A. Commission Order Cross Reference

In Docket No. 2011-0092, Order No. 32055, the Hawai'i Public Utilities Commission ordered Maui Electric:

> "to prepare and file with the commission a Power Supply Improvement Plan ("PSIP") within one hundred and twenty (120) days of the date of this Order, which shall include remedial analyses to supplement the SICR Plan, as well as a comprehensive evaluation of MECO's power supply system and a "detailed strategy and set of resulting action plans to implement changes to MECO's portfolio of generating units and current operating practices.[56]

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.

[56] Docket No. 2011-0092, Order No. 32055, Section VII.; p86–87.

COMPONENT PLANS

Component Plan	PSIP Heading	Page
Generation Fleet Adequacy Plan	Roles of Generation Resources	5-17
Optimal Renewable Energy Portfolio Plan	Generation and Energy Mix	5-8
Generation Commitment and Economic Dispatch Review	Appendix N	N-1
Additional Considerations: Non-transmission alternatives (NTAs)	Appendix O	O-1

Table A-1. Component Plan Cross Reference

FURTHER ACTION: ENERGY STORAGE

Component Plan	PSIP Heading	Page
Energy Storage	Energy Storage Design	5-29

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

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)

Hawaiʻi'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 Hawaiʻi economy that embraces innovation and is globally competitive, dynamic and productive, providing opportunities for all Hawaiʻi'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 Hawaiʻi state government responsible for managing state parks and other natural resources.

Direct Current (DC)

A department within the Hawaiʻi state government responsible for managing Hawaiʻi'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 Hawaiʻi, 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 Hawaiʻi 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 Hawaiʻi:

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 Hawai'i Economic Research Organization (UHERO)

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

V

Variable Renewable Energy

A generator whose output varies with the availability of it primary energy resource, such as wind, the sun, and flowing water. The primary energy source cannot be controlled in the same manner as firm, conventional, fossil-fuel generators. Specifically, while a variable generator (without storage) can be dispatched 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

Lanaʻi & Molokaʻi Modeling

The model used in the analysis for Lanaʻi and Molokaʻi 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 O‘ahu 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.

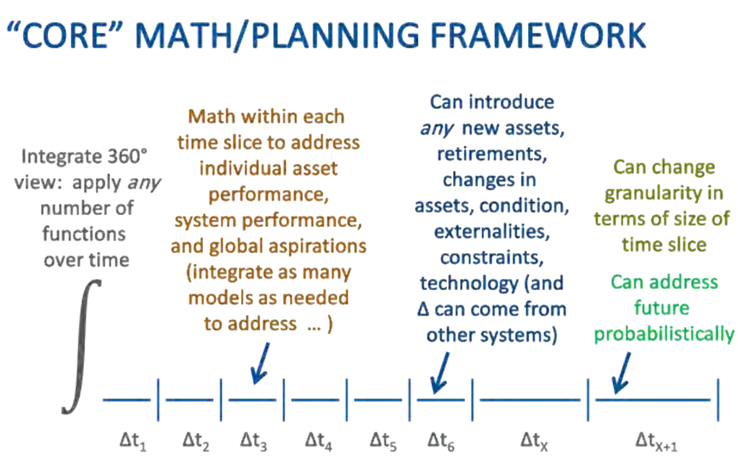

Figure C-1. Black & Veatch Mathematical Modeling Framework

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 Maui Electric power grid.

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

Boundary conditions were established for the expected generation scenarios for the years 2015, 2016, 2017, 2023, and 2030. These years were chosen due to the large changes that occur during this time period, including additions of renewable energy (2015, 2016, 2017), peak load (2023), and additions of new generation units and changes in system loads (2030). The boundary conditions were identified by configuring the generation dispatches to stress the system to determine the stability and contingency reserve requirements for the system.

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METHODOLOGY

The reduction in system inertia and system response due to displacement of conventional generation units by variable energy will result in a less robust power system. This can potentially increase the amount of stages of the Under Frequency Load Shed system (UFLS) that will activate for unit trips and result in lower critical clearing times for all transmission and subtransmission faults.

System Improvement Assumptions

It is assumed that dual primary, communications assisted relaying is installed on all Maui Electric 69 kV and 23 kV circuits and all N-1 faults are cleared in less than 9 cycles.

The extreme variation in feeder loading during daytime and nighttime conditions require an adaptive relaying scheme for the under frequency load shedding system. This system is assumed to be in service in 2017. Due to the requirements of the under frequency load shed scheme, SCADA control of all distribution circuits will be required for the new system. It is assumed that SCADA control will be establish to all substations by 2017.

Control of all distributed generation (DG) PV is assumed in 2017. Control of DG would allow the curtailed PV to provide 10-minute reserves to replace regulation reserves used to counter ramping of the variable generation.

PV Assumptions

It was assumed that only 10 MW of the total DG installed would utilize legacy trip settings for voltage and frequency. The remaining PV was assumed to have extended ride through characteristics allowing the PV to remain online during system contingencies. The settings used for the legacy and extended PV capability are shown below in Table D-1.

PV Type	Protection Type		Settings 1		Settings 2	
			Set Point (Hz or	Time (sec)	Set Point (Hz or	Time (sec)
Legacy	Voltage	Over	1.10	0.99	1.2	0.157
		Under	0.88	1.99	0.5	0.157
	Frequency	Over	60.5	0.157	-	-
		Under	59.3	0.157	-	-
Extended	Voltage	Over	1.10	0.99	1.2	0.157
		Under	0.88	1.99	0.5	0.49
	Frequency	Over	63	19.99	-	-
		Under	57	19.99	-	-

Table D-1. PV Settings

It is important to note that the legacy PV has an under frequency trip setting of 59.3 Hz and a relay time of 0.157 seconds. Based on these settings, an under frequency event is likely to result in tripping of the legacy PV, further depressing system frequency following its tripping. The legacy PV also trips on over frequency at 60.5 Hz also in 0.157 seconds. The loss of legacy PV following a transmission fault will decrease system security. The extended PV settings have an under frequency set point of 57.0 Hz and a relay time of 20 seconds, resulting in minimal PV tripping during under frequency events.

Criteria

The criteria for the system security studies are based on Maui Electric's adopted planning document TPL-001. The planning document outlines the transmission and generation contingencies and the acceptable performance of the system.

The generation planning criteria BAL-502 also contains required characteristics of future energy resources that were used in the system studies.

The overriding criteria used for the analysis was that the system should not activate more than the Stage 1 of the UFLS system during single unit outages, loss of a wind farm or PV source. Stage 1 currently results in the loss of customers that is acceptable to the planning criteria in TPL-001. The settings used for the existing UFLS system are shown below in Table D-2.

UFLS Stage	Set Point (Hz)	Intentional Delay (Sec)	Breaker Time (sec)
Stage 1	58.7	0.000	0.083
Stage 2	58.5	0.000	0.083
Stage 3	58	0.000	0.083

Table D-2. UFLS Settings

Contingency Reserves Analysis

The replacement of traditional generation with variable generation will require additional contingency reserves. Energy Storage Systems (ESS) were added to the system provide system stability and meet the performance requirements of TPL-001.

During analysis, if the simulation resulted in a frequency below 58.7 Hz for a single contingency event, the contingency reserves were increased in 5 MW increments until the frequency stayed above 58.7 Hz. The amount of contingency reserves that just prevented the Stage 2 of UFLS is defined as the minimum level of contingency reserves for the system.

Contingencies

Contingencies of major 69 kV lines with 5 cycle clearing times were utilized to verify system stability for each generation configuration. Unit outages consisted of the larger Maui Electric units or a single contingency wind farm line or transformer. These contingencies were used to identify the level of contingency reserves required to meet the reliability standards set forth in TPL-001. A list of contingencies used for the study is shown below in Table D-3.

	Disturbance	From Bus	To Bus	'ID'	Clearing Time (Cycles)
Unit Trips	MPP 14	301	-	1	-
	MPP 10	108	-	0	-
	MPP 16	302	-	2	-
	HC&S	804	-	4	-
	MPP 15	303	-	3	-
	AWF	90991	-	S3	-
	KWP	90971	-	1	-
Faults	Kanaha_6923	602	202	4	7
	Puunene_6923	4002	4	1	7
	Waiinu_6923	636	236	1	7
	Maa-Lahaluna	39	97	2	5
	Maa-KWP	39	636	1	5
	Maa-Kihei	39	35	1	5
	Kanaha-Puunene	602	401	1	5
	Lahaina-Lahaluna	34	84	1	5

Table D-3. Contingencies

Load and PV Levels

The forecast load growth increases from current peak load levels near 200 MW to 218 MW in 2023, and decreasing through 2030 to 206 MW. DG connected to the system is projected to increase through the years with 130 MW projected in 2030. Table D-4 shows the projected load and DG levels for this study.

	Minimum	Day Minimum	Day Peak	Evening Peak
2015 Load Levels	86.3	135.3	183.6	195.4
2016 Load Levels	87.3	138.7	186.1	197.7
2017 Load Levels	90.7	142.7	191.3	203.7
2023 Load Levels	97.2	154.0	205.6	218.5
2030 Load Levels	91.8	148.5	195.1	206.3

	Nameplate Capacity	Sunny (MW)	Cloudy (MW)
2015 PV Gen	75.0	63.8	7.5
2016 PV Gen	90.0	76.5	9.0
2017 PV Gen	96.0	81.6	9.6
2023 PV Gen	116.0	98.6	11.6
2030 PV Gen	130.0	110.5	13.0

Table D-4. Maui Electric Load and PV Levels

YEAR 2015 ANALYSIS

Power flow cases were created for the day minimum and day peak load times. The day minimum cases assumed a load of 135 MW, with renewable generation resources consisting of 75 MW of distributed PV (12 MW legacy PV) and 72 MW of wind. The day peak cases assumed a load of 183 MW.

The assumptions used for the 2015 cases are listed below:

- These cases assume that 12 MW of PV has legacy trip settings (59.3 Hz/ 60.5 Hz), all other PV has extended ride through
- KPP 3, KPP 4, DTCC1 are baseloaded. Sensitivity cases were run with ½ DTCC2 baseloaded
- Existing protection clearing times were used
- No curtailment of DG resources

2015 Generation Dispatches

Prior to the correction of the PV trip settings, the loss of 12 MW of PV during an under frequency event results in the worst case scenario for the system. Consequently, only the daytime cases were run for the 2015. For line fault contingencies, it is critical that only 12 MW of PV utilize the 60.5 Hz trip setting. With DTCC1, KPP 3, KPP 4 online, the wind must be curtailed for the daytime minimum cases. Details of the generation dispatches for the 2015 study year are shown in Table D-5.

2015								
	Daytime Minimum Load Level				Daytime Peak Load Level			
Wind Level	Windy	Windy	Calm	Calm	Windy	Windy	Calm	Calm
Solar Gen (Cap)	75.0	75.0	75.0	75.0	75.0	75.0	75.0	75.0
Curtailed Solar	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Solar Gen (MW)	63.8	7.5	63.8	7.5	63.8	7.5	63.8	7.5
KPP 1								
KPP 2								
KPP 3	7.0	8.0	8.0	11.0	7.5	8.0	10.0	11.0
KPP 4	7.0	8.0	8.0	11.0	7.5	8.0	10.0	11.0
MPP 14	18.0	17.5	17.0	16.5	17.0	18.0	16.0	19.8
MPP 15	8.0	7.7	8.0	11.5	7.5	8.0	8.0	13.0
MPP 16	18.0	17.5	17.0	16.8	17.0	18.0	16.2	20.0
MPP 17				18.0		17.0	19.0	19.5
MPP 18				11.5		6.0	9.0	10.5
MPP 19				18.0			19.0	19.5
HC&S	11.0	9.0	11.0	12.0	11.0	11.0	10.0	11.0
MPP 10						10.0		12.0
MPP 11								11.5
MPP 12								11.0
MPP 13								
Wind Total	0.0	60.0	0.0	0.0	51.0	72.0	0.0	0.0
Load	132.8	135.2	132.8	133.8	182.3	183.5	181.0	182.8
Reg Up	19.0	20.3	19.0	17.5	20.5	23.6	23.6	8.0
Reg Down	21.0	19.7	21.0	36.5	19.5	29.6	24.4	60.1

Table D-5. 2015 Dispatch Cases KPP 3, KPP 4, DTCC1 Baseloaded

2015 Results

The minimum frequency results are shown in Table D-6 for the 2015 cases.

	Day Min				Day Peak			
	wnd_sun	wnd_cld	clm_sun	clm_cld	wnd_sun	wnd_cld	clm_sun	clm_cld
Outage	Min	Min	Min	Min	Min	Min	Min	Min
M14	58.3	59.4	59.4	59.5	59.4	59.5	59.6	59.6
MGS10						59.7		59.7
M16	58.4	59.4	59.4	59.5	59.5	59.5	59.5	59.5
HC&S	59.6	59.7	59.6	59.6	59.6	59.7	59.7	59.7
M15	59.7	59.8	59.7	59.7	59.8	59.8	59.8	59.7
AWF		59.6			59.6	59.7		
KWP		58.6			58.3	59.0		
Kanaha_6923	59.8	59.8	59.7	59.7	59.9	59.9	59.7	59.8
Puunene_6923	59.8	59.9	59.8	59.8	59.9	59.9	59.8	59.8
Waiinu_6923	59.8	59.6	59.8	59.7	59.7	59.7	59.8	59.7
Maa-Lahaluna	59.8	59.8	59.8	59.6	59.9	59.8	59.7	59.5
Maa-KWP	59.6	59.6	59.6	59.4	59.8	59.8	59.3	59.4
Maa-Puunene	59.0	59.9	58.6	59.2	59.6	59.8	58.9	59.1
Maa-Kihei	59.8	59.9	59.8	59.7	60.0	59.9	59.7	59.6
Kanaha-Puunene	59.8	59.8	59.8	59.8	59.9	59.9	59.8	59.9
Lahaina-Lahaluna	58.9	59.5	59.0	59.3	59.6	59.8	59.2	59.3
	Stage 1	Stage 2	Stage 3					

Table D-6. 2015 Stability Results 12 MW PV that Trips at 59.3 Hz

The M14, M16, and KWP unit trip simulations resulted in stage 2 of load shedding. It should be noted that these results assume only 12 MW of PV trip at the current over frequency setting of 60.5 Hz. Following a line fault, it is critical that no additional PV trip for the high frequency condition. If additional PV is retrofitted such that only 10 MW of PV capacity has the 59.3/60.5 Hz trip settings, the results are slightly improved. Table D-7 shows the contingency results when this retrofit is completed.

	Day Min				Day Peak			
	wnd_sun	wnd_cld	clm_sun	clm_cld	wnd_sun	wnd_cld	clm_sun	clm_cld
Outage	Min	Min	Min	Min	Min	Min	Min	Min
M14	58.5	59.4	59.4	59.5	59.4	59.5	59.6	59.6
MGS10						59.7		59.7
M16	58.5	59.4	59.4	59.5	59.5	59.5	59.5	59.5
HC&S	59.6	59.7	59.6	59.6	59.6	59.7	59.7	59.7
M15	59.7	59.8	59.7	59.7	59.8	59.8	59.8	59.7
AWF		59.6			59.6	59.7		
KWP		58.6			58.3	59.0		
Kanaha_6923	59.8	59.8	59.7	59.7	59.9	59.9	59.7	59.8
Puunene_6923	59.8	59.9	59.8	59.8	59.9	59.9	59.8	59.8
Waiinu_6923	59.8	59.6	59.8	59.7	59.7	59.7	59.8	59.7
Maa-Lahaluna	59.8	59.8	59.8	59.6	59.9	59.8	59.8	59.5
Maa-KWP	59.6	59.6	59.6	59.4	59.8	59.8	59.5	59.4
Maa-Puunene	59.1	59.9	58.9	59.2	59.6	59.8	59.2	59.1
Maa-Kihei	59.8	59.9	59.8	59.7	60.0	59.9	59.7	59.6
Kanaha-Puunene	59.8	59.8	59.8	59.8	59.9	59.9	59.8	59.9
Lahaina-Lahaluna	59.1	59.5	59.1	59.3	59.6	59.8	59.3	59.3
	Stage 1	Stage 2	Stage 3					

Table D-7. 2015 Stability Results: 10 MW PV that Trips at 59.3 Hz

The minimum frequency improved with the lower PV levels, but was not enough to prevent the second stage of load shedding.

We studied the impact that a direct transfer trip would have on the minimum system frequency in 2015. In this scenario, the unit breaker was used to directly trip the first stage of UFLS instead of relying on frequency decay to initiate the trip. The results of these simulations are shown below in Table D-8.

	Day Min				Day Peak			
	wnd_sun	wnd_cld	clm_sun	clm_cld	wnd_sun	wnd_cld	clm_sun	clm_cld
Outage	Min	Min	Min	Min	Min	Min	Min	Min
M14	59.5	59.7	59.5	59.7	59.6	59.7	59.7	59.8
MGS10						59.8		59.8
M16	59.5	59.7	59.5	59.7	59.7	59.7	59.7	59.8
HC&S	59.7	59.8	59.7	59.8	59.7	59.8	59.8	59.8
M15	59.8	59.8	59.8	59.8	59.8	59.9	59.8	59.8
AWF		59.8			59.8	59.8		
KWP		59.2			58.5	59.5		
	Stage 1	Stage 2	Stage 3					

Table D-8. 2015 Stability Results: 12 MW PV that Trips at 59.3 Hz; Transfer Trip Stage 1

With the transfer trip of stage 1, the second stage of load shedding can be avoided. If the transfer trip could be enabled for the loss of any of the combustion turbines, or the KWP plant, the system would meet the reliability criteria.

YEAR 2016 ANALYSIS

Power flow cases were created for the day minimum and day peak load times. The day minimum cases used a load of 138 MW, with renewable generation resources consisting of 90 MW of distributed PV (12 MW legacy PV) and 72 MW of wind. The day peak cases used a load of 186 MW.

The assumptions used for the 2016 cases are listed below:

- These cases assume that 12 MW of PV has legacy trip settings (59.3 60.5 Hz), all other PV has extended ride through. Sensitivity cases run with 10 MW
- KPP 3, KPP 4, and DTCC1 are baseloaded
- Existing protection clearing times were used
- No curtailment of DG resources

2016 Generation Dispatches

As for the 2015 cases, only the daytime cases were run for 2016. The loss of legacy PV due to under-frequency trip settings will worsen the unit trip scenarios, and the PV will also reduce the net load on each stage of load shed. For line fault conditions, it is critical that the legacy PV be limited to only 12 MW of PV for over frequency conditions. With DTCC1, KPP 3, KPP 4 online, the wind must be curtailed for the daytime minimum cases. Details of the generation dispatches for the 2016 study year are shown in Table D-9.

2016								
	Daytime Minimum Load Level				Daytime Peak Load Level			
Wind Level	Windy	Windy	Calm	Calm	Windy	Windy	Calm	Calm
Solar Gen (Cap)	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0
Curtailed Solar	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Solar Gen (MW)	76.5	9.0	76.5	9.0	76.5	9.0	76.5	9.0
KPP 1								
KPP 2								
KPP 3	3.5	7.0	7.5	10.0	5.0	9.0	11.0	10.5
KPP 4	3.5	7.0	7.5	10.0	5.0	9.0	11.0	10.5
MPP 14	8.4	14.7	15.0	16.2	10.0	17.0	13.6	18.8
MPP 15	4.0	6.0	6.0	12.0	5.0	7.5	7.0	13.0
MPP 16	8.4	14.8	15.0	18.0	10.0	17.0	15.0	19.5
MPP 17				19.0		17.0	17.0	19.5
MPP 18				12.0		6.0	8.0	12.0
MPP 19				19.0				19.0
HC&S	8.0	8.0	8.4	12.0	8.5	11.0	12.0	12.0
MPP 10						11.5	12.0	12.0
MPP 11								12.0
MPP 12								12.0
MPP 13								
MPP 4								5.5
MPP 6								
MPP 8								
MPP 9								
Wind Total	23.0	72.0	0.0	0.0	64.5	72.0	0.0	0.0
Load	135.3	138.5	135.9	137.2	184.5	186.0	183.1	185.3
Reg Up	52.2	30.5	28.6	15.6	44.5	22.6	21.0	7.0
Reg Down	4.8	26.5	28.4	55.4	12.5	47.6	46.2	78.0

Table D-9. 2016 Dispatch Cases

The minimum frequency results for 2016 are shown below in Table D-10.

2016 Results

	Day Min				Day Peak			
	wnd_sun	wnd_cld	clm_sun	clm_cld	wnd_sun	wnd_cld	clm_sun	clm_cld
Outage	Min	Min	Min	Min	Min	Min	Min	Min
M14	59.7	59.5	59.5	59.6	59.7	59.5	59.6	59.6
MGS10						59.7	59.6	59.7
M16	59.7	59.5	59.5	59.5	59.7	59.5	59.6	59.6
HC&S	59.7	59.7	59.7	59.6	59.7	59.7	59.6	59.7
M15	59.8	59.8	59.8	59.7	59.8	59.8	59.8	59.7
AWF		59.7			59.7	59.7		
KWP	58.7	58.6			58.5	59.0		
Kanaha_6923	59.8	59.7	59.8	59.7	59.8	59.9	59.8	59.8
Puunene_6923	59.9	59.9	59.9	59.8	59.9	59.9	59.8	59.8
Waiinu_6923	59.7	59.4	59.8	59.7	59.6	59.7	59.8	59.7
Maa-Lahaluna	60.0	59.7	59.8	59.6	59.8	59.9	59.7	59.6
Maa-KWP	60.0	59.5	59.7	59.4	59.8	59.9	59.4	59.4
Maa-Puunene	59.9	59.8	59.5	59.2	59.8	59.8	59.1	59.1
Maa-Kihei	60.0	59.7	59.8	59.7	59.9	60.0	59.8	59.6
Kanaha-Puunene	59.8	59.6	59.9	59.8	59.7	59.9	59.8	59.9
Lahaina-Lahaluna	59.6	59.6	59.3	59.2	59.6	59.8	59.3	59.3
	Stage 1	Stage 2	Stage 3					

Table D-10. 2016 Stability Results - 12 MW PV that Trips at 59.3 Hz

The loss of the KWP plant can result in stage 2 load shedding for the high PV/ minimum daytime load condition.

The impact of reducing the legacy PV to only 10 MW is shown in Table D-11.

	Day Min				Day Peak			
	wnd_sun	wnd_cld	clm_sun	clm_cld	wnd_sun	wnd_cld	clm_sun	clm_cld
Outage	Min	Min	Min	Min	Min	Min	Min	Min
M14	59.7	59.5	59.5	59.6	59.7	59.5	59.6	59.6
MGS10						59.7	59.6	59.7
M16	59.7	59.5	59.5	59.5	59.7	59.5	59.6	59.6
HC&S	59.7	59.7	59.7	59.6	59.7	59.7	59.6	59.7
M15	59.8	59.8	59.8	59.7	59.8	59.8	59.8	59.7
AWF		59.7			59.7	59.7		
KWP	58.7	58.6			58.5	59.0		
Kanaha_6923	59.8	59.7	59.8	59.7	59.8	59.9	59.8	59.8
Puunene_6923	59.9	59.9	59.9	59.8	59.9	59.9	59.8	59.8
Waiinu_6923	59.7	59.4	59.8	59.7	59.6	59.7	59.8	59.7
Maa-Lahaluna	60.0	59.7	59.8	59.6	59.8	59.9	59.7	59.6
Maa-KWP	60.0	59.5	59.7	59.4	59.8	59.9	59.4	59.4
Maa-Puunene	59.9	59.8	59.5	59.2	59.8	59.8	59.1	59.2
Maa-Kihei	60.0	59.7	59.8	59.7	59.9	60.0	59.8	59.6
Kanaha-Puunene	59.8	59.6	59.9	59.8	59.7	59.9	59.8	59.9
Lahaina-Lahaluna	59.6	59.6	59.3	59.2	59.6	59.8	59.3	59.3
	Stage 1	Stage 2	Stage 3					

Table D-11. 2016 Stability Results: 10 MW PV that Trips at 59.3 Hz

The minimum frequency did improve with the lower PV and was able to prevent the second stage of load shedding.

In order to prevent the second stage of load shedding for the loss of a generation unit, we studied the impact that a direct transfer trip would have on the minimum system frequency in 2016. The results of these simulations are shown below in Table D-12.

	Day Min				Day Peak			
	wnd_sun	wnd_cld	clm_sun	clm_cld	wnd_sun	wnd_cld	clm_sun	clm_cld
Outage	Min	Min	Min	Min	Min	Min	Min	Min
M14	59.5	59.7	59.5	59.7	59.6	59.7	59.7	59.8
MGS10						59.8		59.8
M16	59.5	59.7	59.5	59.7	59.7	59.7	59.7	59.8
HC&S	59.7	59.8	59.7	59.8	59.7	59.8	59.8	59.8
M15	59.8	59.8	59.8	59.8	59.8	59.9	59.8	59.8
AWF		59.8			59.8	59.8		
KWP		59.2			58.7	59.5		
	Stage 1	Stage 2	Stage 3					

Table D-12. 2016 Stability Results: 12 MW PV that Trips at 59.3 Hz; Transfer Trip Stage 1

With the transfer trip the second stage of load shedding can be avoided with 12 MW PV that trips at 59.3 Hz. The transfer trip should be enabled for the loss of any of the combustion turbines, or the KWP plant.

YEAR 2017 ANALYSIS

Power flow cases were created for the minimum, day minimum, day peak, and peak load times. Renewable generation resources consist of 96 MW of distributed PV (10 MW legacy PV) and 72 MW of wind.

The year 2017 was selected for analysis due to the large jump in PV between 2015 and 2017, without additional security reserves or dispatchable generation added to counter the increase.

The assumptions used for the 2017 cases are listed below:

- These cases assume that 10 MW of PV has legacy trip settings, all other PV has extended ride through.
  - Sensitivity cases run with 10 MW
- KPP 3, KPP 4, DTCC1, and ½ DTCC2 are baseloaded
  - Sensitivity cases were run without ½ DTCC2 baseloaded
  - Sensitivity cases were run without KPP 3 and KPP 4 baseloaded (mimics 2019 case)
  - Sensitivity cases were run with only DTCC1 baseloaded
- Upgraded protection times were used such that all faults are cleared in 5 cycles
- PV installed after the beginning of 2015 can be curtailed
- DTCC1 minimum generation is reduced to allow more renewable generation

2017 Generation Dispatches

With KPP 3, KPP 4, DTCC1, and ½ DTCC2 online, the wind must be curtailed for the daytime minimum cases. Details of the generation dispatches for the 2017 study year are shown in Table D-13.

2017												
	Minimum		Daytime Minimum Load				Daytime Peak Load Level				Peak Load	
Wind Level	Windy	Calm	Windy	Windy	Calm	Calm	Windy	Windy	Calm	Calm	Windy	Calm
Solar Gen (Cap)	0.0	0.0	81.6	9.6	81.6	9.6	81.6	9.6	81.6	9.6	0.0	0.0
Curtailed Solar			34.0	4.0			11.5					
Solar Gen (MW)			47.6	5.6	81.6	9.6	70.1	9.6	81.6	9.6		
KPP 1												
KPP 2												
KPP 3	3.5	8.0	3.5	3.5	7.0	11.0	3.5	9.0	10.0	11.0	11.0	11.5
KPP 4	3.5	8.0	3.5	3.5	7.0	11.0	3.5	9.0	10.0	11.0	11.0	11.5
MPP 14	9.0	18.3	8.9	13.1	8.7	17.7	8.7	16.5	13.9	18.8	17.5	19.7
MPP 15	4.0	12.0	4.0	6.5	5.0	12.0	4.0	8.0	7.0	12.0	8.0	12.0
MPP 16	9.0	18.2	9.0	13.0	9.5	18.0	9.0	16.5	13.9	18.5	17.5	20.0
MPP 17	14.4	18.0	14.5	16.0	16.0	19.0	14.5	17.0	17.0	19.0	18.0	20.0
MPP 18	4.5	7.0	4.1	5.0	5.0	12.0	4.5	8.0	8.0	10.5	9.0	12.0
MPP 19						19.0		17.0	17.0	19.0	18.0	20.0
HC&S												
MPP 10				12.0		12.0		9.0	10.0	12.0	10.0	12.0
MPP 11										12.0	10.0	12.0
MPP 12										12.0		12.0
MPP 13										12.0		12.0
MPP 4										5.5		5.5
MPP 6										5.5		5.5
MPP 8												5.4
MPP 9												5.4
MPP 1										2.5	2.5	2.5
MPP 2												2.5
MPP 3												2.5
Wind Total	42.0	0.0	46.0	64.5	0.0	0.0	72.0	72.0	0.0	0.0	72.0	0.0
Load	89.9	89.5	141.1	142.7	139.8	141.3	189.8	191.6	188.4	190.9	204.5	204.0
Reg Up	57.4	15.8	55.8	43.0	45.1	12.4	55.6	31.1	34.3	10.4	26.5	6.6
Reg Down	6.4	48.0	6.0	23.2	16.7	59.0	6.2	37.3	31.1	78.8	47.5	90.5

Table D-13. 2017 Dispatch Cases

With KPP 3, KPP 4, DTCC1, and ½ DTCC2 online, the wind and solar must be curtailed for the daytime minimum cases.

We also created some sensitivity dispatch cases that did not have KPP 3 and KPP 4 online. These cases were created to mimic the 2017 system response to the loss of a generating unit. It is noted that the 2017 cases do not have the transmission upgrades necessary to deal with the steady state overload and voltage concerns related to the loss of a transmission line. The cases were only created for the minimum and daytime minimum cases when the baseload assumption changes the dispatch scenarios. These sensitivity case dispatches are shown below in Table D-14 through D-16.

2017 - KPP Not Baseloaded						
	Minimum Load Level		Daytime Minimum Load Level			
Wind Level	Windy	Calm	Windy	Windy	Calm	Calm
Solar Gen (Cap)	0.0	0.0	81.6	9.6	81.6	9.6
Curtailed Solar			34.0			
Solar Gen (MW)			47.6	9.6	81.6	9.6
MPP 14	8.9	19.4	9.4	13.2	15.3	18.3
MPP 15	4.0	12.0	4.0	6.5	7.0	12.0
MPP 16	8.0	19.5	9.0	13.0	15.0	18.0
MPP 17	14.4	19.0	14.5	16.0	16.0	19.0
MPP 18	4.5	7.5	4.1	5.0	5.0	12.0
MPP 19						19.0
HC&S						
MPP 10		12.3		12.0		12.0
MPP 11						11.0
MPP 12						11.0
MPP 13						
Wind Total	51.0	0.0	53.0	67.5	0.0	0.0
Load	90.8	89.7	141.6	142.8	139.9	141.9
Reg Up	42.5	5.9	39.3	26.9	28.0	13.5

Table D-14. 2017 Dispatch Cases - KPP Not Baseloaded

2017 - DTCC2 Not Baseloaded						
	Minimum Load Level		Daytime Minimum Load Level			
Wind Level	Windy	Calm	Windy	Windy	Calm	Calm
Solar Gen (Cap)	0.0	0.0	81.6	9.6	81.6	9.6
Curtailed Solar			34.0	4.0		
Solar Gen (MW)			47.6	5.6	81.6	9.6
KPP 1						
KPP 2						
KPP 3	3.5	8.0	3.5	3.5	9.0	11.0
KPP 4	3.5	8.0	3.5	3.5	9.0	11.0
MPP 14	8.6	18.3	9.5	13.1	11.4	17.7
MPP 15	3.7	12.0	4.0	6.5	5.5	12.0
MPP 16	8.5	18.2	9.0	13.0	11.4	18.0
MPP 17		18.0		16.0		19.0
MPP 18		7.0		5.0		12.0
MPP 19						19.0
HC&S					12.0	
MPP 10				12.0		12.0
MPP 11						
MPP 12						
MPP 13						
Wind Total	63.0	0.0	64.5	64.5	0.0	0.0
Load	90.8	89.5	141.6	142.7	139.9	141.3
Reg Up	50.2	15.8	46.5	43.0	29.7	12.4
Reg Down	4.8	48.0	6.5	23.2	27.3	59.0

Table D-15. 2017 Dispatch Cases: DTCC2 Not Baseloaded

2017 - DTCC1 Only Baseloaded Unit						
	Minimum Load Level		Daytime Minimum Load Level			
Wind Level	Windy	Calm	Windy	Windy	Calm	Calm
Solar Gen (Cap)	0.0	0.0	81.6	9.6	81.6	9.6
Curtailed Solar			21.7			
Solar Gen (MW)			59.9	9.6	81.6	9.6
KPP 1						
KPP 2						
KPP 3						
KPP 4						
MPP 14	9.1	19.4	8.6	13.2	15.3	18.3
MPP 15	3.5	12.0	3.5	6.5	7.0	12.0
MPP 16	8.0	19.5	8.0	13.0	15.0	18.0
MPP 17		19.0		16.0	16.0	19.0
MPP 18		7.5		5.0	5.0	12.0
MPP 19						19.0
HC&S						
MPP 10		12.3		12.0		12.0
MPP 11						11.0
MPP 12						11.0
MPP 13						
Wind Total	70.5	0.0	61.5	67.5	0.0	0.0
Load	91.1	89.7	141.5	142.8	139.9	141.9
Reg Up	34.4	5.9	32.9	26.9	28.0	13.5
Reg Down	4.6	47.3	4.1	23.3	23.8	50.9

Table D-16. 2017 Dispatch Cases: Only DTCC1 Baseloaded

In order to define the boundary conditions an additional dispatch case was created for each of the sensitivity cases listed above based on the baseloaded units. These dispatch cases are shown below in Table D-17.

2017 - Boundary Definition Cases				
	Day Peak	Day Minimum Load Level		
Wind Level	Windy	Windy	Windy	Windy
Solar Gen (Cap)	81.6	81.6	81.6	81.6
Curtailed Solar	34.0	34.0	34.0	23.0
Solar Gen (MW)	47.6	47.6	47.6	58.6
KPP 1				
KPP 2				
KPP 3	11.5	9.0		
KPP 4	11.5	9.0		
MPP 14	18.4	16.5	16.2	19.0
MPP 15	13.0	11.0	8.0	13.0
MPP 16	20.0	17.5	17.0	20.0
MPP 17	20.0		17.0	
MPP 18	7.1		5.0	
MPP 19				
HC&S				
Wind Total	40.3	30.0	30.0	30.0
Load	189.4	140.6	140.8	140.6
Reg Up	1.8	13.0	17.0	1.0
Reg Down	60.0	40.0	28.7	36.0

Table D-17. 2017 Dispatch Cases: Boundary Definition

The first column of Table D-17 shows the boundary case with KPP3, KPP4, DTCC1, and ½ DTCC2 baseloaded. The second column shows the boundary case without DTCC2. The third column lists the boundary case without KPP, and the last column has only DTCC1. These boundary cases were setup to determine the contingency reserves required to prevent stage 2 load shedding without relying on thermal generation.

2017 Results

The contingencies were simulated for each of the dispatch cases listed in Table D-13 through Table D-17. Table D-18 shows the simulation results with KPP3, KPP4, DTCC1, and ½ DTCC2 baseloaded.

	Minimum		Daytime Minimum				Daytime Peak				Peak	
	Windy	Calm	Windy	Windy	Calm	Calm	Windy	Windy	Calm	Calm	Windy	Calm
			Sun	Cld	Sun	Cld	Sun	Cld	Sun	Cld		
Outage	Min	Min	Min	Min	Min	Min	Min	Min	Min	Min	Min	Min
M14	59.7	59.3	59.7	59.6	59.7	59.5	59.7	59.6	59.6	59.6	59.6	59.6
MGS10				59.6		59.7		59.7	59.7	59.7	59.7	59.7
M16	59.7	59.3	59.7	59.6	59.7	59.5	59.7	59.6	59.6	59.6	59.6	59.6
HC&S												
M15	59.8	59.6	59.8	59.8	59.8	59.7	59.9	59.8	59.8	59.7	59.8	59.7
AWF	60.0		59.8	59.7			59.7	59.7			59.7	
KWP	59.2		58.8	58.9			58.6	59.1			59.2	
Kanaha_6	59.5	59.8	59.5	59.6	59.8	59.7	59.4	59.8	59.8	59.8	59.8	59.8
Puunene_	59.9	59.8	59.9	59.9	59.9	59.7	59.9	59.8	59.8	59.8	59.8	59.8
Waiinu_6	59.4	59.7	59.4	59.5	59.8	59.7	59.3	59.8	59.8	59.7	59.8	59.7
Maa-Laha	59.7	59.7	59.7	59.7	59.8	59.6	59.3	60.0	59.7	59.5	60.0	59.5
Maa-KWP	59.7	59.7	59.7	59.7	59.7	59.6	59.4	60.0	59.7	59.5	60.0	59.5
Maa-Kihe	59.7	59.7	59.7	59.8	59.7	59.6	59.5	60.0	59.7	59.6	60.0	59.6
Kanaha-P	59.6	59.8	59.6	59.6	59.9	59.8	59.5	59.9	59.8	59.9	59.9	59.9
Lahaina-L	59.5	59.9	59.5	59.5	59.9	59.8	59.3	59.7	59.8	59.9	59.8	59.9
	Stage1	Stage2	Stage3									

Table D-18. Minimum Frequency Results with KPP 3, KPP 4, DTCC1 and ½ DTCC2 Baseloaded

Table D-18 shows that stage 2 of load shedding can be averted without any additional contingency reserves as long as Maui Electric adheres to the HSIS regulating reserve requirements. Stage 2 was not used even with the boundary case dispatch. The high frequencies encountered in these simulations indicate that if the HSIS regulation requirement is met during all periods of the day, the regulation requirement is larger than the contingency requirement.

Table D-19 shows the minimum frequency results for the 2017 cases without the KPP 3 and KPP4 units baseloaded.

	0 MW BESS						10 MW BESS					
	Minimum		Daytime Minimum				Minimum		Daytime Minimum			
	Windy	Calm	Windy	Windy	Calm	Calm	Windy	Calm	Windy	Windy	Calm	Calm
			Sun	Cld	Sun	Cld			Sun	Cld	Sun	Cld
Outage	Min	Min	Min	Min	Min	Min	Min	Min	Min	Min	Min	Min
M14	59.6	58.6	59.5	59.5	59.3	59.5	59.6	59.4	59.6	59.6	59.4	59.6
MGS10		59.5		59.5		59.6		59.6		59.6		59.7
M16	59.6	58.6	59.6	59.5	59.3	59.5	59.7	59.4	59.6	59.6	59.4	59.6
HC&S												
M15	59.8	59.6	59.8	59.8	59.7	59.7	59.8	59.7	59.8	59.8	59.7	59.7
AWF	59.5		59.5	59.6			59.6		59.6	59.7		
KWP	58.4		58.1	58.5			58.9		58.6	59.1		
Kanaha_6923	59.4	59.8	59.4	59.6	59.8	59.8	59.4	59.8	59.4	59.5	59.9	59.8
Puunene_6923	59.9	59.8	59.9	59.9	59.8	59.8	59.9	59.8	59.9	59.9	59.9	59.8
Waiinu_6923	59.4	59.7	59.4	59.5	59.8	59.7	59.4	59.7	59.4	59.4	59.9	59.7
Maa-Lahaluna	60.0	59.7	60.0	60.0	59.6	59.6	60.0	59.8	59.9	60.0	59.5	59.8
Maa-KWP	60.0	59.7	60.0	60.0	59.6	59.6	60.0	59.8	59.9	60.0	59.5	59.8
Maa-Kihei	60.0	59.8	60.0	60.0	59.6	59.7	60.0	59.8	60.0	60.0	59.5	59.8
Kanaha-Puunene	59.5	59.9	59.5	59.6	59.9	59.9	59.5	59.9	59.4	59.5	59.9	59.9
Lahaina-Lahaluna	59.5	59.9	59.5	59.5	59.8	59.8	59.5	59.9	59.4	59.5	59.9	59.9
	Stage1	Stage2	Stage3									

Table D-19. Minimum Frequency Results with DTCC1 and ½ DTCC2 Baseloaded

Table D-19 shows the minimum frequency results for the sensitivity cases without KPP 3 and KPP 4. The loss of the KWP generation causes the frequency to decay below the stage 2 trip settings. In order to prevent the second stage of load shedding, 10 MW of BESS was added to the simulation. The minimum frequency results with a 10 MW BESS are shown on the right side of Table D-19.

Similar analysis was performed assuming that the DTCC2 would not be baseloaded. The results are shown in Table D-20.

	0 MW BESS						10 MW BESS					
	Minimum		Daytime Minimum				Minimum		Daytime Minimum			
	Windy	Calm	Windy	Windy	Calm	Calm	Windy	Calm	Windy	Windy	Calm	Calm
			Sun	Cld	Sun	Cld			Sun	Cld	Sun	Cld
Outage	Min	Min	Min	Min	Min	Min	Min	Min	Min	Min	Min	Min
M14	59.7	59.3	59.6	59.6	59.6	59.5	59.7	59.6	59.7	59.7	59.7	59.6
MGS10				59.6		59.7				59.7		59.7
M16	59.7	59.3	59.7	59.6	59.6	59.5	59.8	59.5	59.7	59.7	59.7	59.6
HC&S					59.6						59.6	
M15	59.9	59.6	59.8	59.8	59.8	59.7	59.9	59.7	59.9	59.8	59.8	59.7
AWF	59.6		59.6	59.7			59.7		59.7	59.7		
KWP	58.5		58.2	58.9			59.0		58.7	59.3		
Kanaha_6923	59.4	59.8	59.3	59.6	59.8	59.7	59.3	59.8	59.3	59.6	59.9	59.8
Puunene_6923	59.8	59.8	59.8	59.9	59.9	59.7	59.8	59.8	59.8	59.9	59.9	59.8
Waiinu_6923	59.3	59.7	59.3	59.5	59.9	59.7	59.3	59.7	59.3	59.5	59.9	59.7
Maa-Lahaluna	59.4	59.7	59.6	59.7	59.8	59.6	59.1	59.7	59.1	59.8	59.8	59.5
Maa-KWP	59.4	59.7	59.6	59.7	59.8	59.6	59.1	59.7	59.3	59.8	59.8	59.5
Maa-Kihei	59.5	59.7	59.6	59.8	59.8	59.6	59.3	59.7	59.3	59.8	59.8	59.6
Kanaha-Puunene	59.4	59.8	59.3	59.6	59.9	59.8	59.4	59.9	59.3	59.6	59.9	59.9
Lahaina-Lahaluna	59.3	59.9	59.3	59.5	59.9	59.8	59.3	59.9	59.3	59.5	59.9	59.9
	Stage1	Stage2	Stage3									

Table D-20. Minimum Frequency Results with KPP3, KPP4, and DTCC1 Baseloaded

Table D-20 shows the minimum frequency results for the sensitivity cases without DTCC2. The loss of the KWP generation causes the frequency to decay below the stage 2 trip settings. In order to prevent the second stage of load shedding, 10 MW of BESS was added to the simulation. The minimum frequency results with a 10 MW BESS are shown on the right side of Table D-20.

Similar analysis was performed assuming that only DTCC1 would be baseloaded. The results are shown in Table D-21.

	0 MW BESS						20 MW BESS					
	Minimum		Daytime Minimum				Minimum		Daytime Minimum			
	Windy	Calm	Windy	Windy	Calm	Calm	Windy	Calm	Windy	Windy	Calm	Calm
			Sun	Cld	Sun	Cld			Sun	Cld	Sun	Cld
Outage	Min	Min	Min	Min	Min	Min	Min	Min	Min	Min	Min	Min
M14	59.4	58.6	59.4	59.5	59.3	59.5	59.6	59.5	59.6	59.6	59.5	59.7
MGS10		59.5		59.5		59.6		59.6		59.7		59.7
M16	59.6	58.6	59.5	59.5	59.3	59.5	59.7	59.5	59.7	59.7	59.5	59.6
HC&S												
M15	59.8	59.6	59.8	59.8	59.7	59.7	59.9	59.7	59.9	59.8	59.8	59.8
AWF	59.4		59.4	59.6			59.6		59.6	59.7		
KWP	57.9		57.3	58.5			58.8		58.8	59.3		
Kanaha_6923	58.9	59.8	59.1	59.6	59.8	59.8	58.9	59.8	59.1	59.5	59.9	59.8
Puunene_6923	59.7	59.8	59.7	59.9	59.8	59.8	59.7	59.8	59.7	59.9	59.9	59.8
Waiinu_6923	58.9	59.7	59.1	59.5	59.8	59.7	58.9	59.8	59.1	59.4	59.8	59.8
Maa-Lahaluna	59.8	59.7	59.8	60.0	59.6	59.6	59.9	59.5	59.4	59.9	59.4	59.7
Maa-KWP	59.8	59.7	59.8	60.0	59.6	59.6	59.9	59.5	59.4	59.9	59.4	59.7
Maa-Kihei	59.9	59.8	59.8	60.0	59.6	59.7	59.9	59.5	59.5	59.9	59.4	59.7
Kanaha-Puunene	58.9	59.9	59.1	59.6	59.9	59.9	58.9	59.9	59.1	59.5	59.9	59.9
Lahaina-Lahaluna	58.9	59.9	59.1	59.5	59.8	59.8	59.0	59.8	59.1	59.5	59.8	59.9
	Stage1	Stage2	Stage3									

Table D-21. Minimum Frequency Results with Only DTCC1 Baseloaded

Table D-21 shows the minimum frequency results for the sensitivity cases with only DTCC1 baseloaded. The loss of the KWP generation causes the frequency to decay below the stage 3 trip settings. In order to prevent the second stage of load shedding, 20 MW of BESS was added to the simulation. The minimum frequency results with a 20 MW BESS are shown on the right side of Table D-21.

The worst case contingency for the boundary cases was also the loss of the KWP plant at full output. With minimum reserve on the generation units, the minimum frequency was much lower for these dispatch cases. The minimum frequency for the loss of the KWP plant at full output with several levels of additional BESS support is shown in Table D-22.

	Baseloaded Units	DTCC1 KPP3,KPP4 1/2 DTCC2	DTCC1 KPP3,KPP4	DTCC1 1/2 DTCC2	DTCC1
Additional BESS	0 MW	58.6	57.7	57.7	38.6
	5 MW	58.7	58	58.1	45.6
	10 MW	59.3	58.4	58.4	53.2
	15 MW	59.4	58.7	58.7	57.8
	20 MW	59.4	59.3	59.1	58.3
	25 MW	59.5	59.3	59.2	58.7

Table D-22. Minimum Frequency Results for Boundary Cases

The results from Table D-22 define the contingency reserve requirement for the 2017 year as 20 MW of additional BESS being required to prevent Stage 2 UFLS.

YEAR 2023 ANALYSIS

Power flow cases were created for the peak load times. The 2023 year was selected to identify the operating restrictions required to prevent line overloads and low voltage conditions for the peak load in the study time frame. The year has the addition of several new generation units added between 2019 and 2023 and can be used to judge the security of the 2019-2023 period. The peak load is 218.5 MW in 2023 and will drop to 206.3 MW in 2030.

The assumptions used for the 2023 cases are in the list below:

- These cases assume that the Kamalii line upgrade does not take place
  - Sensitivity cases were run with the line upgrade to confirm that the upgrade resolves the low voltage issues
- The Wai'inu–Kanaha line upgrade is included in all cases
- The MPP–Pu'unene and MPP: Wai'inu lines are reconductored in all cases
- Only the peak loading case was studied
- Only steady state analysis was performed

2023 Generation Dispatches

Only the peak cases were run for 2023 since it has the highest peak load in the study time frame. Details of the generation dispatches for the 2023 study year are shown in Table D-23.

2023			
	Peak Load Level		
Wind Level	Windy	Calm	Windy
MPP 14	17.7	19.2	18.0
MPP 15	8.0	11.5	11.5
MPP 16	17.7	19.0	19.0
MPP 17	17.5	20.0	20.0
MPP 18	9.0	12.0	12.0
MPP 19	18.0	20.0	20.0
HC&S			8.0
MPP 10	10.0	12.0	12.0
MPP 11	10.0	12.0	12.0
MPP 12	10.0	12.0	12.0
MPP 13	10.0	12.0	12.0
MPP 4		5.4	5.4
MPP 6		5.4	
MPP 8		5.4	
MPP 9		5.4	
MPP 1	2.5	2.5	2.5
MPP 2	2.5	2.5	2.5
MPP 3		2.5	
WPP ICE 1	7.5	8.0	8.0
WPP ICE 2		8.0	8.0
WPP ICE 3		8.0	8.0
S.Maui ICE 1			
S.Maui ICE 2			
S.Maui ICE 3			
Wind Total	72.0	0.0	36.0
Load	220.4	218.8	226.9
Reg Up	31.6	10.8	15.0
Reg Down	47.5	100.8	77.9

Table D-23. 2023 Peak Generation Dispatch

Each of the 2023 peak cases listed in Table D-23 do not have generation online in South Maui in order to stress the transmission around the South Maui area. The third dispatch was setup as a boundary case that mirrors previous studies performed for Maui Electric and has a system load that is 3% higher than predicted for 2023.

2023 Results

The MPP–Kihei outage is the critical contingency without the new Maʻalaea–Kamalii line. The loss of this line will cause low voltages, line overloads, and potential voltage collapse in the South Maui area.

Figure D-1 shows the impact that this outage has on the South Maui transmission system with the MPP–Kihei outage.

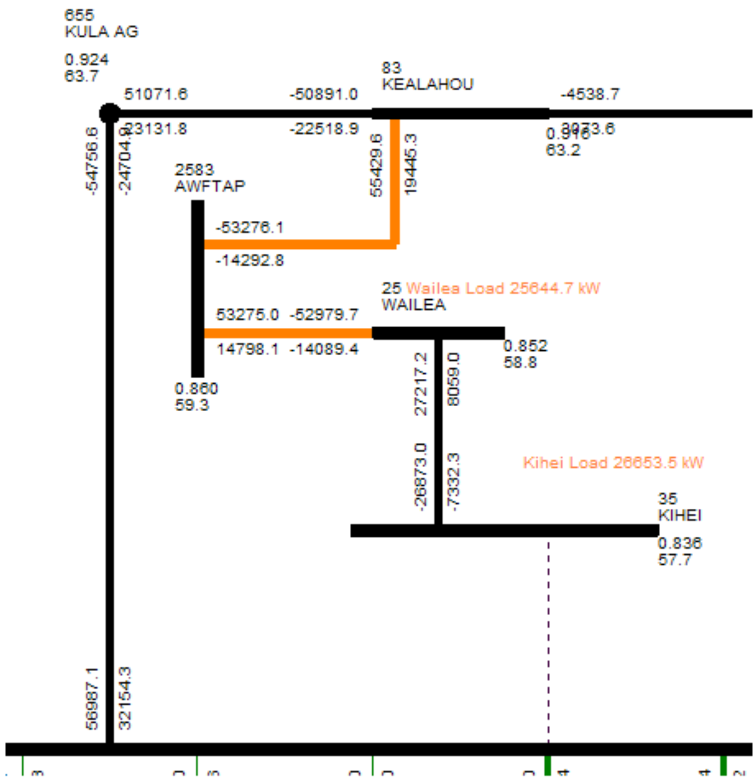

Figure D-1. MPP - Kihei Outage - Boundary Case

With the MPP–Kihei line out of service, the voltage at the Kihei bus is 0.836 pu, and is nearing voltage collapse. The Kealahou–AWFTAP and AWFTAP–Wailea lines are also overloaded. We studied this contingency with several load levels to determine the generation requirements needed in the South Maui area to prevent these low voltage and overload issues. The Kihei voltage remains above 0.90 for load levels below 173 MW with the loss of the MPP–Kihei line. Load levels above 173 MW require generation in South Maui. One 8 MW Wartsilla engine would be sufficient until the load level reaches 193 MW at which time a second unit would be required. When the load level reaches 223 MW, a third unit is required. Table D-24 shows the generation requirements in South Maui to prevent low voltages for various system load levels.

Description	# Units in South Maui to keep Kihei 69kV Voltage > 0.90	System Net Generation
With 7.2 MVAR of cap banks online, Peak Load 223	3	If System load >223
With 7.2 MVAR of cap banks online, High Load of 193	2	If System load >193
With 7.2 MVAR of cap banks online, Medium Load of 173	1	If System load >173
With 7.2 MVAR of cap banks online, Medium Load of 173	0	If System load <173

Table D-24. Generation Required in South Maui to Prevent Low Voltage

YEAR 2030 ANALYSIS

Power flow cases were created for the minimum, day minimum, day peak, and peak load times. Renewable generation resources consist of 130 MW of distributed PV (10 MW legacy PV) and 72 MW of wind. These focus on the generation associated with the Non-Transmission Alternatives which rely on firm generation in the South Maui area to relieve transmission constraints.

The assumptions used for the 2030 cases are in the list below:

- Cases with the Maʻalaea–Kamalii line addition were run
  - Non-Transmission Alternative cases were also run (NTA)
- NTA generation was run with Pumped Storage Hydro (PSH)
  - The use of 8 MW Wartsilla internal combustion engines was also analyzed
- DTCC1 and ½ DTCC2 are baseloaded
  - Sensitivity cases were run with only DTCC1 baseloaded
- Distributed generation was curtailed before the KWP1 plant since the KWP plant is the largest single generation contingency.

2030 Generation Dispatches

Table D-25 shows the dispatch cases created for the 2030 analysis.

	2030											
	Minimum Load Level		Daytime Minimum Load Level				Daytime Peak Load Level				Peak Load Level	
Wind Level	Windy	Calm	Windy	Windy	Calm	Calm	Windy	Windy	Calm	Calm	Windy	Calm
Solar Gen (Cap)	0.0	0.0	110.5	13.0	110.5	13.0	110.5	13.0	110.5	13.0	0.0	0.0
Curtailed Solar			62.9		6.0		31.5					
Solar Gen (MW)			47.6	13.0	104.5	13.0	79.0	13.0	110.5	13.0		
KPP 1												
KPP 2												
KPP 3												
KPP 4												
MPP 14	9.9	18.0	9.5	12.5	9.3	18.5	9.2	16.2	14.8	18.2	17.0	18.8
MPP 15	4.0	12.0	4.0	6.5	4.0	12.0	4.0	8.5	7.0	11.0	8.0	11.5
MPP 16	9.0	19.0	9.0	13.0	9.0	18.0	10.0	16.5	14.8	18.0	17.0	19.0
MPP 17	14.4	18.0	14.5	14.5	14.5	18.0	14.5	17.0	15.5	19.0	18.0	20.0
MPP 18	4.5	7.0	4.1	4.5	4.1	10.0	4.5	8.0	5.0	10.5	9.0	12.0
MPP 19						18.0		17.0		19.0	18.0	20.0
HC&S												
MPP 10		10.0		12.0		10.0		9.0		12.0	10.0	12.0
MPP 11						11.0		9.0	9.0	11.0	10.0	12.0
MPP 12						11.0		9.0	9.0	11.0	10.0	12.0
MPP 13										11.0		12.0
MPP 4												5.4
MPP 6												
MPP 8												
MPP 9												
MPP 1											2.5	2.5
MPP 2												
MPP 3												
WPP ICE 1									6.0	8.0	7.5	8.0
WPP ICE 2										8.0		8.0
WPP ICE 3										8.0		8.0
S.Maui ICE 1		6.5				7.5				8.0	8.0	8.0
S.Maui ICE 2										8.0		8.0
S.Maui ICE 3												8.0
Wind Total	50.0	0.0	58.5	72.0	0.0	0.0	72.0	72.0	0.0	0.0	72.0	0.0
Load	91.8	90.5	147.2	148.0	145.4	147.0	193.2	195.2	191.6	193.7	207.0	205.2
Reg Up	40.5	10.6	39.2	29.6	39.4	16.3	38.1	32.6	32.2	16.5	30.1	11.4
Reg Down	7.3	41.6	6.6	20.6	6.4	45.1	6.7	28.8	25.5	79.9	44.5	95.8

Table D-25. Dispatch Cases with DTCC1 and ½ DTCC2 Baseloaded

Each of these dispatch cases adheres to the HSIS reserve requirements. We created some sensitivity cases to determine the defining boundary cases. These boundary definition dispatch cases are shown below in Table D-26.

2030								
	Minimum Load Level	Daytime Minimum Load Level			Daytime Peak Load Level		Boundary Case Dispatches	
Wind Level	Windy	Windy	Calm	Windy	Windy	Calm	Windy	Windy
Solar Gen (Cap)	0.0	130.0	130.0	13.0	130.0	130.0	130.0	130.0
Curtailed Solar		57.9			12.5		28.2	41.9
Solar Gen (MW)	0.0	52.6	110.5	13.0	98.0	110.5	82.3	68.6
MPP 14	10.6	9.6	9.4	19.5	9.0	20.0	19.9	20.0
MPP 15	4.0	4.0	4.0	13.0	4.0	12.0	13.0	13.0
MPP 16	9.0	9.0	9.0	19.6	10.0	19.5	20.0	20.0
MPP 17			12.4			20.0	20.0	
MPP 18						7.2	7.2	
MPP 19								
HC&S								
MPP 10								
MPP 11				11.0				
MPP 12								
MPP 13								
MPP 1						2.5		
MPP 2								
MPP 3								
Wind Total	68.0	72.0	0.0	72.0	72.0	0.0	30.0	72.0
Load	91.6	147.2	145.3	148.1	193.0	191.7	192.4	193.6
Reg Up	31.4	30.4	35.8	2.2	30.0	1.6	0.2	0.0
Reg Down	7.6	6.6	10.9	39.2	6.0	41.2	44.6	36.0

Table D-26. Dispatch Cases with DTCC1 Baseloaded and 2 Boundary Case Dispatch Cases

The dispatch cases listed in Table D-26 were created to show the impact that removing ½ DTCC2 from the baseload commitment would have on the system stability constraints. The 'Boundary Case Dispatches' were created to show the system response to a contingency assuming all regulating reserve is being carried by battery systems. One of the boundary case dispatches assumed that DTCC1 and ½ DTCC2 were baseloaded, while the other assumed that only DTCC1 was baseloaded.

Simulations were run to determine the size of the regulating reserves needed in addition to the currently installed BESS systems, to prevent the second stage of load shedding. If the system frequency dropped low enough to trigger stage 2 of load shedding, then additional regulating reserves were added in 5 MW increments until the frequency stayed above the stage 2 load shedding setpoint.

2030 Results

The worst case event for each of the dispatch cases simulated was the loss of the KWP unit at maximum output. Since two alternatives for the non-transmission alternative were studied, the pumped storage hydro results are shown because this alternative has a slightly worse frequency response, but does not change the conclusions related to the size of BESS necessary to prevent stage 2 load shedding. Table D-27 and Table D-28 below show the minimum frequency results for the loss of the KWP plant.

Loss of KWP					
Case	Thermal Reserve	0 MW BESS	5 MW BESS	10 MW BESS	*Stage 1
m_wnd	40.5	58.4	58.6	59.7	*Stage 2
m_clm	10.6	-	-	-	
dm_wnd_sun	39.2	58.1	58.4	58.5	
dm_wnd_cld	29.6	58.6	58.7	58.9	
dm_clm_sun	39.4	-	-	-	
dm_clm_cld	16.3	-	-	-	
dp_wnd_sun	38.1	58.2	58.4	58.5	
dp_wnd_cld	32.6	59.1	59.2	59.2	
dp_clm_sun	32.2	-	-	-	
dp_clm_cld	16.5	-	-	-	
p_wnd	30.1	59.2	59.3	59.3	
p_clm	11.4	-	-	-	

Table D-27. Minimum Frequency for Loss of KWP: DTCC1 + ½ DTCC2 (Thermal Reserves)

Loss of KWP					
	Thermal Reserve	10 MW BESS	15 MW BESS	20 MW BESS	*Stage 1
m_wnd	31.4	58.4	58.7	58.9	*Stage 2
dm_wnd_sun	30.4	58.2	58.5	58.8	
dm_wnd_cld	35.8	58.5	58.9	59.1	
dm_clm_sun	-	-	-	-	
dp_wnd_sun	30	58.1	58.5	58.8	
dp_wnd_cld	1.6	58.7	59.2	59.3	

Table D-28. Minimum Frequency for Loss of KWP: DTCC1 Only (Thermal Reserves)

With reserves carried on the thermal units, a BESS system is still required to prevent the second stage of load shedding. From Table D-27, 49.2 MW contingency reserves (39.2 MW thermal reserves + 10 MW BESS) are required to prevent stage 2 for the dm_wnd_sun dispatch case. When DTCC1 is the only thermal unit online, the total contingency reserves required is approximately 50.4 MW (30.4 MW thermal reserves + 20 MW BESS). If ½ of DTCC2 is online, the additional BESS support can be reduced to 10 MW but would have additional thermal reserves online, and additional renewable curtailment.

When the system has all the reserve carried on the BESS systems, the total BESS required to prevent stage 2 load shedding is higher. The results for these cases are shown in Table D-29.

Loss of KWP							
	Thermal Reserve	0 MW	10 MW	15 MW	20 MW	25 MW	*Stage 1
DTCC1 Only	0	-	-	-	58.5	58.9	*Stage 2
DTCC1+1/2 DTCC2	0	Collapse	57.9	58.4	58.6	-	*Stage 3

Table D-29. Minimum Frequency for Loss of KWP with Boundary Cases (BESS Reserves)

If all the reserves are carried on the thermal units, 20 MW of additional BESS support is required with DTCC1 + ½ DTCC2 online. 25 MW of additional BESS support is required with only DTCC1 online.

CONCLUSIONS

EPS has completed analysis for the Maui Electric system defining the boundary conditions as to the operations of the system for the 2015, 2016, 2017, 2023, and 2030 case years. The boundary conditions represent the likely operating requirements due to the large additions of renewable energy and changes in load and generation expected in the future.

To aid in clarifying the different results, security tables were created showing the operating requirements for each year and each configuration within that year. The security tables include data values as to the minimum number for thermal units required, the ramp rate requirements, the regulation requirements, contingency reserves, and 30-minute reserves.

The ramp rate requirement was assumed to be 10% per minute for both PV and wind energy resources. This value was derived from analysis EPS has completed that is not part of this report.

The regulation requirements include values for day time and night time periods. The daytime regulation reserve is calculated as the summation of 20% of the installed DG PV, and 1:1 MW up to 50% of the installed wind. The night time regulation reserve is calculated as only 1:1 MW up to 50% of the installed wind.

For years 2017 and beyond the contingency reserve is calculated as the amount of reserves (energy storage) required in order to meet criteria for the largest unit or wind farm outage. For years before 2017 the contingency reserve is calculated as the amount of spinning reserves required in order to meet criteria for the largest unit or wind farm outage. The 30-minute reserves are equal to the largest unit or wind farm outage and is the required amount of energy to be brought online to displace the short term contingency reserves.

Security Tables

The security tables for the 2015 and 2016 years assume that the utilities are unable to acquire a storage system, and therefore must meet the criteria with their operating practices with their current fleet of units and up to 10 MW of BESS for either contingency or regulation.

MECO 2015- Min Thermal Units, No ESS										
		Capacity (MW)	# of Thermal units required (security constraint)	Ramp Rate Requirements	Regulation Reserves	Regulation Reserves - Night time	Contingency Reserves	30 Minute Reserves	DTT Scheme Required
	Wind	72	DTCC1 + KPP 3, KPP 4	12.5 MW	47.25 MW	36 MW	24 MW	40.2 MW	Yes
PV Level	DG	75							
Largest Unit		30							
	Wind	72	DTCC1 + 1/2 DTCC2 KPP 3, KPP 4	12.5 MW	47.25 MW	36 MW	45 MW	40.2 MW	No
PV Level	DG	75							
Largest Unit		30							
Notes:	1: DTT Scheme refers to a direct transfer trip of Stage 1 of load shedding for select unit outages. In order to prevent the tripping of the second stage of load shedding, the first stage of load shedding should be transfer tripped for the loss of the KWP plant or any of the combustion turbines.								

Table D-30. 2015 Security Table

MECO 2016- Min Thermal Units, No ESS									
		Capacity (MW)	# of Thermal units required (security constraint	Ramp Rate Requirements	Regulation Reserves	Regulation Reserves - Night time	Contingency Reserves	30 Minute Reserves	DTT Scheme Required
	Wind	72	DTCC1 + KPP 3, KPP 4	14 MW	49.5 MW	36 MW	45 MW	40.2 MW	No
PV Level	DG	90							
Largest Unit		30							
Notes:	1: DTT Scheme refers to a direct transfer trip of Stage 1 of load shedding for select unit outages.								

Table D-31. 2016 Security Table

The security tables for years after 2016 assume that the utility will have the capability to install an energy storage system to meet the criteria.

MECO 2017- Min Thermal Units, Maximum ESS									
		Capacity (MW)	# of Thermal units required (security constraint	Ramp Rate Requirements	Regulation Reserves	Regulation Reserves - Night time	Contingency Reserves	30 Minute Reserves
	Wind	72	DTCC1	14.6 MW	50.4 MW	36 MW	25 MW	38.5 MW
PV Level	DG	96						
Largest Unit		30						
	Wind	72	DTCC1 + 1/2 DTCC2	14.6 MW	50.4 MW	36 MW	10 MW	38.5 MW
PV Level	DG	96						
Largest Unit		30						
	Wind	72	DTCC1 + KPP 3, KPP 4	14.6 MW	50.4 MW	36 MW	10 MW	38.5 MW
PV Level	DG	96						
Largest Unit		30						
	Wind	72	DTCC1 + 1/2 DTCC2 KPP 3, KPP 4	14.6 MW	50.4 MW	36 MW	0 MW	38.5 MW
PV Level	DG	96						
Largest Unit		30						
Notes:	1: The DTCC1 + 1/2 DTCC2 minimum unit combination closely matches the 2019 daytime cases since the load increase during the day is offset by the increase in the solar capacity. For this reason, 2019 cases were not run.								

Table D-32. 2017 Security Table

MECO 2030 Baseline- Min Thermal Units, Maximum ESS										
		Capacity (MW)	# of Thermal units required (security constraint	Ramp Rate Requirements	Regulation Reserves	Regulation Reserves - Night time	Contingency Reserves	30-Minute Reserves	Transmission Constraint
	Wind	72	DTCC1	18 MW	55.5 MW	36 MW	25 MW	38.5 MW	No
PV Level	DG	130							
Largest Unit		30							
	Wind	72	DTCC1 + 1/2 DTCC2	18 MW	55.5 MW	36 MW	20 MW	38.5 MW	No
PV Level	DG	130							
Largest Unit		30							
Notes:	1. With the proposed transmission upgrades, the generation dispatch is not constrained by transmission								

Table D-33. 2030 Security Table Baseline

MECO 2030 NTA - PSH Min Thermal Units, Maximum ESS										
		Capacity (MW)	# of Thermal units required (security constraint)	Ramp Rate Requirements	Regulation Reserves	Regulation Reserves - Night time	Contingency Reserves	30 Minute Reserves	Transmission Constraint
	Wind	72	DTCC1	18 MW	55.5 MW	36 MW	25 MW	38.5 MW	Yes
PV Level	DG	130							
Largest Unit		30							
	Wind	72	DTCC1 + 1/2 DTCC2	18 MW	55.5 MW	36 MW	10 MW	38.5 MW	Yes
PV Level	DG	130							
Largest Unit		30							
Notes:	1. With a 30 MW PSH located in South Maui, all transmission constraints can be relieved. Minimum frequency for unit trip events are slightly lower compared to the same contingencies with the proposed ICE units located in South Maui								

Table D-34. 2030 Security Table NTA PSH Case

MECO 2030 NTA - ICE Min Thermal Units, Maximum ESS									
		Capacity (MW)	# of Thermal units required (security constraint	Ramp Rate Requirements	Regulation Reserves	Regulation Reserves - Night time	Contingency Reserves	30-Minute Reserves	Transmission Constraint
	Wind	72	DTCC1	18 MW	55.5 MW	36 MW	25 MW	38.5 MW	Yes
PV Level	DG	130							
Largest Unit		30							
	Wind	72	DTCC1 + 1/2 DTCC2	18 MW	55.5 MW	36 MW	10 MW	38.5 MW	Yes
PV Level	DG	130							
Largest Unit		30							
Notes:	1. With a 24 MW of ICE units located in South Maui, all transmission constraints can be relieved. Minimum frequency for unit trip events are slightly better compared to the same contingencies with the proposed PSH unit located in South Maui. The difference in response between the PSH and ICE units does not warrant a change in the contingency reserve requirements								

Table D-35. 2030 Security Table NTA ICE Case

LANA'I PSIP 2030 SYSTEM SECURITY CASES

This study identifies the security requirements for various generation and load scenarios under study for the Lanaʻi system. As such the cases were intended to establish the boundary conditions for the security analysis.

Assumptions

Several dispatch cases were created to determine the contingency reserve requirements of the Lanaʻi grid for the 2030 year. The assumed load level and PV generation for the island are shown below in Table D-36. Maui Electric provided a zip file containing the Lanaʻi power flow and dynamics database. The Lanaʻi generation characteristics used in this study are listed in Table D-37.

	Minimum	Daytime Minimum	Daytime Peak	Peak
Load Level	1,734	4,020	5,300	5,600
Max PV	-	2,242	2,242	-
Net Load	2,550	1,180	3,058	5,600

Table D-36: Lana'i 2030 Load and PV Generation Levels

	FUEL TYPE	UNIT TYPE	NTL (GROSS MW)	MIN. LOAD (GROSS MW)	Reactive Power Limit	Typically On AGC When Running	Regulating / Load Following Capability	Regulation Mode	MODE OF OPERATION	RAMP RATES (GROSS MW/ MIN)
LANAI GENERATING STATION										
LANAI1	No. 2 Diesel	ICE	1.19	0.25	0.95	No AGC	Yes	5% droop	Peaking	0.50
LANAI2	No. 2 Diesel	ICE	1.19	0.25	0.95	No AGC	Yes	5% droop	Peaking	0.50
LANAI3	No. 2 Diesel	ICE	1.19	0.25	0.95	No AGC	Yes	5% droop	Peaking	0.50
LANAI4	No. 2 Diesel	ICE	1.19	0.25	0.95	No AGC	Yes	5% droop	Peaking	0.50
LANAI5	No. 2 Diesel	ICE	1.19	0.25	0.95	No AGC	Yes	5% droop	Peaking	0.50
LANAI6	No. 2 Diesel	ICE	1.19	0.25	0.95	No AGC	Yes	5% droop	Peaking	0.50
L7,D-7	No. 2 Diesel	ICE	2.20	0.55	1.76	No AGC	Yes	Isoch	Baseload	1.10
L8,D-8	No. 2 Diesel	ICE	2.20	0.55	1.76	No AGC	Yes	5% droop	Baseload	1.10
L9,D-9	No. 2 Diesel	ICE	2.20	0.55	1.76	No AGC	Yes	5% droop	Peaking	1.10
L10,D-10	No. 2 Diesel	ICE	2.20	0.55	1.76	No AGC	Yes	5% droop	Peaking	1.10

Table D-37. Lana'i Generating Characteristics

Table D-38 lists the PV trip settings used in this study, and is based on the IEEE 1547 PV trip settings, existing rule 14H settings, and the proposed 14H extended ride-through settings. The legacy PV has the IEEE 1547 trip settings which are a must-trip standard which means that the distributed generation must cease to energize the circuit by the specified delay times. Rule 14H is a standard that originally mimicked IEEE 1547 but has been modified to incorporate the unique characteristics of island power systems and variable generation. The latest proposed modification to Rule 14H with extended ride-through settings increases the ride-through capability of the PV during severe system events. In addition, it is assumed that all PV that has the 14H (original modification and proposed ride-through settings) can also be curtailed.

Frequency Settings	Under Frequency		Over Frequency	
	Hz	Delay	Hz	Delay
IEEE 1547	59.3	0.167	60.5	0.167
Rule 14H	57.0	0.167	60.5	0.167
Rule 14H Extended	57.0	20.0	63.0	20.0

Voltage Settings	Under Voltage 1		Under Voltage 2		Over Voltage 1		Over Voltage 2	
	PU	Delay	PU	Delay	PU	Delay	PU	Delay
IEEE 1547	0.5	0.167	0.9	2.000	1.1	1.000	1.2	0.167
Rule 14H	0.5	0.167	0.9	2.000	1.1	1.000	1.2	0.167
Rule 14H Extended	0.5	0.500	0.9	2.000	1.1	1.000	1.2	0.167

Table D-38. PV Trip Setting Comparison IEEE 1547 vs. Rule 14H

The database provided by Maui Electric had no PV modeled in the power flow cases nor any associated under-frequency relays that would trip the PV generation at a frequency of 59.3 Hz. Therefore some assumptions were made as to modeling the different amounts or types of PV on the Lana'i system. The PV was modeled in two different scenarios. Scenario 1 assumed 673 KW of legacy PV, 736 kW of Rule 14H PV, and 833 kW of proposed Rule 14H Extended PV based on the estimated installation dates. Scenario 2 assumed that 80 % of the Legacy PV plus Modified Rule 14H PV was retrofitted to proposed Rule 14H Extended PV, resulting in 280 kW of legacy PV and 1960 kW of Rule 14H Extended PV. The two different scenarios were created in order to determine the impact on the ESS recommendations due to an inability to upgrade or retrofit existing PV installations. The two scenarios are shown below in Table D-39.

PV Scenario	1	2
Legacy PV	673	282
Rule 14 PV	736	
Extended PV	833	1960
Total PV	2242	2242

Table D-39. PV Configuration Scenarios

Simulations were used to determine the size of the regulating reserves needed to prevent the second stage of load shedding. If the system frequency dropped low enough to trigger stage 2 of load shedding, then additional contingency reserves were added in 100 kW increments until the frequency stayed above the stage 2 load shedding setpoint. The energy storage system was configured to utilize auto-scheduling that would allow the battery to go to full output 6 cycles after a loss of a unit. It should be noted that it appears that the Lana'i system consists of Stage 1 UFLS settings with slightly different frequency set points and relay timers between stage 1 and stage 2. Due to the characteristics of the Lana'i system, it is possible to trip Stage 2 and not trip Stage 1 with the existing settings.

It is recommended that the UFLS relays for 58.65 Hz and 0.4 second relay timer be changed to 0.2 second delay to allow for better coordination.

The load shedding settings listed in the provided database are shown in Table D-40.

Stage	Frequency (Hz)	Delay (seconds)
Kicker 1	58	3.0
Kicker 2	58	4.5
Stage 1	58.65-58.5	0.2-0.4
Stage 2	57.5	0.25
Stage 3	57	0.1-0.12

Table D-40. Under-Frequency Trip Settings

Dispatch Cases

Table D-41 shows the dispatch cases that were created for the Lana'i 2030 cases.

Unit	Capacity		Day Minimum		Day Peak	
	Pmax	Pmin	A	B	A	B
LANAI1	1188	250	0	0	0	0
LANAI2	1188	250	0	0	0	0
LANAI3	1188	250	0	0	0	0
LANAI4	1188	250	0	250	0	250
LANAI5	1188	250	0	250	0	250
LANAI6	1188	250	0	0	0	0
L7,D-7	2200	550	2200	2200	2200	2200
L8,D-8	2200	550	550	550	920	550
L9,D-9	2200	550	0	0	0	0
L10,D-10	2200	550	0	0	0	0
Thermal Gen			2750	3250	3120	3250
Solar Available			2242	2242	2242	2242
Curtailed Solar			922	1422	0	130
Solar Generation			1320	820	2242	2112
System Load			4020	4020	5300	5300
Regulation Up			1650	3525	1280	3525
Regulation Dn			1650	1650	2020	1650

Table D-41. 2030 Dispatch Cases

The cases where configured for the day minimum and day peak with a minimum generation scenario (A) and a larger generation dispatch scenario (B). Note that the day minimum cases required curtailment of the PV close to 50%. The day peak cases require minimal curtailment, if any.

Results

The ESS size necessary to prevent the second stage of load shedding was tabulated for each of the dispatch cases and each of the PV configuration scenarios. These results are shown in Table D-42.

Dispatch	PV Scenario	Daytime Minimum	Daytime Peak
"A"	1	1600 kW	1500 kW
"A"	2	1400 kW	1300 kW
"B"	1	1400 kW	1300 kW
"B"	2	1100 kW	1100 kW

Table D-42. ESS Size Requirement

The results show that utilizing additional extended ride through PV settings can result in a decrease of ESS size by 200–300 kW. Also, adding additional units online can further decrease ESS size by 200–300 kW, especially for the daytime minimum case.

Security Tables

To aid in clarifying the different results, security tables were created showing the operating requirements. The security tables include data values as to the minimum number for thermal units required, the ramp rate requirements, the regulation requirements, contingency and 30-minute reserves, and required voltage support, and are shown in Table D-43.

The ramp rate requirement was assumed to be 10% per minute for PV energy resources. This value was derived from analysis for other islands EPS has completed that is not part of this report.

The regulation requirements include values for day time and night time periods. The daytime regulation reserve is calculated as the summation of 20% of the installed PV. The night time regulation reserve is calculated as only 50% of the installed wind, and therefore is valued at 0 kW for the Lanaʻi system due to a lack in wind energy resources.

The contingency reserve is calculated as the amount of reserves (energy storage or PV regulation) required in order to meet criteria for the largest unit outage. The 30-minute reserves are equal to the largest unit outage and is the required amount of energy to be brought online to displace the short term contingency reserves.

<table>
<tr><th colspan="2">Value</th><th>Capacity (kW)</th><th># of Thermal units required</th><th>Ramp Rate Require ments</th><th>Regulation Reserves - Day time</th><th>Regulation Reserves - Night time</th><th>Contingency Reserves</th><th>30 Minute Reserves</th><th>Voltage Support (SVC)</th></tr>
<tr><td rowspan="2">PV Level</td><td>Station</td><td>0</td><td rowspan="4">2</td><td rowspan="4">224.2kW / Min</td><td rowspan="4">785 kW

(20% of DG PV)</td><td rowspan="4">0 MW

(50% of Wind)</td><td rowspan="4">1600 kW</td><td rowspan="4">2200 kW</td><td rowspan="4">0</td></tr>
<tr><td>DG</td><td>2242</td></tr>
<tr><td colspan="2">Wind</td><td>0</td></tr>
<tr><td colspan="2">Largest Unit</td><td>2200</td></tr>
<tr><td rowspan="2">PV Level</td><td>Station</td><td>0</td><td rowspan="4">4</td><td rowspan="4">224.2kW / Min</td><td rowspan="4">785 kW

(20% of DG PV)</td><td rowspan="4">0 MW

(50% of Wind)</td><td rowspan="4">1500 kW</td><td rowspan="4">2200 kW</td><td rowspan="4">0</td></tr>
<tr><td>DG</td><td>2242</td></tr>
<tr><td colspan="2">Wind</td><td>0</td></tr>
<tr><td colspan="2">Largest Unit</td><td>2200</td></tr>
</table>

Table D-43. Lana'i Security Tables

MOLOKA'I PSIP 2030 CASES

This study identifies the security requirements for various generation and load scenarios under study for the Moloka'i system. As such the cases were intended to establish the boundary conditions for the security analysis.

Assumptions

Several dispatch cases were created to determine the contingency reserve requirements of the Moloka'i grid for the 2030 year. The assumed load level and PV generation for the island are shown below in Table D-44. Maui Electric provided a zip file containing the Moloka'i power flow and dynamics database. The Moloka'i generation characteristics used in this study are listed in Table D-45.

Table D-45. Moloka'i Generation Characteristics

	Minimum	Daytime Minimum	Daytime Peak	Peak
Load Level	2,550	3,950	5,200	5,600
Max PV	-	2,770	2,770	-
Net Load	2,550	1,180	2,430	5,600

Table D-44. Moloka'i 2030 Load and PV Generation Levels

	FUEL TYPE	UNIT TYPE	NTL (GROSS MW)	MIN. LOAD (GROSS MW)	Reactive Power Limit	Typically On AGC When Running	Regulating / Load Following Capability	Regulation Mode	MODE OF OPERATION	RAMP RATES (GROSS MW/ MIN)
PALAAU GENERATING STATION										
G01	No. 2 Diesel	ICE	1.25	0.4	1.00	No AGC	Yes	4% droop	Cycling	0.5
G02	No. 2 Diesel	ICE	1.25	0.4	1.00	No AGC	Yes	4% droop	Cycling	0.5
G03	No. 2 Diesel	ICE	0.97	0.4	0.78	No AGC	Yes	4% droop	Cycling	0.5
G04	No. 2 Diesel	ICE	0.97	0.4	0.78	No AGC	Yes	4% droop	Cycling	0.5
G05	No. 2 Diesel	ICE	0.97	0.4	0.78	No AGC	Yes	4% droop	Cycling	0.5
G06	No. 2 Diesel	ICE	0.97	0.4	0.78	No AGC	Yes	4% droop	Cycling	0.5
G07	No. 2 Diesel	ICE	2.20	1.1	1.76	No AGC	Yes	Isoch	Baseload	1.1
G08	No. 2 Diesel	ICE	2.20	1.1	1.76	No AGC	Yes	Isoch	Baseload	1.1
G09	No. 2 Diesel	ICE	2.20	1.1	1.76	No AGC	Yes	Isoch	Baseload	1.1
GT1	No. 2 Diesel	CT	2.22	1.1	1.78	No AGC	Yes	4% droop	Peaking	1.1

Table D-45. Moloka'i Generation Characteristics

Table D-46 lists the PV trip settings used in this study, and is based on the IEEE 1547 PV trip settings and the proposed 14H extended ride-through settings. The legacy PV has the IEEE 1547 trip settings which are a must-trip standard which means that the distributed generation must cease to energize the circuit by the specified delay times. The proposed Rule 14H is a ride-through standard that specifies that the distributed generation must stay connected to the system until the abnormal system conditions have existed for at least as long as the delay. In addition, it is assumed that all PV that has the 14H extended ride through settings can also be curtailed.

Frequency Settings	Under Frequency		Over Frequency	
	Hz	Delay	Hz	Delay
IEEE 1547	59.3	0.167	60.5	0.167
Modified Rule 14H	57.0	0.167	60.5	0.167
Proposed 14H Extended	57.0	20.0	63.0	20.0

Voltage Settings	Under Voltage 1		Under Voltage 2		Over Voltage 1		Over Voltage 2	
	PU	Delay	PU	Delay	PU	Delay	PU	Delay
IEEE 1547	0.5	0.167	0.9	2.000	1.1	1.000	1.2	0.167
Modified Rule 14H	0.5	0.167	0.9	2.000	1.1	1.000	1.2	0.167
Proposed 14H Extended	0.5	0.500	0.9	2.000	1.1	1.000	1.2	0.167

Table D-46. PV Trip Setting Comparison IEEE 1547 vs. Rule 14H

The database provided by Maui Electric 30% of the PV being tripped at 59.3 Hz to account for the legacy PV installations. The database had 1,620 kW of distributed PV, resulting in approximately 490 kW of PV capacity that would trip offline using the IEEE 1547 trip settings. We performed a sensitivity analysis that focused on the impact that retrofitting the currently installed PV has on the contingency reserve requirement for the Moloka'i system.

We assumed that the amount of PV that trips at 59.3 Hz would be decreased from 30% to 20% (similar to the amount of PV for the Maui Electric system). This assumption provides for a similar PV to peak system load ratio as seen on the Hawai'i Electric Light, Maui Electric, and Hawaiian Electric systems. The remaining PV utilize the proposed extended ride-through settings. The result would be 324 kW of PV capacity that would use the IEEE 1547 trip settings, and the remainder would use the proposed Rule 14H extended ride-through settings.

To illustrate the importance of retrofitting the existing PV, a case was completed assuming none of the existing PV would be retrofitted. This results in approximately 490 kW that would trip offline at a frequency of 59.3 Hz and 60.5 Hz, and the remaining 1,134 kW PV would use the modified Rule 14H settings and trip offline at 57 Hz with a 10 cycle delay with all other trip settings identical to the IEEE 1547 trip settings. All future PV would use the extended ride-through settings highlighted in Table D-46. The two PV configuration scenarios are shown in Table D-47.

PV Scenario	No Retrofit	With Retrofit
Legacy PV	490 kW	324 kW
Modified Rule 14 H PV	1,134 kW	-
Proposed 14H Extended	1,643 kW	2,939 kW
Total PV	3,263 kW	3,263 kW

Table D-47. PV Configuration Scenarios (Capacity)

Simulations were run to determine the size of the regulating reserves needed to prevent the second stage of load shedding. If the system frequency dropped low enough to trigger stage 2 of load shedding, then additional regulating reserves were added in 100 kW increments until the frequency stayed above the stage 2 load shedding setpoint. The battery system was configured to have a 1% droop response with a deadband of ±0.05 Hz.

The load shedding settings listed in the provided database are shown below in Table D-48.

Stage	Frequency (Hz)	Delay (seconds)
Kicker 1	58.7	5.0
Kicker 2	57.75	2.5
Stage 1	57.5	0.16
Stage 2	57.25	0.75
Stage 3	56	0.5

Table D-48. Under-Frequency Trip Settings

Dispatch Cases

Table D-49 shows the dispatch cases that were created for the Molokaʻi 2030 cases with all values listed in kW.

			Minimum Solar						Maximum Solar					
	Capacity		Daytime Minimum			Daytime Peak Load			Daytime Minimum			Daytime Peak Load		
Unit	Max	Min	Base	Case 'A'	Case 'B'	Base	Case 'A'	Case 'B'	Case 'C'	Case 'D'	Case 'E'	Case 'C'	Case 'D'	Case 'E'
G07	2,200	1,100	2,178	2,066	1,107	2,199	2,196	2,200	1,176	1,113	1,138	1,592	1,192	1,119
G08	2,200	1,100	1,100	1,100	1,100	1,100	1,100	1,100	1,100	1,100	1,100	1,100	1,100	1,100
G09	2,200	1,100			1,100			1,100			1,100			1,100
G01	1,250	400		400			400			400			400	
G02	1,250	400												
G03	970	400												
G04	970	400												
G05	970	400												
G06	970	400												
GT1	2,220	1,100												
Solar Available			2,770	2,770	2,770	2,770	2,770	2,770	2,770	2,770	2,770	2,770	2,770	2,770
Curtailed Solar			2,220	2,490	2,240	590	990	1,680	1,220	1,570	2,270	0	0	620
Solar Generation			550	280	530	2,180	1,780	1,090	1,550	1,200	500	2,770	2,770	2,150
System Load			3,828	3,846	3,837	5,479	5,476	5,490	3,826	3,813	3,838	5,462	5,462	5,469
Regulation Up			1,122	2,084	3,293	1,101	1,954	2,200	2,124	3,037	3,262	1,708	2,958	3,281
Regulation Dn			1,078	966	7	1,099	1,096	1,100	76	13	38	492	92	19

Table D-49. 2030 Dispatch Cases

The base and case 'C' dispatches only have 2 of the 2,200 kW units online. Case 'A' and case 'D' dispatches have two 2,200 kW units plus a 1,250 kW unit online. Case 'B' and case 'E' dispatches have three of the 2,200 kW units online. The base case, case 'A', and case 'B' are all dispatched with as much solar generation curtailed as possible. Case 'C', case 'D', and case 'E' are all accepting the maximum allowable solar generation. Even during the day peak load, case 'E' requires some solar curtailment.

The loss of either the G07 or the G08 unit was simulated for each of the dispatch cases listed above. A line fault and trip was also studied with 27 cycle clearing. This line goes from Palaʻau–Kamehameha (Bus 1012–1091)

Results

The BESS size necessary to prevent the second stage of load shedding was tabulated for each of the unit trips and dispatch cases. These results are shown in Table D-50.

	Retrofit		No Retrofit	
Dispatch	Daytime Peak	Daytime Minimum	Daytime Peak	Daytime Minimum
Base	700 kW	700 kW	1,300 kW	900 kW
Case 'A'	200 kW	200 kW	700 kW	300 kW
Case 'B'	0 kW	0 kW	0 kW	0 kW
Case 'C'	100 kW	0 kW	900 kW	300 kW
Case 'D'	0 kW	0 kW	0 kW	0 kW
Case 'E'	0 kW	0 kW	0 kW	0 kW

Table D-50. BESS Required to Prevent Stage 2 of Load Shedding

Security Tables

Contingency reserves increased by 100 kW for '2x 2200 kW units' and '2x 2200 kW Units + 1x 1200 kW Unit'.

Molokai 2030 Baseline- Min Thermal Units, Maximum ESS - WITH RETROFIT									
		Capacity (kW)	# of Thermal units required (security constraint	Ramp Rate Requirements	Regulation Reserves	Regulation Reserves - Night time	Contingency Reserves	30-Minute Reserves
	Wind	0	2x 2200 kW Units	320 kW	640 kW	0 kW	700 kW	2470 kW
PV Level	DG	3263						
Largest Unit		2200						
	Wind	0	2x 2200 kW Units + 1x 1200 kW Unit	320 kW	640 kW	0 kW	200 kW	2470 kW
PV Level	DG	3263						
Largest Unit		2200						
	Wind	0	3x 2200 kW Units	320 kW	640 kW	0 kW	0 kW	2470 kW
PV Level	DG	3263						
Largest Unit		2200						

Notes:

1: This case represents the case with max PV/Wind with minimum themal units required for system stability. It is the extreme case for the minimum number of operating thermal units on the system.

2: The regulation capacity and the ramp rate limit are the total required for the system as a whole. Any curtailed PV can provide both regulation and/or contingency reserves however the quantity should be adjusted to the expected capacity available as oppsoed to the expected energy levels.

3. This analysis assumes the largest single contingency of future PV/Wind resources is limited to the same level of contingency as the largest thermal unit.

4. The regulating reserves and the contingency reserves are individual requirements and should be summed together to arrive at the total required reserves.

Table D-51. Moloka'i 2030 Baseline Minimum Thermal Units with Retrofit

Molokai 2030 Baseline- Min Thermal Units, Maximum ESS - NO RETROFIT									
		Capacity (kW)	# of Thermal units required (security constraint	Ramp Rate Requirements	Regulation Reserves	Regulation Reserves - Night time	Contingency Reserves	30-Minute Reserves
	Wind	0	2x 2200 kW Units	320 kW	640 kW	0 kW	1300 kW	2617 kW
PV Level	DG	3263						
Largest Unit		2200						
	Wind	0	2x 2200 kW Units + 1x 1200 kW Unit	320 kW	640 kW	0 kW	700 kW	2617 kW
PV Level	DG	3263						
Largest Unit		2200						
	Wind	0	3x 2200 kW Units	320 kW	640 kW	0 kW	0 kW	2617 kW
PV Level	DG	3263						
Largest Unit		2200						

Notes:

1: This case represents the case with max PV/Wind with minimum themal units required for system stability. It is the extreme case for the minimum number of operating thermal units on the system.

2: The regulation capacity and the ramp rate limit are the total required for the system as a whole. Any curtailed PV can provide both regulation and/or contingency reserves however the quantity should be adjusted to the expected capacity available as oppsoed to the expected energy levels.

3. This analysis assumes the largest single contingency of future PV/Wind resources is limited to the same level of contingency as the largest thermal unit.

4. The regulating reserves and the contingency reserves are individual requirements and should be summed together to arrive at the total required reserves.

Table D-52. Moloka'i 2030 Baseline Minimum Thermal Units with No Retrofit

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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 Hawaiʻi, 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.

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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 Lanai, Molokai, and/or Maui:

- *High Sulfur Diesel* (HSD) is a No. 2 oil that is up to 0.4% sulfur content.
- *Medium Sulfur Fuel Oil* (MSFO), and also referred to as Industrial Fuel Oil (IFO) or Bunker Fuel Oil; is less 2% sulfur content.
- *S500* is a low sulfur diesel fuel that is 500 to 10,000 parts per million of sulfur content.
- *Ultra Low Sulfur Diesel* (ULSD) that is as low as 0.0015% sulfur content.
- *Biodiesel*
- *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 Hawaiʻi. For purposes of this PSIP analyses, LNG pricing (delivered to the power generation facilities) were developed as described in Appendix I: LNG to Hawaiʻi.

Maui Electric Fuel Price Forecasts

$/MMBtu	Fuel Price Forecasts							
Year	*HSD (Maui)*	*MSFO (Maui)*	*S500 (Maui)*	*ULSD (Maui)*	*ULSD (Lana'i)*	*ULSD (Moloka'i)*	*Biodiesel (Maui)*	*LNG (Maui, Lana'i, & Moloka'i)*
2014	$22.81	$15.67	$23.40	$33.67	$23.67	$27.30	$33.67	n/a
2015	$22.78	$15.63	$23.37	$30.23	$23.65	$27.35	$30.23	n/a
2016	$22.31	$15.25	$22.89	$30.41	$23.17	$26.95	$30.41	n/a
2017	$22.28	$15.20	$22.86	$31.15	$23.14	$26.98	$31.15	$16.71
2018	$22.77	$15.55	$23.36	$31.83	$23.65	$27.55	$31.83	$16.81
2019	$23.56	$16.12	$24.17	$31.87	$24.46	$28.41	$31.87	$17.00
2020	$24.45	$16.76	$25.09	$31.93	$25.38	$29.38	$31.93	$17.30
2021	$25.45	$17.48	$26.11	$32.17	$26.40	$30.45	$32.17	$17.69
2022	$26.49	$18.24	$27.17	$32.56	$27.47	$31.58	$32.56	$13.73
2023	$27.59	$19.04	$28.31	$32.69	$28.61	$32.77	$32.69	$13.95
2024	$28.69	$19.84	$29.43	$33.19	$29.74	$33.96	$33.19	$14.12
2025	$29.77	$20.62	$30.54	$33.49	$30.85	$35.13	$33.49	$14.33
2026	$30.79	$21.35	$31.59	$33.80	$31.90	$36.24	$33.80	$14.61
2027	$31.97	$22.21	$32.80	$34.11	$33.12	$37.52	$34.11	$15.02
2028	$33.07	$23.00	$33.92	$34.42	$34.25	$38.71	$34.42	$15.39
2029	$34.23	$23.84	$35.12	$34.72	$35.44	$39.98	$34.72	$15.78
2030	$35.33	$24.64	$36.25	$35.03	$36.58	$41.19	$35.03	$16.21

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	1,221.2	1,152.7	124.4	117.4	1,035.3
2016	1,243.3	1,173.6	146.3	138.1	1,035.5
2017	1,274.7	1,203.3	152.3	143.8	1,059.5
2018	1,313.8	1,240.2	160.3	151.3	1,088.9
2019	1,338.4	1,263.4	167.5	158.2	1,105.2
2020	1,356.2	1,280.2	174.5	164.7	1,115.5
2021	1,361.9	1,285.6	179.4	169.4	1,116.3
2022	1,367.3	1,290.7	183.9	173.6	1,117.1
2023	1,372.1	1,295.2	188.1	177.6	1,117.6
2024	1,379.5	1,302.2	192.1	181.3	1,120.9
2025	1,376.2	1,299.1	195.9	184.9	1,114.2
2026	1,370.8	1,294.0	199.5	188.3	1,105.7
2027	1,361.8	1,285.5	203.0	191.6	1,093.9
2028	1,351.0	1,275.3	206.4	194.8	1,080.5
2029	1,332.3	1,257.7	209.5	197.8	1,059.9
2030	1,311.0	1,237.6	212.5	200.6	1,036.9

Loss Factor: 5.60%

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	1,221.2	1,152.7	124.4	117.4	1,035.3
2016	1,243.3	1,173.6	146.3	138.1	1,035.5
2017	1,278.7	1,207.0	152.3	143.8	1,063.2
2018	1,317.9	1,244.0	160.3	151.3	1,092.7
2019	1,342.3	1,267.1	167.5	158.2	1,108.9
2020	1,360.1	1,283.9	174.5	164.7	1,119.2
2021	1,365.8	1,289.3	179.4	169.4	1,120.0
2022	1,371.3	1,294.4	183.9	173.6	1,120.9
2023	1,376.2	1,299.0	188.1	177.6	1,121.5
2024	1,383.6	1,306.0	192.1	181.3	1,124.7
2025	1,380.3	1,303.0	195.9	184.9	1,118.0
2026	1,374.9	1,297.8	199.5	188.3	1,109.5
2027	1,365.8	1,289.3	203.0	191.6	1,097.7
2028	1,355.0	1,279.1	206.4	194.8	1,084.3
2029	1,336.2	1,261.4	209.5	197.8	1,063.6
2030	1,314.9	1,241.2	212.5	200.6	1,040.6

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

Lanaʻi Sales Forecasts (without Dynamic Pricing Adjustments)

Year	Load without DG-PV		Total DG-PV (Uncurtailed)		Sales with DG-PV
	Net Generation: MWh (a)	*Sales: Customer MWh (b)*	*Net MWh (c)*	*Customer MWh (d)*	*Customer MWh (b – d)*
2015	28,715	27,360	3,106	2,959	24,400
2016	29,220	27,840	3,411	3,250	24,590
2017	29,611	28,212	3,596	3,426	24,786
2018	30,043	28,624	3,735	3,559	25,066
2019	30,384	28,949	3,839	3,658	25,291
2020	30,687	29,238	3,943	3,757	25,481
2021	30,963	29,501	4,047	3,856	25,645
2022	31,212	29,739	4,151	3,955	25,783
2023	31,453	29,968	4,185	3,987	25,981
2024	31,693	30,197	4,189	3,991	26,206
2025	31,926	30,418	4,189	3,991	26,427
2026	32,115	30,599	4,204	4,006	26,593
2027	32,283	30,758	4,223	4,024	26,735
2028	32,426	30,895	4,285	4,082	26,812
2029	32,568	31,030	4,356	4,150	26,880
2030	32,713	31,169	4,356	4,150	27,019

1. Adjusted July 2014 Maui Electric forecast
2. Loss factor 4.72%

Table F-5. Lanaʻi Sales Forecasts (without Dynamic Pricing Adjustments)

Moloka'i Sales Forecasts (without Dynamic Pricing Adjustments)

Year	Load without DG-PV		Total DG-PV (Uncurtailed)		Sales with DG-PV
	Net Generation: MWh (a)	*Sales: Customer MWh (b)*	*Net MWh (c)*	*Customer MWh (d)*	*Customer MWh (b – d)*
2015	34,115	31,137	3,584	3,271	27,866
2016	34,202	31,216	3,972	3,625	27,590
2017	34,342	31,344	4,224	3,855	27,489
2018	34,376	31,375	4,326	3,948	27,427
2019	34,397	31,394	4,776	4,359	27,035
2020	34,400	31,397	5,084	4,640	26,757
2021	34,350	31,352	5,224	4,768	26,583
2022	34,299	31,304	5,260	4,801	26,503
2023	34,247	31,258	5,293	4,831	26,426
2024	34,172	31,189	5,320	4,855	26,333
2025	34,115	31,137	5,346	4,879	26,258
2026	34,079	31,104	5,372	4,903	26,200
2027	34,009	31,040	5,399	4,927	26,113
2028	33,954	30,990	5,425	4,951	26,039
2029	33,911	30,951	5,451	4,975	25,976
2030	33,847	30,892	5,470	4,992	25,900

1. Adjusted July 2014 Maui Electric forecast
2. Loss factor 8.73%

Table F-6. Moloka'i Sales Forecasts (without Dynamic Pricing Adjustments)

Net Peak Forecasts

Year	Net Peak (w/o DG-PV + w/ Dynamic Pricing)	Net Peak (w/o DG-PV + w/o Dynamic Pricing)	Total DG-PV)
	MW	MW	MW
2015	195.4	195.4	79.4
2016	197.4	197.7	95.3
2017	197.6	203.7	101.2
2018	203.4	209.8	106.0
2019	207.0	213.6	110.3
2020	208.5	215.2	114.5
2021	210.3	217.1	117.4
2022	211.0	217.8	120.1
2023	211.7	218.5	122.6
2024	211.5	218.3	125.0
2025	211.7	218.5	127.2
2026	210.5	217.3	129.4
2027	208.9	215.6	131.5
2028	205.8	212.4	133.5
2029	203.7	210.2	135.4
2030	199.9	206.3	137.2

1. May 2014 Maui Electric peak forecast

Table F-7. 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.

DR Grid Service Requirements and MW Benefits

Grid Service	Capacity[1]	Non-AGC Ramping[2]	Non-Spinning Reserve[3]	Regulating Reserve[4]	Accelerated Energy Delivery
Frequency	Unlimited	Unlimited	Unlimited	Continuous	Continuous
Event Length	1 hour	1 hour	1 hour	Minutes	Minutes
Event Cost	None	None	None	None	None
Year	*MW*	*MW*	*MW*	*MW*	*MW*
2015	0.8	0.5	0.1	0	0.1
2016	4.7	1.8	0.4	0	0.3
2017	5.6	3.1	0.8	0	0.4
2018	6.5	4.5	1.1	0	0.6
2019	7.4	5.8	1.4	0	0.7
2020	8.4	7.1	1.8	0	0.9
2021	8.4	7.4	1.8	0	1
2022	8.4	7.7	1.8	0	1.1
2023	8.4	7.7	1.8	0	1.1
2024	8.4	7.7	1.8	0	1.1
2025	8.4	7.7	1.8	0	1.1
2026	8.4	7.7	1.8	0	1.1
2027	8.4	7.7	1.8	0	1.1
2028	8.4	7.7	1.8	0	1.1
2029	8.4	7.7	1.8	0	1.1
2030	8.4	7.7	1.8	0	1.1

Table F-8. Demand Response Program Grid Service Requirements and MW Benefits

1 Residential and Small Business Direct Load Control (RBDLC) assumed to have a 1 hour duration limit. RBDLC capacity value equals program potential divided by three to cover 3 hour priority peak period.

2 RBDLC Non-AGC Ramping value equals 75% of program potential (balance assigned to Non-Spinning Reserve).

3 RBDLC Non-Spinning Reserve value equals 25% of program potential (balance assigned to Non-AGC Ramping).

4 Aggregated Regulating Reserves program potential does not provide value in terms of system regulation needs and operational unit dispatch.

Amounts shown in Table F-8 reflect quantities by grid service requirement as modeled in PSIP production cost runs. In practice, system operators may be able to use a single end use resource to provide different grid services at different times as system needs change, provided the resources are not expected to provide multiple grid services simultaneously. For planning purposes though, the end use potentials included in the Integrated Demand Response Portfolio Plan have been allocated to the single grid service deemed to offer the highest value service to customers (to account for the fact that a single end use resource typically cannot provide multiple grid services simultaneously).

RESOURCE CAPITAL COSTS[3]

The calculations for the capital cost for different resources used in the PSIP modeling analyses are shown in Table F-10 through Table F-23.

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-9. 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.

Simple Cycle 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-10. Simple Cycle Combustion Turbine

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-11. Combined Cycle 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-12. 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-13. 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-14. 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-15. 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-16. 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-17. Geothermal, Fully Dispatchable

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

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-19. Waste-to-Energy

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-20. 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-21. Wind, Offshore (Floating Platform)

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

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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.

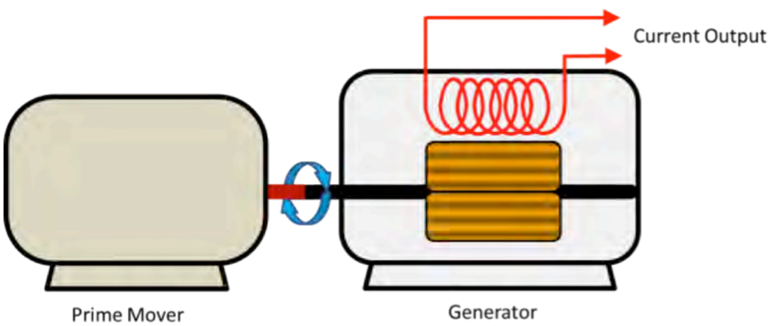


Figure G-1. Turbine-Generator Process

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.

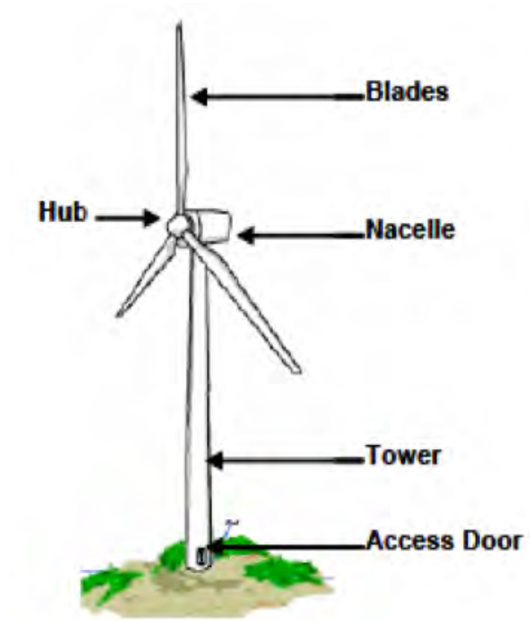


Figure G-2. Wind Turbine and Tower

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%.

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.

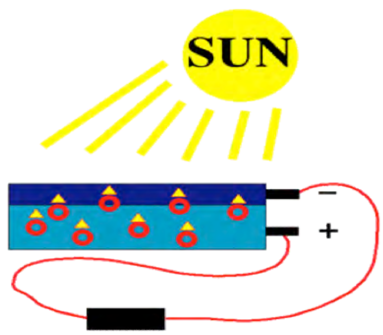


Figure G-3. Schematic of a Photovoltaic (PV) Cell and an Array of PV Panels

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.

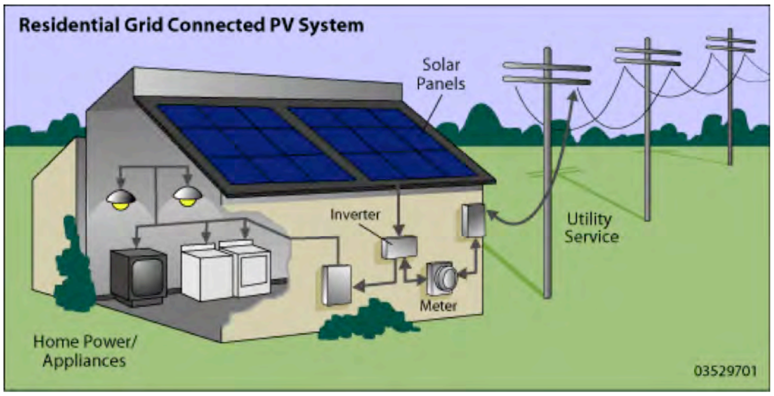


Figure G-4. Residential Distributed Generation PV System

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.

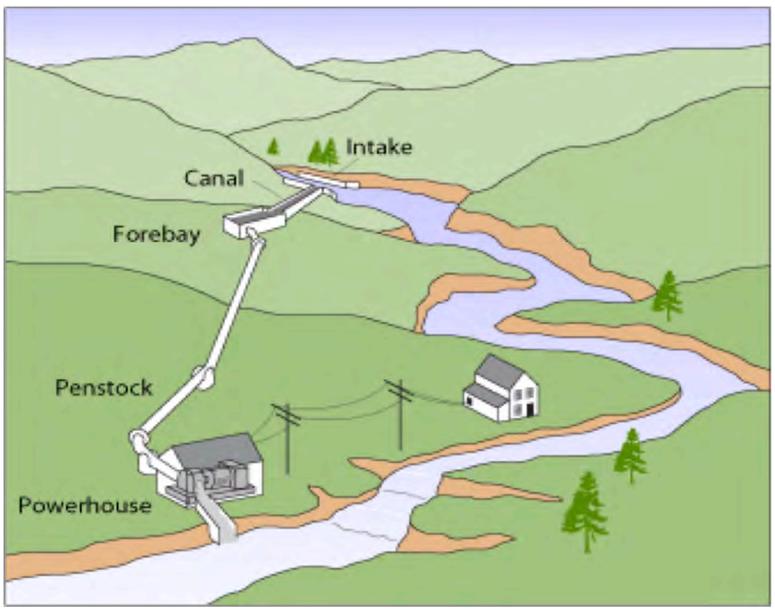


Figure G-5. Run-of-River Hydroelectric Plant

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.

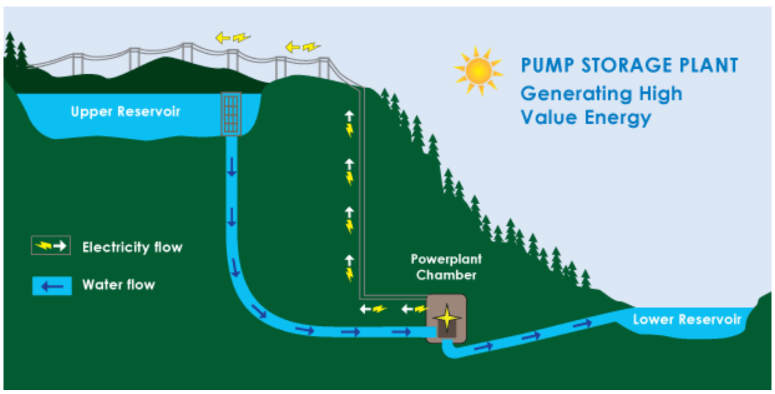


Figure G-6. Pumped Storage Hydroelectricity Plant

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).

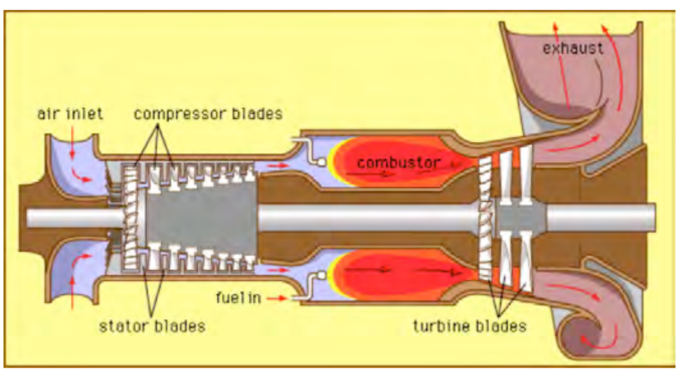


Figure G-7. Gas Turbine Engine

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

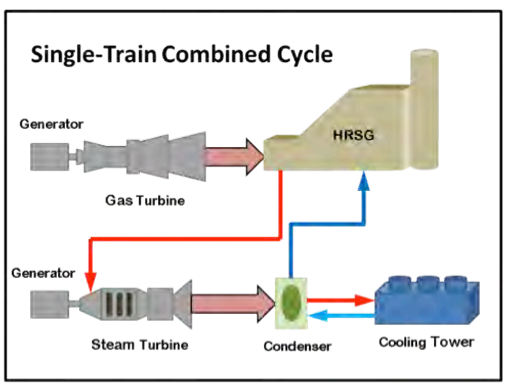
A steam turbine operates by high pressure steam traveling through the turbine blades, causing the turbine shaft to rotate. This high pressure steam can be produced by a variety of technologies including Heat Recovery Steam Generators (HRSG) and fuel-fired boilers. All steam turbines produce firm, dispatchable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



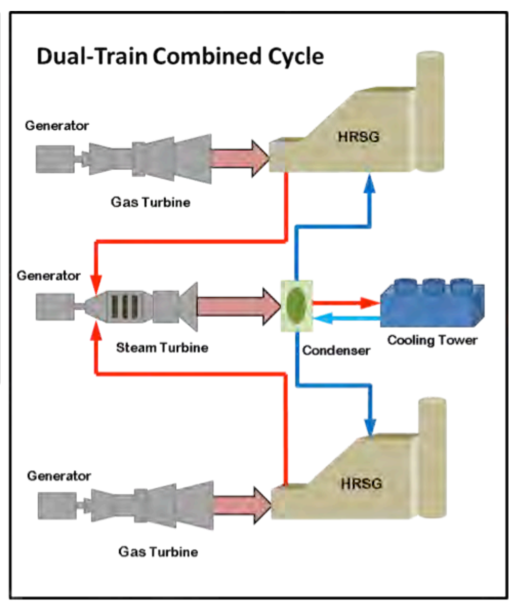


Figure G-8. Combined Cycle Plant: Single-Train and Dual-Train

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.

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.

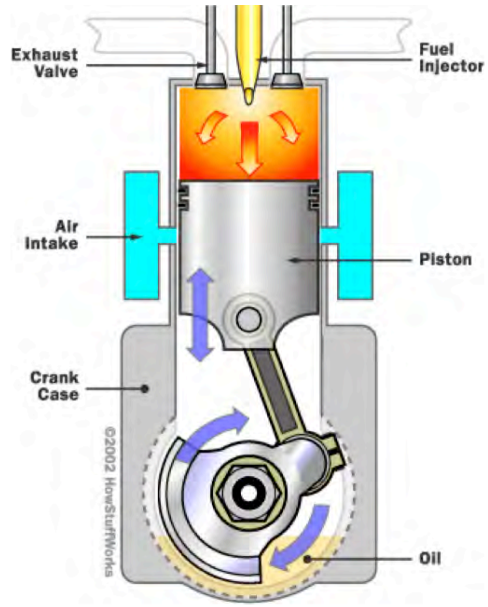


Figure G-9. Diesel Engine

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.

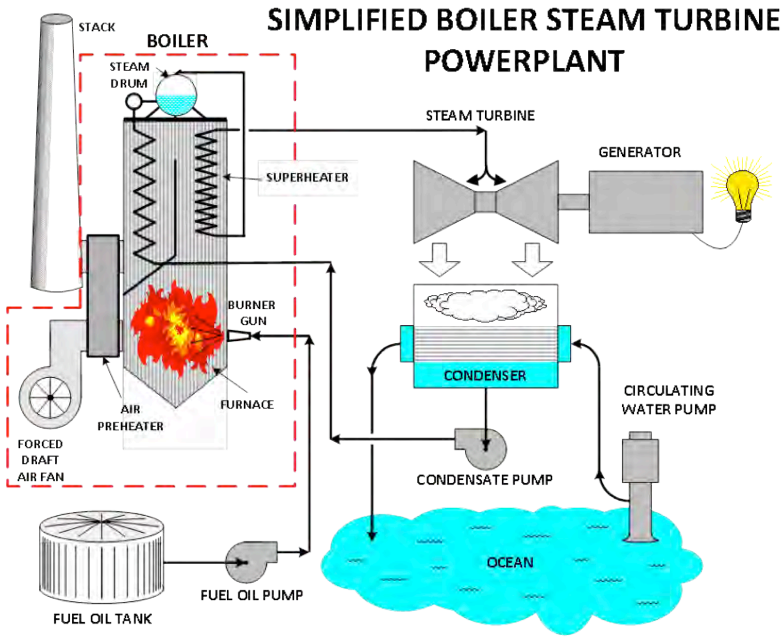


Figure G-10. Simplified Boiler Steam Turbine

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.

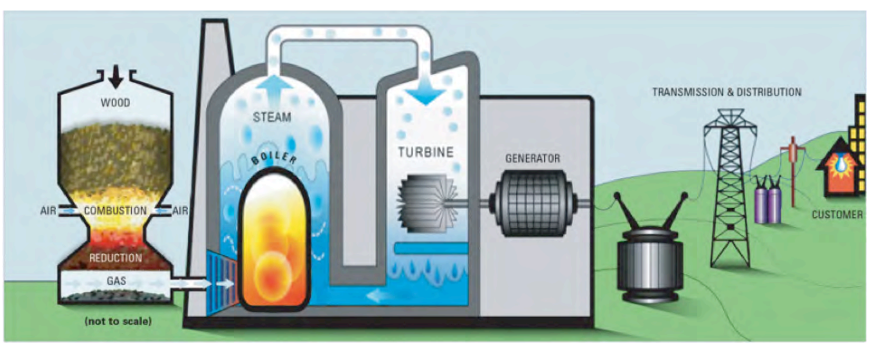


Figure G-11. Biomass Gasification

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.

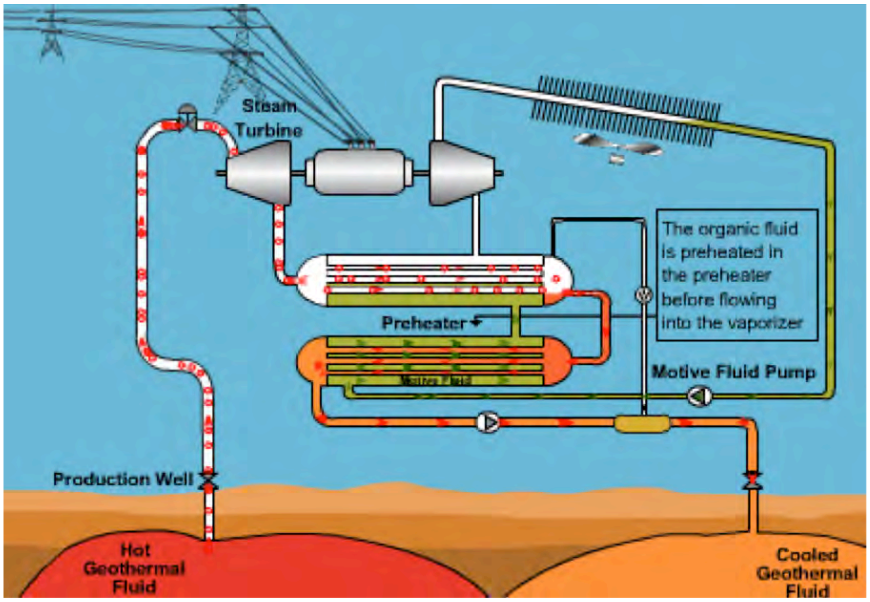


Figure G-12. Geothermal Hybrid Plant

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							PSIP Resource Option?	Comments
	0	1	2	3	4	5	6		
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 Hawaiʻi

Liquefied natural gas (LNG) is critical to reducing customer bills and improving environmental quality in Hawaiʻi. 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 Hawaiʻi'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 Hawaiʻi.

DELIVERING LNG TO HAWAIʻI

Natural gas is not indigenous to Hawaiʻi and must first be liquefied into LNG to be cost effectively transported to Hawaiʻi. LNG can be imported to Hawaiʻi 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 Hawaiʻi 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 Hawai'i 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 Hawai'i 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 Hawaiʻi 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

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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.

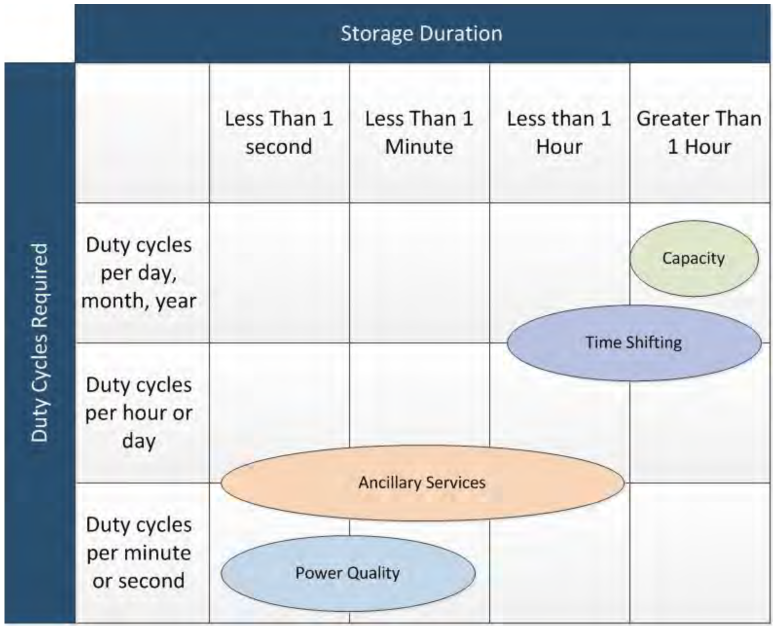

Figure J-1. Energy Storage Applications[13]

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 Hawaiʻi 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	Technology					
	Storage Duration / Discharge	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	Technology					
	Storage Duration / Discharge	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

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	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.

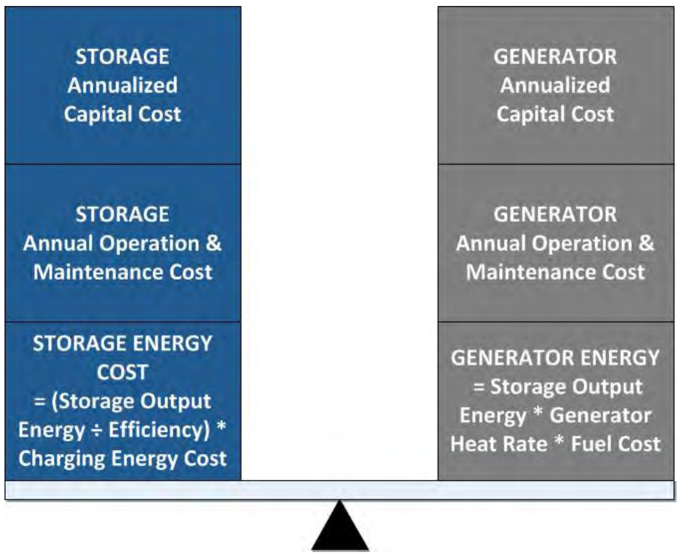

Figure J-2. Energy Storage Economics for Capacity

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.

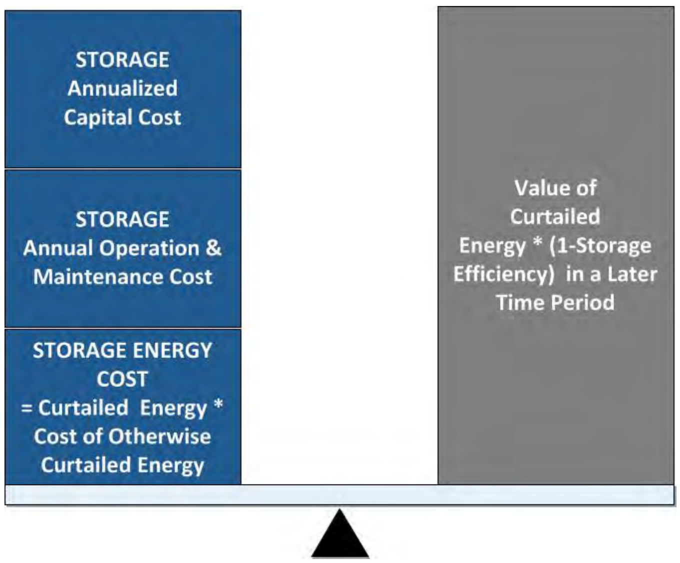

Figure J-3. Energy Storage Economics for Managing Curtailment

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.

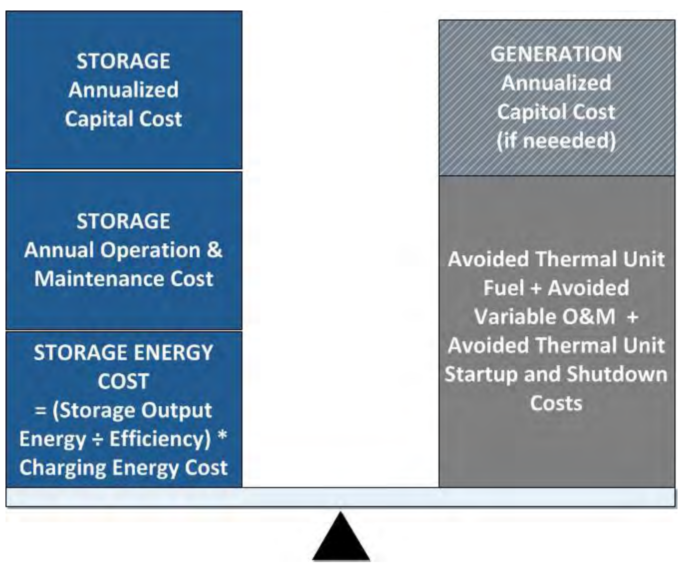

Figure J-4. Energy Storage Economics for Ancillary Services

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 Maui Electric Company.

TRANSFORMATIONAL INVESTMENTS

The transformation of the Maui, Lanai, and Molokai electric grids to reliably and cost effectively enable more renewable generation requires significant investment in virtually every aspect of the business. Investments ranging from new renewable generation resources to enabling technologies for demand side resources and from DGPV enabling grid reinforcements to infrastructure for lower-cost LNG fuel will transform the islands' grids. These transformative investments are described below more in depth.

Liquefied Natural Gas (LNG)

In an effort to reduce customer costs, the Hawaiian Electric Companies are 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).

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 Hawai'i 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 and regasification terminal (likely located in Pearl Harbor). Once regasified, natural gas would be distributed by pipeline to generating stations where it would be consumed[1]. It is anticipated that development, permitting, and implementation of a bulk LNG import and regasification terminal for Hawaiʻi will take up to eight years to complete, and could possibly be placed in service in 2020 to 2022.

Regarding containerized LNG, the Hawaiian Electric Companies 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, the Companies intend 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, the Hawaiian Electric Companies 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 on Maui, Molokai, and Lanai, 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, related to both energy storage and communications, enable the Company to comply with its system security and reliability standards and maintain compliance with these standards through the remainder of the study period.

[1] LNG would continue to be delivered in ISO containers to the neighbor islands.

Facilitation of New or Renewable Energy

Battery Energy Storage Systems (BESS) for Molokai and Lanai, including transmissions and distribution upgrades to accommodate them, are included to facilitate additional renewable energy on those islands. The BESS will allow for the addition of utility scale as-available generation as well as accommodate additional customer sited DG. For Maui, modifications to units M14 and M16 at Maalaea Power Plant are included to reduce the units minimum operating load. These modifications will lower the amount of generation by Maui Electric in order to increase the as-available generation accepted to the Maui system.

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. This plan calls for investments to enable "clearing the existing queue" within the next 18 months, and investments enabling total interconnected DGPV to reach approximately 135 MW for Maui County by 2030. This will continue to provide our customers with an important option to manage their electricity costs and contribute to meeting State RPS goals.

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 Hawaiian Electric 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 Hawaiʻi. To accomplish this, we plan to invest in smart grid.

Two-Way Communications System

The backbone of our Telecom System (fully owned by the Hawaiian Electric Companies) acts as an enabler for all of our operational and corporate business applications, including the smart grid applications. The Hawaiian Electric 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 UtilityIQ) 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

Although this component represent a small portion of costs of Hawaiian Electric's Smart Grid program, the Hawaiian Electric Companies believe in a proactive, transparent, and sustained communication effort to educate and engage our customers is critical to successfully rolling out 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 Hawaiian Electric 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, Flexible 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 increased 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" Kahului units 1 and 2 at the end of February 2014. These units were deactivated but are laid up in a manner that they could be returned to service in an emergency condition. The Kahului Power Plant is scheduled to be retired in 2019.

We intend to further retire/deactivate generating units as new generation and load situations allow. An aggressive plan for deactivation was created and can be adjusted as situations dictate.

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.

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.

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. This category also includes the MPP Tsunami Mitigation project to install infrastructure to mitigate risks to the Maalaea Power Plant, which is in the tsunami inundation zone, and the Waena T&D project, to relocate the Maui Operations Center (Dispatch, Data Center, and Communications) to a facility outside of the tsunami inundation zone.

Asset Management

The asset management category includes costs for the replacement of switchgear, circuit breakers, cable, 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.

Customer Connections

The Company will need to connect new customers throughout the 2015–2030 period. The work in this category includes meter installations.

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

This category consists of information technology project and program hardware and software costs.

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

Reliability

M0000107: Kuihelani Substation

Install a new 10/12.5 MVA, 69-12kV transformer, 12kV switchgear and related equipment at a new substation site in Kahului designed to accommodate future load growth.

M0001039: Kaonoulu Sub

Design and construct a new substation to be located between Ma'alaea Power Plant and Kihei Substation 35 to accommodate current and future load growth. The substation will initially be installed with two 10/12.5 MVA transformers, switchgear and related equipment.

M0001051: Kaonoulu Substation T&D Feeder

Design and construct a new substation to be located between Ma'alaea Power Plant and Kihei Substation 35 to accommodate current and future load growth. The substation will initially be installed with two 10/12.5 MVA transformers, switchgear and related equipment.

M0001251: M19 Capital Overhaul

50,000 hour combustion turbine overhaul.

M0001304: Kuihelani T&D

Install a new 10/12.5 MVA, 69-12kV transformer, 12kV switchgear and related equipment at a new substation site in Kahului designed to accommodate future load growth.

M0001305: Kuihelani Comm

Install a new 10/12.5 MVA, 69-12kV transformer, 12kV switchgear and related equipment at a new substation site in Kahului designed to accommodate future load growth.

M0001543: M14 Capital Overhaul

50,000 hour combustion turbine overhaul.

M0001705: MPP Tsunami Mitigation

Install infrastructure to mitigate risks to the Maʻalaea Power Plant, which is in the tsunami inundation zone.

M0001711: Waiinu-Kanaha 69kV Upgrade

The Company continues to explore non-transmission alternatives to address the need to provide voltage support for Central Maui, and has included the costs for these projects as a placeholder. The placeholder projects are for the upgrade of 4.2 miles of an existing 23kV transmission line to 69kV and upgrade the Waiinu, Kahului and Kanaha substations; upgrade 9 miles of an existing 69kV transmission line conductors starting at MPP to Puʻunene Substation 4; upgrade 7.4 miles of an existing 69kV transmission line conductors starting at Maʻalaea Power Plant to Waiinu Substation 36.

M0001718: M17 50K Capital Overhaul

50,000 hour combustion turbine overhaul.

M0001719: M16 50K Capital Overhaul

50,000 hour combustion turbine overhaul.

M0001720: MPP-Puʻunene Substation 4 Reconduct

The Company continues to explore non-transmission alternatives to address the need to provide voltage support for Central Maui, and has included the costs for these projects as a placeholder. The placeholder projects are for the upgrade of 4.2 miles of an existing 23kV transmission line to 69kV and upgrade the Waiinu, Kahului and Kanaha substations; upgrade 9 miles of an existing 69kV transmission line conductors starting at MPP to Puʻunene Substation 4; upgrade 7.4 miles of an existing 69kV transmission line conductors starting at Maʻalaea Power Plant to Waiinu Substation 36.

M0001721: MPP-Waiinu Substation 36 Reconduct

The Company continues to explore non-transmission alternatives to address the need to provide voltage support for Central Maui, and has included the costs for these projects as a placeholder. The placeholder projects are for the upgrade of 4.2 miles of an existing 23kV transmission line to 69kV and upgrade the Waiinu, Kahului and Kanaha substations; upgrade 9 miles of an existing 69kV transmission line conductors starting at MPP to Puʻunene Substation 4; upgrade 7.4 miles of an existing 69kV transmission line conductors starting at Maʻalaea Power Plant to Waiinu Substation 36.

M0001890: Kaonoulu Substation Land/Easement

Design and construct a new substation to be located between Maʻalaea Power Plant and Kihei Substation 35 to accommodate current and future load growth. The substation will initially be installed with two 10/12.5 MVA transformers, switchgear and related equipment.

M14 50K Overhaul

50,000 hour combustion turbine overhaul.

M19 50K Overhaul

50,000 hour combustion turbine overhaul.

Waena T&D

Relocate the Operations Center (Dispatch, Data Center, and Communications) to a facility outside of the tsunami inundation zone. The new facility will meet current "best practice" control center and disaster resiliency standards.

TRANSFORMATIONAL CAPITAL INVESTMENT PROJECT DESCRIPTIONS

Liquefied Natural Gas

M0001805: M14 LNG Modifications

Plan, design, and construct modifications to the Maʻalaea units to enable operation with liquefied natural gas (LNG).

M0001806: M16 LNG Modifications

Plan, design, and construct modifications to the Maʻalaea units to enable operation with liquefied natural gas (LNG).

M0001807: M17 LNG Modifications

Plan, design, and construct modifications to the Ma'alaea units to enable operation with liquefied natural gas (LNG).

M0001808: M19 LNG Modifications

Plan, design, and construct modifications to the Ma'alaea units to enable operation with liquefied natural gas (LNG).

Moloka'i LNG

Plan, design, and construct modifications to the Moloka'i units to enable operation with liquefied natural gas (LNG).

Waena Gas Pipeline

Install a gas pipeline to transport liquefied natural gas (LNG) from the Company's Waena site to its Ma'alaea Power Plant.

Waena LNG Infrastructure

Install a LNG receiving station, vaporization infrastructure, storage tanks, pumping station, and supporting facilities at the Company's Waena site, to enable the Company to use LNG as a replacement fuel for power generation.

Facilitates New or Renewable Energy

Lana'i Battery

Design, plan, and install a battery energy storage system to address system security requirements identified by Electric Power Systems and to support integration of renewable energy resources.

Lana'i Transmission

Design, plan, and implement transmission and/or distribution infrastructure improvements or additions to integrate the battery energy storage system.

M0001875: M14 Low Load Modifications

Modify Ma'alaea Dual Train Combine Cycle One (DTCC1) to enable reliable operation at lower minimum load, as described in Maui Electric's System Improvement and Curtailment Reduction Plan filed September 3, 2013.

M0001876: M16 Low Load Modifications

Modify Ma'alaea Dual Train Combine Cycle One (DTCC1) to enable reliable operation at lower minimum load, as described in Maui Electric's System Improvement and Curtailment Reduction Plan filed September 3, 2013.

Moloka'i Battery

Design, plan, and install a battery energy storage system to address system security requirements identified by Electric Power Systems and to support integration of renewable energy resources.

Moloka'i Transmission

Design, plan, and implement transmission and/or distribution infrastructure improvements or additions to integrate the battery energy storage system.

Replace Dispatch Generation Levelized Capacity Costs

Maui Kahului 1–4

Retirement costs for removal and remediation.

Maui Ma'alaea 13

Retirement costs for removal and remediation.

Maui Ma'alaea 7, 4, 5, 6, 9, 8

Retirement costs for removal and remediation.

Smart Grid and Demand Response

M0001839: 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

M0001827: TMP West Sites-F/O Miki-Puʻu

Upgrade telecommunications to support efficient, secure, and reliable business and utility operations by improving the speed of service between Miki Basin and Puʻu Kilea.

M0001836: TMP Edge Packet-F/O Kahe-Lah

Extend the packet network to the Lahainaluna Switching Station to support efficient, secure, and reliable business and utility operations.

Maui 20MW Contin BESS (2019)

Install contingency BESS in combination with quick starting generation in South Maui as a non-transmission alternative.

Maui 20MW Reg BESS (2019)

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

CAPITAL EXPENDITURES BY CATEGORY AND PROJECT

Capital Expenditures: 2015–2019

Table K-1 lists the budgeted, annualized dollar amount for each project; with totals by project group and by category, for the years 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 2020–2030 with project totals.

Project	2015	2016	2017	2018	2019
Foundational	**30,224,122**	**50,535,944**	**51,236,291**	**43,095,221**	**68,403,965**
Asset Management	3,398,769	3,065,255	987,721	2,662,061	527,953
Baseline	3,398,769	3,065,255	987,721	2,662,061	527,953
Customer Connections	1,682,020	1,709,592	871,904	898,103	926,179
Baseline	1,682,020	1,709,592	871,904	898,103	926,179
Customer Projects	1,888,772	9,001,582	4,977,049	5,329,360	4,424,774
Baseline	1,888,772	9,001,582	4,977,049	5,329,360	4,424,774
Enterprise IT Framework	928,097	381,901	157,881	191,161	188,277
Baseline	928,097	381,901	157,881	191,161	188,277
Facilities	1,896,131	2,227,735	1,733,500	1,830,518	1,771,225
Baseline	1,896,131	2,227,735	1,733,500	1,830,518	1,771,225
Reliability	19,705,474	33,970,980	42,364,365	32,034,934	60,395,971
M0000102: Kamalii Substation	–	–	–	–	–
M0000107: Kuihelani Substation	228,547	8,269,709	888,445	–	–
M0000986: Ma'alaea-Kamalii 69 kV Line	–	–	–	–	–
M0000988: Ma'alaea Substation 69kV Bkr Addn	–	–	–	–	–
M0001039: Kaonoulu Substation	194,324	1,018,484	7,515,511	–	–
M0001040: Wahikuli Substation Unit #1	–	–	–	–	–
M0001051: Kaonoulu Substation T&D Feeder	6,107	3,710,817	230,200	–	–
M0001247: Kihei-Kamalii 69kv Ln	–	–	–	–	–
M0001248: Wailea-Kamalii 69kv Ln	–	–	–	–	–
M0001251: M19 Capital Overhaul	–	–	–	3,173,768	–
M0001304: Kuihelani T&D	83,198	1,728,673	–	–	–
M0001305: Kuihelani Comm	5,246	1,559,626	140,120	–	–
M0001543: M14 Capital Overhaul	–	–	3,096,659	–	–
M0001705: MPP Tsunami Mitigation	–	–	–	347,393	1,036,688
M0001711: Waiinu-Kanaha 69kV Upgrade	659,618	1,260,494	12,439,611	14,350,144	–
M0001718: M17 50K Capital Overhaul	–	–	3,084,426	–	–

Project	2015	2016	2017	2018	2019
M0001719: M16 50K Capital Overhaul	–	–	–	1,078,383	2,148,560
M0001720: MPP-Pu'unene Substation 4 Reconduct	299,068	2,176,256	298,546	–	–
M0001721: MPP-Waiinu Substation 36 Reconduct	83,079	285,546	2,331,932	–	–
M0001890: Kaonoulu Substation Land/Easement	–	58,022	559,104	–	–
M14 50K Overhaul	–	–	–	–	–
M19 50K Overhaul	–	–	–	–	–
Maui Waiinu to Kanaha	–	–	–	–	39,874,657
Waena T&D	–	–	–	–	–
Baseline	18,146,287	13,903,353	11,779,811	13,085,246	17,336,066
Safety, Security and Environmental	724,859	178,899	143,871	149,084	169,586
Transformational	**19,553,501**	**85,774,836**	**86,902,099**	**58,360,147**	**8,303,876**
DG Enabling Investments	1,303,886	1,303,886	634,856	634,856	634,856
Baseline	1,303,886	1,303,886	634,856	634,856	634,856
Liquefied Natural Gas	9,844,575	46,046,957	39,217,277	–	–
Lana'i LNG conversion	–	3,129,572	–	–	–
M0001804: MPP LNG Infrastructure	–	–	–	–	–
M0001805: M14 LNG Modifications	500,856	1,051,066	980,985	–	–
M0001806: M16 LNG Modifications	500,856	1,051,066	980,985	–	–
M0001807: M17 LNG Modifications	500,856	1,051,066	980,985	–	–
M0001808: M19 LNG Modifications	500,856	1,051,066	980,985	–	–
Maui DTCC1 LNG conversion	–	–	–	–	–
Maui DTCC2 LNG conversion	–	–	–	–	–
Maui LNG Pipeline (Ma'alaea-Waena)	–	–	–	–	–
Maui LNG Regas. – Waena	–	–	–	–	–
Moloka'i LNG	–	3,651,168	–	–	–
Waena Gas Pipeline	2,883,455	22,054,776	23,432,243	–	–
Waena LNG Infrastructure	2,073,810	8,873,639	7,833,645	–	–
Baseline	2,883,885	4,133,537	4,027,450	–	–
New or Renewable Energy	3,450,103	11,287,563	17,947,426	–	–
Lana'i Battery	–	1,462,945	8,748,813	–	–
Lana'i Transmission	–	2,347,179	224,900	–	–
M0001385: Moloka'i Bess	–	–	–	–	–
M0001875: M14 Low Load Modifications	1,573,652	1,496,803	–	–	–
M0001876: M16 Low Load Modifications	1,573,172	1,473,523	–	–	–
Moloka'i Battery	–	1,462,945	8,748,813	–	–
Moloka'i Transmission	–	2,347,179	224,900	–	–
Baseline	303,279	696,989	–	–	–

Project	2015	2016	2017	2018	2019
Replace Dispatch Gen Levelized Capacity Costs	–	–	–	–	0
Maui Kahului 1–4	–	–	–	–	0
Maui Ma'alaea 13	–	–	–	–	–
Maui Ma'alaea 7, 4, 5, 6, 9, 8	–	–	–	–	–
Smart Grid and Demand Response	20,000	13,450,189	10,923,350	1,512,805	1,499,053
M0001839: Smart Grid	–	13,450,189	10,923,350	1,512,805	1,479,053
Baseline	20,000	–	–	–	20,000
System Security Investments	4,934,938	13,686,242	18,179,189	56,212,486	6,169,967
M0001827: TMP West Sites-F/O Miki-Pu'u	–	–	–	2,690,354	–
M0001836: TMP Edge Packet-F/O Kahe-Lah	–	4,340,932	–	–	–
Maui 20MW Contin BESS (2019)	–	–	3,408,542	19,315,074	–
Maui 20MW Reg BESS (2019)	–	–	4,755,466	26,947,643	–
Baseline	4,934,938	9,345,310	10,015,181	7,259,415	6,169,967
Grand Totals	**49,777,623**	**136,310,780**	**138,138,390**	**101,455,368**	**76,707,841**

Table K-1. Capital Expenditures by Category and Project: 2015–2019

Capital Expenditures: 2020–2030 with Project Totals

Table K-2 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	**42,349,549**	**356,143,829**	**220,465,410**	**862,454,338**
Asset Management	2,876,973	15,090,245	16,336,719	44,945,698
Baseline	2,876,973	15,090,245	16,336,719	44,945,698
Customer Connections	1,645,820	8,632,627	9,345,693	25,711,939
Baseline	1,645,820	8,632,627	9,345,693	25,711,939
Customer Projects	10,172,351	53,355,829	57,763,089	146,912,806
Baseline	10,172,351	53,355,829	57,763,089	146,912,806
Enterprise IT Framework	369,650	2,068,884	2,299,038	6,584,889
Baseline	369,650	2,068,884	2,299,038	6,584,889
Facilities	2,421,170	12,699,479	13,748,473	38,328,233
Baseline	2,421,170	12,699,479	13,748,473	38,328,233
Reliability	24,507,327	262,428,128	118,949,409	594,356,590
M0000102: Kamalii Substation	–	–	–	–
M0000107: Kuihelani Substation	–	–	–	9,386,701
M0000986: Ma‘alaea-Kamalii 69 kV Line	–	–	–	–
M0000988: Ma‘alaea Substation 69kV Bkr Addn	–	–	–	–
M0001039: Kaonoulu Substation	–	–	–	8,728,318
M0001040: Wahikuli Substation Unit #1	–	–	–	–
M0001051: Kaonoulu Substation T&D Feeder	–	–	–	3,947,124
M0001247: Kihei-Kamalii 69kv Ln	–	–	–	–
M0001248: Wailea-Kamalii 69kv Ln	–	–	–	–
M0001251: M19 Capital Overhaul	–	–	–	3,173,768
M0001304: Kuihelani T&D	–	–	–	1,811,870
M0001305: Kuihelani Comm	–	–	–	1,704,992
M0001543: M14 Capital Overhaul	–	–	–	3,096,659
M0001705: MPP Tsunami Mitigation	1,113,059	66,816,176	–	69,313,316
M0001711: Waiinu-Kanaha 69kV Upgrade	–	–	–	28,709,868
M0001718: M17 50K Capital Overhaul	–	–	–	3,084,426
M0001719: M16 50K Capital Overhaul	–	–	–	3,226,944
M0001720: MPP-Pu‘unene Substation 4 Reconduct	–	–	–	2,773,870
M0001721: MPP-Waiinu Substation 36 Reconduct	–	–	–	2,700,558
M0001890: Kaonoulu Substation Land/Easement	–	–	–	617,125
M14 50K Overhaul	–	–	3,700,000	3,700,000

K. Capital Investments

Capital Expenditures by Category and Project

Project	2020	2021–2025	2026–2030	Totals
M19 50K Overhaul	–	–	3,700,000	3,700,000
Maui Waiinu to Kanaha	–	–	–	39,874,657
Waena T&D	–	91,000,000	–	91,000,000
Baseline	23,394,268	104,611,952	111,549,409	313,806,394
Safety, Security and Environmental	356,258	1,868,637	2,022,989	5,614,183
Transformational	**5,023,080**	**20,040,412**	**5,534,269**	**289,492,221**
DG Enabling Investments	634,856	613,533	613,533	6,374,262
Baseline	634,856	613,533	613,533	6,374,262
Liquefied Natural Gas	–	–	–	95,108,808
Lana‘i LNG conversion	–	–	–	3,129,572
M0001804: MPP LNG Infrastructure	–	–	–	–
M0001805: M14 LNG Modifications	–	–	–	2,532,907
M0001806: M16 LNG Modifications	–	–	–	2,532,907
M0001807: M17 LNG Modifications	–	–	–	2,532,907
M0001808: M19 LNG Modifications	–	–	–	2,532,907
Maui DTCC1 LNG conversion	–	–	–	–
Maui DTCC2 LNG conversion	–	–	–	–
Maui LNG Pipeline (Ma‘alaea-Waena)	–	–	–	–
Maui LNG Regas. – Waena	–	–	–	–
Moloka‘i LNG	–	–	–	3,651,168
Waena Gas Pipeline	–	–	–	48,370,474
Waena LNG Infrastructure	–	–	–	18,781,094
Baseline	–	–	–	11,044,873
New or Renewable Energy	120,324	631,121	683,252	34,119,787
Lana‘i Battery	–	–	–	10,211,758
Lana‘i Transmission	–	–	–	2,572,079
M0001385: Moloka‘i Bess	–	–	–	–
M0001875: M14 Low Load Modifications	–	–	–	3,070,454
M0001876: M16 Low Load Modifications	–	–	–	3,046,695
Moloka‘i Battery	–	–	–	10,211,758
Moloka‘i Transmission	–	–	–	2,572,079
Baseline	120,324	631,121	683,252	2,434,964
Replace Dispatch Gen Levelized Capacity Costs	–	0	0	0
Maui Kahului 1–4	–	–	–	0
Maui Ma‘alaea 13	–	–	0	0
Maui Ma‘alaea 7, 4, 5, 6, 9, 8	–	0	0	0
Smart Grid and Demand Response	1,366,878	7,731,755	3,320,246	39,824,276
M0001839: Smart Grid	1,366,878	7,731,755	3,320,246	39,784,276

Project	2020	2021–2025	2026–2030	Totals
Baseline	–	–	–	40,000
System Security Investments	2,901,022	11,064,003	917,238	114,065,087
M0001827: TMP West Sites-F/O Miki-Pu‘u	–	–	–	2,690,354
M0001836: TMP Edge Packet-F/O Kahe-Lah	–	–	–	4,340,932
Maui 20MW Contin BESS (2019)	–	–	–	22,723,616
Maui 20MW Reg BESS (2019)	–	–	–	31,703,110
Baseline	2,901,022	11,064,003	917,238	52,607,075
Grand Totals	**47,372,629**	**376,184,241**	**225,999,679**	**1,151,946,559**

Table K-2. Capital Expenditures: 2020–2030 with Project Totals

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L. Preferred Plan Development

Sensitivity analyses are performed to test how a particular condition would affect the Base Plan and if it should be considered for incorporation into the Preferred Plan. The analyses were conducted by the three independent modeling teams (Hawaiian Electric, Black & Veatch, and PA Consulting) and the results are described in this appendix.

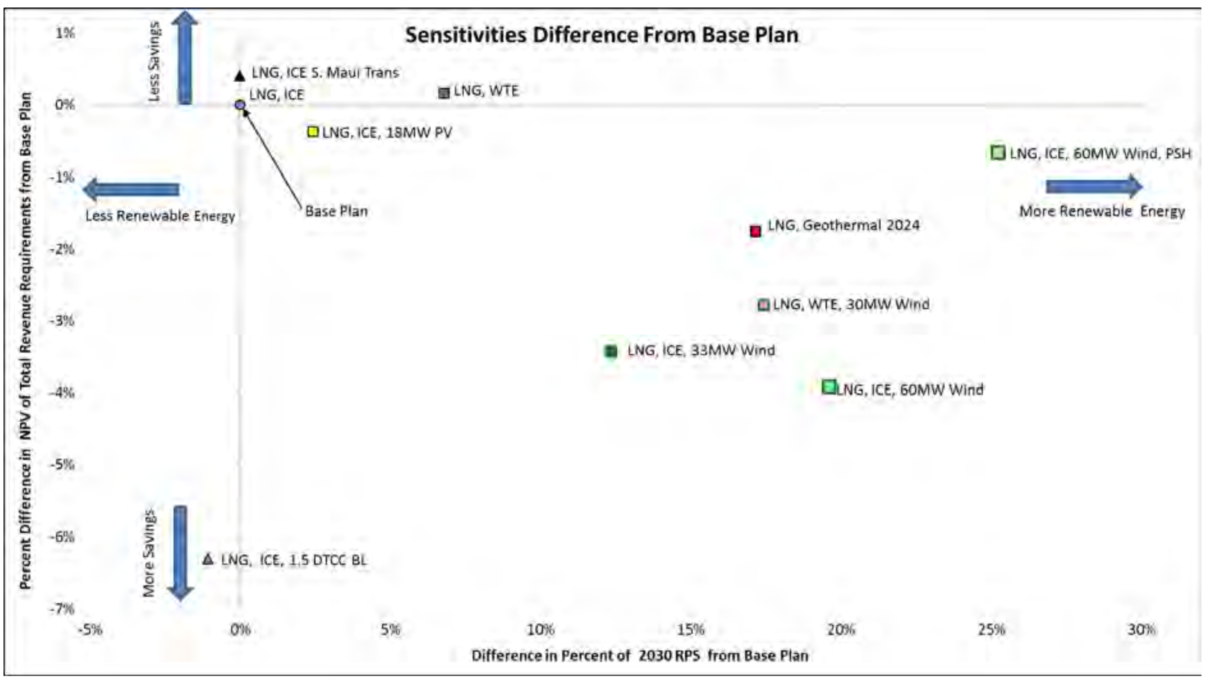


Figure L-1. Sensitivity Difference from Base Plan

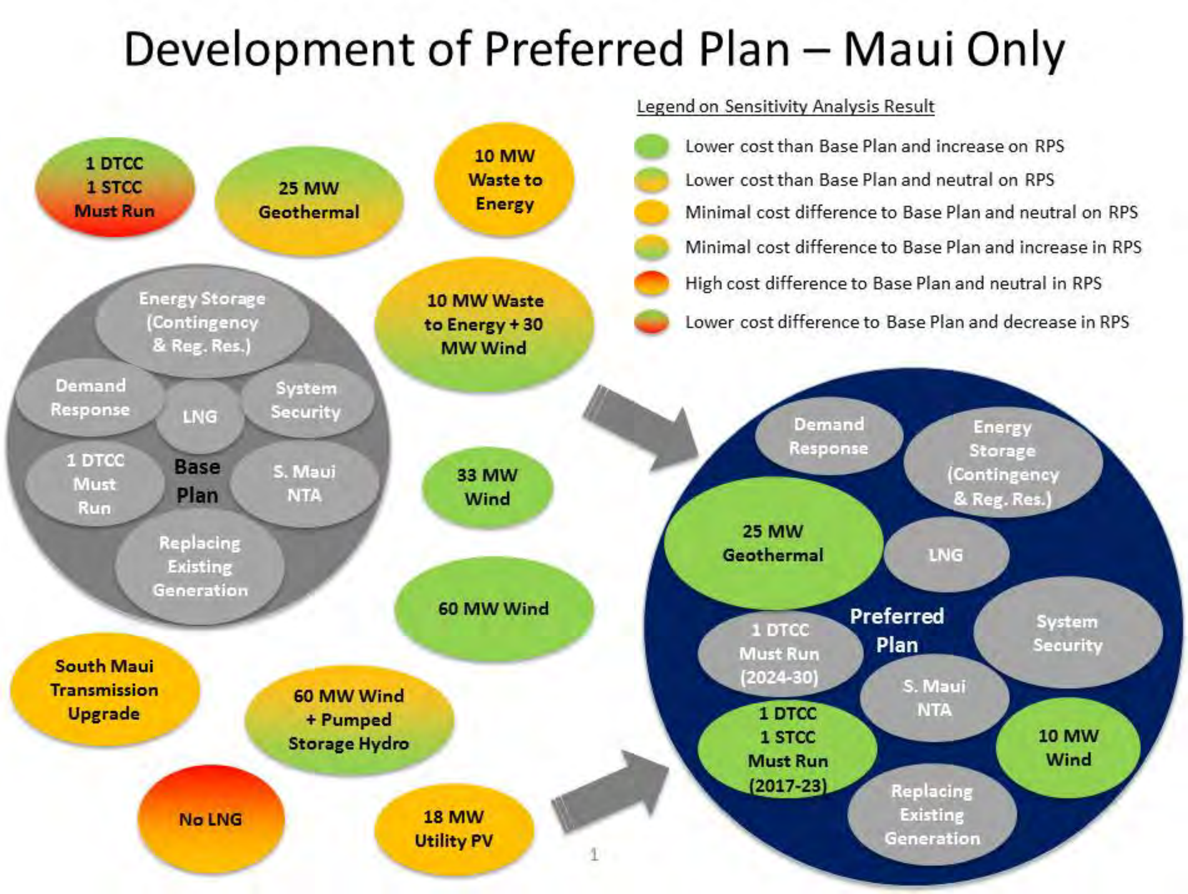


Figure L-2. Process for Developing the Preferred Plan

BASE PLAN

As a platform to work from the Base Plan for Maui incorporated the usage of lower-cost LNG fuel for the most efficient must-run units currently on the Maui system as well as in new generation to reduce customer bills. The Base Plan adds new flexible internal combustion engines (ICE) units to replace the older units at Kahului Power Plant. Removing the must-run status from units while maintaining system security is made possible by including energy storage technology. Non-transmission alternatives to building the Ma'alaea to Kamali'i transmission line also incorporated the use of energy storage systems (ESS) and new quick-starting ICE units. The Base Plan includes the following:

- Conversion of dual-train combined cycles from diesel to LNG.
- Retirement of Kahului Power Plant.

- HC&S contract extended till replacement capacity added.
- Firm generation and contingency ESS in South Maui as a non-transmission alternative.
- Waiʻinu to Kanaha Transmission upgraded for system security.
- Lower minimum load modification of Maʻalaea 14-15-16 combined-cycle.
- Internal combustion engines operating on LNG added for replacement capacity and additional capacity as needed.
- Regulating ESS added for system security.
- DR for demand behavior modification and capacity.

EXISTING GENERATING UNITS

The Base Plan included some assumptions that warranted sensitivity analyses to test their robustness. The sensitivity analyses to test the future of existing generating units included must-run units.

Must-Run Units

The current operation of must-run units include Kahului Units 3 & 4 thermal steam units at Kahului Power Plant and one dual-train combined cycle (DTCC) unit at Maʻalaea Power Plant. In the Base Plan, we assumed only one DTCC unit would be must-run once Kahului Power Plant was retired. Sensitivity analyses performed included the addition of a single-train combined cycle unit at Maʻalaea Power Plant as a must-run unit in the Base Plan. In comparison to the Base Plan the analysis showed the must-run unit addition of a single-train combined cycle unit decreased the overall system costs by about 6 to 7% and decreased the RPS percentage in 2030 by about 0 to 1 %.

SOUTH MAUI TRANSMISSION LINE

In the Base Plan, it was assumed that the required 20 MW contingency ESSs would be placed in South Maui and would be accompanied by three LNG-fired ICE thermal units (at 8.14 MW each) that were needed for capacity when Kahului Power Plant is retired as a non-transmission alternative. This sensitivity analysis assumed that the Maʻalaea to Kamaliʻi transmission line was installed instead of locating the three ICE units in South Maui and building an LNG regasification plant there. In comparison to the Base Plan the analysis showed that the transmission line increased the overall system costs by about one percent, and there would be no change in RPS. It is important to note the contingency ESS and the ICE's have to be located on the same circuit in order to realize the benefits.

ADDITIONAL RENEWABLE ENERGY RESOURCES

The Base Plan includes solar distributed generation (DG-PV) which was incrementally added over time. Sensitivity analyses looked at the effect of adding additional renewable energy resources such as:

- Wind
- Utility-Scale PV

Wind

In the Base Plan, it was assumed that the 72 MW of existing wind farms continued to operate and no additional wind farms were added. Sensitivities around the wind farms include the addition of 33 MW and 60 MW of additional wind farms.

33 MW Wind

This sensitivity analysis assumed that 33 MW of wind farms were added to the existing 72 MW of existing wind farms. In comparison to the Base Plan the analysis showed that the additional wind farms decreased the overall system costs by about 3 to 4% and increased the RPS percentage in 2030 by about 12 to 13 %.

60 MW Wind

This sensitivity analysis assumed that 60 MW of wind farms were added to the existing 72 MW of existing wind farms. In comparison to the Base Plan the analysis showed that the additional wind farms also decreased the overall system costs by about 3 to 4% and increased the RPS percentage in 2030 by about 25 to 26 %.

Utility-Scale PV

In the Base Plan, no utility-scale PV farm was assumed to be added to the system. For sensitivity an 18 MW utility-scale PV farm is added. In comparison to the Base Plan the analysis showed that the additional PV farm decreased the overall system costs by about 0 to 1% and increased the RPS percentage in 2030 by about 2 to 3%.

Pumped Storage Hydro

Pumped storage hydro has operating characteristics similar to a load-shifting energy storage system This resource was assumed to provide firm capacity that can defer future generation and increase renewable energy utilization during excess energy periods. Sensitivity analyses were conducted to examine the effect of adding a pumped storage hydro resource on the system.

25 MW Pumped Storage Hydro and 60 MW Wind

This sensitivity analysis coupled a 60 MW Wind Farm with a 25 MW pumped storage hydro. The energy provided by the 60 MW Wind Farm was used to charge the pumped storage hydro during the morning and day periods when curtailment occurred. The stored energy was then discharged at night during the evening peak. In comparison to the Base Plan the addition of the 25 MW pumped storage hydro and the 60 MW Wind Farm decreased the overall system costs by about 0 to 1% and increased the RPS percentage in 2030 by about 25 to 26%.

When comparing the 60 MW Wind Farm Plan with the 60 MW Wind Farm Plan plus the addition of the 25 MW pumped storage hydro, the result showed pumped storage increased the overall system costs by about 3 to 4% and increased the RPS percentage in 2030 by about 5 to 6%.

FUTURE FIRM RENEWABLE GENERATION MIX

Sensitivity analyses looked at the effect of adding firm renewable energy resources such as:

- Geothermal
- Waste-to-Energy

25 MW Geothermal

This sensitivity analysis assumed a must-run 25MW geothermal plant was added to the system. In comparison to the Base Plan the analysis showed that the geothermal plant decreased the overall system costs by about 1 to 2% and increased the RPS percentage in 2030 by about 17 to 18 %.

10 MW Waste-to-Energy

This sensitivity analysis assumed a must-run 10MW waste-to-energy plant was added to the system. In comparison to the Base Plan the analysis showed that the waste-to-energy plant increased the overall system costs by about 0 to 1%, but increased the RPS percentage in 2030 by about 6 to 7 %.

10 MW Waste-to-Energy and 30 MW Wind

This sensitivity analysis assumed a must-run 10MW waste-to-energy plant and a 30 MW wind farm was added to the system. In comparison to the Base Plan the analysis showed that the combination of the waste-to-energy plant and new wind farm decreased the overall system costs by about 2 to 3% and increased the RPS percentage in 2030 by about 17 to 18 %.

UTILIZING RENEWABLE ENERGY RESOURCES

Each sensitivity analysis looked at the effect of adding renewable energy resources. Along with cost evaluation, utilization of renewable energy with respect to excess energy was also evaluated. Maui Electric's plan to increase operational flexibility through modifications of existing generation, retirement of existing generation, and addition of new flexible generation, allows us to optimize utilization of renewable energy to avoid curtailment.

% RE Utilized	LNG, ICE	LNG, ICE S. Maui Trans	LNG, ICE, 1.5 DTCC BL	LNG, ICE, 33MW Wind	LNG, ICE, 60MW Wind	LNG, ICE, 60MW Wind, PSH	LNG, ICE, 18MW Central PV	LNG, Geothermal 2024, KPP R2019	LNG, Waste to Energy	LNG, Waste to Energy, 30MW Wind	Maui PSIP Preferred Plan
	99.4%	99.4%	98.3%	97.3%	92.4%	94.6%	98.7%	99.4%	99.4%	97.5%	98.4%

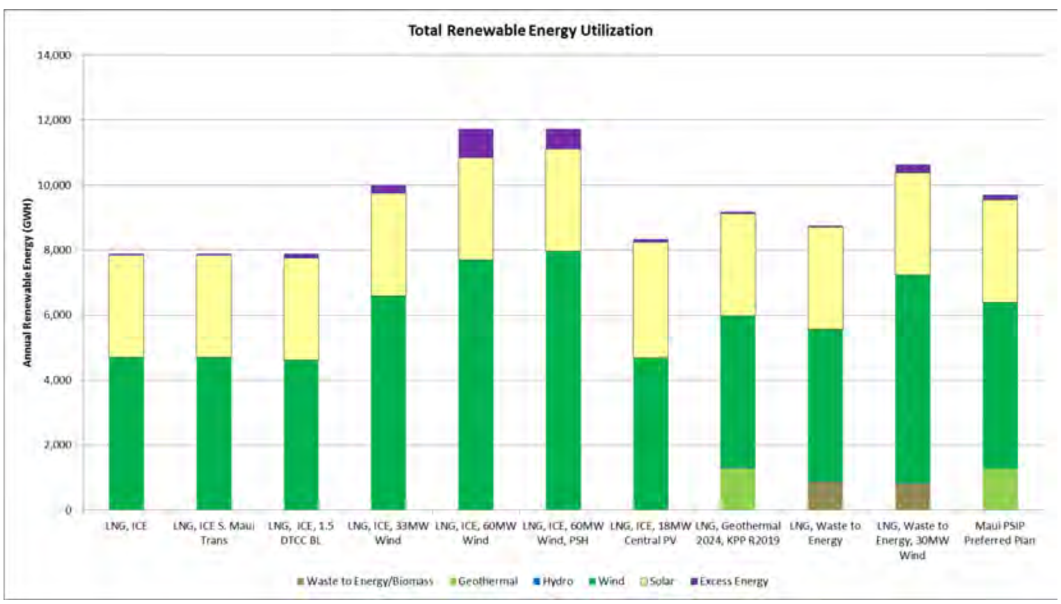


Figure L-3. Total Renewable Energy Utilization by Sensitivity

PREFERRED PLAN

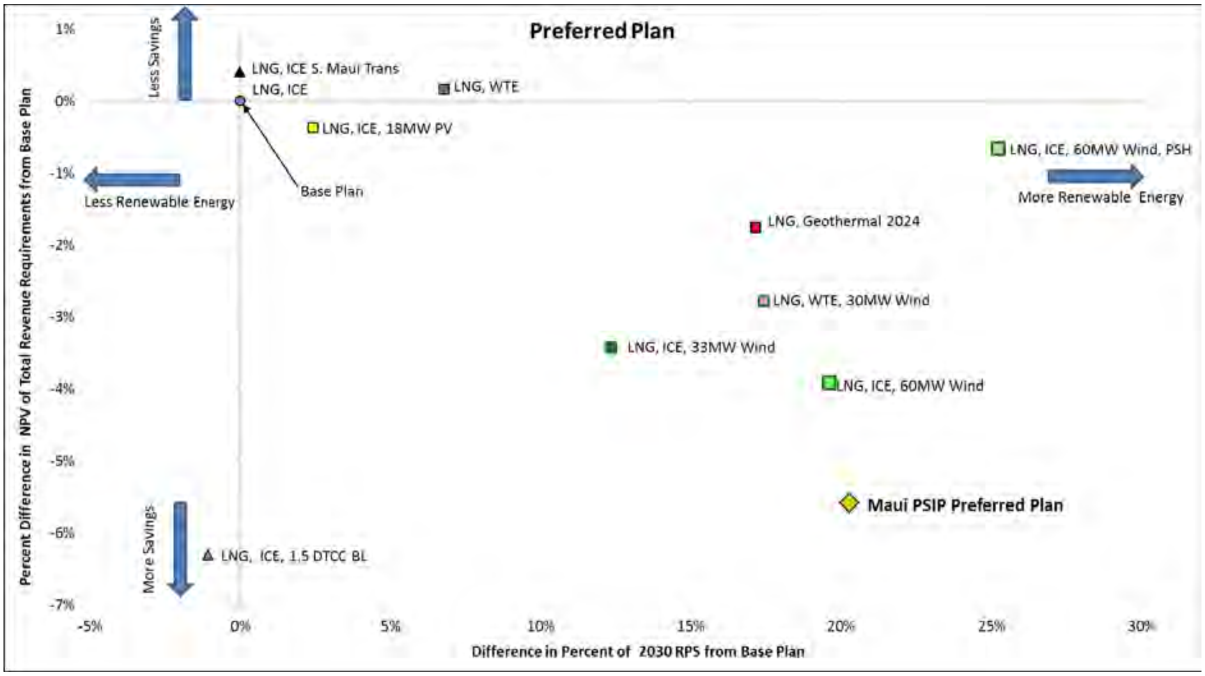


Figure L-4. Preferred Plan

The preferred plan was the culmination of benefits from the individual sensitivities to provide the customers of Maui the largest cost savings while still increasing the amount of clean renewable energy into the mix of system resources.

- Non-transmission alternative in South Maui
- LNG
- Must-run 1½ DTCC
- Reduce fossil fueled must-run units when possible
- 10 MW Wind
- 5 MW Geothermal

The Preferred Plan incorporated demand response programs demand behavior modification, capacity, ramping, offline reserve, and load shifting. The analysis assumed the ICE units fueled by diesel together with the 20 MW contingency ESS were used as the non-transmission alternative in South Maui until the need could be satisfied by geothermal. 1½ DTCC must-run units fueled with LNG to take advantage of the cheaper fuel in earlier years until geothermal could be implemented to provide renewable must-run energy. Fossil fueled must-run units were removed with the decommissioning of Kahului Power Plant and then further reduced from 1½ DTCC to 1 DTCC units when geothermal is available for system security. Additional wind energy was incorporated to further reduce expensive diesel consumption.

When compared to the Base Plan, the Preferred Plan decreased the overall system costs by about 5 to 6% and increased the RPS percentage in 2030 by about 20% to 21%.

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.

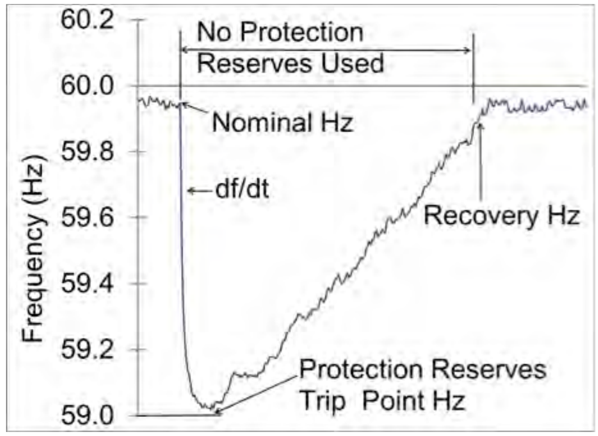
R1.2.1. Each Balance Authority system will be planned to meet the requirements Disturbance Recovery performance in HI-BAL-002 Disturbance Control Performance.

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.

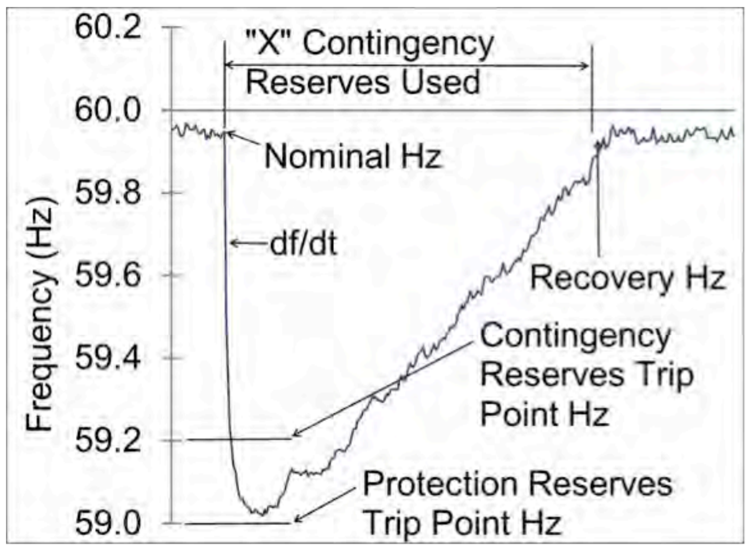
R1.2.4. The system will be planned such that the resultant impacts of inertia, unit response or reserve response will meet the system frequency response characteristics following the loss of the largest single contingency as defined below.

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

Hawaiian Electric
Maui Electric
Hawai'i Electric Light

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 Hawaiʻi. For future as-available resources where no Hawaiʻi 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.

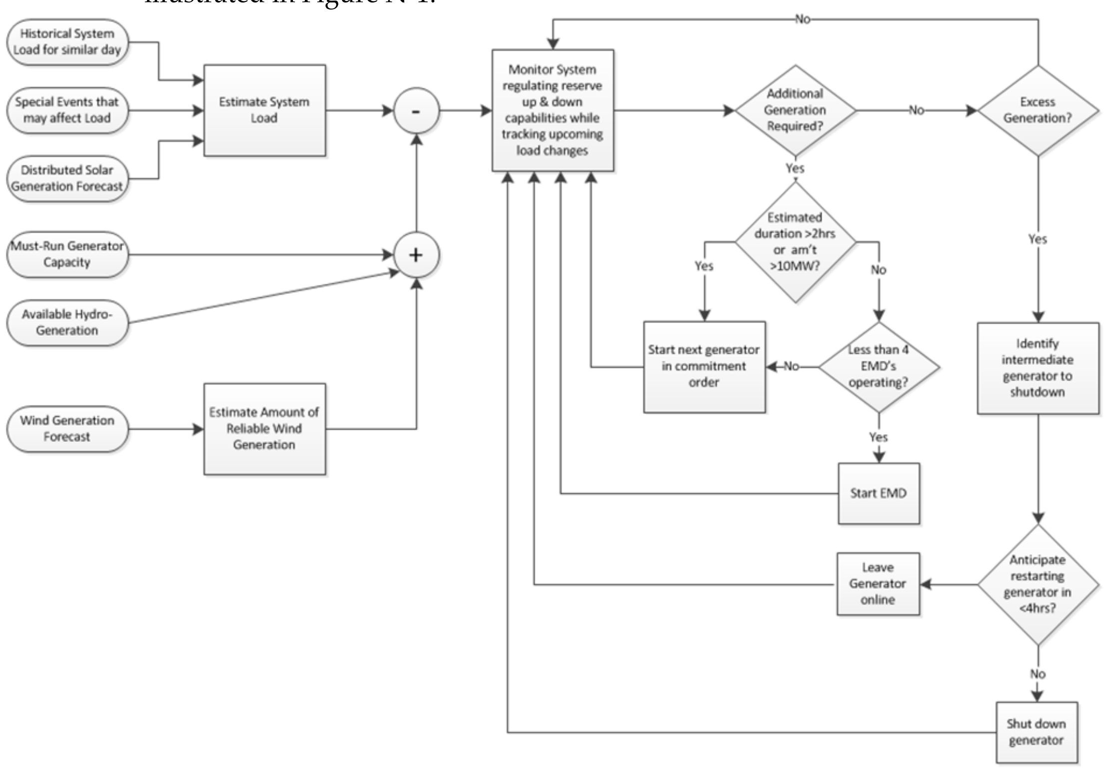

Figure N-1. Daily Generation Dispatch Process

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 Hawai'i Clean Energy Day event on July 22, 2014 with positive public reaction.

In light of this information already being developed for public display, 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.

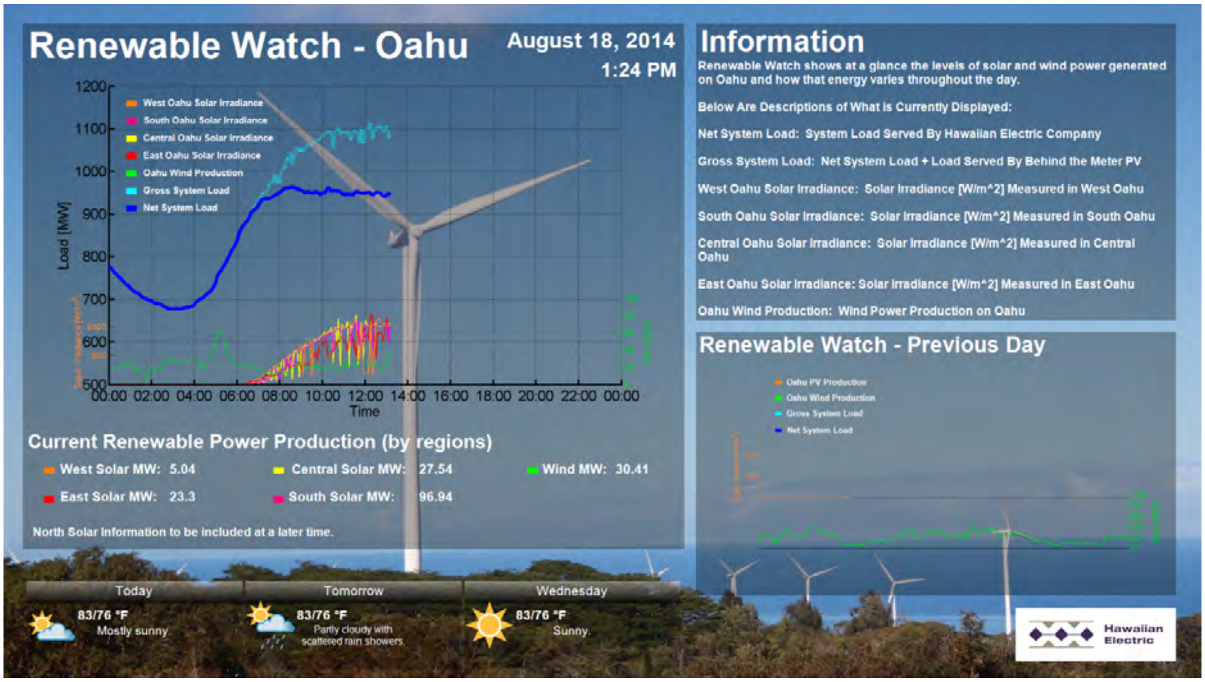

Figure N-2. Renewable Watch–O'ahu Website Screenshot of Information Displayed for August 18, 2014.

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. Non-Transmission Alternative Studies

Non-transmission alternatives (NTAs) were evaluated to avoid transmission capital investments. Two transmission studies completed by Hawaiian Electric Transmission Planning Department evaluated as possible solutions to address the need for capacity and avoid construction of new transmission lines and substations for the following system issues:

- Under voltages, thermal overloads and voltage stability on the Central Maui 23KV system due to the retirement of KPP.
- Under voltages and voltage stability in South Maui; and Overloading of distribution substations.

Those two studies comprise this appendix.

Maalaea-Kamalii Transmission Line Alternatives

Prepared by
Transmission Planning Division
System Planning Department
Hawaiian Electric Company

Original Date: October 16, 2013
Revision Date: February 20, 2014

TPD #2014-03-Rev1

Maalaea-Kamalii Transmission Line Alternatives

Prepared by: ______________________________
LoriAnn Fukuda
Planning Engineer I, Transmission

Approved by: ______________________________
Gemini Yau
Lead Planning Engineer, Transmission

____
Ronald Bushner
Director, Transmission Planning

Revision History

Revision Number	Date	Reason
0	10/16/2013	Original TPD #2013-26
1	2/20/2014	Updated TPD reference number, TPD #2014-03-Rev1, for reissue in 2014. Further explanations of alternatives and reference documents were added with no substantial changes.

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INTRODUCTION

Transmission Planning Division has determined that the Kihei and Wailea substations will have low voltage issues and favorable conditions of possible voltage collapse in the event of an N-1 contingency. An N-1 contingency is when there is a planned or unplanned outage of a transmission facility, such as a transmission line, while all other transmission facilities are still in service. Currently, majority of the South Maui load is served by the Maalaea-Kihei transmission line shown in Figure 1 below. The most severe N-1 contingency occurs with the loss of this line. In the event of losing the Maalaea-Kihei line, low voltage quality at substations in the South Maui area could cause a voltage collapse to occur suddenly. A voltage collapse occurs when the system cannot supply enough reactive power to meet the load demand. This could result in a system network collapse, in other words, an island wide blackout which can take hours to be restored. Possible alternatives were considered to address this issue.

The gross system peak load is forecasted to be 248.9 MW in 2024, the year this study focuses on. The system gross load peaks are shown in Appendix A and do not include demand side management (DSM). At this load level, the South Maui load is approximately 62 MW—25% of the system load.

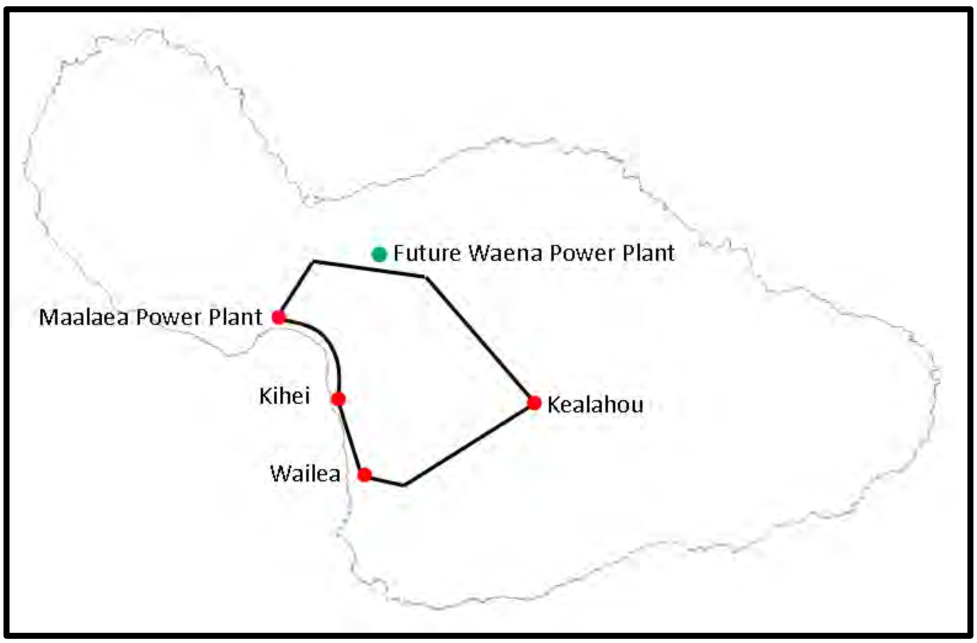

Figure 1: Existing South Maui transmission lines and future Waena Power Plant site

ASSUMPTIONS

The Seimens PTI Power System Simulator, PSS®E, is the program used to study power system transmission networks for steady state and transient conditions. This study uses PSSE powerflow models for the Maui transmission system with following assumptions:

- 2022 peak basecase – Year 2022 model of Maui system at peak load level

- Basecase load scaled uniformly to 248.9 MW—the forecasted load for 2024
- HC&S output—0 MW, end of contract starting January 1, 2015
- Kahului Power Plant retirement starting January 1, 2019
- Conversion of Waiinu-Kanaha 23kV to 69kV in 2018
- Capacitor banks at Kihei—two cap banks at 3.6MVARs each
- Capacitor banks at Wailea—two cap banks at 3.6MVARs each
- Kaheawa Windfarm (KWP) I and II online—with maximum output of 30MW and 21MW respectively
- Auwahi Windfarm—offline (as-available generation)
- Waena Power Plant online with total output of 17 MW (future power plant with a Stage 1plans have two 8.5 MW internal combustion engines (ICE))
- K1 and K2 available as synchronous condenser—6.25MVARs each

DISCUSSION

Under the N-1 contingency, voltages drop below 0.90 per unit (pu) and violates Maui Electric Criteria for Transmission Planning, shown in Table 1. N-1 contingencies use emergency conditions when evaluating voltage levels for the planning criteria. These low voltages occur because the system cannot move power from one area to another over the weak transmission lines without incurring major losses. In other words, the generated MWs cannot be transferred through the long and small conductors. This transfer capability depends on the generation, customer demands and system conditions. The system will not be able to meet the load demands of South Maui due to the large amount of power needed. Furthermore, a concern with low voltages is the possibility of a voltage collapse. When a voltage collapse occurs there could possibly be an island wide blackout which may take hours before service can be restored.

The investigation of the low voltages due to transfer capability limits were first address in the *8 Year Transmission Study, 2009-2016, South/Up-Country Maui* report, see Appendix A.

Table 1:   Maui Electric Voltage Level Criteria

Criteria	Normal Conditions	Emergency Conditions
Over voltage violation	> 1.05 pu	> 1.05 pu
Under voltage violation	< 0.90 pu	< 0.90 pu

To provide a reliable system, the best option should extend the transfer limits or create a reasonable margin from the transfer limits. Extending the transfer limits can be accomplished by providing a shorter path for power flow under an N-1 condition or reducing the load in South Maui. The following transmission and non-transmission possible solutions are discussed in this study:

- Maalaea-Kamalii line
- Distributed Generation (DG)
- Synchronous Condenser

- Static Capacitors
- Energy Storage System (ESS)
- Kealahou-Kihei line
- Hybrid (DG & ESS)
- Combined Heat and Power (CHP)
- Load Curtailment
- Demand Response

These alternatives were considered because they could raise the bus voltages in South Maui to meet the planning criteria. This could be accomplished with the installation of new transmission facilities, new reactive devices, or with load reduction.

Transmission facilities will provide a new power flow to the area. During the N-1 contingency the other path to serve the load at Kihei Substation is through the Maalaea-Kealahou line. With this route power must travel a distance of approximately 28 miles to Kihei Substation. To shorten the distance, new transmission lines were considered. Equipment such as the synchronous condenser and static capacitor banks are common devices used for voltage support. These devices provide reactive power and help control voltages at the load. However, during the event of a voltage collapse, these devices become ineffective. The reduction of load in the area could be thru the addition of generation or load shedding. Various power sources such as DG, ESS or CHP was considered as possible generation could be added in South Maui. Load reduction can also be accomplished by shedding load through programs like demand response or with existing under voltage load shedding scheme, installed as an interim solution.

The best solution should extend the transfer limits or allow the system to be a reasonable margin away from the transfer limit. Although some alternatives considered can increase the bus voltages in the area to meet the planning criteria, it cannot provide voltage support during a voltage collapse. If this problem is not addressed a voltage collapse event is possible and would cause a widespread outage.

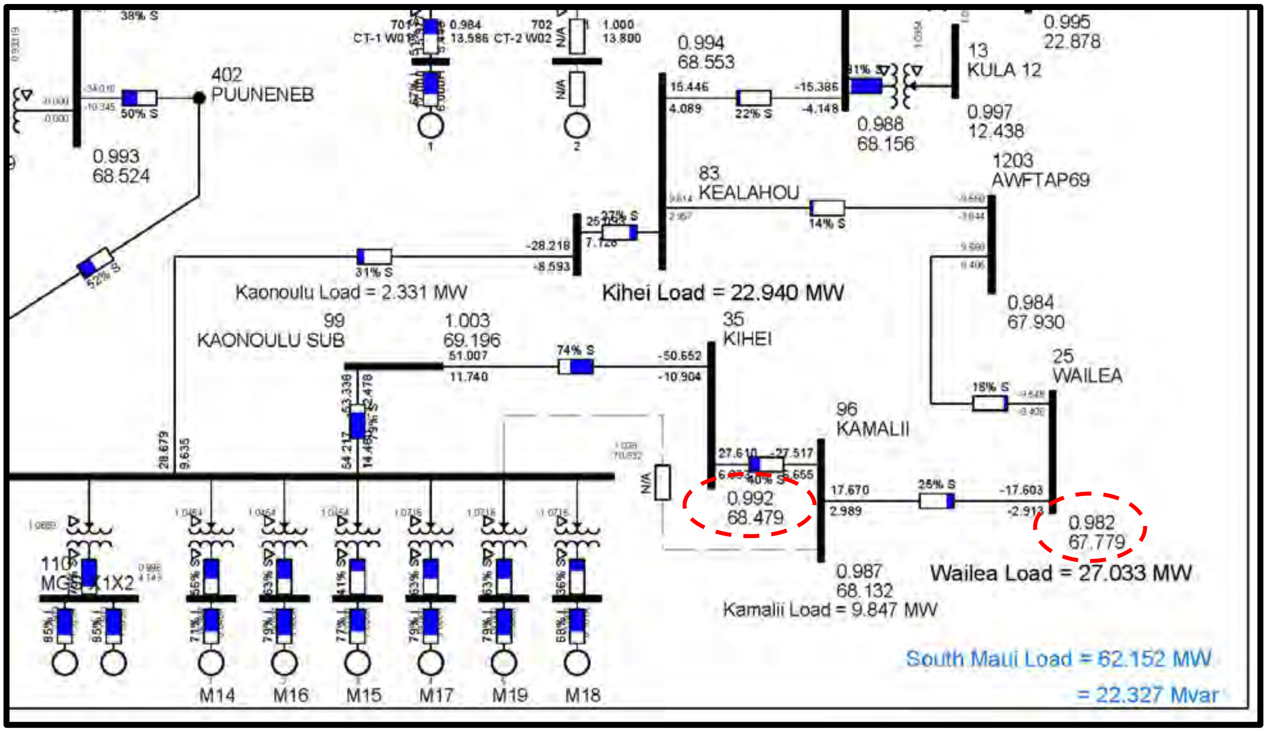

Figure 2: 2024 Normal Conditions

Figure 2 shows 2024 normal conditions without the Maalaea-Kamalii 69kV transmission line. Under normal conditions one capacitor bank at Kihei and one capacitor bank at Wailea are online.

Under the N-1 contingency, voltages drop below 0.90 pu, violating the Transmission Planning criteria, as shown in Figure 3.

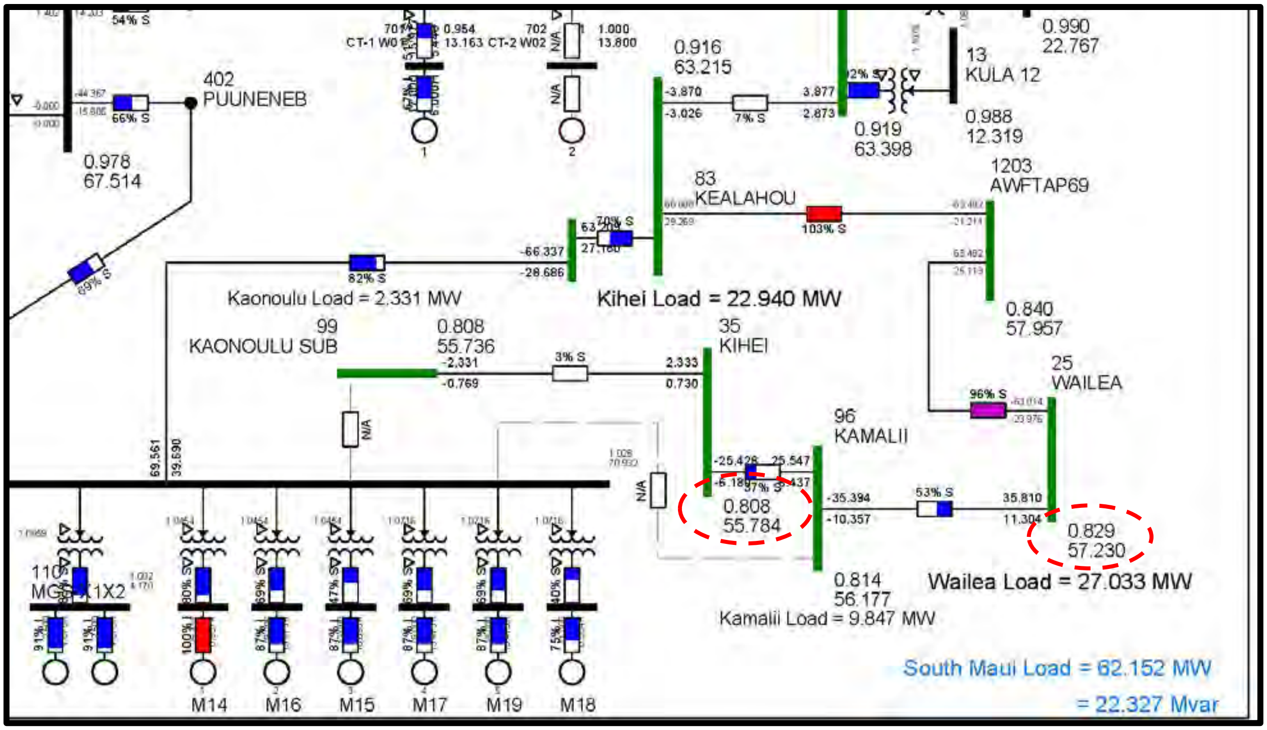

Figure 3: Low voltages under the N-1 contingency of loss of Maalaea-Kihei

Maalaea-Kamalii Line

Currently the South Maui load is served with four primary transformers at Kihei Substation and four primary transformers at Wailea Substation. To improve the distribution system the construction of two new substations were proposed, the Kaonoulu Substation and Kamalii Substation. The Kamalii substation sited to be midway between Kihei and Wailea Substations, across Kamalii Elementary School along Piilani Highway. Kamalii Substation will use the existing Kihei-Wailea 69kV transmission line to interconnect to the system.

To help extend the power transfer limits, the addition of a new transmission line from Maalaea to Kamalii was considered, shown in Figure 4. With the Maalaea-Kamalii transmission line, under the N-1 contingency the bus voltages are significantly above 0.90 pu. As shown in Figure 5, bus voltages are near the voltages under normal conditions, approximately 0.99 pu. This will reduce the possibility of a voltage collapse.

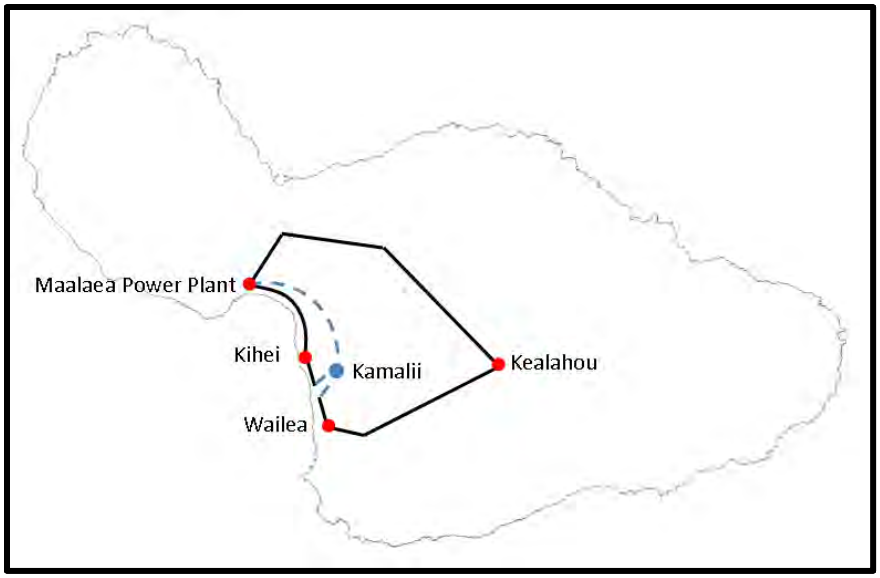

Figure 4: South Maui transmission system with Kamalii Substation and Maalaea-Kamalii 69kV transmission line

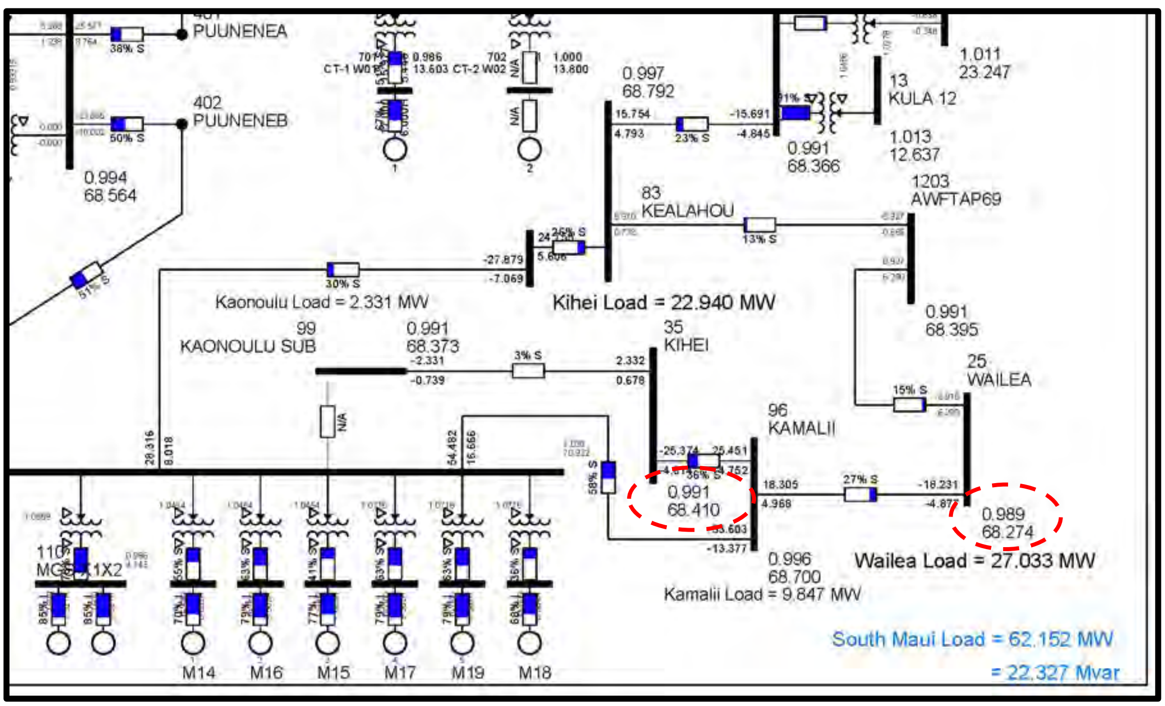

Figure 5: Bus voltages under N-1 contingencies with Maalaea-Kamalii line

Distributed Generation (DG)

A distributed generation (DG) option was considered as a solution to decrease the load in South Maui create margin away from the transfer limit. Several powerflow simulations were conducted in PSS®E to evaluate various levels of generation added to South Maui. Using the South Maui bus voltages as a guideline a DG unit was modeled at Kihei Substation was viewed at different levels to increase the bus voltages to a voltage of 0.95 pu, which provides a reasonable margin above the threshold of 0.90 pu. Adding a total of 20MW of DG to South Maui raised the bus voltages to approximately 0.943 pu, shown in Figure 6.

The DG will mainly need to be operated during the N-1 contingency. Currently, an under voltage load shed (UVLS) scheme is in place for various circuits in South Maui and is discussed later in this report. Therefore, the DG can be started after the UVLS to bring the load back online. Considering it could take at least 8 hours to restore the N-1 contingency, the DG would be operated during that time. The 20MW of DG to South Maui does not include redundancy. The daily operation of the DG and any if any redundancy is needed is beyond the scope of this work.

Since there is no space at Kihei Substation the DG can be distributed at various locations South of Kihei Substation. Therefore, with the loss of the Maalaea-Kihei line the DG will still have the ability to reduce the load on the transformers in South Maui. Having DG near residential areas also raise noise and emission concerns, an environmental impact study will need to be conducted to address these issues.

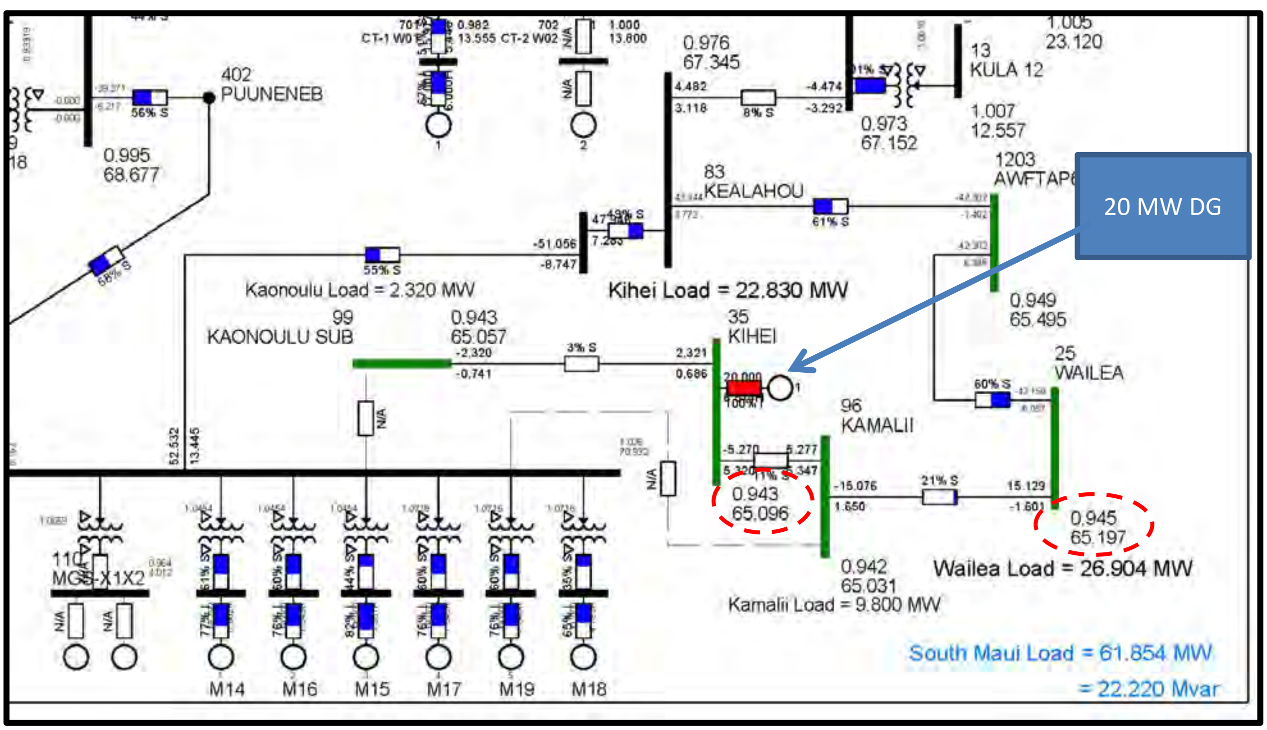

Figure 6: N-1 contingency, loss of Maalaea-Kihei, with a DG alternative

Synchronous Condenser

A synchronous condenser is a synchronous machine that operates without a prime mover or mechanical load. By controlling the field excitation, it can be used to either absorb or supply reactive power – enabling the capability to control terminal voltage.

A synchronous condenser option is capable of maintaining voltage quality within voltage performance standards as stated in the reliability criteria. A power flow analysis was conducted under the assumption that the K1 and K2 units at Kahului Power Plant, anticipated for deactivation in 2014, will be relocated to South Maui and used as synchronous condensers. This will supply an additional 12.5 MVARs to the system (6.25 MVARs from each unit). Voltage levels will be slightly higher than 0.91 pu under a N-1 contingency, shown in Figure 7. However, a synchronous condenser option will not solve the power transfer limit issues that are present under the N-1 contingency. The possibility of a voltage collapse will still be present.

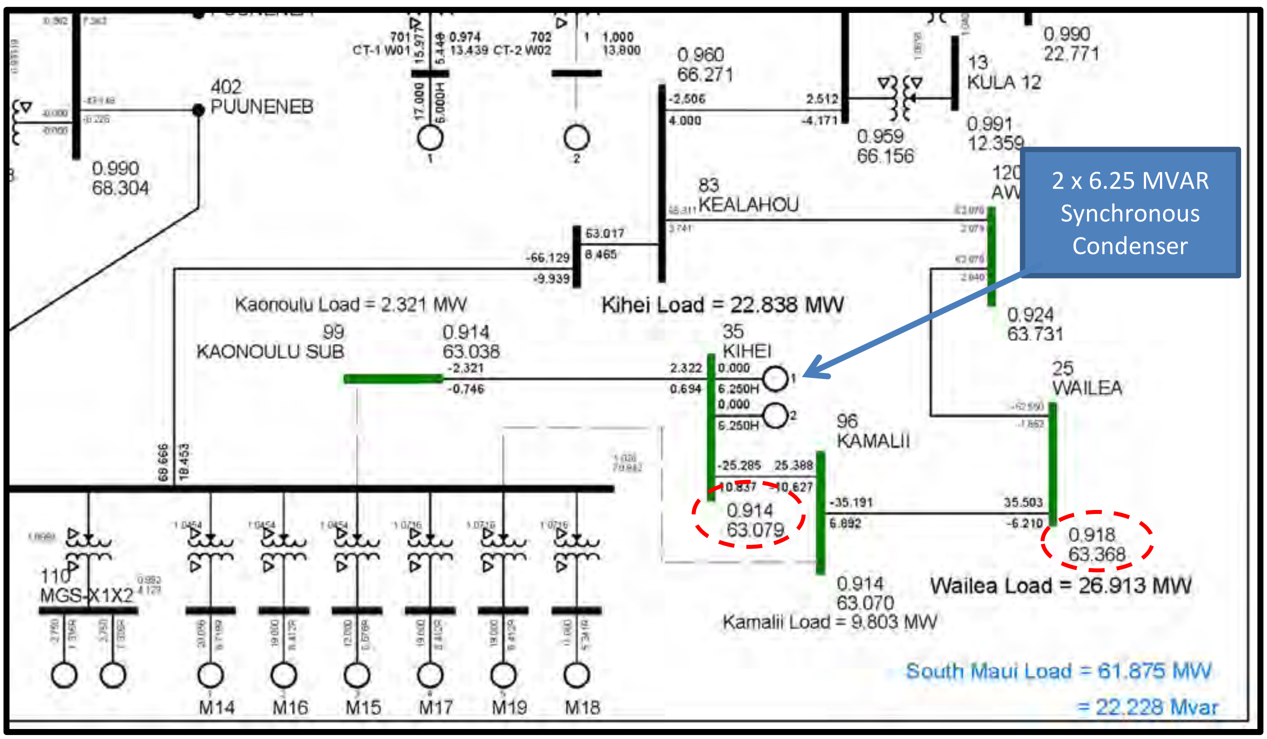

Figure 7: Low voltages with K1 and K2 as synchronous condensers in South Maui

Static Capacitors

A static capacitor is a device that provides reactive power to a high voltage electricity transmission network. It is an automated impedance matching device (where the generator and load impedance are matched) and is designed to bring the power system as close to unity power factor (1.0) as possible. This is important because a high power factor reduces losses and improves voltage regulation at the load. It is called “static” due to the fact that it has no major moving parts (with the exception of internal switchgear). Static capacitor banks are generally cheaper, higher-capacity, faster and more reliable than other power factor correction schemes such as synchronous condensers.

Although static capacitors can increase the voltages to meet the planning criteria it will not help the cause of the low voltages—the transfer capabilities. The static capacitors can increase voltages before a voltage collapse; however it will not provide compensation during a voltage collapse. For the reactive power generated by a capacitor, it is proportional to the voltage squared. Thus, when the voltage decreases, the VARS decrease at an exponential rate, making the situation worse.

Energy Storage System (ESS)

PSSE powerflow simulations were conducted for various MW generation levels to determine the MW needed to raise bus voltages to a reasonable margin above 0.90 pu. With the addition of generation to the area, the possibility of voltage collapse decreases because the system is not at its transfer limits. A 20MW ESS added in South Maui raised bus voltages to 0.943 pu, under the N-1 contingency, as shown below in Figure 8. In anticipation that restoring the line may take at least 8 hours, a 160 MWh ESS would be needed. Similar to the DG, the ESS will need to be interconnected south of Kihei Substation. ESS locations south of Kihei Substation will enable them to have the ability to reduce the load when experiencing an N-1 contingency.

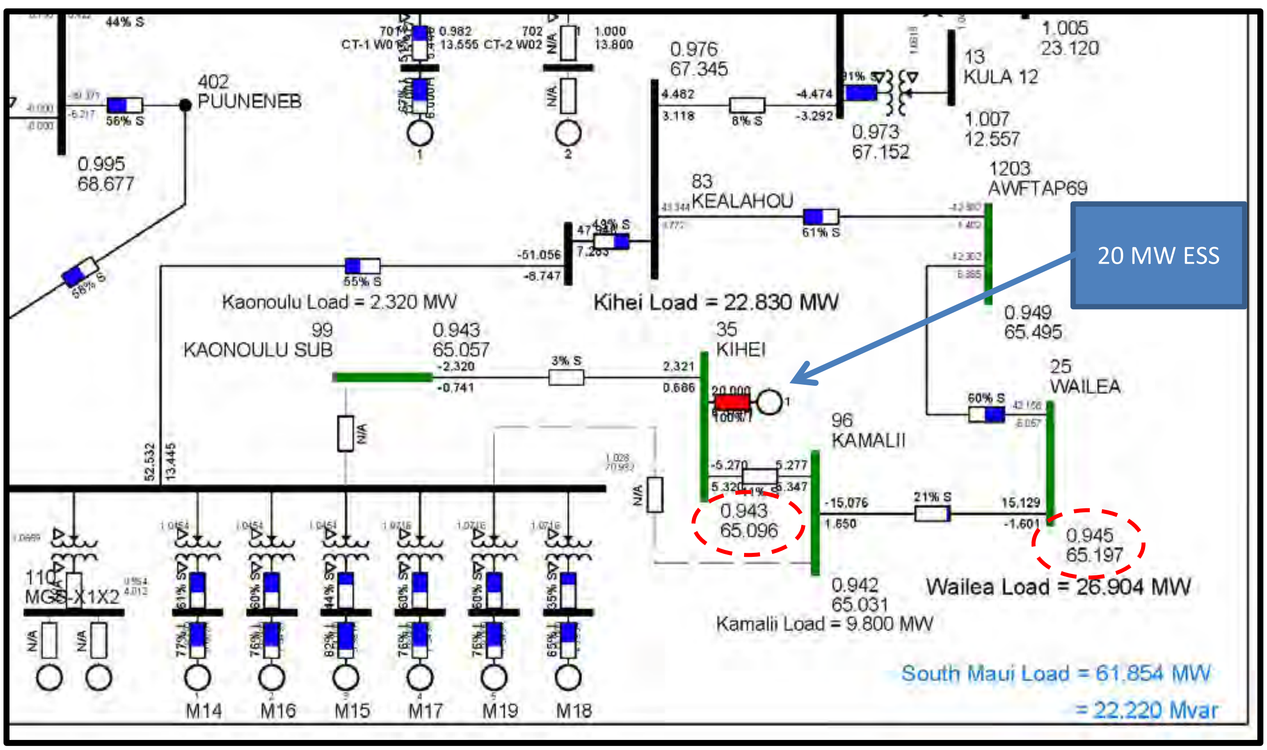

Figure 8: ESS alternative, under N-1 contingency, loss of Maalaea-Kihei

Hybrid (ESS & DG)

The hybrid of ESS and DG was considered, where the ESS would provide a fast response and will need to serve the load until the DG can be started. Similarly with using the ESS and DG alternatives individually, the hybrid will also require a 20MW ESS and a 20MW DG. The MWhs of the ESS will be dependent on the characteristics of the DG. With a hybrid, the MWhs of the ESS would not need to be 8 hours—the anticipated time to restore the line out. The ESS would only need to serve the load long enough for the DG to be started. A typical start up time of a DG unit is 20 minutes. Therefore, the 20MW ESS will need 6.667MWhs. Similar to the installation of the units individually these units will need to also need to be interconnected south of Kihei Substation. Similar to the DG alternative, an environmental impact study will need to be done due to the noise and emission concerns that arise with DG.

Combined Heat and Power (CHP)

Combined heat and power (CHP) integrates generating power and recovers the heat for heating or cooling. With the recovery of heat, CHP has fewer emissions compared to DG. This technology is useful for hotels, as it provides a heat source and will therefore reduce costs. CHP is also on-site and will provide quality, economical and reliable power to the hotel load.

Using CHP to reduce the load in the area can help reduce the risk of low voltages under an N-1 contingency. However, a load reduction of 20MW would be needed—no redundancy was assumed. Table 2 shows a list of hotels in South Maui and if there is enough space to accommodate a CHP unit. Further data will need to be gathered for sites that have space for a CHP unit to determine the size of the units that are possible.

Table 2: South Maui Hotels for possible CHP units

Hotel Name	Space for CHP unit
Four Seasons Resort Maui at Wailea	Yes
Makena Beach & Golf Resort	Yes
Hotel Wailea	Not sure
Wailea Beach Villas	Not sure
Wailea Beach Marriott Resort & Spa	Yes
Grand Wailea	Yes
The Fairmont Kea Lani	Yes
Andaz Maui at Wailea	Not sure

Load Curtailment

Currently to avoid a possible voltage collapse, the Kihei and Wailea Substations have an under voltage load shed (UVLS) scheme settings; Table 3 shows the order of the scheme. The UVLS study, see Appendix B, determined a minimum 150MW system load as a threshold for arming the scheme to ensure the local peaking time of South Maui will be included. Under the N-1, system load may operate near voltage collapse conditions if the system load is greater than 150MW. Therefore, this UVLS scheme has a minimum threshold of system load greater than 150MW to avoid unnecessary load shed.

Customers will need to remain offline until there is no N-1 contingency in effect or if the system load decreases below 150MW. Load curtailment is not intended to defer any system changes or upgrades; it is installed to avoid a whole system collapse.

Table 3: Under Voltage Load Shed Scheme for Kihei and Wailea Substations

Load Shed Block	Substation	Unit #	Feeder #	Voltage Pick-up
1st load shed	Kihei	3	1472, 1473	0.91 pu
2nd load shed	Kihei	4	1515, 1516	0.91 pu
3rd load shed	Kihei	1 and 2	1253, 1254, 1384, 1385	0.91 pu
4th load shed	Wailea	4	1517, 1518	0.91 pu

Kealahou-Kihei 69kV Transmission Line

The Maalaea-Kealahou line also serves the South Maui load. Due to the long distance to serve power, a new transmission line from Kealahou to Kihei substations was considered to lessen the distance, see Figure 9. The Maalaea-Kealahou line has an approximate distance 15 miles long and the estimated distance for Kealahou-Kihei is 7 miles, for an approximate total distance of 23 miles. The Kealahou-Kihei line will shorten the existing power flow line by 5 miles.

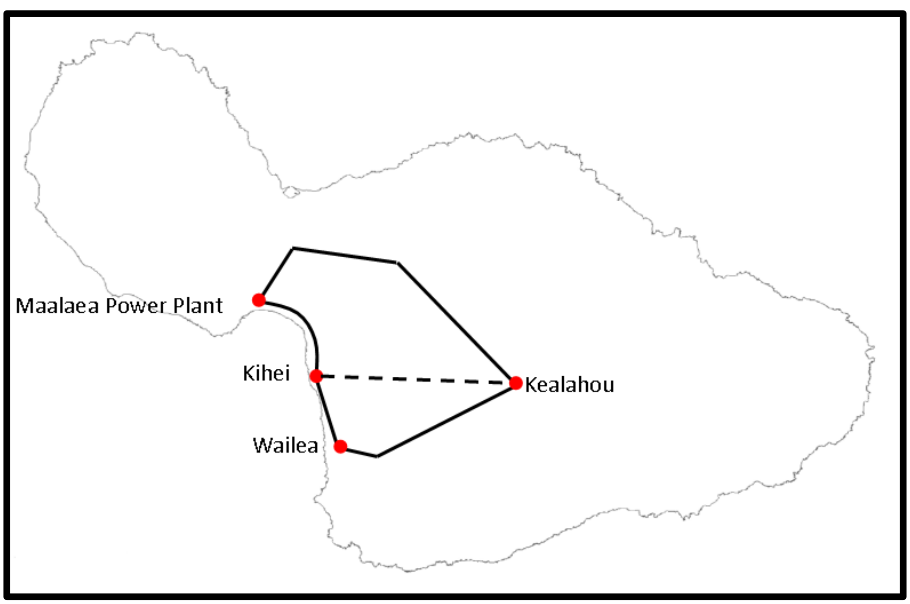

Figure 9: South Maui transmission system with Kamalii Substation and Maalaea-Kamalii 69kV transmission line

A powerflow simulation shows that the installation of a Kealahou-Kihei transmission line, modeled as a 556 AAC, and does not significantly alleviate the low voltage issues in South Maui, as shown in Figure 10. In this case, to raise the voltages to 0.93 pu all capacitor banks in South Maui were needed and no additional support will be available if needed.

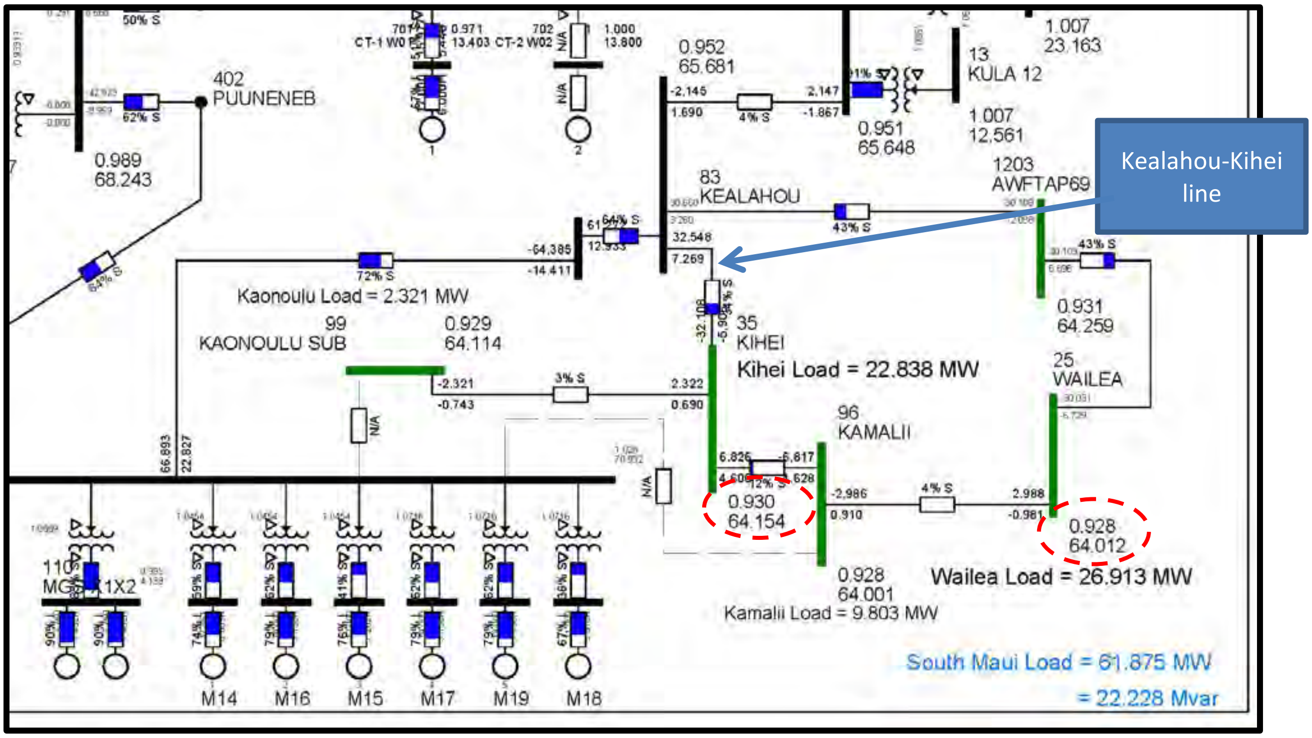

Figure 10: N-1 contingency with Kealahou-Kihei alternative

Outages

Over the last 5 years, historical data have shown that five unscheduled outages of the Maalaea-Kihei line have occurred. These outages had outage duration times ranging from 0-15 minutes. The duration times during these unscheduled outages have been minimal due to the actions of the load dispatchers or the auto transfer schemes in the area's substations. Furthermore, the outages did not occur near the system peak time, these outages occurred between 9:00am-3:00pm. The system peak usually occurs around 7:00pm.

Maintenance on the Maalaea-Kihei line over the last 5 years caused the line to be out of service for approximately 60 times. These scheduled outages had durations from 3-12 hours. Proper planning actions were taken in anticipation of these scheduled outages to avoid low voltage issues in South Maui, which includes load shedding.

Fortunately, the scheduled and unscheduled outages had minimum disruption to customers in the last 5 years. As the loads increase the power outages could occur more frequently due to the system operating at the transfer limits. At this point, the addition of loads will decrease voltages to a point where the system cannot recover, the voltage collapse. By not addressing the problem, Transmission Planning is also in violation of the transmission planning criteria.

Demand Response (DR)

With demand response, the program would need to reduce the load South Maui load by at least 20MW. Loads at Kihei and Wailea substations would need to decrease so less power would be transferred to the area. Voltage collapse could occur suddenly under the right conditions; therefore, the DR needs to be able to respond within 10 minutes.

CONCLUSIONS

Many alternatives were considered to help raise the voltages in South Maui when experiencing an N-1 contingency. However, not all alternatives are viable solutions. Although some alternatives are able to increase voltages to meet the planning criteria for transmission planning, shown in Table 4, not all alternatives can allow the system to operate away from the power transfer limits. These alternatives that were not viable solutions, such as the synchronous condenser and static capacitor, were removed from further consideration. Alternatives that were considered technically viable will need to be economically evaluated.

Table 4: Kihei and Wailea Substations bus voltages

Scenario	Kihei (69kV)	Wailea (69kv)
2024 Normal Conditions	0.992 pu	0.982 pu
N-1 Contingency	0.808 pu	0.829 pu
Maalaea-Kamalii line with N-1 Contingency	0.991 pu	0.989 pu
Distributed Generation alternative with N-1 Contingency	0.943 pu	0.945 pu
Synchronous Condenser alternative with N-1 Contingency	0.914 pu	0.918 pu
Energy Storage System alternative with N-1 Contingency	0.943 pu	0.945 pu
Kealahou-Kihei line alternative with N-1 Contingency	0.930 pu	0.928 pu
N-1 Contingency—outage of Maalaea-Kihei 69kV transmission line Green highlight = under voltage violations Orange highlight= meet voltage criteria but low voltages that cause concern		

APPENDIX A

8 Year Transmission Study, 2009-2016, South/Up-Country Maui

INTEROFFICE CORRESPONDENCE

Hawaiian Electric Co., Inc.

August 6, 2010

To: Chris Reynolds

From: Marc Matsuura

Subject: MECO 8 Year Transmission Study, 2009-2016, South/Up-country Maui

Attached is a copy of the MECO 8 Year Transmission Study, 2009-2016, South/Up-country Maui final report. The report recommends a new 69 kV line to be installed from Maalaea Power Plant to the South Maui area via the Kamalii substation. This report also recognizes that if this solution cannot be applied in the near future, an Undervoltage Load Shedding scheme should be used as an interim solution. If you have any questions, please contact Tammy Okubo at ext. 7286 or Gemini Yau at ext. 7888.

Attachment

cc: D. Park
F. Oshiro
R. Jung
R. Tamayo
S. Sano
Engineering Library
File

Maui Electric Company (MECO)

8 YEAR TRANSMISSION STUDY
2009-2016
SOUTH/UP-COUNTRY MAUI

Prepared by
System Integration Department
Transmission Planning Division
Hawaiian Electric Company, Inc.

April 2010

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APPENDIX A

Executive Summary:

This study discusses the low voltage problems at Kihei and Wailea with the N-1 condition from Maalaea Generating Station (MGS) to Kihei. The N-1 condition is when there is a single line out contingency while the rest of the lines are all in service. For the purposes of this study, the N-1 condition is for the line out from MGS to Kihei unless specified otherwise. With the N-1 case, voltage levels at Kihei and Wailea were below the accepted 0.90 p.u. for 2009 and throughout the duration of the study, which is in violation of MECO transmission planning criteria. More importantly, these areas of low voltage can also result in a voltage collapse situation, which is also discussed in this study.

Three alternatives were considered to address the planning criteria violations. The first alternative considered was to re-conductor the MGS-Kihei-Wailea-Kealahou line, (referred to as the South Maui line). Re-conductoring the South Maui line makes no significant improvement to voltage conditions during an outage of the MGS to Kihei line. Re-conductoring the South Maui line will only raise the voltage at Kihei and Wailea by about 0.02 p.u.

The second alternative considered was to add 3.6 MVARs of capacitors at Kihei Substation for a total of 10.8 MVARs. The addition of the capacitor banks would boost voltages only slightly above 0.90 p.u. With the capacitor banks, there is still a significant possibility of a voltage collapse situation.

The third alternative considered was to build an additional 69 kV transmission line from MGS to the Kihei-Wailea service area, terminating at the new Kamalii Substation. The additional line maintains a transmission connection to the Kihei-Wailea service area in the event of the loss of the 69kV MGS to Kihei line and keeps voltages at Kihei and Wailea well above the 0.90 p.u. standard throughout the study period. Of the three solutions, the new line provides the best answer for the voltage collapse situation.

It is recommended that this line is installed as soon as possible due to the fact that the latest load flow analysis shows that the current system conditions hold the potential of the low voltages at Kihei and Wailea as well as a possible voltage collapse with the loss of the MGS to Kihei 69kV line.

Problem Overview:

There are possible low voltage conditions that exist for the N-1 contingency with the loss of the MGS (39) to Kihei (35) line. This study will evaluate those low voltage conditions as well as evaluate the possible voltage collapse situations that are a result of the low voltage levels.

a. Low Voltage:

With current system conditions in the South/Up-Country Maui area, low voltages are anticipated at Kihei (35) and Wailea (25) Substations with the outage of the MGS-Kihei 69kV line. With the loss of the MGS-Kihei 69kV line, the voltage at Kihei will drop from 0.9947 p.u. to 0.8543 p.u. and the voltage will drop at Wailea from 0.9853 p.u. to 0.8709 p.u., as shown in Table 1.

Year	Projected System Peak Loading (MW)	Kihei (35) Voltage (p.u.)		Wailea (25) Voltage (p.u.)	
		Normal Condition	N-1, MGS-Kihei 69kV line	Normal Condition	N-1, MGS-Kihei 69kV line
2009	201.2 (actual)	0.9947	0.8543	0.9853	0.8709
2010	187.9	0.9976	0.8757	0.9893	0.8903
2011	189.1	0.9974	0.8742	0.9890	0.8890
2012	190.0	0.9973	0.8732	0.9888	0.8880
2013	191.1	0.9971	0.8717	0.9885	0.8867
2014	192.5	0.9968	0.8700	0.9882	0.8851
2015	194.4	0.9965	0.8674	0.9877	0.8828
2016	196.7	0.9960	0.8645	0.9871	0.8801

Table 1: Normal vs. N-1 (MGS-Kihei) Conditions at Kihei (35) and Wailea (25)

The projected system peak loads typically occur during the months of October, November, and December.

b. Voltage Collapse:

A serious consequence of low voltages that currently exists is the possibility of a system wide voltage collapse situation. During system peak conditions, all transmission lines in service, and Kihei (35) as the control bus, there are only approximately 35 MVARs left before the start of a voltage collapse situation, as shown by the QV analysis in Figure 1, and it may start with voltages as high as 0.96 p.u. This means that the system can only handle the addition of 35 more MVARs before the system may start to collapse. Figure 1 also shows the amount of MVARs left drops to approximately 9 MVARs when there is an outage of the MGS-Kihei 69 kV line. The addition of reactive power can occur not only with the addition of loads but also during the transient of a system

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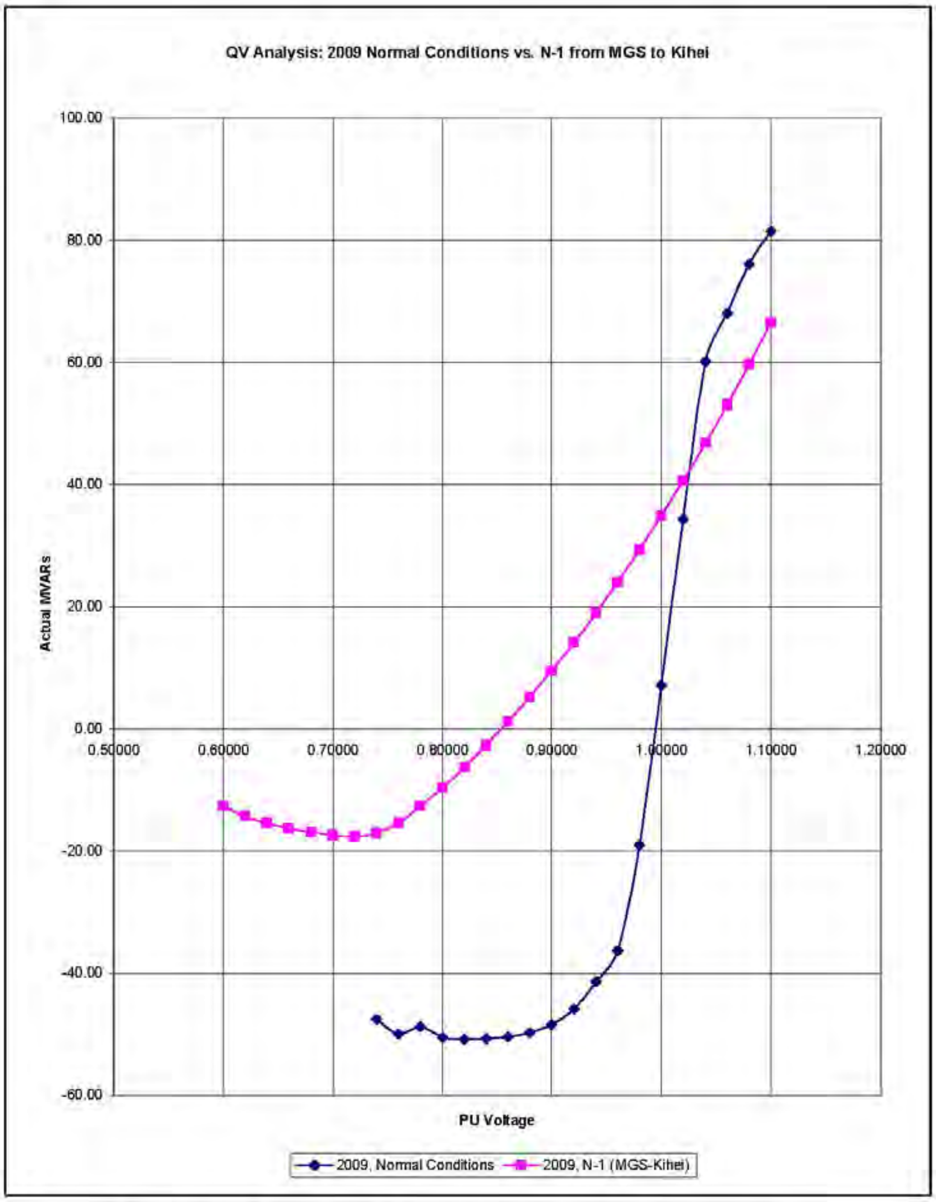

Figure 1: 2009, Normal vs. N-1 (MGS-Kihei) Voltage Collapse Analysis

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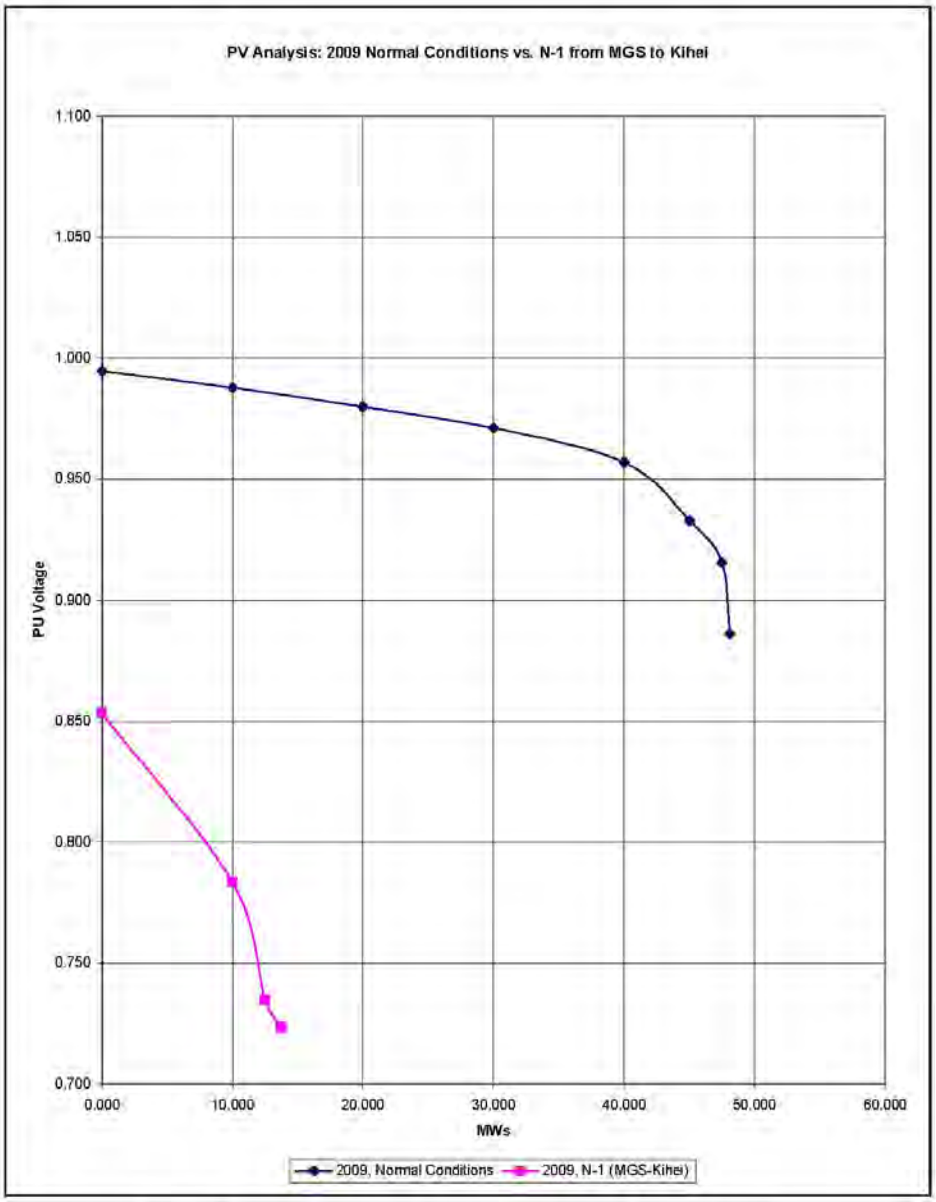

Figure 2: PV Analysis, 2009 Normal Conditions vs. N-1 (MGS-Kihei)

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disturbance such as the loss of the MGS (39) to Kealahou (83) line. Also notice that with the N-1 case, at 0 MVAR, meaning at current conditions with no additional loading or compensation, the voltage is already as low as 0.85 p.u.

Figure 2 shows the PV analysis comparing normal conditions to the case where we lose the line between MGS (39) and Kihei (35). Normal conditions show that the system can handle an additional 40 MW of bus load with dropping voltage to only 0.96 p.u. However, the N-1 condition (with current bus loading conditions) already starts at 0.85 p.u. voltage and cannot handle more than 10 MWs before the voltage starts to collapse.

Alternatives:

Three alternatives considered are a) re-conductoring lines, b) adding capacitor banks to help boost low voltages, and c) add another line from MGS (39) to a new substation at Kamalii (96).

a. Re-conductoring:

The first alternative considered was to re-conductor the existing 336 AAC line with 556 AAC for the South Maui line, between MGS-Kihei-Wailea-Kealahou line (shown as the bolded sections of line in the diagram below). This study found that re-conductoring provides little improvement to the low voltage problems. With the new conductors, during the N-1 condition for the loss of the MGS (39) to Kihei (35) line, the voltages at Kihei (35) and Wailea (25) are raised by approximately 0.02 p.u. For the N-1 case in 2009, re-conductoring boosts Wailea (25) to 0.8883 p.u. and Kihei (35) to 0.8769 p.u. which is still not within the acceptable range. The re-conductoring also provides little improvement to the voltage collapse possibility. As seen in Figure 4, the 556 AAC conductor case follows closely to the curve of the 336 AAC conductor case. With the loss of the MGS (39) to Kihei (35) line, the new conductors only add approximately 4 MVAR at the most before the possibility of a voltage collapse situation.

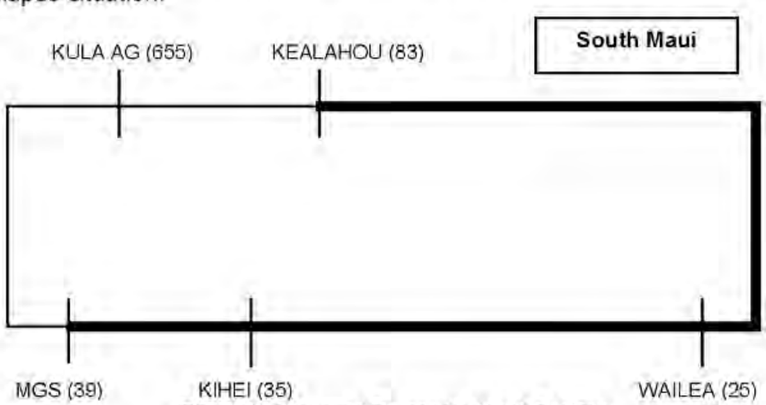

Figure 3: Proposed Re-conductored Section

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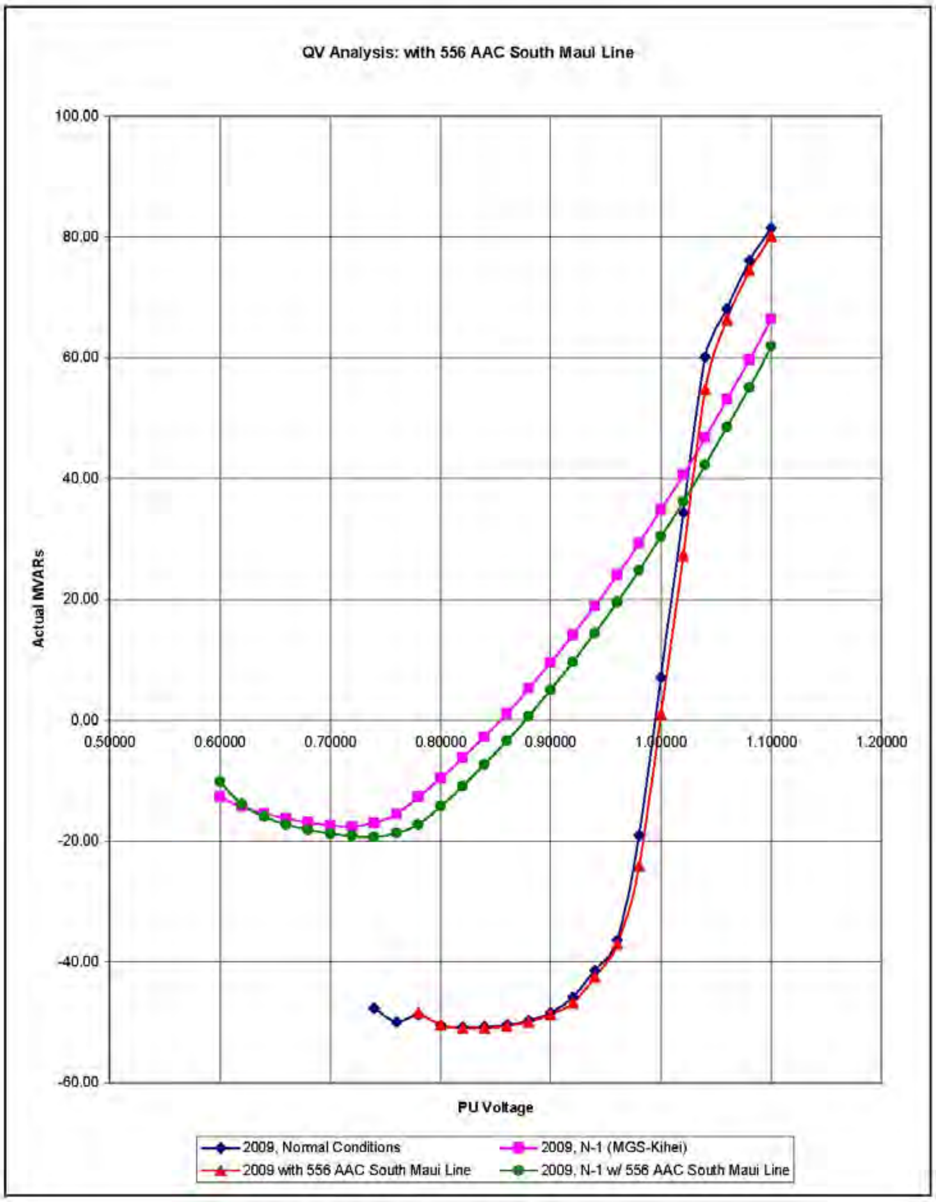

Figure 4: With 556 AAC South Maui Line

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b. Capacitor Banks:

Assuming that the 3.6 MVAR capacitor bank at Kihei A (35-1) is on during peak conditions, it would take turning on the existing 3.6 MVAR capacitor bank at Kihei B (35-2) and the installation of another 3.6 MVAR capacitor bank at Kihei C (35-3) to boost voltage levels at Kihei (35) and Wailea (25) above 0.90 p.u. This solution will only keep voltages slightly above an acceptable level shown below in Table 2.

Year	Kihei (35) Voltage (p.u.)		Wailea (25) Voltage (p.u.)	
	N-1, MGS-Kihei 69kV line	N-1, MGS-Kihei w/ Cap. Banks	N-1, MGS-Kihei 69kV line	N-1, MGS-Kihei w/ Cap. Banks
2009	0.8543	0.9055	0.8709	0.9122
2010	0.8757	0.9242	0.8903	0.9293
2011	0.8742	0.9227	0.8890	0.9280
2012	0.8732	0.9216	0.8880	0.9270
2013	0.8717	0.9209	0.8867	0.9262
2014	0.8700	0.9192	0.8851	0.9247
2015	0.8674	0.9169	0.8828	0.9226
2016	0.8645	0.9146	0.8801	0.9205

Table 2: Kihei (35) and Wailea (25) Voltages for N-1 (MGS-Kihei) w/ Capacitor Banks

The addition of the capacitor bank at Kihei will increase the amount of MVAR left before a voltage collapse situation by approximately 10 MVAR, shown below in Figure 5. However, with a capacitor, $Q=V^2Y$, so as the voltage decreases, the amount of VARs that it can provide will decrease at a quadratic rate. Therefore, the capacitors will provide less and less compensation during a voltage collapse situation, making the situation progressively worse.

Assuming that the 3.60 MVAR capacitor bank at Kihei A (35-1) is on, modeling a synchronous condenser at Kihei C (35-3) shows that in order to maintain a voltage of 0.90 p.u. at Kihei (35) for the N-1 condition (MGS-Kihei) in 2009, would require an additional 6.0552 MVAR from capacitor banks. The system would require 20.5297 MVAR of capacitor banks at Kihei C (35-3) to maintain a voltage of 0.95 p.u. at Kihei (35) and 39.5483 MVAR to maintain a voltage of 1.0 p.u.

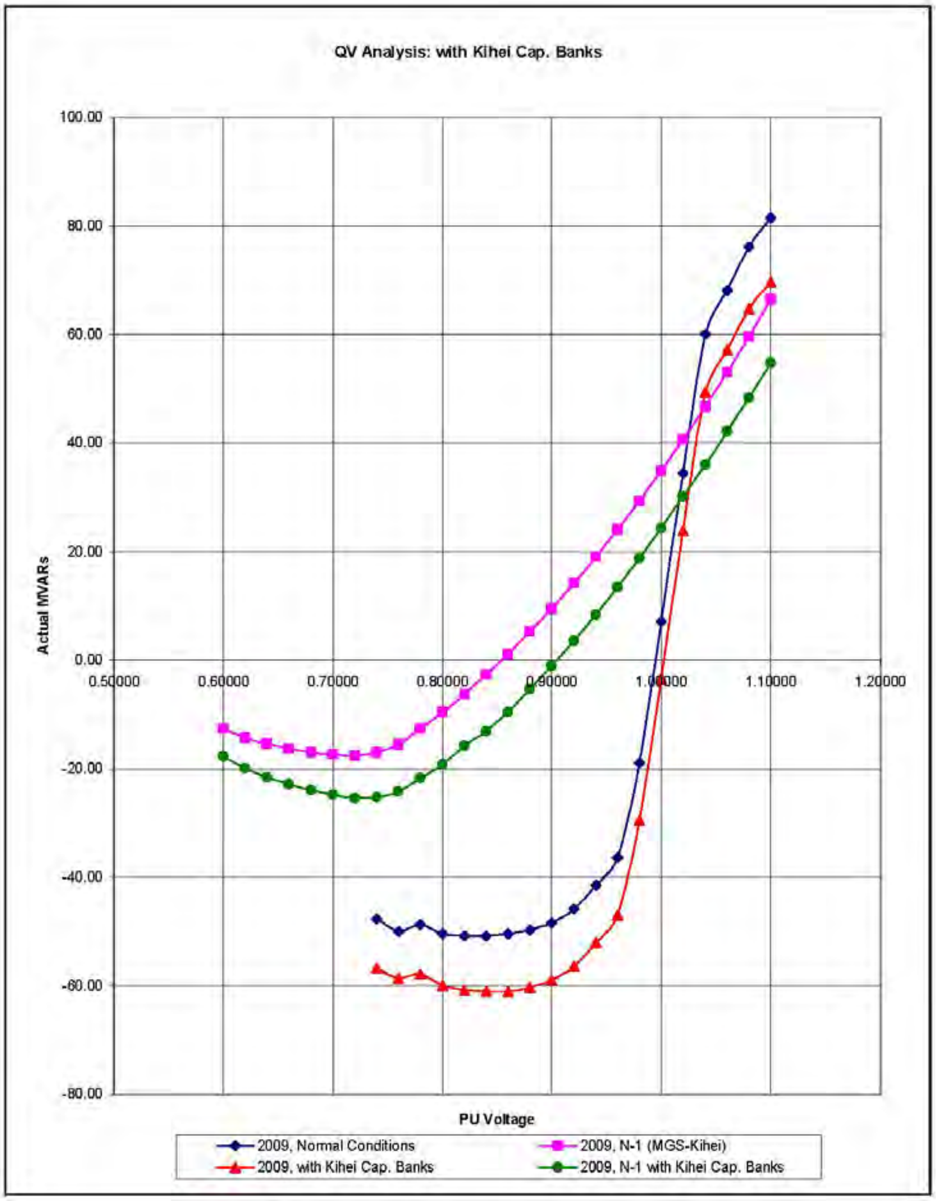

Figure 5: 2009, with Additional Cap. Banks at Kihei

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c. Install a new transmission line from MGS to the new Kamalii Substation:

The addition of a new line from MGS (39) to the Kihei (35) and Wailea (25) area would include the addition of the Kamalii (96) Substation as shown below in Figure 6:

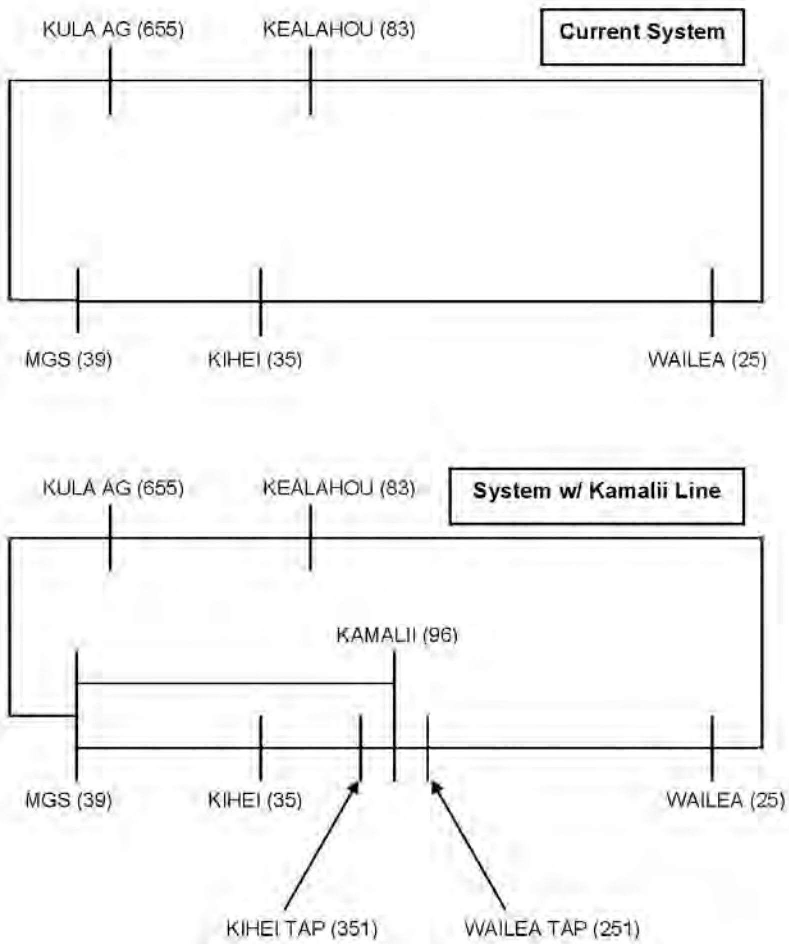

Figure 6: Current System vs. System w/ Kamalii Substation

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By adding the second line to Kamalii (96), the voltage levels at Kihei (35) and Wailea (25) will remain significantly above 0.90 p.u. through the year 2016. Table 3 shows the voltage levels at Kihei (35) and Wailea (25) with a second line during an N-1 condition from MGS (39) to Kihei (35).

Year	Kihei (35) Voltage (p.u.)		Wailea (25) Voltage (p.u.)	
	N-1, MGS-Kihei 69kV line	N-1, MGS-Kihei w/ Kamalii Sub.	N-1, MGS-Kihei 69kV line	N-1, MGS-Kihei w/ Kamalii Sub.
2009	0.8543	0.9893	0.8709	0.9878
2010	0.8757	0.9929	0.8903	0.9916
2011	0.8742	0.9926	0.8890	0.9914
2012	0.8732	0.9924	0.8880	0.9911
2013	0.8717	0.9922	0.8867	0.9909
2014	0.8700	0.9919	0.8851	0.9906
2015	0.8674	0.9915	0.8828	0.9901
2016	0.8645	0.9910	0.8801	0.9896

Table 3: Kihei (35) and Wailea (25) Voltages for N-1 (MGS-Kihei) w/ Kamalii Substation

The additional line will also reduce the possibility of a voltage collapse situation by increasing the amount of MVARs that are left before the start of a collapse as shown in Figure 7. Figure 7 shows that with the second line to the Kamalii (96) Substation, even with an N-1 condition from MGS (39) to Kihei (35), there is only a small decrease of MVARs. This still leaves approximately 33 MVARs before a voltage collapse situation.

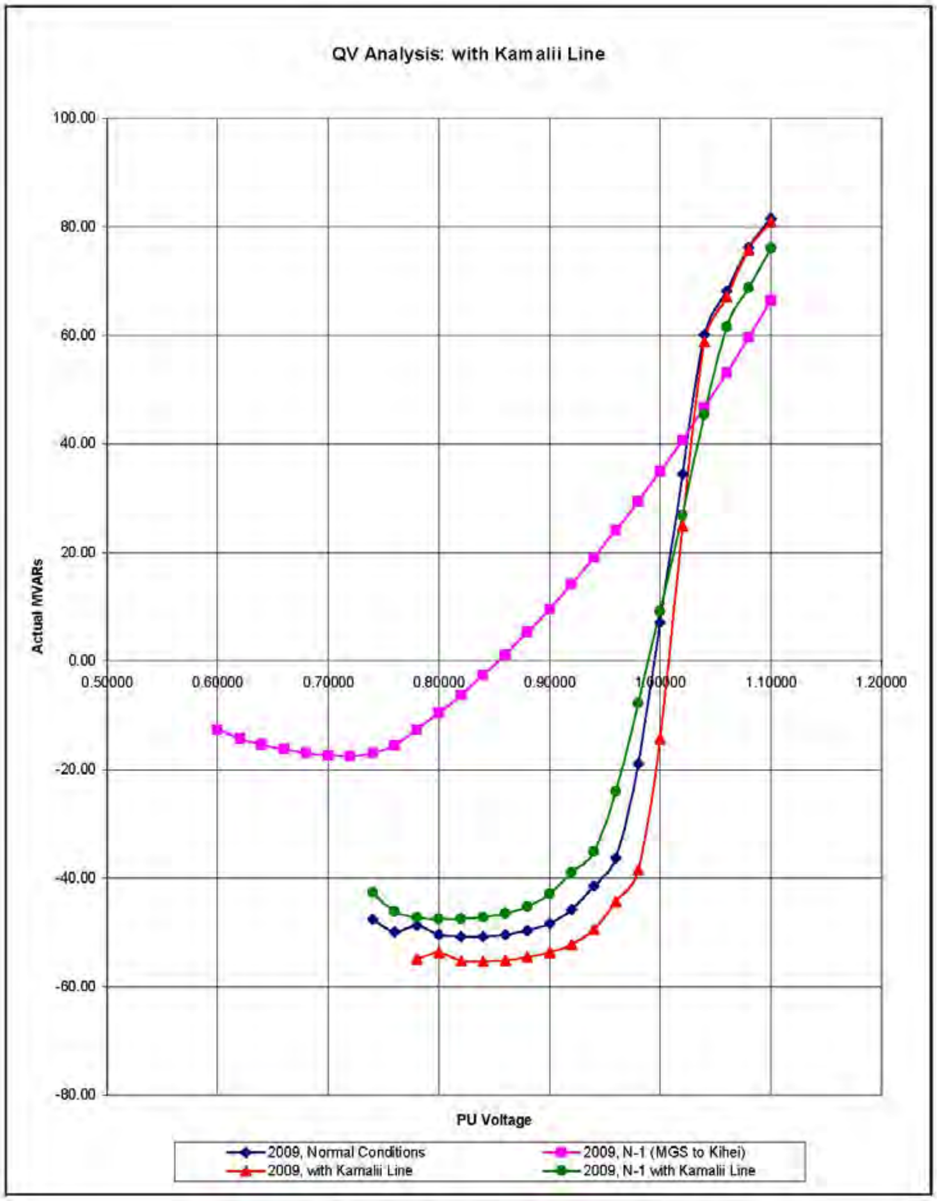

Figure 7: 2009, with Kamalii Line

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Alternative Comparison:

With an N-1 contingency from MGS (39) to Kihei (35), and a total of 10.8 MVAR compensation by capacitor banks at Kihei, the voltage levels at Kihei and Wailea are maintained only slightly above 0.90 p.u. A second line through Kamalii (96) will maintain voltage levels at Kihei (35) and Wailea (25) above 0.985 p.u. at least through the end of this study period, 2016. The Kamalii (96) line will also aide in maintaining voltages at Kihei (35) and Wailea (25) during N-1 contingencies from MGS (39) to Kealahou (83) and from MGS (39) to Puunene (402). These results are listed in Appendix A. Building a second line is essentially avoiding the currently possible N-1 condition.

When comparing the voltage collapse analysis, the line to Kamalii (96) almost doubles the amount of MVAR that is left before the system would go into a voltage collapse situation shown in Figures 8, 10, and 12 for 2009, 2012, and 2016 respectively. As time goes on, the Kamalii line is the only alternative that can maintain the voltage considerably above 0.90 p.u. and handle more MVAR loading.

The comparison of the PV analysis shown in Figures 9, 11, and 13 for 2009, 2012, and 2016, respectively, also shows that the Kamalii line provides the best solution since it can handle significantly more MW loading while staying well above 0.90 p.u. voltage levels.

As discussed previously, to re-conductor the South Maui line is not a viable alternative because it provides no significant improvements to the low voltage problems, nor does it help with the possible voltage collapse situations.

Therefore, the proposed solution would be a second line from MGS (39) to the Kihei - Wailea service area via a new substation in Kamalii (96). Figures 8-13, illustrate the value of the line through Kamalii (96) versus the rest of the alternatives using PV and QV analysis.

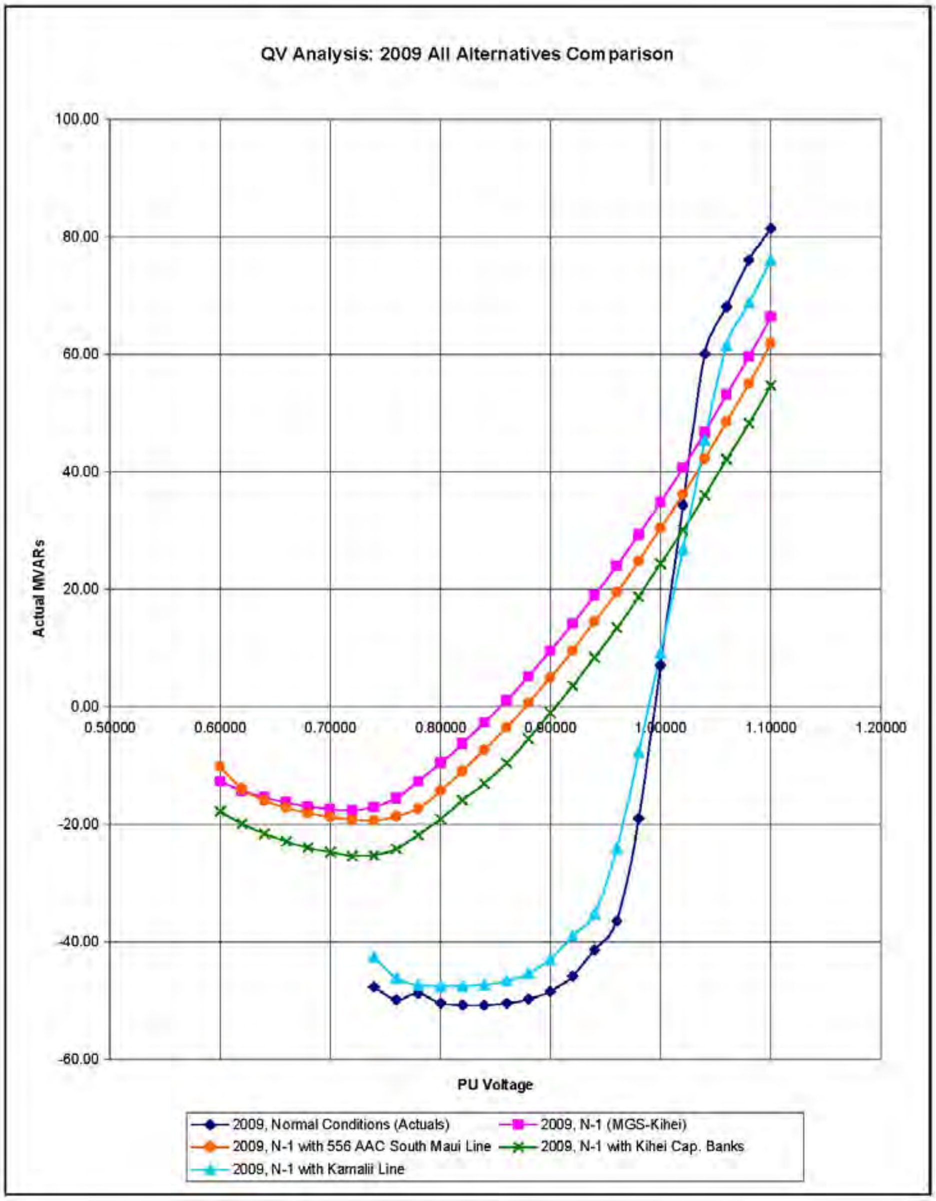

Figure 8: 2009 QV Analysis, All Alternatives Comparison

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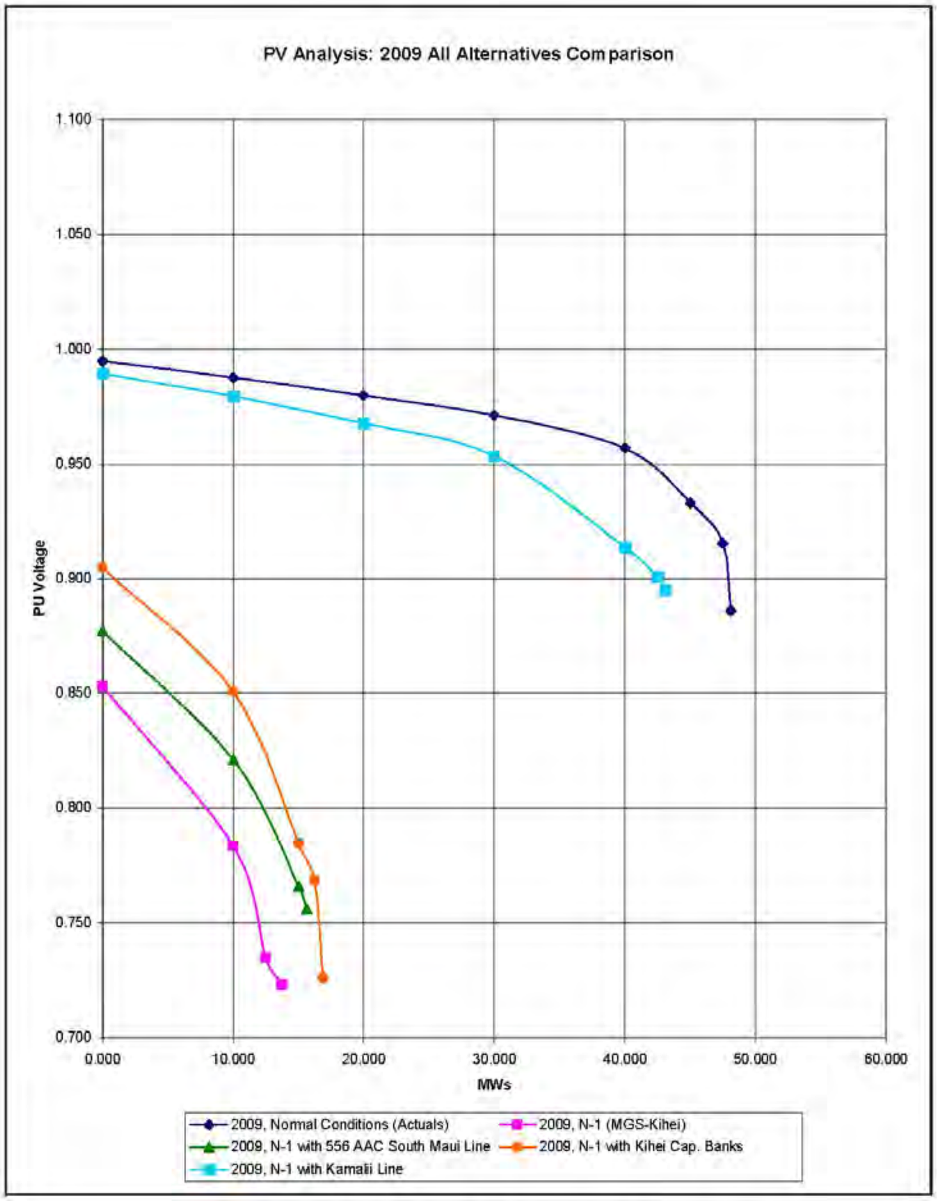

Figure 9: 2009 PV Analysis, All Alternatives Comparison

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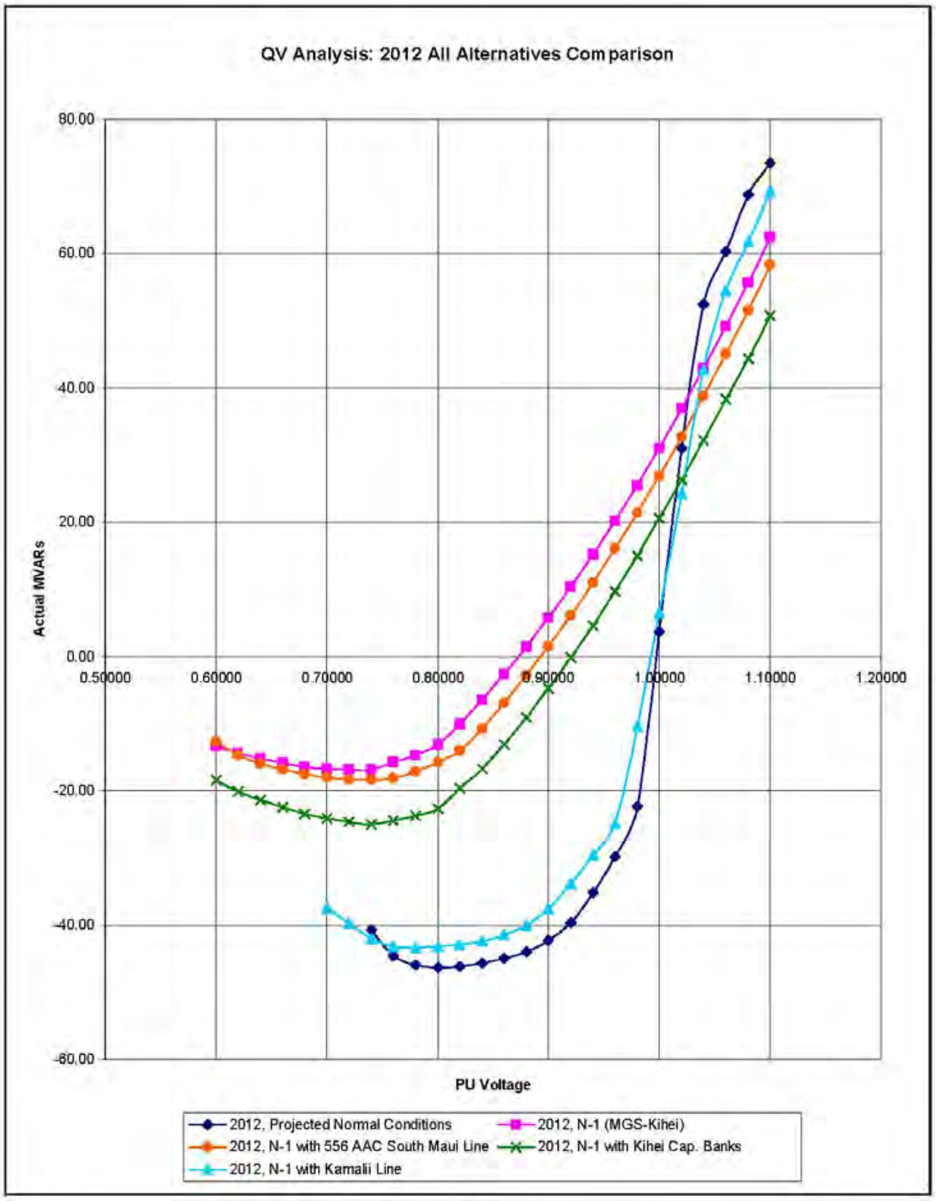

Figure 8: 2012 QV Analysis, All Alternatives Comparison

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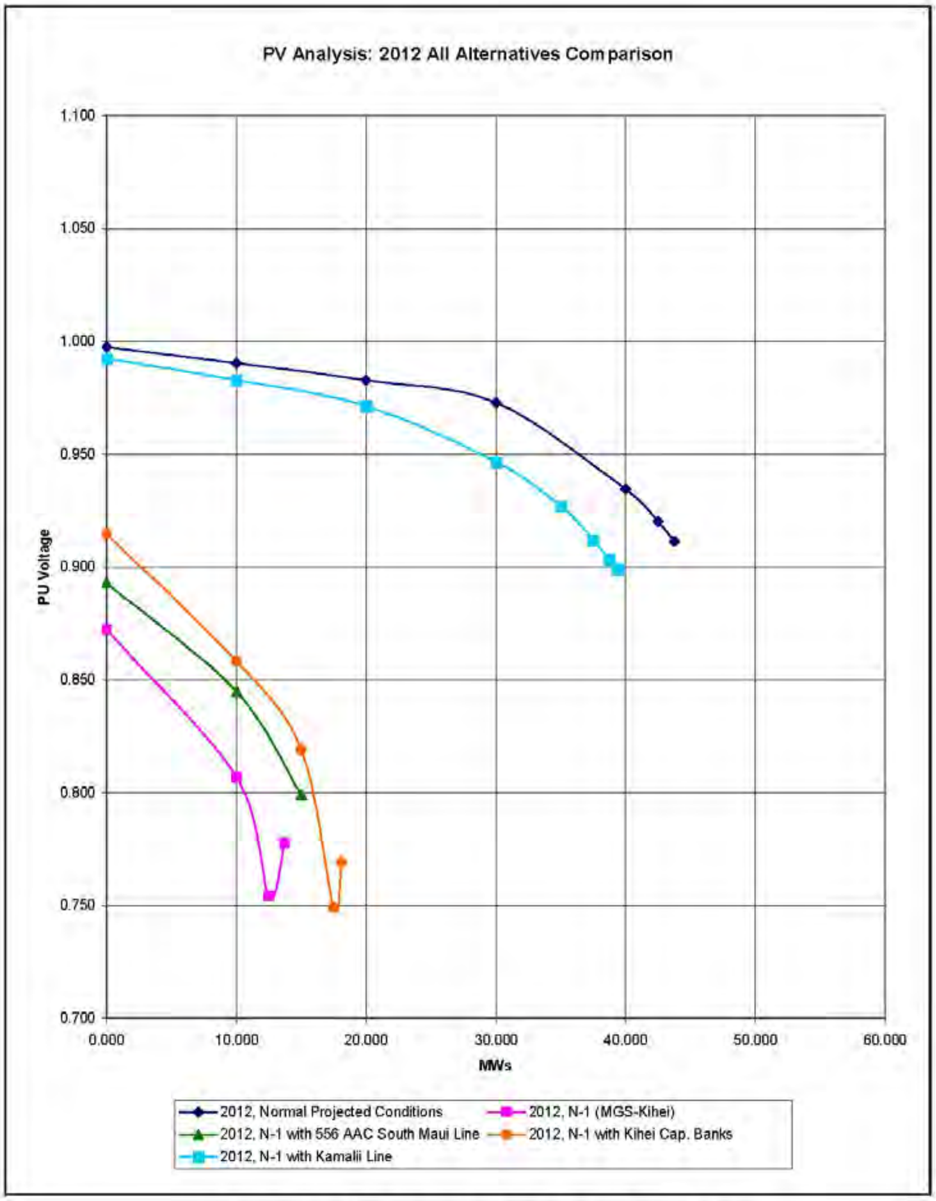

Figure 9: 2012 PV Analysis, All Alternatives Comparison

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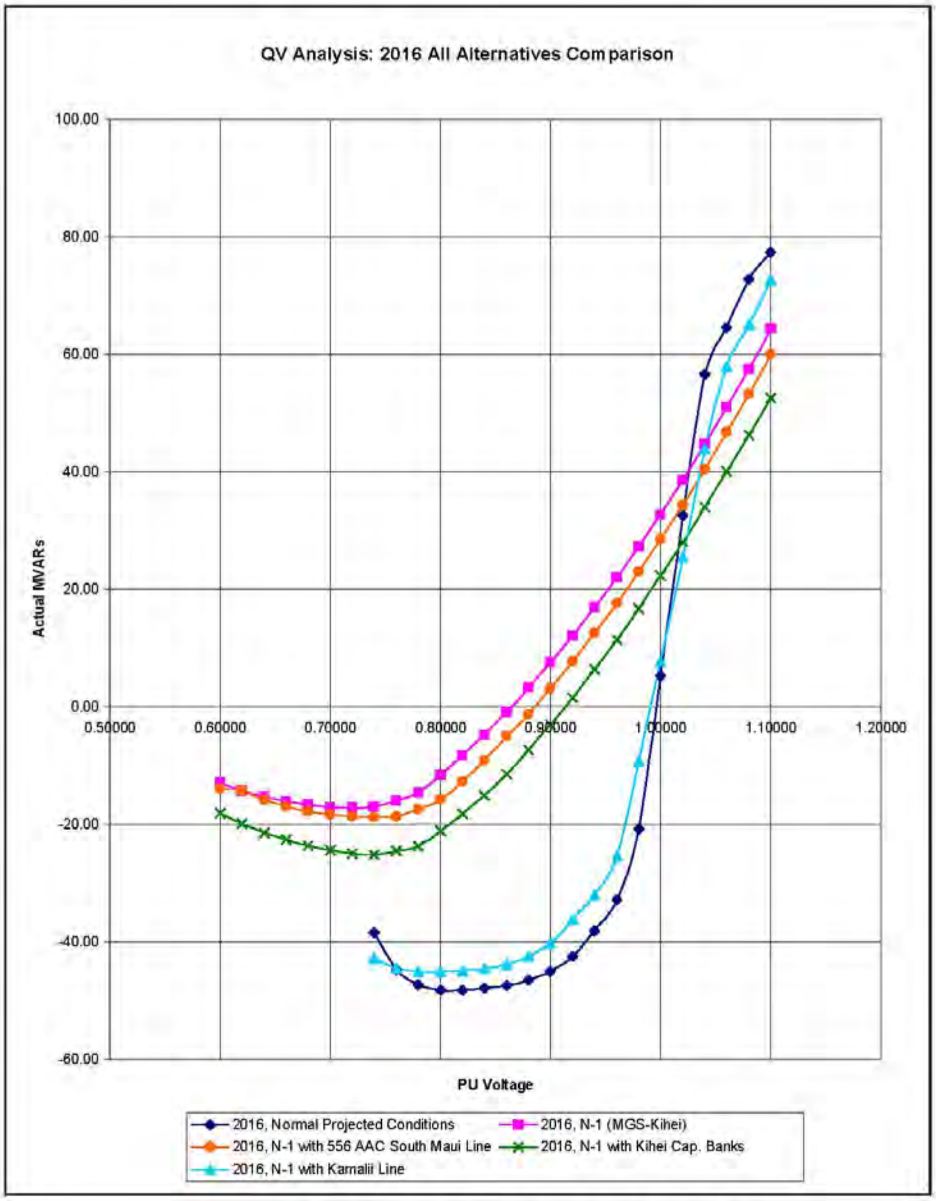

Figure 10: 2016 QV Analysis, All Alternatives Comparison

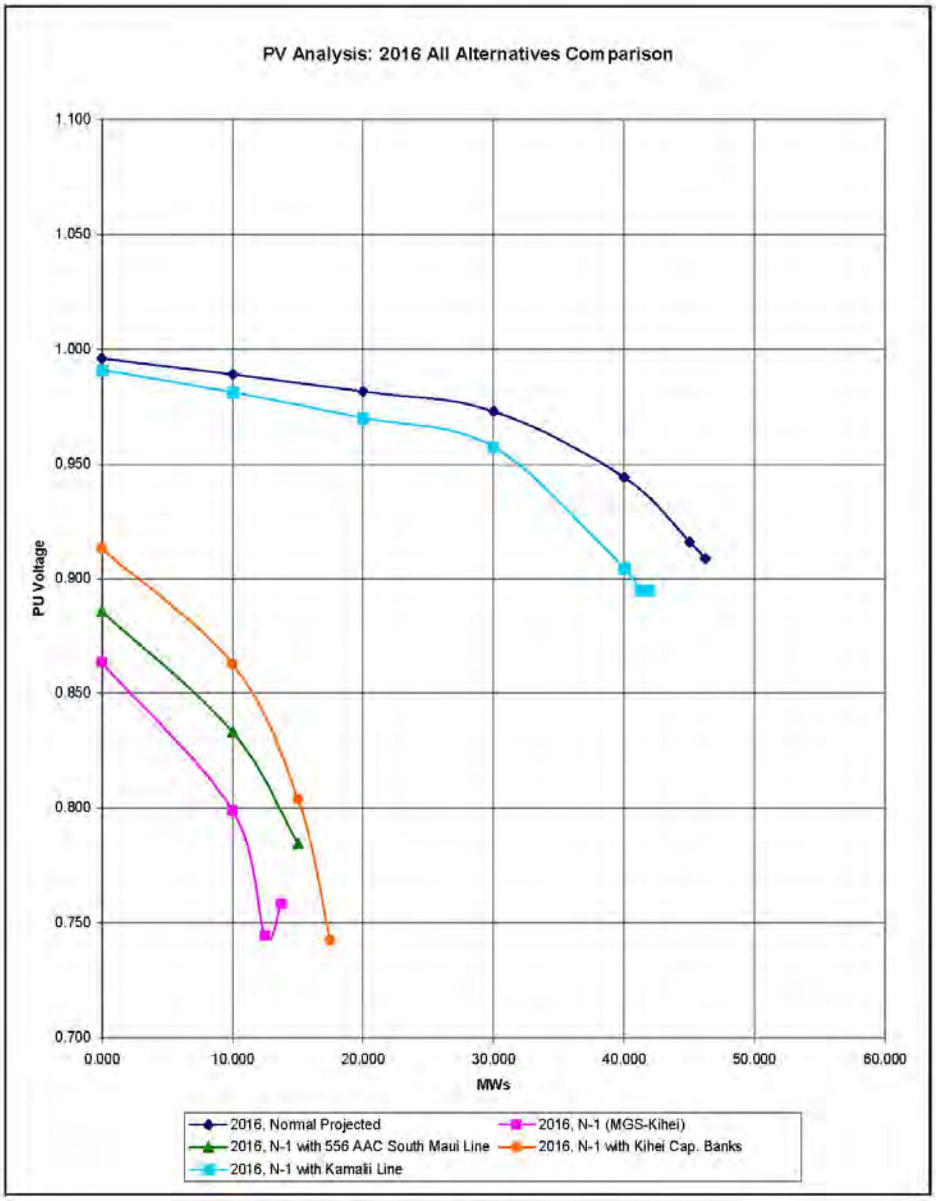

Figure 11: 2016 PV Analysis, All Alternatives Comparison

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Conclusions & Recommendations:

This study discussed the problem of low voltage situations and its consequence of a possible voltage collapse situation. Several alternatives studied included replacing the existing 336 AAC South Maui lines with 556 AAC, adding more capacitor banks at Kihei (35), and building a second line from MGS (39) to the Kihei-Wailea service area via a new substation at Kamalii (96).

The recommended solution is to build the second line to Kamalii from Maalaea because the second line is the only alternative that mitigates the low voltages at Kihei (35) and Wailea (25) during N-1 contingencies as well as reduce the possibility of a voltage collapse situation. Also, the second line is able to mitigate these issues throughout the term of the study period.

It is also recommended that this solution be implemented as soon as possible due to the fact that current system conditions can create the low voltage conditions discussed throughout this report. Until the new line is built, it is recommended that an undervoltage load shedding scheme is followed to avoid a system voltage collapse. The typical heavily-loaded months for the MECO system are September, October, November, and December. During these months, the Undervoltage Load Shedding (UVLS) scheme should be implemented at the Kihei (SUB 35) and Wailea (SUB 25) substations as an interim solution until the MPP-Kamalii line construction is completed. The implementation of this interim solution is contingent upon the results of a detailed UVLS study and installation of the necessary UVLS relays. The UVLS study will evaluate the system peak load conditions as well as other high risk cases such as the outage of the following lines while also losing the MPP-Kihei line:

- MPP to Kealahou (69kV)
- MPP to Puunene (69kV)
- Puunene to Kanaha (69kV)

APPENDIX A

Bus Voltages at Kihei (35) and Wailea (25):

Case	Bus	Voltage (p.u.)							
		2009	2010	2011	2012	2013	2014	2015	2016
Normal	35	0.9947	0.9976	0.9974	0.9973	0.9971	0.9968	0.9965	0.9960
	25	0.9853	0.9893	0.9890	0.9888	0.9885	0.9882	0.9877	0.9871
Normal w/ Kamalii Line (no contingency)	35	1.0075	1.0091	1.0090	1.0089	1.0088	1.0086	1.0084	1.0082
	25	0.9991	1.0017	1.0015	1.0013	1.0012	1.0010	1.0007	1.0003
N-1, MGS to Kihei	35	0.8543	0.8757	0.8742	0.8732	0.8717	0.8700	0.8674	0.8645
	25	0.8709	0.8903	0.8890	0.8880	0.8867	0.8851	0.8828	0.8801
N-1, MGS to Kihei w/ Kamalii Line	35	0.9893	0.9929	0.9926	0.9924	0.9922	0.9919	0.9915	0.9910
	25	0.9878	0.9916	0.9914	0.9911	0.9909	0.9906	0.9901	0.9896
N-1, MGS to Kealahou	35	0.9834	0.9878	0.9875	0.9873	0.9870	0.9866	0.9861	0.9855
	25	0.9657	0.9721	0.9717	0.9714	0.9710	0.9704	0.9697	0.9688
N-1, MGS to Kealahou w/ Kamalii Line	35	1.0032	1.0054	1.0053	1.0051	1.0050	1.0048	1.0046	1.0042
	25	0.9890	0.9928	0.9925	0.9923	0.9920	0.9917	0.9913	0.9907
N-1, MGS to Puunene	35	0.9911	0.9946	0.9944	0.9942	0.9940	0.9937	0.9933	0.9928
	25	0.9792	0.9847	0.9838	0.9835	0.9832	0.9828	0.9822	0.9815
N-1, MGS to Puunene w/ Kamalii Line	35	1.0058	1.0077	1.0076	1.0074	1.0073	1.0072	1.0070	1.0067
	25	0.9951	0.9982	0.9980	0.9978	0.9977	0.9974	0.9970	0.9966

APPENDIX B

Undervoltage Load Shed Study (UVLS): Interim Solution for South Maui Line

ENG 20-4/YT

INTEROFFICE CORRESPONDENCE

Hawaiian Electric Co., Inc.

January 28, 2011

To: Chris Reynolds

From: Dean Arakawa

Subject: MECO Undervoltage Load Shed Study (UVLS): Interim Solution for South Maui Line

Please find attached a copy of the Undervoltage Load Shed Study (UVLS): Interim Solution for South Maui Line. The report specifies requirements for the UVLS scheme necessary to mitigate potential violations to MECO's transmission planning criteria as a result of the deferral of the South Maui 69 kV line project (reference the MECO 8 Year Transmission Study, 2009-2016, South/UP-country Maui report). If you have any questions, please contact Tammy Okubo at ext. 7286 or Gemini Yau at ext. 7888.

TO
Attachment

cc : D. Park
F. Oshiro
R. Jung
M. Ribao
S. Sano
R. Uemura
Engineering Library
TPD File

Maui Electric Company (MECO)

Undervoltage Load Shed Study (UVLS): Interim Solution for South Maui Line

Prepared by
System Integration Department
Transmission Planning Division
Hawaiian Electric Company, Inc.

December 2010

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APPENDIX A- ASSUMED GENERATOR SETTINGS

APPENDIX B- DYNAMIC SIMULATION RESULTS

EXECUTIVE SUMMARY:

The purpose of this study is to develop the requirements for an undervoltage load-shedding (UVLS) scheme as an interim solution for the delayed installation of the additional South Maui 69 kV line as recommended in the MECO 8 Year Transmission Study, 2009-2016, South/Up-country Maui report. The undervoltage load-shedding scheme should be considered a "remedial measure", and does not negate the need for the additional transmission line to the South Maui area. The shedding of load is used to prevent voltage instability and collapse.

This study recommends that the UVLS scheme be armed for any system loads greater than 150 MW. The speed at which this scheme is implemented should be long enough to allow system faults to clear as well as allow enough time for the generators to attempt to mitigate the voltage problem.

The load that will be shed is as follows:

- 1st Load Shed: Kihei Substation, Unit 3
- 2nd Load Shed: Kihei Substation, Unit 4
- 3rd Load Shed: Kihei Substation, Units 1 and 2
- 4th Load Shed: Wailea Substation, Unit 4

The voltage for this scheme will be sampled at the 69kV level to provide a more accurate reading of how the system is behaving. Sampling on the distribution level may lead to a false impression of the system behavior due to the load tap changers (LTC's) on the distribution transformers.

Keep in mind that this scheme should be sufficient for most contingencies. However, for the N-2 contingency, outage of both the MPP to Kihei and MPP to Kealahou 69 kV lines, the scheme may not be able to fully mitigate a collapse in this situation since this extreme situation cuts off two of the main feeders that feed the Kihei and Wailea loads. With these two lines out, the power must flow through a much longer path to reach the load. The scheme may not solve all the undervoltage problems associated with this double contingency, but it will provide a considerable amount of relief.

Again, the UVLS scheme should be considered a "remedial" measure and is not intended to replace other system improvements. Additionally, the scheme should be reviewed following any major system changes or upgrades.

INTRODUCTION:
Purpose:

The purpose of this study is to develop the requirements for an undervoltage load-shedding scheme as an interim solution for the delayed installation of the additional South Maui line as recommended in the MECO 8 Year Transmission Study, 2009-2016, South/Up-country Maui report. The undervoltage load-shedding scheme should be considered a "remedial measure", and does not negate the need for the additional transmission line to the South Maui area. The use of the undervoltage load-shedding scheme is to stabilize system voltages and to prevent a possible system wide voltage collapse.

Kihei and Wailea are susceptible to low voltage conditions during the N-1 contingency (loss of the 69 kV line) from the Maalaea Power Plant (MPP) to the Kihei Substation. With the loss of that line, the power must travel much farther, through the MPP to Kealahou line, to reach the heavy South Maui load. These voltage issues are in violation of the MECO Transmission Planning Criteria and could also create a system wide voltage collapse if the system cannot supply the necessary reactive power to sustain acceptable voltages.

This study will outline the undervoltage load-shedding requirements including:

- System load threshold for "arming" the UVLS scheme
- Amount of load to shed
- Required speed of shedding
- UVLS relay settings

Assumptions:

The following are the assumptions used for this study:

- The peak and min base cases are based off of 2009 actuals
- 100 MW and 125 MW cases are scaled up from the min base case
- 150 MW and 175 MW cases are scaled down from the peak base case
- Generators dispatched as found in Appendix A
- Minimum of 6 MW spinning reserve or half of KWP I online power, whichever greatest
- Minimum of 6 MW down reserve

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- Unless curtailed for down reserve requirements or specified otherwise, KWPI is assumed to be at 80% or 24 MW of output
- Kihei and Wailea Capacitor banks assumed offline to show most pessimistic voltage result

DISCUSSION:
System Load Threshold:

Figures 1 and 2 are PV plots and Figures 3 and 4 are QV plots that compare the curves for different system load scenarios. As stated in the assumptions listed above, the 100 MW and 125 MW cases were scaled up from the Min Base case, which has the South Maui load at approximately 28 % of the total system load. The 150 MW, 175 MW, and the Peak Base cases have a South Maui load equivalent to approximately 23% of the system load. Therefore the plots of the 125 MW case and the 150 MW case behave similarly.

Figures 1 and 3 show that during normal conditions, all system load scenarios can sufficiently support loads in the South Maui area. However, Figures 2 and 4 show that for the N-1 condition from MPP to Kihei, certain system load levels may operate close to possible voltage collapse conditions. These figures show that around 150 MW to 175 MW is a relatively safe margin to use as a system load threshold for arming the UVLS scheme.

Since these cases are snapshots in time, more PV and QV analysis was done to test the sensitivities of the percentage of South Maui area load in comparison with the total system load. The next set of PV and QV curves, Figures 5-8, compare between the South Maui load at 23% and 28% for the 150 MW and 175 MW system load cases. Figures 5-8 show that the difference in load corresponds to a roughly 8-10 MW and MVAR difference for the PV and QV curves, respectively. Therefore, a system load threshold of 150 MW would provide better reliability due to the possibility of South Maui locally peaking at a different time than the rest of the system without having to arm the scheme unnecessarily. Note that the threshold is only the minimum system load that the scheme must be armed, the scheme can also be armed at all times.

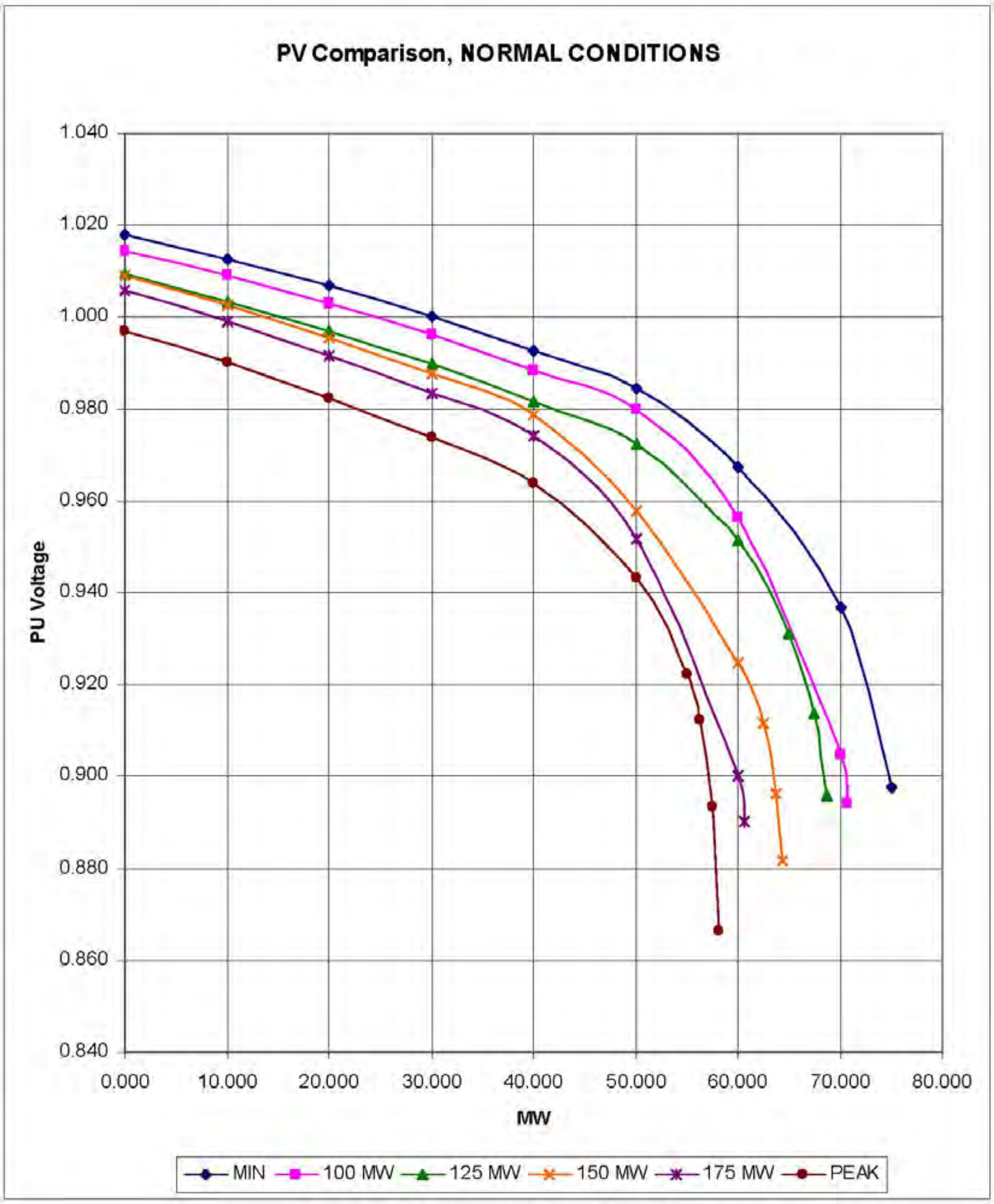

Figure 1: PV Comparison, Normal Conditions

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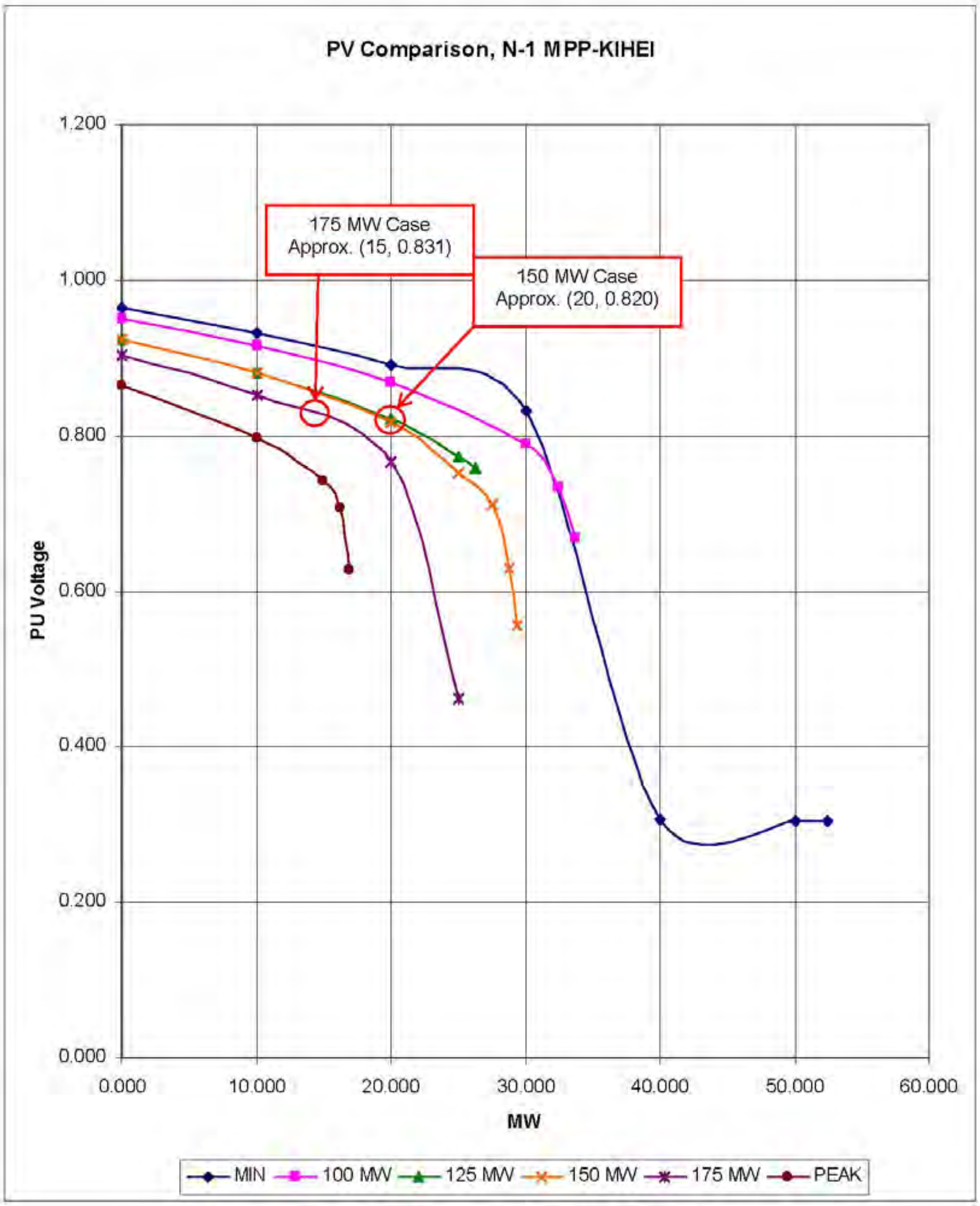

Figure 2: PV Comparison, N-1 MPP to Kihei

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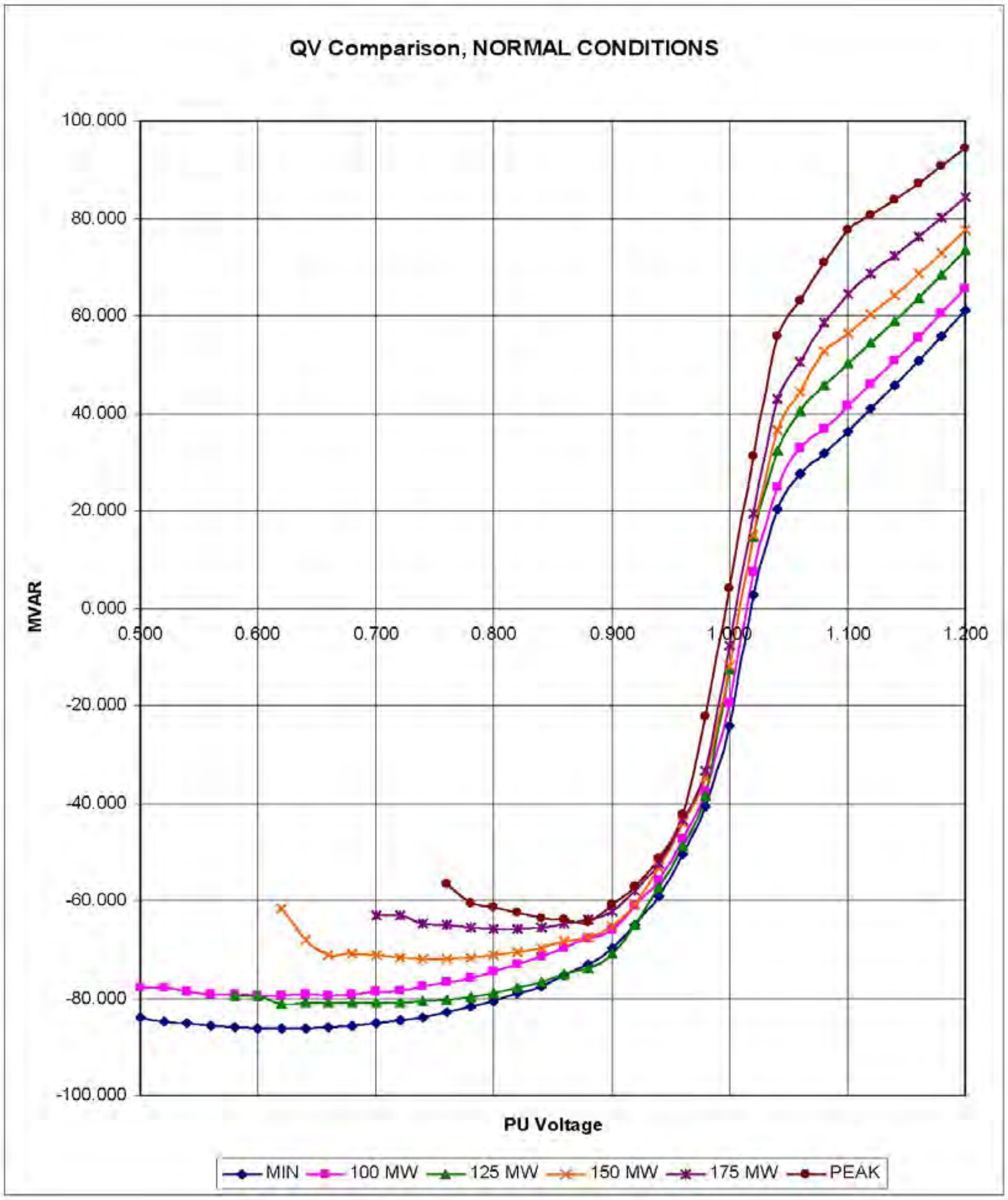

Figure 3: QV Comparison, Normal Conditions

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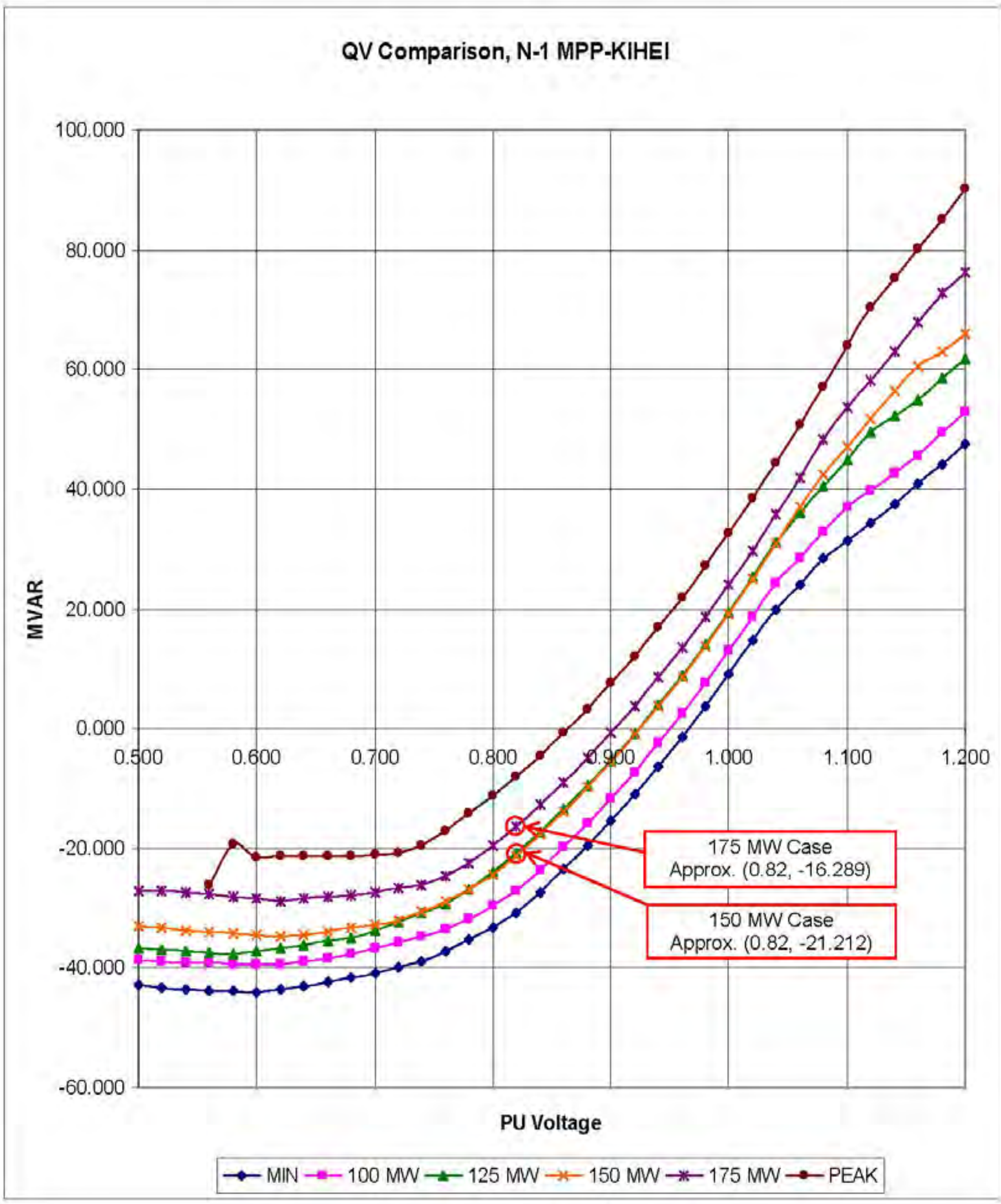

Figure 4: QV Comparison, N-1 MPP to Kihei

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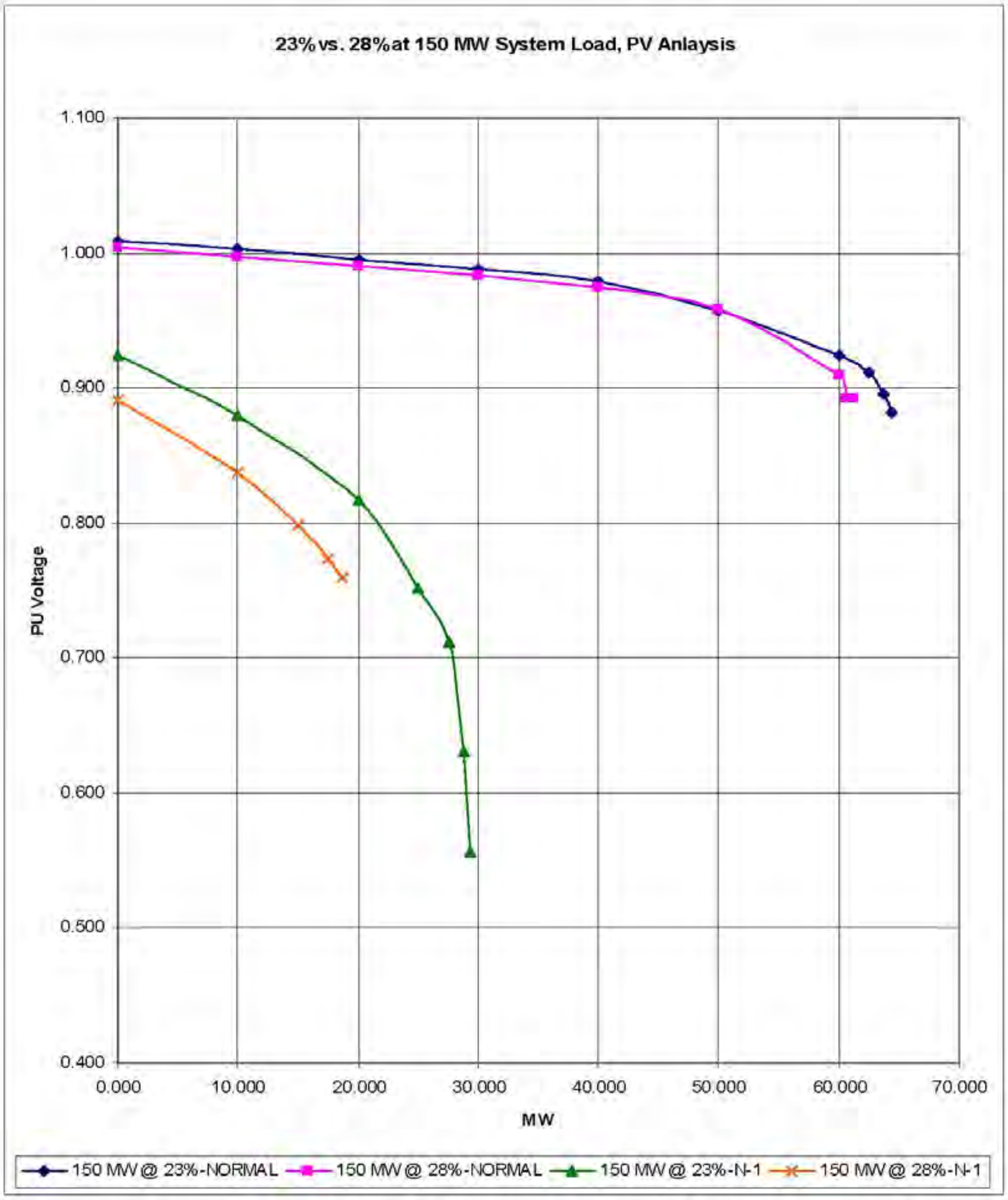

Figure 5: 23% vs. 28% of 150 MW System Load, PV Analysis

NOTE: N-1 condition in figure above is with the line from MPP to Kihei out.

8

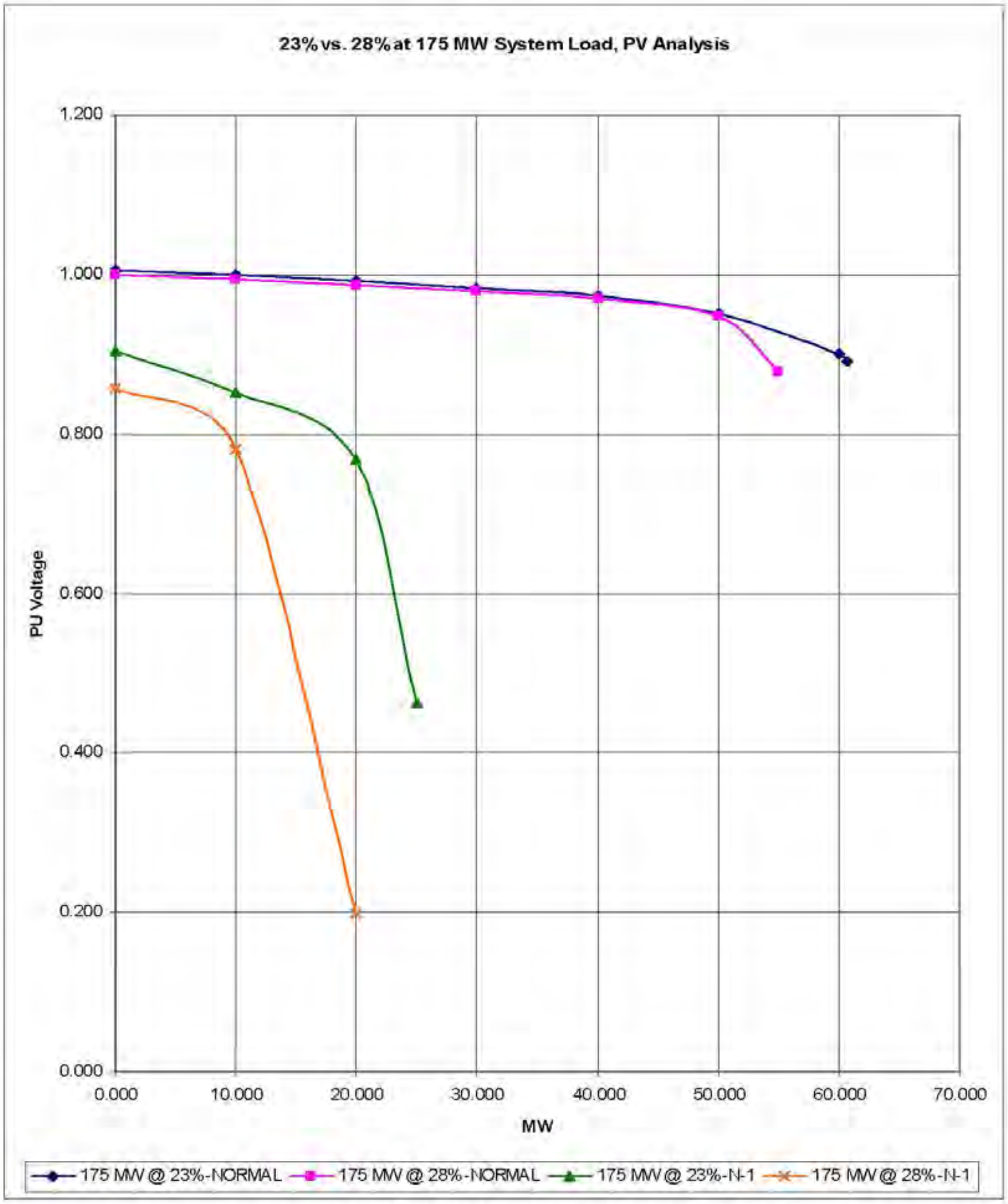

Figure 6: 23% vs. 28% of 175 MW System Load, PV Analysis

NOTE: N-1 condition in figure above is with the line from MPP to Kihei out.

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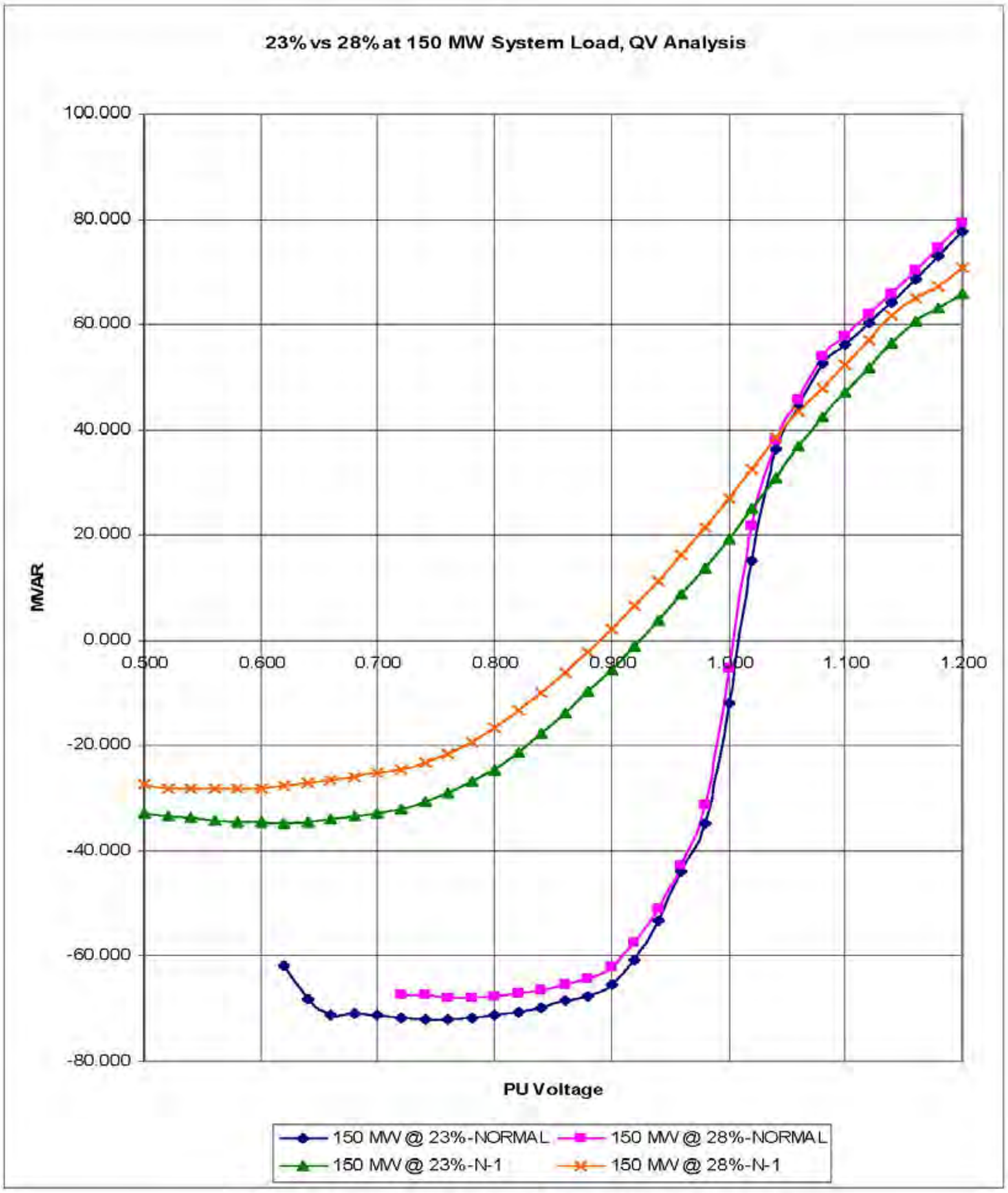

Figure 7: 23% vs. 28% of 150 MW System Load, QV Analysis

NOTE: N-1 condition in figure above is with the line from MPP to Kihei out.

10

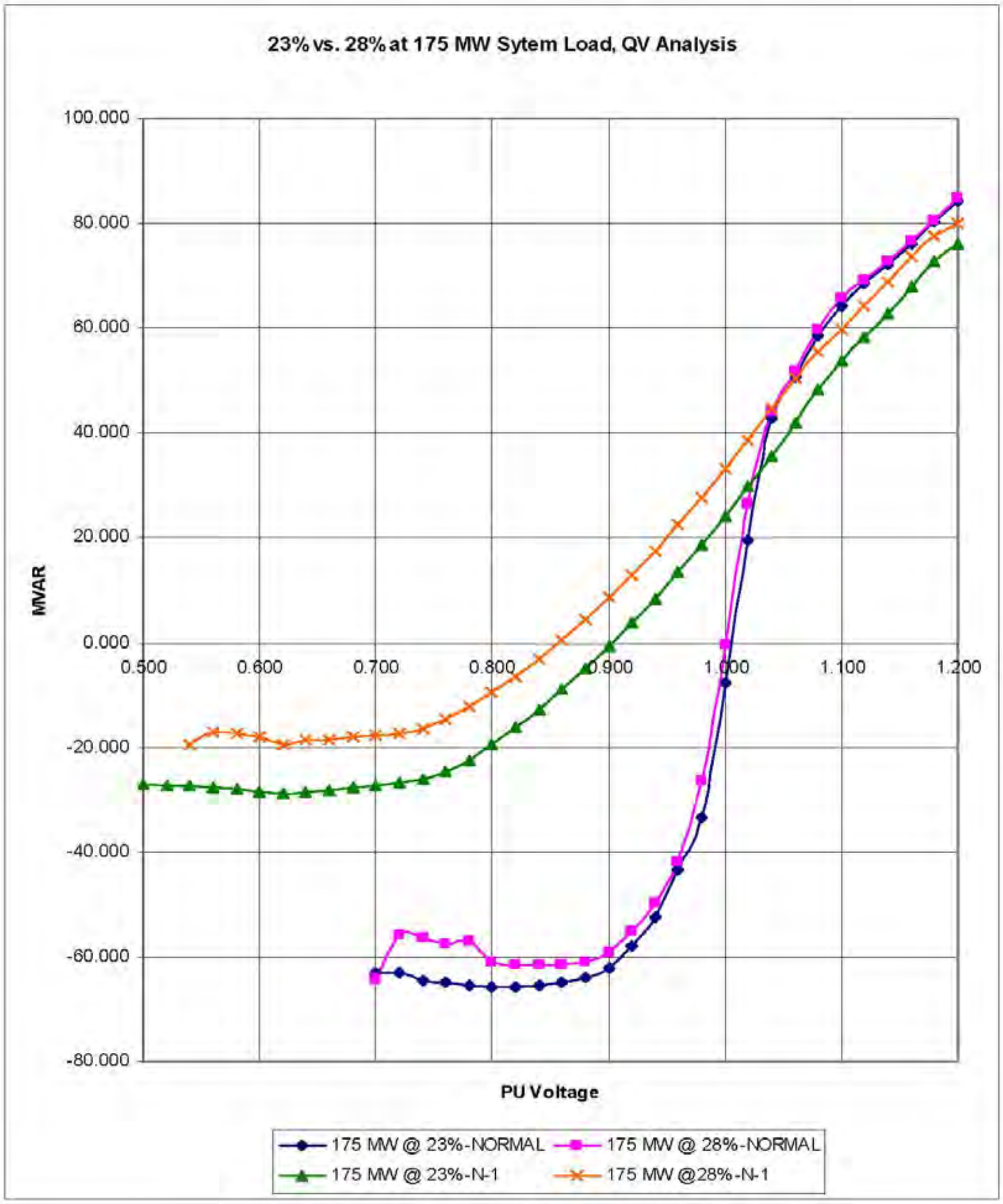

Figure 8: 23% vs. 28% of 175 MW System Load, QV Analysis

NOTE: N-1 condition in figure above is with the line from MPP to Kihei out.

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Amount of Load to Shed:

Below in Table 1 are the voltages at Kihei and Wailea during certain N-1 contingencies. Notice the undervoltage conditions for the loss of the MPP to Kihei line during the system peak. Table 2, also highlights the worst N-2 conditions that can be very detrimental to the MECO system.

CASE	BUS	PU VOLTAGE NORMAL	PU VOLTAGE N-1 MPP-Kihei	PU VOLTAGE N-1 Puunene-Kanaha	PU VOLTAGE N-1 MPP-Puunene	PU VOLTAGE N-1 MPP-Kealahou	
PEAK BASECASE	KIHEI	0.9970	0.8637	0.9916	0.9944	0.9870	SOUTH MAUI 23% OF LOAD
	WAILEA	0.9887	0.8807	0.9794	0.9843	0.9713	
175 MW	KIHEI	1.0057	0.9034	1.0019	1.0040	0.9979	
	WAILEA	0.9991	0.9163	0.9925	0.9962	0.9855	
150 MW	KIHEI	1.0090	0.9246	1.0060	1.0075	1.0022	SOUTH MAUI 28% OF LOAD
	WAILEA	1.0031	0.9351	0.9978	1.0005	0.9911	
125 MW	KIHEI	1.0093	0.9236	1.0065	1.0082	1.0034	
	WAILEA	1.0046	0.9358	0.9997	1.0027	0.9941	
100 MW	KIHEI	1.0145	0.9504	1.0123	1.0135	1.0096	
	WAILEA	1.0106	0.9594	1.0066	1.0088	1.0019	
MIN BASECASE	KIHEI	1.0180	0.9654	1.0161	1.0171	1.0139	
	WAILEA	1.0147	0.9728	1.0133	1.0130	1.0073	

Table 1: Load Flow Voltages for Kihei and Wailea, N-1 Contingencies

CASE	BUS	PU VOLTAGE N-2, Puunene-Kanaha, MPP-Kihei	PU VOLTAGE N-2, MPP-Puunene, MPP-Kihei	PU VOLTAGE N-2, MPP-Kealahou, MPP-Kihei
PEAK BASECASE	KIHEI	0.7886	0.8349	*0.3899
	WAILEA	0.8071	0.8520	*0.4089
175 MW	KIHEI	0.8672	0.8825	0.4295
	WAILEA	0.8808	0.8958	0.4511
150 MW	KIHEI	0.9008	0.9149	0.9248
	WAILEA	0.9117	0.9256	0.6414
125 MW	KIHEI	0.9002	0.9133	0.6461
	WAILEA	0.9128	0.9256	0.6649
100 MW	KIHEI	0.9338	0.9427	0.7999
	WAILEA	0.9430	0.9519	0.8111
MIN BASECASE	KIHEI	0.9522	0.9596	0.8567
	WAILEA	0.9597	0.9671	0.8652

Table 2: Load Flow Voltages for Kihei and Wailea, N-2 Contingencies

*NOTE: Large mismatch in the solution for this specific case; therefore the accuracy is uncertain.

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By using dynamic studies to shed loads in the South Maui area, the amount of load needed to be shed per 1% increase in voltage can be calculated and averaged to approximately 3.3MVA. The following plots and tables show this for the Peak Basecase and the 150 MW case.

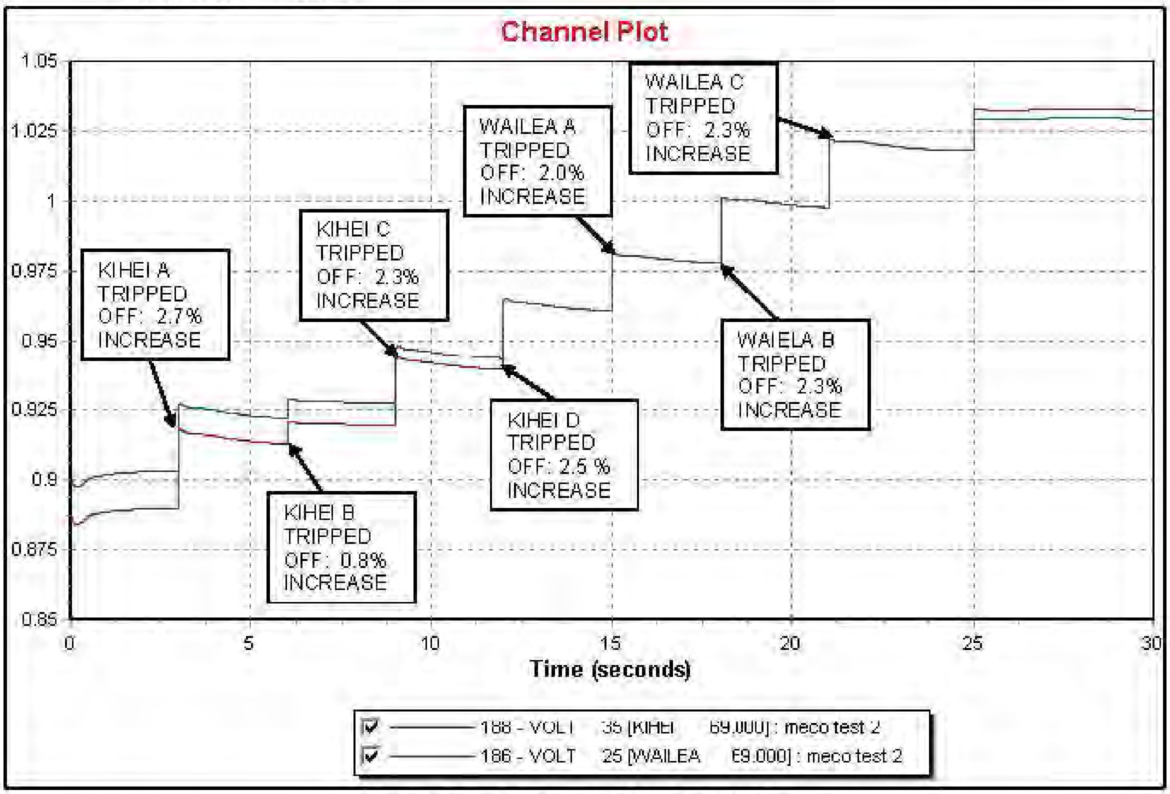

Figure 9: Peak Basecase Manually Shed Load

PEAK CASE					
LOAD TSF	MW	MVAR	MVA	% INCREASE IN VOLTAGE	MVA SHED PER 1% INCREASE
KIHEI A	9.1820	0.8410	9.2204	2.7	3.4150
KIHEI B	2.1563	0.7591	2.2860	0.8	2.8575
KIHEI C	6.1963	2.1812	6.5690	2.3	2.8561
KIHEI D	6.5327	2.3726	6.9502	2.5	2.7801
WAILEA A	6.7263	2.1026	7.0473	2.0	3.5236
WAILEA B	7.6871	2.4030	8.0539	2.3	3.5017
WAILEA C	8.0990	2.5317	8.4855	2.3	3.6893
				AVERAGE:	3.2319

Table 3: Peak Basecase, % Voltage Increase vs. Load Shed

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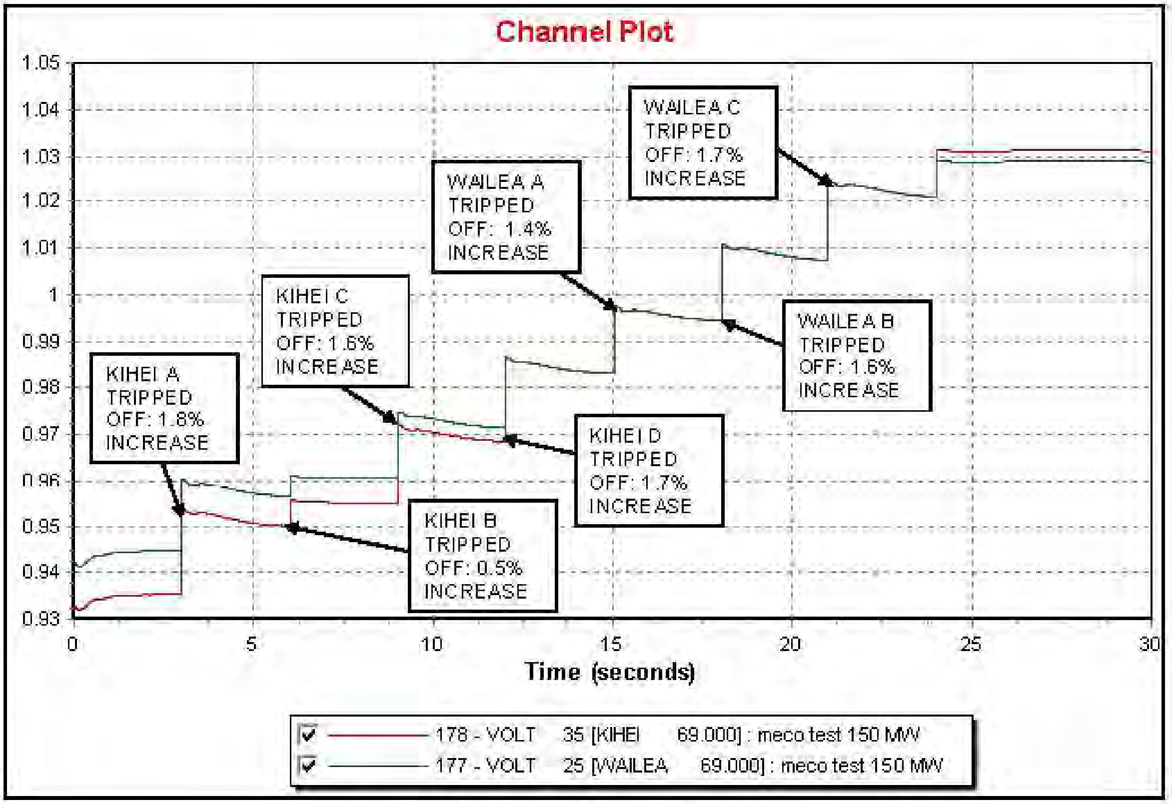

Figure 10: 150 MW Case Manually Shed Load

150 MW CASE					
LOAD TSF	MW	MVAR	MVA	% INCREASE IN VOLTAGE	MVA SHED PER 1% INCREASE
KIHEI A	6.7219	0.6157	6.7500	1.8	3.7500
KIHEI B	1.5786	0.5557	1.6736	0.5	3.3471
KIHEI C	4.5362	1.5968	4.8090	1.6	3.0057
KIHEI D	4.7824	1.7369	5.0880	1.7	2.9930
WAILEA A	4.9241	1.5393	5.1591	1.4	3.6851
WAILEA B	5.6276	1.7592	5.8962	1.6	3.6851
WAILEA C	5.9291	1.8534	6.2120	1.7	3.6541
				AVERAGE:	3.4457

Table 4: 150 MW Case, % Voltage Increase vs. Load Shed

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As an example, to increase the Kihei bus voltage from 0.8637 pu to 0.9 pu during peak load conditions with the loss of the Maalaea-Kihei 69 kV line, as indicated in Table 1, a total of approximately 12 MVA load would have to be shed. To restore the bus to a more stable voltage range, from 0.92 pu to 0.95 pu, about 18 MVA to 28 MVA would have to be shed, respectively.

Speed of Load Shed:
When designing the speed of load shed there are several factors to consider including:
- False tripping due to faults
- Load Tap Changers
- Generator Response

High-impedance faults on the system can result in momentary low voltage conditions until the fault can be cleared. In some cases, it may take several seconds for a fault to clear. The UVLS scheme should provide a long enough delay to avoid nuisance tripping of loads.

The automatic load tap changers (LTC's) on the distribution transformers at the Kihei and Wailea substations regulate the low side of these transformers, and they run on a 30 second time delay. Typically, it is recommended to shed loads before the operation of the LTC's to prevent an increased demand of reactive power to support voltage. However, the results of a load flow analysis (Table 5 below) show that after the loss of the MPP to Kihei line, the system as a whole would require an approximate increase of 4 MW and 15.7 MVAR. But, the increase in load in the South Maui area is small, 0.68 MVAR to Kihei and 0.36 MVAR to Wailea. In fact, for the third case, which allows the taps to move, the amount of power needed for the whole system actually decreases a little. Therefore, for this case, shedding before the LTC movement is not critical.

	CASES	KIHEI		WAILEA		TOTAL SYSTEM	
		REAL (MW)	REACTIVE (MVAR)	REAL (MW)	REACTIVE (MVAR)	REAL (MW)	REACTIVE (MVAR)
1	PEAK NORMAL	24.0673	8.1098	22.5124	8.3729	204.1643	77.6800
2	"INSTANTANEOUS" N-1 WITH LOCKED TAPS	24.0672	8.7897	22.5123	8.7330	208.1694	93.4093
3	N-1 WITH STEPPING TAPS	24.0680	8.7831	22.5126	8.7292	208.0686	92.2274

Table 5: LTC Impact on Load

Lastly, the generators do not respond instantaneously to the low voltage problems. There is a time delay from the sensing of the change in voltage and the generator's response. Since shedding customer load is never ideal, ample time must be given for the generators to attempt to mitigate this problem, before shedding. Therefore, the UVLS relays will delay for at least 60 seconds before load shedding commences. This delay also gives more than enough time to avoid the nuisance tripping for high-impedance faults.

RESULTS AND RECOMMENDATIONS:
Undervoltage Load Shed Scheme:

With the existing equipment at Kihei Substation, feeder 1473 of Unit 3 and feeder 1515 of Unit 4 have the ability to trip offline for undervoltage problems. However, in order to trip Unit 1 and Unit 2, an existing transmission line relay would have to be upgraded. It is recommended for uniformity and to avoid unnecessary confusion that this upgraded relay is used for the shedding of all four units. The voltage will be sampled from the existing coupling capacitors, which measures the 69 kV level. Since the UVLS scheme has a long time delay, the response time delay of the coupling capacitors will not be an issue. As seen previously in this study, Units 3 and 4 (transformers C and D, respectively) of Kihei sum up to about 10 MVA to 13.5 MVA, depending on the total system load. By shedding this load, the voltage in South Maui can improve by about 3% to 4.5%. Units 1 and 2 (transformers A and B, respectively), sum up to about 8.4 MVA to 11.5 MVA. Shedding Units 1 and 2 can improve voltage in the South Maui area by approximately 2.4% to 3.4%.

The future Wailea Unit 4 will also have the capability of undervoltage load shedding. For this study, the existing load at Wailea is assumed to be redistributed equally amongst all four units, which will load Unit 4 at approximately 5.9 MVA at the system peak load condition. Shedding Unit 4 at Wailea, if loaded at around 5.9 MVA, will provide slightly less than 2% increase in the South Maui Voltage.

Table 6 shows the settings used for the relay models.

SUB/UNIT	TIME DELAY	VOLTAGE PICK-UP	LOAD SHED (PEAK CASE)
Kihei/Unit 3	60 seconds	0.91 pu	6.6 MVA
Kihei/Unit 4	90 seconds	0.91 pu	7.0 MVA
Kihei/Unit 1	120 seconds	0.91 pu	9.2 MVA
Kihei/Unit 2	120 seconds	0.91 pu	2.3 MVA
Wailea/Unit 4	150 seconds	0.91 pu	5.9 MVA

Table 6: UVLS Relay Trip Settings

Plots:

The first two plots, Figures 11 and 12, shown below are dynamic plots of the peak system case where the line from MPP to Kihei is tripped at 2 seconds. As shown, the UVLS scheme picks up 60 seconds later by tripping Kihei Unit 3 because the voltage at Kihei settled below 0.91 pu. In this case, the shedding Kihei Unit 3 was enough to raise the Kihei bus voltage above the set point. Keep in mind that these cases do not have any capacitor banks online in Kihei and Wailea to show the most pessimistic cases for this study. Therefore, even though the voltage at Kihei is only slightly above 0.90 pu, typically there will be more VAR support from local capacitor banks to boost the voltage into a more ideal range.

The second set of plots, Figures 13 and 14, show a case where Kihei has an extra heavy reactive load which is modeled as an additional 15 MVAR load at the Kihei bus. Again, the line from MPP to Kihei trips off at the 2 second mark. The plots show that the additional load drags the voltage down lower and triggers the UVLS scheme. The load at Kihei Unit 3 trips off at 62 seconds, followed by Kihei Unit 4 load at 92 seconds, and lastly Kihei Units 1 and 2 at 122 seconds.

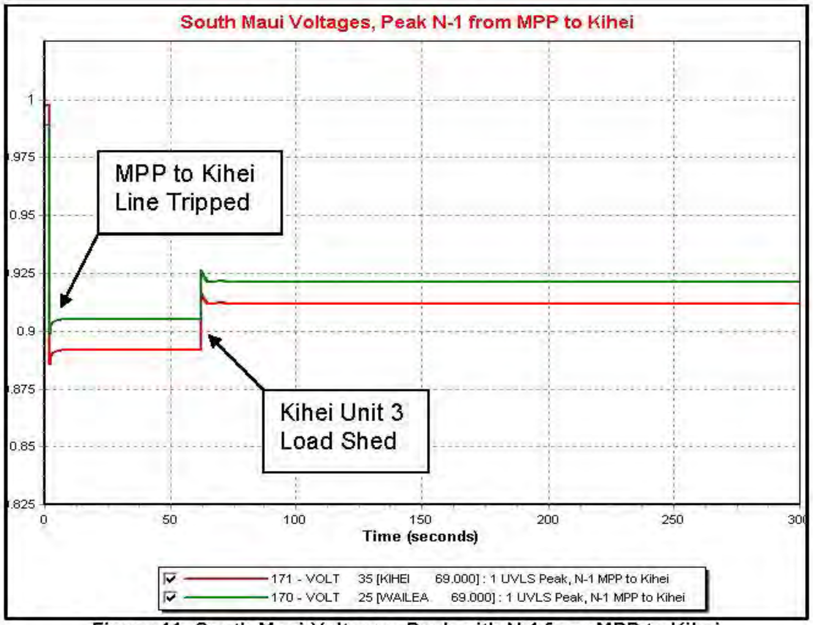

Figure 11: South Maui Voltages, Peak with N-1 from MPP to Kihei

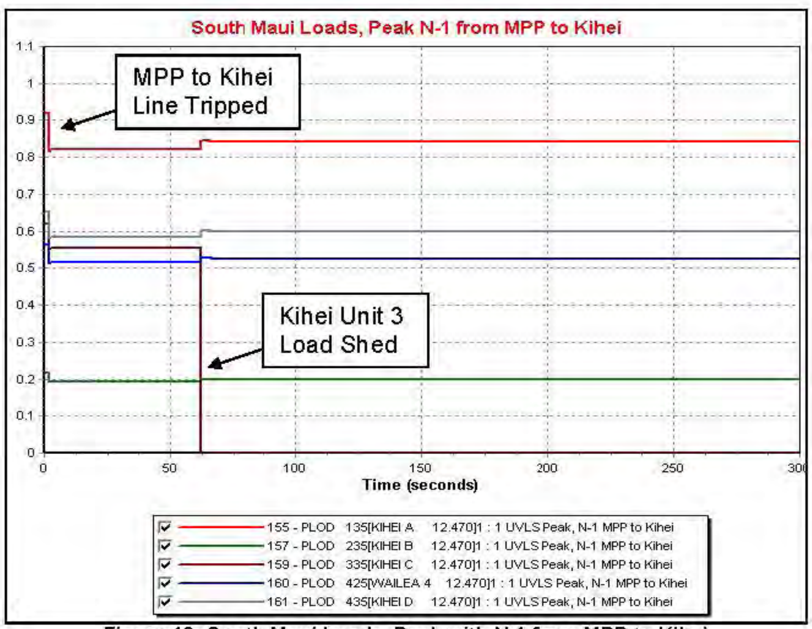

Figure 12: South Maui Loads, Peak with N-1 from MPP to Kihei

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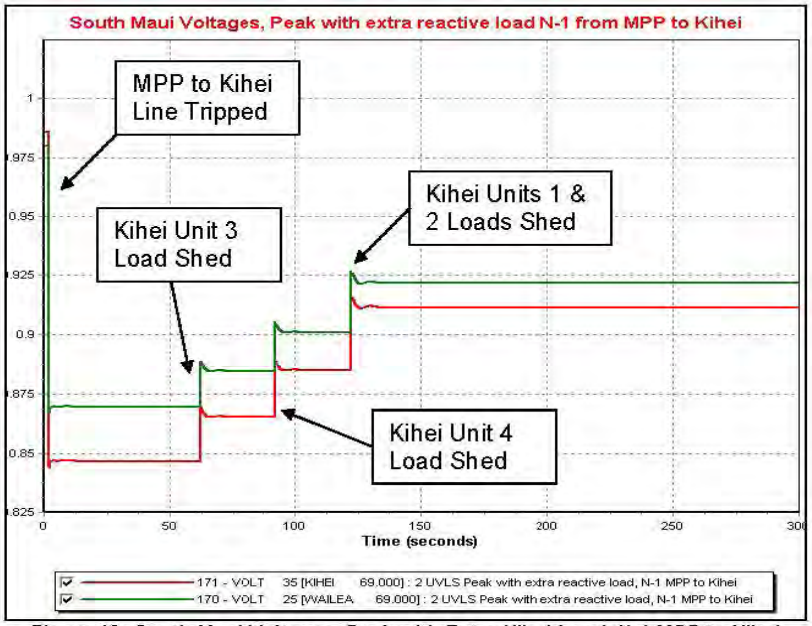

Figure 13: South Maui Voltages, Peak with Extra Kihei Load, N-1 MPP to Kihei

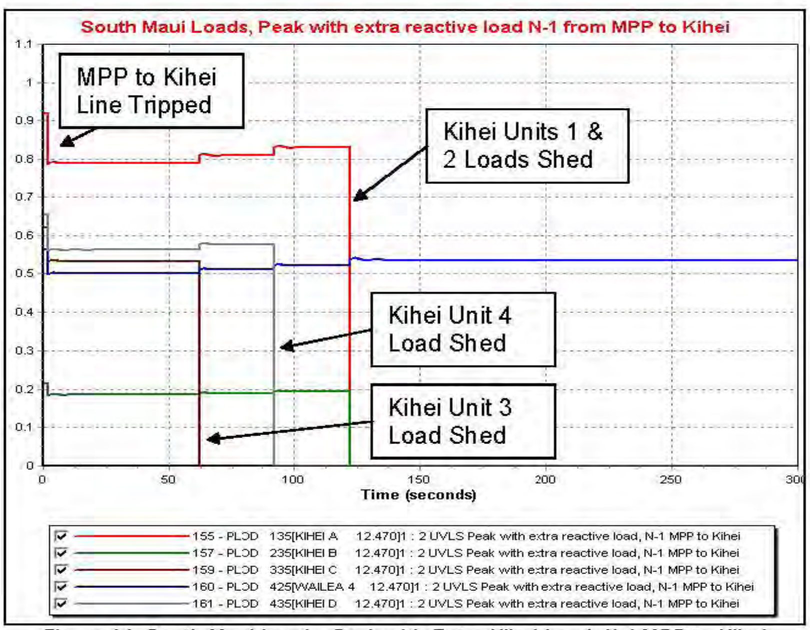

Figure 14: South Maui Loads, Peak with Extra Kihei Load, N-1 MPP to Kihei

Worst-case Scenarios:

Even though the MECO planning criteria does not require to plan for N-2 conditions, it is important that operators are aware of the following scenarios that can cause severe voltage problems as well as the high risk of voltage collapse. As identified earlier, the N-1 case from MPP to Kihei creates low voltage conditions in the South Maui area, as well as puts the MECO system at risk for a possible voltage collapse. When the MPP to Kihei line-out condition is paired with several of the other line-out conditions the system is at great risk for collapse.

Assuming the line from MPP to Kihei is out, if any of the 69 kV lines **from MPP to Puunene, or Puunene to Kanaha, or Kanaha to Pukalani** is out at the same time, it is possible that the system will be either at the point of collapse or very close to it. This is illustrated by the QV plot on the following page. However, the UVLS scheme should be able to mitigate these cases. The dynamic plots for the UVLS scheme implemented for these worst case scenarios can be found in Appendix B.

In addition, if the line from **MPP to Kealahou** is out while the MPP to Kihei line is also out, then the system will be the most susceptible to a collapse because the power that is usually fed by the two lines that are out must now travel all the way from MPP through Puunene, Kanaha, Pukalani, and Kula to serve the South Maui load. Due to the severe nature of this contingency, the UVLS scheme may not be able to mitigate a collapse for this specific case, however the load shedding will make a considerable difference in the resulting voltage.

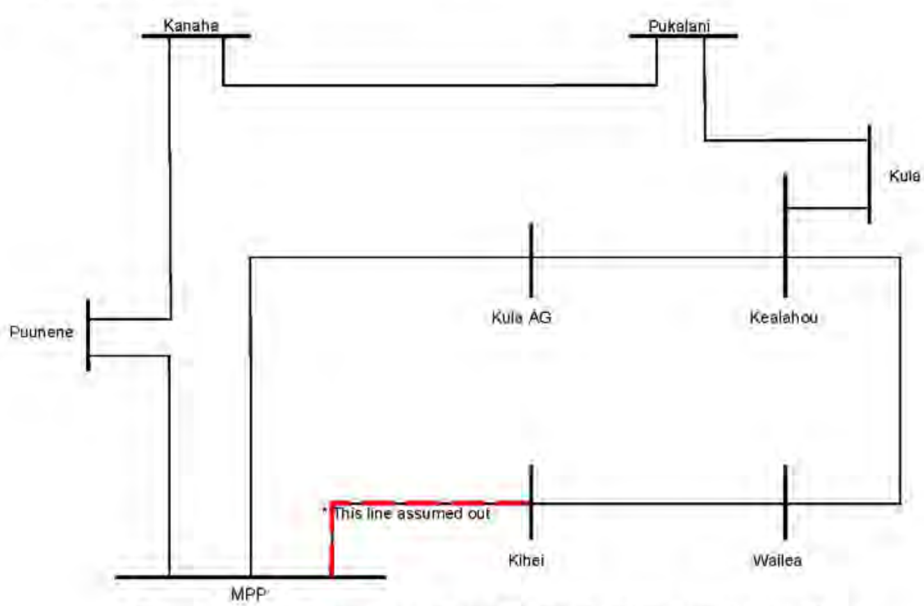

Figure 15: 69 kV Transmission Lines Feeding South/Up-country Maui Area

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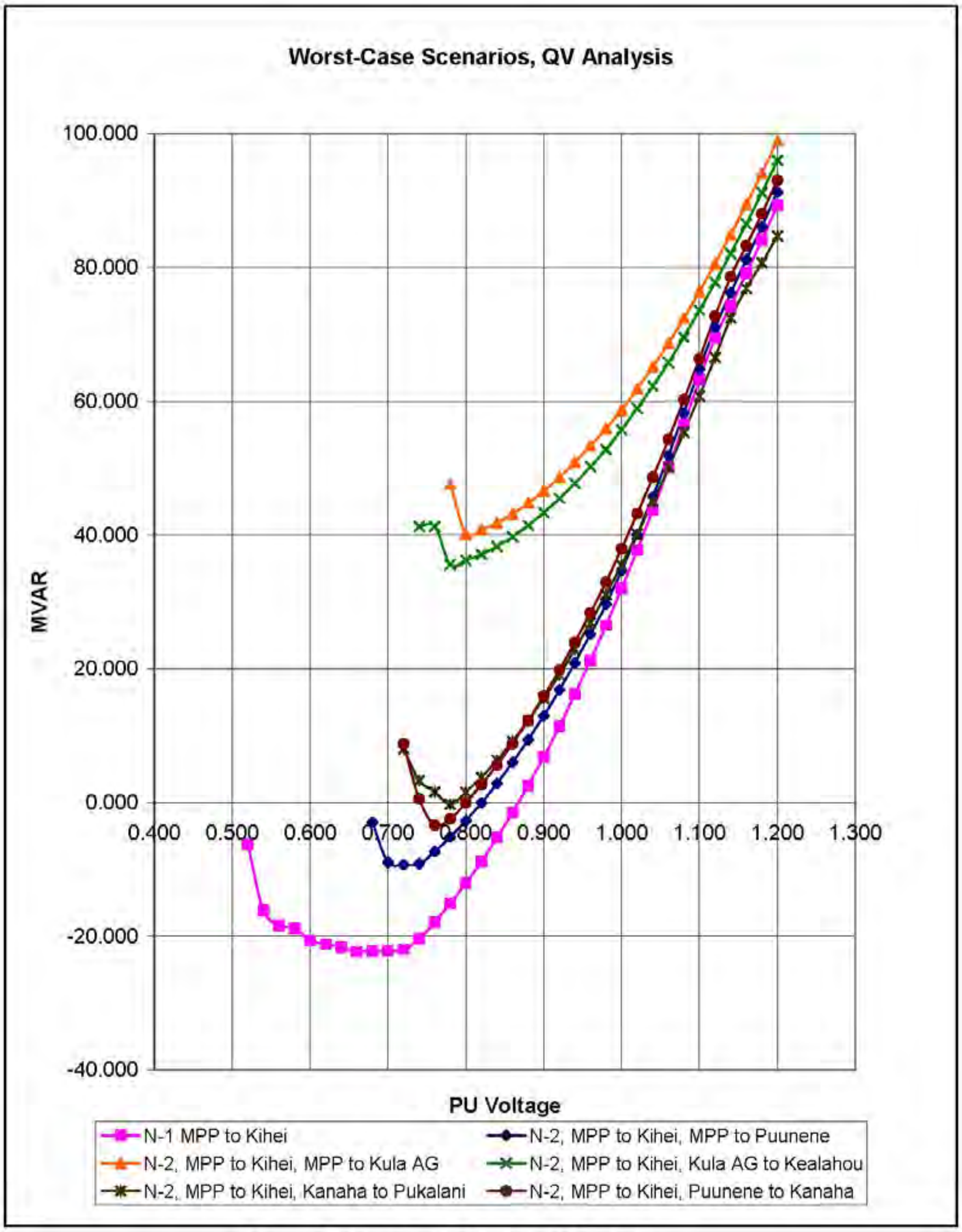

Figure 16: Worst-case Scenario, QV Analysis

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CONCLUSION:

The UVLS scheme is an interim solution for the delayed installation of the second transmission line to the South Maui area. This scheme will help correct undervoltage violations and will help mitigate a system wide voltage collapse.

The UVLS scheme utilizes a relatively long time delay to avoid nuisance tripping, to allow faults to clear, and to allow the generators time to respond. This scheme will shed load in four blocks starting with Kihei Unit 3, then Kihei Unit 4, followed by both Kihei Unit 1 and Unit 2, and lastly Wailea Unit 4. In total, the scheme can shed up to approximately 15 % of the total system load.

Again, the UVLS scheme should be considered a "remedial" measure and is not intended to replace other system improvements. Additionally, the scheme should be reviewed following any major system changes or upgrades.

APPENDIX A

Maalaea-Kamalii Transmission Line Alternatives

Bus Number	Bus Name	Id	Code	VSched (pu)	Remote Bus Number	In Service	Pgen (MW)	Pmax (MW)	Pmin (MW)	Qgen (Mvar)	Qmax (Mvar)	Qmin (Mvar)	Mbase (MVA)	SR	Minimum Load	Min load violation?	DR	
101	KGS-1 11.500	1	-2	1.022	200	0	4.76	5	0	2.9276	3	0	6.25	0	2.5	0	0	
102	KGS-2 11.500	2	-2	1.022	200	0	4.8	5	0	2.0015	3	0	6.25	0	2.5	0	0	
103	KGS-3 11.500	3	2	1.022	200	1	7.5	11.5	0	2.9569	7.1	0	13.53	4	7.5	1	0	
104	KGS-4 11.500	4	2	1.022	200	1	7.5	12.5	0	2.9569	9.375	0	15.63	5	7.5	1	0	
105	MGS-123 4.1600	1	-2	1.031	39	0	1.75	2.5	0	0.7117	1.875	0	3.44	0	2.5	0	0	
105	MGS-123 4.1600	2	-2	1.031	39	0	1.75	2.5	0	0.7117	1.875	0	3.44	0	2.5	0	0	
105	MGS-123 4.1600	3	-2	1.031	39	0	1.75	2.5	0	0.7117	1.875	0	3.44	0	2.5	0	0	
106	MGS-458 4.1600	4	-2	1.031	39	0	3.43	5.6	0	1.4013	4.2	0	7	0	2	0	0	
106	MGS-458 4.1600	5	-2	1.031	39	0	4.41	5.6	0	1.8016	4.2	0	7	0	2	0	0	
106	MGS-458 4.1600	8	-2	1.031	39	0	0	5.6	0	1.491	4.2	0	7	0	2	0	0	
107	MGS-679 4.1600	6	-2	1.031	39	0	3.39	5.6	0	1.3938	4.2	0	7	0	2	0	0	
107	MGS-679 4.1600	7	-2	1.031	39	0	4.4	5.6	0	1.8091	4.2	0	7	0	2	0	0	
107	MGS-679 4.1600	9	-2	1.031	39	0	0	5.6	0	2.1169	4.2	0	7	0	2	0	0	
108	MGS-1011 6.9000	0	-2	1.031	39	0	10.86	12.5	0	5.3381	9.375	0	15.63	0	6	0	0	
108	MGS-1011 6.9000	1	-2	1.031	39	0	5.43	12.5	0	3.6141	9.375	0	15.63	0	6	0	0	
109	MGS-1213 6.9000	2	-2	1.031	39	0	7	12.5	0	3.5871	9.375	0	15.63	0	6	0	0	
109	MGS-1213 6.9000	3	-2	1.031	39	0	7	12.5	0	3.5871	9.375	0	15.63	0	6	0	0	
110	MGS-X1X2 4.1600	1	-2	1.031	39	0	0	2.5	0	1.875	1.875	0	3.44	0	2.5	0	0	
110	MGS-X1X2 4.1600	2	-2	1.031	39	0	2	2.5	0	1.875	1.875	0	3.44	0	2.5	0	0	
301	CT-1 M14 13.800	1	3	1.005	0	1	15.6429	21.5	0	5.886	15	0	26.81	5.8571	12.5	1	3.1429	
302	CT-2 M16 13.800	2	2	1.031	39	1	15.5	21.5	0	5.6598	15	0	26.81	6	12.5	1	3	
303	ST-1 M15 13.800	3	2	1.031	39	1	11	15	0	4.009	12	0	18.5	4	11	1	0	
304	CT-3 M17 13.800	4	2	1.031	39	1	14	21.5	0	4.9051	15	0	26.81	7.5	14	1	0	
305	CT-4 M19 13.800	5	-2	1.031	39	0	16	21.5	0	5.3867	15	0	26.81	0	14	0	0	
306	ST-2 M18 13.800	6	2	1.031	39	1	3	15	0	1.2263	12	0	18.5	12	3	1	0	
804	HC&S TG4 13.800	4	2	0.9501	0	1	8	19.6	0	0.2976	5.1	0	24.5		8	1		
90971	KWPI_1 0.5750	1	-2	1	0	1	3	30	0	0	14.5	0	33.34			1		
						9							Total SR	35.3571		9	6.1429	=Total DR
													SR Flag	0	Min Load Violation Flag	0	0	DR Flag

```
MACHINE SUMMARY:
  BUS# X-- NAME --X BASKV ID      KW      KVAR     QMAX     QMIN  ETERM CURRENT     PF   KVABASE   X T R A N   GENTAP ZONE AREA SWING
   103 KGS-3        11.500 3   7500.0   2956.9   7100.0      0.0 0.9863  8174.0  0.9303 13529.0                       19    2
   104 KGS-4        11.500 4   7500.0   2956.9   9375.0      0.0 1.0074  8002.5  0.9303 15625.0                       19    2
   301 CT-1 M14     13.800 1  15642.9   5886.0 15000.0      0.0 1.0050 16630.5  0.9359 26813.0                       20    2  SYST
   302 CT-2 M16     13.800 2  15500.0   5659.8 15000.0      0.0 1.0042 16431.4  0.9393 26813.0                       20    2
   303 ST-1 M15     13.800 3  11000.0   4009.0 12000.0      0.0 0.9989 11720.2  0.9395 18500.0                       20    2
   304 CT-3 M17     13.800 4  14000.0   4905.1 15000.0      0.0 0.9789 15154.9  0.9438 26813.0                       20    2
   306 ST-2 M18     13.800 6   3000.0   1226.3 12000.0      0.0 0.9659  3355.3  0.9257 18500.0                       20    2
   804 HC&S TG4     13.800 4   8000.0    297.6  5100.0      0.0 0.9501  8426.0  0.9993 24500.0                        9    1
 90971 KWPI_1        0.5750 1   3000.0      0.0 14500.0      0.0 1.0048  2985.6  1.0000 33340.0                       11    1
SUBSYSTEM TOTALS              85142.9 27897.8105075.0      0.0                        204433.0
```

MIN BASECASE

Bus Number	Bus Name	Id	Code	VSched (pu)	Remote Bus Number	In Service	Pgen (MW)	Pmax (MW)	Pmin (MW)	Qgen (Mvar)	Qmax (Mvar)	Qmin (Mvar)	Mbase (MVA)	SR	Minimum Load	Min load violation?	DR	
101	KGS-1 11.500	1	-2	1.022	200	0	4.76	5	0	2.9276	3	0	6.25	0	2.5	0	0	
102	KGS-2 11.500	2	-2	1.022	200	0	4.8	5	0	2.0015	3	0	6.25	0	2.5	0	0	
103	KGS-3 11.500	3	2	1.022	200	1	7.5	11.5	0	3.596	7.1	0	13.53	4	7.5	1	0	
104	KGS-4 11.500	4	2	1.022	200	1	7.5	12.5	0	3.596	9.375	0	15.63	5	7.5	1	0	
105	MGS-123 4.1600	1	-2	1.029	39	0	1.75	2.5	0	0.7117	1.875	0	3.44	0	2.5	0	0	
105	MGS-123 4.1600	2	-2	1.029	39	0	1.75	2.5	0	0.7117	1.875	0	3.44	0	2.5	0	0	
105	MGS-123 4.1600	3	-2	1.029	39	0	1.75	2.5	0	0.7117	1.875	0	3.44	0	2.5	0	0	
106	MGS-458 4.1600	4	-2	1.029	39	0	3.43	5.6	0	1.4013	4.2	0	7	0	2	0	0	
106	MGS-458 4.1600	5	-2	1.029	39	0	4.41	5.6	0	1.8016	4.2	0	7	0	2	0	0	
106	MGS-458 4.1600	8	-2	1.029	39	0	0	5.6	0	1.491	4.2	0	7	0	2	0	0	
107	MGS-679 4.1600	6	-2	1.029	39	0	3.39	5.6	0	1.3938	4.2	0	7	0	2	0	0	
107	MGS-679 4.1600	7	-2	1.029	39	0	4.4	5.6	0	1.8091	4.2	0	7	0	2	0	0	
107	MGS-679 4.1600	9	-2	1.029	39	0	0	5.6	0	2.1169	4.2	0	7	0	2	0	0	
108	MGS-1011 6.9000	0	-2	1.029	39	0	10.86	12.5	0	5.3381	9.375	0	15.63	0	6	0	0	
108	MGS-1011 6.9000	1	-2	1.029	39	0	5.43	12.5	0	3.6141	9.375	0	15.63	0	6	0	0	
109	MGS-1213 6.9000	2	-2	1.029	39	0	7	12.5	0	3.5871	9.375	0	15.63	0	6	0	0	
109	MGS-1213 6.9000	3	-2	1.029	39	0	7	12.5	0	3.5871	9.375	0	15.63	0	6	0	0	
110	MGS-X1X2 4.1600	1	-2	1.029	39	0	0	2.5	0	1.875	1.875	0	3.44	0	2.5	0	0	
110	MGS-X1X2 4.1600	2	-2	1.029	39	0	2	2.5	0	1.875	1.875	0	3.44	0	2.5	0	0	
301	CT-1 M14 13.800	1	3	1.0003	0	1	14.808	21.5	0	5.039	15	0	26.81	6.692	12.5	1	2.308	
302	CT-2 M16 13.800	2	2	1.029	39	1	15	21.5	0	4.7938	15	0	26.81	6.5	12.5	1	2.5	
303	ST-1 M15 13.800	3	2	1.029	39	1	11	15	0	4.5118	12	0	18.5	4	11	1	0	
304	CT-3 M17 13.800	4	2	1.029	39	1	16	21.5	0	5.6397	15	0	26.81	5.5	14	1	2	
305	CT-4 M19 13.800	5	-2	1.029	39	0	16	21.5	0	5.3867	15	0	26.81	0	14	0	0	
306	ST-2 M18 13.800	6	2	1.029	39	1	3	15	0	1.2407	12	0	18.5	12	3	1	0	
804	HC&S TG4 13.800	4	2	0.9501	0	1	8	19.6	0	0.6417	5.1	0	24.5		8	1		
90971	KWPI_1 0.5750	1	2	1.01	0	1	17	30	0	0.8604	14.5	0	33.34			1		
						9							Total SR=	34.692		9	6.808	=Total DR
													SR Flag	0	Min Load Violation Flag	0	0	DR Flag

```
MACHINE SUMMARY:
  BUS# X-- NAME --X BASKV ID      KW      KVAR     QMAX     QMIN  ETERM CURRENT     PF   KVABASE   X T R A N   GENTAP ZONE AREA SWING
   103 KGS-3        11.500 3   7500.0   3543.3   7100.0      0.0 0.9885  8391.6  0.9042 13529.0                       19    2
   104 KGS-4        11.500 4   7500.0   3543.3   9375.0      0.0 1.0085  8224.7  0.9042 15625.0                       19    2
   301 CT-1 M14     13.800 1  14825.4   6111.2 15000.0      0.0 1.0050 15955.8  0.9245 26813.0                       20    2  SYST
   302 CT-2 M16     13.800 2  15000.0   6281.5 15000.0      0.0 1.0056 16172.2  0.9224 26813.0                       20    2
   303 ST-1 M15     13.800 3  11000.0   5025.2 12000.0      0.0 1.0016 12074.6  0.9096 18500.0                       20    2
   304 CT-3 M17     13.800 4  16000.0   6281.5 15000.0      0.0 0.9827 17492.0  0.9308 26813.0                       20    2
   306 ST-2 M18     13.800 6   3000.0   1381.9 12000.0      0.0 0.9656  3420.6  0.9083 18500.0                       20    2
   804 HC&S TG4     13.800 4   8000.0    943.8  5100.0      0.0 0.9501  8478.6  0.9931 24500.0                        9    1
 90971 KWPI_1        0.5750 1  17000.0    620.1 14500.0      0.0 1.0100 16842.9  0.9993 33340.0                       11    1
SUBSYSTEM TOTALS              99825.4 33731.8105075.0      0.0                        204433.0
```

100 MW CASE

Bus Number	Bus Name	Id	Code	VSched (pu)	Remote Bus Number	In Service	Pgen (MW)	Pmax (MW)	Pmin (MW)	Qgen (Mvar)	Qmax (Mvar)	Qmin (Mvar)	Mbase (MVA)	SR	Minimum Load	Min load violation?	DR	
101	KGS-1 11.500	1	2	1.022	200	1	4.8	5	0	1.7623	3	0	6.25	0.2	2.5	1	2.3	
102	KGS-2 11.500	2	2	1.022	200	1	4.8	5	0	1.7623	3	0	6.25	0.2	2.5	1	2.3	
103	KGS-3 11.500	3	2	1.022	200	1	7.5	11.5	0	2.6434	7.1	0	13.53	4	7.5	1	0	
104	KGS-4 11.500	4	2	1.022	200	1	7.5	12.5	0	2.6434	9.375	0	15.63	5	7.5	1	0	
105	MGS-123 4.1600	1	-2	1.029	39	0	1.75	2.5	0	0.7117	1.875	0	3.44	0	2.5	0	0	
105	MGS-123 4.1600	2	-2	1.029	39	0	1.75	2.5	0	0.7117	1.875	0	3.44	0	2.5	0	0	
105	MGS-123 4.1600	3	-2	1.029	39	0	1.75	2.5	0	0.7117	1.875	0	3.44	0	2.5	0	0	
106	MGS-458 4.1600	4	-2	1.029	39	0	3.43	5.6	0	1.4013	4.2	0	7	0	2	0	0	
106	MGS-458 4.1600	5	-2	1.029	39	0	4.41	5.6	0	1.8016	4.2	0	7	0	2	0	0	
106	MGS-458 4.1600	8	-2	1.029	39	0	0	5.6	0	1.491	4.2	0	7	0	2	0	0	
107	MGS-679 4.1600	6	-2	1.029	39	0	3.39	5.6	0	1.3938	4.2	0	7	0	2	0	0	
107	MGS-679 4.1600	7	-2	1.029	39	0	4.4	5.6	0	1.8091	4.2	0	7	0	2	0	0	
107	MGS-679 4.1600	9	-2	1.029	39	0	0	5.6	0	2.1169	4.2	0	7	0	2	0	0	
108	MGS-1011 6.9000	0	-2	1.029	39	0	10.86	12.5	0	5.3381	9.375	0	15.63	0	6	0	0	
108	MGS-1011 6.9000	1	-2	1.029	39	0	5.43	12.5	0	3.6141	9.375	0	15.63	0	6	0	0	
109	MGS-1213 6.9000	2	-2	1.029	39	0	7	12.5	0	3.5871	9.375	0	15.63	0	6	0	0	
109	MGS-1213 6.9000	3	-2	1.029	39	0	7	12.5	0	3.5871	9.375	0	15.63	0	6	0	0	
110	MGS-X1X2 4.1600	1	-2	1.029	39	0	0	2.5	0	1.875	1.875	0	3.44	0	2.5	0	0	
110	MGS-X1X2 4.1600	2	-2	1.029	39	0	2	2.5	0	1.875	1.875	0	3.44	0	2.5	0	0	
301	CT-1 M14 13.800	1	3	1.003	0	1	14.8234	21.5	0	5.8084	15	0	26.81	6.6766	12.5	1	2.3234	
302	CT-2 M16 13.800	2	2	1.029	39	1	14.5	21.5	0	5.3892	15	0	26.81	7	12.5	1	2	
303	ST-1 M15 13.800	3	2	1.029	39	1	11	15	0	4.7904	12	0	18.5	4	11	1	0	
304	CT-3 M17 13.800	4	2	1.029	39	1	14	21.5	0	5.988	15	0	26.81	7.5	14	1	0	
305	CT-4 M19 13.800	5	2	1.029	39	1	14	21.5	0	5.988	15	0	26.81	7.5	14	1	0	
306	ST-2 M18 13.800	6	2	1.029	39	1	8	15	0	3.5928	12	0	18.5	7	3	1	5	
804	HC&S TG4 13.800	4	2	0.9501	0	1	12	19.6	0	1.2949	5.1	0	24.5		8	1		
90971	KWPI_1 0.5750	1	2	1.01	0	1	12	30	0	1.3811	14.5	0	33.34			1		
						12							Total SR=	39.6766		12	9.3234	=Total DR
													SR Flag	0	Min Load Violation Flag	0	0	DR Flag

```
MACHINE SUMMARY:
   BUS# X-- NAME --X BASKV ID      KW      KVAR     QMAX      QMIN  ETERM CURRENT     PF   KVABASE   X T R A N   GENTAP ZONE AREA SWING
    101 KGS-1        11.500 1   4800.0  1762.3   3000.0       0.0 1.0214  5006.1  0.9387   6250.0                      19    2
    102 KGS-2        11.500 2   4800.0  1762.3   3000.0       0.0 0.9947  5140.4  0.9387   6250.0                      19    2
    103 KGS-3        11.500 3   7500.0  2643.4   7100.0       0.0 0.9846  8076.7  0.9431 13529.0                      19    2
    104 KGS-4        11.500 4   7500.0  2643.4   9375.0       0.0 1.0063  7902.4  0.9431 15625.0                      19    2
    301 CT-1 M14     13.800 1  14823.4  5808.4  15000.0       0.0 1.0030 15873.1  0.9311 26813.0                      20    2  SYST
    302 CT-2 M16     13.800 2  14500.0  5389.2  15000.0       0.0 1.0016 15444.6  0.9374 26813.0                      20    2
    303 ST-1 M15     13.800 3  11000.0  4790.4  12000.0       0.0 0.9998 12000.2  0.9168 18500.0                      20    2
    304 CT-3 M17     13.800 4  14000.0  5988.0  15000.0       0.0 0.9811 15520.2  0.9194 26813.0                      20    2
    305 CT-4 M19     13.800 5  14000.0  5988.0  15000.0       0.0 0.9811 15520.2  0.9194 26813.0                      20    2
    306 ST-2 M18     13.800 6   8000.0  3592.8  12000.0       0.0 0.9728  9015.4  0.9122 18500.0                      20    2
    804 HC&S TG4     13.800 4  12000.0  1294.9   5100.0       0.0 0.9501 12703.6  0.9942 24500.0                       9    1
  90971 KWPI_1       0.5750 1  12000.0  1381.1  14500.0       0.0 1.0100 11959.6  0.9934 33340.0                      11    1
 SUBSYSTEM TOTALS             124923.4 43044.5126075.0       0.0                        243746.0
```

125 MW CASE

Bus Number	Bus Name	Id	Code	VSched (pu)	Remote Bus Number	In Service	Pgen (MW)	Pmax (MW)	Pmin (MW)	Qgen (Mvar)	Qmax (Mvar)	Qmin (Mvar)	Mbase (MVA)	SR	Minimum Load	Min load violation?	DR	
101	KGS-1 11.500	1	2	1.0255	200	1	4.8	5	0	1.8503	3	0	6.25	0.2	2.5	1	2.3	
102	KGS-2 11.500	2	2	1.0255	200	1	4.8	5	0	1.8503	3	0	6.25	0.2	2.5	1	2.3	
103	KGS-3 11.500	3	2	1.0255	200	1	11	11.5	0	3.7006	7.1	0	13.53	0.5	7.5	1	3.5	
104	KGS-4 11.500	4	2	1.0255	200	1	12	12.5	0	3.7006	9.375	0	15.63	0.5	7.5	1	4.5	
105	MGS-123 4.1600	1	-2	1.0285	39	0	2.4	2.5	0	0.7762	1.875	0	3.44	0	2.5	0	0	
105	MGS-123 4.1600	2	-2	1.0285	39	0	2.4	2.5	0	0.7762	1.875	0	3.44	0	2.5	0	0	
105	MGS-123 4.1600	3	-2	1.0285	39	0	2.42	2.5	0	0.7826	1.875	0	3.44	0	2.5	0	0	
106	MGS-458 4.1600	4	-2	1.0285	39	0	4.3056	5.6	0	1.8749	4.2	0	7	0	2	0	0	
106	MGS-458 4.1600	5	-2	1.0285	39	0	4.3707	5.6	0	1.1779	4.2	0	7	0	2	0	0	
106	MGS-458 4.1600	8	-2	1.0285	39	0	4.0472	5.6	0	1.7624	4.2	0	7	0	2	0	0	
107	MGS-679 4.1600	6	-2	1.0285	39	0	3.93	5.6	0	3.6373	4.2	0	7	0	2	0	0	
107	MGS-679 4.1600	7	-2	1.0285	39	0	4.3841	5.6	0	1.3854	4.2	0	7	0	2	0	0	
107	MGS-679 4.1600	9	-2	1.0285	39	0	2.5374	5.6	0	1.4266	4.2	0	7	0	2	0	0	
108	MGS-1011 6.9000	0	-2	1.0285	39	0	11	12.5	0	8.0104	9.375	0	15.63	0	6	0	0	
108	MGS-1011 6.9000	1	-2	1.0285	39	0	11	12.5	0	4.1743	9.375	0	15.63	0	6	0	0	
109	MGS-1213 6.9000	2	-2	1.0285	39	0	11	12.5	0	4.2889	9.375	0	15.63	0	6	0	0	
109	MGS-1213 6.9000	3	-2	1.0285	39	0	11	12.5	0	4.2889	9.375	0	15.63	0	6	0	0	
110	MGS-X1X2 4.1600	1	-2	1.0285	39	0	2.4659	2.5	0	1.1241	1.875	0	3.44	0	2.5	0	0	
110	MGS-X1X2 4.1600	2	-2	1.0285	39	0	2.4695	2.5	0	1.1257	1.875	0	3.44	0	2.5	0	0	
301	CT-1 M14 13.800	1	3	1.009	0	1	16.2463	21.5	0	7.7444	15	0	26.81	5.2537	12.5	1	3.7463	
302	CT-2 M16 13.800	2	2	1.0285	39	1	16	21.5	0	7.4179	15	0	26.81	5.5	12.5	1	3.5	
303	ST-1 M15 13.800	3	2	1.0285	39	1	15	15	0	6.8473	12	0	18.5	0	11	1	4	
304	CT-3 M17 13.800	4	2	1.0285	39	1	16	21.5	0	7.1897	15	0	26.81	5.5	14	1	2	
305	CT-4 M19 13.800	5	2	1.0285	39	1	16	21.5	0	7.4179	15	0	26.81	5.5	14	1	2	
306	ST-2 M18 13.800	6	2	1.0285	39	1	8	15	0	3.8231	12	0	18.5	7	3	1	5	
804	HC&S TG4 13.800	4	-2	0.937	0	1	12	13	0	0	5.1	0	24.5		8	1		
90971	KWPI_1 0.5750	1	2	1.008	0	1	18	30	0	0.9746	14.5	-0.2374	33.34			1		
						12							Total SR=	28.7537		12	20.2463	=Total DR
													SR Flag	0	Min Load Violation Flag	0	0	DR Flag

```
MACHINE SUMMARY:
   BUS# X-- NAME --X BASKV ID      KW      KVAR     QMAX      QMIN  ETERM CURRENT     PF   KVABASE   X T R A N   GENTAP ZONE AREA SWING
    101 KGS-1        11.500 1   4800.0  1850.3   3000.0       0.0 1.0217  5035.1  0.9331   6250.0                      19    2
    102 KGS-2        11.500 2   4800.0  1850.3   3000.0       0.0 0.9941  5174.7  0.9331   6250.0                      19    2
    103 KGS-3        11.500 3  11000.0  3700.6   7100.0       0.0 0.9927 11691.0  0.9478 13529.0                      19    2
    104 KGS-4        11.500 4  12000.0  3700.6   9375.0       0.0 1.0130 12396.9  0.9556 15625.0                      19    2
    301 CT-1 M14     13.800 1  16246.3  7744.4  15000.0       0.0 1.0090 17837.2  0.9027 26813.0                      20    2  SYST
    302 CT-2 M16     13.800 2  16000.0  7417.9  15000.0       0.0 1.0079 17497.4  0.9072 26813.0                      20    2
    303 ST-1 M15     13.800 3  15000.0  6847.3  12000.0       0.0 1.0059 16392.6  0.9097 18500.0                      20    2
    304 CT-3 M17     13.800 4  16000.0  7189.7  15000.0       0.0 0.9847 17813.8  0.9121 26813.0                      20    2
    305 CT-4 M19     13.800 5  16000.0  7417.9  15000.0       0.0 0.9855 17894.6  0.9072 26813.0                      20    2
    306 ST-2 M18     13.800 6   8000.0  3823.1  12000.0       0.0 0.9732  9111.0  0.9023 18500.0                      20    2
    804 HC&S TG4     13.800 4  12000.0     0.0   5100.0       0.0 0.9430 12724.7  1.0000 24500.0                       9    1
  90971 KWPI_1       0.5750 1  18000.0   974.6  14500.0    -237.4 1.0080 17883.3  0.9985 33340.0                      11    1
 SUBSYSTEM TOTALS             149846.3 52516.6126075.0    -237.4                        243746.0
```

150 MW CASE

Hawaiian Electric
Maui Electric
Hawai'i Electric Light

Maalaea-Kamalii Transmission Line Alternatives

Bus Number	Bus Name	Id	Code	VSched (pu)	Remote Bus Number	In Service	Pgen (MW)	Pmax (MW)	Pmin (MW)	Qgen (Mvar)	Qmax (Mvar)	Qmin (Mvar)	Mbase (MVA)	SR	Minimum Load	Min load violation?	DR	
101	KGS-1 11.500	1	2	1.025	200	1	4.8	5	0	1.2099	3	0	6.25	0.2	2.5	1	2.3	
102	KGS-2 11.500	2	2	1.025	200	1	4.8	5	0	1.2099	3	0	6.25	0.2	2.5	1	2.3	
103	KGS-3 11.500	3	2	1.025	200	1	11	11.5	0	2.6332	7.1	0	13.53	0.5	7.5	1	3.5	
104	KGS-4 11.500	4	2	1.025	200	1	12	12.5	0	2.8704	9.375	0	15.63	0.5	7.5	1	4.5	
105	MGS-123 4.1600	1	-2	1.0285	39	0	2.4	2.5	0	0.7762	1.875	0	3.44	0	2.5	0	0	
105	MGS-123 4.1600	2	-2	1.0285	39	0	2.4	2.5	0	0.7762	1.875	0	3.44	0	2.5	0	0	
105	MGS-123 4.1600	3	-2	1.0285	39	0	2.42	2.5	0	0.7826	1.875	0	3.44	0	2.5	0	0	
106	MGS-458 4.1600	4	-2	1.0285	39	0	4.3056	5.6	0	1.8749	4.2	0	7	0	2	0	0	
106	MGS-458 4.1600	5	-2	1.0285	39	0	4.3707	5.6	0	1.1779	4.2	0	7	0	2	0	0	
106	MGS-458 4.1600	8	-2	1.0285	39	0	4.0472	5.6	0	1.7624	4.2	0	7	0	2	0	0	
107	MGS-679 4.1600	6	-2	1.0285	39	0	3.93	5.6	0	3.6373	4.2	0	7	0	2	0	0	
107	MGS-679 4.1600	7	-2	1.0285	39	0	4.3841	5.6	0	1.3854	4.2	0	7	0	2	0	0	
107	MGS-679 4.1600	9	-2	1.0285	39	0	2.5374	5.6	0	1.4266	4.2	0	7	0	2	0	0	
108	MGS-1011 6.9000	0	-2	1.0285	39	1	11	12.5	0	9.375	9.375	0	15.63	1.5	6	1	5	
108	MGS-1011 6.9000	1	-2	1.0285	39	0	11	12.5	0	5.3856	9.375	0	15.63	0	6	0	0	
109	MGS-1213 6.9000	2	-2	1.0285	39	0	11	12.5	0	4.2889	9.375	0	15.63	0	6	0	0	
109	MGS-1213 6.9000	3	-2	1.0285	39	0	11	12.5	0	4.2889	9.375	0	15.63	0	6	0	0	
110	MGS-X1X2 4.1600	1	-2	1.0285	39	0	2.4659	2.5	0	1.1241	1.875	0	3.44	0	2.5	0	0	
110	MGS-X1X2 4.1600	2	-2	1.0285	39	0	2.4695	2.5	0	1.1257	1.875	0	3.44	0	2.5	0	0	
301	CT-1 M14 13.800	1	3	1.011	0	1	17.8795	21.5	0	8.4218	15	0	26.81	3.6205	12.5	1	5.3795	
302	CT-2 M16 13.800	2	2	1.0285	39	1	17.5	21.5	0	8.609	15	0	26.81	4	12.5	1	5	
303	ST-1 M15 13.800	3	2	1.0285	39	1	11	15	0	5.2979	12	0	18.5	4	11	1	0	
304	CT-3 M17 13.800	4	2	1.0285	39	1	19	21.5	0	7.9468	15	0	26.81	2.5	14	1	5	
305	CT-4 M19 13.800	5	2	1.0285	39	1	19	21.5	0	7.2846	15	0	26.81	2.5	14	1	5	
306	ST-2 M18 13.800	6	2	1.0285	39	1	11	15	0	3.9734	12	0	18.5	4	3	1	8	
804	HC&S TG4 13.800	4	-2	0.937	0	1	12	13	0	0	5.1	0	24.5		8	1		
90971	KWPI_1 0.5750	1	2	1.0065	0	1	24	30	0	0.749	14.5	-0.2374	33.34			1		
						13							Total SR=	22.1205		13	33.3795	=Total DR
													SR Flag	0	Min Load Violation Flag	0	0	DR Flag

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MACHINE SUMMARY:
  BUS# X-- NAME --X BASKV ID      KW      KVAR     QMAX     QMIN  ETERM CURRENT     PF   KVABASE   X T R A N   GENTAP ZONE AREA SWING
   101 KGS-1        11.500 1   4800.0  2143.5  3000.0      0.0 1.0242  5132.8  0.9131   6250.0                        19    2
   102 KGS-2        11.500 2   4800.0  2143.5  3000.0      0.0 0.9972  5271.7  0.9131   6250.0                        19    2
   103 KGS-3        11.500 3  11000.0  4665.3  7100.0      0.0 0.9978 11974.5  0.9206  13529.0                        19    2
   104 KGS-4        11.500 4  12000.0  5085.6  9375.0      0.0 1.0178 12804.8  0.9207  15625.0                        19    2
   108 MGS-1011     6.9000 0  11000.0  4958.0  9375.0      0.0 0.9935 12144.8  0.9117  15625.0                        20    2
   301 CT-1 M14     13.800 1  17899.2  8423.0 15000.0      0.0 1.0110 19566.8  0.9048  26813.0                        20    2  SYST
   302 CT-2 M16     13.800 2  17500.0  8056.8 15000.0      0.0 1.0098 19078.2  0.9084  26813.0                        20    2
   303 ST-1 M15     13.800 3  11000.0  4958.0 12000.0      0.0 0.9999 12066.7  0.9117  18500.0                        20    2
   304 CT-3 M17     13.800 4  19000.0  8676.5 15000.0      0.0 0.9895 21110.0  0.9096  26813.0                        20    2
   305 CT-4 M19     13.800 5  19000.0  8676.5 15000.0      0.0 0.9895 21110.0  0.9096  26813.0                        20    2
   306 ST-2 M18     13.800 6  11000.0  4958.0 12000.0      0.0 0.9771 12349.1  0.9117  18500.0                        20    2
   804 HC&S TG4     13.800 4  12000.0     0.0  5100.0      0.0 0.9397 12770.3  1.0000  24500.0                         9    1
 90971 KWPI_1       0.5750 1  24000.0   749.0 14500.0   -237.4 1.0065 23856.6  0.9995  33340.0                        11    1
SUBSYSTEM TOTALS             174999.2 63493.8135450.0   -237.4                         259371.0
```

175 MW CASE

Bus Number	Bus Name	Id	Code	VSched (pu)	Remote Bus Number	In Service	Pgen (MW)	Pmax (MW)	Pmin (MW)	Qgen (Mvar)	Qmax (Mvar)	Qmin (Mvar)	Mbase (MVA)	SR	Minimum Load	Min load violation?	DR	
101	KGS-1 11.500	1	2	1.0217	200	1	4.8	5	0	1.7943	3	0	6.25	0.2	2.5	1	2.3	
102	KGS-2 11.500	2	2	1.0217	200	1	4.8	5	0	1.7943	3	0	6.25	0.2	2.5	1	2.3	
103	KGS-3 11.500	3	2	1.0217	200	1	11	11.5	0	3.9053	7.1	0	13.53	0.5	7.5	1	3.5	
104	KGS-4 11.500	4	2	1.0217	200	1	12	12.5	0	4.2571	9.375	0	15.63	0.5	7.5	1	4.5	
105	MGS-123 4.1600	1	-2	1.025	39	0	2.4	2.5	0	0.7762	1.875	0	3.44	0	2.5	0	0	
105	MGS-123 4.1600	2	-2	1.025	39	0	2.4	2.5	0	0.7762	1.875	0	3.44	0	2.5	0	0	
105	MGS-123 4.1600	3	-2	1.025	39	0	2.42	2.5	0	0.7826	1.875	0	3.44	0	2.5	0	0	
106	MGS-458 4.1600	4	-2	1.025	39	0	4.3056	5.6	0	1.8749	4.2	0	7	0	2	0	0	
106	MGS-458 4.1600	5	-2	1.025	39	0	4.3707	5.6	0	1.1779	4.2	0	7	0	2	0	0	
106	MGS-458 4.1600	8	-2	1.025	39	0	4.0472	5.6	0	1.7624	4.2	0	7	0	2	0	0	
107	MGS-679 4.1600	6	-2	1.025	39	0	3.93	5.6	0	3.6373	4.2	0	7	0	2	0	0	
107	MGS-679 4.1600	7	-2	1.025	39	0	4.3841	5.6	0	1.3854	4.2	0	7	0	2	0	0	
107	MGS-679 4.1600	9	-2	1.025	39	0	2.5374	5.6	0	1.4266	4.2	0	7	0	2	0	0	
108	MGS-1011 6.9000	0	2	1.025	39	1	11	12.5	0	5.5177	9.375	0	15.63	1.5	6	1	5	
108	MGS-1011 6.9000	1	2	1.025	39	1	11	12.5	0	5.5177	9.375	0	15.63	1.5	6	1	5	
109	MGS-1213 6.9000	2	-2	1.025	39	1	11	12.5	0	9.375	9.375	0	15.63	1.5	6	1	5	
109	MGS-1213 6.9000	3	-2	1.025	39	0	11	12.5	0	5.3557	9.375	0	15.63	0	6	0	0	
110	MGS-X1X2 4.1600	1	-2	1.025	39	0	2.4659	2.5	0	1.1241	1.875	0	3.44	0	2.5	0	0	
110	MGS-X1X2 4.1600	2	-2	1.025	39	0	2.4695	2.5	0	1.1257	1.875	0	3.44	0	2.5	0	0	
301	CT-1 M14 13.800	1	3	1.01	0	1	19.3283	21.5	0	9.1758	15	0	26.81	2.1717	12.5	1	6.8283	
302	CT-2 M16 13.800	2	2	1.025	39	1	19.25	21.5	0	9.088	15	0	26.81	2.25	12.5	1	6.75	
303	ST-1 M15 13.800	3	2	1.025	39	1	15	15	0	7.1406	12	0	18.5	0	11	1	4	
304	CT-3 M17 13.800	4	2	1.025	39	1	19	21.5	0	7.7897	15	0	26.81	2.5	14	1	5	
305	CT-4 M19 13.800	5	2	1.025	39	1	19	21.5	0	7.1406	15	0	26.81	2.5	14	1	5	
306	ST-2 M18 13.800	6	2	1.025	39	1	11	15	0	3.8949	12	0	18.5	4	3	1	8	
804	HC&S TG4 13.800	4	2	0.937	0	1	12	13	0	1.6233	5.1	0	24.5		8	1		
90971	KWPI_1 0.5750	1	2	1	0	1	24	30	0	0.3887	14.5	-0.2374	33.34			1		
						15							Total SR=	17.9217		15	50.5783	=Total DR
													SR Flag	0	Min Load Violation Flag	0	0	DR Flag

```
MACHINE SUMMARY:
  BUS# X-- NAME --X BASKV ID      KW      KVAR     QMAX     QMIN  ETERM CURRENT     PF   KVABASE   X T R A N   GENTAP ZONE AREA SWING
   101 KGS-1        11.500 1   4800.0  2233.1  3000.0      0.0 1.0215  5182.5  0.9067   6250.0                        19    2
   102 KGS-2        11.500 2   4800.0  2233.1  3000.0      0.0 0.9948  5321.6  0.9067   6250.0                        19    2
   103 KGS-3        11.500 3  11000.0  4860.3  7100.0      0.0 0.9955 12079.7  0.9147  13529.0                        19    2
   104 KGS-4        11.500 4  12000.0  5298.2  9375.0      0.0 1.0152 12921.4  0.9148  15625.0                        19    2
   108 MGS-1011     6.9000 0  11000.0  4815.8  9375.0      0.0 1.0037 11963.5  0.9161  15625.0                        20    2
   108 MGS-1011     6.9000 1  11000.0  4815.8  9375.0      0.0 1.0037 11963.5  0.9161  15625.0                        20    2
   109 MGS-1213     6.9000 2  11000.0  5136.9  9375.0      0.0 0.9908 12252.9  0.9061  15625.0                        20    2
   301 CT-1 M14     13.800 1  19321.3  9175.4 15000.0      0.0 1.0100 21177.5  0.9033  26813.0                        20    2  SYST
   302 CT-2 M16     13.800 2  19250.0  8989.5 15000.0      0.0 1.0094 21048.2  0.9061  26813.0                        20    2
   303 ST-1 M15     13.800 3  15000.0  7063.2 12000.0      0.0 1.0033 16524.5  0.9047  18500.0                        20    2
   304 CT-3 M17     13.800 4  19000.0  8347.4 15000.0      0.0 0.9850 21068.0  0.9155  26813.0                        20    2
   305 CT-4 M19     13.800 5  19000.0  8347.4 15000.0      0.0 0.9850 21068.0  0.9155  26813.0                        20    2
   306 ST-2 M18     13.800 6  11000.0  5136.9 12000.0      0.0 0.9745 12457.9  0.9061  18500.0                        20    2
   804 HC&S TG4     13.800 4  12000.0  1375.9  5100.0      0.0 0.9370 12890.7  0.9935  24500.0                         9    1
 90971 KWPI_1       0.5750 1  24000.0   388.7 14500.0   -237.4 1.0000 24003.1  0.9999  33340.0                        11    1
SUBSYSTEM TOTALS             204171.3 78217.5154200.0   -237.4                         290621.0
```

PEAK BASECASE

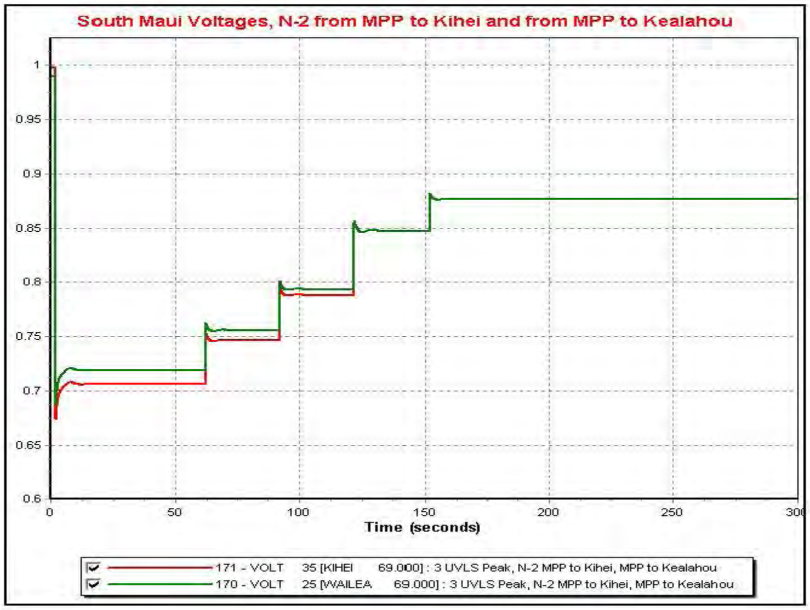
Bus Number	Bus Name	Id	Code	VSched (pu)	Remote Bus Number	In Service	Pgen (MW)	Pmax (MW)	Pmin (MW)	Qgen (Mvar)	Qmax (Mvar)	Qmin (Mvar)	Mbase (MVA)	SR	Minimum Load	Min load violation?	DR	
101	KGS-1	1	2	1.022	200	1	4.8	5	0	2.2331	3	0	6.25	0.2	2.5	1	2.3	
102	KGS-2	2	2	1.022	200	1	4.8	5	0	2.2331	3	0	6.25	0.2	2.5	1	2.3	
103	KGS-3	3	2	1.022	200	1	11	11.5	0	4.8603	7.1	0	13.53	0.5	7.5	1	3.5	
104	KGS-4	4	2	1.022	200	1	12	12.5	0	5.2982	9.375	0	15.63	0.5	7.5	1	4.5	
105	MGS-123	1	-2	1.025	39	0	2.4	2.5	0	0.7762	1.875	0	3.44	0	2.5	0	0	
105	MGS-123	2	-2	1.025	39	0	2.4	2.5	0	0.7762	1.875	0	3.44	0	2.5	0	0	
105	MGS-123	3	-2	1.025	39	0	2.42	2.5	0	0.7826	1.875	0	3.44	0	2.5	0	0	
106	MGS-458	4	2	1.025	39	1	5.6	5.6	0	2.3654	4.2	0	7	0	2	1	3.6	
106	MGS-458	5	2	1.025	39	1	5.6	5.6	0	2.3654	4.2	0	7	0	2	1	3.6	
106	MGS-458	8	2	1.025	39	1	5.6	5.6	0	2.3654	4.2	0	7	0	2	1	3.6	
107	MGS-679	6	2	1.025	39	1	5.6	5.6	0	2.661	4.2	0	7	0	2	1	3.6	
107	MGS-679	7	2	1.025	39	1	5.6	5.6	0	2.661	4.2	0	7	0	2	1	3.6	
107	MGS-679	9	2	1.025	39	1	5.6	5.6	0	2.661	4.2	0	7	0	2	1	3.6	
108	MGS-1011	0	-2	1.025	39	0	11	12.5	0	7.0718	9.375	0	15.63	0	6	0	0	
108	MGS-1011	1	-2	1.025	39	0	11	12.5	0	5.1665	9.375	0	15.63	0	6	0	0	
109	MGS-1213	2	-2	1.025	39	0	11	12.5	0	6.4146	9.375	0	15.63	0	6	0	0	
109	MGS-1213	3	-2	1.025	39	0	11	12.5	0	5.3557	9.375	0	15.63	0	6	0	0	
110	MGS-X1X2	1	-2	1.025	39	0	2.4659	2.5	0	1.1241	1.875	0	3.44	0	2.5	0	0	
110	MGS-X1X2	2	-2	1.025	39	0	2.4695	2.5	0	1.1257	1.875	0	3.44	0	2.5	0	0	
301	CT-1 M14	1	3	1.009	0	1	18.9713	21.5	0	8.8616	15	0	26.81	2.5287	12.5	1	6.4713	
302	CT-2 M16	2	2	1.025	39	1	19	21.5	0	8.8702	15	0	26.81	2.5	12.5	1	6.5	
303	ST-1 M15	3	2	1.025	39	1	15	15	0	7.0961	12	0	18.5	0	11	1	4	
304	CT-3 M17	4	2	1.025	39	1	19	21.5	0	8.8702	15	0	26.81	2.5	14	1	5	
305	CT-4 M19	5	2	1.025	39	1	19	21.5	0	8.8702	15	0	26.81	2.5	14	1	5	
306	ST-2 M18	6	2	1.025	39	1	11	15	0	5.3221	12	0	18.5	4	3	1	8	
804	HC&S TG4	4	2	0.937	0	1	12	13	0	1.3759	5.1	0	24.5		8	1		
90971	KWPI_1	1	2	1	0	1	24	30	0	0.3887	14.5	-0.2374	33.34			1		
						18							Total SR=	14.0287		18	56.5713	=Total DR
													SR Flag	0	Min Load Violation Flag	0	0	DR Flag

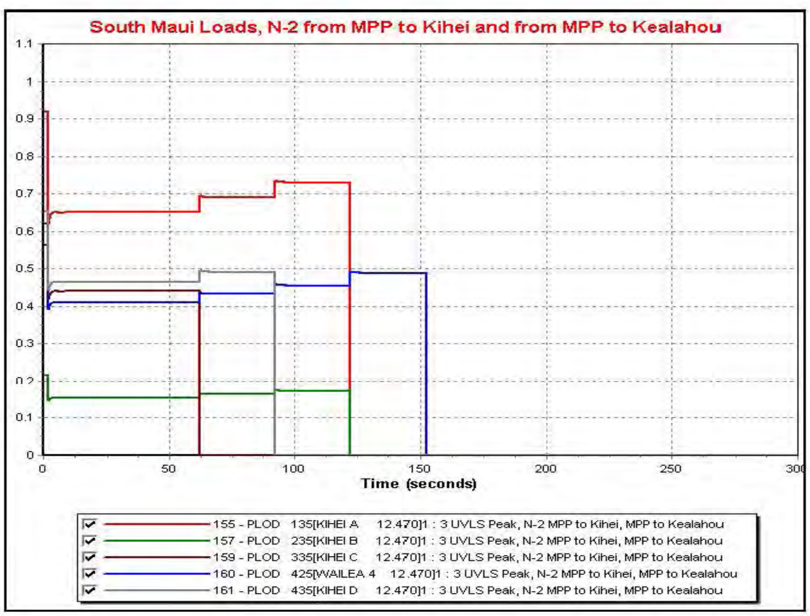
```
MACHINE SUMMARY:
   BUS# X-- NAME --X BASKV ID     KW      KVAR     QMAX     QMIN  ETERM CURRENT    PF   KVABASE   X T R A N   GENTAP ZONE AREA SWING
    101 KGS-1       11.500 1   4800.0  2233.1  3000.0      0.0 1.0215  5182.5  0.9067  6250.0                   19    2
    102 KGS-2       11.500 2   4800.0  2233.1  3000.0      0.0 0.9948  5321.6  0.9067  6250.0                   19    2
    103 KGS-3       11.500 3  11000.0  4860.3  7100.0      0.0 0.9955 12079.7  0.9147 13529.0                   19    2
    104 KGS-4       11.500 4  12000.0  5298.2  9375.0      0.0 1.0152 12921.4  0.9148 15625.0                   19    2
    106 MGS-458     4.1600 4   5600.0  2365.4  4200.0      0.0 0.9948  6110.6  0.9212  7000.0                   20    2
    106 MGS-458     4.1600 5   5600.0  2365.4  4200.0      0.0 0.9948  6110.6  0.9212  7000.0                   20    2
    106 MGS-458     4.1600 8   5600.0  2365.4  4200.0      0.0 0.9948  6110.6  0.9212  7000.0                   20    2
    107 MGS-679     4.1600 6   5600.0  2661.1  4200.0      0.0 0.9996  6202.7  0.9032  7000.0                   20    2
    107 MGS-679     4.1600 7   5600.0  2661.1  4200.0      0.0 0.9996  6202.7  0.9032  7000.0                   20    2
    107 MGS-679     4.1600 9   5600.0  2661.1  4200.0      0.0 0.9996  6202.7  0.9032  7000.0                   20    2
    301 CT-1 M14    13.800 1  18971.3  8861.6 15000.0      0.0 1.0090 20752.2  0.9060 26813.0                   20    2  SYST
    302 CT-2 M16    13.800 2  19000.0  8870.2 15000.0      0.0 1.0090 20781.1  0.9061 26813.0                   20    2
    303 ST-1 M15    13.800 3  15000.0  7096.1 12000.0      0.0 1.0035 16536.6  0.9040 18500.0                   20    2
    304 CT-3 M17    13.800 4  19000.0  8870.2 15000.0      0.0 0.9870 21245.2  0.9061 26813.0                   20    2
    305 CT-4 M19    13.800 5  19000.0  8870.2 15000.0      0.0 0.9870 21245.2  0.9061 26813.0                   20    2
    306 ST-2 M18    13.800 6  11000.0  5322.1 12000.0      0.0 0.9752 12530.5  0.9002 18500.0                   20    2
    804 HC&S TG4    13.800 4  12000.0  1375.9  5100.0      0.0 0.9370 12890.7  0.9935 24500.0                    9    1
  90971 KWPI_1      0.5750 1  24000.0   388.7 14500.0   -237.4 1.0000 24003.1  0.9999 33340.0                   11    1
  SUBSYSTEM TOTALS           204171.3 79359.0151275.0   -237.4                        285746.0
```

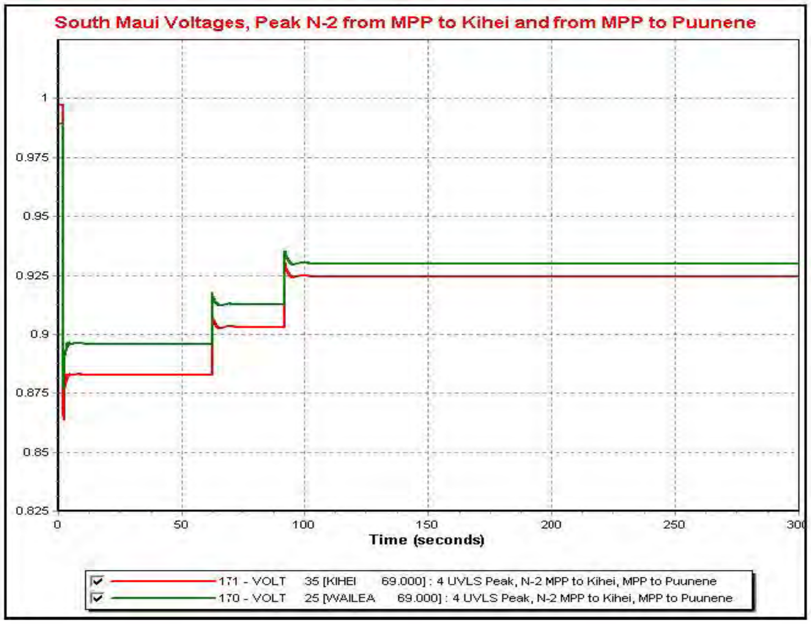
Peak Basecase M4-9 replace M10

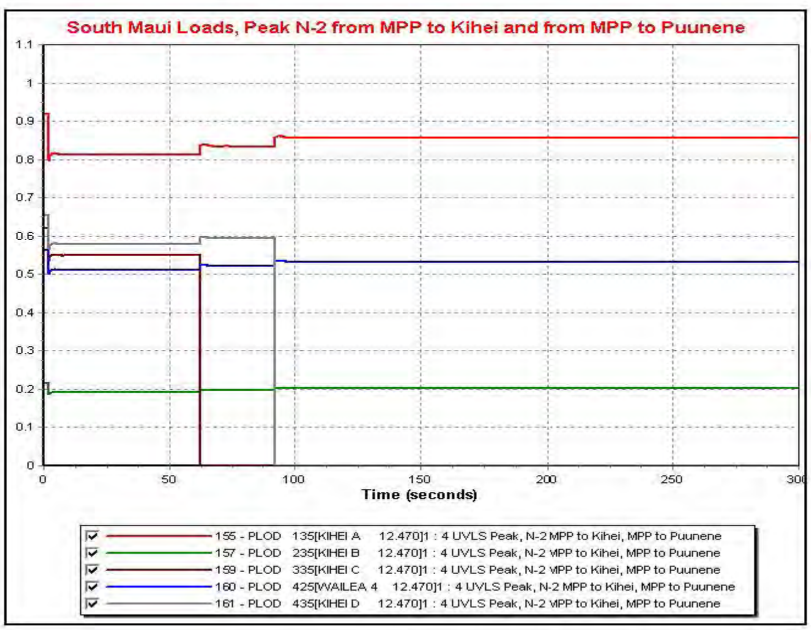
Hawaiian Electric
Maui Electric
Hawai'i Electric Light

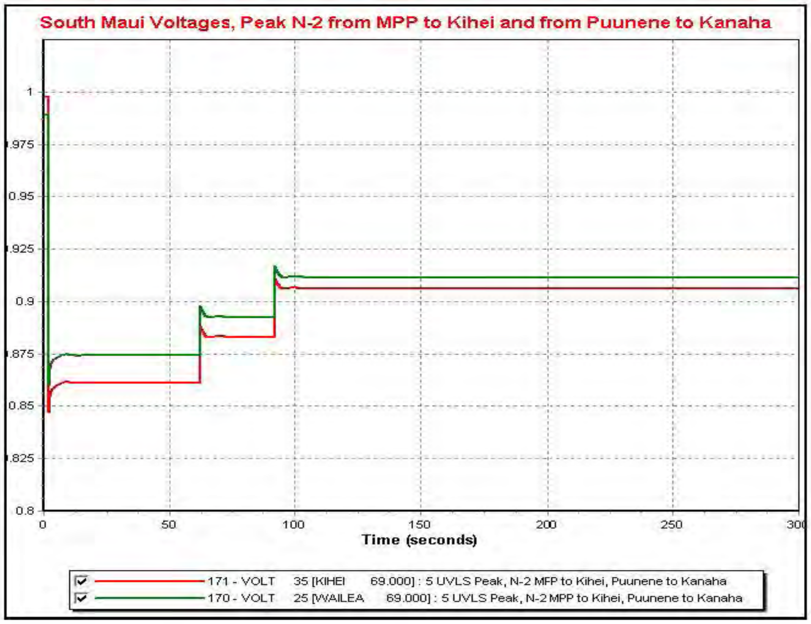
APPENDIX B

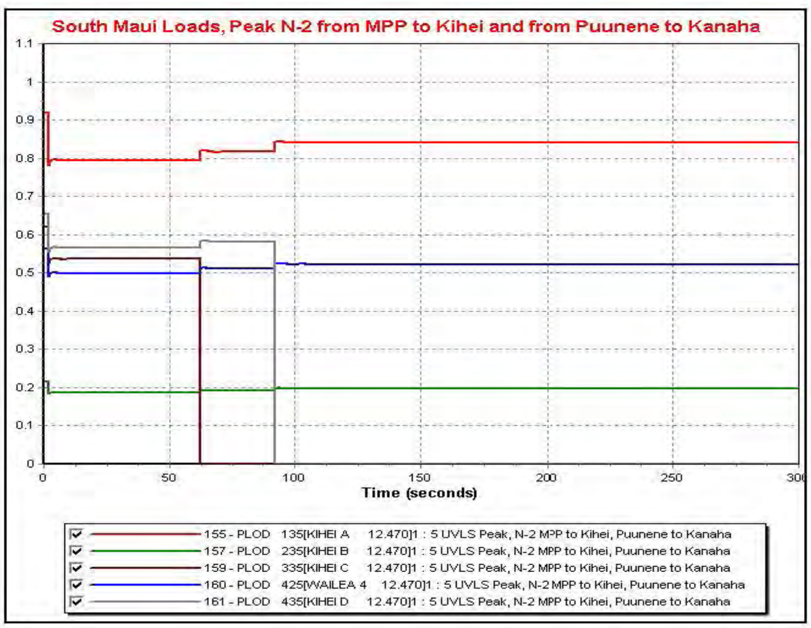

South Maui Voltages, N-2 from MPP to Kihei and from MPP to Kealahou
1
0.95
0.9
0.85
0.8
0.75
0.7
0.65
0.6
0
50
100
150
200
250
Time (seconds)
171 - VOLT 35 [KIHEI 69.000] : 3 UVLS Peak, N-2 MPP to Kihei, MPP to Kealahou
170 - VOLT 25 [WAILEA 69.000] : 3 UVLS Peak, N-2 MPP to Kihei, MPP to Kealahou

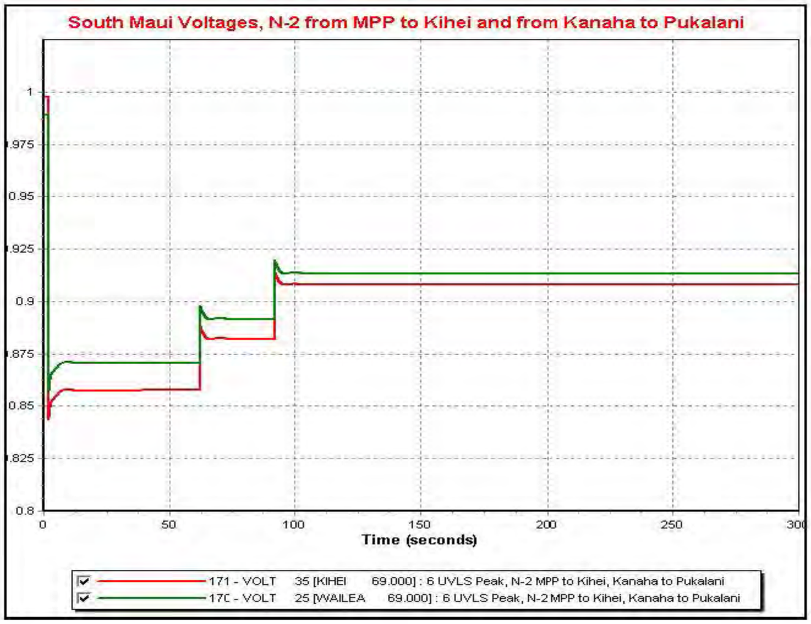

South Maui Loads, N-2 from MPP to Kihei and from MPP to Kealahou
1.1
1
0.9
0.8
0.7
0.6
0.5
0.4
0.3
0.1
0
0
50
100
150
200
250
Time (seconds)
155 - PLOD 135[KIHEI A 12.470]1 : 3 UVLS Peak, N-2 MPP to Kihei, MPP to Kealahou
157 - PLOD 235[KIHEI B 12.470]1 : 3 UVLS Peak, N-2 MPP to Kihei, MPP to Kealahou
159 - PLOD 335[KIHEI C 12.470]1 : 3 UVLS Peak, N-2 MPP to Kihei, MPP to Kealahou
160 - PLOD 425[WAILEA 4 12.470]1 : 3 UVLS Peak, N-2 MPP to Kihei, MPP to Kealahou
161 - PLOD 435[KIHEI D 12.470]1 : 3 UVLS Peak, N-2 MPP to Kihei, MPP to Kealahou

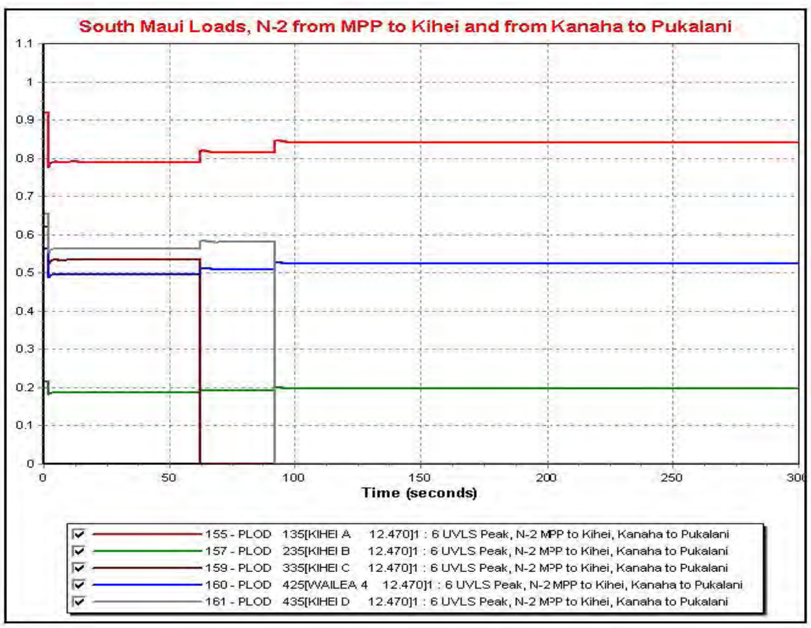

South Maui Voltages, Peak N-2 from MPP to Kihei and from MPP to Puunene
1
0.975
0.95
0.925
0.9
0.875
0.85
0.825
0
50
100
150
200
250
300
Time (seconds)
171 - VOLT 35 [KIHEI 69.000] : 4 UVLS Peak, N-2 MPP to Kihei, MPP to Puunene
170 - VOLT 25 [WAILEA 69.000] : 4 UVLS Peak, N-2 MPP to Kihei, MPP to Puunene

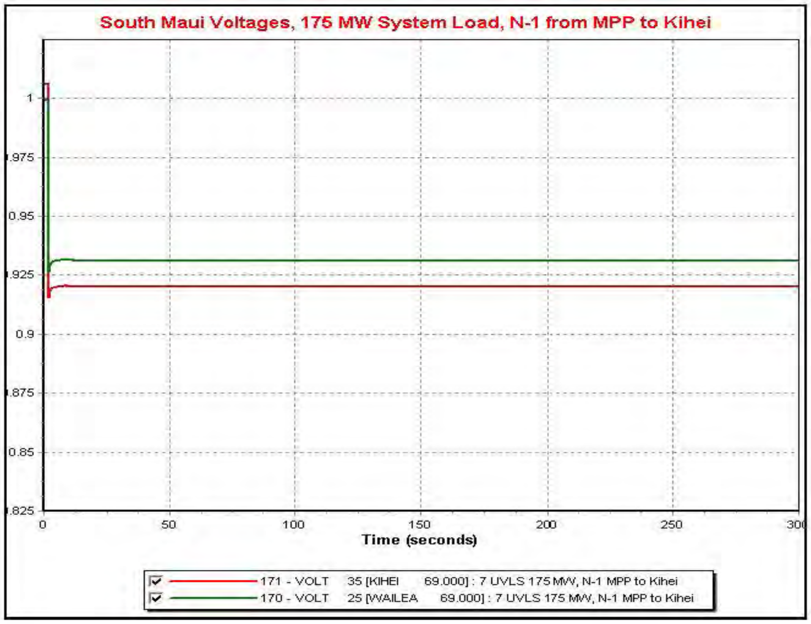

South Maui Loads, Peak N-2 from MPP to Kihei and from MPP to Puunene
1.1
1
0.9
0.8
0.7
0.6
0.5
0.4
0.3
0.2
0.1
0
0
50
100
150
200
250
300
Time (seconds)
155 - PLOD 135[KIHEI A 12.470]1 : 4 UVLS Peak, N-2 MPP to Kihei, MPP to Puunene
157 - PLOD 235[KIHEI B 12.470]1 : 4 UVLS Peak, N-2 MPP to Kihei, MPP to Puunene
159 - PLOD 335[KIHEI C 12.470]1 : 4 UVLS Peak, N-2 MPP to Kihei, MPP to Puunene
160 - PLOD 425[WAILEA 4 12.470]1 : 4 UVLS Peak, N-2 MPP to Kihei, MPP to Puunene
161 - PLOD 435[KIHEI D 12.470]1 : 4 UVLS Peak, N-2 MPP to Kihei, MPP to Puunene

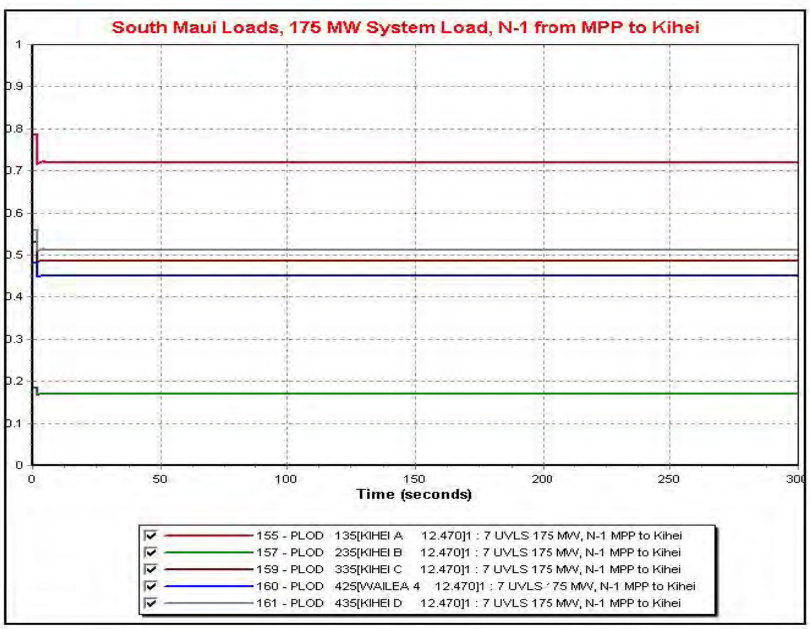

South Maui Voltages, Peak N-2 from MPP to Kihei and from Puunene to Kanaha
Time (seconds)
171 - VOLT 35 [KIHEI 69.000] : 5 UVLS Peak, N-2 MFP to Kihei, Puunene to Kanaha
170 - VOLT 25 [WAILEA 69.000] : 5 UVLS Peak, N-2 MPP to Kihei, Puunene to Kanaha

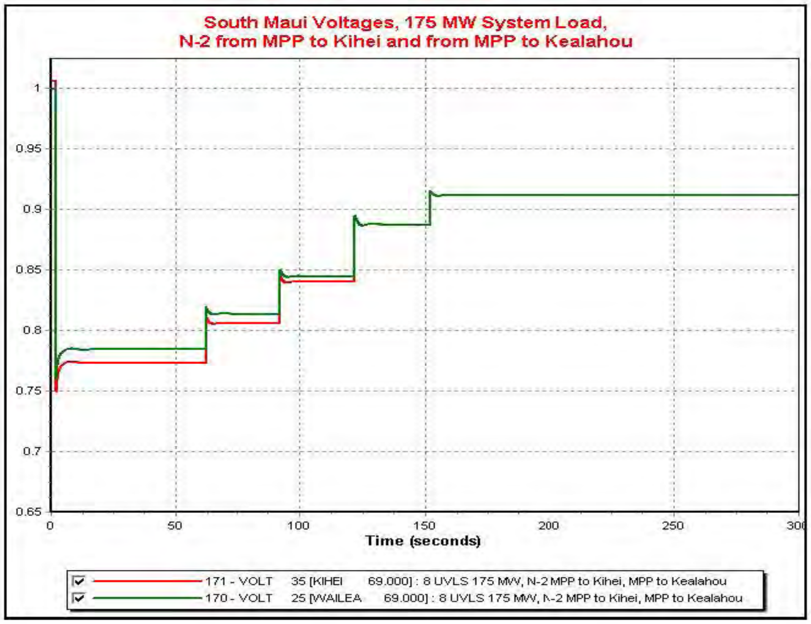

South Maui Loads, Peak N-2 from MPP to Kihei and from Puunene to Kanaha
Time (seconds)
155 - PLOD 135[KIHEI A 12.470]1 : 5 UVLS Peak, N-2 MPP to Kihei, Puunene to Kanaha
157 - PLOD 235[KIHEI B 12.470]1 : 5 UVLS Peak, N-2 MPP to Kihei, Puunene to Kanaha
159 - PLOD 335[KIHEI C 12.470]1 : 5 UVLS Peak, N-2 MPP to Kihei, Puunene to Kanaha
160 - PLOD 425[WAILEA 4 12.470]1 : 5 UVLS Peak, N-2 MPP to Kihei, Puunene to Kanaha
161 - PLOD 435[KIHEI D 12.470]1 : 5 UVLS Peak, N-2 MPP to Kihei, Puunene to Kanaha

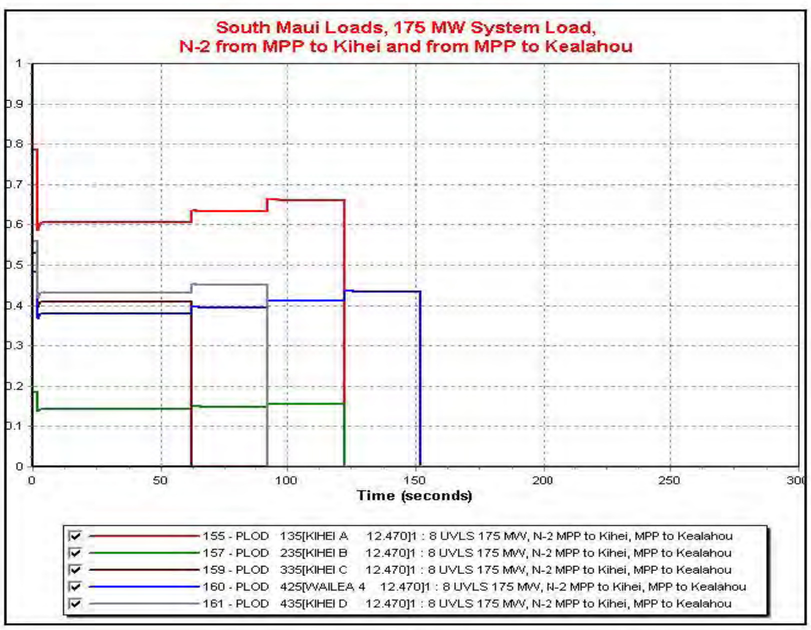

South Maui Voltages, N-2 from MPP to Kihei and from Kanaha to Pukalani
1
.975
0.95
.925
0.9
.875
0.85
.825
0.8
0
50
100
150
200
250
300
Time (seconds)
171 - VOLT 35 [KIHEI 69.000] : 6 UVLS Peak, N-2 MPP to Kihei, Kanaha to Pukalani
170 - VOLT 25 [WAILEA 69.000] : 6 UVLS Peak, N-2 MPP to Kihei, Kanaha to Pukalani

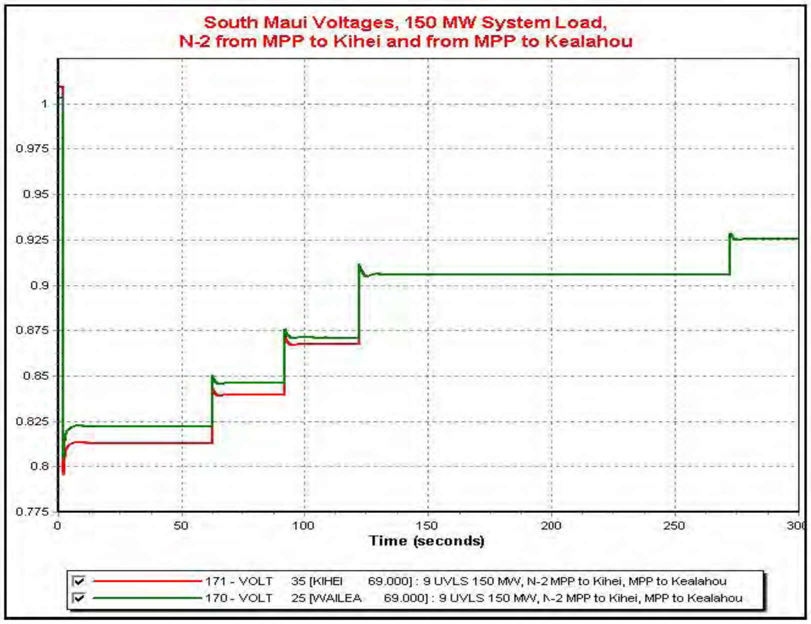

South Maui Loads, N-2 from MPP to Kihei and from Kanaha to Pukalani
1.1
1
0.9
0.8
0.7
0.6
0.5
0.4
0.3
0.2
0.1
0
0
50
100
150
200
250
300
Time (seconds)
155 - PLOD 135[KIHEI A 12.470]1 : 6 UVLS Peak, N-2 MPP to Kihei, Kanaha to Pukalani
157 - PLOD 235[KIHEI B 12.470]1 : 6 UVLS Peak, N-2 MPP to Kihei, Kanaha to Pukalani
159 - PLOD 335[KIHEI C 12.470]1 : 6 UVLS Peak, N-2 MPP to Kihei, Kanaha to Pukalani
160 - PLOD 425[WAILEA 4 12.470]1 : 6 UVLS Peak, N-2 MPP to Kihei, Kanaha to Pukalani
161 - PLOD 435[KIHEI D 12.470]1 : 6 UVLS Peak, N-2 MPP to Kihei, Kanaha to Pukalani

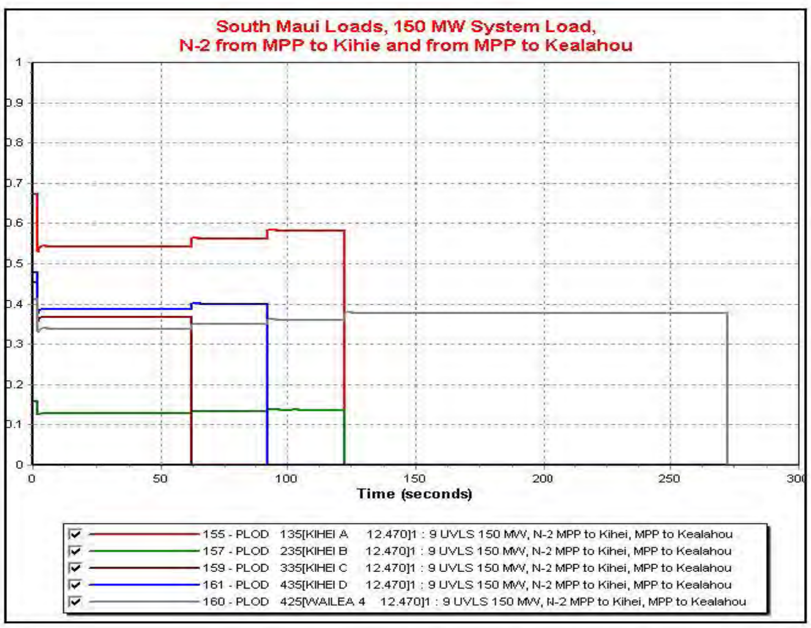

South Maui Voltages, 175 MW System Load, N-1 from MPP to Kihei
1
.975
0.95
.925
0.9
.875
0.85
.825
0
50
100
150
200
250
Time (seconds)
171 - VOLT 35 [KIHEI 69.000] : 7 UVLS 175 MW, N-1 MPP to Kihei
170 - VOLT 25 [WAILEA 69.000] : 7 UVLS 175 MW, N-1 MPP to Kihei


South Maui Loads, 175 MW System Load, N-1 from MPP to Kihei
1
0
0
50
100
150
200
250
Time (seconds)
155 - PLOD 135[KIHEI A 12.470]1 : 7 UVLS 175 MW, N-1 MPP to Kihei
157 - PLOD 235[KIHEI B 12.470]1 : 7 UVLS 175 MW, N-1 MPP to Kihei
159 - PLOD 335[KIHEI C 12.470]1 : 7 UVLS 175 MW, N-1 MPP to Kihei
160 - PLOD 425[WAILEA 4 12.470]1 : 7 UVLS 175 MW, N-1 MPP to Kihei
161 - PLOD 435[KIHEI D 12.470]1 : 7 UVLS 175 MW, N-1 MPP to Kihei


South Maui Voltages, 175 MW System Load,
N-2 from MPP to Kihei and from MPP to Kealahou
1
0.95
0.9
0.85
0.8
0.75
0.7
0.65
0
50
100
150
200
250
Time (seconds)
171 - VOLT 35 [KIHEI 69.000] : 8 UVLS 175 MW, N-2 MPP to Kihei, MPP to Kealahou
170 - VOLT 25 [WAILEA 69.000] : 8 UVLS 175 MW, N-2 MPP to Kihei, MPP to Kealahou


South Maui Loads, 175 MW System Load,
N-2 from MPP to Kihei and from MPP to Kealahou
1
0
50
100
150
200
250
Time (seconds)
155 - PLOD 135[KIHEI A 12.470]1 : 8 UVLS 175 MW, N-2 MPP to Kihei, MPP to Kealahou
157 - PLOD 235[KIHEI B 12.470]1 : 8 UVLS 175 MW, N-2 MPP to Kihei, MPP to Kealahou
159 - PLOD 335[KIHEI C 12.470]1 : 8 UVLS 175 MW, N-2 MPP to Kihei, MPP to Kealahou
160 - PLOD 425[WAILEA 4 12.470]1 : 8 UVLS 175 MW, N-2 MPP to Kihei, MPP to Kealahou
161 - PLOD 435[KIHEI D 12.470]1 : 8 UVLS 175 MW, N-2 MPP to Kihei, MPP to Kealahou


South Maui Voltages, 150 MW System Load,
N-2 from MPP to Kihei and from MPP to Kealahou
1
0.975
0.95
0.925
0.9
0.875
0.85
0.825
0.8
0.775
0
50
100
150
200
250
Time (seconds)
171 - VOLT 35 [KIHEI 69.000] : 9 UVLS 150 MW, N-2 MPP to Kihei, MPP to Kealahou
170 - VOLT 25 [WAILEA 69.000] : 9 UVLS 150 MW, N-2 MPP to Kihei, MPP to Kealahou


South Maui Loads, 150 MW System Load,
N-2 from MPP to Kihie and from MPP to Kealahou
1
0
0
50
100
150
200
250
Time (seconds)
155 - PLOD 135[KIHEI A 12.470]1 : 9 UVLS 150 MW, N-2 MPP to Kihei, MPP to Kealahou
157 - PLOD 235[KIHEI B 12.470]1 : 9 UVLS 150 MW, N-2 MPP to Kihei, MPP to Kealahou
159 - PLOD 335[KIHEI C 12.470]1 : 9 UVLS 150 MW, N-2 MPP to Kihei, MPP to Kealahou
161 - PLOD 435[KIHEI D 12.470]1 : 9 UVLS 150 MW, N-2 MPP to Kihei, MPP to Kealahou
160 - PLOD 425[WAILEA 4 12.470]1 : 9 UVLS 150 MW, N-2 MPP to Kihei, MPP to Kealahou

APPENDIX C

Maui Electric Gross System Peak Load Forecast

Table A.1: Maui Electric System Peak Forecast—Gross MW

System Peak	
Year	Gross Instant (MW)
Act. 2012	199.1
2013	207.8
2014	212.8
2015	218.0
2016	223.0
2017	227.8
2018	232.5
2019	236.3
2020	239.2
2021	241.5
2022	243.5
2023	246.0
2024	248.9

APPENDIX D

Single line Diagrams

Maalaea-Kamalii Transmission Line Alternatives

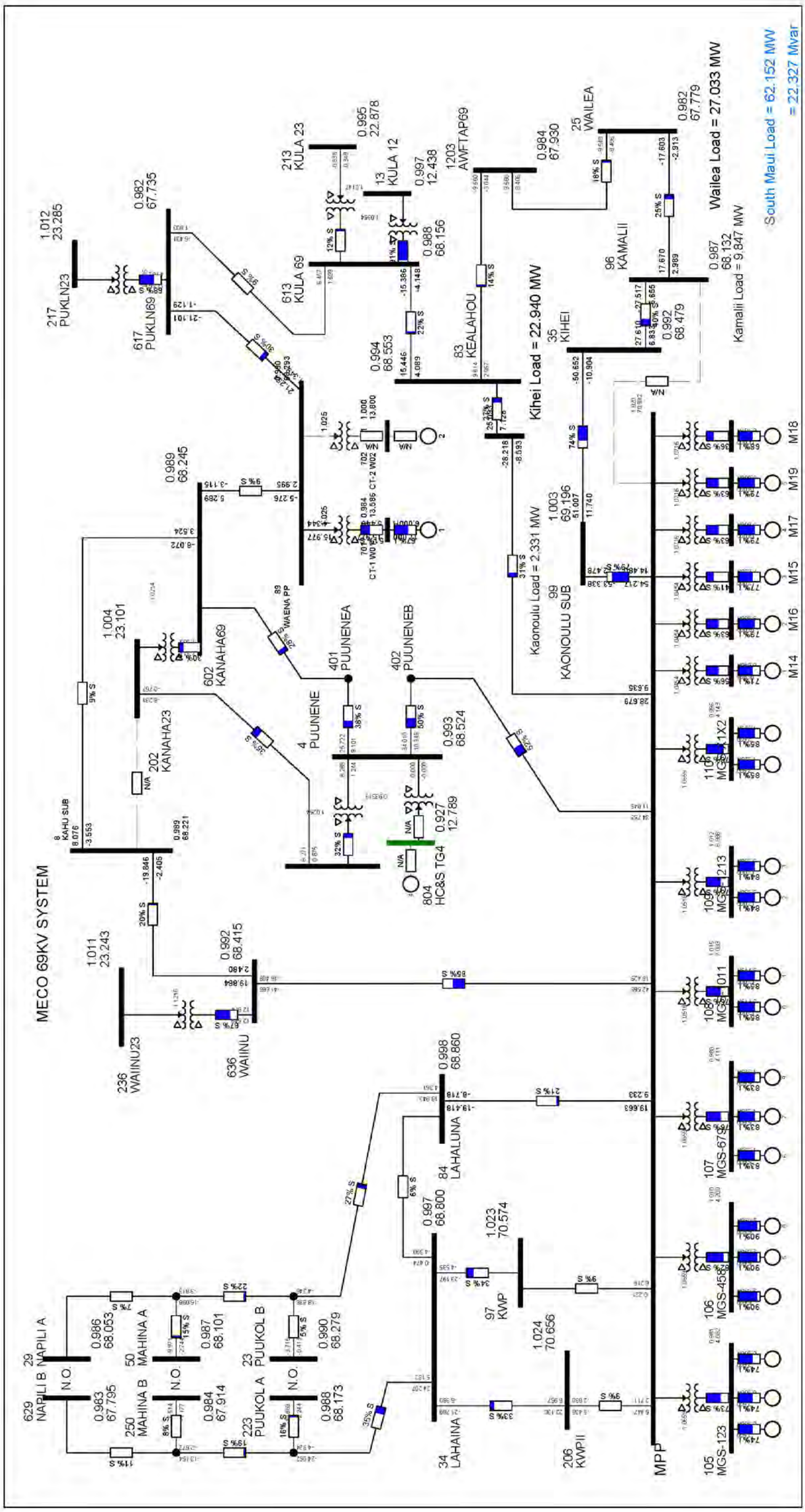


Figure B.1: 2024 normal conditions

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TPD#2013-26
Maalaea-Kamalii Line Alternative

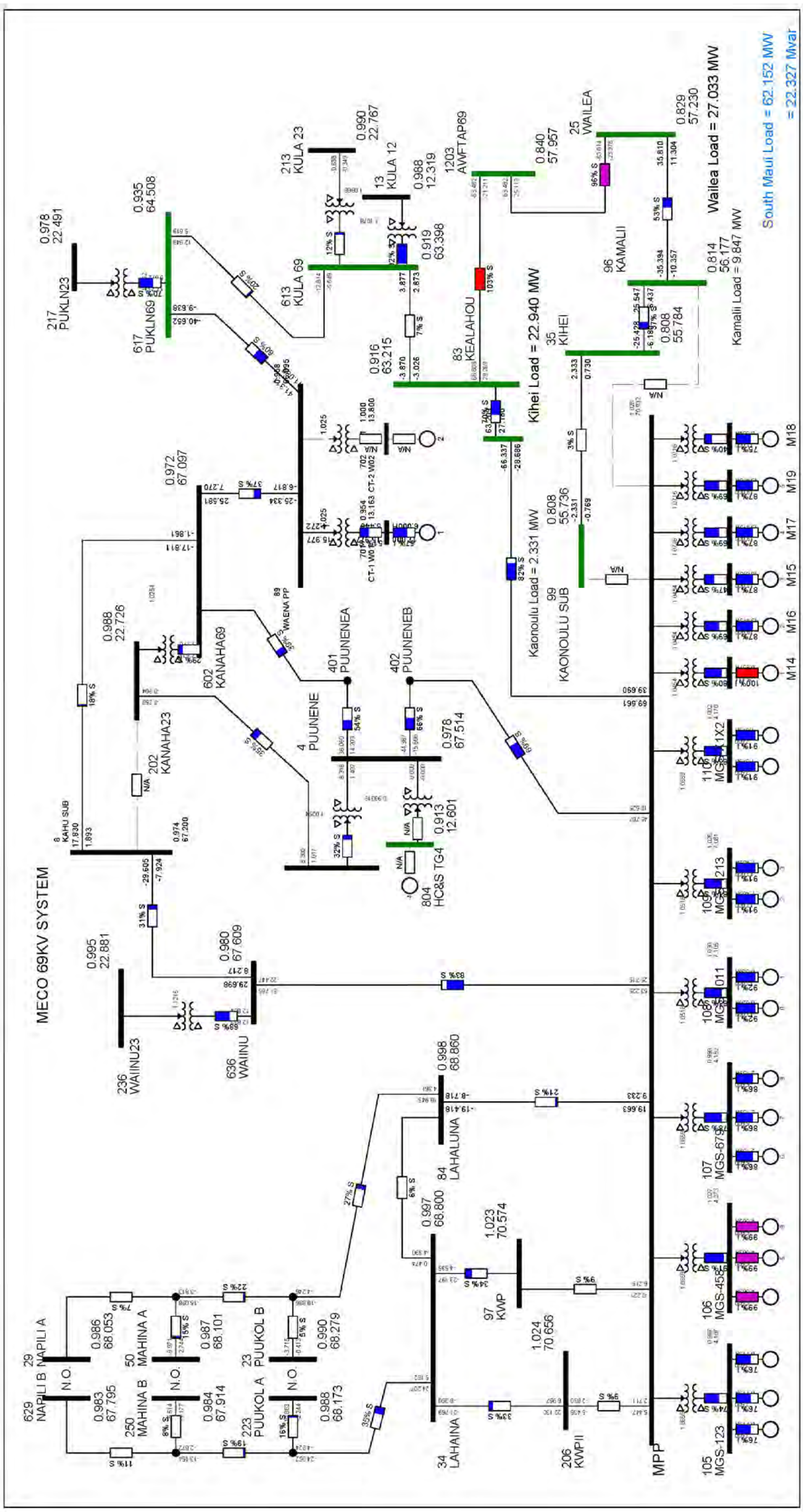

Figure B.2: Low voltage violaitons under N-1, loss of Maalaea-Kihei

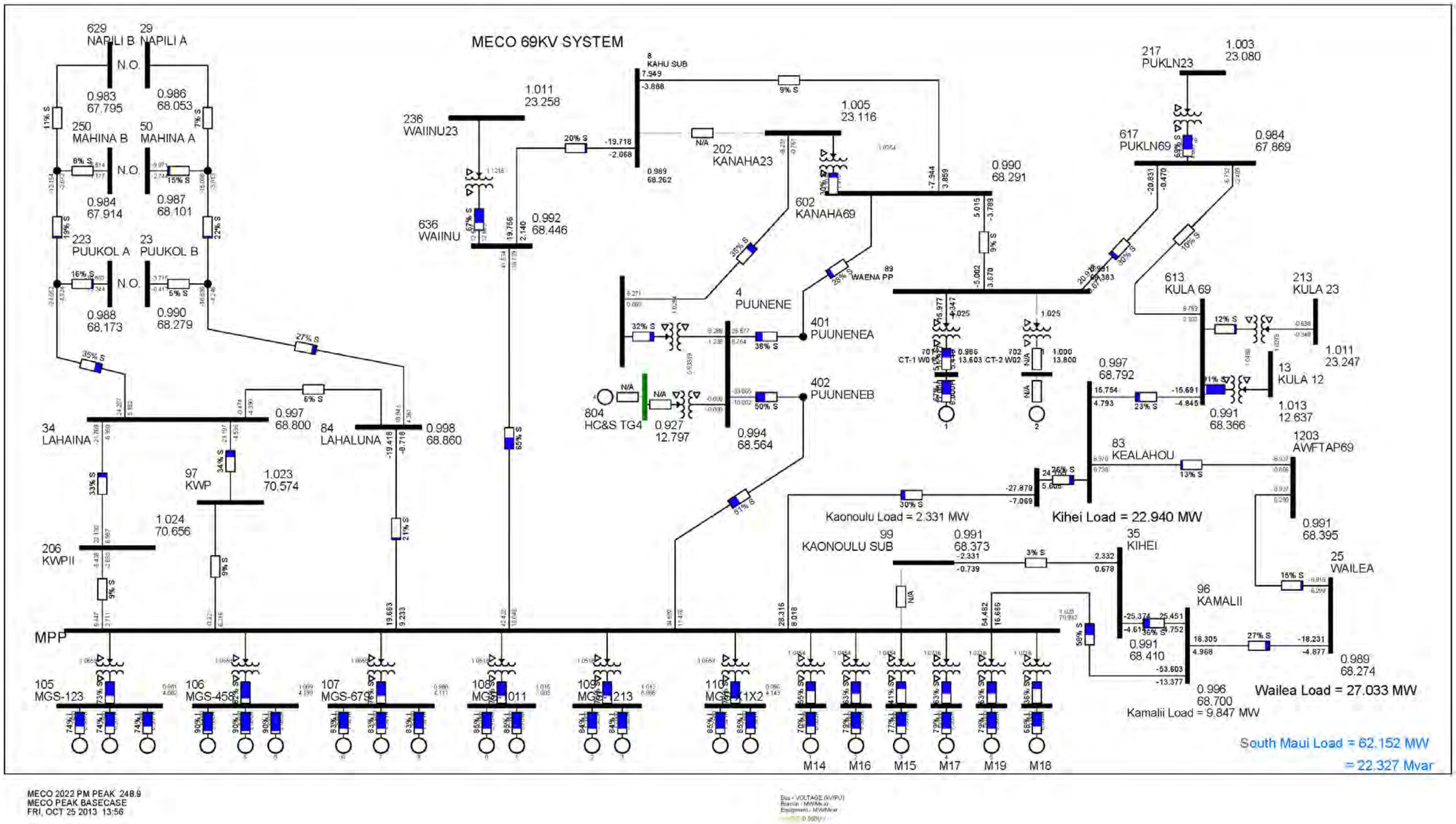

Figure B.3: N-1 conditions with the Maalaea-Kamalii 69kV transmission line

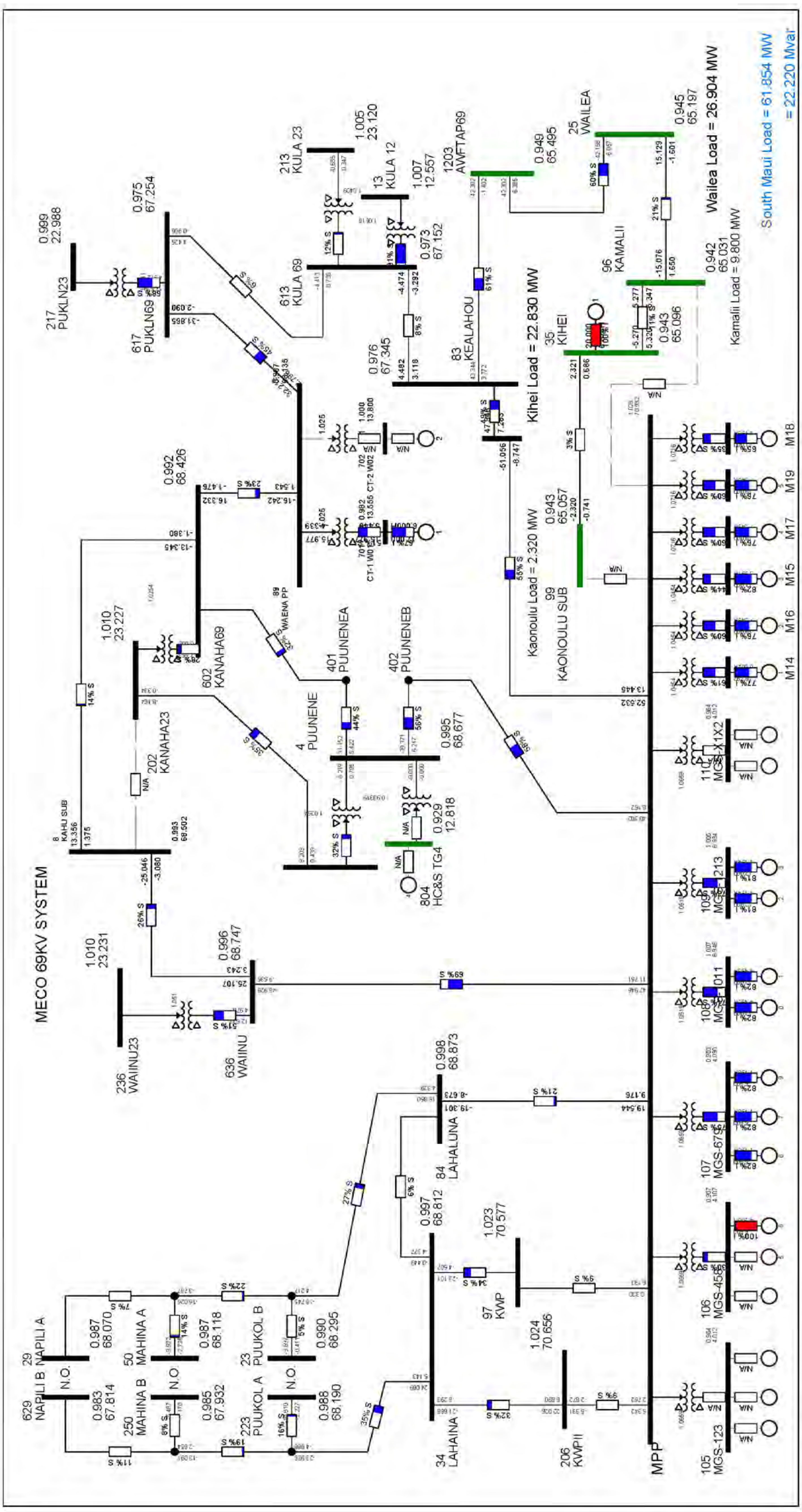

Figure B.4: N-1 conditions with Distributed Generation (DG) alternative

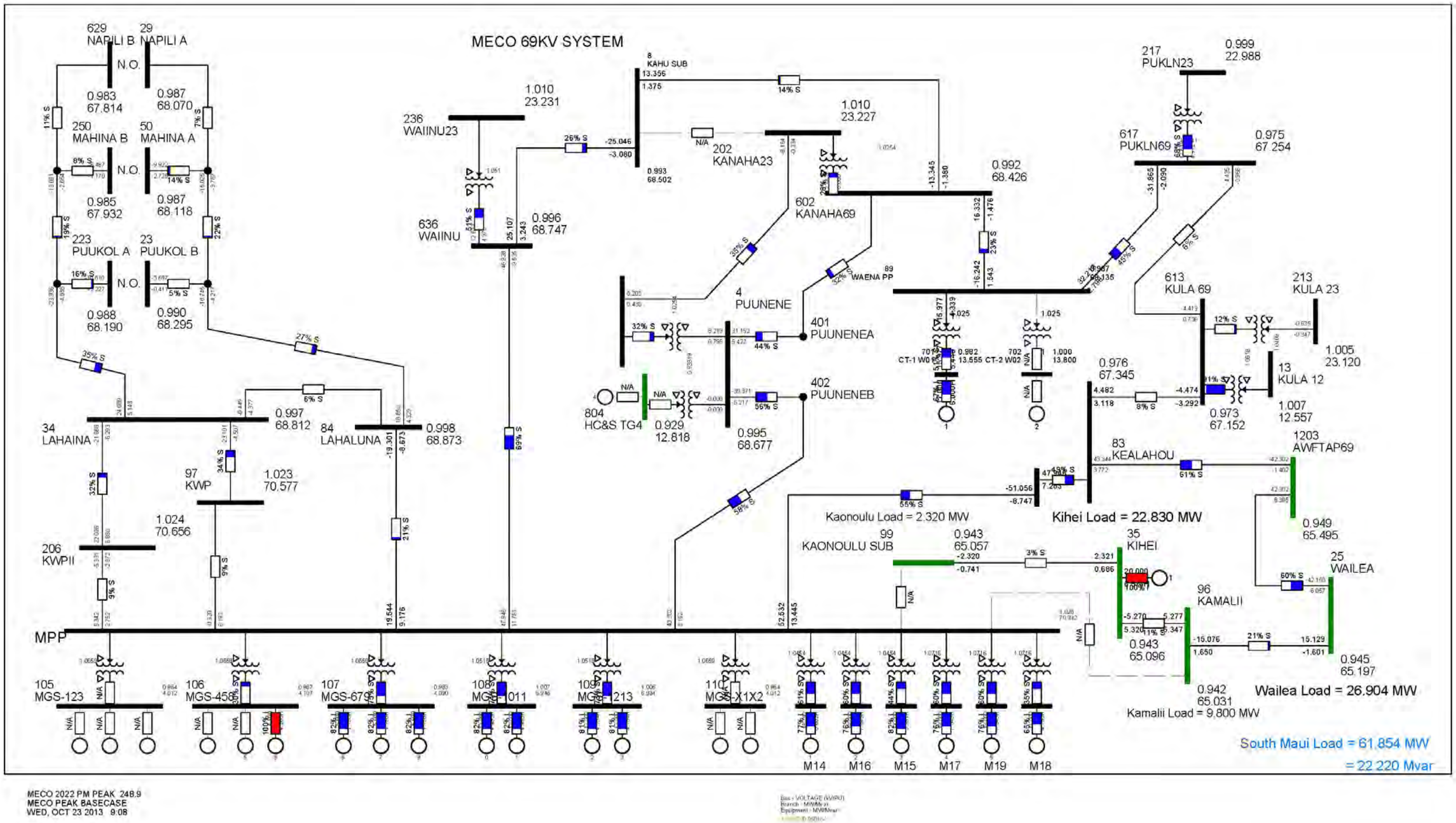

Figure B.5: N-1 conditions with ESS (energy storage system) alternative

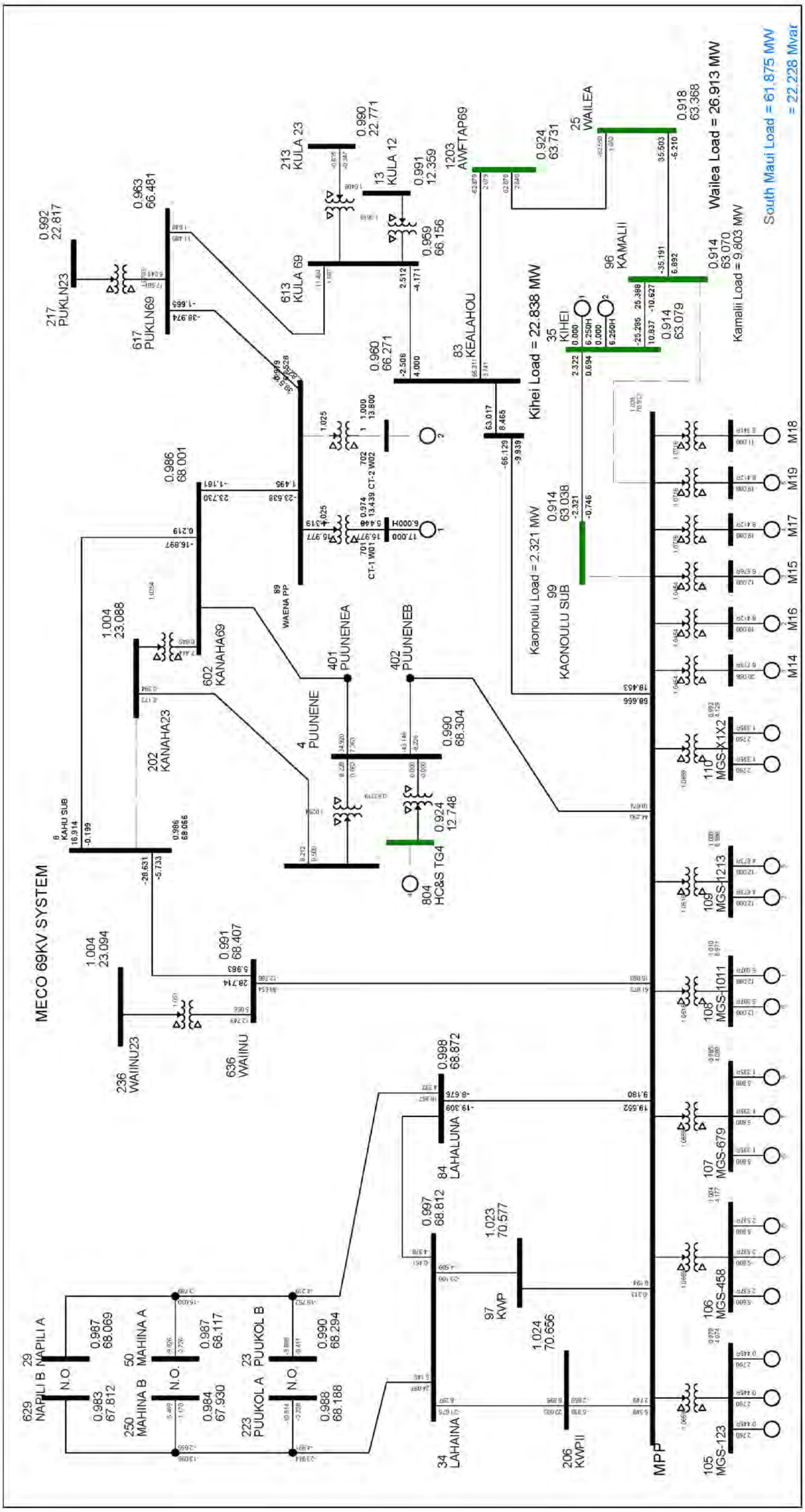

Figure B.6: N-1 conditions with synchronous condensers alternative

Maalaea-Kamalii Transmission Line Alternatives

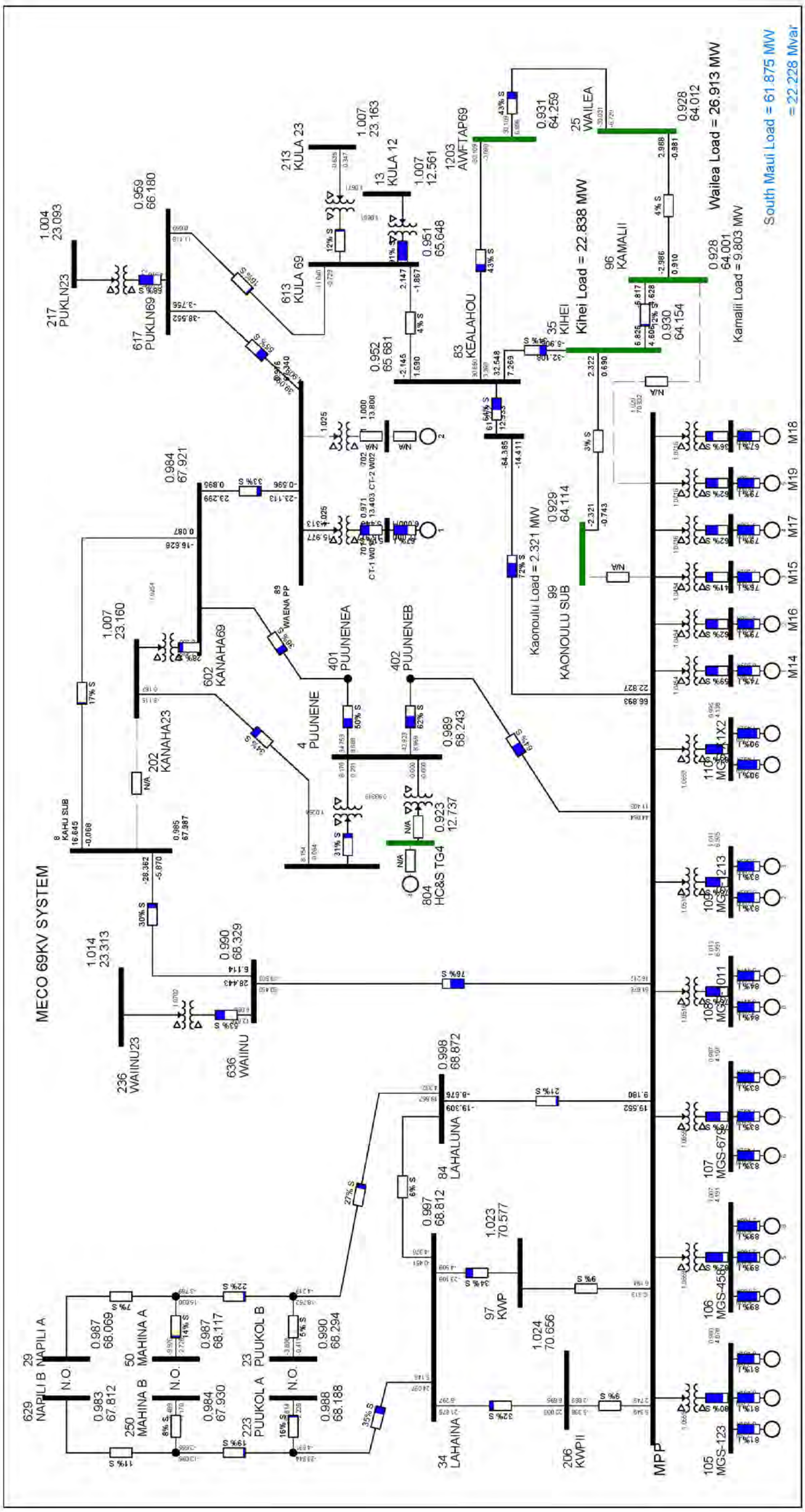

Figure B.7: N-1 conditions with Kealahou-Kihei 69kV transmission line alternative

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TPD#2013-26
Maalaea-Kamalii Line Alternative

Hawaiian Electric
Maui Electric
Hawai'i Electric Light

APPENDIX E

Maui Electric 5 year Historical Peak Load

Table C.1: 2008-2012 Maui System Peak

Maui System Peak	
Year	System Load (MW)
2008	199.0
2009	204.3
2010	203.8
2011	194.1
2012	199.1

Kahului Power Plant Retirement – Comprehensive Assessment

Prepared for

Maui Electric Company, Ltd.

Prepared By:

Hawaiian Electric Company, Inc.
System Planning Department
Transmission Planning Division

August 20, 2014

Reference: TPD 2014-22

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Kahului Power Plant Retirement – Comprehensive Assessment

Prepared By:

Brian Lee
Planning Engineer, Transmission

LoriAnn Fukuda
Planning Engineer, Transmission

Mohit Mehrotra
Planning Engineer, Transmission

Raja Srivastava
Lead Planning Engineer, Transmission

Approved By:

Gemini Yau
Lead Planning Engineer, Transmission

Approved By: 8/20/2014

Ronald Bushner
Director, Transmission Planning

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Methodology 6

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Results and Analysis 6

Thermal Limit Analysis: 7

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Short Circuit Analysis: 8

Discussion 9

Conclusion 9

Appendix A – Thermal Analysis

Appendix B – Voltage Stability Assessment

Appendix C – Short Circuit Analysis

Executive Summary

Maui Electric Company anticipates a reserve capacity shortfall of approximately 40 MW by year 2019, due to the scheduled retirement of Kahului Power Plant. Maui Electric has efforts to procure new resources to meet the reserve capacity shortfall, which may potentially void the need for the Waiinu-Kanaha upgrade project. The Transmission Planning Division at Hawaiian Electric Company has examined various non-transmission alternative options and determined that installing battery storage and/or new generation units on Maui Electric's 23 kV network are viable alternatives to the Waiinu-Kanaha upgrade project. However, considering the civil, corporate and political concerns involved with each non-transmission alternative and the tradeoffs involved with not implementing the Waiinu-Kanaha upgrade project, the Transmission Planning Division recommends Maui Electric Company to continue to pursue the Waiinu-Kanaha upgrade. Maui Electric's interest in procuring new resources should not affect or void the plans to implement the Waiinu-Kanaha upgrade project.

Introduction/Background

Maui Electric Company (MECO) plans to decommission Kahului Power Plant (KPP) on Maui island by the year 2019. The Maui transmission system consists of a 23 kV network and 69 kV network. KPP has a total capacity of approximately 35 MW and connects into the 23 kV network, and the remainder of Maui's generation connects into the 69 kV network. The two networks are interconnected via 23/69 kV tie transformers located at the Waiinu, Kanaha, and Puunene substations. KPP is the only source of generation connected to the 23 kV network. The retirement of the power plant will result in the 23 kV network becoming heavily dependent on power supplied by the 69 kV network.

The Transmission Planning Division (TPD) anticipates the Maui system to become vulnerable to numerous system reliability issues in the event of a system disturbance after decommissioning KPP. TPD conducted a study[1] in the year 2012 regarding MECO's plan to retire KPP, which analyzed several transmission solutions to mitigate the anticipated system issues. The study recommended upgrading the 23 kV Waiinu to Kanaha transmission line to 69 kV, relocating 23 kV load at Kahului to the 69 kV system, and reconductoring the 69 kV Maalaea Power Plant (MPP)-Puunene and 69 kV MPP-Waiinu transmission lines.

MECO will procure resources to meet an anticipated reserve capacity short fall of approximately 40 MW by year 2019, identified in Section 1.6 of the Maui Electric Adequacy of Supply (AOS) report. The procurement of additional resources may potentially void the need for the Waiinu-Kanaha upgrade project. TPD was asked to consider non-transmission alternatives (NTAs) as a possible solution to mitigate the issues that arise with the retirement of KPP. TPD performed several studies and produced reports which analyze the system impacts of various NTA options.

[1] Refer to Docket No. 2011-0092 – MECO 2012 Test Year Rate Case

This report consolidates the findings of the various studies performed by TPD and provides TPD's standpoint regarding whether the Waiinu-Kanaha project should still be pursued taking into consideration that additional generation resources will be procured by year 2019.

Methodology

TPD used a conventional transmission planning software to perform dynamic, steady-state, and short circuit analyses simulating the Maui system with various NTA upgrades under the normal and various N-1 conditions. The results were examined with consideration of the civil, corporate, and political concerns involved with each option to determine the most favorable and engineeringly sound solution to properly address the issues involved with the retirement of KPP.

Assumptions:

The following are the assumptions used in this study unless specified otherwise:

- Referencing of the "23 kV network" in this study does not include the 23 kV circuit from Kula to Haleakala due to its electrical distance from the rest of the 23 kV system.
- The Hana 23 kV circuit is fed from Pukalani.
- Kahului Power Plant is retired by 2019.
- The system upgrade involving the conversion of the 23 kV Waiinu to Kanaha transmission line to 69 kV, relocating 23 kV load at Kahului to the 69 kV system, and reconductoring the 69 kV MPP-Puunene and 69 kV MPP-Waiinu transmission lines will be referred to as the "Waiinu-Kanaha upgrade project" in this report.
- Contract with HC&S will expire in 2014 and HC&S will no longer contribute any generation after year 2014.
- The acceptable "power margin" is between 1.05 - 0.9 per unit (p.u.) voltage per the reliability criteria.
- The acceptable thermal margin is within thermal limits of the normal rating (Rating A) under the normal condition and within thermal limits of the emergency rating (Rating B) for N-1 condition. However, transmission lines operating near the maximum thermal limits are also taken into consideration.
- An N-1 event refers to the loss of a single transmission line or generating unit.

Results and Analysis

Several NTA options were considered:

- New Dispatchable Firm Generation/Distributed Generation (DG).
- Battery Energy Storage System (BESS).
- Demand Response (DR).
- Conversion of some or all existing units at KPP to synchronous condensers.

The conversion of existing KPP units to synchronous condensers does not address the reserve capacity shortfall issue; however, it does potentially mitigate the anticipated low voltage issues resulting from the KPP retirement and void the need for the Waiinu-Kanaha upgrade project and, therefore, was considered as an NTA.

Thermal Limit Analysis:

The retirement of KPP subjects the 23 kV network to become heavily dependent on power to be supplied by the 69 kV network. This places additional burden on the transmission lines and tie transformers that interconnect the 23 kV and 69 kV networks – with KPP decommissioned, more power must flow through these transmission components from the 69 kV network to the 23 kV network to feed the load that had previously been served by KPP.

TPD's Thermal Analysis study identified that, with KPP decommissioned, when the Maui system experiences a disturbance, the tie transformer and transmission line connecting the 23 kV and 69 kV systems will be overloaded; see Appendix A. The study shows that in the N-1 contingency event of losing the 69 kV MPP-Waiinu transmission line, the tie transformer at Kanaha substation and the 69 kV MPP-Puunene transmission line will be overloaded beyond their emergency ratings. Similarly, in the N-1 contingency event of losing the 69 kV MPP-Puunene transmission line, the tie transformer at Waiinu substation is overloaded beyond its emergency rating.

The study also shows that, in addition to thermal overloads of transmission components, suffering a system disturbance will also cause low voltage profiles, below the acceptable voltage margin defined in the reliability criteria, at numerous locations on the 23 kV network. This is expected as the main generation source on the 23 kV system is removed and power must be supplied via the 69 kV network; suffering a system disturbance such as losing a transmission line subjects voltage sources to be electrically farther from load centers and power transfer limits are reduced.

The NTA's were examined focusing on their capability of mitigating the above mentioned issues. If the additional procured resources are interconnected on the 69 kV network, they will not mitigate the burden placed on the tie transformers and transmission lines that connect the 23 kV and 69 kV networks because power must still be supplied from the 69 kV network to the 23 kV network. TPD's Thermal Analysis study examines the system impacts of interconnecting the procured resources on the 23 kV network. The study shows that by installing active power resources on 23 kV network, the tie transformers and transmission lines are able to operate within the acceptable thermal limit margin during an N-1 condition because majority of the load on the 23 kV network is being served by the new resources installed on the 23 kV network, relieving the amount of power needed to travel through the tie transformers and transmission lines. Both BESS and DG options show these results and mitigate low voltage profiles that violate the reliability criteria; however, voltage instability can occur despite voltage profiles being within the acceptable margin; this will be covered more in detail below. The synchronous condenser option does not resolve the thermal overload issues and is not a viable alternative to the Waiinu-Kanaha upgrade project.

Voltage Stability Analysis:

In addition to the thermal overloading of transmission components, the retirement of KPP poses several voltage instability concerns. TPD's Voltage Stability Assessment studies the system impacts of the removal of KPP from the voltage stability standpoint; see Appendix B. The study identifies that the removal of generation at KPP results in voltage sources becoming electrically farther from the 23 kV network load centers, and significantly diminishes the transfer limits of power to the 23 kV network, subjecting the system to operate in conditions of voltage instability, or possibly suffer from an event of voltage collapse, if a system disturbance takes place.

The Voltage Stability Assessment study examines the mitigation capabilities of various NTA options for avoiding violations of voltage criteria and operation in unstable voltage circumstances. The study identified that installing new active power resources (BESS and DG options) on the 69 kV network will not mitigate the voltage issues on the 23 kV network that arise from the removal of KPP; this is because generation must still be supplied from the 69 kV network, thus voltage sources are still electrically far from load centers and/or power transfer capability limits have been reached – installing new procured resources on the 69 kV network will still results in voltage violations and voltage instable/voltage collapse conditions.

The study shows that adding active power resources to the 23 kV network and converting existing KPP units to synchronous condensers will allow voltage profiles within the voltage criteria; however, the study focused on how the NTA options impact the power transfer capability limits and proximity of voltage collapse as voltage instability and voltage collapse may occur despite voltage profiles being well within the acceptable margin.

Adding active power resources to the 23 kV network and converting existing KPP units to synchronous condensers show promising results in improved power transfer capability limits and avoiding voltage instability/voltage collapse, depending on the size of units installed; see Voltage Stability Assessment for detailed analysis. The study identifies that in the event of a disturbance, the DR program option must curtail load on the 23 kV network to maintain total system load of 170 MW, approximately 15 MW (required amount of load needed to be curtailed increases for later years as load continues to grow), in order to maintain system reliability.

Short Circuit Analysis:

TPD performed a study concerning the effects the retirement of KPP will have on the short circuit current, see Appendix C. The study analyzes and compares the short circuit current on the existing Maui transmission system to the Maui system with various changes to its topology (i.e. Maui system with Waiinu-Kanaha upgrade, various NTA options, etc.). The study indicated that the retirement of KPP will induce a possible change in fault current of as much as 5,000 amperes, which may affect relay operations and violate system reliability. The study recommends that with the retirement of KPP and implementation of new system element, the company should re-evaluate the effect of reduced fault current on the Maui system and make necessary changes to protection schemes.

Discussion

Both BESS and DG options are viable alternatives to the Waiinu-Kanaha upgrade project, however, they must be installed on the 23 kV network in order to mitigate the issues that arise with the removal of KPP. Presently, TPD is only aware of the Waena Power Plant (WPP) and South Maui sites as suggested locations to accommodate new addition generation resources – these locations are on the 69 kV network. TPD is skeptical whether suitable land can be acquired to house the new generation resources since the Central Maui area is densely populated by many private and commercial residents. The original KPP site was also considered for possible space to house new resources, however, recent updates to the Maui island tsunami evacuation maps show that the KPP site now resides in a tsunami inundation zone. Converting existing KPP units to synchronous condensers will mitigate voltage issues but will not address the thermal overloading of transmission components issues, thus is not a viable alternative to the Waiinu-Kanaha upgrade project. The DR program is a viable alternative but involves the curtailment of customer load – presently, the expected required amount of load on the 23 kV network to be curtailed is 20 MW for year 2019 to avoid thermal and voltage issues; more load will be required for curtailment as system load continues to grow.

The Waiinu-Kanaha upgrade project involves converting the existing 23 kV Waiinu-Kanaha to 69 kV, and in the process will relocate load at Kahului to the 69 kV network. In addition to the line conversion, 69 kV MPP-Waiinu and 69 kV MPP-Puunene transmission lines will be reconductored to 556 AAC lines. Converting the 23 kV Waiinu-Kanaha line to 69 kV will relieve some burden placed on the transmission components that interconnect the 23 kV and 69 kV networks as load at Kahului (on the 23 kV network) will be relocated to 69 kV network – less power will be required to flow through interconnecting transmission components. The reconductoring of the 69 kV MPP-Waiinu and 69 kV MPP-Puunene transmission lines serves to strengthen the transmission route for power to travel to the 23 kV network to address the issue of those lines operating near or beyond their emergency rating limit in the event of a system disturbance, identified in Thermal Limit Analysis study. The Waiinu-Kanaha upgrade project will mitigate the thermal limit and voltage issues involved with the removal of KPP. As identified in the Voltage Stability Analysis study, it the upgrade project produces favorable results in improving the power transfer capability limits of the Central Maui area and allows the system to operate at a significantly greater proximity away from circumstances which could lead to voltage instability/voltage collapse.

Conclusion

TPD has examined various NTA options that could potentially void the need for the Waiinu-Kanaha Upgrade project. TPD has determined the option involving the conversion of existing KPP units to synchronous condensers is not viable as it will not address thermal limit overload issues that arise with the KPP removal. TPD also does not recommend the DR program option as an alternative to the Wainu-Kanaha upgrade because it requires curtailing more customer load on the 23 kV network than was identified as potential on all of Maui. TPD has determined the NTA options which involve installing BESS and/or DG units on the 69 kV network is not a viable alternative because it will not address the thermal limit overload and voltage issues. But installing BESS and/or DG units on the 23 kV network will address both thermal overload and voltage issues involved with the KPP removal and is a viable alternative to the Waiinu-Kanaha upgrade. However, the only known locations available to accommodate the new resources are the WPP site and a site within the South Maui area, which both are on the 69 kV network. Considering the limited availability of suitable land to accommodate new generation resources on the 23 kV network and the tradeoffs impacting the Maui system without the Waiinu-Kanaha upgrade, TPD concludes that MECO should proceed with the implementation of the Waiinu-Kanaha upgrade project. MECO's procurement of resources to address the anticipated reserve capacity shortfall of 40 MW by year 2019 should not affect or void the plans for the Waiinu-Kanaha upgrade project.

Appendix A – Thermal Analysis

Kahului Power Plant Retirement: Transmission System Steady State Analysis

Prepared for
Maui Electric Company, Ltd.

Prepared by
Hawaiian Electric Company, Inc
System Planning Department
Transmission Planning Division

June 12, 2014

Reference # TPD2014-23

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Kahului Power Plant Retirement: Transmission System Steady State Analysis

Prepared by: LoriAnn Fukuda 8/20/2014
LoriAnn Fukuda
Planning Engineer I

Approved by: 8/20/2014
Gemini Yau
Lead Planning Engineer

Ronald Bushner 8/20/2014
Ronald Bushner
Director, Transmission Planning

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Introduction

Kahului Power Plant (KPP) is scheduled to be decommissioned in 2019. The Maui transmission system consists of a 23kV system and a 69kV system. KPP serves majority of the load on the 23kV system.

Figure 1 identifies the power plants, substations, and transmission lines associated with the KPP retirement. With the retirement of KPP, all of the load on the 23kV system will need to be served from the 69kV system. The Maui transmission system utilizes three 69/23kV tie transformers to interconnect the 69kV system and the 23kV system. These 69/23kV transformers are located at Waiinu Substation, Puunene Substation, and Kanaha Substation.

This study was conducted to identify the transmission system impacts with the retirement of KPP and analyze various solutions necessary to provide safe reliable power to the customers.

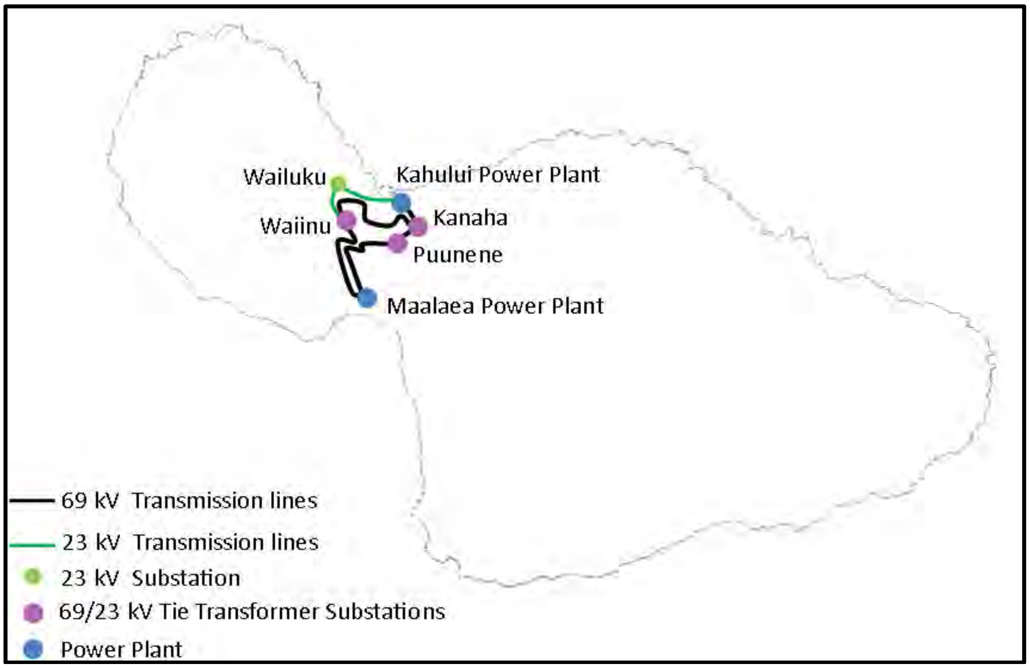

Figure 1: Key central Maui transmission components

Assumptions

The "23kV system" referred in this document consists of the substations within central Maui—Wailuku, Kanaha, Kahului Sub 8, and substations fed by these major substations. Hana is being fed from Pukalani and the distance from the central substations to Haleakala and Kula do not have the same effect from the rest of the 23kV system; therefore, they are not included in the reference to the "23kV system."

This study only evaluates the impact to the system from a steady state point; stability analysis will also need to be conducted.

Model Assumptions

To model the Maui transmission system, we used actual 2013 historical load data to create a benchmark case. From the benchmark case, the following planned transmission system changes were implemented to create the cases for the interested years of study:

- 2014—KPP units K1 and K2 deactivated
- 2014—HC&S Offline
- 2015—Kaonoulu Substation
- 2019—All KPP units decommissioned
- 2019—Waiinu 69/23kV tie transformer enabled to auto-adjust

After the changes are implemented, the cases are uniformly scaled to the forecasted system gross loads.

Load Assumptions

The gross peak and minimum with DSM/NEM/SIA/FIT load forecast used in this study is based on the May 2014 Adopted Maui Electric Sales and Peak Forecasts. This study focused on the 2014 with a load forecast of 197.9 MW and 2019 with a load forecast of 218.3 MW to represent the current system and the system after the retirement of KPP, respectively. Refer to Appendix A for the entire 2014-2030 load forecasts.

Generation Assumptions

Currently, MECO operates two power plants—Kahului Power Plant (KPP) and Maalaea Power Plant (MPP). In addition, the following renewable generation serves the Maui load:

- HC&S—12 MW biomass
- KWP I—30 MW wind farm
- KWP II—21 MW wind farm
- Auwahi—21 MW wind farm
- Makila Hydro—0.5 MW hydro

The system also has two 1 MW units in Hana Substation for emergencies. Appendix B provides an overview of the current Maui system generation.

Thermal Overloads

The amount of power that can flow though the transmission system components, such as conductors and transformers, is limited by its characteristics. Too much current flowing through the conductors and transformers will cause damage due to overheating. Under scenarios with no contingencies, the transmission equipment is evaluated using the normal rating (Rating A). For N-1 contingencies, the system is evaluated with emergency ratings (Rating B). See Appendix C for a single line diagram overview of the central Maui system showing line ratings.

Voltage Violations

The MECO criteria for transmission planning states that under any operating condition, voltages for any bus shall have a maximum of +5% and a minimum of -10% of the nominal voltage. The per unit (pu) values are shown in Table 1.

Table 1: MECO Voltage Criteria for Transmission Planning

Criteria	Normal Conditions	Emergency Conditions
Over voltage violation	> 1.05 pu	> 1.05 pu
Under voltage violation	< 0.90 pu	< 0.90 pu

This report refers to "low voltages", which meet the planning criteria by being above 0.90 pu but are of concern as these voltages can be an under voltage violation in the future. Maintaining voltages within the criteria provides customers with good power quality; so there are no damages to customer equipment. Furthermore, if voltages fall too far below 0.9 pu, the system may not be able to recover and a voltage collapse will occur.

Steady State Analysis

To assess the impact on the transmission system with the retirement of KPP, the cases were subjected to N-1 contingencies. An N-1 contingency occurs when there is an outage of one transmission system component, while all others are in service. The following two contingencies are evaluated, as these contingencies are crucial paths that transfer power from the 69kV system to the 23kV system:

- Contingency 1: Loss of 69kV MPP-Waiinu
- Contingency 2: Loss of 69kV MPP-Puunene

The steady state analysis will identify any thermal overloads or voltage violations that can occur during these contingencies. To see the effects of retiring KPP, analysis was conducted with a case modeling the current system in 2014 and a case with the current system in 2019. Thermal and voltage violations occurred in the 2019 case if no upgrades to the system were made. The following are solutions considered to address the thermal and voltage violations:

- 23kV Waiinu-Kanaha upgrade to 69kV with the reconductoring of MPP-Waiinu and MPP-Puunene from 336AAC to 556AAC
- 25MW Battery Energy Storage System (BESS)
- 40MW Distributed Generation (DG)
- Synchronous condensers from retiring KPP units

Table 2 shows the case assumptions used when analyzing the impacts KPP retiring and the solutions considered. The amount of demand response (DR) needed would need to be similar to the generation provided by the BESS or DG to reduce the load on the 23kV system.

Table 2: KPP Retirement Steady State Case Assumptions

Case	Solution	Description
0	---	• 2014 peak • Load Forecast = 197.9MW
1	---	• 2019 peak • Load Forecast = 218.3MW • HC&S offline • KPP offline • Kaonoulu Substation in service • Waiinu 69/23kV tie transformer auto-adjust enabled
2	Transmission Upgrades	• 2019 peak • Load Forecast = 218.3MW • HC&S offline • KPP offline • Kaonoulu Substation in service • Waiinu 69/23kV tie transformer auto-adjust enabled • 23kV Waiinu-Kanaha upgrade to 69kV • MPP-Waiinu reconductored from 336 to 556 • MPP-Puunene reconductored from 336 to 556 • Remove FDR C from KPP-Kanaha 23kV
3	25 MW BESS	• 2019 peak • Load Forecast = 218.3MW • HC&S offline • KPP offline • Kaonoulu Substation in service • Waiinu 69/23kV tie transformer auto-adjust enabled • 25MW BESS interconnected at KPP
4	40 MW DG	• 2019 peak • Load Forecast = 218.3MW • HC&S offline • KPP offline • Kaonoulu Substation in service • Waiinu 69/23kV tie transformer auto-adjust enabled • 40MW DG interconnected at KPP
5	KPP Units converted to synchronous condensers	• 2019 peak • Load Forecast = 218.3MW • HC&S offline • KPP offline • Kaonoulu Substation in service • Waiinu 69/23kV tie transformer auto-adjust enabled • KPP units converted to synchronous condensers

Results

Currently with KPP online (2014), there are no thermal or voltage violations under normal or N-1 contingency events. The 23kV system it is less dependent on the 69kV system because KPP is serving the load on the 23kV system. This reduces the loading on the 69/23kV tie transformers.

For the 2019 case, under normal conditions, if no system upgrades are made, the Waiinu 69/23kV tie transformer was heavily loaded at 92% of the normal rating. When subjected an N-1 contingency, the loss of MPP-Waiinu showed overloads on the Puunene and Kanaha 69/23kV tie transformers, overloading on the MPP-Puunene 69kV line, as well as under voltage violations for the 23kV system and the Waiinu 69kV bus.

Figure 2 is a magnified excerpt of the 69kV system and identifies the violations of the system under the loss of MPP-Waiinu contingency.

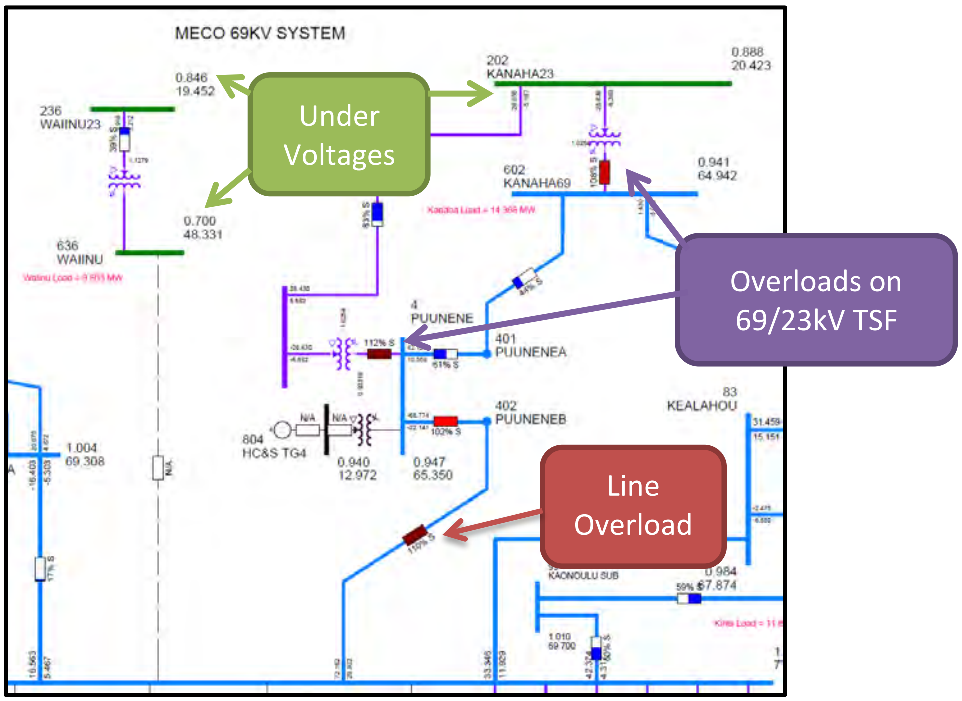

Figure 2: 69kV system current conditions for 2019 under N-1 contingency, loss of MPP-Waiinu

Figure 3 shows the PSSE results for the 69kV and 23kV system in a single line diagram.

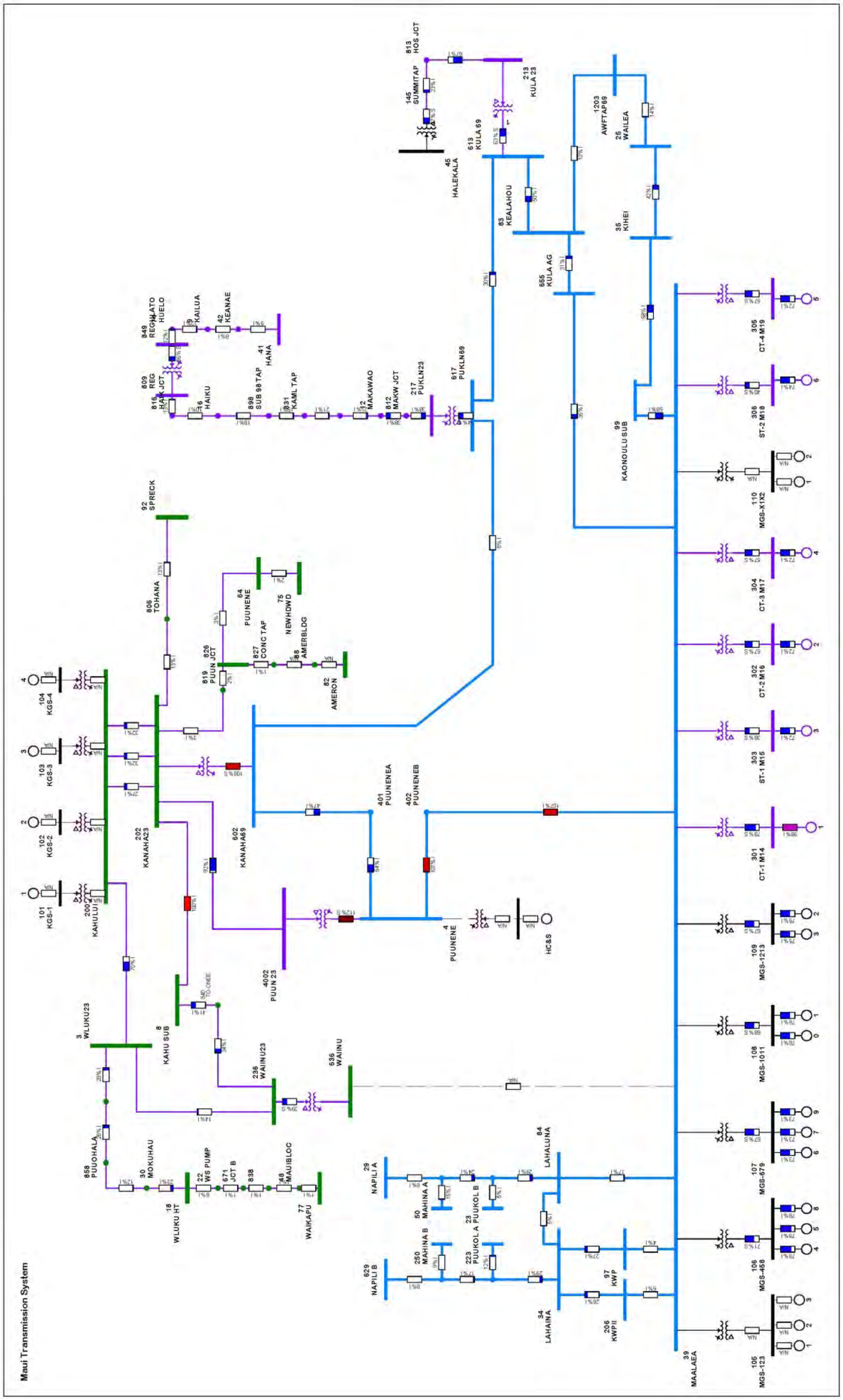

Figure 3: Maui transmission system in 2019 without upgrades under N-1 contingency, loss of MPP-Waiinu

For the loss of MPP-Puunene, the Waiinu 69/23kV tie transformer is overloaded and low voltages occur at Puunene, Kanaha, and Pukalani 69kV Substations. Although the low voltages are within the MECO criteria for transmission planning, the voltages are boarding the 0.90 pu voltage criteria.

Figure 4 shows the overloading of the Waiinu 69/23kV transformer and these low voltage buses with the loss of MPP-Puunene.

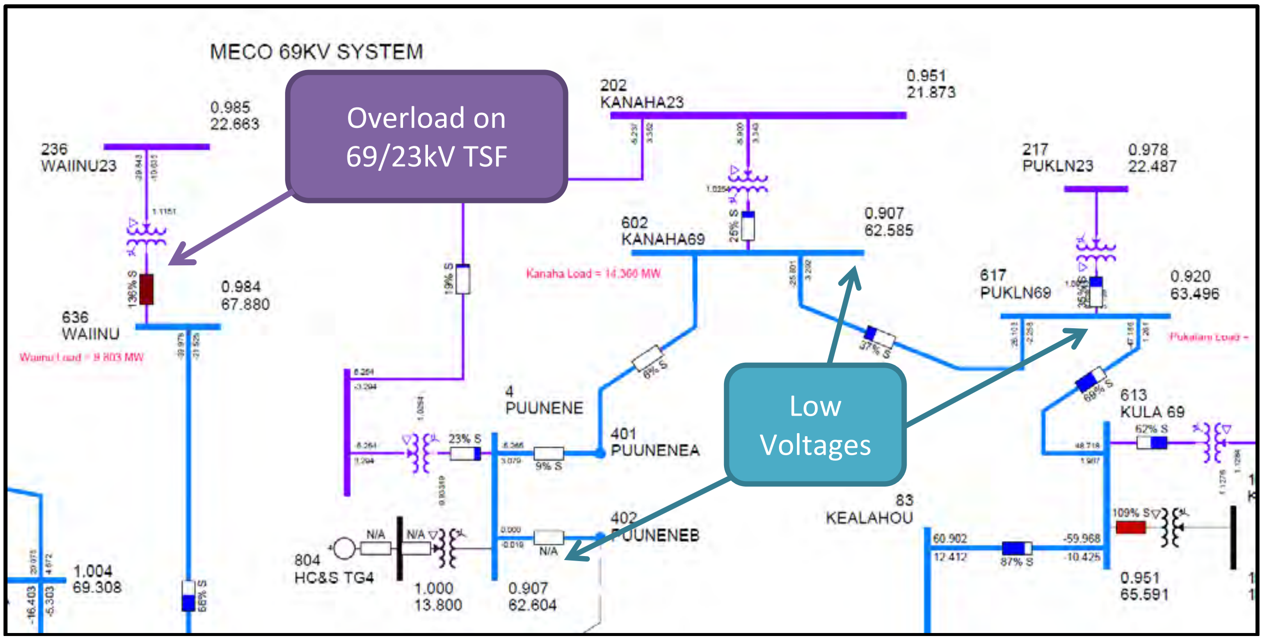

Figure 4: 69kV system with no system upgrades in 2019 under N-1 contingency, loss of MPP-Puunene

If no upgrades are made to the system, thermal and voltage violations occur. To eliminate the violations, a transmission and various non-transmission options were considered as possible solutions. From the 2019 case, the various solutions were modeled and studied to view the impacts to the system. These solutions are explained in detail in the following paragraphs.

Waiinu-Kanaha Transmission Upgrade

The transmission recommendation is to upgrade the current 23kV Waiinu-Kanaha line to 69kV and reconductor MPP-Waiinu and MPP-Puunene from 336AAC to 556AAC. In addition, with the upgrade of the Waiinu-Kanaha line, feeder C from KPP-Kanaha will need to be removed. Along with the Waiinu-Kanaha 23kV upgrade, the Kahului Sub 8, which is located along the Waiinu-Kanaha 23kV line, will also be upgraded to 69kV. By upgrading the23kV Waiinu-Kanaha line to 69kV, the loads on the 23kV system will be switched to the 69kV system. This will reduce the loading on the tie transformers.

With these transmission upgrades, the 2019 system will have no thermal or voltage violations under normal or N-1 contingency events. Figure 5 shows the system in 2019 with the transmission upgrades under N-1 contingency. By relocating more loads on the 69kV system, there is less dependency on the tie transformers and transmission lines that provide support to the 23kV system.

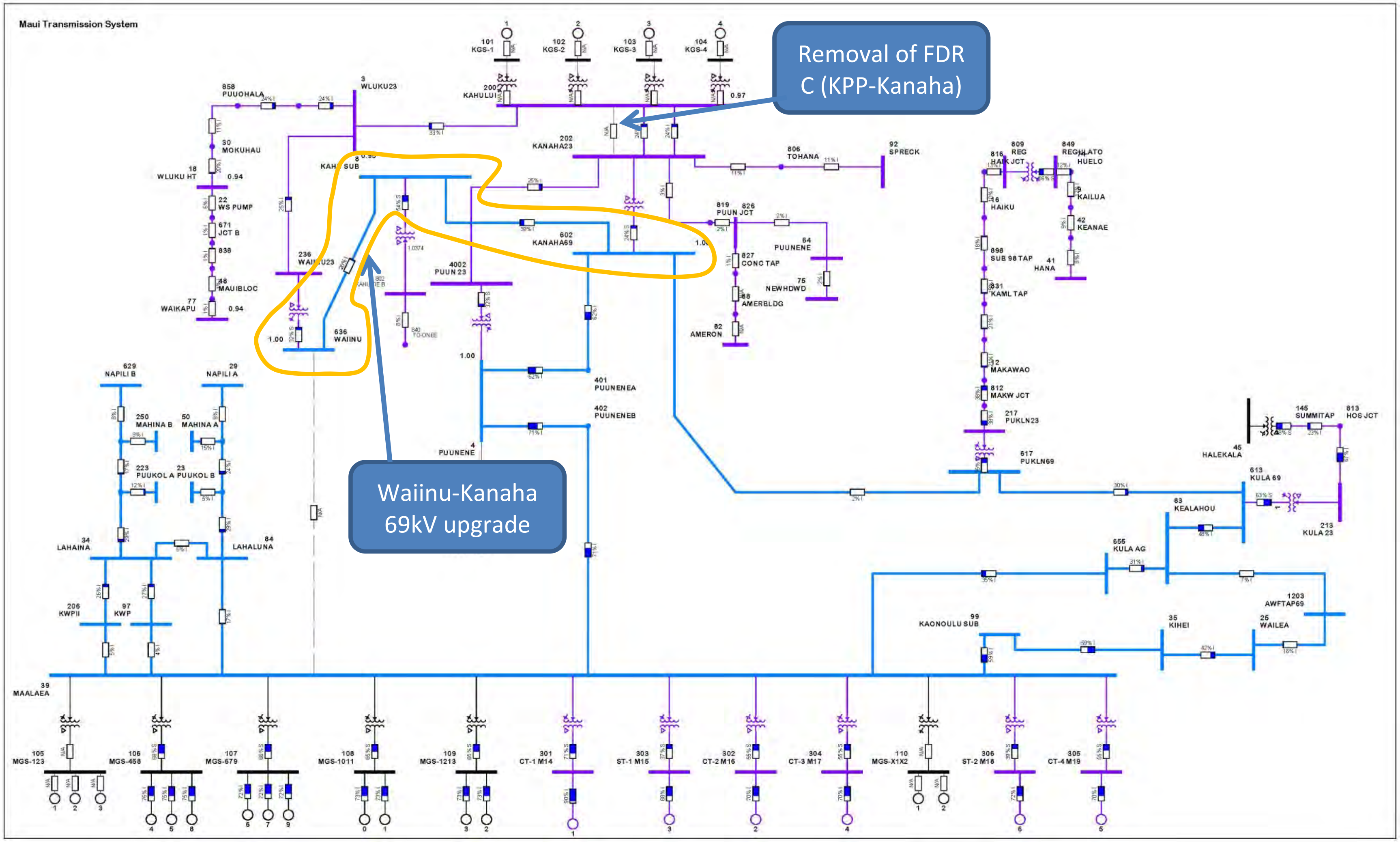

Figure 5: Maui system in 2019 with Transmission Upgrades under N-1 contingency, loss of MPP-Waiinu

25MW Battery Energy Storage System (BESS)

The first non-transmission alternative (NTA) considered was the addition of a 25MW BESS interconnected to the 23kV system; this 25MW:30min BESS was addressed in the 2013 Integrated Resource Plan. For modeling purposes, the 25MW BESS was added to the retiring KPP site. However, the BESS will effectively provide the same support if added anywhere on the 23kV system. The BESS has the ability to respond to system disturbances immediately but will be limited by the MWh parameters. Due to the voltage and thermal issues seen with an N-1 contingency, the BESS will need to be able to supply the 23kV system during this system condition, which could possibly be for multiple hours. Other control settings, operation and parameters of the BESS are beyond the scope of this study.

A BESS has the capabilities to instantaneously respond to system disturbances depending on the controls of the BESS. Due to the under voltages occurring when the system is subject to the N-1 contingencies, if the system peaks occur from the hours of 10:00 AM to 8:00 PM and the contingency occurs during this peak period the BESS would need to supply power during this time. Therefore, the 25MW BESS should have at least an 8 hour duration (200MWh), to allow line crews to repair the line. The BESS can also be paired with DG—discussed in the next section—to reduce the duration needed.

KPP Retirement Steady State Analysis

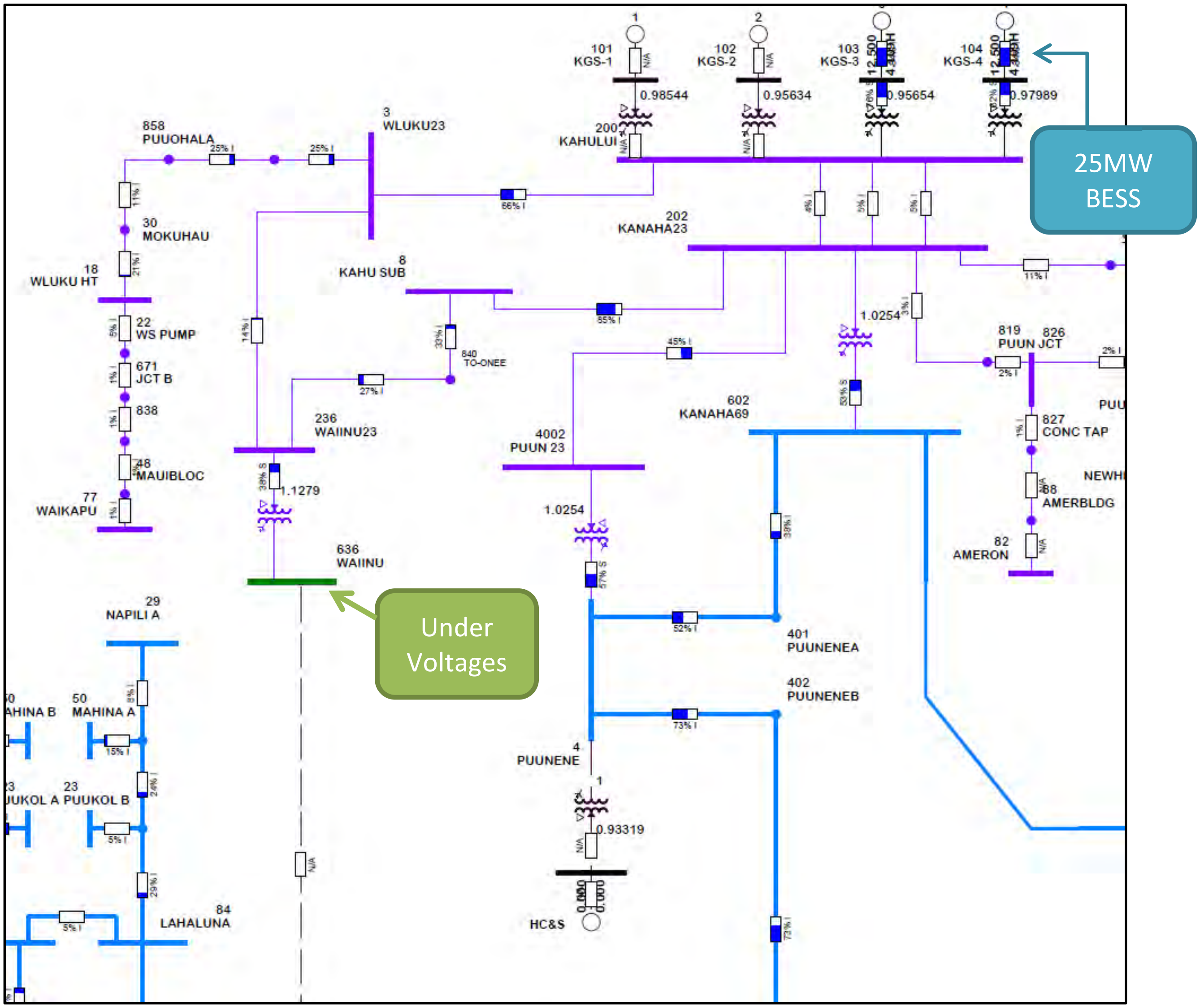

Figure 6: 25MW BESS modeled on the 23kV system improves voltages under N-1 contingency, loss of MPP-Waiinu

With the addition of a 25MW BESS on the 23kV system, when subjected to an N-1 contingency, low voltages occur at the 69kV Waiinu bus. There are no overloads on the 69/23kV tie transformers or the MPP-Puunene line. Furthermore, the low voltages at Waiinu 69kV are due to the control for the Waiinu 69/23kV tie transformer controlling the Waiinu 23kV bus voltage. With capability to control the Waiinu 69/23kV tie transformer tap settings, the Waiinu 69kV bus voltage could be kept within the planning criteria, above 0.90 pu.

40MW Distributed Generation (DG)

Another NTA considered is to have firm DG interconnected into the 23kV system. Having quick starting DG units would minimize the outage seen by the customer. Sizing, fuel, daily operation, and other unit characteristics is beyond the scope of this study, further analysis will need. Adding generation to the 23kV system will help alleviate the loading on the 69/23kV tie transformers, and the 23kV system dependency on the 69kV system would be eliminated. Furthermore, with the retirement of KPP, the system will be deficient of supply by 40MW, so the addition of 40MW of DG to the system would meet the adequacy of supply requirements.

For modeling purposes, five 8.5MW units were added to the KPP site to total approximately 40MW of DG. The specific characteristics of the units can differ from the 8.5MW units that are modeled as well as the interconnection site on the 23kV system. Further analysis will need to be conducted based on the potential locations and parameters of the units which the system will require for stability. The issue of land zoning and air quality permits will also need to be addressed.

Due to the start-up times required for the DG, customers will experience outages. Fast starting units can have start-up times around 5 minutes. Stability analysis will show if the system can maintain a stability until these DG units can provide power. As mentioned before, a combination of BESS and DG can be used to eliminate the outages customers will experience. The BESS will serve the customers until the DG can start-up and output power.

With the 40MW of DG, no thermal or voltage issues occur during normal conditions and with the loss of MPP-Puunene. However, the loss of MPP-Waiinu resulted in under voltage violations for Waiinu 69KV. Similar to the under voltage violation for the BESS NTA for Waiinu 69kV, if the Waiinu 69/23kV tie transformer controls were adjusted properly, the Waiinu 69kV bus voltage could be kept above 0.9pu. Figure 7 shows the 69kV system, under voltage violation for the 69kV Waiinu bus with the loss of MPP-Waiinu. Figure 8 shows the 23kV system with no thermal or under voltage violations under the MPP-Waiinu contingency.

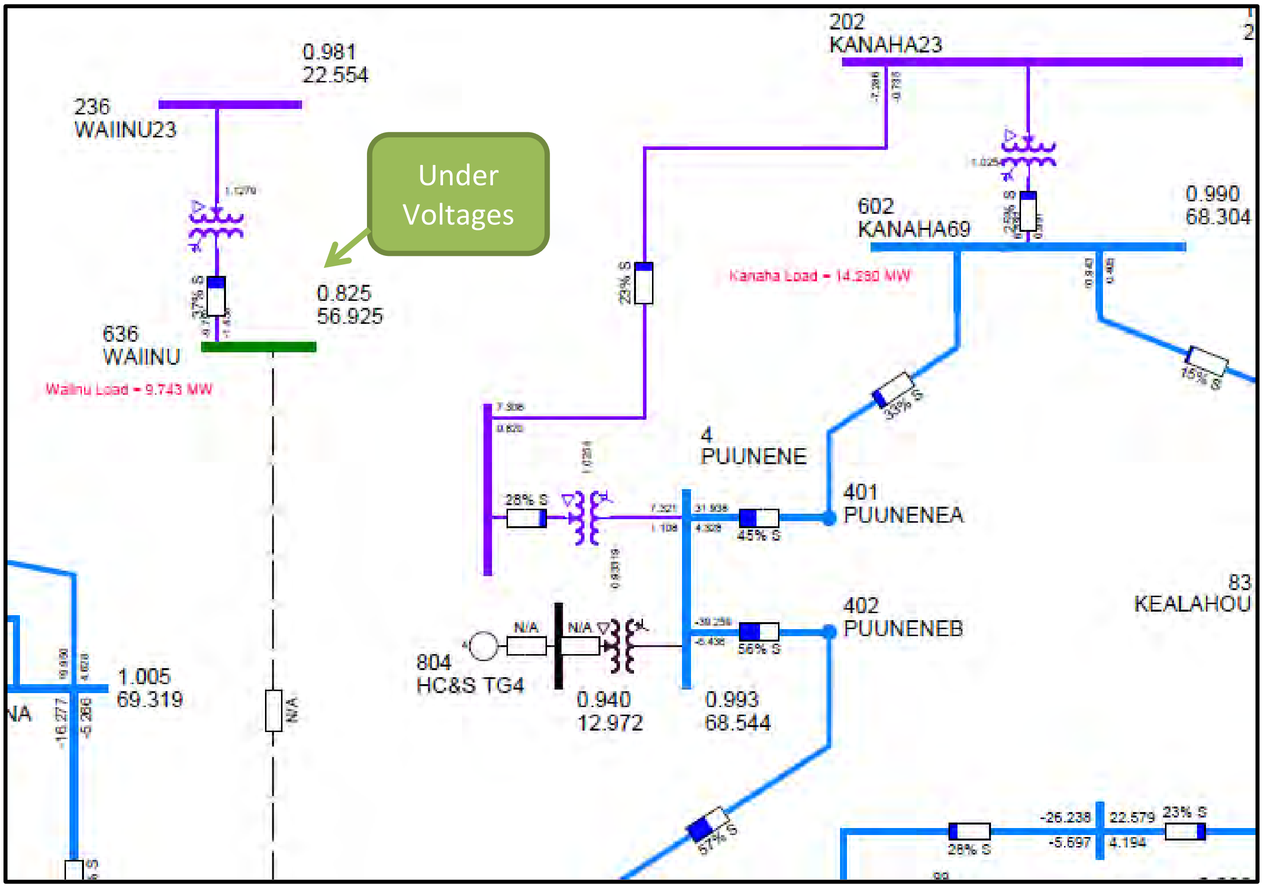

Figure 7: 69KV system with 40MW DG on 23kV system, under N-1 Contingency (loss of MPP-Waiinu) resulting in under voltage violation at Waiinu 69kV bus

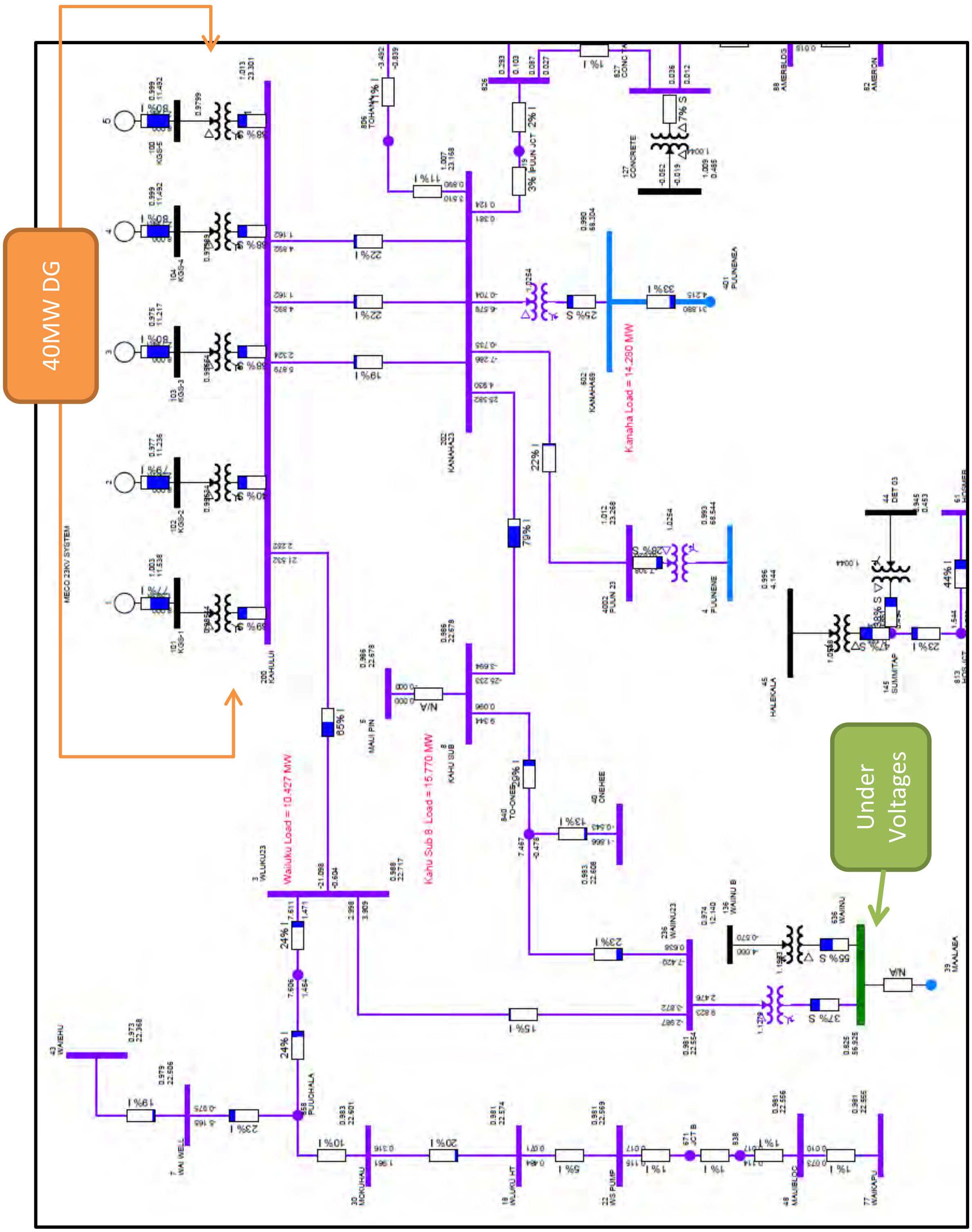

Figure 8: 23kV system with five 8.5MW units for 40MW DG interconnected on 23kV system providing support during N-1 contingency, loss of MPP-Waiinu

Synchronous Condensers

To provide voltage support, another NTA considered was converting the existing KPP units to synchronous condensers. A synchronous machine operating without a prime mover is a synchronous condenser. Controlling of the field excitation allows a synchronous condenser to either absorb or supply reactive power to the system.

Under normal conditions, because of the transferring of load from MPP to the 23kV system, the Waiinu 69/23kV tie transformer is heavily loaded at 93% of its normal rating. As the load increases on the 23kV system, the Waiinu 69/23kV tie transformer will be overloaded. For the MPP-Waiinu N-1 contingency, although the synchronous condensers help the 23kV system voltages remain within the planning criteria, the Puunene and Kanaha 69/23kv tie transformers are overloaded. In addition, the MPP-Puunene is above 100% of its emergency rating and the Waiinu 69kV bus violated the voltage criteria.

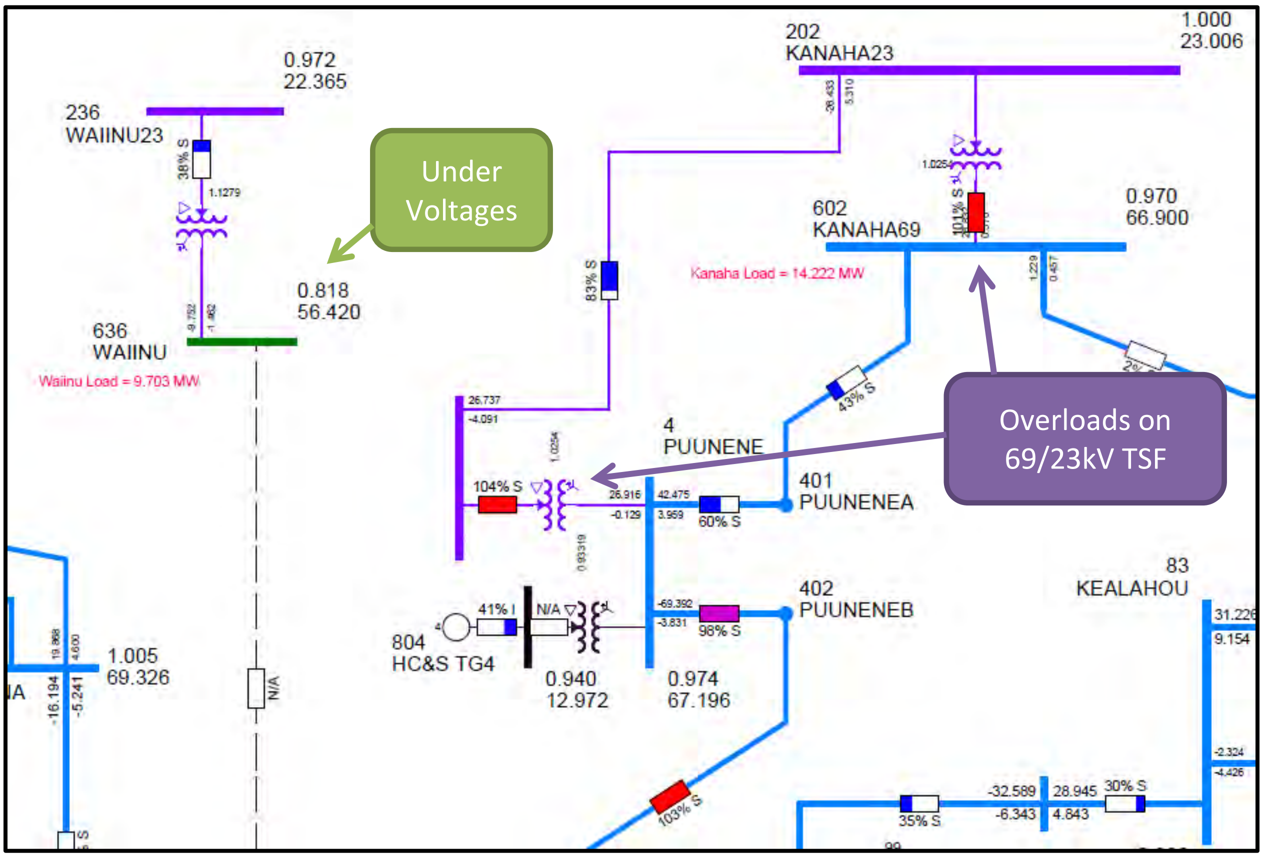

Figure 9: 2019 69kV system with KPP units converted to synchronous condensers subjected to MPP-Waiinu contingency

Due to the overloading issues with using KPP units as synchronous condensers, transmission upgrades will also be needed. The Waiinu 69kV under voltage violation occurs because the transformer taps are being controlled to regulate the 23kV Waiinu bus.

Summary of Results

To address the under voltage violations and overloads on the transmission system with the retirement of KPP, this steady state analysis considered the following system improvements:

- 23kV Waiinu-Kanaha upgrade to 69kV with the reconductoring of MPP-Waiinu and MPP-Puunene from 336AAC to 556AAC
- 25MW BESS
- 40MW DG
- Synchronous condensers from retiring KPP units

The retirement of KPP impacts the 23kV system greatly. With no upgrades to the transmission system and the retirement of KPP violations to the criteria for transmission planning are eminent.

The transmission upgrades resulted in the system having no thermal or voltage issues for normal or N-1 conditions. While the 25MW BESS and 40MW DG had some under voltage violations and high thermal loadings. The KPP units a synchronous condensers managed the under voltages but thermal overloads occur. Table 3 lists the issues of concerns for the various cases that were used in the study.

Table 3: Summary of Analysis

Case	Case Description	Condition	NOTES
0	2014 Current System	Normal	No thermal or voltage violations
		Contingency 1: MPP-Waiinu	No thermal or voltage violations
		Contingency 2: MPP-Puunene	No thermal or voltage violations
1	2019 No Upgrades	Normal	Waiinu 69/23kV loaded at 92% of normal rating
		Contingency 1: MPP-Waiinu	Overloads on MPP-Puunene, Puunene 69/23kV TSF, Kanaha 69/23kV TSF, and under voltages in central Maui 23KV system and Waiinu 69kV bus
		Contingency 2: MPP-Puunene	Overloading on the Waiinu 69/23 kV TSF and low voltages at Puunene, Kanaha and Pukalani 69 subs
2	2019 Transmission Upgrades	Normal	No thermal or voltage violations
		Contingency 1: MPP-Waiinu	No thermal or voltage violations
		Contingency 2: MPP-Puunene	No thermal or voltage violations
3	2019 25MW BESS	Normal	No thermal or voltage violations
		Contingency 1: MPP-Waiinu	Under voltage violation for Waiinu 69kVbus and high loading (97%) on Kanaha-Kahului Sub 8 23kV line (percentages based on emergency ratings)
		Contingency 2: MPP-Puunene	No thermal or voltage violations
4	2019 40MW DG	Normal	No thermal or voltage violations
		Contingency 1: MPP-Waiinu	Under voltage violation for Waiinu 69kV bus and Kanaha-Kahului Sub 8 23kV line loading at 79% (percentages based on emergency loadings)
		Contingency 2: MPP-Puunene	No thermal or voltage violations
5	2019 K1, K2, K3, K4 Synchronous Condenser	Normal	Waiinu 69/23kV TSF loading at 93% of normal rating and MPP-Puunene 69kV line at 79% of normal rating
		Contingency 1: MPP-Waiinu	Under voltage violation for Waiinu 69kV bus, overloading on MPP-Puunene 69kV line, and overloading on Puunene 69/23kV TSF and Kanaha 69/23kV TSF; Kanaha-Kahului Sub 8 line loading at 86% and Puunene-kanaha 23kV line loading at 83% (percentages based on emergency ratings)
		Contingency 2: MPP-Puunene	Overloading on the Waiinu 69/23 kV TSF

Along with the results from the steady state simulations that were modeled, other issues should be considered. Table 4 identifies various pros and cons associated with the various solutions. These pros and cons will need to be further assessed.

Table 4: Pros and Cons for solutions evaluated

Solution	Pros	Cons
Transmission Upgrade	• Does not require large area of land • No zoning, air quality permits required • Product life	• Transmission capital investment
25MW BESS	• Prolong need for transmission infrastructure • Instantaneous response (compared to DG) • No emissions (compared to DG)	• Need to acquire land • Product life • Limited run time • Cost
40MW DG	• Prolong need for transmission infrastructure • Contribute to Adequacy of Supply • Renewable generation with biodiesel	• Need to acquire land • Need to acquire air quality permits • Requires zoning for land (Heavy Industrial) • Noise • Disruption to customers (time required for units to start)
KPP Synchronous Condensers	• Use existing machines	• KPP in Tsunami flood zone • Still require transmission infrastructure upgrades

Conclusion

A steady state analysis was conducted to identify system impacts of the KPP retirement, and evaluated possible solutions. This analysis identified overloading and under voltage violations on the system. To provide safe and reliable power to customers, the system would need an upgrade, to not violate the MECO criteria for Transmission Planning. A transmission upgrade along with several non-transmission upgrades were evaluated for improving the system during normal and contingency scenarios.

Based on the steady state analysis, the transmission upgrades are recommended to maintain a safe reliable system with the retirement of KPP. The transmission upgrades for the 23kV Waiinu-Kanaha conversion to 69kV with MPP-Waiinu and MPP-Puunene reconductoring had a greater effect on improving the system compared to the other solutions. With the transmission upgrades, there were no thermal or voltage violations during normal or N-1 contingency conditions.

Appendix A
Load Forecasts

Based on the May 2014 Maui Adopted Sales and Peak Forecasts

Table A.1: Gross Minimum and Peak System Load Forecast with DSM/NEM/FIT/SIA

Year	Min* (MW)	Peak* (MW)
2014	84.4	197.9
2015	86.2	199.7
2016	88.1	202.1
2017	91.5	208.2
2018	94.9	214.4
2019	97.3	218.3
2020	98.9	220.0
2021	100.6	221.9
2022	101.9	222.6
2023	103.2	223.3
2024	104.3	223.0
2025	105.9	223.3
2026	107.1	222.1
2027	108.2	220.4
2028	108.9	217.1
2029	110.3	214.8
2030	111.3	210.8
*Gross NEM/FIT/SIA are assumed to be zero ; PV has no impact during early morning or evening hours		

Appendix B

Generation Overview

Table B.1: Current Maui Electric Generation Overview

Maui Electric Generation Overview					
Maalaea Power Plant					
Unit	Unit Type	PMAX (Gross MW)	PMIN (Gross MW)	Mode of Operation	Ramp Rates (Gross MW/min)
MX1	ICE	2.5	2.5	Peaking	0.0
MX2	ICE	2.5	2.5	Peaking	0.0
M1	ICE	2.5	2.5	Peaking	0.0
M2	ICE	2.5	2.5	Peaking	0.0
M3	ICE	2.5	2.5	Peaking	0.0
M4	ICE	5.6	2.0	Cycling	1.0
M5	ICE	5.6	2.0	Cycling/Peaking	1.0
M6	ICE	5.6	2.0	Cycling	1.0
M7	ICE	5.6	2.0	Cycling/Peaking	1.0
M8	ICE	5.6	2.0	Cycling	1.0
M9	ICE	5.6	2.0	Cycling	1.0
M10	ICE	12.5	6.0	Cycling	1.0
M11	ICE	12.5	6.0	Cycling	1.0
M12	ICE	12.5	6.0	Cycling	1.0
M13	ICE	12.5	6.0	Cycling	1.0
M14	CT	58	12.5	DTCC-Baseload	2.0
M15	ST		11.0	DTCC-Baseload	DTCC-1.0; STCC-0.5
M16	CT		12.5	DTCC-Baseload	2.0
M17	CT	58	14.0	STCC-Cycling	2.0
M18	ST		3.0	STCC-Baseload	DTCC-1.0; STCC-0.5
M19	CT		14.0	STCC-Baseload	2.0
	TOTAL:	212.1			
Kahului Power Plant					
K1	Boiler/Steam Turbine	5.0	2.50	Cycling	0.10
K2	Boiler/Steam Turbine	5.0	2.50	Cycling	0.10
K3	Boiler/Steam Turbine	11.5	3.50	Baseload	0.10
K4	Boiler/Steam Turbine	12.5	3.50	Baseload	0.10
	TOTAL:	34.0			

Hana Substation					
Unit	Unit Type	PMAX (Gross MW)	PMIN (Gross MW)	Mode of Operation	
H1	ICE	1.0	0.0	Emergency	
H2	ICE	1.0	0.0	Emergency	
Independent Power Producers					
Unit	Unit Type	PMAX (Gross MW)	PMIN (Gross MW)	Mode of Operation	
HC&S	Biomass	12	8.0	Baseload	
Kaheawa I	Wind Farm	30.0		As-Available	
Makila Hydro	Run-of-river	0.5		As-Available	
Auwahi	Wind Farm	21.0		As-Available	
Kaheawa II	Wind Farm	21.0		As-Available	
	TOTAL:	72.5			

Appendix C

Single Line Overview with Line Ratings

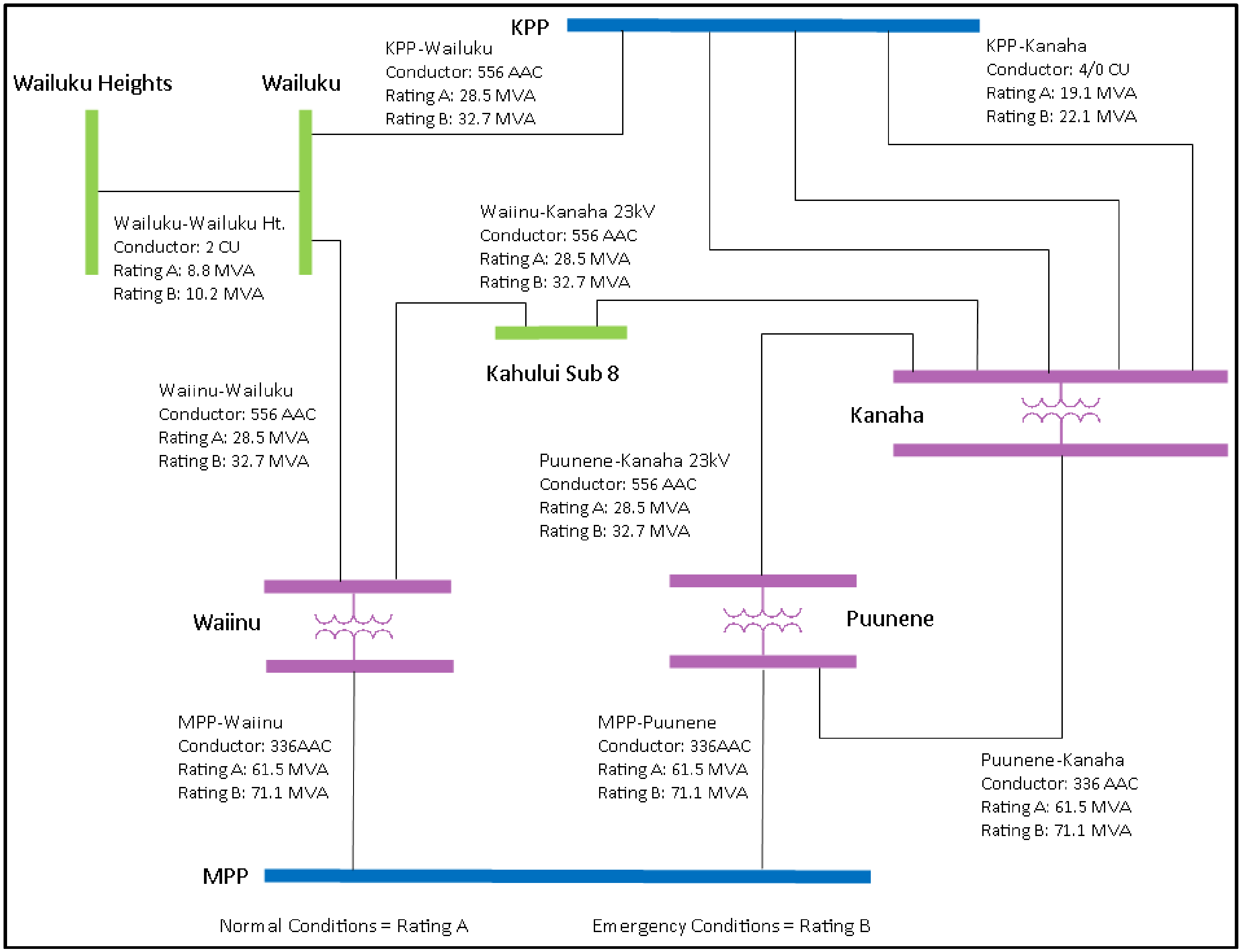

Figure C.1: Overview of Central Maui system showing line ratings

Appendix B – Voltage Stability Assessment

Kahului Power Plant Retirement: Voltage Stability Assessment

Prepared for

Maui Electric Company, Ltd.

Prepared By:

Hawaiian Electric Company, Inc.
System Planning Department
Transmission Planning Division

May 19, 2014

Reference: TPD 2014-21

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Kahului Power Plant Retirement: Voltage Stability Assessment

Prepared By: ______________________
Brian Lee
Planning Engineer, Transmission

Approved By: ______________________
Gemini Yau
Lead Planning Engineer, Transmission

Approved By: Ronald Bushner 8/20/2014
Ronald Bushner
Director, Transmission Planning

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Kahului Power Plant Retirement: Voltage Stability Assessment

Executive Summary:

Hawaiian Electric Company's Transmission Planning Division (TPD) has revisited the topic regarding Maui Electric Company's plan to fully decommission Kahului Power Plant (KPP) by the year 2019. TPD has re-examined the various recommended upgrades suggested in previous studies conducted by TPD with the latest updated system models and also considered several non-transmission alternatives. This study addresses the voltage violation and voltage stability issues involved with the retirement of KPP and outlines how each alternative will potentially impact the system. After revisiting the transmission alternatives in the previous study with the latest system models and load forecast, and considering several non-transmission alternatives (NTAs), TPD recommends that proceeding with the Waiinu-Kanaha upgrade project is the most favorable, economical, and engineeringly sound solution to address voltage issues involved with the retirement of KPP, however, thermal limit and system stability issues involved with the retirement of the power plant should be also considered.

Introduction/Background:

The Maui transmission system consists of a 23 kV network and 69 kV network. KPP has a total capacity of approximately 35 MW and connects into the 23 kV network, and the remainder of Maui's generation connects into the 69 kV network. The two networks are interconnected via 23/69 kV tie transformers located in Waiinu, Kanaha, and Puunene substations. KPP is the only source of generation connected to the 23 kV network. The retirement of the power plant will result in the 23 kV network becoming heavily dependent on power supplied by the 69 kV network via the three tie transformers and induce a diminished limit of power transfer to the 23 kV network, cause voltage sources to be electrically farther from the load center (i.e. the 23 kV network), and remove a reactive power source from the 23 kV network; this potential subjects the 23 kV network to voltage profiles that violate the reliability criteria or are prone to voltage instability in the event suffering a system disturbance. Voltage instability accompanied by a sequence of events (e.g. the loss of a transmission line) will lead to voltage collapse – low, unacceptable voltage profiles in significant parts of the power system – and a possible blackout system event.

TPD performed a study in the past concerning Maui Electric's plan to reduce operation at KPP and its eventual retirement, which analyzed several transmission solutions to address the afore mentioned issues. The study recommended upgrading the 23 kV Waiinu to Kanaha transmission line to 69 kV, relocating 23 kV load at Kahului to the 69 kV system, and reconductoring the 69 kV MPP-Puunene and 69 kV MPP-Waiinu transmission lines. TPD has re-examined all recommendations made in the previous study using the latest updated base case models and load forecasts to re-establish the validity of the recommendation. TPD has also examined several non-transmission alternatives, which align with the Public Utilities Commission's (PUC) vision for the company, to be considered as possible solutions to address the issues.

Kahului Power Plant Retirement: Voltage Stability Assessment

This study will identify the system impacts resulting from the retirement of KPP from a voltage stability standpoint, examine various plausible transmission and non-transmission solutions to rectify observed system issues, and recommend the most suitable solution from a transmission stand point.

Methodology:

TPD used a conventional power-flow program to derive the Power-Voltage (P-V) characteristics of the existing Maui transmission system to determine the system power transfer limits and proximity to a voltage instability event, and the key factors that contribute to its occurrence. The characteristics were compared and contrasted to the P-V characteristics of cases of the existing system with various transmission and non-transmission upgrades to determine the most engineeringly sound solution to avoid violations of the reliability criteria, or even worse, the compromise of system reliability.

Assumptions:

The following are the assumptions used in this study unless specified otherwise:

- Referencing of the “23 kV network” in this study does not include the 23 kV circuit from Kula to Haleakala due to its electrical distance from the rest of the 23 kV system.
- The Hana 23 kV circuit is fed from Pukalani.
- Kahului Power Plant is retired by 2019.
- Contract with HC&S will expire and HC&S will no longer contribute any generation after year 2014.
- The acceptable “power margin” is between 1.05 - 0.9 per unit (p.u.) voltage per the reliability criteria.
- An N-1 event in this study refers to the loss of a transmission line.
- Existing System refers to the present Maui transmission network and reference of the existing (peak) load is the forecasted peak load of year 2014 which is approximately 200 MW.
- Initial reference point (the y-intercept) in P-V plots is the existing system at peak load.

Results and Analysis

The P-V characteristics of the various scenarios are derived for the normal condition and N-1 contingency events identified to result in the most severe system issues. These contingencies are:

- Loss of the 69 kV transmission line between Maalaea Power Plant (MPP) and Waiinu substation, which will be referred to as the 69 kV MPP-Waiinu line. This is a critical line that connects MPP to the 23/69 kV tie transformer at Waiinu, supplying power to the heavily loaded Central Maui and Wailuku area. Losing this line will require power to travel a greater electrical distance via the 23/69 kV tie transformer at Kanaha and Puunene to serve the Wailuku load.

- Loss of the 69 kV transmission line between MPP and Puunene substation, which will be referred to as the 69 kV MPP-Puunene line. This line powers from MPP to the 23/69 kV tie transformers at Kanaha and Puunene. The loss of this line will require power to travel a greater electrical distance via the 23/69 kV tie transformer at Waiinu to serve the Central Maui load.
- Loss of the 23 kV line between Wailuku substation and Waiinu substation, which will be referred to as the 23 kV Wailuku-Waiinu line. This line serves as an important means of providing power from Waiinu to the Wailuku area. Losing this line will require power to travel a greater electrical distance via Kanaha substation.
- Loss of the 23 kV line between Kanaha substation and Kahului substation, which will be referred to as the 23 kV Kanaha-Kahului line unless specified otherwise.

Figure 1 and Figure 2 show the P-V characteristics of the existing system with and without operation of KPP, respectively, for the normal and most severe N-1 conditions. The initial reference point on the P-V curve is at the point where the curve intercepts the y-axis; it depicts the voltage profile of the 23 kV network on the existing system at peak load level. Moving to the right along the x-axis represents natural growth in load on the 23 kV network. Increases to the load on the 23 kV network result in a decline in voltage profile – continual increase of load on the 23 kV network will inevitably violate the reliability criteria. The end of the P-V curve indicates that the power-flow was unable to solve beyond that point which is indicative of voltage collapse. Thus, as the system approaches the vicinity of voltage collapse, it is subject to voltage instability; the system is typically planned to operate well away from these points. The P-V curve exhibits the limits of power transfer to the 23 kV network.

The limitations of power transfer are dependent on the inherent traits of the system and can be extended or reduced through changes to the system. This aspect can be seen in Figure 1, where an N-1 contingency event shifts the power transfer limit of the normal condition curve to the left – this represents a diminished power transfer limit. It can be seen that the loss of 69 kV MPP-Waiinu line is the most severe out of all the N-1 contingencies due the indication of a steeper decline in voltage profile (curve) and quicker occurrence to voltage collapse (as load increases). It can also be seen that voltage collapse can occur well within the acceptable power margin - a voltage profile that does not violate the reliability criteria isn't necessarily safe of voltage instability/voltage collapse. Thus, the alternatives are evaluated on their capabilities of avoiding violations to the reliability criteria and voltage instability/voltage collapse.

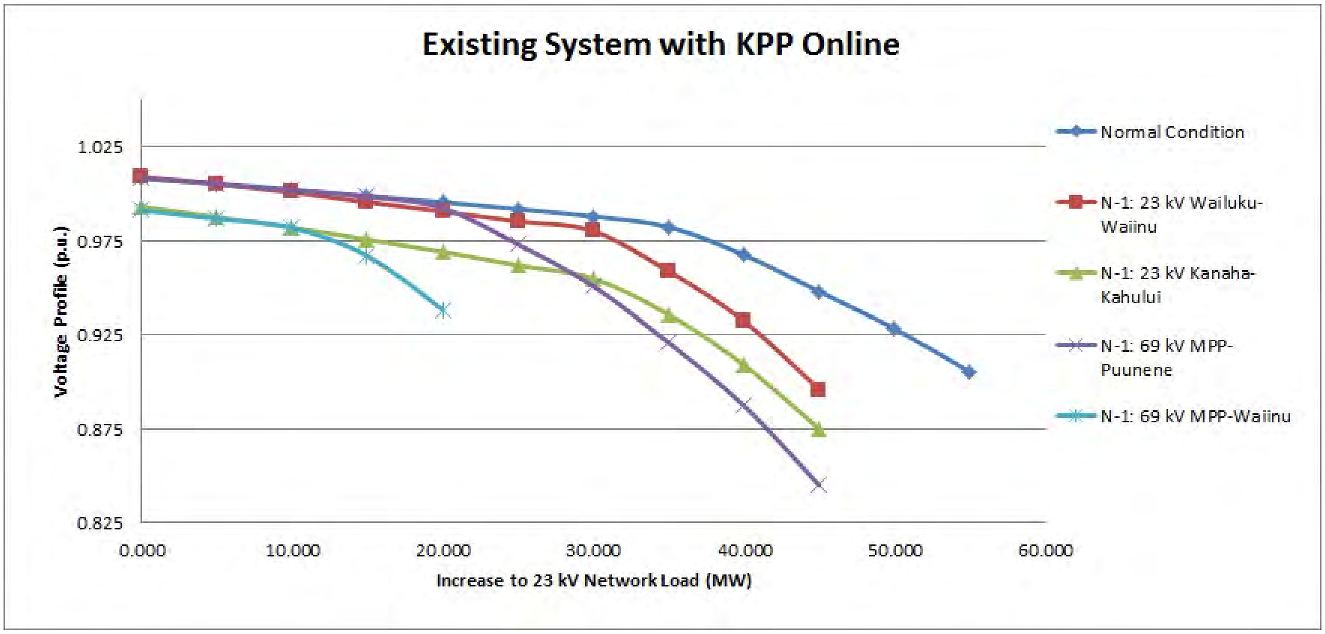

Figure 1: P-V characteristics of existing Maui system with operation of KPP.

As mentioned previously, the power transfer limits can be extended or reduced through changes to the system. A diminished power transfer limit can be expected as a result of the decommissioning of KPP. Without the operation of KPP, the 23 kV network will lose the only source of power generation connected to the 23 kV network and must rely on power supplied by the 69 kV network. This will place an additional burden on the 69 kV transmission lines and 23/69 kV transformers that connect the two networks because the 69 kV network must pick up the demand previously met by KPP.

The system will become vulnerable to voltage instability due to the voltage sources (voltage source for 23 kV network is KPP prior to its decommission; the voltage source will be the generation sources on 69 kV network after KPP retirement) being further away from the load center (i.e. the 23 kV network) and insufficient load reactive compensation on the 23 kV network. This can be seen in Figure 2. It can be observed that with the retirement of KPP, under the N-1 event of losing the 69 kV MPP-Waiinu transmission line, the voltage profile of the 23 kV network is below the sufficient “power margin” and is subjected to voltage collapse at the current 2014 peak load level.

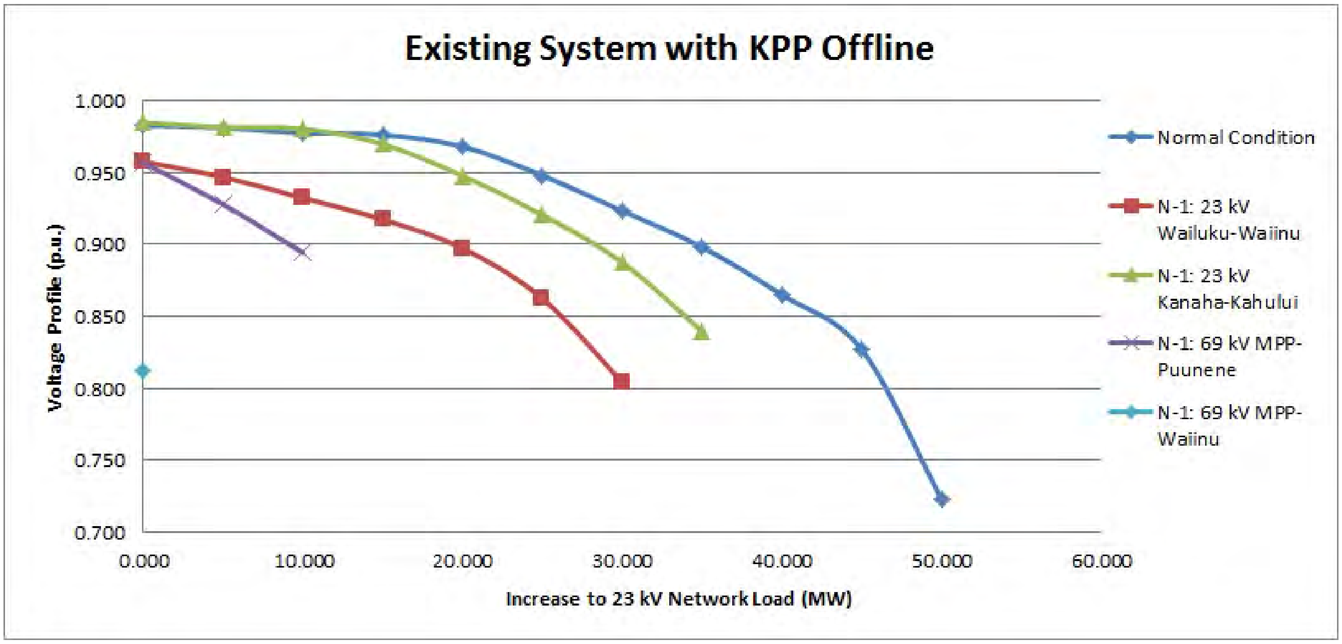

Figure 2: P-V characteristics of existing Maui system without operation of KPP.

Figure 3 compares the P-V characteristics for the normal condition and the most severe N-1 contingency event of the system with and without operation of KPP. It exhibits what changes to the power transfer limit of the 23 kV network is to be expected if KPP is decommissioned without any upgrades to the system.

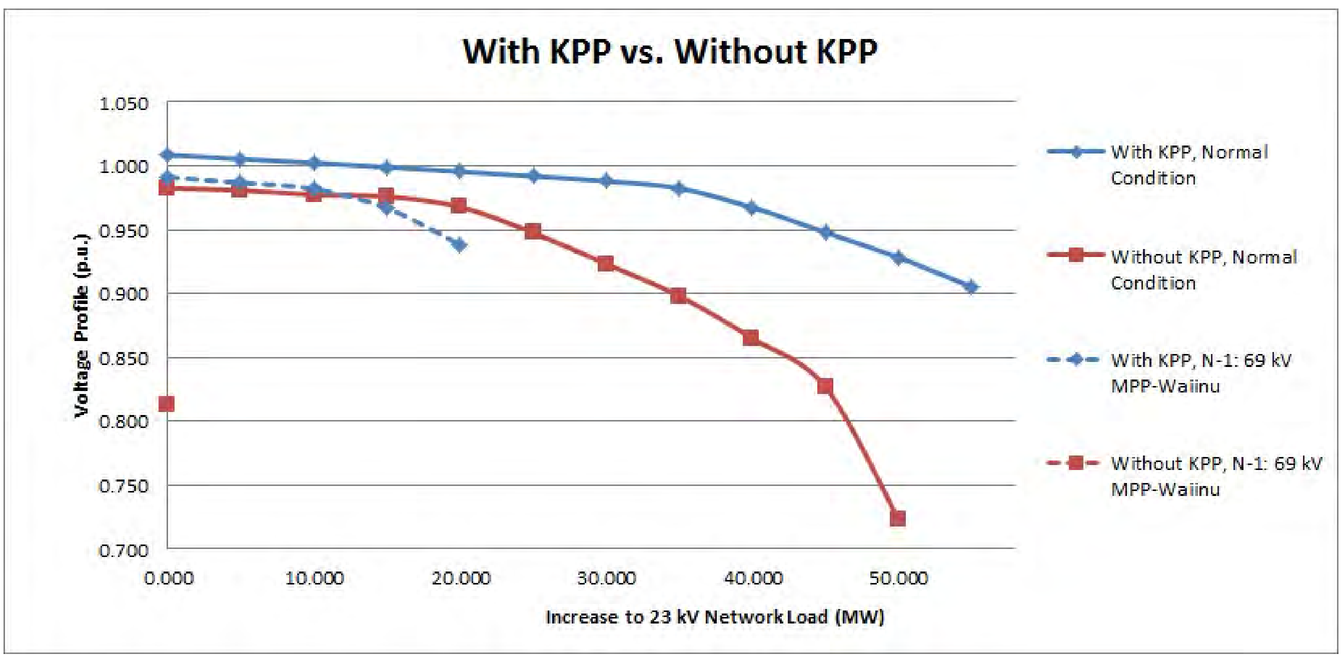

Figure 3: P-V characteristics comparison between system with and without the operation of KPP.

Transmission Solutions

In the past, TPD analyzed several transmission options that would rectify the system's vulnerability to possible voltage instability and voltage collapse events, and avoid any system reliability criteria violations. TPD has revisited the issue and options studied with the latest updated Maui system models and load forecasts. The options are:

- Alternative 1: Construct a new 69 kV transmission line from Waiinu substation to Kanaha substation.
- Alternative 2: Relocate the existing 23 kV transmission line between Waiinu substation and Kanaha substation and its connected elements to the 69 kV network.
- Alternative 3: Build new additional 69 kV MPP-Waiinu, 69 kV MPP-Puunene, and 69 kV Puunene-Kanaha lines of 556 AAC conductor size.
- Alternative 4: Create a link between Kealahou and Kanaha on the 69 kV network via the anticipated new Waena Power Plant (WPP).
- Alternative 5: Install an additional 23/69 kV tie transformer between WPP and Central Maui Landfill Substation (Sub 95), and reconductor the 23 kV section of transmission line from Kanaha to Sub 95.

Figures 4 and 5 below compare the P-V characteristic curves of the various alternatives for the normal condition and the worst N-1 contingency, respectively. It can be seen that Alternative 2 is the most favorable option under normal conditions and most N-1 contingencies. Figure 5 indicates that Alternative 3 is a significantly better option for surviving the most severe N-1 event, the loss of the 69 kV MPP-Waiinu line; this is due to the option involving the construction of three new transmission lines resulting in an extended transfer limit of power to the 23 kV network and improved system reliability in the event of the loss of a transmission line.

Alternative 3 is a considerably more expensive solution that is only favorable under the condition of losing the 69 kV MPP-Waiinu line; in all other cases, its performance is similar or second to the Alternative 2 option. Figure 5 also indicates that Alternatives 4 and 5 are viable solutions for surviving the event of losing the 69 kV MPP-Waiinu. Figures 6, 7, and 8 compare the P-V characteristics of the various alternatives for the loss of the 69 kV MPP-Puunene line, 69 kV Wailuku-Waiinu line, and 69 kV Kanaha-Kahalui line, respectively. From comparing the P-V characteristics of the five alternatives under various N-1 contingency events, TPD has determined:

- Alternatives 1, 2, and 3 are the only viable solutions,
- Alternatives 4 and 5 will result in voltage collapse in the event of losing the 69 kV MPP-Waiinu line
- Alternative 1 is the least favorable solution - has poorer power transfer limit than Alternative 2 and 3, and will violate voltage criteria when 23 kV network load increases by 5 MW .
- Alternative 2 is most favorable solution under normal condition and most N-1 events, and only consists of the upgrade of existing system elements.

- Alternative 3 is a viable solution and significantly more favorable in the event of losing 69 kV MPP-Waiinu line but involves the construction of 3 new transmission lines.

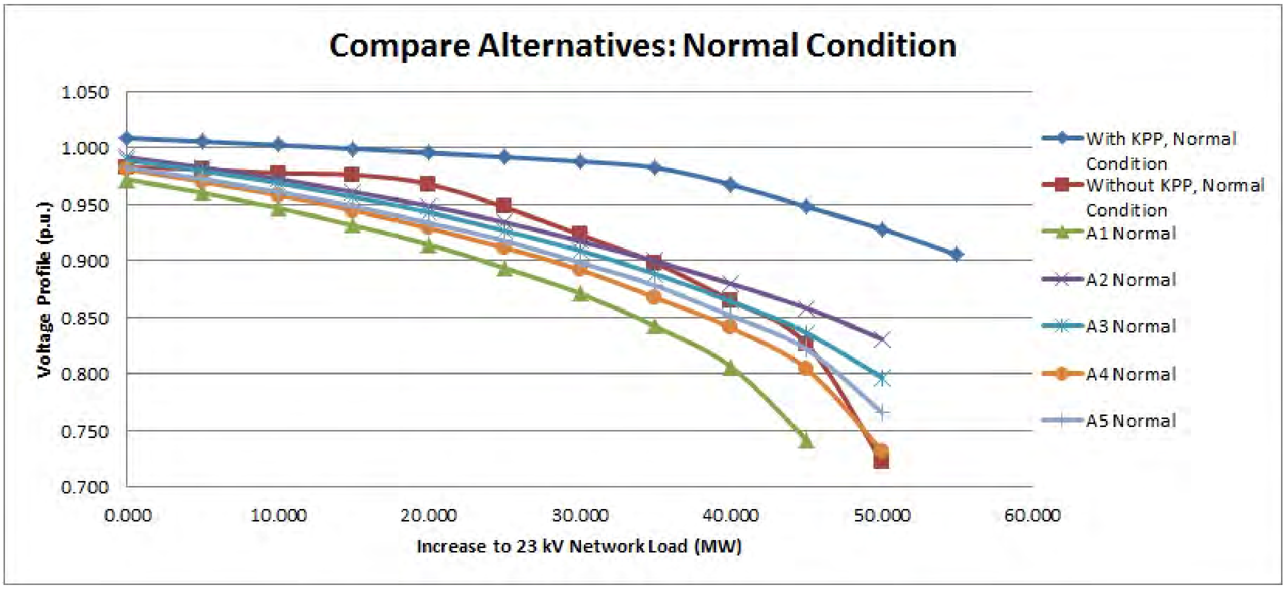

Figure 4: Comparison of P-V characteristics of transmission Alternatives for the normal condition. Alternative 1, Alternative 2, Alternative 3, Alternative 4, and Alternative 5 are represented by A1, A2, A3, A4, and A5 respectively.

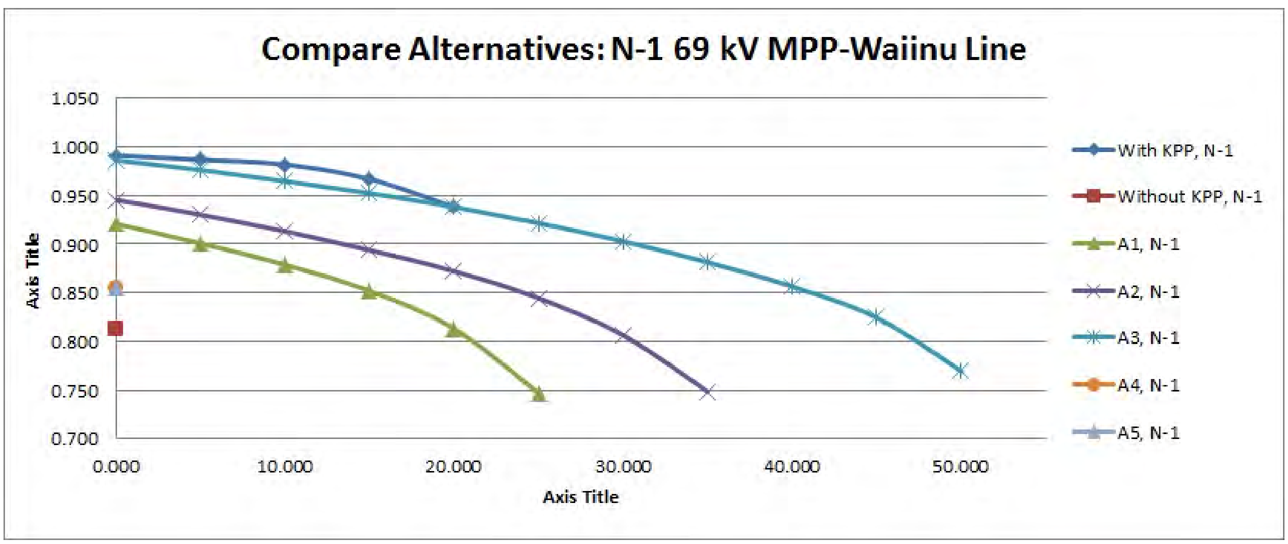

Figure 5: Comparison of P-V characteristics of transmission Alternatives for losing the 69 kV MPP-Waiinu Line. Alternative 1, Alternative 2, Alternative 3, Alternative 4, and Alternative 5 are represented by A1, A2, A3, A4, and A5 respectively.

Figures comparing P-V characteristics of the scenarios for the rest of the most severe contingencies can be seen in the Appendix.

TPD recommends Alternative 2 out of the five alternatives considered. Alternative 2 will adequately avoid voltage criteria violations and voltage instability until the 23 kV network has a load growth of 10 MW. Load growth beyond 10 MW will bring about a voltage profile below the acceptable power margin and possibly subject the 23 kV network to an unstable voltage profile. The 23 kV network will reach a growth of 10 MW when the total system peak load grows to approximately 270 MW, which is beyond the forecasted load.

Alternatives 1, 2, and 3 are viable solutions capable of preventing a voltage instability event from occurring on the current system but may not be adequate to endure thermal limit overloading conditions. Several combinations of the five mentioned alternatives with additional system upgrades were considered to address the thermal limit issues; the advantages of combining the alternatives with an additional system upgrade from a voltage stability standpoint will be discussed. The combinations are:

- Combination 1: Alternative 1 combined with the reconductoring of the 69 kV MPP-Waiinu line and 69 kV MPP-Puunene lines to 556 AAC conductor size transmission lines.
- Combination 2: Alternative 1 combined with the construction of a new secondary 69 kV MPP-Puunene transmission line.
- Combination 3: Alternative 1 combined with Alternative 4.
- Combination 4: Alternative 2 combined with the reconductoring of the 69 kV MPP-Waiinu line and 69 kV MPP-Puunene transmission lines to 556 AAC conductor size transmission lines - Combination 4 is the recommended Waiinu-Kanaha Transmission Line Upgrade project.
- Combination 5: Alternative 2 combined with the construction of a new secondary 69 kV MPP-Puunene transmission line.
- Combination 6: Alternative 2 combined with Alternative 4.
- Combination 7: Alternative 3 combined with Alternative 5.

Waiinu-Kanaha Transmission Line Upgrade project:

Figures 6 and 7 below show a P-V characteristic comparison of the Maui system with KPP, without KPP, with the Alternative 2 option, and with various combinations of one of the afore mentioned alternative options with an additional system upgrade for the normal condition and most severe N-1 condition, respectively.

From a voltage stability standpoint, all combinations mentioned are viable long term solutions capable of maintaining a voltage profile well within the acceptable margin and mitigate unstable voltage profile issues, but it can be seen that only options Combo 5, Combo 6, and Combo 7 produce significantly better P-V characteristics than the suggested Combo 4, which is the recommended alternative in the previous study. However, Combos 5, 6, and 7 involve the construction of one or more new transmission lines. Combo 4 only involves the upgrade of existing transmission lines already on the system (where majority of the line is already capable of being transitioned to 69 kV).

After revisiting the study with the latest system models and load forecast information, Combo 4 (the Waiinu-Kanaha upgrade project) is still the recommended solution to address the voltage instability issues involved with the retirement of KPP alternative out of all the transmission alternatives.

Figure 8 below shows a P-V characteristic comparison of the Maui system operating with and without KPP, and the system operating without KPP under the scenario that Combo 4 is implemented for the normal condition and most severe N-1 contingency.

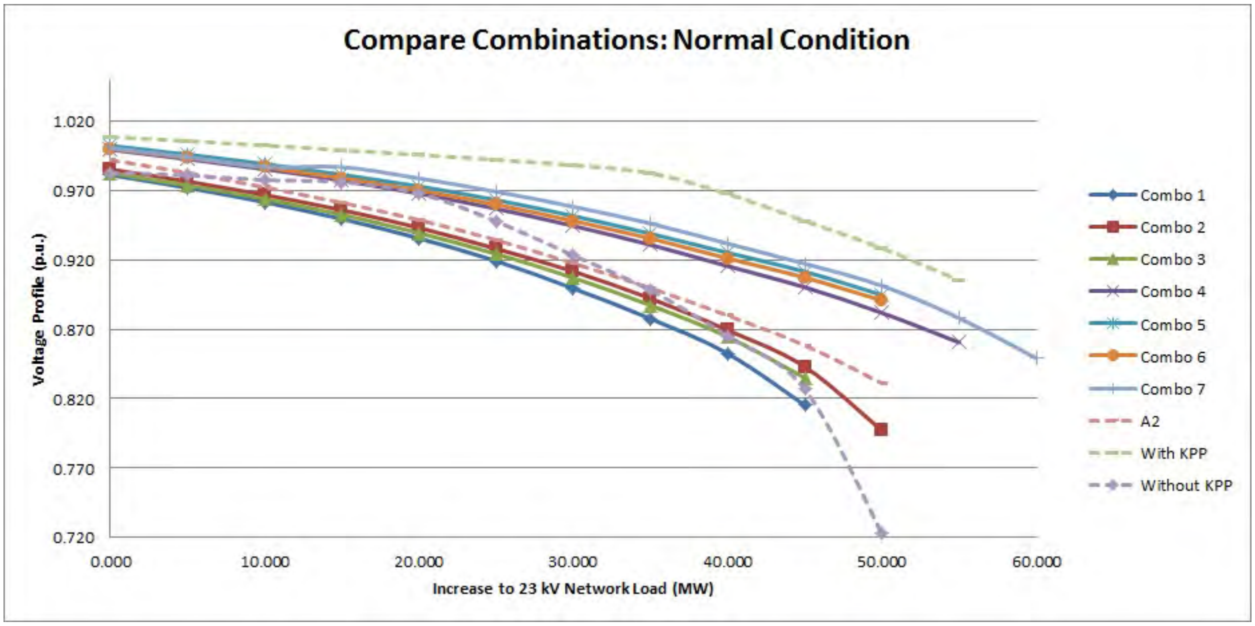

Figure 6: Comparison of P-V characteristics of tranmission Combinations for the normal condition. Combination 1, Combination 2, Combination 3, Combination 4, Combination 5, Combination 6, Combination 7, and Alternative 2 are represented by Combo 1, Combo 2, Combo 3, Combo 4, Combo 5, Combo 6, Combo 7, and A2 respectively.

Kahului Power Plant Retirement: Voltage Stability Assessment

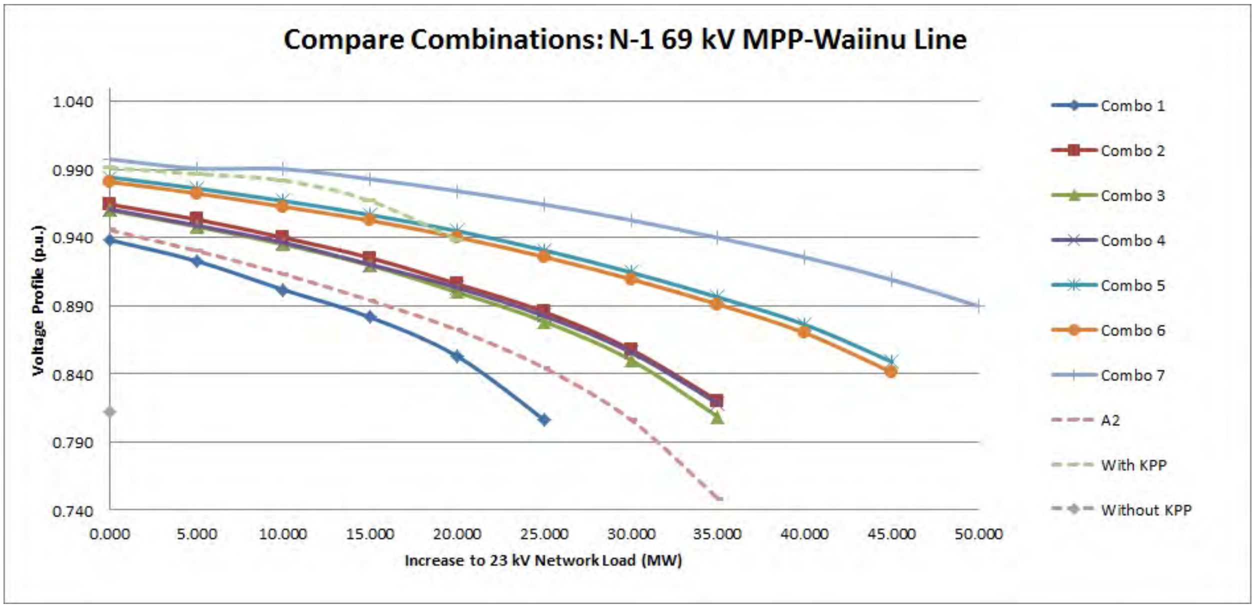

Figure 7: Comparison of P-V characteristics of tranmission Combinations for losing the 69 kV MPP-Waiinu Line. Combination 1, Combination 2, Combination 3, Combination 4, Combination 5, Combination 6, Combination 7, and Alternative 2 are represented by Combo 1, Combo 2, Combo 3, Combo 4, Combo 5, Combo 6, Combo 7, and A2 respectively.

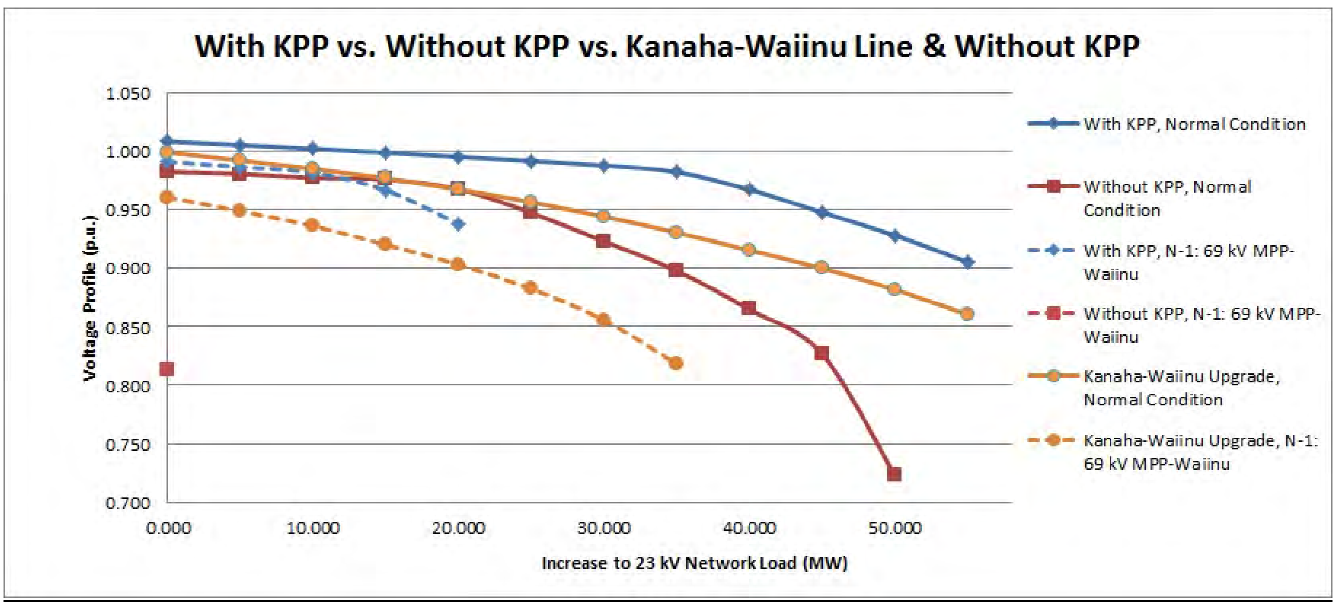

Figure 8: P-V characteristic comparison of the Maui system operating with and without KPP and the system operating without KPP under the scenario that Combo 4 is implemented for the normal condition and most severe N-1 contingency.

Non-Transmission Alternative (NTA) Solutions

There is an anticipated reserve capacity short fall of approximately 40 MW by year 2019, identified in Section 1.6 of the Maui Electric Adequacy of Supply (AOS) report. TPD has considered the possibility that efforts to procure resources to meet the reserve capacity short fall may void the need for the 23 kV Waiinu-Kanaha line upgrade project and the additional reconductoring of the 69 kV MPP-Puunene and 69 kV MPP-Waiinu transmission lines, and has considered the following Non-Transmission Alternatives (NTA):

- Conversion of some or all existing units at KPP to synchronous condensers.
- New Dispatchable Firm Generation.
- Battery Energy Storage System (BESS).
- Demand Response (DR).

Synchronous Condenser Option:

A favorable aspect of the synchronous condenser option is that it would take a considerably shorter amount of time to execute than the other NTA alternatives. However, synchronous condensers are reactive support elements that will only supply reactive power to the system. As mentioned before, removing KPP would mean active power demands on the 23 kV network must be supplied solely by the 69 kV network; this will subject the transformers and transmission lines connecting the 23 kV and 69 kV network to heavier loadings that may possibly violate their thermal limit ratings.

From a voltage stability standpoint, the synchronous condenser option is a viable solution for avoiding violations to the voltage criteria and avoiding voltage instability and voltage collapse events; however, it will not mitigate issues regarding thermal overloads on transmission lines and/or tie transformers because synchronous condensers do not provide active power, thus, will not alleviate the extra burden that can be expected to be placed on transformers and transmission lines connecting the 23 kV and 69 kV network when KPP is retired.

KPP is comprised of two large units, K4 and K3, and two smaller units, K1 and K2. K4, K3, K2, and K1 have reactive capabilities of 9.3 MVar, 7.0 MVar, 3.7 MVar, 3.7 Mvar, respectively. Several scenarios were considered: only the largest unit converted to synchronous condenser, the two largest units converted to synchronous condenser, two largest units and one smaller unit converted to synchronous condenser, and all units converted to synchronous condenser. Figures 9 and 10 show the P-V characteristics of the different scenarios of KPP units converted to synchronous condensers for the normal condition and most severe N-1 contingency event.

Kahului Power Plant Retirement: Voltage Stability Assessment

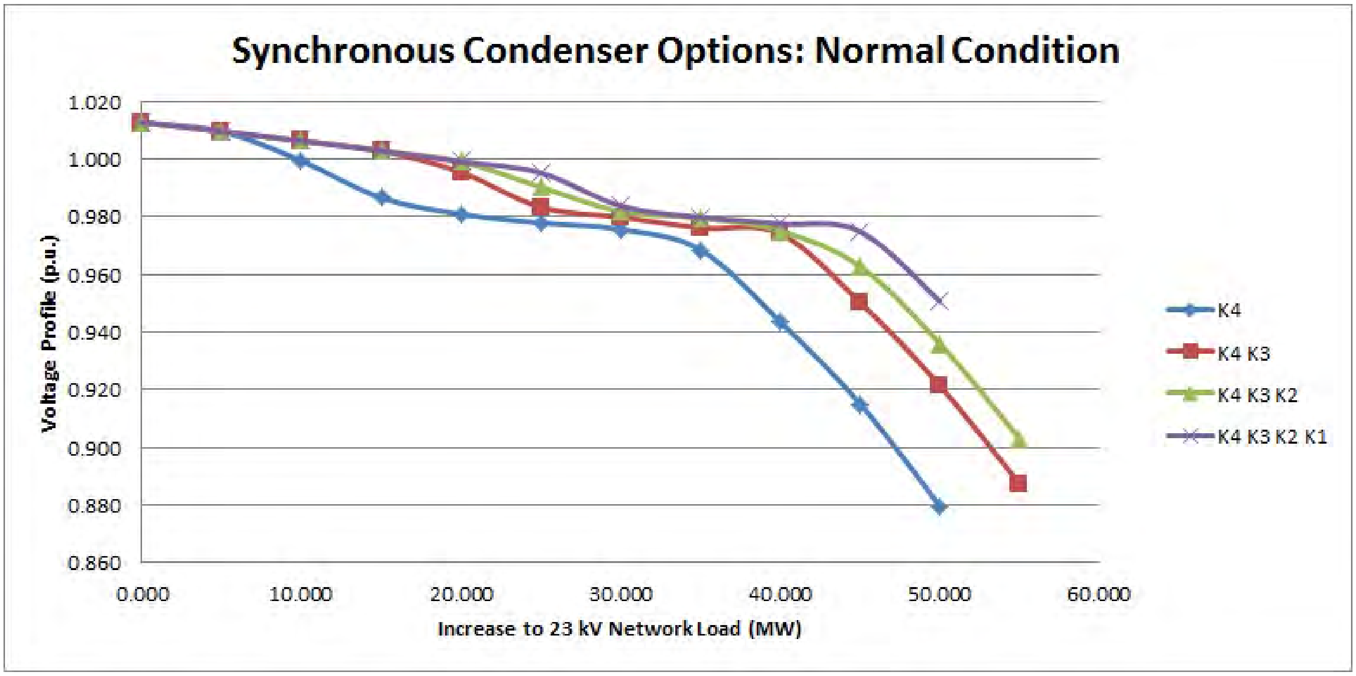

Figure 9: P-V characteristic comparison of different scenarios of KPP units converted to synchronous condensers for the normal condition.

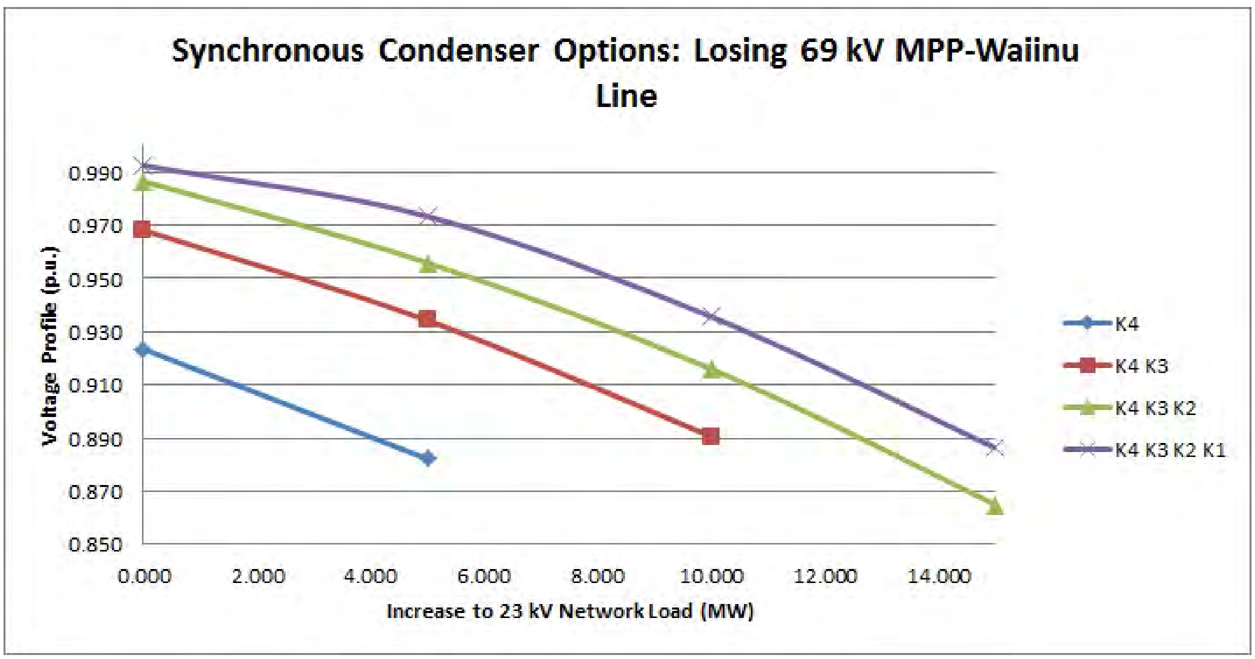

Figure 10: P-V characteristic comparison of different scenarios of KPP units converted to synchronous condensers for the most severe N-1 contingency event.

New Dispatchable Firm Generation:

If the company intends to procure new generation to meet the reserve capacity shortfall, the new generation units may potentially void the need for the Waiinu-Kanaha upgrade project depending on the location of interconnection of the new units. If the new generation is interconnected on the 23 kV network, from a voltage profile standpoint, the system can be expected to behave similar to the existing system with KPP in operation as this would only involve replacing the existing older generation units with new ones – this will not place a burden on the transmission lines and tie transformers that connect the 23 kV and 69 kV network and voltage sources are still close to the 23 kV network load center. However, if the new generation is interconnected to the 69 kV network, the system is expected to experience the same system issues source of generation on the 23 kV being removed; placing new generation units on the 69 kV network will not alleviate burden placed on the transmission lines and tie transformers that connect the 23 kV and 69 kV network, and will not provide reactive support to the 23 kV network – this will still result in the 23 kV network becoming heavily dependent on the 69 kV network for power and may possibly overload the transmission lines and tie transformers that connect the 23 kV and 69 kV network past their rated thermal limits and subject voltage sources to be electrically farther from the 23 kV network load center. A few scenarios or new firm generation on the 23 kV network were considered and compared to the existing operating KPP which has an approximate 35 MW capacity; they are: one new 8 MW unit, one new 15 MW unit, and two new 8 MW units. The P-V characteristic comparison of these scenarios for the normal condition and most severe N-1 contingency are shown in Figure 11 and Figure 12, respectively. For the scenario or new generation connecting to the 69 kV network, the capacity of new generation is arbitrary from a voltage standpoint as the option would not mitigate the issues mentioned. For the study, the scenario considered for study is the first stage of the Waena Power Plant (WPP) project proposed by First Wind – a new 17 MW unit at the WPP site near Pukalani; The P-V characteristics of this scenario is compared with the existing system with and without the operation of KPP, shown in Figure 13.

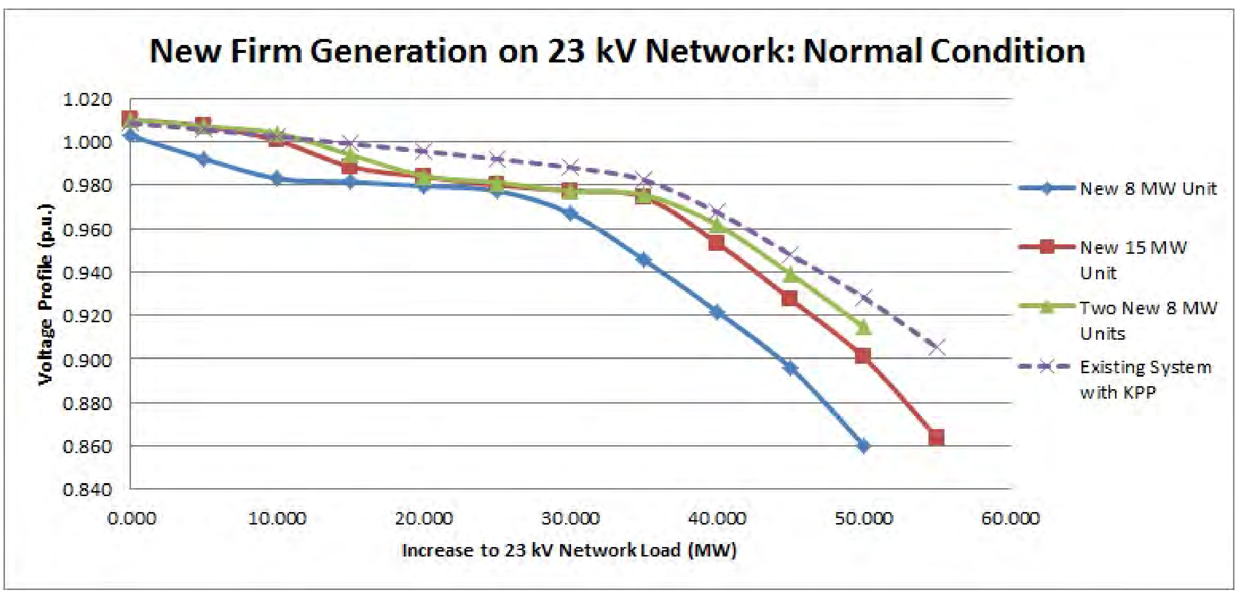

Figure 11: P-V characteristic comparison of different scenarios of new generation of various capacities on the 23 kV network and the existing system for the normal condition.

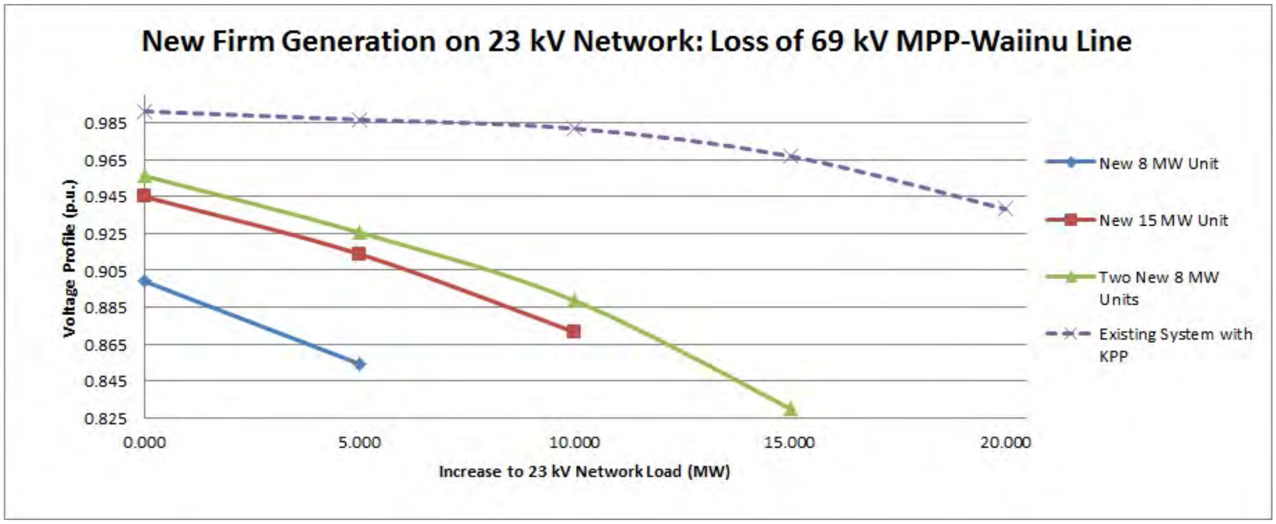

Figure 12: P-V characteristic comparison of different scenarios of new generation of various capacities on the 23 kV network and the existing system for the most severe N-1 contingency event.

It can be observed that the more capacity of new generation added to the 23 kV network, the closer the P-V curve representing new generation approaches the P-V curve that represents the existing system with KPP, which has an approximate 35 MW capacity. This indicates that in order to achieve system characteristics better than the existing system with KPP, the capacity of new generation must be greater than the existing capacity at KPP (i.e. 35 MW). It can be seen that at the existing system load, the new 8 MW unit and new 15 MW unit scenarios settle at point close to the end of a curve – these are unstable voltage points. The two new 8 MW unit scenario is much more favorable as it settles at a point father away from voltage collapse. Installing more capacity of new generation on the 23 kV network will allow the system to operate farther away from the point of voltage collapse.

Voltage issues arise when total system load reaches 170 MW and is accompanied by a severe N-1 contingency if KPP is decommissioned and no additional system upgrades are implented. The new generation units must be brought online when total system load reaches 170 MW to avoid violations to the reliability criteria and possible compromise of system reliability. Historically, system load has been observed to remain at 170 MW or above for approximately 7 hours, see Appendix.

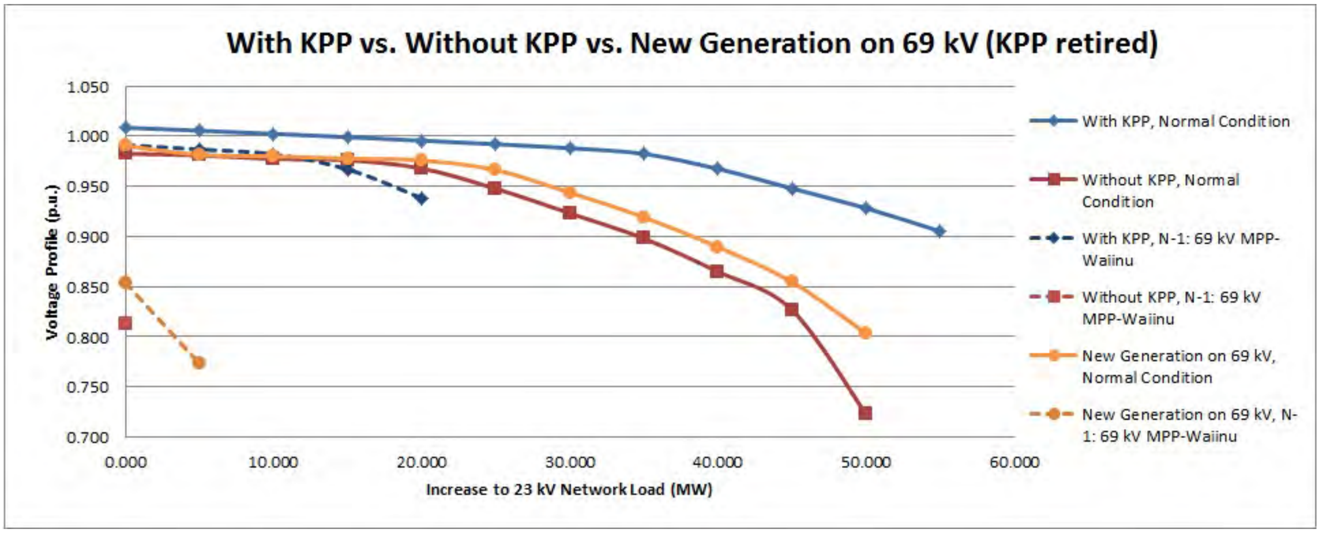

Figure 13: P-V characteristic comparison of the scenario of new generation on the 69 kV network, the existing system with KPP, and the existing system without KPP for the normal condition and most severe N-1 contingency event.

Battery Energy Storage System (BESS) Option:

It is assumed in this study that BESS will be operated to predominantly provide active power because pursuing a battery for the purpose of providing reactive support would be uneconomical as there are less expensive alternatives available that fulfill these needs such as capacitor banks or the already mentioned synchronous condenser option; in this study, the BESS units are modeled to operate at a 0.95 power factor to reflect a unit which predominantly provides active power and minimum reactive power. The BESS option, if located on the 23 kV network, is anticipated to mitigate the thermal limit violation issues involved with the retirement of KPP because it will supply active power to the 23 kV network which will alleviate the stress placed on the transmission lines and tie transformers that connect the 23 kV and 69 kV network when KPP is decommissioned and is also anticipated to mitigate the voltage violation, voltage instability, and voltage collapse issues. However, there are several ambiguities concerning the battery that need to be clarified before it can be determined if the BESS option is a viable, economic, or engineering sound solution to address the issues involved. These ambiguities include: where will the battery be located (on the 23 kV or 69 kV network), will the battery operate as a normal dispatchable unit or solely for the purpose of mitigating system issues during emergency events, what is the size of the battery For planning purposes, these ambiguities need to be addressed.

Similar to the afore mentioned issue in the discussion concerning the new dispatchable firm generation option, if the battery is placed on the 69 kV, the battery will contribute no significant mitigation measures as the voltage sources are still electrically far from the 23 kV network load center and the burden placed on the transmission lines and tie transformers that connect the 23 kV and 69 kV network is not lessened. However, placing the battery on the 23 kV network will alleviate much of the burden placed on the transmission lines and tie transformers that connect the 23 kV and 69 kV network because the battery (i.e. an active and reactive power source) is placed near the load and thus assuages the dependency on power to be supplied by the 69 kV network and aids in mitigating voltages violation, voltage instability, and voltage collapse issues on account that the battery, a voltage source, is closer to the 23 kV network load center. If the battery is operated as a normal dispatchable unit, where the battery will be dispatched to serve peaking system load demands when needed, it raises the issue whether or not there will be sufficient charge in the battery to mitigate system issues in the event of an emergency. However, if the battery is operated to solely be dispatched during emergency events, it raises the question whether or not the battery option is an economical solution. The battery would need to be sized to provide power long enough for the N-1 contingency to be resolved or until total system load recedes below afore mentioned threshold of 170 MW. It has been mentioned that the battery could be used to mitigate system issues just long enough for addition distributed generation sources (fuel units) to be brought online; this option would only be viable if the distributed generation sources, which need to be procured, are on the 23 kV network and would be uneconomical to pursue as the distributed generation source alone would be adequate to mitigate the issues, as seen in the new dispatchable firm generation option.

Several scenarios of different size batteries were considered: a 15 MW BESS, a 20 MW BESS, and a 25 MW BESS. Figures 14 and 15 compare the P-V characteristics of the various sized BESS for the normal condition and most severe N-1 contingency event, respectively. It can be seen in Figure 15 that for all scenarios, the BESS option is viable long term solution capable of mitigating voltage issues; this option is adequate until the 23 kV network load increases by approximately 10 MW, in other words, until the total system load reaches approximately 247 to 250 MW, which is beyond the scope of load forecast.

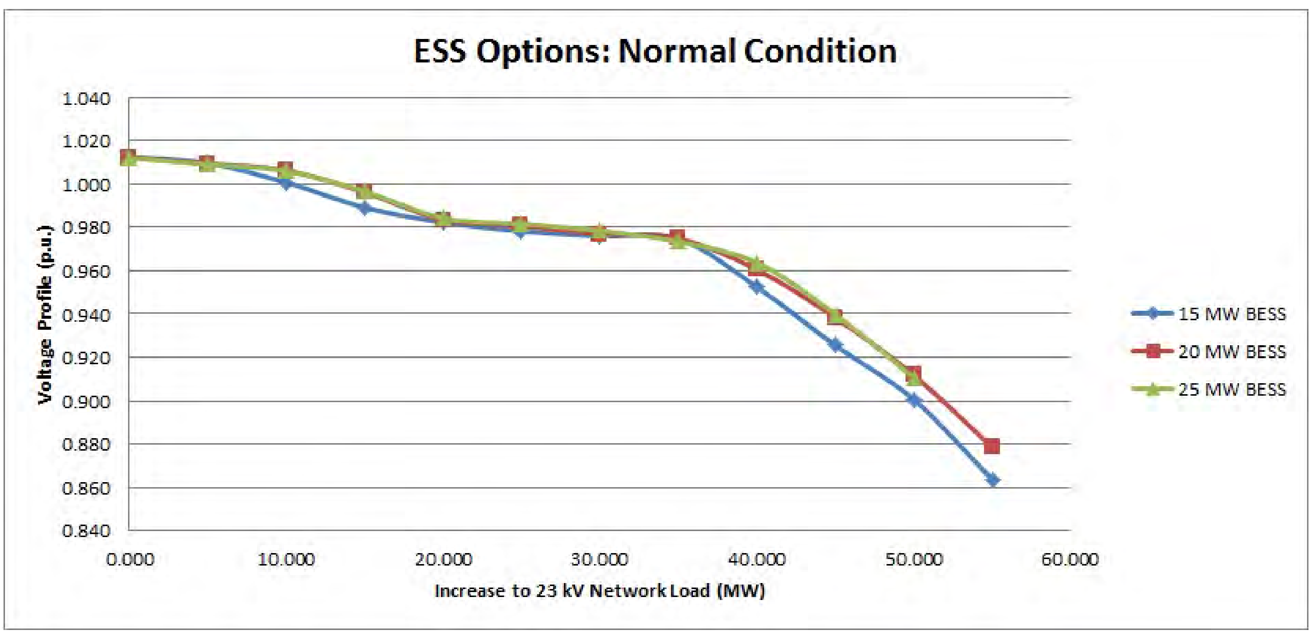

Figure 14: Comparison of P-V characteristics of various sized BESS for the normal condition.

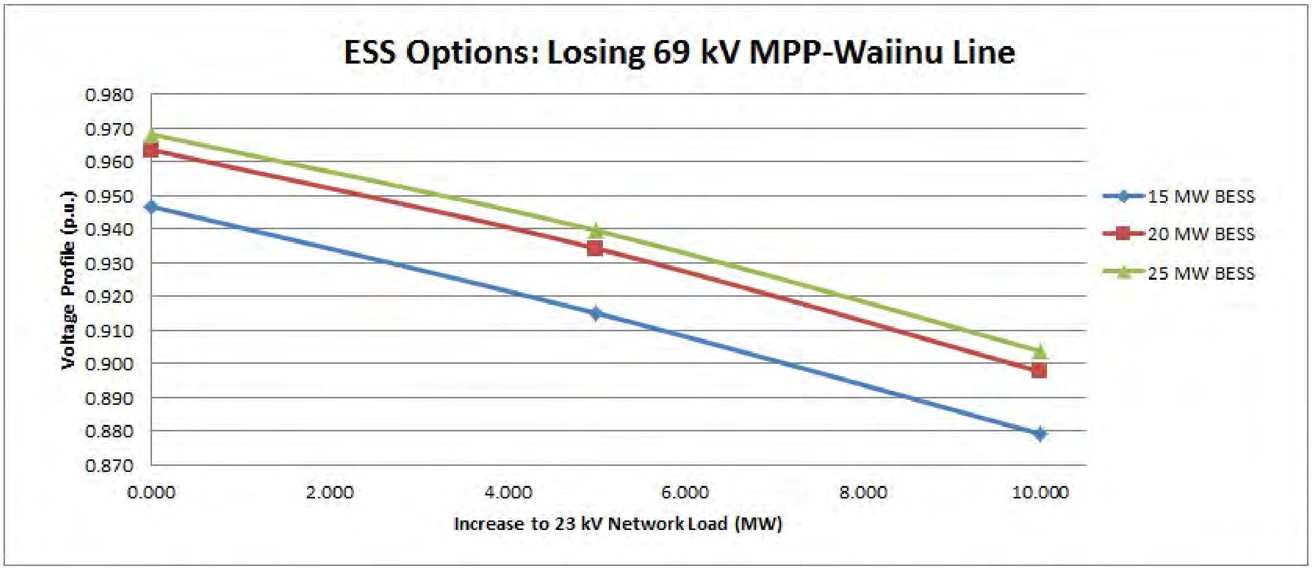

Figure 15: Comparison of P-V characteristics of various sized BESS for the most severe N-1 contingency event.

Demand Response:

The concept of the Demand Response (DR) option to be utilized for the effort of mitigating issues involved with the retirement of KPP is end-use customer consumption of power will be reduced in response to a contingency event to avoid the risk of jeopardizing system reliability. This should operate similarly to existing load shedding schemes – DR program must execute within several cycles of detecting indications that system reliability is at risk of being compromised. As mentioned, voltage issues arise when total system load reaches 170 MW and is accompanied by a severe N-1 contingency if KPP is decommissioned and no additional system upgrades are implanted. The DR program must drop end-use customer load to maintain total system load within the 170 MW benchmark to avoid voltage violation, voltage instability, and voltage collapse issues in the event of a contingency.

Comparing the NTA options:

For the purpose of comparing the NTA options, if numerous scenarios were considered for a NTA option, the scenario that produced the most favorable results was selected to be compared against the other options. The scenario of converting all existing units at KPP to synchronous condensers was selected for the synchronous condenser option, the scenario of two new 8 MW units was selected for the option of installing new firm generation units on the 23 kV network option, and the 25 MW BESS scenario was selected for the BESS option to represent its respective NTA option for comparison. Figure 16 and Figure 17 shown below compare the P-V characteristics of the various NTA options against the Kanaha-Waiinu upgrade and existing system with and without the operation of KPP for the normal condition and most severe N-1 contingency, respectively.

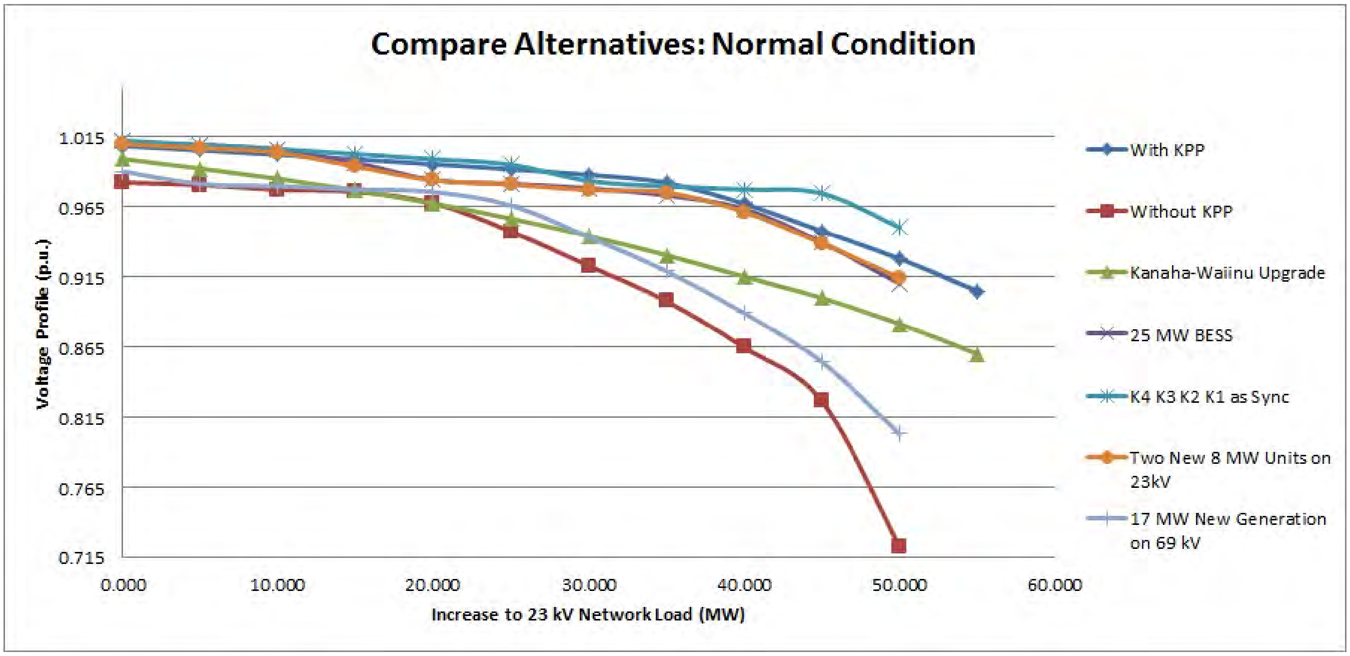

Figure 16: Comparison of P-V characteristics of various NTA options against the Kanaha-Waiinu upgrade and existing system with and without operation of KPP for the normal condition.

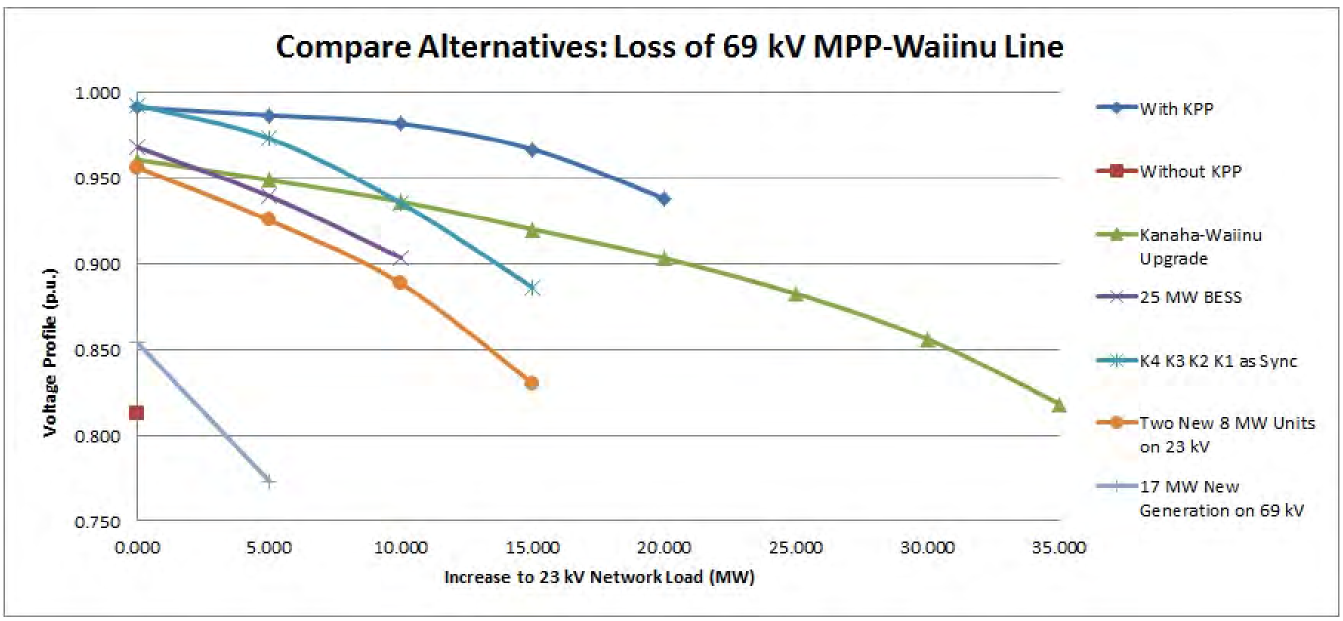

Figure 17: Comparison of P-V characteristics of various NTA options against the Kanaha-Waiinu upgrade and existing system with and without operation of KPP for the most severe N-1 contingency.

Several points should be considered when interpreting Figure 17. The synchronous condenser option seemingly has more favorable results than the BESS and new firm generation on the 23 kV network option, however, results shown are strictly examining the voltage profile; there thermal limit issues involved with the KPP retirement that the synchronous condenser option will not mitigate. The capacity values of new firm generation and BESS considered were arbitrarily selected; it should be noted that choosing to install greater capacity values of BESS and new generation (to be installed on the 23 kV network) units will produce P-V characteristics closer to the curve representing existing system with operation of KPP.

Compare and Contrast Options:

Table 1: Comparison of Transmission and Non-Transmission options studied.

Options	Adequate Until…		
	Growth on 23 kV Network load (in MW) reaches:	In other words, when system peak load (in MW) reaches:	Load forecast indicates this will occur in:
Waiinu-Kanaha Upgrade project	20	Over 270	N/A*
15 MW BESS on 23 kV	5	225	N/A*
20 MW BESS on 23 kV	5 – 8	225 – 240	N/A*
25 MW BESS on 23 kV	10	247	N/A*
K4 as Sync	2 – 3	200 – 203	2016 – 2017
K4 & K3 as Sync	5 – 8	225 – 240	N/A*
K4, K3, & K2 as Sync	10	247	N/A*
K4, K3, K2, & K1 as Sync	10 – 12	247 – 260	N/A*
New 8 MW unit on 23 kV	0	200	2014 – 2015
New 15 MW unit on 23 kV	5	225	N/A*
Two new 8 MW unit on 23 kV	5 – 8	225 – 240	N/A*
New 17 MW unit on 69 kV	0	200	2014 – 2015

N/A* - indicates that the option will be adequate until the system peak load reaches load value that is beyond what is reported in load forecast; the load forecast has forecasted system peak load values until year 2030, thus, these options are adequate even beyond the year 2030 (from a voltage standpoint).

Conclusion

From a voltage standpoint, the Waiinu-Kanaha upgrade project, BESS option, synchronous condenser option, and installing new firm dispatchable generation on the 23 kV network option are viable long term solutions to mitigate voltage issues involved with the retirement of KPP. However, considering the possibility of thermal overloads occurring on the transmission lines and tie transformers that connect the 23 kV and 69 kV network when KPP is decommissioned, TPD does not recommend the synchronous condenser option as an alternative to the Waiinu-Kanaha upgrade project. If new firm dispatchable generation is procured to meet the reserve capacity shortfall, installing the new units on the 23 kV network will mitigate voltage issues and is anticipated to mitigate thermal issues involved with the retirement of KPP, however, installing the generation units on the 23 kV network conflicts with MECO's ultimate plan of converting the entire Maui transmission system to 69 kV. On the other hand, the Waiinu-Kanaha upgrade project mitigates voltage and thermal issues, aligns with MECO's ultimate plan, and also increases the reliability of the system in the aspect that the project will provide a second line to feed Waiinu – in the event of the current most severe N-1, losing the MPP-Waiinu line, the upgraded Waiinu-Kanaha line will provide power to the Waiinu substation to feed the 23 kV network load. The BESS option produces similar results to the option which involves installing new firm generation on the 23 kV network if the BESS is placed on the 23 kV network, however, TPD considers it to be uneconomical to pursue the BESS option considering the possible dispatch scenarios of the BESS unit and its similar characteristics to the new firm generation option. TPD recommends that the company's interest in the procurement of new firm generation, BESS, DR, or any other means to meet the approximate 40 MW reserve capacity short fall by 2019 should not affect or void the plan of the Waiinu-Kanaha upgrade project. TPD still recommends the implementation of the Waiinu-Kanaha upgrade project as it will ensure that the retirement of KPP will not jeopardize system reliability and transition portions of the existing 23 kV network to 69 kV, thus progressing MECO's ultimate plan of converting the entire Maui transmission network to 69 kV and improve the overall system reliability.

Appendix

The comparison of P-V characteristics for the N-1 events of losing the 23 kV Kanaha-Kahului line, 69 kV Maalaea-Puunene line, and 23 kV Wailuku-Waiinu lines are shown below.

Existing system with and without operation of KPP:

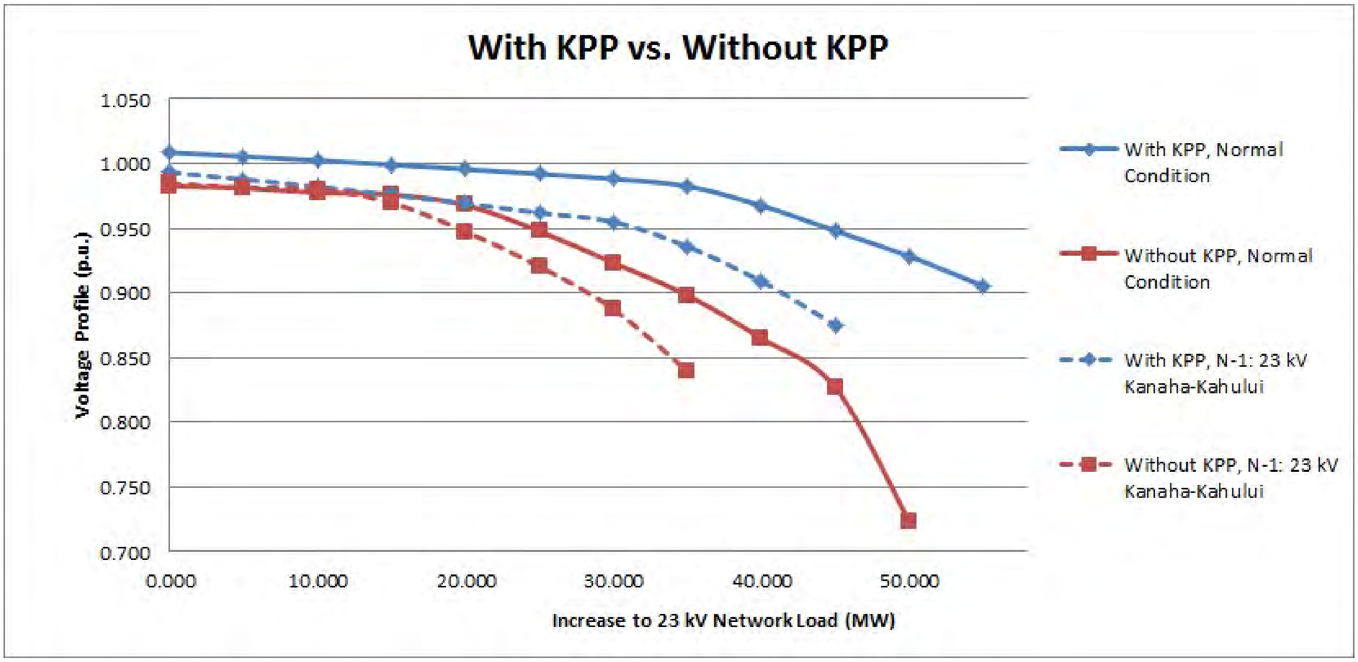

Figure 18: P-V characteristics of existing systen with and without KPP for losing 23 kV Kanaha-Kahului Line.

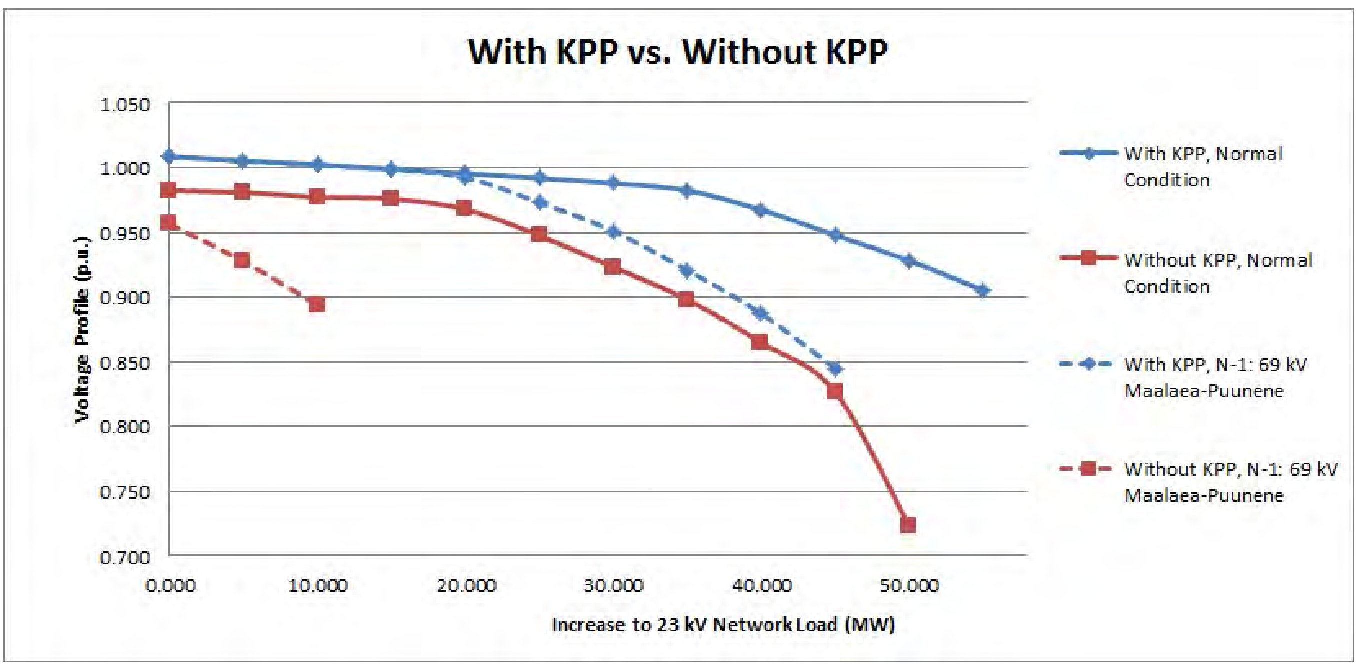

Figure 19: P-V characteristics of existing systen with and without KPP for losing the 69 kV MPP-Puunene Line.

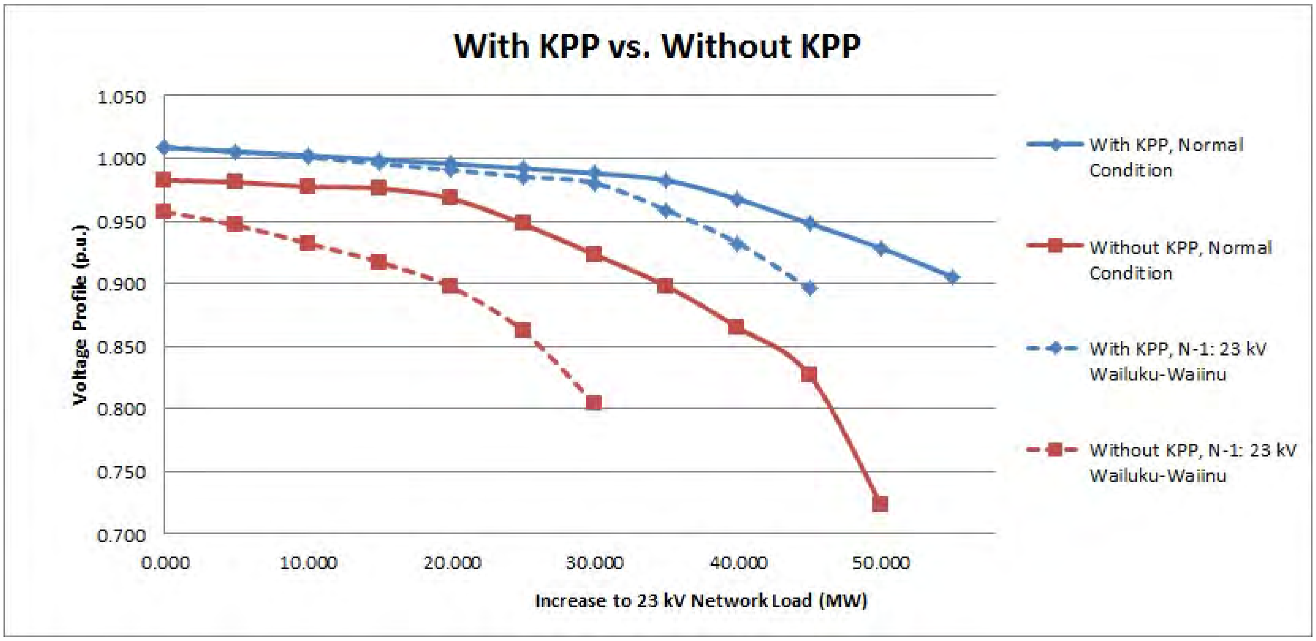

Figure 20: P-V characteristics of existing systen with and without KPP for losing 23 kV Wailuku-Waiinu Line.

<u>P-V characteristic comparison of Alternative 1 - Alternative 5:</u>

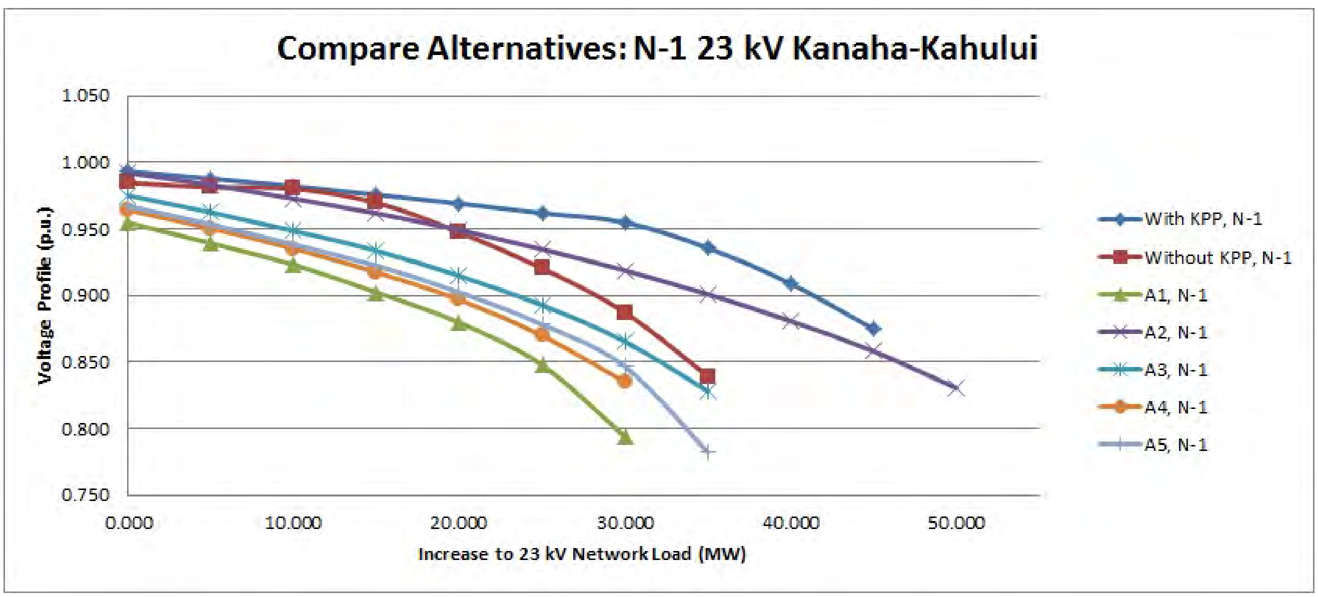

Figure 21: Comparison of P-V characteristics of transmission Alternatives for losing the 23 kV Kanaha-Kahului Line.

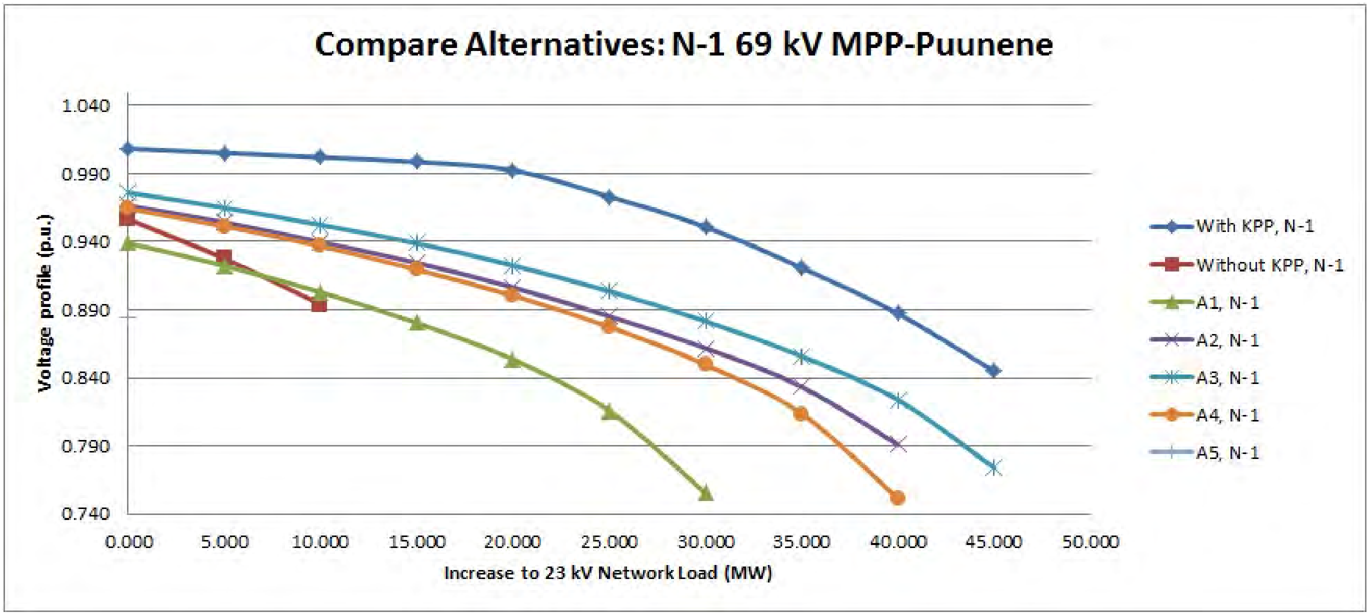

Figure 22: Comparison of P-V characteristics of transmission Alternatives for losing the 69 kV MPP-Puunene Line.

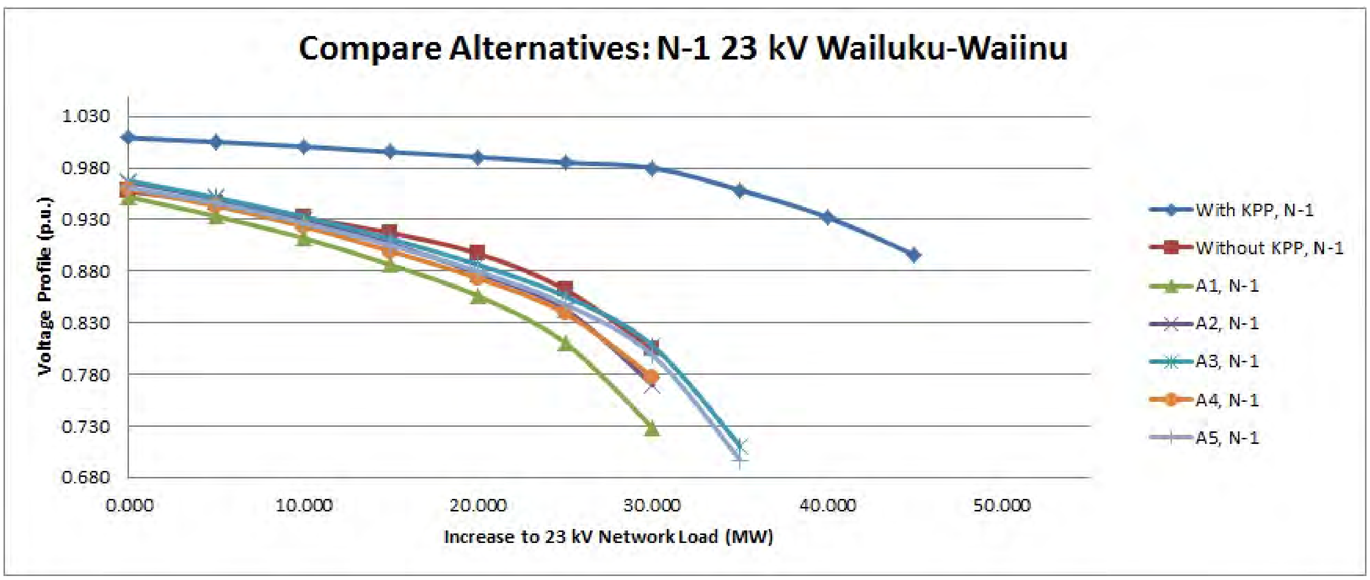

Figure 23; Comparison of P-V characteristics of transmission Alternatives for losing the 23 kV Wailuku-Waiinu Line.

P-V characteristic comparison of Combination 1- Combination 7:

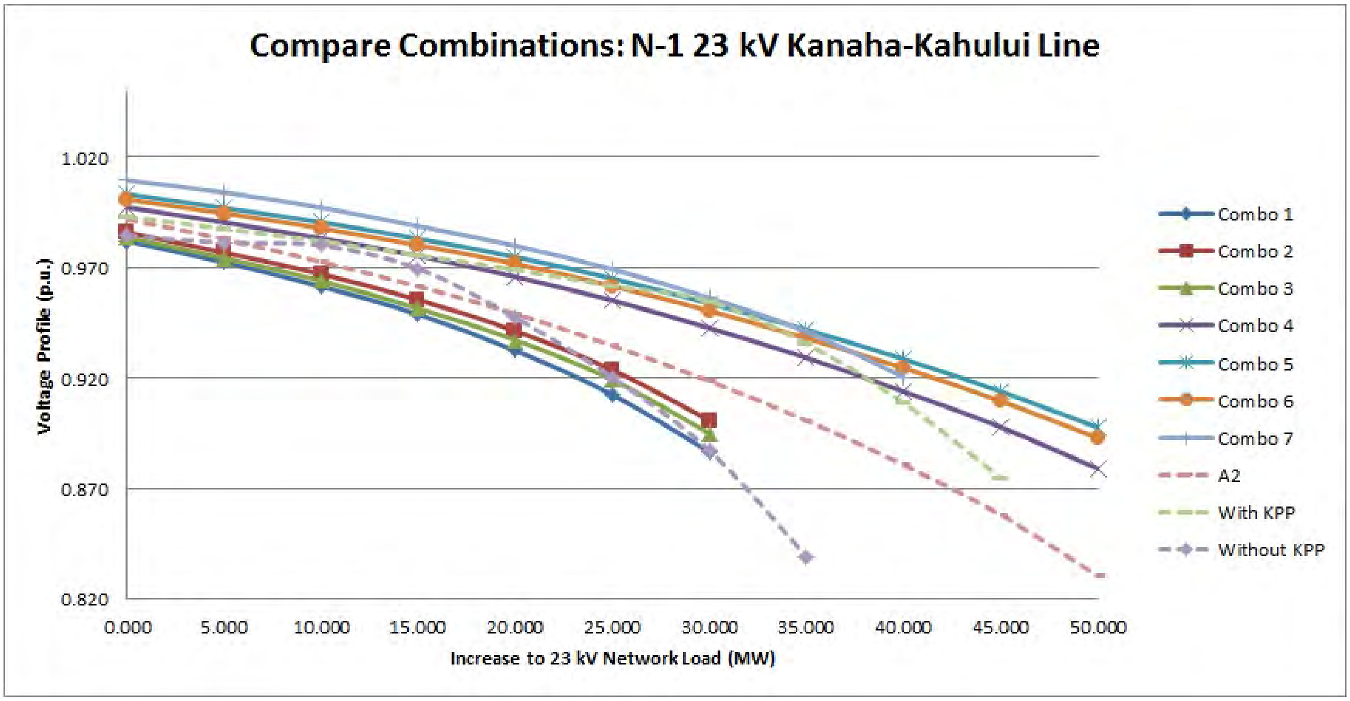

Figure 24; Comparison of P-V characteristics of tranmission Combinations for losing the 23 kV Kanaha-Kahului Line.

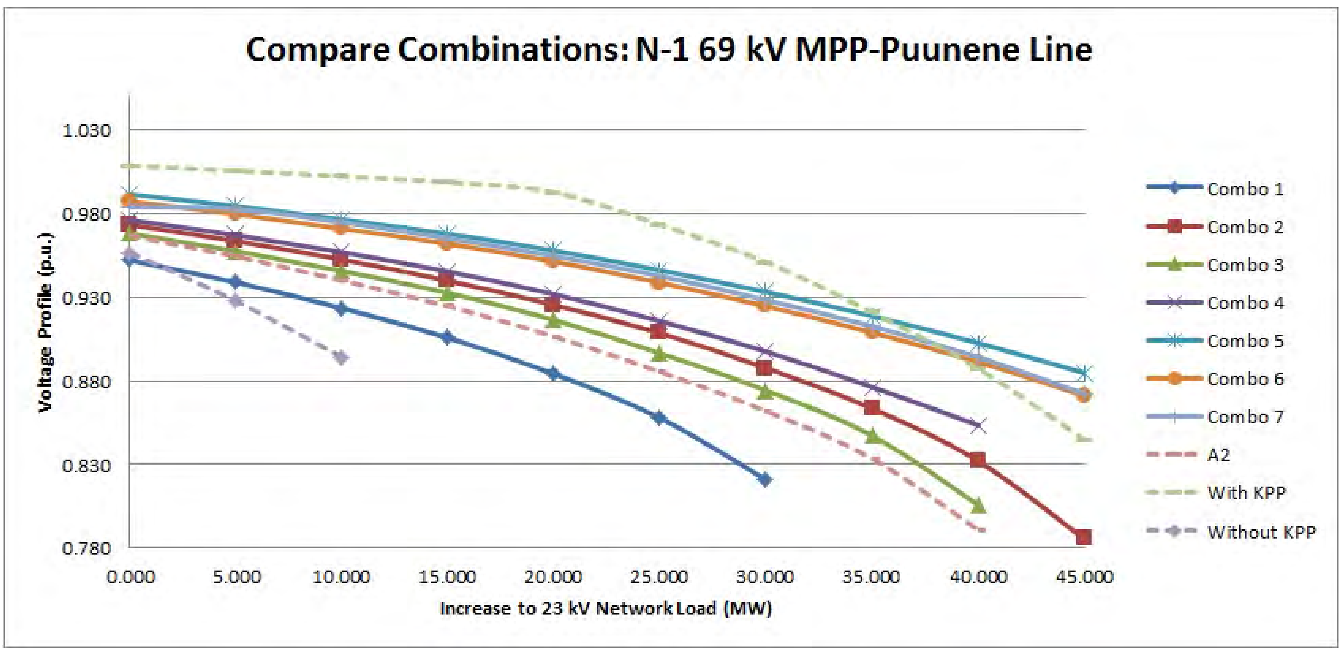

Figure 25 Comparison of P-V characteristics of tranmission Combinations for losing the 69 kV MPP-Puunene Line.

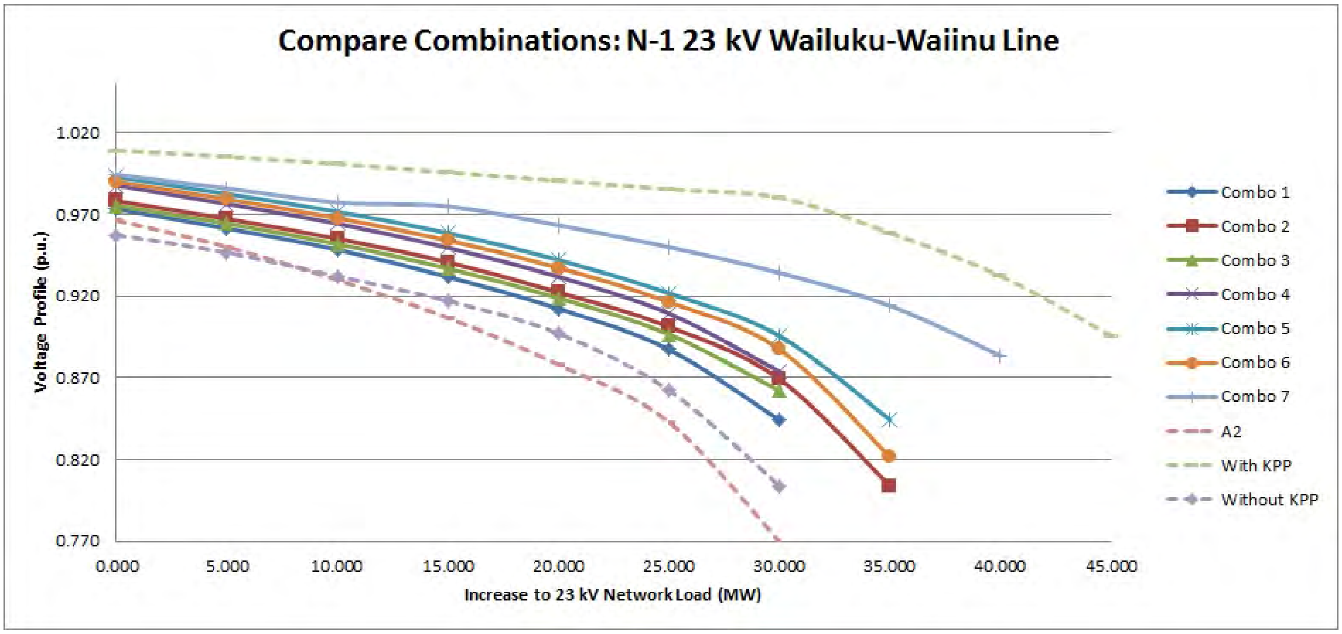

Figure 26: Comparison of P-V characteristics of tranmission Combinations for losing the 23 kV Wailuku-Waiinu Line.

Synchronous Condenser Option:

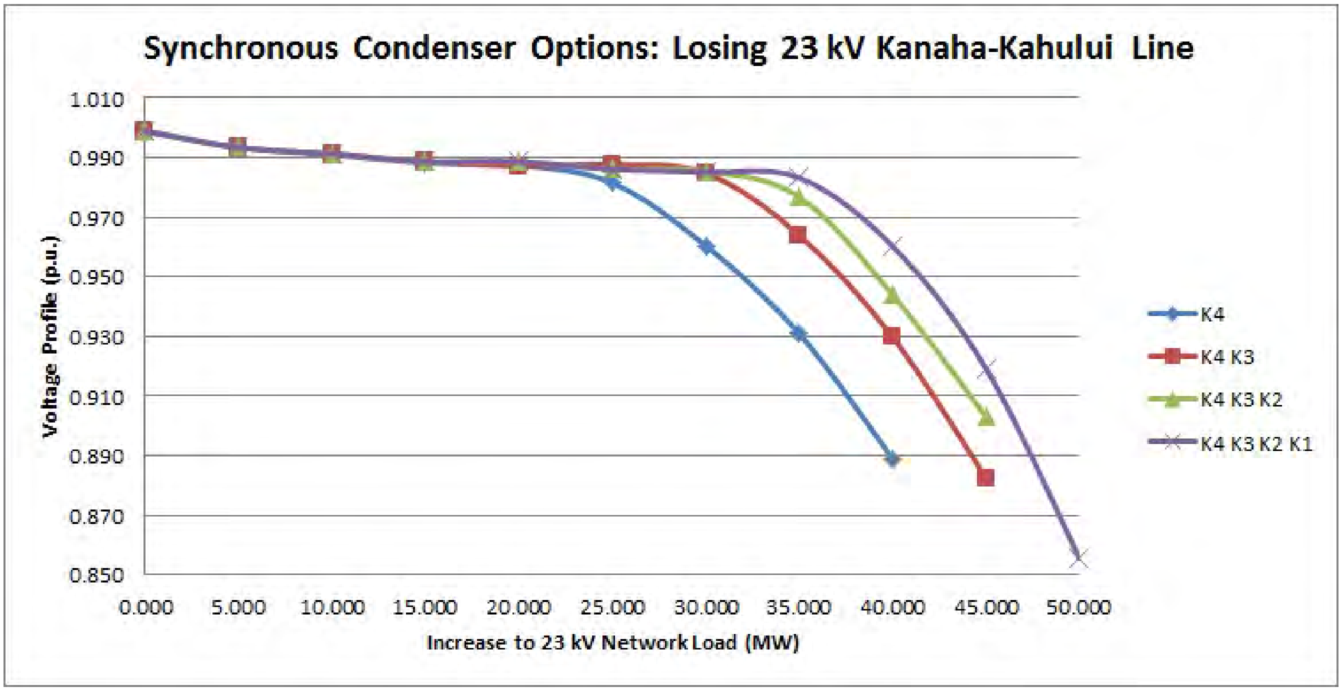

Figure 27: Comparison of P-V characteristics of synchronous condenser options for losing the 23 kV Kanaha-Kahului Line.

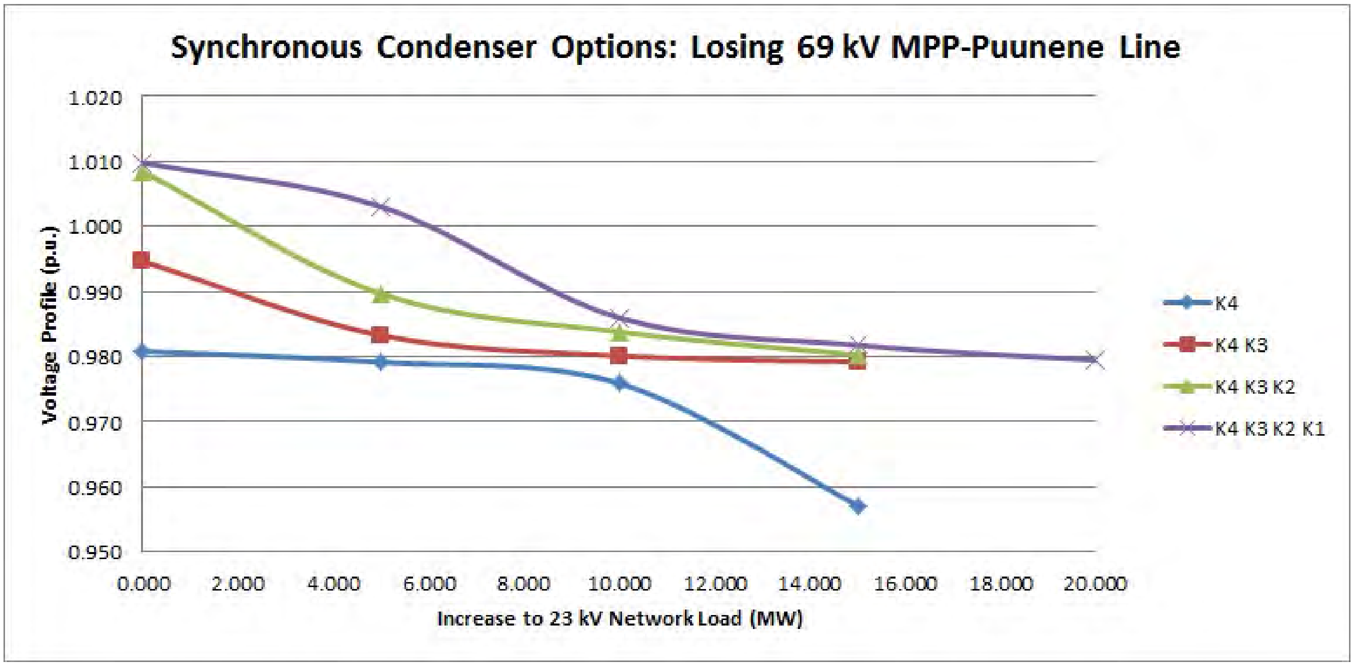

Figure 28: Comparison of P-V characteristics of synchronous condenser options for losing the 69 kV MPP-Puunene Line.

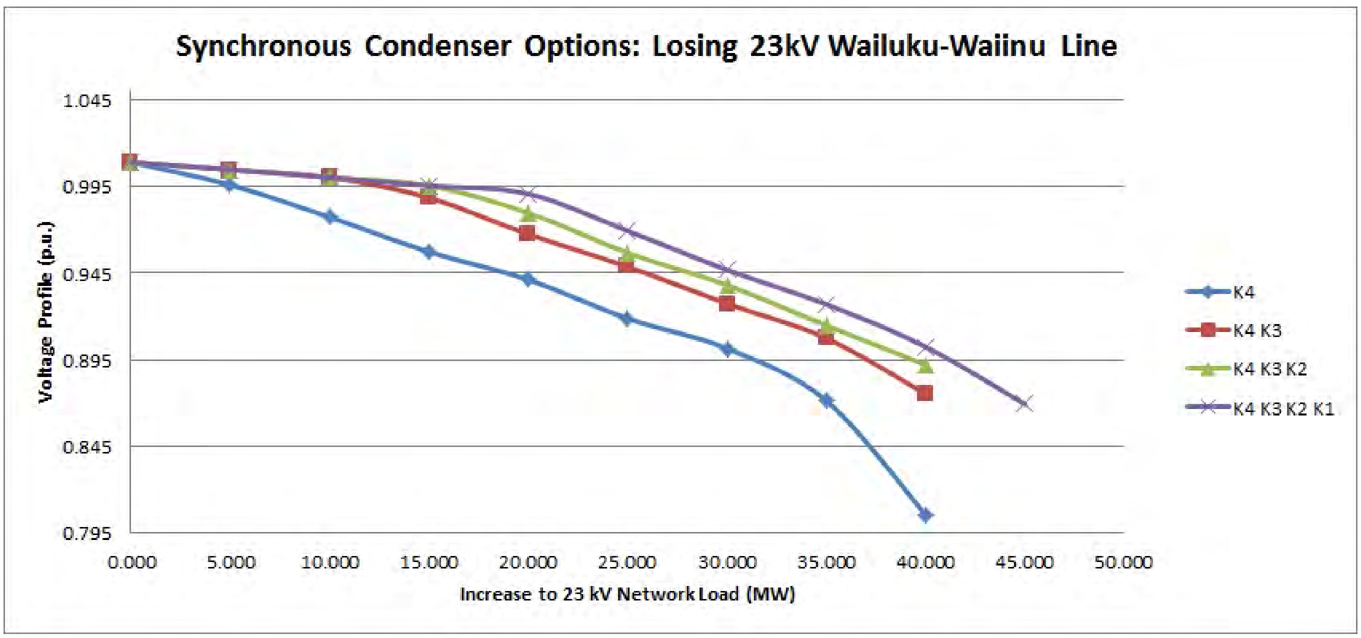

Figure 29: Comparison of P-V characteristics of synchronous condenser options for losing the 23 kV Wailuku-Waiinu Line.

New Firm Generation on 23 kV Network Option:

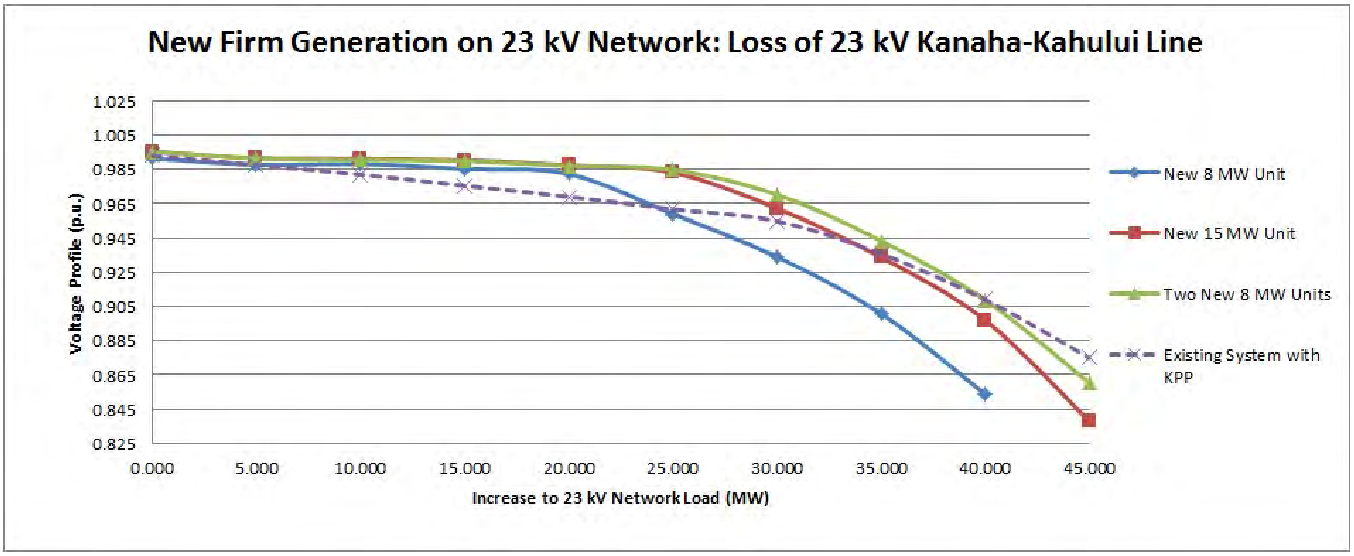

Figure 30: Comparion of P-V characteristics for new firm generation on 23 kV network option for losing the 23 kV Kanaha-Kahului Line.

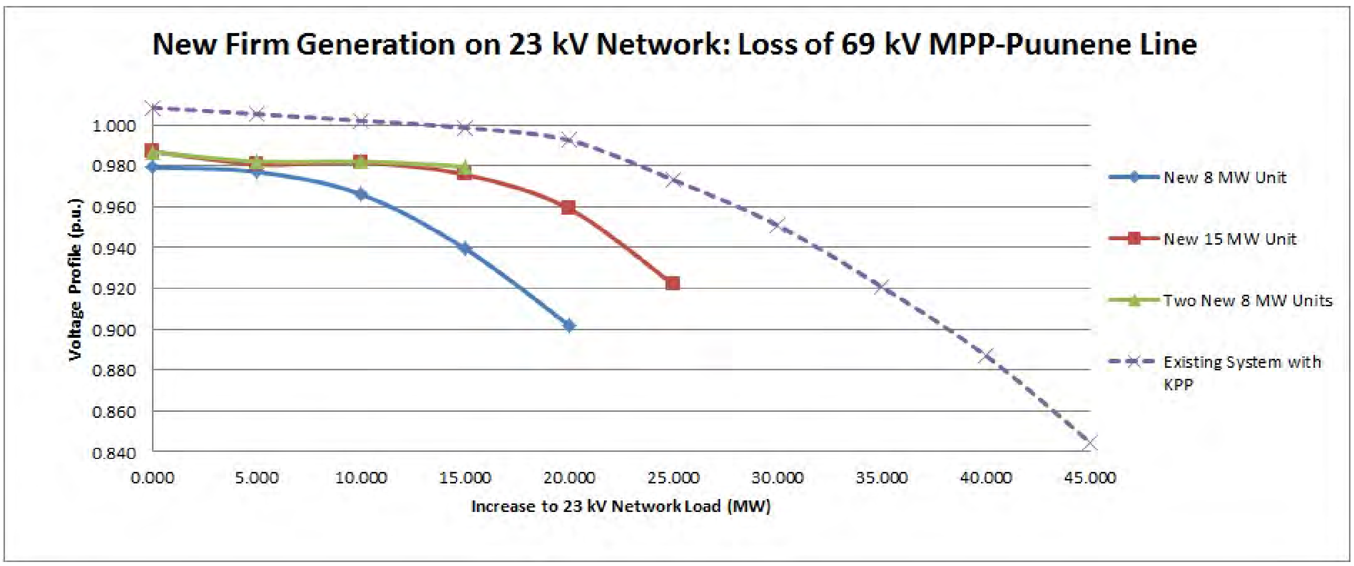

Figure 31: Comparion of P-V characteristics for new firm generation on 23 kV network option for losing the 69 kV MPP-Puunene Line.

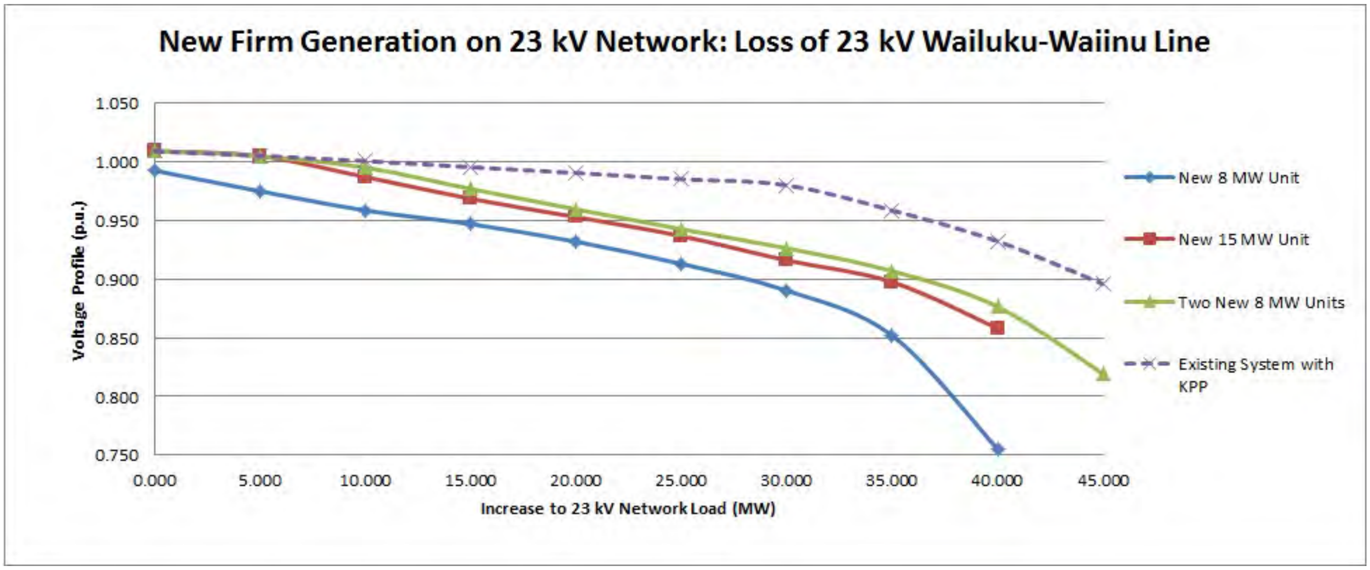

Figure 32: Comparion of P-V characteristics for new firm generation on 23 kV network option for losing the 23 kV Wailuku-Waiinu Line.

New Firm Generation on the 69 kV Network Option:

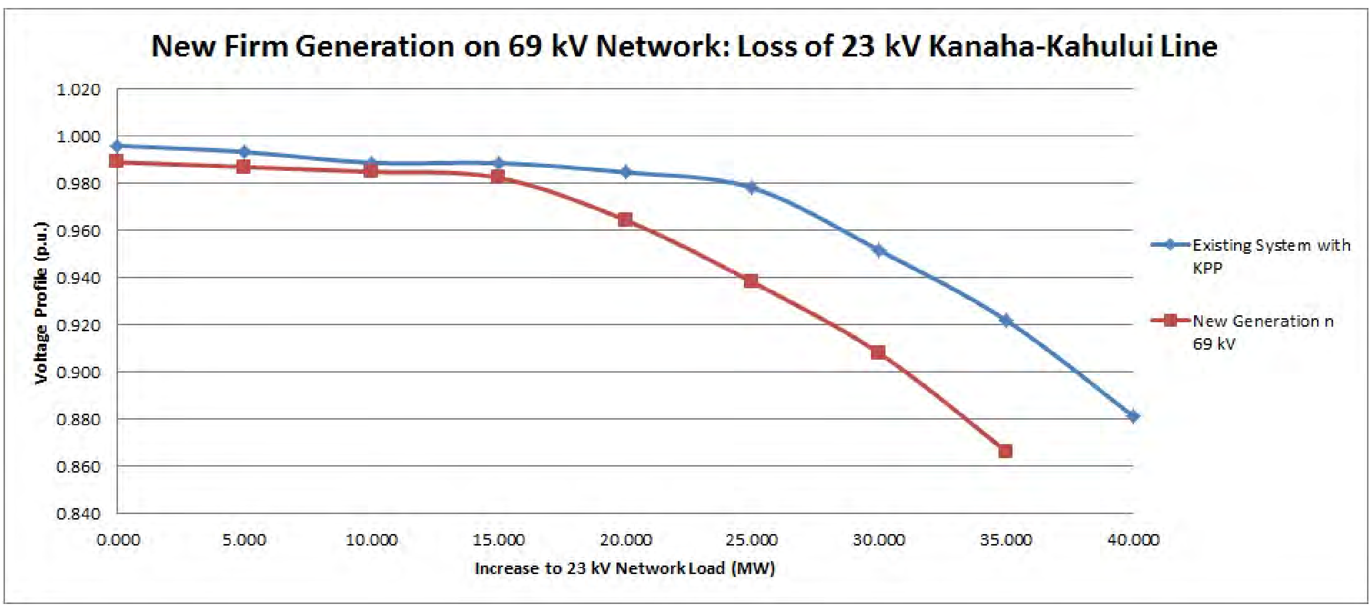

Figure 33: Comparison of P-V characteristics of new firm generation on 69 kV network for losing the 23 kV Kanaha-Kahului Line.

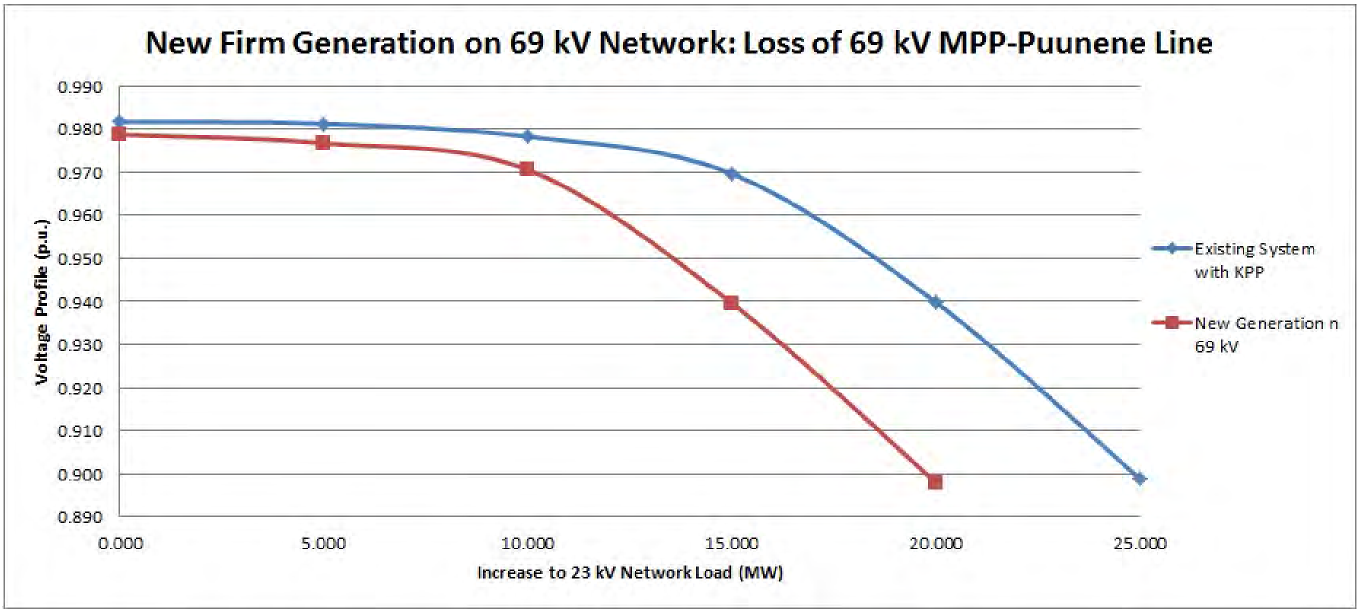

Figure 34: Comparison of P-V characteristics of new firm generation on 69 kV network for losing the 69 kV MPP-Puunene Line.

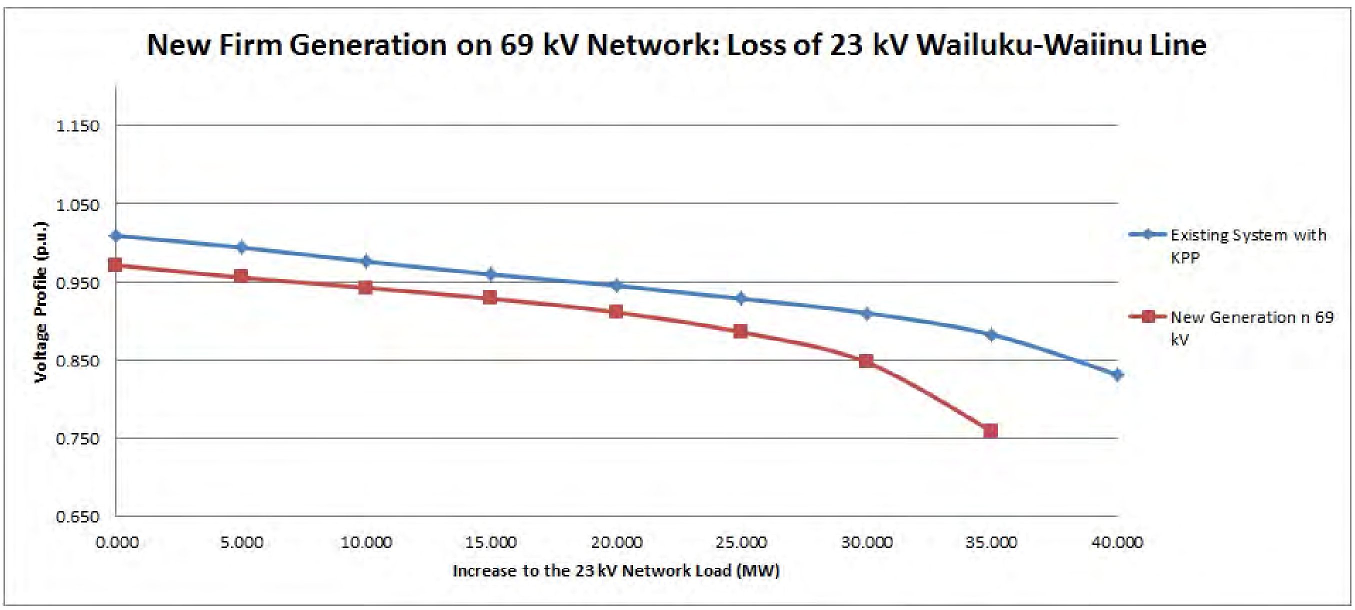

Figure 35; Comparison of P-V characteristics of new firm generation on 69 kV network for losing the 23 kV Wailuku-Waiinu Line.

BESS Option:

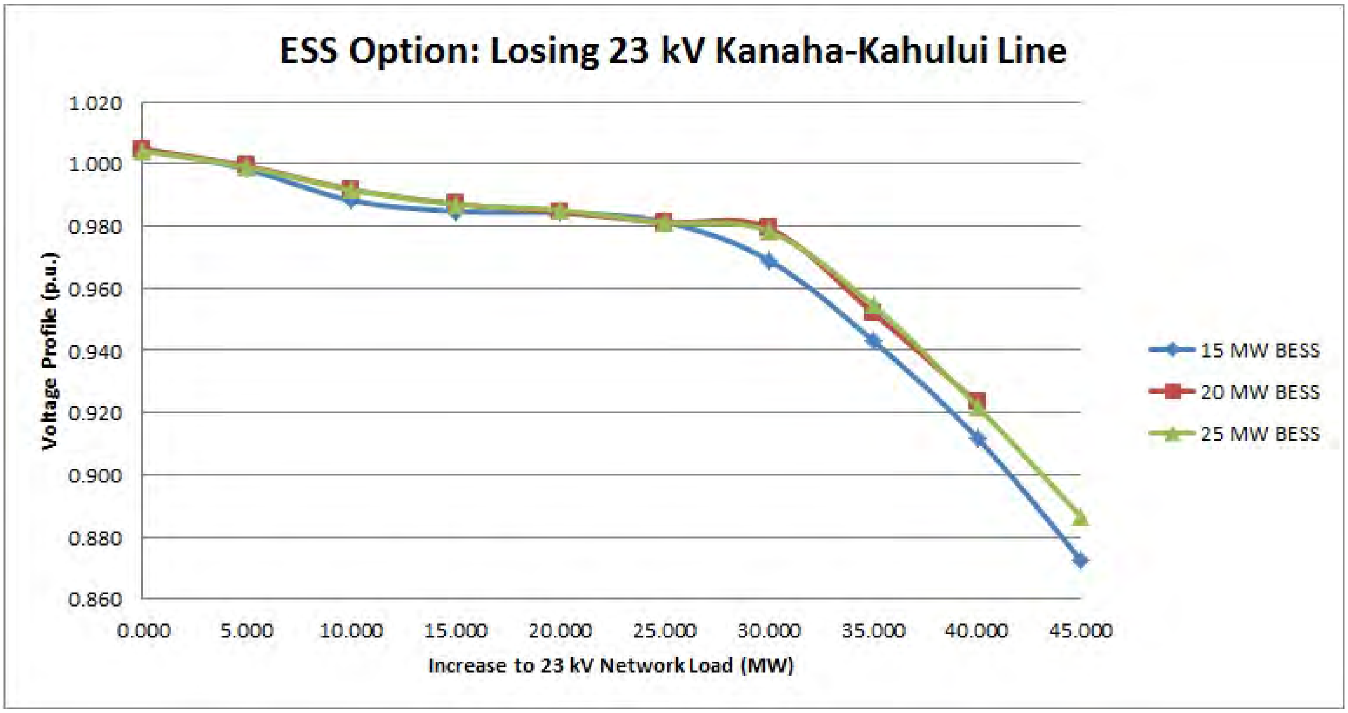

Figure 36: Comparison of P-V characteristics of various BESS options for losing the 23 kV Kanaha-Kahului Line.

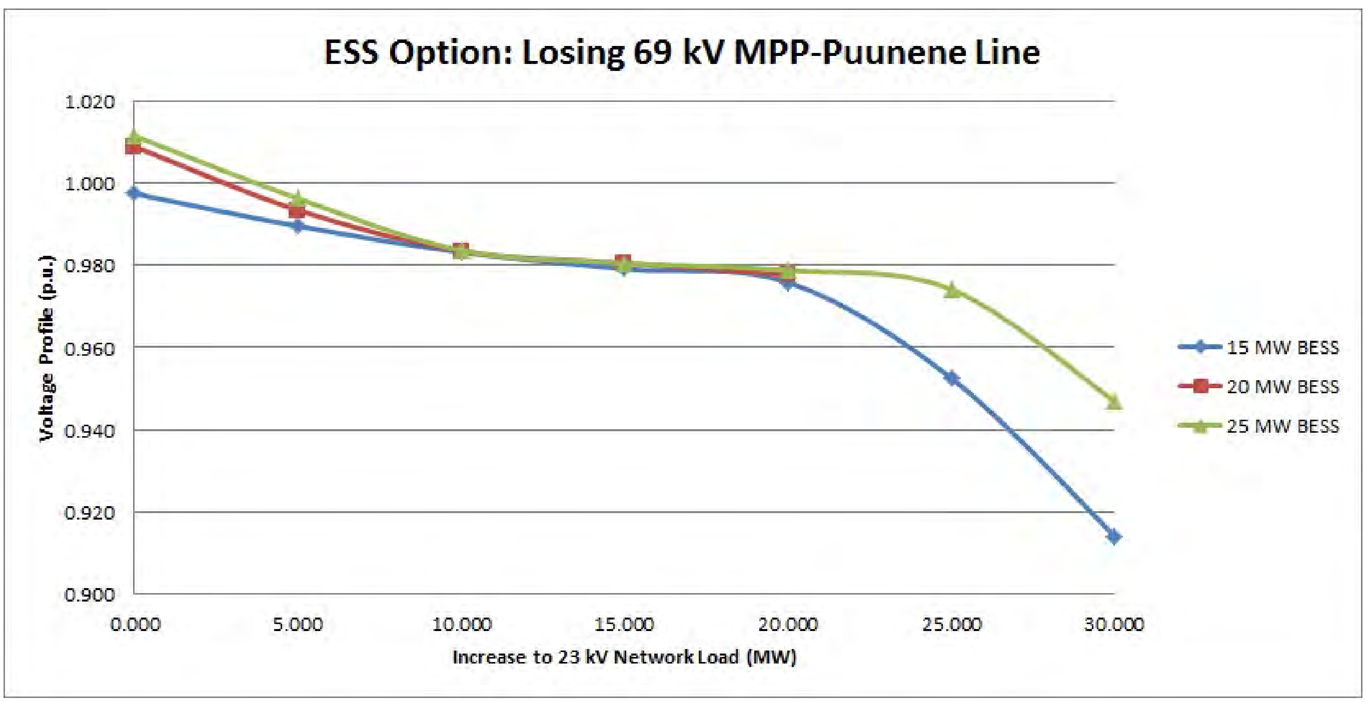

Figure 37 Comparison of P-V characteristics of various BESS options for losing the 69 kV MPP-Puunene Line.

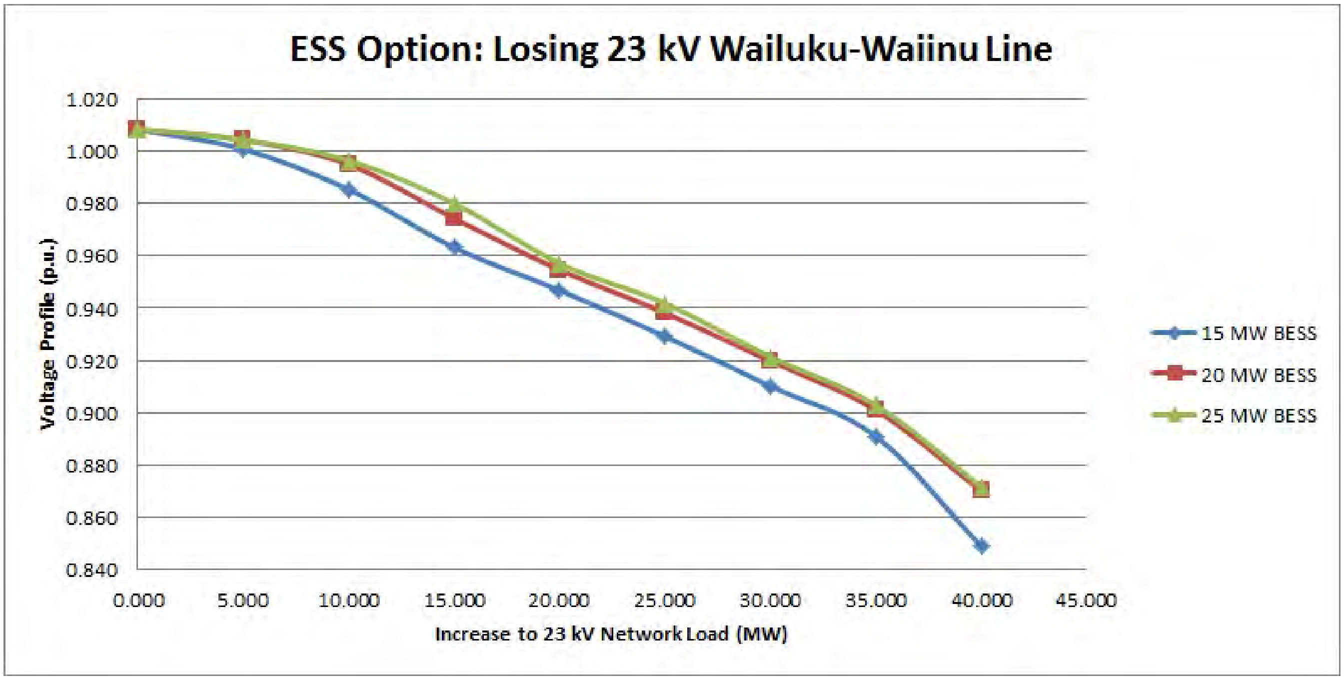

Figure 38: Comparison of P-V characteristics of various BESS options for losing the 23 kV Wailuku-Waiinu Line.

System load above 170 MW:

The longest period of time that the Maui system has historically been observed to have remained 170 MW and above within the last year is 7 hours, which occurred on September 23, 2013.

September 23, 2013	
Hour	System Load (MW)
1	120.2
2	114.3
3	109.6
4	108
5	114.7
6	121.1
7	133.4
8	147.4
9	158.1
10	165.2
11	165.4
12	164.5
13	163.7
14	167.2
15	169.3
16	170.5
17	174
18	177.1
19	178.8
20	186.1
21	183.1
22	170.2
23	152.6
24	133.7

Kahului Power Plant Retirement: Voltage Stability Assessment

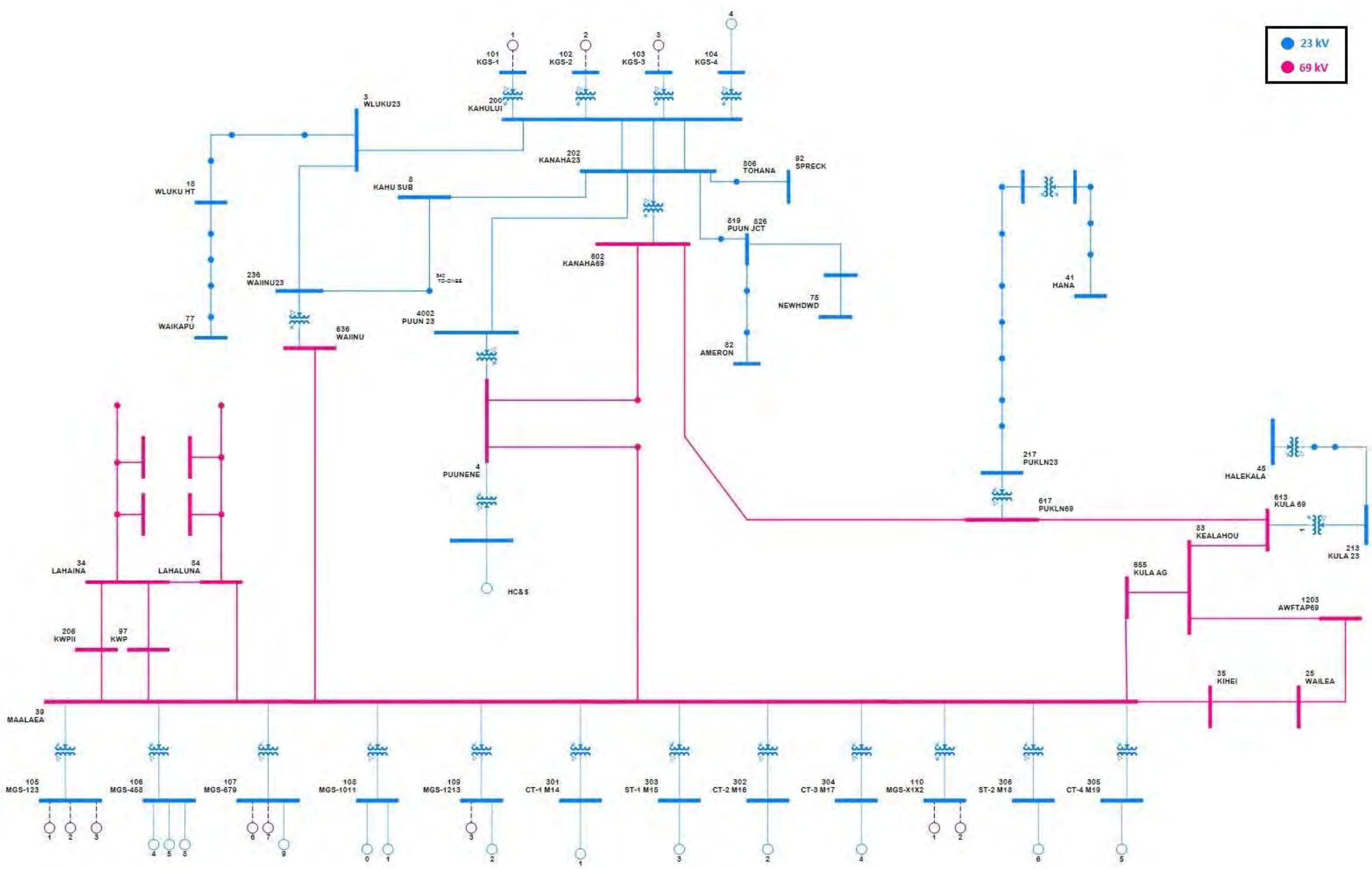

Figure 39: Single line diagram of the existing Maui 23 kV and 69 kV network.

Kahului Power Plant Retirement: Voltage Stability Assessment

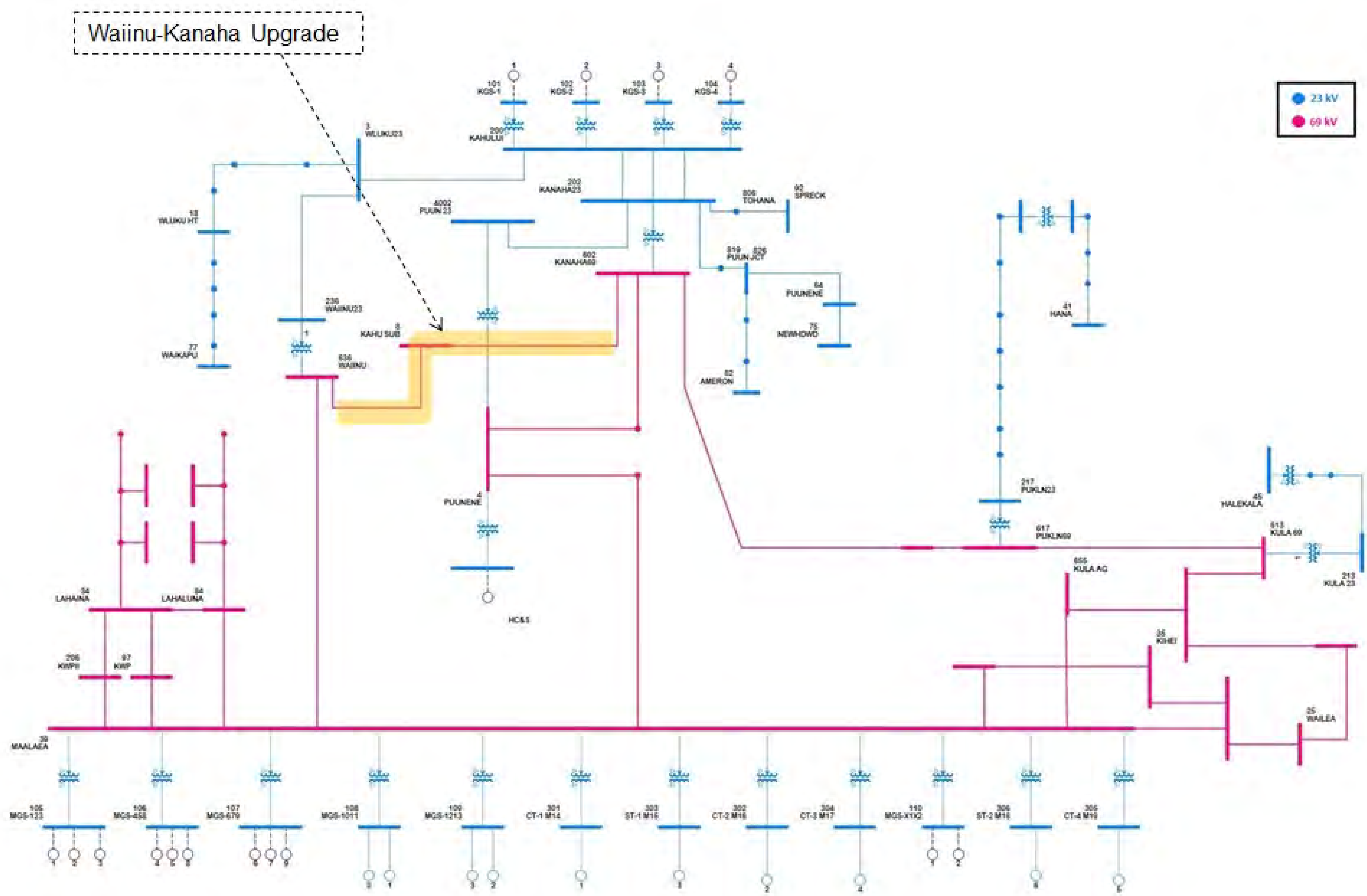

Figure 40: Single line diagram of the existing Maui 23 kV and 69 kV network with Waiinu-Kanaha Upgrade project implemented.

Table 2: Maui System Peak Forecast.

Maui Electric Company, Ltd. (Maui Division) SYSTEM PEAK FORECAST	
Year	System Load
2013	194.5
2014	197.9
2015	199.7
2016	202.1
2017	208.2
2018	214.4
2019	218.3
2020	220.0
2021	221.9
2022	222.6
2023	223.3
2024	223.0
2025	223.3
2026	222.1
2027	220.4
2028	217.1
2029	214.8
2030	210.8

Appendix C – Short Circuit Analysis

Effect of Kahului Power Plant (KPP) Retirement on Short Circuit Current

Prepared For

Transmission Planning Division

Prepared by:

Transmission Planning Division

Dated: August 1, 2014

Reference: TPD 2014-20

Effect of Kahului Power Plant (KPP) Retirement on Short Circuit Current

Prepared By:: RBSrivastava
Raja Srivastava
Lead Transmission Planning Engineer

Approved By: Ronald Bushner 8/20/2014
Ron Bushner
Director, Transmission Planning Division

Revision History

Date	Revision Number	Change Description
August 1, 2014	Original	Original

Executive Summary

Maui Electric Company (Maui Electric) announced the retirement of Kahului Power Plant (KPP) in the year 2019. Transmission Planning Division (TPD) performed a study to determine the effect of the KPP retirement on the short circuit current at various buses in the Maui transmission system.

The study results show that the retirement of KPP 3 & 4 leads to reduced fault current on the 69 KV and 23 KV transmission systems. The change in fault current could be as much as 5000 amperes. Such a large change in fault current may affect the relay operation and the reliable operation of the transmission system. Therefore, it is necessary to re-evaluate the effect of reduced fault current on the Maui system.

The study also shows that the non-transmission alternatives evaluated to address the impact of the retirement of KPP leads to increased fault current on the 69 KV transmission system. The increase in fault current could be as much as 5000 amperes.

Background

Maui Electric announced the retirement of Kahului Power Plant (KPP) in the year 2014. Transmission Planning Division (TPD) has performed a study to determine the effect of the KPP retirement on the short circuit current at various buses in the Maui transmission system. The results of this study are presented in this report.

TPD has also evaluated the effect of KPP retirement on the transmission line overloading, transformer overloading, bus voltage violations, voltage stability, and transient stability of the Maui electrical system. The results of those studies are presented in separate reports.

Figure 1 shows the interaction of Maui 23 KV transmission system near KPP and the rest of the 69 KV transmission system. The 23 KV transmission system near KPP is shown as an orange cloud. KPP is part of this 23 KV transmission system. After KPP retirement, this 23 KV transmission system depends solely on 69 KV transmission system for supply of generation to meet the load. The three substations where this 69 KV – 23 KV transformation takes place are – Waiinu, Puunene, and Kanaha.

Effect of Kahului Power Plant (KPP) Retirement on Short Circuit Current

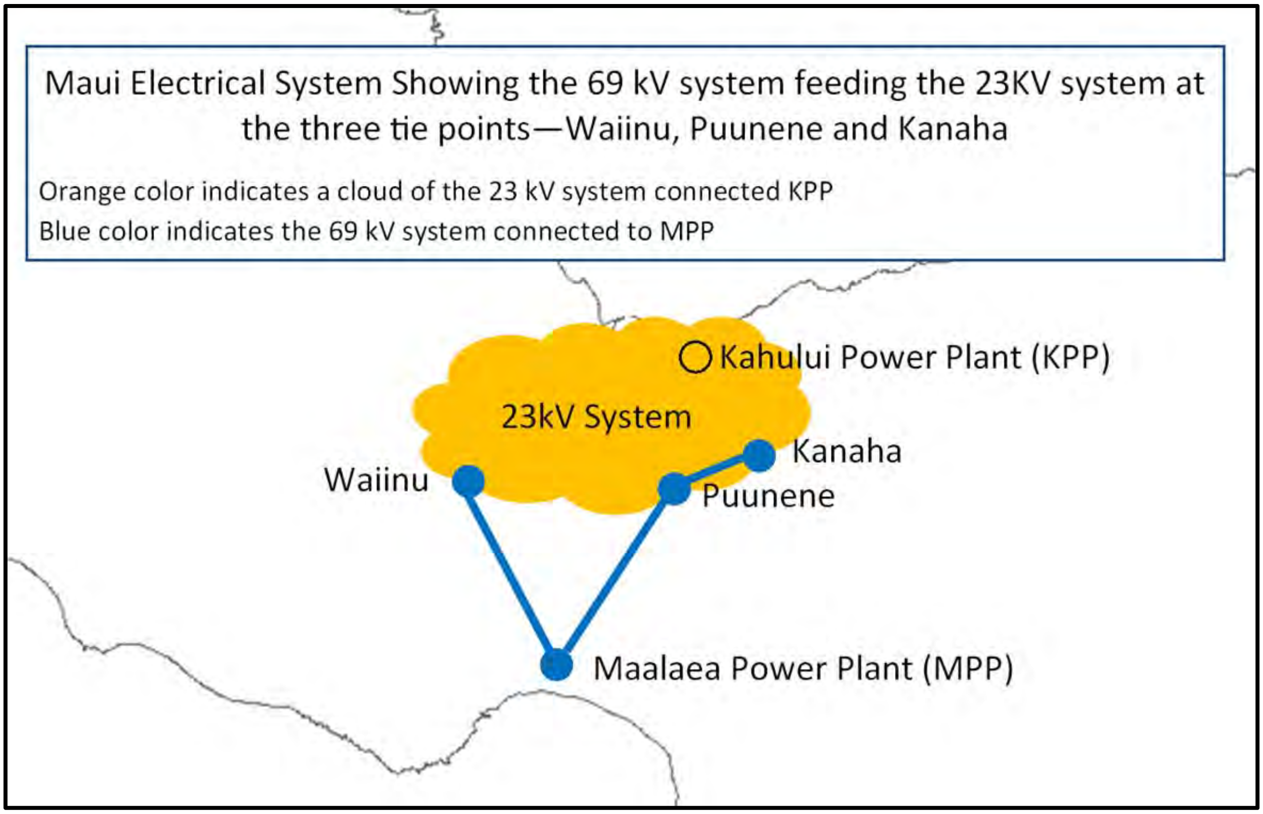

Figure 1 – Maui electrical system showing 69 KV transmission system feeding 23 KV transmission system at three tie points – Waiinu, Puunene, and Kanaha

As part of the KPP retirement study by TPD, PSSE[1] scenarios Case 0 – 5 were created. These scenarios represent the base case and various alternatives considered to alleviate the transmission limitations due to the retirement of KPP. The alternatives considered include transmission alternative,where new transmission upgrades are recommended, and non-transmission alternatives, where no new transmission upgrades are included. The 23kV Waiinu-Kanaha upgrade to 69kV with the reconductoring of MPP-Waiiu and MPP-Puunene is the transmission alternative. These non-transmission alternatives are – a) diesel generators (DG), b) battery (BESS) and c) synchronous condensers. These PSSE scenarios are given in Table 1. The study has also evaluated the effect of KPP retirement on the short circuit current under N-1 conditions. A list of N-1 contingencies are given in Table 2.

Table 1 – PSSE Models used in the Short Circuit Study

	Scenario Name	Scenario Description
Case 0	Case 0 – 2014 Base Case	2014 peak case with HC&S and KPP 3 & 4 on line.
Case 1	2019 Base Case plus KPP 3&4 Retirement	2019 peak case; KPP retired, HC&S retired-- retired generation picked up at Maalaea Power Plant

[1] Power System Simulator for Engineering

Effect of Kahului Power Plant (KPP) Retirement on Short Circuit Current

	Scenario Name	Scenario Description
Case 2	Case 1 plus transmission Upgrades	Case 1 plus the following transmission upgrades • 23 KV Waiinu – Kanaha upgraded to 69 KV • Reconductor MPP – Waiinu and MPP – Puunene from 336 AAC to 556 AAC
Case 3	Case 1 plus diesel generators (DG) on 23 KV system.	Case 1 plus diesel generator (DG) on 23 KV system
Case 4	Case 1 plus battery (BESS) on 23 KV system	Case 1 plus battery (BESS) on 23 KV system
Case 5	Case 1 plus synchronous condenser	Case 1 plus synchronous condenser on 23 KV system

Table 2 – List of contingencies included in the short circuit study

Contingency Name	Contingency Description
None	Cases 0 – 5 plus no line outage
MPP – Waiinu 69 KV line	Cases 0 – 5 plus outage of MPP – Waiinu 69 KV line
MPP – Puunene 69 KV line	Cases 0 – 5 plus outage of MPP – Puunene 69 KV line

The topic of short circuit current was evaluated in a recent study by EPS[2]. The study determined that even for very high renewable wind and solar penetration levels considered in the study, there is sufficient short circuit ratio available for proper operation of the inverter based technologies such as solar and wind generators.

Methodology

PSSE was used to calculate short circuit current. 3-phase fault was applied at each bus in the Maui transmission system. The short circuit currents from PSSE were tabulated.

Post processing of the short circuit current included calculating the percent change in short circuit current in Cases 1 – 5 compared to Case 0.

Assumptions

- The study is a follow-up of the other studies by TPD on KPP retirement. The assumptions are consistent with the assumptions in the other studies performed by TPD on KPP retirement (thermal analysis, voltage stability analysis, transient stability analysis).
- This study is not a High PV/wind penetration study. This topic has been addressed in a study by EPS referenced in the Background section of this report.
- This study solely focuses on the effect of KPP retirement on the short circuit current at the critical buses in the Maui transmission system.

2 "Maui Electric Company, Ltd. Curtailment Reduction Plan Impact Study" Dated June 30, 2014

Results and Analysis

The results of the fault current calculations are given in Appendix A of the report. This table contains the percent change in fault current at substations that are 23 KV and larger compared to Case 0 (base case). The changes in fault currents greater than 5% are highlighted with different colors. The green color highlight indicates that the fault current has decreased 5% and larger with respect to the Case 0. The red color highlight indicates that the fault current has increased 5% and larger with respect to the Case 0 with KPP 3 & 4 in service.

There are several generation dispatches in Cases 1 – 5 with respect to Case 0. These generation dispatches cause either the increase in fault current (generation addition) or decrease in fault current (generation retirement). In general, the KPP 3 & 4 retirement, HC&S retirement lead to decreased fault currents and dispatched units at Maalaea Power Plant (MPP) causes an increase in fault currents. These increase and decrease in fault currents are marked as red and green in Table A.1.

A comparison of the fault current for non-transmission alternatives (Case 3, Case 4, and Case5) shows that the changes in fault current are very similar to each other and are also very similar to the Case 0. This is due to the location of the non-transmission alternatives on the 23 KV transmission system that replaces the retired KPP3 & 4 generators. However, if the non-transmission alternatives are located on the 69 KV transmission system, we expect to notice drastic change in fault current.

Fault Current Due to KPWII Wind Generator – This study shows that addition of KWPII causes substantial increase in fault current. This is due to the fact that PSSE models KWPII wind generator as synchronous condenser. The substantial increase in fault current is contrary to the fact that inverter based technologies do not contribute significantly to the fault current. PSSE calculations are acceptable for planning studies. However, further adjustments to the fault current will be needed for accurate fault current calculations.

Table 3 shows the changes in short circuit fault current at Maui substations 23 KV and larger for Cases 1 & 2. Only changes greater than 5% have been reported. Whereas the increase in fault current due KWPII addition is intuitive, the increase in fault current in Case 2 is counterintuitive because the changes in the fault currents are due to many different factors – KPP 3 & 4 retirement, HC&S retirement, KWPII addition, Maalaea 679 on-line, Maalaea 1213 on-line, and various 23 KV and 69 KV transmission upgrades with change in topology. Therefore, the association of increase and decrease in short circuit current to one factor is next to impossible. To establish such an association, we made several runs to quantify the change in short circuit current due to various transmission upgrades and KPP retirements. The results from these simulations have been discussed below.

Table 3 Fault Current at buses that show change by 5 % and larger (Cases 0, 1, and 2)

(Green highlights show that the fault current has decreased 5% or larger with respect to Case 0, and red highlights show that the fault current has increased 5% or larger with respect to Case 0)

Effect of Kahului Power Plant (KPP) Retirement on Short Circuit Current

				Case0		Case1 (Delta %)				Case2 (Delta %)		
Bus	Name	KV	3PH	MVA	Amp	NoCont	Cont1	Cont2	Bus	NoCont	Cont1	Cont2
Col 1	Col 2	Col 3	Col 4	Col 5	Col 6	Col 7	Col 8	Col 9	Col 1	Col 11	Col 12	Col 13
4	PUUNENE	69.00	3PH	641.23	5,365.40	21.65	22.00	42.69		7.15	23.67	(14.06)
23	PUUKOL B	69.00	3PH	373.99	3,129.30	0.72	(0.35)	(1.52)		0.79	0.17	(1.02)
401	PUUNENEA	69.00	3PH	612.53	5,125.30	20.61	21.07	41.70		2.12	23.43	(22.62)
402	PUUNENEB	69.00	3PH	646.62	5,410.50	20.02	20.17	41.65		7.60	20.79	(11.24)
602	KANAHA69	69.00	3PH	597.10	4,996.20	20.00	20.53	41.08		(1.37)	22.75	(27.10)
636	WAIINU	69.00	3PH	529.15	4,427.60	4.90	16.58	2.92		(18.33)	(367.82)	(8.25)
2060	KWPII34	34.50	3PH	224.70	3,760.40	(13.03)	(13.78)	(14.62)		(13.01)	(13.47)	(14.32)
2061	KWPII_CLT1	34.50	3PH	223.00	3,731.90	(13.22)	(13.97)	(14.81)		(13.20)	(13.66)	(14.51)
136	WAIINU B	12.47	3PH	88.57	4,100.80	1.05	26.53	3.49		(2.15)	(89.74)	0.48

Effect of Transmission Upgrades on Fault Currents

To determine the effect of transmission upgrades on the fault currents, we compared the results of Case 2 (with transmission upgrade) with Case 1 (no transmission upgrade). The change in short circuit current is given in Table 4.

The results show that short circuit current increases. Due to transmission upgrades and change in transmission topology, the equivalent impedances (Thevenin Equivalece) is reduced. The reduction in equivalent impedance gives rise to increased fault current contributions.

Table 4 – 5% or larger change in Short Circuit Current due transmission upgrades

(Case1 is without transmission upgrade and Case2 is with transmission upgrade)

				Case1		Case2 (delta %)		
Bus	Name	KV	3PH	MVA	Amp	NoCont	Cont1	Cont2
4	PUUNENE	69.00	3PH	502.43	4,204.00	(18.50)	2.14	(99.03)
401	PUUNENEA	69.00	3PH	486.31	4,069.10	(23.29)	(23.29)	(23.29)
402	PUUNENEB	69.00	3PH	517.14	4,327.10	(15.53)	(15.53)	(15.53)
602	KANAHA69	69.00	3PH	477.67	3,996.90	(26.72)	(26.72)	(26.72)
617	PUKLN69	69.00	3PH	398.10	3,331.00	(8.87)	(8.87)	(8.87)
636	WAIINU	69.00	3PH	503.22	4,210.60	(24.42)	(24.42)	(24.42)
3	WLUKU23	23.00	3PH	189.28	4,751.30	5.03	5.03	5.03
40	ONEHEE	23.00	3PH	158.97	3,990.40	42.65	42.65	42.65
236	WAIINU23	23.00	3PH	209.12	5,249.50	12.78	12.78	12.78
840	TO-ONEE	23.00	3PH	196.50	4,932.70	48.37	48.37	48.37

Effect of KPP Retirement on 69 KV and 23 KV transmission systems

To determine the effect of KPP retirement on the short circuit current, we created Case 1a from Case 1 by not retiring KPP 3 & 4. Table 5 shows the change in the fault current 5% or larger due to the retirement of KPP 3 & 4. We observe that the change in fault current varies from few amperes to as much as 5000 amperes (Kahului 23 KV substation). Such a large change in fault current may affect the relay operation and thus the reliability of the system. Therefore, it is necessary to review and update the current relay settings after the KPP 3 & 4 retirements.

Table 5 – 5% or larger change in Short Circuit Current due to the retirement of KPP 3 & 4

(Case1 is without KPP 3 & 4 and Case1a is with KPP 3 & 4)

				Case1a		Case1 (delta %)		
Bus	**Name**	**KV**	**3PH**	**MVA**	**Amp**	**NoCont**	**Cont1**	**Cont2**
4	PUUNENE	69.00	3PH	574.73	4,809.00	12.58	12.56	22.84
25	WAILEA	69.00	3PH	520.99	4,359.30	4.54	3.27	5.09
39	MAALAEA	69.00	3PH	1,118.21	9,356.50	8.05	4.76	4.94
83	KEALAHOU	69.00	3PH	546.78	4,575.10	5.76	4.54	8.44
401	PUUNENEA	69.00	3PH	555.94	4,651.80	12.53	12.64	22.83
402	PUUNENEB	69.00	3PH	587.46	4,915.50	11.97	11.71	22.25
602	KANAHA69	69.00	3PH	546.07	4,569.20	12.53	12.72	22.84
613	KULA 69	69.00	3PH	477.68	3,996.90	5.89	5.08	10.26
617	PUKLN69	69.00	3PH	430.39	3,601.30	7.51	7.39	15.61
636	WAIINU	69.00	3PH	542.07	4,535.70	7.17	17.70	5.89
655	KULA AG	69.00	3PH	545.31	4,562.90	5.59	4.32	7.84
1203	AWFTAP69	69.00	3PH	514.11	4,301.80	4.56	3.34	5.33
3	WLUKU23	23.00	3PH	252.35	6,334.50	24.99	34.46	35.83
5	MAUI PIN	23.00	3PH	261.97	6,576.00	26.27	35.01	36.75
7	WAI WELL	23.00	3PH	148.96	3,739.20	16.74	27.39	25.57
8	KAHU SUB	23.00	3PH	273.78	6,872.50	27.04	35.60	37.57
18	WLUKU HT	23.00	3PH	146.35	3,673.80	16.64	27.53	25.52
22	WS PUMP	23.00	3PH	136.64	3,429.90	15.84	26.98	24.53
30	MOKUHAU	23.00	3PH	161.99	4,066.40	17.92	28.51	27.12
33	WS MILL	23.00	3PH	236.00	5,924.10	23.78	33.46	34.39
40	ONEHEE	23.00	3PH	203.03	5,096.50	21.70	31.54	31.84
43	WAIEHU	23.00	3PH	111.30	2,793.80	13.27	24.19	20.89
48	MAUIBLOC	23.00	3PH	79.03	1,983.90	10.35	22.62	17.25
64	PUUNENE	23.00	3PH	118.20	2,967.10	16.07	25.73	25.07
73	KUAU	23.00	3PH	89.29	2,241.50	12.52	21.54	20.06
75	NEWHDWD	23.00	3PH	94.25	2,365.90	13.45	23.26	21.86
77	WAIKAPU	23.00	3PH	78.16	1,961.90	10.26	22.53	17.12
82	AMERON	23.00	3PH	94.45	2,370.90	13.32	23.67	22.15
88	AMERBLDG	23.00	3PH	97.92	2,458.10	13.71	24.06	22.65
92	SPRECK	23.00	3PH	127.80	3,207.90	16.66	25.52	25.27
93	PAIAMKA	23.00	3PH	99.49	2,497.40	13.67	22.67	21.56
200	KAHULUI	23.00	3PH	381.12	9,567.00	41.71	48.83	50.95
202	KANAHA23	23.00	3PH	384.54	9,652.80	36.78	43.90	46.55
217	PUKLN23	23.00	3PH	94.94	2,383.20	1.66	4.98	6.04
236	WAIINU23	23.00	3PH	272.88	6,849.80	23.36	32.88	35.16
671	JCT B	23.00	3PH	119.30	2,994.60	14.32	25.85	22.60
806	TOHANA	23.00	3PH	190.06	4,771.00	22.64	31.21	32.26
819	PUUN JCT	23.00	3PH	207.47	5,207.90	24.53	33.47	34.61
826		23.00	3PH	171.27	4,299.30	21.30	30.48	31.05

Effect of Kahului Power Plant (KPP) Retirement on Short Circuit Current

				Case1a		Case1 (delta %)		
Bus	Name	KV	3PH	MVA	Amp	NoCont	Cont1	Cont2
827	CONC TAP	23.00	3PH	100.86	2,531.90	14.04	24.39	23.07
838		23.00	3PH	80.26	2,014.80	10.48	22.75	17.44
840	TO-ONEE	23.00	3PH	266.07	6,678.90	26.15	34.91	36.71
848	JCT C	23.00	3PH	69.07	1,733.90	10.49	20.46	18.10
858	PUUOHALA	23.00	3PH	207.59	5,211.00	21.58	31.59	31.71
892	BALWNPK	23.00	3PH	110.35	2,770.10	14.83	23.75	23.00
893	PAIAMKA	23.00	3PH	101.26	2,541.90	13.84	22.80	21.75
4002	PUUN 23	23.00	3PH	304.23	7,637.00	25.40	32.33	35.77

Conclusions

The study results shows that the retirement of KPP 3 & 4 leads to reduced fault current on the 69 KV and 23 KV transmission systems. The change in fault current could be as much as 5000 amperes. Such a large change in fault current may affect the relay operation and the reliable operation of the transmission system. Therefore, it is necessary to re-evaluate the effect of reduced fault current on the Maui system.

The study also shows that the non-transmission alternatives evaluated to address the impact of the retirement of KPP leads to increased fault current on the 69 KV transmission system. The increase in fault current could be as much as 5000 amperes.

Appendix A

Effect of Kahului Power Plant (KPP) Retirement on Short Circuit Current

Table A.1 – Change in 3-phase fault current with respect to Case 0

Notes:

- Delta % is defined as percent change with respect to Case 0
- Green highlighted cells indicate that the fault current has decreased by 5% with respect to Case 0.
- Red highlighted cells indicate that the fault current has increased by 5% with respect to Case 0.
- Case 0 – 5 are defined in table below
- Contingencies are defined as below.

Table A.1 – Change in short circuit current with respect to Case 0

				Case0		Case1 (Delta %)				Case2 (Delta %)				Case3 (Delta %)				Case4 (Delta %)				Case5 (Delta %)		
Bus	Name	KV	3PH	MVA	Amp	NoCont	Cont1	Cont2		NoCont	Cont 1	Cont2		NoCont	Cont 1	Cont 2		NoCont	Cont 1	Cont 2		NoCont	Cont 1	Cont 2
Col 1	Col 2	Col 3	Col 4	Col 5	Col 6	Col 7	Col 8	Col 9	Col 10	Col 11	Col 12	Col 13	Col 14	Col 15	Col 16	Col 17	Col 18	Col 19	Col 20	Col 21	Col 22	Col 23	Col 24	Col 25
4	PUUNENE	69.00	3PH	641.23	5,365.40	21.65	22.00	42.69		7.15	23.67	(14.06)		12.36	12.54	25.76		9.75	9.52	17.45		6.94	7.46	20.89
23	PUUKOLB	69.00	3PH	373.99	3,129.30	0.72	(0.35)	(1.52)		0.79	0.17	(1.02)		0.18	0.32	(0.90)		1.62	2.36	1.20		(2.90)	(2.57)	(3.83)
25	WAILEA	69.00	3PH	525.46	4,396.80	5.35	4.42	6.57		5.04	5.07	5.15		3.63	4.00	4.13		4.91	5.88	5.14		(0.37)	0.29	0.28
29	NAPILI A	69.00	3PH	313.68	2,624.70	0.61	(0.28)	(1.27)		0.67	0.15	(0.85)		0.15	0.28	(0.75)		1.36	1.98	1.01		(2.41)	(2.14)	(3.19)
34	LAHAINA	69.00	3PH	563.77	4,717.20	0.99	(0.63)	(2.43)		1.09	0.14	(1.66)		0.20	0.42	(1.43)		2.37	3.46	1.72		(4.52)	(4.00)	(5.93)
35	KIHEI	69.00	3PH	611.07	5,113.10	7.12	5.76	6.10		7.10	6.54	6.14		5.67	5.96	5.01		7.42	8.49	7.07		1.02	1.64	0.55
39	MAALAEA	69.00	3PH	1,070.73	8,959.20	3.97	0.81	(2.67)		4.19	2.32	(1.15)		2.56	2.97	(0.59)		6.62	8.59	5.32		(6.88)	(5.76)	(9.62)
50	MAHINA A	69.00	3PH	352.17	2,946.80	0.65	(0.34)	(1.45)		0.72	0.14	(0.98)		0.15	0.29	(0.86)		1.51	2.21	1.11		(2.73)	(2.43)	(3.61)
83	KEALAHOU	69.00	3PH	548.56	4,590.00	6.07	5.18	11.51		4.71	6.00	5.21		3.20	3.55	5.67		4.09	4.97	5.12		(1.26)	(0.58)	1.25
84	LAHALUNA	69.00	3PH	549.06	4,594.20	1.05	(0.53)	(2.28)		1.15	0.22	(1.54)		0.29	0.50	(1.31)		2.40	3.48	1.77		(4.31)	(3.80)	(5.69)
97	KWP	69.00	3PH	639.70	5,352.70	2.12	0.33	(1.64)		2.24	1.20	(0.78)		1.22	1.46	(0.58)		3.61	4.81	2.89		(4.06)	(3.49)	(5.62)

Effect of Kahului Power Plant (KPP) Retirement on Short Circuit Current

				Case0		Case1 (Delta %)				Case2 (Delta %)				Case3 (Delta %)				Case4 (Delta %)				Case5 (Delta %)		
Bus	Name	KV	3PH	MVA	Amp	NoCont	Cont1	Cont2		NoCont	Cont 1	Cont2		NoCont	Cont 1	Cont 2		NoCont	Cont 1	Cont 2		NoCont	Cont 1	Cont 2
Col 1	Col 2	Col 3	Col 4	Col 5	Col 6	Col 7	Col 8	Col 9	Col 10	Col 11	Col 12	Col 13	Col 14	Col 15	Col 16	Col 17	Col 18	Col 19	Col 20	Col 21	Col 22	Col 23	Col 24	Col 25
206	KWPII	69.00	3PH	623.76	5,219.20	(0.75)	(2.61)	(4.69)		(0.62)	(1.72)	(3.80)		(1.69)	(1.44)	(3.58)		0.81	2.06	0.05		(7.20)	(6.60)	(8.85)
223	PUUKOLA	69.00	3PH	417.02	3,489.40	0.71	(0.47)	(1.78)		0.79	0.10	(1.22)		0.12	0.28	(1.08)		1.72	2.54	1.25		(3.32)	(2.95)	(4.36)
250	MAHINA B	69.00	3PH	347.19	2,905.10	0.60	(0.38)	(1.48)		0.66	0.09	(1.01)		0.10	0.23	(0.90)		1.43	2.12	1.04		(2.74)	(2.44)	(3.61)
401	PUUNEN EA	69.00	3PH	612.53	5,125.30	20.61	21.07	41.70		2.12	23.43	(22.62)		11.13	11.30	24.50		8.37	8.03	16.10		5.79	6.27	19.54
402	PUUNEN EB	69.00	3PH	646.62	5,410.50	20.02	20.17	41.65		7.60	20.79	(11.24)		11.33	11.54	24.98		9.15	9.10	16.85		5.87	6.45	20.26
602	KANAHA 69	69.00	3PH	597.10	4,996.20	20.00	20.53	41.08		(1.37)	22.75	(27.10)		10.39	10.54	23.69		7.53	7.13	15.21		5.08	5.53	18.67
613	KULA 69	69.00	3PH	483.51	4,045.70	7.03	6.59	15.98		4.36	7.33	3.94		3.55	3.89	7.91		3.84	4.47	5.81		(0.39)	0.26	3.94
617	PUKLN69	69.00	3PH	446.42	3,735.40	10.83	11.14	27.35		2.92	12.05	(4.07)		5.34	5.65	14.41		4.41	4.54	9.11		1.58	2.19	10.40
623	PUUKA 69	69.00	3PH	417.02	3,489.40	0.71	(0.47)	(1.78)		0.79	0.10	(1.22)		0.12	0.28	(1.08)		1.72	2.54	1.25		(3.32)	(2.95)	(4.36)
629	NAPILI B	69.00	3PH	305.90	2,559.60	0.54	(0.32)	(1.28)		0.61	0.09	(0.87)		0.10	0.22	(0.78)		1.28	1.88	0.93		(2.39)	(2.14)	(3.16)
636	WAIINU	69.00	3PH	529.15	4,427.60	4.90	16.58	2.92		(18.33)	(367.82)	(8.25)		0.40	0.28	(0.38)		0.63	(8.09)	0.35		(4.51)	(5.33)	(4.87)
650	MAHINA B	69.00	3PH	347.19	2,905.10	0.60	(0.38)	(1.48)		0.66	0.09	(1.01)		0.10	0.23	(0.90)		1.43	2.12	1.04		(2.74)	(2.44)	(3.61)
655	KULA AG	69.00	3PH	545.65	4,565.60	5.64	4.70	10.22		4.53	5.50	5.03		2.98	3.32	5.00		3.97	4.87	4.79		(1.48)	(0.81)	0.61
823	PUUKB 69	69.00	3PH	400.00	3,347.00	0.75	(0.38)	(1.65)		0.83	0.16	(1.11)		0.18	0.34	(0.97)		1.72	2.51	1.27		(3.11)	(2.76)	(4.11)
850	MAHINA A	69.00	3PH	365.90	3,061.60	0.68	(0.36)	(1.51)		0.75	0.14	(1.02)		0.16	0.30	(0.90)		1.56	2.29	1.15		(2.84)	(2.53)	(3.75)
1203	AWFTAP 69	69.00	3PH	517.52	4,330.30	5.18	4.33	6.90		4.79	4.96	5.07		3.37	3.77	4.13		4.57	5.53	4.94		(0.57)	0.11	0.32
971	KWP34	34.50	3PH	333.59	5,582.50	0.76	(0.06)	(0.95)		0.81	0.32	(0.58)		0.44	0.55	(0.37)		1.52	2.09	1.21		(1.82)	(1.58)	(2.52)
2060	KWPII34	34.50	3PH	224.70	3,760.40	(13.03)	(13.78)	(14.62)		(13.01)	(13.47)	(14.32)		(13.27)	(13.19)	(14.06)		(12.31)	(11.82)	(12.65)		(15.17)	(14.98)	(15.86)
2061	KWPII_CLT1	34.50	3PH	223.00	3,731.90	(13.22)	(13.97)	(14.81)		(13.20)	(13.66)	(14.51)		(13.47)	(13.39)	(14.26)		(12.51)	(12.02)	(12.86)		(15.36)	(15.18)	(16.06)
12032	AUWAHI 34	34.50	3PH	199.13	3,332.30	0.32	1.25	3.00		0.03	1.12	1.65		(0.23)	0.84	1.99		0.14	1.25	2.00		(1.27)	(0.11)	1.05

HECO Transmission Planning Division
Reference: TPD 2014-20

Effect of Kahului Power Plant (KPP) Retirement on Short Circuit Current

				Case0		Case1 (Delta %)				Case2 (Delta %)				Case3 (Delta %)				Case4 (Delta %)				Case5 (Delta %)		
Bus	Name	KV	3PH	MVA	Amp	NoCont	Cont1	Cont2		NoCont	Cont 1	Cont2		NoCont	Cont 1	Cont 2		NoCont	Cont 1	Cont 2		NoCont	Cont 1	Cont 2
Col 1	Col 2	Col 3	Col 4	Col 5	Col 6	Col 7	Col 8	Col 9	Col 10	Col 11	Col 12	Col 13	Col 14	Col 15	Col 16	Col 17	Col 18	Col 19	Col 20	Col 21	Col 22	Col 23	Col 24	Col 25
12034	AWFTOTAL	34.50	3PH	199.13	3,332.30	0.32	1.25	3.00		0.03	1.12	1.65		(0.23)	0.84	1.99		0.14	1.25	2.00		(1.27)	(0.11)	1.05
12035	CKT1 BUS A	34.50	3PH	111.91	1,872.80	(1.27)	0.35	2.27		(1.54)	0.09	0.89		(1.66)	(0.18)	1.39		(1.57)	(0.17)	1.11		(2.15)	(0.62)	0.97
12036	AUWAHI_COL1	34.50	3PH	107.67	1,801.90	(1.41)	0.26	2.21		(1.69)	(0.01)	0.83		(1.79)	(0.28)	1.33		(1.72)	(0.30)	1.03		(2.25)	(0.69)	0.94
12037	CKT2 BUS B	34.50	3PH	111.69	1,869.10	(1.28)	0.35	2.27		(1.55)	0.08	0.89		(1.66)	(0.19)	1.38		(1.58)	(0.18)	1.11		(2.15)	(0.63)	0.97
12038	AUWAHI_COL2	34.50	3PH	106.94	1,789.70	(1.44)	0.24	2.20		(1.71)	(0.02)	0.81		(1.81)	(0.30)	1.31		(1.75)	(0.32)	1.01		(2.27)	(0.71)	0.93
3	WLUKU23	23.00	3PH	233.41	5,859.10	18.91	26.99	32.42		22.99	9.96	25.08		(8.05)	(10.20)	(4.27)		(23.22)	(34.69)	(24.55)		(18.01)	(25.07)	(17.43)
5	MAUI PIN	23.00	3PH	241.91	6,072.50	20.16	27.60	33.89		#N/A	#N/A	#N/A		(8.23)	(10.28)	(3.47)		(24.64)	(35.55)	(25.60)		(18.94)	(25.68)	(17.66)
7	WAI WELL	23.00	3PH	142.30	3,572.10	12.84	22.18	23.56		15.30	6.52	17.56		(4.59)	(5.64)	(1.46)		(12.69)	(21.34)	(13.62)		(10.12)	(15.62)	(9.82)
8	KAHU SUB	23.00	3PH	251.88	6,322.80	20.70	27.96	34.56		20.42	31.61	29.17		(8.64)	(10.80)	(3.80)		(25.96)	(37.11)	(26.91)		(19.89)	(26.76)	(18.53)
9	KAILUA	23.00	3PH	21.43	537.80	4.52	4.74	7.04		1.79	3.86	1.35		2.75	3.73	3.18		2.05	1.37	2.72		3.31	3.56	3.43
12	MAKAWAO	23.00	3PH	57.05	1,432.10	2.28	4.70	9.35		0.29	2.95	(0.84)		1.08	1.54	5.21		0.80	0.57	2.56		0.97	1.61	4.82
15	KOKOMO	23.00	3PH	53.07	1,332.30	2.21	4.44	8.83		0.28	2.78	(0.78)		1.04	1.52	4.84		0.77	0.53	2.40		0.98	1.57	4.49
16	HAIKU	23.00	3PH	40.71	1,022.00	2.05	3.64	7.16		0.25	2.29	(0.57)		0.97	1.47	3.71		0.68	0.42	1.91		1.01	1.46	3.48
18	WLUKU HT	23.00	3PH	139.98	3,513.80	12.85	22.44	23.61		15.16	6.43	17.45		(4.47)	(5.45)	(1.30)		(12.43)	(21.09)	(13.36)		(9.92)	(15.41)	(9.61)
22	WS PUMP	23.00	3PH	131.13	3,291.70	12.31	22.19	22.83		14.35	6.01	16.67		(4.10)	(4.94)	(0.96)		(11.47)	(19.83)	(12.34)		(9.18)	(14.49)	(8.87)
30	MOKUHAU	23.00	3PH	154.13	3,869.00	13.73	22.98	24.92		16.43	7.05	18.68		(5.02)	(6.24)	(1.80)		(13.97)	(23.09)	(14.96)		(11.09)	(16.88)	(10.77)
31	KAMOLE	23.00	3PH	43.23	1,085.20	2.13	3.83	7.55		0.30	2.42	(0.56)		1.02	1.52	3.98		0.74	0.48	2.05		1.04	1.51	3.72
33	WS MILL	23.00	3PH	219.38	5,507.00	18.01	26.29	31.17		21.89	9.50	24.02		(7.51)	(9.54)	(3.85)		(21.48)	(32.61)	(22.75)		(16.72)	(23.64)	(16.21)
40	ONEHEE	23.00	3PH	191.26	4,801.00	16.88	25.46	29.78		52.34	46.95	52.01		(6.04)	(7.53)	(1.81)		(17.75)	(27.43)	(18.68)		(13.94)	(19.98)	(13.03)
41	HANA	23.00	3PH	11.83	296.90	2.05	2.14	3.78		0.67	1.49	0.48		1.15	1.80	1.55		0.88	0.58	1.24		1.38	1.53	1.48

Effect of Kahului Power Plant (KPP) Retirement on Short Circuit Current

				Case0		Case1 (Delta %)				Case2 (Delta %)				Case3 (Delta %)				Case4 (Delta %)				Case5 (Delta %)		
Bus	Name	KV	3PH	MVA	Amp	NoCont	Cont1	Cont2		NoCont	Cont 1	Cont2		NoCont	Cont 1	Cont 2		NoCont	Cont 1	Cont 2		NoCont	Cont 1	Cont 2
Col 1	Col 2	Col 3	Col 4	Col 5	Col 6	Col 7	Col 8	Col 9	Col 10	Col 11	Col 12	Col 13	Col 14	Col 15	Col 16	Col 17	Col 18	Col 19	Col 20	Col 21	Col 22	Col 23	Col 24	Col 25
42	KEANAE	23.00	3PH	16.61	416.90	3.31	3.47	5.45		1.22	2.69	0.91		1.97	2.76	2.37		1.46	0.97	2.00		2.35	2.54	2.47
43	WAIEHU	23.00	3PH	107.62	2,701.50	10.31	20.08	19.54		11.97	4.95	14.23		(3.33)	(3.74)	(0.39)		(9.13)	(16.33)	(9.86)		(7.38)	(11.93)	(7.11)
48	MAUIBLOC	23.00	3PH	77.39	1,942.80	8.45	19.82	16.81		8.86	3.32	11.26		(2.00)	(1.73)	0.92		(5.89)	(12.02)	(6.44)		(4.85)	(8.65)	(4.55)
61	HOSMER	23.00	3PH	33.22	834.00	1.46	3.39	6.48		0.66	1.99	0.65		0.86	1.22	3.32		0.76	0.69	1.76		0.79	1.18	3.25
64	PUUNENE	23.00	3PH	113.75	2,855.30	12.79	21.71	24.15		11.91	12.72	13.70		(3.87)	(3.82)	0.28		(11.21)	(16.79)	(11.86)		(8.84)	(12.36)	(8.17)
73	KUAU	23.00	3PH	86.68	2,175.90	9.89	18.31	19.36		9.20	10.09	10.93		(2.96)	(2.48)	0.68		(8.33)	(12.73)	(8.87)		(6.65)	(9.34)	(6.18)
74	HUELO	23.00	3PH	21.83	547.90	4.62	4.82	7.14		1.83	3.94	1.38		2.83	3.81	3.24		2.12	1.39	2.77		3.39	3.62	3.50
75	NEWHDWD	23.00	3PH	91.45	2,295.70	10.80	19.97	21.34		9.59	10.55	11.48		(2.99)	(2.62)	0.90		(8.63)	(13.45)	(9.17)		(6.89)	(9.88)	(6.31)
77	WAIKAPU	23.00	3PH	76.56	1,921.80	8.38	19.76	16.70		8.77	3.27	11.16		(1.98)	(1.68)	0.94		(5.82)	(11.90)	(6.35)		(4.79)	(8.56)	(4.49)
82	AMERON	23.00	3PH	91.84	2,305.50	10.86	20.55	21.85		9.19	10.25	11.22		(2.76)	(2.38)	1.21		(8.09)	(12.99)	(8.60)		(6.48)	(9.55)	(5.88)
88	AMERBLDG	23.00	3PH	95.11	2,387.60	11.16	20.84	22.31		9.52	10.57	11.55		(2.88)	(2.54)	1.14		(8.43)	(13.45)	(8.96)		(6.74)	(9.89)	(6.13)
92	SPRECK	23.00	3PH	122.42	3,073.00	13.00	21.11	23.94		12.82	13.48	14.40		(4.38)	(4.41)	(0.34)		(12.43)	(18.03)	(13.15)		(9.75)	(13.28)	(9.14)
93	PAIAMKA	23.00	3PH	96.24	2,415.70	10.75	19.11	20.69		10.18	11.02	11.89		(3.34)	(3.00)	0.42		(9.40)	(14.13)	(9.98)		(7.47)	(10.39)	(6.96)
145	SUMMITAP	23.00	3PH	29.00	727.80	1.64	3.23	5.69		0.81	2.04	0.82		1.02	1.39	3.10		0.88	0.80	1.75		0.96	1.38	3.04
200	KAHULUI	23.00	3PH	323.69	8,125.30	31.37	37.81	44.81		33.95	31.99	34.54		(18.75)	(21.12)	(12.05)		(63.88)	(78.75)	(64.73)		(43.78)	(52.66)	(41.60)
202	KANAHA 23	23.00	3PH	338.88	8,506.60	28.26	34.39	42.81		29.92	28.42	29.87		(13.73)	(16.20)	(6.28)		(45.82)	(58.78)	(45.09)		(33.11)	(40.90)	(29.25)
213	KULA 23	23.00	3PH	46.70	1,172.20	1.87	4.75	9.47		1.03	2.71	0.97		1.24	1.58	4.77		1.16	1.12	2.53		1.07	1.47	4.62
217	PUKLN23	23.00	3PH	96.72	2,427.80	3.46	7.79	14.81		0.94	5.08	(0.93)		1.93	2.37	9.19		1.61	1.45	4.64		1.47	2.61	8.44
236	WAIINU23	23.00	3PH	254.25	6,382.20	17.75	25.79	32.20		28.26	7.61	30.19		(7.00)	(9.35)	(3.48)		(20.30)	(31.83)	(21.41)		(16.28)	(23.12)	(15.51)
671	JCT B	23.00	3PH	115.19	2,891.50	11.26	21.62	21.27		12.81	5.25	15.18		(3.47)	(4.00)	(0.37)		(9.76)	(17.54)	(10.54)		(7.86)	(12.79)	(7.56)

HECO Transmission Planning Division
Reference: TPD 2014-20

Effect of Kahului Power Plant (KPP) Retirement on Short Circuit Current

				Case0		Case1 (Delta %)				Case2 (Delta %)				Case3 (Delta %)				Case4 (Delta %)				Case5 (Delta %)		
Bus	Name	KV	3PH	MVA	Amp	NoCont	Cont1	Cont2		NoCont	Cont 1	Cont2		NoCont	Cont 1	Cont 2		NoCont	Cont 1	Cont 2		NoCont	Cont 1	Cont 2
Col 1	Col 2	Col 3	Col 4	Col 5	Col 6	Col 7	Col 8	Col 9	Col 10	Col 11	Col 12	Col 13	Col 14	Col 15	Col 16	Col 17	Col 18	Col 19	Col 20	Col 21	Col 22	Col 23	Col 24	Col 25
806	TOHANA	23.00	3PH	178.31	4,475.90	17.54	25.19	30.14		17.99	18.19	19.24		(6.64)	(7.42)	(1.88)		(19.51)	(27.03)	(20.35)		(14.97)	(19.76)	(13.95)
809	REG	23.00	3PH	30.17	757.40	2.30	3.30	6.17		0.55	2.22	(0.04)		1.21	1.78	3.03		0.88	0.59	1.78		1.33	1.66	2.85
812	MAKW JCT	23.00	3PH	70.80	1,777.20	2.71	5.82	11.39		0.52	3.72	(0.85)		1.38	1.83	6.66		1.09	0.88	3.31		1.15	1.96	6.14
813	HOS JCT	23.00	3PH	36.63	919.50	1.56	3.71	7.24		0.73	2.15	0.71		0.94	1.28	3.66		0.84	0.77	1.92		0.84	1.22	3.56
816	HAIK JCT	23.00	3PH	39.72	997.10	2.07	3.61	7.07		0.28	2.28	(0.52)		0.98	1.49	3.64		0.70	0.43	1.90		1.03	1.47	3.43
819	PUUN JCT	23.00	3PH	193.72	4,862.80	19.18	27.17	32.53		19.31	19.37	20.56		(7.14)	(8.13)	(1.94)		(21.47)	(29.82)	(22.23)		(16.39)	(21.71)	(15.09)
826		23.00	3PH	161.84	4,062.40	16.71	25.00	29.36		16.54	16.92	18.01		(5.84)	(6.44)	(1.11)		(17.23)	(24.45)	(18.01)		(13.30)	(17.91)	(12.33)
827	CONC TAP	23.00	3PH	97.88	2,456.90	11.41	21.08	22.68		9.81	10.84	11.83		(2.98)	(2.69)	1.07		(8.72)	(13.85)	(9.27)		(6.96)	(10.19)	(6.34)
831	KAML TAP	23.00	3PH	46.53	1,168.10	2.11	4.00	7.94		0.26	2.51	(0.68)		0.99	1.47	4.23		0.71	0.46	2.13		0.98	1.49	3.95
838		23.00	3PH	78.57	1,972.30	8.55	19.90	16.98		8.99	3.37	11.38		(2.04)	(1.80)	0.89		(6.00)	(12.19)	(6.55)		(4.93)	(8.78)	(4.63)
840	TO-ONEE	23.00	3PH	245.67	6,166.80	20.01	27.44	33.79		58.70	52.46	57.97		(8.23)	(10.37)	(3.59)		(24.52)	(35.62)	(25.53)		(18.91)	(25.74)	(17.68)
848	JCT C	23.00	3PH	67.63	1,697.60	8.57	18.03	18.05		6.95	8.04	8.92		(2.06)	(1.31)	1.59		(5.98)	(9.98)	(6.36)		(4.86)	(7.28)	(4.35)
849	REGULATO	23.00	3PH	26.15	656.40	5.62	5.89	8.40		2.29	4.90	1.74		3.49	4.60	3.88		2.61	1.73	3.37		4.19	4.48	4.30
858	PUUOHALA	23.00	3PH	194.67	4,886.70	16.38	24.98	28.83		19.88	8.63	22.06		(6.57)	(8.34)	(3.10)		(18.52)	(28.96)	(19.70)		(14.52)	(21.08)	(14.10)
892	BALWNPK	23.00	3PH	106.34	2,669.40	11.62	19.85	21.94		11.22	11.99	12.88		(3.74)	(3.55)	0.11		(10.55)	(15.60)	(11.20)		(8.34)	(11.49)	(7.80)
893	PAIAMKA	23.00	3PH	97.89	2,457.20	10.87	19.18	20.84		10.35	11.17	12.05		(3.41)	(3.09)	0.35		(9.59)	(14.35)	(10.18)		(7.61)	(10.56)	(7.10)
898	SUB 98 TAP	23.00	3PH	44.78	1,124.10	2.09	3.90	7.70		0.25	2.45	(0.65)		0.99	1.48	4.07		0.70	0.45	2.06		0.99	1.49	3.81
4002	PUUN 23	23.00	3PH	286.69	7,196.60	20.84	26.77	36.54		20.26	22.97	18.72		(5.80)	(7.18)	2.10		(20.76)	(28.43)	(18.87)		(16.11)	(20.74)	(11.21)
301	CT-1 M14	13.80	3PH	435.39	18,215.30	0.44	0.02	(0.42)		0.46	0.21	(0.23)		0.30	0.36	(0.10)		0.83	1.13	0.69		(0.80)	(0.68)	(1.14)
302	CT-2 M16	13.80	3PH	421.28	17,625.10	0.03	(1.57)	(2.06)		0.18	(0.62)	(1.11)		0.04	(0.25)	(0.86)		0.51	0.92	0.26		(0.97)	(1.09)	(1.73)

Effect of Kahului Power Plant (KPP) Retirement on Short Circuit Current

				Case0		Case1 (Delta %)				Case2 (Delta %)				Case3 (Delta %)				Case4 (Delta %)				Case5 (Delta %)		
Bus	Name	KV	3PH	MVA	Amp	NoCont	Cont1	Cont2		NoCont	Cont 1	Cont2		NoCont	Cont 1	Cont 2		NoCont	Cont 1	Cont 2		NoCont	Cont 1	Cont 2
Col 1	Col 2	Col 3	Col 4	Col 5	Col 6	Col 7	Col 8	Col 9	Col 10	Col 11	Col 12	Col 13	Col 14	Col 15	Col 16	Col 17	Col 18	Col 19	Col 20	Col 21	Col 22	Col 23	Col 24	Col 25
303	ST-1 M15	13.80	3PH	312.06	13,055.50	0.24	(1.22)	(1.81)		0.37	(0.37)	(0.97)		0.19	(0.02)	(0.71)		0.81	1.27	0.54		(1.13)	(1.17)	(1.89)
304	CT-3 M17	13.80	3PH	405.57	16,968.00	(0.06)	(1.74)	(2.19)		0.09	(0.73)	(1.18)		(0.02)	(0.36)	(0.94)		0.38	0.79	0.14		(0.92)	(1.07)	(1.68)
305	CT-4 M19	13.80	3PH	405.57	16,968.00	(0.06)	(1.74)	(2.19)		0.09	(0.73)	(1.18)		(0.02)	(0.36)	(0.94)		0.38	0.79	0.14		(0.92)	(1.07)	(1.68)
306	ST-2 M18	13.80	3PH	297.95	12,465.10	0.23	(1.09)	(1.62)		0.34	(0.33)	(0.87)		0.18	(0.01)	(0.64)		0.74	1.16	0.50		(1.02)	(1.05)	(1.71)
804	HC&S TG4	13.80	3PH	416.99	17,445.60	#N/A	#N/A	#N/A		#N/A	#N/A	#N/A		#N/A	#N/A	#N/A		#N/A	#N/A	#N/A		#N/A	#N/A	#N/A
12031	BURIED_TERT	13.80	3PH	126.96	5,311.60	(0.25)	0.93	2.57		(0.53)	0.70	1.22		(0.64)	0.48	1.72		(0.42)	0.65	1.58		(1.26)	(0.08)	1.19
13	KULA 12	12.47	3PH	77.44	3,585.40	1.52	3.65	9.35		0.58	1.73	0.47		0.75	1.10	4.41		0.71	0.73	2.15		0.34	0.76	4.01
98	KAUHIKO A	12.47	3PH	32.80	1,518.80	1.99	3.23	6.18		0.32	2.04	(0.39)		0.99	1.52	3.17		0.70	0.44	1.71		1.09	1.47	2.99
112	MAKA 12	12.47	3PH	35.56	1,646.60	3.72	6.84	10.31		2.10	5.04	0.71		2.76	3.25	5.67		2.50	2.24	4.75		2.84	3.85	5.48
123	PUUKB 12	12.47	3PH	78.28	3,624.10	0.15	(0.08)	(0.33)		0.18	0.03	(0.22)		0.08	0.12	(0.14)		0.37	0.54	0.29		(0.53)	(0.46)	(0.73)
125	WAILEA A	12.47	3PH	93.34	4,321.70	1.07	1.42	2.92		0.82	1.20	1.02		0.71	1.01	1.49		0.87	1.15	1.34		0.09	0.45	0.96
129	NAPILA12	12.47	3PH	72.43	3,353.30	0.13	(0.09)	(0.31)		0.15	0.02	(0.21)		0.07	0.10	(0.14)		0.33	0.48	0.25		(0.49)	(0.44)	(0.68)
134	LAHAINA 1	12.47	3PH	89.27	4,133.00	0.10	(0.16)	(0.45)		0.13	(0.03)	(0.32)		0.02	0.06	(0.24)		0.36	0.54	0.26		(0.67)	(0.60)	(0.90)
135	KIHEI A	12.47	3PH	84.63	3,918.10	1.14	1.26	1.62		1.02	1.17	0.97		0.90	1.09	1.24		1.12	1.34	1.33		0.30	0.54	0.72
136	WAIINU B	12.47	3PH	88.57	4,100.80	1.05	26.53	3.49		(2.15)	(89.74)	0.48		0.03	16.03	0.16		(0.04)	11.01	(0.16)		(0.42)	12.48	(0.14)
139	MAALA A	12.47	3PH	91.98	4,258.40	0.27	(0.02)	(0.32)		0.28	0.11	(0.19)		0.18	0.22	(0.09)		0.54	0.75	0.45		(0.56)	(0.48)	(0.79)
150	MAHINA 12	12.47	3PH	77.80	3,601.90	0.04	(0.19)	(0.44)		0.06	(0.09)	(0.33)		(0.02)	0.02	(0.24)		0.27	0.43	0.19		(0.61)	(0.54)	(0.80)
155	KULA AG	12.47	3PH	45.01	2,084.10	0.87	1.59	4.61		0.40	1.03	0.50		0.47	0.74	1.58		0.47	0.51	0.97		0.24	0.54	2.02
175	NEWHD WD	12.47	3PH	40.21	1,861.90	5.81	14.75	13.07		4.34	5.41	6.18		(1.29)	(0.14)	1.96		(3.72)	(6.70)	(3.92)		(3.11)	(4.77)	(2.68)
177	WAIKAP12	12.47	3PH	37.46	1,734.40	5.00	15.78	10.31		4.90	1.52	6.98		(0.91)	0.33	1.73		(2.81)	(6.64)	(3.11)		(2.40)	(4.57)	(2.11)

Effect of Kahului Power Plant (KPP) Retirement on Short Circuit Current

				Case0		Case1 (Delta %)				Case2 (Delta %)				Case3 (Delta %)				Case4 (Delta %)				Case5 (Delta %)		
Bus	Name	KV	3PH	MVA	Amp	NoCont	Cont1	Cont2		NoCont	Cont 1	Cont2		NoCont	Cont 1	Cont 2		NoCont	Cont 1	Cont 2		NoCont	Cont 1	Cont 2
Col 1	Col 2	Col 3	Col 4	Col 5	Col 6	Col 7	Col 8	Col 9	Col 10	Col 11	Col 12	Col 13	Col 14	Col 15	Col 16	Col 17	Col 18	Col 19	Col 20	Col 21	Col 22	Col 23	Col 24	Col 25
203	KANAH A	12.47	3PH	96.39	4,462.60	4.47	10.87	24.07		(0.58)	6.58	(5.96)		2.05	2.60	12.19		1.35	0.91	6.63		1.64	2.92	10.82
204	KANAH B	12.47	3PH	86.95	4,025.90	4.10	10.55	23.04		(0.58)	6.14	(6.14)		1.85	3.04	11.63		1.20	0.76	5.66		1.55	3.45	10.39
205	KANAH C	12.47	3PH	95.69	4,430.40	4.36	10.14	23.69		(1.27)	5.84	(6.67)		1.98	2.53	12.00		1.30	0.87	6.51		1.60	2.87	10.66
216	HAIKU 2	12.47	3PH	28.32	1,311.10	4.43	6.64	9.03		2.23	5.62	0.96		3.51	4.03	4.53		3.24	2.98	4.02		3.65	3.96	5.04
225	WAILEA B	12.47	3PH	91.90	4,255.00	1.02	1.37	2.83		0.78	1.15	0.97		0.67	0.97	1.45		0.84	1.11	1.30		0.07	0.42	0.93
234	LAHAINA 2	12.47	3PH	91.71	4,246.30	0.12	(0.16)	(0.45)		0.14	(0.02)	(0.32)		0.04	0.07	(0.23)		0.38	0.57	0.28		(0.68)	(0.61)	(0.92)
235	KIHEI B	12.47	3PH	86.00	3,981.80	1.18	1.29	1.66		1.06	1.21	1.01		0.94	1.13	1.27		1.16	1.38	1.36		0.32	0.56	0.74
325	WAILEA C	12.47	3PH	93.01	4,306.10	1.10	1.45	2.31		0.85	1.23	1.05		0.73	1.03	1.52		0.90	1.17	1.36		0.10	0.46	0.98
335	KIHEI C	12.47	3PH	83.83	3,881.10	1.18	1.30	1.67		1.05	1.21	1.01		0.94	1.12	1.28		1.15	1.37	1.36		0.33	0.57	0.75
336	WAIINU C	12.47	3PH	88.60	4,101.90	1.03	26.32	3.47		(2.16)	(89.87)	0.47		0.02	15.96	0.15		(0.04)	10.97	(0.16)		(0.42)	12.44	(0.14)
405	WLUKU C	12.47	3PH	76.85	3,558.20	7.44	27.82	17.81		8.12	3.63	10.82		(2.27)	0.75	1.07		(5.40)	(13.07)	(5.94)		(4.31)	(9.09)	(4.09)
415	WLUKU D	12.47	3PH	63.87	2,956.90	6.39	26.94	16.04		6.70	2.90	9.36		(1.84)	1.45	1.43		(4.24)	(11.22)	(4.70)		(3.40)	(7.71)	(3.17)
425	WAILEA D	12.47	3PH	84.37	3,906.00	0.73	1.08	3.05		0.48	0.84	0.67		0.43	0.72	1.19		0.58	0.83	1.02		(0.07)	0.27	0.77
435	KIHEI D	12.47	3PH	89.62	4,149.50	1.21	1.31	1.67		1.08	1.23	1.03		0.96	1.15	1.29		1.19	1.42	1.39		0.32	0.56	0.73
443	WAIEHU12	12.47	3PH	55.16	2,553.70	5.90	27.61	15.20		5.85	2.38	8.52		(1.56)	2.46	2.35		(3.56)	(10.17)	(3.97)		(2.87)	(6.91)	(2.63)
511	MPINE	12.47	3PH	59.82	2,769.80	7.20	26.37	18.53		#N/A	#N/A	#N/A		(0.89)	1.94	3.43		(3.18)	(9.36)	(3.51)		(2.44)	(6.87)	(2.03)
534	LAHAINA 5	12.47	3PH	99.42	4,603.10	0.08	(0.22)	(0.54)		0.10	(0.08)	(0.40)		(0.01)	0.03	(0.29)		0.36	0.57	0.26		(0.77)	(0.69)	(1.02)
723	PUUKA 12	12.47	3PH	91.05	4,215.40	0.05	(0.22)	(0.51)		0.08	(0.09)	(0.39)		(0.02)	0.02	(0.28)		0.32	0.51	0.22		(0.72)	(0.64)	(0.95)
729	NAPILB12	12.47	3PH	74.38	3,443.80	0.11	(0.11)	(0.35)		0.14	(0.00)	(0.24)		0.05	0.08	(0.17)		0.32	0.48	0.24		(0.53)	(0.47)	(0.72)
750	MAHINB 12	12.47	3PH	79.14	3,664.20	0.09	(0.14)	(0.40)		0.11	(0.03)	(0.29)		0.02	0.06	(0.21)		0.32	0.48	0.23		(0.59)	(0.52)	(0.79)

Effect of Kahului Power Plant (KPP) Retirement on Short Circuit Current

				Case0		Case1 (Delta %)				Case2 (Delta %)				Case3 (Delta %)				Case4 (Delta %)				Case5 (Delta %)		
Bus	Name	KV	3PH	MVA	Amp	NoCont	Cont1	Cont2		NoCont	Cont 1	Cont2		NoCont	Cont 1	Cont 2		NoCont	Cont 1	Cont 2		NoCont	Cont 1	Cont 2
Col 1	Col 2	Col 3	Col 4	Col 5	Col 6	Col 7	Col 8	Col 9	Col 10	Col 11	Col 12	Col 13	Col 14	Col 15	Col 16	Col 17	Col 18	Col 19	Col 20	Col 21	Col 22	Col 23	Col 24	Col 25
803	KAHUL 3	12.47	3PH	62.02	2,871.20	6.14	26.26	17.96		27.00	26.94	27.76		(1.87)	2.07	2.90		(3.51)	(8.78)	(3.88)		(3.42)	(6.35)	(3.07)
817	PUKLN A	12.47	3PH	93.93	4,348.70	3.03	7.12	16.43		0.49	4.15	(1.32)		1.46	1.93	7.99		1.13	0.96	4.33		1.01	1.57	7.82
834	LAHAIN 4	12.47	3PH	92.05	4,261.60	0.08	(0.19)	(0.49)		0.10	(0.07)	(0.36)		0.00	0.04	(0.26)		0.34	0.54	0.25		(0.71)	(0.64)	(0.94)
917	PUKLN B	12.47	3PH	87.26	4,040.00	2.88	7.08	15.72		0.44	4.01	(1.25)		1.39	1.85	7.87		1.06	0.88	4.23		1.00	1.55	7.17
101	KGS-1	11.50	3PH	84.66	4,250.50	#N/A	#N/A	#N/A		#N/A	#N/A	#N/A		#N/A	#N/A	#N/A		(254.71)	(269.41)	(256.56)		(96.79)	(107.80)	(102.51)
102	KGS-2	11.50	3PH	72.41	3,635.30	#N/A	#N/A	#N/A		#N/A	#N/A	#N/A		#N/A	#N/A	#N/A		(317.45)	(333.15)	(318.80)		(109.24)	(120.27)	(115.26)
103	KGS-3	11.50	3PH	118.79	5,963.50	#N/A	#N/A	#N/A		#N/A	#N/A	#N/A		(114.08)	(120.26)	(113.37)		(128.97)	(142.11)	(132.83)		(108.51)	(122.91)	(115.99)
104	KGS-4	11.50	3PH	270.74	13,592.60	#N/A	#N/A	#N/A		#N/A	#N/A	#N/A		(5.78)	(3.90)	(1.06)		0.10	(2.80)	0.63		(12.46)	(15.71)	(12.62)
164	PUUNENE	7.20	3PH	6.15	493.10	2.09	11.34	6.77		(0.08)	0.99	1.71		0.04	1.78	2.98		(0.20)	(1.99)	(0.08)		(0.34)	(1.12)	0.10
108	MGS-1011	6.90	3PH	386.77	32,362.60	0.07	(1.75)	(2.31)		0.24	(0.67)	(1.23)		0.09	(0.25)	(0.95)		0.61	1.09	0.33		(1.07)	(1.21)	(1.94)
109	MGS-1213	6.90	3PH	309.02	25,856.50	(24.93)	(27.14)	(27.96)		(24.73)	(25.85)	(26.67)		(24.92)	(25.35)	(26.33)		0.79	1.32	0.49		(26.38)	(26.56)	(27.59)
192	SPRECK	4.60	3PH	37.04	4,649.30	5.08	23.81	17.90		3.68	5.37	5.46		(1.07)	2.23	4.09		(2.40)	(5.83)	(2.56)		(1.93)	(4.09)	(1.52)
45	HALEKALA	4.16	3PH	7.08	982.40	2.06	2.29	1.75		1.26	2.01	1.32		1.50	1.96	2.05		1.26	1.15	1.66		1.58	2.07	2.15
105	MGS-123	4.16	3PH	90.23	12,522.20	0.28	0.02	(0.26)		0.30	0.14	(0.15)		0.19	0.23	(0.06)		0.53	0.72	0.44		(0.51)	(0.43)	(0.73)
106	MGS-458	4.16	3PH	267.00	37,056.20	(0.18)	(2.11)	(2.50)		0.00	(0.93)	(1.31)		41.74	41.68	41.33		42.08	42.17	41.84		(0.75)	(0.99)	(1.57)
107	MGS-679	4.16	3PH	193.71	26,884.50	(36.39)	(38.05)	(38.67)		(36.24)	(37.08)	(37.70)		(18.16)	(18.44)	(19.08)		20.47	20.65	20.21		(37.36)	(37.53)	(38.30)
110	MGS-X1X2	4.16	3PH	91.99	12,767.20	0.29	0.02	(0.27)		0.31	0.14	(0.15)		0.20	0.23	(0.06)		0.55	0.74	0.45		(0.52)	(0.44)	(0.74)
173	KUAU A	4.16	3PH	12.47	1,730.70	4.02	22.26	14.68		0.73	1.79	2.53		1.20	4.10	5.43		0.63	(2.69)	0.70		0.59	(1.65)	1.03
403	WLUKU A	4.16	3PH	27.47	3,812.00	3.71	19.73	9.16		3.44	0.82	5.36		(0.60)	2.95	1.89		(1.87)	(4.87)	(2.09)		(1.66)	(3.23)	(1.38)
404	WLUKU B	4.16	3PH	27.52	3,819.20	3.61	19.01	9.88		3.36	0.76	5.25		(0.62)	3.88	1.86		(1.86)	(5.35)	(2.08)		(1.66)	(3.73)	(1.37)

HECO Transmission Planning Division
Reference: TPD 2014-20

Effect of Kahului Power Plant (KPP) Retirement on Short Circuit Current

				Case0		Case1 (Delta %)				Case2 (Delta %)				Case3 (Delta %)				Case4 (Delta %)				Case5 (Delta %)		
Bus	Name	KV	3PH	MVA	Amp	NoCont	Cont1	Cont2		NoCont	Cont 1	Cont2		NoCont	Cont 1	Cont 2		NoCont	Cont 1	Cont 2		NoCont	Cont 1	Cont 2
Col 1	Col 2	Col 3	Col 4	Col 5	Col 6	Col 7	Col 8	Col 9	Col 10	Col 11	Col 12	Col 13	Col 14	Col 15	Col 16	Col 17	Col 18	Col 19	Col 20	Col 21	Col 22	Col 23	Col 24	Col 25
407	WAI WELL	4.16	3PH	26.34	3,655.90	3.66	23.84	11.12		2.67	0.76	5.25		(0.48)	4.21	2.68		(1.66)	(5.95)	(1.87)		(1.49)	(3.66)	(1.19)
418	WLUKUHT	4.16	3PH	47.61	6,607.30	5.35	24.98	14.66		5.08	1.37	7.72		(1.24)	2.28	2.62		(2.86)	(9.69)	(3.21)		(2.31)	(6.68)	(2.05)
431	KAMOLE 4	4.16	3PH	13.60	1,887.50	4.84	6.67	8.29		2.72	5.45	1.87		3.85	4.51	4.25		3.51	3.20	4.45		4.07	4.82	4.73
436	WAIINUA	4.16	3PH	24.16	3,353.30	3.00	19.66	9.04		3.13	(1.52)	5.54		(0.32)	4.26	2.58		(1.15)	(6.01)	(1.31)		(1.20)	(3.22)	(0.80)
440	ONEHEE 4	4.16	3PH	24.23	3,362.20	3.49	20.16	12.93		12.79	14.96	14.74		(0.41)	4.13	3.53		(0.84)	(4.72)	(0.94)		(0.76)	(3.27)	(0.34)
493	PAIAMKA 1	4.16	3PH	33.89	4,703.90	6.02	23.86	17.87		3.92	4.94	5.68		0.42	3.01	5.43		(0.70)	(4.68)	(0.83)		(0.30)	(3.06)	0.10
844	KAHUL 4	4.16	3PH	38.20	5,301.50	5.33	22.63	15.70		14.97	14.87	16.21		(0.23)	2.88	3.85		(1.38)	(6.46)	(1.57)		(1.05)	(4.63)	(0.64)
845	KAHUL 5	4.16	3PH	38.23	5,305.20	5.28	22.50	15.60		14.96	14.87	16.19		(0.23)	3.46	4.43		(1.38)	(6.44)	(1.57)		(1.05)	(4.62)	(0.64)
846	KAHUL 6	4.16	3PH	38.20	5,301.90	4.71	22.58	15.67		14.99	14.90	16.23		(0.87)	2.88	3.85		(1.38)	(6.46)	(1.57)		(1.05)	(4.63)	(0.65)
141	HANA 1	2.40	3PH	7.29	1,754.10	1.08	1.73	5.30		0.34	0.57	0.24		0.60	1.08	2.21		0.48	0.41	0.71		0.63	0.76	1.32
142	KEANAE	2.40	3PH	4.96	1,193.00	0.54	1.16	5.03		0.22	0.06	0.18		0.32	0.73	1.91		0.33	0.38	0.47		0.23	0.34	0.90
161	HOSMER	2.40	3PH	5.16	1,241.00	0.66	0.66	(0.22)		(0.05)	0.49	(0.03)		0.23	0.61	0.44		0.07	(0.04)	0.29		0.40	0.80	0.64
174	HUELO 1	2.40	3PH	2.84	684.00	0.01	(0.01)	0.82		(0.01)	(0.44)	-		(0.01)	0.31	0.37		0.07	0.22	0.15		(0.19)	(0.10)	(0.15)
209	KAILUA A	2.40	3PH	2.58	620.40	(0.03)	(0.05)	0.76		(0.02)	(0.49)	0.02		(0.03)	0.29	0.34		0.06	0.23	0.13		(0.23)	(0.13)	(0.18)
241	HANA 2	2.40	3PH	8.78	2,112.00	1.36	1.42	5.20		0.36	0.84	0.22		0.72	1.26	2.35		0.54	0.39	0.82		0.83	0.97	1.54
422	WSCO PMP	2.40	3PH	48.75	11,728.30	5.75	15.92	11.50		6.18	2.25	8.24		(1.35)	(0.42)	1.27		(3.87)	(8.16)	(4.25)		(3.24)	(5.75)	(2.98)
430	MOKU PMP	2.40	3PH	26.27	6,319.40	3.66	14.13	7.66		3.29	0.75	5.24		(0.48)	1.13	2.03		(1.67)	(4.61)	(1.88)		(1.50)	(3.01)	(1.20)
92031	AUWAHI_SIEM1	0.69	3PH	84.83	70,978.30	(2.40)	(0.29)	1.88		(2.66)	(0.60)	0.54		(2.70)	(0.82)	1.10		(2.71)	(0.95)	0.74		(2.98)	(1.07)	0.88
92032	AUWAHI_SIEM2	0.69	3PH	84.48	70,687.70	(2.42)	(0.31)	1.86		(2.68)	(0.61)	0.53		(2.72)	(0.84)	1.09		(2.74)	(0.97)	0.72		(3.00)	(1.09)	0.87
92061	KWPII_GEN1	0.69	3PH	146.94	122,950.20	(23.26)	(23.77)	(24.37)		(23.27)	(23.59)	(24.20)		(23.41)	(23.37)	(24.00)		(22.74)	(22.42)	(23.03)		(24.64)	(24.53)	(25.15)

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Effect of Kahului Power Plant (KPP) Retirement on Short Circuit Current

				Case0		Case1 (Delta %)				Case2 (Delta %)				Case3 (Delta %)				Case4 (Delta %)				Case5 (Delta %)		
Bus	Name	KV	3PH	MVA	Amp	NoCont	Cont1	Cont2		NoCont	Cont 1	Cont2		NoCont	Cont 1	Cont 2		NoCont	Cont 1	Cont 2		NoCont	Cont 1	Cont 2
Col 1	Col 2	Col 3	Col 4	Col 5	Col 6	Col 7	Col 8	Col 9	Col 10	Col 11	Col 12	Col 13	Col 14	Col 15	Col 16	Col 17	Col 18	Col 19	Col 20	Col 21	Col 22	Col 23	Col 24	Col 25
90971	KWPI_1	0.58	3PH	240.25	241,235.90	0.50	(0.02)	(0.58)		0.53	0.22	(0.34)		0.29	0.37	(0.21)		0.98	1.34	0.79		(1.11)	(0.96)	(1.55)
44	DET 03	0.48	3PH	15.93	19,163.20	1.72	2.51	3.23		0.93	1.85	0.96		1.17	1.58	2.33		0.98	0.88	1.56		1.20	1.65	2.39
127	CONCRETE	0.48	3PH	23.01	27,680.60	3.87	12.95	9.83		2.06	3.13	3.88		(0.59)	0.88	2.49		(1.83)	(4.17)	(1.87)		(1.63)	(2.82)	(1.20)
148	MAUIBLOC	0.48	3PH	10.72	12,888.90	2.53	13.53	5.60		1.56	(0.20)	3.46		0.06	2.11	2.56		(0.39)	(2.59)	(0.50)		(0.47)	(1.41)	(0.15)
182	AMERON	0.48	3PH	26.63	32,029.00	4.34	13.42	10.64		2.59	3.68	4.43		(0.74)	0.65	2.38		(2.25)	(4.75)	(2.33)		(1.96)	(3.26)	(1.53)
188	AMERBLDG	0.48	3PH	3.66	4,401.50	1.83	11.10	6.34		(0.40)	0.66	1.38		0.12	1.90	3.05		0.03	(1.69)	0.18		(0.17)	(0.88)	0.29
501	AUX K1	0.48	3PH	13.90	16,715.70	#N/A	#N/A	#N/A		#N/A	#N/A	#N/A		#N/A	#N/A	#N/A		(12.60)	(15.77)	(13.31)		(8.66)	(12.34)	(10.98)
502	AUX K2	0.48	3PH	10.40	12,511.40	#N/A	#N/A	#N/A		#N/A	#N/A	#N/A		#N/A	#N/A	#N/A		(11.67)	(15.03)	(12.56)		(8.64)	(12.24)	(10.94)
503	AUX K3	0.48	3PH	10.76	12,939.80	#N/A	#N/A	#N/A		#N/A	#N/A	#N/A		(5.04)	(5.20)	(4.09)		(5.06)	(8.20)	(6.17)		(5.70)	(9.61)	(8.36)
504	AUX K4	0.48	3PH	11.88	14,287.90	#N/A	#N/A	#N/A		#N/A	#N/A	#N/A		(0.12)	3.42	3.84		0.39	0.50	1.76		(0.87)	(1.26)	(0.74)
2062	KWPII-BESS	0.48	3PH	139.62	167,939.00	(8.44)	(8.88)	(9.38)		(8.44)	(8.71)	(9.22)		(8.58)	(8.54)	(9.06)		(8.02)	(7.74)	(8.25)		(9.64)	(9.54)	(10.07)
12033	XP_BESS	0.48	3PH	101.47	122,047.80	(0.29)	0.91	2.45		(0.56)	0.63	1.08		(0.63)	0.43	1.64		(0.46)	0.52	1.45		(1.12)	(0.01)	1.23

Kahului Power Plant Retirement:
Transmission System Steady State Analysis

Prepared for
Maui Electric Company, Ltd.

Prepared by
Hawaiian Electric Company, Inc
System Planning Department
Transmission Planning Division

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Kahului Power Plant Retirement: Transmission System Steady State Analysis

Prepared by: LoriAnn Fukuda 8/20/2014

LoriAnn Fukuda
Planning Engineer I

Approved by: 8/20/2014

Gemini Yau
Lead Planning Engineer

Ronald Bushner 8/20/2014

Ronald Bushner
Director, Transmission Planning

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Introduction

Kahului Power Plant (KPP) is scheduled to be decommissioned in 2019. The Maui transmission system consists of a 23kV system and a 69kV system. KPP serves majority of the load on the 23kV system.

Figure 1 identifies the power plants, substations, and transmission lines associated with the KPP retirement. With the retirement of KPP, all of the load on the 23kV system will need to be served from the 69kV system. The Maui transmission system utilizes three 69/23kV tie transformers to interconnect the 69kV system and the 23kV system. These 69/23kV transformers are located at Waiinu Substation, Puunene Substation, and Kanaha Substation.

This study was conducted to identify the transmission system impacts with the retirement of KPP and analyze various solutions necessary to provide safe reliable power to the customers.

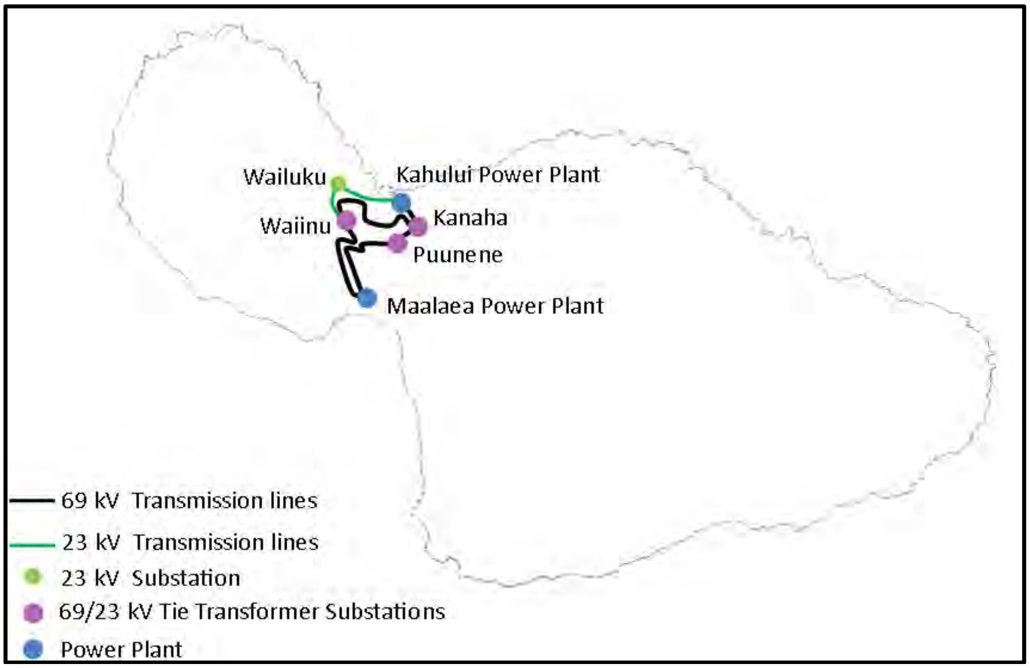

Figure 1: Key central Maui transmission components

Assumptions

The “23kV system” referred in this document consists of the substations within central Maui—Wailuku, Kanaha, Kahului Sub 8, and substations fed by these major substations. Hana is being fed from Pukalani and the distance from the central substations to Haleakala and Kula do not have the same effect from the rest of the 23kV system; therefore, they are not included in the reference to the “23kV system.”

This study only evaluates the impact to the system from a steady state point; stability analysis will also need to be conducted.

Model Assumptions

To model the Maui transmission system, we used actual 2013 historical load data to create a benchmark case. From the benchmark case, the following planned transmission system changes were implemented to create the cases for the interested years of study:

- 2014—KPP units K1 and K2 deactivated
- 2014—HC&S Offline
- 2015—Kaonoulu Substation
- 2019—All KPP units decommissioned
- 2019—Waiinu 69/23kV tie transformer enabled to auto-adjust

After the changes are implemented, the cases are uniformly scaled to the forecasted system gross loads.

Load Assumptions

The gross peak and minimum with DSM/NEM/SIA/FIT load forecast used in this study is based on the May 2014 Adopted Maui Electric Sales and Peak Forecasts. This study focused on the 2014 with a load forecast of 197.9 MW and 2019 with a load forecast of 218.3 MW to represent the current system and the system after the retirement of KPP, respectively. Refer to Appendix A for the entire 2014-2030 load forecasts.

Generation Assumptions

Currently, MECO operates two power plants—Kahului Power Plant (KPP) and Maalaea Power Plant (MPP). In addition, the following renewable generation serves the Maui load:

- HC&S—12 MW biomass
- KWP I—30 MW wind farm
- KWP II—21 MW wind farm
- Auwahi—21 MW wind farm
- Makila Hydro—0.5 MW hydro

The system also has two 1 MW units in Hana Substation for emergencies. Appendix B provides an overview of the current Maui system generation.

Thermal Overloads

The amount of power that can flow though the transmission system components, such as conductors and transformers, is limited by its characteristics. Too much current flowing through the conductors and transformers will cause damage due to overheating. Under scenarios with no contingencies, the transmission equipment is evaluated using the normal rating (Rating A). For N-1 contingencies, the system is evaluated with emergency ratings (Rating B). See Appendix C for a single line diagram overview of the central Maui system showing line ratings.

Voltage Violations

The MECO criteria for transmission planning states that under any operating condition, voltages for any bus shall have a maximum of +5% and a minimum of -10% of the nominal voltage. The per unit (pu) values are shown in Table 1.

Table 1: MECO Voltage Criteria for Transmission Planning

Criteria	Normal Conditions	Emergency Conditions
Over voltage violation	> 1.05 pu	> 1.05 pu
Under voltage violation	< 0.90 pu	< 0.90 pu

This report refers to "low voltages", which meet the planning criteria by being above 0.90 pu but are of concern as these voltages can be an under voltage violation in the future. Maintaining voltages within the criteria provides customers with good power quality; so there are no damages to customer equipment. Furthermore, if voltages fall too far below 0.9 pu, the system may not be able to recover and a voltage collapse will occur.

Steady State Analysis

To assess the impact on the transmission system with the retirement of KPP, the cases were subjected to N-1 contingencies. An N-1 contingency occurs when there is an outage of one transmission system component, while all others are in service. The following two contingencies are evaluated, as these contingencies are crucial paths that transfer power from the 69kV system to the 23kV system:

- Contingency 1: Loss of 69kV MPP-Waiinu
- Contingency 2: Loss of 69kV MPP-Puunene

The steady state analysis will identify any thermal overloads or voltage violations that can occur during these contingencies. To see the effects of retiring KPP, analysis was conducted with a case modeling the current system in 2014 and a case with the current system in 2019. Thermal and voltage violations occurred in the 2019 case if no upgrades to the system were made. The following are solutions considered to address the thermal and voltage violations:

- 23kV Waiinu-Kanaha upgrade to 69kV with the reconductoring of MPP-Waiinu and MPP-Puunene from 336AAC to 556AAC
- 25MW Battery Energy Storage System (BESS)
- 40MW Distributed Generation (DG)
- Synchronous condensers from retiring KPP units

Table 2 shows the case assumptions used when analyzing the impacts KPP retiring and the solutions considered. The amount of demand response (DR) needed would need to be similar to the generation provided by the BESS or DG to reduce the load on the 23kV system.

KPP Retirement Steady State Analysis

Table 2: KPP Retirement Steady State Case Assumptions

Case	Solution	Description
0	---	• 2014 peak • Load Forecast = 197.9MW
1	---	• 2019 peak • Load Forecast = 218.3MW • HC&S offline • KPP offline • Kaonoulu Substation in service • Waiinu 69/23kV tie transformer auto-adjust enabled
2	Transmission Upgrades	• 2019 peak • Load Forecast = 218.3MW • HC&S offline • KPP offline • Kaonoulu Substation in service • Waiinu 69/23kV tie transformer auto-adjust enabled • 23kV Waiinu-Kanaha upgrade to 69kV • MPP-Waiinu reconductored from 336 to 556 • MPP-Puunene reconductored from 336 to 556 • Remove FDR C from KPP-Kanaha 23kV
3	25 MW BESS	• 2019 peak • Load Forecast = 218.3MW • HC&S offline • KPP offline • Kaonoulu Substation in service • Waiinu 69/23kV tie transformer auto-adjust enabled • 25MW BESS interconnected at KPP
4	40 MW DG	• 2019 peak • Load Forecast = 218.3MW • HC&S offline • KPP offline • Kaonoulu Substation in service • Waiinu 69/23kV tie transformer auto-adjust enabled • 40MW DG interconnected at KPP
5	KPP Units converted to synchronous condensers	• 2019 peak • Load Forecast = 218.3MW • HC&S offline • KPP offline • Kaonoulu Substation in service • Waiinu 69/23kV tie transformer auto-adjust enabled • KPP units converted to synchronous condensers

Results

Currently with KPP online (2014), there are no thermal or voltage violations under normal or N-1 contingency events. The 23kV system it is less dependent on the 69kV system because KPP is serving the load on the 23kV system. This reduces the loading on the 69/23kV tie transformers.

For the 2019 case, under normal conditions, if no system upgrades are made, the Waiinu 69/23kV tie transformer was heavily loaded at 92% of the normal rating. When subjected an N-1 contingency, the loss of MPP-Waiinu showed overloads on the Puunene and Kanaha 69/23kV tie transformers, overloading on the MPP-Puunene 69kV line, as well as under voltage violations for the 23kV system and the Waiinu 69kV bus.

Figure 2 is a magnified excerpt of the 69kV system and identifies the violations of the system under the loss of MPP-Waiinu contingency.

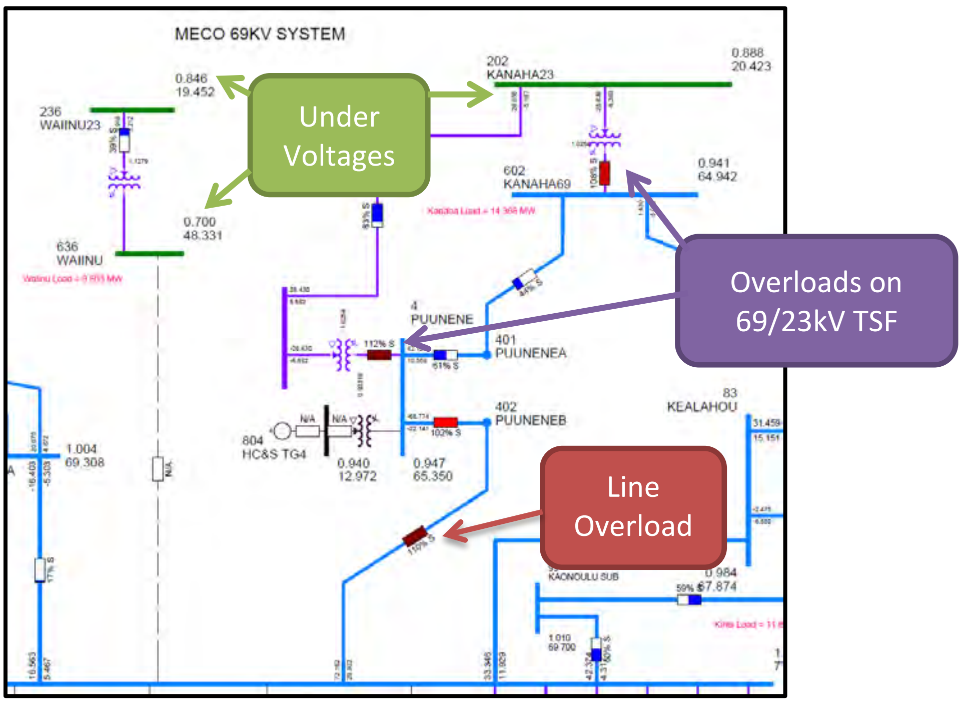

Figure 2: 69kV system current conditions for 2019 under N-1 contingency, loss of MPP-Waiinu

Figure 3 shows the PSSE results for the 69kV and 23kV system in a single line diagram.

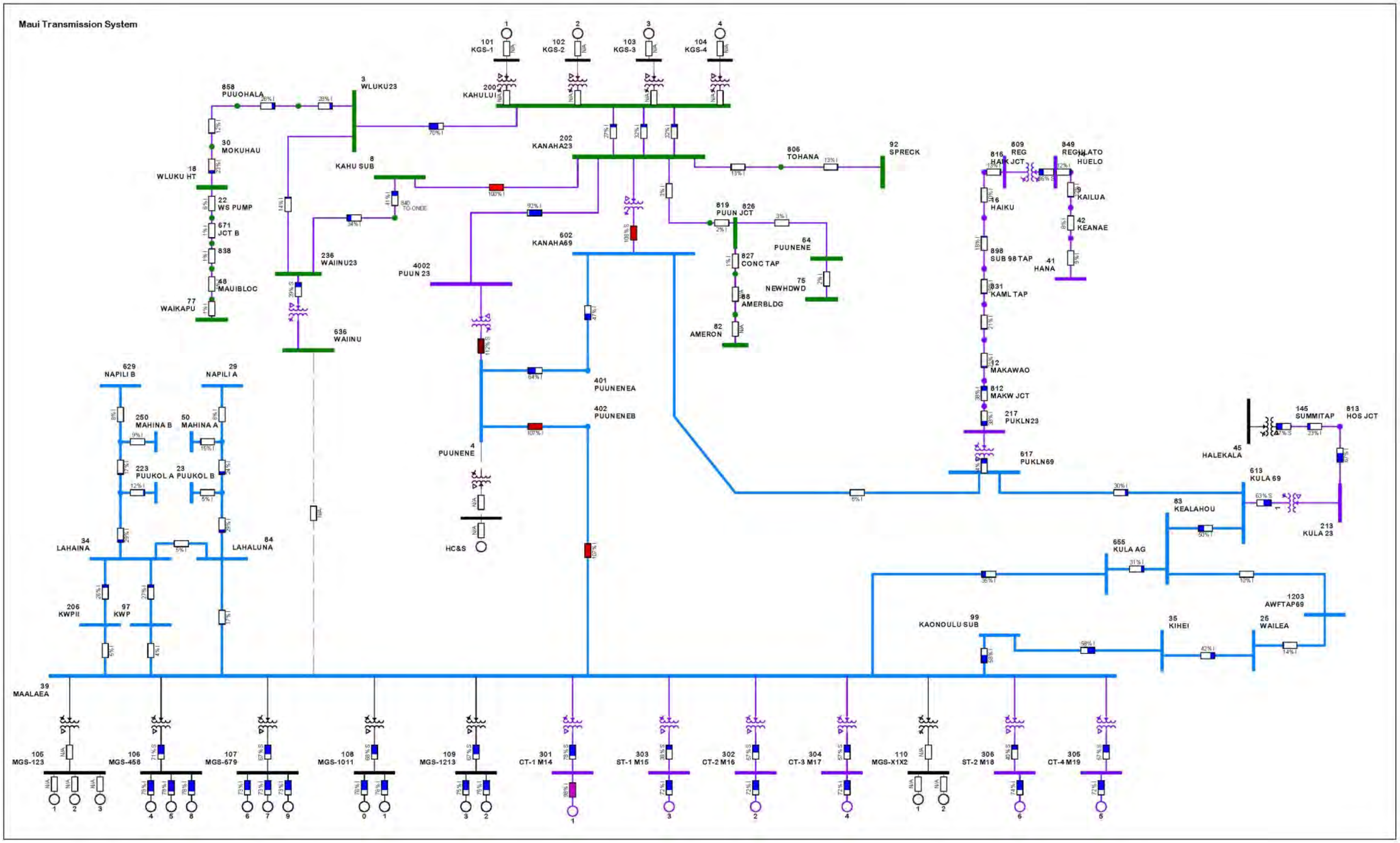

Figure 3: Maui transmission system in 2019 without upgrades under N-1 contingency, loss of MPP-Waiinu

For the loss of MPP-Puunene, the Waiinu 69/23kV tie transformer is overloaded and low voltages occur at Puunene, Kanaha, and Pukalani 69kV Substations. Although the low voltages are within the MECO criteria for transmission planning, the voltages are boarding the 0.90 pu voltage criteria.

Figure 4 shows the overloading of the Waiinu 69/23kV transformer and these low voltage buses with the loss of MPP-Puunene.

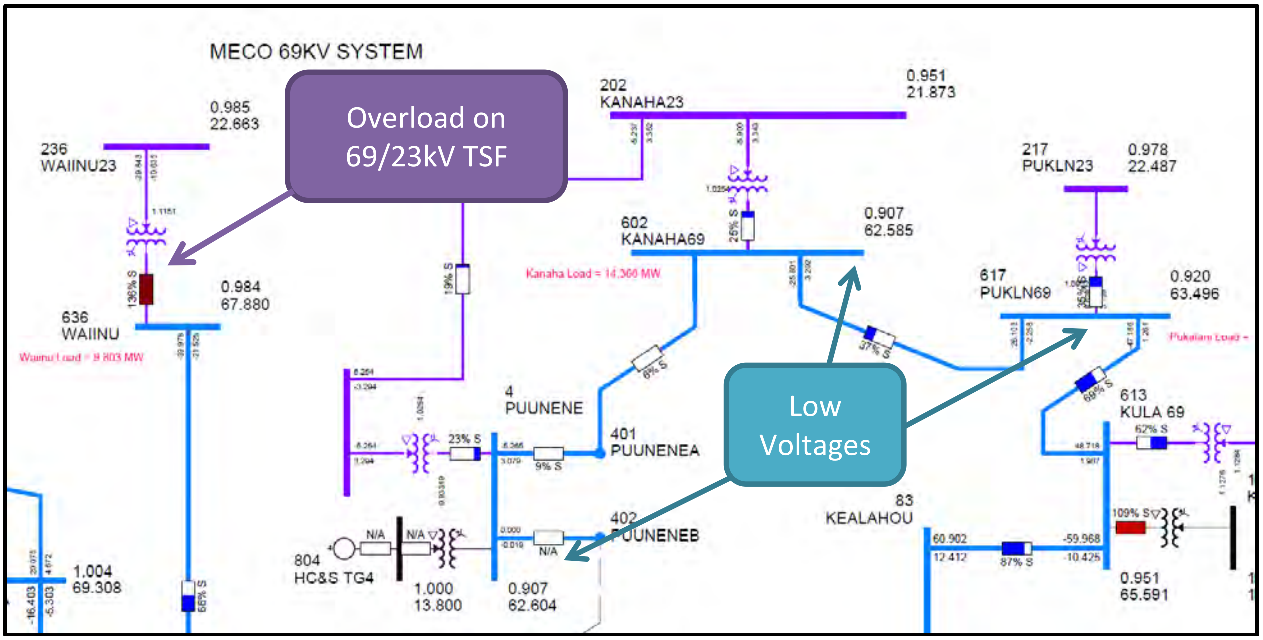

Figure 4: 69kV system with no system upgrades in 2019 under N-1 contingency, loss of MPP-Puunene

If no upgrades are made to the system, thermal and voltage violations occur. To eliminate the violations, a transmission and various non-transmission options were considered as possible solutions. From the 2019 case, the various solutions were modeled and studied to view the impacts to the system. These solutions are explained in detail in the following paragraphs.

Waiinu-Kanaha Transmission Upgrade

The transmission recommendation is to upgrade the current 23kV Waiinu-Kanaha line to 69kV and reconductor MPP-Waiinu and MPP-Puunene from 336AAC to 556AAC. In addition, with the upgrade of the Waiinu-Kanaha line, feeder C from KPP-Kanaha will need to be removed. Along with the Waiinu-Kanaha 23kV upgrade, the Kahului Sub 8, which is located along the Waiinu-Kanaha 23kV line, will also be upgraded to 69kV. By upgrading the23kV Waiinu-Kanaha line to 69kV, the loads on the 23kV system will be switched to the 69kV system. This will reduce the loading on the tie transformers.

With these transmission upgrades, the 2019 system will have no thermal or voltage violations under normal or N-1 contingency events. Figure 5 shows the system in 2019 with the transmission upgrades under N-1 contingency. By relocating more loads on the 69kV system, there is less dependency on the tie transformers and transmission lines that provide support to the 23kV system.

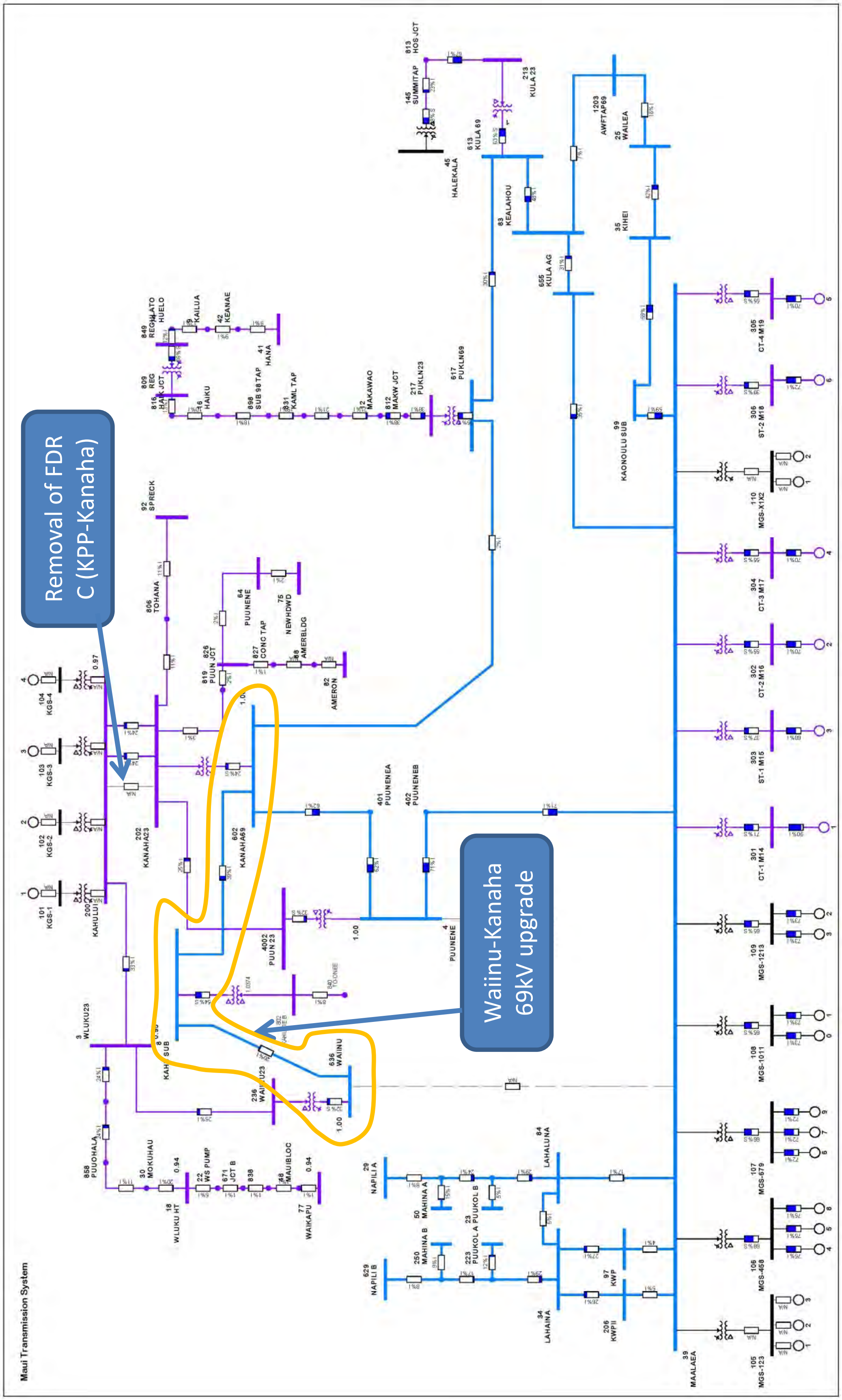

Figure 5: Maui system in 2019 with Transmission Upgrades under N-1 contingency, loss of MPP-Waiinu

25MW Battery Energy Storage System (BESS)

The first non-transmission alternative (NTA) considered was the addition of a 25MW BESS interconnected to the 23kV system; this 25MW:30min BESS was addressed in the 2013 Integrated Resource Plan. For modeling purposes, the 25MW BESS was added to the retiring KPP site. However, the BESS will effectively provide the same support if added anywhere on the 23kV system. The BESS has the ability to respond to system disturbances immediately but will be limited by the MWh parameters. Due to the voltage and thermal issues seen with an N-1 contingency, the BESS will need to be able to supply the 23kV system during this system condition, which could possibly be for multiple hours. Other control settings, operation and parameters of the BESS are beyond the scope of this study.

A BESS has the capabilities to instantaneously respond to system disturbances depending on the controls of the BESS. Due to the under voltages occurring when the system is subject to the N-1 contingencies, if the system peaks occur from the hours of 10:00 AM to 8:00 PM and the contingency occurs during this peak period the BESS would need to supply power during this time. Therefore, the 25MW BESS should have at least an 8 hour duration (200MWh), to allow line crews to repair the line. The BESS can also be paired with DG—discussed in the next section—to reduce the duration needed.

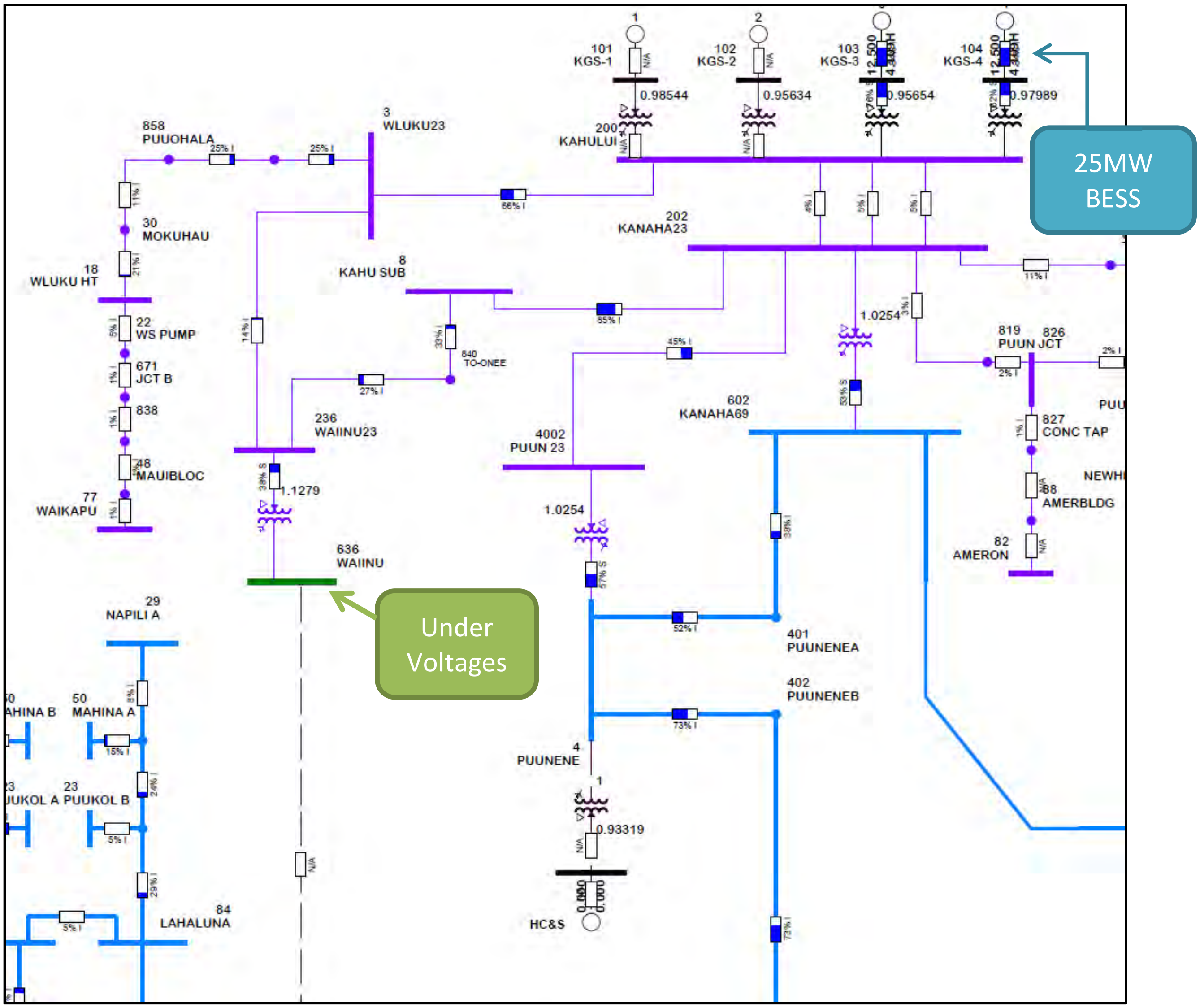

Figure 6: 25MW BESS modeled on the 23kV system improves voltages under N-1 contingency, loss of MPP-Waiinu

With the addition of a 25MW BESS on the 23kV system, when subjected to an N-1 contingency, low voltages occur at the 69kV Waiinu bus. There are no overloads on the 69/23kV tie transformers or the MPP-Puunene line. Furthermore, the low voltages at Waiinu 69kV are due to the control for the Waiinu 69/23kV tie transformer controlling the Waiinu 23kV bus voltage. With capability to control the Waiinu 69/23kV tie transformer tap settings, the Waiinu 69kV bus voltage could be kept within the planning criteria, above 0.90 pu.

40MW Distributed Generation (DG)

Another NTA considered is to have firm DG interconnected into the 23kV system. Having quick starting DG units would minimize the outage seen by the customer. Sizing, fuel, daily operation, and other unit characteristics is beyond the scope of this study, further analysis will need. Adding generation to the 23kV system will help alleviate the loading on the 69/23kV tie transformers, and the 23kV system dependency on the 69kV system would be eliminated. Furthermore, with the retirement of KPP, the system will be deficient of supply by 40MW, so the addition of 40MW of DG to the system would meet the adequacy of supply requirements.

For modeling purposes, five 8.5MW units were added to the KPP site to total approximately 40MW of DG. The specific characteristics of the units can differ from the 8.5MW units that are modeled as well as the interconnection site on the 23kV system. Further analysis will need to be conducted based on the potential locations and parameters of the units which the system will require for stability. The issue of land zoning and air quality permits will also need to be addressed.

Due to the start-up times required for the DG, customers will experience outages. Fast starting units can have start-up times around 5 minutes. Stability analysis will show if the system can maintain a stability until these DG units can provide power. As mentioned before, a combination of BESS and DG can be used to eliminate the outages customers will experience. The BESS will serve the customers until the DG can start-up and output power.

With the 40MW of DG, no thermal or voltage issues occur during normal conditions and with the loss of MPP-Puunene. However, the loss of MPP-Waiinu resulted in under voltage violations for Waiinu 69KV. Similar to the under voltage violation for the BESS NTA for Waiinu 69kV, if the Waiinu 69/23kV tie transformer controls were adjusted properly, the Waiinu 69kV bus voltage could be kept above 0.9pu. Figure 7 shows the 69kV system, under voltage violation for the 69kV Waiinu bus with the loss of MPP-Waiinu. Figure 8 shows the 23kV system with no thermal or under voltage violations under the MPP-Waiinu contingency.

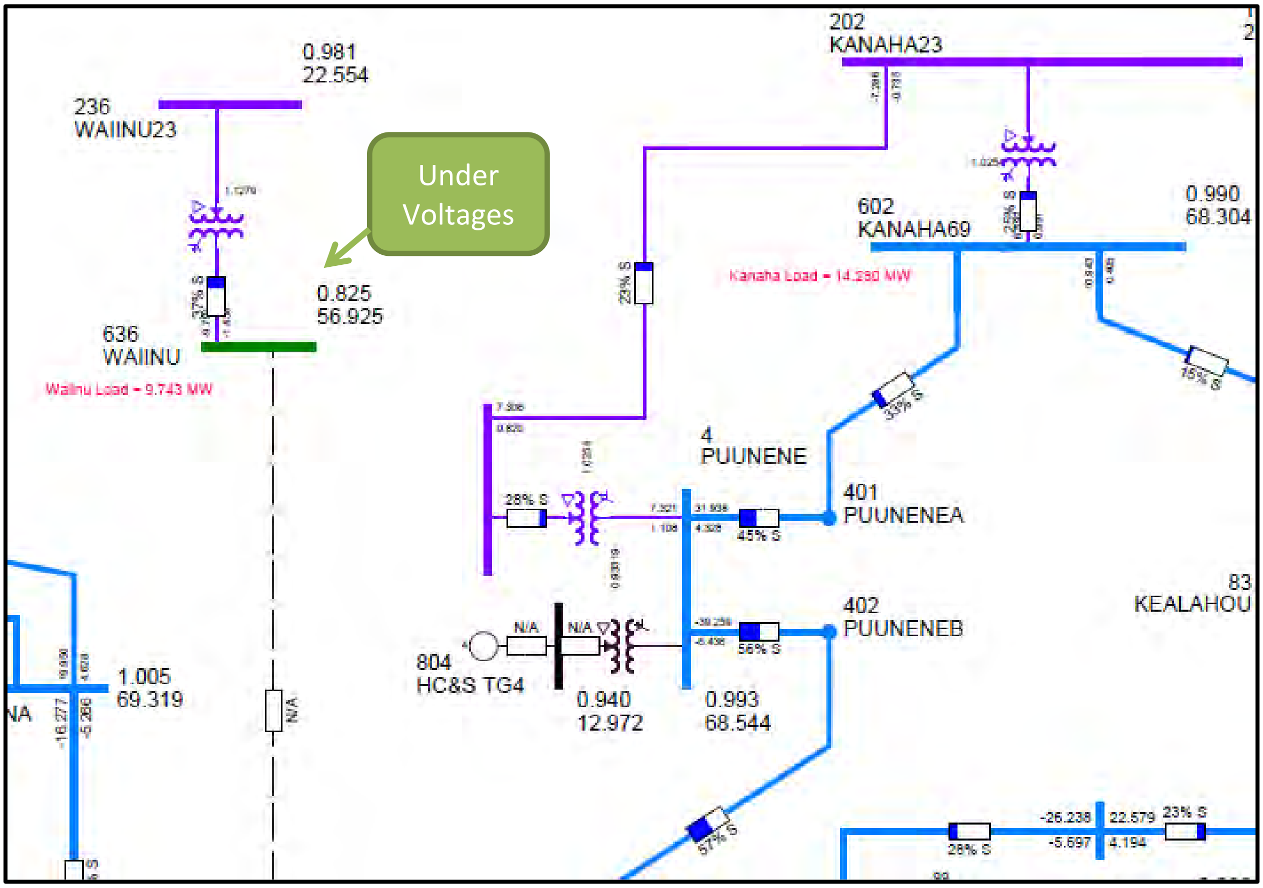

Figure 7: 69KV system with 40MW DG on 23kV system, under N-1 Contingency (loss of MPP-Waiinu) resulting in under voltage violation at Waiinu 69kV bus

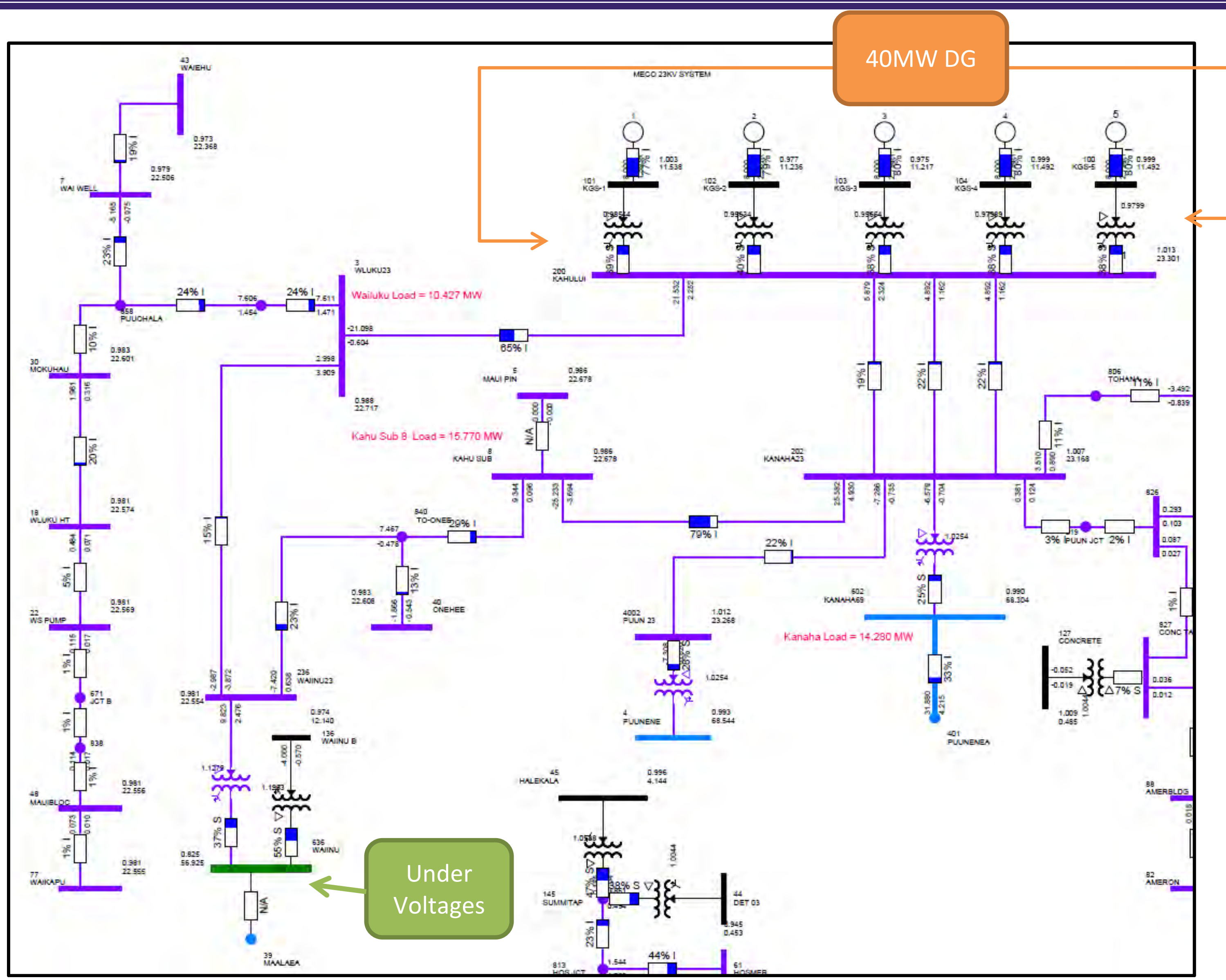

Figure 8: 23kV system with five 8.5MW units for 40MW DG interconnected on 23kV system providing support during N-1 contingency, loss of MPP-Waiinu

Synchronous Condensers

To provide voltage support, another NTA considered was converting the existing KPP units to synchronous condensers. A synchronous machine operating without a prime mover is a synchronous condenser. Controlling of the field excitation allows a synchronous condenser to either absorb or supply reactive power to the system.

Under normal conditions, because of the transferring of load from MPP to the 23kV system, the Waiinu 69/23kV tie transformer is heavily loaded at 93% of its normal rating. As the load increases on the 23kV system, the Waiinu 69/23kV tie transformer will be overloaded. For the MPP-Waiinu N-1 contingency, although the synchronous condensers help the 23kV system voltages remain within the planning criteria, the Puunene and Kanaha 69/23kv tie transformers are overloaded. In addition, the MPP-Puunene is above 100% of its emergency rating and the Waiinu 69kV bus violated the voltage criteria.

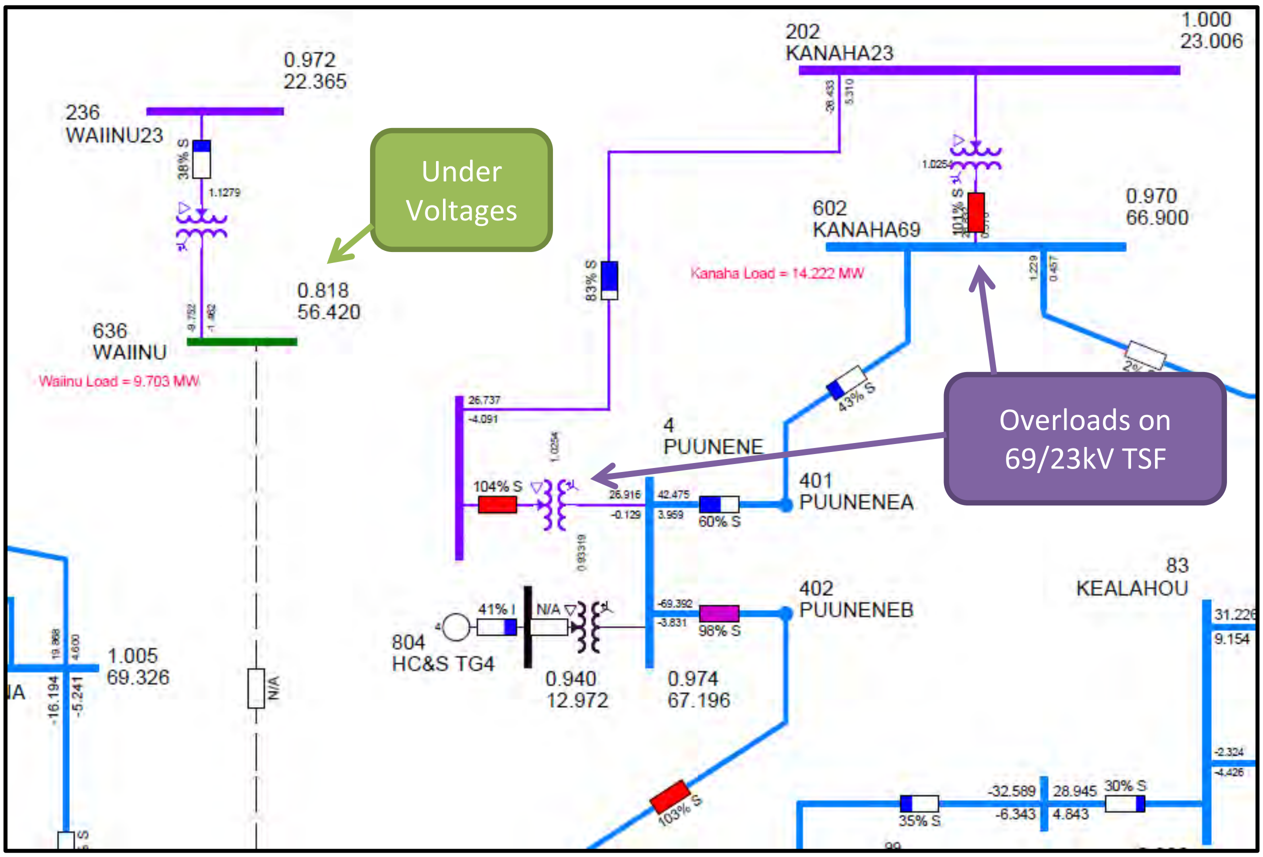

Figure 9: 2019 69kV system with KPP units converted to synchronous condensers subjected to MPP-Waiinu contingency

Due to the overloading issues with using KPP units as synchronous condensers, transmission upgrades will also be needed. The Waiinu 69kV under voltage violation occurs because the transformer taps are being controlled to regulate the 23kV Waiinu bus.

Summary of Results

To address the under voltage violations and overloads on the transmission system with the retirement of KPP, this steady state analysis considered the following system improvements:

- 23kV Waiinu-Kanaha upgrade to 69kV with the reconductoring of MPP-Waiinu and MPP-Puunene from 336AAC to 556AAC
- 25MW BESS
- 40MW DG
- Synchronous condensers from retiring KPP units

The retirement of KPP impacts the 23kV system greatly. With no upgrades to the transmission system and the retirement of KPP violations to the criteria for transmission planning are eminent.

The transmission upgrades resulted in the system having no thermal or voltage issues for normal or N-1 conditions. While the 25MW BESS and 40MW DG had some under voltage violations and high thermal loadings. The KPP units a synchronous condensers managed the under voltages but thermal overloads occur. Table 3 lists the issues of concerns for the various cases that were used in the study.

Table 3: Summary of Analysis

Case	Case Description	Condition	NOTES
0	2014 Current System	Normal	No thermal or voltage violations
		Contingency 1: MPP-Waiinu	No thermal or voltage violations
		Contingency 2: MPP-Puunene	No thermal or voltage violations
1	2019 No Upgrades	Normal	Waiinu 69/23kV loaded at 92% of normal rating
		Contingency 1: MPP-Waiinu	Overloads on MPP-Puunene, Puunene 69/23kV TSF, Kanaha 69/23kV TSF, and under voltages in central Maui 23KV system and Waiinu 69kV bus
		Contingency 2: MPP-Puunene	Overloading on the Waiinu 69/23 kV TSF and low voltages at Puunene, Kanaha and Pukalani 69 subs
2	2019 Transmission Upgrades	Normal	No thermal or voltage violations
		Contingency 1: MPP-Waiinu	No thermal or voltage violations
		Contingency 2: MPP-Puunene	No thermal or voltage violations
3	2019 25MW BESS	Normal	No thermal or voltage violations
		Contingency 1: MPP-Waiinu	Under voltage violation for Waiinu 69kVbus and high loading (97%) on Kanaha-Kahului Sub 8 23kV line (percentages based on emergency ratings)
		Contingency 2: MPP-Puunene	No thermal or voltage violations
4	2019 40MW DG	Normal	No thermal or voltage violations
		Contingency 1: MPP-Waiinu	Under voltage violation for Waiinu 69kV bus and Kanaha-Kahului Sub 8 23kV line loading at 79% (percentages based on emergency loadings)
		Contingency 2: MPP-Puunene	No thermal or voltage violations
5	2019 K1, K2, K3, K4 Synchronous Condenser	Normal	Waiinu 69/23kV TSF loading at 93% of normal rating and MPP-Puunene 69kV line at 79% of normal rating
		Contingency 1: MPP-Waiinu	Under voltage violation for Waiinu 69kV bus, overloading on MPP-Puunene 69kV line, and overloading on Puunene 69/23kV TSF and Kanaha 69/23kV TSF; Kanaha-Kahului Sub 8 line loading at 86% and Puunene-kanaha 23kV line loading at 83% (percentages based on emergency ratings)
		Contingency 2: MPP-Puunene	Overloading on the Waiinu 69/23 kV TSF

Along with the results from the steady state simulations that were modeled, other issues should be considered. Table 4 identifies various pros and cons associated with the various solutions. These pros and cons will need to be further assessed.

Table 4: Pros and Cons for solutions evaluated

Solution	Pros	Cons
Transmission Upgrade	• Does not require large area of land • No zoning, air quality permits required • Product life	• Transmission capital investment
25MW BESS	• Prolong need for transmission infrastructure • Instantaneous response (compared to DG) • No emissions (compared to DG)	• Need to acquire land • Product life • Limited run time • Cost
40MW DG	• Prolong need for transmission infrastructure • Contribute to Adequacy of Supply • Renewable generation with biodiesel	• Need to acquire land • Need to acquire air quality permits • Requires zoning for land (Heavy Industrial) • Noise • Disruption to customers (time required for units to start)
KPP Synchronous Condensers	• Use existing machines	• KPP in Tsunami flood zone • Still require transmission infrastructure upgrades

Conclusion

A steady state analysis was conducted to identify system impacts of the KPP retirement, and evaluated possible solutions. This analysis identified overloading and under voltage violations on the system. To provide safe and reliable power to customers, the system would need an upgrade, to not violate the MECO criteria for Transmission Planning. A transmission upgrade along with several non-transmission upgrades were evaluated for improving the system during normal and contingency scenarios.

Based on the steady state analysis, the transmission upgrades are recommended to maintain a safe reliable system with the retirement of KPP. The transmission upgrades for the 23kV Waiinu-Kanaha conversion to 69kV with MPP-Waiinu and MPP-Puunene reconductoring had a greater effect on improving the system compared to the other solutions. With the transmission upgrades, there were no thermal or voltage violations during normal or N-1 contingency conditions.

Appendix A

Load Forecasts

Based on the May 2014 Maui Adopted Sales and Peak Forecasts

Table A.1: Gross Minimum and Peak System Load Forecast with DSM/NEM/FIT/SIA

Year	Min* (MW)	Peak* (MW)
2014	84.4	197.9
2015	86.2	199.7
2016	88.1	202.1
2017	91.5	208.2
2018	94.9	214.4
2019	97.3	218.3
2020	98.9	220.0
2021	100.6	221.9
2022	101.9	222.6
2023	103.2	223.3
2024	104.3	223.0
2025	105.9	223.3
2026	107.1	222.1
2027	108.2	220.4
2028	108.9	217.1
2029	110.3	214.8
2030	111.3	210.8
*Gross NEM/FIT/SIA are assumed to be zero ; PV has no impact during early morning or evening hours		

Appendix B

Generation Overview

Table B.1: Current Maui Electric Generation Overview

Maui Electric Generation Overview					
Maalaea Power Plant					
Unit	Unit Type	PMAX (Gross MW)	PMIN (Gross MW)	Mode of Operation	Ramp Rates (Gross MW/min)
MX1	ICE	2.5	2.5	Peaking	0.0
MX2	ICE	2.5	2.5	Peaking	0.0
M1	ICE	2.5	2.5	Peaking	0.0
M2	ICE	2.5	2.5	Peaking	0.0
M3	ICE	2.5	2.5	Peaking	0.0
M4	ICE	5.6	2.0	Cycling	1.0
M5	ICE	5.6	2.0	Cycling/Peaking	1.0
M6	ICE	5.6	2.0	Cycling	1.0
M7	ICE	5.6	2.0	Cycling/Peaking	1.0
M8	ICE	5.6	2.0	Cycling	1.0
M9	ICE	5.6	2.0	Cycling	1.0
M10	ICE	12.5	6.0	Cycling	1.0
M11	ICE	12.5	6.0	Cycling	1.0
M12	ICE	12.5	6.0	Cycling	1.0
M13	ICE	12.5	6.0	Cycling	1.0
M14	CT	58	12.5	DTCC-Baseload	2.0
M15	ST		11.0	DTCC-Baseload	DTCC-1.0; STCC-0.5
M16	CT		12.5	DTCC-Baseload	2.0
M17	CT	58	14.0	STCC-Cycling	2.0
M18	ST		3.0	STCC-Baseload	DTCC-1.0; STCC-0.5
M19	CT		14.0	STCC-Baseload	2.0
	TOTAL:	212.1			
Kahului Power Plant					
K1	Boiler/Steam Turbine	5.0	2.50	Cycling	0.10
K2	Boiler/Steam Turbine	5.0	2.50	Cycling	0.10
K3	Boiler/Steam Turbine	11.5	3.50	Baseload	0.10
K4	Boiler/Steam Turbine	12.5	3.50	Baseload	0.10
	TOTAL:	34.0			

KPP Retirement Steady State Analysis

Hana Substation					
Unit	Unit Type	PMAX (Gross MW)	PMIN (Gross MW)	Mode of Operation	
H1	ICE	1.0	0.0	Emergency	
H2	ICE	1.0	0.0	Emergency	
Independent Power Producers					
Unit	Unit Type	PMAX (Gross MW)	PMIN (Gross MW)	Mode of Operation	
HC&S	Biomass	12	8.0	Baseload	
Kaheawa I	Wind Farm	30.0		As-Available	
Makila Hydro	Run-of-river	0.5		As-Available	
Auwahi	Wind Farm	21.0		As-Available	
Kaheawa II	Wind Farm	21.0		As-Available	
	TOTAL:	72.5			

Appendix C

Single Line Overview with Line Ratings

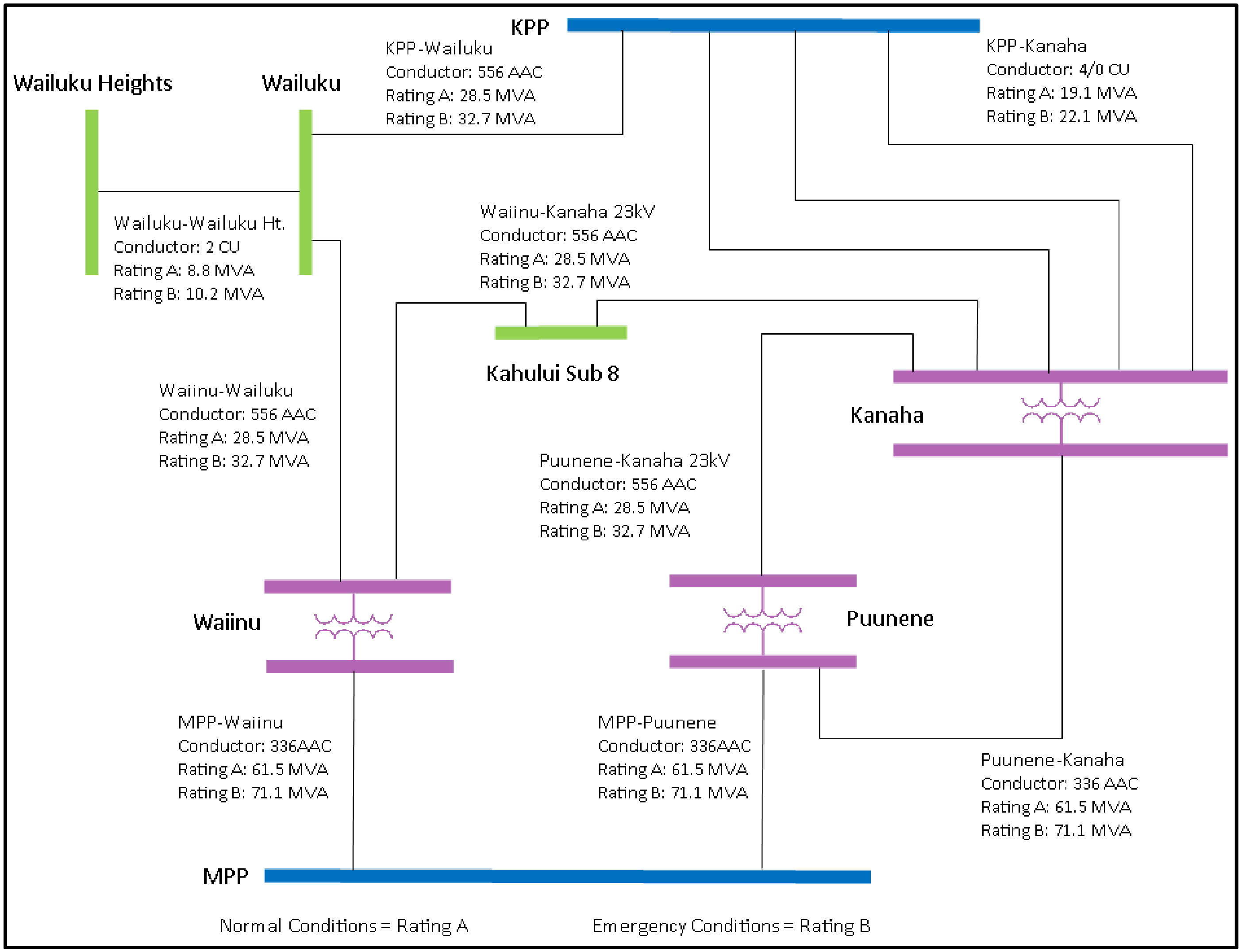

Figure C.1: Overview of Central Maui system showing line ratings

Kahului Power Plant Retirement: Voltage Stability Assessment

Prepared for

Maui Electric Company, Ltd.

Prepared By:

Hawaiian Electric Company, Inc.
System Planning Department
Transmission Planning Division

May 19, 2014

Reference: TPD 2014-21

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Kahului Power Plant Retirement: Voltage Stability Assessment

Prepared By: ______________________
Brian Lee
Planning Engineer, Transmission

Approved By: ______________________
Gemini Yau
Lead Planning Engineer, Transmission

Approved By: ______________________ 8/20/2014
Ronald Bushner
Director, Transmission Planning

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Kahului Power Plant Retirement: Voltage Stability Assessment

Executive Summary:

Hawaiian Electric Company's Transmission Planning Division (TPD) has revisited the topic regarding Maui Electric Company's plan to fully decommission Kahului Power Plant (KPP) by the year 2019. TPD has re-examined the various recommended upgrades suggested in previous studies conducted by TPD with the latest updated system models and also considered several non-transmission alternatives. This study addresses the voltage violation and voltage stability issues involved with the retirement of KPP and outlines how each alternative will potentially impact the system. After revisiting the transmission alternatives in the previous study with the latest system models and load forecast, and considering several non-transmission alternatives (NTAs), TPD recommends that proceeding with the Waiinu-Kanaha upgrade project is the most favorable, economical, and engineeringly sound solution to address voltage issues involved with the retirement of KPP, however, thermal limit and system stability issues involved with the retirement of the power plant should be also considered.

Introduction/Background:

The Maui transmission system consists of a 23 kV network and 69 kV network. KPP has a total capacity of approximately 35 MW and connects into the 23 kV network, and the remainder of Maui's generation connects into the 69 kV network. The two networks are interconnected via 23/69 kV tie transformers located in Waiinu, Kanaha, and Puunene substations. KPP is the only source of generation connected to the 23 kV network. The retirement of the power plant will result in the 23 kV network becoming heavily dependent on power supplied by the 69 kV network via the three tie transformers and induce a diminished limit of power transfer to the 23 kV network, cause voltage sources to be electrically farther from the load center (i.e. the 23 kV network), and remove a reactive power source from the 23 kV network; this potential subjects the 23 kV network to voltage profiles that violate the reliability criteria or are prone to voltage instability in the event suffering a system disturbance. Voltage instability accompanied by a sequence of events (e.g. the loss of a transmission line) will lead to voltage collapse – low, unacceptable voltage profiles in significant parts of the power system – and a possible blackout system event.

TPD performed a study in the past concerning Maui Electric's plan to reduce operation at KPP and its eventual retirement, which analyzed several transmission solutions to address the afore mentioned issues. The study recommended upgrading the 23 kV Waiinu to Kanaha transmission line to 69 kV, relocating 23 kV load at Kahului to the 69 kV system, and reconductoring the 69 kV MPP-Puunene and 69 kV MPP-Waiinu transmission lines. TPD has re-examined all recommendations made in the previous study using the latest updated base case models and load forecasts to re-establish the validity of the recommendation. TPD has also examined several non-transmission alternatives, which align with the Public Utilities Commission's (PUC) vision for the company, to be considered as possible solutions to address the issues.

Kahului Power Plant Retirement: Voltage Stability Assessment

This study will identify the system impacts resulting from the retirement of KPP from a voltage stability standpoint, examine various plausible transmission and non-transmission solutions to rectify observed system issues, and recommend the most suitable solution from a transmission stand point.

Methodology:

TPD used a conventional power-flow program to derive the Power-Voltage (P-V) characteristics of the existing Maui transmission system to determine the system power transfer limits and proximity to a voltage instability event, and the key factors that contribute to its occurrence. The characteristics were compared and contrasted to the P-V characteristics of cases of the existing system with various transmission and non-transmission upgrades to determine the most engineeringly sound solution to avoid violations of the reliability criteria, or even worse, the compromise of system reliability.

Assumptions:

The following are the assumptions used in this study unless specified otherwise:

- Referencing of the "23 kV network" in this study does not include the 23 kV circuit from Kula to Haleakala due to its electrical distance from the rest of the 23 kV system.
- The Hana 23 kV circuit is fed from Pukalani.
- Kahului Power Plant is retired by 2019.
- Contract with HC&S will expire and HC&S will no longer contribute any generation after year 2014.
- The acceptable "power margin" is between 1.05 - 0.9 per unit (p.u.) voltage per the reliability criteria.
- An N-1 event in this study refers to the loss of a transmission line.
- Existing System refers to the present Maui transmission network and reference of the existing (peak) load is the forecasted peak load of year 2014 which is approximately 200 MW.
- Initial reference point (the y-intercept) in P-V plots is the existing system at peak load.

Results and Analysis

The P-V characteristics of the various scenarios are derived for the normal condition and N-1 contingency events identified to result in the most severe system issues. These contingencies are:

- Loss of the 69 kV transmission line between Maalaea Power Plant (MPP) and Waiinu substation, which will be referred to as the 69 kV MPP-Waiinu line. This is a critical line that connects MPP to the 23/69 kV tie transformer at Waiinu, supplying power to the heavily loaded Central Maui and Wailuku area. Losing this line will require power to travel a greater electrical distance via the 23/69 kV tie transformer at Kanaha and Puunene to serve the Wailuku load.

- Loss of the 69 kV transmission line between MPP and Puunene substation, which will be referred to as the 69 kV MPP-Puunene line. This line powers from MPP to the 23/69 kV tie transformers at Kanaha and Puunene. The loss of this line will require power to travel a greater electrical distance via the 23/69 kV tie transformer at Waiinu to serve the Central Maui load.
- Loss of the 23 kV line between Wailuku substation and Waiinu substation, which will be referred to as the 23 kV Wailuku-Waiinu line. This line serves as an important means of providing power from Waiinu to the Wailuku area. Losing this line will require power to travel a greater electrical distance via Kanaha substation.
- Loss of the 23 kV line between Kanaha substation and Kahului substation, which will be referred to as the 23 kV Kanaha-Kahului line unless specified otherwise.

Figure 1 and Figure 2 show the P-V characteristics of the existing system with and without operation of KPP, respectively, for the normal and most severe N-1 conditions. The initial reference point on the P-V curve is at the point where the curve intercepts the y-axis; it depicts the voltage profile of the 23 kV network on the existing system at peak load level. Moving to the right along the x-axis represents natural growth in load on the 23 kV network. Increases to the load on the 23 kV network result in a decline in voltage profile – continual increase of load on the 23 kV network will inevitably violate the reliability criteria. The end of the P-V curve indicates that the power-flow was unable to solve beyond that point which is indicative of voltage collapse. Thus, as the system approaches the vicinity of voltage collapse, it is subject to voltage instability; the system is typically planned to operate well away from these points. The P-V curve exhibits the limits of power transfer to the 23 kV network.

The limitations of power transfer are dependent on the inherent traits of the system and can be extended or reduced through changes to the system. This aspect can be seen in Figure 1, where an N-1 contingency event shifts the power transfer limit of the normal condition curve to the left – this represents a diminished power transfer limit. It can be seen that the loss of 69 kV MPP-Waiinu line is the most severe out of all the N-1 contingencies due the indication of a steeper decline in voltage profile (curve) and quicker occurrence to voltage collapse (as load increases). It can also be seen that voltage collapse can occur well within the acceptable power margin - a voltage profile that does not violate the reliability criteria isn’t necessarily safe of voltage instability/voltage collapse. Thus, the alternatives are evaluated on their capabilities of avoiding violations to the reliability criteria and voltage instability/voltage collapse.

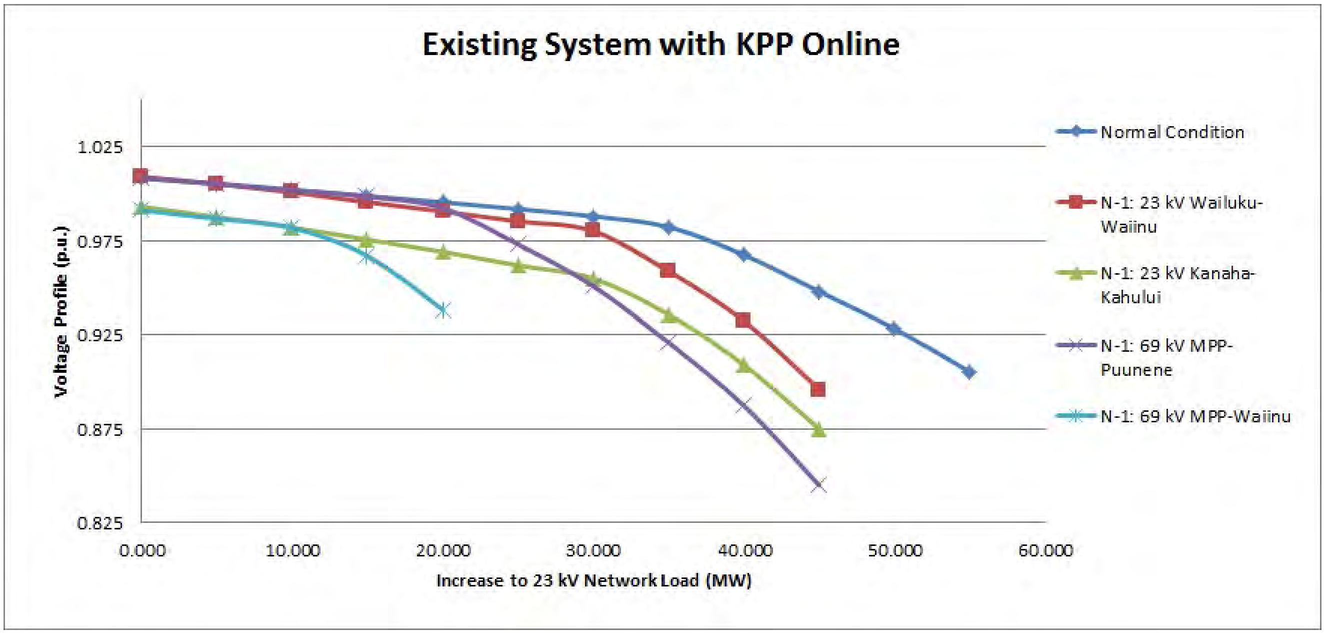

Figure 1: P-V characteristics of existing Maui system with operation of KPP.

As mentioned previously, the power transfer limits can be extended or reduced through changes to the system. A diminished power transfer limit can be expected as a result of the decommissioning of KPP. Without the operation of KPP, the 23 kV network will lose the only source of power generation connected to the 23 kV network and must rely on power supplied by the 69 kV network. This will place an additional burden on the 69 kV transmission lines and 23/69 kV transformers that connect the two networks because the 69 kV network must pick up the demand previously met by KPP.

The system will become vulnerable to voltage instability due to the voltage sources (voltage source for 23 kV network is KPP prior to its decommission; the voltage source will be the generation sources on 69 kV network after KPP retirement) being further away from the load center (i.e. the 23 kV network) and insufficient load reactive compensation on the 23 kV network. This can be seen in Figure 2. It can be observed that with the retirement of KPP, under the N-1 event of losing the 69 kV MPP-Waiinu transmission line, the voltage profile of the 23 kV network is below the sufficient “power margin” and is subjected to voltage collapse at the current 2014 peak load level.

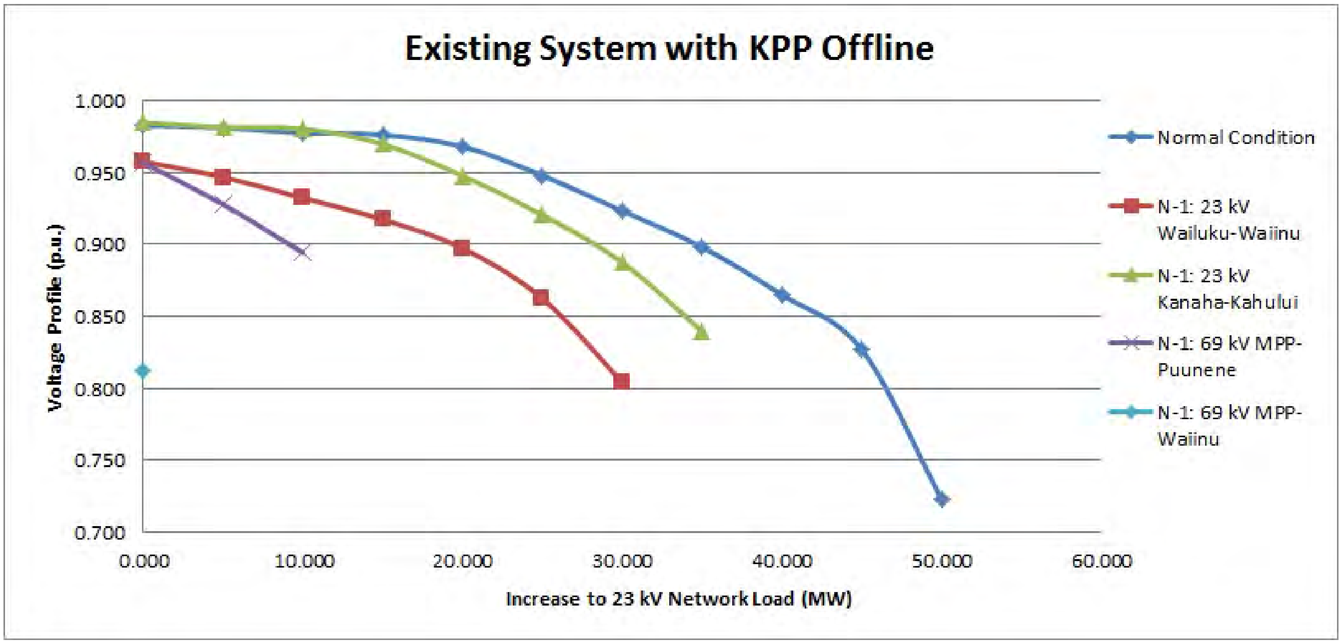

Figure 2: P-V characteristics of existing Maui system without operation of KPP.

Figure 3 compares the P-V characteristics for the normal condition and the most severe N-1 contingency event of the system with and without operation of KPP. It exhibits what changes to the power transfer limit of the 23 kV network is to be expected if KPP is decommissioned without any upgrades to the system.

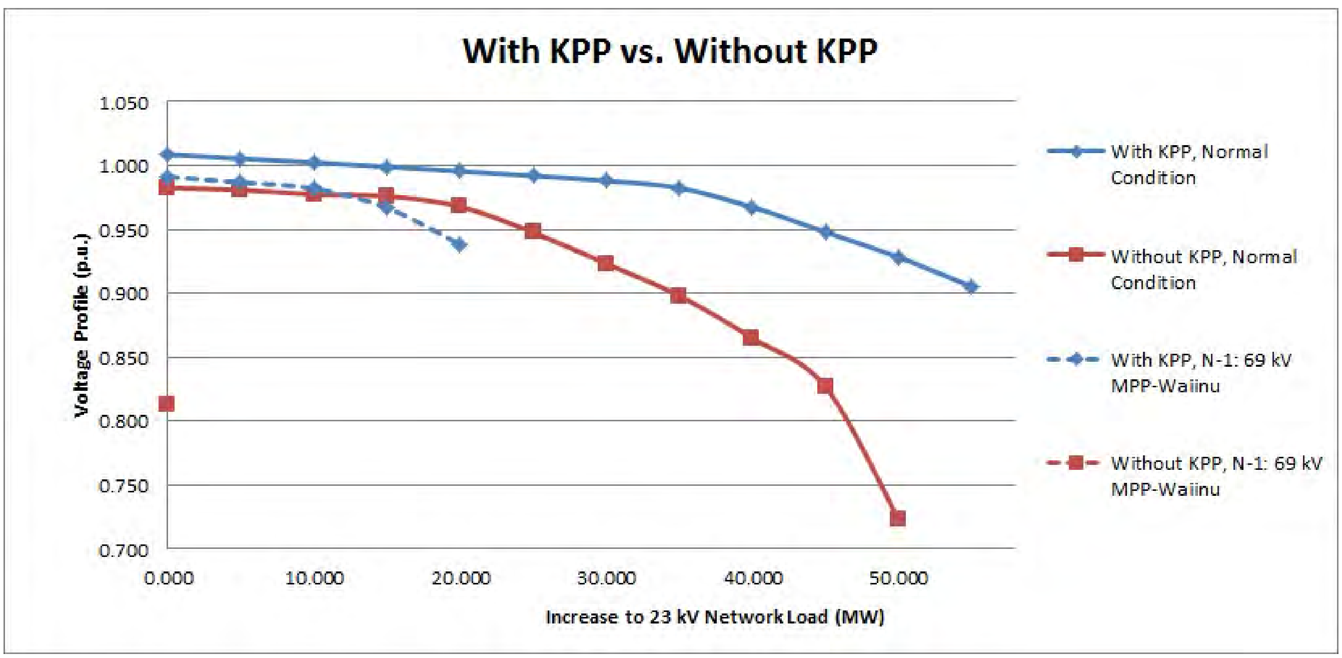

Figure 3: P-V characteristics comparison between system with and without the operation of KPP.

Transmission Solutions

In the past, TPD analyzed several transmission options that would rectify the system's vulnerability to possible voltage instability and voltage collapse events, and avoid any system reliability criteria violations. TPD has revisited the issue and options studied with the latest updated Maui system models and load forecasts. The options are:

- Alternative 1: Construct a new 69 kV transmission line from Waiinu substation to Kanaha substation.
- Alternative 2: Relocate the existing 23 kV transmission line between Waiinu substation and Kanaha substation and its connected elements to the 69 kV network.
- Alternative 3: Build new additional 69 kV MPP-Waiinu, 69 kV MPP-Puunene, and 69 kV Puunene-Kanaha lines of 556 AAC conductor size.
- Alternative 4: Create a link between Kealahou and Kanaha on the 69 kV network via the anticipated new Waena Power Plant (WPP).
- Alternative 5: Install an additional 23/69 kV tie transformer between WPP and Central Maui Landfill Substation (Sub 95), and reconductor the 23 kV section of transmission line from Kanaha to Sub 95.

Figures 4 and 5 below compare the P-V characteristic curves of the various alternatives for the normal condition and the worst N-1 contingency, respectively. It can be seen that Alternative 2 is the most favorable option under normal conditions and most N-1 contingencies. Figure 5 indicates that Alternative 3 is a significantly better option for surviving the most severe N-1 event, the loss of the 69 kV MPP-Waiinu line; this is due to the option involving the construction of three new transmission lines resulting in an extended transfer limit of power to the 23 kV network and improved system reliability in the event of the loss of a transmission line.

Alternative 3 is a considerably more expensive solution that is only favorable under the condition of losing the 69 kV MPP-Waiinu line; in all other cases, its performance is similar or second to the Alternative 2 option. Figure 5 also indicates that Alternatives 4 and 5 are viable solutions for surviving the event of losing the 69 kV MPP-Waiinu. Figures 6, 7, and 8 compare the P-V characteristics of the various alternatives for the loss of the 69 kV MPP-Puunene line, 69 kV Wailuku-Waiinu line, and 69 kV Kanaha-Kahalui line, respectively. From comparing the P-V characteristics of the five alternatives under various N-1 contingency events, TPD has determined:

- Alternatives 1, 2, and 3 are the only viable solutions,
- Alternatives 4 and 5 will result in voltage collapse in the event of losing the 69 kV MPP-Waiinu line
- Alternative 1 is the least favorable solution - has poorer power transfer limit than Alternative 2 and 3, and will violate voltage criteria when 23 kV network load increases by 5 MW .
- Alternative 2 is most favorable solution under normal condition and most N-1 events, and only consists of the upgrade of existing system elements.

- Alternative 3 is a viable solution and significantly more favorable in the event of losing 69 kV MPP-Waiinu line but involves the construction of 3 new transmission lines.

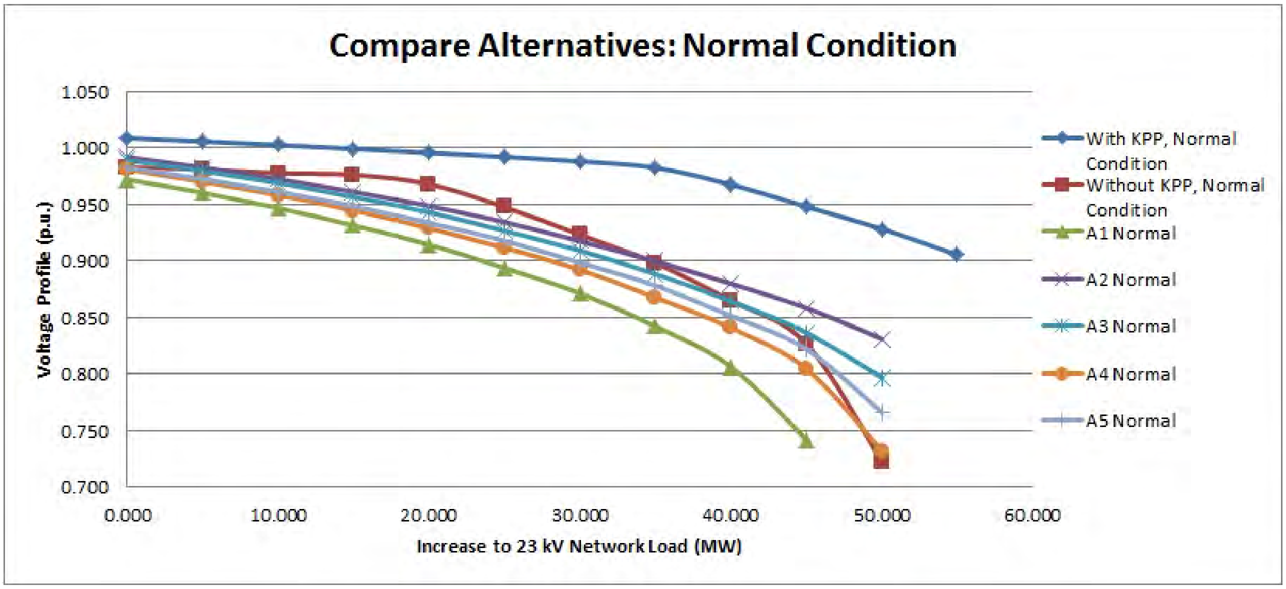

Figure 4: Comparison of P-V characteristics of transmission Alternatives for the normal condition. Alternative 1, Alternative 2, Alternative 3, Alternative 4, and Alternative 5 are represented by A1, A2, A3, A4, and A5 respectively.

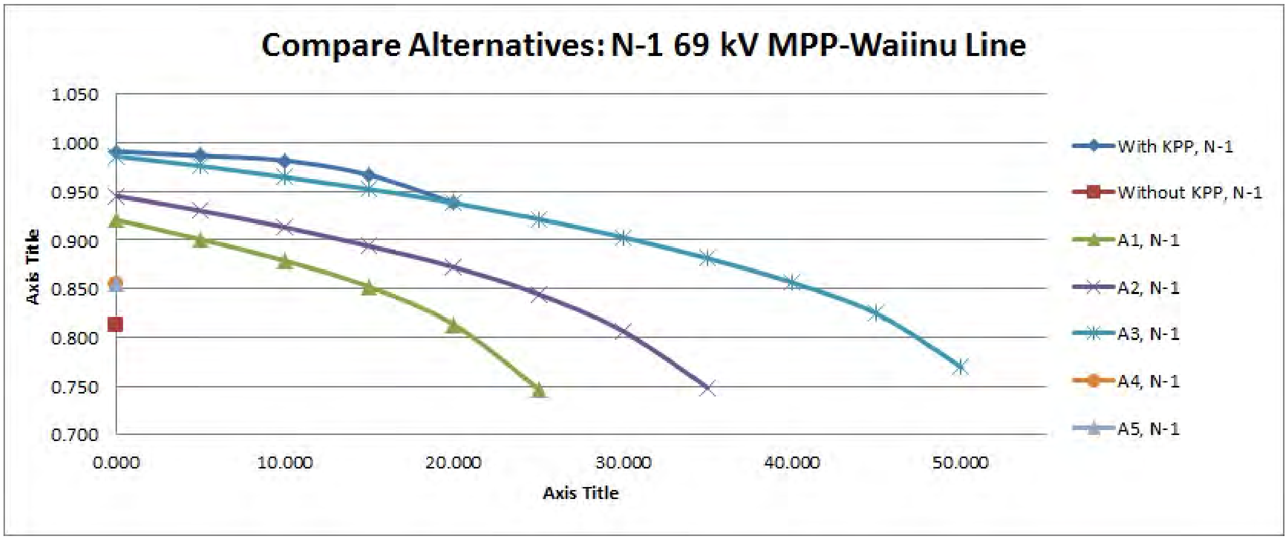

Figure 5: Comparison of P-V characteristics of transmission Alternatives for losing the 69 kV MPP-Waiinu Line. Alternative 1, Alternative 2, Alternative 3, Alternative 4, and Alternative 5 are represented by A1, A2, A3, A4, and A5 respectively.

Figures comparing P-V characteristics of the scenarios for the rest of the most severe contingencies can be seen in the Appendix.

Kahului Power Plant Retirement: Voltage Stability Assessment

TPD recommends Alternative 2 out of the five alternatives considered. Alternative 2 will adequately avoid voltage criteria violations and voltage instability until the 23 kV network has a load growth of 10 MW. Load growth beyond 10 MW will bring about a voltage profile below the acceptable power margin and possibly subject the 23 kV network to an unstable voltage profile. The 23 kV network will reach a growth of 10 MW when the total system peak load grows to approximately 270 MW, which is beyond the forecasted load.

Alternatives 1, 2, and 3 are viable solutions capable of preventing a voltage instability event from occurring on the current system but may not be adequate to endure thermal limit overloading conditions. Several combinations of the five mentioned alternatives with additional system upgrades were considered to address the thermal limit issues; the advantages of combining the alternatives with an additional system upgrade from a voltage stability standpoint will be discussed. The combinations are:

- Combination 1: Alternative 1 combined with the reconductoring of the 69 kV MPP-Waiinu line and 69 kV MPP-Puunene lines to 556 AAC conductor size transmission lines.
- Combination 2: Alternative 1 combined with the construction of a new secondary 69 kV MPP-Puunene transmission line.
- Combination 3: Alternative 1 combined with Alternative 4.
- Combination 4: Alternative 2 combined with the reconductoring of the 69 kV MPP-Waiinu line and 69 kV MPP-Puunene transmission lines to 556 AAC conductor size transmission lines - Combination 4 is the recommended Waiinu-Kanaha Transmission Line Upgrade project.
- Combination 5: Alternative 2 combined with the construction of a new secondary 69 kV MPP-Puunene transmission line.
- Combination 6: Alternative 2 combined with Alternative 4.
- Combination 7: Alternative 3 combined with Alternative 5.

Waiinu-Kanaha Transmission Line Upgrade project:

Figures 6 and 7 below show a P-V characteristic comparison of the Maui system with KPP, without KPP, with the Alternative 2 option, and with various combinations of one of the afore mentioned alternative options with an additional system upgrade for the normal condition and most severe N-1 condition, respectively.

From a voltage stability standpoint, all combinations mentioned are viable long term solutions capable of maintaining a voltage profile well within the acceptable margin and mitigate unstable voltage profile issues, but it can be seen that only options Combo 5, Combo 6, and Combo 7 produce significantly better P-V characteristics than the suggested Combo 4, which is the recommended alternative in the previous study. However, Combos 5, 6, and 7 involve the construction of one or more new transmission lines. Combo 4 only involves the upgrade of existing transmission lines already on the system (where majority of the line is already capable of being transitioned to 69 kV).

After revisiting the study with the latest system models and load forecast information, Combo 4 (the Waiinu-Kanaha upgrade project) is still the recommended solution to address the voltage instability issues involved with the retirement of KPP alternative out of all the transmission alternatives.

Figure 8 below shows a P-V characteristic comparison of the Maui system operating with and without KPP, and the system operating without KPP under the scenario that Combo 4 is implemented for the normal condition and most severe N-1 contingency.

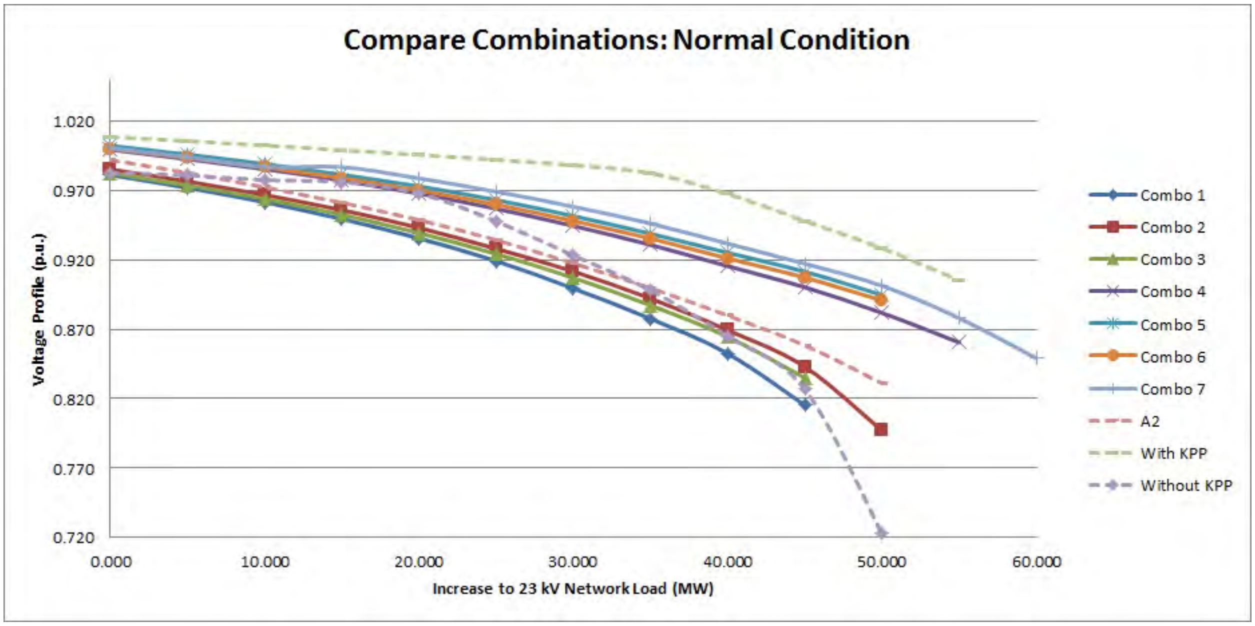

Figure 6: Comparison of P-V characteristics of tranmission Combinations for the normal condition. Combination 1, Combination 2, Combination 3, Combination 4, Combination 5, Combination 6, Combination 7, and Alternative 2 are represented by Combo 1, Combo 2, Combo 3, Combo 4, Combo 5, Combo 6, Combo 7, and A2 respectively.

Kahului Power Plant Retirement: Voltage Stability Assessment

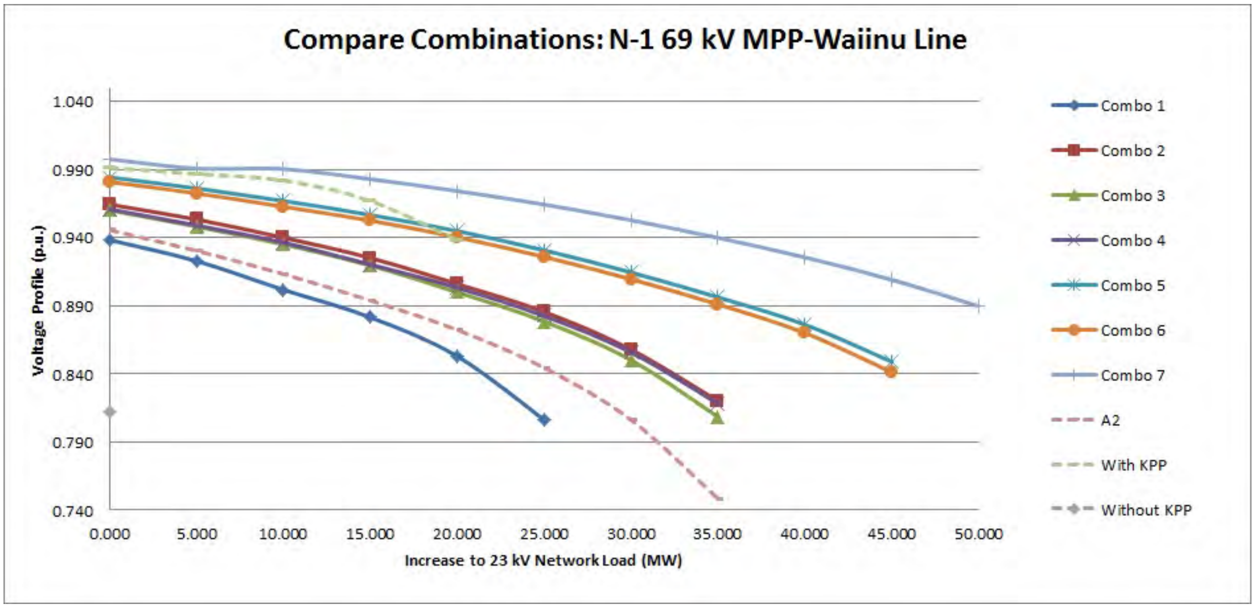

Figure 7: Comparison of P-V characteristics of tranmission Combinations for losing the 69 kV MPP-Waiinu Line. Combination 1, Combination 2, Combination 3, Combination 4, Combination 5, Combination 6, Combination 7, and Alternative 2 are represented by Combo 1, Combo 2, Combo 3, Combo 4, Combo 5, Combo 6, Combo 7, and A2 respectively.

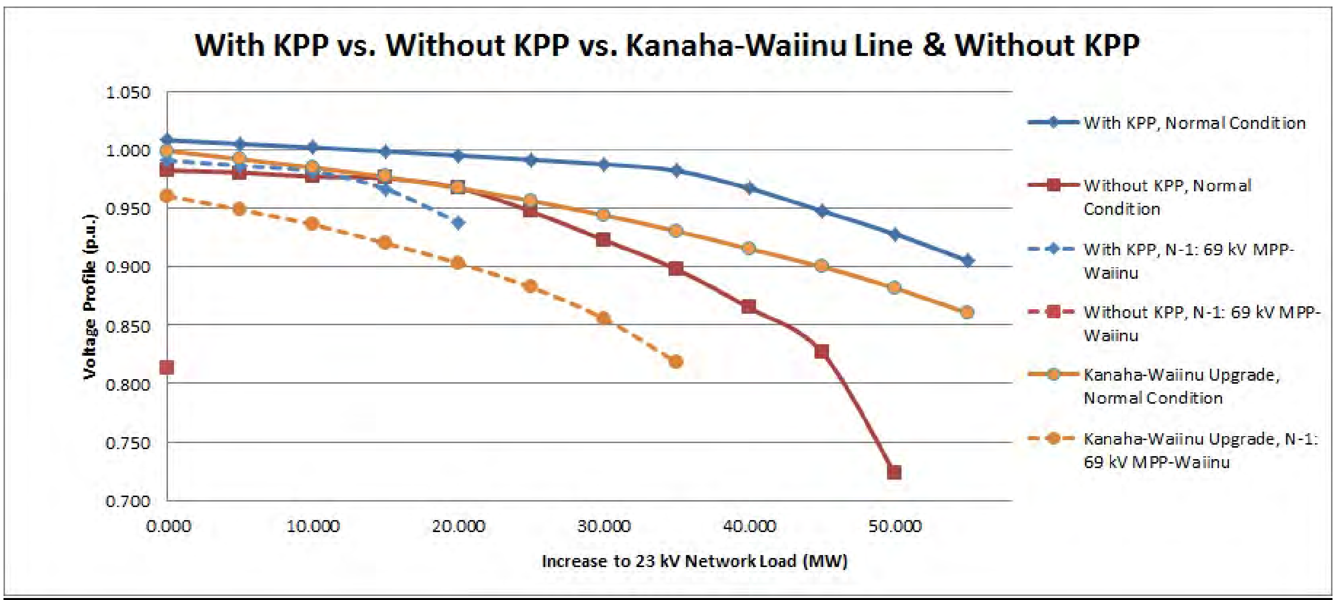

Figure 8: P-V characteristic comparison of the Maui system operating with and without KPP and the system operating without KPP under the scenario that Combo 4 is implemented for the normal condition and most severe N-1 contingency.

Non-Transmission Alternative (NTA) Solutions

There is an anticipated reserve capacity short fall of approximately 40 MW by year 2019, identified in Section 1.6 of the Maui Electric Adequacy of Supply (AOS) report. TPD has considered the possibility that efforts to procure resources to meet the reserve capacity short fall may void the need for the 23 kV Waiinu-Kanaha line upgrade project and the additional reconductoring of the 69 kV MPP-Puunene and 69 kV MPP-Waiinu transmission lines, and has considered the following Non-Transmission Alternatives (NTA):

- Conversion of some or all existing units at KPP to synchronous condensers.
- New Dispatchable Firm Generation.
- Battery Energy Storage System (BESS).
- Demand Response (DR).

Synchronous Condenser Option:

A favorable aspect of the synchronous condenser option is that it would take a considerably shorter amount of time to execute than the other NTA alternatives. However, synchronous condensers are reactive support elements that will only supply reactive power to the system. As mentioned before, removing KPP would mean active power demands on the 23 kV network must be supplied solely by the 69 kV network; this will subject the transformers and transmission lines connecting the 23 kV and 69 kV network to heavier loadings that may possibly violate their thermal limit ratings.

From a voltage stability standpoint, the synchronous condenser option is a viable solution for avoiding violations to the voltage criteria and avoiding voltage instability and voltage collapse events; however, it will not mitigate issues regarding thermal overloads on transmission lines and/or tie transformers because synchronous condensers do not provide active power, thus, will not alleviate the extra burden that can be expected to be placed on transformers and transmission lines connecting the 23 kV and 69 kV network when KPP is retired.

KPP is comprised of two large units, K4 and K3, and two smaller units, K1 and K2. K4, K3, K2, and K1 have reactive capabilities of 9.3 MVar, 7.0 MVar, 3.7 MVar, 3.7 Mvar, respectively. Several scenarios were considered: only the largest unit converted to synchronous condenser, the two largest units converted to synchronous condenser, two largest units and one smaller unit converted to synchronous condenser, and all units converted to synchronous condenser. Figures 9 and 10 show the P-V characteristics of the different scenarios of KPP units converted to synchronous condensers for the normal condition and most severe N-1 contingency event.

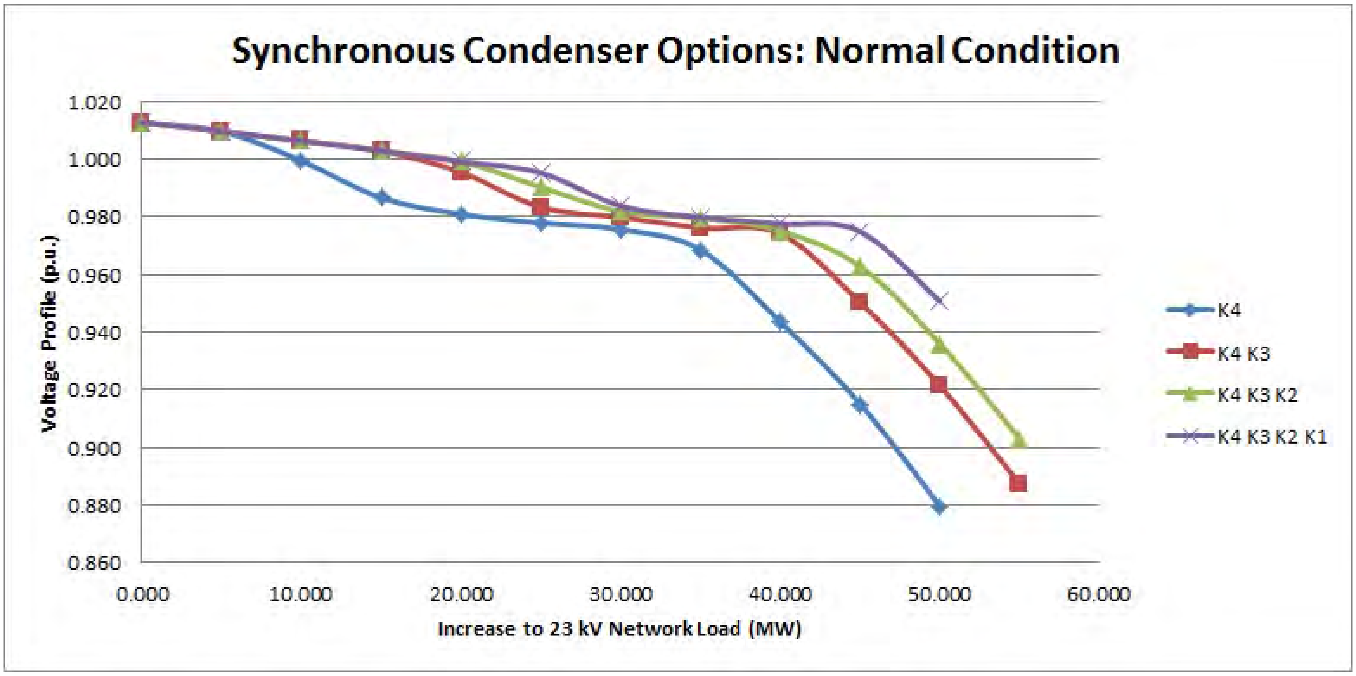

Figure 9: P-V characteristic comparison of different scenarios of KPP units converted to synchronous condensers for the normal condition.

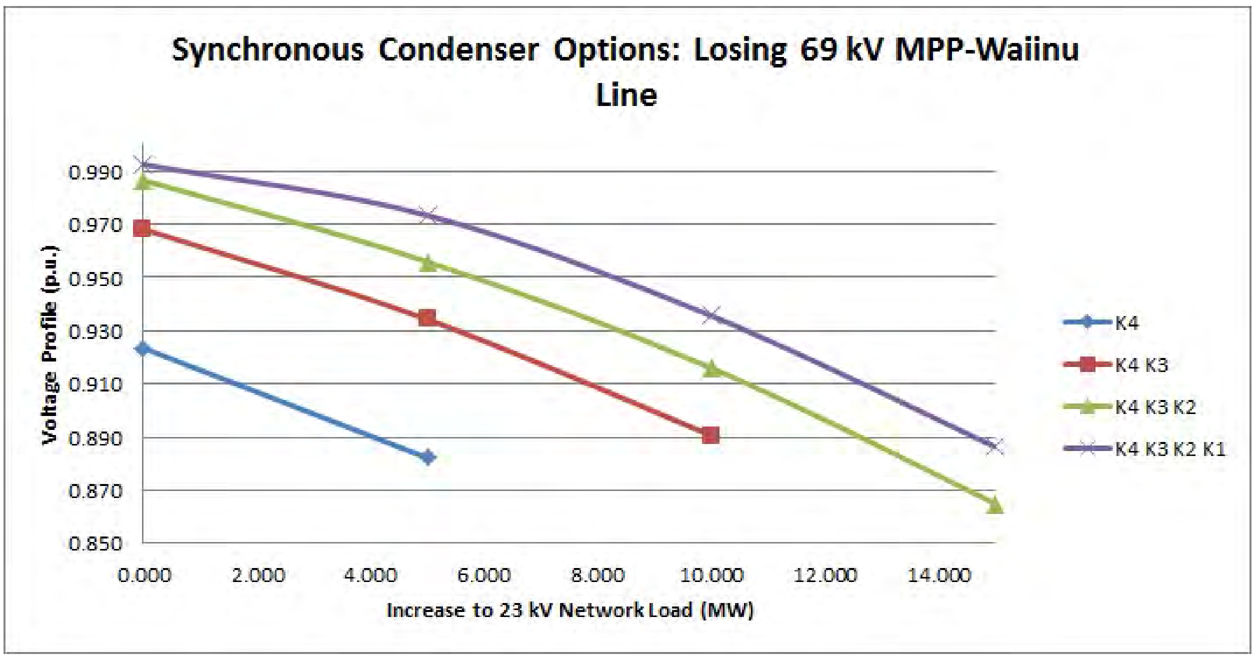

Figure 10: P-V characteristic comparison of different scenarios of KPP units converted to synchronous condensers for the most severe N-1 contingency event.

New Dispatchable Firm Generation:

If the company intends to procure new generation to meet the reserve capacity shortfall, the new generation units may potentially void the need for the Waiinu-Kanaha upgrade project depending on the location of interconnection of the new units. If the new generation is interconnected on the 23 kV network, from a voltage profile standpoint, the system can be expected to behave similar to the existing system with KPP in operation as this would only involve replacing the existing older generation units with new ones – this will not place a burden on the transmission lines and tie transformers that connect the 23 kV and 69 kV network and voltage sources are still close to the 23 kV network load center. However, if the new generation is interconnected to the 69 kV network, the system is expected to experience the same system issues source of generation on the 23 kV being removed; placing new generation units on the 69 kV network will not alleviate burden placed on the transmission lines and tie transformers that connect the 23 kV and 69 kV network, and will not provide reactive support to the 23 kV network – this will still result in the 23 kV network becoming heavily dependent on the 69 kV network for power and may possibly overload the transmission lines and tie transformers that connect the 23 kV and 69 kV network past their rated thermal limits and subject voltage sources to be electrically farther from the 23 kV network load center. A few scenarios or new firm generation on the 23 kV network were considered and compared to the existing operating KPP which has an approximate 35 MW capacity; they are: one new 8 MW unit, one new 15 MW unit, and two new 8 MW units. The P-V characteristic comparison of these scenarios for the normal condition and most severe N-1 contingency are shown in Figure 11 and Figure 12, respectively. For the scenario or new generation connecting to the 69 kV network, the capacity of new generation is arbitrary from a voltage standpoint as the option would not mitigate the issues mentioned. For the study, the scenario considered for study is the first stage of the Waena Power Plant (WPP) project proposed by First Wind – a new 17 MW unit at the WPP site near Pukalani; The P-V characteristics of this scenario is compared with the existing system with and without the operation of KPP, shown in Figure 13.

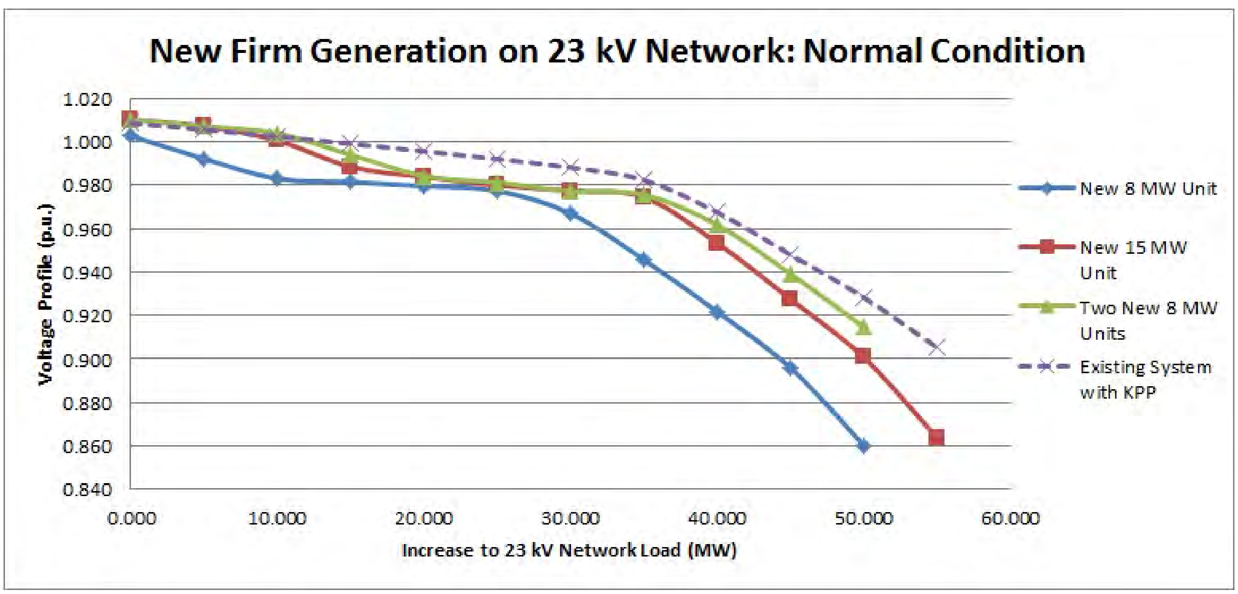

Figure 11: P-V characteristic comparison of different scenarios of new generation of various capacities on the 23 kV network and the existing system for the normal condition.

Kahului Power Plant Retirement: Voltage Stability Assessment

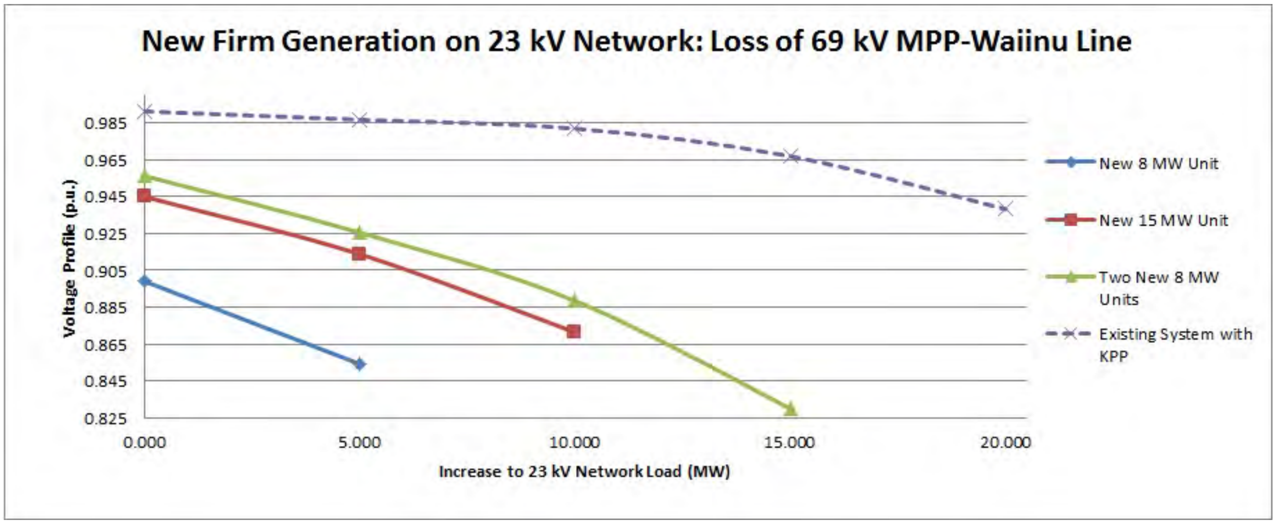

Figure 12: P-V characteristic comparison of different scenarios of new generation of various capacities on the 23 kV network and the existing system for the most severe N-1 contingency event.

It can be observed that the more capacity of new generation added to the 23 kV network, the closer the P-V curve representing new generation approaches the P-V curve that represents the existing system with KPP, which has an approximate 35 MW capacity. This indicates that in order to achieve system characteristics better than the existing system with KPP, the capacity of new generation must be greater than the existing capacity at KPP (i.e. 35 MW). It can be seen that at the existing system load, the new 8 MW unit and new 15 MW unit scenarios settle at point close to the end of a curve – these are unstable voltage points. The two new 8 MW unit scenario is much more favorable as it settles at a point father away from voltage collapse. Installing more capacity of new generation on the 23 kV network will allow the system to operate farther away from the point of voltage collapse.

Voltage issues arise when total system load reaches 170 MW and is accompanied by a severe N-1 contingency if KPP is decommissioned and no additional system upgrades are implented. The new generation units must be brought online when total system load reaches 170 MW to avoid violations to the reliability criteria and possible compromise of system reliability. Historically, system load has been observed to remain at 170 MW or above for approximately 7 hours, see Appendix.

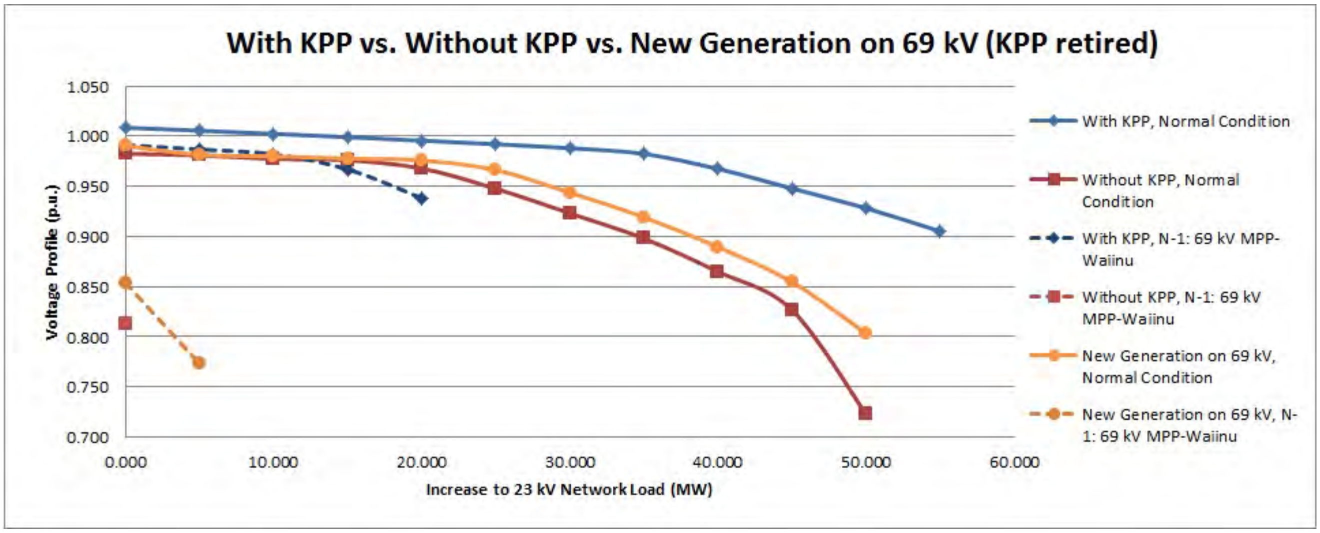

Figure 13: P-V characteristic comparison of the scenario of new generation on the 69 kV network, the existing system with KPP, and the existing system without KPP for the normal condition and most severe N-1 contingency event.

Battery Energy Storage System (BESS) Option:

It is assumed in this study that BESS will be operated to predominantly provide active power because pursuing a battery for the purpose of providing reactive support would be uneconomical as there are less expensive alternatives available that fulfill these needs such as capacitor banks or the already mentioned synchronous condenser option; in this study, the BESS units are modeled to operate at a 0.95 power factor to reflect a unit which predominantly provides active power and minimum reactive power. The BESS option, if located on the 23 kV network, is anticipated to mitigate the thermal limit violation issues involved with the retirement of KPP because it will supply active power to the 23 kV network which will alleviate the stress placed on the transmission lines and tie transformers that connect the 23 kV and 69 kV network when KPP is decommissioned and is also anticipated to mitigate the voltage violation, voltage instability, and voltage collapse issues. However, there are several ambiguities concerning the battery that need to be clarified before it can be determined if the BESS option is a viable, economic, or engineering sound solution to address the issues involved. These ambiguities include: where will the battery be located (on the 23 kV or 69 kV network), will the battery operate as a normal dispatchable unit or solely for the purpose of mitigating system issues during emergency events, what is the size of the battery For planning purposes, these ambiguities need to be addressed.

Similar to the afore mentioned issue in the discussion concerning the new dispatchable firm generation option, if the battery is placed on the 69 kV, the battery will contribute no significant mitigation measures as the voltage sources are still electrically far from the 23 kV network load center and the burden placed on the transmission lines and tie transformers that connect the 23 kV and 69 kV network is not lessened. However, placing the battery on the 23 kV network will alleviate much of the burden placed on the transmission lines and tie transformers that connect the 23 kV and 69 kV network because the battery (i.e. an active and reactive power source) is placed near the load and thus assuages the dependency on power to be supplied by the 69 kV network and aids in mitigating voltages violation, voltage instability, and voltage collapse issues on account that the battery, a voltage source, is closer to the 23 kV network load center. If the battery is operated as a normal dispatchable unit, where the battery will be dispatched to serve peaking system load demands when needed, it raises the issue whether or not there will be sufficient charge in the battery to mitigate system issues in the event of an emergency. However, if the battery is operated to solely be dispatched during emergency events, it raises the question whether or not the battery option is an economical solution. The battery would need to be sized to provide power long enough for the N-1 contingency to be resolved or until total system load recedes below afore mentioned threshold of 170 MW. It has been mentioned that the battery could be used to mitigate system issues just long enough for addition distributed generation sources (fuel units) to be brought online; this option would only be viable if the distributed generation sources, which need to be procured, are on the 23 kV network and would be uneconomical to pursue as the distributed generation source alone would be adequate to mitigate the issues, as seen in the new dispatchable firm generation option.

Several scenarios of different size batteries were considered: a 15 MW BESS, a 20 MW BESS, and a 25 MW BESS. Figures 14 and 15 compare the P-V characteristics of the various sized BESS for the normal condition and most severe N-1 contingency event, respectively. It can be seen in Figure 15 that for all scenarios, the BESS option is viable long term solution capable of mitigating voltage issues; this option is adequate until the 23 kV network load increases by approximately 10 MW, in other words, until the total system load reaches approximately 247 to 250 MW, which is beyond the scope of load forecast.

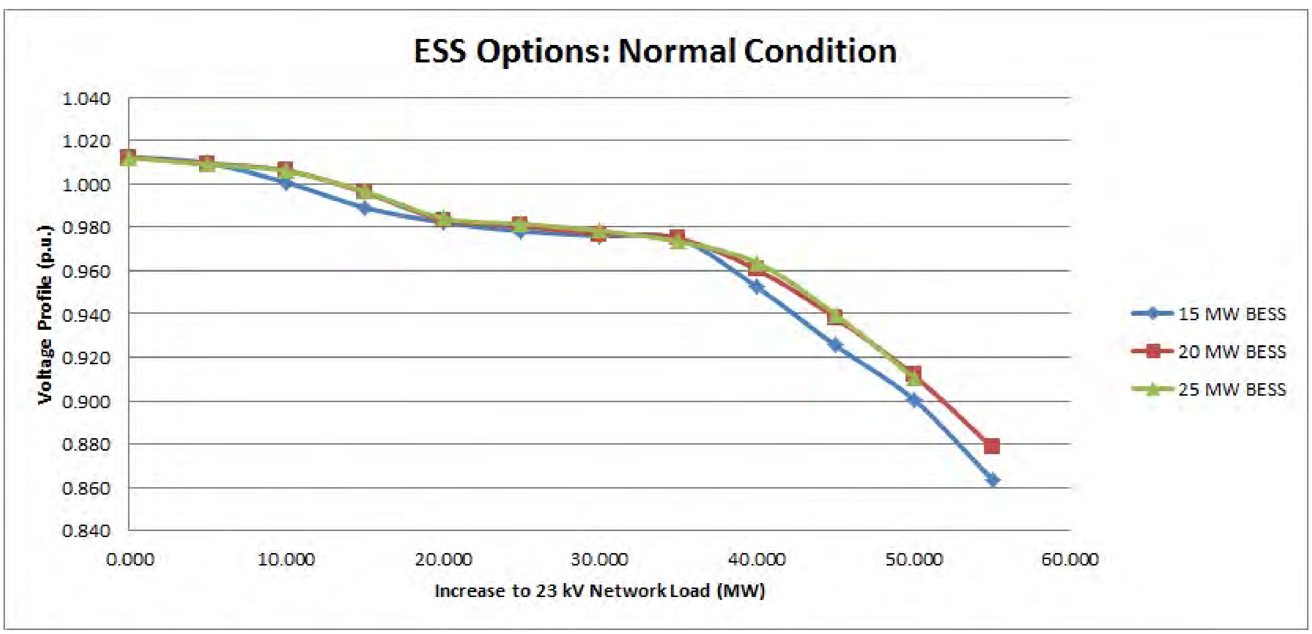

Figure 14: Comparison of P-V characteristics of various sized BESS for the normal condition.

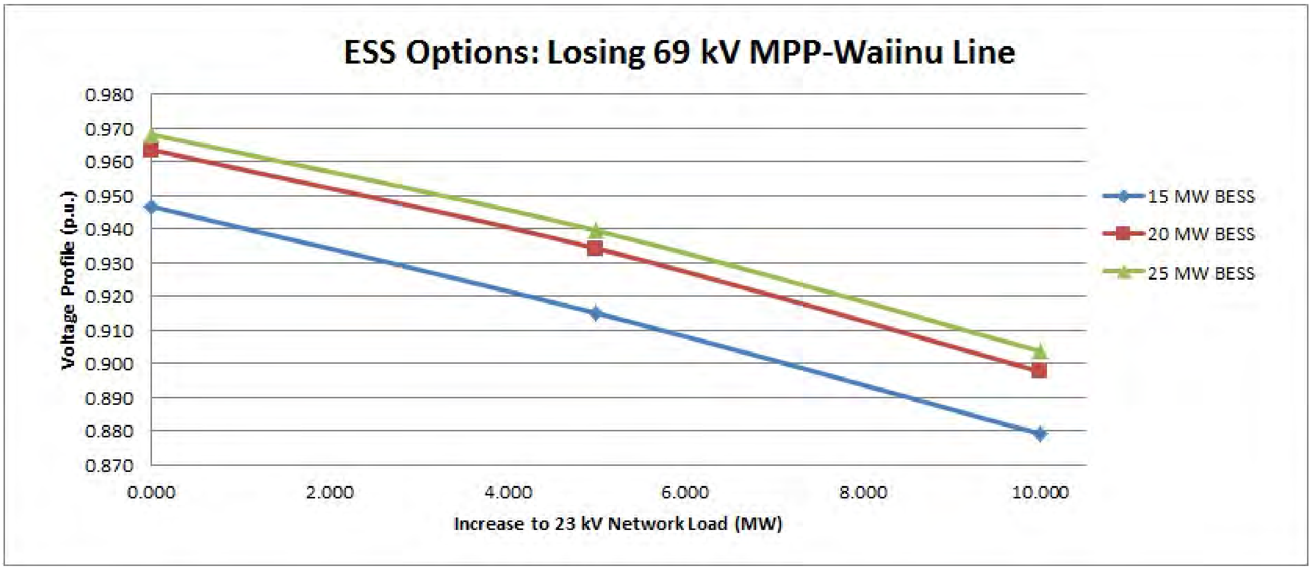

Figure 15: Comparison of P-V characteristics of various sized BESS for the most severe N-1 contingency event.

Demand Response:

The concept of the Demand Response (DR) option to be utilized for the effort of mitigating issues involved with the retirement of KPP is end-use customer consumption of power will be reduced in response to a contingency event to avoid the risk of jeopardizing system reliability. This should operate similarly to existing load shedding schemes – DR program must execute within several cycles of detecting indications that system reliability is at risk of being compromised. As mentioned, voltage issues arise when total system load reaches 170 MW and is accompanied by a severe N-1 contingency if KPP is decommissioned and no additional system upgrades are implanted. The DR program must drop end-use customer load to maintain total system load within the 170 MW benchmark to avoid voltage violation, voltage instability, and voltage collapse issues in the event of a contingency.

Comparing the NTA options:

For the purpose of comparing the NTA options, if numerous scenarios were considered for a NTA option, the scenario that produced the most favorable results was selected to be compared against the other options. The scenario of converting all existing units at KPP to synchronous condensers was selected for the synchronous condenser option, the scenario of two new 8 MW units was selected for the option of installing new firm generation units on the 23 kV network option, and the 25 MW BESS scenario was selected for the BESS option to represent its respective NTA option for comparison. Figure 16 and Figure 17 shown below compare the P-V characteristics of the various NTA options against the Kanaha-Waiinu upgrade and existing system with and without the operation of KPP for the normal condition and most severe N-1 contingency, respectively.

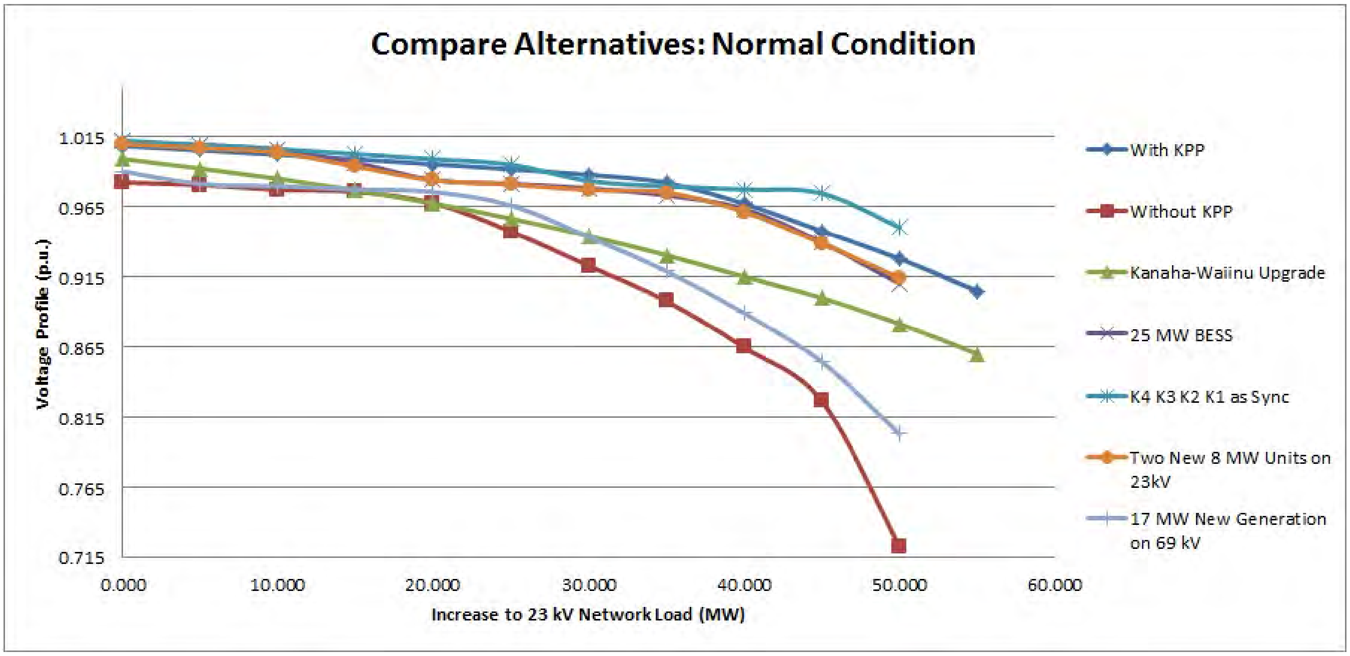

Figure 16: Comparison of P-V characteristics of various NTA options against the Kanaha-Waiinu upgrade and existing system with and without operation of KPP for the normal condition.

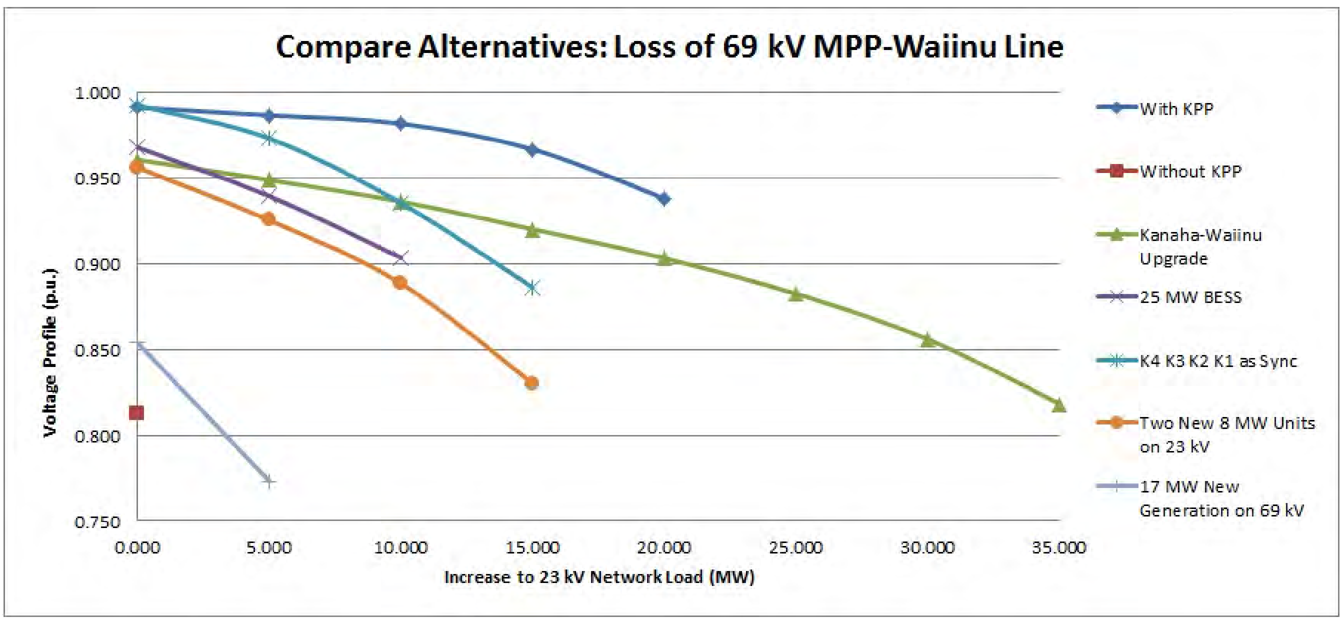

Figure 17: Comparison of P-V characteristics of various NTA options against the Kanaha-Waiinu upgrade and existing system with and without operation of KPP for the most severe N-1 contingency.

Several points should be considered when interpreting Figure 17. The synchronous condenser option seemingly has more favorable results than the BESS and new firm generation on the 23 kV network option, however, results shown are strictly examining the voltage profile; there thermal limit issues involved with the KPP retirement that the synchronous condenser option will not mitigate. The capacity values of new firm generation and BESS considered were arbitrarily selected; it should be noted that choosing to install greater capacity values of BESS and new generation (to be installed on the 23 kV network) units will produce P-V characteristics closer to the curve representing existing system with operation of KPP.

Compare and Contrast Options:

Table 1: Comparison of Transmission and Non-Transmission options studied.

Options	Adequate Until…		
	Growth on 23 kV Network load (in MW) reaches:	In other words, when system peak load (in MW) reaches:	Load forecast indicates this will occur in:
Waiinu-Kanaha Upgrade project	20	Over 270	N/A*
15 MW BESS on 23 kV	5	225	N/A*
20 MW BESS on 23 kV	5 – 8	225 – 240	N/A*
25 MW BESS on 23 kV	10	247	N/A*
K4 as Sync	2 – 3	200 – 203	2016 – 2017
K4 & K3 as Sync	5 – 8	225 – 240	N/A*
K4, K3, & K2 as Sync	10	247	N/A*
K4, K3, K2, & K1 as Sync	10 – 12	247 – 260	N/A*
New 8 MW unit on 23 kV	0	200	2014 – 2015
New 15 MW unit on 23 kV	5	225	N/A*
Two new 8 MW unit on 23 kV	5 – 8	225 – 240	N/A*
New 17 MW unit on 69 kV	0	200	2014 – 2015

N/A* - indicates that the option will be adequate until the system peak load reaches load value that is beyond what is reported in load forecast; the load forecast has forecasted system peak load values until year 2030, thus, these options are adequate even beyond the year 2030 (from a voltage standpoint).

Conclusion

From a voltage standpoint, the Waiinu-Kanaha upgrade project, BESS option, synchronous condenser option, and installing new firm dispatchable generation on the 23 kV network option are viable long term solutions to mitigate voltage issues involved with the retirement of KPP. However, considering the possibility of thermal overloads occurring on the transmission lines and tie transformers that connect the 23 kV and 69 kV network when KPP is decommissioned, TPD does not recommend the synchronous condenser option as an alternative to the Waiinu-Kanaha upgrade project. If new firm dispatchable generation is procured to meet the reserve capacity shortfall, installing the new units on the 23 kV network will mitigate voltage issues and is anticipated to mitigate thermal issues involved with the retirement of KPP, however, installing the generation units on the 23 kV network conflicts with MECO's ultimate plan of converting the entire Maui transmission system to 69 kV. On the other hand, the Waiinu-Kanaha upgrade project mitigates voltage and thermal issues, aligns with MECO's ultimate plan, and also increases the reliability of the system in the aspect that the project will provide a second line to feed Waiinu – in the event of the current most severe N-1, losing the MPP-Waiinu line, the upgraded Waiinu-Kanaha line will provide power to the Waiinu substation to feed the 23 kV network load. The BESS option produces similar results to the option which involves installing new firm generation on the 23 kV network if the BESS is placed on the 23 kV network, however, TPD considers it to be uneconomical to pursue the BESS option considering the possible dispatch scenarios of the BESS unit and its similar characteristics to the new firm generation option. TPD recommends that the company's interest in the procurement of new firm generation, BESS, DR, or any other means to meet the approximate 40 MW reserve capacity short fall by 2019 should not affect or void the plan of the Waiinu-Kanaha upgrade project. TPD still recommends the implementation of the Waiinu-Kanaha upgrade project as it will ensure that the retirement of KPP will not jeopardize system reliability and transition portions of the existing 23 kV network to 69 kV, thus progressing MECO's ultimate plan of converting the entire Maui transmission network to 69 kV and improve the overall system reliability.

Appendix

The comparison of P-V characteristics for the N-1 events of losing the 23 kV Kanaha-Kahului line, 69 kV Maalaea-Puunene line, and 23 kV Wailuku-Waiinu lines are shown below.

<u>Existing system with and without operation of KPP:</u>

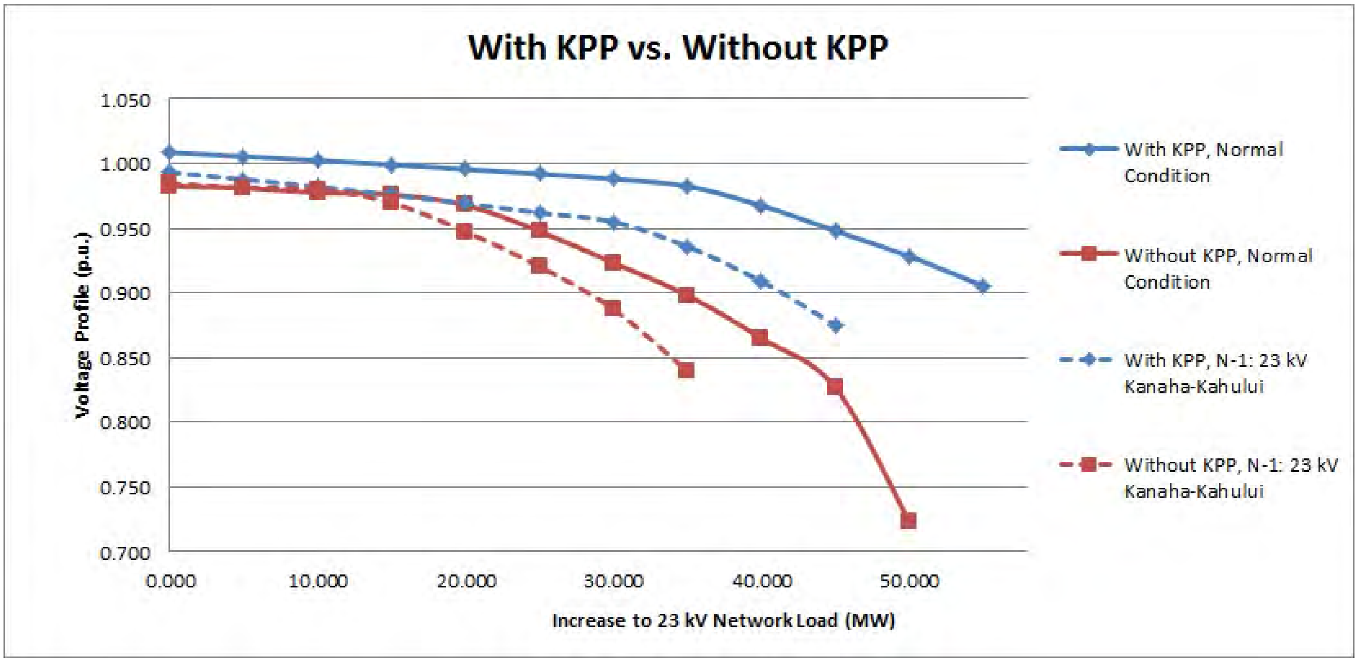

Figure 18: P-V characteristics of existing systen with and without KPP for losing 23 kV Kanaha-Kahului Line.

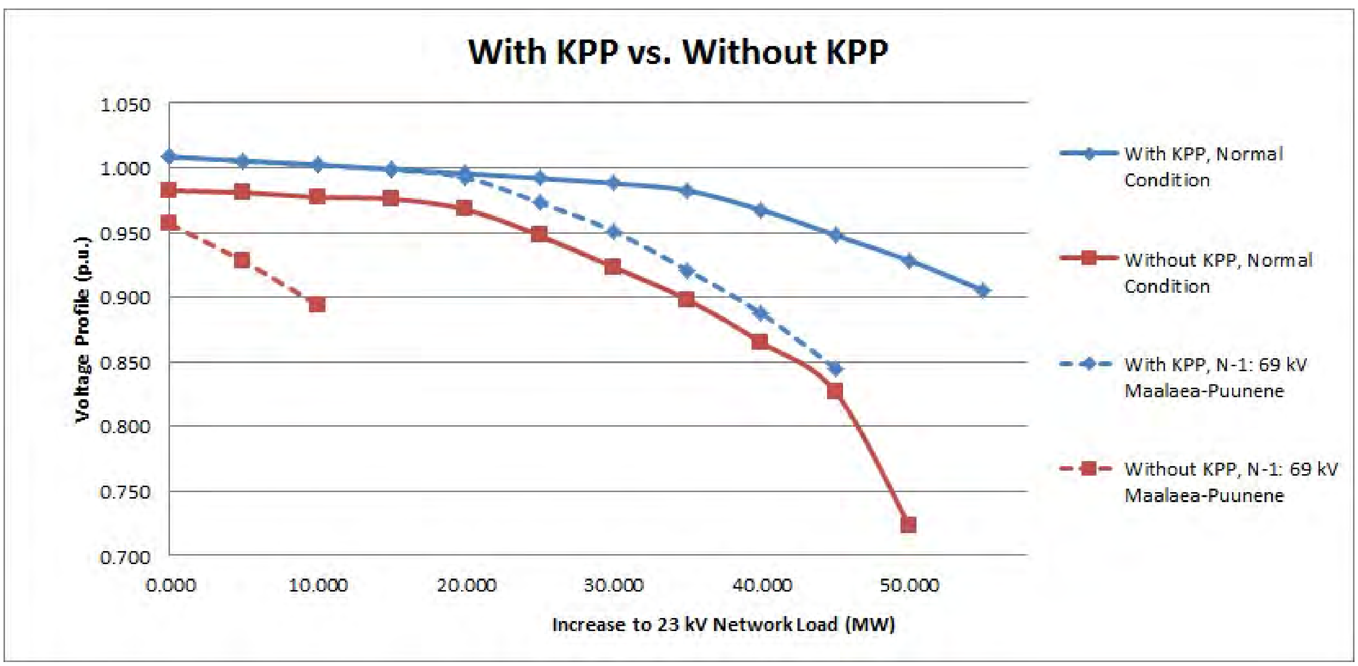

Figure 19: P-V characteristics of existing systen with and without KPP for losing the 69 kV MPP-Puunene Line.

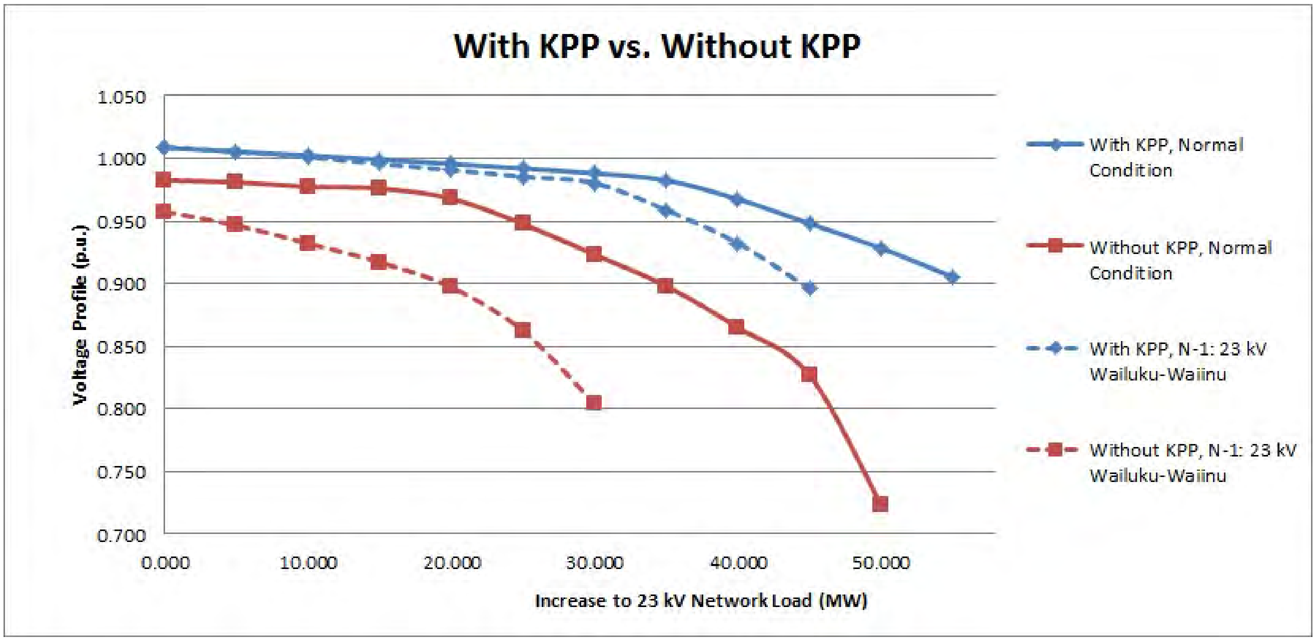

Figure 20: P-V characteristics of existing systen with and without KPP for losing 23 kV Wailuku-Waiinu Line.

P-V characteristic comparison of Alternative 1 - Alternative 5:

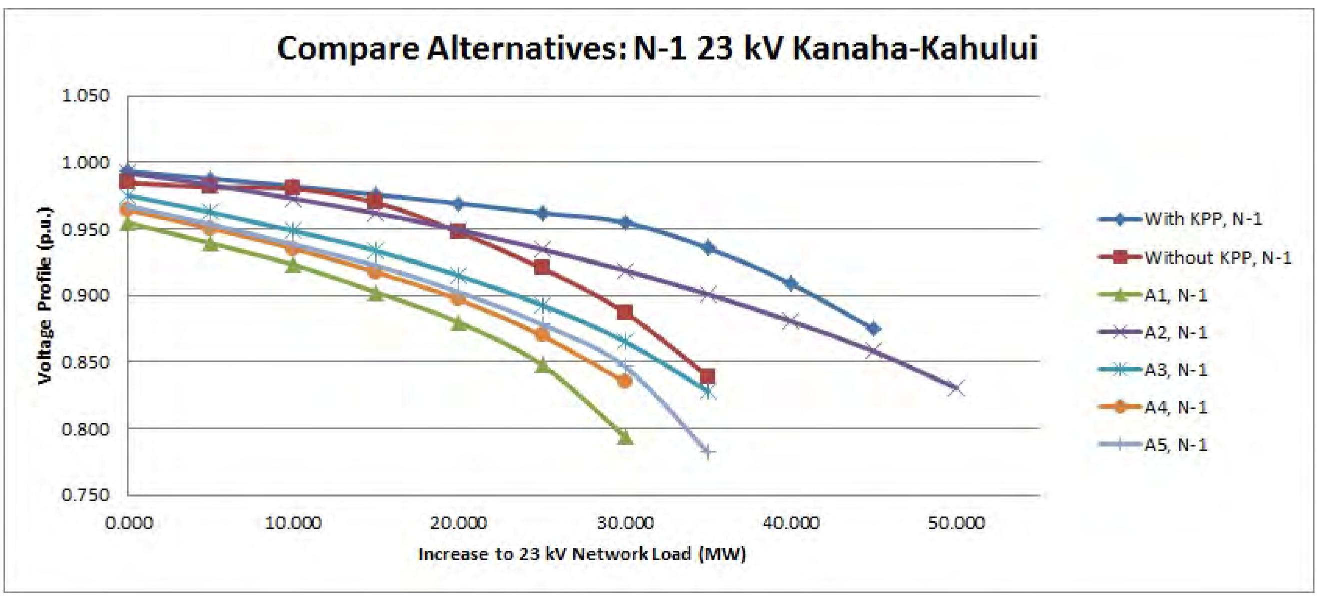

Figure 21: Comparison of P-V characteristics of transmission Alternatives for losing the 23 kV Kanaha-Kahului Line.

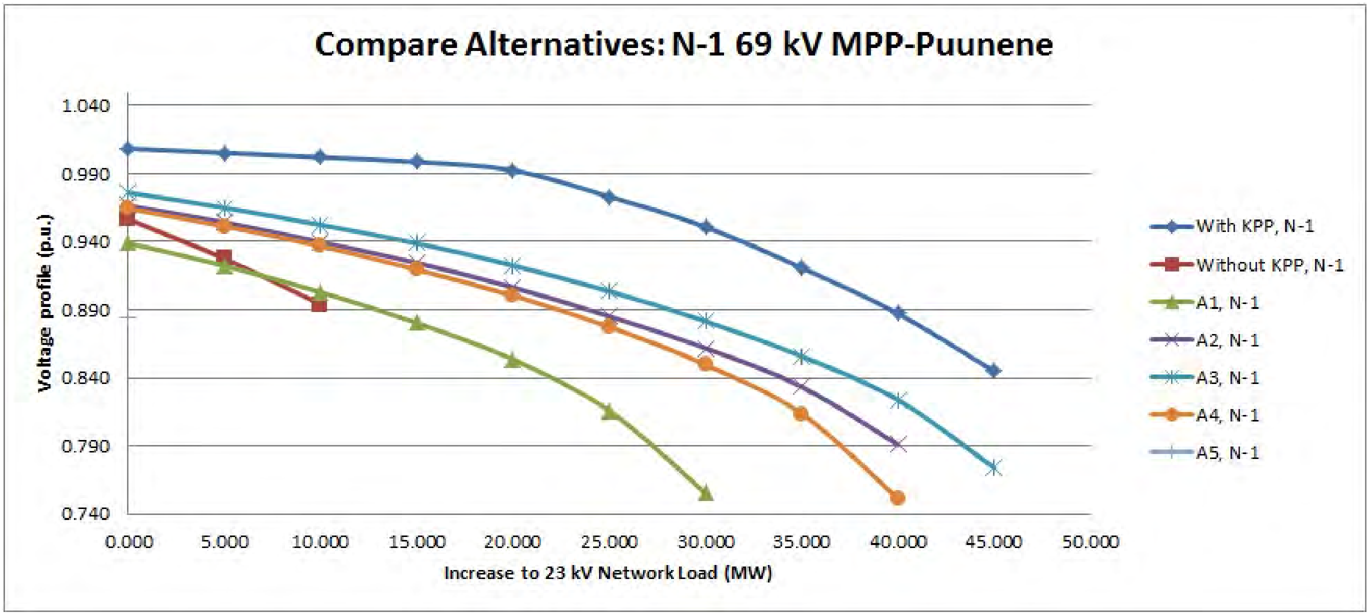

Figure 22: Comparison of P-V characteristics of transmission Alternatives for losing the 69 kV MPP-Puunene Line.

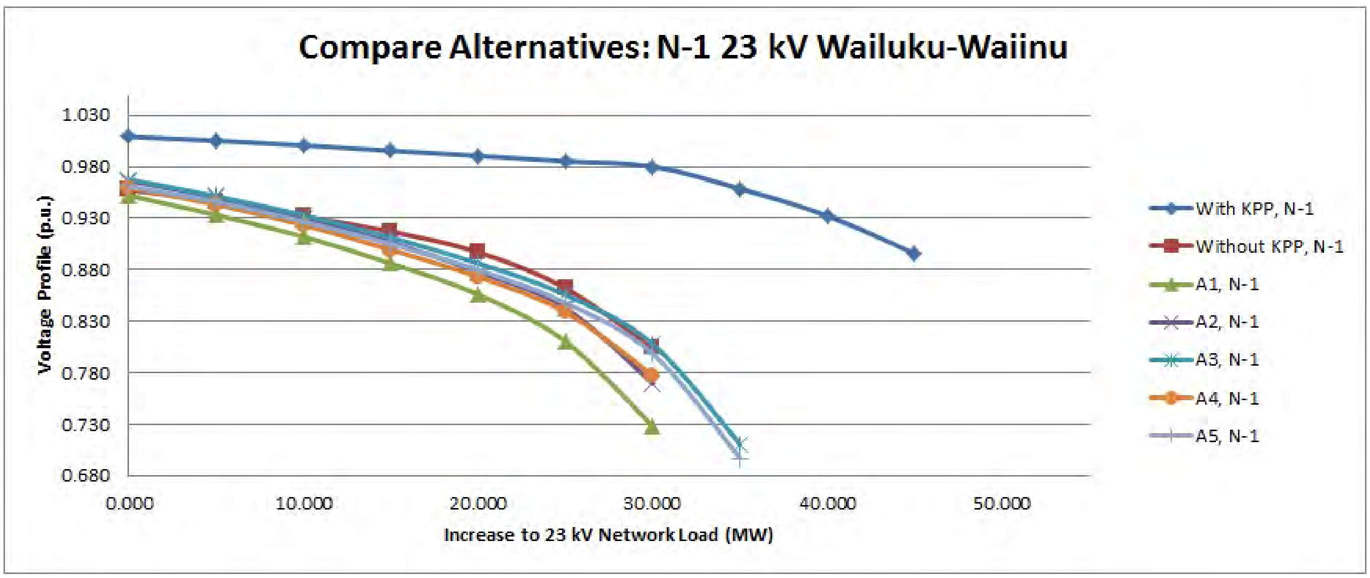

Figure 23; Comparison of P-V characteristics of transmission Alternatives for losing the 23 kV Wailuku-Waiinu Line.

Kahului Power Plant Retirement: Voltage Stability Assessment

P-V characteristic comparison of Combination 1- Combination 7:

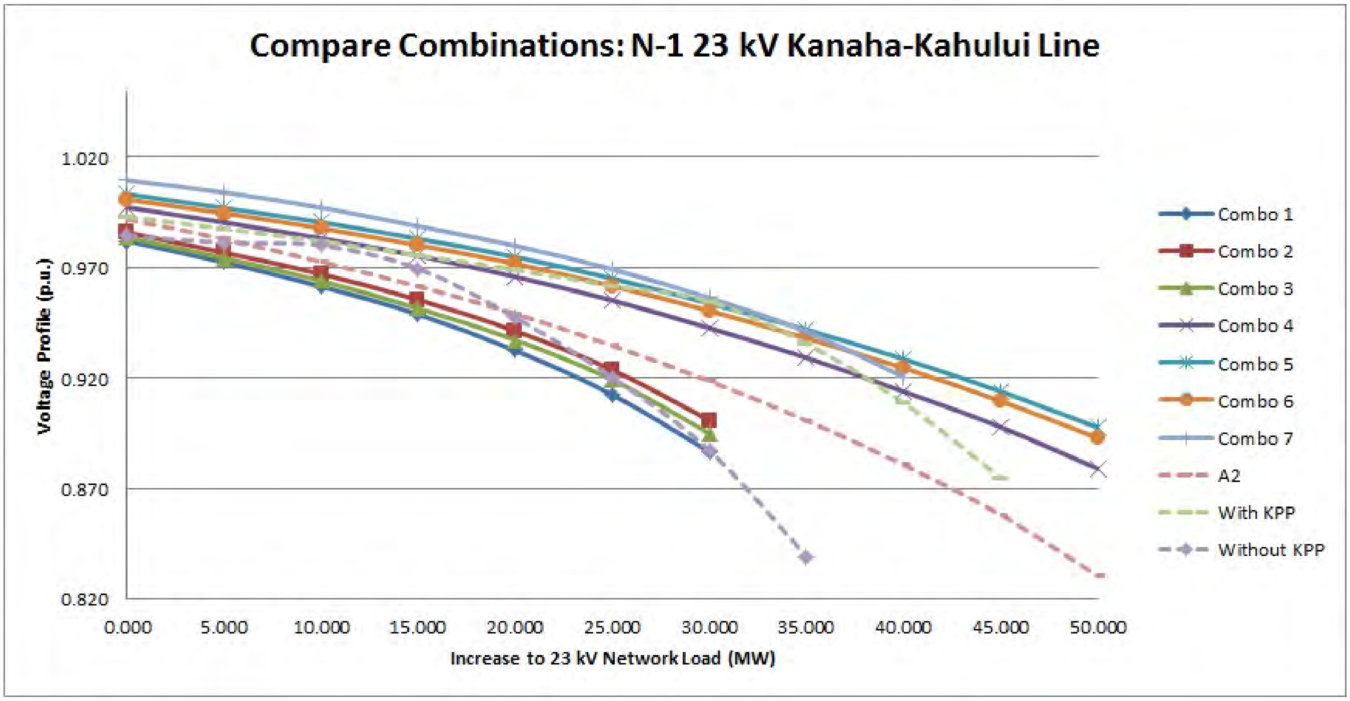

Figure 24; Comparison of P-V characteristics of tranmission Combinations for losing the 23 kV Kanaha-Kahului Line.

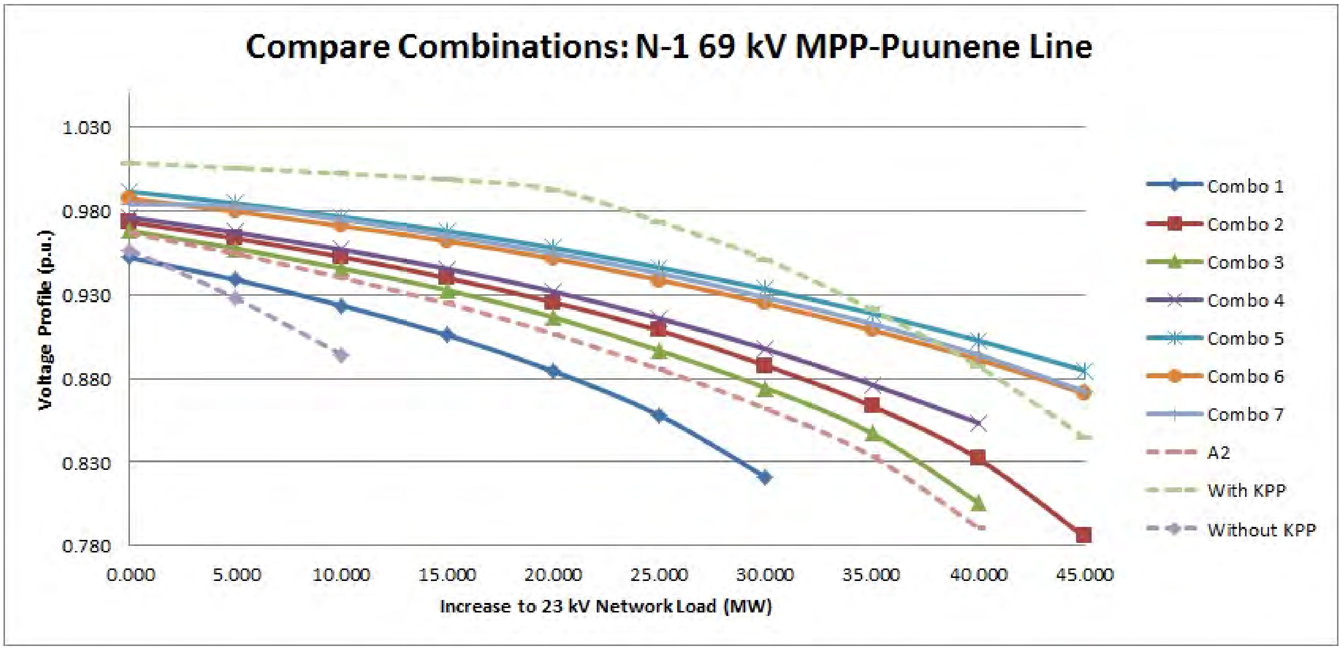

Figure 25 Comparison of P-V characteristics of tranmission Combinations for losing the 69 kV MPP-Puunene Line.

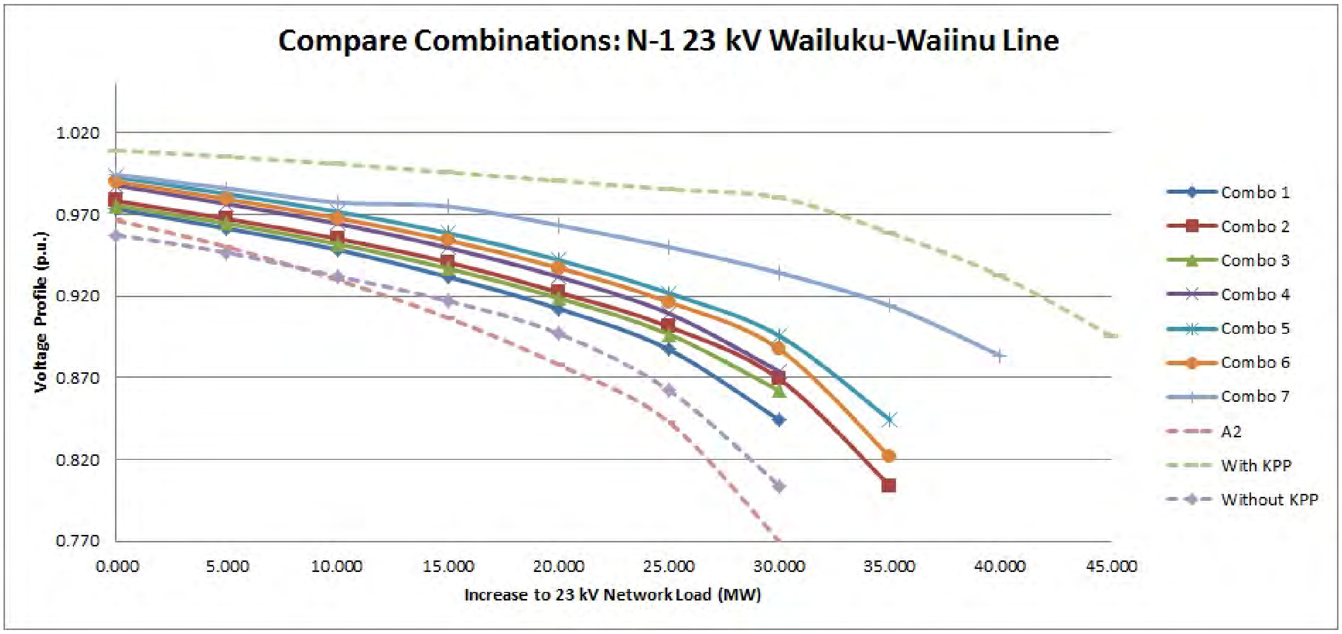

Figure 26: Comparison of P-V characteristics of tranmission Combinations for losing the 23 kV Wailuku-Waiinu Line.

<u>Synchronous Condenser Option:</u>

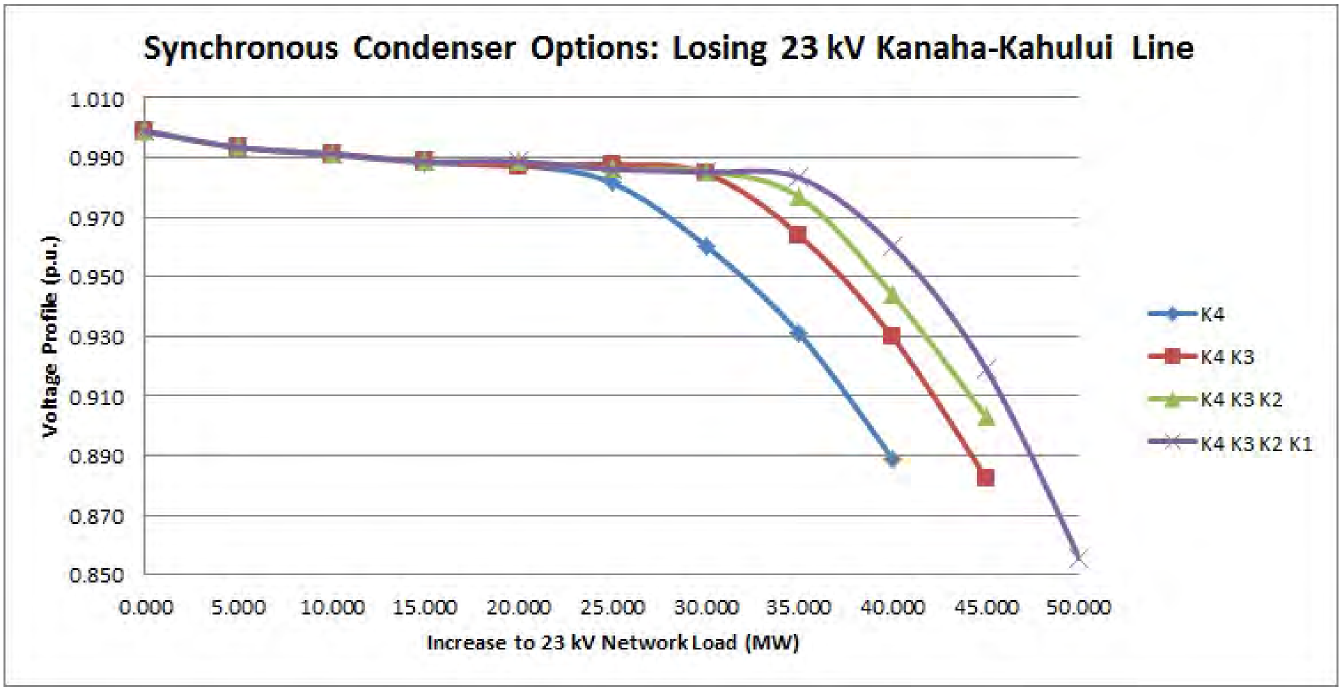

Figure 27: Comparison of P-V characteristics of synchronous condenser options for losing the 23 kV Kanaha-Kahului Line.

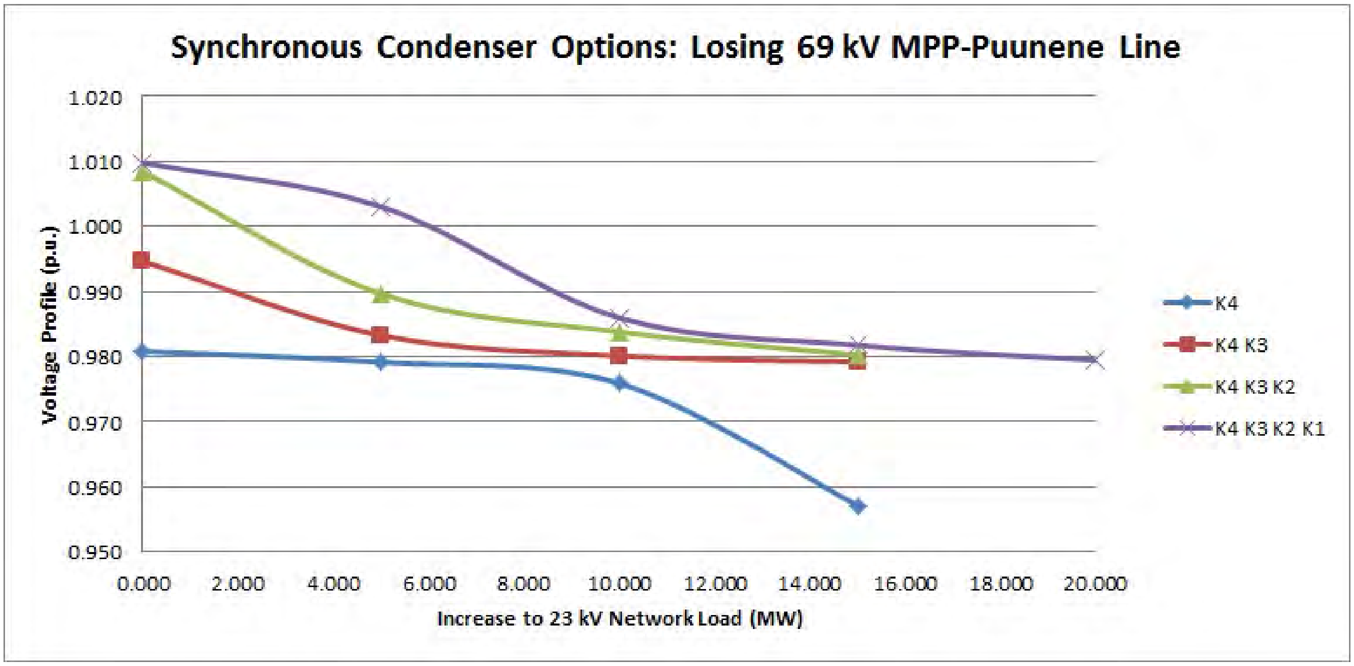

Figure 28: Comparison of P-V characteristics of synchronous condenser options for losing the 69 kV MPP-Puunene Line.

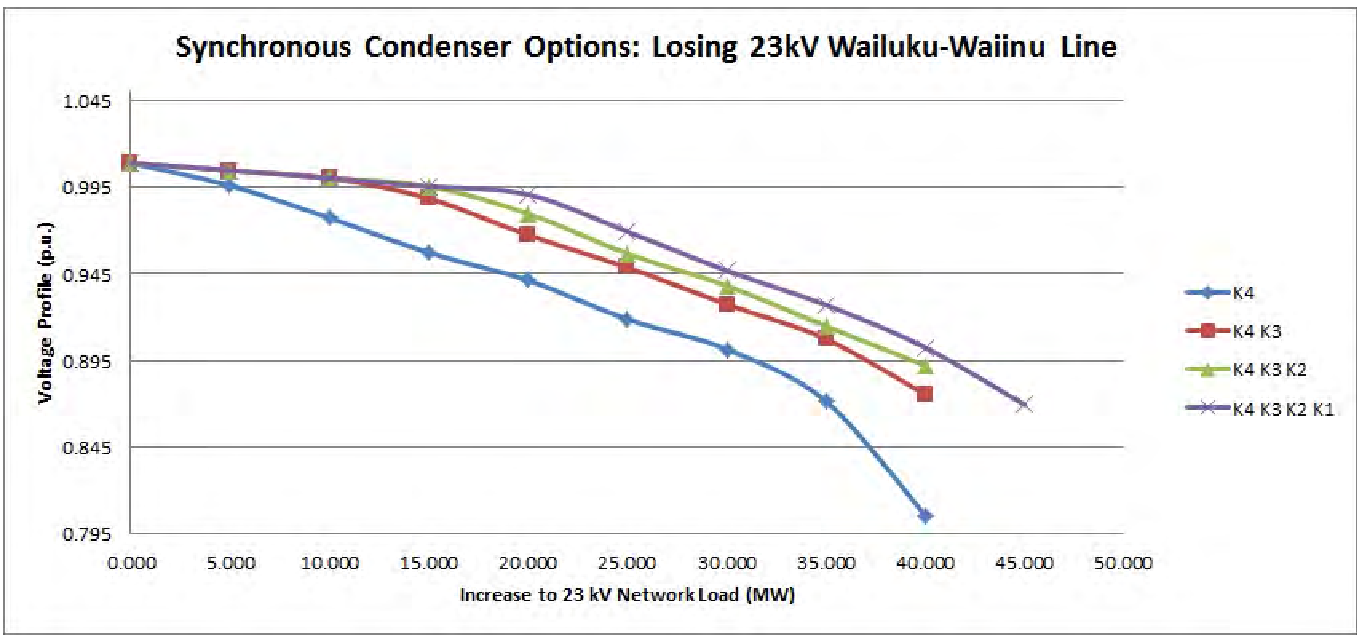

Figure 29: Comparison of P-V characteristics of synchronous condenser options for losing the 23 kV Wailuku-Waiinu Line.

New Firm Generation on 23 kV Network Option:

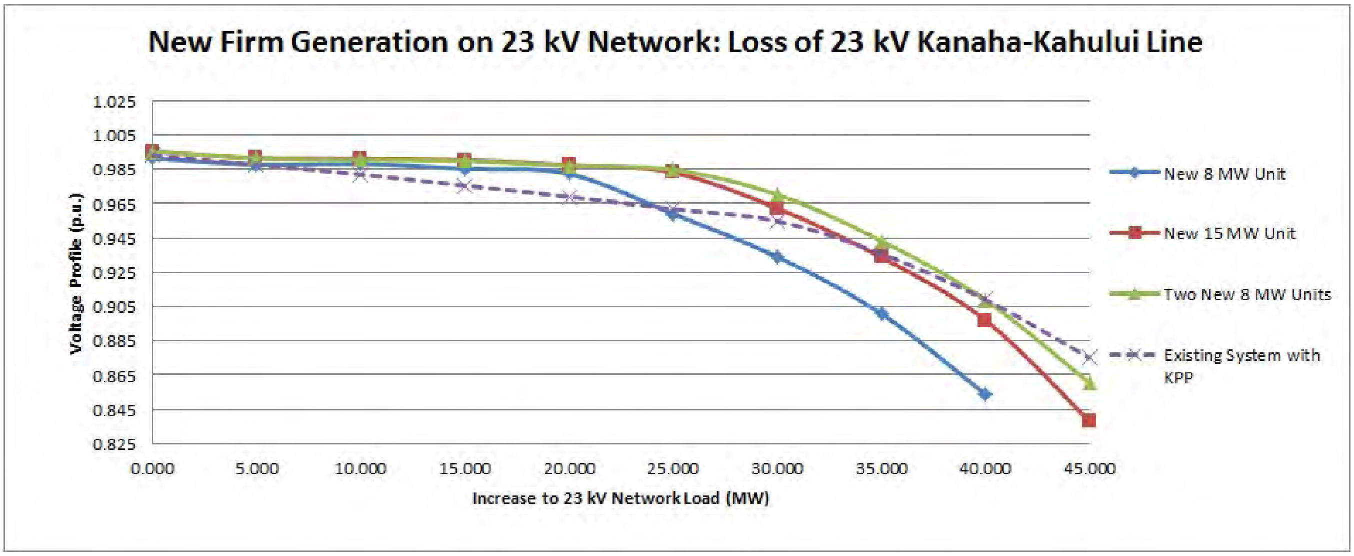

Figure 30: Comparion of P-V characteristics for new firm generation on 23 kV network option for losing the 23 kV Kanaha-Kahului Line.

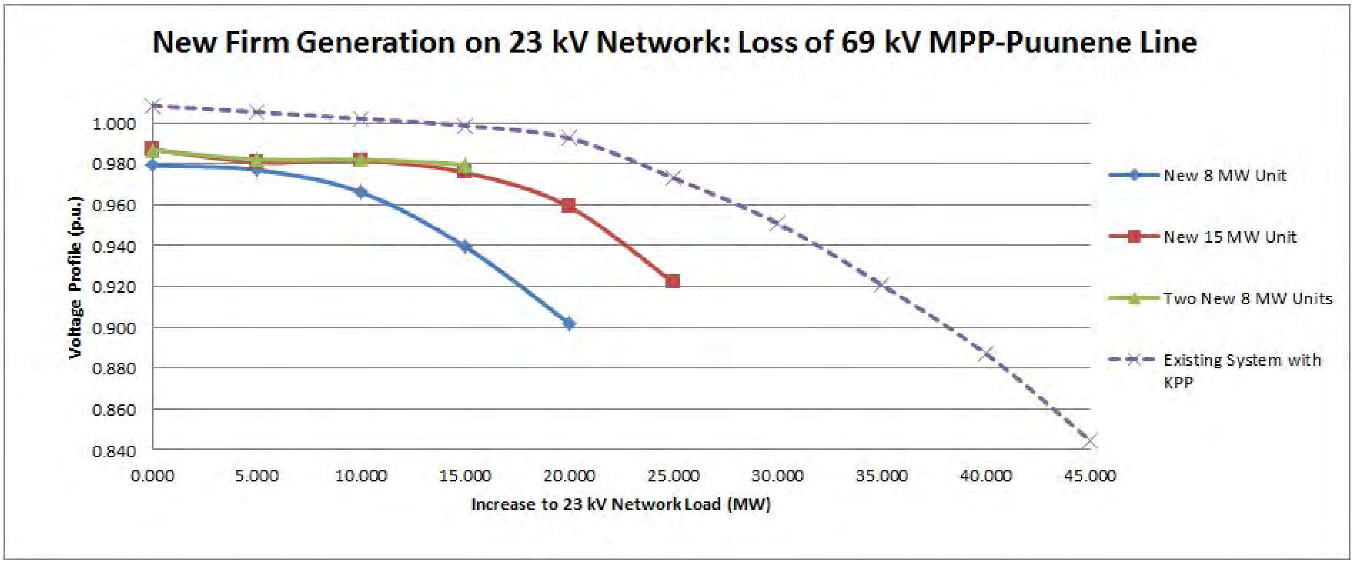

Figure 31: Comparion of P-V characteristics for new firm generation on 23 kV network option for losing the 69 kV MPP-Puunene Line.

Kahului Power Plant Retirement: Voltage Stability Assessment

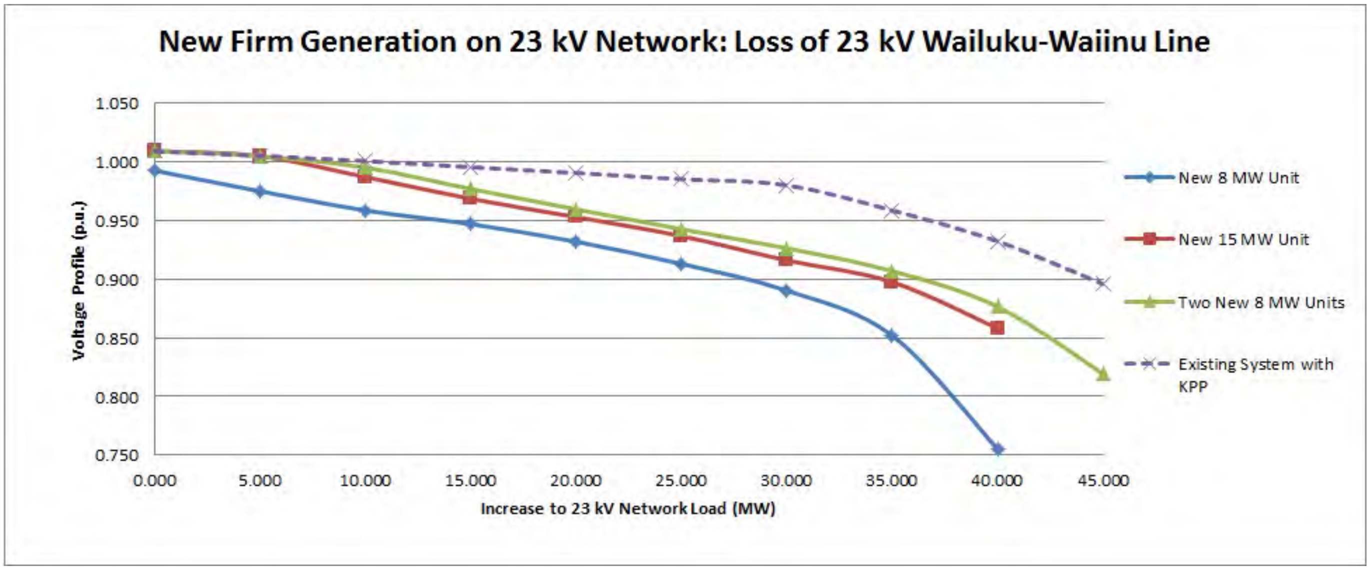

Figure 32: Comparion of P-V characteristics for new firm generation on 23 kV network option for losing the 23 kV Wailuku-Waiinu Line.

New Firm Generation on the 69 kV Network Option:

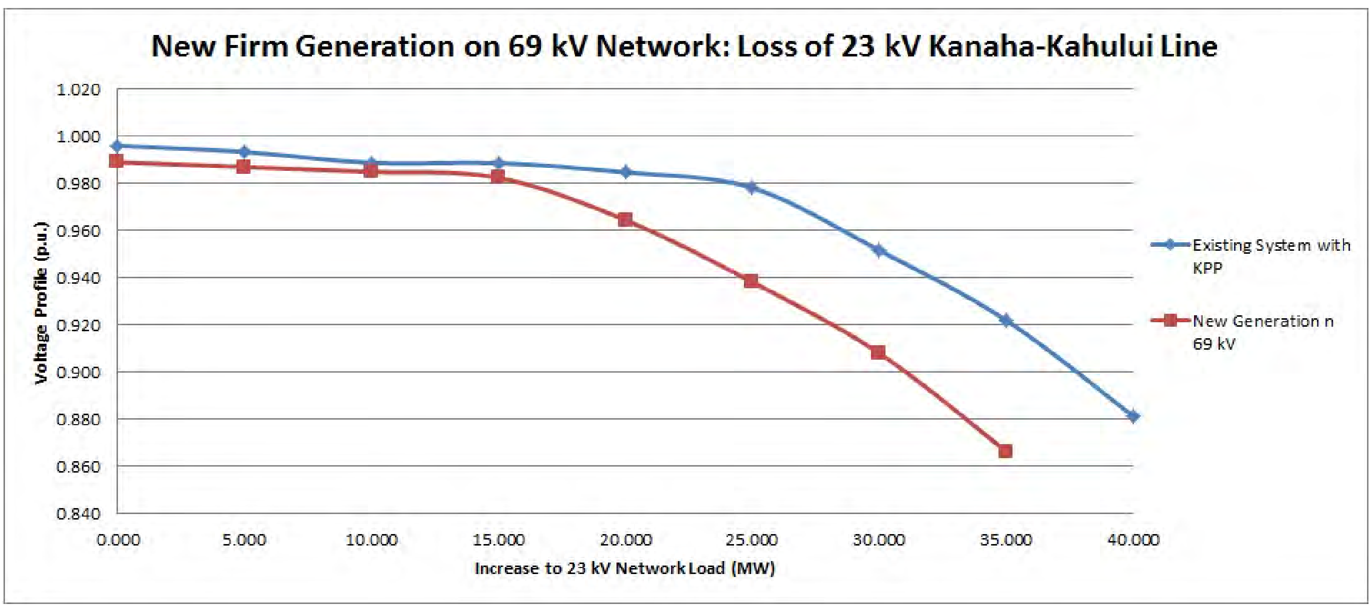

Figure 33: Comparison of P-V characteristics of new firm generation on 69 kV network for losing the 23 kV Kanaha-Kahului Line.

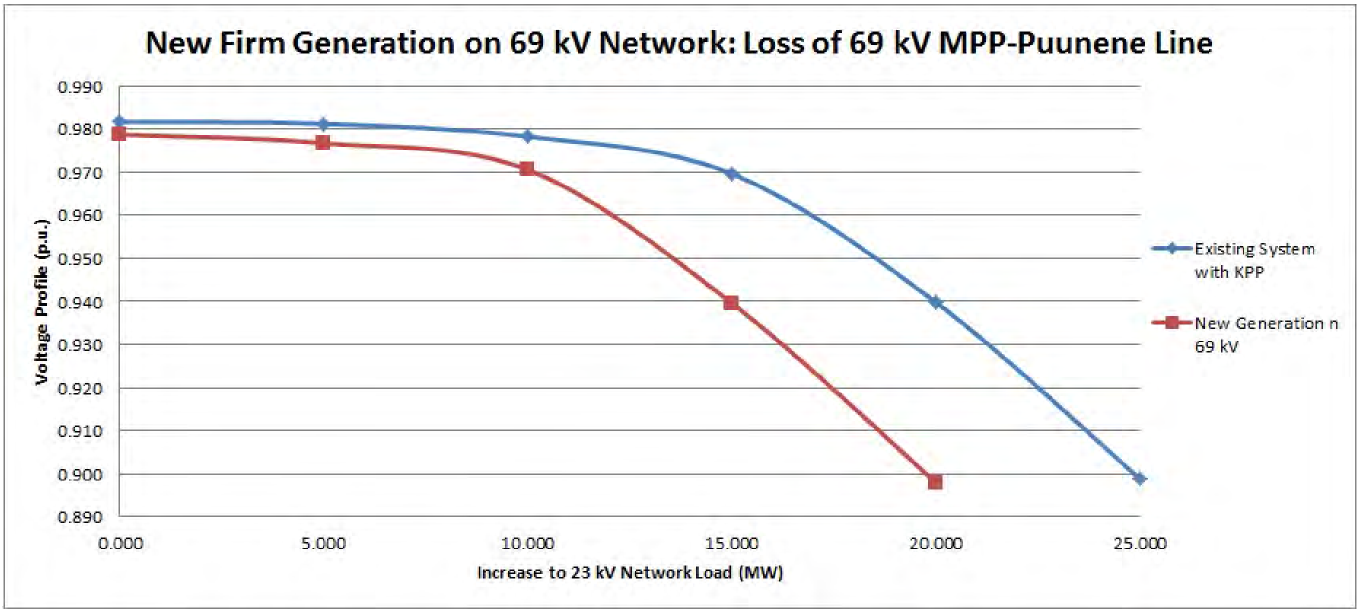

Figure 34: Comparison of P-V characteristics of new firm generation on 69 kV network for losing the 69 kV MPP-Puunene Line.

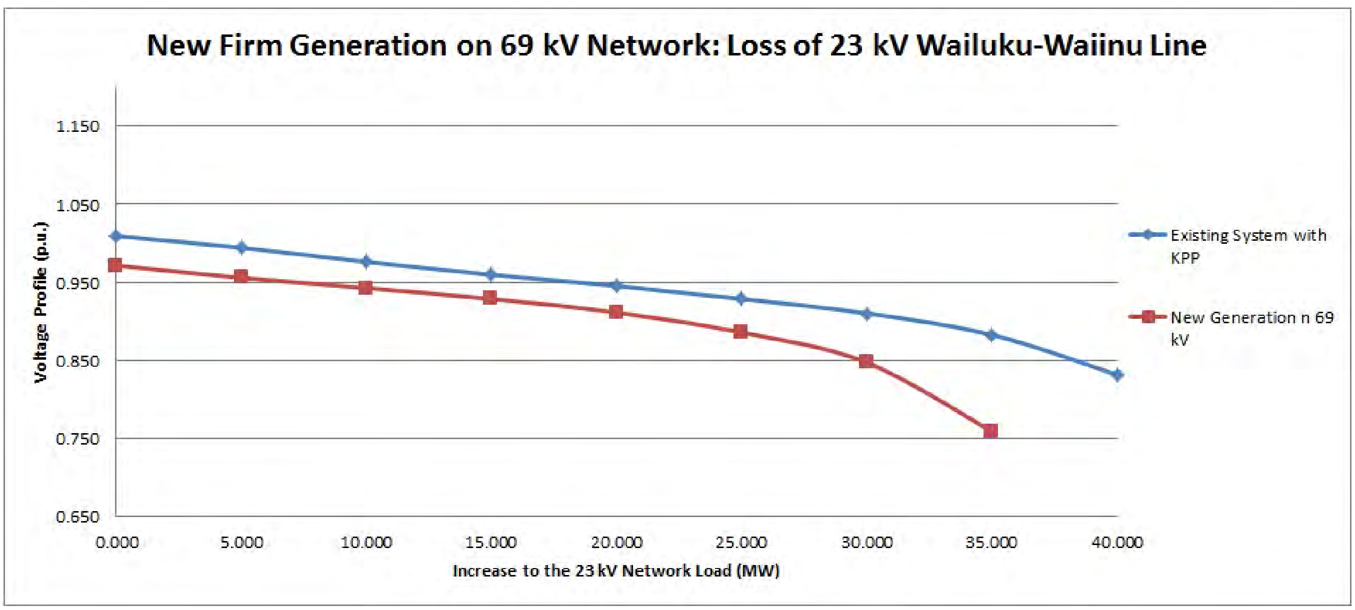

Figure 35; Comparison of P-V characteristics of new firm generation on 69 kV network for losing the 23 kV Wailuku-Waiinu Line.

BESS Option:

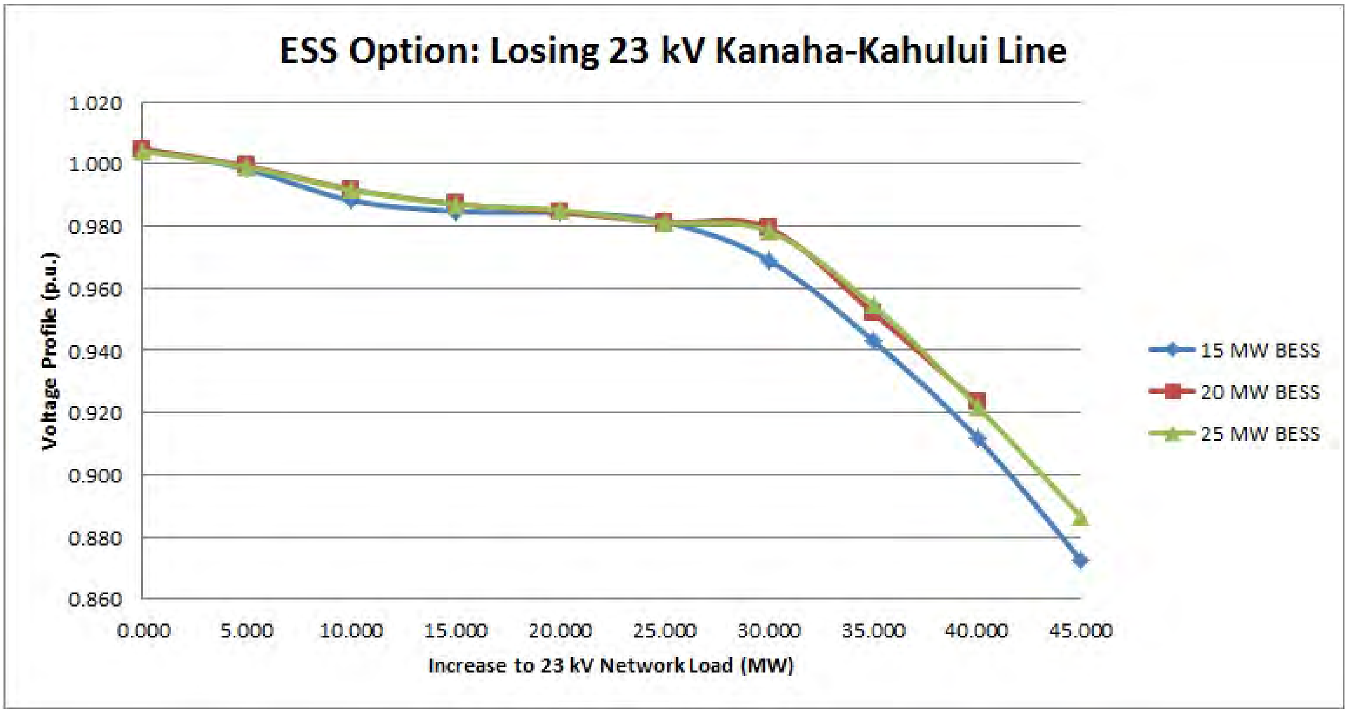

Figure 36: Comparison of P-V characteristics of various BESS options for losing the 23 kV Kanaha-Kahului Line.

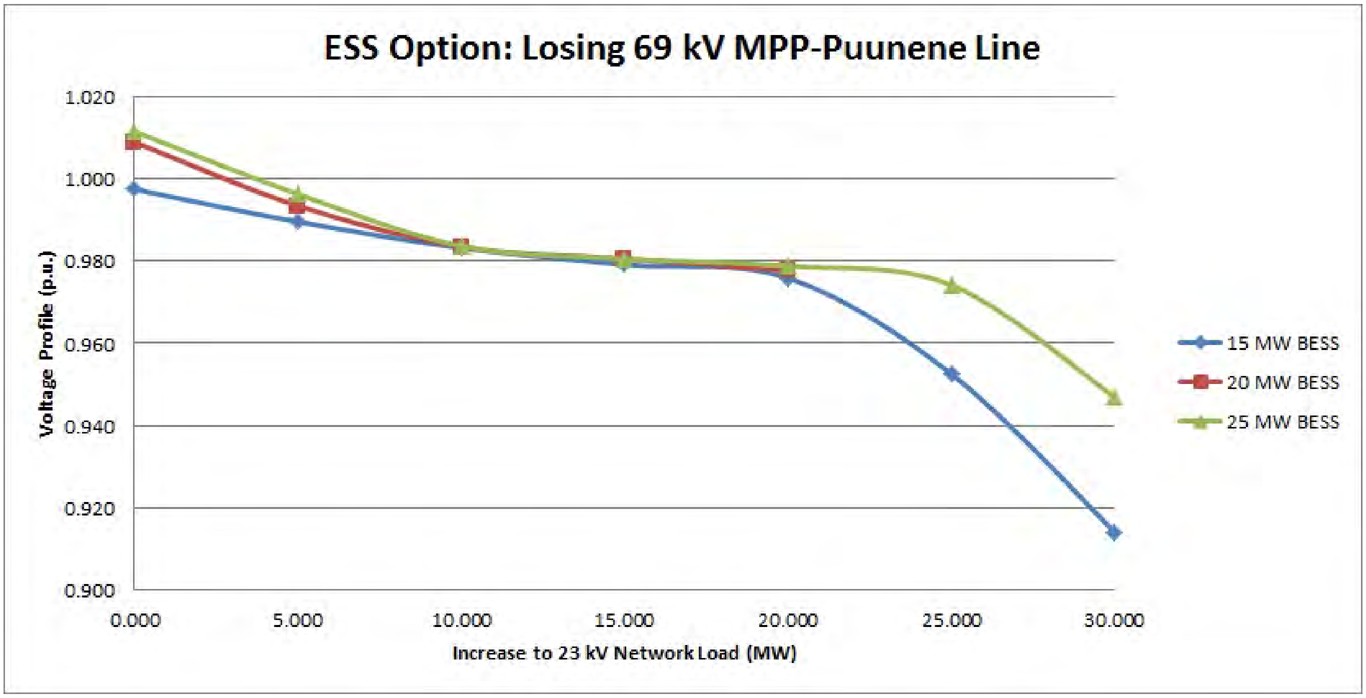

Figure 37 Comparison of P-V characteristics of various BESS options for losing the 69 kV MPP-Puunene Line.

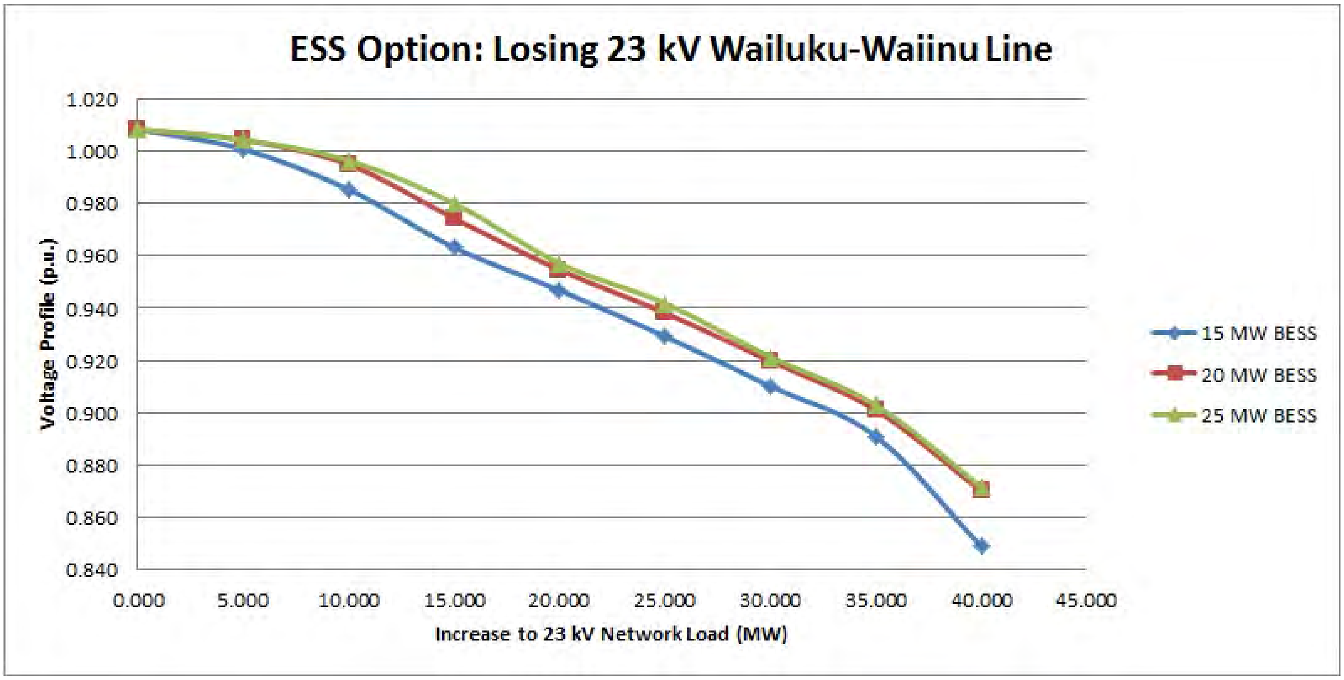

Figure 38: Comparison of P-V characteristics of various BESS options for losing the 23 kV Wailuku-Waiinu Line.

System load above 170 MW:

The longest period of time that the Maui system has historically been observed to have remained 170 MW and above within the last year is 7 hours, which occurred on September 23, 2013.

September 23, 2013	
Hour	System Load (MW)
1	120.2
2	114.3
3	109.6
4	108
5	114.7
6	121.1
7	133.4
8	147.4
9	158.1
10	165.2
11	165.4
12	164.5
13	163.7
14	167.2
15	169.3
16	170.5
17	174
18	177.1
19	178.8
20	186.1
21	183.1
22	170.2
23	152.6
24	133.7

Kahului Power Plant Retirement: Voltage Stability Assessment

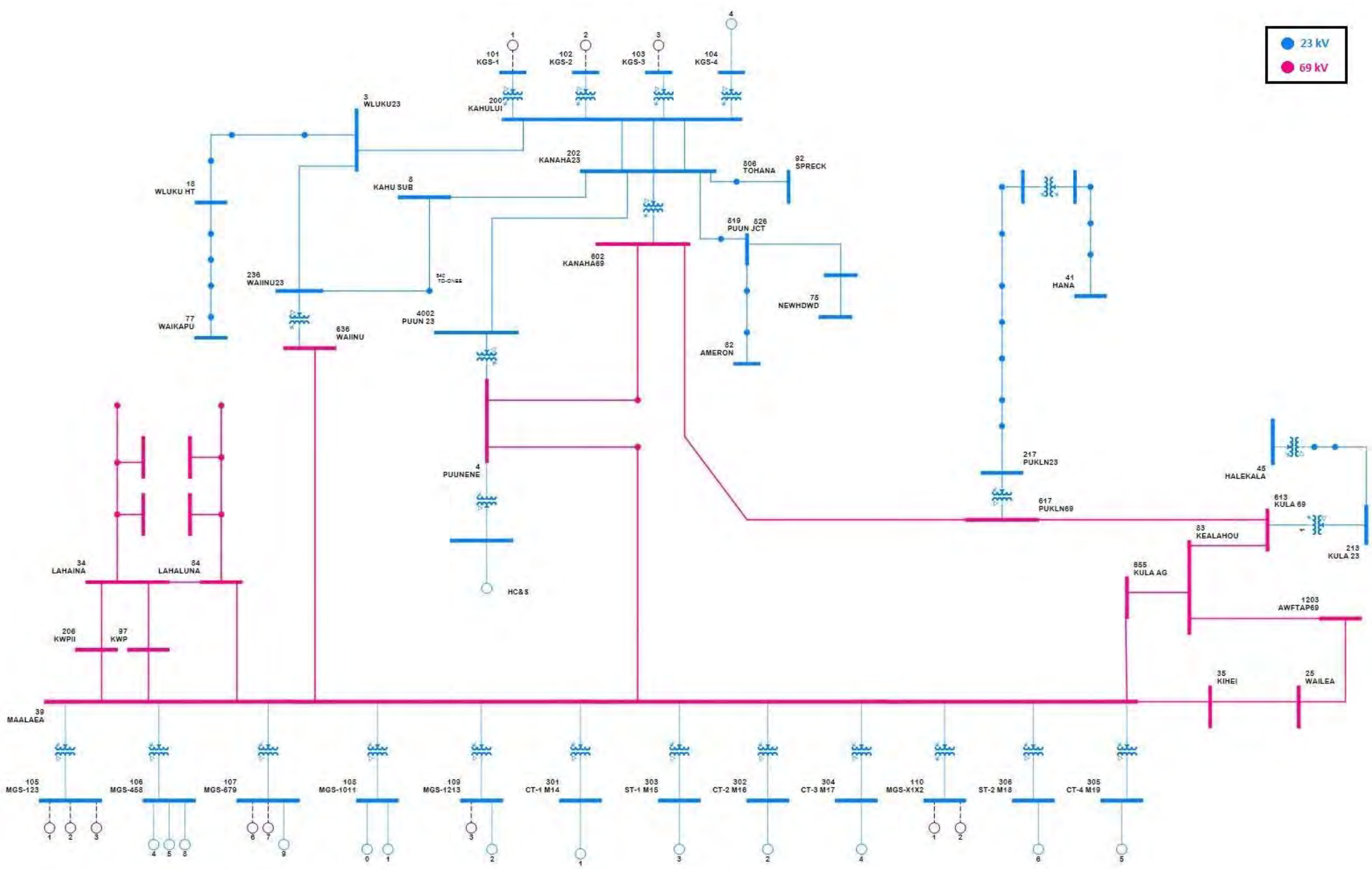

Figure 39: Single line diagram of the existing Maui 23 kV and 69 kV network.

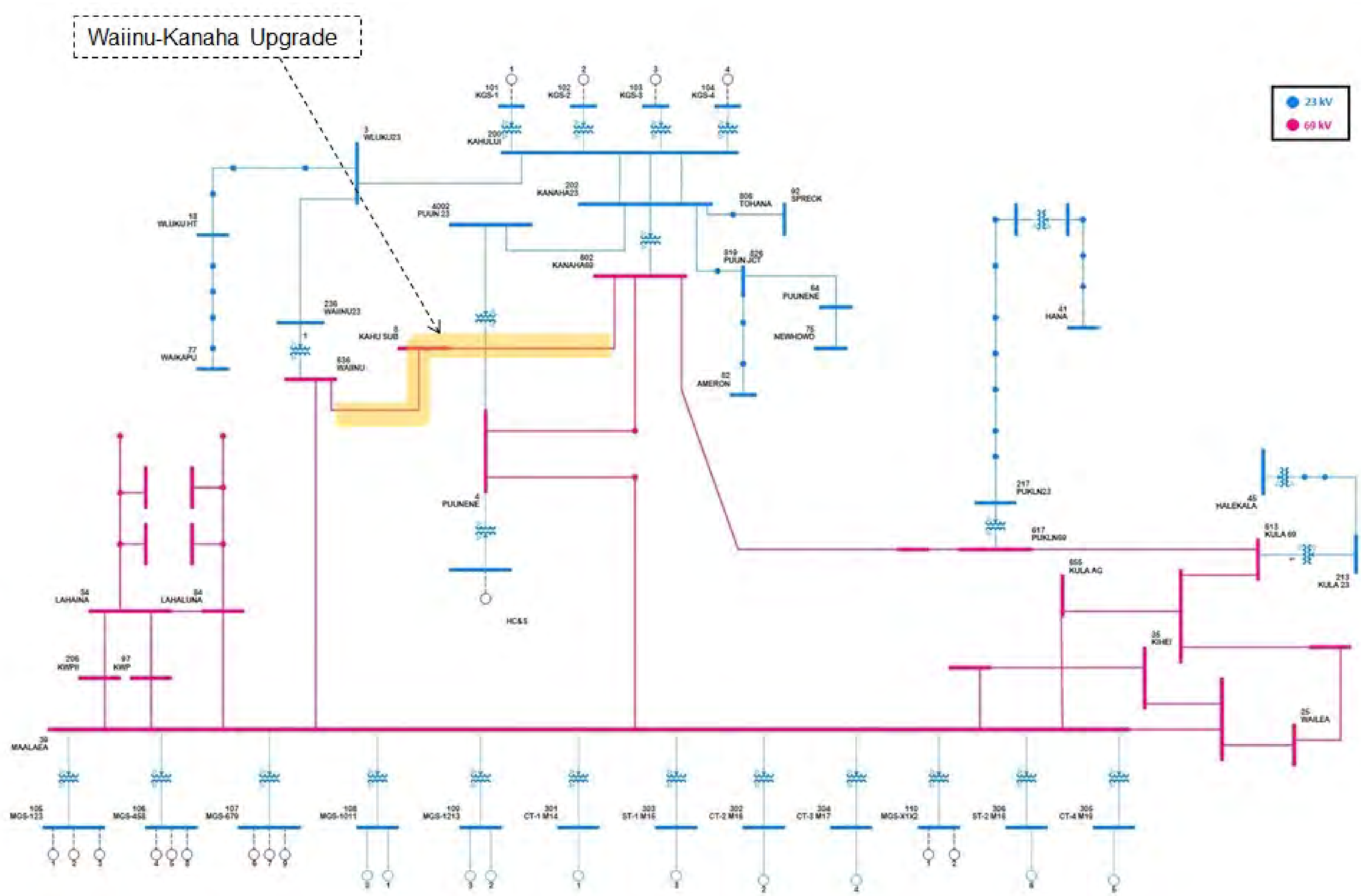

Figure 40: Single line diagram of the existing Maui 23 kV and 69 kV network with Waiinu-Kanaha Upgrade project implemented.

Table 2: Maui System Peak Forecast.

Maui Electric Company, Ltd. (Maui Division) SYSTEM PEAK FORECAST	
Year	System Load
2013	194.5
2014	197.9
2015	199.7
2016	202.1
2017	208.2
2018	214.4
2019	218.3
2020	220.0
2021	221.9
2022	222.6
2023	223.3
2024	223.0
2025	223.3
2026	222.1
2027	220.4
2028	217.1
2029	214.8
2030	210.8

Effect of Kahului Power Plant (KPP) Retirement on Short Circuit Current

Prepared For

Transmission Planning Division

Prepared by:

Transmission Planning Division

Dated: August 1, 2014

Reference: TPD 2014-20

Effect of Kahului Power Plant (KPP) Retirement on Short Circuit Current

Prepared By:: RBSrivastava
Raja Srivastava
Lead Transmission Planning Engineer

Approved By: Ronald Bushner 8/20/2014
Ron Bushner
Director, Transmission Planning Division

Revision History

Date	Revision Number	Change Description
August 1, 2014	Original	Original

Effect of Kahului Power Plant (KPP) Retirement on Short Circuit Current

Executive Summary

Maui Electric Company (Maui Electric) announced the retirement of Kahului Power Plant (KPP) in the year 2019. Transmission Planning Division (TPD) performed a study to determine the effect of the KPP retirement on the short circuit current at various buses in the Maui transmission system.

The study results show that the retirement of KPP 3 & 4 leads to reduced fault current on the 69 KV and 23 KV transmission systems. The change in fault current could be as much as 5000 amperes. Such a large change in fault current may affect the relay operation and the reliable operation of the transmission system. Therefore, it is necessary to re-evaluate the effect of reduced fault current on the Maui system.

The study also shows that the non-transmission alternatives evaluated to address the impact of the retirement of KPP leads to increased fault current on the 69 KV transmission system. The increase in fault current could be as much as 5000 amperes.

Background

Maui Electric announced the retirement of Kahului Power Plant (KPP) in the year 2014. Transmission Planning Division (TPD) has performed a study to determine the effect of the KPP retirement on the short circuit current at various buses in the Maui transmission system. The results of this study are presented in this report.

TPD has also evaluated the effect of KPP retirement on the transmission line overloading, transformer overloading, bus voltage violations, voltage stability, and transient stability of the Maui electrical system. The results of those studies are presented in separate reports.

Figure 1 shows the interaction of Maui 23 KV transmission system near KPP and the rest of the 69 KV transmission system. The 23 KV transmission system near KPP is shown as an orange cloud. KPP is part of this 23 KV transmission system. After KPP retirement, this 23 KV transmission system depends solely on 69 KV transmission system for supply of generation to meet the load. The three substations where this 69 KV – 23 KV transformation takes place are – Waiinu, Puunene, and Kanaha.

Effect of Kahului Power Plant (KPP) Retirement on Short Circuit Current

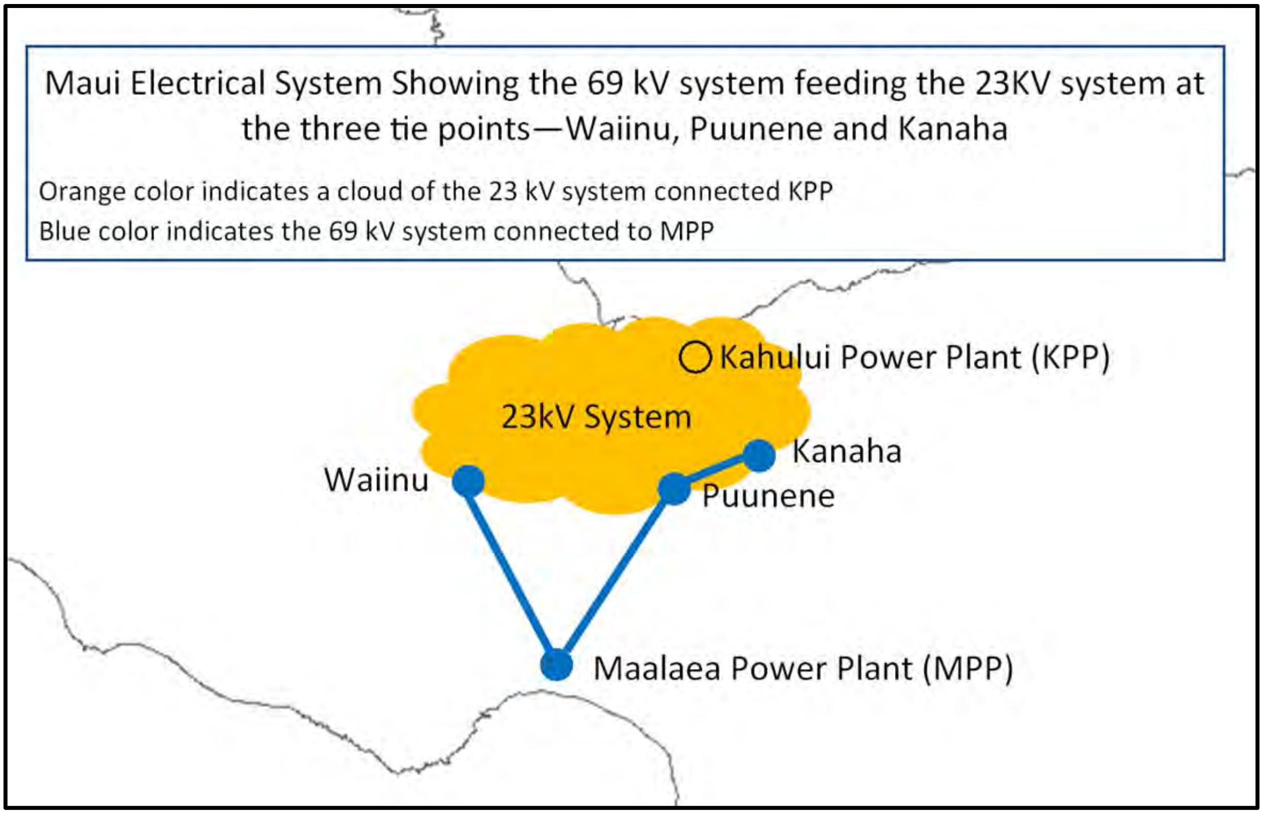

Figure 1 – Maui electrical system showing 69 KV transmission system feeding 23 KV transmission system at three tie points – Waiinu, Puunene, and Kanaha

As part of the KPP retirement study by TPD, PSSE[1] scenarios Case 0 – 5 were created. These scenarios represent the base case and various alternatives considered to alleviate the transmission limitations due to the retirement of KPP. The alternatives considered include transmission alternative,where new transmission upgrades are recommended, and non-transmission alternatives, where no new transmission upgrades are included. The 23kV Waiinu-Kanaha upgrade to 69kV with the reconductoring of MPP-Waiiu and MPP-Puunene is the transmission alternative. These non-transmission alternatives are – a) diesel generators (DG), b) battery (BESS) and c) synchronous condensers. These PSSE scenarios are given in Table 1. The study has also evaluated the effect of KPP retirement on the short circuit current under N-1 conditions. A list of N-1 contingencies are given in Table 2.

Table 1 – PSSE Models used in the Short Circuit Study

	Scenario Name	Scenario Description
Case 0	Case 0 – 2014 Base Case	2014 peak case with HC&S and KPP 3 & 4 on line.
Case 1	2019 Base Case plus KPP 3&4 Retirement	2019 peak case; KPP retired, HC&S retired-- retired generation picked up at Maalaea Power Plant

[1] Power System Simulator for Engineering

	Scenario Name	Scenario Description
Case 2	Case 1 plus transmission Upgrades	Case 1 plus the following transmission upgrades • 23 KV Waiinu – Kanaha upgraded to 69 KV • Reconductor MPP – Waiinu and MPP – Puunene from 336 AAC to 556 AAC
Case 3	Case 1 plus diesel generators (DG) on 23 KV system.	Case 1 plus diesel generator (DG) on 23 KV system
Case 4	Case 1 plus battery (BESS) on 23 KV system	Case 1 plus battery (BESS) on 23 KV system
Case 5	Case 1 plus synchronous condenser	Case 1 plus synchronous condenser on 23 KV system

Table 2 – List of contingencies included in the short circuit study

Contingency Name	Contingency Description
None	Cases 0 – 5 plus no line outage
MPP – Waiinu 69 KV line	Cases 0 – 5 plus outage of MPP – Waiinu 69 KV line
MPP – Puunene 69 KV line	Cases 0 – 5 plus outage of MPP – Puunene 69 KV line

The topic of short circuit current was evaluated in a recent study by EPS[2]. The study determined that even for very high renewable wind and solar penetration levels considered in the study, there is sufficient short circuit ratio available for proper operation of the inverter based technologies such as solar and wind generators.

Methodology

PSSE was used to calculate short circuit current. 3-phase fault was applied at each bus in the Maui transmission system. The short circuit currents from PSSE were tabulated.

Post processing of the short circuit current included calculating the percent change in short circuit current in Cases 1 – 5 compared to Case 0.

Assumptions

- The study is a follow-up of the other studies by TPD on KPP retirement. The assumptions are consistent with the assumptions in the other studies performed by TPD on KPP retirement (thermal analysis, voltage stability analysis, transient stability analysis).
- This study is not a High PV/wind penetration study. This topic has been addressed in a study by EPS referenced in the Background section of this report.
- This study solely focuses on the effect of KPP retirement on the short circuit current at the critical buses in the Maui transmission system.

2 "Maui Electric Company, Ltd. Curtailment Reduction Plan Impact Study" Dated June 30, 2014

Results and Analysis

The results of the fault current calculations are given in Appendix A of the report. This table contains the percent change in fault current at substations that are 23 KV and larger compared to Case 0 (base case). The changes in fault currents greater than 5% are highlighted with different colors. The green color highlight indicates that the fault current has decreased 5% and larger with respect to the Case 0. The red color highlight indicates that the fault current has increased 5% and larger with respect to the Case 0 with KPP 3 & 4 in service.

There are several generation dispatches in Cases 1 – 5 with respect to Case 0. These generation dispatches cause either the increase in fault current (generation addition) or decrease in fault current (generation retirement). In general, the KPP 3 & 4 retirement, HC&S retirement lead to decreased fault currents and dispatched units at Maalaea Power Plant (MPP) causes an increase in fault currents. These increase and decrease in fault currents are marked as red and green in Table A.1.

A comparison of the fault current for non-transmission alternatives (Case 3, Case 4, and Case5) shows that the changes in fault current are very similar to each other and are also very similar to the Case 0. This is due to the location of the non-transmission alternatives on the 23 KV transmission system that replaces the retired KPP3 & 4 generators. However, if the non-transmission alternatives are located on the 69 KV transmission system, we expect to notice drastic change in fault current.

Fault Current Due to KPWII Wind Generator – This study shows that addition of KWPII causes substantial increase in fault current. This is due to the fact that PSSE models KWPII wind generator as synchronous condenser. The substantial increase in fault current is contrary to the fact that inverter based technologies do not contribute significantly to the fault current. PSSE calculations are acceptable for planning studies. However, further adjustments to the fault current will be needed for accurate fault current calculations.

Table 3 shows the changes in short circuit fault current at Maui substations 23 KV and larger for Cases 1 & 2. Only changes greater than 5% have been reported. Whereas the increase in fault current due KWPII addition is intuitive, the increase in fault current in Case 2 is counterintuitive because the changes in the fault currents are due to many different factors – KPP 3 & 4 retirement, HC&S retirement, KWPII addition, Maalaea 679 on-line, Maalaea 1213 on-line, and various 23 KV and 69 KV transmission upgrades with change in topology. Therefore, the association of increase and decrease in short circuit current to one factor is next to impossible. To establish such an association, we made several runs to quantify the change in short circuit current due to various transmission upgrades and KPP retirements. The results from these simulations have been discussed below.

Table 3 Fault Current at buses that show change by 5 % and larger (Cases 0, 1, and 2)

(Green highlights show that the fault current has decreased 5% or larger with respect to Case 0, and red highlights show that the fault current has increased 5% or larger with respect to Case 0)

Effect of Kahului Power Plant (KPP) Retirement on Short Circuit Current

				Case0		Case1 (Delta %)				Case2 (Delta %)		
Bus	Name	KV	3PH	MVA	Amp	NoCont	Cont1	Cont2	Bus	NoCont	Cont1	Cont2
Col 1	Col 2	Col 3	Col 4	Col 5	Col 6	Col 7	Col 8	Col 9	Col 1	Col 11	Col 12	Col 13
4	PUUNENE	69.00	3PH	641.23	5,365.40	21.65	22.00	42.69		7.15	23.67	(14.06)
23	PUUKOL B	69.00	3PH	373.99	3,129.30	0.72	(0.35)	(1.52)		0.79	0.17	(1.02)
401	PUUNENEA	69.00	3PH	612.53	5,125.30	20.61	21.07	41.70		2.12	23.43	(22.62)
402	PUUNENEB	69.00	3PH	646.62	5,410.50	20.02	20.17	41.65		7.60	20.79	(11.24)
602	KANAHA69	69.00	3PH	597.10	4,996.20	20.00	20.53	41.08		(1.37)	22.75	(27.10)
636	WAIINU	69.00	3PH	529.15	4,427.60	4.90	16.58	2.92		(18.33)	(367.82)	(8.25)
2060	KWPII34	34.50	3PH	224.70	3,760.40	(13.03)	(13.78)	(14.62)		(13.01)	(13.47)	(14.32)
2061	KWPII_CLT1	34.50	3PH	223.00	3,731.90	(13.22)	(13.97)	(14.81)		(13.20)	(13.66)	(14.51)
136	WAIINU B	12.47	3PH	88.57	4,100.80	1.05	26.53	3.49		(2.15)	(89.74)	0.48

Effect of Transmission Upgrades on Fault Currents

To determine the effect of transmission upgrades on the fault currents, we compared the results of Case 2 (with transmission upgrade) with Case 1 (no transmission upgrade). The change in short circuit current is given in Table 4.

The results show that short circuit current increases. Due to transmission upgrades and change in transmission topology, the equivalent impedances (Thevenin Equivalece) is reduced. The reduction in equivalent impedance gives rise to increased fault current contributions.

Table 4 – 5% or larger change in Short Circuit Current due transmission upgrades

(Case1 is without transmission upgrade and Case2 is with transmission upgrade)

				Case1		Case2 (delta %)		
Bus	Name	KV	3PH	MVA	Amp	NoCont	Cont1	Cont2
4	PUUNENE	69.00	3PH	502.43	4,204.00	(18.50)	2.14	(99.03)
401	PUUNENEA	69.00	3PH	486.31	4,069.10	(23.29)	(23.29)	(23.29)
402	PUUNENEB	69.00	3PH	517.14	4,327.10	(15.53)	(15.53)	(15.53)
602	KANAHA69	69.00	3PH	477.67	3,996.90	(26.72)	(26.72)	(26.72)
617	PUKLN69	69.00	3PH	398.10	3,331.00	(8.87)	(8.87)	(8.87)
636	WAIINU	69.00	3PH	503.22	4,210.60	(24.42)	(24.42)	(24.42)
3	WLUKU23	23.00	3PH	189.28	4,751.30	5.03	5.03	5.03
40	ONEHEE	23.00	3PH	158.97	3,990.40	42.65	42.65	42.65
236	WAIINU23	23.00	3PH	209.12	5,249.50	12.78	12.78	12.78
840	TO-ONEE	23.00	3PH	196.50	4,932.70	48.37	48.37	48.37

Effect of KPP Retirement on 69 KV and 23 KV transmission systems

To determine the effect of KPP retirement on the short circuit current, we created Case 1a from Case 1 by not retiring KPP 3 & 4. Table 5 shows the change in the fault current 5% or larger due to the retirement of KPP 3 & 4. We observe that the change in fault current varies from few amperes to as much as 5000 amperes (Kahului 23 KV substation). Such a large change in fault current may affect the relay operation and thus the reliability of the system. Therefore, it is necessary to review and update the current relay settings after the KPP 3 & 4 retirements.

Table 5 – 5% or larger change in Short Circuit Current due to the retirement of KPP 3 & 4

(Case1 is without KPP 3 & 4 and Case1a is with KPP 3 & 4)

				Case1a		Case1 (delta %)		
Bus	Name	KV	3PH	MVA	Amp	NoCont	Cont1	Cont2
4	PUUNENE	69.00	3PH	574.73	4,809.00	12.58	12.56	22.84
25	WAILEA	69.00	3PH	520.99	4,359.30	4.54	3.27	5.09
39	MAALAEA	69.00	3PH	1,118.21	9,356.50	8.05	4.76	4.94
83	KEALAHOU	69.00	3PH	546.78	4,575.10	5.76	4.54	8.44
401	PUUNENEA	69.00	3PH	555.94	4,651.80	12.53	12.64	22.83
402	PUUNENEB	69.00	3PH	587.46	4,915.50	11.97	11.71	22.25
602	KANAHA69	69.00	3PH	546.07	4,569.20	12.53	12.72	22.84
613	KULA 69	69.00	3PH	477.68	3,996.90	5.89	5.08	10.26
617	PUKLN69	69.00	3PH	430.39	3,601.30	7.51	7.39	15.61
636	WAIINU	69.00	3PH	542.07	4,535.70	7.17	17.70	5.89
655	KULA AG	69.00	3PH	545.31	4,562.90	5.59	4.32	7.84
1203	AWFTAP69	69.00	3PH	514.11	4,301.80	4.56	3.34	5.33
3	WLUKU23	23.00	3PH	252.35	6,334.50	24.99	34.46	35.83
5	MAUI PIN	23.00	3PH	261.97	6,576.00	26.27	35.01	36.75
7	WAI WELL	23.00	3PH	148.96	3,739.20	16.74	27.39	25.57
8	KAHU SUB	23.00	3PH	273.78	6,872.50	27.04	35.60	37.57
18	WLUKU HT	23.00	3PH	146.35	3,673.80	16.64	27.53	25.52
22	WS PUMP	23.00	3PH	136.64	3,429.90	15.84	26.98	24.53
30	MOKUHAU	23.00	3PH	161.99	4,066.40	17.92	28.51	27.12
33	WS MILL	23.00	3PH	236.00	5,924.10	23.78	33.46	34.39
40	ONEHEE	23.00	3PH	203.03	5,096.50	21.70	31.54	31.84
43	WAIEHU	23.00	3PH	111.30	2,793.80	13.27	24.19	20.89
48	MAUIBLOC	23.00	3PH	79.03	1,983.90	10.35	22.62	17.25
64	PUUNENE	23.00	3PH	118.20	2,967.10	16.07	25.73	25.07
73	KUAU	23.00	3PH	89.29	2,241.50	12.52	21.54	20.06
75	NEWHDWD	23.00	3PH	94.25	2,365.90	13.45	23.26	21.86
77	WAIKAPU	23.00	3PH	78.16	1,961.90	10.26	22.53	17.12
82	AMERON	23.00	3PH	94.45	2,370.90	13.32	23.67	22.15
88	AMERBLDG	23.00	3PH	97.92	2,458.10	13.71	24.06	22.65
92	SPRECK	23.00	3PH	127.80	3,207.90	16.66	25.52	25.27
93	PAIAMKA	23.00	3PH	99.49	2,497.40	13.67	22.67	21.56
200	KAHULUI	23.00	3PH	381.12	9,567.00	41.71	48.83	50.95
202	KANAHA23	23.00	3PH	384.54	9,652.80	36.78	43.90	46.55
217	PUKLN23	23.00	3PH	94.94	2,383.20	1.66	4.98	6.04
236	WAIINU23	23.00	3PH	272.88	6,849.80	23.36	32.88	35.16
671	JCT B	23.00	3PH	119.30	2,994.60	14.32	25.85	22.60
806	TOHANA	23.00	3PH	190.06	4,771.00	22.64	31.21	32.26
819	PUUN JCT	23.00	3PH	207.47	5,207.90	24.53	33.47	34.61
826		23.00	3PH	171.27	4,299.30	21.30	30.48	31.05

Effect of Kahului Power Plant (KPP) Retirement on Short Circuit Current

				Case1a		Case1 (delta %)		
Bus	**Name**	**KV**	**3PH**	**MVA**	**Amp**	**NoCont**	**Cont1**	**Cont2**
827	CONC TAP	23.00	3PH	100.86	2,531.90	14.04	24.39	23.07
838		23.00	3PH	80.26	2,014.80	10.48	22.75	17.44
840	TO-ONEE	23.00	3PH	266.07	6,678.90	26.15	34.91	36.71
848	JCT C	23.00	3PH	69.07	1,733.90	10.49	20.46	18.10
858	PUUOHALA	23.00	3PH	207.59	5,211.00	21.58	31.59	31.71
892	BALWNPK	23.00	3PH	110.35	2,770.10	14.83	23.75	23.00
893	PAIAMKA	23.00	3PH	101.26	2,541.90	13.84	22.80	21.75
4002	PUUN 23	23.00	3PH	304.23	7,637.00	25.40	32.33	35.77

Conclusions

The study results shows that the retirement of KPP 3 & 4 leads to reduced fault current on the 69 KV and 23 KV transmission systems. The change in fault current could be as much as 5000 amperes. Such a large change in fault current may affect the relay operation and the reliable operation of the transmission system. Therefore, it is necessary to re-evaluate the effect of reduced fault current on the Maui system.

The study also shows that the non-transmission alternatives evaluated to address the impact of the retirement of KPP leads to increased fault current on the 69 KV transmission system. The increase in fault current could be as much as 5000 amperes.

Appendix A

Table A.1 – Change in 3-phase fault current with respect to Case 0

Notes:

- Delta % is defined as percent change with respect to Case 0
- Green highlighted cells indicate that the fault current has decreased by 5% with respect to Case 0.
- Red highlighted cells indicate that the fault current has increased by 5% with respect to Case 0.
- Case 0 – 5 are defined in table below
- Contingencies are defined as below.

Table A.1 – Change in short circuit current with respect to Case 0

				Case0		Case1 (Delta %)				Case2 (Delta %)				Case3 (Delta %)				Case4 (Delta %)				Case5 (Delta %)		
Bus	Name	KV	3PH	MVA	Amp	NoCont	Cont1	Cont2		NoCont	Cont 1	Cont2		NoCont	Cont 1	Cont 2		NoCont	Cont 1	Cont 2		NoCont	Cont 1	Cont 2
Col 1	Col 2	Col 3	Col 4	Col 5	Col 6	Col 7	Col 8	Col 9	Col 10	Col 11	Col 12	Col 13	Col 14	Col 15	Col 16	Col 17	Col 18	Col 19	Col 20	Col 21	Col 22	Col 23	Col 24	Col 25
4	PUUNENE	69.00	3PH	641.23	5,365.40	21.65	22.00	42.69		7.15	23.67	(14.06)		12.36	12.54	25.76		9.75	9.52	17.45		6.94	7.46	20.89
23	PUUKOLB	69.00	3PH	373.99	3,129.30	0.72	(0.35)	(1.52)		0.79	0.17	(1.02)		0.18	0.32	(0.90)		1.62	2.36	1.20		(2.90)	(2.57)	(3.83)
25	WAILEA	69.00	3PH	525.46	4,396.80	5.35	4.42	6.57		5.04	5.07	5.15		3.63	4.00	4.13		4.91	5.88	5.14		(0.37)	0.29	0.28
29	NAPILI A	69.00	3PH	313.68	2,624.70	0.61	(0.28)	(1.27)		0.67	0.15	(0.85)		0.15	0.28	(0.75)		1.36	1.98	1.01		(2.41)	(2.14)	(3.19)
34	LAHAINA	69.00	3PH	563.77	4,717.20	0.99	(0.63)	(2.43)		1.09	0.14	(1.66)		0.20	0.42	(1.43)		2.37	3.46	1.72		(4.52)	(4.00)	(5.93)
35	KIHEI	69.00	3PH	611.07	5,113.10	7.12	5.76	6.10		7.10	6.54	6.14		5.67	5.96	5.01		7.42	8.49	7.07		1.02	1.64	0.55
39	MAALAEA	69.00	3PH	1,070.73	8,959.20	3.97	0.81	(2.67)		4.19	2.32	(1.15)		2.56	2.97	(0.59)		6.62	8.59	5.32		(6.88)	(5.76)	(9.62)
50	MAHINA A	69.00	3PH	352.17	2,946.80	0.65	(0.34)	(1.45)		0.72	0.14	(0.98)		0.15	0.29	(0.86)		1.51	2.21	1.11		(2.73)	(2.43)	(3.61)
83	KEALAHOU	69.00	3PH	548.56	4,590.00	6.07	5.18	11.51		4.71	6.00	5.21		3.20	3.55	5.67		4.09	4.97	5.12		(1.26)	(0.58)	1.25
84	LAHALUNA	69.00	3PH	549.06	4,594.20	1.05	(0.53)	(2.28)		1.15	0.22	(1.54)		0.29	0.50	(1.31)		2.40	3.48	1.77		(4.31)	(3.80)	(5.69)
97	KWP	69.00	3PH	639.70	5,352.70	2.12	0.33	(1.64)		2.24	1.20	(0.78)		1.22	1.46	(0.58)		3.61	4.81	2.89		(4.06)	(3.49)	(5.62)

Effect of Kahului Power Plant (KPP) Retirement on Short Circuit Current

				Case0		Case1 (Delta %)				Case2 (Delta %)				Case3 (Delta %)				Case4 (Delta %)				Case5 (Delta %)		
Bus	Name	KV	3PH	MVA	Amp	NoCont	Cont1	Cont2		NoCont	Cont 1	Cont2		NoCont	Cont 1	Cont 2		NoCont	Cont 1	Cont 2		NoCont	Cont 1	Cont 2
Col 1	Col 2	Col 3	Col 4	Col 5	Col 6	Col 7	Col 8	Col 9	Col 10	Col 11	Col 12	Col 13	Col 14	Col 15	Col 16	Col 17	Col 18	Col 19	Col 20	Col 21	Col 22	Col 23	Col 24	Col 25
206	KWPII	69.00	3PH	623.76	5,219.20	(0.75)	(2.61)	(4.69)		(0.62)	(1.72)	(3.80)		(1.69)	(1.44)	(3.58)		0.81	2.06	0.05		(7.20)	(6.60)	(8.85)
223	PUUKOLA	69.00	3PH	417.02	3,489.40	0.71	(0.47)	(1.78)		0.79	0.10	(1.22)		0.12	0.28	(1.08)		1.72	2.54	1.25		(3.32)	(2.95)	(4.36)
250	MAHINA B	69.00	3PH	347.19	2,905.10	0.60	(0.38)	(1.48)		0.66	0.09	(1.01)		0.10	0.23	(0.90)		1.43	2.12	1.04		(2.74)	(2.44)	(3.61)
401	PUUNENEA	69.00	3PH	612.53	5,125.30	20.61	21.07	41.70		2.12	23.43	(22.62)		11.13	11.30	24.50		8.37	8.03	16.10		5.79	6.27	19.54
402	PUUNENEB	69.00	3PH	646.62	5,410.50	20.02	20.17	41.65		7.60	20.79	(11.24)		11.33	11.54	24.98		9.15	9.10	16.85		5.87	6.45	20.26
602	KANAHA 69	69.00	3PH	597.10	4,996.20	20.00	20.53	41.08		(1.37)	22.75	(27.10)		10.39	10.54	23.69		7.53	7.13	15.21		5.08	5.53	18.67
613	KULA 69	69.00	3PH	483.51	4,045.70	7.03	6.59	15.98		4.36	7.33	3.94		3.55	3.89	7.91		3.84	4.47	5.81		(0.39)	0.26	3.94
617	PUKLN69	69.00	3PH	446.42	3,735.40	10.83	11.14	27.35		2.92	12.05	(4.07)		5.34	5.65	14.41		4.41	4.54	9.11		1.58	2.19	10.40
623	PUUKA 69	69.00	3PH	417.02	3,489.40	0.71	(0.47)	(1.78)		0.79	0.10	(1.22)		0.12	0.28	(1.08)		1.72	2.54	1.25		(3.32)	(2.95)	(4.36)
629	NAPILI B	69.00	3PH	305.90	2,559.60	0.54	(0.32)	(1.28)		0.61	0.09	(0.87)		0.10	0.22	(0.78)		1.28	1.88	0.93		(2.39)	(2.14)	(3.16)
636	WAIINU	69.00	3PH	529.15	4,427.60	4.90	16.58	2.92		(18.33)	(367.82)	(8.25)		0.40	0.28	(0.38)		0.63	(8.09)	0.35		(4.51)	(5.33)	(4.87)
650	MAHINA B	69.00	3PH	347.19	2,905.10	0.60	(0.38)	(1.48)		0.66	0.09	(1.01)		0.10	0.23	(0.90)		1.43	2.12	1.04		(2.74)	(2.44)	(3.61)
655	KULA AG	69.00	3PH	545.65	4,565.60	5.64	4.70	10.22		4.53	5.50	5.03		2.98	3.32	5.00		3.97	4.87	4.79		(1.48)	(0.81)	0.61
823	PUUKB 69	69.00	3PH	400.00	3,347.00	0.75	(0.38)	(1.65)		0.83	0.16	(1.11)		0.18	0.34	(0.97)		1.72	2.51	1.27		(3.11)	(2.76)	(4.11)
850	MAHINA A	69.00	3PH	365.90	3,061.60	0.68	(0.36)	(1.51)		0.75	0.14	(1.02)		0.16	0.30	(0.90)		1.56	2.29	1.15		(2.84)	(2.53)	(3.75)
1203	AWFTAP 69	69.00	3PH	517.52	4,330.30	5.18	4.33	6.90		4.79	4.96	5.07		3.37	3.77	4.13		4.57	5.53	4.94		(0.57)	0.11	0.32
971	KWP34	34.50	3PH	333.59	5,582.50	0.76	(0.06)	(0.95)		0.81	0.32	(0.58)		0.44	0.55	(0.37)		1.52	2.09	1.21		(1.82)	(1.58)	(2.52)
2060	KWPII34	34.50	3PH	224.70	3,760.40	(13.03)	(13.78)	(14.62)		(13.01)	(13.47)	(14.32)		(13.27)	(13.19)	(14.06)		(12.31)	(11.82)	(12.65)		(15.17)	(14.98)	(15.86)
2061	KWPII_CLT1	34.50	3PH	223.00	3,731.90	(13.22)	(13.97)	(14.81)		(13.20)	(13.66)	(14.51)		(13.47)	(13.39)	(14.26)		(12.51)	(12.02)	(12.86)		(15.36)	(15.18)	(16.06)
12032	AUWAHI 34	34.50	3PH	199.13	3,332.30	0.32	1.25	3.00		0.03	1.12	1.65		(0.23)	0.84	1.99		0.14	1.25	2.00		(1.27)	(0.11)	1.05

HECO Transmission Planning Division
Reference: TPD 2014-20

Effect of Kahului Power Plant (KPP) Retirement on Short Circuit Current

				Case0		Case1 (Delta %)				Case2 (Delta %)				Case3 (Delta %)				Case4 (Delta %)				Case5 (Delta %)		
Bus	Name	KV	3PH	MVA	Amp	NoCont	Cont1	Cont2		NoCont	Cont 1	Cont2		NoCont	Cont 1	Cont 2		NoCont	Cont 1	Cont 2		NoCont	Cont 1	Cont 2
Col 1	Col 2	Col 3	Col 4	Col 5	Col 6	Col 7	Col 8	Col 9	Col 10	Col 11	Col 12	Col 13	Col 14	Col 15	Col 16	Col 17	Col 18	Col 19	Col 20	Col 21	Col 22	Col 23	Col 24	Col 25
12034	AWFTOTAL	34.50	3PH	199.13	3,332.30	0.32	1.25	3.00		0.03	1.12	1.65		(0.23)	0.84	1.99		0.14	1.25	2.00		(1.27)	(0.11)	1.05
12035	CKT1 BUS A	34.50	3PH	111.91	1,872.80	(1.27)	0.35	2.27		(1.54)	0.09	0.89		(1.66)	(0.18)	1.39		(1.57)	(0.17)	1.11		(2.15)	(0.62)	0.97
12036	AUWAHI_COL1	34.50	3PH	107.67	1,801.90	(1.41)	0.26	2.21		(1.69)	(0.01)	0.83		(1.79)	(0.28)	1.33		(1.72)	(0.30)	1.03		(2.25)	(0.69)	0.94
12037	CKT2 BUS B	34.50	3PH	111.69	1,869.10	(1.28)	0.35	2.27		(1.55)	0.08	0.89		(1.66)	(0.19)	1.38		(1.58)	(0.18)	1.11		(2.15)	(0.63)	0.97
12038	AUWAHI_COL2	34.50	3PH	106.94	1,789.70	(1.44)	0.24	2.20		(1.71)	(0.02)	0.81		(1.81)	(0.30)	1.31		(1.75)	(0.32)	1.01		(2.27)	(0.71)	0.93
3	WLUKU23	23.00	3PH	233.41	5,859.10	18.91	26.99	32.42		22.99	9.96	25.08		(8.05)	(10.20)	(4.27)		(23.22)	(34.69)	(24.55)		(18.01)	(25.07)	(17.43)
5	MAUI PIN	23.00	3PH	241.91	6,072.50	20.16	27.60	33.89		#N/A	#N/A	#N/A		(8.23)	(10.28)	(3.47)		(24.64)	(35.55)	(25.60)		(18.94)	(25.68)	(17.66)
7	WAI WELL	23.00	3PH	142.30	3,572.10	12.84	22.18	23.56		15.30	6.52	17.56		(4.59)	(5.64)	(1.46)		(12.69)	(21.34)	(13.62)		(10.12)	(15.62)	(9.82)
8	KAHU SUB	23.00	3PH	251.88	6,322.80	20.70	27.96	34.56		20.42	31.61	29.17		(8.64)	(10.80)	(3.80)		(25.96)	(37.11)	(26.91)		(19.89)	(26.76)	(18.53)
9	KAILUA	23.00	3PH	21.43	537.80	4.52	4.74	7.04		1.79	3.86	1.35		2.75	3.73	3.18		2.05	1.37	2.72		3.31	3.56	3.43
12	MAKAWAO	23.00	3PH	57.05	1,432.10	2.28	4.70	9.35		0.29	2.95	(0.84)		1.08	1.54	5.21		0.80	0.57	2.56		0.97	1.61	4.82
15	KOKOMO	23.00	3PH	53.07	1,332.30	2.21	4.44	8.83		0.28	2.78	(0.78)		1.04	1.52	4.84		0.77	0.53	2.40		0.98	1.57	4.49
16	HAIKU	23.00	3PH	40.71	1,022.00	2.05	3.64	7.16		0.25	2.29	(0.57)		0.97	1.47	3.71		0.68	0.42	1.91		1.01	1.46	3.48
18	WLUKU HT	23.00	3PH	139.98	3,513.80	12.85	22.44	23.61		15.16	6.43	17.45		(4.47)	(5.45)	(1.30)		(12.43)	(21.09)	(13.36)		(9.92)	(15.41)	(9.61)
22	WS PUMP	23.00	3PH	131.13	3,291.70	12.31	22.19	22.83		14.35	6.01	16.67		(4.10)	(4.94)	(0.96)		(11.47)	(19.83)	(12.34)		(9.18)	(14.49)	(8.87)
30	MOKUHAU	23.00	3PH	154.13	3,869.00	13.73	22.98	24.92		16.43	7.05	18.68		(5.02)	(6.24)	(1.80)		(13.97)	(23.09)	(14.96)		(11.09)	(16.88)	(10.77)
31	KAMOLE	23.00	3PH	43.23	1,085.20	2.13	3.83	7.55		0.30	2.42	(0.56)		1.02	1.52	3.98		0.74	0.48	2.05		1.04	1.51	3.72
33	WS MILL	23.00	3PH	219.38	5,507.00	18.01	26.29	31.17		21.89	9.50	24.02		(7.51)	(9.54)	(3.85)		(21.48)	(32.61)	(22.75)		(16.72)	(23.64)	(16.21)
40	ONEHEE	23.00	3PH	191.26	4,801.00	16.88	25.46	29.78		52.34	46.95	52.01		(6.04)	(7.53)	(1.81)		(17.75)	(27.43)	(18.68)		(13.94)	(19.98)	(13.03)
41	HANA	23.00	3PH	11.83	296.90	2.05	2.14	3.78		0.67	1.49	0.48		1.15	1.80	1.55		0.88	0.58	1.24		1.38	1.53	1.48

Effect of Kahului Power Plant (KPP) Retirement on Short Circuit Current

				Case0		Case1 (Delta %)				Case2 (Delta %)				Case3 (Delta %)				Case4 (Delta %)				Case5 (Delta %)		
Bus	Name	KV	3P H	MVA	Amp	NoC ont	Con t1	Con t2		NoC ont	Cont 1	Con t2		NoC ont	Cont 1	Cont 2		NoC ont	Cont 1	Cont 2		NoC ont	Cont 1	Cont 2
Col 1	Col 2	Col 3	Col 4	Col 5	Col 6	Col 7	Col 8	Col 9	Col 10	Col 11	Col 12	Col 13	Col 14	Col 15	Col 16	Col 17	Col 18	Col 19	Col 20	Col 21	Col 22	Col 23	Col 24	Col 25
42	KEANAE	23.00	3PH	16.61	416.90	3.31	3.47	5.45		1.22	2.69	0.91		1.97	2.76	2.37		1.46	0.97	2.00		2.35	2.54	2.47
43	WAIEHU	23.00	3PH	107.62	2,701.50	10.31	20.08	19.54		11.97	4.95	14.23		(3.33)	(3.74)	(0.39)		(9.13)	(16.33)	(9.86)		(7.38)	(11.93)	(7.11)
48	MAUIBLOC	23.00	3PH	77.39	1,942.80	8.45	19.82	16.81		8.86	3.32	11.26		(2.00)	(1.73)	0.92		(5.89)	(12.02)	(6.44)		(4.85)	(8.65)	(4.55)
61	HOSMER	23.00	3PH	33.22	834.00	1.46	3.39	6.48		0.66	1.99	0.65		0.86	1.22	3.32		0.76	0.69	1.76		0.79	1.18	3.25
64	PUUNENE	23.00	3PH	113.75	2,855.30	12.79	21.71	24.15		11.91	12.72	13.70		(3.87)	(3.82)	0.28		(11.21)	(16.79)	(11.86)		(8.84)	(12.36)	(8.17)
73	KUAU	23.00	3PH	86.68	2,175.90	9.89	18.31	19.36		9.20	10.09	10.93		(2.96)	(2.48)	0.68		(8.33)	(12.73)	(8.87)		(6.65)	(9.34)	(6.18)
74	HUELO	23.00	3PH	21.83	547.90	4.62	4.82	7.14		1.83	3.94	1.38		2.83	3.81	3.24		2.12	1.39	2.77		3.39	3.62	3.50
75	NEWHDWD	23.00	3PH	91.45	2,295.70	10.80	19.97	21.34		9.59	10.55	11.48		(2.99)	(2.62)	0.90		(8.63)	(13.45)	(9.17)		(6.89)	(9.88)	(6.31)
77	WAIKAPU	23.00	3PH	76.56	1,921.80	8.38	19.76	16.70		8.77	3.27	11.16		(1.98)	(1.68)	0.94		(5.82)	(11.90)	(6.35)		(4.79)	(8.56)	(4.49)
82	AMERON	23.00	3PH	91.84	2,305.50	10.86	20.55	21.85		9.19	10.25	11.22		(2.76)	(2.38)	1.21		(8.09)	(12.99)	(8.60)		(6.48)	(9.55)	(5.88)
88	AMERBLDG	23.00	3PH	95.11	2,387.60	11.16	20.84	22.31		9.52	10.57	11.55		(2.88)	(2.54)	1.14		(8.43)	(13.45)	(8.96)		(6.74)	(9.89)	(6.13)
92	SPRECK	23.00	3PH	122.42	3,073.00	13.00	21.11	23.94		12.82	13.48	14.40		(4.38)	(4.41)	(0.34)		(12.43)	(18.03)	(13.15)		(9.75)	(13.28)	(9.14)
93	PAIAMKA	23.00	3PH	96.24	2,415.70	10.75	19.11	20.69		10.18	11.02	11.89		(3.34)	(3.00)	0.42		(9.40)	(14.13)	(9.98)		(7.47)	(10.39)	(6.96)
145	SUMMITAP	23.00	3PH	29.00	727.80	1.64	3.23	5.69		0.81	2.04	0.82		1.02	1.39	3.10		0.88	0.80	1.75		0.96	1.38	3.04
200	KAHULUI	23.00	3PH	323.69	8,125.30	31.37	37.81	44.81		33.95	31.99	34.54		(18.75)	(21.12)	(12.05)		(63.88)	(78.75)	(64.73)		(43.78)	(52.66)	(41.60)
202	KANAHA23	23.00	3PH	338.88	8,506.60	28.26	34.39	42.81		29.92	28.42	29.87		(13.73)	(16.20)	(6.28)		(45.82)	(58.78)	(45.09)		(33.11)	(40.90)	(29.25)
213	KULA 23	23.00	3PH	46.70	1,172.20	1.87	4.75	9.47		1.03	2.71	0.97		1.24	1.58	4.77		1.16	1.12	2.53		1.07	1.47	4.62
217	PUKLN23	23.00	3PH	96.72	2,427.80	3.46	7.79	14.81		0.94	5.08	(0.93)		1.93	2.37	9.19		1.61	1.45	4.64		1.47	2.61	8.44
236	WAIINU23	23.00	3PH	254.25	6,382.20	17.75	25.79	32.20		28.26	7.61	30.19		(7.00)	(9.35)	(3.48)		(20.30)	(31.83)	(21.41)		(16.28)	(23.12)	(15.51)
671	JCT B	23.00	3PH	115.19	2,891.50	11.26	21.62	21.27		12.81	5.25	15.18		(3.47)	(4.00)	(0.37)		(9.76)	(17.54)	(10.54)		(7.86)	(12.79)	(7.56)

Effect of Kahului Power Plant (KPP) Retirement on Short Circuit Current

				Case0		Case1 (Delta %)				Case2 (Delta %)				Case3 (Delta %)				Case4 (Delta %)				Case5 (Delta %)		
Bus	Name	KV	3PH	MVA	Amp	NoCont	Cont1	Cont2		NoCont	Cont 1	Cont2		NoCont	Cont 1	Cont 2		NoCont	Cont 1	Cont 2		NoCont	Cont 1	Cont 2
Col 1	Col 2	Col 3	Col 4	Col 5	Col 6	Col 7	Col 8	Col 9	Col 10	Col 11	Col 12	Col 13	Col 14	Col 15	Col 16	Col 17	Col 18	Col 19	Col 20	Col 21	Col 22	Col 23	Col 24	Col 25
806	TOHANA	23.00	3PH	178.31	4,475.90	17.54	25.19	30.14		17.99	18.19	19.24		(6.64)	(7.42)	(1.88)		(19.51)	(27.03)	(20.35)		(14.97)	(19.76)	(13.95)
809	REG	23.00	3PH	30.17	757.40	2.30	3.30	6.17		0.55	2.22	(0.04)		1.21	1.78	3.03		0.88	0.59	1.78		1.33	1.66	2.85
812	MAKW JCT	23.00	3PH	70.80	1,777.20	2.71	5.82	11.39		0.52	3.72	(0.85)		1.38	1.83	6.66		1.09	0.88	3.31		1.15	1.96	6.14
813	HOS JCT	23.00	3PH	36.63	919.50	1.56	3.71	7.24		0.73	2.15	0.71		0.94	1.28	3.66		0.84	0.77	1.92		0.84	1.22	3.56
816	HAIK JCT	23.00	3PH	39.72	997.10	2.07	3.61	7.07		0.28	2.28	(0.52)		0.98	1.49	3.64		0.70	0.43	1.90		1.03	1.47	3.43
819	PUUN JCT	23.00	3PH	193.72	4,862.80	19.18	27.17	32.53		19.31	19.37	20.56		(7.14)	(8.13)	(1.94)		(21.47)	(29.82)	(22.23)		(16.39)	(21.71)	(15.09)
826		23.00	3PH	161.84	4,062.40	16.71	25.00	29.36		16.54	16.92	18.01		(5.84)	(6.44)	(1.11)		(17.23)	(24.45)	(18.01)		(13.30)	(17.91)	(12.33)
827	CONC TAP	23.00	3PH	97.88	2,456.90	11.41	21.08	22.68		9.81	10.84	11.83		(2.98)	(2.69)	1.07		(8.72)	(13.85)	(9.27)		(6.96)	(10.19)	(6.34)
831	KAML TAP	23.00	3PH	46.53	1,168.10	2.11	4.00	7.94		0.26	2.51	(0.68)		0.99	1.47	4.23		0.71	0.46	2.13		0.98	1.49	3.95
838		23.00	3PH	78.57	1,972.30	8.55	19.90	16.98		8.99	3.37	11.38		(2.04)	(1.80)	0.89		(6.00)	(12.19)	(6.55)		(4.93)	(8.78)	(4.63)
840	TO-ONEE	23.00	3PH	245.67	6,166.80	20.01	27.44	33.79		58.70	52.46	57.97		(8.23)	(10.37)	(3.59)		(24.52)	(35.62)	(25.53)		(18.91)	(25.74)	(17.68)
848	JCT C	23.00	3PH	67.63	1,697.60	8.57	18.03	18.05		6.95	8.04	8.92		(2.06)	(1.31)	1.59		(5.98)	(9.98)	(6.36)		(4.86)	(7.28)	(4.35)
849	REGULATO	23.00	3PH	26.15	656.40	5.62	5.89	8.40		2.29	4.90	1.74		3.49	4.60	3.88		2.61	1.73	3.37		4.19	4.48	4.30
858	PUUOHALA	23.00	3PH	194.67	4,886.70	16.38	24.98	28.83		19.88	8.63	22.06		(6.57)	(8.34)	(3.10)		(18.52)	(28.96)	(19.70)		(14.52)	(21.08)	(14.10)
892	BALWNPK	23.00	3PH	106.34	2,669.40	11.62	19.85	21.94		11.22	11.99	12.88		(3.74)	(3.55)	0.11		(10.55)	(15.60)	(11.20)		(8.34)	(11.49)	(7.80)
893	PAIAMKA	23.00	3PH	97.89	2,457.20	10.87	19.18	20.84		10.35	11.17	12.05		(3.41)	(3.09)	0.35		(9.59)	(14.35)	(10.18)		(7.61)	(10.56)	(7.10)
898	SUB 98 TAP	23.00	3PH	44.78	1,124.10	2.09	3.90	7.70		0.25	2.45	(0.65)		0.99	1.48	4.07		0.70	0.45	2.06		0.99	1.49	3.81
4002	PUUN 23	23.00	3PH	286.69	7,196.60	20.84	26.77	36.54		20.26	22.97	18.72		(5.80)	(7.18)	2.10		(20.76)	(28.43)	(18.87)		(16.11)	(20.74)	(11.21)
301	CT-1 M14	13.80	3PH	435.39	18,215.30	0.44	0.02	(0.42)		0.46	0.21	(0.23)		0.30	0.36	(0.10)		0.83	1.13	0.69		(0.80)	(0.68)	(1.14)
302	CT-2 M16	13.80	3PH	421.28	17,625.10	0.03	(1.57)	(2.06)		0.18	(0.62)	(1.11)		0.04	(0.25)	(0.86)		0.51	0.92	0.26		(0.97)	(1.09)	(1.73)

Effect of Kahului Power Plant (KPP) Retirement on Short Circuit Current

				Case0		Case1 (Delta %)				Case2 (Delta %)				Case3 (Delta %)				Case4 (Delta %)				Case5 (Delta %)		
Bus	Name	KV	3PH	MVA	Amp	NoCont	Cont1	Cont2		NoCont	Cont 1	Cont2		NoCont	Cont 1	Cont 2		NoCont	Cont 1	Cont 2		NoCont	Cont 1	Cont 2
Col 1	Col 2	Col 3	Col 4	Col 5	Col 6	Col 7	Col 8	Col 9	Col 10	Col 11	Col 12	Col 13	Col 14	Col 15	Col 16	Col 17	Col 18	Col 19	Col 20	Col 21	Col 22	Col 23	Col 24	Col 25
303	ST-1 M15	13.80	3PH	312.06	13,055.50	0.24	(1.22)	(1.81)		0.37	(0.37)	(0.97)		0.19	(0.02)	(0.71)		0.81	1.27	0.54		(1.13)	(1.17)	(1.89)
304	CT-3 M17	13.80	3PH	405.57	16,968.00	(0.06)	(1.74)	(2.19)		0.09	(0.73)	(1.18)		(0.02)	(0.36)	(0.94)		0.38	0.79	0.14		(0.92)	(1.07)	(1.68)
305	CT-4 M19	13.80	3PH	405.57	16,968.00	(0.06)	(1.74)	(2.19)		0.09	(0.73)	(1.18)		(0.02)	(0.36)	(0.94)		0.38	0.79	0.14		(0.92)	(1.07)	(1.68)
306	ST-2 M18	13.80	3PH	297.95	12,465.10	0.23	(1.09)	(1.62)		0.34	(0.33)	(0.87)		0.18	(0.01)	(0.64)		0.74	1.16	0.50		(1.02)	(1.05)	(1.71)
804	HC&S TG4	13.80	3PH	416.99	17,445.60	#N/A	#N/A	#N/A		#N/A	#N/A	#N/A		#N/A	#N/A	#N/A		#N/A	#N/A	#N/A		#N/A	#N/A	#N/A
12031	BURIED_TERT	13.80	3PH	126.96	5,311.60	(0.25)	0.93	2.57		(0.53)	0.70	1.22		(0.64)	0.48	1.72		(0.42)	0.65	1.58		(1.26)	(0.08)	1.19
13	KULA 12	12.47	3PH	77.44	3,585.40	1.52	3.65	9.35		0.58	1.73	0.47		0.75	1.10	4.41		0.71	0.73	2.15		0.34	0.76	4.01
98	KAUHIKOA	12.47	3PH	32.80	1,518.80	1.99	3.23	6.18		0.32	2.04	(0.39)		0.99	1.52	3.17		0.70	0.44	1.71		1.09	1.47	2.99
112	MAKA 12	12.47	3PH	35.56	1,646.60	3.72	6.84	10.31		2.10	5.04	0.71		2.76	3.25	5.67		2.50	2.24	4.75		2.84	3.85	5.48
123	PUUKB 12	12.47	3PH	78.28	3,624.10	0.15	(0.08)	(0.33)		0.18	0.03	(0.22)		0.08	0.12	(0.14)		0.37	0.54	0.29		(0.53)	(0.46)	(0.73)
125	WAILEA A	12.47	3PH	93.34	4,321.70	1.07	1.42	2.92		0.82	1.20	1.02		0.71	1.01	1.49		0.87	1.15	1.34		0.09	0.45	0.96
129	NAPILA12	12.47	3PH	72.43	3,353.30	0.13	(0.09)	(0.31)		0.15	0.02	(0.21)		0.07	0.10	(0.14)		0.33	0.48	0.25		(0.49)	(0.44)	(0.68)
134	LAHAINA 1	12.47	3PH	89.27	4,133.00	0.10	(0.16)	(0.45)		0.13	(0.03)	(0.32)		0.02	0.06	(0.24)		0.36	0.54	0.26		(0.67)	(0.60)	(0.90)
135	KIHEI A	12.47	3PH	84.63	3,918.10	1.14	1.26	1.62		1.02	1.17	0.97		0.90	1.09	1.24		1.12	1.34	1.33		0.30	0.54	0.72
136	WAIINU B	12.47	3PH	88.57	4,100.80	1.05	26.53	3.49		(2.15)	(89.74)	0.48		0.03	16.03	0.16		(0.04)	11.01	(0.16)		(0.42)	12.48	(0.14)
139	MAALA A	12.47	3PH	91.98	4,258.40	0.27	(0.02)	(0.32)		0.28	0.11	(0.19)		0.18	0.22	(0.09)		0.54	0.75	0.45		(0.56)	(0.48)	(0.79)
150	MAHINA 12	12.47	3PH	77.80	3,601.90	0.04	(0.19)	(0.44)		0.06	(0.09)	(0.33)		(0.02)	0.02	(0.24)		0.27	0.43	0.19		(0.61)	(0.54)	(0.80)
155	KULA AG	12.47	3PH	45.01	2,084.10	0.87	1.59	4.61		0.40	1.03	0.50		0.47	0.74	1.58		0.47	0.51	0.97		0.24	0.54	2.02
175	NEWHDWD	12.47	3PH	40.21	1,861.90	5.81	14.75	13.07		4.34	5.41	6.18		(1.29)	(0.14)	1.96		(3.72)	(6.70)	(3.92)		(3.11)	(4.77)	(2.68)
177	WAIKAP12	12.47	3PH	37.46	1,734.40	5.00	15.78	10.31		4.90	1.52	6.98		(0.91)	0.33	1.73		(2.81)	(6.64)	(3.11)		(2.40)	(4.57)	(2.11)

HECO Transmission Planning Division
Reference: TPD 2014-20

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Effect of Kahului Power Plant (KPP) Retirement on Short Circuit Current

				Case0		Case1 (Delta %)				Case2 (Delta %)				Case3 (Delta %)				Case4 (Delta %)				Case5 (Delta %)		
Bus	Name	KV	3PH	MVA	Amp	NoCont	Cont1	Cont2		NoCont	Cont 1	Cont2		NoCont	Cont 1	Cont 2		NoCont	Cont 1	Cont 2		NoCont	Cont 1	Cont 2
Col 1	Col 2	Col 3	Col 4	Col 5	Col 6	Col 7	Col 8	Col 9	Col 10	Col 11	Col 12	Col 13	Col 14	Col 15	Col 16	Col 17	Col 18	Col 19	Col 20	Col 21	Col 22	Col 23	Col 24	Col 25
203	KANAH A	12.47	3PH	96.39	4,462.60	4.47	10.87	24.07		(0.58)	6.58	(5.96)		2.05	2.60	12.19		1.35	0.91	6.63		1.64	2.92	10.82
204	KANAH B	12.47	3PH	86.95	4,025.90	4.10	10.55	23.04		(0.58)	6.14	(6.14)		1.85	3.04	11.63		1.20	0.76	5.66		1.55	3.45	10.39
205	KANAH C	12.47	3PH	95.69	4,430.40	4.36	10.14	23.69		(1.27)	5.84	(6.67)		1.98	2.53	12.00		1.30	0.87	6.51		1.60	2.87	10.66
216	HAIKU 2	12.47	3PH	28.32	1,311.10	4.43	6.64	9.03		2.23	5.62	0.96		3.51	4.03	4.53		3.24	2.98	4.02		3.65	3.96	5.04
225	WAILEA B	12.47	3PH	91.90	4,255.00	1.02	1.37	2.83		0.78	1.15	0.97		0.67	0.97	1.45		0.84	1.11	1.30		0.07	0.42	0.93
234	LAHAINA 2	12.47	3PH	91.71	4,246.30	0.12	(0.16)	(0.45)		0.14	(0.02)	(0.32)		0.04	0.07	(0.23)		0.38	0.57	0.28		(0.68)	(0.61)	(0.92)
235	KIHEI B	12.47	3PH	86.00	3,981.80	1.18	1.29	1.66		1.06	1.21	1.01		0.94	1.13	1.27		1.16	1.38	1.36		0.32	0.56	0.74
325	WAILEA C	12.47	3PH	93.01	4,306.10	1.10	1.45	2.31		0.85	1.23	1.05		0.73	1.03	1.52		0.90	1.17	1.36		0.10	0.46	0.98
335	KIHEI C	12.47	3PH	83.83	3,881.10	1.18	1.30	1.67		1.05	1.21	1.01		0.94	1.12	1.28		1.15	1.37	1.36		0.33	0.57	0.75
336	WAIINU C	12.47	3PH	88.60	4,101.90	1.03	26.32	3.47		(2.16)	(89.87)	0.47		0.02	15.96	0.15		(0.04)	10.97	(0.16)		(0.42)	12.44	(0.14)
405	WLUKU C	12.47	3PH	76.85	3,558.20	7.44	27.82	17.81		8.12	3.63	10.82		(2.27)	0.75	1.07		(5.40)	(13.07)	(5.94)		(4.31)	(9.09)	(4.09)
415	WLUKU D	12.47	3PH	63.87	2,956.90	6.39	26.94	16.04		6.70	2.90	9.36		(1.84)	1.45	1.43		(4.24)	(11.22)	(4.70)		(3.40)	(7.71)	(3.17)
425	WAILEA D	12.47	3PH	84.37	3,906.00	0.73	1.08	3.05		0.48	0.84	0.67		0.43	0.72	1.19		0.58	0.83	1.02		(0.07)	0.27	0.77
435	KIHEI D	12.47	3PH	89.62	4,149.50	1.21	1.31	1.67		1.08	1.23	1.03		0.96	1.15	1.29		1.19	1.42	1.39		0.32	0.56	0.73
443	WAIEHU12	12.47	3PH	55.16	2,553.70	5.90	27.61	15.20		5.85	2.38	8.52		(1.56)	2.46	2.35		(3.56)	(10.17)	(3.97)		(2.87)	(6.91)	(2.63)
511	MPINE	12.47	3PH	59.82	2,769.80	7.20	26.37	18.53		#N/A	#N/A	#N/A		(0.89)	1.94	3.43		(3.18)	(9.36)	(3.51)		(2.44)	(6.87)	(2.03)
534	LAHAINA 5	12.47	3PH	99.42	4,603.10	0.08	(0.22)	(0.54)		0.10	(0.08)	(0.40)		(0.01)	0.03	(0.29)		0.36	0.57	0.26		(0.77)	(0.69)	(1.02)
723	PUUKA 12	12.47	3PH	91.05	4,215.40	0.05	(0.22)	(0.51)		0.08	(0.09)	(0.39)		(0.02)	0.02	(0.28)		0.32	0.51	0.22		(0.72)	(0.64)	(0.95)
729	NAPILB12	12.47	3PH	74.38	3,443.80	0.11	(0.11)	(0.35)		0.14	(0.00)	(0.24)		0.05	0.08	(0.17)		0.32	0.48	0.24		(0.53)	(0.47)	(0.72)
750	MAHINB 12	12.47	3PH	79.14	3,664.20	0.09	(0.14)	(0.40)		0.11	(0.03)	(0.29)		0.02	0.06	(0.21)		0.32	0.48	0.23		(0.59)	(0.52)	(0.79)

Effect of Kahului Power Plant (KPP) Retirement on Short Circuit Current

				Case0		Case1 (Delta %)				Case2 (Delta %)				Case3 (Delta %)				Case4 (Delta %)				Case5 (Delta %)		
Bus	Name	KV	3PH	MVA	Amp	NoCont	Cont1	Cont2		NoCont	Cont 1	Cont2		NoCont	Cont 1	Cont 2		NoCont	Cont 1	Cont 2		NoCont	Cont 1	Cont 2
Col 1	Col 2	Col 3	Col 4	Col 5	Col 6	Col 7	Col 8	Col 9	Col 10	Col 11	Col 12	Col 13	Col 14	Col 15	Col 16	Col 17	Col 18	Col 19	Col 20	Col 21	Col 22	Col 23	Col 24	Col 25
803	KAHUL 3	12.47	3PH	62.02	2,871.20	6.14	26.26	17.96		27.00	26.94	27.76		(1.87)	2.07	2.90		(3.51)	(8.78)	(3.88)		(3.42)	(6.35)	(3.07)
817	PUKLN A	12.47	3PH	93.93	4,348.70	3.03	7.12	16.43		0.49	4.15	(1.32)		1.46	1.93	7.99		1.13	0.96	4.33		1.01	1.57	7.82
834	LAHAIN 4	12.47	3PH	92.05	4,261.60	0.08	(0.19)	(0.49)		0.10	(0.07)	(0.36)		0.00	0.04	(0.26)		0.34	0.54	0.25		(0.71)	(0.64)	(0.94)
917	PUKLN B	12.47	3PH	87.26	4,040.00	2.88	7.08	15.72		0.44	4.01	(1.25)		1.39	1.85	7.87		1.06	0.88	4.23		1.00	1.55	7.17
101	KGS-1	11.50	3PH	84.66	4,250.50	#N/A	#N/A	#N/A		#N/A	#N/A	#N/A		#N/A	#N/A	#N/A		(254.71)	(269.41)	(256.56)		(96.79)	(107.80)	(102.51)
102	KGS-2	11.50	3PH	72.41	3,635.30	#N/A	#N/A	#N/A		#N/A	#N/A	#N/A		#N/A	#N/A	#N/A		(317.45)	(333.15)	(318.80)		(109.24)	(120.27)	(115.26)
103	KGS-3	11.50	3PH	118.79	5,963.50	#N/A	#N/A	#N/A		#N/A	#N/A	#N/A		(114.08)	(120.26)	(113.37)		(128.97)	(142.11)	(132.83)		(108.51)	(122.91)	(115.99)
104	KGS-4	11.50	3PH	270.74	13,592.60	#N/A	#N/A	#N/A		#N/A	#N/A	#N/A		(5.78)	(3.90)	(1.06)		0.10	(2.80)	0.63		(12.46)	(15.71)	(12.62)
164	PUUNENE	7.20	3PH	6.15	493.10	2.09	11.34	6.77		(0.08)	0.99	1.71		0.04	1.78	2.98		(0.20)	(1.99)	(0.08)		(0.34)	(1.12)	0.10
108	MGS-1011	6.90	3PH	386.77	32,362.60	0.07	(1.75)	(2.31)		0.24	(0.67)	(1.23)		0.09	(0.25)	(0.95)		0.61	1.09	0.33		(1.07)	(1.21)	(1.94)
109	MGS-1213	6.90	3PH	309.02	25,856.50	(24.93)	(27.14)	(27.96)		(24.73)	(25.85)	(26.67)		(24.92)	(25.35)	(26.33)		0.79	1.32	0.49		(26.38)	(26.56)	(27.59)
192	SPRECK	4.60	3PH	37.04	4,649.30	5.08	23.81	17.90		3.68	5.37	5.46		(1.07)	2.23	4.09		(2.40)	(5.83)	(2.56)		(1.93)	(4.09)	(1.52)
45	HALEKALA	4.16	3PH	7.08	982.40	2.06	2.29	1.75		1.26	2.01	1.32		1.50	1.96	2.05		1.26	1.15	1.66		1.58	2.07	2.15
105	MGS-123	4.16	3PH	90.23	12,522.20	0.28	0.02	(0.26)		0.30	0.14	(0.15)		0.19	0.23	(0.06)		0.53	0.72	0.44		(0.51)	(0.43)	(0.73)
106	MGS-458	4.16	3PH	267.00	37,056.20	(0.18)	(2.11)	(2.50)		0.00	(0.93)	(1.31)		41.74	41.68	41.33		42.08	42.17	41.84		(0.75)	(0.99)	(1.57)
107	MGS-679	4.16	3PH	193.71	26,884.50	(36.39)	(38.05)	(38.67)		(36.24)	(37.08)	(37.70)		(18.16)	(18.44)	(19.08)		20.47	20.65	20.21		(37.36)	(37.53)	(38.30)
110	MGS-X1X2	4.16	3PH	91.99	12,767.20	0.29	0.02	(0.27)		0.31	0.14	(0.15)		0.20	0.23	(0.06)		0.55	0.74	0.45		(0.52)	(0.44)	(0.74)
173	KUAU A	4.16	3PH	12.47	1,730.70	4.02	22.26	14.68		0.73	1.79	2.53		1.20	4.10	5.43		0.63	(2.69)	0.70		0.59	(1.65)	1.03
403	WLUKU A	4.16	3PH	27.47	3,812.00	3.71	19.73	9.16		3.44	0.82	5.36		(0.60)	2.95	1.89		(1.87)	(4.87)	(2.09)		(1.66)	(3.23)	(1.38)
404	WLUKU B	4.16	3PH	27.52	3,819.20	3.61	19.01	9.88		3.36	0.76	5.25		(0.62)	3.88	1.86		(1.86)	(5.35)	(2.08)		(1.66)	(3.73)	(1.37)

Effect of Kahului Power Plant (KPP) Retirement on Short Circuit Current

				Case0		Case1 (Delta %)				Case2 (Delta %)				Case3 (Delta %)				Case4 (Delta %)				Case5 (Delta %)		
Bus	Name	KV	3PH	MVA	Amp	NoCont	Cont1	Cont2		NoCont	Cont 1	Cont2		NoCont	Cont 1	Cont 2		NoCont	Cont 1	Cont 2		NoCont	Cont 1	Cont 2
Col 1	Col 2	Col 3	Col 4	Col 5	Col 6	Col 7	Col 8	Col 9	Col 10	Col 11	Col 12	Col 13	Col 14	Col 15	Col 16	Col 17	Col 18	Col 19	Col 20	Col 21	Col 22	Col 23	Col 24	Col 25
407	WAI WELL	4.16	3PH	26.34	3,655.90	3.66	23.84	11.12		2.67	0.76	5.25		(0.48)	4.21	2.68		(1.66)	(5.95)	(1.87)		(1.49)	(3.66)	(1.19)
418	WLUKUHT	4.16	3PH	47.61	6,607.30	5.35	24.98	14.66		5.08	1.37	7.72		(1.24)	2.28	2.62		(2.86)	(9.69)	(3.21)		(2.31)	(6.68)	(2.05)
431	KAMOLE 4	4.16	3PH	13.60	1,887.50	4.84	6.67	8.29		2.72	5.45	1.87		3.85	4.51	4.25		3.51	3.20	4.45		4.07	4.82	4.73
436	WAIINUA	4.16	3PH	24.16	3,353.30	3.00	19.66	9.04		3.13	(1.52)	5.54		(0.32)	4.26	2.58		(1.15)	(6.01)	(1.31)		(1.20)	(3.22)	(0.80)
440	ONEHEE 4	4.16	3PH	24.23	3,362.20	3.49	20.16	12.93		12.79	14.96	14.74		(0.41)	4.13	3.53		(0.84)	(4.72)	(0.94)		(0.76)	(3.27)	(0.34)
493	PAIAMKA 1	4.16	3PH	33.89	4,703.90	6.02	23.86	17.87		3.92	4.94	5.68		0.42	3.01	5.43		(0.70)	(4.68)	(0.83)		(0.30)	(3.06)	0.10
844	KAHUL 4	4.16	3PH	38.20	5,301.50	5.33	22.63	15.70		14.97	14.87	16.21		(0.23)	2.88	3.85		(1.38)	(6.46)	(1.57)		(1.05)	(4.63)	(0.64)
845	KAHUL 5	4.16	3PH	38.23	5,305.20	5.28	22.50	15.60		14.96	14.87	16.19		(0.23)	3.46	4.43		(1.38)	(6.44)	(1.57)		(1.05)	(4.62)	(0.64)
846	KAHUL 6	4.16	3PH	38.20	5,301.90	4.71	22.58	15.67		14.99	14.90	16.23		(0.87)	2.88	3.85		(1.38)	(6.46)	(1.57)		(1.05)	(4.63)	(0.65)
141	HANA 1	2.40	3PH	7.29	1,754.10	1.08	1.73	5.30		0.34	0.57	0.24		0.60	1.08	2.21		0.48	0.41	0.71		0.63	0.76	1.32
142	KEANAE	2.40	3PH	4.96	1,193.00	0.54	1.16	5.03		0.22	0.06	0.18		0.32	0.73	1.91		0.33	0.38	0.47		0.23	0.34	0.90
161	HOSMER	2.40	3PH	5.16	1,241.00	0.66	0.66	(0.22)		(0.05)	0.49	(0.03)		0.23	0.61	0.44		0.07	(0.04)	0.29		0.40	0.80	0.64
174	HUELO 1	2.40	3PH	2.84	684.00	0.01	(0.01)	0.82		(0.01)	(0.44)	-		(0.01)	0.31	0.37		0.07	0.22	0.15		(0.19)	(0.10)	(0.15)
209	KAILUA A	2.40	3PH	2.58	620.40	(0.03)	(0.05)	0.76		(0.02)	(0.49)	0.02		(0.03)	0.29	0.34		0.06	0.23	0.13		(0.23)	(0.13)	(0.18)
241	HANA 2	2.40	3PH	8.78	2,112.00	1.36	1.42	5.20		0.36	0.84	0.22		0.72	1.26	2.35		0.54	0.39	0.82		0.83	0.97	1.54
422	WSCO PMP	2.40	3PH	48.75	11,728.30	5.75	15.92	11.50		6.18	2.25	8.24		(1.35)	(0.42)	1.27		(3.87)	(8.16)	(4.25)		(3.24)	(5.75)	(2.98)
430	MOKU PMP	2.40	3PH	26.27	6,319.40	3.66	14.13	7.66		3.29	0.75	5.24		(0.48)	1.13	2.03		(1.67)	(4.61)	(1.88)		(1.50)	(3.01)	(1.20)
92031	AUWAHI_SIEM1	0.69	3PH	84.83	70,978.30	(2.40)	(0.29)	1.88		(2.66)	(0.60)	0.54		(2.70)	(0.82)	1.10		(2.71)	(0.95)	0.74		(2.98)	(1.07)	0.88
92032	AUWAHI_SIEM2	0.69	3PH	84.48	70,687.70	(2.42)	(0.31)	1.86		(2.68)	(0.61)	0.53		(2.72)	(0.84)	1.09		(2.74)	(0.97)	0.72		(3.00)	(1.09)	0.87
92061	KWPII_GEN1	0.69	3PH	146.94	122,950.20	(23.26)	(23.77)	(24.37)		(23.27)	(23.59)	(24.20)		(23.41)	(23.37)	(24.00)		(22.74)	(22.42)	(23.03)		(24.64)	(24.53)	(25.15)

HECO Transmission Planning Division
Reference: TPD 2014-20

Effect of Kahului Power Plant (KPP) Retirement on Short Circuit Current

				Case0		Case1 (Delta %)				Case2 (Delta %)				Case3 (Delta %)				Case4 (Delta %)				Case5 (Delta %)		
Bus	Name	KV	3PH	MVA	Amp	NoCont	Cont1	Cont2		NoCont	Cont 1	Cont2		NoCont	Cont 1	Cont 2		NoCont	Cont 1	Cont 2		NoCont	Cont 1	Cont 2
Col 1	Col 2	Col 3	Col 4	Col 5	Col 6	Col 7	Col 8	Col 9	Col 10	Col 11	Col 12	Col 13	Col 14	Col 15	Col 16	Col 17	Col 18	Col 19	Col 20	Col 21	Col 22	Col 23	Col 24	Col 25
90971	KWPI_1	0.58	3PH	240.25	241,235.90	0.50	(0.02)	(0.58)		0.53	0.22	(0.34)		0.29	0.37	(0.21)		0.98	1.34	0.79		(1.11)	(0.96)	(1.55)
44	DET 03	0.48	3PH	15.93	19,163.20	1.72	2.51	3.23		0.93	1.85	0.96		1.17	1.58	2.33		0.98	0.88	1.56		1.20	1.65	2.39
127	CONCRETE	0.48	3PH	23.01	27,680.60	3.87	12.95	9.83		2.06	3.13	3.88		(0.59)	0.88	2.49		(1.83)	(4.17)	(1.87)		(1.63)	(2.82)	(1.20)
148	MAUIBLOC	0.48	3PH	10.72	12,888.90	2.53	13.53	5.60		1.56	(0.20)	3.46		0.06	2.11	2.56		(0.39)	(2.59)	(0.50)		(0.47)	(1.41)	(0.15)
182	AMERON	0.48	3PH	26.63	32,029.00	4.34	13.42	10.64		2.59	3.68	4.43		(0.74)	0.65	2.38		(2.25)	(4.75)	(2.33)		(1.96)	(3.26)	(1.53)
188	AMERBLDG	0.48	3PH	3.66	4,401.50	1.83	11.10	6.34		(0.40)	0.66	1.38		0.12	1.90	3.05		0.03	(1.69)	0.18		(0.17)	(0.88)	0.29
501	AUX K1	0.48	3PH	13.90	16,715.70	#N/A	#N/A	#N/A		#N/A	#N/A	#N/A		#N/A	#N/A	#N/A		(12.60)	(15.77)	(13.31)		(8.66)	(12.34)	(10.98)
502	AUX K2	0.48	3PH	10.40	12,511.40	#N/A	#N/A	#N/A		#N/A	#N/A	#N/A		#N/A	#N/A	#N/A		(11.67)	(15.03)	(12.56)		(8.64)	(12.24)	(10.94)
503	AUX K3	0.48	3PH	10.76	12,939.80	#N/A	#N/A	#N/A		#N/A	#N/A	#N/A		(5.04)	(5.20)	(4.09)		(5.06)	(8.20)	(6.17)		(5.70)	(9.61)	(8.36)
504	AUX K4	0.48	3PH	11.88	14,287.90	#N/A	#N/A	#N/A		#N/A	#N/A	#N/A		(0.12)	3.42	3.84		0.39	0.50	1.76		(0.87)	(1.26)	(0.74)
2062	KWPII-BESS	0.48	3PH	139.62	167,939.00	(8.44)	(8.88)	(9.38)		(8.44)	(8.71)	(9.22)		(8.58)	(8.54)	(9.06)		(8.02)	(7.74)	(8.25)		(9.64)	(9.54)	(10.07)
12033	XP_BESS	0.48	3PH	101.47	122,047.80	(0.29)	0.91	2.45		(0.56)	0.63	1.08		(0.63)	0.43	1.64		(0.46)	0.52	1.45		(1.12)	(0.01)	1.23