A. Commission Order Cross Reference

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

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

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

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

COMPONENT PLANS

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

Table A-1. Component Plan Cross Reference

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

FURTHER ACTION: ENERGY STORAGE

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

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

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

B. Glossary and Acronyms

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

A

Adequacy of Supply

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

Advanced DER Technology Utilization Plan (ADERTUP)

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

Advanced Distribution Management System (ADMS)

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

Advanced Inverter

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

Advanced Metering Infrastructure (AMI)

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

Alternating Current (AC)

An electric current whose flow of electric charge periodically reverses direction. In Hawaiʻi, 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 Hawaiʻi and the mainland United States, the usual power system frequency of 60 hertz (1 hertz (Hz) = 1 cycle per second).

Ancillary Services

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

As-Available Renewable Energy

See Variable Renewable Energy on page B-35.

Avoided Costs

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

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

B

Baseload

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

Baseload Capacity

See Capacity, Generating on page B-4.

Baseload Generation

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

Battery Energy Storage Systems (BESS)

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

Black Start

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

British Thermal Unit (Btu)

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

Buy-All/Sell-All

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

C

Capacitor

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

Capacity Factor (cf)

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

Capacity, Generating

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

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

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

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

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

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

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

Capital Expenditures

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

Carbon Dioxide (CO_2)

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

Combined Cycle (CC)

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

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

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

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

Combined Heat and Power (CHP)

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

Combustion Turbine (CT)

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

Commercial and Industrial Direct Load Control (CIDLC)

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

Commercial and Industrial Dynamic Pricing (CIDP)

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

Conductor Sag

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

Connected Load

See Load, Electric on page B-19.

Contingency Reserve

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

Curtailment

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

D

Daytime Minimum Load (DML)

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

Demand

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

Demand Charge

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

Demand Response (DR)

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

> ***Load Control:*** Includes direct control by the utility or other authorized third party of customer end-uses such as air conditioners, lighting, and motors. Load control may entail partial or load reductions or complete load interruptions. Customers usually receive financial consideration for participation in load control programs.

> ***Price Response:*** Refers to programs that provide pricing incentives to encourage customers to change their electricity usage profile. Price response programs include real-time pricing, dynamic pricing, coincident peak pricing, time-of-use rates, and demand bidding or buyback programs.

Demand-Side Management (DSM)

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

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

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

Department of Land and Natural Resources (DLNR)

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

Direct Current (DC)

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

Distributed Energy Resources Technical Working Group (DER-TWG)

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

DG 2.0

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

Direct Current (DC)

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

Direct Load Control (DLC)

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

Direct Transfer Trip

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

Dispatchable Generation

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

Distributed Circuit Improvement Implementation Plan (DCIIP)

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

Distributed Energy Resources (DER)

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

Distributed Energy Storage

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

Distributed Generation (DG)

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

Distributed Generation Interconnection Capacity Analysis (DGICA)

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

Distribution Automation (DA)

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

Distribution Circuit Monitoring Program (DCMP)

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

Distribution Circuit

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

Distribution Transformer

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

Disturbance Ride-Through

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

Droop

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

Dual-Train Combined Cycle (DTCC)

See Combined Cycle on page B-5.

E

Economic Dispatch

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

Electric Power Research Institute (EPRI)

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

Electric Vehicle (EV)

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

Electricity

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

Energy

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

Emissions

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

Energy Efficiency DSM

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

Energy Efficiency Portfolio Standard (EEPS)

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

Energy Excelerator

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

Energy Management System (EMS)

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

Expense

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

Export Model

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

F

Feeder

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

Firm Capacity

See Capacity, Generating on page B-4.

Feed-In-Tariff (FIT) Program

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

Feed-In-Tariff (FIT)

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

First-In-First-Out (FiFo)

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

Flicker

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

Flywheel

See Storage one page B-31.

Forced Outage

See Outage on page B-23.

Forced Outage Rate

See Outage on page B-23.

Fossil Fuel

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

Frequency

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

Frequency Regulation

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

Full-Forced Outage

See Outage on page B-23.

Full Service Customer

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

G

Generating Capacity

See Capacity, Generating on page B-4.

Generation (Electricity)

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

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

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

Generator (Electric)

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

Geographic Information System (GIS)

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

Gigawatt (GW)

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

Gigawatt-hour (GWh)

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

Grandfather

To exempt a class of customers from changes to the laws or regulations under which they operate.

Greenhouse Gases (GHG)

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

Grid (Electric)

An interconnected network of electric transmission lines and related facilities.

Grid Modernization

The full suite of technologies and capabilities—including the data acquisition capabilities, controlling devices, telecommunications, and control systems—necessary to operate the utility's modernized electric grid. This includes Advanced Metering Infrastructure (AMI) with two-way communications and all the components to implement an Advanced Distribution Management System/Energy Management System. Additional components might include Volt-VAR Optimization (VVO); demand response; control of DG (curtailment and other); adaptive relaying (dynamic load shed); transformer monitoring; and potentially other advanced analytics, reporting, and monitoring capabilities.

Gross Generation

See Generation (Electricity) on page B-14.

Ground Fault Overvoltage

A transient overvoltage issue that occurs when the neutral of a wye grounded system shifts, causing a temporary overvoltage on the unfaulted phase.

Grounding Transformer

A transformer that provides a safe path to ground.

H

Hawai'i Public Utilities Commission (PUC)

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

Hawai'i Revised Statute (HRS)

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

Heat Rate

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

High Voltage Direct Current (HVDC)

An electric power transmission system that uses direct current, rather than alternating current, for bulk transmission.

I

Impacts

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

Impedance

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

Independent Power Producer (IPP)

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

Installed Capacity

See Capacity, Generating on page B-4.

Integrated Demand Response Portfolio Plan (IDRPP)

A Comprehensive Demand Response program proposal filed by the Companies with the Hawai'i Public Utilities Commission on July 28, 2014.

Integrated Interconnection Queue (IIQ)

Recommendations and plan for implementing and organizing an Integrated Interconnection Queue across all DG programs as directed by the Hawai'i Public Utilities Commission in Order 32053, to be filed on August 26, 2014.

Integrated Resource Plan (IRP)

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

Interconnection Charge

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

Interconnection Requirements Study (IRS)

Studies conducted by the Hawaiian Electric Companies on specific DG interconnection requests that may require mitigation measures to ensure circuit stability.

Intermediate Capacity

See Capacity, Generating on page B-4.

Intermittent Renewable Energy

See Variable Renewable Energy on page B-35.

Inverter

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

Islanding

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

K

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

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

L

Laterals
Lines branching off the primary feeder on a distribution circuit.

Levelized Cost of Energy (LCOE)
The price per kilowatt-hour in order for an energy project to break even; it does not include risk or return on investment.

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

Liquefied Natural Gas (LNG)
Natural gas that has been cooled until it turns liquid, in order to make storage and transport easier.

Live-Line Block Closing
Restrictions on the re-closing of feeders with interconnected DG PV systems based on line voltage levels.

Load, Electric

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

Baseload: The minimum load over a given period of time.

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

Load Balancing

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

Load Control Program

A program in which the utility company offers some form of compensation (for example, a bill credit) in return for having permission to control a customer's air conditioner or water heater for short periods of time by remote control.

Load Forecast

An estimate of the level of future energy needs of customers in an electric system. Bottom-up forecasting uses utility revenue meters to develop system-wide loads; used often in projecting loads of specific customer classes. Top-down forecasting uses utility meters at generation and transmission sites to develop aggregate control area loads; useful in determining reliability planning requirements, especially where retail choice programs are not in effect.

Load Management DSM

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

Load Profile

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

Load Shedding

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

Load Tap Changer (LTC)

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

Low Sulfur Fuel Oil (LSFO)

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

Low Sulfur Industrial Fuel Oil (LSIFO)

A fuel oil that contains up to 7,500 parts per million of sulfur; about 0.75% sulfur content. LSIFO is used by Maui Electric and Hawaiʻi Electric Light if a fuel with lower sulfur content than MSFO is needed.

Low Voltages

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

M

Maalaea Power Plant (MPP)

The largest power plant on Maui, with 15 diesel units, a combined cycle gas turbine, and a combined/simple cycle gas turbine totaling 208.42 MW (net) of firm capacity.

Maintenance Outage

See Outage on page B-23.

MBtu

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

Medium Sulfur Fuel Oil (MSFO)

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

Megawatt (MW)

A unit of power, capacity, or demand equal to one million watts. The Companies typically express their generating capacities and system demand in Megawatts.

Megawatt-hour (MWh)

A unit of electric energy equal to one million watt-hours. The Companies from time to time express the energy output of their generators or the amount of energy purchased from Independent Power Producers in megawatt-hours.

MMBtu

One million Btu. See also British Thermal Unit on page B-3.

Modern Grid

An umbrella term used to describe transformed grid, including communications, AMI, ADMS, and DA.

Must Run Unit

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

N

N-1 Contingency

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

Nameplate Generation

See Generation (Electricity) on page B-14.

Net Capacity

See Capacity, Generating on page B-4.

Net Energy Metering (NEM)

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

Net Generation

See Generation (Electricity) on page B-14.

Nitrogen Oxide (NO_x)

A pollutant and strong greenhouse gas emitted by combusting fuels.

Nominal Value (Nominal Dollars)

While a complex topic, at its most basic, value is based on a measure of money over a period of time. Generally expressed in terms of US dollars, nominal value represents a money cost in a given year, usually the current year. As such, nominal dollars can also be referred to as current dollars.

Non-Export Model

A tariff structure governing the interconnection of non-export DG systems.

Non-transmission alternatives

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

North American Electric Reliability Corporation (NERC)

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

O

Off-Peak Energy

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

On-Peak Energy

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

Operation and Maintenance (O&M) Expense

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

Operating Reliability

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

Operating Reserves

There are two types of operating reserves that enable an immediate or near immediate response to an increase in demand. (See also Reserve on page B-28.)

> ***Spinning Reserve Service:*** Provides additional capacity from electricity generators that are on-line, loaded to less than their maximum output, and available to serve customer demand immediately should a contingency occur.
>
> ***Supplemental Reserve Service:*** Provides additional capacity from electricity generators that can be used to respond to a contingency within a short period, usually ten minutes.

Outage

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

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

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

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

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

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

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

P

Partial Outage

See Outage on page B-23.

Peak Demand

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

Peaker

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

Peaking Capacity

See Capacity, Generating on page B-4.

Phase imbalance

A condition in which there is a voltage imbalance across two or more phases of a multi-phase system.

Photovoltaic (PV)

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

Planned Outage

See Outage on page B-23.

Planning Reserve

See Reserve on page B-28.

Plug-in Electric Vehicle (PEV)

An umbrella term encompassing all electric or hybrid electric vehicles that can be recharged through an external electricity source.

Power

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

Power Factor

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

Power Generating Technology

The myriad ways in which electric power is produced, including both commercially available technologies and emerging technologies, as well as hypothetical technologies.

Power Purchase Agreement (PPA)

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

Present Value

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

Primary Lines

The main high-voltage lines of the transmission and distribution network.

Proactive Approach

A forward-looking process governing the forecasting of penetration of DER on distribution circuits, analysis of operational constraints, and pre-emptive mitigation of these constraints.

Public Benefits Fee Administrator (PBFA)

A third-party agent that handles energy efficiency rebates and incentives for the Hawaiian Electric Companies.

Pumped Storage Hydro

See Storage on page B-31.

Q

Qualitative

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

Quantitative

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

R

Ramping Capability

A measure of the speed at which a generating unit can increase or decrease output.

Rate Base

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

Reactive Power

The portion of electricity that establishes and sustains the electric and magnetic fields of alternating-current equipment.

Real Dollars

While a complex topic, at its most basic, value is a measure of money over a period of time. Generally expressed in terms of units of US dollars, real dollars represents the true cost inclusive of inflationary adjustments (such as simple price changes which, of course, are usually price increases). Over time, real dollars are a measure of purchasing power. As such, real dollars can also be referred to as constant dollars.

Recloser

A circuit breaker with the ability to reclose after a fault-induced circuit break.

Reconductoring

The process of replacing the cable or wiring on a distribution or transmission line.

Regulating Reserves

The capacity required to maintain system frequency through fast balancing.

Reliability

The degree of performance of the elements of the bulk electric system that results in electricity being delivered to customers within accepted standards and in the amount desired. Reliability may be measured by the frequency, duration, and magnitude of adverse effects on the electric supply. Electric system reliability can be addressed by considering two basic and functional aspects of the electric system, Adequacy of Supply and System Security. See also System Reliability on page B-33.

Renewable Energy Resources

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

Renewable energy resources include photovoltaics, biomass, hydroelectric, geothermal, solar, and wind. In the future, they could also include the use of ocean thermal, wave, and tidal action technologies. Utility renewable resource applications include bulk electricity generation, on-site electricity generation, distributed electricity generation, non-grid-connected generation, and demand-reduction (energy efficiency) technologies.

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

Renewable Portfolio Standard (RPS)

A goal for the percentage of electricity sales in Hawai'i to be derived from renewable energy sources. The RPS is set by state law. Savings from energy efficiency and displacement or offset technologies are part of the RPS until January 2015, when they will instead be counted toward the new EEPS. The current RPS calls for 10% of net electricity sales by December 31, 2010; 15% of net electricity sales by December 31, 2015; 25% of net electricity sales by December 31, 2020; and 40% of net electricity sales by December 31, 2030.

Repowering

A means of permanently increasing the output and/or the efficiency of conventional thermal generating facilities.

Reserve

There are two types of reserves:

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

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

Reserve Margin (Planning)

The amount of unused available capability of an electric power system at peak load for a utility system as a percentage of total capability. Such capacity may be maintained for the purpose of providing operational flexibility and for preserving system reliability.

Residential Direct Load Control (RDLC)

A demand response program that offers incentives to customers who allow the Hawaiian Electric Companies to install a load control switch on residential electric water heater, so that the load can be curtailed remotely by the utility during times of system need.

Resiliency

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

Retail Rate

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

Reverse Flow

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

Rule 14H

The Hawaiian Electric Company rules governing service connections and facilities on a customer's premises.

Rule 18

The Hawaiian Electric Company rules governing Net Energy Metering.

S

Schedule Q

The tariff structure that governs Hawaiian Electric purchases from qualifying facilities 100kW or less

Scheduled Outage

See Outage on page B-23.

Secondary Lines
Low voltage distribution lines directly serving customers.

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

Service Level Issue
Any issue arising at the point of service provision to customers, including traditional utility service and grounding transformer overloads caused by DG PV.

Service Transformer
A transformer that performs the final voltage step-down from the distribution circuit to levels usable by customers.

Simple-Cycle Combustion Turbine (SCCT)
A generating unit in which the combustion turbine operates in a stand-alone mode, without waste heat recovery.

Single-Train Combined Cycle (STCC)
See Combined Cycle on page B-5.

Small Business Direct Load Control (SBDLC)
A demand response programs that allows the electric utility to curtail load without intervention of an operator at the end user's (customer's) premises. For example, the utility may install a load control switch on an electric water heater or air-conditioning unit, so that the load can be controlled remotely by the utility during times of system need.

Smart Grid
A platform connecting grid hardware devices to smart grid applications, including VVO, AMI, Direct Load Control, and Electric Vehicle Charging.

Smart Inverter Working Group (SIWG)
A working group created by the California Public Utilities Commission to propose updates to the technical requirements of inverters.

Spinning Reserve Service
See Operating Reserves on page B-23.

Standard Interconnection Agreement (SIA)
Rules governing interconnection of distributed generation systems.

Standby Charge

A fixed charge intended to recover significant backup generation facilities the utility must maintain to ensure grid reliability in the event of widespread DG outages.

Static VAR Compensator

A device used provide reactive power in order to smooth voltage swings.

Steady-State Conditions

Conditions governing normal grid operations; contrasted with transient conditions.

Steam Turbine (ST)

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

Storage

A system or a device capable of storing electrical energy to serve as an ancillary service resource on the utility system and/or to provide other energy services. Three major types of energy storage are relevant for consideration in 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 Battery Energy Storage System (BESS).
>
> ***Flywheel:*** A cylinder that spins at very high speeds, storing rotational kinetic energy. A flywheel can be combined with a device that operates either as an electric motor that accelerates the flywheel to store energy or as a generator that produces electricity from the energy stored in the flywheel. The faster the flywheel spins, the more energy it retains. Energy can be drawn off as needed by slowing the flywheel. A large flywheel plant can provide a number of ancillary services including frequency regulation, voltage support (dynamic reactive power supply), and potentially spinning reserve.
>
> ***Pumped Storage Hydro:*** Pumped storage hydro facilities typically use off-peak electricity to pump water from a lower reservoir into one at a higher elevation storing potential energy. When the water stored in the upper reservoir is released, it is passed through hydraulic turbines to generate electricity. The off-peak electrical energy used to pump the water uphill can be stored indefinitely as gravitational energy in the upper reservoir. Thus, two reservoirs in combination can be used to store electrical energy for a long period of time, and in large quantities. A modern

pumped-storage facility can provide a number of ancillary services, such as frequency regulation, voltage support (dynamic reactive power), spinning and non-spinning reserve, load following and black start as well as energy services such as peak shaving and energy arbitrage.

Sulfur Oxide (SO_x)

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

Substation

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

Substation Transformer

Substation-sited transformers used to change voltage levels between transmission lines, or between transmission lines and distribution lines.

Supervisory Control and Data Acquisition (SCADA)

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

Supplemental Reserve Service

See Operating Reserves on page B-23.

Supply-Side Management

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

Switching Station

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

Synchronous Condensers

Devices used to modulate the voltage or power factor of transmission lines. Synchronous condensers typically provide dynamic reactive power support, and are deployed only where dynamic reactive power support needs to be maintained at a particular location.

System

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

System Average Interruption Duration Index (SAIDI)

The average outage duration for each customer served. A reliability indicator.

System Average Interruption Frequency Index (SAIFI)

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

System Reliability

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

System Security

The ability of the electric system to withstand sudden disturbances such as electric short circuits or unanticipated loss of system elements.

T

Tariff

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

Thermal Loading

The maximum current that a conductor can transfer without overheating.

Time-of-Use (TOU) Rates

The pricing of electricity based on the estimated cost of electricity during a particular time block. Time-of-use rates are usually divided into three or four time blocks per twenty-four hour period (on-peak, mid-peak, off-peak and sometimes super off-peak) and by seasons of the year (summer and winter). Real-time pricing differs from TOU rates in that it is based on actual (as opposed to forecasted) prices which may fluctuate many times a day and are weather-sensitive, rather than varying with a fixed schedule.

Total Resource Cost (TRC)

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

Transformer

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

Transient Condition

An aberrant grid condition that begins with an adverse event and ends with the return to steady-state conditions (stable voltage, connection of all loads).

Transient Over Voltage (TrOV)

A transient issue characterized by a sudden spike in voltage above steady-state conditions on a circuit, or on a subset or component of a circuit.

Transmission and Distribution (T&D)

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

Transmission System

The portion of the electric grid the transports bulk energy from generators to the distribution circuits.

Two-Way Communications

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

U

Ultra Low Sulfur Diesel (ULSD)

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

Under Frequency Load Shedding (UFLS)

A system protection scheme used during transient adverse conditions to balance load and generation.

Under Voltage Load Shedding (UVLS)

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

Under Voltage Violation

Bus voltage less than 0.9 per unit.

United States Department of Defense (DOD)

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

United States Department of Energy (DOE)

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

United States Environmental Protection Agency (EPA)

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

University of Hawaiʻi Economic Research Organization (UHERO)

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

V

Variable Renewable Energy

A generator whose output varies with the availability of it primary energy resource, such as wind, the sun, and flowing water. The primary energy source cannot be controlled in the same manner as firm, conventional, fossil-fuel generators. Specifically, while a variable generator (without storage) can be dispatched down, its output cannot be guaranteed 100% of the time when needed. However, the primary energy source may be stored for future use, such as with solar thermal storage, or when converted into electricity via storage technologies. Also referred to as intermittent and as-available renewable energy.

Voltage

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

Voltage Collapse

The sudden and large decrease in the voltage that precipitates shutdown of the electrical system.

Voltage Regulation

A measure of change in the voltage magnitude between the sending and receiving end of a component, such as a transmission or distribution line.

Voltage Regulator Controller

A device used to monitor and regulate voltage levels.

Volt/VAR control

Control over voltage and reactive power levels.

Volt/VAR Optimization (VVO)

The process of monitoring voltages at customer premises through an AMI system, and optimizing them using reactive power control and voltage control capabilities.

W

Watt

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

C. Modeling Analyses Methods

Three teams conducted independent modeling analysis for produce the results presented in the PSIP. The teams included Hawaiian Electric Company generation planning, Black & Veatch, and PA Consulting. Each team employed a different modeling analysis method. In additional, Electric Power Systems employed a grid simulation model to conduct its system security studies.

Each of these four modeling methods are presented.

GRID SIMULATION MODEL FOR SYSTEM SECURITY ANALYSIS

The Transmission Planning Division of Hawaiian Electric Company uses the Siemens PSSE (Version 33) Power-Flow and Transient Stability program for transmission grid modeling and for system security analysis. This program is one of three most commonly used grid simulation programs in United States utilities. The program supports the IEEE (Institute of Electric and Electronic Engineer) generic models for generators and inverters. When available, custom models can preclude generic models.

PSSE is high-performance transmission planning software that has supported the power community with meticulous and comprehensive modeling capabilities for more than 40 years. The probabilistic analyses and advanced dynamics modeling capabilities included in PSSE provide transmission planning and operations engineers a broad range of methodologies for use in the design and operation of reliable networks. PSSE is used for power system transmission analysis in over 115 countries worldwide.

The program has two distinct program models: (1) power flow to represent steady state conditions and (2) stability to represent transients caused by faults and rapid changes in generation. The transient conditions are modeled to about 10 seconds after which most system will stabilize or fail.

After major system disturbances, we use this program to verify the system events as well as to verify the modeling assumptions.

Input to this program includes impedances for all the transmission lines, transformers, and capacitors; detailed information of the electrical characteristics of all generators and inverters (including PV panels and wind turbines); and energy storage devices (such as batteries). The model includes relays for fault clearing and under-frequency load shedding (UFLS).

Electric Power Systems used the PSSE model to conduct its robust and detailed system security studies because the model allows rapid and consistent sharing of data.

HAWAIIAN ELECTRIC: P-MONTH MODELING ANALYSIS METHODS

The Companies used computer models for the PSIP analyses. Production costs of the operating the system is simulated using the P-Month hourly production simulation model. The model is populated with unit data to characterize the resources operating on the system at all hours so that the performance and cost of the system can be evaluated for various future cases. The data from the hourly production simulation model is processed using other internally developed tools to evaluate the results of the simulations.

P-MONTH Hourly Production Simulation Model

Thermal Generation Modeling

The model, P-MONTH, is an hourly production simulation program supplied by the P Plus Corporation (PPC). This model simulates the chronological, hour-by-hour operation of the generation system by dispatching (mathematically allocating) the forecasted hourly load among the generating units in operation. Unit commitment and dispatch levels are based on fuel cost, transmission loss (or "penalty") factors, and transmission system requirements. The load is dispatched by the model such that the overall fuel expense of the system is minimized (that is, "economic dispatch") within the constraints of the system. The model calculates the fuel consumed using the unit dispatch described above, based on the load carried by each unit and the unit's efficiency characteristics. The total fuel consumed is the summation of each unit's hourly fuel consumption.

Variable Generation Modeling

The model calculates the energy produced by renewable resources and other variables using an 8760 hourly profile. This profile is constructed based on historical observed output from in service variable generation or from solar irradiance profiles and measured wind potential for future variable generation. Generation that is produced according to this hourly profile that cannot be accommodated on the system in any one hour will be curtailed per the curtailment order. The curtailment order follows a last in, first out rule whereby the last installed variable renewable resource will be curtailed first, that is, reverse chronological order.

Unit Forced Outage Modeling

The production simulation model can be used by applying one of two techniques: probabilistic or Monte Carlo. Using the probabilistic technique, the model will assume generating units are available to operate (when they are not on overhaul) at some given load that is determined by their normal top load rating and forced outage rate. By this methodology, the units will nearly always be available at a derated capacity that has been reduced to account for the forced outage rate.

PMONTH has a Monte Carlo Simulation option in which random draws are used to create multiple scenarios (iterations) to model the effect of random forced outages of generating units. Each scenario is simulated individually; the averages of the results for all the scenarios represent the expected system results. This Option provides the most accurate simulation of the power system operations if sufficient number of scenarios are used. However, the computer run time can be long if many scenarios are run. The number of scenarios needed to establish a certain level of confidence in the results depends on the objectives of the user and the size of the system. Normally, the system production cost will converge sufficiently between 20 and 30 iterations.

Using the Monte Carlo, or deterministic, technique, forced outages for generating units are treated as random, discrete outages in one week increments. The model will randomly take a generating unit out of service (during periods when it is available) up to a total forced outage time of 5%. By this methodology, the unit can operate at normal top load for 95% of the time when it is not on overhaul but will not be able to operate (that is, will have a zero output) for 5% of the time when it is not on overhaul. For the PSIP, the modeling will use the Monte Carlo methodology to capture the forced outages of all thermal units.

Demand Response Modeling

Demand response programs were modeled to provide several benefits including capacity deferral and regulating reserve. Programs that provide capacity were included in the capacity planning criteria analysis assessment. Programs that provide regulating reserve ancillary services were included in the modeling.

Energy Storage Modeling

The benefits of energy storage for system contingencies are captured in the system security modeling. Regulating reserves were provided by a combination of energy storage and thermal generation. Load shifting was modeled as a scheduled energy storage resource. The roundtrip efficiency was accounted for in the charging of this resource. The charging schedule was optimized to coincide with the hours in which curtailment occurred or the profile of PV energy during the day to minimize day time curtailment. The discharging schedule coincided with the evening peak.

System Security Requirements

The system security requirements were met by including the regulating and contingency reserve capabilities of demand response, energy storage, and thermal generation in the modeling. The system security requirements depend on the levels of PV and wind on the system. The regulating reserve requirements were changed hourly in the model to reflect the dynamic changes in levels of PV and wind throughout the day. Curtailed energy from controllable PV and future wind resources contributed to meeting the regulating reserve requirement. The contingency reserve requirements were changed annually to reflect the largest unit contingency on the system.

Sub-Hourly Model

The P-Month model is an hourly chronological model. Sub-hourly modeling cannot be done using this model. The Companies developed a limited sub-hourly model to assess the any value that the hourly model was not able to capture compared to the modeling sub-hourly when batteries, and other resources that operate like batteries, are on the system.

Key Model Inputs

In addition to the system changes described in the Base Plan, there are several key assumptions that are required for modeling:

1. Energy and hourly load to be served by firm and non-firm generating units
2. Load carrying capability of each firm generating unit
3. Efficiency characteristics of each firm generating unit
4. Variable O&M costs
5. Operating constraints such as must-run units or minimum energy purchases from purchased power producers
6. Overhaul maintenance schedules for the generating units
7. Estimated forced outage rates and maintenance outage rates
8. Regulating reserve requirements
9. Demand response and energy storage resources
10. Fuel price forecasts for fuels used by generating units

Methodology for Post-Processing of Production Simulation Results

Key Outputs

Some of the key outputs from the model are as follows:

1. Generation produced by each firm generation units
2. Generation accepted into the system by non-firm generating units
3. Excess energy not accepted into the system (curtailed energy)
4. Fuel consumption and fuel costs
5. Variable and fixed O&M costs
6. Start-up costs

Post-Processing

The outputs from the model are post-processed using Excel to incorporate the following:

1. Capital costs for new generating units, renewable and energy storage resources, allocated based on capital expenditure profiles
2. Capital costs for utility projects such as fuel conversions or the retirement of existing utility generating units
3. Payments to Independent Power Producers (IPP) for purchased power, including Feed in Tariff projects
4. Fixed O&M for future energy storage resources

All costs are post-processed into annual and total dollars to be used in the Financial Model. All annual, total, and present value (2015$) revenue requirements are also post-processed for use in evaluating the different plans but are not meant to be the "all-in costs" that the Financial Model will be doing. Revenue requirements are characterized as utility and IPP. Utility revenue requirements are categorized into fuel, fixed O&M, variable O&M, and capital. IPP revenue requirements are categorized into capacity and energy payments. Using the revenue requirements from post-processing, plans can be analyzed according to several key metrics.

Key Metrics

The key metrics analyzed through post processing of the model data are as follows:

1. Differential accumulated present value of annual revenue requirements
2. Differential rate impact
3. Monthly bill impact
4. Total system curtailment
5. Renewable Portfolio Standards (RPS)
6. Gas consumption
7. Utility CO_2 emissions
8. Annual Generation Mix
9. Daily Generation Mix by Hour

Lana‘i & Moloka‘i Modeling

The model used in the analysis for Lana‘i and Moloka‘i is an Excel based model focusing on meeting the total sales (energy) forecasted for each year. In this way the amount of energy produced from each resource was assumed to be taken regardless of any profiles. This simplified model shows results that are directionally correct.

The model calculations are broken up into three pieces: existing power purchase agreements, future renewable resources, and utility generation. First, it is assumed that the utility generation will provide a minimum amount of generation for system reliability. Second, the existing power purchase agreements fill in additional energy based on historical purchases. Lastly, future resources can be added to get as close to the total sales as possible. If the total energy provided by the three pieces is less than forecasted sales for a particular year, the utility generation will increase to make up the difference. If the total energy is greater than forecasted sales then the excess is curtailed from newly added resources.

The model will track all costs associated with fuel expense, O&M, capital, and power purchased payments to give annual revenue requirements and total net present value (NPV) consistent with the analysis for the other islands. Similarly, the model will also calculate the Renewable Portfolio Standards (RPS) percent for each year of the plan.

The utility generation component allows for different fuels to be assigned to the units as well as splitting the fuel types as necessary. Fuel usage and associated costs are calculated for each year.

Future renewable resources are identified by the year of installation as well as ownership (for example, utility or IPP). Resource ownership determines the capital expenditures patterns. Either a levelized profile or a declining profile to match company revenue requirements is used in the analysis. Costs for O&M and applicable fuel costs for each year are calculated for the new resources.

PA CONSULTING: PRODUCTION COST MODELING

PA Consulting Group (PA) performed hourly and sub-hourly production cost modeling to support the Hawaiian Electric Companies' development of the PSIPs. The production cost modeling was conducted using the EPIS AURORAxmp software. AURORA is an hourly chronological dispatch model used to model electricity markets. The model has broad capabilities. The primary forecasting capabilities that we used in the model are least cost dispatch and long-term capacity expansion modeling.

The capacity expansion model is an optimization model that determines the most cost effective long-term generation expansion and retirement schedules, based upon assumptions regarding capital costs, operating costs, and operational constraints, as well as system constraints such as reserve margins and spin requirements. The most cost effective plan is based upon the solution with the lowest net present value.

The chronological dispatch model determines the least-cost solution for dispatching resources, including demand side resources, to meet load and reserve margin requirements. The dispatch solution honors individual generator constraints and factors in marginal dispatch costs, including fuel and O&M. Each resource is modeled individually, taking into account the unit-specific cost and operating characteristics. Units are dispatched in the simulation in the order of economic merit (according to dispatch cost) until adequate generation is brought on line to meet the load. The model factors in out-of-merit dispatch due to must-run and must-take requirements. The model also curtails resources if the constrained generation exceeds demand.

The sub-hourly modeling was structured to address the Commission's interest in utilizing sub-hourly modeling to more fully investigate issues raised in the April 28th D&Os. These issues include evaluation of the value of DR and DG in the context of the Company's vision for the future of the utility, and consideration of resources required to support the integration of more intermittent renewable generation resources, and to reduce curtailments where it is economic to do so.

Specifically, PA used the sub-hourly modeling to identify any periods with unserved energy or periods with significant potential for renewable energy curtailment. We evaluated whether changing the resource mix can cost effectively address these issues. This assessment was conducted using iterative analyses to identify whether changing the available resource mix will reduce curtailment or dispatch costs.

AURORA was used to both evaluate a least-cost capacity expansion and retirement plan, and also to model scenarios of alternative resource plans in order to identify the incremental costs associated with alternative policies.

Key Inputs

PA worked with Hawaiian Electric Resource Planning and Black & Veatch to develop a common set of assumptions for the modeling initiative. These assumptions include:

- Resource characteristics (such as capacity, heat rates, ramp rates, minimum-up times, and minimum-down times)
- Characteristics of demand response programs
- Fuel costs
- Types of fuel that each fossil generator will use
- Identification of timing and generators that would be converted to burn LNG
- Fixed and variable operating costs
- Capital costs necessary to extend the life of existing generation
- Costs for new generation technologies (capital and operating)
- Availability of new generation resources (timing and capacities)
- System load forecasts
- Production profiles for variable energy resources.

Hourly Production Cost Modeling

Generation and demand side resources are dispatched to serve the system load. The base case simulations reflect the current configuration in which each island is a stand-alone system.[1] Units with low operating costs relative to other facilities are dispatched often; units with high costs are dispatched less frequently. The hourly dispatch logic is based upon short-run marginal generation costs, which include: fuel costs, variable operating costs, start-up costs, and emission costs. In contrast, the long-term retirement and expansion plan considers all costs rather than just marginal costs. The additional costs in the long run optimization include fixed O&M costs and capital costs.

The hour-by-hour interaction of supply and demand determines how frequently plants are dispatched within a market. The model incorporates logic for a variety of constraints that are incorporated into the least-cost dispatch logic. These constraints include: must-run requirements, minimum load requirements, ramp times, minimum uptimes, and minimum downtimes. The model also includes planned maintenance schedules and forced outage rates. The determination of the least-cost dispatch, subject to constraints, is based upon the model, assuming perfect information about future hourly loads.

PA used an iterative process to develop the preferred PSIP for each island. Our first step was to represent the existing systems within the model and develop simulations for the

[1] A case was run with a 200 MW DC transmission cable connecting the islands of Oʻahu and Maui.

first two years. We used these simulations to calibrate the models to reasonably represent how the current power systems dispatch and to capture the current generation operating costs, fuel costs, and purchase power agreements. We then used the optimization model to develop a least cost base case that factored in constraints related to committed generation retirements, assumptions about future levels of distributed generation, and availability of new generation resources. In the third stage of our analysis we tested alternative scenarios to examine the incremental costs of alternative power supply plans. The analysis in the third stage was based upon modeling specific scenarios over the 2015–2030 time horizon and did not use the long-term resource optimization feature.

Sub-Hourly Production Cost Modeling

The purpose of the sub-hourly modeling was to gain insights regarding ramp constraints, identify potential issues with large amounts of variable supply resources, and identify the potential value of fast response resources, including demand response resources. We use sub-hourly modeling to identify any periods with unserved energy or high frequency, and amounts of renewable energy curtailment. We then assess whether changing the resource mix can cost effectively address these issues.

The sub-hourly modeling was conducted with the previously described production cost model. In order to develop the sub-hourly analysis, it was necessary to convert all the hourly generation and variable supply resource profiles into five-minute profiles. We did not change any assumptions about fuel costs or generator constraints. A brief description of the process for developing the five-minute profiles follows.

We started with available one-minute historic net load profiles, wind production profiles, and solar production profiles. We developed a one-minute gross load profile from the one-minute profiles into five-minute profiles using averages of the five-minute periods. In instances where we did not have sub-hourly data, such as for hydro generation, we assumed that the generation was constant over the one hour period.

PA modeled four days per month at the five-minute level, rather than every day, due to the large amounts of data associated with five-minute modeling. The four representative days included a mid-week weekday (Monday–Thursday), a Friday, and each week-end day.

An overview of PA's sub-hourly modeling methodology follows. This modeling will be conducted at the five-minute intervals.

1. Development of Sub-Hour Modeling Assumptions and Data Inputs

We based inputs to the sub-hourly model on the assumptions agreed upon for the hourly model (fuel costs, generator characteristics, and load forecast) and on one-minute data.

The one-minute data include historic net load profiles, wind production profiles, and solar production profiles. In addition, PA incorporated input from parallel tasks related to development of DG and DR unit characteristics and cost options, as well as how that analysis should be integrated into the sub-hourly chronological dispatch modeling. PA closely coordinated these efforts with the company to ensure that the modeling assumptions and scenarios modeled are consistent with the Company's strategic vision.

2. Translation of Hourly Model Assumptions/Inputs to Five-minute Data

The vast majority of assumptions and inputs used for hourly modeling were used directly in the 5-minute modeling. These include fuel costs, resource capacities and efficiencies, and resource variable operating costs, as well as system operating reserve requirements. In some cases, dynamic information such as resource ramp rates and other time dependent assumptions were adjusted to correspond to the five-minute modeling interval, so that the inputs were correctly incorporated in to the model's economic dispatch algorithms.

3. Development of Five-minute Profiles for Modeling Inputs

We converted renewable generation production profiles from one-minute to five-minute data, and converted the hourly load forecasts to five-minute profiles using the historic one minute load profiles. The conversion ensured consistency between the hourly, one-minute, and five-minute data sets.

Renewable Generation Profiles. Five-minute profiles for wind and solar were constructed from available one-minute data. PA analyzed the one-minute data to develop representative five-minute shapes for typical days in each month. The representative five-minute shapes were not limited to simple averages of one-minute renewable output levels across days, but were structured to represent the extent of variation that exists at the one minute level. There was only one one-minute wind and solar profile per island so all solar and wind resources on each island used the common wind / solar profile. The capacity of the individual units were adjusted so that over a year the total production matched each unit's characteristics.

Load Shape and Distributed Generation Profiles. The derivation of the five-minute load shape profiles required a different analysis, since existing load data reflect behind-the-meter generation. Given time limitations, PA utilize an Excel-based model to construct five-minute load shapes for future years. Future load shapes were based on the current five-minute system load shape and the hourly load forecasts. PA used the five-minute PV production shape and penetration estimates for behind-the-meter solar to allocate the hourly loads into five-minute blocks representing gross system loads (without behind-the-meter generation) and net system loads for future years.

4. Sub-Hourly Model Development and Calibration

PA modeled four days per month at the five-minute level. We did not model all days due to the large amount of data at the five-minute level, and array limitations in the AURORAxmp software. The four representative days included a mid-week weekday (Monday–Thursday), a Friday, and each week-end day. Depending on model run-times and post processing efforts, PA either weighted the midweek day to represent four days, or performed additional simulations to capture a typical week per month to facilitate developing aggregate annual results.

PA developed and validated sub-hourly generation dispatch models for the Maui, O‘ahu, and Hawai‘i Island systems. Since AURORAxmp is currently configured for hourly modeling, PA had to adjust input parameters to facilitate five-minute modeling. PA adjusted input parameters so that each standard Aurora model hour is interpreted as a five-minute period. Hence, each representative day consisted of 288 standard Aurora model hours. Each representative day was modeled independently, and the standard Aurora model hourly output was aggregated through post processing to produce results for the day.

PA conducted a calibration exercise to verify that the model results made sense in the context of the sub-hourly modeling. We also verified that the sub-hourly modeling results are logical and reasonable, based upon PA’s expertise and based upon consultation with generation planning and generation operations staff expertise within the Company. After the results were validated for each system, PA executed simulations of the representative, P5, and P95 cases for each system. Annual system costs and performance metrics were calculated for each set of system conditions.

The simulations provided insights into the resource requirements necessary to meet load requirements with a mix of intermittent and non-intermittent resources. PA used the hourly simulations to capture the full capital and fixed operating costs for the purposes of estimating the total generation system operating costs at the annual level.

BLACK & VEATCH: ADAPTIVE PLANNING MODEL

Black & Veatch is applying its Adaptive Planning Framework to support the PSIP. Adaptive planning provides a framework for modeling complex systems, exploring options (and impacts of constraints), and comparing such options across varying metrics. Key metrics or outcomes would be costs, annual capital commitment required, degree of renewable penetration (capacity, energy served), and system reliability.

The Adaptive Planning Framework manages the overall calculation and cost accounting process. PSIP-specific requirements will be directly addressed by configuring the model:

- Dispatch methodology defined by collective Hawaiian Electric team, based on legal mandates, operational protocols, and defined reserve margins.
- Dispatch models and algorithms tailored to address system constraints (safety, security), loading or ramping criteria defined by Hawaiian Electric by asset class, battery charge, and discharge protocols by size and class of battery, among others.
- Repair times by asset class for projected failures and scheduled outages.
- Full cost accounting of all power supply elements by asset class, nature of cost, and other factors.

Different solution approaches can be applied in adaptive planning. As configured for this plan, the dispatch and economic models do not optimize capacity additions directly, as we believe that there are number of factors and complexities that dictate technology strategies and paths that need to be "engineered". We have, rather, focused on leveraging the model to evaluate alternate technology and capacity plans, including the adequacy of these plans to meet reserve margin or cause curtailment.

For this particular problem, given the complexity, the number of constraints, and the need to consider system security and reliability thresholds in each period, we have elected to apply the following:

- In concert with Hawaiian Electric and PA Consulting, define the general characteristics of base "path" based on central strategy and glide-path analysis. This will define some key initial assumptions regarding technology choice, timing, and retirements.
- Based on this analysis, the B&V team will then define alternative technology mixes or paths that need to be investigated; the focus would be to improve economics, flexibility, grid resiliency, or other factors based on our assessment of year-to-year unit commitment and dispatch data; this effort will also directly explore roles and penetration of battery assets over time.

- The team will generate sensitivities for each path (base and alternative) to stress test results; key variables that can be considered would be aggregate demand by system, the amount of spinning reserves over time (by year coincident with asset mix and by hour to address night-time or off-peak versus peak requirements), timing of capital investments, technology flips (battery versus pumped storage, battery versus thermal for contingency, etc.), timing of retirements, etc.

We believe that this approach maximizes our ability to provide visibility into results and key assumptions, as needed to define optimal PSIP path. It will also allow for direct comparison of decisions and timing that will be critical for Hawaiian Electric in subsequent steps to refine financial engineering of overall rates. Given the short time frame of this study, we do not plan on directly integrating a regulatory or rate model with AP framework, but would work with Hawaiian Electric to apply results of our work within existing spreadsheet models to enable analysis of investment requirements and the nature of investments over the evaluation period.

Economic results will be driven, in part, by market forecasts for fuel (oil, LNG, etc.). The Black & Veatch framework provides robust scenario analysis that will be applied in this case to evaluate:

- Mix and timing of renewable and energy storage assets
- Timing of retirements
- Timing and nature of new generation additions
- Timing and nature of participation from IPPs
- System characteristics
- Reliability risk based on level of investment and intensity of asset type
- Alternate views of costs including market price of fuel, the cost of implementing technology, etc., as needed to address increasingly higher degree of renewable penetration over time.

Economics can be applied in different forms within the model. We can consider:

- Direct capital investment in year of investments driven by project S-curves.
- Levelized costs based on spread of CAPEX and other related costs into an equivalent annual annuity.
- RRF schedule. Capital can be spread and factors can be assigned based on RRF input schedules.
- Third-party contract (IPP, DR, etc.) where the energy or service can be contracted on $/MWh, $/MW, or combination.

Model outputs will be populated within spreadsheets and data viewers to enable direct analysis and comparison (between cases) of:

- Period values by asset; periods can be either 1-hour or 5-minute for PSIP. We will also consider a smaller segment of 1-minute data to test impacts on wind and solar dispatch and spin. Detailed results would include dispatch MW, costs (capital, VOM, FOM), contribution to renewable, and role (contingency, regulation, energy, etc.)
- Aggregated results by asset; basically the same output as available for the period would be available for the asset by year and overall.
- Typical "daily" or 24-hour view; this view would analyze data for each asset by hour in day resulting from dispatch by asset by year. This will allow us to validate the overall dispatch approach, as well as better characterize roles of units. Values calculated would include average, min, max, and standard deviation. This will provide insights into rationale for IPP energy supply schedules for assets that are not anticipated to be owned by Hawaiian Electric.

Time Slice Model within Adaptive Planning Framework.

At the heart of the Adaptive Planning framework is a direct solution mathematical framework that enables direct analysis and "integration" of asset performance and aggregate match of resources to demand (as depicted in the figure below) contribution by asset, aggregate reliability, and costs.

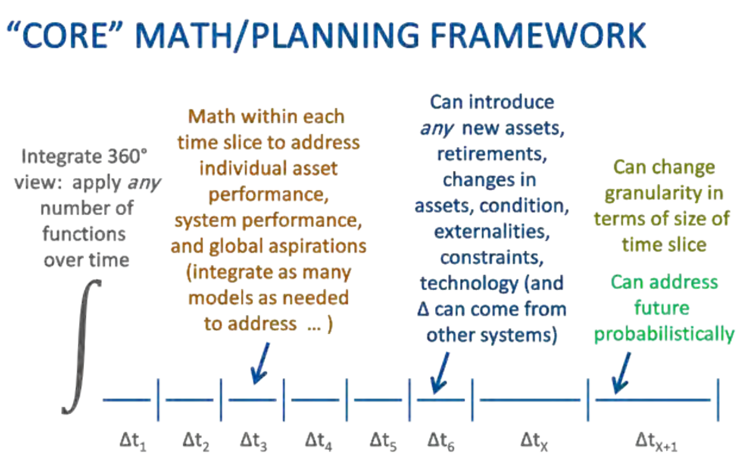

Figure C-1. Black & Veatch Mathematical Modeling Framework

Within the framework, each time slice affords the opportunity for us to:

- Introduce new assets, retire assets, change characteristics (simulate planned outages, etc.).
- Commit assets based on availability, renewable and non-renewable, and economics.

- Incorporate assumptions for wind and solar variability for that particular time slice based on perturbations of the historical wind and solar patterns.
- Incorporate rules for utilizing DG as must-take resource versus curtailable resource.
- Dispatch assets based on protocol and security, and economics including use of DR and energy storage to address ramping or smoothing, forced outages of committed assets, etc.
- Identify boundary conditions (from time slice to time slice) that serve as the basis for evaluating the next time slice; there are a number of instances where actions (such as a start of a 10-minute or 30-minute reserve resource within a particular time slice) will require forward commitment across time slices.

The time slice model works in conjunction with the economic dispatch model to evaluate the situation in the current period and translate this information to subsequent affected time slices. Each time slice considers (takes as input) for each power source:

- Status (available, scheduled outage, forced outage, retired, etc.)
- Operating efficiency
- Fuel characteristics (if applicable)
- Consumable unit costs
- Revenue requirements for capital expenditure

Each time slice also considers demand, adjusted for DR load shaping programs and, as applicable, DG PV. With this information, the time slice model determines:

- Status applicable to next time slice
- Consumable requirements
- Operating costs

The information generated is available at the time-slice or less granular resolution, for example, hourly, monthly, or annually. In addition, the asset hierarchy allows data to be viewed for each power source or aggregated across sources. Capital costs and other outputs associated with those investments would be tabulated by calendar year or other time domain, as required.

Generation Dispatch Methodology

The dispatch model will be used to set the electrical generation outputs to satisfy the electrical demand at the lowest cost while also satisfying system constraints (constrained optimization). These constraints will include system stability (must-run units), minimum downtime and uptime constraints, spinning and non-spinning reserve margin requirements, and non-dispatchable renewable generation. The model will use the following data:

- Variable costs and start-up costs for electrical generation assets
- Ramp rates, minimum downtime, and minimum uptime for electrical generation assets
- Historical reliability and maintainability (MTBF, MTTR) data for all generation assets
- Solar and wind penetration forecast (by time step resolution)
- Solar and wind forecasts (by time step resolution)
- Demand forecasts (by time step resolution)
- System losses

Demand response will be factored into this model via two forms: 1) change in overall "demand" curve as influenced by time-of-day pricing and 2) modeling of specific DR programs.

Energy storage is applied as a resource to supply capacity, regulation, contingency, and other ancillary services associated with frequency response and security. Energy storage added to supply capacity, regulation, or contingency will be modeled via the dispatch model; energy storage added to frequency response will be considered as a cost component of the overall system.

Sub-Hourly Model

Traditional hourly modeling does not expose the operational transients that must be managed during real-time operation of the electric grid. Hence, traditional hourly modeling also does not expose potential value (economic and risk mitigation value, for example) that one set of assets may have over another set of assets, as all transients are softened. Sub-hourly modeling will expose some of this value to support the optimum resource selection that does not violate policy considerations (risk tolerance, renewable goals, budget constraints, fuel diversity, etc.)

Similar to an hourly modeling approach, the sub-hourly model will calculate both commitment (what units are generating power) and dispatch (MW contribution of each asset to the target load) but now at a sub-hourly time step. Maximum daily rate of change will be greater and ramp rate constraints will be hit more often, thereby potentially changing the economic outcome of the simulation as compared to the hourly model. The hourly model assumes dispatch and commitment set points that do not violate any constraints when the time step is one hour, but when the truer transient nature is exposed at the sub-hourly time step, some otherwise masked constraints will likely become controlling.

The sub-hourly model (5 minute time step) will perform a constrained optimization for both asset commitment and asset dispatch against a sub-hourly desired load that utilizes both near term (next few time steps ahead) and intermediate term (out to the largest minimum down time of committed assets) load forecasts. The assets considered include generation (dispatchable and non-dispatchable), demand response, and energy storage. Each asset will have two primary states: available or unavailable. Each unavailable state may have sub-states—for example, scheduled versus unscheduled outage. Each asset will also have a series of constraints or attributes:

- Maximum output (or curtailment)
- Minimum output (or curtailment)
- Ramp up constraint
- Ramp down constraint
- Minimum run time
- Minimum down time
- Maximum run time curve as a function of operating state (energy storage, demand response, emission limits, fuel availability, etc.)
- Time between failures
- Time to restore
- Planned outages
- Startup cost
- Variable cost curve as a function of MW (input/output curve, heat rate curve, O&M, fuel forecast)
- Fixed costs (for annual cost calculations)

There are also system constraints that must be met. These include:

- Spinning reserve requirements (incorporating energy storage and demand response options)
- Grid stability requirements, including must-run units (constraints will be rules-based, as power flow modeling is not envisioned as feasible within the project time constraints)
- Policy constraints (power quality, reliability targets, risk tolerance)

The sub-hourly model will change the state of each asset to optimize the economics within the bounds of the model constraints. Accounting routines will keep track of asset performance ($, MWh, number of starts) and system performance (unserved load, curtailed generation, $, MWh). We envision sensitivities where selected constraints are relaxed and where the load forecast is modified. This will help test the robustness of the plan.

The modeling approach defined above is ideally suited to evaluating, comparing, and contrasting differing strategies regarding the mix of fossil generation, utility renewables versus energy storage, distributed generation versus energy storage, and demand response options. Based on the supply options provided, the model will determine the low-cost means for meeting the required load and base constraints. These constraints can be modified to evaluate other policy considerations (such as greater renewable penetration) that may move the solution away from optimal.

D. System Security Standards

The Hawaiian Electric Company contracted with Electric Power Systems and its two senior project engineers, David A Meyer and David W Burlingame, to conduct a system security and stability study and analysis of the Hawaiʻi Electric Light power grid.

Herewith is a discussion of the study and its resultant effects for system security on the Hawaiʻi Electric Light power grid.

This study identifies the security requirements for various generation and load scenarios under study for the Hawaiʻi Electric Light system. As such, the cases were intended to establish the boundary conditions for the security cases. For instance, if thermal units were utilized, the energy storage was sized to withstand the loss of the largest thermal unit at high generation levels, even though in actual practice, the thermal units may be operating at reduced levels to avoid curtailment of renewables.

Contents

Tables

METHODOLOGY

The methodology used to help determine the security requirements was based on simulating system disturbances, including unit trips and line faults, using four periods throughout the day/night. The load values for the periods came for the forecast data provided by Hawai'i Electric Light. The "Min" period case represents the minimum load found throughout the study year. The "Max" period was represents the maximum load found throughout the study year. The "Min Day" and "Max Day" loads represent the minimum and maximum loads found between the hours of 10 AM and 4 PM.

Each of the four basic period cases included high wind and low wind generation in order to determine the wind related boundary conditions for a total of eight cases. Additional cases were created to help determine the generation commitment related to boundary conditions where practical. For instance, cases may compare the use of two and three thermal units online with different levels of the size of an energy storage system (ESS) size in order to evaluate the contingency reserve requirements.

The key performance criterion used to assess the simulation results was the allowance of no more than one stage of under frequency load shedding (UFLS). Acceptable simulation results must also be stable and exhibit satisfactory voltage conditions.

For each case, the amount of contingency reserves for the system was evaluated. Each case had a total contingency reserve value meeting or exceeding the value of the largest unit contingency. If the sum of the spinning reserves and amount of net load found in Stage 1 of the UFLS scheme did not exceed the size of the largest unit contingency, then an ESS was added and sized to meet the largest unit contingency. For instance, comparing two and three thermal unit cases, the two unit case would have a larger sized ESS compared to the three unit case. The ESS size was increased if necessary to meet the performance criteria.

Note that the required size of ESS was typically determined directly from the simulation results. For some cases, the required value was estimated. The estimates were based on the simulation results and the case configurations. The amount of initial estimated ESS size along with the generation unit outputs, amount of spinning reserves, and renewable curtailment were used to assess the required size.

The simulated system disturbances included unit trips and line faults/outages. The unit trips selected included the larger conventional generation units and centralized wind plants. The variable generation and smaller PGV aggregate units were not included. The line faults included a number of higher sensitivity fault locations based on past studies and preliminary results. Zone 1 fault clearing times were used in addition to longer times. Since some Zone 2 fault locations are known to be beyond the critical clearing times of the system, a cursory assessment of the critical clearing times was made.

Generation Scenarios

The following describes the four generation scenarios used for the study. The cost related aspects of each scenario are not listed and do not effect the security studies.

Scenario 1: No New Additions Reference Case

- No generation additions beyond Hu Honua and DG growth in the study period.
- Includes LNG conversion.

Scenario 2: No New Additions Reference Case

- No generation additions beyond Hu Honua and DG growth in the study period
- Assume new unit will be situated at the same location as Keahole
- New geothermal online date is 2020
- For system stability purposes, this West Hawaii geothermal unit will be designated must-run. Keahole will be allowed to cycle as needed
- Unit will be dispatchable in the 7 to 25 MW range and can supply all system constraints

Scenario 3: High Variable Renewable

- Add 40 MW of wind at Lalamilo
- Assume new unit will provide regulating reserves and ramp control by using advanced inverter capabilities, which will reduce the capacity factor; but will still be very high based on the excellent wind resource
- Online date is 2020

Scenario 4: High Variable Renewable without Ancillary Services

- Add 40 MW of wind at Lalamilo
- Assume new unit will not provide its own regulating reserves and ramp control
- Online date is 2020

Major Study Assumptions

The following describes the major assumptions made for the study.

Performance Criteria:

- Do not exceed Stage 1 UFLS
- System must remain stable
- Satisfactory voltage conditions

UFLS Settings:

- Described in reference file "Hawai'i Electric Light PSIP Assumptions-R1.xlsx"
- Stage 1 58.8 Hz
- Stage 2 58.5 Hz
- Stage 3 58.0 Hz
- Stage 4 57.7 Hz
- Kicker block not modeled (20 second delay at 59.3 Hz)

General Generation Commitment Priority:

- PGV: Must Take (27 MW off-peak, 30 MW on-peak)
- Ho Hunoa: Must Run (10–21.5 MW)
- Keahole Single-Train: Must Run (10–24.5 MW, cycled in some cases)
- Keahole Dual-Train: Cycling (17–53.5 MW)
- HEP Single-Train: Cycling (10–28 MW)
- HEP Dual-Train: Cycling (19.5–58 MW)
- Hill 6: Cycling (8–20 MW)
- Puna CT3: Cycling (8–19 MW)

New Lalamilo Wind:

- 40 MW capacity, 20 MW largest contingency
- 75% Regulating Capacity (self-regulating operations)

Variable Generation Levels:

- Outputs vary to help create boundary conditions for conventional unit outputs

Curtailment:

- New distributed PV was curtailed as necessary. In some minimum cases without PV for Scenarios 3&4, the new Lalamilo was curtailed.

Ramp Rates:

- The addition of an ESS will provide the additional ramping capacity required to meet the ramp rate requirements.

PV Capacities:

- Maximum 85% of total capacity used energy output
- Legacy PV 10 MW (8.5 MW output)
- All other PV, extended ride-through settings

Renewable Contingencies:

- The largest single contingency of wind and PV generation does not exceed the same level of contingency as the largest unit.

Legacy (IEEE 1547) Distributed PV Settings:

Element		Stage 1 Setpoint (Hz, pu)	Stage 1 Time (Sec.)	Stage 2 Setpoint (Hz, pu)	Stage 2 Time (Sec.)
Frequency (Hz)	Under	59.3	0.17	N/A	N/A
	Over	60.5	0.17	N/A	N/A
Voltage (pu)	Under	0.88	2.0	0.5	0.17
	Over	1.1	1.0	1.2	0.17

Table D-1. Legacy/IEEE 1547 Distributed PV Settings

Rule 14H Distributed PV Settings (progressive changes highlighted in blue):

Element		Stage 1 Setpoint (Hz, pu)	Stage 1 Time (Sec.)	Stage 2 Setpoint (Hz, pu)	Stage 2 Time (Sec.)
Frequency (Hz)	Under	57.0	0.17	N/A	N/A
	Over	60.5	0.17	N/A	N/A
Voltage (pu)	Under	0.88	2.0	0.5	0.17
	Over	1.1	1.0	1.2	0.17

Table D-2. Rule 14H Distributed PV Settings

Extended Distributed PV Settings (progressive changes highlighted in blue):

Element		Stage 1 Setpoint (Hz, pu)	Stage 1 Time (Sec.)	Stage 2 Setpoint (Hz, pu)	Stage 2 Time (Sec.)
Frequency (Hz)	Under	57.0	20.0	N/A	N/A
	Over	63.0	20.0	N/A	N/A
Voltage (pu)	Under	0.88	2.0	0.5	0.5
	Over	1.1	1.0	1.2	0.17

Table D-3. Rule Extended Distributed PV Settings

HAWAI'I ELECTRIC LIGHT INTERMEDIATE CASES

Case Descriptions

The intermediate cases chosen for analysis consist of two different study years. The year 2019 was chosen for use with Scenario 1. This is a potential transition year prior to the year 2020 when the new generation in the other three scenarios is added to the system. In 2019, the four load period values are very similar to the 2030 values. The largest difference is 4 MW in the Min Day period. The amount of distributed PV found in 2019 78 MW (85% of capacity). This amount is 19 MW less than 2030, but is does include roughly 2/3 of the PV growth between 2014 and 2030.

The 2025 year for the other three new generation scenarios was chosen primarily due to its high loading and distributed PV levels. The high load levels are found in all four load periods. The distributed PV level is approximately 8 MW less than the 2030 levels at 89 MW. The table below describes the loads for each time period and the PV levels. The initial wind capacity consists of the existing wind capacity. Scenarios 3 and 4 add 40 MW additional wind.

The load and renewable generation capacities are summarized in the following table for the year 2019 and 2025.

	Study Year	
Time Periods	2019	2025
Min	88	91
Min Day	148	153
Max Day	183	188
Max	193	199
PV Capacity	91	105
85% PV Capacity	78	89
Initial Wind Capacity	31	31

Table D-4. Intermediate Case Load Levels (MW)

Generation Dispatches

The dispatches for all generation scenarios and time periods are provided in the following tables. The total amount of generation and initial estimated ESS size is included along with each individual unit output. Note that the Scenario 3 and Scenario 4 dispatches and results overlap due to the identical cases produced without wind. Scenario 3 includes only the wind cases and also includes additional regulation provided by the Lalamilo wind generation.

	Min - 88 MW			Min Day - 148 MW			Max Day - 183 MW		Max - 193 MW		
	High Wind		Low Wind	High Wind		Low Wind	High Wind	Low Wind	High Wind		Low Wind
Generation	3 Units	2 Units	3 Units	3 Units	2 Units	3 Units	3 Units	4 Units	7 Units	6 Units	7 Units
Keahole CT-4	15.0		18.0	17.5		17.3	18.0	19.0	18.5	19.0	19.0
Keahole CT-5								19.0	18.5	19.0	19.0
Keahole ST-7	3.8		4.5	4.4		4.3	4.5	13.3	13.0	13.3	13.3
Keahole 1CTCC	18.8		22.5	21.9		21.6	22.5				
Keahole 2CTCC								51.3	50.0	51.3	51.3
PGV Total	27.0	32.0	32.3	30.0	30.0	29.0	30.0	30.0	30.0	32.0	37.0
Hu Honua	15.0	18.5	20.5	20.5	18.5	20.5	20.5	20.5	20.5	20.5	20.5
Hill Unit No. 6									13.0		19.5
HEP CT1									19.0	19.5	19.5
HEP CT2									19.0	19.5	19.5
HEP ST									16.8	17.3	17.3
HEP 1 UNIT CC											
HEP 2 UNITS CC									54.8	56.3	56.3
As-availables	2.9	15.6	16.2	1.8	3.0	1.2	8.8	5.5	2.2	10.5	15.5
HRD	10.5	10.5	-	10.5	10.5	-	10.5	-	10.5	10.5	-
Apollo	20.5	20.5	-	20.5	20.5	-	20.5	-	20.5	20.5	-
Distributed PV	-	-	-	50.0	74.0	78.0	78.0	78.0	-	-	-
Total Generation	94.7	97.1	91.5	155.2	156.5	150.3	190.8	185.3	201.5	201.6	200.1
ESS for Cont. Res.	-	7.0	10.0	9.0	6.0	9.0	9.0	11.0	-	2.0	3.0

Table D-5. 2019 Scenario 1 Dispatch (MW)

	Min - 91 MW				Min Day - 153 MW				Max Day - 188 MW				Max - 199 MW			
	High Wind		Low Wind		High Wind		Low Wind		High Wind		Low Wind		High Wind		Low Wind	
Generation	3 Units	2 Units	4 Units	3 Units	3 Units	2 Units	3 Units	2 Units	4 Units	3 Units	5 Units	4 Units	7 Units	6 Units	8 Units	7 Units
Keahole CT-4			16.0						18.0		18.0	19.0	18.0	19.5	19.0	19.5
Keahole CT-5											17.3		17.0	19.0	19.0	19.5
Keahole ST-7			4.0						4.5		12.4	4.8	12.3	13.5	13.3	13.7
Keahole 1CTCC			20.0						22.5			23.8				
Keahole 2CTCC											47.7		47.3	52.0	51.3	52.7
PGV Total	30.0	31.0	27.0	35.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	37.0	30.0	38.0
Hu Honua	11.0		20.5	20.5	20.5		20.5		20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5
Hill Unit No. 6															19.5	
HEP CT1													18.0	19.0	19.5	19.5
HEP CT2													18.0		19.5	19.5
HEP ST													15.9	8.4	17.3	17.3
HEP 1 UNIT CC														27.4		
HEP 2 UNITS CC													51.9		56.3	56.3
As-availables	2.7	12.6	2.2	15.1	2.9	2.8	3.0	13.0	2.5	2.2	4.1	3.0	2.5	13.9	3.0	12.3
New Geothermal	23.0	23.0	23.0	24.0	23.0	23.0	23.0	23.0	23.0	23.0	23.0	24.0	23.0	24.0	23.0	24.0
HRD	10.5	10.5			10.5	10.5			10.5	10.5			10.5	10.5		
Apollo	20.5	20.5			20.5	20.5			20.5	20.5			20.5	20.5		
Distributed PV					53.0	73.0	79.0	89.0	65.0	89.0	65.0	89.0				
Total Generation	97.7	97.6	92.7	94.6	160.4	159.8	155.5	155.0	194.5	195.7	190.3	190.3	206.2	205.8	203.6	203.7
ESS for Cont. Res.	-	11.0	5.0	11.0	14.0	15.0	14.0	15.0	8.0	10.0	6.0	11.0	-	2.0	-	5.0

Table D-6. 2025 Scenario 2 Dispatch (MW)

Generation	Min - 91 MW High Wind 2 Units	Min Day - 153 MW High Wind 2 Units	Max Day - 188 MW High Wind 2 Units	Max - 199 MW High Wind 6 Units
Keahole CT-4	-	-	-	19.0
Keahole CT-5	-	-	-	19.0
Keahole ST-7				13.3
Keahole 1CTCC				
Keahole 2CTCC				51.3
PGV Total	29.0	30.0	30.0	30.0
Hu Honua	20.5	20.5	20.5	20.5
Hill Unit No. 6	-	-	-	-
HEP CT1	-	-	-	19.0
HEP CT2	-	-	-	16.0
HEP ST				15.5
HEP 1 UNIT CC				
HEP 2 UNITS CC				50.5
As-availables	3.5	3.9	6.7	3.7
HRD	10.5	10.5	10.5	10.5
Apollo	20.5	20.5	20.5	20.5
New Wind 1/Lalamino	7.5	10.0	10.0	10.0
New Wind 2/Lalamino	7.5	10.0	10.0	10.0
Distributed PV	-	56.0	89.0	-
Total Generation	99.0	161.4	197.2	207.0
ESS for Cont. Res.	8.0	13.0	9.0	-
Lalamino Wind Reg.	12.0	10.0	10.0	10.0

Table D-7. 2025 Scenario 3 Dispatch (MW)

	Min - 91 MW			Min Day - 153 MW		Max Day - 188 MW		Max - 199 MW	
	High Wind	Low Wind		High Wind	Low Wind	High Wind	Low Wind	High Wind	Low Wind
Generation	2 Units	4 Units	3 Units	2 Units	3 Units	2 Units	4 Units	5 Units	8 Units
Keahole CT-4	-	18.0	19.0	-	18.0	-	18.0	19.0	19.0
Keahole CT-5	-	11.0	-	-	-	-	17.0	19.0	19.0
Keahole ST-7		10.2	4.8		4.5		12.3	13.3	13.3
Keahole 1CTCC			23.8		22.5				
Keahole 2CTCC		39.2					47.3	51.3	51.3
PGV Total	29.0	30.0	35.0	30.0	30.0	30.0	30.0	32.0	35.0
Hu Honua	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5
Hill Unit No. 6	-	-	-	-	-	-	-	-	19.5
HEP CT1	-	-	-	-	-	-	-	19.0	19.5
HEP CT2	-	-	-	-	-	-	-	-	19.5
HEP ST								8.4	17.3
HEP 1 UNIT CC								27.4	
HEP 2 UNITS CC									56.3
Puna CT-3	-	-	-	-	-	-	-	-	18.0
As-availables	3.5	3.3	15.4	4.3	3.6	5.7	3.5	4.1	6.2
HRD	10.5	-	-	10.5	-	10.5	-	10.5	-
Apollo	20.5	-	-	20.5	-	20.5	-	20.5	-
New Wind 1/Lalamino	7.5	-	-	20.0	-	20.0	-	20.0	-
New Wind 2/Lalamino	7.5	-	-	20.0	-	20.0	-	20.0	-
Distributed PV	-	-	-	36.0	79.0	70.0	89.0	-	-
Total Generation	99.0	93.0	94.7	161.8	155.6	197.2	190.3	206.3	206.8
ESS for Cont. Res.	-	-	11.0	13.0	14.0	9.0	8.0	-	-

Table D-8. 2025 Scenario 4 Dispatch (MW)

Results

The results are summarized in the security constraints tables below. Definitions and notes for the table categories are also provided. The results indicate that an ESS sized in the range of 20–25 MW will cover all unit trips for all four of the generation scenarios. This range correlates with the largest unit contingencies. Note that the increments in ESS size were 5 MW. Thus the maximum required size may be slightly smaller and the differences between differing unit commitments may not be as evident (<5 MW).

The critical clearing time is roughly 11 cycles for all generation scenarios. This value is much shorter than typical zone 2 total clearing times (~30 cycles). If shorter zone 2 delays are used, such as 15 cycles (~20 cycles total clearing time), the results show some minor improvement but do not meet the performance criteria.

Detailed results for all analysis and scenarios are presented in the following sub-sections.

Security constraint definitions and notes:

- Ramp Rate: The total ramp rate required for the system as a whole including thermal generation and energy storage systems.
- Regulating Reserves (Day): The regulating reserves due to wind and PV generation.
- Regulating Reserves (Night): The regulating reserves due to wind generation.
- Contingency Reserves: The size of additional ESS required to meet the performance criteria.
- 30 Minute Reserves: The largest unit contingency based on the minimum number of thermal units required.
- The regulating reserves and the contingency reserves are individual requirements and should be summed together to arrive at the total required reserves.

	Capacity (MW)	Minimum # of Thermal units required (security constraint	Ramp Rate Requirements	Regulation Reserves - Day time	Regulation Reserves - Night time	Contingency Reserves	30 Minute Reserves
PV Level	78 MW						
Thermal Units	2 (on-line)	2	12.2 MW/min	32 MW Maximum	16 MW Maximum	20 MW	22 MW
Thermal units	3 (on-line)	3	12.2 MW/min	32 MW Maximum	16 MW Maximum	20 MW	25 MW

Table D-9. 2019 Scenario 1 Security Constraints

	Capacity (MW)	Minimum # of Thermal units required (security constraint	Ramp Rate Requirements	Regulation Reserves - Day time	Regulation Reserves - Night time	Contingency Reserves	30 Minute Reserves
PV Level	89 MW						
Thermal Units	2 (on-line)	2	13.6 MW/min	34 MW Maximum	16 MW Maximum	25 MW	25 MW
Thermal units	3 (on-line)	3	13.6 MW/Min	34 MW Maximum	16 MW Maximum	20 MW	25 MW

Table D-10. 2025 Scenario 2 Security Constraints

	Capacity (MW)	Minimum # of Thermal units required (security constraint	Ramp Rate Requirements	Regulation Reserves - Day time	Regulation Reserves - Night time	Contingency Reserves	30 Minute Reserves
PV Level	89 MW						
Thermal Units	2 (on-line)	2	14.6 MW/min	21 MW Maximum	3 MW Maximum	25 MW	22 MW
Thermal units	3 (on-line)	3	14.6 MW/min	21 MW Maximum	3 MW Maximum	20 MW	25 MW

Table D-11. 2025 Scenario 3 Security Constraints

	Capacity (MW)	Minimum # of Thermal units required (security constraint	Ramp Rate Requirements	Regulation Reserves - Day time	Regulation Reserves - Night time	Contingency Reserves	30 Minute Reserves
PV Level	89 MW						
Thermal Units	2 (on-line)	2	17.6 MW/min	54 MW Maximum	36 MW Maximum	25 MW	22 MW
Thermal units	3 (on-line)	3	17.6 MW/min	54 MW Maximum	36 MW Maximum	20 MW	25 MW

Table D-12. 2025 Scenario 4 Security Constraints

Contingency Reserves

The required contingency reserves are based on the size of ESS required to meet the performance criteria for all disturbances and time periods throughout the day. Since zone 2 clearing times for line faults are beyond the critical clearing times, the contingency reserves are solely based on unit trip results. As unit commitments were varied by one unit, the difference in ESS size ranged approximately 5–10 MW. The commitment with the smaller number of thermal units online required this increased amount.

The contingency reserve results for each scenario are summarized below. Some reasonable approximations based on experience were used while interpreting the results in order to determine the minimum required size. Tables showing the results of the larger unit trips and defining results are also provided. The tables indicate the case, time period, disturbance, and the minimum and maximum frequencies. The number of stages of load shedding is defined by the fill color of each minimum frequency results. No color indicates no load shedding.

- Scenario 1: 20 MW (all commitments)
- Scenario 2: 20 MW, 25 MW (less one unit)
- Scenario 3: 20 MW, 25 MW (less one unit) Note that total amount of ESS size required is the sum of the contingency ESS and the regulation coming from the Lalamilo wind generation.
- Scenario 4: 20 MW, 25 MW (less one unit)

UFLS Stages:
1
2
3
4

Table D-13. UFLS Stages Indication

Outage/Fault	Load/Wind Scenario	No. Units	Max/Min Frequencies (Hz)							
			Initial Setup		10 MW ESS		15 MW ESS		20 MW ESS	
			Max	Min	Max	Min	Max	Min	Max	Min
KEAH4	Min/High	3	60.0	58.5	60.0	59.0				
	Min/Low	3	60.0	58.6						
	Day Min/High	3	60.0	58.4	60.0	58.4	60.0	58.5	60.0	58.7
	Day Min/Low	3	60.0	57.9	60.0	57.9	60.0	58.0	60.0	58.7
	Day Max/High	3	60.0	58.3	60.0	58.4	60.0	58.5	60.0	58.7
	Day Max/Low	4	60.0	58.4			60.0	58.6		
	Max/High	7	60.0	59.1						
	Max/Low	7	60.1	58.8						
	Max/High	6	60.2	58.8						
PGV1	Min/High	3	60.0	59.1						
	Min/Low	3	60.0	59.2						
	Min/High	2	60.0	58.8						
	Day Min/High	3	60.0	58.7	60.0	58.7				
	Day Min/Low	3	60.0	58.7	60.0	58.7				
	Day Min/High	2	60.0	58.3	60.0	58.6				
	Day Max/High	3	60.0	58.7	60.0	58.7				
	Day Max/Low	4	60.0	59.3						
	Max/High	7	60.0	59.6						
	Max/Low	7	60.0	59.5						
	Max/High	6	60.0	59.4						
HUHONUA	Min/High	3	60.0	58.6						
	Min/Low	3	60.0	58.7						
	Min/High	2	60.0	58.5	60.0	58.6	60.0	58.8		
	Day Min/High	3	60.0	58.4	60.0	58.5	60.0	58.6	60.0	58.8
	Day Min/Low	3	60.0	58.2	60.0	58.3	60.0	58.6	60.0	58.7
	Day Min/High	2	60.0	57.7	60.0	58.0	60.0	58.4	60.0	58.7
	Day Max/High	3	60.0	58.5	60.0	58.5	60.0	58.7	60.0	58.8
	Day Max/Low	4	60.0	58.7			60.0	58.7		
	Max/High	7	60.0	59.2						
	Max/Low	7	60.0	59.2						
	Max/High	6	60.0	59.1						
APOLLO	Min/High	3	60.0	58.7						
	Min/High	2	60.0	58.6	60.0	58.7	60.0	58.8		
	Day Min/High	3	60.0	58.6	60.0	58.6	60.0	58.7		
	Day Min/High	2	60.0	57.9	60.0	58.0	60.0	58.5	60.0	58.7
	Day Max/High	3	60.0	58.6	60.0	58.6	60.0	58.7		
	Max/High	7	60.0	59.3						
	Max/High	6	60.0	59.2						

Table D-14. 2019 Scenario 1 Summary Results

Outage/Fault	Load/Wind Scenario	No. Units	Max/Min Frequencies (Hz)									
			Initial Setup		10 MW ESS		15 MW ESS		20 MW ESS		25 MW ESS	
			Max	Min	Max	Min	Max	Min	Max	Min	Max	Min
KEAH4	Min/Low	4	60.0	58.7								
	Day Max/High	4	60.0	58.4	60.0	58.5	60.0	58.7				
	Day Max/Low	5	60.0	58.5	60.0	58.6						
	Day Max/Low	4	60.0	58.4			60.0	58.5	60.0	58.7		
	Max/High	7	60.0	59.1								
	Max/Low	8	60.2	58.8								
	Max/High	6	60.1	58.7								
	Max/Low	7	60.2	58.8								
	Day Max/Low	5	60.0	58.5								
	Max/High	7	60.0	59.1								
	Max/Low	8	60.2	58.8								
	Max/High	6	60.1	58.7								
	Max/Low	7	60.1	58.8								
HUHONUA	Min/High	3	60.0	58.7								
	Min/Low	4	60.0	58.7								
	Min/Low	3	60.0	58.7								
	Day Min/High	3	60.0	58.6								
	Day Min/Low	3	60.0	58.4			60.0	58.5				
	Day Max/High	4	60.0	58.6								
	Day Max/Low	5	60.0	58.6								
	Day Max/High	3	60.0	58.4			60.0	58.6				
	Day Max/Low	4	60.0	58.6								
APOLLO	Min/High	3	60.0	58.7								
	Min/High	2	60.0	58.7								
	Day Min/High	3	60.0	58.7								
	Day Min/High	2	60.0	58.5								
	Day Max/High	4	60.0	58.7								
	Day Max/High	3	60.0	58.5			60.0	58.7				
	Max/High	7	60.0	59.3								
	Max/High	6	60.0	59.1								
GEOWEST	Min/High	3	60.0	58.5	60.0	58.8						
	Min/Low	4	60.0	58.5								
	Min/High	2	60.0	58.5								
	Min/Low	3	60.0	58.7								
	Day Min/High	3	60.0	58.4			60.0	58.5	60.0	58.7		
	Day Min/Low	3	60.0	58.0			60.0	58.0	60.0	58.6		
	Day Min/High	2	60.0	58.1					60.0	58.5		
	Day Min/Low	2	60.0	57.9					60.0	58.3	60.0	58.7
	Day Max/High	4	60.0	58.4	60.0	58.5						
	Day Max/Low	5	60.0	58.5	60.0	58.7						
	Day Max/High	3	60.4	58.0			60.0	58.4	60.0	58.7		
	Day Max/Low	4	60.0	58.4			60.0	58.6				
	Max/High	7	60.0	59.0								
	Max/Low	8	60.0	59.0								
	Max/High	6	60.2	58.7								
	Max/Low	7	60.0	59.0								

Table D-15. 2025 Scenario 2 Summary Results

Outage/Fault	Load/Wind Scenario	No. Units	Max/Min Frequencies (Hz) Initial Setup	
			Max	Min
KEAH4	Max/High	6	60.0	59.2
KEAH5	Max/High	6	60.0	59.2
HEP1	Max/High	6	60.0	59.2
PGV1	Min/High	2	60.0	59.4
PGV1	Day Min/High	2	60.0	59.4
	Day Max/High	2	60.0	59.4
	Max/High	6	60.0	59.6
HUHONUA	Min/High	2	60.0	58.9
	Day Min/High	2	60.0	58.7
	Day Max/High	2	60.0	58.7
	Max/High	6	60.0	59.3
APOLLO	Min/High	2	60.0	59.1
	Day Min/High	2	60.0	58.8
	Day Max/High	2	60.0	58.7
	Max/High	6	60.0	59.3
LALWIND	Min/High	2	60.0	59.7
	Day Min/High	2	60.0	59.6
	Day Max/High	2	60.0	59.6
	Max/High	6	60.0	59.7

Table D-16. 2025 Scenario 3 Summary Results

Outage/Fault	Load/Wind Scenario	No. Units	Max/Min Frequencies (Hz) Initial Setup Max	Initial Setup Min	10 MW ESS Max	10 MW ESS Min	15 MW ESS Max	15 MW ESS Min	20 MW ESS Max	20 MW ESS Min
KEAH4	Min/Low	4	60.0	58.4	60.0	58.7				
	Min/Low	3	60.0	58.7						
	Day Min/Low	3	60.0	58.0			60.0	58.0	60.0	58.6
	Day Max/Low	4	60.0	58.3	60.0	58.4	60.0	58.6		
	Max/High	5	60.1	58.7						
	Max/Low	8	60.3	58.8						
	Max/Low	8	60.3	58.8						
KEAH5	Min/Low	4	60.0	58.7	60.0	59.2				
	Day Max/Low	4	60.0	58.4	60.0	58.4	60.0	58.7		
	Max/High	5	60.1	58.7						
	Max/Low	8	60.2	58.8						
HEP1	Max/High	5	60.1	58.7						
	Max/Low	8	60.0	59.1						
PGV1	Min/High	2	60.5	58.5	60.0	58.9				
	Min/Low	4	60.3	58.8	60.0	59.3				
	Min/Low	3	60.0	59.3						
	Day Min/High	2	60.0	58.7						
	Day Min/Low	3	60.0	59.3						
	Day Max/High	2	60.0	58.6	60.0	58.6				
	Day Max/Low	4	60.0	58.8	60.0	59.3				
	Max/High	5	60.0	59.3						
	Max/Low	8	60.0	59.6						
HUHONUA	Min/High	2	60.0	58.1	60.0	58.5				
	Min/Low	4	60.0	58.5	60.0	58.8				
	Min/Low	3	60.0	58.8						
	Day Min/High	2	60.0	58.4			60.0	58.5		
	Day Min/Low	3	60.0	58.6			60.0	58.6		
	Day Max/High	2	60.0	58.3	60.0	58.3	60.0	58.5		
	Day Max/Low	4	60.0	58.5	60.0	58.6	60.0	58.7		
	Max/High	5	60.5	58.7						
	Max/Low	8	60.0	59.3						
APOLLO	Min/High	2	60.0	58.3	60.0	58.7				
	Day Min/High	2	60.0	58.5			60.0	58.6		
	Day Max/High	2	60.0	58.4	60.0	58.4	60.0	58.6		
	Max/High	5	60.4	58.8						
LALWIND	Min/High	2	60.2	58.7	60.0	59.5				
	Day Min/High	2	60.0	58.6			60.0	58.7		
	Day Max/High	2	60.0	58.4	60.0	58.4	60.0	58.7		
	Max/High	5	60.0	58.9						

Table D-17. 2025 Scenario 4 Summary Results

Critical Clearing Time

The critical clearing time for all scenarios was found to be approximately 11 cycles. This value is much shorter than typical zone 2 clearing times (~30 cycles) employed at Hawai'i Electric Light. The worst case line faults were found to be in the Keahole and HEP areas, typically at higher generation levels.

EPS recommends that Hawai'i Electric Light further evaluate the zone 2 timing and critical clearing times once the future generation and renewable energy issues have been solidified. No zone 1 faults were found to exceed the performance criteria or cause any instability issues. Zone 2 faults with reduced delay times (15 cycles) showed some improvement, but did not meet the performance criteria. However, the 15 cycle clearing time may provide some security in actual practice as opposed to studies of the boundary conditions that is not present using the existing clearing times.

Ramp Rates

The required ramp rates for each scenario are listed below. The values are based on the amount of wind and PV generation capacity. It is known that Hawai'i Electric Light's generating units cannot support these ramp rate values on a sustained basis under practical unit commitments. Achieving these ramp rates will require that Hawai'i Electric Light utilize the short-term (emergency) ramping capabilities on its combustion turbines, and that Hu Honua and geothermal plants achieve a 2 MW/min ramp rate. It is assumed that the addition of the ESS will provide the addition ramping capabilities necessary to meet the total ramp rate. This will require additional support from the contingency reserve ESS, however, so long as the regulation capacity is available on the units, the degradation of contingency reserves should be short-term.

- Scenario 1: 12.2 MW/min
- Scenario 2: 13.6 MW/min
- Scenario 3: 14.6 MW/min (75% regulating capacity for Lalamilo)
- Scenario 4: 17.6 MW/min

Regulating Capacity

The required regulating capacity is a calculation based on the amount of available wind capacity and PV energy with a minimum value of 6 MW. Other studies have concluded that up to 50% of the available wind capacity should be applied towards the required regulating capacity. When the actual wind output is less than 50% of capacity, a 1:1 MW/MW ratio should be applied. For instance if the wind capacity is 100 MW, a 25 MW output would require 25 MW of reserves, a 75 MW output would require 1:1 MW up to the maximum 50% value of 50 MW. The amount of regulating capacity required due to the amount of available PV energy is 20%.

The maximum required capacities are listed below for each scenario with and without PV availability (day/night). Note that the amount of regulation for Scenario 1 and Scenario 2 is identical for common years due to the lack of change in renewable generation. Scenario 3 includes 40 MW of self-regulated wind with 75% regulation capacity. A 10 MW (25%) output of the Lalamilo wind is assumed for these results.

With a 10 MW output, 17.5 MW total is available for regulation from Lalamilo at 100% wind capacity.

- Scenario 1: 32 MW/16 MW (Wind: 50%@ 31 MW, PV: 20%@78 MW)
- Scenario 2: 34 MW/16 MW (Wind: 50%@ 31 MW, PV: 20%@89 MW)
- Scenario 3: 21 MW/3 MW (Wind: 50%@ 41 MW, PV: 20%@89 MW)
- Scenario 4: 54 MW/36 MW (Wind: 50%@ 71 MW, PV: 20%@89 MW)

HAWAI'I ELECTRIC LIGHT 2030 CASES

Case Descriptions

The 2030 cases represent the final year of this study. The key difference between the intermediate cases is the amount of forecasted distributed PV. The amount of distributed PV found in 2030 is expected to be 97 MW (85% of capacity). The load levels for the daily load periods do not substantially change from the 2019 levels and are lower than the 2025 levels (1–6 MW).

Similar to the intermediate cases, the amount of wind generation does not change for generation Scenario 1 and Scenario 2. 40 MW of wind capacity is added for Scenarios 3 and 4. The load and renewable generation capacities are summarized in the following table for the year 2030.

Time Periods	Study Year 2030
Min	87
Min Day	152
Max Day	184
Max	193
PV Capacity	114
85% PV Capacity	97
Initial Wind Capacity	31

Table D-18. 2030 Case Load Levels (MW)

Generation Dispatches

The dispatches for all generation scenarios and time periods are provided in the following tables. The total amount of generation and initial estimated ESS size is included along with each individual unit output.

	Min - 87 MW			Min Day - 152 MW			Max Day - 184 MW		Max - 193 MW		
	High Wind		Low Wind	High Wind		Low Wind	High Wind	Low Wind	High Wind		Low Wind
Generation	3 Units	2 Units	3 Units	3 Units	2 Units	3 Units	3 Units	4 Units	7 Units	6 Units	7 Units
Keahole CT-4	15.0	-	18.0	17.5	-	17.3	18.0	19.0	18.5	19.0	19.0
Keahole CT-5	-	-	-	-	-	-	-	19.0	18.5	19.0	19.0
Keahole ST-7	3.8		4.5	4.4		4.3	4.5	13.3	13.0	13.3	13.3
Keahole 1CTCC	18.8		22.5	21.9		21.6	22.5				
Keahole 2CTCC								51.3	50.0	51.3	51.3
PGV Total	27.0	32.0	32.3	30.0	30.0	30.0	30.0	30.0	30.0	32.0	37.0
Hu Honua	15.0	18.5	20.5	20.5	18.5	20.5	20.5	20.5	20.5	20.5	20.5
Hill Unit No. 6	-	-	-	-	-	-	-	-	13.0	-	19.5
HEP CT1	-	-	-	-	-	-	-	-	19.0	19.5	19.5
HEP CT2	-	-	-	-	-	-	-	-	19.0	19.5	19.5
HEP ST									16.8	17.3	17.3
HEP 1 UNIT CC											
HEP 2 UNITS CC									54.8	56.3	56.3
As-availables	1.8	14.7	15.2	2.8	3.4	1.3	8.8	5.5	2.2	10.5	15.5
HRD	10.5	10.5	-	10.5	10.5	-	10.5	-	10.5	10.5	-
Apollo	20.5	20.5	-	20.5	20.5	-	20.5	-	20.5	20.5	-
Distributed PV	-	-	-	53.0	78.0	81.0	79.0	79.0	-	-	-
Total Generation	93.6	96.2	90.5	159.2	160.9	154.4	191.8	186.3	201.5	201.6	200.1
ESS for Cont. Res.	-	7.0	10.0	9.0	6.0	8.0	9.0	11.0	-	2.0	3.0

Table D-19. 2030 Scenario 1 Dispatch (MW)

Generation	Min - 87 MW High Wind 3 Units	Min - 87 MW Low Wind 3 Units	Min Day - 152 MW High Wind 3 Units	Min Day - 152 MW Low Wind 3 Units	Max Day - 184 MW High Wind 4 Units	Max Day - 184 MW High Wind 3 Units	Max Day - 184 MW Low Wind 4 Units	Max Day - 184 MW Low Wind 3 Units	Max - 193 MW High Wind 7 Units	Max - 193 MW High Wind 6 Units	Max - 193 MW Low Wind 7 Units
Keahole CT-4	-	-	-	-	9.6	-	17.0	-	17.0	19.0	19.0
Keahole CT-5	-	-	-	-	-	-	-	-	17.0	19.0	19.0
Keahole ST-7					2.4		4.3		11.9	13.3	13.3
Keahole 1CTCC					12.0		21.3				
Keahole 2CTCC									45.9	51.3	51.3
PGV Total	30.0	30.0	27.0	30.0	30.0	30.0	30.0	36.0	35.0	37.0	36.0
Hu Honua	13.5	20.0	10.0	12.0	11.0	16.0	18.5	20.5	20.0	20.0	20.5
Hill Unit No. 6	-	-	-	-	-	-	-	-	-	-	-
HEP CT1	-	-	-	-	-	-	-	-	16.0	18.5	19.0
HEP CT2	-	-	-	-	-	-	-	-	16.0	-	19.0
HEP ST									14.2	8.2	16.8
HEP 1 UNIT CC										26.7	
HEP 2 UNITS CC									46.2		54.8
Waiau 350 KW Unit	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Waiau 750 KW Unit	0.5	0.5	0.5	0.5	0.1	0.5	0.2	0.5	0.2	0.5	0.5
Puueo 750 KW Unit	0.5	0.5	0.5	0.5	0.1	0.2	0.2	0.5	0.2	0.5	0.5
Puueo new Unit	0.5	2.0	0.2	0.1	0.2	0.5	0.5	1.5	0.2	0.5	1.0
Wailuku 1	0.3	5.5	0.5	0.5	0.2	2.5	1.4	5.5	0.8	4.5	3.1
Wailuku 2	0.5	5.0	0.5	0.5	0.2	2.0	1.0	5.5	0.5	4.5	3.0
As-availables	2.5	13.7	2.4	2.3	1.0	5.9	3.5	13.7	2.1	10.7	8.3
New Geothermal	18.0	23.5	7.0	14.3	13.0	16.0	17.0	22.0	20.0	23.0	23.5
HRD	8.0	1.0	10.5	1.0	10.5	10.5	1.0	1.0	10.5	10.5	1.0
Apollo	20.5	2.0	20.5	2.0	20.5	20.5	2.0	2.0	20.5	20.5	2.0
Distributed PV	-	-	82.0	93.0	93.0	93.0	93.0	93.0	-	-	-
ESS for Cont. Res.	-	10.0	-	-	-	-	-	11.0	-	-	-
Total Generation	92.5	90.2	159.4	154.6	191.0	191.9	186.3	188.2	200.2	199.7	197.4

Table D-20. 2030 Scenario 2 Dispatch (MW)

Generation	Min - 87 MW High Wind 3 Units	Min - 87 MW High Wind 2 Units	Min - 87 MW Low Wind 3 Units	Min Day - 152 MW High Wind 2 Units	Min Day - 152 MW Low Wind 2 Units	Max Day - 184 MW High Wind 3 Units	Max Day - 184 MW High Wind 2 Units	Max Day - 184 MW Low Wind 3 Units	Max - 193 MW High Wind 6 Units	Max - 193 MW Low Wind 7 Units
Keahole CT-4	8.0	-	17.0	-	-	9.6	-	18.8	17.0	19.0
Keahole CT-5	-	-	-	-	-	-	-	-	17.0	19.0
Keahole ST-7	2.0		4.3			2.4		4.7	11.9	13.3
Keahole 1CTCC	10.0		21.3			12.0		23.5		
Keahole 2CTCC									45.9	51.3
PGV Total	27.0	27.0	30.0	30.0	30.0	30.0	30.0	30.0	32.0	36.0
Hu Honua	10.0	10.0	18.5	10.0	15.0	10.0	14.0	19.5	20.0	20.5
Hill Unit No. 6	-	-	-	-	-	-	-	-	-	19.0
HEP CT1	-	-	-	-	-	-	-	-	17.0	19.0
HEP CT2	-	-	-	-	-	-	-	-	17.0	19.0
HEP ST									15.0	16.8
HEP 1 UNIT CC										
HEP 2 UNITS CC									49.0	54.8
As-availables	3.1	6.5	13.2	3.1	11.2	3.6	4.9	14.4	3.4	10.9
HRD	10.5	10.5	1.0	10.5	1.0	10.5	10.5	1.0	10.5	1.0
Apollo	12.0	20.5	2.0	20.5	2.0	20.5	20.5	2.0	20.5	2.0
New Wind 1/Lalamino	10.0	10.0	2.0	10.0	2.0	10.0	10.0	2.0	10.0	2.0
New Wind 2/Lalamino	10.0	10.0	2.0	10.0	2.0	10.0	10.0	2.0	10.0	2.0
Distributed PV	-	-	-	66.0	93.0	85.0	93.0	93.0	-	-
ESS for Cont. Res.	-	-	6.0	-	6.0	-	-	11.0	-	-
Total Generation	92.6	94.5	90.0	160.1	156.2	191.6	192.9	187.4	201.3	199.5

Table D-21. 2030 Scenario 3 Dispatch (MW)

Generation	Min - 87 MW High Wind 3 Units	Min - 87 MW High Wind 2 Units	Min - 87 MW Low Wind 3 Units	Min Day - 152 MW High Wind 2 Units	Min Day - 152 MW Low Wind 2 Units	Max Day - 184 MW High Wind 3 Units	Max Day - 184 MW High Wind 2 Units	Max Day - 184 MW Low Wind 3 Units	Max - 193 MW High Wind 5 Units	Max - 193 MW Low Wind 7 Units
Keahole CT-4	8.0	-	17.0	-	-	9.6	-	18.8	17.0	19.0
Keahole CT-5	-	-	-	-	-	-	-	-	17.0	19.0
Keahole ST-7	2.0		4.3			2.4		4.7	11.9	13.3
Keahole 1CTCC	10.0		21.3			12.0		23.5		
Keahole 2CTCC									45.9	51.3
PGV 1	12.0	13.0	14.0	14.0	14.0	14.0	14.0	14.0	14.0	14.0
PGV 2	9.0	10.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0
PGV new1	1.5	2.0	2.5	2.5	2.5	2.5	2.5	2.5	5.0	5.5
PGV new2	1.5	2.0	2.5	2.5	2.5	2.5	2.5	2.5	5.0	5.5
PGV Total	24.0	27.0	30.0	30.0	30.0	30.0	30.0	30.0	35.0	36.0
Hu Honua	10.0	10.0	18.5	10.0	15.0	10.0	10.0	19.5	20.0	20.5
Hill Unit No. 6	-	-	-	-	-	-	-	-	-	19.0
HEP CT1	-	-	-	-	-	-	-	-	17.0	19.0
HEP CT2	-	-	-	-	-	-	-	-	-	19.0
HEP ST									7.5	16.8
HEP 1 UNIT CC									24.5	
HEP 2 UNITS CC										54.8
As-availables	2.6	2.1	13.3	3.5	11.4	3.8	4.8	14.5	4.2	10.9
HRD	1.0	8.0	1.0	10.5	1.0	10.5	10.5	1.0	10.5	1.0
Apollo	2.0	5.0	2.0	20.5	2.0	20.5	20.5	2.0	20.5	2.0
New Wind 1/Lalamino	20.0	20.0	2.0	20.0	2.0	20.0	20.0	2.0	20.0	2.0
New Wind 2/Lalamino	20.0	20.0	2.0	20.0	2.0	20.0	20.0	2.0	20.0	2.0
Distributed PV	-	-	-	46.0	93.0	65.0	77.0	93.0	-	-
ESS for Cont. Res.	2.0	17.0	6.0	20.0	6.0	5.0	18.0	11.0	4.0	-
Total Generation	89.6	92.1	90.1	160.5	156.4	191.8	192.8	187.5	200.6	199.5

Table D-22. 2030 Scenario 4 Dispatch (MW)

Results

The results are summarized in the security constraints tables below. Similar to the intermediate cases results, the 2030 results indicate that an ESS sized in the range of 20–25 MW will cover all unit trips for all four of the generation scenarios. This range correlates with the largest unit contingencies. Note that the increments in ESS size were 5 MW. Thus the maximum required size may be slightly smaller and the differences between differing unit commitments may not be as evident (<5 MW).

Also similar to the intermediate case results, the critical clearing time is roughly 11 cycles for all generation scenarios. This value is much shorter than typical zone 2 total clearing times (~30 cycles). If shorter zone 2 delays are used, such as 15 cycles (~20 cycles total clearing time), the results show some minor improvement but do not meet the performance criteria.

Detailed results for all analysis and scenarios are presented in the following sub-sections.

	Capacity (MW)	Minimum # of Thermal units required (security constraint	Ramp Rate Requirements	Regulation Reserves - Day time	Regulation Reserves - Night time	Contingency Reserves	30 Minute Reserves
PV Level	97 MW						
Thermal Units	2 (on-line)	2	14.5 MW/min	35 MW Maximum	16 MW Maximum	20 MW	22 MW
Thermal units	3 (on-line)	3	14.5 MW/min	35 MW Maximum	16 MW Maximum	20 MW	25 MW

Table D-23. 2030 Scenario 1 Security Constraints

	Capacity (MW)	Minimum # of Thermal units required (security constraint	Ramp Rate Requirements	Regulation Reserves - Day time	Regulation Reserves - Night time	Contingency Reserves	30 Minute Reserves
PV Level	97 MW						
Thermal Units	2 (on-line)	2	14.5 MW/min	35 MW Maximum	16 MW Maximum	25 MW	25 MW
Thermal units	3 (on-line)	3	14.5 MW/min	35 MW Maximum	16 MW Maximum	20 MW	25 MW

Table D-24. 2030 Scenario 2 Security Constraints

	Capacity (MW)	Minimum # of Thermal units required (security constraint	Ramp Rate Requirements	Regulation Reserves - Day time	Regulation Reserves - Night time	Contingency Reserves	30 Minute Reserves
PV Level	97 MW						
Thermal Units	2 (on-line)	2	15.5 MW/min	23 MW Maximum	3 MW Maximum	25 MW	22 MW
Thermal units	3 (on-line)	3	15.5 MW/min	23 MW Maximum	3 MW Maximum	20 MW	25 MW

Table D-25. 2030 Scenario 3 Security Constraints

	Capacity (MW)	Minimum # of Thermal units required (security constraint	Ramp Rate Requirements	Regulation Reserves - Day time	Regulation Reserves - Night time	Contingency Reserves	30 Minute Reserves
PV Level	97 MW						
Thermal Units	2 (on-line)	2	18.5 MW/min	55 MW Maximum	36 MW Maximum	25 MW	22 MW
Thermal units	3 (on-line)	3	18.5 MW/min	55 MW Maximum	36 MW Maximum	20 MW	25 MW

Table D-26. 2030 Scenario 4 Security Constraints

Contingency Reserves

The required contingency reserves are based on the size of ESS required to meet the performance criteria for all disturbances and time periods throughout the day. Since zone 2 clearing times for line faults are beyond the critical clearing times, the contingency reserves are solely based on unit trip results. As unit commitments were varied by one unit, the difference in ESS size ranged approximately 5–10 MW. The commitment with the smaller number of thermal units online required this increased amount.

The contingency reserve results for each scenario are summarized below. Some engineering judgment was used while interpreting the results in order to determine the minimum required size. Tables showing the results of the larger unit trips and defining results are also provided. The tables indicate the case, time period, disturbance, and the minimum and maximum frequencies. The number of stages of load shedding is defined by the fill color of each minimum frequency results. No color indicates no load shedding.

- Scenario 1: 20 MW (all commitments)
- Scenario 2: 20 MW, 25 MW (less one unit)
- Scenario 3: 20 MW, 25 MW (less one unit)
- Scenario 4: 20 MW, 25 MW (less one unit)

UFLS Stages:
1
2
3
4

Table D-27. UFLS Stages Indication

Outage/Fault	Load/Wind Scenario	No. Units	Max/Min Frequencies (Hz) Initial Setup Max	Initial Setup Min	10 MW ESS Max	10 MW ESS Min	15 MW ESS Max	15 MW ESS Min	20 MW ESS Max	20 MW ESS Min
KEAH4	Min/High	3	60.0	58.5	60.0	58.9				
	Min/Low	3	60.0	58.6						
	Day Min/High	3	60.0	58.4	60.0	58.4	60.0	58.5	60.0	58.7
	Day Min/Low	3	60.0	57.9	60.0	57.9	60.0	58.0	60.0	58.7
	Day Max/High	3	60.0	58.3	60.0	58.4	60.0	58.5	60.0	58.7
	Day Max/Low	4	60.0	58.4			60.0	58.5	60.0	58.7
	Max/High	7	60.0	59.1						
	Max/Low	7	60.1	58.8						
	Max/High	6	60.2	58.8						
HEP1	Max/High	7	60.0	59.1						
	Max/Low	7	60.0	59.0						
	Max/High	6	60.3	58.8						
PGV1	Min/High	3	60.0	59.1						
	Min/Low	3	60.0	59.2						
	Min/High	2	60.0	58.8						
	Day Min/High	3	60.0	58.7	60.0	58.7				
	Day Min/Low	3	60.0	58.7	60.0	58.7				
	Day Min/High	2	60.5	58.0	60.0	58.6				
	Day Max/High	3	60.0	58.7	60.0	58.7				
	Day Max/Low	4	60.0	59.3						
	Max/High	7	60.0	59.6						
	Max/Low	7	60.0	59.5						
	Max/High	6	60.0	59.4						
HUHONUA	Min/High	3	60.0	58.6	60.0	59.0				
	Min/Low	3	60.0	58.7						
	Min/High	2	60.0	58.5	60.0	58.6	60.0	58.8	60.0	59.0
	Day Min/High	3	60.0	58.4	60.0	58.5	60.0	58.6	60.0	58.8
	Day Min/Low	3	60.0	58.2	60.0	58.3	60.0	58.6	60.0	58.8
	Day Min/High	2	60.0	57.8	60.0	57.9	60.0	58.4	60.0	58.7
	Day Max/High	3	60.0	58.5	60.0	58.5	60.0	58.7	60.0	58.8
	Day Max/Low	4	60.0	58.7			60.0	58.7	60.0	58.9
	Max/High	7	60.0	59.2						
	Max/Low	7	60.0	59.2						
	Max/High	6	60.0	59.1						
APOLLO	Min/High	3	60.0	58.7	60.0	59.1				
	Min/High	2	60.0	58.6	60.0	58.7	60.0	58.8	60.0	59.0
	Day Min/High	3	60.0	58.6	60.0	58.6	60.0	58.7	60.0	58.9
	Day Min/High	2	60.0	57.7	60.0	57.9	60.0	58.0	60.0	58.7
	Day Max/High	3	60.0	58.6	60.0	58.6	60.0	58.7	60.0	58.9
	Day Max/Low	4	60.0	58.7						
	Max/High	7	60.0	59.3						
	Max/High	6	60.0	59.2						

Table D-28. 2030 Scenario 1 Summary Results

Outage/Fault	Load/Wind Scenario	No. Units	Max/Min Frequencies (Hz) Initial Setup		10 MW ESS		15 MW ESS	
			Max	Min	Max	Min	Max	Min
KEAH4	Day Max/High	4	60.0	59.3				
	Day Max/Low	4	60.5	58.0	60.0	58.6		
	Max/High	7	60.0	59.2				
	Max/Low	7	60.2	58.8	60.0	59.2		
	Max/High	6	60.1	58.7				
	Max/High	7	60.0	59.2				
HEP1	Max/High	7	60.0	59.3				
	Max/Low	7	60.0	58.9				
	Max/High	6	60.0	58.7				
PGV1	Min/High	3	60.0	59.0				
	Min/Low	3	60.0	59.2	60.0	59.2		
	Day Min/High	3	60.0	58.7				
	Day Min/Low	3	60.0	58.6				
	Day Max/High	4	60.0	58.9				
	Day Max/Low	4	60.0	58.7				
	Day Max/High	3	60.0	58.5				
	Day Max/Low	3	60.0	58.8				
	Max/High	7	60.0	59.5				
	Max/Low	7	60.0	59.5				
	Max/High	6	60.0	59.3				
HUHONUA	Min/High	3	60.0	58.7				
	Min/Low	3	60.0	58.7	60.0	58.7	60.0	58.9
	Day Min/High	3	60.0	58.3	60.0	59.4		
	Day Min/Low	3	60.3	57.9	60.0	58.7		
	Day Max/High	4	60.0	58.6				
	Day Max/Low	4	60.0	58.3	60.0	58.7		
	Day Max/High	3	62.4	58.0	60.0	58.7		
	Day Max/Low	3	60.0	58.5			60.0	58.7
	Max/High	7	60.0	59.2				
	Max/Low	7	60.0	59.2				
	Max/High	6	60.0	58.9				
APOLLO	Min/High	3	60.0	58.7				
	Min/Low	3	60.0	59.9	60.0	59.9		
	Day Min/High	3	60.0	58.4	60.0	58.8		
	Day Min/Low	3	60.0	59.9	60.0	59.9		
	Day Max/High	4	60.0	58.7				
	Day Max/Low	4	60.0	59.9	60.0	59.9		
	Day Max/High	3	60.0	58.2	60.0	58.7		
	Day Max/Low	3	60.0	59.9				
	Max/High	7	60.0	59.3				
	Max/Low	7	60.0	59.9				
	Max/High	6	60.0	59.1				
GEOWEST	Min/High	3	60.0	58.7				
	Min/Low	3	60.0	58.5	60.0	58.5	60.0	58.7
	Day Min/High	3	60.0	59.5				
	Day Min/Low	3	60.1	58.0	60.0	58.9		
	Day Max/High	4	60.0	58.7				
	Day Max/Low	4	60.0	58.3	60.0	58.7		
	Day Max/High	3	60.8	58.0	60.0	58.7		
	Day Max/Low	3	60.0	58.3			60.0	58.5
	Max/High	7	60.0	59.2				
	Max/Low	7	60.0	58.9				
	Max/High	6	60.2	58.7				

Table D-29. 2030 Scenario 2 Summary Results

Outage/Fault	Load/Wind Scenario	No. Units	Max/Min Frequencies (Hz) Initial Setup		10 MW ESS		15 MW ESS		20 MW ESS	
			Max	Min	Max	Min	Max	Min	Max	Min
KEAH4	Min/High	3	60.0	59.3						
	Min/Low	3	60.0	58.5	60.0	58.7				
	Day Max/High	3	60.0	58.7						
	Day Max/Low	3	60.3	58.0			60.0	58.4	60.0	58.7
	Max/High	6	60.0	59.0						
	Max/Low	7	60.2	58.8						
PGV1	Min/High	3	60.0	59.2						
	Min/Low	3	60.0	59.2						
	Min/High	2	60.0	58.9						
	Day Min/High	2	60.0	58.4	60.0	58.9				
	Day Min/Low	2	60.0	58.5	60.0	59.3				
	Day Max/High	3	60.0	58.7						
	Day Max/Low	3	60.0	59.3						
	Day Max/High	2	60.0	58.3	60.0	59.3				
	Max/High	6	60.0	59.4						
	Max/Low	7	60.0	59.5						
HUHONUA	Min/High	3	60.3	58.8						
	Min/Low	3	60.0	58.7	60.0	58.8				
	Min/High	2	60.0	58.6						
	Day Min/High	2	60.0	58.1	60.0	58.6				
	Day Min/Low	2	60.1	57.8	60.1	57.9	60.0	58.6		
	Day Max/High	3	60.0	58.5						
	Day Max/Low	3	60.0	58.5			60.0	58.7	60.0	58.9
	Day Max/High	2	62.3	40.4	60.0	58.5	60.0	58.7		
	Max/High	6	60.0	59.1						
	Max/Low	7	60.0	59.2						
APOLLO	Min/High	3	60.0	59.3						
	Min/Low	3	60.0	59.9	60.0	59.9				
	Min/High	2	60.0	58.6						
	Day Min/High	2	60.0	58.1	60.0	58.7				
	Day Min/Low	2	60.0	59.9	60.0	59.9				
	Day Max/High	3	60.0	58.5						
	Day Max/Low	3	60.0	59.9						
	Day Max/High	2	60.0	57.9	60.0	58.6				
	Max/High	6	60.0	59.1						
	Max/Low	7	60.0	59.9						
LALWIND	Min/High	3	60.0	59.4						
	Min/Low	3	60.0	59.9						
	Min/High	2	60.0	59.2						
	Day Min/High	2	60.0	58.7						
	Day Min/Low	2	60.0	59.9						
	Day Max/High	3	60.0	59.4						
	Day Max/Low	3	60.0	59.9						
	Day Max/High	2	60.0	58.7						
	Max/High	6	60.0	59.7						
	Max/Low	7	60.0	59.9						

Table D-30. 2030 Scenario 3 Summary Results

Outage/Fault	Load/Wind Scenario	No. Units	Max/Min Frequencies (Hz) Initial Setup Max	Initial Setup Min	15 MW ESS Max	15 MW ESS Min	20 MW ESS Max	20 MW ESS Min
KEAH4	Min/High	3	60.0	59.4				
	Min/Low	3	60.0	58.5	60.0	58.8		
	Day Max/High	3	60.0	59.4				
	Day Max/Low	3	60.3	58.0	60.0	58.4	60.0	58.7
	Max/High	5	60.0	58.9				
	Max/Low	7	60.2	58.8				
PGV1	Min/High	3	60.0	59.3				
	Min/Low	3	60.0	59.2	60.0	59.5		
	Min/High	2	60.0	59.5				
	Day Min/High	2	60.0	59.5				
	Day Min/Low	2	60.0	58.5	60.0	59.4		
	Day Max/High	3	60.0	59.3				
	Day Max/Low	3	60.0	59.3	60.0	59.4		
	Day Max/High	2	60.0	59.4				
	Max/High	5	60.0	59.4				
	Max/Low	7	60.0	59.5				
HUHONUA	Min/High	3	60.0	58.9				
	Min/Low	3	60.0	58.7	60.0	59.1		
	Min/High	2	60.0	59.5				
	Day Min/High	2	60.0	59.5				
	Day Min/Low	2	60.1	57.8	60.0	58.7		
	Day Max/High	3	60.0	58.7				
	Day Max/Low	3	60.0	58.5	60.0	58.7		
	Day Max/High	2	60.0	59.5				
	Max/High	5	60.0	59.0				
	Max/Low	7	60.0	59.2				
APOLLO	Min/High	3	60.0	59.9				
	Min/Low	3	60.0	59.9				
	Min/High	2	60.0	59.8				
	Day Min/High	2	60.0	59.1				
	Day Min/Low	2	60.0	59.9				
	Day Max/High	3	60.0	58.7				
	Day Max/Low	3	60.0	59.9				
	Day Max/High	2	60.0	59.0				
	Max/High	5	60.0	59.1				
	Max/Low	7	60.0	59.9				
LALWIND	Min/High	3	60.0	58.8				
	Min/Low	3	60.0	59.9				
	Min/High	2	60.0	59.2				
	Day Min/High	2	60.0	59.1				
	Day Min/Low	2	60.0	59.9				
	Day Max/High	3	60.0	58.7				
	Day Max/Low	3	60.0	59.9				
	Day Max/High	2	60.0	59.0				
	Max/High	5	60.0	59.2				
	Max/Low	7	60.0	59.9				

Table D-31. 2030 Scenario 4 Summary Results

Critical Clearing Time

The critical clearing time for all scenarios was found to be approximately 11 cycles. This value is much shorter than typical zone 2 clearing times (~30 cycles). The worst case line faults were found to be in the Keahole and HEP areas, typically at higher generation levels.

EPS recommends that Hawai'i Electric Light further evaluate the zone 2 timing and critical clearing times once the future generation and renewable energy issues have been solidified. No zone 1 faults were found to exceed the performance criteria or cause any instability issues. Zone 2 faults with reduced delay times (15 cycles) showed some improvement, but did not meet the performance criteria in the boundary scenarios. However, 15 cycle clearing in actual operating conditions will likely avoid system stability issues that have been identified in the boundary cases.

Ramp Rates

The required ramp rates for each scenario are listed below. The values are based on the amount of wind and PV generation capacity. It is known that Hawai'i Electric Light's generating units cannot support these ramp rate values under practical unit commitments. It is assumed that the addition of the ESS will provide the addition ramping capabilities necessary to meet these rates.

- Scenario 1: 14.5 MW/min
- Scenario 2: 14.5 MW/min
- Scenario 3: 15.5 MW/min (75% regulating capacity for Lalamilo)
- Scenario 4: 18.5 MW/min

Regulating Capacity

The required regulating capacity is a calculation based on the amount of available wind capacity and PV energy with a minimum value of 6 MW. Other studies have concluded that up to 50% of the available wind capacity should be applied towards the required regulating capacity. When the actual wind output is less than 50% of capacity, a MW/MW ratio should be applied. For instance if the wind capacity is 100 MW, a 25 MW output would require 25 MW of reserves, a 75 MW output would require the maximum 50% value of 50 MW. The amount of regulating capacity required due to the amount of available PV energy is 20%.

The maximum required capacities are listed below for each scenario with and without PV availability (day/night). Note that the amount of regulation for Scenario 1 and Scenario 2 is identical for common years due to the lack of change in renewable generation. Scenario 3 includes 40 MW of self-regulated wind with 75% regulation capacity. A 10 MW (25%) output of the Lalamilo wind is assumed for these results. With a 10 MW output, 17.5 MW total is available for regulation from Lalamilo at 100% wind capacity.

- Scenario 1: 35 MW/16 MW (Wind: 50%@ 31 MW, PV: 20%@97 MW)
- Scenario 2: 35 MW/16 MW (Wind: 50%@ 31 MW, PV: 20%@97 MW)
- Scenario 3: 23 MW/3 MW (Wind: 50%@ 41 MW, PV: 20%@97 MW)
- Scenario 4: 55 MW/36 MW (Wind: 50%@ 71 MW, PV: 20%@97 MW)

HAWAI'I ELECTRIC LIGHT 2015/2016 OPERATION STUDIES

This portion of the study identifies the generation operating requirements for various generation and load scenarios under study for the Hawai'i Electric Light system. The 2015 and 2016 years were studied to help determine the operational impact that the forecast load and increased PV capacity has on the Hawai'i Electric Light generation operations. Sensitivity to the amount of legacy PV was also studied. The operating requirements were based on the system's response with criteria meeting one stage of UFLS and two stages of UFLS.

Methodology

The methodology used to help determine the generation operating requirements was similar to the security studies. The key difference was the generation commitment and dispatch was configured to meet the regulating reserves with all PV at its anticipated maximum output. Since the focus was the sensitivity to PV levels, the Min and Max loads and time periods were not included in the analysis. Although zone 1 and delayed fault clearing simulations were performed, unit trips were the focus due to the critical clearing time issues discussed in the security studies. The 2015 and 2106 systems were included in the study. The major generation change in this timeframe is the addition of Hu Honua.

The operating requirements to meet the stage 1 UFLS and stage 2 UFLS performance objectives were met, when necessary, using transfer tipping mitigation techniques. Reducing generator output was also explored for certain cases. The transfer tripping method simulated rapid load shedding upon the detection of a system disturbance. This results in a reduction in the amount of frequency decay and minimum frequency. The amount of load shedding included stage 1 or both stage 1 & 2 stages of the existing UFLS scheme. A seven cycle total clearing time was assumed for the transfer trip scheme.

To determine if any mitigation was necessary for the simulations, an initial set of results was created. For all simulations that resulted in UFLS beyond stage 1, subsequent simulations were performed using the transfer trip scheme. This method continued until the results showed a clear improvement in minimum frequency and reduction in the amount of PV being tripped. Typically, these minimum frequency values were greater than 59.3 Hz.

The sensitivity to the amount of legacy PV was included in the analysis. A capacity of 10 MW, consistent with the security studies, and a 13.1 MW (existing capacity) value was used. The legacy PV represents the capacity of PV that may not be able to be modified to provide improved ride-through trip settings. The remaining balance of existing and forecast PV is assumed to have extended ride-through settings. The legacy and extended ride-through settings used are detailed in the security studies portion of this report.

HAWAI'I ELECTRIC LIGHT CASE DESCRIPTIONS & RESULTS

Case Descriptions

The case descriptions are provided in the table below. The table includes the system load and renewable generation levels, net stage 1 and stage 2 UFLS values, and the individual unit commitments/dispatches used for the analysis. The unit commitment is based on the total system demand, a fixed amount of renewables, and meeting the regulating reserve requirements established as part of the security studies. The amount of variable generation was varied to make adjustments to attain the proper levels of regulating reserves and help create more severe system disturbances. Low values of variable generation helped to provide for higher dispatches while high values helped reduce the number of units committed.

	2015				2016			
	Min Day		Max Day		Min Day		Max Day	
	High	Low	High	Low	High	Low	High	Low
Load	140	140	179	179	145	145	179	179
PV	56	56	56	56	67	67	67	67
Wind	31	-	31	-	31	-	31	-
Regulation	27	24	27	13	29	31	29	14
Required Regulation	27	11	27	11	29	13	29	13
Net UFLS Stage 1	8.0	8.0	12.2	12.2	7.2	7.2	10.8	10.8
Net UFLS Stage 2	5.1	5.1	9.0	9.0	3.8	3.8	7.2	7.2
Net UFLS Stage 1&2	13.1	13.1	21.2	21.2	11.0	11.0	18.1	18.1
No. Units	3	4	4	5	3	4	4	4
CT4	9.0	14.5	17.0	18.0	8.0	12.5	13.0	17.5
CT5	-	14.5	8.0	18.0	-	12.5	13.0	17.5
PGV	30.0	30.0	32.0	30.0	30.0	30.0	30.0	35.0
Hu Honua	11.0	14.5	17.5	18.0	10.0	13.0	14.0	17.0
HEP CT1	-	-	-	18.0	-	-	-	
As-availables	8.4	2.1	16.4	2.9	4.5	3.1	8.8	15.8

Table D-32. Case Descriptions (MW)

Summary Results

The summary mitigation results are provided in the table below. The table includes the mitigation techniques required to meet the performance objectives. The results show that using the stated commitments, dispatches, and resultant amount of regulating reserves provided for a maximum stage 2 performance. No additional operational requirements are necessary. To limit the performance to stage 1, transfer tripping of stage 1 and stage 2 ("TT St 1&2) is required to cover all time periods, wind variations, and legacy PV levels studied. For 2015, the system can be limited to transfer tripping of stage 1 if the output of Keahole CT4 is limited to 15 MW or less during maximum day and high wind conditions.

The 2015 and 2016 security constraints tables are also provided. The contingency reserve values are based on the amount of the largest contingency creating the disturbance.

All faults with zone 1 clearing times result in a maximum of stage 1 UFLS. No mitigation is necessary. As discussed in the security studies, zone 2 with clearing times greater than 15 cycles exceed the critical clearing time of the system for several fault locations and conditions. This is true for the 2015/2016 system was well. The critical clearing time is roughly eleven cycles for all transmission lines.

	2015				2016			
	Min Day		Max Day		Min Day		Max Day	
Operating Requirements:	High	Low	High	Low	High	Low	High	Low
10 MW Legacy PV:								
Allow Stage 2	None	None	None	None	None	None	None	None
Allow Stage 1	TT St 1	TT St 1	TT St 1&2*	TT St 1	TT St 1	TT St 1	None	TT St 1&2
13 MW Legacy PV:								
Allow Stage 2	None	None	None	None	None	None	None	None
Allow Stage 1	TT St 1	TT St 1	TT St 1&2*	TT St 1	TT St 1&2	TT St 1	TT St 1	TT St 1&2

* Or TT St 1 & CT4<15 MW

Table D-33. Mitigation Summary Results

	Capacity (MW)	Minimum # of Thermal units required (security constraint	Ramp Rate Requirements	Regulation Reserves - Day time	Regulation Reserves - Night time	Contingency Reserves	30 Minute Reserves
PV Level	56 MW						
Thermal Units	3 (on-line)	3	9.6 MW/min	27 MW Maximum	16 MW Maximum	31 MW	27 MW

Table D-34. 2015 Security Constraints

	Capacity (MW)	Minimum # of Thermal units required (security constraint	Ramp Rate Requirements	Regulation Reserves - Day time	Regulation Reserves - Night time	Contingency Reserves	30 Minute Reserves
PV Level	67 MW						
Thermal Units	3 (on-line)	3	10.9 MW/min	29 MW Maximum	16 MW Maximum	29 MW	27 MW

Table D-35. 2016 Security Constraints

Detailed Results and Discussion

Detailed results showing the progression of mitigation for each system configuration are found in the four tables below. The top portion of the table shows the reference disturbances resulting in more than one stage of UFLS without any mitigation. All of these cases can be mitigated to meet the reliability objectives. The improvements can be seen in the minimum frequency value and amount of PV tripped during the disturbance.

Although the minimum frequency value stated does not precisely represent the frequency at every bus where UFLS can occur, it does give a good representation of the average frequency found throughout the system for these types of disturbances. It can be seen from the minimum frequency values that many of the reference simulation results are slightly under the stage 2 frequency setpoint of 58.5 Hz. Thus, the majority of exceptions can be mitigated to stage 1 performance by speeding up the clearing time for a stage 1 using the transfer trip scheme to trigger the UFLS instead of a frequency based scheme. Note that the number of stages listed for the non-reference simulations correspond to the amount of load shed and not the frequency setpoints normally used for these stages.

The difference in the amount of legacy PV in tables 5–3 and 5–4 is 2.6 MW. This difference is relatively small and does not indicate much of a difference in results for 2015. In 2016, there is some difference in the maximum day, high wind cases. Similar to the majority of results, these stage 2 exceptions are slightly under the stage 2 frequency setpoint.

The commitments shown represent the final configurations studied in detail to determine the operating requirements. Other commitments, that could also meet the regulating reserve requirements and unit minimums, were initially evaluated and included either one more or one less unit committed. With one less unit, these configurations indicated that other, more extreme, mitigation techniques would be required to achieve the proper level of system performance. With one more unit, the regulating reserve levels were larger with much improved system performance often with results indicating only stage 1 or non-load shedding.

The final unit commitments and simulation results help to form the boundary conditions for the generation operating requirements, but do not encompass all of the evaluation that is necessary for final operations of the units. The unit commitments and dispatches, amount of regulating reserves, and simulation results are very specific to the amount of PV and wind generation assumed for each case. Variations for these assumptions must be considered for actual operations.

The number of units online (single plant for PGV) ranges from 3–5 for the time periods and assumptions studied. However, as previously stated, the variable generation has been adjusted to help form the boundary conditions. For instance, although only four units are committed for the maximum day load and low wind, the variable output is very high thus allowing sufficient regulation from the thermal generation units. If the variable generation has lower output or the PV is not at 85% capacity, then another unit may need to be placed online to achieve the desired system performance. Similarly, a unit may be able to be placed offline if the variable generation and wind output are at higher levels such as in the minimum day, low wind cases.

Load/Wind Scenario	Unit trip	Stages Tripped	Min Freq Hz	Net Load/PV Tripped MW	Load Tripped MW	PV Tripped MW
Min Day/High Wind	APOLLO	2	58.47	7.0	29.2	(22.2)
	HUHONUA	2	58.44	7.0	29.2	(22.2)
Min Day/Low Wind	HUHONUA	2	58.42	7.0	29.2	(22.2)
	KEAH4	2	58.41	7.0	29.2	(22.2)
	KEAH5	2	58.40	7.0	29.2	(22.2)
Max Day/High Wind	HEP1	2	58.49	15.2	37.4	(22.2)
	KEAH5	2	58.47	17.2	36.1	(18.9)
Max Day/Low Wind	HUHONUA	2	58.45	15.2	37.4	(22.2)
	KEAH4	2	58.38	15.2	37.4	(22.2)
Transfer Trip Stage 1						
Min Day/High Wind	APOLLO	1	58.80	0.6	14.98	(14.41)
	HUHONUA	1	59.69	8.0	14.98	(6.96)
Min Day/Low Wind	HUHONUA	1	59.42	8.0	14.98	(6.96)
	KEAH4	1	59.33	8.0	14.98	(6.96)
	KEAH5	1	59.31	8.0	14.98	(6.96)
Max Day/High Wind	HEP1	1	59.51	12.2	19.15	(6.96)
	KEAH5	1	59.45	12.2	19.15	(6.96)
Max Day/Low Wind	HUHONUA	1	59.54	12.2	19.15	(6.96)
	KEAH4	2	58.44	15.2	37.39	(22.21)
Transfer Trip Stage 1 & 2						
Max Day/Low Wind	KEAH4	2	59.72	21.2	37.39	(16.16)
Transfer Trip Stage 1, Reduce CT 4						
Max Day/Low Wind	KEAH4	1	59.55	12.2	19.15	(6.96)

Table D-36. 2015 10 MW Legacy PV Results

Load/Wind Scenario	Unit trip	Stages Tripped	Min Freq Hz	Net Load/PV Tripped MW	Load Tripped MW	PV Tripped MW
Min Day/High Wind	APOLLO	2	58.39	5.2	29.2	(24.1)
	HUHONUA	2	58.37	5.2	29.2	(24.1)
Min Day/Low Wind	HUHONUA	2	58.36	5.2	29.2	(24.1)
	KEAH4	2	58.32	5.2	29.2	(24.1)
	KEAH5	2	58.31	5.2	29.2	(24.1)
Max Day/High Wind	HEP1	2	58.42	13.3	37.4	(24.1)
	KEAH4	2	58.42	13.3	37.4	(24.1)
	KEAH5	2	58.42	13.3	37.4	(24.1)
Max Day/Low Wind	APOLLO	2	58.45	13.3	37.4	(24.1)
	HUHONUA	2	58.38	13.3	37.4	(24.1)
	KEAH4	2	58.30	13.3	37.4	(24.1)
Transfer Trip Stage 1						
Min Day/High Wind	APOLLO	1	58.50	(1.7)	15.0	(16.7)
	HUHONUA	1	59.69	8.0	15.0	(7.0)
Min Day/Low Wind	HUHONUA	1	59.42	8.0	15.0	(7.0)
	KEAH4	1	59.33	8.0	15.0	(7.0)
	KEAH5	1	59.31	8.0	15.0	(7.0)
Max Day/High Wind	HEP1	1	59.51	12.2	19.2	(7.0)
	KEAH4	1	59.47	12.2	19.2	(7.0)
	KEAH5	1	59.45	12.2	19.2	(7.0)
Max Day/Low Wind	APOLLO	1	59.48	12.2	19.2	(7.0)
	HUHONUA	1	59.54	12.2	19.2	(7.0)
	KEAH4	2	58.40	13.3	37.4	(24.1)
Transfer Trip Stage 1 & 2						
Max Day/Low Wind	KEAH4	2	59.72	21.2	37.4	(16.2)
Transfer Trip Stage 1, Reduce CT 4						
Max Day/Low Wind	KEAH4	1	59.55	12.2	19.2	(7.0)

Table D-37. 2015 13 MW Legacy PV Results

Load/Wind Scenario	Unit trip	Stages Tripped	Min Freq Hz	Net Load/PV Tripped MW	Load Tripped MW	PV Tripped MW
Min Day/High Wind	APOLLO	2	58.47	4.9	30.3	(25.4)
	HUHONUA	2	58.45	4.9	30.3	(25.4)
Min Day/Low Wind	HUHONUA	2	58.47	4.9	30.3	(25.4)
Max Day/Low Wind	HUHONUA	2	58.45	12.0	37.4	(25.4)
	KEAH4	2	58.34	12.0	37.4	(25.4)
	KEAH5	2	58.33	12.0	37.4	(25.4)
Transfer Trip Stage 1						
Min Day/High Wind	APOLLO	1	58.76	(0.3)	15.5	(15.8)
	HUHONUA	1	59.71	7.2	15.5	(8.3)
Min Day/Low Wind	HUHONUA	1	59.49	7.2	15.5	(8.3)
Max Day/Low Wind	HUHONUA	1	59.47	10.8	19.2	(8.3)
	KEAH4	2	58.43	12.0	37.4	(25.4)
	KEAH5	2	58.42	12.0	37.4	(25.4)
Transfer Trip Stage 1 & 2						
Max Day/Low Wind	KEAH4	2	59.65	18.1	37.4	(19.3)
	KEAH5	2	59.65	18.1	37.4	(19.3)

Table D-38. 2016 10 MW Legacy PV Results

Load/Wind Scenario	Unit trip	Stages Tripped	Min Freq Hz	Net Load/PV Tripped MW	Load Tripped MW	PV Tripped MW
Min Day/High Wind	APOLLO	2	58.38	3.0	30.3	(27.3)
	HUHONUA	2	58.38	3.0	30.3	(27.3)
Min Day/Low Wind	HUHONUA	2	58.40	3.0	30.3	(27.3)
	KEAH4	2	58.42	3.0	30.3	(27.3)
	KEAH5	2	58.42	3.0	30.3	(27.3)
Max Day/High Wind	HUHONUA	2	58.45	10.1	37.4	(27.3)
	KEAH5	2	58.48	13.5	36.8	(23.3)
Max Day/Low Wind	HUHONUA	2	58.41	10.1	37.4	(27.3)
	KEAH4	2	58.24	10.1	37.4	(27.3)
	KEAH5	2	58.22	10.1	37.4	(27.3)
Transfer Trip Stage 1						
Min Day/High Wind	APOLLO	2	58.49	3.0	30.3	(27.3)
	HUHONUA	1	59.71	7.2	15.5	(8.3)
Min Day/Low Wind	HUHONUA	1	59.49	7.2	15.5	(8.3)
	KEAH4	1	59.45	7.2	15.5	(8.3)
	KEAH5	1	59.44	7.2	15.5	(8.3)
Max Day/High Wind	HUHONUA	1	59.67	10.8	19.2	(8.3)
	KEAH5	1	59.64	10.8	19.2	(8.3)
Max Day/Low Wind	HUHONUA	1	59.47	10.8	19.2	(8.3)
	KEAH4	2	58.35	10.1	37.4	(27.3)
	KEAH5	2	58.33	10.1	37.4	(27.3)
Transfer Trip Stage 1 & 2						
Min Day/High Wind	APOLLO	2	59.38	11.0	30.3	(19.3)
Max Day/Low Wind	KEAH4	2	59.65	18.1	37.4	(19.3)
	KEAH5	2	59.65	18.1	37.4	(19.3)

Table D-39. 2016 13 MW Legacy PV Results

E. Essential Grid Services

Grid services include generating capacity plus ancillary services, which are both essential to reliable system operation. Generating capacity is used to meet load demands; ancillary services supplement the generating capacity to help meet demand or correct frequency deviations that occur as a result of normal changes in load and generation, as well as the result of abnormal transient events. Ancillary services can occur in layers, with some taking longer to act than others. The system operator needs to designate which ancillary services are necessary for the system characteristics at the time.

Synchronous generation has traditionally provided generating capacity and ancillary services. Increasing amounts of variable generation, however, diminish the amount of dispatchable generation on the system and the ability of dispatchable generation to provide the needed ancillary services. In many cases, the variable generation resources do not provide the level of ancillary services required for the system's security. In addition, the potential loss of variable distributed generation (whether due to large ramping events or trips due to transient events) has become the largest contingency for which many of the ancillary services must be designed.

For these reasons, new generation resources must have the ability to also provide required ancillary services, or new systems that can provide the ancillary services must be added. Variable generation costs should include the cost of periodic testing and maintenance of their accompanying ancillary systems to ensure the reliability of the electric system. The variable generation protection and control devices should be tested and verified at installation, and tested and maintained periodically after that. Every device should be calibrated and tested at least every three years.

GRID SERVICES

Capacity

Capacity is the maximum reliable amount of electrical output available from a resource. Systems must be operated to ensure there is sufficient capacity online to meet demand in the near term. Systems must be planned and designed to ensure that there is adequate supply of capacity to meet future demands. For dispatchable generation, the capacity is the maximum power output of the generating unit[1]. For variable generation (such as wind or solar power), capacity in the near term is the minimum available amount of output expected in the next one to three hours. The capacity of controlled load in the near term is the minimum level of load under control during each of the four six-hour planning periods of a 24-hour day.

For planning capacity margins, the capacity contribution for variable generation is developed by examining the historical availability during the peak demand periods, to determine the amount of capacity which is very probable to be available in the peak period. Similarly, demand response could contribute to capacity if it is available during the peak period. To count as capacity, the generation does not have to be under automatic generation control (AGC) to reach its maximum rating. Unit control can be by AGC, by human intervention, or a combination, so long as the output is controllable and predictable.

Capacity does not have a response time requirement. However, as stated above, it must be reliably available for a period of time.

Generation capacity should be modeled and tested consistent with HI-Mod-0010 and HI-Mod-0025.[2] Controlled load capacity should be modeled and tested in accordance with capacity testing and modeling requirements for conventional generation capacity. Controlled load will need periodic review and exercising to confirm its stated capacity, as the load characteristics change over time.

1 Generators are designed higher than its prime mover's capability, therefore the generator's nameplate rating can sometimes be higher than what it actually produces.

2 HI-Mod-0010 is the proposed Hawaiian standard for modeling unit capacity used for system studies. HI-Mod-0025 is the proposed Hawaiian standard for testing unit capacity to confirm its model for use in electrical studies.

ANCILLARY SERVICES

Regulating Reserve

Regulating reserve is the amount of unloaded capacity of regulation resources that can be used to match system demand with generation resources and maintain normal frequency. Use of regulating reserve is governed by a command from Automatic Generation Control (AGC) to a change in system demand. A change in system demand results in a change in system frequency, and the AGC program will adjust the generating units under its control to return system frequency to the normal state. A regulation resource is a resource that immediately responds, without delay, to commands from AGC to predictably increase or decrease its generation output. Regulation resources must accurately and predictably respond to AGC commands throughout their range of operation.

Regulation resources can also include non-traditional resources such as controlled loads or storage, providing the necessary control capabilities and response for the AGC interface. Non-generation resources participating in regulation must be capable of sustaining the maximum increase or decrease for at least 30 minutes.

Regulating reserve is used to counter normal changes in load or variable generation. Changes in generation output or controlled loads must be completed within 2 seconds of the AGC command, and must be controllable by AGC to a resolution of 0.1 MW.

In our islanded power system, regulation resources are constantly used to balance load and generation to maintain a 60 Hz frequency reference. The number of controls to regulating resources is greater than larger systems, due to a combination of the impacts of the small system size, its isolation, and the amount of variable wind and solar generation on the systems whose variable output requires additional adjustments from regulating resources. As a result, it has been typical on the island systems that all online resources capable of participating in regulation are used for regulation.

If demand response or storage are used for regulation, the cost of modifying the AGC system to be able to utilize these non-traditional resources as a regulation resource should be included in valuation of these alternate resources. The implementation must include special considerations specific to non-generation resources, such as the need to adopt the regulation algorithms to consider that the limits of the storage or demand response (that is, the response cannot be sustained indefinitely, unlike a dispatchable generator), and to include the rotation of DR within the group to limit impact on DR resources of the same type.

Contingency Reserve

Each of the Companies' systems must be operated such that the system remains operable and the grid frequency can be quickly restored following a contingency situation wherein a generating or transmission resource on the island suddenly trips offline. This can be the largest single unit, the largest combination of dependent units (such as combined cycle units), or the loss of a single transmission line connecting a large generation unit to the system. The contingency reserve is the reserve designated by a system operator to meet these requirements.

Conventional generation, stored energy resources, curtailed variable generation, load shed or DR resources can provide contingency reserves.

Contingency reserves carried on generator resources, including storage, must respond automatically to changes in the system frequency, with a droop response determined by the system operator.

The island systems are unique in that all imbalances between supply and demand result in a change in system frequency. There are no interconnections to draw additional power from in the event of loss of generation. As a result, the island systems rely heavily upon instantaneous underfrequency load-shed to provide protection reserves and contingency reserves. If participating in the instantaneous protection, which may be used for contingency reserves or system protection, DR or load shed must be accurate to ± 0.02 Hz and ± 0.0167 cycles. The response time from frequency trigger to load removal can be no more than 7 cycles.

DR that cannot meet the 7-cycle requirement may be used for a time-delay, or the "kicker block" of under frequency load-shed. This block of load-shed is used for smaller increments of generation loss than the contingency reserves (set at a higher frequency set-point than the faster, instantaneous load-shed). Resources deployed for time-delay load-shed must be controllable within an accuracy of ± 0.02 Hz and ± 0.02 seconds, and have a response time from frequency trigger to load removal adjustable in increments of 0.5 seconds up to 30 seconds, to be considered for use as time delay load-shed.

To ensure consistent performance, DR controls and loads used for contingency reserve should be tested and certified annually. (See HI-Mod-012, HI-Mod-010, and HI-Mod-025, 26, 27.[3]) Annual costs for testing and certification should be included in the total cost for these provisions.

[3] HI-Mod-0012 is the proposed Hawaiian standard for modeling and reporting the dynamic response of system models and results of simulations using these models. HI-Mod-0260 is the proposed Hawaiian standard for verifying plant or excitation equipment used in system models. HI-MOD-0027 is the proposed Hawaiian standard for verifying the models for turbine/governor and frequency control functions.

Controllable load used in any other DR program cannot be included in the loads designated as contingency reserves. The impacts of any DR use on the instantaneous underfrequency load-shed schemes must be evaluated and incorporated into the design to ensure adequate system protection remains.

10-Minute Reserve

Off-line, quick-start resources can be used as 10-minute reserves provided they can be started and synchronized to the grid in 10 minutes or less. These resources may be used for restoring regulation or contingency reserves.

When conditions warrant, a system operator starts the 10-minute reserve resource remotely, and automatically synchronizes it to the power system. The system operator then either loads the resource to a predetermined level, or places it under AGC control, either of which must be completed within 10 minutes. The 10-minute reserve must be able to provide the declared output capability for a minimum of two hours.

The resource can be any resource with a known output capability. Resources can include generators, storage, and controllable loads. A system operator must be able to control these resources to restore regulation or contingency reserves.

30-Minute Reserve

Off-line, 30-minute reserve resources shall be resources that can be operated during normal load and generation conditions, and can be started and synchronized to the grid in 30 minutes or less. They can be counted as capacity resources to meet expected load and demand, or to restore contingency reserves.

When conditions warrant, a system operator starts the resource remotely, synchronizes it, and (if participating in regulating reserves) places it under AGC control within 30 minutes; when it must then be able to serve the capacity for at least three hours.

The 30-minute reserve resource can be any resource with a known capacity. A system operator must be able to control these load resources to restore contingency or regulation reserves.

Long Lead-Time Reserve

Resources that take longer than 30 minutes to be started, synchronized, and placed under AGC control (if participating in regulating reserves) are considered long lead-time reserves. They can be operated during normal load and generation conditions. These resources may be used as capacity resources to meet expected load and demand, and for restoring contingency reserves.

Long lead-time reserves can include any resource with a known capacity. System operators must be able to control these load resources to restore contingency reserves.

Long-lead time resources can be used to meet forecast peak demand, in addition to restoring contingency reserves or the replacement of fast-start reserves. Long-lead time reserves must be able to serve the capacity for at least three hours.

Black Start Resource

A black start resource is a generating unit and its associated equipment that can be started without support from the power system, or is designed to remain energized without connection to the remainder of the power system. A black start resource needs to be able to energize a bus, meeting a system operator's restoration plan needs for real and reactive power capability, frequency, and voltage control. It must also be included in the transmission operator's restoration plan.

A black start resource must be capable of starting within 10 minutes. The starting sequence can be manual or automatic.

Primary Frequency Response

Primary frequency response is a generation resource's automatic response to an increase or decrease in frequency. The primary frequency response is the result of governor control, not control by AGC or frequency triggers, and must be sustainable. Unless controlled by a governor or droop response device, controlled load cannot provide primary frequency control.

The resource must immediately alter its output in direct proportion to the change in frequency, to counter the change in frequency. The response is determined by the design setting, which is specified by the system operator as a droop response from 1 to 5 percent. The response must be measurable within 10 seconds of the change in frequency. Under certain conditions, a certain generator resource may be placed on zero droop (also called isochronous control), such as under disturbance and restoration. Under these conditions, the isochronous generator will control system frequency instead of AGC.

Primary frequency response of a device is subject to the limitations of equipment. Equipment that is at its maximum operating output is not able to increase output in response to low frequency, but will still decrease its output in response to increasing frequency. Any generator at its maximum output, or a variable wind generator producing the maximum output for the available wind energy, may, if designed to have a frequency response, provide downward response to high frequency, but will not be able to increase output in response to low frequency. Curtailed variable generation or conventional generation operating below its maximum limit and above its minimum limit can contribute both upward and downward primary frequency response. Based on the design of its system, energy storage systems can also provide primary frequency response.

Primary frequency response cannot be withdrawn if frequency is within the bandwidth of a reportable disturbance as defined in BAL-HI-002. The primary frequency response should replace the inertia or fast frequency response of the system without a drop in system frequency.

Inertial or Fast Frequency Response

Inertial or fast frequency response is a local response to a change in frequency, reducing its rate of change. The response is immediate (measured in milliseconds), continuous, and proportional to the change in frequency, and does not rely on governor controls. The response is available even if the resource is also being used for other services (such as regulation or ramping). This response is short-lived, lasting not more than two to three seconds.

Inertial response relies on the rotating mass of a conventional generator. It can also be supplied by flywheels. Fast frequency response can be supplied by battery storage. If the inertia or fast response reserves are supplied from a resource that cannot sustain the load, primary or secondary resources must be available to take over without a drop in system frequency.

Secondary Frequency Control

Secondary (or supplemental) frequency control is provided by resources in response to AGC to correct a change in frequency, using both the regulating and contingency reserves. Secondary frequency response can be provided by conventional generation, load control, or variable generation, all of which must be under AGC control. If AGC is disabled, such as during system restoration, secondary frequency control will be provided by manual operation of resources to maintain the isochronous generator within its lower and upper limits. The response requirements for secondary control are the same as for participation in regulating reserves.

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F. Modeling Assumptions Data

The Hawaiian Electric Companies created this PSIP based, in parts, on a realization of the current state of the electric systems in 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.

Tables

UTILITY COST OF CAPITAL AND FINANCIAL ASSUMPTIONS

The Hawaiian Electric Companies finance their investments through two main sources of capital: debt (borrowed money) or equity (invested money). In both cases, we pay a certain rate of return for the use of this money. This rate of return is our *Cost of Capital*.

Table F-1 lists the various sources of capital, their weight (percent of the entire capital portfolio), and their individual rates of return. Composite percentages for costs of capital are presented under the table.

Capital Source	Weight	Rate
Short Term Debt	3.0%	4.0%
Long Term Debt (Taxable Debt)	39.0%	7.0%
Hybrids	0.0%	6.5%
Preferred Stock	1.0%	6.5%
Common Stock	57.0%	11.0%

Composite Weighted Average 9.185%
After-Tax Composite Weighted Average 8.076%

Table F-1. Utility Cost of Capital

FUEL SUPPLY AND PRICES FORECASTS

The potential cost of producing electricity will depend, in part, on the cost of fuels utilized in the generation of power. The cost of different fuels over the next 20-plus years are forecast and used in the PSIP analyses. Maui Electric may burn the following different types of fuels during the study period on Hawaiʻi Island:

- *No.2 Diesel*
- *Medium Sulfur Fuel Oil (MSFO)*, and also referred to as Industrial Fuel Oil (IFO) or Bunker Fuel Oil; is less 2% sulfur content.
- *Low Sulfur Industrial Fuel Oil (LSIFO)* is used when a fuel with lower sulfur content than MSFO is needed. It is about 0.75% sulfur content.
- *Ultra Low Sulfur Diesel (ULSD)* that is as low as 0.0015% sulfur content.
- *Biodiesel*
- *Petroleum Naphtha* is a desulfurized, high-octane fuel derived from crude oil.
- *Liquefied Natural Gas (LNG)* is a natural gas (a fossil fuel) that has been converted to a liquid, which sharply decreases volume and eases transportation and storage.

How the Fuel Price Forecasts Were Derived

Petroleum-Based Diesel Fuels

In general, we derived petroleum-based diesel fuels forecasts by applying the relationship between historical crude oil commodity prices and historical fuel purchase prices to forecasts for the crude oil commodity price. The petroleum-based fuel forecasts reflect U.S. Energy Information Administration (EIA) forecast data for *Imported Crude Oil* and *GDP Chain-Type Price Index* from the 2014 Annual Energy Outlook (AEO2014) year-by-year tables. Historical prices for crude oil are EIA publication table data for the *Monthly Energy Review* and macroeconomic data. Historical actual fuel costs incorporate taxes and certain fuel-related and fuel-handling costs including but not limited to trucking and ocean transport, petroleum inspection, and terminalling fees.

Biodiesel

Biodiesel forecasts are generally derived by comparing commodity forecasts with recent biofuel contracts and RFP bids to determine adjustments needed to derive each company's respective biodiesel price forecast from forecasted commodities. EIA provides low, reference, and high petroleum forecasts, which are used to project low, reference, and high petroleum-based fuel price forecasts. A similar commodity forecast has not been found for biodiesel, although EIA might provide one in the future. In lieu of such a source, we used the Food and Agricultural Policy Research Institute at Iowa State University (FAPRI) to create a reference forecast, which we then scaled on the EIA Petroleum forecasts to create a low and high biodiesel forecast.

Liquefied Natural Gas (LNG)

We do not have historical purchase data for LNG in Hawai'i. For purposes of this PSIP analyses, LNG pricing (delivered to the power generation facilities) were developed as described in Appendix I: LNG to Hawai'i.

Hawai'i Electric Light Fuel Price Forecasts

$/MMBtu	Fuel Price Forecasts						
Year	*No.2 Diesel*	*MSFO*	*LSIFO*	*ULSD*	*Biodiesel*	*Naphtha*	*LNG*
2014	$22.73	$16.01	$18.48	$23.37	$34.00	$23.40	n/a
2015	$22.72	$15.97	$18.56	$23.36	$30.52	$23.41	$16.82
2016	$22.28	$15.59	$19.06	$22.91	$30.71	$23.03	$17.63
2017	$22.26	$15.55	$19.74	$22.89	$31.45	$23.05	$18.29
2018	$22.74	$15.90	$20.46	$23.39	$32.15	$23.53	$19.14
2019	$23.51	$16.48	$21.21	$24.18	$32.18	$24.29	$19.37
2020	$24.38	$17.13	$22.00	$25.07	$32.24	$25.15	$19.42
2021	$25.36	$17.86	$22.84	$26.07	$32.48	$26.10	$20.19
2022	$26.37	$18.62	$23.72	$27.11	$32.88	$27.09	$20.81
2023	$27.45	$19.43	$24.65	$28.21	$33.01	$28.14	$21.42
2024	$28.52	$20.24	$25.60	$29.31	$33.51	$29.19	$22.09
2025	$29.57	$21.03	$26.60	$30.39	$33.82	$30.22	$22.71
2026	$30.57	$21.78	$27.63	$31.42	$34.13	$31.20	$23.36
2027	$31.72	$22.65	$28.71	$32.60	$34.44	$32.32	$24.04
2028	$32.80	$23.45	$29.83	$33.70	$34.75	$33.37	$24.70
2029	$33.93	$24.30	$31.01	$34.86	$35.06	$34.49	$25.49
2030	$35.01	$25.10	$32.23	$35.97	$35.38	$35.55	$26.43

Table F-2. Fuel Price Forecasts

SALES AND PEAK FORECASTS

Sales and net peak forecasts were developed with and without the effects of Dynamic Pricing. As described in the *Integrated Demand Response Portfolio Plan (IDRPP)*[1] Dynamic Pricing is a demand response program that incent customers (on a voluntary basis) to change their energy use behavior, resulting is increased load demand during certain periods of the day and decreased net peak demand.

Sales Forecasts (without Dynamic Pricing Adjustments)

Year	Load without DG PV		Total DG PV (Uncurtailed)		Sales with DG PV
	Net Generation: GWh (a)	*Sales: Customer GWh (b)*	*Net GWh (c)*	*Customer GWh (d)*	*Customer GWh (b – d)*
2015	1,250.0	1,157.4	100.0	92.6	1,064.8
2016	1,269.8	1,170.3	113.9	104.9	1,065.3
2017	1,266.4	1,180.1	125.1	116.6	1,063.5
2018	1,282.5	1,195.1	129.9	121.1	1,074.0
2019	1,294.8	1,206.6	134.4	125.2	1,081.3
2020	1,306.4	1,217.4	139.1	129.7	1,087.7
2021	1,312.1	1,222.8	142.4	132.7	1,090.1
2022	1,319.8	1,229.9	145.9	136.0	1,093.9
2023	1,325.7	1,235.4	149.4	139.2	1,096.1
2024	1,335.4	1,244.4	153.2	142.8	1,101.6
2025	1,336.4	1,245.4	156.1	145.5	1,099.9
2026	1,338.2	1,247.0	159.3	148.4	1,098.6
2027	1,338.2	1,247.1	162.3	151.2	1,095.8
2028	1,336.5	1,245.4	165.7	154.4	1,091.0
2029	1,324.5	1,234.3	168.0	156.6	1,077.7
2030	1,313.8	1,224.3	170.7	159.1	1,065.2

Loss Factor: 7.40% in 2015, 7.84% in 2016, 6.81% in 2017 onward

Table F-3. Sales Forecasts (without Dynamic Pricing Adjustments)

[1] The IDRPP was filed on July 28, 2014.

Sales Forecasts (with Dynamic Pricing Adjustments)

Year	Load without DG PV		Total DG PV (Uncurtailed)		Sales with DG PV
	Net Generation: GWh (a)	*Sales: Customer GWh (b)*	*Net GWh (c)*	*Customer GWh (d)*	*Customer GWh (b – d)*
2015	1,250.0	1,157.5	100.0	92.6	1,064.8
2016	1,269.6	1,170.1	113.9	104.9	1,065.2
2017	1,263.0	1,176.9	125.1	116.6	1,060.4
2018	1,279.0	1,191.9	129.9	121.1	1,070.8
2019	1,291.3	1,203.3	134.4	125.2	1,078.1
2020	1,302.8	1,214.0	139.1	129.7	1,084.4
2021	1,308.5	1,219.4	142.4	132.7	1,086.7
2022	1,316.3	1,226.6	145.9	136.0	1,090.6
2023	1,322.1	1,232.0	149.4	139.2	1,092.8
2024	1,331.7	1,241.0	153.2	142.8	1,098.2
2025	1,332.8	1,242.0	156.1	145.5	1,096.5
2026	1,334.6	1,243.6	159.3	148.4	1,095.2
2027	1,334.6	1,243.7	162.3	151.2	1,092.4
2028	1,332.9	1,242.1	165.7	154.4	1,087.7
2029	1,320.9	1,230.9	168.0	156.6	1,074.3
2030	1,310.2	1,221.0	170.7	159.1	1,061.9

Table F-4. Sales Forecasts (with Dynamic Pricing Adjustments)

Net Peak Forecasts

Year	Net Peak (w/o DG PV + w/o Dynamic Pricing)	Net Peak (w/o DG PV + w/ Dynamic Pricing)	Total DG PV)
	MW	*MW*	*MW*
2015	189.8	189.8	64.8
2016	188.0	188.7	77.8
2017	182.2	189.0	85.7
2018	184.2	191.1	88.6
2019	186.0	192.9	91.4
2020	187.4	194.3	94.1
2021	188.3	195.2	96.3
2022	189.7	196.9	98.5
2023	190.4	197.4	100.6
2024	190.7	197.7	102.7
2025	191.6	198.6	104.7
2026	190.4	197.4	106.6
2027	189.8	196.1	108.5
2028	190.1	194.9	110.3
2029	187.5	193.7	112.0
2030	186.3	192.4	113.7

Table F-5. Net Peak Forecasts

DEMAND RESPONSE

Demand Response Programs

The *Integrated Demand Response Portfolio Plan*[2] introduced seven categories of programs.

Residential and Small Business Direct Load Control Program (RBDLC). This new RBDLC program continues and expands upon the existing RDLC and Small Business Direct Load Control (SBDLC) programs. RBDLC enables new and existing single-family, multi-family, and master metered residential customers, in addition to small businesses, to participate in an interruptible load program for electric water heaters, air conditioning, and other specific end uses.

Residential and Small Business Flexible Program. This new program enables residential and small business customers with targeted devices (such as controllable grid-interactive water heaters) to meet ancillary service requirements by providing adjustable load control and thermal energy storage features over various timeframes.

Commercial & Industrial Direct Load Control Program (CIDLC). The updated CIDLC program allows commercial and industrial customers to help shift load, usually during peak periods, by allowing their central air conditioning, electric water heaters, and other applicable appliances to be remotely cycled or disconnected.

Commercial & Industrial Flexible Program. This new program enables commercial and industrial customers with targeted devices (such as air conditioning, ventilation, refrigeration, water heating, and lighting) to meet ancillary service requirements by providing adjustable load control and/or thermal energy storage features over differing timeframes.

Commercial & Industrial Pumping Program. The Commercial & Industrial Pumping program enables county and privately owned water facilities with pumping loads and water storage capabilities to be dynamically controlled. This will be accomplished by using variable frequency drives and emergency standby generation to adjust power demand and supply at the water facilities, and better balance supply and demand of power system loads.

Customer Firm Generation Program. Commercial and industrial customers who participate in this program allow system operators to dispatch their on-site standby generators to help meet power system load demand. Monitoring equipment on the

[2] *ibid.*

standby generators tracks the usage of program participation, testing, and assures environmental permit compliance.

Dynamic & Critical Peak Pricing program. This program enables load shifting to "smooth" the daily system load profiles based on demand and price.

Cost of DR Programs

Several grid services foretell the cost of the demand response programs. The avoided cost for a grid service is the cost of an alternative resource (energy storage or a generator) providing the equivalent service. Avoided cost could be based on several factors, including installed capacity costs, fuel costs, and cost of alternatives, each of which depends on the current state of the system. Potential avoided cost calculations include:

Capacity: The cost of new capacity deferral.

Regulating Reserve: The cost of a frequency support energy storage device, or the savings from reduced regulating reserve requirements, as calculated using a production cost model.

Contingency Reserve:. For O'ahu, the fuel cost savings resulting from a reduction in the contingency reserve requirement from thermal generation commensurate with the DR resources assumed to meet the contingency reserve requirements, as calculated using a production cost model. For Maui and Hawai'i, this would offset under-frequency load shedding, which potentially provides a customer benefit but not a readily evaluated economic benefit.

Non-AGC Ramping: The fuel cost and maintenance savings resulting from deferring the start of units to compensate for variable energy down ramps.

Non-Spinning Reserve: The cost of maintaining existing resources that currently meet non-spinning reserves (small diesel units).

Advanced Energy Delivery: The production cost savings incurred by shifting demand, as compared to production costs if demand were not shifted.

All of the above avoided costs are offset by the program costs and reduced sales. Where a resource or program can meet two or more grid service requirements, although not simultaneously, the avoided cost is determined by the most economic use. The maximum price paid for a DR program would be the difference between the avoided cost and the program's operational cost. At the maximum price, the overall rate impact to customers would be economically neutral.

Demand Response Grid Service Requirements and MW

Grid Service	Residential and Small Business Direct Load Control				Residential and Small Business Flexible	
	Capacity	*Contingency Reserve*	*Non-AGC Ramping*	*Non-Spinning Reserve*	*Regulating Reserve*	*Accelerated Energy Delivery*
Frequency	Unlimited	Unlimited	Unlimited	Unlimited	Continuous	Continuous
Event Length	1 hour	1 hour	1 hour	1 hour	Minutes	Minutes
Event Cost	None	None	None	None	None	None
Year	*MW*	*MW*	*MW*	*MW*	*MW*	*MW*
2014	0.0	0.0	0.0	0.0	0.0	0.0
2015	0.3	0.0	0.3	0.3	0.2	0.1
2016	1.4	0.0	1.4	1.4	0.3	0.2
2017	2.6	0.0	2.6	2.6	0.5	0.3
2018	3.7	0.0	3.7	3.7	0.7	0.4
2019	4.9	0.0	4.9	4.9	0.9	0.5
2020	6.0	0.0	6.0	6.0	1.1	0.6
2021	6.0	0.0	6.0	6.0	1.2	0.7
2022	6.0	0.0	6.0	6.0	1.4	0.7
2023	6.0	0.0	6.0	6.0	1.4	0.7
2024	6.0	0.0	6.0	6.0	1.4	0.7
2025	6.0	0.0	6.0	6.0	1.4	0.7
2026	6.0	0.0	6.0	6.0	1.4	0.7
2027	6.0	0.0	6.0	6.0	1.4	0.7
2028	6.0	0.0	6.0	6.0	1.4	0.7
2029	6.0	0.0	6.0	6.0	1.4	0.7
2030	6.0	0.0	6.0	6.0	1.4	0.7

Table F-6. Demand Response Program Grid Service Requirements and MW Benefits (1 of 2)

Grid Service	Commercial & Industrial Direct Load Control		Commercial & Industrial Flexible		Commercial & Industrial Pumping		Customer Firm Generation
	Capacity	*Contingency Reserve*	*Regulating Reserve*	*Non-AGC Ramping*	*Regulating Reserve*	*Non-AGC Ramping*	*Capacity*
Frequency	300 hours per year	300 hours per year	Continuous	Continuous	Continuous	Continuous	100 hours per year
Event Length	4 hours maximum	4 hours maximum	Minutes	Minutes	Minutes	Minutes	4 hours maximum
Event Cost	50¢/kWh	50¢/kWh	None	None	None	None	50¢/kWh
Year	*MW*	*MW*	*MW*	*MW*	*MW*	*MW*	*MW*
2014	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2015	0.2	0.0	0.1	0.2	0.0	0.0	0.0
2016	0.6	0.0	0.1	0.3	0.0	0.0	3.0
2017	1.0	0.0	0.2	0.5	0.1	0.1	3.0
2018	1.4	0.0	0.2	0.7	0.1	0.1	3.0
2019	1.8	0.0	0.3	0.9	0.1	0.1	3.0
2020	2.2	0.0	0.3	1.1	0.1	0.1	3.0
2021	2.2	0.0	0.4	1.3	0.2	0.2	3.0
2022	2.2	0.0	0.4	1.4	0.2	0.2	3.0
2023	2.2	0.0	0.4	1.4	0.2	0.2	3.0
2024	2.2	0.0	0.4	1.4	0.2	0.2	3.0
2025	2.2	0.0	0.4	1.4	0.2	0.2	3.0
2026	2.2	0.0	0.4	1.4	0.2	0.2	3.0
2027	2.2	0.0	0.4	1.4	0.2	0.2	3.0
2028	2.2	0.0	0.4	1.4	0.2	0.2	3.0
2029	2.2	0.0	0.4	1.4	0.2	0.2	3.0
2030	2.2	0.0	0.4	1.4	0.2	0.2	3.0

Table F-7. Demand Response Program Grid Service Requirements and MW (2 of 2)

RESOURCE CAPITAL COSTS[3]

The calculations for the capital cost for different resources used in the PSIP modeling analyses are shown in Tables F-46 through F-54.

The overall cost escalation rate used throughout our analyses is 1.83%.

Table Legend

Column Heading	Explanation
NREL Capital Cost, 2009 $, $/kW	The starting basis for capital costs used in the analyses unless noted otherwise
B&V Hawai'i Capital Cost, 2009 $, $/kW	The starting basis for capital cost of the ICE (<100 MW)
BCG Capital Cost, 2009 $, $/kW	The starting basis for capital cost of the ICE (>100 MW)
EIA Capital Cost, 2009 $, $/kW	The starting basis for capital cost of the Waste-to-Energy resource
Capital Cost, Nominal $, $/kW	An escalated capital cost of the resource from 2009 dollars up to the year of installation
EIA Adjustment Factor	A location specific cost adjustment factor for Hawai'i
Utility Adjustment Factor	A technology specific cost adjustment factor
Adjusted Capital Cost, Nominal $, $/kW	An escalated capital cost of the resource that reflects any cost adjustment factors
NREL Fixed O&M, 2009 $, $/kW-year	The starting basis for fixed O&M used in the analyses
Fixed O&M, Nominal $, $/kW	An escalated fixed O&M cost of the resource from 2009 dollars up to the year of installation
NREL Variable O&M, 2009 $, $/MWh	The starting basis for variable O&M used in the analyses
Variable O&M, Nominal $, $/MWh	An escalated variable O&M cost of the resource from 2009 dollars up to the year of installation

Table F-8. Resource Capital Cost Table Legend

3 Calculations were based on *Cost and Performance Data for Power Generation Technologies*, prepared for the National Renewable Energy Laboratory (NREL), Black & Veatch, February 2012.

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Simple Cycle Large (40–100 MW) Aeroderivative Combustion Turbine

Year Installed	NREL Capital Cost, 2009 $ $/kW	Capital Cost Nominal $ $/kW	EIA Adjustment Factor	Utility Adjustment Factor	Adjusted Capital Cost Nominal $ $/kW	NREL Fixed O&M, 2009 $ $/kW-year	Fixed O&M Nominal $ $/kW	NREL Variable O&M, 2009 $ $/MWh	Variable O&M Nominal $ $/MWh
2015	$651.00	$726.04	51.5%	1.46	$1,608.29	$5.26	$5.87	$29.90	$33.35
2020	$651.00	$795.14	51.5%	1.46	$1,761.36	$5.26	$6.42	$29.90	$36.52
2025	$651.00	$870.81	51.5%	1.46	$1,928.99	$5.26	$7.04	$29.90	$40.00
2030	$651.00	$953.69	51.5%	1.46	$2,112.58	$5.26	$7.71	$29.90	$43.80

Table F-9. Simple Cycle Large (40–100 MW) Aeroderivative Combustion Turbine

Simple Cycle Small (<40 MW) Aeroderivative Combustion Turbine

Year Installed	NREL Capital Cost, 2009 $ $/kW	Capital Cost Nominal $ $/kW	EIA Adjustment Factor	Utility Adjustment Factor	Adjusted Capital Cost Nominal $ $/kW	NREL Fixed O&M, 2009 $ $/kW-year	Fixed O&M Nominal $ $/kW	NREL Variable O&M, 2009 $ $/MWh	Variable O&M Nominal $ $/MWh
2015	$651.00	$726.04	51.5%	1.77	$1,945.73	$5.26	$5.87	$29.90	$33.35
2020	$651.00	$795.14	51.5%	1.77	$2,130.91	$5.26	$6.42	$29.90	$36.52
2025	$651.00	$870.81	51.5%	1.77	$2,333.71	$5.26	$7.04	$29.90	$40.00
2030	$651.00	$953.69	51.5%	1.77	$2,555.82	$5.26	$7.71	$29.90	$43.80

Table F-10. Simple Cycle Small (<40 MW) Aeroderivative Combustion Turbine

Internal Combustion (<100 MW) Engine

Year Installed	B&V Hawai'i Capital Cost, 2012 $ $/kW	Capital Cost Nominal $ $/kW	EIA Adjustment Factor	Utility Adjustment Factor	Adjusted Capital Cost Nominal $ $/kW	NREL Fixed O&M, 2009 $ $/kW-year	Fixed O&M Nominal $ $/kW	NREL Variable O&M, 2009 $ $/MWh	Variable O&M Nominal $ $/MWh
2015	$2,810.00	$2,967.54	0.0%	1.00	$2,967.54	$10.14	$11.31	$11.74	$13.09
2020	$2,810.00	$3,249.96	0.0%	1.00	$3,249.96	$10.14	$12.39	$11.74	$14.34
2025	$2,810.00	$3,559.27	0.0%	1.00	$3,559.27	$10.14	$13.56	$11.74	$15.70
2030	$2,810.00	$3,898.02	0.0%	1.00	$3,898.02	$10.14	$14.85	$11.74	$17.20

Table F-11. Internal Combustion (<100 MW) Engine

Internal Combustion (>100 MW) Engine

Year Installed	BCG Capital Cost, 2012 $ $/kW	Capital Cost Nominal $ $/kW	EIA Adjustment Factor	Utility Adjustment Factor	Adjusted Capital Cost Nominal $ $/kW	NREL Fixed O&M, 2009 $ $/kW-year	Fixed O&M Nominal $ $/kW	NREL Variable O&M, 2009 $ $/MWh	Variable O&M Nominal $ $/MWh
2015	$1,352.00	$1,427.80	0.0%	1.20	$1,713.36	$10.14	$11.31	$11.74	$13.09
2020	$1,352.00	$1,563.68	0.0%	1.20	$1,876.42	$10.14	$12.39	$11.74	$14.34
2025	$1,352.00	$1,712.50	0.0%	1.20	$2,055.01	$10.14	$13.56	$11.74	$15.70
2030	$1,352.00	$1,875.49	0.0%	1.20	$2,250.59	$10.14	$14.85	$11.74	$17.20

Table F-12. Internal Combustion (>100 MW) Engine

Residential Photovoltaics

Year Installed	NREL Capital Cost, 2009 $ $/kW	Capital Cost Nominal $ $/kW	EIA Adjustment Factor	Utility Adjustment Factor	Adjusted Capital Cost Nominal $ $/kW	NREL Fixed O&M, 2009 $ $/kW-year	Fixed O&M Nominal $ $/kW	NREL Variable O&M, 2009 $ $/MWh	Variable O&M Nominal $ $/MWh
2015	$4,340.00	$4,840.26	0.0%	1.00	$4,840.26	$48.00	$53.53	$0.00	$0.00
2020	$3,750.00	$4,580.29	0.0%	1.00	$4,580.29	$45.00	$54.96	$0.00	$0.00
2025	$3,460.00	$4,628.29	0.0%	1.00	$4,628.29	$43.00	$57.52	$0.00	$0.00
2030	$3,290.00	$4,819.74	0.0%	1.00	$4,819.74	$41.00	$60.06	$0.00	$0.00

Table F-13. Residential Photovoltaics

Utility Scale Photovoltaics (Fixed Tilt)

Year Installed	NREL Capital Cost, 2009 $ $/kW	Capital Cost Nominal $ $/kW	EIA Adjustment Factor	Utility Adjustment Factor	Adjusted Capital Cost Nominal $ $/kW	NREL Fixed O&M, 2009 $ $/kW-year	Fixed O&M Nominal $ $/kW	NREL Variable O&M, 2009 $ $/MWh	Variable O&M Nominal $ $/MWh
2015	$2,550.00	$2,843.93	0.0%	0.75	$2,132.95	$48.00	$53.53	$0.00	$0.00
2020	$2,410.00	$2,943.60	0.0%	0.75	$2,207.70	$45.00	$54.96	$0.00	$0.00
2025	$2,280.00	$3,049.86	0.0%	0.75	$2,287.39	$43.00	$57.52	$0.00	$0.00
2030	$2,180.00	$3,193.62	0.0%	0.75	$2,395.22	$41.00	$60.06	$0.00	$0.00

Table F-14. Utility Scale Photovoltaics (Fixed Tilt)

Geothermal, Non-Dispatchable

Year Installed	NREL Capital Cost, 2009 $ $/kW	Capital Cost Nominal $ $/kW	EIA Adjustment Factor	Utility Adjustment Factor	Adjusted Capital Cost Nominal $ $/kW	NREL Fixed O&M, 2009 $ $/kW-year	Fixed O&M Nominal $ $/kW	NREL Variable O&M, 2009 $ $/MWh	Variable O&M Nominal $ $/MWh
2015	$5,940.00	$6,624.69	27.2%	1.00	$8,426.61	$36.00	$40.15	$31.00	$34.57
2020	$5,940.00	$7,255.18	27.2%	1.00	$9,228.59	$36.00	$43.97	$31.00	$37.86
2025	$5,940.00	$7,945.68	27.2%	1.00	$10,106.91	$36.00	$48.16	$31.00	$41.47
2030	$5,940.00	$8,701.89	27.2%	1.00	$11,068.81	$36.00	$52.74	$31.00	$45.41

Table F-15. Geothermal, Non-Dispatchable

Geothermal, Fully Dispatchable

Year Installed	NREL Capital Cost, 2009 $ $/kW	Capital Cost Nominal $ $/kW	EIA Adjustment Factor	Utility Adjustment Factor	Adjusted Capital Cost Nominal $ $/kW	NREL Fixed O&M, 2009 $ $/kW-year	Fixed O&M Nominal $ $/kW	NREL Variable O&M, 2009 $ $/MWh	Variable O&M Nominal $ $/MWh
2015	$6,065.00	$6,764.10	27.2%	1.00	$8,603.94	$36.00	$40.15	$31.00	$34.57
2020	$6,065.00	$7,407.86	27.2%	1.00	$9,422.80	$36.00	$43.97	$31.00	$37.86
2025	$6,065.00	$8,112.89	27.2%	1.00	$10,319.59	$36.00	$48.16	$31.00	$41.47
2030	$6,065.00	$8,885.02	27.2%	1.00	$11,301.74	$36.00	$52.74	$31.00	$45.41

Table F-16. Geothermal, Fully Dispatchable

Combined Cycle Turbine

Year Installed	NREL Capital Cost, 2009 $ $/kW	Capital Cost Nominal $ $/kW	EIA Adjustment Factor	Utility Adjustment Factor	Adjusted Capital Cost Nominal $ $/kW	NREL Fixed O&M, 2009 $ $/kW-year	Fixed O&M Nominal $ $/kW	NREL Variable O&M, 2009 $ $/MWh	Variable O&M Nominal $ $/MWh
2015	$1,230.00	$1,371.78	53.1%	1.21	$2,533.86	$6.31	$7.04	$3.67	$4.09
2020	$1,230.00	$1,502.34	53.1%	1.21	$2,775.02	$6.31	$7.71	$3.67	$4.48
2025	$1,230.00	$1,645.32	53.1%	1.21	$3,039.13	$6.31	$8.44	$3.67	$4.91
2030	$1,230.00	$1,801.91	53.1%	1.21	$3,328.37	$6.31	$9.24	$3.67	$5.38

Table F-17. Combined Cycle Turbine

Run-of-River Hydroelectric

Year Installed	NREL Capital Cost, 2009 $ $/kW	Capital Cost Nominal $ $/kW	EIA Adjustment Factor	Utility Adjustment Factor	Adjusted Capital Cost Nominal $ $/kW	NREL Fixed O&M, 2009 $ $/kW-year	Fixed O&M Nominal $ $/kW	NREL Variable O&M, 2009 $ $/MWh	Variable O&M Nominal $ $/MWh
2015	$3,500.00	$3,903.44	19.1%	1.35	$6,276.14	$15.00	$16.73	$24.00	$26.77
2020	$3,500.00	$4,274.94	19.1%	1.35	$6,873.46	$15.00	$18.32	$24.00	$29.31
2025	$3,500.00	$4,681.80	19.1%	1.35	$7,527.63	$15.00	$20.06	$24.00	$32.10
2030	$3,500.00	$5,127.38	19.1%	1.35	$8,244.06	$15.00	$21.97	$24.00	$35.16

Table F-18. Run-of-River Hydroelectric

Wind, Onshore

Year Installed	NREL Capital Cost, 2009 $ $/kW	Capital Cost Nominal $ $/kW	EIA Adjustment Factor	Utility Adjustment Factor	Adjusted Capital Cost Nominal $ $/kW	NREL Fixed O&M, 2009 $ $/kW-year	Fixed O&M Nominal $ $/kW	NREL Variable O&M, 2009 $ $/MWh	Variable O&M Nominal $ $/MWh
2015	$1,980.00	$2,208.23	30.1%	1.00	$2,872.91	$60.00	$66.92	$0.00	$0.00
2020	$1,980.00	$2,418.39	30.1%	1.00	$3,146.33	$60.00	$73.28	$0.00	$0.00
2025	$1,980.00	$2,648.56	30.1%	1.00	$3,445.78	$60.00	$80.26	$0.00	$0.00
2030	$1,980.00	$2,900.63	30.1%	1.00	$3,773.72	$60.00	$87.90	$0.00	$0.00

Table F-19. Wind, Onshore

Wind, Offshore (Floating Platform)

Year Installed	NREL Capital Cost, 2009 $ $/kW	Capital Cost Nominal $ $/kW	EIA Adjustment Factor	Utility Adjustment Factor	Adjusted Capital Cost Nominal $ $/kW	NREL Fixed O&M, 2009 $ $/kW-year	Fixed O&M Nominal $ $/kW	NREL Variable O&M, 2009 $ $/MWh	Variable O&M Nominal $ $/MWh
2015	Not Commercial	Not Commercial	0.0%	Not Commercial	$0.00	$0.00	$0.00	$0.00	Not Commercial
2020	$4,200.00	$5,129.93	30.1%	1.00	$6,674.04	$130.00	$158.78	$0.00	$0.00
2025	$4,090.00	$5,471.02	30.1%	1.00	$7,117.79	$130.00	$173.90	$0.00	$0.00
2030	$3,990.00	$5,845.21	30.1%	1.00	$7,604.62	$130.00	$190.45	$0.00	$0.00

Table F-20. Wind, Offshore (Floating Platform)

Waste-to-Energy

Year Installed	EIA Capital Cost, 2009 $ $/kW	Capital Cost Nominal $ $/kW	EIA Adjustment Factor	Utility Adjustment Factor	Adjusted Capital Cost Nominal $ $/kW	NREL Fixed O&M, 2009 $ $/kW-year	Fixed O&M Nominal $ $/kW	NREL Variable O&M, 2009 $ $/MWh	Variable O&M Nominal $ $/MWh
2015	$8,312.00	$8,777.99	19.6%	1.00	$10,498.48	$392.82	$414.84	$8.75	$9.24
2020	$8,312.00	$9,613.42	19.6%	1.00	$11,497.65	$392.82	$454.32	$8.75	$10.12
2025	$8,312.00	$10,528.36	19.6%	1.00	$12,591.91	$392.82	$497.56	$8.75	$11.08
2030	$8,312.00	$11,530.37	19.6%	1.00	$13,790.32	$392.82	$544.92	$8.75	$12.14

Table F-21. Waste-to-Energy

Biomass Steam

Year Installed	NREL Capital Cost, 2009 $ $/kW	Capital Cost Nominal $ $/kW	EIA Adjustment Factor	Utility Adjustment Factor	Adjusted Capital Cost Nominal $ $/kW	NREL Fixed O&M, 2009 $ $/kW-year	Fixed O&M Nominal $ $/kW	NREL Variable O&M, 2009 $ $/MWh	Variable O&M Nominal $ $/MWh
2015	$3,830.00	$4,271.48	53.6%	1.00	$6,560.99	$95.00	$105.95	$15.00	$16.73
2020	$3,830.00	$4,678.01	53.6%	1.00	$7,185.42	$95.00	$116.03	$15.00	$18.32
2025	$3,830.00	$5,123.23	53.6%	1.00	$7,869.27	$95.00	$127.08	$15.00	$20.06
2030	$3,830.00	$5,610.82	53.6%	1.00	$8,618.22	$95.00	$139.17	$15.00	$21.97

Table F-22. Biomass Steam

Ocean Wave

Year Installed	NREL Capital Cost, 2009 $ $/kW	Capital Cost Nominal $ $/kW	EIA Adjustment Factor	Utility Adjustment Factor	Adjusted Capital Cost Nominal $ $/kW	NREL Fixed O&M, 2009 $ $/kW-year	Fixed O&M Nominal $ $/kW	NREL Variable O&M, 2009 $ $/MWh	Variable O&M Nominal $ $/MWh
2015	$9,240.00	$10,305.08	13.8%	1.00	$11,727.18	$474.00	$528.64	$0.00	$0.00
2020	$6,960.00	$8,501.02	13.8%	1.00	$9,674.16	$357.00	$436.04	$0.00	$0.00
2025	$5,700.00	$7,624.64	13.8%	1.00	$8,676.84	$292.00	$390.60	$0.00	$0.00
2030	$4,730.00	$6,929.29	13.8%	1.00	$7,885.53	$243.00	$355.99	$0.00	$0.00

Table F-23. Ocean Wave

G. Generation Resources

Electricity is typically produced through a turbine-generator process. The turbine rotates and drives a shaft in the generator to create electrical current.

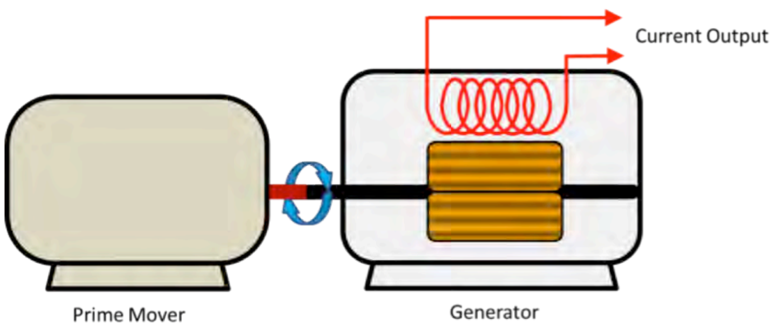

Figure G-1. Turbine-Generator Process

Turbines can be powered by different variable and firm sources. Variable energy is unpredictable because its energy source cannot be scheduled nor can it be controlled. Firm energy can be predicted, scheduled, dispatched, and controlled.

VARIABLE RNEWABLE ENERGY RESOURCES

Several variable renewable energy resources were considered in our PSIP analysis, all of which are currently in our generation mix. This type of energy is variable because its primary energy sources (such as wind, sun, and water) cannot be predicted.

The capacity value (essentially the percent of its "nameplate" generating amount that is available to the grid) of variable renewable energy varies by each resource, and is typically a small percentage of the nameplate value or zero. In addition, because the generation from variable renewable energy cannot be scheduled, it cannot be dispatched; in other words, it cannot be used to help regulate the balance between supply and demand.

Wind

Wind energy generation is the conversion of the wind's kinetic energy into electricity. Wind generating facilities are best located where wind is persistently steady. On Hawai'i with its terrain of hills, valleys, and ridges, variations in siting can have profound effects on the strength and quantity of wind currents.

As the wind turns a wind turbine's blades, the main shaft in the turbine rotates which in turn drives a generator (situated in the nacelle) to produce electricity. The annual capacity factor[1] of wind is generally about 25% at locations throughout Hawai'i, although it can attain a capacity factor of more than 50%.

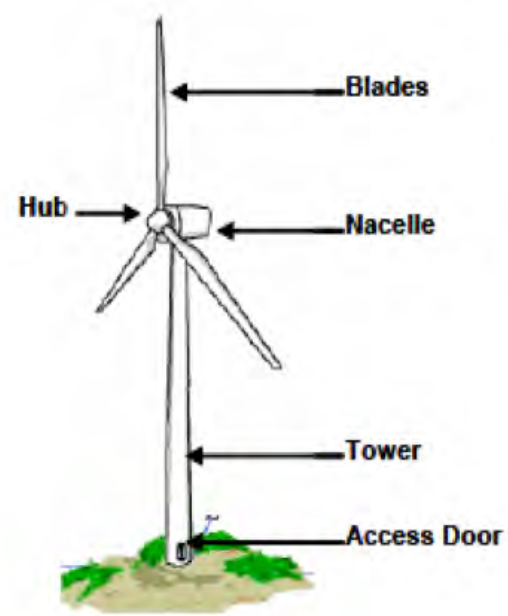

Figure G-2. Wind Turbine and Tower

A wind turbine shuts down when the wind is either too slow or too fast. The size of the wind turbine is generally in direct proportion to how much electricity can be generated. Larger wind turbines generate more power, while smaller turbines generate less. Thus, wind is a variable, non-dispatchable energy source.

[1] The Annual Capacity Factor, expressed in percent, is the amount of energy produced in a year compared to the amount of energy potentially produced by the facility if it was operated at 100% of its rated capacity for 100% of the time in the year.

Solar Photovoltaics

Solar photovoltaic energy is generated from its cells, and not by turning a turbine. Photovoltaic (PV) cells are made of semiconductors (such as silicon). When light strikes the cell, a certain portion of it is absorbed within the semiconductor material. The energy of the absorbed light is transferred to the semiconductor. The energy knocks electrons loose, allowing them to flow freely. This flow of electrons is a current, and by placing metal contacts on the top and bottom of the cell, this electric current can be drawn off for external use. The most common solar cell material is crystalline silicon, but newer materials for making solar cells include thin-film materials.

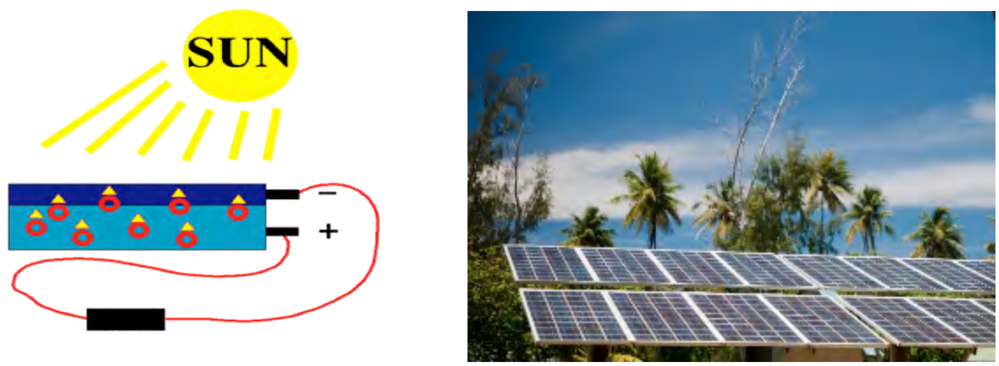

Figure G-3. Schematic of a Photovoltaic (PV) Cell and an Array of PV Panels

Solar PV is a variable renewable energy resource that cannot be scheduled and dispatched. Its annual capacity factor hovers between 18% to 22%. Solar PV only generates power when the sun is out and not blocked by clouds. On cloudless days, solar power gradually increases as the sun rises in the morning, peaks around 2 PM, and then gradually decreases until the sun sets. If at any point during the day a cloud blocks the sun, power output drops suddenly only to jump back up when the cloud passes. Thus, solar PV power generation can be erratic.

While solar PV systems can be made a few different ways, the most predominant is framed panels (as shown in Figure G-3). These panels consist of PV cells packaged as modules and framed into panels using aluminum framing, wiring, and glass enclosures. Multiple panels can be assembled into larger systems as arrays.

Distributed Solar Generation (DG-PV). These arrays can be installed on building rooftops, typically in a fixed direction as illustrated in Figure G-4. This rooftop solar is referred to as distributed generation because of the numerous small PV systems installed in many different locations distributed throughout the grid. These rooftop PV panels produce direct current (DC) electricity fed to an inverter which converts the electricity to alternating current (AC) for use by the building or home. Surplus PV electricity—more than the building can use—flows into the electric power grid.

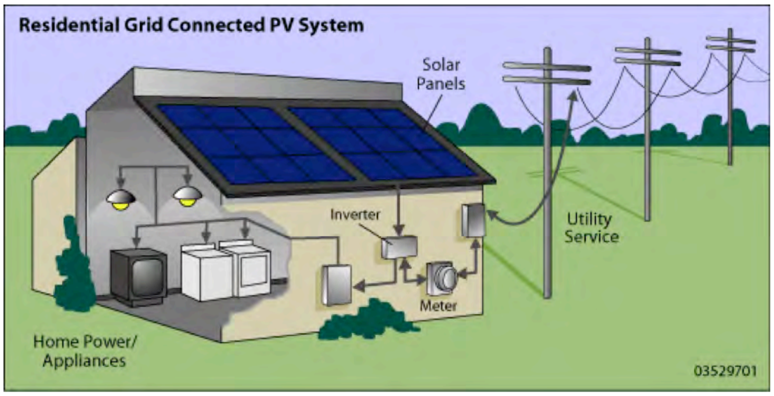

Figure G-4. Residential Distributed Generation PV System

Utility-Scale Solar PV. The PV panel arrays can also be mounted in large-scale ground mounted PV generating facilities (also referred to as "solar farms") that sometimes use tracking systems to actively tilt the PV panels towards the sun as it moves across the sky, thus increasing the annual capacity factor. These panels also produce direct current (DC) electricity. Inverters convert the electricity to alternating current (AC) where it immediately flows into the electric power grid.

Run-Of-River Hydroelectric

Hydropower is power derived from the energy of falling or moving water, which may be harnessed for useful purposes. Since ancient times, hydropower has been used to irrigate and operate various mechanical devices, such as watermills, sawmills, textile mills, dock cranes, and domestic lifts.

For run-of-the-river hydro projects, a portion of a river's water is diverted to a channel, pipeline, or pressurized pipeline (penstock) that delivers it to a waterwheel or turbine. If the river is not flowing, the hydroelectric facility produces no power. The moving water rotates the wheel or turbine, which spins a shaft. The motion of the shaft can be used for mechanical processes (such as pumping water) or it can power a turbine-generator to generate electricity.

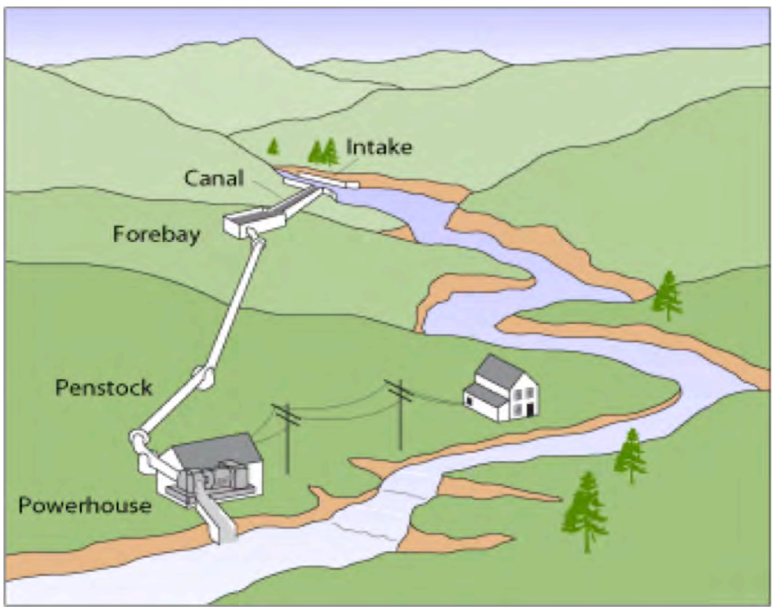

Figure G-5. Run-of-River Hydroelectric Plant

The primary development considerations are finding sites with adequate water flow and pressure, which are located in reasonable proximity to the electric grid for interconnection.

Energy Storage in Combination with Variable Renewable Energy

Wind, solar, and hydroelectric are all variable renewable energy sources. As such, they cannot be used to maintain the stability of an electric power grid, that delicate balance between supply and demand. Energy storage, however, can alleviate this situation and help provide more reliable energy, or in some cases, firm renewable power.

Energy storage can capture excess variable energy—generation that is not currently needed to meet demand—and store it in other forms until needed. This stored energy can later be converted back to its electrical form and returned to the grid as needed. Stored in high enough amounts, these sources could then be treated as firm power than may be scheduled and dispatched. (See Appendix J: Energy Storage Plan for more details.)

Pumped-storage hydroelectricity is a type of hydroelectric energy that includes energy storage. Water is pumped from a lower elevation to a higher elevation, where the stored water can be subsequently released through turbines to produce electricity. Electricity for pumping the water would typically occur during off-peak periods when the cost is low, or when during periods when there is excess energy generation from variable renewable resources. The generated electricity is then used during on-peak periods when demand is higher.

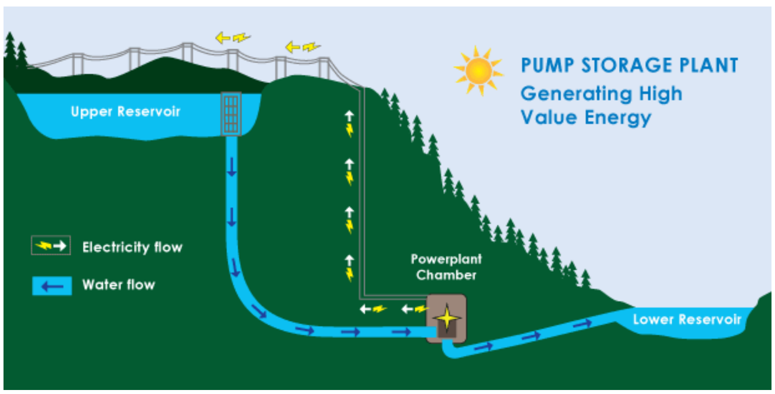

Figure G-6. Pumped Storage Hydroelectricity Plant

FIRM GENERATION

Several types of firm generation are included in our PSIP analysis, many of which are currently in our generation mix. Firm generation is predictable because its energy source (both fossil fuels and renewable fuels) can be scheduled, dispatched, and controlled.

The annual capacity value of firm generation can also be managed. A firm generation source can be operated as much or as little as necessary to meet demand. As such, firm generation is dispatchable; in other words, it can be used to help regulate the balance between supply and demand.

Gas Turbine Engine (or Combustion Turbine)

A gas turbine engine rotates as a result of hot gases (the product of the combustion of fuels) traveling through sets of turbine blades. As illustrated in Figure G-7, the flames themselves do not touch the turbine blades – just the gases produced by the flames. The combustor is where the fuel and air are mixed to enable the combustion process to occur. The fuel for this type of prime mover is either gas or liquid (not coal or biomass).

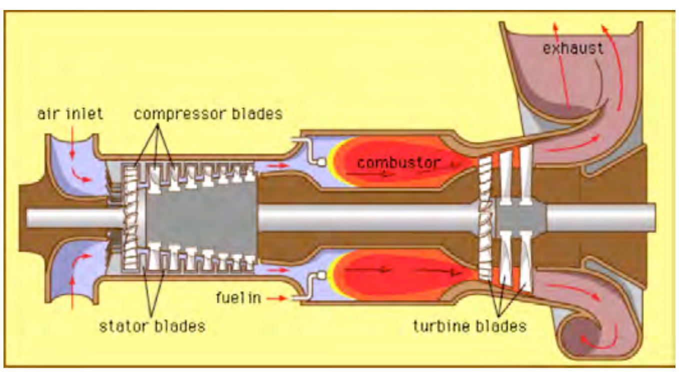

Figure G-7. Gas Turbine Engine

There are two types of gas turbines used for power generation: Aeroderivative and Frame.

Aeroderivative. This class of turbine is smaller (up to 100 MW) and can be quickly started and ramped, which makes them more compatible with grids that have large amounts of variable generation.

Frame. This type of turbine is generally larger (up to 340 MW), but not as fast reacting for both starting and ramping.

Gas turbines produce firm, dispatchable generation.

Steam Turbine: Combined Cycle and Boilers

A steam turbine operates by high pressure steam traveling through the turbine blades, causing the turbine shaft to rotate. This high pressure steam can be produced by a variety of technologies including Heat Recovery Steam Generators (HRSG) and fuel-fired boilers. All steam turbines produce firm, dispatchable generation.

Heat Recovery Steam Generators (HRSG)

HRSG use the high temperature exhaust gas from gas turbines engines to create steam for use in a steam turbine generator. This allows more electricity to be produced without using any additional fuel. The assembly of gas turbine, HRSG, and other auxiliary equipment used is referred to as combined cycle.

Hot combustion gases travel across the gas turbine blades to make the turbine spin where these gases are released at high temperature. A HRSG connects to the end of the gas turbine to take advantage of the energy that remains in the hot exhaust gases. The heat from these hot exhaust gases turns water contained in the HRSG into steam, where it is then sent to a steam turbine causing its connected generator to spin, thus producing electricity. Used steam is then converted back into water and reused again in the HRSG.

As illustrated in Figure G-8, combined cycle turbines can be either "single-train" (that is, one gas turbine and HRSG tied to the steam turbine) or "dual-train" two gas turbines and HRSG assemblies tied to a single steam turbine).

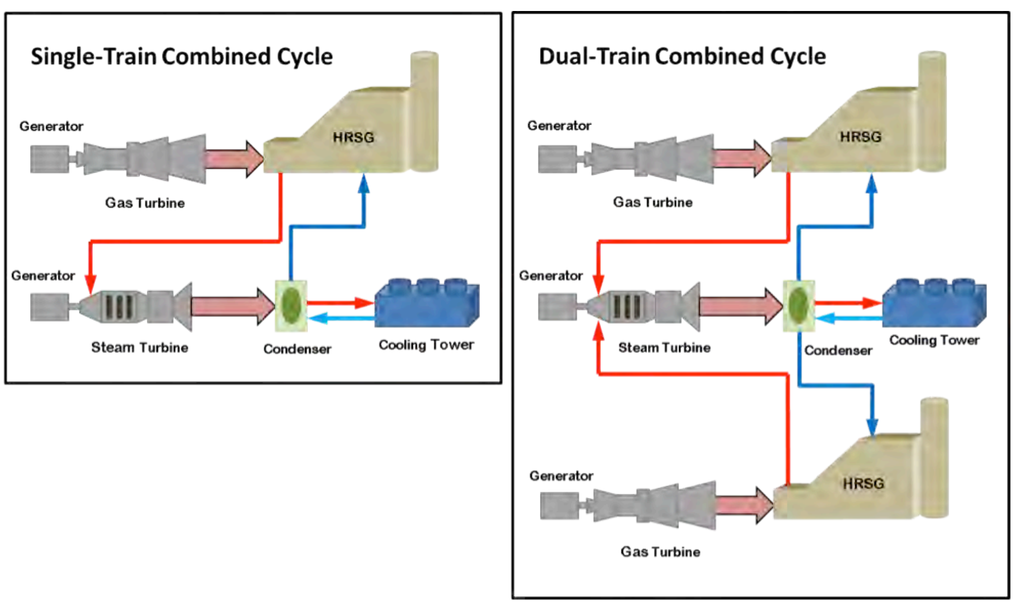

Figure G-8. Combined Cycle Plant: Single-Train and Dual-Train

A dual-train configuration provides twice as much power at a lower cost as a similar sized single-train configuration.

Reciprocating Internal Combustion Engine (RICE) or "Diesel Engine"

The type of reciprocating internal combustion engine used to produce electricity is a diesel engine. These engines can burn a variety of fuels, including diesel, biodiesel, biocrude, heavy oil, natural gas, and biogas. Diesel engines start and ramp quickly. Diesel engines produce firm, dispatchable generation.

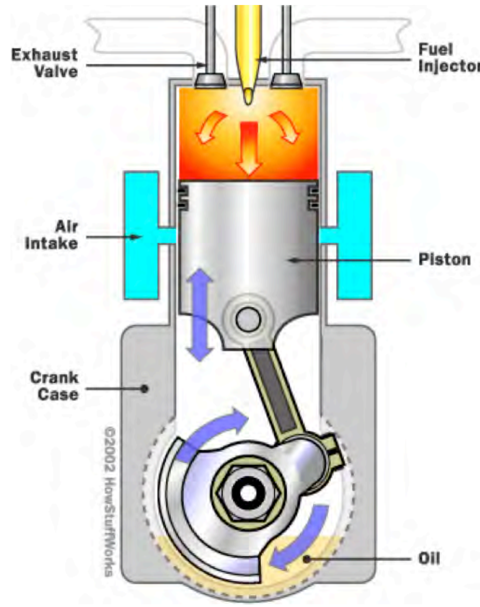

Figure G-9. Diesel Engine

Diesel engines have many combustion chambers called cylinders, each of which drives a piston connected to a common rotating shaft. This shaft is coupled to the generator to make it rotate. The number and size of these cylinders (illustrated as orange in the picture below) determine how much electrical output the engine can produce.

Diesel engine ratings can range from a few kW up to about 18MW. Larger diesel engines, because of their design, preclude them from meeting US Environmental Protection Agency (EPA) air emission limits. In addition, the EPA has different air regulations for diesel engines depending on the size of the cylinders.

Boilers (or Steam Generators)

A boiler furnace is made up primarily of small diameter (about 2-inch) metal tubes welded side by side to make a rectangular box. The tubes, which contain high purity water, are connected to a steam drum. The large fire inside the furnace transmits heat to the water inside the tubes to create steam in the steam drum. Fuel and air are continually added to the furnace to feed the fire.

Steam leaves the steam drum and travels through an independent set of tubes where it is heated to its final temperature by hot combustion exhaust gases. The steam then moves into the steam turbine, causing them to rotate and thus generate electricity. Boilers use a variety of fuels, including coal, biomass, liquid fuel oil, gas, and garbage.

Boilers come in many types, shapes, and sizes. Figure G-10 shows a simplified boiler steam turbine power plant. The boiler itself is outlined in the dotted red box.

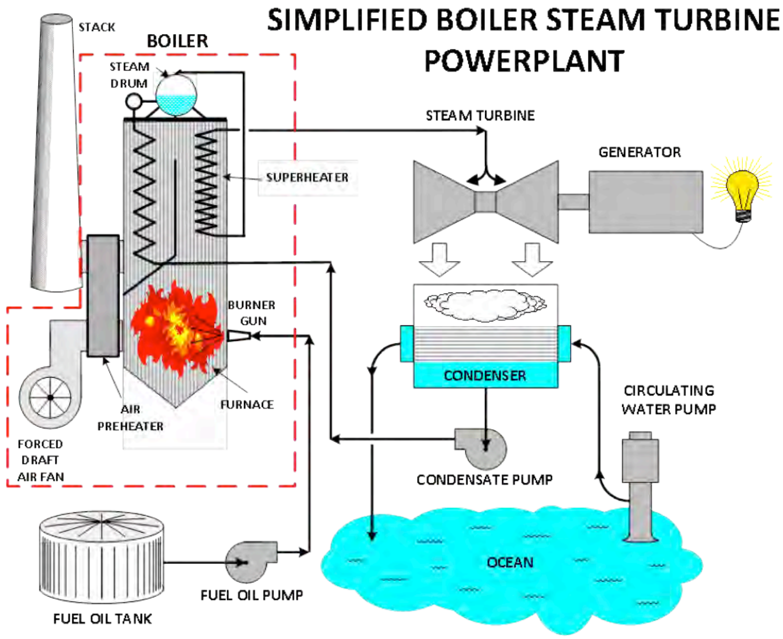

Figure G-10. Simplified Boiler Steam Turbine

Used steam can be converted back into water and reused in the boiler. A condenser forces the steam to travel over metal tubes that contain cold seawater, which causes the steam to turn back into water where it is pumped back into the steam drum, where the generation process begins again.

Renewable Fuel for Boilers–Waste (or Garbage)

Waste-to-energy is a renewable fuel-fired steam-electric power plant in which waste (or garbage) is burned in whole or in part as an alternative to fossil fuels. Paper, organics, and plastic wastes account for the largest share of solid waste used for the waste-to-energy stream. Incinerating solid waste to generate electricity is one method to reduce this waste volume. The fractions of solid waste—paper, wood waste, food waste, yard waste—are forms of a biomass fuel. Americans generate approximately 4.5 pounds of garbage per day. In Hawai'i, solid waste consists primarily of 30% paper, 25% other organics, and 12% plastics with the remainder comprised of metals, glass, and other materials.

Solid waste is mechanically processed in a "front end" system to produce a more homogenous fuel called refuse-derived fuel (RDF). RDF, in its simplest form, is shredded solid waste with the metals removed. This RDF must be processed further to remove other non-combustible materials such as glass, rocks, non-burnables, and aluminum.

Additional screening and shredding stages can be done to further enhance the RDF. The RDF is then fired in the boiler to produce steam that is directed to a turbine or generator.

In general, a robust waste-to-energy generation reduces the amount of landfill refuse by 90%.

Renewable Fuel for Boilers–Biomass

Biomass is another renewable fuel that can be used in boilers as alternatives to fossil fuels such as liquefied natural gas (LNG), oil, and coal.

Biomass is commonly defined as material derived from living organic matter (for example, trees, grasses, animal manure). Biomass includes wood and wood waste, herbaceous crops and crop wastes, food processing wastes such as bagasse, animal manures, and miscellaneous related materials. Biomass can be grown for the purpose of power generation from numerous types of plants, including switchgrass, hemp, corn, poplar, willow, sorghum, sugarcane, and a variety of trees such as eucalyptus and palm.

Biomass can either be burned directly to produce steam to make electricity, or processed into other energy products such as liquid or gaseous biofuel. In general, generating electricity directly from biomass is more efficient than converting it to biofuel. Siting a power generation facility at the source of the biomass, however, is not always feasible. Biofuel's transportability offers an attractive advantage.

Figure G-11 shows a process for converting wood waste into a biogas, which is then burned to create steam to generate electricity.

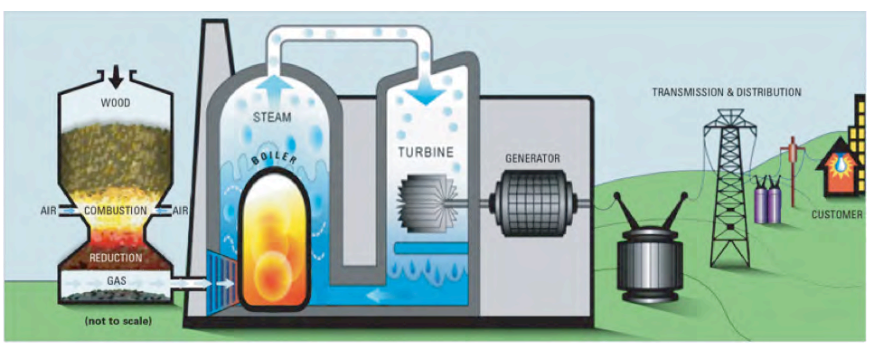

Figure G-11. Biomass Gasification

Aside from their fuel coming from renewable biomass, the power generation components of these facilities are similar to conventional power plants. In many cases, the power plants burn a combination of biofuel and fossil fuel.

Geothermal

Geothermal energy is heat energy from the earth. A layer of hot and molten rock called magma lies below the earth's crust. Heated ground water exposed to this magma can be extracted to provide geothermal energy at the surface. Resources of geothermal energy range from the shallow ground to hot water and hot rock found a few miles beneath the earth's surface where the earth's crust is thinner.

In general, geothermal fluids are tapped through wells, also referred to as "bores" or "bore holes". Except for the higher geothermal temperatures, these wells are similar to oil and gas wells. Geothermal well depths typically range from 600 to 10,000 feet. The fluids surging out of the wells are piped to the power plant. Geothermal steam, or vapor created using geothermal hot water, then spins a turbine-generator to create electricity.

The temperature and quality of the geothermal fluid determines which of the four types of power system that can be used for electrical generation.

Dry Steam Plants. Hot 100% steam is piped directly from geothermal reservoirs into generators in the power plant. The steam spins a turbine-generator to produce electricity. The steam is re-injected into the ground. Dry steam geothermal power plants are rare.

Flash Steam Plants. Fluids between 300°F and 700°F (148–371°C) are brought up through a well. Some of the water turns to steam, which drives the turbine-generator. When the steam cools, it condenses back into water and is re-injected into the ground.

Binary Cycle Plants. Moderately hot geothermal water (less than 300°F) is passed through a heat exchanger. This heat is then transferred to a working fluid (such as isobutene or isopentane) which boils at a lower temperature than water. When that fluid is heated, it turns to vapor which spins the turbine-generator.

Hybrid Plants. Combination of the flash steam and binary cycles.

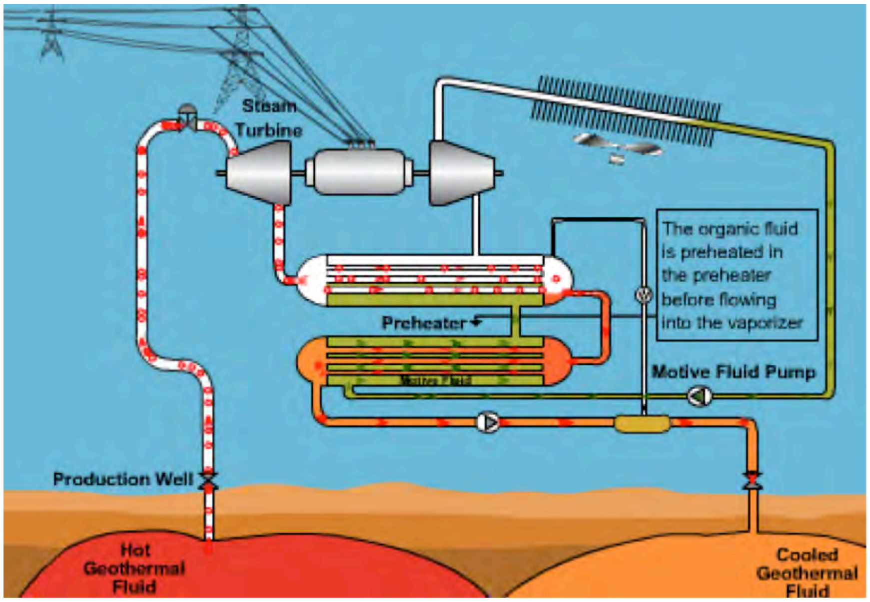

Figure G-12. Geothermal Hybrid Plant

In relation to other renewable energy projects, developing a geothermal power project is relatively complex, and typically involves two major phases: (1) exploratory drilling and (2) project development. The exploratory drilling phase identifies and evaluates potential resources, and drills test well. This phase usually takes a number of years, and in some case, does not identify a viable geothermal resource. After a geothermal resource has been identified, the project development phase begins, which includes drilling production wells and constructing a power plant.

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H. Commercially Ready Technologies

Our analysis for the PSIPs considered both commercially ready generation technologies as well as emerging technologies that, while not commercially ready, might become available during the planning period (2015–2030).

Which emerging technology will be commercially ready before 2030 is impossible to know with any degree of certainty. As a result, with one exception, we did not attempt to decide which of the most promising of the emerging technologies might become available during the planning period. The exception: our analyses performed limited sensitivity of some emerging technologies (for example, Ocean Thermal Energy Storage) to quantify any potential future value.

Our PSIPs are snapshots of the future based on our best available assumptions. As such, *for the PSIPs, we limited the generating resource options to those technologies that are commercially ready as of 2014.*

This planning assumption is for the PSIP analyses only, and does not affect our intent to thoughtfully consider specific projects that include emerging technologies. In other words, we welcome generating technologies not considered in the PSIPs that are proposed in responses to future request for proposals (RFP) for any of our power systems. We will evaluate any proposal on its commercial viability as well as other attributes that are consistent with RFP requirements. Further, nothing in these planning assumptions is intended to modify or change our position for welcoming test projects, pilot projects, or negotiations that involve any specific technology.

COMMERCIAL READINESS INDEX

In order to evaluate whether a technology is commercially ready, the Hawaiian Electric Companies used the Commercial Readiness Index (CRI) methodology developed by the Australian Renewable Energy Agency (ARENA), which was released in February 2014.[1]

NASA first developed a Technology Readiness Level (TRL) in 1974.[2] The TRL ranks technology readiness on a scale of 1 to 9 (1 being the lowest; 9 being the highest level of readiness), with specific attributes identified for each level of readiness.

In 2011, the U.S. Department of Energy published the *Technology Assessment Readiness Guide*,[3] a framework for evaluating energy technologies using the TRL methodology. The TRL methodology characterizes technology readiness from very early stages of a technology life cycle, up to and including commercial readiness.

Building on the work of NASA, ARENA developed a Commercial Readiness Index (CRI), and published the CRI criteria in February 2014 in a document titled *Commercial Readiness Index for Renewable Energy Sectors*.

The CRI scale (1 to 6, with 6 being the highest level of readiness) assesses technology readiness against eight indicators:

- Regulatory environment
- Stakeholder acceptance
- Technical performance
- Financial performance (cost)
- Financial performance (revenue)
- Industry supply chain
- Market opportunity
- Vendor maturity (preference for established companies with strong credit ratings)

ARENA maps its CRI to the TRL, with CRI level 1 corresponding to TRL levels 2 through 8, and CRI level 2 corresponding to TRL level 9. CRI levels 3 through 6, then, include more mature technologies that are closer to commercial deployment, or that are already being used commercially. Except for certain sensitivity analyses, the PSIP did not consider any technologies with a CRI level 4 or less.

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1 *Commercial Readiness Index for Renewable Energy Sectors*. Australian Renewable Energy Agency. © Commonwealth of Australia, February 2014. http://arena.gov.au/files/2014/02/Commercial-Readiness-Index.pdf

2 "Technology Readiness Levels Demystified." August 20, 2010. http://www.nasa.gov/topics/aeronautics/features/trl_demystified.html#.U7W-g7ZdV9c

3 Technology Level Assessment Guide. September 15, 2011. http://www2.lbl.gov/dir/assets/docs/TRL%20guide.pdf

To evaluate power generating technologies included in analysis performed for the PSIPs, the CRI methodology provides practical, objective, and actionable guidance. Therefore, we used this methodology to evaluate emerging generation technology options and their suitability for inclusion as resource options in the PSIPs.

For the PSIPs, only those technologies with a CRI Level of 5 or 6 were considered commercially ready, and included as resource options in the PSIPs.

Table H-1 defines the levels of commercial readiness under the CRI methodology.

CRI Level	Commercial Readiness	Definition[4]
6	Bankable grade asset class	Financial investors view the technology risk as low enough to provide long-term financing. Known standards and performance expectations are in place, along with appropriate warranties. Vendor capabilities (including both technology vendors and EPC vendors), pricing, and other market forces drive market uptake ("demand pull").
5	Market competition driving widespread deployment	Competition is emerging across all areas of the supply chain, with commoditization of key components and financial products.
4	Multiple commercial applications	Full-scale technology demonstrated in an industrial (that is, not R&D) environment for a defined period of time. May still require subsidies. Publicly verifiable data on technical and financial performance. Interest from debt and equity sources, although still requiring government support. Regulatory challenges being addressed in multiple jurisdictions.
3	Commercial scale-up	Deployment of full-scale technology prototype driven by specific policy. The commercial proposition is driven by technology proponents and by market segment participants (a "supply push"). Publicly discoverable data is driving interest from finance and regulatory sectors, but financing products are not yet widely available. Continues to rely on subsidies.
2	Commercial trial	Small scale, first-of-a-kind project funded by 100% at-risk capital and/or government support. Commercial proposition backed by evidence of verifiable performance data that is typically not available to the public. Proves that the essential elements of the technology perform as designed.
1	Hypothetical commercial proposition	Technically ready, but commercially untested and unproven. The commercial proposition is driven by technology advocates, with little or no evidence of verifiable technical data to substantiate claims.
0	Purely hypothetical[5]	Not technically ready. No testing at scale. No technical data.

Table H-1. Commercial Readiness Definitions

[4] Based on *Commercial Readiness Index for Renewable Energy Sectors*. Australian Renewable Energy Agency. © Commonwealth of Australia, February 2014. Table 1. p 5.

[5] Not a part of the CRI methodology. Defined here to classify commercial readiness of certain technologies discussed from time to time in Hawai‘i.

EMERGING GENERATING TECHNOLOGIES

In Hawai'i, certain emerging generating technologies are discussed as potential generating resource options. The most prominent of these are ocean wave/tidal power, ocean thermal energy storage (OTEC), and concentrated solar thermal power (CSP). We evaluated each of these technologies using the CRI ranking methodology. As objective as the CRI methodology attempts to be, the mapping of the indicators for a given technology is necessarily subjective. Reasonable differences of opinion in the state of any one (or even several) of the eight categories of indicators would not change the overall conclusion regarding the commercial readiness of these technologies.

Summary of CRIs for PSIP Resource Candidates

Table H-2 summarizes the commercial readiness of various generating resource technologies.

Technology	CRI Level							PSIP Resource Option?	Comments
	0	1	2	3	4	5	6		
Simple cycle combustion turbine (CT)							x	Yes	
Combined cycle CT + heat recovery steam							x	Yes	
Internal combustion engines—small							x	Yes	
Internal combustion engines—large							x	Yes	
Geothermal							x	Yes	Constrained on Maui and Hawai'i. None for O'ahu.
Biomass steam							x	Yes	
Biomass gasification			x					No	
Run-of-river hydro							x	Yes	Limited amount of MW available in Hawai'i.

Technology	CRI Level 0	1	2	3	4	5	6	PSIP Resource Option?	Comments
Storage hydro							x	No	No available streams to dam for water storage.
Pumped storage hydro							x	Yes	Not considered for base cases. Sensitivities only.
Ocean wave/ tidal				x				No	
Ocean thermal (OTEC)			x					No	
Wind—onshore utility scale							x	Yes	Limited on O'ahu.
Wind—offshore utility scale					x			No	High capital cost, concerns with ability to site and permit.
Wind—distributed generation				x				No	Approximately 3–4 times more expensive installed cost compared to solar DG-PV.
Solar PV—utility scale						x		Yes	
Solar PV—distributed						x		Yes	
Concentrated solar					x			No	
Fuel cells—distributed			x					No	Primary applications are for "high 9s" reliability applications (e.g., data centers).
Fuel cells—utility scale			x					No	
Micro nuclear reactors		x						No	
Solar power satellites	x							No	
Nuclear fusion		x						No	
Energy harvesting from ambient environment	x							No	Early markets will likely be small scale applications, such as PDA charging.

Table H-2. Commercial Readiness of Generating Technologies Considered for PSIPs

Evaluation of Emerging Technologies

Table H-3 through Table H-5 are CRI assessments of emerging generation technologies that were not included as resource options due to a CRI level of 4 or less.

Table H-3 evaluates wave and tidal power as a potential generating resource as, at best, CRI level 3. Therefore, it was not included for consideration in the PSIPs.

CRI Level	Regulatory Environment	Stakeholder Acceptance	Technical Performance	Financial Performance (Cost)	Financial Performance (Revenue)	Supply Chain	Market Opportunity	Company Maturity
6								
5							Market opportunity widely understood. Additional policy support needed to drive uptake.	
4			Performance understood; high confidence in performance.					
3				Various versions of technologies deployed; Cost drivers beginning to be understood.				
2	Ability to permit across various regulatory jurisdictions untested.	Stakeholder support case-by-case basis.			Revenue projections being tested, however investment community not yet willing to underwrite PPAs on widespread basis.	Supply chain not available. Each project typically unique specification. EPC based on time and materials.		
1								Established industry players not yet part of sector.

Table H-3. Wave/Tidal Power Commercial Readiness Evaluation

Table H-4 evaluates ocean thermal energy conversion as a potential generating resource as, at best, CRI level 3. Even though the CRI level would suggest that OTEC is not eligible for consideration at this time, due to interest in this technology for Hawaiʻi and our ongoing negotiations with OTEC International to build an OTEC facility to service Oʻahu, a sensitivity was prepared to evaluate OTEC as a resource option for Oʻahu.

CRI Level	Regulatory Environment	Stakeholder Acceptance	Technical Performance	Financial Performance (Cost)	Financial Performance (Revenue)	Supply Chain	Market Opportunity	Company Maturity
6								
5								
4								Established player (LMCo) considered part of sector.
3							Size of potential market is understood.	
2	Regulatory issues require specific project consideration.	Stakeholder support a case-by-case basis.	Performance forecasts based on pilot project data.	Key costs based on projections. No data at scale.	Revenue projections at scale not tested.			
1						Key elements from specialists.		

Table H-4. Ocean Thermal Energy Conversion (OTEC) Commercial Readiness Evaluation

Table H-5 evaluates concentrated solar thermal power as a generating resource at a CRI level 4. While this resource might be considered during our next planning cycle, it was not included in the PSIPs.

CRI Level	Regulatory Environment	Stakeholder Acceptance	Technical Performance	Financial Performance (Cost)	Financial Performance (Revenue)	Supply Chain	Market Opportunity	Company Maturity
6							Market opportunities clear and understood.	
5					Target is to be cost competitive by 2020.[6]			Leading players with significant balance sheets in sector.
4	Permitting, regulatory challenges based on actual evidence. Policy settings moving to "market pull".	Evidence and experience available to inform stakeholders.	Performance understood. High confidence in future project performance.	Cost drivers understood and tested.	Financing still largely underwritten with government guarantees and subsidies.[7]	Limited supply options but improving.		
3			Multiple technology designs.					
2								
1								

Table H-5. Concentrated Solar Thermal Power (CSP) Commercial Readiness Evaluation

[6] See "*2014, The Year of Concentrating Solar Power.*" U.S. Department of Energy. May 2014.

[7] *Ibid.*

I. LNG to Hawai‘i

Liquefied natural gas (LNG) is critical to reducing customer bills and improving environmental quality in Hawai‘i. High oil prices and more stringent air regulations (the Environmental Protection Agency’s Mercury Air Toxic Standards (MATS) and National Ambient Air Quality Standards (NAAQS)) increase the need to reduce Hawai‘i’s dependence on oil. While the majority of Hawaiian Electric’s current generation portfolio utilizes oil, LNG has emerged as a viable alternative fuel source that may substantially lower fuel costs while reducing greenhouse gas emissions. In late 2012, the Hawaiian Electric Companies and FACTS Global Energy completed studies that confirmed both the technical and commercial feasibility for importing and utilizing LNG in Hawai‘i.

DELIVERING LNG TO HAWAI‘I

Natural gas is not indigenous to Hawai‘i and must first be liquefied into LNG to be cost effectively transported to Hawai‘i. LNG can be imported to Hawai‘i in two ways: bulk LNG or containerized LNG

Bulk LNG. LNG could be transported in bulk via LNG carriers and/or articulated tug barges (ATBs) and received at a bulk LNG import and regasification terminal. The Floating Storage and Regasification Unit (FSRU) is a variant of this option. Pearl Harbor is the best site available for an FSRU when considering factors such as favorable meteorological-ocean conditions, spacious and protected harbor waters, security, cost, and ability to break-bulk (for distribution to the neighbor islands). Natural gas would then be distributed from the FSRU by pipeline to facilities on the individual islands where it would be consumed. Based on our discussions with FERC, we anticipate that a bulk LNG import and regasification terminal project for Hawai‘i will take approximately

6–8 years to complete (1–2 years planning, 2–3 years FERC permitting, and 2–3 years construction) and could possibly be placed in service between 2020 and 2022.

Containerized LNG. LNG could be transported in International Organization for Standardization (ISO) containers using conventional container ships and trucks equipped to handle standard shipping containers. The LNG ISO containers would be delivered directly to the facilities where the LNG would be regasified and consumed. Since FERC permitting is not likely required for LNG delivered by ISO containers, LNG is available today in small quantities, and within a relatively short time for larger quantities.

Containerized LNG RFP

The Company issued an RFP in March 2014, for LNG to be delivered to Hawaiʻi in ISO containers (Containerized LNG RFP). We have completed our evaluation of the proposals and have identified two proposals for more in-depth discussion with the bidders. We currently anticipate negotiating and executing a contract, and subsequently submitting an application to the Commission in the fourth quarter of 2014.

The Containerized LNG RFP called for deliveries to start within a window from October 1, 2016 to June 30, 2017. Based on confidential information received via the Containerized LNG RFP process, we believe that an LNG delivery commencement date in the latter part of 2017 remains viable if the following five key milestones are realized by their noted deadlines.

1. Finalization of the LNG Sales and Purchase Agreement (SPA) by fourth quarter 2014.
2. Application submission to the Commission by fourth quarter 2014.
3. Final Order to import LNG issued by the Commission by June 1, 2015.
4. Granting of all other major permits by June 1, 2015.
5. Clearance or waiver of any remaining LNG SPA conditions precedent by July 1, 2015.

Upon achievement of these milestones, we will make the investments necessary to construct, assemble and aggregate the various pieces of the supply chain needed to deliver LNG to Hawaiʻi in 2017. It nevertheless must be recognized that these milestones are challenging, some of which are beyond our control and they will only be realized if no significant legal, environmental, or social obstacles encumber the process.

DELIVERING LNG IN 2017

Liquefaction Capacity

We believe that ensuring the availability of LNG supply from FortisBC is a critical component for successfully concluding the Containerized LNG RFP process with an executed LNG supply and logistics contract. FortisBC's liquefaction capacity is available under a regulated tariff as early as 2017 and capacity is reserved on a first come, first served basis. The Company believed it was critical to directly secure the required capacity from FortisBC before other parties stepped in. For this reason, on August 8, 2014, we executed an agreement with FortisBC for LNG liquefaction capacity under the FortisBC Rate Schedule 46. FortisBC's liquefaction cost, which is less than $2.70, is competitive with other liquefaction rates and is, in fact, lower than any other rate we are aware of (including the rates offered by other Gulf of Mexico liquefaction projects). In addition, because FortisBC is in British Columbia, Canada, they are not subject to the Jones Act and, therefore, can provide substantial marine transport savings to Hawaiian Electric through the use of international shipping assets.

COST OF SERVICE

The range of proposed conditional delivered LNG pricing to O'ahu power plants and to Hawai'i Island power plants is extremely favorable, and based on the assumed forecasted 2017 natural gas pricing of $3.58/MBtu.

The pricing mechanisms incorporate pass through provisions of most fixed and variable cost components, with the cost stack to be finalized upon filing of the LNG Sales and Purchase Agreement with the Commission. The build-up of the proposed pricing is based on bidders' current cost estimates, and the ranges for fixed, fixed with escalation, and variable price components.

Included in the fixed cost component are the capital assets (marine assets, ISO containers, etc.) and any services that can be contracted at fixed cost over the term of the SPA. The fixed with escalation cost component include the FortisBC liquefaction costs and other labor costs such as marine terminal handling charges and trucking. Included in the variable cost component is the gas commodity, pipeline toll, and fuel consumed for liquefaction, shipping, and trucking.

The Company and our advisors are undertaking due diligence on the cost elements for each segment in the supply chain. Liquefaction costs are set by FortisBC's Rate Schedule 46 and may be subject to periodic adjustments, if approved by the British Columbia

Utilities Commission (BCUC). Analysis to date suggests that there is little risk of a cost increase over the bidder’s estimates, assuming the above stated milestone are achieved by the milestone dates and the SPA is effective no later than July 1, 2015. Discussions regarding the costs are ongoing with the bidders.

To account for the possibility of stranded assets that could result from a transition to a bulk terminal, a cost adder was included in the LNG forecast between the years of 2017 and 2021 to reflect the potential for a reduced amortization period (5 years versus 15 years).

Transition to Bulk Terminal: 2022

The development of a bulk receiving terminal will be subject to FERC review and approval and therefore cannot be realistically achieved by 2017. Siting of such a terminal, whether floating or land-based, will require substantial engineering analysis and stakeholder socialization. After consulting with FERC, a realistic schedule to develop a bulk LNG terminal is approximately 6 to 8 years.

The Galway Group estimated LNG pricing for 2022 and beyond by using current gas commodity forecasts, liquefaction costs from FortisBC, and estimated costs for shipping of the LNG and for a bulk terminal utilizing a FSRU. We are also assuming annual price increases in our forecasting. The build-up of the LNG forecast for 2022 is as follows:

Item	Price
Gas Commodity	$4.31
Pipeline Header (Fixed)	$0.60
Pipeline Cost of Fuel	$0.11
Marketer Fee (Fixed)	$0.01
Liquefaction (Fixed)	$1.99
Liquefaction Cost of Power	$0.91
Process Fuel Gas	$0.04
B.C. LNG Export Tax	$0.00
Marine Terminal	$0.33
LNG FOB FortisBC	$8.30
Shipping	$1.89
FSRU + Gas Pipeline	$2.54
2022 LNG Forecast w/ Bulk Terminal	$12.73

Table I-1. LNG Itemized Pricing

The LNG price forecast escalates beyond 2022 due to increases in the gas commodity price forecast, which is derived from NYMEX futures-derived forecasted values for Henry Hub; and 2% inflation adjustment applied to fixed with escalation and variable cost components.

J. Energy Storage For Grid Applications

Electricity is a commodity that is most efficiently produced when it is needed. The continuously varying demand for electricity requires utilities to have the appropriate mix of generating and demand-side resources to meet these varying demands. Energy storage is an extremely flexible tool for managing the supply-demand balance.

- Energy storage can be a substitute for generation resource alternatives;
- Energy storage can be used in conjunction with generation to help optimize generation capital costs and reduce system operating costs;
- For system security and reliability applications, storage has unique operational characteristics that may provide benefits not available through other resources.

The ability of energy storage to serve in any one of these roles is dependent upon the cost-effectiveness and operational characteristics of the energy storage asset under consideration, and the operational characteristics of all resources on the system.

Until relatively recently, the only way to store electricity in large (or bulk) quantities has been large mechanical storage devices (for example, pumped storage hydro, compressed air energy storage), which are highly dependent on site availability, may face substantial permitting and public acceptance challenges, have high capital costs and require long lead times (more than seven years) to develop. A new generation of chemical energy storage technologies (that is, batteries with new chemistries) and large-scale flywheel devices add to the commercially available options for energy storage in grid applications. In addition, there may be opportunities to aggregate customer-owned energy storage to provide value to all customers.

The Commission requested in the April 28, 2014 Decisions and Orders (D&Os) that the Companies consider the role that energy storage can play in managing the reliability of the electric grid. More specifically, the D&Os include the following topics for the Companies to address in the PSIPs:

- Discuss potential energy storage technologies and their capabilities;
- Analyze the fundamental benefit and costs of energy storage technologies;
- Discuss how energy storage is utilized in the preferred resource plan;
- Provide a plan for utilization of energy storage resources to address steady state frequency control and dynamic stability requirements, and to mitigate other renewable energy integration challenges;
- Provide a plan to improve utilization of existing energy storage on Maui and Lanai to improve system reliability and reduce system operation costs in those systems;
- Discuss the use of customer-side energy storage;
- Analyze the use of pumped storage hydro to provide ancillary services and bulk energy storage for renewable energy.

The Companies share the Commission's interest in energy storage for providing essential grid services. Energy storage has been integrated with certain independent power producer (IPP)-owned wind and solar projects to help manage ancillary service requirements. A project to design and procure storage for contingency reserves to mitigate the impacts from distributed solar on system security was initiated for the Hawai'i Electric Light system. Recently, a Request for Proposals (RFP) for commercial-scale and use of energy services to provide ancillary services was issued by Hawaiian Electric. As more fully described herein, the Companies have also implemented several pilot and demonstration projects.

This Appendix J will address the Commissions' questions about the Companies' plans to utilize energy storage in their systems.

COMMERCIAL STATUS OF ENERGY STORAGE

Pumped storage hydroelectric and compressed air energy storage technologies are mature and proven, with a great deal of performance data in commercial applications. Batteries (particularly lead-acid) and flywheel type energy storage devices have been around for many years and could also be considered mature technologies, but not for grid level applications such as renewable energy integration on island-based grids. The use of batteries and flywheel devices for use in bulk power systems and applications to integrate, or mitigate the impacts of, intermittent renewable energy in island-based electric grid systems is relatively new and there is somewhat limited data regarding their performance in commercial power grid applications. It is therefore worth discussing the status of commercialization of battery and flywheel energy storage for grid applications. This section will discuss several aspects[1] of the status of these technologies in terms of their commercialization. The evidence points to these technologies being at the cusp of commercially readiness.

Regulatory Environment

The regulatory environment for energy storage manufacturers is favorable. Most notably, on October 21, 2013 the California Public Utilities Commission (CPUC) issued the "Decision Adopting Energy Storage Procurement Framework and Design Program[2]." This CPUC decision set a target of 1,325 MW of energy storage to be installed in the three major investor-owned utility systems in California by the end of 2024. Other state commissions are looking at this CPUC decision[3]. This decision provides commercial opportunities for energy storage technology companies and energy storage project developers, and is therefore favorable for the commercial readiness of energy storage technologies. Of interest, the decision excludes pumped storage hydroelectric projects larger than 50 MW, a mature technology, from the target in order to promote development of smaller grid-scale storage projects.

At the federal level, the Federal Energy Regulatory Commission's (FERC) Order No. 755[4], required wholesale markets to develop compensation mechanisms for the provision of frequency regulation, a service that is technically well suited for certain energy storage technologies. The regulatory accounting treatment for energy storage remains an area that will require additional discussions by electric utilities and regulators[5]. For example, energy storage might be implemented for the purpose of relieving grid congestion (functionally classified as transmission), but the same energy storage project might also be able to provide ancillary services (functionally classified as a production service). Grid level energy storage might be implemented to mitigate the effects of variable distributed generation, while at the same time providing other grid support services. However,

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1 See Appendix G for a discussion of the "Commercial Readiness Index" (CRI) and the factors that are considered in determining a CRI.

2 Decision 13-10-040, October 17, 2013 (issued October 21, 2014). PUC Rulemaking 10-12-007. Order Instituting Rulemaking Pursuant to Assembly Bill 2514 to Consider the Adoption of Procurement Targets for Viable and Cost-Effective Energy Storage Systems. Full decision available at: http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M079/K533/79533378.PDF

3 "California poised to adopt first-in-nation energy storage mandate." San Jose Mercury-News. October 16, 2013.

4 *Frequency Regulation Compensation in Organized Wholesale Power Markets*. FERC Order No. 755. FERC Docket Nos. RM11-7-000 and AD10-11-000. Issued October 20, 2011. Order 755 available at: http://www.ferc.gov/whats-new/comm-meet/2011/102011/E-28.pdf

5 Bhatnagar, Currier, Hernandez, Ma, Kirby. *Market and Policy Barriers to Energy Storage Deployment*. Sandia National Laboratory. Report SAND2013-7606. September 2013. Report available at: http://www.sandia.gov/ess/publications/SAND2013-7606.pdf

when leveraging storage for multiple purposes, the energy storage must retain the necessary charge level to satisfy the requirements for each use. For example, storage that is deferring transmission investment must retain sufficient charge to handle the transmission constraint; that stored energy cannot be used to provide other services. These situations present issues for regulators in terms of ensuring that the benefits and costs of energy storage are properly allocated.

Stakeholder Acceptance

There are several dimensions to stakeholder acceptance of energy storage technologies, including:

Industry Acceptance: The electric utility industry, including non-utility project developers, has generally accepted grid-scale energy storage technologies as viable solutions for meeting grid needs. This is evidenced by installations of several hundred megawatts of energy storage worldwide in the past few years, including installations in Hawaiʻi in conjunction with wind and solar projects. Automotive applications for batteries in electric vehicles are expected to drive manufacturing costs down for lithium-ion batteries.[6] As a result, utility industry planners expect distributed energy storage to become more economical and are preparing for distributed storage integration into the future grid.

Equitable Regulatory Environment: Monetization of energy storage benefits is generally available in competitive wholesale market environments, where there are markets for capacity, energy and ancillary services. Monetization in vertically integrated utility markets (including Hawaiʻi) is generally driven by the cost effectiveness of energy storage relative to alternatives that provide similar functions. Cost recovery of energy storage systems is for the most part rationalized in the market. It is worth noting that energy storage project installations do not typically qualify for tax incentives, except in limited circumstances[7].

Public Concerns: Energy storage technologies are generally considered to be safe, however, there are public concerns with these systems related to potential fire hazards, toxic waste disposal, and dam breaches.

Financial Community Acceptance: Most of the capital invested in this sector to date has been in the form of venture capital funding, the purpose of which is to commercialize and refine the technologies and develop viable business models. To date, there is no known example of project level debt financing using project debt secured only by the revenues and the project itself (a typical financing model in the IPP industry). Rather,

[6] See for example: http://www.electric-vehiclenews.com/2010/03/deutsche-bank-battery-costs-appear-to.html

[7] For an example of such exceptions, see http://www.chadbourne.com/Large-Batteries-11-30-2011/

most of the projects have been financed off of the balance sheets of the developers themselves. As the market for energy storage becomes more of a "demand-pull" (as opposed to "supply-push") the interest of the mainstream investment community is growing. Several large financial institutions are marketing financing solutions for energy storage8. Some financial analysts predict that distributed energy storage, when combined with distributed solar PV, is on the cusp of being a technology that is disruptive to the traditional utility business model9.

Technical Performance

Although in general this industry is still in the formative stages, the technical performance of energy storage technologies, particular battery, flywheel systems, and pumped storage hydroelectric is well understood. And, with several hundred megawatts of grid-scale energy storage devices installed worldwide, the body of data is growing rapidly. The technical performance of most of the grid-scale energy storage projects to date (excluding pumped storage hydroelectric) is underwritten with technology performance guarantees (with liquidated damages provisions) from well-capitalized, strong balance sheet, engineering-procurement-construction (EPC) contractors and/or project developers.

Distributed energy storage is being marketed to customers interested in PV as well as enabled by the advent of electric vehicles (EV's) and the interest on the part of the sellers of EV's to address consumer "range-anxiety." Improvement in EV battery technology will increasingly find its way into distributed energy storage applications for consumers, including the ability to use EV's as a storage device for energy consumed in a customer's premises.

Financial Performance

The financial performance of energy storage is dependent upon the particular grid application and energy storage technology being deployed. Grid-scale energy storage costs are still relatively high[10]. In general, the cost of energy storage systems is declining, but challenges remain to deliver grid scale energy storage at low costs. Some sources believe that energy storage costs will decline precipitously over the next decade, at a rate of cost decline similar to that experienced with solar PV technology cost[11]. With respect

[8] For example see: http://www.goldmansachs.com/what-we-do/investing-and-lending/middle-market-financing-and-investing/alternative-energy/

[9] See for example: http://www.utilitydive.com/news/barclays-downgrades-entire-us-electric-utility-sector/266936/

[10] See: Bhatnagar, Currier, et. al.

[11] For example, see: http://rameznaam.com/2013/09/25/energy-storage-gets-exponentially-cheaper-too/

to value (benefits) of utility scale grid storage, as technology improves, the ability of energy storage to cost effectively provide grid services also increases.

Industry Supply Chain and Vendor Maturity

While the energy storage industry has its share of venture capital backed startups, large and well-capitalized equipment manufacturers now offer grid level energy storage technologies and solutions. These companies include, but are not limited to: General Electric, Hitachi, LG, Panasonic and NEC. Tesla Motors has recently announced that it is seeking a location for a large battery manufacturing plant in the US, to supply batteries for its EV's. They are actively developing utility uses for these same batteries and may find their way into grid storage applications, including distributed energy storage. Many of the smaller startups and niche players enjoy investments from, and strategic partnerships with, larger companies. These trends indicate that larger manufacturing companies are making the investments in sales, manufacturing, and service ecosystems that support the long-term viability of the energy storage industry. To date however, there is a lack of standardization in the energy storage industry.

Market Opportunity

The market opportunity for grid-scale energy storage is clearly validated by successful deployments worldwide and by regulatory mandates for energy storage as described above. Distributed energy storage is also viewed as a large market opportunity.

In conclusion, while the grid-scale energy storage industry is clearly in the early stages of commercial viability, it is well beyond the "technology development" stage for many of the available technologies. The Companies can be reasonably confident that energy storage solutions are available that can be designed, financed, constructed, operated and maintained in a manner consistent with the way the Companies deploy other kinds of utility grid infrastructure.

ENERGY STORAGE APPLICATIONS

Defining Characteristics of Energy Storage

Stored energy is generally referred to in physics as "potential energy." Potential energy is found in various forms; for example, the chemical energy stored in the form of a fuel, mechanical energy stored in a spring, gravitational energy stored in water in a reservoir, etc. In practice, most energy storage systems are used to store energy for use (that is, conversion to "kinetic energy") at a later time.

Energy storage systems of interest for electricity grid applications can be defined by the following set of characteristics:

Storage: Amount of energy that can be stored (measured in megawatt-hours)

Capacity (or rate of discharge): the rate (quantity per unit of time) at which the energy storage device can deliver its stored energy to the grid (typically measured in megawatts).

Storage Duration: Hours or minutes of energy storage (this is the amount of energy that can be stored divided by the rate of discharge).

Maximum Depth of Discharge: This is defined by the energy stored in the device at its minimum level divided by the total energy storage. This is a limiting factor in terms of the actual duration of delivery of stored energy from the device to the grid, since once the device reaches its maximum depth of discharge it cannot release any more of its stored energy. This can be a function of chemistry (for example, in a battery) or physical design (for example, in a pumped storage hydroelectric reservoir).

Round trip efficiency: This is the ratio of stored energy available for "release" from the device (AC energy out) to the amount of energy that must be expended to "fill" the device (AC energy in). The perfect storage device would have 100% round trip efficiency (that is, the energy output of the storage device would be equal to the charging energy required.) Actual storage efficiencies range from 70% to 90% depending upon the type of device, size and technology.

Duty Cycles Available: The number of charge/discharge cycles available from the device during a given period of time (measured in cycles per unit of time, for example, cycles per year, cycles per minute).

Grid Applications for Energy Storage

Generalized energy storage applications in electric power grids include the following:

Load Serving Capacity: Energy storage devices can be used to provide the equivalent of generating capacity, provided that the available storage duration is long enough (typically hours). Practical applications include substitution for peaking plants such as combustion turbines in markets where additional capacity is required[12]. In such an application, lower cost generating resources would be used to "fill" the energy storage device, and the stored energy would be released at a later time during peak hours. Load serving capacity requires relatively long storage durations (at least 3 hours to qualify as

[12] Denholm, Jorgenson, Hummon, Jenkin, Palcha, Kirby, Ma, O'Malley. The Value of Energy Storage for Grid Applications. National Renewable Energy Laboratory. NREL/TP-6A20-58465. May 2013. Available at: http://www.nrel.gov/docs/fy13osti/58465.pdf

"capacity" for the Companies' systems) but relatively infrequent use in terms of duty cycles (perhaps 50 – 100 cycles per year).

Time Shifting of Demand and Energy: Energy storage can be used to "shift" demand from one time period to another. Time shifting (also referred to as "load shifting") applications also typically require long duration (hours) of storage in order to be effective. In markets with substantial on-peak/off-peak energy price differentials, storage is valuable in financial arbitrage. In Hawai'i, there is not a large differential between the on peak and off-peak marginal cost of energy production; therefore, price arbitrage is not a primary consideration for energy storage at the grid level. Time shifting using energy storage may be useful in Hawai'i for managing the variability of some renewable energy resources, or to capture the available energy production from variable resources and store it for use at a later time, rather than "spilling" the available energy. Time shifting also requires relatively long storage durations, with the number of duty cycles being dependent on the nature of the market (for price arbitrage) or relative penetration of variable renewable energy and the frequency of curtailment events that could be avoided using energy storage.

Sub-Second Response: Fast acting energy storage can be used to supplement inertia and limit under-frequency load shedding that would occur during faults and other abnormities that occur on the grid, such as loss of generation. See Appendix E, Essential Grid Services.

Power Quality: Some energy storage devices can provide power quality and "ride-through" service. Power quality refers to the quality of the AC voltage in the system. Some energy storage devices can respond to changes in AC voltage by absorbing and releasing energy to "smooth" the sinusoidal AC waveform. For example, this type of functionality is used for some wind plants to ensure that equipment remains connected through transient system conditions.

These energy storage applications and the operational requirements associated with them are mapped in Figure J-1.

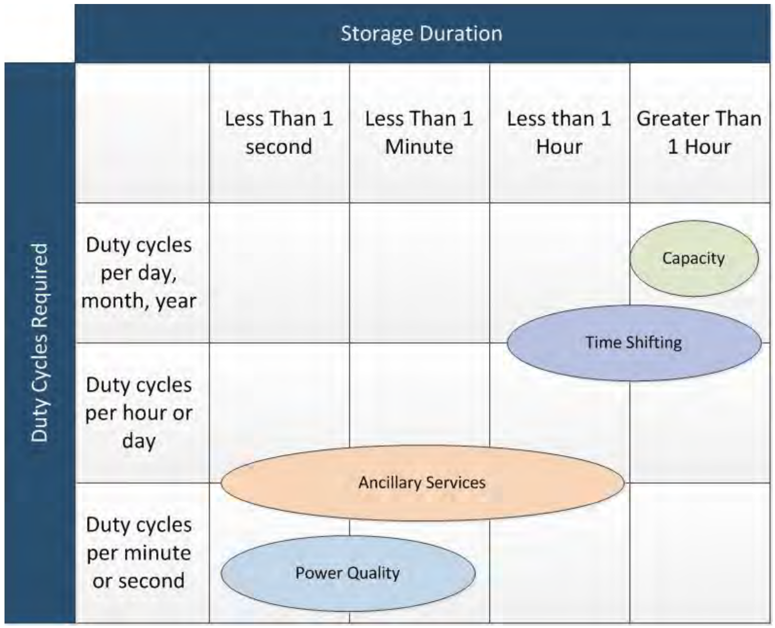

Figure J-1. Energy Storage Applications[13]

ENERGY STORAGE TECHNOLOGIES

Energy storage technologies can be categorized in terms of the physics utilized to store energy. These categories and the types of specific technologies include:

Mechanical: pumped storage hydroelectric (PSH), compressed air energy storage (CAES), flywheels. Underground CAES is not considered viable in Hawaiʻi due to lack of suitable geographic features and structural features conducive to CAES. However, aboveground CAES may be technically viable, but has not been considered at this time. PSH and flywheels are considered for Hawaiʻi and are discussed below.

Electrochemical: secondary batteries (lead-acid, lithium ion, other chemistries)[14], flow batteries. Lead-acid batteries, lithium ion and flow batteries are considered for Hawaiʻi and are discussed below.

Chemical: hydrogen (H_2), synthetic natural gas (SNG). These technologies are not considered for near-term applications in Hawaiʻi. A hydrogen infrastructure is, at best, a

[13] Adapted from International Electrotechnical Commission (IEC) Electrical Energy Storage Whitepaper, December 2011. Available at: http://www.iec.ch/whitepaper/pdf/iecWP-energystorage-LR-en.pdf

[14] "Primary" batteries cannot be recharged (for example, a dry cell flashlight battery). In "Secondary" batteries, the charge/discharge cycle can be reversed, meaning that secondary batteries can be recharged.

decade away. SNG is not economically viable as the round trip efficiency in very low (about 36%)[15].

Thermal: ice storage and grid interactive water heating. Ice storage and other forms of thermal energy storage are not considered here for bulk power applications. Several companies market thermal ice storage systems for managing end-use load (typically air conditioning) against tariff price signals[16]. Thermal energy storage can be useful for implementation by end-users in response to time-based pricing programs that are part of the Companies' demand response initiative (for example, grid interactive water heating).

Electrical: ultra-capacitors, superconducting magnet. These technologies are on the cusp of commercially readiness for grid-scale applications. Ultra-capacitors are increasingly being used in power quality applications[17]. Indeed, the Hawi wind plant in the Hawai'i Electric Light system utilizes an ultra-capacitor to ensure it remains connected through grid transients.

The following subsections briefly discuss the specific energy storage technologies that have been assumed to be available for consideration in the PSIP's. The inclusion of these technologies, and the exclusion of others, does not imply that the Companies are closed to considering other technologies. Specific energy storage proposals will be evaluated on their merits, including the commercial readiness of the technology proposed, utilization in specific grid-scale applications, and other relevant factors.

Flywheels

Flywheels are mechanical devices that store energy in the angular momentum of a rotating mass. The rotating mass is typically mounted on a very low friction bearing. The energy to maintain the angular momentum of the rotating mass is supplied from the grid. During a grid event, such as a sudden loss of load, the inertia of the rotating mass provides energy to drive a generator, which provides replacement power to the grid.

Flywheels are useful to provide inertial response in a power system. They are also increasingly used in commercial applications to provide fast-response, short-term "ride-through" capability that allows seamless transfer of load from the grid to a longer-term backup system such as an emergency generator. Flywheels display excellent load following characteristics over very short duration timeframes. Thus, they are well suited for providing frequency regulation and contingency reserves.

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15 Pascale. KU Leuven. *Energy Storage and Synthetic Natural Gas.* (undated). Available at: http://energy.sia-partners.com/files/2014/05/Paulus_Pascale_ArticleUpdated1.pdf

16 See for example Ice Energy. http://www.ice-energy.com/

17 Daugherty, Leonard. SolRayo. *Ultracapacitors for Renewable Energy Storage*. (undated). Available at: http://www.solrayo.com/SolRayo/Presentations_files/Ultracapacitors_for_Renewable_Energy_Storage_Webinar.pdf

The capital cost of flywheels is fairly high. However, flywheels can provide hundreds of thousands of charge/discharge cycles over their useful life. Flywheel energy storage can be developed in two years or less, not counting regulatory approval lead-times. The round trip efficiency of a flywheel storage system is approximately 85%.

Other than specific site considerations, flywheels have very little environmental impact. Modern metallurgy has produced flywheel technologies that are safe during operation. Several vendors have designs that place flywheels underground for additional safety.

Advanced Lead Acid Batteries

Lead-acid batteries were invented in the mid 19th century. Conventional lead-acid batteries are characterized by low energy density (the amount of energy stored relative to the mass of the battery), relatively high maintenance requirements, and short life cycles. Their principle advantage is the ability to deliver high current over long duration timeframes. Disposal of lead-acid batteries presents environmental considerations, but recycling techniques are well established.

Advanced lead-acid batteries or "UltraBatteries" are now reaching the market. UltraBatteries combine conventional lead-acid batteries with electronic ultra-capacitors to provide high duty cycles. The supercapacitor enhances the power and lifespan of the lead-acid battery, acting as a buffer during high-rate discharge and charge[18]. This makes the UltraBattery a low cost, durable battery technology, with faster discharge/charge rates and a life cycle that is two to three times longer than a regular lead-acid battery[19].

Like all chemical energy storage systems, capital costs for advanced lead acid batteries are still relatively high for grid-scale applications. Round trip efficiencies are also high at around 90%.

Grid-scale advanced lead acid battery projects can be developed in two years or less, not counting regulatory approval lead-times.

The high market penetration of lead-acid batteries in automotive applications has led to successful lead-acid battery recycling programs. Not only does recycling keep lead out of the waste stream, recycling supplies over 80% of the lead used in new lead-acid batteries.[20]

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[18] *UltraBattery: No Ordinary Battery*. Australian Commonwealth Scientific and Industrial Research Organisation (CISRO). Available at: http://www.csiro.au/Outcomes/Energy/Storing-renewable-energy/Ultra-Battery/Technology.aspx

[19] *Ibid.*

[20] Conger, Christine. "Are Batteries Bad for the Environment?" Discovery News. September 16, 2010. Available at: http://www.nbcnews.com/id/39214032/ns/technology_and_science-science/t/are-batteries-bad-environment/#.U_ATm-VdVS8

Lithium Ion Batteries

"Lithium-ion" refers to a wide range of chemistries all involving the transfer of lithium ions between electrodes during charge and discharge cycles of the battery[21]. Lithium ion batteries are very flexible storage devices with high energy density, a fast charge rate, a fast discharge rate, and a low self-discharge rate, making lithium ion batteries ideal for grid applications[22].

Capital costs for lithium ion batteries are declining[23], particularly as the use of lithium ion for electric vehicle batteries rises. Lithium ion batteries themselves have a useful life through 400-500 normal charge/discharge cycles. More frequent use of the full charge/discharge capabilities of lithium ion would shorten the life. Lithium ion battery energy storage can be developed in two years or less, not counting regulatory approval lead-times.

The round trip efficiency for lithium ion technology is around 90%.

Lithium ion batteries do not contain metallic lithium, nor do they contain lead, cadmium, or mercury. Thus, disposal of lithium ion batteries is not a major issue. At the end of their useful life, lithium ion batteries are dismantled and the parts are reused.[24] Overcharging certain lithium ion batteries can lead to explosive battery failure. Thus, the overall safety of lithium ion batteries in grid applications is a function of mechanical design and control systems.

Flow Redox Batteries

A flow battery is charged and discharged by a reversible reduction-oxidation ("redox") reaction between two liquid electrolytes of the battery. Unlike conventional batteries, electrolytes are stored in separated storage tanks, not in the power cell of the battery. During operation, these electrolytes are pumped through a stack of power cells, in which a chemical redox reaction takes place and electricity is produced. The design of the power cell can be optimized for the power rating needed, since this is independent of the amount of electrolyte[25].

Advantages of flow batteries include virtually unlimited cycle life and fast charge/discharge times for the electrolyte, but the power cells do require periodic replacement. Increasing the size of the electrode stack can increase the power output of a

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[21] Energy Storage Association. http://energystorage.org/energy-storage/technologies/lithium-ion-li-ion-batteries

[22] *Lithium Ion Technical Handbook*. Gold Peak Industries (Taiwan), Ltd. http://web.archive.org/web/20071007175038/http://www.gpbatteries.com/html/pdf/Li-ion_handbook.pdf

[23] See for example: http://rameznaam.com/2013/09/25/energy-storage-gets-exponentially-cheaper-too/

[24] See for example: http://auto.howstuffworks.com/fuel-efficiency/vehicles/how-green-are-automotive-lithium-ion-batteries.htm

[25] This paragraph taken from: http://www.imergypower.com/products/redox-flow-battery-technology/

flow battery, and the storage capacity (energy) can be increased by increasing the size of electrolyte storage (or volume of electrolyte tanks). Flow batteries are useful for longer storage duration (hours) applications. Their relatively high capital costs make them less useful for ancillary service applications. Flow batteries are generally considered safe, an important issue for grid-scale batteries where thermal runaway of conventional batteries may cause fire[26].

Capital costs for flow batteries are still relatively high. The round trip efficiency of a flow battery is relatively low at around 72%.

Pumped Storage Hydroelectric

Pumped storage hydroelectric (PSH) is a mature technology that has been successfully implemented around the world in grid applications. In a pumped storage hydro system, water is pumped to a higher elevation using energy made available from generating resources that are otherwise unused (for example, low marginal cost off-peak energy or excess renewable energy that would otherwise be curtailed, etc.). During high demand periods, this stored water drives a hydroelectric pump-turbine to generate electricity.

Pumped storage hydroelectric has a relatively high capital cost, but has a useful life typically in excess of 50 years. Pumped storage is very efficient with round trip efficiencies approaching 80%.

Pumped storage hydro installations are very site dependent. Pumped storage investigations in Hawai'i have previously identified several potential sites in the Companies' service territories, with available output capacities typically less than 100 MW in size. Pumped storage hydro installations also face substantial siting and permitting challenges, particular where new reservoirs must be constructed and subsequently flooded. Because of the site specific challenges and the substantial engineering and construction efforts required to build a PSH project, the typical development time for pumped storage is seven years or longer, posing challenges to the utility planner, particularly in an environment where the need to deliver solutions in the near term is paramount.

Due to the inherent economies of scale, the preponderance of pumped storage hydroelectric installations in the United States are typically hundreds or even thousands of megawatts in size. There is very limited data on capital cost and performance for operating pumped storage hydroelectric installations that are less than 100 MW in size.

Pumped storage hydro is a very useful technology for providing peaking capacity and time shifting capabilities. While pumped storage hydro is a quick-start resource, the

[26] Lamonaca, Martin. "Startup EnerVault Rethinks Flow Battery Chemistry." MIT Technology Review. March 22, 2013.

water column constant of a typical pumped storage system is about 7 seconds (that is, this is the time it takes to get the water moving through the turbine to produce electricity). This is a limiting factor with respect to the utilization of an off-line pumped storage system for providing certain ancillary services. The utilization of adjustable speed pump turbine technology in pumped storage hydroelectric projects can provide operating flexibility compared to conventional pump turbines. The main advantage of using adjustable speed technology is the ability to provide more precise power control. This power control can be maintained over a wider operating range of the pumped storage hydroelectric system, allowing the utility to provide ancillary services, such as frequency regulation, spinning reserve, and load following, in both the generation and pumping modes. These benefits and other attributes of an adjustable speed pump turbine can translate into increased operating efficiencies, improved dynamic behavior, and lower operating costs.

Unlike a battery, which already has charge, or a flywheel that has angular momentum, the start of a pumped storage charging cycle requires the delivery of high levels of electric current to start the motors necessary to pump water to the higher elevation. To put this in perspective, a 30 MW pumped storage system in the Hawaiʻi Electric Light system would require staring 37.5 MW of motor load (assuming an 80% round trip efficiency). The typical daily peak demand of the Hawaiʻi Electric Light system is about 150 MW. Therefore, the start of the motor would represent an instantaneous load increase of 25% on the system. This may result in currents that exceed the short circuit limits of the transmission system, and without mitigation this would result in a significant frequency disturbance.

The primary environmental impacts from pumped storage hydro occur during construction. If construction of new reservoirs and/or water diversion is required, this can lead to substantial permitting challenges.

ECONOMICS OF ENERGY STORAGE

Energy Storage Capital Cost

The costs assumed in the PSIP's for energy storage systems are generally based on actual proposals for energy storage systems and flywheels, and from a combination of sources for pumped storage hydroelectric. The cost of energy storage for any given storage technology is in part a function of the duration of storage required. Table J-1 summarizes the capital costs assumed for the PSIP's mapped against the specific grid services required in the Companies' systems[27].

Grid Service	Storage Duration / Discharge	Technology Flywheel $/KW	Advanced Lead Acid $/KW	Lithium Ion $/KW	Flow Redox $/KW	PSH $/KW
Inertial, Fast Response Reserves	0.05 min / 5000 cycles per year	$997	NA	NA	NA	*
Regulating Reserves	30 min / 1000 cycles per year	$4,459	$1,005	$1,179	$1,596	*
Contingency Reserves	30 min / 20 cycles per year	$2,263	$802	$942	$1,079	*
Capacity, Long-term Reserves	> 3 hours / 50 cycles per year	NA	$4,531	$5,401	$2,559	$4,500[28]

Costs include EPC, land, and overheads. Costs do not include AFUDC. NA = not economic, or unable to provide this service. * PSH may be able to provide these services when operating, but because the upper reservoir capacity of a given pumped storage project site is defined by geology and other factors, PSH would not typically be economical to build for the sole purpose of providing very short duration services.

Table J-1. Energy Storage Technology Capital Cost Assumptions (2015 Overnight $/KW)

Energy Storage Fixed O&M

The PSIP fixed O&M cost assumptions for energy storage were also based on actual proposals, except for pumped storage hydroelectric, which is based on NREL data. Table J-2 summarizes the storage fixed O&M costs.

Grid Service	Storage Duration / Discharge	Technology Flywheel	Advanced Lead Acid	Lithium Ion	Flow Redox	PSH
Inertial, Fast Response Reserves	0.05 min / 5000 cycles per year	58	NA	NA	NA	NA
Regulating Reserves*	30 min / 1000 cycles per year	264	31	32	43	NA
Contingency Reserves	30 min / 20 cycles per year	108	25	27	29	NA
Capacity, Long-term Reserves	> 3 hours / 50 cycles per year	NA	90	105	62	29

Table J-2. Energy Storage Fixed O&M Assumptions (2015 $/KW-Year)

[27] See Appendix E for a discussion of Essential Grid Services in the Companies' systems.

[28] There is relatively little actual data available regarding the cost of utility-scale pumped storage projects less than 100 MW in size. This capital cost assumption for pumped storage used in the PSIP analyses was determined though evaluation of a number of different sources, including a review of confidential screening-level cost estimates for site specific projects in Hawai'i, estimates for a 50 MW pumped storage project in the United Kingdom, NREL data, U.S. Energy Information Administration data, and conversations with a potential pumped storage developer in Hawai'i.

Energy Storage Variable O&M

The PSIP variable O&M cost assumptions for energy storage were also based on actual proposals, except for pumped storage hydroelectric O&M, which is based on NREL data. The variable O&M costs for batteries is solely related to battery and cell replacements and disposal at the end of the duty cycle of the batteries which are assumed to require replacement due to high number of charge/discharge cycles per year associated with provision of regulating reserves. Table J-3 summarizes the storage variable O&M costs

		Technology				
Grid Service	Storage Duration / Discharge	Flywheel	Advanced Lead Acid	Lithium Ion	Flow Redox	PSH
Inertial, Fast Response Reserves	0.05 min / 5000 cycles per year	NA	NA	NA	NA	NA
Regulating Reserves*	30 min / 1000 cycles per year	-0-	88	45	30	NA
Contingency Reserves	30 min / 20 cycles per year	NA	NA	NA	NA	NA
Capacity, Long-term Reserves	> 3 hours / 50 cycles per year	NA	NA	NA	NA	59

Table J-3. Energy Storage Variable O&M Cost Assumptions (2015 $/MWH)

Benefits of Energy Storage

In the Companies' systems, energy storage can be used for several purposes.

- Capacity to serve load
- Manage curtailment of variable renewable generation
- Ancillary services
- Integration of renewables

Benefits of energy storage for each of the above uses depend upon specific operating conditions, the capacity adequacy situation in each of the operating systems, and the other resource options available. In general, energy storage can also be used for multiple purposes. For example, energy storage installed to provide capacity to serve load, could also be available to provide ancillary services, provided it is not being used in its load-serving mode. However, if the storage asset is will be used for multiple purposes, it must be designed to ensure the energy allocation and response capability can serve the combined needs. For example, storage used for contingency reserves must be kept at the necessary charge level to provide the required reserve. If also providing regulation, additional energy storage capacity would be required above the minimum required to meet the contingency reserve requirement.

Capacity

Energy storage can provide capacity to serve load on the Companies' systems, provided that there is a need for capacity[29] and provided that there is the appropriate duration of energy storage available to qualify as capacity[30]. During the PSIP planning period, the Hawaiian Electric and Maui Electric systems are expected to add capacity to replace retiring generation. Thus, energy storage is one of the alternatives that must be considered for providing that capacity.

Figure J-2 conceptually depicts the economic comparison of energy storage to generation for providing capacity.

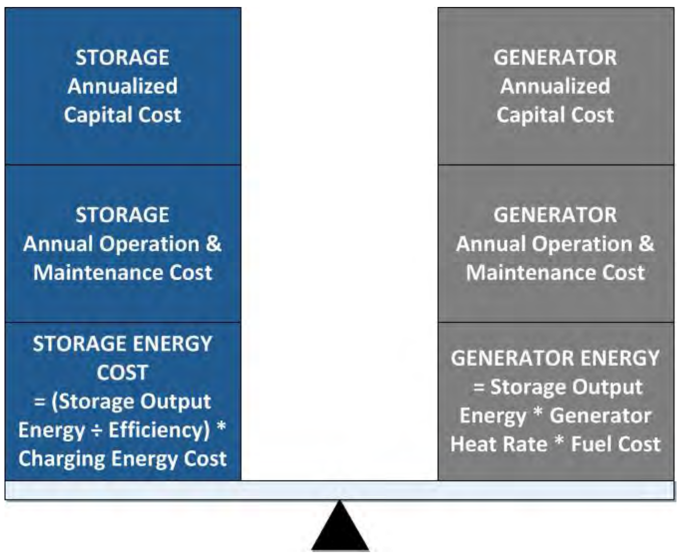


Figure J-2. Energy Storage Economics for Capacity

In this comparison, the energy storage device is compared on a one-for-one basis as a substitute for a generator. A levelized utility revenue requirements factor is applied to the total capital cost of the storage and the generator to determine the annual capital costs. The O&M costs associated with the two alternatives are determined. And finally, the cost of the energy output from each of the assets is computed. In the case of the storage technology, the round trip efficiency must be taken into account, because more energy is required to charge the energy storage asset than is usefully delivered from the same energy storage asset. If the total cost of the energy storage asset were less than the cost of the generator, energy storage would be the most economical alternative[31]. Note that in the case where capacity is not needed, the capacity cost of the generator would be

[29] Denholm, Jorgenson et. al.

[30] Storage is a finite energy resource. When used as a capacity resource, the storage must be carefully designed for the appropriate duration, and the storage energy must be utilized in an appropriate manner. The Companies' criteria require that a resource be able to deliver energy for 3 continuous hours in order to qualify as capacity.

[31] In a proper analysis, any differences in ancillary service costs or benefits associated with the alternatives being compared will also be included.

zero, because existing generation (whose capital cost is sunk) would be able to provide amount of energy required by the system.

Managing Curtailment

Energy storage used to manage variable renewable energy curtailment is an example of a time shifting application for storage, and may have use in the Companies' systems. Energy storage can absorb variable renewable energy that is produced when it is not needed, and return that energy (less round trip losses) to the system at a later time. Figure J-3 conceptually depicts the economics of energy storage in managing curtailment.

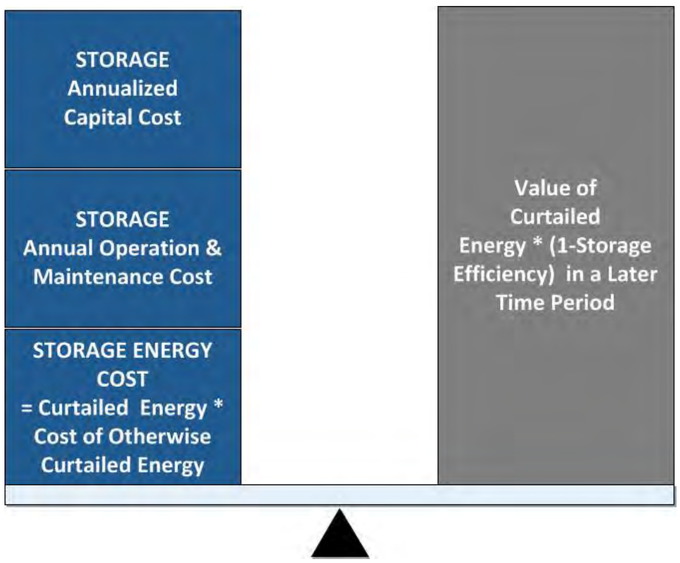


Figure J-3. Energy Storage Economics for Managing Curtailment

The basic economic equation in Figure J-2 is a comparison of the cost of the energy storage versus the value of energy in a later time period of energy that would have otherwise been curtailed (less the round trip efficiency losses since that those losses will not be returned to the system). Note that in Figure J-2 there is a cost associated with the curtailed energy used to charge the energy storage device. Absent the energy storage asset, the payment for the curtailed energy would have been avoided. Thus, this is a cost that is borne by the ratepayer that would otherwise have not been incurred. Further study of Figure J-2 will reveal that the cost comparison includes the capital cost of the energy storage, but it does not explicitly include any capacity value (that is, capital cost) associated with use of the energy in a later time period. Unless there are severe capacity constraints in the system where new capacity is required, the capacity value of the energy used at a later time is essentially zero. At current Company system marginal cost levels, it would almost never be economical to build energy storage exclusively for the purpose of managing energy curtailment. Rather, it is more likely that an energy storage asset already installed for another purpose could also be used to manage curtailment.

Ancillary Services

Energy storage can be used to provide ancillary services, provided that it can respond in the time frames necessary and operate in a coordinated fashion with other generation and demand response resources on the system. Using energy storage to provide ancillary services slightly increases total amount of energy that must be generated in the system due to the round trip losses associated with the energy storage asset. The charging energy may come from thermal resources or from variable renewable resources. However, energy storage may allow energy production costs to be reduced if provision of ancillary services is causing a constraint on the economic commitment and dispatch of generating units. These economics are depicted in Figure J-4.

The value of the energy storage asset in this situation is based on production cost savings (fuel and O&M) that are incurred by storage supplying the ancillary services. Calculation of these benefits requires production simulations.

If capacity is required in the system, short duration energy storage may be more cost effective than adding new generating capacity. If that is the case, the capital cost of the new generation must be added into the benefits that storage can provide.

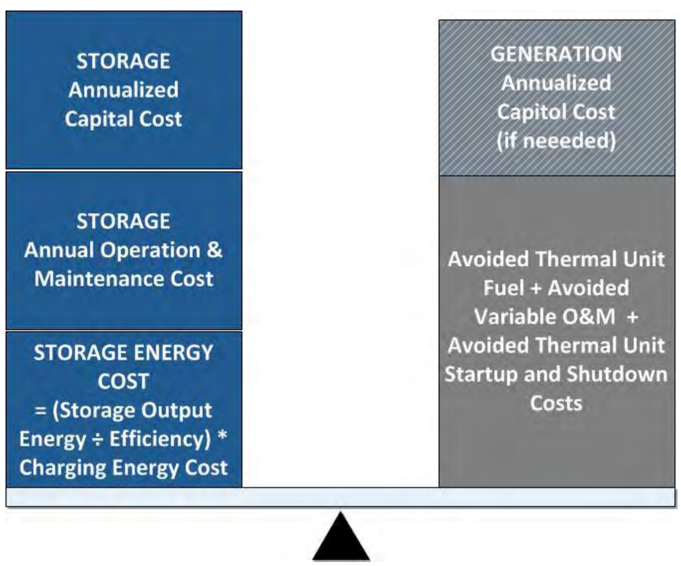


Figure J-4. Energy Storage Economics for Ancillary Services

Integration of Renewables

Another possible use of energy storage in conjunction with renewable energy is to combine the installation of a variable renewable generator with the installation of energy storage. This has been accomplished in the all three of the Companies' main operating systems. The value of this configuration for customers is that it essentially allows the storage to be leveraged to minimize the ancillary service requirements created by the variable generator that would otherwise have to be provided by other resources on the system. Location of storage at the plant allows the sizing to be designed for the plant needs; co-location also simplifies the communications control interface. From a system standpoint, the storage/generation combination is treated as a plant with the combined operational/technical capabilities of the turbines and storage. The economic evaluation is essentially the same as that portrayed for ancillary services in Figure J-4.

It should be noted that in several cases, the installation of the energy storage was feasible only because it was bundled with generation in a way that allowed the project developer to obtain tax advantages for the energy storage that would not be available for a standalone energy storage asset. In other words, energy storage added value to the generation.

Unless marginal thermal generation costs were much higher than they are today, the converse is not true (that is, adding generation does not add value to storage). It does not make economic sense to build excess renewable generators exclusively to provide energy to charge storage assets since in doing so, the marginal capital cost would be the sum of the generator capital cost and the storage capital cost. Rather, it is important that the system be planned to optimize all resources, including generation, demand response, and storage to achieve the lowest cost.

K. Capital Investments

This information represents the 2015–2030 capital expenditure budget for the Hawai'i Electric Light Company.

TRANSFORMATIONAL INVESTMENTS

The transformation of the Hawai'i Island electric power system and grid is being made to cost effectively enable more renewable generation while maintaining the reliability of the grid system. This requires significant investment in virtually every aspect of the business. Investments include new renewable generation resources, installing enabling technologies for demand side resources and DGPV requiring grid reinforcements. Additionally modifications to infrastructure for lower-cost LNG fuel will transform our Island grid reducing the cost to the customer while maintaining grid reliability. These transformative investments are described below more in depth.

Liquefied Natural Gas (LNG)

In an effort to reduce customer costs, Hawai'i Electric Light is pursuing two non-exclusive approaches to import lower-cost LNG to Hawai'i: importation of LNG via ISO (International Organization for Standardization) containers (containerized LNG); and/or importation of LNG via bulk LNG carriers (bulk LNG). Hawai'i Electric Light will receive containers from O'ahu and the supplier will truck the containers to the three (3) sites currently planned for LNG conversion.

The concept of containerized LNG would involve using conventional container ships and trucks equipped to handle ISO containers. The LNG ISO containers would be delivered directly to the generating stations where the LNG would be regasified and consumed.

Shipping and distribution of containerized LNG to Hawaiʻi in volumes sufficient for power generation may possibly be commercialized within three years or less.

The bulk LNG concept would involve transporting LNG across the ocean via LNG carriers and/or articulated tug barges, and receiving it at a bulk LNG import. The bulk system will be designed with a transfer system to load containers for the continued transportation to the Hawaiʻi Electric Light facilities thru the normal barge and truck transportation chain. It is anticipated that development, permitting, and implementation of a bulk LNG import and containerization facility will take up to eight years to complete, and could possibly be placed in service in 2020 to 2022.

Regarding containerized LNG, Hawaiʻi Electric solicited offers from third parties for containerized LNG deliveries via a March 11, 2014 request for proposals ("RFP") and final bids from three potential suppliers were received on May 24, 2014. The responses to the RFP indicate that containerized LNG could be delivered to generating stations on Oʻahu and neighbor islands up to an approximate 30% discount below current petroleum fuel prices. Based on these proposals, Hawaiʻi Electric Light intends to move forward as quickly as it can to bring containerized LNG to Hawaiʻi and to use it in existing and future replacement generating units.

It appears that importing containerized LNG will have the potential of saving the Companies' customers throughout the state substantial amounts on fuel costs. The amount of the savings will depend on the prices for the fuels that are displaced once LNG is available, and the final prices from the on-going RFP. It is uncertain at this time whether a bulk LNG delivery solution would provide as much, the same or more of a cost benefit to customers. Therefore, Hawaiian Electric will continue to pursue the bulk LNG concept as long as there is a potential that it will provide additional benefits and value to our customers.

System Security Investments

To reliably operate a grid rich in variable renewable generation requires the grid operator to manage a new, and to some extent not fully known, set of electrical system security issues. When such a grid is a small islanded system such as Hawaiʻi Island, the criticality of these issues is further heightened, as compared to the large, interconnected grids of North America. The Company's system security analyses, coupled with the PSIP planning processes, have defined a number of new investments required to meet these system security challenges. These investments, "Energy Storage – Contingency Reserve" and "Energy Storage Regulating Reserve," enable the Company to comply with its system security and reliability standards by 2016 and maintain compliance with these standards through the remainder of the study period.

Investments also include telecommunications infrastructure additions to provide SCADA functionality to all distribution substations. SCADA provides for information and control of distribution substation devices for improved reliability and situational awareness. It also provides the communication link to communicate with utility and customer equipment located within and connected to distribution circuits. These include communications to facilitate dynamic under frequency load shedding; provides a "backhaul" for Distribution Automation, AMI, and other Smart Grid technologies; and is a necessary communications link to take advantage of "smart" inverter capabilities, including inverter status, voltage regulation, active inverter control/regulation, and other functionality as described in the DGIP.

Additionally, investments will also include a new Energy Management System (EMS) to replace the current EMS when it reaches the end of its product lifecycles and to take advantage of state-of-the-art hardware and software technologies to properly operate a grid with significantly more monitoring and control points than in the past and to allow for the coordinated operation of the system – both automatic generator controls and T&D switching—and also to interface with the Advanced Distribution Management System (ADMS) and Outage Management System (OMS) planned to allow for coordination with circuit/area-level grid operations such as DR, DA, DG, EV and operations and monitoring of other DERs.

Facilitation of New or Renewable Energy

Additional transmission system infrastructure will be required for the addition of several new renewable energy suppliers. A substation and transmission line interconnection will be required to add a new 25MW Geothermal generating plant in the West Hawaiʻi region in 2025

Additional transmission system infrastructure will be required in the addition of a substation and transmission line interconnection will be required to add a new 20MW Wind generating plant in 2020.

Additional transmission system infrastructure will be required in the addition of a substation and transmission line interconnection will be required to add new 5MW and 20MW battery storage systems in 2017.

The growth of DGPV has prompted a need to ensure fast fault clearing times on the transmission system. The need for fast clearing times is the result of a system dynamics study with the projected DGPV growth that indicated that at the current levels of DGPV the grid will become unstable in the event of a significant fault or loss of a generating unit while there is heavy PV generation. Under normal conditions, the required clearing time is met by existing equipment. However, a failure of one or more pieces of the transmission relay and breaker equipment during a fault can lead to a long clearing time and unstable event. The solutions to reduce the fault clearing time significantly during this contingency include replacing slower clearing circuit breakers, adding breaker failure protection and adding redundancy to the relay communication. Projects to address this are planned over the next 5 years.

DG Enabling Investments

The Distributed Generation Improvement Plan (DGIP) lays out an aggressive plan to enable the integration of significant amounts of new distributed resources, which are expected to be primarily rooftop PV.

The DGIP includes a Distribution Circuit Improvement Implementation Plan (DCIIP) that summarizes specific strategies and action plans, including associated costs and schedules, for circuit upgrades and other mitigation measures to increase the capacity of the Companies' electrical grids and enable the interconnection of additional DG.

In evaluating each company, by circuit and substation transformer, improvements to allow for greater interconnection of DG include: (1) updating LTC and voltage regulator controls to be capable of operating properly under reverse-flow conditions; (2) upgrading substation transformer capacity when load and DG are greater than 50% of capacity in the reverse direction; (3) upgrading primary circuit capacity when load and DG are greater than 50% of capacity in the reverse direction; (4) upgrading customer service transformer capacity when load and DG are greater than 100% of capacity, which also mitigates high voltage; (5) adding a grounding transformer to circuits when 33% of DML is exceeded for applicable circuits; and (6) adding a grounding transformer of 46-kV lines when 50% DML is exceeded. Each of these mitigation measures provides different values to both the utility and the distributed PV owner.

Smart Grid and Demand Response

At the Hawai'i Electric Light Companies, we are committed to achieving modern and fully integrated electric grids on each of the islands we serve—grids that harness advances in networking and information technology and, as a result, deliver tangible benefits to our customers and the state of Hawai'i. To accomplish this, we plan to invest in smart grid.

Two-Way Communications System

The backbone of our Telecom System (fully owned by the Hawai'i Electric Light Companies) acts as an enabler for all of our operational and corporate business applications, including the smart grid applications. The Hawai'i Electric Light

Companies enterprise telecommunications network or backbone is commonly referred to as our Wide Area Network (WAN) and Field Area Network (FAN). The smart grid applications and end devices (such as the smart meters), fault circuit indicators (FCIs), SCADA-enabled distribution line transformers and switches, reside in the Neighborhood Area Network (NAN), which is located beyond the WAN and FAN networks. The foundation of the smart grid platform (the NAN) we intend to implement is a two way communications network that connects points along the distribution grid to our back office software. Smart grid applications run on that network providing detailed information about the performance of the distribution grid.

AMI uses the secure IPv6 network that employs wireless 900MHz radio frequency mesh technology. This wireless technology consists of: access points; routers enabling devices communicating over the radio frequency mesh network to connect to our IT infrastructure through wired or cellular connections; relays, which are repeater devices that extend the reach of the radio frequency signal; and intelligent endpoints (such as third-party smart meters outfitted with network interface cards from Silver Spring Networks).

All Silver Spring Networks devices contain a one watt, two way radio. These devices connect with each other to form a mesh that makes up the Neighborhood Area Network (NAN). Access points and relays will be designed to have multiple paths through the NAN and the utility's WAN to provide high-performance, redundant connections between endpoints and our back office systems and data center. The network interface cards inside smart meters also act as relays (repeaters), further extending the mesh.

The radio frequency mesh network aggregates smart meter data and transmits it to us either through the utility-owned WAN or cellular connection. The mesh network can also transmit other information (such as remote service connects or disconnects) from us to customers. A back office head end system (such as Utility) collects, measures, and analyzes energy consumption, interval and time-of-use data, power quality measures, status logs and other metering data, and manages smart grid devices. Other back office systems manage meter data and integrate that data with customer and billing information.

Customer Engagement

Hawai'i Electric Light believes in a proactive, transparent and sustained communication effort to educate and engage our customers is critical to successfully rolling out the Initial Phase, the initial step in our smart grid plans. Our efforts to engage our customers underscore our commitment to continually improve customer service, modernize the grid, and integrate renewable energy.

We intend to inform customers about installing smart meters, educate them about smart grid benefits, and address their related concerns. Key to this is helping customers understand that, at its core; smart grid technology will offer them more information about their energy use than ever before and give them tools and programs to help them control their energy use, which they can then use to help lower their electricity bills.

Through a multi-pronged approach for the duration of our smart grid roadmap, we intend to build interest from the onset, address questions and concerns, and engage customers in understanding the benefits of smart grid. Our communication program is based on tested and proven industry best practices, and is customized based on research conducted in this market on how to best reach our customers. Our approach seeks to engage our customers with information tailored to their specific needs and questions. Working with trusted third-party groups, we plan to engage customers in direct conversations wherever they are—at home, in their neighborhoods, and online.

Replacement Dispatchable Generation Capacity

New Generation

The Commission provided Hawai'i Electric Light explicit guidance to expeditiously "modernize the generation system to achieve a future with high penetrations of renewable resources." Decision and Order No. 32052, filed April 28, 2014, in Docket No. 2012-0036 (Regarding Integrated Resource Planning), Exhibit A: Commission's Inclinations on the Future of Hawai'i's Electric Utilities (*Commission's Inclinations*) at 4. The Commission recognized that act of "serving load" at all times of the day is becoming less focused on energy provision, and more focused on providing or ensuring the reliability of the grid. Proposed New Generation projects would be a firm generation resource with attributes and optionality consistent with this guidance, including the following abilities:

- Start, synchronize to the grid, and ramp to full load in a few minutes;
- Ramp generation output up and down at fast rates for frequency regulation;
- Operate over a very wide range of loads when synchronized to the gird (that is, more than 12 to 1 turndown);
- Execute multiple starts and stops throughout any operating period;
- Control Volt-Amp Reactive ("VAR") output for voltage regulation;
- Provide an automatic inertial response during major grid contingencies to help stabilize system frequency;
- Efficiently convert fuels to electric power (that is, to operate at low heat rates) over its full range of power output;

- Utilize multiple liquid and gaseous fuels; and
- Black start and "island a defined energy district" at a unique location in central O'ahu, adjacent to a major air field.

These attributes will contribute to maintain grid stability, security, and resiliency as more variable renewable generation is interconnected.

Retirement of Existing Generation Assets

We will aggressively pursue the retirement and replacement of existing generating units. We "deactivated" Shipman Unit 3&4 in 2012. These units are scheduled to be decommissioned in 2015. The deactivation and retirement of these units allows us to focus our existing resources on our existing units.

We intend to further retire/deactivate steam generating units as new generation and load situations allow. An aggressive plan for deactivation was created and can be adjusted as situations dictate. The plan includes deactivation of all steam units on a systematic basis. In order to provide best value to the customer in terms of cost reduction it was deemed necessary to retire units as a pair.

The Puna oil fired plant was placed in cycling mode in mid-2014 and is only operated when there is a need for capacity. This will occur when several other generators are off line for maintenance or overhaul. It is scheduled to be deactivated in 2018 and decommissioned in 2020.

The Hill unit 5 oil fired unit is scheduled for deactivation in 2020 and decommissioning in 2022.

The Hill unit 6 oil fired unit is scheduled for deactivation in 2022 and decommissioning in 2024.

The need for this unit is reduced as lower cost generation is added to the system with the Biomass addition, wind addition and geothermal additional generation. The addition of these new low cost generators will reduce the cost to our customers as well as replace the grid stability support lost by the retirement of the three(23) steam units.

Units that are scheduled to be deactivated will require capital additions in order to prepare them for deactivation. This allows reactivation should it be required. The plans are very specific and be strictly adhered to in order to be in compliance with the environmental operating permits and regulations.

Use of the Puna and Hill power plant sites after the existing units have been retired is very difficult to predict at this time. No current plans exist for the reuse of these sites; however they are possible locations for the Battery storage locations

FOUNDATIONAL INVESTMENTS

The success of the transformational investments discussed above is dependent on a strong foundation. The Company must continue to deliver safe, reliable, and efficient service to all customers. The foundational investments required to sustain operations are described below.

Asset Management

The asset management category includes costs for the replacement of substation equipment, vaults, conductor, switchgear, switches, and batteries. Asset management principles aim to minimize corrective replacement costs, for both O&M expense and capital, by implementing preventive strategies. Work performed on a planned basis, in the normal course of business, can usually be executed at lower, more predictable overall costs and with greater degree of safety to Company employees and the public.

Reliability

The Reliability category consists of production and transmission and distribution capital projects to ensure that the Company's existing generation assets and transmission and distribution grids are available to reliably generate and deliver power to customers. Major projects in this category include overhauls for existing generation assets and the reconductoring and relocation of existing transmission facilities.

Safety, Security and Environmental

The Safety, Security, and Environmental category consists primarily of distribution capital projects and programs to replace and/or relocate poles and transformers to minimize risks to the public and the Company's employees.

Customer Connections

The Company will need to connect new customers throughout the 2015–2030 periods. This work includes preparing the design and packaging of customer-requested work, such as overhead and underground services to new and existing customers along with related overhead and underground additions for construction and/or meter installations actually doing the work.

Customer Projects

The Company will need to complete customer projects throughout the 2015 – 2030 period.

This category of work includes preparing the design and relocations of services to existing customers for both overhead and underground services. The projects included in this category fall under the baseline category. Note -Fully Funded Customer Projects will not appear since numbers are net of CIAC.

Enterprise

Overview of IT Capital Programs and Enterprise Information Systems

The IT related Capital projects and programs projected in the 2015-2030 Capital forecast consists primarily of two categories:

1. IT Capital programs that support the Companies' hardware lifecycle and growth, broken down by IT function or IT service.
2. Enterprise Information Systems based on the Companies' Enterprise Information Systems (EIS) Roadmap (filed with the commission on 6/13/2014), which includes new software implementations, replacements and upgrades.

This document provides a high level overview of each category and their respective project and programs and the following table provides a view of the projects and programs over the specified timeline.

IT Programs

The ITS Department's capital budget consists primarily of IT hardware programs: (1) that maintain and enhance Hawai'i Electric Light's data center and network infrastructure; and (2) to provide the workforce with assets that support employee productivity and communications.

IT Programs	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
IT Infrastructure	$3,083,983	$2,888,867	$2,966,061	$3,112,288	$3,265,724	$3,426,724	$3,595,661	$3,772,927	$3,958,933	$4,154,108	$4,358,906	$4,573,800	$4,799,288	$5,035,893	$5,284,162	$5,544,671
Client Computing	$2,570,982	$2,248,536	$2,353,297	$2,469,314	$2,591,051	$2,718,790	$2,852,826	$2,993,471	$3,141,049	$3,295,903	$3,458,391	$3,628,889	$3,807,793	$3,995,518	$4,192,497	$4,399,187
Copiers/printers	$573,410	$831,271	$675,059	$708,339	$743,261	$779,903	$818,353	$858,697	$901,031	$945,452	$992,063	$1,040,971	$1,092,291	$1,146,141	$1,202,646	$1,261,936
ERP/CIS Hardware Upgrade	$0	$0	$0	$161,000	$1,935,000	$1,891,000	$1,620,000	$320,000	$320,000	$320,000	$2,087,000	$2,052,000	$1,781,000	$481,000	$481,000	$481,000
Collaborative communications	$671,083	$375,998	$405,104	$425,076	$446,032	$468,021	$491,095	$515,306	$540,710	$567,367	$595,339	$624,689	$655,486	$687,801	$721,710	$757,290
MISC Telephone Equipment	$506,256	$405,437	$406,960	$427,023	$448,075	$470,165	$493,344	$517,666	$543,187	$569,966	$598,066	$627,550	$658,488	$690,952	$725,016	$760,759
MISC Office Equipment	$90,826	$102,096	$383,445	$402,348	$422,184	$442,998	$464,838	$487,754	$511,801	$537,032	$563,508	$591,289	$620,439	$651,027	$683,123	$716,801

Table K-1. IT Programs Investments 2015–2030

These programs are needed to maintain and improve upon IT service levels to both Company stakeholders as well as customers through the lifecycle replacement of hardware assets. In addition, the programs account for increased demand for reliable and secure access to information and information technology, primarily driven by (1) employee and facilities growth; (2) increased investment in mobile computing; (3)

escalating need for cyber security and privacy; (4) increased need for enterprise content management; and (5) improved disaster recovery and reliability.

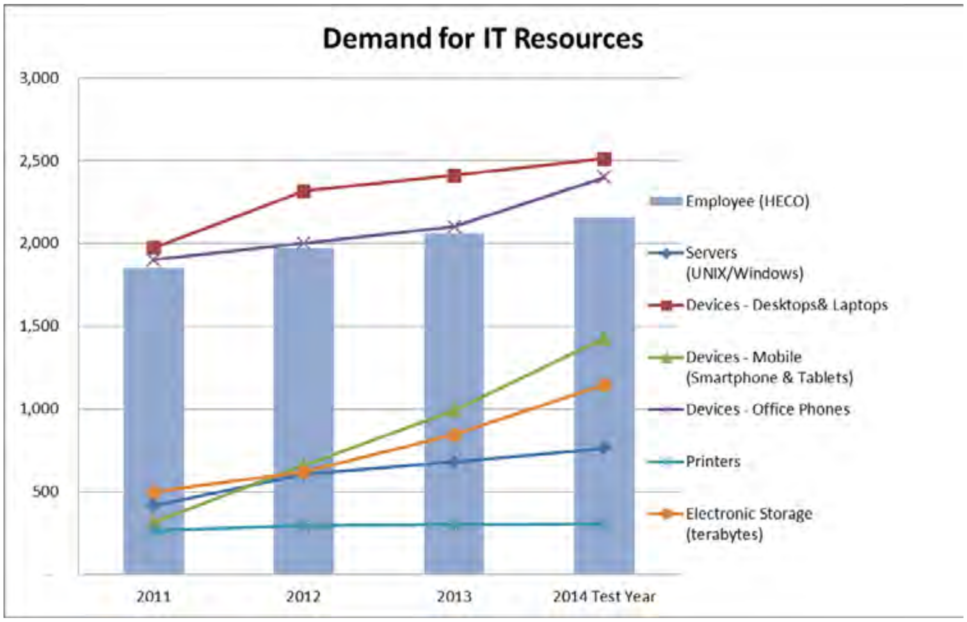


Figure K-1. Demand for IT Resources

A brief description of each of the IT programs is provided below.

IT Infrastructure program: The IT Infrastructure program is needed to maintain and enhance Hawai'i Electric Light's data center and network infrastructure and includes costs to lifecycle the server fleet, networking equipment (routers and switches), and electronic storage, as required to meet the Company's business needs. The IT infrastructure program includes "ERP/CIS Hardware Upgrade" 2018-2030 costs (shown separately as an adjustment above for the purposes of this forecast) to accommodate projected replacement and growth specifically for Enterprise Server hardware needs.

Client computing program: The Client Computing program is needed to provide the workforce with devices and other assets that are managed as part of the client computing environment and support employee productivity and communications. It includes costs to accommodate growth and lifecycle of that environment; including desktop PCs, laptops, mobile devices, and peripherals.

Collaborative Communications program: The Collaborative Communications program includes cost for those hardware assets that enable cost-effective communication and collaboration across time and distance. Specific examples include conferencing enabled telephones, projectors, electronic whiteboards, video conferencing devices, displays, digital signage equipment, microphones and public address ("PA") equipment.

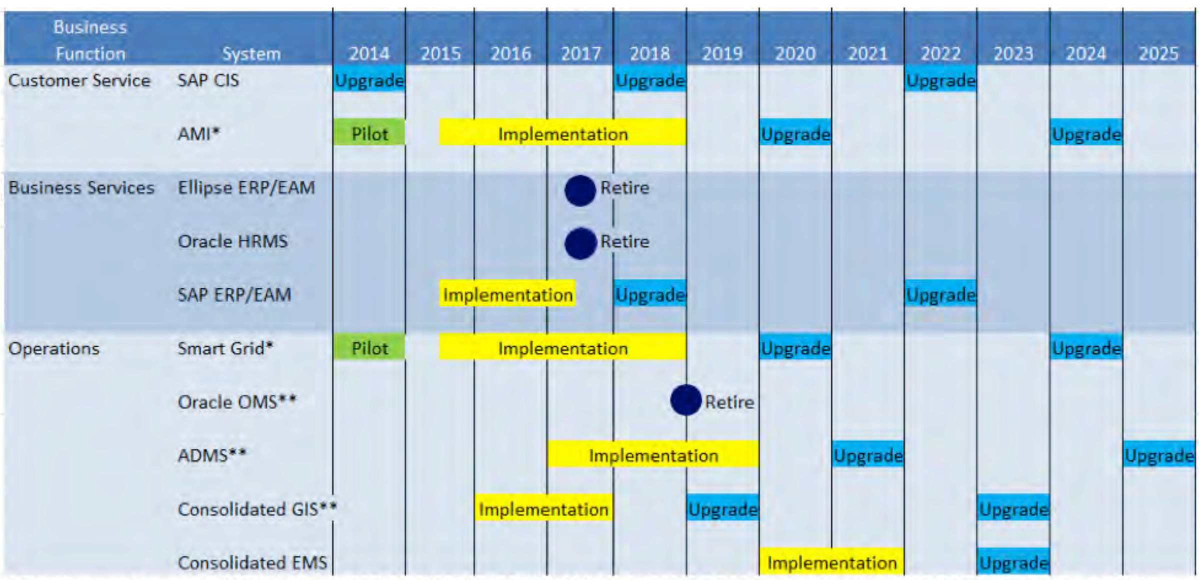
Copiers/Printers: The Copiers/Printers program includes costs to maintain, lifecycle replace, and net new additions for equipment that support the Company's printing and imaging needs. This includes desktop, multi-function, and wide-format printing devices, as well as imaging, scanning and fax devices.

(Miscellaneous) Telephone Equipment: The Telephone equipment program includes costs related to lifecycle and growth of the Company's telephone system including the PBX system, related telephony equipment, and office VOIP and digital phones.

(Miscellaneous) Office Equipment: The Office Equipment program includes costs for lifecycle replacement and installation of new equipment that support the Company mailing operations and general office equipment. Examples include the Company's mail inserter and folding machines used for billing purposes.

Enterprise Information Systems (EIS) Implementation and Upgrade Projects

EIS projects provided in this forecast include projects based on the EIS Roadmap, filed with the commission on 6/13/14.



* This document separates AMI from Smart Grid to reflect the fact that AMI provides customer consumption to customers and to the CIS, while the Smart Grid functions provide Operational capabilities.

** A study is underway to evalute an OMS upgrade or replacement with an ADMS. This document assumes OMS will be replaced by an ADMS. The study also evaluates GIS consolidation and standardizization. This document assumes GIS consolidation. Additional phases for the ADMS and GIS will be added as they are better defined.

Figure K-2. EIS Implementation Plan

The EIS implementation and upgrade projects projected within the Capital forecast are based on the EIS Roadmap with minor adjustments to accommodate the capital forecasting process and adjustment for recent developments. These adjustments include:

- Projected business releases within the overall GIS and ADMS projects.

- The inclusion of a Demand Response Management System project.
- The projection of upgrades through the additional 5 years of the forecast, not accounted for in the EIS roadmap, based on a 4 year average Enterprise Software upgrade cycle.
- The "future software implementations" for years 2023 - 30 are based on average spend of years 2015-2022.
- Smart Grid and AMI explanations will be provided separately, by the Smart Grid project team.

For the purpose of this overview these projects can be viewed in two categories: EIS projects and EIS upgrades. For a more detailed explanation of strategic and other drivers please reference the EIS roadmap. The following overviews are broken out between EIS implementation projects and upgrades.

EIS implementation Projects

ERP/EAM Project: The ERP/EAM project is a major current initiative in the Business Services area of our EIS Roadmap. For a detailed explanation of this project, please reference Dockets 2013-0007 and 2014-0170. The main goals of this effort are to address:

- **Technical Risk:** Replace Ellipse and many workgroup systems with an integrated modern solution. The currently installed Ellipse software and platform is technically obsolete, and continued use of the current version of Ellipse exposes the Companies to rapidly increasing levels of operating risk due to the technical obsolescence of the application software, system software and hardware on which it is dependent. Beyond 2017, there is a significant risk that the Ellipse system will become unsupportable.
- **Vendor Risk:** Implement a solution that is well supported within the utility industry today and into the foreseeable future. There is concern with the long-term vendor commitment to Ellipse. The newest version of Ellipse does not provide the level of electric utility-specific functionality necessary to meet the Companies' key current and future business challenges and opportunities.
- **Business Improvements:** Take the opportunity to improve business processes that increases productivity, efficiency and effectiveness.

EGIS Project: The Geographic Information System (GIS) provides the location of electrical facilities (poles, conductors, transformers, substations, etc.) on a map. It also stores information on how these facilities are connected together to make up the electrical grid. This allows for circuit tracing and allows for the export of this model to other applications such as the Outage Management System (OMS) for outage management and SynerGEE for power flow analysis. This project will migrate from the current multiple instances of different GIS platforms to a single Enterprise GIS solution, across all three companies. This effort includes cleansing and improving the accuracy of the location of electrical facilities.

ADMS Project: The Advanced Distribution Management System (ADMS) project will upgrade and expand the functionality of the current Hawaiian Electric's Outage Management System (OMS) which is used to determine and track electrical outages and deploys this system to across the three companies. An ADMS is comprised of three foundational features: Outage Management used to track and simulate outages; SCADA integration for receiving status and sending commands to the devices in the electrical grid; and Distribution Management System (DMS) which monitors and controls switching at the distribution level in conjunction with Distribution Automation.

Demand Response Management System: A DRMS provides an integrated management application for managing Demand Response programs and implementing demand response events on the distribution grid. Demand response (DR) balances customers' need for electricity with the utilities' responsibility to successfully operate the system. A well-conceived and well-managed portfolio of demand response programs provides cost-effective and useful ancillary services and capacity for grid operations. DR programs may be implemented by the utilities and/or through 3rd-party administrators.

Facilities

Ongoing utility operations require efficient and effective business facilities infrastructure to meet customer and workforce needs. The foundational capital investments required to support these needs include routine investments for building facilities sustenance and vehicle replacements.

FOUNDATIONAL CAPITAL INVESTMENT PROJECT DESCRIPTIONS

This section describes the capital investment projects.

Reliability

H0002612: 6800 Line Recond Ph 2

Replace approximately 6 miles of existing 2/0, 69kV conductors with higher capacity conductors, from P-165 south thru Puu Huluhulu and Puu Waa Waa substations to P-225.

H0002668: 6800 Line Recond Ph 3

Replace approximately 6.9 miles of existing 2/0, 69kV conductors from P-225 south to P-290.

H0002669: 6800 Line Recond Ph 4

Replace approximately 1.5 miles of existing 2/0, 69kV conductors with higher capacity conductors, from P-290 south to P-306X Kaalele Street Intersection.

Keamuku 6200 Reloc Ph 4, 5 and 6

Phases 4, 5 and 6 of approximately 6 phases (one per year) ending in 2022 to increase reliability and accessibility. Relocation of 6200 line from the forest reserve/conservation zone areas to highway right-of-way.

CT 4 - 50,000 Rebuild

50,000 hour combustion turbine overhaul.

CT 5 - 50,000 Rebuild

50,000 hour combustion turbine overhaul.

H0002724: CT5 Zero Time

50,000 hour combustion turbine overhaul.

H0002779: Keamuku 6200 Reloc Ph 1

Phase 1 of approximately 6 phases (one per year) ending in 2022 to increase reliability and accessibility. Relocation of 6200 line from the forest reserve/conservation zone areas to highway right-of-way.

H0002913: Keamuku 6200 Reloc Ph3

Phase 3 of approximately 6 phases (one per year) ending in 2022 to increase reliability and accessibility. Relocation of 6200 line from the forest reserve/conservation zone areas to highway right of way.

H0002914: Keamuku 6200 Reloc Ph2

Phase 2 of approximately 6 phases (one per year) ending in 2022 to increase reliability and accessibility. Relocation of 6200 line from the forest reserve/conservation zone areas to highway right of way.

H0002929: 3300 Line Rebuild Ph 3

Repair, replace and reconductor 20 miles of 34.5kV line which runs from Waimea, over Kohala Mountain and services the North Kohala district.

H0002930: 3300 Line Rebuild Phase 2

Repair, replace and reconductor 20 miles of 34.5kV line which runs from Waimea, over Kohala Mountain and services the North Kohala district.

H0002931: 3300 Line Rebuild - Ph 1

Repair, replace and reconductor 20 miles of 34.5kV line which runs from Waimea, over Kohala Mountain and services the North Kohala district.

TRANSFORMATIONAL CAPITAL INVESTMENT PROJECT DESCRIPTIONS

DG Enabling Investments

DGIP

Circuit upgrades and other mitigation measures to increase the capacity of the electrical grids and enable the interconnection of additional DG.

Liquefied Natural Gas

H0002986: Keahole LNG Conversion

Project to convert the Keahole combustion turbine units to enable operation with LNG and maintain dual fuel capability.

H0002987: CT 3 LNG Conversion

Project to convert CT3 combustion turbine unit to enable operation with LNG and maintain dual fuel capability.

HEP LNG Conversion

Project to convert the HEP plant combustion turbine units to enable operation with LNG and maintain dual fuel capability. The plant is an IPP which we will supply the LNG per the contract and we will be responsible for the equipment conversion cost. A negotiation with the IPP will also be required to accomplish this upgrade

Facilitates New or Renewable Energy Total

Transm. Capital (West Geo)

When the proposed geothermal generating plant is installed in West Hawaiʻi a transmission line interconnection and substation will be installed. The interconnection in the west Hawaiʻi region is much less than one for a generating unit in the east Hawaiʻi regions.

Transm. Capital (Wind)

When the proposed Wind generating plant is installed on Hawaiʻi Island transmission line interconnection and substation will be installed

Replacement DG Levelized Capacity Costs

Hill 5 - Deactivation

The cost for deactivation will be to lay up the plant in a manner that is will be preserved and capable of returning to service with a minimal amount of effort and time when and if the system needs require return to service. The decommissioning costs are to make the unit safe. This will require the removal of all hazardous materials and prepare the unit for the final disposition

Hill 6 - Deactivation

The cost for deactivation will be to lay up the plant in a manner that is will be preserved and capable of returning to service with a minimal amount of effort and time when and if the system needs require return to service. The decommissioning costs are to make the unit safe. This will require the removal of all hazardous materials and prepare the unit for the final disposition

Puna - Deactivation

The cost for deactivation will be to lay up the plant in a manner that is will be preserved and capable of returning to service with a minimal amount of effort and time when and if the system needs require return to service. The decommissioning costs are to make the unit safe. This will require the removal of all hazardous materials and prepare the unit for the final disposition

Smart Grid and Demand Response

H0001917: Smart Grid

The Smart Grid Full Implementation Project will 1) install devices in the field, such as meters, remote controllable switches, fault circuit indicators, capacitors, and load controlling switches, 2) install central office software designed to collect information from the field devices and/or then execute commands or tasks by a system operator for the purposes of managing the grid or managing the utilities' meter reading and field services business processes and 3) provide the Hawaiian Electric Companies' customers with tools which enables them to understand and manage their energy use and energy bill. The benefits for implementing the Smart Grid Full Implementation Project is to 1) lower electricity bills through savings and productivity improvements in utility operations, 2) increase renewable energy through integrated distributed generation, 3) provides tools to the customers to enable them to utilize their energy more effectively/efficiently, and 4) increase reliability through outage notification and distribution automation which can lower SAIFI and CAIDI.

System Security Investments

20 MW Contingency BESS (2017)

The 20 MW battery addition is to provide the system security needs as we begin operating with less steam units in service that provide grid frequency and voltage control during system upsets and loss of generating units. This solution is more cost effective then operating and additional generating unit.

5 MW Regulation BESS (2017)

The 5 MW battery addition is to provide the system security needs as we begin operating with less steam units in service that provide grid frequency and voltage control during system upsets and loss of generating units. This solution is more cost effective then operating and additional generating unit.

Breaker Clearing Time Improvement

The growth of PV has reached the level that has put the electrical system at risk of failure due to a significant fault. This project is for reduction of the clearing time on circuit Breaker to clear the faults faster and preventing a potential collapse of the grid.

CAPITAL EXPENDITURES BY CATEGORY AND PROJECT

Capital Expenditures: 2015–2019

Table K-2 lists the budgeted, annualized dollar amount for each project; with totals by project group and by category, for the years 2015–2019. Table K-3 lists the budgeted, annualized dollar amount for each project; with totals by project group and by category, for the years 2020–2030 with project totals.

Project	2015	2016	2017	2018	2019
Foundational	**61,467,515**	**61,817,185**	**57,486,588**	**63,261,350**	**63,285,593**
Asset Management	1,579,506	813,996	1,115,984	1,152,459	1,157,741
Baseline	1,579,506	813,996	1,115,984	1,152,459	1,157,741
Customer Connections	3,531,590	4,677,292	6,469,981	6,554,503	5,224,555
Baseline	3,531,590	4,677,292	6,469,981	6,554,503	5,224,555
Customer Projects	558,481	5,371,298	-641,680	-623,625	940,565
Baseline	558,481	5,371,298	-641,680	-623,625	940,565
Enterprise IT Network	39,471	80,522	70,261	80,522	40,261
Baseline	39,471	80,522	70,261	80,522	40,261
Facilities	7,854,221	7,512,313	5,237,690	4,155,895	4,863,875
Baseline	7,854,221	7,512,313	5,237,690	4,155,895	4,863,875
Reliability	36,139,572	31,443,943	30,556,255	36,460,215	35,406,072
6200 Line Project (Ph 4, 5 and 6)	0	0	0	0	0
CT 4 - 50,000 Rebuild	0	0	0	0	0
CT 5 - 50,000 Rebuild	0	0	0	0	0
H0002612: 6800 Line Recond Ph 2	7,952,742	0	0	0	0
H0002668: 6800 Line Recond Ph 3	597,934	6,980,000	0	0	0
H0002669: 6800 Line Recond Ph 4	626,090	3,353,000	0	0	0
H0002724: CT5 Zero Time	634,764	3,148,394	0	0	0
H0002779: Keamuku 6200 Reloc Ph 1	0	558,848	10,444,335	0	0
H0002913: Keamuku 6200 Reloc Ph3	0	0	0	608,214	11,606,064
H0002914: Keamuku 6200 Reloc Ph2	0	0	595,215	11,604,995	0
H0002929: 3300 Line Rebuild Ph 3	0	0	0	0	5,845,000
H0002930: 3300 Line Rebuild Phase 2	0	0	0	6,499,640	0
H0002931: 3300 Line Rebuild - Ph 1	0	0	5,136,636	0	0
T0001825: Keamuku 6200 Reloc Ph 4	0	0	0	0	608,214
Baseline	26,328,042	17,403,701	14,380,069	17,747,366	17,346,794

Project	2015	2016	2017	2018	2019
Safety, Security and Environmental	11,764,674	11,917,821	14,678,097	15,481,381	15,652,524
Baseline	11,764,674	11,917,821	14,678,097	15,481,381	15,652,524
Transformational	**22,811,602**	**60,934,136**	**38,705,798**	**11,357,317**	**14,618,804**
DG Enabling Investments	2,045,064	2,045,064	338,084	338,084	338,084
DGIP	2,045,064	2,045,064	338,084	338,084	338,084
Liquefied Natural Gas	3,007,097	14,135,222	12,897,848	0	0
H0002986: Keahole LNG Conversion	1,354,117	6,239,083	4,734,926	0	0
H0002987: CT 3 LNG Conversion	192,980	1,896,139	3,432,921	0	0
HEP LNG Conversion	1,460,000	6,000,000	4,730,000	0	0
LNG Conversion	0	0	0	0	0
Facilitates New or Renewable Energy	4,138,473	0	684,483	3,422,415	9,582,763
Transm. Capital (West Geo)	0	0	0	0	0
Transm. Capital (Wind)	0	0	684,483	3,422,415	9,582,763
Baseline	4,138,473				
Replacement DG Levelized Capacity Costs	0	0	0	0	0
Hill 5 - Deactivation	0	0	0	0	0
Hill 6 - Deactivation	0	0	0	0	0
Puna - Deactivation	0	0	0	0	0
Smart Grid and Demand Response	0	16,495,177	13,423,656	1,917,222	1,835,211
H0001917: Smart Grid	0	16,495,177	13,423,656	1,917,222	1,835,211
System Security Investments	13,620,968	28,258,673	11,361,728	5,679,596	2,862,746
20 MW Contingency BESS (2017)	2,555,086	14,478,823	0	0	0
5 MW Regulation BESS (2017)	862,522	4,887,625	0	0	0
Baseline	6,903,360	5,592,225	8,061,728	5,679,596	2,862,746
Breaker Clearing Time Improvement	3,300,000	3,300,000	3,300,000	0	0
Grand Totals	**84,279,117**	**122,751,321**	**96,192,386**	**74,618,667**	**77,904,397**

Table K-2. Capital Expenditures by Category and Project: 2015–2019

Capital Expenditures: 2020–2030 with Project Totals

Table K-3 lists the budgeted, annualized dollar amount for each project; with totals by project group and by category, for the years 2020–2030 with project totals.

Project	2020	2021–2025	2026–2030	Totals
Foundational	**57,857,221**	**271,338,062**	**277,287,042**	**913,800,553**
Asset Management	1,176,265	6,169,723	6,679,350	19,845,023
Baseline	1,176,265	6,169,723	6,679,350	19,845,023
Customer Connections	5,308,148	27,842,202	30,142,004	89,750,276
Baseline	5,308,148	27,842,202	30,142,004	89,750,276
Customer Projects	955,614	5,012,371	5,426,399	16,999,423
Baseline	955,614	5,012,371	5,426,399	16,999,423
Enterprise IT Network	30,745	291,279	354,625	987,686
Baseline	30,745	291,279	354,625	987,686
Facilities	4,941,697	25,920,097	28,061,130	88,546,917
Baseline	4,941,697	25,920,097	28,061,130	88,546,917
Reliability	28,814,342	118,872,881	112,188,782	429,882,060
6200 Line Project (Ph 4, 5 and 6)	10,000,000	20,000,000	0	30,000,000
CT 4 - 50,000 Rebuild	0	3,900,000	0	3,900,000
CT 5 - 50,000 Rebuild	0	0	4,140,000	4,140,000
H0002612: 6800 Line Recond Ph 2	0	0	0	7,952,742
H0002668: 6800 Line Recond Ph 3	0	0	0	7,577,934
H0002669: 6800 Line Recond Ph 4	0	0	0	3,979,090
H0002724: CT5 Zero Time	0	0	0	3,783,157
H0002779: Keamuku 6200 Reloc Ph 1	0	0	0	11,003,183
H0002913: Keamuku 6200 Reloc Ph3	0	0	0	12,214,277
H0002914: Keamuku 6200 Reloc Ph2	0	0	0	12,200,210
H0002929: 3300 Line Rebuild Ph 3	0	0	0	5,845,000
H0002930: 3300 Line Rebuild Phase 2	0	0	0	6,499,640
H0002931: 3300 Line Rebuild - Ph 1	0	0	0	5,136,636
T0001825: Keamuku 6200 Reloc Ph 4	0	0	0	608,214
Baseline	18,814,342	94,972,881	108,048,782	315,041,977
Safety, Security and Environmental	16,630,410	87,229,509	94,434,752	267,789,168
Baseline	16,630,410	87,229,509	94,434,752	267,789,168

Project	2020	2021–2025	2026–2030	Totals
Transformational	**4,947,607**	**39,259,556**	**20,565,669**	**213,200,492**
DG Enabling Investments	338,084	131,990	131,990	5,706,444
DGIP	338,084	131,990	131,990	5,706,444
Liquefied Natural Gas	0	0	0	30,040,167
H0002986: Keahole LNG Conversion	0	0	0	12,328,127
H0002987: CT 3 LNG Conversion	0	0	0	5,522,040
HEP LNG Conversion	0	0	0	12,190,000
LNG Conversion	0	0	0	0
Facilitates New or Renewable Energy	0	14,992,548	0	32,820,683
Transm. Capital (West Geo)	0	14,992,548	0	14,992,548
Transm. Capital (Wind)	0	0	0	13,689,662
Baseline	0	0	0	4,138,473
Replacement DG Levelized Capacity Costs	0	0	0	0
Hill 5 - Deactivation	0	0	0	0
Hill 6 - Deactivation	0	0	0	0
Puna - Deactivation	0	0	0	0
Smart Grid and Demand Response	1,700,973	8,879,143	3,917,649	48,169,031
H0001917: Smart Grid	1,700,973	8,879,143	3,917,649	48,169,031
System Security Investments	2,908,550	15,255,875	16,516,030	96,464,167
20 MW Contingency BESS (2017)	0	0	0	17,033,909
5 MW Regulation BESS (2017)	0	0	0	5,750,147
Baseline	2,908,550	15,255,875	16,516,030	63,780,111
Breaker Clearing Time Improvement	0	0	0	9,900,000
Grand Totals	**62,804,828**	**310,597,618**	**297,852,711**	**1,127,001,045**

Table K-3. Capital Expenditures: 2020–2030 with Project Totals

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L. Preferred Plan Development

Hawai'i Island is at the forefront of defining and designing the electric system of the future. Our task is especially challenging. We are blessed with immense renewable resources, and yet, the relatively small size of the autonomous island grid system makes integration of certain technologies especially challenging. Nevertheless, we are transforming our power supply portfolio to produce unprecedented levels of renewable energy, while continuing to provide reliable and safe electric service to all customers at a reasonable cost.

The Preferred Plan was developed within a highly analytical, and innovative process. These elements were critical in developing the Preferred Plan. Collaboration between power system planners, consultants, domain experts, and Hawai'i Electric Light leadership was critical in maintaining focus, gaining insights, and meeting the challenge of encouraging independent thinking while maintaining common purpose. Best-of-class analytics were used to construct and evaluate complex plans within a number of contexts: feasibility, costs, risks, flexibility, and sustainability. And with analytics at the center of the effort, in innovative ways we identified ways to leverage energy storage and renewable variable energy sources.

The planning process leveraged the insights gained from analysis performed earlier, both internally and by consultants, described in the Power Supply Plan.[1] It provided the basis for sensitivity analyses, performed in parallel by two modeling teams. Utilizing the expertise of different modeling teams helped gain confidence in the final recommendation by seeing if different models and approaches provided similar, reinforcing results.

[1] Hawai'i Electric Light filed the Power Supply Plan with the Commission on April 21, 2014, Docket No. 2012-0212.

The two teams worked together to move from concept, through refinement, to definition of the Preferred Plan as shown in Figure L-1.

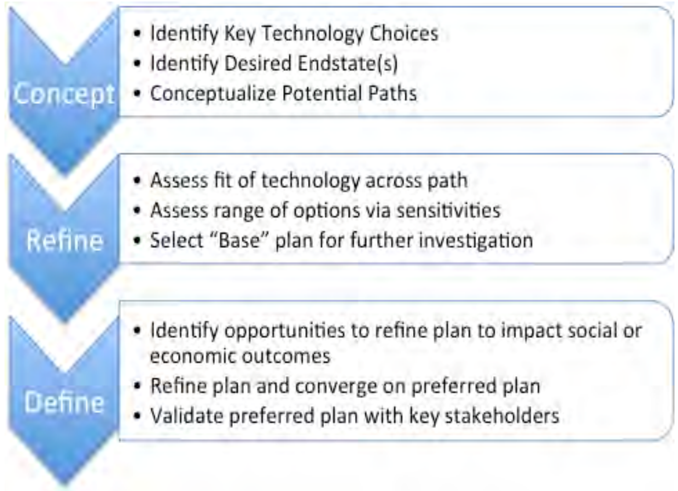

Figure L-1. Process for Developing the Preferred Plan

The analysis focused on transforming today's system into an electrical system that safely and securely integrates various sources of renewable energy by 2030. The analysis was carried out in three major steps:

1. **Develop a Base Plan:** A Base Plan was constructed which was similar to the base plan for the PSP. With an extended time frame, however, changes to fuel and demand forecasts, inclusion of demand response impacts, and various assumptions related to DG-PV.

2. **Perform Sensitivity Analyses:** Sensitivity analyses were then performed to the Base Plan to test candidate changes.

3. **Use Sensitivity Results to Develop the Preferred Plan:** The results of the sensitivity analyses were reviewed and used to develop the Preferred Plan.

Actions taken now and projects developed in the next five years will have an impact on what is possible in the future. Therefore, great care was taken to define a Preferred Plan that is flexible enough to accommodate emerging resource options that become commercially ready in the future. The Preferred Plan positions Hawai'i Electric Light to address both current and emerging technology options.

METHODOLOGY FOR DEVELOPING THE PREFERRED PLAN

The PSIP planning team constructed and evaluated a number of strategy canvases to feed a more granular and complex process that vetted technology options. Development of the Preferred Plan was driven by the following concepts:

- Focus on affordable and stable energy costs while preserving system reliability. Where applicable or where the analysis was indifferent, renewable energy is preferred. The analysis considered feasible options given specifics of each island while evaluating the economic impacts. The economic impact is of significant consideration for Hawaiʻi Island, given that it already incorporates a very high amount of renewable energy so new additions are prioritized by their ability to provide more affordable and stable energy costs.
- Develop a grid with the appropriate mix of resources and operational tools necessary to provide reliable service to our customers.
- Utilize conventional, dispatchable thermal assets and dispatchable renewable energy assets to provide firm generation, regulation and other grid services.
- Utilize LNG to improve fuel supply economics and reduce CO_2 emissions from fossil units where this is a cost-effective strategy.
- Maintain reliability and security by assuring grid operational needs are met and can keep pace with changing mix of generation sources, including leveraging cost-effective energy storage and demand response.

The modeling teams focused on constructing tactical plans to identify specific steps required to transition from current state to future state. This was a complex and iterative process. Plans were broken down into a series of annual capital project/retirement plans; each plan was verified against system security requirements. Operations of the system within each annual plan was carried out by using detailed production simulation models that commit and dispatch assets, manage regulation, utilize energy storage systems (ESS), demand response, and other assets to address variability of solar or wind generation potential. As discussed further in Appendix C, these models apply detailed hourly and sub-hourly dispatch models to evaluate resource options.

The planning process leveraged two different models to address simulation requirements. Collectively, the teams worked together to move the plan from concept, through refinement, to definition of the preferred plan. Specific milestones within the planning process included:

- Identification of key success factors or critical technology investments underpinning the 2030 strategy (that is, diversification of renewables to mitigate negatives of solar energy profiles, early adoption of advanced battery for contingency and regulation reserves, LNG supply for thermal assets). The models also incorporated demand response based on the identified potential quantities and uses.

- Validation of the supply mix and roles between variable renewables, dispatchable renewables, storage, and thermal assets to address system reliability requirements; this mix defines the degree to which variable assets can be cost-effectively leveraged.
- Optimization of the resource portfolio based on requirements during each of year of the study period; identify blend of possible dispatchable and variable generation opportunities.
- Based on economic dispatch requirements and demand requirements (with consideration of capacity value of variable resources and possible impacts of demand response), re-evaluate retirement schedules identified in PSP and identify intrinsic value of shifting retirement dates.
- Identify and test alternate technology mixes, timing, and other pro and cons via sensitivity analysis.
- Expand sensitivity analysis into areas of key interest: the key area of interest was the best way to address security requirements from increasing distributed solar PV, followed by the economic viability of further expanding wind and/or geothermal resources.
- Define the Preferred Plan based sensitivities; verification of plan outcomes by all models and modeling teams.

System reliability requirements for regulating and contingency reserves were met through a variety of resources including demand response, energy storage, and thermal generation. As increasing amounts of renewable variable generation were added to the system, the system reliability requirements change to reflect the new generation mix. The analysis incorporated system security analysis for scenarios presented, in part, in Chapter 4.

Sub-hourly models were deployed during the course of the analysis. Results were compared to hourly models to identify whether substantial changes to the modeling results occurred; sub-hourly models confirmed the need for increased need for system balancing cause by variable resources; increasing the regulating reserve and ramping requirements.

BASE PLAN

The present operation incorporates various generating unit options including daily and seasonal cycling of thermal generation, and planned deactivation and decommission dates for Puna and Hill steam units. The fuel costs, demand forecasts, demand response quantities and uses, and DG-PV growth were set inputs to the analysis.

The demand forecast included consideration of the impact of dynamic pricing in the demand shape as defined in the IDRPP.[2] The impact of demand response on the peak and its possible use for regulating reserve based on IDRPP maximum potential were also inputs to the analysis. These changes were incorporated into the simulation models.

The base plan also includes the following assumptions regarding which units would be converted to LNG fuel, and the start date for the new biomass resource.

- **Utility Generation:** Puna CT3 and Keahole CT4 and CT5 will fuel switch to LNG in 2017.
- **Hamakua Energy Partners (HEP):** Will fuel switch to LNG in 2018.
- **Hu Honua:** Hu Honua is anticipated to be in service from 2015.

Based on an assessment of use under unconstrained economic dispatch, as well as the revised peak forecasts which reflect the impact of dynamic pricing, the Base Plan retained the deactivation and decommission schedules for Puna and Hill, and identified new dates for Hill 6. The first steam unit (Puna) deactivation occurs in 2018. This year was chosen based on the anticipated addition of the Hu Honua facility, with provision to retain capacity during a proving period of the new biomass facility. Units are retired (decommissioned) two years after deactivation. We plan to deactivate the following existing generation:

- Puna steam in 2018
- Hill 5 in 2020
- Hill 6 in 2022

System reliability requirements for regulating and contingency reserves are met through a variety of resources including demand response, energy storage, and dispatchable generation (renewable and fossil resources). As increasing amounts of variable generation are added to the system (through growth in DG-PV, and other projects), the system security requirements change to reflect the new generation mix.

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

SENSITIVITY ANALYSES

Sensitivity analyses were performed on the Base Plan to demonstrate the effect of various changes to the system. The sensitivity analyses evaluated the following:

1. Cost effectiveness of meeting contingency reserves and regulation/ramping due to DG-PV with increased storage or additional online reserves
2. Additional wind in West Hawaiʻi in 2020
   - No limit on curtailment
   - If curtailment of individual projects is excessive, then consider additional analysis
   - Use utility-scale wind operated at reduced dispatch levels (curtailed) to provide ancillary services
3. Dispatchable 25 MW geothermal resource in West Hawaiʻi in 2025
4. Dispatchable 25 MW geothermal resource in East Hawaiʻi in 2020
5. Dispatchable 25 MW geothermal resources in both West and East (2025 and 2020) (total of 50 MW)
6. Pumped Storage Hydro
7. Dispatchable waste-to-energy resource in 2020

Sensitivity analyses were performed to test how resource(s) would affect the Base Plan and whether it should be considered for incorporation into the Preferred Plan.

Additional Wind

The analysis was for a wind facility located in West Hawaiʻi, in a location where there are excellent wind resources and that would not require significant transmission infrastructure to support. The potential energy profile was derived from actual performance of the wind facility at the south part of Hawaiʻi Island.

This sensitivity analysis began with an added 40 MW of wind. An additional 40 MW of wind decreased the overall system costs compared to the Base Plan, but with substantial curtailment of the new facility.

A second sensitivity with 20 MW of wind was analyzed and found to also decrease the overall system cost with less curtailment and a lower initial investment (due to the smaller size). This 20 MW resource was chosen for the Preferred Plan.

Additional Wind Providing Ancillary Services

This sensitivity added 40 MW of wind with the ability to provide ancillary services (regulation and ramping reserves) to the system. The results of this analysis were mixed, with one team showing somewhat increased costs, and the other model showing decreased costs.

Additional 25 MW Geothermal in West Hawai'i

This sensitivity analysis added 25 MW of new geothermal on the west side of Hawai'i Island in 2025. The geothermal was assumed to be dispatchable with 7 MW minimum dispatch load, with the operational and technical characteristics to meet the system security requirements provided by the present Keahole plant and operate in its place. This sensitivity decreased the overall system costs compared to the Base Plan.

Additional 25 MW Geothermal in East Hawai'i

This sensitivity analysis added 25 MW of new geothermal on the east side of Hawai'i Island in 2020. This facility was assumed to have the operational characteristics to support system security, and dispatch range similar to the West Hawai'i case. However, due to the location more transmission infrastructure is required and the facility could not operate to meet security constraints that require generation in West Hawai'i. This sensitivity increased the overall system costs compared to the Base Plan in one model. Although the costs decreased in the other model, it was not as beneficial as the West Hawai'i sensitivity.

Waste-To-Energy

This sensitivity added an 8 MW of waste-to-energy resource in 2020. This sensitivity found the addition of this resource increased the overall system costs compared to the Base Plan by one model, and slightly reduced costs in the other model; in the model where it reduced costs compared to the base plan it was not as cost-effective as wind or West Hawai'i Geothermal.

Additional 25 MW Geothermal in East Hawai'i and 25 MW Geothermal in West Hawai'i

This sensitivity analysis added 25 MW of new geothermal on the east side of Hawai'i Island in 2020 and in West Hawai'i in 2025, incorporating the assumptions of the East and West Hawai'i individual scenarios. This sensitivity was not selected as the preferred plan as the findings were not as beneficial as the wind and West Hawai'i Geothermal scenarios.

Additional Wind and Geothermal

This sensitivity added 20 MW of wind in 2020, and 25 MW of geothermal in West Hawaiʻi in 2025. This sensitivity reduced the overall system costs compared to the Base Plan, although the results of the models did not concur as to whether this was superior to West Hawaiʻi Geothermal as a single addition. Since this plan supported resource diversity, with benefits being provided by the earlier installation of 2020 (as compared to West Hawaiʻi Geothermal in 2025 alone), and as both models identified this as a plan offering reduced costs over the base plan, this was selected as the Preferred Plan.

Energy Storage

Pumped storage hydro (PSH) and load shifting battery energy storage have similar operating characteristics. Both can reduce curtailment by accepting curtailed renewable energy during the day to be discharged at the evening peak.

25 MW Pumped Storage Hydro

This sensitivity analysis added a 25 MW pumped storage hydro in 2020 into the Preferred Plan. The 25 MW pumped storage hydro addition increased the overall system costs compared to the Preferred Plan.

5 MW Battery Energy Storage

This sensitivity analysis added a 5 MW flow battery with characteristics to provide load shifting in 2020. The 5 MW flow battery addition increased the overall system costs compared to the Base Plan .

PREFERRED PLAN

The results of the sensitivity analyses were used to select the Preferred Plan to achieve cost savings to our customers as compared to the base plan, and increase resource diversity and price stability by increasing the amount of renewable energy on the system. The Preferred Plan incorporated demand response programs: demand behavior modification, customer controlled capacity, ramping capabilities, offline reserve, and time of use load shifting. The Preferred Plan incorporates storage for the changing system security and reliability needs from the increasing DG-PV. A 15 MW ESS will be added for system security and reliability, providing fast-responding contingency reserves. A 5 MW storage will provide fast-ramping regulation. New wind and geothermal are added, which, along with the existing and planned renewable resources and DG-PV growth on the system push our RPS estimate to over 90% in 2030.

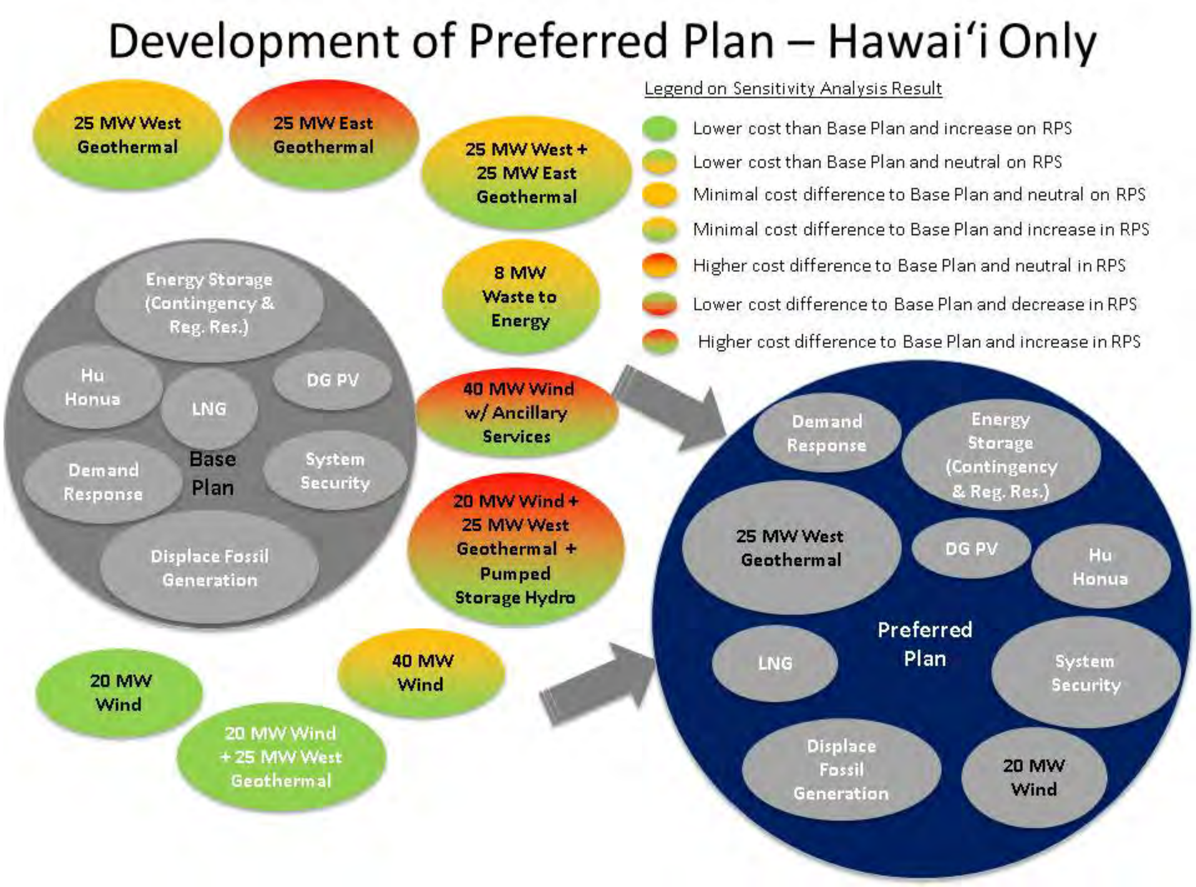

Figure L-2. Process for Developing the Preferred Plan

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M: Planning Standards

This appendix contains the details of the planning standards TPL-001 and BAL-052.

TPL-001-0: TRANSMISSION PLANNING PERFORMANCE REQUIREMENTS

The starting document for HI-TPL-001-0 was NERC standard TPL-001-2 dated August 4, 2011. The standard includes the merging of TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0 into one, single comprehensive, coordinated standard and retirement of TPL-005-0 and TPL-006-0.

The only added complexity was that the differently sized power systems in Hawaiʻi would need different levels of system reliability. The Hawaiʻi standard has three groups to address the different sizes of the various Balancing Areas.

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Working Group Glossary of Terms, Version 1 – 20120304 are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

Balancing Authority (BA): The responsible entity that integrates resource plans ahead of time, maintains load-generation balance within a Balancing Authority Area, and governs the real time operation and control of the Balancing Area. (Source: Modified from Glossary of Terms Used in NERC Reliability Standards February 8, 2012.)

Balancing Authority Area: The collection of generation, transmission, and loads within the metered boundaries of the Balancing Authority. The Balancing Authority maintains load-resource balance within this area. (Source: Glossary of Terms Used in NERC Reliability Standards February 8, 2012)

Base Year: The 2011 BA's transmission and generation system shall be used as the base year to establish performance standards utilized with this standard. (Source: Proposed RSWG proposed definition.)

Cascading: The uncontrolled successive loss of system elements triggered by an incident at any location. Cascading results in widespread electric service interruption that cannot be restrained from sequentially spreading beyond an area predetermined by studies. (Source: Glossary of Terms Used in NERC Reliability Standards February 8, 2012.)

Corrective Action Plan: A list of actions and an associated timetable for implementation to remedy a specific problem. (Source: Glossary of Terms Used in NERC Reliability Standards February 8, 2012.)

Equipment Rating: The maximum and minimum voltage, current, frequency, real and reactive power flows on individual equipment under steady state, short-circuit and transient conditions, as permitted or assigned by the equipment owner. (Source: Glossary of Terms Used in NERC Reliability Standards February 8, 2012.)

Facility: A set of electrical equipment that operates as a single Bulk Electric System Element (for example, a line, a generator, a shunt compensator, transformer, etc.). (Source: Glossary of Terms Used in NERC Reliability Standards February 8, 2012.)

Long-Term Transmission Planning Horizon: Transmission planning period that covers years six through ten or beyond when required to accommodate any known longer lead time projects that may take longer than ten years to complete. (Source: Glossary of Terms Used in NERC Reliability Standards February 8, 2012.)

Near-Term Transmission Planning Horizon: The transmission planning period that covers Year One through five. (Source: Glossary of Terms Used in NERC Reliability Standards February 8, 2012.)

Non-Consequential Load Loss: Non-Interruptible Load loss that does not include: (1) Consequential Load Loss, (2) the response of voltage sensitive load, or (3) load that is disconnected from the system by end-user equipment. (Source: Glossary of Terms Used in NERC Reliability Standards February 8, 2012.)

Off-Peak: Those hours or other periods defined by NAESB business practices, contract, agreements, or guides as periods of lower electrical demand. (Source: Glossary of Terms Used in NERC Reliability Standards February 8, 2012.)

Operating Procedure: A document that identifies specific steps or tasks that should be taken by one or more specific operating positions to achieve specific operating goal(s). The steps in an Operating Procedure should be followed in the order in which they are presented, and should be performed by the position(s) identified. A document that lists the specific steps for a system operator to take in removing a specific transmission line from service is an example of an Operating Procedure. (Source: Glossary of Terms Used in NERC Reliability Standards February 8, 2012.)

Planning Assessment: Documented evaluation of future Transmission system performance and Corrective Action Plans to remedy identified deficiencies. (Source: Glossary of Terms Used in NERC Reliability Standards February 8, 2012.)

Protection System: Protection system are:

- Protective relays which respond to electrical quantities,
- Communications systems necessary for correct operation of protective functions
- Voltage and current sensing devices providing inputs to protective relays,
- Station dc supply associated with protective functions (including batteries, battery chargers, and non-battery-based dc supply), and
- Control circuitry associated with protective functions through the trip coil(s) of the circuit breakers or other interrupting devices.

(Source: Glossary of Terms Used in NERC Reliability Standards February 8, 2012.)

Protection Reserves: The resources under the control of the Under Frequency Load Shedding System designed to protect the system against single or multiple contingency events. (Source: RSWG proposed definition.)

Special Protection System (SPS) or Remedial Action Scheme: An automatic protection system designed to detect abnormal or predetermined system conditions, and take corrective actions other than and/or in addition to the isolation of faulted components to maintain system reliability. Such action may include changes in demand, generation (MW and MVAr), or system configuration to maintain system stability, acceptable voltage, or power flows. An SPS does not include (a) underfrequency or undervoltage load shedding or (b) fault conditions that must be isolated or (c) out-of-step relaying (not designed as an integral part of an SPS). Also called Remedial Action Scheme. (Source: Glossary of Terms Used in NERC Reliability Standards February 8, 2012.)

Stability: The ability of an electric system to maintain a state of equilibrium during normal and abnormal conditions or disturbances. (Source: Glossary of Terms Used in NERC Reliability Standards February 8, 2012.)

System: A combination of generation, transmission, and distribution components. (Source: Glossary of Terms Used in NERC Reliability Standards February 8, 2012.)

Transmission: An interconnected group of lines and associated equipment for the movement or transfer of electric energy between points of supply and points at which it is transformed for delivery to customers. (Source: Modified Glossary of Terms Used in NERC Reliability Standards February 8, 2012.)

Year One: Year One is the first year of planning studies for future planning and evaluation requirements. (Source: Modified Glossary of Terms Used in NERC Reliability Standards February 8, 2012, Reliability First Regional Definitions.)

Introduction

Purpose: Establish Transmission system planning performance requirements within the planning horizon to develop a system that will operate reliably over a broad spectrum of conditions and following a wide range of probable Contingencies.

Applicability: Balancing Authorities (BA)

Facilities: The Facilities are divided into three groups A, B, and C. All groups are divided based on the annual system peak demand.

- Group A: Annual system peak is greater than or equal to 500 MW.
- Group B: Annual system peak is greater than or equal to 50 MW and less than 500 MW.
- Group C: Annual system peak is less than 50 MW.

Effective Date: To be determined

B. Requirements

R1. The BA must maintain system models for performing the studies needed to complete its Planning Assessment. The models must use data consistent with that provided in accordance with the HI-MOD-010 Development and Reporting of Steady State System Models and Simulations and HI-MOD-012 Development and Reporting of Dynamic System Models and Simulations standards, supplemented by other sources as needed, including items represented in the Corrective Action Plan, and must represent projected system conditions. This establishes Category P0 as the normal system condition in Table 1.

R1.1. System models must represent:

R1.1.1. Actual steady-state characteristics of system resources and loads as defined in HI-MOD-010 Development and Reporting of Steady State System Models and Simulations.

R1.1.2. Actual dynamic characteristics of system resources and loads as defined in HI-MOD-012 Development and Reporting of Dynamic System Models and Simulations.

R1.1.3. Planned Facilities and changes to existing Facilities

R1.2. The Generation resources must maintain or better the following characteristics unless the change can be verified by study that the results will provide acceptable reliability. The characteristics of the system that meet the acceptable reliability criteria will be used as the new benchmark for future planning until the reliability criteria is changed.

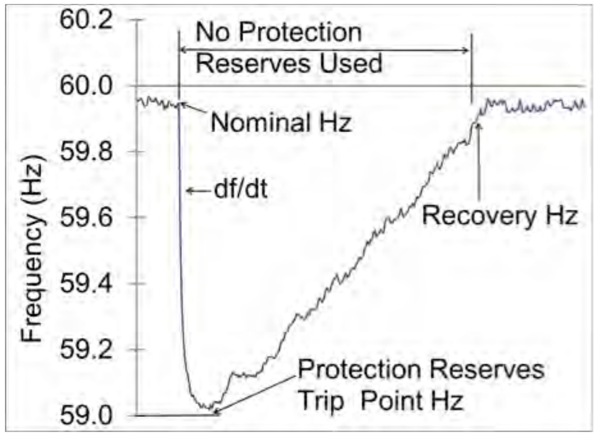
R1.2.1. Each Balance Authority system will be planned to meet the requirements Disturbance Recovery performance in HI-BAL-002 Disturbance Control Performance.

R1.2.2. The loss of the largest single contingency may result in a loss of load within the acceptable reliability criteria defined in BAL-002 Disturbance Control Performance.

R1.2.3. Each resource will have frequency ride-through designed such that all generation, reserves, regulation and voltage control resources will withstand single and excess contingency events defined in HI-BAL-002 Disturbance Control Performance. The ride-through capability will meet the criteria designed to be protected under HI-PRC-006 Underfrequency Load Shedding, without the loss of, or damage to any resource.

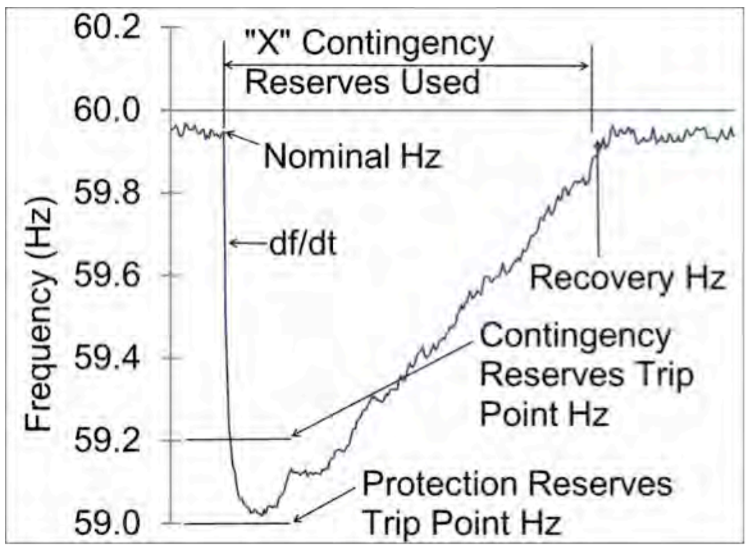
R1.2.4. The system will be planned such that the resultant impacts of inertia, unit response or reserve response will meet the system frequency response characteristics following the loss of the largest single contingency as defined below.

Frequency Response: For all BA systems the loss of the largest unit(s) or any single contingency should not result in activation of the protection reserves. In addition, the rate of change of frequency df/dt is not to increase over historical levels, without prior review of impacts on system protection operation and critical resources. A sample system performance characteristic is shown in the graph below:



System Using No Protection Reserves

An example characteristic graph of a system that utilizing the protection reserves is indicated below:



System Using Protection Reserves

R.1.2.5. The system will be planned such that all generation, reserves, regulation and voltage control resources will withstand the most severe voltage ride-thru requirement for a single contingency event, including both transmission and distribution events and distribution and transmission fault reclose cycles, through the duration of their reclosing cycle, without the loss of or damage to any resource.

R1.2.6. The system will be designed such that all generation, reserves, regulation and voltage control resources will withstand excess contingency events defined in HI-BAL-002 Disturbance Control Performance for voltage ride-thru requirement for an excess contingency event and designed to be protected under HI-PRC-006

Underfrequency Load Shedding, without the loss of or damage to any resource.

R1.2.7. The system will be planned to be transiently and dynamically stable following any single contingency event or any excess contingency event designed to be protected under HI-PRC-006 Underfrequency Load Shedding. Stability will be defined that the system will survive the first swing stability and the second swing and each subsequent swing will be lesser in magnitude than its predecessor (damped response). All swings will be effectively eliminated within 20 seconds of the initiating event.

R1.2.8. The system shall be designed to supply the required ancillary services necessary to provide voltage and frequency response to meet the reliability requirements of each BA's service tariff and R1.2.2.

R2. The BA must prepare an annual Planning Assessment of its system. This Planning Assessment must use current or qualified past studies (as indicated in R2.6), document assumptions, and document summarized results of the steady state analyses, short circuit analyses, and Stability analyses.

R2.1. For the Planning Assessment, the Near-Term Transmission Planning Horizon portion of the steady state analysis must be assessed annually and be supported by current annual studies or qualified past studies as indicated in R2.6. Qualifying studies need to include the following conditions:

R2.1.1. System peak load for either year one or year two, and for year five.

R2.1.2. System minimum with maximum and minimum variable renewables (night-time load) load for one of the five years.

R2.1.3. System minimum day load, maximum variable renewable for one of the five years.

R2.1.4. System day-peak load with maximum variable renewable and minimum variable renewable for one of the five years.

R2.1.5. System peak load, no variable renewable for one of the five years.

R2.1.6. For each of the studies described in R2.1.1 through R2.1.5, sensitivity case(s) must be utilized to demonstrate the impact of changes to the basic assumptions used in the model. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions by a sufficient amount to stress the system within a range of credible conditions that demonstrate a measurable change in system response:

- Real and reactive forecasted load.
- Expected transfers.
- Expected in-service dates of new or modified Transmission Facilities.
- Planned or unplanned outages of critical resources for ancillary services
- Typical generation scenarios including outage of the typically operated generation sources
- Reactive resource capability.
- Generation additions, retirements, or other dispatch scenarios.
- Controllable loads and Demand Side Management.

R2.1.7. When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), the impact of this possible unavailability on system performance must be studied. The studies must be performed for the P0, P1, and P2 categories identified in Table 1 with the conditions that the system is expected to experience during the possible unavailability of the long lead time equipment.

R2.2. For the Planning Assessment, the Long-Term Transmission Planning Horizon portion of the steady state analysis must be assessed annually and be supported by the following annual current study, supplemented with qualified past studies as indicated in R2.6:

R2.2.1. A current study assessing expected system peak load conditions for one of the years in the Long-Term Transmission Planning Horizon and the rationale for why that year was selected.

R2.3. The short circuit analysis portion of the Planning Assessment must be conducted annually addressing the Near-Term Transmission Planning Horizon and can be supported by current or past studies as qualified in R2.6. The analysis must be used to determine whether circuit breakers have interrupting capability for Faults that they will be expected to interrupt using the system short circuit model with any planned generation and Transmission Facilities in service which could impact the study area.

R2.4. For the Planning Assessment, the Near-Term Transmission Planning Horizon portion of the Stability analysis must be assessed annually and be supported by current or past studies as qualified in R2.6. The following studies are required:

R2.4.1. System peak load for one of the five years. System peak load levels must include a load model which represents the expected dynamic behavior of loads that could impact the study area, considering the behavior of induction motor loads or other load characteristics, including the model of distributed generation, Demand Response and other programs that impact system load characteristics. An aggregate system load model which represents the overall dynamic behavior of the load is acceptable.

R2.4.2. System minimum load for one of the five years.

R2.4.3. System minimum with maximum and minimum variable renewables (night-time load) load for one of the five years.

R2.4.4. System minimum day load, maximum variable renewable for one of the five years.

R2.4.5. System day-peak load, maximum and minimum variable renewable for one of the five years.

R2.4.6. System peak load, no variable renewable for one of the five years.

R2.4.7. For each of the studies described in R2.4.1 through R2.4.6, sensitivity case(s) must be utilized to demonstrate the impact of changes to the basic assumptions used in the model. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions by a sufficient amount to stress the system within a range of credible conditions that demonstrate a measurable change in performance:

- Load level, load forecast, or dynamic load model assumptions.
- Expected transfers.
- Expected in service dates of new or modified Transmission Facilities.
- Reactive resource capability
- Maintenance periods of generation resources and alternative resources providing ancillary services.
- Generation additions, retirements, or other dispatch scenarios.

R2.5. For the Planning Assessment, the Long-Term Transmission Planning Horizon portion of the Stability analysis must be assessed to address the impact of proposed material generation additions or changes in that time frame and be supported by current or past studies as qualified in R2.6 and must include documentation to support the technical rationale for determining material changes.

R2.6. Past studies may be used to support the Planning Assessment if they meet the following requirements:

R2.6.1. For steady state, short circuit, or Stability analysis: the study must be five calendar years old or less, unless a technical rationale can be provided to demonstrate that the results of an older study are still valid.

R2.6.2. For steady state, short circuit, or Stability analysis: no material changes have occurred to the system represented in the study. Documentation to support the technical rationale for determining material changes must be included.

R2.7. For planning events shown in Table 1, when the analysis indicates an inability of the system to meet the performance requirements in Table 1, the Planning Assessment must include Corrective Action Plan(s) addressing how the performance requirements will be met. Revisions to the Corrective Action Plan(s) are allowed in subsequent Planning Assessments but the planned system must continue to meet the performance requirements in Table 1. The Corrective Action Plan(s) must:

R2.7.1. List system deficiencies and the associated actions needed to achieve required system performance. Examples of such actions include:

- Installation, modification, retirement, or removal of Transmission and generation Facilities and any associated equipment
- Installation, modification, or removal of Protection Systems or Special Protection Systems
- Installation or modification of automatic generation tripping as a response to a single or multiple Contingency to mitigate Stability performance violations
- Installation or modification of manual and automatic generation runback or tripping as a response to a single or multiple Contingency to mitigate steady state performance violations

- Use of Operating Procedures specifying how long they will be needed as part of the Corrective Action Plan
- Use of rate applications, DSM, alternative resources and technologies, or other initiatives

R2.7.2. Include actions to resolve performance deficiencies identified in multiple sensitivity studies or provide a rationale for why actions were not necessary.

R2.7.3. If situations arise that are beyond the control of the BA that prevent the implementation of a Corrective Action Plan in the required time frame, then the BA is permitted to utilize Non-Consequential Load Loss to correct the situation that would normally not be permitted in Table 1, provided that the BA documents that they are taking actions to resolve the situation. The BA must document the situation causing the problem, alternatives evaluated, and the use of Non-Consequential Load.

R2.7.4. Be reviewed in subsequent annual Planning Assessments for continued validity and implementation status of identified system Facilities and Operating Procedures.

R2.8. For short circuit analysis, if the short circuit current interrupting duty on circuit breakers determined in R2.3 exceeds their Equipment Rating, the Planning Assessment must include a Corrective Action Plan to address the Equipment Rating violations. The Corrective Action Plan must:

R2.8.1. List system deficiencies and the associated actions needed to achieve required system performance.

R2.8.2. Be reviewed in subsequent annual Planning Assessments for continued validity and implementation status of identified System Facilities and Operating Procedures.

R3. For the steady state portion of the Planning Assessment, the BA must perform studies for the Near-Term and Long-Term Transmission Planning Horizons in R2.1, and R2.2. The studies must be based on computer simulation models using data provided in R1.

R3.1. Studies must be performed for planning events to determine whether the system meets the performance requirements in Table 1 based on the Contingency list created in R3.4.

R3.2. Studies must be performed to assess the impact of the extreme events which are identified by the list created in R3.5.

R3.3. Contingency analyses for R3.1 & R3.2 must:

R3.3.1. Simulate the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each Contingency without operator intervention. The analyses must include the impact of subsequent:

- Tripping of generators where simulations show generator bus voltages or high side of the generation step up (GSU) voltages are less than known or assumed minimum generator steady state or ride through voltage limitations. Include in the assessment any assumptions made.
- Tripping of Transmission elements where relay loadability limits are exceeded.
- Tripping of generation and other resources (including distributed resources) where ride-thru capabilities are exceeded

R3.3.2. Simulate the expected automatic operation of existing and planned devices designed to provide steady state control of electrical system quantities when such devices impact the study area. These devices may include equipment such as phase-shifting transformers, load tap changing transformers, and switched capacitors and inductors.

R3.4. Those planning events in Table 1, that are expected to produce more severe system impacts must be identified and a list of those Contingencies to be evaluated for system performance in R3.1 created. The rationale for those Contingencies selected for evaluation must be available as supporting information.

R3.5. Those extreme events in Table 1 that are expected to produce more severe system impacts must be identified and a list created of those events to be evaluated in R3.2. The rationale for those Contingencies selected for evaluation must be available as supporting information. If the analysis concludes there is Cascading caused by the occurrence of extreme events, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) must be conducted.

R4. For the Stability portion of the Planning Assessment, as described in Requirement R2, Parts 2.4 and 2.5, the BA must perform the Contingency analyses listed in

Table 1. The studies must be based on computer simulation models using data provided in Requirement R1.

R4.1. Studies must be performed for planning events to determine whether the system meets the performance requirements in Table 1 based on the Contingency list created in R4.4.

R4.1.1. For planning event P1: No generating unit must pull out of synchronism. A generator being disconnected from the system by fault clearing action or by a Special Protection System is not considered pulling out of synchronism.

R4.1.2. For planning events P2 through P7: When a generator pulls out of synchronism in the simulations, the resulting apparent impedance swings must not result in the tripping of any Transmission system elements other than the generating unit and its directly connected Facilities.

R4.1.3. For planning events P1 through P7: Power oscillations must exhibit acceptable damping as established by the BA.

R4.2. Studies must be performed to assess the impact of the extreme events which are identified by the list created in R4.5.

R4.3. Contingency analyses for R4.1 and R4.2 must:

R4.3.1. Simulate the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each Contingency without operator intervention. The analyses must include the impact of subsequent:

- Successful high speed (less than one second) reclosing and unsuccessful high-speed reclosing into a Fault where high speed reclosing is utilized.
- Tripping of generators where simulations show generator bus voltages or high side of the GSU voltages are less than known or assumed generator low voltage ride through capability. Include in the assessment any assumptions made.
- Tripping of Transmission lines and transformers where transient swings cause Protection System operation based on generic or actual relay models.
- Tripping of all generation sources whose ride-thru capabilities are exceeded.

R4.3.2. Simulate the expected automatic operation of existing and planned devices designed to provide dynamic control of electrical system quantities when such devices impact the study area. These devices may include equipment such as generation exciter control and power system stabilizers, static VAR compensators and power flow controllers.

R4.4. Those planning events in Table 1 that are expected to produce more severe system impacts on its portion of the system, must be identified, and a list created of those Contingencies to be evaluated in R4.1. The rationale for those Contingencies selected for evaluation must be available as supporting information.

R4.5. Those extreme events in Table 1 that are expected to produce more severe system impacts must be identified and a list created of those events to be evaluated in R4.2. The rationale for those Contingencies selected for evaluation must be available as supporting information. If the analysis concludes there is Cascading caused by the occurrence of extreme events, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences of the event(s) must be conducted.

R5. The BA must have criteria for acceptable system steady state voltage limits, post-Contingency voltage deviations, and the transient voltage response for its system. For transient voltage response, the criteria must at a minimum, specify a low voltage level and a maximum length of time that transient voltages may remain below that level.

R6. The BA must define and document, within their Planning Assessment, the criteria or methodology used in the analysis to identify system instability for conditions such as Cascading, voltage instability, or uncontrolled islanding.

R7. The BA must distribute its Planning Assessment results to the Hawaiʻi PUC (or designee) within 30 calendar days upon a written request for the information.

Table 1 – Steady State & Stability Performance Planning Events

Steady State & Stability:

1. The system must remain stable. Cascading and uncontrolled islanding must not occur.
2. Consequential Load Loss as well as generation loss is acceptable as a consequence of any event excluding P0.
3. Simulate the removal of all elements that Protection Systems and other controls are expected to automatically disconnect for each event.
4. Simulate Normal Clearing unless otherwise specified.
5. Planned System adjustments such as Transmission configuration changes and re-dispatch of generation are allowed if such adjustments are executable within the time duration applicable to the Facility Ratings
6. Phase angle separation for line contingency must not preclude automatic reclosing for BA groups B and C, unless system Adjustments can be performed within fifteen minutes.

Steady State Only:

7. Applicable Facility Ratings must not be exceeded.
8. System steady state voltages and post-Contingency voltage deviations must be within acceptable limits as established by the BA.
9. Planning event P0 is applicable to steady state only.
10. The response of voltage sensitive load that is disconnected from the system by end-user equipment associated with an event must not be used to meet steady state performance requirements.

Stability Only:

11. Transient voltage response must be within acceptable limits established by the BA.

Category	Initial Condition	Event[1]	Fault Type[2]	Non-Consequential Load Loss Allowed	Range of Customers Loss Allowed	Applicable BA Groups[3]
P0 No Contingency	Normal system	None	N/A	No	None	A, B, and C
P1 Single Contingency	Normal system	Loss of one of the following: 1. Generator 2. Transmission Circuits 3. Transformer[4] 4. Shunt Device-Ancillary Service Device[5] 5. Generator – no fault	3Ø and SLG for Events 1 through 4, N/A for Event	Yes	Up to 12% generation only	A
				Yes	Up to 15% generation only	B
				Yes	Up to 15% generation only	C

Table 1 – Steady State & Stability Performance Planning Events—Continued						
Category	**Initial Condition**	**Event**[1]	**Fault Type**[2]	**Non-Consequential Load Loss Allowed**	**Range of Customers Loss Allowed**	**Applicable BA Groups**[3]
P2 Single Contingency	Normal system	1. Opening a line section w/o fault[6]	N/A	No	None	A, B, and C
		2. Bus Section fault	SLG	Yes	none	A
				Yes	none	B
				Yes	none	C
		3. Internal Breaker Fault[7] (Transmission line breaker)	SLG	Yes	none	A
				Yes	none	B
				Yes	none	C
P3 Single Contingency	Loss of generator unit followed by System adjustments[8]	Loss of one of the following: 1. Generator 2. Transmission Circuits 3. Transformer[4] 4. Shunt Device/ Ancillary Service Device[5]	3Ø and SLG	No	up to 12%	A
				Yes	up to 40%	B
				Yes	up to 40%	C

Table 1 – Steady State & Stability Performance Planning Events—Continued

Category	Initial Condition	Event[1]	Fault Type[2]	Non-Consequential Load Loss Allowed	Range of Customers Loss Allowed	Applicable BA Groups[3]
P4 Multiple Contingency (Fault plus stuck breaker[10])	Normal system	Loss of multiple elements caused by a stuck breaker[10] (non-Bus-tie Breaker) attempting to clear a Fault on one of the following: 1. Generator 2. Transmission Circuits 3. Transformer[4] 4. Shunt Device[5] 5. Bus Section	SLG	Yes	Up to 65%	A
				Yes	Up to 65%	B[13]
				Yes	Up to 65%	C[13]
		6. Loss of multiple elements caused by a stuck breaker[10] (Bus-tie breaker) attempting to clear a Fault on the associated bus	SLG	Yes	Up to 65%	A[13]
				Yes	Up to 65%	B[13]
				Yes	Up to 65%	C[13]

Table 1 – Steady State & Stability Performance Planning Events—Continued						
Category	**Initial Condition**	**Event[1]**	**Fault Type[2]**	**Non-Consequential Load Loss Allowed**	**Range of Customers Loss Allowed**	**Applicable BA Groups[3]**
P5 Multiple Contingency (Fault plus relay failure to operate)	Normal system	Delayed Fault Clearing due to the failure of a non-redundant relay[12] protecting the Faulted element to operate as designed, for one of the following: 1. Generator 2. Transmission Circuits 3. Transformer[4] 4. Shunt Device[5] 5. Bus Section	SLG	No	None	A
				Yes	Up to 15%	B
				Yes	Up to 15%	C
P6 Multiple Contingency (Two overlapping singles)	Loss of one of the followed by system adjustments[8] 1. Transmission Circuits 2. Transformer[4] 3. Shunt Device[5]	Loss of one of the following: 1. Transmission Circuits 2. Transformer[4] 3. Shunt Device[5]	3Ø	No	Up to 40%	A
				Yes	Up to 65%	B[13]
				Yes	Up to 65%	C[13]
P7 Multiple Contingency (Common Structure)	Normal system	The loss of any two adjacent (vertically or horizontally) circuits on common wood structure[10]	SLG	No	Up to 40%	A
				Yes	Up to 65%	B
				Yes	Up to 65%	C

Table 1 – Steady State & Stability Performance Extreme Events

Steady State & Stability

For all extreme events evaluated:

1. Simulate the removal of all elements that Protection systems and automatic controls are expected to disconnect for each Contingency.
2. Simulate Normal Clearing unless otherwise specified.

Steady State

1. Loss of a single generator, Transmission Circuit, shunt device, or transformer force out of service followed by another single generator, Transmission Circuit, shunt device, or transformer forced out of service prior to system adjustments.
2. Local area events affecting the transmission system such as:
   - **a.** Loss of a tower line with three or more circuits[10].
   - **b.** Loss of all Transmission lines on a common Right-of-Way[10].
   - **c.** Loss of a switching station or substation (loss of one voltage level plus transformers).
   - **d.** Loss of all generating units at a generating station.
   - **e.** Loss of a large load or major load center.
3. Wide area events affecting the Transmission System based on system topology such as:
   - **a.** Loss of two generating stations resulting from conditions such as:
     - **i.** Loss of a large fuel line into an area.
     - **ii.** Loss of the use of a large body of water as the cooling source for generation.
     - **iii.** Wildfires
     - **iv.** Severe weather, for example, hurricanes
     - **v.** A successful cyber attack
     - **vi.** Large earthquake, tsunami or volcanic eruption
   - **b.** Other events based upon operating experience that may result in wide area disturbances.

Stability

1. Loss of a single generator, Transmission circuit, shunt device, or transformer force out of service apply a 3Ø fault on another single generator, Transmission circuit, shunt device, or transformer prior to system adjustments.
2. Local area events affecting the transmission system such as:
   - **a.** 3Ø fault on generator with stuck breaker[9] or a relay failure[12] resulting in Delayed Fault Clearing.
   - **b.** 3Ø fault on Transmission circuit with stuck breaker[9] or a relay failure[12] resulting in Delayed Fault Clearing.
   - **c.** 3Ø fault on transformer with stuck breaker[9] or a relay failure[12] resulting in Delayed Fault Clearing.
   - **d.** 3Ø fault on bus section with stuck breaker[9] or a relay failure[12] resulting in Delayed Fault Clearing.
   - **e.** 3Ø internal breaker fault.
   - **f.** Other events based upon operating experience, such as consideration of initiating events that experience, such as consideration of initiating events that experience suggests may result in wide area disturbances.

Table 1 – Steady State & Stability Performance Footnotes (Planning Event and Extreme Events)

Footnotes

1. If the event analyzed involves system elements at multiple system voltage levels, the lowest system voltage level of the element(s) removed for the analyzed event determines the stated performance criteria regarding allowances for interruptions of Non-Consequential Load Loss.
2. Unless specified otherwise, simulate Normal Clearing of faults. Single line to ground (SLG) or three-phase (3Ø) are the fault types that must be evaluated in Stability simulations for the event described. A 3Ø or a double line to ground fault study indicating the criteria are being met is sufficient evidence that a SLG condition would also meet the criteria.
3. The Applicable BA Groups (A, B or C) is defined under Facilities and is determined by the annual system peak demand.
4. For non-generator step up transformer outage events, the reference voltage, as used in footnote 1, applies to the low-side winding (excluding tertiary windings). For generator and Generator Step Up transformer outage events, the reference voltage applies to the system connected voltage (high-side of the Generator Step Up transformer). Requirements which are applicable to transformers also apply to variable frequency transformers and phase shifting transformers.
5. Requirements which are applicable to shunt devices also apply to FACTS devices that are connected to ground.
6. Opening one end of a line section without a fault on a normally networked Transmission circuit such that the line is possibly serving load radial from a single source point.
7. An internal breaker fault means a breaker failing internally, thus creating a system fault which must be cleared by protection on both sides of the breaker.
8. An objective of the planning process should be to minimize the likelihood and magnitude of interruption of Transmission following Contingency events. System adjustment (as identified in the column entitled 'Initial Condition') when achieved through the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and the re-dispatch does not result in any Non-Consequential Load Loss. Where limited options for re-dispatch exist, sensitivities associated with the availability of those resources should be considered.
9. A stuck breaker means that for a gang-operated breaker, all three phases of the breaker have remained closed. For an independent pole operated (IPO) or an independent pole tripping (IPT) breaker, only one pole is assumed to remain closed. A stuck breaker results in Delayed Fault Clearing.
10. Excludes circuits that share a common structure (Planning event P7, Extreme event steady state 2a) or common Right-of-Way (Extreme event, steady state 2b) for 1 mile or less.
11. An objective of the planning process should be to minimize the likelihood and magnitude of Non-Consequential Load Loss following Contingency events. However, in limited circumstances Non-Consequential Load Loss may be needed to address System performance requirements. When Non-Consequential Load Loss is utilized within the planning process to address system performance requirements, such interruption is limited to circumstances where the Non-Consequential Load Loss is documented, including alternatives evaluated.
12. Applies to the following relay functions or types: pilot (#85), distance (#21), differential (#87), current (#50, 51, and 67), voltage (#27 & 59), directional (#32 & 67), and tripping (#86 & 94).
13. Indicates that the system level for the Category is an extreme event for the Group.

C. Measures

M1. The BA must provide evidence, in electronic or hard copy format, that it is maintaining system models within their respective area, using data consistent with HI-MOD-010 Development and Reporting of Steady State System Models and Simulations and HI-MOD-012 Development and Reporting of Dynamic System Models and Simulations, including items represented in the Corrective Action Plan, representing projected system conditions, and that the models represent the required information in accordance with R1.

M2. The BA must provide dated evidence, such as electronic or hard copies of its annual Planning Assessment, that it has prepared an annual Planning Assessment of its portion of the system in accordance with Requirement R2.

M3. The BA must provide dated evidence, such as electronic or hard copies of the studies utilized in preparing the Planning Assessment, in accordance with Requirement R3.

M4. The BA must provide dated evidence, such as electronic or hard copies of the studies utilized in preparing the Planning Assessment in accordance with Requirement R4.

M5. The BA must provide dated evidence such as electronic or hard copies of the documentation specifying the criteria for acceptable system steady state voltage limits, post-Contingency voltage deviations, and the transient voltage response for its system in accordance with Requirement R5.

M6. The BA must provide dated evidence, such as electronic or hard copies of documentation specifying the criteria or methodology used in the analysis to identify system instability for conditions such as Cascading, voltage instability, or uncontrolled islanding that was utilized in preparing the Planning Assessment in accordance with Requirement R6.

M7. The BA must provide evidence, such as email notices, postal receipts showing recipient and date that it has distributed its Planning Assessment results to the Hawaiʻi PUC (or designee) within 30 calendar days upon a written request for the information in accordance with Requirement R7.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority:

Hawai'i PUC (or designee).

1.2. Data Retention:

The BA must each retain data or evidence to show compliance as identified unless directed by its Hawai'i PUC (or designee) to retain specific evidence for a longer period of time as part of an investigation:

- The models utilized in the current in-force Planning Assessment and one previous Planning Assessment in accordance with Requirement R1 and Measure M1.
- The Planning Assessments performed since the last compliance audit in accordance with Requirement R2 and Measure M2.
- The studies performed in support of its Planning Assessments since the last compliance audit in accordance with Requirement R3 and Measure M3.
- The studies performed in support of its Planning Assessments since the last compliance audit in accordance with Requirement R4 and Measure M4.
- The documentation specifying the criteria for acceptable system steady state voltage limits, post-contingency voltage deviations, and transient voltage response since the last compliance audit in accordance with Requirement R5 and Measure M5.
- The documentation specifying the criteria or methodology utilized in the analysis to identify system instability for conditions such as cascading, voltage instability, or uncontrolled islanding in support of its Planning Assessments since the last compliance audit in accordance with Requirement R6 and Measure M6.
- Three calendar years of the notifications employed in accordance with Requirement R7 and Measure M7.

If the BA is found non-compliant, it must keep information related to the non-compliance until found compliant or the time periods specified above, whichever is longer.

1.3. Compliance Monitoring and Enforcement Processes:

- Compliance Audits: The Hawai'i PUC (or designee) will give notice to the BA within 30 days of years' end for a compliance audit and will complete such audit within 90 days of such information being supplied by the BA.
- Self-Certifications
- Spot Checking
- Compliance Violation Investigations
- Self-Reporting
- Complaints

2. Levels of Non-Compliance for Requirement R1, Measure M1:

2.1. Level 1: The BA's system model failed to represent one of the Requirement R1, Parts 1.1.1 through 1.1.5. for Requirement R1 and Measurement M1.

2.2. Level 2: The BA failed to meet all the requirements of Level 1 for Requirement R1 and Measurement M1.

3. Levels of Non-Compliance for Requirement R2, Measure M2:

3.1. Level 1: The BA failed to comply with Requirement R2, Part 2.6. for Requirement R2 and Measurement M2

3.2. Level 2: The BA failed to meet all the requirements of Level 1 for Requirement R2 and Measurement M2.

4. Levels of Non-Compliance for Requirement R3, Measure M3:

4.1. Level 1: The BA did not identify planning events as described in Requirement R3, Part 3.4 or extreme events as described in Requirement R3, Part 3.5. for Requirement R3 and Measurement M3.

4.2. Level 2: The BA failed to meet all the requirements of Level 1 for Requirement R3 and Measurement M3.

5. Levels of Non-Compliance for Requirement R4, Measure M4:

5.1. Level 1: The BA did not identify planning events as described in Requirement R4, Part 4.4 or extreme events as described in Requirement R4, Part 4.5 for Requirement R4 and Measurement M4.

5.2. Level 2: The BA failed to meet all the requirements of Level 1 for Requirement R4 and Measurement M4.

6. Levels of Non-Compliance for Requirement R5, Measure M5:

6.1. Level 1: N/A

6.2. Level 2: The BA does not have criteria for acceptable system steady state voltage limits, post-Contingency voltage deviations, or the transient voltage response for its system for Requirement R5 and Measurement M5.

7. Levels of Non-Compliance for Requirement R6, Measure M6:

7.1. Level 1: N/A

7.2. Level 2: The BA failed to define and document the criteria or methodology for system instability used within its analysis as described in Requirement R6 for Requirement R6 and Measurement M6.

8. Levels of Non-Compliance for Requirement R7, Measure M7:

8.1. The BA distributed its Planning Assessment results to Hawaiʻi PUC (or designee) but it was more than 30 days but less than or equal to 40 days following the request as described in Requirement R7 for Requirement R7 and Measurement M7.

8.2. The BA failed to meet all the requirements of Level 1 for Requirement R7 and Measurement M7.

BAL-502-0: RESOURCE ADEQUACY ANALYSIS, ASSESSMENT, AND DOCUMENTATION

A. Introduction

Purpose: To establish common criteria for each Balancing Authority (BA) based on "one day in *x* year" (determined by study) loss of load expectation principles or as an alternative a planning methodology based on the single largest unit contingency and an appropriate reserve margin or reserve criteria. The analysis, assessment and documentation of Resource Adequacy, will include Planning Reserve Margins for meeting system load for the BA's system. The analysis will also include resource adequacy analysis for frequency response, spinning reserve, off-line reserves and other resource characteristics required to meet the reliability criteria.

Applicability: Balancing Authorities (BA) are divided into two groups based on the annual system Peak Demand.

- Group A: Annual system peak is greater than 50 MW.
- Group B: Annual system peak is less than or equal to 50 MW.

Effective Date: To be determined

B. Requirements

R1. The Group A utilities will establish at their discretion whether to use Resource Adequacy analysis using requirements defined in either R1.1 or R1.2 for each planning year. Group B will use the planning methodology defined in R1.2 for each planning year.

R1.1. Group A: "one day in *x* year criteria". The utility will establish the methodology and procedures used to establish the "one day in *x* year" criteria to meet the system peak load to be served by the BA. The methodology should evaluate the reliability of the generating resources, the capacity and system requirements of the BA and the alternatives to resource commitment available to meet the desired reliability criteria for each of the BA's utility loss of load expectations methodologies. In addition the methodology should include the consideration of, renewable capacity from as-available renewable resources using the reliability based methods described in R1.2 for L_{QC}. Consideration will also be given to ensure that the enough generating resources are installed on system that have the capability to provide the operating ancillary services such as frequency response, spinning reserve, voltage regulation, frequency regulation and other services during the same time periods included in HI-TPL-001 Transmission Planning Performance Requirements as follows:

R1.1.1. Minimum day load with no as-available renewable generation

R1.1.2. Minimum day load with as-available maximum renewable generation

R1.1.3. Maximum load with no as-available renewable generation

R1.1.4. Maximum load with maximum as-available renewable generation.

R1.2. Group A and Group B: "reserve margin of *xx*% criteria". The utility will maintain a minimum *xx*% Reserve Margin (F_{RM}) over the annual system peak.

$$\frac{\sum_{i=1}^{N} N_i + L_{DR} + L_{QC} - L_{Peak}}{L_{Peak} - L_{DR}} \geq F_{RM}$$

Where:

- F_{RM} is the Reserve Margin.
- N_i is the Normal Net Capability of all firm units.

- L_{DR} is the amount of Interruptible Demand and Direct Control Load Management (DCLM) exclusively available and measureable for the BA's interruption for the entire period of the expected capacity shortfall. Such Interruptible Demand and DCLM will not infringe on the protective reserve for system security required by HI-BAL-006 Underfrequency Load Shedding.
- L_{QC} is the estimated capacity value of grid-side as-available renewable and stored energy generation on the system. The estimated capacity value of grid-side as-available generation and stored energy will be determined by the utility using reliability or statistical based calculation methods depending upon the available data. Reliability based methods that may be used include the effective load carrying capability (ELCC), equivalent conventional power (ECP), or equivalent firm capacity (EFC) methods. Statistical based methods may consist of the relevant time period of the system peak and renewable energy over a time series of data. For example, the estimated capacity L_{QC} is the level where over that system peak period in which 90% of the data points are available to serve the system peak. For existing installations, the capacity value will be calculated using three years of actual data for each group of similar as-available renewables such as wind, hydro, PV, etc. For future installations the estimated capacity value will be based on estimated capacity value calculations for similarly located resources installed in Hawai'i. For future as-available resources where no Hawai'i historical data is available, the best available data shall be used for calculations. For the first year of data, the estimated capacity value shall be adjusted by 0.7 followed by 0.8 after gathering the second year of data. Following the third year of data, the actual data shall be used to determine the capacity value.
- L_{Peak} is the forecasted annual system peak load.

The Reserve Margin analysis will also consider as a secondary planning criteria that the BA's total Normal Net Capability of all firm units of the system less the capacity of the unit(s) scheduled for maintenance less the capacity that would be lost by the Forced Outage of the largest single contingency plus the total amount of interruptible loads plus the estimated capacity value of grid-side as-available renewable and stored energy generation on the system, if appropriate, and dedicated for serving the entire period of the peak ,must be equal to or greater than the forecasted system peak load.

$$\sum_{i=1}^{N} N_i - \sum_{m=1}^{N} N_m - N_{FO} + L_{DR} + L_{QC} \geq L_{Peak}$$

Where:

- N_m is the Normal Net Capability of units on scheduled maintenance.
- N_{FO} is the Normal Net Capability of the largest single contingency lost by Forced Outage.

R1.3. The BA for each Group A system will stipulate the use of either R1.1. or R1.2. for planning. The Resource Adequacy analysis must calculate a Planning Reserve Margin for the applicable group that will either result from the sum of the probabilities for Loss of Load for the system Peak Demand for all days of each planning year analyzed (per R1.1) being equal to *xx*. (This is comparable to a "one day in *x* year" criterion) or document that the applicable Balance Authority has developed a resource plan that encompasses a *xx*% Reserve Margin for Group A (per R1.2). Group B will use the Reserve Margin criteria (per R.1.2). The reserve margin target will be utilized until such a time that a new study determines a change in the reserve margin is warranted.

R1.4. The BA will develop criteria to ensure the generation characteristics address the following system requirements:

R1.4.1. Starting and loading time if resources are to be used as Contingency Reserves as required in HI-BAL-002 Disturbance Control Standard.

R1.4.2. The Frequency and Inertia response characteristics as required in HI-BAL-001 Transmission System Planning Performance Requirements.

R1.4.3. The Voltage and Frequency ride-through characteristics as required in HI-BAL-001 Transmission System Planning Performance Requirements.

R1.4.4. Short circuit current requirements.

R1.4.5. Dispatch characteristics (starting time, ramp rate, minimum values, regulation, etc.) as required to meet the requirements of the planning period.

R1.4.6. Any other ancillary resources required to meet system security requirements which have been identified as necessary through analysis of the planning period.

R1.5. Be performed or verified separately for each of the following planning years:

R1.5.1. Perform an analysis for Year One.

R1.5.2. Perform an analysis or verification when changes in measured non-dispatchable generation or net load changes more than *x* MW/year or *x* MW (amount established by each BA) from Year One or there are planned or unplanned changes in resource development other than nondispatchable generation or DG.

R1.6. Include the following subject matter and documentation of its use:

R1.6.1. Criteria for including planned resource additions in the analysis.

R1.6.2. Load forecast characteristics:

- Median forecast peak load.
- Load forecast uncertainty (reflects variability in the load forecast due to weather and regional economic forecasts).
- Load diversity.
- Seasonal load variations.
- Daily demand modeling assumptions (firm, interruptible).
- Contractual arrangements concerning curtailable or Interruptible Demand.
- Historic resource performance and any projected changes.

Seasonal resource ratings.

- Historic resource performance and any projected changes.

Seasonal resource ratings.

- Resource planned outage schedules, deratings, and retirements.
- Intermittent and energy limited resources such as wind, PV, and cogeneration may be considered holistically using time synchronized data with load. The relevant time period of the system peak must be defined using a minimum of three years of data.

R1.6.3. Transmission limitations that prevent the delivery of generation reserves.

R1.6.3.1. Criteria for including planned Transmission Facility additions in the analysis.

R1.6.3.2. Criteria for remedial action systems employed in lieu of Transmission improvements.

R1.7. Consider the following resource availability characteristics and document how and why they were included in the analysis or why they were not included:

- Common mode outages that affect resource availability.
- Environmental or regulatory restrictions of resource availability.
- Any other demand (load) response programs not included in R1.3.1.
- Sensitivity to resource outage rates.
- Impacts of extreme weather or drought conditions that affect unit availability.

R1.8. Document that capacity resources are appropriately accounted for in its Resource Adequacy analysis.

R2. The BA must annually document the projected load and resource capability, for each area or Transmission constrained sub-area identified in the Resource Adequacy analysis.

R2.1. This documentation must cover each of the years in Year One through ten.

R2.2. This documentation must include the Planning Reserve Margin calculated per requirement R1.1 for each of the three years in the analysis.

R2.3. The documentation as specified per requirement R2.1 and R2.2 must be publicly posted no later than 30 days after the close of the year.

C. Measures

M1. The BA must possess the documentation that a valid Resource Adequacy analysis was performed or verified in accordance with R1.

M2. The BA must possess the documentation of its projected load and resource capability, for each area or Transmission constrained sub-area identified in the Resource Adequacy analysis on an annual basis in accordance with R2.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

1.1.1. Hawai'i PUC (or designee)

1.2. Compliance Monitoring Period and Reset Timeframe

1.2.1. One calendar year

1.3. Data Retention

1.3.1. The BA must retain information from the most current and prior two years. The Hawai'i PUC (or designee) will retain any audit data for five years.

2. Levels of Non-Compliance for Requirement R1, Measure M1:

2.1. Level 1: The BA met one of the following conditions for Requirement R1 and Measurement M1.

2.1.1. The BA Resource Adequacy analysis failed to consider 1 or 2 of the Resource availability characteristics subcomponents under R1.4 and documentation of how and why they were included in the analysis or why they were not included.

2.1.2. The BA Resource Adequacy analysis failed to consider Transmission maintenance outage schedules and document how and why they were included in the analysis or why they were not included per R1.6.

2.2. Level 2: The BA failed to meet all the requirements of Level 1 for Requirement R1 and Measurement M1.

3. Levels of Non-Compliance for Requirement R2, Measure M2:

3.1. Level 1: The BA failed to publicly post the documents as specified per requirement R2.1 and R2.2 later than 30 calendar days prior to the beginning of Year One per R2.3 for Requirement R2 and Measurement M2.

3.2. Level 2: The BA failed to meet all the requirements of Level 1 for Requirement R2 and Measurement M2. The PUC or its designee will give notice to the BA within 30 days of years' end for a compliance audit and will complete such audit within 90 days of such information being supplied by the BA.

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N. System Operation and Transparency of Operations

PRUDENT DISPATCH AND OPERATIONAL PRACTICES

The Companies' unit commitment and economic dispatch policies are based on safe and reliable operation of the system, minimizing operating costs, and complying with contractual and regulatory obligations. The daily generation dispatch process is illustrated in Figure N-1.

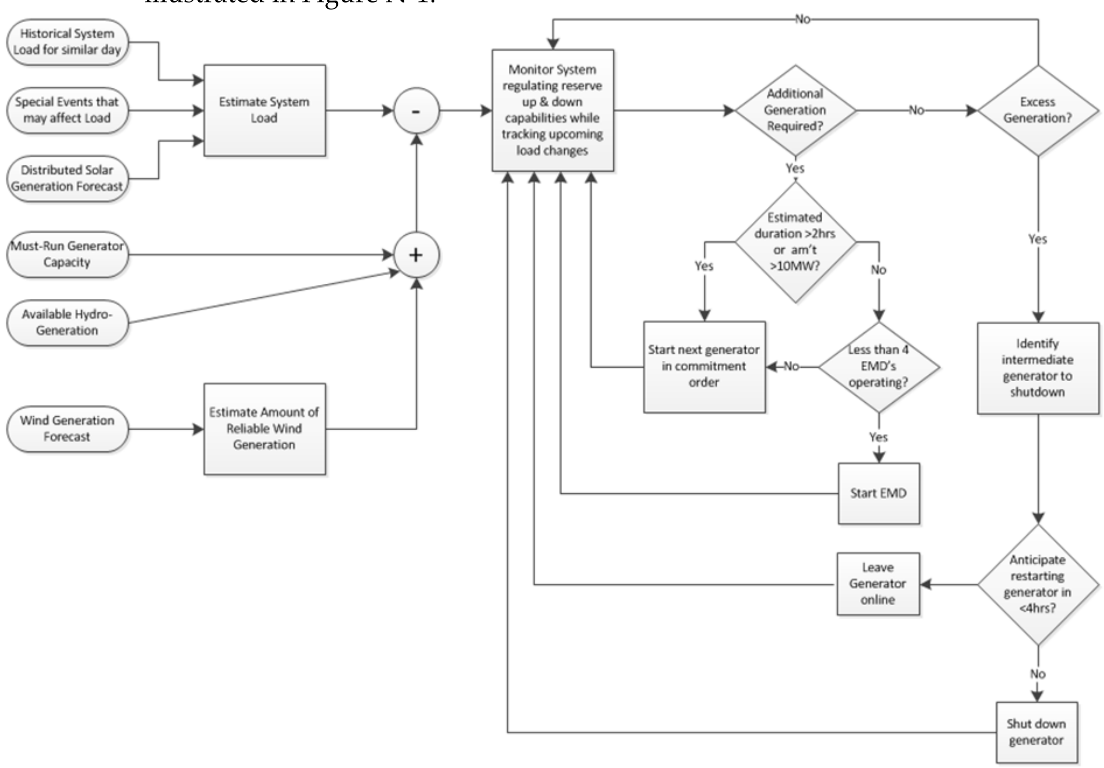

Figure N-1. Daily Generation Dispatch Process

In the future, the goal is for the System Operator to be able to incorporate a more automated approach to unit commitment and dispatch with increased amounts of variable renewable generation (wind and solar), quick-starting engines, energy storage, and demand response resources on the grid. The Energy Manage Systems (EMS) would likely be interfaced/integrated with corresponding Demand Response Management Systems (DRMS) and Energy Storage Management Systems (ESMS). This would also include integrating the demand forecast, with wind and solar forecasts to achieve a net demand to be used for unit commitment.

Minimization of Ancillary Services Costs

The process to identify system security constraints, and the combinations of resources which can be used to meet them, is summarized as follows:

- Determine system constraints.
- Identify the resource mix that meets each of them.
- Select the lowest cost combination of resources to operate.

For all three operating companies, additional security constraints are imposed with increased concentrations of variable renewable resources. Therefore, the projected increase in distributed PV may have an impact on ancillary service costs. The Companies will continually evaluate the economics of using existing resources to meet ancillary service and system security requirements versus meeting those needs with alternative resources including energy storage and demand response.

Maximizing the Use of Available Renewable Energy

The commitment and dispatch of renewable energy resources depends upon the contract terms for those resources and whether or not the system operator has visibility and control over the generation. If the resource can be economically dispatched, it is put under automatic generation control (AGC), and its output is determined by its marginal cost relative to the marginal cost of other resources. Examples of this type of renewable resource includes geothermal, generating units using renewable biofuels, waste-to-energy projects, and other "firm" renewable projects.

To date, variable renewable energy projects are contractually treated as "must-take," variable energy. These resources are accepted regardless of cost, but their output is reduced as needed when all intermediate units are off line and there remains excess energy production. In this case the system operator limits, or "curtails" the output of variable energy providers to the degree necessary to keep the system in balance and provide response reserves. Most curtailments are partial—the output is limited but the resource is not restricted to zero output. When curtailment is necessary due to excess energy, it is performed in a manner consistent with the purchased power agreements associated with the affected resources and in accordance with a priority order established by the system operator.

In addition to excess energy situations, curtailments can also be required for system constraints such as line loading, phase angle separation, line maintenance, and frequency impact from power fluctuations. Curtailments for system constraints are applied to the resources as needed to address these constraints and are not subject to the priority order used for excess energy curtailments. Curtailments are also performed at the request of wind plants for wind conditions, and equipment issues. The number of curtailment events, the reason, and their duration are reported monthly through various reports to the Commission such as the monthly report filed by the Hawaiian Electric Companies in Docket No. 2011-0206 (RSWG).

The vast majority of distributed solar PV is not visible or controllable by the system operator. These resources serve demand ahead of all other resources. Additional growth in distributed solar PV these resources is forecast to cause increased curtailments of utility-scale variable renewable resources, unless distributed solar PV is required to provide the visibility and control to the system operator.

Energy Management Systems (EMS)

The operation of the system is facilitated by use of a centralized Energy Management System (EMS). The EMS provides the system operator with constantly updated, real-time information about the operational state of the system. There are three key program applications within the EMS:

- Supervisory Control and Data Acquisition (SCADA)
- Real-time Automatic Generation Control (AGC)
- Real-time State Estimator

The Companies routinely update the EMS hardware and software platforms for each system in order to ensure reliable operation, to incorporate new industry developments such as protocols and system security measures, and to maintain support from EMS vendors[1]. The most recent migration to a new platform was completed in late 2013.

[1] The Companies operate EMS systems from two different vendors, *Alstom* at Hawai'i Electric Light and Maui Electric, and *Siemens* at Hawaiian Electric.

System Dispatch and Unit Commitment

Unit commitment and dispatch decisions are based upon:

Safety. The Companies' dispatch of generating resources is always subject to ensuring the safety of Company personnel and the general public.

Reliability. Dispatch and unit commitment must adhere to system security and generation adequacy requirements.

Contractual Requirements. Dispatch and unit commitment must adhere to contractual constraints.

Cost. After meeting all the forgoing requirements, the Company commits units and dispatches units based on their marginal cost, with lower cost units being committed and operated before higher cost units.

When determining the unit commitment and dispatch of generating units, the Company does not differentiate between dispatchable IPPs and utility-owned assets. The daily unit commitment modeling tool input date does not differentiate units by ownership. Certain generators do receive a form of priority in terms of energy being accepted onto the system on the basis of the location of the generator, its characteristics, or the contractual obligations unique to the resource. The acceptance of energy is in the following order of preference:

- **Distributed generation:** Distributed generation resources receive preferential treatment as "must take" resources regardless of their economic merit for system dispatch. This includes Standard Interconnection Agreement (SIA) distributed generation and Net Energy Metering (NEM) distributed generation. At the present time, the Companies have no control over, or ability to curtail, distributed generation.
- **Scheduled contractually obligated generation:** These resources are preferentially treated from a dispatch perspective by contract. They are used to serve customer load regardless of their economic merit for system dispatch. Scheduled energy from these resources is taken after distributed generation, but ahead of all other resources including variable energy providers.
- **Contractually must-run, dispatchable generation:** The resources cannot be cycled offline and therefore the minimum dispatch level of these resources are preferentially treated in the system dispatch determination and the energy is accepted from these resources regardless of cost, except during periods of maintenance.
- **Generation to meet system security constraints:** These resources provide energy at least at their minimum dispatch limit, ahead of other resources, similar to contractual must-run and scheduled generation, plus an amount of reserve capability to provide down regulation. However, once dispatched, the continued operating status of these

resources is subject to continual evaluation of their costs relative to other alternative resources that may become available at a lower cost, except where it is required by contract.

- **Variable energy:** As available energy is accepted on the system, regardless of cost, after distributed generation, scheduled energy purchases, and continuously operated generation. This energy is accepted regardless of cost and thus presents a constraint on optimized (lowest) cost. If the energy cannot be accommodated due to low demand, curtailment of the resource is ordered according to an established and approved priority order.
- **Dispatchable resources:** Energy from dispatchable resources is taken on the basis of relative cost (economic dispatch). Resources with the lowest variable energy (fuel and O&M) cost will be committed ahead of resources with higher variable costs. Online resources with lower incremental costs will be dispatched at higher outputs ahead of resources with higher incremental costs. The units operated routinely to meet demand, but cycled offline during minimum demand periods, are described as intermediate units. Short-term (daily) unit commitment decisions do not consider fixed costs associated with these resources because the fixed costs will be incurred regardless of whether or not the unit is operated.

Utilization of Energy Storage and Demand Response

Energy storage and demand response programs can provide the system operator with a flexible resource capable of providing capacity and ancillary services. In order to provide the system operator with appropriate control and visibility of energy storage assets will be equipped with essentially the same telemetry and controls necessary to operate generating units. Demand response used for providing regulation reserves and contingency reserves will also be equipped with appropriate telemetry and controls. The specific interface requirements depend upon whether the storage device or demand response resource is responding automatically, or is under the control of the system operator. DRMS and/or ESMS may be interfaced with or directly incorporated in an EMS. For storage or demand response that is integrated into the EMS, telemetry requirements include:

- For storage, real-time telemetry indicating charging state, amount of energy being produced, device status.
- Control interface to the EMS to enable the increase and decrease of energy output from the storage asset, and for energy input to the storage device for charging.
- For demand response, real-time telemetry indicating breaker status, switch status, and load.

- Control interface to the EMS to enable the triggering of load shed in response to automatic signals (for example, underfrequency) or a command from the system operator.

Depending on the specific application, storage may also be required to respond to local signals. For example, storage may need the capability to respond to a system frequency change in a manner similar to generator governor droop response, which may be used for a contingency reserve response or for frequency responsive regulating reserve. Another example of local response includes the ability of the storage to change output (or absorb energy) in response to another input signal from a variable renewable energy resource in order to provide "smoothing" of the renewable resource output.

A special consideration of short-duration storage is the fact that it is a limited energy resource. This introduces the need for the system operator to be informed regarding the storage asset's charging state, and the need to ensure that the integration and operation of these resources allows for replacement energy sources prior to depletion of the storage. This replacement could be in the form of longer-term storage or generation resources. In order for the value of the demand response to be realized in providing a particular grid service, once called, the load cannot return to the system until after a specified time, which is dependent on the type of grid service being provided by the demand response resource. Accordingly, the system operator similarly requires information regarding the status of demand response, particularly as it relates to the state of the response after an event has been triggered.

Visibility and Transparency in System Dispatch

A high level review of the Renewable Watch websites of various ISOs including PJM, MISO, Cal ISO, and ERCOT shows the following operational information commonly being displayed, along with ISO energy market-specific information such as locational marginal pricing:

- Real time daily demand curve showing actual and forecasted demand, updated at least hourly
- Hourly wind power MW or MWh being produced and forecasted
- Other renewable energy production in MW (California)
- Available generation resources

The Company's Renewable Watch site currently displays the following information, with data updated approximately every 30 minutes:

Net Energy System Load. The system load served by generators on the "utility-side" of the meter including those owned by the utility and by independent power producers (IPP).

Gross System Load. The net system load plus estimated load served by "customer-side" of the meter by DG-PV.

Solar Irradiance Data. This data is measured in different regions of the island, which are used as input to calculating the estimated load served by customer-side PV.

Wind Power Production. Total megawatts of wind power being produced by the various IPP-owned wind farms selling electricity to Hawaiian Electric.

To provide further information to customers about the dispatch of various energy generation resources under the utility's control, the Company is currently partnering with the Blue Planet Foundation to develop and publicly present real time breakouts of the percentage of net energy system load being served by various fuel types, including coal, oil, wind, waste-to-energy, solar, and biofuel. Hawaiian Electric and Blue Planet believe this information will be useful in raising customer awareness of the use of renewable energy versus fossil fuels. A prototype kiosk was displayed at the Hawaiʻi Clean Energy Day event on July 22, 2014 with positive public reaction.

In light of this information already being developed for public display, Hawaiian Electric is agreeable to the following enhancements to its website:

- The information on the Renewable Energy watch website will be supplemented with additional information showing for the previous hour the percentage of the energy supplied by the different resources (IPPs, Renewables, Company generating units).
- A historical archive of the percentage of the energy produced by each of the resource groups for the previous 24 hour period will be maintained so that the customer can view the changes over time.

These enhancements will address the Commission's objectives of showing the significant use of non-utility generation and renewable resources, most of which, with the exception of Hawaiian Electric's biofueled combustion turbine generation CT-1, are IPP owned.

In addition to the above, Hawaiian Electric will also make public a description of its economic dispatch policies and procedures, via posting on its company website. Combined, the enhancements to the Hawaiian Electric website and the sharing of its dispatch policies and procedures will increase visibility and transparency of how generating resources are being dispatched on the Hawaiian Electric system.

As previously mentioned the Companies generating unit commitment and dispatch of the generating units is based on the objective of incurring the least cost to the customers while continuing to maintain system reliability. With the introduction of increasing amounts of renewable resources on the systems, it has become more important to minimize the use of fossil fuels and contending with the dynamic system changes that occur from the new resources so that reliability can be maintained. A screenshot from the Renewable Watch–O'ahu website is shown below in Figure N-2 to provide an example of the variability of the renewable energy resources.

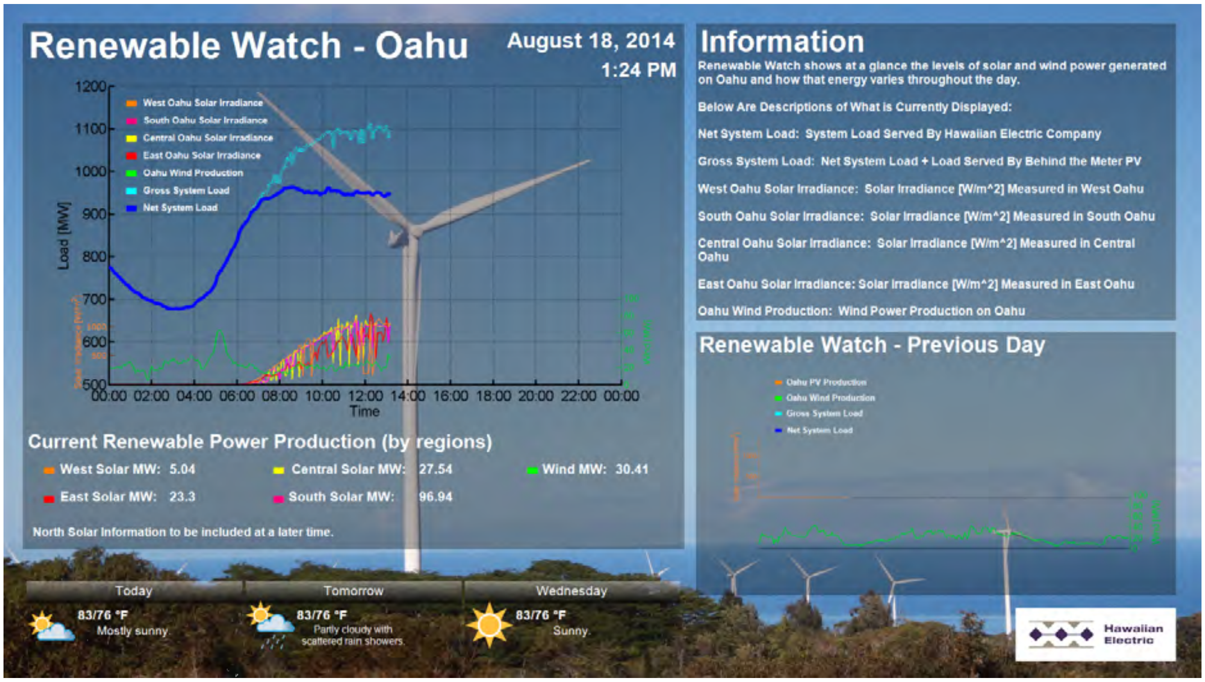

Figure N-2. Renewable Watch–O'ahu Website Screenshot of Information Displayed for August 18, 2014.

Keep in mind that the changes that have been occurring on the Companies' respective systems have been occurring for a few years but at different rates of change. The neighbor island systems (Maui and Hawai'i Island) have been changing at a far more rapid pace due to the high availability of renewable resources that could be used on each island.

CAPACITY VALUE OF VARIABLE GENERATION AND DEMAND RESPONSE

Accurately assessing the capacity value of variable generation and demand response resources are critical components toward meeting customer demand and maintaining system reliability. Because wind and solar are variable resources, determining its capacity value becomes a considerable challenge in order to achieve the confidence required to include variable generation resources to replace firm generation.

Capacity Value of Wind Generation

Hawaiian Electric

The contribution of existing and future wind resources to capacity planning is reflected in the Loss of Load Probability (LOLP) analysis. In the modeling determination of when additional firm capacity may be needed based on the application of Hawaiian Electric's generating system reliability guideline (4.5 years per day), the wind resources' contribution to serving load will be reflected in the LOLP calculations. As such, wind resources' contribution to capacity planning is dependent upon the composition and assumptions in each plan.

Hawai'i Electric Light

The aggregate value of the two existing wind farms (20.5 MW Tawhiri wind generating facility and 10.56 MW Hawi Renewable Development wind farm) contribution to capacity planning is 3.1 MW.

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

Maui Electric

The aggregate value of the three existing wind farms (20 MW Kaheawa Wind Power I, 21 MW Kaheawa Wind Power II, 21 MW Auwahi Wind Energy) contribution to capacity planning is 2 MW.

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

Capacity Value of Solar Generation

The capacity value of existing and future utility-scale and rooftop PV is 0.

Capacity Value of Demand Response

The estimated megawatt potential from the Residential and Small Business Direct Load Control Program, Commercial and Industrial Direct Load Control Program, and Customer Firm Generation Programs are included in PISP capacity planning.

CONCLUSIONS

The Companies understand the importance of visibility and transparency of the economic commitment and economic dispatch to show the customers that a real effort is being made to reduce the use of fossil fuels and to encourage the use of renewable resources. Creating a website with the same information that RTOs or ISOs use to show price of energy for the market may be misleading if the customer is unaware of the system conditions that is dictating how the generating units are being run. The information that is graphically displayed on the existing Renewable Watch websites is a good starting point for creating visibility and transparency. And the Companies recommend that additional information that is being developed by Blue Planet that displays the system load and the percent of power that each resource group is providing to serve that load also be shown to the customers so that they are able to see over time that less fossil fuel generation is being substituted with less costly generation.

O. Diesel Generator Replacement Study

SUMMARY

Hawai'i Electric Light utilizes ten stationary diesel generators (2.5 MW each) as peaking units. The diesel generators units are dispatched from the central control center at the KOCC in Hilo. The engines are kept in standby with the lube oil systems circulating with pre-lube pumps and heaters for fast start. These units can begin generating power within 2.5 minutes and are used for recovery when the variable generation assets generation drops down due to lack of wind.

The diesel generators are approximately 39 years old. The newest diesel is 27 years old and the oldest is 52 years. They have been maintained within the Original Equipment Manufacturers (OEM) recommendations. A study conducted in 2002 by Sargent & Lundy identified the existing diesel generators should be serviceable for an additional 20 to 30 years.

The machines have operated between 500 to 700 hours (each) per year and generated approximately 5,000 MWh (total) annually. The demand on the machines is projected to increase with the generation mix changes planned in the future and additional generation and run time will increase the demand on these units.

The diesel engines have been retrofitted in 2013 with current CO_2 removal catalyst and are compliant with current environmental regulations and should be able to operate an additional 20 to 30 years

The diesel generators have been very reliable for the past 39 years and with proper maintenance and rebuilds they can be expected to operate for at least an additional 20 years.

The economic evaluation was based on the following assumptions:

Option 1 – Maintain existing Diesel generators

- The diesel generators will be operable for the next 20 years with proper maintenance
- Fuel will be ultra low sulfur diesel
- Routine O&M will be based on historical levels
- Engine power pack replacements on a 6,000 hour cycle
- Complete engine rebuilds based on 16,000 hour cycles
- Heat rate on current equipment = 11,700 Btu/kWh

Option 2 – Replace ten (10) diesel generators

- New capital cost for a 2.5 MW diesel generator = $8,125,000
- Heat rate on new diesel generators = 8,500 Btu/kWh
- O&M routine and rebuild costs reduced

Based on these assumptions a 20 year present worth analysis was performed comparing operating and maintaining the existing diesel generators to purchasing and installing 10 new diesel generators (2.5 MW). The results indicated the maintaining the existing diesel generators would be the more economical solution.

Options	Generation MWh/Year	Heat rate Btu/kWh	Capital investment ($1,000)	Net Present Value ($1,000)
1. Current	5,000	11,446	$0	$36,198
2. Replace 10 diesels	5,000	8,500	$81,125	$156,214

Table O-1. Diesel Replacement Options

Based on the economic evaluation the operation of the existing diesel generators for the next 20 years is the lowest cost option for providing the system with peaking capacity.

BACKGROUND

As a part of the PSIP analysis the replacement of the existing ten (10) diesel generators was evaluated to determine if the replacement would reduce the operating costs for the diesel generators and reduce the cost to the customer.

There are ten (10) diesel generators rated at 2.5 MW each located at 3 sites. Table O-2 indicates the location, age, and heat rate for all the diesel generators.

Unit	Capability (MW)	Type	Operating Mode	Service Date	Age	Heat Rtae btu/kwhr
Kanoelehua D11	2.5	Diesel	Peaking	1962	52	11,864
Kanoelehua D15	2.5	Diesel	Peaking	1972	42	11,864
Kanoelehua D16	2.5	Diesel	Peaking	1972	42	11,864
Kanoelehua D17	2.5	Diesel	Peaking	1973	41	11,864
Waimea D12	2.5	Diesel	Peaking	1970	44	11,173
Waimea D13	2.5	Diesel	Peaking	1972	42	11,173
Waimea D14	2.5	Diesel	Peaking	1972	42	11,173
Keahole D21	2.5	Diesel	Peaking	1983	31	11,160
Keahole D22	2.5	Diesel	Peaking	1983	31	11,160
Keahole D23	2.5	Diesel	Peaking	1987	27	11,160

Table O-2. Generation Units Statistics (as of 2014)

Table O-3 details the heat rates of the diesel generators.

Diesel generator	Heat Rate			
Heat Rate	**2011**	**2012**	**2013**	**Average**
WAIMEA	11,557	11,117	10,845	**11,173**
KANOELEHUA	12,226	12,120	11,247	**11,864**
KEAHOLE	11,203	11,077	11,201	**11,160**
			Average	**11,446**

Table O-3. Diesel Generator Heat Rates

The reliability of the diesel generators has been very good for the past five years with an average reliability (Equivalent Availability Factor) of greater than 90% for three of the five years. The decline in 20112 and 2013 was from the installation of the CO_2 catalyst that required the diesel generators to be shut down for period of time to install the new equipment. The new catalyst has also been causing some derates on the units until the engines could be tuned and some engine power pack replacements could be installed.

Diesel Generator	Equiv Avail Factor (EAF)				
	2,014	2013	2012	2011	2010
Waimea D-12	95.2%	95.4%	89.5%	97.5%	97.7%
Waimea D-13	90.5%	73.4%	81.8%	94.4%	97.9%
Waimea D-14	95.3%	85.7%	86.1%	99.1%	98.3%
Kanoelehua D-11	99.5%	97.9%	79.3%	91.2%	99.9%
Kanoelehua D-15	98.5%	90.3%	87.1%	97.9%	99.8%
Kanoelehua D-16	99.1%	97.1%	84.9%	97.6%	99.8%
Kanoelehua D-17	82.3%	86.4%	84.3%	97.7%	99.7%
Keahole D-21	67.0%	67.8%	79.5%	97.0%	97.6%
Keahole D-22	93.2%	82.1%	97.3%	85.6%	77.3%
Keahole D-23	92.9%	71.0%	78.9%	97.5%	97.6%
Average	91.4%	84.7%	84.9%	95.6%	96.6%

Table O-4. Diesel Generator Equivalent Availability Factors

APPROACH

The economic evaluation compared two (2) options:

1. Maintain the existing ten (10) diesel generators
   - Heat rate assumption = 8,500 Btu/kWh
   - Fuel pricing based on 2014 Ultra Low Sulfur diesel prices
   - Routine maintenance costs were based on the 2013 routine costs
     - PM work on the engines monthly
     - Added in 2013 – CO_2 catalyst monitoring
   - Power Pack replacements
     - The engine power pack replacements are based on 6,000 hours of service
     - Replacements are required to maintain engine efficiency
     - Visible emissions were affected by catalyst additions as engines deteriorate so the power pack frequency has increased. The cost is approximately $175,000 per engine per replacement
   - Engine overhauls – complete
     - Power pack replacement
     - Engine removal – shop disassemble and reassemble
     - Line bore engine valve train
     - Repair any engine block cracking

- Cost is approximately $565,900 each rebuild
- Frequency is every 16,000 hours

- Operating assumptions
- Projected service hours to be 500–700 hours per year per engine
  - Estimated 5,000 MWh to generation per engine per year; based on PSIP projected run times and added contingency for uncertainty in modeling projections
- Heat Rate for all engines averages 11,446 Btu/kWh

Cost assumptions are included in Table O-5.

2. Replace ten diesel generators with new

- Assumed new installations will be in 2020
- Heat rate assumption = 8,500 Btu/kWh
- Fuel pricing based on 2014 ultra low sulfur diesel prices
- Estimated cost is based on ENRAL pricing
  - 2.5mw diesel generators
  - $3,250 / kW installed
  - Price per diesel generator = $8,125,000
  - Total capital investment for 10 diesel denerators = $81,125,000
- Routine maintenance costs were based on the 2013 routine costs
  - PM work on the engines monthly
  - PM work is similar for new engines
- Power pack replacements will be less frequent
  - Power pack replacements will begin in 2027
- Engine overhauls – complete
  - Non required in evaluation period

The economic evaluation was based on comparison of the two cases over a 20 year period The net present value (NPV) of the cost to operate and maintain the two options were developed. The lowest NPV of cost would be the best option.

RESULTS

The expected mission of the diesel generators for the next 16 years (based on the PSIP) should be similar to the past. They will be utilized as peaking units as well as fast start assets when there is a system disturbance or loss of a generating unit. The function in these cases will be to restore the voltage and frequency of the system

The exiting ten diesel generators have been maintained with an acceptable level of reliability (greater than 90%) and should be able to be maintained at that level for the next 20 years with proper maintenance, power pack replacements and engine rebuilds.

The results of the economic evaluation indicates the cost to maintain the diesel generators is far less than the cost for installing new similar sized diesel generators. The primary differences in NPV is driven by the capital investment for the new engines being far greater the savings from the lower operating and maintenance costs. Table O-6 shows the net present value analysis.

UNIT	Net Maximum Capacity	O&M Routine															
		2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
		$ / year	$ / year	$ / year	$ / year	$ / year	$ / year	$ / year	$ / year	$ / year	$ / year	$ / year	$ / year	$ / year	$ / year	$ / year	$ / year
Waimea D-12 (emd diesel)	2.50	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000
Waimea D-13 (emd diesel)	2.50	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000
Waimea D-14 (emd diesel)	2.50	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000
Kanoelehua D-11 (fairbank morris dsl)	2.00	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000
Kanoelehua D-15 (emd diesel)	2.50	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000
Kanoelehua D-16 (emd diesel)	2.50	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000
Kanoelehua D-17 (emd diesel)	2.50	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000
Keahole D-21 (emd diesel)	2.50	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000
Keahole D-22 (emd diesel)	2.50	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000
Keahole D-23 (emd diesel)	2.50	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000
Panaewa D-24 (cummins diesel)	1.00																
Ouli D-25 (cummins diesel)	1.00																
Punaluu D-26 (cummins diesel)	1.00																
Kapua D-27 (cummins diesel)	1.00																
Routine O&M	**Total**	**$ 750,000**	**$ 750,000**	**$ 750,000**	**$ 750,000**	**$ 750,000**	**$ 750,000**	**$ 750,000**	**$ 750,000**	**$ 750,000**	**$ 750,000**	**$ 750,000**	**$ 750,000**	**$ 750,000**	**$ 750,000**	**$ 750,000**	**$ 750,000**

UNIT	Net Maximum Capacity	Engine power pack replacement															
		2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
		$ / year	$ / year	$ / year	$ / year	$ / year	$ / year	$ / year	$ / year	$ / year	$ / year	$ / year	$ / year	$ / year	$ / year	$ / year	$ / year
Waimea D-12 (emd diesel)	2.50	$ 174,000											$ 170,000				
Waimea D-13 (emd diesel)	2.50						$ 174,000										
Waimea D-14 (emd diesel)	2.50	$ 174,000						$ 174,000									
Kanoelehua D-11 (fairbank morris dsl)	2.00																
Kanoelehua D-15 (emd diesel)	2.50			$ 174,000					$ 174,000								
Kanoelehua D-16 (emd diesel)	2.50			$ 174,000					$ 174,000								
Kanoelehua D-17 (emd diesel)	2.50				$ 174,000									$ 174,000			
Keahole D-21 (emd diesel)	2.50	$ 174,000											$ 174,000				$ 174,000
Keahole D-22 (emd diesel)	2.50						$ 174,000					$ 174,000					
Keahole D-23 (emd diesel)	2.50					$ 174,000					$ 174,000						$ 174,000
Panaewa D-24 (cummins diesel)	1.00																
Ouli D-25 (cummins diesel)	1.00															$ 174,000	
Punaluu D-26 (cummins diesel)	1.00															$ 174,000	
Kapua D-27 (cummins diesel)	1.00																$ 174,000
																	174000
Routine O&M	**Total**	**$ 522,000**	**$ -**	**$ 348,000**	**$ 174,000**	**$ 174,000**	**$ 348,000**	**$ 174,000**	**$ 348,000**	**$ -**	**$ 174,000**	**$ 174,000**	**$ 344,000**	**$ 174,000**	**$ -**	**$ 348,000**	**$ 522,000**

UNIT	Net Maximum Capacity	Engine / Generator complete rebuild															
		2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
		$ / year	$ / year	$ / year	$ / year	$ / year	$ / year	$ / year	$ / year	$ / year	$ / year	$ / year	$ / year	$ / year	$ / year	$ / year	$ / year
Waimea D-12 (emd diesel)	2.50							$ 565,000									
Waimea D-13 (emd diesel)	2.50											$ 565,000					
Waimea D-14 (emd diesel)	2.50												$ 565,000				
Kanoelehua D-11 (fairbank morris dsl)	2.00																
Kanoelehua D-15 (emd diesel)	2.50														$ 565,000		
Kanoelehua D-16 (emd diesel)	2.50														$ 565,000		
Kanoelehua D-17 (emd diesel)	2.50								$ 565,000				$ 565,000				
Keahole D-21 (emd diesel)	2.50									$ 565,000			$ 565,000				
Keahole D-22 (emd diesel)	2.50									$ 565,000							
Keahole D-23 (emd diesel)	2.50														$ 565,000		
Panaewa D-24 (cummins diesel)	1.00																
Ouli D-25 (cummins diesel)	1.00																
Punaluu D-26 (cummins diesel)	1.00																
Kapua D-27 (cummins diesel)	1.00																
Routine O&M	**Total**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 565,000**	**$ 565,000**	**$1,130,000**	**$ -**	**$ 565,000**	**$1,695,000**	**$ -**	**$1,695,000**	**$ -**	**$ -**

Table O-5. Current Plan Maintenance Costs

Capital rplacement of diesel generators															
Costs	**Resp**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
Cost ($)															
Routine O&M		$ 750,000	$ 750,000	$ 750,000	$ 750,000	$ 750,000	$ 750,000	$ 750,000	$ 750,000	$ 750,000	$ 750,000	$ 750,000	$ 750,000	$ 750,000	$ 750,000
Power pack replacement		$ 522,000	$ -	$ 348,000	$ 174,000		$ 348,000	$ 174,000	$ 348,000	$ -	$ 174,000	$ 174,000	$ 344,000	$ 174,000	$ -
Overhauls		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Escallation	1	1.03	1.06	1.09	1.12	1.15	1.18	1.21	1.24	1.27	1.3	1.34	1.38	1.43
Total cost impact	$	1,272,000	772,500	1,163,880	1,007,160	840,000	1,262,700	1,090,320	1,328,580	930,000	1,173,480	1,201,200	1,465,960	1,275,120	1,072,500
Generation	mwhr	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000
Heat rate	btu/kwhr	8,500	8,500	8,500	8,500	8,500	8,500	8,500	8,500	8,500	8,500	8,500	8,500	8,500	8,500
Heat input	mbtu	42,500	42,500	42,500	42,500	42,500	42,500	42,500	42,500	42,500	42,500	42,500	42,500	42,500	42,500
Fuel costs	$/mbtui	22.73	22.72	22.28	22.26	22.74	23.51	24.38	25.36	26.37	27.45	28.52	29.57	30.57	31.72
Fuel costs	$	$ 965,967	$ 965,406	$ 946,725	$ 945,855	$ 966,480	$ 999,280	$ 1,036,297	$ 1,077,600	$ 1,120,653	$ 1,166,493	$ 1,212,059	$ 1,256,934	$ 1,299,257	$ 1,348,294
Revenue Requirements						11,271,179	15,376,947	14,599,104	13,862,543	13,163,136	12,497,443	11,855,372	11,220,870	10,586,139	9,951,407
Total Costs		$ 2,237,967.06	$ 1,737,906	$ 2,110,605	$ 1,953,015	$ 13,077,658	$ 17,638,928	$ 16,725,721	$ 16,268,723	$ 15,213,789	$ 14,837,416	$ 14,268,631	$ 13,943,765	$ 13,160,515	$ 12,372,201
Escalation factor		1	1.03	1.06	1.09	1.12	1.15	1.18	1.21	1.24	1.27	1.3	1.34	1.38	1.43
Escallated cost		$ 2,237,967	$ 1,790,043	$ 2,237,242	$ 2,128,787	$ 14,646,977	$ 20,284,767	$ 19,736,351	$ 19,685,155	$ 18,865,098	$ 18,843,518	$ 18,549,220	$ 18,684,644	$ 18,161,511	$ 17,692,247
Discount Factor		1.000	0.934	0.872	0.814	0.761	0.710	0.663	0.620	0.579	0.540	0.505	0.471	0.440	0.411
Discounted Cost		$ 2,237,967	$ 1,671,687	$ 1,951,175	$ 1,733,832	$ 11,140,753	$ 14,408,813	$ 13,092,322	$ 12,194,958	$ 10,914,207	$ 10,180,913	$ 9,359,271	$ 8,804,260	$ 7,991,929	$ 7,270,668
NPV benefit	$ 158,181,829	0.448	0.358	0.447	0.426	2.929	4.057	3.947	3.937	3.773	3.769	3.710	3.737	3.632	3.538

Current operation															
Costs	**Resp**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
Cost ($)															
Routine O&M		$ 750,000	$ 750,000	$ 750,000	$ 750,000	$ 750,000	$ 750,000	$ 750,000	$ 750,000	$ 750,000	$ 750,000	$ 750,000	$ 750,000	$ 750,000	$ 750,000
Power pack replacement		$ 522,000	$ -	$ 348,000	$ 174,000	$ 174,000	$ 348,000	$ 174,000	$ 348,000	$ -	$ 174,000	$ 174,000	$ 344,000	$ 174,000	$ -
Overhauls		$ -	$ -	$ -	$ -	$ -	$ -	$ 565,000	$ 565,000	$ 1,130,000	$ -	$ 565,000	$ 1,695,000	$ -	$ 1,695,000
	Escalation	1	1.03	1.06	1.09	1.12	1.15	1.18	1.21	1.24	1.27	1.3	1.34	1.38	1.43
Total cost impact	$	1,272,000	772,500	1,163,880	1,007,160	1,034,880	1,262,700	1,757,020	2,012,230	2,331,200	1,173,480	1,935,700	3,737,260	1,275,120	3,496,350
Generation	mwhr	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000
Heat rate	btu/kwhr	11,700	11,700	11,700	11,700	11,700	11,700	11,700	11,700	11,700	11,700	11,700	11,700	11,700	11,700
Heat input	mbtu	58,500	58,500	58,500	58,500	58,500	58,500	58,500	58,500	58,500	58,500	58,500	58,500	58,500	58,500
Fuel costs	$/mbtui	22.73	22.72	22.28	22.26	22.74	23.51	24.38	25.36	26.37	27.45	28.52	29.57	30.57	31.72
Fuel costs	$	$ 1,329,625	$ 1,328,852	$ 1,303,140	$ 1,301,942	$ 1,330,331	$ 1,375,480	$ 1,426,432	$ 1,483,284	$ 1,542,545	$ 1,605,643	$ 1,668,363	$ 1,730,133	$ 1,788,389	$ 1,855,887
Revenue Requirements		0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Costs		$ 2,601,625.25	$ 2,101,352	$ 2,467,020	$ 2,309,102	$ 2,365,211	$ 2,638,180	$ 3,183,452	$ 3,495,514	$ 3,873,745	$ 2,779,123	$ 3,604,063	$ 5,467,393	$ 3,063,509	$ 5,352,237
Escalation factor		1	1	1	1	1	1	1	1	1	1	1	1	1	1
Escallated cost		$ 2,601,625	$ 2,101,352	$ 2,467,020	$ 2,309,102	$ 2,365,211	$ 2,638,180	$ 3,183,452	$ 3,495,514	$ 3,873,745	$ 2,779,123	$ 3,604,063	$ 5,467,393	$ 3,063,509	$ 5,352,237
Discount Factor		1.000	0.934	0.872	0.814	0.761	0.710	0.663	0.620	0.579	0.540	0.505	0.471	0.440	0.411
Discounted Cost		$ 2,601,625	$ 1,962,413	$ 2,151,572	$ 1,880,693	$ 1,799,022	$ 1,873,970	$ 2,111,777	$ 2,165,472	$ 2,241,115	$ 1,501,525	$ 1,818,481	$ 2,576,252	$ 1,348,090	$ 2,199,513
NPV benefit	$ 36,554,184	0.520	0.420	0.493	0.462	0.473	0.528	0.637	0.699	0.775	0.556	0.721	1.093	0.613	1.070

Table O-6. Net Present Value Analysis

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