: Wind, Offshore

Year Installed	Hawaii Specific Nominal Capital Costs ($/kW)			Hawaii Specific Nominal Fixed O&M Costs ($/kW)			Hawaii Specific Nominal Variable O&M Costs ($/kW)		
2014 PSIPs - HECO, MECO, HELCO									
2015	Not Commercial			$0.00			$0.00		
2020	$5,815.90			$158.19			$0.00		
2025	$6,191.99			$172.94			$0.00		
2030	$6,604.17			$189.08			$0.00		
2016 PSIPs - Oahu									
	Floating Platform, 400MW			Floating Platform, 400MW			Floating Platform, 400MW		
2016	$5,062.00			$96.71			-		
2020	$4,500.00			$103.86			-		
2025	$4,013.00			$113.55			-		
2030	$4,067.00			$124.15			-		
2035	$4,202.00			$135.73			-		
2040	$4,403.00			$148.39			-		
2045	$4,617.00			$162.24			-		
2016 PSIPs - Maui & Hawaii									
	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
2016	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
2020	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
2025	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
2030	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
2035	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
2040	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
2045	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Lazard-v9.0									
	Low		High	Low		High	Low		High
2015	$3,597.29	0	$6,382.29	$61.18	0	$101.97	$13.26	0	$18.35
ATB									
	Low	Mid-Point	High	Low	Mid-Point	High	Low	Mid-Point	High
2016	$5,622.24	$6,738.77	$8,562.43	$127.65	$136.09	$170.91	$0.00	$0.00	$0.00
2020	$5,300.59	$6,442.97	$8,495.64	$125.76	$130.30	$168.82	$0.00	$0.00	$0.00
2025	$4,915.50	$6,163.05	$8,622.91	$128.83	$130.07	$180.85	$0.00	$0.00	$0.00
2030	$4,973.40	$6,548.49	$9,427.42	$134.07	$138.14	$197.73	$0.00	$0.00	$0.00
2035	$5,218.37	$7,063.41	$10,306.99	$143.62	$149.55	$216.17	$0.00	$0.00	$0.00
2040	$5,465.75	$7,615.58	$11,268.62	$153.78	$161.88	$236.34	$0.00	$0.00	$0.00
2045	$5,740.05	$8,195.19	$12,319.97	$166.36	$176.98	$258.39	$0.00	$0.00	$0.00

The cost estimates for offshore wind are presented in Table 3. Note that there are no values for Maui and Hawaii within the 2016 PSIPs because HECO believes that the on-shore wind resource potential for each of these islands exceeds the total maximum electrical demand for each of these islands, and therefore the more expensive off-shore wind option would never be utilized for Maui or Hawaii.

The values from the ATB represent fixed platform turbines, and the ranges reflect designs for shallow and deep water. In comparison the values from the HECO companies represent floating offshore wind turbines, which have several differences relative to the fixed-bottom wind turbine that comprise the vast majority (~99%) of global installations to date. Floating wind turbine technology is less mature than fixed-bottom technology; the first floating turbine was installed in 2009 and four additional machines have been installed in the subsequent years. Because these projects are single turbine, proof-of-concept installations, they historically have been more expensive than fixed-bottom projects ($/kW basis). These projects are not able to achieve economies of scale and have elevated budgets for research and development. Floating technologies are, however, becoming increasingly mature and the first commercial applications are expected to occur by 2020 (Smith et al. 2015).

The economics of floating technologies are different from fixed-bottom technologies. Some elements, such as electric infrastructure, will be more expensive because cables must be able to withstand dynamic loading within the water column, whereas cables for fixed turbines can be laid out directly on the seabed. Other elements, such as installation and O&M costs, will be considerably lower because the entire turbine-substructure unit can be assembled in port and towed to the project site. The tow-out method reduces cost and risk by eliminating the need to conduct lifting operations in the offshore environment. Further, unlike fixed substructures, the weight of floating platforms is relatively insensitive to turbine size. As a result, the economics improve markedly for projects that use industry-leading 8+ MW wind turbines. While there is considerable uncertainty about the future cost of floating technology given its pre-commercial status, it is reasonable to expect that floating projects will be more competitive than fixed-bottom technology in deep water. Further, floating offshore wind in Deep Water could become more competitive than fixed-bottom offshore wind in Shallow Water by the mid- to late-2020s (Musial and Smith 2015).

Preliminary analysis conducted by NREL and the U.S. Department of Energy and presented at the 2015 National Offshore Wind Strategy Meeting held in Washington, DC on December 10th, suggests that a reference floating offshore wind facility installed in 2020 is expected to have an installed capital cost of approximately $4,500/kW, fixed O&M costs of approximately $80/kW-year, and no variable O&M costs. This capital cost estimate is reflected in the 2016 PSIP values. The 2016 PSIP values for capital cost are consistently lower than ATB's fixed turbine range. Moreover, the fixed O&M estimates for the 2016 PSIPs are also much lower than the ATB range.

Table 4: Utility-Scale Photovoltaics

Year Installed	Hawaii Specific Nominal Capital Costs ($/kW)			Hawaii Specific Nominal Fixed O&M Costs ($/kW)			Hawaii Specific Nominal Variable O&M Costs ($/kW)		
2014 PSIPs - HECO, MECO, HELCO									
2015	$3,987.52			$53.42			$0.00		
2020	$4,120.21			$54.76			$0.00		
2025	$4,261.63			$57.20			$0.00		
2030	$4,454.88			$59.63			$0.00		
2016 PSIPs - Oahu									
	20MW			20MW			20MW		
2016	$2,793.00			$22.97			-		
2020	$2,432.00			$24.67			-		
2025	$2,284.00			$26.97			-		
2030	$2,232.00			$29.49			-		
2035	$2,203.00			$32.24			-		
2040	$2,174.00			$35.25			-		
2045	$2,146.00			$38.53			-		
2016 PSIPs - Maui & Hawaii									
	5MW	10MW	20MW	5MW	10MW	20MW	5MW	10MW	20MW
2016	$3,262.00	$2,849.00	$2,574.00	$29.87	$28.20	$24.77	-	-	-
2020	$2,841.00	$2,481.00	$2,241.00	$32.08	$30.29	$26.60	-	-	-
2025	$2,669.00	$2,331.00	$2,105.00	$35.07	$33.11	$29.08	-	-	-
2030	$2,608.00	$2,278.00	$2,057.00	$38.34	$36.20	$31.80	-	-	-
2035	$2,574.00	$2,248.00	$2,031.00	$41.92	$39.58	$34.76	-	-	-
2040	$2,540.00	$2,218.00	$2,004.00	$45.83	$43.27	$38.01	-	-	-
2045	$2,507.00	$2,189.00	$1,978.00	$50.11	$47.31	$41.55	-	-	-
Lazard-v9.0									
	Low		High	Low		High	Low		High
2015	$2,292.28	0	$2,149.01	$13.26	0	$10.20	$0.00	0	$0.00
ATB (100MW Single Axis Tracking)									
	Low	Mid-Point	High	Low	Mid-Point	High	Low	Mid-Point	High
2016	$2,776.69	$3,066.91	$3,293.55	$17.41	$17.41	$17.41	$0.00	$0.00	$0.00
2020	$1,871.89	$2,808.72	$3,537.16	$9.97	$9.97	$9.97	$0.00	$0.00	$0.00
2025	$2,046.54	$2,559.61	$3,867.17	$10.90	$10.90	$10.90	$0.00	$0.00	$0.00
2030	$2,237.48	$2,237.48	$4,227.98	$11.92	$11.92	$11.92	$0.00	$0.00	$0.00
2035	$2,446.23	$2,446.23	$4,622.44	$13.03	$13.03	$13.03	$0.00	$0.00	$0.00
2040	$2,674.46	$2,674.46	$5,053.71	$14.25	$14.25	$14.25	$0.00	$0.00	$0.00
2045	$2,923.99	$2,923.99	$5,525.22	$15.57	$15.57	$15.57	$0.00	$0.00	$0.00

The cost estimates for utility-scale PV are presented in Table 4.[2] The low and high values from Lazard-v9.0 correspond to different types of solar technology. The lower capital cost is associated with fixed-tilt systems, which have a lower capacity factor. The higher capital cost is associated with 1-axis tracking systems, which have a higher capacity factor. Thus, the lower capital cost system actually has a higher levelized cost of electricity (LCOE) than the higher capital cost system. The ATB values reflect cost estimates for single axis tracking solar at 100 MW in size; over 154GW of available capacity has been summarized into this data.

The capital and O&M costs decreased significantly from the 2014 to 2016 PSIPs. Whereas all costs within the 2014 PSIPs are higher than the ranges in Lazard or ATB, the costs from the 2016 PSIPs are much more comparable. The 2016 PSIPs show the utility scale PV coming online in 2020 when the capital costs are slightly higher than the range of costs given by Lazard-v9.0 (except for the 20MW case in Maui and Hawaii) and within the range from the ATB. The future capital cost projections from the 2016 PSIPs are within the ATB range until 2030, at which point they drop below the ATB low-case. This occurs because the PSIP assumed values continue to decline while the ATB capital costs begin to flat-line in real dollars (i.e., they increase nominally). The fixed O&M costs from the 2016 PSIPs are higher than those provided by Lazard-v9.0 and the ATB, both currently and in future years. This is at least partly expected given the ATB values are for a 100 MW solar farm as opposed to HECO, who considered 5 MW, 10 MW and 20 MW projects.

[2] All costs in the above table are in AC. The ATB figures had a DC – AC cost multiplier of 1.1 applied.

Table 5: Residential Photovoltaics

Year	Hawaii Specific Nominal Capital Costs ($/kW)	Hawaii Specific Nominal Fixed O&M Costs ($/kW-year)	Hawaii Specific Nominal Variable O&M Costs ($/kW)
2014 PSIPs - HECO, MECO, HELCO			
2015	$4,830.33	$53.42	$0.00
2020	$4,563.07	$54.76	$0.00
2025	$4,603.00	$57.20	$0.00
2030	$4,785.19	$59.63	$0.00
2016 PSIPs - Oahu			
2016	$3,945.00	n/a	n/a
2020	$3,360.00	n/a	n/a
2025	$3,068.00	n/a	n/a
2030	$2,933.00	n/a	n/a
2035	$2,894.00	n/a	n/a
2040	$2,856.00	n/a	n/a
2045	$2,819.00	n/a	n/a
2016 PSIPs - Maui & Hawaii			
2016	$3,985.00	n/a	n/a
2020	$3,394.00	n/a	n/a
2025	$3,100.00	n/a	n/a
2030	$2,962.00	n/a	n/a
2035	$2,924.00	n/a	n/a
2040	$2,885.00	n/a	n/a
2045	$2,848.00	n/a	n/a

The cost estimates for utility-scale PV are presented in Table 5. There is no cost data for residential photovoltaics provided for the 2016 PSIPs, or within ATB or Lazard-v9.0. However, as exhibited in the 2014 PSIP numbers, there is a substantial cost advantage to utility-scale PV over residential PV due to significant economies of scale.

Table 6: CSP (Concentrated Solar Power)

Year	Hawaii Specific Nominal Capital Costs ($/kW)			Hawaii Specific Nominal Fixed O&M Costs ($/kW-year)			Hawaii Specific Nominal Variable O&M Costs ($/kW)		
2016 PSIPs - Oahu									
	100MW Solar CSP + 10hrs storage			100MW Solar CSP + 10hrs storage			100MW Solar CSP + 10hrs storage		
2016	$12,304.00			$92.38			n/a		
2020	$9,848.00			$99.21			n/a		
2025	$7,694.00			$108.47			n/a		
2030	$7,309.00			$118.59			n/a		
2035	$7,508.00			$129.65			n/a		
2040	$8,209.00			$141.75			n/a		
2045	$8,975.00			$154.98			n/a		
Lazard-v9.0									
	Low	High		Low	High		Low	High	
2015	$12,196.86	$12,545.34		$10.20	$13.26		$0.00	$0.00	
ATB									
	Low	Mid	High	Low	Mid	High	Low	Mid	High
2016	$6,806.97	$11,271.88	$14,219.65	$68.57	$68.57	$68.57	$3.16	$3.16	$3.16
2020	$4,775.03	$7,590.80	$9,567.11	$57.78	$57.78	$57.78	$3.40	$3.40	$3.40
2025	$5,220.54	$7,289.79	$10,459.71	$63.17	$63.17	$63.17	$3.72	$3.72	$3.72
2030	$5,707.61	$6,868.39	$11,435.58	$69.07	$69.07	$69.07	$4.06	$4.06	$4.06
2035	$6,240.12	$7,509.20	$12,502.51	$75.51	$75.51	$75.51	$4.44	$4.44	$4.44
2040	$6,822.32	$8,209.80	$13,668.98	$82.56	$82.56	$82.56	$4.86	$4.86	$4.86
2045	$7,458.83	$8,975.76	$14,944.28	$90.26	$90.26	$90.26	$5.31	$5.31	$5.31

The cost estimates for utility-scale PV are presented in Table 6. Note that there are no estimates for CSP for either the 2014 PSIPs or Maui and Hawaii in the 2016 PSIPs. The data for the 2016 PSIPs assume 10 hours of Thermal Energy Storage (TES), while the data from the ATB includes cases of 6 hours and 12 hours of TES. The 2016 PSIP current capital cost estimates for Oahu are within the bounds provided by Lazard-v9.0 and the ATB. In future years, the 2016 PSIP costs are generally within the bounds provided by the ATB (the lone exception occurs in 2020). However, the HECO fixed O&M estimates are much higher than the Lazard-v9.0 values, and higher than the values from the ATB high-case. The variable O&M values from the ATB are non-zero due to the storage component of CSP, whereas the 2016 PSIP and Lazard-v9.0 values assume no variable O&M costs.

Table 7: Biomass Steam

Year Installed	Hawaii Specific Nominal Capital Costs ($/kW)			Hawaii Specific Nominal Fixed O&M Costs ($/kW)			Hawaii Specific Nominal Variable O&M Costs ($/kW)		
2014 PSIPs - HECO, MECO, HELCO									
2015	$6,547.52			$105.73			$16.69		
2020	$7,158.39			$115.60			$18.25		
2025	$7,826.26			$126.38			$19.96		
2030	$8,556.44			$138.17			$21.82		
2016 PSIPs - Oahu									
	20MW			20MW			20MW		
2016	$5,251.00			$79.05			$12.98		
2020	$5,299.00			$84.90			$13.94		
2025	$5,692.00			$92.82			$15.24		
2030	$6,107.00			$101.48			$16.66		
2035	$6,546.00			$110.95			$18.22		
2040	$6,973.00			$121.30			$19.92		
2045	$7,624.00			$132.61			$21.78		
2016 PSIPs - Maui & Hawaii									
	20MW			20MW			20MW		
2016	$5,251.00			$79.05			$13.00		
2020	$5,299.00			$84.90			$13.96		
2025	$5,692.00			$92.82			$15.26		
2030	$6,107.00			$101.48			$16.69		
2035	$6,546.00			$110.95			$18.25		
2040	$6,973.00			$121.30			$19.95		
2045	$7,624.00			$132.61			$21.81		
Lazard-v9.0									
	Low		High	Low		High	Low		High
2015	$4,072.27	0	$5,481.90	$96.87	0	$96.87	$15.30	0	$15.30
ATB									
	Low	Mid-Point	High	Low	Mid-Point	High	Low	Mid-Point	High
2016	$6,295.43	$6,295.43	$6,295.43	$112.88	$112.88	$112.88	$5.27	$5.27	$5.27
2020	$6,353.86	$6,353.86	$6,353.86	$121.23	$121.23	$121.23	$5.67	$5.67	$5.67
2025	$6,824.89	$6,824.89	$6,824.89	$132.54	$132.54	$132.54	$6.19	$6.19	$6.19
2030	$7,322.28	$7,322.28	$7,322.28	$144.91	$144.91	$144.91	$6.77	$6.77	$6.77
2035	$7,848.51	$7,848.51	$7,848.51	$158.43	$158.43	$158.43	$7.40	$7.40	$7.40
2040	$8,361.96	$8,361.96	$8,361.96	$173.21	$173.21	$173.21	$8.09	$8.09	$8.09
2045	$9,142.12	$9,142.12	$9,142.12	$189.37	$189.37	$189.37	$8.85	$8.85	$8.85

The cost estimates for biomass steam are presented in Table 7. The data from the 2016 PSIPs represent a stand-alone biomass plant (50 MW Net); both capital costs and fixed O&M costs are much lower compared to the 2014 PSIPs. The capital cost used in the 2016 PSIPs for 2020 is within the range provided by Lazard-v9.0. Capital costs from the 2016 PSIPs are also significantly lower than the single values from the ATB in both the current year and the future projections. Fixed O&M costs from the 2016 PSIPs for 2020 are significantly below values from Lazard-v9.0, and for all years they are significantly below the ATB values. Variable O&M costs from the 2016 draft PSIPs in 2020 are similar to values from Lazard-v9.0, while for all years they are higher than the ATB values.

Table 8: Geothermal

Year Installed	Hawaii Specific Nominal Capital Costs ($/kW)			Hawaii Specific Nominal Fixed O&M Costs ($/kW)			Hawaii Specific Nominal Variable O&M Costs ($/kW)		
2014 PSIPs - HECO, MECO, HELCO									
	Non-Dispatchable		Fully Dispatchable	Non-Dispatchable		Fully Dispatchable	Non-Dispatchable		Fully Dispatchable
2015	$8,409.31		$8,586.27	$40.07		$40.07	$34.50		$34.50
2020	$9,193.89		$9,387.36	$43.81		$43.81	$37.72		$37.72
2025	$10,051.66		$10,263.19	$47.89		$47.89	$41.24		$41.24
2030	$10,989.47		$11,220.73	$52.36		$52.36	$45.09		$45.09
2016 PSIPs - Oahu									
2016		n/a			n/a			n/a	
2020		n/a			n/a			n/a	
2025		n/a			n/a			n/a	
2030		n/a			n/a			n/a	
2035		n/a			n/a			n/a	
2040		n/a			n/a			n/a	
2045		n/a			n/a			n/a	
2016 PSIPs - Maui & Hawaii									
		20MW, Fuel Type Lava			20MW, Fuel Type Lava			20MW, Fuel Type Lava	
2016		$8,804.00			$158.11			$2.58	
2020		$9,456.00			$169.81			$2.77	
2025		$10,338.00			$185.65			$3.03	
2030		$11,302.00			$202.97			$3.31	
2035		$12,357.00			$221.91			$3.62	
2040		$13,510.00			$242.62			$3.96	
2045		$14,770.00			$265.25			$4.33	
Lazard-v9.0									
	Low		High	Low		High	Low		High
2015	$5,058.52	0	$7,263.51	$0.00	0	$0.00	$30.59	0	$40.79
ATB									
	Low	Mid-Point	High	Low	Mid-Point	High	Low	Mid-Point	High
2016	$8,040.86	$9,382.79	$14,382.83	$121.32	$121.32	$121.32	$0.00	$0.00	$0.00
2020	$8,635.62	$10,076.81	$15,446.69	$130.30	$130.30	$130.30	$0.00	$0.00	$0.00
2025	$9,441.31	$11,016.96	$16,887.84	$142.45	$142.45	$142.45	$0.00	$0.00	$0.00
2030	$10,322.17	$12,044.83	$18,463.46	$155.74	$155.74	$155.74	$0.00	$0.00	$0.00
2035	$11,285.22	$13,168.60	$20,186.08	$170.27	$170.27	$170.27	$0.00	$0.00	$0.00
2040	$12,338.12	$14,397.22	$22,069.42	$186.16	$186.16	$186.16	$0.00	$0.00	$0.00
2045	$13,489.25	$15,740.46	$24,128.47	$203.53	$203.53	$203.53	$0.00	$0.00	$0.00

The cost estimates for geothermal are presented in Table 8. Note that HECO only considered geothermal projects on Maui and Hawaii. The numbers from ATB are site-specific, which is why the capital cost ranges are large.

The 2016 PSIPs include slightly higher capital cost assumptions and much higher O&M costs compared to the values from the 2014 PSIPs. The capital cost values within the 2016 PSIPs are always within the ATB ranges (near the low-case) but much higher than values from Lazard-v9.0. The 2016 PSIP fixed O&M costs are significantly higher than the ATB estimates throughout the entire horizon.

Table 9: Combined Cycle Turbine

Year Installed	Hawaii Specific Nominal Capital Costs ($/kW)			Hawaii Specific Nominal Fixed O&M Costs ($/kW)			Hawaii Specific Nominal Variable O&M Costs ($/kW)		
2014 PSIPs - HECO, MECO, HELCO									
2015	$2,095.88			$7.02			$4.08		
2020	$2,291.43			$7.68			$4.47		
2025	$2,505.21			$8.39			$4.88		
2030	$2,738.95			$9.18			$5.34		
2016 PSIPs - Oahu									
	152MW (1 x 1)		383MW (3 x 1)	152MW (1 x 1)		383MW (3 x 1)	152MW (1 x 1)		383MW (3 x 1)
2016	$1,660.00		$1,758.00	$17.29		n/a	$4.49		n/a
2020	$1,742.00		$1,845.00	$18.57		n/a	$4.82		n/a
2025	$1,859.00		$1,969.00	$20.30		n/a	$5.27		n/a
2030	$1,991.00		$2,108.00	$22.20		n/a	$5.76		n/a
2035	$2,143.00		$2,270.00	$24.27		n/a	$6.30		n/a
2040	$2,318.00		$2,455.00	$26.53		n/a	$6.89		n/a
2045	$2,535.00		$2,684.00	$29.01		n/a	$7.53		n/a
2016 PSIPs - Maui & Hawaii									
2016	n/a			n/a			n/a		
2020	n/a			n/a			n/a		
2025	n/a			n/a			n/a		
2030	n/a			n/a			n/a		
2035	n/a			n/a			n/a		
2040	n/a			n/a			n/a		
2045	n/a			n/a			n/a		
Lazard-v9.0									
	Low		High	Low		High	Low		High
2015	$1,405.04	0	$1,873.39	$6.32	0	$5.61	$3.57	0	$2.04
ATB									
	Low	Mid-Point	High	Low	Mid-Point	High	Low	Mid-Point	High
2016	$1,578.02	$1,578.02	$1,578.02	$14.77	$14.77	$14.77	$3.16	$3.16	$3.16
2020	$1,654.85	$1,654.85	$1,654.85	$15.86	$15.86	$15.86	$3.40	$3.40	$3.40
2025	$1,767.52	$1,767.52	$1,767.52	$17.34	$17.34	$17.34	$3.72	$3.72	$3.72
2030	$1,890.96	$1,890.96	$1,890.96	$18.96	$18.96	$18.96	$4.06	$4.06	$4.06
2035	$2,037.91	$2,037.91	$2,037.91	$20.73	$20.73	$20.73	$4.44	$4.44	$4.44
2040	$2,203.27	$2,203.27	$2,203.27	$22.66	$22.66	$22.66	$4.86	$4.86	$4.86
2045	$2,408.83	$2,408.83	$2,408.83	$24.78	$24.78	$24.78	$5.31	$5.31	$5.31

The cost estimates for combined cycle turbines are presented in Table 9. Note that no cost estimates for the 2016 PSIPs were included for Maui and Hawaii. The values for the 2016 PSIPs represent either a single-unit 152 MW plant or a three-unit 383 MW plant, both without carbon capture and sequestration (CCS). The low and high values for the Lazard-v9.0 data correspond to different types of configurations of Combined Cycle Turbines. The current capital costs for the 2016 PSIPs are within the bounds from Lazard-v9.0, while the fixed and variable O&M costs are higher. For the current year and all future projections, the 2016 PSIP capital and O&M costs are slightly higher than those from the ATB.

Table 10: Simple Cycle Combustion Turbine

Year Installed	Hawaii Specific Nominal Capital Costs ($/kW)			Hawaii Specific Nominal Fixed O&M Costs ($/kW)			Hawaii Specific Nominal Variable O&M Costs ($/kW)		
2014 PSIPs - HECO, MECO, HELCO									
2015	$1,097.69			$5.85			$33.28		
2020	$1,200.10			$6.40			$36.38		
2025	$1,312.07			$7.00			$39.78		
2030	$1,434.49			$7.65			$43.49		
2016 PSIPs - Oahu									
	100MW Gas / Oil			100MW Gas / Oil			100MW Gas / Oil		
2016	$1,237.00			$9.01			$12.99		
2020	$1,292.00			$9.68			$13.95		
2025	$1,373.00			$10.58			$15.25		
2030	$1,466.00			$11.57			$16.68		
2035	$1,577.00			$12.65			$18.23		
2040	$1,706.00			$13.83			$19.93		
2045	$1,865.00			$15.12			$21.79		
2016 PSIPs - Maui & Hawaii									
	20.5MW Gas / Oil			20.5MW Gas / Oil Maui		20.5MW Gas / Oil Hawaii	20.5MW Gas / Oil Maui		20.5MW Gas / Oil Hawaii
2016	$3,586.00			$140.00		$140.00	$1.26		$1.75
2020	$3,747.00			$150.36		$150.36	$1.35		$1.88
2025	$3,981.00			$164.38		$164.38	$1.48		$2.05
2030	$4,251.00			$179.72		$179.72	$1.62		$2.25
2035	$4,571.00			$196.49		$196.49	$1.77		$2.46
2040	$4,947.00			$214.82		$214.82	$1.93		$2.69
2045	$5,408.00			$234.86		$234.86	$2.11		$2.94
Lazard-v9.0									
	Low		High	Low		High	Low		High
2015	$1,235.87	0	$1,544.84	$5.10	0	$25.49	$4.79	0	$7.65
ATB									
	Low	Mid-Point	High	Low	Mid-Point	High	Low	Mid-Point	High
2016	$1,324.98	$1,324.98	$1,324.98	$7.38	$7.38	$7.38	$13.71	$13.71	$13.71
2020	$1,385.23	$1,385.23	$1,385.23	$7.93	$7.93	$7.93	$14.73	$14.73	$14.73
2025	$1,471.30	$1,471.30	$1,471.30	$8.67	$8.67	$8.67	$16.10	$16.10	$16.10
2030	$1,571.64	$1,571.64	$1,571.64	$9.48	$9.48	$9.48	$17.61	$17.61	$17.61
2035	$1,689.11	$1,689.11	$1,689.11	$10.36	$10.36	$10.36	$19.25	$19.25	$19.25
2040	$1,829.54	$1,829.54	$1,829.54	$11.33	$11.33	$11.33	$21.04	$21.04	$21.04
2045	$2,000.23	$2,000.23	$2,000.23	$12.39	$12.39	$12.39	$23.01	$23.01	$23.01

The cost estimates for simple cycle combustion turbines are presented in Table 10. The 2016 PSIPs have cost estimates for a 100 MW plant on Oahu and a 20.5 MW plant on Maui and Hawaii; the capital and fixed O&M cost estimates are much greater for the 20.5 MW plant versus the 100 MW plant. The 100 MW plant has slightly higher capital and fixed O&M costs compared to the 2014 PSIPs and much lower variable O&M costs. The current capital costs for the 100 MW plant in the 2016 PSIPs are within the bounds from Lazard-v9.0. For both the current year and future projections, the capital costs for the 100 MW plant in the 2016 PSIP are slightly lower to those from the ATB, the fixed O&M costs are slightly higher and the variable O&M costs are slightly lower.

IV. Conclusion

In general, HECO's assumptions for their draft 2016 PSIPs are now much more in line with ATB assumptions. The most significant differences reside in the O&M costs for geothermal and both capital and O&M costs for biomass steam.

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UTILITY-SCALE ONSHORE WIND, UTILITY-SCALE PV, AND CSP POTENTIAL RESOURCE

An NREL report estimated the onshore utility-scale PV and utility-scale wind potential for each of the three main islands we serve: O‘ahu, Maui, and Hawai‘i Island. NREL used a square (four kilometer by four kilometer) grid database that they developed and refined over several years. The grid details solar irradiance at the earth’s surface and wind speeds 80 meters above the earth’s surface. Their study assumed a “typical” year. Based on this database, their study identified areas with high solar or wind potential.

The study excluded areas where the ability to develop utility-scale wind and utility-scale PV was highly unlikely. Exclusions included urban areas, wetlands, park lands, mountainous areas, ravines, and certain agricultural areas. The study then assumed that the remaining land was available to be developed for utility-scale wind, utility-scale PV, or for the dual purpose of both wind and PV together.

The results of the NREL resource potential study are indicative as they do not represent the actual developable land. Some of this “available” land, for instance, might be privately held and not for sale. In reality, the amount of land available for development is likely less than the potential shown in the NREL assessment, perhaps significantly.

The results do suggest renewable resource potential on Maui and Hawai‘i Island that exceeds each island’s native electrical loads. The results for O’ahu, however, suggest that additional utility-scale wind development is less than 100 MW, and that while the resource potential for utility-scale PV is becoming constrained, the addition of a few hundred megawatts is possible. Appendix E: New Resource Options discusses the implications of this NREL study.

Utility-Scale Onshore Wind, Utility-Scale PV, and CSP Potential Resource

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Report prepared by the National Renewable Energy Laboratory and submitted to the HECO companies via email on 3/17/2016.

I. Executive Summary

This report by the National Renewable Energy Laboratory NREL presents estimates for the total amount of developable utility-scale wind, utility-scale solar photovoltaic (PV) and concentrated solar power (CSP) potential for the Hawaiian islands of Oahu, Maui, and Hawaii. These estimates of technical potential do not take into account existing or committed wind and solar plants. Existing solar and wind resource data and the use of standard exclusion factors were utilized by NREL to provide independent estimates. Sites where both solar PV and wind could be deployed were examined together as possible dual use sites.

Tables 1 to 6 show the utility-scale onshore wind and utility-scale solar PV resource potentials (in MWac terms) for the islands of Hawaii, Maui, and Oahu for the following four analyses that differ in terms of land exclusions:

1. Default slope analysis
2. Default slope analysis without DOD exclusions
3. Improved slope analysis without DOD exclusions
4. Improved slope analysis without DOD exclusions with updated agricultural land exclusions.

Tables 1 to 3 show the wind potential with an additional exclusion for each row excluding any site whose mean wind speed at 80m height is lower than the figures stated. Tables 4 to 6 show the utility-scale PV potential organized by two main exclusions, capacity factor and slope. The slope exclusions exclude all land with a slope steeper than the figure stated as potential for PV and the capacity factor exclusions exclude all PV whose capacity factor are lower than the figures stated. The difference between the default and improved slope analyses and the updated agricultural land exclusions are described in sections 4.1 and 4.2.

No technical potential values are provided for CSP. When considering the direct normal irradiance potential and the GIS exclusion factors in the three islands, very limited CSP potential exists.

Table 1 - Utility-Scale Onshore Wind Potential (MWac) for Hawaii

Mean Wind Speed (m/s) at 80m	Analysis 1 (MW)	Analysis 2 (MW)	Analysis 3 (MW)	Analysis 4 (MW)
>= 6.5	3,276	3,276	3,303	3,532
>= 7.5	2,107	2,107	2,123	2,236
>= 8.5	1,290	1,290	1,299	1,334

Table 2 - Utility-Scale Onshore Wind Potential (MWac) for Maui

Mean Wind Speed (m/s) at 80m	Analysis 1 (MW)	Analysis 2 (MW)	Analysis 3 (MW)	Analysis 4 (MW)
>= 6.5	698	698	700	840
>= 7.5	412	412	417	448
>= 8.5	117	117	121	118

Table 3 - Utility-Scale Onshore Wind Potential (MWac) for Oahu

Mean Wind Speed (m/s) at 80m	Analysis 1 (MW)	Analysis 2 (MW)	Analysis 3 (MW)	Analysis 4 (MW)
>= 6.5	174	183	154	162
>= 7.5	81	81	69	68
>= 8.5	19	19	16	16

Table 4 - Utility-Scale Solar PV Potential (MWac) for Hawaii

Capacity Factor (%)	Analysis 1 (MW)		Analysis 2 (MW)		Analysis 3 (MW)		Analysis 4 (MW)	
	Slope 3%	Slope 5%	Slope 3%	Slope 3%	Slope 3%	Slope 5%	Slope 3%	Slope 5%
>= 10	10,868	30,634	10,868	30,703	12,557	33,012	11,514	30,484
>= 12	10,833	30,573	10,833	30,643	12,523	32,949	11,481	30,421
>= 14	10,703	30,036	10,703	30,105	12,385	32,405	11,467	30,039
>= 16	8,339	20,204	8,339	20,273	9,448	21,873	8,646	20,312
>= 18	5,481	14,841	5,481	14,911	6,322	16,338	6,019	15,757
>= 20	2,469	8,315	2,469	8,385	3,075	9,193	3,075	9,189

Table 5 - Utility-Scale Solar PV Potential (MWac) for Maui

Capacity Factor (%)	Analysis 1 (MW)		Analysis 2 (MW)		Analysis 3 (MW)		Analysis 4 (MW)	
	Slope 3%	Slope 5%	Slope 3%	Slope 5%	Slope 3%	Slope 5%	Slope 3%	Slope 5%
>= 10	0	1,321	0	1,321	697	1,443	272	783
>= 12	0	1,321	0	1,321	697	1,443	272	783
>= 14	0	1,321	0	1,321	697	1,443	272	783
>= 16	0	1,321	0	1,321	697	1,443	272	783
>= 18	0	1,321	0	1,321	697	1,443	272	783
>= 20	0	1,110	0	1,110	697	1,230	272	576

Table 6 - Utility-Scale Solar PV Potential (MWac) for Oahu

Capacity Factor (%)	Analysis 1 (MW)		Analysis 2 (MW)		Analysis 3 (MW)		Analysis 4 (MW)	
	Slope 3%	Slope 5%	Slope 3%	Slope 5%	Slope 3%	Slope 5%	Slope 3%	Slope 5%
>= 10	0	1,338	67	2,155	1,527	2,301	583	796
>= 12	0	1,338	67	2,155	1,527	2,301	583	796
>= 14	0	1,338	67	2,155	1,527	2,301	583	796
>= 16	0	1,338	67	2,155	1,527	2,301	583	796
>= 18	0	1,338	67	2,134	1,527	2,277	583	793
>= 20	0	414	67	895	692	968	329	397

II. Report Structure

This report is split into four main sections: introduction, overview of data and modeling assumptions, GIS exclusions, and the resource potential maps (for Analysis 1) for each technology type: utility-scale onshore wind, utility-scale PV, and concentrated solar power.

III. Overview of Data & Modeling Assumptions

a. Utility-Scale Onshore Wind

The REEDS data set containing utility-scale wind speed data was supplied from AWS [1]. A typical meteorological year (TMY) method was used with 20 km summary resolution where simulated hourly wind resource data and statistics were generated for each 3% gross capacity factor interval calculated from the 200 m spatial map. The mean wind speed data at 200 m spatial resolution were attained for 80 m height. The power density assumed was 3 MW/km as used in the Wind Vision report and seen in the Wind Vision Appendices [2].

b. Utility-Scale PV

Mean solar radiation data over the years 1998 to 2014 was taken from the latest National Solar Radiation Database (NSRDB) [3-5] which has 4 km x 4 km and 30 minute resolution. NSRDB is a serially complete collection of meteorological and solar irradiance data sets. The database is managed and updated using the latest methods of research by a specialized team of forecasters at the National Renewable Energy Laboratory (NREL). The data spans 1998 – 2014 and the latest version now uses satellite retrievals. Cloud properties, aerosol depth, and precipitable water vapor are used to calculate Global Horizontal Irradiance (GHI) values at each point in the mesh.

The System Advisor Model (SAM) [6] with parameters DC – AC ratio = 1.5 was used to attain capacity factors for 1-axis tracking panels with tilt fixed at zero. Please refer to Appendix A for an extended list of the SAM parameters used in this analysis. SAM is a performance and financial model which makes performance predictions for grid-connected power projects based on parameters that you specify as inputs to the model. It is distributed for free by NREL. SAM's user interface allows the user to input variables and simulation controls and displays tables and graphs of results. Information on the code can be found in the PVWatts Version 5 Manual [7].

The capacity-weighted average land use for a 1-axis small PV plant was taken to be 8.7acres/MWac [8].

Figure 1 illustrates the inter-annual variability of capacity factors as a function of location index. It highlights the value of having a wide temporal range of data. In this plot the two-dimensional geospatial dataset is displayed as a sequence rather than a map and each point in the sequence corresponds to a latitude and longitude in a geospatial grid. Neighbors in the sequence are either neighbors in latitude or longitude depending on how the data is converted from the geospatial grid, i.e. whether the data is traversed in the latitude or longitude dimension.

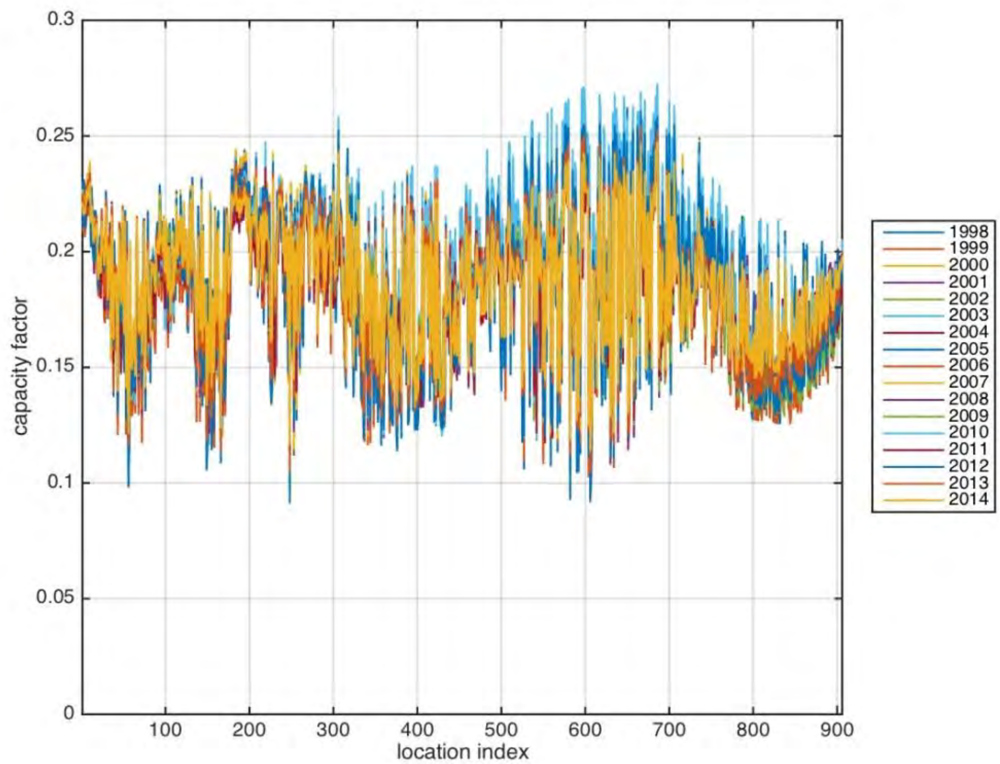


Figure 1: Annual Variability of Solar Capacity Factors

c. Concentrated Solar Power (CSP)

In order to assess the CSP potential for the three islands, a Direct Normal Irradiance (DNI) map has been created using mean values from the NSRDB. In order to assess the CSP potential for the three islands, a Direct Normal Irradiance (DNI) map has been created using mean values from the NSRDB as per the description above. DNI > 400 W/m^2 was calculated by finding the number of half hour intervals in a year where DNI > 400 W/m^2, dividing by the number of half hour intervals in the year and averaging across 1998 – 2014. The value 400 is chosen as a suitable benchmark given the current CSP technology. Figure 2 shows the percentage of half hour intervals for all the years to give some visual indication of the variability in this statistic.

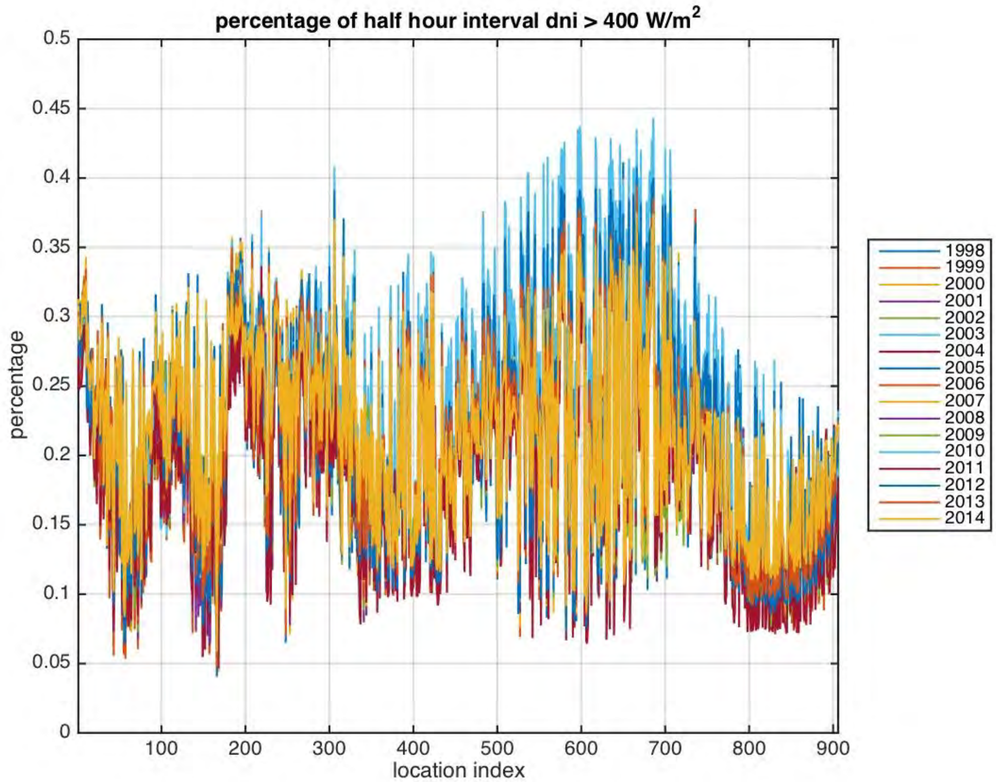


Figure 2: Percentage of Half Hour Interval DNI > 400 W/m^2

IV. GIS Exclusions

Geospatial analysis and mapping of the wind and solar resources was accomplished through the use of Geographic Information Systems (GIS) technology. Using relevant and available geographic data, areas likely to be impediments to development were excluded from consideration. Standard exclusions applied to all technologies were National and State Parks, US Fish & Wildlife Service (FWS) lands, areas zoned as urban, areas classified as Important Agricultural Land, areas within any "A" level flood zone, areas classified as lava flow hazard zones 1 and 2, all military or Department of Defense (DOD) lands, and wetlands. All of these datasets, except for National and State Parks and FWS lands were acquired from the state through the Hawaii Office of Planning website (planning.hawaii.gov). Additional resource-specific exclusions were applied as well. The photovoltaic analysis included exclusions for terrain slopes greater than either 3% or 5%, as well as a minimum contiguous area requirement of 1 km^2. Concentrating solar included a slope exclusion of greater than 3% as well as the minimum contiguous area requirement of 1 square kilometer, plus a minimum resource threshold of 5/kWh/m2/day irradiance. Wind included an exclusion of slopes greater than 20% [9] and a minimum wind speed resource threshold of 6.5 m/s, 7.5 m/s, or 8.5 m/s.

4.1 Improved Slope Analysis

A percent slope analysis was performed in the default analysis in order to create slope constraints of 3% and 5% for PV and 20% for wind. The elevation data used for this analysis was 1/3 arc-second (approx. 10 meter) digital elevation models (DEMs) from the National Elevation Dataset (NED) available through the US Geological Survey's nationalmap.gov. These DEMs are currently the best available, but do contain known artifacts and artificial anomalies due to data sources, processing methods, etc. One of these anomalies is terracing effect, and can be thought of as appearing like artificial terraces in the data. Figure 3 shows a typical agricultural parcel on the island of Oahu.

Figure 3

Figure 4 shows the same area after the results of a 3% slope analysis has been applied. Areas highlighted in yellow are where slope is not more than 3%. All other areas are greater than 3%.

Figure 4

It is evident from aerial photographs that the terracing effect seen in Figure 4 is not a genuine geographic feature, but a result of artifacts in the data. This terracing caused a large number of parcels to be divided incorrectly into strips of land rather than being shown as contiguous areas. This posed no significant problem for the wind analysis, which did not have a minimum contiguous area requirement, but it significantly reduced potential land area for PV, which for the purposes of this study included a minimum contiguous area requirement of 1 km^2. Upon applying that constraint, much potential land such as those areas shown in Figure 2 were eliminated.

In order to compensate for the artifacts in the data and attempt to recover the artificially segmented areas, the Boundary Clean tool was applied using ArcGIS. Boundary Clean is a process by which zones in a raster are expanded and shrunk programmatically over large areas in an attempt to fill in narrow bands or tiny gaps of missing data as well as eliminate tiny stray islands such as those that run along ridges seen in Figure 4.

The expansion/shrinking was run twice, and the results are shown in Figure 5. Large areas of land were unified, and tiny scattered areas were largely eliminated.

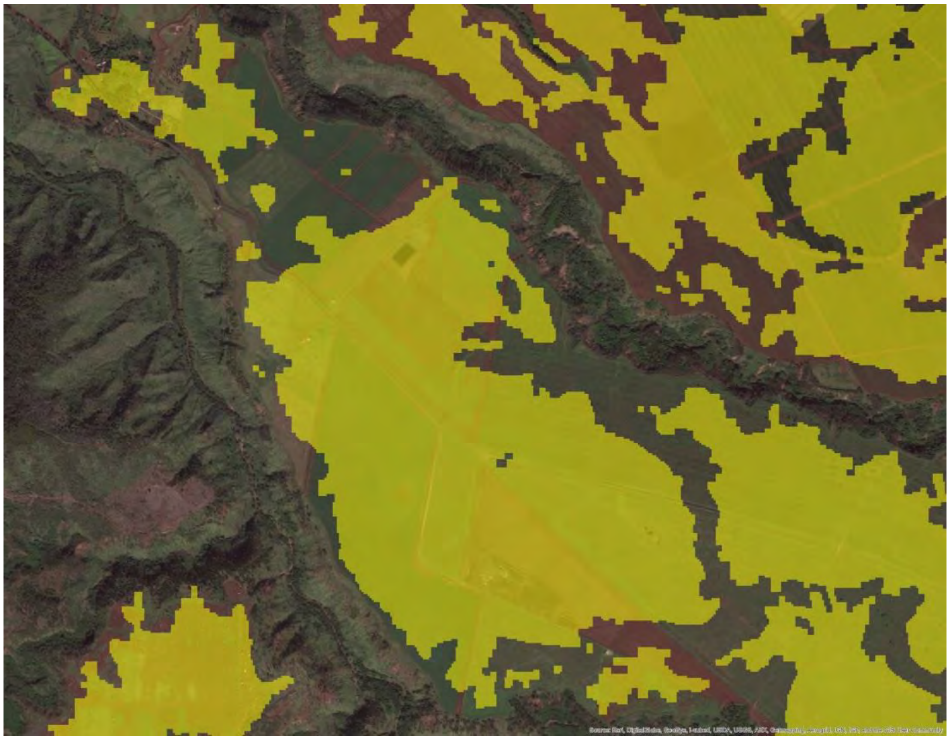


Figure 5

This process was repeated on the 5% and 20% slope analyses, and the resulting "clean" slope areas were used to run the final technical potential analysis.

After applying the minimum contiguous area constraint, available land area for PV development increased significantly. Small land areas were still dropped out, but the larger, now-intact areas remained. For the wind analysis, however, the impact was minimal, and in some cases the clean slope decreased available land area. As previously stated, cleaning the slope analysis filled in gaps, but it also eliminated numerous scattered, tiny, disconnected areas. As the wind analysis did not consider a minimum contiguous area, these tiny areas in the slope data that was not cleaned were left in the original analysis. The net result for wind was the loss of small scattered areas but the gain of areas within filled gaps. By chance, some islands had a net gain and others had a net loss, but in all cases the differences were relatively minor.

Post-processing the calculated slope data by cleaning the boundaries appears to have yielded a more realistic representation of the slope of the terrain, and thus a more realistic estimate of the resource potential in the state. As with any analysis, a site-specific analysis combined with proper ground-truthing should be implemented to verify site suitability, as the methods employed here are suitable only for a broad sweep of the state to understand general scale and distribution of development potential.

4.2 Updated Agricultural Land Exclusions

For Analyses 1, 2, and 3, agricultural land exclusions include lands classified as "Important Agricultural Land" (IAL) in the Hawaii Office of Planning website (planning.hawaii.gov) for both utility-scale onshore wind and utility-scale solar PV.

For Analysis 4, no agricultural land exclusions are considered for utility-scale onshore wind. For utility-scale solar PV, a different agricultural land classification from the Hawaii Office of Planning is used in addition to the IAL exclusions. This alternative agricultural land classification divides agricultural lands in five zoning designations: A, B, C, D, and E. Taking into consideration the statute[1] that details the agricultural land zoning designations, the following exclusions (in addition to IAL exclusions) are applied to the utility-scale solar PV resource assessment for Analysis 4:

- 100% of "A" lands are excluded
- 90% of "B" and "C" lands are excluded

It is important to note that a utility-scale PV resource area was removed if it was made too small to meet the minimum contiguous area requirement (1 km^2) due to an intersection with an "A" land. However, resource areas that fell partially or fully within "B" or "C" lands were not removed based on the minimum continuous area requirement; the total resource area within the "B" or "C" agricultural zone was reduced by 90%.

In summary, Analysis 4 includes the following agricultural land exclusions:

- Utility-scale onshore wind:
    - No agricultural land exclusion is applied

- Utility-scale solar PV:
    - "IAL" lands excluded
    - 100% of "A" agricultural lands excluded
    - 90% of "B" and "C" agricultural lands excluded

[1] http://www.capitol.hawaii.gov/hrscurrent/vol04_Ch0201-0257/HRS0205/HRS_0205-0002.htm

V. Resource Potential Maps

The following self-explanatory maps refer to Analysis 1 and are included herein after in the following order:

<u>Utility-Scale Onshore Wind</u>

- Utility-scale onshore wind development potential for all Hawaiian islands
- Utility-scale onshore wind development potential for Hawaii
- Utility-scale onshore wind development potential for Maui
- Utility-scale onshore wind development potential for Oahu

<u>Utility-Scale PV</u>

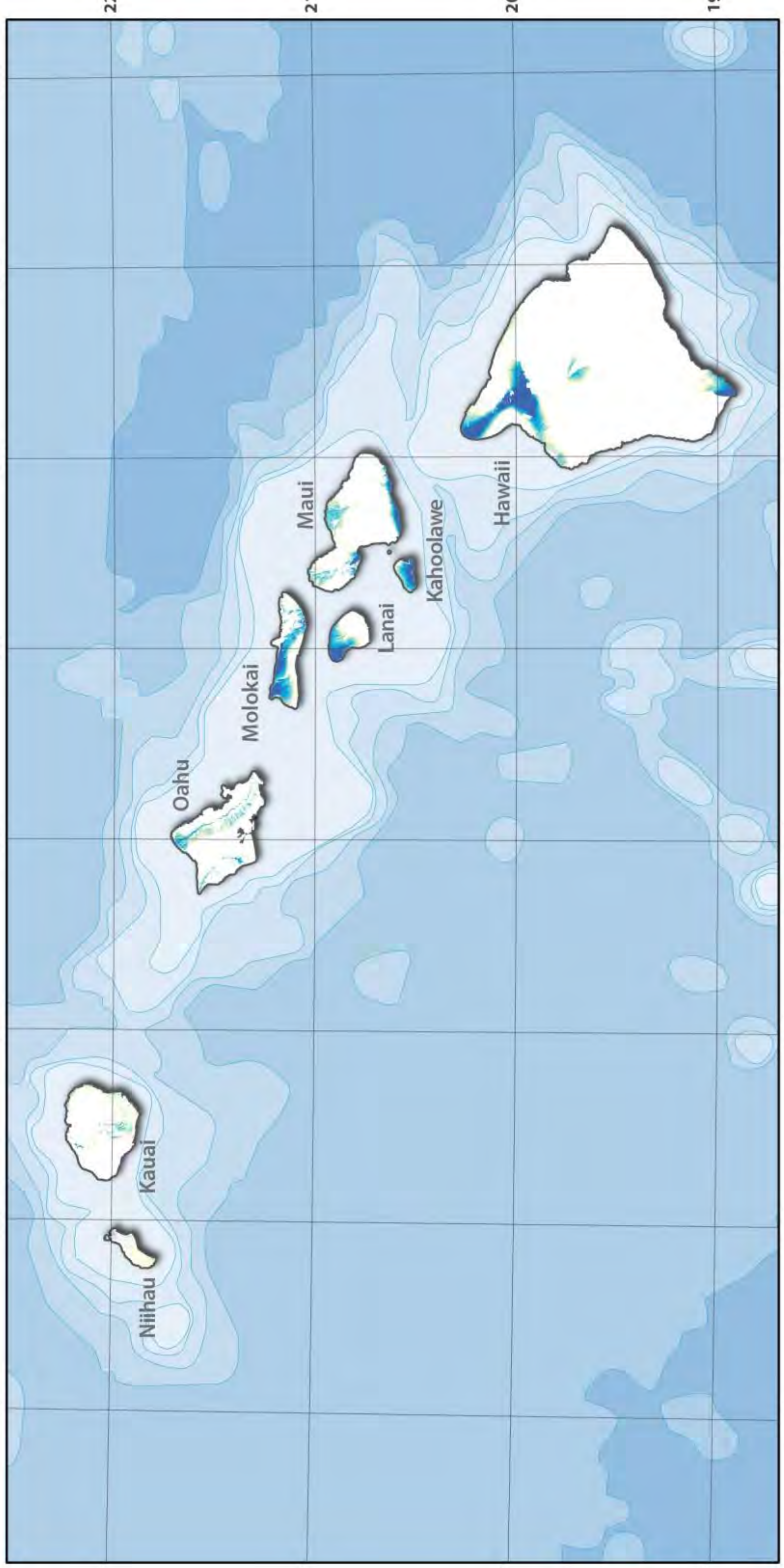
- Capacity factor for all Hawaiian islands
- Utility-scale PV development potential for all Hawaiian islands (3% slope exclusion)
- Utility-scale PV development potential for Hawaii (3% slope exclusion)
- Utility-scale PV development potential for Maui (3% slope exclusion)
- Utility-scale PV development potential for Oahu (3% slope exclusion)
- Utility-scale PV development potential for all Hawaiian islands (5% slope exclusion)
- Utility-scale PV development potential for Hawaii (5% slope exclusion)
- Utility-scale PV development potential for Maui (5% slope exclusion)
- Utility-scale PV development potential for Oahu (5% slope exclusion)

<u>Concentrated Solar Power</u>

- Direct normal irradiance for all Hawaiian islands
- Concentrated solar power development potential for all Hawaiian islands
- Concentrated solar power development potential for Hawaii

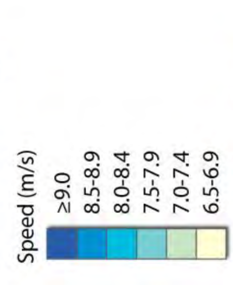
F. National Renewable Energy Laboratory (NREL) Reports

Utility-Scale Onshore Wind, Utility-Scale PV, and CSP Potential Resource



Onshore Wind Speed at 80 m

Analysis of the Hawaiian Islands



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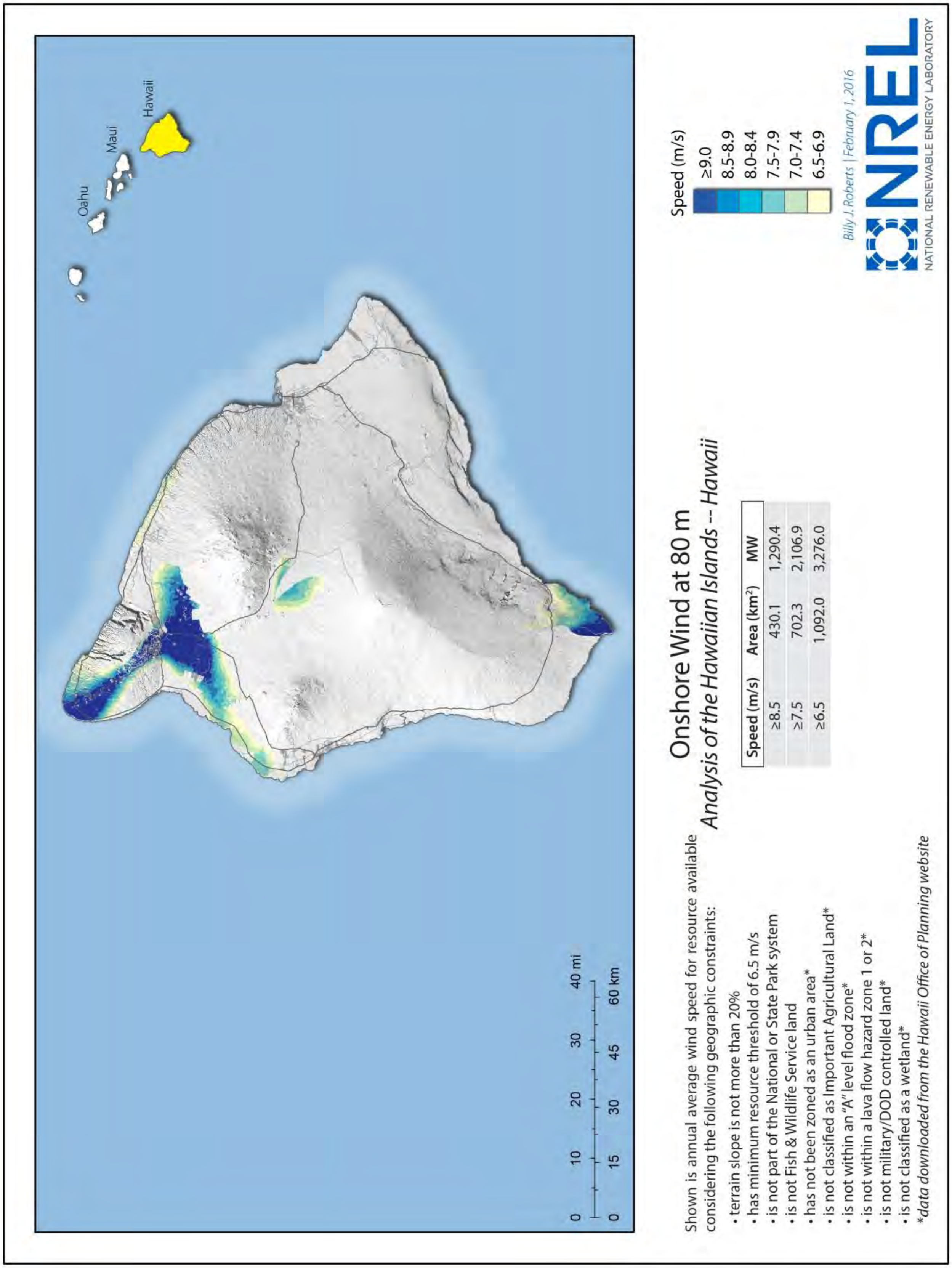
Shown is annual average wind speed for resource available considering the following geographic constraints:

- terrain slope is not more than 20%
- has minimum resource threshold of 6.5 m/s
- is not part of the National or State Park system
- is not Fish & Wildlife Service land
- has not been zoned as an urban area*
- is not classified as Important Agricultural Land*
- is not within an "A" level flood zone*
- is not within a lava flow hazard zone 1 or 2*
- is not military/DOD controlled land*
- is not classified as a wetland*

**data downloaded from the Hawaii Office of Planning website*

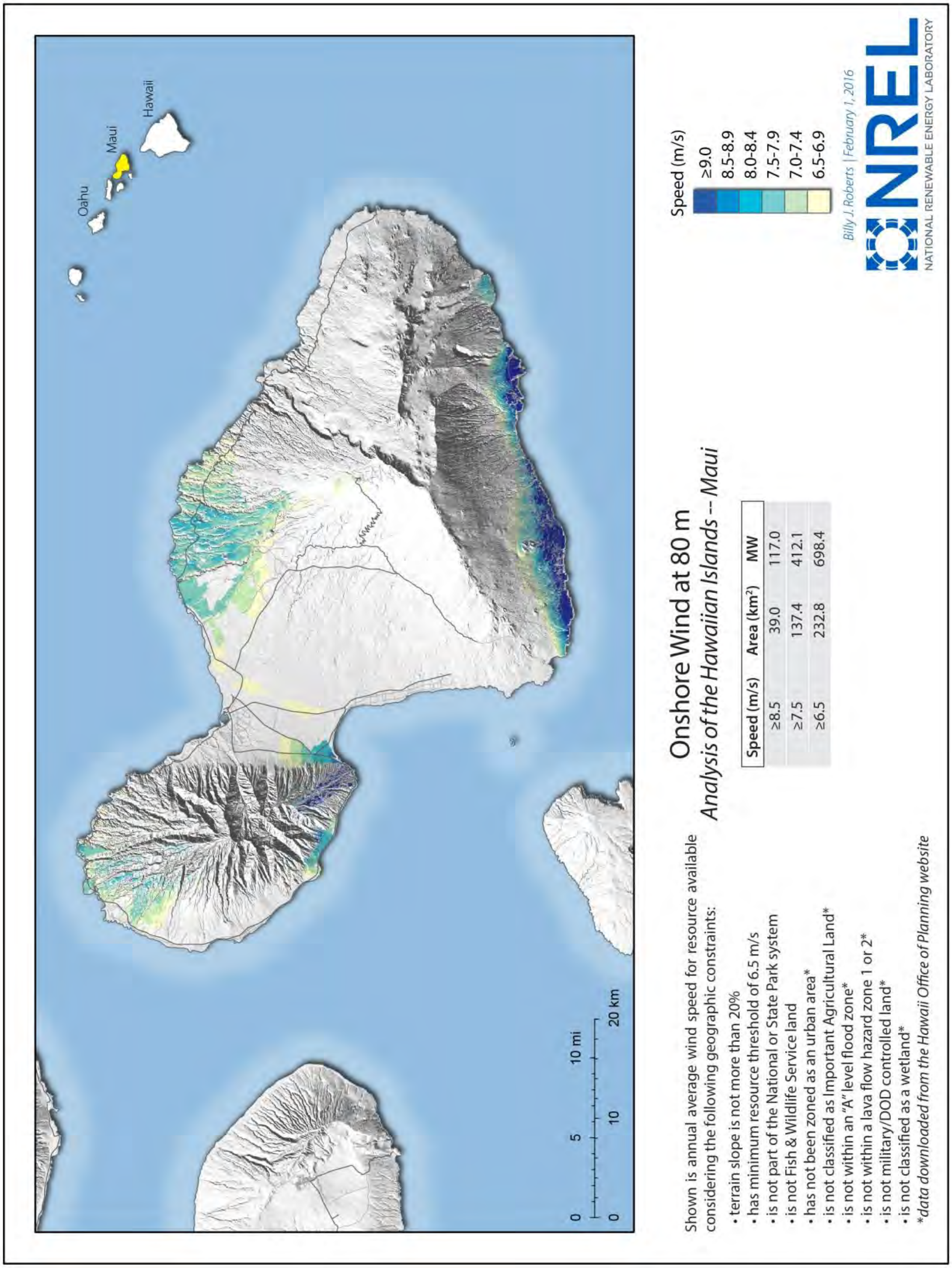
Island	Area (km^2)	MW
Hawaii	1,092.0	3,276.0
Kahoolawe	91.7	275.1
Kauai	110.3	330.9
Lanai	147.5	442.4
Maui	232.8	698.4
Molokai	252.0	755.9
Niihau	76.5	229.4
Oahu	58.0	173.9

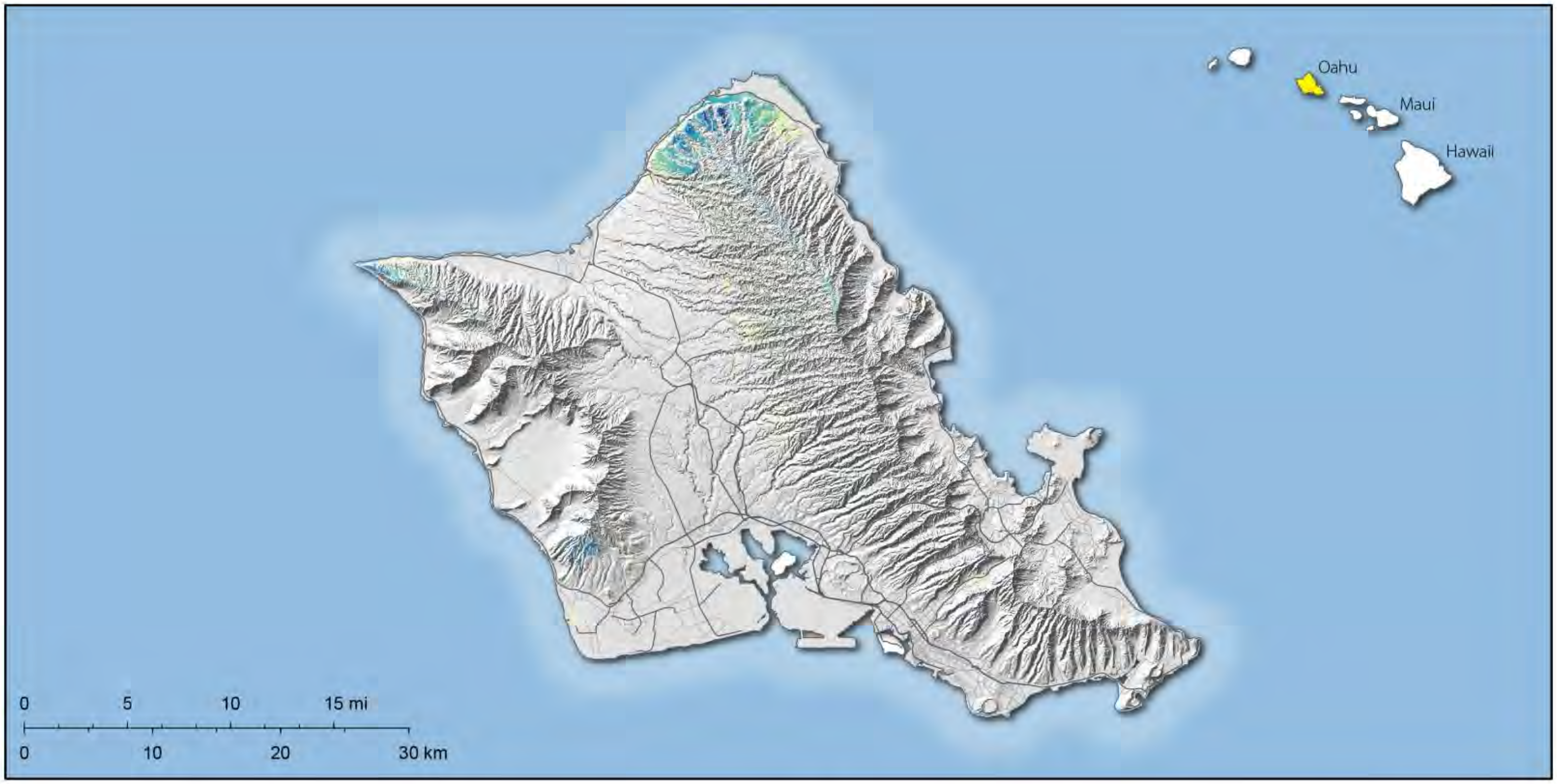


Speed (m/s)	Area (km²)	MW
≥8.5	430.1	1,290.4
≥7.5	702.3	2,106.9
≥6.5	1,092.0	3,276.0

F. National Renewable Energy Laboratory (NREL) Reports

Utility-Scale Onshore Wind, Utility-Scale PV, and CSP Potential Resource





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- has minimum resource threshold of 6.5 m/s
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- has not been zoned as an urban area*
- is not classified as Important Agricultural Land*
- is not within an "A" level flood zone*
- is not within a lava flow hazard zone 1 or 2*
- is not military/DOD controlled land*
- is not classified as a wetland*

data downloaded from the Hawaii Office of Planning website

Onshore Wind at 80 m

Analysis of the Hawaiian Islands -- Oahu

Speed (m/s)	Area (km²)	MW
≥8.5	6.2	18.6
≥7.5	26.9	80.7
≥6.5	58.0	173.9

Speed (m/s)
- ≥9.0
- 8.5-8.9
- 8.0-8.4
- 7.5-7.9
- 7.0-7.4
- 6.5-6.9

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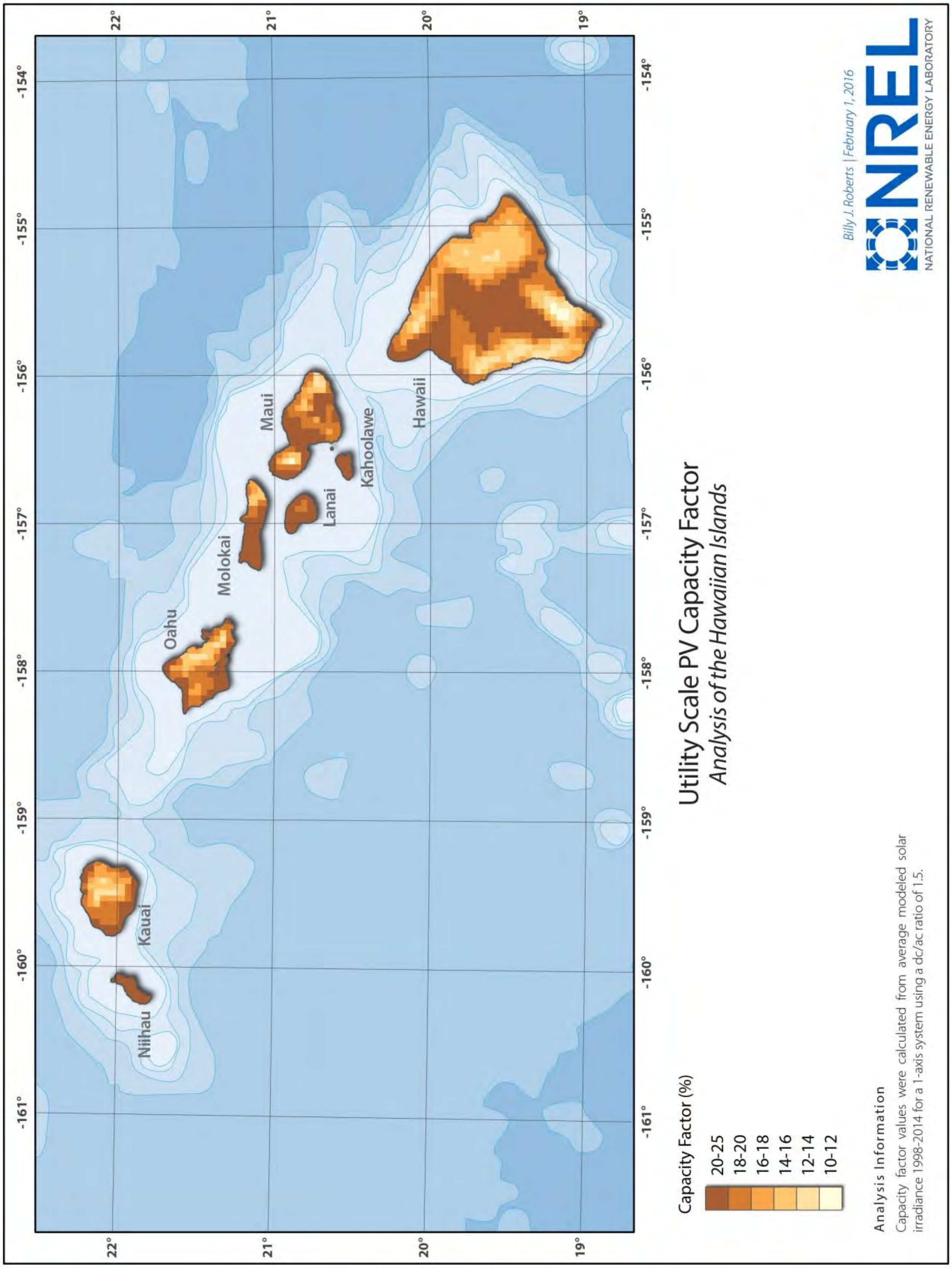
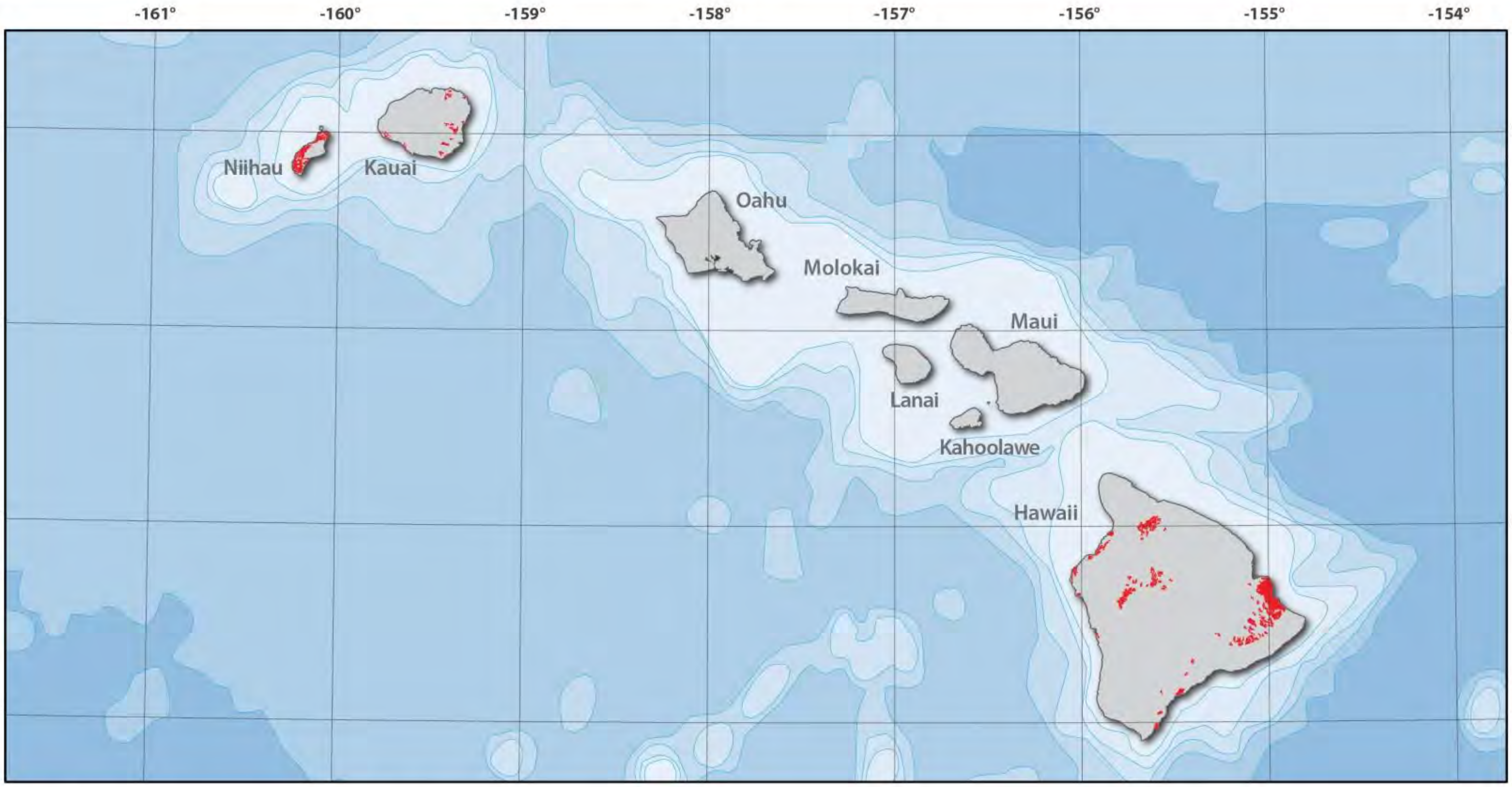
NREL NATIONAL RENEWABLE ENERGY LABORATORY

F. National Renewable Energy Laboratory (NREL) Reports

Utility-Scale Onshore Wind, Utility-Scale PV, and CSP Potential Resource





Capacity factor calculated from average modeled solar irradiance from 1998-2014 for a 1-axis system with a dc/ac ratio of 1.5. Development potential was determined by applying the following geographic constraints:

- terrain slope is not more than 3%
- has a contiguous area of at least 1 km²
- is not part of the National or State Park* system
- is not Fish & Wildlife Service land
- has not been zoned as an urban area*
- is not classified as Important Agricultural Land*
- is not within an "A(x)" level flood zone*
- is not within a lava flow hazard zone 1 or 2*
- is not military/DOD controlled land*
- is not classified as a wetland*

**data acquired from the Hawaii Office of Planning*

Utility Scale PV Development Potential
Analysis of the Hawaiian Islands

Island	Area (km²)	MW	MWh	GW	GWh
Hawaii	382.7	16,302.3	25,947,687.7	16.3	25,947.7
Kahoolawe	0	0	0	0	0
Kauai	32.8	1,398.3	2,318,290.7	1.4	2,318.3
Lanai	1.2	51.0	95,393.7	0.1	95.4
Maui	0	0	0	0	0
Molokai	0	0	0	0	0
Niihau	72.1	3,069.4	5,931,000.5	3.1	5,931.0
Oahu	0	0	0	0	0

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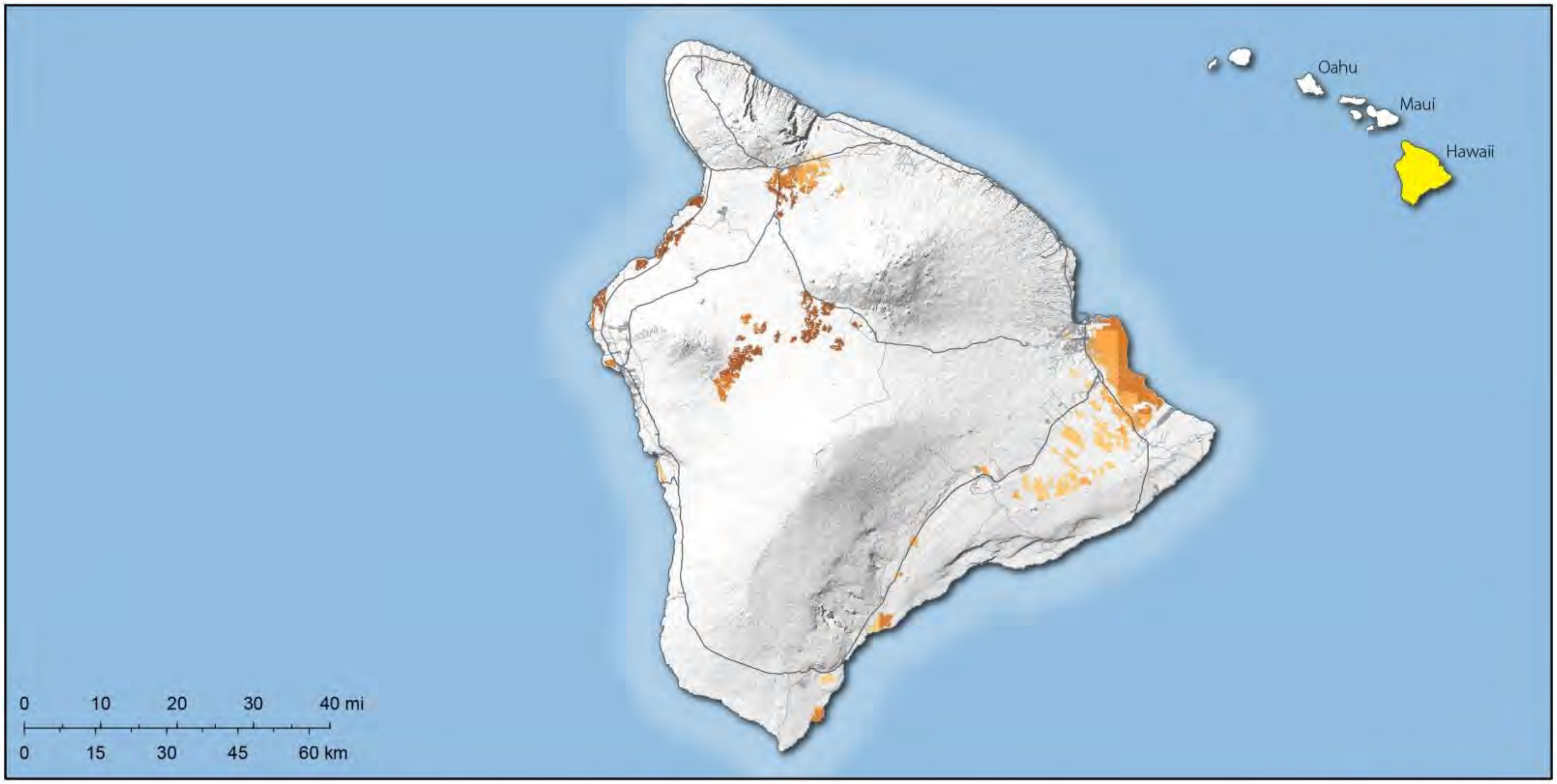

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- is not classified as Important Agricultural Land*
- is not within an "A(x)" level flood zone*
- is not within a lava flow hazard zone 1 or 2*
- is not military/DOD controlled land*
- is not classified as a wetland*

**data acquired from the Hawaii Office of Planning*

Utility Scale PV Development Potential

Analysis of the Hawaiian Islands -- Hawaii

CF Range (%)	Area (km²)	MW	MWh	GW	GWh
≥20	86.9	3,704.0	7,039,667.6	3.7	7,039.7
≥18	193.0	8,220.9	14,441,481.3	8.2	14,441.5
≥16	293.6	12,507.7	20,934,700.7	12.5	20,934.7
≥14	376.9	16,055.4	25,663,262.6	16.1	25,663.3
≥12	381.5	16,250.1	25,898,220.5	16.3	25,898.2
≥10	382.7	16,302.3	25,947,687.7	16.3	25,947.7

Capacity Factor (%)

20-25
18-20
16-18
14-16
12-14
10-12

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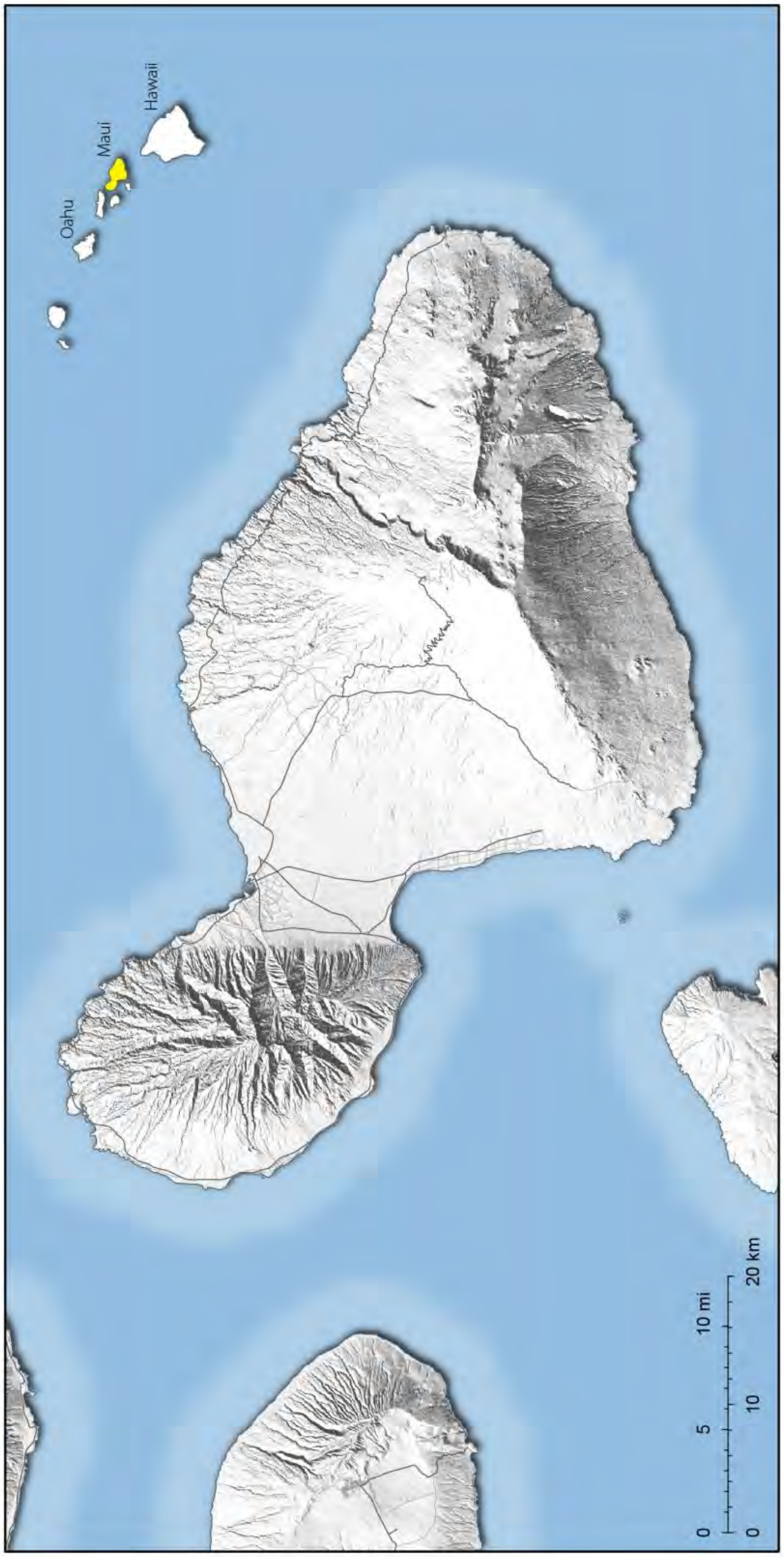

Utility Scale PV Development Potential

Analysis of the Hawaiian Islands -- Maui

Capacity factor calculated from average modeled solar irradiance from 1998-2014 for a 1-axis system with a dc/ac ratio of 1.5. Development potential was determined by applying the following geographic constraints:

- terrain slope is not more than 3%
- has a contiguous area of at least 1 km²
- is not part of the National or State Park* system
- is not Fish & Wildlife Service land
- has not been zoned as an urban area*
- is not classified as Important Agricultural Land*
- is not within an "A(x)" level flood zone*
- is not within a lava flow hazard zone 1 or 2*
- is not military/DOD controlled land*
- is not classified as a wetland*

**data acquired from the Hawaii Office of Planning*

CF Range (%)	Area (km²)	MW	MWh	GW	GWh
≥20	0	0	0	0	0
≥18	0	0	0	0	0
≥16	0	0	0	0	0
≥14	0	0	0	0	0
≥12	0	0	0	0	0
≥10	0	0	0	0	0

Capacity Factor (%)
20-25
18-20
16-18
14-16
12-14
10-12

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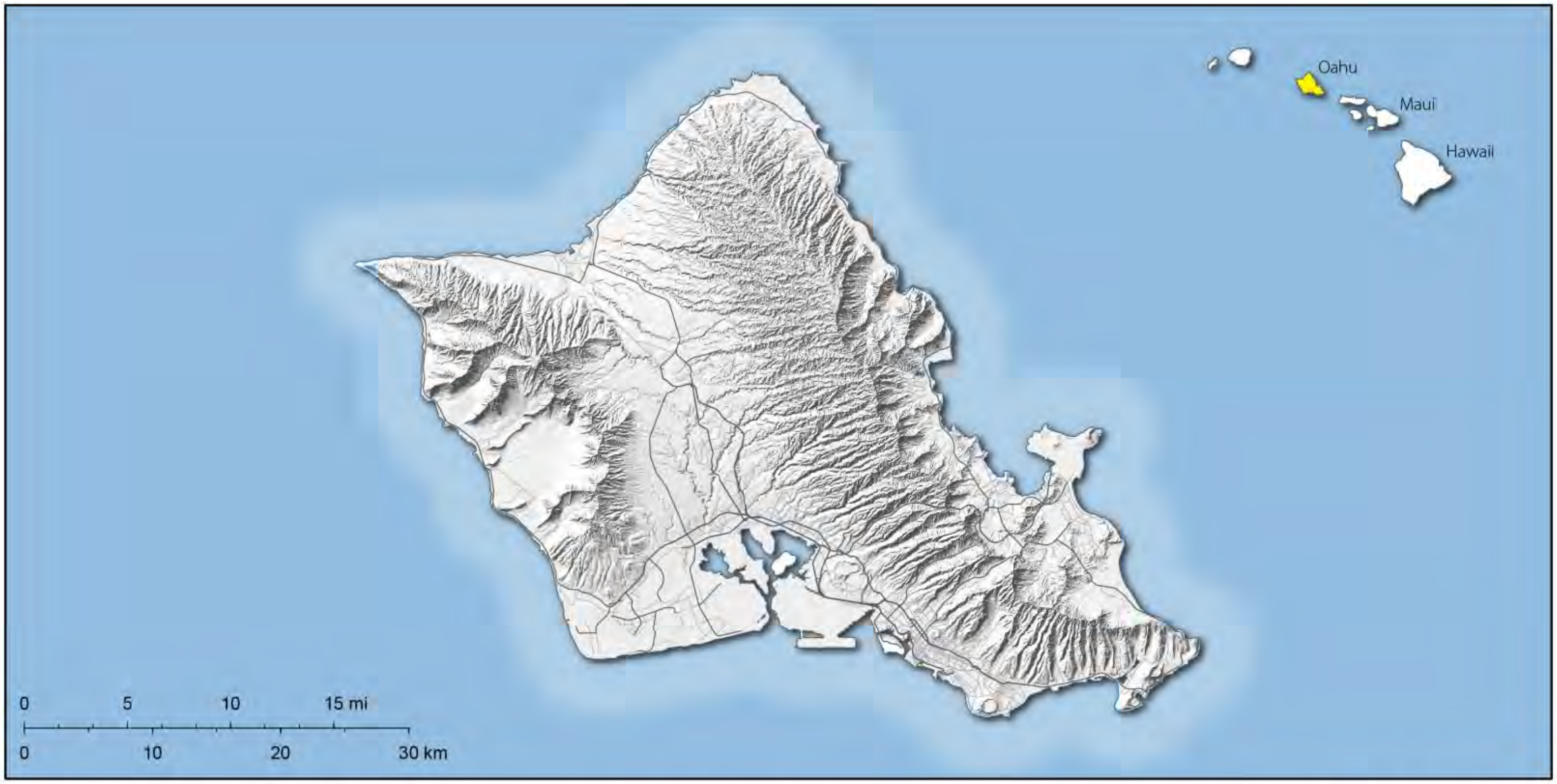

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- is not Fish & Wildlife Service land
- has not been zoned as an urban area*
- is not classified as Important Agricultural Land*
- is not within an "A(x)" level flood zone*
- is not within a lava flow hazard zone 1 or 2*
- is not military/DOD controlled land*
- is not classified as a wetland*

*data acquired from the Hawaii Office of Planning

Utility Scale PV Development Potential

Analysis of the Hawaiian Islands -- Oahu

CF Range (%)	Area (km^2)	MW	MWh	GW	GWh
≥20	0	0	0	0	0
≥18	0	0	0	0	0
≥16	0	0	0	0	0
≥14	0	0	0	0	0
≥12	0	0	0	0	0
≥10	0	0	0	0	0

Capacity Factor (%)
- 20-25
- 18-20
- 16-18
- 14-16
- 12-14
- 10-12

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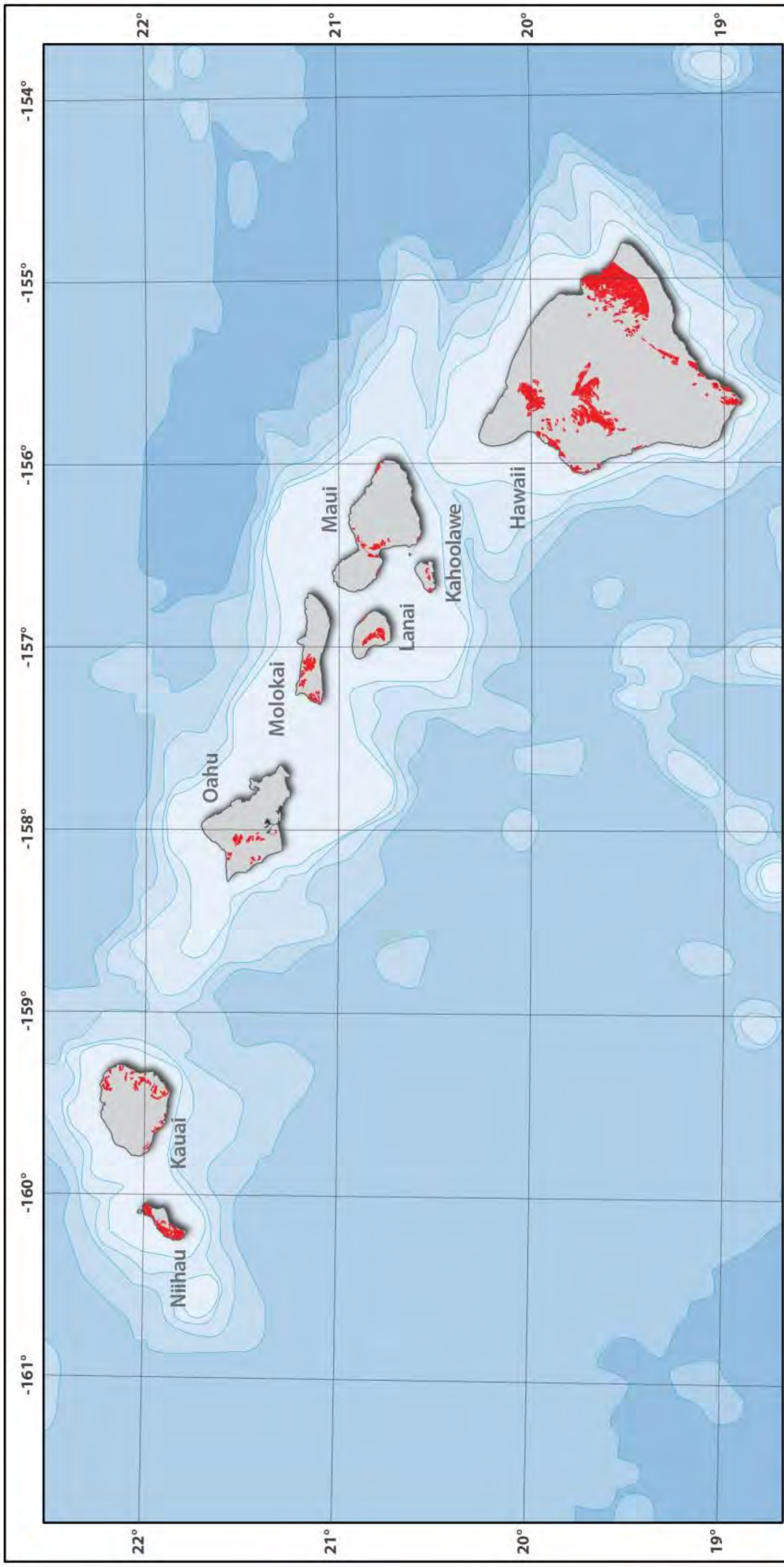

Capacity factor calculated from average modeled solar irradiance from 1998-2014 for a 1-axis system with a dc/ac ratio of 1.5. Development potential was determined by applying the following geographic constraints:

- terrain slope is not more than 5%
- has a contiguous area of at least 1 km^2
- is not part of the National or State Park* system
- is not Fish & Wildlife Service land
- has not been zoned as an urban area*
- is not classified as Important Agricultural Land*
- is not within an "A(x)" level flood zone*
- is not within a lava flow hazard zone 1 or 2*
- is not military/DOD controlled land*
- is not classified as a wetland*

**data acquired from the Hawaii Office of Planning*

Utility Scale PV Development Potential

Analysis of the Hawaiian Islands

Island	Area (km^2)	MW	MWh	GW	GWh
Hawaii	1,078.7	45,951.4	72,608,871.7	46.0	72,608.9
Kahoolawe	8.1	346.6	675,289.3	0.3	675.3
Kauai	85.8	3,656.8	6,054,802.7	3.7	6,054.8
Lanai	41.8	1,781.2	3,227,898.6	1.8	3,227.9
Maui	46.5	1,980.9	3,743,976.3	2.0	3,744.0
Molokai	61.9	2,635.6	5,253,430.0	2.6	5,253.4
Niihau	92.6	3,946.4	7,631,634.0	3.9	7,631.6
Oahu	47.1	2,007.2	3,434,495.9	2.0	3,434.5

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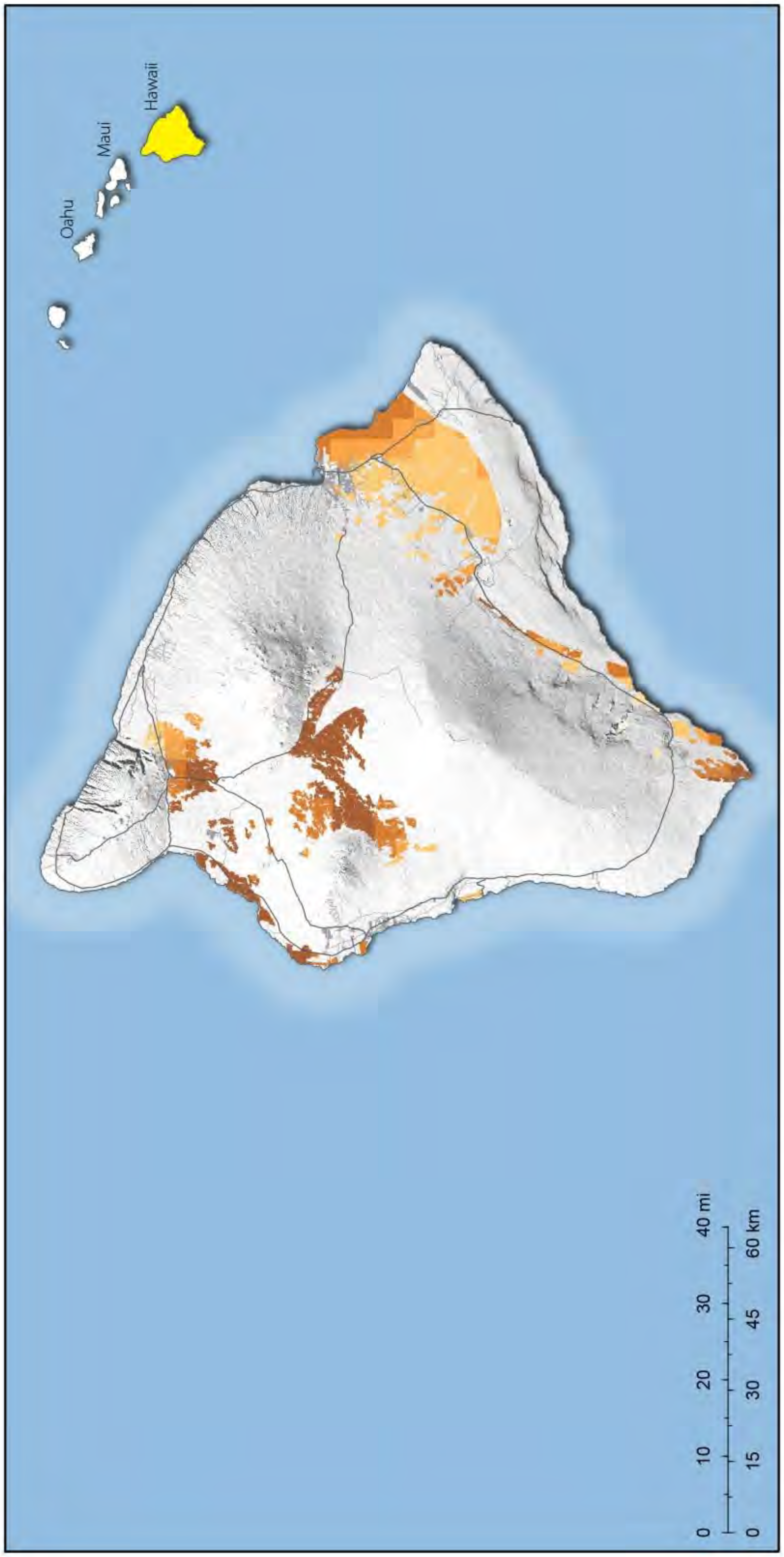

Capacity factor calculated from average modeled solar irradiance from 1998-2014 for a 1-axis system with a dc/ac ratio of 1.5. Development potential was determined by applying the following geographic constraints:

- terrain slope is not more than 5%
- has a contiguous area of at least 1 km²
- is not part of the National or State Park* system
- is not Fish & Wildlife Service land
- has not been zoned as an urban area*
- is not classified as Important Agricultural Land*
- is not within an "A(x)" level flood zone*
- is not within a lava flow hazard zone 1 or 2*
- is not military/DOD controlled land*
- is not classified as a wetland*

**data acquired from the Hawaii Office of Planning*

Utility Scale PV Development Potential

Analysis of the Hawaiian Islands -- Hawaii

CF Range (%)	Area (km²)	MW	MWh	GW	GWh
≥20	292.8	12,472.9	23,708,896.8	12.5	23,708.9
≥18	522.6	22,262.4	39,916,124.8	22.3	39,916.1
≥16	711.4	30,306.2	52,014,707.0	30.3	52,014.7
≥14	1,057.6	45,054.3	71,551,672.7	45.1	71,551.7
≥12	1,076.5	45,860.1	72,521,769.5	45.9	72,521.8
≥10	1,078.7	45,951.4	72,608,871.7	46.0	72,608.9

Capacity Factor (%)
- 20-25
- 18-20
- 16-18
- 14-16
- 12-14
- 10-12

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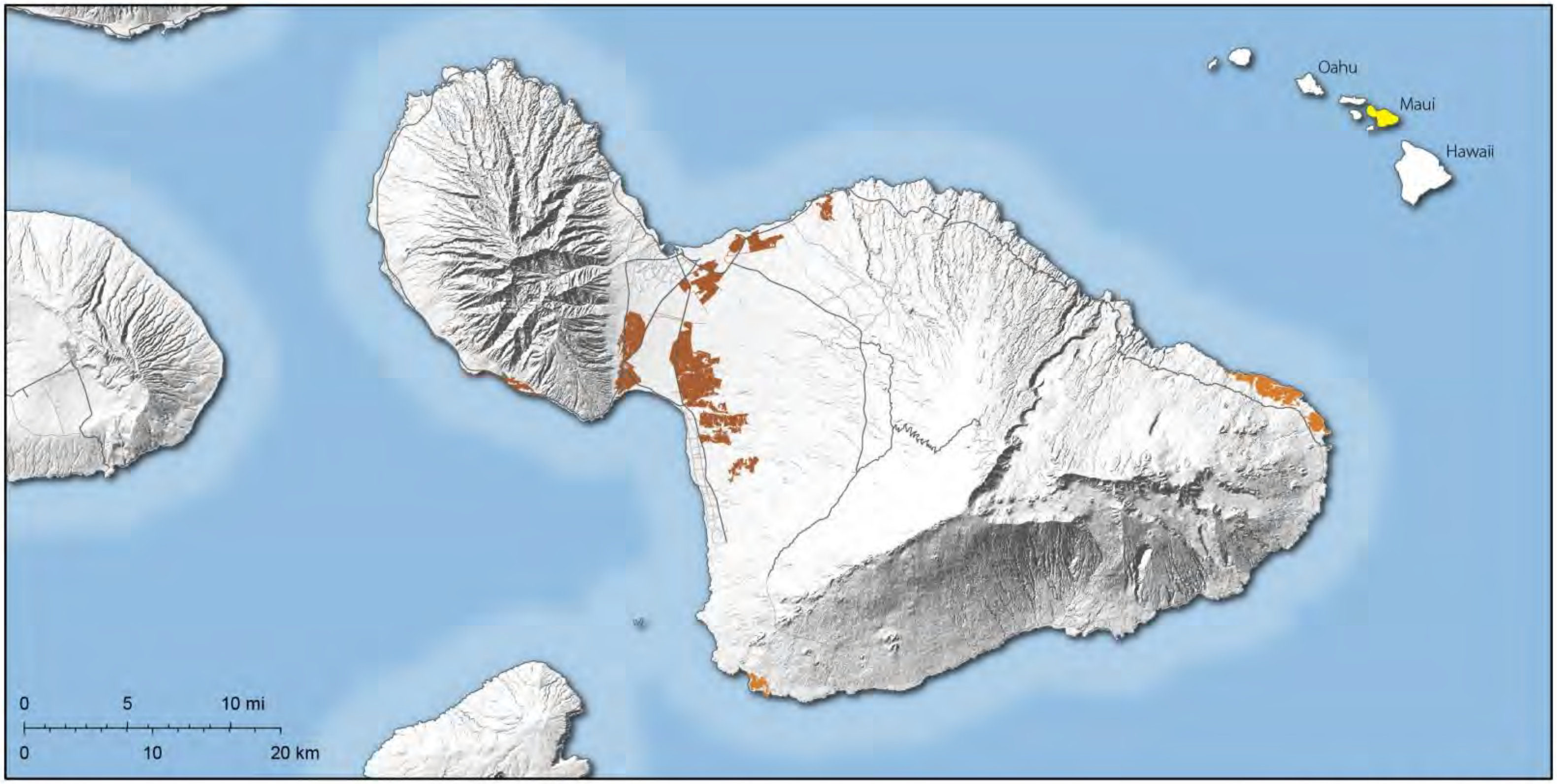

Utility Scale PV Development Potential

Analysis of the Hawaiian Islands -- Maui

Capacity factor calculated from average modeled solar irradiance from 1998-2014 for a 1-axis system with a dc/ac ratio of 1.5. Development potential was determined by applying the following geographic constraints:

- terrain slope is not more than 5%
- has a contiguous area of at least 1 km^2
- is not part of the National or State Park* system
- is not Fish & Wildlife Service land
- has not been zoned as an urban area*
- is not classified as Important Agricultural Land*
- is not within an "A(x)" level flood zone*
- is not within a lava flow hazard zone 1 or 2*
- is not military/DOD controlled land*
- is not classified as a wetland*

**data acquired from the Hawaii Office of Planning*

CF Range (%)	Area (km^2)	MW	MWh	GW	GWh
≥20	39.1	1,665.5	3,236,991.4	1.7	3,237.0
≥18	46.5	1,980.9	3,743,976.3	2.0	3,744.0
≥16	-	-	-	-	-
≥14	-	-	-	-	-
≥12	-	-	-	-	-
≥10	-	-	-	-	-

Capacity Factor (%)

- 20-25
- 18-20
- 16-18
- 14-16
- 12-14
- 10-12

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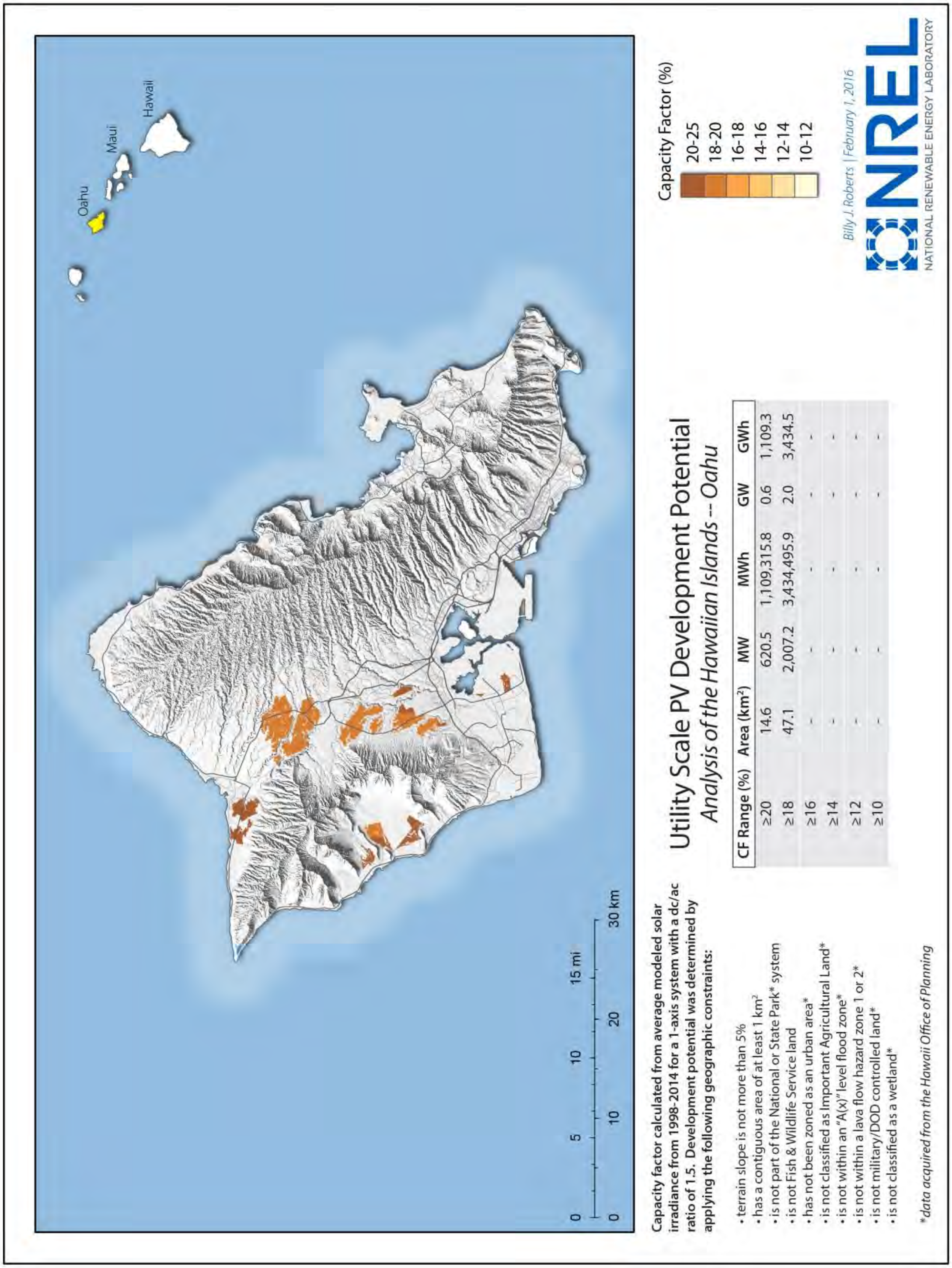
Utility Scale PV Development Potential
Analysis of the Hawaiian Islands -- Oahu
CF Range (%) | Area (km²) | MW | MWh | GW | GWh
≥20 | 14.6 | 620.5 | 1,109,315.8 | 0.6 | 1,109.3
≥18 | 47.1 | 2,007.2 | 3,434,495.9 | 2.0 | 3,434.5
≥16 | - | - | - | - | -
≥14 | - | - | - | - | -
≥12 | - | - | - | - | -
≥10 | - | - | - | - | -
Capacity factor calculated from average modeled solar irradiance from 1998-2014 for a 1-axis system with a dc/ac ratio of 1.5. Development potential was determined by applying the following geographic constraints:
• terrain slope is not more than 5%
• has a contiguous area of at least 1 km²
• is not part of the National or State Park* system
• is not Fish & Wildlife Service land
• has not been zoned as an urban area*
• is not classified as Important Agricultural Land*
• is not within an "A(x)" level flood zone*
• is not within a lava flow hazard zone 1 or 2*
• is not military/DOD controlled land*
• is not classified as a wetland*
*data acquired from the Hawaii Office of Planning
Capacity Factor (%)
20-25
18-20
16-18
14-16
12-14
10-12
0 5 10 15 mi
0 10 20 30 km
Oahu
Maui
Hawaii
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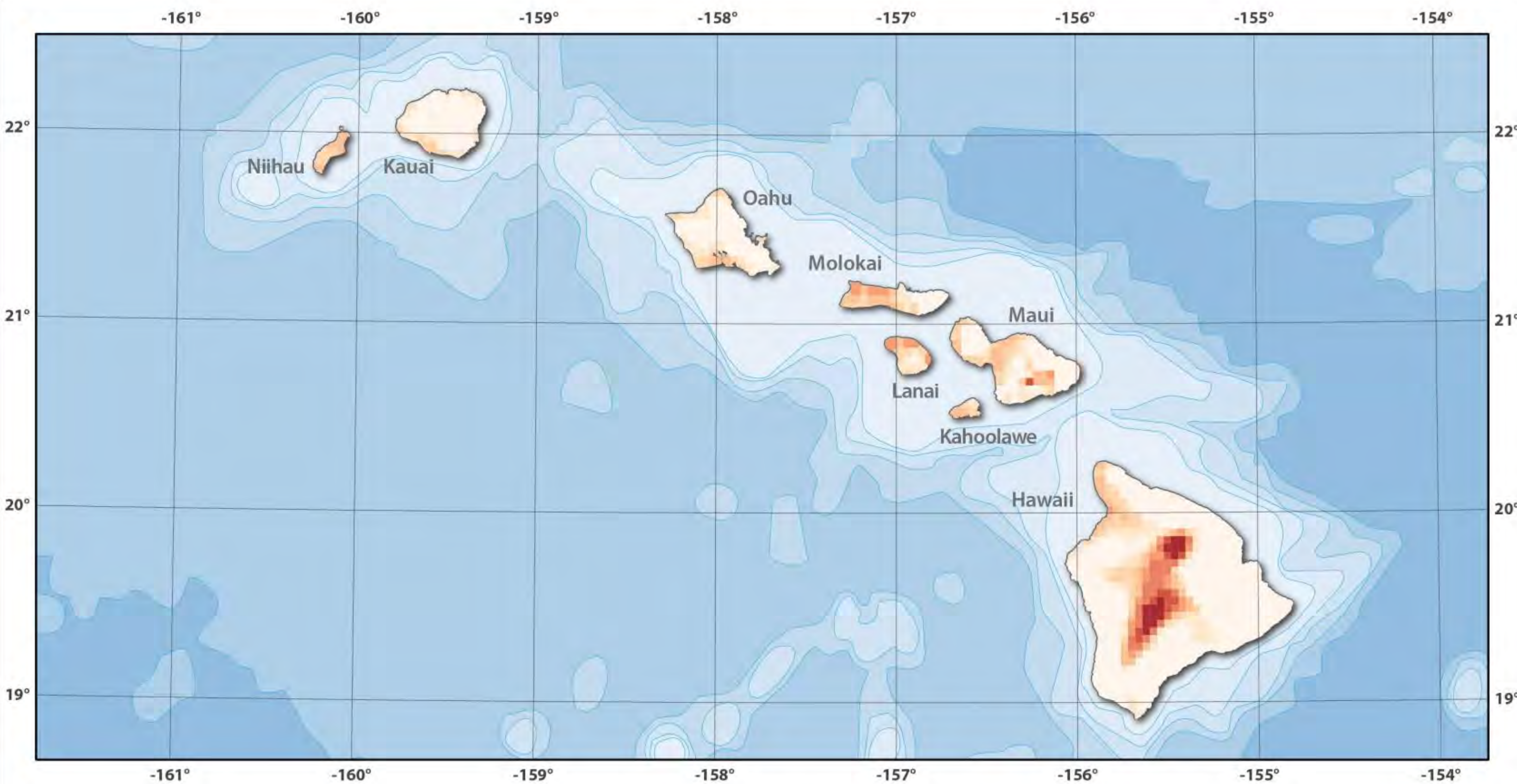

Direct Normal Solar Irradiance
National Solar Radiation Database Version 2.0.0
The Hawaiian Islands

kWh/m²/Day

- >8.0
- 7.5 - 7.9
- 7.0 - 7.4
- 6.5 - 6.9
- 6.0 - 6.4
- 5.5 - 5.9
- 5.0 - 5.4
- <5.0

The Solar Resource Dataset

The concept behind the project is to produce a regularly updated yet high quality solar resource dataset for the United States and surrounding regions that is accessible to the public. The availability of this dataset reduces barriers to penetration of solar by allowing users to both accurately predict the output from solar installations and to verify performance. The map shows the full extent of the current version of the dataset.

Data Summary

This data provides annual average daily total solar resource averaged over surface cells of 0.038 degrees in both latitude and longitude, or nominally 4 km in size. The insolation values represent the resource available to concentrating systems, and were created using the PATMOS-X algorithms for cloud identification and properties, the MMAC radiative transfer model for clear sky calculations and the SASRAB model for cloud sky calculations. The data are averaged from hourly model output over the period 1998-2014.

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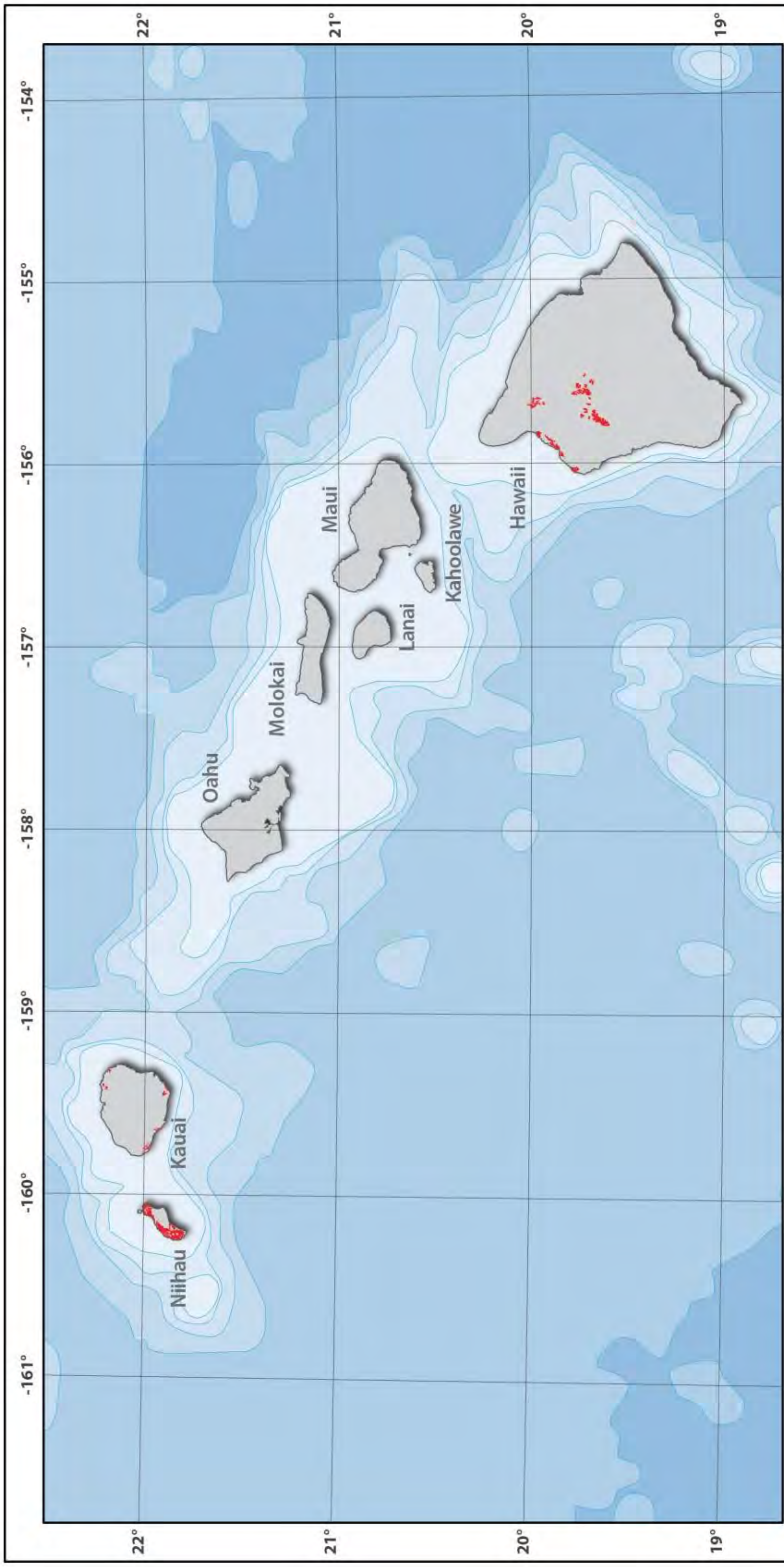

CSP Development Potential
of the Hawaiian Islands

Island	Area (km²)
Hawaii	102.6
Kahoolawe	0
Kauai	12.5
Lanai	1.2
Maui	0
Molokai	0
Niihau	72.1
Oahu	0

Development potential was determined by applying the following geographic and direct normal solar resource constraints:

- minimum resource threshold of 5 kWh/m2/day
- terrain slope is not more than 3%
- has a contiguous area of at least 1 km²
- is not part of the National or State Park* system
- is not Fish & Wildlife Service land
- has not been zoned as an urban area*
- is not classified as Important Agricultural Land*
- is not within an "A(x)" level flood zone*
- is not within a lava flow hazard zone 1 or 2*
- is not military/DOD controlled land*
- is not classified as a wetland*

**data acquired from the Hawaii Office of Planning*

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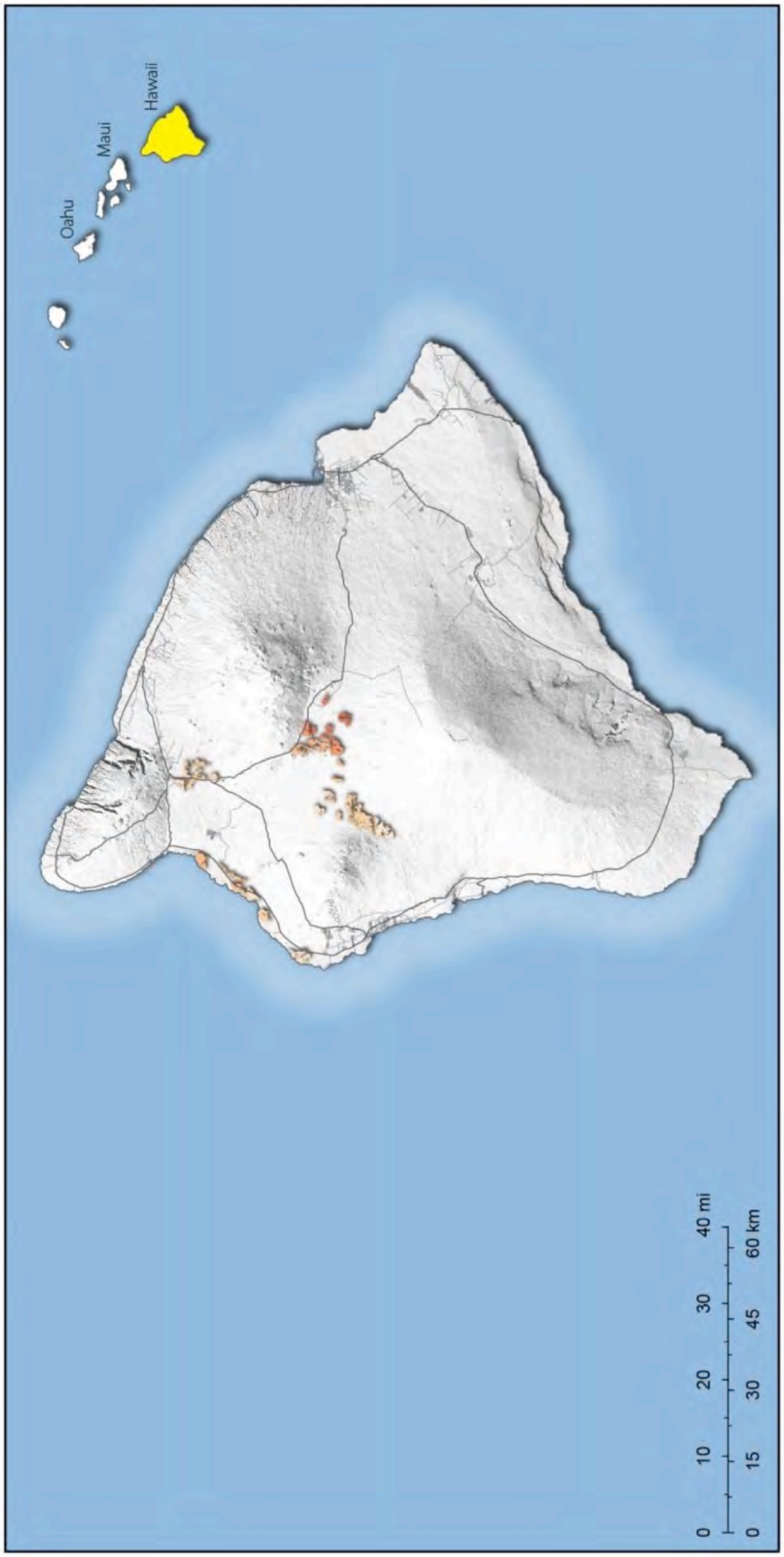

Development potential was determined by applying the following geographic and direct normal solar resource constraints:

- minimum resource threshold of 5 kWh/m2/day
- terrain slope is not more than 3%
- has a contiguous area of at least 1 km^2
- is not part of the National or State Park* system
- is not Fish & Wildlife Service land
- has not been zoned as an urban area*
- is not classified as Important Agricultural Land*
- is not within an "A(x)" level flood zone*
- is not within a lava flow hazard zone 1 or 2*
- is not military/DOD controlled land*
- is not classified as a wetland*

**data acquired from the Hawaii Office of Planning*

CSP Development Potential
Analysis of the Hawaiian Islands -- Hawaii

kWh/m^2/Day
- >8.0
- 7.5 - 7.9
- 7.0 - 7.4
- 6.5 - 6.9
- 6.0 - 6.4
- 5.5 - 5.9
- 5.0 - 5.4
- <5.0

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Appendix A: SAM Parameters

System parameters	Value
self.system_capacity	10000
self.dc_ac_ratio	1.5
self.tilt	0
self.azimuth	180
self.inv_eff	96
self.losses	14.0757
self.array_type	2
self.gcr	0.4
self.adjust_constant	0

Table 7: SAM Parameters

References

[1] AWS Truepower, LLC, NREL REEDS LICENSED DATASETS AND USER'S GUIDE, November 5, 2014.

[2] Wind Vision: A New Era for Wind Power in the United States, U.S. Department of Energy, April 2015.

[3] National Solar Radiation Database (NSRDB), https://nsrdb.nrel.gov

[4] Sengupta, M.; Habte, A.; Gotseff, P.; Weekley, A.; Lopez, A.; Anderberg, M.; Molling, C.; Heidinger, A. (2014). "Physics-Based GOES Product for Use in NREL's National Solar Radiation Database: Preprint." 6 pp. NREL/CP-5D00-62776.

[5] Sengupta, M.; Habte, A.; Gotseff, P.; Weekley, A.; Lopez, A.; Molling, C.; Heidinger, A. (2014). "Physics-Based GOES Satellite Product for Use in NREL's National Solar Radiation Database: Preprint." 9 pp.; NREL/CP-5D00-62237.

[6] System Advisor Model, SAM 2014.1.14: General Description, National Renewable Energy Laboratory, Technical Report No. NREL/TP-6A20-61019.

[7] PVWatts Version 5 Manual, National Renewable Energy Laboratory, September 4, 2014.

[8] Land-Use Requirements for Solar Power Plants in the United States, National Renewable Energy Laboratory, Technical Report No. NREL/TP-6A20-56290, June 2013.

[9] Lopez, Anthony, et al. US renewable energy technical potentials: A GIS-based analysis. National Renewable Energy Laboratory, Technical Report No. NREL/TP-6A20-51946, 2012.

G. Energy Storage Systems

Energy storage—be it Battery Energy Storage Systems (BESS) or Distributed Energy Storage Systems (DESS)—play in integral role in our renewable energy future.

ENERGY STORAGE TECHNOLOGIES

Various sizes of energy storage systems are commercially available ranging from one to two kilowatts of output to hundreds of megawatts, and in output durations of as much as six hours or longer.

For our analyses in developing the 2016 updated PSIPs, we considered a number of commercially-available energy storage technologies: flywheels and pumped storage hydroelectric (PSH); and lithium-ion battery energy storage systems (BESS) and distributed energy storage systems (DESS). We also evaluated hydrogen energy storage, as it is a promising technology.

Flywheels

Flywheels are rotating mechanical devices that store energy in the angular momentum of its rotating mass. A flywheel consists of a rotor (its rotating mass) attached to a motor (mounted on a very low friction bearing) and generator that spins at high speeds. To maintain the angular momentum of its rotating mass, a flywheel's motor acts like load and draws power from the grid, which enables the flywheel to absorb energy.

Flywheels can provide inertia to a power system. During a grid event (such as a sudden loss of load), the inertia from the flywheel's motor drives its generator, creating replacement electricity that is injected back into the grid. Flywheels can thus help avoid a system contingency. On an island power grid, a contingency can result in significant frequency decay extremely quickly, faster than spinning reserve can respond. Flywheels can provide the inertial response necessary to slow the rate of frequency decay, giving spinning reserve enough time to respond.

Flywheels can provide fast-response, short-term “ride-through” capability that allows seamless transfer of load from the grid to a longer-term backup system (such as an emergency generator). Besides providing inertial response, flywheels can be designed to provide energy for fast frequency response.

Flywheels have a minimum and maximum speed. The flywheel’s actual speed indicates its “state of charge”. The minimum speed represents a fully discharged state; the maximum speed represents a fully charged state.

While flywheels are expensive (high capital costs), they can charge and discharge hundreds of thousands of times over their useful life. Flywheel energy storage can be developed in two years or less (omitting regulatory approval lead-times). The round trip efficiency of a flywheel storage system is approximately 85%. Flywheels have very little environmental impact. Modern metallurgy has produced flywheel technologies that are safe during operation. Flywheels can also be placed underground for additional safety.

The more than 400 flywheels currently placed in utility-scale situations have been operating for more than seven million hours.[1]

Beacon Power is the major flywheel manufacturer providing commercial utility-scale systems operating in the United States. Other flywheel manufacturers (such as Amber Kinetics) are working towards bringing their systems to market.

The rotor of a Beacon Power Smart Energy 25 flywheel spins between 8,000 rpm and 16,000 rpm. At 16,000 rpm, a single flywheel can deliver 30 kWh of extractable energy at a power level up to 265 kW for five minutes or as low as 170 kW for ten minutes (Figure G-1).

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[1] http://beaconpower.com/operating-plants/.

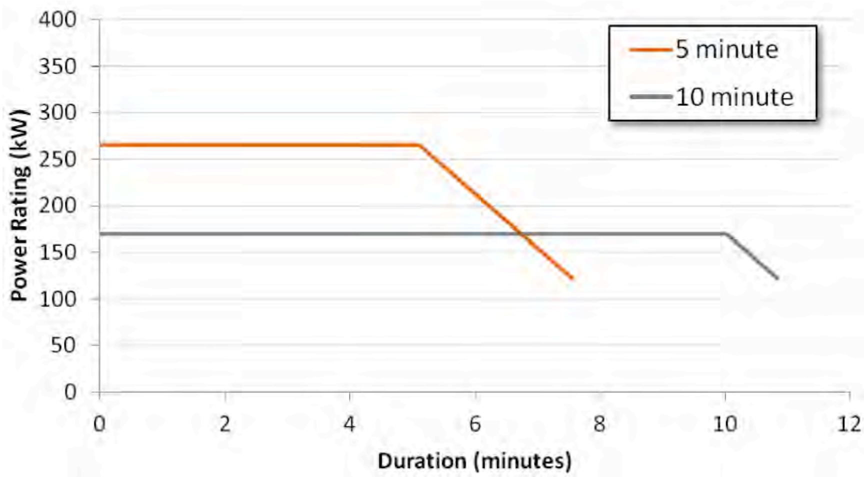

Figure G-1. Flywheel Extractable Energy Rates and Duration

The cyclic life capability of energy storage-based systems is of critical importance for performing frequency regulation. Beacon's flywheel is designed for a minimum 20-year life, with virtually no maintenance required for the mechanical portion of the flywheel system over its lifetime.

Beacon's experience to date in ISO New England involves 6,000 or more effective full charge and discharge cycles per year. The flywheel system is capable of over 175,000 full charge and discharge cycles at a constant full power charge and discharge rate, with no degradation in energy storage capacity over time.

A flywheel's mechanical efficiency for frequency response is over 97 percent; total system round-trip charge and discharge efficiency is 85 percent. Figure G-2 depicts a flywheel's superior capacity when compared with a lithium-ion battery.

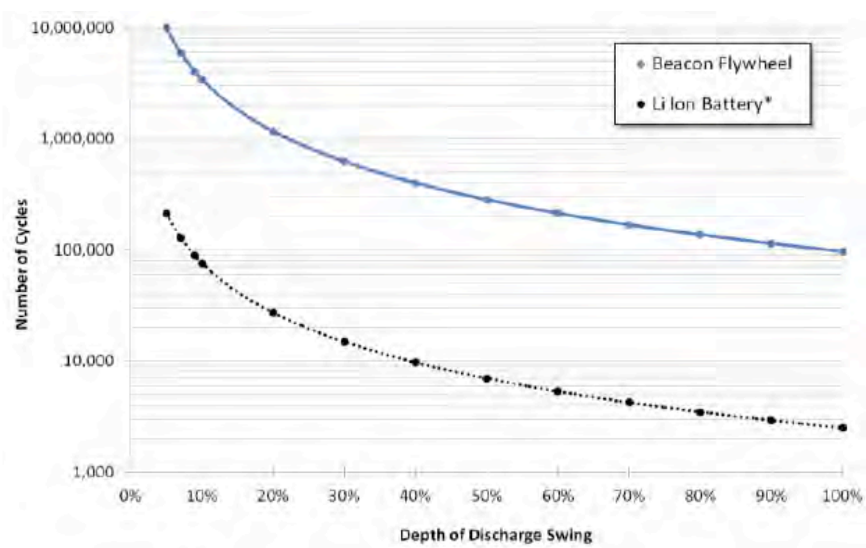

Figure G-2. Flywheel Cycle Life versus Lithium-Ion Battery

Pumped Storage Hydroelectricity (PSH)

Pumped storage hydroelectric (PSH) energy storage is a mature technology that has been successfully implemented around the world in grid applications.

PSH stores energy as gravitational potential energy of water, pumped from a lower elevation reservoir to a higher elevation reservoir. When demand is low or renewable energy production is high, a reversible turbine-generator pumps water from the lower reservoir to the higher one. When energy is needed for the grid, water is released down into the lower reservoir through the turbine-generator, generating electricity. The distance between these two reservoirs—be they natural bodies of water or artificial reservoirs—must be high enough to generate power.

While PSH has a relatively high capital cost, its useful life is 50 years or more. Pumped storage is very efficient, with round trip efficiencies approaching 80%. Figure G-3 shows the typical layout of a PSH project.

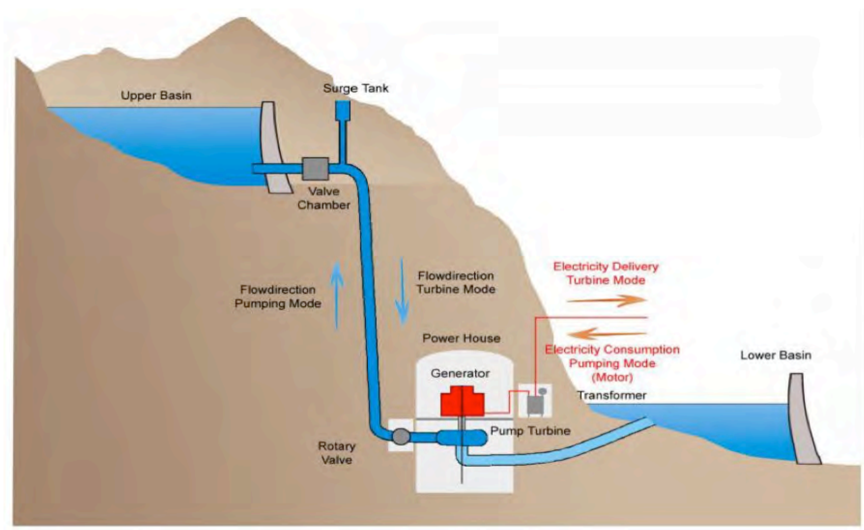

Figure G-3. Typical Pumped Storage Plant Arrangement[2]

PSH can provide peaking capacity and load shifting capabilities. While considered a quick-start resource, PSH takes a brief amount of time (about seven seconds) to start moving the water or to change direction through the turbine to produce electricity (its water column constant). These brief delays are limiting factors for single penstock systems.

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[2] Source: Alstom Power.

An adjustable speed pump turbine provides more precise control, thus providing operating flexibility, which in turn allows PSH to provide ancillary services (such as frequency regulation, spinning reserve, and load following) while generating and pumping. This can increase operating efficiencies, improve dynamic behavior, and lower operating costs.

Unlike a battery (which already has charge) or a flywheel (that has angular momentum), starting a PSH charging cycle requires high levels of electric current to start the motors necessary to pump water to the higher elevation. To put this in perspective, a 30 MW PSH system on the Hawai'i Electric Light grid would require starting 37.5 MW of motor load (assuming an 80% round trip efficiency). Because the typical daily peak demand is about 150 MW, starting the PSH motor represents an instantaneous 25% increase in load. This could cause currents to exceed the short circuit limits of the transmission system, which, without mitigation, would result in a significant frequency disturbance.

Pumped storage is the most widely used form of storage for large electrical grids. More than 120,000 MW of PSH has been installed around the world,[3] most of which exceed 1,000 MW per installation.[4] PSH installations are very site dependent, relatively expensive, and have long lead times for permitting and construction. According to the U.S. Department of Energy:

> Pumped storage is a long-proven storage technology, however, the facilities are very expensive to build, may have controversial environmental impacts, have extensive permitting procedures, and require sites with specific topologic and/or geologic characteristics. As estimated in a report commissioned by EIA, the overnight cost to construct a pumped hydroelectric plant is about $5,600/kW…[5]

Over the years, a number of PSH projects have been studied and proposed in Hawai'i. Table G-1 through Table G-4 show the results of numerous PSH studies in our service areas. These studies shows a wide distribution of the per unit capital cost data, reflecting the site specific nature of PSH.

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3 "Packing Some Power," The *Economist.* May 3, 2012, http://www.economist.com/node/21548495?frsc=dg%7Ca (citing EPRI as their source).

4 https://en.wikipedia.org/wiki/List_of_pumped-storage_hydroelectric_power_stations. (This list is not complete. We are aware of projects not included in this list, and some smaller than the ones listed by this source).

5 http://www.eia.gov/todayinenergy/detail.cfm?id=6910.

O‘ahu

Table G-1 summarizes the historical PSH projects studied on O‘ahu. All costs are nominal dollars.

Site Designation	Study Year	Size (MW)	Hours of Storage	Estimated Capital Cost ($M)	Estimated Capital Cost per kW
Kapa‘a Quarry	No data	No data	No data	No data	No data
Ku Tree Reservoir	No data	No data	No data	No data	No data
Nu‘uanu Reservoir	No data	No data	No data	No data	No data
Koko Crater	1994	160.0	7.5	$161	$1,006
Ka‘au Crater	1994	250.0	8.0	$256	$1,024
Kunia	2004	150.0	8.0	$189	$1,260
Mokuleia	2007	50.0	12.0	$197	$3,940
Hawaiian Cement	2008	7.0–74.0	8.0	No data	No data
Palehua	2014	200.0	6.0	$650	$3,250

Table G-1. Historical Studies of Pumped Storage Hydroelectric Projects on O‘ahu

Hawai‘i Island

Table G-2 summarizes the historical PSH projects studied on Hawai‘i Island. All costs are nominal dollars.

Site Designation	Study Year	Size (MW)	Hours of Storage	Estimated Capital Cost ($M)	Estimated Capital Cost per kW
Pu‘u Wa‘awa‘a	1995	30.0	6.0	$71	$2.367
Pu‘u Anahulu	1995	30.0	6.0	$71	$2,367
Pu‘u Enuhe	1995	30.0	6.0	$61	$2,033
Hawi	2004	10.0	5.0	$39	$3,900
Waimea	2004	2.3	12.0	$17	$7,391
Kaupulehu / Kukio	2006	50.0	5.0	$239	$4,780
Mauna Kea 15a	2016	56.4	5.0	$228	$4,046
Mauna Kea 5	2016	22.9	5.0	$105	$4,583
Mauna Kea 15a + 8c	2016	97.0	5.0	$422	$4,352
Kohala 12	2016	18.1	5.0	$89	$5,426
Kohala 8	2016	39.6	5.0	$239	$6,036

Table G-2. Historical Studies of Pumped Storage Hydroelectric Projects on Hawai‘i Island

Maui

Table G-3 summarizes the historical PSH projects studied on Maui. All costs are nominal dollars.

Site Designation	Study Year	Size (MW)	Hours of Storage	Estimated Capital Cost ($M)	Estimated Capital Cost per kW
Ma'alaea	1995	30.0	6.0	$83	$2,767
Honokowai	1995	30.0	6.0	$77	$2,567
Kahoma	1995	30.0	6.0	$104	$3,467
Pu'u Makua	2006	50.0	12.0	$169	$3,380
Lahaina West	2007	14.7	5.0	$62	$4,218
Lahaina West	2007	6.9	3.6	$39	$5,652
Makawao	2007	31.2	5.0	$220	$7,051
Kihei	2008	50.0	9.0	$315	$6,300

Table G-3. Historical Studies of Pumped Storage Hydroelectric Projects on Maui

Moloka'i

Table G-4 summarizes the historical PSH projects studied on Moloka'i. All costs are nominal dollars.

Site Designation	Study Year	Size (MW)	Hours of Storage	Estimated Capital Cost ($M)	Estimated Capital Cost per kW
East Moloka'i # 1	2007	3.0	5.0	$15	$5,000
East Moloka'i # 2	2007	1.0	5.0	$7	$7,000
West Moloka'i	2007	8.6	5.0	$57	$6,628

Table G-4. Historical Studies of Pumped Storage Hydroelectric Projects on Moloka'i

The vast majority of these studies are for PSH project less than 100 MW. Because the typical PSH installation in the United States is about 1,000 MW, there is limited data on the capital cost and performance for 100 MW PSH projects. Our research uncovered only a few instances of proposed (not constructed) comparably-sized PSH projects.

Based on limited data, we are using a capital cost estimate of $3,500 per kW in 2016 dollars for a 30–50 MW utility-scale PSH project, evaluating it against other storage options. This is optimistic; the average capital cost of all past studies itemized in the above tables is $4,050 per kW (not adjusted for inflation). The forecasted trend for PSH capital cost is flat in real terms, reflecting a mature technology.[6] These uncertain costs are in addition to the substantial permitting challenges any PSH project would face in Hawai'i.

6 *E-storage: Shifting From Cost to Value Wind and Solar Applications.* World Energy Council. 2016. Table 6a: "Assumptions underpinning development of specific cumulated investment costs to 2030".

We will consider solicitations for PSH projects from experienced developers who can manage project risks, meet our specific power grid needs, and provide customer benefits that exceed those of other storage technology providers.

Lithium-Ion Energy Storage Systems

Lithium-ion refers to a wide range of chemistries all involving the transfer of lithium-ions between electrodes during charge and discharge cycles of the battery.[7] Lithium-ion batteries are very flexible storage devices with high energy density, a fast charge rate, a fast discharge rate, and a low self-discharge rate, making lithium-ion batteries ideal for grid applications.[8]

Lithium-ion energy storage technologies have rapidly advanced to the point that they are commercially available for utility-scale and distributed energy applications. These advances have been led by the development of advanced lithium-ion batteries for use in consumer electronics and automotive applications. According to a recent report from the Electric Power Research Institute (EPRI), battery energy storage "…is emerging as a potential technology solution for the utility industry because of a confluence of industry drivers related to both energy storage technology advancement as well as transformations in the electric power enterprise."[9]

The EPRI report identifies several trends within the energy storage industry:

- Technological advances in energy storage with active cycling capabilities, combined with longer useful asset lives.
- Declining costs and performance improvements in lithium-ion battery technologies.
- A pipeline of innovative research and development related to more advanced storage technologies, which could lead to lower costs and longer durations of energy storage.

Capital costs for lithium-ion batteries are declining,[10] particularly as the use of lithium-ion for electric vehicle batteries rises. Even with their current commercial status, the expectations are for lithium-ion battery performance to improve, and for costs to continue to drop.

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7 Energy Storage Association. http://energystorage.org/energy-storage/technologies/lithium-ion-li-ion-batteries.

8 *Lithium Ion Technical Handbook*. Gold Peak Industries (Taiwan), Ltd. http://web.archive.org/web/20071007175038/http://www.gpbatteries.com/html/pdf/Li-ion_handbook.pdf.

9 Electric Power Research Institute Inc. *Energy Storage Valuation Analysis: 2015: Objectives, Methodologies, Summary Results, and Research Directions*, Technical Update 3002006068, January 2016.

10 See for example: http://rameznaam.com/2013/09/25/energy-storage-gets-exponentially-cheaper-too/.

Utility-scale lithium-ion batteries installations can be easily scaled in size; have relatively short lead times for procurement, engineering, and installation; and have ultimate flexibility for permitting and siting them at available real estate or existing utility plant sites. Lithium-ion energy storage systems can be configured for a number of different applications at various voltage levels. This flexibility makes lithium-ion energy storage systems an excellent candidate for providing non-transmission alternatives in constrained areas.

Lithium-ion batteries themselves have a useful life through 4,000 to 5,000 normal charge-discharge cycles. More frequent use of the full charge-discharge capabilities of lithium-ion would shorten the life. Lithium-ion battery energy storage can be developed in two years or less, not counting regulatory approval lead-times. The typical efficiency of lithium-ion batteries is 80%–90%, depending on the application.

The use of lithium-ion batteries is largely being driven today by automotive and consumer electronic applications. Disposal of these kinds of lithium-ion batteries presents a challenge. A great deal of effort is being put into developing proper disposal and recycling methods for lithium-ion batteries.[11] Lithium-ion batteries, however, do not contain metallic lithium, nor do they contain lead, cadmium, or mercury. At the end of their useful life, lithium-ion batteries can be dismantled and the parts reused.[12]

In its comments filed on January 15, 2016 in Docket 2014-0183, Paniolo Power states: "…while larger battery systems are starting to be built, batteries used for long duration, utility-scale applications must still be considered in the development phase… Battery technologies for long duration storage should be considered still under development as they are simultaneously attempting to improve the chemical compositions, storage capacity, operating life, disposal issues, and costs of batteries."[13] Based on current conditions, however, we find that Paniolo Power's characterization of long duration BESS to be off the mark. Lithium-ion battery technology has made substantial advances in cost and performance. Several vendors have reached a level of maturity and capitalization that they can offer performance guarantees on utility-scale lithium-ion battery systems. Kauai Island Utility Cooperative (KIUC) has contracted to purchase power from a solar PV project that incorporates a four-hour lithium-ion energy storage system. We find this indicative of the maturity of lithium-ion as a long-duration energy storage option.

[11] See for example: http://energy.gov/sites/prod/files/2015/06/f23/es229_gaines_2015_o.pdf.

[12] See for example: http://auto.howstuffworks.com/fuel-efficiency/vehicles/how-green-are-automotive-lithium-ion-batteries.htm.

[13] Docket 2014-0183, Comments of Paniolo Power, January 15, 2016, pp 23–24.

Distributed Energy Storage Systems (DESS)

A distributed energy storage system (DESS) is essentially a lithium-ion battery located on a customer's property that helps control DG-PV generation. High penetrations of DG-PV create many challenges: uncertain amounts and low reliability of generation, inadequate dispatching or scheduling control, and safety concerns with energy feedback. Optimally located DESS batteries can mitigate many of the challenges. DESS can also provide backup power, voltage correction, and demand response.

Long-term benefits include improved system control and reliability of essentially uncontrolled DG-PV, and improved system reliability. DESS can also help reduce peak loads, help regulate voltage and frequency, and allow more time for service restoration during scheduled or accidental power interruptions.

DESS typically last for 15 years or more, are capable of over 3,000 charge-discharge cycles, have a round trip efficiency greater than 95%, and generally cost between 15¢–25¢ per kWh.

Hydrogen Energy Storage

According to NREL: "… hydrogen can play an important role in transforming our energy future if hydrogen storage technologies are improved."[14]

Hydrogen is a versatile energy storage carrier, with high energy density, that holds significant promise for stationary, portable, and transport applications. Hydrogen could be used to "de-carbonize" applications that rely on natural gas. In electricity applications, hydrogen can be produced through electrolysis with "excess" variable renewable energy (for example, energy available for production by wind and solar resources at times when the net system demand for electricity is low). Hydrogen can be stored under pressure in storage vessels or underground caverns. The stored hydrogen is then used in fuel cells or to produce electricity, thus providing a means of load shifting in grids with high penetrations of variable renewable resources.[15]

While Europe has a relatively robust commercial supply chain for hydrogen production and storage for industrial uses,[16] hydrogen storage technology for electricity is still in the research and development phase. In the United States, demonstration projects have been constructed that integrate wind turbines and solar PV with electrolyzer systems to

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[14] http://www.nrel.gov/hydrogen/proj_storage.html.

[15] *Program on Technology Innovation: Hydrogen Energy Systems Development in Europe*, Technical Update 3002007274. Electric Power Research Institute, January 2016.

[16] *Ibid.*

produce hydrogen. A significant challenge towards commercialization is the ability to scale the hydrogen systems to larger sizes.[17]

We believe that hydrogen energy storage systems hold great promise. The availability of commercial hydrogen energy storage systems, however, is limited at this time. We will continue to monitor developments in this technology, and as appropriate, include hydrogen energy storage in future power supply plan updates.

ENERGY STORAGE APPLICATIONS

For these updated PSIPs, we developed detailed assumptions for several applications, using several technologies. These applications included:

Inertia: provides ride-through of momentary system disruptions to avoid a system contingency.

Contingency: instantaneously (less than seven cycles, for faster for Lana‘i and Moloka‘i) provides inertial response, slowing the change in frequency, and provides fast frequency response and energy following the loss of generation contingencies.

Regulation: provides frequency response and frequency regulation under automatic generation control (AGC).

Variable renewable smoothing: responds to changes in a variable resources output when coupled with that variable resource or group of resources. Thus, the net impact of the storage and variable resource is smoothed and has less impact on system frequency. This reduces the need for primary frequency response and regulation reserves from other system resources.

Load Shifting: stores energy for use at a later time to serve demand. As an alternative to installing new equipment or modifying circuits, the storage may be installed so the energy can be used to reduce circuit or transmission constraints in lieu of providing non-transmission alternatives.

[17] http://www.renewableenergyworld.com/articles/2014/07/hydrogen-energy-storage-a-new-solution-to-the-renewable-energy-intermittency-problem.html.

Table G-5 summaries the applications, uses, duty cycles, technologies, and sizes of energy storage systems.

Application	Duration	Storage Duty Cycles	Depth of Discharge	Energy Storage	Sizes Available to Planners (MW)
Inertia	Seconds	5,000 per year	Deep: up to100%	Flywheels	10
Contingency	Up to 30 minutes	~10 per year	Deep: up to100%	Lithium-Ion BESS	1, 5, 10, 20, 50, 100
Regulation	Up to 30 minutes	~15,000 per year	Shallow: 20% to 50%	Lithium-Ion BESS	1, 5, 10, 20, 50, 100
				PSH	30, 50
Load Shifting	1–8 hours	Daily	Deep: up to100%	Lithium-Ion BESS	1, 5, 10, 20, 50, 100; 2 for grid support
				PSH	30, 50
				CSP with Storage	100

Table G-5. Updated PSIP Energy Storage Applications, Sizes, Technologies

In practice, a single energy storage installation can be used for more than its primary purpose. For instance, a load shifting battery can also provide regulation service if required. A contingency battery could, in theory, provide some load shifting. A 20 MW, 30-minute hour battery (that is, 10 MWh) could provide 10 hours of load shifting storage if the output of the battery system is limited to 1 MW (1 MW x 10 hours = 10 MWh). The key is to closely manage the battery's charge and discharge cycling to maintain its useful life based on its designed application.

While being able to provide grid services other than load shifting (such as regulation reserve), the cost of PSH solely to provide these other grid services would not be justified.

Cost Assumptions Related to Energy Storage

Figure G-4 depicts the underlying constant 2016 dollar assumptions for the capital costs associated with selected sizes, technologies, and applications for energy storage systems assumed in the 2016 updated PSIP. (Refer to Appendix J: Modeling Assumptions Data for the specific capital cost assumptions for energy storage resources.)

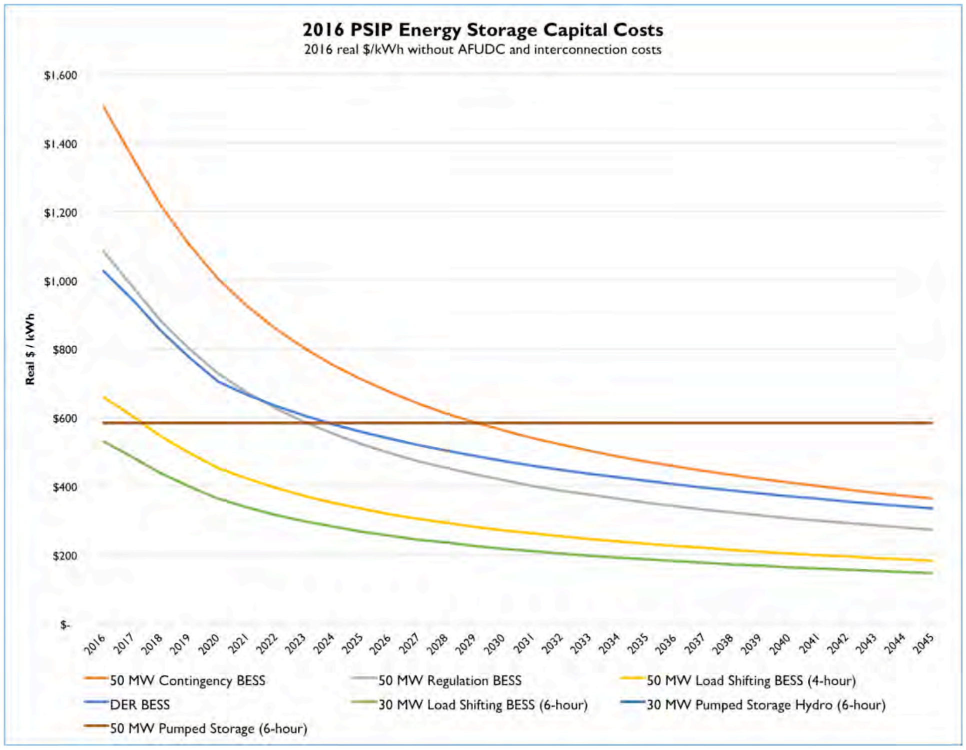

Figure G-4. 2016 Updated PSIP Energy Storage Capital Costs

The method for determining the capital and operating costs assumptions for energy storage systems was largely the same as for new utility-scale generating facilities. The primary source of data for current prices and forward curves was IHS Energy consultants. Prices were adjusted for Hawai‘i using RSMeans city indices. Prices were adjusted upwards by 4% to account for Hawai‘i general excise taxes.

Adjustments to BESS prices and costs were made based on the different applications. The application affects the “duty cycle” of the BESS, which in turn drives certain design parameters including the spacing of cells to better dissipate heat (longer duration storages requires more spacing, resulting in larger footprints) and air conditioning requirements. More frequent and deeper discharge of BESS requires replacement of battery cells more often in order to maintain output.[18]

5-5-5 Battery Initiative

Advances in battery storage technologies have drawn significant attention, such as the 5-5-5 battery initiative.

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[18] Some vendors oversize the battery from the start, so that as the batteries degrade over time and the project’s output declines to the customer’s specified output requirements. Others provide warranty wraps where they replace cells as they degrade so that the desire output is maintained.

In 2013, the United States Department of Energy awarded the Joint Center for Energy Storage Research (JCESR), led by Argonne National Laboratory, with a $120 million grant to address "the scientific and engineering research needed to advance the next generation of electrochemical energy storage for both transportation and the grid."[19]

In a written statement before the Subcommittee on Energy Committee on Science, Space, and Technology of the United States House of Representatives, Director George Crabtree explained the vision and mission of JCESR through this grant:

> JCESR's vision addresses the two largest energy sectors in the U.S.: transportation and the electricity grid, which together account for two-thirds of our energy use. Our vision is aggressively transformative: to enable widespread penetration of electric vehicles that replace foreign oil with domestic electricity, reduce carbon emissions, and lower energy use; and to modernize the electricity grid by breaking the century-old constraint of matching instantaneous demand with instantaneous generation, enabling widespread deployment of clean and sustainable but variable wind and solar electricity while increasing reliability, flexibility and resilience. Both transformations can be achieved with a single disruptive breakthrough: high-performance, low-cost electricity storage, beyond today's commercial lithium-ion technology. JCESR's vision is to transform transportation and the grid with the next generation beyond lithium-ion electricity storage.
>
> JCESR's mission goals are to provide two prototypes, one for transportation and one for the grid, which, when scaled to manufacturing, are capable of providing five times the energy density at one-fifth the cost of commercial batteries in January 2012 when our proposal was prepared, summarized by the shorthand expression "5-5-5".[20]

JCESR implemented and continuously refines a new paradigm for battery research and development that integrated discovery science, battery design, research prototyping, and manufacturing collaboration in a single, highly interactive organization. JCESR expects this new paradigm to accelerate the pace of discovery and innovation and shorten the time from conceptualization to commercialization.

At the date of this statement, JCESR research has resulted in 26 invention disclosures with a dozen patent applications, and has selected and begun to converge four next-generation prototype concepts. In addition, JCESR is testing several candidate materials and batteries in half-cell and full cell prototypes.

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[19] *Grid Energy Storage*, published by the U.S. Department of Energy, December 2013. p 42.

[20] Written Statement of George Crabtree, Director, Joint Center for Energy Storage Research (JCESR), Argonne National Laboratory, University of Illinois at Chicago. Before the Subcommittee on Energy Committee on Science, Space, and Technology United States House of Representatives; Hearing on: Department of Energy (DOE) Innovation Hubs, June 17, 2015. pp 1–2.

H. Analytical Models and Methods

We are employing a number of analytical models to develop our 2016 updated PSIPs. Our System Planning team, our Transmission and Distribution Planning team, and several consultants process numerous individual and overlapping model runs using these tools. Together, we are performing a thorough, exhaustive analysis to develop a series of alternative plans. Then, from those plans, we are developing Preferred Plans for each operating utility to provide reasonable cost, reliable energy to our customers while reaching our 100% RPS goal.

These modeling tools and the team running the tool include:

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

SIEMENS PTI PSSE FOR SYSTEM SECURITY ANALYSIS

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

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

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

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

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

P-MONTH MODELING ANALYSIS METHODS

Our System Planning Department uses the P-Month hourly production simulation model to perform analyses for developing alternative plans for the 2016 updated PSIPs.

The P-Month modeling tool includes these characteristics:

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

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

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

We use computer models for the 2016 updated PSIP analyses. Production costs of the operating the system is simulated using the P-Month hourly production simulation model. The model is populated with unit data to characterize the resources operating on the system at all hours so that the performance and cost of the system can be evaluated for various future cases. The data from the hourly production simulation model is processed using other internally developed tools to evaluate the results of the simulations.

P-Month Hourly Production Simulation Model

Thermal Generation Modeling

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

Variable Generation Modeling

The model for energy produced by renewable resources and other variables uses a 8,760 hourly profile (365 days at 24 hours a day). This profile is constructed based on historical observed output from in service variable generation or from solar irradiance profiles and measured wind potential for future variable generation. Generation that is produced according to this hourly profile that cannot be accommodated on the system, in any one hour is curtailed per the established curtailment order for resources modeled as controllable. The curtailment order follows a last in, first out rule whereby the last installed variable renewable resource is curtailed first, that is, reverse chronological order for resources designated as being able to be controlled.

Unit Forced Outage Modeling

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

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

Using the Monte Carlo, or deterministic, technique, forced outages for generating units are treated as random, discrete outages in one week increments. The model randomly takes a generating unit out of service (during periods when it is available) up to a total forced outage time of 5%. By this methodology, the unit can operate at normal top load for 95% of the time when it is not on overhaul but is not able to operate (that is, has a zero output) for 5% of the time when it is not on overhaul. For the 2016 updated PSIPs, the modeling uses the Monte Carlo methodology to capture the forced outages of all thermal units.

Demand Response Modeling

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

Energy Storage Modeling

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

System Security Requirements

The system security requirements are included through regulating and contingency reserve requirements. The requirements are met using contribution of services from demand response, energy storage, and thermal generation in the modeling. The system security requirements depend on the levels of PV and wind on the system. The regulating reserve requirements were changed hourly in the model to reflect the dynamic changes in levels of PV and wind throughout the day. Curtailed energy from controllable

PV and future wind resources contributed to meeting the regulating reserve requirement. The contingency reserve requirements for O‘ahu were changed annually to reflect the largest unit contingency on the system.

Sub-Hourly Model

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

Key Model Inputs

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

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

Methodology for Post-Processing of Production Simulation Results

Key Outputs

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

- Generation produced by each firm generation unit
- Generation accepted into the system by non-firm generating units
- Excess energy not accepted into the system (curtailed energy)
- Fuel consumption and fuel costs

- Variable and fixed O&M costs
- Start-up costs

Post-Processing

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

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

All costs are post-processed into annual and total dollars to be used in the financial model. All annual, total, and present value (2016 dollar) revenue requirements are also post-processed for use in evaluating the different plans but are not meant to be the "all-in costs" that the financial model considers. Revenue requirements are characterized as utility and IPP. Utility revenue requirements are categorized into fuel, fixed O&M, variable O&M, and capital. IPP revenue requirements are categorized into capacity and energy payments. Using the revenue requirements from post-processing, plans can be analyzed according to several key metrics.

Key Metrics

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

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

Lana'i & Moloka'i Modeling

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

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

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

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

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

ADAPTIVE PLANNING FOR PRODUCTION SIMULATION

Black & Veatch is applying its Adaptive Planning (AP) for Production Simulation to support the 2016 updated PSIP analysis. AP for Production Simulation provides a framework for modeling complex systems, exploring options (impacts of constraints), and comparing such options across varying metrics. Key metrics or outcomes associated with this analysis include costs, degree of renewable penetration (both capacity and energy served), utilization of demand response and distributed energy resources, avoided costs associated with demand response, and metrics associated with generation-related grid security.

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

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

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

Black & Veatch possesses deep domain expertise in the technologies deployed—from design, operations, and reliability perspectives—as well as deep domain expertise in complex simulation. This combination provides critical thinking and credibility needed in addressing very complex and costly investment decisions across PSIP areas of interest.

Given the desire and need for massive transformation, the underlying model must be very technically robust to assure that all transformative steps are both rational and fully understood. Key aspects that can be specifically addressed include technology selection and implementation, plant refurbish and upgrades, retirements, DER build out, and participation and structure of DR programs.

Black & Veatch capabilities and reputation are critical for both credibility of the process and model as well as credibility of the results, given that the interactions between conventional power production, renewable resources, storage, and customers are very complex, and given that 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 for Production Simulation to leverage the cloud is also particularly valuable for PSIP where exploration across decision dimensions is needed. For example, automated processes can be leveraged to explore the solution space (that is, timing and volumes of DER resources, timing and volumes of utility-scale renewable and energy storage resources). This enables the PSIP team to see and illustrate value and strength of strategies and sensitivity of strategies to key underlying assumptions.

Configuration Methodology

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

Thermal Generation

Firm thermal generation resources are modeled as having the ability to meet demand, up and down regulation, contingency, and frequency response (modeled as system inertia requirements based on system state). Assets are committed based on the combined minimum load operating, minimum load fuel, startup time, and associated startup costs.

These assets are dispatched by AP for Production Simulation's optimizer to achieve the lowest possible fuel and variable operating costs based on a given set of constraints.

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

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

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

Variable Generation

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

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

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

Central Energy Storage

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

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

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

Distributed Energy Resources

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

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

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

Demand Response

Demand response can be evaluated in two ways.

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

- Hourly load modification projections by product.
- Hourly ancillary services projections.

- Program fixed and incentive costs.

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

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

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

System Security

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

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

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

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

Time Slice Model within AP for Production Simulation

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

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

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

- Status (available, scheduled outage, forced outage, retired).

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

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

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

Commitment and Dispatch Methodology

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

When determining commitment (units that are online), the model endeavors to meet both demand (incorporating load-shift demand response) and grid security requirements. It starts up or shuts down generating resources as needed to meet these requirements. It prioritizes the resources online to include units required to support system security, to meet goals such as maximizing renewable resource use, and to meet the requirements of power purchase agreements. The load shifting battery charge and discharge cycle is optimized for each day based on load net of wind and solar generation and DR load shift.

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

Demand Response Methodology

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

When combining the potential of individual DR products into a portfolio, it must be recognized that each end-use device is limited in its ability to provide multiple services at a time. Typically, an end device can provide one load building and one load reduction service simultaneously. For example, a water heater participating in a pricing program that builds load during midday to take advantage of solar generation can at the same time provide FFR—a reduction in load in response to a sudden loss of a generating asset. It cannot provide FFR during evening hours when the water heater is reducing load under the pricing program, as this would constitute providing two load reducing services simultaneously. Similarly, a water heater cannot simultaneously provide both FFR and regulating reserve because, once turned off to provide one service, there is no potential available to provide the other service. As such, the DR potential for each product must be managed to prevent over allocation of end-use devices.

AP for Production Simulation maps end-use devices to DR products to ensure full range of services are evaluated while ensuring no double allocation of services. These mapping rules are:

1. Pricing Programs (TOU, DALS, and RTP) are mutually exclusive: a single end device can only participate in one Pricing Program.
2. FFR and NSAR[1] cannot be called at the same time for a single end device; however an end device may be called under FFR and then immediately be called to participate in NSAR.
3. An end device cannot provide FFR and NSAR at the same time as RR.

[1] NSAR program is a 10-minute supplemental reserve resource capable of replacing other resources that are used for spinning reserves. When paired with an FFR program, it can also be used to replace a contingency grid battery.

4. End devices participating in pricing programs can provide FFR, NSAR, or RR while building load.
5. End devices participating in pricing programs cannot provide FFR, NSAR, or RR while decreasing load.

The DR end-use allocation is based on the best value derived from the end-use device. Since both the DR potential (air conditioner load is higher in the summer and peaks during midday) and the needs of the generation and transmission system are dynamic by hour, DR potential is allocated for each hour. The allocation is complex as some system constraints are dynamic. For example, the system security requirement that sets the FFR need is based on the unit commitment, which is determined by the allocation of DR end-use devices for regulating reserves and load shifting. Given the finite DR potential, the optimal allocation often requires the layering of the constraints such that all constraints are satisfied and the DR potential is not over allocated.

Order and priority between underlying resources are managed as follows:

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

The load shift (described in priority and order 1) is evaluated as an outer loop to the simulation model to optimize between pricing and incentive products. Potential associated with pricing products is allocated in a manner consistent with the anticipated price signal flexibility. Potential associated with products under a tiered rate schedule is allocated approximately as required by the generation system, but is constant for each hour within a tier. Potential associated with pricing products set via a forward-looking, hourly pricing scheme is tailored hour-by-hour and therefore more closely matches the requirement of the generation system. The load shift is MWh neutral on a daily basis; the increase and decrease each day does not change the overall demand associated with that day.

Tradeoffs between pricing products and incentive programs are evaluated for distinct levels of pricing products taken (0%, 50%, 100%). When less than 100% of the pricing product is used for load shift, the remainder of the end product's potential is made available (where there is overlap) for FFR, NSAR, and so on.

Each level of participation is compared for each day; the case with the lowest generation cost defines the percent of pricing product taken for that day.

The pricing products may reduce or postpone new generation as pricing programs shift loads and thereby reduce the annual peak. This reduces the need for new units to meet the reserve margin requirements.

Sub-Hourly Model

Traditional hourly modeling does not expose the operational transients that must be managed during real-time operation of the electric grid. Traditional hourly modeling also does not expose potential value (economic and risk mitigation value, for example) that one set of resources may have over another set of resources, as all transients are softened. Sub-hourly modeling exposes some of this value to support the optimum resource selection that does not violate policy considerations (risk tolerance, renewable goals, budget constraints, fuel diversity)

Similar to an hourly modeling approach, the sub-hourly model calculates both commitment (which units are generating power) and dispatch (MW contributed by each asset to achieve the target demand), but now at a sub-hourly time step. Maximum daily rate of change is greater and ramp rate constraints are hit more often, thereby potentially changing the economic outcome of the simulation as compared to the hourly model.

The sub-hourly model (five-minute time step) performs a constrained optimization for asset dispatch against a sub-hourly desired load. The resources considered include generation (dispatchable and non-dispatchable), demand response, and energy storage. Each asset has two primary states: available or unavailable. Each unavailable state may have sub-states (for example, scheduled versus unscheduled outages). There are also system constraints that must be met. These include:

- Spinning reserve requirements (incorporating energy storage and demand response options).
- Grid stability requirements, either must-run units or verification that adequate inertia is present on the system given system conditions.

- Policy constraints (power quality, reliability targets, risk tolerance).

The sub-hourly model changes the state of each asset to optimize the economics within the bounds of the model constraints. Accounting routines keep track of asset performance ($, MWh, number of starts) and system performance (unserved load, curtailed generation, $, MWh).

This modeling approach is ideally suited to evaluating, comparing, and contrasting differing strategies regarding the mix of fossil generation, utility renewables versus energy storage, distributed generation versus energy storage, and demand response options. Based on the supply options provided, the model determines the low-cost means for meeting the required load within constraints. These constraints can be modified to evaluate other policy considerations (such as greater renewable penetration).

Model Outputs and Visualization Tools

AP for Production Simulation output is generally organized into views of differing granularity according to the following:

- *Periodic Values:* This can be period to period (five-minute, hourly, daily, or annual) and consists of period inputs (assets available, state, demand), production factors (individual asset production or utilization in support of grid services), consumables (fuel, chemicals), and other variable O&M costs.
- *Average Day:* This view aggregates and averages all period values into a single day "view" by year, showing system behavior, unit participation and ramping, and provision of services during peak and off-peak periods.
- *Specific Day:* Similar to Average Day, this view provides the same outputs but for a specific day or range of days, showing the variability of system resources from day-to-day and year-to-year. This view is particularly valuable in understanding the variability in the value of grid services and optimizing DR portfolio.
- *Aggregations by Resource Type:* All views are available either by individual asset, DR program, or aggregated by type of asset. This shows how different asset classes are utilized in matching demand or providing grid services.
- *Comparisons:* Comparison views are applied against two cases to identify differences in outcomes, year-to-year or period-to-period.
- *Avoided Costs:* Avoided cost views are generated by mathematically "subtracting" an underlying base or reference case from the subject case. In particular, grid service values (or value of DR program) are based on mathematically assessing differential system costs against differential resources available to provide the grid services.

DG-PV ADOPTION MODEL

BCG developed the proprietary DG-PV Adoption Model to forecast and optimize the adoption of customer-sited energy resources. The model primarily determines the quantity and total power supply of DG-PV (with and without storage), together with the given retail or export rate when this adoption would occur. BCG has applied this model throughout the United States, Europe, and Australia with high levels of success. The model helps develop perspectives from a customer-centric approach regarding compensation levels, and resulting amounts and timing of customer-sited energy resources.

The model was used to forecast future quantities of grid-supply up to the cap, self-supply quantities, and potential future DG-PV combined with the possibility of the adoption of customer-sited storage. The model was also used to evaluate the potential impact of grid defection.

The DG-PV Adoption Model examines the relationship between customer economics and technology adoption—net present value (NPV), internal rate of return (IRR), and payback time for adopting DG-PV with or without a storage system. The model optimizes the distributed energy resource system configuration to yield the highest NPV given technology costs, appropriate investment tax credits, and retail or time-of-use (TOU) and export rates. The model then applies optimum results to a regression-based relationship of previous DG-PV adoption to determine the number of future installs and the total sum of energy provided. This approach allows for distributed energy values to be optimized and forecasted based on customer logic and economics, then integrated into the system resource mix as an optimized resource. The model can also integrate explicit integration costs to fine-tune the customer adoption levels as necessary.

BCG is a global consultancy with 84 offices across 46 countries of the world with over 50 years of experience in the energy sector. BCG has successfully completed over 3,400 engagements across the energy value chain including over 1,400 engagements involving renewable and distributed energy resources.

BCG has been involved in the PSIP process since 2014 and is intimately familiar with the exceptional complexities surrounding Hawai‘i's energy markets. For the 2016 updated PSIPs, BCG performed customer economic and adoption modeling of DG-PV and energy storage systems to determine how to best forecast and optimize these components. This wealth of experience, coupled with local understanding, positions BCG as being uniquely suited to support the Companies craft a solution that optimizes DERs in Hawai‘i's energy future.

BCG worked with the Companies as well as Black &Veatch to develop the following assumptions that were used to develop DG-PV forecasts:

- Progression of technology costs for DG-PV technology from 2016–2045.
- Progression of technology costs for customer storage technology from 2016–2045.
- Future value of storage based on the Black & Veatch Adaptive Planning for Production Simulation model.
- Historical relationships for Hawai‘i, by island, between NPV, IRR, and payback time and levels of customer adoption for DG-PV.
- PV irradiance profiles for each island served.
- Current load and consumption profiles for each rate schedule.
- Current and addressable populations for DG-PV and customer storage.

The model then outputs the:

- Optimum NPV, IRR, and payback period for a given load profile, system configuration, rate schedule, and build year.
- Overall number of installed DG-PV systems and energy capacity through 2045 based on NPV and payback periods.

CUSTOMER ENERGY STORAGE SYSTEM ADOPTION MODEL

BCG's proprietary Customer Energy Storage System Adoption Model forecasts customer installations of storage. The model first calculates economics (including payback time) of customer-sited storage installed in a given year based on the total value of storage that it provides. Based on this payback, the model forecasts the percent of eligible customers that adopt storage systems. Eligible customers are assumed to be those who have yet to install a storage system. The correlation of payback to percent of eligible customers is based on the historical correlation of payback time for a DG-PV system and the percent of eligible customers that adopted DG-PV. Given a similar economic profile, a similar percent of customers adopt a storage system as have adopted historical DG-PV, mainly because the two investments are similar.

The model uses the following as inputs:

- Customer storage technology cost forecasts through 2045, including lithium-ion battery, balance-of-system, installation, and annual O&M costs.
- Customer storage technology performance forecasts through 2045, including energy capacity, power capacity, round-trip efficiency, and equipment life expectancy.
- The value of storage forecasts through 2045 based on Black & Veatch's model, including the value of various grid services that can be fulfilled by storage systems (including day-ahead load shift and time of use, FFR, and regulating reserve), while ensuring no double counting. The value is based on the avoided cost to the electric system for the grid services that the storage systems provide (as calculated by the Adaptive Planning for Production Simulation model).
- Historical payback time of DG-PV.

Using these inputs, the storage system adoption model first calculates customer economics for installing storage systems in a given year, and then forecasts customer adoption of storage systems based on the customer economics. The model then outputs the customer storage system adoption forecasts through 2045 (based on system-optimized compensation at avoided cost).

This modeling tool is suitable to calculate the system-optimal level of standalone storage systems to include in the PSIP planning process for two key reasons:

- It forecasts the amount of cost-effective standalone storage systems that could provide grid services.
- It forecasts customers adopting distributed energy resources by using actual historical correlations between customer payback time and adoption rate.

These forecasts are then used as input to the DR potential forecast and DR avoided cost modeling, which in turn generates DR amounts and load shapes that are included in overall system planning.

POWERSIMM PLANNER MODELING TOOL

The electric supply system with increasing amounts of variable generation has broad needs for flexible generation to manage increased daily ramps, greater regulation requirements, substantial amounts of energy storage—all of which require closer analysis. Uncertainties also include the physical dynamics of weather-driven renewable generation and load, uncertainty in adoption rate of DER, storage system capabilities and costs, and market prices of fuel and emissions.

Ascend Analytics uses its PowerSimm software to simulate future conditions to capture system operations at a more detailed level necessary to properly plan for a 100% renewable supply portfolio. Ascend's software models at the minute level, and employs stochastic programming to select the most robust resource plan to meet future needs.

Ascend analyzed converting the current generation fleet to firing LNG. Our analysis determines the optimal power supply resource mix. Ascend's PowerSimm software:

- Determines optimal expansion plan with consideration of costs, system reliability and flexibility, resource adequacy, and uncertainty of fuel prices, carbon, and meteorology impacting renewable generation and load.
- Provides a robust evaluation of the economic merits of combined-cycle (CC) units and internal combustion engines (ICEs) versus flexible storage for O‘ahu that captures the extrinsic value of each asset to provide flexible energy and ancillary services.
- Determines the change in costs and risks in costs for meeting PSIP portfolio emission constraints without LNG.
- Develops optimal unit retirements with consideration of costs, resource adequacy, and system flexibility needs.
- Develops a detailed economic evaluation of energy storage system relative to alternative supply from either fossil fuel or biomass resources.
- Evaluates the cost effectiveness of energy storage for regulating reserve using sub-hourly modeling.
- Determines the relative value of customer demand response.
- Determines regulation and contingent reserve requirements for each island served as a function of solar and wind.
- Determines the cost tradeoff between renewable curtailment and alternative actions of either cycling thermal generation or utilizing storage.

Ascend Analytics is a leading energy analytics software company that serves as the analytic infrastructure supporting portfolio management and planning decisions for a host of national utilities. Ascend provides analytic solutions that systematically capture and incorporate uncertainty into the decision making process. In addition, Ascend models physical system operations in greater details than other production cost modeling and planning software. In 2014, Ascend supported the nearly $1 billion acquisition of renewable hydro generation in a resource plan for NorthWestern Energy in Montana. The resource plan proceedings were conducted in the Montana Supreme Court Chambers with Ascend testifying and receiving the distinction of modeling "fully consistent with industry best practices" by the independent experts retained by the Commission to review Ascend's modeling.

PowerSimm Planner

Ascend Analytics completed analysis in 2015 that valued for Hawaiian Electric the conversion of its oil based generation fleet to LNG. Through this PowerSimm modeling analysis, Ascend proved the value of a structured framework that models uncertainty in key risk drivers including: weather, load, renewable generation, renewable penetration rates, and market fuel prices and carbon. Ascend plans to leverage these modeling capabilities of uncertainty combined with a more granular physical representation of Hawaiian Electric's power supply system at the minutely level. In addition, Ascend plans to expand upon the detailed modeling of minutely level system operations to determine the optimal power supply resource mix inclusive of uncertainty. The use of minutely dispatch operations also supports evaluation of system capabilities to meet dynamic ramps and maintain system frequency.

Ascend brings the unique capability to model system operations in greater physical detail over a broad spectrum of future operating conditions at a granular level of minutely dispatch. In addition, Ascend's capacity expansion logic integrates the more granular system modeling and uncertainty to pick the most robust supply plan to meet Hawaiian Electric's future needs over a broad spectrum of future simulated meteorological conditions and market prices.

Ascend has found that while deterministic runs with sensitivities provide insight into portfolio management decisions, the limited set of information of deterministic runs compared to probabilistically enveloping future states through Monte Carlo simulations can bias results. Furthermore, simulating future conditions with "meaningful uncertainty" can better articulate dimensions of risks for each of the future supply portfolios.

PowerSimm Planner's capacity expansion module determines optimal future supply portfolios by selecting the best supply portfolio over all simulated future conditions. This is a substantial improvement over other solutions that are limited to picking the best portfolio over a single deterministic run (and often with only load duration curve granularity). By determining the best portfolio over all future states, PowerSimm provides a more robust future supply portfolio.

Description of PowerSimm Planner

PowerSimm Planner provides optimal resource planning analysis that combines detailed system operations, including minutely level dispatch modeling, with simulations of the principal risk factors determining physical and financial uncertainty. PowerSimm Planner directly incorporates risk into to the resource selection process by finding the optimal expansion plan over a broad set of future simulated conditions to jointly minimize costs and risks. The selected optimal resource expansion plans provide distributions of costs where risk can be monetized as a direct cost; thus, enabling uncertainty to be valued in direct comparison of alternative expansion plans.

Underlying the risk based decision analysis framework of PowerSimm Planner are simulations of future conditions that rigorously realize the standard of "meaningful uncertainty". The realization of physical uncertainty begins with weather and then the resultant load and renewable generation levels. Financial uncertainty extends to commodity prices for fuel following market expectations of future prices uncertainty including episodic high and low price events. Carbon is also simulated based on ranges in forecast expectations of carbon prices.

System operations are measured down to minutely level generation and load with determination of ancillary service components of regulating reserves and contingent reserves as a function of renewable generation levels. The more granular dispatch conditions enable the physical system modeling to reflect actual system operations chronologically through time.

Recognizing the computational burden of the simulations, dispatch, and summary of results, Ascend utilizes a parallel distributed computing system: "The Ascend Cloud". This bank of computers supports resource planning analysis without compromising the modeling. The model inputs and outputs can be readily accessed through the Ascend Cloud.

PowerSimm Resource Selection

PowerSimm Planner performs optimal capacity expansion planning to determine the least cost and least risk resource options to meet future load. The optimal expansion plan analysis determines the least cost resource mix to meet a target reserve margin to maintain system reliability. Because utility planning involves a trade-off between long-term capital investment decisions and variable operating costs, the optimal expansion plan seeks to minimize the net present value (NPV) of future variable and fixed costs. To account for capital investment decisions not fully amortized over the 30 year planning horizon, the levelized cost for future resource options are used.

The expansion planning problem can be more formally stated as:

Minimize:	Portfolio costs = net PV power cost + fixed PV cost
Subject to:	Resource adequacy requirements
	RPS standards
	Regulation and contingent reserve requirements
	Thermal generation operating characteristics
	Battery storage operating characteristics and life cycles
Where:	Costs = net power costs + fixed costs
	Net power costs = fuel + variable O&M + emissions
	Fixed costs = fixed revenue requirement of portfolio in each year calculated from the financial model

The addition of new generation resources follows from both the requirement to ensure reliable generation supply and the economics of new generation.

While using deterministic runs with sensitivities provides insight into portfolio management decisions, this limited set of information biases results. This bias is not observed when realized through probabilistically enveloping future states through Monte Carlo simulations. Figure H-1 illustrates this effect by taking the expected value of Monte Carlo simulations shown in the solid black line that removes the bias of the orange line by depending on a limited set of future conditions. Furthermore, simulating future conditions with "meaningful uncertainty" better articulates some dimensions of risks for each of the proposed portfolios.

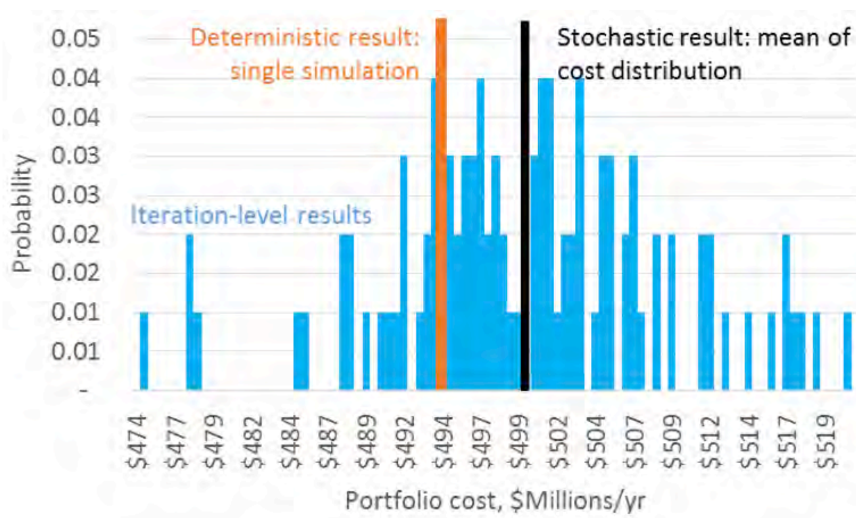

Figure H-1. Deterministic versus Stochastic Simulation Based Results

The use of Monte Carlo simulations can be combined with the Resource Selection module of PowerSimm Planner to systematize the resource selection process. PowerSimm's Resource Selection module automates the resource selection process of determining the optimal future supply portfolios. The methodology provides the best supply portfolio overall based on simulated future conditions. The ability to select the optimal portfolio over a broad spectrum of future conditions without loss of generation modeling details provides substantial advantages over picking the best portfolio from a single deterministic run. The optimization of future supply portfolio utilizes a stochastic dynamic program to minimize the net present value of costs over all simulations subject to a series of constraints, most notably, capacity. By determining the best portfolio overall future states, PowerSimm provides a more robust future supply portfolio.

For purposes of illustration, Ascend draws a sporting analogy for resource selection under uncertainty. Selection of an optimal resource portfolio over the first deterministic run is equivalent to finding the best swimmer (Michael Phelps) and the second run may be akin to the best cyclist (Chris Froom), and the third would be the best runner (Ryan Hall). In resource planning, we're not interested in the best athlete for any individual event, but the best athlete over all three events (Figure H-2). We want the best triathlete, the best resource portfolio over a broad set of future states. The portfolio may not be the best for any individual future run, however, the portfolio performs the best overall future states.

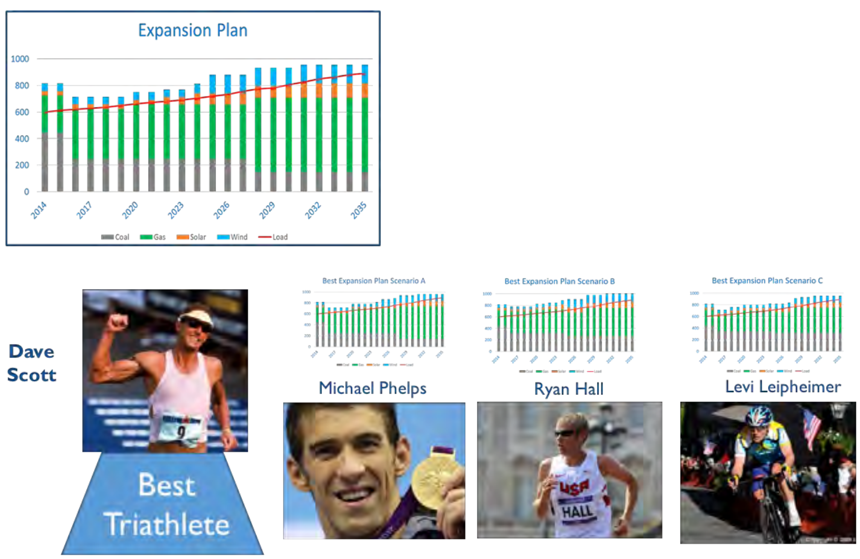

Figure H-2. Triathlete Analogy to Expansion Planning

By incorporating uncertainty into the expansion planning process, this analysis builds upon the concept of risk and simulations that produce "meaningful uncertainty". The challenge of incorporating uncertainty into capacity expansion planning is further met by the need to address the value of resource flexibility. The modeling requirements to account for resource flexibility require hourly simulations and modeling asset start-up and shut down costs and times and generation ramp rates. More flexible resources can quickly and cost effectively cycle—a core asset attribute to support the addition of more renewable generation. The addition of uncertainty and detailed hourly generation characteristics distinguishes the rigor of capacity expansion planning used in this analysis.

Comparison with Traditional Capacity Expansion Models

PowerSimm Planner includes many features unavailable or limited in traditional capacity expansion models for a number of modeling areas.

Physical generation asset operating characteristics (such as heat rate curves, ramp rates, min-up, min-down, and others. Traditional capacity expansion models have no ability to capture asset operating characteristics other than plant capacity. Integrated models dispatch generation consistent with the full set of plant operating constraints. By overlooking the physical constraints of asset operations, these models introduce potential biases and inconsistencies when selecting intermediate and peaking resources by not modeling asset flexibility.

Chronological relationship of load. Traditional capacity expansion models use load duration curves, which removes the hourly and daily pattern of load.

Chronological relationship to market prices. Traditional capacity expansion models use of price duration curves removes the hourly and daily pattern of market prices. Moreover, the structural relationship between system load and market prices are not maintained.

Imports and exports. Both models account for imports and exports, but the inability of traditional capacity expansion models to capture physical asset details introduces resource selection biases and inconsistencies. For example, a peaking unit may be designated as having the ability to provide exports when the start-up and shut-down costs or minimum run-times may make an off-system sale uneconomic.

Ancillary services. Traditional capacity expansion models do not have the ability to model ancillary services.

Simulation Framework

PowerSimm develops realistic simulations of future conditions to probabilistically envelope the expected value and range of potential future cases. Figure H-3 depicts the framework to simulate physical and financial uncertainty. The simulation of future conditions is initiated with before-delivery simulations of forward/forecast prices, which then evolve to the final monthly price expiration. Weather simulations then drive renewable generation and load. Spot prices are simulated as a function of load, renewable generation, and other potential variables of supply.

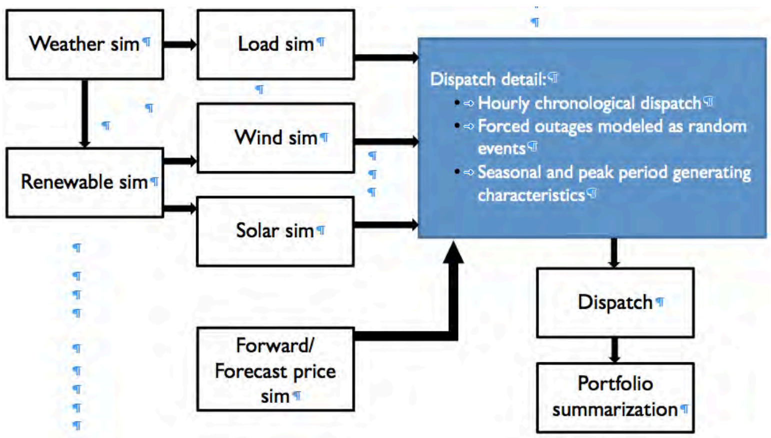

Figure H-3. PowerSimm Process Flow Diagram

The simulation framework of PowerSimm addresses uncertainty as viewed through today's market expectations (forward/forecast prices) and the future realized delivery conditions for load, spot prices, and generation.

Simulation of Commodity Prices and Physical Components

Simulation of electric system and customer loads follows from a common analytical structure that seeks to preserve the fundamental relationship between demand and price. The simulation process is divided into two separate components: before delivery and during delivery. The before-delivery simulation of forward/forecast prices evolves current expectations through time from the start date to the end of the simulation horizon. The simulations during delivery capture the relationship of physical system conditions (that is, weather, load, wind, solar, unit outages, and when applicable transmission). The inter-relationship between before-delivery and during-delivery simulations is central to linking expectations to realized observations.

For forward/forecast prices representing before-delivery simulations, monthly prices are evolved into the future from the current forward/forecast prices through expiration of each contract or forecast month. This process of evolving forward/forecast prices into the future draws on the observed behavior of forward contract variability and covariate relationships to create future monthly price projections. Within each before-delivery simulation, observed commodity prices behavior, volatility, rate of reversion, and covariate relationships across commodities drive price movements to ultimately arrive at a final evolved price at delivery. The average of these final evolved prices across all simulations for each monthly price equals the current forecast expectation of the price at delivery. Similarly, the average of the simulated electric spot prices for a given month equals the current forecast price for that month. Seasonal hydro conditions are also correlated with the simulated forward/forecast prices.

The during-delivery simulation process begins with simulation of weather. PowerSimm simulates weather using a cascading vector auto-regression approach across multiple locations. This approach maintains both the temporal and spatial correlations of weather patterns for the region. Ascend applies a cascading vector auto-regression approach to maintain inter-month temperature correlations consistent with the historical data. For example, if a hot July day is likely to be followed by another hot July day, the cascading vector auto-regression method captures this effect. The application of weather simulations supports the analysis of uncertainty through hundreds of weather cases without the limitation of the pure historical record where extreme weather events beyond observed conditions may occur (but with a low probability). The second step of the process combines these weather simulations with other factors in the load simulation process.

Load and Price Simulation

PowerSimm uses the weather simulations as well as forecasted input load values, scaling and shaping the simulated load shapes to match forecasted monthly demand and peak demand values. The simulations of electric load use a state-space modeling framework to estimate seasonal patterns, daily and hourly time series patterns, and the impact of weather. The state-space framework of PowerSimm produces results that reflect the explained effects of weather and time-series patterns and the unexplained components of uncertainty.

The during-delivery simulation of prices addresses the more intuitive simulations of system conditions and spot prices. System conditions of unit outages, supply stack composition, system imports and exports, and transmission outages are separated independent of weather but can also serve as determinants to the spot price of electricity.

LONG-TERM CASE DEVELOPMENT AND RESOLVE

Achieving a 100% RPS in 2045 would require dramatic changes in how energy is generated and used. Traditional resource planning has focused on matching the peak load and reliability needs of the system with thermal generating resources to maintain the quality of service. Planning with increasing levels of energy from variable renewable resources shifts the planning paradigm away from maintaining sufficient peak capacity towards determining the quantity and type of measures needed to integrate those resources at least cost. This requires both new planning tools and a broad perspective on how energy is produced and consumed, with the potential addition of transportation as a substantial new end-use to the electric sector.

Given the multi-decade lifetime of infrastructure built today, the decisions made now and in the near future have a potentially significant impact on the ability to meet the 100% RPS target in 2045 as well as the ultimate total cost of achieving this goal. However, the long timeline also means significant uncertainty exists about future technology costs and capabilities, fuel prices, and other factors that may have a major impact on the cost of the transition. The Hawaiian Electric Companies and Hawaiʻi have no control over such factors; these are the future conditions that are essentially inevitable on the islands. Understanding these factors and how they affect the cost effectiveness of investments made today is critical. Near-term decisions should be both consistent with the islands' long-term goals and robust against a range a future uncertainties. Another necessary step is therefore to identify the controllable decision levers available in formulating a robust, least regrets plan to best handle what happens in the future.

The difference between planning elements that happen to the islands served versus those that are decision levers is dependent on many complex and interacting factors. Global market prices for fuels and technologies, as well as technological innovation, fall into the first category. Others (such as battery procurement) can be directly decided by the Companies. But what about customer behavior, renewable resource portfolio diversity, or transportation infrastructure? These typically fall outside of the traditional Company planning cases, but can be influenced by tariff design and policy development. Identifying these factors early in the planning process, engaging stakeholders in a discourse around the policy issues, and arriving at a consensus about the policy directives is critical to create long-term policy certainty and thus enable effective planning.

Energy and Environmental Economics (E3) was retained to address these key questions. E3 has multiple contracts with the California State Agencies to support their long-term planning efforts to meet both RPS and greenhouse gas (GHG) reduction targets and were responsible for developing the four United States deep decarbonization cases used in the COP 21 process to help reach climate agreements in Paris, December of 2015. E3 also has a long history working with both the Hawai'i Public Utilities Commission and the Companies on energy issues in Hawai'i.

In this analysis, E3 first investigated what the least cost planning decisions for the Companies should be given current policy and economic trends on the islands to create a business-as-usual case. E3 then developed cases that satisfy potential policy directives to adapt to higher renewables. The cases account for the value of creating a portfolio with more diversity, more control of variable renewable resources, the evolution of the transportation sector to electric vehicles powered by hydrogen or synthetic natural gas, and flexible loads capable of responding to supply-side needs. E3 compared the costs of each of these cases and the decisions that need to be made to achieve them, forming the basis for discussion in a state policy decision process.

Case Development

Based on E3's prior work for the Companies exploring the operational impacts and integration requirements of higher renewable penetration levels on the islands, E3 also identified and included in their analysis several current trends with significant implications for the Companies' planning processes. These trends include:

- Low renewable portfolio diversity: high levels of customer adoption of DG-PV.
- Non-dispatchable renewable supply: limited utility control (via curtailment) over renewable generation.
- Load inflexibility: limited ability of loads to respond to supply conditions.

Figure H-4 illustrates how these trends might manifest themselves in a 100% renewable generation case.

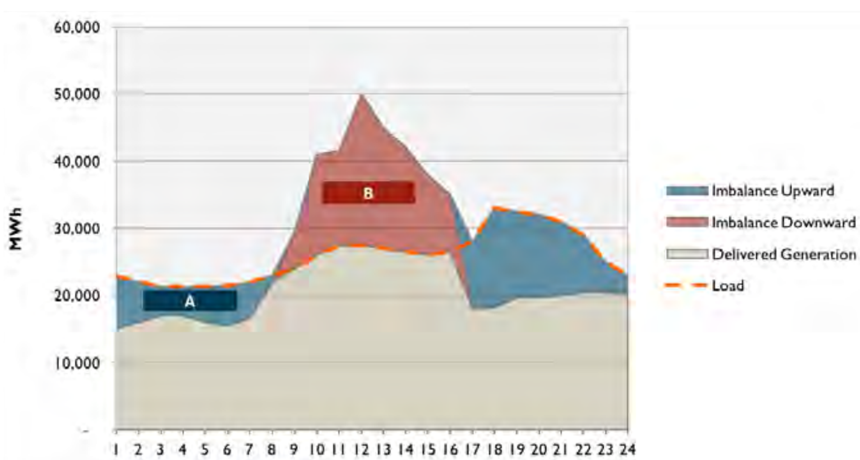

Figure H-4. Example Dispatch at 100% Renewables

In this case, the renewable portfolio consists of largely solar energy, so energy production is concentrated during the daylight hours. The load is assumed to be inflexible. The combination of these factors results in oversupply in the middle of the day (imbalance downward, B) and undersupply at night (imbalance upward, A). If the renewable generation were not curtailable, the consequence of the daytime oversupply would be an over-generation reliability event. The nighttime undersupply results in a traditional loss-of-load reliability event. Building storage to meet such imbalances is the approach that is often considered, but such storage requires substantial capital investment and is potentially unsuited to imbalances that may persist over a number of days, or even weeks or months. Renewable portfolio diversity to reduce the oversupply levels or the deployment of load controllability equipment may be more cost-effective integration alternatives. Incorporating the available alternatives into a single modeling framework is necessary to identify trade-offs and synergies among them, and optimally combine them.

E3 investigated a series of cases exploring potential futures in Hawai‘i to determine the planning solutions needed in each one. These cases are defined by the factors on the system described by the categories in Figure H-5. Within each of these categories, E3 investigated two or more different potential futures. Each case is defined by a set of assumptions describing customer behavior, renewable diversity, and transportation infrastructure, reflecting the decisions the Companies may have limited control over but may be impacted by state-level policy developments.

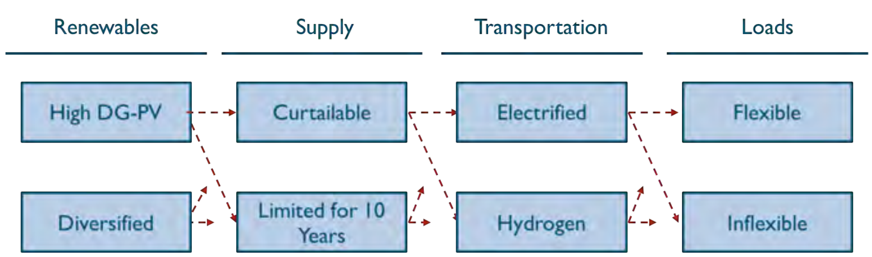

Figure H-5. Case Drivers of Potential Hawaiian Electric Futures

These cases explore the impact of the following policy decision points for Hawai‘i that depend on price and political drivers:

High consumer PV adoption versus diverse resource portfolio: E3 analyzed the differences among integration solution needs when consumer adoption of DG-PV is allowed to grow to high levels compared to a more diverse portfolio of resources.

Curtailment of supply: E3 explored the impact on resource plans of whether the Companies have full control over curtailing new generation resources, compared to a case where contracts or technological constraints limit the curtailment capability for some time.

Low-carbon economy transition: To decarbonize the entire economy of Hawai‘i, either fossil-fueled services (such as transportation) must be electrified and served by clean electric generation, or a transition must be made to using gas (such as hydrogen or synthetic methane) as an energy carrier. E3 considered both load electrification and gas (hydrogen or synthetic natural gas) transition cases. Under the gas transition case, gas is produced on the island and functions as a controllable load with a daily consumption requirement. Conversely, in the base electrification case, E3 used electric loads (including EVs) to balance renewable generation. Previous work has shown that electrification does not provide the same flexibility as the gas generation path but could ultimately be a less expensive path for decarbonizing Hawai‘i.

Load participation: Increasing levels of efficiency and substantial growth in flexible loads are a cornerstone of most long-term high RPS cases E3 has studied so far. The levels of flexible loads are partially dependent on tariff design, market development, technological capabilities and pricing for distributed generation technologies. The cases explore the amounts and types of flexible loads needed to substantially mitigate integration challenges.

The simple matrix (shown in Figure H-5) leads to eight Cases that E3 described, provided input data for, and modeled. The matrix is not meant to be an exhaustive list of all key drivers or decarbonization paths, but is an attempt to develop a workable number of cases suitable to explore initial analysis and stakeholder discussion. The number of cases can be expanded to include other critical elements or additional sensitivities based on initial results as well as feedback from either the Commission or key stakeholders. For each case, E3 also explored sensitivities to the uncertainty around market fuel and technology pricing.

Modeling Approach

Developing Case Data

Variable renewable energy poses challenges to traditional electricity sector planning and procurement as well as day-to-day reliable operations of the grid. Analyses of these challenges generally focus on near-term issues related to supply-side flexibility. These challenges can often be solved within traditional paradigms of supply-side dispatch. However, such a focus may ignore the broader context and longer-term challenges and opportunities presented by transitioning away from imported energy, not just of the electric sector, but for the energy system more broadly. For instance, a large transformation in transportation away from internal combustion engines has major implications for the electricity sector that need to be factored into long-term energy planning. E3 has drawn on its work in developing deep decarbonization paths for both California[2] and the United States[3] to develop multiple paths and a strategic vision for transforming Hawai‘i’s energy future. Combinations of the case drivers shown in Figure H-5 form each of the cases investigated. Case development consisted of the following three tasks.

Task 1. Demand Case Development. As the first step in developing the vision for the electric sector under a 100% renewable penetration, E3 focused on the potential for other energy system choices to impact the electricity sector. This focused on new electric loads from:

- Direct transportation electrification (that is, electric vehicles)
- Building electrification
- Electric fuel production: hydrogen electrolysis and power-to-gas synthetic natural gas

These new loads affect the load shapes of the electric sector, the overall demand for electricity, and the potential supply portfolios that can meet their demand. This is a very important context for the electricity sector, not just for the challenges that these new loads pose, but for the opportunities they present. This is a first-cut, case analysis to assess the scale of these potential impacts. E3 developed energy transformation case demand forecasts based on previous work developing deep decarbonization paths for California and the U.S. These focused on key choices in the transportation sector and buildings:

- Light duty vehicles
- Heavy-duty vehicles
- Buses
- Thermal end-uses (water and space heating)

E3 utilized all available data for Hawai‘i to develop a realistic assessment of future electricity demand from activities in these sectors.

Task 2. Renewable Portfolio Development. In this task, E3 developed prospective renewable portfolios for supplying levels of overall electricity demand developed in Task 1. The first portfolio is composed of reference renewable supply assumptions, with high levels of DG-PV. Additional portfolios are based on existing renewable energy potential data and reflect policy direction to procure the best prospective portfolios to minimize supply and demand imbalances (that is, 100% solar would exacerbate supply and demand imbalances) versus cost and development potential constraints. The level that a

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[2] https://ethree.com/public_projects/energy_principals_study.php.

[3] http://unsdsn.org/wp-content/uploads/2014/09/US_DDPP_Report_Final.pdf.

resource can be curtailed is also factored into the portfolios to reflect potential transition times to the Companies' full control of the renewable fleet, including DG-PV systems.

Task 3. Load Development. E3 first assessed the flexibility from the new loads detailed in Task 1. Many of these loads come associated with storage, which allows them to mitigate their demands on the electricity sector. For example, a car battery connected to the grid offers the ability to delay or advance its charging needs based on its inherent chemical storage capacity. End-uses in buildings offer thermal storage to perform activities like pre-cooling and pre-heating to manage loads with regards to supply conditions. Electric fuel production may be the most flexible of all, taking advantage of existing gas infrastructure or hydrogen storage to flexibly operate plants during periods of over generation.

E3 also examined permanent load shaping. Here, targeted energy efficiency can reduce loads during times of the day where consistent supply deficits occur. For example, aggressive lighting efficiency can reduce nighttime load in a high-solar case, increasing the coincidence of demand and supply. Permanent load shifting could provide pre-cooling opportunities at mid-day to reduce nighttime cooling loads.

Developing Optimal Resource Portfolios for Each Case

For each case and selected fuel price and capital cost sensitivities, E3 used its investment model RESOLVE to develop optimal resource portfolios for meeting the RPS targets. (RESOLVE is an optimization tool that selects a least cost portfolio of renewable resources and integration solutions over a chosen time horizon. E3 built it for the California State Agencies to study cost-effective integration solutions including demand response and a range of storage technologies, and to determine the value of regional integration in mitigating renewable integration costs.)

Price sensitivities are developed under each of the cases to include plausible future market price trajectories for both fuel and capital investments.

A number of factors influence the cost effectiveness of a conversion of oil-fueled generation to LNG, including capital expenditures necessary for the conversion, oil and LNG price trends and spreads, and quantity of energy generated by the converted plants. The payback of thermal capital investments also depends on the expected energy demand, which is influenced by renewable energy production and energy use patterns.

The optimal resource mix depends in part on the price trajectory of energy storage technologies. E3 does not have confidence that an accurate prediction of energy storage technology price can be made out to 2045. Therefore, E3 considered several price trajectories to evaluate the expected price impact on the resource mix.

Figure H-6 shows the conceptual effects of uncertain storage pricing.

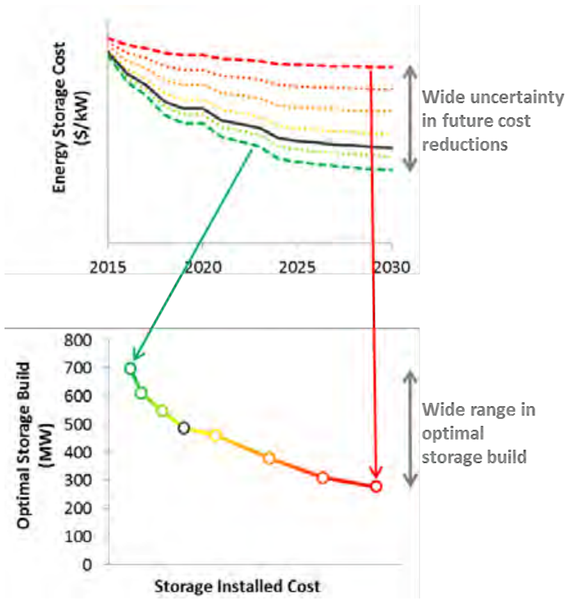


Figure H-6. Conceptual Effect of Storage Price Sensitivity

Beyond energy storage, a broad suite of integration solutions was employed to meet the RPS targets (Table H-1). The applicability of many of these strategies relies on decisions made outside the electricity sector itself (for example, EV penetration determines the availability of EV load to manage imbalances).

Resource	Balancing Direction	Balancing Timeframe	Resource Potential
Flexible building thermal loads	Both	Seconds to hours	Depends on electrified thermal end-uses, controllable equipment, and customer participation.
EV charging management	Both	Seconds to hours	Depends on available public and private infrastructure as well as overall electric vehicle penetration.
Hydrogen electrolysis	Both	Seconds to weeks	Depends on demand for hydrogen in other sectors (primarily transportation).
Power-to-gas synthetic natural gas	Both	Seconds to months	Depends on demand for gas and available gas storage facilities.
Targeted energy efficiency	Upward	Hours	Depends on end-use electricity demands .
Permanent load shaping	Both	Hours	Depends on building loads and customer incentives.
Battery storage	Both	Seconds to days	Effective balancing, but at high capital cost and efficiency penalty.
Pumped storage hydro	Both	Seconds to months	Depends on site availability.
Flexible renewable generation	Upward	Minutes to days	Depends on available renewable fuels (geothermal).
Flexible thermal generation	Both	Seconds to hours	Depends on price of available fossil fuels.
Curtailment	Downward	—	Depends on controllability of renewable resources.
Inter-island transmission	Both	Seconds to hours	Balancing benefits depend on the complementarity of load and renewables being connected.

Table H-1. System Balancing Options

How these balancing solutions are implemented in the context of a low-carbon electricity grid is shown in an example from the U.S. deep decarbonization paths analysis (Figure H-7). This chart shows the Western Interconnection in a high renewables case during a week in March. In this case, high penetrations of renewable generation necessitate the dispatch of flexible fuel production, battery storage, flexible building loads, and EV charging in order to effectively manage periods of over- and under-supply. Those loads are available for dispatch because of the electrification of transportation under this case. As control over energy supply is reduced, participation from other resources-like loads are a critical element for maintaining a low-cost, reliable electricity grid.

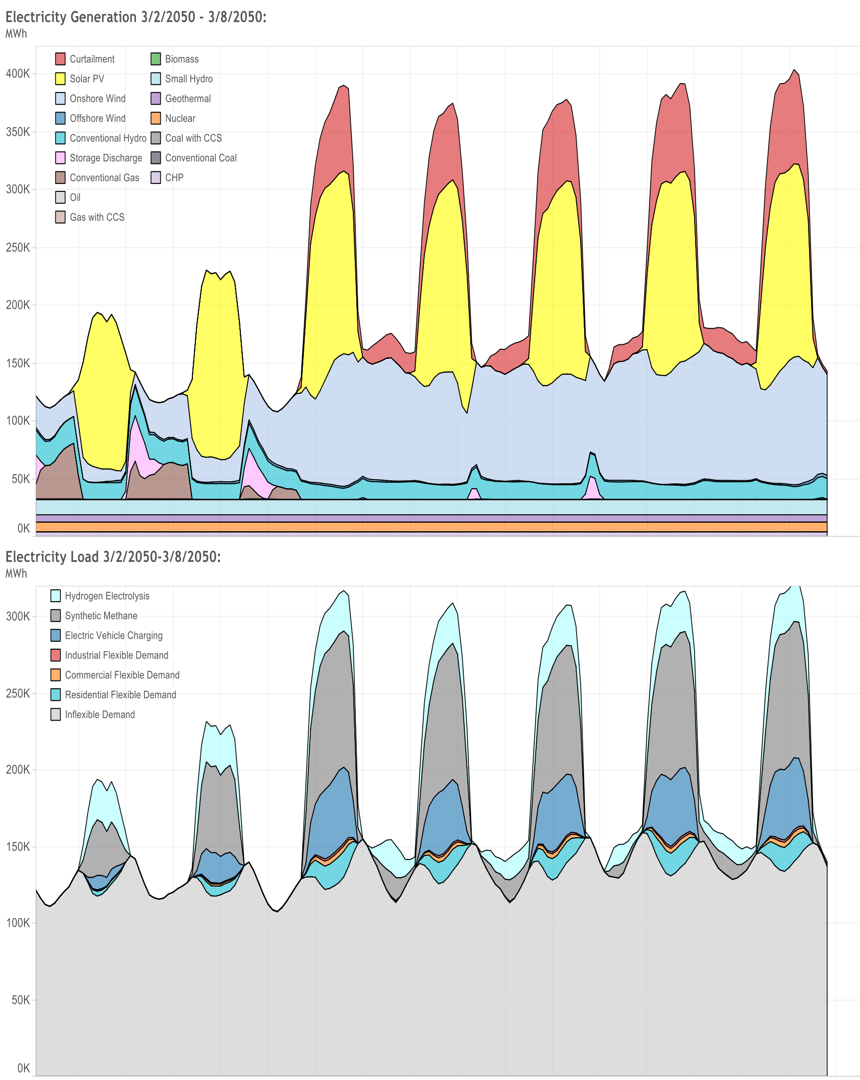


Figure H-7. Dispatch at 100% Renewables: Supply (top) and Demand (bottom)

Economic Selection of Optimal Renewable Integration Solutions using RESOLVE

Planning the development of a 100% RPS compliant electric energy system presents a number of challenges. The plan must choose a portfolio of varied resources that work in concert to reliably meet consumer electricity demand while accommodating the variability of renewable energy resources. Every hour of the planning horizon, the system must satisfy several operational constraints including reliability needs, for example generator minimum generating levels, ramping constraints, contractual obligations, and reserve requirements. Figure H-8 shows a hypothetical day when generating resources must operate to meet the following constraints:

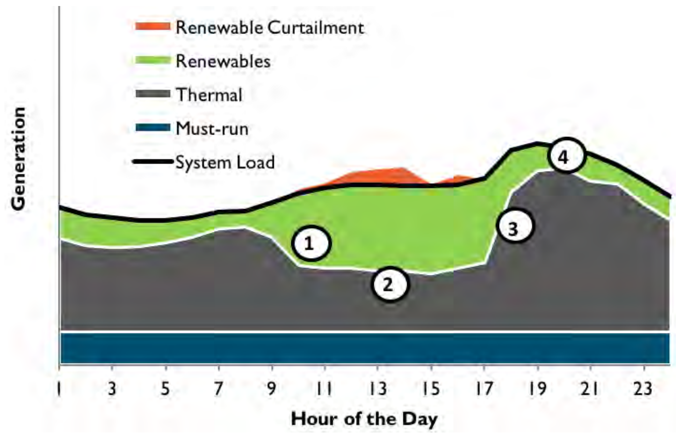


Figure H-8. Renewable Integration Challenges

Key to Figure H-8 numbers:

1. Downward ramping capability: ramp capability must be available to meet morning ramps as solar production increases and the net load drops.
2. Minimum generation: resources must be capable of lowering their output sufficiently, either by turning off generation, or ramping down output, such that low midday net loads are balanced while reliability requirements are still met.
3. Upward ramping capability: ramp capability must be available to meet capacity needs as solar production falls in the evening.
4. Peaking capability: peak loads must be met, often after solar generation has dropped off.

There are many different combinations of resources that can be included in the resource portfolio to meet reliability needs, so determining the least cost portfolio must be done through an optimization framework. Figure H-9 shows the resource mix under three hypothetical renewable integration strategies.

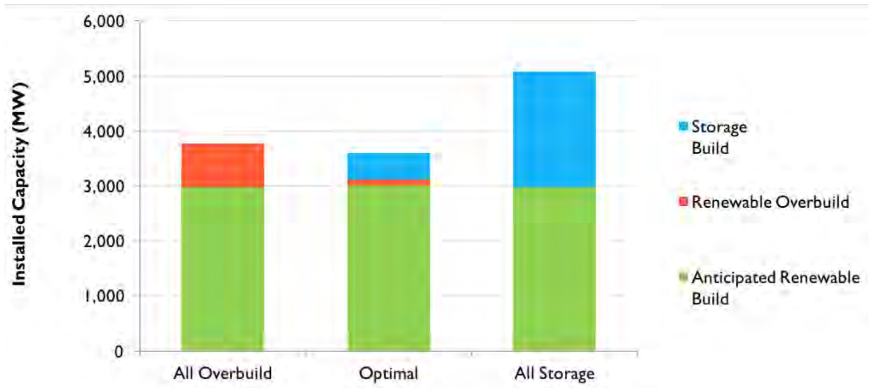


Figure H-9. Hypothetical Renewable Integration Strategies

The lowest cost portfolio of renewables and integration solutions at any point in time is a mix of resources that minimizes both operating costs and capacity expenditures over the planning horizon. The value of each integration solution changes over time depending on the evolving needs of the system. Those selected in an optimal resource portfolio offer the greatest net value over their lifetime in combination with the other resources selected. Some technologies may be stepping stones to longer term portfolios. In addition, a robust analysis incorporates the costs of the enabling technologies on the grid (for example, interconnection, control systems).

Figure H-10 depicts an optimal tradeoff between renewable overbuilding and other integration solutions. The optimal point for each resource is where the benefit of the marginal unit of any resource to the system is equal to its marginal cost. In reality, each type of resource adds a dimension to the optimization; each combination of resources has complex operational interactions. Finding the least cost solution requires a sophisticated optimization model that treats operational and investment costs while satisfying operational and reliability constraints.

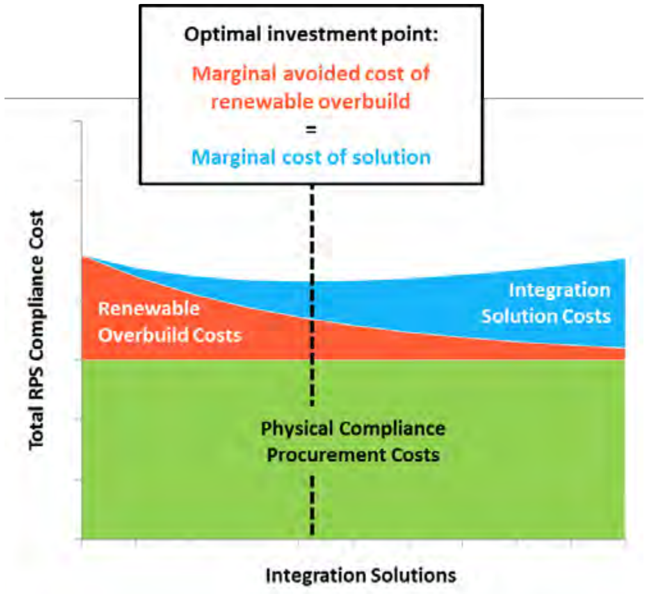


Figure H-10. Tradeoff Curve Between Integration Strategies

The optimal resource mix depends on a number of assumptions about the future state of the world. An optimal resource plan should be robust to uncertain future trajectories of fuel prices, technology costs, and consumer adoption of DER.

For each case investigated in the analysis, E3 used its RESOLVE model to optimize resource portfolios over a planning horizon out to 2045. RESOLVE builds on the REFLEX advanced production simulation model to optimize investment decisions subject to detailed hourly operational constraints including reserve requirements, ramping limitations, and unit-commitment constraints. Using its demonstrated methodology, Ascend Analytics is determining the electric power system's operating and contingency reserve requirements on an annual basis. These reserve requirements serve as input data for RESOLVE, which then determines an optimal resource plan that adjusts the portfolio of resources on an annual basis. RESOLVE selects the optimal portfolio of resources to be installed in each year, choosing from generation retrofits, battery energy storage, demand management, thermal generation, and renewable generation. The solution found by RESOLVE co-optimizes investment and operational costs.

E3 is developing long-term strategic options for the electric sector under high penetrations of renewable energy. Over the full planning horizon and considering the uncertainties involved, E3 is identifying near-term least regrets planning decisions.

PLEXOS FOR POWER SYSTEMS

PLEXOS® provides a platform for economic analyses of energy systems that co-optimizes the contributions from energy, ancillary services, fuels, emissions, water resources, and transmission systems from sub-hourly chronological scheduling to analyze long-term planning. The model datasets for the islands are developed from reference case assumptions provided by the Companies. PLEXOS provides detailed modeling of the generation resources, including thermal, wind, solar PV, battery storage, demand response, distributed energy resources, hydroelectric, and pumped-storage hydro in these data sets. Energy Exemplar provides output from the island data sets for benchmarking with existing models used by the Companies.

Energy Exemplar contributes data in capacity expansion plans for all five islands served combined with economic analyses of those expansion plans. The expansion plans are produced under several cases.

The Energy Exemplar project team are highly trained and experienced in implementing PLEXOS models and the economic analysis of power systems. The PLEXOS modeling approach implements its models as physical systems with economic and financial impacts. The model uses engineering inputs for generation resources, resulting in operational and financial outputs that depend on forecasts of market conditions (such as fuel prices and contract positions for the scarce resources that power the various assets). PLEXOS is reliable simulation software using state-of-the-art mathematical optimization combined with the latest data handling. Combined with visualization and distributed computing methods, the model provides a high-performance, robust simulation system for electric power that is leading edge, open, and transparent. PLEXOS meets the demands of energy market participants, system planners, investors, regulators, consultants, and analysts with a comprehensive range of features seamlessly integrating electric, water, gas, and heat production, transportation and demand over simulated timeframes from minutes to decades. PLEXOS is one of the fastest, most sophisticated, most cost-effective software available for performing the analyses required to develop the 2016 updated PSIPs.

PLEXOS is reliable simulation software that uses state-of-the-art mathematical optimization, combined with the latest data handling, visualization, and distributed computing methods, to provide a high-performance, robust simulation system for electric power, water and gas. Its processing is open and transparent. PLEXOS meets the demands of energy market participants, system planners, investors, regulators, consultants, and analysts with a comprehensive range of features. The model seamlessly integrates electric, water, gas, and heat production; transportation; and demand over simulated timeframes from minutes to decades—all delivered through a common simulation engine with easy-to-use interface and integrated data platform. PLEXOS is one of the fastest and most sophisticated software available today for the task at hand, and also the most cost-effective.

Energy Exemplar developed PLEXOS datasets to model generation resources for Oʻahu, Hawaiʻi Island, Maui, Lanaʻi, and Molokaʻi. Each island model implements two modeling approaches:

- Unit commitment and economic dispatch to evaluate the economics of the generation system (including energy and ancillary services).
- Capacity expansion modeling for portfolio optimization and RPS modeling.

The analysis includes evaluating DR programs, existing economic fleet retirement, expansion to satisfy RPS targets (including renewable and traditional resources), expansion, and economic modeling of battery storage devices. This tool also develops sub-hourly models to capture the benefits conveyed by flexible resources, especially in a resource mix that includes high variable renewable penetration.

HOW MODELS WERE USED IN OUR ANALYSIS

The AP for Production Simulation, DG-PV Adoption, Customer Energy Storage System, PowerSimm Planner, RESOLVE, and PLEXOS for Power System models were all used to support our analysis for the 2016 updated PSIPs. An explanation of how each was used follows.

AP for Production Simulation

Black & Veatch provided DR portfolio evaluations to support the current PSIP effort. Our analyses supported three interrelated aspects of the PSIP by providing:

- System avoided cost value to support customer battery resource build-out analysis.
- Ability of the DR portfolio to meet the needs of the generating and transmission system.
- Maximum MW by year, by program for determining DR program costs.

These analyses required full production simulation modeling of the generating system including gross demand, centralized firm and variable generation assets, PPA contract obligations, security requirements, DER volumes, and DR products.

System avoided cost value for customer battery resource build-out focused on the value that customer batteries could provide by better utilizing non-firm renewable generation resources (that is, reducing wind or solar curtailment) and provided value by ensuring that the build-out assumptions were rooted in the needs of the generating system. The value was determined by taking the difference between the system cost with and without an estimated battery build-out. The analysis considered the ability of the customer battery to load shift to best avoid curtailment and provide spin equivalent.

The ability of the DR portfolio to meet system needs was determined by modeling the system with the DR portfolio and associated customer batteries. The available DR portfolio, excluding customer batteries, was defined in a separate Potential Study that characterized the end uses available on each island by their ability to provide the various DR products (FFR, RR, RTP, and so on). The build-out of customer batteries was defined subsequent to the step described above. The DR and customer batteries were allowed to respond to system energy and security needs in conjunction with the central assets available for each case evaluated.

The following results were compiled and provided to other modeling teams:

- Material adjustments to the resource plan.
- Effective impact on the system load shape, by hour.
- Ability to provide effective spin, by hour.

Using this method ensured that the PSIP DR evaluation was consistent with the analysis performed to support the 2015 DR filing. It also ensured that all modeling teams utilized the same DR profiles.

Based on the above analysis, the maximum MW by year associated with each DR product and customer class was provided to the Companies to support the development of a bottoms-up estimate of the cost to implement DR.

DG-PV Adoption Model

The DG-PV Adoption Model was used to address Observation and Concern #3, and focused on DER Integration.

The model was a key tool in the DER iterative cycle as part of the PSIP Decision Framework. The model forecasted market DG-PV customer adoption amounts for self-supply, grid-supply up to a cap, and potential future DG-PV products while also considering related integration costs. The model forecasted DG-PV customer adoption amounts optimized for the electric system.

In the future, the model can be used to fine-tune the DG PV forecasts as technology costs, tax credits, grid service compensation rates, retail rates or other underlying assumptions change.

Customer Energy Storage System Model

The Customer Energy Storage System Adoption Model was used to address Observation and Concern #6; it focused on ancillary services, in particular the services that can be provided by distributed storage systems through the proposed DR programs.

The model was a key tool in the DER and DR iterative cycles as part of the PSIP Decision Framework. The model forecasted customer adoption of distributed storage when compensated at avoided cost for providing grid services through the proposed DR programs.

In the future the model can be used to fine-tune distributed storage forecasts as technology costs, tax credits, value of storage figures, or other underlying assumptions change.

PowerSimm Planner

Ascend's PowerSimm modeling tool was used to evaluate costs associated with renewable expansion plans. By optimizing dispatch according to unit characteristics, forecasted fuel prices, load, and renewables; the expected costs associated to each plan can be measured and accounted for. In addition, by introducing stochastic simulations into the modeling framework, PowerSimm is able to output a realistic range of possible future costs for each portfolio. By summarizing the range of costs through a risk premium, the Companies can directly compare the merits of trading off expected costs for higher risk.

In addition to cost and risk, Ascend's PowerSimm software is also able to measure dumped energy in every renewable expansion plan. These results are used to determine the amount of load-shifting battery storage required, and to calculate the cost of this storage. PowerSimm is able to model the effect of adding this storage to the portfolio, so this process of measuring dump energy and calculating storage costs can be repeated. By running multiple studies for a given expansion plan with varying levels of battery storage, we are able to hone in on a level of battery storage that strikes the right balance between minimizing costs and minimizing dump energy.

The Ascend regulation tool is an interactive modelling tool that can be used to estimate one-hour ramps and regulation for a variety of fixed scenarios for daytime and nighttime requirements. Behind the scenes, an analysis script runs a large number of scenarios where it scales historical minutely data to forecasted load wind and solar capacities. The regulation tool allows you to query the output of these runs interactively. Users are given the option to choose a base or high DG-PV forecast, the year, solar adders, that adds capacity to utility solar baseline forecasts, and wind adders, similar to solar adders. Regulation and ramp statistics are also shown for the strategic and aggressive strategies for the selected year, and are partitioned by daytime and nighttime. Graphs of regulation and ramps are also included for each of the three themes, and a historic window allows scrolling through time, showing two consecutive days of load, utility solar, wind, DG-PV, net load, load-following, regulation, and regulation requirements.

The one-hour ramp statistic is calculated as the difference between the net load at a given time and the net load exactly one hour prior to that time. The maximum ramp for each year is reported both for the daytime and nighttime. Regulation is calculated as the difference between net load and load-following, where net load is load (solar and wind) and load-following is a linear interpolation of net load through minute 0 of each hour. Regulation is then separated into regulation-up (regulation > 0) and regulation-down (regulation < 0) to remove bias from 0 regulation calculated at minute 0 of each hour. The 95th percentile of regulation-up and the negative of the 5th percentile of regulation-down are then averaged together to form the regulation requirement. These one-sided confidence bounds combine to form a 95% confidence interval for regulation, without including the zero regulation calculated at minute zero of each hour.

RESOLVE

E3 assessed the long term plan for Oahu.

The E3 analysis determined how the decisions to build out the system might change depending on the policy direction Hawai‘i takes in the future to meet their RPS goals, and how the uncertainty surrounding pricing of fuels and technology affect those decisions.

The long term focus of the E3 scope emphasizes investigation of the large scale changes in Hawai‘i energy policy over the time horizon to 2045 rather than the near term detailed modeling of system operations. The result is an evaluation of several different policy ‘futures’ under uncertain cost trajectories for technologies and fuels. This framework is the basis for evaluating long-term policy pathways in Hawai‘i that may be expanded in the future to include greater detail on the input assumptions and definition of additional cases to be investigated.

The core of the analysis is several cases that represent different policy directions in Hawai‘i. Each of these cases is a potential set of future system conditions that can be targeted by development of policy in Hawai‘i. These represent controllable decision levers available to Hawai‘i in formulating a robust, least regrets plan to best handle what happens in the future. A least regrets plan has to be robust against aspects that Hawai‘i has no control over. These include external forces such as global commodity prices and future technology pricing.

PLEXOS for Power System

PLEXOS for Power Systems models many features of the power systems on O‘ahu, Maui, Hawai‘i, Lana‘i, and Moloka‘i. PLEXOS optimizes the 30-year expansion plan for these islands subject to RPS. PLEXOS also simulates 30-years of hourly system operation, including the co-optimization of energy and ancillary services subject to fuel limits, renewable portfolio standards, the availability of storage devices, the curtailment (or not) of renewable resources, the typical operation of existing resources, and many other limitations.

PLEXOS models the variety of expansion themes that are addressed in the PSIP analysis plan. This allows for an economic analysis of the various approaches and also a view of how each island’s power system would operate in the context of several expansion strategies. PLEXOS provides the ability to model both the long-term operation of these systems and the very detailed operations of the system to a degree that is unique amongst simulation models in this area.

PLEXOS is also used for the development of optimal storage capacity sizing. In this situation, the sub-hourly capabilities of PLEXOS are particularly important to understanding the economic value of storage capability.

FINANCIAL FORECAST AND RATE IMPACT MODEL

PA Consulting Energy and Utilities team developed the Financial Forecast and Rate Impact Model specifically for modeling the impacts of key metrics (such as revenue requirements, rates, and average customer bills) for the Updated PSIPs. The model's design reflects important and unique characteristics of the Companies' business: timing and frequency of rate cases, revenue adjustment mechanisms (RAM), maintenance of the target capital structure, and customer usage and bill composition. PA Consulting initially developed this financial model for the 2014 PSIPs. Since then, the model has been refined and updated to reflect the most current conditions, including recent regulatory changes to the RAM.

The model comprises a comprehensive and interconnected set of detailed modules, each representing a key aspect of the company's financial framework. These modules calculate average customer bills, income statements, cash flow statement, and balance sheets. Additional modules, in turn, calculate detailed schedules of annual capital expenditures, and annual debt and equity issuances.

The model's foundation uses the PSIP case variables to build a range of company financial data, including:

- Annual reports (income statements, cash flow statements, and balance sheets)
- Schedules of existing debt
- Operation and maintenance (O&M) expenses not covered by the PSIPs
- Annual capital expenditures not directly covered by the PSIP cases (transmission, distribution, and other general expenditures)
- Rate structures
- Projections of customer count and average usage
- Sales forecasts
- Most recent net plant values for all generation units

The Financial Forecast & Rate Impact Model requires two key inputs for each PSIP case—production costs (such as fuel prices, power purchase agreements (PPAs), variable and fixed O&M expenses) and incremental capital expenditures. From this input, the model automatically updates all modules to reflect the resultant financial impact on each PSIP case. These financial impacts—pass-through of fuel and PPA costs, application of the appropriate RAM and surcharges for the capital expenditures, updated rate case calculations, and revised debt and equity issuances—lead to updated revenue requirements, rates, and average bill values.

PA Consulting Group's Energy and Utilities team is uniquely qualified to create and implement this financial model. The team has extensive experience in utility accounting, complex financial modeling, and support of rate cases and other regulatory filings.

Several Modules Comprise the Modeling Tool

PA Consulting Group's Energy and Utilities team updated and refined this model that was specifically created to perform financial analysis for the Companies' PSIPs.

The Financial Forecast and Rate Impact Model is comprised of several modules (Figure H-11). The model also includes a discussion that contains the inputs feeding into the calculation modules, and a dashboard that captures all the major outputs from the various modules.

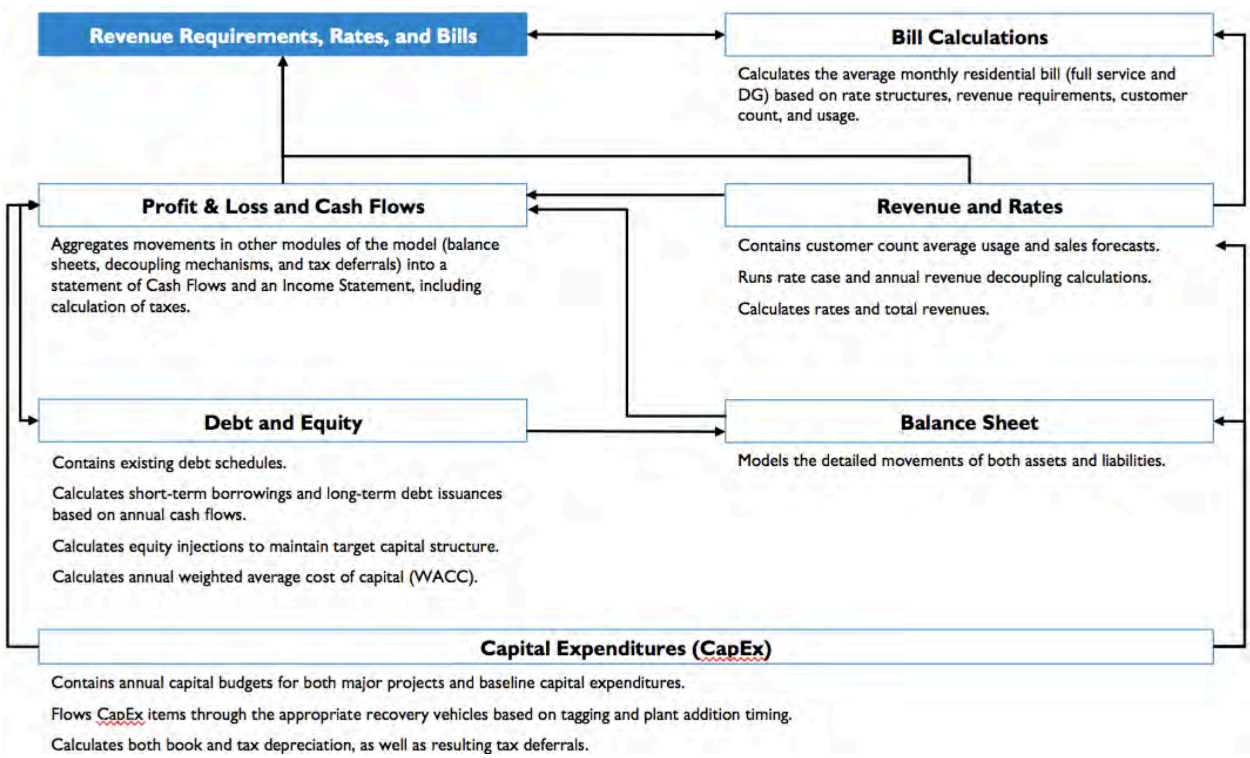


Figure H-11. High-Level Module Structure of the Financial Forecast and Rate Impact Model

Bill Calculations

This module calculates the average monthly bill for full service and DG residential customers. It:

- Calculates average bills under both current rate structures and the proposed DG 2.0 framework, with fixed rates calculated for both cases.

- Bases the bill calculations on forecasts of annual number of DG customers and usage, production, and export for an average DG customer.

Profit & Loss and Cash Flow

This module primarily aggregates movements from other modules of the model (for example, balance sheet, decoupling mechanisms, and tax deferrals) into a statement of Cash Flows and an Income Statement.

For the statement of Cash Flows:

- Produces detailed schedules of operating, investment, and financing cash flows.
- For operating cash flow, key inputs from other modules include depreciation, change in tax deferrals, change in regulatory assets, and change in accounts receivable and accounts payable.
- Investment cash flow is driven by capital expenditures, which are calculated and picked up from the CapEx module.
- Financing cash flow is driven by the base dividend payments calculated from Net Income in the Income Statement, combined with the debt and equity issuances, and additional dividend payments calculated in the Debt and Equity module.

For the Income Statement:

- Key movements picked up from other modules include Total Revenues, Revenue Balancing Adjustment (RBA), depreciation, and interest expenses.
- Fuel, PPA, and variable and fixed production O&M costs come directly from the PSIP production simulation input, while the remaining O&M items are escalated annually by inflation, adjusted for any specific project-related savings or cost increases.
- Income and revenue taxes are calculated directly, with tax deferrals added from the CapEx module.

Revenue and Rates

This module contains various calculations that add up to a total annual revenue requirement:

- Periodic rate case calculations, with both a calculation of allowed return in order to adjust rates, and a calculation of net allowed revenue for RBA adjustments.
- Detailed RAM and RBA calculations, which reflect the most recent adjustments to the RAM.
- Mark-up of fuel and PPA costs by the revenue tax adjustment factor, to allow pass-through in rates.

- Calculation of total effective rates, by summarizing and adding up the different rate components contributed by RAM, RBA, other surcharges, rate case adjustments, and fuel and PPA pass-through.
- Calculation of total annual revenues, by multiplying the total effective rate with the total forecasted sales provided by (and used in) the PSIP production simulation.

Debt and Equity

This module calculates short-term borrowing, long-term debt issuance, equity injections, and additional dividend payouts:

- Based on an objective to maintain a minimum ending cash balance, short-term borrowing, and long-term debt are used to cover any shortfalls from the net cash flow before financing. Short-term borrowing is exhausted first, with any remaining shortfall covered by long-term debt.
- Upon issuance of debt, equity injections are calculated (if necessary) to maintain the target capital structure.
- Interest expense on new debt is calculated, with short-term borrowings carrying full interest expense in the year of issuance, and long-term debt carrying half a year's interest expenses in the year of issuance, and a full year of interest expense starting in the year following issuance.
- In years with equity over the target ratio, the model calculates additional dividend payments to achieve target capital structure.
- The weighted average cost of capital by year is calculated based on currently-authorized equity returns and forecasted debt rates using the target capital structure.

Balance Sheet

The module presents detailed annual assets movements, including:

- Utility Plant in Service, Accumulated Depreciation, and Construction Work in Progress, driven by annual changes of these items in the CapEx module.
- Annual change in Customer Accounts Receivables are based on annual relative change in Total Revenues.

Also presents detailed annual liabilities movements, including:

- Common Stock and debt balances are driven by calculations in the Debt and Equity module
- Any increase in Retained Earnings is net of any additional dividends paid out as part of the optimization of the capital structure.

- Accounts Payable adjusted annually based on average relative annual change in capital expenditures, fuel, and PPA costs.

For both assets and liabilities, all items that are not explicitly driven by calculations in other parts of the model are kept constant.

Capital Expenditures (CapEx)

This module contains detailed annual capital budgets, and calculations of surcharges, securitization (if applicable), and depreciation (book and tax). The module:

- Details capital expenditures and plant additions by year for baseline and major projects (RAM definition).
- Summarizes plant additions by asset category for depreciation purposes and allows for the inclusion and exclusion of specific projects depending on the cases modeled.
- Summarizes plant additions by surcharge category (Preapproved Baseline, Major Project, or REIP) for decoupling calculations in the Revenue and Rates module.
- Calculates average baseline capital investments for use in the RAM adjustment.
- Calculates accumulated depreciation and depreciation expense by asset (production plant) and by asset category (transmission, distribution, and general).
- Calculates tax depreciation and subsequent deferred tax impact on book and tax depreciation differences.
- Calculates the annual securitization payments associated with the retirement and removal of individual generating units (if applicable).

I. Financial Analyses and Bill Impact Calculations

In our Preferred Plans, the Companies developed alternative approaches to achieve 100% RPS, analyzed the differentials between cases, and prepared comprehensive total customer bill impact and rate analyses. These results are described in Chapter 4: Financial Impacts.

Preparing comprehensive bill impact and rate analyses for a nearly 30-year planning period is an unusual level of financial planning and projections in the industry. While the Preferred Plans provide the expected fuel cost, operating costs, and capital investments for critical resources given our resource cost assumptions and fuel price forecasts, the capital investments and operating expenses for the balance of our utility business needs to be projected and incorporated into the comprehensive bill impact and rate analyses; in other words, our non-power supply costs.

To meet this challenge, we developed a top-down methodology to project this "balance-of-utility business" capital and expense requirements.

ITERATIVE TOP-DOWN METHODOLOGY

Our non-power supply cost structure—and correspondingly its revenue requirement and customer bills in total—comprise four primary elements.

- Operating & maintenance costs.
- Taxes other than income and public benefits fund.
- Return on and of existing utility asset investments.
- Return on and of future utility asset investments, net of productivity savings.

We projected each of these major elements individually, and then apply a financing capacity test and a rate change test.

Financing Capacity Test

We currently have a limit to the amount of new capital expenditures we can finance on terms acceptable to both customers and shareholders. As the financing constraint is assumed to not be binding if the NextEra Energy merger is consummated, it is not applied to Theme 2. However, as Themes 1 and 3 may occur under either a merged or a stand-alone future, there's a ceiling on the total capital expenditures of the consolidate plan in a given year or period of years.

For the unmerged future, the annual capital expenditures of the Preferred Plans and the future annual capital expenditures for the balance of the business are summed by year to determine if the total capital expenditures are within the Company's financing capacity. Projected capital expenditures for the balance of the utility business are evaluated for operational needs along with the need to stay within the Company's financing capacity. The adjusted balance of business capital expenditure plan is then used for the customer bill and rate impact analyses.

Rate Change Test

There are also economic and policy limitations to levels of future changes in customer bills and rates. While the science of these limits maybe somewhat less precise than the financing capacity limits discussed above, these limits are real and constraining.

To determine an annual rate change test limitation for each operating utility against which to test the plans, three different approaches to project annual rate changes were considered. These are:

- Rates adjust at the rate of inflation.
- Rates adjust at a blended rate, reflecting fuel price forecasts[1] and general inflation for "business as usual"[2] operations, for both 2015 U.S Energy Information Administration's (EIA) Reference and February 2016 EIA Short-Term Energy Outlook (STEO) fuel price forecasts.
- Rates adjust at the rate of price change over the prior decade.

[1] The fuel price component of these rate trajectories have been adjusted to reflect fuel blending required to meet environmental regulations.

[2] "Business as usual" in this context means continued use of the existing generating portfolio and fuel types, consistent with environmental regulations.

These approaches, when applied to each operating utility, result in the following annual rate change ceilings (shown in Figure I-1 through Figure I-3).

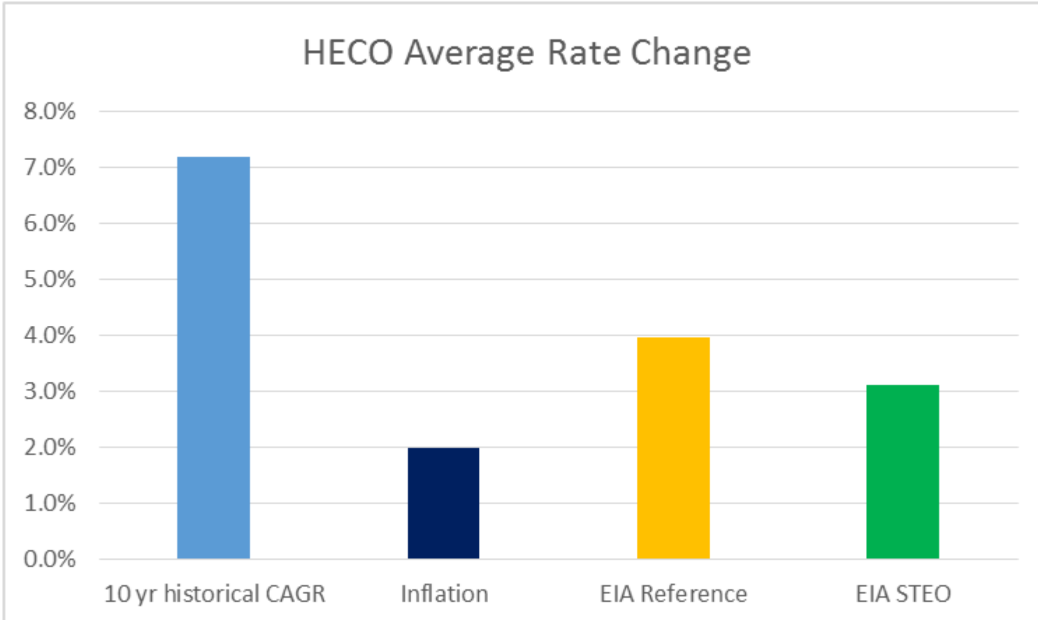


Figure I-1. Hawaiian Electric Average Rate Change

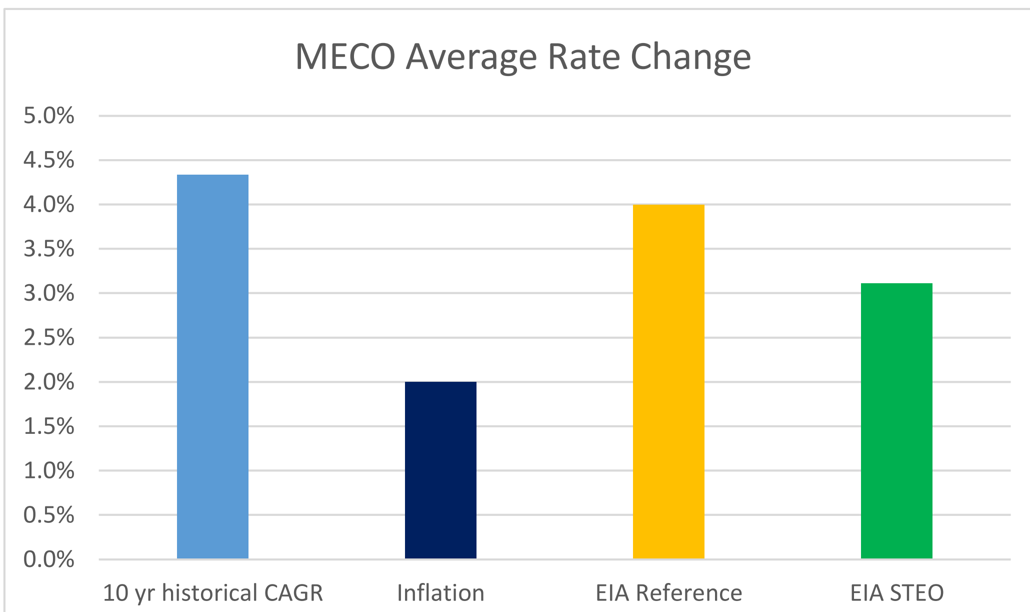


Figure I-2. Maui Electric Average Rate Change

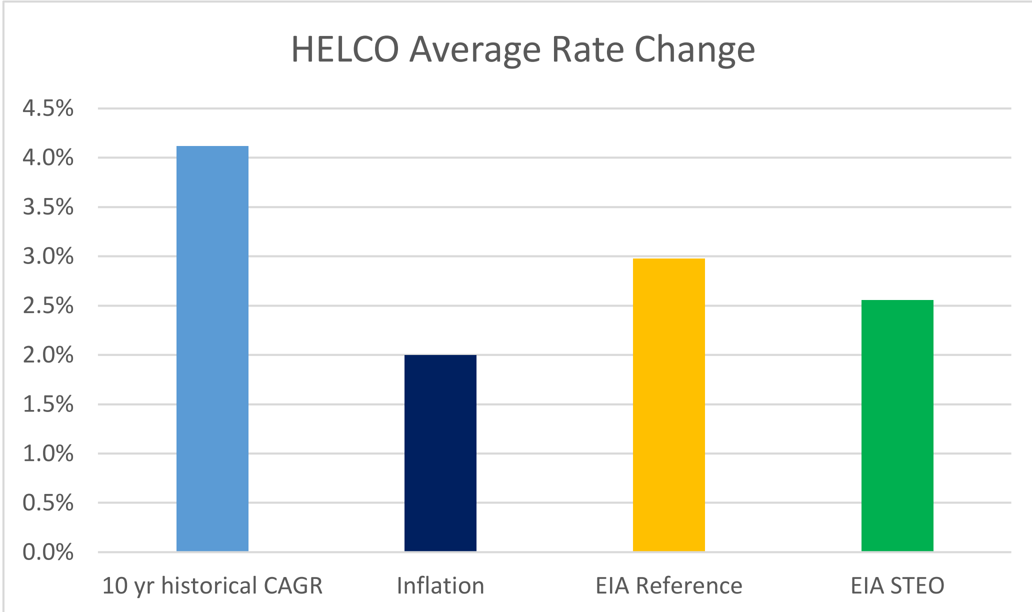


Figure I-3. Hawai'i Electric Light Average Rate Change

In addition to these annual rate change data points, we understand that there is a price point beyond which customers have economically feasible alternatives to grid supply. While there are many quantitative and qualitative factors that go into such a decision, we know that we must deliver to our customers an attractive total value proposition of affordability, reliability, and convenience. Based on these analyses, we targeted an annual rate change ceiling of 4%, while giving consideration to the operational needs for balance of the utility business capital expenditures.

The lumpy rate increases inherent with tradition rate base treatment of major capital projects are a challenge in this context. One approach that could be used to smooth out the rate impact of major capital investments is to allow for the inclusion of the Construction Work in Progress (CWIP) associated with major projects to be included in rate base. This approach would also benefit customers through a lower total cost for each project, as AFUDC financing charges would not be added to a project's cost. This treatment for major capital investments is one that a number of other jurisdictions have adopted; while we have not included that treatment in our rate and bill impact calculations, we believe it is a concept that should be considered, perhaps for all new major projects greater than $50M, as these plans move from proposals to projects.

It is important to note that annual rate change is a more constraining constraint as compared to total bill impact because of the anticipated sales volume reduction impact of energy efficiency measures.

Impact of Energy Efficiency Portfolio Standard on Rates and Customer Bills

Hawai'i's Energy Efficiency Portfolio Standard (EEPS) is guiding significant improvements in energy efficiency across all customers and is a primary driver of the decline in kWh sales through 2030. These usage declines are incorporated into the sales forecasts used for the PSIP analyses. Figure I-5 provides a perspective on the significance of this impact on projected sales volume for O'ahu. While these net sales figures include the impact of both EEPS and the standard DER penetration assumptions, the DER impact is generally constant year to year, so the shape of the curve is driven by the EEPS impact.

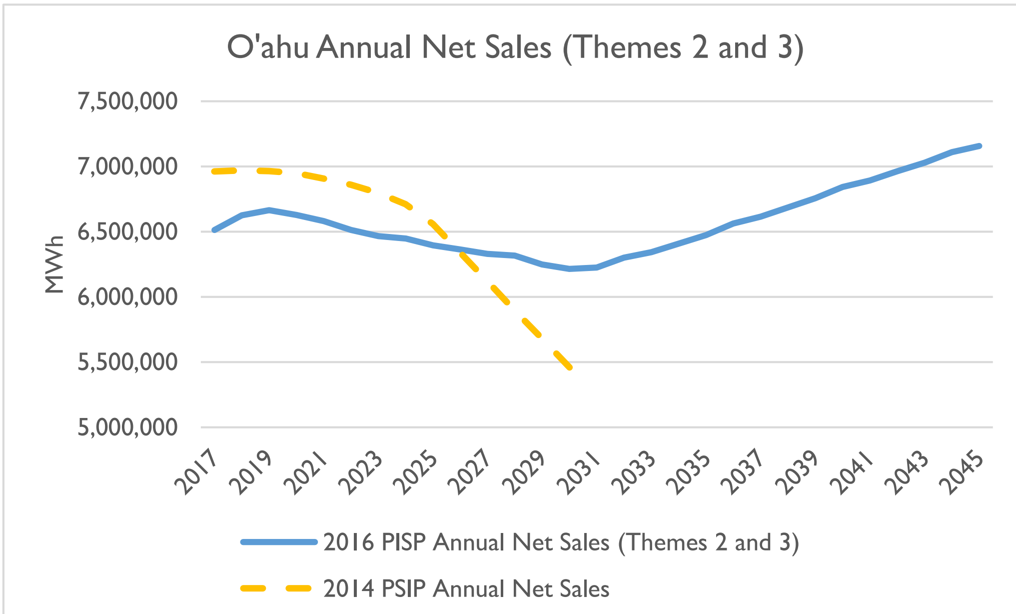


Figure I-5. Impact of Energy Efficiency Portfolio Standard on Sales

These sales volume changes are allocated across all customer classes in the PSIP analyses and do impact both the residential rate and residential customer bill impact analyses. While factors, including the applicable level of DG-PV penetration, do impact the specific calculations by theme for each island, the calculated usage per non-DG-PV residential customer varies with the EEPS driven net sales decline, as shown in Figure I-6.

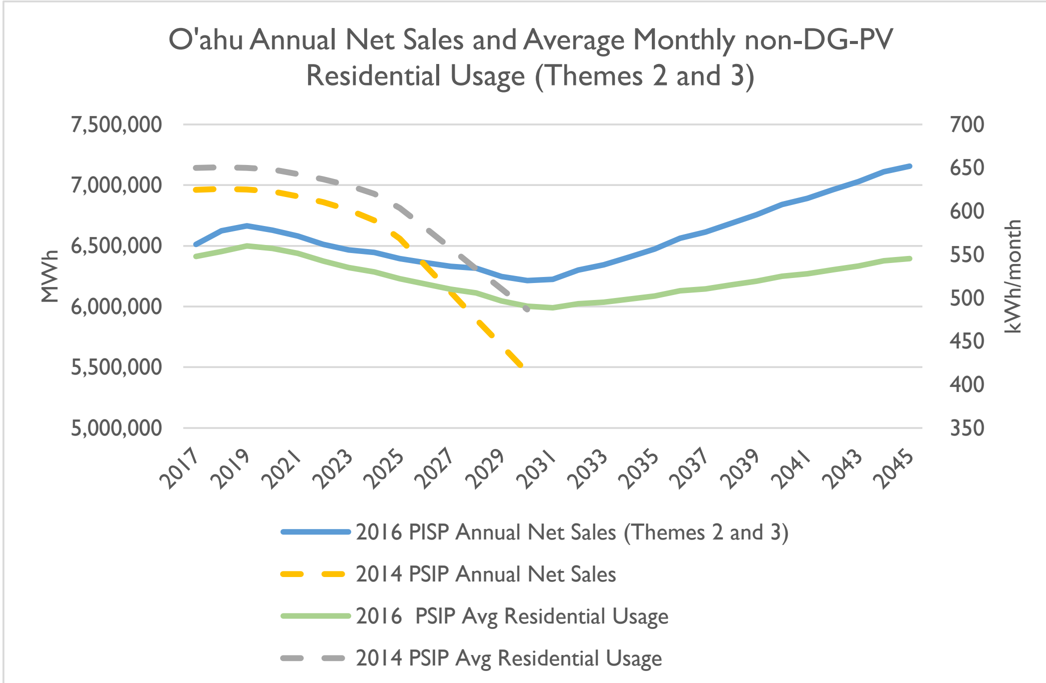


Figure I-6. Impact of Energy Efficiency Portfolio Standard on Sales & Residential Usage

Applying the Rate Change Test Iteratively

To test each merged and unmerged scenario against this initial rate change limit, we have combined the annual capital expenditures, fuel, and operating costs associated with the PSIP Preferred Plans with the annual capital expenditure and operating cost projections for the balance of the utility business to calculate an initial rate impact for each. We use the twelve month average 2015 residential rate level for each island as the starting point for this analysis. The use of a twelve month average rate provides some degree of smoothing to the very volatile monthly rates customers have experienced, due to the dramatic swings in oil prices.

For any year in which an operating utility plan results in a rate change greater than the annual ceiling, we review and adjust the timing and magnitude of the capital expenditures associated with the balance of the utility business.

Through iteration we calculate a balance-of-utility business capital expenditure profile that results in annual rate changes less than or equal to the ceiling in all years of the planning period and is consistent across all themes, so as to ease direct comparison of revenue requirements and customer bill impacts between themes.

Alignment with Existing Capital Plans and Ability to Meet Customer Requirements Test

This top-down, balance-of-utility business constrained capital expenditure plan will be reviewed to ensure that it reflects investment levels that will continually meet customer requirements for new service, maintain or enhance service reliability, and enable timely modernization of the grid to enable the distributed energy resources called for in the PSIP Preferred Plans. Management judgment will be applied to the timing and magnitude of the total capital expenditure plan to adjust as appropriate so as to ensure these critical customer requirements will be met. This may result in specific years where the resulting rate change is higher than the initially targeted ceiling.

This judgment will be applied consistent with the capital allocation process that is now being utilized. This process allocates available capital funds to types of work through a prioritization process at the type of work level, rather than to specific projects. This is a higher level prioritization than was used in the 2014 PSIPs. (Further information on the Companies' prioritization process will be provided as part of the Capital Budget Workbook update to be filed following this PSIP.)

Resource Usage Test

Lastly, final balance-of-utility business capital expenditure plan will be reviewed from a resource management perspective. Cost effective execution of capital work requires effective use of existing and future company resources, especially in transmission and distribution. A degree of consistency in the level of investment is highly desirable given the availability and mobilization costs of contract resources in Hawaiʻi and the required investment and timeline for training and development of Company resources. Here again, management judgment will be applied to determine if adjustments to the magnitude and timing of the final balance-of-utility business capital expenditure plan is required.

OPERATIONS AND MAINTENANCE EXPENSES

Operating and maintenance (O&M) expenses are a broad category of expense, which we have projected in three distinct ways. First, PSIP-related O&M is projected for each resource plan as modeled, based on the resource cost, retirement, and transition costs associated with each resource plan. Second, for Smart Grid and ERP, specific O&M cost adjustments are used, consistent with the respective General Order 7 applications.[3] The remaining operating and maintenance costs are projected to increase at the rate of

[3] Applications to the Commission for approval to commit funds in excess of $2.5 million.

inflation over the 30 year forecast period. The starting point for projected these future costs are 2015 actual expenses.

This assumption represents an intense pressure on operating costs, as labor costs comprise a significant percentage of these operating costs and skilled labor costs have consistently risen at rates above inflation in recent years. When this relationship is extended out over 30 years, it implies either a reversal of this labor cost relationship or very significant productivity gains must be achieved in order to meet this operating cost projection. If such gains are not achieved, future operating costs will be higher than the costs incorporated into the customer bill impact and rate analyses.

TAXES OTHER THAN INCOME AND PUBLIC BENEFITS FUND

A material component of a customer’s total electric bill is comprised of various taxes the Companies pay, as well as the public benefit fund charge the Companies collect to fund Hawaiʻi Energy’s energy efficiency programs. The laws and regulations that govern these taxes and fees are assumed to remain constant throughout the forecast period. Taxes on fuel that are assessed volumetrically are projected consistent with the plan’s expected fuel consumption. Other fees are assumed to increase at the rate of inflation.

The current public benefit fund charge of 2% of electric revenues, including revenue taxes, has been applied throughout the planning period.

RETURN ON AND OF EXISTING UTILITY ASSETS

The Companies have $4.1 billion of net utility assets, as of December 31, 2015, including $1.0 billion of generating property, plant, and equipment assets. These existing assets are currently used and useful for utility service, are being depreciated, and the net balance is in rate base earning a return, based on the authorized capital structure and return on equity. The customer bill impact and rate impact analysis assumes the currently authorized capital structure, return on equity, and interim rate adjustment mechanisms are constant over the forecast period. Similarly, the analyses assume that depreciation rates for existing plant remain the same. Lastly, the analyses assume that upon retirement, undepreciated plant balances are transferred to a regulatory asset amortized over 20 years and that removal costs in excess of removal costs already recovered from customers, if any, are given the same regulatory treatment.

CAPITAL INVESTMENTS IN POWER SUPPLY ASSETS

For each theme's resource plan, all of the capital investments associated with the plan are summed by year to reflect the total annual capital expenditure for the new resources envisioned in the plan. In addition, each plan also includes the capital expenditures required for the major reliability investments for each existing generating unit that is expected to operate well into the 2030s or beyond. Lastly, routine generation capital expenditures already planned for 2017 through 2020 are included, and a provision of $1 million per year per unit for capital expenditures associated with break or fix activities is included for each existing generating unit that remains operational beyond 2020.

These capital expenditures have all been modeled using the traditional rate base approaches for determining revenue requirements and customer rates. This approach assigns the capital cost recovery risk for these investments to customers and to the extent certain customers disconnect from the grid or significantly reduce their grid consumption, capital cost recovery would be shifted to the remaining customers. While the Company is not yet in a position to make a specific proposal, we believe it is likely that capital cost recovery for certain of these power supply investments would be appropriately treated as a cost that cannot be bypassed. To the extent that we determine this is the case, we would anticipate including such a recommendation as part of any filing seeking approval of such a capital project.

BALANCE-OF-UTILITY BUSINESS CAPITAL INVESTMENTS

The iterative top down methodology uses capital investments, excluding power supply, also referred to as "balance-of-utility business" capital expenditures, as the adjustable input to achieve an acceptable rate trajectory. The balance of utility business capital expenditures are divided into two specific categories:

Very large projects, requiring GO7 approval, specifically Smart Grid and ERP/EAM, are shown with the total cost assuming the Next Era merger is consummated. Total capital expenditures and deferred software costs for these projects[4] are projected as follows:

- Smart Grid: $346 million
- ERP/EAM: $52 million
- All other utility capital expenditures.

[4] These are the cost estimates available at the time of this analysis. For the most complete and current cost estimates for these projects, please refer to the most recent filings applicable to each.

It should be noted that capital expenditures for new office or yard facilities are not included in the customer bill impact and rate impact analyses. If, as the Company continues to evaluate our facility requirements in the normal course of business, new facility investments can be justified, those would be evaluated on a stand-alone business case basis.

To frame the level of balance-of-utility business capital expenditures required over the forecast period, we considered several sources and perspectives. These include:

- Balance-of-utility business capital expenditure benchmark data for US utilities indicate that for utilities with aging T&D assets, capital expenditures in the $400 to $600 per customer per year range are typical. This would suggest the following ranges for each Hawaiian Electric Company:
  - Hawaiian Electric: $120 million to $180 million
  - Maui Electric: $30 million to $45 million
  - Hawaiʻi Electric Light: $30 million to $45 million
- Hawaiian Electric's most recent five years have averaged approximately $190 million
- Engineering assessments across the Hawaiian Electric grids indicate significant reliability and capability issues that need to be addressed to ensure reliable service, particularly so given Hawaii's exposure to hurricanes and other major storms.
- Historical averages for a panel of US utilities indicate that approximately $7.5 billion in balance of business utility capital expenditures are required for each 1% growth in GDP. Using DBEDT's forecasted growth rate of 2.33%, the projected balance-of-utility business capital expenditures are:
  - Hawaiian Electric: $178 million
  - Maui Electric: $44 million
  - Hawaiʻi Electric Light: $43 million

Given these data, it is expected that the combination of the PSIP Preferred Plan capital expenditures and rate change limits will constrain balance-of-utility business capital expenditures for at least the first 10 to 15 years of the planning period in both merged and unmerged scenarios.

RETIREMENT AND REMOVAL COSTS

All of the Preferred Plans call for the deactivation and subsequent retirement of existing fossil generation units. For financial modeling, each unit is considered to be retired two years after it is deactivated, unless reactivation is explicitly planned in the resource plan. Further, we have assumed that each unit is removed in the year following retirement.

The net book value at retirement and the removal costs represent prudent expenditures that have served customers for many years and thus will need to be recovered from customers. We expect to seek Commission approval for recording these costs as a regulatory asset, to be amortized and recovered from customers over the 20 years following unit retirement. The financial results presented in this report are based on this approach.

Table I-1 presents the net book value of the units to be retired, annual depreciation expense, as well as the estimated removal costs for each.

Millions / Unit	Net Book Value: December 31, 2015	Annual Depreciation Expense	Estimated Removal Costs
Honolulu 8 & 9	$49.4	$1.6	$20.0
Waiau 3 & 4	$22.7	$0.9	$20.0
Waiau 5 & 6	$39.8	$1.2	$20.0
Kahe 1–3	$76.7	$2.4	$30.0
Kahe 4	$24.9	$1.0	$10.0
Kahului 1–4	$5.4	$1.4	$10.9
Puna Steam	$11.4	$0.4	$4.0
Hill 5 & 6	$14.5	$1.0	$9.0

Table I-1. Financial Data of Units to Be Retired

With the shift to renewable energy sources, several of the resource plans call for converting the generator of retired generating units for use as a synchronous condenser. In those cases, we have assumed that the generator assets and common plant that continue to be used for synchronous condenser operations will have a net book value of $2 million per unit that will remain in service and $1 million of removal costs will be avoided.

The net book value at retirement and the removal costs incurred represent prudent expenditures that have served customers for many years and thus will need to be recovered from customers. The financial results represent recovery of these costs from customers over a 20-year period following unit retirement.

In prior PSIPs, we modeled the recovery of retirement and removal costs through a securitization mechanism. While this approach could be used, it may not prove to be cost effective because these costs are somewhat smaller than previously anticipated and are spread out over a number of years. This makes the administrative costs of establishing and using a securitization mechanism appear impractical.

We expect to seek Commission approval for recording these costs as a regulatory asset, to be amortized and recovered from customers over the 20-years following unit retirement.

There is one aspect of a standard utility securitization that does seem to be appropriate for these costs. Recovery of these costs on a non-bypassable basis from all current and future customers would be appropriate, as all current customers have benefited from the use of these assets. While this rate design topic is beyond the scope of this 2016 updated PSIP, we suggest that this concept be considered in future rate design discussions relating to retirement and removal costs.

J. Modeling Assumptions Data

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

This appendix summarizes the assumptions utilized to perform the PSIP analyses. It includes:

- Reliability criteria
- Utility cost of capital
- Fuel price forecasts and availability
- Energy sales and peak demand forecasts
- Resource capital costs
- Demand response data inputs

RELIABILITY CRITERIA

Adequacy of Supply

Every year, we file an Adequacy of Supply (AOS) report. This report indicates how the generation capacity on each island's power grid is able to meet all reasonably expected demand as well as provide a reasonable reserve to meet emergencies. The AOS incorporates a Loss-of-Load Probability (LOLP) of, at most, one outage day every 4½ years in its overall capacity planning criteria.

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

Required Regulating Reserve

General Electric (GE), working under a contract with the Hawaiʻi Natural Energy Institute (HNEI)[1], developed a formula for determining the amount of regulating reserve necessary to maintain the minute-to-minute balance between supply and demand on the Oʻahu grid. The formula is:

Required regulating reserve amount equals the sum of:

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

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

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

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

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

Required regulating reserve amount equals the sum of:

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

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

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

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

The greater of 6 MW, or

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

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

UTILITY COST OF CAPITAL AND FINANCIAL ASSUMPTIONS

The Hawaiian Electric Companies finance their investments through two main sources of capital: debt (borrowed money) or equity (invested money). In both cases, we pay a certain rate of return for the use of this money. This rate of return is our *Cost of Capital*.

Table J-1 lists the various sources of capital, their weight (percent of the entire capital portfolio), and their individual rates of return. Composite percentages for costs of capital are presented under the table.

Capital Source	Weight	Rate
Short Term Debt	3.0%	4.0%
Long Term Debt (Taxable Debt)	39.0%	7.0%
Hybrids	0.0%	6.5%
Preferred Stock	1.0%	6.5%
Common Stock	57.0%	11.0%

Composite Weighted Average 9.185%
After-Tax Composite Weighted Average 8.076%

Table J-1. Utility Cost of Capital

FUEL PRICE FORECASTS AND AVAILABILITY

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

This appendix summarizes the assumptions utilized to perform the PSIP analyses.

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

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

Petroleum-Based Fuels

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

When the 2015 AEO was published in April 2015 Brent crude oil was approximately $60 a barrel. Over the remainder of 2015 Brent crude oil continued to drop to below $40 per barrel at the end of 2015, which is below the 2015 AEO low economic growth case which estimated 2016 Brent crude oil at over $50 per barrel. Because the 2016 Annual Energy Outlook (2016 AEO) update from the EIA is not expected until June 2016, alternative Forward/Hybrid pricing forecasts were initially presented in the Interim PSIP to account for the Companies' expectation that 2016 AEO forecasts would be lower than the 2015 AEO. However, since the time the Interim PSIP was filed, the Companies developed an alternative fuel price forecast which relies on the more recent February 2016 EIA Short Term Energy Outlook (STEO), which is published by the EIA on a monthly basis and accounts for current market prices. This newly developed forecast (STEO Adjusted Forecast) utilizes the 2016 and 2017 Brent crude oil forecasts from the February 2016 STEO and is escalated using similar escalation factors as those for the EIA 2015 AEO Brent crude oil forecast. It is the Companies' view that this pricing curve under the STEO Adjusted Forecast is a more conservative (lower prices) estimate than what the EIA 2016 AEO Reference forecast may be when released in June, 2016. To capture the potential for higher future prices and objectively assess the competitiveness of competing resources that reduces the risk of high commodity prices, the 2015 AEO fuel price forecast remains unchanged from the Interim PSIP.

Biodiesel forecasts are generally derived by comparing commodity forecasts with recent biofuel contracts and RFP bids to determine adjustments needed to derive each company's respective biodiesel price forecast from forecasted commodities. EIA provides low, reference, and high petroleum forecasts, which are used to project low, reference, and high petroleum-based fuel price forecasts. A similar commodity forecast has not been found for biodiesel, although EIA might provide one in the future. In lieu of such a source, the biodiesel forecast is based on the Food and Agricultural Policy Institute at the University of Missouri (FAPRI) forecast of biodiesel prices in the United States.

While the EIA forecast provides petroleum prices through 2040, FAPRI provides biodiesel pricing through 2024 and then that trend is extrapolated by Hawaiian Electric out to 2045. The EIA forecast trend is also extrapolated from 2040-2045. In the Interim PSIP Report, it was noted that as a result of extending both forecasts beyond their provided period, the extrapolated forecast resulted in an unlikely case in which biodiesel prices falling below oil prices in later years. Since the Interim PSIP Report, the biodiesel forecasts have been adjusted to correct this issue and better correlate with the respective 2015 AEO and February 2016 STEO fuel price forecasts for petroleum-based fuels.

LNG Fuel Price Forecasts

Fuel price forecasts for this PSIP Update report were developed using commodity price forecasts published by the EIA: 2015 Annual Energy Outlook (AEO) and February 2016 Short Term Energy Outlook (STEO). The 2015 EIA fuel price forecast used average Henry Hub spot prices for natural gas (2013 dollars per million Btu), adjusted from 2013 dollars to nominal dollars.

As described in the Interim PSIP, since the time the EIA 2015 Annual Energy Outlook (AEO) was published in April 2015, Brent crude oil has dropped from $60 a barrel to less than $40 a barrel, and natural gas prices dropped from $3/MMBtu to less than $2/MMBtu. Because the 2016 Annual Energy Outlook (2016 AEO) update from the EIA is not expected until June 2016, alternative Forward/Hybrid pricing forecasts were initially presented in the Interim PSIP to account for the Companies' expectation that 2016 AEO forecasts would be lower than the 2015 AEO. However, since the time the Interim PSIP was filed, the Companies developed an alternative fuel price forecast which relies on the more recent February 2016 EIA Short Term Energy Outlook (STEO), which is published by the EIA on a monthly basis and accounts for current market prices. This newly developed forecast (STEO Adjusted Forecast) utilizes the 2016 and 2017 natural gas forecasts from the February 2016 STEO and is escalated using the same escalation factors from the EIA 2015 AEO natural gas forecast. It is the Companies' view that this pricing curve under the STEO Adjusted Forecast is a more conservative (lower prices) estimate than what the EIA 2016 AEO Reference forecast may be when released in June, 2016. To capture the potential for higher future prices and objectively assess the competitiveness of competing resources that reduces the risk of high commodity prices, the 2015 AEO fuel price forecast remains unchanged from the Interim PSIP.

To develop the delivered LNG fuel price forecasts (2015 AEO and STEO Adjusted), the Companies used cost information for the pipeline transport, LNG liquefaction, transportation of the LNG, and transportation logistics from the Companies' Containerized LNG Supply to Hawai'i RFP and added the natural gas prices from the EIA 2015 AEO and EIA February 2016 STEO, adjusted to the Station 2 gathering point pricing in British Columbia. The EIA forecasts are based on Henry Hub pricing. Henry Hub, a Louisiana natural gas distribution hub and pricing point for natural gas futures contracts traded on the New York Mercantile Exchange (NYMEX), is currently at a 15-year price low. The price is expected to increase gradually over the next decade as the shale gas market rebalances. The LNG price forecasts used in the PSIP attempts to account for natural gas that is sourced from British Columbia. Historically, and based on the future's market pricing, gas sourced from Alberta (AECO market) and British Columbia (Station 2 gathering point) has traded at a discount to the United States Henry Hub pricing.

For Oahu's LNG pricing curves, a negative 26.5% basis was applied to create a Station 2 equivalent Henry Hub price. For example, a $2.00/MMBtu Henry Hub price would equate to a $1.47/MMBtu Station 2 price. A 4.5% adder was applied to the derived Station 2 price to account for shrinkage on the pipelines from the Station 2 gathering point to the liquefaction plant.

The Companies contemplates that the natural gas for its LNG will be procured under a daily or monthly index, gathered at Station 2 and transported on the Spectra Energy Westcoast Transmission T-South pipeline. T-South is a looped (multiple pipeline) system that moves gas from Station 2 to the Huntingdon/Sumas (Sumas) trading pool. T-South firm capacity can be procured at a rolled-in tariff rate, meaning that if capital improvements are required to increase pipeline capacity, expansion costs are borne by all users on the pipeline. Charges to use the pipeline will be at a fixed tariff CAD/GJ rate, converted to $/MMBtu. As a mature depreciating pipeline system, the general trend is towards stable long-term rates. The current rate is approximately $0.32/MMBtu.

From the Sumas hub, gas will be distributed on the Fortis regulated Coastal Transmission System (CTS) to the existing FortisBC Energy Inc. (FEI) LNG facility on Tilsbury Island in Delta, British Columbia, Canada on the Fraser River. The CTS pipeline rate is regulated under the Rate Schedule 50 (RS50) tariff in units of CAD/GJ and converted to $/MMBtu for the Hawaiian Electric contract. The FEI CTS system is designed to meet high winter peaking demand and is therefore under-utilized for a majority of the year. Therefore, if more flat non-peaking load is added, by Hawaiian Electric or other industrial demand, the general trend would be for rates to reduce. This is reflected in the RS50 rate floor which decreases as demand increases. The current tariff rate under RS50 is approximately $0.42/ MMBtu.

The LNG fuel price forecast included in Table J-2 through Table J-7 represent the total variable costs of the LNG, which includes the gas commodity, taxes, port fees, wharfage, stevedoring, and other ancillary delivery service charges. Table J-8 and Table J-9 are the total nominal LNG costs, inclusive of fixed and variable costs. Fixed costs include liquefaction, pipeline tolls (for tariff service), and shipping charges.

Hawaiian Electric Fuel Forecasted Fuel Prices—Nominal Dollars

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

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

Hawaiian Electric Fuel Forecasted Fuel Prices—Nominal Dollars

$/MMBtu	Hawaiian Electric Fuel Price Forecasts					
	Feb 2016 EIA STEOe					*2015 FAPRI Low*
Year	LSFO	Diesel	ULSD	40% LSFO/ 60% ULSD	LNG	Biodiesel
2016	$6.77	$9.28	$10.22	$8.78	n/a	$16.37
2017	$9.07	$11.67	$12.67	$11.16	n/a	$20.82
2018	$9.69	$12.34	$13.38	$11.83	n/a	$22.90
2019	$10.10	$12.80	$13.86	$12.28	n/a	$22.78
2020	$10.48	$13.24	$14.32	$12.71	n/a	$23.00
2021	$10.87	$13.67	$14.78	$13.14	$7.19	$23.47
2022	$11.36	$14.22	$15.35	$13.68	$6.67	$23.71
2023	$11.88	$14.79	$15.95	$14.25	$6.82	$23.97
2024	$12.43	$15.40	$16.58	$14.84	$6.97	$24.30
2025	$13.00	$16.03	$17.24	$15.46	$7.12	$24.61
2026	$13.60	$16.68	$17.92	$16.11	$7.28	$25.39
2027	$14.24	$17.38	$18.66	$16.81	$7.45	$26.24
2028	$14.92	$18.12	$19.43	$17.54	$7.62	$27.13
2029	$15.63	$18.90	$20.24	$18.31	$7.80	$28.05
2030	$16.38	$19.72	$21.09	$19.12	$7.98	$29.01
2031	$17.18	$20.58	$21.99	$19.98	$8.17	$30.02
2032	$18.02	$21.51	$22.96	$20.89	$8.37	$31.09
2033	$18.91	$22.47	$23.96	$21.85	$8.58	$32.21
2034	$19.85	$23.48	$25.01	$22.85	$8.79	$33.37
2035	$20.79	$24.50	$26.08	$23.86	$9.00	$34.51
2036	$21.80	$25.60	$27.21	$24.95	$9.27	$35.73
2037	$22.87	$26.75	$28.41	$26.09	$9.51	$37.02
2038	$23.96	$27.93	$29.64	$27.26	$9.80	$38.30
2039	$25.16	$29.22	$30.98	$28.54	$10.25	$39.71
2040	$26.50	$30.66	$32.48	$29.97	$10.84	$41.30
2041	$27.91	$32.06	$33.90	$31.39	n/a	$42.88
2042	$29.39	$33.62	$35.51	$32.95	n/a	$44.43
2043	$30.96	$35.27	$37.21	$34.59	n/a	$45.96
2044	$32.60	$37.00	$38.99	$36.31	n/a	$47.47
2045	$34.34	$38.81	$40.86	$38.13	n/a	$48.95

Table J-3. Hawaiian Electric Fuel Price Forecasts (2 of 2)

Maui Electric Fuel Forecasted Fuel Prices—Nominal Dollars

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

Table J-4. Maui Electric Fuel Price Forecasts (1 of 2)

Maui Electric Fuel Forecasted Fuel Prices—Nominal Dollars

$/MMBtu	Maui Electric Fuel Price Forecasts						
	Feb 2016 EIA STEO						*2015 FAPRI Low*
Year	MSFO	Diesel	ULSD (Maui)	ULSD (Moloka'i)	ULSD (Lana'i)	LNG	Biodiesel
2016	$5.54	$9.43	$9.99	$11.07	$14.08	n/a	$16.70
2017	$7.51	$12.09	$12.73	$13.78	$16.80	n/a	$21.23
2018	$8.04	$12.83	$13.49	$14.55	$17.62	n/a	$23.36
2019	$8.38	$13.33	$14.00	$15.08	$18.20	n/a	$23.23
2020	$8.71	$13.80	$14.49	$15.59	$18.76	n/a	$23.46
2021	$9.04	$14.27	$14.98	$16.09	$19.31	$9.58	$23.94
2022	$9.45	$14.87	$15.60	$16.71	$19.98	$9.12	$24.19
2023	$9.90	$15.50	$16.25	$17.38	$20.69	$9.30	$24.45
2024	$10.37	$16.16	$16.93	$18.07	$21.43	$9.50	$24.79
2025	–	$16.84	$17.64	$18.79	$22.20	$9.69	$25.10
2026	–	$17.56	$18.38	$19.54	$23.00	$9.89	$25.93
2027	–	$18.33	$19.17	$20.35	$23.86	$10.10	$26.83
2028	–	$19.14	$20.01	$21.20	$24.76	$10.32	$27.77
2029	–	$20.00	$20.89	$22.09	$25.70	$10.55	$28.74
2030	–	$20.89	$21.82	$23.03	$26.70	$10.78	$29.76
2031	–	$21.84	$22.80	$24.02	$27.75	$11.02	$30.83
2032	–	$22.86	$23.84	$25.08	$28.86	$11.27	$31.96
2033	–	$23.92	$24.94	$26.18	$30.03	$11.52	$33.14
2034	–	$25.03	$26.08	$27.34	$31.25	$11.79	$34.37
2035	–	$26.15	$27.24	$28.51	$32.48	$12.05	$35.58
2036	–	$27.36	$28.48	$29.76	$33.79	$12.37	$36.88
2037	–	$28.63	$29.79	$31.08	$35.17	$12.66	$38.24
2038	–	$29.92	$31.12	$32.43	$36.59	$13.01	$39.59
2039	–	$31.35	$32.59	$33.91	$38.14	$13.51	$41.09
2040	–	$32.94	$34.23	$35.55	$39.86	$14.16	$42.78
2041	–	$34.53	$35.85	$37.13	$41.35	n/a	$44.44
2042	–	$36.27	$37.63	$38.91	$43.17	n/a	$46.08
2043	–	$38.10	$39.51	$40.78	$45.07	n/a	$47.70
2044	–	$40.02	$41.48	$42.75	$47.07	n/a	$49.29
2045	–	$42.04	$43.56	$44.81	$49.17	n/a	$50.86

Table J-5. Maui Electric Fuel Price Forecasts (2 of 2)

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

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

Table J-6. Hawai'i Electric Light Fuel Price Forecasts (1 of 2)

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

$/MMBtu	Hawai'i Electric Light Fuel Price Forecasts					
	Feb 2016 EIA STEO					*2015 FAPRI Reference*
Year	MSFO	Diesel	ULSD	Naptha	LNG	Biodiesel
2016	$5.84	$9.88	$10.24	$11.40	n/a	$16.86
2017	$7.83	$12.46	$12.88	$13.84	n/a	$21.44
2018	$8.37	$13.19	$13.62	$14.56	n/a	$23.59
2019	$8.72	$13.68	$14.13	$15.06	n/a	$23.46
2020	$9.05	$14.15	$14.61	$15.54	n/a	$23.69
2021	$9.39	$14.62	$15.10	$16.01	$9.81	$24.18
2022	$9.81	$15.21	$15.70	$16.60	$9.34	$24.42
2023	$10.27	$15.83	$16.33	$17.22	$9.53	$24.69
2024	$10.74	$16.48	$17.00	$17.86	$9.73	$25.03
2025	$11.24	$17.16	$17.70	$18.53	$9.93	$25.35
2026	$11.75	$17.86	$18.42	$19.23	$10.14	$26.16
2027	$12.31	$18.62	$19.20	$19.98	$10.35	$27.04
2028	$12.90	$19.42	$20.02	$20.77	$10.58	$27.95
2029	$13.52	$20.26	$20.88	$21.60	$10.81	$28.91
2030	$14.17	$21.14	$21.78	$22.47	$11.04	$29.90
2031	$14.86	$22.07	$22.74	$23.39	$11.29	$30.95
2032	$15.59	$23.06	$23.76	$24.37	$11.54	$32.06
2033	$16.36	$24.11	$24.83	$25.39	$11.80	$33.22
2034	$17.17	$25.20	$25.95	$26.46	$12.07	$34.42
2035	$17.99	$26.30	$27.07	$27.54	$12.34	$35.61
2036	$18.87	$27.48	$28.28	$28.69	$12.67	$36.87
2037	$19.79	$28.72	$29.56	$29.91	$12.96	$38.21
2038	$20.74	$29.99	$30.86	$31.15	$13.32	$39.53
2039	$21.78	$31.39	$32.29	$32.52	$13.83	$40.99
2040	$22.94	$32.94	$33.89	$34.03	$14.48	$42.65
2041	$24.16	$34.46	$35.44	$35.41	n/a	$44.28
2042	$25.45	$36.15	$37.17	$37.03	n/a	$45.89
2043	$26.81	$37.92	$38.98	$38.73	n/a	$47.47
2044	$28.24	$39.79	$40.90	$40.51	n/a	$49.03
2045	$29.74	$41.75	$42.91	$42.39	n/a	$50.57

Table J-7. Hawai'i Electric Light Fuel Price Forecasts (2 of 2)

LNG Total Price Forecasts

February 2016 EIA STEO Henry Hub Spot Prices for Natural Gas–Nominal Dollars

Nominal $/MMBtu	February 2016 EIA STEO Henry Hub Natural Gas Futures		
Year	*O'ahu Total Cost*	*Maui Total Cost*	*Hawai'i Island Total Cost*
2021	$13.45	$15.82	$16.04
2022	$12.99	$15.40	$15.62
2023	$13.18	$15.63	$15.86
2024	$13.38	$15.87	$16.11
2025	$13.59	$16.12	$16.36
2026	$13.80	$16.37	$16.62
2027	$14.02	$16.64	$16.89
2028	$14.24	$16.91	$17.16
2029	$14.47	$17.19	$17.45
2030	$14.71	$17.47	$17.74
2031	$14.96	$17.77	$18.04
2032	$15.22	$18.08	$18.35
2033	$15.49	$18.39	$18.67
2034	$15.76	$18.71	$19.00
2035	$16.03	$19.04	$19.33
2036	$16.36	$19.42	$19.72
2037	$16.66	$19.77	$20.08
2038	$17.02	$20.19	$20.50
2039	$17.53	$20.76	$21.07
2040	$18.20	$21.48	$21.80

Table J-8. February 2016 STEO Henry Hub Spot Prices for Natural Gas

2015 EIA Henry Hub Spot Prices for Natural Gas (Reference Case)–Nominal Dollars

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

Table J-9. 2015 EIA Henry Hub Spot Prices for Natural Gas (Reference)

Hawaiian Electric Fuel Price Forecasts (Nominal Dollars)

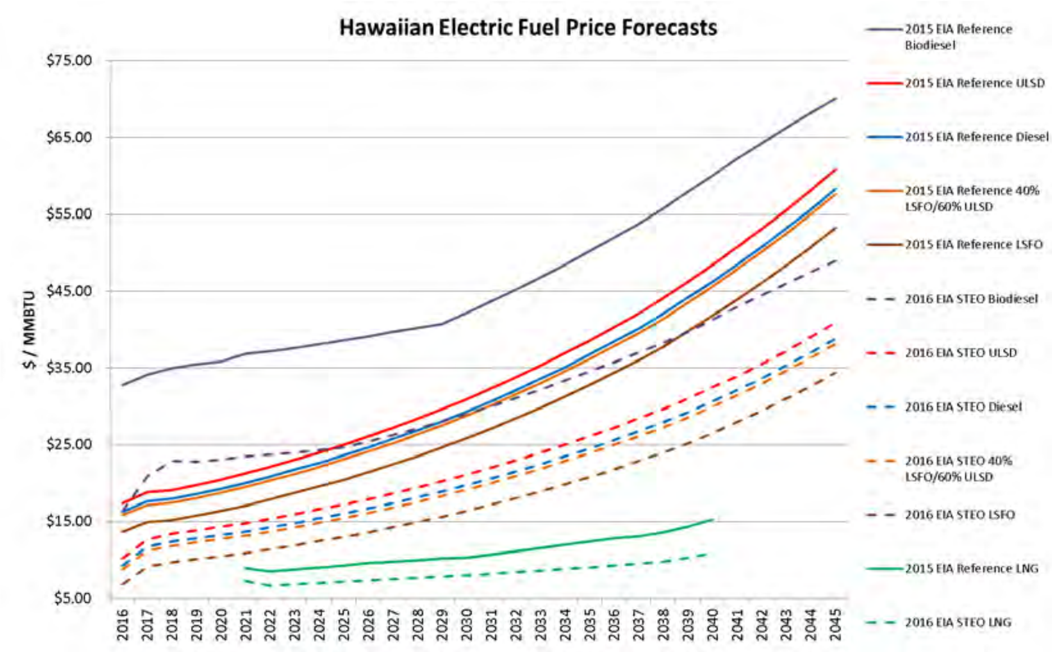


Figure J-1. Hawaiian Electric Fuel Price Forecasts

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

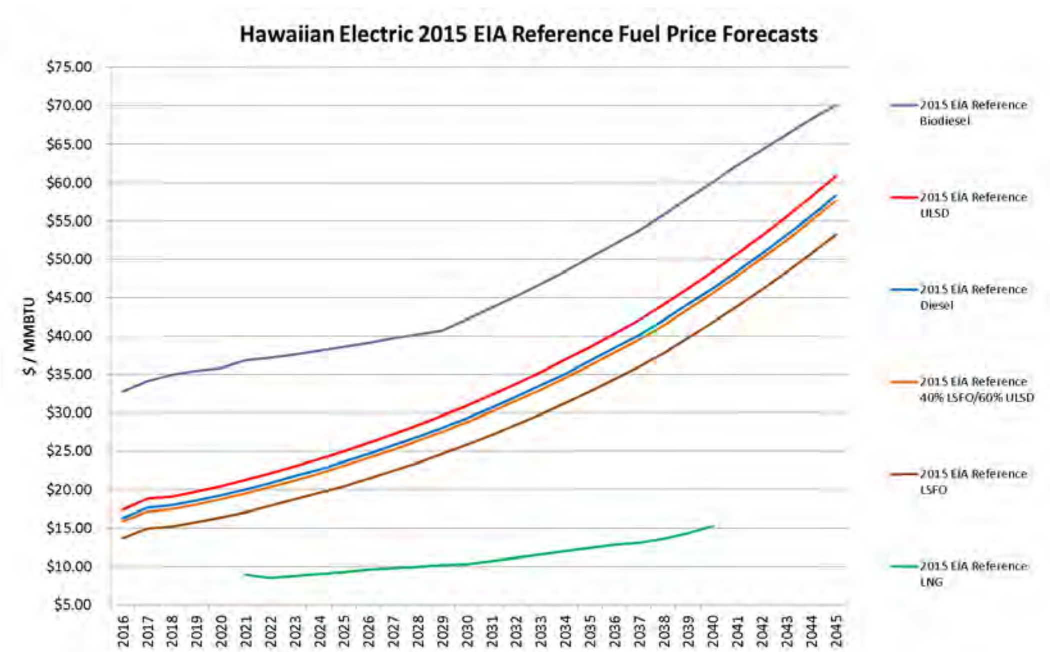


Figure J-2. Hawaiian Electric 2015 EIA Reference Fuel Price Forecasts

Hawaiian Electric February 2016 EIA STEO Fuel Price Forecasts (Nominal Dollars)

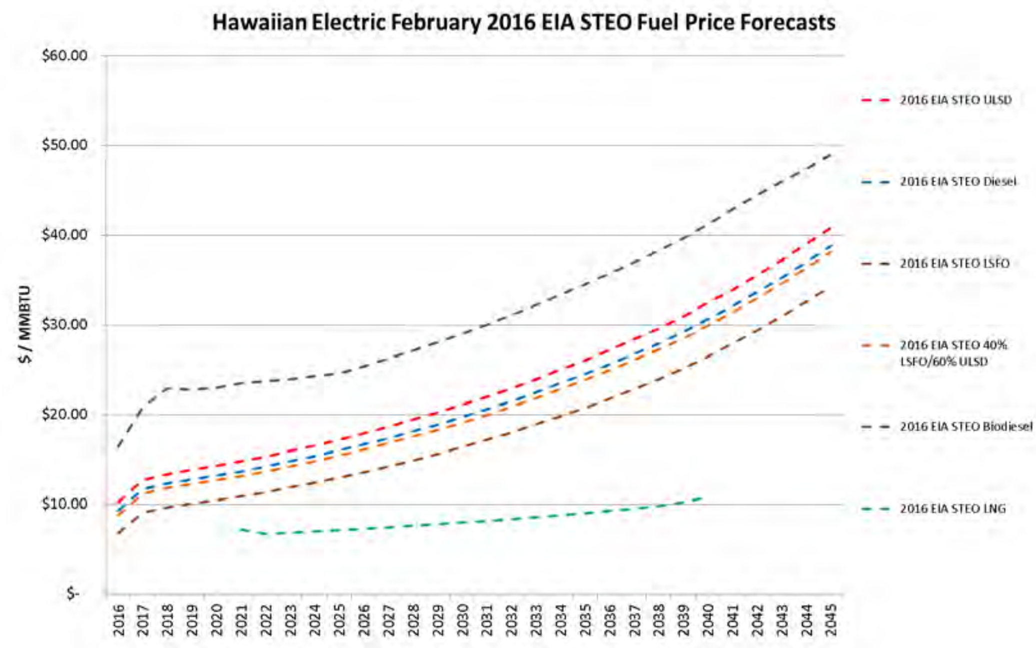


Figure J-3. Hawaiian Electric February 2016 EIA STEO Fuel Price Forecasts

Maui Electric Fuel Price Forecasts (Nominal Dollars)

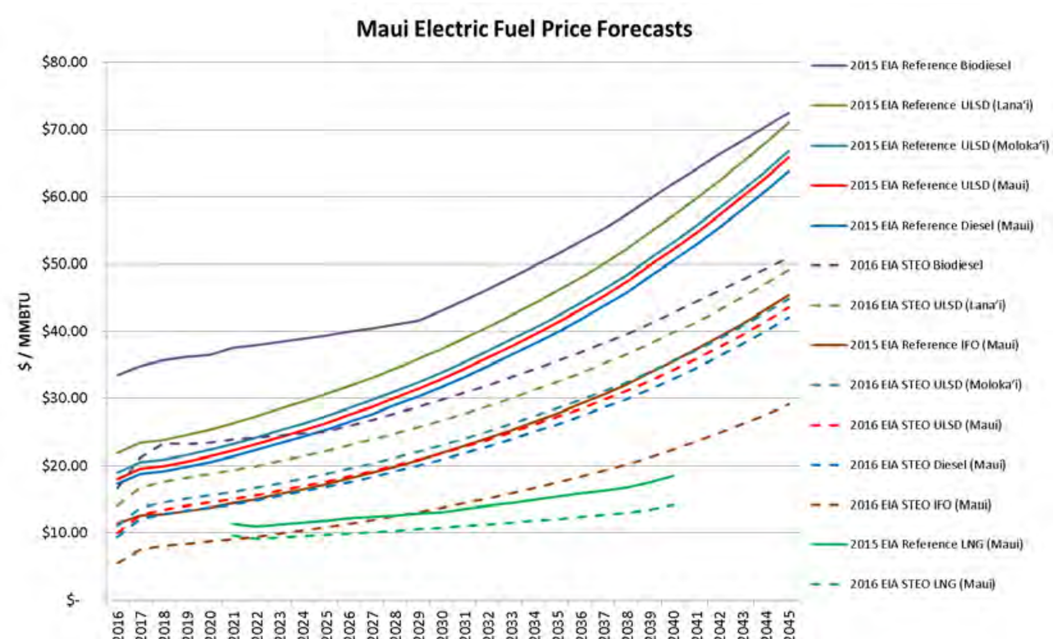


Figure J-4. Maui Electric Fuel Price Forecasts

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

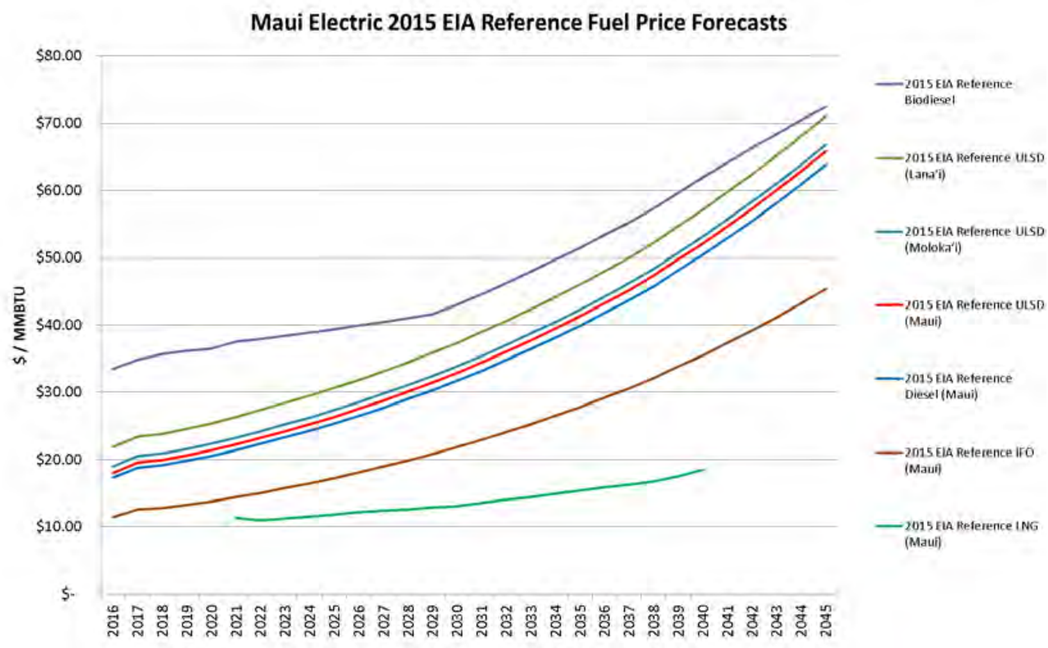


Figure J-5. Maui Electric 2015 EIA Reference Fuel Price Forecasts

Maui Electric February 2016 EIA STEO Fuel Price Forecasts (Nominal Dollars)

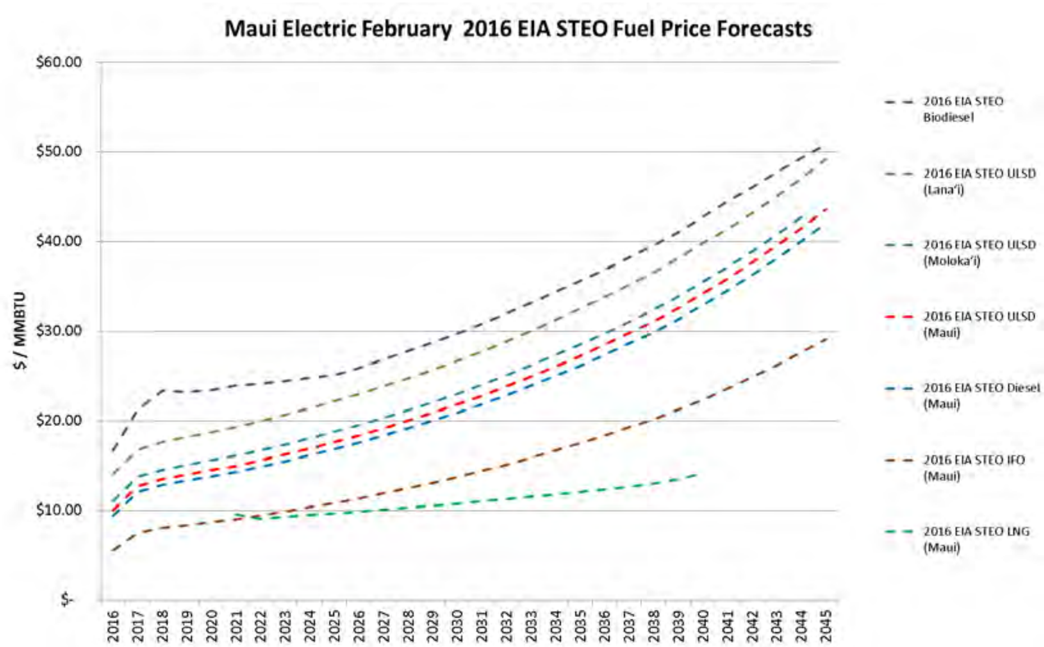


Figure J-6. Maui Electric February 2016 EIA STEO Fuel Price Forecasts

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

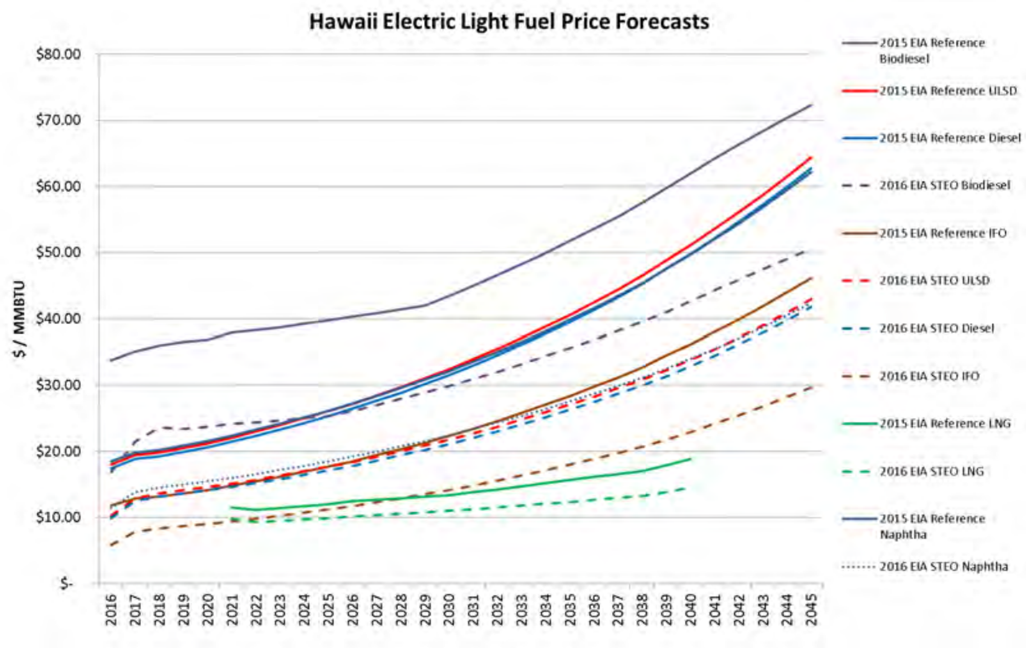


Figure J-7. Hawai'i Electric Light Fuel Price Forecasts

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

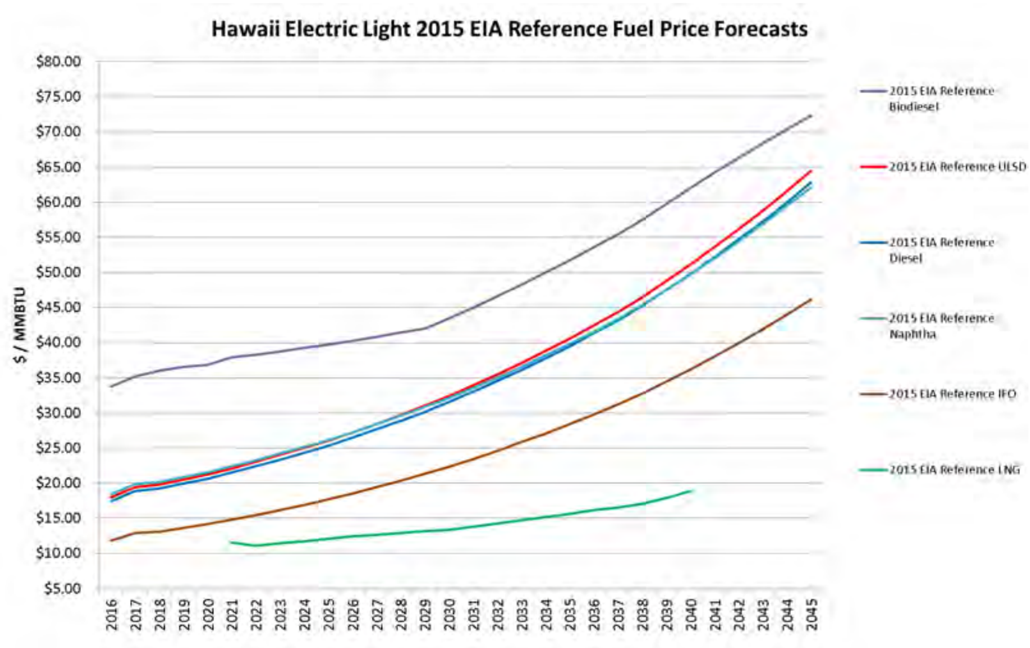


Figure J-8. Hawai'i Electric Light 2015 EIA Reference Fuel Price Forecasts

Hawai'i Electric Light February 2016 EIA STEO Fuel Price Forecasts (Nominal Dollars)

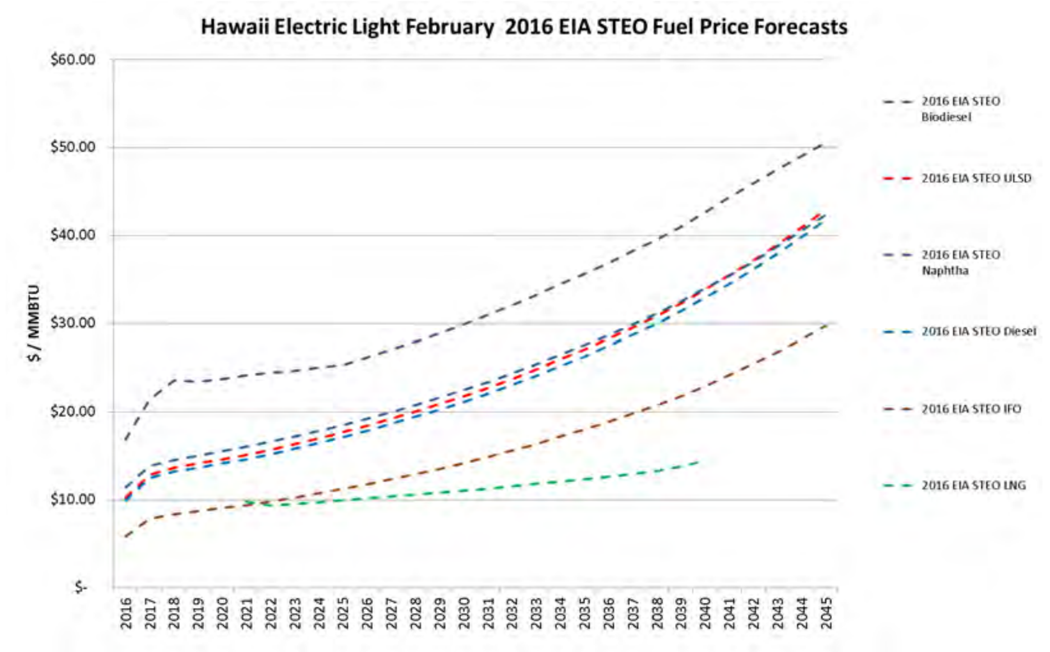


Figure J-9. Hawai'i Electric Light February 2016 EIA STEO Fuel Price Forecasts

ENERGY SALES AND PEAK DEMAND FORECAST

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

The forecast developed for the February 2016 interim filing was one of the key assumptions that fed into the beginning of an iterative process used to determine varying levels of customer adoption of DER and participation in DR programs to achieve system optimization. As described in Appendix C: Analysis Methodologies, the PSIP optimization process involves iterative cycles that analyze DER, DR and utility-scale resources in production simulation and financial rate models toward selecting a preferred plan. Forecast sensitivities were developed as a result of varying the levels of DER and DESS adoption.

Sales and Peak Demand Projections Methodology

The Company develops sales and peak demand forecasts on an annual basis and utilizes the latest information available at the time the forecast is prepared. The sales and peak forecasts adopted in May 2015 for all islands were used as the starting point for the sales and peak demand analyses, as they were the most currently available forecasts. As part of the first iteration in the PSIP optimization process the DG projections in the May 2015 forecast were updated to reflect modifications to the existing Company tariffs identified in Decision and Order No. 33258 in Docket No. 2014-0192 received in October 2015 for use in the February 2016 interim filing. This order approved revised interconnection standards, the closing of the Net Energy Metering program and new options for customers aimed at continuing the growth of rooftop solar while ensuring safe and reliable service.

The methodology for deriving net peak demand and energy requirements to be served by the Company begins with the identification of key factors that affect load growth. These factors include the economic outlook, analysis of existing and proposed large customer loads, and impacts of customer-sited technologies such as energy efficiency measures and customer-sited distributed generation (DG-PV). Impacts from emerging technologies such as electric vehicles (EV) and storage are also evaluated given their significant potential impact on future demand for energy.

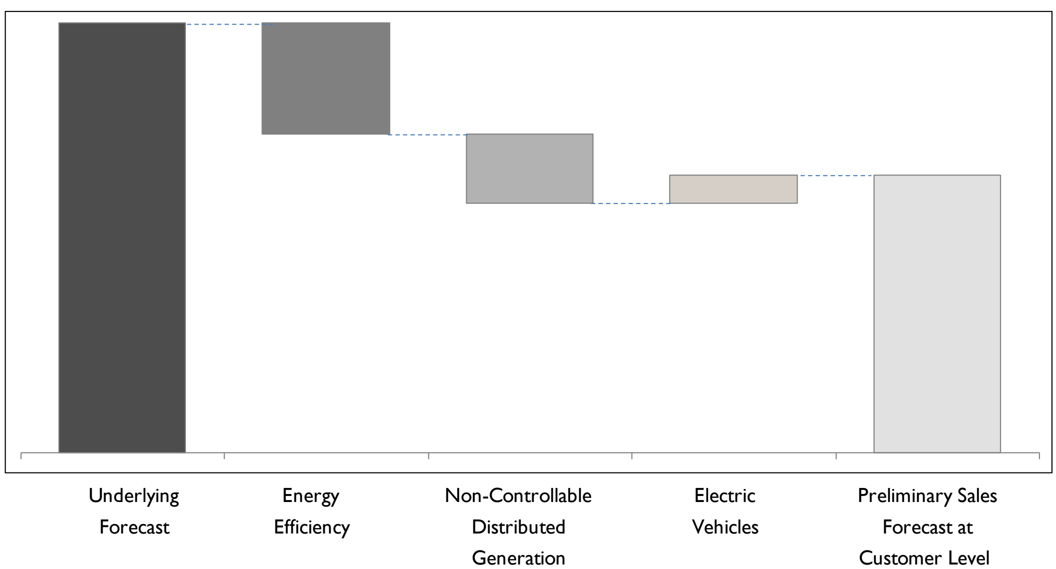
Following the February 2016 interim filing the forecasts (one per island) were updated as sensitivities associated with the DER projections were developed. Two iterations of developing DER forecasts were performed which fed into the PSIP optimization cycle.

Forecast sensitivities focused around varying the levels of DG-PV and DESS adoption as key planning assumptions were adjusted such as the inclusion of integration costs associated with DG-PV penetration and system costs as the adoption of these technologies are sensitive to energy prices among other things.

The Company reached out to Hawaii Energy to assist with the development of alternative energy efficiency forecasts to better address potential uncertainties. At this time, it is a work in progress that is not be available to support the April 2016 PSIP analyses, however, as part of a larger iterative cycle, the PSIP analyses could be incorporated into the ongoing Energy Efficiency Technical Working Group process.

Energy Sales Forecast

In general, the underlying economy driven sales forecast ("underlying forecast") is first derived by using econometric methods and historical sales data, excluding impacts from energy efficiency measures and DG. This methodology captures the impact of economic growth, which are typically the most influential factor when forecasting long-term changes in sales and peak demand. Estimates of impacts from energy efficiency measures, DG installed through the Company's tariffed programs and electric vehicles (referred to as "layers") are then incorporated to adjust the underlying forecast to arrive at a preliminary sales forecast. This methodology is illustrated below in the following chart (Figure J-10). The forecast is then used to drive the DER optimization routine.



Sales forecast will be further modified by future controllable DG export product which will be discussed in later chapters

Figure J-10. Illustrative Waterfall Methodology for Developing the Sales Forecast

The forecasted sales used to be served by each operating company through the study period expressed at the customer level is shown in Figure J-11 through Figure J-15. This forecast depicts the starting point of the iterative cycle used in the February 2016 interim filing analyses. Data for the sales forecast projections are detailed in Table J-10 through Table J-14.

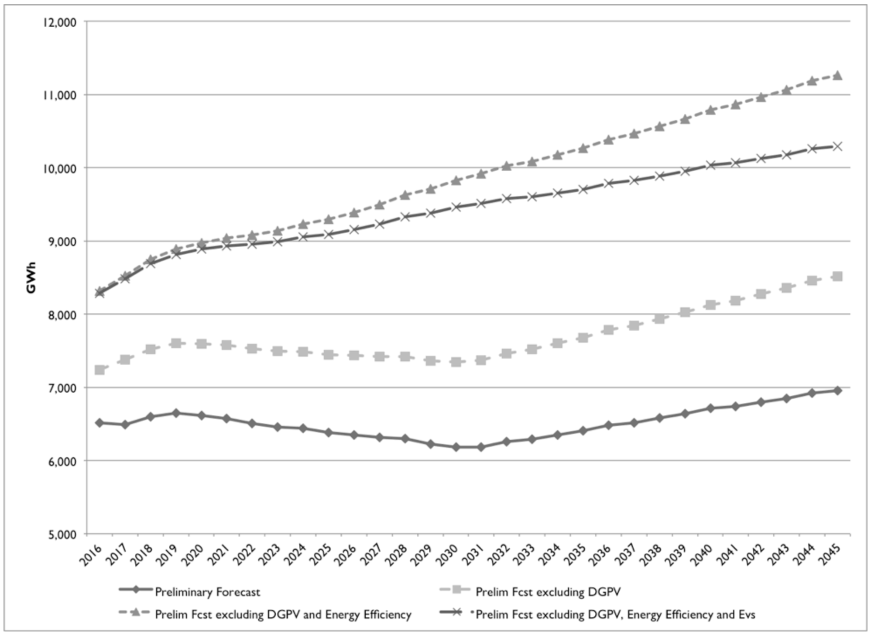


Figure J-11. O'ahu Customer Level Sales Forecast

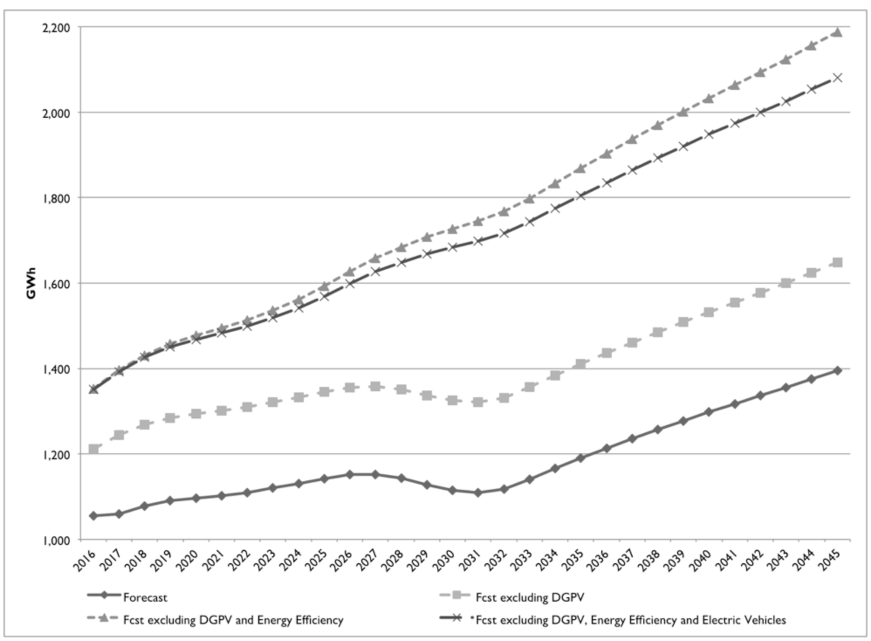


Figure J-12. Maui Island Customer Level Sales Forecast

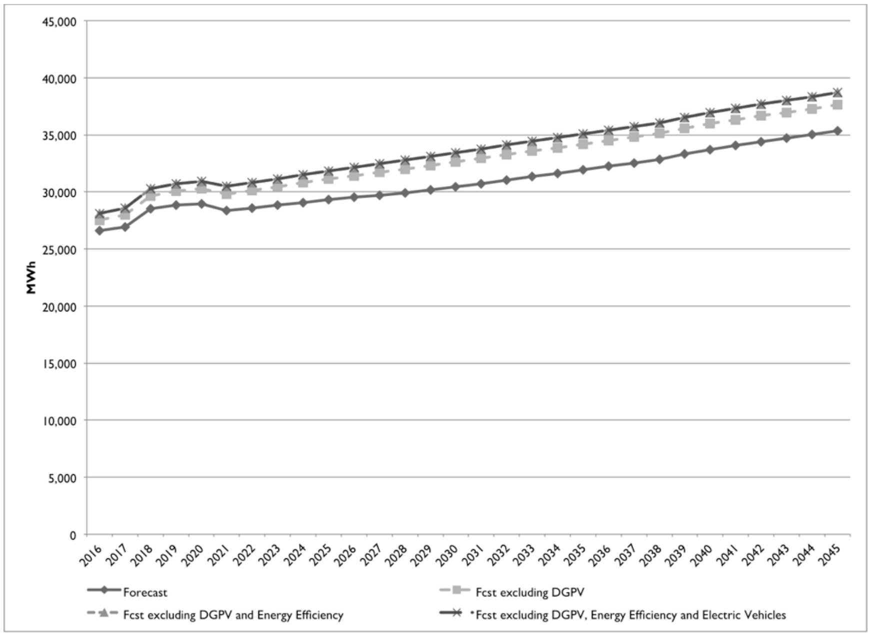


Figure J-13. Lana'i Customer Level Sales Forecast

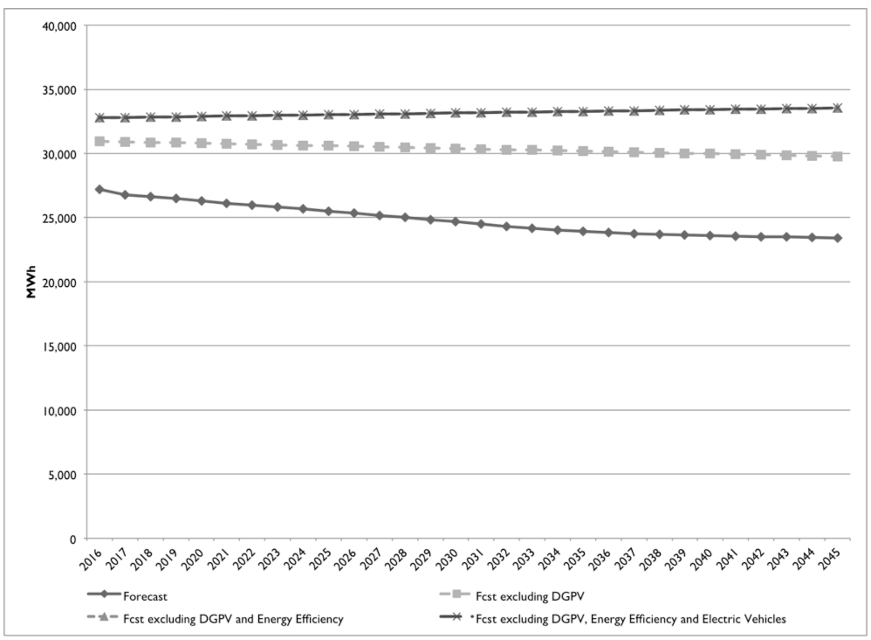


Figure J-14. Moloka'i Customer Level Sales Forecast

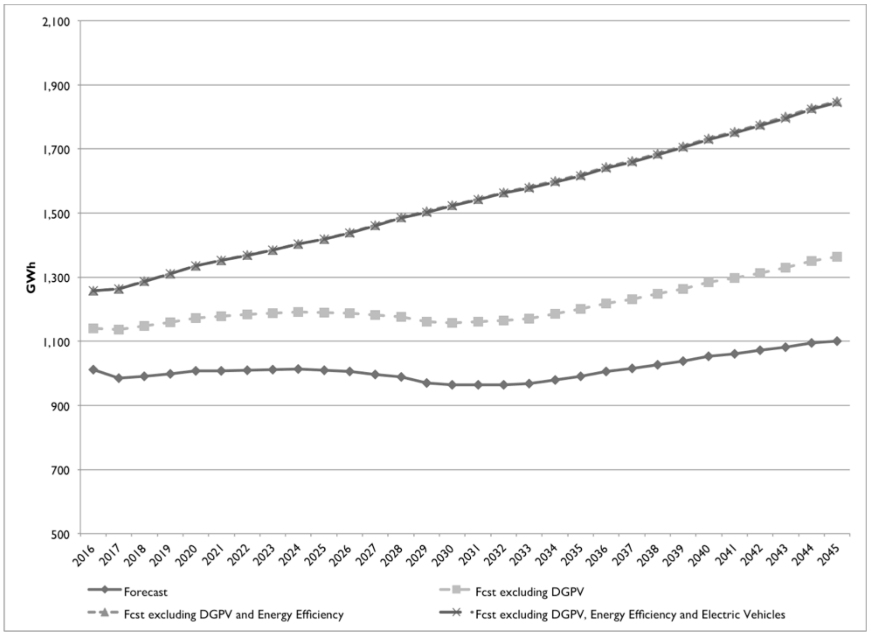


Figure J-15. Hawai‘i Island Customer Level Sales Forecast

Following the February 2016 interim filing two additional DER forecasts were developed as part of the second iteration in the optimization cycle.

Underlying Forecast. The underlying forecast incorporates projections for key drivers of the economy prepared by the University of Hawai‘i Economic Research Organization (UHERO) in April 2015 such as job counts, personal income and resident population. Electricity price and weather variables are also included in the models.

Energy Efficiency. The preliminary projections for impacts associated with energy efficiency measures over the next five to ten years were assumed to be consistent with historical average annual impacts achieved by the Public Benefits Fund Administrator, Hawai‘i Energy. In addition to the impacts from Hawai‘i Energy's programs, changes to building and manufacturing codes and standards would be integrated into the marketplace over time contributing to market transformation. Collectively, these changes would support energy efficiency impacts growing at a faster pace in order to meet the longer term energy efficiency goal in 2030 (expressed in GWh). This pace is identified in the framework that governs the achievement of Energy Efficiency Portfolio Standards (EEPS) in the State of Hawai‘i as prescribed in Hawai‘i Revised Statutes § 269-96, and set by the Commission in Decision and Order No. 30089 in Docket No. 2010-0037. It was assumed the 30% sales reduction goal would continue beyond 2030. The preliminary projections did not consider participation in DR programs.

To determine the peak demand savings from energy efficiency, an average annual ratio between historical efficiency sales and peak impacts was applied to the projected annual energy impacts.

There is a significant uncertainty regarding the degree customers will engage in the adoption of energy efficiency measures, building practices and participation in DR programs. This will have a direct impact on projected sales and peak demand levels. If customer adoption is lower than projected, then demand for energy could exceed the forecasted levels and conversely, higher than projected would lower customer demand for energy. Over the 30-year planning period, participation may be higher or lower than the forecast depending on factors such as customer preferences, general economic conditions and availability of affordable technology. Although all future unknowns cannot be identified, the Company will work together with Hawaiʻi Energy to develop alternative energy efficiency forecasts to better understand and address potential uncertainties.

Distributed Generation. The projections for impacts associated with distributed generation photovoltaic (DG-PV) systems installed under the Company's tariffed programs (legacy NEM, SIA, grid-supply to cap, self-supply and potential future grid-supply) were developed separately by program for residential and commercial customers and aggregated into an overall forecast for DG-PV systems. As part of the iteration process three DG-PV forecasts were developed.

Iteration 1 – February 2016 interim filing

In the near term (through 2017) assumptions based on recent historical activity were made regarding the timing of system installations associated with the remaining applications in the legacy NEM queue. Near term SIA projections (through 2017) were based on known projects with anticipated installation dates in the two year window. Beyond 2017 the Company used a customer adoption model developed by Boston Consulting Group which forecasted future quantities of grid-supply up to the cap, self-supply, SIA and potential future grid-supply DG-PV systems. The model examines the relationship between economics and DG-PV adoption based on payback time, net present value (NPV) and internal rate of return (IRR) from the customer's perspective. For the potential future grid-supply program, it was assumed that exported to the grid would be compensated at utility-scale PV LCOE. A methodology was developed to calculate integration costs, but not yet incorporated in the DG PV adoption forecast.

Figure J-16 through Figure J-18 depicts the preliminary DG-PV forecasts for Oʻahu, Hawaiʻi Island, and Maui developed in iteration 1 to support the February 2016 interim report.

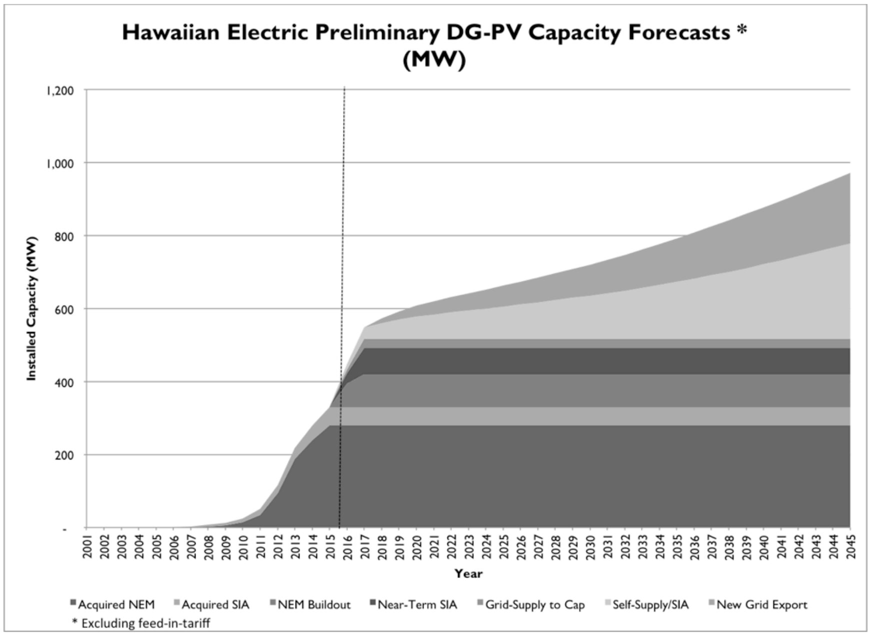


Figure J-16. O'ahu Preliminary DG-PV Capacity Forecasts

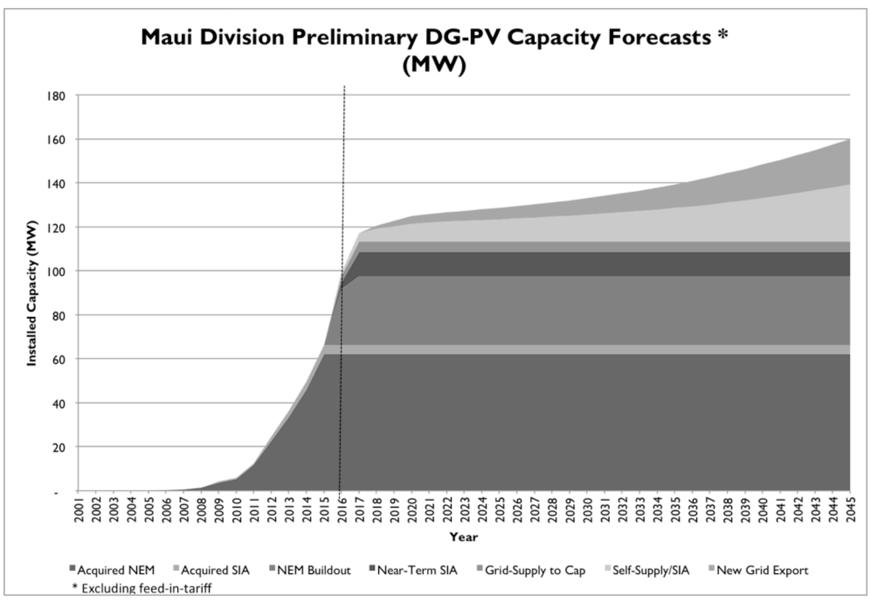


Figure J-17. Maui Island Preliminary DG-PV Capacity Forecasts

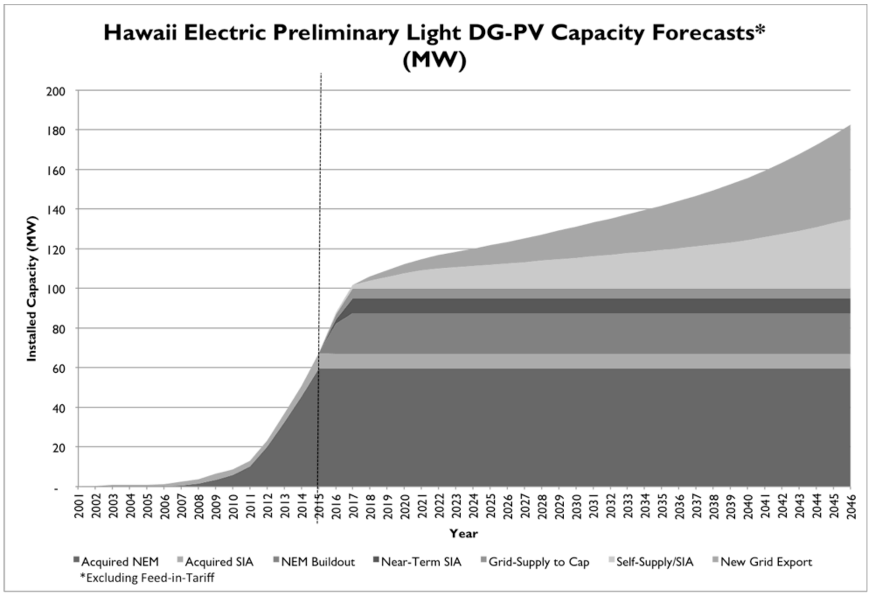


Figure J-18. Hawai'i Island Preliminary DG-PV Capacity Forecasts

Iteration 2 – Inclusion of integration costs

Following the February 2016 interim filing the DG-PV forecast was updated to include integration costs to refine the forecast.

Iteration 2 – Higher DG Market Potential

A higher DG market potential forecast scenario was also developed. For the residential customers the Company assumed that 100% of the single-family residential electricity sales would be offset by DG-PV by 2045. The Company assumed that it was unlikely to offset 100% of the commercial customers' load given the amount of rooftop space required and therefore focused on business sectors that currently participate or are likely to participate in a Company program. Roughly 20-25% of the total commercial sales would be offset by DG-PV in 2045 for all islands with the exception of Lanai (7%) which has fairly low participation to date.

The forecast was not done from a maximum rooftop potential perspective and did not consider whether it was cost effective from a customer or system level perspective. To achieve this higher level of DG-PV will likely require mandates or significant additional customer incentives.

See Figure J-19 through Figure J-23 for a comparison between the three DG-PV forecasts. Data corresponding to the DG-PV forecast figures are detailed in Table J-25 through Table J-29.

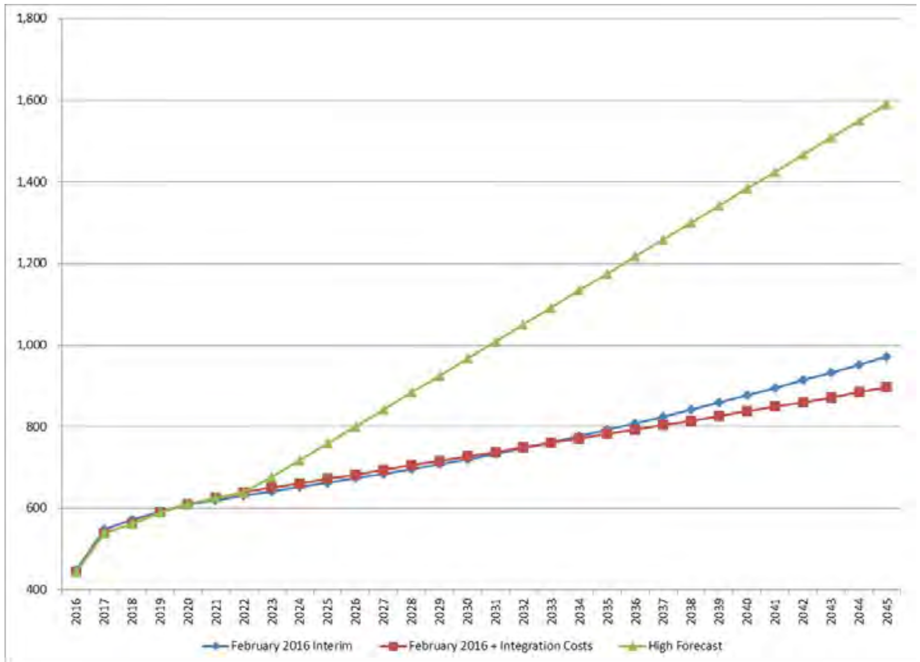


Figure J-19. O'ahu DG-PV Capacity Forecast Comparison

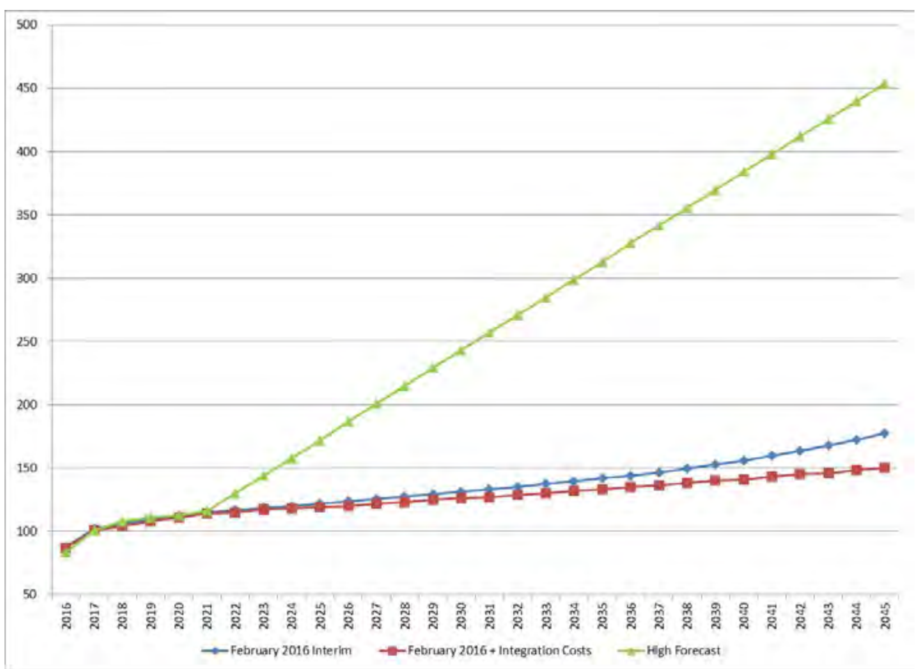


Figure J-20. Maui Island DG-PV Capacity Forecast Comparison

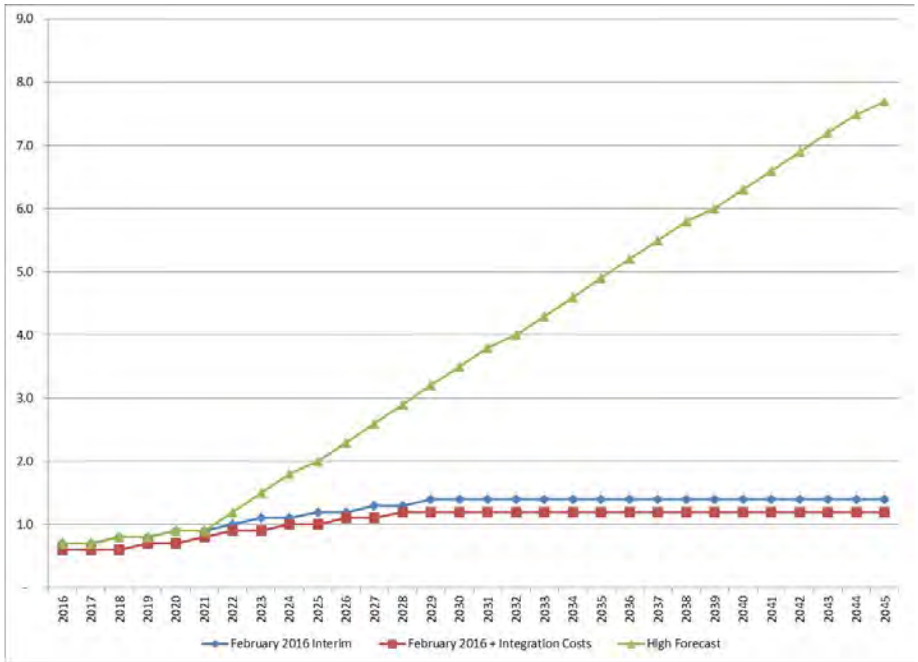


Figure J-21. Lana'i Island DG-PV Capacity Forecast Comparison

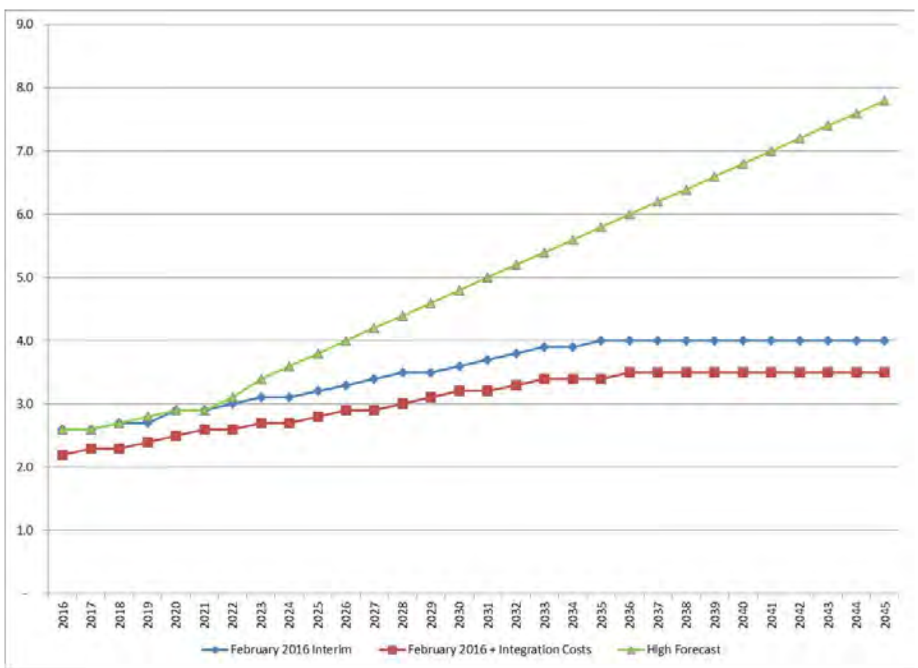


Figure J-22. Moloka'i Island DG-PV Capacity Forecast Comparison

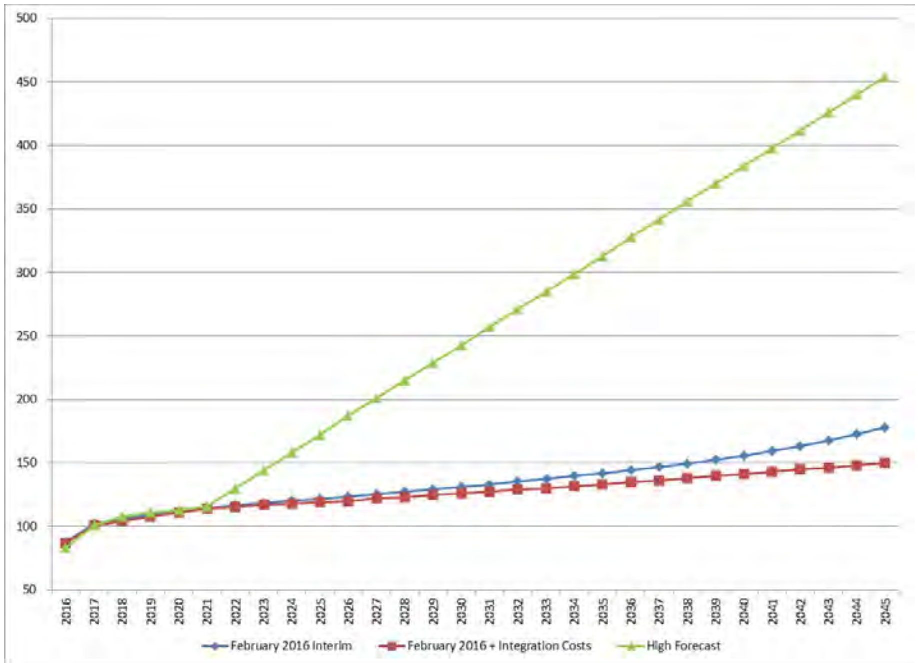


Figure J-23. Hawai'i Island DG-PV Capacity Forecast Comparison

Electric Vehicles. The development of the electric vehicles forecast was based on estimating the number of electric vehicles purchased per year using a historical average annual growth rate then multiplying by an estimate of the annual energy used per vehicle. The annual energy used per vehicle was based on the average miles driven per year as stated in the Hawai'i Data Book multiplied by the energy required per mile averaged over a 2015 Nissan Leaf, Chevy Volt, Chevy Spark and Tesla Model S.

Peak Demand Forecast

The peak demand forecast was derived using Itron's proprietary modeling software, MetrixLT. The software utilizes load profiles by rate schedule from class load studies conducted by the Company and the underlying sales forecast derived by rate schedule. The rate schedule load profiles adjusted for forecasted sales are aggregated to produce system profiles. The Company employed the highest system demands to calculate the underlying annual system. After determining the underlying peak forecast, the Company made adjustments that were outside of the underlying forecasts, for example impacts from energy efficiency measures. No adjustments were made to the underlying system peak forecast for DG-PV or electric vehicles as forecasted system peaks are expected to occur during the evening.

The underlying peak forecast for Lana‘i and Moloka‘i Divisions were derived by employing a sales load factor method which compares the annual sales in MWh against the peak load in MW multiplied by the number of hours during the year.

The peak demands of each operating company forecasted through the study period expressed at the net generation level are in Figure J-24 through Figure J-28 and do not include the impacts of customers' distributed storage systems or the effects of DR programs on the peaks. Data for the peak forecast projections are detailed in Table J-15 through Table J-19.

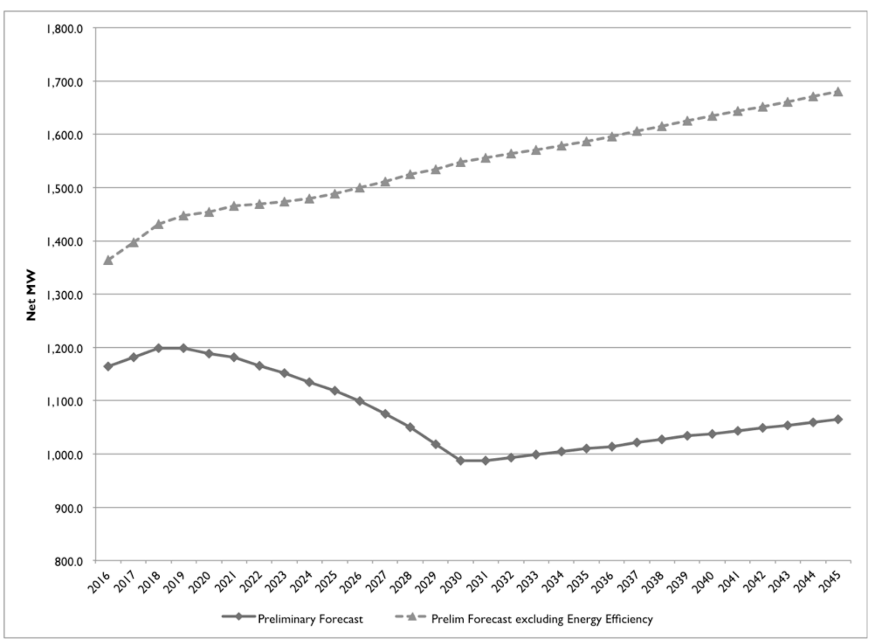


Figure J-24. O‘ahu Generation Level Peak Demand

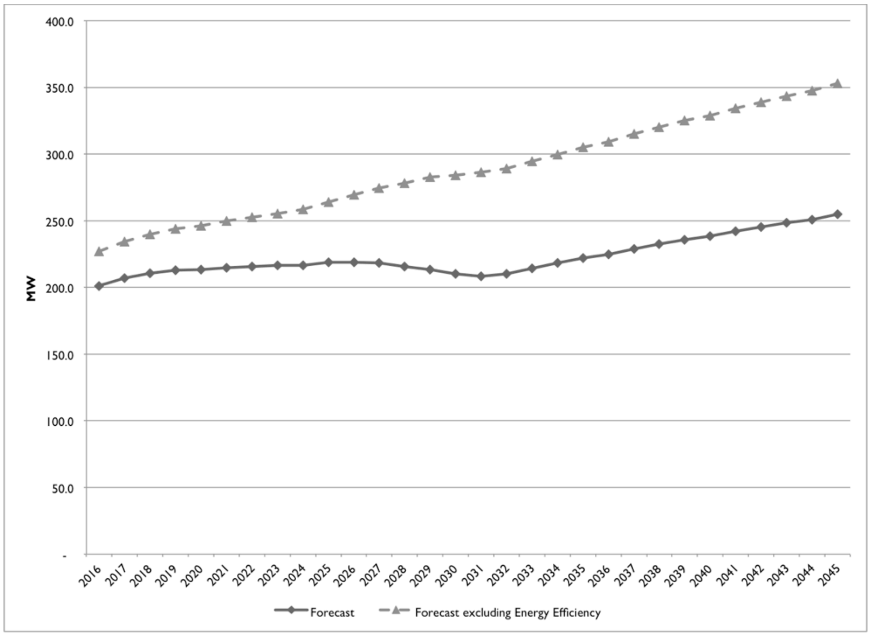


Figure J-25. Maui Island Generation Level Peak Demand

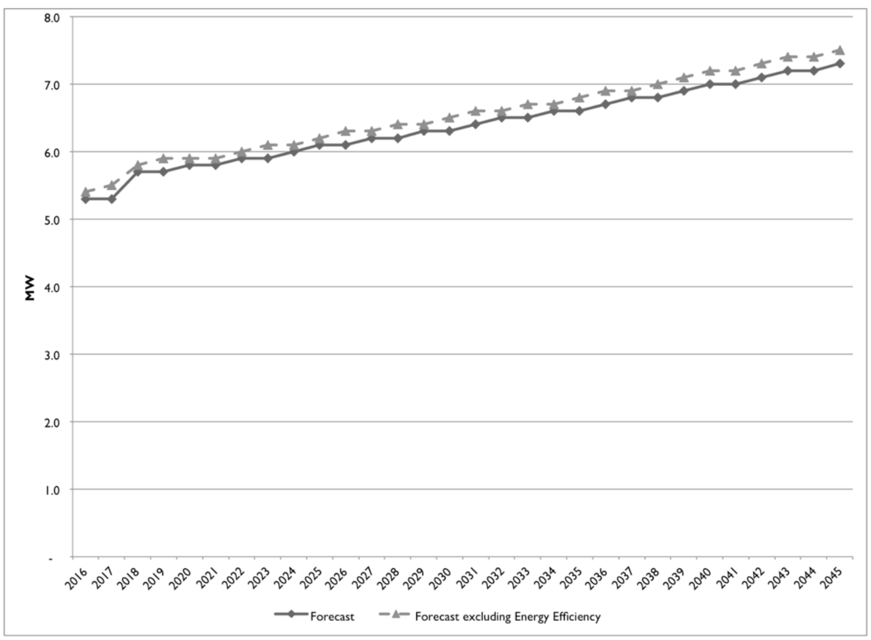


Figure J-26. Lana‘i Generation Level Peak Demand

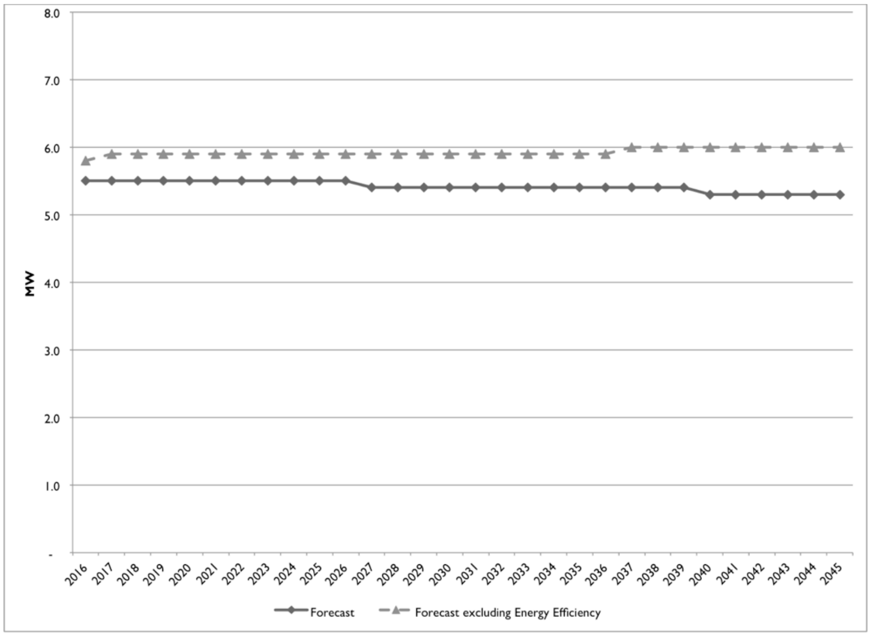


Figure J-27. Moloka'i Generation Level Peak Demand

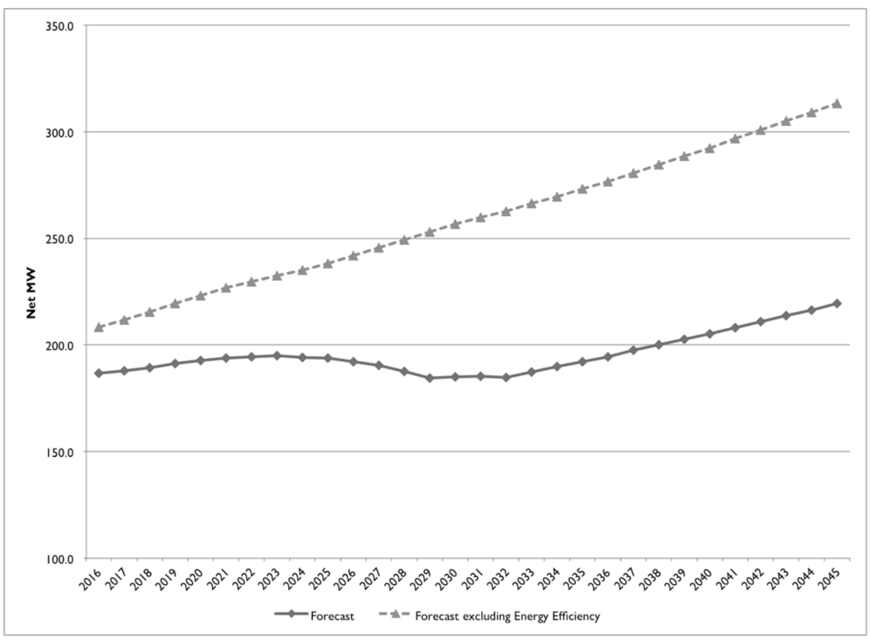


Figure J-28. Hawai'i Island Generation Level Peak Demand

Comparison to the August 2014 PSIP Forecast

The forecasts used in this filing are generally lower than the forecast used in the August 2014 PSIP filing for Hawaiian Electric and Hawaiʻi Electric Light for most of the PSIP planning range (Table J-20 and Table J-24). The primary factors contributing to the lower sales forecast in this filing are: 1) slower economic growth projection used to derive the underlying sales forecast and 2) the higher preliminary DG-PV potential. Although the national and local economy has been recovering since the great recession ended, UHERO lowered their economic outlook forecast to reflect the recovery taking longer and being less resilient than previously expected.

The forecast for Maui Electric used in this filing is similar to, but slightly lower than the forecast used in the August 2014 PSIP filing for the first several years of the PSIP planning range, then generally higher in the longer term (Table J-21 through Table J-23). While the twin effects of a weaker economic outlook and higher preliminary DG-PV potential affects underlying sales for Maui; this is partially mitigated by lower electricity prices in the near-term driving consumption and offsetting downward sales pressure.

A more optimistic real personal income per capita outlook for Maui specifically in 2025 and beyond, contributes to a higher underlying sales forecast in the long-term.

The forecast for Lanaʻi Division used in this filing is higher than the previous forecast used in the PSIP filing as newer information associated with the land owner's plans were incorporated (Table J-22). The near term forecast reflects anticipated changes to the resort operations, and the long term impacts includes assumptions around an increase in the number of people on the island related to the expansion plans.

The forecast for Molokaʻi Division used in this filing is lower than the forecast used in the PSIP filing (Table J-23). The primary factor driving the lower sales forecast is impact associated with the higher preliminary DG-PV potential.

The DG-PV forecasts for all companies reflect continued customer interest in the near term including a faster pace of releasing the legacy NEM queue, the changes made to the Federal Investment Tax Credit beyond 2016, and interest in the new programs such as grid-supply and self-supply. The lower sales were partially offset by the effects of lower electricity prices driven by lower fuel oil prices and new construction projects identified between forecasts. The energy efficiency forecasts were also refreshed with additional historical years of performance by Hawaiʻi Energy and the assumption of achieving a 30% sales reduction in 2030 were applied to different sales forecast resulting in achieving different impact levels. The impacts from the energy efficiency refresh had varying results for each company. Hawaiian Electric's energy impacts were lower in the near term and higher in the long term when compared against the PSIP forecast. Hawaiʻi Electric Light's were higher in the near term and lower in the long term and Maui Division was lower for the entire planning range.

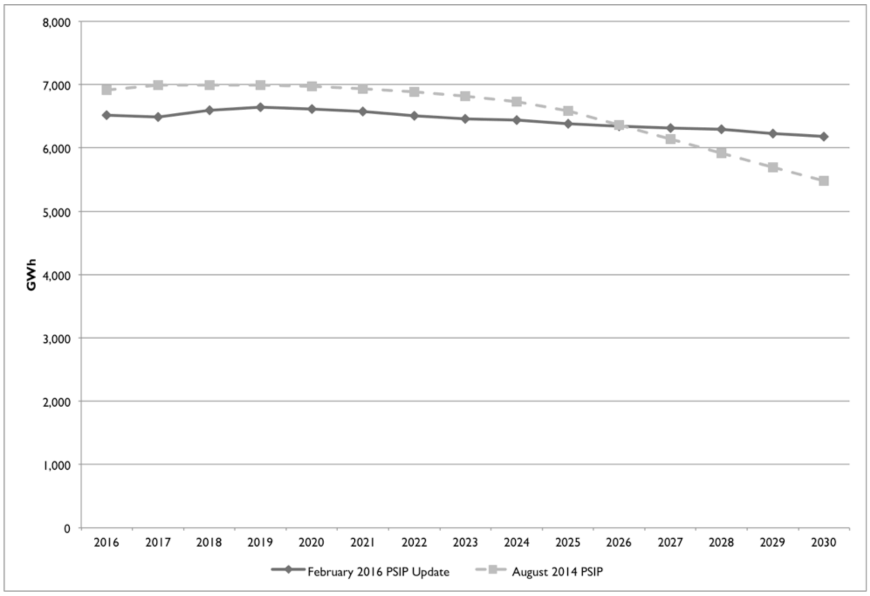


Figure J-29. O'ahu Sales Forecast Comparison

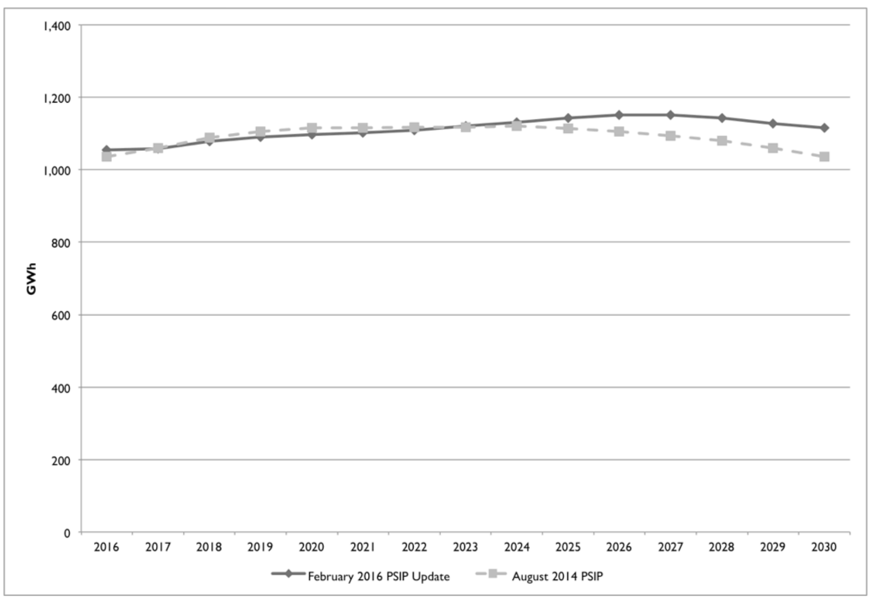


Figure J-30. Maui Island Sales Forecast Comparison

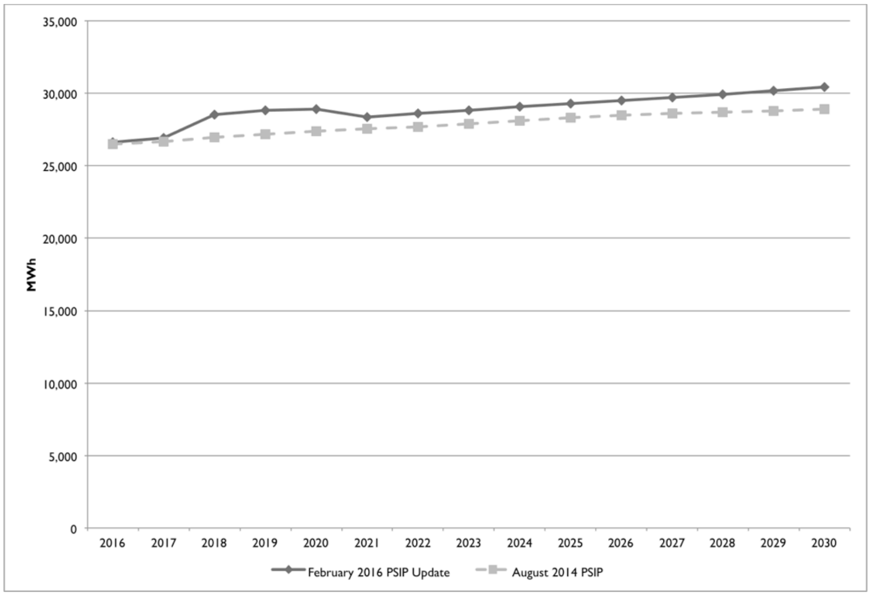


Figure J-31. Lana‘i Sales Forecast Comparison

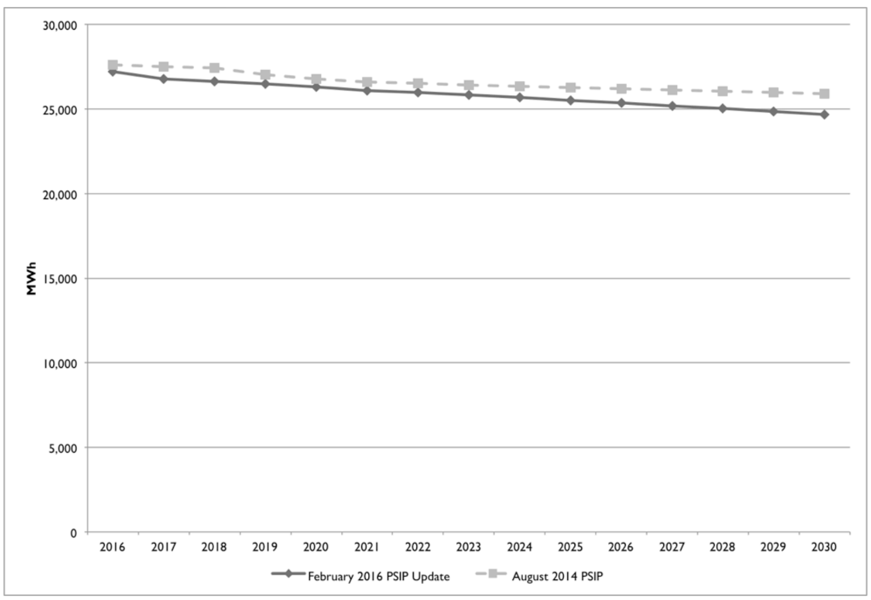


Figure J-32. Moloka‘i Sales Forecast Comparison

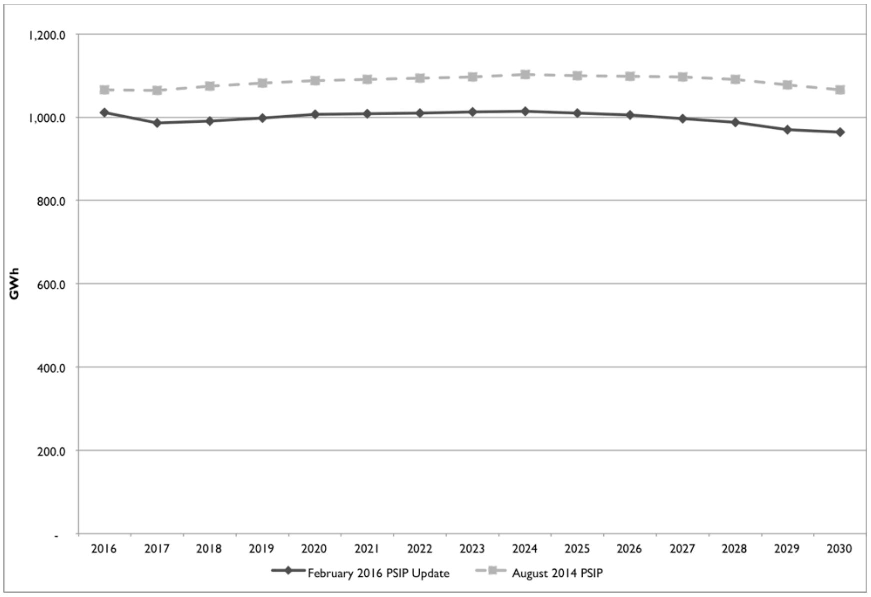


Figure J-33. Hawai'i Island Sales Forecast Comparison

See Table J-20 through Table J-24 for the detailed sales comparison between the preliminary sales forecast and PSIP sales forecast.

Note that the peak forecasts were developed using the method described in the prior page and the differences between the current preliminary forecasts and the PSIP forecast are a result of the differences in the sales forecasts.

UHERO's Economic Forecasts

UHERO's forecasts for non-farm jobs, personal income, and visitor arrivals were used in developing the sales forecasts. Figure J-34 through Figure J-367 compare the economic forecasts developed by UHERO in 2015 against the forecast developed in 2014, illustrating the less optimistic outlook between the two forecasts. See also Table J-30 through Table J-32 for a comparison between UHERO's April 2014 and April 2015 economic forecasts.

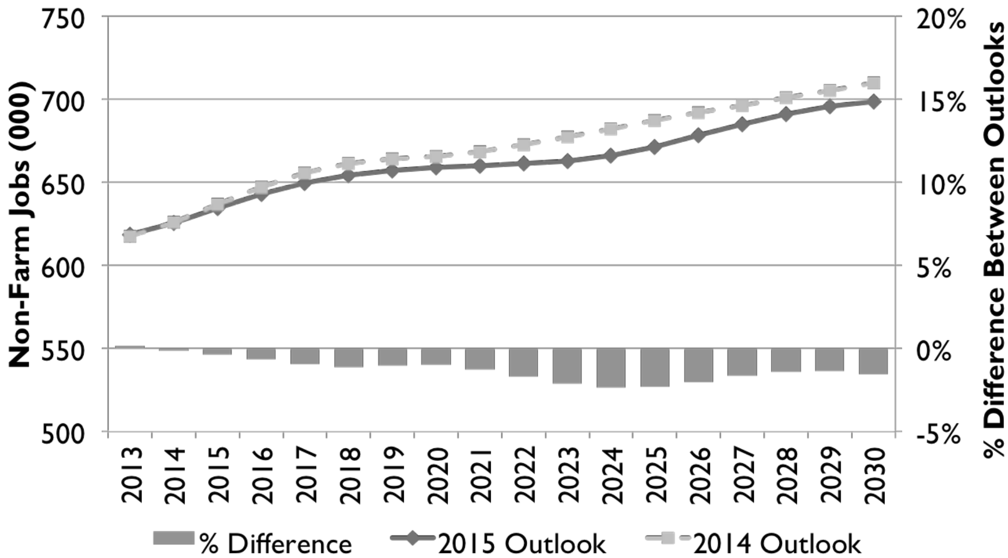


Figure J-34. Hawai'i Non-Farm Job Count Forecast Comparison

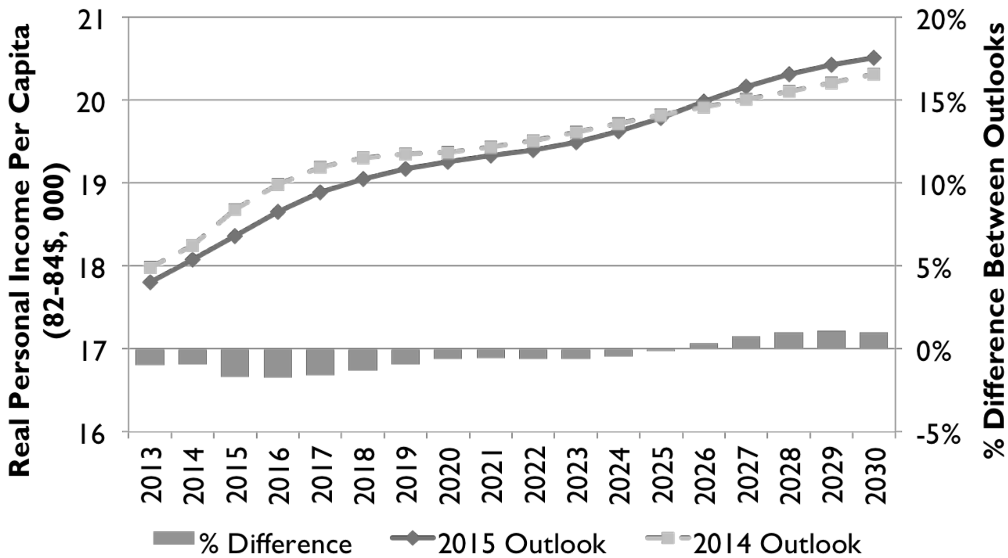


Figure J-35. Hawai'i Real Personal Income per Capita Forecast Comparison

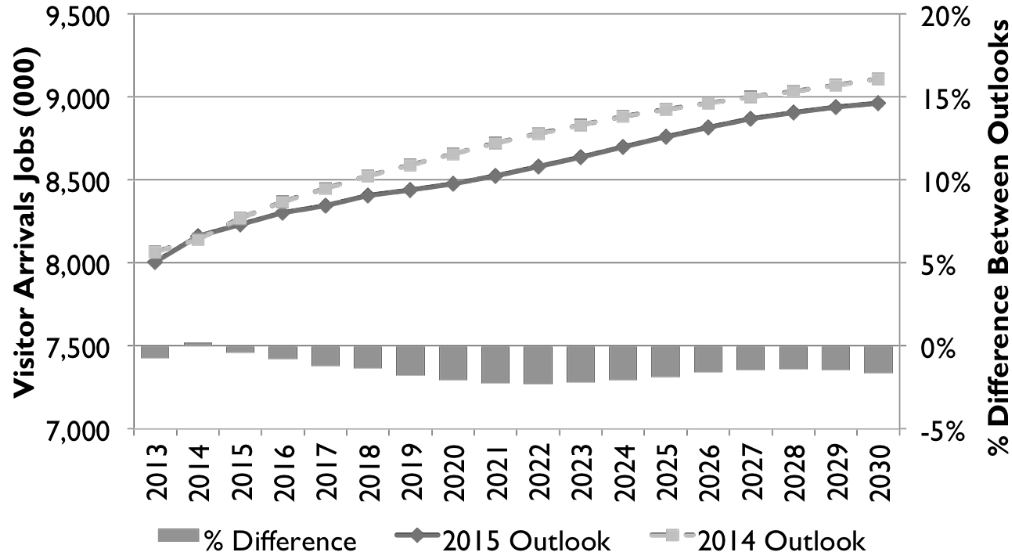


Figure J-36. Hawai'i Visitor Arrival Forecast Comparison

Load Profiles

Available generating resources must be able to meet a demand profile over a period of time that doesn't include customer-sited distributed generation. Our analysis used a demand profile in two ways:

- An annual hourly load profile (8,760 data points: 365 days at 24 hours a day).
- A sub-hourly load profile data, which model intra-hour issues associated with ramping of generating resources and energy storage in response to variable renewable generation.

Because of the proliferation of customer-sited distributed generation, the net load profile has changed dramatically over the past few years. Our analysis assumed a system gross load profile. The model includes the profile of customer-sited distributed generation, which results in the net load to be served.

Sub-Hourly Profile

Black & Veatch has developed sub-hourly profiles for variable generation that includes rooftop solar panels, and utility-scale solar and wind. These profiles form the backbone for evaluating the impacts of variable generation and the fleet's ability to meet demand.

Black & Veatch's model is based on historical changes in minute-to-minute generation by asset type and island. Using historical data, the model creates a probability distribution function based on time of day and current generation levels. The probability, then, is a distribution of all the possible changes in demand for an asset type. Combining this probability with random number generation results in the change in output for the next time step for that asset.

The model "fills in" the sub-hourly generation of each asset in between the hourly generation profiles provided by the Hawaiian Electric planning group. Black & Veatch's model ensures that energy production over each day with the sub-hourly profiles matches the production from the hourly model. This daily energy matching aligns total production with models that employ only hourly data.

The difference between the modeling data for sub-hourly versus hourly is dramatic. Figure J-37 depicts an example day of an hourly profile on the Hawaiian Electric grid and the output profile from the Black & Veatch model.

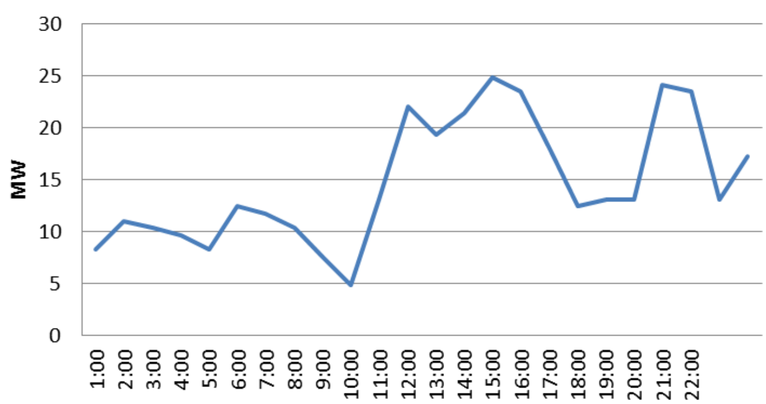


Figure J-37. Wind Unit Day Hourly Profile Example

Figure J-38 depicts an example day of an hourly profile on the Hawaiian Electric grid and the output profile from the Black & Veatch model.

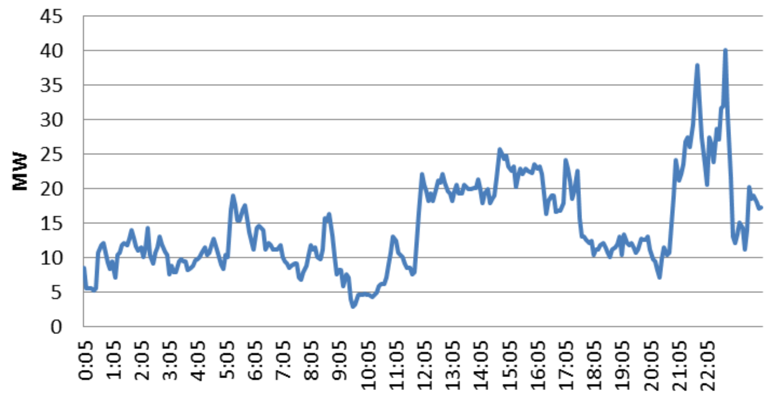


Figure J-38. Wind Unit Day Sub-Hourly Profile Example

SALES FORECASTS

O'ahu Customer Level Sales Forecast – February 2016 Interim

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

Table J-10. O'ahu Customer Level Sales Forecast (GWh)

Maui Island Customer Level Sales Forecast – February 2016 Interim

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

Table J-11. Maui Island Customer Level Sales Forecast (GWh)

Lana'i Customer Level Sales Forecast – February 2016 Interim

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

Table J-12. Lana'i Customer Level Sales Forecast (MWh)

Moloka'i Customer Level Sales Forecast - February 2016 Interim

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

Table J-13. Moloka'i Customer Level Sales Forecast (MWh)

Hawai'i Island Customer Level Sales Forecast - February 2016 Interim

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

Table J-14. Hawai'i Island Customer Level Sales Forecast (GWh)

PEAK DEMAND FORECASTS

O'ahu Generation Level Peak Demand Forecast

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

* System peak occurs in the evening.

Table J-15. O'ahu Generation Level Peak Demand Forecast (MW)

Maui Island Generation Level Peak Demand Forecast

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

* System peak occurs in the evening.

Table J-16. Maui Island Generation Level Peak Demand Forecast (MW)

Lana'i Generation Level Peak Demand Forecast

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

* System peak occurs in the evening.

Table J-17. Lana'i Generation Level Peak Demand Forecast (MW)

Moloka'i Generation Level Peak Demand Forecast

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

* System peak occurs in the evening.

Table J-18. Moloka'i Generation Level Peak Demand Forecast (MW)

Hawai'i Island Generation Level Peak Demand Forecast

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

* System peak occurs in the evening.

Table J-19. Hawai'i Island Generation Level Peak Demand Forecast (MW)

SALES FORECAST COMPARISONS

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

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

Table J-20. O'ahu Interim 2016 PSIP versus 2014 PSIP Sales Forecast Comparisons (GWh)

Maui Island Interim 2016 PSIP versus 2014 PSIP Sales Forecast Comparisons

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

* Includes off-grid and leap year impacts.

Table J-21. Maui Island Interim 2016 PSIP versus 2014 PSIP Sales Forecast Comparisons (GWh)

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

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

* Includes off-grid and leap year impacts.

Table J-22. Lana'i Interim 2016 PSIP versus 2014 PSIP Sales Forecast Comparisons (MWh)

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

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

* Includes off-grid and leap year impacts.

Table J-23. Moloka'i Interim 2016 PSIP versus 2014 PSIP Sales Forecast Comparisons (MWh)

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

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

Table J-24. Hawai'i Island Interim 2016 PSIP versus 2014 PSIP Sales Forecast Comparisons (GWh)

O'ahu DG-PV Forecast Cumulative Installed Capacity

	February 2016 Interim Filing	February 2016+ Integrations Costs	High DG-PV
Year	*MW*	*MW*	*MW*
2016	447	445	445
2017	548	538	538
2018	572	563	563
2019	591	589	589
2020	608	610	610
2021	620	626	626
2022	631	639	639
2023	642	650	676
2024	652	661	717
2025	663	672	759
2026	674	683	800
2027	685	694	842
2028	696	705	884
2029	708	716	925
2030	720	727	967
2031	733	738	1,009
2032	747	749	1,050
2033	761	760	1,092
2034	776	771	1,134
2035	791	782	1,175
2036	808	793	1,217
2037	824	804	1,259
2038	841	815	1,300
2039	859	826	1,342
2040	877	837	1,384
2041	895	849	1,425
2042	914	860	1,467
2043	933	872	1,508
2044	952	884	1,550
2045	971	897	1,592

Table J-25. O'ahu DG-PV Forecast Cumulative Installed Capacity

Maui DG-PV Forecast Cumulative Installed Capacity

	February 2016 Interim Filing	February 2016+ Integrations Costs	High DG-PV
Year	*MW*	*MW*	*MW*
2016	99	98	99
2017	117	115	117
2018	120	118	120
2019	123	122	123
2020	125	124	126
2021	126	126	129
2022	127	127	142
2023	127	128	156
2024	128	129	169
2025	129	130	182
2026	129	130	195
2027	130	131	208
2028	131	132	222
2029	132	133	235
2030	133	134	248
2031	134	135	261
2032	135	136	275
2033	136	137	288
2034	138	138	301
2035	139	139	314
2036	141	140	327
2037	143	142	341
2038	144	143	354
2039	146	144	367
2040	148	145	380
2041	150	147	394
2042	153	148	407
2043	155	150	420
2044	157	151	433
2045	160	153	446

Table J-26. Maui DG-PV Forecast Cumulative Installed Capacity

Lana‘i DG-PV Forecast Cumulative Installed Capacity

	February 2016 Interim Filing	February 2016+ Integrations Costs	High DG-PV
Year	*MW*	*MW*	*MW*
2016	0.7	0.6	0.7
2017	0.7	0.6	0.7
2018	0.8	0.6	0.8
2019	0.8	0.7	0.8
2020	0.9	0.7	0.9
2021	0.9	0.8	0.9
2022	1.0	0.9	1.2
2023	1.1	0.9	1.5
2024	1.1	1.0	1.8
2025	1.2	1.0	2.0
2026	1.2	1.1	2.3
2027	1.3	1.1	2.6
2028	1.3	1.2	2.9
2029	1.4	1.2	3.2
2030	1.4	1.2	3.5
2031	1.4	1.2	3.8
2032	1.4	1.2	4.0
2033	1.4	1.2	4.3
2034	1.4	1.2	4.6
2035	1.4	1.2	4.9
2036	1.4	1.2	5.2
2037	1.4	1.2	5.5
2038	1.4	1.2	5.8
2039	1.4	1.2	6.0
2040	1.4	1.2	6.3
2041	1.4	1.2	6.6
2042	1.4	1.2	6.9
2043	1.4	1.2	7.2
2044	1.4	1.2	7.5
2045	1.4	1.2	7.7

Table J-27. Lana‘i DG-PV Forecast Cumulative Installed Capacity

Moloka'i DG-PV Forecast Cumulative Installed Capacity

	February 2016 Interim Filing	February 2016+ Integrations Costs	High DG-PV
Year	*MW*	*MW*	*MW*
2016	2.6	2.2	2.6
2017	2.6	2.3	2.6
2018	2.7	2.3	2.7
2019	2.7	2.4	2.8
2020	2.9	2.5	2.9
2021	2.9	2.6	2.9
2022	3.0	2.6	3.1
2023	3.1	2.7	3.4
2024	3.1	2.7	3.6
2025	3.2	2.8	3.8
2026	3.3	2.9	4.0
2027	3.4	2.9	4.2
2028	3.5	3.0	4.4
2029	3.5	3.1	4.6
2030	3.6	3.2	4.8
2031	3.7	3.2	5.0
2032	3.8	3.3	5.2
2033	3.9	3.4	5.4
2034	3.9	3.4	5.6
2035	4.0	3.4	5.8
2036	4.0	3.5	6.0
2037	4.0	3.5	6.2
2038	4.0	3.5	6.4
2039	4.0	3.5	6.6
2040	4.0	3.5	6.8
2041	4.0	3.5	7.0
2042	4.0	3.5	7.2
2043	4.0	3.5	7.4
2044	4.0	3.5	7.6
2045	4.0	3.5	7.8

Table J-28. Moloka'i DG-PV Forecast Cumulative Installed Capacity

Hawai‘i Island DG-PV Forecast Cumulative Installed Capacity

	February 2016 Interim Filing	February 2016+ Integrations Costs	High DG-PV
Year	*MW*	*MW*	*MW*
2016	88	87	83
2017	102	101	101
2018	106	104	108
2019	109	108	111
2020	112	111	113
2021	115	114	116
2022	117	115	130
2023	118	117	144
2024	120	118	158
2025	122	119	172
2026	124	120	187
2027	125	122	201
2028	127	123	215
2029	129	125	229
2030	131	126	243
2031	133	127	257
2032	135	129	271
2033	137	130	285
2034	140	132	299
2035	142	133	313
2036	144	135	328
2037	147	136	342
2038	149	138	356
2039	152	140	370
2040	156	141	384
2041	159	143	398
2042	163	145	412
2043	168	146	426
2044	172	148	440
2045	178	150	454

Table J-29. Hawai‘i Island DG-PV Forecast Cumulative Installed Capacity

UHERO STATE OF HAWAI'I FORECASTS

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

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

Table J-30. State of Hawai'i 2014 and 2015 Non-Agricultural Job Forecasts

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

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

Table J-31. State of Hawai'i 2014 and 2015 Real Personal Income per Capita Forecasts ($000)

State of Hawai'i 2014 and 2015 Visitor Arrivals Forecasts

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

Table J-32. State of Hawai'i 2014 and 2015 Visitor Arrivals Forecasts

RESOURCE CAPITAL COSTS

New Resource Cost Assumptions: O‘ahu (1 of 4)

Hawai‘i specific nominal overnight capital cost $/kW$_{AC}$,[2] without AFUDC

Nominal $/kW	Replacement Resource Capital Cost Assumptions: O‘ahu						
Technology	Onshore Wind*	Offshore Wind Floating Platform*	Onshore Wind + Cable*	Onshore Wind + Cable*	Utility-Scale Solar PV*	Solar DG-PV	CSP w/ 10 Hours Storage
Size (MW)	30	400	200	400	20	DG-PV	100
Fuel	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Source	IHS Energy RSMeans	NREL	IHS Energy RSMeans Vendor Quotes	IHS Energy RSMeans Vendor Quotes	IHS Energy RSMeans	IHS Energy RSMeans	NREL
Island	O‘ahu	O‘ahu	Maui to O‘ahu	Maui to O‘ahu	O‘ahu	O‘ahu	O‘ahu
2016	$2,448	$5,061	NA	NA	$2,768	$3,945	$12,304
2017	$2,487	$4,848	NA	NA	$2,602	$3,716	$12,525
2018	$2,426	$4,625	NA	NA	$2,522	$3,573	$11,681
2019	$2,411	$4,564	NA	NA	$2,459	$3,457	$10,781
2020	$2,464	$4,499	$5,095	$4,571	$2,407	$3,360	$9,848
2021	$2,504	$4,430	$5,205	$4,671	$2,367	$3,285	$8,874
2022	$2,570	$4,357	$5,322	$4,777	$2,332	$3,218	$7,867
2023	$2,627	$4,247	$5,454	$4,898	$2,303	$3,160	$7,813
2024	$2,674	$4,132	$5,557	$4,990	$2,279	$3,111	$7,756
2025	$2,705	$4,012	$5,662	$5,083	$2,259	$3,068	$7,694
2026	$2,736	$4,024	$5,755	$5,165	$2,245	$3,034	$7,627
2027	$2,756	$4,036	$5,848	$5,247	$2,232	$3,004	$7,555
2028	$2,788	$4,047	$5,945	$5,332	$2,222	$2,976	$7,478
2029	$2,813	$4,057	$6,047	$5,420	$2,213	$2,952	$7,396
2030	$2,851	$4,066	$6,151	$5,513	$2,207	$2,933	$7,309

* = Amounts have been reduced by the $500,000 state tax credit cap

Table J-33. Replacement Resource Capital Cost Assumptions w/o AFUDC: O‘ahu 2016–2030 (1 of 4)

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

New Resource Cost Assumptions: O‘ahu (2 of 4)

Hawai‘i specific nominal overnight capital cost $/kW$_{AC}$, without AFUDC

Nominal $/kW	Replacement Resource Capital Cost Assumptions: O‘ahu						
Technology	Onshore Wind*	Offshore Wind Floating Platform*	Onshore Wind + Cable*	Onshore Wind + Cable*	Utility-Scale Solar PV*	Solar DG-PV	CSP w/ 10 Hours Storage
Size (MW)	30	400	200	400	20	< 10 kW	100
Fuel	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Source	IHS Energy RSMeans	NREL	IHS Energy RSMeans Vendor Quotes	IHS Energy RSMeans Vendor Quotes	IHS Energy RSMeans	IHS Energy RSMeans	NREL
Island	O‘ahu	O‘ahu	Maui to O‘ahu	Maui to O‘ahu	O‘ahu	O‘ahu	O‘ahu
2031	$2,874	$4,074	$6,254	$5,603	$2,201	$2,925	$7,216
2032	$2,908	$4,081	$6,359	$5,695	$2,196	$2,917	$7,117
2033	$2,933	$4,121	$6,466	$5,788	$2,190	$2,910	$7,245
2034	$2,968	$4,161	$6,575	$5,883	$2,184	$2,902	$7,375
2035	$2,993	$4,201	$6,685	$5,980	$2,178	$2,894	$7,508
2036	$3,028	$4,241	$6,798	$6,078	$2,172	$2,887	$7,643
2037	$3,055	$4,281	$6,912	$6,178	$2,167	$2,879	$7,781
2038	$3,091	$4,321	$7,029	$6,280	$2,161	$2,872	$7,921
2039	$3,118	$4,361	$7,147	$6,384	$2,155	$2,864	$8,064
2040	$3,155	$4,402	$7,268	$6,489	$2,149	$2,856	$8,209
2041	$3,182	$4,442	$7,391	$6,596	$2,144	$2,849	$8,356
2042	$3,220	$4,482	$7,516	$6,705	$2,138	$2,841	$8,507
2043	$3,248	$4,527	$7,643	$6,816	$2,132	$2,834	$8,660
2044	$3,287	$4,571	$7,773	$6,929	$2,126	$2,827	$8,816
2045	$3,316	$4,616	$7,904	$7,044	$2,121	$2,819	$8,975

* = Amounts have been reduced by the $500,000 state tax credit cap

Table J-34. Replacement Resource Capital Cost Assumptions w/o AFUDC: O‘ahu 2031–2045 (2 of 4)

New Resource Cost Assumptions: O'ahu (3 of 4)

Hawai'i specific nominal overnight capital cost $/kW$_{AC}$, without AFUDC

Nominal $/kW	Replacement Resource Capital Cost Assumptions: O'ahu						
Technology	Combined Cycle Gas	Combined Cycle Gas	Simple Cycle Gas	Biomass	Internal Combustion	Internal Combustion	Internal Combustion
Size (MW)	383 (3 x 1)	152 (1 x 1)	100	20	27 (3 x 9 MW)	54 (6 x 9 MW)	100 (6 x 16.8 MW) Power Barge
Fuel	Gas / Oil	Gas / Oil	Gas / Oil	Biomass	Gas / Oil	Gas / Oil	Gas / Oil
Source	NextEra	NextEra	Gas Turbine World RSMeans	NREL	Hawaiian Electric	Hawaiian Electric Schofield Application	Hawaiian Electric
Island	O'ahu	O'ahu	O'ahu	O'ahu, Maui, Hawai'i Island	O'ahu, Maui, Hawai'i Island	O'ahu, Maui, Hawai'i Island	O'ahu
2016	$1,758	$1,660	$1,237	$6,296	$3,177	$2,493	$1,758
2017	$1,783	$1,683	$1,253	$6,092	$3,219	$2,526	$1,783
2018	$1,797	$1,697	$1,261	$6,178	$3,238	$2,541	$1,797
2019	$1,822	$1,720	$1,277	$6,269	$3,280	$2,574	$1,822
2020	$1,845	$1,742	$1,292	$6,354	$3,319	$2,604	$1,845
2021	$1,870	$1,766	$1,309	$6,446	$3,362	$2,638	$1,870
2022	$1,896	$1,790	$1,326	$6,541	$3,406	$2,672	$1,896
2023	$1,921	$1,813	$1,342	$6,633	$3,448	$2,705	$1,921
2024	$1,944	$1,836	$1,358	$6,725	$3,487	$2,736	$1,944
2025	$1,969	$1,859	$1,373	$6,826	$3,527	$2,768	$1,969
2026	$1,992	$1,881	$1,388	$6,918	$3,564	$2,797	$1,992
2027	$2,021	$1,909	$1,408	$7,019	$3,617	$2,838	$2,021
2028	$2,051	$1,937	$1,428	$7,121	$3,668	$2,878	$2,051
2029	$2,079	$1,963	$1,447	$7,222	$3,716	$2,916	$2,079
2030	$2,108	$1,991	$1,466	$7,323	$3,766	$2,955	$2,108

Table J-35. Replacement Resource Capital Cost Assumptions w/o AFUDC: O'ahu 2016–2030 (3 of 4)

New Resource Cost Assumptions: O‘ahu (4 of 4)

Hawai‘i specific nominal overnight capital cost $/kW$_{AC}$, without AFUDC

Nominal $/kW	Replacement Resource Capital Cost Assumptions: O‘ahu						
Technology	Combined Cycle Gas	Combined Cycle Gas	Simple Cycle Gas	Biomass	Internal Combustion	Internal Combustion	Internal Combustion
Size (MW)	383 (3 x 1)	152 (1 x 1)	100	20	27 (3 x 9 MW)	54 (6 x 9 MW)	100 (6 x 16.8 MW) Power Barge
Fuel	Gas / Oil	Gas / Oil	Gas / Oil	Biomass	Gas / Oil	Gas / Oil	Gas / Oil
Source	NextEra	NextEra	Gas Turbine World RSMeans	NREL	Hawaiian Electric	Hawaiian Electric Schofield Application	Hawaiian Electric
Island	O‘ahu	O‘ahu	O‘ahu	O‘ahu, Maui, Hawai‘i Island	O‘ahu, Maui, Hawai‘i Island	O‘ahu, Maui, Hawai‘i Island	O‘ahu
2031	$2,139	$2,019	$1,487	$7,425	$3,819	$2,997	$1,729
2032	$2,169	$2,048	$1,507	$7,528	$3,872	$3,038	$1,761
2033	$2,202	$2,079	$1,530	$7,638	$3,930	$3,083	$1,792
2034	$2,234	$2,110	$1,552	$7,743	$3,986	$3,127	$1,825
2035	$2,270	$2,143	$1,577	$7,850	$4,050	$3,178	$1,857
2036	$2,304	$2,176	$1,601	$7,952	$4,112	$3,226	$1,891
2037	$2,342	$2,211	$1,627	$8,062	$4,179	$3,279	$1,925
2038	$2,379	$2,246	$1,653	$8,166	$4,246	$3,331	$1,959
2039	$2,419	$2,284	$1,681	$8,267	$4,317	$3,387	$1,995
2040	$2,455	$2,318	$1,706	$8,361	$4,382	$3,439	$2,031
2041	$2,499	$2,360	$1,737	$8,512	$4,461	$3,501	$2,067
2042	$2,544	$2,403	$1,768	$8,665	$4,542	$3,564	$2,104
2043	$2,590	$2,446	$1,800	$8,821	$4,623	$3,628	$2,142
2044	$2,637	$2,490	$1,832	$8,979	$4,707	$3,693	$2,181
2045	$2,684	$2,535	$1,865	$9,141	$4,791	$3,760	$2,220

Table J-36. Replacement Resource Capital Cost Assumptions w/o AFUDC: O‘ahu 2031–2045 (4 of 4)

New Resource Cost Assumptions: Maui, Lana‘i, Moloka‘i, Hawai‘i Island (1 of 4)

Hawai‘i specific nominal overnight capital cost $/kW$_{AC}$ (without AFUDC)

Nominal $/kW	Replacement Resource Capital Cost Assumptions: Maui, Lana‘i, Moloka‘i, Hawai‘i Island							
Technology	Onshore Wind*	Onshore Wind*	Onshore Wind*	Onshore Wind*	Utility-Scale Solar PV*	Utility-Scale Solar PV*	Utility-Scale Solar PV*	Utility-Scale Solar PV*
Size (MW)	10	20	30	1 (10 x 100 kW)	1	5	10	20
Fuel	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Source	IHS, RSMeans	IHS, RSMeans	IHS, RSMeans	Indicative quote from NPS + install estimate	IHS, RSMeans	IHS, RSMeans	IHS, RSMeans	IHS, RSMeans
Island	Hawai‘i Maui	Hawai‘i Maui	Hawai‘i Maui	Lana‘i Moloka‘i	Lana‘i Moloka‘i	Hawai‘i Maui	Hawai‘i Maui	Hawai‘i Maui
2016	$4,121	$2,943	$2,448	$4,900	$3,523	$3,162	$2,799	$2,549
2017	$4,187	$2,990	$2,487	$5,044	$3,283	$2,968	$2,630	$2,396
2018	$4,084	$2,916	$2,426	$4,909	$3,169	$2,876	$2,549	$2,323
2019	$4,058	$2,898	$2,411	$4,842	$3,077	$2,801	$2,484	$2,264
2020	$4,148	$2,962	$2,464	$4,958	$3,003	$2,741	$2,431	$2,216
2021	$4,216	$3,010	$2,504	$5,088	$2,946	$2,695	$2,391	$2,180
2022	$4,327	$3,089	$2,570	$5,234	$2,896	$2,654	$2,355	$2,148
2023	$4,425	$3,159	$2,627	$5,416	$2,853	$2,620	$2,325	$2,121
2024	$4,503	$3,215	$2,674	$5,520	$2,819	$2,591	$2,301	$2,098
2025	$4,556	$3,252	$2,705	$5,622	$2,790	$2,569	$2,281	$2,080
2026	$4,609	$3,290	$2,736	$5,692	$2,770	$2,552	$2,266	$2,067
2027	$4,643	$3,314	$2,756	$5,758	$2,751	$2,537	$2,253	$2,055
2028	$4,697	$3,352	$2,788	$5,830	$2,736	$2,525	$2,242	$2,046
2029	$4,739	$3,382	$2,813	$5,910	$2,724	$2,515	$2,234	$2,038
2030	$4,803	$3,428	$2,851	$5,995	$2,716	$2,508	$2,228	$2,032

* = Amounts have been reduced by the $500,000 state tax credit cap

Table J-37. Replacement Resource Capital Cost Assumptions w/o AFUDC: Maui, Lana‘i, Moloka‘i, Hawai‘i Island 2016–2030 (1 of 4)

New Resource Cost Assumptions: Maui, Lana‘i, Moloka‘i, Hawai‘i Island (2 of 4)

Hawai‘i specific nominal overnight capital cost $/kW$_{AC}$ (without AFUDC)

Nominal $/kW	Replacement Resource Capital Cost Assumptions: Maui, Lana‘i, Moloka‘i, Hawai‘i Island							
Technology	Onshore Wind*	Onshore Wind*	Onshore Wind*	Onshore Wind*	Utility-Scale Solar PV*	Utility-Scale Solar PV*	Utility-Scale Solar PV*	Utility-Scale Solar PV*
Size (MW)	10	20	30	1 (10 x 100 kW)	1	5	10	20
Fuel	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Source	IHS, RSMeans	IHS, RSMeans	IHS, RSMeans	Indicative quote from NPS + install estimate	IHS, RSMeans	IHS, RSMeans	IHS, RSMeans	IHS, RSMeans
Island	Hawai‘i Maui	Hawai‘i Maui	Hawai‘i Maui	Lana‘i Moloka‘i	Lana‘i Moloka‘i	Hawai‘i Maui	Hawai‘i Maui	Hawai‘i Maui
2031	$4,842	$3,456	$2,874	$6,071	$2,707	$2,501	$2,222	$2,027
2032	$4,900	$3,497	$2,908	$6,149	$2,699	$2,494	$2,216	$2,022
2033	$4,942	$3,527	$2,933	$6,227	$2,690	$2,487	$2,210	$2,016
2034	$5,001	$3,569	$2,968	$6,307	$2,682	$2,480	$2,204	$2,011
2035	$5,043	$3,599	$2,993	$6,387	$2,673	$2,474	$2,198	$2,006
2036	$5,104	$3,642	$3,028	$6,468	$2,665	$2,467	$2,192	$2,000
2037	$5,148	$3,673	$3,055	$6,551	$2,657	$2,460	$2,186	$1,995
2038	$5,209	$3,717	$3,091	$6,634	$2,648	$2,453	$2,180	$1,990
2039	$5,254	$3,749	$3,118	$6,718	$2,640	$2,447	$2,174	$1,984
2040	$5,317	$3,794	$3,155	$6,803	$2,632	$2,440	$2,168	$1,979
2041	$5,364	$3,827	$3,182	$6,889	$2,624	$2,433	$2,163	$1,974
2042	$5,428	$3,872	$3,220	$6,977	$2,615	$2,427	$2,157	$1,968
2043	$5,475	$3,906	$3,248	$7,065	$2,607	$2,420	$2,151	$1,963
2044	$5,541	$3,953	$3,287	$7,154	$2,599	$2,413	$2,145	$1,958
2045	$5,590	$3,988	$3,316	$7,244	$2,591	$2,407	$2,139	$1,953

* = Amounts have been reduced by the $500,000 state tax credit cap

Table J-38. Replacement Resource Capital Cost Assumptions w/o AFUDC: Maui, Lana‘i, Moloka‘i, Hawai‘i Island 2031–2045 (2 of 4)

New Resource Cost Assumptions: Maui, Lana‘i, Moloka‘i, Hawai‘i Island (3 of 4)

Hawai‘i specific nominal overnight capital cost $/kW$_{AC}$ (without AFUDC)

Nominal $/kW	Replacement Resource Capital Cost Assumptions: Maui, Lana‘i, Moloka‘i, Hawai‘i Island						
Technology	DG Solar PV	Simple Cycle Gas	Biomass	Biomass	Geothermal	Internal Combustion	Internal Combustion
Size (MW)	DG-PV	20.5	1	20	20	1	9
Fuel	n/a	Gas / Oil	Biomass	Biomass	n/a	Oil	Gas / Oil
Source	IHS, RSMeans	NextEra	HECO Research of Comparable Plants	NREL	NREL	NextEra	NextEra
Island	Hawai‘i, Maui, Lana‘i, Moloka‘i	Hawai‘i Maui	Lana‘i, Moloka‘i	Hawai‘i Maui	Hawai‘i Maui	Lana‘i, Moloka‘i	Hawai‘i Maui
2016	$3,985	$3,586	$8,334	$6,296	$8,804	$10,394	$5,407
2017	$3,753	$3,634	$8,064	$6,092	$8,963	$10,532	$5,479
2018	$3,609	$3,655	$8,179	$6,178	$9,124	$10,593	$5,510
2019	$3,492	$3,702	$8,298	$6,269	$9,289	$10,731	$5,582
2020	$3,394	$3,747	$8,411	$6,354	$9,456	$10,859	$5,649
2021	$3,318	$3,795	$8,533	$6,446	$9,626	$11,000	$5,722
2022	$3,251	$3,844	$8,659	$6,541	$9,799	$11,142	$5,796
2023	$3,192	$3,892	$8,781	$6,633	$9,976	$11,280	$5,868
2024	$3,142	$3,936	$8,902	$6,725	$10,155	$11,408	$5,935
2025	$3,100	$3,981	$9,036	$6,826	$10,338	$11,540	$6,003
2026	$3,065	$4,023	$9,158	$6,918	$10,524	$11,661	$6,066
2027	$3,034	$4,082	$9,291	$7,019	$10,713	$11,832	$6,155
2028	$3,007	$4,140	$9,427	$7,121	$10,906	$12,000	$6,243
2029	$2,982	$4,194	$9,560	$7,222	$11,103	$12,157	$6,324
2030	$2,962	$4,251	$9,694	$7,323	$11,302	$12,322	$6,410

Table J-39. Replacement Resource Capital Cost Assumptions w/o AFUDC: Maui, Lana‘i, Moloka‘i, Hawai‘i Island 2016–2030 (3 of 4)

New Resource Cost Assumptions: Maui, Lana'i, Moloka'i, Hawai'i Island (4 of 4)

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

Nominal $/kW	Replacement Resource Capital Cost Assumptions: Maui, Lana'i, Moloka'i, Hawai'i Island						
Technology	DG Solar PV	Simple Cycle Gas	Biomass	Biomass	Geothermal	Internal Combustion	Internal Combustion
Size (MW)	DG-PV	20.5	1	20	20	1	9
Fuel	n/a	Gas / Oil	Biomass	Biomass	n/a	Oil	Gas / Oil
Source	IHS, RSMeans	NextEra	HECO Research of Comparable Plants	NREL	NREL	NextEra	NextEra
Island	Hawai'i, Maui, Lana'i, Moloka'i	Hawai'i Maui	Lana'i, Moloka'i	Hawai'i Maui	Hawai'i Maui	Lana'i, Moloka'i	Hawai'i Maui
2031	$2,955	$4,311	$9,829	$7,425	$11,506	$12,494	$6,500
2032	$2,947	$4,371	$9,966	$7,528	$11,713	$12,668	$6,590
2033	$2,939	$4,436	$10,111	$7,638	$11,924	$12,856	$6,688
2034	$2,931	$4,499	$10,250	$7,743	$12,138	$13,040	$6,783
2035	$2,924	$4,571	$10,391	$7,850	$12,357	$13,250	$6,893
2036	$2,916	$4,641	$10,527	$7,952	$12,579	$13,453	$6,998
2037	$2,908	$4,717	$10,673	$8,062	$12,806	$13,672	$7,112
2038	$2,901	$4,792	$10,810	$8,166	$13,036	$13,890	$7,226
2039	$2,893	$4,873	$10,944	$8,267	$13,271	$14,123	$7,347
2040	$2,885	$4,947	$11,068	$8,361	$13,510	$14,338	$7,459
2041	$2,878	$5,036	$11,267	$8,512	$13,753	$14,596	$7,593
2042	$2,870	$5,126	$11,470	$8,665	$14,001	$14,859	$7,730
2043	$2,863	$5,219	$11,677	$8,821	$14,253	$15,126	$7,869
2044	$2,855	$5,313	$11,887	$8,979	$14,509	$15,398	$8,010
2045	$2,848	$5,408	$12,101	$9,141	$14,770	$15,676	$8,154

Table J-40. Replacement Resource Capital Cost Assumptions w/o AFUDC: Maui, Lana'i, Moloka'i, Hawai'i Island 2031–2045 (4 of 4)

Hawaiian Electric
Maui Electric
Hawai'i Electric Light

Replacement Resource Construction Expenditure Profiles: O'ahu

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

Table J-41. Replacement Resource Construction Expenditure Profiles: O'ahu (1 of 2)

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

Table J-42. Replacement Resource Construction Expenditure Profiles: O'ahu (2 of 2)

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

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

Table J-43. Replacement Resource Construction Expenditure Profiles: Maui, Lana'i, Moloka'i, Hawai'i Island (1 of 2)

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

Table J-44. Replacement Resource Construction Expenditure Profiles: Maui, Lana'i, Moloka'i, Hawai'i Island (2 of 2)

Energy Storage Cost Assumptions: Inertia and Contingency Applications (1 of 2)

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

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

Table J-45. Energy Storage Cost Assumptions: Inertia and Contingency Applications 2016–2030 (1 of 2)

Energy Storage Cost Assumptions: Inertia and Contingency Applications (2 of 2)

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

Nominal $/kWh	Energy Storage Cost Assumptions: Inertia and Contingency Applications					
Application	Inertia	Contingency				
Size (MW)	10	1	5	20	50	100
Technology	Flywheel	Lithium-Ion				
Duration Hours	0.25	0.5				
Turnaround Efficiency	85%	81%				
Discharge Cycles Per Year	15,000	Up to 10				
Depth of Discharge	100%	Up to 100%				
Plant Life Years	15%	15				
2031	$4,409	$706	$706	$706	$706	$706
2032	$4,327	$693	$693	$693	$693	$693
2033	$4,255	$682	$682	$682	$682	$682
2034	$4,190	$671	$671	$671	$671	$671
2035	$4,133	$662	$662	$662	$662	$662
2036	$4,083	$654	$654	$654	$654	$654
2037	$4,038	$647	$647	$647	$647	$647
2038	$3,998	$641	$641	$641	$641	$641
2039	$3,962	$635	$635	$635	$635	$635
2040	$3,930	$630	$630	$630	$630	$630
2041	$3,902	$625	$625	$625	$625	$625
2042	$3,876	$621	$621	$621	$621	$621
2043	$3,854	$617	$617	$617	$617	$617
2044	$3,833	$614	$614	$614	$614	$614
2045	$3,815	$611	$611	$611	$611	$611

Table J-46. Energy Storage Cost Assumptions: Inertia and Contingency Applications 2031–2045 (2 of 2)

Energy Storage Cost Assumptions: Regulation / Renewable Smoothing Applications (1 of 2)

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

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

Table J-47. Energy Storage Cost Assumptions: Regulation / Renewable Smoothing 2016–2030 (1 of 2)

Energy Storage Cost Assumptions: Regulation / Renewable Smoothing Applications (2 of 2)

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

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

Table J-48. Energy Storage Cost Assumptions: Regulation / Renewable Smoothing Applications 2031–2045 (2 of 2)

Energy Storage Cost Assumptions: Load Shifting and Grid Support Applications (1 of 2)

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

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

Table J-49. Energy Storage Cost Assumptions: Load Shifting and Grid Support Applications 2016–2030 (1 of 2)

Energy Storage Cost Assumptions: Load Shifting and Grid Support Applications (2 of 2)

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

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

Table J-50. Energy Storage Cost Assumptions: Load Shifting and Grid Support Applications 2031–2045 (2 of 2)

Energy Storage Cost Assumptions: Residential, Commercial, and Long Duration Load Shifting Applications (1 of 2)

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

Nominal $/kWh	Energy Storage Cost Assumptions: Residential, Commercial, and Long Duration Load Shifting Applications						
Application	Residential		Commercial		Long Duration Load Shifting		
Size (MW)	0.002		0.050	1.000	30.000	30.000	50.000
Technology	Lithium-Ion w/o inverter	Lithium-Ion w/ inverter & Balance of Plant	Lithium-Ion		Lithium-Ion	Pumped-Storage Hydro	
Duration Hours	4.0		2.0		6.0		
Turnaround Efficiency	88%		88%		80%		
Discharge Cycles Per Year	Up to 365		Up to 365		Up to 365		
Depth of Discharge	Up to 100%		Up to 100%		Up to 100%		
Plant Life Years	10		10		15	40	
2016	$506	$1,026	$553	$553	$530	$583	$583
2017	$465	$961	$511	$511	$493	$594	$594
2018	$416	$884	$461	$461	$454	$605	$605
2019	$373	$817	$417	$417	$421	$615	$615
2020	$335	$757	$378	$378	$391	$626	$626
2021	$317	$729	$359	$359	$371	$638	$638
2022	$303	$706	$342	$342	$353	$649	$649
2023	$290	$687	$328	$328	$339	$661	$661
2024	$280	$670	$316	$316	$326	$673	$673
2025	$270	$655	$305	$305	$316	$685	$685
2026	$262	$643	$296	$296	$306	$697	$697
2027	$256	$632	$289	$289	$298	$710	$710
2028	$250	$623	$282	$282	$291	$723	$723
2029	$245	$615	$276	$276	$285	$736	$736
2030	$240	$608	$271	$271	$280	$749	$749

Table J-51. Energy Storage Cost Assumptions: Residential, Commercial, and Long Duration Load Shifting Applications 2016–2030 (1 of 2)

Energy Storage Cost Assumptions: Residential, Commercial, and Long Duration Load Shifting Applications (2 of 2)

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

Nominal $/kWh	Energy Storage Cost Assumptions: Residential, Commercial, and Long Duration Load Shifting Applications						
Application	Residential		Commercial		Long Duration Load Shifting		
Size (MW)	0.002		0.050	1.000	30.000	30.000	50.000
Technology	Lithium-Ion w/o inverter	Lithium-Ion w/ inverter & Balance of Plant	Lithium-Ion		Lithium-Ion	Pumped-Storage Hydro	
Duration Hours	4.0		2.0		6.0		
Turnaround Efficiency	88%		88%		80%		
Discharge Cycles Per Year	Up to 365		Up to 365		Up to 365		
Depth of Discharge	Up to 100%		Up to 100%		Up to 100%		
Plant Life Years	10		10		15	40	
2016	$236	$601	$267	$267	$275	$762	$762
2017	$232	$596	$263	$263	$271	$776	$776
2018	$229	$591	$259	$259	$268	$790	$790
2019	$227	$587	$256	$256	$264	$804	$804
2020	$224	$583	$253	$253	$262	$819	$819
2021	$222	$579	$251	$251	$259	$833	$833
2022	$220	$576	$249	$249	$257	$848	$848
2023	$218	$574	$247	$247	$255	$864	$864
2024	$217	$571	$245	$245	$253	$879	$879
2025	$216	$569	$243	$243	$252	$895	$895
2026	$214	$567	$242	$242	$250	$911	$911
2027	$213	$565	$241	$241	$249	$928	$928
2028	$212	$564	$240	$240	$248	$944	$944
2029	$211	$563	$239	$239	$247	$961	$961
2030	$211	$561	$238	$238	$246	$979	$979

Table J-52. Energy Storage Cost Assumptions: Residential, Commercial, and Long Duration Load Shifting Applications 2030–2045 (2 of 2)

Energy Storage Construction Expenditure Profiles: Inertia and Contingency Applications

All costs are for lithium-ion batteries.

	Energy Storage Construction Expenditure Profiles: Inertia and Contingency Applications					
Application	Inertia	Contingency				
Years Before Commercial Operation Date	10 MW	1 MW	5 MW	20 MW	50 MW	100 MW
–6	00%	00%	00%	00%	00%	00%
–5	00%	00%	00%	00%	00%	00%
–4	00%	00%	00%	00%	00%	00%
–3	00%	00%	00%	00%	00%	00%
–2	20%	00%	00%	20%	20%	20%
–1	80%	100%	100%	80%	80%	80%
Total COD	100%	100%	100%	100%	100%	100%

Table J-53. Energy Storage Construction Expenditure Profiles: Inertia and Contingency Applications

Energy Storage Construction Expenditure Profiles: Regulation/Renewable Smoothing Applications

All costs are for lithium-ion batteries.

	Energy Storage Construction Expenditure Profiles: Inertia and Contingency Applications				
Application	Regulation/Renewable Smoothing				
Years Before Commercial Operation Date	1 MW	5 MW	20 MW	50 MW	100 MW
–6	00%	00%	00%	00%	00%
–5	0%	00%	00%	00%	00%
–4	00%	00%	00%	00%	00%
–3	00%	00%	00%	00%	00%
–2	00%	00%	20%	20%	20%
–1	100%	100%	80%	80%	80%
Total COD	100%	100%	100%	100%	100%

Table J-54. Energy Storage Construction Expenditure Profiles: Regulation/Renewable Smoothing Applications

Energy Storage Construction Expenditure Profiles: Load Shifting and Grid Support Applications

All costs are for lithium-ion batteries.

	Energy Storage Construction Expenditure Profiles: Load Shifting and Grid Support Applications					
Application	Load Shifting					*Grid Support*
Years Before Commercial Operation Date	1 MW	5 MW	20 MW	50 MW	100 MW	*5 MW*
–6	00%	00%	00%	00%	00%	00%
–5	00%	00%	00%	00%	00%	00%
–4	00%	00%	00%	00%	00%	00%
–3	00%	00%	00%	00%	00%	00%
–2	00%	00%	20%	20%	30%	00%
–1	100%	100%	80%	80%	70%	100%
Total COD	100%	100%	100%	100%	100%	100%

Table J-55. Energy Storage Construction Expenditure Profiles: Load Shifting and Grid Support Applications

Energy Storage Construction Expenditure Profiles: Residential, Commercial, and Long Duration Load Shifting Applications

	Energy Storage Construction Expenditure Profiles: Residential, Commercial, and Long Duration Load Shifting Applications						
Application	Residential		Commercial		Long Duration Load Shifting		
Technology	Lithium-Ion w/o inverter	Lithium-Ion w/ inverter & Balance of Plant	Lithium-Ion		Lithium-Ion	Pumped-Storage Hydro	
Years Before Commercial Operation Date	0.002 MW		0.050 MW		30.000 MW		50.000 MW
–6	n/a	n/a	n/a	n/a	00%	5%	5%
–5	n/a	n/a	n/a	n/a	00%	10%	10%
–4	n/a	n/a	n/a	n/a	00%	10%	10%
–3	n/a	n/a	n/a	n/a	00%	20%	20%
–2	n/a	n/a	n/a	n/a	30%	30%	30%
–1	n/a	n/a	n/a	n/a	70%	25%	25%
Total COD	n/a	n/a	n/a	n/a	100%	100%	100%

Table J-56. Energy Storage Construction Expenditure Profiles: Residential, Commercial, and Long Duration Load Shifting Applications

DEMAND RESPONSE DATA INPUTS

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

The primary modeling data assumptions originated from the Navigant Potential Study. The study forecasted the quantity of MW by customer class and end use device that the Companies can target in each DR program.

The end uses are identified in the following tables. Table J-57 lists the DR end uses for residential customers; Table J-58 lists the DR end uses for commercial, industrial, and small business customers.

Building Type	End Uses
Electric Vehicles	EV
Photovoltaics	PV
Residential	Cooling, water heating, and other

Table J-57. DR End Uses for Residential Customers

Customer Storage is a End Use for Residential customers, as well as other building types. Storage was not forecasted in the gross load profile. In the interim DR filing, the gross load profile did include customer storage, but the PSIP modeling assumed no customer storage as the base case, the case to build on. BCG has created a econometrics model to better forecast customer uptake of customer storage based on the customers payback period, provided DR incentives or reduced price and other state and federal incentives. The forecasted number for customer storage is added into each DR portfolio case, but because each case is different, we were not able to consistently settle on one case for DR or storage. Once all inputs for the Preferred Case are accepted, the forecasted Customer Storage potential will be locked in with the entire DR portfolio potential.

Building Type	End Uses
Education	Cooling, lighting, ventilation, water heating, and other
Electric Vehicles	EV
Grocery	Cooling, lighting, ventilation, water heating, and other
Health	Cooling, lighting, ventilation, water heating, and other
Hotel	Cooling, lighting, ventilation, water heating, and other
Industrial	Whole facility
Large Multi-Family	Cooling, lighting, water heating, and other
Military	Cooling, heating, lighting, ventilation, water heating, and other
Office	Cooling, heating, lighting, ventilation, water heating, and other
Photovoltaics	PV
Restaurant	Cooling, lighting, ventilation, water heating, and other
Retail	Cooling, heating, lighting, ventilation, water heating, and other
Warehouse	Whole facility
Water Pumping	Whole facility

Table J-58. DR End Uses for Commercial, Industrial, and Small Business Customers

The Navigant Potential Study determined the maximum achievable potential of end-use devices to provide specific services (fast frequency response, non-spin auto response, regulating reserves, load building, and load reduction) through specific DR programs (time of use, day ahead load shift, real-time pricing, critical peak incentive, minimum load building, fast frequency response, non-spin auto response, and regulating reserves). AP for Production Simulation uses annual weekday and weekend potential data by DR program, customer class, building type, and end use. Figure J-39 shows the potential, under available programs, to decrease load using the cooling end use available from military buildings on O'ahu. It is a snapshot based on a weekday during September 2030.

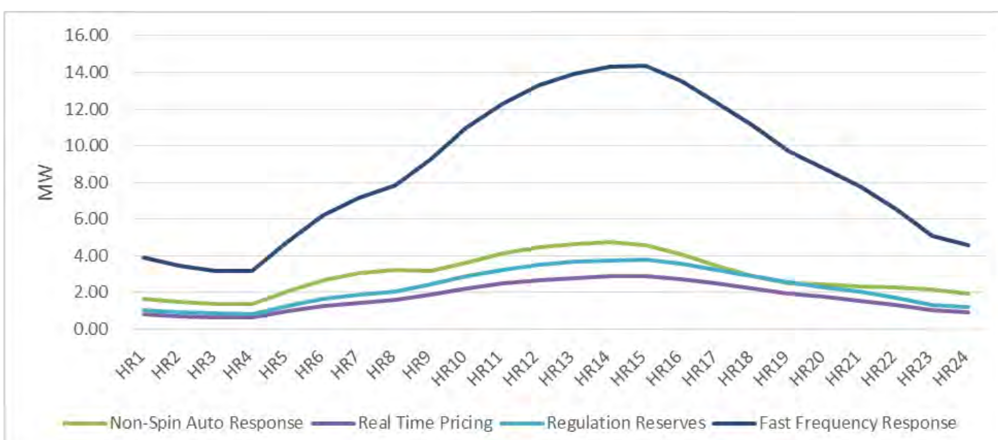


Figure J-39. Example Load Decrease Potential Supporting DR Programs

In general, DR programs grow over time. Figure J-40 shows how Regulation Reserves potential considering all customer classes and all end uses on O'ahu is expected to increase between 2018 (the first year available) and 2045. This data also represents a September weekday snapshot.

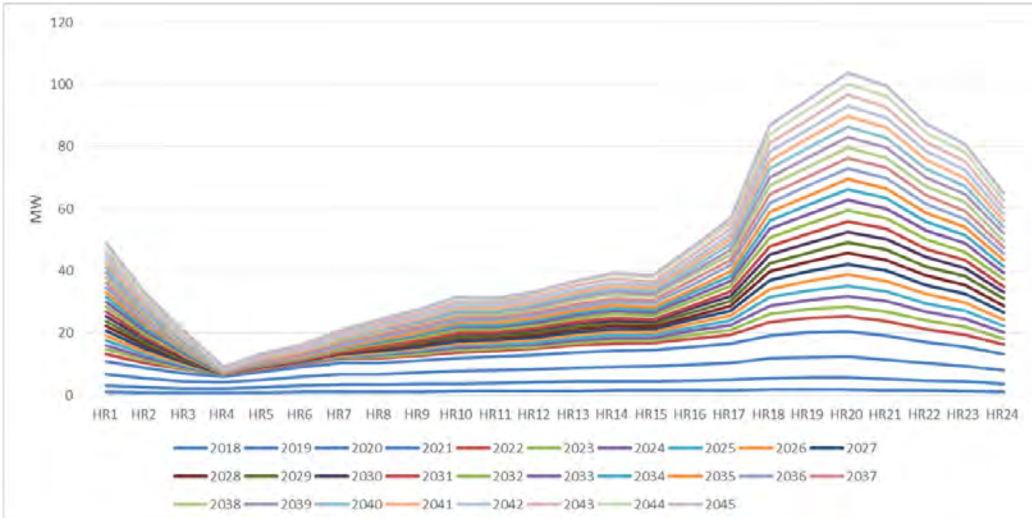


Figure J-40. O'ahu Regulating Reserve DR Program Growth Over Time

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

AP for Production Simulation also includes system security constraints (provided by the Companies) for DR to improve grid stability specifically for O'ahu. These constraints focus on eliminating under-frequency load shedding (UFLS) after a contingency event such as a unit trip. The constraints include data on net system load, kinetic energy, and the largest contingency. This data enables AP for Production Simulation to determine the amount of Fast Frequency Response and segregated customer end-use devices necessary to handle a contingency. Kinetic energy by unit is included in Table J-59. O'ahu's largest contingency unit is, prior to retirement, AES, Kahe 5, then Kahe 6.

Unit	Kinetic Energy (MW)	Unit	Kinetic Energy (MW)
AES	614	KMCBH-1	25
CIP C-1	765	KMCBH-2	25
H-Power Off Peak	209	KMCBH-3	25
H-Power On Peak	209	KMCBH-4	25
JBPHH-1	46.6	KMCBH-5	25
JBPHH-2	46.6	KMCBH-6	25
JBPHH-3	46.6	Schofield 1 (SCH-1)	22.6
JBPHH-4	46.6	Schofield 2 (SCH-2)	22.6
JBPHH-5	46.6	Schofield 3 (SCH-3)	22.6
JBPHH-6	46.6	Schofield 4 (SCH-4)	22.6
Kahe 1	426	Schofield 5 (SCH-5)	22.6
Kahe 2	426	Schofield 6 (SCH-6)	22.6
Kahe 3	357	Waiau 3	225
Kahe 4	357	Waiau 4	222
Kahe 5	692	Waiau 5	261
Kahe 6	692	Waiau 6	256
Kahe 7–10 3x1 CC	1,074.5	Waiau 7	426
Kalaeloa-1 (CT+ST)	878	Waiau 8	426
Kalaeloa-2 (CT+ST)	591	Waiau 9	447
		Waiau 10	447

Table J-59. Kinetic Energy by Unit for O'ahu

Demand Response Portfolio

A portfolio of DR programs is under development. While a preliminary, interim program portfolio application was filed on December 30, 2015, that portfolio is currently being revised, an updated application will be filed in mid-2016, following the filing of a PSIP Preferred Plan and any subsequent iterations thereof. The information below reflects both the current state of the DR portfolio, pending final refinements prior to the final DR program portfolio application. The sections that follow describe each proposed DR program, the methodology for calculating program costs, the methodology for determining the avoided costs associated with the portfolio (the means of reducing system costs if replaced with DR), and the targeted MWs to be utilized by the Companies given the deployment of the Preferred Plan.

Demand Response Programs

The DR program portfolio application presented a suite of DR programs that are candidates for the portfolio. Each of the nine DR programs was designed to deliver a specific grid service. The figure below has been updated since the interim DR application,[3] to reflect the new grid service naming convention (FFR2 and Replacement Reserves).

DR Program	Grid Service Delivered
Real-Time Pricing (RTP)	Capacity
Time-of-Use (TOU)	
Day-Ahead Load Shift (DALS)	
Minimum Load (ML)	
PV Curtailment (PVC)	
Critical Peak Incentive (CPI)	
Fast Frequency Response (FRR)	Fast Frequency Response 2
Regulating Reserve (RR)	Regulating Reserve
Non-Spin Auto Response (NSAR)	Replacement Reserve (10-Minute)

Table J-60. DR Program to Grid Service Mapping

Descriptions of these programs follow.

Real-Time Pricing. RTP is a capacity grid service resource capable of providing hourly retail rate prices to customers up to six hours before the event day starts. Retail rates will be based on weather, system resource availability, and forecasted load profile. As mentioned earlier, Residential RTP requires an AMI infrastructure to be in place where the customers are able to change their electric usage pattern based on the different hourly retail rates provided by the Companies.

Time-of-Use. TOU is a capacity grid service resource capable of providing a static period pricing rate for on-peak, off-peak, and mid-day times of the day to residential customers only. Customers are encouraged, through the price differential, to shift their energy usage from the peak time of day to the night or middle of the day, when solar PV is at its peak. Once RTP becomes available, TOU programs are expected to end and the participants will have an opportunity to enroll into RTP.

Day-Ahead Load Shift. DALS is a capacity grid service resource capable of providing a static period pricing rate are delivered six hours before the event start day for on-peak, off-peak, and mid-day times of the day to commercial customers only. Customers are encouraged, through the price differential, to shift their energy usage from the peak time of day to the night or middle of the day, when solar PV is at its peak."

Minimum Load. ML is a capacity grid service resource capable of providing increased load in the middle of the day by incentivizing customers to shift their usage to the middle of the day. While identified as an option, this program was not used in any of the

[3] See Docket No. 2015-0412, Interim DR Program Portfolio Application filing, filed December 30, 2015.

portfolios' analysis because the benefits of load shifting programs, such as TOU, DALS, or RTP, were already fulfilling the load flattening benefits.

PV Curtailment. PVC is a capacity grid service resource capable of issuing curtailment of customer's PV during times when minimum must run generators are within a specified threshold limit that requires more load on the system in order to prevent sudden shut down of an online generator.

Critical Peak Pricing. CPI is a capacity grid service resource capable of providing peak load reduction during emergency situations when not enough generation resources are available. The current existing Commercial DLC program could be re-classified under this program as part of the initial migration.

Fast Frequency Response. FFR program is a FFR grid service resource capable of responding to contingency events within 30 cycles or less.[4] A customer who enrolls in this program would have to be able to offer load resources that could respond to a local discrete response in 30 cycles or less.

Regulating Reserve. RR is a grid service resource capable of providing up and down reserves to balance the variability of the system given high renewable penetration. A customer who enrolls in this program must be able to provide a load resource that could respond within two seconds.

Non-Spin Auto Response. NSAR is a 10-minute spinning reserve capable of replacing other resources that are used for Spinning Reserves. It may also be used for the replacement of a contingency grid battery when paired with an FFR program. A customer who is enrolled in this NSAR program would have 10-minutes to respond and reduce their enrolled load resource.

Methodology for Determining Cost of DR Programs

For this PSIP Update, and subsequently for the updated DR program portfolio application, program costs have been developed using a bottom-up approach. This represents a change from the levelized, top-down approach taken during the DR interim application. These costs are embedded into the production cost models when performing optimization of resource plans. The Companies will continue to refine cost assumptions in advance of the final DR application is submitted to provide the best possible 2-year proposed budget and the 15-year avoided cost analysis to be provided as part of the final DR application.

[4] 30 cycles is the maximum FFR response requirement dependent on total MW available. The requirement may be less than 30 cycles after further analysis.

Finally, an inflation rate of 1.8% and annual replacement rate of 5% was used to calculate costs. The following is an excerpt from the Companies response to PSIP IR-40[5] regarding the method of calculating costs:

> In the DR Interim Application, costs were determined using the levelized costs as part of the Potential Study (See Exhibit A of the DR Interim Application). In order to estimate and assess the cost effectiveness of the programs in its current status, a top down approach of levelized cost was used for the DR Interim Application. For the April PSIP Update and final DR Program Portfolio Application filing to be filed in Docket No. 2015-0412 later this year, a bottom-up approach will be used for a more accurate representation of the cost of each of the programs. Key to the bottom-up approach will be estimating the enabling cost of each customer, quantifying their material, incentive, and installation costs. The cost will then be multiplied by the number of customers expected to be enrolled in each program. Followed by additional costs such as labor, marketing, evaluation, and general outside services will then be added to complete the overall cost of the DR program portfolio. The MWs determined through the avoided cost analysis supports the number of customer appliances that are needed on each program. The number of expected customers will be derived and supported from the potential study and the avoided cost analysis update. These updates will be filed as exhibits in the upcoming final DR Program Portfolio Application to be filed in Docket No. 2015-0412 later this year.
>
> Foundationally, historical DR costs incurred by the Companies have been used to calculate the necessary program costs for programs similar to those in the Companies' current portfolio. For program costs associated with proposed programs that are new to the Companies, such as RR, responses to the Companies' Grid Services request for proposals, as well as data derived from mainland markets have been used to derive cost estimates."
>
> The key to an accurate program cost projection is the DR Potential Study, which will continue to be updated during the process. While certain costs remain uncertain, such as incentive structures, the Companies have derived incentives from the avoided costs of the programs, less the anticipated administrative and operational costs. The Companies will continue to modify costs over time as programs are implemented and actual costs are tracked.

The approach described above has already been undertaken, and the new program costs resulting from that process are as follows:

[5] ?How is this referenced

Island	NPV Cost
O'ahu	$323,087,299
Maui	$19,411,699
Hawai'i Island	$20,112,813
Moloka'i	$666,532
Lana'i	$750,911
DRMS	$13,414,991

Table J-61. DR Program Net Present Value Costs

Methodology for Determining Avoided Costs of DR Programs

Avoided cost analysis for DR programs allows the Companies to compare the system costs of a resource plan with DR programs against the system costs of a resource plan without DR programs.

The following is an excerpt from the Demand Response Interim application:

> Each program will be designed to provide resources that can either directly or in combination with other programs, replace a more costly resource. An iteration analyzing which combination presented the best cost-effective DR programs was performed in the Avoided Cost Analysis. The Avoided Cost analysis resulted in advancing programs that were beneficial for each island in terms of their relative benefit and ultimately their contribution to a cost beneficial portfolio… The cost-effectiveness analysis determined which islands were capable of implementing a cost-effective DR Portfolio, although further analysis is required before finalizing the entire portfolio of programs for each island.

The Companies, in tandem with Black & Veatch modelers, have developed specific modeling techniques to evaluate the range of services provided by DR based on the characteristics of each service combined with the performance characteristics of the individual end uses. The methodology for calculating the avoided cost, as well as the specific modeling techniques is described in Appendix H, under the Adaptive Planning for Production Simulation description.

The avoided cost for a grid service is the cost of an alternative resource (energy storage or a generator) to provide the equivalent service. Avoided costs are based on several factors, including installed capacity costs, fuel costs, and cost of alternatives, each of which depends on the current state of the system. Additionally, alterations to a baseline resource capital plan promote meaningful avoided costs opportunities. In the context of the PSIP Update, the following represent examples of potential avoided cost values of DR across the different systems:

O'ahu: The DR portfolio enables the deferral of units at the KMBCH station and/or JBPHH station. Other avoided costs include improved heat rate performance and reduced fuel costs.

Maui: The DR portfolio enables the deferral of two ICE. Other avoided costs include improved heat rate performance and reduced fuel costs.

Moloka'i: The DR portfolio enables improved heat rate performance and reduced fuel costs.

Lana'i: The DR portfolio enables improved heat rate performance and reduced fuel costs.

Hawai'i Island: The DR portfolio enables the reduction of the contingency battery by 1 MW through the combination of FFR and NSAR demand response products. Other avoided costs include improved heat rate performance and reduced fuel costs.

During the PSIP modeling process, multiple plans were created, generating multiple DR portfolios. The DR portfolios include varying amounts of end device potentials, including customer storage, by year and island. Customer storage uptake forecasting is synergistic with DR portfolio optimization, and the resource is considered as a DR end use capable of providing multiple grid services.

The DR portfolio development started with the resource stack for each plan, then created the DR portfolio from that plan, but did not add that new portfolio into the plan, unless that case would proceed towards the Preferred Plan. The Preferred Plans incorporated the DR portfolios shown below, but the iterative step of optimizing the Preferred Plan with DR is not yet complete. Optimization of the DR portfolio will be performed in the next iteration. The final cost, avoided cost and cost effectiveness analysis will utilize the optimized DR portfolio and include it within the Final DR Application, anticipated for filing in mid-2016.

DR Grid Service Portfolio: O‘ahu (1 of 2)

Customer	Commercial			
Program	*Regulating Reserves*	*Pricing*	*Fast Frequency Response*	*Non-Spin Auto Response*
Grid Service	RR	Capacity	FFR	Replacement Reserves
Frequency	Continuous	Daily	Contingency Event	Contingency Event
Event Length	30 minutes	24 hours	10 minutes	1 hour
Year	MW	MW	MW	MW
2016	–	–	–	–
2017	–	1.5	1.9	2.6
2018	–	4.7	5.8	4.4
2019	–	8.2	9.1	9.5
2020	–	11.6	11.6	13.2
2021	–	17.4	18.6	14.8
2022	–	19.4	18.0	14.8
2023	–	19.1	15.0	14.7
2024	–	19.3	15.9	14.8
2025	–	19.4	16.1	14.6
2026	–	19.6	16.4	14.9
2027	–	19.7	16.7	15.1
2028	–	20.3	18.5	15.4
2029	–	20.2	18.0	15.8
2030	–	20.3	19.0	16.4
2031	–	20.7	18.9	17.1
2032	–	21.4	19.4	18.0
2033	–	22.0	20.7	18.8
2034	–	22.7	20.6	19.6
2035	–	24.2	20.5	19.8
2036	–	25.5	20.6	20.3
2037	–	26.8	21.5	22.1
2038	–	28.1	22.2	23.0
2039	–	29.5	23.4	24.1
2040	–	31.0	23.7	24.4
2041	–	32.4	24.0	24.9
2042	0.7	33.9	24.1	25.2
2043	1.7	35.7	24.3	25.5
2044	2.7	37.2	24.6	26.0
2045	2.3	38.7	25.0	26.4

Table J-62. O‘ahu DR Program Grid Service Portfolio: MW (1 of 2)

DR Grid Service Portfolio: O'ahu (2 of 2)

Customer	Residential				Small Business		
Program	*RR*	*Pricing*	*FFR*	*NSAR*	*Pricing*	*FFR*	*NSAR*
Grid Service	RR	Capacity	FFR	Replacement Reserves	Capacity	FFR	Replacement Reserves
Frequency	Continuous	Daily	Contingency	Contingency	Daily	Contingency	Contingency
Event Length	30 minutes	24 hours	10 minutes	1 hour	24 hours	10 minutes	1 hour
Year	MW	MW	MW	MW	MW	MW	MW
2016	–	–	–	–	–	–	–
2017	–	2.6	3.6	1.9	1.5	0.8	1.4
2018	0.3	7.9	14.9	4.1	4.5	2.7	2.8
2019	0.8	13.3	19.3	8.3	7.6	3.4	5.6
2020	1.4	11.5	27.5	12.7	5.3	5.5	8.3
2021	2.1	18.2	31.4	14.6	8.0	10.4	9.3
2022	2.8	21.9	40.4	16.0	8.9	10.6	9.3
2023	3.3	24.5	32.4	18.1	8.9	7.0	9.4
2024	3.7	26.7	33.1	20.3	9.0	7.3	9.5
2025	4.2	29.0	33.6	22.3	9.2	7.6	9.3
2026	4.3	28.6	34.1	24.1	9.5	8.0	9.4
2027	4.2	29.8	34.5	25.8	9.8	8.5	9.6
2028	4.5	30.7	38.8	27.3	10.3	9.2	9.8
2029	4.9	30.8	38.2	28.5	10.5	9.9	9.9
2030	5.1	31.0	40.2	29.5	10.7	10.8	10.1
2031	5.3	31.1	40.2	30.4	11.5	11.9	10.9
2032	5.3	31.5	38.2	31.4	12.8	12.8	11.8
2033	5.7	31.7	42.9	31.5	14.4	14.0	12.9
2034	5.8	31.8	40.4	31.8	15.8	15.3	14.1
2035	5.9	32.4	39.7	32.0	17.2	16.3	15.1
2036	6.4	32.6	40.1	31.2	18.6	17.4	16.2
2037	8.9	32.6	47.6	33.4	20.0	19.5	18.0
2038	10.8	32.6	41.8	33.4	21.4	20.5	19.1
2039	11.9	32.8	48.8	33.1	23.0	21.8	20.4
2040	13.5	33.1	48.8	33.0	24.8	22.4	21.1
2041	14.4	33.4	43.4	32.2	26.2	23.1	22.2
2042	15.2	33.5	43.8	31.4	27.6	23.9	22.9
2043	16.4	33.5	44.4	30.6	29.3	24.3	23.3
2044	17.3	33.8	43.7	29.8	30.8	24.7	23.7
2045	17.3	33.9	42.3	29.1	32.2	25.0	24.1

Table J-63. O'ahu DR Program Grid Service Portfolio: MW (2 of 2)

DR Grid Service Portfolio: Maui

Customer	Commercial		Residential		Small Business	
Program	*RR*	*Pricing*	*RR*	*Pricing*	*RR*	*Pricing*
Grid Service	RR	Capacity	RR	Capacity	RR	Capacity
Frequency	Continuous	Daily	Continuous	Daily	Continuous	Daily
Event Length	30 minutes	24 hours	30 minutes	24 hours	30 minutes	24 hours
Year	MW	MW	MW	MW	MW	MW
2016	–	–	–	–	–	–
2017	–	0.2	–	0.6	–	0.3
2018	0.0	0.5	0.3	1.8	0.1	0.8
2019	0.0	1.0	0.8	3.1	0.2	1.4
2020	0.1	0.2	1.8	0.4	0.4	0.2
2021	0.1	0.5	2.9	1.2	0.6	0.5
2022	0.1	1.1	3.7	2.6	0.7	0.9
2023	0.2	1.8	4.0	4.0	0.7	1.5
2024	0.2	1.9	4.3	4.4	0.7	1.6
2025	0.4	2.1	4.6	4.7	0.8	1.7
2026	0.4	2.1	5.0	4.9	0.8	1.8
2027	0.4	1.9	5.5	4.8	0.9	1.7
2028	0.4	1.9	5.9	4.7	0.9	1.7
2029	0.5	1.9	6.2	5.1	1.0	1.7
2030	0.5	1.9	6.5	4.9	1.1	1.7
2031	0.5	1.9	6.9	4.8	1.1	1.8
2032	0.6	2.0	7.3	5.3	1.2	1.9
2033	0.6	1.9	7.8	5.1	1.3	1.8
2034	0.6	2.0	8.4	5.3	1.3	1.9
2035	0.7	2.0	8.8	5.5	1.4	2.0
2036	0.7	2.2	9.3	6.0	1.5	2.1
2037	0.7	2.1	9.7	5.8	1.5	2.1
2038	0.7	2.2	10.1	6.2	1.6	2.3
2039	0.8	2.3	10.6	6.4	1.7	2.3
2040	0.8	2.3	10.8	6.5	1.7	2.4
2041	0.8	2.2	11.6	6.6	1.8	2.3
2042	0.8	2.2	12.0	6.4	1.8	2.3
2043	0.9	2.3	12.3	6.9	1.9	2.5
2044	0.9	2.4	12.8	7.0	1.9	2.6
2045	0.9	2.4	13.1	7.2	2.0	2.6

Table J-64. Maui DR Program Grid Service Portfolio: MW

DR Grid Service Portfolio: Lana'i

Customer	Commercial		Residential		Small Business	
Program	*RR*	*Pricing*	*RR*	*Pricing*	*RR*	*Pricing*
Grid Service	RR	Capacity	RR	Capacity	RR	Capacity
Frequency	Continuous	Daily	Continuous	Daily	Continuous	Daily
Event Length	30 minutes	24 hours	30 minutes	24 hours	30 minutes	24 hours
Year	MW	MW	MW	MW	MW	MW
2016	0.00	0.00	0.00	0.00	0.00	0.00
2017	0.00	0.00	0.00	0.02	0.00	0.01
2018	0.00	0.00	0.01	0.05	0.00	0.02
2019	0.00	0.00	0.02	0.08	0.00	0.04
2020	0.00	0.04	0.05	0.07	0.01	0.03
2021	0.00	0.06	0.07	0.10	0.01	0.04
2022	0.00	0.07	0.09	0.11	0.01	0.04
2023	0.00	0.08	0.10	0.12	0.01	0.04
2024	0.01	0.08	0.12	0.12	0.02	0.04
2025	0.01	0.08	0.12	0.12	0.02	0.05
2026	0.01	0.08	0.14	0.12	0.02	0.05
2027	0.01	0.08	0.15	0.14	0.02	0.05
2028	0.01	0.09	0.16	0.13	0.02	0.05
2029	0.01	0.09	0.18	0.14	0.03	0.05
2030	0.02	0.09	0.19	0.14	0.03	0.05
2031	0.02	0.09	0.21	0.14	0.03	0.05
2032	0.02	0.09	0.22	0.14	0.03	0.05
2033	0.02	0.09	0.23	0.15	0.03	0.06
2034	0.02	0.09	0.24	0.15	0.04	0.05
2035	0.02	0.09	0.27	0.15	0.04	0.06
2036	0.02	0.09	0.28	0.15	0.04	0.06
2037	0.02	0.10	0.29	0.16	0.04	0.06
2038	0.02	0.10	0.29	0.16	0.04	0.06
2039	0.02	0.10	0.30	0.18	0.04	0.06
2040	0.02	0.10	0.31	0.17	0.05	0.06
2041	0.02	0.10	0.32	0.16	0.05	0.06
2042	0.03	0.10	0.34	0.17	0.05	0.07
2043	0.03	0.11	0.35	0.16	0.05	0.06
2044	0.03	0.11	0.37	0.17	0.05	0.06
2045	0.03	0.11	0.37	0.18	0.05	0.07

Table J-65. Lana'i DR Program Grid Service Portfolio: MW

DR Grid Service Portfolio: Moloka‘i

Customer	Commercial		Residential		Small Business	
Program	*RR*	*Pricing*	*RR*	*Pricing*	*RR*	*Pricing*
Grid Service	RR	Capacity	RR	Capacity	RR	Capacity
Frequency	Continuous	Daily	Continuous	Daily	Continuous	Daily
Event Length	30 minutes	24 hours	30 minutes	24 hours	30 minutes	24 hours
Year	MW	MW	MW	MW	MW	MW
2016	0.00	0.00	0.00	0.00	0.00	0.00
2017	0.00	0.00	0.00	0.02	0.00	0.01
2018	0.00	0.01	0.01	0.06	0.00	0.03
2019	0.00	0.02	0.02	0.10	0.00	0.04
2020	0.00	0.02	0.05	0.07	0.01	0.03
2021	0.00	0.04	0.08	0.10	0.01	0.04
2022	0.00	0.04	0.10	0.12	0.02	0.05
2023	0.00	0.04	0.11	0.11	0.02	0.05
2024	0.00	0.04	0.12	0.12	0.02	0.05
2025	0.01	0.04	0.12	0.14	0.02	0.05
2026	0.01	0.04	0.13	0.12	0.02	0.05
2027	0.01	0.04	0.14	0.12	0.02	0.05
2028	0.01	0.04	0.15	0.13	0.02	0.05
2029	0.01	0.04	0.16	0.13	0.02	0.05
2030	0.01	0.03	0.17	0.13	0.02	0.05
2031	0.01	0.03	0.18	0.15	0.03	0.05
2032	0.01	0.03	0.19	0.15	0.03	0.05
2033	0.01	0.03	0.19	0.15	0.03	0.04
2034	0.01	0.03	0.20	0.16	0.03	0.05
2035	0.01	0.03	0.21	0.16	0.03	0.05
2036	0.02	0.03	0.21	0.16	0.03	0.05
2037	0.02	0.03	0.21	0.15	0.03	0.05
2038	0.02	0.03	0.22	0.15	0.03	0.05
2039	0.02	0.03	0.23	0.15	0.03	0.05
2040	0.02	0.03	0.23	0.15	0.03	0.05
2041	0.02	0.03	0.24	0.15	0.04	0.05
2042	0.02	0.03	0.24	0.16	0.04	0.05
2043	0.02	0.03	0.24	0.15	0.03	0.05
2044	0.02	0.03	0.25	0.15	0.03	0.05
2045	0.02	0.03	0.26	0.15	0.04	0.05

Table J-66. Moloka‘i DR Program Grid Service Portfolio: MW

DR Grid Service Portfolio: Hawai'i Island (1 of 2)

Customer	Commercial			
Program	*Regulating Reserves*	*Pricing*	*Fast Frequency Response*	*Non-Spin Auto Response*
Grid Service	RR	Capacity	FFR	Replacement Reserves
Frequency	Continuous	Daily	Contingency Event	Contingency Event
Event Length	30 minutes	24 hours	10 minutes	1 hour
Year	MW	MW	MW	MW
2016	RR	Capacity	FFR	Replacement Reserves
2017	Continuous	Daily	Contingency Event	Contingency Event
2018	30 minute	24 hours	10 minutes	1 hour
2019	MW	MW	MW	MW
2020	0.00	–	0.0	–
2021	0.00	0.15	0.0	–
2022	0.00	0.44	0.0	–
2023	0.00	0.74	0.11	0.51
2024	0.01	0.78	0.09	0.51
2025	0.02	1.17	0.09	0.51
2026	0.02	1.28	0.09	0.51
2027	0.02	1.27	0.09	0.50
2028	0.02	1.25	0.09	0.50
2029	0.02	1.22	0.09	0.50
2030	0.02	1.20	0.09	0.50
2031	0.02	1.17	0.09	0.49
2032	0.02	1.12	0.09	0.49
2033	0.02	1.12	0.09	0.49
2034	0.02	1.13	0.09	0.48
2035	0.02	1.16	0.09	0.48
2036	0.02	1.17	0.09	0.48
2037	0.02	1.19	0.09	0.48
2038	0.02	1.21	0.09	0.48
2039	0.02	1.22	0.09	0.47
2040	0.02	1.22	0.09	0.47
2041	0.02	1.23	0.08	0.47
2042	0.02	1.24	0.08	0.47
2043	0.02	1.25	0.08	0.46
2044	0.02	1.26	0.08	0.46
2045	0.02	1.26	0.08	0.46

Table J-67. Hawai'i Island DR Program Grid Service Portfolio: MW (1 of 2)

DR Grid Service Portfolio: Hawai‘i Island (2 of 2)

Customer	Residential				Small Business			
Program	RR	Pricing	FFR	NSAR	RR	Pricing	FFR	NSAR
Grid Services	RR	Capacity	FFR	Repl.	RR	Capacity	FFR	Repl.
Frequency	Continuous	Daily	Contingency	Contingency	Continuous	Daily	Contingency	Contingency
Event Length	30 minute	24 hours	10 minutes	1 hour	30 minutes	24 hours	10 minutes	1 hour
Year	MW	MW	MW	MW	MW	MW	MW	MW
2016	–	–	–	–	–	–	–	–
2017	–	0.65	–	–	–	0.31	–	–
2018	0.19	1.95	–	–	0.01	0.94	–	–
2019	0.57	3.29	1.0	0.57	0.00	1.58	0.24	0.40
2020	1.17	2.51	1.0	0.57	0.00	1.05	0.24	0.40
2021	1.80	3.77	1.0	0.58	0.02	1.59	0.24	0.40
2022	2.02	4.19	1.0	0.58	0.02	1.75	0.24	0.40
2023	2.02	4.22	1.0	0.58	0.02	1.75	0.24	0.40
2024	2.04	4.32	1.0	0.58	0.02	1.74	0.24	0.40
2025	2.06	4.55	1.0	0.58	0.02	1.74	0.24	0.40
2026	2.10	4.77	1.0	0.59	0.02	1.73	0.24	0.40
2027	2.10	4.98	1.0	0.59	0.02	1.71	0.24	0.41
2028	2.10	5.16	1.0	0.59	0.02	1.66	0.24	0.41
2029	2.07	5.29	1.0	0.59	0.02	1.64	0.25	0.41
2030	2.06	5.27	1.0	0.59	0.02	1.64	0.25	0.41
2031	2.08	5.34	1.0	0.59	0.02	1.62	0.25	0.41
2032	2.11	5.39	1.0	0.60	0.02	1.60	0.25	0.42
2033	2.14	5.41	1.0	0.60	0.03	1.59	0.25	0.41
2034	2.17	5.46	1.0	0.60	0.03	1.61	0.25	0.41
2035	2.22	5.58	1.0	0.60	0.03	1.61	0.25	0.41
2036	2.26	5.69	1.0	0.61	0.04	1.63	0.25	0.41
2037	2.34	5.82	1.0	0.61	0.04	1.63	0.25	0.41
2038	2.43	5.96	1.0	0.61	0.05	1.64	0.25	0.41
2039	2.69	6.07	1.0	0.62	0.05	1.65	0.24	0.41
2040	2.96	6.21	1.0	0.62	0.05	1.67	0.24	0.40
2041	3.22	6.31	1.0	0.63	0.06	1.69	0.24	0.40
2042	3.50	6.43	1.0	0.63	0.06	1.70	0.24	0.40
2043	3.77	6.53	1.0	0.63	0.07	1.70	0.24	0.40
2044	4.06	6.67	1.0	0.64	0.07	1.70	0.24	0.40
2045	4.34	6.81	1.0	0.64	0.07	1.73	0.23	0.40

Table J-68. Hawai‘i Island DR Program Grid Service Portfolio: MW (2 of 2)

K. Candidate Plan Data

Candidate plans are a method of analyzing the numerous resources and variables to ultimately arrive at the Preferred Plans. This appendix lists the candidate plans (cases) that Hawaiian Electric, Hawaiʻi Electric Light, and Maui Electric created and ran to develop the Preferred Plans.

HAWAIIAN ELECTRIC

Hawaiian Electric First Iteration Cases

Case Name	Case 1: 100% Renewable Reference Case	Case 1: 100% Renewable Reference Case
Case Label	15_IDR	15_IDR_LF
DER Forecast	Market	Market
Fuel Price	High	Low
2016	137.2 MW Waiver PV Projects added 12/31/2016	137.2 MW Waiver PV Projects added 12/31/2016
2017		
2018	Six -8.14 MW Schofield Plants added Install 25MW Future PV Install 24MW NPM Wind	Six -8.14 MW Schofield Plants added Install 25MW Future PV Install 24MW NPM Wind
2019	90 MW Contingency BESS	90 MW Contingency BESS
2020	Install 50MW Future PV Install 100MW JBPHH Plant, 12/2020	Install 50MW Future PV Install 100MW JBPHH Plant, 12/2020
2021	Waiau 3 & 4 Deactivated, 1/2021 Install 27 MW KMCBH Plant, 6/2021	Waiau 3 & 4 Deactivated, 1/2021 Install 27 MW KMCBH Plant, 6/2021
2022	AES Deactivated 9/2022 Install 50MW Future Wind Install 50MW Future PV	
2023		
2024	Waiau 5 & 6 Deactivated, 1/2024	Waiau 5 & 6 Deactivated, 1/2024
2025	Install 50MW Future Wind	Install 50MW Future Wind
2026		
2027		
2028	Install 50MW Future PV	Install 50MW Future PV
2029		
2030		
2031	Install 50MW Future PV	Install 50MW Future PV
2032		
2033	Install 50MW Future PV	Install 50MW Future PV
2034		
2035	Install 50MW Future PV	Install 50MW Future PV
2036	Install 50MW Future PV	Install 50MW Future PV
2037	Install 50MW Future Wind Install 50MW Future PV	Install 50MW Future Wind Install 50MW Future PV
2038	Install 50MW Future PV	Install 50MW Future PV
2039		
2040		
2041		
2042		
2043		
2044		
2045		

Table K-1. Hawaiian Electric First Iteration Cases (1 of 5)

Case Name	Case 2: 100% Renewable with Modernization	Case 2: 100% Renewable with Modernization
Case Label	15_2DR	15_2DR_LF
DER Forecast	Market	Market
Fuel Price	High	Low
2016	137.2 MW Waiver PV Projects added 12/31/2016	137.2 MW Waiver PV Projects added 12/31/2016
2017		
2018	Six -8.14 MW Schofield Plants added Install 25MW Utility PV Install 24MW NPM Wind	Six -8.14 MW Schofield Plants added Install 25MW Utility PV Install 24MW NPM Wind
2019	90 MW Contingency BESS added	90 MW Contingency BESS added
2020	Install 50MW Utility PV Install 100MW JBPHH Plant, 12/2020 K1-3 Deactivated 12/2020	Install 50MW Utility PV Install 100MW JBPHH Plant, 12/2020 K1-3 Deactivated 12/2020
2021	Install 27 MW KMCBH Plant, 6/2021 Install 3x1CC on Diesel, 6/2021	Install 27 MW KMCBH Plant, 6/2021 Install 3x1CC on Diesel, 6/2021
2022	Waiau 3 & 4 Deactivated, 1/2022 Kahe 4 Deactivated, 1/2022 AES Deactivated 9/2022 Install 50MW Onshore Wind Install 50MW Utility PV	Waiau 3 & 4 Deactivated, 1/2022 Kahe 4 Deactivated, 1/2022 AES Deactivated 9/2022 Install 50MW Onshore Wind Install 50MW Utility PV
2023		
2024	Waiau 5 & 6 Deactivated, 1/2024	Waiau 5 & 6 Deactivated, 1/2024
2025	Install 50MW Onshore Wind	Install 50MW Onshore Wind
2026		
2027		
2028	Install 50MW Utility PV	Install 50MW Utility PV
2029		
2030		
2031	Install 50MW Utility PV	Install 50MW Utility PV
2032		
2033	Install 50MW Utility PV	Install 50MW Utility PV
2034		
2035	Install 50MW Utility PV	Install 50MW Utility PV
2036	Install 50MW Utility PV	Install 50MW Utility PV
2037	Install 50MW Onshore Wind Install 50MW Utility PV	Install 50MW Onshore Wind Install 50MW Utility PV
2038	Install 50MW Utility PV	Install 50MW Utility PV
2039		
2040		
2041		
2042		
2043		
2044		
2045		

Table K-2. Hawaiian Electric First Iteration Cases (2 of 5)

Case Name	Case 3: 100% Renewable with Transitional LNG Fuel	Case 3: 100% Renewable with Transitional LNG Fuel
Case Label	15_3DR	15_3DR_LF
DER Forecast	Market	Market
Fuel Price	High	Low
2016	137.2 MW Waiver PV Projects added 12/31/2016	137.2 MW Waiver PV Projects added 12/31/2016
2017		
2018	Six -8.14 MW Schofield Plants added Install 25MW Utility PV Install 24MW NPM Wind	Six -8.14 MW Schofield Plants added Install 25MW Utility PV Install 24MW NPM Wind
2019	90 MW Contingency BESS added	90 MW Contingency BESS added
2020	Install 50MW Utility PV Install 100MW JBPHH Plant, 12/2020	Install 50MW Utility PV Install 100MW JBPHH Plant, 12/2020
2021	K1-6, KPLP: LNG, 1/2021 Waiau 3 & 4 Deactivated, 1/2021 Install 27 MW KMCBH Plant, 6/2021	K1-6, KPLP: LNG, 1/2021 Waiau 3 & 4 Deactivated, 1/2021 Install 27 MW KMCBH Plant, 6/2021
2022	AES Deactivated 9/2022 Install 50MW Onshore Wind Install 50MW Utility PV	AES Deactivated 9/2022 Install 50MW Onshore Wind Install 50MW Utility PV
2023		
2024	Waiau 5 & 6 Deactivated, 1/2024	Waiau 5 & 6 Deactivated, 1/2024
2025	Install 50MW Onshore Wind	Install 50MW Onshore Wind
2026		
2027		
2028	Install 50MW Utility PV	Install 50MW Utility PV
2029		
2030		
2031	Install 50MW Utility PV	Install 50MW Utility PV
2032		
2033	Install 50MW Utility PV	Install 50MW Utility PV
2034		
2035	Install 50MW Utility PV	Install 50MW Utility PV
2036	Install 50MW Utility PV	Install 50MW Utility PV
2037	Install 50MW Onshore Wind Install 50MW Utility PV	Install 50MW Onshore Wind Install 50MW Utility PV
2038	Install 50MW Utility PV	Install 50MW Utility PV
2039		
2040	LNG Contract ends 12/31/2040 Kahe Units on LNG switch to BioD KPLP switch to BioD	LNG Contract ends 12/31/2040 Kahe Units on LNG switch to BioD KPLP switch to BioD
2041		
2042		
2043		
2044		
2045		

Table K-3. Hawaiian Electric First Iteration Cases (3 of 5)

Case Name	Case 4: 100% Renewable with Modernization and Transitional LNG Fuel	Case 4: 100% Renewable with Modernization and Transitional LNG Fuel
Case Label	15_4DR	15_4DR_LF
DER Forecast	Market	Market
Fuel Price	High	Low
2016	137.2 MW Waiver PV Projects added 12/31/2016	137.2 MW Waiver PV Projects added 12/31/2016
2017		
2018	Six -8.14 MW Schofield Plants added Install 25MW Utility PV Install 24MW NPM Wind	Six -8.14 MW Schofield Plants added Install 25MW Utility PV Install 24MW NPM Wind
2019	90 MW Contingency BESS added	90 MW Contingency BESS added
2020	Install 50MW Utility PV Install 100MW JBPHH Plant, 12/2020 K1-3 Deactivated 12/2020	Install 50MW Utility PV Install 100MW JBPHH Plant, 12/2020 K1-3 Deactivated 12/2020
2021	K5-6, KPLP: LNG, 1/2021 Install 27 MW KMCBH Plant, 6/2021 Install 3x1CC on LNG, 6/2021	K5-6, KPLP: LNG, 1/2021 Install 27 MW KMCBH Plant, 6/2021 Install 3x1CC on LNG, 6/2021
2022	Waiau 3 & 4 Deactivated, 1/2022 Kahe 4 Deactivated, 1/2022 AES Deactivated 9/2022 Install 50MW Onshore Wind Install 50MW Utility PV	Waiau 3 & 4 Deactivated, 1/2022 Kahe 4 Deactivated, 1/2022 AES Deactivated 9/2022 Install 50MW Onshore Wind Install 50MW Utility PV
2023		
2024	Waiau 5 & 6 Deactivated, 1/2024	Waiau 5 & 6 Deactivated, 1/2024
2025	Install 50MW Onshore Wind	Install 50MW Onshore Wind
2026		
2027		
2028	Install 50MW Utility PV	Install 50MW Utility PV
2029		
2030		
2031	Install 50MW Utility PV	Install 50MW Utility PV
2032		
2033	Install 50MW Utility PV	Install 50MW Utility PV
2034		
2035	Install 50MW Utility PV	Install 50MW Utility PV
2036	Install 50MW Utility PV	Install 50MW Utility PV
2037	Install 50MW Onshore Wind Install 50MW Utility PV	Install 50MW Onshore Wind Install 50MW Utility PV
2038	Install 50MW Utility PV	Install 50MW Utility PV
2039		
2040	LNG Contract ends 12/31/2040 Kahe Units on LNG switch to BioD KPLP switch to BioD	LNG Contract ends 12/31/2040 Kahe Units on LNG switch to BioD KPLP switch to BioD
2041		
2042		
2043		
2044		

2045		

Table K-4. Hawaiian Electric First Iteration Cases (4 of 5)

Case Name	Case 5: 100% Renewable with Limited Modernization	Case 5: 100% Renewable with Limited Modernization
Case Label	15_5DR	15_5DR_LF
DER Forecast	Market	Market
Fuel Price	High	Low
2016	137.2 MW Waiver PV Projects added 12/31/2016	137.2 MW Waiver PV Projects added 12/31/2016
2017		
2018	Six -8.14 MW Schofield Plants added Install 25MW Utility PV Install 24MW NPM Wind	Six -8.14 MW Schofield Plants added Install 25MW Utility PV Install 24MW NPM Wind
2019	90 MW Contingency BESS added	90 MW Contingency BESS added
2020	Install 50MW Utility PV	Install 50MW Utility PV
2021		
2022	Install 100MW JBPHH Plant, 1/2022 AES Deactivated 9/2022 Install 50MW Onshore Wind Install 50MW Utility PV	Install 100MW JBPHH Plant, 1/2022 AES Deactivated 9/2022 Install 50MW Onshore Wind Install 50MW Utility PV
2023	Install 54 MW KMCBH Plant, 1/2023 Waiau 3 & 4 Deactivated, 1/2023	Install 54 MW KMCBH Plant, 1/2023 Waiau 3 & 4 Deactivated, 1/2023
2024		
2025	Install 50MW Onshore Wind Kahe 6 Deactivated, 1/2025	Install 50MW Onshore Wind Kahe 6 Deactivated, 1/2025
2026		
2027		
2028	Install 50MW Utility PV	Install 50MW Utility PV
2029		
2030		
2031	Install 50MW Utility PV	Install 50MW Utility PV
2032		
2033	Install 50MW Utility PV	Install 50MW Utility PV
2034		
2035	Install 50MW Utility PV	Install 50MW Utility PV
2036	Install 50MW Utility PV	Install 50MW Utility PV
2037	Install 50MW Onshore Wind Install 50MW Utility PV	Install 50MW Onshore Wind Install 50MW Utility PV
2038	Install 50MW Utility PV	Install 50MW Utility PV
2039		
2040		
2041		
2042		
2043		
2044		
2045		

Table K-5. Hawaiian Electric First Iteration Cases (5 of 5)

Hawaiian Electric Second Iteration Cases

Case Name	Theme 1, Case 1: Aggressive Wind, No Storage	Theme 1, Case 2: Aggressive Wind, No Storage
Case Label	16_T1aWWH30_v0	16_T1aWWL30_v0
DER Forecast	High	High
Fuel Price	High	Low
2016	27.6 MW Waiver PV Projects added 12/31/2016	27.6 MW Waiver PV Projects added 12/31/2016
2017		
2018	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install 10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install 10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)
2019	90 MW Contingency BESS added	90 MW Contingency BESS added
2020	Install 20MW Onshore Wind Install 360 MW Utility PV	Install 20MW Onshore Wind Install 360 MW Utility PV
2021		
2022	Install 100MW JBPHH Plant, 1/2022 AES Deactivated 9/2022	Install 100MW JBPHH Plant, 1/2022 AES Deactivated 9/2022
2023	Install 54 MW KMCBH Plant, 1/2023 Waiau 3 & 4 Deactivated, 1/2023	Install 54 MW KMCBH Plant, 1/2023 Waiau 3 & 4 Deactivated, 1/2023
2024		
2025	Install 1600 MW Offshore Wind	Install 1600 MW Offshore Wind
2026		
2027		
2028		
2029		
2030		
2031		
2032		
2033		
2034		
2035		
2036		
2037		
2038		
2039		
2040		
2041		
2042		
2043		
2044		
2045		

Table K-6. Hawaiian Electric Second Iteration Cases (1 of 47)

Case Name	Theme 1, Case 3: Aggressive Wind, Low Storage	Theme 1, Case 4: Aggressive Wind, Low Storage
Case Label	16_T1aWWH30_v2	16_T1aWWL30_v2
DER Forecast	High	High
Fuel Price	High	Low
2016	27.6 MW Waiver PV Projects added 12/31/2016	27.6 MW Waiver PV Projects added 12/31/2016
2017		
2018	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install 10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install 10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)
2019	90 MW Contingency BESS added	90 MW Contingency BESS added
2020	Install 20MW Onshore Wind Install 360 MW Utility PV	Install 20MW Onshore Wind Install 360 MW Utility PV
2021		
2022	Install 100MW JBPHH Plant, 1/2022 AES Deactivated 9/2022	Install 100MW JBPHH Plant, 1/2022 AES Deactivated 9/2022
2023	Install 54 MW KMCBH Plant, 1/2023 Waiau 3 & 4 Deactivated, 1/2023	Install 54 MW KMCBH Plant, 1/2023 Waiau 3 & 4 Deactivated, 1/2023
2024		
2025	Install 1600 MW Offshore Wind Install (2) 280 MW x 4 hr Energy Storage	Install 1600 MW Offshore Wind Install (2) 280 MW x 4 hr Energy Storage
2026		
2027		
2028		
2029		
2030		
2031		
2032		
2033		
2034		
2035		
2036		
2037		
2038		
2039		
2040	Install (2) 100 MW x 4 hr Energy Storage	Install (2) 100 MW x 4 hr Energy Storage
2041		
2042		
2043		
2044		
2045		

Table K-7. Hawaiian Electric Second Iteration Cases (2 of 47)

Case Name	Theme 1, Case 5: Aggressive Wind, Medium Storage	Theme 1, Case 6: Aggressive Wind, Medium Storage
Case Label	16_T1aWWH30_v4	16_T1aWWL30_v4
DER Forecast	High	High
Fuel Price	High	Low
2016	27.6 MW Waiver PV Projects added 12/31/2016	27.6 MW Waiver PV Projects added 12/31/2016
2017		
2018	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install 10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install 10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)
2019	90 MW Contingency BESS added	90 MW Contingency BESS added
2020	Install 20MW Onshore Wind Install 360 MW Utility PV	Install 20MW Onshore Wind Install 360 MW Utility PV
2021		
2022	Install 100MW JBPHH Plant, 1/2022 AES Deactivated 9/2022	Install 100MW JBPHH Plant, 1/2022 AES Deactivated 9/2022
2023	Install 54 MW KMCBH Plant, 1/2023 Waiau 3 & 4 Deactivated, 1/2023	Install 54 MW KMCBH Plant, 1/2023 Waiau 3 & 4 Deactivated, 1/2023
2024		
2025	Install 1600 MW Offshore Wind Install (2) 1350 MW x 4 hr Energy Storage	Install 1600 MW Offshore Wind Install (2) 1350 MW x 4 hr Energy Storage
2026		
2027		
2028		
2029		
2030	Install (2) 150 MW x 4 hr Energy Storage	Install (2) 150 MW x 4 hr Energy Storage
2031		
2032		
2033		
2034		
2035		
2036		
2037		
2038		
2039		
2040		
2041		
2042		
2043		
2044		
2045	Install (2) 100 MW x 4 hr Energy Storage	Install (2) 100 MW x 4 hr Energy Storage

Table K-8. Hawaiian Electric Second Iteration Cases (3 of 47)

Case Name	Theme 1, Case 7: Aggressive Wind, High Storage	Theme 1, Case 8: Aggressive Wind, High Storage
Case Label	16_T1aWWH30_v3	16_T1aWWL30_v3
DER Forecast	High	High
Fuel Price	High	Low
2016	27.6 MW Waiver PV Projects added 12/31/2016	27.6 MW Waiver PV Projects added 12/31/2016
2017		
2018	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install 10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install 10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)
2019	90 MW Contingency BESS added	90 MW Contingency BESS added
2020	Install 20MW Onshore Wind Install 360 MW Utility PV	Install 20MW Onshore Wind Install 360 MW Utility PV
2021		
2022	Install 100MW JBPHH Plant, 1/2022 AES Deactivated 9/2022	Install 100MW JBPHH Plant, 1/2022 AES Deactivated 9/2022
2023	Install 54 MW KMCBH Plant, 1/2023 Waiau 3 & 4 Deactivated, 1/2023	Install 54 MW KMCBH Plant, 1/2023 Waiau 3 & 4 Deactivated, 1/2023
2024		
2025	Install 1600 MW Offshore Wind Install (2) 1850 MW x 4 hr Energy Storage	Install 1600 MW Offshore Wind Install (2) 1850 MW x 4 hr Energy Storage
2026		
2027		
2028		
2029		
2030	Install (2) 200 MW x 4 hr Energy Storage	Install (2) 200 MW x 4 hr Energy Storage
2031		
2032		
2033		
2034		
2035		
2036		
2037		
2038		
2039		
2040		
2041		
2042		
2043		
2044		
2045	Install (2) 100 MW x 4 hr Energy Storage	Install (2) 100 MW x 4 hr Energy Storage

Table K-9. Hawaiian Electric Second Iteration Cases (4 of 47)

Case Name	Theme 1, Case 9: Aggressive Solar	Theme 1, Case 10: Aggressive Solar
Case Label	16_T1aSSH30_v2	16_T1aSSL30_v2
DER Forecast	High	High
Fuel Price	High	Low
2016	27.6 MW Waiver PV Projects added 12/31/2016	27.6 MW Waiver PV Projects added 12/31/2016
2017		
2018	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install 10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install 10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)
2019	90 MW Contingency BESS added	90 MW Contingency BESS added
2020	Install 20MW Onshore Wind Install 360 MW Utility PV	Install 20MW Onshore Wind Install 360 MW Utility PV
2021		
2022	Install 100MW JBPHH Plant, 1/2022 AES Deactivated 9/2022	Install 100MW JBPHH Plant, 1/2022 AES Deactivated 9/2022
2023	Install 54 MW KMCBH Plant, 1/2023 Waiau 3 & 4 Deactivated, 1/2023	Install 54 MW KMCBH Plant, 1/2023 Waiau 3 & 4 Deactivated, 1/2023
2024		
2025		
2026		
2027	Install 2820 MW Utility PV Install (2) 1450 MW x 4 hr Energy Storage	Install 2820 MW Utility PV Install (2) 1450 MW x 4 hr Energy Storage
2028		
2029		
2030		
2031		
2032		
2033		
2034		
2035		
2036		
2037		
2038		
2039		
2040	Install (2) 80 MW x 4 hr Energy Storage	Install (2) 80 MW x 4 hr Energy Storage
2041		
2042		
2043		
2044		
2045	Install (2) 40 MW x 4 hr Energy Storage	Install (2) 40 MW x 4 hr Energy Storage

Table K-10. Hawaiian Electric Second Iteration Cases (5 of 47)

Case Name	Theme 2, Case 11: Solar and Wind	Theme 2, Case 12: Solar and Wind
Case Label	16_T2aWv1L	16_T2aWv1H
DER Forecast	High	High
Fuel Price	Low	High
2016	27.6 MW Waiver PV Projects added 12/31/2016	27.6 MW Waiver PV Projects added 12/31/2016
2017		
2018	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install 10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install 10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)
2019	90 MW Contingency BESS added	90 MW Contingency BESS added
2020	Install 100MW JBPHH Plant, 12/2020 Kahe 1, 2, 3 Deactivated, 12/2020 Install 20MW of Onshore Wind Install 620MW of Utility PV	Install 100MW JBPHH Plant, 12/2020 Kahe 1, 2, 3 Deactivated, 12/2020 Install 20MW of Onshore Wind Install 620MW of Utility PV
2021	Install 27 MW KMCBH Plant, 6/2021 Install 3x1 CC, 6/2021	Install 27 MW KMCBH Plant, 6/2021 Install 3x1 CC, 6/2021
2022	AES Deactivated 9/2022 Waiau 3 & 4 Deactivated, 1/2022 Kahe 4 Deactivated, 1/2022	AES Deactivated 9/2022 Waiau 3 & 4 Deactivated, 1/2022 Kahe 4 Deactivated, 1/2022
2023		
2024	Waiau 5 & 6 Deactivated, 1/2024	Waiau 5 & 6 Deactivated, 1/2024
2025		
2026		
2027		
2028	Install (1) 50 MW x 4 hr Energy Storage	Install (1) 50 MW x 4 hr Energy Storage
2029		
2030	Waiau 7 & 8 Deactivated, 1/2030 Install 400MW of Offshore Wind Install (1) 50 MW and (3) 100MW x 4 hr Energy Storage	Waiau 7 & 8 Deactivated, 1/2030 Install 400MW of Offshore Wind Install (1) 50 MW and (3) 100MW x 4 hr Energy Storage
2031		
2032		
2033		
2034		
2035		
2036		
2037		
2038		
2039		
2040	Install 670MW of Utility PV Install 400MW of Offshore Wind Install (9) 100MW x 4 hr Energy Storage	Install 670MW of Utility PV Install 400MW of Offshore Wind Install (9) 100MW x 4 hr Energy Storage
2041		
2042		
2043		
2044		

2045	Install 2150MW of Utility PV	Install 2150MW of Utility PV

Table K-11. Hawaiian Electric Second Iteration Cases (6 of 47)

Case Name	Theme 2, Case 13: Solar and Wind	Theme 2, Case 14: Solar and Wind
Case Label	16_T2bWv1L	16_T2bWv1H
DER Forecast	Market	Market
Fuel Price	Low	High
2016	27.6 MW Waiver PV Projects added 12/31/2016	27.6 MW Waiver PV Projects added 12/31/2016
2017		
2018	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install 10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install 10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)
2019	90 MW Contingency BESS added	90 MW Contingency BESS added
2020	Install 100MW JBPHH Plant, 12/2020 Kahe 1, 2, 3 Deactivated, 12/2020 Install 20MW of Onshore Wind Install 380MW of Utility PV	Install 100MW JBPHH Plant, 12/2020 Kahe 1, 2, 3 Deactivated, 12/2020 Install 20MW of Onshore Wind Install 380MW of Utility PV
2021	Install 27 MW KMCBH Plant, 6/2021 Install 3x1 CC, 6/2021	Install 27 MW KMCBH Plant, 6/2021 Install 3x1 CC, 6/2021
2022	AES Deactivated 9/2022 Waiau 3 & 4 Deactivated, 1/2022 Kahe 4 Deactivated, 1/2022	AES Deactivated 9/2022 Waiau 3 & 4 Deactivated, 1/2022 Kahe 4 Deactivated, 1/2022
2023		
2024	Waiau 5 & 6 Deactivated, 1/2024	Waiau 5 & 6 Deactivated, 1/2024
2025		
2026		
2027		
2028		
2029		
2030	Waiau 7 & 8 Deactivated, 1/2030 Install 400MW of Offshore Wind	Waiau 7 & 8 Deactivated, 1/2030 Install 400MW of Offshore Wind
2031		
2032		
2033		
2034		
2035		
2036		
2037		
2038		
2039		
2040	Install 1440MW of Utility PV Install 400MW of Offshore Wind	Install 1440MW of Utility PV Install 400MW of Offshore Wind
2041		
2042		
2043		
2044		
2045	Install 1620MW of Utility PV	Install 1620MW of Utility PV

Table K-12. Hawaiian Electric Second Iteration Cases (7 of 47)

Case Name	Theme 2, Case 15: Solar	Theme 2, Case 16: Solar
Case Label	16_T2aSv1L	16_T2aSv1H
DER Forecast	High	High
Fuel Price	Low	High
2016	27.6 MW Waiver PV Projects added 12/31/2016	27.6 MW Waiver PV Projects added 12/31/2016
2017		
2018	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install 10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install 10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)
2019	90 MW Contingency BESS added	90 MW Contingency BESS
2020	Install 100MW JBPHH Plant, 12/2020 Kahe 1, 2, 3 Deactivated, 12/2020 Install 20MW of Onshore Wind Install 620MW of Utility PV	Install 100MW JBPHH Plant, 12/2020 Kahe 1, 2, 3 Deactivated, 12/2020 Install 20MW of Onshore Wind Install 620MW of Utility PV
2021	Install 27 MW KMCBH Plant, 6/2021 Install 3x1 CC, 6/2021	Install 27 MW KMCBH Plant, 6/2021 Install 3x1 CC, 6/2021
2022	AES Deactivated 9/2022 Waiau 3 & 4 Deactivated, 1/2022 Kahe 4 Deactivated, 1/2022	AES Deactivated 9/2022 Waiau 3 & 4 Deactivated, 1/2022 Kahe 4 Deactivated, 1/2022
2023		
2024	Waiau 5 & 6 Deactivated, 1/2024	Waiau 5 & 6 Deactivated, 1/2024
2025		
2026		
2027		
2028		
2029		
2030	Waiau 7 & 8 Deactivated, 1/2030 Install 500MW of Utility PV	Waiau 7 & 8 Deactivated, 1/2030 Install 500MW of Utility PV
2031		
2032		
2033		
2034		
2035		
2036		
2037		
2038		
2039		
2040	Install 2320MW of Utility PV	Install 2320MW of Utility PV
2041		
2042		
2043		
2044		
2045		

Table K-13. Hawaiian Electric Second Iteration Cases (8 of 47)

Case Name	Theme 2, Case 17: Solar	Theme 2, Case 18: Solar
Case Label	16_T2bSv1L	16_T2bSv1H
DER Forecast	Market	Market
Fuel Price	Low	High
2016	27.6 MW Waiver PV Projects added 12/31/2016	27.6 MW Waiver PV Projects added 12/31/2016
2017		
2018	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install 10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install 10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)
2019	90 MW Contingency BESS added	90 MW Contingency BESS
2020	Install 100MW JBPHH Plant, 12/2020 Kahe 1, 2, 3 Deactivated, 12/2020 Install 20MW of Onshore Wind Install 380MW of Utility PV	Install 100MW JBPHH Plant, 12/2020 Kahe 1, 2, 3 Deactivated, 12/2020 Install 20MW of Onshore Wind Install 380MW of Utility PV
2021	Install 27 MW KMCBH Plant, 6/2021 Install 3x1 CC, 6/2021	Install 27 MW KMCBH Plant, 6/2021 Install 3x1 CC, 6/2021
2022	AES Deactivated 9/2022 Waiau 3 & 4 Deactivated, 1/2022 Kahe 4 Deactivated, 1/2022	AES Deactivated 9/2022 Waiau 3 & 4 Deactivated, 1/2022 Kahe 4 Deactivated, 1/2022
2023		
2024	Waiau 5 & 6 Deactivated, 1/2024	Waiau 5 & 6 Deactivated, 1/2024
2025		
2026		
2027		
2028		
2029		
2030	Waiau 7 & 8 Deactivated, 1/2030 Install 890MW of Utility PV	Waiau 7 & 8 Deactivated, 1/2030 Install 890MW of Utility PV
2031		
2032		
2033		
2034		
2035		
2036		
2037		
2038		
2039		
2040	Install 2110MW of Utility PV	Install 2110MW of Utility PV
2041		
2042		
2043		
2044		
2045		

Table K-14. Hawaiian Electric Second Iteration Cases (9 of 47)

Case Name	Theme 2, Case 19: Solar and Wind, HL and ME 100% RE 2040	Theme 2, Case 20: Solar and Wind, HL and ME 100% RE 2040
Case Label	16_T2aWv1L40	16_T2aWv1H40
DER Forecast	High	High
Fuel Price	Low	High
2016	27.6 MW Waiver PV Projects added 12/31/2016	27.6 MW Waiver PV Projects added 12/31/2016
2017		
2018	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install 10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install 10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)
2019	90 MW Contingency BESS added	90 MW Contingency BESS added
2020	Install 100MW JBPHH Plant, 12/2020 Kahe 1, 2, 3 Deactivated, 12/2020 Install 20MW of Onshore Wind Install 340MW of Utility PV	Install 100MW JBPHH Plant, 12/2020 Kahe 1, 2, 3 Deactivated, 12/2020 Install 20MW of Onshore Wind Install 340MW of Utility PV
2021	Install 27 MW KMCBH Plant, 6/2021 Install 3x1 CC, 6/2021	Install 27 MW KMCBH Plant, 6/2021 Install 3x1 CC, 6/2021
2022	AES Deactivated 9/2022 Waiau 3 & 4 Deactivated, 1/2022 Kahe 4 Deactivated, 1/2022	AES Deactivated 9/2022 Waiau 3 & 4 Deactivated, 1/2022 Kahe 4 Deactivated, 1/2022
2023		
2024	Waiau 5 & 6 Deactivated, 1/2024	Waiau 5 & 6 Deactivated, 1/2024
2025		
2026		
2027		
2028		
2029		
2030	Waiau 7 & 8 Deactivated, 1/2030 Install 400MW of Offshore Wind	Waiau 7 & 8 Deactivated, 1/2030 Install 400MW of Offshore Wind
2031		
2032		
2033		
2034		
2035		
2036		
2037		
2038		
2039		
2040	Install 400MW of Offshore Wind	Install 400MW of Offshore Wind
2041		
2042		
2043		
2044		
2045	Install 3100MW of Utility PV	Install 3040MW of Utility PV

Table K-15. Hawaiian Electric Second Iteration Cases (10 of 47)

Case Name	Theme 2, Case 21: Solar and Wind, HL and ME 100% RE 2040	Theme 2, Case 22: Solar and Wind, HL and ME 100% RE 2040
Case Label	16_T2bWv1L40	16_T2bWv1H40
DER Forecast	Market	Market
Fuel Price	Low	High
2016	27.6 MW Waiver PV Projects added 12/31/2016	27.6 MW Waiver PV Projects added 12/31/2016
2017		
2018	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install 10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install 10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)
2019	90 MW Contingency BESS added	90 MW Contingency BESS added
2020	Install 100MW JBPHH Plant, 12/2020 Kahe 1, 2, 3 Deactivated, 12/2020 Install 20MW of Onshore Wind Install 400MW of Utility PV	Install 100MW JBPHH Plant, 12/2020 Kahe 1, 2, 3 Deactivated, 12/2020 Install 20MW of Onshore Wind Install 400MW of Utility PV
2021	Install 27 MW KMCBH Plant, 6/2021 Install 3x1 CC, 6/2021	Install 27 MW KMCBH Plant, 6/2021 Install 3x1 CC, 6/2021
2022	AES Deactivated 9/2022 Waiau 3 & 4 Deactivated, 1/2022 Kahe 4 Deactivated, 1/2022	AES Deactivated 9/2022 Waiau 3 & 4 Deactivated, 1/2022 Kahe 4 Deactivated, 1/2022
2023		
2024	Waiau 5 & 6 Deactivated, 1/2024	Waiau 5 & 6 Deactivated, 1/2024
2025		
2026		
2027		
2028		
2029		
2030	Waiau 7 & 8 Deactivated, 1/2030 Install 400MW of Offshore Wind	Waiau 7 & 8 Deactivated, 1/2030 Install 400MW of Offshore Wind
2031		
2032		
2033		
2034		
2035		
2036		
2037		
2038		
2039		
2040	Install 400MW of Offshore Wind	Install 400MW of Offshore Wind
2041		
2042		
2043		
2044		
2045	Install 3040MW of Utility PV	Install 3040MW of Utility PV

Table K-16. Hawaiian Electric Second Iteration Cases (11 of 47)

Case Name	Theme 2, Case 23: Solar, HL and ME 100% RE 2040	Theme 2, Case 24: Solar, HL and ME 100% RE 2040
Case Label	16_T2aSv1L40	16_T2aSv1H40
DER Forecast	High	High
Fuel Price	Low	High
2016	27.6 MW Waiver PV Projects added 12/31/2016	27.6 MW Waiver PV Projects added 12/31/2016
2017		
2018	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install 10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install 10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)
2019	90 MW Contingency BESS added	90 MW Contingency BESS added
2020	Install 100MW JBPHH Plant, 12/2020 Kahe 1, 2, 3 Deactivated, 12/2020 Install 20MW of Onshore Wind Install 400MW of Utility PV	Install 100MW JBPHH Plant, 12/2020 Kahe 1, 2, 3 Deactivated, 12/2020 Install 20MW of Onshore Wind Install 400MW of Utility PV
2021	Install 27 MW KMCBH Plant, 6/2021 Install 3x1 CC, 6/2021	Install 27 MW KMCBH Plant, 6/2021 Install 3x1 CC, 6/2021
2022	AES Deactivated 9/2022 Waiau 3 & 4 Deactivated, 1/2022 Kahe 4 Deactivated, 1/2022	AES Deactivated 9/2022 Waiau 3 & 4 Deactivated, 1/2022 Kahe 4 Deactivated, 1/2022
2023		
2024	Waiau 5 & 6 Deactivated, 1/2024	Waiau 5 & 6 Deactivated, 1/2024
2025		
2026		
2027		
2028		
2029		
2030	Waiau 7 & 8 Deactivated, 1/2030 Install 440MW of Utility PV	Waiau 7 & 8 Deactivated, 1/2030 Install 500MW of Utility PV
2031		
2032		
2033		
2034		
2035		
2036		
2037		
2038		
2039		
2040	Install 280MW of Utility PV	Install 280MW of Utility PV
2041		
2042		
2043		
2044		
2045	Install 2320MW of Utility PV	Install 2360MW of Utility PV

Table K-17. Hawaiian Electric Second Iteration Cases (12 of 47)

Case Name	Theme 2, Case 25: Solar, HL and ME 100% RE 2040	Theme 2, Case 26: Solar, HL and ME 100% RE 2040
Case Label	16_T2bSv1L40	16_T2bSv1H40
DER Forecast	Market	Market
Fuel Price	Low	High
2016	27.6 MW Waiver PV Projects added 12/31/2016	27.6 MW Waiver PV Projects added 12/31/2016
2017		
2018	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install 10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install 10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)
2019	90 MW Contingency BESS added	90 MW Contingency BESS added
2020	Install 100MW JBPHH Plant, 12/2020 Kahe 1, 2, 3 Deactivated, 12/2020 Install 20MW of Onshore Wind Install 380MW of Utility PV	Install 100MW JBPHH Plant, 12/2020 Kahe 1, 2, 3 Deactivated, 12/2020 Install 20MW of Onshore Wind Install 380MW of Utility PV
2021	Install 27 MW KMCBH Plant, 6/2021 Install 3x1 CC, 6/2021	Install 27 MW KMCBH Plant, 6/2021 Install 3x1 CC, 6/2021
2022	AES Deactivated 9/2022 Waiau 3 & 4 Deactivated, 1/2022 Kahe 4 Deactivated, 1/2022	AES Deactivated 9/2022 Waiau 3 & 4 Deactivated, 1/2022 Kahe 4 Deactivated, 1/2022
2023		
2024	Waiau 5 & 6 Deactivated, 1/2024	Waiau 5 & 6 Deactivated, 1/2024
2025		
2026		
2027		
2028		
2029		
2030	Waiau 7 & 8 Deactivated, 1/2030 Install 1040MW of Utility PV	Waiau 7 & 8 Deactivated, 1/2030 Install 1040MW of Utility PV
2031		
2032		
2033		
2034		
2035		
2036		
2037		
2038		
2039		
2040	Install 560MW of Utility PV	Install 560MW of Utility PV
2041		
2042		
2043		
2044		
2045	Install 1460MW of Utility PV	Install 1460MW of Utility PV

Table K-18. Hawaiian Electric Second Iteration Cases (13 of 47)

Case Name	Theme 2, Case 27: Solar and Wind, with Storage	Theme 2, Case 28: Solar and Wind, with Storage
Case Label	16_T2aWv1LBf	16_T2aWv1HBf
DER Forecast	High	High
Fuel Price	Low	High
2016	27.6 MW Waiver PV Projects added 12/31/2016	27.6 MW Waiver PV Projects added 12/31/2016
2017		
2018	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install 10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install 10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)
2019	90 MW Contingency BESS added	90 MW Contingency BESS added
2020	Install 100MW JBPHH Plant, 12/2020 Kahe 1, 2, 3 Deactivated, 12/2020 Install 20MW of Onshore Wind Install 620MW of Utility PV	Install 100MW JBPHH Plant, 12/2020 Kahe 1, 2, 3 Deactivated, 12/2020 Install 20MW of Onshore Wind Install 620MW of Utility PV
2021	Install 27 MW KMCBH Plant, 6/2021 Install 3x1 CC, 6/2021	Install 27 MW KMCBH Plant, 6/2021 Install 3x1 CC, 6/2021
2022	AES Deactivated 9/2022 Waiau 3 & 4 Deactivated, 1/2022 Kahe 4 Deactivated, 1/2022	AES Deactivated 9/2022 Waiau 3 & 4 Deactivated, 1/2022 Kahe 4 Deactivated, 1/2022
2023		
2024	Waiau 5 & 6 Deactivated, 1/2024	Waiau 5 & 6 Deactivated, 1/2024
2025		
2026		
2027		
2028	Install (1) 50 MW x 4 hr Energy Storage	Install (1) 50 MW x 4 hr Energy Storage
2029		
2030	Waiau 7 & 8 Deactivated, 1/2030 Install 400MW of Offshore Wind Install (1) 50 MW and (3) 100MW x 4 hr Energy Storage	Waiau 7 & 8 Deactivated, 1/2030 Install 400MW of Offshore Wind Install (1) 50 MW and (3) 100MW x 4 hr Energy Storage
2031		
2032		
2033		
2034		
2035		
2036		
2037		
2038		
2039		
2040	Install 670MW of Utility PV Install 400MW of Offshore Wind Install (9) 100MW x 4 hr Energy Storage	Install 670MW of Utility PV Install 400MW of Offshore Wind Install (9) 100MW x 4 hr Energy Storage
2041		
2042		
2043		

2044		
2045	Install 2150MW of Utility PV	Install 2150MW of Utility PV

Table K-19. Hawaiian Electric Second Iteration Cases (14 of 47)

Case Name	Theme 2, Case 29: Solar and Wind, with Storage	Theme 2, Case 30: Solar and Wind, with Storage
Case Label	16_T2bWv1LBf	16_T2bWv1HBf
DER Forecast	Market	Market
Fuel Price	Low	High
2016	27.6 MW Waiver PV Projects added 12/31/2016	27.6 MW Waiver PV Projects added 12/31/2016
2017		
2018	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install 10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install 10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)
2019	90 MW Contingency BESS added	90 MW Contingency BESS added
2020	Install 100MW JBPHH Plant, 12/2020 Kahe 1, 2, 3 Deactivated, 12/2020 Install 20MW of Onshore Wind Install 380MW of Utility PV	Install 100MW JBPHH Plant, 12/2020 Kahe 1, 2, 3 Deactivated, 12/2020 Install 20MW of Onshore Wind Install 380MW of Utility PV
2021	Install 27 MW KMCBH Plant, 6/2021 Install 3x1 CC, 6/2021	Install 27 MW KMCBH Plant, 6/2021 Install 3x1 CC, 6/2021
2022	AES Deactivated 9/2022 Waiau 3 & 4 Deactivated, 1/2022 Kahe 4 Deactivated, 1/2022	AES Deactivated 9/2022 Waiau 3 & 4 Deactivated, 1/2022 Kahe 4 Deactivated, 1/2022
2023		
2024	Waiau 5 & 6 Deactivated, 1/2024	Waiau 5 & 6 Deactivated, 1/2024
2025		
2026		
2027		
2028		
2029		
2030	Waiau 7 & 8 Deactivated, 1/2030 Install 400MW of Offshore Wind	Waiau 7 & 8 Deactivated, 1/2030 Install 400MW of Offshore Wind
2031		
2032		
2033		
2034		
2035		
2036		
2037		
2038		
2039		
2040	Install 1440MW of Utility PV Install 400MW of Offshore Wind Install (13) 100MW x 4 hr Energy Storage	Install 1440MW of Utility PV Install 400MW of Offshore Wind Install (13) 100MW x 4 hr Energy Storage
2041		
2042		
2043		
2044		
2045	Install 1620MW of Utility PV	Install 1620MW of Utility PV

Table K-20. Hawaiian Electric Second Iteration Cases (15 of 47)

Case Name	Theme 2, Case 31: Solar, with Storage	Theme 2, Case 32: Solar, with Storage
Case Label	16_T2aSv1LBf	16_T2aSv1HBf
DER Forecast	High	High
Fuel Price	Low	High
2016	27.6 MW Waiver PV Projects added 12/31/2016	27.6 MW Waiver PV Projects added 12/31/2016
2017		
2018	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install 10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install 10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)
2019	90 MW Contingency BESS added	90 MW Contingency BESS
2020	Install 100MW JBPHH Plant, 12/2020 Kahe 1, 2, 3 Deactivated, 12/2020 Install 20MW of Onshore Wind Install 620MW of Utility PV	Install 100MW JBPHH Plant, 12/2020 Kahe 1, 2, 3 Deactivated, 12/2020 Install 20MW of Onshore Wind Install 620MW of Utility PV
2021	Install 27 MW KMCBH Plant, 6/2021 Install 3x1 CC, 6/2021	Install 27 MW KMCBH Plant, 6/2021 Install 3x1 CC, 6/2021
2022	AES Deactivated 9/2022 Waiau 3 & 4 Deactivated, 1/2022 Kahe 4 Deactivated, 1/2022	AES Deactivated 9/2022 Waiau 3 & 4 Deactivated, 1/2022 Kahe 4 Deactivated, 1/2022
2023		
2024	Waiau 5 & 6 Deactivated, 1/2024	Waiau 5 & 6 Deactivated, 1/2024
2025		
2026		
2027		
2028		
2029		
2030	Waiau 7 & 8 Deactivated, 1/2030 Install 500MW of Utility PV Install (4) 100MW x 4 hr Energy Storage	Waiau 7 & 8 Deactivated, 1/2030 Install 500MW of Utility PV Install (4) 100MW x 4 hr Energy Storage
2031		
2032		
2033		
2034		
2035		
2036		
2037		
2038		
2039		
2040	Install 2320MW of Utility PV Install (21) 100MW x 4 hr Energy Storage	Install 2320MW of Utility PV Install (21) 100MW x 4 hr Energy Storage
2041		
2042		
2043		
2044		
2045		

Table K-21. Hawaiian Electric Second Iteration Cases (16 of 47)

Case Name	Theme 2, Case 33: Solar, with Storage	Theme 2, Case 34: Solar, with Storage
Case Label	16_T2bSv1LBf	16_T2bSv1HBf
DER Forecast	Market	Market
Fuel Price	Low	High
2016	27.6 MW Waiver PV Projects added 12/31/2016	27.6 MW Waiver PV Projects added 12/31/2016
2017		
2018	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install 10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install 10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)
2019	90 MW Contingency BESS added	90 MW Contingency BESS
2020	Install 100MW JBPHH Plant, 12/2020 Kahe 1, 2, 3 Deactivated, 12/2020 Install 20MW of Onshore Wind Install 380MW of Utility PV	Install 100MW JBPHH Plant, 12/2020 Kahe 1, 2, 3 Deactivated, 12/2020 Install 20MW of Onshore Wind Install 380MW of Utility PV
2021	Install 27 MW KMCBH Plant, 6/2021 Install 3x1 CC, 6/2021	Install 27 MW KMCBH Plant, 6/2021 Install 3x1 CC, 6/2021
2022	AES Deactivated 9/2022 Waiau 3 & 4 Deactivated, 1/2022 Kahe 4 Deactivated, 1/2022	AES Deactivated 9/2022 Waiau 3 & 4 Deactivated, 1/2022 Kahe 4 Deactivated, 1/2022
2023		
2024	Waiau 5 & 6 Deactivated, 1/2024	Waiau 5 & 6 Deactivated, 1/2024
2025		
2026		
2027		
2028		
2029		
2030	Waiau 7 & 8 Deactivated, 1/2030 Install 890MW of Utility PV Install (3) 100MW x 4 hr Energy Storage	Waiau 7 & 8 Deactivated, 1/2030 Install 890MW of Utility PV Install (3) 100MW x 4 hr Energy Storage
2031		
2032		
2033		
2034		
2035		
2036		
2037		
2038		
2039		
2040	Install 2110MW of Utility PV Install (10) 100MW x 4 hr Energy Storage	Install 2110MW of Utility PV Install (10) 100MW x 4 hr Energy Storage
2041		
2042		
2043		
2044		
2045		

Table K-22. Hawaiian Electric Second Iteration Cases (17 of 47)

Case Name	Theme 2, Case 35: Solar and Wind, with Storage, HL and ME 100% RE 2040	Theme 2, Case 36: Solar and Wind, with Storage, HL and ME 100% RE 2040
Case Label	16_T2aWv1LBf40	16_T2aWv1HBf40
DER Forecast	High	High
Fuel Price	Low	High
2016	27.6 MW Waiver PV Projects added 12/31/2016	27.6 MW Waiver PV Projects added 12/31/2016
2017		
2018	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install 10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install 10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)
2019	90 MW Contingency BESS added	90 MW Contingency BESS added
2020	Install 100MW JBPHH Plant, 12/2020 Kahe 1, 2, 3 Deactivated, 12/2020 Install 20MW of Onshore Wind Install 340MW of Utility PV	Install 100MW JBPHH Plant, 12/2020 Kahe 1, 2, 3 Deactivated, 12/2020 Install 20MW of Onshore Wind Install 340MW of Utility PV
2021	Install 27 MW KMCBH Plant, 6/2021 Install 3x1 CC, 6/2021	Install 27 MW KMCBH Plant, 6/2021 Install 3x1 CC, 6/2021
2022	AES Deactivated 9/2022 Waiau 3 & 4 Deactivated, 1/2022 Kahe 4 Deactivated, 1/2022	AES Deactivated 9/2022 Waiau 3 & 4 Deactivated, 1/2022 Kahe 4 Deactivated, 1/2022
2023		
2024	Waiau 5 & 6 Deactivated, 1/2024	Waiau 5 & 6 Deactivated, 1/2024
2025		
2026		
2027		
2028		
2029		
2030	Waiau 7 & 8 Deactivated, 1/2030 Install 400MW of Offshore Wind	Waiau 7 & 8 Deactivated, 1/2030 Install 400MW of Offshore Wind
2031		
2032		
2033		
2034		
2035		
2036		
2037		
2038		
2039		
2040	Install 400MW of Offshore Wind Install (2) 100MW x 4 hr Energy Storage	Install 400MW of Offshore Wind Install (2) 100MW x 4 hr Energy Storage
2041		
2042		
2043		
2044		
2045	Install 3100MW of Utility PV	Install 3040MW of Utility PV

Table K-23. Hawaiian Electric Second Iteration Cases (18 of 47)

Case Name	Theme 2, Case 37: Solar and Wind, with Storage, HL and ME 100% RE 2040	Theme 2, Case 38: Solar and Wind, with Storage, HL and ME 100% RE 2040
Case Label	16_T2bWv1LBf40	16_T2bWv1HBf40
DER Forecast	Market	Market
Fuel Price	Low	High
2016	27.6 MW Waiver PV Projects added 12/31/2016	27.6 MW Waiver PV Projects added 12/31/2016
2017		
2018	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install 10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install 10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)
2019	90 MW Contingency BESS added	90 MW Contingency BESS added
2020	Install 100MW JBPHH Plant, 12/2020 Kahe 1, 2, 3 Deactivated, 12/2020 Install 20MW of Onshore Wind Install 400MW of Utility PV	Install 100MW JBPHH Plant, 12/2020 Kahe 1, 2, 3 Deactivated, 12/2020 Install 20MW of Onshore Wind Install 400MW of Utility PV
2021	Install 27 MW KMCBH Plant, 6/2021 Install 3x1 CC, 6/2021	Install 27 MW KMCBH Plant, 6/2021 Install 3x1 CC, 6/2021
2022	AES Deactivated 9/2022 Waiau 3 & 4 Deactivated, 1/2022 Kahe 4 Deactivated, 1/2022	AES Deactivated 9/2022 Waiau 3 & 4 Deactivated, 1/2022 Kahe 4 Deactivated, 1/2022
2023		
2024	Waiau 5 & 6 Deactivated, 1/2024	Waiau 5 & 6 Deactivated, 1/2024
2025		
2026		
2027		
2028		
2029		
2030	Waiau 7 & 8 Deactivated, 1/2030 Install 400MW of Offshore Wind	Waiau 7 & 8 Deactivated, 1/2030 Install 400MW of Offshore Wind
2031		
2032		
2033		
2034		
2035		
2036		
2037		
2038		
2039		
2040	Install 400MW of Offshore Wind Install (1) 100MW x 4 hr Energy Storage	Install 400MW of Offshore Wind Install (1) 100MW x 4 hr Energy Storage
2041		
2042		
2043		
2044		
2045	Install 3040MW of Utility PV	Install 3040MW of Utility PV

Table K-24. Hawaiian Electric Second Iteration Cases (19 of 47)

Case Name	Theme 2, Case 39: Solar, with Storage, HL and ME 100% RE 2040	Theme 2, Case 40: Solar, with Storage, HL and ME 100% RE 2040
Case Label	16_T2aSv1LBf40	16_T2aSv1HBf40
DER Forecast	High	High
Fuel Price	Low	High
2016	27.6 MW Waiver PV Projects added 12/31/2016	27.6 MW Waiver PV Projects added 12/31/2016
2017		
2018	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install 10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install 10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)
2019	90 MW Contingency BESS added	90 MW Contingency BESS added
2020	Install 100MW JBPHH Plant, 12/2020 Kahe 1, 2, 3 Deactivated, 12/2020 Install 20MW of Onshore Wind Install 400MW of Utility PV	Install 100MW JBPHH Plant, 12/2020 Kahe 1, 2, 3 Deactivated, 12/2020 Install 20MW of Onshore Wind Install 400MW of Utility PV
2021	Install 27 MW KMCBH Plant, 6/2021 Install 3x1 CC, 6/2021	Install 27 MW KMCBH Plant, 6/2021 Install 3x1 CC, 6/2021
2022	AES Deactivated 9/2022 Waiau 3 & 4 Deactivated, 1/2022 Kahe 4 Deactivated, 1/2022	AES Deactivated 9/2022 Waiau 3 & 4 Deactivated, 1/2022 Kahe 4 Deactivated, 1/2022
2023		
2024	Waiau 5 & 6 Deactivated, 1/2024	Waiau 5 & 6 Deactivated, 1/2024
2025		
2026		
2027		
2028		
2029		
2030	Waiau 7 & 8 Deactivated, 1/2030 Install 440MW of Utility PV Install (2) 100MW x 4 hr Energy Storage	Waiau 7 & 8 Deactivated, 1/2030 Install 500MW of Utility PV Install (2) 100MW x 4 hr Energy Storage
2031		
2032		
2033		
2034		
2035		
2036		
2037		
2038		
2039		
2040	Install 280MW of Utility PV Install (2) 100MW x 4 hr Energy Storage	Install 280MW of Utility PV Install (2) 100MW x 4 hr Energy Storage
2041		
2042		
2043		
2044		

2045	Install 2320MW of Utility PV	Install 2360MW of Utility PV

Table K-25. Hawaiian Electric Second Iteration Cases (20 of 47)

Case Name	Theme 2, Case 41: Solar, with Storage, HL and ME 100% RE 2040	Theme 2, Case 42: Solar, with Storage, HL and ME 100% RE 2040
Case Label	16_T2bSv1LBf40	16_T2bSv1HBf40
DER Forecast	Market	Market
Fuel Price	Low	High
2016	27.6 MW Waiver PV Projects added 12/31/2016	27.6 MW Waiver PV Projects added 12/31/2016
2017		
2018	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install 10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install 10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)
2019	90 MW Contingency BESS added	90 MW Contingency BESS added
2020	Install 100MW JBPHH Plant, 12/2020 Kahe 1, 2, 3 Deactivated, 12/2020 Install 20MW of Onshore Wind Install 380MW of Utility PV	Install 100MW JBPHH Plant, 12/2020 Kahe 1, 2, 3 Deactivated, 12/2020 Install 20MW of Onshore Wind Install 380MW of Utility PV
2021	Install 27 MW KMCBH Plant, 6/2021 Install 3x1 CC, 6/2021	Install 27 MW KMCBH Plant, 6/2021 Install 3x1 CC, 6/2021
2022	AES Deactivated 9/2022 Waiau 3 & 4 Deactivated, 1/2022 Kahe 4 Deactivated, 1/2022	AES Deactivated 9/2022 Waiau 3 & 4 Deactivated, 1/2022 Kahe 4 Deactivated, 1/2022
2023		
2024	Waiau 5 & 6 Deactivated, 1/2024	Waiau 5 & 6 Deactivated, 1/2024
2025		
2026		
2027		
2028		
2029		
2030	Waiau 7 & 8 Deactivated, 1/2030 Install 1040MW of Utility PV Install (4) 100MW x 4 hr Energy Storage	Waiau 7 & 8 Deactivated, 1/2030 Install 1040MW of Utility PV Install (4) 100MW x 4 hr Energy Storage
2031		
2032		
2033		
2034		
2035		
2036		
2037		
2038		
2039		
2040	Install 560MW of Utility PV Install (3) 100MW x 4 hr Energy Storage	Install 560MW of Utility PV Install (3) 100MW x 4 hr Energy Storage
2041		
2042		
2043		
2044		

2045	Install 1460MW of Utility PV	Install 1460MW of Utility PV

Table K-26. Hawaiian Electric Second Iteration Cases (21 of 47)

Case Name	Theme 3, Case 43: Solar and Wind	Theme 3, Case 44: Solar and Wind
Case Label	16_T3aWv1L	16_T3aWv1H
DER Forecast	High	High
Fuel Price	Low	High
2016	27.6 MW Waiver PV Projects added 12/31/2016	27.6 MW Waiver PV Projects added 12/31/2016
2017		
2018	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install 10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install 10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)
2019	90 MW Contingency BESS added	90 MW Contingency BESS added
2020	Install 20MW of Onshore Wind Install 620MW of Utility PV	Install 20MW of Onshore Wind Install 620MW of Utility PV
2021		
2022	Install 100MW JBPHH Plant, 1/2022 AES Deactivated 9/2022	Install 100MW JBPHH Plant, 1/2022 AES Deactivated 9/2022
2023	Install 54MW KMBCH Plant, 1/2023 Waiau 3 & 4 Deactivated, 1/2023	Install 54MW KMBCH Plant, 1/2023 Waiau 3 & 4 Deactivated, 1/2023
2024		
2025	Kahe 6 Deactivated, 1/2025	Kahe 6 Deactivated, 1/2025
2026		
2027		
2028		
2029		
2030	Waiau 5 & 6 Deactivated, 1/2030 Install 400MW of Offshore Wind	Waiau 5 & 6 Deactivated, 1/2030 Install 400MW of Offshore Wind
2031		
2032		
2033		
2034		
2035		
2036		
2037		
2038		
2039		
2040	Install 670MW of Utility PV Install 400MW of Offshore Wind	Install 670MW of Utility PV Install 400MW of Offshore Wind
2041		
2042		
2043		
2044		
2045	Install 2150MW of Utility PV	Install 2150MW of Utility PV

Table K-27. Hawaiian Electric Second Iteration Cases (22 of 47)

Case Name	Theme 3, Case 45: Solar and Wind	Theme 3, Case 46: Solar and Wind
Case Label	16_T3bWv1L	16_T3bWv1H
DER Forecast	Market	Market
Fuel Price	Low	High
2016	27.6 MW Waiver PV Projects added 12/31/2016	27.6 MW Waiver PV Projects added 12/31/2016
2017		
2018	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install 10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install 10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)
2019	90 MW Contingency BESS added	90 MW Contingency BESS added
2020	Install 20MW of Onshore Wind Install 380MW of Utility PV	Install 20MW of Onshore Wind Install 380MW of Utility PV
2021		
2022	Install 100MW JBPHH Plant, 1/2022 AES Deactivated 9/2022	Install 100MW JBPHH Plant, 1/2022 AES Deactivated 9/2022
2023	Install 54MW KMBCH Plant, 1/2023 Waiau 3 & 4 Deactivated, 1/2023	Install 54MW KMBCH Plant, 1/2023 Waiau 3 & 4 Deactivated, 1/2023
2024		
2025	Kahe 6 Deactivated, 1/2025	Kahe 6 Deactivated, 1/2025
2026		
2027		
2028		
2029		
030	Waiau 5 & 6 Deactivated, 1/2030 Install 400MW of Offshore Wind	Waiau 5 & 6 Deactivated, 1/2030 Install 400MW of Offshore Wind
2031		
2032		
2033		
2034		
2035		
2036		
2037		
2038		
2039		
2040	Install 1440MW of Utility PV Install 400MW of Offshore Wind	Install 1440MW of Utility PV Install 400MW of Offshore Wind
2041		
2042		
2043		
2044		
2045	Install 1620MW of Utility PV	Install 1620MW of Utility PV

Table K-28. Hawaiian Electric Second Iteration Cases (23 of 47)

Case Name	Theme 3, Case 47: Solar	Theme 3, Case 48: Solar
Case Label	16_T3aSv1L	16_T3aSv1H
DER Forecast	High	High
Fuel Price	Low	High
2016	27.6 MW Waiver PV Projects added 12/31/2016	27.6 MW Waiver PV Projects added 12/31/2016
2017		
2018	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install 10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install 10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)
2019	90 MW Contingency BESS added	90 MW Contingency BESS added
2020	Install 20MW of Onshore Wind Install 620MW of Utility PV	Install 20MW of Onshore Wind Install 620MW of Utility PV
2021		
2022	Install 100MW JBPHH Plant, 1/2022 AES Deactivated 9/2022	Install 100MW JBPHH Plant, 1/2022 AES Deactivated 9/2022
2023	Install 54MW KMBCH Plant, 1/2023 Waiau 3 & 4 Deactivated, 1/2023	Install 54MW KMBCH Plant, 1/2023 Waiau 3 & 4 Deactivated, 1/2023
2024		
2025	Kahe 6 Deactivated, 1/2025	Kahe 6 Deactivated, 1/2025
2026		
2027		
2028		
2029		
2030	Waiau 5 & 6 Deactivated, 1/2030 Install 500MW of Utility PV	Waiau 5 & 6 Deactivated, 1/2030 Install 500MW of Utility PV
2031		
2032		
2033		
2034		
2035		
2036		
2037		
2038		
2039		
2040	Install 2320MW of Utility PV	Install 2320MW of Utility PV
2041		
2042		
2043		
2044		
2045		

Table K-29. Hawaiian Electric Second Iteration Cases (24 of 47)

Case Name	Theme 3, Case 49: Solar	Theme 3, Case 50: Solar
Case Label	16_T3bSv1L	16_T3bSv1H
DER Forecast	Market	Market
Fuel Price	Low	High
2016	27.6 MW Waiver PV Projects added 12/31/2016	27.6 MW Waiver PV Projects added 12/31/2016
2017		
2018	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install 10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install 10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)
2019	90 MW Contingency BESS added	90 MW Contingency BESS added
2020	Install 20MW of Onshore Wind Install 440MW of Utility PV	Install 20MW of Onshore Wind Install 440MW of Utility PV
2021		
2022	Install 100MW JBPHH Plant, 1/2022 AES Deactivated 9/2022	Install 100MW JBPHH Plant, 1/2022 AES Deactivated 9/2022
2023	Install 54MW KMBCH Plant, 1/2023 Waiau 3 & 4 Deactivated, 1/2023	Install 54MW KMBCH Plant, 1/2023 Waiau 3 & 4 Deactivated, 1/2023
2024		
2025	Kahe 6 Deactivated, 1/2025	Kahe 6 Deactivated, 1/2025
2026		
2027		
2028		
2029		
2030	Waiau 5 & 6 Deactivated, 1/2030 Install 890MW of Utility PV	Waiau 5 & 6 Deactivated, 1/2030 Install 890MW of Utility PV
2031		
2032		
2033		
2034		
2035		
2036		
2037		
2038		
2039		
2040	Install 1370MW of Utility PV	Install 870MW of Utility PV
2041		
2042		
2043		
2044		
2045	Install 740MW of Utility PV	Install 1240MW of Utility PV

Table K-30. Hawaiian Electric Second Iteration Cases (25 of 47)

Case Name	Theme 3, Case 51: Solar and Wind, HL and ME 100% RE 2040	Theme 3, Case 52: Solar and Wind, HL and ME 100% RE 2040
Case Label	16_T3aWv1L40	16_T3aWv1H40
DER Forecast	High	High
Fuel Price	Low	High
2016	27.6 MW Waiver PV Projects added 12/31/2016	27.6 MW Waiver PV Projects added 12/31/2016
2017		
2018	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install 10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install 10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)
2019	90 MW Contingency BESS added	90 MW Contingency BESS added
2020	Install 20MW of Onshore Wind Install 620MW of Utility PV	Install 20MW of Onshore Wind Install 400MW of Utility PV
2021		
2022	Install 100MW JBPHH Plant, 1/2022 AES Deactivated 9/2022	Install 100MW JBPHH Plant, 1/2022 AES Deactivated 9/2022
2023	Install 54MW KMBCH Plant, 1/2023 Waiau 3 & 4 Deactivated, 1/2023	Install 54MW KMBCH Plant, 1/2023 Waiau 3 & 4 Deactivated, 1/2023
2024		
2025	Kahe 6 Deactivated, 1/2025	Kahe 6 Deactivated, 1/2025
2026		
2027		
2028		
2029		
2030	Waiau 5 & 6 Deactivated, 1/2030 Install 400MW of Offshore Wind	Waiau 5 & 6 Deactivated, 1/2030 Install 400 MW of Offshore Wind
2031		
2032		
2033		
2034		
2035		
2036		
2037		
2038		
2039		
2040	Install 670MW of Utility PV Install 400MW of Offshore Wind	Install 400 MW of Offshore Wind
2041		
2042		
2043		
2044		
2045	Install 2150MW of Utility PV	Install 3040 MW of Utility PV

Table K-31. Hawaiian Electric Second Iteration Cases (26 of 47)

Case Name	Theme 3, Case 53: Solar and Wind, HL and ME 100% RE 2040	Theme 3, Case 54: Solar and Wind, HL and ME 100% RE 2040
Case Label	16_T3bWv1L40	16_T3bWv1H40
DER Forecast	Market	Market
Fuel Price	Low	High
2016	27.6 MW Waiver PV Projects added 12/31/2016	27.6 MW Waiver PV Projects added 12/31/2016
2017		
2018	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install 10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install 10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)
2019	90 MW Contingency BESS added	90 MW Contingency BESS added
2020	Install 20MW of Onshore Wind Install 380MW of Utility PV	Install 20MW of Onshore Wind Install 380MW of Utility PV
2021		
2022	Install 100MW JBPHH Plant, 1/2022 AES Deactivated 9/2022	Install 100MW JBPHH Plant, 1/2022 AES Deactivated 9/2022
2023	Install 54MW KMBCH Plant, 1/2023 Waiau 3 & 4 Deactivated, 1/2023	Install 54MW KMBCH Plant, 1/2023 Waiau 3 & 4 Deactivated, 1/2023
2024		
2025	Kahe 6 Deactivated, 1/2025	Kahe 6 Deactivated, 1/2025
2026		
2027		
2028		
2029		
2030	Waiau 5 & 6 Deactivated, 1/2030 Install 400MW of Offshore Wind	Waiau 5 & 6 Deactivated, 1/2030
2031		
2032		
2033		
2034		
2035		
2036		
2037		
2038		
2039		
2040	Install 1440MW of Utility PV Install 400MW of Offshore Wind	Install 1440MW of Utility PV
2041		
2042		
2043		
2044		
2045	Install 1620MW of Utility PV	Install 2000MW of Utility PV

Table K-32. Hawaiian Electric Second Iteration Cases (27 of 47)

Case Name	Theme 3, Case 55: Solar and Wind, HL and ME 100% RE 2040	Theme 3, Case 56: Solar and Wind, HL and ME 100% RE 2040
Case Label	16_T3aSv1L40	16_T3aSv1H40
DER Forecast	High	High
Fuel Price	Low	High
2016	27.6 MW Waiver PV Projects added 12/31/2016	27.6 MW Waiver PV Projects added 12/31/2016
2017		
2018	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install 10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install 10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)
2019	90 MW Contingency BESS added	90 MW Contingency BESS added
2020	Install 20MW of Onshore Wind Install 620MW of Utility PV	Install 20MW of Onshore Wind Install 400MW of Utility PV
2021		
2022	Install 100MW JBPHH Plant, 1/2022 AES Deactivated 9/2022	Install 100MW JBPHH Plant, 1/2022 AES Deactivated 9/2022
2023	Install 54MW KMBCH Plant, 1/2023 Waiau 3 & 4 Deactivated, 1/2023	Install 54MW KMBCH Plant, 1/2023 Waiau 3 & 4 Deactivated, 1/2023
2024		
2025	Kahe 6 Deactivated, 1/2025	Kahe 6 Deactivated, 1/2025
2026		
2027		
2028		
2029		
2030	Waiau 5 & 6 Deactivated, 1/2030 Install 500MW of Utility PV	Waiau 5 & 6 Deactivated, 1/2030 Install 500MW of Utility PV
2031		
2032		
2033		
2034		
2035		
2036		
2037		
2038		
2039		
2040	Install 2320MW of Utility PV	Install 180 MW of Utility PV
2041		
2042		
2043		
2044		
2045		Install 2360MW of Utility PV

Table K-33. Hawaiian Electric Second Iteration Cases (28 of 47)

Case Name	Theme 3, Case 57: Solar and Wind, HL and ME 100% RE 2040	Theme 3, Case 58: Solar and Wind, HL and ME 100% RE 2040
Case Label	16_T3bSv1L40	16_T3bSv1H40
DER Forecast	Market	Market
Fuel Price	Low	High
2016	27.6 MW Waiver PV Projects added 12/31/2016	27.6 MW Waiver PV Projects added 12/31/2016
2017		
2018	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install 10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install 10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)
2019	90 MW Contingency BESS added	90 MW Contingency BESS added
2020	Install 20MW of Onshore Wind Install 380MW of Utility PV	Install 20MW of Onshore Wind Install 380MW of Utility PV
2021		
2022	Install 100MW JBPHH Plant, 1/2022 AES Deactivated 9/2022	Install 100MW JBPHH Plant, 1/2022 AES Deactivated 9/2022
2023	Install 54MW KMBCH Plant, 1/2023 Waiau 3 & 4 Deactivated, 1/2023	Install 54MW KMBCH Plant, 1/2023 Waiau 3 & 4 Deactivated, 1/2023
2024		
2025	Kahe 6 Deactivated, 1/2025	Kahe 6 Deactivated, 1/2025
2026		
2027		
2028		
2029		
2030	Waiau 5 & 6 Deactivated, 1/2030 Install 890MW of Utility PV	Waiau 5 & 6 Deactivated, 1/2030 Install 1040MW of Utility PV
2031		
2032		
2033		
2034		
2035		
2036		
2037		
2038		
2039		
2040	Install 2110MW of Utility PV	Install 560 MW of Utility PV
2041		
2042		
2043		
2044		
2045		Install 2000MW of Utility PV

Table K-34. Hawaiian Electric Second Iteration Cases (29 of 47)

Case Name	Theme 3, Case 59: Solar and Wind, with Storage	Theme 3, Case 60: Solar and Wind, with Storage
Case Label	16_T3aWv1LBf	16_T3aWv1HBf
DER Forecast	High	High
Fuel Price	Low	High
2016	27.6 MW Waiver PV Projects added 12/31/2016	27.6 MW Waiver PV Projects added 12/31/2016
2017		
2018	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install 10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install 10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)
2019	90 MW Contingency BESS added	90 MW Contingency BESS added
2020	Install 20MW of Onshore Wind Install 620MW of Utility PV	Install 20MW of Onshore Wind Install 620MW of Utility PV
2021		
2022	Install 100MW JBPHH Plant, 1/2022 AES Deactivated 9/2022	Install 100MW JBPHH Plant, 1/2022 AES Deactivated 9/2022
2023	Install 54MW KMBCH Plant, 1/2023 Waiau 3 & 4 Deactivated, 1/2023	Install 54MW KMBCH Plant, 1/2023 Waiau 3 & 4 Deactivated, 1/2023
2024		
2025	Kahe 6 Deactivated, 1/2025	Kahe 6 Deactivated, 1/2025
2026		
2027		
2028	Install (1) 50 MW x 4 hr Energy Storage	Install (1) 50 MW x 4 hr Energy Storage
2029		
2030	Waiau 5 & 6 Deactivated, 1/2030 Install 400MW of Offshore Wind Install (1) 50 MW and (3) 100MW x 4 hr Energy Storage	Waiau 5 & 6 Deactivated, 1/2030 Install 400MW of Offshore Wind Install (1) 50 MW and (3) 100MW x 4 hr Energy Storage
2031		
2032		
2033		
2034		
2035		
2036		
2037		
2038		
2039		
2040	Install 670MW of Utility PV Install 400MW of Offshore Wind Install (9) 100MW x 4 hr Energy Storage	Install 670MW of Utility PV Install 400MW of Offshore Wind Install (9) 100MW x 4 hr Energy Storage
2041		
2042		
2043		
2044		
2045	Install 2150MW of Utility PV	Install 2150MW of Utility PV

Table K-35. Hawaiian Electric Second Iteration Cases (30 of 47)

Case Name	Theme 3, Case 61: Solar and Wind, with Storage	Theme 3, Case 62: Solar and Wind, with Storage
Case Label	16_T3bWv1LBf	16_T3bWv1HBf
DER Forecast	Market	Market
Fuel Price	Low	High
2016	27.6 MW Waiver PV Projects added 12/31/2016	27.6 MW Waiver PV Projects added 12/31/2016
2017		
2018	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install 10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install 10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)
2019	90 MW Contingency BESS added	90 MW Contingency BESS added
2020	Install 20MW of Onshore Wind Install 380MW of Utility PV	Install 20MW of Onshore Wind Install 380MW of Utility PV
2021		
2022	Install 100MW JBPHH Plant, 1/2022 AES Deactivated 9/2022	Install 100MW JBPHH Plant, 1/2022 AES Deactivated 9/2022
2023	Install 54MW KMBCH Plant, 1/2023 Waiau 3 & 4 Deactivated, 1/2023	Install 54MW KMBCH Plant, 1/2023 Waiau 3 & 4 Deactivated, 1/2023
2024		
2025	Kahe 6 Deactivated, 1/2025	Kahe 6 Deactivated, 1/2025
2026		
2027		
2028		
2029		
2030	Waiau 5 & 6 Deactivated, 1/2030 Install 400MW of Offshore Wind	Waiau 5 & 6 Deactivated, 1/2030 Install 400MW of Offshore Wind
2031		
2032		
2033		
2034		
2035		
2036		
2037		
2038		
2039		
2040	Install 1440MW of Utility PV Install 400MW of Offshore Wind Install (13) 100MW x 4 hr Energy Storage	Install 1440MW of Utility PV Install 400MW of Offshore Wind Install (13) 100MW x 4 hr Energy Storage
2041		
2042		
2043		
2044		
2045	Install 1620MW of Utility PV	Install 1620MW of Utility PV

Table K-36. Hawaiian Electric Second Iteration Cases (31 of 47)

Case Name	Theme 3, Case 63: Solar, with Storage	Theme 3, Case 64: Solar, with Storage
Case Label	16_T3aSv1LBf	16_T3aSv1HBf
DER Forecast	High	High
Fuel Price	Low	High
2016	27.6 MW Waiver PV Projects added 12/31/2016	27.6 MW Waiver PV Projects added 12/31/2016
2017		
2018	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install 10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install 10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)
2019	90 MW Contingency BESS added	90 MW Contingency BESS added
2020	Install 20MW of Onshore Wind Install 620MW of Utility PV	Install 20MW of Onshore Wind Install 620MW of Utility PV
2021		
2022	Install 100MW JBPHH Plant, 1/2022 AES Deactivated 9/2022	Install 100MW JBPHH Plant, 1/2022 AES Deactivated 9/2022
2023	Install 54MW KMBCH Plant, 1/2023 Waiau 3 & 4 Deactivated, 1/2023	Install 54MW KMBCH Plant, 1/2023 Waiau 3 & 4 Deactivated, 1/2023
2024		
2025	Kahe 6 Deactivated, 1/2025	Kahe 6 Deactivated, 1/2025
2026		
2027		
2028		Install (1) 50 MW x 4 hr Energy Storage
2029		
2030	Waiau 5 & 6 Deactivated, 1/2030 Install 500MW of Utility PV Install (4) 100MW x 4 hr Energy Storage	Waiau 5 & 6 Deactivated, 1/2030 Install 500MW of Utility PV Install (2) 100 MW x 4 hr Energy Storage
2031		
2032		
2033		
2034		
2035		
2036		
2037		
2038		
2039		
2040	Install 2320MW of Utility PV Install (21) 100MW x 4 hr Energy Storage	Install 2320MW of Utility PV Install (10) 100 MW and (1) 50MW x 4 hr Energy Storage
2041		
2042		
2043		
2044		
2045		

Table K-37. Hawaiian Electric Second Iteration Cases (32 of 47)

Case Name	Theme 3, Case 65: Solar, with Storage	Theme 3, Case 66: Solar, with Storage
Case Label	16_T3bSv1LBf	16_T3bSv1HBf
DER Forecast	Market	Market
Fuel Price	Low	High
2016	27.6 MW Waiver PV Projects added 12/31/2016	27.6 MW Waiver PV Projects added 12/31/2016
2017		
2018	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install 10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install 10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)
2019	90 MW Contingency BESS added	90 MW Contingency BESS added
2020	Install 20MW of Onshore Wind Install 440MW of Utility PV	Install 20MW of Onshore Wind Install 440MW of Utility PV
2021		
2022	Install 100MW JBPHH Plant, 1/2022 AES Deactivated 9/2022	Install 100MW JBPHH Plant, 1/2022 AES Deactivated 9/2022
2023	Install 54MW KMBCH Plant, 1/2023 Waiau 3 & 4 Deactivated, 1/2023	Install 54MW KMBCH Plant, 1/2023 Waiau 3 & 4 Deactivated, 1/2023
2024		
2025	Kahe 6 Deactivated, 1/2025	Kahe 6 Deactivated, 1/2025
2026		
2027		
2028		
2029		
2030	Waiau 5 & 6 Deactivated, 1/2030 Install 890MW of Utility PV Install (1) 100 MW and (1) 50MW x 4 hr Energy Storage	Waiau 5 & 6 Deactivated, 1/2030 Install 890MW of Utility PV Install (1) 100 MW and (1) 50MW x 4 hr Energy Storage
2031		
2032		
2033		
2034		
2035		
2036		
2037		
2038		
2039		
2040	Install 1370MW of Utility PV Install (5) 100MW x 4 hr Energy Storage	Install 870MW of Utility PV Install (3) 100MW x 4 hr Energy Storage
2041		
2042		
2043		
2044		
2045	Install 740MW of Utility PV Install (3) 100MW x 4 hr Energy Storage	Install 1240MW of Utility PV Install (5) 100MW x 4 hr Energy Storage

Table K-38. Hawaiian Electric Second Iteration Cases (33 of 47)

Case Name	Theme 3, Case 67: Solar and Wind, with Storage, HL and ME 100% RE 2040	Theme 3, Case 68: Solar and Wind, with Storage, HL and ME 100% RE 2040
Case Label	16_T3aWv1LBf40	16_T3aWv1HBf40
DER Forecast	High	High
Fuel Price	Low	High
2016	27.6 MW Waiver PV Projects added 12/31/2016	27.6 MW Waiver PV Projects added 12/31/2016
2017		
2018	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install 10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install 10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)
2019	90 MW Contingency BESS added	90 MW Contingency BESS added
2020	Install 20MW of Onshore Wind Install 620MW of Utility PV	Install 20MW of Onshore Wind Install 400MW of Utility PV
2021		
2022	Install 100MW JBPHH Plant, 1/2022 AES Deactivated 9/2022	Install 100MW JBPHH Plant, 1/2022 AES Deactivated 9/2022
2023	Install 54MW KMBCH Plant, 1/2023 Waiau 3 & 4 Deactivated, 1/2023	Install 54MW KMBCH Plant, 1/2023 Waiau 3 & 4 Deactivated, 1/2023
2024		
2025	Kahe 6 Deactivated, 1/2025	Kahe 6 Deactivated, 1/2025
2026		
2027		
2028	Install (1) 50 MW x 4 hr Energy Storage	
2029		
2030	Waiau 5 & 6 Deactivated, 1/2030 Install 400MW of Offshore Wind Install (1) 50 MW and (3) 100MW x 4 hr Energy Storage	Waiau 5 & 6 Deactivated, 1/2030 Install 400 MW of Offshore Wind
2031		
2032		
2033		Install (1) 50MW x 4 hr Energy Storage
2034		
2035		
2036		
2037		
2038		
2039		
2040	Install 670MW of Utility PV Install 400MW of Offshore Wind Install (9) 100MW x 4 hr Energy Storage	Install 400 MW of Offshore Wind Install (2) 100MW x 4 hr Energy Storage
2041		
2042		
2043		
2044		
2045	Install 2150MW of Utility PV	Install 3040 MW of Utility PV Install (14) 100MW x 4 hr Energy Storage

Table K-39. Hawaiian Electric Second Iteration Cases (34 of 47)

Case Name	Theme 3, Case 69: Solar and Wind, with Storage, HL and ME 100% RE 2040	Theme 3, Case 70: Solar and Wind, with Storage, HL and ME 100% RE 2040
Case Label	16_T3bWv1LBf40	16_T3bWv1HBf40
DER Forecast	Market	Market
Fuel Price	Low	High
2016	27.6 MW Waiver PV Projects added 12/31/2016	27.6 MW Waiver PV Projects added 12/31/2016
2017		
2018	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install 10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install 10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)
2019	90 MW Contingency BESS added	90 MW Contingency BESS added
2020	Install 20MW of Onshore Wind Install 380MW of Utility PV	Install 20MW of Onshore Wind Install 380MW of Utility PV
2021		
2022	Install 100MW JBPHH Plant, 1/2022 AES Deactivated 9/2022	Install 100MW JBPHH Plant, 1/2022 AES Deactivated 9/2022
2023	Install 54MW KMBCH Plant, 1/2023 Waiau 3 & 4 Deactivated, 1/2023	Install 54MW KMBCH Plant, 1/2023 Waiau 3 & 4 Deactivated, 1/2023
2024		
2025	Kahe 6 Deactivated, 1/2025	Kahe 6 Deactivated, 1/2025
2026		
2027		
2028		
2029		
2030	Waiau 5 & 6 Deactivated, 1/2030 Install 400MW of Offshore Wind	Waiau 5 & 6 Deactivated, 1/2030
2031		
2032		
2033		
2034		
2035		
2036		
2037		
2038		
2039		
2040	Install 1440MW of Utility PV Install 400MW of Offshore Wind Install (13) 100MW x 4 hr Energy Storage	Install 1440MW of Utility PV Install (7) 100MW x 4 hr Energy Storage
2041		
2042		
2043		
2044		
2045	Install 1620MW of Utility PV	Install 2000MW of Utility PV Install (6) 100 MW and (1) 50MW x 4 hr Energy Storage

Table K-40. Hawaiian Electric Second Iteration Cases (35 of 47)

Case Name	Theme 3, Case 71: Solar and Wind, with Storage, HL and ME 100% RE 2040	Theme 3, Case 72: Solar and Wind, with Storage, HL and ME 100% RE 2040
Case Label	16_T3aSv1LBf40	16_T3aSv1HBf40
DER Forecast	High	High
Fuel Price	Low	High
2016	27.6 MW Waiver PV Projects added 12/31/2016	27.6 MW Waiver PV Projects added 12/31/2016
2017		
2018	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install 10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install 10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)
2019	90 MW Contingency BESS added	90 MW Contingency BESS added
2020	Install 20MW of Onshore Wind Install 620MW of Utility PV	Install 20MW of Onshore Wind Install 400MW of Utility PV
2021		
2022	Install 100MW JBPHH Plant, 1/2022 AES Deactivated 9/2022	Install 100MW JBPHH Plant, 1/2022 AES Deactivated 9/2022
2023	Install 54MW KMBCH Plant, 1/2023 Waiau 3 & 4 Deactivated, 1/2023	Install 54MW KMBCH Plant, 1/2023 Waiau 3 & 4 Deactivated, 1/2023
2024		
2025	Kahe 6 Deactivated, 1/2025	Kahe 6 Deactivated, 1/2025
2026		
2027		
2028		
2029		
2030	Waiau 5 & 6 Deactivated, 1/2030 Install 500MW of Utility PV Install (4) 100MW x 4 hr Energy Storage	Waiau 5 & 6 Deactivated, 1/2030 Install 500MW of Utility PV Install (1) 100MW x 4 hr Energy Storage
2031		
2032		
2033		
2034		
2035		
2036		
2037		
2038		
2039		
2040	Install 2320MW of Utility PV Install (21) 100MW x 4 hr Energy Storage	Install 180 MW of Utility PV Install (1) 100MW x 4 hr Energy Storage
2041		
2042		
2043		
2044		
2045		Install 2360MW of Utility PV Install (10) 100 MW and (1) 50MW x 4 hr Energy Storage

Table K-41. Hawaiian Electric Second Iteration Cases (36 of 47)

Case Name	Theme 3, Case 73: Solar and Wind, with Storage, HL and ME 100% RE 2040	Theme 3, Case 74: Solar and Wind, with Storage, HL and ME 100% RE 2040
Case Label	16_T3bSv1LBf40	16_T3bSv1HBf40
DER Forecast	Market	Market
Fuel Price	Low	High
2016	27.6 MW Waiver PV Projects added 12/31/2016	27.6 MW Waiver PV Projects added 12/31/2016
2017		
2018	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install 10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install 10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)
2019	90 MW Contingency BESS added	90 MW Contingency BESS added
2020	Install 20MW of Onshore Wind Install 380MW of Utility PV	Install 20MW of Onshore Wind Install 380MW of Utility PV
2021		
2022	Install 100MW JBPHH Plant, 1/2022 AES Deactivated 9/2022	Install 100MW JBPHH Plant, 1/2022 AES Deactivated 9/2022
2023	Install 54MW KMBCH Plant, 1/2023 Waiau 3 & 4 Deactivated, 1/2023	Install 54MW KMBCH Plant, 1/2023 Waiau 3 & 4 Deactivated, 1/2023
2024		
2025	Kahe 6 Deactivated, 1/2025	Kahe 6 Deactivated, 1/2025
2026		
2027		
2028		
2029		
2030	Waiau 5 & 6 Deactivated, 1/2030 Install 890MW of Utility PV Install (3) 100MW x 4 hr Energy Storage	Waiau 5 & 6 Deactivated, 1/2030 Install 1040MW of Utility PV Install (2) 100MW x 4 hr Energy Storage
2031		
2032		
2033		
2034		
2035		
2036		
2037		
2038		
2039		
2040	Install 2110MW of Utility PV Install (10) 100MW x 4 hr Energy Storage	Install 560 MW of Utility PV Install (1) 100 MW and (1) 50MW x 4 hr Energy Storage
2041		
2042		
2043		
2044		
2045		Install 2000MW of Utility PV Install (6) 100MW x 4 hr Energy Storage

Table K-42. Hawaiian Electric Second Iteration Cases (37 of 47)

Case Name	Theme 2, Case 75: Solar and Wind	Theme 2, Case 76: Solar and Wind
Case Label	16_T2aWv2L40	16_T2aWv2H40
DER Forecast	High	High
Fuel Price	Low	High
2016	27.6 MW Waiver PV Projects added 12/31/2016	27.6 MW Waiver PV Projects added 12/31/2016
2017		
2018	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)
2019	90 MW Contingency BESS added	90 MW Contingency BESS added
2020	Install 100MW JBPHH Plant, 12/2020 Kahe 1, 2, 3 Deactivated, 12/2020 Install 30MW of Onshore Wind Install 60MW of Utility PV	Install 100MW JBPHH Plant, 12/2020 Kahe 1, 2, 3 Deactivated, 12/2020 Install 30MW of Onshore Wind Install 60MW of Utility PV
2021	Install 27 MW KMCBH Plant, 6/2021 Install 3x1 CC, 6/2021	Install 27 MW KMCBH Plant, 6/2021 Install 3x1 CC, 6/2021
2022	AES Deactivated 9/2022 Waiau 3 & 4 Deactivated, 1/2022 Kahe 4 Deactivated, 1/2022	AES Deactivated 9/2022 Waiau 3 & 4 Deactivated, 1/2022 Kahe 4 Deactivated, 1/2022
2023		
2024	Waiau 5 & 6 Deactivated, 1/2024	Waiau 5 & 6 Deactivated, 1/2024
2025		
2026		
2027		
2028		
2029		
2030	Waiau 7 & 8 Deactivated, 1/2030 Install 20MW of Utility PV	Waiau 7 & 8 Deactivated, 1/2030 Install 20MW of Utility PV
2031		
2032		
2033		
2034		
2035		
2036		
2037		
2038		
2039		
2040	Install 500MW of Utility PV	Install 500MW of Utility PV
2041		
2042		
2043		
2044		
2045	Install 1200MW of Offshore Wind	Install 1200MW of Offshore Wind

Table K-43. Hawaiian Electric Second Iteration Cases (38 of 47)

Case Name	Theme 2, Case 77: Solar and Wind	Theme 2, Case 78: Solar and Wind
Case Label	16_T2bWv2L40	16_T2bWv2H40
DER Forecast	Market	Market
Fuel Price	Low	High
2016	27.6 MW Waiver PV Projects added 12/31/2016	27.6 MW Waiver PV Projects added 12/31/2016
2017		
2018	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)
2019	90 MW Contingency BESS added	90 MW Contingency BESS added
2020	Install 100MW JBPHH Plant, 12/2020 Kahe 1, 2, 3 Deactivated, 12/2020 Install 30MW of Onshore Wind Install 60MW of Utility PV	Install 100MW JBPHH Plant, 12/2020 Kahe 1, 2, 3 Deactivated, 12/2020 Install 30MW of Onshore Wind Install 60MW of Utility PV
2021	Install 27 MW KMCBH Plant, 6/2021 Install 3x1 CC, 6/2021	Install 27 MW KMCBH Plant, 6/2021 Install 3x1 CC, 6/2021
2022	AES Deactivated 9/2022 Waiau 3 & 4 Deactivated, 1/2022 Kahe 4 Deactivated, 1/2022	AES Deactivated 9/2022 Waiau 3 & 4 Deactivated, 1/2022 Kahe 4 Deactivated, 1/2022
2023		
2024	Waiau 5 & 6 Deactivated, 1/2024	Waiau 5 & 6 Deactivated, 1/2024
2025		
2026		
2027		
2028		
2029		
2030	Waiau 7 & 8 Deactivated, 1/2030 Install 400MW of Offshore Wind	Waiau 7 & 8 Deactivated, 1/2030 Install 400MW of Offshore Wind
2031		
2032		
2033		
2034		
2035		
2036		
2037		
2038		
2039		
2040	Install 520MW of Utility PV	Install 520MW of Utility PV
2041		
2042		
2043		
2044		
2045	Install 1200MW of Offshore Wind	Install 1200MW of Offshore Wind

Table K-44. Hawaiian Electric Second Iteration Cases (39 of 47)

Case Name	Theme 2, Case 79: Solar and Wind, Accelerated Build Out	Theme 2, Case 80: Solar and Wind, Accelerated Build Out
Case Label	16_T2aW25v2L40	16_T2aW25v2H40
DER Forecast	High	High
Fuel Price	Low	High
2016	27.6 MW Waiver PV Projects added 12/31/2016	27.6 MW Waiver PV Projects added 12/31/2016
2017		
2018	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)
2019	90 MW Contingency BESS added	90 MW Contingency BESS added
2020	Install 100MW JBPHH Plant, 12/2020 Kahe 1, 2, 3 Deactivated, 12/2020 Install 30MW of Onshore Wind Install 60MW of Utility PV	Install 100MW JBPHH Plant, 12/2020 Kahe 1, 2, 3 Deactivated, 12/2020 Install 30MW of Onshore Wind Install 60MW of Utility PV
2021	Install 27 MW KMCBH Plant, 6/2021 Install 3x1 CC, 6/2021	Install 27 MW KMCBH Plant, 6/2021 Install 3x1 CC, 6/2021
2022	AES Deactivated 9/2022 Waiau 3 & 4 Deactivated, 1/2022 Kahe 4 Deactivated, 1/2022	AES Deactivated 9/2022 Waiau 3 & 4 Deactivated, 1/2022 Kahe 4 Deactivated, 1/2022
2023		
2024	Waiau 5 & 6 Deactivated, 1/2024	Waiau 5 & 6 Deactivated, 1/2024
2025	Install 400MW of Offshore Wind	Install 400MW of Offshore Wind
2026		
2027		
2028		
2029		
2030	Waiau 7 & 8 Deactivated, 1/2030 Install 20MW of Utility PV	Waiau 7 & 8 Deactivated, 1/2030 Install 20MW of Utility PV
2031		
2032		
2033		
2034		
2035		
2036		
2037		
2038		
2039		
2040	Install 500MW of Utility PV	Install 500MW of Utility PV
2041		
2042		
2043		
2044		
2045	Install 800MW of Offshore Wind	Install 800MW of Offshore Wind

Table K-45. Hawaiian Electric Second Iteration Cases (40 of 47)

Case Name	Theme 2, Case 81: Solar and Wind, Accelerated Build Out	Theme 2, Case 82: Solar and Wind, Accelerated Build Out
Case Label	16_T2bW25v2L40	16_T2bW25v2H40
DER Forecast	Market	Market
Fuel Price	Low	High
2016	27.6 MW Waiver PV Projects added 12/31/2016	27.6 MW Waiver PV Projects added 12/31/2016
2017		
2018	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)
2019	90 MW Contingency BESS added	90 MW Contingency BESS added
2020	Install 100MW JBPHH Plant, 12/2020 Kahe 1, 2, 3 Deactivated, 12/2020 Install 30MW of Onshore Wind Install 60MW of Utility PV	Install 100MW JBPHH Plant, 12/2020 Kahe 1, 2, 3 Deactivated, 12/2020 Install 30MW of Onshore Wind Install 60MW of Utility PV
2021	Install 27 MW KMCBH Plant, 6/2021 Install 3x1 CC, 6/2021	Install 27 MW KMCBH Plant, 6/2021 Install 3x1 CC, 6/2021
2022	AES Deactivated 9/2022 Waiau 3 & 4 Deactivated, 1/2022 Kahe 4 Deactivated, 1/2022	AES Deactivated 9/2022 Waiau 3 & 4 Deactivated, 1/2022 Kahe 4 Deactivated, 1/2022
2023		
2024	Waiau 5 & 6 Deactivated, 1/2024	Waiau 5 & 6 Deactivated, 1/2024
2025	Install 400MW of Offshore Wind	Install 400MW of Offshore Wind
2026		
2027		
2028		
2029		
2030	Waiau 7 & 8 Deactivated, 1/2030	Waiau 7 & 8 Deactivated, 1/2030
2031		
2032		
2033		
2034		
2035		
2036		
2037		
2038		
2039		
2040	Install 520MW of Utility PV	Install 520MW of Utility PV
2041		
2042		
2043		
2044		
2045	Install 1200MW of Offshore Wind	Install 1200MW of Offshore Wind

Table K-46. Hawaiian Electric Second Iteration Cases (41 of 47)

Case Name	Theme 2, Case 83: Solar and Wind, Static Utility Build Out	Theme 2, Case 84: Solar and Wind, Static Utility Build Out
Case Label	16_T2abWv2L40	16_T2abWv2H40
DER Forecast	High	High
Fuel Price	Low	High
2016	27.6 MW Waiver PV Projects added 12/31/2016	27.6 MW Waiver PV Projects added 12/31/2016
2017		
2018	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)
2019	90 MW Contingency BESS added	90 MW Contingency BESS added
2020	Install 100MW JBPHH Plant, 12/2020 Kahe 1, 2, 3 Deactivated, 12/2020 Install 30MW of Onshore Wind Install 60MW of Utility PV	Install 100MW JBPHH Plant, 12/2020 Kahe 1, 2, 3 Deactivated, 12/2020 Install 30MW of Onshore Wind Install 60MW of Utility PV
2021	Install 27 MW KMCBH Plant, 6/2021 Install 3x1 CC, 6/2021	Install 27 MW KMCBH Plant, 6/2021 Install 3x1 CC, 6/2021
2022	AES Deactivated 9/2022 Waiau 3 & 4 Deactivated, 1/2022 Kahe 4 Deactivated, 1/2022	AES Deactivated 9/2022 Waiau 3 & 4 Deactivated, 1/2022 Kahe 4 Deactivated, 1/2022
2023		
2024	Waiau 5 & 6 Deactivated, 1/2024	Waiau 5 & 6 Deactivated, 1/2024
2025		
2026		
2027		
2028		
2029		
2030	Waiau 7 & 8 Deactivated, 1/2030 Install 400MW of Offshore Wind	Waiau 7 & 8 Deactivated, 1/2030 Install 400MW of Offshore Wind
2031		
2032		
2033		
2034		
2035		
2036		
2037		
2038		
2039		
2040	Install 520MW of Utility PV	Install 520MW of Utility PV
2041		
2042		
2043		
2044		
2045	Install 1200MW of Offshore Wind	Install 1200MW of Offshore Wind

Table K-47. Hawaiian Electric Second Iteration Cases (42 of 47)

Case Name	Theme 3, Case 85: Solar and Wind	Theme 3, Case 86: Solar and Wind
Case Label	16_T3aWv2L40	16_T3aWv2H40
DER Forecast	High	High
Fuel Price	Low	High
2016	27.6 MW Waiver PV Projects added 12/31/2016	27.6 MW Waiver PV Projects added 12/31/2016
2017		
2018	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)
2019	90 MW Contingency BESS added	90 MW Contingency BESS added
2020	Install 30MW of Onshore Wind	Install 30MW of Onshore Wind
2021		
2022	Install 100MW JBPHH Plant, 1/2022 AES Deactivated 9/2022	Install 100MW JBPHH Plant, 1/2022 AES Deactivated 9/2022
2023	Install 54MW KMBCH Plant, 1/2023 Waiau 3 & 4 Deactivated, 1/2023	Install 54MW KMBCH Plant, 1/2023 Waiau 3 & 4 Deactivated, 1/2023
2024		
2025	Kahe 6 Deactivated, 1/2025	Kahe 6 Deactivated, 1/2025
2026		
2027		
2028		
2029		
2030	Waiau 5 & 6 Deactivated, 1/2030	Waiau 5 & 6 Deactivated, 1/2030
2031		
2032		
2033		
2034		
2035		
2036		
2037		
2038		
2039		
2040	Install 400MW of Offshore Wind	Install 400MW of Offshore Wind
2041		
2042		
2043		
2044		
2045	Install 420MW of Utility PV Install 800MW of Offshore Wind	Install 420MW of Utility PV Install 800MW of Offshore Wind

Table K-48. Hawaiian Electric Second Iteration Cases (43 of 47)

Case Name	Theme 3, Case 87: Solar and Wind	Theme 3, Case 88: Solar and Wind
Case Label	16_T3bWv2L40	16_T3bWv2H40
DER Forecast	Market	Market
Fuel Price	Low	High
2016	27.6 MW Waiver PV Projects added 12/31/2016	27.6 MW Waiver PV Projects added 12/31/2016
2017		
2018	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)
2019	90 MW Contingency BESS added	90 MW Contingency BESS added
2020	Install 30MW of Onshore Wind	Install 30MW of Onshore Wind
2021		
2022	Install 100MW JBPHH Plant, 1/2022 AES Deactivated 9/2022	Install 100MW JBPHH Plant, 1/2022 AES Deactivated 9/2022
2023	Install 54MW KMBCH Plant, 1/2023 Waiau 3 & 4 Deactivated, 1/2023	Install 54MW KMBCH Plant, 1/2023 Waiau 3 & 4 Deactivated, 1/2023
2024		
2025	Kahe 6 Deactivated, 1/2025	Kahe 6 Deactivated, 1/2025
2026		
2027		
2028		
2029		
2030	Waiau 5 & 6 Deactivated, 1/2030 Install 40MW of Utility PV	Waiau 5 & 6 Deactivated, 1/2030 Install 40MW of Utility PV
2031		
2032		
2033		
2034		
2035		
2036		
2037		
2038		
2039		
2040	Install 800MW of Offshore Wind	Install 800MW of Offshore Wind
2041		
2042		
2043		
2044		
2045	Install 160MW of Utility PV Install 800MW of Offshore Wind	Install 160MW of Utility PV Install 800MW of Offshore Wind

Table K-49. Hawaiian Electric Second Iteration Cases (44 of 47)

Case Name	Theme 3, Case 89: Solar and Wind, Accelerated Build Out	Theme 3, Case 90: Solar and Wind, Accelerated Build Out
Case Label	16_T3aW25v2L40	16_T3aW25v2H40
DER Forecast	High	High
Fuel Price	Low	High
2016	27.6 MW Waiver PV Projects added 12/31/2016	27.6 MW Waiver PV Projects added 12/31/2016
2017		
2018	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)
2019	90 MW Contingency BESS added	90 MW Contingency BESS added
2020	Install 30MW of Onshore Wind	Install 30MW of Onshore Wind
2021		
2022	Install 100MW JBPHH Plant, 1/2022 AES Deactivated 9/2022	Install 100MW JBPHH Plant, 1/2022 AES Deactivated 9/2022
2023	Install 54MW KMBCH Plant, 1/2023 Waiau 3 & 4 Deactivated, 1/2023	Install 54MW KMBCH Plant, 1/2023 Waiau 3 & 4 Deactivated, 1/2023
2024		
2025	Kahe 6 Deactivated, 1/2025 Install 400MW of Offshore Wind	Kahe 6 Deactivated, 1/2025 Install 400MW of Offshore Wind
2026		
2027		
2028		
2029		
2030	Waiau 5 & 6 Deactivated, 1/2030	Waiau 5 & 6 Deactivated, 1/2030
2031		
2032		
2033		
2034		
2035		
2036		
2037		
2038		
2039		
2040		
2041		
2042		
2043		
2044		
2045	Install 420MW of Utility PV Install 800MW of Offshore Wind	Install 420MW of Utility PV Install 800MW of Offshore Wind

Table K-50. Hawaiian Electric Second Iteration Cases (45 of 47)

Case Name	Theme 3, Case 91: Solar and Wind, Accelerated Build Out	Theme 3, Case 92: Solar and Wind, Accelerated Build Out
Case Label	16_T3bW25v2L40	16_T3bW25v2H40
DER Forecast	Market	Market
Fuel Price	Low	High
2016	27.6 MW Waiver PV Projects added 12/31/2016	27.6 MW Waiver PV Projects added 12/31/2016
2017		
2018	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)
2019	90 MW Contingency BESS added	90 MW Contingency BESS added
2020	Install 30MW of Onshore Wind	Install 30MW of Onshore Wind
2021		
2022	Install 100MW JBPHH Plant, 1/2022 AES Deactivated 9/2022	Install 100MW JBPHH Plant, 1/2022 AES Deactivated 9/2022
2023	Install 54MW KMBCH Plant, 1/2023 Waiau 3 & 4 Deactivated, 1/2023	Install 54MW KMBCH Plant, 1/2023 Waiau 3 & 4 Deactivated, 1/2023
2024		
2025	Kahe 6 Deactivated, 1/2025 Install 400MW of Offshore Wind	Kahe 6 Deactivated, 1/2025 Install 400MW of Offshore Wind
2026		
2027		
2028		
2029		
2030	Waiau 5 & 6 Deactivated, 1/2030 Install 40MW of Utility PV	Waiau 5 & 6 Deactivated, 1/2030 Install 40MW of Utility PV
2031		
2032		
2033		
2034		
2035		
2036		
2037		
2038		
2039		
2040	Install 400MW of Offshore Wind	Install 400MW of Offshore Wind
2041		
2042		
2043		
2044		
2045	Install 160MW of Utility PV Install 800MW of Offshore Wind	Install 160MW of Utility PV Install 800MW of Offshore Wind

Table K-51. Hawaiian Electric Second Iteration Cases (46 of 47)

Case Name	Theme 3, Case 93: Solar and Wind, Static Utility Build Out	Theme 3, Case 94: Solar and Wind, Static Utility Build Out
Case Label	16_T3abWv2L40	16_T3abWv2H40
DER Forecast	High	High
Fuel Price	Low	High
2016	27.6 MW Waiver PV Projects added 12/31/2016	27.6 MW Waiver PV Projects added 12/31/2016
2017		
2018	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)
2019	90 MW Contingency BESS added	90 MW Contingency BESS added
2020	Install 30MW of Onshore Wind	Install 30MW of Onshore Wind
2021		
2022	Install 100MW JBPHH Plant, 1/2022 AES Deactivated 9/2022	Install 100MW JBPHH Plant, 1/2022 AES Deactivated 9/2022
2023	Install 54MW KMBCH Plant, 1/2023 Waiau 3 & 4 Deactivated, 1/2023	Install 54MW KMBCH Plant, 1/2023 Waiau 3 & 4 Deactivated, 1/2023
2024		
2025	Kahe 6 Deactivated, 1/2025	Kahe 6 Deactivated, 1/2025
2026		
2027		
2028		
2029		
2030	Waiau 5 & 6 Deactivated, 1/2030 Install 40MW of Utility PV	Waiau 5 & 6 Deactivated, 1/2030 Install 40MW of Utility PV
2031		
2032		
2033		
2034		
2035		
2036		
2037		
2038		
2039		
2040	Install 800MW of Offshore Wind	Install 800MW of Offshore Wind
2041		
2042		
2043		
2044		
2045	Install 160MW of Utility PV Install 800MW of Offshore Wind	Install 160MW of Utility PV Install 800MW of Offshore Wind

Table K-52. Hawaiian Electric Second Iteration Cases (47 of 47)

Hawaiian Electric Third Iteration Cases

Case Name	Theme 2, Case 95: Solar and Wind	Theme 2, Case 96: Solar and Wind
Case Label	16_T2aWv3L	16_T2aWv3H
DER Forecast	High	High
Fuel Price	Low	High
2016	27.6 MW Waiver PV Projects added 12/31/2016	27.6 MW Waiver PV Projects added 12/31/2016
2017		
2018	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)
2019	90 MW Contingency BESS added	90 MW Contingency BESS added
2020	Install 100MW JBPHH Plant, 12/2020 Kahe 1, 2, 3 Deactivated, 12/2020 Install 30MW of Onshore Wind Install 60MW of Utility PV	Install 100MW JBPHH Plant, 12/2020 Kahe 1, 2, 3 Deactivated, 12/2020 Install 30MW of Onshore Wind Install 60MW of Utility PV
2021	Install 27 MW KMCBH Plant, 6/2021 Install 3x1 CC, 6/2021	Install 27 MW KMCBH Plant, 6/2021 Install 3x1 CC, 6/2021
2022	AES Deactivated 9/2022 Waiau 3 & 4 Deactivated, 1/2022 Kahe 4 Deactivated, 1/2022	AES Deactivated 9/2022 Waiau 3 & 4 Deactivated, 1/2022 Kahe 4 Deactivated, 1/2022
2023		
2024	Waiau 5 & 6 Deactivated, 1/2024	Waiau 5 & 6 Deactivated, 1/2024
2025		
2026		
2027		
2028		
2029		
2030	Waiau 7 & 8 Deactivated, 1/2030 Install 20MW of Utility PV	Waiau 7 & 8 Deactivated, 1/2030 Install 20MW of Utility PV
2031		
2032		
2033		
2034		
2035		
2036		
2037		
2038		
2039		
2040	Install 500MW of Utility PV	Install 500MW of Utility PV
2041		
2042		
2043		
2044		
2045	Install 1200 MW of Offshore Wind	Install 1200 MW of Offshore Wind

Table K-53. Hawaiian Electric Third Iteration Cases (1 of 31)

Case Name	Theme 3, Case 97: Solar and Wind	Theme 3, Case 98: Solar and Wind
Case Label	16_T2bWv3L	16_T2bWv3H
DER Forecast	Market	Market
Fuel Price	Low	High
2016	27.6 MW Waiver PV Projects added 12/31/2016	27.6 MW Waiver PV Projects added 12/31/2016
2017		
2018	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)
2019	90 MW Contingency BESS added	90 MW Contingency BESS added
2020	Install 100MW JBPHH Plant, 12/2020 Kahe 1, 2, 3 Deactivated, 12/2020 Install 30MW of Onshore Wind Install 60MW of Utility PV	Install 100MW JBPHH Plant, 12/2020 Kahe 1, 2, 3 Deactivated, 12/2020 Install 30MW of Onshore Wind Install 60MW of Utility PV
2021	Install 27 MW KMCBH Plant, 6/2021 Install 3x1 CC, 6/2021	Install 27 MW KMCBH Plant, 6/2021 Install 3x1 CC, 6/2021
2022	AES Deactivated 9/2022 Waiau 3 & 4 Deactivated, 1/2022 Kahe 4 Deactivated, 1/2022	AES Deactivated 9/2022 Waiau 3 & 4 Deactivated, 1/2022 Kahe 4 Deactivated, 1/2022
2023		
2024	Waiau 5 & 6 Deactivated, 1/2024	Waiau 5 & 6 Deactivated, 1/2024
2025		
2026		
2027		
2028		
2029		
2030	Waiau 7 & 8 Deactivated, 1/2030 Install 400MW of Offshore Wind	Waiau 7 & 8 Deactivated, 1/2030 Install 400MW of Offshore Wind
2031		
2032		
2033		
2034		
2035		
2036		
2037		
2038		
2039		
2040	Install 520MW of Utility PV	Install 520MW of Utility PV
2041		
2042		
2043		
2044		
2045	Install 1200MW of Offshore Wind	Install 1200MW of Offshore Wind

Table K-54. Hawaiian Electric Third Iteration Cases (2 of 31)

Case Name	Theme 2, Case 99: Solar and Wind, HL and ME 100% RE 2040	Theme 2, Case 100: Solar and Wind, HL and ME 100% RE 2040
Case Label	16_T2aWv3L40	16_T2aWv3H40
DER Forecast	High	High
Fuel Price	Low	High
2016	27.6 MW Waiver PV Projects added 12/31/2016	27.6 MW Waiver PV Projects added 12/31/2016
2017		
2018	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)
2019	90 MW Contingency BESS added	90 MW Contingency BESS added
2020	Install 100MW JBPHH Plant, 12/2020 Kahe 1, 2, 3 Deactivated, 12/2020 Install 30MW of Onshore Wind Install 60MW of Utility PV	Install 100MW JBPHH Plant, 12/2020 Kahe 1, 2, 3 Deactivated, 12/2020 Install 30MW of Onshore Wind Install 60MW of Utility PV
2021	Install 27 MW KMCBH Plant, 6/2021 Install 3x1 CC, 6/2021	Install 27 MW KMCBH Plant, 6/2021 Install 3x1 CC, 6/2021
2022	AES Deactivated 9/2022 Waiau 3 & 4 Deactivated, 1/2022 Kahe 4 Deactivated, 1/2022	AES Deactivated 9/2022 Waiau 3 & 4 Deactivated, 1/2022 Kahe 4 Deactivated, 1/2022
2023		
2024	Waiau 5 & 6 Deactivated, 1/2024	Waiau 5 & 6 Deactivated, 1/2024
2025		
2026		
2027		
2028		
2029		
2030	Waiau 7 & 8 Deactivated, 1/2030 Install 20MW of Utility PV	Waiau 7 & 8 Deactivated, 1/2030 Install 20MW of Utility PV
2031		
2032		
2033		
2034		
2035		
2036		
2037		
2038		
2039		
2040		
2041		
2042		
2043		
2044		
2045	Install 1200 MW of Offshore Wind Install 320 MW of Utility PV	Install 1200 MW of Offshore Wind Install 320 MW of Utility PV

Table K-55. Hawaiian Electric Third Iteration Cases (3 of 31)

Case Name	Theme 2, Case 101: Solar and Wind, HL and ME 100% RE 2040	Theme 2, Case 102: Solar and Wind, HL and ME 100% RE 2040
Case Label	16_T2bWv3L40	16_T2bWv3H40
DER Forecast	Market	Market
Fuel Price	Low	High
2016	27.6 MW Waiver PV Projects added 12/31/2016	27.6 MW Waiver PV Projects added 12/31/2016
2017		
2018	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)
2019	90 MW Contingency BESS added	90 MW Contingency BESS added
2020	Install 100MW JBPHH Plant, 12/2020 Kahe 1, 2, 3 Deactivated, 12/2020 Install 30MW of Onshore Wind Install 60MW of Utility PV	Install 100MW JBPHH Plant, 12/2020 Kahe 1, 2, 3 Deactivated, 12/2020 Install 30MW of Onshore Wind Install 60MW of Utility PV
2021	Install 27 MW KMCBH Plant, 6/2021 Install 3x1 CC, 6/2021	Install 27 MW KMCBH Plant, 6/2021 Install 3x1 CC, 6/2021
2022	AES Deactivated 9/2022 Waiau 3 & 4 Deactivated, 1/2022 Kahe 4 Deactivated, 1/2022	AES Deactivated 9/2022 Waiau 3 & 4 Deactivated, 1/2022 Kahe 4 Deactivated, 1/2022
2023		
2024	Waiau 5 & 6 Deactivated, 1/2024	Waiau 5 & 6 Deactivated, 1/2024
2025		
2026		
2027		
2028		
2029		
2030	Waiau 7 & 8 Deactivated, 1/2030 Install 400MW of Offshore Wind	Waiau 7 & 8 Deactivated, 1/2030 Install 400MW of Offshore Wind
2031		
2032		
2033		
2034		
2035		
2036		
2037		
2038		
2039		
2040		
2041		
2042		
2043		
2044		
2045	Install 1200MW of Offshore Wind Install 140MW of Utility PV	Install 1200MW of Offshore Wind Install 140MW of Utility PV

Table K-56. Hawaiian Electric Third Iteration Cases (4 of 31)

Case Name	Theme 2, Case 103: Solar and Wind, DG PV Regulation	Theme 2, Case 104: Solar and Wind, DG PV Regulation
Case Label	16_T2aWv3Hhc	16_T2bWv3Hhc
DER Forecast	High minus 10%	Market minus 10%
Fuel Price	High	High
2016	27.6 MW Waiver PV Projects added 12/31/2016	27.6 MW Waiver PV Projects added 12/31/2016
2017		
2018	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)
2019	90 MW Contingency BESS added	90 MW Contingency BESS added
2020	Install 100MW JBPHH Plant, 12/2020 Kahe 1, 2, 3 Deactivated, 12/2020 Install 30MW of Onshore Wind Install 60MW of Utility PV	Install 100MW JBPHH Plant, 12/2020 Kahe 1, 2, 3 Deactivated, 12/2020 Install 30MW of Onshore Wind Install 60MW of Utility PV
2021	Install 27 MW KMCBH Plant, 6/2021 Install 3x1 CC, 6/2021	Install 27 MW KMCBH Plant, 6/2021 Install 3x1 CC, 6/2021
2022	AES Deactivated 9/2022 Waiau 3 & 4 Deactivated, 1/2022 Kahe 4 Deactivated, 1/2022	AES Deactivated 9/2022 Waiau 3 & 4 Deactivated, 1/2022 Kahe 4 Deactivated, 1/2022
2023		
2024	Waiau 5 & 6 Deactivated, 1/2024	Waiau 5 & 6 Deactivated, 1/2024
2025		
2026		
2027		
2028		
2029		
2030	Waiau 7 & 8 Deactivated, 1/2030 Install 20MW of Utility PV	Waiau 7 & 8 Deactivated, 1/2030 Install 400MW of Offshore Wind
2031		
2032		
2033		
2034		
2035		
2036		
2037		
2038		
2039		
2040	Install 500MW of Utility PV	Install 520MW of Utility PV
2041		
2042		
2043		
2044		
2045	Install 1200 MW of Offshore Wind	Install 1200MW of Offshore Wind

Table K-57. Hawaiian Electric Third Iteration Cases (5 of 31)

Case Name	Theme 2, Case 105: Solar and Wind, DG PV Regulation, HL and ME 100% RE 2040	Theme 2, Case 106: Solar and Wind, DG PV Regulation, HL and ME 100% RE 2040
Case Label	16_T2aWv3H40hc	16_T2bWv3H40hc
DER Forecast	High minus 10%	Market minus 10%
Fuel Price	High	High
2016	27.6 MW Waiver PV Projects added 12/31/2016	27.6 MW Waiver PV Projects added 12/31/2016
2017		
2018	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)
2019	90 MW Contingency BESS added	90 MW Contingency BESS added
2020	Install 100MW JBPHH Plant, 12/2020 Kahe 1, 2, 3 Deactivated, 12/2020 Install 30MW of Onshore Wind Install 60MW of Utility PV	Install 100MW JBPHH Plant, 12/2020 Kahe 1, 2, 3 Deactivated, 12/2020 Install 30MW of Onshore Wind Install 60MW of Utility PV
2021	Install 27 MW KMCBH Plant, 6/2021 Install 3x1 CC, 6/2021	Install 27 MW KMCBH Plant, 6/2021 Install 3x1 CC, 6/2021
2022	AES Deactivated 9/2022 Waiau 3 & 4 Deactivated, 1/2022 Kahe 4 Deactivated, 1/2022	AES Deactivated 9/2022 Waiau 3 & 4 Deactivated, 1/2022 Kahe 4 Deactivated, 1/2022
2023		
2024	Waiau 5 & 6 Deactivated, 1/2024	Waiau 5 & 6 Deactivated, 1/2024
2025		
2026		
2027		
2028		
2029		
2030	Waiau 7 & 8 Deactivated, 1/2030 Install 20MW of Utility PV	Waiau 7 & 8 Deactivated, 1/2030 Install 400MW of Offshore Wind
2031		
2032		
2033		
2034		
2035		
2036		
2037		
2038		
2039		
2040		
2041		
2042		
2043		
2044		
2045	Install 1200 MW of Offshore Wind Install 320 MW of Utility PV	Install 1200MW of Offshore Wind Install 140MW of Utility PV

Table K-58. Hawaiian Electric Third Iteration Cases (6 of 31)

Case Name	Theme 2, Case 107: Solar and Wind, Static Utility Build Out	Theme 2, Case 108: Solar and Wind, Static Utility Build Out
Case Label	16_T2abWv3L	16_T2abWv3H
DER Forecast	High	High
Fuel Price	Low	High
2016	27.6 MW Waiver PV Projects added 12/31/2016	27.6 MW Waiver PV Projects added 12/31/2016
2017		
2018	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)
2019	90 MW Contingency BESS added	90 MW Contingency BESS added
2020	Install 100MW JBPHH Plant, 12/2020 Kahe 1, 2, 3 Deactivated, 12/2020 Install 30MW of Onshore Wind Install 60MW of Utility PV	Install 100MW JBPHH Plant, 12/2020 Kahe 1, 2, 3 Deactivated, 12/2020 Install 30MW of Onshore Wind Install 60MW of Utility PV
2021	Install 27 MW KMCBH Plant, 6/2021 Install 3x1 CC, 6/2021	Install 27 MW KMCBH Plant, 6/2021 Install 3x1 CC, 6/2021
2022	AES Deactivated 9/2022 Waiau 3 & 4 Deactivated, 1/2022 Kahe 4 Deactivated, 1/2022	AES Deactivated 9/2022 Waiau 3 & 4 Deactivated, 1/2022 Kahe 4 Deactivated, 1/2022
2023		
2024	Waiau 5 & 6 Deactivated, 1/2024	Waiau 5 & 6 Deactivated, 1/2024
2025		
2026		
2027		
2028		
2029		
2030	Waiau 7 & 8 Deactivated, 1/2030 Install 400MW of Offshore Wind	Waiau 7 & 8 Deactivated, 1/2030 Install 400MW of Offshore Wind
2031		
2032		
2033		
2034		
2035		
2036		
2037		
2038		
2039		
2040	Install 520MW of Utility PV	Install 520MW of Utility PV
2041		
2042		
2043		
2044		
2045	Install 1200MW of Offshore Wind	Install 1200MW of Offshore Wind

Table K-59. Hawaiian Electric Third Iteration Cases (7 of 31)

Case Name	Theme 2, Case 109: Solar and Wind, Static Utility Build Out, HL and ME 100% RE 2040	Theme 2, Case 110: Solar and Wind, Static Utility Build Out, HL and ME 100% RE 2040
Case Label	16_T2abWv3L40	16_T2abWv3H40
DER Forecast	High	High
Fuel Price	Low	High
2016	27.6 MW Waiver PV Projects added 12/31/2016	27.6 MW Waiver PV Projects added 12/31/2016
2017		
2018	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)
2019	90 MW Contingency BESS added	90 MW Contingency BESS added
2020	Install 100MW JBPHH Plant, 12/2020 Kahe 1, 2, 3 Deactivated, 12/2020 Install 30MW of Onshore Wind Install 60MW of Utility PV	Install 100MW JBPHH Plant, 12/2020 Kahe 1, 2, 3 Deactivated, 12/2020 Install 30MW of Onshore Wind Install 60MW of Utility PV
2021	Install 27 MW KMCBH Plant, 6/2021 Install 3x1 CC, 6/2021	Install 27 MW KMCBH Plant, 6/2021 Install 3x1 CC, 6/2021
2022	AES Deactivated 9/2022 Waiau 3 & 4 Deactivated, 1/2022 Kahe 4 Deactivated, 1/2022	AES Deactivated 9/2022 Waiau 3 & 4 Deactivated, 1/2022 Kahe 4 Deactivated, 1/2022
2023		
2024	Waiau 5 & 6 Deactivated, 1/2024	Waiau 5 & 6 Deactivated, 1/2024
2025		
2026		
2027		
2028		
2029		
2030	Waiau 7 & 8 Deactivated, 1/2030 Install 400MW of Offshore Wind	Waiau 7 & 8 Deactivated, 1/2030 Install 400MW of Offshore Wind
2031		
2032		
2033		
2034		
2035		
2036		
2037		
2038		
2039		
2040		
2041		
2042		
2043		
2044		
2045	Install 1200MW of Offshore Wind Install 140MW of Utility PV	Install 1200MW of Offshore Wind Install 140MW of Utility PV

Table K-60. Hawaiian Electric Third Iteration Cases (8 of 31)

Case Name	Theme 2, Case 111: Solar and Wind, Utility Storage	Theme 2, Case 112: Solar and Wind, Utility Storage, HL and ME 100% RE 2040
Case Label	16_T2aWv3LBp	16_T2aWv3LBp40
DER Forecast	High	High
Fuel Price	Low	Low
2016	27.6 MW Waiver PV Projects added 12/31/2016	27.6 MW Waiver PV Projects added 12/31/2016
2017		
2018	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)
2019	90 MW Contingency BESS added	90 MW Contingency BESS added
2020	Install 100MW JBPHH Plant, 12/2020 Kahe 1, 2, 3 Deactivated, 12/2020 Install 30MW of Onshore Wind Install 60MW of Utility PV	Install 100MW JBPHH Plant, 12/2020 Kahe 1, 2, 3 Deactivated, 12/2020 Install 30MW of Onshore Wind Install 60MW of Utility PV
2021	Install 27 MW KMCBH Plant, 6/2021 Install 3x1 CC, 6/2021	Install 27 MW KMCBH Plant, 6/2021 Install 3x1 CC, 6/2021
2022	AES Deactivated 9/2022 Waiau 3 & 4 Deactivated, 1/2022 Kahe 4 Deactivated, 1/2022	AES Deactivated 9/2022 Waiau 3 & 4 Deactivated, 1/2022 Kahe 4 Deactivated, 1/2022
2023		
2024	Waiau 5 & 6 Deactivated, 1/2024	Waiau 5 & 6 Deactivated, 1/2024
2025		
2026		
2027		
2028		
2029		
2030	Waiau 7 & 8 Deactivated, 1/2030 Install 20MW of Utility PV	Waiau 7 & 8 Deactivated, 1/2030 Install 20MW of Utility PV
2031		
2032		
2033		
2034		
2035		
2036		
2037		
2038		
2039		
2040	Install 500MW of Utility PV	Install 500MW of Utility PV
2041		
2042		
2043		
2044		
2045	Install 1200 MW of Offshore Wind Install 550 MW of 8-hour batteries	Install 1200 MW of Offshore Wind Install 500 MW of 8-hour batteries

Table K-61. Hawaiian Electric Third Iteration Cases (9 of 31)

Case Name	Theme 2, Case 113: Solar and Wind, Circuit Level Storage	Theme 2, Case 114: Solar and Wind, Circuit Level Storage, HL and ME 100% RE 2040
Case Label	16_T2aWv3LCBf	16_T2aWv3LCBf40
DER Forecast	High w/circuit battery	High w/circuit battery
Fuel Price	Low	Low
2016	27.6 MW Waiver PV Projects added 12/31/2016	27.6 MW Waiver PV Projects added 12/31/2016
2017		
2018	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)
2019	90 MW Contingency BESS added	90 MW Contingency BESS added
2020	Install 100MW JBPHH Plant, 12/2020 Kahe 1, 2, 3 Deactivated, 12/2020 Install 30MW of Onshore Wind Install 60MW of Utility PV	Install 100MW JBPHH Plant, 12/2020 Kahe 1, 2, 3 Deactivated, 12/2020 Install 30MW of Onshore Wind Install 60MW of Utility PV
2021	Install 27 MW KMCBH Plant, 6/2021 Install 3x1 CC, 6/2021	Install 27 MW KMCBH Plant, 6/2021 Install 3x1 CC, 6/2021
2022	AES Deactivated 9/2022 Waiau 3 & 4 Deactivated, 1/2022 Kahe 4 Deactivated, 1/2022	AES Deactivated 9/2022 Waiau 3 & 4 Deactivated, 1/2022 Kahe 4 Deactivated, 1/2022
2023		
2024	Waiau 5 & 6 Deactivated, 1/2024	Waiau 5 & 6 Deactivated, 1/2024
2025		
2026		
2027		
2028		
2029		
2030	Waiau 7 & 8 Deactivated, 1/2030 Install 20MW of Utility PV	Waiau 7 & 8 Deactivated, 1/2030 Install 20MW of Utility PV
2031		
2032		
2033		
2034		
2035		
2036		
2037		
2038		
2039		
2040	Install 500MW of Utility PV	Install 500MW of Utility PV
2041		
2042		
2043		
2044		
2045	Install 1200 MW of Offshore Wind Install 250 MW of 8-hour batteries	Install 1200 MW of Offshore Wind Install 200 MW of 8-hour batteries

Table K-62. Hawaiian Electric Third Iteration Cases (10 of 31)

Case Name	Theme 3, Case 115: Solar and Wind	Theme 3, Case 116: Solar and Wind
Case Label	16_T3aWv3L	16_T3aWv3H
DER Forecast	High	High
Fuel Price	Low	High
2016	27.6 MW Waiver PV Projects added 12/31/2016	27.6 MW Waiver PV Projects added 12/31/2016
2017		
2018	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)
2019	90 MW Contingency BESS added	90 MW Contingency BESS added
2020	Install 30MW of Onshore Wind	Install 30MW of Onshore Wind
2021		
2022	Install 100MW JBPHH Plant, 1/2022 AES Deactivated 9/2022	Install 100MW JBPHH Plant, 1/2022 AES Deactivated 9/2022
2023	Install 54MW KMBCH Plant, 1/2023 Waiau 3 & 4 Deactivated, 1/2023	Install 54MW KMBCH Plant, 1/2023 Waiau 3 & 4 Deactivated, 1/2023
2024		
2025	Kahe 6 Deactivated, 1/2025	Kahe 6 Deactivated, 1/2025
2026		
2027		
2028		
2029		
2030	Waiau 5 & 6 Deactivated, 1/2030	Waiau 5 & 6 Deactivated, 1/2030
2031		
2032		
2033		
2034		
2035		
2036		
2037		
2038		
2039		
2040	Install 400MW of Offshore Wind	Install 400MW of Offshore Wind
2041		
2042		
2043		
2044		
2045	Install 800 MW of Offshore Wind Install 420 MW of Utility PV	Install 800 MW of Offshore Wind Install 420 MW of Utility PV

Table K-63. Hawaiian Electric Third Iteration Cases (11 of 31)

Case Name	Theme 3, Case 117: Solar and Wind	Theme 3, Case 118: Solar and Wind
Case Label	16_T3bWv3L	16_T3bWv3H
DER Forecast	Market	Market
Fuel Price	Low	High
2016	27.6 MW Waiver PV Projects added 12/31/2016	27.6 MW Waiver PV Projects added 12/31/2016
2017		
2018	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)
2019	90 MW Contingency BESS added	90 MW Contingency BESS added
2020	Install 30MW of Onshore Wind	Install 30MW of Onshore Wind
2021		
2022	Install 100MW JBPHH Plant, 1/2022 AES Deactivated 9/2022	Install 100MW JBPHH Plant, 1/2022 AES Deactivated 9/2022
2023	Install 54MW KMBCH Plant, 1/2023 Waiau 3 & 4 Deactivated, 1/2023	Install 54MW KMBCH Plant, 1/2023 Waiau 3 & 4 Deactivated, 1/2023
2024		
2025	Kahe 6 Deactivated, 1/2025	Kahe 6 Deactivated, 1/2025
2026		
2027		
2028		
2029		
2030	Waiau 5 & 6 Deactivated, 1/2030 Install 40MW of Utility PV	Waiau 5 & 6 Deactivated, 1/2030 Install 40MW of Utility PV
2031		
2032		
2033		
2034		
2035		
2036		
2037		
2038		
2039		
2040	Install 800MW of Offshore Wind	Install 800MW of Offshore Wind
2041		
2042		
2043		
2044		
2045	Install 800MW of Offshore Wind Install 160 MW of Utility PV	Install 800MW of Offshore Wind Install 160 MW of Utility PV

Table K-64. Hawaiian Electric Third Iteration Cases (12 of 31)

Case Name	Theme 3, Case 119: Solar and Wind, HL and ME 100% RE 2040	Theme 3, Case 120: Solar and Wind, HL and ME 100% RE 2040
Case Label	16_T3aWv3L40	16_T3aWv3H40
DER Forecast	High	High
Fuel Price	Low	High
2016	27.6 MW Waiver PV Projects added 12/31/2016	27.6 MW Waiver PV Projects added 12/31/2016
2017		
2018	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)
2019	90 MW Contingency BESS added	90 MW Contingency BESS added
2020	Install 30MW of Onshore Wind	Install 30MW of Onshore Wind
2021		
2022	Install 100MW JBPHH Plant, 1/2022 AES Deactivated 9/2022	Install 100MW JBPHH Plant, 1/2022 AES Deactivated 9/2022
2023	Install 54MW KMBCH Plant, 1/2023 Waiau 3 & 4 Deactivated, 1/2023	Install 54MW KMBCH Plant, 1/2023 Waiau 3 & 4 Deactivated, 1/2023
2024		
2025	Kahe 6 Deactivated, 1/2025	Kahe 6 Deactivated, 1/2025
2026		
2027		
2028		
2029		
2030	Waiau 5 & 6 Deactivated, 1/2030	Waiau 5 & 6 Deactivated, 1/2030
2031		
2032		
2033		
2034		
2035		
2036		
2037		
2038		
2039		
2040		
2041		
2042		
2043		
2044		
2045	Install 1200 MW of Offshore Wind Install 420 MW of Utility PV	Install 1200 MW of Offshore Wind Install 420 MW of Utility PV

Table K-65. Hawaiian Electric Third Iteration Cases (13 of 31)

Case Name	Theme 3, Case 121: Solar and Wind, HL and ME 100% RE 2040	Theme 3, Case 122: Solar and Wind, HL and ME 100% RE 2040
Case Label	16_T3bWv3L40	16_T3bWv3H40
DER Forecast	Market	Market
Fuel Price	Low	High
2016	27.6 MW Waiver PV Projects added 12/31/2016	27.6 MW Waiver PV Projects added 12/31/2016
2017		
2018	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)
2019	90 MW Contingency BESS added	90 MW Contingency BESS added
2020	Install 30MW of Onshore Wind	Install 30MW of Onshore Wind
2021		
2022	Install 100MW JBPHH Plant, 1/2022 AES Deactivated 9/2022	Install 100MW JBPHH Plant, 1/2022 AES Deactivated 9/2022
2023	Install 54MW KMBCH Plant, 1/2023 Waiau 3 & 4 Deactivated, 1/2023	Install 54MW KMBCH Plant, 1/2023 Waiau 3 & 4 Deactivated, 1/2023
2024		
2025	Kahe 6 Deactivated, 1/2025	Kahe 6 Deactivated, 1/2025
2026		
2027		
2028		
2029		
2030	Waiau 5 & 6 Deactivated, 1/2030 Install 40MW of Utility PV	Waiau 5 & 6 Deactivated, 1/2030 Install 40MW of Utility PV
2031		
2032		
2033		
2034		
2035		
2036		
2037		
2038		
2039		
2040	Install 400MW of Offshore Wind	Install 400MW of Offshore Wind
2041		
2042		
2043		
2044		
2045	Install 1200MW of Offshore Wind Install 160 MW of Utility PV	Install 1200MW of Offshore Wind Install 160 MW of Utility PV

Table K-66. Hawaiian Electric Third Iteration Cases (14 of 31)

Case Name	Theme 3, Case 123: Solar and Wind, DG PV Regulation	Theme 3, Case 124: Solar and Wind, DG PV Regulation
Case Label	16_T3aWv3Hhc	16_T3bWv3Hhc
DER Forecast	High minus 10%	Market minus 10%
Fuel Price	High	High
2016	27.6 MW Waiver PV Projects added 12/31/2016	27.6 MW Waiver PV Projects added 12/31/2016
2017		
2018	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)
2019	90 MW Contingency BESS added	90 MW Contingency BESS added
2020	Install 30MW of Onshore Wind	Install 30MW of Onshore Wind
2021		
2022	Install 100MW JBPHH Plant, 1/2022 AES Deactivated 9/2022	Install 100MW JBPHH Plant, 1/2022 AES Deactivated 9/2022
2023	Install 54MW KMBCH Plant, 1/2023 Waiau 3 & 4 Deactivated, 1/2023	Install 54MW KMBCH Plant, 1/2023 Waiau 3 & 4 Deactivated, 1/2023
2024		
2025	Kahe 6 Deactivated, 1/2025	Kahe 6 Deactivated, 1/2025
2026		
2027		
2028		
2029		
2030	Waiau 5 & 6 Deactivated, 1/2030	Waiau 5 & 6 Deactivated, 1/2030 Install 40MW of Utility PV
2031		
2032		
2033		
2034		
2035		
2036		
2037		
2038		
2039		
2040	Install 400MW of Offshore Wind	Install 800MW of Offshore Wind
2041		
2042		
2043		
2044		
2045	Install 800 MW of Offshore Wind Install 420 MW of Utility PV	Install 800MW of Offshore Wind Install 160 MW of Utility PV

Table K-67. Hawaiian Electric Third Iteration Cases (15 of 31)

Case Name	Theme 3, Case 125: Solar and Wind, DG PV Regulation, HL and ME 100% RE 2040	Theme 3, Case 126: Solar and Wind, DG PV Regulation, HL and ME 100% RE 2040
Case Label	16_T3aWv3H40hc	16_T3bWv3H40hc
DER Forecast	High minus 10%	Market minus 10%
Fuel Price	High	High
2016	27.6 MW Waiver PV Projects added 12/31/2016	27.6 MW Waiver PV Projects added 12/31/2016
2017		
2018	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)
2019	90 MW Contingency BESS added	90 MW Contingency BESS added
2020	Install 30MW of Onshore Wind	Install 30MW of Onshore Wind
2021		
2022	Install 100MW JBPHH Plant, 1/2022 AES Deactivated 9/2022	Install 100MW JBPHH Plant, 1/2022 AES Deactivated 9/2022
2023	Install 54MW KMBCH Plant, 1/2023 Waiau 3 & 4 Deactivated, 1/2023	Install 54MW KMBCH Plant, 1/2023 Waiau 3 & 4 Deactivated, 1/2023
2024		
2025	Kahe 6 Deactivated, 1/2025	Kahe 6 Deactivated, 1/2025
2026		
2027		
2028		
2029		
2030	Waiau 5 & 6 Deactivated, 1/2030	Waiau 5 & 6 Deactivated, 1/2030 Install 40MW of Utility PV
2031		
2032		
2033		
2034		
2035		
2036		
2037		
2038		
2039		
2040		Install 400MW of Offshore Wind
2041		
2042		
2043		
2044		
2045	Install 1200 MW of Offshore Wind Install 420 MW of Utility PV	Install 1200MW of Offshore Wind Install 160 MW of Utility PV

Table K-68. Hawaiian Electric Third Iteration Cases (16 of 31)

Case Name	Theme 3, Case 127: Solar and Wind, Static Utility Build Out	Theme 3, Case 128: Solar and Wind, Static Utility Build Out
Case Label	16_T3abWv3L	16_T3abWv3H
DER Forecast	High	High
Fuel Price	Low	High
2016	27.6 MW Waiver PV Projects added 12/31/2016	27.6 MW Waiver PV Projects added 12/31/2016
2017		
2018	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)
2019	90 MW Contingency BESS added	90 MW Contingency BESS added
2020	Install 30MW of Onshore Wind	Install 30MW of Onshore Wind
2021		
2022	Install 100MW JBPHH Plant, 1/2022 AES Deactivated 9/2022	Install 100MW JBPHH Plant, 1/2022 AES Deactivated 9/2022
2023	Install 54MW KMBCH Plant, 1/2023 Waiau 3 & 4 Deactivated, 1/2023	Install 54MW KMBCH Plant, 1/2023 Waiau 3 & 4 Deactivated, 1/2023
2024		
2025	Kahe 6 Deactivated, 1/2025	Kahe 6 Deactivated, 1/2025
2026		
2027		
2028		
2029		
2030	Waiau 5 & 6 Deactivated, 1/2030 Install 40MW of Utility PV	Waiau 5 & 6 Deactivated, 1/2030 Install 40MW of Utility PV
2031		
2032		
2033		
2034		
2035		
2036		
2037		
2038		
2039		
2040	Install 800MW of Offshore Wind	Install 800MW of Offshore Wind
2041		
2042		
2043		
2044		
2045	Install 800MW of Offshore Wind Install 160 MW of Utility PV	Install 800MW of Offshore Wind Install 160 MW of Utility PV

Table K-69. Hawaiian Electric Third Iteration Cases (17 of 31)

Case Name	Theme 3, Case 129: Solar and Wind, Static Utility Build Out, HL and ME 100% RE 2040	Theme 3, Case 130: Solar and Wind, Static Utility Build Out, HL and ME 100% RE 2040
Case Label	16_T3abWv3L40	16_T3baWv3H40
DER Forecast	High	High
Fuel Price	Low	High
2016	27.6 MW Waiver PV Projects added 12/31/2016	27.6 MW Waiver PV Projects added 12/31/2016
2017		
2018	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)
2019	90 MW Contingency BESS added	90 MW Contingency BESS added
2020	Install 30MW of Onshore Wind	Install 30MW of Onshore Wind
2021		
2022	Install 100MW JBPHH Plant, 1/2022 AES Deactivated 9/2022	Install 100MW JBPHH Plant, 1/2022 AES Deactivated 9/2022
2023	Install 54MW KMBCH Plant, 1/2023 Waiau 3 & 4 Deactivated, 1/2023	Install 54MW KMBCH Plant, 1/2023 Waiau 3 & 4 Deactivated, 1/2023
2024		
2025	Kahe 6 Deactivated, 1/2025	Kahe 6 Deactivated, 1/2025
2026		
2027		
2028		
2029		
2030	Waiau 5 & 6 Deactivated, 1/2030 Install 40MW of Utility PV	Waiau 5 & 6 Deactivated, 1/2030 Install 40MW of Utility PV
2031		
2032		
2033		
2034		
2035		
2036		
2037		
2038		
2039		
2040	Install 400MW of Offshore Wind	Install 400MW of Offshore Wind
2041		
2042		
2043		
2044		
2045	Install 1200MW of Offshore Wind Install 160 MW of Utility PV	Install 1200MW of Offshore Wind Install 160 MW of Utility PV

Table K-70. Hawaiian Electric Third Iteration Cases (18 of 31)

Case Name	Theme 1, Case 131: Solar and Wind, HL and ME 100% RE 2030	Theme 1, Case 132: Solar and Wind, HL and ME 100% RE 2030
Case Label	16_T1aWL30v6	16_T1aWH30v6
DER Forecast	High	High
Fuel Price	Low	High
2016	27.6 MW Waiver PV Projects added 12/31/2016	27.6 MW Waiver PV Projects added 12/31/2016
2017		
2018	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)
2019	90 MW Contingency BESS added	90 MW Contingency BESS added
2020	Install 30MW Onshore Wind Install 200MW of Utility PV	Install 30MW Onshore Wind Install 200MW of Utility PV
2021		
2022	Install 100MW JBPHH Plant, 1/2022 AES Deactivated 9/2022 Install 200MW of Utility PV	Install 100MW JBPHH Plant, 1/2022 AES Deactivated 9/2022 Install 200MW of Utility PV
2023	Install 54MW KMBCH Plant, 1/2023 Waiau 3 & 4 Deactivated, 1/2023	Install 54MW KMBCH Plant, 1/2023 Waiau 3 & 4 Deactivated, 1/2023
2024	Install 220 MW of Utility PV	Install 220 MW of Utility PV
2025	Kahe 6 Deactivated, 1/2025	Kahe 6 Deactivated, 1/2025
2026		
2027		
2028		
2029		
2030	Waiau 5 & 6 Deactivated, 1/2030 Install 200 MW of Offshore Wind	Waiau 5 & 6 Deactivated, 1/2030 Install 200MW of Offshore Wind
2031		
2032	Install 200 MW of Offshore Wind	Install 200 MW of Offshore Wind
2033		
2034	Install 200 MW of Offshore Wind	Install 200 MW of Offshore Wind
2035		
2036	Install 200 MW of Offshore Wind	Install 200 MW of Offshore Wind
2037		
2038		
2039		
2040		
2041		
2042		
2043		
2044		
2045		

Table K-71. Hawaiian Electric Third Iteration Cases (19 of 31)

Case Name	Theme 2, Case 133: Wind, HL and ME 100% RE 2040	Theme 2, Case 134: Wind, HL and ME 100% RE 2040
Case Label	16_PT2aWv4L	16_PT2aWv4H
DER Forecast	High	High
Fuel Price	Low	High
2016	27.6 MW Waiver PV Projects added 12/31/2016	27.6 MW Waiver PV Projects added 12/31/2016
2017		
2018	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)
2019	90 MW Contingency BESS added	90 MW Contingency BESS added
2020	Install 100MW JBPHH Plant, 12/2020 Kahe 1, 2, 3 Deactivated, 12/2020 Install 30MW of Onshore Wind Install 60MW of Utility PV	Install 100MW JBPHH Plant, 12/2020 Kahe 1, 2, 3 Deactivated, 12/2020 Install 30MW of Onshore Wind Install 60MW of Utility PV
2021	Install 27 MW KMCBH Plant, 6/2021 Install 3x1 CC, 6/2021	Install 27 MW KMCBH Plant, 6/2021 Install 3x1 CC, 6/2021
2022	AES Deactivated 9/2022 Waiau 3 & 4 Deactivated, 1/2022 Kahe 4 Deactivated, 1/2022	AES Deactivated 9/2022 Waiau 3 & 4 Deactivated, 1/2022 Kahe 4 Deactivated, 1/2022
2023		
2024	Waiau 5 & 6 Deactivated, 1/2024	Waiau 5 & 6 Deactivated, 1/2024
2025		
2026		
2027		
2028		
2029		
2030	Waiau 7 & 8 Deactivated, 1/2030 Install 200MW of Offshore Wind	Waiau 7 & 8 Deactivated, 1/2030 Install 200MW of Offshore Wind
2031		
2032		
2033		
2034		
2035		
2036		
2037		
2038		
2039		
2040	Install 200MW of Offshore Wind	Install 200MW of Offshore Wind
2041		
2042		
2043		
2044		
2045	Install 400MW of Offshore Wind	Install 400MW of Offshore Wind

Table K-72. Hawaiian Electric Third Iteration Cases (20 of 31)

Case Name	Theme 2, Case 135: Wind, HL and ME 100% RE 2040	Theme 2, Case 136: Wind, HL and ME 100% RE 2040
Case Label	16_PT2bWv4L	16_PT2bWv4H
DER Forecast	Market	Market
Fuel Price	Low	High
2016	27.6 MW Waiver PV Projects added 12/31/2016	27.6 MW Waiver PV Projects added 12/31/2016
2017		
2018	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)
2019	90 MW Contingency BESS added	90 MW Contingency BESS added
2020	Install 100MW JBPHH Plant, 12/2020 Kahe 1, 2, 3 Deactivated, 12/2020 Install 30MW of Onshore Wind Install 60MW of Utility PV	Install 100MW JBPHH Plant, 12/2020 Kahe 1, 2, 3 Deactivated, 12/2020 Install 30MW of Onshore Wind Install 60MW of Utility PV
2021	Install 27 MW KMCBH Plant, 6/2021 Install 3x1 CC, 6/2021	Install 27 MW KMCBH Plant, 6/2021 Install 3x1 CC, 6/2021
2022	AES Deactivated 9/2022 Waiau 3 & 4 Deactivated, 1/2022 Kahe 4 Deactivated, 1/2022	AES Deactivated 9/2022 Waiau 3 & 4 Deactivated, 1/2022 Kahe 4 Deactivated, 1/2022
2023		
2024	Waiau 5 & 6 Deactivated, 1/2024	Waiau 5 & 6 Deactivated, 1/2024
2025		
2026		
2027		
2028		
2029		
2030	Waiau 7 & 8 Deactivated, 1/2030 Install 200MW of Offshore Wind	Waiau 7 & 8 Deactivated, 1/2030 Install 200MW of Offshore Wind
2031		
2032		
2033		
2034		
2035		
2036		
2037		
2038		
2039		
2040	Install 200MW of Offshore Wind	Install 200MW of Offshore Wind
2041		
2042		
2043		
2044		
2045	Install 400MW of Offshore Wind	Install 400MW of Offshore Wind

Table K-73. Hawaiian Electric Third Iteration Cases (21 of 31)

Case Name	Theme 2, Case 137: Solar, HL and ME 100% RE 2040	Theme 2, Case 138: Solar, HL and ME 100% RE 2040
Case Label	16_PT2aSv4L	16_PT2aSv4H
DER Forecast	High	High
Fuel Price	Low	High
2016	27.6 MW Waiver PV Projects added 12/31/2016	27.6 MW Waiver PV Projects added 12/31/2016
2017		
2018	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)
2019	90 MW Contingency BESS added	90 MW Contingency BESS added
2020	Install 100MW JBPHH Plant, 12/2020 Kahe 1, 2, 3 Deactivated, 12/2020 Install 30MW of Onshore Wind Install 60MW of Utility PV	Install 100MW JBPHH Plant, 12/2020 Kahe 1, 2, 3 Deactivated, 12/2020 Install 30MW of Onshore Wind Install 60MW of Utility PV
2021	Install 27 MW KMCBH Plant, 6/2021 Install 3x1 CC, 6/2021	Install 27 MW KMCBH Plant, 6/2021 Install 3x1 CC, 6/2021
2022	AES Deactivated 9/2022 Waiau 3 & 4 Deactivated, 1/2022 Kahe 4 Deactivated, 1/2022	AES Deactivated 9/2022 Waiau 3 & 4 Deactivated, 1/2022 Kahe 4 Deactivated, 1/2022
2023		
2024	Waiau 5 & 6 Deactivated, 1/2024	Waiau 5 & 6 Deactivated, 1/2024
2025		
2026		
2027		
2028		
2029		
2030	Waiau 7 & 8 Deactivated, 1/2030 Install 400MW of Utility PV	Waiau 7 & 8 Deactivated, 1/2030 Install 400MW of Utility PV
2031		
2032		
2033		
2034		
2035		
2036		
2037		
2038		
2039		
2040	Install 200MW of Utility PV	Install 200MW of Utility PV
2041		
2042		
2043		
2044		
2045		

Table K-74. Hawaiian Electric Third Iteration Cases (22 of 31)

Case Name	Theme 2, Case 139: Solar, HL and ME 100% RE 2040	Theme 2, Case 140: Solar, HL and ME 100% RE 2040
Case Label	16_PT2bSv4L	16_PT2bSv4H
DER Forecast	Market	Market
Fuel Price	Low	High
2016	27.6 MW Waiver PV Projects added 12/31/2016	27.6 MW Waiver PV Projects added 12/31/2016
2017		
2018	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)
2019	90 MW Contingency BESS added	90 MW Contingency BESS added
2020	Install 100MW JBPHH Plant, 12/2020 Kahe 1, 2, 3 Deactivated, 12/2020 Install 30MW of Onshore Wind Install 60MW of Utility PV	Install 100MW JBPHH Plant, 12/2020 Kahe 1, 2, 3 Deactivated, 12/2020 Install 30MW of Onshore Wind Install 60MW of Utility PV
2021	Install 27 MW KMCBH Plant, 6/2021 Install 3x1 CC, 6/2021	Install 27 MW KMCBH Plant, 6/2021 Install 3x1 CC, 6/2021
2022	AES Deactivated 9/2022 Waiau 3 & 4 Deactivated, 1/2022 Kahe 4 Deactivated, 1/2022	AES Deactivated 9/2022 Waiau 3 & 4 Deactivated, 1/2022 Kahe 4 Deactivated, 1/2022
2023		
2024	Waiau 5 & 6 Deactivated, 1/2024	Waiau 5 & 6 Deactivated, 1/2024
2025		
2026		
2027		
2028		
2029		
2030	Waiau 7 & 8 Deactivated, 1/2030 Install 400MW of Utility PV	Waiau 7 & 8 Deactivated, 1/2030 Install 400MW of Utility PV
2031		
2032		
2033		
2034		
2035		
2036		
2037		
2038		
2039		
2040	Install 200MW of Utility PV	Install 200MW of Utility PV
2041		
2042		
2043		
2044		
2045		

Table K-75. Hawaiian Electric Third Iteration Cases (23 of 31)

Case Name	Theme 2, Case 141: Solar and Wind, HL and ME 100% RE 2040	Theme 2, Case 142: Solar and Wind, HL and ME 100% RE 2040
Case Label	16_PT2aSWv4L	16_PT2aSWv4H
DER Forecast	High	High
Fuel Price	Low	High
2016	27.6 MW Waiver PV Projects added 12/31/2016	27.6 MW Waiver PV Projects added 12/31/2016
2017		
2018	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)
2019	90 MW Contingency BESS added	90 MW Contingency BESS added
2020	Install 100MW JBPHH Plant, 12/2020 Kahe 1, 2, 3 Deactivated, 12/2020 Install 30MW of Onshore Wind Install 60MW of Utility PV	Install 100MW JBPHH Plant, 12/2020 Kahe 1, 2, 3 Deactivated, 12/2020 Install 30MW of Onshore Wind Install 60MW of Utility PV
2021	Install 27 MW KMCBH Plant, 6/2021 Install 3x1 CC, 6/2021	Install 27 MW KMCBH Plant, 6/2021 Install 3x1 CC, 6/2021
2022	AES Deactivated 9/2022 Waiau 3 & 4 Deactivated, 1/2022 Kahe 4 Deactivated, 1/2022	AES Deactivated 9/2022 Waiau 3 & 4 Deactivated, 1/2022 Kahe 4 Deactivated, 1/2022
2023		
2024	Waiau 5 & 6 Deactivated, 1/2024	Waiau 5 & 6 Deactivated, 1/2024
2025		
2026		
2027		
2028		
2029		
2030	Waiau 7 & 8 Deactivated, 1/2030 Install 100MW of Utility PV Install 200MW of Offshore Wind	Waiau 7 & 8 Deactivated, 1/2030 Install 100MW of Utility PV Install 200MW of Offshore Wind
2031		
2032		
2033		
2034		
2035		
2036		
2037		
2038		
2039		
2040	Install 200MW of Utility PV Install 200MW of Offshore Wind	Install 200MW of Utility PV Install 200MW of Offshore Wind
2041		
2042		
2043		
2044		

2045	Install 300MW of Utility PV Install 400MW of Offshore Wind	Install 300MW of Utility PV Install 400MW of Offshore Wind

Table K-76. Hawaiian Electric Third Iteration Cases (24 of 31)

Case Name	Theme 2, Case 143: Solar and Wind, HL and ME 100% RE 2040	Theme 2, Case 144: Solar and Wind, HL and ME 100% RE 2040
Case Label	16_PT2bSWv4L	16_PT2bSWv4H
DER Forecast	Market	Market
Fuel Price	Low	High
2016	27.6 MW Waiver PV Projects added 12/31/2016	27.6 MW Waiver PV Projects added 12/31/2016
2017		
2018	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)
2019	90 MW Contingency BESS added	90 MW Contingency BESS added
2020	Install 100MW JBPHH Plant, 12/2020 Kahe 1, 2, 3 Deactivated, 12/2020 Install 30MW of Onshore Wind Install 60MW of Utility PV	Install 100MW JBPHH Plant, 12/2020 Kahe 1, 2, 3 Deactivated, 12/2020 Install 30MW of Onshore Wind Install 60MW of Utility PV
2021	Install 27 MW KMCBH Plant, 6/2021 Install 3x1 CC, 6/2021	Install 27 MW KMCBH Plant, 6/2021 Install 3x1 CC, 6/2021
2022	AES Deactivated 9/2022 Waiau 3 & 4 Deactivated, 1/2022 Kahe 4 Deactivated, 1/2022	AES Deactivated 9/2022 Waiau 3 & 4 Deactivated, 1/2022 Kahe 4 Deactivated, 1/2022
2023		
2024	Waiau 5 & 6 Deactivated, 1/2024	Waiau 5 & 6 Deactivated, 1/2024
2025		
2026		
2027		
2028		
2029		
2030	Waiau 7 & 8 Deactivated, 1/2030 Install 100MW of Utility PV Install 200MW of Offshore Wind	Waiau 7 & 8 Deactivated, 1/2030 Install 100MW of Utility PV Install 200MW of Offshore Wind
2031		
2032		
2033		
2034		
2035		
2036		
2037		
2038		
2039		
2040	Install 200MW of Utility PV Install 200MW of Offshore Wind	Install 200MW of Utility PV Install 200MW of Offshore Wind
2041		
2042		
2043		
2044		

2045	Install 300MW of Utility PV Install 400MW of Offshore Wind	Install 300MW of Utility PV Install 400MW of Offshore Wind

Table K-77. Hawaiian Electric Third Iteration Cases (25 of 31)

Case Name	Theme 3, Case 145: Wind, HL and ME 100% RE 2040	Theme 3, Case 146: Wind, HL and ME 100% RE 2040
Case Label	16_PT3aWv4L	16_PT3aWv4H
DER Forecast	High	High
Fuel Price	Low	High
2016	27.6 MW Waiver PV Projects added 12/31/2016	27.6 MW Waiver PV Projects added 12/31/2016
2017		
2018	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)
2019	90 MW Contingency BESS added	90 MW Contingency BESS added
2020	Install 30MW of Onshore Wind Install 60MW of Utility PV	Install 30MW of Onshore Wind Install 60MW of Utility PV
2021		
2022	Install 100MW JBPHH Plant, 1/2022 AES Deactivated 9/2022	Install 100MW JBPHH Plant, 1/2022 AES Deactivated 9/2022
2023	Install 54MW KMBCH Plant, 1/2023 Waiau 3 & 4 Deactivated, 1/2023	Install 54MW KMBCH Plant, 1/2023 Waiau 3 & 4 Deactivated, 1/2023
2024		
2025	Kahe 6 Deactivated, 1/2025	Kahe 6 Deactivated, 1/2025
2026		
2027		
2028		
2029		
2030	Waiau 5 & 6 Deactivated, 1/2030 Install 200MW of Offshore Wind	Waiau 5 & 6 Deactivated, 1/2030 Install 200MW of Offshore Wind
2031		
2032		
2033		
2034		
2035		
2036		
2037		
2038		
2039		
2040	Install 200MW of Offshore Wind	Install 200MW of Offshore Wind
2041		
2042		
2043		
2044		
2045	Install 400MW of Offshore Wind	Install 400MW of Offshore Wind

Table K-78. Hawaiian Electric Third Iteration Cases (26 of 31)

Case Name	Theme 3, Case 147: Wind, HL and ME 100% RE 2040	Theme 3, Case 148: Wind, HL and ME 100% RE 2040
Case Label	16_PT3bWv4L	16_PT3bWv4H
DER Forecast	Market	Market
Fuel Price	Low	High
2016	27.6 MW Waiver PV Projects added 12/31/2016	27.6 MW Waiver PV Projects added 12/31/2016
2017		
2018	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)
2019	90 MW Contingency BESS added	90 MW Contingency BESS added
2020	Install 30MW of Onshore Wind Install 60MW of Utility PV	Install 30MW of Onshore Wind Install 60MW of Utility PV
2021		
2022	Install 100MW JBPHH Plant, 1/2022 AES Deactivated 9/2022	Install 100MW JBPHH Plant, 1/2022 AES Deactivated 9/2022
2023	Install 54MW KMBCH Plant, 1/2023 Waiau 3 & 4 Deactivated, 1/2023	Install 54MW KMBCH Plant, 1/2023 Waiau 3 & 4 Deactivated, 1/2023
2024		
2025	Kahe 6 Deactivated, 1/2025	Kahe 6 Deactivated, 1/2025
2026		
2027		
2028		
2029		
2030	Waiau 5 & 6 Deactivated, 1/2030 Install 200MW of Offshore Wind	Waiau 5 & 6 Deactivated, 1/2030 Install 200MW of Offshore Wind
2031		
2032		
2033		
2034		
2035		
2036		
2037		
2038		
2039		
2040	Install 200MW of Offshore Wind	Install 200MW of Offshore Wind
2041		
2042		
2043		
2044		
2045	Install 400MW of Offshore Wind	Install 400MW of Offshore Wind

Table K-79. Hawaiian Electric Third Iteration Cases (27 of 31)

Case Name	Theme 3, Case 149: Solar, HL and ME 100% RE 2040	Theme 3, Case 150: Solar, HL and ME 100% RE 2040
Case Label	16_PT3aSv4L	16_PT3aSv4H
DER Forecast	High	High
Fuel Price	Low	High
2016	27.6 MW Waiver PV Projects added 12/31/2016	27.6 MW Waiver PV Projects added 12/31/2016
2017		
2018	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)
2019	90 MW Contingency BESS added	90 MW Contingency BESS added
2020	Install 30MW of Onshore Wind Install 60MW of Utility PV	Install 30MW of Onshore Wind Install 60MW of Utility PV
2021		
2022	Install 100MW JBPHH Plant, 1/2022 AES Deactivated 9/2022	Install 100MW JBPHH Plant, 1/2022 AES Deactivated 9/2022
2023	Install 54MW KMBCH Plant, 1/2023 Waiau 3 & 4 Deactivated, 1/2023	Install 54MW KMBCH Plant, 1/2023 Waiau 3 & 4 Deactivated, 1/2023
2024		
2025	Kahe 6 Deactivated, 1/2025	Kahe 6 Deactivated, 1/2025
2026		
2027		
2028		
2029		
2030	Waiau 5 & 6 Deactivated, 1/2030 Install 400MW of Utility PV	Waiau 5 & 6 Deactivated, 1/2030 Install 400MW of Utility PV
2031		
2032		
2033		
2034		
2035		
2036		
2037		
2038		
2039		
2040	Install 200MW of Utility PV	Install 200MW of Utility PV
2041		
2042		
2043		
2044		
2045		

Table K-80. Hawaiian Electric Third Iteration Cases (28 of 31)

Case Name	Theme 3, Case 151: Solar, HL and ME 100% RE 2040	Theme 3, Case 152: Solar, HL and ME 100% RE 2040
Case Label	16_PT3bSv4L	16_PT3bSv4H
DER Forecast	Market	Market
Fuel Price	Low	High
2016	27.6 MW Waiver PV Projects added 12/31/2016	27.6 MW Waiver PV Projects added 12/31/2016
2017		
2018	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)
2019	90 MW Contingency BESS added	90 MW Contingency BESS added
2020	Install 30MW of Onshore Wind Install 60MW of Utility PV	Install 30MW of Onshore Wind Install 60MW of Utility PV
2021		
2022	Install 100MW JBPHH Plant, 1/2022 AES Deactivated 9/2022	Install 100MW JBPHH Plant, 1/2022 AES Deactivated 9/2022
2023	Install 54MW KMBCH Plant, 1/2023 Waiau 3 & 4 Deactivated, 1/2023	Install 54MW KMBCH Plant, 1/2023 Waiau 3 & 4 Deactivated, 1/2023
2024		
2025	Kahe 6 Deactivated, 1/2025	Kahe 6 Deactivated, 1/2025
2026		
2027		
2028		
2029		
2030	Waiau 5 & 6 Deactivated, 1/2030 Install 400MW of Utility PV	Waiau 5 & 6 Deactivated, 1/2030 Install 400MW of Utility PV
2031		
2032		
2033		
2034		
2035		
2036		
2037		
2038		
2039		
2040	Install 200MW of Utility PV	Install 200MW of Utility PV
2041		
2042		
2043		
2044		
2045		

Table K-81. Hawaiian Electric Third Iteration Cases (29 of 31)

Case Name	Theme 3, Case 153: Solar and Wind, HL and ME 100% RE 2040	Theme 3, Case 154: Solar and Wind, HL and ME 100% RE 2040
Case Label	16_PT3aSWv4L	16_PT3aSWv4H
DER Forecast	High	High
Fuel Price	Low	High
2016	27.6 MW Waiver PV Projects added 12/31/2016	27.6 MW Waiver PV Projects added 12/31/2016
2017		
2018	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)
2019	90 MW Contingency BESS added	90 MW Contingency BESS added
2020	Install 30MW of Onshore Wind Install 60MW of Utility PV	Install 30MW of Onshore Wind Install 60MW of Utility PV
2021		
2022	Install 100MW JBPHH Plant, 1/2022 AES Deactivated 9/2022	Install 100MW JBPHH Plant, 1/2022 AES Deactivated 9/2022
2023	Install 54MW KMBCH Plant, 1/2023 Waiau 3 & 4 Deactivated, 1/2023	Install 54MW KMBCH Plant, 1/2023 Waiau 3 & 4 Deactivated, 1/2023
2024		
2025	Kahe 6 Deactivated, 1/2025	Kahe 6 Deactivated, 1/2025
2026		
2027		
2028		
2029		
2030	Waiau 5 & 6 Deactivated, 1/2030 Install 100MW of Utility PV Install 200MW of Offshore Wind	Waiau 5 & 6 Deactivated, 1/2030 Install 100MW of Utility PV Install 200MW of Offshore Wind
2031		
2032		
2033		
2034		
2035		
2036		
2037		
2038		
2039		
2040	Install 200MW of Utility PV Install 200MW of Offshore Wind	Install 200MW of Utility PV Install 200MW of Offshore Wind
2041		
2042		
2043		
2044		
2045	Install 300MW of Utility PV Install 400MW of Offshore Wind	Install 300MW of Utility PV Install 400MW of Offshore Wind

Table K-82. Hawaiian Electric Third Iteration Cases (30 of 31)

Case Name	Theme 3, Case 155: Solar and Wind, HL and ME 100% RE 2040	Theme 3, Case 156: Solar and Wind, HL and ME 100% RE 2040
Case Label	16_PT3bSWv4L	16_PT3bSWv4H
DER Forecast	Market	Market
Fuel Price	Low	High
2016	27.6 MW Waiver PV Projects added 12/31/2016	27.6 MW Waiver PV Projects added 12/31/2016
2017		
2018	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)
2019	90 MW Contingency BESS added	90 MW Contingency BESS added
2020	Install 30MW of Onshore Wind Install 60MW of Utility PV	Install 30MW of Onshore Wind Install 60MW of Utility PV
2021		
2022	Install 100MW JBPHH Plant, 1/2022 AES Deactivated 9/2022	Install 100MW JBPHH Plant, 1/2022 AES Deactivated 9/2022
2023	Install 54MW KMBCH Plant, 1/2023 Waiau 3 & 4 Deactivated, 1/2023	Install 54MW KMBCH Plant, 1/2023 Waiau 3 & 4 Deactivated, 1/2023
2024		
2025	Kahe 6 Deactivated, 1/2025	Kahe 6 Deactivated, 1/2025
2026		
2027		
2028		
2029		
2030	Waiau 5 & 6 Deactivated, 1/2030 Install 100MW of Utility PV Install 200MW of Offshore Wind	Waiau 5 & 6 Deactivated, 1/2030 Install 100MW of Utility PV Install 200MW of Offshore Wind
2031		
2032		
2033		
2034		
2035		
2036		
2037		
2038		
2039		
2040	Install 200MW of Utility PV Install 200MW of Offshore Wind	Install 200MW of Utility PV Install 200MW of Offshore Wind
2041		
2042		
2043		
2044		
2045	Install 300MW of Utility PV Install 400MW of Offshore Wind	Install 300MW of Utility PV Install 400MW of Offshore Wind

Table K-83. Hawaiian Electric Third Iteration Cases (31 of 31)

Hawaiian Electric Final Plans

Case Name	Final Plan, Theme 1 (Case 131)	Final Plan, Theme 1 (Case 132)
Case Label	16_T1aWL30v6	16_T1aWH30v6
DER Forecast	High	High
Fuel Price	Low	High
2016	27.6 MW Waiver PV Projects added 12/31/2016	27.6 MW Waiver PV Projects added 12/31/2016
2017		
2018	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)
2019	90 MW Contingency BESS added Convert H8 & 9 to synchronous condenser	90 MW Contingency BESS added Convert H8 & 9 to synchronous condenser
2020	Install 30MW Onshore Wind Install 200MW of Utility PV	Install 30MW Onshore Wind Install 200MW of Utility PV
2021		
2022	Install 100MW JBPHH Plant, 1/2022 AES Deactivated 9/2022 Install 200MW of Utility PV	Install 100MW JBPHH Plant, 1/2022 AES Deactivated 9/2022 Install 200MW of Utility PV
2023	Install 54MW KMBCH Plant, 1/2023 Waiau 3 & 4 Deactivated, 1/2023 Waiau 3 & 4 converted to synchronous condenser	Install 54MW KMBCH Plant, 1/2023 Waiau 3 & 4 Deactivated, 1/2023 Waiau 3 & 4 converted to synchronous condenser
2024	Install 220 MW of Utility PV	Install 220 MW of Utility PV
2025	Kahe 6 Deactivated, 1/2025 Kahe 6 converted to synchronous condenser	Kahe 6 Deactivated, 1/2025 Kahe 6 converted to synchronous condenser
2026		
2027		
2028		
2029		
2030	Waiau 5 & 6 Deactivated, 1/2030 Install 200 MW of Offshore Wind	Waiau 5 & 6 Deactivated, 1/2030 Install 200MW of Offshore Wind
2031		
2032	Install 200 MW of Offshore Wind	Install 200 MW of Offshore Wind
2033		
2034	Install 200 MW of Offshore Wind	Install 200 MW of Offshore Wind
2035		
2036	Install 200 MW of Offshore Wind	Install 200 MW of Offshore Wind
2037		
2038		
2039		
2040		
2041		
2042		
2043		
2044		
2045		

Table K-84. Hawaiian Electric Final Cases (1 of 3)

Case Name	Final Plan, Theme 2 (Case 143)	Final Plan, Theme 2 (Case 144)
Case Label	16_PT2bSWv4L	16_PT2bSWv4H
DER Forecast	Market	Market
Fuel Price	Low	High
2016	27.6 MW Waiver PV Projects added 12/31/2016	27.6 MW Waiver PV Projects added 12/31/2016
2017		
2018	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)
2019	90 MW Contingency BESS added Convert H8 & 9 to synchronous condenser	90 MW Contingency BESS added Convert H8 & 9 to synchronous condenser
2020	Install 100MW JBPHH Plant, 12/2020 Kahe 1, 2, 3 Deactivated, 12/2020 Install 30MW of Onshore Wind Install 60MW of Utility PV	Install 100MW JBPHH Plant, 12/2020 Kahe 1, 2, 3 Deactivated, 12/2020 Install 30MW of Onshore Wind Install 60MW of Utility PV
2021	Install 27 MW KMCBH Plant, 6/2021 Install 3x1 CC, 6/2021	Install 27 MW KMCBH Plant, 6/2021 Install 3x1 CC, 6/2021
2022	AES Deactivated 9/2022 Waiau 3 & 4 Deactivated, 1/2022 Kahe 4 Deactivated, 1/2022 Kahe 1, 2, 3 converted to synchronous condenser	AES Deactivated 9/2022 Waiau 3 & 4 Deactivated, 1/2022 Kahe 4 Deactivated, 1/2022 Kahe 1, 2, 3 converted to synchronous condenser
2023		
2024	Waiau 5 & 6 Deactivated, 1/2024	Waiau 5 & 6 Deactivated, 1/2024
2025		
2026		
2027		
2028		
2029		
2030	Waiau 7 & 8 Deactivated, 1/2030 Install 100MW of Utility PV Install 200MW of Offshore Wind	Waiau 7 & 8 Deactivated, 1/2030 Install 100MW of Utility PV Install 200MW of Offshore Wind
2031		
2032		
2033		
2034		
2035		
2036		
2037		
2038		
2039		
2040	Install 200MW of Utility PV Install 200MW of Offshore Wind	Install 200MW of Utility PV Install 200MW of Offshore Wind
2041		
2042		
2043		

2044		
2045	Install 300MW of Utility PV Install 400MW of Offshore Wind	Install 300MW of Utility PV Install 400MW of Offshore Wind

Table K-85. Hawaiian Electric Final Cases (2 of 3)

Case Name	Final Plan, Theme 3 (Case 155)	Final Plan, Theme 3 (Case 156)
Case Label	16_PT3bSWv4L	16_PT3bSWv4H
DER Forecast	Market	Market
Fuel Price	Low	High
2016	27.6 MW Waiver PV Projects added 12/31/2016	27.6 MW Waiver PV Projects added 12/31/2016
2017		
2018	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)
2019	90 MW Contingency BESS added Convert H8 & 9 to synchronous condenser	90 MW Contingency BESS added Convert H8 & 9 to synchronous condenser
2020	Install 30MW of Onshore Wind Install 60MW of Utility PV	Install 30MW of Onshore Wind Install 60MW of Utility PV
2021		
2022	Install 100MW JBPHH Plant, 1/2022 AES Deactivated 9/2022	Install 100MW JBPHH Plant, 1/2022 AES Deactivated 9/2022
2023	Install 54MW KMBCH Plant, 1/2023 Waiau 3 & 4 Deactivated, 1/2023 Waiau 3 & 4 converted to synchronous condenser	Install 54MW KMBCH Plant, 1/2023 Waiau 3 & 4 Deactivated, 1/2023 Waiau 3 & 4 converted to synchronous condenser
2024		
2025	Kahe 6 Deactivated, 1/2025 Kahe 6 converted to synchronous condenser	Kahe 6 Deactivated, 1/2025 Kahe 6 converted to synchronous condenser
2026		
2027		
2028		
2029		
2030	Waiau 5 & 6 Deactivated, 1/2030 Install 100MW of Utility-scale Solar Install 200MW of Offshore Wind	Waiau 5 & 6 Deactivated, 1/2030 Install 100MW of Utility-scale Solar Install 200MW of Offshore Wind
2031		
2032		
2033		
2034		
2035		
2036		
2037		
2038		
2039		
2040	Install 200MW of Utility PV Install 200MW of Offshore Wind	Install 200MW of Utility PV Install 200MW of Offshore Wind
2041		
2042		
2043		
2044		

2045	Install 300MW of Utility PV Install 400MW of Offshore Wind	Install 300MW of Utility PV Install 400MW of Offshore Wind

Table K-86. Hawaiian Electric Final Cases (3 of 3)

HAWAI'I ELECTRIC LIGHT

Hawai'i Electric Light First Iteration, PSIP Interim: 100% RE in 2045 with LNG.

Case Name	Interim: 100% Renewable in 2045, with LNG	Interim: 100% Renewable in 2045, with LNG
Case Label	33	35
DER Forecast	Preliminary Market	Preliminary Market
Fuel Price	2015 EIA Reference	April 2015 Low
2016		
2017		
2018		
2019		
2020		
2021		
2022		
2023		
2024		
2025	Install 25 MW Geo Puna Steam Deactivated	Install 25 MW Geo Puna Steam Deactivated
2026		
2027		
2028		
2029	Install 21 MW Biomass Hill 5 Deactivated	Install 21 MW Biomass Hill 5 Deactivated
2030		
2031		
2032		
2033		
2034		
2035		
2036		
2037		
2038		
2039	Naptha & ULSD to biofuel	Naptha & ULSD to biofuel
2040	Diesel to biofuel	Diesel to biofuel
2041		
2042		
2043		
2044		
2045	IFO to biofuel	IFO to biofuel

Table K-87. Hawai'i Electric Light Cases (1 of 15)

First Iteration, PSIP Interim: 100% RE in 2045 without LNG.

Case Name	Interim: 100% Renewable in 2045, without LNG	Interim: 100% Renewable in 2045, without LNG
Case Label	34a	36a
DER Forecast	Preliminary Market	Preliminary Market
Fuel Price	2015 EIA Reference	2016 Forward/Hybrid Curve
2016		
2017		
2018		
2019		
2020		
2021		
2022		
2023		
2024		
2025	Install 25 MW Geo Puna Steam Deactivated	Install 25 MW Geo Puna Steam Deactivated
2026		
2027		
2028		
2029	Install 21 MW Biomass Hill 5 Deactivated	Install 21 MW Biomass Hill 5 Deactivated
2030		
2031		
2032		
2033		
2034		
2035		
2036		
2037		
2038		Naptha to biofuel
2039	Naptha & ULSD to biofuel	ULSD to biofuel
2040	Diesel to biofuel	Diesel to biofuel
2041		
2042		
2043		
2044		
2045	IFO to biofuel	IFO to biofuel

Table K-88. Hawai'i Electric Light Cases (2 of 15)

Second Iteration, Theme 1: Aggressive 100% RE with minimal biofuels.

Case Name	Theme 1: 100% Renewable in 2030,with Firm Renewable Additions	Theme 1: 100% Renewable in 2030,with Firm Renewable Additions
Case Label	40g3	40s
DER Forecast	High	High
Fuel Price	2015 EIA Reference	February 2016 EIA STEO
2016		
2017		
2018		
2019		
2020		
2021		
2022	Install 20 MW Geo Puna Steam Deactivated	Install 20 MW Geo Puna Steam Deactivated
2023		
2024	Install 20 MW Biomass Hill 5 Deactivated	Install20 MW Biomass Hill 5 Deactivated
2025		
2026	Install 20 MW Geo Hill 6 deactivated	Install20 MW Geo Hill 6 deactivated
2027		
2028	Install 30 MW Wind	Install 30 MW Wind
2029		
2030	Install 30MW/6hr LS BESS x 2 Biofuel	Install 30MW/6hr LS BESS x 2 Biofuel
2031		
2032		
2033		
2034		
2035	Install 30MW/6hr LS BESS	Install 30MW/6hr LS BESS
2036		
2037		
2038		
2039		
2040	Install 30MW/6hr LS BESS	Install 30MW/6hr LS BESS
2041		
2042		
2043		
2044		
2045	Install 30MW/6hr LS BESS	Install 30MW/6hr LS BESS

Table K-89. Hawai'i Electric Light Cases (3 of 15)

Second Iteration, Theme 1: Aggressive 100% RE with minimal biofuels.

Case Name	Theme 1: 100% Renewable in 2030, without Firm RE Additions; Wind & PV Only	Theme 1: 100% Renewable in 2030, without Firm RE Additions; Wind & PV Only
Case Label	40o4	40t
DER Forecast	High	High
Fuel Price	2015 EIA Reference	February 2016 EIA STEO
2016		
2017		
2018		
2019		
2020	Install 30 MW Wind	Install 30 MW Wind
2021		
2022	Install 30 MW Wind	Install 30 MW Wind
2023	Install 30 MW Pumped storage hydro	Install 30 MW Pumped storage hydro
2024	Install 30 MW Wind	Install 30 MW Wind
2025		
2026	Install 30 MW Wind	Install 30 MW Wind
2027		
2028	Install 30 MW Wind	Install 30 MW Wind
2029		
2030	Install 210 MW Wind Install 720 MWH storage (30MW/6hr LS BESS, 4 ea) Biofuel	Install 210 MW Wind Install 720 MWH storage (30MW/6hr LS BESS, 4 ea) Biofuel
2031		
2032		
2033		
2034		
2035		
2036		
2037		
2038		
2039		
2040	Install 30 MW Wind	Install 30 MW Wind
2041		
2042		
2043		
2044		
2045	Install 30 MW Wind	Install 30 MW Wind

Table K-90. Hawai'i Electric Light Cases (4 of 15)

Second Iteration, Theme 2: Path to 100% RE with LNG, High DG PV forecast.

Case Name	Theme 2: 100% Renewable in 2040 with LNG	Theme 2: 100% Renewable in 2040 with LNG
Case Label	39a	39g
DER Forecast	High	High
Fuel Price	2015 EIA Reference	February 2016 EIA STEO
2016		
2017		
2018		
2019		
2020		
2021	LNG CC Units	LNG CC Units
2022	Install 20 MW Geo Puna Steam Deactivated	Install 20 MW Geo Puna Steam Deactivated
2023		
2024		
2025		
2026		
2027	Install 20 MW Biomass Hill 5 Deactivated	
2028		Install 20 MW Biomass Hill 5 Deactivated
2029		
2030	Install 20 MW Geo Hill 6 deactivated	
2031		
2032		Install 20 MW Geo Hill 6 deactivated
2033		
2034		
2035		
2036		
2037		
2038		
2039		
2040	Biofuel	Biofuel
2041		
2042		
2043		
2044		
2045		

Table K-91. Hawai'i Electric Light Cases (5 of 15)

Second Iteration, Theme 2: Path to 100% RE with LNG, Market DG PV forecast.

Case Name	Theme 2: 100% Renewable in 2040 with LNG	Theme 2: 100% Renewable in 2040 with LNG
Case Label	39f	39b
DER Forecast	Market	Market
Fuel Price	2015 EIA Reference	February 2016 EIA STEO
2016		
2017		
2018		
2019		
2020		
2021	LNG CC Units	LNG CC Units
2022	Install 20 MW Geo Puna Steam Deactivated	Install 20 MW Geo Puna Steam Deactivated
2023		
2024		
2025		
2026		
2027	Install 20 MW Biomass Hill 5 Deactivated	
2028		Install 20 MW Biomass Hill 5 Deactivated
2029		
2030	Install 20 MW Geo Hill 6 deactivated	
2031		
2032		Install 20 MW Geo Hill 6 deactivated
2033		
2034	Install 20 MW Wind	
2035		
2036		
2037		Install 20 MW Wind
2038	Install 20 MW Wind	
2039		
2040	Biofuel	Install 20 MW Wind Biofuel
2041		
2042		
2043		
2044		
2045		

Table K-92. Hawai'i Electric Light Cases (6 of 15)

Second Iteration, Theme 2: Path to 100% RE with LNG, High DG PV forecast.

Case Name	Theme 2: 100% Renewable in 2045 with LNG	Theme 2: 100% Renewable in 2045 with LNG
Case Label	39c	39i
DER Forecast	High	High
Fuel Price	2015 EIA Reference	February 2016 EIA STEO
2016		
2017		
2018		
2019		
2020		
2021	LNG CC Units	LNG CC Units
2022	Install 20 MW Geo Puna Steam Deactivated	Install 20 MW Geo Puna Steam Deactivated
2023		
2024		
2025		
2026		
2027	Install 20 MW Biomass Hill 5 Deactivated	
2028		Install 20 MW Biomass Hill 5 Deactivated
2029		
2030	Install 20 MW Geo Hill 6 deactivated	
2031		
2032		
2033		
2034		
2035		Install 20 MW Geo Hill 6 deactivated
2036		
2037		
2038		
2039		
2040		
2041		
2042		
2043		
2044		
2045	Biofuel	Biofuel

Table K-93. Hawai'i Electric Light Cases (7 of 15)

Second Iteration, Theme 2: Path to 100% RE with LNG, Market DG PV forecast.

Case Name	Theme 2: 100% Renewable in 2045 with LNG	Theme 2: 100% Renewable in 2045 with LNG
Case Label	39h	39d
DER Forecast	Market	Market
Fuel Price	2015 EIA Reference	February 2016 EIA STEO
2016		
2017		
2018		
2019		
2020		
2021	LNG CC Units	LNG CC Units
2022	Install 20 MW Geo Puna Steam Deactivated	Install 20 MW Geo Puna Steam Deactivated
2023		
2024		
2025		
2026		
2027	Install 20 MW Biomass Hill 5 Deactivated	
2028		Install 20 MW Biomass Hill 5 Deactivated
2029		
2030	Install 20 MW Geo Hill 6 deactivated	
2031		
2032		Install 20 MW Geo Hill 6 deactivated
2033		
2034	Install 20 MW Wind	
2035		
2036		
2037		Install 20 MW Wind
2038	Install 20 MW Wind	
2039		
2040		
2041		Install 20 MW Wind
2042	Install 20 MW Wind	
2043		
2044		
2045	Biofuel	Biofuel

Table K-94. Hawai'i Electric Light Cases (8 of 15)

Second Iteration, Theme 3: Path to 100% RE without LNG, high DG PV forecast.

Case Name	Theme 3: 100% Renewable in 2040 without LNG	Theme 3: 100% Renewable in 2040 without LNG
Case Label	42s	42q
DER Forecast	High	High
Fuel Price	2015 EIA Reference	February 2016 EIA STEO
2016		
2017		
2018		
2019		
2020		
2021		
2022	Install 20 MW Geo Puna Steam Deactivated	Install 20 MW Geo Puna Steam Deactivated
2023		
2024		
2025		
2026		
2027	Install 20 MW Biomass Hill 5 Deactivated	
2028		Install 20 MW Biomass Hill 5 Deactivated
2029		
2030		
2031		
2032		
2033	Install 20 MW Geo Hill 6 deactivated	
2034		
2035		Install 20 MW Geo Hill 6 deactivated
2036		
2037		
2038		
2039		
2040	Biofuel	Biofuel
2041		
2042		
2043		
2044		
2045		

Table K-95. Hawai'i Electric Light Cases (9 of 15)

Second Iteration, Theme 3: Path to 100% RE without LNG, Market DG PV forecast.

Case Name	Theme 3: 100% Renewable in 2040 without LNG	Theme 3: 100% Renewable in 2040 without LNG
Case Label	42r	42p
DER Forecast	Market	Market
Fuel Price	2015 EIA Reference	February 2016 EIA STEO
2016		
2017		
2018		
2019		
2020		
2021		
2022	Install 20 MW Geo Puna Steam Deactivated	Install 20 MW Geo Puna Steam Deactivated
2023		
2024		
2025		
2026		
2027	Install 20 MW Biomass Hill 5 Deactivated	
2028		Install 20 MW Biomass Hill 5 Deactivated
2029		
2030		
2031		
2032		
2033	Install 20 MW Geo Hill 6 deactivated	
2034		Install 20 MW Geo Hill 6 deactivated
2035	Install 20 MW Wind	
2036		
2037		Install 20 MW Wind
2038		
2039		
2040	Install 20 MW Wind Biofuel	Install 20 MW Wind Biofuel
2041		
2042		
2043		
2044		
2045		

Table K-96. Hawai'i Electric Light Cases (10 of 15)

Second Iteration, Theme 3: Path to 100% RE without LNG, high DG PV forecast.

Case Name	Theme 3: 100% Renewable in 2045 without LNG	Theme 3: 100% Renewable in 2045 without LNG
Case Label	42o	42k
DER Forecast	High	High
Fuel Price	2015 EIA Reference	February 2016 EIA STEO
2016		
2017		
2018		
2019		
2020		
2021		
2022	Install 20 MW Geo Puna Steam Deactivated	Install 20 MW Geo Puna Steam Deactivated
2023		
2024		
2025		
2026		
2027	Install 20 MW Biomass Hill 5 Deactivated	
2028		Install 20 MW Biomass Hill 5 Deactivated
2029		
2030		
2031		
2032		
2033	Install 20 MW Geo Hill 6 deactivated	
2034		
2035		Install 20 MW Geo Hill 6 deactivated
2036		
2037		
2038		
2039		
2040		
2041		
2042		
2043		
2044		
2045	Biofuel	Biofuel

Table K-97. Hawai'i Electric Light Cases (11 of 15)

Second Iteration, Theme 3: Path to 100% RE without LNG, Market DG PV forecast.

Case Name	Theme 3: 100% Renewable in 2045 without LNG	Theme 3: 100% Renewable in 2045 without LNG
Case Label	42n	42h
DER Forecast	Market	Market
Fuel Price	2015 EIA Reference	February 2016 EIA STEO
2016		
2017		
2018		
2019		
2020		
2021		
2022	Install 20 MW Geo Puna Steam Deactivated	Install 20 MW Geo Puna Steam Deactivated
2023		
2024		
2025		
2026		
2027	Install 20 MW Biomass Hill 5 Deactivated	
2028		Install 20 MW Biomass Hill 5 Deactivated
2029		
2030		
2031		
2032		
2033	Install 20 MW Geo Hill 6 deactivated	
2034		
2035	Install 20 MW Wind	Install 20 MW Geo Hill 6 deactivated
2036		
2037		Install 20 MW Wind
2038		
2039		
2040	Install 20 MW Wind	
2041		
2042		Install 20 MW Wind
2043		
2044		
2045	Biofuel	Biofuel

Table K-98. Hawai'i Electric Light Cases (12 of 15)

Third Iteration, Theme 1: Aggressive 100% RE with minimal biofuels.

Case Name	Theme 1: 100% Renewable in 2030,with Firm Renewable Additions	Theme 1: 100% Renewable in 2030,with Firm Renewable Additions
Case Label	50w4	50x2
DER Forecast	High	High
Fuel Price	2015 EIA Reference	February 2016 EIA STEO
2016		
2017		
2018		
2019		
2020		
2021		
2022	Install 20 MW Geo Puna Steam Deactivated	Install 20 MW Geo Puna Steam Deactivated
2023		
2024	Install 20 MW Biomass Hill 5 Deactivated	Install20 MW Biomass Hill 5 Deactivated
2025		
2026	Install 20 MW Geo Hill 6 deactivated	Install20 MW Geo Hill 6 deactivated
2027		
2028	Install 30 MW Wind	Install 30 MW Wind
2029		
2030	Install 30MW/6hr LS BESS, Install 30 MW Pumped Storage Hydro, Biofuel	Install 30MW/6hr LS BESS, Install 30 MW Pumped Storage Hydro, Biofuel
2031		
2032		
2033		
2034		
2035		
2036		
2037		
2038		
2039		
2040		
2041		
2042		
2043		
2044		
2045		

Table K-99. Hawai'i Electric Light Cases (13 of 15)

Third Iteration, Theme 2: Path to 100% RE with LNG, Market DG PV forecast.

Case Name	Theme 2: 100% Renewable in 2040 with LNG	Theme 2: 100% Renewable in 2040 with LNG
Case Label	49f1	49f1_lowfuel
DER Forecast	Market	Market
Fuel Price	2015 EIA Reference	February 2016 EIA STEO
2016		
2017		
2018		
2019		
2020		
2021		
2022	Install 20 MW Geo Puna Steam Deactivated	Install 20 MW Geo Puna Steam Deactivated
2023		
2024		
2025		
2026		
2027	Install 20 MW Biomass Hill 5 Deactivated	Install 20 MW Biomass Hill 5 Deactivated
2028		
2029		
2030	Install 20 MW Geo Hill 6 deactivated	Install 20 MW Geo Hill 6 deactivated
2031		
2032		
2033		
2034	Install 20 MW Wind	Install 20 MW Wind
2035		
2036		
2037		
2038	Install 20 MW Wind	Install 20 MW Wind
2039		
2040	Biofuel	Biofuel
2041		
2042		
2043		
2044		
2045		

Table K-100. Hawai'i Electric Light Cases (14 of 15)

Third Iteration, Theme 3: Path to 100% RE without LNG, Market DG PV forecast.

Case Name	Theme 3: 100% Renewable in 2040 without LNG	Theme 3: 100% Renewable in 2040 without LNG
Case Label	52t	52u
DER Forecast	Market	Market
Fuel Price	2015 EIA Reference	February 2016 EIA STEO
2016		
2017		
2018		
2019		
2020		
2021		
2022	Install 20 MW Geo Puna Steam Deactivated	Install 20 MW Geo Puna Steam Deactivated
2023		
2024		
2025		
2026		
2027	Install 20 MW Biomass Hill 5 Deactivated	Install 20 MW Biomass Hill 5 Deactivated
2028		
2029		
2030	Install 20 MW Geo Hill 6 deactivated	Install 20 MW Geo Hill 6 deactivated
2031		
2032		
2033		
2034	Install 20 MW Wind	Install 20 MW Wind
2035		
2036		
2037		
2038	Install 20 MW Wind	Install 20 MW Wind
2039		
2040	Biofuel	Biofuel
2041		
2042		
2043		
2044		
2045		

Table K-101. Hawai'i Electric Light Cases (15 of 15)

MAUI ELECTRIC

Theme 1 Cases

DG-PV Forecast	Fuel Forecast	Primary RE Type	Biofuel	Plan	Case
High DG-PV	2015 EIA Reference	Non-Firm	Biofuel & BESS		33
	2015 EIA Reference	Firm	Biofuel & BESS	Final	34
	Feb 2016 EIA STEO	Non-Firm	Biofuel & BESS		35
	Feb 2016 EIA STEO	Firm	Bio		36
	Feb 2016 EIA STEO	Firm	No BESS		45
	Feb 2016 EIA STEO	Firm	Biofuel & BESS		46
	Feb 2016 EIA STEO	Firm	Biofuel & BESS	Sensitivity on Final	55

Table K-102. Maui Theme 1 Cases

Theme 2 Cases

DG-PV Forecast	Fuel Forecast	100% RE Target	Plan	Case
Interim	Interim High	100% RE 2045	Interim	8
	Interim Low	100% RE 2045	Interim	10
High DG-PV	2015 EIA Reference	100% RE 2045		29
	2015 EIA Reference	100% RE 2040		42
	Feb 2016 EIA STEO	100% RE 2045		30
	Feb 2016 EIA STEO	100% RE 2040		41
Market DG-PV	2015 EIA Reference	100% RE 2045		24
	2015 EIA Reference	100% RE 2040		38
	2015 EIA Reference	100% RE 2040	Final	52
	Feb 2016 EIA STEO	100% RE 2045		23
	Feb 2016 EIA STEO	100% RE 2040		37
	Feb 2016 EIA STEO	100% RE 2040	Sensitivity on Final	62

Table K-103. Maui Theme 2 Cases

Theme 3 Cases

DG-PV Forecast	Fuel Forecast	100% RE Target	Plan	Case
Interim	Interim High	100% RE 2045	Interim	9
	Interim Low	100% RE 2045	Interim	11
High DG-PV	2015 EIA Reference	100% RE 2045		31
	2015 EIA Reference	100% RE 2040		44
	Feb 2016 EIA STEO	100% RE 2045		32
	Feb 2016 EIA STEO	100% RE 2040		43
Market DG-PV	2015 EIA Reference	100% RE 2045		26
	2015 EIA Reference	100% RE 2040		40
	2015 EIA Reference	100% RE 2040	Final	54
	Feb 2016 EIA STEO	100% RE 2045		25
	Feb 2016 EIA STEO	100% RE 2040		39
	Feb 2016 EIA STEO	100% RE 2040	Sensitivity on Final	53

Table K-104. Maui Theme 3 Cases

PSIP Interim Filing Cases 8 & 9: High Fuel Forecast

Case Name	Case 8	Case 9
Case Label	ICE & Geo	ICE & Geo without LNG
DER Forecast	Interim	Interim
Fuel Price	Interim High	Interim High
2016		
2017	5.74 MW of PV Projects	5.74 MW of PV Projects
2018		
2019		
2020		
2021		
2022	Install Eight - 9 MW ICE	Install Eight - 9 MW ICE
2023		
2024		
2025		
2026		
2027		
2028		
2029		
2030		
2031		
2032		
2033		
2034		
2035	Install 20 MW Geothermal	Install 20 MW Geothermal
2036		
2037		
2038		
2039	Install Two - 5 MW 4 hr BESS for Capacity	Install Two - 5 MW 4 hr BESS for Capacity
2040		
2041	Install 20 MW Geothermal	Install 20 MW Geothermal
2042		
2043		
2044		
2045		

Table K-105. Maui PSIP Interim Filing Cases 8 & 9: Interim High Fuel Forecast

PSIP Interim Filing Cases 10 & 11: Low Fuel Forecast

Case Name	Case 10	Case 11
Case Label	ICE & Geo Low Fuel	ICE & Geo Low Fuel without LNG
DER Forecast	Interim	Interim
Fuel Price	Interim Low	Interim Low
2016		
2017	5.74 MW of PV Projects	5.74 MW of PV Projects
2018		
2019		
2020		
2021		
2022	Install Eight - 9 MW ICE	Install Eight - 9 MW ICE
2023		
2024		
2025		
2026		
2027		
2028		
2029		
2030		
2031		
2032		
2033		
2034		
2035	Install 20 MW Geothermal	Install 20 MW Geothermal
2036		
2037		
2038		
2039	Install Two - 5 MW 4 hr BESS for Capacity	Install Two - 10 MW 4 hr BESS for Capacity
2040		
2041	Install 20 MW Geothermal	Install 20 MW Geothermal
2042		
2043		
2044		
2045		

Table K-106. Maui PSIP Interim Filing Cases 10 & 11: Interim Low Fuel Forecast

Maui PSIP Cases 23 & 24

Case Name	Case 23	Case 24
Case Label	MLB45	MHB45
DER Forecast	Market DG-PV	Market DG-PV
Fuel Price	Feb 2016 EIA STEO	2015 EIA Reference
2016		
2017	5.74 MW of PV Projects	5.74 MW of PV Projects
2018		
2019		
2020	Install 30 MW Future Wind	Install Two - 30 MW Future Wind
2021		
2022	Install Two - 9 MW ICE, Install 20 MW Biomass, Install 20 MW 1hr BESS for South Maui Non-Transmission Alternative	Install Two - 9 MW ICE, Install 20 MW Biomass, Install 20 MW 1hr BESS for South Maui Non-Transmission Alternative
2023		
2024		
2025		
2026		
2027		
2028		
2029		
2030		
2031		
2032		
2033		
2034		
2035		
2036		
2037		Renew 20 MW 4hr BESS with a 30 MW 6 hr BESS for Capacity
2038		
2039		
2040	Install 20 MW Biomass, Install 30 MW Future Wind	Install 20 MW Biomass, Install 30 MW Future Wind
2041		
2042		
2043		
2044		
2045	Install Four - 30 MW Future Wind, Install Three - 20 MW 1 hr BESS for Regulation	

Table K-107. Maui PSIP Cases 23 & 24

Maui PSIP Cases 25 & 26

Case Name	Case 25	Case 26
Case Label	ULB45	UHB45
DER Forecast	Market DG-PV	Market DG-PV
Fuel Price	Feb 2016 EIA STEO	2015 EIA Reference
2016		
2017	5.74 MW of PV Projects	5.74 MW of PV Projects
2018		
2019		
2020	Install Two - 30 MW Future Wind	Install Two - 30 MW Future Wind
2021		
2022	Install Two - 9 MW ICE, Install 20 MW Biomass, Install 20 MW 4 hr BESS for Capacity, Install 20 MW 1hr BESS for South Maui Non-Transmission Alternative	Install Two - 9 MW ICE, Install 20 MW Biomass, Install 30 MW Future Wind, Install 20 MW 4 hr BESS for Capacity, Install 20 MW 1hr BESS for South Maui Non-Transmission Alternative
2023		
2024		
2025	Install 30 MW Future Wind	Install 30 MW Future Wind
2026		
2027		
2028		
2029		
2030		
2031		
2032		
2033		
2034		
2035	Install 30 MW Future Wind	
2036		
2037	Renew 20 MW 4hr BESS with a 30 MW 6 hr BESS for Capacity	Renew 20 MW 4hr BESS with a 30 MW 6 hr BESS for Capacity
2038		
2039		
2040	Install 20 MW Biomass	Install 20 MW Biomass, Install 30 MW Future Wind
2041		
2042		
2043		
2044		
2045	Install Two - 30 MW Future Wind	Install Two - 30 MW Future Wind, Install Three - 20 MW Future PV

Table K-108. Maui PSIP Cases 25 & 26

Maui PSIP Cases 29 & 30

Case Name	Case 29	Case 30
Case Label	MHH45	MLH45
DER Forecast	High DG-PV	High DG-PV
Fuel Price	2015 EIA Reference	Feb 2016 EIA STEO
2016		
2017	5.74 MW of PV Projects	5.74 MW of PV Projects
2018		
2019		
2020	Install Two - 30 MW Future Wind	Install 30 MW Future Wind
2021		
2022	Install Two - 9 MW ICE, Install 20 MW Biomass, Install 20 MW 1hr BESS for South Maui Non-Transmission Alternative	Install Two - 9 MW ICE, Install 20 MW Biomass, Install 20 MW 1hr BESS for South Maui Non-Transmission Alternative
2023		
2024		
2025		
2026		
2027		
2028		
2029		
2030		
2031		
2032		
2033		
2034		
2035		
2036		
2037		Install 30 MW 6 hr BESS for Capacity
2038		
2039		
2040	Install 20 MW Biomass, Install 30 MW Future Wind	Install 20 MW Biomass
2041		
2042		
2043		
2044		
2045	Install Three - 30 MW Future Wind, Install Three - 20 MW 1 hr BESS for Regulation	Install Four - 30 MW Future Wind, Install Three - 20 MW 1 hr BESS for Regulation

Table K-109. Maui PSIP Cases 29 & 30

Maui PSIP Cases 31 & 32

Case Name	Case 31	Case 32
Case Label	UHH45	ULH45
DER Forecast	High DG-PV	High DG-PV
Fuel Price	2015 EIA Reference	Feb 2016 EIA STEO
2016		
2017	5.74 MW of PV Projects	5.74 MW of PV Projects
2018		
2019		
2020	Install Two - 30 MW Future Wind	Install Two - 30 MW Future Wind
2021		
2022	Install Two - 9 MW ICE, Install 20 MW Biomass, Install 30 MW Future Wind, Install 20 MW 4 hr BESS for Capacity, Install 20 MW 1hr BESS for South Maui Non-Transmission Alternative	Install Two - 9 MW ICE, Install 20 MW Biomass, Install 20 MW 4 hr BESS for Capacity, Install 20 MW 1hr BESS for South Maui Non-Transmission Alternative
2023		
2024		
2025	Install 30 MW Future Wind	Install 30 MW Future Wind
2026		
2027		
2028		
2029		
2030		
2031		
2032		
2033		
2034		
2035		
2036		
2037	Renew 20 MW 4hr BESS with a 30 MW 6 hr BESS for Capacity	Renew 20 MW 4hr BESS with a 30 MW 6 hr BESS for Capacity
2038		
2039		
2040	Install 20 MW Biomass, Install 30 MW Future Wind	Install 20 MW Biomass
2041		
2042		
2043		
2044		
2045	Install 30 MW Future Wind, Install Two - 20 MW Future PV	Install 30 MW Future Wind, Install Three - 20 MW Future PV

Table K-110. Maui PSIP Cases 31 & 32

Maui PSIP Cases 33 & 34

Case Name	Case 33	Case 34
Case Label	THH30AABioBESS	THH30BioBESS
DER Forecast	High DG-PV	High DG-PV
Fuel Price	2015 EIA Reference	2015 EIA Reference
2016		
2017	5.74 MW of PV Projects	5.74 MW of PV Projects
2018		
2019		
2020	Install 30 MW Future Wind	Install 30 MW Future Wind
2021		
2022	Install 30 MW Pumped Storage Hydro, Install 20 MW Biomass, Install 20 MW 1hr BESS for South Maui Non-Transmission Alternative	Install 30 MW Pumped Storage Hydro, Install 20 MW Biomass, Install 20 MW 1hr BESS for South Maui Non-Transmission Alternative
2023		
2024		
2025		
2026		
2027		
2028		
2029		
2030	Install Five - 30 MW Future Wind, Install Two - 20 MW Biomass, Install 30 MW 6 hr BESS for Load Shifting	Install Two - 20 MW Geothermal, Install Two - 20 MW Biomass
2031		
2032		
2033		
2034		
2035	Install 30 MW Future Wind	
2036		
2037		
2038		
2039		
2040	Install 30 MW Future Wind	Install 30 MW Future Wind
2041		
2042		
2043		
2044		
2045	Install 30 MW Future Wind, Install Three - 20 MW 1 hr BESS for Regulation	Install 30 MW Future Wind, Install Three - 20 MW 1 hr BESS for Regulation

Table K-111. Maui PSIP Cases 33 & 34

Maui PSIP Cases 35 & 36

Case Name	Case 35	Case 36
Case Label	TLH30AABioBESS	TLH30
DER Forecast	High DG-PV	High DG-PV
Fuel Price	Feb 2016 EIA STEO	Feb 2016 EIA STEO
2016		
2017	5.74 MW of PV Projects	5.74 MW of PV Projects
2018		
2019		
2020	Install 30 MW Future Wind	Install 30 MW Future Wind
2021		
2022	Install 30 MW Pumped Storage Hydro, Install 20 MW Biomass, Install 20 MW 1hr BESS for South Maui Non-Transmission Alternative	Install 30 MW Pumped Storage Hydro, Install 20 MW Biomass, Install 20 MW 1hr BESS for South Maui Non-Transmission Alternative
2023		
2024		
2025		
2026		
2027		
2028		
2029		
2030	Install Five - 30 MW Future Wind, Install Two - 20 MW Biomass, Install 30 MW 6 hr BESS for Load Shifting	Install Two - 20 MW Geothermal, Install Two - 20 MW Biomass, Install Sixteen - 30 MW 6 hr BESS for Load Shifting
2031		
2032		
2033		
2034		
2035	Install 30 MW Future Wind	Install Four - 30 MW 6 hr BESS for Load Shifting
2036		
2037		
2038		
2039		
2040	Install 30 MW Future Wind	Install 30 MW Future Wind, Install Four - 30 MW 6 hr BESS for Load Shifting
2041		
2042		
2043		
2044		
2045	Install 30 MW Future Wind, Install Three - 20 MW 1 hr BESS for Regulation	Install Two - 30 MW Future Wind, Install Twelve - 30 MW 6 hr BESS for Load Shifting

Table K-112. Maui PSIP Cases 35 & 36

Maui PSIP Cases 37 & 38

Case Name	Case37	Case 38
Case Label	MLB40	MHB40
DER Forecast	Market DG-PV	Market DG-PV
Fuel Price	Feb 2016 EIA STEO	2015 EIA Reference
2016		
2017	5.74 MW of PV Projects	5.74 MW of PV Projects
2018		
2019		
2020	Install 30 MW Future Wind	Install Two - 30 MW Future Wind
2021		
2022	Install Two - 9 MW ICE, Install 20 MW Biomass, Install 20 MW 1hr BESS for South Maui Non-Transmission Alternative	Install Two - 9 MW ICE, Install 20 MW Biomass, Install 20 MW 1hr BESS for South Maui Non-Transmission Alternative
2023	Convert K2 & K4 to Synchronous Condensers	Convert K2 & K4 to Synchronous Condensers
2024		
2025		
2026		
2027		
2028		
2029		
2030		
2031		
2032		
2033		
2034		
2035		
2036		
2037	Install 30 MW 6 hr BESS for Capacity	Install 30 MW 6 hr BESS for Capacity
2038		
2039		
2040	Install 20 MW Biomass, Install 30 MW Future Wind	Install 20 MW Biomass, Install 30 MW Future Wind
2041		
2042		
2043		
2044		
2045	Install Four - 30 MW Future Wind, Install Three - 20 MW 1 hr BESS for Regulation	Install Four -30 MW Future Wind, Install Three - 20 MW Future PV Install Three - 20 MW 1 hr BESS for Regulation

Table K-113. Maui PSIP Cases 37 & 38

Maui PSIP Cases 39 & 40

Case Name	Case 39	Case 40
Case Label	ULB40	UHB40
DER Forecast	Market DG-PV	Market DG-PV
Fuel Price	Feb 2016 EIA STEO	2015 EIA Reference
2016		
2017	5.74 MW of PV Projects	5.74 MW of PV Projects
2018		
2019		
2020	Install Two - 30 MW Future Wind	Install Two - 30 MW Future Wind
2021		
2022	Install Two - 9 MW ICE, Install 20 MW Biomass, Install 20 MW 1hr BESS for South Maui Non-Transmission Alternative	Install Two - 9 MW ICE, Install 20 MW Biomass, Install 30 MW Future Wind, Install 20 MW 4 hr BESS for Capacity, Install 20 MW 1hr BESS for South Maui Non-Transmission Alternative
2023		
2024		
2025	Install 30 MW Future Wind	Install 30 MW Future Wind
2026		
2027		
2028		
2029		
2030		
2031		
2032		
2033		
2034		
2035	Install 30 MW Future Wind	
2036		
2037		Renew 20 MW 4hr BESS with a 30 MW 6 hr BESS for Capacity
2038		
2039		
2040	Install 20 MW Biomass	Install 20 MW Biomass, Install 30 MW Future Wind
2041		
2042		
2043		
2044		
2045	Install Two - 30 MW Future Wind	Install 30 MW Future Wind, Install Three - 20 MW Future PV

Table K-114. Maui PSIP Cases 39 & 40

Maui PSIP Cases 41 & 42

Case Name	Case 41	Case 42
Case Label	MLH40	MHH40
DER Forecast	High DG-PV	High DG-PV
Fuel Price	2015 EIA Reference	Feb 2016 EIA STEO
2016		
2017	5.74 MW of PV Projects	5.74 MW of PV Projects
2018		
2019		
2020	Install 30 MW Future Wind	Install Two - 30 MW Future Wind
2021		
2022	Install Two - 9 MW ICE, Install 20 MW Biomass, Install 20 MW 1hr BESS for South Maui Non-Transmission Alternative	Install Two - 9 MW ICE, Install 20 MW Biomass, Install 20 MW 1hr BESS for South Maui Non-Transmission Alternative
2023		
2024		
2025		
2026		
2027		
2028		
2029		
2030		
2031		
2032		
2033		
2034		
2035		
2036		
2037	Install 30 MW 6 hr BESS for Capacity	Install 30 MW 6 hr BESS for Capacity
2038		
2039		
2040	Install 20 MW Biomass, Install 30 MW Future Wind	Install 20 MW Biomass
2041		
2042		
2043		
2044		
2045	Install Three - 30 MW Future Wind, Install Three - 20 MW 1 hr BESS for Regulation	Install Three - 30 MW Future Wind, Install Three - 20 MW 1 hr BESS for Regulation

Table K-115. Maui PSIP Cases 41 & 42

Maui PSIP Cases 43 & 44

Case Name	Case 43	Case 44
Case Label	ULH40	UHH40
DER Forecast	High DG-PV	High DG-PV
Fuel Price	2015 EIA Reference	Feb 2016 EIA STEO
2016		
2017	5.74 MW of PV Projects	5.74 MW of PV Projects
2018		
2019		
2020	Install Two - 30 MW Future Wind	Install Two - 30 MW Future Wind
2021		
2022	Install Two - 9 MW ICE, Install 20 MW Biomass, Install 20 MW 4 hr BESS for Capacity, Install 20 MW 1hr BESS for South Maui Non-Transmission Alternative	Install Two - 9 MW ICE, Install 20 MW Biomass, Install 30 MW Future Wind, Install 20 MW 1hr BESS for South Maui Non-Transmission Alternative
2023		
2024		
2025	Install 30 MW Future Wind	Install 30 MW Future Wind
2026		
2027		
2028		
2029		
2030		
2031		
2032		
2033		
2034		
2035	Install 30 MW Future Wind	
2036		
2037	Renew 20 MW 4hr BESS with a 30 MW 6 hr BESS for Capacity	
2038		
2039		
2040	Install 20 MW Biomass	Install 20 MW Biomass, Install 30 MW Future Wind
2041		
2042		
2043		
2044		
2045	Install 30 MW Future Wind	Install 30 MW Future Wind, Install Three - 20 MW Future PV

Table K-116. Maui PSIP Cases 43 & 44

Maui PSIP Cases 45 & 46

Case Name	Case 45	Case 46
Case Label	TLH30Bio	TLH30BioBESS
DER Forecast	High DG-PV	High DG-PV
Fuel Price	Feb 2016 EIA STEO	Feb 2016 EIA STEO
2016		
2017	5.74 MW of PV Projects	5.74 MW of PV Projects
2018		
2019		
2020	Install 30 MW Future Wind	Install 30 MW Future Wind
2021		
2022	Install 30 MW Pumped Storage Hydro, Install 20 MW Biomass, Install 20 MW 1hr BESS for South Maui Non-Transmission Alternative	Install 30 MW Pumped Storage Hydro, Install 20 MW Biomass, Install 20 MW 1hr BESS for South Maui Non-Transmission Alternative
2023		
2024		
2025		
2026		
2027		
2028		
2029		
2030	Install Two - 20 MW Geothermal, Install Two - 20 MW Biomass	Install Two - 20 MW Geothermal, Install Two - 20 MW Biomass, Install Two - 30 MW 6 hr BESS for Load Shifting
2031		
2032		
2033		
2034		
2035		Install 30 MW 6 hr BESS for Load Shifting
2036		
2037		
2038		
2039		
2040	Install 30 MW Future Wind	Install 30 MW Future Wind
2041		
2042		
2043		
2044		
2045	Install Two - 30 MW Future Wind, Install 20 MW 1 hr BESS for Regulation	Install Two - 30 MW Future Wind

Table K-117. Maui PSIP Cases 45 & 46

Maui PSIP Final Theme 1 Cases 34 & 55

Case Name	Case 34	Case 55
Case Label	THH30BioBESS	TLH30BioBESS
DER Forecast	High DG-PV	High DG-PV
Fuel Price	2015 EIA Reference	Feb 2016 EIA STEO
2016		
2017	5.74 MW of PV Projects	5.74 MW of PV Projects
2018		
2019		
2020	Install 30 MW Future Wind	Install 30 MW Future Wind
2021		
2022	Install 30 MW Pumped Storage Hydro, Install 20 MW Biomass, Install 20 MW 1hr BESS for South Maui Non-Transmission Alternative Install two - 30 MW Synchronous Condenser (Maalaea)	Install 30 MW Pumped Storage Hydro, Install 20 MW Biomass, Install 20 MW 1hr BESS for South Maui Non-Transmission Alternative Install two - 30 MW Synchronous Condenser (Maalaea)
2023	Convert K1, K2, K3, K4 to Synchronous Condensers	Convert K1, K2, K3, K4 to Synchronous Condensers
2024		
2025		
2026		
2027		
2028		
2029		
2030	Install Two - 20 MW Geothermal, Install Two - 20 MW Biomass	Install Two - 20 MW Geothermal, Install Two - 20 MW Biomass
2031		
2032		
2033		
2034		
2035		
2036		
2037		
2038		
2039		
2040	Install 30 MW Future Wind	Install 30 MW Future Wind
2041		
2042		
2043		
2044		
2045	Install 30 MW Future Wind, Install Three - 20 MW 1 hr BESS for Regulation	Install 30 MW Future Wind, Install Three - 20 MW 1 hr BESS for Regulation

Table K-118. Maui PSIP Final Theme 1 Cases 34 & 55

Maui PSIP Final Theme 2 Cases 52 & 62

Case Name	Case 52	Case 62
Case Label	MHB40	MLB40
DER Forecast	Market DG-PV	Market DG-PV
Fuel Price	2015 EIA Reference	Feb 2016 EIA STEO
2016		
2017	5.74 MW of PV Projects	5.74 MW of PV Projects
2018		
2019		
2020	Install Two - 30 MW Future Wind	Install Two - 30 MW Future Wind
2021		
2022	Install Two - 9 MW ICE, Install 20 MW Biomass, Install 20 MW 4 hr BESS for Capacity, Install 20 MW 1hr BESS for South Maui Non-Transmission Alternative Install two - 30 MW Synchronous Condenser (Maalaea)	Install Two - 9 MW ICE, Install 20 MW Biomass, 20 MW 4 hr BESS for Capacity, Install 20 MW 1hr BESS for South Maui Non-Transmission Alternative Install two - 30 MW Synchronous Condenser (Maalaea)
2023	Convert K1, K2, K3, K4 to Synchronous Condensers	Convert K1, K2, K3, K4 to Synchronous Condensers
2024		
2025		
2026		
2027		
2028		
2029		
2030		
2031		
2032		
2033		
2034		
2035		
2036		
2037	Renew 20 MW 4hr BESS with a 30 MW 6 hr BESS for Capacity	Renew 20 MW 4hr BESS with a 30 MW 6 hr BESS for Capacity
2038		
2039		
2040	Install 20 MW Biomass, Install Two - 20 MW Geothermal, Install Four - 30 MW Future Wind Install Two - 20 MW 1hr BESS for Regulation	Install 20 MW Biomass, Install Two - 20 MW Geothermal, Install Four - 30 MW Future Wind Install Two - 20 MW 1hr BESS for Regulation
2041		
2042		
2043		
2044		
2045	Install 30 MW Future Wind, Install Two - 20 MW Future PV	Install 30 MW Future Wind, Install Two - 20 MW Future PV

Table K-119. Maui PSIP Final Theme 2 Cases 52 & 62

Maui PSIP Final Theme 2 Cases 54 & 53

Case Name	Case 54	Case 53
Case Label	UHB40	ULB40
DER Forecast	Market DG-PV	Market DG-PV
Fuel Price	2015 EIA Reference	Feb 2016 EIA STEO
2016		
2017	5.74 MW of PV Projects	5.74 MW of PV Projects
2018		
2019		
2020	Install Two - 30 MW Future Wind	Install Two - 30 MW Future Wind
2021		
2022	Install Two - 9 MW ICE, Install 20 MW Biomass, Install 30 MW Future Wind, Install 20 MW 4 hr BESS for Capacity, Install 20 MW 1hr BESS for South Maui Non-Transmission Alternative Install two - 30 MW Synchronous Condenser (Maalaea)	Install Two - 9 MW ICE, Install 20 MW Biomass, Install 30 MW Future Wind, Install 20 MW 4 hr BESS for Capacity, Install 20 MW 1hr BESS for South Maui Non-Transmission Alternative Install two - 30 MW Synchronous Condenser (Maalaea)
2023	Convert K1, K2, K3, K4 to Synchronous Condensers	Convert K1, K2, K3, K4 to Synchronous Condensers
2024		
2025	Install 30 MW Future Wind	Install 30 MW Future Wind
2026		
2027		
2028		
2029		
2030		
2031		
2032		
2033		
2034		
2035		
2036		
2037	Renew 20 MW 4hr BESS with a 30 MW 6 hr BESS for Capacity	Renew 20 MW 4hr BESS with a 30 MW 6 hr BESS for Capacity
2038		
2039		
2040	Install 20 MW Biomass, Install Two - 20 MW Geothermal, Install Two - 30 MW Future Wind Install Two - 20 MW 1hr BESS for Regulation	Install 20 MW Biomass, Install Two - 20 MW Geothermal, Install Two - 30 MW Future Wind Install Two - 20 MW 1hr BESS for Regulation
2041		
2042		
2043		
2044		
2045	Install 30 MW Future Wind, Install Two - 20 MW Future PV	Install 30 MW Future Wind, Install Two - 20 MW Future PV

Table K-120. Maui PSIP Final Theme 2 Cases 54 & 53

Lana'i Cases

Theme 1

DG-PV Forecast	Fuel Forecast	Biomass	Must Run	BESS	Plan	Case
High DG-PV	2015 EIA Reference	Yes	Yes	Yes		1
	2015 EIA Reference	No	Yes	Yes		2
	2015 EIA Reference	No	No	Yes		3
	Feb 2016 EIA STEO	Yes	Yes	Yes		5
	Feb 2016 EIA STEO	No	Yes	Yes		6
	Feb 2016 EIA STEO	No	No	No	Sensitivity on Final	11
	2015 EIA Reference	No	No	No	Final	12

Table K-121. Lana'i Theme 1 Cases

Theme 3

DG-PV Forecast	Fuel Forecast	Biomass	Must Run	BESS	Plan	Case
High DG-PV	2015 EIA Reference	Yes	Yes	Yes		9
	Feb 2016 EIA STEO	Yes	Yes	Yes		10
Market DG-PV	2015 EIA Reference	No	Yes	No		7
	Feb 2016 EIA STEO	No	Yes	No		8
	2015 EIA Reference	No	No	No	Final	13
	Feb 2016 EIA STEO	No	No	No	Sensitivity on Final	14

Table K-122. Lana'i Theme 3 Cases

Lana‘i Cases 1 & 2

Case Name	Case 1	Case 2
Case Label		
DER Forecast	High DG-PV	High DG-PV
Fuel Price	2015 EIA Reference	2015 EIA Reference
2016		
2017		
2018		
2019		
2020	2 MW Wind	2 MW Wind
2021		
2022		
2023		
2024		
2025		
2026		
2027		
2028		
2029		
2030	1 MW Biomass	
2031		
2032		
2033		
2034		
2035		
2036		
2037		
2038		
2039		
2040	1 MW Wind, 1 MW 4 hr LS BESS	1 MW Wind, 1 MW 4 hr LS BESS
2041		
2042		
2043		
2044		
2045	1 MW Wind	1 MW 4 hr LS BESS

Table K-123. Lana‘i Cases 1 & 2

Lana'i Cases 3 & 4

Case Name	Case 3	Case 4
Case Label		
DER Forecast	High DG-PV	High DG-PV
Fuel Price	2015 EIA Reference	Feb 2016 EIA STEO
2016		
2017		
2018		
2019		
2020	3 MW Wind	2 MW Wind
2021		
2022		
2023		
2024		
2025		
2026		
2027		
2028		
2029		
2030	1 MW Wind	1 MW Biomass
2031		
2032		
2033		
2034		
2035		
2036		
2037		
2038		
2039		
2040	1 MW 4 hr LS BESS	1 MW 4 hr LS BESS
2041		
2042		
2043		
2044		
2045	1 MW Wind	1 MW Wind

Table K-124. Lana'i Cases 3 & 4

Lana'i Cases 5 & 6

Case Name	Case 5	Case 6
Case Label		
DER Forecast	High DG-PV	High DG-PV
Fuel Price	Feb 2016 EIA STEO	Feb 2016 EIA STEO
2016		
2017		
2018		
2019		
2020	2 MW Wind	3 MW Wind
2021		
2022		
2023		
2024		
2025		
2026		
2027		
2028		
2029		
2030		
2031		
2032		
2033		
2034		
2035		
2036		
2037		
2038		
2039		
2040	1 MW 4 hr LS BESS	1 MW Wind
2041		
2042		
2043		
2044		
2045	1 MW Wind	1 MW 4 hr LS BESS

Table K-125. Lana'i Cases 5 & 6

Lana'i Cases 7 & 8

Case Name	Case 7	Case 8
Case Label		
DER Forecast	Market DG-PV	Market DG-PV
Fuel Price	2015 EIA Reference	Feb 2016 EIA STEO
2016		
2017		
2018		
2019		
2020	2 MW Wind	2 MW Wind
2021		
2022		
2023		
2024		
2025		
2026		
2027		
2028		
2029		
2030	1 MW Wind	
2031		
2032		
2033		
2034		
2035		
2036		
2037		
2038		
2039		
2040		1 MW Wind
2041		
2042		
2043		
2044		
2045	1 MW Wind	

Table K-126. Lana'i Cases 7 & 8

Lanaʻi Cases 9 & 10

Case Name	Case 9	Case 10
Case Label		
DER Forecast	High DG-PV	High DG-PV
Fuel Price	2015 EIA Reference	Feb 2016 EIA STEO
2016		
2017		
2018		
2019		
2020	2 MW Wind	2 MW Wind
2021		
2022		
2023		
2024		
2025		
2026		
2027		
2028		
2029		
2030	1 MW Biomass	1 MW Biomass
2031		
2032		
2033		
2034		
2035		
2036		
2037		
2038		
2039		
2040	1 MW Wind, 1 MW 4 hr LS BESS	1 MW 4 hr LS BESS
2041		
2042		
2043		
2044		
2045	1 MW 4 hr LS BESS	1 MW Wind

Table K-127. Lanaʻi Cases 9 & 10

Lana'i Final Theme 1 Cases 11 & 12

Case Name	Case 11	Case 12
Case Label		
DER Forecast	High DG-PV	High DG-PV
Fuel Price	Feb 2016 EIA STEO	2015 EIA Reference
2016		
2017		
2018		
2019	Install two - 5 MVA Synchronous Condenser	Install two - 5 MVA Synchronous Condenser
2020	3 MW Wind	3 MW Wind
2021		
2022		
2023		
2024		
2025		
2026		
2027		
2028		
2029		
2030	1 MW Wind	1 MW Wind
2031		
2032		
2033		
2034		
2035		
2036		
2037		
2038		
2039		
2040		
2041		
2042		
2043		
2044		
2045	1 MW Wind	1 MW Wind

Table K-128. Lana'i Final Theme 1 Cases 11 & 12

Lana'i Final Theme 3 Cases 13 & 14

Case Name	Case 13	Case 14
Case Label		
DER Forecast	Market DG-PV	Market DG-PV
Fuel Price	2015 EIA Reference	Feb 2016 EIA STEO
2016		
2017		
2018		
2019	Install two - 5 MVA Synchronous Condenser	Install two - 5 MVA Synchronous Condenser
2020	3MW Wind	3MW Wind
2021		
2022		
2023		
2024		
2025		
2026		
2027		
2028		
2029		
2030	1 MW Wind	1 MW Wind
2031		
2032		
2033		
2034		
2035		
2036		
2037		
2038		
2039		
2040	1 MW Wind	1 MW Wind
2041		
2042		
2043		
2044		
2045		

Table K-129. Lana'i Final Theme 3 Cases 13 & 14

Moloka'i Cases

Theme 1

DG-PV Forecast	Fuel Forecast	Biomass	Must Run	BESS	Plan	Case
High DG-PV	2015 EIA Reference	Yes	Yes	Yes		1
	2015 EIA Reference	No	Yes	Yes		2
	2015 EIA Reference	No	No	Yes		3
	Feb 2016 EIA STEO	Yes	Yes	No		4
	Feb 2016 EIA STEO	No	Yes	No		5
	Feb 2016 EIA STEO	No	No	No		6
	Feb 2016 EIA STEO	No	No	Yes		11
	2015 EIA Reference	No	No	No	Final	16
	Feb 2016 EIA STEO	No	No	No	Sensitivity on Final	17

Table K-130. Moloka'i Theme 1 Cases

Theme 3

DG-PV Forecast	Fuel Forecast	Biomass	Must Run	BESS	Plan	Case
High DG-PV	2015 EIA Reference	Yes	Yes	Yes		9
	Feb 2016 EIA STEO	Yes	Yes	No		10
Market DG-PV	2015 EIA Reference	No	Yes	Yes		7
	Feb 2016 EIA STEO	No	Yes	No		8
	Feb 2016 EIA STEO	No	No	Yes		12
	2015 EIA Reference	No	No	Yes		13
	Feb 2016 EIA STEO	No	No	No	Sensitivity on Final	14
	2015 EIA Reference	No	No	No	Final	15

Table K-131. Moloka'i Theme 3 Cases

Moloka‘i Cases 1 & 2

Case Name	Case 1	Case 2
Case Label		
DER Forecast	High DG-PV	High DG-PV
Fuel Price	2015 EIA Reference	2015 EIA Reference
2016		
2017		
2018		
2019		
2020	4 MW Wind	4 MW Wind
2021		
2022		
2023		
2024		
2025		
2026		
2027		
2028		
2029		
2030	1 MW Biomass	
2031		
2032		
2033		
2034		
2035		
2036		
2037		
2038		
2039		
2040	1 MW 4 hr LS BESS	1 MW 4 hr LS BESS
2041		
2042		
2043		
2044		
2045		1 MW 4 hr LS BESS

Table K-132. Moloka‘i Cases 1 & 2

Moloka'i Cases 3 & 4

Case Name	Case 3	Case 4
Case Label		
DER Forecast	High DG-PV	High DG-PV
Fuel Price	2015 EIA Reference	Feb 2016 EIA STEO
2016		
2017		
2018		
2019		
2020	5 MW Wind	3 MW Wind
2021		
2022		
2023		
2024		
2025		
2026		
2027		
2028		
2029		
2030		1 MW Biomass
2031		
2032		
2033		
2034		
2035		
2036		
2037		
2038		
2039		
2040	1 MW 4 hr LS BESS	
2041		
2042		
2043		
2044		
2045		

Table K-133. Moloka'i Cases 3 & 4

Moloka'i Cases 5 & 6

Case Name	Case 5	Case 6
Case Label		
DER Forecast	High DG-PV	High DG-PV
Fuel Price	Feb 2016 EIA STEO	Feb 2016 EIA STEO
2016		
2017		
2018		
2019		
2020	3 MW Wind	4 MW Wind
2021		
2022		
2023		
2024		
2025		
2026		
2027		
2028		
2029		
2030		
2031		
2032		
2033		
2034		
2035		
2036		
2037		
2038		
2039		
2040		
2041		
2042		
2043		
2044		
2045	1 MW Wind	

Table K-134. Moloka'i Cases 5 & 6

Moloka'i Cases 7 & 8

Case Name	Case 7	Case 8
Case Label		
DER Forecast	Market DG-PV	Market DG-PV
Fuel Price	2015 EIA Reference	Feb 2016 EIA STEO
2016		
2017		
2018		
2019		
2020	4 MW Wind	3 MW Wind
2021		
2022		
2023		
2024		
2025		
2026		
2027		
2028		
2029		
2030		
2031		
2032		
2033		
2034		
2035		
2036		
2037		
2038		
2039		
2040	1 MW 4 hr LS BESS	1 MW Wind
2041		
2042		
2043		
2044		
2045		

Table K-135. Moloka'i Cases 7 & 8

Moloka'i Cases 9 & 10

Case Name	Case 9	Case 10
Case Label		
DER Forecast	High DG-PV	High DG-PV
Fuel Price	2015 EIA Reference	Feb 2016 EIA STEO
2016		
2017		
2018		
2019		
2020	4 MW Wind	3 MW Wind
2021		
2022		
2023		
2024		
2025		
2026		
2027		
2028		
2029		
2030	1 MW Biomass	1 MW Biomass
2031		
2032		
2033		
2034		
2035		
2036		
2037		
2038		
2039		
2040	1 MW 4 hr LS BESS	
2041		
2042		
2043		
2044		
2045		

Table K-136. Moloka'i Cases 9 & 10

Moloka'i Cases 11, 12, & 13

Case Name	Case 11	Case 12	Case 13
Case Label			
DER Forecast	High DG-PV	Market DG-PV	Market DG-PV
Fuel Price	Feb 2016 EIA STEO	Feb 2016 EIA STEO	2015 EIA Reference
2016			
2017			
2018			
2019			
2020	5 MW Wind	5MW Wind	5MW Wind
2021			
2022			
2023			
2024			
2025			
2026			
2027			
2028			
2029			
2030			
2031			
2032			
2033			
2034			
2035			
2036			
2037			
2038			
2039			
2040	1 MW 4 hr LS BESS	1 MW 4 hr LS BESS	1 MW 4 hr LS BESS
2041			
2042			
2043			
2044			
2045		1MW Wind	1MW Wind

Table K-137. Moloka'i Cases 11, 12, & 13

Moloka'i Final Theme 1 Cases 16 & 17

Case Name	Case 16	Case 17
Case Label		
DER Forecast	High DG-PV	High DG-PV
Fuel Price	2015 EIA Reference	Feb 2016 EIA STEO
2016		
2017		
2018	Install two - 5 MVA Synchronous Condenser	Install two - 5 MVA Synchronous Condenser
2019		
2020	5 MW Wind	5 MW Wind
2021		
2022		
2023		
2024		
2025		
2026		
2027		
2028		
2029		
2030		
2031		
2032		
2033		
2034		
2035		
2036		
2037		
2038		
2039		
2040		
2041		
2042		
2043		
2044		
2045		

Table K-138. Moloka'i Final Theme 1 Cases 16 & 17

Moloka‘i Final Theme 3 Cases 14 & 15

Case Name	Case 14	Case 15
Case Label		
DER Forecast	Market DG-PV	Market DG-PV
Fuel Price	Feb 2016 EIA STEO	2015 EIA Reference
2016		
2017		
2018	Install two - 5 MVA Synchronous Condenser	Install two - 5 MVA Synchronous Condenser
2019		
2020	5MW Wind	5MW Wind
2021		
2022		
2023		
2024		
2025		
2026		
2027		
2028		
2029		
2030		
2031		
2032		
2033		
2034		
2035		
2036		
2037		
2038		
2039		
2040		
2041		
2042		
2043		
2044		
2045	1MW Wind	1MW Wind

Table K-139. Moloka‘i Final Theme 3 Cases 14 & 15

L. EPRI Reserve Determination

HECO/EPRI RESERVE DETERMINATION 2015/2016 PROJECT SUMMARY

The overall goal of this project is to use methods developed by EPRI as part of their research into the impacts of wind and solar on system operations to propose a new HECO method for determining operating reserve requirements. Since HECO is an island system with high sensitivity to frequency swings compared to mainland interconnections, the project is focused on short-term frequency regulating reserve. Using a multi-cycle power system operations model (one that simulates the multiple decision-making procedures taken in real operations), the study will analyze costs, area control error (ACE) and frequency with the current reserve requirement determination method and the proposed reserve method. This will be done for both current and future renewable penetration on the Oahu system. The study will also look at sensitivities including utilization of battery energy storage and use of regulation reserve during renewable ramping periods combined with a generating contingency event.

Using multi-cycle models to represent the various decisions made by HECO operators, and stochastic representation of wind, solar, load and outages, short term operations are being examined. This will allow for better understanding of how reserves are currently being used, and how new methods, including those based on the stochastic nature of wind, solar and load, could improve upon the optimal amount of reserve needed for the system. The findings from this study will inform the development of new short term operational tools to manage wind and solar variability and uncertainty. This may include conditional rules for procurement and deployment of reserves. It is also expected to examine the operation of a battery storage unit that will be installed and used for providing reserves. By adding progressively more detail to the model, each of the above can be examined. At the end of the project, EPRI will work with HECO to ensure that lessons learned can be transferred to operating practices and their EMS tools. The aim is not, however, to develop online operating tools, but rather examine some of the potential operating solutions through realistic simulations.

The team is using the FESTIV simulation tool which incorporates unit commitment, economic dispatch, automatic generation control, and contingency-based operator action. The tool is unique in being able to simulate the long-term scheduling and commitment of resources days and hours ahead, while also simulating the fast second-to-second control and frequency impacts of the system. So far, the following work has been accomplished to date:

- The team has collected 8 weeks of high-resolution load, conventional generation and renewable data and constructed the input files necessary to run the simulation tool
- The team has developed a module to better simulate frequency of the HECO system using the HECO frequency bias and ACE.
- The team has developed a module to mimic HECO's "equal lambda criterion" AGC simulation model, which determines production levels based on HECO generator quadratic cost functions.
- The team has incorporated numerous reliability must run, derate, and other specific rules to benchmark unit generation, frequency, and ACE.
- The team has performed simulations of all 8 weeks using the base case reserve requirement method.

Going forward the team will be analyzing the frequency and ACE impacts of all 8 weeks with the current reserve methodology, the EPS-proposed reserve methodology, and the EPRI research reserve methodology. The team is also evaluating the impact of allowing all units but Kahe5 and Kahe6 as flexible (rather than must-run) to understand how this will change the benefits and impacts of the reserve methodologies. It will evaluate the periods where greater imbalance was occurring, and using probabilistic renewable generation forecasts and variability statistics, propose a reserve requirement determination method with improved performance based on economic or reliability factors. All but the EPRI research reserve methodology will be completed by the end of March. A preliminary evaluation of the benefits of implementing the EPRI methodology is expecting by the end of Q2 2016, and the final analysis and report for the entire effort is expected by end of Q4 2016.

Assessment of EPS Reserve Methodology

Here we provide an assessment of the EPS proposed reserve methodology based on the report "Proposed HECO Regulation – From Measured Wind and Estimated Solar Data" published August 5, 2014 and provided to EPRI by HECO. Based on a high-level review of the proposed approach, EPRI's assessment indicates a more efficient reserve procurement approach can be specified while still maintaining a satisfactory level of reliability. We describe suggestions on improvements below in four improvement categories.

Improvement 1: Assumption of correlation of wind and solar, and with load

In the EPS proposal, the total regulation requirement is given in terms of separate requirements for wind and solar, based on covering large ramps of each type of resource. By adding the separate requirements for covering wind and PV ramping in isolation to get to total required regulation, the method is essentially assuming that wind and solar are perfectly correlated (i.e., the largest wind ramp will happen at the same time as the largest solar ramp). Just as the EPS proposed method calculates reserve requirements based on total wind or total solar rather than summing up the requirement to cover the ramping of individual wind plants and individual solar plants, the reserve determination requirement should consider the total ramp from total renewables based on output level rather than each technology individually. For example, it may be that the EPS method requires substantial regulation requirement to cover wind ramps that are ramping down during a period when solar is ramping up such that the net variability is not as significant. Similarly, the reserve requirement should also be evaluated with load to cover the net load variability and not just the aggregate renewable ramping. Requirements can use multi-dimensional lookup tables for regulation requirements (e.g., for particular wind, solar, and load conditions, carry X MW of regulation reserve). With further analysis, this enhancement to the method can reduce the amount of reserve while having negligible reliability impacts. This would involve looking at the relationship between wind, solar and load variability and, based on this relationship, developing a requirement to cover the maximum largest ramps. One of the key challenges here will be ensuring sufficient representative data is available such that the worst case events can be identified; if there is not sufficient confidence in this, then some margin may be needed above the amount that data analysis may identify as needed.

Improvement 2: 1:1 Ratio and Percentage Level cap

The EPS approach seems to use a 1:1 approach that requires 1 MW of reserve for every MW of production, up to a certain percentage level of wind or solar, above which no incremental reserve requirements are needed. We were unable to determine why these approaches were taken based on the data available to EPRI; the use of 1:1 ratios and the cap percentage above which no more is needed both seem arbitrary. The figure below shows that application of the EPS requirement in red for PV ramping data from MECO results in holding more than twice the reserve required to cover ramps for some lower PV levels and a deficit in reserve to fully cover PV ramps for some higher PV levels . Even if the system required 100% compliance of meeting the 20-minute ramp, a segmented curve that doesn't keep the arbitrary 1:1 ratio can be used as shown below in yellow. This would meet all of the historical ramps based on the data shown, such that over-procuring reserve requirements would be significantly reduced. Even if a margin is desired, it can be seen that the yellow line is significantly lower at lower PV output. Applying a segmented reserve requirement curve approach for each operating company may reduce costs by reducing unnecessary reserves while providing greater compliance by covering ramp events between 20 and 30 MW outputs in this example that wouldn't have been guaranteed in the previous method.

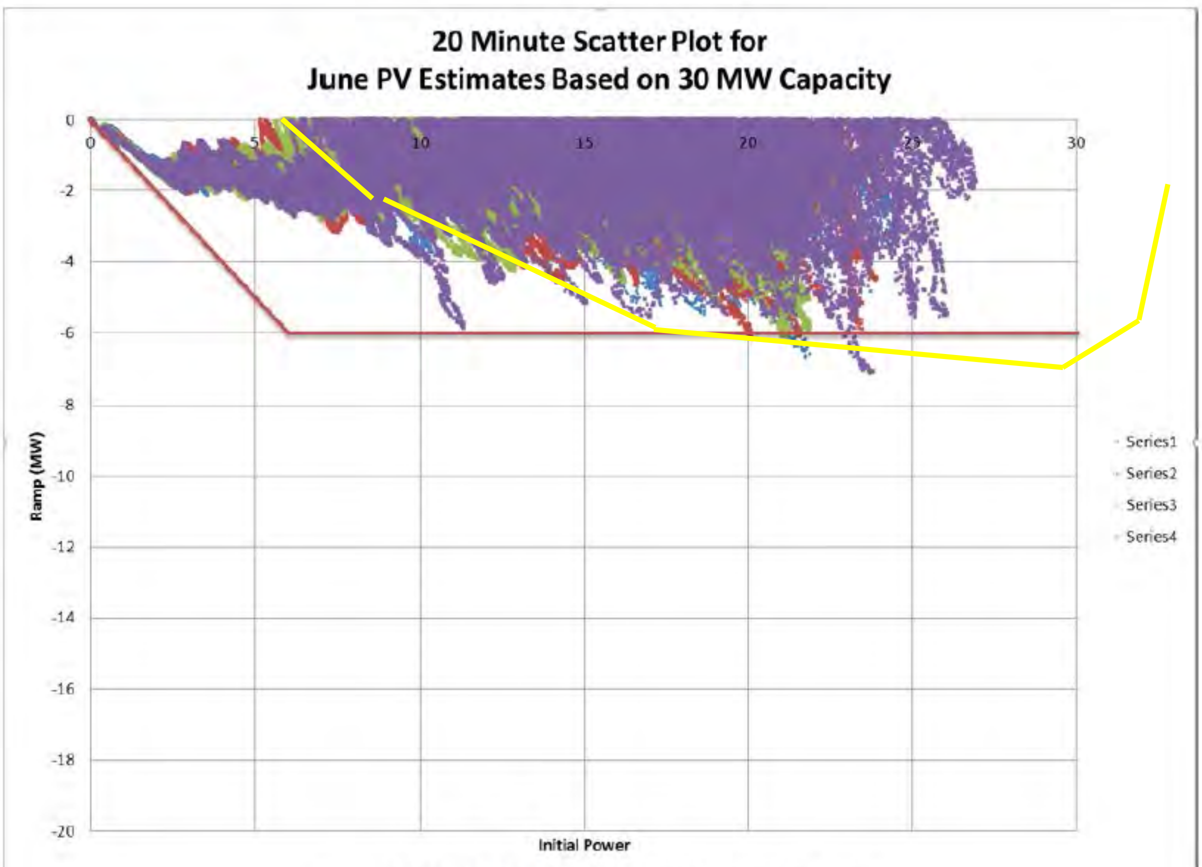


Figure 4 : MECO 20-Minute Solar Ramps for June

Improvement 3: 100% compliance assumption

In the mainland U.S. balancing compliance requirements are based on statistically ensuring that imbalances do not get large enough to trigger under-frequency load shedding for N-1 and rare, defined other credible events (e.g., n-2). For normal balancing, the current NERC standard is that the imbalance be less than some specified MW level for 90% of the time . For an interconnected system with similar peak load to HECO, the imbalance level must be less than approximately 25 MW for 90% of the time. Due to the isolated nature of all the HECO island systems, the allowable imbalance levels must be maintained lower than on mainland systems, as there are no neighboring areas to net out impacts and because frequency excursions are much larger for similar sized imbalances. However, adjusting the HECO reserve requirement to allow for potential deficiency of a few MW 1% or less of the time, is not likely to adversely impact reliability. As a hypothetical example, the segmented reserve requirement represented by the orange trace in the same MECO PV ramping chart below would likely provide 99.9% compliance for meeting its ramping requirements (based on graphical observation without reviewing data), and any imbalances would cause a deviation of less than one MW with little impact to frequency error. HECO may further improve its reserve requirement approach by reviewing its operating criteria for the level of imbalance that can cause a significant frequency deviation, any added safety margins (to account for starting frequency), and its agreed upon risk tolerance (or compliance standard) on how often allow deviations of different magnitude can be allowed.

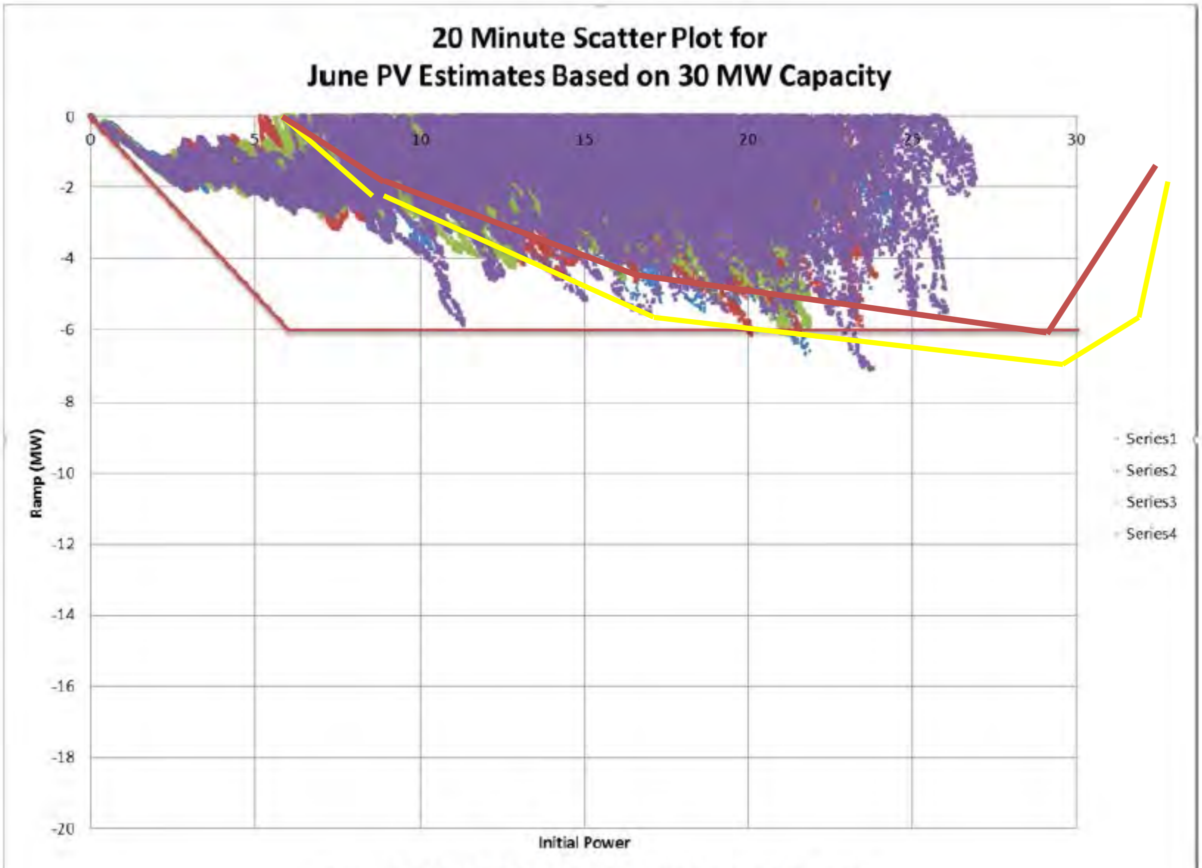


Figure 4 : MECO 20-Minute Solar Ramps for June

Improvement 4: Impact on the predictability of ramp conditions

The EPS reserve methodology determines regulation requirements based on the ramp levels of wind and solar at various output levels. However, it does not consider the predictability of those ramps. For example, solar ramp down during the evening when the sun comes down is relatively easier to meet compared to a random cloud cover that was not predicted. This is because the prediction of the ramp allows the operator to schedule the commitment of additional resources in advance such that they are prepared to turn on when the ramp occurs, and may not be needed during other periods. The predictability (or unpredictability) of the ramp can have a large impact on the reserve requirement. It is unclear as to whether this impact can increase or decrease requirements, as that would depend on the accuracy of HECO's renewable resource forecasts, and its scheduling efficiency (scheduling and commitment of resources outside of regulating resources).

Other Reserve Determination Methods that Consider Renewable Output

A number of other areas with high renewable penetrations are beginning to adjust their operating reserve requirements (mostly regulation reserve) to incorporate the impacts of renewables. A few web links to documents summarizing some of these emerging requirements are provided at the end of this section for further reference.

ERCOT, although much larger than HECO, is also an isolated balancing area, although it has relatively small DC connection with other areas. ERCOT was one of the first regions that adjusted its reserve requirements based on renewable impact and keep a level of reserve that is not constant. The following occurs in ERCOT's regulation reserve requirement methodology:

- ERCOT bases its regulation needs based on meeting 95th percentile of all ramps, based on study of data from the previous month and the same month in the previous year (e.g. when calculating requirements for March 2016, they use mid-January to mid-February 2016 data and March 2015 data).
- Requirements are calculated for each hour of the day in the following month, giving a 24 hour time series of requirements.
- ERCOT bases its regulation needs on meeting the NERC Control Performance Standard 1 that dictates how well it should balance generation and load
- The increase of regulation due to wind generation is about 0.5% of installed capacity. For 1,000 MW capacity increase in wind, the regulation requirement is increased by 4-6 MW. These requirements were based on overall impacts on imbalance to the net load
- The original level is based on previous deployments of the regulation, with regulation being used to meet overall net load imbalance

Other areas have described small changes to their regulation reserve requirements based on increased renewable penetrations. This typically includes regulation requirements that might be based on a percentage of load plus some quantity based on the expected renewable output. Most of these are not as transparent as to how they are calculated as compared to ERCOT. For example, SPP describes their regulation requirement as "based upon a percentage of forecasted load, adjusted up or down to account for resource output variability, and may vary on an hourly basis." The incremental requirements from wind generation are based on both the anticipated forecast and the anticipated hour to hour change.

Other areas in the continental U.S. are also introducing new reserve products, similar to regulation. These products, typically referred to as ramping capability or flexibility reserve, are reserve held to be used in a continuous basis (similar to regulation), but are deployed on a 5-10 minute time frame rather than a second-to-second time frame. The requirements are used primarily to accommodate for renewable forecast error and renewable output ramps. The requirements are typically based on historical renewable ramps over the time frame of interest (typically 5 minutes, 10 minutes, or 30 minutes), and expectation to meet some percentile of those ramp events (e.g., 95%). These products are now present in areas including California ISO, MidContinent ISO, and Public Service of Colorado. Others may introduce similar reserve products in the near future.

References:

Electric Power Research Institute, Reserve Determination Methods for Variable Generation: Industry Practices and the current research, Product ID 3002004242, Oct. 2014.

Ela et al., Operating reserve and variable generation, NREL tech report, 2011. Available: http://www.nrel.gov/docs/fy11osti/51978.pdf

ERCOT, Methodologies for Determining Ancillary Service Requirements. www.ercot.com/content/mktinfo/dam/kd/ERCOT%20Methodologies%20for%20Determining%20Ancillary%20Service%20Requir.zip (opens up zip file directly which contains word document)

MISO, ramp capability white paper, 2013. Available: https://www.misoenergy.org/Library/Repository/Communication%20Material/Key%20Presentations%20and%20Whitepapers/Ramp%20Capability%20for%20Load%20Following%20in%20MISO%20Markets%20White%20Paper.pdf

CAISO, flexible ramping product project page: Available: https://www.caiso.com/informed/Pages/StakeholderProcesses/FlexibleRampingProduct.aspx

Use of Renewables for Active Power Management

In many parts of the country and elsewhere in the world, renewables (wind and solar power) are used for various active power ancillary services to assist in meeting energy requirements and reliability needs. We will go through different types with brief descriptions and references.

Service 1: Congestion management and redispatch

In many areas of the United States wind power is used for redispatch to maintain the energy balance and ensure transmission constraints are within their normal and contingency limits. In most of the U.S. independent system operators, wind is used to assist in congestion management. When a transmission constraint is limited, and wind may be the most efficient or only option to bring the flow within limits, the system operator will send a direction to curtail within the next five minutes and the wind resource will do so. This can also be important when thermal generation plants are at their minimum stable generating limits where they cannot back down any further and cannot turn off due to their minimum off time and start-up times when required to be on in the near future. It is feasible that curtailment of wind and/or solar could be an economic means to handle high penetrations, where it is less expensive to curtail than cycle units on and off. For example, Xcel Energy use this procedure in their Colorado service territory (which is a vertically integrated balancing authority) to allow them to turn off coal units. During nighttime periods, coal could be turned off and wind provide AGC to manage variability. This may also reduce the amount of variability present in the system, either by reducing up-ramps of wind or solar (downwards reserve) or by pre-curtailing before periods of large ramp downs in wind or solar.

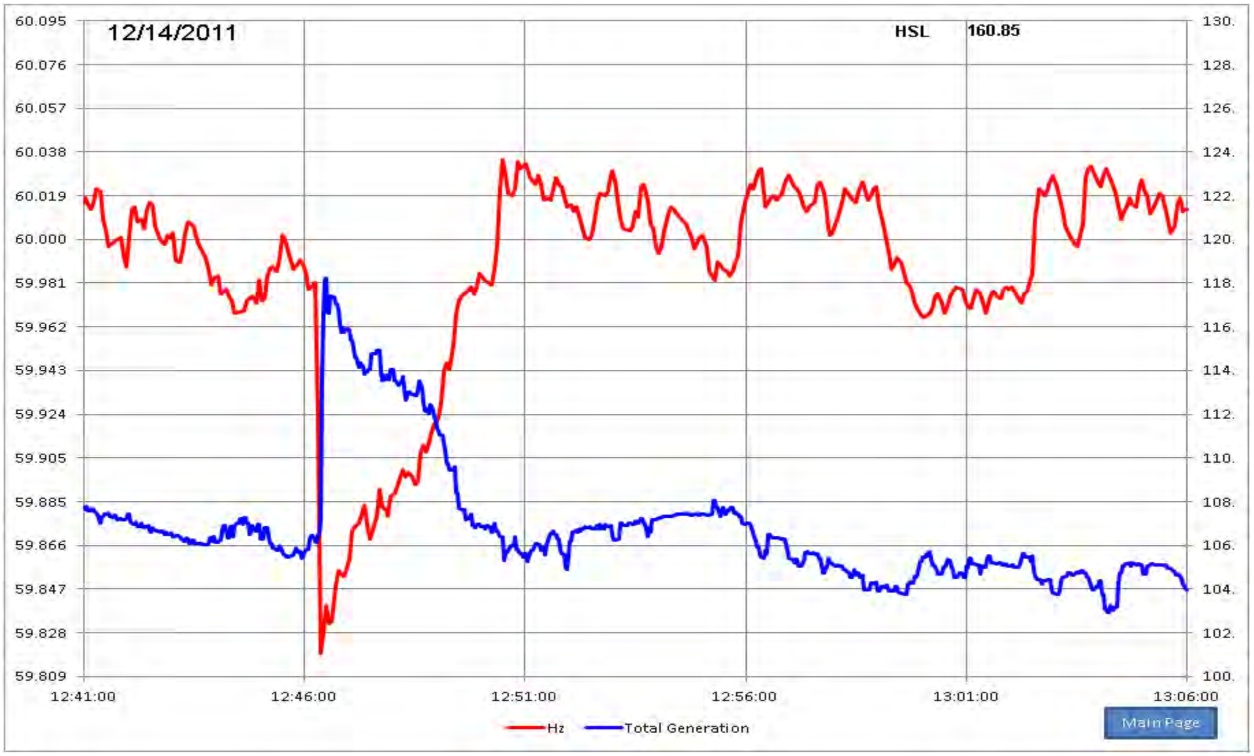
More information can be found in the following:

NYISO, Integration of wind into system dispatch, 2008. Available: http://www.ferc.gov/CalendarFiles/20090303120334-NYISO%20Wind%20White%20Paper%20October%202008.pdf

MISO dispatchable intermittent resource program: https://www.misoenergy.org/Library/Repository/Meeting%20Material/Stakeholder/Workshops%20and%20Special%20Meetings/2011/DIR%20Workshops/20110413%20DIR%20Implementation%20Workshop%20Presentation.pdf

Service 2: Frequency control

Wind power can also provide frequency control, similar to the control of the turbine governor droop, such that it can responded rapidly to system frequency to help stabilize frequency. It is able to provide fast response particularly to over-frequency events by reducing impact, as seen in the chart below. To provide sufficient under-frequency response, the plant has to be pre-curtailed which may have economic or contractual consequences. If curtailed, it is able to provide a fast response, and in ERCOT is required to do so only when curtailed for other reasons. Solar is able to perform similarly. The impact of the forecast accuracy of renewable output can also impact the ability of renewable generation to provide frequency response (particularly under-frequency response), as when the forecast is wrong, the amount of frequency response from the renewable plant may be less than anticipated. The controls to perform in this manner are readily available from the major wind turbine manufacturers, although they do need to be retrofitted to plants where they are not already installed. That said, having these controls enabled could potentially allow for other resources to be decommitted at times of high wind or solar output, when those resources can be curtailed to provide frequency response.



(Taken from ERCOT website)

http://www.nrel.gov/electricity/transmission/pdfs/wind_workshop2_05sharma.pdf

http://www.nerc.com/pa/Stand/Reliability%20Standards/BAL-001-TRE-1.pdf (Reliability criteria in ERCOT that describes wind's participation in providing primary frequency control)

http://www.nrel.gov/docs/fy14osti/60574.pdf

EPRI and NREL organized a project, as well as associated workshops, on the above topics of active power control for wind. More details can be found at http://www.nrel.gov/electricity/transmission/active_power.html

M. Component Plans

To date, there have been four Commission Orders that have directed that the Companies create a series of component plans: Order No. 32053 (Hawaiian Electric); Order No. 31758 (Hawaiʻi Electric Light); Order No. 32055 (Maui Electric); and Order No. 33320, which reiterated most of the included in the previous Orders.

These component plans and the operating utilities to which they apply are: :

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

Integrated throughout our planning and analysis, the Companies have worked toward satisfying the requirements stated in each of the component plans. Chapter 8: Action Plan also addresses our plans to meet the requirements specified by the Commission in the above referenced Orders. This Appendix M provides additional details regarding these component plans.

FOSSIL GENERATION RETIREMENT PLAN

Considerations in Retirement Plans

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

Fossil generation assets are used to provide bulk power needs and for providing system reliability (i.e. adequacy of supply and system security). Because of the inertia and stability benefits of spinning generation (as opposed to inverter based resources), thermal resources have been used to keep voltage and power flows within equipment thermal limits, stabilize and regulate system frequency, and stabilize and regulate voltage.

Retirements of a thermal resource can be considered when it is no longer cost-effective to continue to operate and maintain, and when it no longer is required to serve reliability needs.

Units are considered for retirement when all of the below are true:

- The cost of maintaining and operating the unit to provide bulk power needs is more expensive than an alternative means of serving bulk demand (e.g. a new unit is would be more economical, even taking into account the capital cost of the new unit, or the aggregate capacity value of a variable renewable resource is sufficient to retire the unit).
- The unit is no longer required to meet adequacy of supply requirements (i.e. providing capacity to meet reserve margins).
- The unit is not required for system security reasons, such as offline reserves, fast-start, system restoration, or other critical functions, or are not the most economic means of meeting system security (e.g. when a different generator, BESS, DR, etc. can provide a more economical source of these essential grid services).

Retirements are evaluated by performing production simulations comparing costs and reliability metrics, with and without the resources.

The plans in this PSIP update reflect planned retirement dates of existing thermal units based on new resource energy additions consistent with each plan and an analysis of the best use of resources under a high fuel price scenario (since under a high fuel price scenario, use of less efficient thermal resources is desirable). These retirement dates may be adjusted based on further optimization including future updates to our resource plans and conditions existing at the time of the decision (e.g. actual availability of new resources, level of success of DR programs, and fuel price outlook).

The operation of each thermal resource is continually evaluated for its ability to economically provide bulk capacity and reliability services. As the need for thermal units decline, they are considered for daily or seasonal cycling.

Hawaiian Electric's Plan for Retiring Fossil Generation

We plan to deactivate or retire all existing steam generating units by 2030. In general, a generating unit will be retired two years after it is deactivated.

Table M-1 shows the retirement schedule for Hawaiian Electric thermal generation under each of the different Themes discussed in Chapter 3.

Last Year of Service	Theme 1	Theme 2	Theme 3
2020		Kahe 1,2 & 3	
2021			
2022	AES	AES Kahe 4 Waiau 3 & 4	AES
2023	Waiau 3 & 4		Waiau 3 & 4
2024		Waiau 5 & 6	
2025	Kahe 6		Kahe 6
2026			
2027			
2028			
2029			
2030	Waiau 5 & 6	Waiau 7 & 8	Waiau 5 & 6

Table M-1. Hawaiian Electric Fossil Generation Retirement Plans

The deactivation plan for all steam units was developed on a systematic basis. In order to provide the most cost reduction to the customer, we deemed it necessary to retire units in pairs because unit pairs share one control room, operator staff, and common equipment.

Hawai'i Electric Light's Plan for Retiring Fossil Generation

All existing Hawaiʻi Electric Light steam-generating units are to be deactivated by 2033.

Table M-2 shows the retirement schedule for Hawaiian Electric thermal generation under each of the different Themes discussed in Chapter 3. The plan(s) filed in the PSIP show potential dates of certain resources where they could be removed from service based upon the identified new renewable energy additions. The dates and resources shown are the probable dates assuming the additions, and based on analysis of which resources are operated the least under a high-fuel scenario and discussed above may be adjusted based on further optimization. If retirement is enabled through addition of a new resource, two years for the new resource to become reliable and proven will be scheduled before retirement. Generally, a resource would be used for replacement capacity for a period of time before retirement as needed while the new resource is proven.

Last Year of Service	Theme 1	Theme 2	Theme 3
2020			
2021			
2022	Puna Steam	Puna Steam	Puna Steam
2023			
2024	Hill 5		
2025			
2026	Hill 6		
2027		Hill 5	Hill 5
2028			
2029			
2030		Hill 6	Hill 6
2031			
2032			
2033			

Table M-2. Hawai'i Electric Light Fossil Generation Deactivation Plans

Maui Electric Retirement Plan

The four units at the Kahului Power Plant (KPP) are the only units planned for retirement by 2045 within the Maui Electric systems on Maui, Molokaʻi, and Lanaʻi. As additional renewable energy resources are added to the respective systems, units on all islands will instead be deactivated. Like Units K1 and K2 at KPP today, the deactivated units could be called upon to provide capacity to the system on an as-needed basis.

KPP will be retired upon the installation of replacement generation capacity on Maui along with upgrades to the transmission system or by November 30, 2024 (to comply with environmental regulations), whichever occurs first. Current plans are to have the new capacity and transmission upgrades in place by December 31, 2022.

Table M-3 shows Maui Electric's retirement schedule for existing fossil fuel generating resources.

Last Year of Service	Theme 1	Theme 2	Theme 3
2020			
2021			
2022	Kahului 1,2,3,& 4	Kahului 1,2,3,& 4	Kahului 1,2,3,& 4
2023			
2024			
2025			
2026			
2027			
2028			
2029			
2030			
2031			
2032			
2033			
2034			

Table M-3. Maui Electric Fossil Fuel Generation Retirement Plan

Background

KPP consists of four steam units totaling 35.92 MW (net) of firm generating capacity with Units K1-K4 installed in 1948, 1949, 1954, 1966, respectively. When operating, these units provide firm generation and contribute to system security by providing regulating reserve, system inertia, and voltage support to the Maui system.

Prior to 2010, K1 and K2 were operated daily from approximately 6 a.m. to 10 p.m. to serve daytime demand. In December 2010, the operation of K1 and K2 was changed to approximately 2 p.m. to 10 p.m. on alternating days to serve peak demand during the late afternoon to evening period. This change in operation was one of the Maui

Operating Measures[1] (MOMs) implemented to help reduce the amount of curtailment of energy that was anticipated when the second and third wind farms (Kaheawa Wind Power II and Auwahi Wind Energy) were added to the system. As a result, the energy produced by K1 and K2 was reduced from about 60 GWh annually, to about 15 GWh annually. This enabled the system to accept more energy from the Maui wind farms.

On September 3, 2013, Maui Electric filed its System Improvement and Curtailment Reduction Plan (SICRP). In that plan, the Company noted that in addition to implementing the remaining MOMs, it had both reduced the minimum loads on units K3 and K4 and allocated regulating reserve to those units. In 2014, K1 and K2 were deactivated as committed to in the SICRP, though they can be, and have been activated to avoid capacity shortfalls as well as for other system security requirements.

The operational changes made at KPP contributed to a significant decrease in curtailment of wind energy from 35% in the first quarter of 2013 to less than 10% since.

Environmental Regulations

In May 2013, the State of Hawaiʻi Department of Health (DOH) advised Maui Electric of new requirements relating to cooling water discharge at KPP, impacting its National Pollution Discharge Elimination System (NPDES) permit. As a result Maui Electric anticipated it would have to retire KPP by 2019, ahead of the need to meet the new cooling water discharge requirements, or implement a solution that would meet NPDES standards. This was reflected in the 2014 PSIP.

In late 2014, Maui Electric chose to pursue a 9.5-year compliance plan to be included in the NPDES permit. Inclusion of the compliance plan allows Maui Electric to continue operating KPP beyond 2019, and provides additional time to secure replacement capacity and complete the necessary transmission upgrades in Central Maui. The NPDES permit containing the 9.5-year compliance plan was approved in June 2015, giving Maui Electric until November 30, 2024 to cease water discharges at KPP, effectively requiring termination of generation at the facility at that time.

Potential alternatives (which would likely require a modification to the existing NPDES permit) to terminating the discharge of water from KPP such as a cooling tower, deep ocean discharge, and injection wells, all face a multitude of barriers (permitting, property acquisition, easements) that would jeopardize their ability to be completed before the expiration of the NPDES permit. In fact, given the need for discretionary permits, and

[1] The MOMs include (1) operating units K1 and K2 on alternating days, (2) limiting up reserve to a maximum of 50 MW, (3) allocating up reserve to the KPW II BESS, (3) allocating 3 MW down reserve to the KWP II BESS, and (4) modifying automatic generation controls (AGC) to allow implementation of the MOMs.

cooperation and coordination from other landowners, it is questionable whether these solutions could be implemented at all.

Other Considerations

In addition to addressing the concerns of the Commission regarding the curtailment of wind energy, and meeting environmental requirements, there are other factors which further solidify Maui Electric's decision to retire KPP, including:

- Tsunami Mitigation – given its location along the Kahului shoreline, KPP is very susceptible to damage should Maui be impacted by a tsunami. As the need arises and is appropriate, Maui Electric will replace generating assets with generating facilities out of the tsunami inundation zone that will make the Maui grid more resilient against such a natural disaster.[2]
- Renewable Energy Integration – the reduction to base load generation on Maui associated with retiring KPP will provide additional headroom for accepting as-available renewable energy. Quick starting units will also be sought to replace KPP's generating capacity, allowing greater operational flexibility.

Replacement Generation

Absent any replacement capacity, the retirement of KPP will result in a reserve capacity shortfall of at least 40 MW. Meanwhile system peaks on Maui have been trending upward, driving the potential need for even more future capacity. In order to ensure adequate generating capacity for Maui's customers, Maui Electric will be requesting a docket be opened to initiate the procurement of the necessary capacity.

Among the characteristics that will be required of the units will be quick-start ability, which will assist with the integration of as-available renewable energy onto the grid. Additionally, renewable energy solutions that can meet the operational requirements of the replacement capacity and be cost effective to customers will be encouraged to participate in the procurement process.

A portion of the replacement capacity may also be located in South Maui in order to address existing under-voltage risks in that part of the island. The generation would serve as a non-transmission alternative (NTA) to upgrading the transmission line serving South Maui, which has received significant community opposition due to the aesthetic impact of the proposed upgrades.

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[2] Both KPP and Ma'alaea Power Plant are located in the tsunami inundation zone. As a result, the threat of damage from a tsunami plays in a role in Maui Electric's decisions on where to locate future generation or other assets.

The candidate plans considered a number of options for the replacement capacity for KPP; the plan development process is discussed in Chapter 3. Ultimately, the resource will be selected based on the option that provides the best value to Maui Electric's customers.

Along with Maui Electric's efforts to procure replacement capacity, we will continue to pursue non-generation alternatives to help meet the island's capacity needs, while minimizing future traditional generation. These alternatives include, but are not limited to, demand response, time-of-use rates, and energy storage.

Central Maui Transmission and Distribution Projects

The Central Maui region plays a critical role on the island of Maui as it is the center of government and commerce. The Central Maui region is served by both the 69kV system and the 23 kV system with power provided by the Ma'alaea Power Plant (MPP) and KPP. However, the retirement of KPP primarily impacts the 23kV system, which serves the areas of Kahului, Wailuku, and Wai'ehu. Over 13,000 Maui Electric customers are on the 23 kV system, including University of Hawaiʻi Maui College, Baldwin High School, Maui High School, Maui Mall, Community Clinic of Maui, Armory Reserve, Maui Arts & Cultural Center, Hale Makua, Maui Beach Hotel, Maui Sea Side Hotel, Wallace Theaters, Maui VET Center, War Memorial Stadium, Nan Inc., Sack N Save, Foodland, Young Brothers, State of Hawaiʻi Department of Transportation Harbors Division, County of Maui water facilities and waste water treatment pumps, Central Maui Landfill, and Ameron. It is imperative to continue to provide reliable, electrical services to this area.

After the retirement of KPP, the Central Maui load on the 23 kV system will be served by MPP, and the capacity-constrained MPP-Waiinu and MPP-Kanaha 69kV transmission lines. The Central Maui transmission system will need to be upgraded to ensure stability of the Maui system. In addition, the 23 kV system has three 69/23 kV transformers that connect the 23 kV system and the 69 kV system. These transformers are located at Waiinu, Kanaha, and Pu'unene substations. The loss of either the MPP-Waiinu 69kV or the MPP-Kanaha 69kV transmission lines (i.e. defined as a N-1 contingency) during higher system load conditions results in under voltages and thermal overload conditions.

Additionally, under the contingencies noted above, there is the potential for overloads to occur on the remaining transformers, depending on the load. If there is too much power being transferred to the 23 kV system from the 69 kV system, the system may not be able to manage the transfer and can experience a voltage collapse and/or load shedding scenarios in the event of further system disturbances or unanticipated loadings levels in the Central Maui region. In order to support the retirement of KPP, and as part of grid modernization efforts, Maui Electric is proposing to upgrade the existing 23 kV Waiinu-Kanaha line to 69 kV, which includes 69kV upgrades to the existing Waiinu and Kanaha substations, as well as a major addition to the existing Kahului Substation, and reconductoring (i.e. increase the transmission line capacity) of the existing MPP-Waiinu and MPP-Kanaha 69kV transmission line.

These upgrades address the required N-1 Transmission Planning criteria, maintain required voltage limits, strengthen and complete the critical 69kV link for Central Maui, and allow for continued and reliable service under contingency conditions (i.e. during system maintenance and forced outages) and higher system load conditions.

The Kahului Power Plant Retirement-Comprehensive Assessment (included in the 2014 Maui Electric PSIP) provides the technical analysis to locally reduce the amount of load and help with the voltage issues on the 23 kV system. In addition to upgrading the transmission system, NTAs such as internal combustion distributed generation (DG), battery energy storage system (BESS), and synchronous condensers were considered; however, the analysis concluded that upgrading the transmission and distribution system is the most technically sound and viable option.

In an effort to more thoroughly investigate NTA options, a third party NTA study was conducted in a joint effort by the engineering and planning firms of Tetra Tech and CH2M Hill. The NTAs assessed included:

- Firm Dispatchable Distributed Generation (FDDG) – similar to conventional generation, available to the utility for immediate dispatch
- Distributed Standby Generation (DSG) – emergency generators
- Photovoltaic/Battery (PV/Battery) – combination
- Firm Dispatchable Generation/Battery Energy Storage System (FDG/BESS)
- Synchronous Condenser
- Static Capacitor Banks
- Demand Response (DR)

The CH2MHill / TetraTech report identified Firm Dispatchable Distributed Generation (FDDG) as the only feasible non-transmission alternative that would effectively address the contingency overload and under voltage conditions in Central Maui. The TetraTech/CH2MHill report concluded: The only NTA that addresses the loss of generation from KPP, supports voltage stability, and prevents thermal overloads is the addition of new FDDG on the 23 kV system that is strategically located to serve the Kahului, Waiinu, and Wailuku areas. A potential site was identified in the Central Maui area; however, the County of Maui indicated that it does not consider FDDG in the Central Maui region as a viable NTA citing noise, traffic, and emissions concerns. Similarly, a major real estate developer noted their concerns with the placement of FDDG in the Central Maui area citing impacts to future residential development plans.

In addition, the FDDG option poses transmission issues as this option requires major transmission line upgrades from the FDDG to the existing transmission system, as well as a redundant transmission line tie-in (to address the N-1 criteria) to the existing 23kV system. Without the NTA FDDG option, Maui Electric will need to upgrade the existing 23 kV system.

Based on analyses completed to date, the Central Maui transmission and distribution projects provide the most certain path toward ensuring continued reliability and operational flexibility in the Central Maui area. Other options are subject to far greater uncertainty regarding the potential to provide the necessary remedies prior to retirement of KPP.

The completion of the transmission system upgrades and the acquisition of replacement generating capacity are both targeted for completion by the time KPP is schedule to retire in 2022. Given the magnitude and complexity of both of these projects, the target retirement date provides a prudent amount of schedule flexibility ahead of the 2024 expiration of the NPDES permit, however work towards these efforts will have to begin this year.

Capacity Value of Variable Generation and Demand Response

In evaluating whether firm capacity generators can be retired and replaced with new renewable resources, the reliable contribution of those resources to firm generation must be considered.

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

Capacity Value of Wind Generation

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

For Hawai'i Island and Maui, the planning criteria are based on a 30% capacity margin and do not include LOLP. The capacity value of wind is based on historical data collected from each wind facility. The capacity value is established based on the daily historical the availability of the wind resource to serve demand during the peak periods when capacity is needed.

At this time, there are no existing wind facilities on Lana'i and Moloka'i. However, if Lana'i and Moloka'i develop wind facilities in the future, historical data would be required to establish the capacity value of a wind facility on Lana'i and Moloka'i. It should be noted that the established capacity value differs on Oahu, Maui and Hawai'i Island due to varying wind regimes.

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

Maui Electric Capacity Value of Wind. The aggregate value of the three existing wind farms' (30 MW Kaheawa Wind Power I, 21 MW Kaheawa Wind Power II, and 21 MW Auwahi Wind Energy) contribution to capacity planning is 2 MW based on historical examination of available wind capacity during the peak period hours.

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

Hawai'i Electric Light Capacity Value of Wind. The aggregate capacity planning value of the two existing wind farms (20.5 MW Tawhiri wind farm and 10.56 MW Hawi Renewable Development wind farm) is 3.1 MW. This is based on an historical examination of available wind capacity during the peak period hours. The capacity value of the hydroelectric facilities is 0.7 MW using the same methodology used to determine the capacity value of wind.

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

Capacity Value of Solar Generation

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

Capacity Value of Demand Response

The estimated megawatt potential from the Residential and Small Business Direct Load Control Program, Commercial and Industrial Direct Load Control Program, Customer Firm Generation Program, and Time-of-use Programs are included in PSIP capacity planning based on updated program potential received in March 2016 for this PSIP Update.

GENERATION FLEXIBILITY PLAN

Hawaiian Electric: Increasing Operational Flexibility of Existing Steam Generators

Hawaiian Electric has reviewed current generating unit operation, previous cycling and turn-down studies, Electric Power Research Institute (EPRI) publications, and other relevant industry literature. We have taken a holistic approach to operational flexibility and are working to change procedures and policies accordingly. Historic limitations such as having all burners in service are being evaluated and modified as applicable. Flexibility in this context refers to unit turn down, on/off cycling (daily cycling), and ramp rates. These items are not one or the other, but rather optimizing each of them.

On/Off (Daily) Cycling

Enabling the base loaded units to operate in an on/off cycle mode (that is, daily cycling) would maximize variable renewable generation by lowering the amount of must-run generation on the power system. Kahe 1–4 and Waiau 7 and 8 will be able to cycle daily as necessary. It is unlikely that Waiau 7 and 8 will cycle because system reliability criteria currently require two units to be online at Waiau at all times. We will, however, be modifying procedures and practices for when or if it becomes necessary. Kahe 1–4 will be able to cycle daily as necessary. Based on preliminary testing, it is expected that Kahe 1–4 and Waiau 7 and 8 will be able to perform "hot start ups" in 3.5 hours or less (that is, the startup time from "putting fires in the boiler" to "firm" (ready for full dispatch) will be 3.5 hours or less).

The ability to change operation from baseload to cycling is largely based on procedures, training, and technical review of the units' capabilities. Cycling increases maintenance and the wear and tear on the equipment. We do expect this and envision the need to implement improvement projects to enhance the cycling ability as necessary. Potential modifications would include enlarging super heat header drains, reheat header drains, and turbine throttle drains to allow for better temperature control during startup. Additional potential modifications include nitrogen gas blanket systems to prevent air leakage during shutdown and turbine bypass systems to protect the reheat section of the boilers. Projects are to be selected based on anticipated cycles and benefit to the system and for customers.

In June 2013, a cycling test was conducted on Kahe 3; we successfully demonstrated the ability to cycle each day from June 16–20. The average startup time was 2.6 hours. The demonstration test proved that the 90 MW steam units are capable of daily cycling.

We are also evaluating our startup practices on Waiau 5 and Waiau 6, which are already cycled daily, and expect to improve their start times to be consistent with what is planned for Kahe 1–4 and Waiau 7 and 8.

Kahe 5 and 6 are not suitable for daily cycling. The units have operating constraints that make daily cycling challenging or infeasible. However, Kahe 5 and 6 are candidates for seasonal layup should that provide benefit for the system operation.

Expanded Turn Down Range

The baseload units are also being evaluated for expanded turndown to lower loads. Currently the minimum load on Kahe 1–4 and Waiau 7 and 8 is 25 MW (gross). To achieve further lower minimum loads, we reviewed EPRI publications, OEM documentation, a 1992 Hawaiian Electric/Stone & Webster Variable Pressure Operation study, a Hawaiian Electric/Stanley Consultants Flexibility Study, and miscellaneous industry publications. In the previous Hawaiian Electric empirical studies, the limitations to turn downs were evaluated. In most cases, changes to procedures and policy will allow reduction in defined minimum load points. For example, modification of requirements for maintaining drum pressure and 'all' burners in service allow for much improved unit flexibility. A circulation study for low load conditions on Kahe 1 is being conducted. Further studies will be recommended based on the outcome of the Kahe 1 circulation study. No major limitations are expected and recommended modifications will be considered based on significance, cost, and value.

Kahe 1–4 and Waiau 7 and 8 are expected to have unit minimums reduced to 5 MW (gross). Reducing unit minimums to 5 MW (gross) will provide enhanced flexibility to the power system as the unit is providing almost zero net output.[3] For this operating condition, the unit could ramp up to full load without having to proceed through a startup and synchronization protocol. Depending on the duration of the low load, operating in this condition will provide the same benefits as taking the unit offline while using less fuel than for a startup. Exact economics are being further evaluated but operating at 5 MW (gross) for 6 hours appears to use about the same amount of fuel as one hot start up. More importantly, with the generating units operating at 5 MW (gross), they still provide ancillary services not provided by variable generation, including dispatchable VARS, system inertia, and short circuit current.

During the period of June 16–20, 2014, a demonstration of low load operation was conducted on Kahe 3; it was operated for extended duration at 5 MW (gross) with reduced drum pressure. Boiler, turbine, and balance of plant equipment were monitored

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[3] The auxiliary load is approximately 4 MW, and the output to the system is approximately 1 MW (net).

for performance and limitations that may hinder the low load operation. All required operating parameters remained within limitations.

Operating at such reduced minimum loads and then ramping to higher loads would induce large thermal cycles on the equipment. While the thermal cycle is less than that of daily cycling, there is still associated wear and tear and increased maintenance associated with such operation. While procedural changes, operating policy modification, and operator training represent the largest part of enabling enhanced turndown, certain improvements will certainly enhance operational flexibility. Modifying the boiler feed pumps to operate in variable speed will greatly enhance the capabilities of the condensate system. At the reduced loads, the current fixed speed pumps operate well off their best efficiency points. At low loads, the existing pumps operate in a manner that will compromise reliability and increase maintenance cost. Similarly, the feed regulator valves operate at a point that will compromise reliability and increase maintenance. Variable speed boiler feed pumps is an example of a capital improvement that will enhance unit flexibility. Variable speed force draft fans will provide similar improvement in operational flexibility. Control system tuning will also be necessary to improve operation at low loads and to automate some manual operations.

At megawatt levels less than 20 MW (gross), some form of sliding (that is, reduced) drum pressure is necessary for operations of Kahe 1–4 and Waiau 7 and 8. This reduced pressure operations helps reduce thermal stress on the steam turbine and improves circulation in the boiler tubes. System consequences need to be considered when operating units at this reduced pressure. Specifically, unit response to system disturbances will not be as robust as with the unit at full pressure. The unit with multiple burners removed from service and at reduced pressure means reduced capacity at these low loads. The units will not be able to ramp as fast with the reduced pressure. However, depending on system conditions, the benefits of reduced minimum loads are more valuable than negative implications.

Kahe 5 minimum load will also be reduced. Work and testing will be conducted to prove that Kahe 5 can safely and continuously operate at reduced pressure, and with less than all burners in service at load down to 25 MW (gross). Kahe 6 minimum load will remain at 45 MW (gross). Kahe 6 has emission limitations that will prevent operation below the current minimum of 45 MW (gross).

Ramp Rates

Kahe 1 and 2 and Waiau 7 and 8 will have adjusted ramp rates of 4 MW per minute at full pressure when in the normal operating range (that is, at loads above 30 MW gross). Control tuning and enhancement will be necessary to allow for this change. At reduced load pressures, ramp rates are estimated to be 2 MW per minute.

Kahe 3 and 4 have modern turbine control systems and therefore have an enhanced ability to run in coordinated control. Kahe 3 and 4, when at full pressure and in the normal operating range (above 30 MW), will be able to ramp at 5 MW per minute. At reduced load and pressure, the unit will be able to ramp at 2 MW per minute.

Kahe 5 and 6, when at full pressure and in the normal operating range, will be able to ramp at 3 MW per minute. Kahe 5, when at reduced pressure and load, will be able to ramp at 2 MW per minute.

Ramp testing and tuning will be conducted on each unit. Proposed ramp rates are based on testing conducted in the 2009–2012 time frames. Enhancements to coordinated control systems logic will be necessary to ensure these rates are achieved without negative consequences. Upgrades to the GCRTU (communication and control between the generating unit and System Operation) will also enhance the ability to improve ramp rates. These projects are already planned.

Operational flexibility will be improved on our generating units. The units will be able to operate in modes that best meet system demands. Table M-4 summarizes these unit-operating conditions.

Unit	Current		Near Future				
	Ramp Rate	Pmin	Ramp Rate	Pmin (MWg)	Burners Pulled	Pmax (at Pmin)	Hot Start Time Online/Full Load (hours)
Kahe 1 NOP	2.5	25	4	25	1	86/86	2.5/3.5
Kahe 1 NOP	—	—	4	20	2	69/86	—
Kahe 1 VPO (900 psi)	—	—	2	5	4 (estimated)	43	—
Kahe 2 NOP	2.5	25	4	25	0	86/86	2.5/3.5
Kahe 2 NOP	—	—	4	20	0	86/86	—
Kahe 2 VPO (900 psi)	—	—	2	5	4 (estimated)	43	—
Kahe 3 NOP	2.5	25	5	25	0	90/90	2.5/3.5
Kahe 3 NOP	—	—	5	20	3	72/90	—
Kahe 3 VPO (900 psi)	—	—	2	5	8–9	45	—
Kahe 4 NOP	2.5	25	5	25	1	89/89	2.5/3.5
Kahe 4 NOP	—	—	5	20	3	66/89	—
Kahe 4 VPO (900 psi)	—	—	2	5	8–9	45	—
Kahe 5 NOP	2.5	45	3	70	0	142/142	4/6
Kahe 5 NOP	—	—	—	45	2	135	—
Kahe 5 VPO	—	—	2	25	varies	—	—
Kahe 6 NOP	2.5	45	3	45	2	135	—
Waiau 7 NOP	3	25	4	25	1	87/87	2.5/3.5
Waiau 7 NOP	—	—	4	20	3	69/87	—
Waiau 7 VPO (900 psi)	—	—	2	5	8–9	—	—
Waiau 8 NOP	3	25	4	25	1	90/90	2.5/3.5
Waiau 8 NOP	—	—	4	20	3	69/90	—
Waiau 8 VPO (900 psi)	—	—	2	5	8–9	—	—

NOP = normal operating pressure
VPO = variable pressure operations (hybrid)

Table M-4. Hawaiian Electric Ramp Rate Improvements

Maui Electric Generation Flexibility Plan

Maui Electric has implemented many changes in our generation fleet to increase flexibility and renewable acceptance. These have previously been described in our System Improvement and Curtailment Reduction Plan (SICRP) and subsequent annual updates and included:

- Implementation of the Maui Operation Measures
- Reduction in the number of baseloaded units
- Deactivation of KPP units 1 and 2

- Lowering of the minimums on KPP units 3 and 4
- Study and implementation of new regulating reserve requirements
- Automation of curtailment though our Automatic Generation Control (AGC) system

The existing Maui Electric generation fleet has operating characteristics that are quick starting, flexible, fuel-efficient, and dispatchable to accommodate the integration of existing and additional variable renewable energy resources without significant curtailment.[4] Quick-starting generation has the ability to remain off-line until it is required to support the system, such as during a large down ramp event when the wind or solar resources suddenly become unavailable. Other units that may need additional time to start and connect to the system will need a resource to bridge the time required to supply generation (for example, demand response and energy storage). Flexible generation refers to units that can be held off-line until called upon for generation, allowing us to maximize variable renewable generation.

Roles of Current Generation

Kahului Power Plant. Kahului Power Plant consists of four (4) Steam units (K1, K2, K3, and K4) provide firm generation, regulating reserve, system inertia, voltage support to Central Maui, and contribute to system security. These units use an industrial fuel oil that is lower cost than diesel. As noted above, K1 and K2 units were deactivated on February 1, 2014, however, they can be reactivated in the event of a generation capacity shortfall, 23kV transmission voltage support, or other system need.

Maʻalaea Power Plant. Maʻalaea Power Plant has two (2) Dual-Train Combined Cycle units (DTCC1 and DTCC2). These units provide firm generation, regulating reserve, and system inertia. These units can start and provide generation in a relatively short time period. When operated in the dual-train combined cycle configuration, these units are the most efficient generating resources on the island. DTCC 1 is a must run generating unit that contribute to system security. Modifications are planned on this unit in January 2017 to allow it to operate at a lower capacity minimum level. This will allow more opportunity to integrate variable renewable energy when available, and transition to LNG will lower cost to customers. DTCC2 was changed from a baseload unit to an offline unit that can be operated in combined cycle or simple cycle mode when there is a capacity need or when renewable energy is not available.

Maʻalaea Power Plant also has fifteen (15) Internal Combustion Diesel units (MX1, MX2, M1, M2, M3, M4, M5, M6, M7, M8, M9, M10, M11, M12, and M13). These units provide firm generation and regulating reserve. These units can start and provide firm generation

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

in a relatively short time period. Five of these units (X1, X2, M1, M2, and M3) are quick-starting units that can be used for emergency and as a transition unit to starting a larger diesel unit. (MX1, MX2, M1, M2, and M3 units do not contribute regulating reserves when they are online because they run at top load). These units will remain off-line and be available for contribution to system security and system load as needed after other off-line non-fossil fuel resources, such as DR and energy storage, have been used to its fullest availability and ability. Generator controls were upgraded on four (4) of the diesel units to enable remote monitoring and operation of the generating units for better response to system disturbances and system demands due to the increase in variable renewable resources on the system.

DTCC1, DTCC2, and M4–M13 units have operating ranges that can ramp up and down to accommodate fluctuations in the availability of variable renewable energy and/or system load.

Hana. Hana has (2) Internal Combustion Diesel units that provide firm generation and primarily provide support to the Hana area during transmission maintenance and system disturbance. These units will continue to be operated to support the Hana area.

Lana'i-Miki Basin. Lana'i has a centralized generating station with nine (9) Internal Combustion Diesel units that provide firm generation, regulating reserve, and system inertia. These units can start and provide generation in a relatively short time period. Generator control upgrades were completed in 2015 to enable remote monitoring and operation of the generating units. Maui Electric also has an agreement to operate a Combined Heat and Power (CHP) unit that is expected to return to service in 2017. The Lana'i system does not have AGC and therefore the demand for electricity is shared equally between the online units in an isochronous mode of operation. Maui Electric runs a minimum number of baseloaded units on Lana'i – typically two. The CHP unit will replace one (1) of the two (2) diesel units that provide baseload power for the system at Miki basin. When additional units are needed, they are committed in the most economical order given operational constraints. Maui Electric applied for and is awaiting approval from DOH for modifications to our air permit that allow lower minimum operating levels on the baseloaded units to accommodate the addition of more renewables to the system.

Moloka'i–Pala'au. Moloka'i has a centralized generating station with nine (9) internal combustion diesel units and one (1) diesel combustion turbine that can start and provide firm generation regulating reserve, and system inertia. These internal combustion diesel units can start and provide generation in a relatively short time period. Maui Electric currently operates with two base loaded units on Molaka'i because this is the lowest number of base loaded units that satisfy our single contingency criteria. When additional units are needed, they are committed in the most economical order given operational constraints. The Molakaʻi system does not have AGC and therefore the demand for electricity is shared equally between the online units in an isochronous mode of operation. Maui Electric applied for and received approval from the DOH for modifications to our air permit that allow lower minimum operating levels on the baseloaded units to accommodate the addition of more renewables to the system. Additionally, generator control upgrades are planned to enable remote monitoring and operation of the generating units.

Hawaiʻi Electric Light Plan for Increasing Generation Flexibility

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

Similar to the Maui system, which also has large variable energy sources, Hawaiʻi Electric Light has implemented many changes in our generation fleet and operation of the assets to increase flexibility and renewable acceptance.

- Retirement of Shipman plant.
- Lowering of the minimums on Hill 5, Hill 6 and Puna steam.
- Increasing ramp rate and primary frequency response for Hill 5, Hill 6 and Puna.
- Variable regulating reserve requirements based on real-time observation of variability and incorporating the variable solar and wind forecast uncertainty band.
- Implementation of centrally controlled curtailment for larger distributed solar and FIT projects.
- Addition of remote control curtailment for the Wailuku River Hydro project.
- Reduction in number of units continuously operating for system security.

On/Off Cycling

The results of past security analysis produced minimum criteria for system reliability for generation units. With that information, units not necessary for system security and reliability are subject to economic unit commitment dispatch, with consideration of the incurred daily cycling costs. The present system operation at Hawai'i Electric Light incorporates routine daily cycling of the Hamakua Energy Partners (HEP) combined–cycle plant. Puna Steam is currently cycled on a seasonal basis: left offline with preservation measures for extended periods and brought back on line when needed to ensure adequate capacity. However, based on the present low cost of its fuel, Puna can economically serve demand and will be utilized to serve demand. As shown in the preferred plan, and discussed in the retirement plan, large fossil units are assumed to be displaced by appropriately designed renewable energy and become subject to cycling, layup or retirement.

There have been occasional adequacy of supply issues created through increasing offline cycling. The present operation represents a significant reduction in the number of fossil generation units historically operated and relies more upon cycling. There has been some reliability impact from the increased cycling of generating units, due to the increased potential for shortfall due to delay in startup or startup failure, and reduction of capacity available within two hours or less by putting Puna steam into layup. The commitment of generation has been complicated by the large amount of variable energy from wind and solar, the later which continues to increase. To facilitate operation, state-of-the art forecasting tools have been integrated into the control room. However there remains a great deal of uncertainty in the forecast, which can lead to under- or over-committing the generation. Under-committing occurs when production is lower or a down-ramp occurs, and may lead to a generation shortfall and need for supplemental or emergency generation.

Expanded Turn Down Range

Hawai'i Electric Light improved the turndown of its steam units to lower loads. Minimum dispatch limits decreased by 3 MW to 5 MW for Hill 5, and 7 MW to 8 MW for Hill 6, respectively, since mid-2012. The minimum turndown for Puna Steam was also reduced significantly to 6 MW. A new burner tip has been installed in Hill 5 and is being tested as allowing an additional reduction by 1 MW in minimum load. . The minimum economic dispatch limits for other significant units are 27 MW for Puna Geothermal, and 10 MW for Keahole in single-train (combined cycle), the same limit applies for HEP in single-train (which is subject to offline cycling). The regulation limit is 5 MW lower for Puna Geothermal Unit and 1 MW lower for the combined cycle units. H

Fast-Start Resources

Existing generation resources provide a significant amount of fast-start, fast-ramping capability. The resources consist of small diesel units and simple cycle gas turbines

For supplemental and emergency purposes, including to cover for forecast errors, Hawai'i Electric Light has available 46.3 MW that can be started in 20 minutes or less, and 29.5 MW from small diesel units that can be brought online in 2.5 minutes or less. These units are increasingly used to cover for start-failure of cycled units and short-term generation needs caused by forecast error. The availability of these units allows the operator to adjust generation quickly in response to changes in net demand. They are also used to restore under frequency load-shed.

The existing available capacity for fast-start resources is sufficient to meet the supplemental reserve requirements for the Preferred Plan.

Frequency Response, Regulation, and Ramp Rates

Generators and technologies differ in their ability to contribute to essential grid services. Tables providing a summary of technical and operational attributes of existing and potential future resources were provided in the April 2014 Power Supply Plan. In order to best meet system needs for frequency response, regulation, and ramping, new generation additions are required to provide these capabilities to maintain system security and reliability. Moreover, where possible, ramping and regulation capabilities are being improved from existing resources. As part of continuous improvement initiatives, ramp rates were increased for all the steam units respectively, since mid-2012. Increased dispatch range also improves regulation capabilities by allowing a larger contribution of a generator to both up and down reserve. Additional projects to continue to improve generation flexibility can be found in the Power Supply Plan[5].

As part of its expansion to 38 MW, Puna Geothermal Ventures (PGV) changed its facility characteristics from a passive energy source to one that provides frequency response, voltage response, and dispatch under Automatic Generation Control (AGC). PGV can now contribute to primary frequency response, though at this date the range of the response has been limited both because of controls issues and because the facility has been derated since Tropical Storm Iselle. Hawai'i Electric Light plans to continue working with Puna Geothermal in increasing its operational flexibility, following its restoration to 34.5 MW capacity and higher. In the Preferred Plan, the evaluation of new firm capacity renewable resources assumed these resources would provide the grid services comparable to similarly sized conventional plants. Of particular importance in

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

achieving 100% RE is a resource that can provide the system reliability requirements presently met by the generating units at Keahole Power Plant, through provision of similar operational and technical capabilities and a location electrically near to Keahole, to support East-West power flows and voltages without requiring significant transmission infrastructure. Future new utility-scale variable generation such as the wind plants included in the Preferred Plan will also be designed to incorporate technical and operational capabilities available in present day wind plants, including inertial response, ramp rate control, frequency response, active power control, and disturbance ride-through to contribute to grid operational requirements, mitigate impacts of the variability, and lesson the need for other resources to provide such services.

Due to the impacts of DG-PV, increased contingency response (that is, fast frequency-responding reserves) as well as fast-ramping regulating reserves are required, in addition to ride-through capabilities from DG-PV To meet these needs, an energy storage system with response capabilities in excess of generation capabilities will be added to the system to provide contingency reserves. To meet the faster ramping capabilities, the fast ramp capabilities of the existing combustion turbines will be leveraged.

MUST-RUN GENERATION REDUCTION PLAN

Hawaiian Electric

Integrating renewables into our system needs to be accomplished safely and reliably. As discussed earlier, improving the flexibility of the generating fleet is an important piece to integrating larger amounts of variable resources. Maintaining system security is also very important because without it, the ability of the system to withstand sudden disturbances is compromised. System security is maintained by operating the system with sufficient inertia or fast frequency response, or primary frequency response, limiting the magnitude of the contingency event, maintaining adequate contingency reserves and maintaining system fault current; at times requiring the system operator to sacrifice efficiency for reliability.

The approach taken in this PSIP update was to define and determine the amount of technology-neutral ancillary services for meeting reliability criteria instead of relying on must run generating units. This allows other resources to be used to provide the necessary ancillary services to make the system secure if them meet the requirement defined by the analyses. Demand Response programs, Distributed Energy Resources, and fast frequency response storage technologies could be used to provide the ancillary services and would displace the need to run firm generating units which would provide headroom for more renewables on the system. Synchronous condensers will also be used to provide the required system fault current to operate protective relays on the system instead of requiring generating units to be run. Together, this will reduce the system requirement for requiring generating units to be run to make the system safe and reliable.

Hawaiʻi Electric Light and Maui Electric

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

For system security and reliability, previous system security analysis has identified present minimum must-run security generation, with which the system can generally operate with acceptable reliability.

The selection of resources to meet this constraint is based upon economics. It is probable that firm dispatchable renewable energy, to the extent that is available and cost-effective, can in the future provide all the must-run unit requirements and maintain acceptable system security and reliability.

It is theoretically feasible to remove some or all fossil must-run generation prior to the dispatchable renewable energy resources by utilizing alternative resources. This may enable reduction in generation use, which, depending upon the cost of replacement resources and other tools used to operate the system, can be evaluated for cost effectiveness. Additional analysis based on planning criteria will be performed to identify additional system security constraints beyond the PSIP, which may identify additional resource needs, and/or operational constraints for reduced must-run generators. Prior to altering operational requirements based on system security, the system operators will be provided with resources and operating criteria to ensure acceptable system security based on the through planning analysis. New resources for system security and reliability must go through an operational proving to ensure the performance meets the objectives.

ENVIRONMENTAL COMPLIANCE PLAN

MATS Compliance Strategy[6]

MATS

The MATS rule is applicable only to the steam electric units on Hawaiian Electric's O'ahu system. The MATS rule requires Hawaiian Electric control and measure PM emissions as well as fuel moisture content as surrogates for reducing hazardous air pollutants, including heavy metals and acid gases, from its oil-fired steam generating units by April 2016[8]. The EPA's MATS originally required Hawaiian Electric to reduce emissions of HAPs, including heavy metals and acid gases, from its oil-fired steam generating units by April 2015. On November 6, 2013, Hawaiian Electric obtained from the State DOH a one-year extension on the April 2015 compliance date[7], and now has until April 16, 2016, to comply with MATS.[8] To be ready for the April 2016 compliance date, Hawaiian Electric conducted emissions testing for each steam unit on O'ahu that is subject to the MATS PM emission standard. Tests involved measuring PM emissions to confirm the effectiveness and repeatability of potential MATS solutions. Testing throughout 2014 and 2015 allowed Hawaiian Electric to collect data in order to confirm the accuracy of the MATS solution chosen. As announced in the Companies' January 2016 Update of Fuels Master Plan (FMP)[9], Hawaiian Electric's preferred compliance solution was to utilize a 70/30 blend of Low Sulphur Fuel Oil (LSFO) and diesel at Kahe units 5 and 6, but to continue using 100% LSFO at Kahe units 1-4 and Waiau units 3-8. Subsequent to the issuance of the January 2016 FMP, additional testing on Kahe units 5 and 6 demonstrated that the units can meet MATS requirements using 100% LSFO. This is a departure from Hawaiian Electric's initial concern that all units would have to burn a more expensive 70/30 or 60/40 MATS fuel.

Greater detail about Hawaiian Electric's environmental compliance for MATS and NAAQS can be found in Appendix D: Current Generation Portfolios.

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6 Hawaiian Electric was granted a one-year MATS compliance extension, which places the compliance deadline at April 16, 2016. A second one-year extension is available to utilities through an Administrative Order that would be issued by the EPA. Based on the evaluation criteria established by the EPA in a December 16, 2011 Policy Memorandum, the second one-year extension must be based on a system reliability assessment and is considered a much more difficult extension to obtain.

7 The MATS compliance date is set forth in Title 40 of the Code of Federal Regulations (CFR), Part 63, Subpart UUUUU, National Standards for Hazardous Air Pollutants: Coal-and Oil-fired Electric Utility Steam Generating Units.

8 Only Hawaiian Electric's units are subject to MATS.

9 The FMP is filed semi-annually, currently in Docket No. 2012-0217. It is used to continually update the Commission and other interested parties of the Companies' fuel strategies and procurement timelines.

NAAQS

At this time, NAAQS rules are only expected to impact Hawaiian Electric. In order to demonstrate attainment of the new 1-hour for sulfur dioxide in the vicinity of the Kahe and Waiau Generating Stations, it is unclear at this time whether it will be necessary to reduce the use of LSFO and switch to a lower emissions fuel blend. The best case scenario, absent the use of natural gas, would be utilizing 100% LSFO to comply with NAAQS. The Companies currently believe the worst-case scenario would be blending 40% LSFO with 60% lower sulfur fuel. For planning purposes, the Companies used a conservative approach and assumed the 40/60 blend will be required.

The Clean Air Act (CAA) requires the EPA to set NAAQS for pollutants considered harmful to public health and the environment. The six "criteria" pollutants are carbon monoxide (CO), lead, nitrogen dioxide (NO2), ozone, PM and SO2. The CAA also requires the EPA to review the NAAQS every five years and to revise the NAAQS to reflect the latest scientific information on the impacts of air pollution on public health and the environment. In 2010, the EPA revised the NAAQS for SO2 and NO2 and made them more stringent. Also, the compliance requirements for particles less than 2.5 micrometers in diameter (PM2.5 or "fine particles") were made more stringent. Based on the Companies' preliminary analysis, the new SO2 standard poses the greatest compliance challenge for the Companies. Even though NAAQS potential emission reduction requirements for existing units have been pushed back from the original deadline of 2017, to the 2025 timeframe the Companies had to consider a variety of compliance options for its long-term fuel procurement strategy and planning assumptions. Lowering sulfur emissions to the required levels could be achieved by either switching to a lower sulfur fuel, or by installing air quality control equipment (backend controls).

The Companies believe that the most cost effective way to meet the future NAAQS compliance requirements is to use a fuel that meets the requirements as opposed to installing costly backend controls. To the extent that LNG is lower cost compared to the petroleum-based compliance option, it will result in cost-savings to customers. LNG has emerged as a viable option that will comply with air emission standards, while also substantially lowering fuel costs.

Greenhouse Gas (GHG) Regulations

State of Hawai'i Act 234 requires a statewide reduction of GHG emissions by January 1, 2020 to levels at or below the statewide GHG emission levels in 1990. The state GHG rules became effective on June 30, 2014, and require all entities that have the potential to emit GHGs in excess of established thresholds to reduce GHG emissions by 16 percent below 2010 baseline emission levels by January 1, 2020. Affected facilities were required to submit an Emissions Reduction Plan (EmRP) to the DOH for approval by June 30, 2015.

Hawaiian Electric, Maui Electric, and Hawaiʻi Electric Light have a total of eleven facilities affected by the state GHG rule. Together, these facilities account for almost 56 percent of the 2010 baseline emissions from all affected facilities in Hawaii. Hawaiian Electric made use of the partnering provisions in the DOH GHG rule to prepare a single

EmRP that covers all eleven of the Company's affected facilities, and has committed to a 16 percent reduction in GHG emissions company-wide. Hawaiian Electric submitted the Company's EmRP to the DOH on June 30, 2015. Pursuant to the State's GHG rule, the DOH will incorporate the proposed facility-specific GHG emission limits into each facility's covered source permit based on the 2020 levels specified in Hawaiian Electric's approved EmRP.

As part of a negotiated amendment to the Power Purchase Agreement between AES Hawaiʻi and Hawaiian Electric, Hawaiian Electric has agreed to include the AES Hawaiʻi coal-fired power plant on O'ahu as a partner in the Company's EmRP. Similarly, with the planned acquisition of the HEP facility by Hawai'i Electric Light, the GHG emissions from the HEP facility will also be addressed in the Company's EmRP. Both the AES PPA amendment and the HEP acquisition are subject to PUC approval so the inclusion of these facilities in the Company's EmRP is also subject to PUC approval. Hawaiian Electric is working closely with the DOH on the timing of the EmRP modifications to address these changes in the partnership

As part of the President's Climate Action Plan, the EPA was directed to adopt GHG emission limits for new and existing EGUs. The EPA issued the final federal rule for GHG emission reductions from existing electric generating units, also known as the Clean Power Plan, on August 3, 2015. The Clean Power Plan set interim state-wide emissions limits for existing EGUs operating in the 48 contiguous states that must be met on average from 2022 through 2029; final limits will apply from 2030. On February 9, 2016, however, the U.S. Supreme Court granted a stay of the Clean Power Plan pending resolution of several challenges to the rule until several petitions for review in the U.S. Court of Appeals for the D.C. Circuit Court can be heard and a decision is rendered.

The final Clean Power Plan did not set forth guidelines for Alaska, Hawaii, Puerto Rico, or Guam because the Best System of Emission Reduction established for the contiguous states is not appropriate for these locations. The EPA indicated its intent to work with the governments for Alaska, Hawaiʻi, Puerto Rico, and Guam to gather additional information on emissions reduction measures available in these jurisdictions, particularly with respect to renewable generation. However, given the recent Supreme Court decision and pending further action by EPA and federal courts, the timing for establishing federal

GHG emission reduction requirements that may affect Hawaiian Electric's power plants is uncertain.

316(b) Fish Protection Regulations

Section 316(b) of the Clean Water Act requires that National Pollutant Discharge Elimination System (NPDES) permits for facilities with once-through cooling water systems ensure that the location, design, construction, and capacity of the systems reflect the best technology available to minimize harmful impacts on the environment. Most impacts are to early life stages of fish and shellfish that become pinned against cooling water intake structures (impingement) and are drawn into cooling water systems and affected by heat, chemicals, or physical stress (entrainment).

The EPA issued the final 316(b) fish protection rule on May 19, 2014. This rule titled, *Final Regulation to Establish Requirements for Cooling Water Intake Structures at Existing Facilities*, applies to Hawaiian Electric's Honolulu, Kahe, and Waiau steam electric generating stations. The Kahe and Waiau facilities are required to comply with the impingement and entrainment standards. The Honolulu facility, due to its lower actual intake water flow when operating, may only have to comply with the impingement standard. Honolulu is currently deactivated and will only be required to comply with the 316(b) fish protection rule when it is reactivated.

The final regulation does not specify the best technology available (BTA) standard for entrainment, but states that "the Director must establish BTA standards for entrainment for each intake on a site-specific basis." [§125.94(d), Page 538] In Hawai‘i, the "Director" is the Director of the Hawai‘i DOH.

Significant studies at Kahe and Waiau need to be completed before the DOH can make a final determination of the technology requirements for the affected facilities. Six years of impingement and entrainment data have been collected at Kahe and Waiau and will be used to complete the required studies for these facilities. A preliminary review of the data indicates that closed-cycle cooling (CCC) or cylindrical wedgewire screens will not be required to comply with the 316(b) rule, but fish friendly traveling screens and fish return systems may be required.

No firm deadline for compliance is specified in the final rule; facility-specific compliance schedules will be developed based upon the results of the required studies, in consultation with DOH, and in coordination with the facilities' NPDES permit cycles.

NPDES compliance also impacts Maui Electric's Kahului Power Plant (KPP). As discussed in the Fossil Generation Retirement Plan, Maui Electric plans to retire KPP's generating units no later than November 30, 2024 in accordance with the compliance plan as approved by the DOH in July 2015.

KEY GENERATOR UTILIZATION PLAN

This discussion recognizes the unique economic and operational challenges that exist for key O‘ahu and Maui generating units.

AES Hawai‘i (AES)

AES is a 180 MW coal-fired power plant serving O‘ahu. The existing Power Purchase Agreement (PPA) between AES and Hawaiian Electric expires on September 1, 2022. The PSIPs assume that the AES PPA is not renewed as of its expiration date.

Kalaeloa Energy Partners (KPLP)

KPLP is a combined-cycle combustion turbine generator that currently operates on LSFO. The Power Purchase Agreement (PPA) between KPLP and Hawaiian Electric will expire on May 23, 2016. As shown in its Adequacy of Supply report filed April 11, 2014, in the absence of new capacity, Hawaiian Electric needs KPLP's capacity of 208 MW to meet the generating system reliability guideline. In the absence of KPLP, it is estimated that there would be a reserve capacity shortfall of about 175 MW.

Hawaiian Electric is currently negotiating in good faith with KPLP for an extension to the PPA for six years, to approximately 2022. Among the terms being negotiated are: (1) the term of the extension; (2) fuel flexibility including LNG; and (3) operational flexibility including increased turndown to lower loads and extended simple-cycle operation. KPLP has represented that it needs to invest substantial capital to address equipment deterioration, so that it would be able to operate at high levels of reliability beyond the term of the existing PPA, and this is being considered in the negotiations.

At an appropriate price and with appropriate operate operating flexibility, KPLP represents a viable future generator for the O‘ahu power system, especially if it converts to LNG. Unfortunately, the KPLP facility does not have adequate space for LNG storage or regasification. Accordingly, Hawaiian Electric is considering installing such facilities at its property that abuts the KPLP facility, and the possibility of providing natural gas to KPLP from these facilities. Any final agreement would be reflected in an amendment to the PPA that would be submitted for Commission review and approval.

The KPLP facility is expected to be a viable generator in 2022 after the expiration of the potential six-year extension to its PPA, and would be a candidate for a new PPA in the succeeding time period. Because KPLP is an IPP, it is impossible to identify its value in the future without a finalized contract identifying pricing, operating flexibility, and other parameters.

Campbell Industrial Park Combustion Turbine No. 1 (CIP CT-1)

CIP CT-1 is a combustion turbine that currently operates firing biodiesel and is the type of generating unit that is compatible and complementary on a power system with increasing amounts of variable renewable generation. CIP CT-1 provides offline reserve, online spinning reserve, and can be turned on and synchronized to the grid within 22 minutes. It can also be readily turned off in order to accept more variable renewable generation onto the grid. When operating, it contributes a relatively high level of system inertia, can help manage system frequency by responding to minute-to-minute load demand control signals, and can ramp up rapidly to offset rapid down ramps of variable renewable generation.

The fuel efficiency of CIP CT-1 is lower than the AES and KPLP units. For example, at maximum load, its fuel efficiency is about 11,700 Btu/kWh-net. Kahe 6 has a fuel efficiency of about 10,050 Btu/kWh-net at full load. In combination with the higher cost of biodiesel compared to LSFO, CIP CT-1 is the highest cost generator on the O‘ahu power system.

Once the Schofield Generating Station (SGS) is in service first quarter of 2018, CIP CT-1 will switch to using diesel as its normal operating fuel. The biodiesel that would have otherwise been used at CIP CT-1 will subsequently be used in the new SGS engines. Pacific Biodiesel supplies the biodiesel currently used in CIP CT-1 via a contract that has a minimum purchase amount of 2 million gallons per year. This contract expires in November 2017. Whether operated on diesel or biodiesel, CIP CT-1 represents a vital resource for the O‘ahu system due to its operating characteristics. The frequency with which CIP CT-1 is operated will depend on its relative fuel cost and system conditions.

Other Generating Units Owned and Operated by Hawaiian Electric

In order to reduce costs to customers, Hawaiian Electric is pursuing the use of LNG in a new 383 MW 3 x 1 combined cycle plant to be constructed at the Kahe site. If approved, the new Kahe combined cycle plant would enter service in 2021.

Use of and retirements of existing generation depends ultimately on the plan that is approved. Unit retirement plans are described in Hawaiian Electric’s Plan for Retiring Fossil Generation.

Role of Thermal Generation in the Future

With a mandate for 100% RPS by 2045, we envision declining utilization of thermal generating units that are oil fired. Thermal generation is however desirable, to accommodate cleaner and less price volatile LNG and / or to provide strategic use of liquid biofuels that allow the thermal units to “back up” the variable renewable energy and energy storage systems in those situations when there is no alternative to meet system demand other than by relying on the thermal generation fleet.

Maui Electric Key Generation Units

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

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

Large diesel internal combustion engines (M10, M11, M12, M13): operational flexibility through startup availability and dispatch. It is also anticipated that the small and mid-size diesel units will be operated very infrequently, as they will be designated to operate during peak load periods or when variable renewable resources are unavailable.

Hawai‘i Electric Light Key Generation Units

The Puna Geothermal Venture facility provides firm capacity renewable energy, and will continue to be a significant resource towards renewable energy goals for the foreseeable future.

The dual train combined cycle units at Keahole and HEP provide benefits that include system security, fuel efficiency, and fuel flexibility. Conversion to LNG offers potential to stabilize costs associated with oil. These resources have flexible operational characteristics, can cycle offline, and will continue to be used to economically serve demand.

The steam units provide excellent system stability and primary frequency response, and with the present modifications, good dispatch range ad ramping capability. The minimum dispatch limit (in MW) is lower than combined cycle units. The three steam units are presently the lowest cost resources to serve demand due to the low cost of IFO fuel, and are being leveraged to economically serve demand now and for the near term, assuming the fuel costs remain such that these remain lower cost than alternate available resources. However, the units are inefficient and not expected to remain cost-competitive under scenarios of higher fuel costs, and are not candidates for switching to more expensive renewable energy fuels and assumed to be candidates for decreased operation or retirement with the addition of renewable resources.

The fast-start diesels and simple cycle combustion turbines, which have played a large part in the integration of the present high levels of variable renewable energy and support the amount of off-line cycling and low online reserves of today, will continue to play important roles in providing fast replacement reserves and supplemental reserves for forecast errors, ramping events, forced outages (including failed start) and other short term and emergency energy needs.

OPTIMAL RENEWABLE ENERGY PORTFOLIO PLAN

Hawaiian Electric's Renewable Energy Portfolio Plan

Hawaiian Electric's optimized plan is described in Chapter 5.

Hawai'i Electric Light's Renewable Energy Portfolio Plan

Hawai'i Electric Light's optimized plan is described in Chapter 7.

Maui Electric's Renewable Energy Portfolio Plan

Maui Electric's optimized plan is described in Chapter 6.

GENERATION COMMITMENT AND ECONOMIC DISPATCH REVIEW

The Generation Commitment and Economic Dispatch Reviews are similar for all three operating utilities.

Prudent Dispatch and Operational Practices

Our unit commitment and economic dispatch policies are based on safe and reliable operation of the system, minimizing operating costs, and complying with contractual and regulatory obligations. The daily generation dispatch process is illustrated in Figure M-1.

With increasing amounts of distributed solar, large amounts of wind power, and increased offline cycling, state-of-the art forecasting tools have been integrated into the control room. These tools are used to inform unit commitment decisions with forecast power production, variability, and indication of uncertainty in the forecast. However there remains a great deal of uncertainty in the forecast, which can lead to under- or over-committing the generation. Under-committing occurs when production is lower or a down-ramp occurs, and may lead to a generation shortfall and need for supplemental or emergency generation.

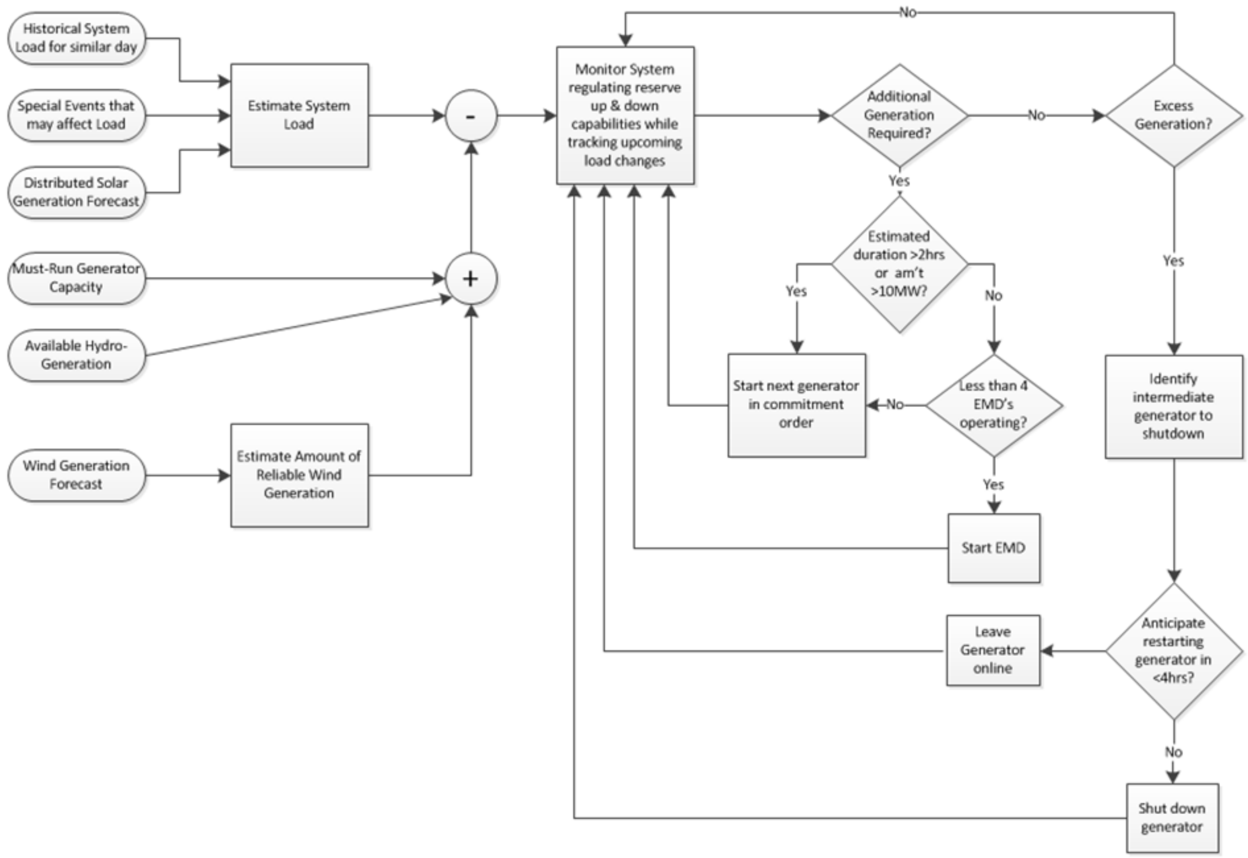

Figure M-1. Daily Generation Dispatch Process

Maui Electric and Hawai'i Electric Light have integrated its state-of-the art wind and PV forecasting into the control room, which is used for the daily unit commitment decisions. The amount of online reserves carried is adapted in real-time based on upon the observed variability of the net demand, primarily driven by wind and solar. Unit commitment and economic dispatch are based on economic dispatch, subject to the security constraints, PGV contract levels, unit limits, and must-take energy. A factor in unit commitment is the duration of the load to be served. With the increase in DG-PV, a shorter day peak occurs during which it may be more economic to startup a faster-starting but less-efficient resource such as a simple cycle turbine. Maui Electric also has to factor in reactivation of its deactivated units based on capacity and transmission planning requirements to meet daily peak load and 23kV line voltage support.

Additional projects are being developed which will further integrate the forecasting and services and visualization into the EMS and provide additional visibility and control of distributed energy resources. In the future, the unit commitment decisions will incorporate net-demand forecasts, which include the forecast wind and solar production and demand response options. For supplemental frequency control and reserves new resources will be integrated into the EMS, including storage, demand response, and response capabilities from variable resources.

Minimization of Ancillary Services Costs

The process to identify system security constraints, and the combinations of resources which can be used to meet them, is summarized as follows:

- Determine system constraints.
- Identify the resource mix that meets each of them.
- Select the lowest cost combination of resources to operate.

For all three operating utilities, additional security constraints are imposed with increased concentrations of variable renewable resources. Therefore, the projected increase in DG-PV may have an impact on ancillary service costs. We will continually evaluate the economics of using existing resources to meet ancillary service and system security requirements versus meeting those needs with alternative resources including energy storage and demand response.

Maximizing the Use of Available Renewable Energy

The commitment and dispatch of renewable energy resources depends upon the contract terms for those resources and whether or not the system operator has visibility and control over the generation. If the resource can be economically dispatched, it is put under automatic generation control (AGC), and its output is determined by its marginal cost relative to the marginal cost of other resources. Examples of this type of renewable resource includes geothermal, generating units using renewable biofuels, waste-to-energy projects, and other "firm" renewable projects. In the PSIP plans, the value of dispatchable renewable energy has been identified as providing value by displacing maximum amount of fossil fuels through the high capacity factor. However, these types of resources are not available on Oahu, unless procured through interconnection to other islands.

Variable renewable energy projects have been contractually treated as must-take, variable energy. These are accepted regardless of cost, but their output is reduced as needed when all intermediate units are offline and there remains excess energy production. In this case, the system operator curtails the output of variable energy providers to the degree necessary to keep the system in balance and provide response reserves. Most curtailments are partial—the output is limited, but the resource is not restricted to zero output. When excess energy necessitates curtailment, it is performed in a manner consistent with the purchased power agreements associated with the affected resources and in accordance with a priority order established by the system operator.

In addition to excess energy situations, curtailments can also be required for system constraints such as line loading, phase angle separation, line maintenance, and frequency impact from power fluctuations. Curtailments for system constraints are applied to the resources as needed to address these constraints and are not subject to the priority order used for excess energy curtailments. Curtailments are also performed at the request of wind plants for wind conditions, and equipment issues.

The vast majority of DG-PV is not visible or controllable by the system operator. These resources serve demand ahead of all other resources. Additional growth in DG-PV is forecast to cause increased curtailments of utility-scale variable renewable resources, unless DG-PV is required to provide the visibility and control to the system operator.

As the islands evolve to every increasing levels of renewable energy, the ability to treat any type of energy as "must take" is increasingly limited in the absence of storage. The islands serve only the demand on the island systems and cannot export excess production as is done in other interconnected areas. Accommodating the renewable resources will displace existing generation that provided dispatchable energy, adjusted to meet demand, and many other characteristics to keep the power system stable and operable. These capabilities to adjust output to serve demand, respond to frequency, regulate voltage, etc. will be increasing relied upon from variable resources and firm renewable resources as the systems are transformed to economically and reliably serve the energy needs of the future with 100% renewable energy. This increasing contribution to grid management will require changes to both procurement terms and technical and operational capabilities of all renewable resources, including distributed energy resources.

Energy Management Systems (EMS)

The operation of the system is facilitated by use of a centralized Energy Management System (EMS). The EMS provides the system operator with constantly updated, real-time information about the operational state of the system. There are three key program applications within the EMS:

- Supervisory Control and Data Acquisition (SCADA)
- Real-time Automatic Generation Control (AGC)
- Real-time State Estimator

Currently, Moloka'i and Lana'i do not have AGC capability due to their small size, and rely upon isochronous control units for frequency regulation.

All three Companies routinely update the EMS hardware and software platforms for each system in order to ensure reliable operation, to incorporate new industry developments such as protocols and system security measures, and to maintain support from EMS vendors.[10] With the transformation of the utility systems additional interfaces are required to the EMS for control of distributed generation, new types of resources such as storage, demand response integration, and variable generators which have varying levels of reserve depending upon set point and available resource. This will require modifications to the interface, new controls, and modeling of the resources within AGC.

To accommodate the migration to smart-grid network and integration of new resources and the use of the communications protocols to support this, the companies are hardening the security of their EMS systems. Hawai'i Electric Light has tested MPLS communication to a remote terminal unit from a secured EMS network.

Additional applications are being developed to facility with dispatch decisions and system management with the changing resource mix. AS one example, in 2016 an adaptive underfrequency load-shed application will be integrated in the Hawai'i Electric Light system to assign circuits to underfrequency load-shed tiers in real-time, reflecting the telemetered demand on each circuit and total load-shed quantity needed at the time.

System Dispatch and Unit Commitment

Unit commitment and dispatch decisions are based upon:

Safety. Our dispatch of generating resources is always subject to ensuring the safety of personnel and the general public.

Reliability. Dispatch and unit commitment must adhere to system security and generation adequacy requirements.

Contractual Requirements. Dispatch and unit commitment must adhere to contractual constraints.

Cost. After meeting all the forgoing requirements, we commit units and dispatches units based on their marginal cost, with lower cost units being committed and operated before higher cost units.

When determining the unit commitment and dispatch of generating units, we do not differentiate between dispatchable IPPs and utility-owned assets. The daily unit commitment modeling tool input date does not differentiate units by ownership. Certain generators do receive a form of priority in terms of energy being accepted onto the

[10] We operate EMS systems from two different vendors, *Alstom* at Hawai'i Electric Light and Maui Electric, and *Siemens* at Hawaiian Electric.

system on the basis of the location of the generator, its characteristics, or the contractual obligations unique to the resource. The acceptance of energy is in the following order of preference:

Distributed Generation: Distributed generation resources receive preferential treatment as "must take" resources regardless of their economic merit for system dispatch. At the present time, we have no control over, or ability to curtail, distributed generation.

Scheduled Contractually Obligated Generation: These resources are preferentially treated from a dispatch perspective by contract. They are used to serve customer load regardless of their economic merit for system dispatch. Scheduled energy from these resources is taken after distributed generation, but ahead of all other resources including variable energy providers.

Contractually Must-Run, Dispatchable Generation: The resources cannot be cycled offline and therefore the minimum dispatch level of these resources are preferentially treated in the system dispatch determination and the energy is accepted from these resources regardless of cost, except during periods of maintenance.

Generation to Meet System Security Constraints: These resources provide energy at least at their minimum dispatch limit, ahead of other resources, similar to contractual must-run and scheduled generation, plus an amount of reserve capability to provide down regulation. However, once dispatched, the continued operating status of these resources is subject to continual evaluation of their costs relative to other alternative resources that may become available at a lower cost, except where it is required by contract.

Variable Energy: Variable energy is accepted on the system, regardless of cost, after distributed generation, scheduled energy purchases, and continuously operated generation. This energy is accepted regardless of cost and thus presents a constraint on optimized (lowest) cost. If the energy cannot be accommodated due to low demand, curtailment of the resource is ordered according to an established and approved priority order. As discussed above, variable energy will increasingly be treated as dispatchable and contribute to grid management. This will require additional EMS interfaces.

Dispatchable Resources: Energy from dispatchable resources is taken on the basis of relative cost (economic dispatch). Resources with the lowest variable energy (fuel and O&M) cost will be committed ahead of resources with higher variable costs. Online resources with lower incremental costs will be dispatched at higher outputs ahead of resources with higher incremental costs. The units operated routinely to meet demand, but cycled offline during minimum demand periods, are described as intermediate units. Short-term (daily) unit commitment decisions do not consider fixed costs associated with these resources because the fixed costs will be incurred regardless of whether or not the unit is operated.

Compliance: Permit restrictions or requirements may affect the operation of generation units

Generator Availability: Generators may be out of service for planned maintenance or unplanned reasons

Transmission Constraints: Transmission and distribution maintenance plans

As-available Forecasts: Operational decisions may be different based on wind and solar forecasts versus perfect knowledge of the resource

Weather: Conditions or other risk conditions may require adjustment of the generation mix to provide additional security margin

Distributed Energy Resources: At present, visibility and control of distributed energy resources is limited to only larger sites and FIT projects. As with utility scale variable generation, DER will be increasing integrated into the EMS, including monitoring and control capabilities. Adaptive Underfrequency Load-shedding: This new application is being developed to enable effective load shed protection schemes under high DG-PV penetration. With increasing amounts of self-generation, the available demand for underfrequency load-shed on each circuit is highly variable ad dependent upon solar PV production. The amount of load that must be shed is dependent upon net system demand and contingencies. As mentioned above, the EMS is being adapted at Hawai‘i Electric Light in 2016 to assign circuits to the load shed scheme stages dynamically, based on telemetered available circuit demand and the total system net demand.

Utilization of Energy Storage and Demand Response

Energy storage and demand response (DR) programs can provide the system operator with a flexible resource capable of providing capacity and ancillary services. To provide the system operator with appropriate control and visibility, energy storage assets are equipped with essentially the same telemetry and controls necessary to operate generating units. DR used for providing regulating reserves and contingency reserves is also equipped with appropriate telemetry and controls. The specific interface requirements depend upon whether the storage device or demand response resource is responding automatically, or is under the control of the system operator. DRMS and ESMS is interfaced with or directly incorporated in an EMS. For storage or demand response that is integrated into the EMS, telemetry requirements include:

- For storage, real-time telemetry indicating charging state, amount of energy being produced, device status.

- Control interface to the EMS to enable the increase and decrease of energy output from the storage asset, and for energy input to the storage device for charging.
- For demand response, real-time telemetry indicating breaker status, switch status, and load.
- Control interface to the EMS to enable the triggering of load shed in response to automatic signals (for example, underfrequency) or a command from the system operator.

Depending on the specific application, storage may also be required to respond to local signals. For example, storage may need the capability to respond to a system frequency change in a manner similar to generator governor droop response, which may be used for a contingency reserve response or for frequency responsive regulating reserve. Another example of local response includes the ability of the storage to change output (or absorb energy) in response to another input signal from a variable renewable energy resource in order to provide "smoothing" of the renewable resource output.

A special consideration of short-duration storage is the fact that it is a limited energy resource. This introduces the need for the system operator to be informed regarding the storage asset's charging state, and the need to ensure that the integration and operation of these resources allows for replacement energy sources prior to depletion of the storage. This replacement could be in the form of longer-term storage or generation resources. In order for the value of the demand response to be realized in providing a particular grid service, once called, the load cannot return to the system until after a specified time, which is dependent on the type of grid service being provided by the demand response resource. Accordingly, the system operator similarly requires information regarding the status of demand response, particularly as it relates to the state of the response after an event has been triggered.

Visibility and Transparency in System Dispatch

A high level review of the Renewable Watch websites of various ISOs including PJM, MISO, Cal ISO, and ERCOT, shows the following operational information commonly being displayed, along with ISO energy market-specific information such as locational marginal pricing:

- Real time daily demand curve showing actual and forecasted demand, updated at least hourly
- Hourly wind power MW or MWh being produced and forecasted
- Other renewable energy production in MW (California)
- Available generation resources

Our Renewable Watch site currently displays the following information, with data updated approximately every 30 minutes:

Net Energy System Load. The system load served by generators on the "utility-side" of the meter including those owned by the utility and by independent power producers (IPP).

Gross System Load. The net system load plus estimated load served by the customer side of the meter by DG-PV.

Solar Irradiance Data. This data is measured in different regions of the island, which are used as input to calculating the estimated load served by DG-PV.

Wind Power Production. Total megawatts of wind power being produced by the various IPP-owned wind farms selling electricity to the Companies.

To provide further information to customers about the dispatch of various energy generation resources under the utility's control, we are currently partnering with the Blue Planet Foundation to develop and publicly present real time breakouts of the percentage of net energy system load being served by various fuel types, including coal, oil, wind, waste-to-energy, solar, and biofuel. Hawaiian Electric and Blue Planet believe this information will be useful in raising customer awareness of the use of renewable energy versus fossil fuels. A prototype kiosk was displayed at the Hawai'i Clean Energy Day event on July 22, 2014 with positive public reaction.

In light of this information already being developed for public display, we are agreeable to the following enhancements to our website. The information on the Renewable Energy watch website will be supplemented with additional information showing for the previous hour the percentage of the energy supplied by the different resources (IPPs, Renewables, Company generating units). A historical archive of the percentage of the energy produced by each of the resource groups for the previous 24-hour period will be maintained so that the customer can view the changes over time.

These enhancements will address the Commission's objectives of showing the significant use of non-utility generation and renewable resources, most of which, with the exception of our combustion turbine generation CIP CT-1, which uses biofuels, are IPP owned.

In addition, we also make public a description of its economic dispatch policies and procedures, via posting on its company website. Combined, the enhancements to our website and the sharing of its dispatch policies and procedures will increase visibility and transparency of how generating resources are being dispatched on the power grid.

Our generating unit commitment and dispatch of the generating units is based on the objective of incurring the least cost to the customers while continuing to maintain system reliability. With the introduction of increasing amounts of renewable resources on the systems, it has become more important to minimize the use of fossil fuels and contending with the dynamic system changes that occur from the new resources so that reliability can be maintained. A screenshot from the Renewable Watch–O‘ahu website is shown below in Figure M-2 to provide an example of the variability of the renewable energy resources.

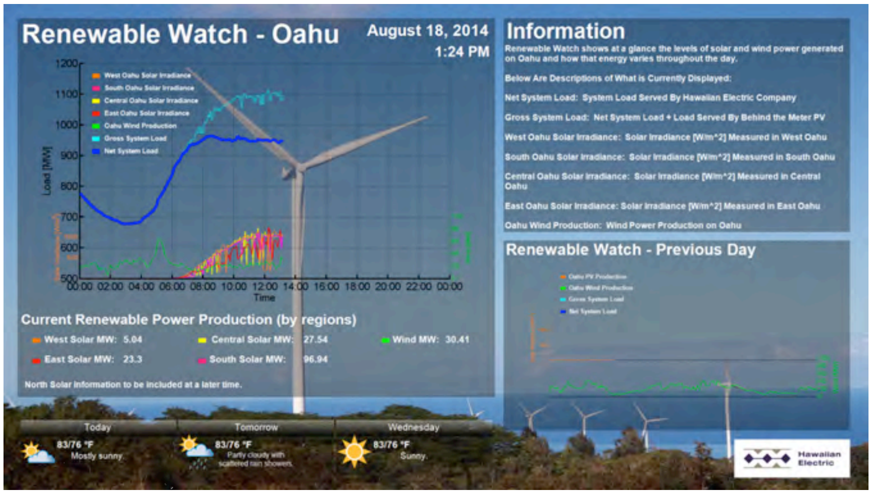

Figure M-2. Renewable Watch–O‘ahu Website Screenshot

Keep in mind that the changes that have been occurring on the all Company respective systems for a few years, but at different rates of change. Maui and Hawai‘i Island have been changing at a far more rapid pace due to the high availability of renewable resources that could be used on each island.

We understand the importance of visibility and transparency of the economic commitment and economic dispatch to show the customers that a real effort is being made to reduce the use of fossil fuels and to encourage the use of renewable resources. Creating a website with the same information that RTOs or ISOs use to show price of energy for the market may be misleading if the customer is unaware of the system conditions that is dictating how the generating units are being run. The information that is graphically displayed on the existing Renewable Watch websites is a good starting point for creating visibility and transparency.

We are working with Blue Plant to incorporate additional information displays that include the system load and the percent of power to service load provided by each resource group. We recommend showing this additional information to customers so that they are able to see, over time, that fossil fuel generation is being substituted with less costly generation.

N. Integrating DG-PV on Our Distribution Circuits

Nearly half of our distribution circuits are penetrated with PV past 100% of daytime minimum load—a now ubiquitous part of the distribution grid. Further integration of PV onto the distribution system will require modernization to achieve an advanced distribution system that leverages new technologies to enable customer choice and multidirectional power flow.

This appendix details the methodology, assumptions, and investment strategies available at the distribution circuit level to integrate greater amounts of PV.

Integration costs were developed for two DG-PV cases: the base DG-PV forecast and the high DG-PV forecast. The system-wide forecasts developed for each of the operating companies served as the basis for distributing DG-PV onto the distribution system. Simulations of our distribution system model informed the PV integration cost estimates.

We considered various solutions and strategies leveraging traditional solutions, emerging technologies, and advanced inverter capabilities. The portfolio of strategies and associated costs were then used as an input to the iterative Distributed Energy Resources (DER) cycle as part of the optimization process.

DISTRIBUTED GENERATION INTERCONNECTION PLAN UPDATE

This report is intended to provide an update to the specific strategies to implement circuit upgrades and mitigation measures to interconnect additional distributed generation we filed with the Distributed Generation Interconnection Plan (DGIP).[1]

This update reflects a deeper analysis of the distribution system than was done in the DGIP to more accurately identify the necessary circuit upgrades to integrate higher amounts of PV through field experience in our high DG-PV environment in combination with the advancements we have made in modeling our distribution system. This analysis was facilitated by the completion of models of each of our island distribution systems in late 2015.

Since the DGIP filing in 2014, we have upgraded 64 load tap changer controllers on O‘ahu, totaling $380,000, which modernized our voltage regulation equipment to accommodate reverse power flow. We've completed research on ground fault overvoltage and no longer require grounding transformers on the distribution level.[2]

DG-PV Integration Plans and Costs Methodology

The development of integration plans and costs for the two DG-PV forecasts followed a five step process. When DG-PV installations exceed a circuit's hosting capacity,[3] that distribution circuit will likely require upgrades to accommodate the additional DG-PV.

The following method was used to study the integration solutions:

1. Allocate PV forecasts to the distribution circuits
2. Model impact of forecasted PV on distribution system
3. Identify solution options to integrate forecasted PV
4. Quantify integration plans and costs for all solutions
5. Derive integration cost estimates

Each step in the methodology is described below.

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[1] Hawaiian Electric Companies filed its Distributed Generation Interconnection Plan on August 26, 2014 to comply with Order No 32053 issued by the Hawai‘i Public Utilities Commission on April 28, 2014, in Docket No. 2011-0206.

[2] As discussed later in this appendix, concerns remain with respect to ground fault overvoltage on the sub-transmission (46kV) level. However, the 67 grounding transformers totaling $4.4M at Maui Electric and the 16 grounding transformers totaling $1.1M on Hawai'i Electric Light, as stated in the DGIP, are no longer required in most situations provided PV systems meet the Companies current transient overvoltage standards. See DGIP At 3-6.

[3] The Hawaiian Electric Companies filed its Circuit Level Hosting Capacity analyses on December 11, 2015 in Docket No. 2014-0192. The Hawaiian Electric Companies proposed the PV Circuit Hosting Capacity Analysis method to support their proposal to integrate circuit hosting capacities into the interconnection process. The PV Circuit Hosting Capacity Analysis method identifies the distribution circuit capacity to safely and reliably interconnect Distributed Generation (DG) PV resources.

Step 1: Allocate PV Forecast to the Distribution Circuits

The DG-PV forecasts reflect the overall, or system wide forecasted growth of DG-PV on each island grid for the two DG-PV scenarios. To determine the cost to integrate these total DG-PV levels, the impact to each individual circuit was analyzed. The installation of DG-PV is a customer choice; thus, we cannot predict the exact installation location of future DG-PV at the circuit level. We used a circuit allocation methodology that reflects Hawai‘i’s mature PV market, that is, we assumed PV would grow proportionally into the future and maintain the same relative circuit penetration levels that exist today, with the rationale that the PV industry has identified and penetrated those market segments, neighborhoods and circuits with the resources and market drivers to adopt PV.

The method increased each circuit’s existing PV level year over year by the growth rate determined by the base and high DG-PV forecasts through 2045. A circuit was allowed to grow up to its maximum potential which was determined by estimating the number of single family homes residing on each circuit. The future PV systems were sized to offset that customer’s historical 12 month energy consumption. The maximum potential considered the commercial sector by estimating that 25% of commercial customers on a circuit installed PV. Where Hawai‘i Electric Light and Maui Electric did not have detailed demographic data of a circuit, customer counts and rate class information were used as a proxy to estimate the maximum PV potential of the circuit.

The initial run of integration costs were based on the original system-wide forecasts in Figure N-1 and Figure N-2.

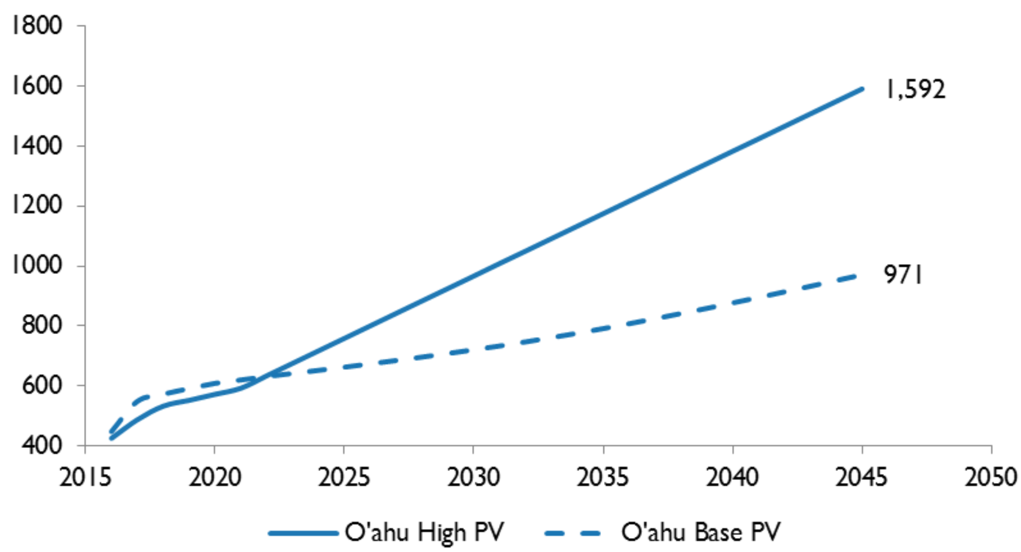

Figure N-1. O‘ahu System-Wide DG-PV Forecast, Base and High Case

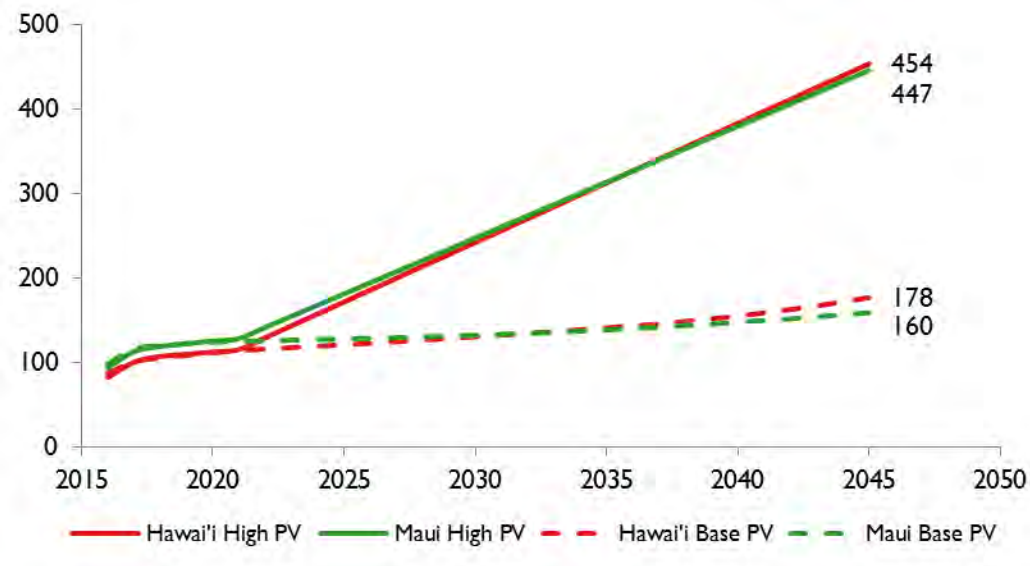

Figure N-2. Maui and Hawai'i Island System-Wide DG-PV Forecast, Base and High Case

A circuit did not receive additional growth after the year in which it reached its maximum PV potential. Not all circuits reached their maximum potential because of current low penetration amounts which reflect neighborhoods with low customer demand for PV. Many currently saturated circuits reached their maximum potential well before 2045.

The PV forecast by circuit is provided in the later section titled, DG-PV Forecast by Distribution Circuit.

Step 2: Modeled Impact of Forecasted PV on Distribution System

The forecasted PV of each circuit was compared to its hosting capacity and operational circuit limit.[4] A circuit forecasted to exceed its hosting capacity was analyzed to determine the cost to integrate the forecasted PV amount. A circuit that did not realize PV growth exceeding its hosting capacity did not incur major circuit upgrades; therefore, an integration cost was not determined for that circuit. Table N-1 and Table N-2 show the number of circuits, for each operating company, that are forecasted to exceed their hosting capacity and operational circuit limit in the base DG-PV case and high DG-PV case.

Base-PV Case	Total Distribution Circuits	Exceeded Hosting Capacity Only	Exceeded Operational Circuit Limit
Hawaiian Electric	416	64	86
Maui Electric	137	44	7
Hawaii Electric Light	135	49	22

Table N-1. Number of Circuits by Company, Forecasted to Exceed Hosting Capacity and Operational Circuit Limit, Base DG-PV Case

High DG-PV Case	Total Distribution Circuits	Exceeded Hosting Capacity Only	Exceeded Operational Circuit Limit
Hawaiian Electric	416	41	160
Maui Electric	137	76	76
Hawaii Electric Light	135	20	94

Table N-2. Number of Circuits by Company, Forecasted to Exceed Hosting Capacity and Operational Circuit Limit, High DG-PV Case.

Three areas were assessed in determining integration costs: thermal capacity, voltage quality, and operational flexibility. The hosting capacity models[5] were used to grow each circuit to its forecasted PV amount. A conductor that exceeded 100% of its thermal rating from the reverse power flow of PV was flagged for mitigation.

Analyzing voltage quality requires a deeper analysis of the hosting capacity models, and analysis results vary by location. Mitigation of unacceptable voltage levels normally requires multiple iterations of load flow simulations. Consequently, a cross section of

[4] The hosting capacity is the level of PV that a circuit may host without requiring upgrades to the primary part of the distribution system. The operational circuit limit defines the reverse power threshold at the substation to maintain the operational flexibility of the circuit. For further discussion, see the "Distributed Energy Resources Planning" section at the end of this appendix.

[5] See "Rooftop PV Interconnections: A Methodology of Determining PV Circuit Hosting Capacity" filed in Docket No. 2014-0192, on December 11, 2015.

representative circuits with their forecasted PV growth amounts were analyzed and analysis results were applied to all distribution circuits. Areas where PV caused voltage to rise more than 2.5% of nominal on the primary were flagged because the circuit models stop at the distribution transformer (primary part of the distribution system). ANSI Standard C84.1, Range A, requires delivery of voltage to customers at ±5% of nominal voltage. Our typical design of the distribution system allows for 2.5% voltage drop/rise between the substation and the distribution transformer (primary side) and 2.5% voltage drop/rise between the distribution transformer and the customer meter, amounting to the delivery of voltage within ±5% of nominal voltage. Localized areas where voltage exceeds this criterion were flagged for mitigation.

Maintaining the flexibility of the distribution system is vital to the reliability and safety of electrical service to our customers. If the forecasted reverse power flow from PV of a circuit exceeds that circuit's operational circuit limit then that circuit was flagged for mitigation.

Step 3: Identify Solution Options to Integrate Forecasted PV

The identification of solutions to resolve thermal capacity, voltage quality, and operational flexibility issues are categorized as traditional "wires" solutions and technology "non-wires" solutions. While many different solutions exist, Table N-3describes the various solution options considered in this analysis. The most cost-effective option was then used in the DER iterative cycles when accounting for integration costs in forecasting DG-PV adoption.

Solution Portfolio		
Issue	*Traditional (Wires)*	*Technology (Non-Wires)*
Thermal Capacity	Overhead and Underground Conductor Upgrade Distribution Transformer Upgrade	Battery Energy Storage
Voltage Quality	Voltage Regulator Installation Distribution Transformer and Secondary Conductor Upgrades	Var Compensation Devices (power electronics, fast switching capacitors, advanced inverters)
Operational Flexibility	Re-Configure Circuit New Circuit and/or Substation Transformer	Battery Energy Storage Advanced Inverter DER Controllability

Table N-3. Portfolio of Solutions to Integrate Forecasted DG-PV Amounts

It is important to draw a distinction between mitigation and optimization solutions. The analysis completed here should be interpreted as necessary upgrades; absent the implementation of these solutions would result in unsustainable DG-PV growth because of the impact it poses to the safety and reliability of the distribution system, including its effect on non-participating customers. Particularly when considering technology solutions, these are deployed to mitigate the impacts of DG-PV and generally are not providing circuit optimization or improved efficiencies, rather maintaining or restoring the integrity of the distribution system.

The following describe in detail each of the solutions in the portfolio.

Overhead and underground conductor upgrade. The generation of excess rooftop PV energy will create reverse power flow that may overload conductors past 100% of their thermal rating. To create additional rated capacity, conductors are upgraded to a larger size. Load flow simulations of the hosting capacity models with PV grown to the forecasted amounts determined with a better degree of accuracy the total length of overloaded conductors in the base and high DG-PV cases. The total length of overloaded conductors by circuit were scheduled for upgrade between the year the PV forecast per circuit exceeded the hosting capacity and ending in the year PV growth stopped. The cost to upgrade overhead conductors including wood pole construction is estimated at

$1,100,000 per mile in 2016$. The cost to upgrade underground conductors including duct bank and manhole installation is estimated at $4,300,000 per mile in 2016$.

Voltage regulator installation. A voltage regulator is a traditional solution that corrects voltage power quality issues, and is installed on circuits where the PV forecast exceeds that circuit's hosting capacity. High and low voltage will be the number one barrier to interconnection in the near-term.

Load flow simulations of representative circuits demonstrated that neighborhoods or sections of circuits may experience high and/or low voltage. Every circuit is unique and will vary in its voltage quality issues. Based on the representative analysis, an assumption was made that up to three voltage regulators per circuit would be required to correct voltage impacts. Each circuit that exceeded its PV hosting capacity incurred a voltage regulator installation for three consecutive years following the year in which its hosting capacity was exceeded, except in the case where PV growth stopped in less than three years. The cost to install a single phase regulator and three phase regulator is estimated at $25,000 and $75,000 respectively, and does not include potential wood pole replacement. For the purposes of this analysis, the unitized cost per voltage regulator installation was estimated at $41,667 in 2016$; the average cost of installing two (2) single phase regulators and one (1) three-phase regulator.

Distribution (service or secondary) transformer replacement. Distribution transformers are deemed overloaded, and therefore upgraded, if the ratio of aggregate PV connected to a transformer to the transformer rating exceeds 200%.[6] In other cases, secondary high voltage will necessitate an upgrade of secondary conductors in addition to the replacement of the distribution transformer.[7] The load flow simulations of the hosting capacity models determined that in the base DG-PV case, 16% of distribution transformers would have a PV penetration (aggregate PV connected to a single transformer divided by transformer rating) in excess of 200%, and 26% in the high DG-PV case. These results were applied to predict the amount of future transformer upgrades required to resolve both loading and voltage issues, which can be mutually exclusive. The average cost for this upgraded is estimated at $13,500, representing the estimated average cost between a transformer upgrade to address overloading and an upgrade to address secondary high voltage. In practice, correction of secondary high voltage may cost more than $13,500, particularly if underground construction is required;

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6 The Companies worked with their distribution transformer manufacturer to determine the appropriate PV penetration level as to not severely impact the life and performance of the transformer. Based upon the results of the manufacturer analysis, it was determined that we would allow 200% PV penetration on a distribution transformer before taking remedial action.

7 Distribution transformer upgrades can be triggered well in advanced of a circuit reaching hosting capacity. Issues related to distribution transformer upgrades were not considered in establishing a circuit's hosting capacity. Whether a distribution transformer upgrade is required is dependent on a set of localized factors.

however for this analysis all service transformer work was assumed to cost $13,500 in 2016$.

Re-configure circuits. The most cost-effective method to resolve the loss of operational flexibility is to re-configure a circuit. Before requiring any type of substation upgrades, planners will analyze the circuits to determine whether a circuit is capable of re-configuration with an intertied circuit. This analysis was not performed in the development of the integration costs except for a few cases; the vast majority of operational circuit limit exceedances were resolved with substation upgrades. As circuits approach these limits in future years, we will always seek to avoid substation upgrades where possible. No capital costs were assigned for this work.

Substation upgrades. Substation upgrades are triggered in two ways: (1) if operational flexibility is lost where reverse power loads the substation transformer more than 50% of its highest transformer rating, or (2) with controllable PV, reverse power flow loads the substation transformer more than 100% of its highest transformer rating. Current operational practice is to maintain operational flexibility during normal operation, and therefore reverse power flow is roughly limited to 50% of its highest rating. However if PV is controllable through the use of advanced inverters, it is possible to allow reverse power flow to load the transformer up to 100% of its thermal rating during normal operation, and regulate the PV power output during abnormal conditions.

There are a number of factors to consider in determining the cost of a substation upgrades. The scope of the upgrade could include building a completely new substation on new land, installing a new substation transformer and circuit(s) in an existing substation, installing a new circuit at an existing substation transformer, or converting a 4kV substation to 12kV.[8] Broad assumptions were made for this analysis; in practice detailed engineering will determine the scope of the upgrade.

The base assumption for a substation upgrade is $10,000,000 which includes: two (46kV) terminations, two (2) substation transformers, two (2) 12kV switchgears, four (4) 12kV feeders, one (1) acre of land, and communication infrastructure. We unitized the cost on a per feeder basis with considerations of various factors. For example, if a substation transformer exceeded the 50% limit, the two circuits it serves require a substation upgrade. If the existing substation has space for an additional substation transformer, land costs were subtracted from the base $10,000,000 and divided by four feeders to arrive at the per feeder cost. In this example, the per feeder cost is $2,000,000. The range

[8] If 4kV substation transformers or circuits require an upgrade, we will convert that area to a higher primary voltage, instead of installing additional 4 kV substations. This is part of an overall strategy to convert 4kV areas to higher primary voltages. These costs were not included in the DGIP based upon the assumption that 4kV circuits would eventually be converted. However in this analysis these costs are included because the 4 kV conversion projects would not coincide with PV growth. This adds significant cost over what was reported in the DGIP. 4kV conversions are higher in cost than new substation installations ($5M vs $2-3M on a per feeder basis) because of the labor hours required to retrofit a circuit with higher primary voltage wires and transformers.

of costs used for a substation upgrade varies between $1,000,000 and $5,000,000 per feeder in 2016$. Each circuit was analyzed at a high level (without detailed engineering) to determine the most appropriate cost of the upgrade.

Battery energy storage systems. Deploying distributed battery energy storage systems behind or in front of the meter can relieve distribution system congestion and maintain operational flexibility. Strategically located storage can avoid conductor overloads, while simultaneously maintaining operational flexibility. Battery cost assumptions are provided in the resource cost forecast in Figure N-3.

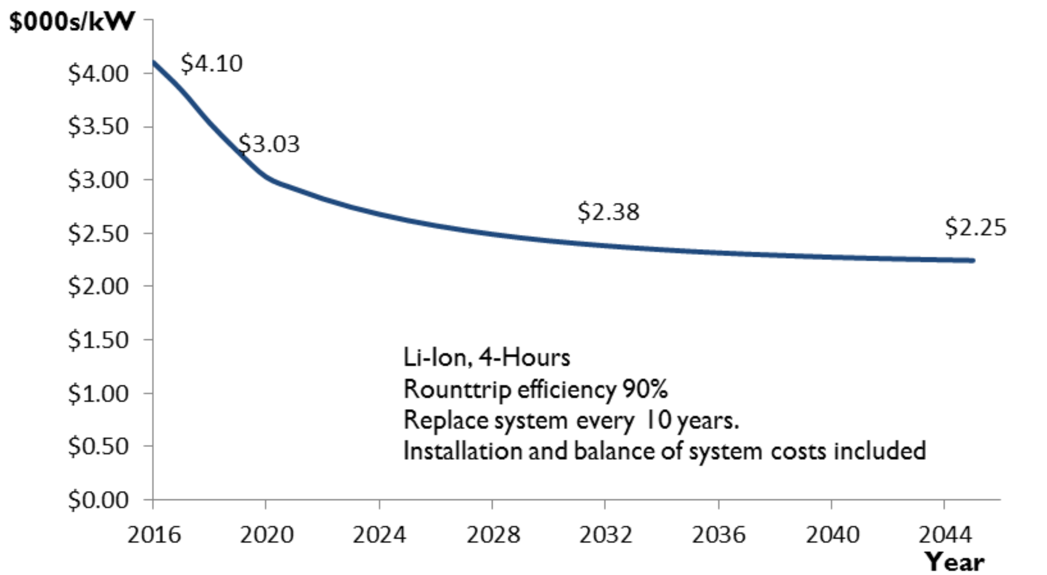

Figure N-3. BESS Cost Assumptions

Battery energy storage systems should be held accountable when deployed to relieve capacity and operational flexibility issues. One important design characteristic for this type of battery energy storage system is to ensure each morning the battery capacity is available to store that day's excess energy. For this analysis, a 4-hour charge/discharge cycle battery was assumed.

While battery energy storage systems may avoid the installation of a new substation, circuit or conductor upgrade, the current state of the technology estimate a 10-year lifecycle. Replacement storage quantities and costs were included in the integration cost estimates 10 years from the original deployment of a battery energy storage system. It should be noted that conductor upgrades and substation upgrades have life cycles in excess of 20 years; therefore, not assumed to require replacement. In addition, battery energy storage system failure must be accounted for. Rather than building redundant storage, the cost effective option is a combination of energy storage and circuit-level control of advanced inverter powered DG-PV. If a battery fails and compromises the safety and reliability of the system, DER control mechanisms should activate to regulate the active power output, particular if failures occur en masse.

Var compensation devices. Var compensation devices leverage modern power electronics to provide fast acting reactive power to reduce voltage fluctuations, and regulate circuit voltages to avoid the high voltage effects of deep penetrations of DG-PV. These devices come in many different forms: low voltage static compensators, fast switching capacitors, inline power regulators, and advanced inverters. These types of devices, located on the secondary part of the distribution system, can potentially provide more cost-effective and efficient regulation to mitigate voltage quality impacts and displace traditional, slower acting equipment such as capacitor banks and voltage regulators. This distributed voltage regulation technique represents a departure from traditional industry methods of voltage regulation. While we have started to demonstrate and assess these innovative devices, the technology is a relatively recent development and has yet to achieve widespread adoption across the industry. We will determine the viability and deployment of these devices once we complete our assessment of these devices from a planning and operating perspective.

To quantify the cost of these devices, representative circuits were modeled to determine the quantity of existing inverters that are required to have reactive power capabilities to mitigate existing high voltages. It was determined that for O‘ahu and Maui 12% of the existing inverter fleet would require retrofit. However, a smart inverter retrofit is not the sole method to resolve high voltage issues given the implementation challenges with customer ownership of the PV inverters. Therefore, the analysis assumed a non-specific solution that includes all device strategies discussed above. An estimated cost to install power electronic devices that provide reactive power compensation was based on a unitized cost estimated at $855 per kilowatt in 2016$. This cost was derived from an NREL report discussing PV costs for residential, commercial and utility-scale systems[9] in Hawai‘i.

Advanced inverter DER controls infrastructure. As PV continues to grow on our distribution system, distribution system management will become increasingly multifaceted and require controllability of customer DER assets by the system operator to maintain safe, efficient, reliable operations. Advanced inverters will play a pivotal role to enable controllability, which we now require as part of our most recent revisions to interconnection Rule 14H. The cost to implement DER controls include foundational infrastructure such as: advanced distribution management system, a distributed energy

[9] See Chung, Davidson, et al (September 2015). U.S. Photovoltaic Prices and Cost Breakdowns: Q1 2015 Benchmarks for Residential Commercial and Utility-Scale Systems. Golden, CO: National Renewable Energy Laboratory, TP-6A20-64746. At 7-9. This report states the cost to install a 5.2kW PV system in Hawai'i is $3,280/kW in 2015$. The $855/kW unitized cost was derived by subtracting the supply chain, balance of system, PV module and racking, customer acquisition, overheads, and profit costs from the $3,280 estimate.

resource management system (DERMS), advanced metering infrastructure (AMI); however, for the purposes of the integration cost estimates, only infrastructure required to directly implement controls on a DER asset are considered. Controllability costs are not incurred until 2018, at which time it is assumed that the DERMS and AMI projects are installed and capable of initiating basic controls of DER assets. The cost of the DERMS and AMI projects were not included in this study's integration costs. It is assumed that every new DER system will be outfitted with the necessary hardware/software to enable controllability; this cost is estimated at $1,500 per system. Assuming an average PV system size of 6KW, the number of total PV systems installed each year was determined. This $1,500 per DER system cost estimate is a high-level estimation of the cost of communication hardware (i.e. communication gateway) and any associated firmware costs.

It is important to note that this technology is still largely being developed within the utility and solar industry.[10] We assumed for this study availability of these capabilities in 2018.

[10] The California Smart Inverter Working Group recently filed DER communication recommendations with its Public Utilities Commission; a decision is still pending. Arizona Public Service and Tucson Electric Power are currently running rooftop solar programs testing smart inverter capabilities, including inverter communications, http://www.solarelectricpower.org/utility-solar-blog/2015/january/arizonas-utility-owned-solar-programs-new-price-models,-grid-integration-and-collaboration.aspx.

Step 4: Quantify Integration Plans and Costs for All Solutions

Upon completion of the circuit specific analysis, the portfolio of integration solutions were each quantified into various strategies. This section describes the different strategies (and associated costs) that were considered to integrate PV in the base and high DG-PV cases. The strategies fell into two general categories—traditional or wires solutions and technology or non-wire solutions—that were then used to create three DER integration strategies in the base case and four DER integration strategies in the high DG-PV case.

- Strategy 1: Traditional or wires solutions to integrate the base DG-PV case.
- Strategy 2: Technology or non-wires solutions to integrate the base DG-PV case.
- Strategy 3: No storage solution with advanced inverter controls to integrate the base DG-PV case.
- Strategy 4: Traditional or wires solutions to integrate the high DG-PV case.
- Strategy 5: Traditional or wires solutions with advanced inverter controls to integrate the high DG-PV case.
- Strategy 6: Technology or non-wires solutions to integrate the high DG-PV case.
- Strategy 7: Least storage solution with advanced inverter controls to integrate the high DG-PV case.

Strategy 1 and 4: Traditional or Wires Solutions

Traditional or wires solutions solve thermal equipment overloads, degraded voltage quality, or loss of operational flexibility by upgrading or installing conductors, transformers, or voltage regulators. In these two strategies, operational flexibility is maintained by creating a new substation and/or circuits whenever the reverse power flow from excess PV generation exceeds 50% of the transformer rating.

Traditional upgrades address the root cause deficiency in the distribution system; these types of upgrades are proven, tested solutions with an asset life of 20+ years compared to less traditional solutions such as energy storage. However, depending on the scope of the solution, traditional solutions may have significantly longer installation times.

Figure N-4 through Figure N-9 summarize by island, the cost to integrate PV under strategy 1: traditional solutions in the base DG-PV case, and strategy 4: traditional solutions in the high DG-PV case.

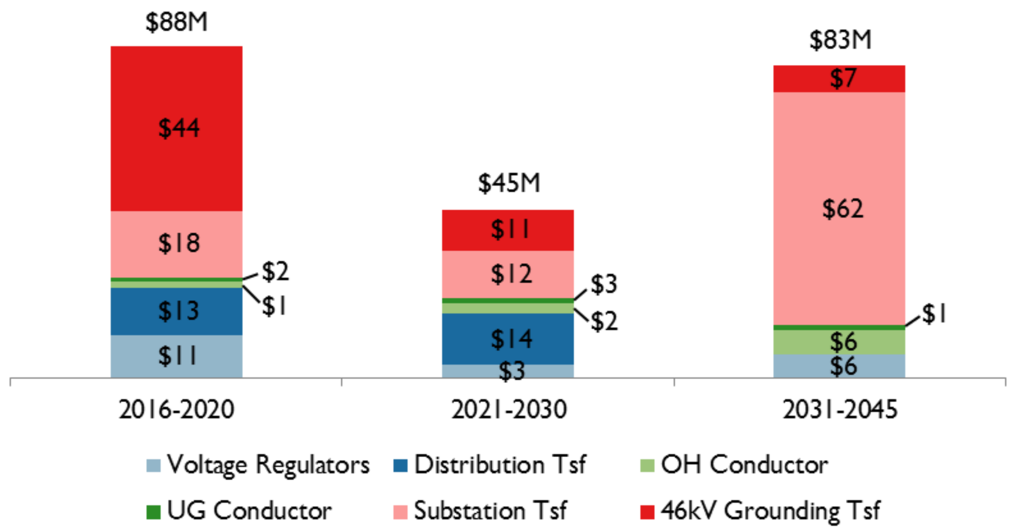

Figure N-4. O'ahu Island: Strategy 1 Annualized Integration Costs, Nominal $M

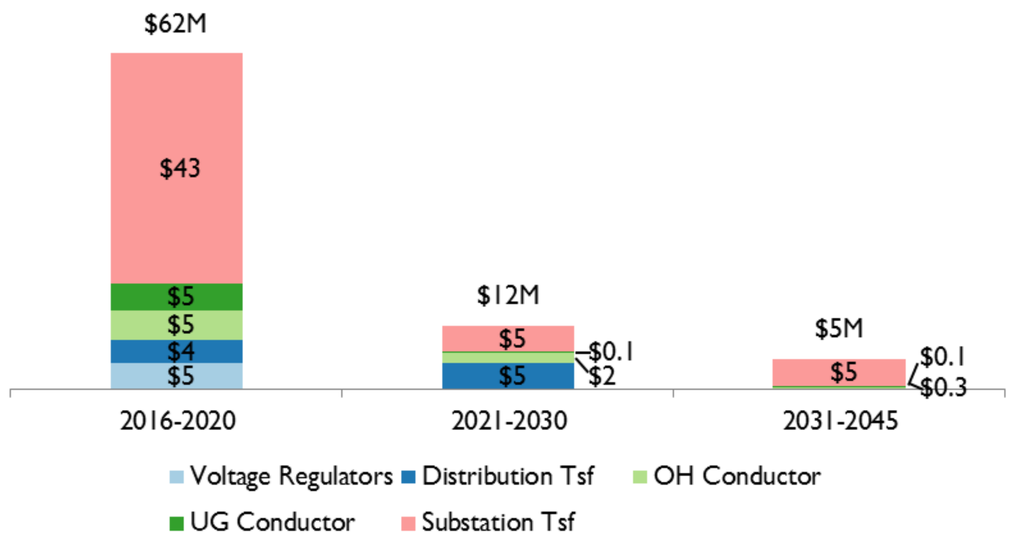

Figure N-5. Maui Island: Strategy 1 Annualized Integration Costs, Nominal $M

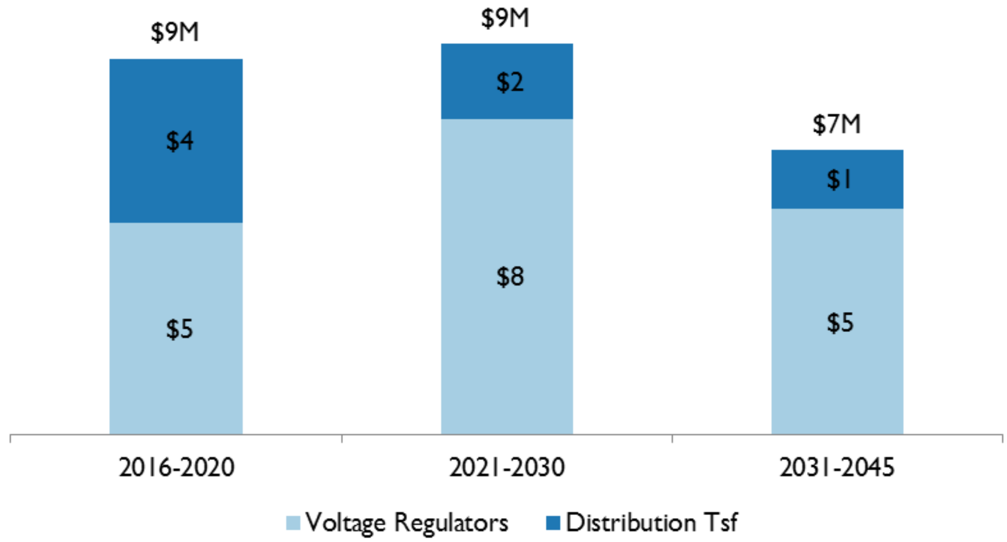

Figure N-6. Hawai'i Island: Strategy 1 Annualized Integration Costs, Nominal $M

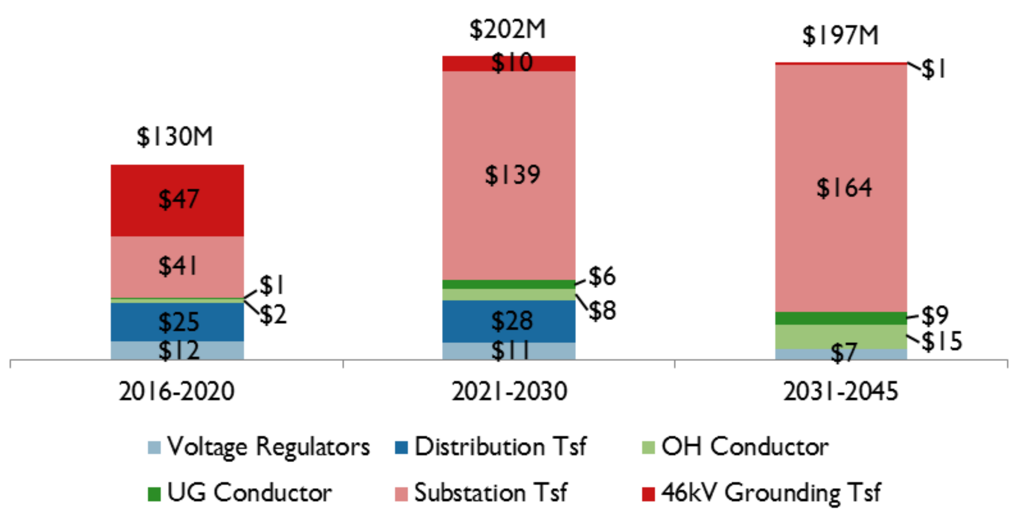

Figure N-7. O'ahu: Strategy 4 Annualized Integration Costs, Nominal $M

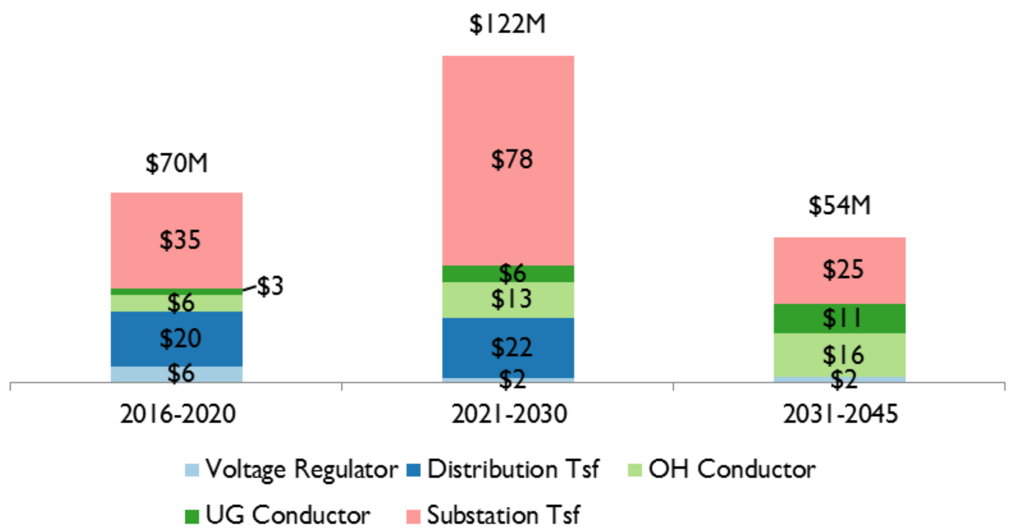

Figure N-8. Maui Island: Strategy 4 Annualized Integration Costs, Nominal $M

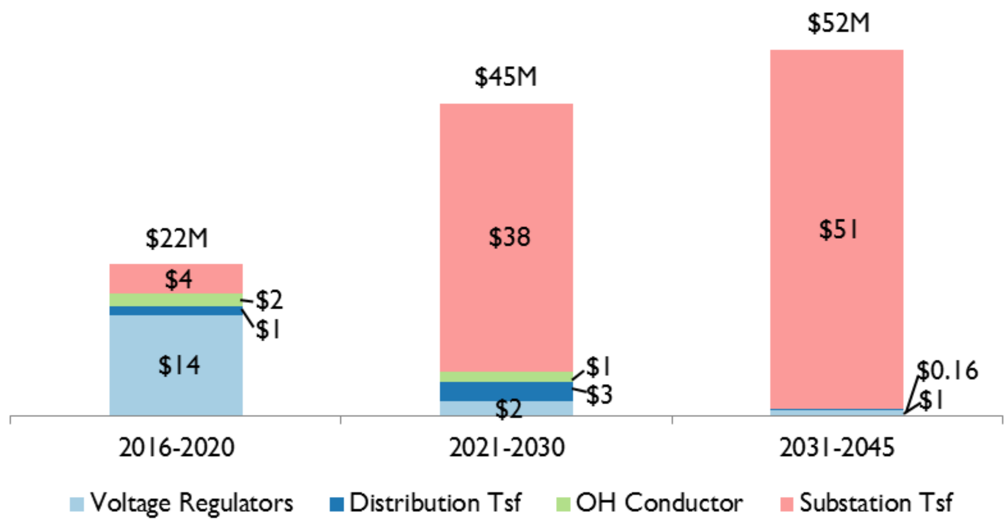

Figure N-9. Hawai'i Island: Strategy 4 Annualized Integration Costs, Nominal $M

Strategy 5: Traditional or Wires Solutions with DER Controls

This strategy is presented solely in the high DG-PV case because the PV penetration in the base case does not cause any substation transformer to exceed 50% of its thermal rating. In this strategy, the reverse power from PV is operationally allowed to exceed the 50% criterion but not exceed 100% of the substation transformer's thermal rating. In the high DG-PV case, any reverse power flow that exceeds of 100% of the transformer's thermal rating, triggers a substation upgrade; this criterion significantly reduces number of substation upgrades compared to Strategy 4. To protect the distribution system from the loss of all operational flexibility, controllability of advanced inverters for PV systems that exceed a circuit's operational circuit limit is a mandatory requirement. Much in the way that larger PV systems on the distribution system require direct control by the system operator,[11] the capability for the system operator to control these rooftop PV systems, aggregated by circuit, is essential to maintaining the operational flexibility and by extension, the safety and reliability of the distribution system.

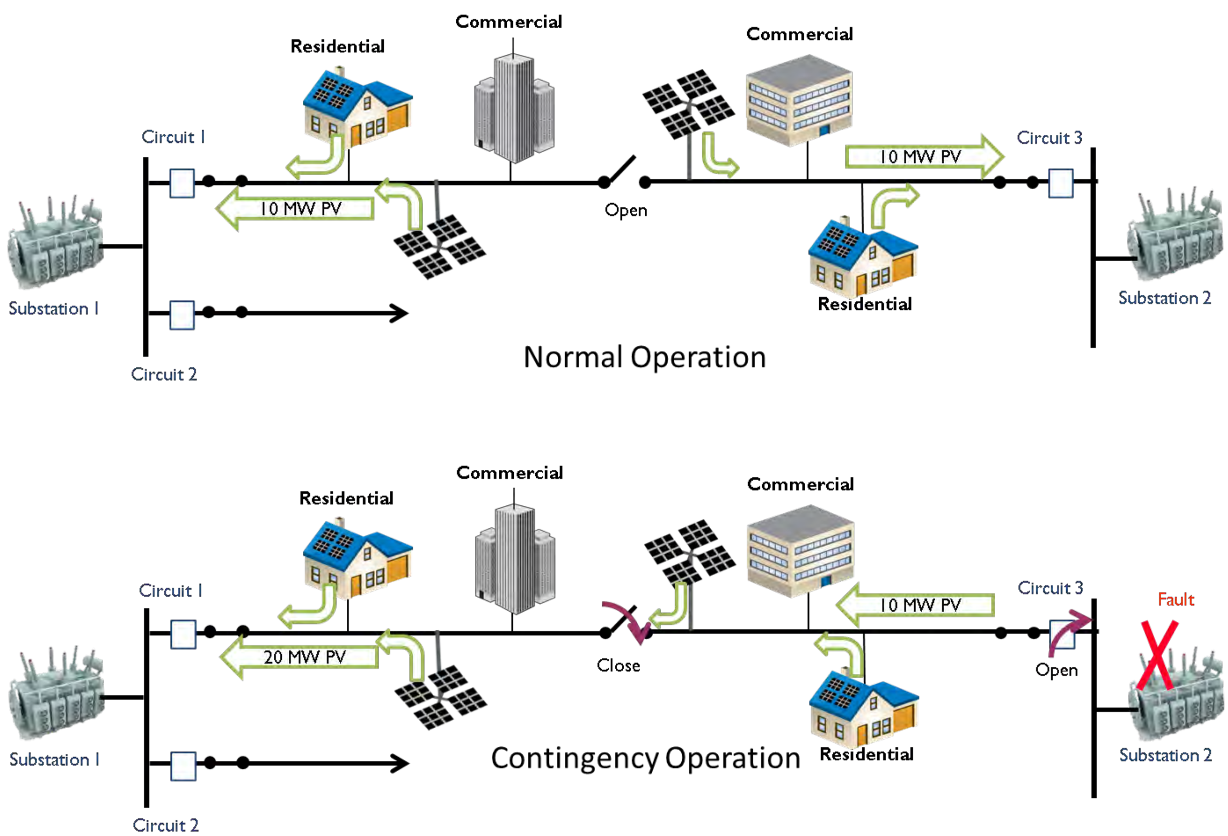

Figure N-10. Example of an Overloaded Substation During a Contingency Event

As Figure N-10 illustrates, if neighboring substations were both loaded with reverse power flow equal to 100% of their rated capacity (10MW), and one of these substations required servicing or suffered an outage due to a fault, the neighboring substation would need to provide reliable electric service to the circuit that is out of service. The out of service circuit would then be transferred to the neighboring substation transformer that remains in service to restore electric service to those customers experiencing an outage. Before doing so, the system operator would turn off the PV systems on the out of service circuit before restoring service to prevent those PV systems from turning on when service is restored. Failing to turn off the PV systems of the customers undergoing a transfer to

[11] Per Rule 14 paragraph H, supervisory control is mandatory for generating facilities with an aggregate capacity greater than 1MW to ensure prompt response to system abnormalities, and may be required for facilities between 250 KW and 1 MW. At Maui Electric and Hawai'i Electric Light, supervisory control is mandatory for facilities 250kW and greater. See HECO, MECO, HELCO Rule 14.

the neighboring circuit may then cause an overload of 200% (20MW) to the in-service substation transformer—the combination of the PV systems on the existing in-service circuits and the PV systems that were transferred from the now out-of-service circuits.

Figure N-11 through Figure N-13 summarize by island, the cost to integrate PV under strategy 5: traditional solutions with DER controllability in the high DG-PV case.

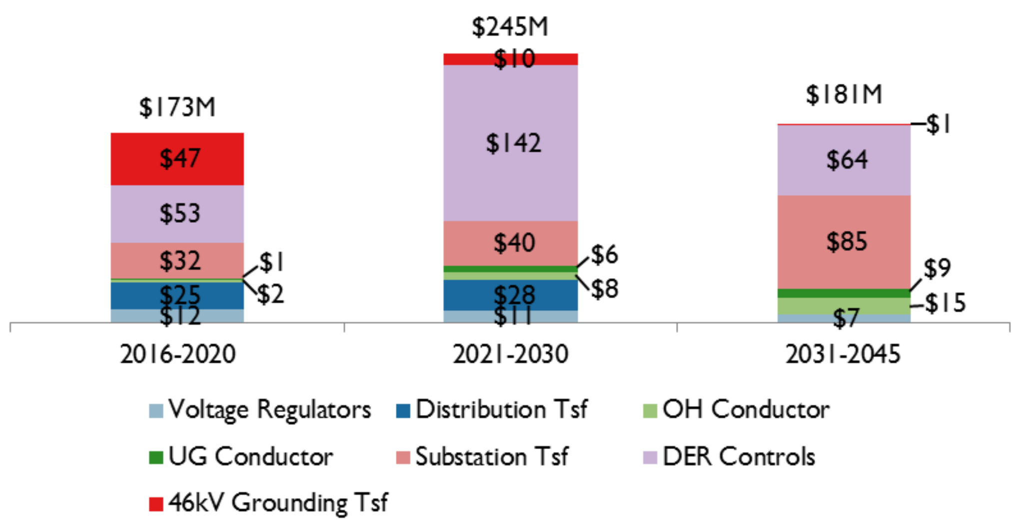

Figure N-11. O'ahu: Strategy 5 Annualized Integration Costs, Nominal $M

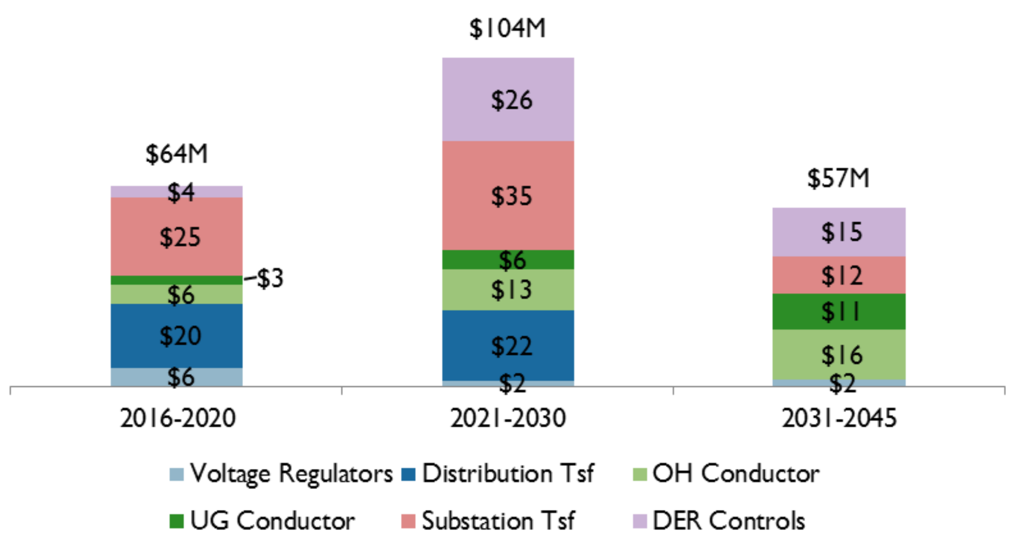

Figure N-12. Maui Island: Strategy 5 Annualized Integration Costs, Nominal $M

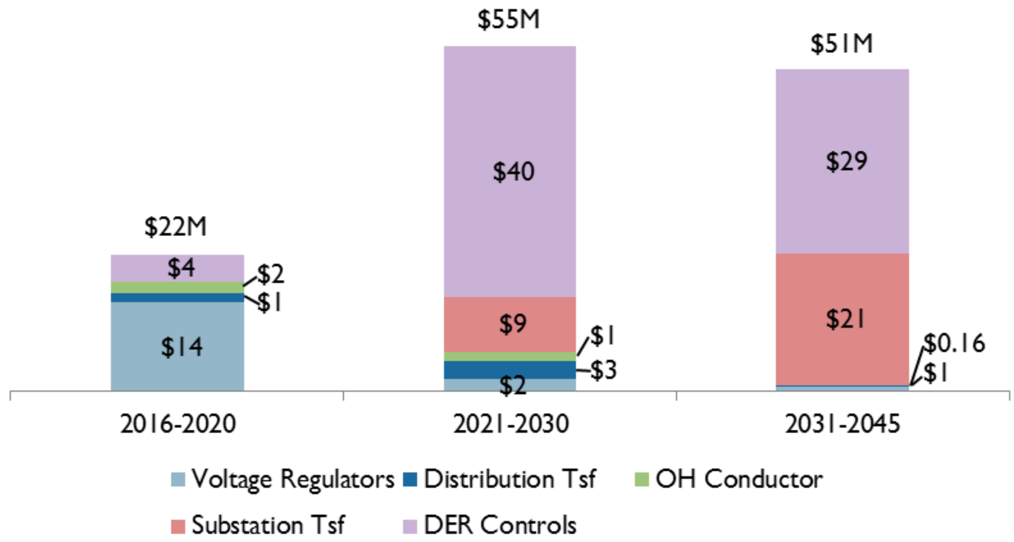

Figure N-13. Hawai'i Island: Strategy 5 Annualized Integration Costs, Nominal $M

Strategy 2 and 6: Technology or Non-Wires Solutions

Technology or non-wires solutions leverage new technologies and distributed energy resources to resolve PV impacts. Energy storage is selected to store excess energy thereby restoring any lost operational flexibility and avoiding the installation of new circuits or substations, as indicated in strategies 1 and 4. It is further assumed, that storage is strategically located on the distribution system to simultaneously alleviate overloaded conductors and service transformers.

One tenet of utility planning is to plan for failure of equipment. In the case of battery energy storage, if an energy storage system that was previously relied upon to alleviate an overload fails, contingencies must be taken to prevent the reverse power flow from the PV systems causing damage to the utility equipment. To plan for this contingency, PV facilities should be controllable through advanced inverters by the system operators in the event that a battery energy storage device fails, and consequently overloads equipment. If centralized control is unavailable, local energy management systems may autonomously manage the local energy while receiving signals from the utility during contingency operations to avoid unsafe operating conditions.

This strategy of utilizing battery energy storage systems is cost prohibitive compared to strategies 3 and 7; however, storage may provide other ancillary benefits—such as energy shifting and frequency regulation. Battery storage would also reduce sub-transmission congestion by reducing the amount of energy exported to the sub-transmission and transmission system.

Lastly, voltage quality impacts are mitigated with the use of var compensation devices as described in the previous section. While these technologies have yet to reach widespread adoption, this distributed voltage regulation philosophy and devices may represent the future of voltage regulation and improved distribution system efficiencies.

Figure N-14 through Figure N-19 summarize by island, the cost to integrate PV under strategy 2: technology solutions in the base DG-PV case, and strategy 4: technology solutions in the high DG-PV case.

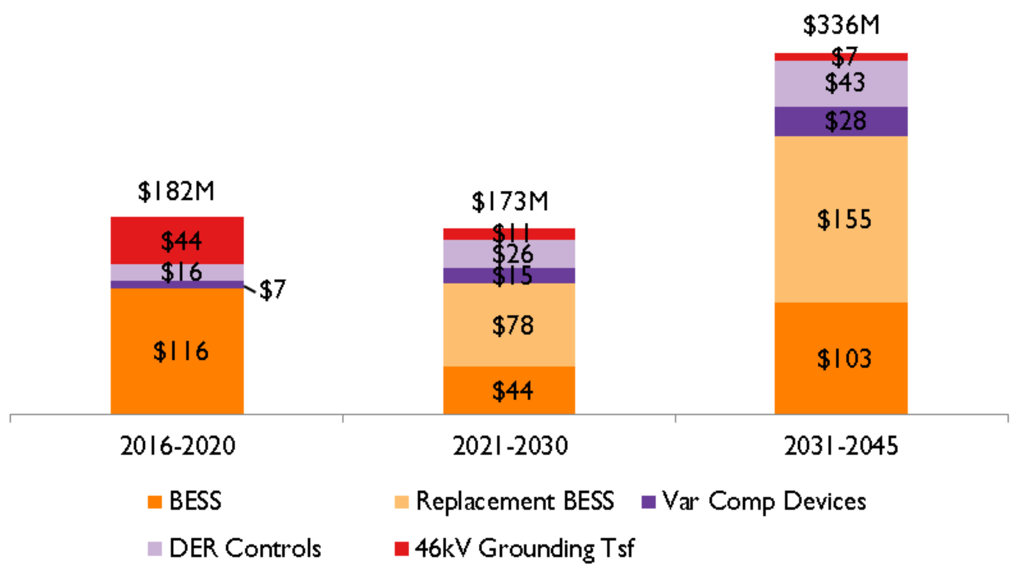

Figure N-14. O'ahu: Strategy 2 Annualized Integration Costs, Nominal $M

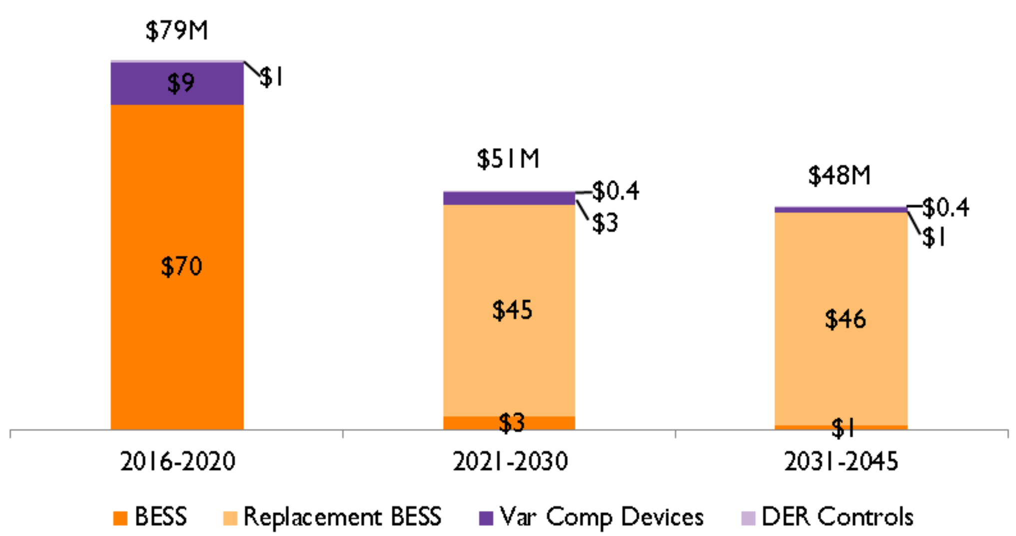

Figure N-15. Maui Island: Strategy 2 Annualized Integration Costs, Nominal $M

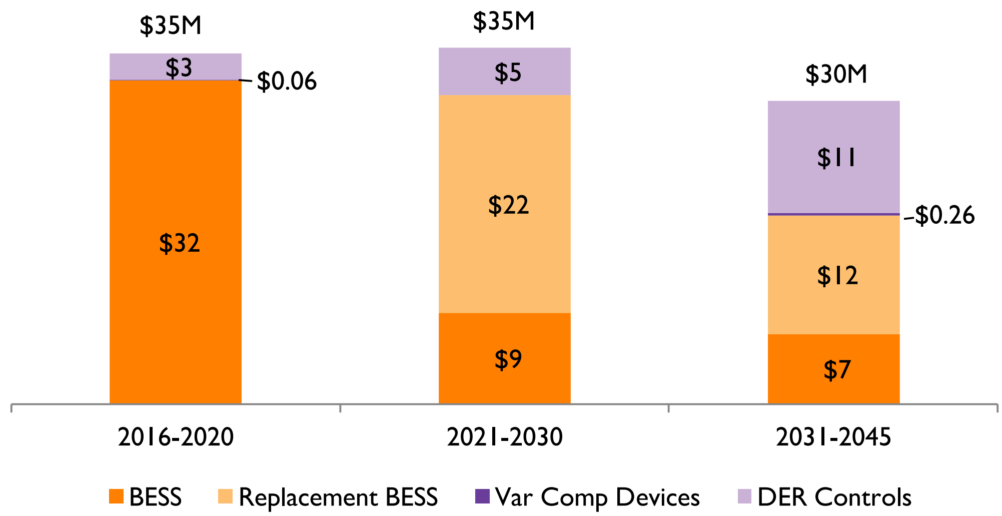

Figure N-16. Hawai'i Island: Strategy 2 Annualized Integration Costs, Nominal $M

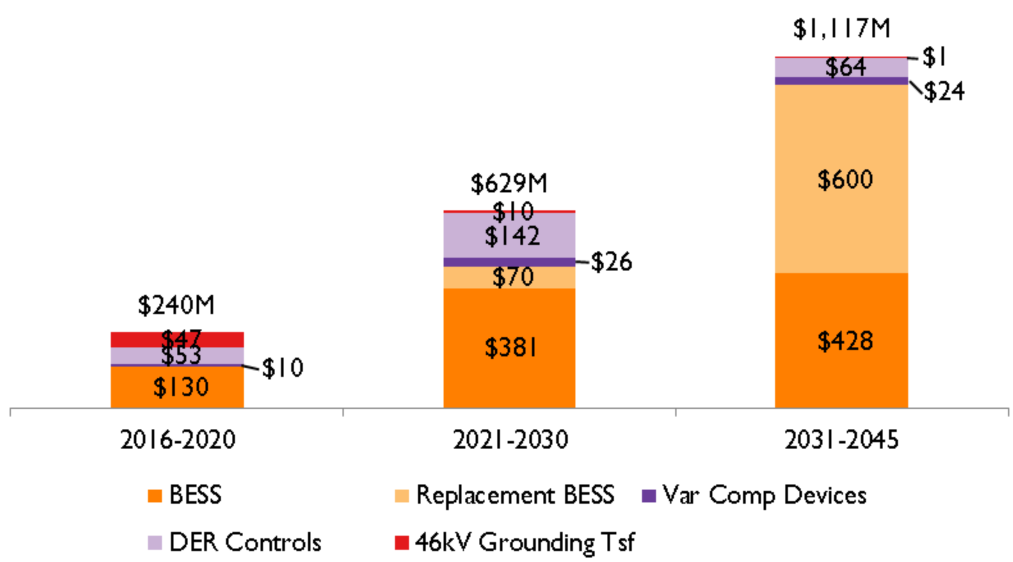

Figure N-17. O'ahu: Strategy 6 Annualized Integration Costs, Nominal $M

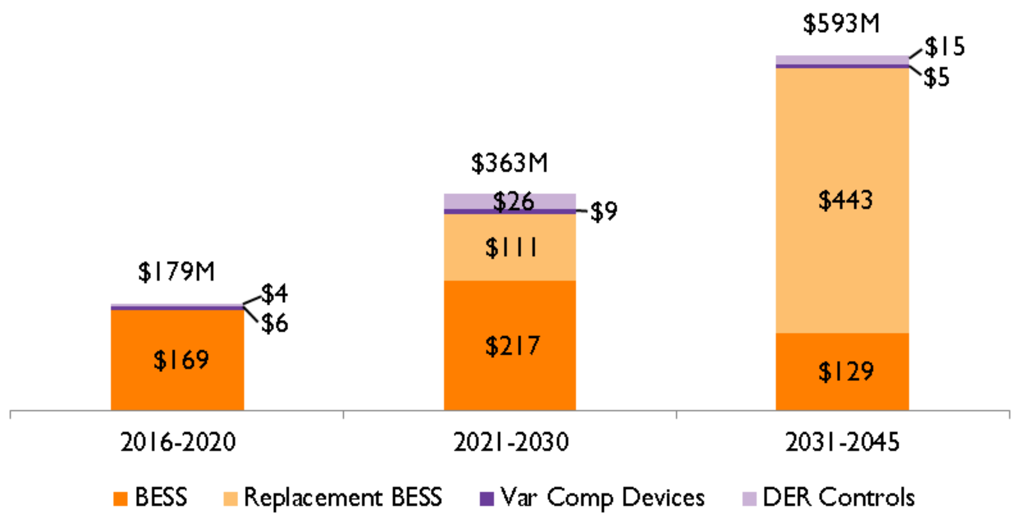

Figure N-18. Maui Island: Strategy 6 Annualized Integration Costs, Nominal $M

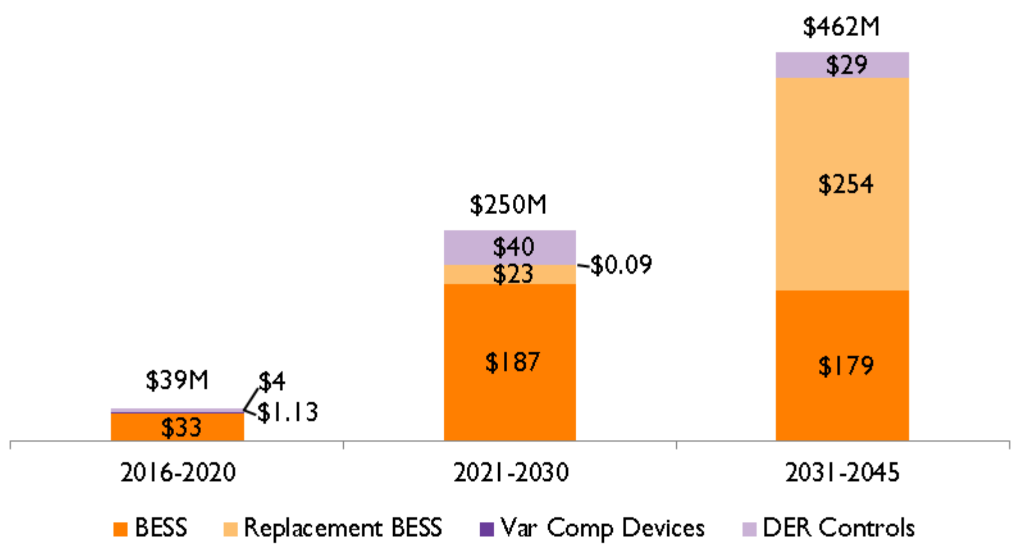

Figure N-19. Hawai'i Island: Strategy 6 Annualized Integration Costs, Nominal $M

Strategy 3 and 7: Least Storage Solution with Advanced Inverter Controls

This strategy is a variation of the technology solutions described in strategy 2 and 6, with the exception that normal operating practices are modified in that operational flexibility is not maintained during normal conditions, similar to strategy 5. The analysis demonstrates that storage is not required in the base DG-PV case and minimal storage in the high DG-PV case; however direct control of the PV facilities through the use of advanced inverter controls is required to allow the system operator to restore the operational flexibility when needed. Sub-transmission congestion is increased under this strategy but manageable with advanced inverter controls.

There is the potential for increased curtailment of distributed resources in these strategies but we are unable to quantify those amounts at this time, as it is highly dependent on the location of the DER assets.

Potential conductor upgrades are still required to avoid equipment overloads. Visibility of service transformer loading is more easily accessible than primary conductor loading. In this integration strategy, it is assumed that in the future, energy management system development will advance to have the capability to regulate the PV production in very localized areas as to not overload the service transformer. This measure of control can avoid service transformer replacements, and is reflected in the cost estimate of these strategies. Conductor upgrades were selected over storage because of the comparative cost effectiveness.

In the first 2 to 3 years of this strategy, voltage regulators and substation transformers are required at which time those solutions are phased out and replaced with advanced inverter controllability and var compensation devices.

Figure N-20 through Figure N-25 summarize by island, the cost to integrate PV under strategy 3 and strategy 7: least storage solution with advanced inverter controls.

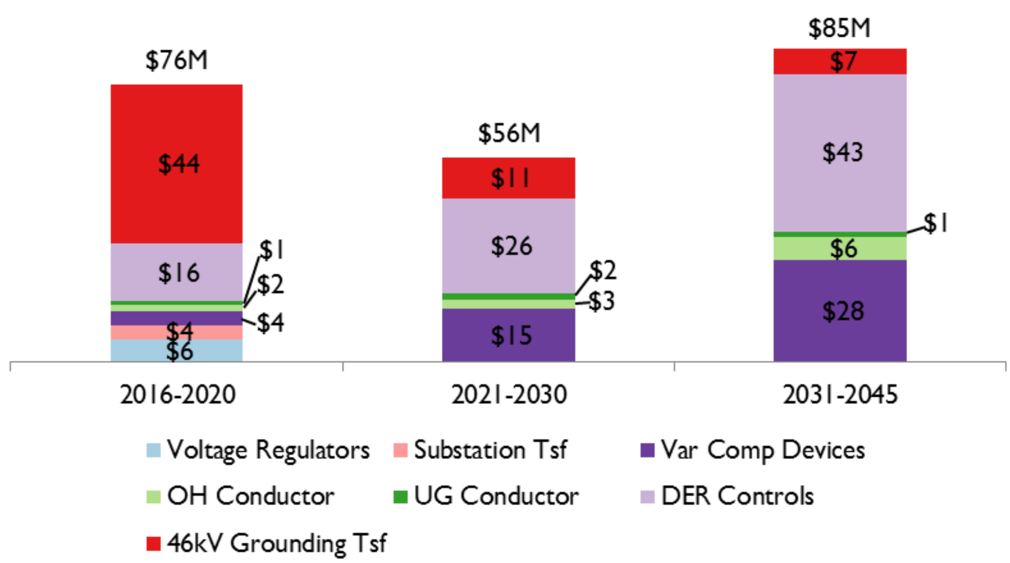

Figure N-20. O‘ahu: Strategy 3 Annualized Integration Costs, Nominal $M

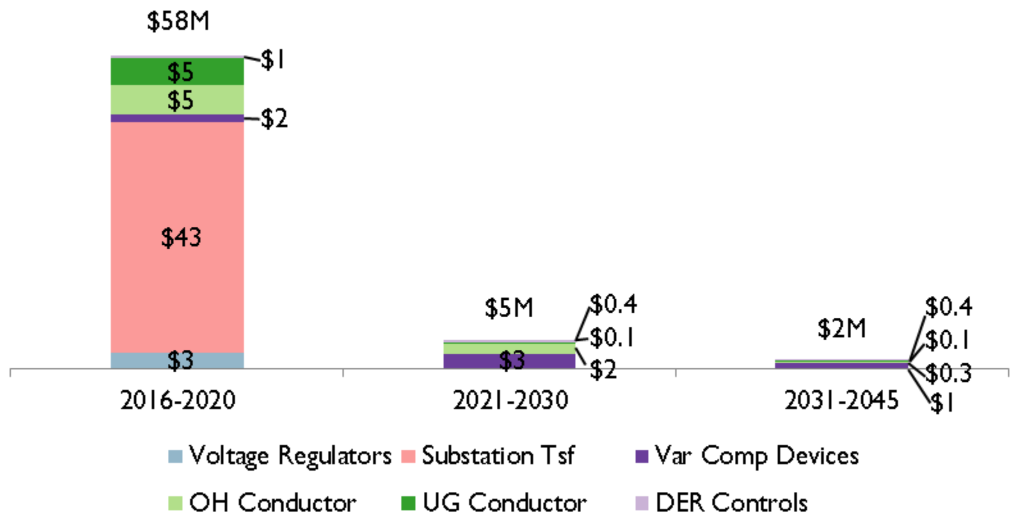

Figure N-21. Maui Island: Strategy 3 Annualized Integration Costs, Nominal $M

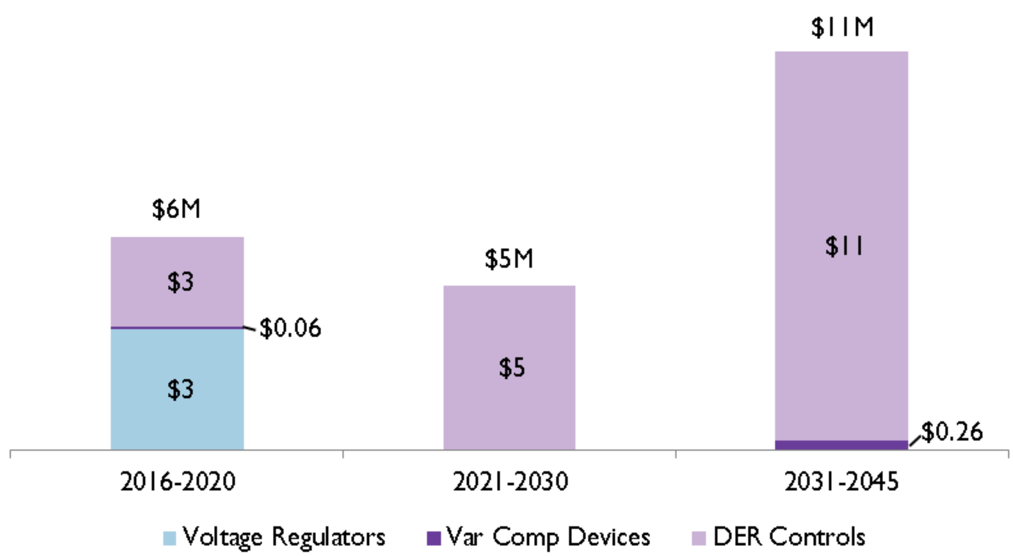

Figure N-22. Hawai‘i Island: Strategy 3 Annualized Integration Costs, Nominal $M

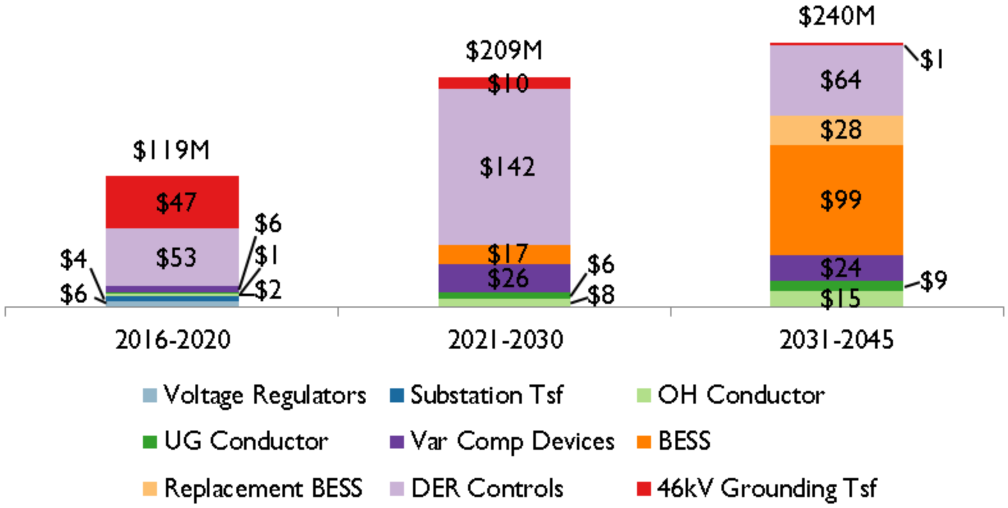

Figure N-23. O'ahu: Strategy 7 Annualized Integration Costs, Nominal $M

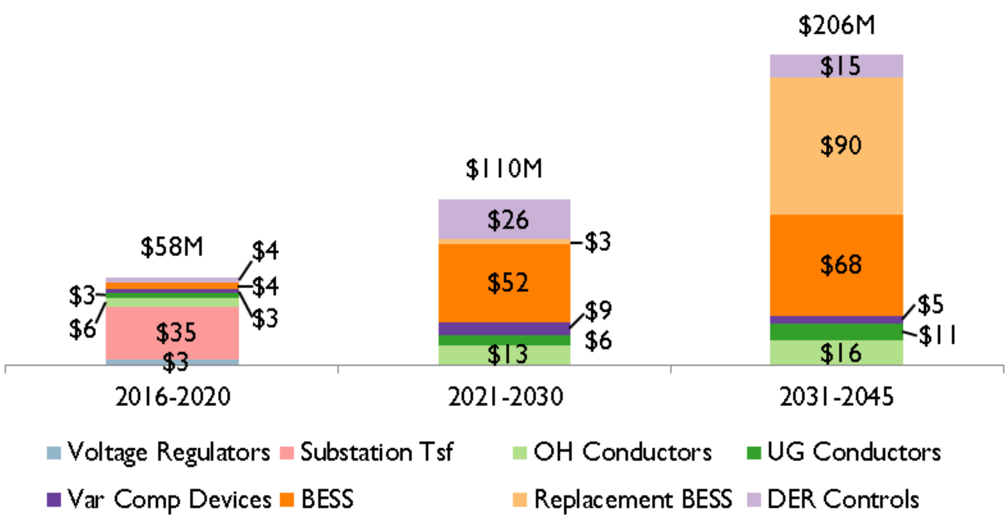

Figure N-24. Maui Island: Strategy 7 Annualized Integration Costs, Nominal $M

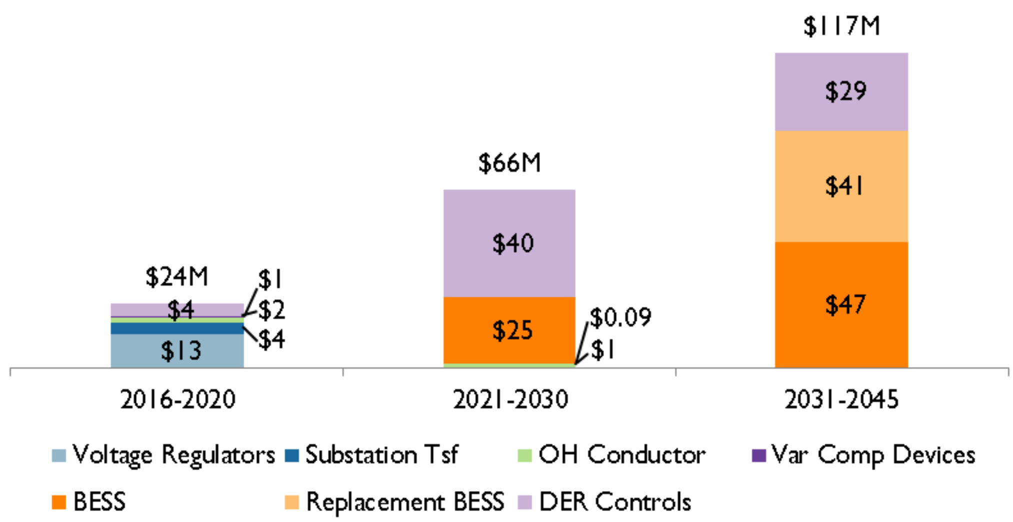

Figure N-25. Hawai'i Island: Strategy 7 Annualized Integration Costs, Nominal $M

Results of Integration Cost Analysis

Figure N-26 and Figure N-27 show the comparative costs for the different integration strategies for both the base and high DG-PV case per island in nominal $ with a 1.8% escalation rate.

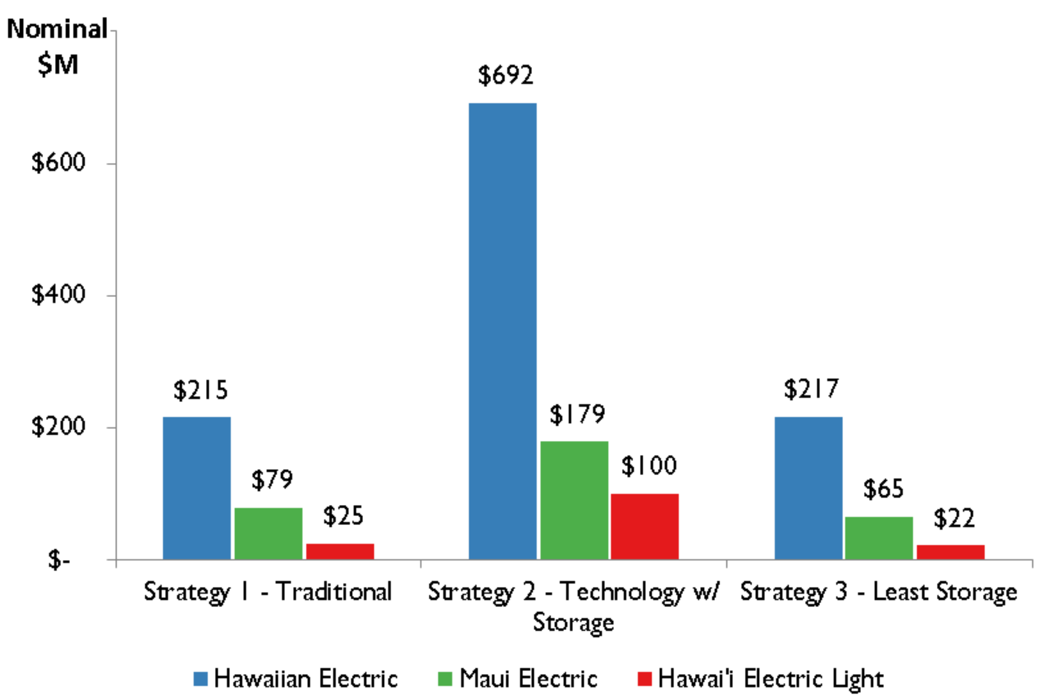

Figure N-26. Base DG-PV Forecast Total Integration Cost by Integration Strategy by Island.

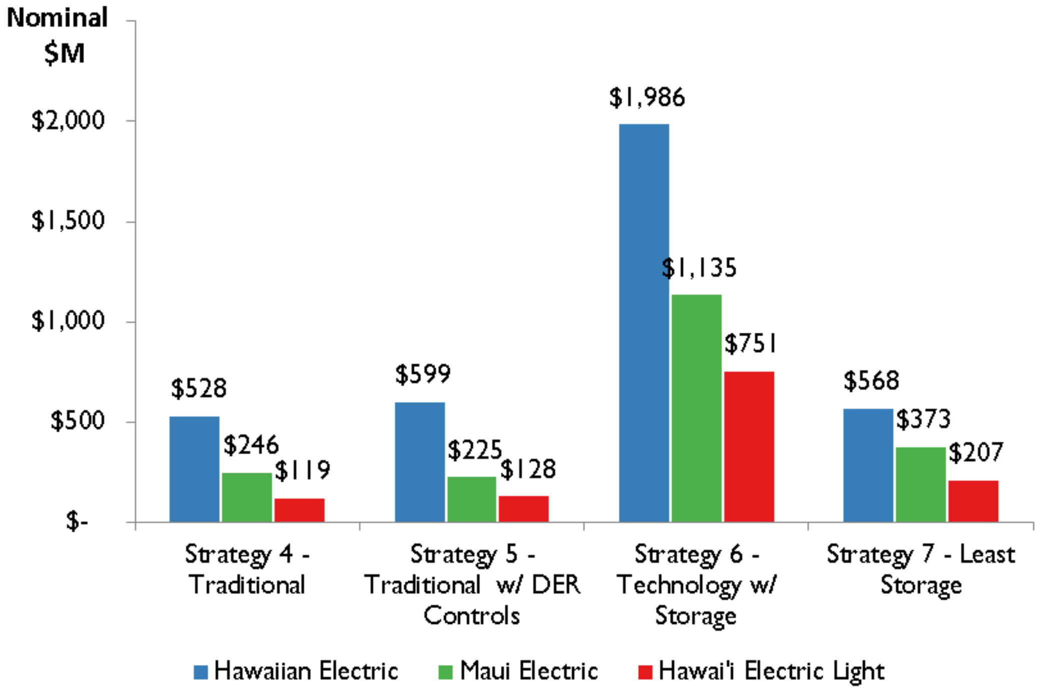

Figure N-27. High DG-PV Forecast Integration Cost by Integration Strategy by Island

When viewing the 30-year planning horizon, the least storage option is the is a cost competitive strategy, relative to the other options, across the three islands in the base DG-PV case (on O‘ahu the "traditional" strategy has a negligible cost difference when compared to the "least storage" strategy). However, in the high DG-PV case, the traditional integration strategy is the lowest cost strategy across the three islands. The least storage strategy becomes more cost competitive if the cost to implement advanced inverter DER controls is significantly lower than that assumed in this analysis.

Table N-4 summarizes the capital expenditures required in the near-term, 5-year period for each strategy, indicating that the least storage strategy is a cost competitive strategy.

Island Grid	Strategy 1	Strategy 2	Strategy 3	Forecasted PV
O‘ahu	$88M	$182M	$76M	608MW
Maui	$62M	$79M	$58M	125MW
Hawai‘i Island	$9M	$35M	$6M	112MW

Table N-4. Near-Term Cost Comparison

It is likely that a mix of solutions from different strategies is deployed to resolve various integration issues in the near-term to strike the appropriate balance between cost and schedule. We prioritize solutions that meet near-term interconnection needs but are also useful in the longer term timeframe. These analyses represent a sound guide to the capital investments required to integrate various levels of DG-PV when considering a portfolio of solutions.

Full tabular results of the various strategies are provided in the later section titled, Integration Strategy Cost Estimates, including integration results for Lana‘i and Moloka‘i.

Step 5: Derive Integration Cost Estimates

The following cost curves (Figure N-28 through Figure N-33) were developed in real or constant 2016$ terms to define the relationship between total DG-PV megawatts interconnected and the associated integration costs. These cost curves can be used to estimate the integration costs for a range of DG-PV with proper escalation rates applied.

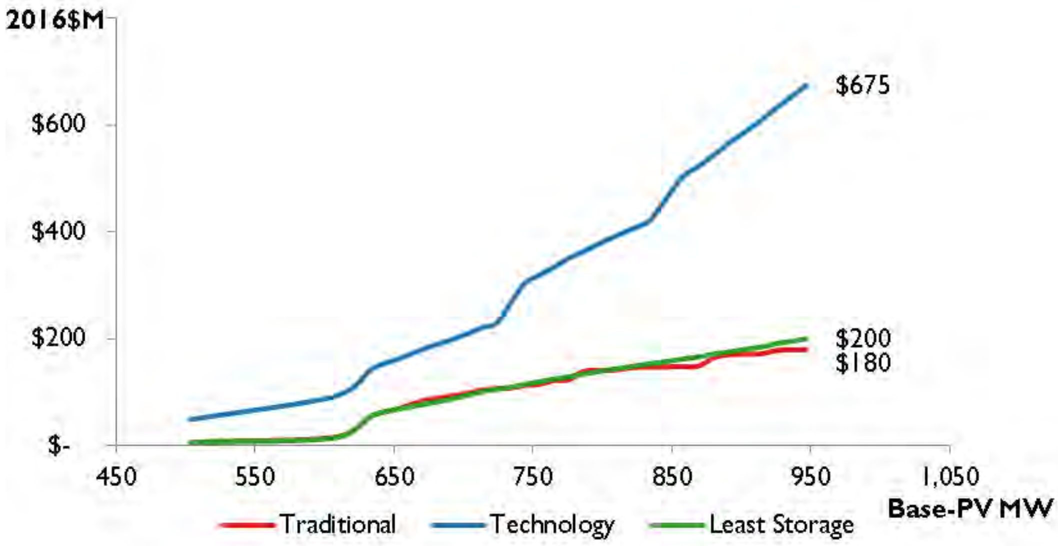

Figure N-28. O'ahu Base DG-PV Integration Cost Curve by Integration Strategy, Real $M

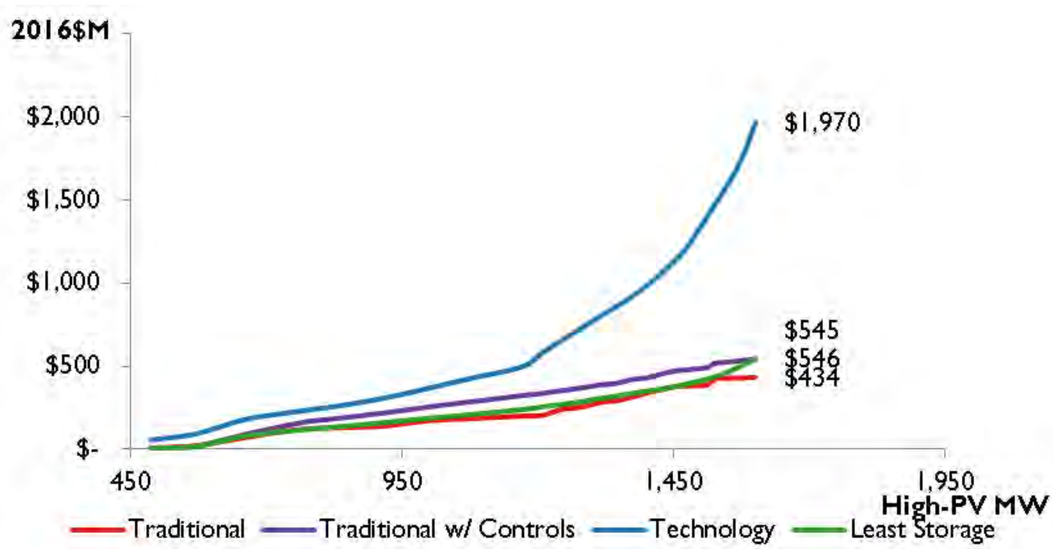

Figure N-29. O'ahu High DG-PV Integration Cost Curve by Integration Strategy, Real $M

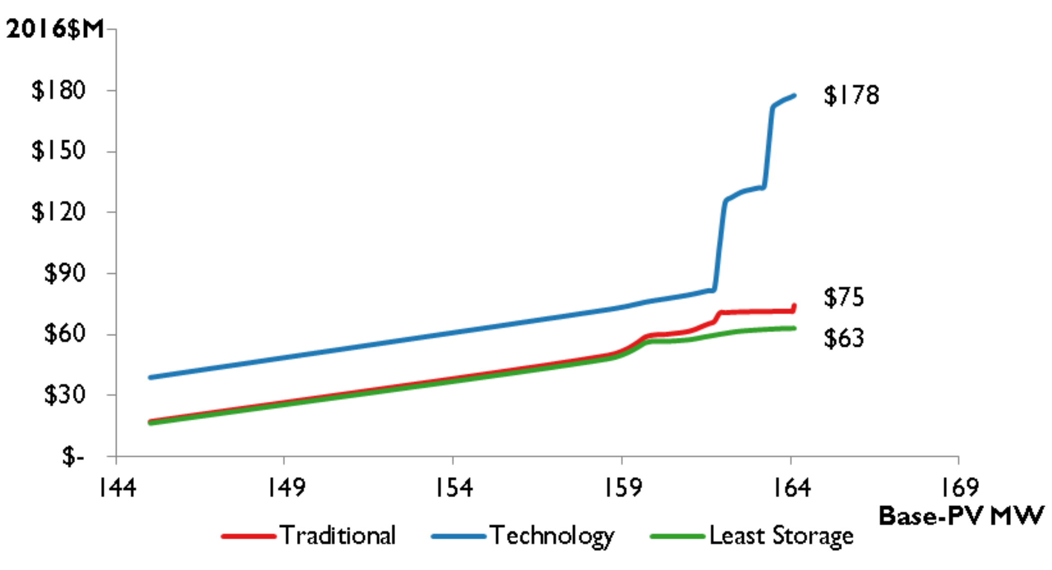

Figure N-30. Maui Base DG-PV Integration Cost Curve by Integration Strategy, Real $M

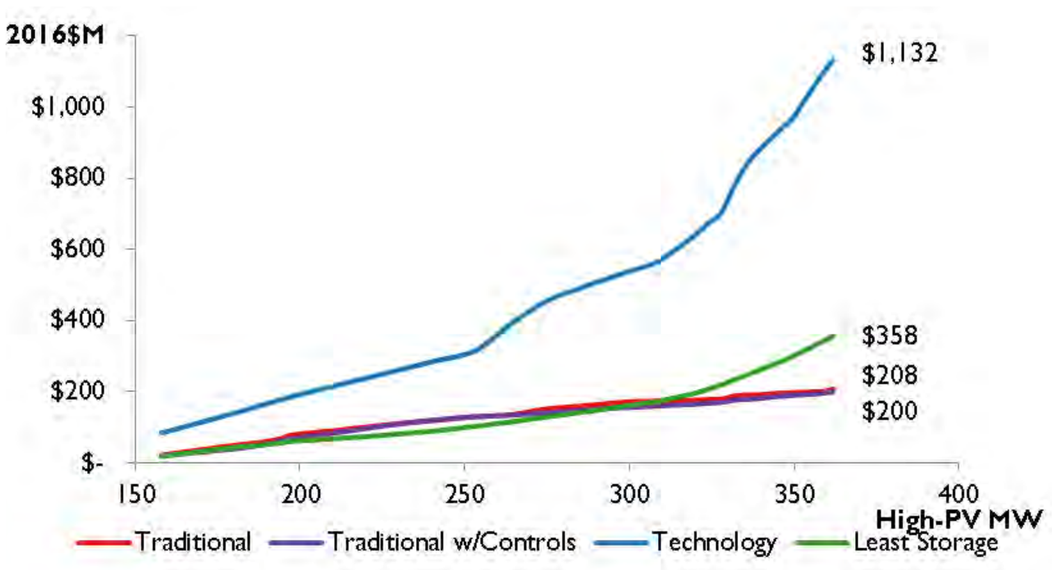

Figure N-31. Maui Island High DG-PV Integration Cost Curve by Integration Strategy, Real $M

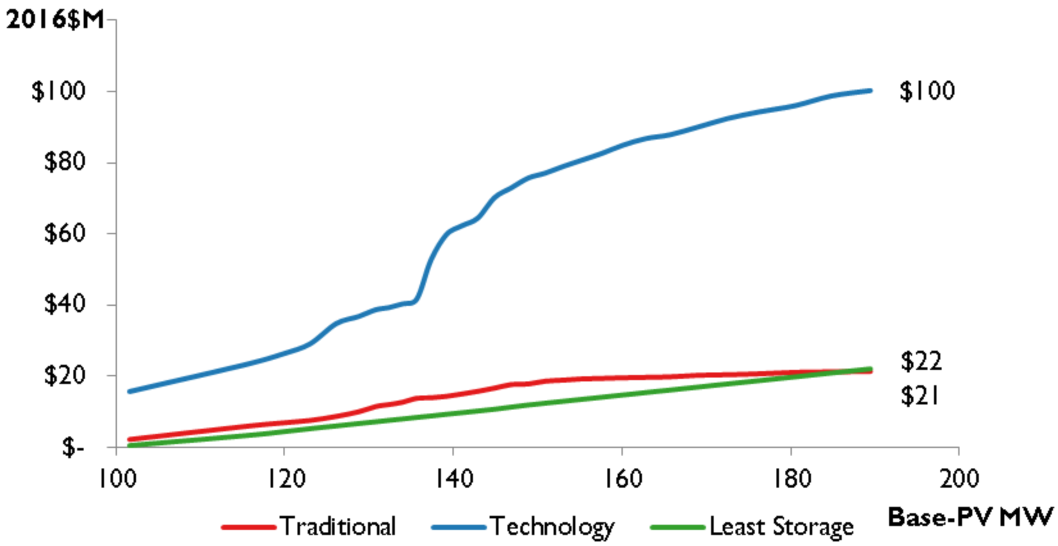

Figure N-32. Hawai'i Island Base DG-PV Integration Cost Curve by Integration Strategy, Real $M

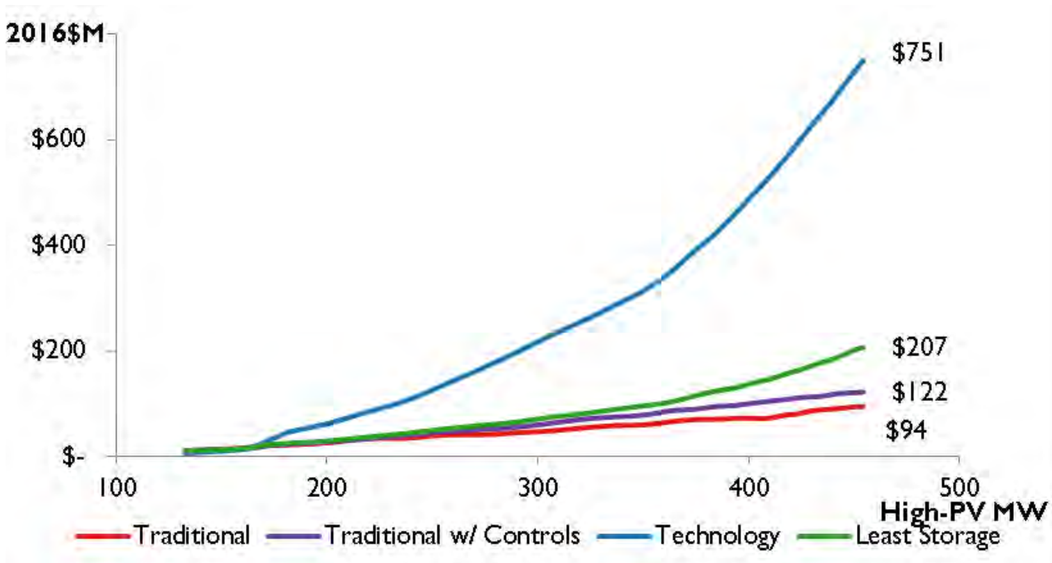

Figure N-33. Hawai'i Island High DG-PV Integration Cost Curve by Integration Strategy, Real $M

Integration Plans and Costs Sensitivities

Integration costs are sensitive to different policy decisions. For example, the vast majority of substation upgrades can be avoided if interconnection of PV is limited to the operational circuit limit until advanced inverter DER controllability is implemented.

Near-Term Capital Investments

Many of the near-term investments correct the deficiencies in power quality caused by the net energy metering program. If a program to retrofit net energy metering PV systems with advanced inverters, energy storage, or export limits were instituted, new grid export systems can sustainably interconnect at a lower capital integration cost. Alternatively, limiting DG-PV installation to no greater than the circuit's hosting capacity would reduce integration costs.

Energy Storage and Demand Response

Though storage was shown to be cost prohibitive, the figures below illustrate the storage requirements to integrate DG-PV in the base and high DG-PV cases. One PV integration benefit to storage at the circuit level is its ability to resolve potential sub-transmission or system level impacts by storing excess PV energy, while providing grid benefits with the discharge of the stored energy. Because of the interest in energy storage, the quantities of storage determined in this analysis are shown in Figure N-34 and Figure N-35.

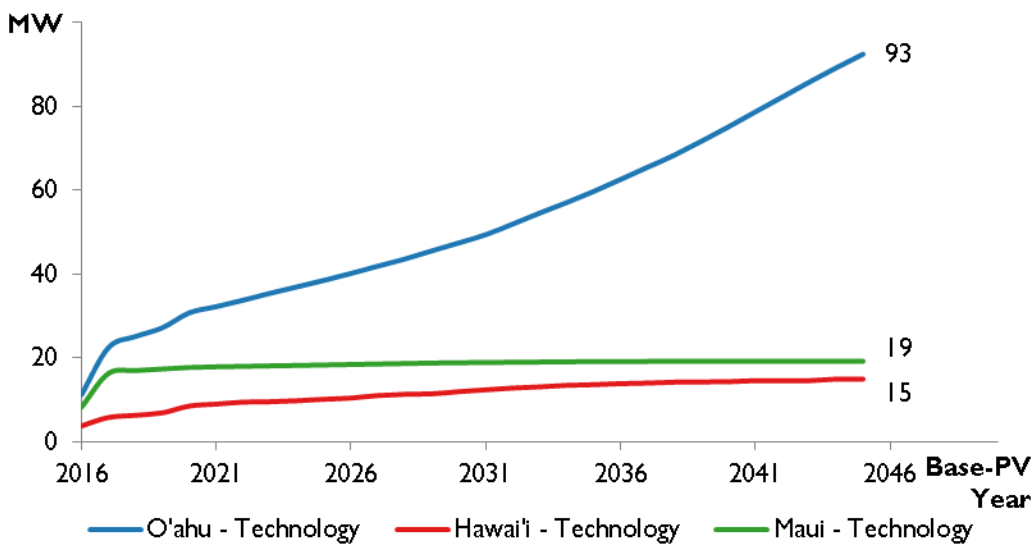

Figure N-34. Storage Requirements Determined in Strategy 2, by Island

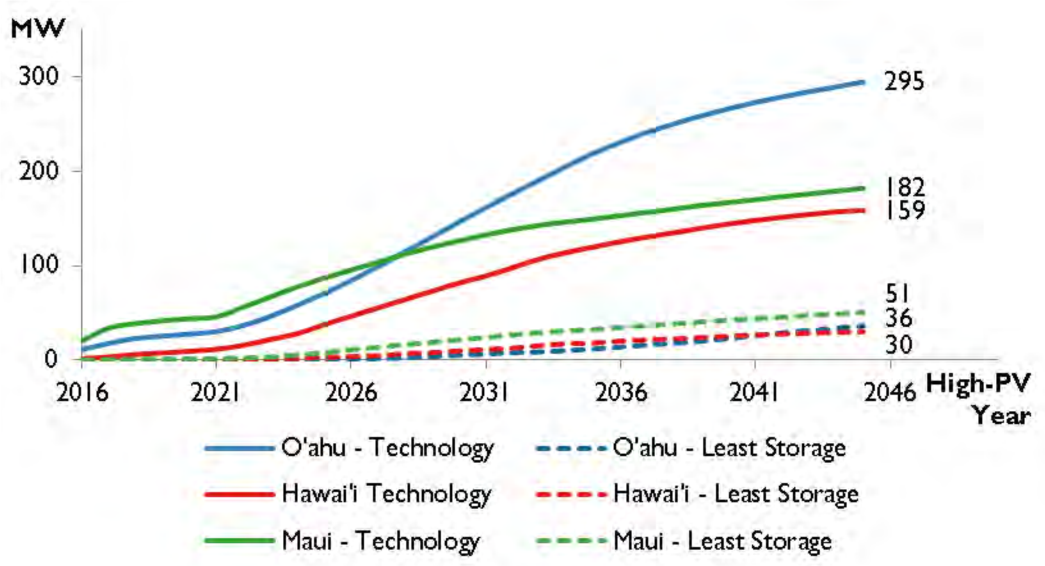

Figure N-35. Storage Requirements Determined in Strategy 6 and 7, by Island

If an energy storage system demand response program can closely coordinate deployment of assets to meet circuit needs, customer investment in storage can offset part of the capital costs associated with integration strategies 2 and 7.

Modified Load Profile

If customer behavior and demand response can effectively modify the traditional load profile of a distribution circuit to one that aligns customer consumption with DG-PV production (as illustrated in the Figure N-36), then the circuit hosting capacity would increase, and integration costs would be reduced in the mid- and long-term.

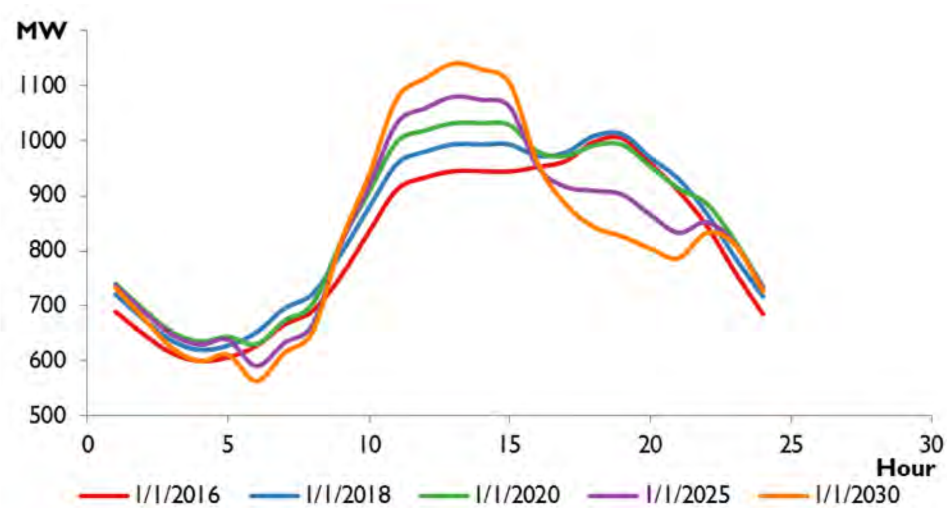

Figure N-36. Modified Load Profiles from Changing Customer Behavior and DR

Sub-Transmission Impacts

Within the seven integration strategies described above, sub-transmission impacts were not analyzed; at its current state, significant impacts to the sub-transmission system have not been observed. Where utility scale projects are interconnected to the sub-transmission system, interconnection studies were performed to resolve such impacts on a case-by-case basis. Based upon the recently completed circuit hosting capacity analysis in combination with the forecasted rooftop PV in this report, additional sub-transmission analysis will be required in the future, and would follow the process laid out in the circuit hosting capacity analysis. It would be reasonable to assume that impacts to the sub-transmission system would occur if all circuits connected to the sub-transmission circuit were built out with DG-PV to its circuit hosting capacity limit.

Based upon past interconnection studies, the recurrent technical issues on the sub-transmission system are: equipment overloads and ground fault overvoltage. The DGIP indicated the requirement for grounding transformers on the sub-transmission system to address ground fault overvoltage. Ground fault overvoltage can occur from a sub-transmission fault where the feed-in of fault current from the PV systems on the distribution system create a neutral-shift, ground fault overvoltage. Since the filing of the DGIP, we conducted an inverter ground fault overvoltage study with the National Renewable Energy Laboratory[12] to study the inverter behavior during single line to ground faults. While the tests were positive for distribution-level faults (wye-ground: wye-ground transformer configurations), testing of sub-transmission faults (delta-wye-ground transformer configurations) was inconclusive as to whether inverters will cause damaging ground fault overvoltages. More analysis and examination of this issue is necessary, so the integration costs conservatively assumed that sub-transmission grounding transformers were required where needed. On O‘ahu, 59 sub-transmission lines will exceed 100% penetration of daytime minimum load, requiring an installation of a grounding transformer on each of these circuits at a cost of $61M.[13] Each grounding transformer installation is $950,000 per transformer.

As congestion on the sub-transmission system increases interconnection costs for future sub-transmission generation increase, or in certain situations preclude future interconnections of sub-transmission projects (utility scale PV, wind, community based renewables, or firm thermal generation).

Technology integration strategies 2 and 6 depend heavily on energy storage deployment, effectively reducing the export of energy to the transmission system, and lowering the likelihood for sub-transmission capacity issues. Whereas, least storage strategies 3 and 7

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[12] Hoke, Nelson, et al (August 2015). *Inverter Ground Fault Overvoltage Testing*. Golden, CO: National Renewable Energy Laboratory, TP-5D00-64173.

[13] The Maui Electric and Hawai'i Electric Light systems do not have a sub-transmission system.

allow all energy above the operational circuit limits to flow to the sub-transmission system; thereby, increasing the likelihood for sub-transmission capacity issues.

One solution to consider in resolving potential sub-transmission congestion can be in the form of autonomous scheduled active power control or regulation or dynamic active power regulation remotely set by a system operator through the use of advanced inverters. This reserved active power can then be used for upward regulation, akin to the current operation of the bulk generating system. This solution would require SCADA for all elements of and equipment on the circuit. If PV is operated in this mode of operation, the sub-transmission congestion issues are effectively reduced by the reduction of reverse power flow.

Additional Considerations

Ancillary Services

Allowing reverse power flow up to 100% of the substation transformer—as in Strategies 3, 5, and 7—may preclude distributed resources from providing certain ancillary services because equipment will be near or at capacity. If for example, fast frequency response is desired but the transformer is loaded to full capacity, there is no additional capacity to provide services. However, using storage or scheduled active power control as part of a demand response program can create the necessary capacity to provide those services. These distributed energy resources and its intended operation must be holistically integrated in the overall planning of the distribution system.

Underfrequency Load Shed Scheme

With our distribution systems forecasted to experience deeper penetrations of PV, the underfrequency load shed scheme will continue to function at reduced effectiveness. As substations become net generators instead of net consumers of load, the shedding of the sub-transmission lines or distribution substations during underfrequency contingencies may further deepen the frequency sag. We are in the process of modifying our current underfrequency load shed scheme to better function under our high DG-PV environment. However, the forecasted PV growth further reinforces the need to design the system to avoid any load shedding during loss of generation contingencies.

Distribution System Overview and the Planning Process

The distribution system is the part of the electric power system that distributes or disperses power from the transmission system to individual customers. To deliver electricity to spatially diverse customers, engineers must strike the appropriate balance between reliability and power quality in order to design an economically viable distribution system.

The term "one-way power flow" is often said to describe the traditional method of power system design. One example of one-way power flow refers to the architecture of the distribution system. Due to the historical nature of the electric system, our distribution systems are predominantly designed as a radial system; that is, starting at the substation the distribution circuit is designed to handle greater capacity (or bigger wires) and tapers outward (or designed with less capacity, smaller wires) as the system distributes power to customers farther away from the substation. In other words, the capacity of the distribution circuit closest to the substation is the greatest as it must have the throughput to push power to all customers on a circuit. As one moves towards the end of a circuit (farther away from the substation), there are less customers left to serve; therefore, less capacity or throughput is required. When considering distributed generation, as more sources of generation are installed deeper into the distribution system, the smaller wires at the end of the circuit may lack the capacity to accommodate excess energy that flows back towards the substation.

One major component of the distribution system (Figure N-37) is the distribution substation; this is the point in the electric power system where the transmission or sub-transmission system delivers power at high voltages and converts the power to medium voltage for distribution of power at safer and more economical means. Our system consists of 2,400 volt, 4,160 volts, 11,500 volts, 12,470 volts, and 24,940 volt systems; these voltages are also known as the primary part or primary voltage of the distribution system. The substation generally feeds two circuits (or feeders) that serve as the means to deliver power to customers—circuit or circuits are often seen as poles and wires at the side of a road. Higher voltage distribution circuits have more capacity than lower voltage distribution systems. The lower voltage distribution systems—2,400 volt and 4,160 volt—are at higher risk for power quality and capacity issues. Often times, these issues are resolved by converting these circuits to a higher voltage, like 12,470 volts.

The final major component of the distribution system is the distribution transformer, sometimes referred to as the service transformer. This piece of equipment converts the medium voltage, 2,400 through 24,940 volts, to a lower voltage, 120/240 volts for final delivery to customers. The majority of appliances and devices used by consumers operate at 120 or 240 volts. Residential customers normally share a distribution transformer, and are delivered power via wires that branch out from transformer to each individual home. Larger customers who have bigger load requirements often have a dedicated transformer and service connection.

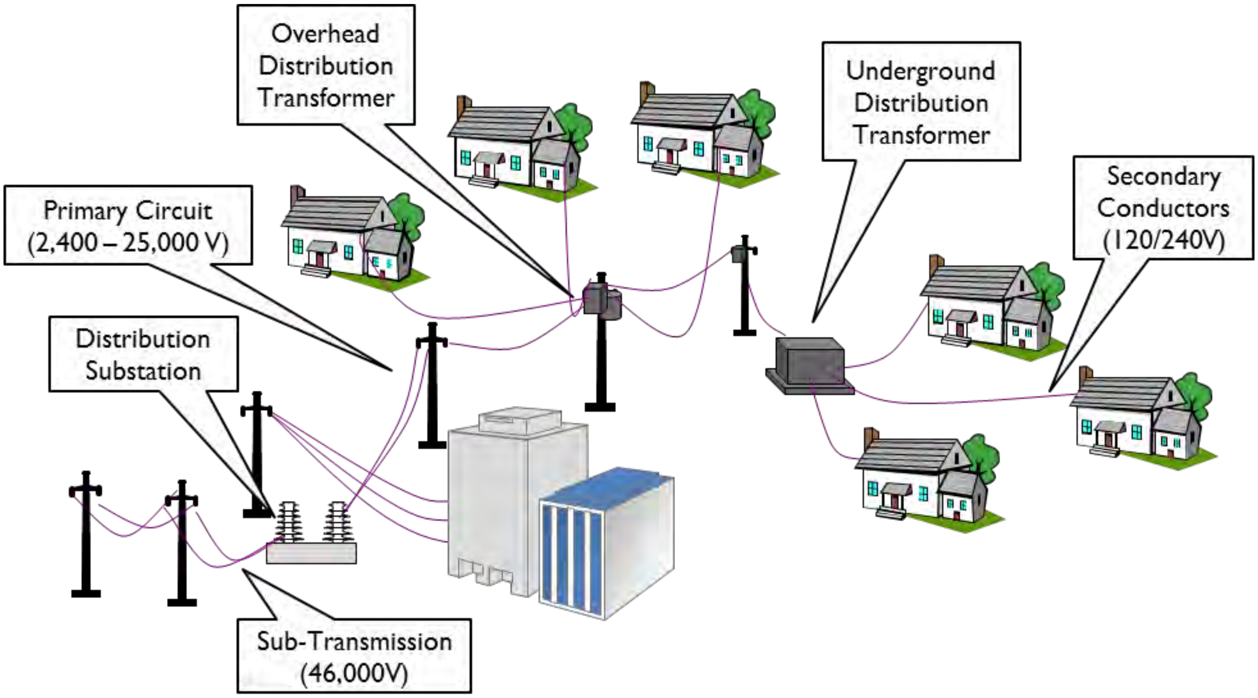

Figure N-37. Illustration of the Major Components of the Distribution System

To ensure the reliability of electric service to all customers, radially fed circuits are designed to be tied to one another, providing operators flexibility. The tying of circuits within the distribution system provides system operators the flexibility to re-configure the distribution system to restore power during a contingency and provide continuity of service—a power outage, equipment failure planned and unplanned maintenance. Distribution planners also re-configure circuits to maintain reliability and power quality for customers; for example, significant load growth may create power quality or capacity issues, in which case, a portion of a circuit is permanently transferred to another circuit to avoid overloading equipment or degrading power quality.

Figure N-38 illustrates the operational flexibility concept. Should a substation be taken out-of-service, planned or unplanned, a neighboring substation can restore power by closing a switch that ties the two circuits together, but normally open during normal operations.

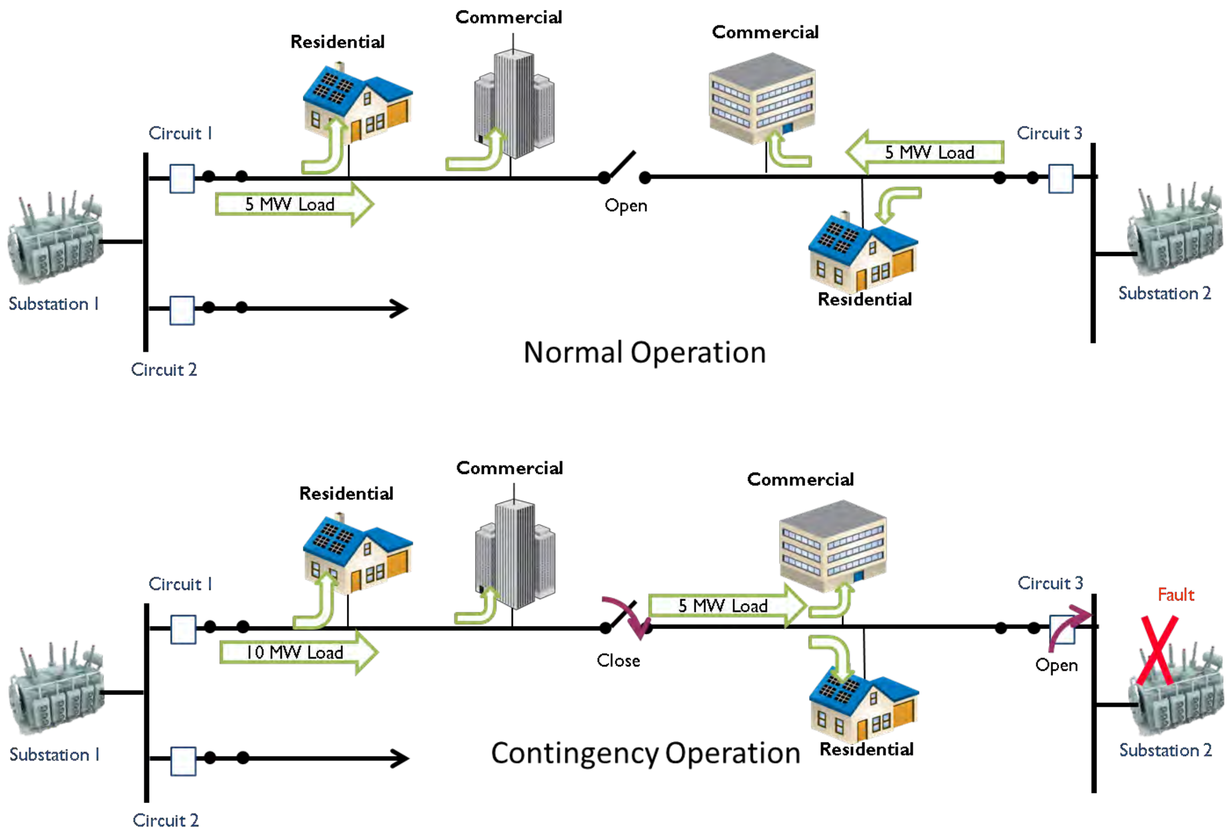

Figure N-38. Illustration of Operational Flexibility

Maintaining this operational flexibility plays a critical part in our ability to provide all customers reliable electric service.

Distribution Planning

On an annual basis, Distribution Planning conducts Substation Load and Capacity Analysis (SLACA) of the distribution system. This entails analysis of the previous year's substation transformer loading data—from our SCADA system, if available—to examine whether the highest peak load observed at the substation transformer violates distribution planning criteria. That is, a substation transformer shall have the capacity to not only accommodate the highest peak demand and any forecasted load growth, but also accommodate the load from the loss of a neighboring substation transformer—whether due to maintenance, equipment failure, or electrical fault—based upon the greater of the transformer loss-of-life rating, protective fuse rating, or cooling rating. Simply put, these ratings can be viewed as the thermal limit of the transformer. Failure to meet this criterion may result in overloaded equipment.

As discussed in the previous section, there are often multiple ties between circuits that provide system operators strategies to transfer or re-configure circuits to ensure a path to provide electric power service to customers. The SLACA analysis provides the system operators the confidence that at any point in the day, circuits may be re-configured to provide power during an abnormal or contingency situation. To better understand this concept, a rough rule of thumb can be applied; at peak load conditions, transformers are loaded to 50% of its rated capacity. In other words, a 50% transformer capacity reserve margin is maintained during normal circuit configurations or operations to ensure the operational flexibility of the system. This 50% reserve margin is then used to accommodate the load (or reverse power from PV) of a neighboring out-of-service substation transformer.

It is common for the configuration of the distribution system to change from year to year; this also affects PV hosting capacities. The following factors drive the dynamic nature of the distribution system: changing customer behavior, load growth, load imbalances, or degradation of power quality. Also, power quality is analyzed to ensure the appropriate standards are being met.

Upon completion of the SLACA analysis any planning criteria (including loss of operational flexibility) violations are addressed. Planners first seek the most efficient, least cost strategy. Permanently re-configuring a circuit by transferring load from a substation that exceeds the 50% capacity threshold to a neighboring substation that is loaded less than 50% represents a least cost solution that may restore operational flexibility. If least cost solutions fail to resolve the planning criteria violations, longer lead, more costly solutions are sought. Planners may order the construction of a new substation to create capacity. This type of solution is usually triggered based upon the 10-year load forecast that is updated each year and informed by the SLACA analysis. Load growth is determined by new customer service requests, economic or land development projections, and load trends. Unlike mainland utilities, the SLACA analysis is not completed seasonally. Hawaiʻi does not see significant load variations between winter and summer months, nor do we benefit from increased capability of utility equipment due to cooler ambient temperatures.

Distribution Planning also performs similar capacity analysis on the sub-transmission system, utilizing a similar process to resolve any capacity issues.

Distributed Energy Resource Planning

Distributed Energy Resource (DER) planning and the exponential PV growth experienced within the last couple of years have evolved the traditional distribution planning process. We recently employed a process and methodology to perform hosting capacity analysis to more appropriately predict and plan for the integration of DG-PV. As shown in Figure N-39, almost 50% of the distribution circuits have more PV than the daytime minimum load; reverse flow is the new norm on our Hawaiʻi grids. This is not the case for other systems throughout the United States.

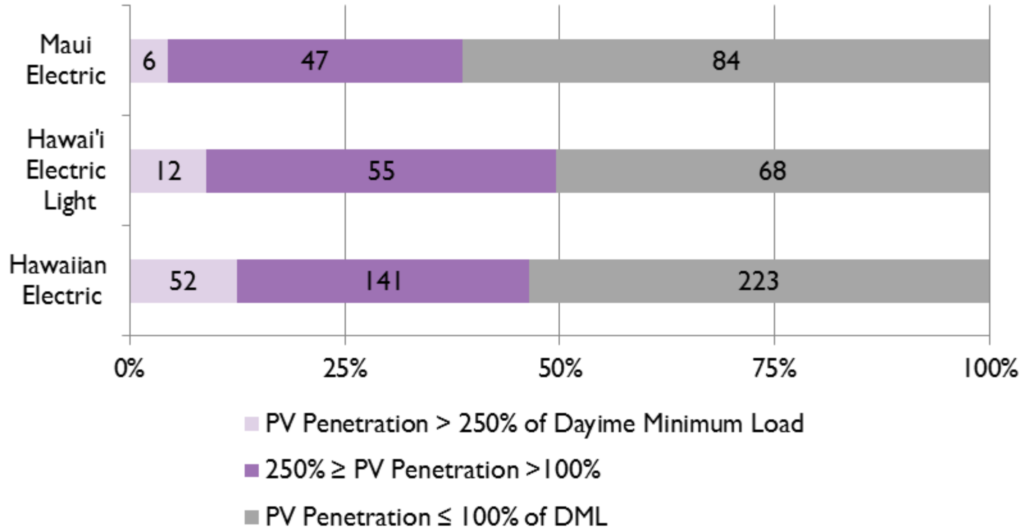

Figure N-39. Circuit PV Penetration in terms of Daytime Minimum Load

Based on previous high DG-PV penetration studies we have conducted coupled with field experience, the hosting capacity analysis evaluates (1) voltage quality, (2) equipment/wire capacity, and (3) operational flexibility. Undoubtedly, there are many more potential impacts that can affect the safety, reliability, and power quality of electric service to all of our customers, but these three issues are of the most immediate near-term concerns. As part of the hosting capacity analysis, an Operational Circuit Limit is also determined. This limit defines the reverse power threshold at the substation to maintain the operational flexibility of the circuit—the same principle described as part of the Distribution Planning process above.

A PV system's impact to a distribution system is highly dependent on its actual location with consideration of a number of factors: load, circuit impedance, neighboring PV systems. The hosting capacity analysis, through software simulation and analytics, determines the amount of PV a circuit can accommodate, regardless of location, before violating one of the three criteria discussed above. The interconnection of PV above that hosting capacity may incur capital improvements to mitigate any violations of the three hosting capacity criteria evaluated as part of the analysis. More details regarding the hosting capacity analysis can be found in the document titled, Rooftop PV Interconnections: A Methodology of Determining PV Circuit Hosting Capacity filed in Docket No. 2014-0192, on December 11, 2015.

As discussed in the preceding section, the distribution system is typically planned around the peak demand of a circuit. With the introduction of PV, distribution system planning must now account for minimum load, high generation periods in addition to the traditional evening peak period.

Under the net energy metering program, it was common practice for customers to size PV systems to offset their annual energy usage; the unintended technical consequence of this practice results in energy exports greater than the customer's typical peak load, which the distribution system was originally designed to accommodate. Consequently, during solar peak hours and daytime load levels, the peak export of energy onto the distribution system is greater in magnitude and more coincident than a customer's evening peak load. This increased power flow during minimum load periods will create power quality and capacity impacts that must be addressed before integrating high amounts of PV. Figure N-40 illustrates this point; a customer with the average 6 kW PV system is sized to zero-out his or her annual energy usage. This equates to an average monthly consumption of 806 kWh (531 kWh per weekdays per month). On a typical residential load profile, this energy usage equates to a peak demand of 2.3 kW. During daytime minimum loads, when this customer is assumed to be at work, the PV exports up to 4.5 kW. During daytime hours the load flow on the secondary part of the system is 4.5 kW, as opposed to its previous peak loading of 2.3 kW in the evening; nearly double the normal peak loading. This amount of exported energy exceeds any inherent design margins of the distribution system. A combination of smart energy management and circuit upgrades can restore the robustness of the distribution system.

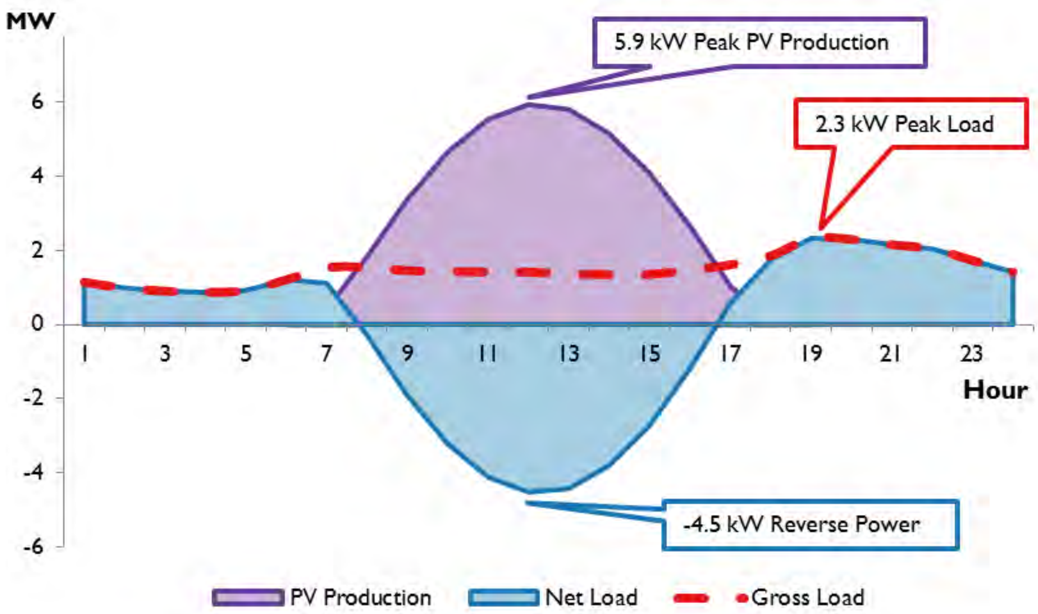

Figure N-40. Typical Weekday Residential Customer Load Profile with a 6 kW PV system sized to zero out annual consumption

The lack of PV production diversity as compared to the load diversity seen during the evening peak load creates PV integration challenges on the distribution system. Load diversity and the non-coincident behavior of customers allow distribution planners to plan the distribution system under peak demand conditions with certainty that customers will not simultaneously consume power at their peak; the distribution system is designed to accommodate diversified customer load—not the maximum potential load. For instance, a service transformer serving 10 homes typically has a diversity factor[14] as much as 45% In contrast, PV systems lack the same type of diversity as all PV production is a function of the sun's irradiance and not a function of diverse human behavior. Diversity from the placement, angle, and direction of a PV system equates to roughly 75-85% of the maximum capacity; not nearly the same overall reduction as load diversity. Put another way, the sun does not shine when customers are consuming the most electricity.

By necessity the hosting capacity analysis will develop into a more dynamic and granular analysis, as battery, electric vehicle, and the deployment of other distributed resources continue to grow. Battery standards that recognize a battery's unique characteristic of functioning as a load and generator will be established to create grid positive benefits; charging when the system most needs load, discharging when it most needs generation—in steady-state and transient conditions.

As the State continues to electrify transportation, electric vehicle charging should coincide with system needs as to not impress undue strain on utility equipment and operations. The dynamic hosting capacity models should integrate these behind the meter distributed energy resources to efficiently, design, plan, and operate the distribution grid.

DG-PV Forecasts by Distribution Circuits

DG-PV forecasts for all circuits on our three major grid are presented in Table N-5 through Table N-10 for Hawaiian Electric, Maui Electric, ad Hawaiʻi Electric Light circuits.

Legend: OCL = Operational Circuit Limit; HC = Posted Hosting Capacity

[14] Diversity factor is the ratio of actual coincient peak load to the sum of all customers' non-coincident peak peak load. For example, the total non-coincident peak load for 10 homes may be 100kW but at any given time the total loads that must be served by the utility 4.5kW. In other words, not all homes are running its water heater, oven, and other appliances at the same time.

Hawaiian Electric Distribution Circuit Base DG-PV Forecast (kW)

Circuit	OCL	HC	2016	2017	2018	2019	2020	2030	2040	2045
Circuit 1	6,044	5,137	1,119	1,372	1,432	1,479	1,522	1,803	2,170	2,170
Circuit 2	5,170	2,392	3,308	4,055	4,233	4,370	4,499	5,287	5,287	5,287
Circuit 3	5,692	484	961	1,178	1,229	1,269	1,307	1,547	1,884	2,085
Circuit 4	361	307	–	–	–	–	–	–	–	–
Circuit 5	4,770	3,284	3,163	3,877	4,047	4,179	4,302	5,094	6,201	6,523
Circuit 6	2,556	2,173	383	470	490	506	521	617	751	831
Circuit 7	1,198	1,019	148	181	189	195	201	217	217	217
Circuit 8	1,940	319	1,020	1,250	1,305	1,348	1,387	1,643	2,000	2,214
Circuit 9	1,301	951	1,041	1,276	1,332	1,375	1,416	1,677	2,041	2,058
Circuit 10	5,107	4,341	2,003	2,456	2,564	2,647	2,725	3,227	3,928	4,348
Circuit 11	689	585	–	–	–	–	–	–	–	–
Circuit 12	1,714	1,457	–	–	–	–	–	–	–	–
Circuit 13	6,272	5,331	154	188	196	203	209	247	301	333
Circuit 14	573	438	635	778	813	839	864	960	960	960
Circuit 15	5,750	4,887	3,480	4,266	4,454	4,598	4,734	5,606	6,824	7,553
Circuit 16	5,701	1,825	2,208	2,706	2,825	2,917	3,003	3,556	4,329	4,791
Circuit 17	5,699	4,605	2,659	3,259	3,402	3,513	3,616	4,282	5,213	5,677
Circuit 18	2,402	2,042	–	–	–	–	–	–	–	–
Circuit 19	3,003	2,553	–	–	–	–	–	–	–	–
Circuit 20	7,330	6,185	529	648	677	699	719	852	1,037	1,148
Circuit 21	5,331	4,499	178	218	228	235	242	287	349	386
Circuit 22	4,733	3,901	–	–	–	–	–	–	–	–
Circuit 23	6,741	5,747	1,055	1,293	1,350	1,393	1,434	1,699	2,068	2,289
Circuit 24	1,448	575	840	1,029	1,074	1,109	1,142	1,352	1,493	1,493
Circuit 25	7,601	4,006	2,933	3,595	3,753	3,875	3,989	4,724	5,750	6,365
Circuit 26	1,005	854	246	302	315	325	335	397	483	534
Circuit 27	771	465	568	696	727	750	772	915	1,113	1,233
Circuit 28	4,190	3,686	565	693	723	747	769	910	1,108	1,226
Circuit 29	4,187	3,386	3,514	4,308	4,497	4,643	4,780	5,660	6,296	6,296
Circuit 30	6,569	5,583	1,144	1,402	1,464	1,511	1,556	1,842	2,243	2,483
Circuit 31	5,359	4,555	1,151	1,411	1,473	1,520	1,565	1,565	1,565	1,565
Circuit 32	1,211	1,029	457	560	585	604	622	736	833	833
Circuit 33	3,114	1,758	–	–	–	–	–	–	–	–
Circuit 34	3,107	2,641	–	–	–	–	–	–	–	–
Circuit 35	6,611	5,619	2,025	2,482	2,591	2,675	2,754	2,777	2,777	2,777
Circuit 36	4,151	3,635	208	255	266	275	283	335	408	452

Circuit	OCL	HC	2016	2017	2018	2019	2020	2030	2040	2045
Circuit 37	2,806	2,385	–	–	–	–	–	–	–	–
Circuit 38	4,488	3,737	273	334	349	361	371	439	535	592
Circuit 39	1,403	1,193	–	–	–	–	–	–	–	–
Circuit 40	1,873	249	1,865	2,286	2,387	2,464	2,537	2,673	2,673	2,673
Circuit 41	3,266	2,252	312	383	399	412	424	503	612	677
Circuit 42	3,126	2,657	–	–	–	–	–	–	–	–
Circuit 43	4,186	3,558	520	637	665	687	707	838	1,020	1,129
Circuit 44	5,293	1,234	283	347	362	374	385	455	554	614
Circuit 45	5,673	4,822	2,476	2,476	2,476	2,476	2,476	2,476	2,476	2,476
Circuit 46	1,380	1,161	1,074	1,316	1,374	1,419	1,460	1,666	1,666	1,666
Circuit 47	3,559	3,025	–	–	–	–	–	–	–	–
Circuit 48	4,529	3,850	–	–	–	–	–	–	–	–
Circuit 49	3,102	2,637	3,117	3,821	3,989	4,119	4,240	5,021	5,337	5,337
Circuit 50	5,323	4,426	2,909	3,566	3,722	3,843	3,956	4,685	5,703	5,913
Circuit 51	3,931	3,126	1,844	2,260	2,359	2,436	2,508	2,970	3,615	4,001
Circuit 52	4,736	2,867	2,292	2,809	2,932	3,028	3,117	3,691	4,493	4,973
Circuit 53	5,383	6,171	3,342	4,097	4,277	4,416	4,546	5,383	6,553	7,253
Circuit 54	4,830	4,355	3,074	3,768	3,870	3,870	3,870	3,870	3,870	3,870
Circuit 55	6,640	5,120	2,810	2,810	2,810	2,810	2,810	2,810	2,810	2,810
Circuit 56	2,289	1,001	763	935	976	1,007	1,037	1,228	1,495	1,655
Circuit 57	5,837	3,689	748	917	958	989	1,018	1,205	1,467	1,624
Circuit 58	3,014	2,562	4	4	5	5	5	6	7	8
Circuit 59	6,331	3,121	246	301	314	325	334	396	482	533
Circuit 60	3,667	3,117	338	415	433	447	460	545	663	734
Circuit 61	2,895	2,461	190	233	243	251	258	306	373	412
Circuit 62	4,599	4,180	2,446	2,998	3,130	3,231	3,326	3,939	4,795	5,308
Circuit 63	4,789	4,544	2,668	3,271	3,414	3,525	3,629	4,297	5,231	5,581
Circuit 64	4,747	4,445	4,837	5,929	6,021	6,021	6,021	6,021	6,021	6,021
Circuit 65	3,651	3,341	1,534	1,880	1,962	2,026	2,086	2,470	2,534	2,534
Circuit 66	3,366	2,861	1,786	2,189	2,285	2,359	2,429	2,876	3,498	3,498
Circuit 67	4,703	3,402	2,370	2,370	2,370	2,370	2,370	2,370	2,370	2,370
Circuit 68	4,308	3,662	1,984	2,433	2,539	2,622	2,699	3,196	3,549	3,549
Circuit 69	5,586	4,100	2,163	2,651	2,768	2,858	2,942	3,484	4,241	4,694
Circuit 70	4,351	3,698	1,461	1,791	1,870	1,931	1,987	2,353	2,865	3,171
Circuit 71	8,420	7,157	3,285	4,027	4,204	4,340	4,468	5,291	6,441	7,130
Circuit 72	930	506	8	10	10	11	11	13	16	18
Circuit 73	5,289	4,496	2,955	3,622	3,781	3,904	4,019	4,759	5,793	6,412
Circuit 74	6,899	841	1,018	1,248	1,303	1,345	1,385	1,640	1,996	2,209

Circuit	OCL	HC	2016	2017	2018	2019	2020	2030	2040	2045
Circuit 75	7,393	4,965	160	196	204	211	217	257	313	346
Circuit 76	3,528	2,999	–	–	–	–	–	–	–	–
Circuit 77	2,673	2,594	52	64	66	69	71	84	102	113
Circuit 78	7,301	1,140	3,048	3,737	3,901	4,027	4,146	4,910	5,936	5,936
Circuit 79	1,470	706	1,894	1,894	1,894	1,894	1,894	1,894	1,894	1,894
Circuit 80	5,814	3,867	1,640	2,011	2,099	2,167	2,231	2,642	3,216	3,560
Circuit 81	5,352	3,730	2,687	3,294	3,439	3,551	3,655	4,328	5,269	5,832
Circuit 82	220	445	136	167	174	180	185	220	267	296
Circuit 83	1,968	1,673	904	904	904	904	904	904	904	904
Circuit 84	3,688	3,134	1,863	2,284	2,384	2,462	2,534	3,001	3,305	3,305
Circuit 85	5,288	4,495	1,168	1,431	1,494	1,543	1,588	1,881	2,289	2,534
Circuit 86	6,597	5,607	941	1,153	1,204	1,243	1,280	1,515	1,793	1,793
Circuit 87	5,113	5,647	2,759	3,382	3,530	3,645	3,752	4,443	4,758	4,758
Circuit 88	2,363	1,839	711	711	711	711	711	711	711	711
Circuit 89	2,488	2,419	1,052	1,290	1,347	1,390	1,430	1,430	1,430	1,430
Circuit 90	5,510	4,684	658	806	842	869	895	1,059	1,290	1,380
Circuit 91	1,351	474	593	727	759	784	807	956	1,163	1,288
Circuit 92	3,605	3,064	–	–	–	–	–	–	–	–
Circuit 93	2,416	1,356	1,537	1,884	1,966	2,030	2,090	2,466	2,466	2,466
Circuit 94	4,283	3,640	6	7	8	8	8	10	12	13
Circuit 95	6,936	5,896	3,372	3,372	3,372	3,372	3,372	3,372	3,372	3,372
Circuit 96	7,190	6,112	506	620	647	668	688	815	992	1,098
Circuit 97	7,570	6,435	–	–	–	–	–	–	–	–
Circuit 98	3,979	3,382	291	357	373	385	396	469	566	566
Circuit 99	13,437	10,102	–	–	–	–	–	–	–	–
Circuit 100	4,164	3,539	–	–	–	–	–	–	–	–
Circuit 101	4,381	3,724	3,140	3,849	4,018	4,149	4,271	5,058	6,157	6,527
Circuit 102	4,691	1,374	1,719	2,107	2,200	2,271	2,338	2,769	3,370	3,731
Circuit 103	6,866	5,836	1,490	1,826	1,907	1,969	2,026	2,358	2,358	2,358
Circuit 104	2,085	1,079	1,324	1,623	1,694	1,749	1,800	2,132	2,596	2,873
Circuit 105	1,609	1,367	891	1,092	1,140	1,178	1,212	1,435	1,559	1,559
Circuit 106	6,462	2,525	1,555	1,906	1,989	2,054	2,114	2,504	3,048	3,374
Circuit 107	1,905	816	1,225	1,502	1,568	1,619	1,667	1,974	2,163	2,163
Circuit 108	5,240	3,794	2,262	2,773	2,894	2,989	3,076	3,643	4,435	4,909
Circuit 109	4,903	1,667	1,747	2,142	2,236	2,309	2,377	2,814	3,426	3,792
Circuit 110	349	296	330	404	422	436	448	531	584	584
Circuit 111	1,287	678	782	958	1,000	1,033	1,063	1,259	1,425	1,425
Circuit 112	3,746	3,184	2,622	3,214	3,355	3,464	3,566	4,079	4,079	4,079

Circuit	OCL	HC	2016	2017	2018	2019	2020	2030	2040	2045
Circuit 113	7,039	5,983	4,665	5,719	5,970	6,164	6,345	7,514	8,062	8,062
Circuit 114	5,755	4,892	3,272	4,011	4,187	4,323	4,450	5,270	6,416	7,101
Circuit 115	1,862	890	1,991	2,440	2,547	2,630	2,707	3,010	3,010	3,010
Circuit 116	1,393	697	905	1,110	1,158	1,196	1,231	1,458	1,775	1,861
Circuit 117	2,519	765	429	526	549	567	583	691	841	931
Circuit 118	430	700	6	8	8	8	9	10	12	14
Circuit 119	2,006	1,399	–	–	–	–	–	–	–	–
Circuit 120	4,969	3,214	320	392	410	423	435	516	628	695
Circuit 121	8,943	6,377	378	463	484	499	514	609	741	820
Circuit 122	2,169	1,102	873	1,070	1,117	1,153	1,187	1,405	1,711	1,847
Circuit 123	2,344	1,992	241	295	308	318	328	388	473	523
Circuit 124	4,831	4,107	–	–	–	–	–	–	–	–
Circuit 125	1,435	1,086	1,671	1,671	1,671	1,671	1,671	1,671	1,671	1,671
Circuit 126	6,644	4,806	–	–	–	–	–	–	–	–
Circuit 127	5,187	4,409	–	–	–	–	–	–	–	–
Circuit 128	1,604	1,364	415	509	532	549	565	669	815	902
Circuit 129	1,681	916	666	816	852	880	905	1,072	1,305	1,445
Circuit 130	1,352	1,086	343	420	439	453	467	552	673	744
Circuit 131	2,267	1,446	748	917	957	988	1,017	1,204	1,466	1,623
Circuit 132	2,449	2,082	518	518	2,018	2,018	3,518	3,518	3,518	3,518
Circuit 133	5,337	4,536	1,058	1,297	1,354	1,398	1,439	1,705	2,075	2,297
Circuit 134	2,267	1,002	911	1,117	1,166	1,204	1,239	1,467	1,786	1,977
Circuit 135	2,752	515	1,026	1,258	1,313	1,356	1,396	1,653	2,012	2,227
Circuit 136	4,602	2,088	600	736	768	793	816	840	840	840
Circuit 137	1,505	1,809	8	10	10	11	11	13	16	17
Circuit 138	5,753	5,889	1,214	1,488	1,554	1,604	1,651	1,956	2,381	2,635
Circuit 139	3,459	2,468	3,029	3,713	3,876	4,002	4,119	4,598	4,598	4,598
Circuit 140	3,856	3,863	773	948	990	1,022	1,052	1,246	1,516	1,679
Circuit 141	2,659	1,905	1,736	2,128	2,221	2,293	2,361	2,796	3,403	3,767
Circuit 142	2,792	2,539	998	998	998	998	998	998	998	998
Circuit 143	1,889	1,583	1,488	1,488	1,488	1,488	1,488	1,488	1,488	1,488
Circuit 144	8,363	7,109	600	736	768	793	816	966	1,176	1,302
Circuit 145	6,223	5,290	300	368	384	396	408	483	588	651
Circuit 146	6,528	5,549	2,207	2,706	2,825	2,916	3,002	3,555	4,328	4,790
Circuit 147	3,308	2,812	132	162	169	175	180	213	259	287
Circuit 148	2,783	2,366	1,694	2,076	2,167	2,238	2,304	2,728	3,321	3,676
Circuit 149	6,292	5,081	569	697	728	751	773	916	1,115	1,234
Circuit 150	2,983	2,028	272	334	348	360	370	439	470	470

Circuit	OCL	HC	2016	2017	2018	2019	2020	2030	2040	2045
Circuit 151	5,020	4,267	2,519	3,088	3,223	3,328	3,426	4,057	4,618	4,618
Circuit 152	5,741	3,499	587	719	751	775	798	945	1,150	1,273
Circuit 153	4,106	2,067	232	284	296	306	315	373	454	503
Circuit 154	4,941	1,152	–	–	–	–	–	–	–	–
Circuit 155	5,774	4,908	–	–	–	–	–	–	–	–
Circuit 156	4,879	4,147	–	–	–	–	–	–	–	–
Circuit 157	3,629	3,084	87	87	87	87	87	87	87	87
Circuit 158	889	499	316	387	404	417	420	420	420	420
Circuit 159	2,132	984	589	722	754	778	801	949	1,155	1,278
Circuit 160	5,736	4,137	535	656	684	707	728	862	1,049	1,161
Circuit 161	6,310	4,551	1,246	1,527	1,594	1,646	1,694	2,007	2,443	2,704
Circuit 162	4,056	3,448	364	446	465	480	494	585	713	789
Circuit 163	1,911	1,624	206	208	208	208	208	208	208	208
Circuit 164	725	920	629	629	629	629	629	629	629	629
Circuit 165	1,877	1,595	–	–	–	–	–	–	–	–
Circuit 166	1,032	877	398	487	509	525	541	640	670	670
Circuit 167	5,120	4,352	578	709	740	764	786	931	1,133	1,254
Circuit 168	3,546	963	1,226	1,503	1,569	1,620	1,667	1,974	2,404	2,660
Circuit 169	4,029	2,935	3,628	4,447	4,643	4,794	4,935	5,623	5,623	5,623
Circuit 170	1,120	952	409	502	524	541	557	659	803	806
Circuit 171	4,969	3,827	248	304	318	328	338	400	487	539
Circuit 172	2,755	2,342	362	443	463	478	492	582	709	785
Circuit 173	624	531	442	442	442	442	442	442	442	442
Circuit 174	3,230	2,745	928	1,137	1,187	1,226	1,262	1,494	1,537	1,537
Circuit 175	7,927	5,784	692	848	885	914	941	1,114	1,356	1,501
Circuit 176	721	613	–	–	–	–	–	–	–	–
Circuit 177	4,497	3,822	1,617	1,982	2,069	2,136	2,199	2,604	2,747	2,747
Circuit 178	7,024	6,024	1,275	1,562	1,631	1,684	1,734	2,053	2,299	2,299
Circuit 179	3,851	3,052	115	141	147	151	156	185	225	249
Circuit 180	5,782	4,088	83	102	106	109	113	133	162	180
Circuit 181	83	62	–	–	–	–	–	–	–	–
Circuit 182	3,416	2,510	116	142	148	153	157	186	227	251
Circuit 183	11,185	9,507	500	613	640	661	680	805	980	1,085
Circuit 184	5,907	5,021	270	331	346	357	367	435	529	586
Circuit 185	6,299	5,354	1,945	2,384	2,489	2,570	2,646	3,133	3,557	3,557
Circuit 186	1,088	707	957	1,174	1,225	1,265	1,302	1,542	1,877	2,070
Circuit 187	3,487	2,964	355	435	454	469	483	572	696	771
Circuit 188	6,420	5,641	282	346	361	373	384	455	554	613

Circuit	OCL	HC	2016	2017	2018	2019	2020	2030	2040	2045
Circuit 189	60	52	–	–	–	–	–	–	–	–
Circuit 190	4,546	3,864	–	–	–	–	–	–	–	–
Circuit 191	3,108	2,642	2,350	2,881	3,008	3,105	3,197	3,786	4,009	4,009
Circuit 192	1,030	450	635	778	812	838	863	1,022	1,244	1,377
Circuit 193	3,249	759	–	–	–	–	–	–	–	–
Circuit 194	4,897	4,163	1,897	2,325	2,427	2,506	2,580	2,874	2,874	2,874
Circuit 195	4,138	3,518	1,373	1,373	1,373	1,373	1,373	1,373	1,373	1,373
Circuit 196	7,671	6,520	2,649	3,247	3,389	3,500	3,603	4,266	5,193	5,748
Circuit 197	10,634	9,039	4,440	5,443	5,682	5,867	6,040	7,152	8,053	8,053
Circuit 198	952	809	203	249	260	268	268	268	268	268
Circuit 199	4,410	3,749	1,676	2,054	2,145	2,214	2,280	2,699	3,154	3,154
Circuit 200	4,112	1,608	1,137	1,394	1,455	1,503	1,547	1,832	1,935	1,935
Circuit 201	4,019	3,416	2,551	3,127	3,264	3,370	3,470	4,109	4,697	4,697
Circuit 202	4,355	2,666	1,694	2,077	2,168	2,238	2,304	2,433	2,433	2,433
Circuit 203	505	430	87	107	111	115	118	140	144	144
Circuit 204	5,370	4,565	39	47	49	51	52	62	76	84
Circuit 205	983	835	–	–	–	–	–	–	–	–
Circuit 206	3,562	3,027	–	–	–	–	–	–	–	–
Circuit 207	4,274	3,083	58	71	74	76	78	93	113	125
Circuit 208	3,627	1,295	836	1,024	1,069	1,104	1,136	1,346	1,638	1,813
Circuit 209	1,711	1,454	545	668	697	720	741	878	1,069	1,118
Circuit 210	3,125	2,693	1,537	1,884	1,967	2,031	2,090	2,475	3,013	3,336
Circuit 211	6,616	5,808	3,213	3,938	4,111	4,245	4,370	5,175	6,300	6,973
Circuit 212	5,706	5,033	2,562	3,141	3,279	3,386	3,485	4,127	5,024	5,561
Circuit 213	1,903	1,471	1,139	1,396	1,457	1,505	1,549	1,834	2,233	2,471
Circuit 214	8,176	6,950	350	429	448	462	476	564	686	760
Circuit 215	5,354	3,717	1,590	1,949	2,035	2,101	2,163	2,561	2,780	2,780
Circuit 216	2,008	1,706	609	609	609	609	609	609	609	609
Circuit 217	5,447	4,630	1,120	1,373	1,433	1,480	1,523	1,804	2,196	2,431
Circuit 218	3,541	3,010	1,371	1,681	1,754	1,811	1,865	2,208	2,688	2,975
Circuit 219	179	152	–	–	–	–	–	–	–	–
Circuit 220	2,869	2,438	1,993	2,444	2,551	2,634	2,711	3,211	3,908	4,326
Circuit 221	6,009	4,641	1,722	2,111	2,204	2,276	2,343	2,774	3,377	3,738
Circuit 222	2,079	1,767	1,602	1,964	2,050	2,117	2,179	2,580	3,141	3,338
Circuit 223	5,005	2,998	907	1,112	1,160	1,198	1,233	1,461	1,778	1,968
Circuit 224	2,919	2,127	350	429	448	462	476	564	686	760
Circuit 225	8,145	6,776	863	1,058	1,105	1,141	1,174	1,391	1,693	1,874
Circuit 226	1,186	578	322	395	413	426	432	432	432	432

Circuit	OCL	HC	2016	2017	2018	2019	2020	2030	2040	2045
Circuit 227	190	162	35	42	44	46	47	56	68	75
Circuit 228	2,419	676	917	1,124	1,173	1,211	1,247	1,477	1,797	1,990
Circuit 229	7,351	6,249	2,573	3,154	3,293	3,400	3,500	4,144	5,045	5,550
Circuit 230	4,579	3,892	1,027	1,259	1,315	1,357	1,397	1,655	2,014	2,230
Circuit 231	2,090	1,777	599	735	767	792	815	965	1,175	1,301
Circuit 232	4,899	4,237	96	118	123	127	131	155	188	208
Circuit 233	7,858	4,263	2,930	3,591	3,749	3,871	3,985	4,719	5,744	6,358
Circuit 234	1,663	1,532	294	361	377	389	400	474	577	639
Circuit 235	5,011	4,027	2,338	2,866	2,916	2,916	2,916	2,916	2,916	2,916
Circuit 236	8,704	4,964	3,984	4,884	5,098	5,264	5,419	6,417	7,193	7,193
Circuit 237	4,312	4,027	2,592	3,177	3,316	3,424	3,525	4,174	5,081	5,615
Circuit 238	748	717	958	958	958	958	958	958	958	958
Circuit 239	3,566	3,031	1,897	2,326	2,428	2,507	2,580	3,056	3,720	4,118
Circuit 240	4,602	4,036	2	3	3	3	3	4	5	5
Circuit 241	8,243	6,839	2,600	2,833	2,833	2,833	2,833	2,833	2,833	2,833
Circuit 242	1,597	1,256	365	447	467	482	496	588	715	792
Circuit 243	177	2,344	–	–	–	–	–	–	–	–
Circuit 244	2,979	3,794	679	832	868	897	923	1,093	1,330	1,473
Circuit 245	5,261	3,543	2,168	2,658	2,775	2,865	2,949	3,492	4,251	4,387
Circuit 246	711	226	–	–	–	–	–	–	–	–
Circuit 247	4,259	3,857	438	537	560	578	596	705	858	950
Circuit 248	4,452	793	1,099	1,347	1,406	1,452	1,494	1,770	1,945	1,945
Circuit 249	3,632	432	228	280	292	302	310	368	448	495
Circuit 250	2,345	1,993	1,140	1,397	1,459	1,506	1,550	1,836	2,166	2,166
Circuit 251	8,975	5,107	8,105	9,935	10,372	10,709	11,024	12,473	12,473	12,473
Circuit 252	2,897	963	1,507	1,847	1,928	1,990	2,049	2,426	2,664	2,664
Circuit 253	108	92	–	–	–	–	–	–	–	–
Circuit 254	7,195	6,288	585	717	748	773	795	942	1,147	1,269
Circuit 255	5,548	5,328	536	657	686	709	729	864	1,052	1,164
Circuit 256	3,836	3,624	726	890	930	960	988	1,170	1,424	1,576
Circuit 257	5,354	5,059	1,474	1,807	1,886	1,947	2,005	2,374	2,890	3,199
Circuit 258	5,212	2,335	4,705	5,768	6,021	6,217	6,400	7,579	9,226	10,212
Circuit 259	3,216	2,781	6,168	7,561	7,893	8,150	8,390	8,838	8,838	8,838
Circuit 260	8,148	5,689	4,628	5,673	5,922	6,115	6,294	7,454	9,074	10,044
Circuit 261	4,605	3,914	2,195	2,691	2,809	2,901	2,986	3,536	4,304	4,636
Circuit 262	5,475	4,654	1,483	1,818	1,898	1,960	2,017	2,389	2,812	2,812
Circuit 263	3,763	3,199	2,552	2,552	2,552	2,552	2,552	2,552	2,552	2,552
Circuit 264	5,762	4,898	4,075	4,173	4,173	4,173	4,173	4,173	4,173	4,173

Circuit	OCL	HC	2016	2017	2018	2019	2020	2030	2040	2045
Circuit 265	5,107	3,907	762	934	975	1,007	1,036	1,227	1,494	1,653
Circuit 266	3,937	3,346	182	223	233	240	247	293	357	395
Circuit 267	2,933	2,493	471	578	603	623	641	650	650	650
Circuit 268	6,033	5,128	1,623	1,989	2,077	2,144	2,207	2,614	3,182	3,522
Circuit 269	4,641	3,945	–	–	–	–	–	–	–	–
Circuit 270	4,421	3,758	1,116	1,368	1,428	1,474	1,518	1,797	2,009	2,009
Circuit 271	4,171	3,545	2,511	3,078	3,213	3,317	3,415	4,044	4,577	4,577
Circuit 272	1,154	981	495	607	633	654	673	797	970	1,074
Circuit 273	2,143	1,822	457	561	585	604	622	737	897	973
Circuit 274	2,946	2,504	1,520	1,864	1,946	2,009	2,068	2,449	2,925	2,925
Circuit 275	7,570	5,984	3,619	4,437	4,632	4,782	4,923	4,931	4,931	4,931
Circuit 276	3,122	3,475	4,129	4,129	4,129	4,129	4,129	4,129	4,129	4,129
Circuit 277	4,614	4,103	2,334	2,862	2,987	3,084	3,175	3,760	4,577	5,067
Circuit 278	4,340	3,953	2,186	2,680	2,798	2,888	2,973	3,521	4,286	4,690
Circuit 279	1,177	1,057	986	1,208	1,261	1,302	1,341	1,588	1,933	2,139
Circuit 280	2,936	2,495	897	1,099	1,147	1,185	1,220	1,444	1,758	1,946
Circuit 281	1,316	772	1,169	1,433	1,496	1,545	1,590	1,883	2,032	2,032
Circuit 282	4,214	780	1,137	1,394	1,455	1,502	1,546	1,831	2,229	2,468
Circuit 283	3,839	2,871	1,028	1,260	1,315	1,358	1,398	1,656	2,015	2,231
Circuit 284	2,299	1,954	1,798	2,204	2,300	2,375	2,445	2,895	3,520	3,520
Circuit 285	5,662	1,636	2,961	3,630	3,789	3,912	4,027	4,769	5,806	6,427
Circuit 286	5,271	4,480	33	41	43	44	45	54	66	73
Circuit 287	3,252	2,048	1,978	2,425	2,531	2,614	2,691	3,186	3,399	3,399
Circuit 288	9,600	3,270	3,026	3,709	3,872	3,998	4,115	4,874	5,338	5,338
Circuit 289	2,667	3,617	265	325	339	350	360	427	520	575
Circuit 290	2,772	1,028	1,170	1,434	1,497	1,546	1,592	1,885	2,294	2,540
Circuit 291	4,820	3,749	968	1,187	1,239	1,280	1,317	1,560	1,899	2,102
Circuit 292	5,222	2,086	970	1,189	1,242	1,282	1,320	1,563	1,903	2,106
Circuit 293	5,768	4,903	1,383	1,695	1,769	1,827	1,881	2,227	2,711	3,001
Circuit 294	6,307	3,281	767	940	981	1,013	1,043	1,235	1,503	1,664
Circuit 295	4,017	3,617	328	403	420	434	447	529	644	713
Circuit 296	4,136	2,357	412	505	527	545	561	664	808	895
Circuit 297	3,545	1,694	1,575	1,931	2,015	2,081	2,142	2,537	2,795	2,795
Circuit 298	4,054	3,446	2,444	2,996	3,128	3,230	3,325	3,937	4,507	4,507
Circuit 299	6,304	3,496	844	1,035	1,080	1,115	1,148	1,360	1,655	1,832
Circuit 300	4,455	1,469	1,791	2,195	2,292	2,366	2,436	2,885	3,512	3,887
Circuit 301	1,053	496	484	593	619	639	658	779	948	1,050
Circuit 302	4,019	3,416	1,763	2,161	2,256	2,329	2,397	2,839	3,456	3,825

Circuit	OCL	HC	2016	2017	2018	2019	2020	2030	2040	2045
Circuit 303	6,695	3,596	4,674	5,729	5,981	6,175	6,357	7,528	9,164	9,263
Circuit 304	2,526	2,147	1,365	1,673	1,747	1,798	1,798	1,798	1,798	1,798
Circuit 305	1,852	740	964	1,182	1,234	1,274	1,312	1,553	1,891	2,093
Circuit 306	2,635	1,809	68	83	87	90	92	109	133	147
Circuit 307	4,943	4,202	2,091	2,563	2,676	2,763	2,844	3,368	4,100	4,337
Circuit 308	1,236	1,051	1,080	1,324	1,382	1,427	1,469	1,574	1,574	1,574
Circuit 309	1,140	714	469	575	600	620	638	755	920	928
Circuit 310	6,808	5,787	465	569	594	614	632	748	911	1,008
Circuit 311	6,285	5,342	460	564	589	608	626	741	902	998
Circuit 312	3,034	2,579	–	–	–	–	–	–	–	–
Circuit 313	3,923	2,934	1,799	2,206	2,303	2,377	2,447	2,898	3,484	3,484
Circuit 314	5,183	4,405	1,612	1,976	2,063	2,130	2,192	2,353	2,353	2,353
Circuit 315	3,086	2,623	489	599	626	646	665	788	959	1,061
Circuit 316	1,536	1,305	265	325	339	350	361	427	520	575
Circuit 317	5,006	3,868	48	59	62	64	65	78	94	104
Circuit 318	5,261	3,540	216	265	276	285	294	348	424	469
Circuit 319	4,865	4,135	349	428	447	462	475	563	685	758
Circuit 320	5,762	2,253	2,266	2,778	2,900	2,994	3,082	3,650	4,010	4,010
Circuit 321	337	287	79	96	101	104	107	127	154	171
Circuit 322	4,669	4,724	747	916	956	987	1,016	1,204	1,465	1,620
Circuit 323	144	123	–	–	–	–	–	–	–	–
Circuit 324	5,894	5,010	2,371	2,371	2,371	2,371	2,371	2,371	2,371	2,371
Circuit 325	608	588	501	615	642	662	682	808	983	1,081
Circuit 326	1,410	762	858	1,052	1,098	1,133	1,167	1,382	1,682	1,862
Circuit 327	1,463	511	1,311	1,311	1,311	1,311	1,311	1,311	1,311	1,311
Circuit 328	6,119	5,201	3,099	3,799	3,966	4,095	4,216	4,992	5,819	5,819
Circuit 329	1,610	1,369	1,053	1,290	1,347	1,391	1,432	1,695	2,055	2,055
Circuit 330	5,881	4,999	3,528	4,325	4,515	4,661	4,798	5,127	5,127	5,127
Circuit 331	924	785	95	116	121	125	129	152	186	205
Circuit 332	7,351	3,171	3,679	4,510	4,708	4,861	5,004	5,926	7,214	7,985
Circuit 333	5,964	5,069	1,020	1,250	1,305	1,347	1,387	1,642	1,999	2,213
Circuit 334	2,507	2,131	479	587	613	633	652	772	940	1,040
Circuit 335	3,598	3,058	1,369	1,369	1,369	1,369	1,369	1,369	1,369	1,369
Circuit 336	5,827	4,953	2,046	2,508	2,619	2,704	2,783	2,945	2,945	2,945
Circuit 337	3,697	3,143	1,061	1,301	1,358	1,402	1,444	1,710	2,081	2,304
Circuit 338	959	815	204	204	204	204	204	204	204	204
Circuit 339	9,020	7,667	2,362	2,647	2,647	2,647	2,647	2,647	2,647	2,647
Circuit 340	3,646	3,099	1,452	1,780	1,858	1,918	1,974	2,338	2,846	3,151

Circuit	OCL	HC	2016	2017	2018	2019	2020	2030	2040	2045
Circuit 341	746	634	–	–	–	–	–	–	–	–
Circuit 342	4,140	1,454	1,864	2,286	2,386	2,463	2,536	3,003	3,656	4,046
Circuit 343	5,806	4,935	2,484	3,045	3,178	3,282	3,378	4,001	4,326	4,326
Circuit 344	4,257	3,619	1,738	2,131	2,225	2,297	2,364	2,367	2,367	2,367
Circuit 345	9,447	6,464	738	905	944	975	1,004	1,189	1,447	1,602
Circuit 346	4,257	3,619	1,580	1,937	2,022	2,088	2,150	2,546	3,099	3,251
Circuit 347	6,038	3,233	2,664	3,266	3,409	3,520	3,623	4,291	5,223	5,700
Circuit 348	3,111	1,014	1,179	1,446	1,509	1,558	1,604	1,899	2,312	2,559
Circuit 349	419	356	473	580	605	625	643	761	927	1,026
Circuit 350	6,149	3,240	2,547	3,123	3,260	3,366	3,465	4,103	4,995	5,529
Circuit 351	3,133	2,663	–	–	–	–	–	–	–	–
Circuit 352	2,391	1,567	44	44	44	44	44	44	44	44
Circuit 353	7,969	5,222	–	–	–	–	–	–	–	–
Circuit 354	6,602	5,612	24	29	31	32	33	39	47	52
Circuit 355	6,104	5,188	121	149	155	160	165	195	238	263
Circuit 356	3,888	3,304	46	56	59	61	63	74	90	100
Circuit 357	4,256	3,618	–	–	–	–	–	–	–	–
Circuit 358	2,982	2,535	1,070	1,312	1,369	1,414	1,455	1,724	2,098	2,322
Circuit 359	6,054	949	3,858	4,730	4,937	5,098	5,248	6,214	7,565	8,374
Circuit 360	1,341	513	595	595	595	595	595	595	595	595
Circuit 361	277	122	151	151	151	151	151	151	151	151
Circuit 362	6,306	5,364	1,308	1,604	1,674	1,729	1,780	2,107	2,565	2,840
Circuit 363	4,376	3,725	1,679	2,053	2,053	2,053	2,053	2,053	2,053	2,053
Circuit 364	5,368	4,562	3,881	4,757	4,966	5,127	5,278	6,185	6,185	6,185
Circuit 365	4,712	2,283	1,561	1,914	1,998	2,063	2,124	2,515	3,061	3,388
Circuit 366	4,162	1,910	1,120	1,373	1,434	1,480	1,524	1,805	2,197	2,432
Circuit 367	2,068	1,758	1,173	1,438	1,501	1,550	1,595	1,889	2,299	2,545
Circuit 368	4,623	1,336	1,540	1,887	1,970	2,034	2,094	2,480	3,019	3,342
Circuit 369	5,678	4,380	2,925	3,585	3,743	3,864	3,978	4,711	5,734	6,347
Circuit 370	3,020	524	526	645	674	695	716	848	1,032	1,142
Circuit 371	4,080	913	2,136	2,618	2,733	2,822	2,905	3,440	4,188	4,635
Circuit 372	5,743	4,882	3,688	4,521	4,720	4,873	5,016	5,940	7,138	7,138
Circuit 373	7,141	5,038	4,995	6,123	6,392	6,600	6,794	8,045	8,421	8,421
Circuit 374	4,249	3,612	1,302	1,596	1,666	1,720	1,770	2,096	2,233	2,233
Circuit 375	4,040	3,434	754	924	965	996	1,026	1,215	1,479	1,623
Circuit 376	1,431	1,216	847	1,039	1,084	1,120	1,153	1,208	1,208	1,208
Circuit 377	1,821	717	1,084	1,328	1,387	1,432	1,474	1,745	2,124	2,222
Circuit 378	308	262	37	37	37	37	37	37	37	37

Circuit	OCL	HC	2016	2017	2018	2019	2020	2030	2040	2045
Circuit 379	3,073	2,069	1,454	1,782	1,860	1,921	1,977	2,341	2,850	3,155
Circuit 380	1,552	1,319	1,666	2,042	2,131	2,201	2,265	2,683	2,699	2,699
Circuit 381	1,106	640	907	1,112	1,161	1,199	1,234	1,461	1,779	1,969
Circuit 382	–	–	40,100	49,157	51,315	52,983	54,542	64,588	78,625	87,030

Table N-5. Hawaiian Electric Distribution Circuit Base DG-PV Forecast (kW)

Hawaiian Electric Distribution Circuit High DG–PV Forecast (kW)

Circuit	OCL	HC	2016	2017	2018	2019	2020	2030	2040	2045
Circuit 1	6,044	5,137	1,119	1,282	1,402	1,453	1,506	2,547	3,634	3,634
Circuit 2	5,170	2,392	3,308	3,789	4,143	4,294	4,450	6,752	6,752	6,752
Circuit 3	5,692	484	961	1,101	1,203	1,247	1,293	2,186	3,127	3,598
Circuit 4	361	307	–	–	–	–	–	–	–	–
Circuit 5	4,770	3,284	3,163	3,623	3,961	4,106	4,255	7,196	7,987	7,987
Circuit 6	2,556	2,173	383	439	480	497	515	871	1,247	1,434
Circuit 7	1,198	1,019	148	169	185	192	199	336	481	553
Circuit 8	1,940	319	1,020	1,168	1,277	1,324	1,372	2,320	3,320	3,819
Circuit 9	1,301	951	1,041	1,193	1,304	1,352	1,401	2,369	3,389	3,523
Circuit 10	5,107	4,341	2,003	2,295	2,509	2,601	2,695	4,558	6,521	7,502
Circuit 11	689	585	–	–	–	–	–	–	–	–
Circuit 12	1,714	1,457	–	–	–	–	–	–	–	–
Circuit 13	6,272	5,331	154	176	192	199	207	349	500	575
Circuit 14	573	438	635	727	795	825	854	1,445	2,067	2,378
Circuit 15	5,750	4,887	3,480	3,987	4,359	4,519	4,683	7,918	11,328	13,033
Circuit 16	5,701	1,825	2,208	2,529	2,765	2,866	2,970	5,023	7,186	7,297
Circuit 17	5,699	4,605	2,659	3,045	3,330	3,452	3,577	6,049	7,141	7,141
Circuit 18	2,402	2,042	–	–	–	–	–	–	–	–
Circuit 19	3,003	2,553	–	–	–	–	–	–	–	–
Circuit 20	7,330	6,185	529	606	662	687	712	1,203	1,721	1,981
Circuit 21	5,331	4,499	178	204	223	231	239	405	579	667
Circuit 22	4,733	3,901	–	–	–	–	–	–	–	–
Circuit 23	6,741	5,747	1,055	1,208	1,321	1,369	1,419	2,399	3,433	3,950
Circuit 24	1,448	575	840	962	1,051	1,090	1,130	1,910	2,733	2,957
Circuit 25	7,601	4,006	2,933	3,359	3,673	3,808	3,946	6,672	8,143	8,143
Circuit 26	1,005	854	246	282	308	320	331	560	801	922
Circuit 27	771	465	568	651	711	737	764	1,292	1,849	2,127
Circuit 28	4,190	3,686	565	647	708	734	760	1,286	1,839	1,874
Circuit 29	4,187	3,386	3,514	4,026	4,402	4,563	4,728	7,760	7,760	7,760
Circuit 30	6,569	5,583	1,144	1,310	1,433	1,485	1,539	2,603	3,723	4,284
Circuit 31	5,359	4,555	1,151	1,318	1,441	1,494	1,548	2,618	3,029	3,029
Circuit 32	1,211	1,029	457	524	573	594	615	1,040	1,488	1,712
Circuit 33	3,114	1,758	–	–	–	–	–	–	–	–
Circuit 34	3,107	2,641	–	–	–	–	–	–	–	–
Circuit 35	6,611	5,619	2,025	2,319	2,536	2,629	2,724	4,006	4,006	4,006

Circuit	OCL	HC	2016	2017	2018	2019	2020	2030	2040	2045
Circuit 36	4,151	3,635	208	239	261	270	280	474	678	780
Circuit 37	2,806	2,385	–	–	–	–	–	–	–	–
Circuit 38	4,488	3,737	273	313	342	354	367	621	888	1,022
Circuit 39	1,403	1,193	–	–	–	–	–	–	–	–
Circuit 40	1,873	249	1,865	2,137	2,336	2,422	2,510	4,137	4,137	4,137
Circuit 41	3,266	2,252	312	357	391	405	420	710	1,016	1,169
Circuit 42	3,126	2,657	–	–	–	–	–	–	–	–
Circuit 43	4,186	3,558	520	596	651	675	700	1,183	1,410	1,410
Circuit 44	5,293	1,234	283	324	354	367	380	643	920	1,059
Circuit 45	5,673	4,822	2,476	2,476	2,476	2,476	2,476	2,476	2,476	2,476
Circuit 46	1,380	1,161	1,074	1,230	1,345	1,394	1,445	2,443	3,130	3,130
Circuit 47	3,559	3,025	–	–	–	–	–	–	–	–
Circuit 48	4,529	3,850	–	–	–	–	–	–	–	–
Circuit 49	3,102	2,637	3,117	3,571	3,905	4,047	4,194	6,801	6,801	6,801
Circuit 50	5,323	4,426	2,909	3,332	3,643	3,777	3,914	6,618	7,377	7,377
Circuit 51	3,931	3,126	1,844	2,112	2,309	2,394	2,481	4,195	6,001	6,904
Circuit 52	4,736	2,867	2,292	2,625	2,870	2,975	3,083	5,214	7,459	7,938
Circuit 53	5,383	6,171	3,342	3,828	4,186	4,339	4,497	7,604	9,635	9,635
Circuit 54	4,830	4,355	3,074	3,521	3,850	3,991	4,135	5,335	5,335	5,335
Circuit 55	6,640	5,120	2,810	2,810	2,810	2,810	2,810	2,810	2,810	2,810
Circuit 56	2,289	1,001	763	873	955	990	1,026	1,735	2,482	2,856
Circuit 57	5,837	3,689	748	857	937	972	1,007	1,703	2,436	2,451
Circuit 58	3,014	2,562	4	4	5	5	5	8	12	14
Circuit 59	6,331	3,121	246	281	308	319	331	559	564	564
Circuit 60	3,667	3,117	338	387	424	439	455	769	1,101	1,267
Circuit 61	2,895	2,461	190	218	238	247	256	432	618	712
Circuit 62	4,599	4,180	2,446	2,446	2,446	2,446	2,446	2,446	2,446	2,446
Circuit 63	4,789	4,544	2,668	3,056	3,342	3,464	3,590	6,070	7,046	7,046
Circuit 64	4,747	4,445	4,837	5,541	6,058	6,280	6,508	7,472	7,472	7,472
Circuit 65	3,651	3,341	1,534	1,757	1,921	1,991	2,063	3,489	3,999	3,999
Circuit 66	3,366	2,861	1,786	2,046	2,237	2,318	2,403	4,063	4,962	4,962
Circuit 67	4,703	3,402	2,370	2,715	2,969	3,077	3,189	3,347	3,347	3,347
Circuit 68	4,308	3,662	1,984	2,273	2,485	2,576	2,670	4,515	4,895	4,895
Circuit 69	5,586	4,100	2,163	2,478	2,709	2,808	2,910	4,921	7,040	7,348
Circuit 70	4,351	3,698	1,461	1,674	1,830	1,897	1,966	3,324	4,756	5,472
Circuit 71	8,420	7,157	3,285	3,763	4,115	4,265	4,420	7,474	10,693	12,302
Circuit 72	930	506	8	9	10	11	11	19	27	31
Circuit 73	5,289	4,496	2,955	3,384	3,701	3,836	3,975	6,722	8,100	8,100

Circuit	OCL	HC	2016	2017	2018	2019	2020	2030	2040	2045
Circuit 74	6,899	841	1,018	1,166	1,275	1,322	1,370	2,316	3,313	3,812
Circuit 75	7,393	4,965	160	183	200	207	215	363	519	597
Circuit 76	3,528	2,999	–	–	–	–	–	–	–	–
Circuit 77	2,673	2,594	52	60	65	67	70	118	169	195
Circuit 78	7,301	1,140	3,048	3,492	3,818	3,958	4,101	6,935	7,400	7,400
Circuit 79	1,470	706	1,894	2,170	2,372	2,459	2,548	3,241	3,241	3,241
Circuit 80	5,814	3,867	1,640	1,640	1,640	1,640	1,640	1,640	1,640	1,640
Circuit 81	5,352	3,730	2,687	3,078	3,366	3,489	3,616	6,114	8,182	8,182
Circuit 82	220	445	136	156	171	177	183	310	444	510
Circuit 83	1,968	1,673	904	1,036	1,132	1,174	1,216	2,057	2,060	2,060
Circuit 84	3,688	3,134	1,863	2,134	2,334	2,419	2,507	4,239	4,769	4,769
Circuit 85	5,288	4,495	1,168	1,338	1,463	1,516	1,571	2,657	3,801	4,041
Circuit 86	6,597	5,607	941	1,078	1,178	1,222	1,266	1,793	1,793	1,793
Circuit 87	5,113	5,647	2,759	3,160	3,455	3,582	3,712	6,223	6,223	6,223
Circuit 88	2,363	1,839	711	815	891	924	957	1,619	2,060	2,060
Circuit 89	2,488	2,419	1,052	1,205	1,318	1,366	1,416	2,394	2,895	2,895
Circuit 90	5,510	4,684	658	753	824	854	885	1,496	2,141	2,463
Circuit 91	1,351	474	593	680	743	770	798	1,350	1,932	2,222
Circuit 92	3,605	3,064	–	–	–	–	–	–	–	–
Circuit 93	2,416	1,356	1,537	1,760	1,925	1,995	2,068	3,496	3,706	3,706
Circuit 94	4,283	3,640	6	7	8	8	8	14	20	22
Circuit 95	6,936	5,896	3,372	3,372	3,372	3,372	3,372	3,372	3,372	3,372
Circuit 96	7,190	6,112	506	579	634	657	681	1,151	1,647	1,894
Circuit 97	7,570	6,435	–	–	–	–	–	–	–	–
Circuit 98	3,979	3,382	291	334	365	378	392	566	566	566
Circuit 99	13,437	10,102	–	–	–	–	–	–	–	–
Circuit 100	4,164	3,539	–	–	–	–	–	–	–	–
Circuit 101	4,381	3,724	3,140	3,597	3,933	4,077	4,225	7,144	7,992	7,992
Circuit 102	4,691	1,374	1,719	1,719	1,719	1,719	1,719	1,719	1,719	1,719
Circuit 103	6,866	5,836	1,490	1,707	1,866	1,934	2,005	3,390	3,772	3,772
Circuit 104	2,085	1,079	1,324	1,516	1,658	1,719	1,781	3,012	4,309	4,957
Circuit 105	1,609	1,367	891	1,021	1,116	1,157	1,199	2,028	2,901	3,023
Circuit 106	6,462	2,525	1,555	1,781	1,947	2,018	2,092	3,537	5,060	5,411
Circuit 107	1,905	816	1,225	1,404	1,535	1,591	1,649	2,788	3,628	3,628
Circuit 108	5,240	3,794	2,262	2,591	2,833	2,937	3,043	5,146	7,362	7,598
Circuit 109	4,903	1,667	1,747	2,002	2,188	2,269	2,351	3,975	5,687	6,202
Circuit 110	349	296	330	378	413	428	443	750	1,073	1,234
Circuit 111	1,287	678	782	895	979	1,015	1,052	1,779	2,545	2,889

Circuit	OCL	HC	2016	2017	2018	2019	2020	2030	2040	2045
Circuit 112	3,746	3,184	2,622	3,004	3,284	3,404	3,528	5,543	5,543	5,543
Circuit 113	7,039	5,983	4,665	5,344	5,843	6,057	6,277	9,526	9,526	9,526
Circuit 114	5,755	4,892	3,272	3,748	4,098	4,248	4,403	7,444	9,977	9,977
Circuit 115	1,862	890	1,991	2,280	2,493	2,584	2,678	4,474	4,474	4,474
Circuit 116	1,393	697	905	1,037	1,134	1,175	1,218	2,059	2,946	3,325
Circuit 117	2,519	765	429	491	537	557	577	976	1,396	1,606
Circuit 118	430	700	6	7	8	8	9	14	21	24
Circuit 119	2,006	1,399	–	–	–	–	–	–	–	–
Circuit 120	4,969	3,214	320	367	401	416	431	728	1,042	1,199
Circuit 121	8,943	6,377	378	433	473	491	508	860	958	958
Circuit 122	2,169	1,102	873	1,000	1,093	1,133	1,174	1,985	2,840	3,268
Circuit 123	2,344	1,992	241	276	302	313	324	548	784	903
Circuit 124	4,831	4,107	–	–	–	–	–	–	–	–
Circuit 125	1,435	1,086	1,671	1,914	2,093	2,170	2,248	2,895	2,895	2,895
Circuit 126	6,644	4,806	–	–	–	–	–	–	–	–
Circuit 127	5,187	4,409	–	–	–	–	–	–	–	–
Circuit 128	1,604	1,364	415	476	520	539	559	945	1,352	1,556
Circuit 129	1,681	916	666	763	834	864	896	1,515	2,167	2,493
Circuit 130	1,352	1,086	343	393	430	445	462	780	1,116	1,285
Circuit 131	2,267	1,446	748	857	937	971	1,006	1,701	2,434	2,800
Circuit 132	2,449	2,082	518	593	649	673	697	1,179	1,464	1,464
Circuit 133	5,337	4,536	1,058	1,212	1,326	1,374	1,424	2,408	3,445	3,508
Circuit 134	2,267	1,002	911	1,044	1,141	1,183	1,226	2,073	2,966	3,412
Circuit 135	2,752	515	1,026	1,176	1,285	1,332	1,381	2,335	3,341	3,843
Circuit 136	4,602	2,088	600	687	752	779	807	–	–	–
Circuit 137	1,505	1,809	8	9	10	10	11	18	26	30
Circuit 138	5,753	5,889	1,214	1,391	1,521	1,576	1,634	2,762	3,682	3,682
Circuit 139	3,459	2,468	3,029	3,469	3,793	3,932	4,075	6,063	6,063	6,063
Circuit 140	3,856	3,863	773	886	969	1,004	1,041	1,760	2,517	2,896
Circuit 141	2,659	1,905	1,736	1,988	2,174	2,253	2,335	3,949	5,649	6,500
Circuit 142	2,792	2,539	998	1,143	1,250	1,296	1,343	1,467	1,467	1,467
Circuit 143	1,889	1,583	1,488	1,705	1,733	1,733	1,733	1,733	1,733	1,733
Circuit 144	8,363	7,109	600	687	752	779	807	1,365	1,953	2,247
Circuit 145	6,223	5,290	300	344	376	390	404	683	976	1,123
Circuit 146	6,528	5,549	2,207	2,528	2,765	2,866	2,970	5,022	6,797	6,797
Circuit 147	3,308	2,812	132	151	166	172	178	301	430	495
Circuit 148	2,783	2,366	1,694	1,940	2,121	2,199	2,279	3,854	5,513	5,727
Circuit 149	6,292	5,081	569	651	712	738	765	1,294	1,851	2,129

Circuit	OCL	HC	2016	2017	2018	2019	2020	2030	2040	2045
Circuit 150	2,983	2,028	272	312	341	354	366	470	470	470
Circuit 151	5,020	4,267	2,519	2,886	3,155	3,270	3,389	5,731	6,082	6,082
Circuit 152	5,741	3,499	587	672	735	762	789	1,335	1,910	2,197
Circuit 153	4,106	2,067	232	265	290	301	312	527	754	867
Circuit 154	4,941	1,152	–	–	–	–	–	–	–	–
Circuit 155	5,774	4,908	–	–	–	–	–	–	–	–
Circuit 156	4,879	4,147	–	–	–	–	–	–	–	–
Circuit 157	3,629	3,084	87	87	87	87	87	87	87	87
Circuit 158	889	499	316	362	395	410	425	718	1,028	1,182
Circuit 159	2,132	984	589	675	738	765	792	1,340	1,917	2,206
Circuit 160	5,736	4,137	535	613	670	694	720	1,217	1,741	2,003
Circuit 161	6,310	4,551	1,246	1,427	1,560	1,617	1,676	2,834	3,989	3,989
Circuit 162	4,056	3,448	364	416	455	472	489	827	1,159	1,159
Circuit 163	1,911	1,624	206	208	208	208	208	208	208	208
Circuit 164	725	920	629	720	788	816	846	1,431	1,467	1,467
Circuit 165	1,877	1,595	–	–	–	–	–	–	–	–
Circuit 166	1,032	877	398	455	498	516	535	904	1,294	1,489
Circuit 167	5,120	4,352	578	662	724	750	778	1,315	1,881	2,165
Circuit 168	3,546	963	1,226	1,404	1,535	1,592	1,649	2,789	3,990	4,591
Circuit 169	4,029	2,935	3,628	4,156	4,544	4,710	4,882	5,088	5,088	5,088
Circuit 170	1,120	952	409	469	513	532	551	932	1,333	1,533
Circuit 171	4,969	3,827	248	284	311	322	334	565	808	930
Circuit 172	2,755	2,342	362	414	453	469	487	823	1,177	1,354
Circuit 173	624	531	442	506	554	574	595	1,006	1,439	1,469
Circuit 174	3,230	2,745	928	1,063	1,162	1,205	1,248	2,111	3,001	3,001
Circuit 175	7,927	5,784	692	792	866	898	930	1,573	2,251	2,590
Circuit 176	721	613	–	–	–	–	–	–	–	–
Circuit 177	4,497	3,822	1,617	1,852	2,025	2,099	2,175	3,679	4,211	4,211
Circuit 178	7,024	6,024	1,275	1,460	1,596	1,655	1,715	2,900	3,764	3,764
Circuit 179	3,851	3,052	115	131	144	149	154	261	373	429
Circuit 180	5,782	4,088	83	95	104	108	111	188	270	310
Circuit 181	83	62	–	–	–	–	–	–	–	–
Circuit 182	3,416	2,510	116	133	145	150	156	263	377	433
Circuit 183	11,185	9,507	500	573	626	649	673	1,138	1,627	1,872
Circuit 184	5,907	5,021	270	309	338	351	363	614	879	1,011
Circuit 185	6,299	5,354	1,945	2,228	2,436	2,525	2,617	4,425	5,022	5,022
Circuit 186	1,088	707	957	1,097	1,199	1,243	1,288	2,178	3,116	3,534
Circuit 187	3,487	2,964	355	407	445	461	478	808	1,156	1,330

Circuit	OCL	HC	2016	2017	2018	2019	2020	2030	2040	2045
Circuit 188	6,420	5,641	282	323	354	367	380	642	919	1,057
Circuit 189	60	52	–	–	–	–	–	–	–	–
Circuit 190	4,546	3,864	–	–	–	–	–	–	–	–
Circuit 191	3,108	2,642	2,350	2,692	2,944	3,052	3,162	5,347	5,473	5,473
Circuit 192	1,030	450	635	727	795	824	854	1,444	2,065	2,376
Circuit 193	3,249	759	–	–	–	–	–	–	–	–
Circuit 194	4,897	4,163	1,897	2,173	2,376	2,462	2,552	4,315	4,339	4,339
Circuit 195	4,138	3,518	1,373	1,573	1,720	1,783	1,848	2,547	2,547	2,547
Circuit 196	7,671	6,520	2,649	3,034	3,318	3,439	3,564	6,026	8,157	8,157
Circuit 197	10,634	9,039	4,440	5,087	5,562	5,765	5,975	9,517	9,517	9,517
Circuit 198	952	809	203	232	254	263	268	268	268	268
Circuit 199	4,410	3,749	1,676	1,920	2,099	2,176	2,255	3,813	4,618	4,618
Circuit 200	4,112	1,608	1,137	1,303	1,425	1,477	1,530	2,588	3,400	3,400
Circuit 201	4,019	3,416	2,551	2,922	3,195	3,312	3,432	5,804	6,161	6,161
Circuit 202	4,355	2,666	1,694	1,941	2,122	2,199	2,279	3,854	3,897	3,897
Circuit 203	505	430	87	100	109	113	117	144	144	144
Circuit 204	5,370	4,565	39	44	48	50	52	88	126	144
Circuit 205	983	835	–	–	–	–	–	–	–	–
Circuit 206	3,562	3,027	–	–	–	–	–	–	–	–
Circuit 207	4,274	3,083	58	66	72	75	78	131	188	216
Circuit 208	3,627	1,295	836	957	1,046	1,085	1,124	1,901	2,720	3,129
Circuit 209	1,711	1,454	545	624	683	708	733	1,240	1,774	2,041
Circuit 210	3,125	2,693	1,537	1,761	1,925	1,995	2,068	3,497	5,003	5,078
Circuit 211	6,616	5,808	3,213	3,680	4,024	4,171	4,323	7,310	9,474	9,474
Circuit 212	5,706	5,033	2,562	2,935	3,209	3,327	3,448	5,830	7,214	7,214
Circuit 213	1,903	1,471	1,139	1,304	1,426	1,478	1,532	2,591	3,706	4,113
Circuit 214	8,176	6,950	350	401	438	454	471	796	1,139	1,311
Circuit 215	5,354	3,717	1,590	1,821	1,992	2,064	2,139	3,618	4,244	4,244
Circuit 216	2,008	1,706	609	697	762	790	819	1,385	1,464	1,464
Circuit 217	5,447	4,630	1,120	1,283	1,403	1,454	1,464	1,464	1,464	1,464
Circuit 218	3,541	3,010	1,371	1,570	1,717	1,780	1,845	3,119	4,462	4,877
Circuit 219	179	152	–	–	–	–	–	–	–	–
Circuit 220	2,869	2,438	1,993	2,283	2,497	2,588	2,682	4,535	6,316	6,316
Circuit 221	6,009	4,641	1,722	1,973	2,157	2,236	2,317	3,918	5,606	5,659
Circuit 222	2,079	1,767	1,602	1,835	2,006	2,080	2,155	3,645	4,802	4,802
Circuit 223	5,005	2,998	907	1,039	1,136	1,177	1,220	2,063	2,952	3,163
Circuit 224	2,919	2,127	350	401	438	454	471	796	1,029	1,029
Circuit 225	8,145	6,776	863	989	1,081	1,121	1,162	1,964	2,810	3,233

Circuit	OCL	HC	2016	2017	2018	2019	2020	2030	2040	2045
Circuit 226	1,186	578	322	369	404	419	434	734	1,050	1,207
Circuit 227	190	162	35	40	43	45	47	79	88	88
Circuit 228	2,419	676	917	1,050	1,148	1,190	1,233	2,086	2,984	3,433
Circuit 229	7,351	6,249	2,573	2,948	3,223	3,341	3,462	5,854	6,995	6,995
Circuit 230	4,579	3,892	1,027	1,177	1,287	1,334	1,382	2,337	3,344	3,847
Circuit 231	2,090	1,777	599	686	751	778	806	1,363	1,951	2,244
Circuit 232	4,899	4,237	96	110	120	125	129	218	312	360
Circuit 233	7,858	4,263	2,930	3,356	3,669	3,804	3,942	6,665	8,207	8,207
Circuit 234	1,663	1,532	294	337	369	382	396	669	679	679
Circuit 235	5,011	4,027	2,338	2,679	2,929	3,036	3,146	4,380	4,380	4,380
Circuit 236	8,704	4,964	3,984	4,564	4,990	5,172	5,360	8,657	8,657	8,657
Circuit 237	4,312	4,027	2,592	2,969	3,246	3,365	3,487	5,896	7,079	7,079
Circuit 238	748	717	958	1,097	1,199	1,243	1,288	2,179	2,328	2,328
Circuit 239	3,566	3,031	1,897	2,173	2,376	2,463	2,553	4,316	6,175	7,061
Circuit 240	4,602	4,036	2	3	3	3	3	6	8	9
Circuit 241	8,243	6,839	2,600	2,978	3,256	3,376	3,498	3,515	3,515	3,515
Circuit 242	1,597	1,256	365	418	457	474	491	830	1,188	1,366
Circuit 243	177	2,344	–	–	–	–	–	–	–	–
Circuit 244	2,979	3,794	679	777	850	881	913	1,544	2,209	2,541
Circuit 245	5,261	3,543	2,168	2,484	2,716	2,815	2,917	4,933	5,756	5,756
Circuit 246	711	226	–	–	–	–	–	–	–	–
Circuit 247	4,259	3,857	438	502	548	568	589	996	1,425	1,640
Circuit 248	4,452	793	1,099	1,259	1,376	1,426	1,478	2,500	3,410	3,410
Circuit 249	3,632	432	228	261	286	296	307	519	743	855
Circuit 250	2,345	1,993	1,140	1,306	1,428	1,480	1,534	2,593	3,630	3,630
Circuit 251	8,975	5,107	8,105	9,284	10,152	10,413	10,413	10,413	10,413	10,413
Circuit 252	2,897	963	1,507	1,726	1,887	1,956	2,027	3,428	4,128	4,128
Circuit 253	108	92	–	–	–	–	–	–	–	–
Circuit 254	7,195	6,288	585	670	733	759	787	1,331	1,776	1,776
Circuit 255	5,548	5,328	536	614	672	696	722	1,220	1,740	1,740
Circuit 256	3,836	3,624	726	832	910	943	977	1,653	1,989	1,989
Circuit 257	5,354	5,059	1,474	1,688	1,846	1,914	1,983	3,353	4,798	5,520
Circuit 258	5,212	2,335	4,705	5,390	5,893	6,109	6,331	8,958	8,958	8,958
Circuit 259	3,216	2,781	6,168	6,253	6,253	6,253	6,253	6,253	6,253	6,253
Circuit 260	8,148	5,689	4,628	5,301	5,796	6,009	6,227	10,529	13,715	13,715
Circuit 261	4,605	3,914	2,195	2,515	2,750	2,850	2,954	4,995	6,101	6,101
Circuit 262	5,475	4,654	1,483	1,699	1,858	1,926	1,996	3,375	4,276	4,276
Circuit 263	3,763	3,199	2,552	2,923	3,196	3,271	3,271	3,271	3,271	3,271

Circuit	OCL	HC	2016	2017	2018	2019	2020	2030	2040	2045
Circuit 264	5,762	4,898	4,075	4,668	5,104	5,291	5,483	5,637	5,637	5,637
Circuit 265	5,107	3,907	762	873	954	989	1,025	1,733	1,925	1,925
Circuit 266	3,937	3,346	182	208	228	236	245	414	592	681
Circuit 267	2,933	2,493	471	540	590	612	634	650	650	650
Circuit 268	6,033	5,128	1,623	1,859	2,033	2,107	2,184	3,692	5,283	5,706
Circuit 269	4,641	3,945	–	–	–	–	–	–	–	–
Circuit 270	4,421	3,758	1,116	1,278	1,398	1,449	1,501	2,539	3,098	3,098
Circuit 271	4,171	3,545	2,511	2,876	3,144	3,260	3,378	5,712	6,041	6,041
Circuit 272	1,154	981	495	567	620	643	666	1,126	1,611	1,853
Circuit 273	2,143	1,822	457	524	573	594	615	1,041	1,489	1,713
Circuit 274	2,946	2,504	1,520	1,742	1,904	1,974	2,046	3,459	4,389	4,389
Circuit 275	7,570	5,984	3,619	4,146	4,533	4,699	4,870	6,395	6,395	6,395
Circuit 276	3,122	3,475	4,129	4,129	4,129	4,129	4,129	4,129	4,129	4,129
Circuit 277	4,614	4,103	2,334	2,674	2,924	3,031	3,141	5,311	6,926	6,926
Circuit 278	4,340	3,953	2,186	2,504	2,738	2,838	2,941	4,974	6,154	6,154
Circuit 279	1,177	1,057	986	1,129	1,235	1,280	1,326	1,798	1,798	1,798
Circuit 280	2,936	2,495	897	1,027	1,123	1,164	1,206	2,040	2,919	3,358
Circuit 281	1,316	772	1,169	1,339	1,464	1,518	1,573	2,660	3,496	3,496
Circuit 282	4,214	780	1,137	1,302	1,424	1,476	1,530	2,587	3,701	4,258
Circuit 283	3,839	2,871	1,028	1,177	1,287	1,335	1,383	2,339	3,346	3,849
Circuit 284	2,299	1,954	1,798	2,059	2,251	2,334	2,419	4,090	4,985	4,985
Circuit 285	5,662	1,636	2,961	3,392	3,709	3,845	3,984	6,737	7,920	7,920
Circuit 286	5,271	4,480	33	38	42	43	45	76	109	125
Circuit 287	3,252	2,048	1,978	2,266	2,478	2,568	2,662	4,501	4,863	4,863
Circuit 288	9,600	3,270	3,026	3,466	3,790	3,928	4,071	6,802	6,802	6,802
Circuit 289	2,667	3,617	265	304	332	344	357	603	862	992
Circuit 290	2,772	1,028	1,170	1,340	1,464	1,464	1,464	1,464	1,464	1,464
Circuit 291	4,820	3,749	968	1,109	1,213	1,257	1,303	2,203	3,152	3,627
Circuit 292	5,222	2,086	970	1,112	1,215	1,260	1,306	2,208	3,111	3,111
Circuit 293	5,768	4,903	1,383	1,464	1,464	1,464	1,464	1,464	1,464	1,464
Circuit 294	6,307	3,281	767	878	960	996	1,032	1,745	2,496	2,871
Circuit 295	4,017	3,617	328	376	411	426	442	747	903	903
Circuit 296	4,136	2,357	412	472	516	535	555	938	1,342	1,361
Circuit 297	3,545	1,694	1,575	1,804	1,973	2,045	2,119	3,583	4,239	4,239
Circuit 298	4,054	3,446	2,444	2,800	3,062	3,174	3,289	5,561	5,972	5,972
Circuit 299	6,304	3,496	844	967	1,057	1,096	1,136	1,921	2,748	3,162
Circuit 300	4,455	1,469	1,791	2,052	2,243	2,325	2,410	4,075	5,830	6,707
Circuit 301	1,053	496	484	554	606	628	651	1,100	1,574	1,811

Circuit	OCL	HC	2016	2017	2018	2019	2020	2030	2040	2045
Circuit 302	4,019	3,416	1,763	2,019	2,208	2,288	2,372	4,010	5,737	5,758
Circuit 303	6,695	3,596	4,674	5,354	5,854	6,068	6,289	10,430	10,430	10,430
Circuit 304	2,526	2,147	1,365	1,564	1,710	1,772	1,837	2,893	2,893	2,893
Circuit 305	1,852	740	964	1,105	1,208	1,252	1,298	2,194	3,139	3,611
Circuit 306	2,635	1,809	68	78	85	88	91	155	221	254
Circuit 307	4,943	4,202	2,091	2,395	2,619	2,715	2,813	4,757	5,801	5,801
Circuit 308	1,236	1,051	1,080	1,237	1,352	1,402	1,453	2,457	3,039	3,039
Circuit 309	1,140	714	469	537	587	609	631	1,067	1,527	1,757
Circuit 310	6,808	5,787	465	532	582	603	625	1,057	1,512	1,740
Circuit 311	6,285	5,342	460	527	576	597	619	1,047	1,497	1,723
Circuit 312	3,034	2,579	–	–	–	–	–	–	–	–
Circuit 313	3,923	2,934	1,799	2,061	2,254	2,336	2,421	4,094	4,949	4,949
Circuit 314	5,183	4,405	1,612	1,846	2,019	2,093	2,169	3,667	3,805	3,805
Circuit 315	3,086	2,623	489	560	612	635	658	1,112	1,591	1,831
Circuit 316	1,536	1,305	265	304	332	344	357	603	731	731
Circuit 317	5,006	3,868	48	55	60	62	65	109	157	180
Circuit 318	5,261	3,540	216	247	271	280	291	491	703	809
Circuit 319	4,865	4,135	349	400	438	454	470	795	1,137	1,308
Circuit 320	5,762	2,253	2,266	2,596	2,838	2,942	3,049	5,155	5,474	5,474
Circuit 321	337	287	79	90	99	102	106	179	256	295
Circuit 322	4,669	4,724	747	856	936	970	1,005	1,620	1,620	1,620
Circuit 323	144	123	–	–	–	–	–	–	–	–
Circuit 324	5,894	5,010	2,371	2,716	2,970	3,079	3,190	3,581	3,581	3,581
Circuit 325	608	588	501	574	628	651	675	1,141	1,632	1,878
Circuit 326	1,410	762	858	983	1,074	1,114	1,154	1,952	2,792	3,212
Circuit 327	1,463	511	1,311	1,502	1,511	1,511	1,511	1,511	1,511	1,511
Circuit 328	6,119	5,201	3,099	3,550	3,882	4,024	4,170	7,051	7,283	7,283
Circuit 329	1,610	1,369	1,053	1,206	1,318	1,367	1,416	2,395	3,426	3,519
Circuit 330	5,881	4,999	3,528	4,041	4,419	4,580	4,747	6,592	6,592	6,592
Circuit 331	924	785	95	108	119	123	127	215	308	355
Circuit 332	7,351	3,171	3,679	4,215	4,608	4,777	4,951	8,371	10,701	10,701
Circuit 333	5,964	5,069	1,020	1,168	1,277	1,324	1,372	2,320	3,319	3,818
Circuit 334	2,507	2,131	479	549	600	622	645	1,090	1,560	1,795
Circuit 335	3,598	3,058	1,369	1,568	1,714	1,777	1,842	2,649	2,649	2,649
Circuit 336	5,827	4,953	2,046	2,344	2,563	2,657	2,753	4,210	4,210	4,210
Circuit 337	3,697	3,143	1,061	1,216	1,329	1,378	1,428	2,415	3,455	3,975
Circuit 338	959	815	204	233	255	264	274	463	663	762
Circuit 339	9,020	7,667	2,362	2,705	2,958	3,066	3,178	4,111	4,111	4,111

Circuit	OCL	HC	2016	2017	2018	2019	2020	2030	2040	2045
Circuit 340	3,646	3,099	1,452	1,663	1,818	1,885	1,953	3,303	4,675	4,675
Circuit 341	746	634	–	–	–	–	–	–	–	–
Circuit 342	4,140	1,454	1,864	2,136	2,335	2,421	2,509	4,242	6,069	6,982
Circuit 343	5,806	4,935	2,484	2,845	3,111	3,225	3,342	5,651	5,760	5,760
Circuit 344	4,257	3,619	1,738	1,991	2,177	2,257	2,339	3,468	3,468	3,468
Circuit 345	9,447	6,464	738	845	924	958	993	1,679	2,402	2,764
Circuit 346	4,257	3,619	1,580	1,810	1,979	2,052	2,126	3,596	4,565	4,565
Circuit 347	6,038	3,233	2,664	3,052	3,337	3,459	3,584	6,061	7,164	7,164
Circuit 348	3,111	1,014	1,179	1,351	1,477	1,531	1,587	2,683	3,838	4,416
Circuit 349	419	356	473	542	592	614	636	1,076	1,539	1,770
Circuit 350	6,149	3,240	2,547	2,918	3,191	3,307	3,428	5,796	7,505	7,505
Circuit 351	3,133	2,663	–	–	–	–	–	–	–	–
Circuit 352	2,391	1,567	44	44	44	44	44	44	44	44
Circuit 353	7,969	5,222	–	–	–	–	–	–	–	–
Circuit 354	6,602	5,612	24	27	30	31	32	55	78	90
Circuit 355	6,104	5,188	121	139	152	157	163	276	395	454
Circuit 356	3,888	3,304	46	53	58	60	62	105	150	172
Circuit 357	4,256	3,618	–	–	–	–	–	–	–	–
Circuit 358	2,982	2,535	1,070	1,226	1,340	1,389	1,440	2,435	3,483	3,940
Circuit 359	6,054	949	3,858	4,420	4,833	5,009	5,191	8,778	11,248	11,248
Circuit 360	1,341	513	595	682	746	773	801	1,355	1,464	1,464
Circuit 361	277	122	151	173	189	196	203	343	491	565
Circuit 362	6,306	5,364	1,308	1,499	1,639	1,699	1,761	2,977	4,259	4,433
Circuit 363	4,376	3,725	1,679	1,923	2,103	2,180	2,259	3,517	3,517	3,517
Circuit 364	5,368	4,562	3,881	4,445	4,861	5,038	5,221	7,650	7,650	7,650
Circuit 365	4,712	2,283	1,561	1,788	1,956	2,027	2,101	3,552	5,003	5,003
Circuit 366	4,162	1,910	1,120	1,283	1,403	1,455	1,507	2,549	3,647	4,196
Circuit 367	2,068	1,758	1,173	1,343	1,469	1,523	1,578	2,668	3,817	4,392
Circuit 368	4,623	1,336	1,540	1,764	1,929	1,999	2,072	3,503	5,012	5,766
Circuit 369	5,678	4,380	2,925	3,350	3,663	3,797	3,935	6,654	9,264	9,264
Circuit 370	3,020	524	526	603	659	683	708	1,198	1,713	1,971
Circuit 371	4,080	913	2,136	2,447	2,675	2,773	2,874	4,859	6,938	6,938
Circuit 372	5,743	4,882	3,688	4,225	4,620	4,789	4,962	8,391	8,592	8,592
Circuit 373	7,141	5,038	4,995	5,722	6,256	6,485	6,721	9,886	9,886	9,886
Circuit 374	4,249	3,612	1,302	1,491	1,630	1,690	1,751	2,961	3,670	3,670
Circuit 375	4,040	3,434	754	864	945	979	1,015	1,716	2,455	2,824
Circuit 376	1,431	1,216	847	971	1,061	1,100	1,140	1,928	2,223	2,223
Circuit 377	1,821	717	1,084	1,241	1,357	1,407	1,458	2,465	3,527	3,686

Circuit	OCL	HC	2016	2017	2018	2019	2020	2030	2040	2045
Circuit 378	308	262	37	42	46	47	49	83	119	137
Circuit 379	3,073	2,069	1,454	1,665	1,821	1,887	1,956	3,307	4,732	5,216
Circuit 380	1,552	1,319	1,666	1,908	2,086	2,163	2,241	3,789	4,163	4,163
Circuit 381	1,106	640	907	1,039	1,136	1,178	1,221	2,064	2,953	3,398
Circuit 382	–	–	24,363	40,100	81,458	122,815	164,173	381,960	381,960	381,960

Table N-6. Hawaiian Electric Distribution Circuit High DG-PV Forecast (kW)

Maui Electric Distribution Circuit Base DG–PV Forecast (kW)

Circuit	OCL	HC	2016	2017	2018	2019	2020	2030	2040	2045
Circuit 1	3,302	2,871	2,476	2,845	2,845	2,845	2,845	2,845	2,845	2,845
Circuit 2	1,233	1,072	852	873	873	873	873	873	873	873
Circuit 3	166	145	170	170	170	170	170	170	170	170
Circuit 4	22	19	32	32	32	32	32	32	32	32
Circuit 5	29	26	48	56	57	57	58	60	63	65
Circuit 6	188	163	215	215	215	215	215	215	215	215
Circuit 7	3,192	2,776	948	1,018	1,018	1,018	1,018	1,018	1,018	1,018
Circuit 8	3,602	3,132	3,063	3,536	3,592	3,592	3,592	3,592	3,592	3,592
Circuit 9	473	411	1,118	1,291	1,312	1,326	1,339	1,383	1,452	1,452
Circuit 10	330	287	998	1,033	1,033	1,033	1,033	1,033	1,033	1,033
Circuit 11	283	246	436	486	486	486	486	486	486	486
Circuit 12	77	67	9	9	9	9	9	9	9	9
Circuit 13	–	–	166	166	166	166	166	166	166	166
Circuit 14	5,807	5,049	1,452	1,452	1,452	1,452	1,452	1,452	1,452	1,452
Circuit 15	2,141	1,862	823	823	823	823	823	823	823	823
Circuit 16	5,115	4,448	2,065	2,384	2,423	2,449	2,472	2,554	2,698	2,698
Circuit 17	4,569	3,973	2,163	2,497	2,537	2,565	2,589	2,675	2,835	2,891
Circuit 18	6,033	5,246	1,447	1,670	1,697	1,715	1,732	1,789	1,896	1,985
Circuit 19	8,174	7,108	7,963	7,963	7,963	7,963	7,963	7,963	7,963	7,963
Circuit 20	1,117	971	850	895	895	895	895	895	895	895
Circuit 21	199	173	31	35	36	36	37	38	40	42
Circuit 22	5,168	4,494	2,111	2,111	2,111	2,111	2,111	2,111	2,111	2,111
Circuit 23	5,963	5,185	3,213	3,680	3,680	3,680	3,680	3,680	3,680	3,680
Circuit 24	1,133	985	3,885	4,485	4,557	4,607	4,650	4,805	4,929	4,929
Circuit 25	1,806	1,570	4,492	5,186	5,269	5,327	5,377	5,556	5,559	5,559
Circuit 26	629	547	1,337	1,337	1,337	1,337	1,337	1,337	1,337	1,337
Circuit 27	7,439	6,469	7,064	7,064	7,064	7,064	7,064	7,064	7,064	7,064
Circuit 28	539	469	571	659	670	677	684	690	690	690
Circuit 29	2,599	2,260	3,115	3,596	3,654	3,694	3,728	3,829	3,829	3,829
Circuit 30	2,103	1,829	2,901	3,350	3,398	3,398	3,398	3,398	3,398	3,398
Circuit 31	153	133	553	608	608	608	608	608	608	608
Circuit 32	6,784	5,899	1,717	1,717	1,717	1,717	1,717	1,717	1,717	1,717
Circuit 33	3,009	2,616	2,734	3,157	3,207	3,242	3,273	3,382	3,477	3,477
Circuit 34	2,091	1,818	589	680	691	697	697	697	697	697
Circuit 35	2,003	1,742	189	219	222	225	227	234	248	260
Circuit 36	2,361	2,053	3,066	3,445	3,445	3,445	3,445	3,445	3,445	3,445

Circuit	OCL	HC	2016	2017	2018	2019	2020	2030	2040	2045
Circuit 37	1,728	1,502	245	245	245	245	245	245	245	245
Circuit 38	950	826	4,619	5,333	5,342	5,342	5,342	5,342	5,342	5,342
Circuit 39	4,118	3,580	4,086	4,718	4,761	4,761	4,761	4,761	4,761	4,761
Circuit 40	2,366	2,057	570	659	669	676	683	705	748	783
Circuit 41	12,197	10,606	3,083	3,083	3,083	3,083	3,083	3,083	3,083	3,083
Circuit 42	1,255	1,091	331	382	388	392	396	409	434	454
Circuit 43	4,481	3,897	2,853	2,853	2,853	2,853	2,853	2,853	2,853	2,853
Circuit 44	1,354	1,178	1,030	1,190	1,206	1,206	1,206	1,206	1,206	1,206
Circuit 45	1,502	1,306	1,415	1,634	1,660	1,678	1,694	1,732	1,732	1,732
Circuit 46	1,286	1,119	1,210	1,210	1,210	1,210	1,210	1,210	1,210	1,210
Circuit 47	–	–	–	–	–	–	–	–	–	–
Circuit 48	1,470	1,278	670	670	670	670	670	670	670	670
Circuit 49	–	–	22	26	26	26	26	27	29	30
Circuit 50	–	–	–	–	–	–	–	–	–	–
Circuit 51	4,885	4,248	501	579	588	595	600	600	600	600
Circuit 52	2,255	1,961	3,066	3,278	3,278	3,278	3,278	3,278	3,278	3,278
Circuit 53	1,557	1,354	995	995	995	995	995	995	995	995
Circuit 54	–	–	227	227	227	227	227	227	227	227
Circuit 55	850	740	1,304	1,418	1,418	1,418	1,418	1,418	1,418	1,418
Circuit 56	319	277	476	549	558	564	569	588	589	589
Circuit 57	510	443	1,465	1,465	1,465	1,465	1,465	1,465	1,465	1,465
Circuit 58	1,424	1,238	1,892	1,912	1,912	1,912	1,912	1,912	1,912	1,912
Circuit 59	2,861	2,488	3,105	3,585	3,642	3,682	3,716	3,840	3,890	3,890
Circuit 60	1,036	901	7	8	8	8	8	9	9	10
Circuit 61	5,040	4,383	4,584	5,028	5,028	5,028	5,028	5,028	5,028	5,028
Circuit 62	1,285	1,118	395	456	463	468	473	488	518	542
Circuit 63	13,815	12,013	1,980	2,286	2,322	2,348	2,370	2,449	2,534	2,534
Circuit 64	4,346	3,779	466	466	466	466	466	466	466	466
Circuit 65	5,733	4,986	2,636	2,706	2,706	2,706	2,706	2,706	2,706	2,706
Circuit 66	714	621	34	34	34	34	34	34	34	34
Circuit 67	738	642	1,153	1,153	1,153	1,153	1,153	1,153	1,153	1,153
Circuit 68	1,792	1,558	2,328	2,688	2,731	2,760	2,786	2,871	2,871	2,871
Circuit 69	3,834	3,334	3,544	3,862	3,862	3,862	3,862	3,862	3,862	3,862
Circuit 70	3,736	3,249	1,137	1,195	1,195	1,195	1,195	1,195	1,195	1,195
Circuit 71	1,720	1,496	430	496	504	510	515	532	564	583
Circuit 72	3,406	2,962	899	1,037	1,054	1,066	1,076	1,111	1,178	1,183
Circuit 73	7,841	6,818	7,736	8,933	9,076	9,174	9,261	9,521	9,521	9,521
Circuit 74	830	722	257	297	301	305	308	311	311	311

Circuit	OCL	HC	2016	2017	2018	2019	2020	2030	2040	2045
Circuit 75	951	827	100	100	100	100	100	100	100	100
Circuit 76	4,062	3,532	2,348	2,706	2,706	2,706	2,706	2,706	2,706	2,706
Circuit 77	2,991	2,601	613	708	719	727	734	758	803	814
Circuit 78	5,882	5,115	1,443	1,666	1,693	1,694	1,694	1,694	1,694	1,694
Circuit 79	3,908	3,398	1,066	1,066	1,066	1,066	1,066	1,066	1,066	1,066
Circuit 80	3,928	3,416	438	504	504	504	504	504	504	504
Circuit 81	3,494	3,038	1,205	1,205	1,205	1,205	1,205	1,205	1,205	1,205
Circuit 82	2,645	2,300	2,754	2,974	2,974	2,974	2,974	2,974	2,974	2,974
Circuit 83	1,596	1,388	1,315	1,315	1,315	1,315	1,315	1,315	1,315	1,315
Circuit 84	3,169	2,756	2,207	2,548	2,589	2,617	2,642	2,730	2,894	2,913
Circuit 85	–	–	–	–	–	–	–	–	–	–
Circuit 86	5,449	4,738	2,896	3,344	3,398	3,435	3,467	3,488	3,488	3,488
Circuit 87	1,055	917	585	585	585	585	585	585	585	585
Circuit 88	560	487	909	909	909	909	909	909	909	909
Circuit 89	625	543	837	846	846	846	846	846	846	846
Circuit 90	418	364	597	611	611	611	611	611	611	611
Circuit 91	75	65	95	109	111	112	113	117	124	130
Circuit 92	1,002	872	1,214	1,402	1,425	1,440	1,454	1,462	1,462	1,462
Circuit 93	122	106	159	159	159	159	159	159	159	159
Circuit 94	207	180	316	364	370	374	378	390	414	433
Circuit 95	804	700	1,448	1,549	1,549	1,549	1,549	1,549	1,549	1,549
Circuit 96	276	240	299	299	299	299	299	299	299	299
Circuit 97	599	521	332	348	348	348	348	348	348	348
Circuit 98	1,037	902	56	56	56	56	56	56	56	56
Circuit 99	520	452	12	14	14	14	14	15	15	16
Circuit 100	377	328	382	382	382	382	382	382	382	382
Circuit 101	2106	1831	2,625	3,031	3,079	3,113	3,142	3,247	3,441	3,602
Circuit 102	2604	2265	644	661	661	661	661	661	661	661

Table N-7. Maui Electric Distribution Circuit Base DG-PV Forecast (kW)

Maui Electric Distribution Circuit High DG–PV Forecast (kW)

Circuit	OCL	HC	2016	2017	2018	2019	2020	2030	2040	2045
Circuit 1	3,302	2,871	2,661	3,114	3,269	3,367	3,435	6,436	7,697	7,697
Circuit 2	1,233	1,072	916	1,072	1,125	1,159	1,182	2,215	3,342	3,874
Circuit 3	166	145	225	263	276	285	290	544	599	599
Circuit 4	22	19	43	50	53	54	55	104	138	138
Circuit 5	29	26	52	61	64	66	67	125	189	219
Circuit 6	188	163	284	332	349	359	366	686	1,035	1,200
Circuit 7	3,192	2,776	1,019	1,094	1,094	1,094	1,094	1,094	1,094	1,094
Circuit 8	3,602	3,132	3,292	3,851	4,044	4,165	4,248	7,077	7,077	7,077
Circuit 9	473	411	1,202	1,406	1,476	1,521	1,551	2,906	4,385	5,083
Circuit 10	330	287	1,073	1,255	1,318	1,358	1,385	2,595	3,915	4,539
Circuit 11	283	246	469	549	576	593	605	1,134	1,711	1,984
Circuit 12	77	67	12	14	15	15	15	29	43	44
Circuit 13	–	–	219	256	269	277	283	530	800	927
Circuit 14	5,807	5,049	1,917	2,242	2,355	2,425	2,474	4,635	6,240	6,240
Circuit 15	2,141	1,862	1,087	1,271	1,335	1,375	1,402	2,628	3,965	4,597
Circuit 16	5,115	4,448	2,219	2,597	2,726	2,808	2,864	5,367	6,252	6,252
Circuit 17	4,569	3,973	2,324	2,719	2,855	2,941	3,000	5,621	6,816	6,816
Circuit 18	6,033	5,246	1,178	1,178	1,178	1,178	1,178	1,178	1,178	1,178
Circuit 19	8,174	7,108	9,043	9,462	9,462	9,462	9,462	9,462	9,462	9,462
Circuit 20	1,117	971	914	1,069	1,122	1,156	1,179	2,210	3,334	3,865
Circuit 21	199	173	33	38	40	42	42	79	120	139
Circuit 22	5,168	4,494	2,521	2,950	3,097	3,190	3,254	6,097	6,398	6,398
Circuit 23	5,963	5,185	3,453	4,040	4,242	4,369	4,457	7,346	7,346	7,346
Circuit 24	1,133	985	4,175	4,885	5,129	5,283	5,388	5,992	5,992	5,992
Circuit 25	1,806	1,570	4,827	5,648	5,930	6,108	6,230	8,241	8,241	8,241
Circuit 26	629	547	1,337	1,337	1,337	1,337	1,337	1,337	1,337	1,337
Circuit 27	7,439	6,469	7,708	7,708	7,708	7,708	7,708	7,708	7,708	7,708
Circuit 28	539	469	614	718	754	777	792	1,485	2,240	2,597
Circuit 29	2,599	2,260	3,347	3,916	4,112	4,236	4,320	8,096	8,236	8,236
Circuit 30	2,103	1,829	3,118	3,648	3,830	3,945	4,024	7,540	8,085	8,085
Circuit 31	153	133	594	696	730	752	767	1,438	2,169	2,515
Circuit 32	6,784	5,899	1,717	1,717	1,717	1,717	1,717	1,717	1,717	1,717
Circuit 33	3,009	2,616	2,938	3,438	3,610	3,718	3,792	6,752	6,752	6,752
Circuit 34	2,091	1,818	633	741	778	801	817	1,531	2,310	2,678
Circuit 35	2,003	1,742	203	238	250	257	263	366	366	366
Circuit 36	2,361	2,053	3,295	3,855	4,048	4,169	4,253	6,854	6,854	6,854

Circuit	OCL	HC	2016	2017	2018	2019	2020	2030	2040	2045
Circuit 37	1,728	1,502	279	327	343	353	361	535	535	535
Circuit 38	950	826	4,964	5,808	6,098	6,281	6,407	8,395	8,395	8,395
Circuit 39	4,118	3,580	4,391	5,138	5,395	5,557	5,668	7,838	7,838	7,838
Circuit 40	2,366	2,057	464	464	464	464	464	464	464	464
Circuit 41	12,197	10,606	2,598	2,598	2,598	2,598	2,598	2,598	2,598	2,598
Circuit 42	1,255	1,091	355	416	437	450	459	860	1,297	1,504
Circuit 43	4,481	3,897	3,704	4,333	4,550	4,686	4,780	6,631	6,631	6,631
Circuit 44	1,354	1,178	1,107	1,296	1,360	1,401	1,429	2,678	4,040	4,684
Circuit 45	1,502	1,306	1,520	1,779	1,868	1,924	1,962	3,677	5,548	6,432
Circuit 46	1,286	1,119	1,330	1,556	1,633	1,682	1,716	3,216	4,852	5,625
Circuit 47	–	–	–	–	–	–	–	–	–	–
Circuit 48	1,470	1,278	884	1,034	1,086	1,118	1,141	2,138	3,225	3,739
Circuit 49	–	–	24	28	29	30	31	57	87	101
Circuit 50	–	–	–	–	–	–	–	–	–	–
Circuit 51	4,885	4,248	539	630	662	682	696	1,043	1,043	1,043
Circuit 52	2,255	1,961	3,295	3,855	4,048	4,169	4,253	5,720	5,720	5,720
Circuit 53	1,557	1,354	1,200	1,200	1,200	1,200	1,200	1,200	1,200	1,200
Circuit 54	–	–	299	350	368	379	386	724	1,092	1,266
Circuit 55	850	740	1,402	1,640	1,722	1,774	1,809	3,390	5,115	5,930
Circuit 56	319	277	511	598	628	647	660	1,236	1,865	2,162
Circuit 57	510	443	1,712	2,003	2,103	2,166	2,209	4,140	6,246	6,624
Circuit 58	1,424	1,238	2,033	2,379	2,498	2,573	2,624	4,918	6,504	6,504
Circuit 59	2,861	2,488	3,337	3,904	4,099	4,222	4,306	8,070	8,628	8,628
Circuit 60	1,036	901	7	9	9	9	10	18	27	31
Circuit 61	5,040	4,383	4,927	5,764	6,052	6,234	6,359	8,835	8,835	8,835
Circuit 62	1,285	1,118	424	496	521	537	548	1,026	1,548	1,795
Circuit 63	13,815	12,013	2,128	2,489	2,614	2,692	2,746	3,617	3,617	3,617
Circuit 64	4,346	3,779	616	720	756	779	795	1,236	1,236	1,236
Circuit 65	5,733	4,986	2,833	3,315	3,481	3,585	3,657	6,852	7,565	7,565
Circuit 66	714	621	45	52	55	57	58	108	163	164
Circuit 67	738	642	1,275	1,492	1,566	1,613	1,646	3,084	4,653	5,394
Circuit 68	1,792	1,558	2,502	2,927	3,073	3,165	3,229	6,050	6,810	6,810
Circuit 69	3,834	3,334	3,808	4,456	4,679	4,819	4,915	7,941	7,941	7,941
Circuit 70	3,736	3,249	1,222	1,429	1,501	1,546	1,577	2,955	4,458	5,168
Circuit 71	1,720	1,496	462	540	567	584	596	1,117	1,686	1,954
Circuit 72	3,406	2,962	966	1,130	1,186	1,222	1,246	2,336	3,524	4,085
Circuit 73	7,841	6,818	8,314	9,190	9,190	9,190	9,190	9,190	9,190	9,190
Circuit 74	830	722	276	323	339	349	356	668	1,008	1,168

Circuit	OCL	HC	2016	2017	2018	2019	2020	2030	2040	2045
Circuit 75	951	827	132	154	162	167	170	319	481	557
Circuit 76	4,062	3,532	2,523	2,952	3,100	3,193	3,257	6,103	6,758	6,758
Circuit 77	2,991	2,601	659	735	735	735	735	735	735	735
Circuit 78	5,882	5,115	1,551	1,815	1,834	1,834	1,834	1,834	1,834	1,834
Circuit 79	3,908	3,398	1,407	1,646	1,729	1,780	1,816	3,403	5,134	5,946
Circuit 80	3,928	3,416	471	551	578	596	608	1,139	1,241	1,241
Circuit 81	3,494	3,038	1,205	1,205	1,205	1,205	1,205	1,205	1,205	1,205
Circuit 82	2,645	2,300	2,960	3,463	3,636	3,745	3,820	7,036	7,036	7,036
Circuit 83	1,596	1,388	1,735	2,030	2,132	2,196	2,240	4,197	6,332	6,769
Circuit 84	3,169	2,756	2,372	2,775	2,914	3,001	3,061	5,736	6,224	6,224
Circuit 85	–	–	–	–	–	–	–	–	–	–
Circuit 86	5,449	4,738	3,112	3,642	3,824	3,938	4,017	6,833	6,833	6,833
Circuit 87	1,055	917	717	838	880	907	925	1,733	2,615	3,031
Circuit 88	560	487	1,056	1,235	1,297	1,336	1,362	2,553	3,852	4,465
Circuit 89	625	543	900	1,052	1,105	1,138	1,161	2,176	3,282	3,805
Circuit 90	418	364	642	751	788	812	828	1,552	2,341	2,714
Circuit 91	75	65	102	119	125	129	131	246	249	249
Circuit 92	1,002	872	1,305	1,527	1,603	1,651	1,684	1,688	1,688	1,688
Circuit 93	122	106	191	208	212	218	225	366	512	593
Circuit 94	207	180	319	347	354	365	376	612	855	991
Circuit 95	804	700	1,462	1,594	1,626	1,675	1,725	1,728	1,728	1,728
Circuit 96	276	240	346	378	385	397	409	665	930	959
Circuit 97	599	521	335	365	372	383	395	500	500	500
Circuit 98	1,037	902	57	62	63	65	67	109	152	176
Circuit 99	520	452	12	13	13	14	14	23	32	37
Circuit 100	377	328	474	541	573	619	663	2,227	2,759	2,759
Circuit 101	2,106	1,831	2,188	2,188	2,188	2,188	2,188	2,188	2,188	2,188
Circuit 102	2,604	2,265	661	753	799	862	923	2,753	2,753	2,753

Table N-8. Maui Electric Distribution Circuit High DG-PV Forecast (kW)

Hawai'i Electric Light Distribution Circuit Base DG–PV Forecast (kW)

Circuit	OCL	HC	2016	2017	2018	2019	2020	2030	2040	2045
Circuit 1	6,279	5,337	1,334	1,549	1,612	1,659	1,706	1,996	2,370	2,701
Circuit 2	1,552	1,319	340	395	411	423	435	509	604	689
Circuit 3	1,952	1,659	–	–	–	–	–	–	–	–
Circuit 4	2,529	2,150	261	303	315	325	334	390	464	528
Circuit 5	4,994	4,245	83	96	100	103	106	124	148	168
Circuit 6	2,621	2,228	–	–	–	–	–	–	–	–
Circuit 7	4,560	3,876	925	1,074	1,117	1,150	1,183	1,384	1,643	1,872
Circuit 8	4,641	1,795	1,044	1,212	1,261	1,299	1,335	1,562	1,855	2,114
Circuit 9	846	375	217	253	263	270	278	325	386	440
Circuit 10	2,200	85	348	404	420	433	445	520	618	704
Circuit 11	199	–	–	–	–	–	–	–	–	–
Circuit 12	3,846	85	100	100	100	100	100	100	100	100
Circuit 13	1,457	83	123	142	148	153	157	184	218	248
Circuit 14	2,504	2,129	397	461	480	494	508	594	706	804
Circuit 15	149	127	7	8	8	9	9	10	12	14
Circuit 16	2,012	598	877	1,018	1,059	1,087	1,087	1,087	1,087	1,087
Circuit 17	1,602	953	292	339	352	363	373	436	518	590
Circuit 18	2,881	624	517	600	624	642	661	773	918	1,046
Circuit 19	2,223	1,597	587	681	709	730	750	878	1,042	1,188
Circuit 20	696	272	133	154	161	165	170	199	236	269
Circuit 21	3,504	1,040	1,530	1,777	1,848	1,903	1,957	2,289	2,718	3,098
Circuit 22	2,080	85	76	88	91	94	97	113	134	153
Circuit 23	5,493	2,714	2,993	3,476	3,616	3,723	3,828	4,478	5,317	6,060
Circuit 24	2,781	851	619	719	748	771	792	927	1,101	1,254
Circuit 25	8,169	2,431	4,542	5,275	5,488	5,650	5,810	6,797	8,070	9,197
Circuit 26	1,155	–	–	–	–	–	–	–	–	–
Circuit 27	3,789	3,221	1,728	2,006	2,087	2,149	2,209	2,585	3,069	3,194
Circuit 28	5,923	5,034	1,185	1,376	1,431	1,474	1,515	1,773	2,105	2,399
Circuit 29	1,408	1,196	179	207	216	222	228	267	317	362
Circuit 30	4,644	1,857	1,758	2,042	2,124	2,187	2,249	2,631	3,124	3,560
Circuit 31	8,263	7,029	1,080	1,254	1,304	1,343	1,381	1,616	1,918	2,186
Circuit 32	6,539	5,558	231	231	231	231	231	231	231	231
Circuit 33	10,737	9,123	2,510	2,915	3,032	3,122	3,210	3,755	4,459	4,808
Circuit 34	3,243	2,756	1,124	1,305	1,358	1,398	1,438	1,682	1,997	2,276
Circuit 35	312	215	281	326	339	349	359	420	499	569
Circuit 36	3,291	1,818	812	943	981	1,010	1,038	1,137	1,137	1,137

Circuit	OCL	HC	2016	2017	2018	2019	2020	2030	2040	2045
Circuit 37	841	715	109	127	132	136	139	163	194	221
Circuit 38	2,653	2,255	88	102	106	110	113	132	157	178
Circuit 39	2,479	2,107	1,006	1,168	1,215	1,251	1,287	1,505	1,787	2,037
Circuit 40	1,492	533	442	514	534	550	566	662	786	895
Circuit 41	3,459	460	631	733	762	785	807	944	1,121	1,277
Circuit 42	1,309	424	541	629	654	673	692	810	962	1,056
Circuit 43	962	81	119	138	144	148	152	178	211	241
Circuit 44	5,490	770	871	1,012	1,053	1,084	1,114	1,304	1,548	1,764
Circuit 45	1,506	764	712	827	860	885	910	1,065	1,265	1,441
Circuit 46	6,002	599	756	878	913	940	967	1,131	1,343	1,530
Circuit 47	5,097	284	298	347	361	371	382	447	530	604
Circuit 48	661	146	203	235	245	252	259	303	360	410
Circuit 49	1,526	146	144	168	174	179	184	216	256	292
Circuit 50	1,324	315	522	607	631	650	668	782	906	906
Circuit 51	1,167	2,043	1,421	1,421	1,421	1,421	1,421	1,421	1,421	1,421
Circuit 52	3,211	6,199	7,168	7,168	7,168	7,168	7,168	7,168	7,168	7,168
Circuit 53	2,988	864	1,047	1,216	1,265	1,302	1,339	1,567	1,860	2,080
Circuit 54	4,007	3,406	1,566	1,818	1,891	1,947	2,002	2,343	2,782	3,170
Circuit 55	1,677	1,425	494	574	597	614	632	739	877	1,000
Circuit 56	352	299	123	143	148	153	157	184	218	248
Circuit 57	1,035	548	429	499	519	534	549	643	763	870
Circuit 58	74	62	10	10	10	10	10	10	10	10
Circuit 59	3,462	1,758	1,648	1,914	1,991	2,050	2,108	2,466	2,928	3,337
Circuit 60	2,628	2,108	1,611	1,871	1,946	2,004	2,061	2,411	2,862	3,262
Circuit 61	1,448	1,252	945	1,097	1,141	1,175	1,209	1,414	1,679	1,913
Circuit 62	1,489	1,274	119	138	144	148	152	178	211	241
Circuit 63	1,958	940	504	586	609	627	645	754	896	1,021
Circuit 64	1,586	1,354	158	183	190	196	202	236	280	319
Circuit 65	2,879	2,471	509	591	615	633	651	762	904	1,031
Circuit 66	1,858	1,579	694	806	838	863	888	900	900	900
Circuit 67	586	498	–	–	–	–	–	–	–	–
Circuit 68	1,132	283	209	242	252	260	267	312	371	422
Circuit 69	1,920	480	402	467	486	500	514	602	714	814
Circuit 70	1,937	1,674	804	933	971	1,000	1,028	1,202	1,428	1,627
Circuit 71	2,692	2,328	400	465	484	498	512	599	711	811
Circuit 73	6,379	4,121	2,866	3,328	3,462	3,564	3,665	4,288	5,091	5,802
Circuit 74	6,752	3,386	3,543	4,115	4,281	4,407	4,532	5,302	6,295	7,174
Circuit 75	515	438	194	226	235	242	248	291	345	393

Circuit	OCL	HC	2016	2017	2018	2019	2020	2030	2040	2045
Circuit 76	7,449	3,229	2,790	3,240	3,370	3,470	3,568	4,175	4,957	5,649
Circuit 77	851	724	597	693	721	742	763	893	1,060	1,208
Circuit 78	5,542	1,949	2,658	3,087	3,211	3,306	3,400	3,977	4,723	5,382
Circuit 79	119	76	–	–	–	–	–	–	–	–
Circuit 80	226	120	–	–	–	–	–	–	–	–
Circuit 81	1,463	480	750	871	906	933	959	1,122	1,332	1,518
Circuit 82	6,860	4,489	2,500	2,904	3,021	3,110	3,198	3,741	4,442	5,062
Circuit 83	245	208	193	224	233	240	247	289	343	391
Circuit 84	227	57	72	84	87	89	92	108	128	146
Circuit 85	676	190	189	220	229	236	242	283	337	384
Circuit 86	469	399	259	301	313	322	332	388	461	525
Circuit 87	233	198	143	167	173	178	184	215	255	291
Circuit 88	9,204	7,823	1,641	1,906	1,982	2,041	2,099	2,455	2,915	3,322
Circuit 89	2,002	1,701	860	999	1,039	1,070	1,100	1,287	1,528	1,741
Circuit 90	3,210	2,805	3,300	3,300	3,300	3,300	3,300	3,300	3,300	3,300
Circuit 91	2,905	938	662	769	800	824	847	991	1,176	1,341
Circuit 92	376	122	147	171	178	183	188	220	261	298
Circuit 93	859	128	167	194	202	208	214	251	298	339
Circuit 94	324	117	161	187	194	200	205	240	285	325
Circuit 95	331	43	45	52	54	56	57	67	80	91
Circuit 96	1,129	219	182	211	220	226	233	272	323	369
Circuit 97	5,660	4,811	388	450	469	482	496	580	689	785
Circuit 98	4,943	4,202	374	434	452	465	478	559	664	757
Circuit 99	991	172	162	188	196	202	208	243	288	329
Circuit 100	1,001	851	270	313	326	336	345	404	479	546
Circuit 101	364	310	52	60	62	64	66	77	92	105
Circuit 102	2,812	2,390	636	738	768	791	813	951	1,129	1,287
Circuit 103	4,907	4,171	1,582	1,838	1,912	1,968	2,024	2,368	2,811	3,204
Circuit 104	4,623	2,681	2,622	3,045	3,167	3,261	3,353	3,923	4,658	5,309
Circuit 105	6,136	1,483	1,744	2,026	2,107	2,170	2,231	2,610	3,099	3,531
Circuit 106	722	171	175	203	212	218	224	262	311	355
Circuit 107	408	126	186	216	225	231	238	278	330	377
Circuit 108	311	–	–	–	–	–	–	–	–	–
Circuit 109	3,792	3,223	691	802	835	859	884	1,034	1,227	1,399
Circuit 110	5,574	4,738	272	316	329	339	349	408	484	552
Circuit 111	4,103	626	252	292	304	313	322	377	447	510
Circuit 112	4,693	3,989	1,143	1,327	1,381	1,422	1,462	1,710	2,031	2,314
Circuit 113	1,316	1,118	16	19	19	20	20	24	28	32

Circuit	OCL	HC	2016	2017	2018	2019	2020	2030	2040	2045
Circuit 114	798	678	133	154	161	165	170	199	236	269
Circuit 115	146	124	500	500	500	500	500	500	500	500
Circuit 116	762	648	500	500	500	500	500	500	500	500
Circuit 117	2,610	836	843	979	1,018	1,048	1,078	1,261	1,497	1,706
Circuit 118	6,995	1,070	1,164	1,352	1,406	1,448	1,489	1,742	2,068	2,357
Circuit 119	2,666	585	521	605	630	648	667	780	926	1,055
Circuit 120	2,396	2,037	856	994	1,034	1,064	1,094	1,280	1,520	1,732
Circuit 121	58	–	100	–	–	–	–	–	–	–
Circuit 122	351	167	174	202	210	216	222	260	309	352
Circuit 123	944	802	150	175	182	187	192	225	267	304
Circuit 124	1,117	16	4	4	4	5	5	5	6	7
Circuit 125	3,522	1,008	883	1,025	1,066	1,098	1,129	1,321	1,568	1,787
Circuit 126	1,518	1,129	504	585	609	627	645	754	895	1,020
Circuit 127	192	163	47	54	56	58	60	70	83	95
Circuit 128	118	101	46	53	55	57	59	69	81	93
Circuit 129	1,990	1,691	1,158	1,345	1,399	1,440	1,481	1,733	2,057	2,345
Circuit 130	816	694	463	537	559	576	592	692	822	937
Circuit 131	4,112	3,495	1,038	1,206	1,254	1,291	1,328	1,553	1,844	2,102
Circuit 132	3,475	2,954	2,236	2,597	2,701	2,782	2,860	3,346	3,973	4,528
Circuit 133	1,271	–	–	–	–	–	–	–	–	–
Circuit 134	952	–	–	–	–	–	–	–	–	–
Circuit 135	698	435	255	296	308	317	326	382	453	517
Circuit 136	1,928	1,606	611	710	738	760	782	915	1,086	1,238

Table N-9. Hawai‘i Electric Light Distribution Circuit Base DG-PV Forecast (kW)

Hawai‘i Electric Light Distribution Circuit High DG–PV Forecast (kW)

Circuit	OCL	HC	2016	2017	2018	2019	2020	2030	2040	2045
Circuit 1	6,279	5,337	1,904	2,325	2,484	2,544	2,606	5,591	8,837	10,210
Circuit 2	1,552	1,319	534	652	697	713	731	1,568	2,478	2,933
Circuit 3	1,952	1,659	68	83	89	91	93	200	316	374
Circuit 4	2,529	2,150	420	513	548	561	575	1,234	1,950	2,308
Circuit 5	4,994	4,245	162	198	212	217	222	476	753	891
Circuit 6	2,621	2,228	68	83	89	91	93	200	316	374
Circuit 7	4,560	3,876	1,666	2,036	2,175	2,227	2,281	4,894	7,538	7,538
Circuit 8	4,641	1,795	1,310	1,600	1,709	1,750	1,793	3,846	5,416	5,416
Circuit 9	846	375	328	401	428	439	449	964	1,524	1,804
Circuit 10	2,200	85	491	600	641	656	672	1,442	2,279	2,698
Circuit 11	199	–	68	83	89	91	93	200	316	374
Circuit 12	3,846	85	136	166	178	182	186	400	632	737
Circuit 13	1,457	83	134	163	174	178	183	392	620	734
Circuit 14	2,504	2,129	756	924	987	1,011	1,036	2,222	3,512	4,157
Circuit 15	149	127	7	9	10	10	10	22	35	41
Circuit 16	2,012	598	742	907	969	992	1,016	2,180	2,610	2,610
Circuit 17	1,602	953	365	445	476	487	499	1,071	1,692	2,003
Circuit 18	2,881	624	740	904	966	990	1,014	2,174	3,437	4,068
Circuit 19	2,223	1,597	822	1,004	1,073	1,099	1,126	2,415	3,817	4,518
Circuit 20	696	272	201	246	263	269	275	591	934	1,105
Circuit 21	3,504	1,040	1,223	1,223	1,223	1,223	1,223	1,223	1,223	1,223
Circuit 22	2,080	85	82	100	107	110	113	242	382	452
Circuit 23	5,493	2,714	4,517	5,517	5,895	6,036	6,183	13,265	17,295	17,295
Circuit 24	2,781	851	930	1,136	1,213	1,242	1,273	2,730	4,315	4,838
Circuit 25	8,169	2,431	6,101	7,453	7,963	8,154	8,352	16,854	16,854	16,854
Circuit 26	1,155	–	68	83	89	91	93	200	316	374
Circuit 27	3,789	3,221	2,331	2,848	3,042	3,115	3,191	6,846	6,960	6,960
Circuit 28	5,923	5,034	1,423	1,738	1,857	1,902	1,948	4,179	6,606	7,579
Circuit 29	1,408	1,196	280	341	365	374	383	821	1,298	1,461
Circuit 30	4,644	1,857	2,054	2,509	2,681	2,745	2,812	2,934	2,934	2,934
Circuit 31	8,263	7,029	1,608	1,964	2,098	2,149	2,201	4,280	4,280	4,280
Circuit 32	6,539	5,558	42	52	55	56	58	124	196	230
Circuit 33	10,737	9,123	3,416	4,172	4,458	4,565	4,676	10,031	15,856	17,214
Circuit 34	3,243	2,756	1,749	1,946	1,946	1,946	1,946	1,946	1,946	1,946
Circuit 35	312	215	389	475	507	520	532	1,142	1,230	1,230
Circuit 36	3,291	1,818	1,303	1,591	1,700	1,741	1,783	1,866	1,866	1,866

Circuit	OCL	HC	2016	2017	2018	2019	2020	2030	2040	2045
Circuit 37	841	715	121	148	158	162	166	355	562	665
Circuit 38	2,653	2,255	96	117	125	128	131	282	445	527
Circuit 39	2,479	2,107	1,388	1,696	1,812	1,855	1,901	4,077	5,428	5,428
Circuit 40	1,492	533	864	1,056	1,128	1,155	1,183	2,538	3,044	3,044
Circuit 41	3,459	460	1,051	1,284	1,372	1,405	1,439	3,087	3,746	3,746
Circuit 42	1,309	424	651	795	850	870	891	1,913	3,023	3,530
Circuit 43	962	81	129	158	169	173	177	380	600	710
Circuit 44	5,490	770	1,237	1,511	1,614	1,653	1,693	3,633	5,618	5,618
Circuit 45	1,506	764	1,564	1,910	2,041	2,090	2,141	2,389	2,389	2,389
Circuit 46	6,002	599	1,149	1,404	1,500	1,536	1,573	1,887	1,887	1,887
Circuit 47	5,097	284	463	565	604	618	633	1,359	2,148	2,543
Circuit 48	661	146	271	331	354	362	371	796	1,259	1,490
Circuit 49	1,526	146	251	306	327	335	343	737	1,165	1,379
Circuit 50	1,324	315	660	806	861	882	903	1,938	3,063	3,626
Circuit 51	1,167	2,043	272	332	355	363	372	798	1,262	1,494
Circuit 52	3,211	6,199	734	896	957	980	1,004	2,154	3,405	4,031
Circuit 53	2,988	864	1,436	1,754	1,874	1,919	1,966	4,217	6,666	7,808
Circuit 54	4,007	3,406	2,184	2,668	2,851	2,919	2,990	6,416	9,266	9,266
Circuit 55	1,677	1,425	709	867	926	948	971	2,084	3,293	3,737
Circuit 56	352	299	201	246	263	269	275	591	934	1,106
Circuit 57	1,035	548	499	610	652	667	684	1,437	1,437	1,437
Circuit 58	74	62	14	17	18	18	19	40	63	75
Circuit 59	3,462	1,758	2,365	2,889	3,087	3,161	3,238	6,946	8,762	8,762
Circuit 60	2,628	2,108	2,211	2,701	2,886	2,955	3,027	6,407	6,407	6,407
Circuit 61	1,448	1,252	962	962	962	962	962	962	962	962
Circuit 62	1,489	1,274	286	349	373	382	391	776	776	776
Circuit 63	1,958	940	701	856	915	937	959	2,058	3,253	3,850
Circuit 64	1,586	1,354	218	266	284	291	298	639	1,010	1,196
Circuit 65	2,879	2,471	702	857	916	938	961	2,061	3,257	3,705
Circuit 66	1,858	1,579	735	898	959	982	1,006	2,159	2,749	2,749
Circuit 67	586	498	68	83	89	91	93	200	316	374
Circuit 68	1,132	283	283	346	370	379	388	832	1,315	1,557
Circuit 69	1,920	480	552	674	720	737	755	1,620	2,560	3,031
Circuit 70	1,937	1,674	1,040	1,270	1,357	1,390	1,424	3,054	4,135	4,135
Circuit 71	2,692	2,328	1,337	1,633	1,745	1,786	1,830	3,926	6,122	6,122
Circuit 73	6,379	4,121	3,590	4,385	4,685	4,798	4,914	10,543	14,919	14,919
Circuit 74	6,752	3,386	4,561	5,572	5,953	6,096	6,244	13,396	15,389	15,389
Circuit 75	515	438	236	288	308	315	323	693	995	995

Circuit	OCL	HC	2016	2017	2018	2019	2020	2030	2040	2045
Circuit 76	7,449	3,229	3,942	4,816	5,145	5,269	5,397	11,578	12,755	12,755
Circuit 77	851	724	849	1,037	1,108	1,134	1,162	2,439	2,439	2,439
Circuit 78	5,542	1,949	3,631	4,436	4,739	4,853	4,971	8,743	8,743	8,743
Circuit 79	119	76	68	83	89	91	93	200	316	374
Circuit 80	226	120	68	83	89	91	93	200	316	374
Circuit 81	1,463	480	1,014	1,238	1,323	1,355	1,388	2,977	4,705	5,363
Circuit 82	6,860	4,489	3,039	3,712	3,966	4,062	4,160	8,925	10,103	10,103
Circuit 83	245	208	293	358	383	392	401	861	1,169	1,169
Circuit 84	227	57	84	102	109	112	114	245	388	459
Circuit 85	676	190	226	276	295	302	310	665	1,050	1,243
Circuit 86	469	399	420	513	548	561	575	1,234	1,545	1,545
Circuit 87	233	198	189	231	246	252	259	555	877	1,038
Circuit 88	9,204	7,823	3,236	3,953	4,224	4,325	4,430	4,930	4,930	4,930
Circuit 89	2,002	1,701	1,322	1,615	1,725	1,766	1,809	3,557	3,557	3,557
Circuit 90	3,210	2,805	3,300	3,300	3,300	3,300	3,300	3,300	3,300	3,300
Circuit 91	2,905	938	1,038	1,268	1,354	1,387	1,421	3,047	4,817	5,702
Circuit 92	376	122	217	265	284	290	298	638	1,009	1,194
Circuit 93	859	128	201	245	262	269	275	590	933	1,104
Circuit 94	324	117	461	563	601	616	631	1,307	1,307	1,307
Circuit 95	331	43	68	83	89	91	94	201	317	375
Circuit 96	1,129	219	343	419	448	458	469	1,007	1,592	1,884
Circuit 97	5,660	4,811	501	612	654	670	686	1,472	1,559	1,559
Circuit 98	4,943	4,202	848	1,035	1,106	1,133	1,160	1,837	1,837	1,837
Circuit 99	991	172	273	333	356	365	373	801	1,266	1,499
Circuit 100	1,001	851	426	520	556	569	583	1,250	1,976	2,339
Circuit 101	364	310	80	98	104	107	109	235	371	439
Circuit 102	2,812	2,390	881	1,076	1,150	1,177	1,206	1,425	1,425	1,425
Circuit 103	4,907	4,171	2,107	2,574	2,750	2,816	2,885	6,189	7,161	7,161
Circuit 104	4,623	2,681	3,043	3,615	3,615	3,615	3,615	3,615	3,615	3,615
Circuit 105	6,136	1,483	2,274	2,777	2,968	3,039	3,113	4,984	4,984	4,984
Circuit 106	722	171	283	346	369	378	387	831	1,313	1,554
Circuit 107	408	126	202	247	264	270	277	594	701	701
Circuit 108	311	–	68	83	89	91	93	200	316	374
Circuit 109	3,792	3,223	1,406	1,409	1,409	1,409	1,409	1,409	1,409	1,409
Circuit 110	5,574	4,738	825	1,008	1,077	1,103	1,130	1,775	1,775	1,775
Circuit 111	4,103	626	521	636	679	696	713	1,472	1,472	1,472
Circuit 112	4,693	3,989	1,433	1,433	1,433	1,433	1,433	1,433	1,433	1,433
Circuit 113	1,316	1,118	17	21	23	23	24	51	81	96

Circuit	OCL	HC	2016	2017	2018	2019	2020	2030	2040	2045
Circuit 114	798	678	185	226	241	247	253	543	858	1,016
Circuit 115	146	124	680	758	758	758	758	758	758	758
Circuit 116	762	648	680	710	710	710	710	710	710	710
Circuit 117	2,610	836	1,366	1,668	1,782	1,825	1,869	4,011	6,339	7,369
Circuit 118	6,995	1,070	2,138	2,612	2,791	2,858	2,927	6,153	6,153	6,153
Circuit 119	2,666	585	954	1,165	1,245	1,274	1,305	2,800	4,427	4,952
Circuit 120	2,396	2,037	1,299	1,587	1,696	1,736	1,778	3,815	6,031	6,571
Circuit 121	58	–	136	166	178	182	186	400	632	748
Circuit 122	351	167	271	331	353	362	371	795	1,257	1,264
Circuit 123	944	802	234	286	305	313	320	687	1,087	1,286
Circuit 124	1,117	16	679	829	886	907	929	957	957	957
Circuit 125	3,522	1,008	1,620	1,979	2,115	2,165	2,218	4,758	5,067	5,067
Circuit 126	1,518	1,129	686	838	895	917	939	2,014	3,184	3,768
Circuit 127	192	163	51	62	66	68	70	149	236	280
Circuit 128	118	101	146	179	191	196	200	430	680	805
Circuit 129	1,990	1,691	1,661	2,029	2,168	2,220	2,274	3,257	3,257	3,257
Circuit 130	816	694	744	909	971	994	1,019	1,084	1,084	1,084
Circuit 131	4,112	3,495	1,227	1,499	1,601	1,640	1,679	3,603	5,695	6,741
Circuit 132	3,475	2,954	3,196	3,904	4,171	4,271	4,375	9,235	9,235	9,235
Circuit 133	1,271	–	68	83	89	91	93	200	316	374
Circuit 134	952	–	68	83	89	91	93	200	316	374
Circuit 135	698	435	493	603	644	659	675	1,449	2,111	2,111
Circuit 136	1,928	1,606	874	1,067	1,140	1,167	1,196	2,565	4,055	4,800

Table N-10. Hawai‘i Electric Light Distribution Circuit High DG-PV Forecast (kW)

INTEGRATION STRATEGY COSTS ESTIMATES

Table N–11 through Table N–45 include the annualized cost and volumes of for each integration strategy, by island, in the near–, mid–, and long–term planning horizons.

Upgrade [Nominal $000]	2016–2020	2021–2030	2031–2045	Total
Voltage Regulators	$11,336	$3,322	$6,125	$20,784
Distribution Tsf	$12,565	$13,737	–	$26,302
OH Conductor	$1,574	$2,584	$6,480	$10,638
UG Conductor	$951	$1,547	$1,358	$3,856
Substation Tsf	$17,977	$12,433	$61,874	$92,284
46kV Grounding Tsf	$43,532	$11,048	$7,013	$61,592
Grand Total	*$87,935*	*$44,672*	*$82,850*	*$215,457*
Voltage Regulators (Qty)	259	68	99	426
Distribution Tsf (Qty)	880	880	–	1,760
OH Conductor (Ft)	7	11	20	38
UG Conductor (Ft)	1,133	1,601	1,171	3,905
Substation Tsf (Qty)	5	4	12	21
46kV Grounding Tsf (Qty)	44	10	5	59

Table N–11. O‘ahu Integration Strategy 1 Annualized Cost and Volumes

Upgrade [Nominal $000]	2016–2020	2021–2030	2031–2045	Total
BESS	$116,445	$43,630	$103,495	$263,570
Replacement BESS	–	$77,815	$155,004	$232,819
Var Comp Devices	$7,300	$14,552	$27,776	$49,628.09
DER Controls	$15,792	$25,925	$42,838	$84,554
46kV Grounding Tsf	$43,532	$11,048	$7,013	$61,592
Grand Total	*$183,069*	*$172,969*	*$336,127*	*$692,165*
BESS (kW)	30,817	16,682	45,022	92,521
BESS (kWh)	123,268	66,728	180,088	370,084
Replacement BESS (kW)	–	30,817	67,523	98,340
Replacement BESS (kWh)	–	123,268	270,092	393,360
Var Comp Devices (kW)	8,283	14,383	21,861	44,527
46kV Grounding Tsf (Qty)	44	10	5	59

Table N–12. O‘ahu Integration Strategy 2 Annualized Cost and Volumes

Upgrade [Nominal $000]	2016–2020	2021–2030	2031–2045	Total
Substation Tsf	$4,072	–	–	$4,072
Var Comp Devices	$3,786	$14,552	$27,776	$46,114
OH Conductor	$1,574	$2,584	$6,480	$10,638
UG Conductor	$951	$1,547	$1,358	$3,856
DER Controls	$15,792	$25,925	$42,838	$84,554
46kV Grounding Tsf	$43,532	$11,048	$7,013	$61,592
Grand Total	*$75,831*	*$55,656*	*$85,465*	*$216,952*
Voltage Regulators (Qty)	140	–	–	140
Substation Tsf (Qty)	2	–	–	2
Var Comp Devices (kW)	8,283	14,383	21,861	44,527
OH Conductor (Ft)	7,278	10,582	20,370	38,230
UG Conductor (Ft)	1,133	1,601	1,171	3,905
46kV Grounding Tsf (Qty)	44	10	5	59

Table N–13. Oʻahu Integration Strategy 3 Annualized Cost and Volumes

Upgrade [Nominal $000]	2016–2020	2021–2030	2031–2045	Total
Voltage Regulators	$12,130	$11,260	$7,324	$30,714
Distribution Tsf	$25,237	$27,591	–	$52,828
OH Conductor	$2,454	$7,654	$15,366	$25,473
UG Conductor	$994	$6,062	$8,544	$15,600
Substation Tsf	$41,281	$138,875	$164,473	$344,629
46kV Grounding Tsf	$47,452	$10,069	$1,407	$58,927
Grand Total	*$129,548*	*$201,511*	*$197,113*	*$528,171*
Voltage Regulators (Qty)	270	214	107	591
Distribution Tsf (Qty)	1,770	1,770	–	3,540
OH Conductor (Ft)	11,448	30,517	50,316	92,281
UG Conductor (Ft)	1,173	6,172	7,129	14,474
Substation Tsf (Qty)	9	46	32	87
46kV Grounding Tsf (Qty)	48	9	1	58

Table N–14. Oʻahu Integration Strategy 4 Annualized Cost and Volumes

Upgrade [Nominal $000]	2016–2020	2021–2030	2031–2045	Total
Voltage Regulators	$12,130	$11,260	$7,324	$30,714
Distribution Tsf	$25,237	$27,591	–	$52,828
OH Conductor	$2,454	$7,654	$15,366	$25,473
UG Conductor	$994	$6,062	$8,544	$15,600
Substation Tsf	$31,934	$40,316	$84,797	$157,047
DER Controls	$52,560	$141,901	$63,974	$258,436
46kV Grounding Tsf	$47,452	$10,069	$1,407	$58,927
Grand Total	*$172,761*	*$244,853*	*$181,412*	*$599,025*
Voltage Regulators (Qty)	270	214	107	591
Distribution Tsf (Qty)	1,770	1,770	–	3,540
OH Conductor (Ft)	11,448	30,517	50,316	92,281
UG Conductor (Ft)	1,173	6,172	7,129	14,474
Substation Tsf (Qty)	6	11	20	37
46kV Grounding Tsf (Qty)	48	9	1	58

Table N-15. O‘ahu Integration Strategy 5 Annualized Cost and Volumes

Upgrade [Nominal $000]	2016–2020	2021–2030	2031–2045	Total
BESS	$129,997	$381,236	$427,831	$939,064
Replacement BESS	–	$69,845	$600,370	$670,214
Var Comp Devices	$9,641	$25,831	$23,790	$59,262
DER Controls	$52,560	$141,901	$63,974	$258,436
46kV Grounding Tsf	$47,452	$10,069	$1,407	$58,927
Grand Total	*$239,649*	*$628,882*	*$1,117,372*	*$1,985,903*
BESS (kW)	27,662	118,686	148,554	294,902
BESS (kWh)	110,648	474,744	594,216	1,179,608
Replacement BESS (kW)	–	27,662	262,385	290,047
Replacement BESS (kWh)	–	110,648	1,049,540	1,160,188
Var Comp Devices (kW)	10,906	25,317	19,467	55,690
46kV Grounding Tsf (Qty)	48	9	1	58

Table N-16. O‘ahu Integration Strategy 6 Annualized Cost and Volumes

Upgrade [Nominal $000]	2016–2020	2021–2030	2031–2045	Total
Voltage Regulators	$6,060	–	–	$6,060
Substation Tsf	$4,072	–	–	$4,072
Var Comp Devices	$5,522	$25,831	$23,790	$55,143
BESS	–	$17,232	$99,427	$116,659
Replacement BESS	–	–	$27,666	$27,666
OH Conductor	$2,454	$7,654	$15,366	$25,473
UG Conductor	$994	$6,062	$8,544	$15,600
DER Controls	$52,560	$141,901	$63,974	$258,436
46kV Grounding Tsf	$47,452	$10,069	$1,407	$58,927
Grand Total	*$119,113*	*$208,749*	*$240,174*	*$568,036*
Voltage Regulators (Qty)	137	–	–	137
Substation Tsf (Qty)	2	–	–	2
Var Comp Devices (kW)	10,906	25,317	19,467	55,690
BESS (kW)	–	5,083	31,056	36,139
BESS (kWh)	–	20,332	124,224	144,556
Replacement BESS (kW)	–	–	12,182	12,182
Replacement BESS (kWh)	–	–	48,728	48,728
OH Conductor (Ft)	11,448	30,517	50,316	92,281
UG Conductor (Ft)	1,173	6,172	7,129	14,474
46kV Grounding Tsf (Qty)	48	9	1	58

Table N–17. O‘ahu Integration Strategy 7 Annualized Cost and Volumes

Upgrade [Nominal $000]	2016–2020	2021–2030	2031–2045	Total
Voltage Regulators	$4,720	–	–	$4,720
Distribution Tsf	$4,426	$4,839	–	$9,265
OH Conductor	$5,332	$1,901	$348	$7,582
UG Conductor	$5,114	$102	$71	$5,286
Substation Tsf	$42,704	$4,781	$5,033	$52,518
Grand Total	*$62,296*	*$11,623*	*$5,451*	*$79,370*
Voltage Regulators (Qty)	111	–	–	111
Distribution Tsf (Qty)	310	310	–	620
OH Conductor (Ft)	25,244	7,786	1,211	34,242
UG Conductor (Ft)	6,236	110	61	6,407
Substation Tsf (Qty)	16	1	3	20

Table N–18. Maui Integration Strategy 1 Annualized Cost and Volumes

Upgrade [Nominal $000]	2016–2020	2021–2030	2031–2045	Total
BESS	$69,775	$2,981	$858	$73,614
Replacement BESS	–	$45,226	$45,705	$90,931
Var Comp Devices	$8,951	$2,742	$975	$12,668
DER Controls	$564	$420	$394	$1,378
Grand Total	*$79,290*	*$51,369*	*$47,932*	*$178,591*
BESS (kW)	17,778	1,126	365	19,268
BESS (kWh)	71,111	4,503	1,459	77,074
Replacement BESS (kW)	–	17,778	19,797	37,575
Replacement BESS (kWh)	–	71,111	79,188	150,299
Var Comp Devices (kW)	10,335	2,717	814	13,866

Table N–19. Maui Integration Strategy 2 Annualized Cost and Volumes

Upgrade [Nominal $000]	2016–2020	2021–2030	2031–2045	Total
Voltage Regulators	$2,903	–	–	$2,903
Substation Tsf	$42,704	–	–	$42,704
Var Comp Devices	$1,582	$2,742	$975	$5,299
OH Conductor	$5,332	$1,901	$348	$7,582
UG Conductor	$5,114	$102	$71	$5,286
DER Controls	$564	$420	$394	$1,378
Grand Total	*$58,198*	*$5,165*	*$1,788*	*$65,152*
Voltage Regulators (Qty)	69	–	–	69
Substation Tsf (Qty)	16	–	–	16
Var Compensation Devices (KW)	10,335	2,717	814	13,866
OH Conductor (Ft)	25,244	7,786	1,211	34,242
UG Conductor (Ft)	6,236	110	61	6,407

Table N–20. Maui Integration Strategy 3 Annualized Cost and Volumes

Upgrade [Nominal $000]	2016–2020	2021–2030	2031–2045	Total
Voltage Regulator	$5,966	$1,741	$1,969	$9,676
Distribution Tsf	$20,369	$22,269	–	$42,638
OH Conductor	$5,975	$13,178	$16,083	$35,236
UG Conductor	$2,686	$6,171	$11,211	$20,068
Substation Tsf	$35,288	$78,174	$24,510	$137,972
Grand Total	*$70,285*	*$121,534*	*$53,773*	*$245,591*
Voltage Regulators (Qty)	140	35	32	207
Distribution Tsf (Qty)	1,429	1,429	–	2,858
OH Conductor (Ft)	27,639	53,547	52,471	133,657
UG Conductor (Ft)	3,182	6,390	9,304	18,875
Substation Tsf (Qty)	11	16	4	31

Table N–21. Maui Integration Strategy 4 Annualized Cost and Volumes

Upgrade [Nominal $000]	2016–2020	2021–2030	2031–2045	Total
Voltage Regulators	$5,966	$1,741	$1,969	$9,676
Distribution Tsf	$20,369	$22,269	–	$42,638
OH Conductor	$5,975	$13,178	$16,083	$35,236
UG Conductor	$2,686	$6,171	$11,211	$20,068
Substation Tsf	$25,144	$34,587	$12,085	$71,816
DER Controls	$3,624	$26,491	$15,327	$45,441
Grand Total	*$63,764*	*$104,438*	*$56,675*	*$224,876*
Voltage Regulators (Qty)	140	35	32	207
Distribution Tsf (Qty)	1,429	1,429	–	2,858
OH Conductor (Ft)	27,639	53,547	52,471	133,657
UG Conductor (Ft)	3,182	6,390	9,304	18,875
Substation Tsf (Qty)	8	8	3	19

Table N–22. Maui Integration Strategy 5 Annualized Cost and Volumes

Upgrade [Nominal $000]	2016–2020	2021–2030	2031–2045	Total
BESS	$168,736	$216,615	$129,169	$514,520
Replacement BESS	–	$111,087	$443,313	$554,401
Var Comp Devices	$6,460	$8,913	$4,857	$20,230
DER Controls	$3,624	$26,491	$15,327	$45,441
Grand Total	*$178,820*	*$363,106*	*$592,667*	*$1,134,592*
BESS (kW)	43,825	82,679	55,747	182,252
BESS (kWh)	175,301	330,718	222,989	729,008
Replacement BESS (kW)	–	43,825	192,843	236,668
Replacement BESS (kWh)	–	175,301	771,371	946,672
Var Comp Devices (kW)	7,362	8,864	3,936	20,163

Table N–23. Maui Integration Strategy 6 Annualized Cost and Volumes

Upgrade [Nominal $000]	2016–2020	2021–2030	2031–2045	Total
Voltage Regulators	$3,449	–	–	$3,449
Substation Tsf	$35,288	–	–	$35,288
Var Comp Devices	$2,519	$8,913	$4,857	$16,289
BESS	$4,210	$51,868	$67,688	$123,765
Replacement BESS	–	$2,932	$90,443	$93,374
OH Conductors	$5,975	$13,178	$16,083	$35,236
UG Conductors	$2,686	$6,171	$11,211	$20,068
DER Controls	$3,624	$26,491	$15,327	$45,441
Grand Total	*$57,750*	*$109,552*	*$205,608*	*$372,910*
Voltage Regulators (Qty)	82	–	–	82
Substation Tsf (Qty)	11	–	–	11
Var Comp Devices (kW)	7,362	8,864	3,936	20,163
BESS (kW)	1,173	20,234	29,261	50,668
BESS (kWh)	4,693	80,935	117,046	202,673
Replacement BESS (kW)	–	1,173	39,553	40,727
Replacement BESS (kWh)	–	4,693	158,214	162,907
OH Conductor (Ft)	27,639	53,547	52,471	133,657
UG Conductor (Ft)	3,182	6,390	9,304	18,875

Table N–24. Maui Integration Strategy 7 Annualized Cost and Volumes

Upgrade [Nominal $000]	2016–2020	2021–2030	2031–2045	Total
Voltage Regulator	$636	–	–	$636
Distribution Tsf	$328	$358	–	$686
OH Conductor	–	–	–	–
UG Conductor	–	–	–	–
Substation Tsf	–	–	–	–
Grand Total	*$964*	*$358*	–	*$1,323*
Voltage Regulators (Qty)	15	–	–	15
Distribution Tsf (Qty)	25	25	–	50
OH Conductor (Ft)	–	–	–	–
UG Conductor (Ft)	–	–	–	–
Substation Tsf (Qty)	–	–	–	–

Table N–25. Moloka‘i Integration Strategy 1 Annualized Cost and Volumes

Upgrade [Nominal $000]	2016–2020	2021–2030	2031–2045	Total
BESS	$3,883	$58	$98	$4,039
Replacement BESS	–	$2,499	$2,370	$4,868
Var Comp Devices	$368	$65	$30	$464
DER Controls	$16	$5	$11	$33
Grand Total	*$4,268*	*$2,627*	*$2,509*	*$9,404*
BESS (kW)	980	21	43	1,044
BESS (kWh)	3,920	85	171	4,175
Replacement BESS (kW)	–	980	1,025	2,005
Replacement BESS (kWh)	–	3,920	4,101	8,021
Var Comp Devices (kW)	424	68	24	515

Table N–26. Moloka‘i Integration Strategy 2 Annualized Cost and Volumes

Upgrade [Nominal $000]	2016–2020	2021–2030	2031–2045	Total
Voltage Regulator	$420	–	–	$420
Var Comp Devices	$75	$65	$30	$170
DER Controls	$16	$5	$11	$33
Grand Total	*$511*	*$71*	*$41*	*$623*
Voltage Regulators (Qty)	10	–	–	10
Var Comp Devices (kW)	424	68	24	515

Table N–27. Moloka‘i Integration Strategy 3 Annualized Cost and Volumes

Upgrade [Nominal $000]	2016–2020	2021–2030	2031–2045	Total
Voltage Regulators	$636	–	–	$636
Distribution Tsf	$2,093	$2,451	–	$4,544
OH Conductor	–	–	–	–
UG Conductor	–	–	–	–
Substation Tsf	–	–	–	–
Grand Total	*$2,729*	*$2,451*	–	*$5,181*
Voltage Regulators (Qty)	15	–	–	15
Distribution Tsf (Qty)	103	103	–	206
OH Conductor (Ft)	–	–	–	–
UG Conductor (Ft)	–	–	–	–
Substation Tsf (Qty)	–	–	–	–

Table N–28. Moloka‘i Integration Strategy 4 Annualized Cost and Volumes

Upgrade [Nominal $000]	2016–2020	2021–2030	2031–2045	Total
Voltage Regulators	$636	–	–	$636
Distribution Tsf	$2,093	$2,451	–	$4,544
OH Conductor	–	–	–	–
UG Conductor	–	–	–	–
Substation Tsf	–	–	–	–
DER Controls	$100	$199	$245	$545
Grand Total	*$2,830*	*$2,650*	*$245*	*$5,725*
Voltage Regulators (Qty)	15	–	–	–
Distribution Tsf (Qty)	103	103	–	206
OH Conductor (Ft)	–	–	–	–
UG Conductor (Ft)	–	–	–	–
Substation Tsf (Qty)	–	–	–	–

Table N–29. Moloka‘i Integration Strategy 5 Annualized Cost and Volumes

Upgrade [Nominal $000]	2016–2020	2021–2030	2031–2045	Total
BESS	$5,994	$1,677	$2,080	$9,750
Replacement BESS	–	$3,954	$6,550	$10,504
Var Comp Devices	$334	$110	$77	$521
DER Controls	$100	$199	$245	$545
Grand Total	*$6,428*	*$5,941*	*$8,951*	*$21,320*
BESS (kW)	1,561	641	900	3,101
BESS (kWh)	6,242	2,562	3,599	12,403
Replacement BESS (kW)	–	1,561	2,848	4,408
Replacement BESS (kWh)	–	6,242	11,390	17,632
Var Comp Devices (kW)	377	114	61	553

Table N–30. Moloka'i Integration Strategy 6 Annualized Cost and Volumes

Upgrade [Nominal $000]	2016–2020	2021–2030	2031–2045	Total
Voltage Regulators	$420	–	–	$420
Var Comp Devices	$199	$110	$77	$386
BESS	–	–	–	–
Replacement BESS	–	–	–	–
DER Controls	$100	$199	$245	$545
Grand Total	*$720*	*$309*	*$322*	*$1,351*
Voltage Regulators (Qty)	10	–	–	10
Var Comp Devices (kW)	377	114	61	553
BESS (kW)	–	–	–	–
BESS (kWh)	–	–	–	–
Replacement BESS (kW)	–	–	–	–
Replacement BESS (kWh)	–	–	–	–

Table N–31. Moloka'i Integration Strategy 7 Annualized Cost and Volumes

Upgrade [Nominal $000]	2016–2020	2021–2030	2031–2045	Total
Voltage Regulators	$255	–	–	$255
Distribution Tsf	$114	$125	–	$239
OH Conductor	–	–	–	–
UG Conductor	–	–	–	–
Substation Tsf	–	–	–	–
Grand Total	*$369*	*$125*	–	*$493*
Voltage Regulators (Qty)	6	–	–	6
Distribution Tsf (Qty)	10	10	–	20
OH Conductor (Ft)	–	–	–	–
UG Conductor (Ft)	–	–	–	–
Substation Tsf (Qty)	–	–	–	–

Table N–32. Lana‘i Integration Strategy 1 Annualized Cost and Volumes

Upgrade [Nominal $000]	2016–2020	2021–2030	2031–2045	Total
BESS	$3,954	$275	$815	$5,043
Replacement BESS	–	$2,569	$2,868	$5,438
Var Comp Devices	$107	$133	$250	$490
DER Controls	$28	$26	$89	$143
Grand Total	*$4,089*	*$3,003*	*$4,022*	*$11,114*
BESS (kW)	1,010	104	355	1,470
BESS (kWh)	4,042	418	1,422	5,881
Replacement BESS (kW)	–	1,010	1,244	2,255
Replacement BESS (kWh)	–	4,042	4,976	9,018
Var Comp Devices (kW)	123	131	197	451

Table N–33. Lana‘i Integration Strategy 2 Annualized Cost and Volumes

Upgrade [Nominal $000]	2016–2020	2021–2030	2031–2045	Total
Voltage Regulators	$168	–	–	$168
Var Comp Devices	$36	$133	$250	$419
DER Controls	$28	$26	$89	$143
Grand Total	*$232*	*$159*	*$339*	*$730*
Voltage Regulators (Qty)	4	–	–	4
Var Comp Devices (kW)	123	131	197	451

Table N–34. Lana‘i Integration Strategy 3 Annualized Cost and Volumes

Upgrade [Nominal $000]	2016–2020	2021–2030	2031–2045	Total
Voltage Regulators	$255	$158	–	$412
Distribution Tsf	$742	$869	–	$1,610
OH Conductor	–	–	–	–
UG Conductor	–	–	–	–
Substation Tsf	–	–	–	–
Grand Total	*$996*	*$1,026*	–	*$2,023*
Voltage Regulators (Qty)	6	3	–	9
Distribution Tsf (Qty)	37	37	–	73
OH Conductor (Ft)	–	–	–	–
UG Conductor (Ft)	–	–	–	–
Substation Tsf (Qty)	–	–	–	–

Table N–35. Lana‘i Integration Strategy 4 Annualized Cost and Volumes

Upgrade [Nominal $000]	2016–2020	2021–2030	2031–2045	Total
Voltage Regulators	$255	$158	–	$412
Distribution Tsf	$742	$869	–	$1,610
OH Conductor	–	–	–	–
UG Conductor	–	–	–	–
Substation Tsf	–	–	–	–
DER Controls	$73	$849	$133	$1,055
Grand Total	*$1,069*	*$1,875*	*$133*	*$3,077*
Voltage Regulators (Qty)	6	3	–	9
Distribution Tsf (Qty)	37	37	–	73
OH Conductor (Ft)	–	–	–	–
UG Conductor (Ft)	–	–	–	–
Substation Tsf (Qty)	–	–	–	–

Table N–36. Lana‘i Integration Strategy 5 Annualized Cost and Volumes

Upgrade [Nominal $000]	2016–2020	2021–2030	2031–2045	Total
BESS	$1,262	$4,962	$1,268	$7,492
Replacement BESS	–	$850	$8,062	$8,911
Var Comp Devices	$17	$143	$17	$177
DER Controls	$73	$849	$133	$1,055
Grand Total	*$1,352*	*$6,804*	*$9,479*	*$17,635*
BESS (kW)	337	1,923	532	2,791
BESS (kWh)	1,348	7,690	2,127	11,165
Replacement BESS (kW)	–	337	3,512	3,849
Replacement BESS (kWh)	–	1,348	14,049	15,396
Var Comp Devices (kW)	19	137	15	171

Table N–37. Lana‘i Integration Strategy 6 Annualized Cost and Volumes

Upgrade [Nominal $000]	2016–2020	2021–2030	2031–2045	Total
Voltage Regulators	$168	$158	–	$326
Var Comp Devices	$10	$143	$17	$170
BESS	–	–	–	–
Replacement BESS	–	–	–	–
DER Controls	$73	$849	$133	$1,055
Grand Total	*$251*	*$1,149*	*$150*	*$1,551*
Voltage Regulators (Qty)	4	–	–	4
Var Comp Devices (kW)	19	137	15	171
BESS (kW)	–	–	–	–
BESS (kWh)	–	–	–	–
Replacement BESS (kW)	–	–	–	–
Replacement BESS (kWh)	–	–	–	–

Table N–38. Lana‘i Integration Strategy 7 Annualized Cost and Volumes

Upgrade [Nominal $000]	2016–2020	2021–2030	2031–2045	Total
Voltage Regulators	$5,054	$7,527	$5,375	$17,956
Distribution Tsf	$3,908	$1,792	$1,413	$7,113
OH Conductor	–	–	–	–
UG Conductor	–	–	–	–
Substation Tsf	–	–	–	–
Grand Total	*$8,963*	*$9,320*	*$6,787*	*$25,069*
Voltage Regulators (Qty)	72	94	54	220
Distribution Tsf (Qty)	318	126	85	529
OH Conductor (Ft)	–	–	–	–
UG Conductor (Ft)	–	–	–	–
Substation Tsf (Qty)	–	–	–	–

Table N–39. Hawai'i Island Integration Strategy 1 Annualized Cost and Volumes

Upgrade [Nominal $000]	2016–2020	2021–2030	2031–2045	Total
BESS	$32,177	$9,048	$6,975	$48,200
Replacement BESS	–	$21,656	$11,781	$33,437
Var Comp Devices	$57	–	$258	$315
DER Controls	$2,589	$4,694	$11,144	$18,426
Grand Total	*$34,822*	*$35,398*	*$30,158*	*$100,378*
BESS (kW)	8,586	3,439	2,991	15,016
BESS (kWh)	34,344	13,756	11,964	60,064
Replacement BESS (kW)	–	8,586	5,105	–
Replacement BESS (kWh)	–	34,344	20,420	54,764
Var Comp Devices (kW)	63	–	230	293

Table N–40. Hawai'i Island Integration Strategy 2 Annualized Cost and Volumes

Upgrade [Nominal $000]	2016–2020	2021–2030	2031–2045	Total
Voltage Regulators	$3,472	–	–	$3,472
Var Comp Devices	$57	–	$258	$315
DER Controls	$2,589	$4,694	$11,144	$18,426
Grand Total	$6,117	$4,694	$11,402	$22,213
Voltage Regulators (Qty)	50	–	–	50
Var Comp Devices (kW)	63	–	230	293

Table N–41. Hawai'i Island Integration Strategy 3 Annualized Cost and Volumes

Upgrade [Nominal $000]	2016–2020	2021–2030	2031–2045	Total
Voltage Regulators	$14,327	$2,107	$760	$17,194
Distribution Tsf	$1,397	$2,737	$161	$4,295
OH Conductor	$1,803	$1,492	–	$3,295
UG Conductor	–	–	–	–
Substation Tsf	$4,109	$38,258	$51,456	$93,823
Grand Total	*$21,635*	*$44,594*	*$52,377*	*$118,607*
Voltage Regulators (Qty)	191	25	8	224
Distribution Tsf (Qty)	115	195	10	320
OH Conductor (Ft)	24,159	17,652	–	41,811
UG Conductor (Ft)	–	–	–	–
Substation Tsf (Qty)	4	26	31	61

Table N–42. Hawai'i Island Integration Strategy 4 Annualized Cost and Volumes

Upgrade [Nominal $000]	2016–2020	2021–2030	2031–2045	Total
Voltage Regulators	$14,327	$2,107	$760	$17,194
Distribution Tsf	$1,397	$2,737	$161	$4,295
OH Conductor	$1,803	$1,492	–	$3,295
UG Conductor	–	–	–	–
Substation Tsf	–	$8,794	$21,176	$29,970
DER Controls	$4,364	$40,012	$29,229	$73,604
Grand Total	*$21,890*	*$55,142*	*$51,326*	*$128,358*
Voltage Regulators (Qty)	191	25	8	224
Distribution Tsf (Qty)	115	195	10	320
OH Conductor (Ft)	24,159	17,652	–	41,811
UG Conductor (Ft)	–	–	–	–
Substation Tsf (Qty)	–	6	14	20

Table N–43. Hawai'i Island Integration Strategy 5 Annualized Cost and Volumes

Upgrade [Nominal $000]	2016–2020	2021–2030	2031–2045	Total
BESS	$33,076	$187,013	$178,911	$398,999
Replacement BESS	–	$23,280	$254,356	$277,636
Var Comp Devices	$1,130	$94	–	$1,224
DER Controls	$4,364	$40,012	$29,229	$73,604
Grand Total	*$38,570*	*$250,398*	*$462,495*	*$751,463*
BESS (kW)	9,334	72,449	76,950	158,733
BESS (kWh)	37,336	289,796	307,800	634,932
Replacement BESS (kW)	–	9,334	110,713	120,047
Replacement BESS (kWh)	–	37,336	442,852	480,188
Var Comp Devices (kW)	1,276	93	–	1,370

Table N–44. Hawai'i Island Integration Strategy 6 Annualized Cost and Volumes

Upgrade [Nominal $000]	2016–2020	2021–2030	2031–2045	Total
Voltage Regulators	$12,675	–	–	$12,675
Substation Tsf	$4,109	–	–	$4,109
Var Comp Devices	$742	$94	–	$836
BESS	–	$24,735	$46,802	$71,537
Replacement BESS	–	–	$41,189	$41,189
OH Conductor	$1,803	$1,492	–	$3,295
DER Controls	$4,364	$40,012	$29,229	$73,604
Grand Total	*$23,692*	*$66,334*	*$117,219*	*$207,244*
Voltage Regulators (Qty)	168	–	–	168
Substation Tsf (Qty)	4	–	–	4
Var Comp Devices (kW)	1,276	93	–	1,370
BESS (kW)	–	9,732	20,318	30,050
BESS (kWh)	–	38,928	81,272	120,200
Replacement BESS (kW)	–	–	18,030	18,030
Replacement BESS (kWh)	–	–	72,120	72,120
OH Conductor (Ft)	24,159	17,652	–	41,811

Table N–45. Hawai'i Island Integration Strategy 7 Annualized Cost and Volume

O. System Security

System security (or Operating Reliability) is defined by NERC as *the ability of the system to withstand sudden disturbances*.[1] These disturbances or contingencies can be the loss of generation or electrical faults that can cause sudden changes to frequency, voltage and current. Operating equilibrium following these disturbances must be restored to prevent damage to utility and end-use equipment, and to ensure public safety.

The focus of this system security analysis was on loss of generation contingency events. A full assessment of system security must evaluate steady state and transient voltage stability, rotor angle stability, and an in-depth analysis of our current under frequency load shed (UFLS) schemes; specifically how DG-PV and demand response affect the MW capacities and coordination of UFLS blocks.

How System Security is Typically Maintained

The transmission planning criteria establishes the design requirements to safely deliver real and reactive power to the distribution system. These criteria require the planning engineer to design mitigation measures to ensure system security is maintained for planned and contingency events. Some fundamental design philosophies to ensure system security include the following:

- Redundant transmission lines for capacity transfer and contingencies
- Transmission network/spatial integrity of transmission corridors
- Breaker-and- a- half or ring-bus schemes for generating units
- Limit the magnitude of the contingency

[1] NERC, *Definition of "Adequate Level of Reliability"*, December 2007, http://www.nerc.com/docs/pc/Definition-of-ALR-approved-at-Dec-07-OC-PC-mtgs.pdf.

- Design requirements of synchronous generators (high inertia constants, high short-circuit ratio, excitation systems that are independent of system voltage, reserve capacity, etc.)
- Protective relay schemes to ensure public safety and protect equipment
- Under frequency load shed schemes to prevent system collapse and reduce restoration times

System security is maintained by operating the system with sufficient inertia, limiting the magnitude of the contingency event, maintaining adequate contingency reserves and maintaining system fault current; at times requiring the system operator to sacrifice efficiency for reliability

Inertia: the electrical system includes many rotating components which have inertia, including traditional synchronous generators (large rotating electromagnets coupled to heavy turbines or internal combustion engines), and rotating customer loads (usually induction electrical motors connected to appliances, pumps). During a contingency, the inertia in these rotating mass will resist changes to their rotational speed (i.e. limit the rate of change of frequency). Inertia, along with droop response, also provides the dampening characteristic to the frequency response profile following a contingency event as a synchronous generator continuously resists change its rotational speed. Hence, an electrical system with high inertia is more robust and can withstand contingency events better than a low inertia system.

Operational actions to protect against contingencies: 1) limit the magnitude of the disturbance; 2) reconfigure the system to mitigate risks; and 3) ensure the system is carrying the necessary contingency reserves to mitigate the adverse effects of these contingency events.

Fault protection: synchronous generators provide sufficient system fault current to activate protective relay schemes within the critical clearing times of transmission lines and generators. System fault current is also required to ensure protective relay schemes at the distribution system can detect and isolate downed power lines to ensure public safety and prevent equipment damage. Also note that an electrical system with a high capacity of fault current is less susceptible to the adverse effects of harmonic currents.

How System Security Relates to This PSIP

Resource planning must incorporate fundamental system security parameters because online resources can affect both the magnitude of the disturbance and the ability of the system to respond. For example, the size of the largest resource on the system defines the largest contingency that must be protected against, and the characteristics of available resources determine the system response.

On island systems with very high levels of wind and solar resources, the most critical security concern is displacement of thermal generators, reducing system inertia and the available system fault current.[2] This concern dominates because (a) the largest loss of generation contingency becomes a larger percentage of the total supply; and (b) the large contingency on the low inertia system will require multiple blocks of under frequency load shed (UFLS) to stabilize system frequency. While there are other potential system security concerns, such as voltage stability and reactive power capacity, mitigating these issues can be somewhat independent of the resource plan. [3] As such, this PSIP filing we will focus exclusively on determining system requirements to maintain frequency stability. Voltage stability, MVAR analysis, and rotor angle stability will be analyzed in future studies.

System security considerations are incorporated into this PSIP Update in a supportive role and do not constrain the candidate resource plans beyond limiting the magnitude of the contingency as stated above. Currently, thermal generators provide the necessary system security attributes but at some point in time, technology-neutral resources will be available in sufficient capacities to augment and replace these attributes.

Each candidate resource plan is evaluated to determine if system security requirements are met. If not, we add DR or supply-side resources to bring the plan into compliance with technology-neutral requirements.

Balancing Supply-Demand Fluctuations

Electric systems have to obey the conservation of energy law. Supply must always equal demand to maintain system frequency at 60 Hz. The automatic generation controls (AGC) must constantly dispatch regulating reserves to maintain this balance over various timeframes. As more variable resources are integrated into the system, the capacity and ramping requirements of the system's regulating reserves will increase. Similar to the issues of lower system inertia and available fault current, displacement of thermal generation reduces the online regulating reserve capacity of the system so DER/DR resource and/or central station storage will be required to maintain system frequency within acceptable limits.

Like system security, the need to balance supply and demand is incorporated into this PSIP Update. We first design resource strategies based on load and RPS requirements. We then determine if the system has adequate regulation and adequate ramping to follow net load, primarily driven by the characteristics of the variable generation resources. If regulating reserves are not adequate, technology-neutral alternatives will be added with the objective to minimize cost and other impacts of such modifications.

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[2] Low short-circuit current also affects power quality.

[3] For example, static VAR compensators can provide voltage regulation and MVAR capacity, and some inertia.

APPROACH TO ANALYZING SYSTEM SECURITY IN THIS PSIP

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

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

Step 1: Establish Operational Reliability Criteria

The ultimate criterion for system security is straightforward to specify: ensure public safety, protect utility and end-user equipment, minimize load shedding events and prevent an island-wide blackout. The original PSIP was developed to meet the requirements of HI-TPL-001.

In this PSIP Update, we revised HI-TPL-001 to focus specifically on single contingency loss of generation events to determine acceptable UFLS capacities. For O‘ahu, HI-TPL-001 was revised to no UFLS for single generator contingency events while Maui and Hawai‘i Island allow 15% system load. The Moloka‘i and Lana‘i systems were removed from HI-TPL-001 since these systems are unique island distribution systems that do not qualify as transmission systems. Further revisions to HI-TPL-001 are required for multiple contingency events, both loss of generation and/or loss of transmission elements.

Under-frequency load shedding (UFLS) is a means to restore system frequency to operating equilibrium for various loss of generation contingency events. Ultimately, it is the last line of defense of system security to prevent system blackouts but it has shortcomings for future conditions in Hawai‘i. Under high levels of distributed PV penetration, the residential load net of PV is reduced so UFLS schemes are less effective, compromising system security. Instead of disconnecting distribution circuits, future UFLS schemes must incorporate a more surgical approach to maintain sufficient capacities during the day to be effective.

Minimum Fault-Current: Electrical faults are the most severe disturbance that can cause extensive damage to equipment and pose a safety risk to the public. Protective relay schemes are designed to locate and isolate these faults within cycles to ensure equipment protection and maintain system reliability. However, if the system fault current is insufficient, protective relays cannot detect and isolate the faulted element as designed. Downed transmission lines that cannot be isolated appear as a large system load, causing localized "brown-outs" could trigger extensive UFLS. This also poses a safety risk to both equipment and the public.

Step 2: Define Technology-Neutral Ancillary Services for Meeting Reliability Criteria

Any electric system has three fundamental real power ancillary service needs, presented in order of speed of response. Only the first and third are strictly about system security, but we include all for context.

Frequency Response is needed to reduce the rate of change of frequency (RoCoF) to help stabilize system frequency immediately following a sudden loss of generation or load.

Regulation is needed to meet short-term changes in load and supply within seconds and minutes, because of solar fluctuations or the variable wind resources.

Replacement Reserves are needed to restore the faster services (above) after they are deployed, in order to be ready for the next event or further changes in net load.[4] Replacement Reserves are deployed in the minutes-to-hours timeframe and provide capacity to restore system frequency to 60 Hz following a contingency event or supplement Regulating Reserves because of forecast errors.

Other system operators define their ancillary services to serve these same basic needs, but each one's specific services depend on its system characteristics and history. The Electric Reliability Council of Texas (ERCOT) has proposed to re-design its Frequency Response as increasing renewable penetration raises new challenges in its "islanded" system separated from the rest of the mainland. However, system operators within large interconnected systems such as the Eastern Interconnection do not explicitly define Frequency Response products since the system has a vast amount of inertia to support frequency naturally.

The ancillary services products we propose for the Hawaiian Islands look like those being proposed in ERCOT, with a few additional elements to address Hawaiian-specific

[4] The North American Electric Reliability Corporation (NERC) refers to these three services as "Primary Control", "Secondary Control", and "Tertiary Control", respectively. (See NERC *Balancing and Frequency Control* Technical Document prepared by the NERC Resources Subcommittee, Jan 26, 2011.) We use the more descriptive titles for greater clarity.

needs: the small systems here are vulnerable to over-frequency in the event of a load trip. Fast Frequency Response Down would address that problem without having to rely on downward reserves from generators running at higher-than-economic output levels, as is current practice.

Table O-1, Table O-2, and Table O-3 presents the real power services proposed for Hawai'i, along with technical specifications that any resource type would have to meet in order to provide that service.

Note that this table does not include fault-current since the protective relay schemes are designed to operate only with synchronous generators. Therefore, identifying cost effective technology-neutral ancillary services will not be pursued at this time. Fault current can be provided by online generators while they are required by the resource plan for meeting system demand and, once retired, by converting those generators to synchronous condensers that do not produce power but can provide fault current, voltage regulation, and reactive power (MVARS).

The Companies recognize that these definitions deviate from the Grid Services definitions filed in the Supplemental Report under the IDRPP (Docket No. 2007-0341) in November of 2015. These reflect further refinement to the services as defined in that filing and the Supplemental Report will be updated to reflect the refined service definitions.

Frequency Response

Reduce the rate of change of frequency (RoCoF) within cycles after a contingency, providing more time for PFR to deploy.

Frequency Response: Real-Power Ancillary Services		
Instantaneous Inertia (II)	Reduce the rate of change of frequency	
Examples of Suitable Resources	*Equipment Requirements*	*Performance Requirements*
■ Synchronous generators (incl. pump storage) and flywheels ■ Synchronous motor loads also provide inertia; Hawaiian Electric may plan around them but wouldn't procure or control them ■ Synchronous condensers	■ Spinning mass electromagnetically coupled to grid	■ Natural characteristics of synchronous generators ■ Proportional response to changes in speed
Primary Frequency Reserves (PFR)	Stabilize frequency in either direction w/response proportional to changes in speed or frequency	
■ Synchronous generators ■ Inverter-interfaced generators and storage	■ Governor or control system meeting minimum performance requirements for droop and deadband	■ Initiation governed by deadband less than ±X Hz ■ Linear response to changes in speed or frequency ■ Time to max: a few seconds (for example, 16 seconds in ERCOT FAS) ■ Duration: TBD based on Replacement response time
Fast Frequency Reserves 1 Up (FFR1Up)	Reduce the rate of change of frequency w/response proportional to the generation contingency	
■ Very fast-response resources (likely central station), such as batteries, flywheels, and curtailed PV	■ Control system capable of responding to signals within specified response time ■ 2-way real-time communications	■ Trigger: signal from large trip or df/dt ■ Initiation time and time to max: several cycles (for example, six cycles total reaction time, as determined by Hawai'i Electric Light contingency reserve storage study) ■ Duration: TBD based on Replacement response time and resource capabilities (for example, 10 minutes in ERCOT; 30 minute in Hawai'i Electric Light to allow replacement by gas turbine.)
Fast Frequency Reserves 2 Up (FFR2Up)	Reduce the rate of change of frequency w/response proportional to the generation contingency	
■ Distributed resources w/autonomous control, including DR from fairly constant loads that can curtail nearly instantaneously	■ Under-frequency relays that can respond within specified response time ■ 1-way real-time communication (user to operator) to allow operator to measure how much load is available to curtail	■ Trigger: df/dt ■ Initiation time (and time to max): a fraction of a second, but slower than FFR1 (for example, 0.5 seconds in ERCOT FAS) ■ Duration: TBD based on Replacement response time and DR capabilities (for example, 1 hour in ERCOT FAS)
Fast Frequency Reserves Down (FFRDown)	Quickly restore supply-demand balance following a loss of load; reduces operational down reserves form synchronous generation	
■ Inverter-interfaced generators and storage ■ Distributed resources w/autonomous control, including DR from loads that can increase almost instantaneously	■ Over-frequency relays that can respond within specified response time ■ 1-way real-time communication (user to operator) to allow operator to measure how much generation is available to drop or load is available to increase	■ Trigger: df/dt ■ Initiation time (and time to max): a fraction of a second, similar to FFR2 (for example, 0.5 seconds in ERCOT FAS) ■ Duration: TBD based on Replacement response time and resource capabilities (for example, 1 hour in ERCOT FAS)

Table O-1. Frequency Response: Real-Power Ancillary Services

Regulation

Meet second-to-second and minute-to-minute net load fluctuations around trend and forecast errors, until Replacement can take over; help restore frequency after contingencies.

Regulation: Real-Power Ancillary Services		
Regulation Reserves Up (RegUp)		
Examples of Suitable Resources	*Equipment Requirements*	*Performance Requirements*
▪ Synchronous generators ▪ Battery energy storage, flywheels ▪ Inverter-interfaced generation (for example, curtailed wind/PV) ▪ DR might meet "continuously controllable" requirements, incl. industrial loads, EVs, aggregated smaller on-off loads (e.g, heaters, compressors)	▪ 2-way real-time communication to allow exchange of AGC signal and signal response with operator ▪ Continuous controllability	▪ Continuously follow AGC control signals with sufficient accuracy ▪ Time to max: minutes (for example, 5 minutes in ERCOT) ▪ Duration at max: TBD based on Replacement response time and resource capabilities (for example, 1 hour in ERCOT)
Regulation Reserves Down (RegDown)		
▪ Similar to RegUp plus small load banks	▪ 2-way real-time communication to allow exchange of AGC signal and signal response with operator ▪ Continuous controllability	▪ Similar to RegUp, but in the other direction

Table O-2 Regulation: Real-Power Ancillary Services

Replacement

Replace output of faster reserves (or restoration of shed loads) so they could deploy again; meet sustained ramps and forecast errors beyond Regulation duration.

Replacement: Real-Power Ancillary Services		
Replacement Reserves (RR)		
Examples of Suitable Resources	*Equipment Requirements*	*Performance Requirements*
▪ Generators ▪ DR that cannot react fast enough to provide FFR ▪ Energy storage	▪ One-way communication (operator to user) and controls to remotely curtail loads	▪ Response time(s): TBD based on needs and resource capabilities. Consider two response times (for example, 10 and 30 minutes in ERCOT FAS) ▪ Duration: TBD based on needs and resource capabilities (for example, 1 hour in ERCOT FAS) ▪ Full deployment capability by the set Response Time(s) (for example, 10 minutes or 30 minutes)

Table O-3. Replacement: Real-Power Ancillary Services

Step 3: Determine the Amount of Ancillary Services Needed to Support the Resource Plan

The amounts of each type of ancillary service needed to meet system security vary by island, resource strategy, and time period. That is because Frequency Response needs are driven by the size of the largest contingency, which is generally the largest unit online at the time. Regulation needs are driven by the variability of net load (that is, load minus renewable generation output), which depends especially on the amount of PV and wind. And Replacement reserve needs are driven by the amounts of Frequency Response and Regulation needed.

Frequency Response Requirements. Our analytical methodology for determining the necessary amounts of Frequency Response services builds upon the FFR analyses performed in the Integrated Demand Response Portfolio Plan Supplement: System Response Requirements dated November 6, 2015 (Docket No. 2007-0341). In this PSIP, Fast Frequency Reserve requirements are determined for selected years for each candidate resource plan, under a range of system inertia, system load, and PFR for the largest contingency. The specific modeling approach and key assumptions are described in the next section of this appendix.

Regulation Requirements. Our methodology for determining the amount of Regulation needed is described in System Operating and Reliability Criteria in Appendix J.

Replacement Reserve Requirements. All systems currently have quick-start generation. With the addition of the Schofield units and resource plans, O‘ahu will have approximately 200 MW of quick-start generation so additional replacement reserves to supplement or displace this capacity may not be required in the near future. The system’s RR requirements are dependent on FFR and RR capacities and performance. Once these DR/DER resources have been identified and characterized, RR capacities can be evaluated and technology-neutral resource benefits quantified.

Fault Current Requirements. Hawaiian Electric’s Transmission Planning Criteria for Stability Analysis requires modeling of common N-1 and N-2 electrical faults to maintain system stability. Simulations were performed to determine the MVA capacity required to meet minimum fault current levels for three phase, line-to-line, and single line to ground faults are established for each substation 46kV bus. . This ensures proper operation of protective relay schemes.

For the Maui and Hawai‘i Island systems, the minimum fault current requirements at the distribution substations have not been determined. Therefore, the MVA capacities provided by the current must-run thermal units will be maintained.

Step 4: Find Lowest Reasonable Cost Solution Considering All Types of Qualified Resources

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

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

As stated earlier, thermal units are required to provide system fault current from 2016 through a period of time when retired units can be converted to synchronous condensers as dictated by the resource plan. To reduce potential curtailment in the interim, fossil fired steam units can operate in in VPO[5] if available.

We develop the initial pre-DR solution to meet the Frequency Response requirement as follows (recall that the Frequency Response need was reduced to an FFR requirement, as described in the prior step): In the pre-DR solution, we first assess how much FFR2 is required to meet HI-TPL-001. We then determine if FFR2 capacities are sufficient and if not, evaluate alternatives to meet system security requirements. This could be to limit the magnitude of the contingency, supplement FFR2 with increased system inertia (operate units in VPO if available), or supplement FFR2 with FFR1.

The initial pre-DR solution meets Regulation needs from the lowest-cost available resources by including regulation as a minimum “spinning reserve” constraint in the dispatch model. If not enough regulation is available, batteries or other resources are added. Note that these needs have already been met before determining Frequency Response needs and solutions.

Once we have a pre-DR solution that meets system security, we determine how much DR can meet the AS technical requirements and cost-effectively substitute for the pre-DR resources.

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5 Variable Pressure Operation entails partial burner operation with lower operating pressures. This lowers the operating load at the expense of lower or negligible reserve capacities for dispatch.

Finally, after having added DR and other resources to support system security, we assess whether another iteration of system security analysis is warranted. For example, if the amount of synchronous generation decreases substantially, more FFR or system inertia may be needed.

Step 5: Identify Flexible Planning and Future Analyses to Optimize Over Time

The PSIP provides a framework to support future decision-making, not a set-in-stone plan. It recognizes the need for flexibility. It recognizes that actual future procurement decisions will incorporate new information and sharpen specific analyses that are not practical or appropriate for the PSIP. But the PSIP can identify ways to maintain flexibility, and future developments to look for, and some of the analyses to conduct when decisions have to be made.

Future analyses may include the following:

- Steady state load flow and transient analysis tools to transmit DER to the transmission system
- Damping of oscillatory instabilities for a low-inertia system. Siemens PSS®E is limited to point in time contingency events and is not suited to analyze instability caused by frequency oscillations
- Power quality impacts to the transmission system
- Smart inverter controls and characteristics required to meet system security
- Effects of Rapid Transit in O‘ahu

Some of these analyses will require modeling tools and/or outside support.

MODELING ASSUMPTIONS FOR ANALYZING FREQUENCY RESPONSE

Overview of Modeling Approach

We use the Siemens PSS®E power flow model, Version 33.7, to analyze system security following a contingency. The analysis starts with the hourly load and generation data from the production cost simulations. It also incorporates data on the physical characteristics of all of the generators (i.e., capacities and H-constants determining inertia, and ramp rates), loads, and transmission and distribution elements. The equations in the model reflect the physical operation of an AC power system, including the response of relays and equipment to changes in system conditions. We are thereby able to simulate system stability immediately following the generation contingency. We focus the analysis on two informative hours, which we select using a one-bus simplified version of PSSE: a "typical hour" when the probability of the contingency event is relatively high, and a "boundary" hour when the contingency event is more severe but the probability is low. For each of these hours, we analyze in detail the frequency response reserve requirements to meet TPL-001.

Modeling of Specific Types of Elements

The following assumptions are common across cases:

- The kinetic energy for each generator was calculated by multiplying the unit H-constant by the unit MVA rating. This does not take into account the inertia contribution from the unit's auxiliary loads. For the system, the total kinetic energy is the sum of all unit kinetic energies. This does not take into account the inertia contribution from system load.
- Loads are modeled to have a frequency dependence of 1%. This equates to a 1% decline in real power consumption for a 1% drop in frequency. For example, in a 1000 MW system, load will decrease by 10 MW for a system frequency of 59.4 Hz, a decrease of 0.6 Hz. This relationship is attributed to the makeup of the system load, with a portion of it consisting of motor loads. The frequency response from motor loads is about equal to 1 to 2 percent of load.
- Legacy PV inverters are those inverters that have already been installed in Hawai'i that have an operating range of 59.3 Hz to 60.5 Hz. The table below shows the assumptions made as to the amount of inverters that still have these frequency ranges. These figures were estimated by the Companies based on a review of the inventory of installed inverters and what ride through standards applied to these inverters. If a contingency drives system frequency outside of this range, inverters are required to disconnect from the system within 0.16 seconds (for simplicity, legacy PV is modeled to disconnect immediately). The capacity of legacy PV that would disconnect at 60.5 Hz is higher than the capacity that at 59.3 Hz, as shown in Table 4 below. In the simulations, the amount of generation lost is less than the nameplate capacity to the extent that PV capacity factors are below 100% for the simulated hour. All other DG-PV will continue generating if frequency remains between 56 Hz to 64 Hz.

Legacy PV Capacities					
ISLAND	**O'ahu**	**Hawai'i**	**Maui**	**Moloka'i**	**Lana'i**
Size PV Systems (kW) @ 59.3 Hz	**73,824**	**4,781**	**6,743**	**811**	**96**
Size PV Systems (kW) @ 60.5 Hz	**105,691**	**30,599**	**29,853**	**1,920**	**227**

Table O-4. Estimated Legacy PV Capacities

To simulate the performance of autonomous-controlled inverter-based systems, DER resources are modeled with droop response. Droop response is inversely proportional to the system's frequency response profile so this resource would be characterized as PFR.

Fast frequency response one (FFR1) was modeled as a step change to full output within 12-cycles to simulate Auto-scheduling control of a battery energy storage system (BESS). In Auto-scheduling control, the BESS will receive a command to dispatch to full output on an open-breaker signal from AES or Kahe 5/6. Fast frequency response two (FFR2) was modeled as a df/dt initiated response in 30-cycles to simulate Demand Response load control technology in the near future. For both FFR1 and FFR2, we assumed the capacity would be available for the duration of the event until the system is stable (approximately 30 minutes). Otherwise, loss of this capacity could trigger a secondary contingency event. (If supplemental reserves from Demand Response are available, the duration of FFR can be reduced.)

Screening Tool

A screening tool was created to address the probability of a contingency event occurring for any given case. A simplified system network model was created in PSS®E to accept input data from the hourly production cost simulation data for each plan. Automation of the model is implemented using Python[6]. The entire network impedance structure was collapsed into an equivalent single bus system. Therefore, the screening method does not take into account network effects such as voltage variations across the system. The focus of this analysis is the loss of generation contingency event so the key metric is the frequency nadir[7] due to MW imbalances. Voltage issues will be addressed in future analyses.

The screening tool estimates the system frequency response to a generator trip for each hour of the year and is not meant to replicate a fully detailed simulation. The frequency nadir is calculated by PSS®E based on a trip of the largest loaded unit for every hour in the study year. The frequency nadir data is processed in Excel to produce charts to graphically illustrate the estimated risk to the system.

[6] Python is a high level, dynamic, object-orient programming language that can be utilized to automate or customize PSSE study procedures.

[7] The lowest frequency point at which the frequency decline is arrested.

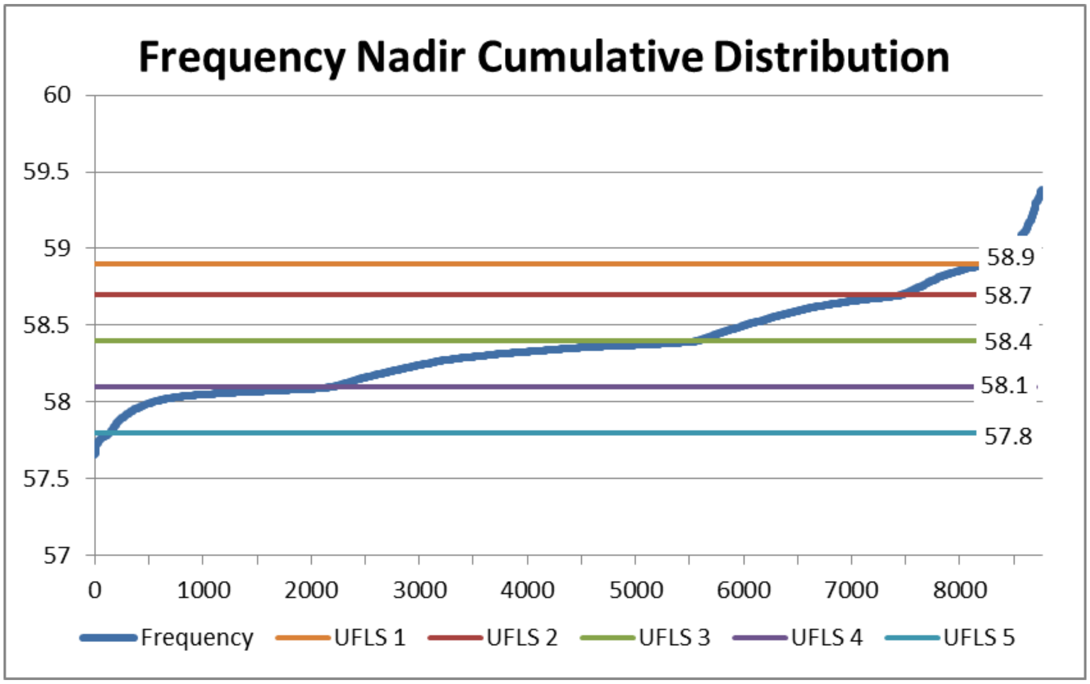


Figure O-1. Frequency Nadir Duration Curve

Figure O-1 shows the duration curve of the frequency nadirs for all the hours in 2023. The horizontal lines show the UFLS blocks for O'ahu. The example chart above shows that we will are exposed to tripping UFLS block 1 (58.9Hz) for about 8,000 hours of the year. Furthermore, for roughly 2,000 hours in the year, we are exposed to tripping UFLS block 4 (58.1 Hz) indicating a significantly risk to the system.

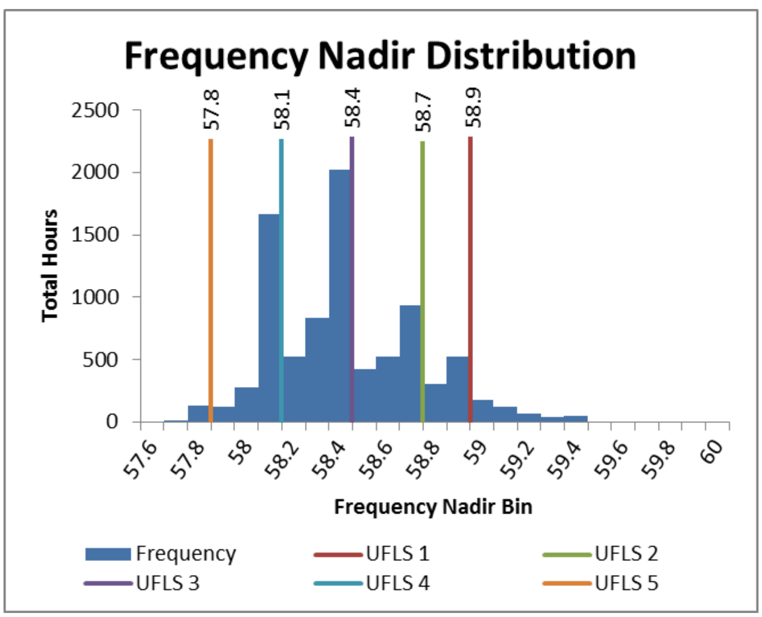


Figure O-2. Frequency Nadir Histogram

Figure O-2 shows the hourly distribution of the frequency nadirs as a result of loss of generation contingency events for 2023. The same source data for the chart above was used to generate this chart, which grouped the nadir data in 0.1Hz frequency buckets.

Using the frequency nadir distribution chart, two hours are selected for further analysis using the full PSS®E system model. The first hour is chosen by selecting a severe nadir from a large frequency grouping that can occur more frequently in the year (large bar on graph, with significant blocks load shed).

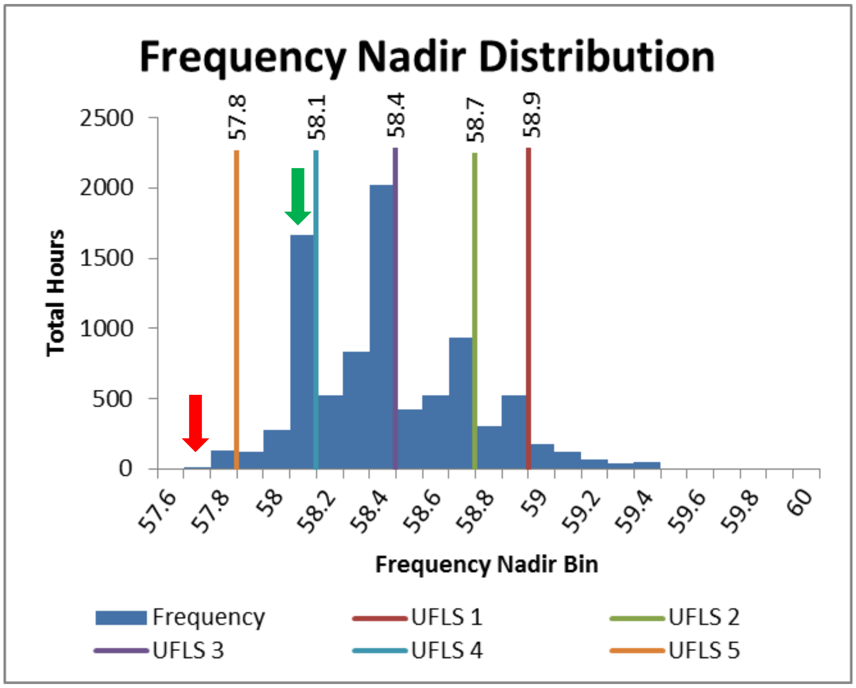


Figure O-3. Frequency Nadir Histogram – Selection

Figure O-3 illustrates the selection of hours for more detailed analysis. The green arrow represents a typical hour for a range of frequency nadirs from 58.0 - 58.1 Hz that could occur 1636 hours in 2023. The red arrow represents a boundary hour for a range of frequency nadirs from 57.6 - 57.8 Hz that could occur 129 hours in 2023. The selected hours are further analyzed using the comprehensive PSS®E database.

Additional screening was performed for the Hawai'i Electric Light analysis to evaluate loss of DG-PV due to the increased exposure to transmission system faults that cause transient voltage issues.

Limitations of Modeling Simulations

Production Cost simulations optimize system performance and cannot take into account operational changes to mitigate system risks. For example, it's typical for system operators to commit non-economic units to mitigate system risks when transmission lines are taken out of service for maintenance.

Dynamic models are a critical component of transient analyses. Governor and exciter models with default settings are adequate for simulating system contingency events when many units are running. As more units are taken offline, more sophisticated dynamic governor and exciter models may be required. This is also true for dynamic models for central station PV and wind turbine models provided by independent power producers.

Distributed PV is currently modeled as negative loads. Advanced inverter models are being developed and will be available in 2016 after which advanced inverter functions and any benefits they provide can be captured.

O'AHU CANDIDATE PLANS

Before analyzing future system security needs, we examine the current state of the system. We start with an assessment of recent historical events, followed by a projection of system security preparedness for 2016. We also include in this section an assessment of system security needs for 2019, since that is very early in the planning horizon, before the candidate resource plans diverge. The candidate plans will be assessed in the following section of this appendix.

State of the System

The O'ahu system is currently at risk because of the proliferation of DG-PV. Distributed PV poses the biggest challenge to system security because it imposes fundamentally conflicting requirements on the electrical system; 1) the reduction of system load displaces synchronous generators and 2) DG-PV increases regulating and contingency reserve requirements that are traditionally provided by synchronous generators. More specifically, transformation of the electrical system must address the following system security issues:

- DG-PV displaces synchronous generators that provide essential grid services like inertia, regulating reserves, and system fault current
- DG-PV reduces the capacity of the system's under frequency load shed scheme (UFLS)
- Legacy DG-PV increases the magnitude of a loss of generation contingency
- DG-PV is currently an uncontrollable and invisible resource

The design of O'ahu's electrical system is based on the inherent characteristics of synchronous generators. A synchronous generator is basically a large rotating magnet that provides essential grid services like inertia and fault current to the system; two critical parameters required to maintain system stability. As synchronous generators are cycled offline to make room for as-available resources, the stability margin of the system is reduced and we begin to approach the stability limits of the system.

Besides the loss of these stability parameters, lower daytime loads increases the magnitude of the generation contingency. Prior to the proliferation of DG-PV, an AES trip at full output typically represented 15 – 18% of the system generation. Today, an AES trip combined with loss of generation from legacy PV can represent 30% - 35% of the typical daytime load, doubling the magnitude of the contingency event.

Lower system inertia and the larger magnitude contingency increases the rate of change of frequency (RoCoF), reducing the time for traditional governor droop and demand response to arrest the decay in system frequency. Analysis of recent AES trip events confirms that O'ahu's electrical system is operating with a smaller stability margin and is relying on multiple blocks of UFLS to help stabilize system frequency.

The UFLS scheme is designed to stabilize system frequency for severe loss of generation contingency events and acts as a last resort system preservation scheme to prevent an island-wide blackout. Under frequency load shed schemes are implemented in blocks of load. These load shed blocks are coordinated to shed increasing amounts of load at various frequency settings, progressively increasing the amount of load shed as for lower system frequency nadirs. The intent is to preserve the system for the low probability/high impact contingency events or unforeseen cascading events.

Under frequency load shedding must characterize load to shed low impact loads and avoid critical load like hospitals, emergency responders, schools, etc. Unfortunately, the proliferation of DG-PV is primarily on these residential distribution circuits so the daytime UFLS capacities for Blocks 1-3 continue to degrade and it's becoming more difficult to find residential load to shed. Demand Response will have a similar impact on UFLS schemes except load shed capacities in Blocks 4 and 5 will also be decreased.

Historical Contingency Events on Oahu

O'ahu has experienced several AES trip events over the past two years that required multiple blocks of UFLS to stabilize system frequency. On June 9, 2014, AES experienced a turbine trip at full output that resulted in an effective loss of 198 MW. With the additional loss of 50 MW of generation from Legacy PV, the contingency event was 248 MW that represents a 30% loss of generation. The system was carrying 310 MW of contingency reserves at the time of the AES trip, exceeding the capacity of the contingency event. Lower system inertia and the magnitude of the contingency event drove the frequency nadir to 58.4 Hz in less than 3 seconds. Three blocks of UFLS (approximately 110 MW) were initiated to stabilize system frequency.

On July 22, 2015, AES experienced a turbine trip at full output that resulted in an effective loss of 201 MW. With the additional loss of 55 MW of generation from Legacy PV, the contingency event was 256 MW that represents a 29% loss of generation. The system was carrying 283 MW of contingency reserves at the time of the AES trip, exceeding the capacity of the contingency event. Lower system inertia and the magnitude of the contingency event drove the frequency nadir to 58.4 Hz in 3.25 seconds. Three blocks of UFLS (approximately 82 MW) were initiated to stabilize system frequency.

On July 23, 2015, AES experienced a breaker trip at full output that resulted in an effective loss of 180 MW. With the additional loss of 55 MW of generation from Legacy PV, the contingency event was 235 MW that represents a 28% loss of generation. The system was carrying 297 MW of contingency reserves at the time of the AES trip, exceeding the capacity of the contingency event. Lower system inertia and the magnitude of the contingency event drove the frequency nadir to 58.5 Hz in less than 3 seconds. Three blocks of UFLS (approximately 82 MW) were initiated to stabilize system frequency.

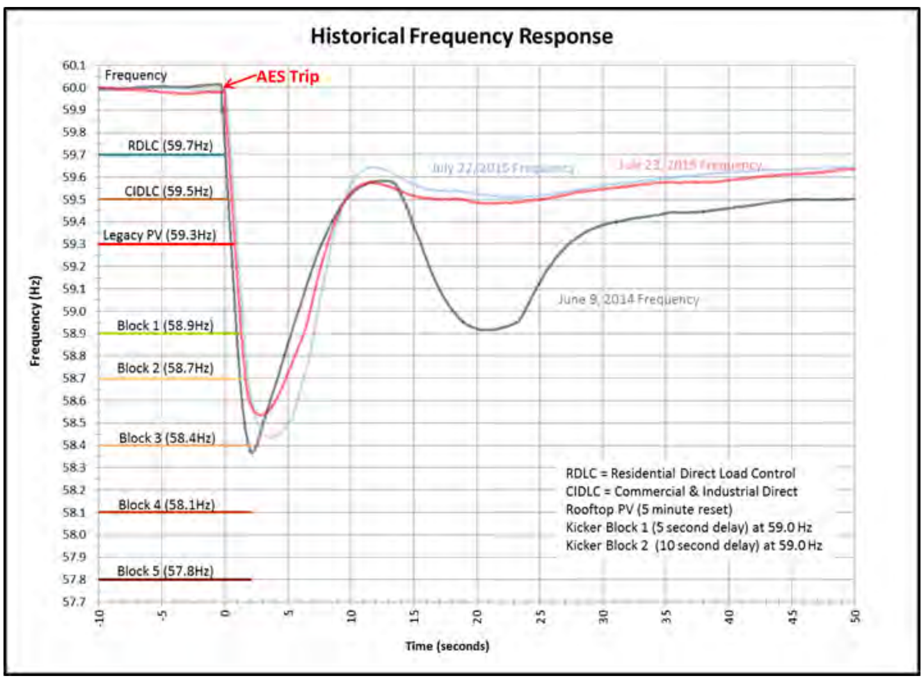


Figure O-4. Frequency Response Profile of Historic Contingency Events

Figure O-4 shows the frequency response profiles of these events.

Hawaiian Electric
Maui Electric
Hawai'i Electric Light

	June 9, 2014 Event 9:49 AM	July 22, 2015 Event 11:23 AM	July 23, 2015 Event 11:22 AM
System Load	830 MW	890 MW	850 MW
Generator Units On-Line	K1, K2, K3, K4, K5, K6, W7, W8, AES, H-POWER, KPLP	K1, K2, K3, K4, K6, W4, W6, W7, W8, AES, H-POWER, KPLP	K1, K2, K3, K4, K6, W4, W6, W7, W8, AES, H-POWER, KPLP
Total Kinetic Energy	6233	6059	6059
Synchronous Inertia Response	211	169	197
AES Gross MW Loss of Generation	198 MW	198 MW	180 MW
Excess Spinning Reserve	130 MW	103 MW	117 MW
Excess Quick Load Pick Up	50 MW	72 MW	78 MW
Estimated PV Tripped at 59.3Hz	50 MW	56 MW	55 MW
Frequency Nadir	58.4 Hz	58.4 Hz	58.5 Hz
Rate of Change of Frequency*	-0.94	-0.75	-0.84
Number of UFLS Blocks Shed	Blocks 1-3 (96 MW) & Block 5 (13.5 MW)**	Kicker Block 1 (20 MW) & Blocks 1-2 (62 MW)	Kicker Block 1 (20 MW) & Blocks 1-2 (65 MW)
*Note: Circuit in Block 5 tripped causing additional load shed			

Table O-5. Historical Contingency Events

Table O-5 shows the system characteristics of the historical system events.

Frequency Response Analysis for O'ahu in 2016

System security analysis was performed on two hours that were selected from the Theme 3 production cost simulations that represents a typical hour and a boundary condition.

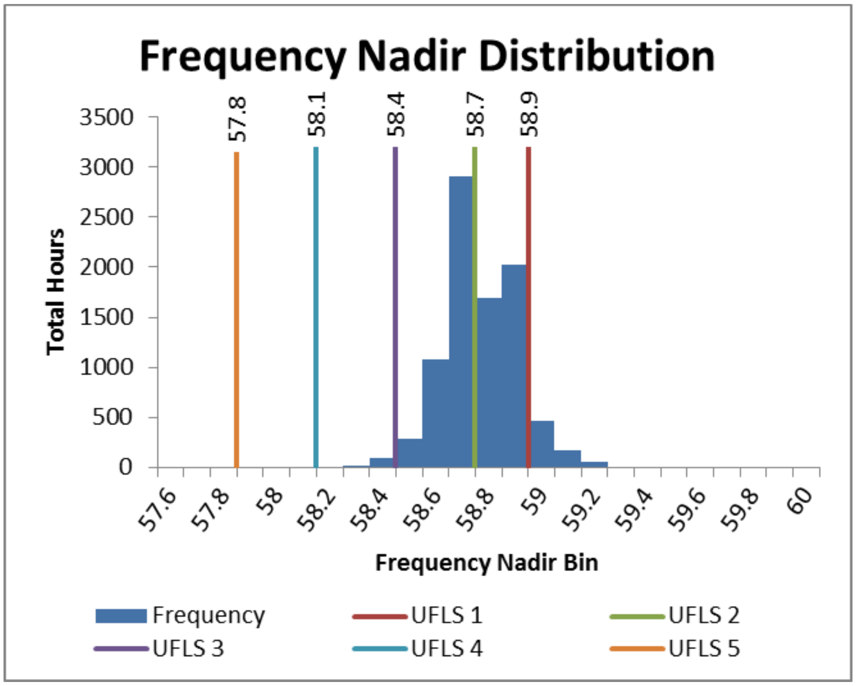


Figure O-5. Frequency Nadir Histogram 2016

Figure O-5 is a histogram of the expected frequency nadirs for N-1 generator contingency events for the entire year in 2016. This figure shows the probability distribution of the number of hours in the year where a N-1 generator contingency event would result in a drop to the frequency nadir. The typical hour selected from the maximum distribution of 2904 hours was 1:00 PM on Monday, October 10. The frequency nadir range for the typical hour is 58.6 – 58.7 Hz that requires two blocks of UFLS to stabilize system frequency.

The boundary hour selected from a minimum distribution of 99 hours was 2:00 PM on Sunday, April 10. The frequency nadir range for the boundary hour is 58.3 – 58.4 Hz that requires three blocks of UFLS to stabilize system frequency.

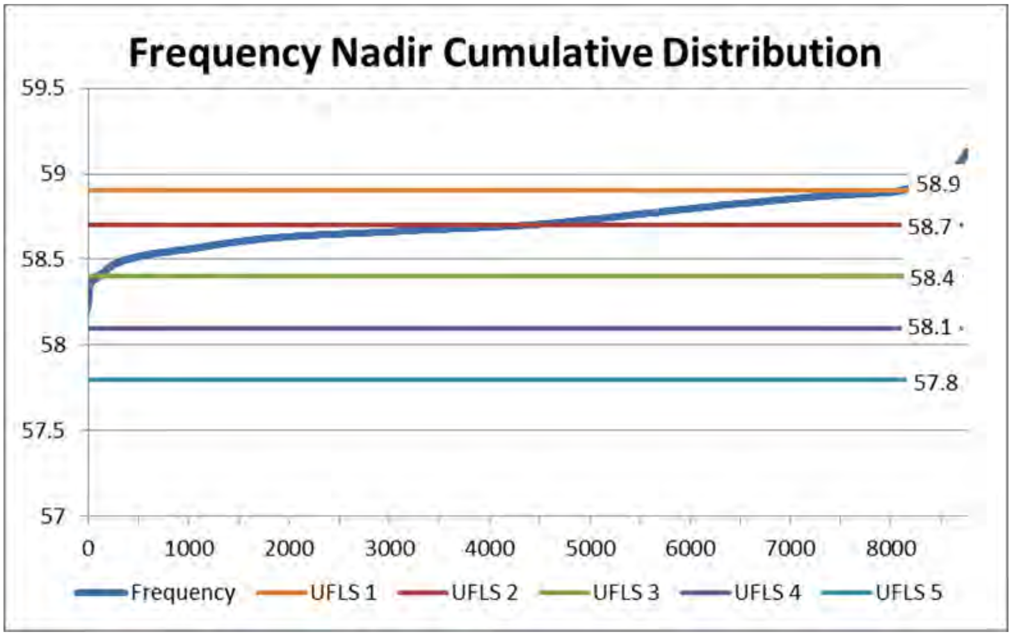


Figure O-6. Frequency Nadir Distribution Curve 2016

Figure O-6 shows the frequency nadir duration curve for 2016.

Unit Commitment Order	Unit Ratings							HECO 2016 (Typical) Mon 10/10/16 Hour 13			HECO 2016 (Boundary) Sun 4/10/16 Hour 14		
	Pmax	Pmin	VPO Max	VPO Min	Inertia H	Unit MVA	Unit K.E.	Pgen	up reg (spin)	down reg	Pgen	up reg (spin)	down reg
HPOWER-1	46.0	25.0			2.78	75.0	209	41.0	5.0	16.0	44.0	2.0	19.0
HPOWER-2	22.5	10.0			3.41	42.1	144				10.0	12.5	0.0
AES	180.0	63.0			2.57	239.0	614	180.0	0.0	117.0	180.0	0.0	117.0
Kalaeloa CT-1	84.0	29.0			4.96	119.2	591	81.0	3.0	52.0	84.0	0.0	55.0
Kalaeloa ST	40.0	10.0			4.70	61.1	287	37.0		27.0	40.0	0.0	30.0
Kahe 5	134.6	64.7			4.36	158.8	692	64.7	69.9	0.0	64.7	69.9	0.0
Kahe 6	133.8	63.9			4.36	158.8	692	63.9	69.9	0.0			
Kahe 3	86.2	23.7	25.0	5.0	3.54	101.0	357	26.0	60.2	2.3	18.0	0.0	13.0
Kahe 4	85.3	23.6	25.0	5.0	3.54	101.0	357	26.0	59.3	2.4	8.0	0.0	3.0
Kahe 2	82.2	23.8	25.0	5.0	4.44	96.0	426	26.0	56.2	2.2	10.0	0.0	5.0
Kahe 1	82.2	23.8	25.0	5.0	4.44	96.0	426	19.0	0.0	14.0	5.0	0.0	0.0
Kalaeloa CT-2	84.0	29.0			4.96	119.2	591	81.0	3.0	52.0	84.0	0.0	55.0
Waiau 8	86.2	24.1	25.0	5.0	4.44	96.0	426	23.0	0.0	18.0	7.0	0.0	2.0
Waiau 7	83.3	23.8	25.0	5.0	4.44	96.0	426	26.0	57.3	2.2			
Waiau 5	54.5	23.5			4.07	64.0	261	23.5	31.0	0.0	25.0	29.5	1.5
Waiau 6	53.7	23.8			4.00	64.0	256	23.8	29.9	0.0			
CIP1	112.2	41.2			4.72	162.0	765						
Waiau 10	49.9	5.9			7.84	57.0	447	5.9	44.0	0.0	5.9	44.0	0.0
Waiau 9	52.9	5.9			7.84	57.0	447						
Total Wind	99	0						12			23		
-Kahuku	30	0						4			11		
-Kawailoa	69	0						8			12		
DG-PV	447	0						331			281		
Station PV	10	0						10			7		
Total Kinetic Energy									7059			5828	
Total Load									1100			897	
Total Thermal Generation									748			586	
Total Renewable Generation									353			311	
Total Generation									1101			897	
Excess Generation									1			0	
Total Up Regulation									489			158	
Total Down Regulation									305			301	
Legacy DG-PV	59.3Hz Capacity			73.8				59.3Hz Output		54.7	59.3Hz Output		46.4
	60.5Hz Capacity			105.7				60.5Hz Output		78.3	60.5Hz Output		66.4

Table O-6. Unit Commitment and Dispatch 2016

Table O-6 shows the unit commitment and dispatch schedules for the typical hour (10/16/2016 at 1:00 PM) and boundary hour (4/10/2016 at 2:00 PM).

Loss of Generation

Simulations were performed to determine system performance for the largest loss of generation contingency for the typical and boundary hours. For O'ahu, this is an AES turbine trip at full output and the subsequent loss of generation from legacy PV.

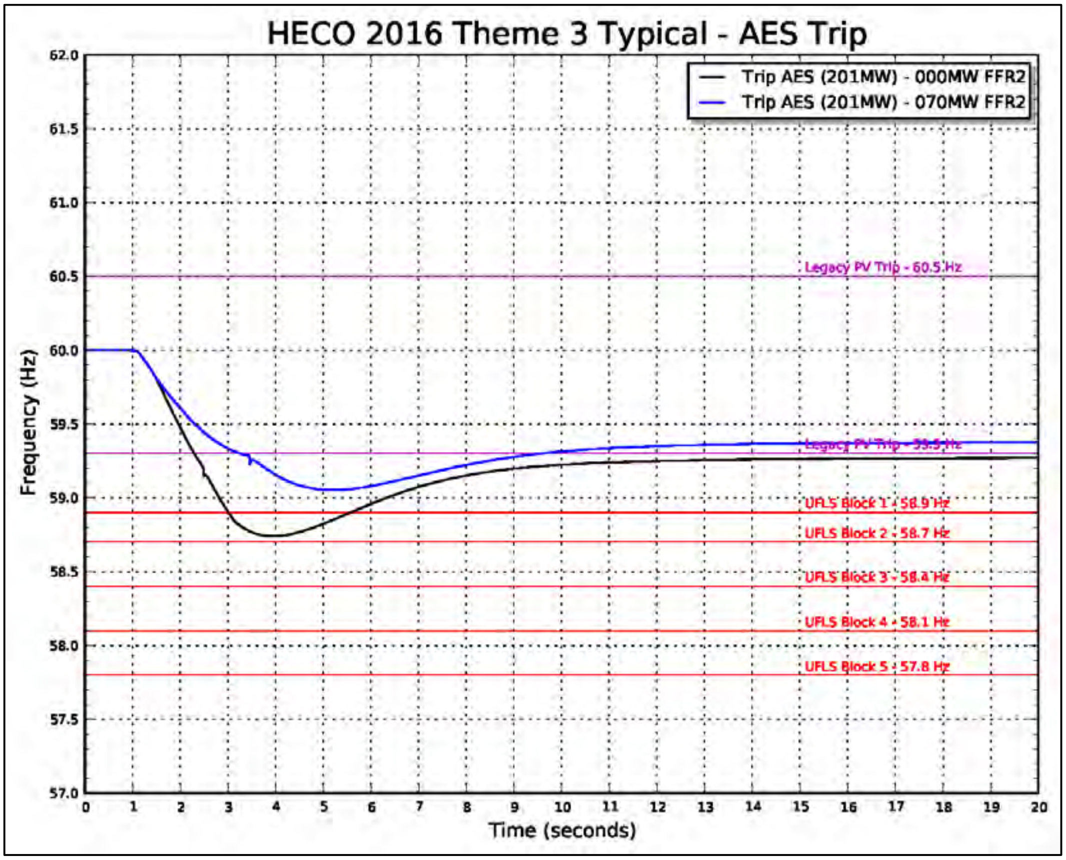


Figure O-7. Frequency Response Profile FFR2 Typical Hour

Figure O-7 shows the frequency response profile for an AES turbine trip for a typical hour. System kinetic energy is 7059 MW-sec and the capacity of legacy PV that will disconnect from the system is approximately 55 MW. With no FFR, the frequency nadir is 59.8 Hz, and one block of UFLS is required to stabilize system frequency. The capacity of FFR2 required to bring the system into compliance with TPL-001, no UFLS, is 70 MW.

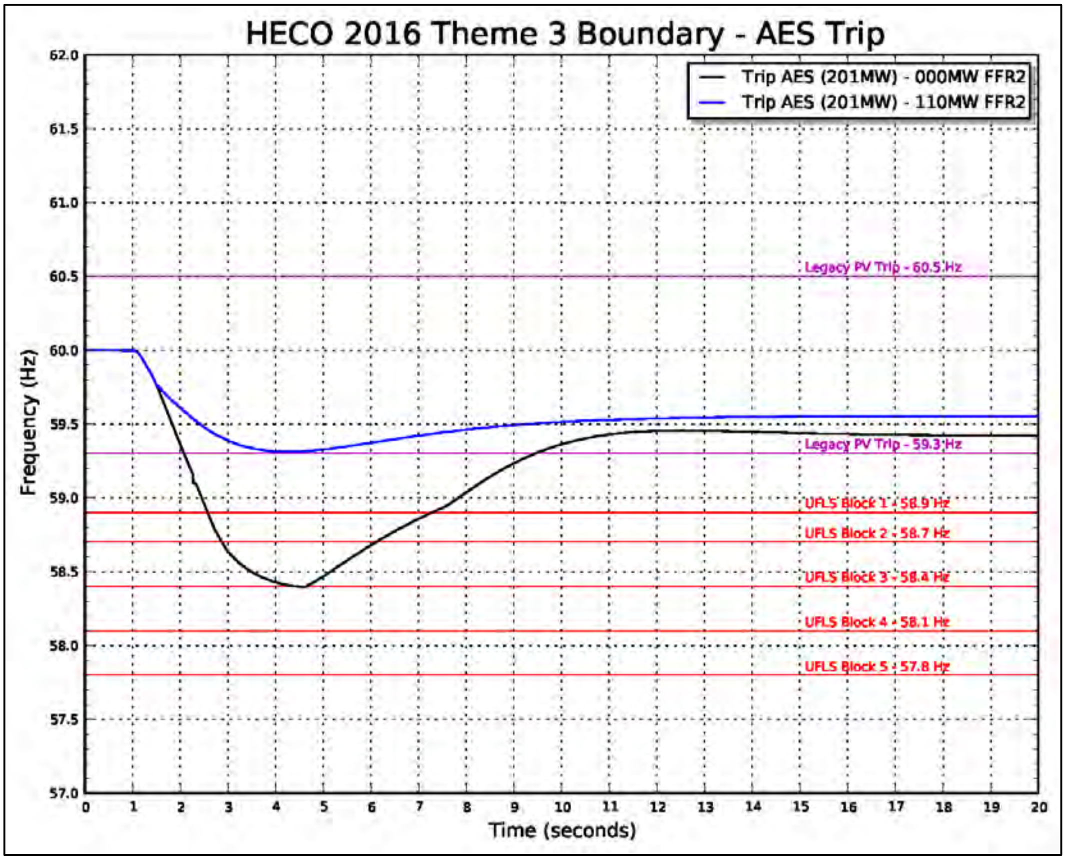


Figure O-8. Frequency Response Profile FFR2 Boundary Hour

Figure O-8 shows the frequency response profile for the boundary hour. The capacity of FFR2 required to bring the system into compliance with TPL-001 is 100 MW.

Fault Current Analysis for 2016

Simulations were performed for three phase-to-ground, two phase-to-ground, single phase-to-ground, and line-to-line faults for different unit commitment schedules while monitoring 46kV bus currents. Units were cycled offline until one or more of the Minimum Acceptable Fault Current Limits from Table O-7 were violated.

The unit commitment schedule that meets the Minimum Acceptable Fault Current Limits was HPOWER 1, HPOWER 2, AES, and Kahe 5 with a total of 515 MVA fault current capacity. Any combination of synchronous generating units or synchronous condensers that total 515 MVA will provide sufficient fault current to ensure proper operation of relay protection schemes.

PSSE BUS	46kV Bus #	Circuit Name	Circuit Breaker
ARCH46A	4101	Archer 42A	6041
ARCH46A	4101	Archer 41	6043
ARCH46B	4102	Archer 43	6051
ARCH46B	4102	Archer 44A	6053
ARCH46C	4103	Archer 46	6072
HLWA46A	4121	Halawa 1	4865
HLWA46A	4121	Halawa 2	4864
HLWA46B	4122	Halawa 3	4863
HLWA46B	4122	Halawa 4	4883
SCH 46A	4181	School - Puunui	4582
SCH 46B	4182	School - Nuuanu	4409
IWI 46A	4131	Iwilei 1	4401
IWI 46B	4132	Iwilei 2	4402
KOOL46D	4154	Koolau - Kahuku	4464
KOOL46A	4151	Koolau - Wailupe 1	4467
KOOL46B	4152	Koolau - Wailupe 2	4477
KOOL46C	4153	Koolau - Aikahi	4465
KOOL46A	4151	Koolau - Kaneohe	4466
KOOL46C	4153	Koolau - Nuuanu - Laelae	4484
KOOL46D	4154	Koolau - Pohakupu	4469
KOOL46B	4152	Koolau - Kailua	4414
PUKE46A	4171	Pukele 1	4813
PUKE46B	4172	Pukele 3	4815
PUKE46C	4173	Pukele 5	4820
PUKE46C	4173	Pukele 6	4817
PUKE46D	4174	Pukele 7	4818
PUKE46D	4174	Pukele 8	4819
MAKA46A	4161	Makalapa 42	5133
MAKA46C	4163	Makalapa 46	5128
WHWA46A	4191	Wahiawa - Waialua 2	4683
WHWA46C	4193	Wahiawa - Milikua	4621
WHWA46B	4192	Wahiawa - Mililani	4448
WHWA46C	4193	Wahiawa - Waimano	4449
KAHE46B	4142	Kahe - Mikilua	4714
KAHE46A	4141	Kahe - Standard Oil 1	4717
KAHE46B	4142	Kahe- Standard Oil 2	4715
KAHE46A	4141	Kahe - Permanente	4716
CEIP46A	4111	CEIP 42	5156

PSSE BUS	46kV Bus #	Circuit Name	Circuit Breaker
CEIP46C	4113	CEIP 45	5159
CEIP46C	4113	CEIP 46	5160
EWAN46A	4341	Ewa Nui 41	5338
EWAN46A	4341	Ewa Nui 42	5339
WAIAU46	4201	Waiau - Steel Mill	4653
WAIAU46	4201	Waiau - Barbers Point	4486
WAIAU46	4201	Waiau - Mililani	4453

Table O-7. Minimum Fault Current (1 of 3)

Minimum Acceptable Fault Current (Amps) [1]	Fault Current (Amps)	Line out Scenario	Minimum Acceptable Fault Current (Amps) [1]	Fault Current (Amps)	Line out Scenario
3372	3380	IWILEI-AIRPORT 1	3364	3740	IWILEI-AIRPORT 1
3330	3380	IWILEI-AIRPORT 1	3444	3740	IWILEI-AIRPORT 1
3376	3406	IWILEI-AIRPORT 1	3515	3771	IWILEI-AIRPORT 1
3371	3406	IWILEI-AIRPORT 1	3500	3771	IWILEI-AIRPORT 1
2591	3382	IWILEI-AIRPORT 1	2171	3742	IWILEI-AIRPORT 1
2834	3887	HALAWA-KAHE AB 1	2242	4192	HALAWA-KAHE AB 1
2704	3887	HALAWA-KAHE AB 1	2068	4192	HALAWA-KAHE AB 1
2596	3880	HALAWA-KAHE AB 1	1901	4184	HALAWA-KAHE AB 1
2894	3880	HALAWA-KAHE AB 1	2247	4184	HALAWA-KAHE AB 1
8366	8944	IWILEI-AIRPORT 1	7154	10093	IWI 46A-SCH 46B 1
7034	8944	IWILEI-AIRPORT 1	5565	10093	IWI 46A-SCH 46B 1
5476	8961	IWILEI-AIRPORT 1	3751	10388	IWILEI-AIRPORT 1
6375	8961	IWILEI-AIRPORT 1	4577	10388	IWILEI-AIRPORT 1
1002	3606	HALAWA-KOOLAU 1	600	4027	HALAWA-KOOLAU 1
1832	3658	HALAWA-KOOLAU 1	1186	3977	HALAWA-KOOLAU 1
1926	3636	HALAWA-KOOLAU 1	1245	3951	HALAWA-KOOLAU 1
2599	3603	HALAWA-KOOLAU 1	2014	3913	HALAWA-KOOLAU 1
2220	3658	HALAWA-KOOLAU 1	1561	3977	HALAWA-KOOLAU 1
2633	3603	HALAWA-KOOLAU 1	2056	3913	HALAWA-KOOLAU 1
2095	3606	HALAWA-KOOLAU 1	1409	4027	HALAWA-KOOLAU 1
2027	3636	HALAWA-KOOLAU 1	1385	3951	HALAWA-KOOLAU 1
3115	3760	KOOLAU-PUKELE 2	2649	4140	KOOLAU-PUKELE 2
2732	3784	KOOLAU-PUKELE 2	2119	4168	KOOLAU-PUKELE 2
2497	3814	KOOLAU-PUKELE 2	1823	4205	KOOLAU-PUKELE 2
2373	3814	KOOLAU-PUKELE 2	1696	4205	KOOLAU-PUKELE 2
2806	3731	KOOLAU-PUKELE 2	2176	4104	KOOLAU-PUKELE 2

Minimum Acceptable Fault Current (Amps) [1]	Fault Current (Amps)	Line out Scenario	Minimum Acceptable Fault Current (Amps) [1]	Fault Current (Amps)	Line out Scenario
3040	3731	KOOLAU-PUKELE 2	2475	4104	KOOLAU-PUKELE 2
4816	6483	MAKALAPA-WAIAU 2	3516	6717	MAKALAPA-WAIAU 2
5730	6435	MAKALAPA-WAIAU 2	4860	6585	MAKALAPA-WAIAU 2
921	3547	WAHIAWA-WAIAU 1	512	4238	WAHIAWA-WAIAU 1
1433	3516	WAHIAWA-WAIAU 1	927	4006	WAHIAWA-WAIAU 1
2814	3627	WAHIAWA-WAIAU 1	2289	4625	WAHIAWA-WAIAU 1
2048	3516	WAHIAWA-WAIAU 1	1417	4006	WAHIAWA-WAIAU 1
1708	3647	CEIP-KAHE CD 1	1293	3854	CEIP-KAHE CD 1
2541	3828	CEIP-KAHE CD 1	2489	4057	CEIP-KAHE CD 1
1693	3647	CEIP-KAHE CD 1	1276	3854	CEIP-KAHE CD 1
2205	3828	CEIP-KAHE CD 1	1290	4057	CEIP-KAHE CD 1
3224	3663	CEIP-AES 2	2618	3868	CEIP-AES 2
3264	4185	CEIP-AES 2	3473	4460	CEIP-AES 2
2441	4185	CEIP-AES 2	1461	4460	CEIP-AES 2
2646	3755	CEIP-EWA NUI 1	1951	4138	CEIP-EWA NUI 1
2843	3755	CEIP-EWA NUI 1	2247	4138	CEIP-EWA NUI 1
2655	6411	KALAE-AES 1	1659	7209	KALAE-AES 1
3994	6411	KALAE-AES 1	2793	7209	KALAE-AES 1
1748	6411	KALAE-AES 1	1122	7209	KALAE-AES 1

Table O-8. Minimum Fault Current (2 of 3)

Minimum Acceptable Fault Current (Amps) [1]	Fault Current (Amps)	Line out Scenario	Minimum Acceptable Fault Current (Amps) [1]	Fault Current (Amps)	Line out Scenario
3415	4185	IWILEI-AIRPORT 1	2920	2927	IWILEI-AIRPORT 1
3501	4185	IWILEI-AIRPORT 1	2883	2927	IWILEI-AIRPORT 1
3568	4223	IWILEI-AIRPORT 1	2924	2950	IWILEI-AIRPORT 1
3548	4223	IWILEI-AIRPORT 1	2919	2950	IWILEI-AIRPORT 1
2495	4188	IWILEI-AIRPORT 1	2244	2929	IWILEI-AIRPORT 1
2665	4550	HALAWA-KAHE AB 1	2451	3366	HALAWA-KAHE AB 1
2492	4550	HALAWA-KAHE AB 1	2338	3366	HALAWA-KAHE AB 1
2370	4540	HALAWA-KAHE AB 1	2245	3360	HALAWA-KAHE AB 1
2677	4540	HALAWA-KAHE AB 1	2503	3360	HALAWA-KAHE AB 1
8062	11219	IWI 46A-SCH 46B 1	7217	7746	IWILEI-AIRPORT 1
6570	11219	IWI 46A-SCH 46B 1	6071	7746	IWILEI-AIRPORT 1
4966	12313	IWI 46A-SCH 46B 1	4730	7760	IWILEI-AIRPORT 1

Minimum Acceptable Fault Current (Amps) [1]	Fault Current (Amps)	Line out Scenario	Minimum Acceptable Fault Current (Amps) [1]	Fault Current (Amps)	Line out Scenario
5805	12313	IWI 46A-SCH 46B 1	5504	7760	IWILEI-AIRPORT 1
925	4559	HALAWA-KOOLAU 1	868	3123	HALAWA-KOOLAU 1
1659	4358	HALAWA-KOOLAU 1	1587	3168	HALAWA-KOOLAU 1
1737	4327	HALAWA-KOOLAU 1	1668	3149	HALAWA-KOOLAU 1
2368	4281	HALAWA-KOOLAU 1	2251	3120	HALAWA-KOOLAU 1
2022	4358	HALAWA-KOOLAU 1	1922	3168	HALAWA-KOOLAU 1
2436	4281	HALAWA-KOOLAU 1	2280	3120	HALAWA-KOOLAU 1
1894	4559	HALAWA-KOOLAU 1	1814	3123	HALAWA-KOOLAU 1
1842	4327	HALAWA-KOOLAU 1	1755	3149	HALAWA-KOOLAU 1
2945	4605	KOOLAU-PUKELE 2	2695	3256	KOOLAU-PUKELE 2
2527	4640	KOOLAU-PUKELE 2	2364	3277	KOOLAU-PUKELE 2
2285	4685	KOOLAU-PUKELE 2	2160	3303	KOOLAU-PUKELE 2
2164	4685	KOOLAU-PUKELE 2	2054	3303	KOOLAU-PUKELE 2
2592	4561	KOOLAU-PUKELE 2	2428	3231	KOOLAU-PUKELE 2
2844	4561	KOOLAU-PUKELE 2	2630	3231	KOOLAU-PUKELE 2
4425	6968	MAKALAPA-WAIAU 2	4164	5614	MAKALAPA-WAIAU 2
5549	6743	MAKALAPA-WAIAU 2	4952	5572	MAKALAPA-WAIAU 2
352	5264	WAHIAWA-WAIAU 1	797	3072	WAHIAWA-WAIAU 1
683	4655	WAHIAWA-WAIAU 1	1240	3045	WAHIAWA-WAIAU 1
1931	6381	WAHIAWA-WAIAU 1	2434	3141	WAHIAWA-WAIAU 1
1082	4655	WAHIAWA-WAIAU 1	1772	3045	WAHIAWA-WAIAU 1
1042	4087	CEIP-KAHE CD 1	1478	3158	CEIP-KAHE CD 1
1978	4316	CEIP-KAHE CD 1	2182	3315	CEIP-KAHE CD 1
1025	4087	CEIP-KAHE CD 1	1465	3158	CEIP-KAHE CD 1
949	4316	CEIP-KAHE CD 1	1855	3315	CEIP-KAHE CD 1
3003	4096	CEIP-AES 2	2788	3172	CEIP-AES 2
3051	4774	CEIP-AES 2	2798	3624	CEIP-AES 2
2160	4774	CEIP-AES 2	2046	3624	CEIP-AES 2
2427	4609	CEIP-EWA NUI 1	2288	3252	CEIP-EWA NUI 1
2660	4609	CEIP-EWA NUI 1	2459	3252	CEIP-EWA NUI 1
2412	8233	KALAE-AES 1	2297	5552	KALAE-AES 1
3627	8233	KALAE-AES 1	3452	5552	KALAE-AES 1
1655	8233	KALAE-AES 1	1513	5552	KALAE-AES 1

Table O-9. Minimum Fault Current (2 of 3)

Note 1 = Minimum Acceptable Fault Current provided by Protection group

Simulations were performed for electrical faults on the 138 kV transmission system busses. A three-phase fault was placed on 28 busses to evaluate system performance to normally cleared and delayed clearing faults. Normally cleared faults are isolated in 5-cycles and delayed clearing faults are isolated in 18-cycles to simulate a breaker that fails to open. Simulations for the normally cleared faults did not produce any system security issues.

2016 138 kV Fault Analysis						
Circuit Outage	**Bus Fault**	**Bkr Fail**	**BFTD**	**2nd Outage**	**Typical Hour Condition**	**Boundary Hour Condition**
AES-CEIP 1	AES	320	15	AES-HP	Unstable	Unstable
AES-HP	AES	320	15	AES-CEIP 1	Unstable	Unstable
AES-CEIP 2	AES	323	15	AES Gen	Stable	Stable
AES-Kalaeloa	AES	456	15	CIP Gen	Stable	Unstable
AES-CEIP 1	CEIP	276	18	Kahe-CEIP 2	Stable	Unstable
Kahe-CEIP 2	CEIP	276	18	AES-CEIP 1	Unstable	Unstable
AES-CEIP 2	CEIP	279	18	CEIP-Ewa Nui	Stable	Unstable
CEIP-Ewa Nui	CEIP	279	18	AES-CEIP 2	Stable	Unstable
CEIP-Ewa Nui	EWA	384	18	Waiau-Ewa Nui 2	Stable	Stable
Waiau-Ewa Nui 2	EWA	384	18	CEIP-Ewa Nui	Stable	Stable
Kalaeloa-Ewa Nui	EWA	387	18	Waiau-Ewa Nui 1	Stable	Stable
Waiau-Ewa Nui 1	EWA	387	18	Kalaeloa-Ewa Nui	Stable	Stable
Halawa-Iwilei	HLWA	158	18	Halawa-Makalapa	Stable	Stable
Halawa-Makalapa	HLWA	158	18	Halawa-Iwilei	Stable	Stable
Halawa-School	HLWA	161	18	Kahe-Halawa 1	Stable	Stable
Kahe-Halawa 1	HLWA	161	18	Halawa-School	Stable	Stable
Halawa-Koolau	HLWA	176	18	Kahe-Halawa 2	Stable	Stable
Kahe-Halawa 2	HLWA	176	18	Halawa-Koolau	Stable	Stable
Kahe-Wahiawa	KAHE	129	18	K1 Gen	Stable	Unstable
Kahe-Halawa 2	KAHE	132	18	K2 Gen	Stable	Unstable
Kahe-Halawa 1	KAHE	168	18	K3 Gen	Stable	Unstable
Kahe-Waiau	KAHE	171	18	K4 Gen	Stable	Unstable
Kahe-CEIP 2	KAHE	246	18	K5 Gen	Stable	Unstable
Kahe-CEIP 1	KAHE	249	18	K6 Gen	Stable	Unstable
Kalaeloa-Ewa Nui	KPLP	310	18	Kal2 Gen	Unstable	Unstable
AES-Kalaeloa	KPLP	313	18	Kal1 Gen	Stable	Stable
Waiau-Makalapa 1	MKLPA	260	18	Makalapa Tsf 3	Stable	Stable
Halawa-Makalapa	MKLPA	263	18	Waiau-Makalapa 2	Stable	Stable
Waiau-Makalapa 2	MKLPA	263	18	Halawa-Makalapa	Stable	Stable
Makalapa-Airport	MKLPA	266	18	Makalapa Tsf 1	Stable	Stable
Kahe-Waiau	WAIAU	102	18	W5 Gen	Stable	Stable
Waiau-Koolau 2	WAIAU	105	18	W6 Gen	Stable	Stable
Waiau-Wahiawa	WAIAU	108	18	W8 Gen	Stable	Stable
Waiau-Koolau 1	WAIAU	111	18	W7 Gen	Stable	Stable
Waiau-Ewa Nui 1	WAIAU	179	18	Waiau-Makalapa 2	Stable	Stable
Waiau-Makalapa 2	WAIAU	179	18	Waiau-Ewa Nui 1	Stable	Stable
Waiau-Ewa Nui 2	WAIAU	302	18	Waiau-Makalapa 1	Stable	Stable
Waiau-Makalapa 1	WAIAU	302	18	Waiau-Ewa Nui 2	Stable	Stable
Waiau-Wahiawa	WHWA	145	18	Wahiawa Tsf 3	Stable	Stable

Table O-10. Summary of Results for the Fault Analysis

Table O-10 shows the results of the breaker failure analysis. For the typical hour, 4 simulations resulted in unstable operation and for the boundary hour, 14 simulations resulted in unstable operation. In all simulations, HPOWER loses synchronism with the system.

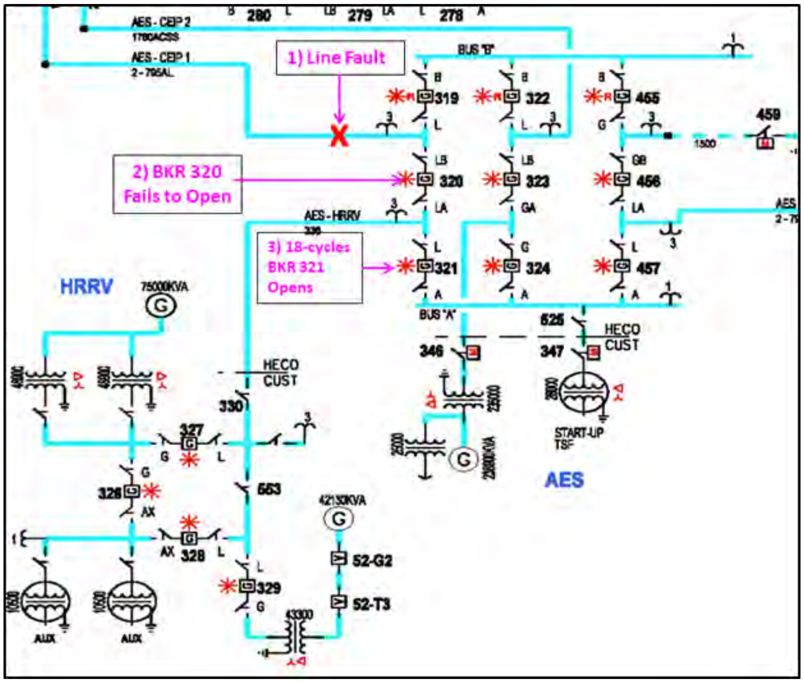


Figure O-9. Breaker Failure Diagram

Figure O-9 is a diagram that illustrates the breaker failure simulation. 1) A three-phase fault is placed on the AES-CEIP 1 transmission line; 2) BKR 320 fails to open; 3) BKR 321 opens 18-cycles later.

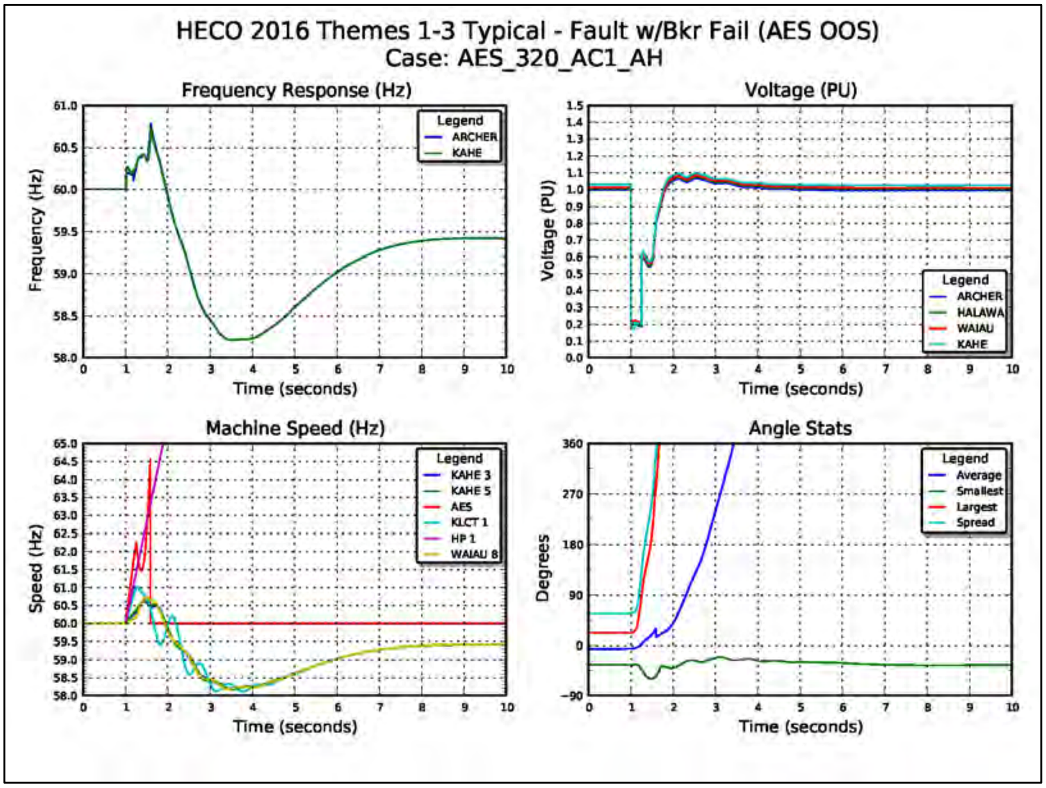


Figure O-10. System Performance for BKR 320 Failure Analysis

Figure O-10 shows four plots that illustrate unstable operation for a fault on the AES-CEIP 1 line and BKR 320 fails to operate. The Machine Speed plot shows AES (red) begin to accelerate before tripping while HPOWER 1 (magenta) loses synchronism with the system. This occurs when an electrical fault cannot be cleared before the critical clearing time of a generator, causing these units to accelerate and slip a pole. Both AES and HPOWER 1 have low inertia constants (2.78 and 2.57 MJ/MVA respectively) that determines the shorter critical clearing times of these units. AES has out of step relay protection but HPOWER 1 and HPOWER 2 do not. More analysis is required to determine mitigation alternatives.

2019 – Compliance with TPL-001

System security analysis was performed on two hours that were selected from the Theme 3 production cost simulations that represents a typical hour and a boundary condition.

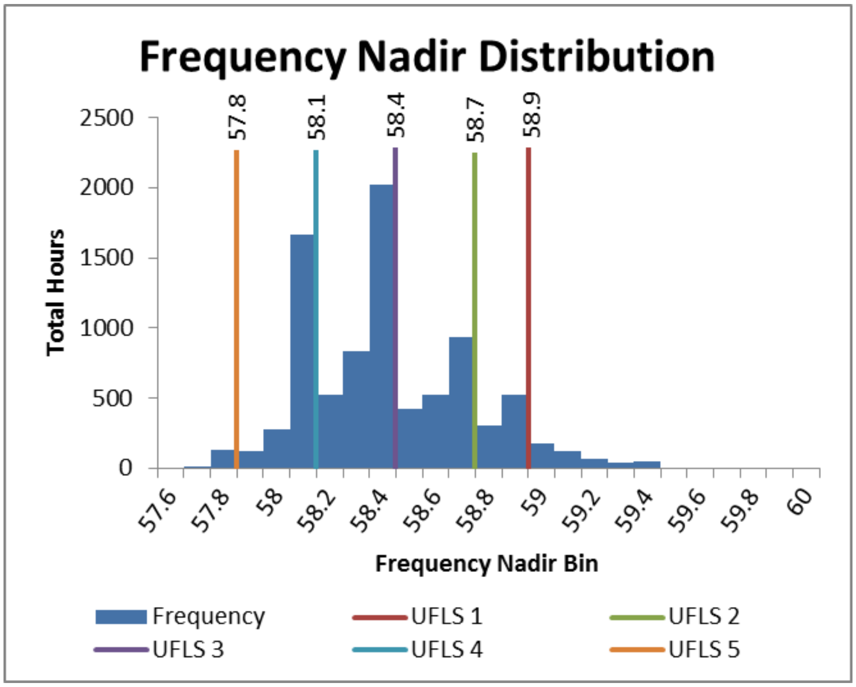


Figure O-11. Frequency Nadir Histogram for 2019

Figure O-11 is a histogram of the expected frequency nadirs for N-1 generator contingency events for the entire year from the Theme 3 production cost simulations. The typical hour was selected from the maximum distribution of 1665 hours was 1:00 PM on Friday, September 6. The frequency nadir range for the typical hour is 58.0 - 58.1 Hz that requires four blocks of UFLS to stabilize system frequency.

The boundary hour selected from a minimum distribution of 5 hours was 1:00 PM on Saturday, January 26. The frequency nadir range for the boundary hour is 57.6 – 57.7 Hz that requires five blocks of UFLS to stabilize system frequency.

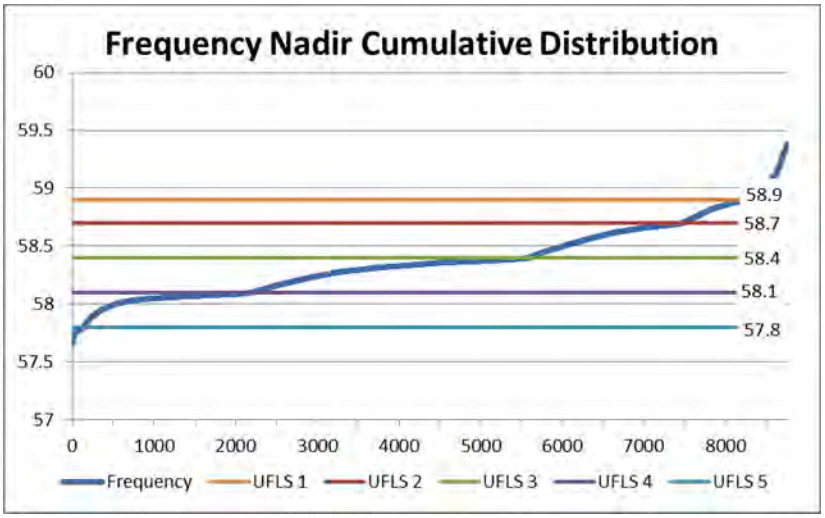


Figure O-12. Frequency Nadir Duration Curve 2019

Figure O-12 shows the frequency nadir duration curve for 2019.

Unit Commitment Order	Unit Ratings							Theme 3 - HECO 2019 (Typical) Fri 9/6/19 Hour 11			Theme 3 - HECO 2019 (Boundary) Sat 1/26/19 Hour 13		
	Pmax	Pmin	VPO Max	VPO Min	Inertia H	Unit MVA	Unit K.E.	Pgen	up reg (spin)	down reg	Pgen	up reg (spin)	down reg
HPOWER-1	46.0	25.0			2.78	75.0	209	46.0	0.0	21.0	41.0	5.0	16.0
HPOWER-2	22.5	10.0			3.41	42.1	144	18.0	4.5	8.0			
AES	180.0	63.0			2.57	239.0	614	180.0	0.0	117.0	180.0	0.0	117.0
Kalaeloa CT-1	84.0	29.0			4.96	119.2	591	84.0	0.0	55.0			
Kalaeloa ST	40.0	10.0			4.70	61.1	287	40.0		30.0			
Kahe 5	134.6	64.7			4.36	158.8	692	64.7	69.9	0.0	64.7	69.9	0.0
Kahe 6	133.8	63.9			4.36	158.8	692	63.9	69.9	0.0	71.0	62.8	7.1
Kahe 3	86.2	23.7	25.0	5.0	3.54	101.0	357						
Kahe 4	85.3	23.6	25.0	5.0	3.54	101.0	357						
Kahe 2	82.2	23.8	25.0	5.0	4.44	96.0	426						
Kahe 1	82.2	23.8	25.0	5.0	4.44	96.0	426						
Kalaeloa CT-2	84.0	29.0			4.96	119.2	591	84.0	0.0	55.0			
Waiau 8	86.2	24.1	25.0	5.0	4.44	96.0	426						
Waiau 7	83.3	23.8	25.0	5.0	4.44	96.0	426						
Waiau 5	54.5	23.5			4.07	64.0	261						
Waiau 6	53.7	23.8			4.00	64.0	256						
CIP1	112.2	41.2			4.72	162.0	765						
Waiau 10	49.9	5.9			7.84	57.0	447						
Waiau 9	52.9	5.9			7.84	57.0	447						
Schofield 1	8.0	2.0			0.99	10.9	11						
Schofield 2	8.0	2.0			0.99	10.9	11						
Schofield 3	8.0	2.0			0.99	10.9	11						
Schofield 4	8.0	2.0			0.99	10.9	11						
Schofield 5	8.0	2.0			0.99	10.9	11						
Schofield 6	8.0	2.0			0.99	10.9	11						
Honolulu 8	0.0	0.0			1.99	62.5	124	0.0	Synch. Cond.		0.0	Synch. Cond.	
Honolulu 9	0.0	0.0			1.95	64.0	125	0.0	Synch. Cond.		0.0	Synch. Cond.	
Total Wind	133	0						28			38		
-Kahuku	30	0						6			4		
-Kawailoa	69	0						13			10		
-Na Pua Makani	24	0						8			21		
-Future Wind	10	0						1			3		
DG-PV	664	0						438			366		
Station PV	163	0						132			130		
Total Kinetic Energy									4070			2457	
Total Load									1179			891	
Total Thermal Generation									581			357	
Total Renewable Generation									598			534	
Total Generation									1179			891	
Excess Generation									0			0	
Total Up Regulation									144			138	
Total Down Regulation									286			140	
Legacy DG-PV	59.3Hz Capacity			73.8				59.3Hz Output		48.7	59.3Hz Output		40.7
	60.5Hz Capacity			105.7				60.5Hz Output		69.7	60.5Hz Output		58.3

Table O-11. Commitment and Dispatch 2019

Table O-11 shows the unit commitment and dispatch for the typical hour (9/16/2019, 11:00 AM) and boundary hour (1/26/2019, 1:00 PM).

Loss of Generation

Simulations were performed for the largest loss of generation contingency event to determine the frequency response reserve requirements to bring the system into compliance with TPL-001.

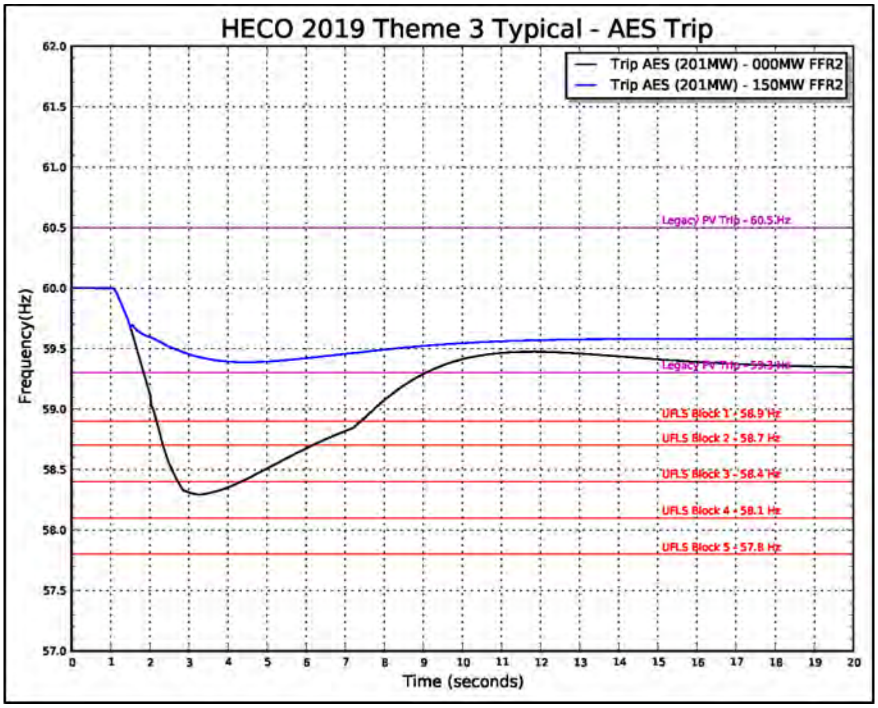


Figure O-13. Frequency Response Profile for FFR2 Typical Hour

Figure O-13 shows the frequency response profile for an AES turbine trip for a typical hour. System kinetic energy is 4070 MW-sec and the capacity of legacy PV that will disconnect from the system is approximately 49 MW. With no FFR2, the frequency nadir is 58.3 Hz and three blocks of UFLS are required to stabilize system frequency. The capacity of FFR2required, which Demand Response could be used to meet this capacity, to bring the system into compliance with TPL-001 is 150 MW.

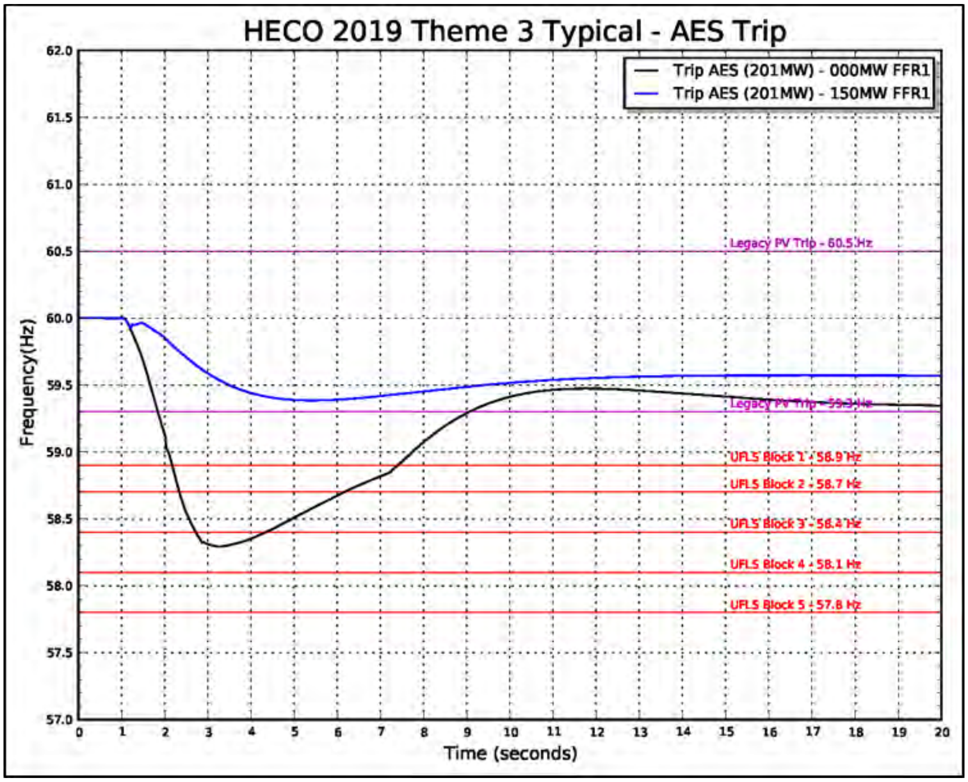


Figure O-14. Frequency Response Profile for FFR1 Typical Hour

Figure O-14 shows the frequency response profile for the FFR1 analysis. The capacity of FFR1 required to bring the system into compliance with TPL-001 is 150 MW.

The frequency response profiles are results from the simulations for the typical hour.

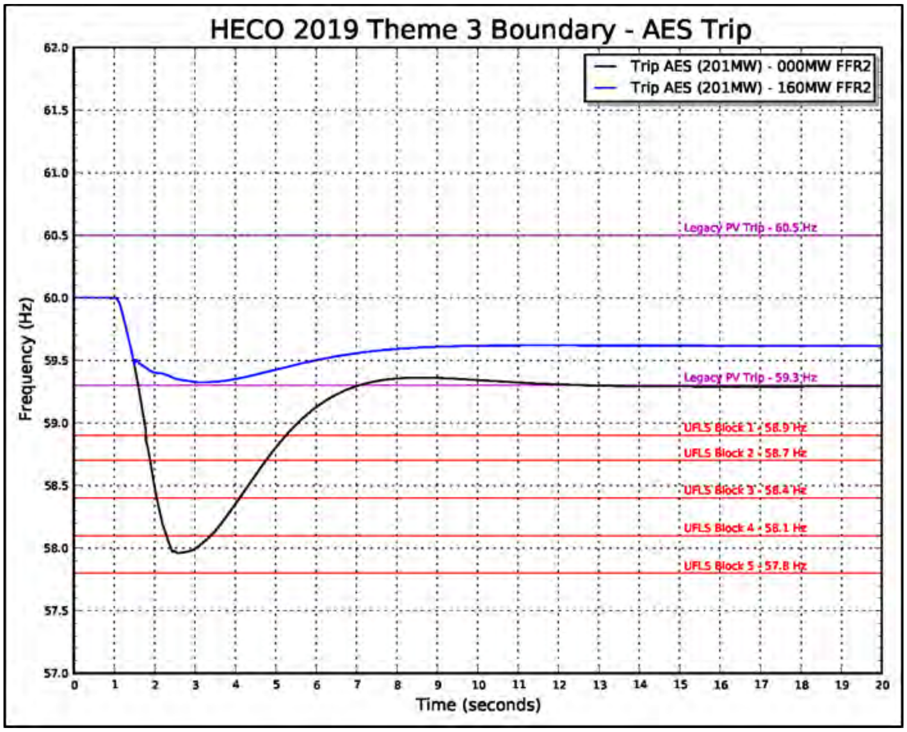


Figure O-15. Frequency Response Profile for FFR2 Boundary Hour

Figure O-15 shows the frequency response profile for an AES turbine trip for a boundary hour. System kinetic energy is 2457 MW-sec and the capacity of legacy PV that will disconnect from the system is approximately 41 MW. With no FFR, the frequency nadir is 58.4 Hz and three blocks of UFLS are required to stabilize system frequency. The capacity of FFR2 required to bring the system into compliance with TPL-001 is 160 MW.

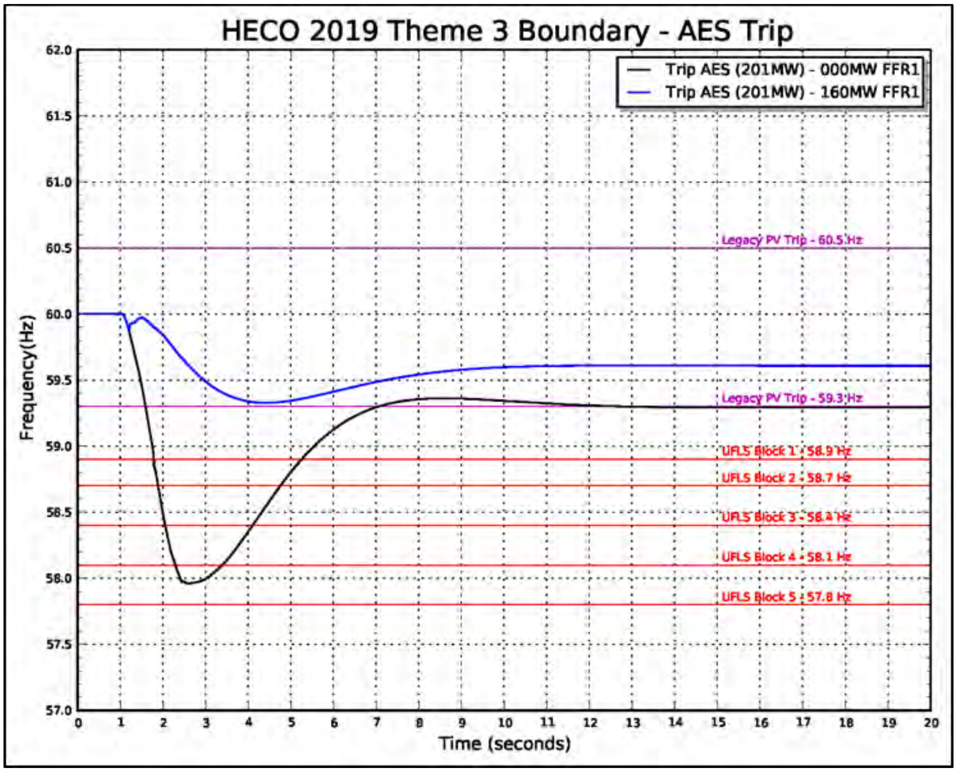


Figure O-16. Frequency Response Profile for FFR1 Boundary Hour

Figure O-16 shows the frequency response profile for this analysis. The capacity of FFR1 required to bring the system into compliance with TPL-001 is 160 MW.

2019 Sensitivity Analysis

A sensitivity analysis was performed to determine the frequency response reserve requirements to meet TPL-001 if AES was dispatched to a lower output. The next largest generator contingency is Kahe 5 or 6 at 134.6 MW.

Unit Commitment Order	Unit Ratings							Theme 3 - HECO 2019 (Typical) Fri 9/6/19 Hour 11 [AES at 134MW]			Theme 3 - HECO 2019 (Boundary) Sat 1/26/19 Hour 13 [AES at 134MW]		
	Pmax	Pmin	VPO Max	VPO Min	Inertia H	Unit MVA	Unit K.E.	Pgen	up reg (spin)	down reg	Pgen	up reg (spin)	down reg
HPOWER-1	46.0	25.0			2.78	75.0	209	46.0	0.0	21.0	41.0	5.0	16.0
HPOWER-2	22.5	10.0			3.41	42.1	144	18.0	4.5	8.0			
AES	180.0	63.0			2.57	239.0	614	134.0	46.0	71.0	134.0	46.0	71.0
Kalaeloa CT-1	84.0	29.0			4.96	119.2	591	84.0	0.0	55.0			
Kalaeloa ST	40.0	10.0			4.70	61.1	287	40.0		30.0			
Kahe 5	134.6	64.7			4.36	158.8	692	87.7	46.9	23.0	87.7	46.9	23.0
Kahe 6	133.8	63.9			4.36	158.8	692	86.9	46.9	23.0	94.0	39.8	30.1
Kahe 3	86.2	23.7	25.0	5.0	3.54	101.0	357						
Kahe 4	85.3	23.6	25.0	5.0	3.54	101.0	357						
Kahe 2	82.2	23.8	25.0	5.0	4.44	96.0	426						
Kahe 1	82.2	23.8	25.0	5.0	4.44	96.0	426						
Kalaeloa CT-2	84.0	29.0			4.96	119.2	591	84.0	0.0	55.0			
Waiau 8	86.2	24.1	25.0	5.0	4.44	96.0	426						
Waiau 7	83.3	23.8	25.0	5.0	4.44	96.0	426						
Waiau 5	54.5	23.5			4.07	64.0	261						
Waiau 6	53.7	23.8			4.00	64.0	256						
CIP1	112.2	41.2			4.72	162.0	765						
Waiau 10	49.9	5.9			7.84	57.0	447						
Waiau 9	52.9	5.9			7.84	57.0	447						
Schofield 1	8.0	2.0			0.99	10.9	11						
Schofield 2	8.0	2.0			0.99	10.9	11						
Schofield 3	8.0	2.0			0.99	10.9	11						
Schofield 4	8.0	2.0			0.99	10.9	11						
Schofield 5	8.0	2.0			0.99	10.9	11						
Schofield 6	8.0	2.0			0.99	10.9	11						
Honolulu 8	0.0	0.0			1.99	62.5	124	0.0	Synch. Cond.		0.0	Synch. Cond.	
Honolulu 9	0.0	0.0			1.95	64.0	125	0.0	Synch. Cond.		0.0	Synch. Cond.	
Total Wind	133	0						21%	28		29%	38	
-Kahuku	30	0							6			4	
-Kawailoa	69	0							13			10	
-Na Pua Makani	24	0							8			21	
-Future Wind	10	0							1			3	
DG-PV	664	0						66%	438		55%	366	
Station PV	163	0						81%	132		80%	130	
Total Kinetic Energy									4070			2457	
Total Load									1179			891	
Total Thermal Generation									581			357	
Total Renewable Generation									598			534	
Total Generation									1179			891	
Excess Generation									0			0	
Total Up Regulation									144			138	
Total Down Regulation									286			140	
Legacy DG-PV	59.3Hz Capacity			73.8				59.3Hz Output		48.7	59.3Hz Output		40.7
	60.5Hz Capacity			105.7				60.5Hz Output		69.7	60.5Hz Output		58.3

Table O-12. Unit Commitment and Dispatch Sensitivity

Table O-12 shows the revised dispatch for this analysis. The output of AES was reduced to 134 MW and the outputs of Kahe 5 and Kahe 6 were increased to meet system load.

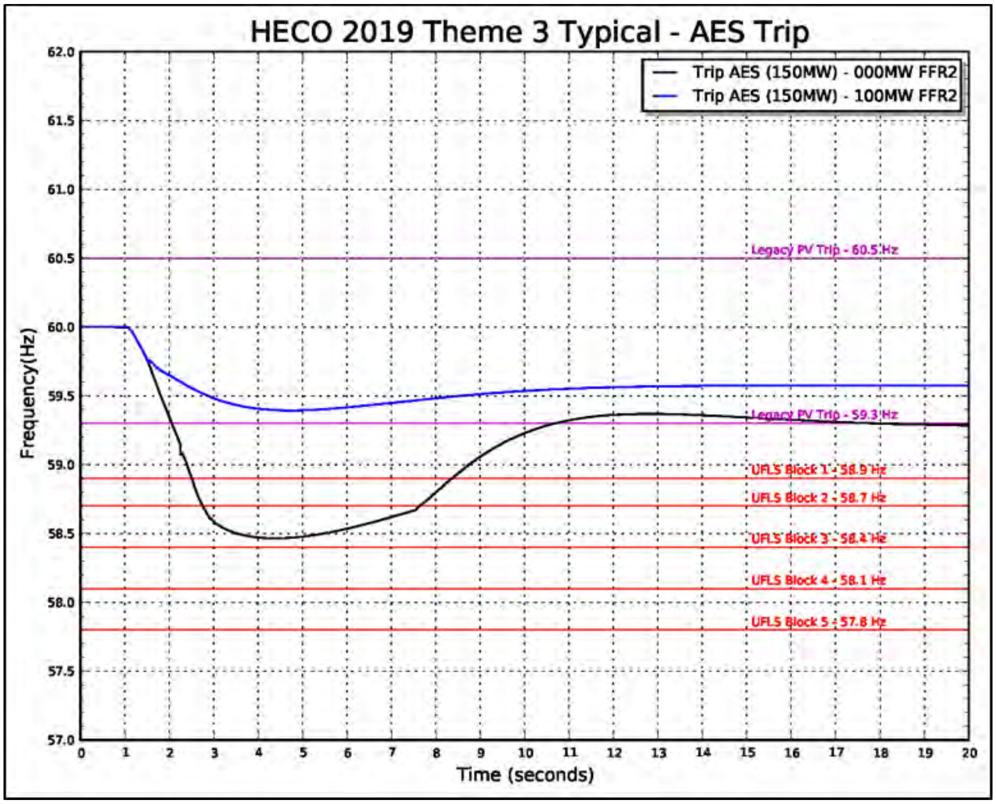


Figure O-17. Frequency Response Profile FFR2 Sensitivity Typical Hour

Figure O-17 shows the frequency response profile for an AES turbine trip dispatched at 134 MW while supplying 16 MW of auxiliary load (150 MW net loss of generation) for a typical hour. System kinetic energy is 4070 MW-sec and the capacity of legacy PV that will disconnect from the system is approximately 49 MW. With no FFR2, the frequency nadir breaches 58.5 Hz and two blocks of UFLS are required to stabilize system frequency. The capacity of FFR2 required to bring the system into compliance with TPL-001 is 100 MW.

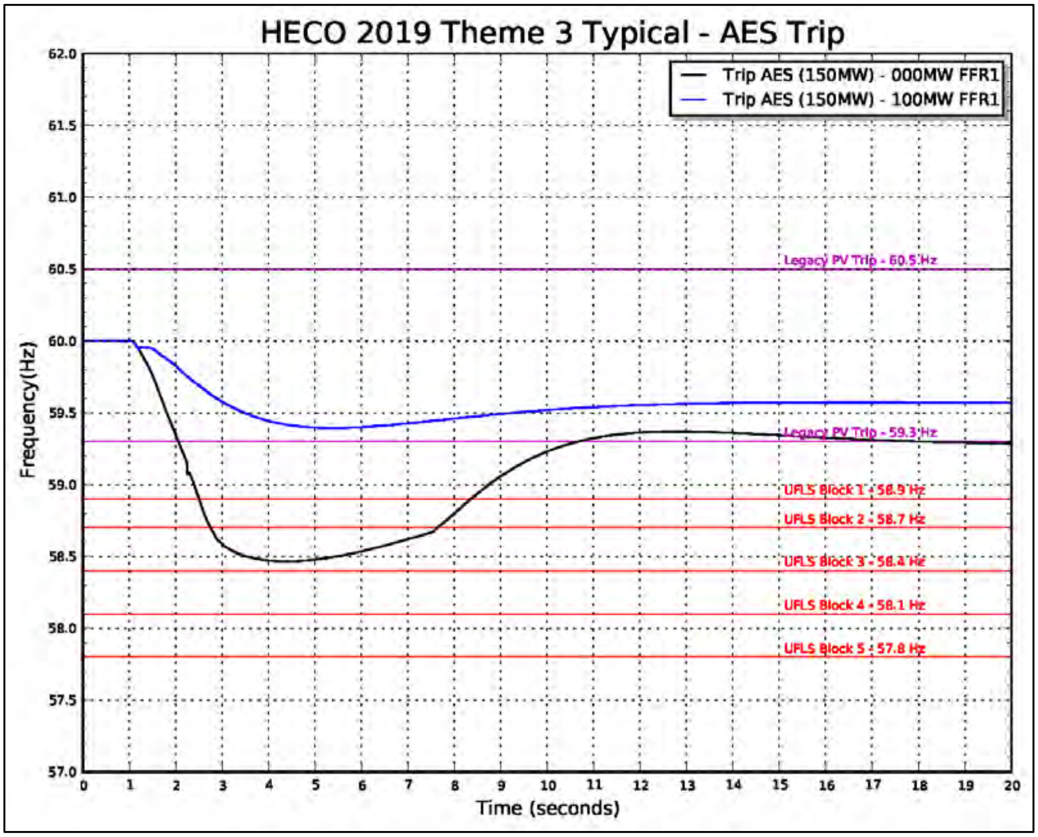


Figure O-18. Frequency Response Profile FFR1Sensitivity Typical Hour

Figure O-18 shows the frequency response profile for this analysis. The capacity of FFR1 required to bring the system into compliance with TPL-001 is 100 MW.

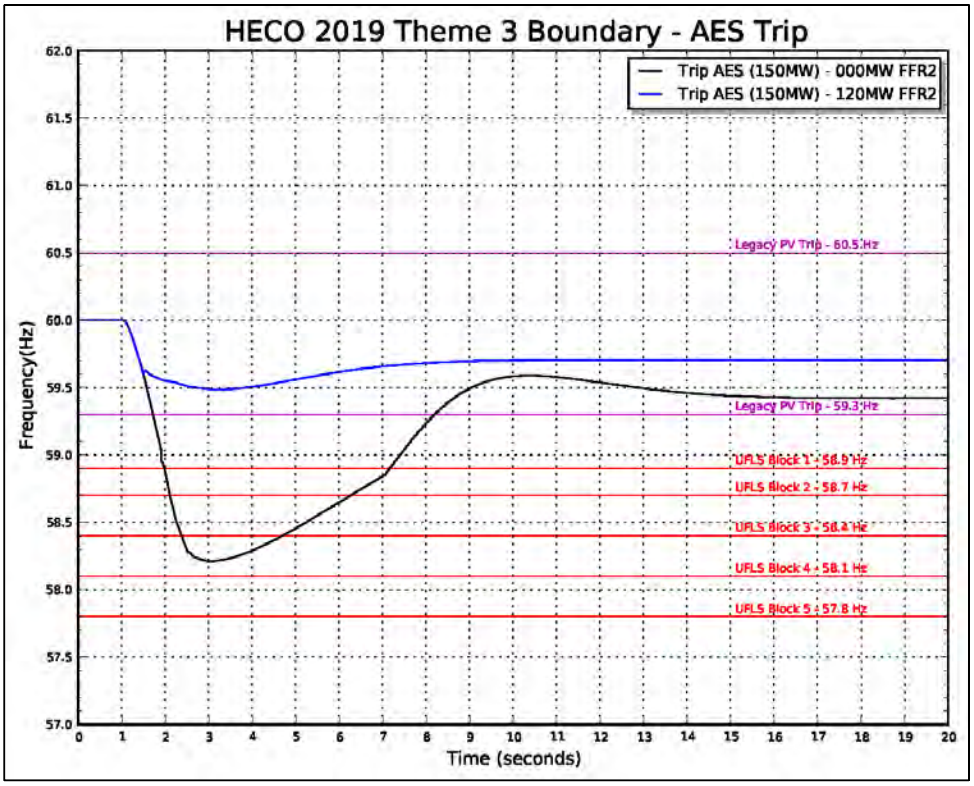


Figure O-19. Frequency Response Profile FFR2 Sensitivity Boundary Hour

Figure O-19 shows the frequency response profile for an AES turbine trip dispatched at 134 MW while supplying 16 MW of auxiliary load (150 MW net loss of generation) for a typical hour. System kinetic energy is 2457 MW-sec and the capacity of legacy PV that will disconnect from the system is approximately 41 MW. With no FFR2, the frequency nadir reaches 58.3 Hz and three blocks of UFLS are required to stabilize system frequency. The capacity of FFR2 required to bring the system into compliance with TPL-001 is 120 MW.

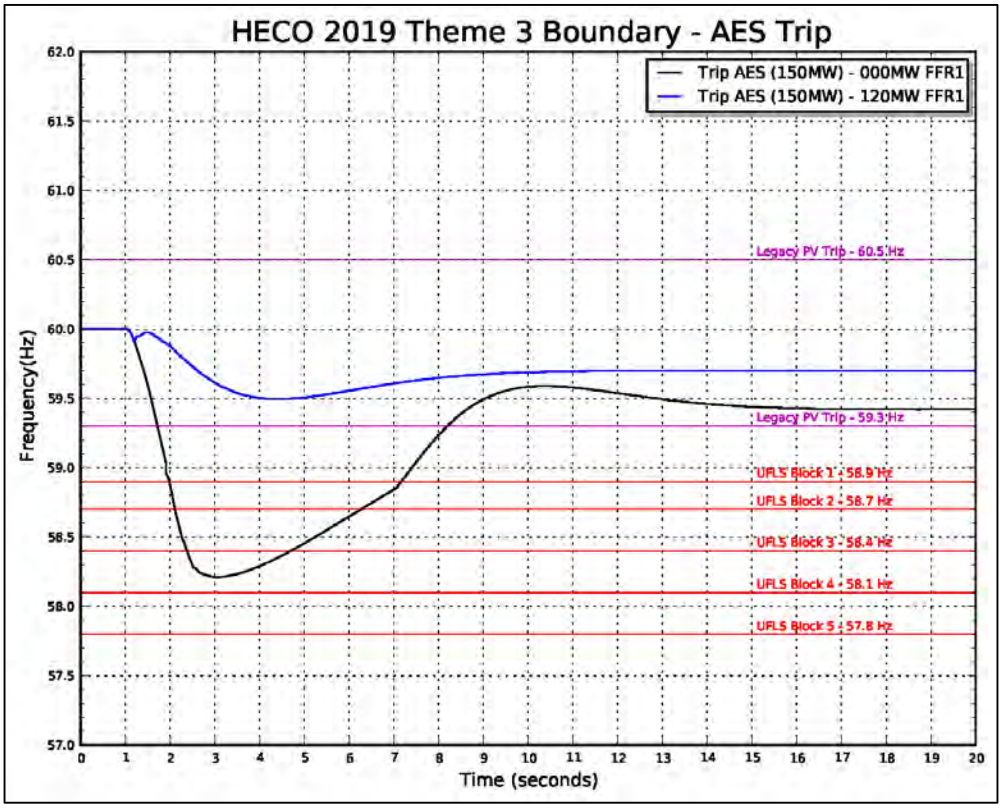


Figure O-20. Frequency Response Profile FFR1 Sensitivity Boundary Hour

Figure O-20 shows the frequency response profile for this analysis. The capacity of FFR1required to bring the system into compliance with TPL-001 is 120 MW.

138 kV Fault Analysis

Simulations were performed for 39 transmission system breakers. A three-phase fault was placed on a transmission line to evaluate system performance for normally cleared and delayed clearing faults. Normally cleared faults are isolated in 5-cycles and delayed clearing faults are isolated in 18-cycles to simulate a breaker that fails to open. Simulations for the normally cleared faults did not produce any system security issues.

2019 138 kV Fault Analysis						
Circuit Outage	Bus Fault	Bkr Fail	BFTD	2nd Outage	Typical Hour Condition	Boundary Hour Condition
AES-CEIP 1	AES	320	15	AES-HP	Unstable	Unstable
AES-HP	AES	320	15	AES-CEIP 1	Unstable	No Plot
AES-CEIP 2	AES	323	15	AES Gen	Stable	Stable
AES-Kalaeloa	AES	456	15	CIP Gen	Unstable	Unstable
AES-CEIP 1	CEIP	276	18	Kahe-CEIP 2	Unstable	Unstable
Kahe-CEIP 2	CEIP	276	18	AES-CEIP 1	Unstable	Unstable
AES-CEIP 2	CEIP	279	18	CEIP-Ewa Nui	Unstable	Unstable
CEIP-Ewa Nui	CEIP	279	18	AES-CEIP 2	Unstable	Unstable
CEIP-Ewa Nui	EWA	384	18	Waiau-Ewa Nui 2	Stable	Unstable
Waiau-Ewa Nui 2	EWA	384	18	CEIP-Ewa Nui	Unstable	Unstable
Kalaeloa-Ewa Nui	EWA	387	18	Waiau-Ewa Nui 1	Stable	Unstable
Waiau-Ewa Nui 1	EWA	387	18	Kalaeloa-Ewa Nui	Unstable	Unstable
Halawa-Iwilei	HLWA	158	18	Halawa-Makalapa	Stable	Unstable
Halawa-Makalapa	HLWA	158	18	Halawa-Iwilei	Stable	Unstable
Halawa-School	HLWA	161	18	Kahe-Halawa 1	Stable	Unstable
Kahe-Halawa 1	HLWA	161	18	Halawa-School	Stable	Unstable
Halawa-Koolau	HLWA	176	18	Kahe-Halawa 2	Stable	Unstable
Kahe-Halawa 2	HLWA	176	18	Halawa-Koolau	Stable	Unstable
Kahe-Wahiawa	KAHE	129	18	K1 Gen	Unstable	Unstable
Kahe-Halawa 2	KAHE	132	18	K2 Gen	Unstable	Unstable
Kahe-Halawa 1	KAHE	168	18	K3 Gen	Unstable	Unstable
Kahe-Waiau	KAHE	171	18	K4 Gen	Unstable	Unstable
Kahe-CEIP 2	KAHE	246	18	K5 Gen	Stable	Unstable
Kahe-CEIP 1	KAHE	249	18	K6 Gen	Stable	Unstable
Kalaeloa-Ewa Nui	KPLP	310	18	Kal2 Gen	Unstable	Unstable
AES-Kalaeloa	KPLP	313	18	Kal1 Gen	Stable	Stable
Waiau-Makalapa 1	MKLPA	260	18	Makalapa Tsf 3	Stable	Unstable
Halawa-Makalapa	MKLPA	263	18	Waiau-Makalapa 2	Stable	Unstable
Waiau-Makalapa 2	MKLPA	263	18	Halawa-Makalapa	Stable	Unstable
Makalapa-Airport	MKLPA	266	18	Makalapa Tsf 1	Stable	Unstable
Kahe-Waiau	WAIAU	102	18	W5 Gen	Stable	Unstable
Waiau-Koolau 2	WAIAU	105	18	W6 Gen	Stable	Unstable
Waiau-Wahiawa	WAIAU	108	18	W8 Gen	Stable	Unstable
Waiau-Koolau 1	WAIAU	111	18	W7 Gen	Stable	Unstable
Waiau-Ewa Nui 1	WAIAU	179	18	Waiau-Makalapa 2	Stable	Unstable
Waiau-Makalapa 2	WAIAU	179	18	Waiau-Ewa Nui 1	Unstable	Unstable
Waiau-Ewa Nui 2	WAIAU	302	18	Waiau-Makalapa 1	Stable	Unstable
Waiau-Makalapa 1	WAIAU	302	18	Waiau-Ewa Nui 2	Unstable	Unstable
Waiau-Wahiawa	WHWA	145	18	Wahiawa Tsf 3	Stable	Stable

Table O-13. Summary of Results for the 2019 Breaker Failure Analysis

Table O-13 shows the results of the breaker failure analysis. For the typical hour, 16 simulations resulted in unstable operation. For the boundary hour, 36 simulations resulted in unstable operation. One simulation for the boundary hour could not be solved.

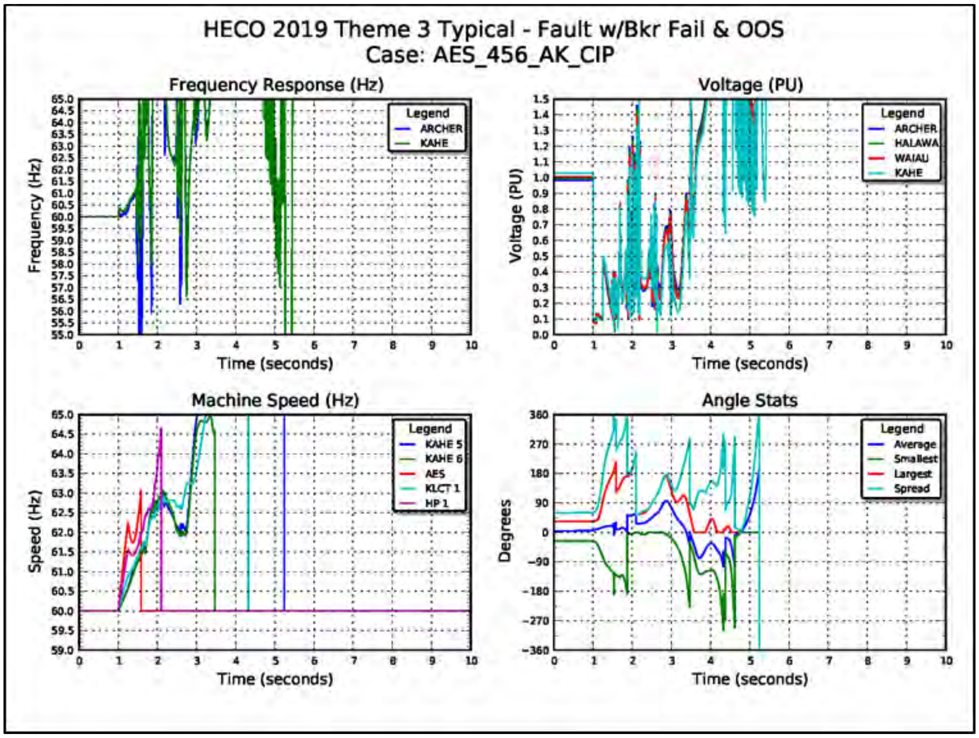


Figure O-21. System Performance for BKR 456 Failure Analysis

Figure O-21 shows four plots that illustrate unstable operation for a fault on the AES-Kalaeloa line and BKR 456 fails to operate. The Machine Speed plot shows Kahe 5 (blue) and Kalaeloa CT1 (teal) losing synchronism with the system. More analysis is required to determine mitigation alternatives for rotor angle instability.

Theme 1 – Aggressive Renewables

Summary

System security analyses were not performed on a specific resource plan for Theme 1 in the time available. High-level fatal flaw assessments were performed on the Theme 1 2045 plans by applying system security requirements for Themes 2 and 3.

Theme 2 – LNG Plan

2023

System security analysis was performed on two hours that were selected from the Theme 2 production cost simulations that represents a typical hour and a boundary condition.

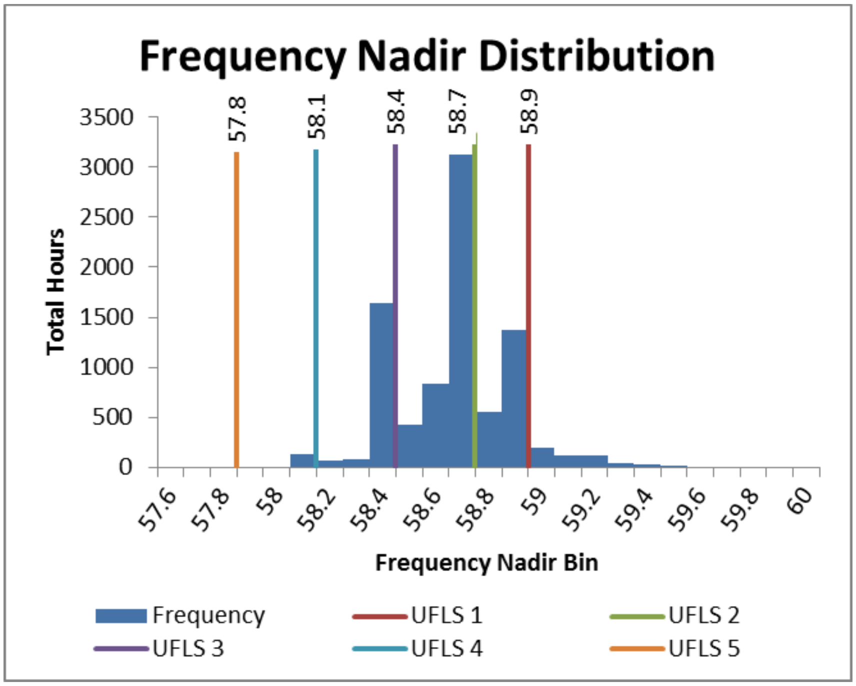


Figure O-22. Frequency Nadir Histogram for 2023

Figure O-22 is a histogram of the expected frequency nadirs for N-1 generator contingency events for the entire year. The typical hour selected from the maximum distribution of 1636 hours was 3:00 PM on Tuesday, August 22. The frequency nadir range for the typical hour is 58.3 – 58.4 Hz that requires two blocks of UFLS to stabilize system frequency.

The boundary hour selected from a minimum distribution of 129 hours was 5:00 AM on Sunday, September 3. The frequency nadir range for the boundary hour is 58.1 – 58.2 Hz that requires four blocks of UFLS to stabilize system frequency.

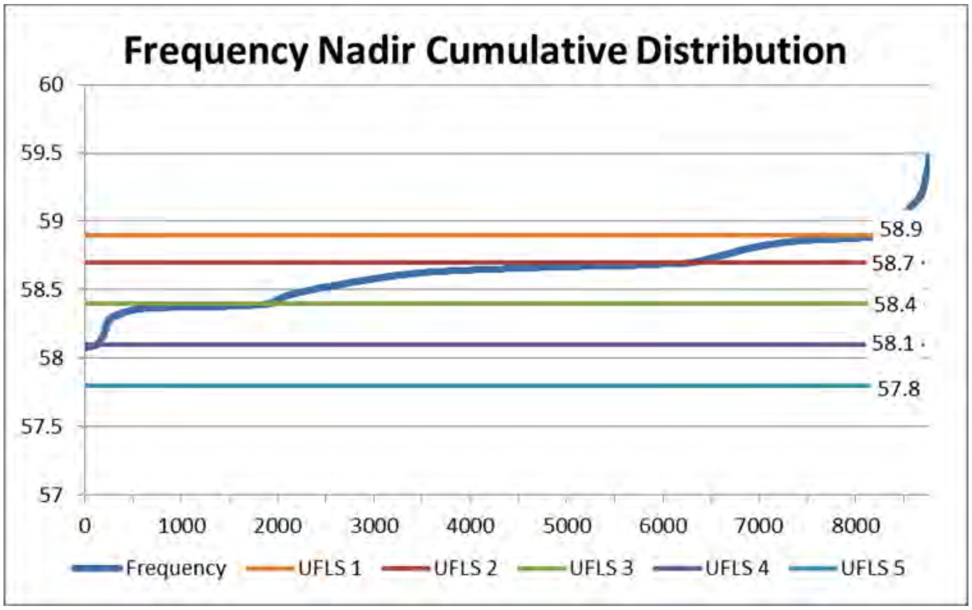


Figure O-23. Frequency Nadir Duration Curve for 2023

Figure O-23 shows the frequency nadir duration curve for 2023.

Unit Commitment Order	Unit Ratings							Theme 2 - HECO 2023 (Typical) Tue 8/22/23 Hour 15			Theme 2 - HECO 2023 (Boundary) Sun 9/3/23 Hour 5		
	Pmax	Pmin	VPO Max	VPO Min	Inertia H	Unit MVA	Unit K.E.	Pgen	up reg (spin)	down reg	Pgen	up reg (spin)	down reg
HPOWER-1	46.0	25.0			2.78	75.0	209	45.0	1.0	20.0	35.0	11.0	10.0
HPOWER-2	22.5	10.0			3.41	42.1	144	21.0	1.5	11.0			
Kalaeloa CT-1	84.0	29.0			4.96	119.2	591	80.0	4.0	51.0	84.0	0.0	55.0
Kalaeloa ST	40.0	10.0			4.70	61.1	287	10.0	30.0	0.0	38.0	2.0	28.0
GE-CT1	77.0	42.0			3.40	98.5	335	72.0	5.0	30.0	77.0	0.0	35.0
GE-CT2	77.0	42.0			3.40	98.5	335				77.0	0.0	35.0
GE-CT3	77.0	42.0			3.40	98.5	335				77.0	0.0	35.0
GE-ST1	152.0	22.0			7.60	200.0	1520	22.0	130.0	0.0	152.0	0.0	130.0
Kalaeloa CT-2	84.0	29.0			4.96	119.2	591				84.0	0.0	55.0
Kahe 5	134.6	64.7			4.36	158.8	692						
Kahe 6	133.8	63.9			4.36	158.8	692						
Waiau 8	86.2	24.1	25.0	5.0	4.44	96.0	426						
Waiau 7	83.3	23.8	25.0	5.0	4.44	96.0	426						
KMCBH 1	9.2	4.6			0.99	10.9	11						
KMCBH 2	9.2	4.6			0.99	10.9	11						
KMCBH 3	9.2	4.6			0.99	10.9	11						
JBPHH 1	16.8	6.7			0.99	21.8	22						
JBPHH 2	16.8	6.7			0.99	21.8	22						
JBPHH 3	16.8	6.7			0.99	21.8	22						
JBPHH 4	16.8	6.7			0.99	21.8	22						
JBPHH 5	16.8	6.7			0.99	21.8	22						
JBPHH 6	16.8	6.7			0.99	21.8	22						
Waiau 5	54.5	23.5			4.07	64.0	261						
Waiau 6	53.7	23.8			4.00	64.0	256						
Waiau 10	49.9	5.9			7.84	57.0	447						
Waiau 9	52.9	5.9			7.84	57.0	447						
CIP1	112.2	41.2			4.72	162.0	765						
Schofield 1	8.0	2.0			0.99	10.9	11						
Schofield 2	8.0	2.0			0.99	10.9	11						
Schofield 3	8.0	2.0			0.99	10.9	11						
Schofield 4	8.0	2.0			0.99	10.9	11						
Schofield 5	8.0	2.0			0.99	10.9	11						
Schofield 6	8.0	2.0			0.99	10.9	11						
Honolulu 8	0.0	0.0			1.99	62.5	124	0.0	Synch. Cond.		0.0	Synch. Cond.	
Honolulu 9	0.0	0.0			1.95	64.0	125	0.0	Synch. Cond.		0.0	Synch. Cond.	
Kahe 1	0.0	0.0			2.05	96.0	197	0.0	Synch. Cond.		0.0	Synch. Cond.	
Kahe 2	0.0	0.0			2.05	96.0	197	0.0	Synch. Cond.		0.0	Synch. Cond.	
Kahe 3	0.0	0.0			1.71	101.0	173	0.0	Synch. Cond.		0.0	Synch. Cond.	
Total Wind	153	0						37			19		
-Kahuku	30	0						4			4		
-Kawailoa	69	0						16			6		
-Na Pua Makani	24	0						14			0		
-Future Wind	30	0						3			9		
DG-PV	807	0						489			0		
Station PV	783	0						449			0		
Total Kinetic Energy									3334			4452	
Total Load									1225			643	
Total Thermal Generation									250			624	
Total Renewable Generation									975			19	
Total Generation									1225			643	
Excess Generation									0			0	
Total Up Regulation									172			13	
Total Down Regulation									112			383	
Legacy DG-PV	59.3Hz Capacity			73.8				59.3Hz Output		44.7	59.3Hz Output		0.0
	60.5Hz Capacity			105.7				60.5Hz Output		64.0	60.5Hz Output		0.0

Table O-14. Commitment and Dispatch 2023

Table O-14 shows the unit commitment and dispatch for the typical hour (8/22/2023, 3:00 PM) and boundary hour (9/3/2023, 5:00 AM).

Loss of Generation

Simulations were performed for the largest loss of generation contingency event to determine the frequency response reserve requirements to bring the system into compliance with TPL-001.

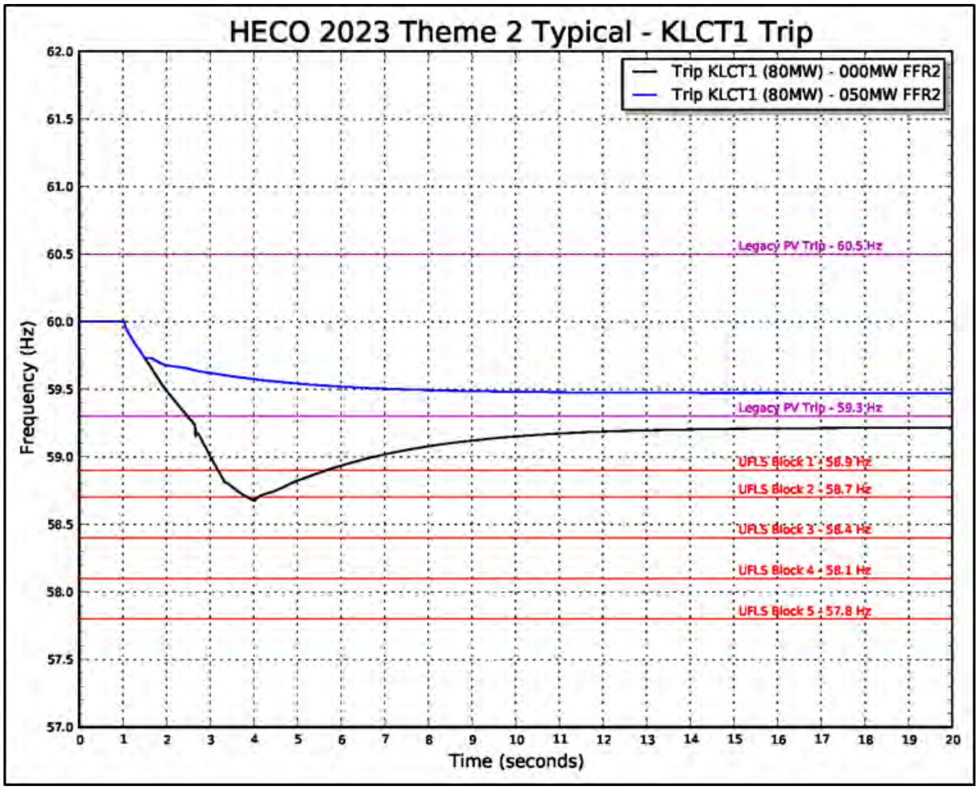


Figure O-24. Frequency Response Profile for FFR2 Typical Hour

Figure O-24 shows the frequency response profile for a Kalaeloa CT1 trip, the largest contingency at that time, at 80 MW for a typical hour. System kinetic energy is 3334 MW-sec and the capacity of legacy PV that will disconnect from the system is approximately 45 MW. With no FFR2, the frequency nadir reaches 58.7 Hz and two blocks of UFLS are required to stabilize system frequency. The capacity of FFR2 required to bring the system into compliance with TPL-001 is 50 MW.

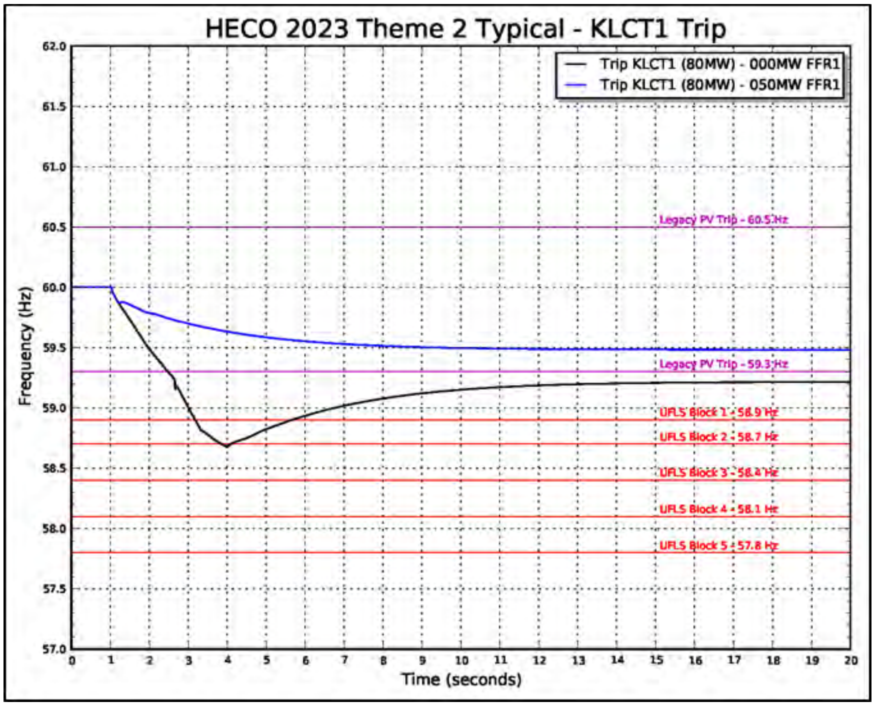


Figure O-25. Frequency Response Profile for FFR1 Typical Hour

Figure O-25 shows the frequency response profile for the FFR1 analysis. The capacity of FFR1 required to bring the system into compliance with TPL-001 is 50 MW.

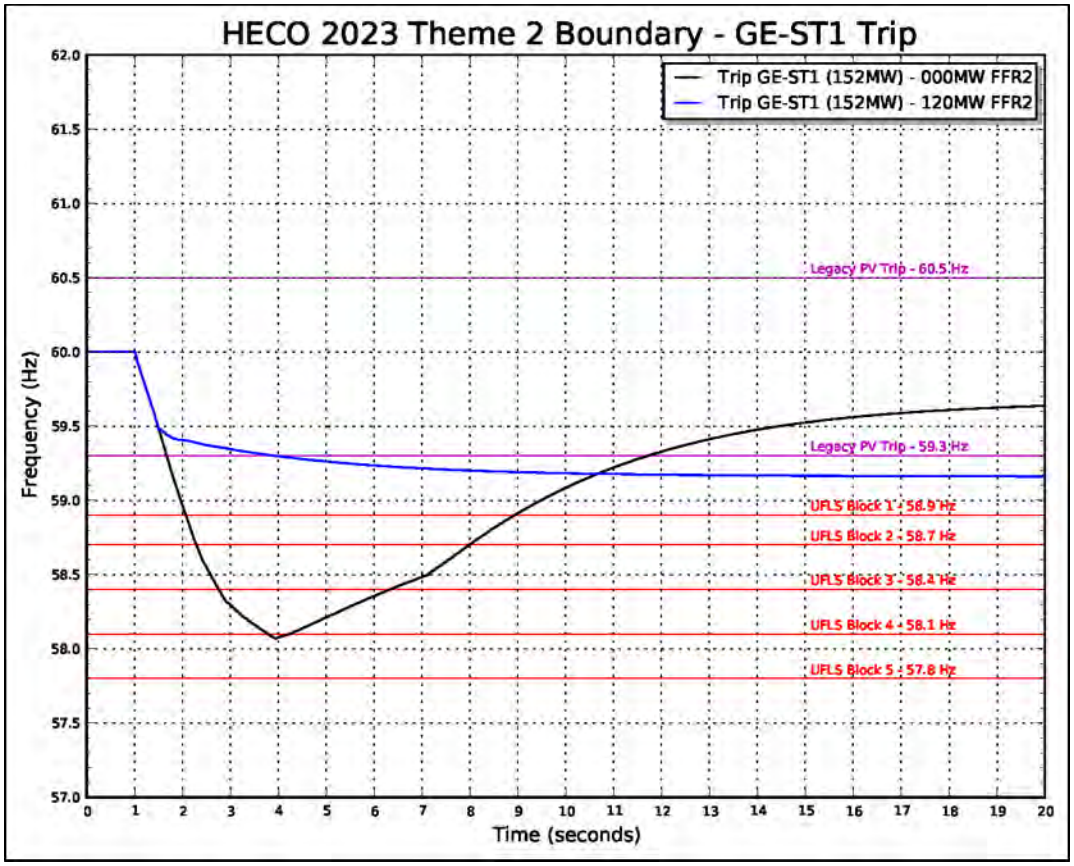


Figure O-26. Frequency Response Profile for FFR2 Boundary Hour

Figure O-26 shows the frequency response profile for a GE single train combined cycle (STCC) trip at 120 MW for a boundary hour. System kinetic energy is 4452 MW-sec. With no FFR2, the frequency nadir breaches 58.1 Hz and four blocks of UFLS are required to stabilize system frequency. The capacity of FFR2 required to bring the system into compliance with TPL-001 is 120 MW.

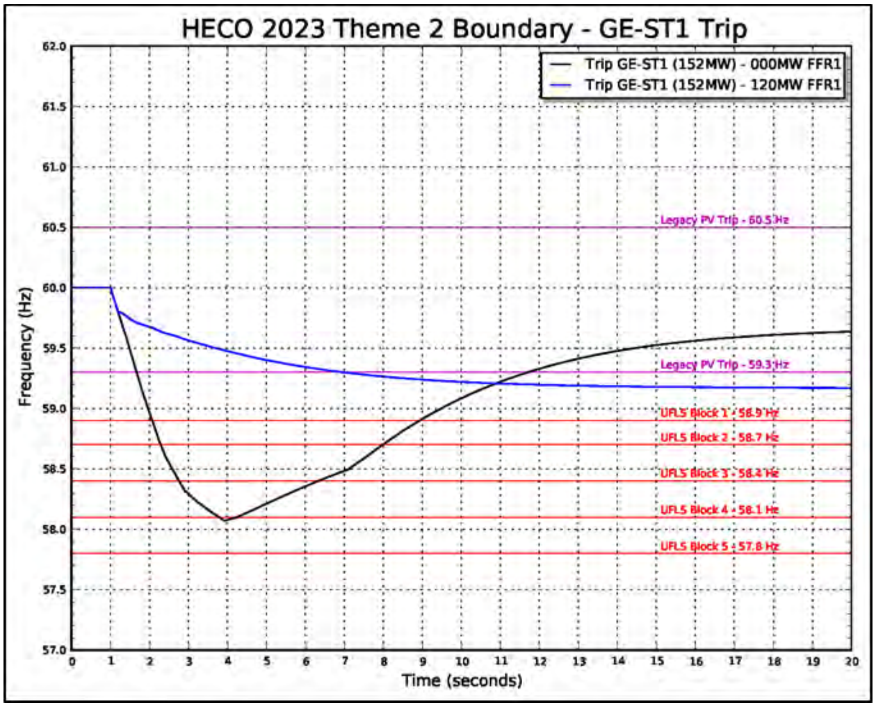


Figure O-27. Frequency Response Profile for FFR1 Boundary Hour

Figure O-27 shows the frequency response profile for the FFR1 analysis. The capacity of FFR1 required to bring the system into compliance with TPL-001 is 120 MW.

138 kV Fault Analysis

Simulations were performed for 39 transmission system breakers. A three-phase fault was placed on a transmission line to evaluate system performance for normally cleared and delayed clearing faults. Normally cleared faults are isolated in 5-cycles and delayed clearing faults are isolated in 18-cycles to simulate a breaker that fails to open. Simulations for the normally cleared faults did not produce any system security issues.

2023 138 kV Fault Analysis						
Circuit Outage	Bus Fault	Bkr Fail	BFTD	2nd Outage	Typical Hour Condition	Boundary Hour Condition
AES-CEIP 1	AES	320	15	AES-HP	Unstable	Stable
AES-HP	AES	320	15	AES-CEIP 1	Unstable	Stable
AES-CEIP 2	AES	323	15	AES Gen	Stable	Stable
AES-Kalaeloa	AES	456	15	CIP Gen	Stable	Stable
AES-CEIP 1	CEIP	276	18	Kahe-CEIP 2	Unstable	Unstable
Kahe-CEIP 2	CEIP	276	18	AES-CEIP 1	Unstable	Unstable
AES-CEIP 2	CEIP	279	18	CEIP-Ewa Nui	Unstable	Unstable
CEIP-Ewa Nui	CEIP	279	18	AES-CEIP 2	Unstable	Unstable
CEIP-Ewa Nui	EWA	384	18	Waiau-Ewa Nui 2	Unstable	Stable
Waiau-Ewa Nui 2	EWA	384	18	CEIP-Ewa Nui	Unstable	Stable
Kalaeloa-Ewa Nui	EWA	387	18	Waiau-Ewa Nui 1	Unstable	Stable
Waiau-Ewa Nui 1	EWA	387	18	Kalaeloa-Ewa Nui	Unstable	Stable
Halawa-Iwilei	HLWA	158	18	Halawa-Makalapa	Stable	Stable
Halawa-Makalapa	HLWA	158	18	Halawa-Iwilei	Stable	Stable
Halawa-School	HLWA	161	18	Kahe-Halawa 1	Stable	Stable
Kahe-Halawa 1	HLWA	161	18	Halawa-School	Unstable	Stable
Halawa-Koolau	HLWA	176	18	Kahe-Halawa 2	Unstable	Stable
Kahe-Halawa 2	HLWA	176	18	Halawa-Koolau	Unstable	Stable
Kahe-Wahiawa	KAHE	129	18	K1 Gen	Unstable	Unstable
Kahe-Halawa 2	KAHE	132	18	K2 Gen	Unstable	Unstable
Kahe-Halawa 1	KAHE	168	18	K3 Gen	Unstable	Unstable
Kahe-Waiau	KAHE	171	18	K4 Gen	Unstable	Unstable
Kahe-CEIP 2	KAHE	246	18	K5 Gen	Unstable	Unstable
Kahe-CEIP 1	KAHE	249	18	K6 Gen	Unstable	Unstable
Kalaeloa-Ewa Nui	KPLP	310	18	Kal2 Gen	Unstable	Unstable
AES-Kalaeloa	KPLP	313	18	Kal1 Gen	Unstable	Stable
Waiau-Makalapa 1	MKLPA	260	18	Makalapa Tsf 3	Stable	Stable
Halawa-Makalapa	MKLPA	263	18	Waiau-Makalapa 2	Stable	Stable
Waiau-Makalapa 2	MKLPA	263	18	Halawa-Makalapa	Stable	Stable
Makalapa-Airport	MKLPA	266	18	Makalapa Tsf 1	Stable	Stable
Kahe-Waiau	WAIAU	102	18	W5 Gen	Stable	Stable
Waiau-Koolau 2	WAIAU	105	18	W6 Gen	Stable	Stable
Waiau-Wahiawa	WAIAU	108	18	W8 Gen	Unstable	Stable
Waiau-Koolau 1	WAIAU	111	18	W7 Gen	Stable	Stable
Waiau-Ewa Nui 1	WAIAU	179	18	Waiau-Makalapa 2	Stable	Stable
Waiau-Makalapa 2	WAIAU	179	18	Waiau-Ewa Nui 1	Stable	Stable
Waiau-Ewa Nui 2	WAIAU	302	18	Waiau-Makalapa 1	Stable	Stable
Waiau-Makalapa 1	WAIAU	302	18	Waiau-Ewa Nui 2	Stable	Stable
Waiau-Wahiawa	WHWA	145	18	Wahiawa Tsf 3	Unstable	Stable

Table O-15. Summary of Results for the 2023 Breaker Failure Analysis

Table O-15 shows the results of the breaker failure analysis. For the typical hour, 19 simulations resulted in unstable operation. For the boundary hour, 11 simulations resulted in unstable operation. System inertia for the boundary hour is higher than the typical hour that could impact rotor angle stability. Further analyses will be performed to determine mitigation alternatives.

2030

System security analysis was performed for two hours that represents a typical hour and a boundary condition.

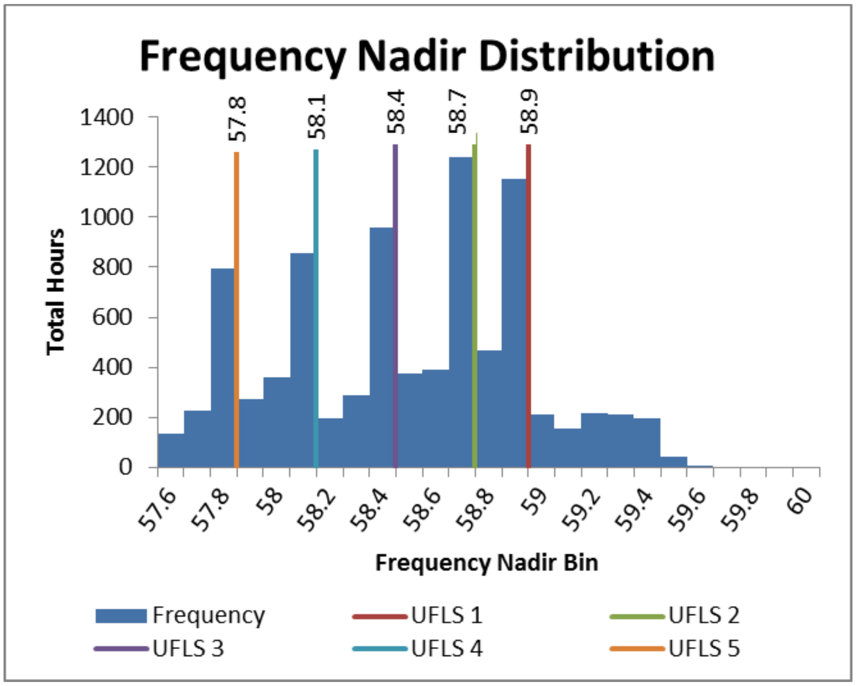


Figure O-28. Frequency Nadir Histogram for 2030

Figure O-28 is a histogram of the expected frequency nadirs for N-1 generator contingency events for the entire year. The typical hour selected from the maximum distribution of 797 hours was 1:00 PM on Friday, April 5. The frequency nadir range for the typical hour is 57.7 – 57.8 Hz that requires five blocks of UFLS to stabilize system frequency.

The boundary hour selected from the minimum distribution of 133 hours was 3:00 AM on Sunday, May 17. The frequency nadir range for the boundary hour is 57.5 – 57.6 Hz that requires five blocks of UFLS to stabilize system frequency.

Hawaiian Electric
Maui Electric
Hawai'i Electric Light

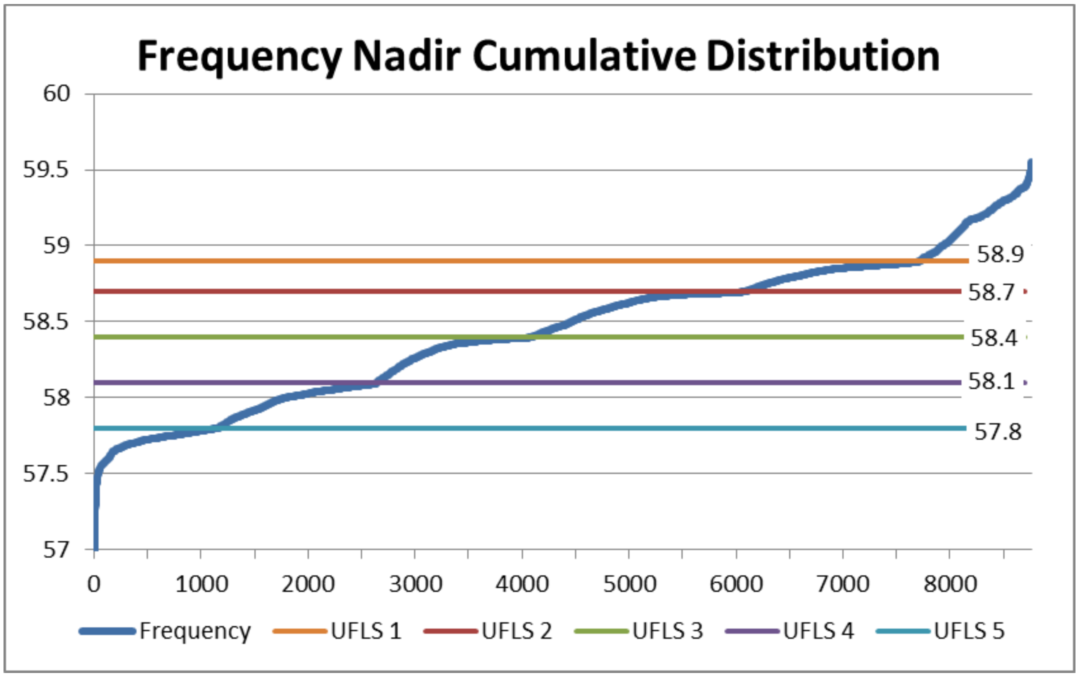


Figure O-29. Frequency Nadir Duration Curve for 2030

Figure O-29 shows the frequency nadir duration curve for 2030.

Unit Commitment Order	Unit Ratings							Theme 2 - HECO 2030 (Typical) Fri 4/5/30 Hour 13			Theme 2 - HECO 2030 (Boundary) Sun 3/17/30 Hour 3		
	Pmax	Pmin			Inertia H	Unit MVA	Unit K.E.	Pgen	up reg (spin)	down reg	Pgen	up reg (spin)	down reg
HPOWER-1	46.0	25.0			2.78	75.0	209	46.0	0.0	21.0	36.0	10.0	11.0
HPOWER-2	22.5	10.0			3.41	42.1	144	22.5	0.0	12.5			
GE-CT1	70.0	36.0			3.40	98.5	335				42.0	28.0	6.0
GE-CT2	75.0	41.0			3.40	98.5	335						
GE-CT3	76.0	41.0			3.40	98.5	335						
GE-ST1	162.0	28.0			7.60	200.0	1520						
Kalaeloa CT-1	84.0	29.0			4.96	119.2	591						
Kalaeloa ST	40.0	10.0			4.70	61.1	287						
Kalaeloa CT-2	84.0	29.0			4.96	119.2	591						
Kahe 5	134.6	64.7			4.36	158.8	692						
Kahe 6	133.8	63.9			4.36	158.8	692						
KMCBH 1	9.2	4.6			0.99	10.9	11						
KMCBH 2	9.2	4.6			0.99	10.9	11						
KMCBH 3	9.2	4.6			0.99	10.9	11						
JBPHH 1	16.8	6.7			0.99	21.8	22						
JBPHH 2	16.8	6.7			0.99	21.8	22						
JBPHH 3	16.8	6.7			0.99	21.8	22						
JBPHH 4	16.8	6.7			0.99	21.8	22						
JBPHH 5	16.8	6.7			0.99	21.8	22						
JBPHH 6	16.8	6.7			0.99	21.8	22						
Waiau 10	49.9	5.9			7.84	57.0	447						
CIP1	112.2	41.2			4.72	162.0	765						
Waiau 9	52.9	5.9			7.84	57.0	447						
Schofield 1	8.0	2.0			0.99	10.9	11						
Schofield 2	8.0	2.0			0.99	10.9	11						
Schofield 3	8.0	2.0			0.99	10.9	11						
Schofield 4	8.0	2.0			0.99	10.9	11						
Schofield 5	8.0	2.0			0.99	10.9	11						
Schofield 6	8.0	2.0			0.99	10.9	11						
Honolulu 8	0.0	0.0			1.99	62.5	124	0.0	Synch. Cond.		0.0	Synch. Cond.	
Honolulu 9	0.0	0.0			1.95	64.0	125	0.0	Synch. Cond.		0.0	Synch. Cond.	
Kahe 3	0.0	0.0			1.71	101.0	173	0.0	Synch. Cond.		0.0	Synch. Cond.	
Kahe 2	0.0	0.0			2.05	96.0	197	0.0	Synch. Cond.		0.0	Synch. Cond.	
Kahe 1	0.0	0.0			2.05	96.0	197	0.0	Synch. Cond.		0.0	Synch. Cond.	
Total Wind	553	0						202			433		
-Kahuku	30	0						21			13		
-Kawailoa	69	0						21			14		
-Na Pua Makani	24	0						21			21		
-Future Wind	30	0						6			6		
-Offshore Wind	400	0						133			379		
DG-PV	1354	0						715			0		
Station PV	783	0						218			0		
Total Kinetic Energy									1168			1359	
Total Load									1203			511	
Total Thermal Generation									69			78	
Total Renewable Generation									1135			433	
Total Generation									1203			511	
Excess Generation									0			0	
Total Up Regulation									0			38	
Total Down Regulation									34			17	
Legacy DG-PV	59.3Hz Capacity		73.8					59.3Hz Output		39.0	59.3Hz Output		0.0
	60.5Hz Capacity		105.7					60.5Hz Output		55.8	60.5Hz Output		0.0

Table O-16. Unit Commitment and Dispatch 2030

Table O-16 shows the unit commitment and dispatch for the typical and boundary hours. Simulations were performed for these system conditions to determine system security requirements.

Loss of Generation

Simulations were performed for the largest loss of generation contingency event to determine the frequency response reserves requirements to bring the system into compliance with TPL-001.

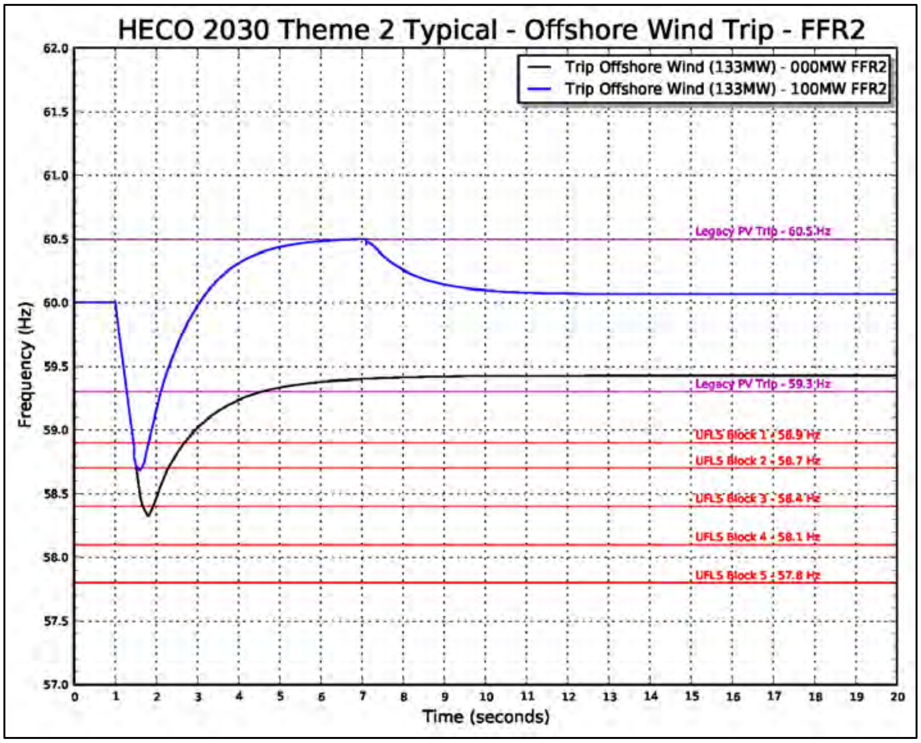


Figure O-30. Frequency Response Profile for FFR2 Typical Hour

Figure O-30 shows the frequency response profile for a cable trip of an offshore wind turbine carrying 133 MW for a typical hour. System kinetic energy is 1168 MW-sec and the capacity of legacy PV that will disconnect from the system is 39 MW. With no FFR2, the frequency nadir breaches 58.4 Hz requiring 3 blocks of UFLS to stabilize system frequency. Simulations of 100 MW of FFR2 in conjunction with the 2 blocks of UFLS over compensates for this contingency, causing system frequency to exceed 60.5 Hz. The 30-cycle time delay is too long to dispatch FFR2, indicating that there is no amount of FFR2 that will bring the system into compliance with TPL-001.

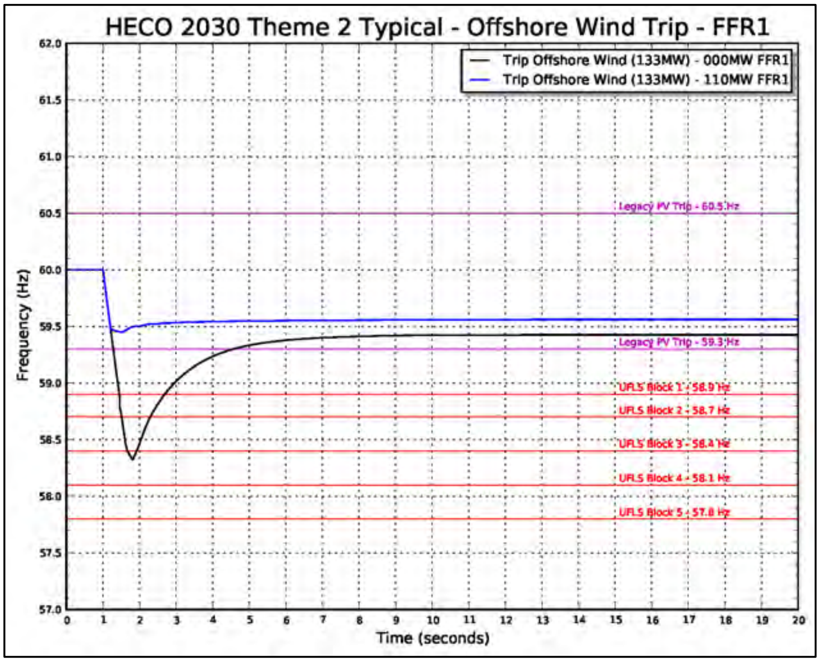


Figure O-31. Frequency Response Profile for FFR1 Typical Hour

Figure O-31 shows the frequency response profile for the FFR1 analysis. The capacity of FFR1 required to bring the system into compliance with TPL-001 is 110 MW.

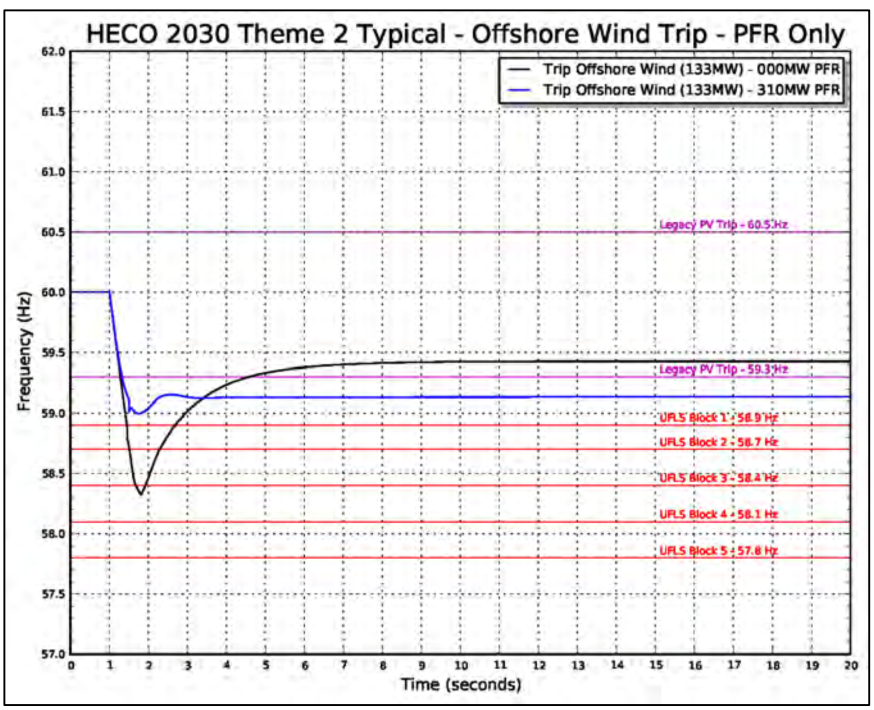


Figure O-32. Frequency Response Profile for PFR Typical Hour

Figure O-32 shows the frequency response profile for the PFR analysis. The capacity of PFR required to bring the system into compliance with TPL-001 is 310 MW.

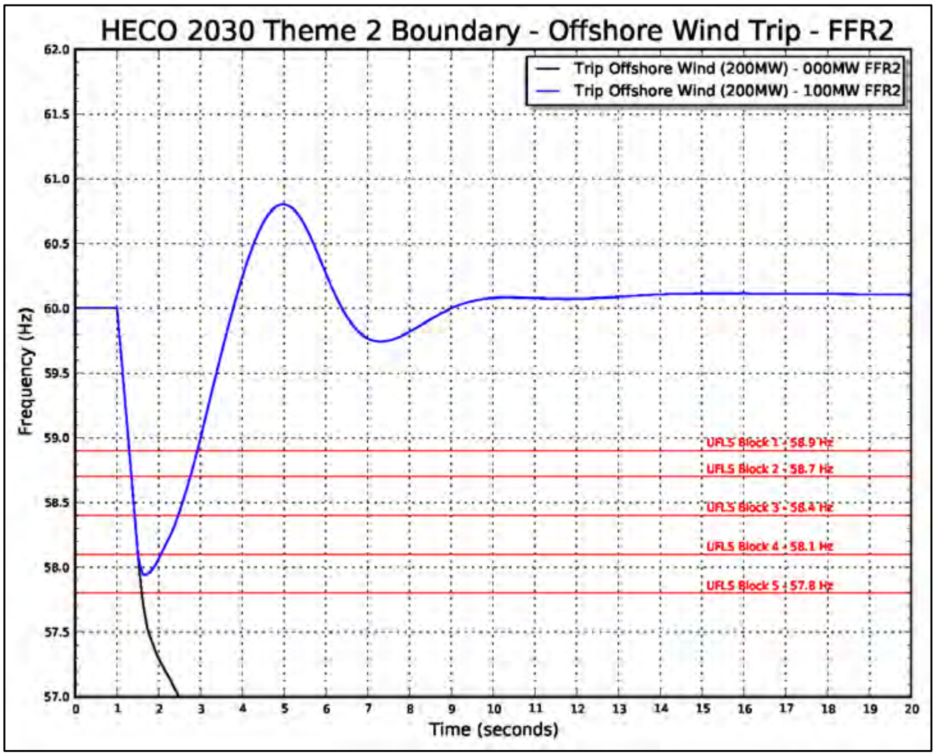


Figure O-33. Frequency Response Profile for FFR2 Boundary Hour

Figure O-33 shows the frequency response profile for a cable trip of an offshore wind turbine carrying 200 MW for a boundary hour. System kinetic energy is 1359 MW-sec. With 100 MW of FFR2, the frequency nadir breaches 58.0 Hz that initiates 4 blocks of UFLS. The 100 MW of FFR2 in conjunction with the 4 blocks of UFLS over compensates for this contingency and causes system frequency to exceed 60.5 Hz. Therefore, there is no amount of FFR2 that will bring the system into compliance with TPL-001.

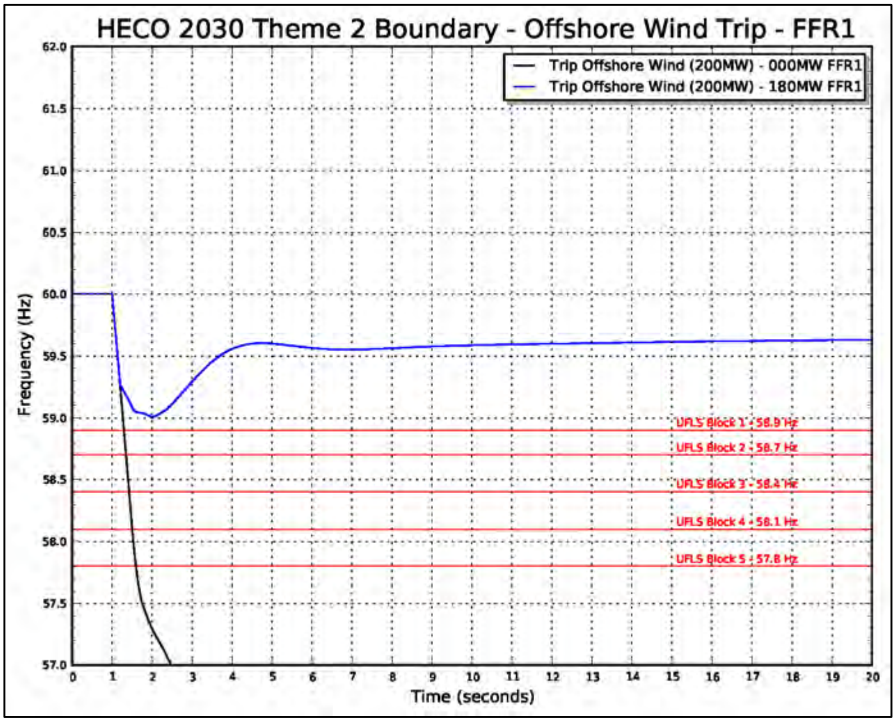


Figure O-34. Frequency Response Profile for FFR1 Boundary Hour

Figure O-34 shows the frequency response profile for the FFR1 analysis. The capacity of FFR1 required to bring the system into compliance with TPL-001 is 180 MW.

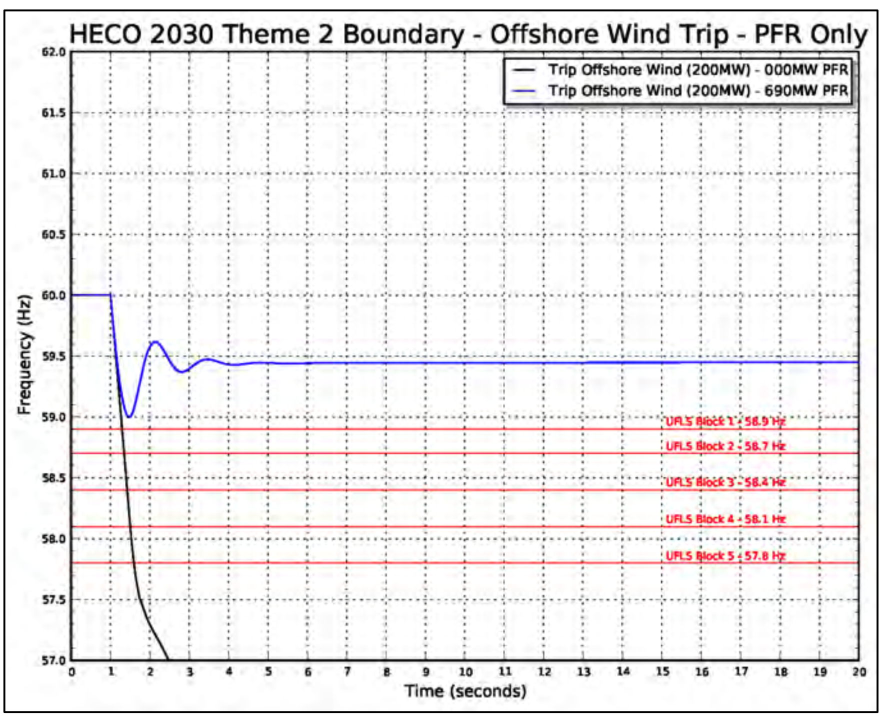


Figure O-35. Frequency Response Profile for PFR Boundary Hour

Figure O-35 shows the frequency response profile for the PFR analysis. The capacity of PFR required to bring the system into compliance with TPL-001 is 690 MW.

138 kV Fault Analysis

Simulations were performed for electrical faults on the 138 kV transmission system busses. A three-phase fault was placed on 39 busses to evaluate system performance to normally cleared and delayed clearing faults. Normally cleared faults are isolated in 5-cycles and delayed clearing faults are isolated in 18-cycles to simulate a breaker that fails to open. Simulations for the normally cleared faults did not produce any significant system security issues.

2030 138 kV Fault Analysis						
Circuit Outage	Bus Fault	Bkr Fail	BFTD	2nd Outage	Typical Hour Condition	Boundary Hour Condition
AES-CEIP 1	AES	320	15	AES-HP	Unstable	Unstable
AES-HP	AES	320	15	AES-CEIP 1	Unstable	Unstable
AES-CEIP 2	AES	323	15	AES Gen	Unstable	Stable
AES-Kalaeloa	AES	456	15	CIP Gen	Unstable	Stable
AES-CEIP 1	CEIP	276	18	Kahe-CEIP 2	Unstable	Stable
Kahe-CEIP 2	CEIP	276	18	AES-CEIP 1	Unstable	Unstable
AES-CEIP 2	CEIP	279	18	CEIP-Ewa Nui	Unstable	Stable
CEIP-Ewa Nui	CEIP	279	18	AES-CEIP 2	Unstable	Unstable
CEIP-Ewa Nui	EWA	384	18	Waiau-Ewa Nui 2	Stable	Stable
Waiau-Ewa Nui 2	EWA	384	18	CEIP-Ewa Nui	Unstable	Stable
Kalaeloa-Ewa Nui	EWA	387	18	Waiau-Ewa Nui 1	Stable	Stable
Waiau-Ewa Nui 1	EWA	387	18	Kalaeloa-Ewa Nui	Unstable	Stable
Halawa-Iwilei	HLWA	158	18	Halawa-Makalapa	Stable	Stable
Halawa-Makalapa	HLWA	158	18	Halawa-Iwilei	Stable	Stable
Halawa-School	HLWA	161	18	Kahe-Halawa 1	Stable	Stable
Kahe-Halawa 1	HLWA	161	18	Halawa-School	Stable	Stable
Halawa-Koolau	HLWA	176	18	Kahe-Halawa 2	Stable	Stable
Kahe-Halawa 2	HLWA	176	18	Halawa-Koolau	Stable	Stable
Kahe-Wahiawa	KAHE	129	18	K1 Gen	Unstable	Stable
Kahe-Halawa 2	KAHE	132	18	K2 Gen	Unstable	Stable
Kahe-Halawa 1	KAHE	168	18	K3 Gen	Unstable	Stable
Kahe-Waiau	KAHE	171	18	K4 Gen	Unstable	Stable
Kahe-CEIP 2	KAHE	246	18	K5 Gen	Unstable	Stable
Kahe-CEIP 1	KAHE	249	18	K6 Gen	Unstable	Stable
Kalaeloa-Ewa Nui	KPLP	310	18	Kal2 Gen	Unstable	Stable
AES-Kalaeloa	KPLP	313	18	Kal1 Gen	Stable	Stable
Waiau-Makalapa 1	MKLPA	260	18	Makalapa Tsf 3	Stable	Stable
Halawa-Makalapa	MKLPA	263	18	Waiau-Makalapa 2	Stable	Stable
Waiau-Makalapa 2	MKLPA	263	18	Halawa-Makalapa	Stable	Stable
Makalapa-Airport	MKLPA	266	18	Makalapa Tsf 1	Stable	Stable
Kahe-Waiau	WAIAU	102	18	W5 Gen	Stable	Unstable
Waiau-Koolau 2	WAIAU	105	18	W6 Gen	Unstable	Unstable
Waiau-Wahiawa	WAIAU	108	18	W8 Gen	Stable	Unstable
Waiau-Koolau 1	WAIAU	111	18	W7 Gen	Unstable	Unstable
Waiau-Ewa Nui 1	WAIAU	179	18	Waiau-Makalapa 2	Stable	Unstable
Waiau-Makalapa 2	WAIAU	179	18	Waiau-Ewa Nui 1	Unstable	Unstable
Waiau-Ewa Nui 2	WAIAU	302	18	Waiau-Makalapa 1	Stable	Unstable
Waiau-Makalapa 1	WAIAU	302	18	Waiau-Ewa Nui 2	Unstable	Unstable
Waiau-Wahiawa	WHWA	145	18	Wahiawa Tsf 3	Stable	Stable

Table O-17. Summary of Results for the 2030 Breaker Failure Analysis

Table O-17 shows the results of the breaker failure analysis. For the typical hour, 21 simulations resulted in unstable operation. For the boundary hour, 12 simulations resulted in unstable operation. System inertia for the boundary hour is higher than the typical hour that could impact rotor angle stability.

2045

System security analysis was performed for two hours that represents a typical hour and a boundary condition. An additional screening metric was applied to select hours when the output from offshore wind was high to simulate the trip of a 200 MW cable.

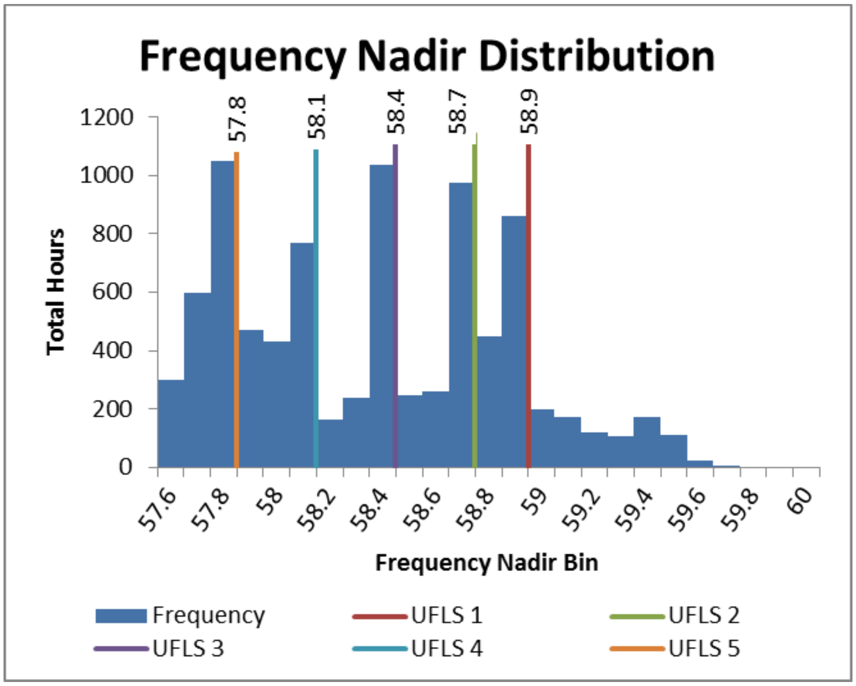


Figure O-36. Frequency Nadir Histogram for 2045

Figure O-36 is a histogram of the expected frequency nadirs for N-1 generator contingency events for the entire year. The typical hour selected from the maximum distribution of 1049 hours was 2:00 PM on Thursday, July 6. The frequency nadir range for the typical hour is 57.7 – 57.8 Hz that requires five blocks of UFLS to stabilize system frequency.

The boundary hour selected from the minimum distribution of 298 hours was 4:00 PM on Sunday, May 15. The frequency nadir range for the boundary hour is 57.5 – 57.6 Hz that requires five blocks of UFLS to stabilize system frequency.

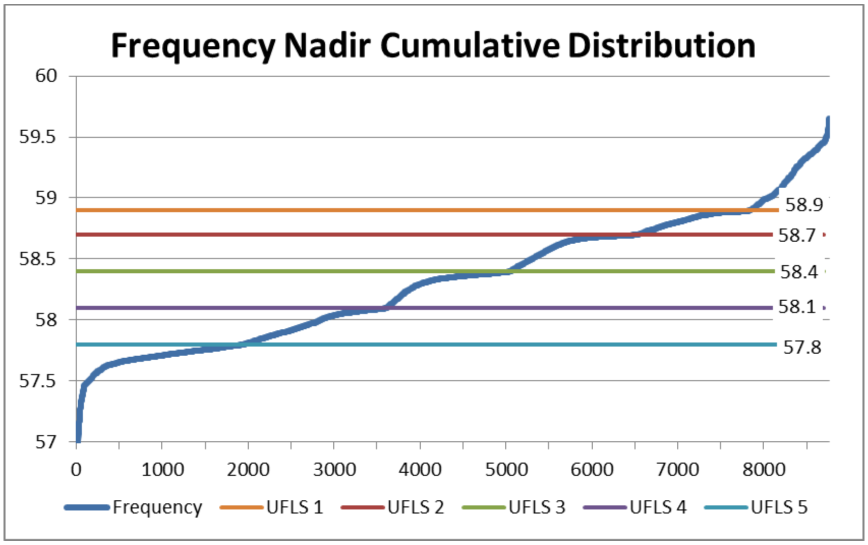


Figure O-37. Frequency Nadir distribution Curve for 2030

Figure O-37 shows the frequency nadir duration curve for 2030.

Unit Commitment Order	Unit Ratings							Theme 2 - HECO 2045 (Typical) Thu 7/6/45 Hour 14			Theme 2 - HECO 2045 (Boundary) Sun 5/14/45 Hour 16		
	Pmax	Pmin			Inertia H	Unit MVA	Unit K.E.	Pgen	up reg (spin)	down reg	Pgen	up reg (spin)	down reg
HPOWER-1	46.0	25.0			2.78	75.0	209	46.0	0.0	21.0	41.0	5.0	16.0
HPOWER-2	22.5	10.0			3.41	42.1	144				21.0	1.5	11.0
GE-CT1	70.0	36.0			3.40	98.5	335						
GE-CT2	75.0	41.0			3.40	98.5	335						
GE-CT3	76.0	41.0			3.40	98.5	335						
GE-ST1	162.0	28.0			7.60	200.0	1520						
JBPHH 1	16.8	6.7			0.99	21.8	22						
JBPHH 2	16.8	6.7			0.99	21.8	22						
JBPHH 3	16.8	6.7			0.99	21.8	22						
JBPHH 4	16.8	6.7			0.99	21.8	22						
JBPHH 5	16.8	6.7			0.99	21.8	22						
JBPHH 6	16.8	6.7			0.99	21.8	22						
KMCBH 1	9.2	4.6			0.99	10.9	11						
KMCBH 2	9.2	4.6			0.99	10.9	11						
KMCBH 3	9.2	4.6			0.99	10.9	11						
Kalaeloa CT-1	84.0	29.0			4.96	119.2	591						
Kalaeloa ST	40.0	10.0			4.70	61.1	287						
Schofield 1	8.0	2.0			0.99	10.9	11						
Schofield 2	8.0	2.0			0.99	10.9	11						
Schofield 3	8.0	2.0			0.99	10.9	11						
Schofield 4	8.0	2.0			0.99	10.9	11						
Schofield 5	8.0	2.0			0.99	10.9	11						
Schofield 6	8.0	2.0			0.99	10.9	11						
Kalaeloa CT-2	84.0	29.0			4.96	119.2	591						
Kahe 5	134.6	64.7			4.36	158.8	692						
Kahe 6	133.8	63.9			4.36	158.8	692						
Waiau 8	86.2	24.1	25.0	5.0	4.44	96.0	426						
Waiau 7	83.3	23.8	25.0	5.0	4.44	96.0	426						
CIP1	112.2	41.2			4.72	162.0	765						
Waiau 10	49.9	5.9			7.84	57.0	447						
Waiau 9	52.9	5.9			7.84	57.0	447						
Honolulu 8	0.0	0.0			1.99	62.5	124	0.0	Synch. Cond.		0.0	Synch. Cond.	
Honolulu 9	0.0	0.0			1.95	64.0	125	0.0	Synch. Cond.		0.0	Synch. Cond.	
Kahe 3	86.2	23.7	25.0	5.0	1.71	101.0	173	0.0	Synch. Cond.		0.0	Synch. Cond.	
Kahe 2	82.2	23.8	25.0	5.0	2.05	96.0	197	0.0	Synch. Cond.		0.0	Synch. Cond.	
Kahe 1	82.2	23.8	25.0	5.0	2.05	96.0	197	0.0	Synch. Cond.		0.0	Synch. Cond.	
Total Wind	953	0						320			247		
-Kahuku	30	0						14			8		
-Kawailoa	69	0						23			19		
-Na Pua Makani	24	0						21			16		
-Future Wind	30	0						0			0		
-Offshore Wind	800	0						262			204		
DG-PV	2518	0						1077			723		
Station PV	3603	0						128			81		
Total Kinetic Energy									1024			1168	
Total Load									1571			1113	
Total Thermal Generation									46			62	
Total Renewable Generation									1525			1051	
Total Generation									1571			1113	
Excess Generation									0			0	
Total Up Regulation									0			7	
Total Down Regulation									21			27	
Legacy DG-PV	59.3Hz Capacity		0.0					59.3Hz Output		0.0	59.3Hz Output		0.0
	60.5Hz Capacity		0.0					60.5Hz Output		0.0	60.5Hz Output		0.0

Table O-18. Unit Commitment and Dispatch 2045

Table O-18 shows the unit commitment and dispatch for the typical and boundary hours. Simulations were performed for these system conditions to determine system security requirements.

Loss of Generation

Simulations were performed for the largest loss of generation contingency event to determine the frequency response reserves requirements to bring the system into compliance with TPL-001.

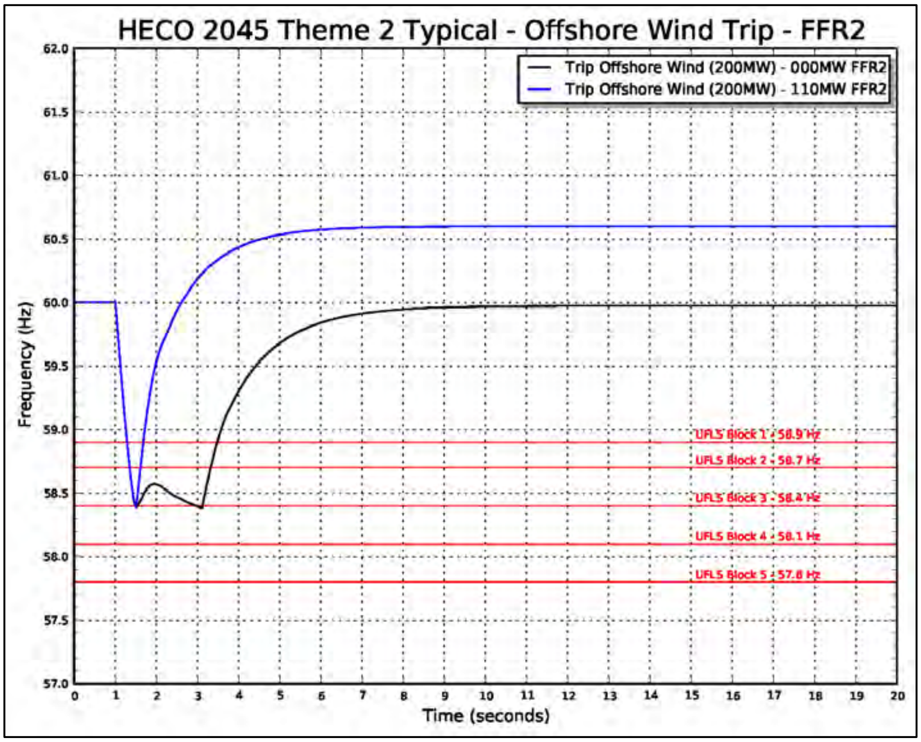


Figure O-38. Frequency Response Profile for FFR2 Typical Hour

Figure O-38 shows the frequency response profile for a 200 MW cable trip from an offshore wind facility. System kinetic energy is 1024 MW-sec. With 110 MW of FFR2, the frequency nadir hits 58.4 Hz requiring 3 blocks of UFLS to stabilize system frequency. Simulations of 110 MW of FFR2 in conjunction with the 3 blocks of UFLS over compensates for this contingency, causes system frequency to exceed 60.5 Hz. The 30-cycle time delay is too long to dispatch FFR2, indicating that there is no amount of FFR2 that will bring the system into compliance with TPL-001.

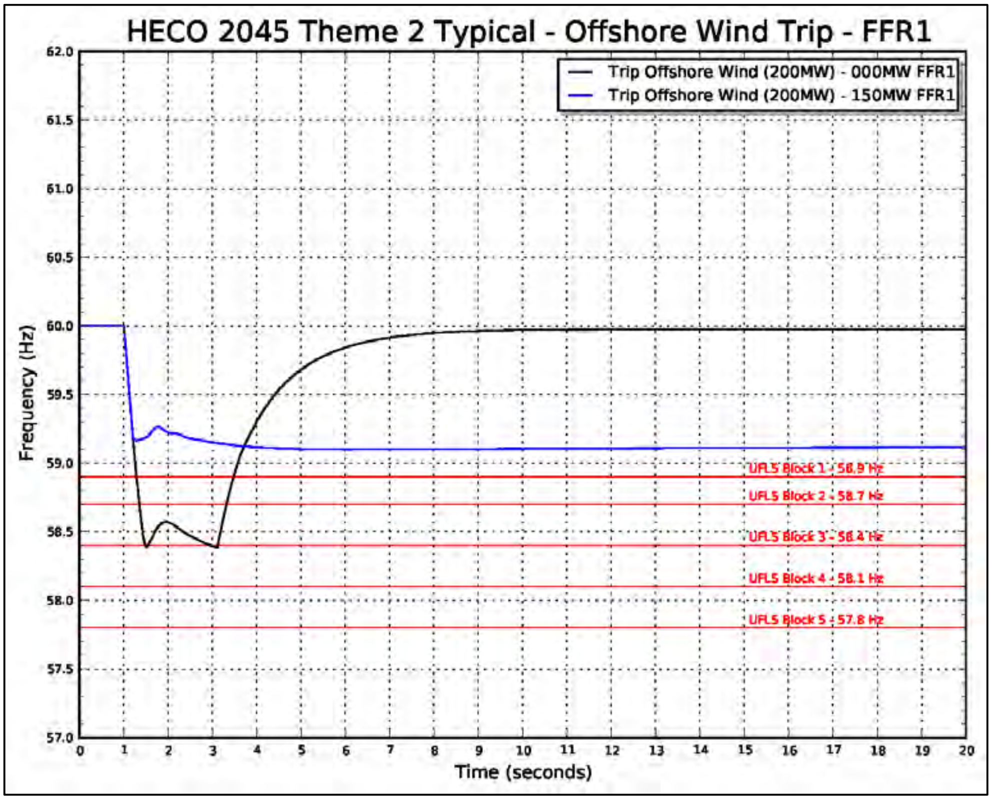


Figure O-39. Frequency Response Profile for FFR1 Typical Hour

Figure O-39 shows the frequency response profile for the FFR1 analysis. The capacity of FFR1 required to bring the system into compliance with TPL-001 is 150 MW.

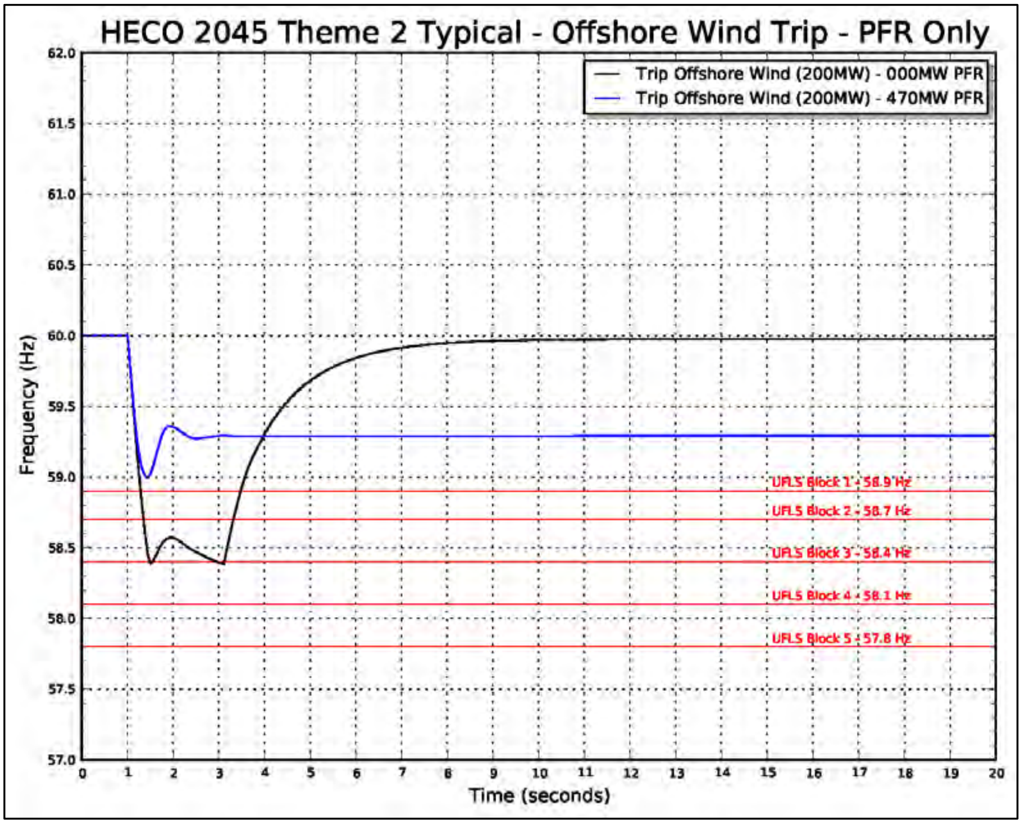


Figure O-40. Frequency Response Profile for PFR Typical Hour

Figure O-40 shows the frequency response profile for the PFR analysis. The capacity of PFR required to bring the system into compliance with TPL-001 is 470 MW.

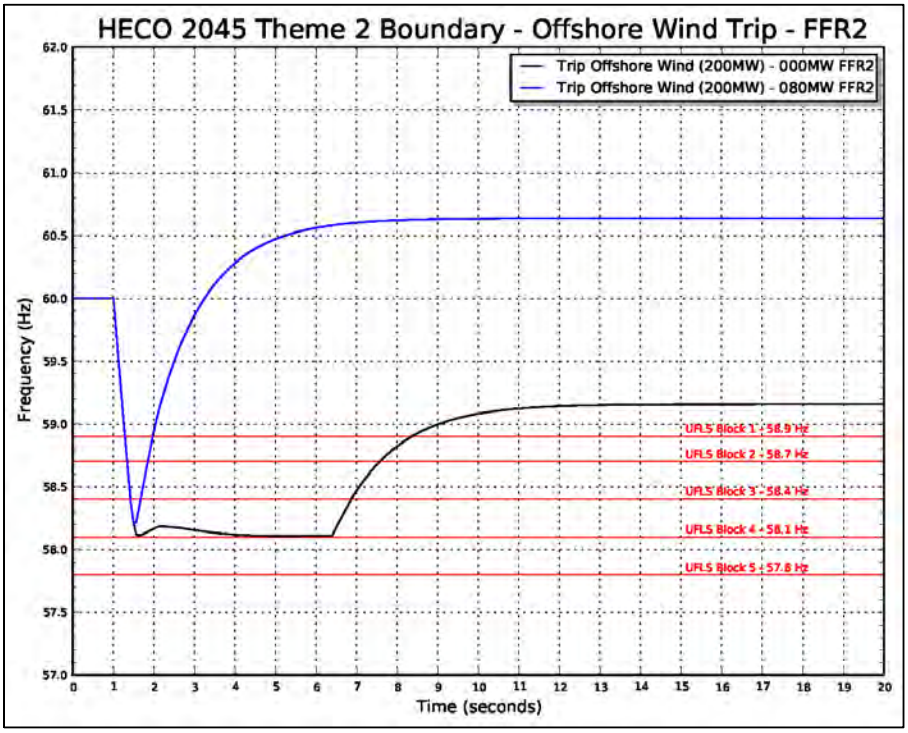


Figure O-41. Frequency Response Profile for FFR2 Boundary Hour

Figure O-41 shows the frequency response profile for a 200 MW cable trip from an offshore wind facility. With 80 MW of FFR2, the frequency nadir hits 59.3 Hz that initiates 2 blocks of UFLS that over compensates for this contingency, causes system frequency to exceed 60.5 Hz. Therefore, there is no amount of FFR2 that will bring the system into compliance with TPL-001.

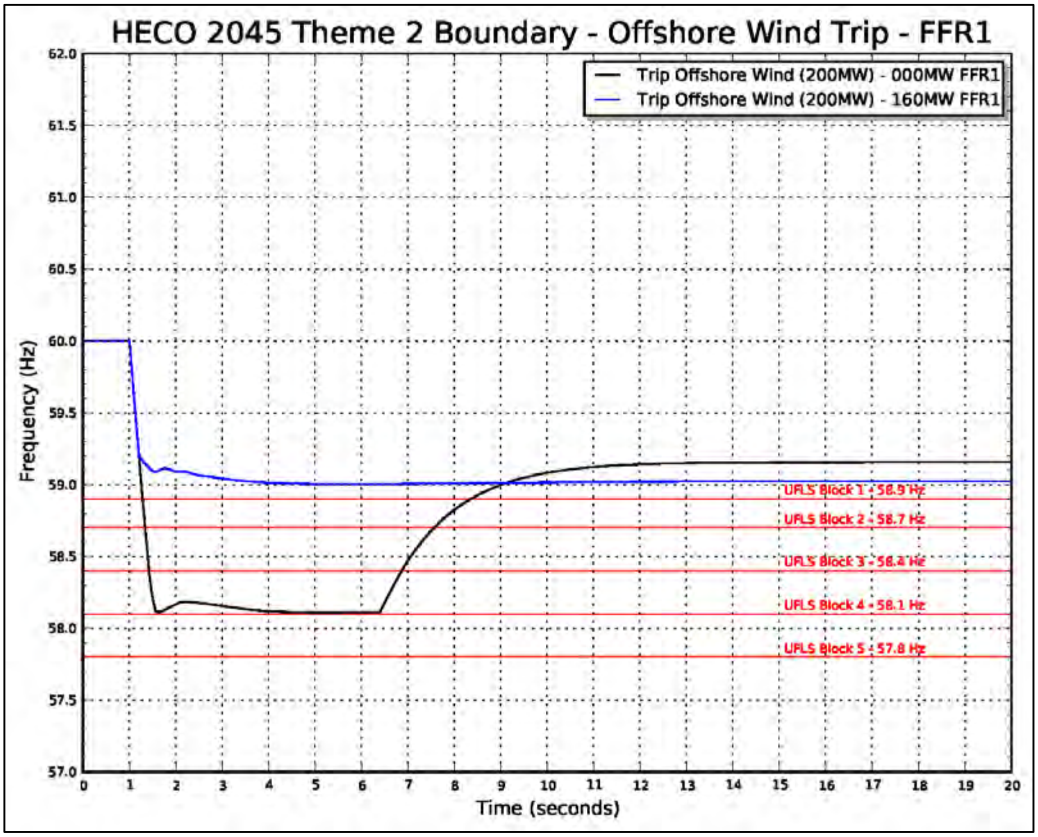


Figure O-42. Frequency Response Profile for FFR1 Boundary Hour

Figure O-42 shows the frequency response profile for the FFR1 analysis. The capacity of FFR1 required to bring the system into compliance with TPL-001 is 160 MW.

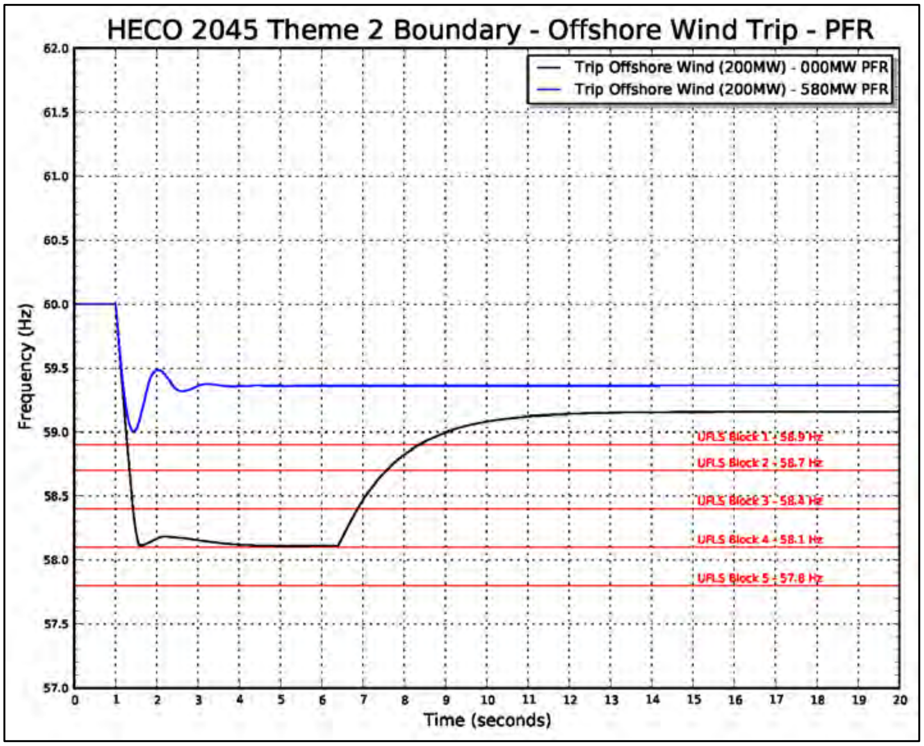


Figure O-43. Frequency Response Profile for PFR Boundary Hour

Figure O-43 shows the frequency response profile for the PFR analysis. The capacity of PFR required to bring the system into compliance with TPL-001 is 580 MW.

138 kV Fault Analysis

Simulations were performed for electrical faults on the 138 kV transmission system busses. A three-phase fault was placed on 28 busses to evaluate system performance to normally cleared and delayed clearing faults. Normally cleared faults are isolated in 5-cycles and delayed clearing faults are isolated in 18-cycles to simulate a breaker that fails to open. Simulations for the normally cleared faults did not produce any system security issues.

2045 138 kV Fault Analysis						
Circuit Outage	Bus Fault	Bkr Fail	BFTD	2nd Outage	Typical Hour Condition	Boundary Hour Condition
AES-CEIP 1	AES	320	15	AES-HP	Unstable	Unstable
AES-HP	AES	320	15	AES-CEIP 1	Unstable	Unstable
AES-CEIP 2	AES	323	15	AES Gen	Unstable	Stable
AES-Kalaeloa	AES	456	15	CIP Gen	Unstable	Stable
AES-CEIP 1	CEIP	276	18	Kahe-CEIP 2	Unstable	Unstable
Kahe-CEIP 2	CEIP	276	18	AES-CEIP 1	Unstable	Unstable
AES-CEIP 2	CEIP	279	18	CEIP-Ewa Nui	Unstable	Unstable
CEIP-Ewa Nui	CEIP	279	18	AES-CEIP 2	Unstable	Unstable
CEIP-Ewa Nui	EWA	384	18	Waiau-Ewa Nui 2	Stable	Stable
Waiau-Ewa Nui 2	EWA	384	18	CEIP-Ewa Nui	Unstable	Stable
Kalaeloa-Ewa Nui	EWA	387	18	Waiau-Ewa Nui 1	Stable	Stable
Waiau-Ewa Nui 1	EWA	387	18	Kalaeloa-Ewa Nui	Unstable	Stable
Halawa-Iwilei	HLWA	158	18	Halawa-Makalapa	Stable	Stable
Halawa-Makalapa	HLWA	158	18	Halawa-Iwilei	Stable	Stable
Halawa-School	HLWA	161	18	Kahe-Halawa 1	Stable	Stable
Kahe-Halawa 1	HLWA	161	18	Halawa-School	Stable	Stable
Halawa-Koolau	HLWA	176	18	Kahe-Halawa 2	Stable	Stable
Kahe-Halawa 2	HLWA	176	18	Halawa-Koolau	Stable	Stable
Kahe-Wahiawa	KAHE	129	18	K1 Gen	Unstable	Unstable
Kahe-Halawa 2	KAHE	132	18	K2 Gen	Unstable	Unstable
Kahe-Halawa 1	KAHE	168	18	K3 Gen	Unstable	Unstable
Kahe-Waiau	KAHE	171	18	K4 Gen	Unstable	Unstable
Kahe-CEIP 2	KAHE	246	18	K5 Gen	Unstable	Unstable
Kahe-CEIP 1	KAHE	249	18	K6 Gen	Unstable	Unstable
Kalaeloa-Ewa Nui	KPLP	310	18	Kal2 Gen	Unstable	Unstable
AES-Kalaeloa	KPLP	313	18	Kal1 Gen	Stable	Stable
Waiau-Makalapa 1	MKLPA	260	18	Makalapa Tsf 3	Stable	Stable
Halawa-Makalapa	MKLPA	263	18	Waiau-Makalapa 2	Stable	Stable
Waiau-Makalapa 2	MKLPA	263	18	Halawa-Makalapa	Stable	Stable
Makalapa-Airport	MKLPA	266	18	Makalapa Tsf 1	Stable	Stable
Kahe-Waiau	WAIAU	102	18	W5 Gen	Stable	Stable
Waiau-Koolau 2	WAIAU	105	18	W6 Gen	Unstable	Stable
Waiau-Wahiawa	WAIAU	108	18	W8 Gen	Stable	Stable
Waiau-Koolau 1	WAIAU	111	18	W7 Gen	Unstable	Stable
Waiau-Ewa Nui 1	WAIAU	179	18	Waiau-Makalapa 2	Stable	Stable
Waiau-Makalapa 2	WAIAU	179	18	Waiau-Ewa Nui 1	Unstable	Stable
Waiau-Ewa Nui 2	WAIAU	302	18	Waiau-Makalapa 1	Stable	Stable
Waiau-Makalapa 1	WAIAU	302	18	Waiau-Ewa Nui 2	Unstable	Stable
Waiau-Wahiawa	WHWA	145	18	Wahiawa Tsf 3	Stable	Stable

Table O-19. Summary of Results for the 2045 Breaker Failure Analysis

Table O-19 shows the results of the breaker failure analysis. For the boundary hour, 13 simulations resulted in unstable operation.

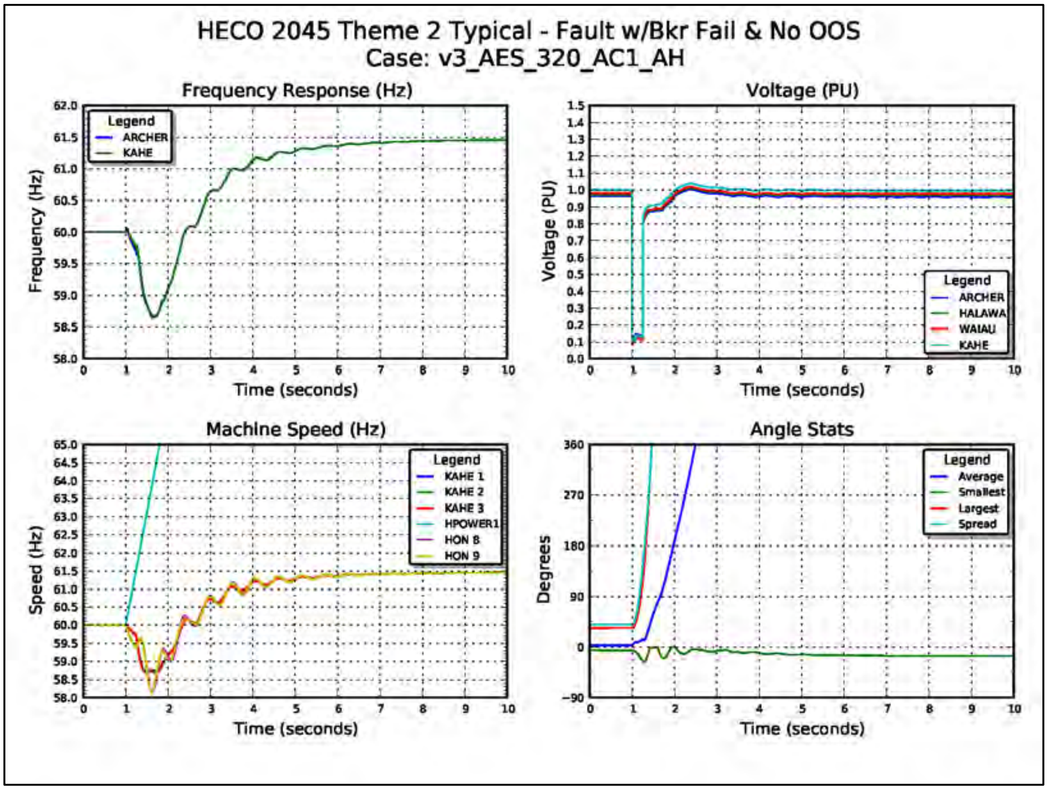


Figure O-44. System Performance for BKR 320 Failure Analysis

Figure O-44 shows four plots that illustrate unstable operation for a fault on the AES-CEIP 1 line and BKR 320 fails to operate. The Machine Speed plot shows HPOWER 1 (teal) losing synchronism with the system. HPOWER 1 has a low inertia constant (2.57 MJ/MVA) that determines the shorter critical clearing time. More analysis is required to determine mitigation alternatives.

Theme 3 – No LNG Unmerged Plan

2045

System security analysis was performed for two hours that represents a typical hour and a boundary condition. An additional screening metric was applied to select hours when the output from offshore wind was high to simulate the trip of a 200 MW cable.

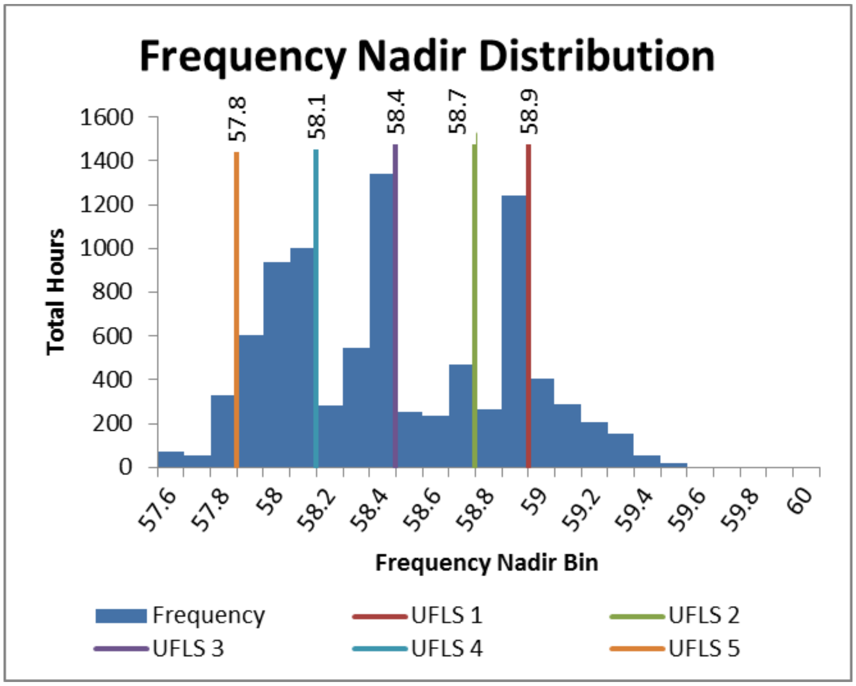


Figure O-45. Frequency Nadir Histogram for 2045

Figure O-45 is a histogram of the expected frequency nadirs for N-1 generator contingency events for the entire year. The typical hour selected from the maximum distribution of 1338 hours was 7:00 AM on Monday, November 27. The frequency nadir range for the typical hour was 58.3 – 58.4 Hz that that would require 3 blocks of UFLS to stabilize system frequency.

The boundary hour selected from a minimum distribution of 71 hours was 3:00 AM on Sunday, March 19. The frequency nadir range for the boundary hour was 57.5 – 57.6 Hz that would require all 5 blocks of UFLS to stabilize system frequency.

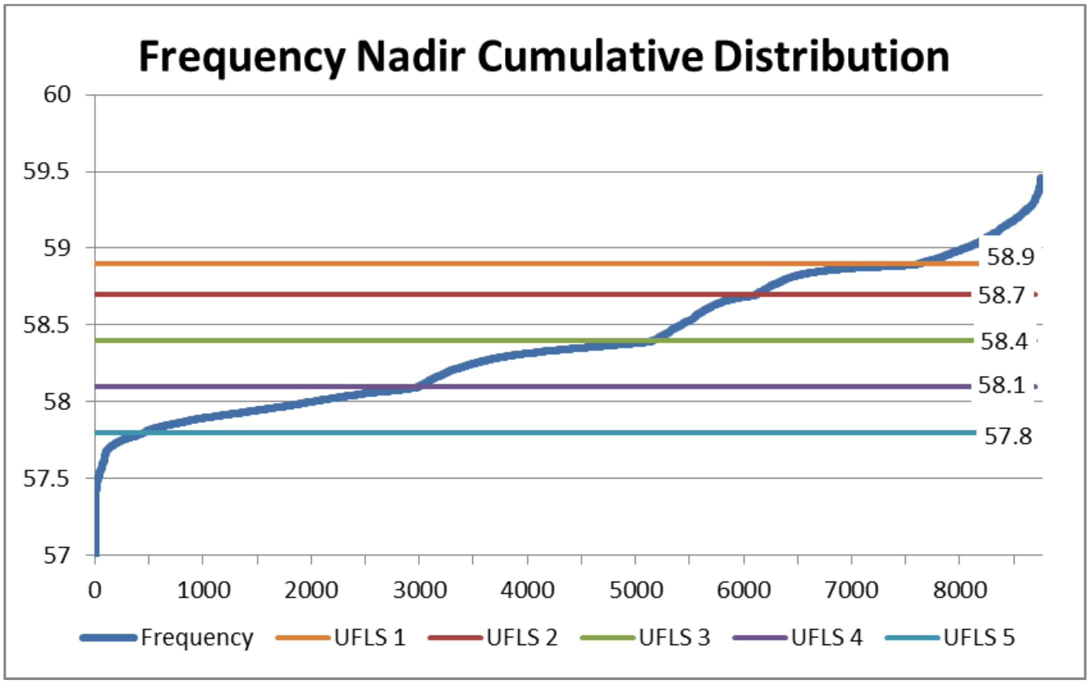


Figure O-46. Frequency Nadir Duration Curve for 2045

Figure O-46 shows the frequency nadir duration curve for the entire year.

Unit Commitment Order	Unit Ratings							Theme 3 - HECO 2045 (Typical) Mon 11/27/45 Hour 7			Theme 3 - HECO 2045 (Boundary) Sun 3/19/45 Hour 3		
	Pmax	Pmin			Inertia H	Unit MVA	Unit K.E.	Pgen	up reg (spin)	down reg	Pgen	up reg (spin)	down reg
HPOWER-1	46.0	25.0			2.78	75.0	209	33.0	13.0	8.0	35.0	11.0	10.0
HPOWER-2	22.5	10.0			3.41	42.1	144						
JBPHH 1	16.8	6.7			0.99	21.8	22	6.7	10.1	0.0			
JBPHH 2	16.8	6.7			0.99	21.8	22	6.7	10.1	0.0			
JBPHH 3	16.8	6.7			0.99	21.8	22	6.7	10.1	0.0			
JBPHH 4	16.8	6.7			0.99	21.8	22	6.7	10.1	0.0			
JBPHH 5	16.8	6.7			0.99	21.8	22	6.7	10.1	0.0			
JBPHH 6	16.8	6.7			0.99	21.8	22	6.7	10.1	0.0			
Kalaeloa CT-1	84.0	29.0			4.96	119.2	591	44.4	39.6	15.4			
Kalaeloa ST	40.0	10.0			4.70	61.1	287	21.2	18.8	11.2			
KMCBH 1	9.2	4.6			0.99	10.9	11	4.6	4.6	0.0			
KMCBH 2	9.2	4.6			0.99	10.9	11	4.6	4.6	0.0			
KMCBH 3	9.2	4.6			0.99	10.9	11	4.6	4.6	0.0			
KMCBH 4	9.2	4.6			0.99	10.9	11	4.6	4.6	0.0			
KMCBH 5	9.2	4.6			0.99	10.9	11	4.6	4.6	0.0			
KMCBH 6	9.2	4.6			0.99	10.9	11	4.6	4.6	0.0			
Kalaeloa CT-2	84.0	29.0			4.96	119.2	591	44.4	39.6	15.4			
Schofield 1	8.0	2.0			0.99	10.9	11	2.0	6.0	0.0			
Schofield 2	8.0	2.0			0.99	10.9	11	2.0	6.0	0.0			
Schofield 3	8.0	2.0			0.99	10.9	11	2.0	6.0	0.0			
Schofield 4	8.0	2.0			0.99	10.9	11	2.0	6.0	0.0			
Schofield 5	8.0	2.0			0.99	10.9	11	2.0	6.0	0.0			
Schofield 6	8.0	2.0			0.99	10.9	11	2.0	6.0	0.0			
Kahe 5	134.6	64.7			4.36	158.8	692						
Kahe 3	86.2	23.7	25.0	5.0	1.71	101.0	173						
Kahe 4	85.3	23.6	25.0	5.0	3.54	101.0	357						
Kahe 2	82.2	23.8	25.0	5.0	2.05	96.0	197						
Kahe 1	82.2	23.8	25.0	5.0	2.05	96.0	197						
Waiau 8	86.2	24.1	25.0	5.0	4.44	96.0	426						
Waiau 7	83.3	23.8	25.0	5.0	4.44	96.0	426						
CIP1	112.2	41.2			4.72	162.0	765						
Waiau 10	49.9	5.9			7.84	57.0	447						
Waiau 9	52.9	5.9			7.84	57.0	447						
Waiau 5	0.0	0.0			1.95	64.0	125	0.0	Synch. Cond.		0.0	Synch. Cond.	
Waiau 6	0.0	0.0			1.88	64.0	120	0.0	Synch. Cond.		0.0	Synch. Cond.	
Kahe 6	133.8	63.9			4.36	158.8	692	0.0	Synch. Cond.		0.0	Synch. Cond.	
Waiau 3	47.0	23.7			4.51	57.5	259	0.0	Synch. Cond.		0.0	Synch. Cond.	
Waiau 4	46.5	23.5			4.51	57.5	259	0.0	Synch. Cond.		0.0	Synch. Cond.	
Total Wind	953	0						685			569		
-Kahuku	30	0						3			5		
-Kawailoa	69	0						12			20		
-Na Pua Makani	24	0						21			21		
-Future Wind	30	0						4			8		
-Offshore Wind	800	0						645			515		
DG-PV	2518	0						0			0		
Station PV	3603	0						0			0		
Total Kinetic Energy									3392			1664	
Total Load									908			604	
Total Thermal Generation									223			35	
Total Renewable Generation									685			569	
Total Generation									908			604	
Excess Generation									0			0	
Total Up Regulation									235			11	
Total Down Regulation									50			10	
Legacy DG-PV		59.3Hz Capacity		0.0				59.3Hz Output		0.0	59.3Hz Output		0.0
		60.5Hz Capacity		0.0				60.5Hz Output		0.0	60.5Hz Output		0.0

Table O-20. Unit Commitment and Dispatch 2045

Hawaiian Electric
Maui Electric
Hawai'i Electric Light

Table O-20 shows the unit commitment and dispatch for the typical and boundary hours. Simulations were performed for these system conditions to determine system security requirements.

Loss of Generation

Simulations were performed for the largest loss of generation contingency event to determine the frequency response reserves requirements to bring the system into compliance with TPL-001.

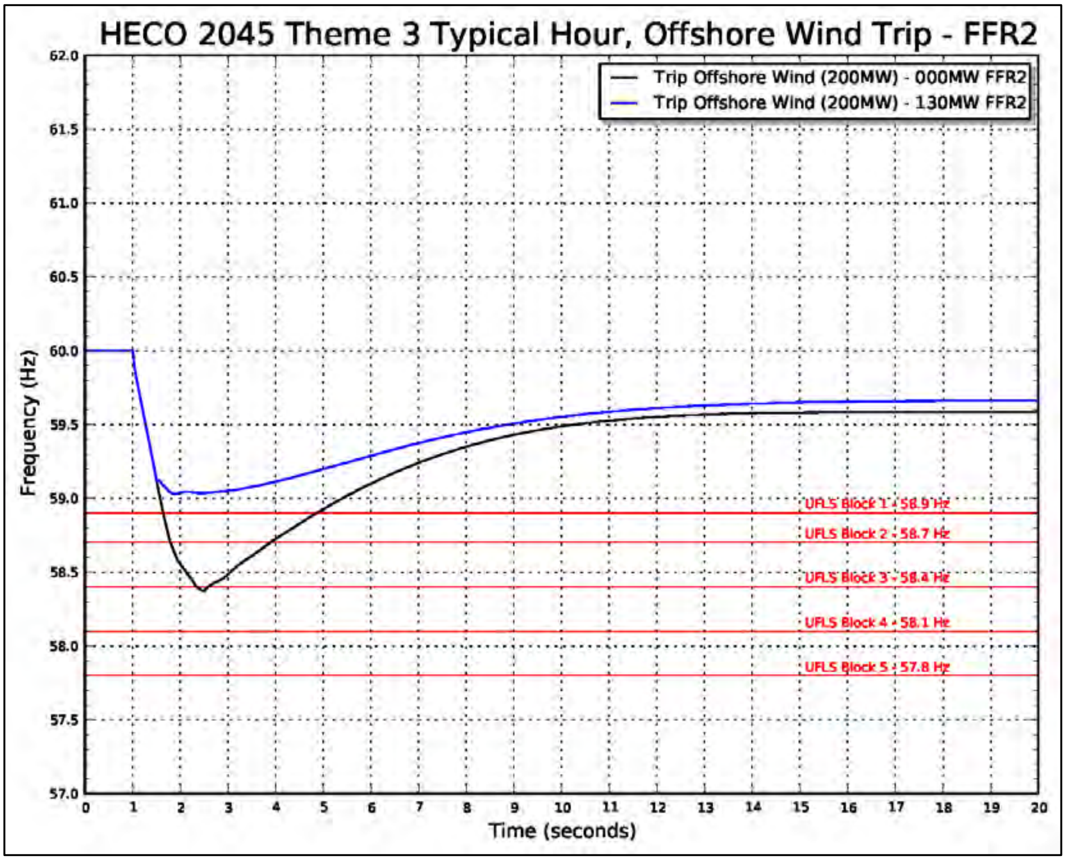


Figure O-47. Frequency Response Profile for FFR2 Typical Hour

Figure O-47 shows the frequency response profile for a 200 MW cable trip of an offshore wind plant for the typical hour. System kinetic energy is 3392 MW-sec. Without FFR2, the frequency nadir breaches 58.4 Hz requiring 3 blocks of UFLS to stabilize system frequency. The capacity of FFR2 required to bring the system into compliance with TPL-001 is 130 MW.

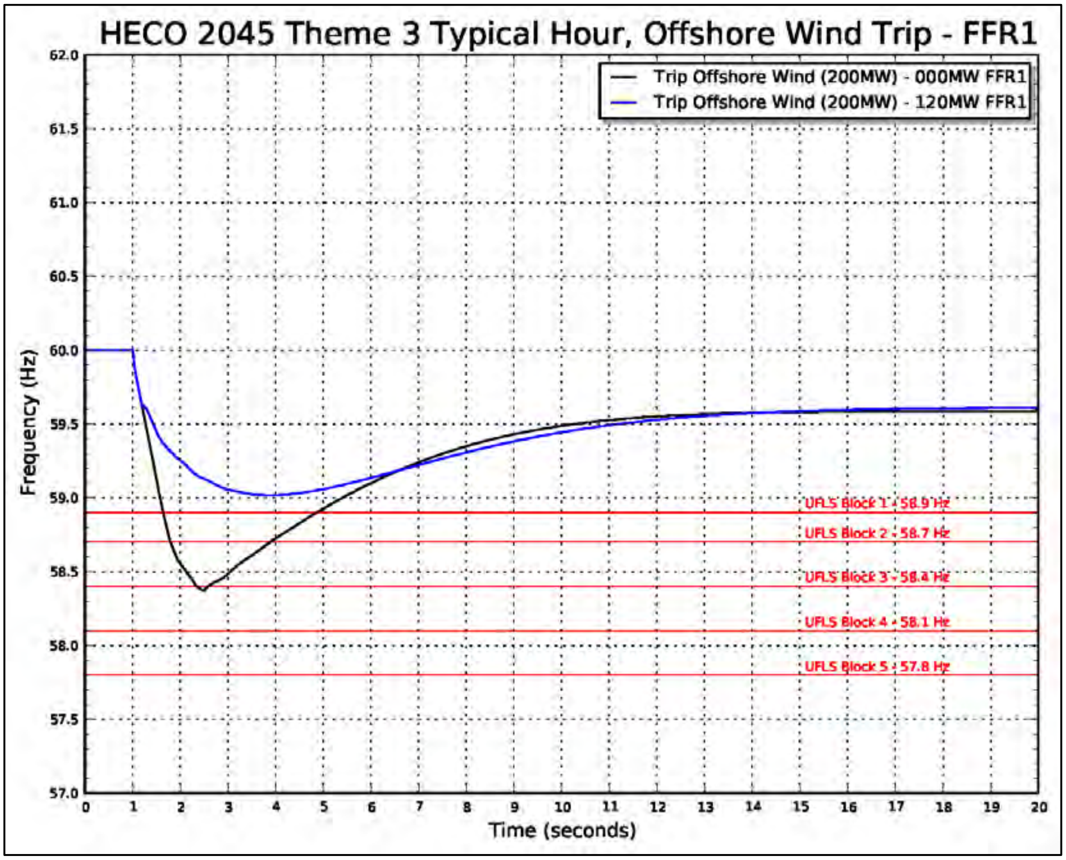


Figure O-48. Frequency Response Profile for FFR1 Typical Hour

Figure O-48 shows the frequency response profile for the FFR1 analysis. The capacity of FFR1 required to bring the system into compliance with TPL-001 is 120 MW.

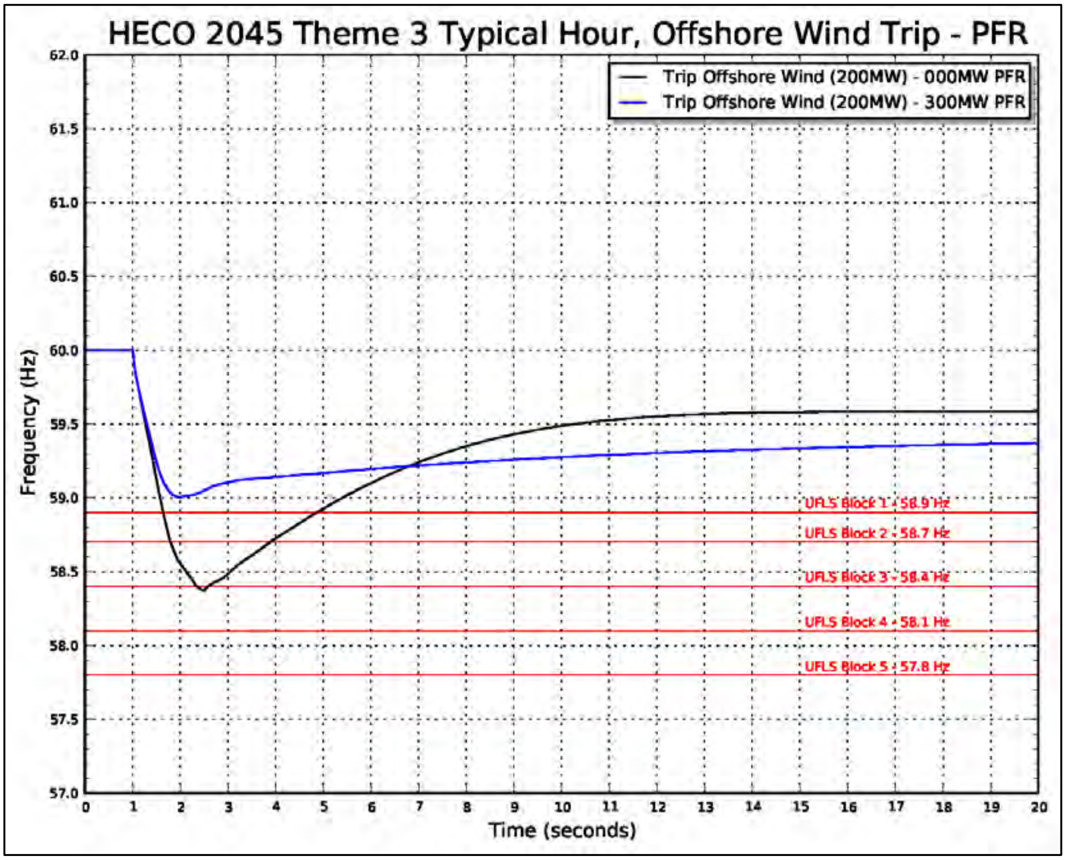


Figure O-49. Frequency Response Profile for PFR Typical Hour

Figure O-49 shows the frequency response profile for the PFR analysis. The capacity of PFR required to bring the system into compliance with TPL-001 is 300 MW.

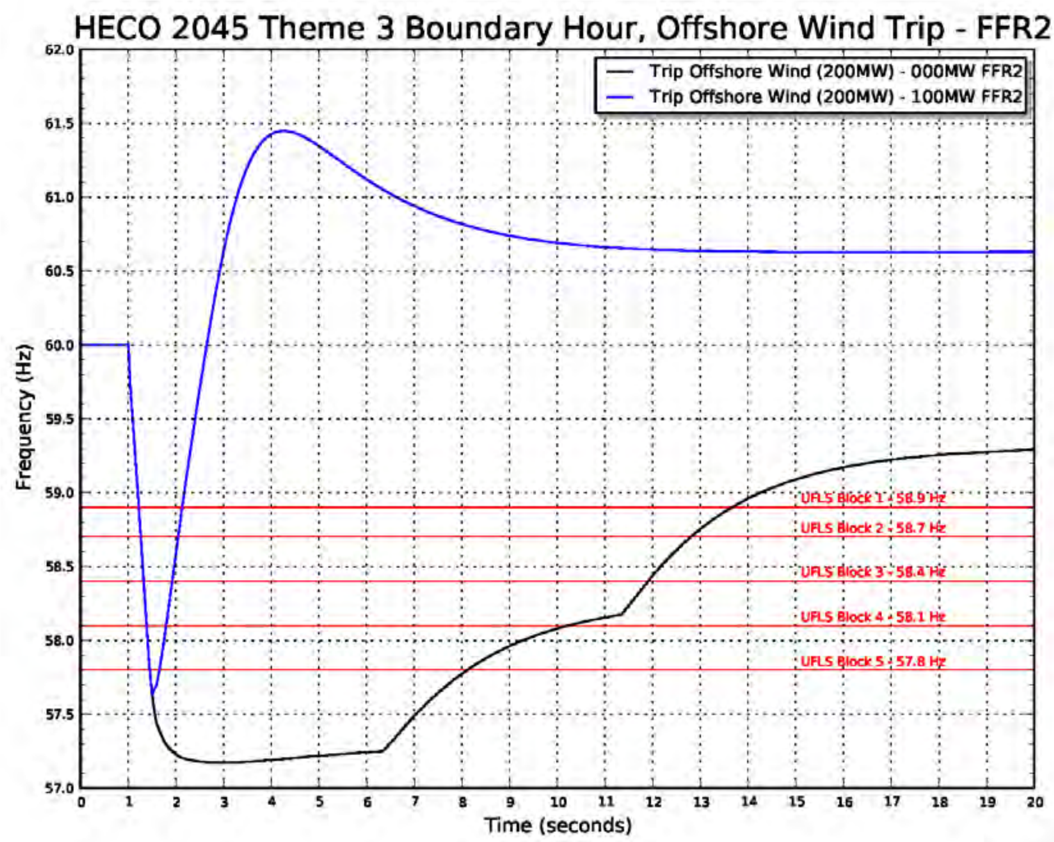


Figure O-50. Frequency Response Profile for FFR2 Boundary Hour

Figure O-50 shows the frequency response profile for a 200 MW cable trip of an offshore wind plant for the typical hour. System kinetic energy is 1664 MW-sec. Without FFR2, the frequency nadir reaches 57.2 Hz requiring 5 blocks of UFLS to stabilize system frequency. Simulations of 100 MW of FFR2 in conjunction with the 5 blocks of UFLS over compensates for this contingency, causing system frequency to exceed 61.4 Hz. The 30-cycle time delay is too long to dispatch FFR2, indicating that there is no amount of FFR2 that will bring the system into compliance with TPL-001.

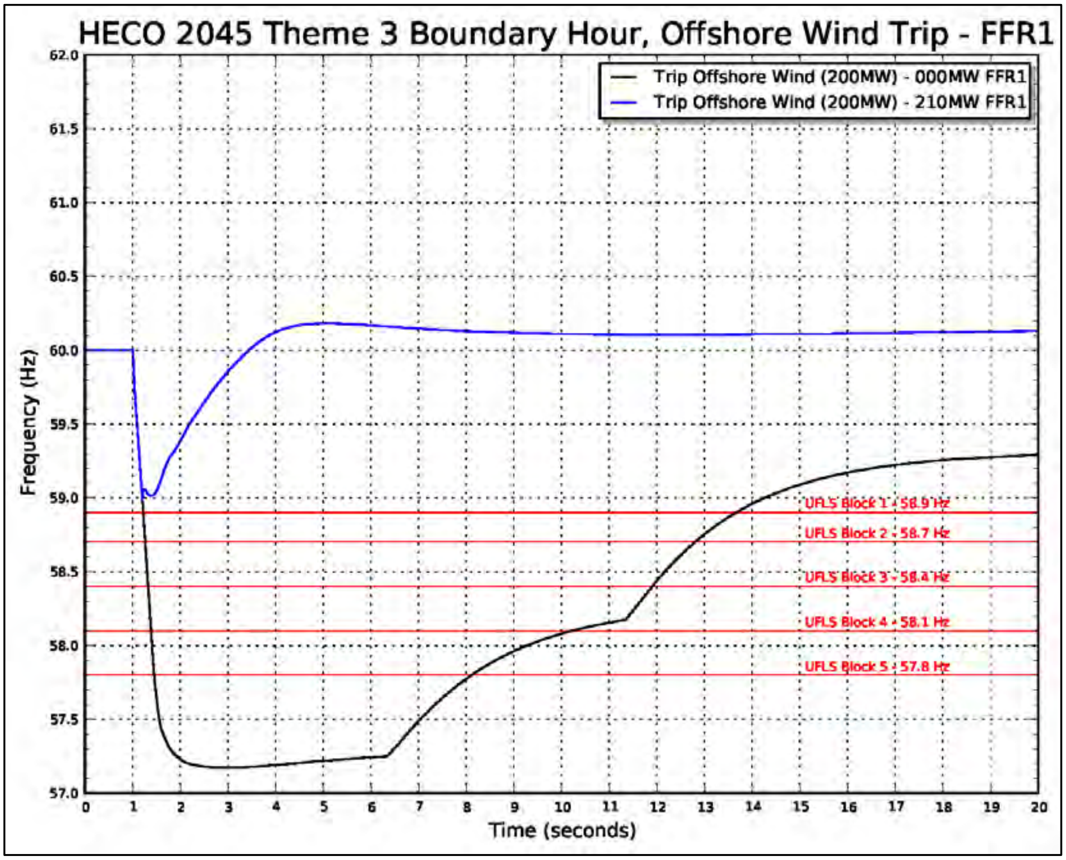


Figure O-51. Frequency Response Profile for FFR1 Boundary Hour

Figure O-51 shows the frequency response profile for the FFR1 analysis. The capacity of FFR1 required to bring the system into compliance with TPL-001 is 210 MW.

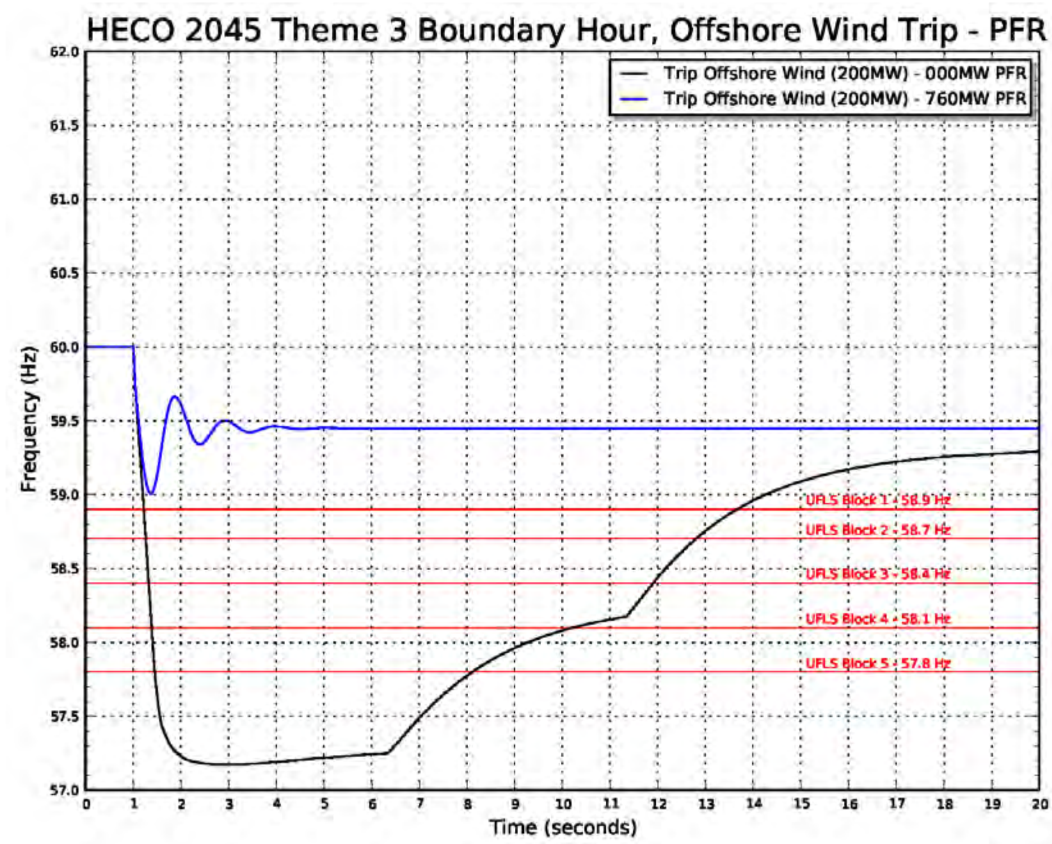


Figure O-52. Frequency Response Profile for PFR Boundary Hour

Figure O-52 shows the frequency response profile for this simulation. The capacity of PFR required to bring the system into compliance with TPL-001 is 760 MW.

138 kV Fault Analysis

Simulations were performed for a 138 kV breaker failure on multiple transmission busses to determine rotor angle stability for the typical and boundary hours. There were no rotor angle stability issues for the typical hour.

2045 138 kV Fault Analysis						
Circuit Outage	Bus Fault	Bkr Fail	BFTD	2nd Outage	Typical Hour Condition	Boundary Hour Condition
AES-CEIP 1	AES	320	15	AES-HP	Unstable	Unstable
AES-HP	AES	320	15	AES-CEIP 1	Unstable	Unstable
AES-CEIP 2	AES	323	15	AES Gen	Stable	Unstable
AES-Kalaeloa	AES	456	15	CIP Gen	Stable	Unstable
AES-CEIP 1	CEIP	276	18	Kahe-CEIP 2	Unstable	Unstable
Kahe-CEIP 2	CEIP	276	18	AES-CEIP 1	Unstable	Unstable
AES-CEIP 2	CEIP	279	18	CEIP-Ewa Nui	Unstable	Unstable
CEIP-Ewa Nui	CEIP	279	18	AES-CEIP 2	Unstable	Unstable
CEIP-Ewa Nui	EWA	384	18	Waiau-Ewa Nui 2	Stable	Unstable
Waiau-Ewa Nui 2	EWA	384	18	CEIP-Ewa Nui	Stable	Unstable
Kalaeloa-Ewa Nui	EWA	387	18	Waiau-Ewa Nui 1	Stable	Unstable
Waiau-Ewa Nui 1	EWA	387	18	Kalaeloa-Ewa Nui	Stable	Unstable
Halawa-Iwilei	HLWA	158	18	Halawa-Makalapa	Stable	Unstable
Halawa-Makalapa	HLWA	158	18	Halawa-Iwilei	Stable	Unstable
Halawa-School	HLWA	161	18	Kahe-Halawa 1	Unstable	Unstable
Kahe-Halawa 1	HLWA	161	18	Halawa-School	Stable	Stable
Halawa-Koolau	HLWA	176	18	Kahe-Halawa 2	Stable	Unstable
Kahe-Halawa 2	HLWA	176	18	Halawa-Koolau	Stable	Stable
Kahe-Wahiawa	KAHE	129	18	K1 Gen	Unstable	Unstable
Kahe-Halawa 2	KAHE	132	18	K2 Gen	Unstable	Unstable
Kahe-Halawa 1	KAHE	168	18	K3 Gen	Unstable	Unstable
Kahe-Waiau	KAHE	171	18	K4 Gen	Unstable	Unstable
Kahe-CEIP 2	KAHE	246	18	K5 Gen	Unstable	Unstable
Kahe-CEIP 1	KAHE	249	18	K6 Gen	Unstable	Unstable
Kalaeloa-Ewa Nui	KPLP	310	18	Kal2 Gen	Unstable	Unstable
AES-Kalaeloa	KPLP	313	18	Kal1 Gen	Unstable	Unstable
Waiau-Makalapa 1	MKLPA	260	18	Makalapa Tsf 3	Stable	Unstable
Halawa-Makalapa	MKLPA	263	18	Waiau-Makalapa 2	Stable	Unstable
Waiau-Makalapa 2	MKLPA	263	18	Halawa-Makalapa	Stable	Unstable
Makalapa-Airport	MKLPA	266	18	Makalapa Tsf 1	Stable	Unstable
Kahe-Waiau	WAIAU	102	18	W5 Gen	Unstable	Unstable
Waiau-Koolau 2	WAIAU	105	18	W6 Gen	Unstable	Unstable
Waiau-Wahiawa	WAIAU	108	18	W8 Gen	Unstable	Unstable
Waiau-Koolau 1	WAIAU	111	18	W7 Gen	Unstable	Unstable
Waiau-Ewa Nui 1	WAIAU	179	18	Waiau-Makalapa 2	Unstable	Unstable
Waiau-Makalapa 2	WAIAU	179	18	Waiau-Ewa Nui 1	Unstable	Unstable
Waiau-Ewa Nui 2	WAIAU	302	18	Waiau-Makalapa 1	Unstable	Unstable
Waiau-Makalapa 1	WAIAU	302	18	Waiau-Ewa Nui 2	Unstable	Unstable
Waiau-Wahiawa	WHWA	145	18	Wahiawa Tsf 3	Unstable	Stable

Table O-21. Summary of Results for the 2045 Breaker Failure Analysis

Table O-21 shows the results of the breaker failure analysis. For the typical hour, only 24 simulations resulted in unstable operation. For the boundary hour, all but 3 simulations resulted in unstable operation. Further analyses will be performed to determine mitigation alternatives.

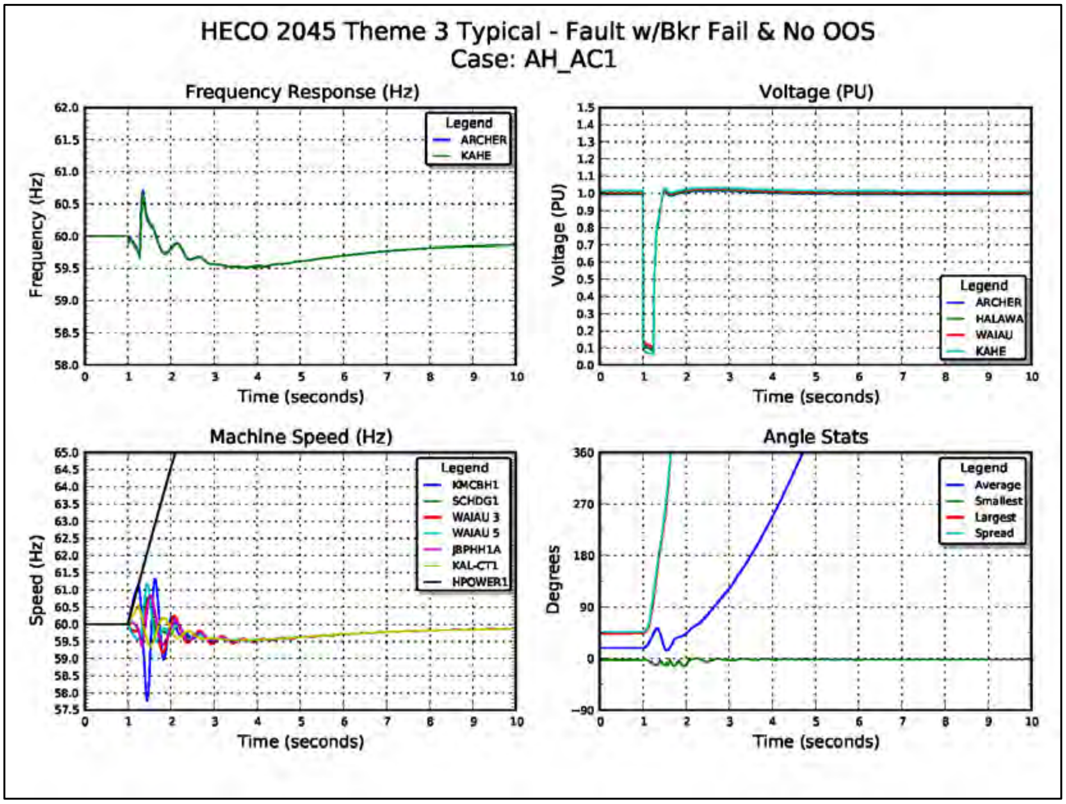


Figure O-53. System Performance for BKR 129 Failure Analysis

Figure O-53 shows four plots that illustrate unstable operation for a fault on the AES-CEIP 1 line and BKR 320 fails to operate. The Machine Speed plot shows HPOWER 1 (black) losing synchronism with the system. HPOWER 1 has a low inertia constant (2.57 MJ/MVA) that determines the shorter critical clearing time. More analysis is required to determine mitigation alternatives.

Summary

The O'ahu system does not meet the requirements of TPL-001. Simulations were performed to determine the capacity of FFR2, FFR1 and PFR required to the system into compliance with TPL-001 in 2019.

Compliance with TPL-001

The capacities of FFR2 and FFR1 required to meet TPL-001 is 150 MW for the typical hour and 160 MW for the boundary hour. The capacities are equivalent because system inertia is relatively high so the 18-cycle delay in deployment of FFR2 has no impact in the frequency response profile.

A sensitivity analysis was performed if AES were dispatch to a lower output. The capacity of FFR2 and FFR1 required to meet TPL-001 with AES dispatch at 134 MW is 100 MW for the typical hour and 120 MW for the boundary hour. The capacities are higher than the 90 MW BESS assumption that was used for the PSIP because the production cost simulated hours were different from the analysis performed to size the 90 MW BESS. The table below shows that the FFR1 and PFR capacities will provide frequency response reserves through 2045 for Themes 2 and 3. More detailed analyses will be conducted to support the GO7 application that will be submitted to meet the service date of 2019.

Frequency Response Analysis TPL-001 Compliance				
Freq Response	Theme 3			
	2019		2019	
	Typical AES 201 MW	Boundary AES 201 MW	Typical AES 134 MW	Boundary AES 134 MW
FFR2	150	160	100	120
FFR1	150	160	100	120
PFR	-	-	-	-

Table O-22. Summary of Analysis to Meet TPL-001

Table O-22 shows the results of the FFR analysis to bring the system into compliance with TPL-001 for an AES turbine trip and the sensitivity analysis with AES dispatched to 134 MW.

Oah'u Frequency Response Analysis Results								
Freq Response	Theme 2						Theme 3	
	2023		2030		2045		2045	
	Typical KLCT 80 MW	Boundary GEST 120 MW	Typical Wind 133 MW	Boundary Wind 200 MW	Typical Wind 200 MW	Boundary Wind 200 MW	Typical Wind 200 MW	Boundary Wind 200 MW
FFR2	50	120	100	No Solution	No Solution	No Solution	130	No Solution
FFR1	50	120	110	180	150	160	120	210
PFR	-	-	310	690	470	580	300	760

Table O-23. Summary of Frequency Response Reserve Analysis

Table O-23 shows the results of the FFR2, FFR1, and PFR analysis. The 100 MW of FFR1 in 2019 for AES dispatched at 134 MW will meet the Theme 2 and Theme 3 FFR1 requirements through 2045. If 90 MW of FFR1 is installed in 2019, additional FFR2 and PFR will be required for Themes 2 and 3 to meet TPL-001.

MAUI COUNTY CANDIDATE PLANS

State of the System

Analyses was conducted to evaluate the Maui island system to determine if additional FFR is required to meet HI-TPL-001 in addition to the existing BESS installed as part of the Kahiawa Wind Farm .

Historical Contingency Events on Maui

On March 1, 2012, the system experienced the loss of two Ma'alaea generating units trip offline. The total system generation prior to the event was 155 MW. Ma'alaea M16 generating unit breaker opened at 13:32:35 with an output of 19.7 MW. The frequency decreased to 58.4 Hz and tripped Block 1 & 2 on UFLS for the frequency to recover. After a short recovery, M19 tripped offline with an output of 20.2 MW. The loss of M19 decreased the frequency to 57.7 Hz and triggered Block 3 on UFLS.

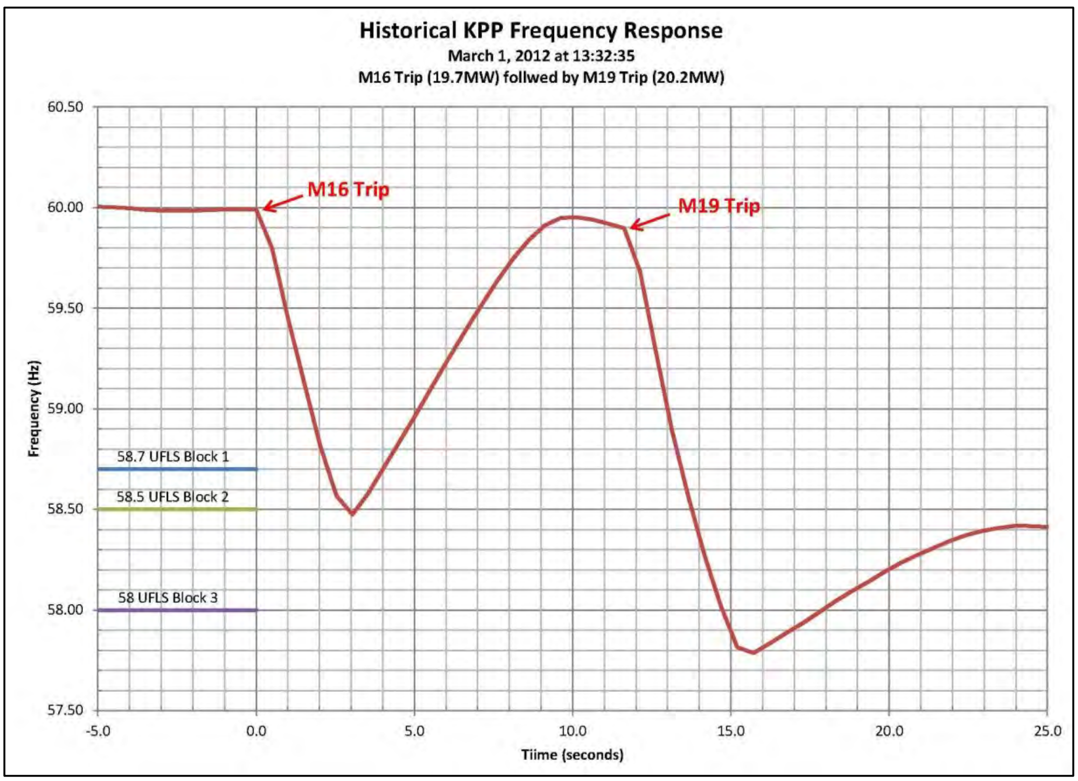


Figure O-54. Frequency Response Profile for Historic Events

Figure O-54 shows the frequency response profile for the M16 and M19 trip. The M16 trip causes the frequency nadir to breach 58.5 Hz that required 2 blocks of UFLS to stabilize system frequency.

2016

System security analysis was performed on two hours that were selected from the production cost analyses that represents a typical hour and a boundary condition.

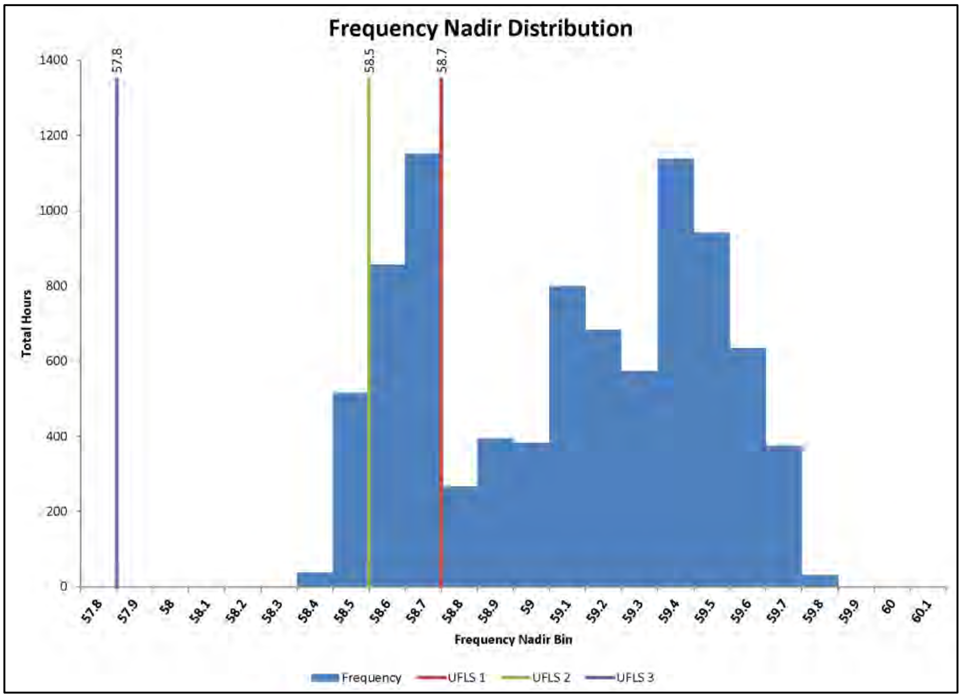


Figure O-55. Frequency Nadir Histogram for 2016

Figure O-55 is a histogram of the expected frequency nadirs for N-1 generator contingency events for the entire year. The typical hour selected from the maximum distribution of 516 hours was 2:00 PM on Monday, April 18. The frequency nadir range for the typical hour is 58.4 – 58.5 Hz that requires two blocks of UFLS to stabilize system frequency.

The boundary hour selected from a minimum distribution of 1 hour was 1:00 PM on Saturday, November 26. The frequency nadir range for the boundary hour is 58.3 – 58.4 Hz that requires two blocks of UFLS to stabilize system frequency.

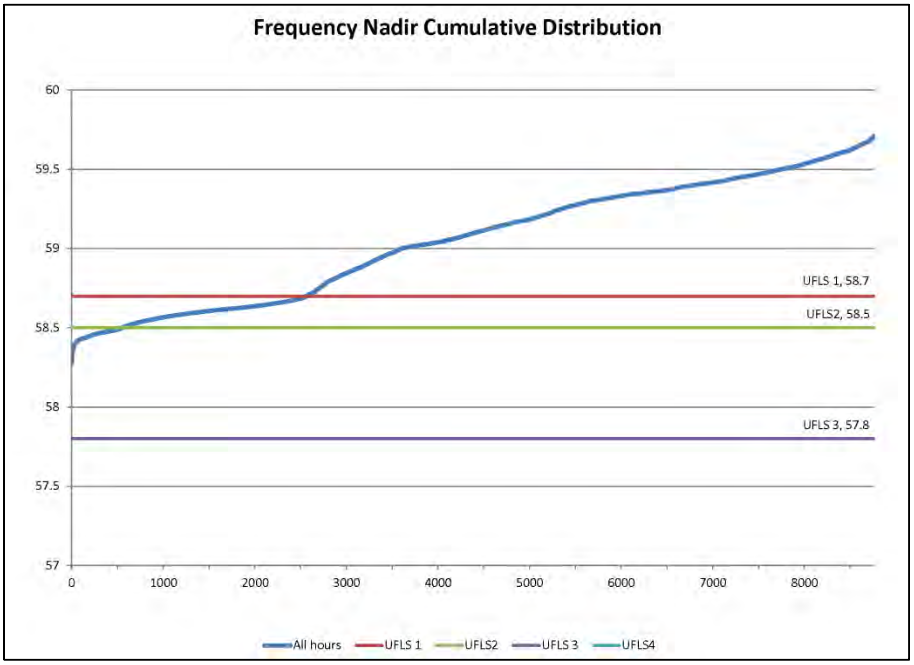


Figure O-56. Frequency Nadir Duration Curve for 2016

Figure O-56 shows the frequency nadir duration curve for 2016.

Unit Commitment Order	Unit Ratings					Maui 2016 (Typical) Mon 4/13/2016 Hour14			Maui 2016 (Boundary) Sat 3/11/2045 Hour13		
	Pmax	Pmin	Inertia H	Unit MVA	Unit K.E.	Pgen	up reg (spin)	down reg	Pgen	up reg (spin)	down reg
Kahului 3	11.5	3.0	6.53	13.5	88	5.0	6.5	2.0	5.0	6.5	2.0
Kahului 4	11.5	3.0	3.48	13.5	47	5.0	6.5	2.0	5.0	6.5	2.0
M14	20.0	5.9	2.02	28.8	58	13.5	6.5	7.6			
M15	13.0	6.0	2.46	18.5	46	8.0	5.0	2.0			
M16	20.0	5.9	2.02	26.8	54	13.5	6.5	7.6			
Kahului 1	4.8	2.3	5.23	6.3	33						
Kahului 2	4.9	2.3	5.23	6.3	33						
M17	19.5	5.9	2.02	26.8	54	6.0	13.5	0.1	13.0	6.5	7.1
M18	12.8	3.0	2.46	18.5	46				4.0	8.8	1.0
M19	19.5	5.9	2.02	26.8	54						
Maalae10	12.3	7.9	3.28	15.6	51						
Maalae12	12.3	7.9	3.28	15.6	51						
Maalae13	12.3	7.9	3.28	15.6	51						
Maalae11	12.3	7.9	3.28	15.6	51						
Maalaea4	5.5	1.9	2.28	7.0	16						
Maalaea6	5.5	1.9	2.28	7.0	16						
Maalaea9	5.5	1.9	2.28	7.0	16						
Maalaea8	5.5	1.9	2.28	7.0	16						
Maalaea5	5.5	1.9	2.28	7.0	16						
Maalaea1	2.5	2.5	0.83	3.4	3						
Maalaea3	2.5	2.5	0.83	3.4	3						
Maalaea2	2.5	2.5	0.83	3.4	3						
MaalaeX2	2.5	2.5	0.83	3.4	3						
MaalaeX1	2.5	2.5	0.83	3.4	3						
Maalaea7	5.5	1.9	2.28	7.0	16						
Total Wind	72	0				58			55		
-KWP	30	0				28			29		
-Auwahi	21	0				21			21		
-KWPII	21	0				9			5		
DG-PV	98.96	0				73			59		
Total System MVA							128			72	
Total Kinetic Energy							347			235	
Total Load							177			140	
Total Thermal Generation							51			27	
Total Renewable Generation							131			114	
Total Generation							182			141	
Excess Generation							5			1	
Regulation Requirement[1]							0			0	
Total Up Regulation							45			28	
Total Down Regulation							21			12	
Legacy DG-PV	59.3Hz Capacity			6.7		59.3Hz Output		5.0	59.3Hz Output		4.0
	60.5Hz Capacity			29.9		60.5Hz Output		22.0	60.5Hz Output		17.8

Table O-24. Unit Commitment and Dispatch for 2016

Table O-24 shows the unit commitment and dispatch schedules for the typical hour (4/18/2016 at 2:00 PM) and boundary hour (11/26/2016 at 1:00 PM).

Loss of Generation

Simulations were performed for the largest loss of generation contingency event to determine the frequency response reserves requirements to bring the system into compliance with TPL-001.

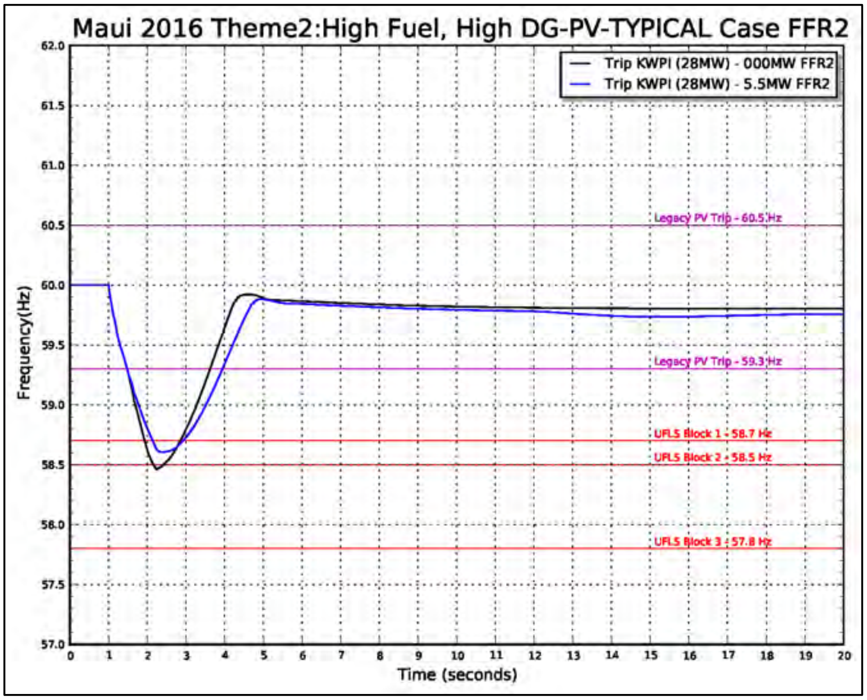


Figure O-57. Frequency Response Profile for FFR2 Typical Hour

Figure O-57 shows the frequency response profile for a KWP wind plan trip at 28 MW for a typical hour. System kinetic energy is 347 MW-sec and the capacity of legacy PV that will disconnect from the system is 4 MW. With no FFR, the frequency nadir breaches 58.5 Hz and two blocks of UFLS are required to stabilize system frequency. The capacity of FFR2 required to bring the system into compliance with TPL-001, only one UFLS block, is 5.5 MW.

Hawaiian Electric
Maui Electric
Hawai'i Electric Light

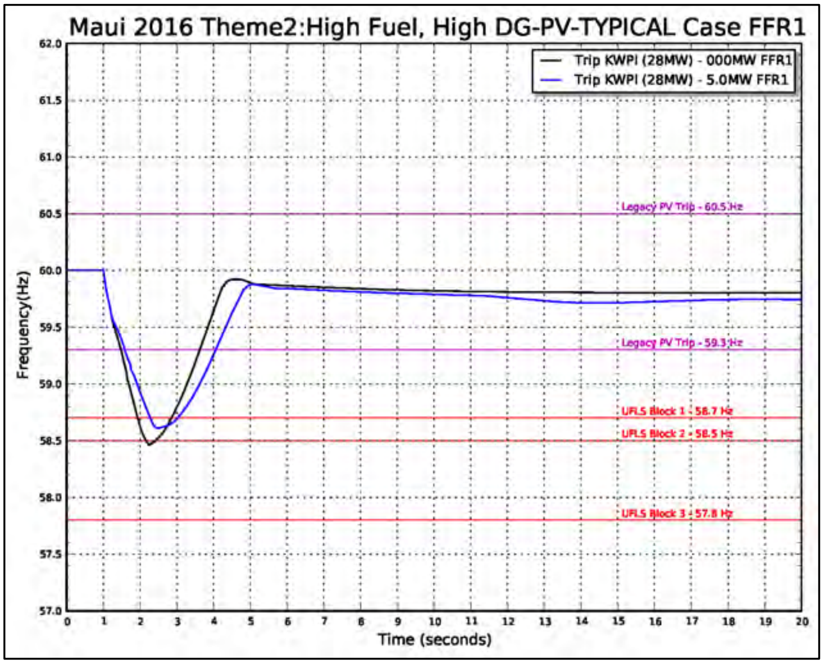


Figure O-58. Frequency Response Profile for FFR1 Typical Hour

Figure O-58 shows the frequency response profile for the FFR1 analysis for the typical hour. The capacity of FFR1 required to bring the system into compliance with TPL-001 is 5 MW.

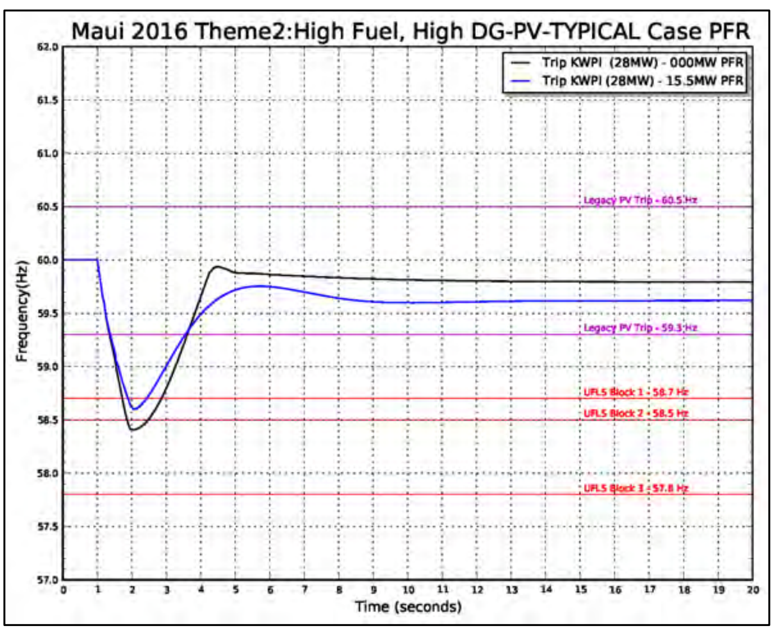


Figure O-59. Frequency Response Profile for PFR Typical Hour

Figure O-59 shows the frequency response profile for the PFR analysis for the typical hour. The capacity of PFR required to bring the system into compliance with TPL-001 is 15.5 MW.

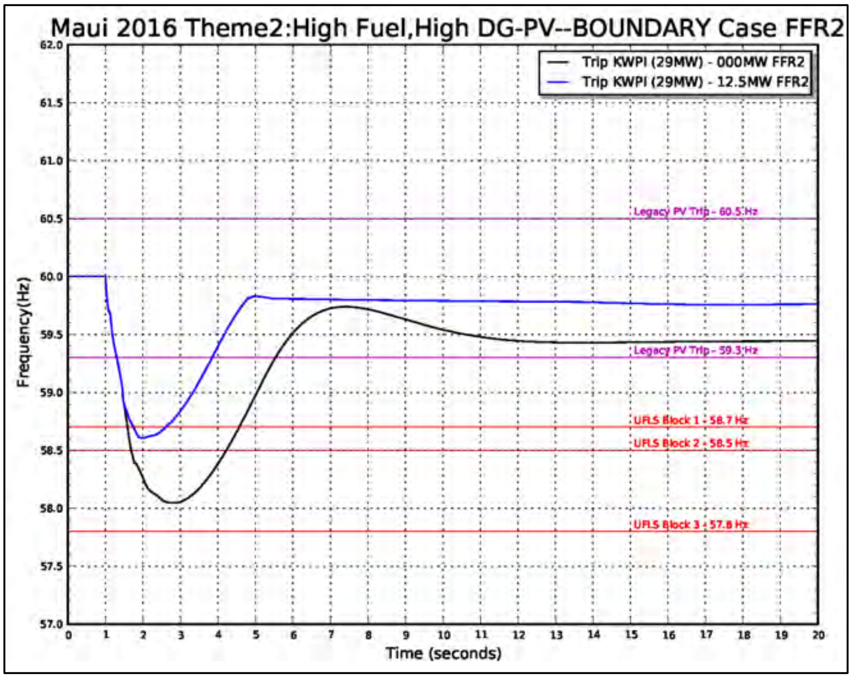


Figure O-60. Frequency Response Profile for FFR2 Boundary Hour

Figure O-60 shows the frequency response profile for a KPW wind plan trip at 29 MW for a typical hour. System kinetic energy is 235 MW-sec and the capacity of legacy PV that will disconnect from the system is approximately 5 MW. With no FFR, the frequency nadir breaches 58.5 Hz and two blocks of UFLS are required to stabilize system frequency. The capacity of FFR2 required to bring the system into compliance with TPL-001 is 5.5 MW.

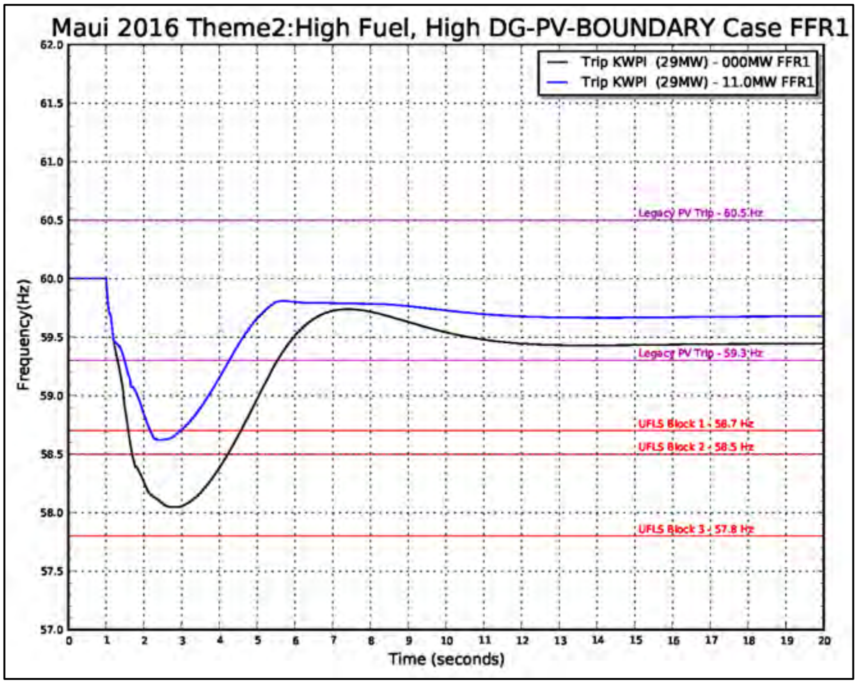


Figure O-61. Frequency Response Profile for FFR1 Boundary Hour

Figure O-61 shows the frequency response profile for the FFR1 analysis for the boundary hour. The capacity of PFR required to bring the system into compliance with TPL-001 is 11 MW.

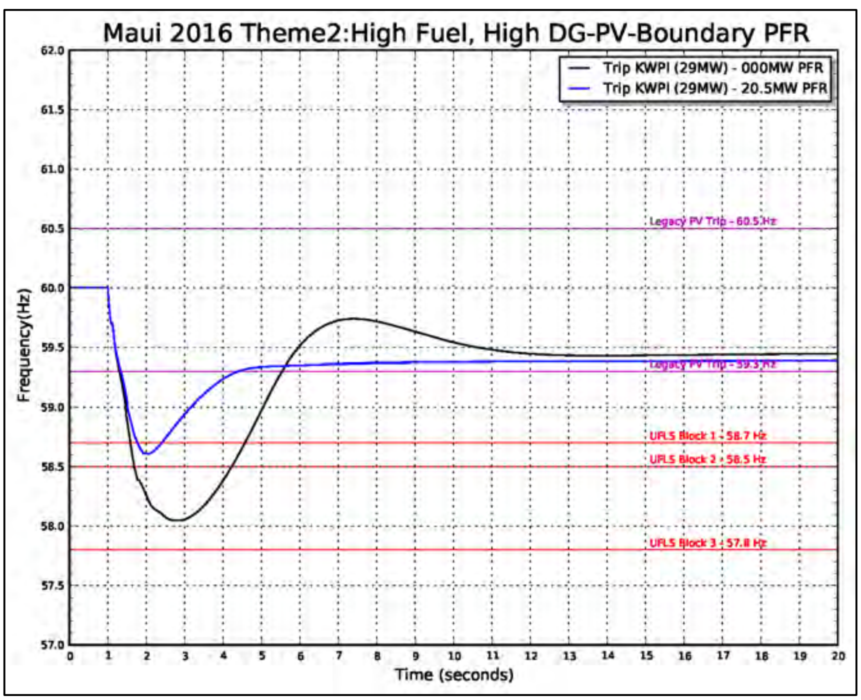


Figure O-62. Frequency Response Profile for PFR Boundary Hour

Figure O-62 shows the frequency response profile for the PFR analysis for the boundary hour. The capacity of PFR required to bring the system into compliance with TPL-001 is 20.5 MW.

69 kV Fault Analysis

Simulations were performed for electrical faults on the 69 kV transmission lines for the typical and boundary hours. A three-phase fault was placed on a transmission line to evaluate system performance to normally cleared faults and delayed clearing faults. Normally cleared faults are isolated in 5-cycles and delayed clearing faults are isolate in 24 cycles to simulate Zone 2 clearing. Simulations for both normally cleared faults and delayed cleared faults did not produce and system stability issues but some faults triggered loss of generation events.

2016 69 kV and 23 kV Fault Delayed ClearingAnalysis			
Circuit Outage	**3-phase Fault Near**	**Typical Hour Condition**	**Boundary Hour Condition**
Maalaea-Kihei	Kihei	Stable	Stable/Loadshed
	Maalaea	Stable	Stable
Maalaea-Waiinu	Waiinu	Stable	Stable
	Maalaea	Stable	Stable
Maalaea-Puunene	Puunene	Stable	Stable
	Maalaea	Stable	Stable
Maalaea-KWP I	KWP I	Stable	Stable/Loadshed
	Maalaea	Stable	Stable
Maalaea-KWP II	KWP II	Stable	Stable/Loadshed
	Maalaea	Stable	Stable
Maalaea-Lahainaluna	Lahainaluna	Stable	Stable
	Maalaea	Stable	Stable
Kahului-FDR1	FDR1	Stable	Stable
	Kahului	Stable	Stable
Kahului-FDR2	FDR2	Stable	Stable
	Kahului	Stable	Stable
Kahului-Wailuku	Wailuku	Stable	Stable
	Kahului	Stable	Stable

Table O-25. Summary of Results for the 2016 Fault Analysis

Table O-25 summarized the results of the delayed clearing fault analysis. There were three simulations for the boundary hour that resulted in load shedding.

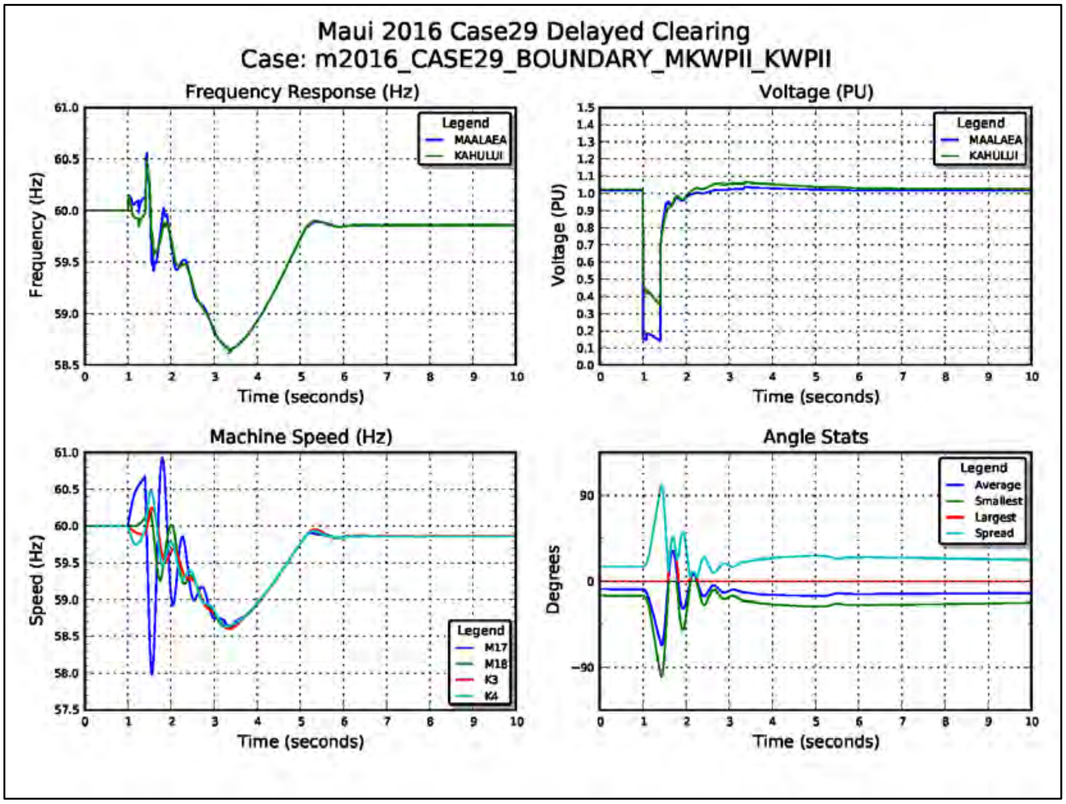


Figure O-63. System Performance for Delayed Clearing Analysis

Figure O-63 shows four plots that illustrate loss of DG-PV due a delayed clearing fault on the Ma'alaea-KWP II circuit for the boundary hour. The system frequency peak is greater than 60.5 Hz so approximately 18 MW of legacy will disconnect from the system.

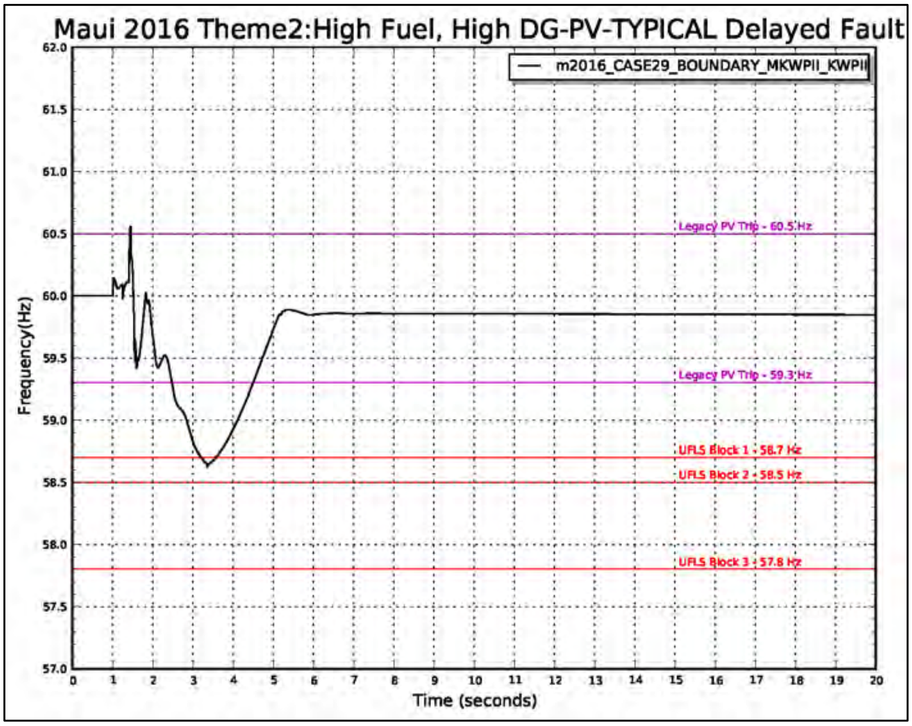


Figure O-64. Frequency Response Profile for Delayed Clearing Fault

Figure O-64 shows the frequency response profile for the delayed clearing fault. System performance meets the requirements of TPL-001.

2019—Compliance with TPL-001

Simulations were performed for the typical and boundary hours to determine the system requirements to bring the system into compliance with TPL-001 for the largest loss of generation contingency.

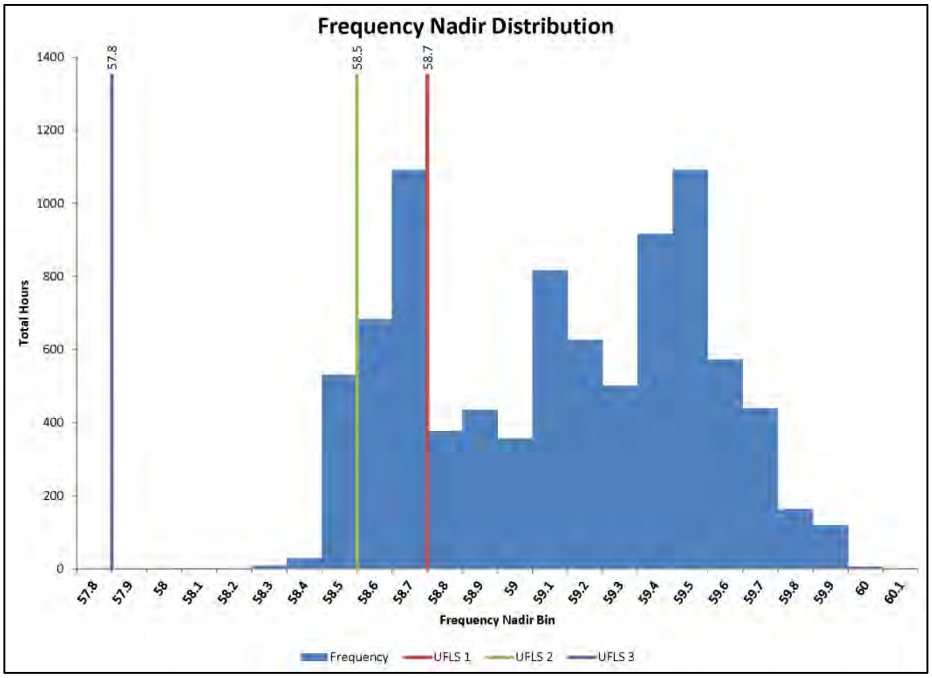


Figure O-65. Frequency Nadir Histogram for 2019

Figure O-65 is a histogram of the expected frequency nadirs for N-1 generator contingency events for the entire year. The typical hour selected from the maximum distribution of 530 hours was 2:00 PM on Monday, December 16. The frequency nadir range for the typical hour is 58.4 - 58.5 Hz that requires two blocks of UFLS to stabilize system frequency.

The boundary hour selected from a minimum distribution of 1 hour was 2:00 PM on Sunday, March 17. The frequency nadir range for the boundary hour is 58.2 – 58.3 Hz that requires two blocks of UFLS to stabilize system frequency.

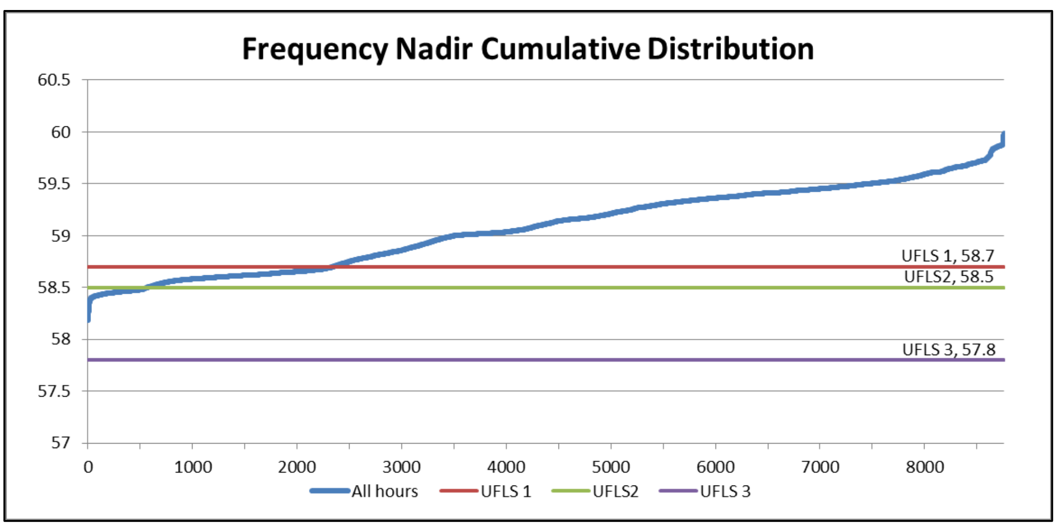


Figure O-66. Frequency Nadir Duration Curve for 2019

Figure O-66 shows the frequency nadir duration curve for 2016.

Unit Commitment Order	Unit Ratings					Maui 2019 (Typical) Mon 12/16/2019 Hour14			Maui 2019 (Boundary) Sun 3/17/2019 Hour14		
	Pmax	Pmin	Inertia H	Unit MVA	Unit K.E.	Pgen	up reg (spin)	down reg	Pgen	up reg (spin)	down reg
Kahului 3	11.5	3.0	6.53	13.5	88	5.0	6.5	2.0	5.0	6.5	2.0
Kahului 4	11.5	3.0	3.48	13.5	47	5.0	6.5	2.0	5.0	6.5	2.0
M14	20.0	5.9	2.02	28.8	58	9.0	11.0	3.1	8.0	12.0	2.1
M15	13.0	4.0	2.46	18.5	46	4.0	9.0	0.0	4.0	9.0	0.0
M16	20.0	5.9	2.02	26.8	54	9.0	11.0	3.1	8.0	12.0	2.1
Kahului 1	4.8	2.3	5.23	6.3	33						
Kahului 2	4.9	2.3	5.23	6.3	33						
M17	19.5	5.9	2.02	26.8	54	6.0	13.5	0.1			
M18	12.8	3.0	2.46	18.5	46						
M19	19.5	5.9	2.02	26.8	54						
Maalae10	12.3	7.9	3.28	15.6	51						
Maalae12	12.3	7.9	3.28	15.6	51						
Maalae13	12.3	7.9	3.28	15.6	51						
Maalae11	12.3	7.9	3.28	15.6	51						
Maalaea4	5.5	1.9	2.28	7.0	16						
Maalaea6	5.5	1.9	2.28	7.0	16						
Maalaea9	5.5	1.9	2.28	7.0	16						
Maalaea8	5.5	1.9	2.28	7.0	16						
Maalaea5	5.5	1.9	2.28	7.0	16						
Maalaea1	2.5	2.5	0.83	3.4	3						
Maalaea3	2.5	2.5	0.83	3.4	3						
Maalaea2	2.5	2.5	0.83	3.4	3						
MaalaeX2	2.5	2.5	0.83	3.4	3						
MaalaeX1	2.5	2.5	0.83	3.4	3						
Maalaea7	5.5	1.9	2.28	7.0	16						
Total Wind	72	0				70			53		
-KWP	30	0				28			30		
-Auwahi	21	0				21			2		
-KWPII	21	0				21			21		
DG-PV	120.3	0				65			92		
Station PV	5.74	0				3			0		
Total System MVA							128			101	
Total Kinetic Energy							347			293	
Total Load							170			169	
Total Thermal Generation							38			30	
Total Renewable Generation							138			145	
Total Generation							176			175	
Excess Generation							6			6	
Regulation Requirement[1]							0			0	
Total Up Regulation							58			46	
Total Down Regulation							10			8	
Legacy DG-PV	59.3Hz Capacity			6.7		59.3Hz Output		3.6	59.3Hz Output		5.2
	60.5Hz Capacity			29.9		60.5Hz Output		16.1	60.5Hz Output		22.8

Table O-26. Unit Commitment and Dispatch for 2019

Table O-26 shows the unit commitment and dispatch schedules for the typical hour (12/16/2019 at 2:00 PM) and boundary hour (3/17/2019 at 2:00 PM).

Loss of Generation

Simulations were performed for the largest loss of generation contingency event to determine the frequency response reserves requirements to bring the system into compliance with TPL-001.

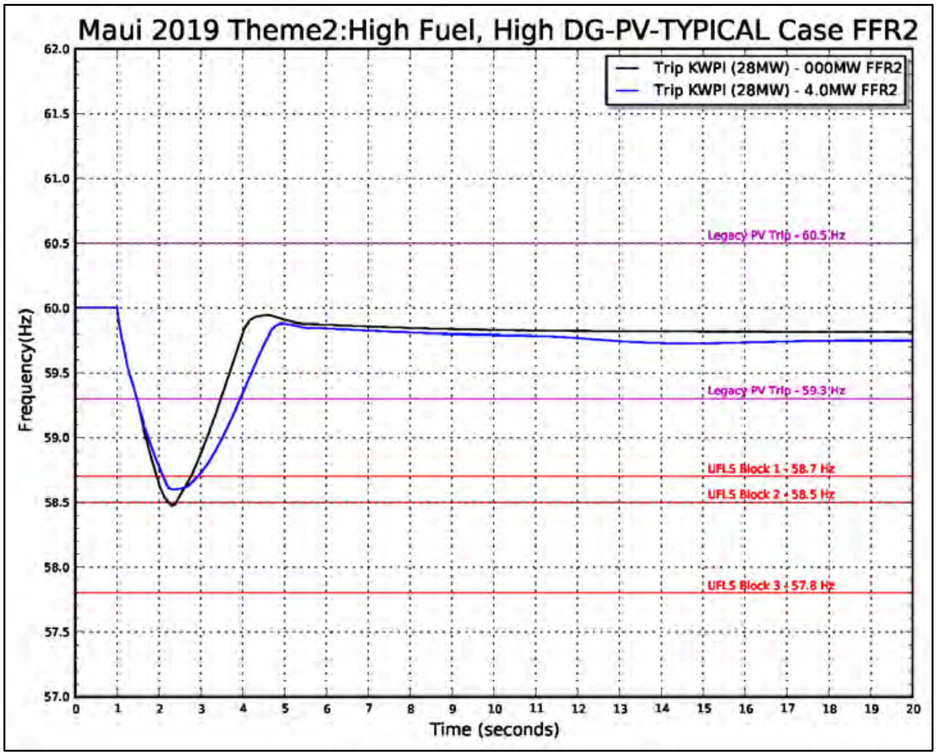


Figure O-67. Frequency Response Profile for FFR2 Typical Hour

Figure O-67 shows the frequency response profile for a KWP wind plant trip at 28 MW output for a typical hour. System kinetic energy is 347MW-sec and the capacity of legacy PV that will disconnect from the system is approximately 3.6 MW. With no FFR, the frequency nadir breaches 58.5 Hz and two blocks of UFLS is required to stabilize system frequency. The capacity of FFR2 required to bring the system into compliance with TPL-001 is 4 MW.

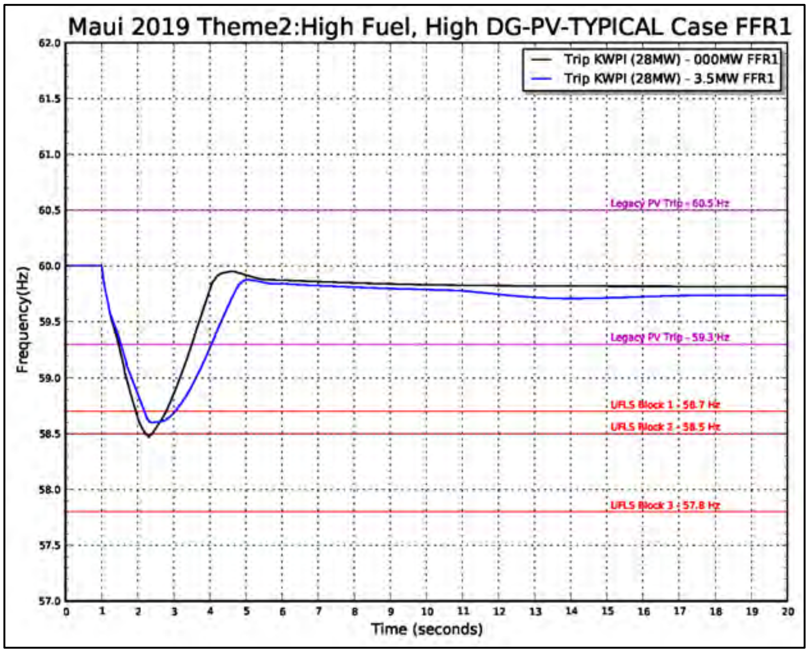


Figure O-68. Frequency Response Profile for FFR1 Typical Hour

Figure O-68 shows the frequency response profile for the FFR1 analysis for a typical hour. The capacity of FFR1 required to meet TPL-001 is 3.5 MW.

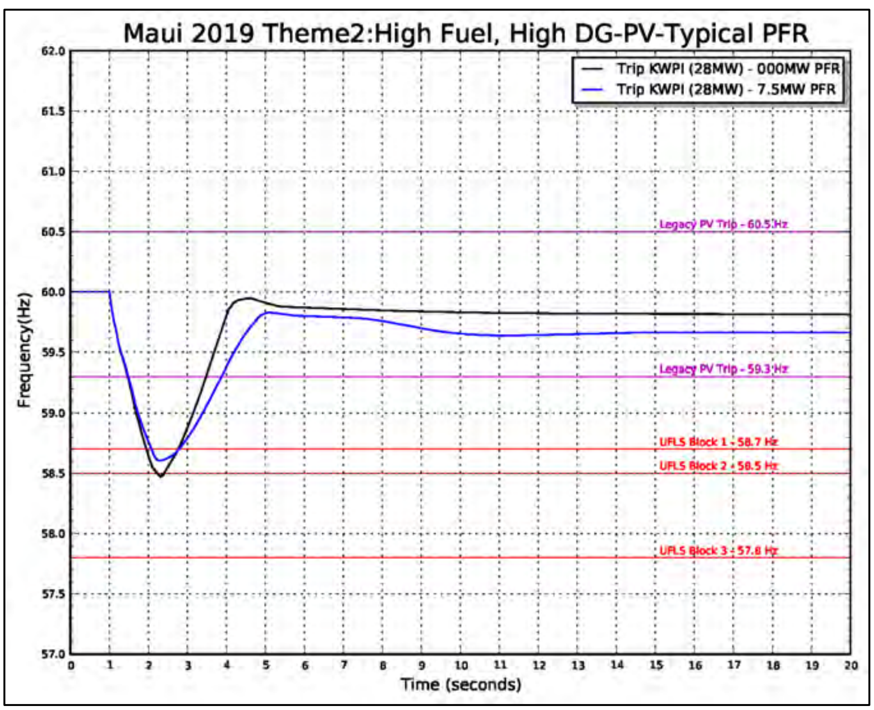


Figure O-69. Frequency Response Profile for PFR Typical Hour

Figure O-69 is the frequency response profile for the PFR analysis for the typical hour. The capacity of PFR required to meet TPL-001 is 7.5 MW.

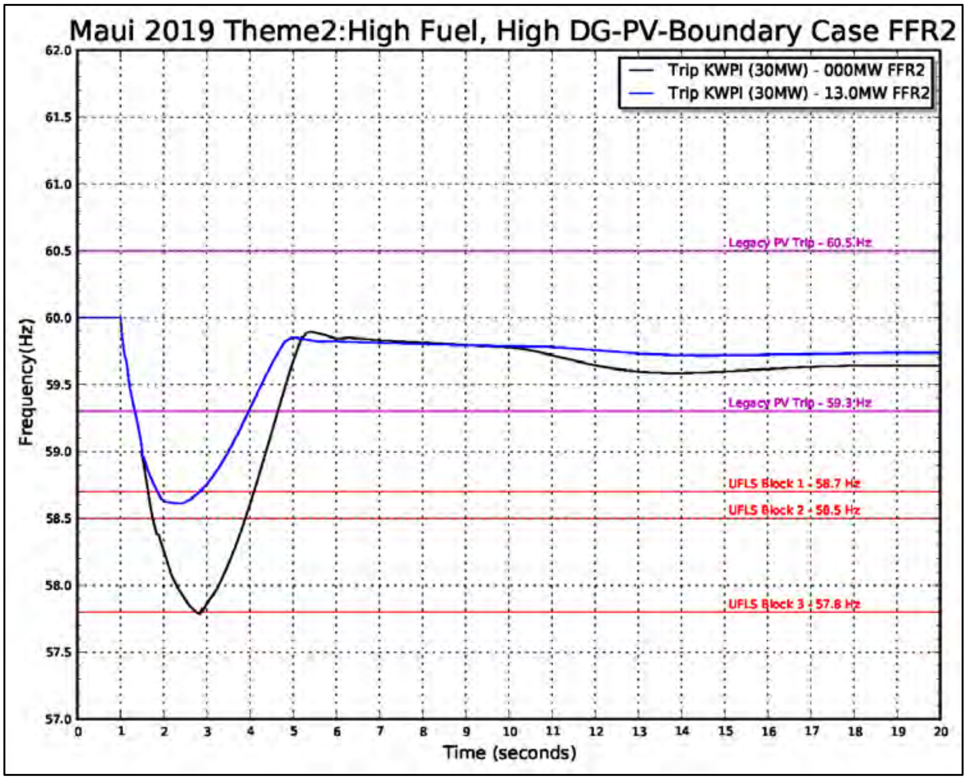


Figure O-70. Frequency Response Profile for FFR2 Boundary Hour

Figure O-70 shows the frequency response profile for a KWP wind plant trip at 30 MW for the boundary hour. System kinetic energy is 293 MW-sec and the capacity of legacy PV that will disconnect from the system is approximately 5.2 MW. With no FFR, the frequency nadir is 57.5 Hz and three blocks of UFLS is required to stabilize system frequency. The capacity of FFR2 required to bring the system into compliance with TPL-001 is 13 MW.

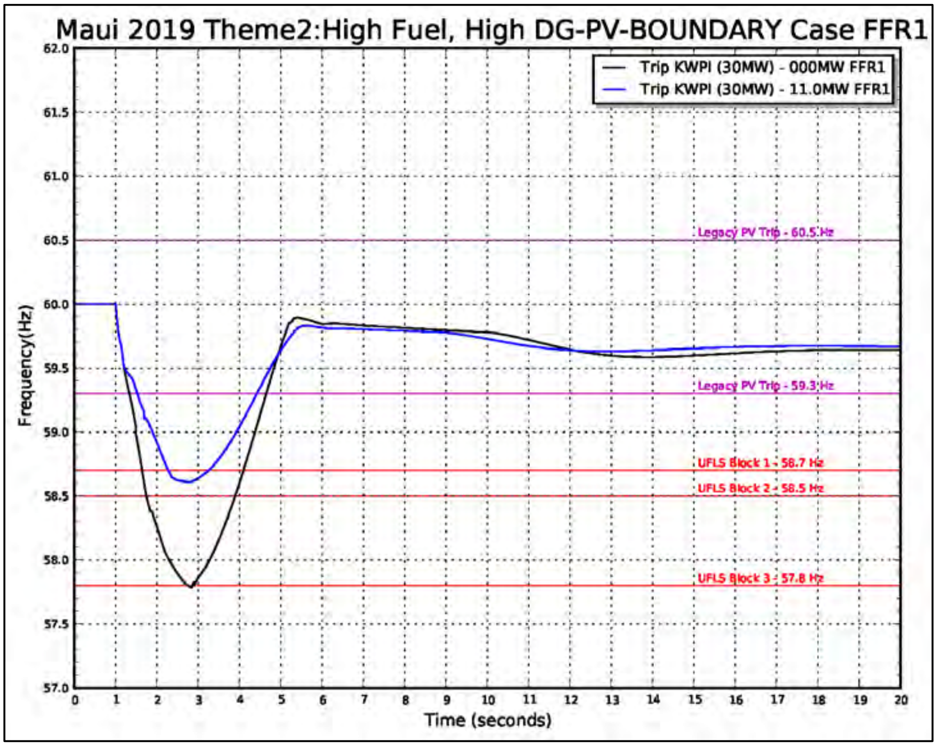


Figure O-71. Frequency Response Profile for FFR1 Boundary Hour

Figure O-71 shows the frequency response profile for the FFR1 analysis for a boundary hour. The capacity of FFR1 required to meet TPL-001 is 11 MW.

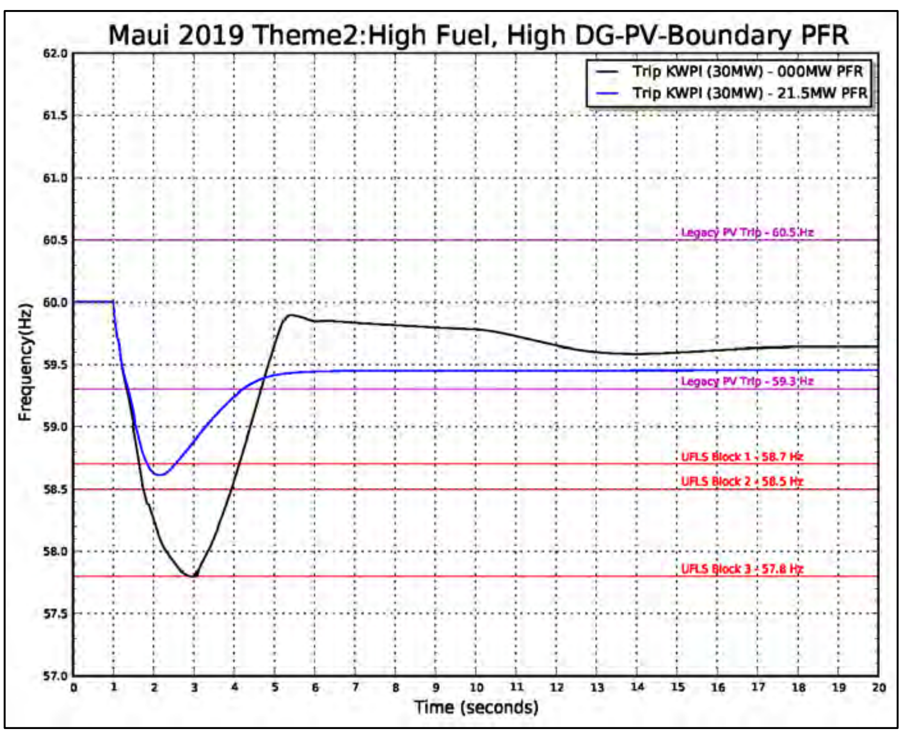


Figure O-72. Frequency Response Profile for PFR Boundary Hour

Figure O-72 shows the frequency response profile for the PFR analysis for a typical hour. The capacity of PFR required to meet TPL-001 is 21.5 MW.

69 kV Fault Analysis

Simulations were performed for electrical faults on the 69 kV transmission lines for the typical and boundary hours. Simulations for both the normally cleared faults and delayed clearing faults did not produce any rotor angle stability issues or loss of generation from over frequency events.

2019 69Kv and 23 kV Fault Delayed Clearing Analysis			
Circuit Outage	**3-phase Fault Near**	**Typical Hour Condition**	**Boundary Hour Condition**
Maalaea-Kihei	Kihei	Stable	Stable
	Maalaea	Stable	Stable
Maalaea-Waiinu	Waiinu	Stable	Stable
	Maalaea	Stable	Stable
Maalaea-Puunene	Puunene	Stable	Stable
	Maalaea	Stable	Stable
Maalaea-KWP I	KWP I	Stable	Stable
	Maalaea	Stable	Stable
Maalaea-KWP II	KWP II	Stable	Stable
	Maalaea	Stable	Stable
Maalaea-Lahainaluna	Lahainaluna	Stable	Stable
	Maalaea	Stable	Stable
Kahului-FDR1	FDR1	Stable	Stable
	Kahului	Stable	Stable
Kahului-FDR2	FDR2	Stable	Stable
	Kahului	Stable	Stable
Kahului-Wailuku	Wailuku	Stable	Stable
	Kahului	Stable	Stable

Table O-27. Summary of Results for the 20232019 Fault Analysis

Table O-27 summarizes the results of the delayed clearing fault analysis. There were no system security issues.

Theme 1 – Aggressive Renewables Plan

Summary

System security analyses were not performed on any resource plan for Theme 1. A high-level fatal flaw assessment was performed on the Theme 1 2045 plans by applying system security requirements for Themes 2 and 3.

Theme 2 – LNG Plan

2023

System security analysis was performed for two hours that represents a typical hour and a boundary condition.

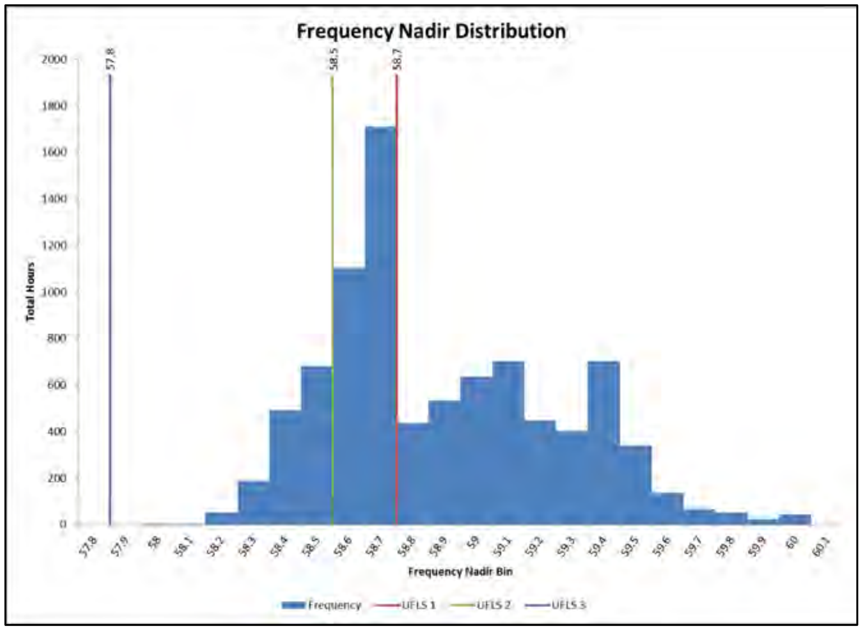


Figure O-73. Frequency Nadir Histogram for 2023

Figure O-73 is a histogram of the expected frequency nadirs for N-1 generator contingency events for the entire year. The typical hour selected from the maximum distribution of 682 hours was 12:00 PM on Friday, June 2. The frequency nadir range for the typical hour is 58.4 – 58.5 Hz that requires 2 blocks of UFLS to stabilize system frequency.

The boundary hour selected from a minimum distribution of 1 hour was 1:00 PM on Sunday, July 23. The frequency nadir range for the boundary hour was 57.9 – 58.0 Hz that would require 2 blocks of UFLS to stabilize system frequency.

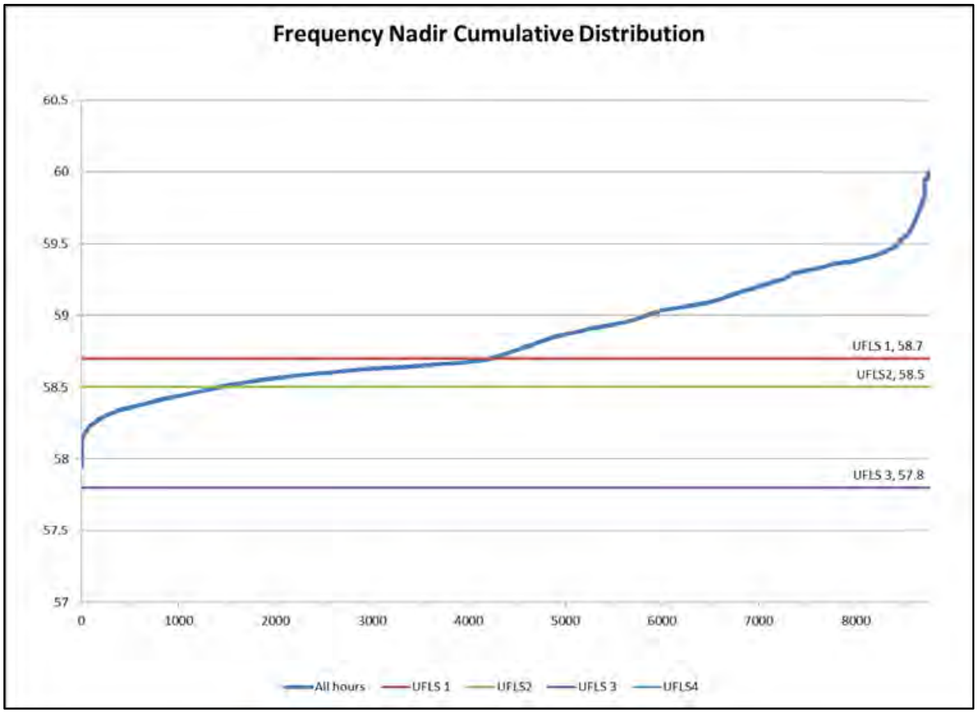


Figure O-74. Frequency Nadir Duration Curve 2023

Figure O-74 shows the frequency nadir duration curve for 2023.

Unit Commitment Order	Unit Ratings					Maui 2023 (Typical) Fri 6/2/2023 Hour12			Maui 2023 (Boundary) Sun 7/23/2023 Hour13		
	Pmax	Pmin	Inertia H	Unit MVA	Unit K.E.	Pgen	up reg (spin)	down reg	Pgen	up reg (spin)	down reg
Biomass1	20.0		3.48	25.0	87	8.0	12.0	8.0	8.0	12.0	8.0
M14	20.0	5.9	2.02	28.8	58	7.0	13.0	1.1	9.0	11.0	3.1
M15	13.0	6.0	2.46	18.5	46				6.0	7.0	0.0
M16	20.0	5.9	2.02	26.8	54						
M17	19.5	5.9	2.02	26.8	54	6.0	13.5	0.1			
M18	12.8	3.0	2.46	18.5	46						
M19	19.5	5.9	2.02	26.8	54						
Maalae10	12.3	7.9	3.28	15.6	51						
Maalae12	12.3	7.9	3.28	15.6	51						
Maalae13	12.3	7.9	3.28	15.6	51						
Maalae11	12.3	7.9	3.28	15.6	51						
Maalaea4	5.5	1.9	2.28	7.0	16						
Maalaea6	5.5	1.9	2.28	7.0	16						
Maalaea9	5.5	1.9	2.28	7.0	16						
Maalaea8	5.5	1.9	2.28	7.0	16						
Maalaea5	5.5	1.9	2.28	7.0	16						
Maalaea1	2.5	2.5	0.83	3.4	3						
Maalaea3	2.5	2.5	0.83	3.4	3						
Maalaea2	2.5	2.5	0.83	3.4	3						
MaalaeX2	2.5	2.5	0.83	3.4	3						
MaalaeX1	2.5	2.5	0.83	3.4	3						
Maalaea7	5.5	1.9	2.28	7.0	16						
ICE9_1	9.0	4.0	0.99	11.3	11						
ICE9_2	9.0	4.0	0.99	11.3	11						
Kahului 1	0.0	0.0	2.62	6.3	16	0.0	Sync. Condenser				
Kahului 2	0.0	0.0	2.62	6.3	16						
Kahului 3	0.0	0.0	3.27	13.5	44				0.0	Sync. Condenser	
Kahului 4	0.0	0.0	1.74	15.6	27	0.0	Sync. Condenser		0.0	Sync. Condenser	
Total Wind	132	0				62			50		
-KWP	30	0				23			29		
-Auwahi	21	0				19			1		
-KWPII	21	0				20			20		
-New Wind 1	30	0									
-New Wind 2	30	0									
DG-PV	122.7	0				87			97		
DER Grid Ex	22	0				24			17		
Total System MVA							103			101	
Total Kinetic Energy							243			262	
Total Load							186			182	
Total Thermal Generation							21			23	
Total Renewable Generation							173			164	
Total Generation							194			187	
Excess Generation							8			5	
Regulation Requirement[1]							0			0	
Total Up Regulation							27			18	
Total Down Regulation							1			3	
Legacy DG-PV	59.3Hz Capacity			6.7		59.3Hz Output		4.8	59.3Hz Output		5.3
	60.5Hz Capacity			29.9		60.5Hz Output		21.2	60.5Hz Output		23.6

Table O-28. Unit Commitment and Dispatch Schedule 2023

Table O-28 shows the unit commitment and dispatch schedules for the typical hour (6/2/2023 at 12:00 PM) and boundary hour (7/23/2023 at 1:00 PM).

Loss of Generation

Simulations were performed for the largest loss of generation contingency event to determine the frequency response reserves requirements to bring the system into compliance with TPL-001.

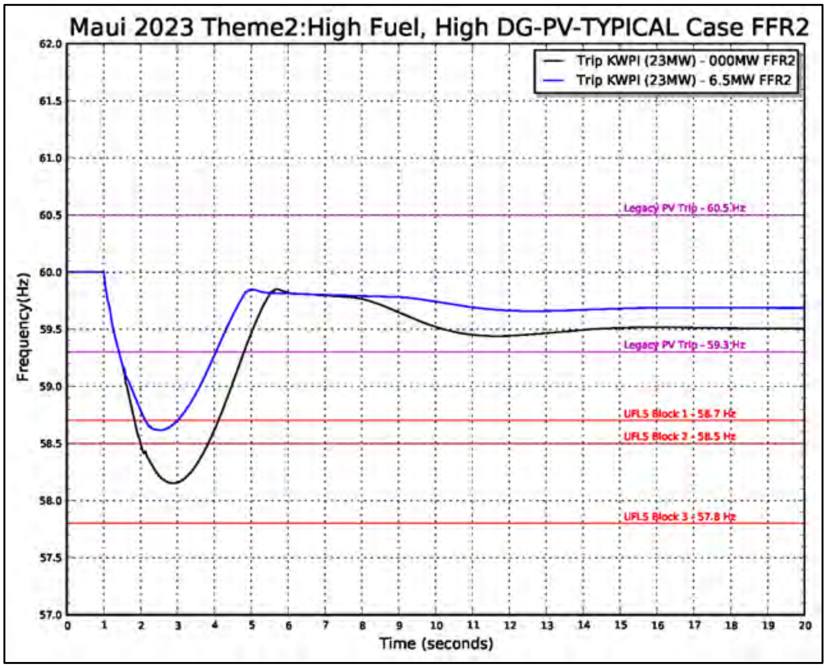


Figure O-75. Frequency Response Profile for FFR2 Typical Hour

Figure O-75 shows the frequency response profile for a KWP wind plant trip at 23 MW output for a typical hour. System kinetic energy is 243 MW-sec and the capacity of legacy PV that will disconnect from the system is approximately 4.8 MW. With no FFR, the frequency nadir breaches 58.2 Hz and two blocks of UFLS is required to stabilize system frequency. The capacity of FFR2 required to bring the system into compliance with TPL-001 is 6.5 MW.

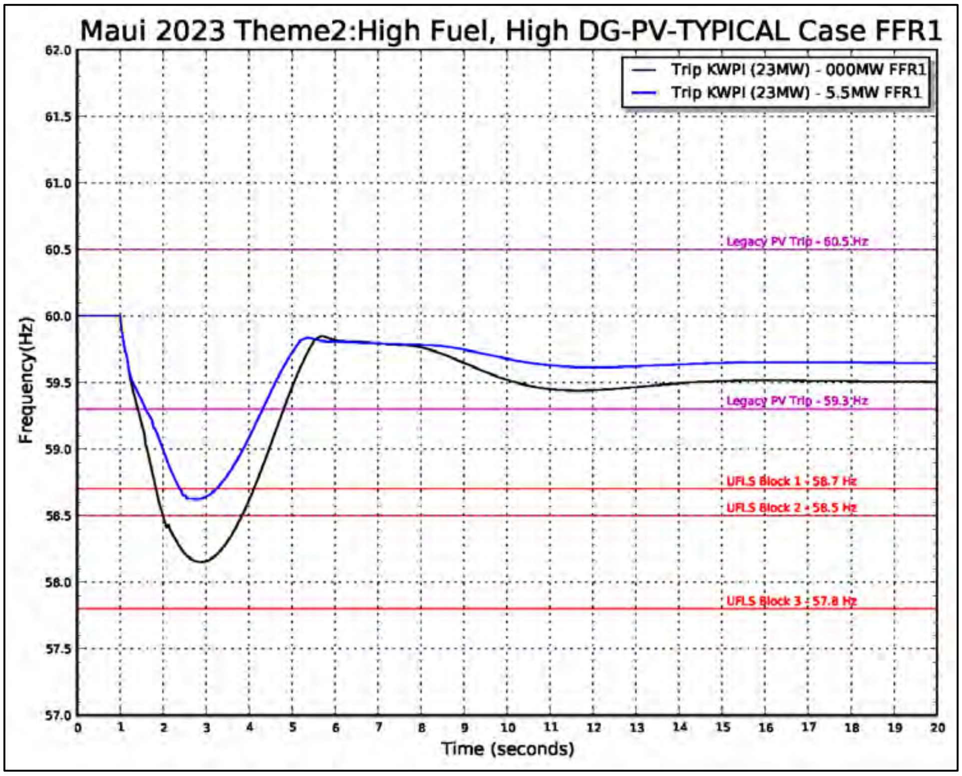


Figure O-76. Frequency Response Profile for FFR1 Typical Hour

Figure O-76 shows the frequency response profile for the FFR1 analysis for a typical hour. The capacity of FFR1 required to meet TPL-001 is 5.5 MW.

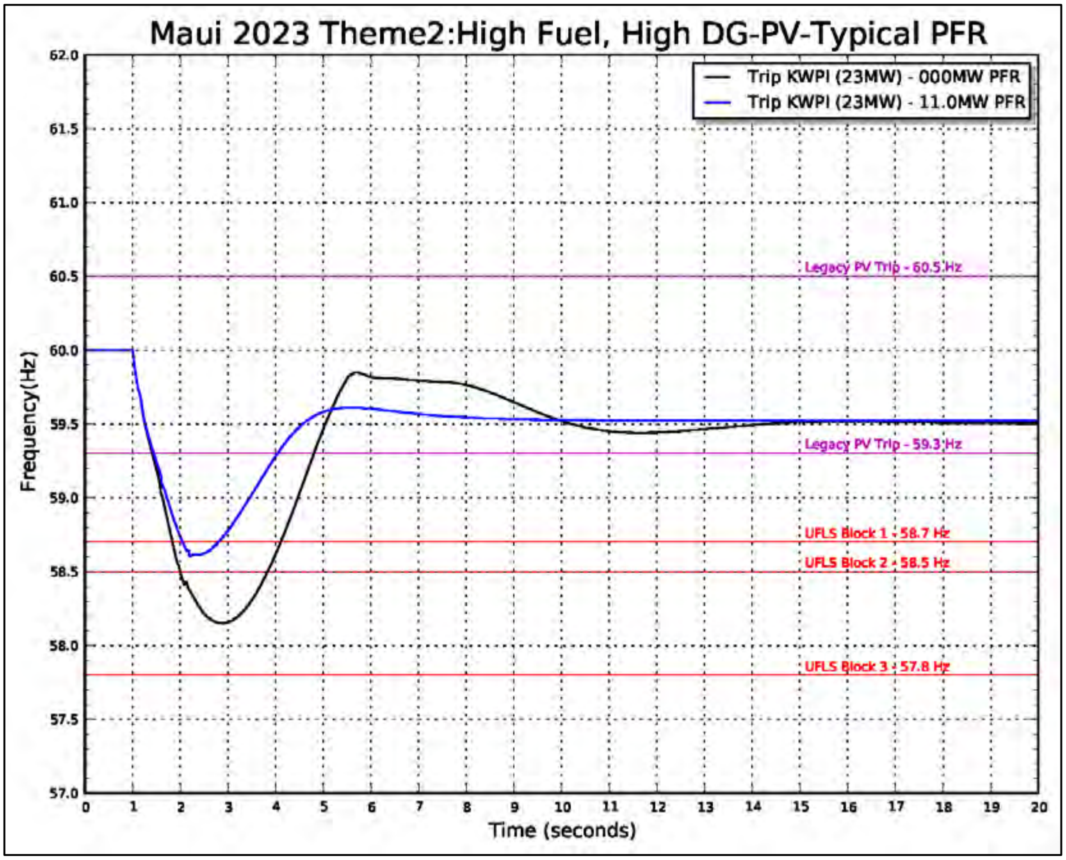


Figure O-77. Frequency Response Profile for PFR Typical Hour

Figure O-77 shows the frequency response profile for the PFR analysis for a typical hour. The capacity of PFR required to meet TPL-001 is 11 MW.

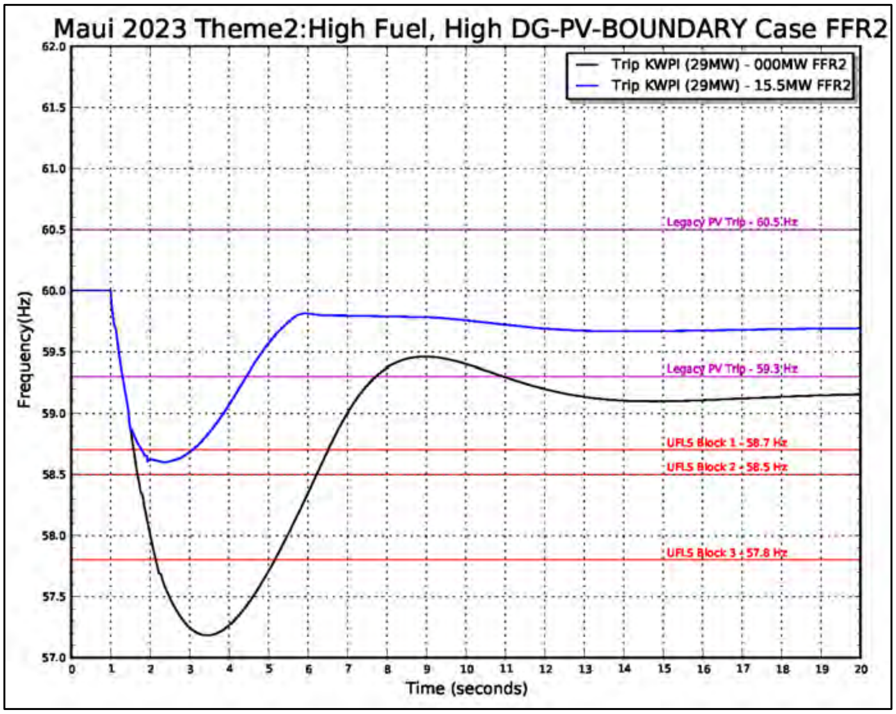


Figure O-78. Frequency Response Profile for FFR2 Boundary Hour

Figure O-78 shows the frequency response profile for a KWP wind plant trip at 29 MW output for a boundary hour. System kinetic energy is 262 MW-sec and the capacity of legacy PV that will disconnect from the system is approximately 5.3 MW. With no FFR, the frequency nadir breaches 57.2 Hz and three blocks of UFLS is required to stabilize system frequency. The capacity of FFR2 required to bring the system into compliance with TPL-001 is 15.5 MW.

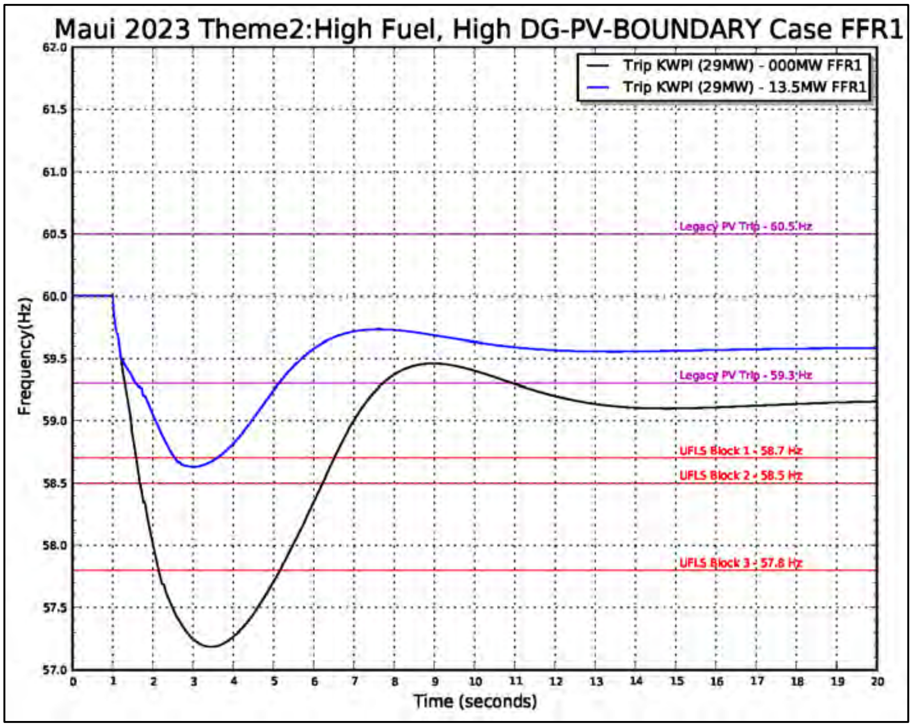


Figure O-79. Frequency Response Profile for FFR1 Boundary Hour

Figure O-79 shows the frequency response profile for the FFR1 analysis for a boundary hour. The capacity of FFR1 required to meet TPL-001 is 13.5 MW.

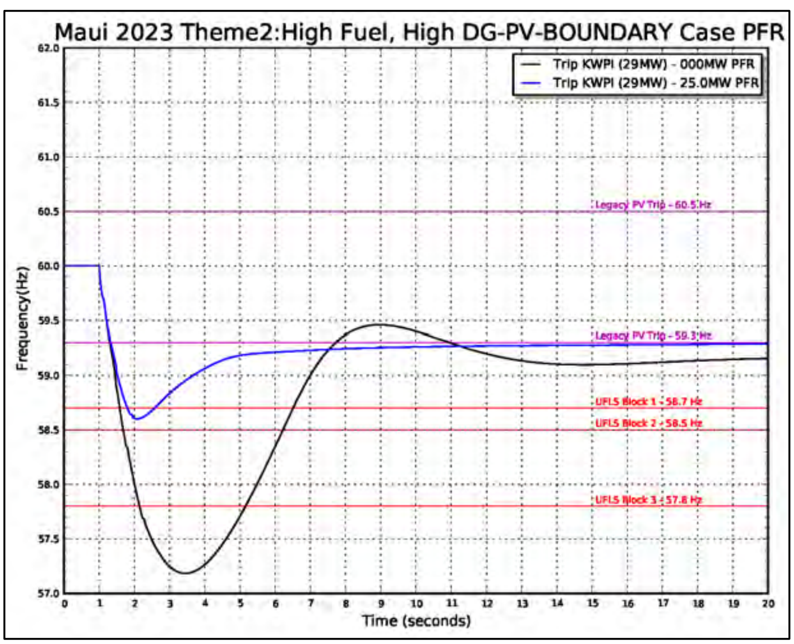


Figure O-80. Frequency Response Profile for PFR Boundary Hour

Figure O-80 shows the frequency response profile for the PFR analysis for a boundary hour. The capacity of PFR required to meet TPL-001 is 25 MW.

69 kV Fault analysis

Simulations were performed for electrical faults on the 69 kV transmission lines for the typical and boundary hours. Simulations for both the normally cleared faults and delayed clearing faults did not produce any rotor angle stability issues or loss of generation from over frequency events.

2023 69 kV and 23 kV Fault Normal Clearing Analysis			
Circuit Outage	3-phase Fault Near	Typical Hour Condition	Boundary Hour Condition
Maalaea-Kihei	Kihei	Stable	Stable
	Maalaea	Stable	Stable
Maalaea-Waiinu	Waiinu	Stable	Stable
	Maalaea	Stable	Stable
Maalaea-Puunene	Puunene	Stable	Stable
	Maalaea	Stable	Stable
Maalaea-KWP I	KWP I	Stable	Stable
	Maalaea	Stable	Stable
Maalaea-KWP II	KWP II	Stable	Stable
	Maalaea	Stable	Stable
Maalaea-Lahainaluna	Lahainaluna	Stable	Stable
	Maalaea	Stable	Stable
Kahului-FDR1	FDR1	Stable	Stable
	Kahului	Stable	Stable
Kahului-FDR2	FDR2	Stable	Stable
	Kahului	Stable	Stable
Kahului-Wailuku	Wailuku	Stable	Stable
	Kahului	Stable	Stable

Table O-29. Summary of Results for the 2023 Fault Analysis

Table O-29 summarizes the results of the fault analysis. There was no stability or loss of load events for this analysis.

2045

System security analysis was performed for two hours that represents a typical hour and a boundary condition.

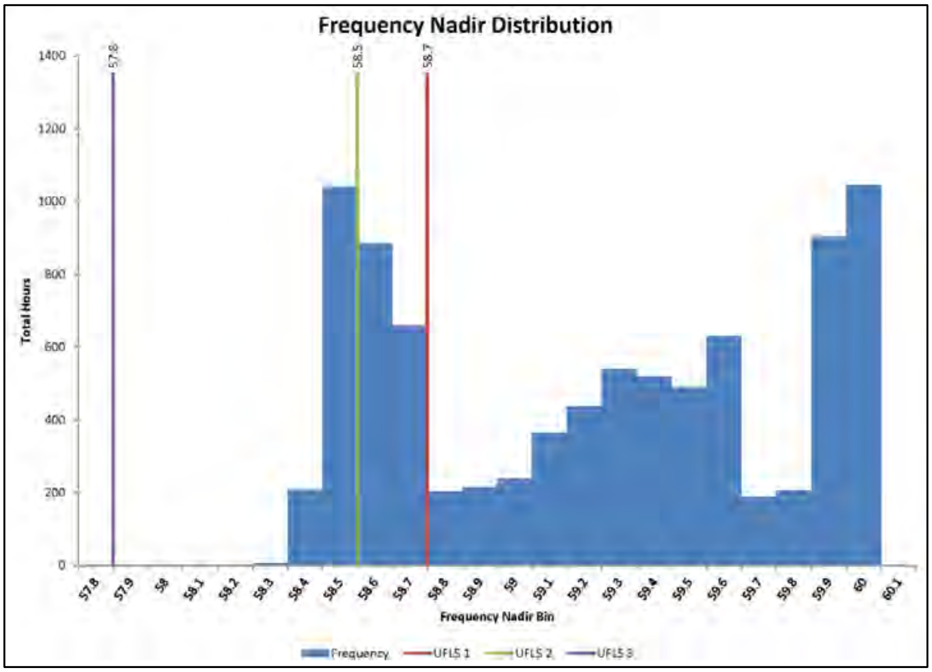


Figure O-81. Frequency Nadir Histogram for 2045

Figure O-81 is a histogram of the expected frequency nadirs for N-1 generator contingency events for the entire year. The typical hour selected from the maximum distribution of 516 hours was 2:00 PM on Monday, April 13. The frequency nadir range for the typical hour is 58.4 – 58.5 Hz that requires two blocks of UFLS to stabilize system frequency.

The boundary hour selected from a minimum distribution of 1 hour was 1:00 PM on Saturday, March 11. The frequency nadir range for the boundary hour is 58.3 – 58.4 Hz that requires two blocks of UFLS to stabilize system frequency.

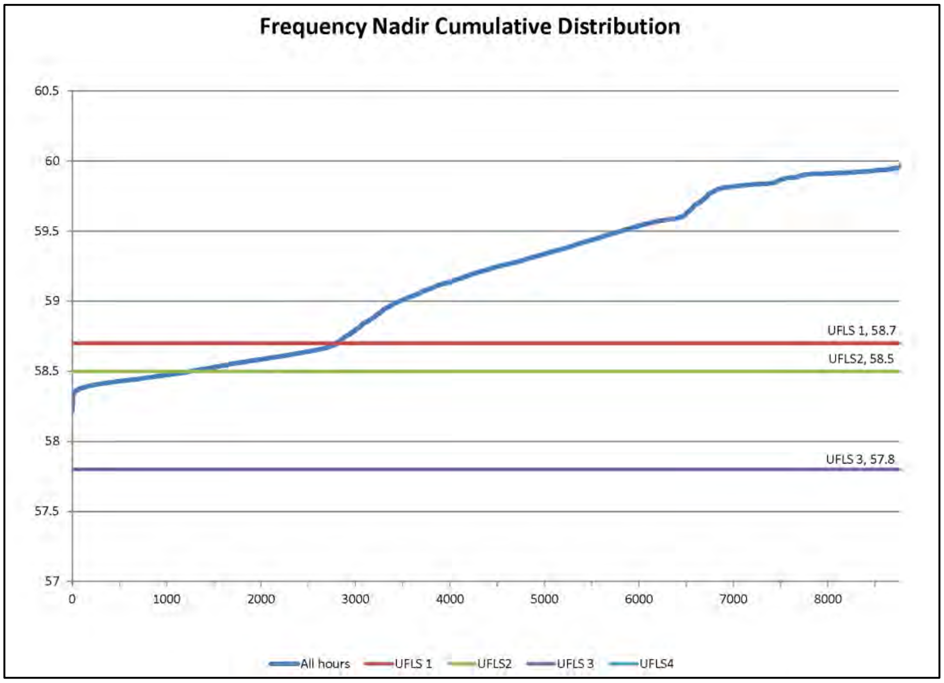


Figure O-82. Frequency Nadir Duration Curve for 2045

Figure O-82 shows the frequency nadir duration curve for 2045.

Unit Commitment Order	Unit Ratings					Maui 2045 (Typical) Tues 4/13/2045 Hour14			Maui 2045 (Boundary) Sun 3/19/2045 Hour15		
	Pmax	Pmin	Inertia H	Unit MVA	Unit K.E.	Pgen	up reg (spin)	down reg	Pgen	up reg (spin)	down reg
M14	20.0	5.9	2.02	28.8	58						
M15	13.0	6.0	2.46	18.5	46						
M16	20.0	5.9	2.02	26.8	54						
M17	19.5	5.9	2.02	26.8	54						
M18	12.8	3.0	2.46	18.5	46						
M19	19.5	5.9	2.02	26.8	54						
Maalae10	12.3	7.9	3.28	15.6	51						
Maalae12	12.3	7.9	3.28	15.6	51						
Maalae13	12.3	7.9	3.28	15.6	51						
Maalae11	12.3	7.9	3.28	15.6	51						
Maalaea4	5.5	1.9	2.28	7.0	16						
Maalaea6	5.5	1.9	2.28	7.0	16						
Maalaea9	5.5	1.9	2.28	7.0	16						
Maalaea8	5.5	1.9	2.28	7.0	16						
Maalaea5	5.5	1.9	2.28	7.0	16						
Maalaea1	2.5	2.5	0.83	3.4	3						
Maalaea3	2.5	2.5	0.83	3.4	3						
Maalaea2	2.5	2.5	0.83	3.4	3						
MaalaeX2	2.5	2.5	0.83	3.4	3						
MaalaeX1	2.5	2.5	0.83	3.4	3						
Maalaea7	5.5	1.9	2.28	7.0	16						
ICE9_1	9.0	4.0	0.99	11.3	11						
ICE9_2	9.0	4.0	0.99	11.3	11						
Biomass1	20.0		3.48	25.0	87	8.0	12.0	8.0	8.0	12.0	8.0
Biomass2	20.0		3.48	25.0	87	8.0	12.0	8.0	8.0	12.0	8.0
Kahului 1	0.0	0.0	2.62	6.3	16	0.0	Sync. Condenser		0.0	Sync. Condenser	
Kahului 2	0.0	0.0	2.62	6.3	16	0.0	Sync. Condenser		0.0	Sync. Condenser	
Kahului 3	0.0	0.0	3.27	13.5	44	0.0	Sync. Condenser		0.0	Sync. Condenser	
Kahului 4	0.0	0.0	1.74	15.6	27	0.0	Sync. Condenser		0.0	Sync. Condenser	
SYNC COND	0.0	0.0	1.74	60.0	104	0.0	Sync. Condenser		0.0	Sync. Condenser	
Total Wind	252	0				59			52		
-KWP	30	0				28			30		
-Auwahi	21	0				11			3		
-KWPII	21	0				20			19		
-New Wind 1	30	0									
-New Wind 2	30	0									
-New Wind 3	30	0									
-New Wind 4	30	0									
-New Wind 5	30	0									
-New Wind 6	30	0									
DG-PV	139.3	0				84			87		
DER Grid Ex	328	0				114			96		
Total System MVA							50			50	
Total Kinetic Energy							382			382	
Total Load							235			215	
Total Thermal Generation							16			16	
Total Renewable Generation							257			235	
Total Generation							273			251	
Excess Generation							38			36	
Regulation Requirement[1]							0			0	
Total Up Regulation							24			24	
Total Down Regulation							16			16	
Legacy DG-PV	59.3Hz Capacity			0.0		59.3Hz Output		0.0	59.3Hz Output		0.0
	60.5Hz Capacity			0.0		60.5Hz Output		0.0	60.5Hz Output		0.0

Table O-30. Unit Commitment and Dispatch for 2045

Table O-30 shows the unit commitment and dispatch schedules for the typical hour (4/13/2045 at 2:00 PM) and boundary hour (3/19/2045 at 3:00 PM).

Loss of Generation

Simulations were performed for the largest loss of generation contingency event to determine the frequency response reserves requirements to bring the system into compliance with TPL-001.

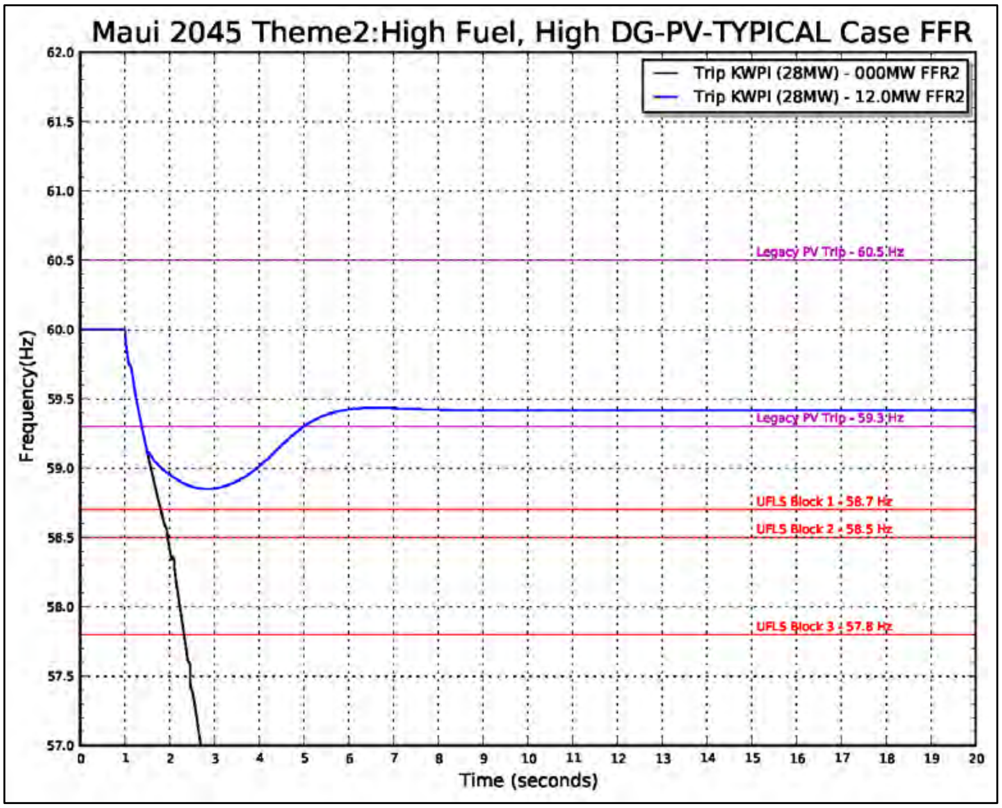


Figure O-83. Frequency Response Profile for FFR2 Typical Hour

Figure O-83 shows the frequency response profile for a KPW wind plan trip at 28 MW output for a typical hour. System kinetic energy is 382 MW-sec. With no FFR, the system will not survive a KWP trip. The total capacity of Grid Supply DG-PV is 114 MW so the first block of UFLS is actually a loss of generation so the UFLS has a cascading effect on declining frequency. The capacity of FFR2 required to bring the system into compliance with TPL-001 is 12 MW.

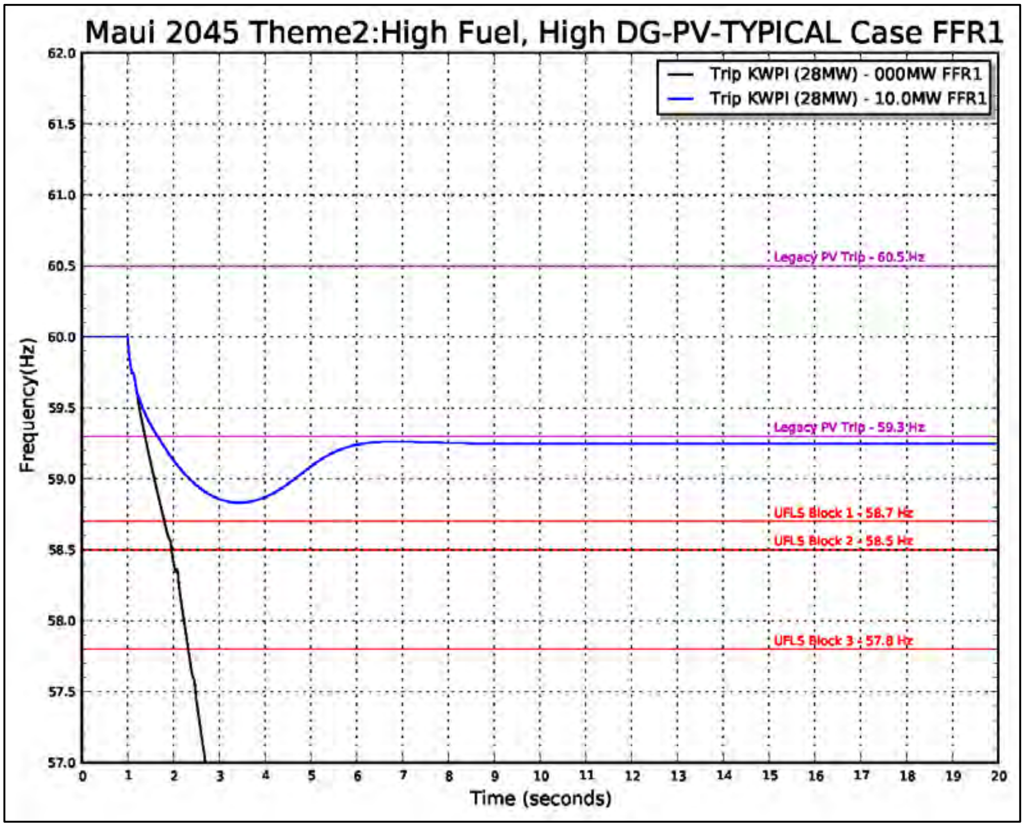


Figure O-84. Frequency Response Profile for FFR1 Typical Hour

Figure O-84 shows the frequency response profile for the FFR1 analysis. The capacity of FFR1 required to bring the system to avoid UFLS Block 1 and brings the system into compliance with TPL-001 is 10 MW.

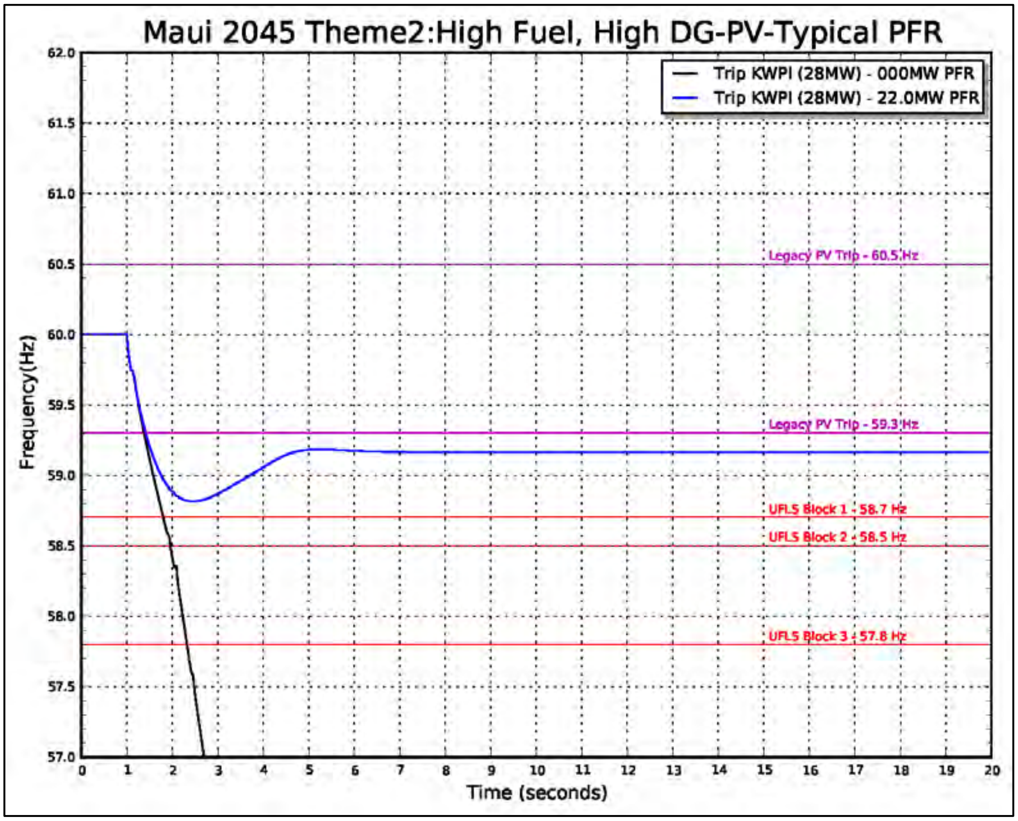


Figure O-85. Frequency Response Profile for PFR Typical Hour

Figure O-85 shows the frequency response profile for the PFR analysis for a typical hour. The capacity of PFR required to bring the system to avoid UFLS Block 1 and brings the system into compliance with TPL-001 is 22 MW.

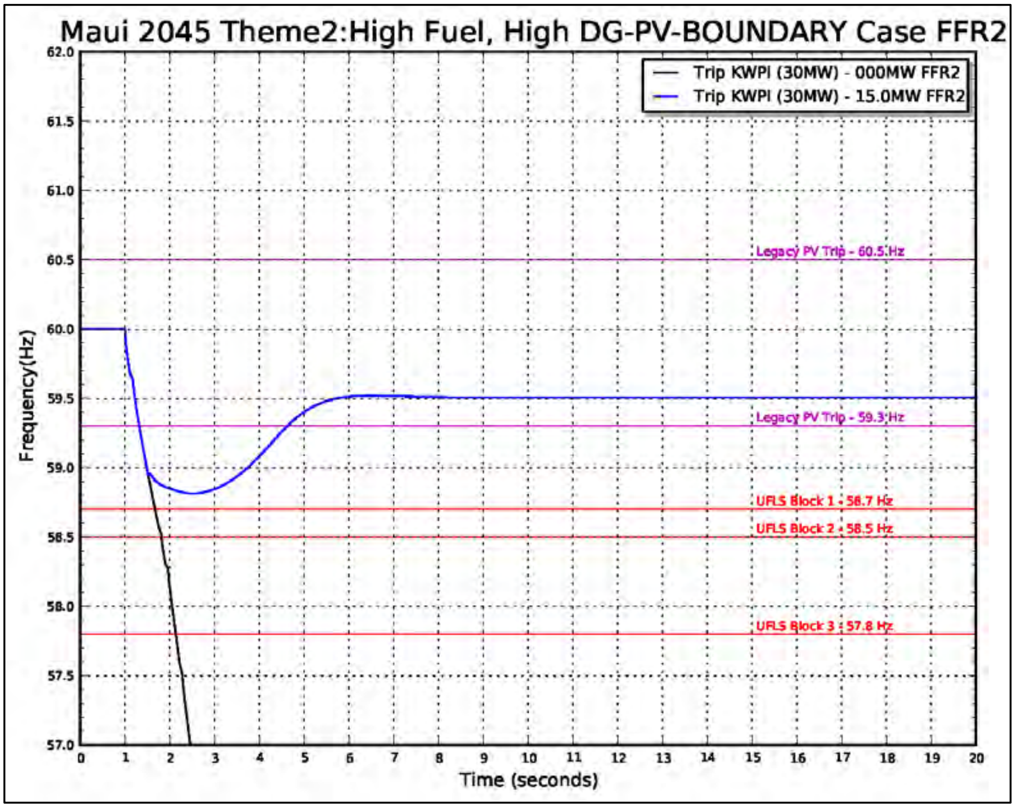


Figure O-86. Frequency Response Profile for FFR2 Boundary Hour

Figure O-86 shows the frequency response profile for a KPW wind plan trip at 30 MW output for a boundary hour. System kinetic energy is 382 MW-sec. With no FFR, the system will not survive a KWP II trip. The total capacity of Grid Supply DG-PV is 96 MW so the first block of UFLS is actually a loss of generation so the UFLS has a cascading effect on declining frequency. The capacity of FFR2 required to bring the system into compliance with TPL-001 is 15 MW.

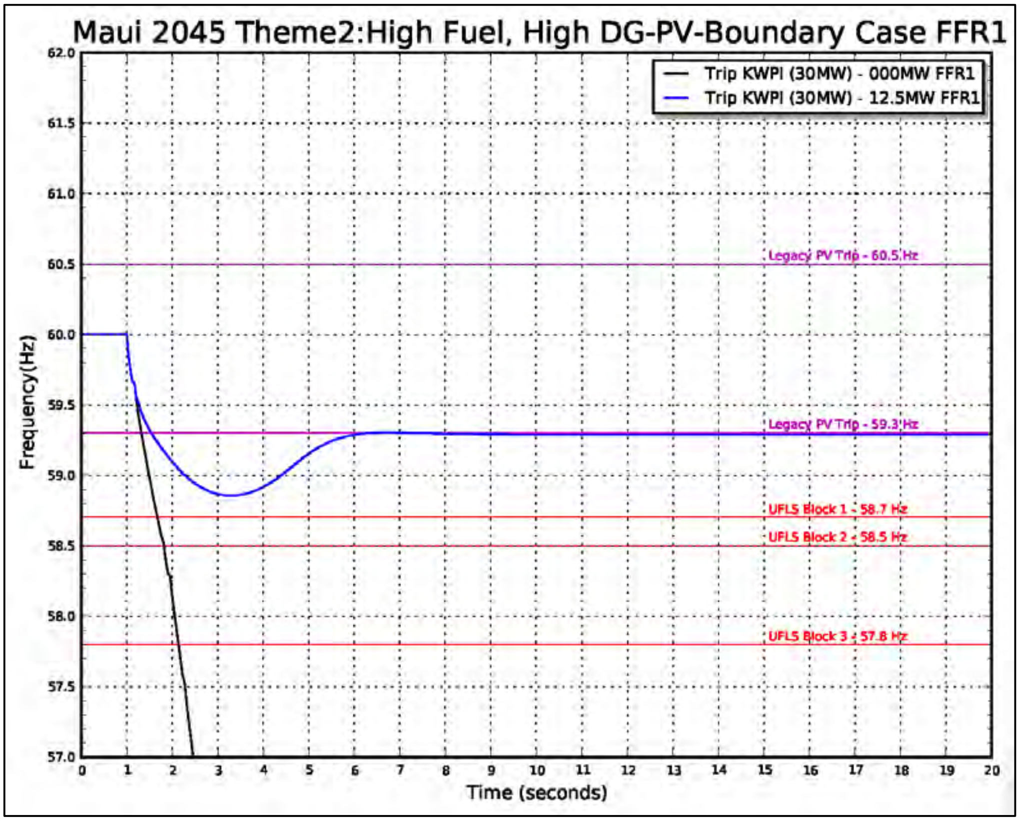


Figure O-87. Frequency Response Profile for FFR1 Boundary Hour

Figure O-87 shows the frequency response profile for the FFR1 analysis for a boundary hour. The capacity of FFR1 required to bring the system to avoid UFLS Block 1 and brings the system into compliance with TPL-001 is 12.5 MW.

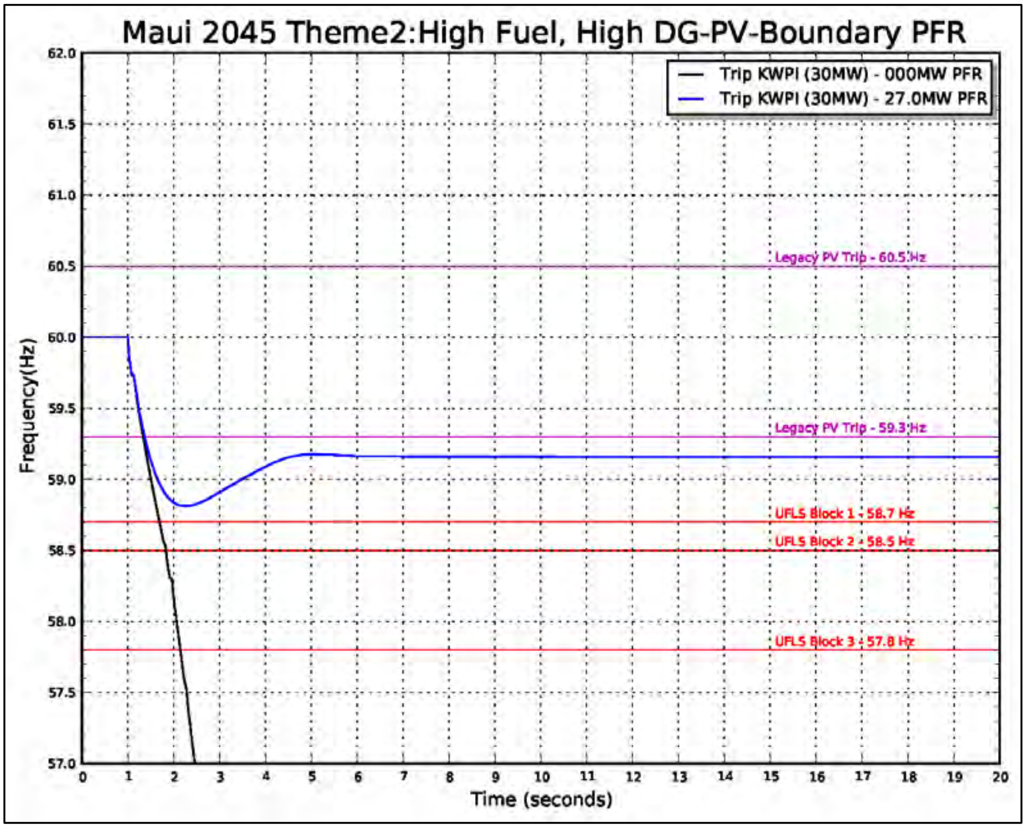


Figure O-88. Frequency Response Profile for PFR Boundary Hour

Figure O-88 shows the frequency response profile for the PFR analysis for a boundary hour. The capacity of PFR required to bring the system to avoid UFLS Block 1 and brings the system into compliance with TPL-001 is 27 MW.

69 kV Fault Analysis

Simulations were performed for electrical faults on the 69 kV transmission lines for the typical and boundary hours. A three-phase fault was placed on a transmission line to evaluate system performance to normally cleared faults and delayed clearing faults. Normally cleared faults are isolated in 5-cycles and delayed clearing faults are isolate in 24 cycles to simulate Zone 2 clearing. Simulations did not produce any system security issues.

2045 69 kV and 23 kV Fault Delayed ClearingAnalysis			
Circuit Outage	**3-phase Fault Near**	**Typical Hour Condition**	**Boundary Hour Condition**
Maalaea-Kihei	Kihei	Stable	Stable
	Maalaea	Stable	Stable
Maalaea-Waiinu	Waiinu	Stable	Stable
	Maalaea	Stable	Stable
Maalaea-Puunene	Puunene	Stable	Stable
	Maalaea	Stable	Stable
Maalaea-KWP I	KWP I	Stable	Stable
	Maalaea	Stable	Stable
Maalaea-KWP II	KWP II	Stable	Stable
	Maalaea	Stable	Stable
Maalaea-Lahainaluna	Lahainaluna	Stable	Stable
	Maalaea	Stable	Stable
Kahului-FDR1	FDR1	Unstable	Unstable
	Kahului	Stable	Stable
Kahului-FDR2	FDR2	Unstable	Unstable
	Kahului	Stable	Stable
Kahului-Wailuku	Wailuku	Stable	Stable
	Kahului	Stable	Stable

Table O-31. Summary of Results for the 2045 Fault Analysis

Table O-31 summarizes the results of the fault analysis. For each hour, 2 simulations resulted in unstable operation. Further analysis is required to determine mitigation alternatives.

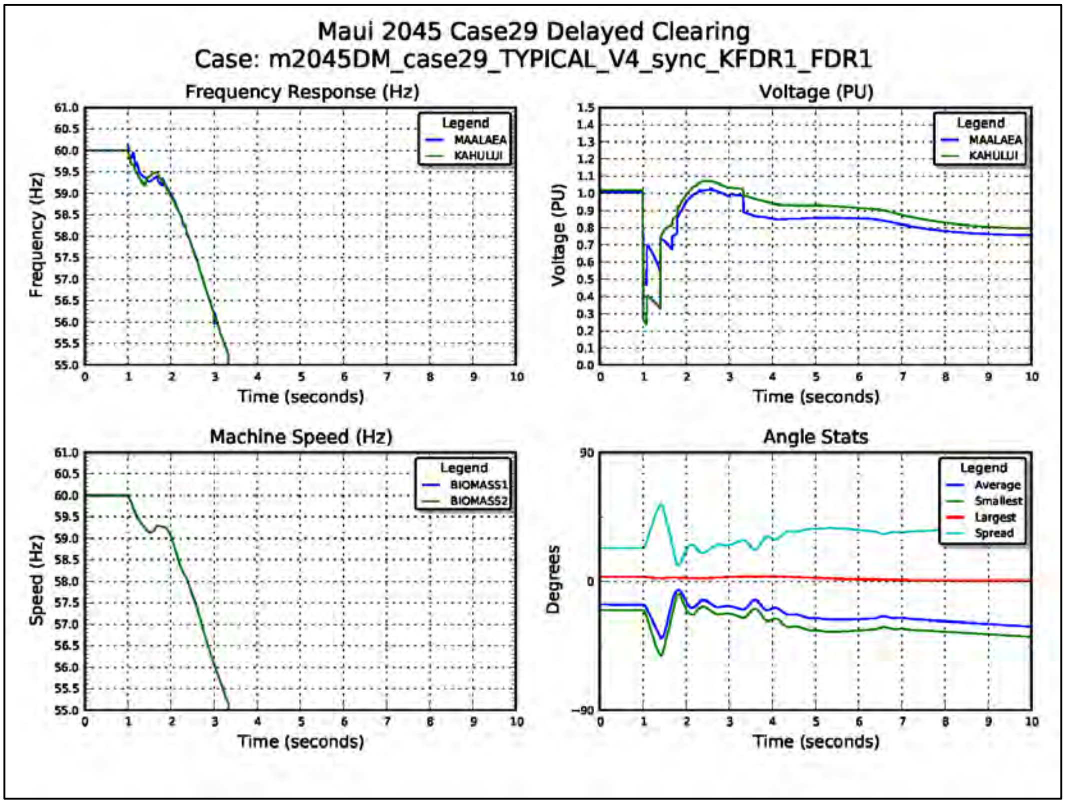


Figure O-89. System Performance for a Delayed Clearing 23 kV Fault

Figure O-89 shows four plots that illustrate system instability for a delayed clearing fault on the Kahului 23 kV circuit for the typical hour. The system frequency plot shows system will collapse. In addition to the two biomass units, KWP I and KWP II trip offline for a total of 64 MW. More analysis is required to determine mitigation alternatives.

Theme 3 – No LNG Plan

2045

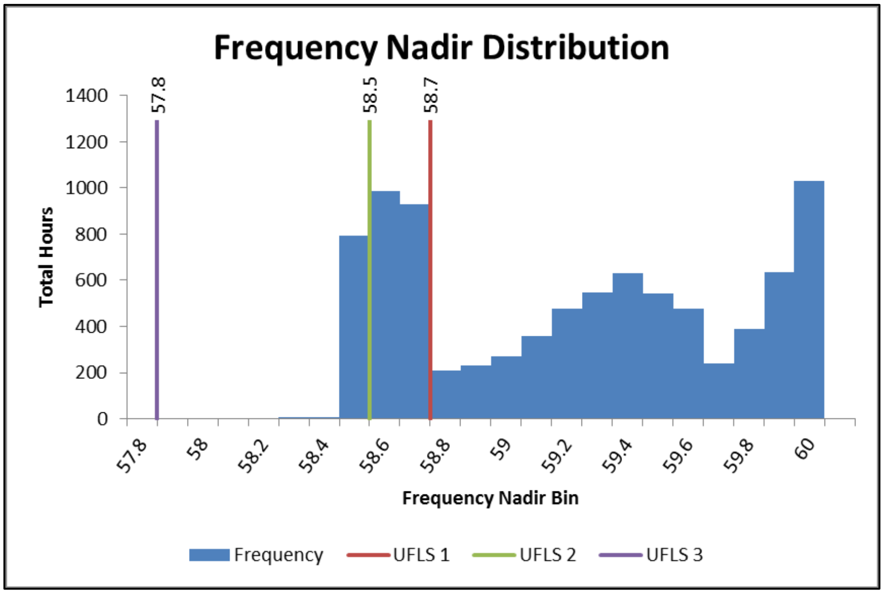


Figure O-90. Frequency Nadir Histogram for 2045

Figure O-90 is a histogram of the expected frequency nadirs for N-1 generator contingency events for the entire year. The typical hour selected from the maximum distribution of 791 hours was 11:00 AM on Monday, May 15. The frequency nadir range for the typical hour is 58.4 – 58.5 Hz that requires 2 blocks of UFLS to stabilize system frequency.

The boundary hour selected from a minimum distribution of 5 hours was 3:00 PM on Sunday, March 19. The frequency nadir range for the boundary hour is 58.2 – 58.3 Hz that requires 2 blocks of UFLS to stabilize system frequency.

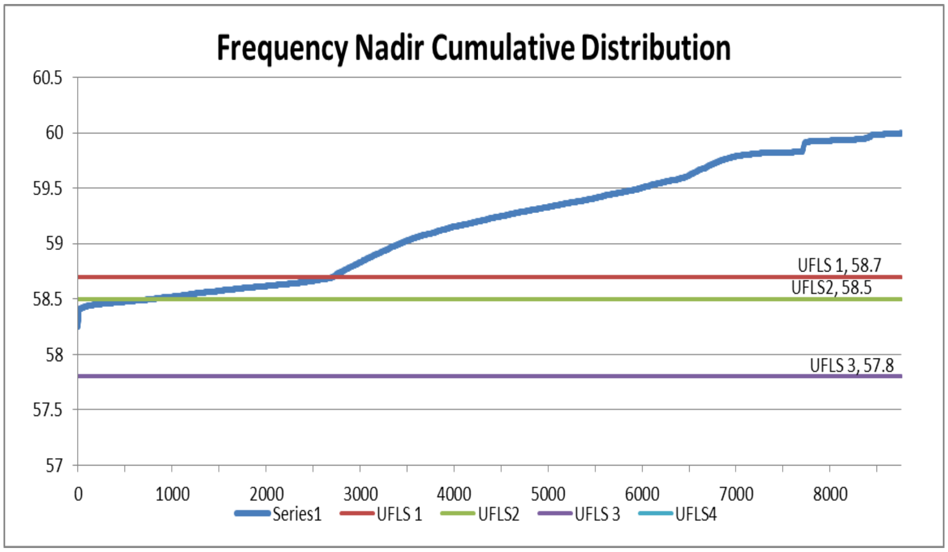


Figure O-91. Frequency Nadir Duration Curve for 2045

Figure O-91 shows the frequency nadir duration curve for the entire year.

Unit Commitment Order	Unit Ratings					Maui 2045 (Typical) Tues 4/13/2045 Hour14			Maui 2045 (Boundary) Sun 3/19/2045 Hour15		
	Pmax	Pmin	Inertia H	Unit MVA	Unit K.E.	Pgen	up reg (spin)	down reg	Pgen	up reg (spin)	down reg
M14	20.0	5.9	2.02	28.8	58						
M15	13.0	6.0	2.46	18.5	46						
M16	20.0	5.9	2.02	26.8	54						
M17	19.5	5.9	2.02	26.8	54						
M18	12.8	3.0	2.46	18.5	46						
M19	19.5	5.9	2.02	26.8	54						
Maalae10	12.3	7.9	3.28	15.6	51						
Maalae12	12.3	7.9	3.28	15.6	51						
Maalae13	12.3	7.9	3.28	15.6	51						
Maalae11	12.3	7.9	3.28	15.6	51						
Maalaea4	5.5	1.9	2.28	7.0	16						
Maalaea6	5.5	1.9	2.28	7.0	16						
Maalaea9	5.5	1.9	2.28	7.0	16						
Maalaea8	5.5	1.9	2.28	7.0	16						
Maalaea5	5.5	1.9	2.28	7.0	16						
Maalaea1	2.5	2.5	0.83	3.4	3						
Maalaea3	2.5	2.5	0.83	3.4	3						
Maalaea2	2.5	2.5	0.83	3.4	3						
MaalaeX2	2.5	2.5	0.83	3.4	3						
MaalaeX1	2.5	2.5	0.83	3.4	3						
Maalaea7	5.5	1.9	2.28	7.0	16						
ICE9_1	9.0	4.0	3.28	11.3	37						
ICE9_2	9.0	4.0	3.28	11.3	37						
Biomass1	20.0		3.48	25.0	87	8.0	12.0	8.0	8.0	12.0	8.0
Biomass2	20.0		3.48	25.0	87	8.0	12.0	8.0	8.0	12.0	8.0
Kahului 1	0.0	0.0	2.62	6.3	16	0.0	Sync. Condenser		0.0	Sync. Condenser	
Kahului 2	0.0	0.0	2.62	6.3	16	0.0	Sync. Condenser		0.0	Sync. Condenser	
Kahului 3	0.0	0.0	3.27	13.5	44	0.0	Sync. Condenser		0.0	Sync. Condenser	
Kahului 4	0.0	0.0	1.74	15.6	27	0.0	Sync. Condenser		0.0	Sync. Condenser	
SYNC COND	0.0	0.0	1.74	60.0	104	0.0	Sync. Condenser		0.0	Sync. Condenser	
Total Wind	252	0				59			52		
-KWP	30	0				28			30		
-Auwahi	21	0				11			3		
-KWPII	21	0				20			19		
-New Wind 1	90	0									
-New Wind 2	90	0									
DG-PV	98.96	0				84			87		
DER Grid Ex	328	0				114			96		
Total System MVA							50			50	
Total Kinetic Energy							382			382	
Total Load							235			215	
Total Thermal Generation							16			16	
Total Renewable Generation							257			235	
Total Generation							273			251	
Excess Generation							38			36	
Regulation Requirement[1]							0			0	
Total Up Regulation							24			24	
Total Down Regulation							16			16	
Legacy DG-PV	59.3Hz Capacity			0.0		59.3Hz Output		0.0	59.3Hz Output		0.0
	60.5Hz Capacity			0.0		60.5Hz Output		0.0	60.5Hz Output		0.0

Table O-32. Unit Commitment and Dispatch Schedule 2045

Table O-32 shows the unit commitment and dispatch schedules for the typical hour (5/15/2045 at 11:00 AM) and boundary hour (3/19/2045 at 3:00 PM).

Loss of Generation

Simulations were performed for the largest loss of generation contingency event to determine the frequency response reserves requirements to bring the system into compliance with TPL-001.

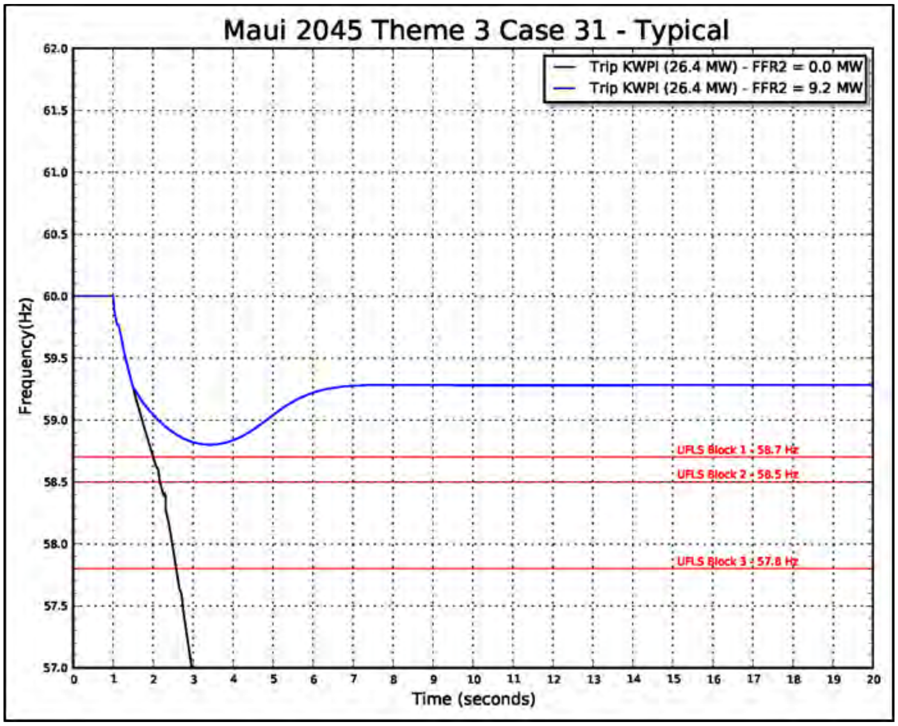


Figure O-92. Frequency Response Profile for FFR2 Typical Hour

Figure O-92 shows the frequency response profile for a KWP trip at 26.4 MW output for a typical hour. System kinetic energy is 305 MW-sec. With no FFR2, the system will not survive a KWP trip. The capacity of Grid Export DG-PV is 98.6 MW so the first block of UFLS constitutes a second loss of generation contingency. The entire UFLS scheme has a cascading effect on declining frequency with each UFLS block exacerbating the contingency until system collapse. The capacity of FFR2 required to bring the system into compliance with TPL-001 is 9.2 MW.

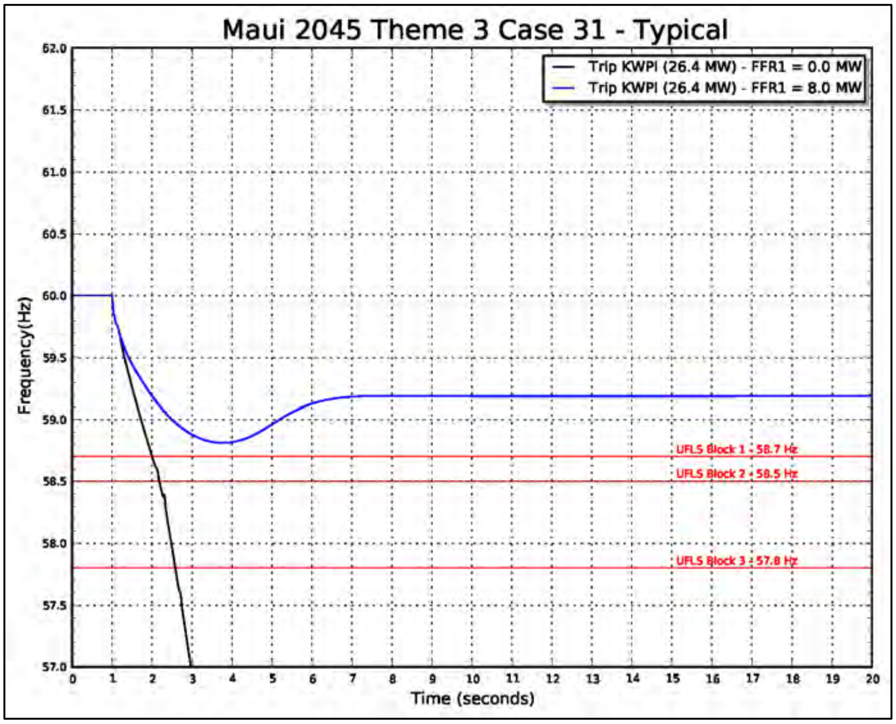


Figure O-93. Frequency Response Profile for FFR1 Typical Hour

Figure O-93 shows the frequency response profile for the FFR1 analysis for a typical hour. The capacity of FFR1 required to bring the system into compliance with TPL-001 is 8 MW.

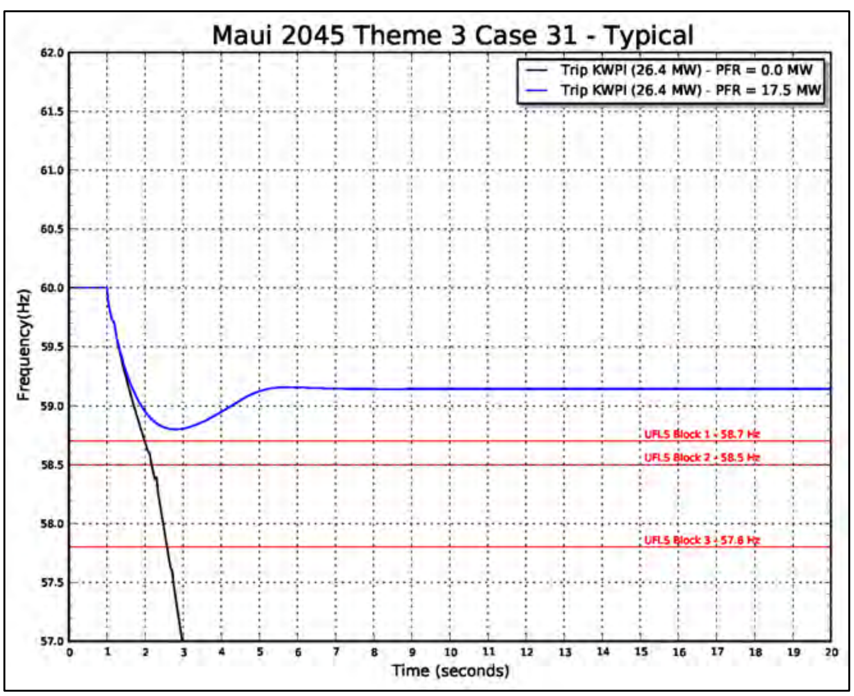


Figure O-94. Frequency Response Profile for PFR Typical Hour

Figure O-94 shows the frequency response profile for the PFR analysis for a typical hour. The capacity of PFR required to bring the system into compliance with TPL-001 is 17.5 MW.

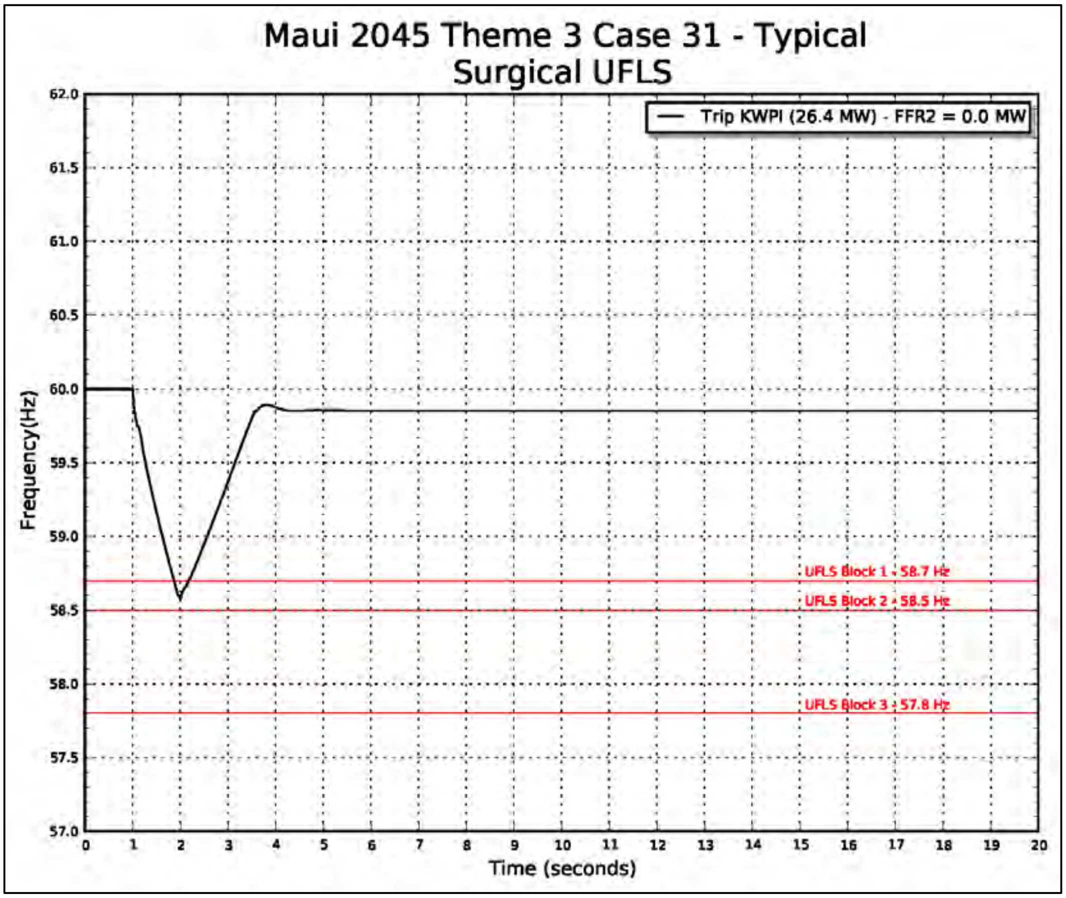


Figure O-95. Frequency Response Profile for Behind-the-Meter Load Shedding

Figure O-95 shows the frequency response profile if behind the meter load shedding was available. The frequency nadir is 58.6 Hz and meets the requirements of TPL-001 without FFR.

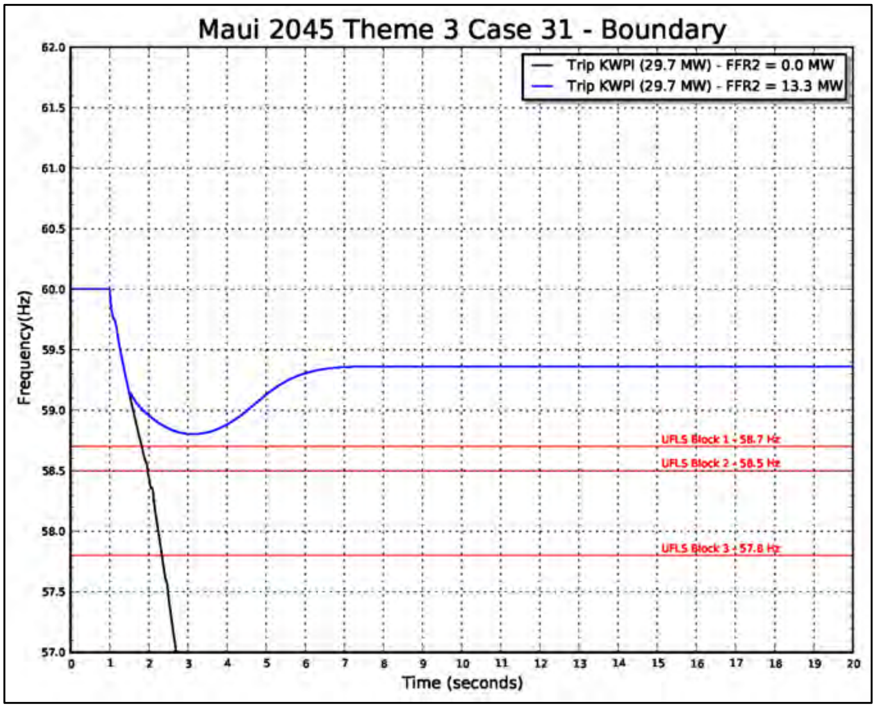


Figure O-96. Frequency Response Profile for FFR2 Boundary Hour

Figure O-96 shows the frequency response profile for a KWP trip at 29.7 MW output for a boundary hour. System kinetic energy is 305 MW-sec. With no FFR2, the system will not survive a biomass unit trip. The capacity of Grid Export DG-PV is 98.2 MW so the first block of UFLS constitutes a second loss of generation contingency. The entire UFLS scheme has a cascading effect on declining frequency with each UFLS block exacerbating the contingency until system collapse. The capacity of FFR2 required to bring the system into compliance with TPL-001 is 13.3 MW.

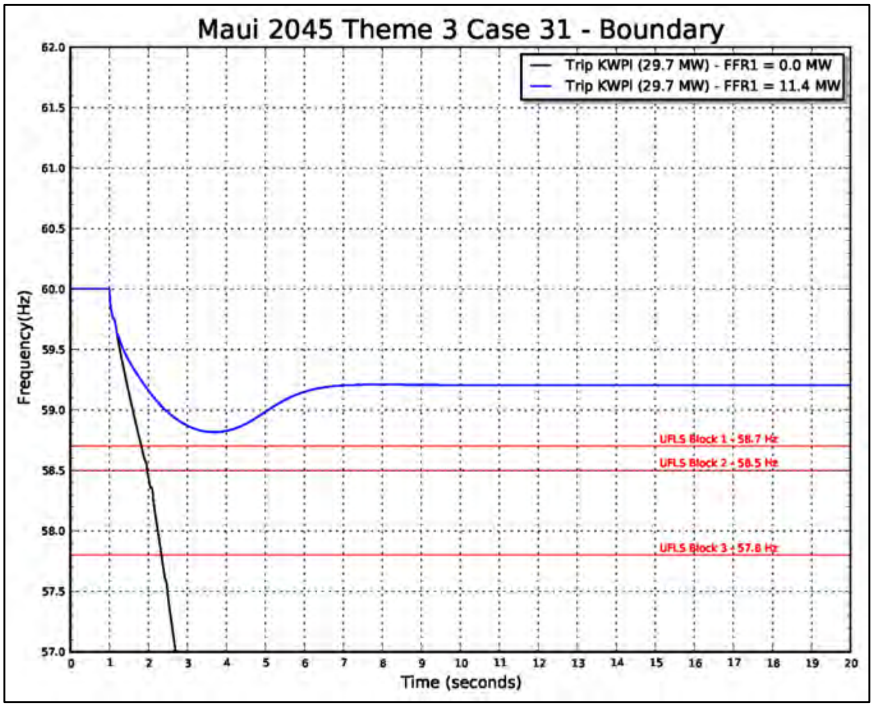


Figure O-97. Frequency Response Profile for FFR1 Boundary Hour

Figure O-97 shows the frequency response profile for the FFR1 analysis for a boundary hour. The capacity of FFR1 required to bring the system into compliance with TPL-001 is 11.4 MW.

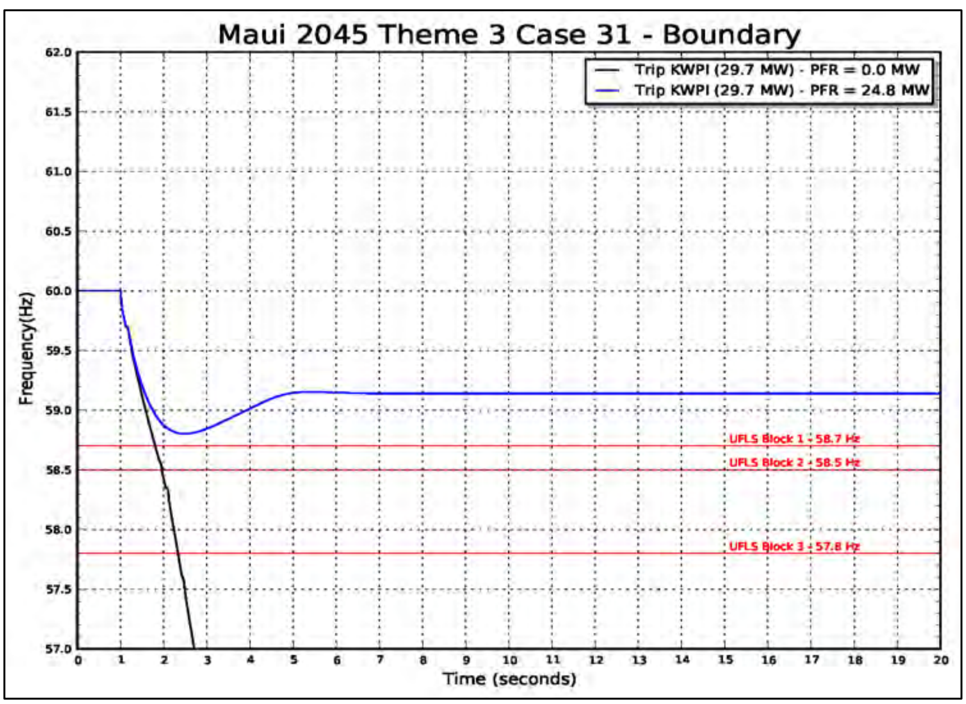


Figure O-98. Frequency Response Profile for PFR Boundary Hour

Figure O-98 shows the frequency response profile for the PFR analysis for a boundary hour. The capacity of PFR required to bring the system into compliance with TPL-001 is 24.8 MW.

69 kV Fault Analysis

Simulations were performed for electrical faults on the 69 kV transmission lines for the typical and boundary hours. A three-phase fault was placed on a transmission line to evaluate system performance to normally cleared faults and delayed clearing faults. Normally cleared faults are isolated in 5-cycles and delayed clearing faults are isolate in 24 cycles to simulate Zone 2 clearing. Simulations for the normally cleared faults did not produce any significant system security issues. Simulations for the 69kV fault analysis did not produce any significant system security issues.

2045 69 kV and 23 kV Fault Delayed Clearing Analysis			
Circuit Outage	3-phase Fault Near	Typical Hour Condition	Boundary Hour Condition
Maalaea-Kihei	Kihei	Stable	Stable
	Maalaea	Stable	Stable
Maalaea-Waiinu	Waiinu	Stable	Stable
	Maalaea	Stable	Stable
Maalaea-Puunene	Puunene	Stable	Stable
	Maalaea	Stable	Stable
Maalaea-KWP I	KWP I	Stable	Stable
	Maalaea	Stable	Stable
Maalaea-KWP II	KWP II	Stable	Stable
	Maalaea	Stable	Stable
Maalaea-Lahainaluna	Lahainaluna	Stable	Stable
	Maalaea	Stable	Stable
Kahului-FDR1	FDR1	Unstable	Unstable
	Kahului	Unstable	Unstable
Kahului-FDR2	FDR2	Unstable	Unstable
	Kahului	Unstable	Unstable
Kahului-Wailuku	Wailuku	Stable	Stable
	Kahului	Stable	Stable

Table O-33. Summary of Resulsts Delayed Clearing Fault Analysis 2045

Table O-33 summarizes the results of the fault analysis. For each hour, 4 simulations resulted in unstable operation. Further analysis is required to determine mitigation alternatives.

Summary

The Maui system does not meet the requirements of TPL-001. Simulations were performed to determine the capacity of FFR2 and FFR1 required to the system into compliance with TPL-001 in 2019.

Compliance with TPL-001

The capacities of frequency response reserves required to bring Maui into compliance with TPL-001 are listing in Table O-34 below.

Maui Frequency Response Analysis Results								
Freq Response	Theme 2						Theme 3	
	2019		2023		2045		2045	
	Typical KWP 28 MW	Boundary KWP 30 MW	Typical KWP 23 MW	Boundary KWP 29 MW	Typical KWP 28 MW	Boundary KWP 30 MW	Typical KWP 26.4 MW	Boundary KWP 30 MW
FFR2	4	13	6.5	15.5	12	15	9.2	13.3
FFR1	3.5	11	5.5	13.5	10	12.5	8	11.4
PFR	7.5	21.5	11	25	22	27	17.5	24.8

Table O-34. Summary of Frequency Response Analysis

Table O-34 shows the results of the FFR2, FFR1, and PFR analysis. The capacities of FFR1 required to meet TPL-001 is 3.5 MW for the typical hour and 11 MW for the boundary hour. These capacities of will not bring the resource plans for Themes 2 and 3 into compliance with TPL-001 through 2045 without additional resources from FFR2, PFR, or more system inertia.

HAWAII ELECTRIC LIGHT CANDIDATE PLANS

State of the System

The Hawaiʻi Electric Light (HELCO) system does not meet standard HI-TPL-001 for loss of generation contingency events so FFR analysis are performed for 2019.

Hawai'i Electric Light has the highest penetration of renewable resources in the nation and the system often operates with the minimum must-run units for system security. In addition to the frequency stability issues that face O'ahu and Maui, characteristics of the Hawaiʻi Electric Light transmission system increase the exposure to electrical faults. The Hawai'i transmission system covers a very large territory and has approximately 640 miles of 69 kV transmission lines. In addition, Hawaiʻi Electric Light 's transmission planning criteria is N-1 because of the potential rate impacts for cost recovery from a smaller customer base which is similar to Maui Electric. The Hawai'i Electric Light transmission system is also more susceptible to steady state and transient voltage stability issues.

Date/Time	Line	Type of Fault	Lowest Voltages at Keahole (A/B/C phase)	Load Loss (MW)	Frequency Peak
Sun 8/23/15 0055 hrs	7500/9300	2-Line-Gnd	0.28pu / 0.26pu / 0.79pu	17	60.68
Sun 8/23/15 1455 hrs	8100/8200	3-phase	0.44pu / 0.46pu / 0.42pu	17	60.41
Sun 8/23/15 1502 hrs	6800	3-phase	0.43pu / 0.43pu / 0.45pu	10	60.2
Sun 8/23/15 1541 hrs	6200	3-phase	0.45pu/ 0.45pu / 0.45pu	14	60.28
Wed 9/2/15 1605 hrs	7100	3-phase	0.33pu / 0.37pu / 0.34pu	20	60.43
Thu 9/3/15 1454 hrs	8100/8200	3-phase	0.41pu / 0.43pu / 0.41pu	18	60.41
Sun 9/13/15 1541 hrs	7100	A-Gnd	0.61pu / 0.86pu / 0.61pu	5	60.17
Sun 9/13/15 1641 hrs	7100	3-phase	0.28pu / 0.30pu / 0.28pu	17	60.32
Tue 9/15/15 1733hrs	7500/9300	A-Gnd	0.26pu / 0.68pu / 0.66pu	20	60.5

Table O-35. Hawai'i Electric Light Historic Transmission Faults

Table O-35 shows some of the more severe electrical faults on the 69 kV transmission system that illustrates the increase exposure to multi-phase electrical faults that can trigger loss of load. Therefore, fault simulations will be included in the analysis to bring the system into compliance with TPL-001.

Hawai'i relies on under frequency load shedding for frequency response reserves for N-1 loss of generation contingency events. Hawai'i Electric Light has implemented a dynamic UFLS scheme to meet the requirements specified in TPL-001 that allows 15% of the system load to be shed on single loss of generation contingency events.

	Setpoint (Hz)	df/dt	% System Net Demand
Block 1	59.1	0.5 Hz/sec	5%
Block 2	58.8	0.5 Hz/sec	10%
Block 3	58.5	N/A	10%
Block 4	58.2	N/A	15%
Block 5	57.9	N/A	10%
Block 6	57.6	N/A	20%
Kicker Block (>9 sec TD)	59.3	N/A	5 MW

Table O-36. Hawai'i Electric Light Dynamic UFLS

Table O-36 shows the capacities of the UFLS scheme. The dynamic UFLS scheme allows Blocks 1 and 2 to be initiated on df/dt settings for severe loss of generation contingency events; or by frequency set points for less severe contingencies but in most instances, the df/dt relays are activated. The dynamic UFLS scheme continuously monitors distribution circuit loads such that Blocks 1 and 2 will meet the 15% load shed requirement established by TPL-001.

Historical

2016

System security analysis was performed on multiple hours that were selected from the Theme 3 production cost simulations that represents a typical hour, a boundary condition, and for some cases, an alternate hour to evaluate the impacts of high DG-PV penetration.

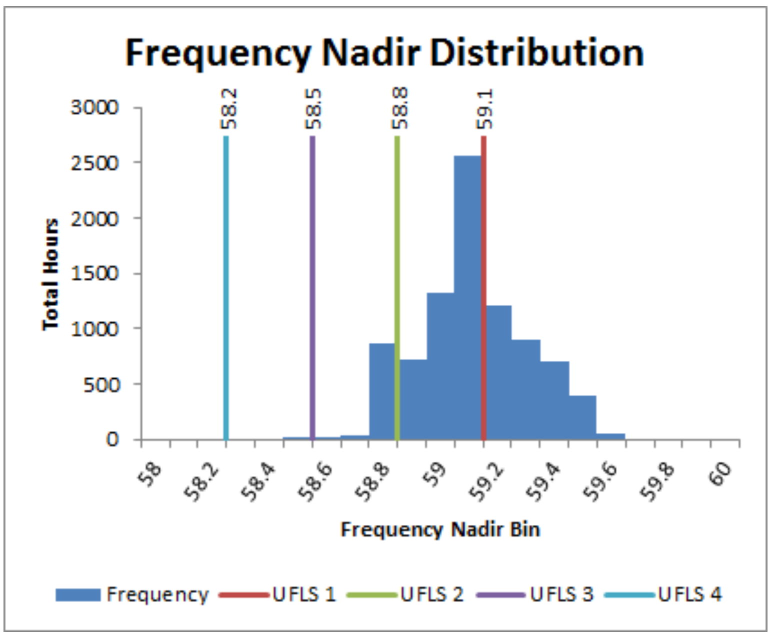


Figure O-99. Frequency Nadir Histogram for 2016

Figure O-99 is a histogram of the expected frequency nadirs for N-1 generator contingency events for the entire year. The typical hour selected from the maximum distribution of 869 hours was 12:00 PM on Thursday, March 3. The frequency nadir range for the typical hour is 58.7 – 58.8 Hz that requires two blocks of UFLS to stabilize system frequency.

The boundary hour was selected from a minimum distribution of 1 hour was 5:00 AM on Sunday, July 10. The frequency nadir range for the boundary hour is 58.4 – 58.5 Hz that requires three blocks of UFLS to stabilize system frequency.

The alternate hour was selected from the boundary hours to maximize DG-PV for the purpose of analyzing loss of generation contingency caused by delay cleared faults.

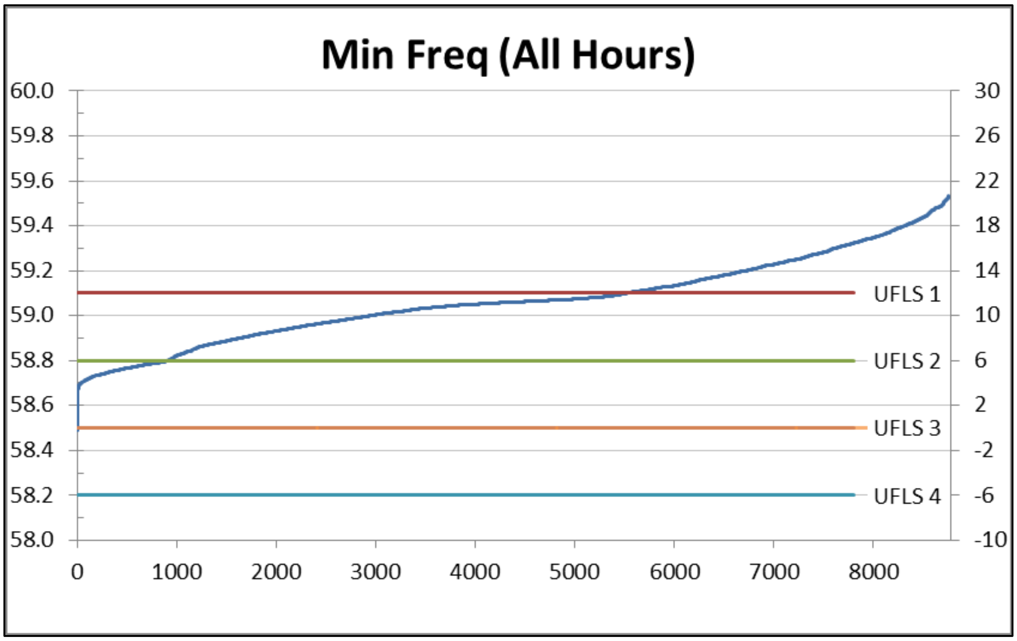


Figure O-100. Frequency Nadir Duration Curve 2016

Figure O-100 shows the frequency nadir duration curve for 2016.

Unit Commitment Order	Unit Ratings							HELCO 2016 (Typical) Thu 3/3/16 Hour 12			HELCO 2016 (Boundary) Sun 7/10/16 Hour 5			HELCO 2016 (Alt) Sun 9/4/16 Hour 12		
	Pmax	Pmin			Inertia H	Unit MVA	Unit K.E.	Pgen	up reg (spin)	down reg	Pgen	up reg (spin)	down reg	Pgen	up reg (spin)	down reg
PGV	38.0	22.0			2.94	59.4	174	30.3	7.7	8.3	33.4	4.6	11.4	32.9	5.1	10.9
Keahole STCC	25.0	7.0			3.13	46.5	146	24.5	0.5	17.5	22.0	3.0	15.0	20.3	4.7	13.3
Keahole DTCC	54.0	7.0			2.77	71.8	199									
Keahole CT4	20.0	7.0			2.10	25.2	53									
Keahole CT5	20.0	7.0			2.10	25.2	53									
HEP STCC	28.5	9.0			1.96	58.9	116	14.1	14.4	5.1						
HEP DTCC	60.0	18.5			1.78	94.4	168									
Hill 5	13.5	5.0			2.20	15.6	34	8.2	5.3	3.2	11.6	1.9	6.6			
Hill 6	20.5	8.0			2.53	27.5	70	11.6	8.9	3.6	19.7	0.8	11.7	11.4	9.1	3.4
Keah CT2	13.8	5.0			4.44	22.2	99									
Puna CT3	20.0	7.0			4.96	29.6	147									
Geo1	20.0				5.00	40.0	200									
Geo2	20.0				5.00	40.0	200									
Biomass1	20.0				3.16	28.0	88									
HELCO Hydro	4.7	0.0			1.07	5.6	6	2.8			2.7			1.8		
Wailuku Hydro	12.1	0.0			2.42	12.2	30	2.9			0.7			7.7		
Apollo	20.5	0.0						4.9			3.8			17.9		
HRD	10.5	0.0						0.0			1.9			4.1		
Hydro	16.8	0						6			3			10		
Wind	31.0	0						5			6			22		
DG-PV	88.4	0						65			0			56		
Total Kinetic Energy									576			460			426	
Total Load									164			96			152	
Total Thermal Generation									89			87			65	
Total Renewable Generation									75			9			87	
Total Generation									164			96			152	
Excess Generation									0			0			0	
Total Up Regulation									37			10			19	
Total Down Regulation									38			45			28	
Legacy DG-PV	59.3Hz Capacity		7.4					59.3Hz Output		5.4	59.3Hz Output		0.0	59.3Hz Output		4.7
	60.5Hz Capacity		26.4					60.5Hz Output		19.3	60.5Hz Output		0.0	60.5Hz Output		16.7

Table O-37. Unit Commitment and Dispatch 2016

Table O-37 shows the unit commitment and dispatch schedules for the typical hour (3/3/2016 at 12:00 PM), boundary hour (7/10/2016 at 5:00 AM), and an alternate hour (9/4/2016 AT 12:00 pm).

Loss of Generation Contingency

Simulations were performed for the largest loss of generation contingency event to determine the frequency response reserves requirements to bring the system into compliance with TPL-001.

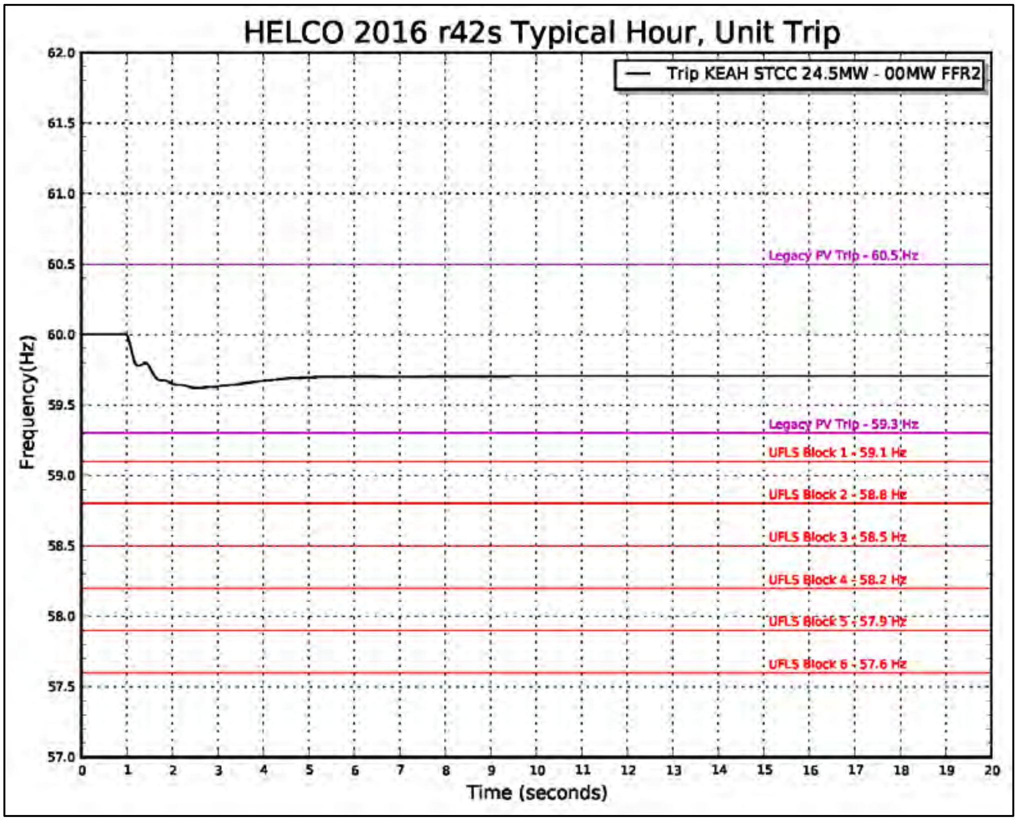


Figure O-101. Frequency Response Profile FFR2 Typical Hour

Figure O-101 shows the frequency response profile for a Keahole STCC trip at 24.5 MW output. System kinetic energy is 576 MW-sec and the capacity of legacy PV that will disconnect from the system is approximately 5.4 MW. No FFR2 is required because Hawaiʻi Electric Light 's UFLS scheme uses df/dt relays for Blocks 1 and 2. The capacity of df/dt UFLS was 24.6 MW which is basically FFR at the distribution circuit level as opposed to behind the meter.

The effectiveness of df/dt is evident in the frequency response profile. The initial RoCoF is immediately reduced when UFLS Blocks 1 and 2 are shed. This avoids tripping legacy PV.

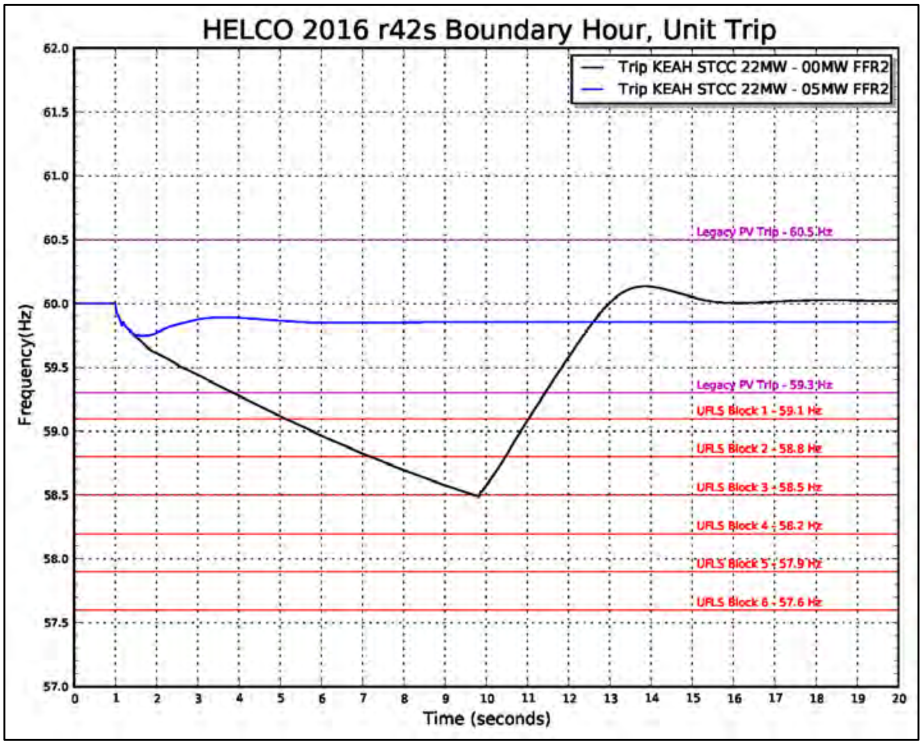


Figure O-102. Frequency Response Profile FFR2 Boundary Hour

Figure O-102 shows the frequency response profile for a Keahole STCC trip at 22 MW output for the boundary hour. System kinetic energy is 460 MW-sec. The capacity of FFR2 required to bring the system into compliance with TPL-001 is 5 MW. This is in addition to the 14.4 MW of df/dt UFLS from Blocks 1 and 2.

69 kV Fault Analysis

Simulations were performed for electrical faults on the 69 kV transmission lines for the typical and boundary hours. A three-phase fault was placed on a transmission line to evaluate system performance to normally cleared faults and delayed clearing faults. Normally cleared faults are isolated in 5-cycles and delayed clearing faults are isolate in 24 cycles to simulate Zone 2 clearing. Simulations for the normally cleared faults did not produce any system stability issues.

2016 69kV Fault Delayed Clearing Analysis			
Line No Outage	3-phase Fault Near	Typical Hour Condition	Boundary Hour Condition
L6100	Kanoelehua	Stable	Stable
	Kaumana	Unstable	Unstable
L6200	Kaumana	Stable	Stable
	Keamuku	Stable	Stable
L6300	Kilauea	Stable	Stable
	Puna	Stable	Stable
L6400	Kanoelehua	Stable	Stable
	Puna	Unstable	Unstable
L6500	Kaumana	Stable	Stable
	Pohoiki	Stable	Stable
L6600	Kamaoa	Stable	Stable
	Kilauea	Stable	Stable
L6700	Kahaluu	Stable	Stable
	Keahole	Stable	Stable
L6800	Keahole	Stable	Stable
	Keamuku	Stable	Stable
L7100	Anaehoomalu	Stable	Stable
	Poopoomino	Stable	Stable
L7200	Keamuku	Stable	Stable
	Waimea	Stable	Stable
L7300	Ouli	Stable	Stable
	Waimea	Stable	Stable
L7400	Pepeekeo	Stable	Stable
	Wailuku	Stable	Stable
L7500	Kailua	Unstable	Unstable
	Keahole	Stable	Stable
L7600	Honokaa	Stable	Stable
	Pepeekeo	Stable	Stable
L7700	Haina	Stable	Stable
	Waimea	Stable	Stable
L7800	Kanoelehua	Unstable	Unstable
	Puueo	Unstable	Unstable
L8100	Anaehoomalu	Stable	Stable
	Keamuku	Stable	Stable
L8200	Anaehoomalu	Stable	Stable
	Mauna Lani	Stable	Stable
L8300	Mauna Lani	Stable	Stable
	Ouli	Stable	Stable
L8400	Pepeekeo	Unstable	Unstable
	Puueo	Stable	Stable
L8500	Kaumana	Stable	Stable
	Keamuku	Stable	Stable
L8600	Kahaluu	Stable	Stable
	Kealia	Stable	Stable
L8700	Pohoiki	Stable	Stable
	Puna	Stable	Stable
L8800	Haina	Stable	Stable
	Honokaa	Stable	Stable
L9100	Keahole	Stable	Stable
	Poopoomino	Unstable	Unstable
L9200	Kaumana	Stable	Stable
	Wailuku	Stable	Unstable
L9300	Kailua	Unstable	Unstable
	Keahole	Stable	Stable
L9500	Kahaluu	Stable	Stable
	Kailua	Stable	Stable
L9600	Kamaoa	Stable	Stable
	Kealia	Stable	Stable

Table O-38. Summary of Results for the Fault Analysis

Table O-38 summarizes the results of the fault analysis. For the typical hour, 8 simulations resulted in unstable operation and 9 simulations resulted in unstable operation for the boundary hour.

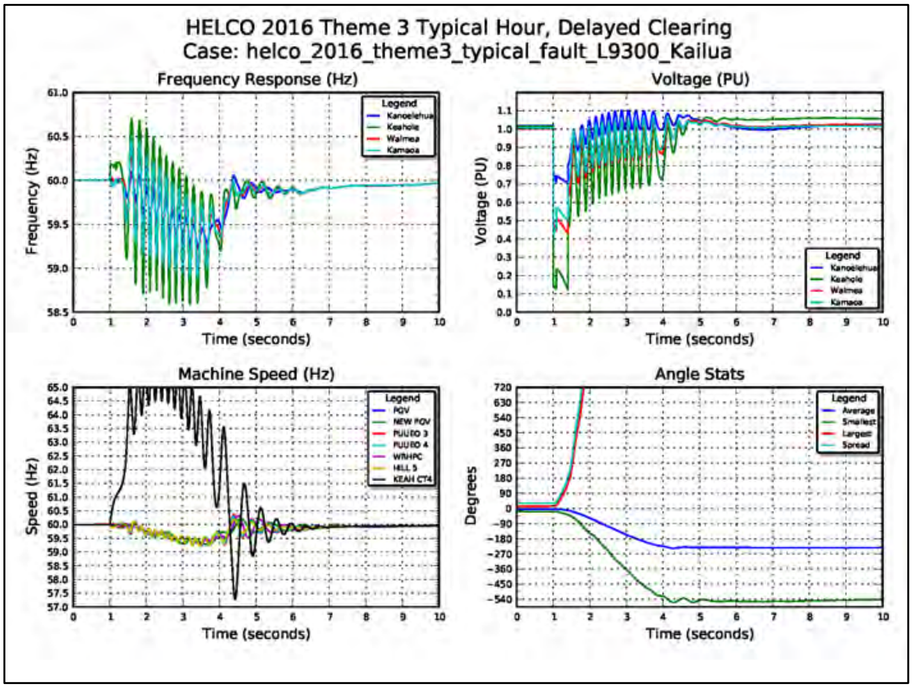


Figure O-103. System Performance for Delayed Clearing Failure Analysis

Figure O-103 shows four plots that illustrate unstable operation for a delayed clearing fault on the L9300 Kailua circuit for the typical hour. The Machine Speed plot shows Keahole CT4 (black) losing synchronism with the system. More analysis is required to determine mitigation measures.

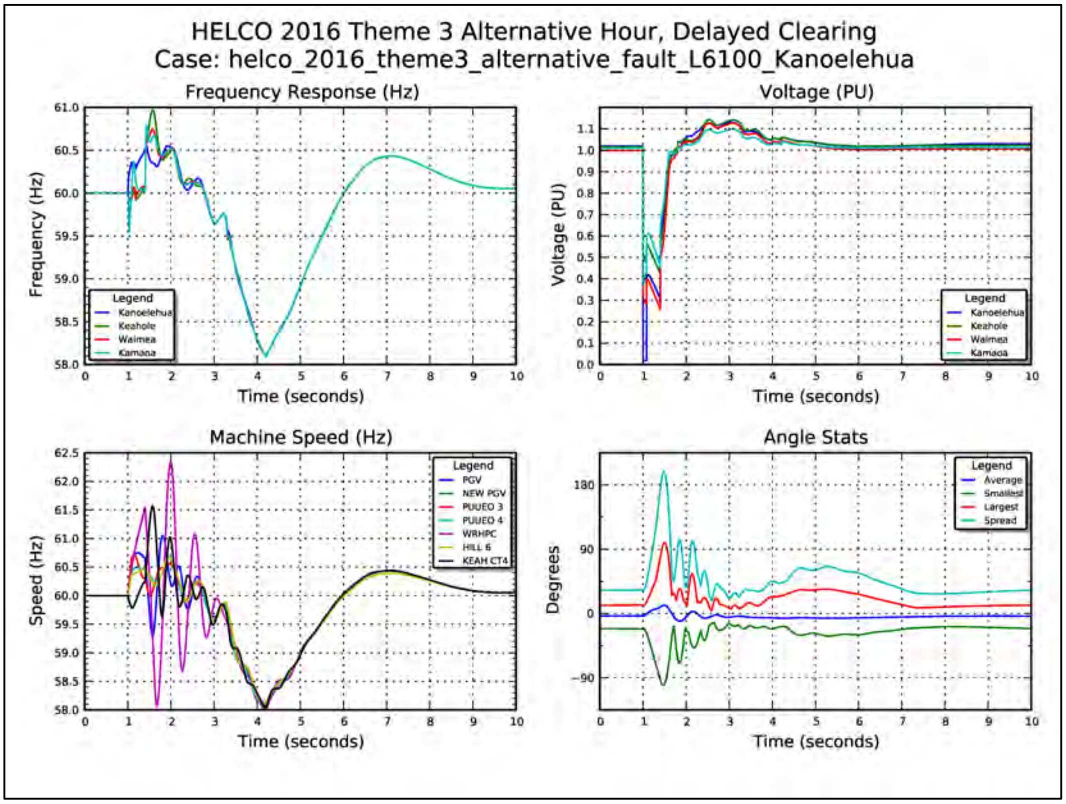


Figure O-104. System Performance Delayed Clearing Load Shed Analysis

Figure O-104 shows four plots that illustrate system performance for a delayed clearing fault on the L6100 Kanoelehua circuit for the alternative hour. System voltage exceeds 1.1 PU, tripping all 56 MW of DG-PV on over voltage. Simulations were performed to determine the frequency response capacities required to bring the system into compliance with TPL-001.

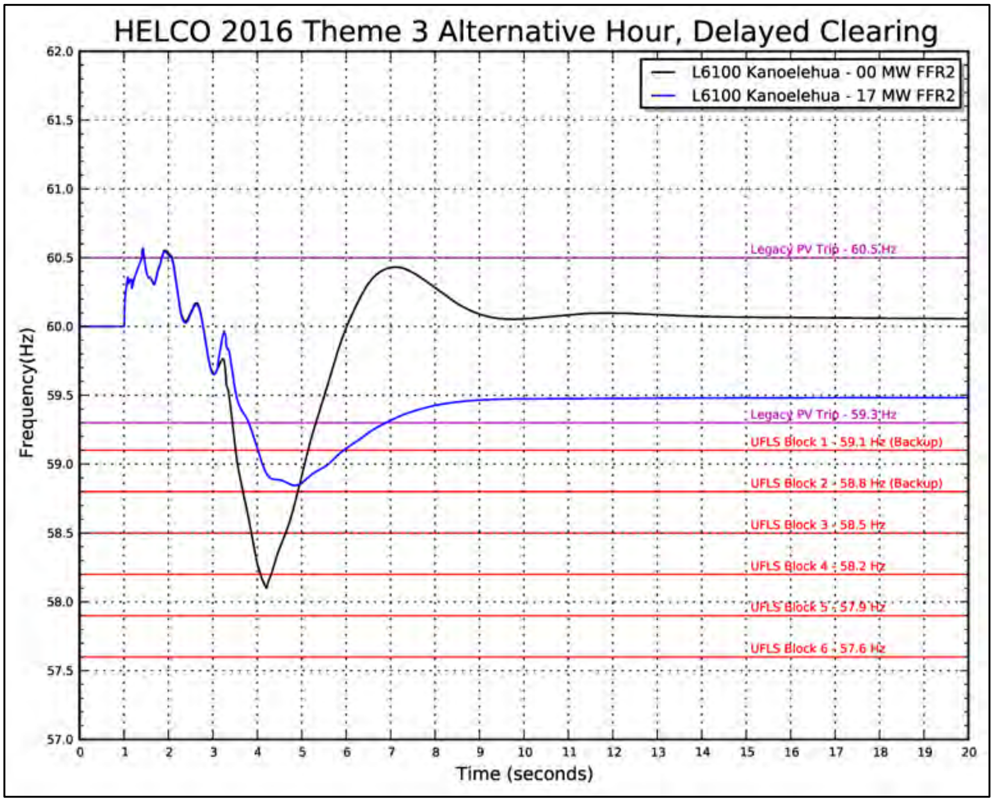


Figure O-105. Frequency Response Profile FFR2 Alternate Hour

Figure O-105 shows the frequency response profile for the FFR2 analysis. The first system peak is caused by the fault. Approximately 17 MW of legacy PV disconnects at 60.5 Hz but 56 MW of DG-PV disconnects on over voltage. System frequency begins to decay and triggers UFLS Blocks 1&2 on df/dt (22.8 MW), causing a momentary stabilization of system frequency (black plot). Frequency continues to decay until the nadir hits 58.1 Hz, requiring 4 blocks of UFLS to stabilize system frequency. The capacity of FFR2 required to bring the system into compliance with TPL-001 is 17 MW.

2019 – Compliance with TPL-001-02

System security analysis was performed on three hours that were selected from the Theme 3 production cost simulations that represents a typical hour, a boundary condition, and an alternate hour to evaluate the impacts of high DG-PV penetration.

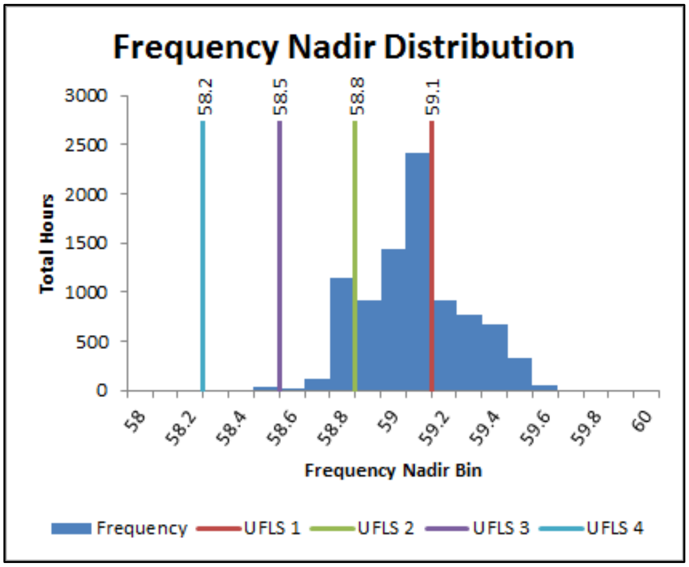


Figure O-106. Frequency Nadir Histogram 2019

Figure O-106 is a histogram of the expected frequency nadirs for N-1 generator contingency events for the entire year. The typical hour selected from the maximum distribution of 1665 hours was 12:00 PM on Monday, August 19. The frequency nadir range for the typical hour is 58.0 - 58.1 Hz that requires four blocks of UFLS to stabilize system frequency.

The boundary hour selected from a minimum distribution of 5 hours was 1:00 PM on Saturday, January 26. The frequency nadir range for the boundary hour is 57.6 – 57.7 Hz that requires five blocks of UFLS to stabilize system frequency.

The alternate hour was selected from the boundary hours to maximize DG-PV for the purpose of analyzing loss of generation contingency caused by delay cleared faults.

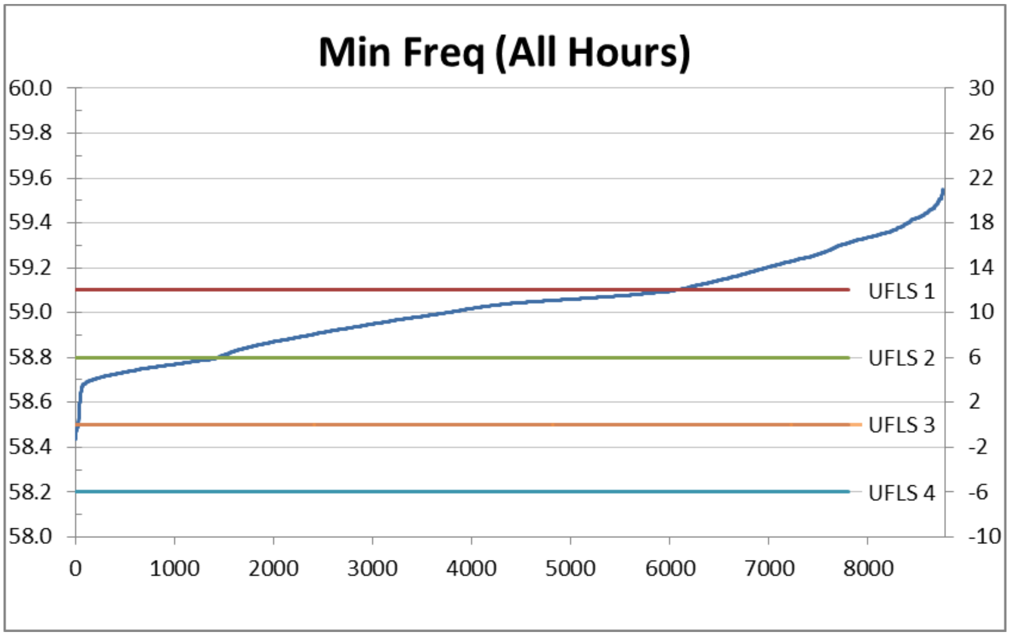


Figure O-107. Frequency Nadir Duration Curve 2019

Figure O-107 shows the frequency nadir duration curve for the entire year.

Unit Commitment Order	Unit Ratings							HELCO 2019 (Typical) Wed 8/14/19 Hour 10			HELCO 2019 (Boundary) Mon 6/17/19 Hour 1			HELCO 2019 (Alt) Mon 6/17/19 Hour 15		
	Pmax	Pmin			Inertia H	Unit MVA	Unit K.E.	Pgen	up reg (spin)	down reg	Pgen	up reg (spin)	down reg	Pgen	up reg (spin)	down reg
PGV	38.0	22.0			2.94	59.4	174				35.3	2.7	13.3	35.6	2.4	13.6
Keahole STCC	25.0	7.0			3.13	46.5	146				24.5	0.5	17.5	22.0	3.0	15.0
Keahole DTCC	54.0	7.0			2.77	71.8	199	25.7	28.3	18.7						
Keahole CT4	20.0	7.0			2.10	25.2	53									
Keahole CT5	20.0	7.0			2.10	25.2	53									
HEP STCC	28.5	9.0			1.96	58.9	116	28.0	0.5	19.0						
HEP DTCC	60.0	18.5			1.78	94.4	168									
Hill 5	13.5	5.0			2.20	15.6	34	8.0	5.5	3.0	11.0	2.5	6.0	8.0	5.5	3.0
Hill 6	20.5	8.0			2.53	27.5	70	11.0	9.5	3.0						
Keah CT2	13.8	5.0			4.44	22.2	99									
Puna CT3	20.0	7.0			4.96	29.6	147									
Geo1	20.0				5.00	40.0	200									
Geo2	20.0				5.00	40.0	200									
Biomass1	20.0				3.16	28.0	88									
HELCO Hydro	4.7	0.0			1.07	5.6	6	3.1			3.6			3.6		
Wailuku Hydro	12.1	0.0			2.42	12.2	30	8.3			2.7			5.8		
Apollo	20.5	0.0						16.6			18.1			19.3		
HRD	10.5	0.0						5.3			1.8			10.5		
Wind1	20.0	0.0														
Wind2	20.0	0.0														
Wind3	20.0	0.0														
Hydro	16.8	0						11			6			9		
Wind	31.0	0						22			20			30		
DG-PV	116.2	0						63			0			66		
Total Kinetic Energy									454			390			390	
Total Load									169			97			171	
Total Thermal Generation									73			71			66	
Total Renewable Generation									96			26			105	
Total Generation									169			97			171	
Excess Generation									0			0			0	
Total Up Regulation									44			6			11	
Total Down Regulation									44			37			32	
Legacy DG-PV	59.3Hz Capacity		7.4					59.3Hz Output		4.0	59.3Hz Output		0.0	59.3Hz Output		4.2
	60.5Hz Capacity		26.4					60.5Hz Output		14.2	60.5Hz Output		0.0	60.5Hz Output		15.0

Table O-39. Unit Commitment and Dispatch 2019

Table O-39 shows the unit commitment and dispatch for the typical hour (8/19/2019, 12:00 PM), boundary hour (6/17/2019, 1:00 AM), and alternative hour (6/17/2019, 3:00 PM).

Loss of Generation

Simulations were performed for the largest loss of generation contingency event to determine the frequency response reserves requirements to bring the system into compliance with TPL-001.

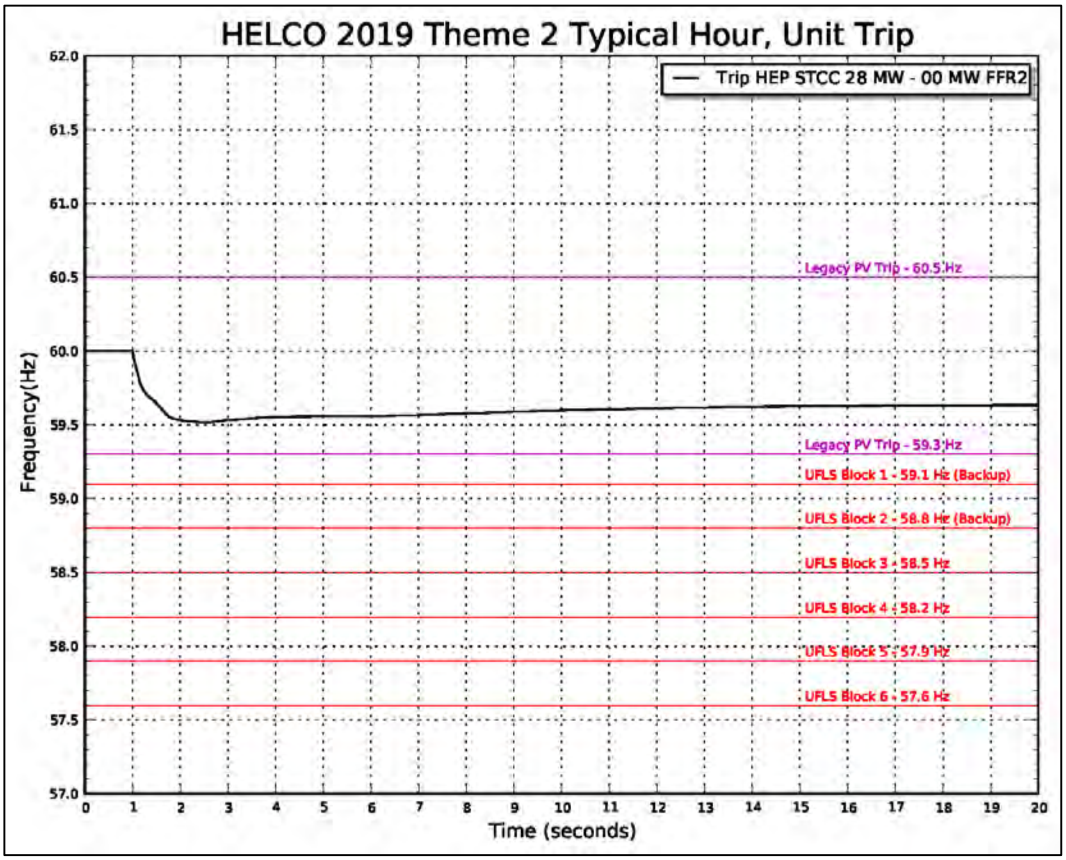


Figure O-108. Frequency Response Profile FFR2 Typical Hour

Figure O-108 shows the frequency response profile for a HEP STCC trip at 28 MW for a typical hour. System kinetic energy is 454 MW-sec and the capacity of legacy PV that will disconnect from the system is 4 MW. No FFR2 is required because Hawaiʻi Electric Light 's UFLS scheme uses df/dt relays for Blocks 1 and 2. The df/dt UFLS capacity that was shed was 25.4 MW that is basically FFR at the distribution circuit level as opposed to behind the meter.

The effectiveness of df/dt is evident in the frequency response profile. The initial RoCoF is immediately reduced when UFLS Blocks 1 and 2 are shed. This avoids tripping legacy PV.

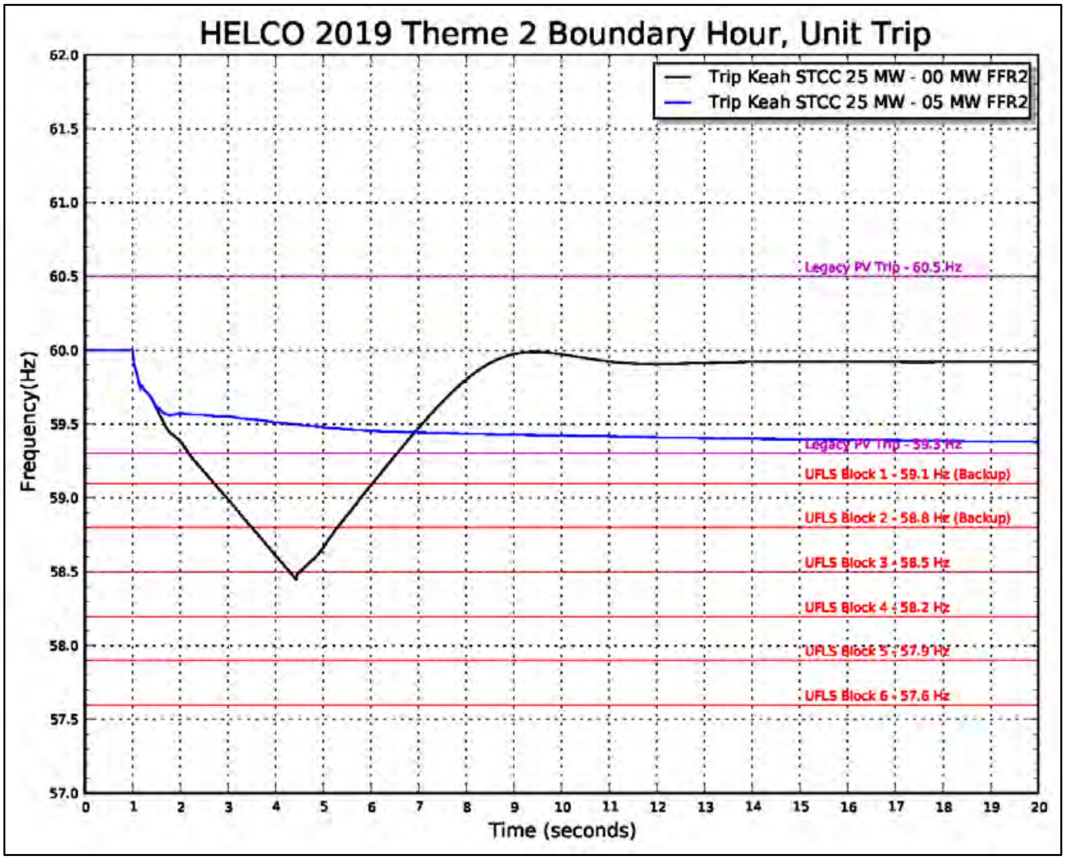


Figure O-109. Frequency Response Profile FFR2 Boundary Hour

Figure O-109 shows the frequency response profile for a Keahole STCC trip at 25 MW for a boundary hour. System kinetic energy is 390 MW-sec. With no FFR2, the frequency nadir breaches 58.5 Hz requiring 3 blocks of UFLS to stabilize system frequency. The capacity of FFR2 required to bring the system into compliance with TPL-001 is 5 MW. This is in addition to the 14.6 MW of df/dt UFLS from Blocks 1 and 2.

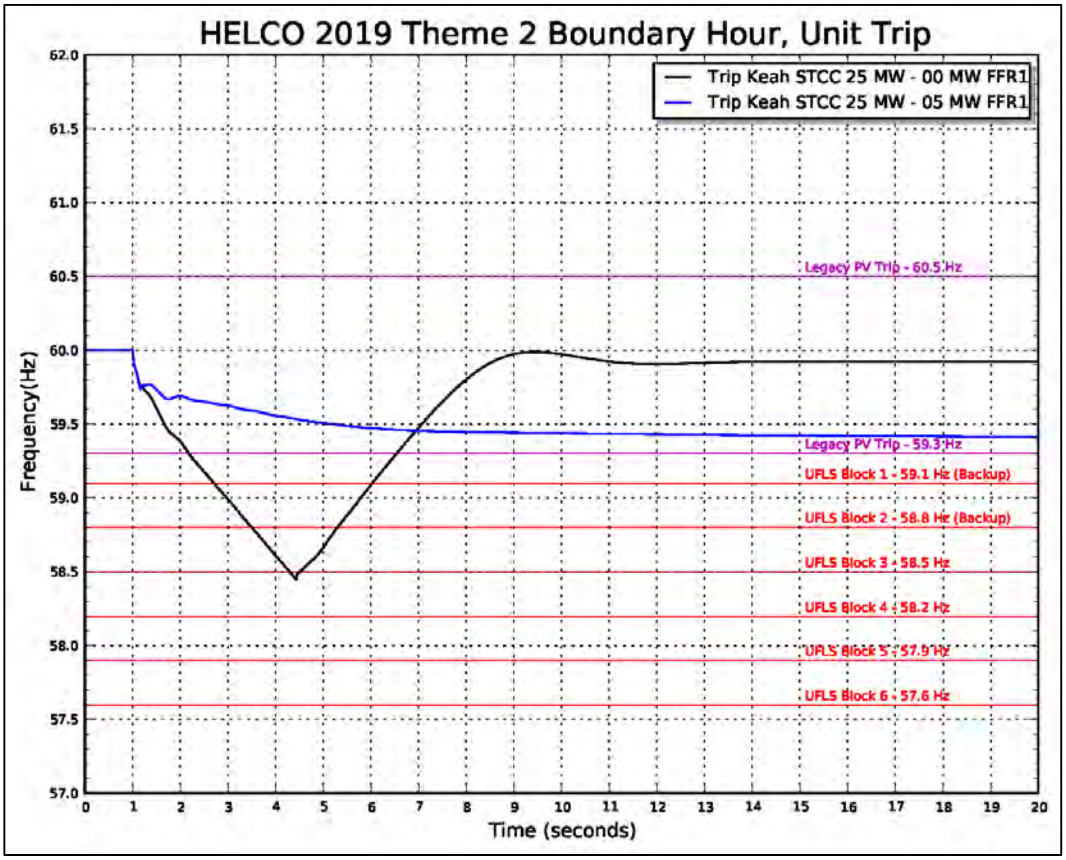


Figure O-110. Frequency Response Profile FFR1 Boundary Hour

Figure O-110 shows the frequency response profile for the FFR1 analysis. The capacity of FFR1 required to bring the system into compliance with TPL-001 is 5 MW.

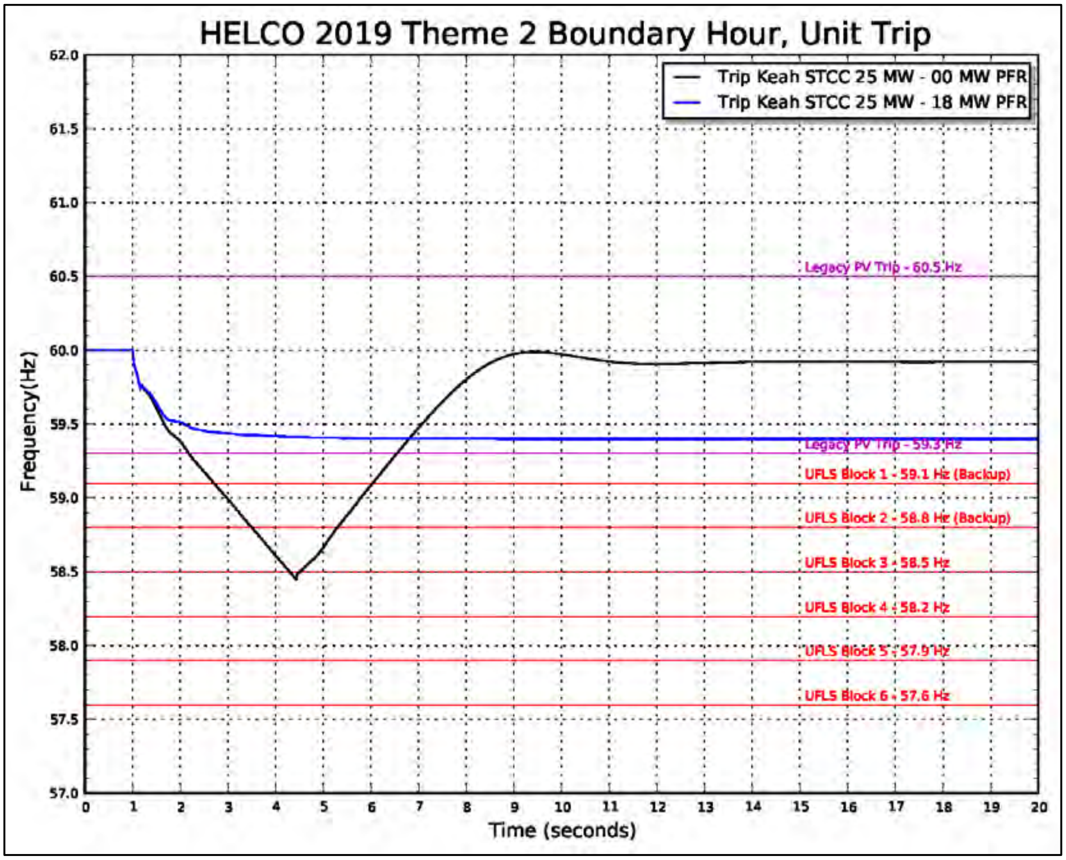


Figure O-111. Frequency Response Profile PFR Boundary Hour

Figure O-111 shows the frequency response profile for the PFR analysis. The capacity of PFR required to bring the system into compliance with TPL-001 is 18 MW.

69 kV Fault Analysis

Simulations were performed for electrical faults on the 69 kV transmission lines for the typical and boundary hours. Simulations for normally cleared faults did not produce and system stability issues.

2019 69 kV Fault Delayed Clearing Analysis			
Line No Outage	3-phase Fault Near	Typical Hour Condition	Boundary Hour Condition
L6100	Kanoelehua	Stable	Unstable
	Kaumana	Unstable	Unstable
L6200	Kaumana	Stable	Stable
	Keamuku	Stable	Stable
L6300	Kilauea	Stable	Stable
	Puna	Stable	Stable
L6400	Kanoelehua	Stable	Stable
	Puna	Unstable	Unstable
L6500	Kaumana	Stable	Stable
	Pohoiki	Stable	Stable
L6600	Kamaoa	Stable	Stable
	Kilauea	Stable	Stable
L6700	Kahaluu	Stable	Stable
	Keahole	Stable	Stable
L6800	Keahole	Stable	Stable
	Keamuku	Stable	Stable
L7100	Anaehoomalu	Stable	Stable
	Poopoomino	Stable	Stable
L7200	Keamuku	Stable	Stable
	Waimea	Stable	Stable
L7300	Ouli	Stable	Stable
	Waimea	Stable	Stable
L7400	Pepeekeo	Stable	Stable
	Wailuku	Stable	Stable
L7500	Kailua	Stable	Unstable
	Keahole	Stable	Stable
L7600	Honokaa	Stable	Stable
	Pepeekeo	Stable	Stable
L7700	Haina	Stable	Stable
	Waimea	Stable	Stable
L7800	Kanoelehua	Unstable	Unstable
	Puueo	Unstable	Unstable
L8100	Anaehoomalu	Stable	Stable
	Keamuku	Stable	Stable
L8200	Anaehoomalu	Stable	Stable
	Mauna Lani	Stable	Stable
L8300	Mauna Lani	Stable	Stable
	Ouli	Stable	Stable
L8400	Pepeekeo	Unstable	Unstable
	Puueo	Stable	Stable
L8500	Kaumana	Stable	Stable
	Keamuku	Stable	Stable
L8600	Kahaluu	Stable	Stable
	Kealia	Stable	Stable
L8700	Pohoiki	Stable	Stable
	Puna	Stable	Stable
L8800	Haina	Stable	Stable
	Honokaa	Stable	Stable
L9100	Keahole	Stable	Stable
	Poopoomino	Stable	Unstable
L9200	Kaumana	Stable	Stable
	Wailuku	Unstable	Unstable
L9300	Kailua	Stable	Unstable
	Keahole	Stable	Stable
L9500	Kahaluu	Stable	Stable
	Kailua	Stable	Stable
L9600	Kamaoa	Stable	Stable
	Kealia	Stable	Stable

Table O-40. Summary of Results for Delayed Clearing Fault Analysis

Table O-40 summarizes the results of the fault analysis. For the typical hour, 6 simulations resulted in unstable operation and 10 simulations resulted in unstable operation for the boundary hour.

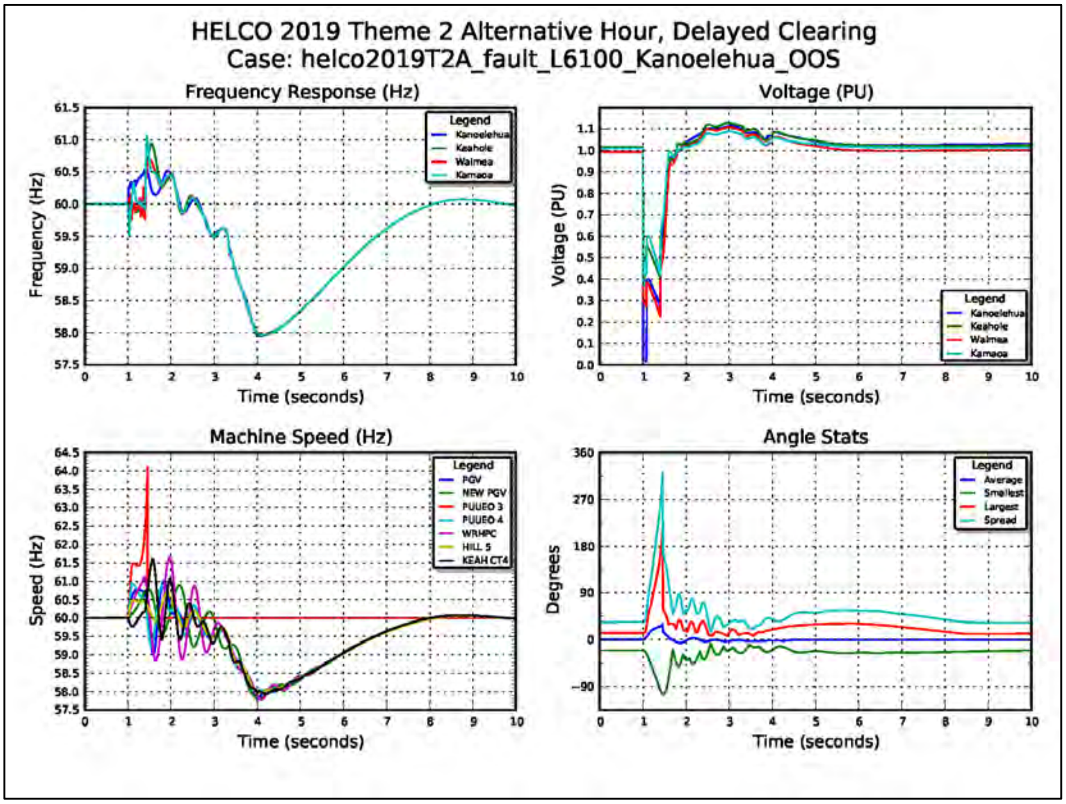


Figure O-112. System Performance for Delayed Clearing Fault

Figure O-112 shows four plots that illustrate system performance for a delayed clearing fault on the L6100 Kanoelehua circuit for the alternative hour. System voltage exceeds 1.1 PU, tripping all 66 MW of DG-PV on over voltage. Simulations were performed to determine the frequency response capacities required to bring the system into compliance with TPL-001.

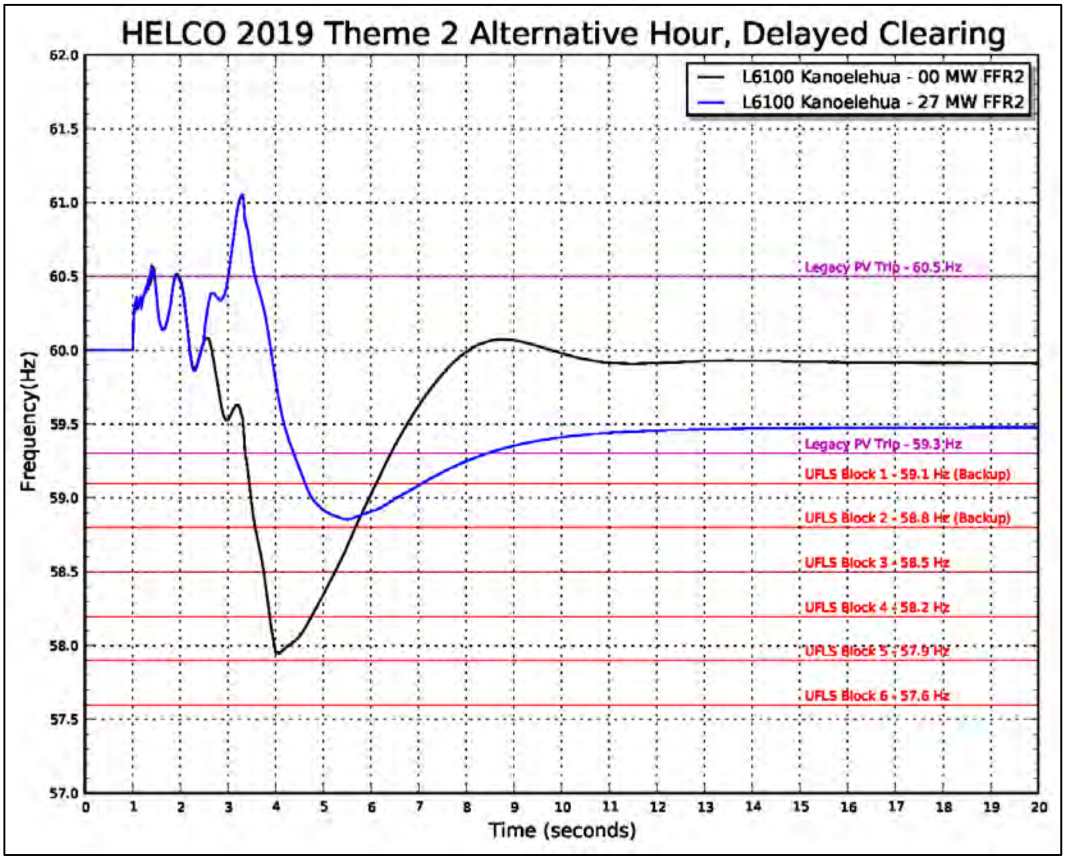


Figure O-113. Frequency Response Profile for FFR2 Alternate Hour

Figure O-113 shows the frequency response profile for the FFR2 analysis. The first system peak is caused by the fault. Approximately 66 MW of DG-PV will disconnect on over voltage. System frequency begins to decay and triggers UFLS Blocks 1&2 on df/dt (14.6 MW), causing a momentary stabilization of system frequency (black plot). Frequency continues to decay until the nadir breaches 58 Hz, requiring 4 blocks of UFLS to stabilize system frequency. The capacity of FFR2 required to bring the system into compliance with TPL-001 is 27 MW. However, this capacity of FFR2 over compensates and initially drives system frequency to 61.1 Hz.

Auto-Schedule control for the BESS is designed to dispatch to full output on a breaker signal from that largest generating unit(s) and is fully deployed in 12-cycles (FFR1) but is not designed to respond to over frequency events. Simulations were performed to determine the capacity of PFR from a BESS with a 3% droop setting. The HELCO generating units are set to 4% droop response.

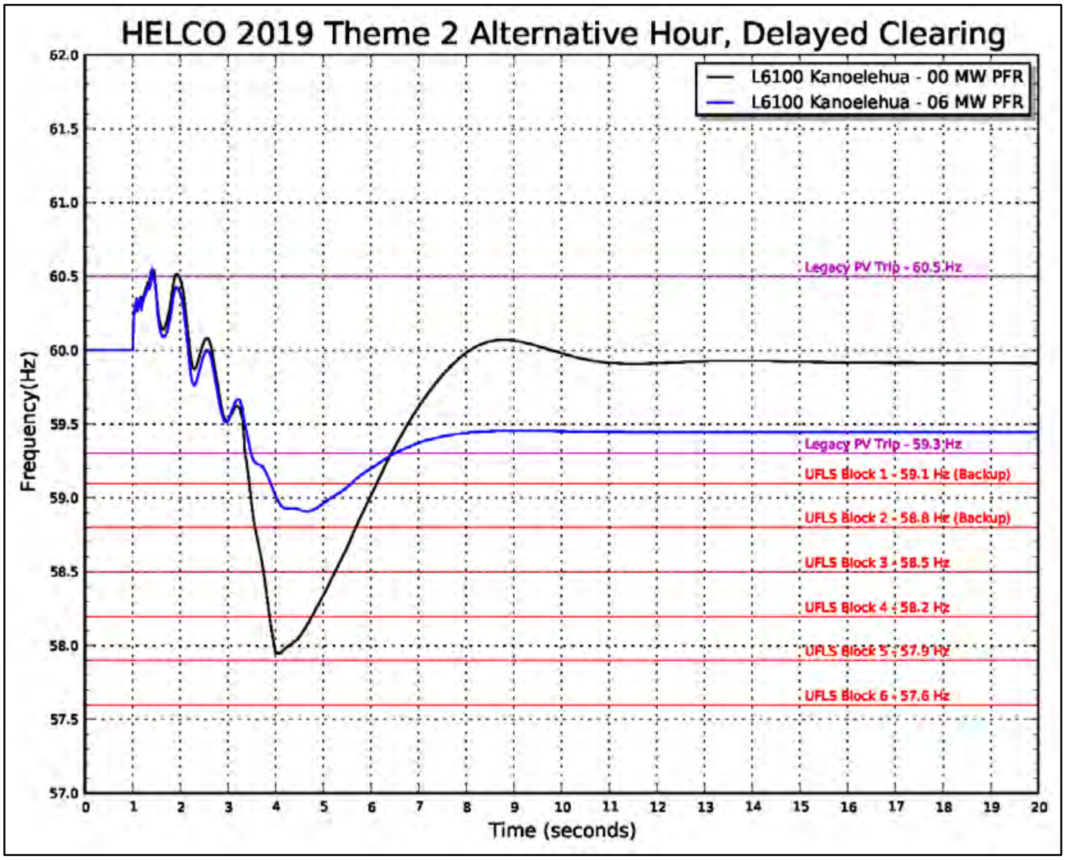


Figure O-114. Frequency Response Profile for PFR Alternate Hour

Figure O-114 shows the frequency response profile for the PFR analysis provided by a BESS. The capacity of PFR at 3% droop response required to bring the system into compliance with TPL-001 is 6 MW. This is in addition to the 14.6 MW of df/dt UFLS from Blocks 1 and 2.

Theme 1 – Aggressive Renewables Plan

Summary

System security analyses were not performed on any resource plan for Theme 1. A high-level fatal flaw assessment was performed on the Theme 1 2045 plans by applying system security requirements for Themes 2 and 3.

Theme 2 – LNG Plan

2023

System security analysis was performed on three hours that were selected from the Theme 2 production cost simulations that represents a typical hour and a boundary condition.

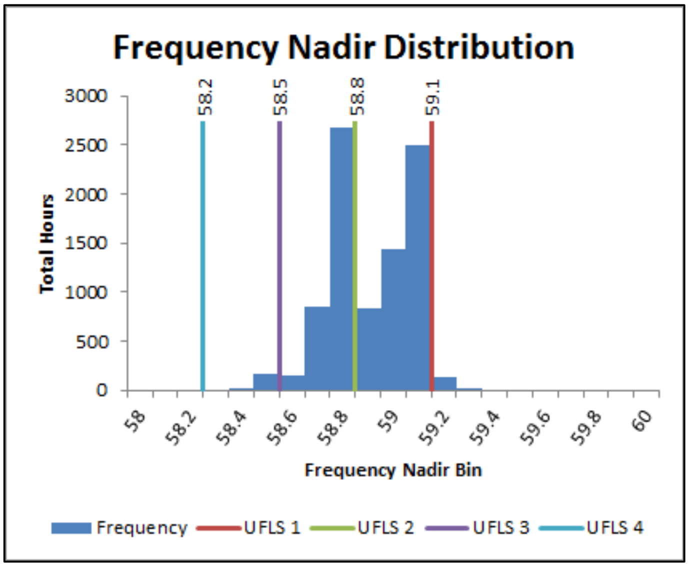


Figure O-115. Frequency Nadir Histogram 2023

Figure O-115 is a histogram of the expected frequency nadirs for N-1 generator contingency events for the entire year. The typical hour selected from the maximum distribution of 2676 hours was 1:00 PM on Friday, January 20. The frequency nadir range for the typical hour is 58.7 - 58.8 Hz that requires four blocks of UFLS to stabilize system frequency.

The boundary hour selected from a minimum distribution of 6 hours was 1:00 PM on Sunday, December 31. The frequency nadir range for the boundary hour is 58.4 – 58.5 Hz that requires five blocks of UFLS to stabilize system frequency.

The alternate hour was selected from the boundary hours to maximize DG-PV for the purpose of analyzing loss of generation contingency caused by delay cleared faults.

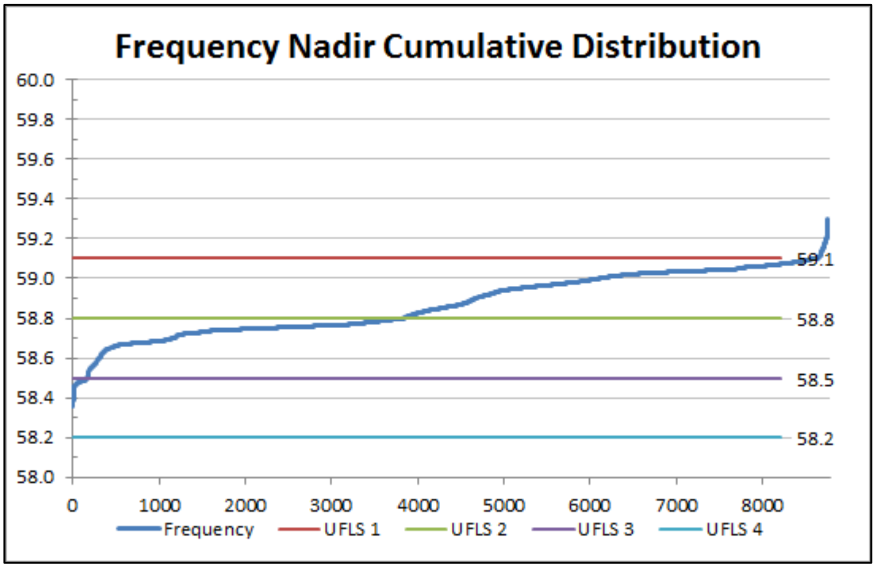


Figure O-116. Frequency Nadir Duration Curve

Figure O-116 shows the frequency nadir duration curve for the entire year.

Unit Commitment Order	Unit Ratings							HELCO 2023 (Typical) Fri 1/20/23 Hour 13			HELCO 2023 (Boundary) Sun 12/31/23 Hour 13		
	Pmax	Pmin			Inertia H	Unit MVA	Unit K.E.	Pgen	up reg (spin)	down reg	Pgen	up reg (spin)	down reg
PGV	38.0	22.0			2.94	59.4	174	33.1	4.9	11.1	33.1	4.9	11.1
Keahole STCC	25.0	7.0			3.13	46.5	146	14.8	10.2	7.8			
Keahole DTCC	54.0	7.0			2.77	71.8	199						
Keahole CT4	20.0	7.0			2.10	25.2	53						
Keahole CT5	20.0	7.0			2.10	25.2	53						
HEP STCC	28.5	9.0			1.96	58.9	116	16.6	11.9	7.6			
HEP DTCC	60.0	18.5			1.78	94.4	168						
Hill 5	13.5	5.0			2.20	15.6	34						
Hill 6	20.5	8.0			2.53	27.5	70						
Keah CT2	13.8	5.0			4.44	22.2	99						
Puna CT3	20.0	7.0			4.96	29.6	147						
Geo1	20.0				5.00	40.0	200	20.0	0.0	20.0	17.7	2.3	17.7
Geo2	20.0				5.00	40.0	200						
Biomass1	20.0				3.16	28.0	88						
HELCO Hydro	4.7	0.0			1.07	5.6	6	2.5			3.0		
Wailuku Hydro	12.1	0.0			2.42	12.2	30	2.8			2.8		
Apollo	20.5	0.0						6.2			0.0		
HRD	10.5	0.0						0.0			5.3		
Wind1	20.0	0.0											
Wind2	20.0	0.0											
Wind3	20.0	0.0											
Hydro	16.8	0						5			6		
Wind	31.0	0						6			5		
DG-PV	124.7	0						88			88		
Total Kinetic Energy									672			410	
Total Load									184			150	
Total Thermal Generation									84			51	
Total Renewable Generation									100			99	
Total Generation									184			150	
Excess Generation									0			0	
Total Up Regulation									27			7	
Total Down Regulation									46			29	
Legacy DG-PV	59.3Hz Capacity			7.4				59.3Hz Output		5.2	59.3Hz Output		5.2
	60.5Hz Capacity			26.4				60.5Hz Output		18.7	60.5Hz Output		18.7

Table O-41. Unit Commitment and Dispatch Schedule 2023

Table O-41 shows the unit commitment and dispatch for the typical hour (1/20/2023, 1:00 PM), boundary hour (12/31/2023, 1:00 PM).

Loss of Generation

Simulations were performed for the largest loss of generation contingency event to determine the frequency response reserves requirements to bring the system into compliance with TPL-001.

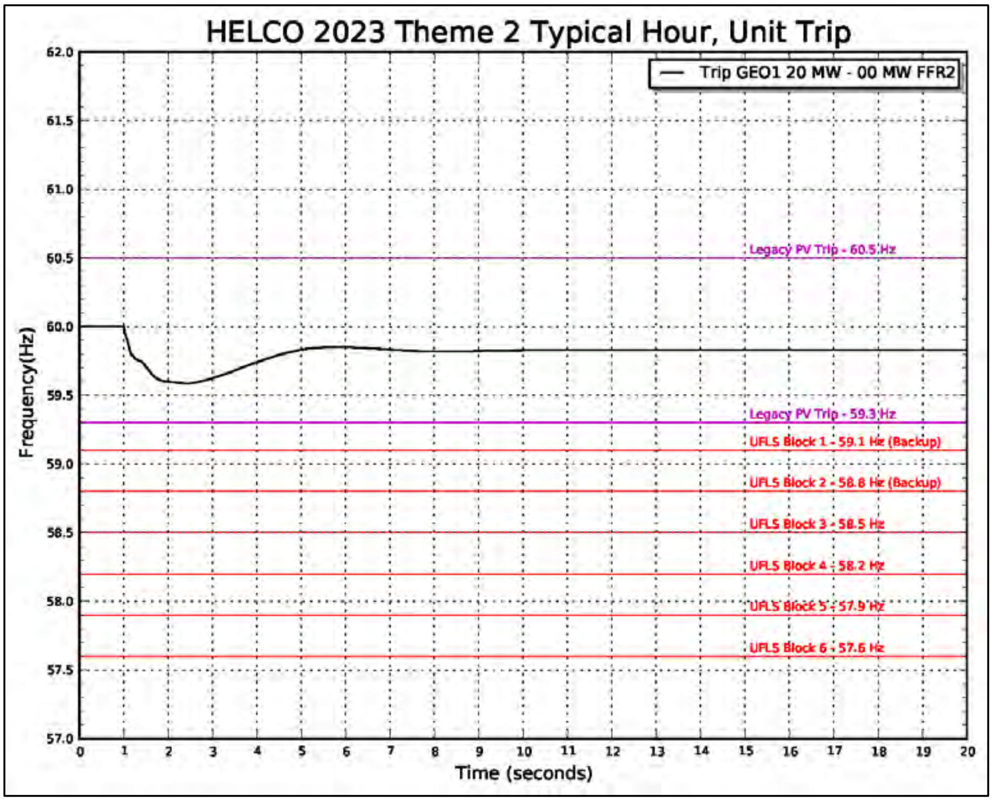


Figure O-117. Frequency Response Profile for FFR2 Typical Hour

Figure O-117 shows the frequency response profile for a geothermal unit trip at 20 MW for a typical hour. System kinetic energy is 672 MW-sec and the capacity of legacy PV that will disconnect from the system is approximately 5.2 MW. No FFR2 is required because Hawaiʻi Electric Light 's UFLS scheme uses df/dt relays for Blocks 1 and 2. The df/dt UFLS capacity that was shed was 27.6 MW that is basically FFR at the distribution circuit level as opposed to behind the meter.

The effectiveness of df/dt is evident in the frequency response profile. The initial RoCoF is immediately reduced when UFLS Blocks 1 and 2 are shed. This avoids tripping legacy PV.

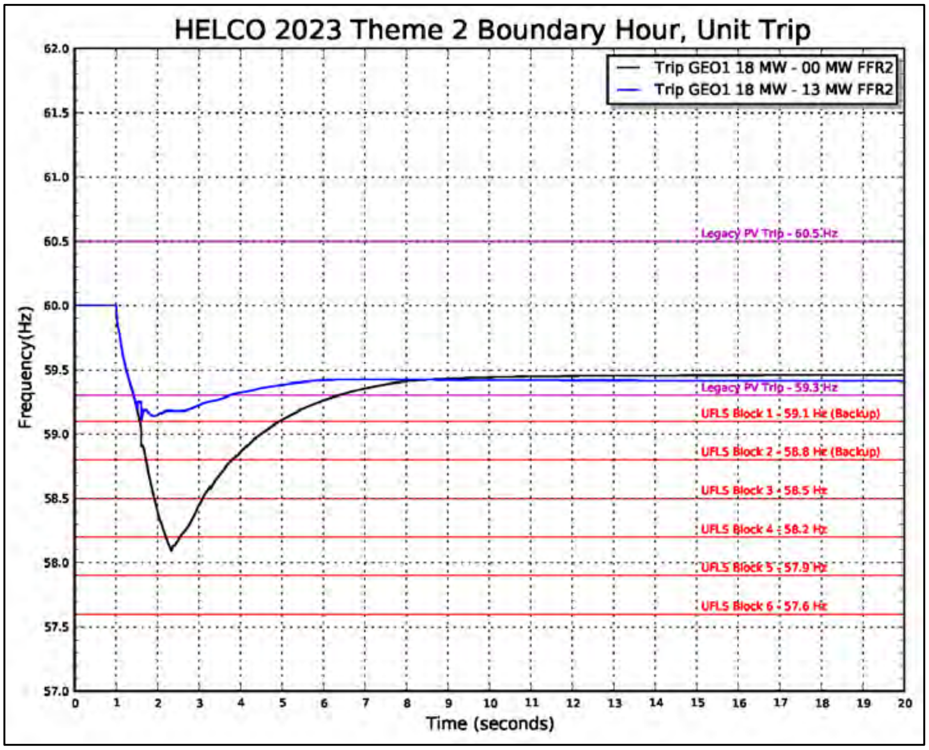


Figure O-118. Frequency Response Profile FFR2 Boundary Hour

Figure O-118 shows the frequency response profile for a geothermal unit trip at 18 MW for a boundary hour. System kinetic energy is 410 MW-sec and the capacity of legacy PV that will disconnect from the system is 5.2 MW. The capacity of FFR2 required to bring the system into compliance with TPL-001 is 13 MW. This is in addition to the 22.5 MW of df/dt UFLS from Blocks 1 and 2.

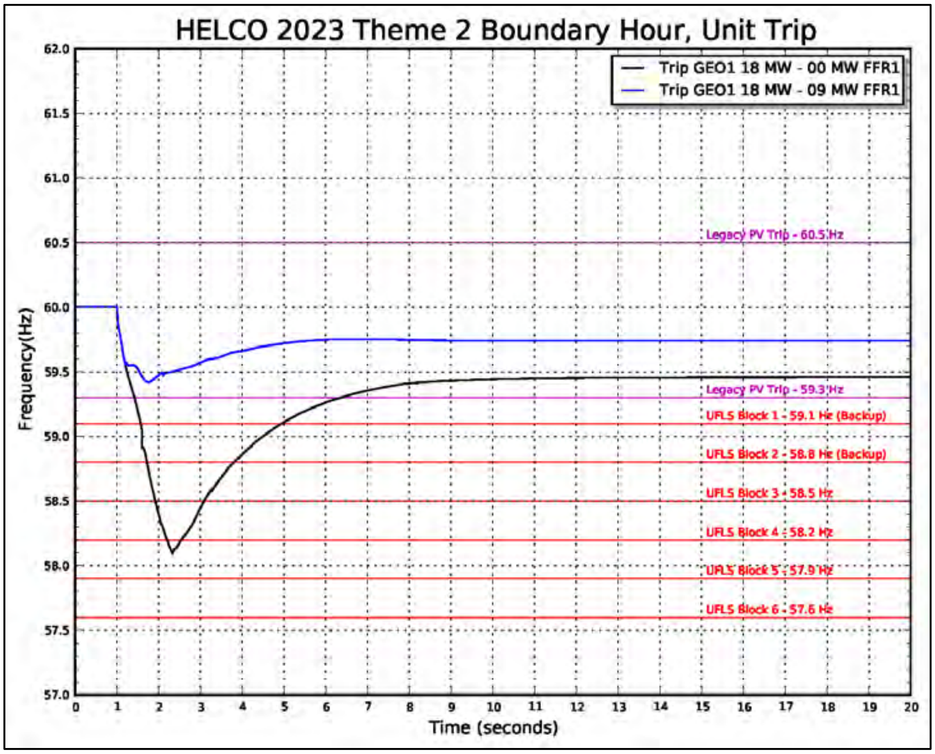


Figure O-119. Frequency Response Profile FFR1 Boundary Hour

Figure O-119 shows the frequency response profile for the FFR1 analysis. The capacity of FFR1 required to bring the system into compliance with TPL-001 is 9 MW. This is in addition to the 22.5 MW of df/dt UFLS from Blocks 1 and 2.

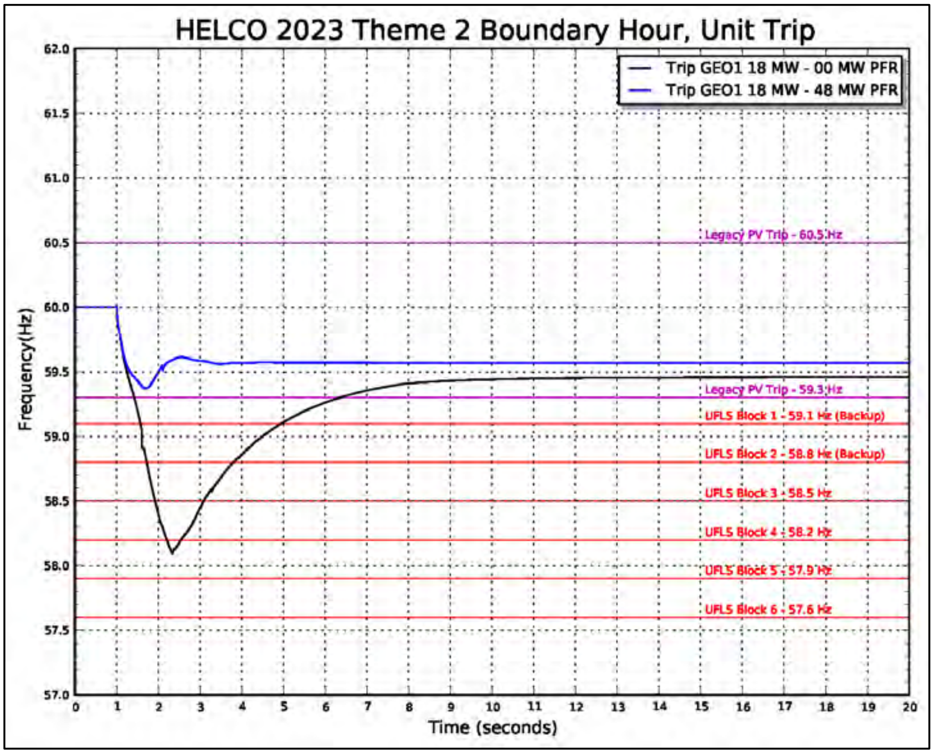


Figure O-120. Frequency Response Profile PFR Boundary Hour

Figure O-120 shows the frequency response profile for the PFR analysis. The capacity of FFR1 required to bring the system into compliance with TPL-001 is 48 MW.

69 kV Fault Analysis

Simulations were performed for electrical faults on the 69 kV transmission lines for the typical and boundary hours. Simulations for normally cleared faults did not produce and system stability issues.

2023 69kV Fault Delayed Clearing Analysis			
Line No Outage	3-phase Fault Near	Typical Hour Condition	Boundary Hour Condition
L6100	Kanoelehua	Stable	Unstable
	Kaumana	Unstable	Unstable
L6200	Kaumana	Stable	Stable
	Keamuku	Stable	Stable
L6300	Kilauea	Stable	Stable
	Puna	Stable	Stable
L6400	Kanoelehua	Stable	Unstable
	Puna	Stable	Unstable
L6500	Kaumana	Stable	Unstable
	Pohoiki	Stable	Stable
L6600	Kamaoa	Stable	Stable
	Kilauea	Stable	Stable
L6700	Kahaluu	Stable	Stable
	Keahole	Stable	Stable
L6800	Keahole	Stable	Stable
	Keamuku	Stable	Stable
L7100	Anaehoomalu	Stable	Stable
	Poopoomino	Stable	Stable
L7200	Keamuku	Stable	Stable
	Waimea	Stable	Stable
L7300	Ouli	Stable	Stable
	Waimea	Stable	Stable
L7400	Pepeekeo	Stable	Unstable
	Wailuku	Stable	Unstable
L7500	Kailua	Stable	Stable
	Keahole	Stable	Stable
L7600	Honokaa	Stable	Unstable
	Pepeekeo	Stable	Stable
L7700	Haina	Stable	Stable
	Waimea	Stable	Unstable
L7800	Kanoelehua	Unstable	Unstable
	Puueo	Stable	Unstable
L8100	Anaehoomalu	Stable	Stable
	Keamuku	Stable	Stable
L8200	Anaehoomalu	Stable	Unstable
	Mauna Lani	Stable	Stable
L8300	Mauna Lani	Stable	Stable
	Ouli	Stable	Stable
L8400	Pepeekeo	Stable	Unstable
	Puueo	Stable	Stable
L8500	Kaumana	Stable	Stable
	Keamuku	Stable	Unstable
L8600	Kahaluu	Stable	Stable
	Kealia	Stable	Stable
L8700	Pohoiki	Stable	Stable
	Puna	Stable	Unstable
L8800	Haina	Stable	Unstable
	Honokaa	Stable	Stable
L9100	Keahole	Stable	Stable
	Poopoomino	Stable	Stable
L9200	Kaumana	Stable	Unstable
	Wailuku	Stable	Unstable
L9300	Kailua	Stable	Stable
	Keahole	Stable	Stable
L9500	Kahaluu	Stable	Stable
	Kailua	Stable	Stable
L9600	Kamaoa	Stable	Stable
	Kealia	Stable	Stable

Table O-42. Summary of Results Delayed Clearing Fault Analysis

Table O-42 summarizes the results of the fault analysis. For the typical hour, 2 simulations resulted in unstable operation and 18 simulations resulted in unstable operation for the boundary hour.

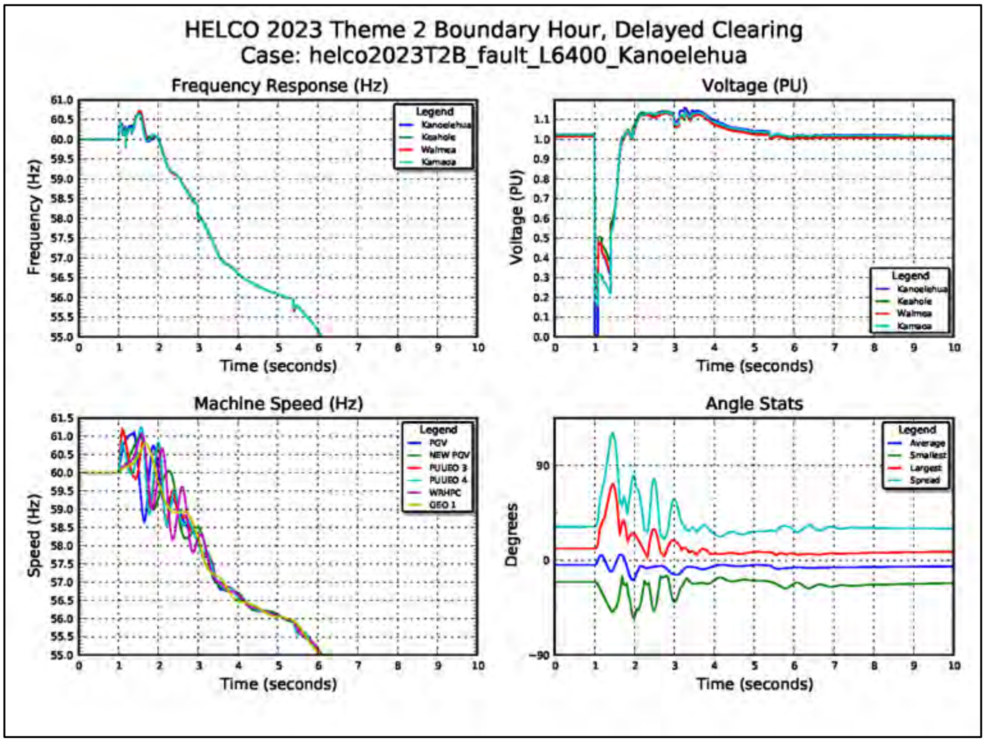


Figure O-121. System Performance for Delayed Clearing Fault

Figure O-121 shows four plots that illustrate system performance for a delayed clearing fault on the L6400 Kanoelehua circuit for the boundary hour. System voltage exceeds 1.1 PU, tripping all units on the system including 88 MW of DG-PV on over voltage. The system will not survive an extended over voltage event. Simulations were performed to determine the frequency response capacities required to bring the system into compliance with TPL-001.

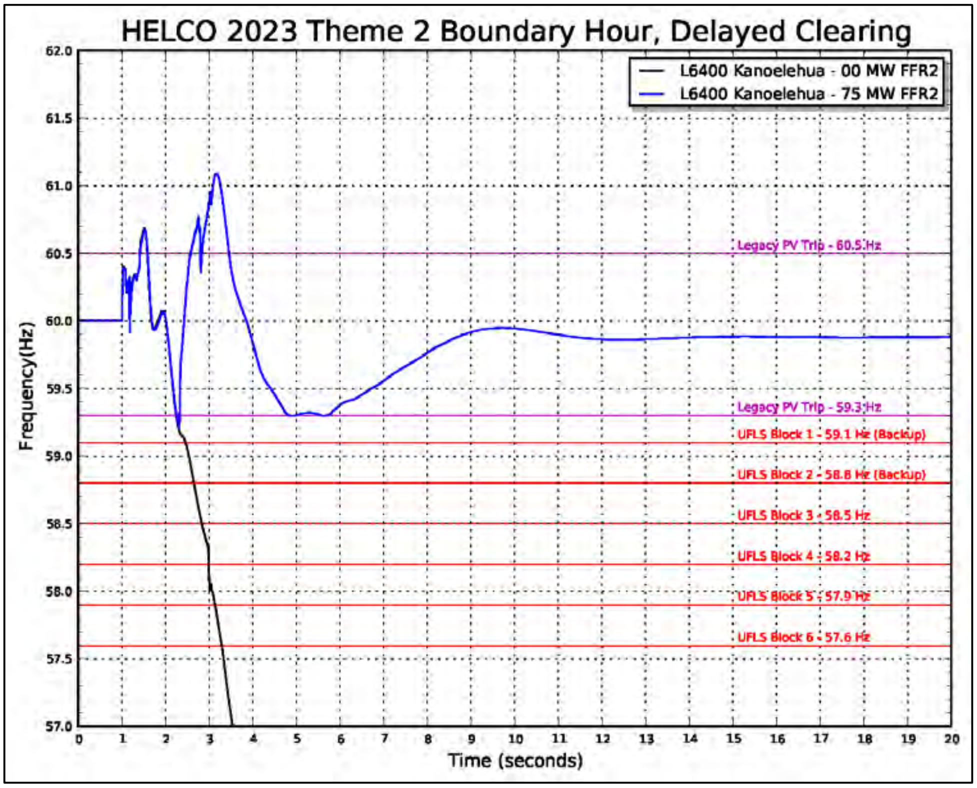


Figure O-122. Frequency Response Profile for FFR2 Boundary Hour

Figure O-122 shows the frequency response profile for the FFR2 analysis. The first system peak is caused by the fault. All generating resources disconnect from the system on over voltage. System frequency begins to decay and triggers UFLS Blocks 1&2 on df/dt (22.5 MW), causing a momentary stabilization of system frequency (black plot). Frequency continues to decay below 57 Hz despite 5 blocks of UFLS. The capacity of FFR2 required to bring the system into compliance with TPL-001 is 75 MW. However, this capacity of FFR2 over compensates and initially drives system frequency to 61.1 Hz.

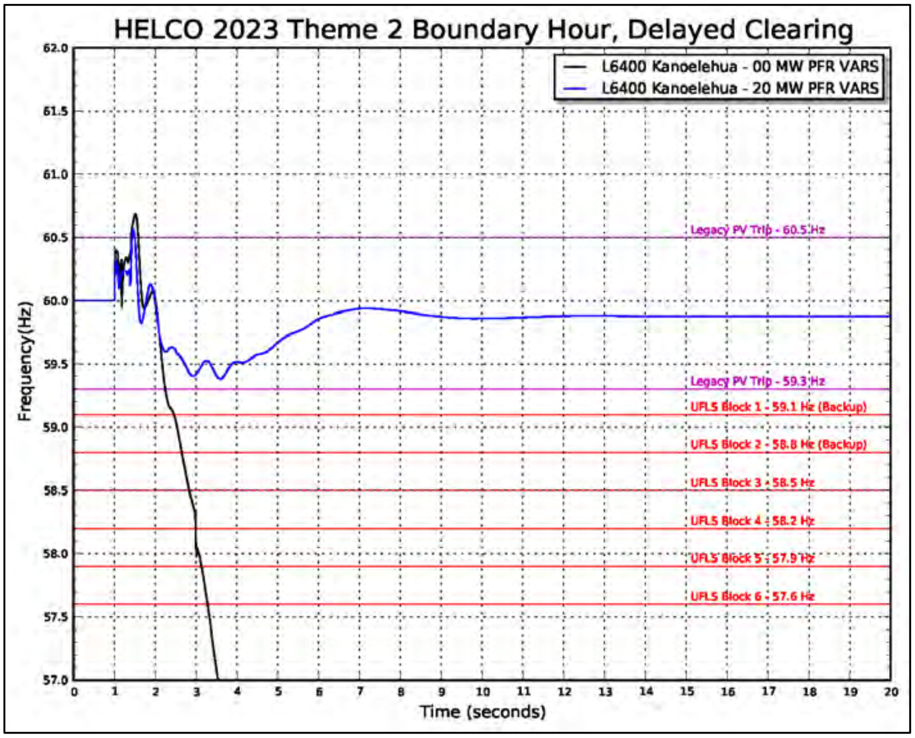


Figure O-123. Frequency Response Profile for PFR Boundary Hour

Figure O-123 shows the frequency response profile for the PFR analysis provided by a BESS. The capacity of PFR at 3% droop response required to bring the system into compliance with TPL-001 is 20 MW. This is in addition to the 22.5 MW of df/dt UFLS from Blocks 1 and 2.

2045

System security analysis was performed on three hours that were selected from the Theme 2 production cost simulations that represents a typical hour and a boundary condition.

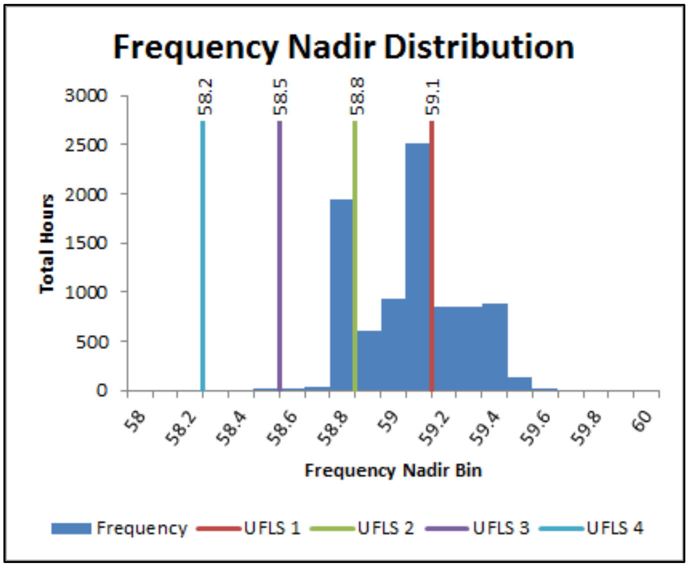


Figure O-124. Frequency Nadir Histogram 2045

Figure O-124 is a histogram of the expected frequency nadirs for N-1 generator contingency events for the entire year. The typical hour selected from the maximum distribution of 1947 hours was 3:00 PM on Sunday, April 9. The frequency nadir range for the typical hour is 58.7 - 58.8 Hz that requires 2 blocks of UFLS to stabilize system frequency.

The boundary hour selected from a minimum distribution of 6 hours was 1:00 PM on Friday, February 10. The frequency nadir range for the boundary hour is 58.4 – 58.5 Hz that requires 3 blocks of UFLS to stabilize system frequency.

The alternate hour was selected from the boundary hours to maximize DG-PV for the purpose of analyzing loss of generation contingency caused by delay cleared faults.

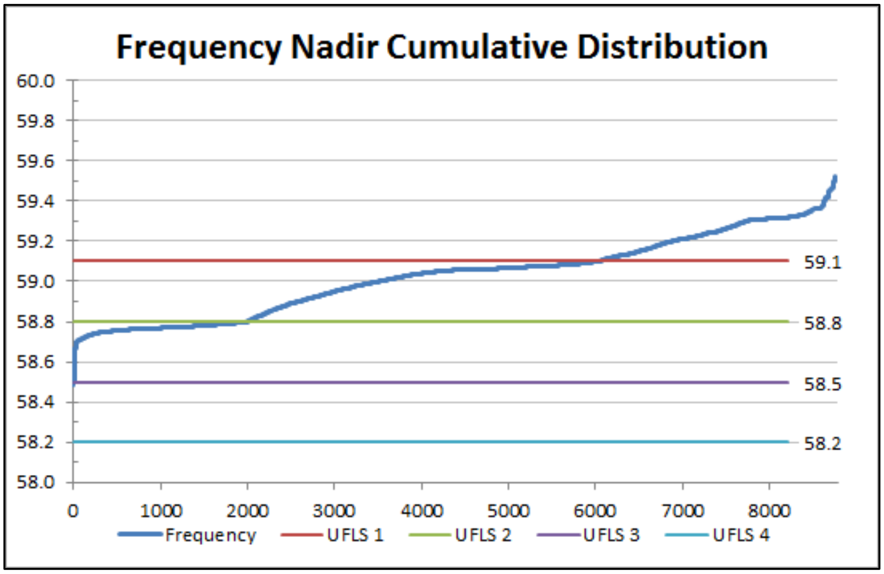


Figure O-125. Frequency Nadir Duration Curve 2045

Figure O-125 shows the frequency nadir duration curve for the entire year.

Unit Commitment Order	Unit Ratings							HELCO 2045 (Typical) Sun 4/9/45 Hour 15			HELCO 2045 (Boundary) Fri 2/10/45 Hour 13		
	Pmax	Pmin			Inertia H	Unit MVA	Unit K.E.	Pgen	up reg (spin)	down reg	Pgen	up reg (spin)	down reg
PGV	38.0	22.0			2.94	59.4	174	33.7	4.3	11.7			
Keahole STCC	25.0	7.0			3.13	46.5	146						
Keahole DTCC	54.0	7.0			2.77	71.8	199						
Keahole CT4	20.0	7.0			2.10	25.2	53						
Keahole CT5	20.0	7.0			2.10	25.2	53						
HEP STCC	28.5	9.0			1.96	58.9	116				26.4	2.1	17.4
HEP DTCC	60.0	18.5			1.78	94.4	168						
Hill 5	13.5	5.0			2.20	15.6	34						
Hill 6	20.5	8.0			2.53	27.5	70						
Keah CT2	13.8	5.0			4.44	22.2	99						
Puna CT3	20.0	7.0			4.96	29.6	147						
Geo1	20.0				5.00	40.0	200	20.0	0.0	20.0	20.0	0.0	20.0
Geo2	20.0				5.00	40.0	200	19.6	0.4	19.6	20.0	0.0	20.0
Biomass1	20.0				3.16	28.0	88	12.3	7.7	12.3	18.0	2.0	18.0
HELCO Hydro	4.7	0.0			1.07	5.6	6	4.1			1.9		
Wailuku Hydro	12.1	0.0			2.42	12.2	30	0.8			0.0		
Apollo	20.5	0.0						0.0			7.5		
HRD	10.5	0.0						3.6			1.3		
Wind1	20.0	0.0						0.0			4.0		
Wind2	20.0	0.0						0.0			4.0		
Wind3	20.0	0.0											
Hydro	16.8	0						5			2		
Wind	31.0	0						4			17		
DG-PV	158	0						70			83		
Total Kinetic Energy									699			640	
Total Load									165			186	
Total Thermal Generation									86			84	
Total Renewable Generation									79			102	
Total Generation									165			186	
Excess Generation									0			0	
Total Up Regulation									12			4	
Total Down Regulation									64			75	
Legacy DG-PV	59.3Hz Capacity		0.0					59.3Hz Output		0.0	59.3Hz Output		0.0
	60.5Hz Capacity		0.0					60.5Hz Output		0.0	60.5Hz Output		0.0

Table O-43. Unit Commitment and Dispatch Schedule 2045

Table O-43 shows the unit commitment and dispatch for the typical hour (4/9/2045, 3:00 PM), boundary hour (2/10/2045, 1:00 PM).

Loss of Generation

Simulations were performed for the largest loss of generation contingency event to determine the frequency response reserves requirements to bring the system into compliance with TPL-001.

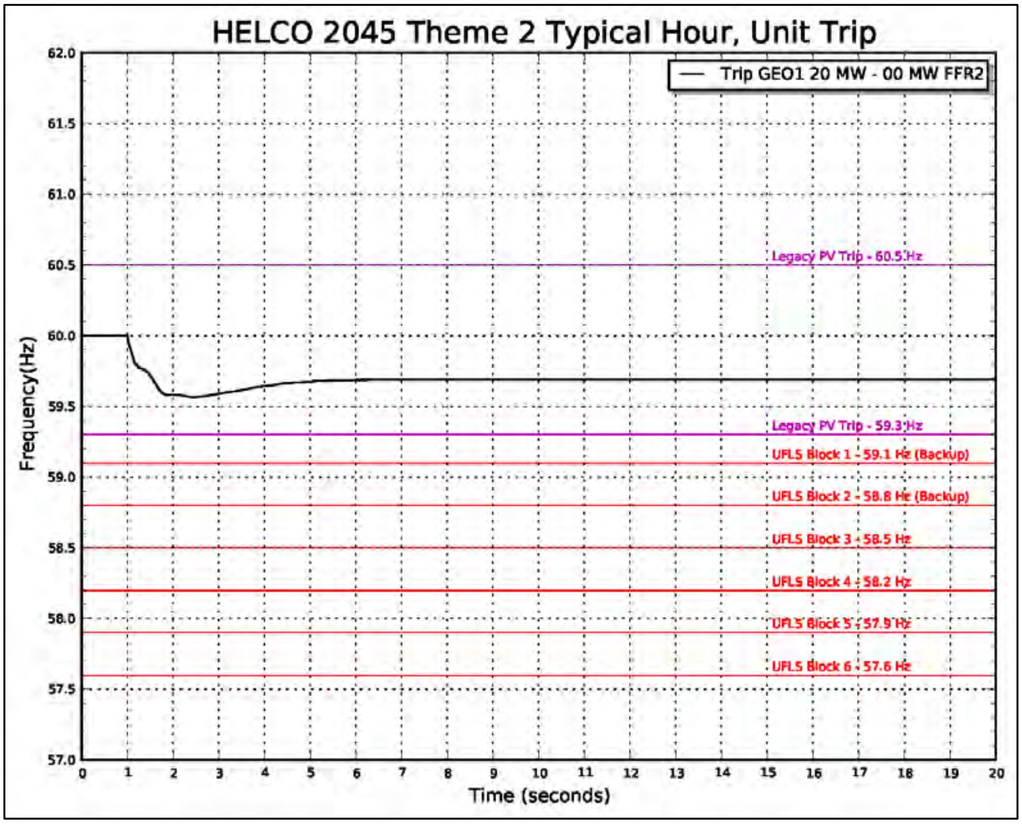


Figure O-126. Frequency Response Profile FFR2 Typical Hour

Figure O-126 shows the frequency response profile for a geothermal unit trip at 20 MW for a typical hour. System kinetic energy is 699 MW-sec. No FFR2 is required because Hawai'i Electric Light 's UFLS scheme uses df/dt relays for Blocks 1 and 2. The df/dt UFLS capacity that was shed was 24.8 MW that is basically FFR at the distribution circuit level as opposed to behind the meter.

The effectiveness of df/dt is evident in the frequency response profile. The initial RoCoF is immediately reduced when UFLS Blocks 1 and 2 are shed. This avoids tripping legacy PV.

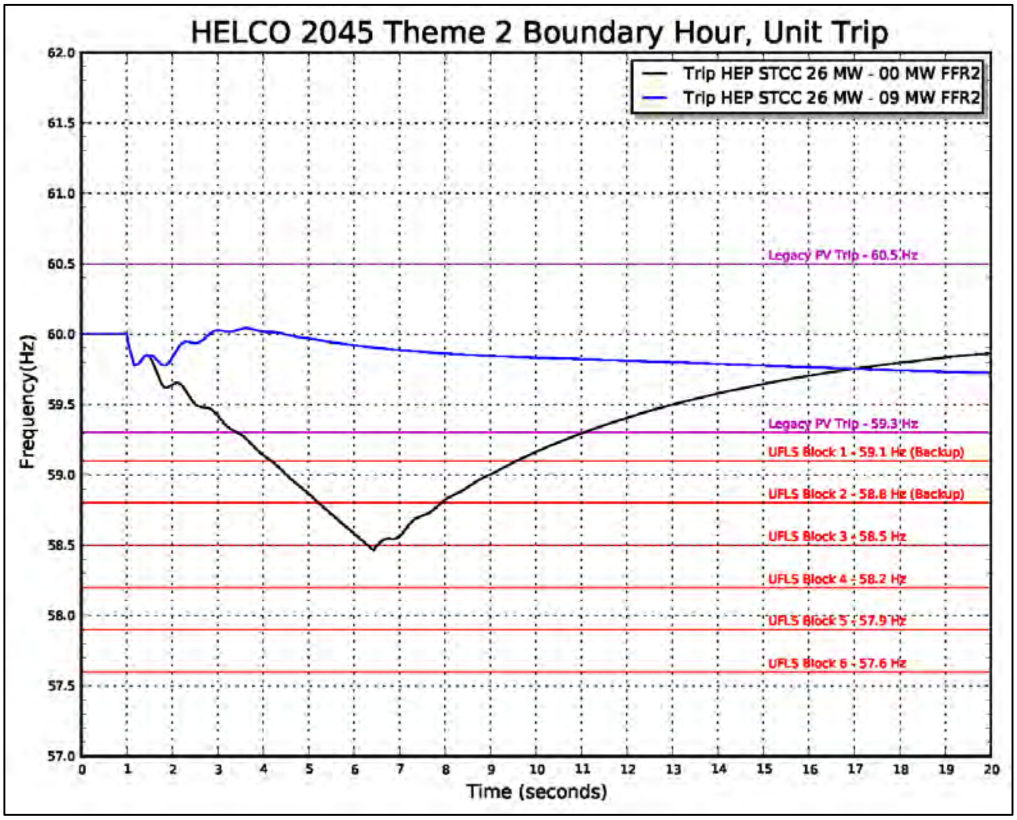


Figure O-127. Frequency Response Profile FFR2 Boundary Hour

Figure O-127 shows the frequency response profile for a HEP STCC unit trip at 26 MW for a boundary hour. System kinetic energy is 640 MW-sec. The capacity of FFR2 required to bring the system into compliance with TPL-001 is 9 MW. This is in addition to the 27.9 MW of df/dt UFLS from Blocks 1 and 2.

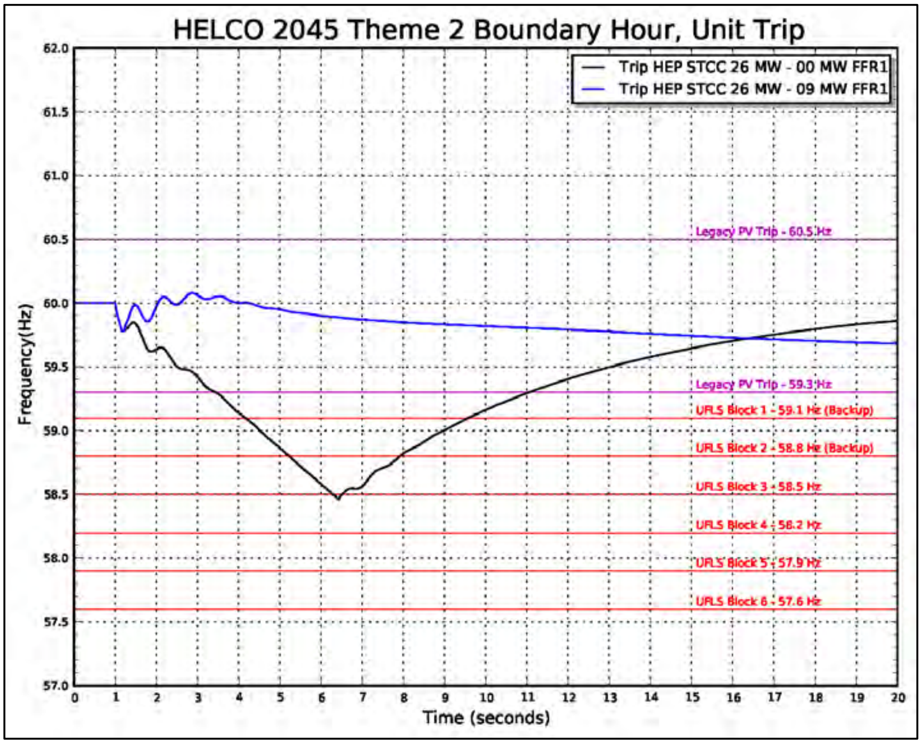


Figure O-128. Frequency Response Profile FFR1 Boundary Hour

Figure O-128 shows the frequency response profile for the FFR1 analysis. The capacity of FFR1 required to bring the system into compliance with TPL-001 is 9 MW. This is in addition to the 27.9 MW of df/dt UFLS from Blocks 1 and 2.

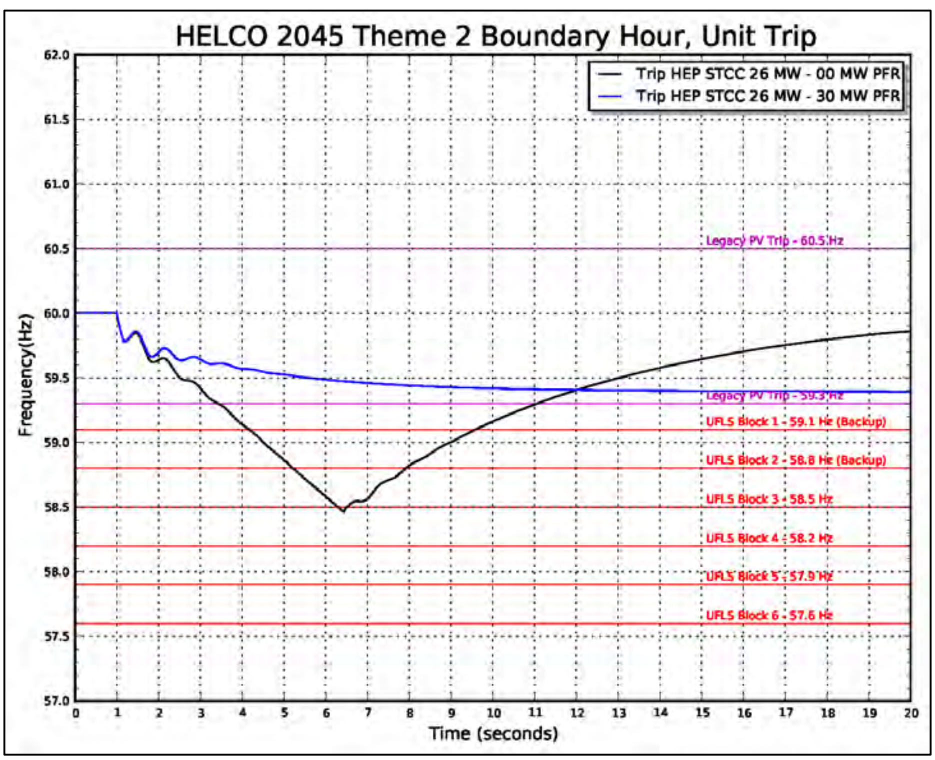


Figure O-129. Frequency Response Profile PFR Boundary Hour

Figure O-129 shows the frequency response profile for the PFR analysis. The capacity of FFR1 required to bring the system into compliance with TPL-001 is 30 MW. This is in addition to the 27.9 MW of df/dt UFLS from Blocks 1 and 2.

69 kV Fault Analysis

Simulations were performed for electrical faults on the 69 kV transmission lines for the typical and boundary hours. Simulations for normally cleared faults did not produce and system stability issues.

2045 69kV Fault Delayed Clearing Analysis			
Line No Outage	3-phase Fault Near	Typical Hour Condition	Boundary Hour Condition
L6100	Kanoelehua	Unstable	Stable
	Kaumana	Unstable	Stable
L6200	Kaumana	Stable	Stable
	Keamuku	Stable	Stable
L6300	Kilauea	Stable	Stable
	Puna	Stable	Stable
L6400	Kanoelehua	Stable	Stable
	Puna	Unstable	Stable
L6500	Kaumana	Stable	Stable
	Pohoiki	Stable	Stable
L6600	Kamaoa	Stable	Stable
	Kilauea	Stable	Stable
L6700	Kahaluu	Stable	Stable
	Keahole	Stable	Stable
L6800	Keahole	Stable	Stable
	Keamuku	Stable	Stable
L7100	Anaehoomalu	Stable	Stable
	Poopoomino	Stable	Stable
L7200	Keamuku	Stable	Stable
	Waimea	Stable	Stable
L7300	Ouli	Stable	Stable
	Waimea	Stable	Stable
L7400	Pepeekeo	Unstable	Stable
	Wailuku	Unstable	Stable
L7500	Kailua	Stable	Stable
	Keahole	Stable	Stable
L7600	Honokaa	Stable	Stable
	Pepeekeo	Stable	Stable
L7700	Haina	Stable	Stable
	Waimea	Stable	Stable
L7800	Kanoelehua	Unstable	Unstable
	Puueo	Unstable	Stable
L8100	Anaehoomalu	Stable	Stable
	Keamuku	Stable	Stable
L8200	Anaehoomalu	Stable	Stable
	Mauna Lani	Stable	Stable
L8300	Mauna Lani	Stable	Stable
	Ouli	Stable	Stable
L8400	Pepeekeo	Unstable	Stable
	Puueo	Unstable	Stable
L8500	Kaumana	Stable	Stable
	Keamuku	Stable	Stable
L8600	Kahaluu	Stable	Stable
	Kealia	Stable	Stable
L8700	Pohoiki	Stable	Stable
	Puna	Stable	Stable
L8800	Haina	Stable	Stable
	Honokaa	Stable	Unstable
L9100	Keahole	Stable	Stable
	Poopoomino	Stable	Stable
L9200	Kaumana	Unstable	Stable
	Wailuku	Unstable	Stable
L9300	Kailua	Stable	Stable
	Keahole	Stable	Stable
L9500	Kahaluu	Stable	Stable
	Kailua	Stable	Stable
L9600	Kamaoa	Stable	Stable
	Kealia	Stable	Stable

Table O-44. Summary of Results Delayed Clearing Fault Analysis

Table O-44 summarizes the results of the fault analysis. For the typical hour, 11 simulations resulted in unstable operation and 2 simulations resulted in unstable operation for the boundary hour.

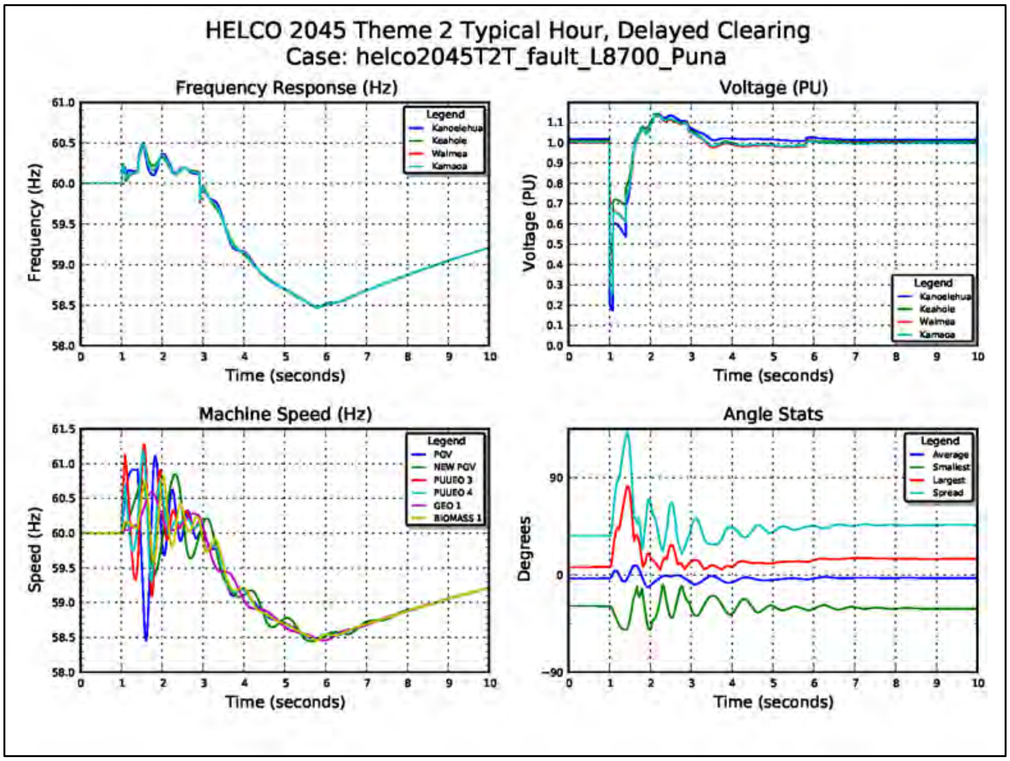


Figure O-130. System Performance to Delayed Clearing Fault

Figure O-130 shows four plots that illustrate system performance for a delayed clearing fault on the L8700 Puna circuit for a typical hour. System voltage exceeds 1.1 PU, tripping all 70 MW of DG-PV on over voltage. Simulations were performed to determine the frequency response capacities required to bring the system into compliance with TPL-001.

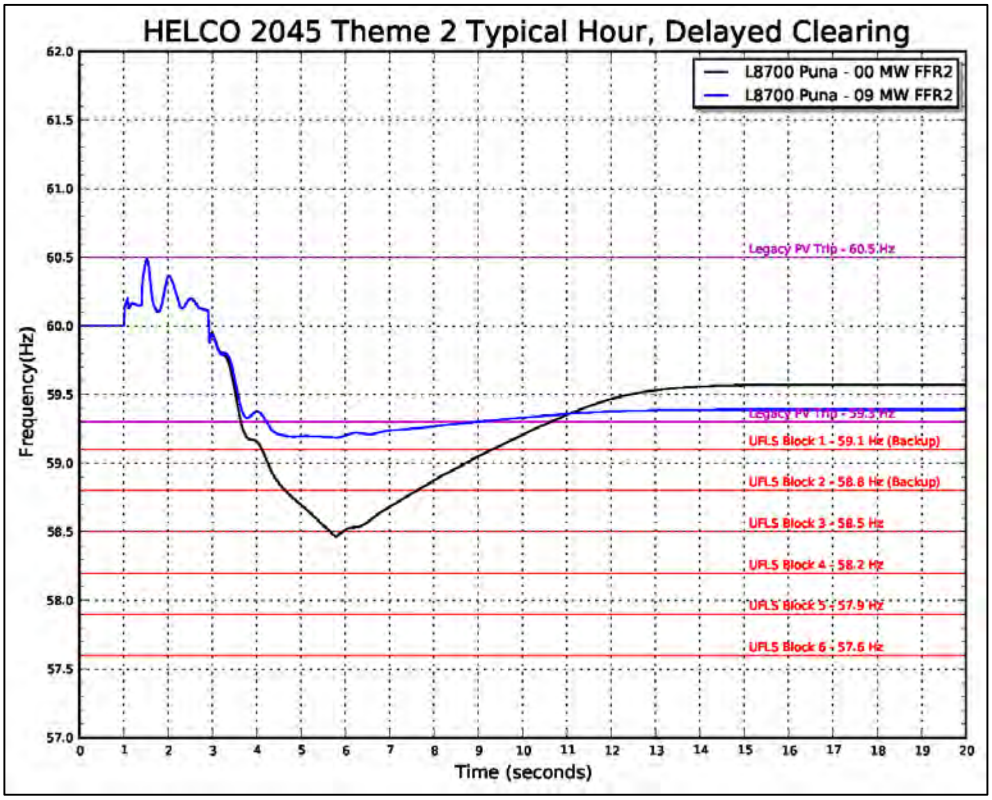


Figure O-131. Frequency Response Profile for FFR2 Typical Hour

Figure O-131 shows the frequency response profile for the FFR2 analysis. The first system peak is caused by the fault. Approximately 70 MW of DG-PV will disconnect on over voltage. System frequency begins to decay and triggers UFLS Blocks 1&2 on df/dt (24.8 MW), causing a momentary stabilization of system frequency (black plot). Frequency continues to decay until the nadir hits 58.5 Hz, requiring 3 blocks of UFLS to stabilize system frequency. The capacity of FFR2 required to bring the system into compliance with TPL-001 is 9 MW. This is in addition to the 24.8 MW of df/dt UFLS from Blocks 1 and 2.

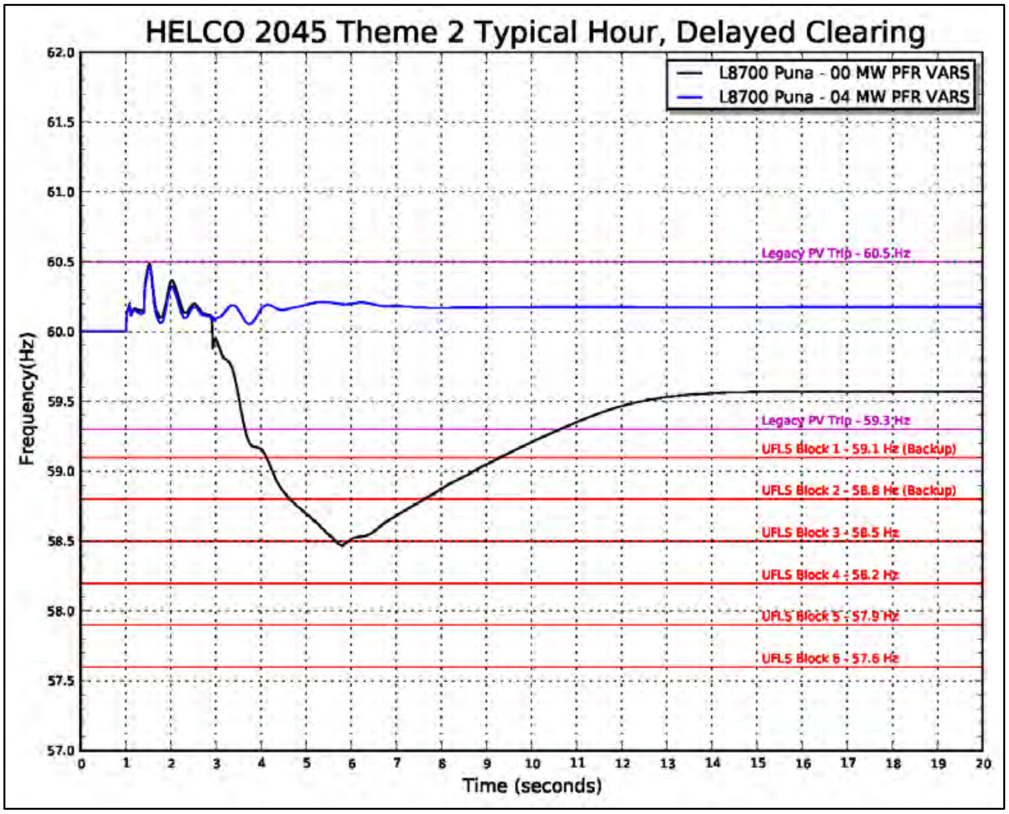


Figure O-132. Frequency Response Profile for PFR Typical Hour

Figure O-132 shows the frequency response profile for the PFR analysis provided by a BESS. The capacity of PFR at 3% droop response required to bring the system into compliance with TPL-001 is 4 MW. This is in addition to the 24.8 MW of df/dt UFLS from Blocks 1 and 2.

Theme 3 – No LNG Plan

2023

System security analysis was performed on three hours that were selected from the Theme 3 production cost simulations that represents a typical hour and a boundary condition. The boundary hour has 82 MW of DG-PV so selection of an alternate hour was not required.

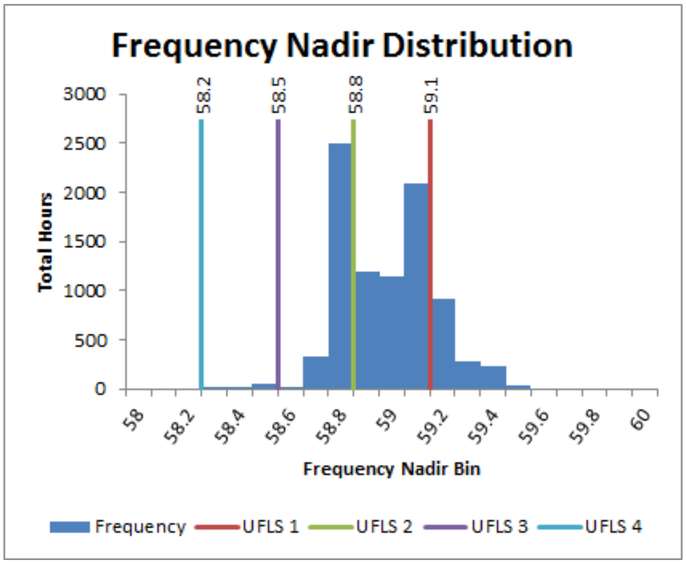


Figure O-133. Frequency Nadir Histogram 2023

Figure O-133 is a histogram of the expected frequency nadirs for N-1 generator contingency events for the entire year. The typical hour selected from the maximum distribution of 2493 hours was 9:00 AM on Thursday, October 26. The frequency nadir range for the typical hour is 58.7 - 58.8 Hz that requires 2 blocks of UFLS to stabilize system frequency.

The boundary hour selected from a minimum distribution of 1 hour was 10:00 AM on Monday, December 11. The frequency nadir range for the boundary hour is 58.2 – 58.3 Hz that requires five blocks of UFLS to stabilize system frequency.

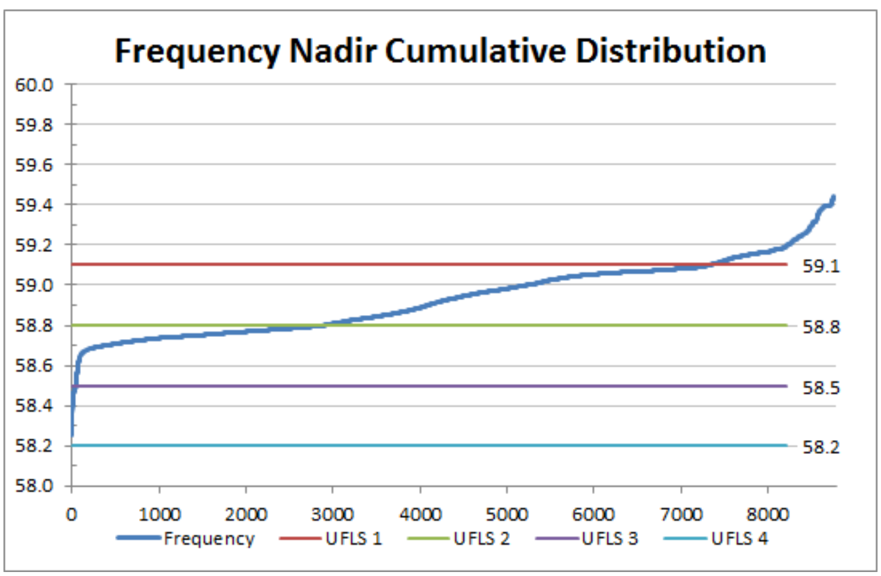


Figure O-134. Frequency Nadir Cumulative Distribution

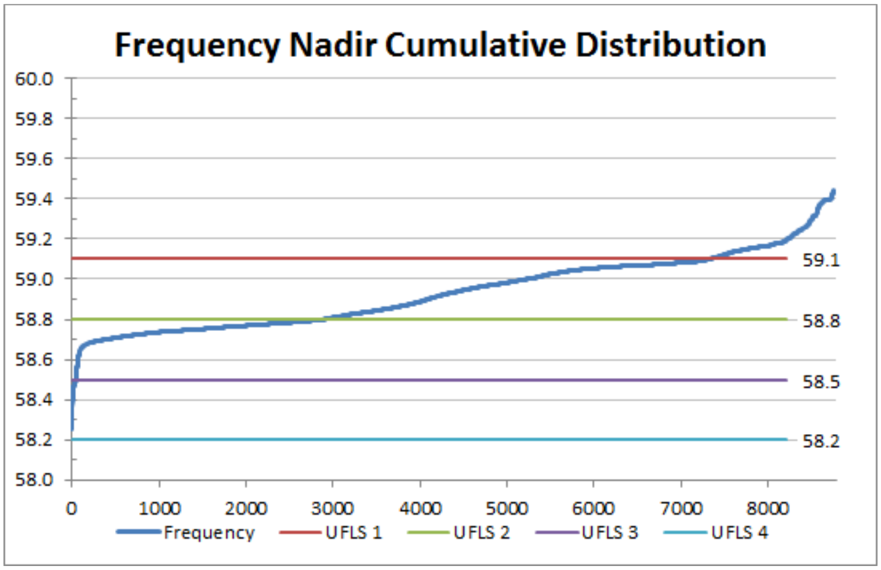


Figure O-135. Frequency Nadir Duration Curve 2023

Figure O-135 shows the frequency nadir duration curve for the entire year.

Unit Commitment Order	Unit Ratings							HELCO 2023 (Typical) Thu 10/26/23 Hour 9			HELCO 2023 (Boundary) Mon 12/11/23 Hour 10		
	Pmax	Pmin			Inertia H	Unit MVA	Unit K.E.	Pgen	up reg (spin)	down reg	Pgen	up reg (spin)	down reg
PGV	38.0	22.0			2.94	59.4	174	36.4	1.6	14.4	36.4	1.6	14.4
Keahole STCC	25.0	7.0			3.13	46.5	146				21.9	3.1	14.9
Keahole DTCC	54.0	7.0			2.77	71.8	199	25.3	28.7	18.3			
Keahole CT4	20.0	7.0			2.10	25.2	53						
Keahole CT5	20.0	7.0			2.10	25.2	53						
HEP STCC	28.5	9.0			1.96	58.9	116						
HEP DTCC	60.0	18.5			1.78	94.4	168						
Hill 5	13.5	5.0			2.20	15.6	34						
Hill 6	20.5	8.0			2.53	27.5	70	11.0	9.5	3.0			
Keah CT2	13.8	5.0			4.44	22.2	99						
Puna CT3	20.0	7.0			4.96	29.6	147						
Geo1	20.0				5.00	40.0	200	20.0	0.0	20.0	20.0	0.0	20.0
Geo2	20.0				5.00	40.0	200						
Biomass1	20.0				3.16	28.0	88						
HELCO Hydro	4.7	0.0			1.07	5.6	6	2.1			3.0		
Wailuku Hydro	12.1	0.0			2.42	12.2	30	0.0			0.0		
Apollo	20.5	0.0						15.6			7.1		
HRD	10.5	0.0						4.5			0.0		
Hydro	16.8	0						13%	2		18%	3	
Wind	31.0	0						65%	20		23%	7	
DG-PV	150.4	0						31%	47		55%	82	
Total Kinetic Energy									679			556	
Total Load									162			171	
Total Thermal Generation									93			78	
Total Renewable Generation									70			92	
Total Generation									162			171	
Excess Generation									0			0	
Total Up Regulation									40			5	
Total Down Regulation									56			49	
Legacy DG-PV		59.3Hz Capacity		7.4				59.3Hz Output		2.3	59.3Hz Output		4.0
		60.5Hz Capacity		26.4				60.5Hz Output		8.3	60.5Hz Output		14.4

Table O-45. Unit Commitment and Dispatch Schedule 2023

Table O-45 shows the unit commitment and dispatch for the typical hour (10/26/2023, 9:00 AM), boundary hour (12/11/2023, 10:00 AM).

Loss of Generation

Simulations were performed for the largest loss of generation contingency event to determine the frequency response reserves requirements to bring the system into compliance with TPL-001.

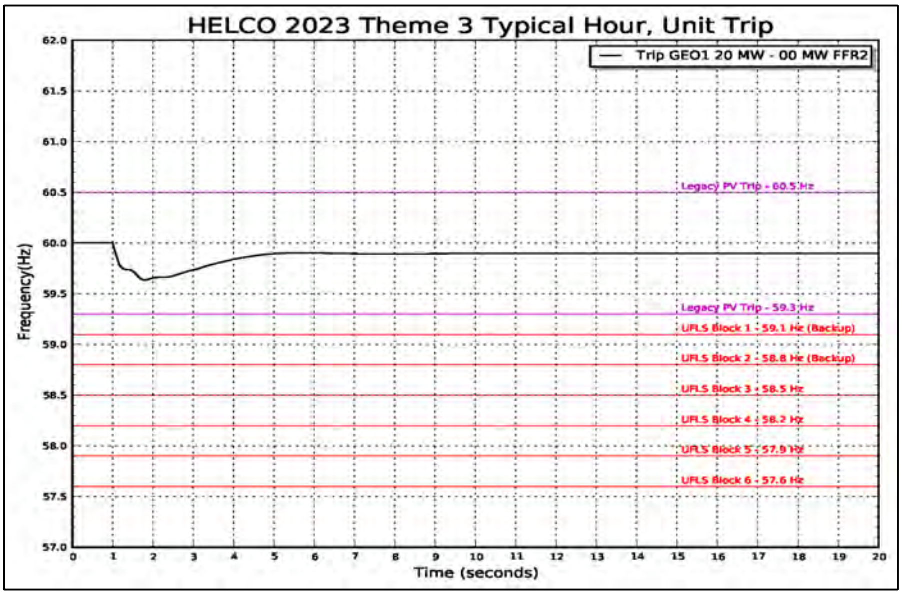


Figure O-136. Frequency Response Profile for FFR2 Typical Hour

Figure O-136 shows the frequency response profile for a geothermal unit trip at 20 MW for a typical hour. System kinetic energy is 679 MW-sec and the capacity of legacy PV that will disconnect from the system is 2.3 MW. No FFR2 is required because Hawai'i Electric Light 's UFLS scheme uses df/dt relays for Blocks 1 and 2. The df/dt UFLS capacity that was shed was 24.3 MW that is basically FFR at the distribution circuit level as opposed to behind the meter.

The effectiveness of df/dt is evident in the frequency response profile. The initial RoCoF is immediately reduced when UFLS Blocks 1 and 2 are shed. This avoids tripping legacy PV.

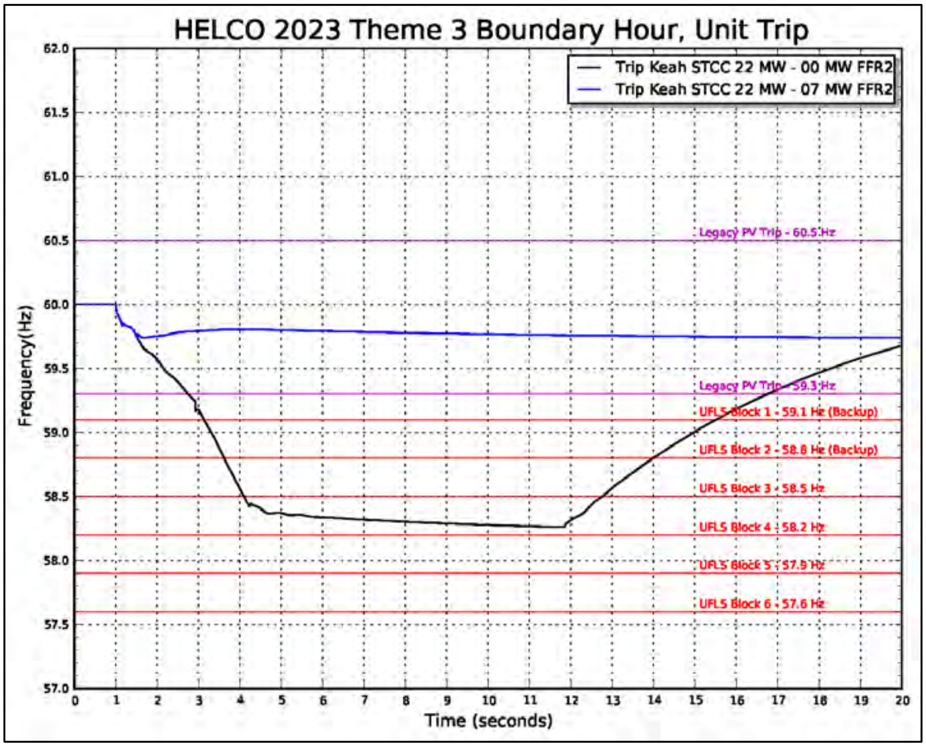


Figure O-137. Frequency Response Profile for FFR2 Boundary Hour

Figure O-137 shows the frequency response profile for a Keahole STCC trip at 22 MW for a boundary hour. System kinetic energy is 556 MW-sec and the capacity of legacy PV that will disconnect from the system is 4 MW. The capacity of FFR2 required to bring the system into compliance with TPL-001 is 7 MW. This is in addition to the 25.7 MW of df/dt UFLS from Blocks 1 and 2.

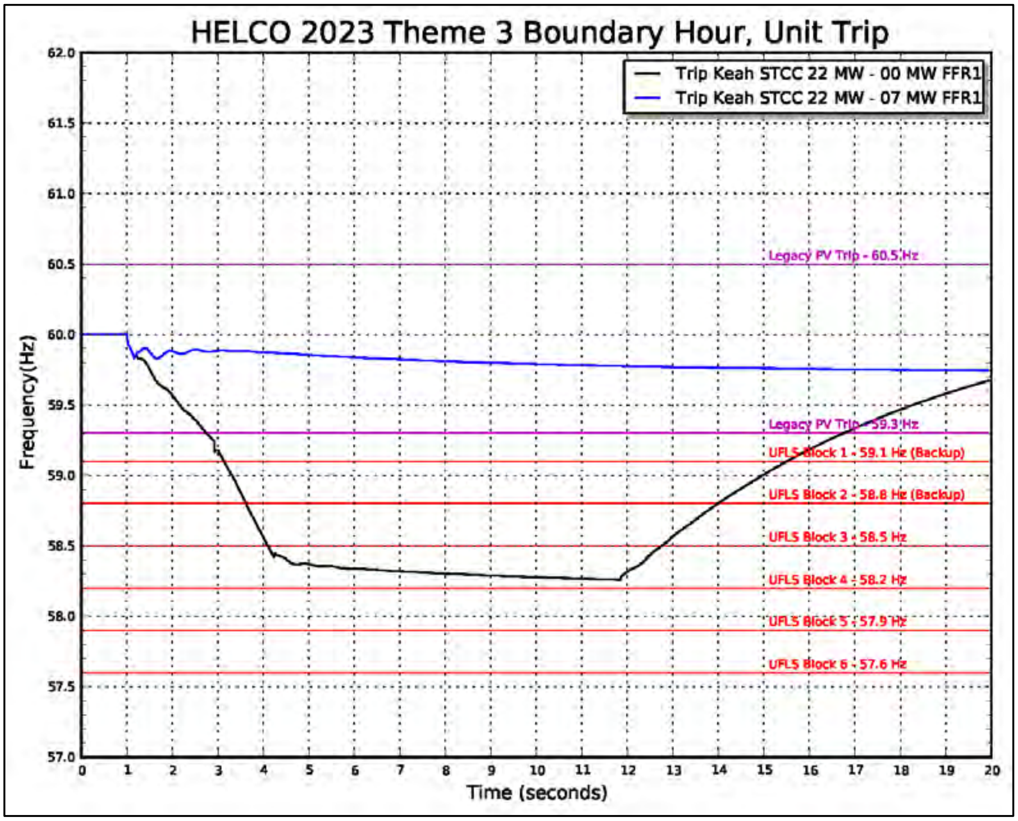


Figure O-138. Frequency Response Profile for FFR1 Boundary Hour

Figure O-138 shows the frequency response profile for the FFR1 analysis for the boundary hour. The capacity of FFR1 required to bring the system into compliance with TPL-001 is 7 MW. This is in addition to the 25.7 MW of df/dt UFLS from Blocks 1 and 2.

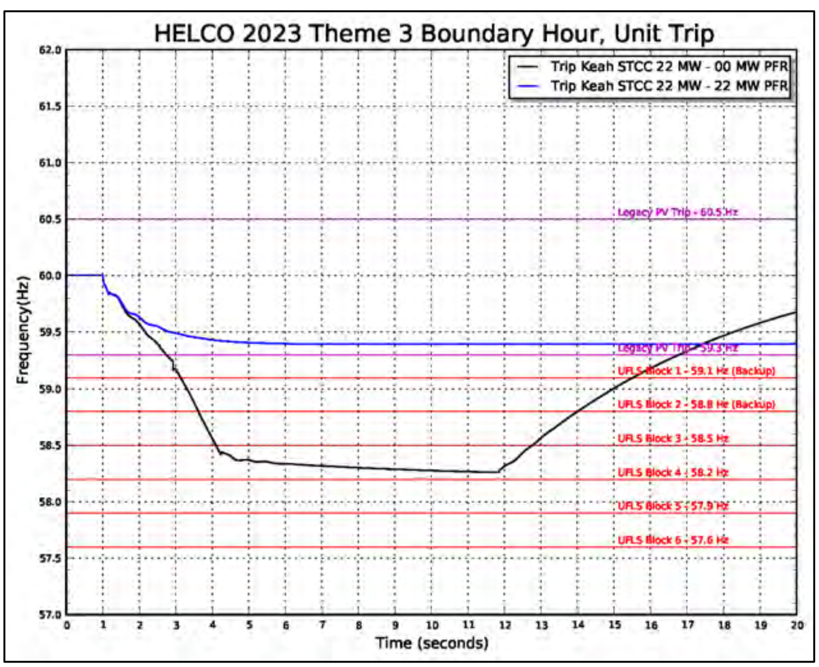


Figure O-139. Frequency Response Profile for PFR Boundary Hour

Figure O-139. shows the frequency response profile for the PFR analysis for the boundary hour. The capacity of PFR required to bring the system into compliance with TPL-001 is 22 MW. This is in addition to the 25.7 MW of df/dt UFLS from Blocks 1 and 2.

69 kV Fault Analysis

Simulations were performed for electrical faults on the 69 kV transmission lines for the typical and boundary hours. Simulations for normally cleared faults did not produce and system stability issues.

2023 69kV Fault Delayed Clearing Analysis			
Line No Outage	3-phase Fault Near	Typical Hour Condition	Boundary Hour Condition
L6100	Kanoelehua	Stable	Unstable
	Kaumana	Stable	Unstable
L6200	Kaumana	Stable	Stable
	Keamuku	Stable	Stable
L6300	Kilauea	Stable	Stable
	Puna	Stable	Stable
L6400	Kanoelehua	Stable	Stable
	Puna	Stable	Unstable
L6500	Kaumana	Stable	Stable
	Pohoiki	Stable	Stable
L6600	Kamaoa	Stable	Stable
	Kilauea	Stable	Stable
L6700	Kahaluu	Stable	Stable
	Keahole	Stable	Stable
L6800	Keahole	Stable	Stable
	Keamuku	Stable	Stable
L7100	Anaehoomalu	Stable	Stable
	Poopoomino	Stable	Stable
L7200	Keamuku	Stable	Stable
	Waimea	Stable	Stable
L7300	Ouli	Stable	Stable
	Waimea	Stable	Stable
L7400	Pepeekeo	Stable	Stable
	Wailuku	Stable	Stable
L7500	Kailua	Stable	Stable
	Keahole	Stable	Stable
L7600	Honokaa	Stable	Stable
	Pepeekeo	Stable	Stable
L7700	Haina	Stable	Stable
	Waimea	Stable	Stable
L7800	Kanoelehua	Unstable	Unstable
	Puueo	Unstable	Unstable
L8100	Anaehoomalu	Stable	Stable
	Keamuku	Stable	Stable
L8200	Anaehoomalu	Stable	Stable
	Mauna Lani	Stable	Stable
L8300	Mauna Lani	Stable	Stable
	Ouli	Stable	Stable
L8400	Pepeekeo	Stable	Unstable
	Puueo	Stable	Stable
L8500	Kaumana	Stable	Stable
	Keamuku	Stable	Stable
L8600	Kahaluu	Stable	Stable
	Kealia	Stable	Stable
L8700	Pohoiki	Stable	Stable
	Puna	Stable	Unstable
L8800	Haina	Stable	Stable
	Honokaa	Stable	Stable
L9100	Keahole	Stable	Stable
	Poopoomino	Stable	Stable
L9200	Kaumana	Stable	Stable
	Wailuku	Unstable	Unstable
L9300	Kailua	Stable	Stable
	Keahole	Stable	Stable
L9500	Kahaluu	Stable	Stable
	Kailua	Stable	Stable
L9600	Kamaoa	Stable	Stable
	Kealia	Stable	Stable

Table O-46. Summary of Results Delayed Clearing Fault Analysis

Table O-46 summarizes the results of the fault analysis. For the typical hour, 3 simulations resulted in unstable operation and 8 simulations resulted in unstable operation for the boundary hour.

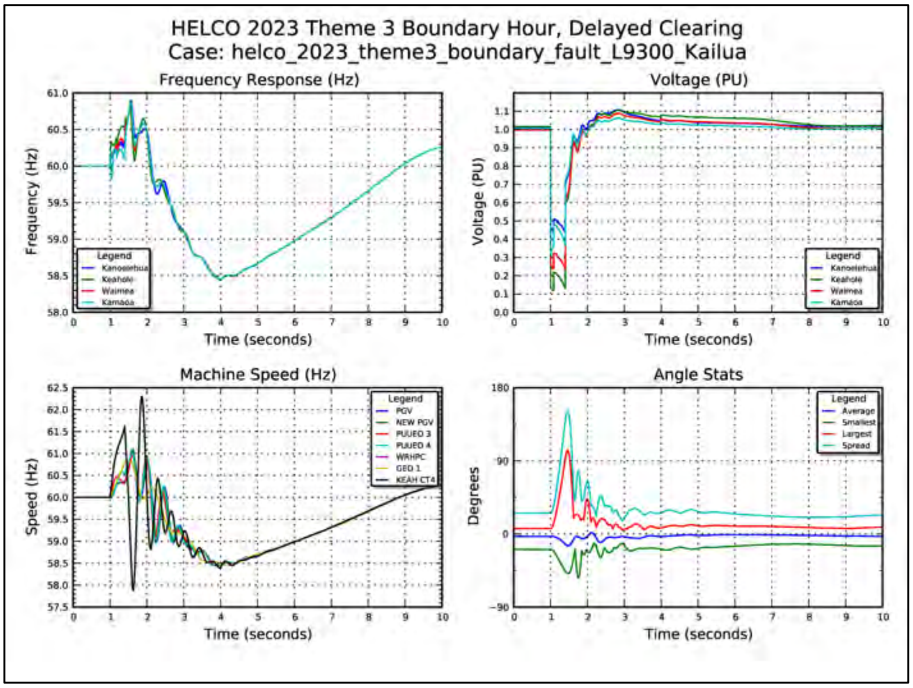


Figure O-140. System Performance to Delayed Clearing Fault

Figure O-140 shows four plots that illustrate system performance for a delayed clearing fault on the L9300 Kailua circuit for the boundary hour. System voltage exceeds 1.1 PU, tripping all 82 MW of DG-PV on over voltage. Simulations were performed to determine the frequency response capacities required to bring the system into compliance with TPL-001.

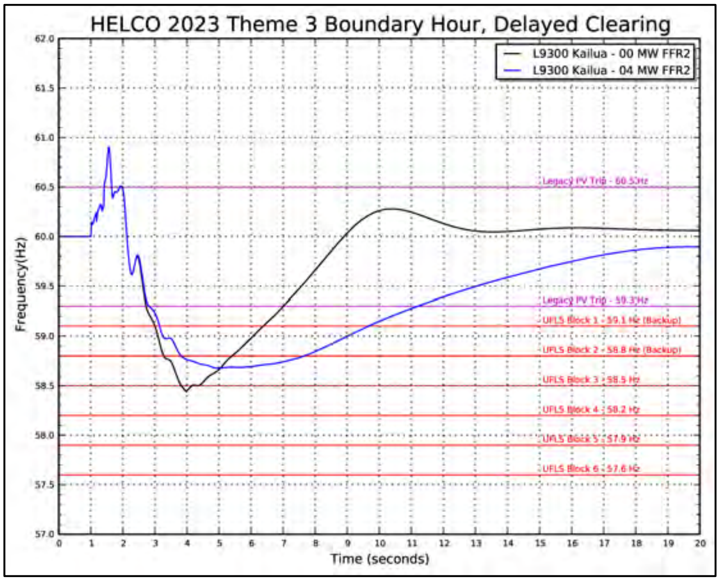


Figure O-141. Frequency Response Profile FFR2 Boundary Hour

Figure O-141 shows the frequency response profile for the FFR2 analysis. The first system peak is caused by the fault. Approximately 82 MW of DG-PV will disconnect on over voltage. System frequency begins to decay and triggers UFLS Blocks 1&2 on df/dt (25.7 MW), causing a momentary stabilization of system frequency (black plot). Frequency continues to decay until the nadir hits 58.5 Hz, requiring 3 blocks of UFLS to stabilize system frequency. The capacity of FFR2 required to bring the system into compliance with TPL-001 is 4 MW.

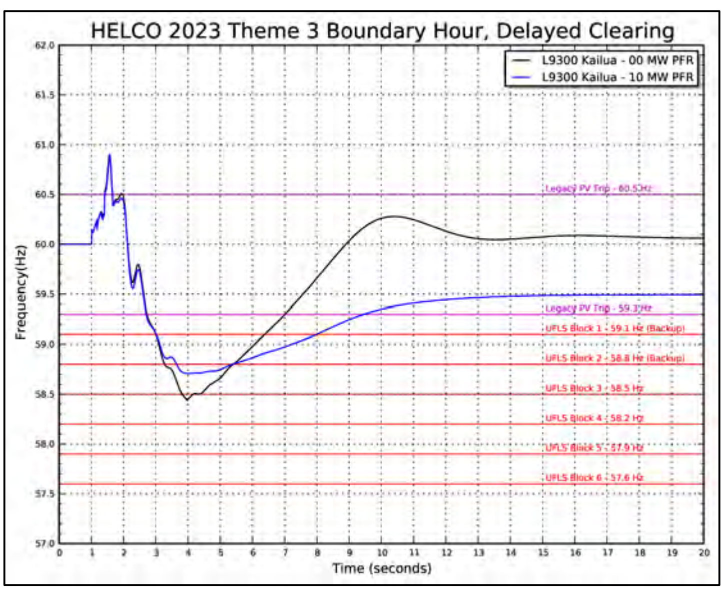


Figure O-142. Frequency Response Profile PFR Boundary Hour

Figure O-142 shows the frequency response profile for the PFR analysis provided by a BESS. The capacity of PFR at 3% droop response required to bring the system into compliance with TPL-001 is 10 MW. This is in addition to the 25.7 MW df/dt UFLS from Blocks 1 and 2.

2045

System security analysis was performed for two hours that represents a typical hour and a boundary condition.

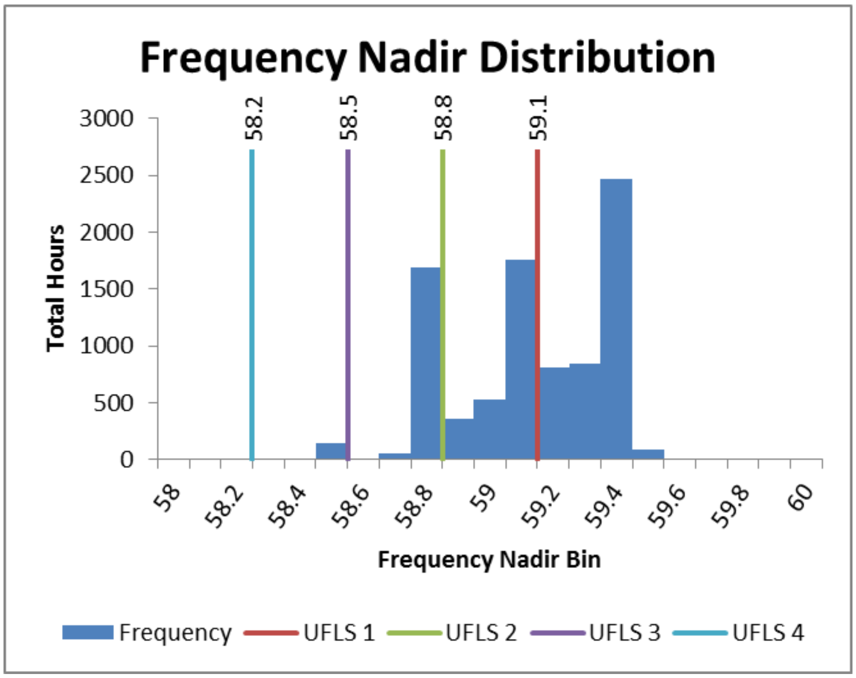


Figure O-143. Frequency Nadir Histogram 2045

Figure O-143 is a histogram of the expected frequency nadirs for N-1 generator contingency events for the entire year. The typical hour selected from the maximum distribution of 1690 hours was 9:00 AM on Wednesday, January 18. The frequency nadir range for the typical hour is 58.7 – 58.8 Hz that requires two blocks of UFLS to stabilize system frequency.

The boundary hour selected from a minimum distribution of 148 hours was 5:00 PM on Sunday, December 24. The frequency nadir range for the boundary hour is 58.4 – 58.5 Hz that requires three blocks of UFLS to stabilize system frequency.

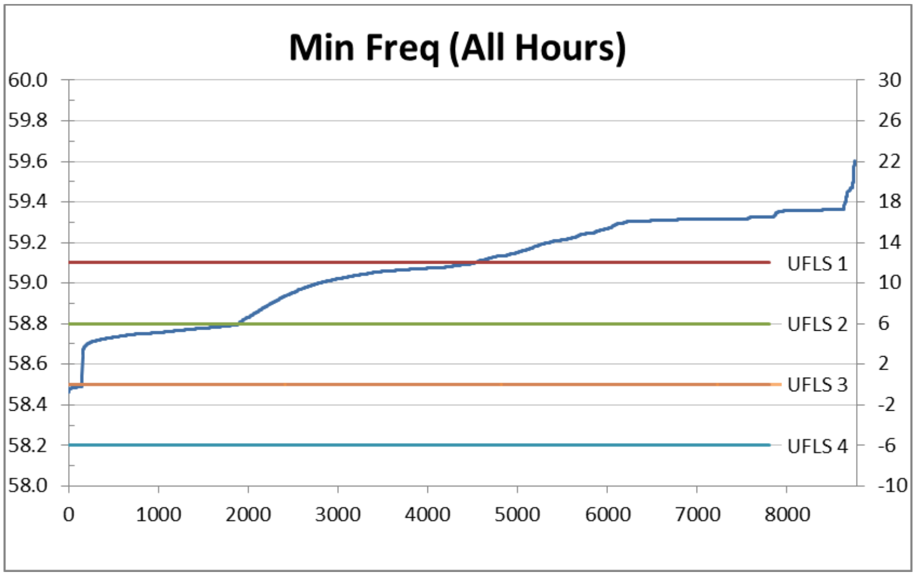


Figure O-144. Frequency Nadir Duration Curve 2045

Figure O-144 shows the frequency nadir duration curve for the entire year.

Unit Commitment Order	Unit Ratings							HELCO 2045 (Typical) Wed 1/18/45 Hour 9			HELCO 2045 (Boundary) Sun 12/24/45 Hour 17		
	Pmax	Pmin			Inertia H	Unit MVA	Unit K.E.	Pgen	up reg (spin)	down reg	Pgen	up reg (spin)	down reg
PGV	38.0	22.0			2.94	59.4	174	30.7	7.3	8.7	36.9	1.1	14.9
Keahole STCC	25.0	7.0			3.13	46.5	146						
Keahole DTCC	54.0	7.0			2.77	71.8	199						
Keahole CT4	20.0	7.0			2.10	25.2	53						
Keahole CT5	20.0	7.0			2.10	25.2	53						
HEP STCC	28.5	9.0			1.96	58.9	116						
HEP DTCC	60.0	18.5			1.78	94.4	168						
Hill 5	13.5	5.0			2.20	15.6	34						
Hill 6	20.5	8.0			2.53	27.5	70						
Keah CT2	13.8	5.0			4.44	22.2	99						
Puna CT3	20.0	7.0			4.96	29.6	147						
Geo1	20.0				5.00	40.0	200	20.0	0.0	20.0	19.8	0.2	19.8
Geo2	20.0				5.00	40.0	200	20.0	0.0	20.0	19.3	0.7	19.3
Biomass1	20.0				3.16	28.0	88	12.1	7.9	12.1			
HELCO Hydro	4.7	0.0			1.07	5.6	6	2.5			3.0		
Wailuku Hydro	12.1	0.0			2.42	12.2	30	4.0			0.8		
Apollo	20.5	0.0						0.0			12.7		
HRD	10.5	0.0						0.0			0.7		
Hydro	16.8	0						6			4		
Wind	31.0	0						0			13		
DG-PV	435	0						109			87		
Total Kinetic Energy									699			610	
Total Load									198			181	
Total Thermal Generation									83			76	
Total Renewable Generation									116			105	
Total Generation									198			181	
Excess Generation									0			0	
Total Up Regulation									15			2	
Total Down Regulation									61			54	
Legacy DG-PV	59.3Hz Capacity			0.0				59.3Hz Output		0.0	59.3Hz Output		0.0
	60.5Hz Capacity			0.0				60.5Hz Output		0.0	60.5Hz Output		0.0

Table O-47. Unit Commitment and Dispatch Schedule 2045

Table O-47 shows the unit commitment and dispatch schedules for the typical hour (1/18/45 at 9:00 AM) and boundary hour (12/24/45 at 5:00 PM).

Loss of Generation

Simulations were performed for the largest loss of generation contingency event to determine the frequency response reserves requirements to bring the system into compliance with TPL-001.

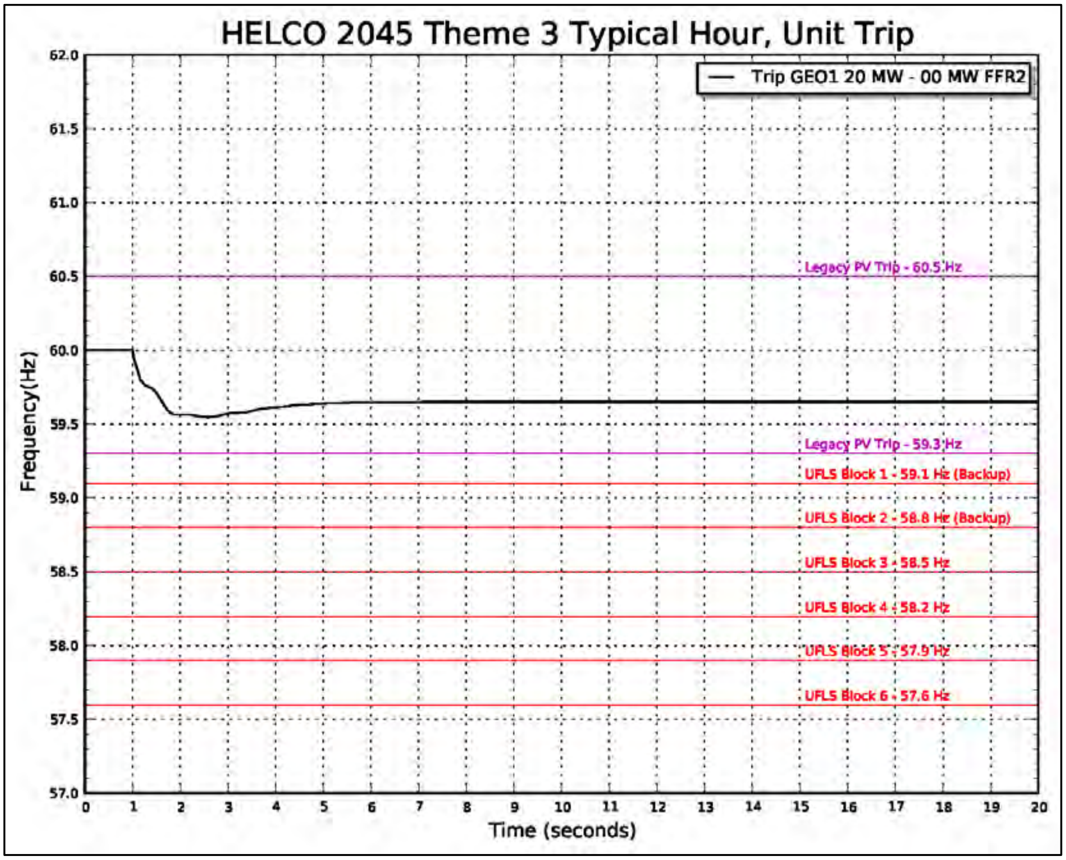


Figure O-145. Frequency Response Profile for FFR2 Typical Hour

Figure O-145shows the frequency response profile for Geothermal 1 at 20 MW for a typical hour. System kinetic energy is 699 MW-sec. No FFR2 is required because Hawaiʻi Electric Light 's UFLS scheme uses df/dt relays for Blocks 1 and 2. No FFR2 is required because Hawaiʻi Electric Light 's UFLS scheme uses df/dt relays for Blocks 1 and 2. The df/dt UFLS capacity that was 29.7 MW. The performance of the df/dt UFLS is basically FFR at the distribution circuit level as opposed to behind the meter.

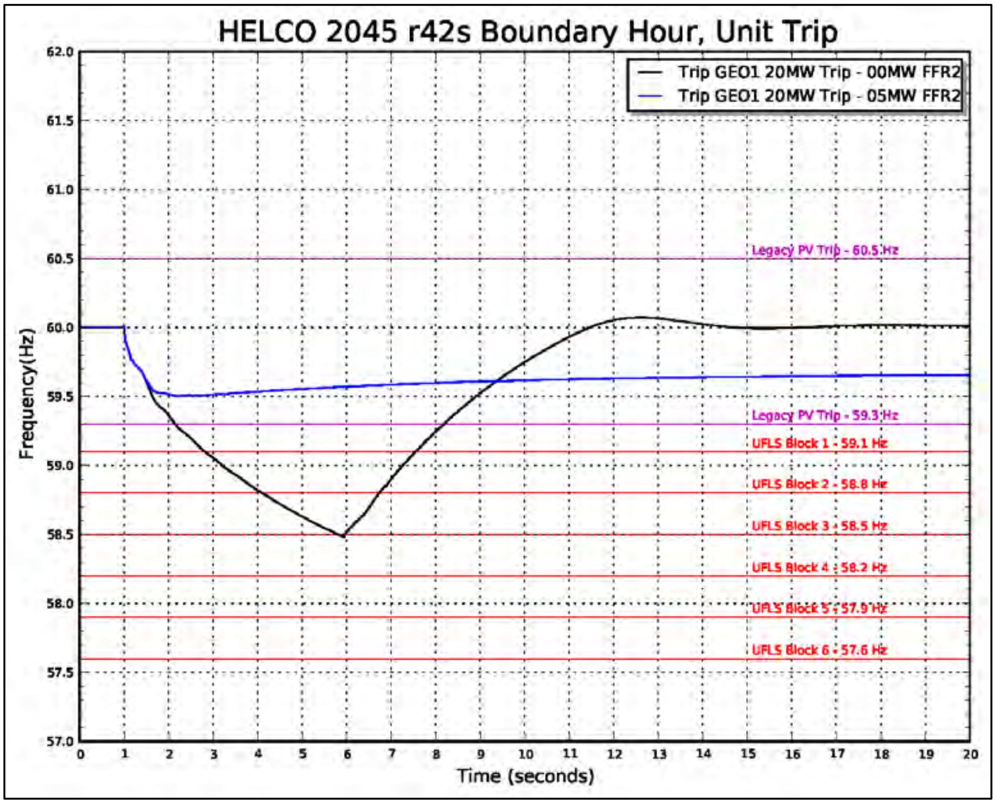


Figure O-146. Frequency Response Profile FFR2 Boundary Hour

Figure O-146 shows the frequency response profile for Geothermal 1 at 19.8 MW for a boundary hour. System kinetic energy is 610 MW-sec. Without FFR2, the frequency nadir reaches 58.5 Hz requiring 3 blocks of UFLS to stabilize system frequency. The capacity of FFR2 required to bring the system into compliance with TPL-001 is 5 MW. This is in addition to the 27.2 MW of df/dt UFLS from Blocks 1 and 2.

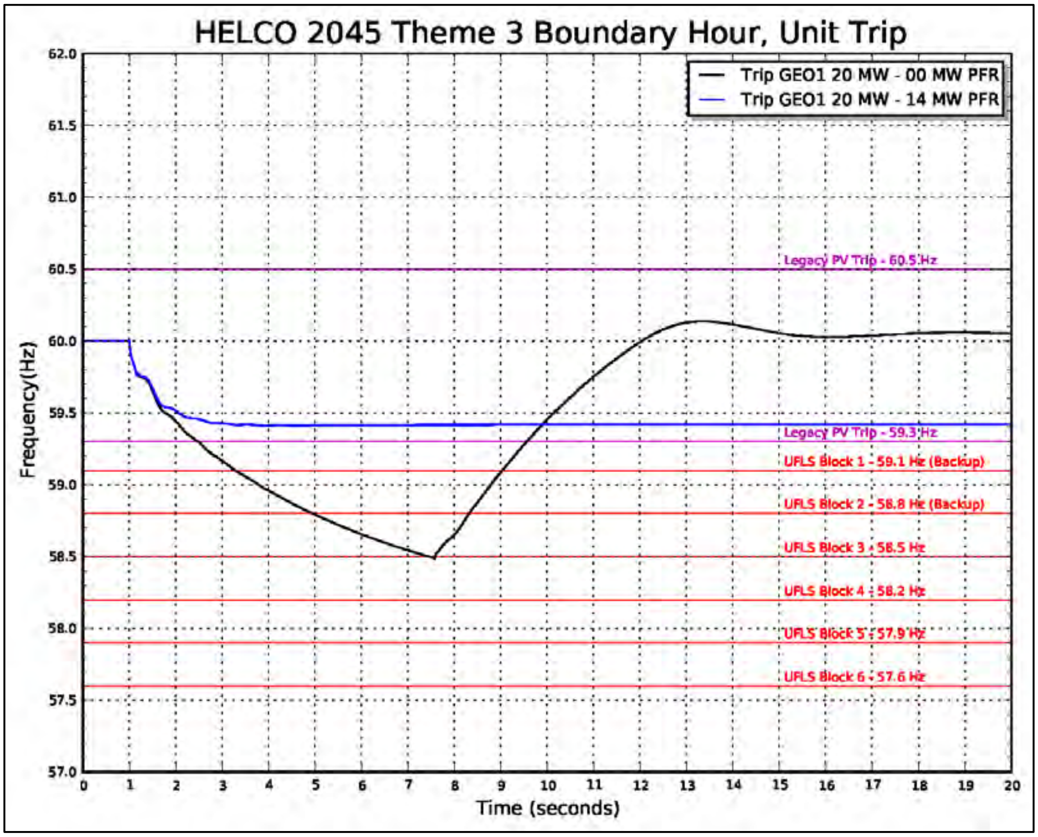


Figure O-147. Frequency Response Profile PFR Boundary Hour

Figure O-147 shows the frequency response profile for the PFR analysis. The capacity of PFR required to bring the system into compliance with TPL-001 is 14 MW. This is in addition to the 27.2 MW of df/dt UFLS from Blocks 1 and 2.

69 kV Fault Analysis

Simulations were performed for electrical faults on the 69 kV transmission lines for the typical and boundary hours. Simulations for normally cleared faults did not produce and system stability issues.

2045 69kV Fault Delayed Clearing Analysis			
Line No Outage	3-phase Fault Near	Typical Hour Condition	Boundary Hour Condition
L6100	Kanoelehua	Stable	Stable
	Kaumana	Stable	Unstable
L6200	Kaumana	Stable	Stable
	Keamuku	Stable	Stable
L6300	Kilauea	Stable	Stable
	Puna	Stable	Stable
L6400	Kanoelehua	Stable	Stable
	Puna	Stable	Unstable
L6500	Kaumana	Stable	Stable
	Pohoiki	Stable	Stable
L6600	Kamaoa	Stable	Stable
	Kilauea	Stable	Stable
L6700	Kahaluu	Stable	Stable
	Keahole	Stable	Stable
L6800	Keahole	Stable	Stable
	Keamuku	Stable	Stable
L7100	Anaehoomalu	Stable	Stable
	Poopoomino	Stable	Stable
L7200	Keamuku	Stable	Stable
	Waimea	Stable	Stable
L7300	Ouli	Stable	Stable
	Waimea	Stable	Stable
L7400	Pepeekeo	Stable	Stable
	Wailuku	Stable	Stable
L7500	Kailua	Stable	Stable
	Keahole	Stable	Stable
L7600	Honokaa	Stable	Stable
	Pepeekeo	Stable	Stable
L7700	Haina	Stable	Stable
	Waimea	Stable	Stable
L7800	Kanoelehua	Unstable	Unstable
	Puueo	Stable	Unstable
L8100	Anaehoomalu	Stable	Stable
	Keamuku	Stable	Stable
L8200	Anaehoomalu	Stable	Stable
	Mauna Lani	Stable	Stable
L8300	Mauna Lani	Stable	Stable
	Ouli	Stable	Stable
L8400	Pepeekeo	Stable	Unstable
	Puueo	Stable	Stable
L8500	Kaumana	Stable	Stable
	Keamuku	Stable	Stable
L8600	Kahaluu	Stable	Stable
	Kealia	Stable	Stable
L8700	Pohoiki	Stable	Stable
	Puna	Stable	Stable
L8800	Haina	Stable	Stable
	Honokaa	Stable	Stable
L9100	Keahole	Stable	Stable
	Poopoomino	Stable	Stable
L9200	Kaumana	Stable	Stable
	Wailuku	Stable	Unstable
L9300	Kailua	Stable	Stable
	Keahole	Stable	Stable
L9500	Kahaluu	Stable	Stable
	Kailua	Stable	Stable
L9600	Kamaoa	Stable	Stable
	Kealia	Stable	Stable

Table O-48. Summary of Results for Delayed Clearing Fault Analysis 2045

Table O-48 summarizes the results of the fault analysis. For the typical hour, 1 simulation resulted in unstable operation and 6 simulations resulted in unstable operation for the boundary hour.

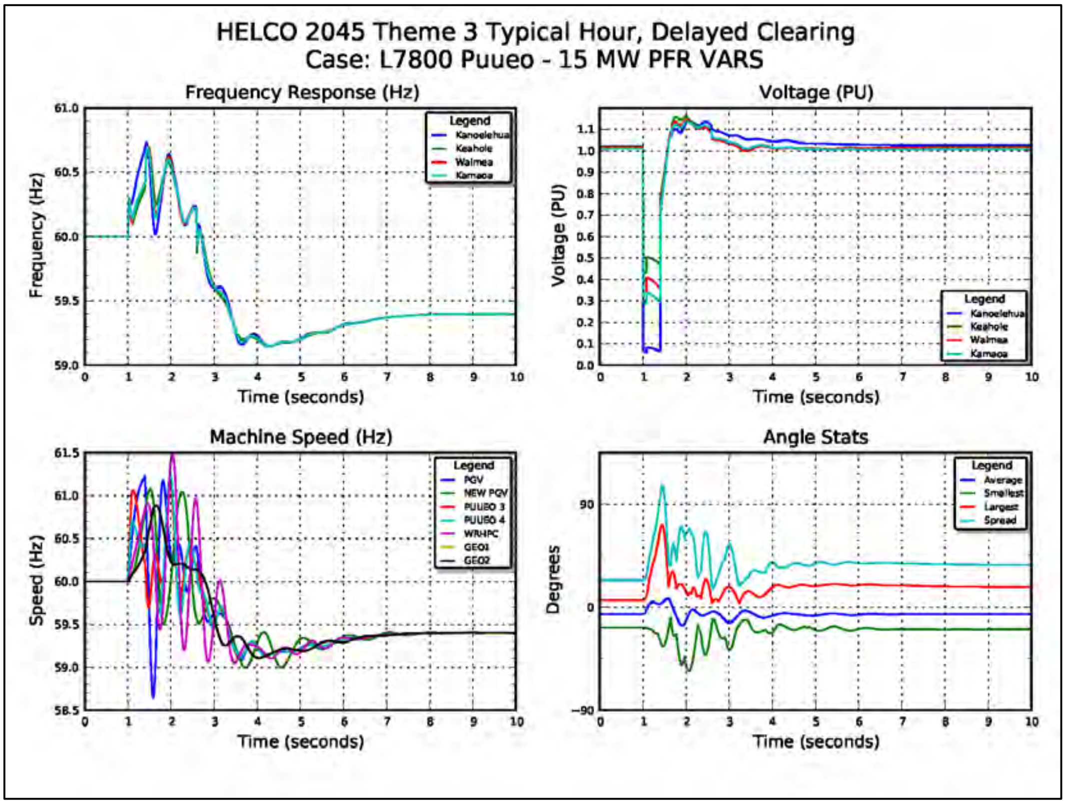


Figure O-148. System Performance to Delayed Clearing Fault

Figure O-148 shows four plots that illustrate system performance for a delayed clearing fault on the L7800 Puueo circuit for the typical hour. System voltage exceeds 1.1 PU, tripping all 109 MW of DG-PV on over voltage. Simulations were performed to determine the frequency response capacities required to bring the system into compliance with TPL-001.

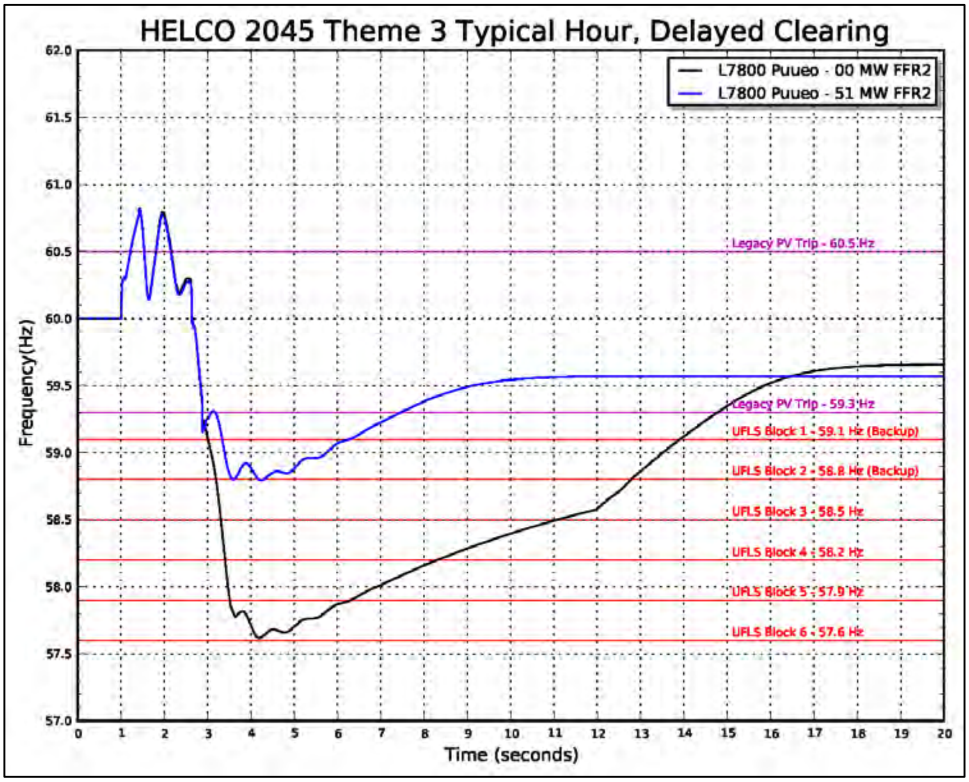


Figure O-149. Frequency Response Profile for FFR2 Typical Hour

Figure O-149 shows the frequency response profile for the FFR2 analysis. The first system peak is caused by the fault. Approximately 87 MW of DG-PV will disconnect on over voltage. System frequency begins to decay and triggers UFLS Blocks 1&2 on df/dt (29.7 MW) that momentarily stabilizes system frequency but continues to decay until the nadir hits 57.7 Hz, requiring 4 blocks of UFLS to stabilize system frequency. The capacity of FFR2 required to bring the system into compliance with TPL-001 is 51 MW.

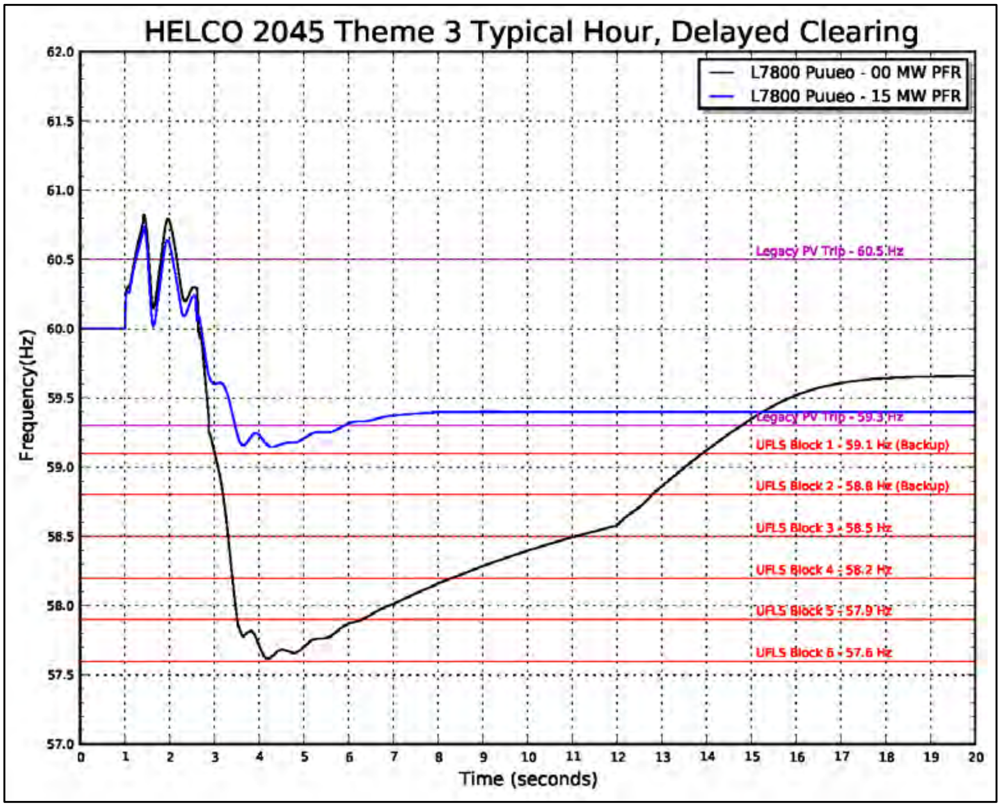


Figure O-150. Frequency Response Profile for PFR Typical Hour

Figure O-150 shows the frequency response profile for the PFR analysis. The capacity of PFR required to bring the system into compliance with TPL-001 is 15 MW. This is in addition to the 29.7 MW of df/dt UFLS from Blocks 1 and 2

Summary

The Hawai'i system has the unique transmission covers a very large territory and has approximately 640 miles of 69 kV transmission lines. This increases the exposure to electrical faults that can cause large capacities of DG-PV to disconnect from the system because system frequency and/or voltage exceed inverter ride-through settings.

Hawai'i Electric Light is implementing a dynamic UFLS scheme to meet the requirements specified in TPL-001 that allows 15% of the system load to be shed on single loss of generation contingency events. The dynamic UFLS scheme initiates 15% load shedding on df/dt relays which provides similar frequency response from FFR2 except the load shedding is at the distribution circuit.

Compliance with TPL-001

Hawai'i Electric Light relies on its dynamic UFLS scheme to meet TPL-001. As DG-PV capacities increase, df/dt UFLS capacities will reduce and other resources must be available to stabilize system frequency. The capacity of FFR1 from a BESS to meet TPL-001 for a unit trip is 5 MW. And PFR for response to delayed clearing faults range from 5 to 15 MW.

The tables below show that the FFR1 and PFR capacities will provide frequency response reserves through 2045 for Themes 2 and 3. More detailed analyses will be conducted to support the GO7 application that will be submitted to meet the service date of 2019 for the BESS.

Frequency Response Analysis TPL-001 Compliance			
Reserve	Theme 2		
	2019		
	Typical HEP STCC 28 MW	Boundary KH STCC 25 MW	Alternate L6100 Kano D/C Fault
FFR2	0	5	27
FFR1	-	5	N/A
PFR	-	18	6

Table O-49. Summary of Analysis to Meet TPL-001

Table O-49 shows the results of the FFR2, FFR1, and PFR analysis. The capacity of FFR1 required to meet TPL-001 is 5 MW for the boundary hour and the capacity of PFR to the alternate hour is 6 MW.

Hawai'i Frequency Response Analysis Results									
Reserve	Theme 2								
	2020			2023			2045		
	Typical KH STCC 22 MW	Boundary HEP STCC 27 MW	Alternate L9600 Kealia D/C Fault	Typical Kamaoa WF 20 MW	Boundary Geo 18 MW	Alternate L6400 Kano D/C Fault	Typical Geo 20 MW	Boundary HEP STCC 26 MW	Alternate L8700 Puna D/C Fault
FFR2	0	14	31	0	13	75	0	9	9
FFR1	-	14	N/A	-	9	N/A	-	9	N/A
PFR	-	50	6	-	48	20	-	30	4

Table O-50. Summary of Frequency Response Analysis Theme 2

Hawai'i Frequency Response Analysis Results						
Reserve	Theme 3					
	2023			2045		
	Typical Geo 20 MW	Boundary KH STCC 22 MW	Alternate L9300 Kailua D/C Fault	Typical Geo 20 MW	Boundary Geo 20 MW	Alternate L7800 Puueo D/C Fault
FFR2	0	7	4	0	4	51
FFR1	-	7	N/A	-	4	N/A
PFR	-	22	10	-	14	15

Table O-51. Summary of Frequency Response Analysis Theme 3

Table O-50 and Table O-51 shows the results of the FFR2, FFR1, and PFR simulations for Themes 2 and 3 respectively. The 5 MW of FFR1 from a BESS installed in 2019 will not bring the resource plans for Theme 2 into compliance with TPL-001 in 2045 without additional resources from FFR2, PFR, or more system inertia.

MOLOKA'I

State of the System

The electrical system on Moloka'i is a radial distribution system operating at a nominal 12 kV and is not under the jurisdiction of TPL-001. The guideline established for this analysis is to keep the system nadir above 56 Hz for the largest loss of generation contingency to prevent loss of DG-PV. A 2 MW contingency BESS that is owned by HNEI is scheduled for installation in 2Q2016. All analyses modeled the performance of the BESS.

2016

Production cost simulations were not performed at the time of this writing so a screening process was not performed for Molokai. Unit commitment and dispatch cases were developed based on historical data to meet the load forecast.

Unit Commitment Order	Unit Ratings							Molokai 2016 (Typical) 12/28/16 Hour 15			Molokai 2016 (Boundary) xx/xx/16 Hour xx		
	Pmax	Pmin	VPO Max	VPO Min	Inertia H	Unit MVA	Unit K.E. (Mjoules)	Pgen	up reg (spin)	down reg	Pgen	up reg (spin)	down reg
PA D7	2.2	0.3	N/A	N/A	1.1	2.8	3.0	0.5	1.5	0.2			
PA D8	2.2	0.3	N/A	N/A	1.1	2.8	3.0	0.5	1.5	0.2			
PALAAU1	1.3	0.3			0.3	1.3	0.4						
PALAAU2	1.3	0.3			0.3	1.3	0.4						
PALAAU3	1.0	0.3			0.3	1.3	0.4						
PALAAU4	1.0	0.3			0.3	1.3	0.4						
PALAAU5	1.0	0.3			0.3	1.3	0.4						
PALAAU6	1.0	0.3			0.3	1.3	0.4						
PA D9	2.2	0.3	N/A	N/A	1.1	2.8	3.0						
Wind	N/A	N/A						N/A	N/A		N/A	N/A	
DG-PV	2.6	0.0						0.7	1.8		0.0		
Station PV	N/A	N/A						N/A	N/A		N/A	N/A	
Total Kinetic Energy									6.1			0.0	
Total Load									2.9			0.0	
Total Thermal Generation									1.1			0.0	
Total Renewable Generation									1.8			0.0	
Total Generation									2.9			0.0	
Excess Generation									0.0			0.0	
Total Up Regulation									2.9			0.0	
Total Down Regulation									0.4			0.0	
Legacy DG-PV	59.3Hz Capacity			0.8				59.3Hz Output		0.6	59.3Hz Output		0.0
	60.5Hz Capacity			2.0				60.5Hz Output		1.4	60.5Hz Output		0.0

Table O-52. Unit Commitment and Dispatch 2016

Table O-52 shows the unit commitment and dispatch schedule for a typical hour.

Loss of Generation

Simulations were performed for the largest loss of generation contingency event to determine the frequency response reserves requirements to keep the system frequency nadir above 56 Hz. The Molokai system is a 12 kV radial distribution system and is not required to meet TPL-001.

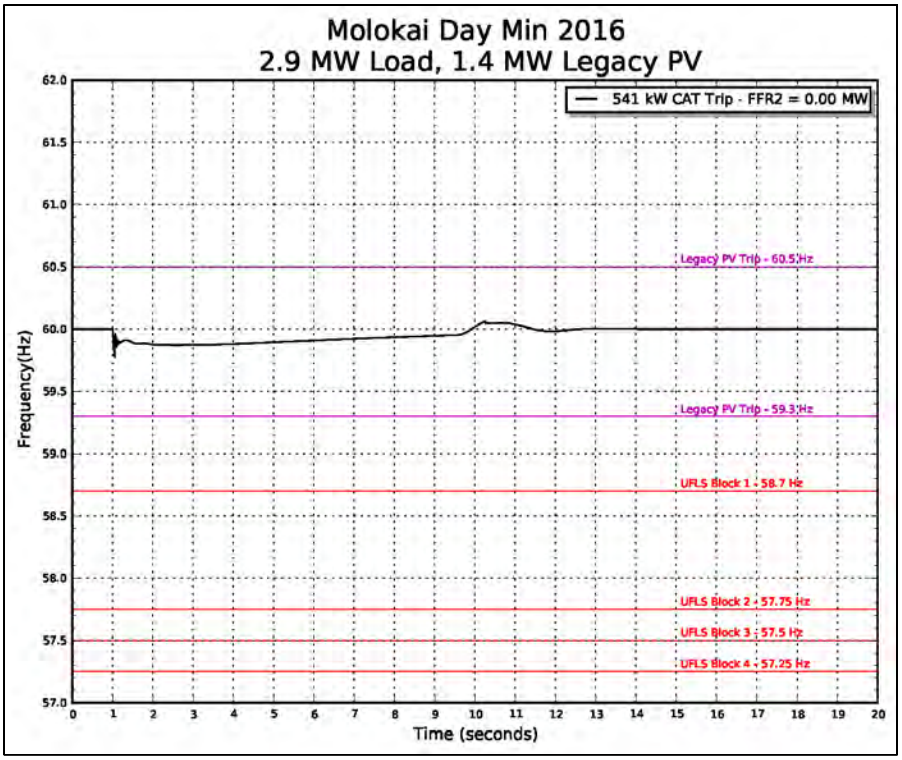


Figure O-151. Frequency Response Profile FFR2 Analysis

Figure O-151 shows the frequency response profile for a trip of Palaau Unit 7 at 500 kW. System kinetic energy is 6 MW-sec and the capacity of legacy PV that will disconnect from the system is 600 kW. Response from the 2 MW BESS limits the frequency nadir to 59.8 Hz. No FFR2 is required because the frequency nadir remains above 56 Hz.

12 kV Fault Analysis

Simulations were performed for a close-in fault (5-cycle clearing time) and a high-impedance fault (24-cycle clearing time). Simulations for these analyses did not produce any system stability issues. There are instances of distribution voltages exceeding 1.1 PU but the 2 MW BESS is able to keep system frequency above 56 Hz.

2045

Unit Commitment Order	Unit Ratings					Molokai 2045 Sat 8/12/2045 Hour 12			Molokai 2016 (Boundary) xx/xx/16 Hour xx		
	Pmax	Pmin	Inertia H	Unit MVA	Unit K.E. (Mjoules)	Pgen	up reg (spin)	down reg	Pgen	up reg (spin)	down reg
PA D7	2.2	0.6	1.100	2.75	3.025						
PA D8	2.2	0.6	1.100	2.75	3.025						
PALAAU1	1.0	0.5	0.343	1.25	0.428						
PALAAU2	1.0	0.5	0.343	1.25	0.428						
PALAAU3	1.0	0.5	0.343	1.25	0.428						
PALAAU4	1.0	0.5	0.343	1.25	0.428						
PALAAU5	1.0	0.5	0.343	1.25	0.428						
PALAAU6	1.0	0.5	0.343	1.25	0.428						
PA D9	2.2	0.6	1.100	2.75	3.025						
Sync Cond1			2.61	2.75	7.178	0.0	Sync Cond.				
Sync Cond2			2.61	2.75	7.178	0.0	Sync Cond.				
Total Wind	5					3.0					
-Wind_1	2.5	0.0				1.0					
-Wind_2	2.5	0.0				2.0					
DG-PV	4.015					0.26					
Station PV	N/A										
Total Kinetic Energy							14.355			0.000	
Total Load							3.26			0.00	
Total Thermal Generation							0.00			0	
Total Renewable Generation							3.26			0	
Total Generation							3.26			0	
Excess Generation							0.00			0	
Total Up Regulation							0.00			0	
Total Down Regulation							0.00			0	
Legacy DG-PV	59.3Hz Capacity	0				59.3Hz Output		0.000	59.3Hz Output		0.000
	60.5Hz Capacity	0				60.5Hz Output		0.000	60.5Hz Output		0.000

Table O-53. Unit Commitment and Dispatch Schedule 2045

Table O-57 shows the unit commitment and dispatch schedule for the 2045 analysis. Note that there are no synchronous units committed in Hour 12. The synchronous condensers have relatively high H-constants that provide inertia to the system as well as MVAR and system fault current.

Loss of Generation

Simulations were performed for the largest loss of generation contingency event to determine the frequency response reserves requirements to keep the system frequency nadir above 56 Hz.

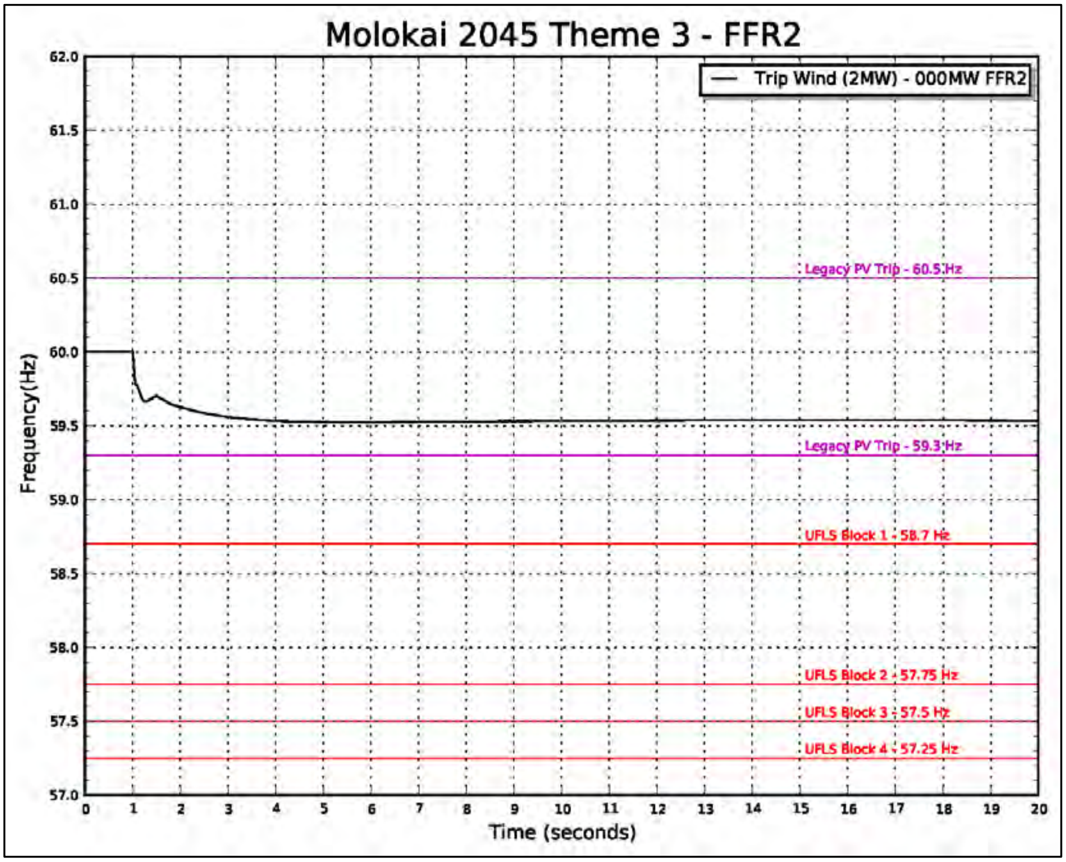


Figure O-152. Frequency Response Profile for FFR2

Figure O-152 shows the frequency response profile for the trip of a wind turbine at 2 MW output. System kinetic energy is 14.4 MW-sec due in large part to the synchronous condensers. Response from the 2 MW BESS limits the frequency nadir above 59.5 Hz so no FFR2 is required.

12 kV Fault Analysis

Simulations were performed for a close-in fault (5-cycle clearing time) and a high-impedance fault (24-cycle clearing time). Simulations for these analyses did not produce any system stability issues.

Summary

Moloka'i is a radial distribution system so the requirements of TPL-001 do not apply. The criteria established for this analysis is to keep frequency above 56 Hz so DG-PV does not trigger a cascading contingency event.

The model of the 2 MW HNEI BESS provides sufficient frequency reserves to maintain system security for loss of generation and low impedance faults for resource plans in

2045. Once the BESS is in service, the model can be tuned to simulate actual performance and system security analysis must be performed on all resource plans.

LANA'I

State of the System

The island of Lana'i has a relatively small capacity of DG-PV so system performance has not been adversely affected like the other islands. The 1 MW Lana'i Solar Farm also has a regulating BESS that helps power delivered to the system.

2016

Production cost simulations were not performed at the time of this writing so a screening process was not performed for Lanai. Unit commitment and dispatch cases were developed based on historical data to meet the load forecast.

Unit Commitment Order	Unit Ratings							Lanai 2016 (Typical) 03/16/16 Hour 12			Lanai 2016 (Boundary) xx/xx/16 Hour xx		
	Pmax	Pmin	VPO Max	VPO Min	Inertia H	Unit MVA	Unit K.E. (Mjoules)	Pgen	up reg (spin)	down reg	Pgen	up reg (spin)	down reg
L7,D-7	2.20	0.55	N/A	N/A	1.10	2.8	3.0	0.75	1.45	0.20			
L8,D-8	2.20	0.55	N/A	N/A	1.10	2.8	3.0	0.75	1.45	0.20			
LANAI1	1.00	0.50			0.34	1.3	0.4						
LANAI2	1.00	0.50			0.34	1.3	0.4						
LANAI3	1.00	0.50			0.34	1.3	0.4						
LANAI4	1.00	0.50			0.34	1.3	0.4						
LANAI5	1.00	0.50			0.34	1.3	0.4						
LANAI6	1.00	0.50			0.34	1.3	0.4						
CHP	0.83	0.00	N/A	N/A	0.34	1.3	0.4						
Wind	N/A	N/A						N/A	N/A		N/A	N/A	
DG-PV	0.66	0.00						70%	0.46		0%		
Station PV	1.00	0.00						80%	0.80		0%		
Total Kinetic Energy									6.05			0.00	
Total Load									2.76			0.00	
Total Thermal Generation									1.50			0.00	
Total Renewable Generation									1.26			0.00	
Total Generation									2.76			0.00	
Excess Generation									0.00			0.00	
Total Up Regulation									2.90			0.00	
Total Down Regulation									0.40			0.00	
Legacy DG-PV	59.3Hz Capacity			0.10				59.3Hz Output		0.07	59.3Hz Output		0.00
	60.5Hz Capacity			0.43				60.5Hz Output		0.30	60.5Hz Output		0.00

Table O-54. Unit Commitment and Dispatch 2016

Table O-54 shows the unit commitment and dispatch for 2016.

Loss of Generation

Simulations were performed for the largest loss of generation contingency event to determine the frequency response reserves requirements to keep the system frequency nadir above 56 Hz.

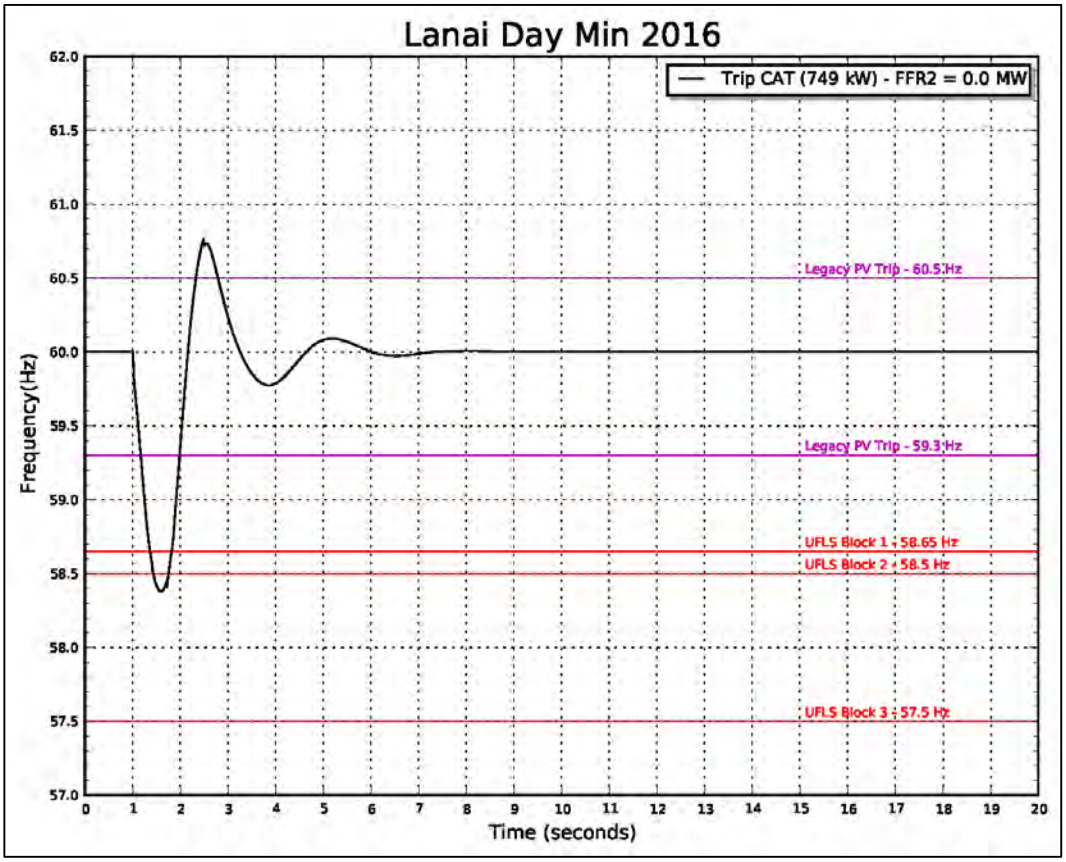


Figure O-153. Frequency Response Profile FFR2

Figure O-153 shows the frequency response profile for a trip of Miki Basin Unit 7 at 749 kW. System kinetic energy is 6 MW-sec and the capacity of legacy PV that will disconnect from the system is 70 kW. The frequency nadir remains above 56 Hz so no FFR2 is required.

12 kV Fault Analysis

Simulations were performed for a close-in fault (5-cycle clearing time) and a high-impedance fault (24-cycle clearing time).

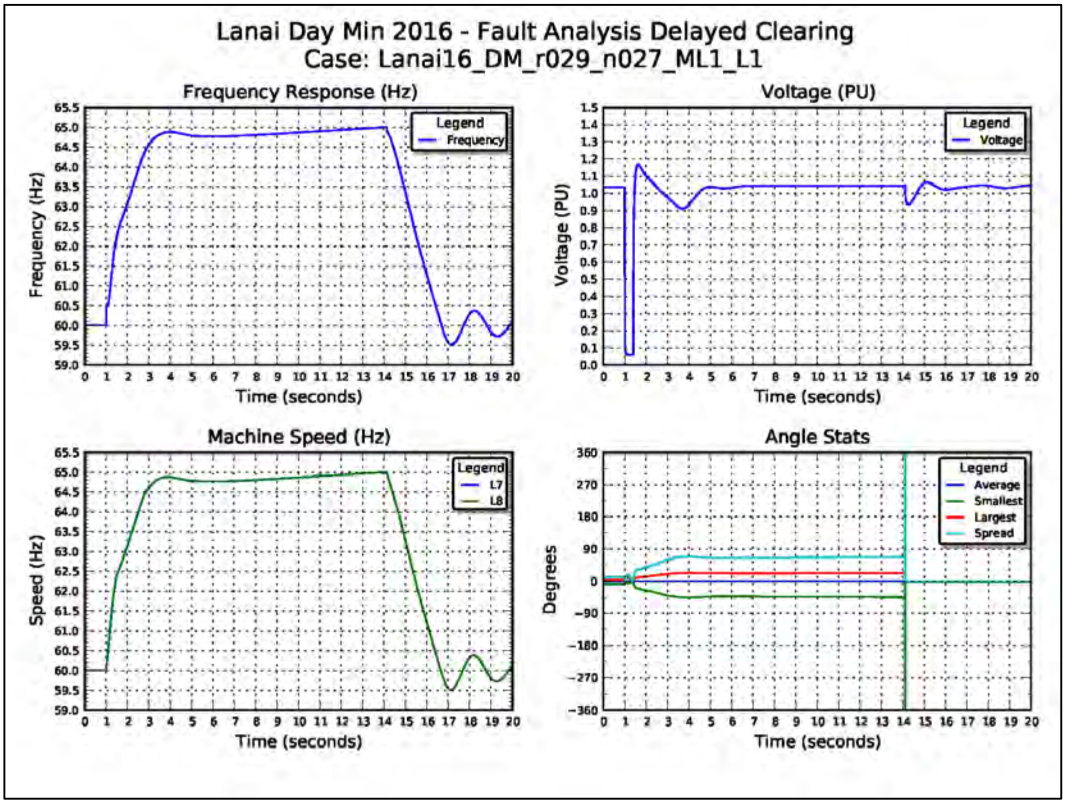


Figure O-154. System Performance to a High Impedance Fault

Figure O-154 shows four plots that illustrate system performance in response to a high impedance fault on the Miki Basin to Lanai City #1 distribution circuit. The system frequency plot shows frequency exceeds 64 Hz that will trip all DG-PV. At 65 Hz, the Lana'i Solar Farm trips so frequency is restored to 60 Hz. More in-depth analysis is required to determine mitigation alternatives.

2020

Unit commitment and dispatch cases that were developed based on historical data to meet the load forecast.

Unit Commitment Order	Unit Ratings							Lanai 2020 (Theme 1)			Lanai 2020		
	Pmax	Pmin			Inertia H	Unit MVA	Unit K.E. (Mjoules)	Pgen	up reg (spin)	down reg	Pgen	up reg (spin)	down reg
L7,D-7	2.20	0.55			1.10	2.75	3.03						
L8,D-8	2.20	0.55			1.10	2.75	3.03						
LANAI1	1.00	0.50			0.34	1.25	0.43						
LANAI2	1.00	0.50			0.34	1.25	0.43						
LANAI3	1.00	0.50			0.34	1.25	0.43						
LANAI4	1.00	0.50			0.34	1.25	0.43						
LANAI5	1.00	0.50			0.34	1.25	0.43						
LANAI6	1.00	0.50			0.34	1.25	0.43						
CHP	0.83	0.00			0.34	1.25	0.43	0.83					
Sync. Cond.	0.0	0.0			2.60	5.00	13.00	0.00	Sync. Condenser				
Sync. Cond.	0.0	0.0			2.60	5.00	13.00						
Total Wind	3.00	0.00						0.75				N/A	
-New Wind 1	1.50	0.00						0.38	1.13	0.38			
-New Wind 2	1.50	0.00						0.38	1.13	0.38			
DG-PV	0.87	0.00						0.58					
Station PV	1.00	0.00						0.39					
Total Kinetic Energy									13.43			0.00	
Total Load									2.55			0.00	
Total Thermal Generation									0.83			0.00	
Total Renewable Generation									1.72			0.00	
Total Generation									2.55			0.00	
Excess Generation									0.00			0.00	
Total Up Regulation									2.25			0.00	
Total Down Regulation									0.75			0.00	
Legacy DG-PV		59.3Hz Capacity		0.10				59.3Hz Output		0.06	59.3Hz Output		0.00
		60.5Hz Capacity		0.43				60.5Hz Output		0.28	60.5Hz Output		0.00

Table O-55. Unit Commitment and Dispatch Schedule 2020

Table O-55 shows the unit commitment and dispatch schedule for this analysis.

Loss of Generation

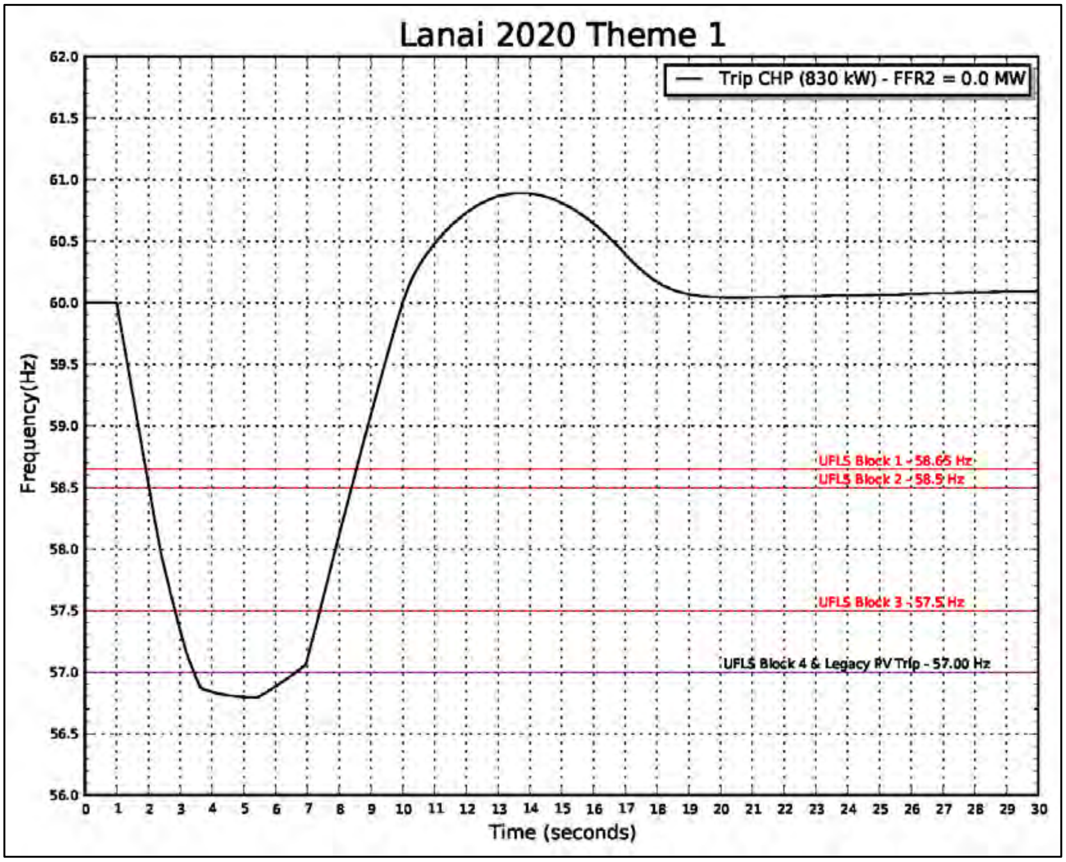


Figure O-155. Frequency Response Profile for FFR2

Figure O-155 shows the frequency response profile for a CHP unit trip at 830 kW. System kinetic energy is 13.4 MW-sec, due in large part to the synchronous condenser. The frequency nadir remains above 56 Hz so no FFR2 is required.

12 kV Fault Analysis

Simulations were performed for a close-in fault (5-cycle clearing time) and a high-impedance fault (24-cycle clearing time).

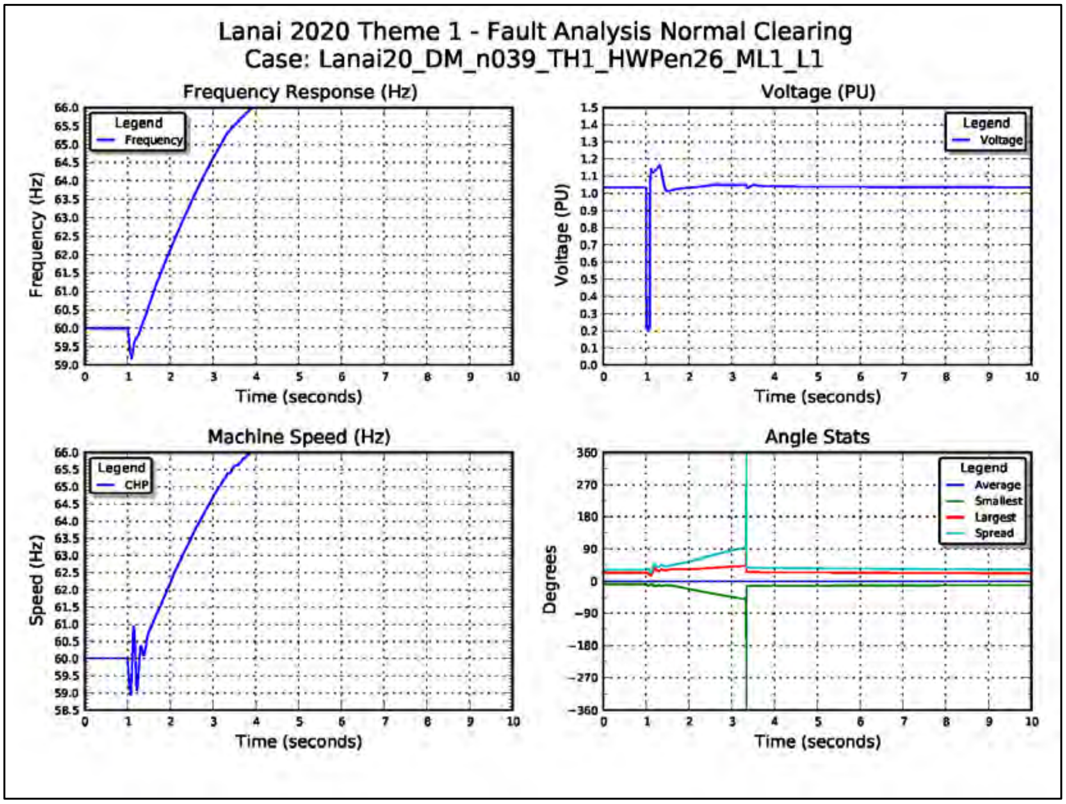


Figure O-156. System Performance Close-in Fault

Figure O-160. shows four plots that illustrate system performance in response to a close-in fault on the Miki Basin to Lanai City #1 distribution circuit. The system frequency plot shows frequency exceeds 66 Hz that will trip all DG-PV. More in-depth analysis is required to determine mitigation alternatives.

2045

Unit Commitment Order	Unit Ratings							Lanai 2045 (Theme 1)			Lanai 2045		
	Pmax	Pmin			Inertia H	Unit MVA	Unit K.E. (Mjoules)	Pgen	up reg (spin)	down reg	Pgen	up reg (spin)	down reg
L7,D-7	2.20	0.55			1.10	2.75	3.03						
L8,D-8	2.20	0.55			1.10	2.75	3.03						
LANAI1	1.00	0.50			0.34	1.25	0.43						
LANAI2	1.00	0.50			0.34	1.25	0.43						
LANAI3	1.00	0.50			0.34	1.25	0.43						
LANAI4	1.00	0.50			0.34	1.25	0.43						
LANAI5	1.00	0.50			0.34	1.25	0.43						
LANAI6	1.00	0.50			0.34	1.25	0.43						
CHP	0.83	0.00			0.34	1.25	0.43	0.83					
Sync. Cond.	0.00	0.00			2.60	5.00	13.00	0.00	Sync. Condenser				
Sync. Cond.	0.00	0.00			2.60	5.00	13.00						
Total Wind	5.00	0.00						0.00				N/A	
-New Wind 1	1.50	0.00						0.00	1.50	0.00			
-New Wind 2	1.50	0.00						0.00	1.50	0.00			
-New Wind 3	1.00	0.00						0.00	1.00	0.00			
-New Wind 4	1.00	0.00						0.00	1.00	0.00			
DG-PV	0.87	0.00						1.31					
Station PV	1.00	0.00						0.87					
Total Kinetic Energy									13.43			0.00	
Total Load									3.01			0.00	
Total Thermal Generation									0.83			0.00	
Total Renewable Generation									2.18			0.00	
Total Generation									3.01			0.00	
Excess Generation									0.00			0.00	
Total Up Regulation									5.00			0.00	
Total Down Regulation									0.00			0.00	
Legacy DG-PV	59.3Hz Capacity			0.00				59.3Hz Output		0.00	59.3Hz Output		0.00
	60.5Hz Capacity			0.00				60.5Hz Output		0.00	60.5Hz Output		0.00

Table O-56. Unit Commitment and Dispatch Schedule 2045

Table O-56 show the unit commitment and dispatch schedule for the 2045 analysis.

Loss of Generation

Simulations were performed for the largest loss of generation contingency event to determine the frequency response reserves requirements to keep the system frequency nadir above 56 Hz.

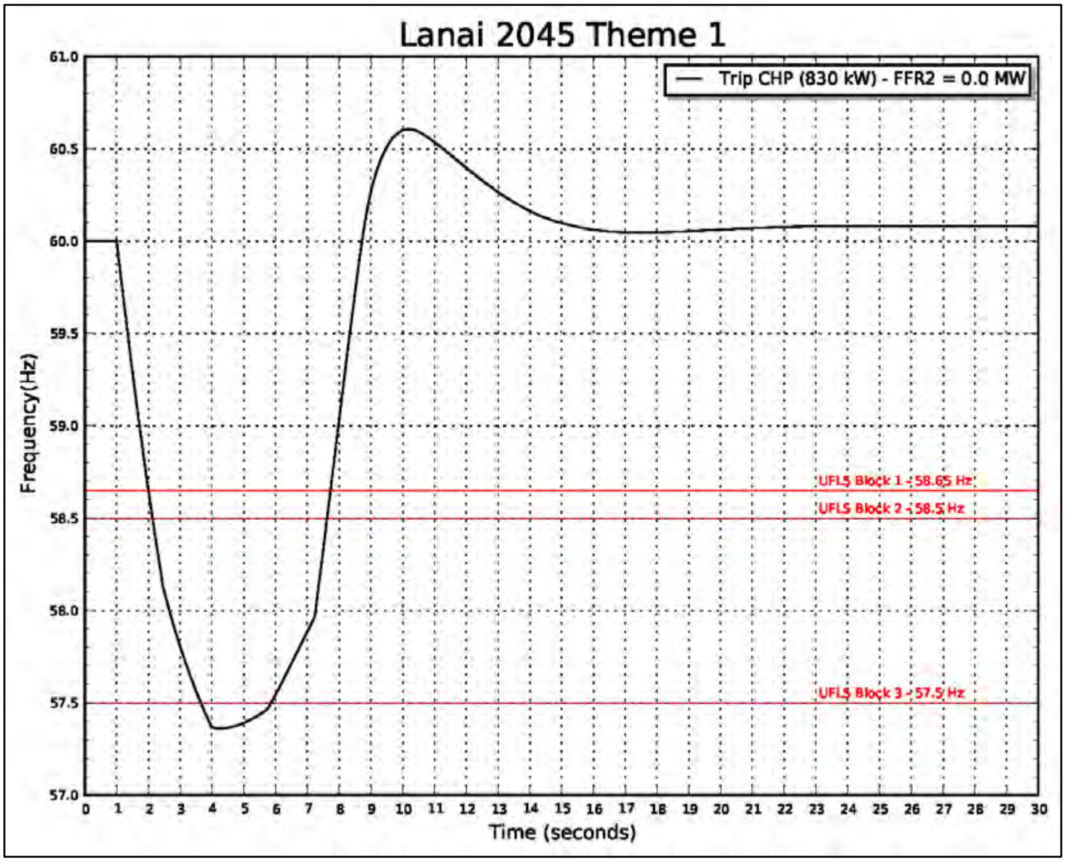


Figure O-157. Frequency Response Profile for FFR2

Figure O-157 shows the frequency response profile for a CHP unit trip at 830 kW. System kinetic energy is 13.4 MW-sec, due in large part to the synchronous condenser. The frequency nadir remains above 56 Hz so no FFR2 is required.

12 kV Fault Analysis

Simulations were performed for a close-in fault (5-cycle clearing time) and a high-impedance fault (24-cycle clearing time).

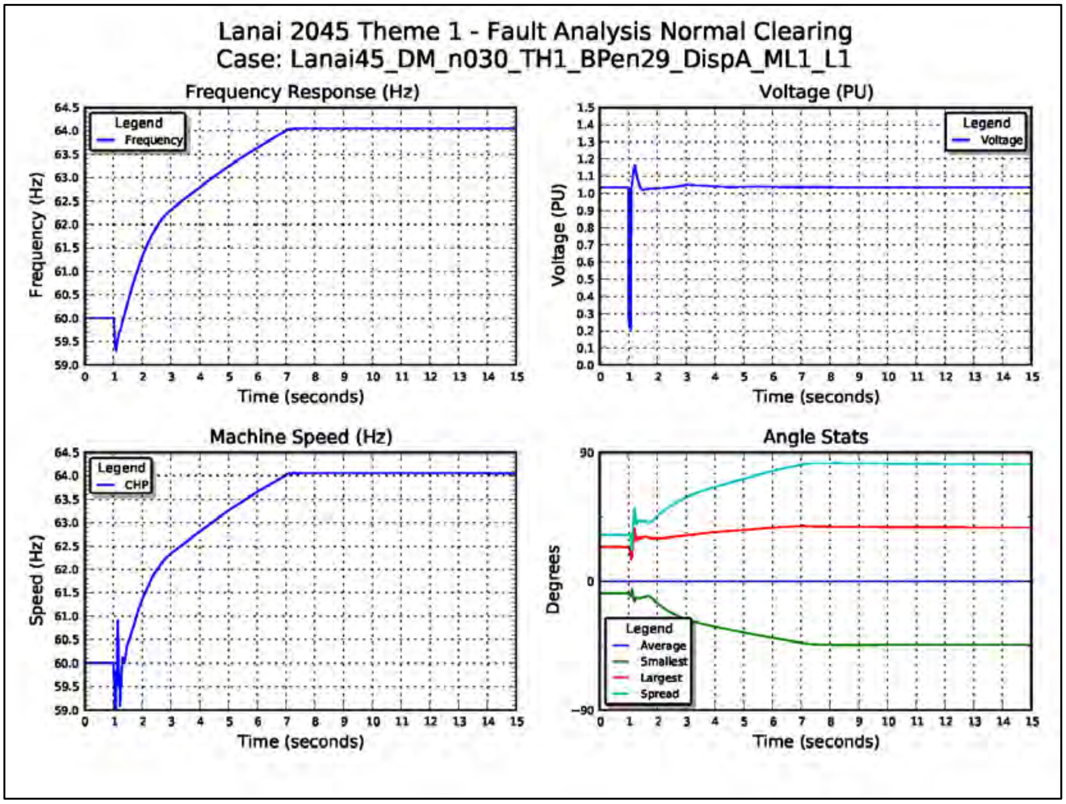


Figure O-158. System Performance to a Close-in Fault

Figure O-158 shows four plots that illustrate system performance in response to a close-in fault on the Miki Basin to Lanai City #1 distribution circuit. The system frequency plot shows frequency exceeds 64 Hz that will trip all DG-PV. More in-depth analysis is required to determine mitigation alternatives.

Summary

Lana'i is a radial distribution system so the requirements of TPL-001 do not apply. The criteria established for this analysis is to keep frequency above 56 Hz so DG-PV does not trigger a cascading contingency event.

Lana'i does not have the DG-PV penetration of the other islands but simulations indicate that both close-in faults and high impedance faults will drive system frequency above 64 Hz and exceed the new ride-through requirements of DG-PV. More analysis is required to determine mitigation alternatives.

SUPPLEMENTAL FAST FREQUENCY RESPONSE ANALYSIS

Fast Frequency Response Analysis

The FFR capacities were determined for the largest loss of generator contingency and the subsequent loss of legacy PV. For O‘ahu, this is an AES turbine trip (201 MW) and 55 MW of legacy PV. For the O‘ahu analyses, the contingency does not change because the energy from AES is significantly lower than the other fossil-fired units.

Fast frequency response one (FFR1) was modeled as a step change to full output within 12-cycles to simulate Auto-scheduling control of a battery energy storage system (BESS). In Auto-scheduling control, the BESS will receive a command to dispatch to full output on an open-breaker signal from AES or Kahe 5/6. Fast frequency response two (FFR2) was modeled as a df/dt initiated response in 30-cycles to simulate Demand Response load control technology in the near future.

The kinetic energy for each unit was calculated by multiplying the unit H-constant by the unit MVA rating. This does not take into account the inertia contribution from the unit's auxiliary loads. Also, the system kinetic energy is the sum of all unit kinetic energies. This does not take into account the inertia contribution from system load.

The simulation evaluated various system conditions to determine FFR requirements. Different unit commitment cases were analyzed to meet system load requirements at various levels of spinning reserves. The assumption is that the capacity of FFR is available for the duration of the event until the system is stable (approximately 30 minutes). Otherwise, loss of this capacity could trigger a secondary contingency event. If supplemental reserves from Demand Response are available, the duration of FFR can be reduced.

The kinetic energy for each unit was calculated by multiplying the unit H-constant by the unit MVA rating. This does not take into account the inertia contribution from the unit's auxiliary loads. Also, the system kinetic energy is the sum of all unit kinetic energies. This does not take into account the inertia contribution from system load.

Case	COMMITMENT ORDER	PMAX	PMIN	MAX TOTAL GEN	MIN TOTAL GEN	MVA BASE	H MW-s/MVA	KE MW-s	TOTAL MVA	TOTAL KE
	H-Power 1	46.0	46.0	46	46	75	2.78	209	75	209
	H-Power 2	22.5	22.5	69	69	42.1	3.41	144	117	352
	Waiau 7	83.3	23.8	152	92	96	4.44	426	213	778
	Waiau 8	86.2	24.1	238	116	96	4.44	426	309	1205
C1	AES	180.0	180.0	418	296	239	2.57	614	548	1819
C2	Kalaeloa CC1*	104.0	65.0	522	361	180.3	4.87	878	728	2697
C3	Kahe 5	134.6	64.7	657	426	158.8	4.36	692	887	3389
C4	Kahe 6	133.8	63.9	790	490	158.8	4.36	692	1046	4081
C5	Kahe 3	86.2	23.7	877	514	101	3.54	357	1147	4438
C6	Kahe 2	82.2	23.8	959	538	96	4.44	426	1243	4865
C7	Kahe 1	82.2	23.8	1041	561	96	4.44	426	1339	5291
C8	Kahe 4	85.3	23.6	1126	585	101	3.54	357	1440	5648
	Kalaeloa CC2**	104.0	0.0	1230	585	119.2	4.96	591	1559	6239
	Waiau 5	54.5	23.5	1285	608	64	4.07	261	1623	6500
	Waiau 6	53.7	23.8	1339	632	64	4.00	256	1687	6756
	CIP1	112.2	41.2	1451	673	162	4.72	765	1849	7520
	Waiau 4	46.5	23.5	1497	697	57.5	4.51	259	1907	7780
	Waiau 3	47.0	23.7	1544	721	57.5	4.51	259	1964	8039
	Waiau 10	49.9	5.9	1594	727	57	7.84	447	2021	8486
	Waiau 9	52.9	5.9	1647	732	57	7.84	447	2078	8933

*MVA and H constant based on CT and ST
**MVA and H constant based on single CT, No increase in PMIN when second CC online

Table O-57. Unit Commitment and Dispatch 2016

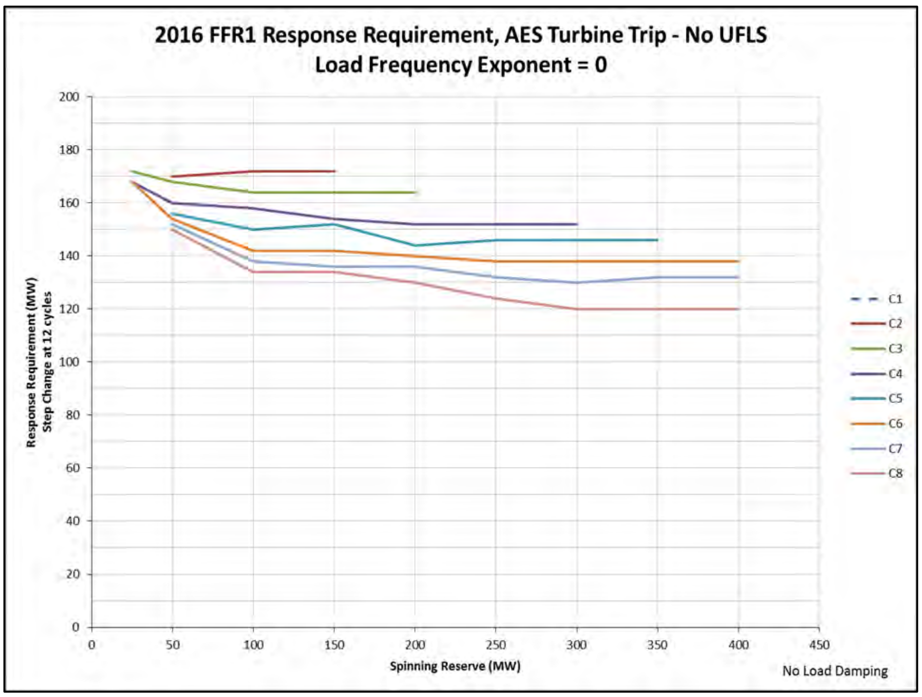


Figure O-159. System Requirements for FFR2 2016

Figure O-159 shows the system requirements for FFR1 for the different dispatch cases. The simulation for dispatch case C1 could not be solved that indicates system inertia is too low and there is no capacity of FFR1 that can stabilize system frequency for this contingency.

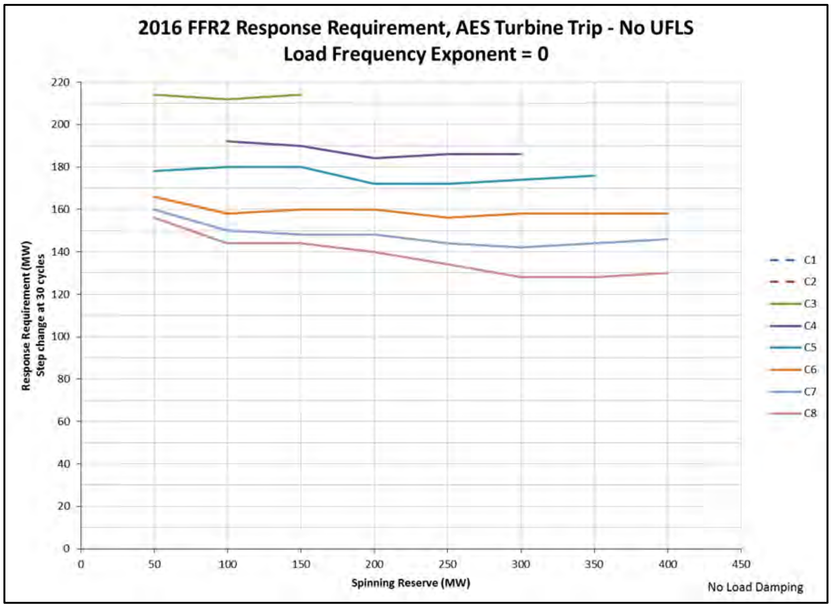


Figure O-160.

Figure O-160 shows the system requirements for FFR2 for the different dispatch cases. The simulations for dispatch cases C1 and C2 could not be solved that indicates system inertia is too low and there is no capacity of FFR2 that can stabilize system frequency for this contingency.

In the FFR1 analysis, the simulation for dispatch case C2 was able to produce a solution. Dispatch case C2 is the commitment of the Kalaeloa CT and ST which are relatively high inertia units. However, the difference in deployment times between FFR1 and FFR2 (18-cycles or 0.3 seconds) was enough to cause system instability. This illustrates how a fraction of a second can impact system security on a very low inertia system so the precision of FFR deployment is critical. Another perspective is that dispatch case C2 is operating the system close to its stability limit.

Fast Frequency Response 2 Sensitivity Analysis

Frequency response from synchronous generators is proportional to the magnitude of the contingency, whether its inertial response, primary (governor) response, exciter/field forcing, etc. Large steam turbines are better equipped to respond to an under frequency event as opposed to an over frequency event so preservation of this principle of proportional frequency response is critical to maintain system security. Over compensation of FFR2 will likely cause more problems that the initial loss of generation contingency because the capacity of legacy PV that will disconnect from the system at 60.5 Hz is higher than the capacity that disconnects at 59.3 Hz.

A sensitivity analysis was performed to illustrate this risk. The FFR2 requirement for Case 6 at 50 MW spinning reserves was applied to the lower inertia case. Tripping Kahe 5 in Case 3 results in a high rate of change of frequency (RoCoF) sufficient to initiate the df/dt trigger for 165 MW of FFR2. This can occur when units with high H-constants (e,g, Kalaeloa CT1 and CT2; or Kahe Units 5 and 6) are offline for maintenance and generation is replaced with cycling units or ICE's. The generation capacity is the same but the difference in system inertia can be drastic.

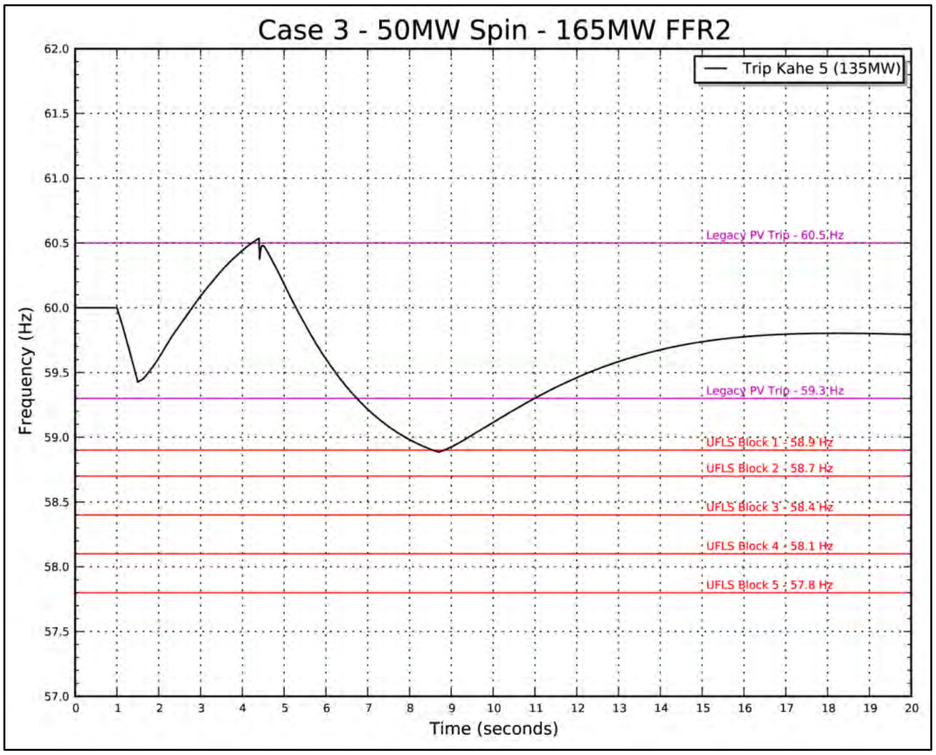


Figure O-161. Frequency Response Profile FFR2

Figure O-161 shows the frequency response profile for this simulation. Deployment of FFR2 has a dramatic impact on the RoCoF so the frequency nadir is approximately 59.4 Hz. However, this amount of load shed is significantly more that the system requires, causing system frequency to over-shoot to 60.5 Hz and tripping 74 MW of legacy PV.

Here are alternatives to ensure the correct amount of FFR2 is deployed:

- Maintain system inertia by running units in variable pressure operation
- Disable FFR2 during low system inertia conditions
- Limit the loss of generation contingency during low system inertia conditions
- Adjustable df/dt settings by the System Operator

Adjustable df/dt settings will require real-time communication and control of DR resources and full utilization of the DRMS capabilities. The initial implementation phase of the Demand Response program should add FFR2 in incremental capacities until communication infrastructure is in place to prevent over compensation.

Observations

Here are some observations about our system security work.

- Inertia, fault current, FFR and PFR when supplied in sufficient quantities by Demand Response or distributed resources can displace must-run generating units for system security.
- Distributed resources not part of an UFLS load shed scheme can provide frequency response reserves like PFR. This is true on any island.
- UFLS is a fundamental part of system security; however, DG-PV and DR reduce UFLS capacities. Demand response load shedding can be more problematic because availability of load resources are more unpredictable and a DER resource (DG-PV) with batteries. . DG-PV reduce residential load shed block capacities whereas demand response is targeting residential, small businesses, light industrial, etc. so this will reduce capacities in UFLS blocks 4 and 5 on O‘ahu which are the last line of defense to prevent system collapse (our bulk load-shed blocks).
- All islands will need “surgical” behind the meter load shedding in the future. In the interim, O‘ahu, Maui, and Hawai‘i Island should consider an intentional islanding scheme in parallel with UFLS.
- Frequency response from synchronous generators is proportional to the magnitude of the contingency event whether it's inertial response or droop response. Over compensation of FFR2 (demand response load shedding) can cause more problems than the initial contingency event because synchronous generators are better equipped to increase output than reduce or absorb energy. Therefore, implementation of DR programs must coincide with communication infrastructure and technologies that ensure we always adhere to the fundamental principle of proportional response to contingency events.
- When system inertia is high, FFR2 and FFR1 performance is equivalent (except for the proportional response issue as stated above). As system inertia is reduced, the time delay of FFR2 is long enough that no sufficient quantity of FFR2 can prevent UFLS on O‘ahu or meet TPL-001 on the other islands.
- If distributed resources are to be used for ancillary services, distribution circuit capacity must be available for this to occur.
- Managing the magnitude of the contingency is fundamental to system security. Economies of scale can reduce cost by reducing the maximum allowable contingency (e.g. 200 MW for O‘ahu).
- For Moloka‘i (today) and Lana‘i, installation of high H-constant synchronous condensers (such as old retired steam unit generators) will add more inertia than the current generating fleet of internal combustion engines. This improves system stability, adds load for PV, and provides voltage support and fault current.

TPL-001-02: TRANSMISSION PLANNING PERFORMANCE REQUIREMENTS

The starting document for HI-TPL-001-2 was HI-TPL-001. The standard was revised to reflect the distinct electrical systems for O'ahu, Maui, and Hawai'i Island. Lana'i and Moloka'i were removed from HI-TPL-001-02 because they are 12 kV distribution systems.

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Working Group Glossary of Terms, Version 1 – 20120304 are not repeated here. New or revised definitions become approved when this proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

Balancing Authority (BA): The responsible entity that integrates resource plans ahead of time, maintains load-generation balance within a Balancing Authority Area, and governs the real time operation and control of the Balancing Area. (Source: Modified from Glossary of Terms Used in NERC Reliability Standards February 8, 2012.)

Balancing Authority Area: The collection of generation, transmission, and loads within the metered boundaries of the Balancing Authority. The Balancing Authority maintains load-resource balance within this area. (Source: Glossary of Terms Used in NERC Reliability Standards February 8, 2012.)

Base Year: The 2011 Balancing Authority's transmission and generation system shall be used as the base year to establish performance standards utilized with this standard. (Source: Proposed RSWG proposed definition.)

Cascading: The uncontrolled successive loss of system elements triggered by an incident at any location. Cascading results in widespread electric service interruption that cannot be restrained from sequentially spreading beyond an area predetermined by studies. (Source: Glossary of Terms Used in NERC Reliability Standards February 8, 2012.)

Consequential Load Loss: All Load that is no longer served by the Transmission system as a result of Transmission Facilities being removed from service by a Protection System operation designed to isolate a fault. (Source: Glossary of Terms Used in NERC Reliability Standards; Term Approved August 4, 2011.)

Contingency Reserve: The provision of capacity deployed by the Balancing Authority to meet reliability requirements in Table D-58.

Corrective Action Plan: A list of actions and an associated timetable for implementation to remedy a specific problem. (Source: Glossary of Terms Used in NERC Reliability Standards February 8, 2012.)

Equipment Rating: The maximum and minimum voltage, current, frequency, real and reactive power flows on individual equipment under steady-state, short-circuit and transient conditions, as permitted or assigned by the equipment owner. (Source: Glossary of Terms Used in NERC Reliability Standards February 8, 2012.)

Facility: A set of electrical equipment that operates as a single Bulk Electric System Element (for example, a line, a generator, a shunt compensator, transformer, etc.). (Source: Glossary of Terms Used in NERC Reliability Standards February 8, 2012.)

Frequency Bias: A value expressed in MW/0.1 Hz that is set into the Automatic Generation Control's (AGC) Area Control Error (ACE) algorithm that allows the Balancing Authority to control system frequency.

Frequency Response: The sum of the change in demand, plus the change in generation, divided by the change in frequency, expressed in megawatts per 0.1 Hz (MW/0.1 Hz)

Long-Term Transmission Planning Horizon: Transmission planning period that covers years six through ten or beyond when required to accommodate any known longer lead time projects that may take longer than ten years to complete. (Source: Glossary of Terms Used in NERC Reliability Standards February 8, 2012.)

Near-Term Transmission Planning Horizon: The transmission planning period that covers Year One through five. (Source: Glossary of Terms Used in NERC Reliability Standards February 8, 2012.)

Non-Consequential Load Loss: Non-Interruptible Load loss that does not include: (1) Consequential Load Loss, (2) the response of voltage sensitive load, or (3) load that is disconnected from the system by end-user equipment. (Source: Glossary of Terms Used in NERC Reliability Standards February 8, 2012.)

Off-Peak: Those hours or other periods defined by NAESB business practices, contract, agreements, or guides as periods of lower electrical demand. (Source: Glossary of Terms Used in NERC Reliability Standards February 8, 2012.)

Operating Procedure: A document that identifies specific steps or tasks that should be taken by one or more specific operating positions to achieve specific operating goal(s). The steps in an Operating Procedure should be followed in the order in which they are presented, and should be performed by the positions identified. A document that lists the specific steps for a system operator to take in removing a specific transmission line from service is an example of an Operating Procedure. (Source: Glossary of Terms Used in NERC Reliability Standards February 8, 2012.)

Planning Assessment: Documented evaluation of future Transmission system performance and Corrective Action Plans to remedy identified deficiencies. (Source: Glossary of Terms Used in NERC Reliability Standards February 8, 2012.)

Protection System: Protection Systems are:

- Protective relays which respond to electrical quantities,
- Communications systems necessary for correct operation of protective functions
- Voltage and current sensing devices providing inputs to protective relays,
- Station dc supply associated with protective functions (including batteries, battery chargers, and non-battery-based dc supply), and
- Control circuitry associated with protective functions through the trip coil(s) of the circuit breakers or other interrupting devices. (Source: Glossary of Terms Used in NERC Reliability Standards February 8, 2012.)

Protection Reserves: The resources under the control of the Under Frequency Load Shedding System or Under Voltage Load Shedding System designed to protect the system against single or multiple contingency events. (Source: RSWG proposed definition.)

Special Protection System (SPS) or Remedial Action Scheme: An automatic protection system designed to detect abnormal or predetermined system conditions, and take corrective actions other than and/or in addition to the isolation of faulted components to maintain system reliability. Such action may include changes in demand, generation (MW and MVAR), or system configuration to maintain system stability, acceptable voltage, or power flows. An SPS does not include under-frequency or under-voltage load shedding or out-of-step relaying (not designed as an integral part of an SPS). Also called Remedial Action Scheme. (Source: Glossary of Terms Used in NERC Reliability Standards February 8, 2012.)

Stability: The ability of an electric system to maintain a state of equilibrium during normal and abnormal conditions or disturbances. (Source: Glossary of Terms Used in NERC Reliability Standards February 8, 2012.)

System: A combination of generation, transmission, and distribution components. (Source: Glossary of Terms Used in NERC Reliability Standards February 8, 2012.)

Transmission Line: A system of structures, wires, insulators, and associated hardware that carry electrical energy form one point to another in an electric power system. Lines are operated at relatively high voltages varying from nominal 69 kV up to 138 kV.

Introduction

Purpose: Establish Transmission system planning performance requirements within the planning horizon to develop a system that will operate reliably over a broad spectrum of conditions and following a wide range of probable Contingencies.

Applicability: Balancing Authorities (BA)

Facilities: The facilities are divided into three island systems.

O'ahu: 2015 Data

- Daytime peak load: 1110 MW
- Daytime minimum load: 551 MW
- Nighttime peak load: 1204 MW
- Nighttime minimum load: 506 MW
- Minimum total capacity of synchronous generation needed to provide adequate system fault current: 482.6 MVA

Maui: 2015 Data

- Daytime peak load: 180.9 MW
- Daytime minimum load: 88.6 MW
- Nighttime peak load: 206.6 MW
- Nighttime minimum load: 74.5 MW
- Minimum total capacity of synchronous generation needed to provide adequate system fault current: 101.3 MVA

Hawai'i Island: 2015 Data

- Daytime peak load: 173.1 MW
- Daytime minimum load: not applicable
- Nighttime peak load: 191.5 MW
- Nighttime minimum load: 82.6 MW
- Minimum total capacity of synchronous generation needed to provide adequate system fault current: 140 MVA

Effective Date: April 1, 2016

Requirements

R1. The BA must maintain system models for performing the studies needed to complete its Planning Assessment. The models must use data consistent with that provided in accordance with the HI-MOD-010 Development and Reporting of Steady-State System Models and Simulations and HI-MOD-012 Development and Reporting of Dynamic System Models and Simulations standards, supplemented by other sources as needed, including items represented in the Corrective Action Plan, and must represent projected system conditions. This establishes Category P0 as the normal system condition in Table D-58.

R1.1. System models must represent:

R1.1.1. Actual steady-state characteristics of system resources and loads as defined in HI-MOD-010 Development and Reporting of Steady-State System Models and Simulations.

R1.1.2. Actual dynamic characteristics of system resources and loads as defined in HI-MOD-012 Development and Reporting of Dynamic System Models and Simulations.

R1.1.3. Planned Facilities and changes to existing Facilities

R1.2. The Generation resources must maintain or better the following characteristics unless the change can be verified by study that the results will provide acceptable reliability. The characteristics of the system that meet the acceptable reliability criteria will be used as the new benchmark for future planning until the reliability criteria is changed.

R1.2.1. Each BA system will be planned to meet the requirements of Table D-58.

R1.2.2. The loss of the largest single contingency may result in a loss of load within the acceptable performance criteria defined in Table D-58.

R1.2.3. Each resource will have frequency ride-through designed such that all generation, reserves, regulation, and voltage control resources will withstand contingency events defined in Table D-58.

R1.2.4. The system will be planned such that the resultant impacts of inertia, unit response, or reserve response will withstand contingency events defined in Table D-58.

R1.2.5. The system will be planned such that all generation, reserves, regulation, and voltage control resources will withstand the most severe voltage ride-through requirement for a single contingency event, including both transmission and distribution events and distribution and transmission fault reclose cycles, through the duration of their reclosing cycle, without the loss of or damage to any resource.

R1.2.6. The system will be designed such that all generation, reserves, regulation, and voltage control resources will withstand contingency events defined in Table D-58.

R1.2.7. The system will be planned to be transiently and dynamically stable following any single contingency event or any excess contingency event designed to be protected under HI-PRC-006 under-frequency load shedding. Stability will be defined such that the system will survive the first swing stability and the second swing, and each subsequent swing will be lesser in magnitude than its predecessor (damped response). All swings will be effectively eliminated within five seconds of the initiating event.

R1.2.8. The system will be designed to supply the required ancillary services necessary to provide voltage and frequency response to meet the reliability requirements of each BA's service tariff and Table D-58.

R2. The BA must prepare a Planning Assessment of its system. This Planning Assessment must use current or qualified past studies (as indicated in R2.6), document assumptions, and document summarized results of the steady-state analyses, short circuit analyses, and stability analyses.

R2.1. For the Planning Assessment, the Near-Term Transmission Planning Horizon portion of the steady-state analysis must be assessed annually and be supported by current annual studies or qualified past studies as indicated in R2.6. Qualifying studies need to include the following conditions:

R2.1.1. System peak load for either year one or year two, and for year five.

R2.1.2. System minimum with maximum and minimum variable renewables (night-time load) load for one of the five years.

R2.1.3. System minimum day load, maximum variable renewable for one of the five years.

R2.1.4. System day-peak load with maximum variable renewable and minimum variable renewable for one of the five years.

R2.1.5. System peak load, no variable renewable for one of the five years.

R2.1.6. For each of the studies described in R2.1.1 through R2.1.5, one or more sensitivity cases must demonstrate the impact of changes to the basic assumptions used in the model. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions by a sufficient amount to stress the system within a range of credible conditions that demonstrate a measurable change in system response:

- Real and reactive forecasted load.
- Expected transfers.
- Expected in-service dates of new or modified Transmission Facilities.
- Planned or unplanned outages of critical resources for ancillary services.
- Typical generation scenarios including outage of the typically operated generation sources.
- Reactive resource capability.
- Generation additions, retirements, or other dispatch scenarios.
- Controllable loads and Demand Side Management.

R2.1.7. When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), the impact of this possible unavailability on system performance must be studied. The studies must be performed for the P0, P1, and P2 categories identified in Table D-58 with the conditions that the system is expected to experience during the possible unavailability of the long lead time equipment.

R2.2. For the Planning Assessment, the Long-Term Transmission Planning Horizon portion of the steady-state analysis must be assessed annually and be supported by the following annual current study, supplemented with qualified past studies as indicated in R2.6:

R2.2.1. A current study assessing expected system peak load conditions for one of the years in the Long-Term Transmission Planning Horizon and the rationale for why that year was selected.

R2.3. The short circuit analysis portion of the Planning Assessment must be conducted annually addressing the Near-Term Transmission Planning Horizon and can be supported by current or past studies as qualified in R2.6.

- Minimum short circuit current for proper relay operation: The minimum short circuit current for each BA is specified in the Introduction.
- Maximum short circuit current interrupting capabilities of the breakers must be within the limits for proper breaker operation. The analysis must be used to determine whether circuit breakers have interrupting capability for Faults that they will be expected to interrupt using the system short circuit model with any planned generation and Transmission Facilities in service which could impact the study area.

R2.4. For the Planning Assessment, the Near-Term Transmission Planning Horizon portion of the Stability analysis must be assessed annually and be supported by current or past studies as qualified in R2.6. The following studies are required:

R2.4.1. System peak load for one of the five years. System peak load levels must include a load model which represents the expected dynamic behavior of loads that could impact the study area, considering the behavior of induction motor loads or other load characteristics, including the model of distributed generation, Demand Response, and other programs that impact system load characteristics. An aggregate system load model which represents the overall dynamic behavior of the load is acceptable.

R2.4.2. System minimum load for one of the five years.

R2.4.3. System minimum with maximum and minimum variable renewables (night-time load) load for one of the five years.

R2.4.4. System minimum day load, maximum variable renewable for one of the five years.

R2.4.5. System day-peak load, maximum and minimum variable renewable for one of the five years.

R2.4.6. System peak load, no variable renewable for one of the five years.

R2.4.7. For each of the studies described in R2.4.1 through R2.4.6, one or more sensitivity cases must be utilized to demonstrate the impact of changes to the basic assumptions used in the model. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions by a sufficient amount to stress the system within a range of credible conditions that demonstrate a measurable change in performance:

- Load level, load forecast, or dynamic load model assumptions.
- Expected transfers.
- Expected in service dates of new or modified Transmission Facilities.
- Reactive resource capability.
- Maintenance periods of generation resources and alternative resources providing ancillary services.
- Generation additions, retirements, or other dispatch scenarios.

R2.5. For the Planning Assessment, the Long-Term Transmission Planning Horizon portion of the Stability analysis must be assessed to address the impact of proposed material generation additions or changes in that time frame and be supported by current or past studies as qualified in R2.6 and must include documentation to support the technical rationale for determining material changes.

R2.6. Past studies may be used to support the Planning Assessment if they meet the following requirements for steady-state, short circuit, or Stability analysis:

R2.6.1. The study must be five calendar years old or less, unless a technical rationale can be provided to demonstrate that the results of an older study are still valid.

R2.6.2. No material changes have occurred to the system represented in the study. Documentation to support the technical rationale for determining material changes must be included.

R2.7. For planning events shown in Table D-58 when the analysis indicates an inability of the system to meet the performance requirements, the Planning Assessment must include Corrective Action Plan(s) addressing how the performance requirements will be met. Revisions to the Corrective Action Plan(s) are allowed in subsequent Planning Assessments, but the planned system must continue to meet the performance requirements in Table D-58. The Corrective Action Plan(s) must:

R2.7.1. List system deficiencies and the associated actions needed to achieve required system performance. Examples of such actions include:

- Installation, modification, retirement, or removal of Transmission and generation Facilities and any associated equipment.
- Installation, modification, or removal of Protection Systems or Special Protection Systems.
- Installation or modification of automatic generation tripping as a response to a single or multiple Contingency to mitigate Stability performance violations.
- Installation or modification of manual and automatic generation runback or tripping as a response to a single or multiple Contingency to mitigate steady-state performance violations.
- Use of Operating Procedures specifying how long they will be needed as part of the Corrective Action Plan.
- Use of rate applications, DSM, alternative resources and technologies, or other initiatives.

R2.7.2. Include actions to resolve performance deficiencies identified in multiple sensitivity studies or provide a rationale for why actions were not necessary.

R2.7.3. If situations arise that are beyond the control of the BA that prevent the implementation of a Corrective Action Plan in the required time frame, then the BA is permitted to utilize Non-Consequential Load Loss to correct the situation that would normally not be permitted in Table D-58, provided that the BA documents that they are taking actions to resolve the situation. The BA must document the situation causing the problem, alternatives evaluated, and the use of Non-Consequential Load.

R2.7.4. Be reviewed in subsequent annual Planning Assessments for continued validity and implementation status of identified system Facilities and Operating Procedures.

R2.8. For short circuit analysis, if the short circuit current interrupting duty on circuit breakers determined in R2.3 exceeds their Equipment Rating, the Planning Assessment must include a Corrective Action Plan to address the Equipment Rating violations. The Corrective Action Plan must:

R2.8.1. List system deficiencies and the associated actions needed to achieve the required system performance.

R2.8.2. Be reviewed in subsequent annual Planning Assessments for continued validity and implementation status of identified System Facilities and Operating Procedures.

R3. For the steady-state portion of the Planning Assessment, the BA must perform studies for the Near-Term and Long-Term Transmission Planning Horizons in R2.1 and R2.2. The studies must be based on computer simulation models using data provided in R1.

R3.1. Studies must be performed for planning events to determine whether the system meets the performance requirements in Table D-58 based on the Contingency list created in R3.4.

R3.2. Studies must be performed to assess the impact of the extreme events which are identified by the list created in R3.5.

R3.3. Contingency analyses for R3.1 and R3.2 must:

R3.3.1. Simulate the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each Contingency without operator intervention. The analyses must include the impact of subsequent:

- Tripping of generators where simulations show generator bus voltages or high side of the generation step up (GSU) voltages are less than known or assumed minimum generator steady-state or ride-through voltage limitations. Include in the assessment any assumptions made.
- Tripping of transmission elements where loadability limits are exceeded.

- Tripping of generation and other resources (including distributed resources) where ride-through capabilities are exceeded.

R3.3.2. Simulate the expected automatic operation of existing and planned devices designed to provide steady-state control of electrical system quantities when such devices impact the study area. These devices may include equipment such as phase-shifting transformers, load tap changing transformers, and switched capacitors and inductors.

R3.4. Those planning events in Table D-58 that are expected to produce more severe system impacts must be identified and a list of those Contingencies to be evaluated for system performance in R3.1 created. The rationale for those Contingencies selected for evaluation must be available as supporting information.

R3.5. Those extreme events in Table D-58 that are expected to produce more severe system impacts must be identified and a list created of those events to be evaluated in R3.2. The rationale for those Contingencies selected for evaluation must be available as supporting information. If the analysis concludes there is Cascading caused by the occurrence of extreme events, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) must be conducted.

R4. For the Stability portion of the planning assessment (as described in R2.4 and R2.5), the BA must perform the contingency analyses listed in Table D-58. The studies must be based on computer simulation models using data provided in R1.

R4.1. Studies must be performed for planning events to determine whether the system meets the performance requirements in Table D-58 based on the Contingency list created in R4.4. For planning events P1 through P4:

R4.1.1. No generating unit can pull out of synchronism.

R4.1.2. Power oscillations must exhibit acceptable damping as established by the BA.

R4.2. Studies must be performed to assess the impact of the extreme events identified by the list created in R4.5.

R4.3. Contingency analyses for R4.1 and R4.2 must:

R4.3.1. Simulate the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each Contingency without operator intervention. The analyses must include the impact of subsequent:

- Successful high speed (less than one second) reclosing and unsuccessful high-speed reclosing into a Fault where high speed reclosing is utilized.

- Tripping of generators where simulations show generator bus voltages or high side of the GSU voltages are less than known or assumed generator low voltage ride through capability. Include in the assessment any assumptions made.
- Tripping of Transmission lines and transformers where transient swings cause Protection System operation based on generic or actual relay models.
- Tripping of all generation sources whose ride-through capabilities are exceeded.

R4.3.2. Simulate the expected automatic operation of existing and planned devices designed to provide dynamic control of electrical system quantities when such devices impact the study area. These devices may include equipment such as generation exciter control and power system stabilizers, static VAR compensators, and power flow controllers.

R4.4. Those planning events in Table D-58 that are expected to produce more severe system impacts on its portion of the system must be identified and a list created of those Contingencies to be evaluated in R4.1. The rationale for those Contingencies selected for evaluation must be available as supporting information.

R4.5. Those extreme events in Table D-58 that are expected to produce more severe system impacts must be identified and a list created of those events to be evaluated in R4.2. The rationale for those Contingencies selected for evaluation must be available as supporting information. If the analysis concludes there is Cascading caused by the occurrence of extreme events, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences of the event(s) must be conducted.

R5. The BA shall have criteria for acceptable system steady-state voltage limits, post-contingency voltage deviations, transient voltage response, transmission facilities overloading criteria, and dynamic stability criteria (voltage and frequency). For transient voltage response, the criteria shall at the minimum specify a low voltage level and a maximum length of time that transient voltages may remain below that level.

R6. The BA shall define and document, within their Planning Assessment, the criteria or the methodology used in the analysis to identify system instability for conditions such as cascading, voltage instability, or uncontrolled islanding.

Planning Events

Planning Event	Initial Condition	Event	Non-Consequential Load Shed			UFLS or UVLS		
			O'ahu	Maui	Hawai'i Island	O'ahu	Maui	Hawai'i Island
P0: No Contingency	Normal system N-1 Maintenance N-2 Maintenance	None	n/a	n/a	n/a	None	None	None
P1.1: Loss of One Generating Unit	Normal system	Unit Trip Bus Fault	None	None	None	None	15%	15%
P.1.2: Loss of One Transmission Element	Normal system	SLG, 2Ø, 3Ø, Breaker Fail	None	None	None	None	None	None
P2.1: Loss of Two Generating Units	Normal system	Unit Trip Bus Fault	tbd	tbd	tbd	tbd	tbd	tbd
P2.2: Loss of Two Transmission Elements	N-1	SLG, 2Ø, 3Ø, Breaker Fail	None	tbd	tbd	None	tbd	tbd
P3.1: Loss of Multiple Generating Units	Normal system	Loss of Combined Cycle unit	tbd	tbd	tbd	tbd	tbd	tbd
P3.2: Loss of Multiple Transmission Elements	N-2	SLG, 2Ø, 3Ø, Breaker Fail	tbd	tbd	tbd	tbd	tbd	tbd
P4: Catastrophic Event	Normal system	Loss of Generating Station Loss of Transmission Corridor	tbd	tbd	tbd	tbd	tbd	tbd

Table D-58. Transmission Performance Requirements

Measures

M1. The BA must provide evidence, in hard copy format, that it is maintaining system models within their respective area, using data consistent with HI-MOD-010 Development and Reporting of Steady-State System Models and Simulations and HI-MOD-012 Development and Reporting of Dynamic System Models and Simulations, including items represented in the Corrective Action Plan, representing projected system conditions, and that the models represent the required information in accordance with R1.

M2. The BA must provide dated evidence (such as electronic or hard copies) that it has prepared an annual Planning Assessment of its portion of the system in accordance with R2.

M3. The BA must provide dated evidence (such as electronic or hard copies) of the studies utilized in preparing the Planning Assessment in accordance with R3.

M4. The BA must provide dated evidence (such as electronic or hard copies) of the studies utilized in preparing the Planning Assessment in accordance with R4.

M5. The BA must provide dated evidence (such as electronic or hard copies) of the documentation specifying the criteria for acceptable system steady-state voltage limits, post contingency voltage deviations, and transient voltage utilized in preparing the Planning Assessment in accordance with R5.

M6. The BA must provide dated evidence (such as electronic or hard copies) of documentation specifying the criteria or methodology used in the analysis to identify system instability for conditions such as cascading, voltage instability, or uncontrolled islanding that was utilized in preparing the Planning Assessment in accordance with R6.

Compliance

C1. Compliance Monitoring Process

C1.1. Compliance Enforcement Authority: Hawai‘i Public Utilities Commission (Commission) or its designee.

C1.2. Data Retention: The BA must retain data or evidence to show compliance as identified unless directed by the Commission (or designee) to retain specific evidence for a longer period of time as part of an investigation:

- The models utilized in the current in-force Planning Assessment and one previous Planning Assessment in accordance with R1 and M1.
- The Planning Assessments performed since the last compliance audit in accordance with R2 and M2.
- The studies performed in support of its Planning Assessments since the last compliance audit in accordance with R3 and M3.
- The studies performed in support of its Planning Assessments since the last compliance audit in accordance with R4 and M4.
- The documentation specifying the criteria for acceptable system steady-state voltage limits, post-contingency voltage deviations, and transient voltage response since the last compliance audit in accordance with R5 and M5.
- The documentation specifying the criteria or methodology utilized in the analysis to identify system instability for conditions (such as cascading, voltage instability or uncontrolled islanding) in support of its Planning Assessments since the last compliance audit in accordance with R6 and M6.

If the BA is found non-compliant, it must keep information related to the non-compliance until found compliant or the time periods specified above, whichever is longer.

C1.3. Compliance monitoring and enforcement processes:

- Compliance Audits: The Commission (or designee) will give notice to the BA within 30 days of years' end for a compliance audit and will complete such audit within 90 days of such information being supplied by the BA.
- Self-certifications
- Spot checking
- Compliance violation investigations
- Self-reporting
- Complaints

C2. Levels of non-compliance for R1 and M1:

C2.1. Level 1: The BA's system model failed to represent one of the requirement in R1.1.1 through R1.1.5.

C2.2. Level 2: The BA failed to meet all the requirements of C2.1 Level 1.

C3. Levels of non-compliance for R2 and M2:

C3.1. Level 1: The BA failed to comply with R2.6.

C3.2. Level 2: The BA failed to meet all the requirements of C3.1 Level 1.

C4. Levels of non-compliance for R3 and M3:

C4.1. Level 1: The BA did not identify planning events as described in R3.4 or extreme events as described in R3.5.

C4.2. Level 2: The BA failed to meet all the requirements of C4.1 Level 1.

C5. Levels of non-compliance for R4 and M4:

C5.1. Level 1: The BA did not identify planning events as described in R4.4 or extreme events as described in R4.5.

C5.2. Level 2: The BA failed to meet all the requirements of C5.1 Level 1.

C6. Levels of non-compliance for R5 and M5:

C6.1. Level 1: not applicable.

C6.2. Level 2: The BA does not have criteria for acceptable system steady-state voltage limits, post-contingency voltage deviations, or the transient voltage response for its system for R5 and M5.

C7. Levels of non-compliance for R6 and M6:

C7.1. Level 1: not applicable.

C7.2. Level 2: The BA failed to define and document the criteria or methodology for system instability used within its analysis as described in R6 and M6.

P. Consultant Reports

Three consultants worked in concert with the Companies to perform the modeling and analyses required to develop our Preferred Plans. We then compared their results to ours to determine how closely aligned they were.

Ascend Analytics ran their PowerSimm Planner model; Energy and Environmental Economics (E3) ran long-term case development through their RESOLVE program; Energy Exemplar ran PLEXOS for power systems.

ASCEND ANALYTICS: POWERSIMM PLANNER

Ascend created a pair of expansion plans for analysis. These plans were conceived with the objective of reaching the RPS goas purely with wind, solar, and battery assets. Two alternate strategies were used to meet these targets: strategic and aggressive. The strategic plan builds renewables at a deliberate pace, calculated to meet the RPS requirements exactly in each of the target years: 30% renewable energy in 2020, 40% in 2030, 70% in 2040, and 100% in 2045. Since the targets increase the most in the later years, the strategic plan starts slow, and builds from there. The aggressive plan is an inversion of the strategic. It builds rapidly in the early years, vastly exceeding the RPS targets, and slows down in later years, eventually reaching the 100% target in 2045. The early presence of renewables allows this plan to enjoy lower exposure to fuel price risk, but this added security comes at a high cost.

Figure P-1 and Figure P-2 show the renewable generation levels for the strategic and aggressive plans.

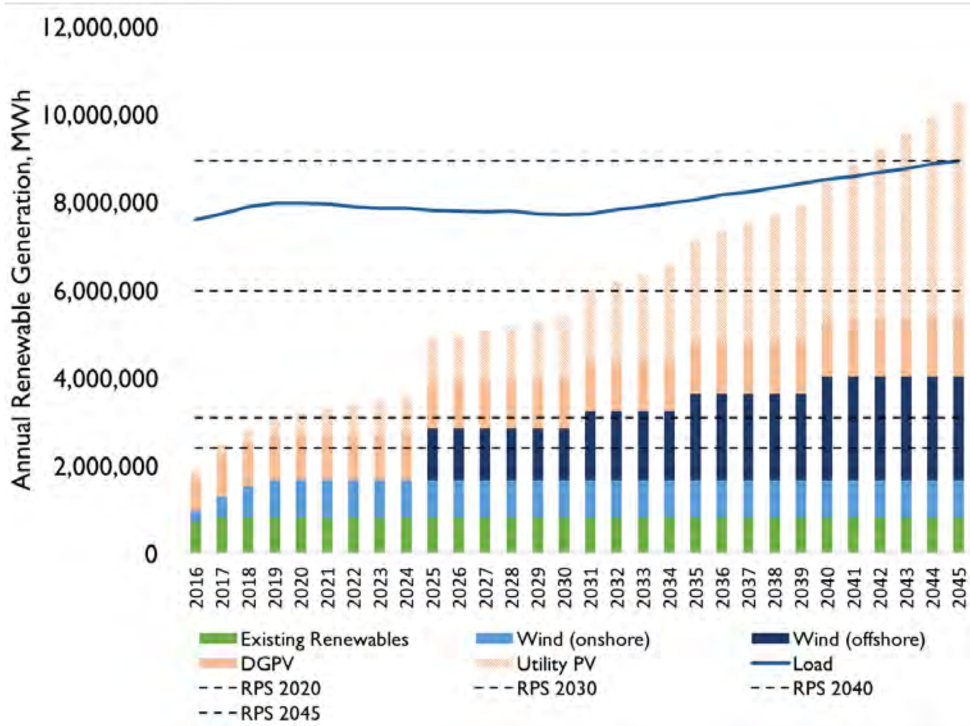


Figure P-1. Renewable Generation, Strategic Plan

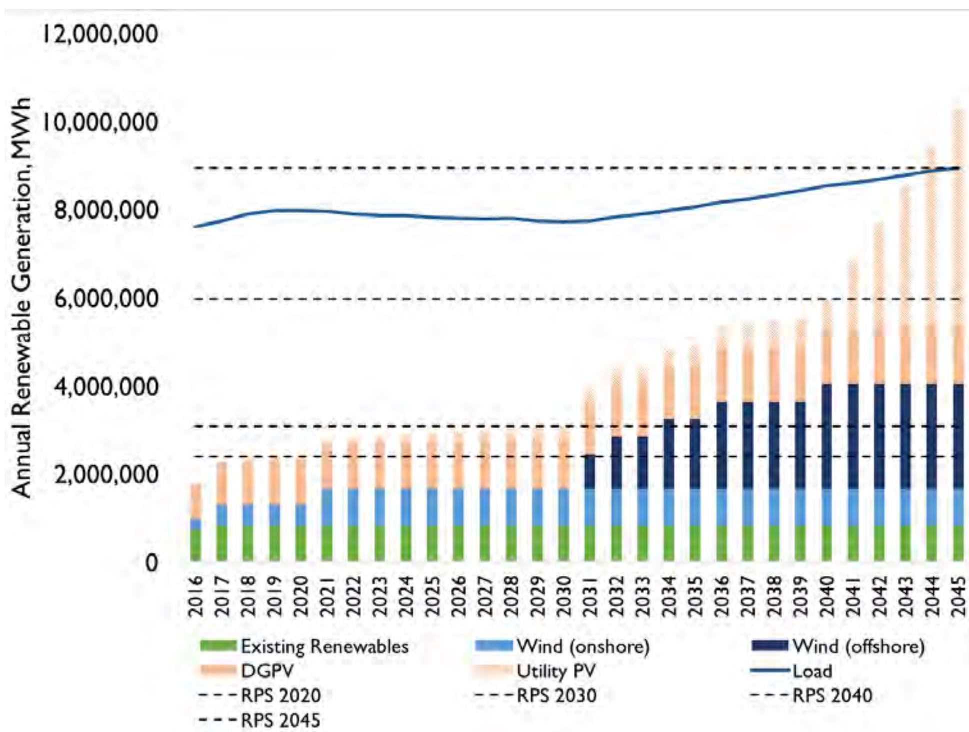


Figure P-2. Renewable Generation, Aggressive Plan

The heavy presence of renewable resources, particularly solar, in both plans results in large amounts of dumped energy during the day, when solar generation far exceeds demand. In addition, their intermittent nature means that, even when present in large amounts, renewables are still often unable to serve load on their own. The two problems share a common solution in batteries. The right amount of load-shifting battery storage can be used to capture over-generation during peak hours and provide energy when wind and solar resources are silent. By building batteries at a rate proportional to the growth of renewables, the strategic and aggressive plans avoid the problem of over- and under-production and provide a reliable system. Because the aggressive plan builds renewables early, its need for load-shifting comes much sooner than in the strategic plan. As battery costs are expected to continue to decline over the next 30 years, this leaves the aggressive plan in the disadvantageous position of building batteries soon, before it makes economic sense to do so. Ascend's results show that what the aggressive plan gains in fuel savings, it loses by building batteries too early.

Figure P-3 illustrates this point. It shows the net present value (in 2016 dollars) of all relevant costs associated to the strategic and aggressive plans. The costs considered include fixed and variable generation costs, the capital costs of building new renewables, and capital costs of building batteries. Figure P-3 also includes a risk premium factor, which measures each portfolio's exposure to market risk. The risk premium can be thought of as a reasonable worst-case scenario; a portfolio may exceed its average cost, but would not be expected to exceed the risk premium. The aggressive portfolio carries lower risk and generation costs, but pays with greatly increased capital costs.

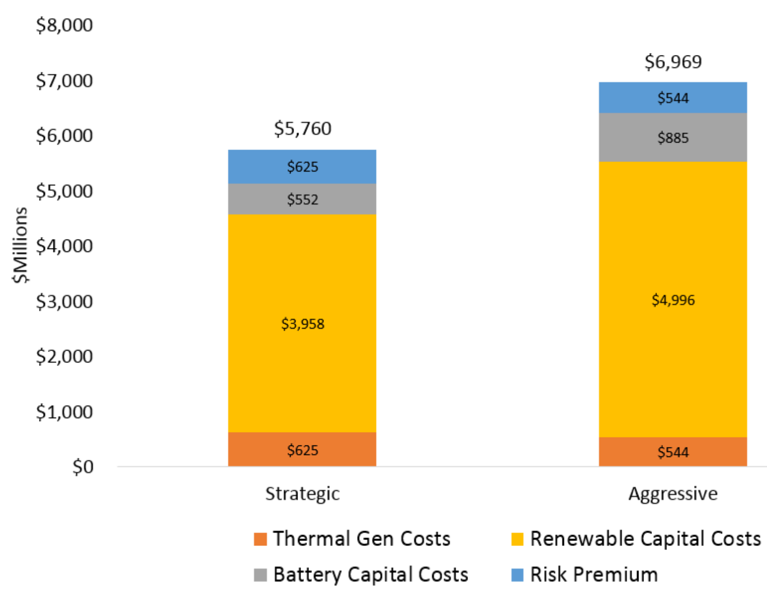


Figure P-3. Net Present Value of Portfolio Costs

E3: RESOLVE

E3 finds that for the fuel cost assumptions, investment in LNG is more cost effective than the alternative fuel oil case in 2030. This is contingent on the cost of LNG supply infrastructure remaining as assumed (including, for example, storage, piping, and delivery terminal, being less than $15 Million per year in the low fuel scenario, and less than $260 Million per year in the high fuel scenario).

HECO PSIP – Investigation of Least Cost Policy Decisions to Achieve Hawaii's RPS Goals

Contents

Executive Summary

HECO hired Energy and Environmental Economics (E3) to develop long term analysis for PSIP support based on their extensive experience in developing software and long-term planning scenarios in both California and New York as well as their our work in Hawaii. The study tests whether HECO's "least regrets" short term investment decisions are robust under a variety of different policy cases and fuel and technology price forecast uncertainty. In particular, E3 was asked to test the robustness of HECO's proposal to invest in LNG facilities as an early step in their effort to develop a 100% Renewables Portfolio Standard (RPS) compliant plan. E3 tested the decision to invest in LNG under each of the forecasted fuel price trajectories developed by HECO, and the technology costs identified in the February PSIP filing. E3 included its own estimates of battery costs and tested the sensitivity of the solution to different battery cost trajectories. This data was then fed into E3's Renewable Integration Solutions Model (RESOLVE) to develop least cost expansion plans consistent with the forecast assumptions in each case.

The key findings from the study include the following:

1. E3 investigated LNG cost effectiveness for each of the HECO created fuel price scenarios. In both the high and low fuel price scenarios, the relatively low LNG fuel price assumptions produce substantial savings over the next several decades. Our analysis estimates that the fuel savings created by an investment in LNG would produce fuel savings of approximately $112 million/year in the low fuel scenario, and $383 million/year in the high fuel scenario for the Reference case in 2030. Investments in LNG, under these fuel price assumptions, are cost effective if the required capital investments in storage, piping, and delivery terminal are less than the estimated benefits. . The robustness of this decision is not impacted by either early electrification of the transportation sector nor the decision to produce synthetic fuels for transportation. Also, because LNG is largely a direct replacement for fuel oil, the least cost decision is not impacted by the build decision of other renewable resources. This result holds true across a variety of different policy cases[1], as shown in Figure 1 below, which shows the incremental cost in cents per kWh of electricity consumed of each case we tested relative to a reference case under both

[1] Each of the policy cases investigated are described in detail in Section Case Descriptions

the low and high fuel price assumptions provided by HECO. The difference in cost between the LNG and No-LNG options is primarily driven by the large fuel price spread in all fuel price scenarios.

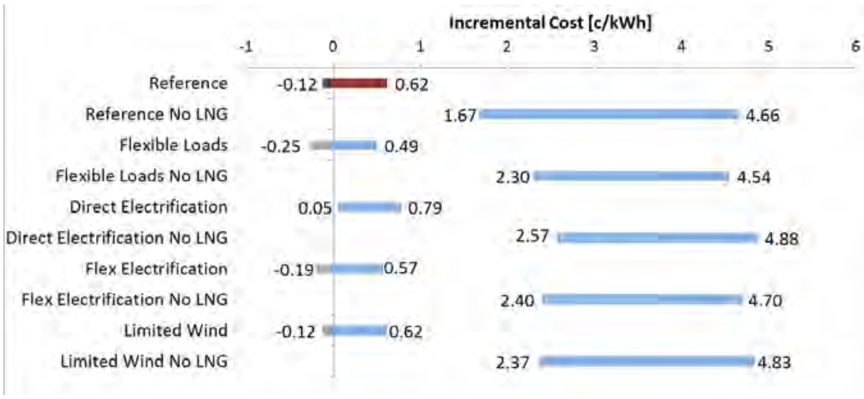


Figure 1. Comparison of operating and incremental fixed costs in 2030

2. Fuel costs, though important today for making decisions about which near-term capacity investments to make, are expected to become a minority component of the total investments that Hawaii will incur to reach its 100% RPS. The majority of expenditure through 2045 is on capital assets including PV, wind, storage, and biofuel capacity.. The fraction of operating costs as part of the total investment in new fixed assets plus variable operating costs decreases substantially over time, as shown in Figure 2. Given this relationship, the total cost of the long term plan will primarily be driven by the selection of the lowest capital cost resources over the planning period.

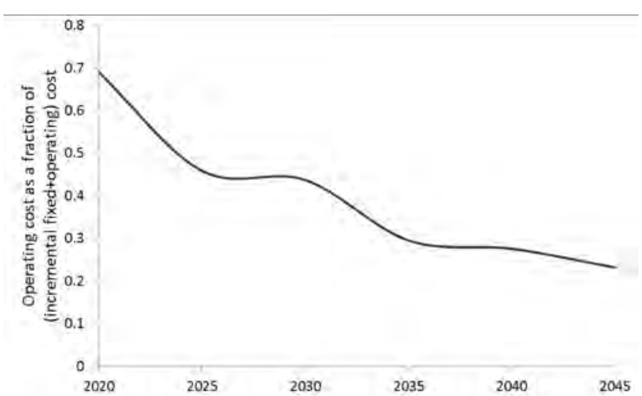


Figure 2. Operating costs as a fraction of total incremental fixed investments plus operating costs

3. The specific least cost solution in each scenario varies depending on the constraints and cost assumptions. All of the solutions, however, depend on developing a balanced portfolio of a substantial amount of high quality solar, supplemented by offshore wind when it becomes cost effective because of either solar overgeneration or land use limitations, and balanced with storage and the ability to cost-effectively curtail renewable resources.
4. While not a direct finding of the E3 study, the very high costs of fuels, land and food in Hawaii makes it imperative that Hawaii continue to focus on not just on the narrower achievement of the aggressive RPS target, but all of the 3 pillars common to all sustainable deep decarbonization pathways:

    a. Decarbonize the power sector via renewable energy or through the use of biofuels
    b. Electrify transportation and end uses in buildings
    c. Continue to invest in conservation. Because of the inherent limits on renewable potential on an island system, investment in conservation may be a critical strategy for HECO's ability to reach the 100% RPS target in 2045.

1 Introduction

HECO hired Energy and Environmental Economics (E3) to leverage the extensive planning work it has conducted in both California[2] and in New York[3] to assist utilities and state agencies comply with their aggressive clean energy standards. Given the short period of time available to study the HECO system needs under the PSIP schedule, E3's scope was limited to several key questions in informing a least-cost long-term plan for Oahu.

The E3 analysis is designed to determine how the decisions to build out the lowest-cost long-term plan might change depending on the policy direction Hawaii takes in the future to meet its RPS goals, and how the uncertainty surrounding pricing of fuels and technology affect those decisions. Presented here is a framework for evaluating those decisions to inform policy making. The long-term focus of the E3 scope emphasizes investigation of the large-scale changes in Hawaii energy policy over the time horizon to 2045, rather than the near-term detailed modeling of system operations that is covered in other efforts under the PSIP. The result is an evaluation of several different policy 'futures' under uncertain cost trajectories for technologies and fuels. Given the short study period, the framework presented here is the basis for evaluation of long-term policy pathways in Hawaii that may be expanded in the future to include refinement and greater detail on the input assumptions, and definition of additional cases to be investigated.

[2] E3 has worked in California:

- with the 5 largest utilities (PG&E,SCE, SDG&E,LADWP, and SMUD) to develop a high RPS compliance plan, developed integration models for the CAISO and the utilities (REFLEX and RESOLVE),
- developed a portfolio evaluation model (RPS Calculator) for the CPUC to be used in planning the grid and evaluating need,
- defined multiple scenarios or pathways for compliance for the Governor's office and the CA state agencies using the PATHWAYS model,
- and most recently estimated the total integration needs by pathway and portfolio using the RESOLVE model.

[3] E3 has worked in New York:

- for NYSERDA in designing a "Full Value Tariff" suitable for the goals outlined in the REV proceeding, developed a benefit cost methodology
- for the NY PSC to evaluate demand response,
- and developed a model for Consolidated Edison to design and incentivize least cost portfolios of distributed resources to meet local grid needs.

The core of the analysis is several cases that represent different policy directions in Hawaii. Each of these cases is a potential set of future system conditions that can be used to facilitate development of energy policy in Hawaii. The cases are designed to highlight the *controllable decision levers* available in formulating a robust, least-regrets plan to best handle what happens in the future. A least-regrets plan has to be robust against things that Hawaii has no control over – the things that *happen* to the islands. These include external forces such as global commodity prices and future technology pricing.

Within each case below E3 investigates a range of pricing scenarios that cover the uncertainty in both the forecast of the costs of various fuels and the costs and availability of different technologies – the things that happen to the islands. Fuel pricing sensitivities are included for oil, LNG, and biofuels. The fuel price trajectories include the "Reference," "High" and "Low" cases developed by the HECO team. Technology cost sensitivities are investigated for storage.

The specifics of each case define the constraints on how the future will evolve in Hawaii. All other decisions on system operations and resource procurement are made by the RESOLVE model to minimize costs under each fuel price and technology sensitivity. The RESOLVE model, described in the previous filing[4], is an optimal investment model that includes a representation of hourly operations to capture system needs driven by increasing renewable energy penetration. In each case, the resources selected by RESOLVE represent the overall least-cost procurement solution over the period of study from 2020 to 2045, subject to the constraints on procurement in each case.

The cases include:

1. **Reference Case.** The Reference Case extends current policy trends forward. Moving away from the Reference Case to those below will require policy action.
2. **Transportation Case.** The Transportation Case assumes policy to accelerate alternative fuel vehicle adoptions on the islands. Two variants of this case are investigated: (1) a case where electric vehicle adoption is the policy direction taken named "**Direct Electrification**"; and (2), where hydrogen and other produced fuel vehicles and infrastructure are used named "**Produced Fuels**".

[4] Power Supply Improvement Plan Update Interim Status Report, February 2016, Page C-36.

3. **Flexible Loads Case.** The Flexible Loads case assumes a greater degree of flexible loads on Oahu, reflecting policy moves towards providing the control systems for flexible load participation in balancing and the compensation mechanisms to incentivize effective use of flexible load products.
4. **Flexible Electrification.** If Hawaii could use both flexible loads from the flexible loads case and a high EV adoption policy where smart charging could also be used for load balancing, what would least cost procurement look like over time?
5. **Limited RE Potential.** Oahu is renewable energy resource constrained and will have to move beyond the resources available on the island to meet the 100% RPS requirement. The opportunities to do this include both offshore wind, which the RESOLVE model finds is selected in large amounts if its adoption is unconstrained, and imported biofuels. Just how many of these off-island resources are selected will depend on the onshore renewable energy potentials. This case investigates two variants of renewable energy constraints. The first looks at how the least cost investment decisions on Oahu change if offshore wind is limited. The second investigates how many off-island resources are required if the potential for utility scale onshore solar production is reduced from 3452 MW[5] to 600 MW, reflecting a case where solar procurement on Oahu may be limited.

[5] Addendum to Report: Utility-Scale Onshore Wind, Utility-Scale PV, and CSP Potential Resource, NREL, February 29th, 2016.

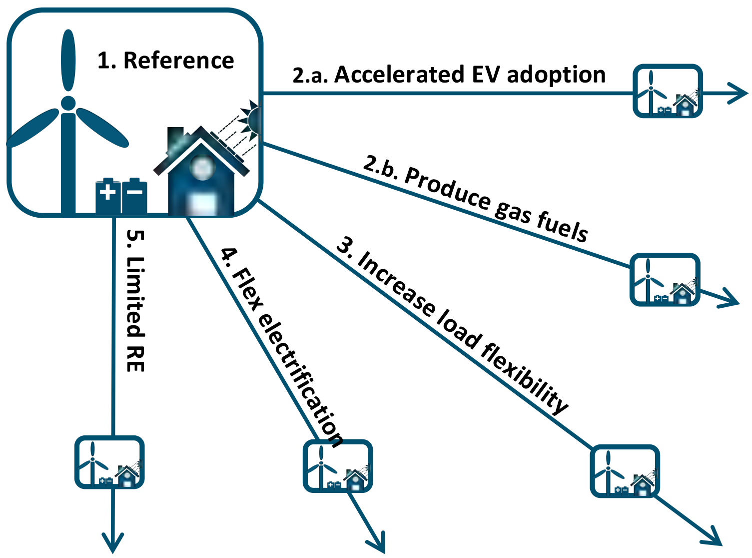


Figure 3. Cases tested against reference case

Each case is both compliant with existing RPS policy in Hawaii and seeks to maintain existing reliability. The questions E3 investigates by modeling each of the cases are described in Section 2. Each of the cases are described in detail in Section 4 where reference is made to the numerical inputs to each case that are specified in an accompanying appendix. A brief summary of findings can be found in Section 3 with a more detailed examination of results in Section 5. Section 6 presents next steps if more time was available for the study.

2 Questions Investigated

In the document "Commission's Inclinations on the Future of Hawaii's Electric Utilities", the Hawaii PUC laid out several goals for the HECO companies in planning the future grid. These included:

- Seek high penetrations of lower-cost, new utility-scale resources
- Modernize the generation system to achieve a future with high penetrations of renewable resources
- Exhaust all opportunities to achieve operational efficiencies in existing plants
- Pursue opportunities to lower fuel costs in existing power plants

These goals are clear, consistent with policy and laudable. However developing long term plans to satisfy them using the existing models and planning framework in Hawaii, and in most jurisdictions, translates into an extensive number of cases defining alternative investments. These cases will vary in their performance when tested against scenarios of different forecast assumptions. The E3 RESOLVE model can reduce the number of cases needed by identifying the least cost investments that meet future needs under a range of assumptions about what the world will look like. E3 aligned their cases with parallel HECO PSIP planning processes by using the same range of input assumptions surrounding load projections, resource cost projections, resource potentials, operating characteristics, reserve requirements, and fuel prices. Given the timeline and scope of the present study and the current, most pressing policy decisions, the findings from investigating each of the policy cases have been used to answer a focused set of questions pertinent to the PSIP. These include:

- Should Hawaii build LNG infrastructure?
- Which of the policy decisions are the most favorable?
- In each of the policy cases what are the major investment decisions and when are they made?
- What is the impact on procurement when the price of storage is varied?
- How much curtailment is included in least cost operations?
- How does the Produced Fuels case compare to Direct Electrification?

3 Summary of Findings

The results of the analysis are presented in detail in Section 5. In responding to the questions in the previous section there are a number of key findings. Where not specified, the findings below are for the cases where LNG is included. All cases are run for Hawaii state RPS targets of 40% in 2030, 70% in 2040, and 100% in 2045.

3.1 Should Hawaii build LNG infrastructure?

- E3 finds that for the HECO fuel cost assumptions, investment in LNG is more cost effective than the alternative fuel oil case in 2030. This is contingent on the cost of LNG supply infrastructure including, for example, storage, piping, and delivery terminal, being less than $112 million/year in the low fuel scenario, and less than $383 million/year in the high fuel scenario for the Reference case.

- LNG cost effectiveness is driven by the spread between LNG and fuel oil prices assumed in the HECO fuel forecasts.
- Using the HECO reference fuel scenario in the Reference Case, 150 MW of LNG are installed in 2020, another 360 MW of LNG are installed in 2025, and another 400 MW of LNG are installed in 2035. Note that this result assumes that HECO has already invested in the necessary LNG piping and storage facilities necessary to construct new LNG burning new resources.
- LNG remains in all cases in 2045 to offer contingency reserves when it is assumed to be converted to biodiesel. In the Reference Case, 400 MW of LNG remain in 2045.
- LNG is a close substitute for fuel oil, which makes this fuel switch insensitive and largely independent on the build of other resources.

3.2 Which of the policy decisions are most favorable?

- The difference in the estimated total cost to electricity consumers between the different policy decisions is small relative to the total costs of developing any of the policy compliant cases. In 2030, for example, the most cost effective policy solution on a c/kWh of load impact basis is Flexible loads. The least cost effective is the Direct Electrification case. However the difference between these two solutions in cost is only approximately 0.35 c/kWh.
- The analysis does not factor in the potential gasoline savings to customers from replacing their conventional vehicles with electric vehicles so the Direct Electrification case may be more favorable than reflected in these cases if consumer's total costs of energy (electricity plus avoided gasoline purchase) are fully captured.
- The relatively small difference in total costs between cases is a result of the relatively few options available to meet RPS requirements. Ultimately, there are not enough on-island renewable resources to meet 100% RPS, requiring relatively large amounts of either offshore wind or imported biofuel.

3.3 In each of the policy cases what are the major investment decisions and when are they made?

- The path to achieving 100% RPS requires all of the identified solar and wind potential available on the island.
- If offshore wind is available, small installations are made in 2025 and 2035, and a large installation (800 MW in the Reference case) is made in 2040. These investments are selected ahead (lower cost) of using all of the solar capacity on the island.
- Wind is invested in ahead (lower cost) of the remaining solar potential because of the reduced marginal curtailment and consequent reduced need for investment in battery storage, lowering the cost of wind relative to solar.
- Biofuels are selected even when offshore wind investment is unlimited in the model. Biofuels provide a valuable balancing function that would otherwise have to be provided by expensive batteries. Even though they can be less costly that investing in batteries, biofuel investments are still relatively expensive and happen in the 2035 to 2045 time period.

3.4 What is the impact on procurement when the price of storage is varied?

- Forecasts of storage prices are very uncertain and the storage results are very sensitive to prices. Increasing storage prices by 10% has a dramatic effect on procurement. Total storage in 2045 decreases from 1940 MW in the Reference case to 1020 MW, increases offshore wind to 2490 MW from 1060 MW, and increases biofuels to 1110 MW from 860 MW in the Reference case. In addition, total utility scale solar online in 2045 drops from the maximum potential of 3450 MW to 1300 MW.
- Across storage price variants, the build decisions between now and 2030 remain consistent. Investments in long lead time resources such as LNG that require active policy measures to implement are relatively unaffected by storage pricing. These factors make storage pricing relatively benign as a factor influencing near term planning decisions when in the context of total investment cost to reach 100% RPS in 2045.

3.5 How much curtailment is included in least cost operations?

- In the Reference, Flexible Loads, Direct Electrification, and Flex Electrification cases curtailment is approximately 20% of annual renewable energy production in 2045. The high levels of curtailment are also related to the relatively high cost of fuel. The RESOLVE model prefers building more renewable resources with higher amounts of investment in storage and curtailment because of expected higher future fuel prices.
- Curtailment shapes and levels vary significantly between whether LNG is present or not.Because future LNG prices are expected to be much lower than other fuels, curtailment across LNG cases is 3-4% in 2035 compared to the much higher10% in the No-LNG case.
- In the limited wind case, curtailment is 14% in 2040 and 10% in 2045. In 2045, all renewable potential, both onshore and offshore, is built on Oahu, resulting in an economic choice between building batteries to utilize more of the curtailed energy, or importing biofuels. Batteries are built, causing the reduction in curtailment in the final period.

3.6 How does the Produced Fuels case compare to direct electrification?

- Produced fuels scenario requires a large amount of additional load, which is expensive to meet in a resource constrained environment. As converting biofuels for hydrogen and synthetic methane fuel production is not a sensible solution due to the cost and inefficiency of such a process, relying on a substantial amount of of offshore wind would likely be needed to pursue this pathway. Exploring high renewable systems heavily dependent on wind would require additional model capability not deployable in the time frame available for this study.

4 Case Descriptions

4.1 Reference case

This is a business as usual (BAU) scenario that takes current policy trends and extrapolates them forward. This case is compliant with the RPS goals, including a high number of rooftop PV adoptions equal to the economic adoption forecasted by the HECO team. Rooftop PV is assumed controllable by 2019. Loads are relatively inflexible, with most of the additional balancing needs for renewables happening on the supply side. Electric vehicle adoption is consistent with the Hawaii EV sales target for 2030 pro-rated to Honolulu County, and held constant out to 2045. Where curtailment of both utility scale and rooftop PV systems is possible, utility scale resources are curtailed first.

The inputs below are necessary to define the starting conditions and defined annual inputs for the RESOLVE model. These can be thought of as the constraints on the system conditions expected in the future, including what resources are built over the modeling time horizon. All other investment and operating decisions on how to balance system load will be made by the RESOLVE model to minimize costs.

4.1.1 Case defining inputs

4.1.1.1 Hourly load and load forecast data

The Oahu hourly load shape from 2014 was used as a basis for the load forecast. This shape was first scaled to HECO's projected peak load in each year through 2045 (annual load growth of 1.15%). Peak load reaches 1,667 MW in 2045 from 1,170 MW in 2014. Additional transportation load was then applied to the base load shape. The annual transportation loads used were developed by Evolved Energy based on stock rollover and EV sales targets and are shown in Table 1.

Table 1. Annual transportation load (GWh) in three transportation cases.

	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

In the Reference and Direct Electrification cases, workplace charging availability is assumed to gradually reach 50% of all vehicles by 2045 from 10% in 2020 (Figure 4) and the electric vehicle load is shaped accordingly. The shapes used for the electric vehicle loads are based on E3's work with the PATHWAYS model in California. These normalized shapes are shown in Figure 4.

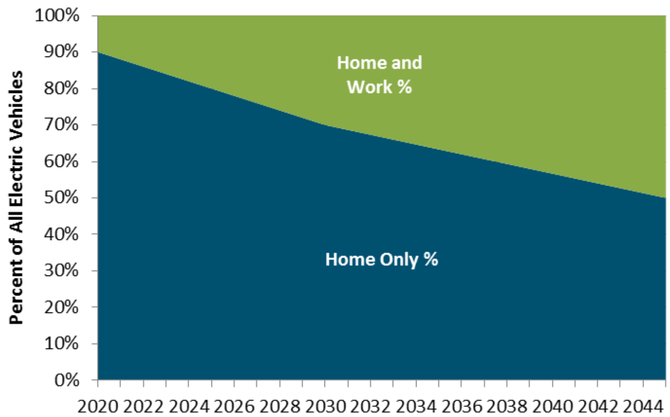


Figure 4. Percent of electric vehicles with workplace charging availability.

Figure 5. Example load shapes for Home Only and Home and Work charging.

In the flexible load sensitivity scenarios, the percent of vehicles that can be charged flexibly is increased gradually from 0% in 2020 to 50% in 2030 to 100% in 2050. In addition, we model a fraction of the heating and cooling loads on Oahu are flexible. Heating and cooling loads are assumed to be a similar fraction of total load to forecasts from California: 12% of total annual load. We assume that 1% of these loads is flexible in 2020, 10% in 2030, and 25% in 2045. These loads are then allowed to dispatched within daily constraints on energy budget, minimum hourly load, and maximum hourly load derived from the static load shapes for each end use.

4.1.1.2 Conventional generator fleet

Each scenario described here includes a treatment of Oahu's generator fleet, including currently planned additions and retirements as well as operating characteristics.

To reduce runtime, individual units are aggregated to the plant level. Table 2 shows the installed capacities assumed through 2030. All existing and planned capacity is assumed retired at the end of 2030.

Table 2. Planned installed capacities (MW).

Plant	Technology	2020	2025	2030
Waiau_ST_5to6	Steam	108	108	0
Waiau_ST_7to8	Steam	169	169	169
Waiau_CT	CT	103	103	103
Kahe_1to4	Steam	336	0	0
Kahe_5to6	Steam	268	0	0
CIP	CT	120	120	120
KPLP	Combined Cycle	208	208	208
AES	Coal	180	180	180
H-Power	Refuse	46	38	38
HIA	Biodiesel	8	8	8
Fixed_Purchase	Fixed Purchase	2	2	2
LMS100CT	CT	0	191	191
LM6000CT	CT	0	84	126
LM6000CC	Combined Cycle	0	175	175
ICE	ICE	49	98	98

The full-load heat rates assumed for each plant are shown in Table 3 below.

Table 3. Full load heat rates for Oahu generators.

Plant	Full Load Heat Rate (MMBtu/hr)
Waiau_ST_5to6	11.512
Waiau_ST_7to8	10.361
Waiau_CT	12.514
Kahe_1to4	9.896

Kahe_5to6	9.887
CIP	11.388
KPLP	9.156
AES	17.295
H-Power	47.022
HIA	10.209
LMS100CT	9.199
LM6000CT	10.006
LM6000CC	7.632
ICE	8.834

In addition, RESOLVE is allowed to build new generic generators: combined cycle (CC), combustion turbine (CT), or internal combustion engine (ICE). The full load heat rates for these generator types are shown in Table 4.

Table 4. Full load heat rates for new generators.

Plant	Full Load Heat Rate (MMBtu/hr)
CC	7,000
CT	10,006
ICE	8,834

4.1.1.3 Renewable generation

Hourly shapes for utility PV, onshore wind, and offshore wind are based on HECO's 2014 profiles. Current planned capacities of utility PV (12.4 MW) and onshore wind (99 MW) were included in all scenarios through 2030. In addition, up to 154 MW of additional onshore wind and up to 3,452 MW of additional utility PV were allowed to be built. Depending on the scenario, offshore wind potential was either left unconstrained or limited to 400 MW.

4.1.1.4 Fuel prices used here are based on HECO's projections

Three fuel price scenarios developed by HECO were used: Reference, Low, and High (Figure 6). Within each fuel price scenario, LNG prices are consistently lower than the price for LSFO and biodiesel.

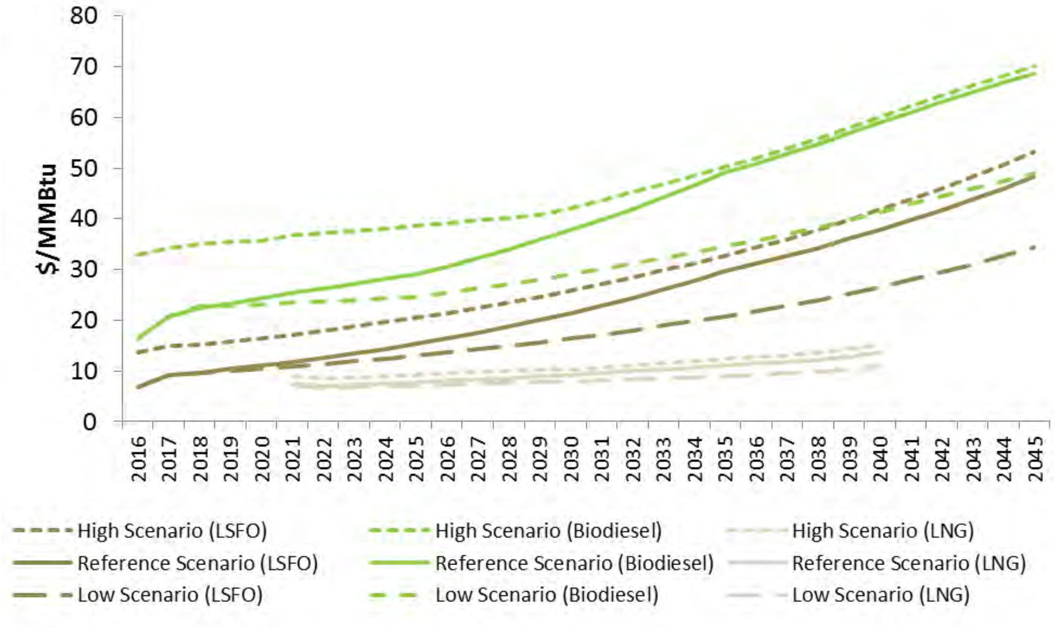


Figure 6. HECO's three fuel price scenarios.

4.1.1.5 Rooftop PV

Rooftop PV forecasted capacity through 2045 was included based on HECO's previous filing (Table 5)[6]. Additional renewables to meet the RPS requirement are selected by the RESOLVE model to find the least cost procurement plan.

Table 5. Rooftop PV capacity installations.

Date	Cumulative MW
2020	577
2025	605
2030	635
2035	672
2040	721
2045	779

4.1.1.6 Generation and Storage Costs

The capital costs for each technology are shown in Table 6. These were provided by HECO in their

Table 6.Capital costs of generation options out to 2045.

[6] Data from "Hawaiian Electric 2016 Forecast Data 20160217.xlsx" on the HECO FTP site.

$/kW (AC) Year	On-Shore Wind	Offshore Wind	Utility Scale Solar PV	Combined Cycle Gas
2016	2405	4971	2719	1727
2020	2253	4115	2201	1687
2025	2263	3356	1890	1647
2030	2181	3112	1689	1613
2035	2095	2940	1524	1589
2040	2020	2818	1376	1572
2045	1942	2703	1242	1572

Energy storage cost and performance inputs are based on a review of the literature and projections from manufacturers and developers, including:

- *Lazard's Levelized Cost of Storage Analysis – version 1.0 (*Lazard, 2015);[7]
- *DOE/EPRI 2013 Electricity Storage Handbook in Collaboration with NRECA* (Sandia National Laboratories, 2013);[8]
- *Electrical energy storage systems: A comparative life cycle cost analysis* (Zakery and Syri, Renewable and Sustainable Energy Reviews 2015);[9]
- *Rapidly falling costs of battery packs and electric vehicles* (Nykvist and Nilsson, Nature Climate Change 2015);[10]
- *2015 Greentechmedia coverage on current battery manufacturers*
- *Tesla Powerwall webpage (Last visited March 2016);*[11]
- *Capital Cost Review of Power Generation Technologies; Recommendations for WECC's 10- and 20-year studies (E3, 2014); only used for pumped hydro*[12]

Capital investment and O&M costs are annualized using E3's WECC Pro Forma tool. A 15% adder is added on top of the capital costs shown in Table 6 to take into account EPC and

[7] Available at: https://www.lazard.com/media/2391/lazards-levelized-cost-of-storage-analysis-10.pdf
[8] Available at: http://www.sandia.gov/ess/publications/SAND2013-5131.pdf
[9] Available at: http://www.sciencedirect.com/science/article/pii/S1364032114008284
[10] Available at: http://www.nature.com/nclimate/journal/v5/n4/full/nclimate2564.html
[11] Available at: https://www.teslamotors.com/powerwall
[12] Available at: https://www.wecc.biz/Reliability/2014_TEPPC_Generation_CapCost_Report_E3.pdf

installation costs. E3 modeled replacement of the battery pack in year 8 and replacement of the battery power conversion system in year 10. Replacement costs are assumed to be equal to the capital costs of the replacement item in the year of replacement (not including the 15% adder).

Cost and performance assumptions for energy storage technologies are summarized in the tables below.

Table 7. Energy storage performance and resource potential by technology

Charging Efficiency	Discharging Efficiency	Financing Lifetime (yr)	Replacement (yr)	Minimum duration (hrs)
92%	92%	16	8	0

Table 8. Energy storage cost assumptions

	Cost Metric	2020	2025	2030
Mid	Storage Cost ($/kWh)	238	200	183
	Power Conversion System Cost ($/kW)	247	217	204
	Fixed O&M Battery/Reservoir ($/kWh-yr)	4.8	4.0	3.7
	Fixed O&M PCS ($/kW-yr)	4.9	4.3	4.1
Low	Storage Cost ($/kWh)	175	141	121
	Power Conversion System Cost ($/kW)	158	133	119
	Fixed O&M Battery/Reservoir ($/kWh-yr)	3.5	2.8	2.4
	Fixed O&M PCS ($/kW-yr)	3.2	2.7	2.4
High	Storage Cost ($/kWh)	444	366	366
	Power Conversion System Cost ($/kW)	365	358	358
	Fixed O&M Battery/Reservoir ($/kWh-yr)	6.7	5.5	5.5
	Fixed O&M PCS ($/kW-yr)	5.5	5.4	5.4

4.1.1.7 Reserve Requirements

System security and reserve requirements, including forecasted needs. These were calculated by GE[13] and included in the previous filing.

4.1.1.8 Day Sampling and Day Weights

To reduce problem size, E3 developed a methodology for selecting a sample of days from a larger set and applying weights appropriately to reflect the long-run distributions of key

[13] Power Supply Improvement Plan Update Interim Status Report, February 2016, Page 4-21.

metrics including hourly load, hourly solar, hourly onshore wind, hourly offshore wind, and hourly net load. The load and renewable shapes from 2014 were used. In total, the scenarios presented here include 41 sampled days for each investment year.

4.2 Transportation

There are two transportation cases. The first assumes a direct electrification policy where the vehicle fleet becomes all electric by 2035. The other is a produced fuels case, where hydrogen and LNG are used as vehicle fuels. These cases are not intended to be predictive but represent maximum technical potential estimates of electrified transportation demand.

4.2.1 Direct Electrification

The direct electrification case is a variant of the Reference Case where higher amounts of electric vehicles are adopted over time, changing the forecasted electric load. The other factors of the Reference Case remain the same. The electric vehicle adoptions are determined based on forecasted aggressive EV policy impacts that cause penetrations of EVs in light-duty auto and truck subsectors to reach 100% by 2035.

4.2.1.1 Case defining inputs

- Electric vehicle sales and corresponding annual load associated with them. Stock rollover combined with a 2035 100% EV target is used to generate the load increases in each year. Adopted electric vehicles have a fixed charging profile.

4.2.2 Produced Fuels

The produced fuels case assumes there is a hydrogen and synthetic gas economy developed on Hawaii through investment in the necessary infrastructure to support it. This includes increased hydrogen and synthetic methane production capabilities and development of storage facilities. Penetrations of hydrogen fuel-cell vehicles in light-duty auto and truck subsectors reach 100% by 2035. Penetration of hydrogen fuel cell vehicles in freight truck subsector reaches 50% by 2035 due to range and duty-cycle limitations. Penetration of LNG vehicles in freight truck subsector reaches 50% by 2035. The cost of the infrastructure to produce fuels is very uncertain. In this analysis E3 does not try to quantify those costs. Instead, the incremental costs of operating the reference case system with and without hydrogen infrastructure is calculated to show the estimated incremental cost impact from all other infrastructure investments to meet the RPS goals.

4.2.2.1 Case defining inputs

- Hydrogen and LNG vehicle sales and corresponding annual load associated with the production of fuels. Stock rollover combined with a 2035 produced fuel vehicle fleet target of 100% is used to generate the load increases in each year based on the experience E3 has in modeling decarbonization for the US with its PATHWAYS model[14]. Hydrogen and LNG production is different from electric vehicles because the production of fuel is uncoupled from the use of the vehicle. This case therefore has more flexibility in how it affects load profiles: the gas production infrastructure behaves like a large battery system. However, the losses involved in producing and consuming fuels result in significantly higher load increases than the Direct Electrification case. Both the peak MWs and the quantity of produced fuel storage are key variables in sizing a system like this. The costs of this type of infrastructure are very uncertain. This analysis assumes a peak MW production of fuels of 25% of peak load as a first cut investigation into produced fuel viability.

E3 generated the annual electricity load corresponding to the Reference Case and each of the transportation scenarios using stock rollover logic. These are paired with vehicle charging characteristics in the case of EVs to develop a flexibility constrained resource from the aggregate electric vehicles. The dataset contains the following inputs:

- Vehicle stock. The forecasted vehicles of each type, in each year, and in each case.
- Final energy demand. The final energy demand of vehicles of each type, in each year, and in each case.

[14] Policy implications of deep decarbonization in the United States, November 2015, http://usddpp.org/downloads/2015-report-on-policy-implications.pdf

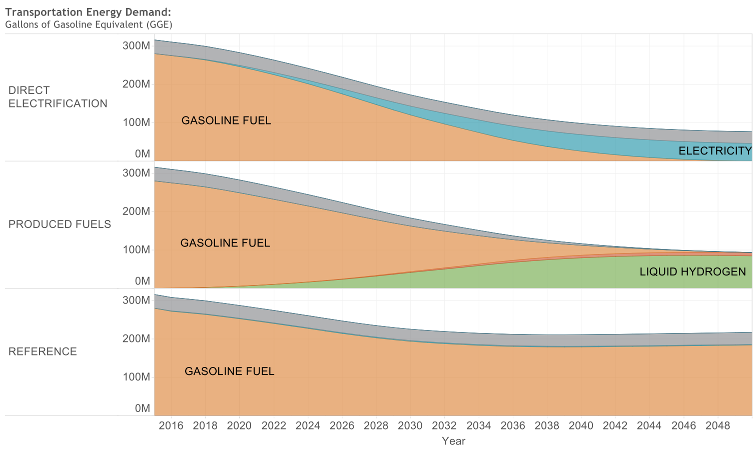


Figure 7. Transportation fuel mix under different transportation policy scenarios

- Electricity load. The change in annual load cause by vehicles of each type, in each year, and in each case.

Figure 8. The additional electric load over the Reference case in each of the transportation cases

4.3 Flexible loads

This case is a variant on the Reference Case that assumes policy incentivizing greater flexible load participation by customers. This case assumes a greater level of investment in controls infrastructure and development of tariffs or compensation mechanisms that support participation and make possible the dispatchability of demand side technologies such as space heating, space cooling, and water heating. E3 models a portion of these end-uses as flexible within constraints on total daily end-use energy demand as well as minimum hourly demand and maximum hourly demand on each day.

Load flexibility (also referred to as demand response or DR) can serve as an important resource for keeping Hawaii's electricity grid stable, resilient, and efficient while facilitating the transition to high penetration levels of renewable energy and providing economic benefits to HECO's ratepayers. HECO has already begun conducting studies on the potential of a range of end-use loads to provide various grid services such as ramping, regulating reserve, and contingency reserve. In addition, residential, commercial, and industrial end uses may be able to provide system value by shifting load to times of high renewable generation levels, making it possible to utilize renewable energy that might otherwise be curtailed. Achieving dispatchability of demand side technologies such as space heating, space cooling, and water heating would require investment in controls infrastructure and development of tariffs or compensation mechanisms that support participation. E3 uses HECO's DR potential studies as a basis to derive reasonable estimates for the portion of these end-uses that may be dispatchable.

E3 also uses end-use load profiles developed for the California State Agencies' PATHWAYS[15] project to derive operational constraints including daily end-use energy demand, minimum hourly demand and maximum hourly demand on each day. While an accurate assessment of flexible load potentials and characteristics over the next 30 years is not possible, E3 includes a treatment of flexible loads in the RESOLVE model with the goal of understanding the benefit of flexible load capability to HECO's future grid and the operational characteristics that may be most valuable.

4.3.1 Case defining inputs

- Annual flexible load technology adoptions along with parameters defining their behavior in dispatch. These are included in the attached spreadsheet titled "DR_Potentials". Included in the spreadsheet are the components needed to model different levels of flexible loads in REFLEX, including:
    - HECO's annual energy and peak demand projections by end-use
    - HECO's estimates of DR program potential
    - E3 calculations of fractions of end uses that are shiftable
    - Demand profiles by end-use developed for the California State Agencies' PATHWAYS study

[15] California State Agencies PATHWAYS Project: Long-term Greenhouse Gas Reduction Scenarios, April 2015, http://www.arb.ca.gov/html/fact_sheets/e3_2030scenarios.pdf

- HECO end-use annual energy demands shaped with PATHWAYS demand profiles

4.4 Flexible Electrification

This case investigates the impact on incremental cost of meeting the RPS and the investment decisions made to get there when both flexible loads and smart charging EV policy are adopted. The combined impact of these two policies will increase the balancing capabilities of the system and reduce the need for other flexibility solutions, such as battery investments.

4.4.1 Case defining inputs

- This case is a combination of the Flexible Loads case and the Direct Electrification Transportation case with modifications. The modifications include a characterization of the flexible charging capabilities of the EV fleet, increasing the balancing capabilities of that resource.

4.5 Limited Renewables

4.5.1 Limited Wind

With plans existing for up to 1200 MW of offshore wind, this could be a valuable resource for Oahu to reach its RPS targets. There is not enough potential on the island itself to meet 100% RPS, therefore additional resources must be procured. The options considered in the previous PSIP filing include offshore wind and imported biofuels. The results from the RESOLVE model will show that if offshore wind procurement is unconstrained a significant number of MWs are selected as part of a least cost portfolio over the next 30 years in many of the E3 cases. This case investigates how the solution changes if offshore wind development is constrained.

4.5.1.1 Case defining inputs

- This is a variant of the reference case and includes a cap on the total offshore wind that can be online of 400 MW.

4.5.2 Limited Utility Scale Solar Potential

NREL recently revised down their estimate of how much utility scale solar potential exists on Oahu. In this case we explore how the build decisions are affected over the course of the planning period if utility scale solar resources are limited to 600 MW.

4.5.2.1 Case defining inputs

- This is a variant of the reference case and includes a cap on the total utility scale solar of 600 MW.

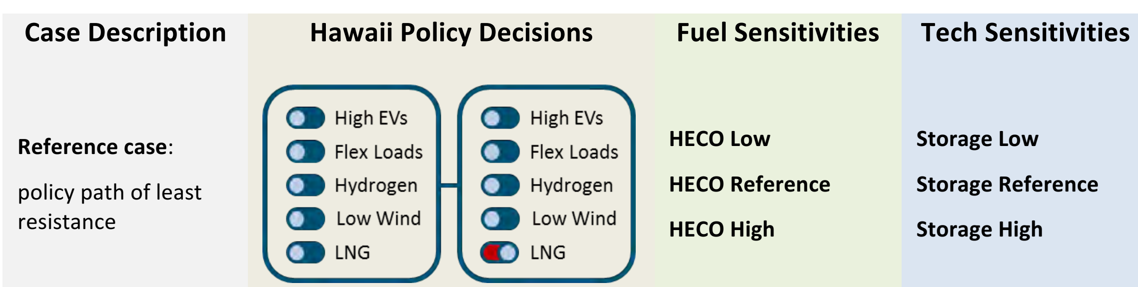
5 Results

The cases investigated are listed below in Figure 9. Each of the cases represents a set of policy decisions that could be taken by Hawaii to influence how the long term RPS goals are met. The cases all include fuel and technology price sensitivities. The fuel price sensitivities include the HECO low, reference, and high fuel price trajectories. The price of storage is also varied to determine the effect on investment decisions.

Each case is run for both the policy decision to invest in LNG and the policy decision not to. By including the evaluation of LNG in all cases, E3 focuses specifically on the near term decision facing HECO by investigating how that decision might impact the long term investments to meet Hawaii's RPS targets.

The costs reported for each case are the total annualized investment costs and variable costs related to energy production. They do not include the infrastructure costs for LNG such as storage, delivery terminal facilities etc, the cost of electric or produced fuel vehicles, EV charging and hydrogen production and storage infrastructure, existing infrastructure costs, or costs for new transmission and distribution investments.

The difference in cost between the LNG and non LNG variants can be thought of as the breakeven cost between investing in LNG infrastructure and staying with fuel oil. For the particular fuel and technology price scenario, if LNG infrastructure costs less than the difference between the two variants, then LNG investment is a cost effective decision.



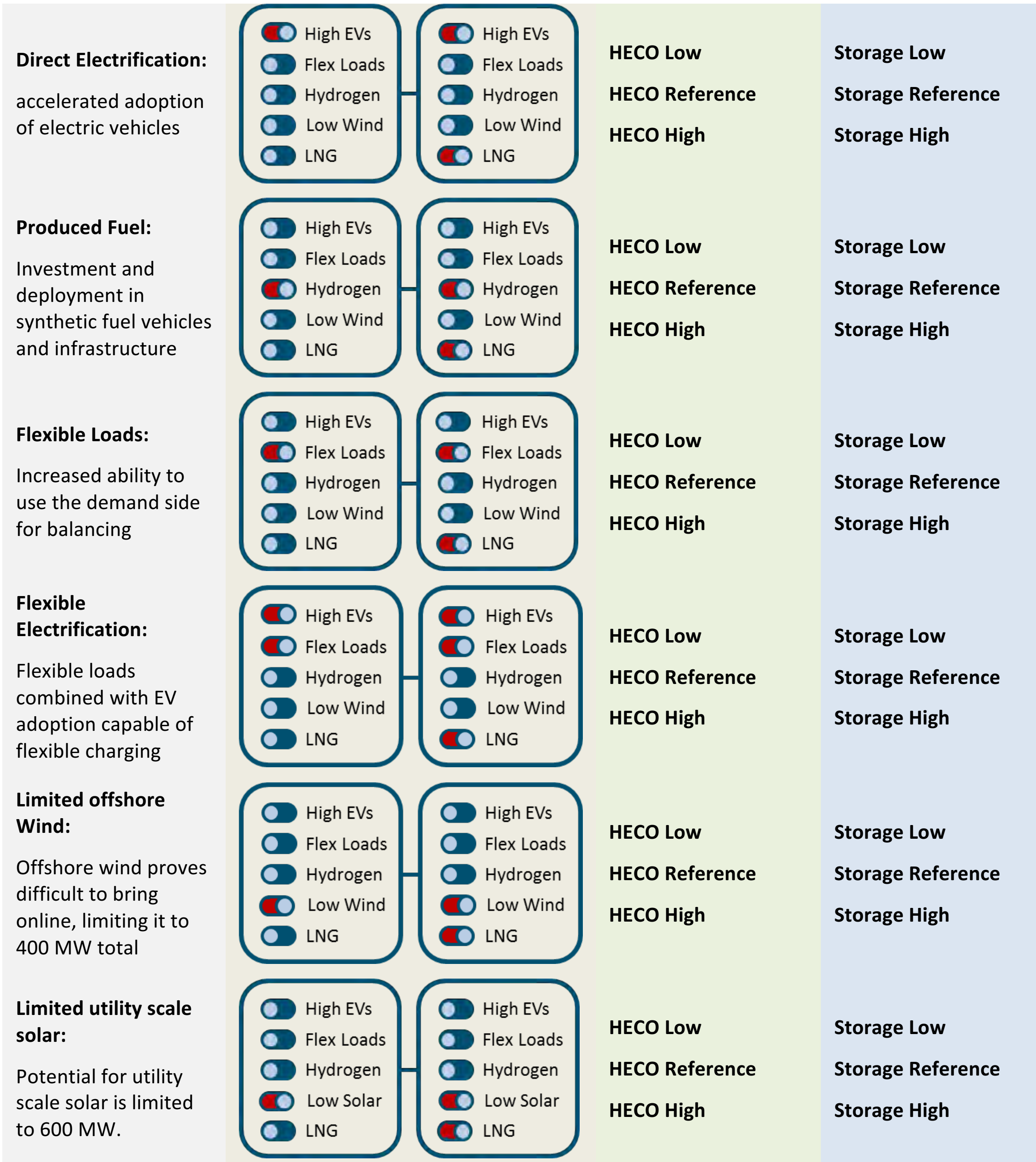


Figure 9. Case descriptions

As specified in section 2, the questions we investigate in this analysis are as follows:

- Should Hawaii build LNG infrastructure?
- How do the different policy cases rank in total cost, or impact to ratepayers, under the different fuel and technology cost scenarios?
- In each of the policy cases, what are the major investment decisions, and when are they made?

We use a 5 year time step across the modeling period from present day out to 2045. The investment decisions made in each time step represent investments determined to be made in that year or the 5 years around that year. For example, investments identified for the 2020 time step represent investments any time between mid-2017 to mid-2022.

For many of the cases presented below, LNG fueled generating capacity remains in 2045. We assume that the LNG contract ends in 2040, and that this capacity is converted to biofuels in 2045 or before to comply with the RPS targets. However, we retain the LNG designation for this capacity in the results to indicate that it is not new build, and to differentiate it from dedicated new construction biofuel generation.

In order to develop and present results in the limited time available for the study, we focused only on meeting the Hawaii state RPS targets. This allows an apples-to-apples comparison of the presented results for better understanding of the dynamics between different resource selection decisions.

5.1 Should Hawaii build LNG infrastructure?

To investigate whether Hawaii should build LNG infrastructure, E3 used RESOLVE to find the annualized operating cost and incremental investment cost of new assets for each of the policy cases and each of the HECO fuel price forecasts. These are shown in Figure 10 below for the year 2030. These costs include the investment in new LNG power plants and the operation of those plants. In every case, the LNG variant is significantly less expensive.

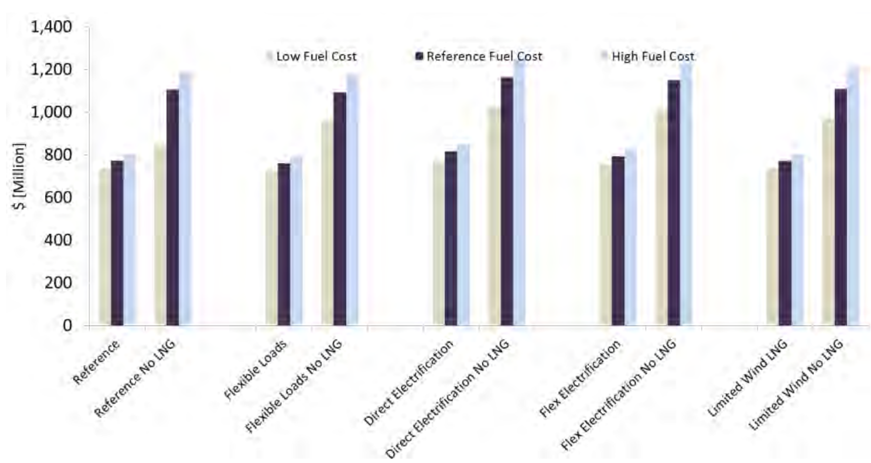


Figure 10. Total annualized fixed (incremental new investments) and operating costs in 2030

The difference in cost between the LNG and No-LNG cases is the amount that HECO can invest in LNG infrastructure, such as storage capacity, while still remaining below the cost of the alternative No-LNG case. Table 9 shows the difference in cost under each of the fuel price sensitivities. If the annualized cost of the LNG infrastructure is less than ~$112M in the low fuel price case to ~$383M in the high fuel price case then LNG is found to be cost effective for this set of assumptions in the Reference case. In the other policy cases, the low fuel cost scenario has a larger barrier to cost effectiveness for LNG.

Table 9. Annualized fixed and operating cost savings in 2030: LNG vs no-LNG case

Cost Savings $M/yr	Fuel Price Sensitivity		
Case	**Low**	**Reference**	**High**
Reference	112	334	383
EV	242	331	384
Flexible Loads	247	348	401
Flex Electrification	255	356	404
Limit Wind	236	336	399

These benefits depend on the spread between LNG and fuel oil. The decision to invest in LNG or not is therefore strongly tied to the HECO fuel forecast assumptions. Figure 11 shows the incremental capacity additions and retirements in each of the periods studied. In the LNG case, the first MWs of LNG capacity are selected in 2020. That capacity is then expanded in 2025 and 2035. The long term projection of relative fuel prices is therefore important in deciding whether to invest in LNG or not.

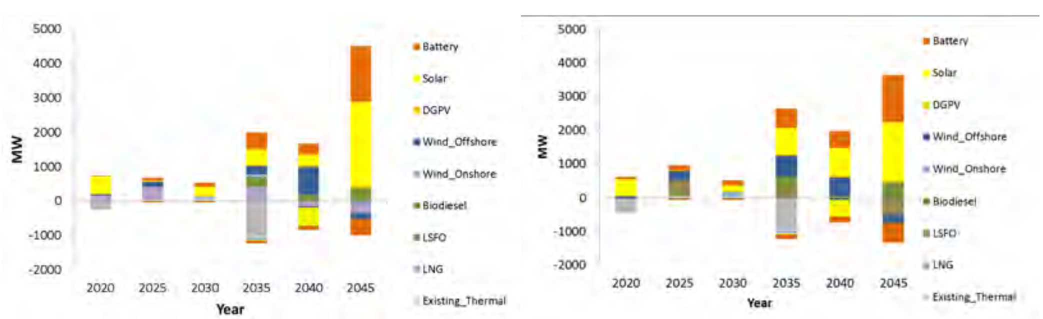


Figure 11. Reference case incremental additions and retirements: LNG variant (left) No-LNG variant (right)

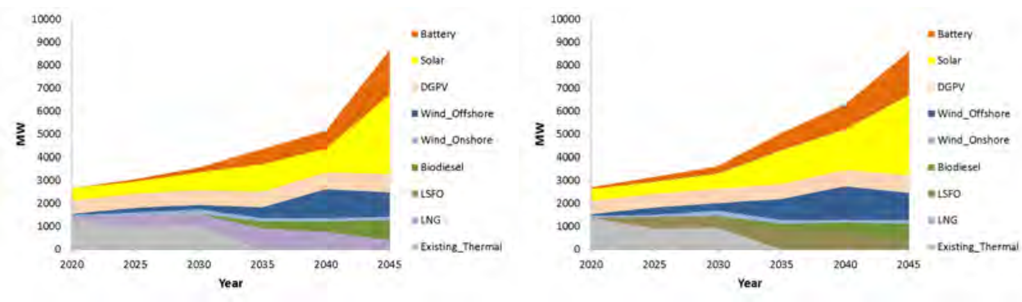


Figure 12. Reference case resource mix by technology type: LNG variant (left) No-LNG variant (right)

Though fuel costs could have a significant impact on the decision to invest in LNG, the total cost of meeting RPS goals is dominated by capital investments. Low variable cost but high fixed cost resources, including batteries, photovoltaics and wind, see the largest procurement over the period of study. Fuel costs will represent a diminishing portion of revenue recovery – the increasing proportion of renewables and storage infrastructure will act as a hedge against global fuel price volatility.

In the Reference LNG case, for example, the incremental annual fixed costs attributed to new resource additions increase to nearly $2billion per year by 2045. Figure 13 shows the progression of the incremental fixed costs over the period of study and Figure 14 shows the corresponding operating cost. Even by 2025, the operating cost becomes relatively small compared with the incremental fixed costs. This is before including fixed costs related to existing infrastructure, supporting LNG infrastructure, and new distribution and transmission infrastructure. As the RPS increases, the importance of fuel costs in resource procurement decisions becomes marginalized. Figure 11 shows LNG being installed in 2035 but beyond that time period, only fuel switching to biodiesel is selected from conventional generation options.

In all cases, the increase in cost over the 5 year period from 2040 to 2045 is significant, approaching an increase in annual fixed cost of ~$800M. This does not include the costs of distribution and transmission infrastructure required to support the transition to 100% RPS.

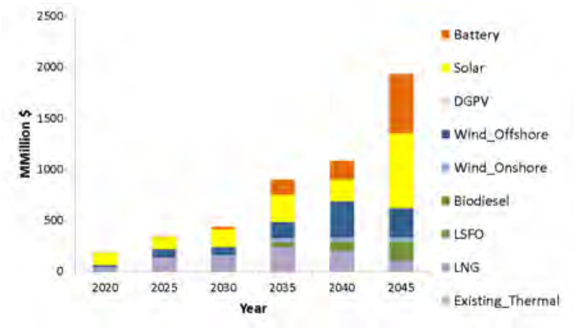


Figure 13. Annual incremental fixed cost from new capacity additions in the Reference LNG case

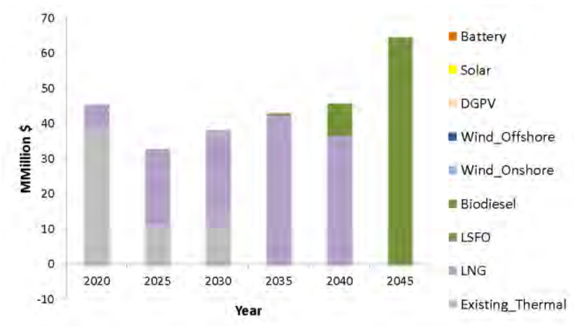


Figure 14. Annual operating cost of the system in the Reference LNG case

5.2 Which policy decisions are the most favorable?

In 2030, the most significant driver of differences in the annualized cost impact of reaching Hawaii's RPS goals is whether LNG is selected or not. Figure 15 shows the operating and incremental fixed costs of each policy scenario relative to the Reference case with Reference fuel assumptions. The range of each bar represents the low to high fuel scenarios.

The Reference No-LNG case is up to ~4 c/kWh of load higher cost in 2030 over the set of HECO fuel price assumptions. The result is similar in the Flexible Loads, Limited Wind, Direct Electrification (EV), and Flexible Electrification cases. These costs do not reflect the indirect costs of LNG such as the storage facilities.

The impact on costs of different policy scenarios are less pronounced in 2030. The effect of these policies is to change least cost procurement strategy over time. In 2030 the impact on procurement is relatively small due to the lower RPS. Flexible loads however show an impact of ~0.1 c/kWh of load savings in the LNG variant. The Direct Electrification case shows a slight increase of up to 0.2 c/kWh. Both the Limited Wind case and the Flex Electrification case change very little on a c/kWh basis relative to the Reference case.

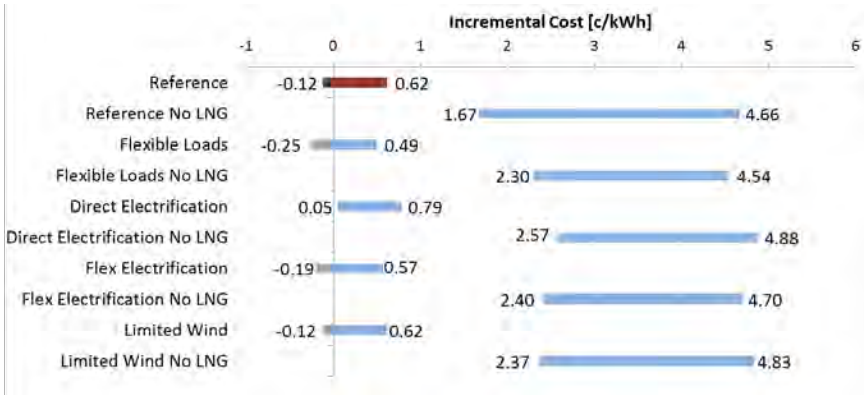


Figure 15. Comparison of operating and incremental fixed costs in 2030

In 2045, the procurement strategy in each of the cases varies quite significantly, yet the cost spread between cases is still relatively close, as seen in Figure 16 . The most favorable strategy is shown to the flexible electrification case. The benefits of this and the Direct Electrification case may be even more pronounced if electric vehicles as a replacement for conventionally fueled vehicles bring cost savings to consumers.

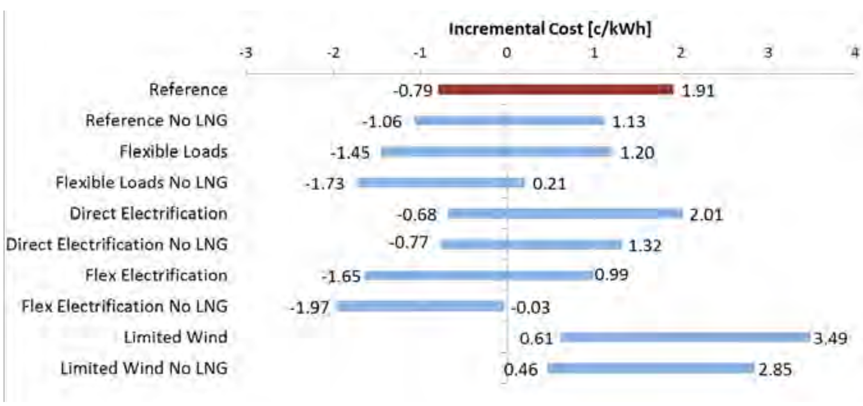


Figure 16. Comparison of operating and incremental fixed costs in 2045

5.3 In each of the policy cases, what are the major investment decisions, and when are they made?

Procurement decisions across the Reference, Flexible Load, Direct Electrification, and Flexible Electrification scenarios remain relatively consistent. Figure 17 through Figure 20 present the procurement and retirement decisions and the total installed capacity for each technology type.

In all cases, the scheduled retirements of ~1000 MW of existing thermal generation happen in 2035 and must be replaced with new resources[16]. The new resources include a combination of new LNG and biofuels and additional renewables alongside battery storage. LNG represents a diminishing but important balancing resource through 2045. The LNG in 2045 shown in the results below is used only to offer contingency reserves, and is assumed to be converted to biofuel.

The flexible load cases reduce the total procurement of batteries, explaining some of the savings of those cases over the Reference. In all cases, the majority of battery procurement happens in 2035 and beyond, with most batteries procured in the final 2045 time period. The significant jump from 70% to 100% RPS in the final time period triggers building over 2000 MW of solar over a 5 year period, requiring storage build of over 1500 MW to utilize the solar produced energy.

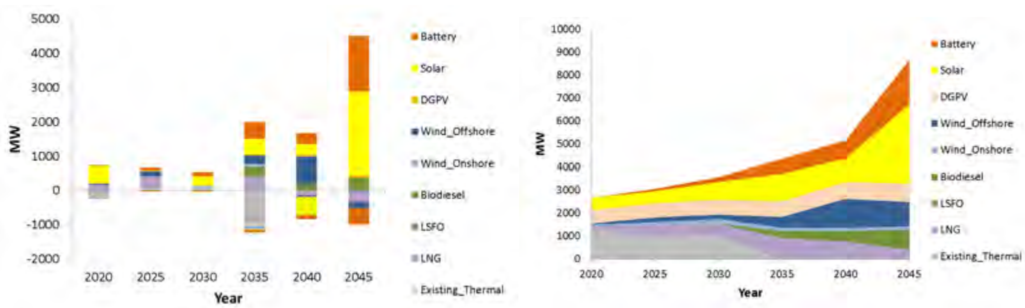
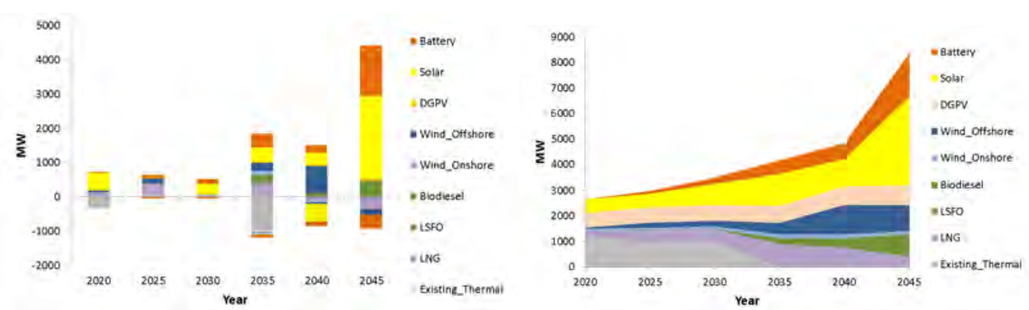


Figure 17. Reference Case LNG: capacity retirements and installations (left), total installed capacity (right)



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[16] The Oahu existing resource characteristics, including retirement dates, were taken from data provided by HECO to E3 on November 25th 2015 in support of their efforts to estimate system interconnection limits for uncontrolled DGPV.

Figure 18. Flexible Loads LNG: capacity retirements and installations (left), total installed capacity (right)

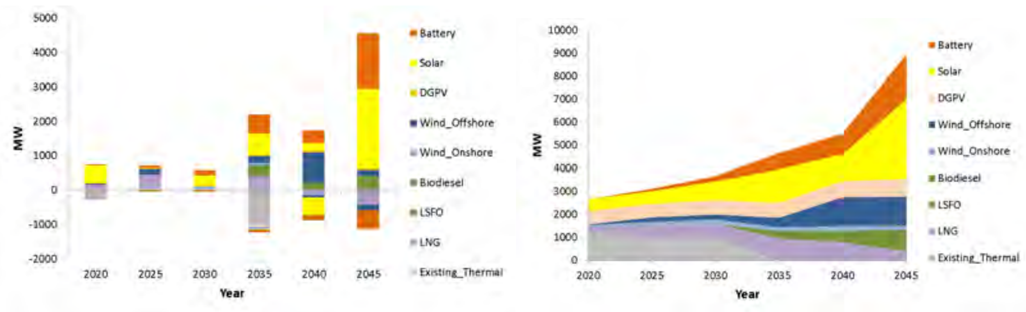


Figure 19. Direct Electrification LNG: capacity retirements and installations (left), total installed capacity (right)

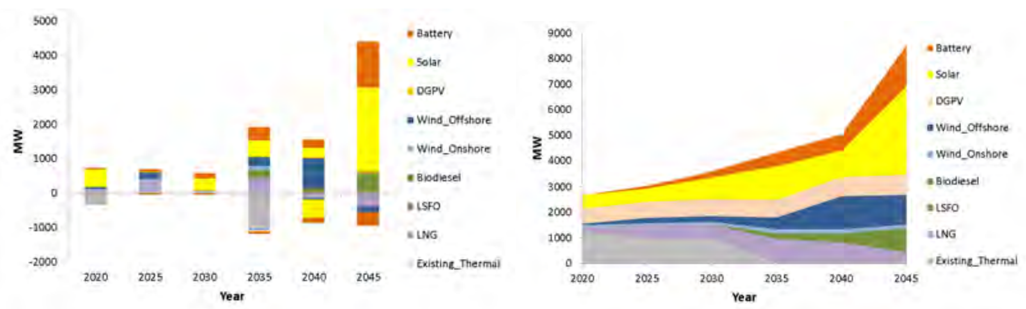


Figure 20. Flex Electrification LNG: capacity retirements and installations (left), total installed capacity (right)

In all cases, the limit to renewables that can be installed on Oahu Island is reached, requiring procurement of off-island generation. Off-island options in RESOLVE include offshore wind generation and imported biofuels. The cases presented above allow unlimited procurement of offshore wind. Total installed wind peaks in 2040, and remains above 1000 MW through 2045. The impact of limiting the offshore wind potential to 400 MW is shown below in Figure 21.

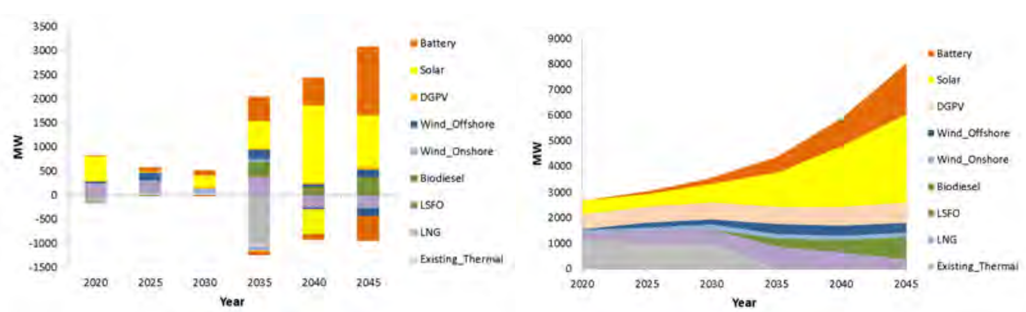


Figure 21. Limited Wind LNG: capacity retirements and installations (left), total installed capacity (right)

The full island potential of utility scale solar is reached in 2045 in the unlimited wind cases. Prior to that, offshore wind is procured, adding capacity in 2025, 2035, and 2040. Limiting offshore wind capacity to 400 MW pushes procurement of utility scale solar and batteries into earlier years.

Limiting the onshore utility scale PV potential to 600 MW triggers a transition to offshore wind with 800 MW installed by 2035 and 2700 MW installed by 2045 compared to 450 MW and 1050 MW in the Reference case, respectively. The number of biofuel MWs is also higher in the limited solar case compared to the Reference, increasing from 860 MW to 1100 MW in 2045, while the number of batteries drops by 500 MW. Batteries are required to shift solar overgeneration energy in the middle of the day in the Reference case. This service is reduced in the low solar case because wind produces energy in all hours rather than just during daylight.

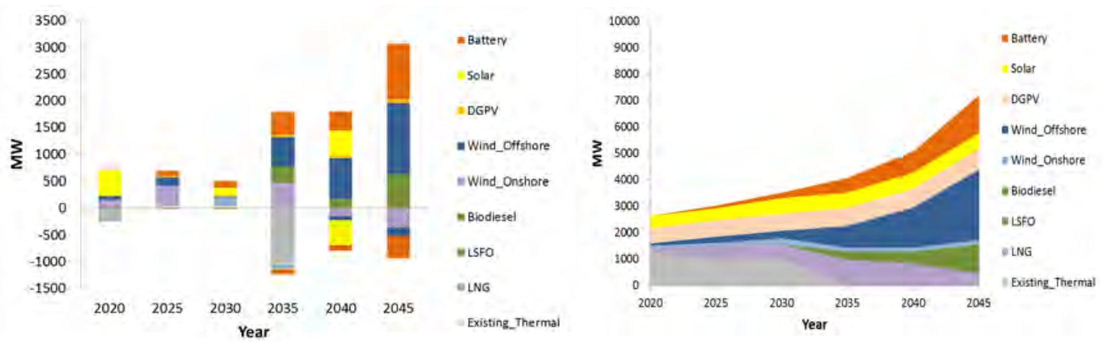


Figure 22. Limited Solar LNG: capacity retirements and installations (left), total installed capacity (right)

The capacity of offshore wind needed to meet RPS requirements in 2045 is large at 2700 MW – a number that has not currently been shown as available to the island. In the case where wind is capped at a lower amount, the remaining RPS requirement would be served by biofuels.

5.4 What is the impact on procurement when the price of storage is varied?

In the low storage case in Figure 23 below, 2150 MW of storage is online in 2045, with 1030 MW of offshore wind and 860 MW of biofuels. This is not significantly different in the Reference case where 1940 MW of storage is online in 2045, with 1060 MW of offshore wind and 860 MW of biofuels. Lower storage prices than in the Reference case are not projected to significantly impact procurement decisions. However, moving to the high storage cost trajectory shown in Figure 25, the amount of storage selected drops to 1020 MW, offshore wind increases to 2490 MW, and 1110 MW of biofuels are online. In addition, total utility scale solar online in 2045 drops from the maximum potential of 3450 MW to 1300 MW. With the projected cost assumptions in the Reference case inputs, procurement decisions in the least cost solution are clearly sensitive to increases in the storage price.

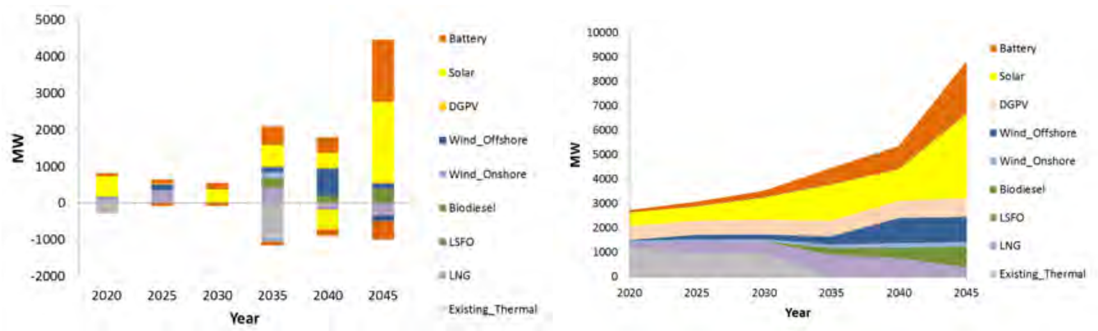


Figure 23. Low storage cost: capacity retirements and installations (left), total installed capacity (right)

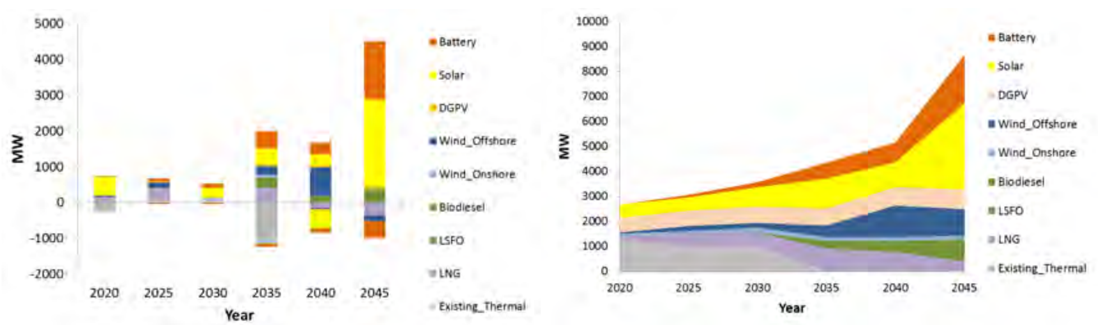


Figure 24. Reference: capacity retirements and installations (left), total installed capacity (right)

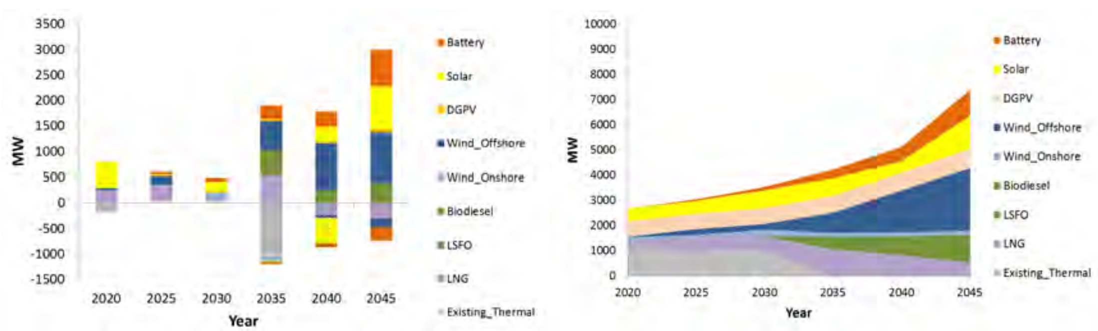


Figure 25. High storage cost: capacity retirements and installations (left), total installed capacity (right)

Higher storage prices can dramatically change the nature of the solution to RPS compliance. Across storage price variants though, the build decisions between now and 2030 remain consistent. Furthermore, storage is a short lead time investment whose optimal deployment is contingent on storage and PV pricing in each year. Investments in longer lead time resources such as LNG that require active policy measures to implement are relatively unaffected by storage pricing. These factors make storage pricing benign as a factor influencing near term planning decisions.

Storage is only one capital investment in a capital dominant portfolio of resources, required to reach 100% RPS by 2045. The decisions made, and the cost of the overall solution will be sensitive to the costs of all of the resources selected, including storage, wind, solar, LNG, and biofuels. Additional work is needed to explore the uncertainties in capital costs and the potential effects those uncertainties have on the decisions going forward.

5.5 How much curtailment is included in least cost operations?

Curtailment of renewables can be a low cost solution to achieving RPS targets. When curtailment first starts happening, only small amounts of energy on particularly problematic days need to be curtailed. An example problematic day could include high solar and wind output coupled with an unusually low midday load that occurs about once a year. If this is the first day of the year where curtailment starts to happen as renewables installations rise, the resulting energy lost only on that day will amount to a very low total energy over the year. As renewable installations rise further however, curtailment will start to happen on other days as well, until curtailment becomes a regular feature in daily dispatch. Higher levels of curtailment start to become more costly as increasing amounts of annual energy are discarded.

In each case run in this analysis, the RESOLVE model makes the least cost tradeoff between curtailing renewables and building other competing integration solutions, for example storage, LNG, and biofuels. The matrix below shows the curtailment levels found for each case. The cost of curtailment is the building of additional renewable capacity to meet the RPS requirements. The tradeoff is therefore the building of some additional renewable capacity against the building of alternative capacity that can prevent curtailment like storage or more flexible generating capacity.

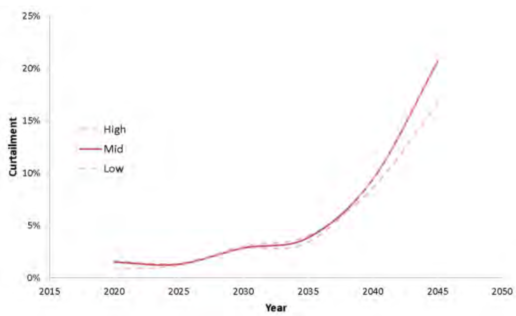
This tradeoff is evident for each of the cases – the low cost fuel scenario has less curtailment because the alternatives become cheaper. This trend however is far less pronounced in the

LNG case than the No-LNG case. Since LNG is more competitive than fuel oil, the levels of curtailment remain lower and fuel cost does not strongly affect the curtailment level.

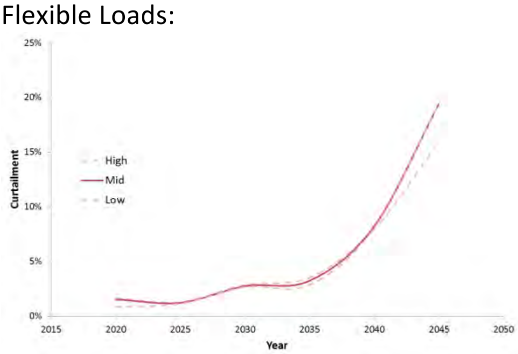
As with the procurement decisions, the Reference, Flexible Loads, Direct Electrification and Flex Electrification cases all follow a very similar curtailment pattern, though that pattern is significantly different when comparing LNG vs No-LNG. In both the LNG and No-LNG variants, curtailment reaches around 20% of all renewable annual energy by 2045. Curtailment decreases in the final years of the limited offshore wind case, reflecting the limited resources available on the island. In 2045, all solar and wind resources are built, therefore building batteries to utilize more of that generation is in direct competition with biofuels. More batteries are built and the total curtailment falls to 10%.

Case With LNG

Reference Case:



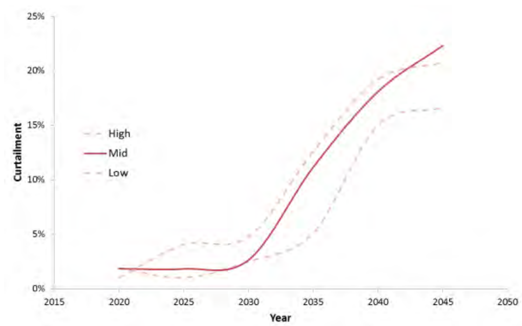
Flexible Loads:



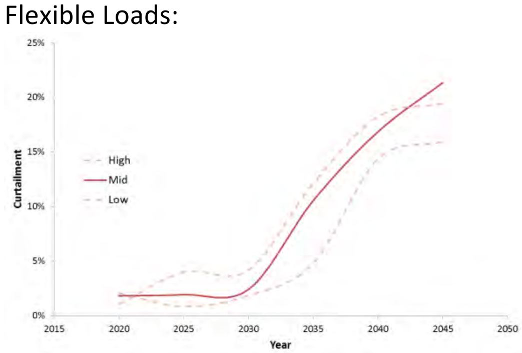
Direct Electrification:

Case Without LNG

Reference Case:



Flexible Loads:



Direct Electrification:

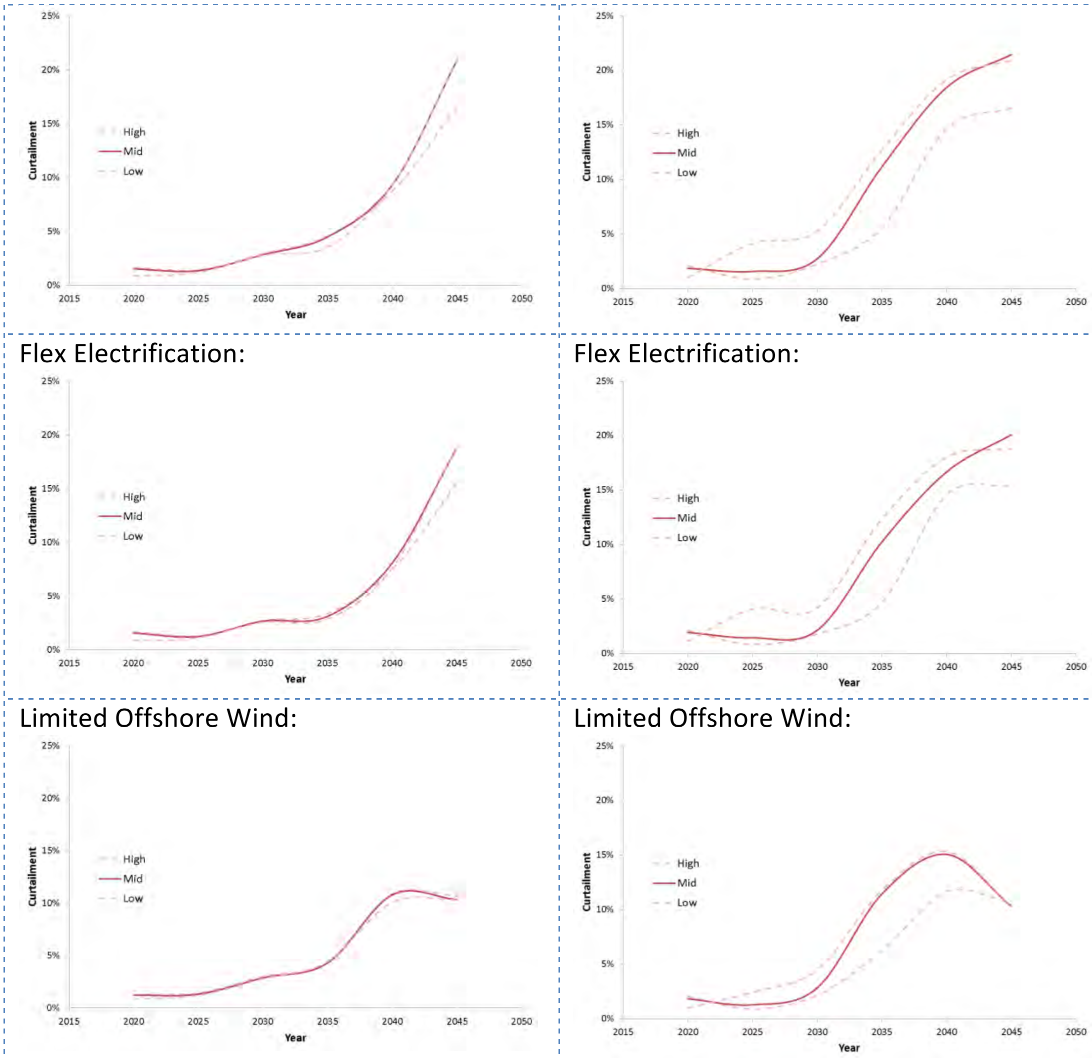


Figure 26. Matrix of renewable curtailment by case

5.6 How does the Produced Fuels case compare to Direct Electrification?

The Produced Fuels case assumes full conversion to synthetic fuel vehicles by 2035, thus adding a large amount of annual electric load to serve the transportation demand. In an already resource-limited system such as Oahu's, this scenario would be a difficult – maybe even infeasible – as it would require additional renewable resources for fuel production. As converting biofuels for hydrogen and synthetic methane fuel production is not a sensible solution due to the cost and inefficiency of such a process, relying on increased the deployment of offshore wind would likely be needed to pursue this pathway. Providing balancing for wind energy, however, poses challenges distinct from those encountered in a solar-dominated system. 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. Figure 27 shows the distribution of daily capacity factors based on 2014 offshore wind data: 12% of all days had average capacity factor of less than 10% while 3% of days had average capacity factors of more than 90%.

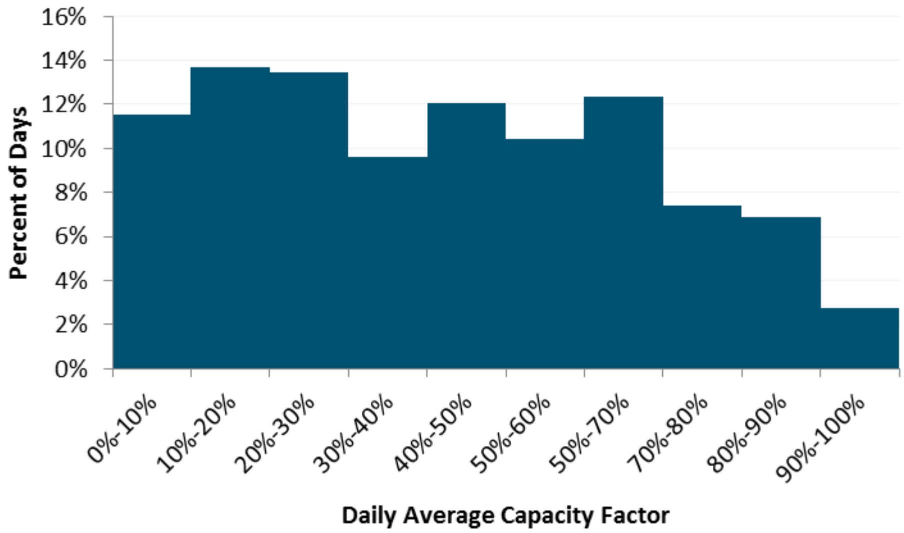


Figure 27. Distribution of daily capacity factors of offshore wind (2014 data).

The balancing requirements of wind are therefore different from those of solar, as wind cannot be balanced on a diurnal basis. Wind patterns can often persist for days or even weeks. In its current formulation, RESOLVE models independent days only, so cannot capture these wind balancing dynamics. Further model development would be required to fully investigate decarbonization pathways heavily dependent on wind deployment.

6 Next Steps

Given the limited amount of time available, the scope of this study was necessarily limited to an initial exploration of the solutions available to Hawaii to integrate 100% renewables. This type of planning framework and system modeling can be used to answer an extensive array of questions about specific planning options or least cost portfolio planning in general. In the study presented above, there are several additional components identified as useful for further study in the PSIP context:

1. The fuel cost spreads in the HECO provided fuel cost scenarios are a major driver of cost effectiveness of LNG. The resulting fuel cost savings of the LNG case are offset by an unknown investment cost in LNG infrastructure. Extended analysis looking at both estimated infrastructure costs and additional forecasted fuel price spreads would improve understanding of the cost effectiveness of the LNG option. In addition, sensitivities on timing of the LNG investment could help understand the potential tradeoffs available between fuel cost savings in the near-term, and increased certainty around fuel price spreads longer term.
2. A key conclusion of the above study is that fuel costs, though important for making decisions about which short term capacity investments to make, are only a small part of the total investments that Hawaii will face when reaching 100% RPS. The majority of expenditure through 2045 is on capital assets including PV, wind, storage, and low capacity factor biofuel capacity. The impacts of how the prices of each of these technologies evolve over time, and how they evolve relative to each other, will have more influence on choices in Hawaii than fuel price sensitivities.
3. Total annual energy curtailment of resources is shown in the above study to give an idea of the tradeoff with investments in other integration solutions. However, to understand the tradeoff between overbuilding renewables and these other solutions, specifically storage in the later years, the cost of the technologies being selected on the margin is important to understand. For example, at total curtailment levels of 10% solar, the marginal curtailment of an additional MW of solar could be 50% or higher. At these levels of marginal curtailment, solar becomes significantly more expensive, and batteries can be more cost effective. Understanding the marginal curtailment and therefore why the least cost decision in a particular year is storage is useful to understand the dynamics of the investment choices, the expected operations required of the system, and inform the types of regulatory and policy choices that may be needed to achieve least cost operations.
4. Policy and regulatory choices in the above study are assumed implicitly in the case definitions. For example, EV incentives may be needed to reach such high electrification in the Direct Electrification case. However, there are many other regulatory and policy changes that would be required to reach the least cost operations modeled in RESOLVE. Examples could include contract structures that

allow for curtailment, efficient dispatch of resources offering curtailment, compensation for low capacity factor generation offering predominantly reserves etc. In further study, these potential barriers to effective implementation could be identified and solutions proposed.

5. In the study above, the technology types considered were necessarily generic. However, within each technology type there are multiple variants that offer a variety of different operating capabilities at different price points. For example, storage technology includes lithium ion, flow batteries, and many other variants that all have different capabilities, price points, and expected price evolution. A more comprehensive study could look at what the merits of each variant look like in context of the other technology solutions available. Furthermore, there are many novel integration solutions proposed with uncertain pricing and benefits. The RESOLVE model and framework can be used to evaluate the near and medium term value of these frontier technologies.
6. The produced fuels case is dependent on high levels of offshore wind development with seasonally varying production. Modeling of the sizing and costing of a system to serve Oahu effectively therefore needs to include a treatment of these wind characteristics. This type of analysis requires further model development.

ASCEND ANALYTICS REPORT

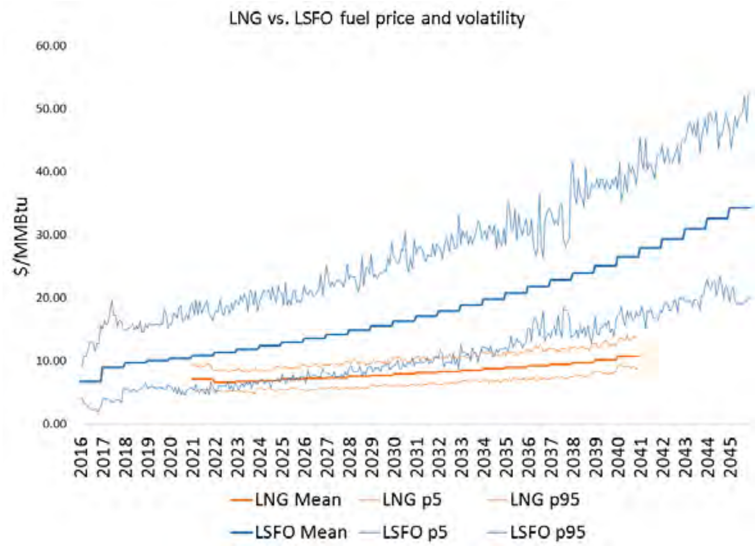
Overview of Current Status and Next Steps

Ascend Analytics' PowerSimm software has been applied to assess the ancillary service requirements and distribution of future production costs. Ascend has applied its PowerSimm stochastic simulation engine to probabilistically envelope future market and weather conditions impacting energy supply. This analysis is being performed on the O'ahu preferred plans (themes 1, 2 and 3). These results will monetize the risk that arises from fuel volatility and variant weather conditions to allow direct comparison between plans that trade risk for capital costs of renewable generation. The stochastic analysis also will be applied to assess the economic merit of renewable generation. This stochastic analysis will be repeated for the Hawaii Island and Maui preferred plans, as well as a pair of custom plans developed by Ascend. In addition, further refinements to the O'ahu plans will be made to ensure that the results are lined up properly with HECO's models. Results will be sent out as simulations are completed and checked.

Ascend has also developed Excel tools for forecasting regulation requirements on the island of Oahu, Maui and Hawaii. This tool allows Hawaiian Electric to understand the flexibility needs of a portfolio with high renewable penetration. Preliminary results and graphics from this tool are presented below.

Valuation of Risk

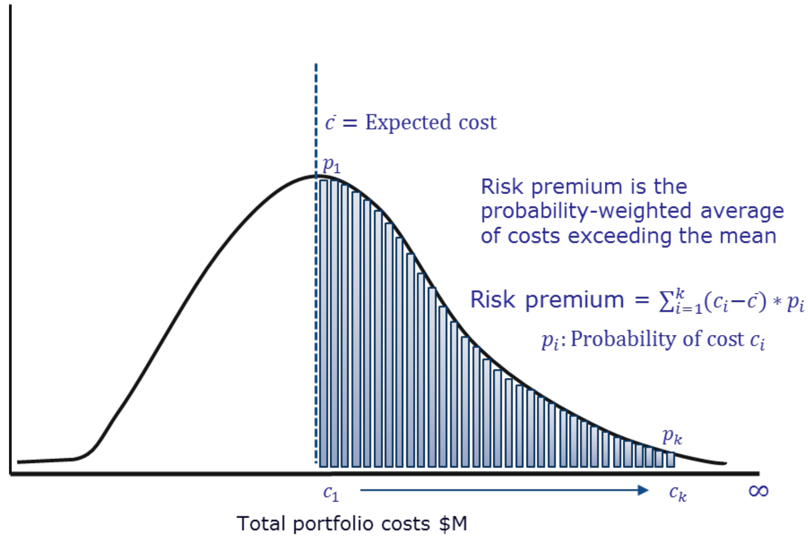
PowerSimm's simulation engine produces realistic simulations of fuel prices, load, renewable generation, and weather. These simulations are subjected to rigorous validation testing to substantiate consistency with underlying causal factor of weather for load and renewables combined with unexplained variability. Market prices for oil, LNG, and bio diesel are simulated based on market expectations of uncertainty through option implied volatilities. The following chart shows the mean, 5^{th} and 95^{th} percentiles of Ascend's simulation results for oil and LNG.



Given the validated simulation engine results for forward/forecast fuel prices, load, renewables, and weather, PowerSimm dispatches HECO's resources each iteration for all years of the study horizon in order to arrive at a distribution of future costs. The expected value of portfolio costs is therefore a robust metric to determine the cost ranking of the different portfolio options, but it does not capture the differences in risk between the portfolios.

PowerSimm monetizes the difference in the shapes of these distribution by use of the risk premium, defined as the integral of the cost distribution above the mean. This is similar to the approach taken by traders to evaluate the value of an option, or by insurance companies in valuing a policy. The derivation of the risk premium is illustrated graphically in the chart below.

Illustration of Risk Premium Concept



The risk premium can be added to the expected value to better approximate the full distribution of costs, and portfolios can be directly compared based on the sum of expected cost plus the risk premium. This risk metric improves upon traditional planning approaches such as cost-at-risk or efficient frontier analysis by providing a single number by which to compare portfolios, rather than requiring a planner to decide on a weighting between cost and risk.

NPV of Portfolio Costs for Themes 1-3

PowerSimm produces a Net Present Value (NPV) of the long-term costs of each plan by calculating future capital expenditures and generation dispatch costs associated with each theme scenario using a 7% discount rate, and includes the unique risk premium for each portfolio.

Assuming the same existing capital infrastructure currently in place for each scenario, we discounted the capital expenditures for each theme, which includes the construction for each new generation unit scheduled to come online in the next 30 years, as well as the costs associated with integrating DGPV units into the system. Generation dispatch costs are calculated using variable and fuel costs which were modeled after the predicted capacity factor for each unit.

Regulation Tool

The Ascend Regulation Tool is an interactive modelling tool that can be used to estimate 1 hour ramps and regulation for a variety of fixed scenarios for day-time and night-time requirements by scaling historical data to correlate with the forecasted load, wind and solar capacities. The regulation tool can query the output of these runs interactively, and allows for the option to choose DGPV forecast scenarios, observed year, and predicted incremental utility solar and wind capacity.

The 1-hour ramp statistic is calculated as the difference between the net-load at a given time and the net-load exactly 1 hour prior to that time. The maximum ramp for each year is reported both for the day-time and night-time. Regulation is calculated as the difference between net-load and load-following, where net load is load – solar – wind, and load following is a linear interpolation of net load through minute 0 of each hour. Regulation is then separated into regulation-up (regulation > 0) and regulation-down (regulation < 0) to remove bias from 0 regulation calculated at minute 0 of each hour. The 95th percentile of regulation-up and the negative of the 5th percentile of regulation-down are then averaged together to form the regulation requirement. These 1 sided confidence bounds combine to form a 95% confidence interval for regulation, without including the zero regulation calculated at minute zero of each hour.

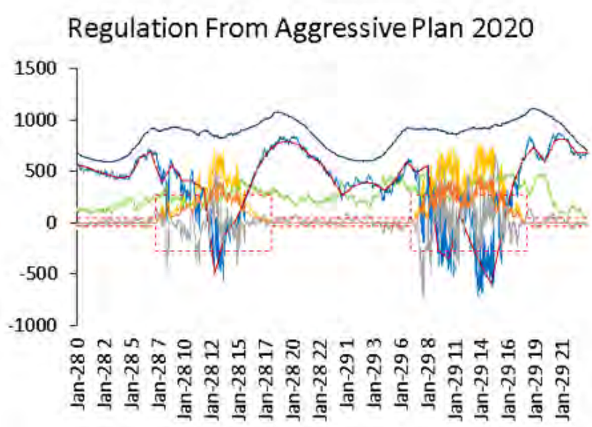
Graphs of regulation and ramps are included below for our internal scenarios as a sample of the key insights gained into load, utility solar, wind, DGPV, net-load, load-following, regulation, and regulation requirements.

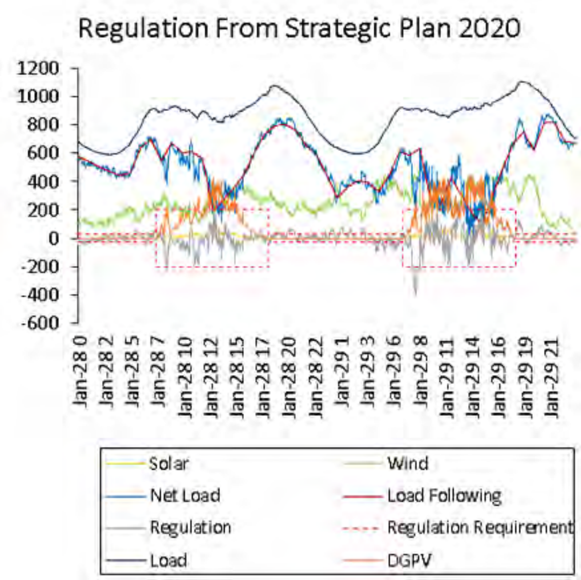
Regulation From Aggressive Plan 2020

Year	2020	
Day-Time Regulation	276	MW
Night-Time Regulation	38	MW
Day-Time Ramp Up	809	MW
Day-Time Ramp Down	(791)	MW
Night-Time Ramp Up	337	MW
Night-Time Ramp Down	(451)	MW

Regulation From Strategic Plan 2020

Year	2020	
Day-Time Regulation	203	MW
Night-Time Regulation	31	MW
Day-Time Ramp Up	611	MW
Day-Time Ramp Down	(582)	MW
Night-Time Ramp Up	265	MW
Night-Time Ramp Down	(395)	MW



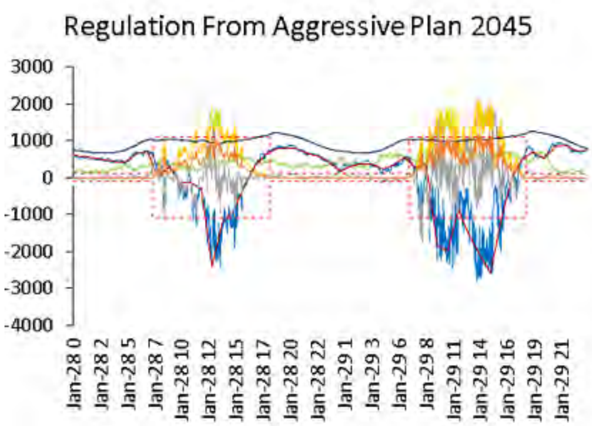


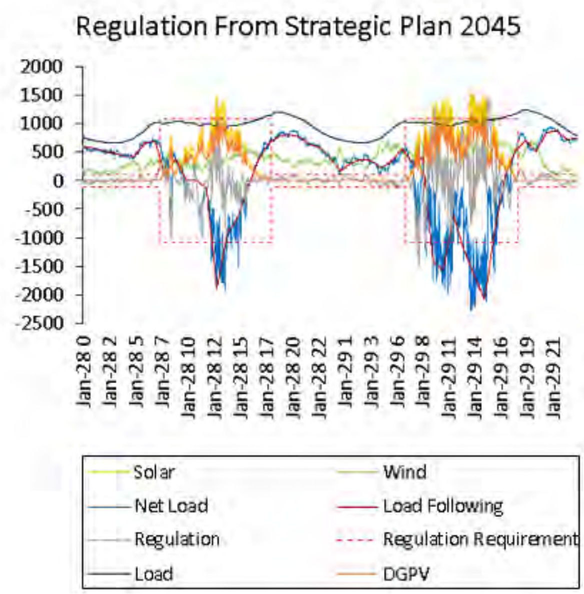
Regulation From Aggressive Plan 2045

Year	2045	
Day-Time Regulation	1,090	MW
Night-Time Regulation	103	MW
Day-Time Ramp Up	3,014	MW
Day-Time Ramp Down	(3,100)	MW
Night-Time Ramp Up	1,145	MW
Night-Time Ramp Down	(926)	MW

Regulation From Strategic Plan 2045

Year	2045	
Day-Time Regulation	1,090	MW
Night-Time Regulation	103	MW
Day-Time Ramp Up	3,014	MW
Day-Time Ramp Down	(3,100)	MW
Night-Time Ramp Up	1,145	MW
Night-Time Ramp Down	(926)	MW

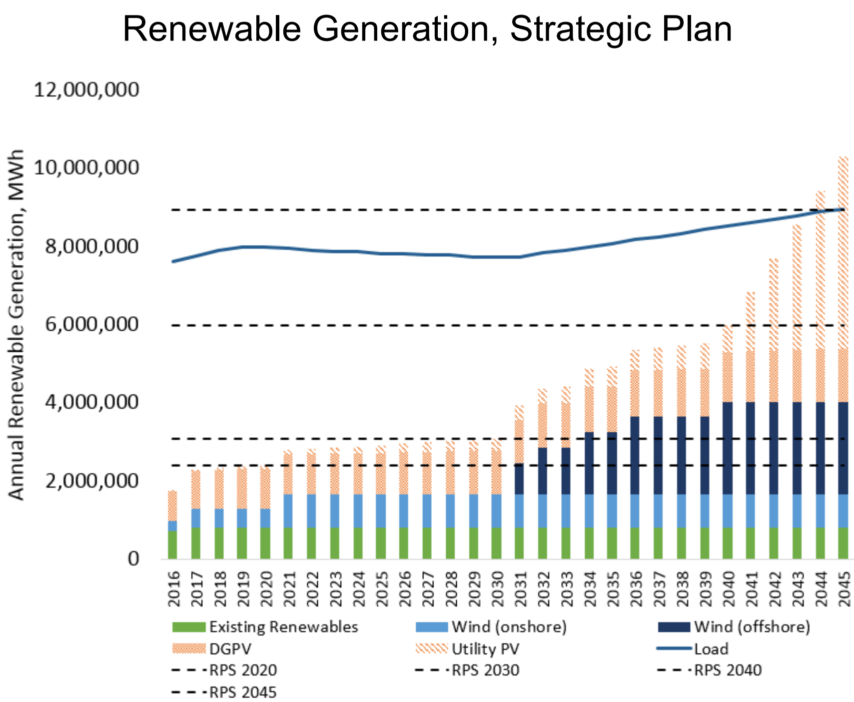


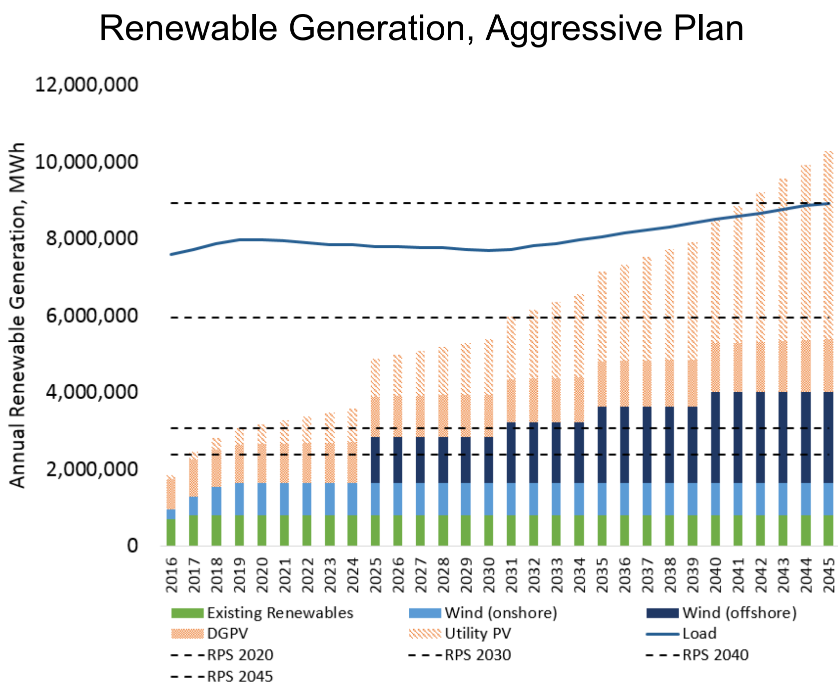


Next Steps - Ascend Expansion Plans

In addition to the preferred plan's put forth by HECO, Ascend created a pair of expansion plans for analysis. These plans were conceived with the objective of reaching the RPS goas purely with wind, solar and battery assets. Two alternate strategies were used to meet these targets, which we have dubbed aggressive and strategic. The strategic plan builds renewables at a deliberate pace, calculated to meet the RPS requirements exactly in each of the target years: 30% renewable energy in 2020, 40% in 2030, 70% in 2040, and 100% in 2045. Since the targets increase the most in the later years, the strategic plan starts slow, and ups the pace later on. The aggressive plan is an inversion of the strategic. It builds rapidly in the early years, vastly exceeding the RPS targets, and slows down in later years, eventually hitting the 100% target in 2045. The early presence of renewables allows this plan to enjoy lower exposure to fuel price risk, but this added security comes at a high cost.

The following charts show the renewable generation levels for the aggressive and strategic plans:





The heavy presence of renewable resources, particularly solar, in both plans results in large amounts of dumped energy during the day when solar generation far exceeds demand. The intermittent nature of renewable generation means that even when concentrated at utility scale, renewables are often unable to reliably serve load. Implementing battery technology as a storage solution can be used to capture over-generation during peak hours and provide energy when wind and solar resources are silent. By building batteries at a rate proportional to the growth of renewables, the aggressive and strategic plans avoid the problem of over and under-production and provide a reliable system. However, because the aggressive plan builds renewables so early, its need for load-shifting comes on much sooner than in the strategic plan. As battery costs are expected to decline significantly over the next 30 years, this leaves the aggressive plan in the disadvantageous position of building batteries soon, before it makes economic sense to do so. Ascend's results will show that what the aggressive plan gains in fuel savings, it loses by building batteries too early.