# V. APPENDICES

# Appendix A: Glossary

This Glossary contains the terms used through the Integrated Resource Plan Report. It not only helps you better understand the concepts presented, but also clarifies the meaning of the terms used. Some glossary entries are included to simply give you a more complete understanding of electricity, electric utilities, and energy generation.

# A

### Adequacy of Supply

See "Reliability" on page A-20.

### Amp

The International System base unit of electric current, an amp is a unit of electric current equal to a flow of one coulomb per second. (See also "Watt" on page A-24.)

### Apparent Power

See "Power" on page A-18.

### Average Demand

See "Demand" on page A-5.

### Avoided Costs

The costs that the utility would avoid by purchasing capacity and energy from a qualifying facility. 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 which is generated or supplied continuously over a period of time. Baseload units are designed for nearly continuous operation at or near full capacity to provide all or part of the baseload.

### Baseload Capacity

See "Capacity, Generating" on page A-3.

### Black Start

A black start restores operation to a power plant without relying on the external electric power transmission network.

### British Thermal Unit (Btu)

The British thermal unit is a unit of energy equal to about 1055 joules, and describes the energy content of fuels. A Btu is defined as 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.

### Bus Bar

A bus bar (also busbar) is a strip (or bar) or tube made of copper, brass, or aluminum that conducts electricity within a switchboard, distribution board, substation, battery bank, or other electrical apparatus. The bus bar's size (ranging from $10mm^2$ wide to tubes $20cm^2$ in diameter) determines the maximum current that it can safely carry.

## C

### Capacitor

A capacitor is a device that helps improve the efficiency of the flow of electricity through distribution lines by reducing energy losses. It is installed in substations and on poles. Usually it is installed to correct an unwanted condition in an electrical system.

### Capacity, Generating

The rated continuous load-carrying ability, expressed in megawatts (MW) or megavolt-amperes (MVA) of generation, transmission, or other electrical equipment. It is the maximum power that a machine or system can produce or carry under specified conditions, usually expressed in kilowatts or megawatts. (Sometimes referred to as Supply Capacity.)

Types of capacity include the following:

***Baseload Capacity:*** Capacity used to serve an essentially constant level of customer demand. Baseload generating units typically operate whenever they are available, and they generally have a capacity factor that is above 60%.

***Firm Capacity:*** Capacity that is as firm as the seller's native load unless modified by contract. Associated energy may or may not be taken at option of purchaser. Supporting reserve is carried by the seller.

***Installed Capacity:*** Also called ICAP, the total wattage of all generators able to be scheduled to serve a given service or control area.

***Intermediate Capacity:*** Capacity intended to operate fewer hours per year than baseload capacity but more than peaking capacity. Typically, such generating units have a capacity factor of 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:*** Capacity used to serve peak demand. Peaking generating units operate a limited number of hours per year, and their capacity factor is normally less than 20%.

***Unconstrained Capacity:*** Also called UCAP, the total wattage of all generators that actually deliver power to serve a given service or control area. UCAP may be determined through a de-rating process that corrects for loss of capacity due to high air temperatures (which may reduce capacity of combustion turbines), past failure probabilities for specific generators, or other means.

**Capacity Factor**

The ratio of the total energy actually generated by a generating unit for a specified period to the maximum possible energy it could have generated if operated at the maximum capacity rating for the same specified period, expressed as a percent. Also referred to as Power Factor.

**Capital Investment Costs**

The costs associated with capital improvements, including planning, the acquisition and development of land, the design and construction of new facilities, the making of renovations or additions to existing facilities, the construction of built-in equipment and consultant and staff services in planning, design and construction. Capital investment costs for a program are the sum of the program's capital improvement project costs.

**Carbon Dioxide ($CO_2$)**

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

**Cogenerator**

A generator that primarily produces heat; steam; chilled water; or chilled air and, as a byproduct, produces electricity.

**Cogeneration**

Production of electricity from steam, heat, or other forms of energy produced as a by-product of another process. Also called Combined Heat and Power (CHP).

**Coincident Demand**

See "Demand" on page A-5.

**Combined Cycle**

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.

***Dual-Train Combined Cycle:*** 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, which is directed to the single steam turbine.

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

### Combined Heat and Power (or Cogeneration)

See "Cogeneration" on page A-4.

### Combustion Turbine

Any of several types of high speed (usually gas-fired) generators using principles and designs of jet engines to produce low cost, high efficiency power

### Coincidence Factor

This variable is used in calculations of consumers' power costs. The coincidence factor is linked to the degree by which a given consumer's peak demand coincides with the peaks of other consumers on a given system. The lower, (read: worse), a customer's load profile (the ratio of his/her average load to his/her peak load), the more the coincidence factor could contribute to exceptionally high costs for the delivery of power from the generator to the consumer, especially during peak seasons. Most of the customers we encounter can make changes to their operating methods or their facilities' systems to improve their load profiles. Better load profiles lead to better prices for power.

### Cost Effectiveness

A measure of economic efficiency calculated by dividing the cost by a measure of effective means (for example, tons of air pollution reduced).

### Costs

The full and life cycle costs of a resource option.

## D

### Demand

The rate at which electric energy is delivered to or by a system or part of a system, generally expressed in kilowatts or megawatts, at a given instant or averaged over any designated interval of time. Demand should not be confused with Load. Types of demand include the following:

***Average Demand:*** The electric energy delivered over any interval of time as determined by dividing the total energy by the units of time in the interval.

***Coincident Demand:*** The sum of two or more demands that occur in the same demand interval.

***Firm Demand:*** That portion of the Contract Demand that a power supplier is obligated to provide except when system reliability is threatened or during emergency conditions.

***Instantaneous Demand:*** The rate of energy delivered at a given instant.

***Integrated Demand:*** The average of the instantaneous demands over the demand interval.

***Interruptible Demand:*** The magnitude of customer demand that, in accordance with contractual arrangements, can be interrupted by direct control of the system operator or by action of the customer at the direct request of the system operator. In some instances, the demand reduction may be initiated by the direct action of the system operator (remote tripping) with or without notice to the customer in accordance with contractual provisions. Interruptible Demand as defined here does not include Direct Control Load Management.

***Non-Coincident Demand:*** The sum of two or more demands that occur in different demand intervals.

***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.

### Demand Charge

A fee based on the peak amount of electricity used during the billing cycle. Residential customers are generally not levied a demand charge.

### Demand-Side Management

Often abbreviated DSM, it refers to the planning, implementation, and monitoring of activities designed to encourage consumers to modify patterns of electricity usage, including the timing and level of electricity demand. DSM covers the complete range of load-shape objectives, including strategic conservation and load management, as well as strategic load growth. Indirect Demand-Side Management includes such programs as conservation, improvements in efficiency of electrical energy use, rate incentives, rebates, and other similar activities to influence electricity use.

Demand-side management is controlled by users whereas supply-side management is controlled by the utilities. (See also “Supply-Side Management” on page A-22.)

### Direct Control Load Management

The magnitude of customer demand that can be interrupted at the time of the seasonal peak load by direct control of the system operator by interrupting power supply to individual appliances or equipment on customer premises. This type of control usually reduces the demand of residential customers.

### Direct Load Control (DLC)

This Demand-Side Management category represents the consumer load that can be interrupted at the time of annual peak load by direct control of the utility system operator. Direct Load Control does not include Interruptible Load. The utility installs a device such as a radio-controlled device on the HVAC equipment or water heater. During periods of heavy use of electricity (generally peak hours), the utility will send a radio signal to the appliance with this device and turn off the appliance for a set period of time.

### Distillate Fuel Oil

A general classification for one of the petroleum fractions produced in conventional distillation operations. It is used primarily for space heating, on-and-off-highway diesel engine fuel (including railroad engine fuel and fuel for agriculture machinery), and electric power generation. Included are Fuel Oils No. 1, No. 2, and No. 4; and Diesel Fuels No. 1, No. 2, and No. 4. Heavier oils are commonly referred to as No. 5, No.6, and/or Bunker C.

### Distributed Generation (DG)

A system utilizing small generators located on a utility's distribution system for the purpose of meeting local (substation level) peak loads, displacing the need to build additional (or upgrade) local distribution lines, or both. In other words, distributed generation collect electricity generated from many small energy sources.

Distributed energy resource (DER) systems are small-scale power generators (typically in the range of 3 kW to 10,000 kW) used as an alternative or enhancement of the traditional electric power system. With the advent of small (less than 100 kW) microturbine generators, distributed generation is beginning to include customer and marketer-owned capacity feeding single loads (for example, a chiller plant), customers, or small groups of customers.

While distributed generation might reduce environmental impacts, it usually comes with high costs.

### Dual-Train Combined Cycle

See "Combined Cycle" on page A-4.

## E

### Emissions

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

### Energy Adjustment Cost

A clause in the rate schedule that provides for adjustment of the amount of a bill as the cost of fuel varies from a specified base amount per unit. The specified base amount is determined when rates are approved. This item is shown on all customer bills and indicates the current rate for any necessary adjustment in the cost of fuel used by the company. It can be a credit or a debit. The fuel adjustment lags two months behind the actual price of the fuel. For example, the cost of oil in January will be reflected in March's fuel adjustment.

### Energy Efficiency DSM

Utility electric marketing programs designed to encourage the utility's customers to adopt energy-efficient technologies that lower total electricity usage. The major goals of these programs are to defer the need for new generating capacity and reduce the total consumption of energy resources. For example, utility programs that promote compact fluorescent light bulbs, solar water heating through rebates.

### Energy Resource

An electric generating plant or demand side measure that produces or saves electric energy or capacity.

### ENERGY STAR®

ENERGY STAR® is a government-backed program helping businesses and individuals protect the environment through superior energy efficiency. In 1992 the US Environmental Protection Agency (EPA) introduced ENERGY STAR® as a voluntary labeling program designed to identify and promote energy-efficient products to reduce greenhouse gas emissions. The ENERGY STAR® label is now on major appliances, office equipment, lighting, home electronics, and more. EPA has also extended the label to cover new homes and commercial and industrial buildings. These products deliver the same or better performance as comparable models while using less energy and saving money. ENERGY STAR® also provides easy-to-use home and building assessment tools so that homeowners and building managers can start down the path to greater efficiency and cost savings.[1]

### Environmental Externality

This comprises a subset of all externalities and results from impacts on environmental quality. For example, even after utilities comply with all environmental regulations, emissions may be non-zero and these residual emissions may result in impacts to third parties. If these impacts are not internalized in utility decisions, then they are considered to be external to the utility and hence environmental externalities.

---

[1] http://www.energystar.gov

### Evaluation Report

The Evaluation Report provides an update to the most recent filing of the Integrated Resource Plan. The Report includes recent developments and events, including changes in forecasts.

### Externality

The consequences of emissions and other effects that result from the production of electric power not internalized in the price of the transaction. When these consequences affect third parties (that is, those other than the producers and consumers of the fuel cycle activity) in a way that is not reflected in the price of electricity, they are termed hidden social costs or externalities. These costs may be either positive or negative, conferring benefits or imposing costs that are not reflected in the costs of production or sale price of electricity, and include environmental, cultural, and general benefits and costs.

### External Benefits

The external economics encompass the benefits to or positive impacts on the activities of parties outside the utility and its ratepayers. External benefits include environmental, cultural, and general economic benefits (such as the benefits of having a transmission network in place).

### External Costs

The external diseconomies encompass the costs to or negative impacts on the activities of parties outside the utility and its ratepayers. External benefits include environmental, cultural, and general economic benefits (such as unregulated air pollutants).

## F

### Firm Capacity

See "Capacity, Generating" on page A-3.

### Firm Demand

See "Demand" on page A-5.

### Firm Power

Power or power producing capacity intended to be available at all times during the period covered by a guaranteed commitment to deliver, even under adverse conditions.

### Forced Outage

See "Outage" on page A-17.

### Forced Outage Rate

See "Outage" on page A-17.

### 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.

## G

### Generating Capacity

See "Capacity, Generating" on page A-3.

### Generation Asset Management

A program to manage the operating capability, condition, reliability and service life of existing generating units. The programs include technical and economic assessments of options to modernize or increase the capacity of the existing units.

### 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)

***Gross Generation:*** The electrical output at the terminals of the generator, usually expressed in megawatts (MW). Also referred to as nameplate generation.

***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.

### Gigawatt (GW)

A unit of power equal to one billion watts, and is also used as a measurement of the output of a power station.

### Green Build

The USGBC's Annual International Green Building Conference and Expo. Professionals from around the world gather to advance the market and state-of-the-art green building. The conference provides an annual meeting place for the rapidly expanding green building industry. Green Build showcases the leading edge green technologies worldwide and delivers educational programs that highlight benchmarks of sustainability across a broad array of issues including site location and development, water use, energy, materials, indoor environmental quality, biophelia, health and productivity and financing.

### Green Power

Electricity that is generated exclusively from "green", environmentally friendly resources (such as solar, wind, tidal, geothermal, and biomass). Resources used to generate electricity that are replaced naturally, or by human contribution (municipal solid waste incineration and landfill methane). Renewable energy may include fuels and technologies such as solar photovoltaic energy, solar thermal energy, wind power, low head hydropower, geothermal energy, landfill and mine based methane gas, energy from waste and sustainable biomass energy.

### Greenhouse Gases

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

### Gross Generation

See "Generation" on page A-10.

## H

### Heat Pump

A device that removes heat from one source and dissipates it elsewhere. In a building, it would heat the air in winter and cool the air in the summer. Several different types of heat pumps exist, but the most common are air to air heat exchangers.

## 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.

### Independent Power Producer (IPP)

A private entity that operates a generation facility and sells power to electric utilities for resale to retail customers, but is not affiliated with an electric utility.

### Installed Capacity

See "Capacity, Generating" on page A-3.

### Instantaneous Demand

See "Demand" on page A-5.

**Integrated Demand**
See "Demand" on page A-5.

**Integrated Resource Plan (IRP)**
The process by which electric utilities identify the resources or the mix of resources for meeting near- and long-term consumer energy needs.

**Integrated Resource Plan-93 (IRP-1)**
HECO's first integrated resource plan, approved by the Commission on March 31, 1995, in Decision and Order No. 13839 in Docket No. 7257.

**Integrated Resource Plan-1998 (IRP-2)**
HECO's second integrated resource plan, found by the Commission in Order No. 18340, in Docket No. 95-0347, as sufficient to meet IRP Framework criteria.

**Integrated Resource Plan 2005 (IRP-3)**
HECO's third integrated resource plan.

**Integrated Resource Plan 2008 (IRP-4)**
HECO's fourth integrated resource plan.

**Intermediate Capacity**
See "Capacity, Generating" on page A-3.

**Interruptible Demand**
See "Demand" on page A-5.

**Interruptible Rates**
The rates charged for interruptible service. The interruption is based on emergency and operational considerations affecting the system. The rates for this service are lower than for firm service. Customers on this service would be interrupted before customers on firm service when such interruptions become necessary.

**IRP Framework**
The framework for integrated resource planning established by the Commission in Decision and Order No. 11523, filed March 12, 1992, in Docket No. 6617 and subsequently revised by Decision and Order No. 11630, filed on May 22, 1992, in Docket No. 6617.

## J

**Joule**
A joule is the standard measurement for an amount of heat in the International System of Units. While there are many definitions for a joule,

two are most relevant to electricity. A joule equals the energy expended in passing an electric current of one ampere through a resistance of one ohm for one second; or a joule is the work required to produce one watt of power for one second (or one watt second, comparable to a kilowatt hour). There are 3.6 million joules in one kilowatt hour.

## K

### Kilowatt (kW)

A measure of demand for power during a preset time--minutes, hours, days, months equal to a 1,000 watts. A 100-watt light bulb used for 10 hours is equivalent to a kilowatt. (See also "Watt" on page A-24.)

### Kilowatt Hour (kWh)

Kilowatt hour is the basic unit of electric energy equal to 1 kilowatt or 1,000 watts of power used for one hour. The amount of power the customer uses is measured in kilowatt hours and often simply abbreviated as kWh. For example, a 100 watt light bulb that burns for 10 hours = 1 kWh (100 watts x 10 hrs.) or 1,000 watts used in 10 hours. (See also Joule on page A-12.)

## L

### Least-Cost Plan (LCP)

The plan which will provide energy and services at the lowest cost (implies rates) to consumers, utilities, and society.

### Leadership in Energy and Environmental Design (LEED®)

LEED was created to:

- Define "green building" by establishing a common standard of measurement.
- Promote integrated, whole-building design practices.
- Recognize environmental leadership in the building industry.
- Stimulate green competition.
- Raise consumer awareness of green building benefits.
- Transform the building market.

LEED provides a complete framework for assessing building performance and meeting sustainability goals. Based on well-founded scientific standards, LEED emphasizes state of the art strategies for sustainable site development, water savings, energy efficiency, materials selection and indoor environmental quality. LEED recognizes achievements and promotes expertise in green building through a comprehensive system offering project certification, professional accreditation, training and practical resources.[2]

---

2 http://www.usgbc.org/DisplayPage.aspx?CategoryID=19 and http://www.usgbc.org

### Leadership in Energy and Environmental Design Green Building Rating System®

A voluntary, consensus-based national standard for developing high-performance, sustainable buildings. Members of the U.S. Green Building Council representing all segments of the building industry developed LEED and continue to contribute to its evolution. LEED standards are currently available or under development for:

- New commercial construction and major renovation projects (LEED-NC)
- Existing building operations (LEED-EB)
- Commercial interiors projects (LEED-CI)
- Core and shell projects (LEED-CS)
- Homes (LEED-H)
- Neighborhood Development (LEED-ND)

### Life-Cycle Costs

The total cost impact over the life of the program. Life-cycle costs include research and development cost, investment cost (the one-time cost of instituting the program) and operation and maintenance cost.

### Load

Load is the amount of power delivered, as required, at any point or points in the system. A load is created by the power demands of residential and industrial customer equipment (lights and machinery).

### 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 turn off the air conditioner or water heater for short periods of time by remote control. This control allows the utility to reduce peak demand.

### Load Factor

A measure of the degree of uniformity of demand over a period of time, equivalent to the ratio of average demand to peak demand expressed as a percentage. It is calculated by dividing the total energy provided by a system during the period by the product of the peak demand during the period and the number of hours in the period.

### Load Following

An electric system's process of regulating its generation to follow the changes in its customers' demand.

### Load Forecast

An estimate of the level of future energy needs. Bottom-up uses utility revenue meters to develop system-wide loads; used often in projecting loads of specific customer classes. Top-down 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 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. The major goal of these programs is to defer the need for new generating capacity.

### 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 deter electric service. Load shedding is most often ordered to "shed" power and block customers supply because demand for electricity exceeds supply.

## M

### Maintenance Outage

See "Outage" on page A-17.

### Megawatt (MW)

A unit of power equal to one million watts, and is also used as a measurement of the output of a power station.

### MBtu and MMBtu

A thousand Btu and a million Btu, respectively. See also British Thermal Unit (Btu) on page A-2.

### Monetization

The specific act of estimating a dollar value associated with the impacts of a particular emission, discharge or release. Usually expressed as a dollar per unit released (that is, $/ton) or sometimes as cents or mills per unit of energy (that is, cents/kWh).

### Multi-Attribute

Analysis that requires or includes several types of information or data to evaluate an impact.

## N

### Nameplate Generation

See “Generation” on page A-10.

### Net Capacity

See “Capacity, Generating“ on page A-3.

### Net Generation

See “Generation” on page A-10.

### Nitrogen Oxide ($NO_x$)

A pollutant emitted by combusting fuels.

### Nominal Value versus Real Value

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

### Non-Coincident Demand

See “Demand” on page A-5.

## O

### Objective

A statement of the end result, product or condition desired, for the accomplishment of which a course of action is taken.

### Obligation to Serve

The obligation of a utility to provide electric service to any customer who seeks that service and is willing to pay the rates set for that service. Traditionally, utilities have assumed the obligation to serve in return for an exclusive monopoly franchise.

### Off-Peak Energy

Off-peak energy is the 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

On-peak energy is electric energy supplied during periods of relatively high system demand as specified by the supplier.

### Operation and Maintenance Cost (O&M)

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

### 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 A-21.)

***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.

***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.

***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.

***Planned Outage:*** Removing the equipment from service availability for inspection and/or general overhaul of one or more major equipment groups. This outage usually is scheduled well in advance.

# P

### Participant Test

Quantifies the benefit a participant can derive from a DSM program. This test measures whether the DSM measure is economically attractive to the participating customer.

### Peak Demand

See “Demand” on page A-5.

### Peaker

A peaker is a power plant that generally runs to meet peak demand, usually 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 A-3.

### Planned Outage

See “Outage” on page A-17.

### Planning Reserve

See “Reserve” on page A-21.

### Power

The rate at which energy is transferred. Electrical energy is usually measured in watts. Also used for a measurement of capacity.

***Apparent Power:*** The product of the volts and amperes. It comprises both real and reactive power, usually expressed in kilovolt-ampere (kVA) or megavolt-amperes (MVA).

***Reactive Power:*** The portion of electricity that establishes and sustains the electric and magnetic fields of alternating-current equipment. Reactive power must be supplied to most types of magnetic equipment, such as motors and transformers. It also must supply the reactive losses on transmission facilities. Reactive power is provided by generators, synchronous condensers, or electrostatic equipment such as capacitors and directly influences electric system voltage. It is usually expressed in kilovars (kvar) or megavars (Mvar).

***Real Power:*** The rate of producing, transferring, or using electrical energy, usually expressed in kilowatts (kW) or megawatts (MW).

### Power Factor

See “Capacity Factor” on page A-4.

## Q

### Qualifying Facility

A cogeneration or small power production facility that meets certain ownership, operating, and efficiency criteria established by the Federal Energy Regulatory Commission (FERC) pursuant to the Public Utility Regulatory Policies Act (PURPA). (See the Code of Federal Regulations, Title 18, Part 292.) Systems obtaining power through renewable sources such as wind may also designated as Qualifying Facilities.

### 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

### 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 cash, working capital, 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.

### Ratemaking Authority

A utility commission's legal authority to fix, modify, approve, or disapprove rates, as determined by the powers given the commission by a State or Federal legislature.

### Ratepayer Impact Measure Test

Includes the lost revenue from the reduced electricity sales as a cost. Values less than one indicate that average rates may increase over the life of the program. This test needs to be interpreted cautiously, since rate increases in the years immediately following the implementation of the program are weighted much higher than the rate impacts (which often, decreases) in future years.

### Ratepayers

The utility customers who pay the utility's costs for service through electric power rates.

### Reactive Power

See "Reserve" on page A-21.

### Real Power

See "Reserve" on page A-21.

### Real Value

See "Nominal Value versus Real Value" on page A-16.

### 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 and Security.

***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.

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

### Renewable Energy Resources

Renewable energy resources 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 probably 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.

### Repowering

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

### Reserve

There are two types of reserve energy.

***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.

***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 (Operating)

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.

### Residual Fuel Oil

The topped crude of refinery operation, includes No. 5 and No. 6 fuel oils as defined in ASTM Specification D396 and Federal Specification VV-F-815C; Navy Special fuel oil as defined in Military Specification MIL-F-859E including Amendment 2 (NATO Symbol F- 77); and Bunker C fuel oil. Residual fuel oil is used for the production of electric power, space heating, vessel bunkering, and various industrial purposes. Imports of residual fuel oil include imported crude oil burned as fuel.

## S

### Security

See "Reliability" on page A-20.

### Selective Catalytic Reduction (SCR)

The use of a catalyst and ammonia to reduce NOx emissions from fossil fueled power plants and industrial boilers.

### Shareholder Incentives

Lost margins is where a utility company is able to recover from ratepayers the estimated amount of revenues lost by the utility due to the implementation of DSM measures. DSM shareholders' incentives represents the utility company's ability to recover from ratepayers money based on the estimated effectiveness of the programs. Shareholder incentives are calculated by accumulating the avoided capacity and production costs for a single year of implementation (absent evaluation expenses) and 14 residual years of impacts for each program.

### Simple Cycle Combustion Turbine

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

### Single-Train Combined Cycle

See "Combined Cycle" on page A-4.

### Societal Cost Test

Compares the capacity and fuel savings with the utility program costs, plus customer costs and externalities costs while adding back tax credits.

### Spinning Reserve Service

See "Operating Reserves" on page A-17.

### 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 consultant.

### Substation

A substation is a small building or fenced in yard containing switches, transformers, and other equipment and structures for the purpose of adjusting voltage, monitoring 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 homes, schools, and factories.

### Supplemental Reserve Service

See "Operating Reserves" on page A-17.

### Supply Capacity

See "Capacity, Generating" on page A-3.

### Supply-Side Management

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

Supply-side management is controlled by the utilities, whereas demand-side management is controlled by users. (See also "Demand-Side Management" on page A-6.)

## T

### Tariff

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

### Time-of-Use (TOU) 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 Test

This test compares the capacity and fuel savings with the utility program costs plus customer costs.

### Transformer

A transformer is 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.

## U

### Unconstrained Capacity

See “Capacity, Generating“ on page A-3.

### U.S. Green Building Council (USGBC)

The USGBC is a national coalition of leaders from across the building industry working to promote buildings that are environmentally responsible, profitable and healthy places to live and work. Council members work together to develop LEED products and resources, the Green Build annual International Conference and Expo, policy guidance, and educational and marketing tools that support the adoption of sustainable building.

### Utility Cost Test

Compares utility costs and fuel and capacity with utility program costs. Values greater than one indicate that the life-cycle fuel and capacity savings exceed the lifecycle program costs. Values greater than one indicate that the net present value of revenue requirements will be reduced.

### Utility-Earned Incentives
Costs in the form of incentives paid to the utility for achievement in consumer participation in DSM programs. These financial incentives are intended to influence the utility's consideration of DSM as a resource option by addressing cost recovery, lost revenue, and profitability.

## V

### Volt
A volt is a unit of electrical pressure. It measures the force or push of electricity. Volts represent pressure, correspondent to the pressure of water in a pipe. A volt is the unit of electromotive force or electric pressure analogous to water pressure in pounds per square inch. It is the electromotive force which, if steadily applied to a circuit having a resistance of one ohm, will produce a current of one ampere. (See also "Watt" on page A-24.)

### Voltage
Voltage is a measure of the force of moving energy.

## W

### Watt
A watt is a basic electrical unit of power. This term is commonly used to rate appliances using relatively small amounts of electricity. Wattage is stamped on light bulbs and all appliances. There is a mathematical relationship between watts, volts, and amps which is expressed as:

$$\text{Watts} = \text{Amps} \times \text{Volts}$$

For example: a 120 volt, 15 amp circuit carries 1,800 watts. (See also "Amp" on page A-2 and "Volt" on page A-24.)

### Weighting and Ranking
A valuing system that uses estimates derived from other economic methodologies and expert judgment: weights are assigned to emission; discharges and releases are based on their relative impacts. These combined values yield a total score for each resource alternative that allows for an overall ranking of all alternatives. With the focus on the relative impacts of different resources, weighting and ranking facilitates consensus and helps to assure that more comprehensive thinking has gone into the overall assessment.

# Appendix B: Acronyms

The acronyms used throughout the 2013 Integrated Resource Plan Report, as well as in past IRP reports. Some acronyms are included to simply give a more complete understanding of electricity, electric utilities, and energy generation.

## A

| | |
|---|---|
| A/C | Air Conditioning |
| AFBC | Atmospheric Fluidized Bed Coal |
| AFUDC | Allowance for Funds Used During Construction |
| AG | Advisory Group |
| AOS | Adequacy of Supply |
| APWRR | Accumulated Present Worth of Revenue Requirements |

## B

| | |
|---|---|
| B/C | Benefit/Cost ratio |
| BACT | Best Available Control Technology |
| BIA | Building Industries Association |
| BPL | Broadband over Power Lines |
| Btu | British Thermal Unit |

## C

| | |
|---|---|
| C&I | Commercial and Industrial |
| CAP | Community Action Programs |
| CC | Combined-Cycle |
| CFL | Compact Fluorescent Lamp |
| CHP | Combined Heat and Power |
| CICR | Commercial and Industrial Customized Rebate |
| CIDLC | Commercial and Industrial Direct Load Control |
| CIDP | Commercial and Industrial Dynamic Pricing |
| CIEE | Commercial and Industrial Energy Efficiency |
| CINC | Commercial and Industrial New Construction |
| CIP | Campbell Industrial Park |
| CO | Carbon Monoxide |
| $CO_2$ | Carbon Dioxide |
| CPP | Critical Peak Pricing |
| CT | Combustion Turbine |

## D

| | |
|---|---|
| D&O | Decision and Order |
| DBEDT | Department of Business, Economic Development, and Tourism |
| DER | Distributed Energy Resources |
| DG | Distributed Generation |
| DG/CHPTC | Distributed Generation/Combined Heat and Power Technical Committee |
| DLC | Direct Load Control |
| DLNR | Department of Land and Natural Resources |
| DOD | United States Department of Defense |
| DOE | United States Department of Energy |
| DR | Demand Response |
| DSM | Demand-Side Management |
| DSTC | Demand-Side Technical Committee |
| DTCC | Dual-Train Combined Cycle |
| DTCT | Dual-Train Combustion Turbine |
| DTST | Dual-Train Steam Turbine |

## E

| | |
|---|---|
| ECM | Energy Efficiency Measure |
| EE | Energy Efficiency |
| EEPS | Energy Efficiency Portfolio Standard |
| EER | Energy Efficiency Ratio |
| EFOR | Equivalent Forced Outage Rate |
| EIA | Energy Information Agency |
| EIS | Environmental Impact Statement |
| EM&V | Evaluation Measurement and Verification |
| EMS | Energy Management System |
| EOTP | East Oahu Transmission Project |
| EPA | United States Environmental Protection Agency |
| ESH | Energy Solutions for Home |
| ESP | Electrostatic Precipitator |

## F

| | |
|---|---|
| FOR | Forced Outage Rate |

## G

| | |
|---|---|
| GEM | General Equilibrium Model |
| GHG | Greenhouse Gases |
| GSP | Gross State Product |
| GW | Gigawatt (1,000,000,000 Watts) |
| GWh | Gigawatt-hour |

## H

| | |
|---|---|
| HECO | Hawaiian Electric Company, Inc |
| HELCO | Hawaii Electric Light Company, Inc |
| HFC | Hydrofluorocarbon |
| HRD | Hawaii Renewable Development |
| HRS | Hawaii Revised Statute |
| HVAC | Heating Ventilation and Air Conditioning |

## I

| | |
|---|---|
| IE | Independent Entity |
| IO | Input-Output |
| IPP | Independent Power Producers |
| IRP | Integrated Resource Plan |
| ITC | Integration Technical Committee |

## K

| | |
|---|---|
| kV | Kilovolt (1,000 volts) |
| kW | Kilowatt (1,000 Watts) |
| kWh | Kilowatt-hour |

## L

| | |
|---|---|
| LED | Light Emitting Diode |
| LFTC | Load Forecasting Technical Committee |
| LM | Load Management |
| LNG | Liquefied Natural Gas |
| LOLH | Loss Of Load Hours |
| LOLP | Loss of Load Probability |
| LSFO | Low Sulfur Fuel Oil |
| LSIFO | Low Sulfur Industrial Fuel Oil |

## M

| | |
|---|---|
| MAA | Multi-Attribute Analysis |
| MAP | Maximum Achievable Potential |
| MECO | Maui Electric Company, Ltd |
| MBtu | Thousand British Thermal Unit (1,000 Btu) |
| MMBtu | Million British Thermal Unit (1,000,000 Btu) |
| MSFO | Medium Sulfur Fuel Oil |
| MSW | Municipal Solid Waste |
| MW | Megawatts (1,000,000 Watts) |
| MWh | Megawatt-hour |

## N

| | |
|---|---|
| NEM | Net Energy Metering |
| NERC | North American Electric Reliability Council |
| NOx | Nitrogen Oxide |
| NREL | National Renewable Energy Laboratory |

## O

| | |
|---|---|
| O&M | Operation and Maintenance |

## P

| | |
|---|---|
| PBFA | Public Benefits Fee Administrator |
| PBR | Performance Based Ratemaking |
| PFC | Perfluorocarbon |
| PGV | Puna Geothermal Ventures |
| PM10 | Particulate Matter under 10 microns |
| PPA | Purchased Power Agreement |
| PSH | Pumped Storage Hydro |
| PTI | Power Technologies, Inc. |
| PUC | Hawaii Public Utilities Commission |
| PV | Photovoltaic |
| PW | Present Worth |
| PWRR | Present Worth of Revenue Requirements |

## R

| | |
|---|---|
| RCEA | Residential Customer Energy Awareness |
| RDLC | Residential Direct Load Control |
| RE | Renewable Energy |
| REEPS | Residential End-use Energy Planning System |
| REWH | Residential Efficient Water Heating |
| RFD | Refuse-Derived Fuel |
| RIM | Rate Impact Measure |
| RLI | Residential Low Income |
| RNC | Residential New Construction |
| RPS | Renewable Portfolio Standard |
| RWHE | Residential Water Heating Existing |
| RWHN | Residential Water Heating New |

## S

| | |
|---|---|
| SC | Societal Cost |
| SCCT | Simple-Cycle Combustion Turbine |
| SCR | Selective Catalytic Conversion |
| SEER | System Energy Efficiency Ratio |
| SNG | Synthetic Natural Gas |
| SOx | Sulfur Oxide |
| SRO | Supply-Side Resource Option |
| SSTC | Supply-Side Technical Committee |
| ST | Steam Turbine |
| STIG | Steam Injection Gas turbine |
| SWH | Solar Water Heater |

## T

| | |
|---|---|
| T&D | Transmission and Distribution |
| TOU | Time-of-use |
| TRC | Total Resource Cost |

## U

| | |
|---|---|
| UC | Utility Cost |
| UHERO | University of Hawaii Economic Research Organization |
| UIF | Unit Information Form |
| ULSD | Ultra Low Sulfur Diesel |

## V

| | |
|---|---|
| VAR | Volts-Amperes Reactive |
| VOC | Volatile Organic Compounds |

## W

| | |
|---|---|
| W/H | Water Heater |
| WECC | Western Electric Coordinating Council |

W

# Appendix C:
# Commission Documents

The Hawaii Public Utilities Commission (Commission) issued four orders under two dockets that initiated and outlined the IRP process. These documents are:

- A Framework for Integrated Resource Planning (revised)
- Initiating HECO Companies' Integrated Resource Planning Process
- Establishing the Advisory Group for the HECO Companies' Integrated Resource Planning Process
- Identifying Issues and Questions for the Hawaiian Electric Companies' Integrated Resource Planning Process
- Amending Procedural Schedule for the Hawaiian Electric Companies' Integrated Resource Planning Process

This appendix contains a brief description of each document together with the actual document issued by the Commission

# CONTENTS

# Overview

Every docket issued by the Commission contains three main areas of information:

**Details:** The names, titles, firms, and organizations of the Applicant Contact for the docket, the Parties to which the docket applies, Intervenors (people who respond to the docket), and other Participants.

**Dates:** The start and end data of all hearings on the docket.

**Documents:** The responses, comments, letters, motions, notices, statements, and other documents submitted by the Commission, the Parties, and the Intervenors.

The four major documents surrounding the 2013 IRP process were issued by the Commission under two numbered dockets (the first four digits in the docket number refer to the year of issuance):

- Docket Number 2012-0036: Instituting a Proceeding to Investigate Proposed Amendments to the Framework for Integrated Resource Planning
- Docket Number 2009-0108: Instituting a Proceeding Regarding Integrated Resource Planning

All of the information posted about these dockets can be viewed on the Commission's web site, in the Document Management System. Simply enter the docket number into the search box.

# Documents

Four Commission documents directly affect the IRP process.

## A Revised Framework for Integrated Resource Planning

Docket Number 2009-0108, *Decision and Order*, filed 14 March 2011, and Exhibit A: *A Framework for Integrated Resource Planning*. This order issued a revised Framework for Integrated Resource Planning (IRP) which states the goal of the Companies' IRP process. The revised IRP Framework includes scenario planning as a new tool for the Companies' development of its Action Plan.

**A FRAMEWORK FOR INTEGRATED RESOURCE PLANNING**
March 9, 1992
Revised: March 14, 2011

**STATE OF HAWAII**
**PUBLIC UTILITIES COMMISSION**

Exhibit A

# TABLE OF CONTENTS

STATE OF HAWAII
PUBLIC UTILITIES COMMISSION

A FRAMEWORK FOR INTEGRATED RESOURCE PLANNING

March 9, 1992
Revised: March 14, 2011

I. Definitions

Unless otherwise clear from the context, as used in this framework:

"Action Plan" means an implementation plan and schedule for the specific actions, resource options, and programs to be executed by the utility to serve its customers' future energy needs and requirements in a manner consistent with the framework. The Action Plan covers the first five (5) years of the twenty (20) year horizon based on the Scenarios analyzed.

"Advisory Group" means the collection of individuals, selected by the Commission from public and private entities and the general public, who will contribute to the utility's integrated resource planning process.

"Commission" means the State of Hawaii Public Utilities Commission.

"Consumer Advocate" means the Division of Consumer Advocacy of the Department of Commerce and Consumer Affairs.

"Demand-side management" means actions or measures designed to influence utility customer uses of energy to produce desired changes in demand. It includes, but may not be limited to, conservation, load management, energy efficiency, and renewable displacement or offset technologies.

"Independent Entity" means the person or entity selected by the Commission to provide unbiased integrated resource planning process oversight.

"Integrated Resource Planning Report" means the entire filing submitted by the utility pursuant to Section IV.D.1 below.

"Objective" means a statement of the end result, product, or condition desired, for the accomplishment of which a course of action is taken.

"Public Benefits Fee Administrator" or "PBF Administrator" means the third-party administrator contracted by the Commission to operate and manage energy efficiency programs in accordance with Hawaii Revised Statutes Chapter 269, Part VII (Public Benefits Fee), and any other applicable laws, rules, and Commission decision(s).

"Resource Plan" means a set of resources, programs, or actions over the twenty (20) year planning horizon resulting from the analyses performed for the Scenarios developed during the integrated resource planning process governed by this framework.

"Scenarios" means a manageable range of possible future circumstances or set of possible circumstances reflecting potential energy-related policy choices, uncertain circumstances, and risks facing the utility and its customers, which will be the basis for the plans analyzed. A Scenario may not consist of a particular project.

"Supply-side" means resources designed to supply power into the utility system.

"Utility" means Hawaiian Electric Company, Inc., Maui Electric Company, Limited, Hawaii Electric Light Company, Inc., Kauai Island Utility Cooperative, and The Gas Company and their successors in interest, as applicable.

II. Goal and Governing Principles

A. Goal of Integrated Resource Planning

The goal of integrated resource planning is to develop an Action Plan that governs how the utility will meet energy objectives and customer energy needs consistent with state energy policies and goals, while providing safe and reliable utility service at reasonable cost, through the development of Resource Plans and Scenarios of possible futures that provide a broader long-term perspective.

B. Governing Principles (Statements of Policy)

1. The development of Scenarios, Resource Plans and the Action Plan is the responsibility of each utility. The utility shall develop Resource Plans and an Action Plan in consultation with Advisory Group(s), the public, and the Independent Entity, subject to the oversight and approval of the Commission.

2. Resource Plans and the Action Plan shall comport with applicable federal, state, and county laws, formally adopted state and county plans, and other applicable administrative and regulatory requirements.

3. Resource Plans and the Action Plan shall be developed upon consideration and analyses of the short and long-term costs, effectiveness, benefits, and risks of all appropriate, available, and feasible resource options and the adequacy and reliability of energy services.

4. Resource Plans and the Action Plan shall consider the plans' impacts on the utility's customers, the environment, culture, community lifestyles, the State's economy, and society.

5. Resource Plans and the Action Plan shall consider the utility's financial integrity, available sources of capital, ownership structure, size, and physical capability.

6. Integrated resource planning shall, where appropriate and applicable, consider governmentally established energy policies in effect at that time.

7. Integrated resource planning shall be an open and transparent public process that provides opportunities for public participation and feedback and creates broad-based awareness of the complex and sometimes conflicting objectives and issues the utility and the Commission must resolve.

8. Integrated resource planning shall be focused on planning analyses across a range of Scenarios to guide the utility in developing a reasonable and prudent Action Plan.

9. Integrated resource planning shall consider generation, transmission and distribution infrastructure requirements and associate capital and operating costs, including operational changes, grid upgrades, system capacity additions or replacements, and technological advances.

10. The utility is entitled to recover all appropriate and reasonable integrated resource planning and implementation costs, as approved by the Commission.

III. Roles

A. Commission

1. The Commission's responsibility is to determine whether the utility's Action Plan is in the public interest and represents a reasonable course for meeting the goal and objectives of integrated resource planning as set forth in this framework.

2. The Commission will select the Independent Entity and the Advisory Group members for each utility's integrated resource planning process.

3. The Commission will review the utility's Scenarios, Resource Plans, Action Plan, and evaluations, and generally monitor the utility's implementation of its Action Plan. Upon review, the Commission shall approve, reject, approve in part or reject in part the Action Plan, or require modifications of the utility's Scenarios, Resource Plans and Action Plan, as applicable.

4. The Commission will ensure that the parties to the utility's integrated resource planning docket shall cooperate in expediting Commission review and any hearings on the utility's Resource Plans and Action Plan. To the extent feasible and applicable, the Commission will render its decision on a utility's Action Plan within six (6) months of the utility's filing of its Integrated Resource Planning Report, unless the Commission decides in its discretion that an evidentiary hearing is warranted in which case the Commission will render its decision shortly after the hearing. The Commission acknowledges that the purpose of the integrated resource planning process is to provide a broad, long-term perspective for future utility planning, and that its review and any approval given to the Action Plan is intended to apply only to more general, high-level planning issues.

5. Timely Commission review, approval, consent, or other action described in this framework, is essential to the efficient and effective execution of this integrated resource planning process. Accordingly, to expedite Commission action in this integrated resource planning process, whenever Commission review, approval, consent, or action is required under this framework (other than the review of a utility's Resource Plans and the review and approval of the Action Plan (as described in Sections III.A.3 and III.A.4 above)), the Commission may do so in an informal expedited process. The Commission hereby authorizes its Chairperson, or the Chairperson's designee (which designee shall not be the Independent Entity, but may be another Commissioner, a member of the Commission staff, a Commission hearings officer, or a Commission-hired consultant), in consultation with other Commissioners, Commission staff, and the Independent Entity, to take any such action on behalf of the Commission.

6. In the event of a pending unresolved dispute, matter, or issue that arises prior to the utility filing its Integrated Resource Planning Report, and after the utility, Independent Entity, and Advisory Group have attempted to resolve that dispute, matter, or issue, the Independent Entity may elect to submit the dispute, matter, or issue to the Commission for resolution, in which event the Commission may use an informal expedited process, as described in Section III.A.5 immediately above, to resolve the dispute, matter, or issue within thirty (30) days. The Commission will serve as an arbiter of last resort, and there shall be no right to hearing or appeal from this informal expedited dispute resolution process. The Commission encourages affected parties to seek to work cooperatively to resolve any dispute, matter, or issue, with the option to seek the assistance of the Independent Entity, who may offer to mediate, but who has no decision-making authority. The Independent Entity shall keep the Commission apprised of issues that arise between or among the parties.

B. Utility

1. The utility is responsible for developing Scenarios and Resource Plans to provide a long-term perspective which will be utilized to guide and develop the Action Plan for near term initiatives, consistent with the goal and objectives set forth in this framework.

2. The utility shall prepare and submit to the Commission, at the time or times specified in this framework, the utility's Resource Plans and Action Plan as contained in its Integrated Resource Planning Report. The Action Plan will be submitted for Commission approval. As timely Commission review is dependent on the utility filing its Integrated Resource Planning Report at the time specified in this framework, no extension of such deadline will be granted except upon a showing of excusable neglect.

3. The utility shall implement the Commission-approved Action Plan once approved by the Commission.

4. The utility shall periodically examine and evaluate its Action Plan, in accordance with the framework and as directed by the Commission.

5. For a utility that is not responsible for administering its own energy efficiency programs and is thus subject to administration by the PBF Administrator, such utility shall work collaboratively with the PBF Administrator to design energy efficiency demand-side management programs for the integrated resource planning process.

C. Independent Entity

1. The Independent Entity's responsibility shall be to provide unbiased oversight of the integrated resource planning process (including the utility's development of Scenarios, Resource Plans, and the Action Plan) in a cost-effective and timely manner.

2. The Independent Entity shall directly report to, take direction from, and be accountable to, the Commission or the Commission's designee. The Independent Entity's responsibilities include:

   a. Advisory. The Independent Entity shall:

      (1) advise the Commission on the status and substantive issues during the integrated resource planning process;

      (2) provide technical expertise and advice to the Commission or its designee regarding planning issues;

      (3) be available to the Commission or its designee on matters relating to compliance with this framework; and

      (4) provide recommendations for improving future planning processes, as appropriate.

   b. Monitoring and Reporting. The Independent Entity shall:

      (1) monitor and report on the integrated resource planning process;

      (2) utilize its best efforts to ensure that the utility is able to meet the deadlines set forth in Section IV.C, and shall notify the Commission or its designee as soon as the Independent Entity is aware that the utility may not be able to meet a deadline set forth in Section IV.C;

      (3) report to the Commission or its designee on the status and evaluation of the integrated resource planning process at

key phases during the process but no less than once per quarter in writing, to enable focused review of the planning process and keep the Commission apprised of key phases. The quarterly reports shall include an informational summary and update of the status of the planning process that is suitable for publication to the general public. The reports should also identify any issues and concerns that have been raised by the Advisory Group, the Utility, or members of the public, and the status of addressing any such issues and concerns;

(4) promptly inform the Commission or its designee regarding any substantial disputes;

(5) consistent with this framework, report immediately to the Commission or its designee any failure of the utility to make available to Advisory Group members and intervenors relevant planning information necessary, in the Independent Entity's discretion, for an independent review and assessment of the planning analysis and proposed resource options; and

(6) certify that the planning process, up to the date of the certification, was conducted consistent with the framework. Each certification shall include such information as may be specified by the Commission and shall be provided to the Commission no later than ten (10) days following the utility's completion of each of the following key phases: establishment of Scenarios to be evaluated, establishment of planning assumptions, end of the analyses resulting in the Resource Plans for the Scenarios, development of the Action Plan, and filing of the Integrated Resource Planning Report. The Commission may require a similar certification for other steps in the process.

c. Facilitating Public Participation and Input. The Independent Entity shall:

(1) chair and develop the agendas for the Advisory Group meetings in coordination with the utility;

(2) facilitate communications and communication protocols between the utility, Advisory Group, and the public; and

(3) ensure that the utility provides consideration to input, guidance, and recommendations from Advisory Group

members and the public that, in the Independent Entity's discretion, merit consideration.

d. The Independent Entity shall have no authority to resolve disputes, but may offer to informally mediate between disputing parties. The Independent Entity may seek to submit a pending unresolved dispute, matter, or issue to the Commission for resolution, pursuant to Section III.A.6.

3. Selection. The Commission shall select the Independent Entity. In doing so, the Commission, at its election, may seek input from the utility and others.

a. The Independent Entity shall be qualified for the tasks the Independent Entity must perform, as evidenced by relevant credentials in energy technology and planning.

b. The Independent Entity shall be impartial and shall not have a conflict of interest with the utility, individual, or entity who potentially stands to gain financially or otherwise from the outcome of the integrated resource planning process of the utility.

4. Contracting. The selection of the Independent Entity shall be subject to a contract with the Commission or its designee setting forth the responsibilities of the Independent Entity. The contract shall provide that the Independent Entity directly report to, take direction from, and be accountable to, the Commission.

D. Consumer Advocate

1. The Consumer Advocate has the statutory responsibility to represent, protect, and advance the interests of the utility's customers. The Consumer Advocate, therefore, has the duty to ensure that the utility's integrated resource planning process and Action Plan promote the interest of the utility's customers and are reasonable and in the public interest.

2. The Consumer Advocate shall be a party to the utility's integrated resource planning docket and a member of any and all Advisory Groups established in the utility's integrated resource planning process. The Consumer Advocate shall also participate in all public hearings and other sessions held in furtherance of the utility's efforts in integrated resource planning.

E. Public Benefits Fee Administrator

1. The PBF Administrator shall participate in Advisory Group meetings, public hearings, and other sessions to support the forecasts of energy efficiency demand-side management programs developed in furtherance of the utility's efforts in integrated resource planning.

2. The PBF Administrator shall work collaboratively with the utility and other stakeholders on new studies and forecasts to determine the technical and economic potential for a broad variety of energy efficiency demand-side management measures within Hawaii.

3. The PBF Administrator shall provide timely information pertaining to energy efficiency demand-side management programs to the utility for use in the integrated resource planning process, including, but not limited to:

   a. In order for the utility to consider resource options and identify planning assumptions for the planning process described in Section IV below, descriptions of the energy efficiency programs that will be considered in development of the Scenarios, Resource Plans, and Action Plan, and projections of the gross and net (of free-riders) energy and demand savings, estimated participant costs, and estimated program budgets, for such energy efficiency programs over the twenty (20) year and five (5) year planning periods to be considered in the development of the Scenarios, Resource Plans, and Action Plan; and

   b. On an annual basis, the expenditures anticipated and actually made, the target group size and level of achievement of energy and demand impacts anticipated and actually attained, and assessments of any substantial differences between original estimates and actual experience by program.

4. Notwithstanding anything to the contrary, for any utility responsible for administering its own energy efficiency programs and thus not subject to administration by the PBF Administrator, this Section III.E and other provisions in this framework specifically pertaining to the PBF Administrator shall not apply to such utility's integrated resource planning process.

F. Advisory Groups

1. Mission Statement. The mission of the Advisory Group is to provide the utility with the benefit of community perspectives by participating in the utility's integrated resource planning process and representing diverse community, environmental, social, political, or cultural interests consistent with this framework's goal.

2. The Advisory Group shall represent interests that are affected by the utility's Resource Plans and that possess the ability to provide significant perspective or useful expertise in the development of the Resource Plans. These entities may include state and county agencies, and environmental, cultural, business, and community interest groups. An Advisory Group should be representative of as broad a spectrum of affected interests as practicable, subject to the limitation that the interests represented should not be so numerous or duplicative as to make deliberations as a group unwieldy.

3. The utility shall consider the input of each Advisory Group, but is not bound to follow the recommendations of any such Advisory Group.

4. Advisory Group meetings shall be held during key phases of the integrated resource planning process, as well as between full integrated resource planning cycles.

5. The utility shall attend Advisory Group meetings chaired by the Independent Entity.

6. Advisory Group members may act as individuals and there is no requirement for group decision-making. However, to the extent possible or practicable, Advisory Group members are encouraged to work collaboratively to attempt to arrive at a consensus on issues.

7. Advisory Group members may request that the Independent Entity seek a response from, or make a recommendation to, the utility concerning any issue relevant to this framework. The Independent Entity may, at its discretion, present these questions or recommendations to the utility as appropriate. The utility shall respond in writing and the Independent Entity shall, in turn, share such response with the Advisory Group members. The Independent Entity shall also provide copies of these questions and recommendations, and the utility's response, in its reports to the Commission.

8. All data reasonably necessary for an Advisory Group to participate in the utility's integrated resource planning process shall be provided by the utility as requested by the Independent Entity, subject to protecting the confidentiality of customer-specific and other confidential or proprietary information.

9. All reasonable out-of-pocket costs incurred by Advisory Group members (other than representatives of governmental agencies, a for-profit entity, or an association of for-profit entities) related to participation in the integrated resource planning process as an Advisory Group member, shall be paid for by the utility, subject to Commission approval. Such costs shall be recovered as part of the utility's cost of integrated resource planning.

G. The Public

1. To encourage and maximize public participation in each utility's integrated resource planning process, opportunities for such participation shall be provided. Participation may be provided through public hearings, meetings or forums, public outreach programs, an opportunity to submit comments, and by way of intervention in Commission proceedings or participation in Advisory Groups as set forth in this framework.

2. The utility is encouraged to conduct public meetings or provide public forums for the purpose of obtaining the input of those in the public who may or may not be represented by a member of, or interests of a member of, the Advisory Group.

IV. The Planning Process

A. Major Steps

There are four major steps in the integrated resource planning process: planning, programming, implementation, and evaluation.

1. Planning is that process in which the utility's needs are identified; the utility's objectives are identified; the assumptions, costs, risks, trends, expected events (if any), and uncertainties are identified or clarified; the Scenarios are developed to reflect possible futures dealing with uncertain circumstances and risks facing the utility and its customers; the utility's system needs (such as, in the case of an electric utility, generation, transmission and distribution needs) are identified; the cost, effectiveness, and benefits of each resource option, program, or action under each Scenario are determined; and analyses conducted are explained. The product of this process is the utility's Resource Plans. The planning horizon for Resource Plans is twenty (20) years. Unless otherwise ordered by the Commission, the twenty (20) year period shall begin on January 1 of the calendar year set by the schedule specified in Section IV.C.4 below.

2. Programming is that process by which the utility's Resource Plans are evaluated and resources, programs, and actions from one or more Resource Plans are scheduled for implementation over the first five (5) years of the twenty (20) year planning period through the development of an Action Plan. In this process, a determination is made as to: the options selected to be implemented; the order in which the selected options are to be implemented; the phases or steps in which each option is to be implemented; the expected target group and the annual size of the target group or annual target level of penetration of demand-side management programs; the supply-side system additions and potential resource procurement method; relevant transmission system additions; and the estimated annual expenditures required by the utility to support implementation of the options. The result of this process is the Action Plan. The Action Plan represents a strategy and timetable/schedule for implementation of the options. The Action Plan may incorporate transmission and distribution projects that the utility has analyzed in any of the utility's separate and distinct general planning processes.

3. Implementation is that process by which the resources, programs, and actions to be implemented are acquired and instituted in accordance with the utility's Action Plan.

4. Evaluation, which occurs between planning cycles, is that process by which the Action Plan is assessed against what was projected in the planning and programming stages of the planning cycle.

10

B. The Planning Cycle

The utility shall conduct a major review of its integrated resource planning process every three (3) years. In such a review, a new twenty (20) year time horizon shall be adopted, the integrated resource planning process repeated, and the utility's Action Plan fully re-analyzed. Utilities that are affiliated may conduct their integrated resource planning in coordination with each other or in parallel, since the integrated resource planning for one island utility may affect the choices and actions of an affiliated utility on another island. The timing of the utility's integrated resource planning cycles shall be in accordance with dates established by the Commission.

C. The Docket

1. Each planning cycle for a utility shall commence with the issuance of a Commission order opening a docket for the utility's integrated resource planning process. The docket will be considered an investigatory proceeding, and not a contested case proceeding, and will serve as a repository for the requisite filings, a forum for resolution of approval requests and disputes, and Action Plan approval in the manner and under the circumstances described in the framework.

2. The docket will remain open and be maintained throughout the planning cycle for the filing of documents, the resolution of procedural disputes, and other purposes related to the utility's Resource Plans and Action Plan.

3. Within sixty (60) days after the opening of the docket, the Independent Entity shall be selected and retained by the Commission.

4. Within ninety (90) days after the opening of the docket, the utility shall prepare and file with the Commission, in consultation with the Consumer Advocate and the Independent Entity, a schedule that it intends to follow in its integrated resource planning process.

5. Within one hundred and twenty (120) days after the opening of the docket, the Advisory Group(s) shall be established by the Commission. The Commission, with the assistance of the Independent Entity, shall openly solicit, in each county in which the utility provides service or conducts utility business, representatives of public and private entities to serve on an Advisory Group to provide input to the utility in its integrated resource planning process. Nothing herein prevents the Commission from seeking assistance in conducting its solicitation. Subject to Commission approval, a separate Advisory Group may be formed for each stage of the integrated resource planning process.

6. If time permits, the utility may conduct public meetings or provide public forums at various phases of its integrated resource planning process for the purpose of obtaining the input of those in the public who are not or may not be represented by a member of, or the interests of a member of, the Advisory Group.

7. Unless extended for excusable neglect by Commission order, the utility shall file its Integrated Resource Planning Report and associated Action Plan within one year after the selection of the Advisory Group(s) by the Commission. To encourage public awareness of the filing of the utility's proposed Action Plan, a copy of the Action Plan and the supporting analyses shall be made available for public review at the Commission's office and to the extent applicable, at the office of the Commission's representative in the county serviced by the utility. The utility shall also post electronic copies of the Action Plan and the supporting analyses online on its website. The utility shall note the availability of the documents for public review at these locations in its published notice. During the pendency of the docket, the utility shall make copies of the executive summary of the Action Plan available to the general public, upon request, at no cost, except the cost of duplication.

8. Within seven (7) days of the filing of its Integrated Resource Planning Report, the utility shall cause to be published in a newspaper of general circulation in the State a notice informing the general public that the utility has filed its Integrated Resource Planning Report and proposed Action Plan for the Commission's approval.

9. Applications to intervene or to participate without intervention shall be filed with the Commission not later than twenty (20) days after the publication by the utility of the notice described in Section IV.C.8 above informing the general public of the filing of its Integrated Resource Planning Report and proposed Action Plan, notwithstanding the opening of the docket before such publication. Intervenor or participant status shall continue through the life of the docket unless the intervenor or participant withdraws or is dismissed by the Commission.

10. Upon the filing of a utility's Integrated Resource Planning Report, the Commission may conduct a public hearing or hearings for the purpose of securing public input on the utility's proposal. The Commission may also conduct such informal public meetings as it deems advisable.

11. To the extent feasible and applicable, the Commission will render its decision on a utility's application for approval of its Action Plan within six (6) months of the utility's filing of its Integrated Resource Planning Report, unless the Commission decides in its discretion that an evidentiary hearing is warranted in which case the Commission will render its decision shortly after the hearing.

D. Submissions to the Commission

1. The utility shall file its Integrated Resource Planning Report as follows.

   a. The utility shall include in its filing a full and detailed description of the key phases of its integrated resource planning process. The utility shall fully describe, as applicable:

(1) The planning objectives and principal issues that have been used and considered to provide guidance or be the basis for decisions made in the integrated resource planning process.

(2) The Scenarios developed to reflect possible futures dealing with uncertain circumstances and risks facing the utility and its customers, which were used as the basis for the Resource Plans analyzed, including the rationale used to select and formulate the various Scenarios.

(3) The assumptions and the basis of the assumptions underlying the Scenarios and Resource Plans, and the key drivers of uncertainty that may have a significant impact on the assumptions.

(4) The risks, trends, expected events (if any), and uncertainties associated with the Scenarios and Resource Plans.

(5) The forecasts made and any assumptions underlying the forecasts.

(6) The resource options or mix of resource options considered in the development of the Resource Plans for the Scenarios.

(7) The needs of the utility system, such as identification of supply-side or transmission additions. The proposed procurement method for resources should be identified.

(8) A detailed description of the analysis or analyses upon which the Resource Plans and Action Plan are based, the data, the source of the data, and the methodologies used, which may include without limitation: revenue requirement calculations, estimates of the potential impact of the plans on rates, bills and customer energy use, external costs, identification of the risks and benefits, renewable portfolio standards and energy efficiency portfolio standards compliance, reliability impacts, and sensitivity analysis.

b. The utility shall include in its filing a full and detailed description of the Action Plan, which shall fully describe, among other things:

(1) An implementation schedule that shows the resources, programs, actions, or phases of resources, programs, or actions to be implemented in each of the five (5) years of the Action Plan.

(2) The estimated expenditures required by the utility to support implementation of each option or phase of such option.

(3) The steps anticipated in order to realize and implement the supply-side and demand-side resources included in the schedule.

(4) How the Action Plan was developed based on the Resource Plans and Scenarios analyzed.

c. The submissions should be simply and clearly written and, to the extent feasible and practicable, in non-technical language. Charts, graphs, and other visual devices may be utilized to aid in understanding the Scenarios, Resource Plans, the Action Plan, and the analyses made by the utility. The utility shall provide an executive summary of the Scenarios, Resource Plans, analyses, and Action Plan, and shall appropriately index its submissions.

2. The utility shall submit an evaluation report as follows.

a. The utility shall submit a minimum of one evaluation report between integrated resource planning cycles, preferably in the middle of the three (3) year period set forth in Section IV.B above.

b. The PBF Administrator shall provide timely information pertaining to the status of, and any updates to, the energy efficiency demand-side management programs being implemented. This shall include, but not be limited to: descriptions of the energy efficiency programs as actually implemented, identification of any changes to the projections of the gross and net (of free-riders) energy and demand savings, estimated participant costs, and updates to the estimated program budgets. To the extent the PBF Administrator has provided a report or submission on the relevant information to the Commission, the utility may incorporate such report or submission by reference in order to avoid duplication of reporting efforts or information.

c. The utility shall include in its evaluation report an assessment of the continuing validity of the forecasts and the assumptions upon which its Resource Plans and Action Plan were fashioned, and update these assumptions as appropriate.

d. The utility shall also include for each option or phase of each option included in the Action Plan, for the time period covered by the evaluation report, a comparison of:

(1) The expenditures anticipated to be made and the expenditures actually made.

(2) The level of achievement of energy and demand impacts anticipated and the level actually attained.

(3) The target group size or level of penetration anticipated for each demand-side management program and the size or level actually realized.

14

(4) The effects of program implementation anticipated and the effects actually experienced.

e. The utility shall provide an assessment of all substantial differences between original estimates and actual experience and what the actual experience may portend for the future (e.g., the identification of any updates to the resources, programs, or actions the utility plans to implement as it relates to the Action Plan). Such assessment shall include the basis for any changes to the then-current Action Plan and a description of any analyses conducted.

3. The Action Plan approved by the Commission shall provide guidance for utility expenditures for capital projects, power purchase arrangements, and any applicable demand-side management programs. However, notwithstanding approval of the Action Plan: (a) a capital project, an expenditure for any capital project, and any portion of the Action Plan or program, project, or action contained therein shall be submitted by separate application to the Commission for review to the extent specifically required under applicable Commission statutes or rules, including, but not limited to, paragraph 2.3.g.2 of General Order No. 7, General Order No. 9, and Hawaii Revised Statutes Chapter 269 (e.g., Hawaii Revised Statutes §§ 269-17, 269-19, 269-27.2, and 269-27.6), as amended or may be amended from time to time; and (b) no obligation under any power purchase arrangement shall be undertaken, and no expenditure for any specific demand-side management program included in the Action Plan shall be made, without prior Commission approval.

4. The utility may file separate application submittals with the Commission before the Commission issues a decision approving the Action Plan and the Commission may review such individual applications in parallel with the review of the Action Plan. The utility shall explain why it is necessary or prudent for the utility to file its application prior to the approval of the Action Plan.

5. The utility may integrate transmission and distribution projects into its Resource Plans and Action Plan.

6. The Resource Plans and Action Plan resulting from this framework are intended to be dynamic, and not fixed and unchanging. The Resource Plans and Action Plan are intended to be flexible enough to account for changes in planning assumptions, forecasts, and circumstances. This will allow for major decisions regarding the implementation of options (both supply-side and demand-side resources) to be made incrementally, based on the best and current available information at the time decisions are made. The Resource Plans shall identify what information is critical to the decision-making process, and also identify when the strategic decisions need to be made.

7. Current Action Plan

    a. Each utility shall maintain a current, up-to-date Action Plan.

    b. To revise or amend its Action Plan, the utility shall provide notice of any revisions or amendments to the Action Plan to the Commission, the Independent Entity and the Advisory Group(s) through a filing in the docket with an opportunity for comment within fourteen days of the date of filing. In its notice filing, the utility shall provide the following information:

        (1) the extent to which any proposed actions are not consistent with the approved Action Plan;

        (2) the extent to which any proposed actions would affect any other aspects of the approved Action Plan; and

        (3) whether the proposed actions and resulting associated changes in the Action Plan are reasonable and in the public interest.

    If no Commission action is taken on the utility's notice filing within thirty (30) days of the notice filing, the revisions or amendments are deemed approved. The Commission, however, at its option may suspend the filing for further Commission review.

V. Planning Guidelines

A. Purpose of the Planning Guidelines

The planning guidelines shall govern the process and development of each utility's Scenarios, Resource Plans and Action Plan to the extent applicable. The planning guidelines are intended to ensure that the planning process is useful for planning and regulatory purposes and is supported by sufficient, inclusive, and sound analysis.

B. General Planning Guidelines.

1. The implementation of planning is the responsibility of each utility provided that each utility shall:

    a. comply with the planning guidelines and other provisions identified in this framework and any specific orders by the Commission; and

    b. consider the input, comments and suggestions provided by Advisory Group members and the general public, to the extent feasible.

16

2. Analysis supporting the Integrated Resource Planning Report shall:

   a. provide meaningful support for the reasonableness of the Action Plan; and

   b. address those issues and concerns identified by the Advisory Group(s) and the general public that the Independent Entity determines have merit, to the extent feasible.

C. Specific Planning Guidelines

The process for developing utility Scenarios, Resource Plans and Action Plan, to the extent applicable, shall include the following.

1. Identification of principal issues.

   a. The utility, with input from the Advisory Group(s), shall identify and define the principal issues to be addressed in the planning process.

   b. At the beginning of each planning review cycle the Commission may specify questions and issues that the specific round of planning analysis and the resulting plans and Action Plan should address.

2. Characterization of existing system and conditions. The utility should provide a description of the existing utility system, any operational issues and existing constraints.

3. Identification of uncertainties and factors that affect utility planning.

4. Identification of planning objectives.

   a. At the outset of the planning process, the utility, with input from its Advisory Group, shall identify planning objectives that can be used to provide guidance and basis for decisions to be made throughout the planning process. The Commission may specify planning objectives or criteria to be considered in the planning process.

   b. Objectives shall be used to provide guidance or the basis for decision-making throughout the integrated resource planning process.

   c. The utility should provide measures of the achievement of the planning objectives to the extent practicable.

   d. To the extent practicable, the Integrated Resource Planning Report shall summarize how the planning objectives were used throughout the process.

5. Determination of planning Scenarios and forecasts.

   a. Each utility, with input from its Advisory Group(s), shall develop a manageable range of Scenarios to guide utility planning.

   b. The utility, with input from its Advisory Group(s), shall develop a range of forecasts of the necessary planning analysis parameters over the planning time frame. Forecasts may be developed for each planning Scenario, may be developed based on the assumptions associated with each Scenario or may be based on independent criteria as may be appropriate for and consistent with the planning analysis. Forecasts assumptions may be developed before or after Scenarios are developed.

6. Identification of resource options.

   a. The utility shall consider all appropriate, available, and feasible resource options in the development of the reasonable range of Scenarios and associated possible futures. Options may include: energy efficiency demand-side management programs; demand response and load management programs; distributed generation resources; smart grid measures; measures to mitigate constraints to the incorporation of as available or variable renewable generation resources; alternative renewable fuels; energy storage resources; alternative measures to provide ancillary services; and retirement or protective storage of existing generation units and related facilities.

   b. The utility shall include among the resource options to be considered in Section V.C.6.a immediately above, the options currently in use, promoted, planned, or programmed for implementation by the utility.

   c. The utility shall also include among the resource options to be considered in Section V.C.6.a above, the resource options that are or may be supplied by persons or entities other than the utility.

   d. The utility shall, upon review of the range of Scenarios to be analyzed, screen out those options that are not reasonably appropriate to Hawaii, are not reasonably expected to be available to address the identified range of Scenarios, or are clearly infeasible. The utility, with the input of the Advisory Group(s), may establish such other criteria for screening out clearly infeasible options.

   e. The utility shall identify the assumptions underlying any resource option or the cost or benefit of any option or any analysis performed.

   f. The utility shall also identify risks and uncertainties associated with resource options.

g. The utility shall further identify any technological limitations, infrastructural constraints, legal and governmental policies or requirements, and other constraints that impact any option or the utility's analysis.

h. The utility shall consider measures, strategies, and programs to address limitations and constraints that may negatively impact its ability to achieve the objectives identified.

7. Models.

a. The utility may utilize any technically or commercially reasonable model or models in performing the technical analyses required to develop Resource Plans for the Scenarios developed.

b. Each model used shall be fully described and documented.

c. The Independent Entity, an Advisory Group member representing that group (as determined by the Independent Entity) and the Commission or its designee may review a utility's modeling program, documentation and input, output, and diagnostic files, provided that such person (i) certifies in writing that it is not a competitor of the utility or the company providing the modeling program; and (ii) executes any reasonable, appropriate confidentiality or other agreements required by the utility or the model vendor.

8. Analyses.

a. The utility, with input from its Advisory Group(s), shall develop Scenarios to guide the utility's integrated resource planning process. Such Scenarios shall reflect possible futures dealing with uncertain circumstances and risks facing the utility, other stakeholders, and the utility's customers.

b. The utility, with input from its Advisory Group(s), shall develop a reasonable scope and number of Resource Plans for the Scenarios developed. One or more Resource Plans may be developed for each Scenario. A sufficient number of Resource Plans will be developed and analyzed to ensure that the results of the utility planning process are meaningful and will address the scope of the identified issues. However, the number and scope of Resource Plans developed and analyzed will consider the limitations of utility planning resources and the planning process schedule.

c. The utility shall analyze all options in the Resource Plans on a consistent and comparable basis. The utility may use any reasonable and appropriate means to assure that such equal consideration is given.

d. In addition to addressing risks and planning uncertainties through consideration of Scenarios, the utility may utilize sensitivity analysis to determine the extent to which uncertainties affect analysis results and conclusions.

e. Notwithstanding the above, the utility shall compare the options on a present value basis. For this purpose, the utility shall discount the estimated annual costs (and benefits, as appropriate) using reasonable and appropriate discount rates, assumptions and procedures. The utility shall fully explain the rationale for its choice of discount rates, assumptions and procedures.

f. The analyses shall identify the resources to be acquired through available procurement mechanisms. The analyses shall consider and identify, to the extent feasible, those resources which the utility proposes to acquire through its available resource procurement mechanisms, including any competitive bidding, feed-in tariff, bilateral contract negotiation, net energy metering, demand response tariffs, or other approved, applicable, or proposed procurement mechanisms.

g. The utility shall conduct planning analyses to determine, evaluate, and compare the merits of the resources, programs, and actions in the Resource Plans.

h. In its integrated resource planning process, the utility may use information, data, analyses and results from relevant planning studies conducted by the industry, utility, or others, as part of other regulatory dockets or general planning processes. The analyses conducted as part of the integrated resource planning process may in turn be used in other general planning processes or studies.

9. Determination of Resource Plans.

The utility shall rank or descriptively prioritize the final Resource Plans (i.e., preferred plan, secondary plan, parallel plan, contingency plan) based upon such criteria as it may establish with the advice of its Advisory Group.

10. Determination of Action Plan.

a. Based on its analyses, the utility shall develop its Action Plan, which shall identify those resource options or the mix of resource options or specific actions that the utility anticipates will enable it to reasonably attain the planning objectives in light of the uncertainty regarding the planning Scenarios.

b. The utility shall review the Resource Plans to identify common themes, resources, programs, and actions that demonstrate robust value to balance costs and risks, and provide the greatest value and flexibility across as many of the evaluated Scenarios and Resource Plans as reasonably practicable.

c. The Action Plan may contain elements of resources, programs, and actions from one or more of the identified Resource Plans. The proposed Action Plan may not be the least expensive plan and may include resource options and contingency measures to reasonably address the uncertain future circumstances identified in the various planning Scenarios.

d. The Action Plan shall identify the intended means of procurement or implementation of each resource, action, or program included in the Action Plan. The Action Plan shall specify which resources are proposed to be exempt or subject to waivers from requirements of any applicable competitive bidding framework or other resource acquisition mechanism approved by the Commission.

e. The Action Plan shall specify the proposed scope of any request for proposal for any specific generation resource or block of generation resources that the Resource Plans state will be subject to competitive bidding, including, but not limited to, the size, timing, and operational characteristics and other preferred attributes of the generation resource or block of generation resources.

VI. Other Matters

A. Cost Recovery

The utility shall be entitled to recover its integrated resource planning and implementation costs that are reasonably incurred as determined by the Commission. The utility shall record costs associated with its integrated resource planning process in separate accounts to allow review of the actual costs incurred as compared to the forecasted costs presented in each rate case or other equivalent cost-recovery mechanism.

B. Intervenor Funding

1. Upon the issuance of the Commission's final order on the utility's Action Plan or any amendment thereto, the Commission may grant an intervenor or participant (other than a governmental agency, a for-profit entity, or an association of for-profit entities) recovery of all or part of the intervenor's or participant's direct out-of-pocket costs reasonably and necessarily incurred in intervention or participation. Any recovery and the amount of such recovery shall be in the sole

discretion of the Commission. Any intervenor or participant (who plans to seek intervenor funding) must file a budget with the Commission within thirty (30) days after intervention or participation is granted to that intervenor or participant, setting forth:

a. The identification of specific areas or issues to which the intervenor or participant plans to provide a contribution;

b. The estimated cost of intervention or participation to be incurred by the intervenor or participant;

c. The level of funding expected to be funded from other sources; and

d. The net amount of the estimated cost of intervention or participation that the intervenor or participant plans to seek recovery of from the utility's ratepayers.

2. To be eligible for such recovery:

   a. The intervenor or participant must show a need for financial assistance;

   b. The intervenor or participant must demonstrate that it has made reasonable efforts to secure funding elsewhere, without success;

   c. The intervenor or participant must maintain accurate and meaningful books of account on the expenditures incurred; and

   d. The Commission must find that the intervenor or participant made a substantial productive contribution in assisting the Commission.

3. An intervenor's or participant's books of account shall be subject to audit, and the Commission may impose other requirements in any specific case.

4. Such allowance may be made only upon the application of the intervenor or participant within twenty (20) days after the issuance of the Commission's final order, together with justification and documented proof of the costs incurred.

5. The Commission may also provide for periodic recovery of all or part of an intervenor's or participant's direct out-of-pocket costs reasonably and necessarily incurred in its intervention or participation in a docket for approval of a utility's Action Plan, or any amendments to the Action Plan, via periodic installments during the course of the docket. To be eligible for this option, in addition to complying with and meeting the requirements set forth in this Section VI.B.5 (except for the requirement set forth in Section VI.B.4 immediately above), an intervenor or participant shall file a letter request with the Commission seeking approval for periodic cost recovery and shall include in that filing its basis for seeking periodic cost recovery together with its justification and documented proof of the costs incurred.

6. The costs of intervenor or participant funding authorized by the Commission pursuant to this Section VI.B.6 shall be paid for by the utility, subject to recovery as part of its costs of integrated resource planning.

CERTIFICATE OF SERVICE

The foregoing order was served on the date of filing by mail, postage prepaid, and properly addressed to the following parties:

JEFFREY T. ONO
EXECUTIVE DIRECTOR
DEPARTMENT OF COMMERCE AND CONSUMER AFFAIRS
DIVISION OF CONSUMER ADVOCACY
P. O. Box 541
Honolulu, HI 96809

DEAN MATSUURA
MANAGER, REGULATORY AFFAIRS
HAWAIIAN ELECTRIC COMPANY, INC.
P.O. Box 2750
Honolulu, HI 96840-0001

KENT D. MORIHARA, ESQ.
KRIS N. NAKAGAWA, ESQ.
MORIHARA LAU & FONG LLP
Davies Pacific Center
841 Bishop Street, Suite 400
Honolulu, HI 96813

Counsel for KAUAI ISLAND UTILITY COOPERATIVE

TOM KOBASHIGAWA
THE GAS COMPANY, LLC
745 Fort Street, 18th Floor
Honolulu, HI 96813

GREGG J. KINKLEY, ESQ.
DEPARTMENT OF THE ATTORNEY GENERAL
425 Queen Street
Honolulu, HI 96813

Counsel for DBEDT

<u>Certificate of Service</u>
Page 2

LINCOLN S.T. ASHIDA, ESQ.
WILLIAM V. BRILHANTE, JR., ESQ.
MICHAEL J. UDOVIC, ESQ.
DEPARTMENT OF THE CORPORATION COUNSEL
COUNTY OF HAWAII
101 Aupuni Street, Suite 325
Hilo, HI 96720

Counsel for the COUNTY OF HAWAII

BRIAN T. MOTO, ESQ.
MICHAEL J. HOPPER, ESQ.
DEPARTMENT OF THE CORPORATION COUNSEL
COUNTY OF MAUI
200 South High Street
Wailuku, Maui, Hawaii 96793

Counsel for the COUNTY OF MAUI

ALFRED B. CASTILLO, JR., ESQ.
AMY I. ESAKI, ESQ.
MONA CLARK, ESQ.
OFFICE OF THE COUNTY ATTORNEY
COUNTY OF KAUAI
4444 Rice Street, Suite 220
Lihue, HI 96766-1300

Counsel for the COUNTY OF KAUAI

HENRY Q CURTIS
KAT BRADY
LIFE OF THE LAND
76 North King Street, Suite 203
Honolulu, HI 96817

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

Certificate of Service
Page 3

DOUGLAS A. CODIGA, ESQ.
SCHLACK ITO LOCKWOOD PIPER & ELKIND
Topa Financial Center
745 Fort Street, Suite 1500
Honolulu, HI 96813

Counsel for BLUE PLANET FOUNDATION

ISAAC H. MORIWAKE, ESQ.
DAVID L. HENKIN, ESQ.
EARTHJUSTICE
223 South King Street, Suite 400
Honolulu, HI 96813-4501

Counsel for HAWAII SOLAR ENERGY ASSOCIATION

THOMAS C. GORAK, ESQ.
GORAK & BAY, L.L.C.
1161 Ikena Circle
Honolulu, HI 96821

Counsel for MARRIOTTS

DEAN T. YAMAMOTO, ESQ.
SCOTT W. SETTLE, ESQ.
JODI SHIN YAMAMOTO, ESQ.
YAMAMOTO & SETTLE
700 Bishop Street, Suite 200
Honolulu, HI 96813

Counsel for FOREST CITY HAWAII RESIDENTIAL, INC.

H. RAY STARLING
PROGRAM MANAGER
HAWAII ENERGY EFFICIENCY PROGRAM
1132 Bishop Street, Ste. 1800
Honolulu, HI 96813

## Initiating HECO Companies' IRP Process

Docket Number 2012-0036, Order Number 30233: *Initiating HECO Companies' Integrated Resource Planning Process*, filed 01 March 2012. This order formally commenced the IRP process for the Companies.

BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF HAWAII

----- In the Matter of ----- )
)
PUBLIC UTILITIES COMMISSION ) DOCKET NO. 2012-0036
)
Regarding Integrated Resource )
Planning. )
)

ORDER NO. 30233

INITIATING HECO COMPANIES'
INTEGRATED RESOURCE PLANNING PROCESS

FILED
2012 MAR -1 A 11:02
PUBLIC UTILITIES
COMMISSION

BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF HAWAII

| | | |
|---|---|---|
| ----- In the Matter of ----- | ) | |
| | ) | |
| PUBLIC UTILITIES COMMISSION | ) | Docket No. 2012-0036 |
| | ) | |
| Regarding Integrated Resource Planning. | ) | Order No. 30233 |
| | ) | |

INITIATING HECO COMPANIES'
INTEGRATED RESOURCE PLANNING PROCESS

By this Order, the commission commences the Integrated Resource Planning ("IRP") cycle for HAWAIIAN ELECTRIC COMPANY, INC. ("HECO"), MAUI ELECTRIC COMPANY, LIMITED ("MECO") and HAWAII ELECTRIC LIGHT COMPANY, INC. ("HELCO")[1] to examine the IRP Report and Action Plan, to be submitted to the commission, in compliance with the commission's *A Framework for Integrated Resource Planning, Revised March 14, 2011* for electric and gas utilities. This docket is to be followed by commencement of the IRP cycles for the Kauai Island Utility Cooperative and The Gas Company in the near future.

[1]HECO, MECO and HELCO are collectively referred to as the "Hawaiian Electric Companies."

I.

Background

The Hawaiian Electric Companies are required to develop, prepare, and submit an IRP Report and Action Plan to the commission, pursuant to the Framework for Integrated Resource Planning adopted by the commission in In Re Public Util. Comm'n, Docket No. 6617 and revised in In Re Public Util. Comm'n, Docket No. 2009-0108 ("Revised Framework").[2] On March 14, 2011, the commission approved and adopted the Revised Framework to govern energy resource planning by energy utilities in the State of Hawaii. The Revised Framework incorporates for the first time the concept of scenario planning, which is designed to capture variations in planning assumptions and forecasts as well as high

[2]"Integrated Resource Planning Report" and "Action Plan" are defined in the Revised Framework, at 1, to mean:

> "Integrated Resource Planning Report" means the entire filing submitted by the utility pursuant to Section IV.D.1 [of the Revised Framework].
>
> "Action Plan" means an implementation plan and schedule for the specific actions, resource options, and programs to be executed by the utility to serve its customers' future energy needs and requirements in a manner consistent with the framework. The Action Plan covers the first five (5) years of the twenty (20) year horizon based on the Scenarios analyzed.

level planning estimates of the costs and benefits of resource options. In addition, to better ensure a timely and transparent process, the commission incorporated into the Revised Framework an Independent Entity ("IE") to facilitate the IRP process and verify that the process is conducted in a manner consistent with the Revised Framework.[3] The Revised Framework also calls for a more robust Advisory Group, selected by the commission. These elements are expected to improve the quality of IRP process and build community awareness and support in the face of difficult choices that may have to be made to achieve the State's energy goals.

The overall goal of this IRP is to develop an Action Plan that governs how the Hawaiian Electric Companies will meet energy objectives and customer energy of needs of HECO, MECO, and HELCO. It is imperative that the Action Plan be consistent with State energy policies and goals, while providing safe and reliable utility service at reasonable costs. This will require the development of resource plans and scenarios of possible futures that provide a broader long-term perspective.

[3] See Revised Framework, III.C.1, at 5.

II.

Discussion

A.

Roles of the Participants and Procedural Matters

The Revised Framework defines the roles of the commission, the Utility (in this case the Hawaiian Electric Companies), the IE, the Consumer Advocate,[4] the Public Benefits Fee ("PBF") Administrator, the Advisory Group, and the general public.

The commission's primary responsibility is to determine whether the Hawaiian Electric Companies' Action Plan is in the public interest and represents a reasonable course for meeting the goal and objectives of IRP as set forth in the Revised Framework.[5] The commission is required to select the IE within sixty (60) days of publishing this order and the Advisory Group members within one hundred and twenty (120) days of issuing this order.[6] To the extent feasible and applicable, the commission will render its decision on the Hawaiian Electric Companies'

[4]The DEPARTMENT OF COMMERCE AND CONSUMER AFFAIRS, DIVISION OF CONSUMER ADVOCACY ("Consumer Advocate"), is ex officio a party to this proceeding, pursuant to Hawaii Revised Statutes ("HRS") § 269-51 and Hawaii Administrative Rules ("HAR") § 6-61-62(a).

[5]See Revised Framework, III.A.1., at 3.

[6]Id., IV.C.3 and IV.C.5., at 11.

Action Plan within six (6) months of filing of its IRP Report, unless the commission decides in its discretion that an evidentiary hearing is warranted in which case the commission will render its decision shortly after the hearing.[7]

The Hawaiian Electric Companies are responsible for developing scenarios and resource plans for HECO, MECO, and HELCO to provide a long-term perspective which will be utilized to guide and develop the Action Plan for near term initiatives.[8] Within ninety (90) days the publishing of this order the Hawaiian Electric Companies shall prepare and file with the commission, in consultation with the. IE and the Consumer Advocate, the proposed schedule for the development of the IRP.[9] Also, within one year after the commission selection of the Advisory Group, the Hawaiian Electric Companies will file with the commission the IRP Report and Action Plan for HECO, MECO, and HELCO.[10] As timely commission review is dependent on the utility filing its IRP Report at the time specified in this order, no extension of such deadline will be granted except upon a showing of excusable neglect.

---

[7] Id., IV.C.11., at 12.

[8] Id., III.B.1., at 4.

[9] Id., IV.C.4., at 11.

[10] Id., IV.C.7., at 12.

Intervention into this docket will not be ripe until the Hawaiian Electric Companies file their IRP Report and proposed Action Plan with the commission.[11]

The IE shall be responsible for providing unbiased oversight of the IRP process (including the Hawaiian Electric Companies' development of scenarios, resource plans, and the Action Plan) in a cost-effective and timely manner.[12] The IE shall report directly to, take direction from, and be accountable to, the commission.[13]

The Consumer Advocate has the statutory responsibility to represent, protect, and advance the interests of the Hawaiian Electric Companies' customers.[14] The Consumer Advocate, therefore, has the duty to ensure that the Hawaiian Electric Companies' integrated resource planning process and Action Plan promote the interest of the Hawaiian Electric Companies' customers and are reasonable and in the public interest. The Consumer Advocate shall also participate in all public hearings

---

[11] Id.

[12] Id., III.C.1., at 5.

[13] Id.

[14] See HRS § 269-51

and other sessions held in furtherance of the Hawaiian Electric Companies' efforts in IRP.[15]

The PBF Administrator shall participate in Advisory Group meetings, public hearings, and other sessions to support the forecasts of energy efficiency demand-side management programs developed in furtherance of the utilities' efforts in IRP.[16]

The Advisory Group shall represent interests that are affected by the Hawaiian Electric Companies' resource plans and that possess the ability to provide significant perspective or useful expertise in the development of the resource plans. Members of the Advisory Group may include State and county agencies, and environmental, cultural, business, and community interest groups.[17] Advisory Group members may act as individuals and there is no requirement for group decision-making.[18] However, to the extent possible or practicable, Advisory Group members are encouraged to work collaboratively to attempt to arrive at a consensus on issues.[19] The Hawaiian Electric Companies shall

---

[15]Revised Framework, III.D.1., at 7.

[16]Id., III.E.1., at 7.

[17]Id., III.F.2., at 8.

[18]Id., III.F.6., at 9.

[19]Id.

consider the input of each Advisory Group, but is not bound to follow the recommendations of any such Advisory Group.[20] All reasonable out-of-pocket costs incurred by Advisory Group members (other than representatives of governmental agencies, a for-profit entity, or an association of for-profit entities) related to participation in the integrated resource planning process as an Advisory Group member, shall be paid for by the utility, subject to commission approval. Such costs shall be recovered as part of the Hawaiian Electric Companies' cost of integrated resource planning.[21]

Individuals interested in serving on the Advisory Group may apply to the commission via United States mail by sending a letter of interest together with a resume or curriculum vitae, and referencing the instant docket proceeding. Letters should be sent to the Public Utilities Commission, 465 South King Street #103, Honolulu, HI 96813. The deadline for applying to serve on the Advisory Group is one hundred (100) days from the publishing of this order. Interested persons may also provide suggestions on what persons or groups that should serve on the Advisory Group.

---

[20] Id., III.F.3., at 9.

[21] Id., III.F.9., at 9.

The Hawaiian Electric Companies' shall also provide opportunities for public participation in the development of the IRP. Participation may be provided through public hearings, meetings or forums, public outreach programs or other methods that the Hawaiian Electric Companies deem appropriate and effective to encourage and maximize public participation.[22] The commission is also seeking input from the public at this time on which key policy and technical issues should be considered in the IRP. Such public guidance relating to IRP issues can be submitted to the commission via United States mail at the address stated above.

A summary of the significant procedural milestones for this docket are contained in the table below:

| Milestone | Timing |
|---|---|
| 1. Docket opens | Day 1 |
| 2. Independent Entity selected by the commission | 60 Days from docket opening |
| 3. Hawaiian Electric Companies file a IRP schedule with the commission. | 90 Days from docket opening |
| 4. Deadline to apply to serve on the Advisory Group | 100 Days from the docket opening |
| 5. Commission establishes the Advisory Group | 120 Days from docket opening |
| 6. Hawaiian Electric Companies file the IRP Report and Action Plan with the commission | 365 days from the establishment of the Advisory Group. |
| 7. Hawaiian Electric Companies publish in the newspaper a notice that they have filed the IRP Report and Action Plan with the commission | 7 days after filing IRP Report and Action Plan |

[22] Id., III.G.1., at 9.

| Milestone | Timing |
|---|---|
| 8. Applications to intervene are due to the commission | 20 days after publication by the HECO Companies |
| 9. Commission renders a decision on the IRP Action Plan within 6 months, to the extent possible. | 180 days from the Hawaiian Electric Companies' filing of the IRP Report and Action Plan |

III.

Orders

THE COMMISSION ORDERS:

1. This docket is opened to formally commence the next integrated resource planning cycle for HECO, MECO and HELCO and to examine the IRP Report and Action Plan for all three companies.

2. HECO, HELCO, MECO, and the Consumer Advocate are named as parties to this Docket.

3. Within ninety days of this Order, the Hawaiian Electric Companies, the IE and the Consumer Advocate will file an IRP schedule with the commission.

4. Within one year of the commission selecting the Advisory Group, the Hawaiian Electric Companies shall file their IRP Report and Action Plan with the commission.

DONE at Honolulu, Hawaii MAR - 1 2012.

PUBLIC UTILITIES COMMISSION
OF THE STATE OF HAWAII

By Hermina Morita
Hermina Morita, Chair

By John E. Cole
John E. Cole, Commissioner

By Michael E. Champley
Michael E. Champley, Commissioner

APPROVED AS TO FORM:

Catherine P. Awakuni
Catherine P. Awakuni
Commission Counsel

2012-0036.sl

CERTIFICATE OF SERVICE

The foregoing order was served on the date of filing by mail, postage prepaid, and properly addressed to the following parties:

JEFFREY T. ONO
EXECUTIVE DIRECTOR
DEPARTMENT OF COMMERCE AND CONSUMER AFFAIRS
DIVISION OF CONSUMER ADVOCACY
P. O. Box 541
Honolulu, HI 96809

DEAN K. MATSUURA
MANAGER, REGULATORY AFFAIRS
HAWAIIAN ELECTRIC COMPANY, INC.
P. O. Box 2750
Honolulu, HI 96840-0001

H. RAY STARLING
PROGRAM MANAGER
HAWAII ENERGY
1132 Bishop Street, Suite 1800
Honolulu, HI 96813
(Courtesy Copy)

## Establishing the Advisory Group

Docket Number 2012-0036, Order Number 30513: *Establishing the Advisory Group for the HECO Companies' Integrated Resource Planning Process*, filed 29 June 2012. This order established a 68-person Advisory Group, its members and their affiliations, and detailed its responsibilities in providing community perspectives to the Companies.

BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF HAWAII

| | | |
|---|---|---|
| ---- In the Matter of ---- | ) | |
| | ) | |
| PUBLIC UTILITIES COMMISSION | ) | DOCKET NO. 2012-0036 |
| | ) | |
| Regarding Integrated Resource Planning | ) | |

ORDER NO. 30513

ESTABLISHING THE ADVISORY GROUP FOR
THE HECO COMPANIES' INTEGRATED RESOURCE PLANNING PROCESS

FILED
2012 JUN 29 P 2:18
PUBLIC UTILITIES COMMISSION

BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF HAWAII

| | |
|---|---|
| ---- In the Matter of ---- ) | |
| ) | |
| PUBLIC UTILITIES COMMISSION ) | Docket No. 2012-0036 |
| ) | |
| Regarding Integrated Resource ) | Order No. 30513 |
| Planning ) | |

ESTABLISHING THE ADVISORY GROUP FOR
THE HECO COMPANIES' INTEGRATED RESOURCE PLANNING PROCESS

By this Order, the commission establishes the Advisory Group for the current Integrated Resource Planning ("IRP") cycle for HAWAIIAN ELECTRIC COMPANY, INC. ("HECO"), MAUI ELECTRIC COMPANY, LIMITED ("MECO") and HAWAII ELECTRIC LIGHT COMPANY, INC. ("HELCO")[1], in compliance with the commission's Framework for Integrated Resource Planning, Revised March 14, 2011 for electric and gas utilities.[2] The Hawaiian Electric Companies have one year from the filing of this Order to file their Integrated Resource Plan Reports and Action plans with the commission.

[1]HECO, MECO and HELCO are collectively referred to as the "Hawaiian Electric Companies."

[2]See A Framework for Integrated Resource Planning, Revised March 14, 2011, Decision and Order, filed on March 14, 2011, in Docket No. 2009-0108 ("Revised Framework").

I.

## Background

The goal of integrated resource planning is to develop an Action Plan that governs how the Hawaiian Electric Companies will meet energy objectives and customer energy needs consistent with state energy policies and goals, while providing safe and reliable utility service at reasonable cost, through the development of Resource Plans and Scenarios of possible futures that provide a broader long-term perspective.[3] As part of this process, the commission is tasked with establishing an Advisory Group to provide the Hawaiian Electric Companies with the benefit of community perspectives by participating in the utility's integrated resource planning process and representing diverse community, environmental, social, political, or cultural

[3]"Integrated Resource Planning Report" and "Action Plan" are defined in the Revised Framework, at 1, to mean:

> "Integrated Resource Planning Report" means the entire filing submitted by the utility pursuant to Section IV.D.1 [of the Revised Framework].
>
> "Action Plan" means an implementation plan and schedule for the specific actions, resource options, and programs to be executed by the utility to serve its customers' future energy needs and requirements in a manner consistent with the framework. The Action Plan covers the first five (5) years of the twenty (20) year horizon based on the Scenarios analyzed.

interests consistent with the Revised Framework's goal.[4] The Advisory Group represents interests that are affected by the Hawaiian Electric Companies' resource plans and possesses the ability to provide significant perspective or useful expertise in the development of the resource plans. Advisory Group members may act as individuals; there is no requirement for group decision-making.[5] However, to the extent possible or practicable, Advisory Group members are encouraged to work collaboratively to attempt to arrive at a consensus on issues.[6] The Hawaiian Electric Companies shall consider the input of each Advisory Group member, but are not bound to follow the recommendations of the Advisory Group.[7]

Once the Advisory Group is established, the Hawaiian Electric Companies have one year to file their IRP reports and Action Plans with the commission.[8]

---

[4] See Revised Framework, III.F.2 at 8.

[5] Id., III.F.6., at 9.

[6] Id.

[7] Id., III.F.3., at 9.

[8] Id., IV.C.7,.at 12

II.

Advisory Group Members

To complete the task of establishing the Advisory Group, the commission solicited applications and sent out invitation letters to certain individuals and organizations asking them to take part. The commission received numerous responses and selected sixty eight people from across the Hawaiian Electric Companies' service territories to take part in the Advisory Group. The individuals selected include state and county officials, and environmental, cultural, business, and community interest groups. The Advisory Group members represent as broad a spectrum of affected interests as practicable. The Advisory Group members are as follows:

| Island | Name | Organization |
|---|---|---|
| Hawaii | Barry T. Mizuno | Hawaii Island Resident |
| Hawaii | Bobby Jean Leithead-Todd | County of Hawaii Planning Director |
| Hawaii | Dominic Yagong | Hawaii County Council |
| Hawaii | Donn Mende | Hawaii National Bank |
| Hawaii | Gregory P. Barbour | Natural Energy Laboratory of Hawaii Authority |
| Hawaii | K. Angel Pilago | Hawaii County Council |
| Hawaii | Kyle Datta | Ulupono Initiative |
| Hawaii | Matthew M. Hamabata | Kohala Center |
| Hawaii | Neil "Dutch" Kuyper | Parker Ranch |
| Hawaii | Niniau Simmons | County of Hawaii - Housing Office |
| Hawaii | Representative Denny Coffman | Chair, Energy and Environmental Protection |
| Hawaii | Representative Robert N. Herkes | Chair, Consumer Protection and Commerce |
| Hawaii | Robert K. Lindsey, Jr. | Office of Hawaiian Affairs |
| Hawaii | Robert Rapier | Merica International, LLC |
| Hawaii | Will Rolston | Hawaii County Energy Office |
| Lanai | Alberta De Jetley | Lanai Chamber of Commerce |
| Lanai | Chris Lavvorn | Castle & Cooke Renewable Energy |

| | | |
|---|---|---|
| Lanai | Ronald K. McOmber | Lanai Resident |
| Lanai | Sally Kaye | Friends of Lanai |
| Maui | Carol Reimann | Maui Hotel & Lodging Association |
| Maui | Dick Mayer | University of Hawaii Maui College |
| Maui | Doug McLeod | County of Maui Energy Office |
| Maui | Elle Cochran | Maui County Council |
| Maui | Gladys C. Baisa | Maui County Council |
| Maui | Jeanne Unemori Skog | Maui Economic Development Board, Inc. |
| Maui | Jennifer Chirico | University of Hawaii Maui College |
| Maui | Lee Jakeway | Hawaiian Commercial & Sugar Company |
| Maui | Senator Rosalyn H. Baker | Chair, Commerce and Consumer Protection |
| Maui | Sumner Erdman | Ulupalakua Ranch Inc. |
| Maui | Kal Kobayashi | Maui County Energy Office |
| Maui | Senator J. Kalani English | Senator representing Senate District 6 |
| Maui | William Spence | Maui County Office of Planning |
| Molokai | Clay Rumbaoa | Molokai Ranch |
| Molokai | Emillia Noordhoek | Sustainable Molokai |
| Molokai | Greg Kahn | I Aloha Molokai |
| Molokai | Karen Holt | Molokai Community Service Council |
| Oahu | Al Chee | Chevron |
| Oahu | Asia Yeary | U.S. Environmental Protection Agency, Region 9 |
| Oahu | Bash Nola | Blue Planet |
| Oahu | Bradley Splanger | NAVFAC |
| Oahu | David Tanoue | City and County of Honolulu - Office of Planning |
| Oahu | Dawn Lippert | PICHTR |
| Oahu | Donna Domingo | ILWU |
| Oahu | H. Ray Starling | Hawaii Energy |
| Oahu | Henry Curtis | Life of the Land |
| Oahu | Isaac Moriwake | Earth Justice |
| Oahu | Jeff Kent | Office of Hawaiian Affairs |
| Oahu | Jeff Ono | Consumer Advocate |
| Oahu | Jim Spaeth | Department of Energy |
| Oahu | Jim Tollefson | Chamber of Commerce |
| Oahu | Kevin Kawahara | Oahu Resident |
| Oahu | Lauren Zirbel | Hawaii Food Industry Association |
| Oahu | Leslie Cole-Brooks | Hawaii Solar Energy Association |
| Oahu | Mark Fox | Nature Conservancy |
| Oahu | Mark Glick | DBEDT Energy Office |
| Oahu | Maurice Kaya | PICHTR |
| Oahu | Michael Hamnett | The Research Corporation of University of Hawaii |
| Oahu | Miles Kubo | Energy Industries |

| | | |
|---|---|---|
| Oahu | Paul Luersen | American Planning Association |
| Oahu | Paul Migliorato | Pacific Resources |
| Oahu | Pono Shim | Enterprise Honolulu |
| Oahu | Robert Piper | Honolulu Community Action Program |
| Oahu | Robin Campaniano | Ulupono Initiative |
| Oahu | Ryan McCauley | Hoku Solar, Inc. |
| Oahu | Senator Mike Gabbard | Chair, Energy and Environment |
| Oahu | Tina Yamaki | Hotel and Lodging Association |
| Oahu | Tom Gorak | Solar Energy Industries Association |
| Oahu | Warren Bollmeier | Hawaii Renewable Energy Alliance |

III.

Orders

THE COMMISSION ORDERS:

1. The Advisory Group for the Hawaiian Electric Companies' Integrated Resource Planning process is established, as set forth herein.

2. The Hawaiian Electric Companies have one year from the date of this Order to file their Integrated Resource Planning Reports and Action Plans with the commission.

DONE at Honolulu, Hawaii JUN 2 9 2012.

PUBLIC UTILITIES COMMISSION
OF THE STATE OF HAWAII

By Hermina Morita
Hermina Morita, Chair

By John E. Cole
John E. Cole, Commissioner

By Michael E. Champley
Michael E. Champley, Commissioner

APPROVED AS TO FORM:

Catherine P. Awakuni
Catherine P. Awakuni
Commission Counsel

2012-0036.cp

CERTIFICATE OF SERVICE

The foregoing order was served on the date of filing by mail, postage prepaid, and properly addressed to the following parties:

JEFFREY T. ONO
EXECUTIVE DIRECTOR
DEPARTMENT OF COMMERCE AND CONSUMER AFFAIRS
DIVISION OF CONSUMER ADVOCACY
P. O. Box 541
Honolulu, HI 96809

DEAN K. MATSUURA
MANAGER, REGULATORY AFFAIRS
HAWAIIAN ELECTRIC COMPANY, INC.
P. O. Box 2750
Honolulu, HI 96840-0001

In addition, the foregoing order was sent via electronic mail to the Advisory Group members named herein.

## Identifying Issues and Questions

Docket Number 2012-0036, Order Number 30534: *Identifying Issues and Questions for the Hawaiian Electric Companies' Integrated Resource Planning Process*, filed 19 July 2012. This order identifies several issues, questions, and objectives the Companies must address in the Integrated Resource Planning cycle, and include in their IRP report and Action Plan.

BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF HAWAII

| | |
|---|---|
| ---- In the Matter of ----) <br> ) <br> PUBLIC UTILITIES COMMISSION ) <br> ) <br> Regarding Integrated Resource ) <br> Planning. ) | DOCKET NO. 2012-0036 |

ORDER NO. 30534

IDENTIFYING ISSUES AND QUESTIONS FOR THE
HAWAIIAN ELECTRIC COMPANIES' INTEGRATED RESOURCE PLANNING PROCESS

FILED

2012 JUL 19 P 2:33

PUBLIC UTILITIES
COMMISSION

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF HAWAII

| | |
|---|---|
| ---- In the Matter of ---- PUBLIC UTILITIES COMMISSION Regarding Integrated Resource Planning. | Docket No. 2012-0036 Order No. 30534 |

IDENTIFYING ISSUES AND QUESTIONS FOR THE HAWAIIAN ELECTRIC COMPANIES' INTEGRATED RESOURCE PLANNING PROCESS

By this Order, the commission, on its own motion, identifies several issues, questions, and objectives to be addressed in the current Integrated Resource Planning ("IRP") cycle and are to be included in the Action Plan and IRP Report filed by HAWAIIAN ELECTRIC COMPANY, INC. ("HECO"), MAUI ELECTRIC COMPANY, LIMITED ("MECO"), and HAWAII ELECTRIC LIGHT COMPANY, INC. ("HELCO")[1], in compliance with the commission's Framework for Integrated Resource Planning, Revised March 14, 2011 for electric and gas utilities.[2]

---

[1]HECO, MECO and HELCO are collectively referred to as the "Hawaiian Electric Companies."

[2]See A Framework for Integrated Resource Planning, Revised March 14, 2011, Decision and Order, filed on March 14, 2011, in Docket No. 2009-0108 ("Revised Framework").

I.

Background

The goal of integrated resource planning is to develop an Action Plan that governs how the Hawaiian Electric Companies will meet energy objectives and customer energy needs consistent with state energy policies and goals, while providing safe and reliable utility service at reasonable cost, through the development of Resource Plans and Scenarios of possible futures that provide a broader long-term perspective.[3] As part of the process to develop the Action Plan and Resource Plans, the commission may specify questions and issues that the Hawaiian Electric Companies shall address.[4] The commission may also

---

[3]"Integrated Resource Planning Report" and "Action Plan" are defined in the Revised Framework, at 1, to mean:

> "Integrated Resource Planning Report" means the entire filing submitted by the utility pursuant to Section IV.D.1 [of the Revised Framework].
>
> "Action Plan" means an implementation plan and schedule for the specific actions, resource options, and programs to be executed by the utility to serve its customers' future energy needs and requirements in a manner consistent with the framework. The Action Plan covers the first five (5) years of the twenty (20) year horizon based on the Scenarios analyzed.

[4]Revised Framework, Section V.C.1, at 17.

specify planning objectives and criteria for the Hawaiian Electric Companies to consider in the planning process.[5]

To date, several issues regarding the future design and operation of the Hawaiian Electric Companies system have been raised. For instance, during the Twenty-Sixth Legislature of the State of Hawaii, Regular Session of 2012, both the House of Representatives and Senate adopted House Concurrent Resolution No. 58, H.D. 1, S.D. 1 ("H.C.R. 58"), which directs the commission to consider the following in the IRP process for electric utilities:

1. Strategies to replace the existing fossil fuel based electricity generating plants with renewable energy resources;

2. Transmission of firm or intermittent electricity between islands, including plans to develop undersea electricity transmission cables;

3. Electricity generated using geothermal steam on geothermal resources to replace or mitigate fossil fuel-based generation;

4. Hydrogen and other available energy storage technologies as a source of stored energy to stabilize the grid when necessary; and

5. Electricity from waste-to-energy facilities to serve as an untapped fuel source.

---

[5]Revised Framework, Section V.C.4.a, at 17.

H.C.R. 58, Twenty-Sixth Legislature of the State of Hawaii, Regular Session of 2012, at 2.

Other legislative directives include the attainment of the renewable portfolio standard ("RPS") and the energy efficiency portfolio standard ("EEPS").[6] Furthermore, the commission itself has identified issues in other dockets for the Hawaiian Electric Companies to address in this cycle of the IRP.[7] The IRP Planning Report to be filed with the commission in this docket should explain the process utilized to make the determination of what is the most appropriate fuel supply in order to achieve the highest and best use of the CT-1 generating unit.

---

[6] See Hawaii Revised Statutes ("HRS") § 269-92 and § 269-96, respectively.

[7] For instance, the commission, in Decision and Order No. 30384, filed on May 14, 2012, in Docket No. 2011-0337, directed HECO:

> to ascertain in Docket No. 2012-0036, the Integrated Resource Planning docket, whether the current exclusive use of biofuel in CIP CT-1 reflects the highest or best use of the unit. For example, can greater efficiencies, and/or overall system benefits be gained if CIP CT-1 is used to support the maximum integration [of] renewable through the use of more efficient and/or cheaper fuels, rather than limiting CIP CT-1 use as a biofuel peaking unit with a negligible contribution to the Renewable Portfolio Standard.

Decision and Order No. 30384 at 12, n. 26.

II.

Issues, Questions, and Objectives

The commission finds it prudent and appropriate to, on its own motion, establish several issues, questions, and objectives to guide the Hawaiian Electric Companies through its planning process. The issues, questions, and objectives identified herein are topics that must, at a minimum, be addressed in the planning process, and are offered to supplement the list of issues and objectives to be identified and defined by the Hawaiian Electric Companies, with input from the Advisory Group. In other words, the IRP Report to be filed with the commission should explain how these issues were considered and factored into the Action Plan. Except for a clear indication of the commission's emphasis on addressing the reasonableness of costs and affordability of energy services, the issues specified in this Order are not intended to be given more priority than other issues identified by the Hawaiian Electric Companies, with input from the Advisory Group.

During its planning process and in development of their Action Plan and IRP Report, the Hawaiian Electric Companies shall consider whether their Action Plan and IRP Report comply with the commission's Revised Framework. Included in this underlying issue are the following sub-issues, questions, and objectives that the Hawaiian Electric Companies shall consider, at a minimum:

A. <u>Reasonable Cost and Rate Impacts</u>

Whether the Action Plan and IRP Report result in affordable electric utility services. Reasonable cost is an important objective for resource planning identified in the statement of the goal of Integrated Resource Planning.[8] The affordability of utility-provided energy services is a primary concern and objective of the commission, especially in light of the need for timely implementation of statutory standards and goals and the need to maintain reliable energy service. Among any other possible measures of the achievement of this objective, the Hawaiian Electric Companies' planning analysis shall include meaningful measures of the rate impacts of the Resource Plans and Action Plan evaluated in accordance with the planning scenarios, forecasts, and sensitivity analyses. The Hawaiian Electric Companies shall determine meaningful measures of rate impacts with input from the Advisory Group.

As part of their analyses of the cost and rate impacts to its customers, the Hawaiian Electric Companies shall consider the following:

---

[8]Revised Framework, Section II.A, at 2.

1. What costs and rate impacts result from full attainment of the RPS.[9] This evaluation shall include comparison of full attainment of the RPS with various levels of partial attainment as well as exceeding the RPS.

2. What costs and rate impacts result from full attainment of the EEPS.[10] This evaluation shall include comparison of the full attainment of the EEPS with alternate levels of partial attainment as well as exceeding the EEPS.

3. Whether and to what extent utility customers who do not have a renewable energy device or have implemented energy efficiency measures could face high cost and rate impacts if utility sales decrease for any of several possible causes. The planning process should consider circumstances that could compound to result in high utility fixed costs and/or low utility

---

[9]The current RPS law requires that an electric utility company that sells electricity in the State shall have an RPS standard of: (1) 10% of net electricity sales by December 21, 2010; (2) 15% of net electricity sales by December 31, 2015; (3) 25% of net electricity sales by December 31, 2020; and (4) 40% of net electricity sales by December 31, 2030. See HRS §269-92(a).

[10]The current EEPS law requires the commission to establish a standard that achieves four thousand three hundred gigawatt hours of electricity use reductions statewide by 2030. See HRS § 269-96(b). The commission, by Decision and Order No. 30089, filed on January 3, 2012, in Docket No. 2010-0037, established A Framework for Energy Efficiency Portfolio Standards (the "EEPS Framework"). The EEPS Framework sets forth interim energy efficiency savings goals of 196.5 gigawatt hours per year from 2009 to 2010 and 196.4 gigawatt hours of savings each year from 2011 - 2015. See EEPS Framework at 8.

system sales and evaluate the extent to which these circumstances could lead to high rate impacts and possible customer exit or self-generation.

B. Resource Plans / Strategies

Whether the Hawaiian Electric Companies' Resource Plans effectively ensure affordable electric rates, maintain service reliability, and accommodate expected increasing proportions of variable and/or intermittent renewable generation resources. The Hawaiian Electric Companies shall develop Resource Plans and Strategies that include comparative analysis of the costs and benefits of the following:

1. Whether possible alternate inter-island and inter-utility-system transmission connections may be utilized to increase utilization of renewable energy resources, lower costs of existing fossil-fuel resources, or provide other net benefits, across multiple islands.

2. Whether adoption and utilization of a smart grid, including smart meters, should be completed by the Hawaiian Electric Companies. The Hawaiian Electric Companies shall analyze how these technologies could enable the electrical grid to be operated more efficiently and reliably, customer service to be enhanced, customers loads controlled remotely to accommodate additional renewable energy resources and energy efficiency and

conservation to be increased through real-time transparency of energy usage and costs. One specific question is to what extent can the existing and future distribution system design criteria and operation practices be modified to enable greater interconnection of distributed renewable energy resources.

3. Whether alternative strategies to comply with expected and possible changes in environmental regulations should be utilized. One specific question is to what extent generation fuel switching strategies could result in the net reduction in capital and operating costs for compliance with new environmental regulations.

4. Whether modifications of the fuel supply portfolio and delivery infrastructure for existing utility and non-utility fossil generation resources should be considered in order to reduce system fuel costs and/or reduce environmental compliance costs. The planning process should include comparative analysis of the total costs (capital, fuel and operating) and merits of fuel supply strategies to utilize alternate fuels, supply procurement methods and delivery options. One specific question is the fuel supply infrastructure requirements, including costs, necessary to provide diverse fuel sourcing, procurement and delivery options.[11]

---

[11]Significant changes in the utilities' fuel supply needs or portfolio will affect their demand for fuel oil, impacting the

5. Whether and to what extent the existing fleet of utility and non-utility fossil generation resources should be modernized and/or adapted to achieve greater efficiency, reliability, flexibility and to reduce renewable energy curtailment. The planning process should include comparative analysis of the costs and merits of strategies to retire units (with or without replacement), minimize the amount of must-run fossil generation and enhance the operational flexibility of generating units to reduce costs and increase renewable energy penetration.

6. Whether new technologies, measures and strategies should be utilized in order to decrease reliance on fossil-fuel generation resources to provide essential grid ancillary services and accommodate expected increasing proportions of variable and/or intermittent renewable generation resources. The planning process should include comparative analysis of the costs and merits of possible non-fossil fuel resources, technologies or programs to provide quick-response capacity and other ancillary services. Possible options to be

---

refineries operating in Hawaii. Conversely, significant changes in fuel output by refineries operating in Hawaii will affect the utilities' fuel supply options. While both changes may have significant effects for the State's economy, the commission's purview is limited to the latter situation. The Hawaiian Electric Companies, with input from the Advisory Group, should consider a scenario wherein significant changes in output by refineries operating in Hawaii effectively limit the utilities' fuel supply options.

analyzed should include modifications to existing fossil and renewable energy generating units, customer demand response programs and energy storage resources.

7. What additions and modifications to existing transmission and subtransmission systems are required to meet system and/or local load growth, comply with reliability planning criteria, interconnect new generation resources regardless of ownership or technology, retire with replacement aging and antiquated grid infrastructure and mitigate transmission congestion (bottlenecks). The result of these analyses were to provide the long-term transmission capital investment requirements for the Hawaiian Electric Companies. One specific question is to what extent fossil generation must operate due to lack of sufficient transmission capacity or other grid operational constraints such as local voltage support, while solar or wind resources are being curtailed.

C. Action Plan validation and execution

Whether the Hawaiian Electric Companies' Action Plan complies with the Revised Framework and provides "the greatest value and flexibility across as many of the evaluated Scenarios and Resource Plans as reasonably practicable".[12] The Hawaiian

[12] Id., Section V.C.10.b, at 21.

Electric Companies shall determine and demonstrate that their Action Plan represents a reasonable course of action.

The Action Plan is intended to be dynamic, and not fixed and unchanging.[13] In particular, the Action Plan is intended to be:

> [F]lexible enough to account for changes in planning assumptions, forecasts, and circumstances. This will allow for major decisions regarding the implementation of options (both supply-side and demand-side resources) to be made incrementally, based on the best and current available information at the time decisions are made.

Revised Framework, Section IV.D.6, at 15. While the Action Plan is intended to be a "living" document that remains flexible enough to remain relevant, the commission re-emphasizes its intent to carefully examine the Hawaiian Electric Companies' proposed modifications to the Action Plan as they may arise.[14] In

---

[13]Id., Section IV.D.6, at 15.

[14]The Revised Framework, at Section IV.7.b, provides:

> To revise or amend its Action Plan, the utility shall provide notice of any revisions or amendments to the Action Plan to the Commission, the Independent Entity and the Advisory Group(s) through a filing in the docket with an opportunity for comment within fourteen days of the date of filing. In its notice filing, the utility shall provide the following information:
>
> > (1) the extent to which any proposed actions are not consistent with the approved action plan;

addition, the commission makes clear that failure by the Hawaiian Electric Companies to adhere to their Action Plan, whether by active modification or by omission, may affect subsequent approvals of applications.

III.

Orders

THE COMMISSION ORDERS that the Hawaiian Electric Companies shall, at a minimum, address the issues, questions, and objectives set forth in Section II of this Order. Specifically, the Hawaiian Electric Companies' IRP Report to be filed with the commission shall explain how these issues were considered and factored into the Action Plan.

---

(2) the extent to which any proposed actions would affect any other aspects of the approved action plan; and
(3) whether the proposed actions and resulting associated changes in the action plan are reasonable and in the public interest.

DONE at Honolulu, Hawaii JUL 19 2012.

PUBLIC UTILITIES COMMISSION
OF THE STATE OF HAWAII

By Hermina Morita
Hermina Morita, Chair

By Michael E. Champley
Michael E. Champley, Commissioner

By Lorraine H. Akiba
Lorraine H. Akiba, Commissioner

APPROVED AS TO FORM:

Catherine P. Awakuni
Catherine P. Awakuni
Commission Counsel

2012-0036.ac

CERTIFICATE OF SERVICE

The foregoing order was served on the date of filing by mail, postage prepaid, and properly addressed to the following parties:

JEFFERY T. ONO
EXECUTIVE DIRECTOR
DEPARTMENT OF COMMERCE AND CONSUMER AFFAIRS
DIVISION OF CONSUMER ADVOCACY
P. O. Box 541
Honolulu, HI 96809

DEAN K. MATSUURA
MANAGER, REGULATORY AFFAIRS
HAWAIIAN ELECTRIC COMPANY, INC.
P. O. Box 2750
Honolulu, HI 96840-0001

In addition, the foregoing order was sent via electronic mail to the Advisory Group members named in Order No. 30513.

## Amending Procedural Schedule for the Hawaiian Electric Companies IRP Process

Docket Number 2012-0036, Order Number 31311: *Amending Procedural Schedule for the Hawaiian Electric Companies' Integrated Resource Planning Process*, filed 21 June 2013. This order added another Advisory Group meeting to be held between July 8 and July 12, 2013.

BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF HAWAII

| | |
|---|---|
| ----- In the Matter of -----)<br>)<br>PUBLIC UTILITIES COMMISSION )<br>)<br>Regarding Integrated Resource )<br>Planning. )<br>) | DOCKET NO. 2012-0036 |

ORDER NO. 31311

AMENDING PROCEDURAL SCHEDULE FOR THE
HAWAIIAN ELECTRIC COMPANIES' INTEGRATED RESOURCE PLANNING PROCESS

BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF HAWAII

| | |
|---|---|
| ----- In the Matter of -----) | |
| PUBLIC UTILITIES COMMISSION ) | Docket No. 2012-0036 |
| Regarding Integrated Resource ) Planning. ) | Order No. 31311 |

AMENDING PROCEDURAL SCHEDULE FOR THE
HAWAIIAN ELECTRIC COMPANIES' INTEGRATED RESOURCE PLANNING PROCESS

By this Order, the commission, on its own motion, notwithstanding the deadline of Friday, June 28, 2013 for the Hawaiian Electric Companies[1] to file their finalized Integrated Resource Planning ("IRP") Report(s), amends the IRP 2013 Schedule ("Schedule") submitted by the Hawaiian Electric Companies on May 30, 2012, in compliance with Order No. 30233, Ordering Paragraph 3, filed March 1, 2012 in this proceeding.

I.

Background

Several IRP Advisory Group ("Advisory Group") members have submitted communications ("Letters") expressing concerns

[1]HAWAIIAN ELECTRIC COMPANY, INC. ("HECO"), MAUI ELECTRIC COMPANY, LIMITED ("MECO"), and HAWAII ELECTRIC LIGHT COMPANY, INC. ("HELCO") are collectively referred to as the "Hawaiian Electric Companies."

and offering suggestions and/or requests regarding the procedures at the final phase of the IRP process.[2]

The Schedule filed with the commission at the beginning of the IRP process provided for review of the IRP Action Plans and the Draft IRP Report(s) by the Advisory Group several weeks prior to finalization and filing of the Final IRP Report(s).[3] As noted in the Letters, some Advisory Group members advocate that there has not been sufficient opportunity for the Advisory Group to review the Draft IRP Action Plans and the IRP Draft Report(s) prior to filing.[4]

In a May 15, 2013 letter from Chair Hermina Morita to the Advisory Group, it was noted that the IRP Framework establishes a strict and explicit standard regarding whether the

---

[2]Several communications have been submitted to the commission or forwarded to the commission by the IRP Independent Entity, including a memorandum from the Department of Business, Economic Development, and Tourism, dated June 3, 2013, and two letters from two separate groups of Advisory Group members, one dated June 11, 2013 and the other dated June 12, 2013.

[3]See Hawaiian Electric Companies' IRP Schedule, dated and filed May 30, 2012.

[4]The Draft Action Plans presented to the Advisory Group on May 30, 2013 were available in the form of presentation slides and were made available only one hour prior to the beginning of the presentation by the Hawaiian Electric Companies to the Advisory Group.

deadline for filing the Final IRP Report(s) can be extended.[5] In accordance with that standard, the June 28, 2013 deadline for filing the IRP Report(s) will not be extended. Notwithstanding the Final IRP Report(s) filing deadline of June 28, 2013, to allow the Advisory Group to complete its review within the context of the IRP Framework and the Schedule, the commission will amend the Schedule to provide additional steps to receive input from the Advisory Group.

The commission has and continues to rely upon the thoughtful comments and recommendations offered by the Advisory Group as a critical source of input as to the progress and efficacy of this IRP process. As such, the commission notes here that all Advisory Group comments offered during the period following the filing of the Final IRP Report(s) will become part of the official record reviewed and utilized by the commission in rendering its decision. Similarly, all prior comments submitted to date by both members of the Advisory Group and those interested members of the public will be reviewed and

[5]As quoted in the May 15, 2013 letter from the commission to the Advisory Group: "[A]s timely Commission review is dependent on the utility filing its Integrated Resource Planning Report at the time specified in the framework, no extension of such deadline will be granted except upon a showing of excusable neglect." (quoting A Framework for Integrated Resource Planning, revised March 14, 2011, Section III.B.2, Docket No. 2009-0108, Decision and Order, filed March 14, 2011.)

given due consideration by the commission prior to the issuance of any final determination.[6] The commission would like to note, finally, that any steps added to the IRP process subsequent to the filing of the Final IRP Report(s) will ensure Advisory Group members the opportunity to give the commission direct input for review and consideration, which the commission strongly encourages irrespective of a commenter's official status in the proceeding as party, intervenor, or otherwise.

II.

Orders

THE COMMISSION ORDERS:

1. As stated below, the Hawaiian Electric Companies' Final IRP Report deadline shall remain June 28, 2013.

2. Phase 6 of the IRP 2013 Schedule, filed on May 30, 2012, is amended as shown below whereby the Hawaiian Electric Companies shall hold an Advisory Group meeting no sooner than July 8, 2013 and no later than July 12, 2013 for the purpose of reviewing and discussing the Final IRP Report(s) ("Advisory Group Meeting").

---

[6]The IRP Independent Entity has ensured the filing into the record of voluminous IRP source materials, including all received comments offered by Advisory Group members and the general public.

| Task Name | Start | Finish |
|---|---|---|
| Phase 6 - File IRP Report | 5/6/13 | 5/17/13 |
| 1. Draft IRP Report (HECO, HELCO, MECO) | 5/20/13 | 5/31/13 |
| 2. AG Review draft report | 5/20/13 | 5/31/13 |
| 3. Finalize IRP Report | 6/3/13 | 6/28/13 |
| 4. Report Filed with the Commission | 6/28/13 | 6/28/13 |
| 5. Publish Notice of Filing in Newspaper | 6/28/13 | 7/5/13 |
| ***6. Advisory Group Meeting to Review Final IRP Report(s) [single day meeting; see date range]*** | ***7/8/13*** | ***7/12/13*** |

Amendments emphasized.

The Advisory Group may provide comments to the commission regarding any and all aspects of the IRP process and the HECO Companies' IRP Report(s) within seven (7) days after the Advisory Group Meeting.

3. The Hawaiian Electric Companies shall respond to the Advisory Group's comments in accordance with Section III.F.3 of the IRP Framework.

4. The IRP Independent Entity shall provide the certification of the outstanding phases of the IRP process required by the IRP Framework within ten (10) days of the Advisory Group Meeting.

DONE at Honolulu, Hawaii JUN 21 2013.

PUBLIC UTILITIES COMMISSION
OF THE STATE OF HAWAII

By Hermina Morita
Hermina Morita, Chair

By Michael E. Champley
Michael E. Champley, Commissioner

By Lorraine H. Akiba
Lorraine H. Akiba, Commissioner

APPROVED AS TO FORM:

Catherine P. Awakuni
Catherine P. Awakuni
Commission Counsel

2012-0036.sr

CERTIFICATE OF SERVICE

The foregoing order was served on the date of filing by mail, postage prepaid, and properly addressed to the following parties:

JEFFERY T. ONO
EXECUTIVE DIRECTOR
DEPARTMENT OF COMMERCE AND CONSUMER AFFAIRS
DIVISION OF CONSUMER ADVOCACY
P. O. Box 541
Honolulu, HI 96809

DEAN K. MATSUURA
MANAGER, REGULATORY AFFAIRS
HAWAIIAN ELECTRIC COMPANY, INC.
P. O. Box 2750
Honolulu, HI 96840-0001

J. CARL FREEDMAN
HAIKU DESIGN & ANALYSIS
4234 Hana Highway
Haiku, HI 96708

In addition, the foregoing order was sent via electronic mail to the Advisory Group members by the commission's Independent Entity.

# Appendix D: Advisory Group

The Advisory Group is comprised of 68 members who represent diverse interests on the five Hawaii islands served by the Hawaiian Electric Company. The Advisory Group's role is to give the utility the benefit of its useful expertise and its perspective of the diverse community, environmental, social, political, or cultural interests they represent through its participation in the integrated resource planning process.

# CONTENTS

# TABLES

[This page is intentionally left blank.]

# Advisory Group Members

From responses to invitations to individuals and organizations, the PUC selected 68 people from the five service territory islands to be members of the Advisory Group to represent as broad a spectrum of affected interests as practicable.

Table D-1: Advisory Group Members (by last name)

| Name | Organization | Island |
|---|---|---|
| Baisa, Gladys C. | Maui County Council | Maui |
| Baker, Senator Rosalyn H. | Chair, Commerce and Consumer Protection | Maui |
| Barbour, Gregory P. | Natural Energy Laboratory of Hawaii Authority | Hawaii |
| Bollmeier, Warren | Hawaii Renewable Energy Alliance | Oahu |
| Campaniano, Robin | Ulupono Initiative | Oahu |
| Chee, Al | Chevron | Oahu |
| Chirico, Jennifer | University of Hawaii Maui College | Maui |
| Cochran, Elle | Maui County Council | Maui |
| Coffman, Representative Denny | Chair, Energy and Environmental Protection | Hawaii |
| Cole-Brooks, Leslie | Hawaii Solar Energy Association | Oahu |
| Curtis, Henry | Life of the Land | Oahu |
| Datta, Kyle | Ulupono Initiative | Hawaii |
| De Jetley, Alberta | Lanai Chamber of Commerce | Lanai |
| Domingo, Donna | ILWU | Oahu |
| English, Senator J. Kalani | Senate District 6 | Maui |
| Erdman, Sumner | Ulupalakua Ranch Inc. | Maui |
| Fox, Mark | Nature Conservancy | Oahu |
| Gabbard, Senator Mike | Chair, Energy and Environment | Oahu |
| Glick, Mark | DBEDT Energy Office | Oahu |
| Gorak, Tom | Solar Energy Industries Association | Oahu |
| Hamabata, Matthew M. | Kohala Center | Hawaii |
| Hamnett, Michael | The Research Corporation of University of Hawaii | Oahu |
| Herkes, Representative Robert N. | Chair, Consumer Protection and Commerce | Hawaii |
| Holt, Karen | Molokai Community Service Council | Molokai |
| Jakeway, Lee | Hawaiian Commercial & Sugar Company | Maui |
| Kahn, Greg | I Aloha Molokai | Molokai |

## Appendix D: Advisory Group

Advisory Group Members

| Name | Organization | Island |
|---|---|---|
| Kawahara, Kevin | Oahu Resident | Oahu |
| Kaya, Maurice | PICHTR | Oahu |
| Kaye, Sally | Friends of Lanai | Lanai |
| Kent, Jeff | Office of Hawaiian Affairs | Oahu |
| Kobayashi, Kal | Maui County Energy Office | Maui |
| Kubo, Miles | Energy Industries | Oahu |
| Kuyper, Neil “Dutch” | Parker Ranch | Hawaii |
| Lavvorn, Chris | Castle & Cooke Renewable Energy | Lanai |
| Leithead-Todd, Bobby Jean | County of Hawaii Planning Director | Hawaii |
| Lindsey, Robert K. Jr. | Office of Hawaiian Affairs | Hawaii |
| Lippert, Dawn | PICHTR | Oahu |
| Luersen, Paul | American Planning Association | Oahu |
| Mayer, Dick | University of Hawaii Maui College | Maui |
| McCauley, Ryan | Hoku Solar, Inc. | Oahu |
| McLeod, Doug | County of Maui Energy Office | Maui |
| McOmber, Ronald K. | Lanai Resident | Lanai |
| Mende, Donn | Hawaii National Bank | Hawaii |
| Migliorato, Paul | Pacific Resources | Oahu |
| Mizuno, Barry T. | Hawaii Island Resident | Hawaii |
| Moriwake, Isaac | Earth Justice | Oahu |
| Nola, Bash | Blue Planet | Oahu |
| Noordhoek, Emillia | Sustainable Molokai | Molokai |
| Ono, Jeff | Consumer Advocate | Oahu |
| Pilago, K. Angel | Hawaii County Council | Hawaii |
| Piper, Robert | Honolulu Community Action Program | Oahu |
| Rapier, Robert | Merica International, LLC | Hawaii |
| Reimann, Carol | Maui Hotel & Lodging Association | Maui |
| Rolston, Will | Hawaii County Energy Office | Hawaii |
| Rumbaoa, Clay | Molokai Ranch | Molokai |
| Shim, Pono | Enterprise Honolulu | Oahu |
| Simmons, Niniau | County of Hawaii – Housing Office | Hawaii |
| Skog, Jeanne Unemori | Maui Economic Development Board, Inc. | Maui |
| Spaeth, Jim | Department of Energy | Oahu |
| Spence, William | Maui County Office of Planning | Maui |
| Splanger, Bradley | NAVFAC | Oahu |
| Starling, H. Ray | Hawaii Energy | Oahu |

| Name | Organization | Island |
|---|---|---|
| Tanoue, David | City and County of Honolulu – Office of Planning | Oahu |
| Tollefson, Jim | Chamber of Commerce | Oahu |
| Yagong, Dominic | Hawaii County Council | Hawaii |
| Yamaki, Tina | Hotel and Lodging Association | Oahu |
| Yeary, Asia | U.S. Environmental Protection Agency, Region 9 | Oahu |
| Zirbel, Lauren | Hawaii Food Industry Association | Oahu |

See "Establishing the Advisory Group" in *Appendix C: Commission Documents* for this same list, only grouped by island.

# Advisory Group Meetings

Advisory Group meetings were held throughout the IRP planning cycle. In total, there were 17 meetings (including 10 group meetings, five technical sessions, one conference call, and one work session. The types of meetings and their dates follow.

Table D-2: Advisory Group Meetings

| # | Meeting | Date |
|---|---|---|
| 1 | Meeting 1 | 23 July 2012 |
| 2 | Meeting 2 | 7 August 2012 |
| 3 | Meeting 3 | 20, 21, & 24 August 2012 |
| 4 | Meeting 4 | 24 September 2012 |
| 5 | Meeting 5 | 25 October 2012 |
| 6 | Technical Session 1 | 30 October 2012 |
| 7 | Meeting 6 | 19 November 2012 |
| 8 | Technical Session 2 | 18 December 2012 |
| 9 | Technical Session 3 | 31 January 2013 |
| 10 | Meeting 7 | 25 February 2013 |
| 11 | Conference Call | 28 March 2013 |
| 12 | Meeting 8 | 2 April 2013 |
| 13 | Technical Session 4 | 8 April 2013 |
| 14 | Work Session | 17 April 2013 |
| 15 | Technical Session 5 | 22 April 2013 |
| 16 | Meeting 9 | 1 May 2013 |
| 17 | Meeting 10 | 30 May 2013 |

## Meeting Agendas

The following page contain the agendas for each of these meetings.

### 1. Meeting 1: 23 July 2012

Hawaii Public Utilities Commission Docket No. 2012-0036
Integrated Resource Planning (IRP) For:
Hawaiian Electric Company, Inc. (HECO)
Maui Electric Company, Ltd. (MECO)
Hawaii Electric and Light Company, Inc. (HELCO)

# IRP Advisory Group Meeting #1
# Agenda

**July 23, 2012 9:30 AM – 3:30 PM**

Training Room #2, Eighth Floor
American Savings Bank Tower
1001 Bishop Street, Honolulu, HI
(Located at the corner of King and Alakea Streets)

| | |
|---|---|
| 9:30 am | (1) Welcome & Introductions |
| 10:00 am | (2) The IRP Process |
| | (a) Presentation (IE): The IRP Process and Framework |
| | Questions |
| | (b) Presentation (IE): Meeting and Communications Protocols |
| | Questions |
| 10:45 am | (3) HECO / MECO / HELCO 2013 IRP |
| | Presentation (HECO Companies): Schedule and Process |
| 11:45 am | Lunch Break |
| 12:45 pm | (3) HECO / MECO / HELCO 2013 IRP |
| | Continued Presentation (HECO Companies): Schedule and Process |
| | Questions and Discussion |
| 1:45 pm | (4) Introduction to Principal Issues and Objectives |
| | (a) Framing / Context (IE) |
| | (b) Commission Order Identifying Issues and Questions (IE) |
| | (c) Introduction to Objectives and Principal Issues (HECO Companies) |
| | Clarification Questions |
| | Discussion as time allows (This topic is a main part of Meeting #2 Agenda) |
| 2:45 pm | (5) General Questions and Comments |
| 3:15 pm | (6) What's Next |
| 3:30 pm | Adjourn |

## 2. Meeting 2: 7 August 2012

Hawaii Public Utilities Commission Docket No. 2012-0036
Integrated Resource Planning (IRP) For:
Hawaiian Electric Company, Inc. (HECO)
Maui Electric Company, Ltd. (MECO)
Hawaii Electric and Light Company, Inc. (HELCO)

# IRP Advisory Group Meeting #2
# Agenda

**August 7, 2012 9:45 AM – 3:15 PM (Please Arrive Early ~ 9:35 AM)**

| | |
|---|---|
| UH Maui College: | Ka'a'ike Building, Room 105 C&D (map attached) |
| UH Manoa: | Kuykendall Hall, Room 201 (map attached) |
| UH Hilo: | Mo'okini Library, Room 359 (map attached) |
| UHMC Lanai: | Lanai Education Center, Room 106 |
| UHMC Molokai: | Molokai Education Center, Room 103 |
| UH West Hawaii: | 81-964 Halekii Street<br>Central Kona Center, Kealakekua<br>Building 4, Room 3 |

| | |
|---|---|
| 9:35 am | Arrival and Video Conference Room Orientation |
| 9:45 am | (1) Welcome & Introductions |
| 10:00 am | (2) Process Review and Update<br>Presentation (HECO): Review of Process and Schedule<br>Questions |
| 10:15 am | (3) Existing Utility Systems and Conditions<br>(a) Presentation (HECO): HECO System<br>(b) Presentation (MECO): MECO Systems<br>(c) Presentation (HELCO): HELCO System<br>Questions |
| 12:00 noon | Lunch Break |
| 1:00 pm | (4) Principal Issues<br>Presentation (HECO): Principal Issues<br>Questions and Discussion |
| 1:30 pm | (5) Planning Objectives<br>(a) Status Report (HECO)<br>(b) Facilitated Discussion (IE): List of Objectives<br>(c) Facilitated Discussion (IE): Meaningful Measures of Rate Impacts |
| 2:45 pm | (6) What's Next |
| 3:00 pm | (7) General Questions and Comments |
| 3:30 pm | Adjourn |

### 3. Meeting 3: 20, 21, & 24 August 2012

Hawaii Public Utilities Commission Docket No. 2012-0036
Integrated Resource Planning (IRP) For:
Hawaiian Electric Company, Inc. (HECO)
Maui Electric Company, Ltd. (MECO)
Hawaii Electric and Light Company, Inc. (HELCO)

# IRP Advisory Group Meetings #3
# Meeting Notice and Draft Agendas

**August 20, 21, 24, 2012**

Training Room #2, Eighth Floor
American Savings Bank Tower
1001 Bishop Street, Honolulu, HI
(Located at the corner of King and Alakea Streets)

**Monday, August 20 – 9:00 am to 5:00 pm**

Morning Session – Introduction to Scenario Planning and Isolating Essential Drivers

Lunch (1 hour)

Afternoon Session - Moving from Essential Drivers to Rough Scenario Frameworks

**Tuesday, August 21 - 8:30 am to 4:30 pm** (will try to end by 3:30pm)

Morning Session – Moving from Scenario Frameworks to Scenario Insights

Lunch (1 hour)

Afternoon Session - Closing in on Candidate Scenarios

**Friday, August 24 – 10:00 am to 3:00 pm**

Morning Session – Review of Emerging Refined Scenarios

Lunch (1 hour)

Afternoon Session - Discuss What the Scenarios Mean for IRP

### 4. Meeting 4: 24 September 2012

Hawaii Public Utilities Commission Docket No. 2012-0036
Integrated Resource Planning (IRP) For:
Hawaiian Electric Company, Inc. (HECO)
Maui Electric Company, Ltd. (MECO)
Hawaii Electric and Light Company, Inc. (HELCO)

# IRP Advisory Group Meetings #4
# Agenda

**September 24, 2012 9:45 AM – 3:30 PM (Please arrive early if possible ~9:25am)**

**Video-Conference at Several Locations:**

| | |
|---|---|
| Honolulu, Oahu | HECO ITS Dept., Pauahi Tower, 1003 Bishop Street, 5th floor |
| Hilo, Hawaii | HELCO Main Office, 1200 Kilauea Avenue |
| Kona, Hawaii | HELCO Engineering Office, 74-5519 Kaiwi Street |
| Kahului, Maui | MECO Auditorium, 210 W. Kamehameha Avenue |

| | |
|---|---|
| 9:45 am | Arrival and Video Conference Room Orientation |
| 10:00 am | (1) Welcome and Introductions |
| | (2) Process Status Report (Independent Entity (IE)) |
| 10:20 am | (3) Principal Issues |
| | Presentation (HECO): Principal Issues Draft |
| | Discussion / Comments |
| 10:50 am | (4) Objectives and Measures of Attainment |
| | Presentation (HECO): Objectives and Metrics Draft |
| | Presentation (HECO): Reponses to Comments Matrix |
| | Discussion / Comments |
| 11:20 am | (5) Proposed Planning Scenarios |
| | Presentation (HECO): Proposed Scenarios Draft |
| | Discussion / Comments re: Scenarios / Stories |
| 12:00 noon | Lunch |
| 1:00 pm | (5) Proposed Planning Scenarios (con't) |
| | Discussion / Comments re: Demand, Resource and Price Projections |
| 2:50 pm | (6) What's Next |
| 3:00 pm | (7) General Questions and Comments |
| 3:30 pm | Adjourn |

### 5. Meeting 5: 25 October 2012

Hawaii Public Utilities Commission Docket No. 2012-0036
Integrated Resource Planning (IRP) For:
Hawaiian Electric Company, Inc. (HECO)
Maui Electric Company, Ltd. (MECO)
Hawaii Electric and Light Company, Inc. (HELCO)

# IRP Advisory Group Meeting #5
# Agenda

**October 25, 2012 9:45 AM – 3:30 PM**

Training Room #2, Eighth Floor
American Savings Bank Tower
1001 Bishop Street, Honolulu, HI
(Located at the corner of King and Alakea Streets)

9:45 am **(1) Introductions and Welcome**

9:55 am **(2) Responses to Specific IRPAG Member Questions**

(a) IE clarification questions to County of Maui (COM) regarding COM request to make an IRPAG presentation at the November 15 IRPAG meeting regarding community value studies.

Brief Discussion

(b) IE response to general question submitted by Sally Kaye, Lana'i, October 1, 2012 regarding scope and purpose of IRP process.

Brief Discussion

10:15 am **(3) Current Strategies – What's Been Happening?**

Presentation (HECO Companies): Jose Dizon

Questions

10:45 am **(4) IRP Process and Schedule**

Presentation (HECO Companies): Lisa Giang

Questions and Discussion

11:10 am **(5) Supply – Side Resource Options**

Presentation (HECO Companies): Art Seki

Clarifying Questions

11:45 am **Lunch Break**

12:45 pm **(6) Strategies / Resource Plans**

Presentation (HECO Companies): Lisa Giang

Questions and Discussion

2:00 pm Break

(6) Continued Discussion of Strategies / Resource Plans

2:45 pm **(7) General Questions and Comments**

3:15 pm **(8) What's Next**

3:30 pm **Adjourn**

## 6. Technical Session 1: 30 October 2012

Hawaii Public Utilities Commission Docket No. 2012-0036
Integrated Resource Planning (IRP) For:
Hawaiian Electric Company, Inc. (HECO)
Maui Electric Company, Ltd. (MECO)
Hawaii Electric and Light Company, Inc. (HELCO)

# IRP Advisory Group Meeting
# Technical Session Agenda

**October 30, 2012 9:45 AM – 3:30 PM**

Training Room #2, Eighth Floor
American Savings Bank Tower
1001 Bishop Street, Honolulu, HI
(Located at the corner of King and Alakea Streets)

9:45 am **Introductions and Review Agenda**

9:55 am **Morning Session**

- Step by step explanation of IRP process with questions by IE, Commission staff and IRPAG members
  - IRP modeling and analysis methods
  - Action Plan development and analysis
  - Discussion of how the required principal issues will be addressed
  - Does intended approach meet Framework requirements?
  - What alternate approaches are possible?
  - Does IE or Commission need to take any immediate action to ensure good (or at least sufficient) results?

Noon **Lunch**

1:00 pm **Afternoon Session** (not necessarily in the order listed):

- Continuation of topics above if necessary
- Questions by IRPAG members
- Questions on UIF forms or other supply options
- Questions regarding forecasts and projections

3:00 pm **What's Next and Process Scheduling**

3:30 pm **Adjourn**

## 7. Meeting 6: 19 November 2012

Hawaii Public Utilities Commission Docket No. 2012-0036
Integrated Resource Planning (IRP) For:
Hawaiian Electric Company, Inc. (HECO)
Maui Electric Company, Ltd. (MECO)
Hawaii Electric and Light Company, Inc. (HELCO)

# IRP Advisory Group Meeting #6
# Agenda

**Monday, November 19, 2012 9:45 AM – 3:30 PM**

Training Room #2, Eighth Floor
American Savings Bank Tower
1001 Bishop Street, Honolulu, HI
(Located at the corner of King and Alakea Streets)

| | |
|---|---|
| 9:45 am | **(1) Introductions and Welcome** |
| 9:55 am | **(2) IRP Process and Schedule**<br>Presentation (HECO Companies): Lisa Giang<br>Questions |
| 10:15 am | **(3) Addressing Qualitative Metrics**<br>Presentation (HECO Companies): Lisa Giang<br>Discussion |
| 11:00 am | **(4) Characterization / Information re: Resource Options**<br>Questions and Discussion |
| 12 Noon | **Lunch Break** |
| 1:00 pm | **(5) Explanation of Analysis of Principal Issues**<br>Presentation (HECO Companies): Lisa Giang<br>Questions and Discussion |
| 3:00 pm | **(6) General Questions and Comments** |
| 3:15 pm | **(7) What's Next** |
| 3:30 pm | **Adjourn** |

## 8. Technical Session 2: 18 December 2012

Hawaii Public Utilities Commission Docket No. 2012-0036
Integrated Resource Planning (IRP) For:
Hawaiian Electric Company, Inc. (HECO)
Maui Electric Company, Ltd. (MECO)
Hawaii Electric and Light Company, Inc. (HELCO)

# IRP Advisory Group Meeting
# Technical Session Agenda

**December 18, 2012 9:30 AM – 3:30 PM**

Queen Liliuokalani Conference Room
King Kalakaua Building
335 Merchant Street, 1st Floor

| | |
|---|---|
| 9:30 am | **Introductions and Review Agenda** |
| 9:40 am | **Morning Session**<br>• Questions by the IE (List of questions to be provided in advance of the technical session)<br>• Outstanding Issues and Questions by IRPAG Members |
| Noon | **Lunch** |
| 1:00 pm | **Afternoon Session**<br>• Continuation of Morning Session |
| 3:00 pm | **What's Next and Process Scheduling** |
| 3:30 pm | **Adjourn** |

## 9. Technical Session 3: 31 January 2013

Hawaii Public Utilities Commission Docket No. 2012-0036
Integrated Resource Planning (IRP) For:
Hawaiian Electric Company, Inc. (HECO)
Maui Electric Company, Ltd. (MECO)
Hawaii Electric and Light Company, Inc. (HELCO)

# IRP Advisory Group Meeting
# Technical Session #3 Agenda

**January 31, 2012 9:30 AM – 3:30 PM**

Training Room #2, Eighth Floor
American Savings Bank Tower
1001 Bishop Street, Honolulu, HI
(Located at the corner of King and Alakea Streets)

9:30 am **Introductions and Review Agenda**

9:40 am **Morning Session**

- General discussion of objectives and metrics to address the impacts of utility plans on the "environment, culture, community lifestyles, the State's economy and society"
  - Methods to determine and express qualitative metrics
  - Identification of specific metrics
  - Immediate or potential future actions to determine and express meaningful metrics
- Summary of findings and identification of follow-up actions

Noon **Lunch**

1:00 pm **Afternoon Session (if necessary)**

- Continuation of Morning Session

3:30 pm **Adjourn**

## 10. Meeting 7: 25 February 2013

Hawaii Public Utilities Commission Docket No. 2012-0036
Integrated Resource Planning (IRP) For:
Hawaiian Electric Company, Inc. (HECO)
Maui Electric Company, Ltd. (MECO)
Hawaii Electric and Light Company, Inc. (HELCO)

# IRP Advisory Group Meeting #7
# Agenda

**Monday, February 25, 2013 10:00 AM – 3:30 PM**

Training Room #2, Eighth Floor
American Savings Bank Tower
1001 Bishop Street, Honolulu, HI
(Located at the corner of King and Alakea Streets)

10:00 am **(1) Introductions and Welcome**

10:05 am **(2) Status Report on HECO Companies' Analysis of Resource Plans**

Presentation (HECO Companies): Lisa Giang

Brief Discussion

10:45 am **(3) Discussion of Qualitative Objectives and Metrics**

General discussion of objectives and metrics to address the impacts of utility plans on the "environment, culture, community lifestyles, the State's economy and society"

Review of written materials/comments by IRPAG members

Discussion and refinement of a list of metrics, impacts and concerns to characterize and evaluate resource plans and action plans

Discussion of possible formats, methods and or procedures to document impacts and concerns regarding the resource plans and action plans

12 Noon **Lunch Break**

1:00 pm **(3) Continuation of Morning Discussions**

3:00 pm **(4) Discussion/Clarification of Next Steps**

3:30 pm **Adjourn**

## 11. Conference Call: 28 March 2013

There was no official agenda for this conference call, only a short paragraph in an email.

MARCH 28 TELEPHONE CONFERENCE MEETING

1. **The telephone conference bridge for the March 28 IRPAG Phone Conference** can be accessed as follows:

   The call in number is: 888-482-3560.
   The access code is: 5863753

   The conference will begin at 10:00am and continue to completion but not beyond 3:30pm. If the conference continues into the afternoon, there will be a break for lunch.

   **The purpose of the March 28 phone conference** is to continue discussions begun at IRPAG Mtg. #7 on February 25 regarding methods to specify and present qualitative metrics, especially metrics pertaining to cultural values and community lifestyles. The phone conference will address preparation for the IRPAG meeting / work session scheduled on April 17 for this purpose. The phone conference will be facilitated by the IE. All IRPAG members interested in these topics are invited to participate.

## 12. Meeting 8: 2 April 2013

Hawaii Public Utilities Commission Docket No. 2012-0036
Integrated Resource Planning (IRP) For:
Hawaiian Electric Company, Inc. (HECO)
Maui Electric Company, Ltd. (MECO)
Hawaii Electric and Light Company, Inc. (HELCO)

# IRP Advisory Group Meeting #8
# Agenda

**Tuesday, April 2, 2013 10:00 AM – 3:30 PM**

HECO King St. Building Auditorium
900 Richards Street, 2nd Floor
Honolulu, Hawaii
(Use entrance on King Street between Richards and Alakea Streets)

10:00 am **(1) Welcome and Introduction**

10:10 am **(2) Presentation of the Analyses of Resource Plans**

Presentation (HECO Companies): Lisa Giang

Oahu System
Maui System
Big Island System
Lanai System
Molokai System

Clarification Questions

12 Noon **Lunch Break**

1:00 pm **(3) Presentation of Materials Addressing Specific Principal Issues**

Presentation (HECO Companies): Lisa Giang

Clarification Questions: (HECO panel available)

2:00 pm **(4) Questions and Discussion**

3:15 pm **(5) Clarification of Next Steps**

3:30 pm **Adjourn**

### 13. Technical Session 4: 8 April 2013

Hawaii Public Utilities Commission Docket No. 2012-0036
Integrated Resource Planning (IRP) For:
Hawaiian Electric Company, Inc. (HECO)
Maui Electric Company, Ltd. (MECO)
Hawaii Electric and Light Company, Inc. (HELCO)

# IRP Advisory Group Technical Session Agenda

**Monday, April 8, 2013 10:00 AM – 3:30 PM**

HECO King St. Building Auditorium
900 Richards Street, 2nd Floor
Honolulu, Hawaii
(Use entrance on King Street between Richards and Alakea Streets)

| | |
|---|---|
| 10:00 am | **(1) Welcome and Introduction** |
| 10:10 am | **(2) Process Status and Remaining Tasks** |
| | Presentation (HECO Companies) |
| | Questions and Comments |
| 10:40 am | **(3) Presentation of the Analyses of Resource Plans** |
| | Presentation (HECO Companies): Lisa Giang |
| | Clarification Questions |
| | Comments |
| 12 Noon | **Lunch Break** |
| 1:00 pm | **(4) Questions and Discussion (including technical questions)** |
| | Questions by the IE |
| | Questions by the Commission and Consumer Advocate |
| | Questions and Comments by the IRPAG |
| 3:00 pm | **(5) Next Steps and Discussion of Process Scheduling** |
| 3:30 pm | **Adjourn** |

## 14. Work Session: 17 April 2013

Hawaii Public Utilities Commission Docket No. 2012-0036
Integrated Resource Planning (IRP) For:
Hawaiian Electric Company, Inc. (HECO)
Maui Electric Company, Ltd. (MECO)
Hawaii Electric and Light Company, Inc. (HELCO)

# IRP Advisory Group Work Session
# Qualitative Metrics

# Agenda

**Wednesday, April 17, 2013 10:00 AM – 3:30 PM**

Training Room #2, Eighth Floor
American Savings Bank Tower
1001 Bishop Street, Honolulu, HI
(Located at the corner of King and Alakea Streets)

10:00 am **(1) Welcome and Announcements**

10:05 am **(2) Explanation of Process for Characterizing Qualitative Metrics**

Presentation by the IE

Clarifications / Discussion / Modifications

10:30 am **(3) Work Session: Identification of specific impacts, concerns and issues for specific resource technologies and resource options**

Review and populate list of resource technologies, resource options and plan elements

Breakout groups by sets of technologies, resource options and plan elements.

Full group check-in to compare progress

12 Noon **Lunch Break**

1:00 pm **(3) Work Session: Continuation of identification; refinement of characterization, notes and mitigation measures**

Framing afternoon session objectives

Breakout groups (or not) as determined

Full group check-in to summarize progress and characterize sense of agreement/completion

Work on summary tables/presentation (time permitting)

3:00 pm **(4) Discussion / Clarification of Next Steps**

3:30 pm **Adjourn**

### 15. Technical Session 5: 22 April 2013

Hawaii Public Utilities Commission Docket No. 2012-0036
Integrated Resource Planning (IRP) For:
Hawaiian Electric Company, Inc. (HECO)
Maui Electric Company, Ltd. (MECO)
Hawaii Electric and Light Company, Inc. (HELCO)

# IRP Advisory Group Technical Session #5
# Agenda

**Monday, April 22, 2013 10:00 AM – 3:30 PM**

HECO King St. Building Auditorium
900 Richards Street, 2nd Floor
Honolulu, Hawaii
(Use entrance on King Street between Richards and Alakea Streets)

| | |
|---|---|
| 10:00 am | **(1) Welcome and Introduction** |
| 10:10 am | **(2) Questions and Clarifications Regarding the Strategist Model** |
| | Clarification Questions and Responses |
| 11:10 am | **(3) Questions and Clarifications Regarding the Resource Plan Analyses** |
| | Clarification Questions and Responses |
| 12 Noon | **Lunch Break** |
| 1:00 pm | **(4) Questions and Clarifications Regarding the Rate Impact Analyses** |
| | Clarification Questions and Responses |
| 2:00 pm | **(4) Continued Questions Regarding the Resource Plan Analyses** |
| | Clarification Questions and Responses |
| 2:00 pm | **(5) Next Steps and Discussion of Process Scheduling** |
| 3:30 pm | **Adjourn** |

## 16. Meeting 9: 1 May 2013

Hawaii Public Utilities Commission Docket No. 2012-0036
Integrated Resource Planning (IRP) For:
Hawaiian Electric Company, Inc. (HECO)
Maui Electric Company, Ltd. (MECO)
Hawaii Electric and Light Company, Inc. (HELCO)

# IRP Advisory Group Meeting #9
# Agenda

**Wednesday, May 1, 2013 10:00 AM – 3:30 PM**

Training Room #2, Eighth Floor
American Savings Bank Tower
1001 Bishop Street, Honolulu, HI
(Located at the corner of King and Alakea Streets)

| | |
|---|---|
| 10:00 am | **(1) Welcome and Update on Recent Meetings**<br>Brief Presentation by the IE |
| 10:20 am | **(2) Addressing the Principal Issues**<br>Presentation (HECO Companies): How the Principal Issues have been addressed in the IRP process<br>Clarification Questions<br>Discussion |
| 12 Noon | **Lunch Break** |
| 1:00 pm | **(3) Continuation of Morning Session** |
| 2:30 pm | **(4) General Comments and Next Steps** |
| 3:30 pm | **Adjourn** |

### 17. Meeting 10: 30 May 2013

Hawaii Public Utilities Commission Docket No. 2012-0036
Integrated Resource Planning (IRP) For:
Hawaiian Electric Company, Inc. (HECO)
Maui Electric Company, Ltd. (MECO)
Hawaii Electric and Light Company, Inc. (HELCO)

# IRP Advisory Group Meeting #10
# Agenda

**Thursday, May 30, 2013 10:00 AM – 3:30 PM**

HECO King St. Building Auditorium
900 Richards Street, 2nd Floor
Honolulu, Hawaii
(Use entrance on King Street between Richards and Alakea Streets)

| | |
|---|---|
| 10:00 am | **(1) Welcome and Introduction**<br>Brief IRP Process Status Update (IE) |
| 10:30 am | **(2) HECO Draft Action Plan**<br>Opening Comments (HECO Companies)<br>Presentation (HECO Companies) |
| | **(3) HELCO Draft Action Plan**<br>Presentation (HECO Companies) |
| | **(4) MECO Draft Action Plan**<br>Presentation (HECO Companies) |
| 12:30 pm | **Lunch Break** |
| 1:30 pm | **(5) Clarification Questions on Draft Action Plans** |
| 2:30 pm | **(6) Advisory Group General Questions and Comments** |
| 3:15 pm | **(7) Next Steps** |
| 3:30 pm | **Adjourn** |

# Advisory Group Materials

Each Advisory Group meeting included many various documents, mostly from the Companies and the Independent Entity. The meetings also generated follow-up questions, comments, suggestions, and other documents by the Companies and the Independent Entity, but mostly from Advisory Group members.

Most file names begin with a four-digit number: the first two numbers correspond to the numbered folders; the second two numbers are simply sequential as documents were received or created.

All of this information can be found on the web site: http://www.irpie.com.

# Responses to Advisory Group Comments

The Companies responded directly to three comments from the Advisory Group in October 2012, and also answered to a request from the Independent Entity for responses to a number of other Advisory Group comments.

The Companies responded to these additional comments in June 2013.

This correspondence is recorded in the following sections.

## Transmittal of Requested Responses

# Hawaiian Electric Companies' Responses to Comments re: AG Meeting #4

October 22, 2012

Attn: Carl Freedman, Independent Entity ("IE")

On October 2, 2012, the Hawaiian Electric Companies received an email from the IE with attachments containing comments, questions, and requests received within the comment period following IRP Advisory Group ("AG") meeting #4 held September 24, 2012.

Please find attached as Attachment 1, the Hawaiian Electric Companies' responses to the following requests for written responses:

1. Correspondence dated October 1, 2012 from Greg Kahn, I Aloha Molokai ("IAM") identified as AG comment #0346.
2. Correspondence dated October 1, 2012 from Doug McLeod and Kal Kobayashi, County of Maui identified as AG comment #0347.
3. Correspondence dated September 29, 2012 from Lee Jakeway, Director, Energy Development, Hawaiian Commercial & Sugar Co. identified as AG comment #0356.

Thank you,
Lisa

**Lisa K. K. Giang, P.E.**
*Director, Corporate Energy Planning Division*
*System Planning Department*
*Hawaiian Electric Company*

## Responses to Advisory Group Comments

The Companies responded to the following Advisory Group comments.

### *Advisory Group Comment 0346*

On October 1, 2012, Greg Kahn, I Aloha Molokai (IAM), requested a response to these four comments.

**Comment:** *In [AG Comment] #0308, I suggested that "Community" and "Cultural" be considered as separate Objectives.*

**Response:** The Companies have revised Objective 1 to provide separate qualitative metrics for culture and community (see Chapter 3: Objectives and Metrics).

**Comment:** *In [AG Comment] #0317, I hoped that adverse environmental impact would each be defined as a separate metric, as are the emissions ones. (I clarified this as a verbal comment during the following meeting.)*

**Response:** In the Objectives and Metrics document dated September 14, 2012, the Companies had already added a qualitative metric to address the non-air emissions related impacts under Objective 2: "Other potential non-air emissions related environmental impacts (for example, siting, land conversion, endangered species, invasive species)". The Companies have now also added another qualitative metric under Objective 2: "Impact on water resources". Some information on water usage of potential future resources is being provided in the Supply-Side Resource Options Unit Information Forms (UIFs).

**Comment:** *In [AG Comment] #0336, my Critical Theme entry of "Economic Factors Shaping the Energy Debate" did not receive a response.*

**Response:** The Companies' financial integrity is included in Objective 7: "Annual revenue requirements for capital".

**Comment:** *In Docket No. 2012-0036 [the subject docket], my comment that "monthly bill" be used as a standard of measure for impact on a customer rather than the term "rate" does not appear in "discussion on Objectives".*

**Response:** This metric was added as part of Objective 7: "Nominal residential bill" with an associated description of "Nominal monthly residential bill based on a typical monthly consumption."

### *Advisory Group Comment 0347*

On October 1, 2012, Doug McLeod and Kal Kobayashi, County of Maui, requested a response these four comments.

**Comment:** *We request that HECO respond in writing to all of our written comments, including comments submitted on July 30, 2012 [AG Comment 0311] relating to objectives and metrics, comments submitted on August 14, 2012 [AG Comment 0318], and comments submitted on August 29, 2012 [AG Comment 0327]. We note that HECO excluded references to our written comments in HECO's Discussion on Objectives from AG Meeting #2 document.*

**Response:**

In response to AG Comment 0311, all of which apply to Chapter 3: Objectives and Metrics, We:

- Reworded the opening paragraph to reflect the full quote from the Framework document.
- Incorporated the suggested deletion of metric "Potential impacts on and computability with community lifestyles" in Objective 1.
- Expect that the suggested metric addition referencing "community acceptance" can be captured in the qualitative metrics under Objective 1.
- Considered the suggested revision of "Protect Hawaii's Environment, Culture, and Communities" within Objective 1 and Objective 2.
- Considered the suggested revision to the second metric under Objective 2 about "sulfur oxides" to include reportable pollutants without taking action.
- Considered the suggested addition of the metric "Generation process water" without taking action. We did, however, add another qualitative metric under Objective 2 about the impact on water resources because some information on water usage of potential future resources are being provided in the UIFs.
- Considered the suggested metric "Renewable energy curtailed during a 30% oil supply disruption" for Objective 2 without taking action.
- Edited the first metric under Objective 3 from "Share of delivered energy linked to oil" to "Share of delivered energy from imported fossil fuels".
- Did not incorporated the suggested metric "Annual revenue requirement for fuel", however we added another metric to Objective 3: "Share of the resource plan's cost linked to imported fossil fuels".
- Considered adding a "willingness to pay" metric to Objective 3 without taking action because related surveys would not be conducted nor completed within the IRP process. Advisory Group members, however, are able to provide their perspectives and comments on the issues throughout the planning process.

- Captured, and further refined, the suggested revision to the formula for the third metric under Objective 3: "Amount of Imported fuel oils".
- Considered the suggested revision to objective "Reduce dependency on imported oil, increase energy security, and improve price stability" in our revisions to Objective 3 and Objective 4.
- Changed Objective 4 from "Increase the Use of Renewable Energy Resources" to "Increase the Use of Indigenous Energy Resources".
- Reflected curtailed energy in the second metric under Objective 4: "Renewable energy curtailed".
- Changed Objective 5 from "Maintain Reliability" to "Provide Reliable Service".
- Changed the fourth metric under Objective 5 to read "Geographic diversity of generating resources".
- Renamed the metric "Fossil fueled generation efficiency" to read "Generation efficiency", added a formula, and moved it to be the first metric under Objective 6.
- Considered changing Objective 7 to "Provide electricity in an economically sustainable manner", but determined it is difficult to define "sustainable". While Objective 7 remains "Provide Electricity at Reasonable Cost", we rewrote the accompanying descriptive paragraph.
- Changed the fifth metric under Objective 7 from "Impact to state economy" to read "Impact to the local economy".

In response to AG Comment 0318:

- The Companies (with representatives from MECO) held public meetings on the islands of Lanai and Molokai. For a detailed summary of those meetings, see Appendix G: Public Commentary.
- We noted the suggested addition of metric "Maintain reliable service", although this is captured in Objective 5.
- We directed comments 3, 4, and 5 to fellow Advisory Group members and the Independent Entity.

In response to AG Comment 0327: The Companies noted the comments directed towards fellow AG members, however, we disagree that the scenarios were rejected on August 24.

**Comment:** *Regarding HECO's first proposed objective, Protect Hawaii's Culture and Communities, we note that its metric, Potential impacts on, and compatibility with, community lifestyles, has no accompanying formula. Further, no details were provided at the September 24 meeting on this issue, nor was there an opportunity to discuss the merits of incorporating community-based surveys as a means to assess the compatibility of possible resource plans and preferred attributes with community lifestyles, as we suggested in our July 30 comments and with our September 17 submission of the Executive Summary of the Molokai Data Book. Accordingly, we respectfully request, pursuant to section III.C.2.c.(3) of the IRP Framework, that the*

*Independent Entity shall ensure that the utility provides consideration to input by the County of Maui on this matter.*

**Response:** The Companies considered this comment without taking action because the surveys would not be conducted nor completed within the IRP process. Advisory Group members are able to provide their perspectives and comments on the issues throughout the planning process. See the Objective 1 metrics — "Potential impacts on, and compatibility with, community lifestyles" and "Potential impact to Hawaii's culture and cultural values" — in Chapter 3: Objectives and Metrics, for where results from surveys led and conducted by others could be incorporated.

**Comment:** *We are willing to make a presentation in a future IRP AG meeting if the IE believes it would be beneficial to help explain our proposal. We would seek the assistance of a professional involved with the assessment of community values to support our presentation, which would be expected to take 30 minutes plus 15 minutes for a Q&A session. We would also work with the IRP IE to structure the presentation to address any issues and questions that he and the Commission may have, including addressing issues relating to the time frame and the costs associated with this effort.*

**Response:** No response was required from the Companies, instead we directed this comment to the Independent Entity.

**Comment:** *We suggest that the Commission and the IRP IE consider hiring an independent expert to determine how community input can best be incorporated into IRP. If the IRP IE or the PUC oversees the methodology to obtain community input it may be considered more unbiased.*

**Response:** No response was required from the Companies, instead we directed this comment to the Independent Entity.

### *Advisory Group Comment 0356*

On September 29, 2012, Lee Jakeway, Director, Energy Development, Hawaiian Commercial & Sugar Co., requested that the Companies address previously submitted additions to the descriptions of the four scenarios:

**Comment:**

- *"A Big Leap" Scenario:* This is a world in which … "the utility invests in its own renewable energy generation systems for sale of electricity to its customers and to help meet State RPS goals."
- *"Stuck in the Middle" Scenario:* This is a world in which … "the majority of electric power generation is now produced by IPPs and the utility migrates towards becoming a transmission service company."
- *"No Fire" Scenario:* This is a world in which … "During the era of high oil prices, the electric utility converted is generating units to [aero derivatives] fueled by imported LNG, but now LNG has become expensive compared to oil. Converting the [aero derivatives] generating

units to run on oil is difficult because the transport and storage infrastructure for oil no longer exists."

- *"Moved by Passions" Scenario:* This is a world in which … "the utility must use cleaner alternative forms of energy to avoid paying penalties for carbon emission regulations."

**Response:** The Companies understand this request refers to Advisory Group comment 0328, submitted August 28, 2012, on the original draft scenarios. We did consider these comments but determined that it would be more appropriate to consider them during the strategy discussion.

## Request for Responses to Additional Comments

# Carl Freedman, Independent Entity

**Hawaii Public Utilities Commission Docket No. 2012-0036**
**Integrated Resource Planning (IRP) For:**
**Hawaiian Electric Company, Inc. (HECO)**
**Maui Electric Company, Ltd. (MECO)**
**Hawaii Electric and Light Company, Inc. (HELCO)**

May 6, 2013

**To:** Ross Sakuda, Hawaiian Electric Companies

**From:** Carl Freedman, IRP Independent Entity (IE)

**Re:** Inquiry Regarding Responses to Advisory Group Comments

This is an inquiry to determine whether the Hawaiian Electric Companies intend or are willing (without formal request by the IE) to provide responses to several comments and questions submitted by members of the IRP Advisory Group (IRPAG). Please initially respond to this inquiry by Wednesday, May 8, 2013 by indicating (a) whether responses will be provided without further formal request by the IE, (b) a proposed date by which responses would be provided and (c) the proposed method and format for responses. Initial response to this inquiry and any written responses to the IRPAG comments listed below should be addressed by one or more documents transmitted by email memo addressed to upload@irpie.com. for posting on the IRPIE.COM web site and distribution to the IRPAG.

This inquiry applies to the following documents posted on the IRPIE.COM web site in the folder: "03 IRPAG Comment Uploads":

0399 Comments Mtg 7 Sally Kaye IRP word questions 3.02.13.pdf

10301 Comments Mtg 7 Betsy Cole Comment about review of resource and action plans.pdf

10302 Comments Mtg 8 Dawn Lippert NREL Renewable Energy Cost Curves 2002.pdf

> Response regarding this document would address the related questions posed in several IRPAG meetings, including: why increasing cost escalation assumptions are used in the resource plan analyses in light of historical and projected decreasing trends and; what is the basis for the assumed increasing escalation factors.

10303 Comments Mtg 8 Life_of_the_Land_Comments_re_IRP.pdf

10305 Comments Mtg 8 Sally Kaye IRP word questions 4.7.13.pdf

10305 Comments Tech Session Apr8 Will Rolston RSWGDemandSideOptionsSubgroupWhitepaper12-5-12(1200HST).pdf

10306 Comments Tech Session Apr 8 EPA_DOE LCA comments for IRP.pdf

10307 Comments Tech Session Apr 8 EPA_DOE LCA 2-pager 4.12.13.pdf

10309 Sally Kaye IRP word questions 4.14.13.pdf

10310 Comments Mtg 8 Blue Planet IRPmeeting#8comments 042113.pdf
10311 Comments EPA Compliance Cost Letter with Enclosure.PDF
10312 Comments Elizabeth Cole disruptivechallenges.pdf
10313 Comments Elizabeth Cole Disruptive Challenges_ Financial Implications.pdf
10314 Comments Earthjustice Isaac Moriwake.pdf
10315 Comments Sally Kaye IRP word questions 4.22.13.pdf
10316 Comments Consumer Advocate Synapse questions for 4-22-13 mtng.pdf
10317 Comments Earthjustice 2013-5-2 IRP-AG.pdf
10318 Comments Sally Kaye IRP word questions 5.3.13.pdf

Respectfully submitted,
Carl Freedman, IRP IE

## Answer to Request for Additional Responses

May 8, 2013

To: Carl Freedman, IRP Independent Entity (IE)

From: Ross Sakuda, Hawaiian Electric Company, Inc.

Re: Inquiry Regarding Responses to Advisory Group Comments Dated May 6, 2013

In accordance with Order No. 30513, ordering paragraph No. 2, filed June 29, 2012, the Companies are committed to fulfilling our obligation to file the IRP Final Report and Action Plan by June 28, 2013 and to address the Commission's Issues.[1] We are committed to considering the comments of the Advisory Group (AG) and to building their understanding of our analysis and Action Plan. The Companies plan to file a summary response in matrix form with the report to address the comments from the AG.

The Companies have considered the IRP AG comments and questions throughout this IRP process. We have used these comments and questions to inform the Companies' preparation of the analytical results, and will continue to consider them in the development of the Action Plan and the IRP Report.

- The Companies answered many of these comments and questions verbally at the IRP AG meetings and Technical Sessions.
- Some comments and questions have resulted in modifications to the calculations in the analyses (such as the costs for retirement of existing generating units, costs for continuing the operation of the existing generating units, and including transmission costs), as well as additional analyses (such as sequencing the retirement of existing generation over a longer period, and assessing the capacity value of wind) to provide more clarity in addressing the Principal Issues.
- As explained at the May 1st IRP AG meeting, the Companies have reviewed the renewable energy cost curves and, with support from consultants, the Companies will provide a response to be included in the report.
- The Companies are also updating the "Environmental Compliance Alternatives" document dated March 26, 2012 to include the costs for the fuel switching alternatives.

While we are sensitive to the need to take the inputs and comments of the Advisory Group ("AG") into account as we complete the analyses and develop the Action Plan, providing formal, written responses to comments and questions identified in this inquiry totaling about 81 pages covering over 90 comments/questions, as well as additional comments and questions that continue to be submitted on an ongoing basis, such as Life of the Land's recent submittal of 34 pages with 75 questions, would divert the Companies' resources at this time from documenting the analyses and completing the

[1] Order 30513, filed June 29, 0212 at 6: "The Hawaiian Electric Companies have one year from the date of this Order to file their Integrated Resource Planning Reports and Action Plans with the commission."

filing by June 28, 2013, and could diminish the quality of the IRP Final Report and Action Plan.

The Companies are working to document all the analyses and plan to provide the updated files to the IRP AG as requested. The Companies are also moving toward a presentation of the Draft Action Plan at the next IRP AG meeting on May 30, 2013. This meeting provides another opportunity to address questions and comments. If there are specific comments and/or questions on the referenced list that the IE feels it is imperative to formally discuss at the May 30, 2013 IRP AG meeting, the Companies request that the IE specify which those are at least one week prior to the meeting.

It would be useful to have a meeting between the Consumer Advocate, you and me to have a constructive discussion of the work that can be accomplished in the remaining time.

Thank you for your consideration.

## Responses to Additional Advisory Group Comments

The IRP Advisory Group (AG) contributed significant input and guidance to the Companies throughout the entire IRP process, through active participation and the submission of numerous comments. The Advisory Group's contributions changed and shaped the objectives, scenarios, and many aspects of the analysis, and were considered in the overall approach to IRP and Draft Action Plan. In each Advisory Group meeting, the Companies provided additional information to requests for clarification and responses to questions from the Advisory Group. The following matrix identifies the key issues on which the Advisory Group and Independent Entity (IE) made comments, with a summary of the Companies' response and reference to the section in the report where it is addressed in more detail. Related comments from Advisory Group members and the IE were included under each issue to provide additional insight and reference. This matrix is not intended to be an exhaustive and comprehensive list of questions submitted by the Advisory Group, rather it is intended to supplement the IE's minutes of the Advisory Group meetings and record of comments submitted during the IRP process found on the irpie.com website.

### Lanai Wind – What are the comparative economics of Lanai Wind to other wind options, using consistent cost assumptions or sensitivity analysis?

Company Response: The Lanai Wind project was analyzed to compare its cost with the undersea cable against other renewable resources.

| AG Member & Organization | Date | Summary of Comment | Response |
|---|---|---|---|
| Carl Freedman; IE | 5/10/13 | Prices/costs assumed for various wind projects are not consistent, difficult to compare. | As explained at AG Meeting #8 on April 2, 2013, AG Technical Session #4 on April 8, 2013, AG Technical Session #5 on April 22, 2013, and AG Meeting #9 on May 1, 2013, the Lanai Wind project was modeled at a levelized pricing per the signed Term Sheet. Other wind resources were also modeled as levelized pricing based on the UIF data for several wind classes. The different wind classes reflects different energy outputs from wind farms which affects $/kWh values for the different 10 MW size installations. |
| Sally Kaye; Friends of Lanai | 5/5/13 | Discuss why Lanai Wind appears in so many resource plans. | Lanai Wind was considered during the renewable screening phase of the modeling. Resource plans were constructed with and without Lanai Wind in 2020. Based on this comparative analysis, Lanai Wind was deemed to be cost effective and carried forward in future resource plans. |
| Sally Kaye; Friends of Lanai | 4/24/13 | Is Lanai Wind treated consistently with other wind projects in regards to escalation of kWh price? | Lanai Wind is escalated consistent with its term sheet. |
| Consumer Advocate | 4/22/13 | Why is Lanai Wind cheaper than Oahu wind before the cable costs? | Lanai Wind is comparable to onshore wind before cable costs. Please see Bus Bar Cost Analysis in Chapter 7. |

## Inter-Island and Inter-Utility System Transmission – What analysis has been done to examine the economics, value, and optimization of inter-island transmission?

Company Response: Grid ties between Oahu and Hawaii Island and Oahu and Maui, as well as a generation tie between the Oahu grid and Lanai Wind were analyzed to examine the economics, value and optimization of inter-island transmission. Assumptions regarding the capacity of the cable, cable, costs, interconnection charges, installation date, debt rate, and return on equity were established to assess the comparative cost and benefits. Levelized costs were calculated to set the minimum difference between the costs of energy on each island that must be overcome before energy is transferred on economic dispatch between grids. This cost differential decreases substantially as the amount of energy transmitted increases. Please see Chapter 11 for a more detailed discussion.

| AG Member & Organization | Date | Summary of Comment | Response |
|---|---|---|---|
| Carl Freedman; IE | 5/10/13 | Can the Companies meet RPS without inter-island transmission of energy?<br>What analysis has been done to examine the economics and feasibility of on-island versus other-island wind or other renewable generation? Is it more economical to provide renewable resources on Oahu than providing renewable resources on another island utilizing a cable?<br>Does interconnection provide value to other islands when used to transport economical generation of low-priced LNG on Oahu to flow to connected neighbor islands? | On island renewable energy, the interisland transmission of energy, and their effect on the RPS were addressed in Chapters 8 and 11. |
| Henry Curtis; Life of the Land<br>Gregory Khan;<br>I Aloha Molokai | 5/6/13 | Will AC cables between islands within Maui County be part of the filing with the Public Utilities Commission?<br>Have the Companies concluded that a Maui wind facility tied to Oahu (gen tie) is preferable to interconnection of HECO and MECO grids (grid tie)? | Please see Chapter 11 for an analysis of Lanai Wind and a grid tie between Maui and Oahu. |
| Sally Kaye; Friends of Lanai | 5/5/13 | What is the standard for reliability in regards to redundancy of the cable lines used to interconnect the islands?<br>How was the cost of the cable between Lanai and Oahu calculated? What distance and route were used?<br>Where are infrastructure upgrade costs on Oahu reflected? | The inter-island cable configurations and costs were provided in the document "Interisland Transmission Interconnection Capital Cost Estimate" provided on February 21, 2013, revised document provided on March 26, 2013, and included as Appendix H in this filed IRP report. |
| Sally Kaye; Friends of Lanai | 3/2/13 | Why were on-Oahu infrastructure upgrade costs necessary for inter-island transmission not included in the inter-island transmission material? | The on-Oahu infrastructure upgrade costs associated with the interisland cable included interisland transmission costs as shown in Appendix H. |

**Renewable Cost Curves – Explain the rationale for the cost escalation projections that the Company adopted for renewable energy in its analysis.**

Company Response: As explained at the AG Meeting #9 on May 1, 2013, the NREL cost curves depict a declining cost in constant, real dollars pegged in year 2000. The Strategist model accounts for cost in terms of nominal dollars which includes inflation. If a negative escalation was to be applied to the resources in the model, there would eventually come a time in the future that the costs would end up negative, which is unrealistic. As a means of addressing the AG comments, different escalation rates were used in the scenarios, including zero escalation for one scenario which results in renewable technology costs declining in real dollars and being flat in nominal dollars.

| AG Member & Organization | Date | Summary of Comment | Response |
|---|---|---|---|
| Dawn Lippert; PICHTR | 5/1/13 | How has the utility addressed the potential decline in the costs of renewables, as shown by NREL? How does a zero escalation in renewable energy costs represent declining cost curves? | The potential decline in renewable technology costs was addressed in Blazing a Bold Frontier by assuming a 0% construction cost escalation for renewables. The NREL cost curves provided by the AG depict a declining cost in constant, real dollars pegged in year 2000. However, the Strategist model accounts for cost in terms of nominal dollars which includes inflation. In IRP, it is assumed that after accounting for inflation, the declining real dollar cost in renewable technologies would appear flat in nominal dollars. Additionally, the Companies reviewed and assessed the NREL data provided by the AG. This assessment is provided in Appendix K in the IRP report. |
| Henry Curtis; Life of the Land<br>Gregory Khan; I Aloha Molokai | 5/6/13 | Will declining prices be modeled for the installed price of photovoltaic panels? | Please see response to above. |

**Cycling/Must Run – Explain the basis for the designation of "must run" units and what analysis has been done on economic dispatch and flexibility.**

Company Response: For Hawaiian Electric, all future resource plans, regardless of scenario, were developed to satisfy the load service capability (Rule 1) and quick load pickup criteria (Rule 2), the reliability guideline, and the spinning reserve requirements at a minimum. Hawaiian Electric's current reliability guideline of 4.5 years per day was applied in computer simulations in addition to the Rule 1 criteria using the Strategist model to determine the appropriate timing of supply side resource additions. HELCO and MECO's Maui Division uses a similar form of Rule 1, however, HELCO and MECO do not have a Rule 2 criteria. Instead separate capacity planning criteria (See Chapter 8) was used to determine the timing of additional generating units. Please see Chapter 8 for a more detailed discussion.

| AG Member & Organization | Date | Summary of Comment | Response |
|---|---|---|---|
| Consumer Advocate | 5/20/13 | Why are some units labeled as must run units?<br>What are the technical or economic reasons for designating specific units as must runs?<br>Analysis should be done where must run plants are turned off for weeks and months at a time to better understand plant flexibility and potential for lower rates. | Please see Chapter 8 for analysis of the additional cycling of baseloaded units. |

**Process of Developing Draft Action Plan – How did the companies use the multitude of resource plan analyses to form usable findings that resulted in the development of a robust Draft Action Plan, and has the Company prioritized the resource plans?**

Company Response: The Companies reviewed all the analyses and Resource Plans to develop the Action Plan. The Companies defined Preferred, Contingency, Parallel, and Secondary Resource Plans in developing the Action Plans.

| AG Member & Organization | Date | Summary of Comment | Response |
|---|---|---|---|
| Carl Freedman; IE | 5/10/13 | It is not clear how the multitude of various resource plan analyses is converging on useable finding that will result in a robust Action Plan.<br>It is not clear how resource plans are considered to serve as desirable objectives for the Action Plan. It is not clear what types of finding and conclusions the Companies plan to draw from the analyses or whether these will adequately support the Action Plan. | Please see Chapters 8–11 and 19. |

**Use of HECO CIP CT-1 Generating Facility – What analysis was done to assess the highest and best use of the CIP CT-1 generating facility?**

Company Response: The Companies performed seven analysis runs under the Stuck in the Middle scenario to determine the most cost-effective plan for fuel to burn in the CIP CT 1 unit, and how best to operate the unit. These runs addressed the most cost-effective plan in both the short term and in the long term. Please see Chapter 10 for a more detailed discussion of the analysis and the conclusions drawn.

| AG Member & Organization | Date | Summary of Comment | Response |
|---|---|---|---|
| Carl Freedman; IE | 5/10/13 | What benefits would be gained by using CT-1 unit to support the maximum integration of renewables?<br>Discuss analysis regarding using CT-1 to provide both up and down regulation/operating reserves, rather than to provide system spinning reserves.<br>Discuss analysis of converting CT-1 to a combined-cycle unit as a means to provide more efficient fuel use and/or to support maximum integration of renewables. | Please see Chapter 10 for an analysis of future options for CIP CT-1. |

**Scope of Resource Options – Discuss the scope of resource options that were considered and analyzed in the modeling.**

Company Response: The breadth of resource options analyzed in this IRP is described in Chapter 7.

| AG Member & Organization | Date | Summary of Comment | Response |
|---|---|---|---|
| Carl Freedman; IE | 5/10/13 | What investments in utility system infrastructure or expenditures toward mitigating system operating protocols are sufficient and justified to accommodate additional variable renewable distributed generation resources? (Reference pgs. 9–10)<br>What are the merits of customer-sited distributed generation as a potential resource strategy? (Reference pgs. 9–10)<br>What are the economics and potential for providing ancillary services to accommodate additional variable generation resources? (Reference pgs. 9–10) | The growth of NEM/FIT was incorporated into the sales and peak forecasts. In addition, the annual and cumulative impacts of NEM/FIT were summarized in the preferred plan sheets for the Hawaiian Electric Companies. |

**Energy Storage – What value and impacts would storage technologies contribute to stabilizing the grid when necessary?**

Company Response: The costs and benefits of energy storage was analyzed in Chapter 8.

| AG Member & Organization | Date | Summary of Comment | Response |
|---|---|---|---|
| Carl Freedman; IE | 5/10/13 | What is the ability of storage technologies to stabilize the grid when necessary? Why are hydrogen storage and pumped hydroelectric storage technologies not analyzed as energy storage options? What impacts, if any, would a battery storage resource have on the stabilization of the grid? Why was energy storage not analyzed for Hawaii Island? | Please see Chapter 8 for the battery analysis and discussion on existing battery studies. |
| Dawn Lippert; PICHTR | 5/1/13 AG meeting | What assumptions were used in determining the costs of batteries in the future? | The costs for the batteries are provided in Appendix K and the description of the scenarios provide the escalation rates applied in that given scenario. |

### Waste to Energy – What analysis was required in order to provide a meaningful assessment of the merits of waste-to-energy resources?

Company Response: Waste to energy resources were considered during the firm timing step of the analysis. Resource plans that considered waste to energy resources can be found in Appendix O.

| AG Member & Organization | Date | Summary of Comment | Response |
|---|---|---|---|
| Carl Freedman; IE | 5/10/13 | What analysis has been done to incorporate the effect that tipping fees may have on the cost competitiveness of waste-to-energy resources? If there is value in waste-to-energy resource, identify the steps required to enable consideration of effective procurement. | Bus bar costs for all resource options in this IRP have been prepared using the O&M and capital cost escalation assumptions in Blazing a Bold Frontier and Stuck in the Middle. The $ per kwh cost of the waste-to-energy resource was prepared with and without tipping fees. |
| Henry Curtis; Life of the Land<br>Gregory Khan; I Aloha Molokai | 5/6/13 | Will negative stream flows be modeled to reflect waste-to-to energy tipping fees? | Please see the bus bar cost analysis in Chapter 7 for the cost of a waste-to-energy resource with tipping fees. |

### EPA Compliance – Explain how the Companies analyzed cost comparisons and estimates to achieve EPA compliance, including alternatives to fuel switching.

Company Response: Alternatives to meeting future environmental compliance regulations were analyzed in Chapter 9. Fuel switching to lower sulfur fuels was found to be the most robust strategy for the Hawaiian Electric Companies.

| AG Member & Organization | Date | Summary of Comment | Response |
|---|---|---|---|
| Carl Freedman; IE | 5/10/13 | What extent would generation fuel switching strategies result in the net reduction in capital and operating cost for compliance with environmental regulations? | Please see Chapter 9 for an analysis of environmental compliance alternatives. |
| Bash Nola; Blue Planet | 4/17/13 | Has the cost effectiveness of repowering existing facilities to obtain quick start, dispatchable, firm /intermediate capacity in lieu of adding new combustion turbines or ICE's to back stop the addition of greater amounts of renewable intermittent energy?<br>Have various degrees of EPA compliance (i.e. such a retrofitting only a portion of the existing generation fleet, but retire other units) been analyzed, so EPA compliance is not viewed as an all or nothing analysis? | The analysis for CIP CT-1 in Chapter 10 included converting the unit to combined cycle. No other repowering of existing facilities was evaluated.<br>The various combinations of retrofitting only a portion of the existing generation fleet and deactivating or decommissioning other units would fall in between the extremes that were analyzed and discussed in Chapter 9. Detailed studies would need to be conducted to obtain better cost estimates for deactivating or decommissioning existing generating units. |

| | | | |
|---|---|---|---|
| Isaac Moriwake; Earth Justice | 4/24/13 | What options besides back-end controls and fuel switching have been considered to meet EPA compliance? How have variable renewables been evaluated in regards to compliance? | The alternatives for EPA compliance were previously provided on March 26, 2013 as the document called "Environmental Compliance Alternatives" and is now provided in Chapter 9 of the IRP report. Although incorporating variable renewable generation decreases fossil fuel generation, variable renewable generation alone is not an alternative for complying with the EPA regulations. |

**Levelized Cost Calculations – How can technologies be compared objectively without levelized cost comparisons?**

Company Response: Bus bar costs for all resource options was provided in Appendix K.

| AG Member & Organization | Date | Summary of Comment | Response |
|---|---|---|---|
| Consumer Advocate | 5/20/13 | Have levelized cost calculations been prepared for each technology? How have they been incorporated into the analyses?<br>Comparison between technologies is difficult without levelized costs. | Please see Chapter 7 for bus bar costs of all resource options in IRP. |

**Reasonable Costs and Rate Impacts – Describe the Companies' evaluation of an "all-in" assessment of the cost of providing electric utility service, including costs of smart grid, ancillary services necessary to accommodate variable resources, transmission and distribution, life extension and increased maintenance cost for older generation units.**

Company Response: An "all-in" rate impact analysis was provided in Chapter 8.

| AG Member & Organization | Date | Summary of Comment | Response |
|---|---|---|---|
| Carl Freedman; IE | 5/10/13 | The objective required by the Principal Issues is an "all-in" assessment of the cost of providing electric utility service, including costs of smart grid, ancillary services necessary to accommodate variable resources, transmission and distribution, life extension and increased maintenance cost for older generation units.<br>Discuss/clarify assumptions regarding escalation, discount rates, and inflation.<br>Discuss any implicit assumptions regarding inflation. | Please see Chapter 8 for the "all-in" analysis for rate impacts. |

**RPS Costs and Rate Impact – Explain the analysis on the cost and rate impacts resulting from various levels of RPS attainment and the basis for the approach in the Draft Action Plan.**

Company Response: The cost and rate impact of various levels of RPS attainment was analyzed in Chapter 8. The RPS percentage of the preferred plans is described in Chapter 19.

| AG Member & Organization | Date | Summary of Comment | Response |
|---|---|---|---|
| Warren Bollmeier; Hawaii Renewable Energy Alliance | 6/10/13 | What are the Companies' cost/pricing criteria for acquiring utility-scale renewables? | Please see Chapter 18 for a discussion on the recent results of the Invitation for Waiver Projects. |
| Consumer Advocate | 5/20/13 | What analysis has been done to accurately reflect the inclusion of customer-sited generation in meeting RPS?<br>Discuss analysis of the potential benefits of aggregating renewable energy portfolios among the islands. | Growth in NEM/FIT was included in the development of the sales and peak forecast that was used by the Strategist model. Each scenario had a different NEM/FIT forecast consistent with the scenario narrative. The impact of NEM/FIT was accounted for in the outside the model calculations for the renewable energy percentage by system and consolidated RPS. |
| Carl Freedman; IE | 5/10/13 | Determination and statement on the cost and rate impacts resulting from various levels of RPS attainment. (Reference pgs. 14–15)<br>Does implementation of RPS result in increased costs/rates, if so what are these costs and how do they affect the rates?<br>Discuss costs/rate impacts of various levels of RPS attainment?<br>Discuss the analysis that has been done to evaluate RPS with and without inter-island cable costs. | Various levels of RPS attainment were evaluated. In particular, resource plans were constructed for each system with no RPS requirement. For these resource plans, renewable resources were added economically and on a consolidated basis, could meet the current RPS law. While the plans demonstrated that renewable resources can be added cost effectively, the availability and cost of the renewables will ultimately be determined by the RFP and competitive bidding processes.<br><br>Please see Chapter 8 for the RPS Rate Impact analysis. |

**EEPS Costs and Rate Impact – What analysis has been done on the cost and rate impacts from various levels and strategies for attainment of EEPS.**

Company Response: The cost and rate impact of various levels of EEPS was analyzed in Chapter 8.

| AG Member & Organization | Date | Summary of Comment | Response |
|---|---|---|---|
| Consumer Advocate | 5/20/13 | Analyses to date have shown that higher levels of investment in energy efficiency results in lower total resource costs, what analysis has been done to examine exceeding EEPS by more than 10%? Specifically impacts of 150% EEPS.<br>Bill impacts for participants and non-participants should be calculated based on revised monthly consumption levels for the different EE forecasts. How has avoided electricity costs as a result of energy efficiency been analyzed in regards to the costs of meeting EEPS? | Higher levels of energy efficiency were shown to lower total resource costs and raise electricity rates in scenarios with declining load where energy efficiency did not provide capacity deferral benefits. In scenarios where there is load growth, higher levels of energy efficiency were shown to lower rates. It is expected that a 150% level of energy efficiency would be consistent with this trend. |
| C6rl Freedman; IE | 5/10/13 | Determination and statement on the cost and rate impacts resulting from various levels of EEPS attainment. What analysis has been done to explore geographically targeted energy efficiency and load management opportunities? (Reference pgs. 15–16)<br>Analyses to date have shown that higher levels of investment in energy efficiency results in lower total resource costs, what analysis has been done to examine exceeding EEPS by more than 10%? | Please see Chapter 8 for the EEPS Rate Impact analysis. |

**Rate Impact Analysis – What analysis was done to evaluate the rate impacts on customers without renewable energy or energy efficiency resources under various forecasts and scenarios?**

Company Response: A comparative analysis of utility customers and customers choosing to self generate, via PV or LNG fueled Fuel Cell, was provided in Chapter 19.

| AG Member & Organization | Date | Summary of Comment | Response |
|---|---|---|---|
| Warren Bollmeier; Hawaii Renewable Energy Alliance | 6/10/13 | Have the HECO Companies' conducted their own internal cost/benefits analysis of the net metering program?<br>Will this study be shared with the AG? | The Companies have not conducted a cost/benefit analysis of the net energy metering program. However, the Companies recognize that it is unfair for customers who cannot afford to install their own system to incur the additional burden for costs no longer contributed to by NEM customers, This is one consideration of the "Fairness" for all customers strategic theme that is part of the foundation of the development of the Action Plans.<br>Please see Chapter 16 for discussion of integrating high penetration of variable distributed generation. |
| Carl Freedman; IE | 5/10/13 | Whether and to what extent utility customers who do not have a renewable energy device or have implemented energy efficiency measures face high costs and rate impacts if utility sales decrease for any of several possible causes?<br>What are the quantifiable costs and rate impacts to captive customers?<br>Why were CHP or solar photovoltaic resources as possible options for customer self-generation and exit not analyzed? | The resource plans in Blazing a Bold Frontier assume very high growth in NEM/FIT. Implicit in this assumption is extensive customer exit as former utility customers now self-generate. The capacity provided by self-generation is summarized annually in the action plan modeling runs and is already accounted for in the scenario sales and peak forecast.<br>The IRP did not consider the specific resources that customers could use to self-generate but rather considered the total system impact of a growing number of customers choosing to self-generate. |

**Smart Grid Implementation – What are the benefits, costs and technical requirements of a smart grid and how will it enable greater interconnection of renewable distributed generators?**

Company Response: The cost and benefits of Smart Grid was analyzed in Chapter 12.

| AG Member & Organization | Date | Summary of Comment | Response |
|---|---|---|---|
| Carl Freedman; IE | 5/10/13 | Quantify the potential benefits or costs of smart grid resource, smart meters, remote control of customer loads, real-time rate transparency, distribution system design criteria and operating practices.<br>Which specific smart grid measures will be targeted for each of the utilities?<br>What is the extent to which identified resources or system operation practices will be able to accommodate greater interconnection of renewable distributed generation?<br>Explain what the Companies did to assess distribution system options to enable greater interconnection of distributed renewable energy generation. | Please see Chapter 12 for an analysis of Smart Grid and its implementation. |
| Henry Curtis; Life of the Land<br>Gregory Khan; I Aloha Molokai | 5/6/13 | What are the potential negative impacts associated with Smart Grid implementation?<br>How was the cost/benefits of Smart Grid Implementation analyzed? | Please see above. |

**Fuel Supply and Infrastructure – How have the changes in Hawaii's fuel refineries affected the Companies' planning for fuel supply and pricing?**

Company Response: The Fuels Master Plan for the Hawaiian Electric Companies has been provided in Appendix I. A study of LNG imports to Hawaii was provided in Appendix N.

| AG Member & Organization | Date | Summary of Comment | Response |
|---|---|---|---|
| Carl Freedman; IE | | What are the effects of significant changes in output of Hawaii's fuel refineries?<br>How will these possible/anticipated changes in refinery infrastructure affect fuel supply and price or reliability in the future?<br>What actions are being considered regarding the HECO Companies' role in providing LNG infrastructure versus obtaining contracts for fuel delivery? | Please see Appendices I and N. |

| Essential Grid Ancillary Services. – What are the best measures and costs of providing ancillary services needed to accommodate increasing amounts of variable generation? | | | |
|---|---|---|---|
| Company Response: A discussion of ancillary services was provided in Chapter 13. | | | |
| AG Member & Organization | Date | Summary of Comment | Response |
| Warren Bollmeier; Hawaii Renewable Energy Alliance | 6/10/13 | What is HECO's plan for the provision of any necessary ancillary services to facilitate increased levels of utility –scale renewable project?<br>What is HECO's provision of ancillary services to facilitate increased levels of renewable DG? | Please see Chapter 13 for discussion on Ancillary Services. |
| Carl Freedman; IE | 5/10/13 | What measures and investments are necessary and reasonable to enable higher levels of variable renewable distributed generation?<br>What are the best measures and cost of providing ancillary services needed to accommodate increasing amounts of variable renewable generation?<br>How has the costs of providing necessary ancillary services been incorporated in the resource planning analysis?<br>What the relative costs and benefits of various methods of providing ancillary services? (Reference pgs. 22–23)<br>What measures identified in the RSWG process have been considered or included in the analysis of this Principal Issue? What have the Companies done to assess the cost benefit analysis of implementing or accommodating additional customer-sited distributed generation? | Please see Chapter 13 for discussion on Ancillary Services. |
| Will Rolston; County of Hawaii | 4/8/13 | Discussion of Demand Response providing necessary ancillary services. | Please see Chapters 7 and 8 for a discussion of demand response. |

**LNG – The assumptions used by the Companies in the LNG analysis should be reevaluated.**

| AG Member & Organization | Date | Summary of Comment | Response |
|---|---|---|---|
| Warren Bollmeier; Hawaii Renewable Energy Alliance | 6/10/13 | In regards to HELCO's plan:<br>How will LNG be imported, in ISO containers?<br>Will LNG be shipped directly to and stored on the Big Island?<br>How will it be converted?<br>How will it be transferred to the power plants etc.?<br>Is this approach cost effective in the long run?<br>In regards to MECO's plan<br>Is shipping ISO containers directly to Maui a more cost effective approach? | Please see Chapters 9 and 19–22 for analysis and Action Plan of LNG. |
| Consumer Advocate | 5/20/13 | The assumptions regarding the cost of converting existing units coupled with the fixed $10 million deactivation cost, may unrealistically favor the conversion of existing units over new builds.<br>Questions assumption generic LNG consumption forecast embedded in the LNG price forecast to account for the large fixed capital costs of new LNG infrastructure. | Please see Appendix N for the LNG price forecast information. |

**Modeling – Explain the constraints of using the Strategist model and what analysis was done outside of the model to deal with these constraints?**

Company Response: An "all in" rate analysis could not be performed using the outputs of the Strategist model alone. While Strategist projects future costs for fuel, generating unit capital, and production operating and maintenance costs, significant time was spent to include existing non-generation costs and future non-generation projects into the rate analysis to better approximate future rates of the preferred, contingency, parallel and secondary plans. The development of the rates analysis described in Chapter 19.

| AG Member & Organization | Date | Summary of Comment | Response |
|---|---|---|---|
| Consumer Advocate | 5/20/13 | Strategist is not able to model the hourly ramp up and ramp down constraints associated with a combination of high levels of wind and solar.<br>What have the Companies done in regards to benchmarking or model validation? | The Companies have calibrated the Strategist model with the hourly chronological model PREL to establish Hawaiian Electric's reliability criteria. There is no way of calibrating hourly ramp up and ramp down constraints between Strategist and an hourly chronological model. |

| | | | |
|---|---|---|---|
| Henry Curtis; Life of the Land<br>Gregory Khan; I Aloha Molokai | 5/6/13 | What were the user-determined inputs used? | All the user-defined inputs for the Strategist model were provided in the input files for each resource plan. The Independent Entity, Consumer Advocate, and the Advisory Group representative Life of the Land received the numerous input files for many resource plans. |

**Firm Resource Analysis in Model – Explain the manner Firm Resources are applied in the model and explain how the Companies ensure that the most appropriate and economical resource are selected?**

Company Response: The modeling and analysis performed to meet the capacity planning criteria of the Hawaiian Electric Companies is detailed in Chapter 8.

| AG Member & Organization | Date | Summary of Comment | Response |
|---|---|---|---|
| Consumer Advocate | 5/20/13 | Why are wind and solar not given any credit to meeting firm requirements, which is inconsistent with the treatment of these resources in other jurisdictions? | The Hawaiian Electric Companies' peak occurs in the evening when solar would not provide any capacity value.<br>The Companies assessed the capacity value of wind as discussed in Chapter 15 of the IRP report. |
| Carl Freedman; IE | 5/10/13 | Explain the manner it is applied in the model and discuss why it is not revisited and reexamined at a later step in the process?<br>Because the Firm Resources selected in the first step are not reexamined, how does the company ensure that the most appropriate and economical resources are selected?<br>Why are the Firm Resources in the first step allowed to include resources selected for economic criteria rather than strictly reliability related? | The first step in the modeling analysis was to construct timing runs to ensure that the resource plans met the utility capacity planning criteria. Only firm resources were made available and the most cost effective of these were carried forward in subsequent resource plans. In timing runs where a firm resource was added for cost and not to meet capacity planning criteria, the resource was noted in the timing run but not carried forward into future plans unless the resource was again chosen in the screening step of the analysis which allowed variable resources to add to the resource plans. The diagnostic files provided to the AG denote whether a resource was added to lower cost or to meet capacity planning criteria and it is possible for a firm resource to do both. |
| Henry Curtis; Life of the Land<br>Gregory Khan; I Aloha Molokai | 5/6/13 | If Demand Response is able to defer new generation, is it given a firm capacity value? | Yes, demand response was given firm capacity value in the IRP analysis as discussed in Chapter 8 of the IRP report. |
| Bash Nola; Blue Planet | 4/17/13 | Why was a more Hawaii-appropriate energy planning process, which would start with indigenous resources (both firm and intermittent) as the first screen not used? | Please see responses to above. |

### Qualitative Metrics – How are the Companies utilizing qualitative metrics in the development of the Draft Action Plan?

Company Response: The qualitative metrics, as defined by the Advisory Group, were applied to the Draft Action Plan to help inform the Company of potential impacts. These metrics will continue to guide the Company's decision making process beyond the Integrated Resource Planning process. For example, the Company intends to make the qualitative metric considerations an integral part in future RFPs for developers to address in their development of their project proposals.

| AG Member & Organization | Date | Summary of Comment | Response |
|---|---|---|---|
| Henry Curtis; Life of the Land<br>Gregory Khan;<br>I Aloha Molokai | 5/6/13 | How will HECO deal with the Qualitative Metrics in the community/public meetings?<br>Will renewable energy projects strongly favored by the community be considered more favorable than projects that do not have community support? | Chapter 17 reflects qualitative metrics for various resources. The Companies did not screen out any resources based on these metrics. Qualitative metrics identify many of the challenges and impacts associated with implementing any new resource which must be mitigated and addressed before development can occur. Therefore, even though the Action Plan and resource plans include the various resources the Companies recognized that there is no certainty that they can be implemented and alternative plans may need to be considered |

### Objectives and Metrics – How have the Companies considered Advisory Group input on the Objectives and Metrics?

Company Response: The Advisory Group's comments were considered and used to shape the final Objectives and Metrics used in the IRP Report. Please see below some examples of Advisory Group comments and how they were incorporated.

| AG Member & Organization | Date | Summary of Comment | Response |
|---|---|---|---|
| Tom Gorak; Solar Energy Industries Association | 11/7/12 | Need a metric that shows how costs may be reduced by DSM/DR | DSM/DR will be incorporated into the load forecast |
| Consumer Advocate | 10/1/12 | Objective 1: Include evaluation of impact on, and compatibility with, Hawaii's culture and cultural heritage. | Revised Objective 1. |
| Consumer Advocate | 10/1/12 | Objective 2 & Metric 2e: Include impact on Hawaii's water resources. | Objective Metric 2e added. |
| Consumer Advocate | 10/1/12 | Objective 3: Suggests changing objective to include all imported fossil fuels, not just imported oil. | Changed to imported fuels. So there will be different metrics for fossil oil, LNG, and biofuels. |
| Bash Nola; Blue Planet Foundation | 10/1/12 | Objective 3: Recommends revising objective to focus on reducing dependence on all imported fossil fuels, not just imported oil. | Changed to imported fuels. So there will be different metrics for fossil oil, LNG, and biofuels. |

| | | | |
|---|---|---|---|
| Bash Nola; Blue Planet Foundation | 10/1/12 | Metric 2a: Recommends revising carbon intensity metric to include lifecycle emissions of greenhouse gases. | Metric has been revised to tons instead of intensity. |
| Doug McLeod & Kal Kobayashi; County of Maui | 10/1/12 | Questions weighting of metrics. | The AG members can weigh the objectives and metrics on their own. |
| Isaac Moriwake; Earth Justice | 10/1/12 | Recommends revising Metric 2a to "greenhouse gas intensity" and including life-cycle analysis. | Revised Metric 2a. Changed to tons instead of intensity. |
| Sally Kaye; Friends of Lanai | 8/31/12 | Objectives and Metrics are not adequately informed by a stronger concern for Hawaii's environment, along with a recognition of its significance to the planning process. We cannot limit this discussion/concern to "emissions" as it currently reads. | Added potential non-emission related environmental impacts metric recognizing that implementing projects may have significant environmental impacts other than emissions. |
| Gregory Kahn; I Aloha Molokai | 8/13/12 | Include language that not only considers the benefits of renewables on the environment, but also the potential negative consequences such as damage to reefs, erosion, etc. | Added potential non-emission related environmental impacts metric recognizing that implementing projects may have significant environmental impacts other than emissions. |
| Mark Fox; Nature Conservancy | — | Request that in addition to greenhouse gas emission reduction, Hawaiian Electric also articulate within this objective the environmental sustainability standards it is implementing to mitigate potential risks to Hawaii's environment from locally produced biofuels. | Added potential non-emission related environmental impacts metric.<br>Note comments 315 and 316 are the same. |
| Doug McLeod & Kal Kobayashi; County of Maui | 7/30/12 | Revised wording in opening paragraph of Objectives & Metrics | Comment noted. The paragraph was re-worked. |
| Doug McLeod & Kal Kobayashi; County of Maui | 7/30/12 | Revised objective description for "Increase the use of renewable energy resources" | Comment noted. The objective description has been substantially re-worded. |
| Doug McLeod & Kal Kobayashi; County of Maui | 7/30/12 | Revised metric description for "Resource Diversity Index" | See geographic diversity of generating resources (5d) metric |
| Doug McLeod & Kal Kobayashi; County of Maui | 7/30/12 | Revised objective description for "Provide Reliable Service" | Comment noted. The objective description has been substantially re-worded. |
| Doug McLeod & Kal Kobayashi; County of Maui | 7/30/12 | Delete metric "As-available Resource Penetration" | Comment noted. Metric (5b) description has been re-worded. |
| Doug McLeod & Kal Kobayashi; County of Maui | 7/30/12 | Revise metric "Appropriate mix of baseload, cycling, peaking generating capacity, and as-available" to represent the curtailed energy in GWh. | Curtailed energy is a separate metric (6b). |

| | | | |
|---|---|---|---|
| Doug McLeod & Kal Kobayashi; County of Maui | 7/30/12 | Move metric "Share of delivered energy linked to oil" under objective "Provide Electricity in an Economically Sustainable Manner" | Comment noted. Metric was moved to 3a and re-worded. |
| Doug McLeod & Kal Kobayashi; County of Maui | 7/30/12 | Revise metric title to "Annual revenue requirements for fuel". Previous title "Annual revenue requirements for capital. | Comment noted. Fuel costs have been listed elsewhere (objective 3). |
| Doug McLeod & Kal Kobayashi; County of Maui | 7/30/12 | Delete metric "Impact to the State Economy" | Comment noted. The metric description has been re-worded (7e). |
| Doug McLeod & Kal Kobayashi; County of Maui | 7/30/12 | Add formula for metric "Fossil Fueled Generation Efficiency".<br>Formula: Sum (Fossil Fuel Energy consumed) / Sum (Electrical Energy from Fossil Fuel) | Formula added to metric 6a. |
| Doug McLeod & Kal Kobayashi; County of Maui | 7/30/12 | Revise objective title to "Provide Electricity in an Environmentally Sustainable Manner" | Comment noted. The single objective has been split into two (3 and 4). |
| Doug McLeod & Kal Kobayashi; County of Maui | 7/30/12 | Add metric "Community acceptance of the "preferred attributes" for competitive bidding, such as technology and locational preferences and/or rejections and resource scale (see II.C.4.a and IV.E.5 of the Competitive Bidding Framework)" | Comment noted. See metric 1. |
| Doug McLeod & Kal Kobayashi; County of Maui | 7/30/12 | Revise formula for metric "Amount of imported fuel oils" to all imported liquid fuels. | Cannot determine the quantity of biofuels that will be imported. The formula has been re-worked (3b). |
| Doug McLeod & Kal Kobayashi; County of Maui | 7/30/12 | Revise metric title to "Sulfur oxides (Sox) emissions and all other reportable pollutants" | Added metrics for NOx and Particulates. See Objective 2. |
| Gregory Kahn;<br>I Aloha Molokai | 7/30/12 | Distill Objectives 1–4 in 2–3 objectives and construct 3 separate objectives for community, cultural, and environmental components from Objective 5. Increase prominence of energy conservation in the Objectives language | Separated culture and communities from environment objective (See objectives 1 and 2).<br>The responsibility for the implementation of energy efficiency and conservation programs have been transferred from the utilities to the Public Benefits Fee Administrator. See Figures 4 (HECO), 9, 14, 18 (MECO) and 22 (HELCO) of the Quantification document for quantification. |
| Sally Kaye; Friends of Lanai | 7/30/12 | Metrics "Reserve Margin", "As-available Resource Penetration", "System Regulating Capability", "System Power Quality", and "Appropriate mix of baseload, cycling…" should be calculated for each island separately | All metrics will be calculated separately for each island. |
| Sally Kaye; Friends of Lanai | 7/30/12 | Revised objective description for "Provide/Distribute Electricity at a Reasonable Cost", Objective #3 | Comment noted. Some of this comment is captured in metric 2e. |

| | | | |
|---|---|---|---|
| Sally Kaye; Friends of Lanai | 7/30/12 | Delete Objective "Reduce Dependency on Imported Oil, Increase Energy Security, and Improve Price Stability" and all associated metrics | Comment noted. The objective has been heavily re-worked. |
| Dawn Lippert; PICHTR | 7/27/12 | Change metric "Share of energy resources linked to oil" to "Share of energy resources with potential volatility" | Metric (3a) title revised to "Share of delivered energy linked to oil price or other volatile resources". |
| Dawn Lippert; PICHTR | 7/27/12 | Add new metrics for Energy Efficiency & demand response | The impact of energy efficiency is embedded in the sales forecast under each scenario. Thus, a separate metric for EE is not informative. Demand response will be evaluated as a resource option (strategy) similar to the supply side resources |
| Dawn Lippert; PICHTR | 7/27/12 | Change "electricity rates" metric to a "total bill" metric | Added metric for electricity rate impact by rate class (7a). Added nominal residential bill metric based on an average monthly consumption (7b). |
| Dawn Lippert; PICHTR | 7/27/12 | Add "Diversity" metric (include geographic diversity) | Added and revised metrics for resource diversity index metric (4c) and geographic diversity of generating resources metric (5d). |
| Dawn Lippert; PICHTR | 7/27/12 | Add "Positively impact the state economy" objective | See impact to local economy (7e) metric. This metric is qualitative, so it could include job creation as a positive criteria in a simplified model (utilized for evaluation). |
| Leslie Cole-Brooks; HSEA | 7/27/12 | Tax credits and their benefits should be part of the "impact to state economy" metric | Tax credits are captured in the scenarios and the impact to the local economy (7e) metric. This metric is qualitative, so it could include tax credits as a positive criteria in a simplified model (utilized for evaluation). |
| Bash Nola; Blue Planet | 7/26/12 | Stabilize electric rates in a cost effective manner. | Captured in objective "Provide Electricity at a Reasonable Cost" (7). |
| Bash Nola; Blue Planet | 7/26/12 | Achieve 100% Renewable Energy Generation Mix, or at least maximize the penetration of renewable resources for each island grid.<br>Replace/Retire fossil fueled generation – 30% within the next 10 years; remainder over the following 10 years. | 100% Renewable generation and retirement/replace fossil generation will be considered as potential resource strategies |
| Bash Nola; Blue Planet | 7/26/12 | Supplant existing fossil fuels in remaining generation resources needed to maintain system reliability and stability. | Biofuels and LNG will be considered as potential strategies |
| Bash Nola; Blue Planet | 7/26/12 | Production Cost Analysis and Ratepayer Impacts. | Production cost analysis and ratepayer impacts considered in objective "Provide Electricity at a Reasonable Price" |
| Bash Nola; Blue Planet | 7/26/12 | System/Utility Capitalization requirements | Capitalization requirements quantified in annual revenue requirements for capital metric |

| | | | |
|---|---|---|---|
| Bash Nola; Blue Planet | 7/26/12 | The formula of 'Dumped energy in GWh" must be qualified to exclude curtailment of excess energy from renewable resources unless such curtailment serves to maximize the use of renewable resources during peak load periods. | Must-run units, hydro units, storage units, and purchase transactions may generate energy above what is required by the load. That excess energy is called dump energy. Economic dispatch of available resources to meet load requirements dictates curtailment. |
| Bash Nola; Blue Planet | 7/26/12 | Add Demand Response & Energy Efficiency Metric | The impact of energy efficiency is embedded in the sales forecast under each scenario. Thus, a separate metric for EE is not informative. See Figures 4 of (HECO), 9, 14, 18 (MECO) and 22 (HELCO), of Quantifying the Scenario document, for partial quantification.<br>Demand response will be evaluated as a resource option similar to other supply side resources |
| Bash Nola; Blue Planet | 7/26/12 | Establish target levels for "System Regulating Capability" | The system regulating capability metric measures the capability of the system to manage the variability of the intermittent output from the as-available resources. The target would be highly dependent upon system characteristics and would be different for each island. |
| Bash Nola; Blue Planet | 7/26/12 | For "System power quality" metric, maintain system voltage levels specified in GO #7 or establish a target of 0.94 pu to 1.02 pu | Comment noted. Target range given can be used in evaluation of metric 5c. |
| Bash Nola; Blue Planet | 7/26/12 | "Appropriate mix of baseload, cycling, peaking generating…" to be determined by the level of reliability to be maintained as well as meeting load duration curve | The appropriate mix of baseload, cycling, peaking generating capacity, and as-available generation depends on load shape to be served by the generating units and the characteristics of these units. The comment may be used during evaluation of metric 6c. |
| Bash Nola; Blue Planet | 7/26/12 | Nominal Price of Electricity: How does this relate to the fact that rates are now decoupled from kWh sales? | The nominal price of electricity metric (7a) is used to compare the impact of different plans and their impact on revenue requirements. |
| Bash Nola; Blue Planet | 7/26/12 | Add Total annual revenue requirement metric | Captured in total resource cost metric (7d). |
| Bash Nola; Blue Planet | 7/26/12 | Add Total Capital cost for generation & transmission upgrades metric | Captured in metric annual revenue requirements for capital metric (7c). |
| Bash Nola; Blue Planet | 7/26/12 | "Total Resource Cost" metric needs to capture cost effective DSM and Energy. Eff. Programs added to the resource mix. | The total resource cost metric (7d) will capture energy efficiency program costs. |
| Bash Nola; Blue Planet | 7/26/12 | Add "Production cost" metric | Production cost is captured in the nominal price of electricity metric (7a). |
| Bash Nola; Blue Planet | 7/26/12 | Add "Expected Reduction in oil use" metric | Captured in two metrics share of delivered energy linked to oil price or other volatile resources (3a) and amount of imported fuel oil (3b). |
| Bash Nola; Blue Planet | 7/26/12 | Add "Rate impacts" metric | See nominal price of electricity metric (7a) and Nominal Residential Bill (7b). |

| | | | |
|---|---|---|---|
| Bash Nola; Blue Planet | 7/26/12 | Expanded on objective description for "Protect Hawaii's Environment, Culture, and Communities" | Comment noted. See metrics 1 and 2. |
| Bash Nola; Blue Planet | 7/26/12 | Add "NOx" & "Particulates" metric | Added nitrous oxides (NOx) emissions intensity and particulate (PM) emissions intensity (metrics 2c and 2d). |
| Bash Nola; Blue Planet | 7/26/12 | Add "Total cost for Environmental Compliance" metric | Captured in Total Resource Cost (7d) and Nominal Cost of Electricity (7a) metrics |
| Bash Nola; Blue Planet | 7/26/12 | Stabilize electric rates in a cost effective manner. | Captured in objective "Provide Electricity at a Reasonable Cost" (7). |
| Bash Nola; Blue Planet | 7/26/12 | 2. Achieve 100% Renewable Energy Generation Mix, or at least maximize the penetration of renewable resources for each island grid: Replace/Retire fossil fueled generation – 30% within the next 10 years; remainder over the following 10 years. | 100% Renewable generation and retirement/replace fossil generation will be considered as potential resource strategies |
| Bash Nola; Blue Planet | 7/26/12 | 3. Supplant existing fossil fuels in remaining generation resources needed to maintain system reliability and stability. | Biofuels and LNG will be considered as potential strategies |

## Scenarios – How have the Companies considered Advisory Group input on defining the Scenarios?

Company Response: During the scenario planning workshop, the Advisory Group developed and voted on the critical axes that defined the four scenarios used in this IRP. The Hawaiian Electric Companies then crafted narratives for the four scenarios and quantified planning assumptions consistent with each scenario.

| AG Member & Organization | Date | Summary of Comment | Response |
|---|---|---|---|
| Asia Yeary; EPA | 10/1/12 | Scenarios: Expand definition of economic conditions to include conditions of the entire State, not just utility. | The state economic conditions are covered in the scenario descriptions but the purpose of IRP is planning for the utility, not the state. |
| Asia Yeary; EPA | 10/1/12 | Scenarios: LNG should be varied from scenario to scenario. | The LNG forecast was revised for some of the scenarios. |
| Consumer Advocate | 10/1/12 | (Synapse) Scenarios: Proposed scenarios do not include reference case. Want detailed explanation how individual resources will be screened. | Individual resources were not compared to a reference case. Resource strategies were analyzed under all four scenarios which may be just a single resource. |
| Consumer Advocate | 10/1/12 | (Synapse) Scenarios: Wants scenarios to include full range of available energy efficiency and self- generation resources (above and beyond those planned by PBF Administrator). | The Companies are not responsible for energy efficiency programs so there is no way of analyzing "a full range" if it's not provided by the PBFA. |

| | | | |
|---|---|---|---|
| Bash Nola; Blue Planet Foundation | 10/1/12 | Scenarios: Revise LNG price forecast so not same in all scenarios. | LNG price forecast revised so they are not the same in all scenarios. |
| Bash Nola; Blue Planet Foundation | 10/1/12 | Align LNG forecasted variation with forecasted oil price variation. | The LNG forecast were revised for some of the scenarios. |
| Bash Nola; Blue Planet Foundation | 10/1/12 | Forecast a baseline environmental compliance cost to determine "high", "reference", and "low" forecast. | There are no historical environmental compliance costs. |
| Bash Nola; Blue Planet Foundation | 10/1/12 | Scenarios: Questions methodology of construction cost forecasts. | The escalation rate was revised in the scenarios. |
| Bash Nola; Blue Planet Foundation | 10/1/12 | Scenarios: Disagrees with estimate of $0 for greenhouse gas regulations. | There are no GHG regulations in place so having a scenario with $0 is plausible. |
| Doug McLeod & Kal Kobayashi; County of Maui | 10/1/12 | "Comments that scenarios are confusing and make arbitrary decisions.<br>♦ questions future natural gas production<br>♦ asking what the lowest cost energy sources are<br>♦ will no future recessions occur<br>♦ asking if higher upfront cost of RE made w/o fuel or water inputs can be justified based on long term price stability<br>♦ wants isolated analysis for risk of supply disruption for any fuel imported from outside of Hawaii and the water consumption of different resource generation options." | No specific suggestions were provided. LNG forecasts for some of the scenarios were revised to create more distinction between the scenarios. The cost of energy sources and price stability are part of the objectives and metrics and water consumption has been added to the metrics. |
| Henry Curtis; Life of the Land | 10/1/12 | Suggests adding excluded ranges to scenarios. | Load curves included peak reduction. Scenarios included lower/zero escalation for renewable energy costs. |
| Henry Curtis; Life of the Land | 10/1/12 | Provides insightful observation related to sensitivity analysis and scenario analysis. | The sensitivity analysis changes only one variable and scenario analysis changes several variables at the same time. |
| Henry Curtis; Life of the Land | 10/1/12 | Question regarding inflation estimates in general operating costs and renewable energy construction costs. | Included in revised Scenarios document. |
| Isaac Moriwake; Earth Justice | 10/1/12 | Request response on comment #333 regarding RPS treatment. | The RPS levels are an external force because the legislature could change the requirements at any time. |
| Isaac Moriwake; Earth Justice | 10/1/12 | Recommends altering the stories involving LNG. | Scenarios were revised to use different forecasts. |
| Isaac Moriwake; Earth Justice | 10/1/12 | Wants to incorporate potential game-changing renewable technology breakthrough and cost reductions. | Scenarios were revised to use different escalation rate for renewables relative to other resources. |

| | | | |
|---|---|---|---|
| Isaac Moriwake; Earth Justice | 10/1/12 | Wants to incorporate volatility of fuel prices in addition to overall price level. | The current model is unable to do this and to do this outside of the model would require a substantial amount of time which the schedule will not permit |
| Doug McLeod & Kal Kobayashi; County of Maui | 8/29/12 | Due to the rejection of the draft scenarios on August 24, the following comments and recommendations build upon the collaborative efforts of the Scenario Planning Workshop, particularly upon my collaboration with the August Subgroup #1 and the August Subgroup #1. I appreciate HECO's offer to allow its Advisory Group to independently develop the scenarios. I find it to be a trustworthy gesture. Accordingly, I do not fault HECO and its consultant with the drafting of the rejected set of scenarios because they did their best to work with what I feel were an incomplete set of "winning" recommendations. Therefore, the following comments and recommendations are directed primarily to my fellow Advisory Group members and I encourage AG members to respond to the proposed scenarios below because if the AG doesn't support what I have to offer, then why should HECO and its consultant support it either. | Scenario comment noted. |
| Doug McLeod & Kal Kobayash; County Of Maui | 8/29/12 | 1. This scenario planning process is "not seeing the forest for the trees."<br>Uncertainties, or driving forces, in the IRP process can be addressed with several different planning tools, including the use of scenario analysis, sensitivity analysis, multi-attribute analysis, and by analyzing the individual metrics associated with the planning objectives. The current single focus on the use of scenario analysis misses the big picture because there has been no discussion on what planning uncertainty is best analyzed by which planning tool. I feel that the uses of scenarios should be reserved for primary uncertainties, aka the driving forces in the working environment (as shown in Figure 1 of our pre-workshop package), that cannot be fully analyzed with other planning tools. Sensitivity and other analysis tools should be used to address secondary uncertainties, or the driving forces in the contextual environment, per Figure 1. For example, although I cannot recall the specific examples provided by Bash Nola, I believe that he listed a good set of uncertainties that can be addressed with the use of sensitivity analysis. | Scenario comment noted. |

| | | | |
|---|---|---|---|
| | | For another example, I'll use the proposed scenarios developed by the August 21 Subgroup #5. I first feel that Subgroup #5 incorporated two very important uncertainties: one relating to disasters and another one relating to consumers' willingness-to-pay. However, I think that those two uncertainties can be better addressed by analyzing metrics associated with planning objectives. For example, regarding uncertainties related to disasters, the County of Maui proposed two metrics under the proposed objective, Provide Reliable Service. The first metric, submitted after the first IRP meeting, is Renewable Energy Curtailed during a 30% oil supply disruption. The second metric was submitted after the second IRP meeting and it is Robustness of the grid from natural and man-made hazard/emergencies, relative to other final resource plans. I ask my fellow AG members to review these two proposed metrics and to consider this in the context of scenarios and to discuss this issue in our upcoming meeting on the subject of planning objectives. Further, regarding the uncertainty related to consumers' willingness-to-pay, the County of Maui also proposed a Willingness-to-Pay metric under the proposed objective, Provide Electricity in an Economically Sustainable Manner. I also ask that the Advisory Group consider this recommendation in the context of scenarios and to discuss this in our upcoming meeting on planning objectives. | |
| Doug McLeod & Kal Kobayashi; County of Maui | 8/29/12 | 2. Scenarios were not relevant enough and they may miss primary driving forces. Planning scenarios that do not focus on primary uncertainties, or the driving forces in the working environment, can miss or allow a utility to side-step some very important possible eventualities, such as the impact to a utility if a majority of its customers self generate their own power. | Scenario comment noted. |

| | | | |
|---|---|---|---|
| Doug McLeod & Kal Kobayashi; County of Maui | 8/29/12 | 3. Proposed Scenarios<br>The following proposed scenarios attempt to address all of the above by addressing two primary driving forces: the total amount of self-generation and the relative cost of alternative energy. This is a revised version of what the August 21 Subgroup #1 produced. I revised the horizontal axis with a different expression of consumer choice; one choice where the consumer totally relies on the grid for electrical energy services (western hemisphere) and the other choice where the consumer provides some or all of its own electrical energy services (eastern hemisphere). The vertical axis is expanded to reflect the cost of alternative energy relative to oil costs. | Scenario comment noted. |
| Lee Jakeway; Hawaiian Commercial &Sugar Company | 8/28/12 | Scenario description edits | Scenario comment noted. |
| Henry Curtis; Life of the Land | 8/28/12 | A Comparative Analysis of HECO's Proposed Scenario. Table characterizing the differences in the critical uncertainties for the 4 scenarios | Scenario comment noted. |
| Warren Bollmeier; Hawaii Renewable Energy Alliance | 8/28/12 | Scenario description edits | Scenario comment noted. |

# Appendix E:
# Quantifying the Scenarios

This appendix contains tables of the data used to generate the trend graphs in Chapter 6: Four Planning Scenarios. The data tables are broken into groups that correspond to groups of trend graphs so that the data can be more easily compared with the associated graphs. Thus, the tables in this appendix are grouped in a number of sections, each corresponding to a group of graphs in Chapter 6.

The Table of Content of the appendix begins on the next page, followed by the separate appendices.

# CONTENTS

# TABLES

## Appendix E-1: Quantification of Sales Forecasts



## Appendix E-2: Quantification of Peak Forecasts

## Appendix E-1: Quantification of Sales Forecasts

Table E-1: Quantification of Sales Forecasts

| Forecast Layer | Blazing a Bold Frontier | Stuck in the Middle | No Burning Desire | Moved by Passion |
|---|---|---|---|---|
| Underlying Economic Forecast | Low | Base | High | Base |
| Renewable Self-Generation (% of Base) | 110% | 60% | 35% | 100% |
| EEPS (% of Base) | 110% | 75% | 75% | 100% |
| Electric Vehicles (% of Base) | 200% | 100% | 50% | 100%[1] |

[1] For HELCO only; the electric vehicles impacts are forecasted only in the high scenario in HELCO's forecasts. Therefore the electric vehicles impacts for the Blazing a Bold Frontier is HELCO's high scenario, Stuck in the Middle is 50% of the high scenario, No Burning Desire is 25% of the high scenario, and Moved by Passion is 0% of the high scenario.

## *Hawaiian Electric Sales Forecast Data Summary by Scenario*

Table E-2: HECO Blazing a Bold Frontier Scenario Sales Forecast Data (GWh)

| Year | Underlying Economic Forecast | Renewable Self Generation | Non-PBFA EEPS Contribution | PBFA DSM Programs | Electric Vehicles | No PBFA DSM Sales Forecast | Sales Forecast |
|---|---|---|---|---|---|---|---|
| | *A* | *B* | *C* | *D* | *E* | *F=A+B+C+E* | *G=F+D* |
| 2012 | 7,107 | (30) | (13) | (49) | 4 | 7,068 | 7,020 |
| 2013 | 7,115 | (109) | (38) | (146) | 7 | 6,974 | 6,829 |
| 2014 | 7,132 | (204) | (64) | (243) | 12 | 6,876 | 6,633 |
| 2015 | 7,157 | (302) | (90) | (340) | 17 | 6,783 | 6,443 |
| 2016 | 7,239 | (419) | (115) | (437) | 27 | 6,731 | 6,294 |
| 2017 | 7,224 | (516) | (141) | (534) | 39 | 6,606 | 6,072 |
| 2018 | 7,166 | (613) | (166) | (631) | 54 | 6,440 | 5,809 |
| 2019 | 7,187 | (710) | (192) | (728) | 71 | 6,356 | 5,628 |
| 2020 | 7,223 | (806) | (217) | (826) | 92 | 6,291 | 5,466 |
| 2021 | 7,253 | (903) | (243) | (923) | 117 | 6,224 | 5,301 |
| 2022 | 7,303 | (992) | (269) | (1,020) | 145 | 6,187 | 5,167 |
| 2023 | 7,355 | (1,069) | (294) | (1,117) | 176 | 6,168 | 5,051 |
| 2024 | 7,410 | (1,136) | (320) | (1,214) | 211 | 6,165 | 4,951 |
| 2025 | 7,466 | (1,194) | (345) | (1,311) | 248 | 6,176 | 4,865 |
| 2026 | 7,507 | (1,244) | (371) | (1,408) | 290 | 6,182 | 4,773 |
| 2027 | 7,547 | (1,288) | (397) | (1,505) | 333 | 6,196 | 4,690 |
| 2028 | 7,587 | (1,328) | (422) | (1,602) | 379 | 6,216 | 4,614 |
| 2029 | 7,628 | (1,365) | (448) | (1,700) | 428 | 6,243 | 4,543 |
| 2030 | 7,669 | (1,401) | (473) | (1,797) | 479 | 6,274 | 4,477 |
| 2031 | 7,709 | (1,435) | (493) | (1,894) | 532 | 6,313 | 4,420 |
| 2032 | 7,749 | (1,468) | (506) | (1,991) | 584 | 6,360 | 4,369 |
| 2033 | 7,789 | (1,499) | (519) | (2,088) | 637 | 6,408 | 4,320 |

Table E-3: HECO Stuck in the Middle Scenario Sales Forecast Data (GWh)

| Year | Underlying Economic Forecast | Renewable Self Generation | Non-PBFA EEPS Contribution | PBFA DSM Programs | Electric Vehicles | No PBFA DSM Sales Forecast | Sales Forecast |
|---|---|---|---|---|---|---|---|
| | *A* | *B* | *C* | *D* | *E* | *F=A+B+C+E* | *G=F+D* |
| 2012 | 7,206 | (16) | (9) | (33) | 2 | 7,183 | 7,150 |
| 2013 | 7,349 | (60) | (26) | (99) | 4 | 7,266 | 7,167 |
| 2014 | 7,500 | (111) | (44) | (166) | 6 | 7,351 | 7,185 |
| 2015 | 7,669 | (165) | (61) | (232) | 9 | 7,452 | 7,220 |
| 2016 | 7,906 | (229) | (79) | (298) | 13 | 7,613 | 7,315 |
| 2017 | 8,029 | (282) | (96) | (364) | 20 | 7,671 | 7,306 |
| 2018 | 8,131 | (335) | (113) | (430) | 27 | 7,710 | 7,279 |
| 2019 | 8,285 | (387) | (131) | (497) | 36 | 7,803 | 7,306 |
| 2020 | 8,434 | (440) | (148) | (563) | 46 | 7,892 | 7,329 |
| 2021 | 8,538 | (492) | (166) | (629) | 58 | 7,938 | 7,309 |
| 2022 | 8,660 | (541) | (183) | (695) | 72 | 8,008 | 7,312 |
| 2023 | 8,778 | (583) | (201) | (761) | 88 | 8,082 | 7,321 |
| 2024 | 8,892 | (620) | (218) | (828) | 105 | 8,159 | 7,332 |
| 2025 | 9,007 | (651) | (236) | (894) | 124 | 8,244 | 7,350 |
| 2026 | 9,099 | (678) | (253) | (960) | 145 | 8,313 | 7,352 |
| 2027 | 9,192 | (702) | (270) | (1,026) | 167 | 8,386 | 7,360 |
| 2028 | 9,287 | (724) | (288) | (1,093) | 190 | 8,464 | 7,371 |
| 2029 | 9,382 | (745) | (305) | (1,159) | 214 | 8,546 | 7,387 |
| 2030 | 9,478 | (764) | (323) | (1,225) | 239 | 8,631 | 7,406 |
| 2031 | 9,577 | (783) | (336) | (1,291) | 266 | 8,724 | 7,433 |
| 2032 | 9,677 | (801) | (345) | (1,357) | 292 | 8,823 | 7,466 |
| 2033 | 9,777 | (818) | (354) | (1,424) | 319 | 8,924 | 7,500 |

Table E-4: HECO No Burning Desire Scenario Sales Forecast Data (GWh)

| Year | Underlying Economic Forecast | Renewable Self Generation | Non-PBFA EEPS Contribution | PBFA DSM Programs | Electric Vehicles | No PBFA DSM Sales Forecast | Sales Forecast |
|---|---|---|---|---|---|---|---|
| | *A* | *B* | *C* | *D* | *E* | *F=A+B+C+E* | *G=F+D* |
| 2012 | 7,357 | (9) | (9) | (33) | 1 | 7,340 | 7,307 |
| 2013 | 7,653 | (35) | (26) | (99) | 2 | 7,594 | 7,495 |
| 2014 | 7,961 | (65) | (44) | (166) | 3 | 7,855 | 7,689 |
| 2015 | 8,312 | (96) | (61) | (232) | 4 | 8,159 | 7,928 |
| 2016 | 8,741 | (133) | (79) | (298) | 7 | 8,535 | 8,238 |
| 2017 | 9,035 | (164) | (96) | (364) | 10 | 8,785 | 8,420 |
| 2018 | 9,311 | (195) | (113) | (430) | 14 | 9,015 | 8,585 |
| 2019 | 9,634 | (226) | (131) | (497) | 18 | 9,295 | 8,799 |
| 2020 | 9,940 | (257) | (148) | (563) | 23 | 9,558 | 8,995 |
| 2021 | 10,173 | (287) | (166) | (629) | 29 | 9,749 | 9,120 |
| 2022 | 10,410 | (316) | (183) | (695) | 36 | 9,947 | 9,252 |
| 2023 | 10,629 | (340) | (201) | (761) | 44 | 10,133 | 9,371 |
| 2024 | 10,825 | (361) | (218) | (828) | 53 | 10,299 | 9,471 |
| 2025 | 11,025 | (380) | (236) | (894) | 62 | 10,472 | 9,578 |
| 2026 | 11,199 | (396) | (253) | (960) | 73 | 10,623 | 9,663 |
| 2027 | 11,375 | (410) | (270) | (1,026) | 83 | 10,778 | 9,752 |
| 2028 | 11,554 | (423) | (288) | (1,093) | 95 | 10,939 | 9,846 |
| 2029 | 11,736 | (434) | (305) | (1,159) | 107 | 11,104 | 9,945 |
| 2030 | 11,921 | (446) | (323) | (1,225) | 120 | 11,273 | 10,048 |
| 2031 | 12,130 | (456) | (336) | (1,291) | 133 | 11,471 | 10,180 |
| 2032 | 12,343 | (467) | (345) | (1,357) | 146 | 11,677 | 10,320 |
| 2033 | 12,559 | (477) | (354) | (1,424) | 159 | 11,888 | 10,464 |

Table E-5: HECO Moved by Passion Scenario Sales Forecast Data (GWh)

| Year | Underlying Economic Forecast | Renewable Self Generation | Non-PBFA EEPS Contribution | PBFA DSM Programs | Electric Vehicles | No PBFA DSM Sales Forecast | Sales Forecast |
|---|---|---|---|---|---|---|---|
| | *A* | *B* | *C* | *D* | *E* | *F=A+B+C+E* | *G=F+D* |
| 2012 | 7,206 | (27) | (12) | (44) | 2 | 7,170 | 7,125 |
| 2013 | 7,349 | (99) | (35) | (132) | 4 | 7,218 | 7,086 |
| 2014 | 7,500 | (185) | (58) | (221) | 6 | 7,262 | 7,041 |
| 2015 | 7,669 | (274) | (81) | (309) | 9 | 7,322 | 7,013 |
| 2016 | 7,906 | (381) | (105) | (397) | 13 | 7,434 | 7,037 |
| 2017 | 8,029 | (469) | (128) | (486) | 20 | 7,451 | 6,965 |
| 2018 | 8,131 | (558) | (151) | (574) | 27 | 7,449 | 6,875 |
| 2019 | 8,285 | (645) | (174) | (662) | 36 | 7,501 | 6,839 |
| 2020 | 8,434 | (733) | (198) | (750) | 46 | 7,549 | 6,799 |
| 2021 | 8,538 | (821) | (221) | (839) | 58 | 7,555 | 6,716 |
| 2022 | 8,660 | (902) | (244) | (927) | 72 | 7,586 | 6,659 |
| 2023 | 8,778 | (972) | (267) | (1,015) | 88 | 7,627 | 6,612 |
| 2024 | 8,892 | (1,033) | (291) | (1,104) | 105 | 7,674 | 6,570 |
| 2025 | 9,007 | (1,085) | (314) | (1,192) | 124 | 7,731 | 6,540 |
| 2026 | 9,099 | (1,131) | (337) | (1,280) | 145 | 7,776 | 6,496 |
| 2027 | 9,192 | (1,171) | (361) | (1,368) | 167 | 7,828 | 6,459 |
| 2028 | 9,287 | (1,207) | (384) | (1,457) | 190 | 7,885 | 6,428 |
| 2029 | 9,382 | (1,241) | (407) | (1,545) | 214 | 7,948 | 6,403 |
| 2030 | 9,478 | (1,273) | (430) | (1,633) | 239 | 8,014 | 6,381 |
| 2031 | 9,577 | (1,304) | (448) | (1,722) | 266 | 8,091 | 6,369 |
| 2032 | 9,677 | (1,334) | (460) | (1,810) | 292 | 8,175 | 6,365 |
| 2033 | 9,777 | (1,363) | (472) | (1,898) | 319 | 8,261 | 6,363 |

## *HELCO Sales Forecast Data Summary by Scenario*

Table E-6: HELCO Blazing Bold Frontier Scenario Sales Forecast Data (GWh)

| Year | Underlying Economic Forecast | Renewable Self Generation | Non-PBFA EEPS Contribution | PBFA DSM Programs | Electric Vehicles | No PBFA DSM Sales Forecast | Sales Forecast |
|---|---|---|---|---|---|---|---|
| | *A* | *B* | *C* | *D* | *E* | *F=A+B+C+E* | *G=F+D* |
| 2012 | 1,068 | (4) | (2) | (22) | 0 | 1,062 | 1,040 |
| 2013 | 1,066 | (14) | (6) | (37) | 0 | 1,046 | 1,009 |
| 2014 | 1,064 | (21) | (10) | (52) | 0 | 1,034 | 982 |
| 2015 | 1,068 | (26) | (14) | (67) | 1 | 1,028 | 962 |
| 2016 | 1,076 | (32) | (18) | (81) | 1 | 1,027 | 946 |
| 2017 | 1,087 | (38) | (21) | (96) | 2 | 1,030 | 933 |
| 2018 | 1,100 | (42) | (25) | (111) | 3 | 1,036 | 925 |
| 2019 | 1,113 | (47) | (29) | (126) | 4 | 1,041 | 915 |
| 2020 | 1,125 | (52) | (33) | (140) | 6 | 1,046 | 906 |
| 2021 | 1,138 | (56) | (37) | (155) | 8 | 1,052 | 897 |
| 2022 | 1,151 | (60) | (41) | (170) | 10 | 1,059 | 889 |
| 2023 | 1,164 | (64) | (45) | (185) | 13 | 1,067 | 883 |
| 2024 | 1,186 | (69) | (49) | (200) | 16 | 1,085 | 885 |
| 2025 | 1,197 | (73) | (53) | (214) | 19 | 1,091 | 876 |
| 2026 | 1,213 | (78) | (56) | (229) | 23 | 1,101 | 872 |
| 2027 | 1,224 | (82) | (60) | (244) | 27 | 1,109 | 865 |
| 2028 | 1,236 | (87) | (64) | (259) | 32 | 1,116 | 858 |
| 2029 | 1,247 | (91) | (68) | (274) | 37 | 1,124 | 851 |
| 2030 | 1,259 | (96) | (72) | (288) | 42 | 1,134 | 845 |
| 2031 | 1,271 | (100) | (75) | (303) | 48 | 1,144 | 841 |
| 2032 | 1,284 | (105) | (77) | (318) | 54 | 1,156 | 838 |
| 2033 | 1,296 | (109) | (79) | (333) | 61 | 1,169 | 837 |

Table E-7: HELCO Stuck in the Middle Scenario Sales Forecast Data (GWh)

| Year | Underlying Economic Forecast | Renewable Self Generation | Non-PBFA EEPS Contribution | PBFA DSM Programs | Electric Vehicles | No PBFA DSM Sales Forecast | Sales Forecast |
|---|---|---|---|---|---|---|---|
| | A | B | C | D | E | F=A+B+C+E | G=F+D |
| 2012 | 1,117 | (2) | (1) | (15) | 0 | 1,114 | 1,099 |
| 2013 | 1,142 | (8) | (4) | (25) | 0 | 1,131 | 1,105 |
| 2014 | 1,171 | (12) | (7) | (35) | 0 | 1,153 | 1,117 |
| 2015 | 1,197 | (14) | (9) | (45) | 0 | 1,174 | 1,129 |
| 2016 | 1,229 | (18) | (12) | (55) | 1 | 1,200 | 1,144 |
| 2017 | 1,261 | (21) | (15) | (66) | 1 | 1,227 | 1,162 |
| 2018 | 1,295 | (23) | (17) | (76) | 1 | 1,256 | 1,181 |
| 2019 | 1,328 | (26) | (20) | (86) | 2 | 1,284 | 1,199 |
| 2020 | 1,357 | (28) | (23) | (96) | 3 | 1,309 | 1,213 |
| 2021 | 1,386 | (31) | (25) | (106) | 4 | 1,334 | 1,228 |
| 2022 | 1,414 | (33) | (28) | (116) | 5 | 1,358 | 1,242 |
| 2023 | 1,441 | (35) | (31) | (126) | 6 | 1,382 | 1,256 |
| 2024 | 1,469 | (38) | (33) | (136) | 8 | 1,406 | 1,270 |
| 2025 | 1,494 | (40) | (36) | (146) | 10 | 1,427 | 1,281 |
| 2026 | 1,525 | (42) | (39) | (156) | 12 | 1,455 | 1,299 |
| 2027 | 1,552 | (45) | (41) | (166) | 14 | 1,480 | 1,314 |
| 2028 | 1,581 | (48) | (44) | (176) | 16 | 1,505 | 1,329 |
| 2029 | 1,609 | (50) | (46) | (186) | 19 | 1,532 | 1,345 |
| 2030 | 1,639 | (52) | (49) | (197) | 21 | 1,559 | 1,362 |
| 2031 | 1,668 | (55) | (51) | (207) | 24 | 1,586 | 1,380 |
| 2032 | 1,697 | (57) | (52) | (217) | 27 | 1,615 | 1,398 |
| 2033 | 1,728 | (60) | (54) | (227) | 31 | 1,645 | 1,418 |

Table E-8: HELCO No Burning Desire Scenario Sales Forecast Data (GWh)

| Year | Underlying Economic Forecast | Renewable Self Generation | Non-PBFA EEPS Contribution | PBFA DSM Programs | Electric Vehicles | No PBFA DSM Sales Forecast | Sales Forecast |
|---|---|---|---|---|---|---|---|
| | *A* | *B* | *C* | *D* | *E* | *F=A+B+C+E* | *G=F+D* |
| 2012 | 1,192 | (1) | (1) | (15) | 0 | 1,190 | 1,174 |
| 2013 | 1,247 | (5) | (4) | (25) | 0 | 1,238 | 1,213 |
| 2014 | 1,306 | (7) | (7) | (35) | 0 | 1,293 | 1,257 |
| 2015 | 1,339 | (8) | (9) | (45) | 0 | 1,322 | 1,276 |
| 2016 | 1,377 | (10) | (12) | (55) | 0 | 1,355 | 1,300 |
| 2017 | 1,408 | (12) | (15) | (66) | 0 | 1,382 | 1,317 |
| 2018 | 1,457 | (13) | (17) | (76) | 1 | 1,427 | 1,352 |
| 2019 | 1,503 | (15) | (20) | (86) | 1 | 1,469 | 1,384 |
| 2020 | 1,548 | (17) | (23) | (96) | 1 | 1,510 | 1,414 |
| 2021 | 1,594 | (18) | (25) | (106) | 2 | 1,553 | 1,447 |
| 2022 | 1,640 | (19) | (28) | (116) | 2 | 1,595 | 1,479 |
| 2023 | 1,687 | (21) | (31) | (126) | 3 | 1,639 | 1,513 |
| 2024 | 1,736 | (22) | (33) | (136) | 4 | 1,685 | 1,549 |
| 2025 | 1,785 | (23) | (36) | (146) | 5 | 1,730 | 1,584 |
| 2026 | 1,834 | (25) | (39) | (156) | 6 | 1,776 | 1,620 |
| 2027 | 1,883 | (26) | (41) | (166) | 7 | 1,823 | 1,656 |
| 2028 | 1,932 | (28) | (44) | (176) | 8 | 1,869 | 1,692 |
| 2029 | 1,981 | (29) | (46) | (186) | 9 | 1,915 | 1,728 |
| 2030 | 2,028 | (31) | (49) | (197) | 11 | 1,959 | 1,762 |
| 2031 | 2,075 | (32) | (51) | (207) | 12 | 2,004 | 1,797 |
| 2032 | 2,124 | (33) | (52) | (217) | 14 | 2,052 | 1,835 |
| 2033 | 2,175 | (35) | (54) | (227) | 15 | 2,102 | 1,875 |

Table E-9: HELCO Moved by Passion Scenario Sales Forecast Data (GWh)

| Year | Underlying Economic Forecast | Renewable Self Generation | Non-PBFA EEPS Contribution | PBFA DSM Programs | Electric Vehicles | No PBFA DSM Sales Forecast | Sales Forecast |
|---|---|---|---|---|---|---|---|
| | *A* | *B* | *C* | *D* | *E* | *F=A+B+C+E* | *G=F+D* |
| 2012 | 1,117 | (4) | (2) | (20) | 0 | 1,112 | 1,092 |
| 2013 | 1,142 | (13) | (5) | (34) | 0 | 1,124 | 1,090 |
| 2014 | 1,171 | (19) | (9) | (47) | 0 | 1,142 | 1,095 |
| 2015 | 1,197 | (24) | (12) | (60) | 0 | 1,161 | 1,100 |
| 2016 | 1,229 | (29) | (16) | (74) | 0 | 1,183 | 1,109 |
| 2017 | 1,261 | (34) | (19) | (87) | 0 | 1,208 | 1,120 |
| 2018 | 1,295 | (38) | (23) | (101) | 0 | 1,234 | 1,133 |
| 2019 | 1,328 | (43) | (27) | (114) | 0 | 1,258 | 1,144 |
| 2020 | 1,357 | (47) | (30) | (128) | 0 | 1,280 | 1,152 |
| 2021 | 1,386 | (51) | (34) | (141) | 0 | 1,302 | 1,160 |
| 2022 | 1,414 | (55) | (37) | (155) | 0 | 1,322 | 1,167 |
| 2023 | 1,441 | (59) | (41) | (168) | 0 | 1,342 | 1,174 |
| 2024 | 1,469 | (63) | (44) | (181) | 0 | 1,362 | 1,181 |
| 2025 | 1,494 | (67) | (48) | (195) | 0 | 1,379 | 1,184 |
| 2026 | 1,525 | (71) | (51) | (208) | 0 | 1,402 | 1,194 |
| 2027 | 1,552 | (75) | (55) | (222) | 0 | 1,423 | 1,201 |
| 2028 | 1,581 | (79) | (58) | (235) | 0 | 1,443 | 1,208 |
| 2029 | 1,609 | (83) | (62) | (249) | 0 | 1,464 | 1,216 |
| 2030 | 1,639 | (87) | (66) | (262) | 0 | 1,486 | 1,224 |
| 2031 | 1,668 | (91) | (68) | (276) | 0 | 1,508 | 1,233 |
| 2032 | 1,697 | (95) | (70) | (289) | 0 | 1,532 | 1,243 |
| 2033 | 1,728 | (99) | (72) | (302) | 0 | 1,557 | 1,254 |

## *Maui Sales Forecast Data Summary by Scenario*

Table E-10: Maui Blazing Bold Frontier Scenario Sales Forecast Data (GWh)

| Year | Underlying Economic Forecast | Renewable Self Generation | Non-PBFA EEPS Contribution | PBFA DSM Programs | Electric Vehicles | No PBFA DSM Sales Forecast | Sales Forecast |
|---|---|---|---|---|---|---|---|
| | A | B | C | D | E | F=A+B+C+E | G=F+D |
| 2012 | 1,098 | (10) | (2) | (8) | 1 | 1,087 | 1,079 |
| 2013 | 1,096 | (35) | (6) | (23) | 1 | 1,057 | 1,034 |
| 2014 | 1,097 | (60) | (10) | (38) | 1 | 1,029 | 991 |
| 2015 | 1,093 | (83) | (14) | (53) | 2 | 998 | 945 |
| 2016 | 1,094 | (109) | (18) | (68) | 3 | 970 | 902 |
| 2017 | 1,091 | (133) | (22) | (83) | 4 | 940 | 858 |
| 2018 | 1,092 | (154) | (26) | (98) | 6 | 918 | 820 |
| 2019 | 1,091 | (169) | (30) | (113) | 8 | 901 | 788 |
| 2020 | 1,094 | (180) | (34) | (128) | 10 | 891 | 763 |
| 2021 | 1,092 | (188) | (38) | (143) | 13 | 879 | 736 |
| 2022 | 1,092 | (194) | (42) | (158) | 17 | 873 | 715 |
| 2023 | 1,094 | (199) | (46) | (173) | 21 | 871 | 697 |
| 2024 | 1,100 | (203) | (50) | (188) | 25 | 873 | 684 |
| 2025 | 1,101 | (206) | (54) | (203) | 30 | 871 | 668 |
| 2026 | 1,107 | (209) | (58) | (218) | 35 | 876 | 657 |
| 2027 | 1,112 | (211) | (61) | (233) | 41 | 880 | 646 |
| 2028 | 1,119 | (214) | (65) | (248) | 47 | 887 | 639 |
| 2029 | 1,121 | (215) | (69) | (264) | 54 | 891 | 627 |
| 2030 | 1,126 | (217) | (73) | (279) | 61 | 897 | 618 |
| 2031 | 1,131 | (219) | (76) | (294) | 68 | 904 | 610 |
| 2032 | 1,139 | (221) | (78) | (309) | 76 | 915 | 607 |
| 2033 | 1,141 | (223) | (80) | (324) | 84 | 922 | 598 |

Table E-11: Maui Stuck in the Middle Scenario Sales Forecast Data (GWh)

| Year | Underlying Economic Forecast | Renewable Self Generation | Non-PBFA EEPS Contribution | PBFA DSM Programs | Electric Vehicles | No PBFA DSM Sales Forecast | Sales Forecast |
|---|---|---|---|---|---|---|---|
| | *A* | *B* | *C* | *D* | *E* | *F=A+B+C+E* | *G=F+D* |
| 2012 | 1,124 | (5) | (1) | (5) | 0 | 1,118 | 1,113 |
| 2013 | 1,145 | (19) | (4) | (15) | 0 | 1,122 | 1,107 |
| 2014 | 1,169 | (33) | (7) | (26) | 1 | 1,130 | 1,104 |
| 2015 | 1,183 | (46) | (9) | (36) | 1 | 1,129 | 1,093 |
| 2016 | 1,201 | (59) | (12) | (46) | 1 | 1,130 | 1,084 |
| 2017 | 1,216 | (73) | (15) | (56) | 2 | 1,131 | 1,074 |
| 2018 | 1,240 | (84) | (18) | (67) | 3 | 1,141 | 1,074 |
| 2019 | 1,258 | (92) | (20) | (77) | 4 | 1,150 | 1,073 |
| 2020 | 1,278 | (98) | (23) | (87) | 5 | 1,162 | 1,074 |
| 2021 | 1,293 | (102) | (26) | (98) | 7 | 1,171 | 1,074 |
| 2022 | 1,309 | (106) | (28) | (108) | 8 | 1,183 | 1,076 |
| 2023 | 1,326 | (109) | (31) | (118) | 10 | 1,196 | 1,078 |
| 2024 | 1,346 | (111) | (34) | (128) | 13 | 1,214 | 1,086 |
| 2025 | 1,358 | (112) | (37) | (139) | 15 | 1,224 | 1,086 |
| 2026 | 1,374 | (114) | (39) | (149) | 18 | 1,239 | 1,090 |
| 2027 | 1,392 | (115) | (42) | (159) | 20 | 1,256 | 1,097 |
| 2028 | 1,411 | (117) | (45) | (169) | 24 | 1,274 | 1,104 |
| 2029 | 1,423 | (117) | (47) | (180) | 27 | 1,285 | 1,106 |
| 2030 | 1,440 | (118) | (50) | (190) | 30 | 1,302 | 1,112 |
| 2031 | 1,456 | (119) | (52) | (200) | 34 | 1,318 | 1,118 |
| 2032 | 1,477 | (121) | (53) | (210) | 38 | 1,341 | 1,131 |
| 2033 | 1,493 | (121) | (55) | (221) | 42 | 1,358 | 1,138 |

Table E-12: Maui No Burning Desire Scenario Sales Forecast Data (GWh)

| Year | Underlying Economic Forecast | Renewable Self Generation | Non-PBFA EEPS Contribution | PBFA DSM Programs | Electric Vehicles | No PBFA DSM Sales Forecast | Sales Forecast |
|---|---|---|---|---|---|---|---|
| | *A* | *B* | *C* | *D* | *E* | *F=A+B+C+E* | *G=F+D* |
| 2012 | 1,149 | (3) | (1) | (5) | 0 | 1,144 | 1,139 |
| 2013 | 1,197 | (11) | (4) | (15) | 0 | 1,183 | 1,167 |
| 2014 | 1,253 | (19) | (7) | (26) | 0 | 1,228 | 1,202 |
| 2015 | 1,313 | (27) | (9) | (36) | 0 | 1,277 | 1,241 |
| 2016 | 1,377 | (35) | (12) | (46) | 1 | 1,331 | 1,285 |
| 2017 | 1,439 | (42) | (15) | (56) | 1 | 1,383 | 1,327 |
| 2018 | 1,506 | (49) | (18) | (67) | 1 | 1,441 | 1,375 |
| 2019 | 1,568 | (54) | (20) | (77) | 2 | 1,496 | 1,419 |
| 2020 | 1,631 | (57) | (23) | (87) | 3 | 1,553 | 1,466 |
| 2021 | 1,684 | (60) | (26) | (98) | 3 | 1,602 | 1,505 |
| 2022 | 1,738 | (62) | (28) | (108) | 4 | 1,652 | 1,545 |
| 2023 | 1,791 | (63) | (31) | (118) | 5 | 1,702 | 1,584 |
| 2024 | 1,848 | (65) | (34) | (128) | 6 | 1,756 | 1,627 |
| 2025 | 1,891 | (66) | (37) | (139) | 8 | 1,796 | 1,658 |
| 2026 | 1,938 | (66) | (39) | (149) | 9 | 1,841 | 1,692 |
| 2027 | 1,984 | (67) | (42) | (159) | 10 | 1,885 | 1,726 |
| 2028 | 2,032 | (68) | (45) | (169) | 12 | 1,932 | 1,762 |
| 2029 | 2,071 | (69) | (47) | (180) | 13 | 1,969 | 1,789 |
| 2030 | 2,117 | (69) | (50) | (190) | 15 | 2,013 | 1,823 |
| 2031 | 2,163 | (70) | (52) | (200) | 17 | 2,059 | 1,858 |
| 2032 | 2,219 | (70) | (53) | (210) | 19 | 2,114 | 1,904 |
| 2033 | 2,264 | (71) | (55) | (221) | 21 | 2,160 | 1,939 |

Table E-13: Maui Moved by Passion Scenario Sales Forecast Data (GWh)

| Year | Underlying Economic Forecast | Renewable Self Generation | Non-PBFA EEPS Contribution | PBFA DSM Programs | Electric Vehicles | No PBFA DSM Sales Forecast | Sales Forecast |
|---|---|---|---|---|---|---|---|
| | *A* | *B* | *C* | *D* | *E* | *F=A+B+C+E* | *G=F+D* |
| 2012 | 1,124 | (9) | (2) | (7) | 0 | 1,114 | 1,107 |
| 2013 | 1,145 | (31) | (5) | (21) | 0 | 1,108 | 1,088 |
| 2014 | 1,169 | (54) | (9) | (34) | 1 | 1,106 | 1,072 |
| 2015 | 1,183 | (76) | (13) | (48) | 1 | 1,095 | 1,047 |
| 2016 | 1,201 | (99) | (16) | (62) | 1 | 1,087 | 1,025 |
| 2017 | 1,216 | (121) | (20) | (75) | 2 | 1,078 | 1,002 |
| 2018 | 1,240 | (140) | (23) | (89) | 3 | 1,079 | 990 |
| 2019 | 1,258 | (153) | (27) | (103) | 4 | 1,081 | 979 |
| 2020 | 1,278 | (164) | (31) | (116) | 5 | 1,089 | 972 |
| 2021 | 1,293 | (171) | (34) | (130) | 7 | 1,095 | 964 |
| 2022 | 1,309 | (176) | (38) | (144) | 8 | 1,103 | 960 |
| 2023 | 1,326 | (181) | (41) | (157) | 10 | 1,114 | 956 |
| 2024 | 1,346 | (185) | (45) | (171) | 13 | 1,129 | 958 |
| 2025 | 1,358 | (187) | (49) | (185) | 15 | 1,137 | 952 |
| 2026 | 1,374 | (190) | (52) | (198) | 18 | 1,150 | 952 |
| 2027 | 1,392 | (192) | (56) | (212) | 20 | 1,165 | 953 |
| 2028 | 1,411 | (194) | (60) | (226) | 24 | 1,181 | 955 |
| 2029 | 1,423 | (196) | (63) | (240) | 27 | 1,191 | 952 |
| 2030 | 1,440 | (197) | (67) | (253) | 30 | 1,206 | 953 |
| 2031 | 1,456 | (199) | (69) | (267) | 34 | 1,221 | 954 |
| 2032 | 1,477 | (201) | (71) | (281) | 38 | 1,243 | 962 |
| 2033 | 1,493 | (202) | (73) | (294) | 42 | 1,259 | 965 |

## *Lanai Sales Forecast Data Summary by Scenario*

Table E-14: Lanai Blazing Bold Frontier Scenario Sales Forecast Data (MWh)

| Year | Underlying Economic Forecast | Renewable Self Generation | Non-PBFA EEPS Contribution | PBFA DSM Programs | Electric Vehicles | No PBFA DSM Sales Forecast | Sales Forecast |
|---|---|---|---|---|---|---|---|
| | A | B | C | D | E | F=A+B+C+E | G=F+D |
| 2012 | 24,530 | (39) | (44) | (168) | – | 24,447 | 24,279 |
| 2013 | 24,378 | (86) | (133) | (505) | – | 24,159 | 23,655 |
| 2014 | 24,292 | (119) | (222) | (841) | – | 23,952 | 23,111 |
| 2015 | 24,206 | (152) | (310) | (1,177) | – | 23,745 | 22,567 |
| 2016 | 24,187 | (185) | (399) | (1,514) | – | 23,603 | 22,089 |
| 2017 | 24,035 | (218) | (487) | (1,850) | – | 23,330 | 21,480 |
| 2018 | 23,950 | (251) | (576) | (2,186) | – | 23,123 | 20,936 |
| 2019 | 23,864 | (284) | (665) | (2,523) | – | 22,915 | 20,393 |
| 2020 | 23,844 | (318) | (753) | (2,859) | – | 22,772 | 19,913 |
| 2021 | 23,693 | (350) | (842) | (3,195) | – | 22,501 | 19,305 |
| 2022 | 23,607 | (383) | (930) | (3,532) | – | 22,294 | 18,762 |
| 2023 | 23,522 | (416) | (1,019) | (3,868) | – | 22,086 | 18,218 |
| 2024 | 23,500 | (451) | (1,108) | (4,205) | – | 21,942 | 17,737 |
| 2025 | 23,351 | (483) | (1,196) | (4,541) | – | 21,672 | 17,131 |
| 2026 | 23,265 | (516) | (1,285) | (4,877) | – | 21,464 | 16,587 |
| 2027 | 23,179 | (549) | (1,374) | (5,214) | – | 21,257 | 16,043 |
| 2028 | 23,157 | (583) | (1,462) | (5,550) | – | 21,111 | 15,561 |
| 2029 | 23,008 | (615) | (1,551) | (5,886) | – | 20,843 | 14,956 |
| 2030 | 22,923 | (648) | (1,639) | (6,223) | – | 20,635 | 14,412 |
| 2031 | 22,837 | (681) | (1,706) | (6,559) | – | 20,450 | 13,890 |
| 2032 | 22,814 | (716) | (1,752) | (6,896) | – | 20,346 | 13,450 |
| 2033 | 22,666 | (747) | (1,797) | (7,232) | – | 20,122 | 12,890 |

Table E-15: Lanai Stuck in the Middle Scenario Sales Forecast Data (MWh)

| Year | Underlying Economic Forecast | Renewable Self Generation | Non-PBFA EEPS Contribution | PBFA DSM Programs | Electric Vehicles | No PBFA DSM Sales Forecast | Sales Forecast |
|---|---|---|---|---|---|---|---|
| | *A* | *B* | *C* | *D* | *E* | *F=A+B+C+E* | *G=F+D* |
| 2012 | 24,692 | (21) | (30) | (115) | – | 24,641 | 24,526 |
| 2013 | 24,745 | (47) | (91) | (344) | – | 24,607 | 24,263 |
| 2014 | 24,845 | (65) | (151) | (573) | – | 24,629 | 24,056 |
| 2015 | 25,023 | (83) | (211) | (803) | – | 24,729 | 23,926 |
| 2016 | 25,235 | (101) | (272) | (1,032) | – | 24,862 | 23,830 |
| 2017 | 25,333 | (119) | (332) | (1,261) | – | 24,881 | 23,620 |
| 2018 | 25,510 | (137) | (393) | (1,491) | – | 24,981 | 23,490 |
| 2019 | 25,703 | (155) | (453) | (1,720) | – | 25,095 | 23,375 |
| 2020 | 25,977 | (173) | (514) | (1,949) | – | 25,290 | 23,341 |
| 2021 | 26,110 | (191) | (574) | (2,179) | – | 25,345 | 23,166 |
| 2022 | 26,315 | (209) | (634) | (2,408) | – | 25,472 | 23,064 |
| 2023 | 26,524 | (227) | (695) | (2,637) | – | 25,602 | 22,964 |
| 2024 | 26,795 | (246) | (755) | (2,867) | – | 25,794 | 22,927 |
| 2025 | 26,927 | (263) | (816) | (3,096) | – | 25,848 | 22,752 |
| 2026 | 27,135 | (281) | (876) | (3,325) | – | 25,978 | 22,652 |
| 2027 | 27,338 | (299) | (936) | (3,555) | – | 26,102 | 22,547 |
| 2028 | 27,615 | (318) | (997) | (3,784) | – | 26,299 | 22,515 |
| 2029 | 27,745 | (335) | (1,057) | (4,013) | – | 26,352 | 22,338 |
| 2030 | 27,946 | (353) | (1,118) | (4,243) | – | 26,475 | 22,232 |
| 2031 | 28,148 | (372) | (1,163) | (4,472) | – | 26,613 | 22,141 |
| 2032 | 28,430 | (391) | (1,194) | (4,701) | – | 26,845 | 22,144 |
| 2033 | 28,553 | (408) | (1,225) | (4,931) | – | 26,920 | 21,990 |

Table E-16: Lanai No Burning Desire Scenario Sales Forecast Data (MWh)

| Year | Underlying Economic Forecast | Renewable Self Generation | Non-PBFA EEPS Contribution | PBFA DSM Programs | Electric Vehicles | No PBFA DSM Sales Forecast | Sales Forecast |
|---|---|---|---|---|---|---|---|
| | *A* | *B* | *C* | *D* | *E* | *F=A+B+C+E* | *G=F+D* |
| 2012 | 25,585 | (12) | (30) | (115) | – | 25,543 | 25,428 |
| 2013 | 25,980 | (27) | (91) | (344) | – | 25,862 | 25,518 |
| 2014 | 26,445 | (38) | (151) | (573) | – | 26,256 | 25,683 |
| 2015 | 26,910 | (48) | (211) | (803) | – | 26,650 | 25,848 |
| 2016 | 27,450 | (59) | (272) | (1,032) | – | 27,119 | 26,087 |
| 2017 | 27,840 | (69) | (332) | (1,261) | – | 27,439 | 26,177 |
| 2018 | 28,305 | (80) | (393) | (1,491) | – | 27,833 | 26,342 |
| 2019 | 28,770 | (90) | (453) | (1,720) | – | 28,227 | 26,507 |
| 2020 | 29,315 | (101) | (514) | (1,949) | – | 28,700 | 26,751 |
| 2021 | 29,700 | (111) | (574) | (2,179) | – | 29,015 | 26,836 |
| 2022 | 30,165 | (122) | (634) | (2,408) | – | 29,409 | 27,001 |
| 2023 | 30,630 | (133) | (695) | (2,637) | – | 29,803 | 27,165 |
| 2024 | 31,180 | (143) | (755) | (2,867) | – | 30,282 | 27,415 |
| 2025 | 31,560 | (154) | (816) | (3,096) | – | 30,591 | 27,495 |
| 2026 | 32,025 | (164) | (876) | (3,325) | – | 30,985 | 27,659 |
| 2027 | 32,490 | (175) | (936) | (3,555) | – | 31,379 | 27,824 |
| 2028 | 33,045 | (186) | (997) | (3,784) | – | 31,863 | 28,079 |
| 2029 | 33,420 | (196) | (1,057) | (4,013) | – | 32,167 | 28,153 |
| 2030 | 33,885 | (206) | (1,118) | (4,243) | – | 32,561 | 28,318 |
| 2031 | 34,350 | (217) | (1,163) | (4,472) | – | 32,970 | 28,498 |
| 2032 | 34,910 | (228) | (1,194) | (4,701) | – | 33,488 | 28,787 |
| 2033 | 35,280 | (238) | (1,225) | (4,931) | – | 33,817 | 28,886 |

Table E-17: Lanai Moved by Passion Scenario Sales Forecast Data (MWh)

| Year | Underlying Economic Forecast | Renewable Self Generation | Non-PBFA EEPS Contribution | PBFA DSM Programs | Electric Vehicles | No PBFA DSM Sales Forecast | Sales Forecast |
|---|---|---|---|---|---|---|---|
| | *A* | *B* | *C* | *D* | *E* | *F=A+B+C+E* | *G=F+D* |
| 2012 | 24,692 | (35) | (40) | (153) | – | 24,616 | 24,463 |
| 2013 | 24,745 | (78) | (121) | (459) | – | 24,546 | 24,087 |
| 2014 | 24,845 | (108) | (201) | (764) | – | 24,536 | 23,771 |
| 2015 | 25,023 | (138) | (282) | (1,070) | – | 24,603 | 23,533 |
| 2016 | 25,235 | (169) | (363) | (1,376) | – | 24,704 | 23,328 |
| 2017 | 25,333 | (198) | (443) | (1,682) | – | 24,691 | 23,010 |
| 2018 | 25,510 | (228) | (524) | (1,988) | – | 24,758 | 22,771 |
| 2019 | 25,703 | (258) | (604) | (2,293) | – | 24,841 | 22,547 |
| 2020 | 25,977 | (289) | (685) | (2,599) | – | 25,003 | 22,404 |
| 2021 | 26,110 | (318) | (765) | (2,905) | – | 25,026 | 22,121 |
| 2022 | 26,315 | (349) | (846) | (3,211) | – | 25,121 | 21,910 |
| 2023 | 26,524 | (379) | (926) | (3,517) | – | 25,219 | 21,702 |
| 2024 | 26,795 | (410) | (1,007) | (3,822) | – | 25,379 | 21,556 |
| 2025 | 26,927 | (439) | (1,088) | (4,128) | – | 25,401 | 21,273 |
| 2026 | 27,135 | (469) | (1,168) | (4,434) | – | 25,498 | 21,064 |
| 2027 | 27,338 | (499) | (1,249) | (4,740) | – | 25,590 | 20,850 |
| 2028 | 27,615 | (530) | (1,329) | (5,046) | – | 25,755 | 20,709 |
| 2029 | 27,745 | (559) | (1,410) | (5,351) | – | 25,776 | 20,425 |
| 2030 | 27,946 | (589) | (1,490) | (5,657) | – | 25,867 | 20,209 |
| 2031 | 28,148 | (619) | (1,551) | (5,963) | – | 25,977 | 20,014 |
| 2032 | 28,430 | (651) | (1,592) | (6,269) | – | 26,187 | 19,918 |
| 2033 | 28,553 | (679) | (1,634) | (6,574) | – | 26,240 | 19,666 |

## *Molokai Sales Forecast Data Summary by Scenario*

Table E-18: Molokai Blazing Bold Frontier Scenario Sales Forecast Data (MWh)

| Year | Underlying Economic Forecast | Renewable Self Generation | Non-PBFA EEPS Contribution | PBFA DSM Programs | Electric Vehicles | No PBFA DSM Sales Forecast | Sales Forecast |
|---|---|---|---|---|---|---|---|
| | *A* | *B* | *C* | *D* | *E* | *F=A+B+C+E* | *G=F+D* |
| 2012 | 29,856 | (116) | (55) | (208) | – | 29,685 | 29,477 |
| 2013 | 29,492 | (434) | (165) | (625) | – | 28,893 | 28,268 |
| 2014 | 29,210 | (744) | (274) | (1,042) | – | 28,191 | 27,149 |
| 2015 | 28,928 | (1,054) | (384) | (1,459) | – | 27,489 | 26,031 |
| 2016 | 28,724 | (1,368) | (494) | (1,875) | – | 26,862 | 24,986 |
| 2017 | 28,363 | (1,674) | (604) | (2,292) | – | 26,085 | 23,793 |
| 2018 | 28,081 | (1,983) | (714) | (2,709) | – | 25,384 | 22,675 |
| 2019 | 27,799 | (2,280) | (823) | (3,126) | – | 24,696 | 21,570 |
| 2020 | 27,592 | (2,541) | (933) | (3,542) | – | 24,118 | 20,575 |
| 2021 | 27,234 | (2,719) | (1,043) | (3,959) | – | 23,472 | 19,512 |
| 2022 | 26,952 | (2,857) | (1,153) | (4,376) | – | 22,942 | 18,566 |
| 2023 | 26,670 | (2,961) | (1,263) | (4,793) | – | 22,446 | 17,654 |
| 2024 | 26,460 | (3,049) | (1,372) | (5,209) | – | 22,038 | 16,829 |
| 2025 | 26,105 | (3,104) | (1,482) | (5,626) | – | 21,519 | 15,892 |
| 2026 | 25,823 | (3,156) | (1,592) | (6,043) | – | 21,074 | 15,031 |
| 2027 | 25,540 | (3,200) | (1,702) | (6,460) | – | 20,638 | 14,179 |
| 2028 | 25,327 | (3,247) | (1,812) | (6,877) | – | 20,268 | 13,392 |
| 2029 | 24,976 | (3,273) | (1,921) | (7,293) | – | 19,782 | 12,488 |
| 2030 | 24,694 | (3,304) | (2,031) | (7,710) | – | 19,358 | 11,648 |
| 2031 | 24,411 | (3,334) | (2,114) | (8,127) | – | 18,963 | 10,836 |
| 2032 | 24,195 | (3,371) | (2,170) | (8,544) | – | 18,653 | 10,110 |
| 2033 | 23,847 | (3,390) | (2,227) | (8,960) | – | 18,231 | 9,270 |

Table E-19: Molokai Stuck in the Middle Scenario Sales Forecast Data (MWh)

| Year | Underlying Economic Forecast | Renewable Self Generation | Non-PBFA EEPS Contribution | PBFA DSM Programs | Electric Vehicles | No PBFA DSM Sales Forecast | Sales Forecast |
|---|---|---|---|---|---|---|---|
| | *A* | *B* | *C* | *D* | *E* | *F=A+B+C+E* | *G=F+D* |
| 2012 | 30,480 | (63) | (37) | (142) | – | 30,380 | 30,238 |
| 2013 | 30,452 | (237) | (112) | (426) | – | 30,103 | 29,677 |
| 2014 | 30,503 | (406) | (187) | (710) | – | 29,910 | 29,200 |
| 2015 | 30,555 | (575) | (262) | (995) | – | 29,718 | 28,723 |
| 2016 | 30,691 | (746) | (337) | (1,279) | – | 29,608 | 28,329 |
| 2017 | 30,639 | (913) | (412) | (1,563) | – | 29,314 | 27,751 |
| 2018 | 30,738 | (1,082) | (487) | (1,847) | – | 29,170 | 27,323 |
| 2019 | 30,777 | (1,243) | (561) | (2,131) | – | 28,973 | 26,841 |
| 2020 | 30,918 | (1,386) | (636) | (2,415) | – | 28,896 | 26,480 |
| 2021 | 30,905 | (1,483) | (711) | (2,699) | – | 28,711 | 26,011 |
| 2022 | 30,909 | (1,558) | (786) | (2,984) | – | 28,565 | 25,581 |
| 2023 | 30,936 | (1,615) | (861) | (3,268) | – | 28,460 | 25,192 |
| 2024 | 31,057 | (1,663) | (936) | (3,552) | – | 28,458 | 24,906 |
| 2025 | 30,967 | (1,693) | (1,011) | (3,836) | – | 28,263 | 24,427 |
| 2026 | 30,982 | (1,722) | (1,085) | (4,120) | – | 28,175 | 24,055 |
| 2027 | 31,026 | (1,746) | (1,160) | (4,404) | – | 28,120 | 23,716 |
| 2028 | 31,105 | (1,771) | (1,235) | (4,689) | – | 28,098 | 23,410 |
| 2029 | 31,047 | (1,785) | (1,310) | (4,973) | – | 27,952 | 22,980 |
| 2030 | 31,092 | (1,802) | (1,385) | (5,257) | – | 27,904 | 22,647 |
| 2031 | 31,087 | (1,819) | (1,441) | (5,541) | – | 27,827 | 22,286 |
| 2032 | 31,195 | (1,839) | (1,480) | (5,825) | – | 27,876 | 22,051 |
| 2033 | 31,150 | (1,849) | (1,518) | (6,109) | – | 27,783 | 21,674 |

Table E-20: Molokai No Burning Desire Scenario Sales Forecast Data (MWh)

| Year | Underlying Economic Forecast | Renewable Self Generation | Non-PBFA EEPS Contribution | PBFA DSM Programs | Electric Vehicles | No PBFA DSM Sales Forecast | Sales Forecast |
|---|---|---|---|---|---|---|---|
| | *A* | *B* | *C* | *D* | *E* | *F=A+B+C+E* | *G=F+D* |
| 2012 | 31,064 | (37) | (37) | (142) | – | 30,990 | 30,848 |
| 2013 | 30,930 | (138) | (112) | (426) | – | 30,680 | 30,253 |
| 2014 | 30,966 | (237) | (187) | (710) | – | 30,542 | 29,831 |
| 2015 | 31,082 | (335) | (262) | (995) | – | 30,485 | 29,490 |
| 2016 | 31,354 | (435) | (337) | (1,279) | – | 30,582 | 29,303 |
| 2017 | 31,467 | (533) | (412) | (1,563) | – | 30,523 | 28,960 |
| 2018 | 31,727 | (631) | (487) | (1,847) | – | 30,609 | 28,762 |
| 2019 | 32,006 | (725) | (561) | (2,131) | – | 30,719 | 28,588 |
| 2020 | 32,344 | (808) | (636) | (2,415) | – | 30,899 | 28,484 |
| 2021 | 32,532 | (865) | (711) | (2,699) | – | 30,956 | 28,256 |
| 2022 | 32,822 | (909) | (786) | (2,984) | – | 31,127 | 28,143 |
| 2023 | 33,061 | (942) | (861) | (3,268) | – | 31,258 | 27,990 |
| 2024 | 33,397 | (970) | (936) | (3,552) | – | 31,491 | 27,939 |
| 2025 | 33,562 | (988) | (1,011) | (3,836) | – | 31,564 | 27,728 |
| 2026 | 33,773 | (1,004) | (1,085) | (4,120) | – | 31,684 | 27,563 |
| 2027 | 33,995 | (1,018) | (1,160) | (4,404) | – | 31,816 | 27,412 |
| 2028 | 34,330 | (1,033) | (1,235) | (4,689) | – | 32,061 | 27,373 |
| 2029 | 34,439 | (1,041) | (1,310) | (4,973) | – | 32,087 | 27,115 |
| 2030 | 34,666 | (1,051) | (1,385) | (5,257) | – | 32,230 | 26,973 |
| 2031 | 34,912 | (1,061) | (1,441) | (5,541) | – | 32,409 | 26,868 |
| 2032 | 35,208 | (1,073) | (1,480) | (5,825) | – | 32,656 | 26,830 |
| 2033 | 35,331 | (1,078) | (1,518) | (6,109) | – | 32,734 | 26,625 |

Table E-21: Molokai Moved by Passion Scenario Sales Forecast Data (MWh)

| Year | Underlying Economic Forecast | Renewable Self Generation | Non-PBFA EEPS Contribution | PBFA DSM Programs | Electric Vehicles | No PBFA DSM Sales Forecast | Sales Forecast |
|---|---|---|---|---|---|---|---|
| | *A* | *B* | *C* | *D* | *E* | *F=A+B+C+E* | *G=F+D* |
| 2012 | 30,480 | (105) | (50) | (189) | – | 30,325 | 30,136 |
| 2013 | 30,452 | (395) | (150) | (568) | – | 29,908 | 29,339 |
| 2014 | 30,503 | (677) | (250) | (947) | – | 29,577 | 28,630 |
| 2015 | 30,555 | (958) | (349) | (1,326) | – | 29,247 | 27,921 |
| 2016 | 30,691 | (1,244) | (449) | (1,705) | – | 28,998 | 27,293 |
| 2017 | 30,639 | (1,522) | (549) | (2,084) | – | 28,567 | 26,484 |
| 2018 | 30,738 | (1,803) | (649) | (2,463) | – | 28,286 | 25,824 |
| 2019 | 30,777 | (2,072) | (749) | (2,842) | – | 27,956 | 25,115 |
| 2020 | 30,918 | (2,310) | (848) | (3,220) | – | 27,760 | 24,539 |
| 2021 | 30,905 | (2,472) | (948) | (3,599) | – | 27,485 | 23,885 |
| 2022 | 30,909 | (2,597) | (1,048) | (3,978) | – | 27,264 | 23,286 |
| 2023 | 30,936 | (2,691) | (1,148) | (4,357) | – | 27,096 | 22,739 |
| 2024 | 31,057 | (2,772) | (1,248) | (4,736) | – | 27,037 | 22,302 |
| 2025 | 30,967 | (2,822) | (1,347) | (5,115) | – | 26,798 | 21,683 |
| 2026 | 30,982 | (2,869) | (1,447) | (5,494) | – | 26,665 | 21,172 |
| 2027 | 31,026 | (2,909) | (1,547) | (5,873) | – | 26,570 | 20,697 |
| 2028 | 31,105 | (2,952) | (1,647) | (6,251) | – | 26,506 | 20,254 |
| 2029 | 31,047 | (2,975) | (1,747) | (6,630) | – | 26,325 | 19,695 |
| 2030 | 31,092 | (3,004) | (1,847) | (7,009) | – | 26,241 | 19,232 |
| 2031 | 31,087 | (3,031) | (1,922) | (7,388) | – | 26,134 | 18,746 |
| 2032 | 31,195 | (3,065) | (1,973) | (7,767) | – | 26,157 | 18,390 |
| 2033 | 31,150 | (3,081) | (2,024) | (8,146) | – | 26,045 | 17,899 |

# Appendix E-2: Quantification of Peak Forecasts

## *Hawaiian Electric Peak Forecast Data Summary by Scenario*

Table E-22: HECO Blazing a Bold Frontier Scenario Peak Forecast Data (MW)

| Year | Underlying Economic Forecast | Renewable Self Generation | Non-PBFA EEPS Contribution | PBFA DSM Programs | Electric Vehicles | No PBFA DSM Sales Forecast | Peak Forecast |
|---|---|---|---|---|---|---|---|
| | *A* | *B* | *C* | *D* | *E* | *F=A+B+C+E* | *G=F+D* |
| 2012 | 1,167 | – | (4) | (14) | – | 1,163 | 1,149 |
| 2013 | 1,175 | – | (8) | (28) | – | 1,167 | 1,139 |
| 2014 | 1,181 | – | (11) | (43) | – | 1,170 | 1,126 |
| 2015 | 1,185 | – | (15) | (58) | – | 1,170 | 1,112 |
| 2016 | 1,188 | – | (19) | (73) | – | 1,169 | 1,096 |
| 2017 | 1,189 | – | (23) | (88) | – | 1,166 | 1,078 |
| 2018 | 1,181 | – | (26) | (103) | – | 1,155 | 1,051 |
| 2019 | 1,187 | – | (30) | (118) | – | 1,157 | 1,039 |
| 2020 | 1,193 | – | (34) | (133) | – | 1,159 | 1,026 |
| 2021 | 1,200 | – | (38) | (148) | – | 1,162 | 1,014 |
| 2022 | 1,206 | – | (41) | (163) | – | 1,165 | 1,002 |
| 2023 | 1,214 | – | (45) | (178) | – | 1,169 | 991 |
| 2024 | 1,226 | – | (49) | (193) | – | 1,178 | 985 |
| 2025 | 1,239 | – | (53) | (208) | – | 1,186 | 978 |
| 2026 | 1,245 | – | (56) | (223) | – | 1,189 | 966 |
| 2027 | 1,251 | – | (60) | (238) | – | 1,191 | 953 |
| 2028 | 1,257 | – | (64) | (253) | – | 1,193 | 940 |
| 2029 | 1,263 | – | (68) | (268) | – | 1,195 | 928 |
| 2030 | 1,269 | – | (71) | (283) | – | 1,198 | 915 |
| 2031 | 1,275 | – | (73) | (298) | – | 1,202 | 904 |
| 2032 | 1,281 | – | (75) | (313) | – | 1,206 | 893 |
| 2033 | 1,288 | – | (77) | (328) | – | 1,210 | 883 |

Table E-23: HECO Stuck in the Middle Scenario Peak Forecast Data (MW)

| Year | Underlying Economic Forecast | Renewable Self Generation | Non-PBFA EEPS Contribution | PBFA DSM Programs | Electric Vehicles | No PBFA DSM Sales Forecast | Peak Forecast |
|---|---|---|---|---|---|---|---|
| | *A* | *B* | *C* | *D* | *E* | *F=A+B+C+E* | *G=F+D* |
| 2012 | 1,183 | – | (3) | (10) | – | 1,180 | 1,171 |
| 2013 | 1,212 | – | (5) | (19) | – | 1,207 | 1,187 |
| 2014 | 1,240 | – | (8) | (30) | – | 1,232 | 1,203 |
| 2015 | 1,267 | – | (10) | (40) | – | 1,257 | 1,217 |
| 2016 | 1,297 | – | (13) | (50) | – | 1,284 | 1,234 |
| 2017 | 1,320 | – | (15) | (60) | – | 1,305 | 1,244 |
| 2018 | 1,338 | – | (18) | (70) | – | 1,320 | 1,250 |
| 2019 | 1,367 | – | (20) | (81) | – | 1,347 | 1,266 |
| 2020 | 1,393 | – | (23) | (91) | – | 1,370 | 1,279 |
| 2021 | 1,409 | – | (26) | (101) | – | 1,383 | 1,282 |
| 2022 | 1,426 | – | (28) | (111) | – | 1,398 | 1,287 |
| 2023 | 1,444 | – | (31) | (121) | – | 1,413 | 1,292 |
| 2024 | 1,466 | – | (33) | (132) | – | 1,433 | 1,301 |
| 2025 | 1,489 | – | (36) | (142) | – | 1,453 | 1,311 |
| 2026 | 1,504 | – | (38) | (152) | – | 1,466 | 1,314 |
| 2027 | 1,519 | – | (41) | (162) | – | 1,478 | 1,316 |
| 2028 | 1,534 | – | (44) | (172) | – | 1,490 | 1,318 |
| 2029 | 1,549 | – | (46) | (183) | – | 1,503 | 1,320 |
| 2030 | 1,563 | – | (49) | (193) | – | 1,514 | 1,322 |
| 2031 | 1,578 | – | (50) | (203) | – | 1,528 | 1,325 |
| 2032 | 1,594 | – | (51) | (213) | – | 1,543 | 1,330 |
| 2033 | 1,610 | – | (53) | (223) | – | 1,557 | 1,334 |

Table E-24: HECO No Burning Desire Scenario Peak Forecast Data (MW)

| Year | Underlying Economic Forecast | Renewable Self Generation | Non-PBFA EEPS Contribution | PBFA DSM Programs | Electric Vehicles | No PBFA DSM Sales Forecast | Peak Forecast |
|---|---|---|---|---|---|---|---|
| | *A* | *B* | *C* | *D* | *E* | *F=A+B+C+E* | *G=F+D* |
| 2012 | 1,208 | – | (3) | (10) | – | 1,205 | 1,196 |
| 2013 | 1,262 | – | (5) | (19) | – | 1,257 | 1,237 |
| 2014 | 1,315 | – | (8) | (30) | – | 1,307 | 1,278 |
| 2015 | 1,373 | – | (10) | (40) | – | 1,363 | 1,323 |
| 2016 | 1,432 | – | (13) | (50) | – | 1,419 | 1,369 |
| 2017 | 1,484 | – | (15) | (60) | – | 1,469 | 1,408 |
| 2018 | 1,529 | – | (18) | (70) | – | 1,511 | 1,441 |
| 2019 | 1,588 | – | (20) | (81) | – | 1,568 | 1,487 |
| 2020 | 1,639 | – | (23) | (91) | – | 1,616 | 1,525 |
| 2021 | 1,676 | – | (26) | (101) | – | 1,650 | 1,549 |
| 2022 | 1,710 | – | (28) | (111) | – | 1,682 | 1,571 |
| 2023 | 1,746 | – | (31) | (121) | – | 1,715 | 1,594 |
| 2024 | 1,782 | – | (33) | (132) | – | 1,748 | 1,617 |
| 2025 | 1,818 | – | (36) | (142) | – | 1,782 | 1,640 |
| 2026 | 1,846 | – | (38) | (152) | – | 1,807 | 1,655 |
| 2027 | 1,874 | – | (41) | (162) | – | 1,833 | 1,670 |
| 2028 | 1,902 | – | (44) | (172) | – | 1,858 | 1,686 |
| 2029 | 1,931 | – | (46) | (183) | – | 1,885 | 1,702 |
| 2030 | 1,960 | – | (49) | (193) | – | 1,911 | 1,719 |
| 2031 | 1,995 | – | (50) | (203) | – | 1,945 | 1,742 |
| 2032 | 2,031 | – | (51) | (213) | – | 1,980 | 1,766 |
| 2033 | 2,067 | – | (53) | (223) | – | 2,015 | 1,791 |

Table E-25: HECO Moved by Passion Scenario Peak Forecast Data (MW)

| Year | Underlying Economic Forecast | Renewable Self Generation | Non-PBFA EEPS Contribution | PBFA DSM Programs | Electric Vehicles | No PBFA DSM Sales Forecast | Peak Forecast |
|---|---|---|---|---|---|---|---|
| | *A* | *B* | *C* | *D* | *E* | *F=A+B+C+E* | *G=F+D* |
| 2012 | 1,183 | – | (3) | (13) | – | 1,180 | 1,167 |
| 2013 | 1,212 | – | (7) | (26) | – | 1,205 | 1,179 |
| 2014 | 1,240 | – | (10) | (40) | – | 1,230 | 1,190 |
| 2015 | 1,267 | – | (14) | (53) | – | 1,253 | 1,200 |
| 2016 | 1,297 | – | (17) | (67) | – | 1,280 | 1,213 |
| 2017 | 1,320 | – | (20) | (80) | – | 1,300 | 1,219 |
| 2018 | 1,338 | – | (24) | (94) | – | 1,314 | 1,220 |
| 2019 | 1,367 | – | (27) | (107) | – | 1,340 | 1,232 |
| 2020 | 1,393 | – | (31) | (121) | – | 1,362 | 1,241 |
| 2021 | 1,409 | – | (34) | (135) | – | 1,375 | 1,240 |
| 2022 | 1,426 | – | (38) | (148) | – | 1,388 | 1,240 |
| 2023 | 1,444 | – | (41) | (162) | – | 1,403 | 1,241 |
| 2024 | 1,466 | – | (44) | (175) | – | 1,422 | 1,246 |
| 2025 | 1,489 | – | (48) | (189) | – | 1,441 | 1,252 |
| 2026 | 1,504 | – | (51) | (203) | – | 1,453 | 1,250 |
| 2027 | 1,519 | – | (55) | (216) | – | 1,464 | 1,248 |
| 2028 | 1,534 | – | (58) | (230) | – | 1,476 | 1,246 |
| 2029 | 1,549 | – | (61) | (243) | – | 1,488 | 1,244 |
| 2030 | 1,563 | – | (65) | (257) | – | 1,498 | 1,241 |
| 2031 | 1,578 | – | (67) | (271) | – | 1,511 | 1,241 |
| 2032 | 1,594 | – | (68) | (284) | – | 1,526 | 1,241 |
| 2033 | 1,610 | – | (70) | (298) | – | 1,540 | 1,242 |

## *HELCO Peak Forecast Data Summary by Scenario*

Table E-26: HELCO Blazing a Bold Frontier Scenario Peak Forecast Data (MW)

| Year | Underlying Economic Forecast | Renewable Self Generation | Non-PBFA EEPS Contribution | PBFA DSM Programs | Electric Vehicles | No PBFA DSM Sales Forecast | Peak Forecast |
|---|---|---|---|---|---|---|---|
| | A | B | C | D | E | F=A+B+C+E | G=F+D |
| 2012 | 181 | – | (1) | (5) | – | 180 | 176 |
| 2013 | 180 | – | (1) | (7) | – | 179 | 172 |
| 2014 | 180 | – | (2) | (9) | – | 178 | 169 |
| 2015 | 177 | (0.1) | (2) | (12) | – | 175 | 163 |
| 2016 | 182 | (0.1) | (3) | (14) | – | 179 | 165 |
| 2017 | 185 | (0.1) | (4) | (16) | – | 181 | 165 |
| 2018 | 187 | (0.1) | (4) | (19) | – | 183 | 164 |
| 2019 | 189 | (0.1) | (5) | (21) | – | 184 | 163 |
| 2020 | 191 | (0.1) | (5) | (23) | – | 186 | 162 |
| 2021 | 193 | (0.1) | (6) | (26) | – | 187 | 161 |
| 2022 | 196 | (0.1) | (7) | (28) | – | 189 | 161 |
| 2023 | 198 | (0.1) | (7) | (31) | – | 191 | 160 |
| 2024 | 201 | (0.1) | (8) | (33) | – | 193 | 160 |
| 2025 | 204 | (0.1) | (8) | (35) | – | 196 | 160 |
| 2026 | 207 | (0.2) | (9) | (38) | – | 197 | 160 |
| 2027 | 209 | (0.2) | (9) | (40) | – | 199 | 159 |
| 2028 | 211 | (0.2) | (10) | (42) | – | 201 | 159 |
| 2029 | 214 | (0.2) | (11) | (45) | – | 203 | 158 |
| 2030 | 216 | (0.2) | (11) | (47) | – | 205 | 158 |
| 2031 | 219 | (0.2) | (12) | (49) | – | 207 | 158 |
| 2032 | 222 | (0.2) | (12) | (52) | – | 210 | 158 |
| 2033 | 224 | (0.2) | (12) | (54) | – | 212 | 158 |

Table E-27: HELCO Stuck in the Middle Scenario Peak Forecast Data (MW)

| Year | Underlying Economic Forecast | Renewable Self Generation | Non-PBFA EEPS Contribution | PBFA DSM Programs | Electric Vehicles | No PBFA DSM Sales Forecast | Peak Forecast |
|---|---|---|---|---|---|---|---|
| | *A* | *B* | *C* | *D* | *E* | *F=A+B+C+E* | *G=F+D* |
| 2012 | 190 | 0.0 | (0) | (3) | 0 | 189 | 186 |
| 2013 | 192 | 0.0 | (1) | (5) | 0 | 191 | 187 |
| 2014 | 195 | 0.0 | (1) | (6) | 0 | 194 | 188 |
| 2015 | 199 | (0.1) | (2) | (8) | 0 | 198 | 190 |
| 2016 | 202 | (0.1) | (2) | (10) | 0 | 200 | 190 |
| 2017 | 207 | (0.1) | (2) | (11) | 0 | 205 | 193 |
| 2018 | 210 | (0.1) | (3) | (13) | 0 | 207 | 194 |
| 2019 | 214 | (0.1) | (3) | (14) | 0 | 211 | 196 |
| 2020 | 218 | (0.1) | (4) | (16) | 0 | 214 | 198 |
| 2021 | 222 | (0.1) | (4) | (18) | 0 | 218 | 201 |
| 2022 | 226 | (0.1) | (4) | (19) | 0 | 222 | 203 |
| 2023 | 231 | (0.1) | (5) | (21) | 0 | 226 | 205 |
| 2024 | 234 | (0.1) | (5) | (22) | 0 | 229 | 207 |
| 2025 | 238 | (0.1) | (6) | (24) | 0 | 232 | 208 |
| 2026 | 243 | (0.1) | (6) | (26) | 0 | 236 | 211 |
| 2027 | 247 | (0.1) | (6) | (27) | 0 | 240 | 213 |
| 2028 | 251 | (0.1) | (7) | (29) | 0 | 244 | 215 |
| 2029 | 256 | (0.1) | (7) | (30) | 0 | 248 | 218 |
| 2030 | 260 | (0.1) | (8) | (32) | 0 | 252 | 220 |
| 2031 | 264 | (0.1) | (8) | (34) | 0 | 256 | 223 |
| 2032 | 269 | (0.1) | (8) | (35) | 0 | 261 | 225 |
| 2033 | 273 | (0.1) | (8) | (37) | 0 | 265 | 228 |

Table E-28: HELCO No Burning Desire Scenario Peak Forecast Data (MW)

| Year | Underlying Economic Forecast | Renewable Self Generation | Non-PBFA EEPS Contribution | PBFA DSM Programs | Electric Vehicles | No PBFA DSM Sales Forecast | Peak Forecast |
|---|---|---|---|---|---|---|---|
| | *A* | *B* | *C* | *D* | *E* | *F=A+B+C+E* | *G=F+D* |
| 2012 | 203 | 0.00 | (0) | (3) | 0 | 203 | 200 |
| 2013 | 212 | 0.00 | (1) | (5) | 0 | 211 | 206 |
| 2014 | 221 | 0.00 | (1) | (6) | 0 | 220 | 214 |
| 2015 | 222 | (0.04) | (2) | (8) | 0 | 220 | 212 |
| 2016 | 230 | (0.04) | (2) | (10) | 0 | 228 | 219 |
| 2017 | 230 | (0.04) | (2) | (11) | 0 | 227 | 216 |
| 2018 | 242 | (0.04) | (3) | (13) | 0 | 239 | 226 |
| 2019 | 249 | (0.04) | (3) | (14) | 0 | 246 | 231 |
| 2020 | 256 | (0.04) | (4) | (16) | 0 | 252 | 236 |
| 2021 | 263 | (0.04) | (4) | (18) | 0 | 259 | 241 |
| 2022 | 271 | (0.04) | (4) | (19) | 0 | 266 | 247 |
| 2023 | 279 | (0.04) | (5) | (21) | 0 | 274 | 253 |
| 2024 | 287 | (0.04) | (5) | (22) | 0 | 281 | 259 |
| 2025 | 295 | (0.04) | (6) | (24) | 0 | 289 | 265 |
| 2026 | 302 | (0.07) | (6) | (26) | 0 | 296 | 270 |
| 2027 | 309 | (0.07) | (6) | (27) | 0 | 303 | 276 |
| 2028 | 317 | (0.07) | (7) | (29) | 0 | 310 | 281 |
| 2029 | 324 | (0.07) | (7) | (30) | 0 | 317 | 287 |
| 2030 | 332 | (0.07) | (8) | (32) | 0 | 324 | 292 |
| 2031 | 340 | (0.07) | (8) | (34) | 0 | 332 | 298 |
| 2032 | 347 | (0.07) | (8) | (35) | 0 | 339 | 304 |
| 2033 | 355 | (0.07) | (8) | (37) | 0 | 346 | 309 |

Table E-29: HELCO Moved by Passion Scenario Peak Forecast Data (MW)

| Year | Underlying Economic Forecast | Renewable Self Generation | Non-PBFA EEPS Contribution | PBFA DSM Programs | Electric Vehicles | No PBFA DSM Sales Forecast | Peak Forecast |
|---|---|---|---|---|---|---|---|
| | *A* | *B* | *C* | *D* | *E* | *F=A+B+C+E* | *G=F+D* |
| 2012 | 190 | 0.0 | (1) | (4) | 0 | 189 | 185 |
| 2013 | 192 | 0.0 | (1) | (6) | 0 | 191 | 185 |
| 2014 | 195 | 0.0 | (2) | (8) | 0 | 194 | 185 |
| 2015 | 199 | (0.1) | (2) | (11) | 0 | 197 | 187 |
| 2016 | 202 | (0.1) | (3) | (13) | 0 | 199 | 186 |
| 2017 | 207 | (0.1) | (3) | (15) | 0 | 204 | 189 |
| 2018 | 210 | (0.1) | (4) | (17) | 0 | 206 | 189 |
| 2019 | 214 | (0.1) | (4) | (19) | 0 | 210 | 190 |
| 2020 | 218 | (0.1) | (5) | (21) | 0 | 213 | 191 |
| 2021 | 222 | (0.1) | (5) | (23) | 0 | 217 | 193 |
| 2022 | 226 | (0.1) | (6) | (26) | 0 | 220 | 195 |
| 2023 | 231 | (0.1) | (6) | (28) | 0 | 224 | 196 |
| 2024 | 234 | (0.1) | (7) | (30) | 0 | 227 | 197 |
| 2025 | 238 | (0.1) | (8) | (32) | 0 | 231 | 199 |
| 2026 | 243 | (0.2) | (8) | (34) | 0 | 234 | 200 |
| 2027 | 247 | (0.2) | (9) | (36) | 0 | 238 | 202 |
| 2028 | 251 | (0.2) | (9) | (38) | 0 | 242 | 203 |
| 2029 | 256 | (0.2) | (10) | (41) | 0 | 246 | 205 |
| 2030 | 260 | (0.2) | (10) | (43) | 0 | 249 | 207 |
| 2031 | 264 | (0.2) | (11) | (45) | 0 | 254 | 209 |
| 2032 | 269 | (0.2) | (11) | (47) | 0 | 258 | 211 |
| 2033 | 273 | (0.2) | (11) | (49) | 0 | 262 | 213 |

## *Maui Peak Forecast Data Summary by Scenario*

Table E-30: Maui Blazing a Bold Frontier Scenario Peak Forecast Data (MW)

| Year | Underlying Economic Forecast | Renewable Self Generation | Non-PBFA EEPS Contribution | PBFA DSM Programs | Electric Vehicles | No PBFA DSM Sales Forecast | Peak Forecast |
|---|---|---|---|---|---|---|---|
| | *A* | *B* | *C* | *D* | *E* | *F=A+B+C+E* | *G=F+D* |
| 2012 | 186 | – | (1) | (2) | – | 186 | 184 |
| 2013 | 187 | – | (1) | (5) | – | 185 | 181 |
| 2014 | 187 | – | (2) | (7) | – | 185 | 178 |
| 2015 | 186 | – | (2) | (9) | – | 184 | 174 |
| 2016 | 185 | – | (3) | (12) | – | 182 | 171 |
| 2017 | 185 | – | (4) | (14) | – | 181 | 168 |
| 2018 | 185 | – | (4) | (16) | – | 181 | 165 |
| 2019 | 185 | – | (5) | (19) | – | 180 | 162 |
| 2020 | 185 | – | (5) | (21) | – | 180 | 159 |
| 2021 | 185 | – | (6) | (23) | – | 179 | 156 |
| 2022 | 185 | – | (7) | (26) | – | 178 | 152 |
| 2023 | 185 | – | (7) | (28) | – | 178 | 150 |
| 2024 | 185 | – | (8) | (31) | – | 178 | 147 |
| 2025 | 187 | – | (8) | (33) | – | 178 | 145 |
| 2026 | 188 | – | (9) | (35) | – | 179 | 144 |
| 2027 | 189 | – | (9) | (38) | – | 179 | 142 |
| 2028 | 190 | – | (10) | (40) | – | 180 | 140 |
| 2029 | 191 | – | (11) | (42) | – | 180 | 138 |
| 2030 | 192 | – | (11) | (45) | – | 181 | 136 |
| 2031 | 191 | – | (12) | (47) | – | 179 | 132 |
| 2032 | 190 | – | (12) | (49) | – | 178 | 129 |
| 2033 | 189 | – | (12) | (52) | – | 177 | 125 |

Table E-31: Maui Stuck in the Middle Scenario Peak Forecast Data (MW)

| Year | Underlying Economic Forecast | Renewable Self Generation | Non-PBFA EEPS Contribution | PBFA DSM Programs | Electric Vehicles | No PBFA DSM Sales Forecast | Peak Forecast |
|---|---|---|---|---|---|---|---|
| | *A* | *B* | *C* | *D* | *E* | *F=A+B+C+E* | *G=F+D* |
| 2012 | 191 | – | (0) | (2) | – | 191 | 189 |
| 2013 | 195 | – | (1) | (3) | – | 194 | 191 |
| 2014 | 199 | – | (1) | (5) | – | 198 | 193 |
| 2015 | 202 | – | (2) | (6) | – | 200 | 194 |
| 2016 | 204 | – | (2) | (8) | – | 202 | 194 |
| 2017 | 207 | – | (2) | (10) | – | 205 | 195 |
| 2018 | 211 | – | (3) | (11) | – | 209 | 197 |
| 2019 | 215 | – | (3) | (13) | – | 212 | 199 |
| 2020 | 218 | – | (4) | (14) | – | 214 | 200 |
| 2021 | 221 | – | (4) | (16) | – | 217 | 201 |
| 2022 | 224 | – | (4) | (18) | – | 220 | 202 |
| 2023 | 228 | – | (5) | (19) | – | 223 | 204 |
| 2024 | 231 | – | (5) | (21) | – | 226 | 205 |
| 2025 | 235 | – | (6) | (22) | – | 229 | 207 |
| 2026 | 239 | – | (6) | (24) | – | 232 | 208 |
| 2027 | 242 | – | (6) | (26) | – | 236 | 210 |
| 2028 | 246 | – | (7) | (27) | – | 239 | 212 |
| 2029 | 249 | – | (7) | (29) | – | 242 | 213 |
| 2030 | 253 | – | (8) | (30) | – | 245 | 215 |
| 2031 | 255 | – | (8) | (32) | – | 247 | 215 |
| 2032 | 258 | – | (8) | (34) | – | 250 | 216 |
| 2033 | 260 | – | (8) | (35) | – | 252 | 216 |

Table E-32: Maui No Burning Desire Scenario Peak Forecast Data (MW)

| Year | Underlying Economic Forecast | Renewable Self Generation | Non-PBFA EEPS Contribution | PBFA DSM Programs | Electric Vehicles | No PBFA DSM Sales Forecast | Peak Forecast |
|---|---|---|---|---|---|---|---|
| | *A* | *B* | *C* | *D* | *E* | *F=A+B+C+E* | *G=F+D* |
| 2012 | 195 | – | (0) | (2) | – | 194 | 193 |
| 2013 | 204 | – | (1) | (3) | – | 203 | 200 |
| 2014 | 214 | – | (1) | (5) | – | 213 | 208 |
| 2015 | 224 | – | (2) | (6) | – | 223 | 216 |
| 2016 | 235 | – | (2) | (8) | – | 233 | 225 |
| 2017 | 246 | – | (2) | (10) | – | 244 | 234 |
| 2018 | 258 | – | (3) | (11) | – | 255 | 244 |
| 2019 | 269 | – | (3) | (13) | – | 266 | 253 |
| 2020 | 280 | – | (4) | (14) | – | 276 | 262 |
| 2021 | 290 | – | (4) | (16) | – | 286 | 270 |
| 2022 | 299 | – | (4) | (18) | – | 295 | 277 |
| 2023 | 309 | – | (5) | (19) | – | 304 | 285 |
| 2024 | 318 | – | (5) | (21) | – | 313 | 292 |
| 2025 | 327 | – | (6) | (22) | – | 322 | 299 |
| 2026 | 335 | – | (6) | (24) | – | 329 | 305 |
| 2027 | 344 | – | (6) | (26) | – | 337 | 311 |
| 2028 | 352 | – | (7) | (27) | – | 345 | 318 |
| 2029 | 360 | – | (7) | (29) | – | 353 | 324 |
| 2030 | 368 | – | (8) | (30) | – | 360 | 330 |
| 2031 | 377 | – | (8) | (32) | – | 369 | 337 |
| 2032 | 385 | – | (8) | (34) | – | 377 | 343 |
| 2033 | 394 | – | (8) | (35) | – | 385 | 350 |

Table E-33: Maui Moved by Passion Scenario Peak Forecast Data (MW)

| Year | Underlying Economic Forecast | Renewable Self Generation | Non-PBFA EEPS Contribution | PBFA DSM Programs | Electric Vehicles | No PBFA DSM Sales Forecast | Peak Forecast |
|---|---|---|---|---|---|---|---|
| | *A* | *B* | *C* | *D* | *E* | *F=A+B+C+E* | *G=F+D* |
| 2012 | 191 | – | (1) | (2) | – | 190 | 188 |
| 2013 | 195 | – | (1) | (4) | – | 194 | 190 |
| 2014 | 199 | – | (2) | (6) | – | 198 | 191 |
| 2015 | 202 | – | (2) | (8) | – | 200 | 191 |
| 2016 | 204 | – | (3) | (11) | – | 202 | 191 |
| 2017 | 207 | – | (3) | (13) | – | 204 | 191 |
| 2018 | 211 | – | (4) | (15) | – | 208 | 193 |
| 2019 | 215 | – | (4) | (17) | – | 211 | 194 |
| 2020 | 218 | – | (5) | (19) | – | 213 | 194 |
| 2021 | 221 | – | (5) | (21) | – | 216 | 195 |
| 2022 | 224 | – | (6) | (23) | – | 219 | 195 |
| 2023 | 228 | – | (6) | (26) | – | 221 | 196 |
| 2024 | 231 | – | (7) | (28) | – | 224 | 196 |
| 2025 | 235 | – | (8) | (30) | – | 227 | 197 |
| 2026 | 239 | – | (8) | (32) | – | 230 | 198 |
| 2027 | 242 | – | (9) | (34) | – | 234 | 199 |
| 2028 | 246 | – | (9) | (36) | – | 237 | 200 |
| 2029 | 249 | – | (10) | (38) | – | 240 | 201 |
| 2030 | 253 | – | (10) | (41) | – | 243 | 202 |
| 2031 | 255 | – | (11) | (43) | – | 245 | 202 |
| 2032 | 258 | – | (11) | (45) | – | 247 | 202 |
| 2033 | 260 | – | (11) | (47) | – | 249 | 202 |

## *Lanai Peak Forecast Data Summary by Scenario*

Table E-34: Lanai Blazing a Bold Frontier Scenario Peak Forecast Data (MW)

| Year | Underlying Economic Forecast | Renewable Self Generation | Non-PBFA EEPS Contribution | PBFA DSM Programs | Electric Vehicles | No PBFA DSM Sales Forecast | Peak Forecast |
|---|---|---|---|---|---|---|---|
| | *A* | *B* | *C* | *D* | *E* | *F=A+B+C+E* | *G=F+D* |
| 2012 | 4.3 | – | (0.013) | (0.050) | – | 4.3 | 4.2 |
| 2013 | 4.3 | – | (0.027) | (0.101) | – | 4.3 | 4.2 |
| 2014 | 4.3 | – | (0.040) | (0.153) | – | 4.3 | 4.1 |
| 2015 | 4.3 | – | (0.053) | (0.206) | – | 4.2 | 4.0 |
| 2016 | 4.3 | – | (0.066) | (0.259) | – | 4.2 | 4.0 |
| 2017 | 4.3 | – | (0.080) | (0.312) | – | 4.2 | 3.9 |
| 2018 | 4.3 | – | (0.093) | (0.365) | – | 4.2 | 3.8 |
| 2019 | 4.3 | – | (0.106) | (0.418) | – | 4.2 | 3.8 |
| 2020 | 4.3 | – | (0.119) | (0.470) | – | 4.2 | 3.7 |
| 2021 | 4.2 | – | (0.133) | (0.523) | – | 4.1 | 3.5 |
| 2022 | 4.2 | – | (0.146) | (0.576) | – | 4.1 | 3.5 |
| 2023 | 4.2 | – | (0.159) | (0.629) | – | 4.0 | 3.4 |
| 2024 | 4.2 | – | (0.172) | (0.682) | – | 4.0 | 3.3 |
| 2025 | 4.2 | – | (0.186) | (0.734) | – | 4.0 | 3.3 |
| 2026 | 4.2 | – | (0.199) | (0.787) | – | 4.0 | 3.2 |
| 2027 | 4.2 | – | (0.212) | (0.840) | – | 4.0 | 3.1 |
| 2028 | 4.1 | – | (0.225) | (0.893) | – | 3.9 | 3.0 |
| 2029 | 4.1 | – | (0.239) | (0.946) | – | 3.9 | 2.9 |
| 2030 | 4.1 | – | (0.252) | (0.998) | – | 3.8 | 2.8 |
| 2031 | 4.1 | – | (0.259) | (1.051) | – | 3.8 | 2.8 |
| 2032 | 4.1 | – | (0.265) | (1.104) | – | 3.8 | 2.7 |
| 2033 | 4.1 | – | (0.272) | (1.157) | – | 3.8 | 2.7 |

Table E-35: Lanai Stuck in the Middle Scenario Peak Forecast Data (MW)

| Year | Underlying Economic Forecast | Renewable Self Generation | Non-PBFA EEPS Contribution | PBFA DSM Programs | Electric Vehicles | No PBFA DSM Sales Forecast | Peak Forecast |
|---|---|---|---|---|---|---|---|
| | *A* | *B* | *C* | *D* | *E* | *F=A+B+C+E* | *G=F+D* |
| 2012 | 4.3 | – | (0.009) | (0.034) | – | 4.3 | 4.3 |
| 2013 | 4.3 | – | (0.018) | (0.069) | – | 4.3 | 4.2 |
| 2014 | 4.4 | – | (0.027) | (0.105) | – | 4.4 | 4.3 |
| 2015 | 4.4 | – | (0.036) | (0.141) | – | 4.4 | 4.2 |
| 2016 | 4.4 | – | (0.045) | (0.177) | – | 4.4 | 4.2 |
| 2017 | 4.4 | – | (0.054) | (0.213) | – | 4.3 | 4.1 |
| 2018 | 4.5 | – | (0.063) | (0.249) | – | 4.4 | 4.2 |
| 2019 | 4.5 | – | (0.072) | (0.285) | – | 4.4 | 4.1 |
| 2020 | 4.6 | – | (0.081) | (0.321) | – | 4.5 | 4.2 |
| 2021 | 4.6 | – | (0.090) | (0.357) | – | 4.5 | 4.2 |
| 2022 | 4.6 | – | (0.099) | (0.393) | – | 4.5 | 4.1 |
| 2023 | 4.7 | – | (0.108) | (0.429) | – | 4.6 | 4.2 |
| 2024 | 4.7 | – | (0.117) | (0.465) | – | 4.6 | 4.1 |
| 2025 | 4.7 | – | (0.127) | (0.501) | – | 4.6 | 4.1 |
| 2026 | 4.8 | – | (0.136) | (0.537) | – | 4.7 | 4.1 |
| 2027 | 4.8 | – | (0.145) | (0.573) | – | 4.7 | 4.1 |
| 2028 | 4.9 | – | (0.154) | (0.609) | – | 4.7 | 4.1 |
| 2029 | 4.9 | – | (0.163) | (0.645) | – | 4.7 | 4.1 |
| 2030 | 4.9 | – | (0.172) | (0.681) | – | 4.7 | 4.0 |
| 2031 | 5.0 | – | (0.176) | (0.717) | – | 4.8 | 4.1 |
| 2032 | 5.0 | – | (0.181) | (0.753) | – | 4.8 | 4.1 |
| 2033 | 5.0 | – | (0.186) | (0.789) | – | 4.8 | 4.0 |

Table E-36: Lanai No Burning Desire Scenario Peak Forecast Data (MW)

| Year | Underlying Economic Forecast | Renewable Self Generation | Non-PBFA EEPS Contribution | PBFA DSM Programs | Electric Vehicles | No PBFA DSM Sales Forecast | Peak Forecast |
|---|---|---|---|---|---|---|---|
| | *A* | *B* | *C* | *D* | *E* | *F=A+B+C+E* | *G=F+D* |
| 2012 | 4.5 | – | (0.009) | (0.034) | – | 4.5 | 4.5 |
| 2013 | 4.6 | – | (0.018) | (0.069) | – | 4.6 | 4.5 |
| 2014 | 4.7 | – | (0.027) | (0.105) | – | 4.7 | 4.6 |
| 2015 | 4.7 | – | (0.036) | (0.141) | – | 4.7 | 4.5 |
| 2016 | 4.8 | – | (0.045) | (0.177) | – | 4.8 | 4.6 |
| 2017 | 4.9 | – | (0.054) | (0.213) | – | 4.8 | 4.6 |
| 2018 | 5.0 | – | (0.063) | (0.249) | – | 4.9 | 4.7 |
| 2019 | 5.1 | – | (0.072) | (0.285) | – | 5.0 | 4.7 |
| 2020 | 5.2 | – | (0.081) | (0.321) | – | 5.1 | 4.8 |
| 2021 | 5.2 | – | (0.090) | (0.357) | – | 5.1 | 4.8 |
| 2022 | 5.3 | – | (0.099) | (0.393) | – | 5.2 | 4.8 |
| 2023 | 5.4 | – | (0.108) | (0.429) | – | 5.3 | 4.9 |
| 2024 | 5.5 | – | (0.117) | (0.465) | – | 5.4 | 4.9 |
| 2025 | 5.6 | – | (0.127) | (0.501) | – | 5.5 | 5.0 |
| 2026 | 5.7 | – | (0.136) | (0.537) | – | 5.6 | 5.0 |
| 2027 | 5.8 | – | (0.145) | (0.573) | – | 5.7 | 5.1 |
| 2028 | 5.8 | – | (0.154) | (0.609) | – | 5.6 | 5.0 |
| 2029 | 5.9 | – | (0.163) | (0.645) | – | 5.7 | 5.1 |
| 2030 | 6.0 | – | (0.172) | (0.681) | – | 5.8 | 5.1 |
| 2031 | 6.1 | – | (0.176) | (0.717) | – | 5.9 | 5.2 |
| 2032 | 6.2 | – | (0.181) | (0.753) | – | 6.0 | 5.3 |
| 2033 | 6.3 | – | (0.186) | (0.789) | – | 6.1 | 5.3 |

Table E-37: Lanai Moved by Passion Scenario Peak Forecast Data (MW)

| Year | Underlying Economic Forecast | Renewable Self Generation | Non-PBFA EEPS Contribution | PBFA DSM Programs | Electric Vehicles | No PBFA DSM Sales Forecast | Peak Forecast |
|---|---|---|---|---|---|---|---|
| | A | B | C | D | E | F=A+B+C+E | G=F+D |
| 2012 | 4.3 | – | (0.012) | (0.046) | – | 4.3 | 4.2 |
| 2013 | 4.3 | – | (0.024) | (0.091) | – | 4.3 | 4.2 |
| 2014 | 4.4 | – | (0.036) | (0.139) | – | 4.4 | 4.2 |
| 2015 | 4.4 | – | (0.048) | (0.188) | – | 4.4 | 4.2 |
| 2016 | 4.4 | – | (0.060) | (0.236) | – | 4.3 | 4.1 |
| 2017 | 4.4 | – | (0.072) | (0.284) | – | 4.3 | 4.0 |
| 2018 | 4.5 | – | (0.084) | (0.332) | – | 4.4 | 4.1 |
| 2019 | 4.5 | – | (0.096) | (0.380) | – | 4.4 | 4.0 |
| 2020 | 4.6 | – | (0.108) | (0.428) | – | 4.5 | 4.1 |
| 2021 | 4.6 | – | (0.120) | (0.476) | – | 4.5 | 4.0 |
| 2022 | 4.6 | – | (0.133) | (0.524) | – | 4.5 | 3.9 |
| 2023 | 4.7 | – | (0.145) | (0.572) | – | 4.6 | 4.0 |
| 2024 | 4.7 | – | (0.157) | (0.620) | – | 4.5 | 3.9 |
| 2025 | 4.7 | – | (0.169) | (0.668) | – | 4.5 | 3.9 |
| 2026 | 4.8 | – | (0.181) | (0.716) | – | 4.6 | 3.9 |
| 2027 | 4.8 | – | (0.193) | (0.764) | – | 4.6 | 3.8 |
| 2028 | 4.9 | – | (0.205) | (0.812) | – | 4.7 | 3.9 |
| 2029 | 4.9 | – | (0.217) | (0.860) | – | 4.7 | 3.8 |
| 2030 | 4.9 | – | (0.229) | (0.908) | – | 4.7 | 3.8 |
| 2031 | 5.0 | – | (0.235) | (0.956) | – | 4.8 | 3.8 |
| 2032 | 5.0 | – | (0.241) | (1.004) | – | 4.8 | 3.8 |
| 2033 | 5.0 | – | (0.247) | (1.052) | – | 4.8 | 3.7 |

## *Molokai Peak Forecast Data Summary by Scenario*

Table E-38: Molokai Blazing a Bold Frontier Scenario Peak Forecast Data (MW)

| Year | Underlying Economic Forecast | Renewable Self Generation | Non-PBFA EEPS Contribution | PBFA DSM Programs | Electric Vehicles | No PBFA DSM Sales Forecast | Peak Forecast |
|---|---|---|---|---|---|---|---|
| | *A* | *B* | *C* | *D* | *E* | *F=A+B+C+E* | *G=F+D* |
| 2012 | 5.2 | – | (0.016) | (0.062) | – | 5.2 | 5.1 |
| 2013 | 5.2 | – | (0.033) | (0.125) | – | 5.2 | 5.0 |
| 2014 | 5.1 | – | (0.049) | (0.190) | – | 5.1 | 4.9 |
| 2015 | 5.1 | – | (0.066) | (0.256) | – | 5.0 | 4.8 |
| 2016 | 5.0 | – | (0.082) | (0.321) | – | 4.9 | 4.6 |
| 2017 | 5.0 | – | (0.099) | (0.386) | – | 4.9 | 4.5 |
| 2018 | 4.9 | – | (0.115) | (0.452) | – | 4.8 | 4.3 |
| 2019 | 4.9 | – | (0.131) | (0.517) | – | 4.8 | 4.3 |
| 2020 | 4.8 | – | (0.148) | (0.583) | – | 4.7 | 4.1 |
| 2021 | 4.8 | – | (0.164) | (0.648) | – | 4.6 | 4.0 |
| 2022 | 4.7 | – | (0.181) | (0.714) | – | 4.5 | 3.8 |
| 2023 | 4.7 | – | (0.197) | (0.779) | – | 4.5 | 3.7 |
| 2024 | 4.6 | – | (0.213) | (0.844) | – | 4.4 | 3.5 |
| 2025 | 4.6 | – | (0.230) | (0.910) | – | 4.4 | 3.5 |
| 2026 | 4.5 | – | (0.246) | (0.975) | – | 4.3 | 3.3 |
| 2027 | 4.5 | – | (0.263) | (1.041) | – | 4.2 | 3.2 |
| 2028 | 4.5 | – | (0.279) | (1.106) | – | 4.2 | 3.1 |
| 2029 | 4.5 | – | (0.296) | (1.172) | – | 4.2 | 3.0 |
| 2030 | 4.4 | – | (0.312) | (1.237) | – | 4.1 | 2.9 |
| 2031 | 4.4 | – | (0.320) | (1.303) | – | 4.1 | 2.8 |
| 2032 | 4.3 | – | (0.329) | (1.368) | – | 4.0 | 2.6 |
| 2033 | 4.3 | – | (0.337) | (1.433) | – | 4.0 | 2.5 |

Table E-39: Molokai Stuck in the Middle Scenario Peak Forecast Data (MW)

| Year | Underlying Economic Forecast | Renewable Self Generation | Non-PBFA EEPS Contribution | PBFA DSM Programs | Electric Vehicles | No PBFA DSM Sales Forecast | Peak Forecast |
|---|---|---|---|---|---|---|---|
| | *A* | *B* | *C* | *D* | *E* | *F=A+B+C+E* | *G=F+D* |
| 2012 | 5.4 | – | (0.011) | (0.043) | – | 5.4 | 5.3 |
| 2013 | 5.4 | – | (0.022) | (0.085) | – | 5.4 | 5.3 |
| 2014 | 5.4 | – | (0.034) | (0.130) | – | 5.4 | 5.2 |
| 2015 | 5.4 | – | (0.045) | (0.174) | – | 5.4 | 5.2 |
| 2016 | 5.4 | – | (0.056) | (0.219) | – | 5.3 | 5.1 |
| 2017 | 5.4 | – | (0.067) | (0.263) | – | 5.3 | 5.1 |
| 2018 | 5.4 | – | (0.078) | (0.308) | – | 5.3 | 5.0 |
| 2019 | 5.4 | – | (0.090) | (0.353) | – | 5.3 | 5.0 |
| 2020 | 5.4 | – | (0.101) | (0.397) | – | 5.3 | 4.9 |
| 2021 | 5.4 | – | (0.112) | (0.442) | – | 5.3 | 4.8 |
| 2022 | 5.4 | – | (0.123) | (0.487) | – | 5.3 | 4.8 |
| 2023 | 5.5 | – | (0.134) | (0.531) | – | 5.4 | 4.8 |
| 2024 | 5.5 | – | (0.146) | (0.576) | – | 5.4 | 4.8 |
| 2025 | 5.5 | – | (0.157) | (0.620) | – | 5.3 | 4.7 |
| 2026 | 5.5 | – | (0.168) | (0.665) | – | 5.3 | 4.7 |
| 2027 | 5.5 | – | (0.179) | (0.710) | – | 5.3 | 4.6 |
| 2028 | 5.5 | – | (0.190) | (0.754) | – | 5.3 | 4.6 |
| 2029 | 5.5 | – | (0.202) | (0.799) | – | 5.3 | 4.5 |
| 2030 | 5.5 | – | (0.213) | (0.843) | – | 5.3 | 4.4 |
| 2031 | 5.5 | – | (0.218) | (0.888) | – | 5.3 | 4.4 |
| 2032 | 5.5 | – | (0.224) | (0.933) | – | 5.3 | 4.3 |
| 2033 | 5.5 | – | (0.230) | (0.977) | – | 5.3 | 4.3 |

Table E-40: Molokai No Burning Desire Scenario Peak Forecast Data (MW)

| Year | Underlying Economic Forecast | Renewable Self Generation | Non-PBFA EEPS Contribution | PBFA DSM Programs | Electric Vehicles | No PBFA DSM Sales Forecast | Peak Forecast |
|---|---|---|---|---|---|---|---|
| | *A* | *B* | *C* | *D* | *E* | *F=A+B+C+E* | *G=F+D* |
| 2012 | 5.5 | | (0.011) | (0.043) | – | 5.5 | 5.4 |
| 2013 | 5.5 | – | (0.022) | (0.085) | – | 5.5 | 5.4 |
| 2014 | 5.5 | – | (0.034) | (0.130) | – | 5.5 | 5.3 |
| 2015 | 5.5 | – | (0.045) | (0.174) | – | 5.5 | 5.3 |
| 2016 | 5.5 | – | (0.056) | (0.219) | – | 5.4 | 5.2 |
| 2017 | 5.5 | – | (0.067) | (0.263) | – | 5.4 | 5.2 |
| 2018 | 5.6 | – | (0.078) | (0.308) | – | 5.5 | 5.2 |
| 2019 | 5.6 | – | (0.090) | (0.353) | – | 5.5 | 5.2 |
| 2020 | 5.7 | – | (0.101) | (0.397) | – | 5.6 | 5.2 |
| 2021 | 5.7 | – | (0.112) | (0.442) | – | 5.6 | 5.1 |
| 2022 | 5.8 | – | (0.123) | (0.487) | – | 5.7 | 5.2 |
| 2023 | 5.8 | – | (0.134) | (0.531) | – | 5.7 | 5.1 |
| 2024 | 5.9 | – | (0.146) | (0.576) | – | 5.8 | 5.2 |
| 2025 | 5.9 | – | (0.157) | (0.620) | – | 5.7 | 5.1 |
| 2026 | 6.0 | – | (0.168) | (0.665) | – | 5.8 | 5.2 |
| 2027 | 6.0 | – | (0.179) | (0.710) | – | 5.8 | 5.1 |
| 2028 | 6.1 | – | (0.190) | (0.754) | – | 5.9 | 5.2 |
| 2029 | 6.1 | – | (0.202) | (0.799) | – | 5.9 | 5.1 |
| 2030 | 6.1 | – | (0.213) | (0.843) | – | 5.9 | 5.0 |
| 2031 | 6.2 | – | (0.218) | (0.888) | – | 6.0 | 5.1 |
| 2032 | 6.2 | – | (0.224) | (0.933) | – | 6.0 | 5.0 |
| 2033 | 6.3 | – | (0.230) | (0.977) | – | 6.1 | 5.1 |

Table E-41: Molokai Moved by Passion Scenario Peak Forecast Data (MW)

| Year | Underlying Economic Forecast | Renewable Self Generation | Non-PBFA EEPS Contribution | PBFA DSM Programs | Electric Vehicles | No PBFA DSM Sales Forecast | Peak Forecast |
|---|---|---|---|---|---|---|---|
| | *A* | *B* | *C* | *D* | *E* | *F=A+B+C+E* | *G=F+D* |
| 2012 | 5.4 | – | (0.015) | (0.057) | – | 5.4 | 5.3 |
| 2013 | 5.4 | – | (0.030) | (0.113) | – | 5.4 | 5.3 |
| 2014 | 5.4 | – | (0.045) | (0.173) | – | 5.4 | 5.2 |
| 2015 | 5.4 | – | (0.060) | (0.232) | – | 5.3 | 5.1 |
| 2016 | 5.4 | – | (0.075) | (0.292) | – | 5.3 | 5.0 |
| 2017 | 5.4 | – | (0.090) | (0.351) | – | 5.3 | 5.0 |
| 2018 | 5.4 | – | (0.105) | (0.411) | – | 5.3 | 4.9 |
| 2019 | 5.4 | – | (0.119) | (0.470) | – | 5.3 | 4.8 |
| 2020 | 5.4 | – | (0.134) | (0.530) | – | 5.3 | 4.7 |
| 2021 | 5.4 | – | (0.149) | (0.589) | – | 5.3 | 4.7 |
| 2022 | 5.4 | – | (0.164) | (0.649) | – | 5.2 | 4.6 |
| 2023 | 5.5 | – | (0.179) | (0.708) | – | 5.3 | 4.6 |
| 2024 | 5.5 | – | (0.194) | (0.768) | – | 5.3 | 4.5 |
| 2025 | 5.5 | – | (0.209) | (0.827) | – | 5.3 | 4.5 |
| 2026 | 5.5 | – | (0.224) | (0.887) | – | 5.3 | 4.4 |
| 2027 | 5.5 | – | (0.239) | (0.946) | – | 5.3 | 4.3 |
| 2028 | 5.5 | – | (0.254) | (1.006) | – | 5.2 | 4.2 |
| 2029 | 5.5 | – | (0.269) | (1.065) | – | 5.2 | 4.2 |
| 2030 | 5.5 | – | (0.284) | (1.125) | – | 5.2 | 4.1 |
| 2031 | 5.5 | – | (0.291) | (1.184) | – | 5.2 | 4.0 |
| 2032 | 5.5 | – | (0.299) | (1.244) | – | 5.2 | 4.0 |
| 2033 | 5.5 | – | (0.307) | (1.303) | – | 5.2 | 3.9 |

## Appendix E-3: Sales Forecast Data

### *Hawaiian Electric Sales Forecast Data*

Table E-42: HECO Sales Forecast Data (GWh)
*Includes Underlying Economic, Renewable Self Generation, Non-PBFA EEPS Contribution, PBFA DSM Programs, and Electric Vehicle Forecasts*

| Year | Historical | Blazing a Bold Frontier | Stuck in the Middle | No Burning Desire | Moved by Passion |
|---|---|---|---|---|---|
| 1992 | 6,650 | – | – | – | – |
| 1993 | 6,607 | – | – | – | – |
| 1994 | 6,797 | – | – | – | – |
| 1995 | 6,963 | – | – | – | – |
| 1996 | 7,091 | – | – | – | – |
| 1997 | 7,040 | – | – | – | – |
| 1998 | 6,938 | – | – | – | – |
| 1999 | 6,998 | – | – | – | – |
| 2000 | 7,212 | – | – | – | – |
| 2001 | 7,277 | – | – | – | – |
| 2002 | 7,390 | – | – | – | – |
| 2003 | 7,522 | – | – | – | – |
| 2004 | 7,733 | – | – | – | – |
| 2005 | 7,721 | – | – | – | – |
| 2006 | 7,701 | – | – | – | – |
| 2007 | 7,675 | – | – | – | – |
| 2008 | 7,556 | – | – | – | – |
| 2009 | 7,378 | – | – | – | – |
| 2010 | 7,277 | – | – | – | – |
| 2011 | 7,242 | – | – | – | – |
| 2012 | 6,976 | 7,020 | 7,150 | 7,307 | 7,125 |
| 2013 | – | 6,829 | 7,167 | 7,495 | 7,086 |
| 2014 | – | 6,633 | 7,185 | 7,689 | 7,041 |
| 2015 | – | 6,443 | 7,220 | 7,928 | 7,013 |
| 2016 | – | 6,294 | 7,315 | 8,238 | 7,037 |
| 2017 | – | 6,072 | 7,306 | 8,420 | 6,965 |
| 2018 | – | 5,809 | 7,279 | 8,585 | 6,875 |
| 2019 | – | 5,628 | 7,306 | 8,799 | 6,839 |
| 2020 | – | 5,466 | 7,329 | 8,995 | 6,799 |
| 2021 | – | 5,301 | 7,309 | 9,120 | 6,716 |
| 2022 | – | 5,167 | 7,312 | 9,252 | 6,659 |
| 2023 | – | 5,051 | 7,321 | 9,371 | 6,612 |
| 2024 | – | 4,951 | 7,332 | 9,471 | 6,570 |
| 2025 | – | 4,865 | 7,350 | 9,578 | 6,540 |
| 2026 | – | 4,773 | 7,352 | 9,663 | 6,496 |
| 2027 | – | 4,690 | 7,360 | 9,752 | 6,459 |
| 2028 | – | 4,614 | 7,371 | 9,846 | 6,428 |
| 2029 | – | 4,543 | 7,387 | 9,945 | 6,403 |
| 2030 | – | 4,477 | 7,406 | 10,048 | 6,381 |
| 2031 | – | 4,420 | 7,433 | 10,180 | 6,369 |
| 2032 | – | 4,369 | 7,466 | 10,320 | 6,365 |
| 2033 | – | 4,320 | 7,500 | 10,464 | 6,363 |

Table E-43: HECO No PBFA DSM Sales Forecast Data (GWh)

*Includes Underlying Economic, Renewable Self Generation, Non-PBFA EEPS Contribution, and Electric Vehicle Forecasts*

| Year | Historical | Blazing a Bold Frontier | Stuck in the Middle | No Burning Desire | Moved by Passion |
|---|---|---|---|---|---|
| 1992 | 6,650 | – | – | – | – |
| 1993 | 6,607 | – | – | – | – |
| 1994 | 6,797 | – | – | – | – |
| 1995 | 6,963 | – | – | – | – |
| 1996 | 7,091 | – | – | – | – |
| 1997 | 7,040 | – | – | – | – |
| 1998 | 6,938 | – | – | – | – |
| 1999 | 6,998 | – | – | – | – |
| 2000 | 7,212 | – | – | – | – |
| 2001 | 7,277 | – | – | – | – |
| 2002 | 7,390 | – | – | – | – |
| 2003 | 7,522 | – | – | – | – |
| 2004 | 7,733 | – | – | – | – |
| 2005 | 7,721 | – | – | – | – |
| 2006 | 7,701 | – | – | – | – |
| 2007 | 7,675 | – | – | – | – |
| 2008 | 7,556 | – | – | – | – |
| 2009 | 7,378 | – | – | – | – |
| 2010 | 7,277 | – | – | – | – |
| 2011 | 7,242 | – | – | – | – |
| 2012 | 6,976 | 7,068 | 7,183 | 7,340 | 7,170 |
| 2013 | – | 6,974 | 7,266 | 7,594 | 7,218 |
| 2014 | – | 6,876 | 7,351 | 7,855 | 7,262 |
| 2015 | – | 6,783 | 7,452 | 8,159 | 7,322 |
| 2016 | – | 6,731 | 7,613 | 8,535 | 7,434 |
| 2017 | – | 6,606 | 7,671 | 8,785 | 7,451 |
| 2018 | – | 6,440 | 7,710 | 9,015 | 7,449 |
| 2019 | – | 6,356 | 7,803 | 9,295 | 7,501 |
| 2020 | – | 6,291 | 7,892 | 9,558 | 7,549 |
| 2021 | – | 6,224 | 7,938 | 9,749 | 7,555 |
| 2022 | – | 6,187 | 8,008 | 9,947 | 7,586 |
| 2023 | – | 6,168 | 8,082 | 10,133 | 7,627 |
| 2024 | – | 6,165 | 8,159 | 10,299 | 7,674 |
| 2025 | – | 6,176 | 8,244 | 10,472 | 7,731 |
| 2026 | – | 6,182 | 8,313 | 10,623 | 7,776 |
| 2027 | – | 6,196 | 8,386 | 10,778 | 7,828 |
| 2028 | – | 6,216 | 8,464 | 10,939 | 7,885 |
| 2029 | – | 6,243 | 8,546 | 11,104 | 7,948 |
| 2030 | – | 6,274 | 8,631 | 11,273 | 8,014 |
| 2031 | – | 6,313 | 8,724 | 11,471 | 8,091 |
| 2032 | – | 6,360 | 8,823 | 11,677 | 8,175 |
| 2033 | – | 6,408 | 8,924 | 11,888 | 8,261 |

## *HELCO Sales Forecast Data*

Table E-44: HELCO Sales Forecast Data (GWh)

*Includes Underlying Economic, Renewable Self Generation, Non-PBFA EEPS Contribution, PBFA DSM Programs, and Electric Vehicle Forecasts*

| Year | Historical | Blazing a Bold Frontier | Stuck in the Middle | No Burning Desire | Moved by Passion |
|---|---|---|---|---|---|
| 1992 | 791 | – | – | – | – |
| 1993 | 802 | – | – | – | – |
| 1994 | 836 | – | – | – | – |
| 1995 | 847 | – | – | – | – |
| 1996 | 876 | – | – | – | – |
| 1997 | 894 | – | – | – | – |
| 1998 | 903 | – | – | – | – |
| 1999 | 922 | – | – | – | – |
| 2000 | 954 | – | – | – | – |
| 2001 | 960 | – | – | – | – |
| 2002 | 995 | – | – | – | – |
| 2003 | 1,046 | – | – | – | – |
| 2004 | 1,083 | – | – | – | – |
| 2005 | 1,116 | – | – | – | – |
| 2006 | 1,149 | – | – | – | – |
| 2007 | 1,163 | – | – | – | – |
| 2008 | 1,141 | – | – | – | – |
| 2009 | 1,120 | – | – | – | – |
| 2010 | 1,110 | – | – | – | – |
| 2011 | 1,104 | – | – | – | – |
| 2012 | 1,085 | 1,040 | 1,099 | 1,174 | 1,091 |
| 2013 | – | 1,009 | 1,105 | 1,213 | 1,089 |
| 2014 | – | 982 | 1,117 | 1,257 | 1,094 |
| 2015 | – | 962 | 1,129 | 1,276 | 1,098 |
| 2016 | – | 946 | 1,144 | 1,300 | 1,107 |
| 2017 | – | 933 | 1,162 | 1,317 | 1,117 |
| 2018 | – | 925 | 1,181 | 1,352 | 1,129 |
| 2019 | – | 915 | 1,199 | 1,384 | 1,140 |
| 2020 | – | 906 | 1,213 | 1,414 | 1,147 |
| 2021 | – | 897 | 1,228 | 1,447 | 1,155 |
| 2022 | – | 889 | 1,242 | 1,479 | 1,162 |
| 2023 | – | 883 | 1,256 | 1,513 | 1,168 |
| 2024 | – | 885 | 1,270 | 1,549 | 1,174 |
| 2025 | – | 876 | 1,281 | 1,584 | 1,178 |
| 2026 | – | 872 | 1,299 | 1,620 | 1,187 |
| 2027 | – | 865 | 1,314 | 1,656 | 1,193 |
| 2028 | – | 858 | 1,329 | 1,692 | 1,200 |
| 2029 | – | 851 | 1,345 | 1,728 | 1,207 |
| 2030 | – | 845 | 1,362 | 1,762 | 1,215 |
| 2031 | – | 841 | 1,380 | 1,797 | 1,224 |
| 2032 | – | 838 | 1,398 | 1,835 | 1,233 |
| 2033 | – | 837 | 1,418 | 1,875 | 1,244 |

Table E-45: HELCO No PBFA DSM Sales Forecast Data (GWh)

*Includes Underlying Economic, Renewable Self Generation, Non-PBFA EEPS Contribution, and Electric Vehicle Forecasts*

| Year | Historical | Blazing a Bold Frontier | Stuck in the Middle | No Burning Desire | Moved by Passion |
|---|---|---|---|---|---|
| 1992 | 791 | – | – | – | – |
| 1993 | 802 | – | – | – | – |
| 1994 | 836 | – | – | – | – |
| 1995 | 847 | – | – | – | – |
| 1996 | 876 | – | – | – | – |
| 1997 | 894 | – | – | – | – |
| 1998 | 903 | – | – | – | – |
| 1999 | 922 | – | – | – | – |
| 2000 | 954 | – | – | – | – |
| 2001 | 960 | – | – | – | – |
| 2002 | 995 | – | – | – | – |
| 2003 | 1,046 | – | – | – | – |
| 2004 | 1,083 | – | – | – | – |
| 2005 | 1,116 | – | – | – | – |
| 2006 | 1,149 | – | – | – | – |
| 2007 | 1,163 | – | – | – | – |
| 2008 | 1,141 | – | – | – | – |
| 2009 | 1,120 | – | – | – | – |
| 2010 | 1,110 | – | – | – | – |
| 2011 | 1,104 | – | – | – | – |
| 2012 | 1,085 | 1,062 | 1,114 | 1,190 | 1,111 |
| 2013 | – | 1,046 | 1,131 | 1,238 | 1,123 |
| 2014 | – | 1,034 | 1,153 | 1,293 | 1,141 |
| 2015 | – | 1,028 | 1,174 | 1,322 | 1,159 |
| 2016 | – | 1,027 | 1,200 | 1,355 | 1,180 |
| 2017 | – | 1,030 | 1,227 | 1,382 | 1,204 |
| 2018 | – | 1,036 | 1,256 | 1,427 | 1,230 |
| 2019 | – | 1,041 | 1,284 | 1,469 | 1,254 |
| 2020 | – | 1,046 | 1,309 | 1,510 | 1,275 |
| 2021 | – | 1,052 | 1,334 | 1,553 | 1,296 |
| 2022 | – | 1,059 | 1,358 | 1,595 | 1,316 |
| 2023 | – | 1,067 | 1,382 | 1,639 | 1,336 |
| 2024 | – | 1,085 | 1,406 | 1,685 | 1,356 |
| 2025 | – | 1,091 | 1,427 | 1,730 | 1,372 |
| 2026 | – | 1,101 | 1,455 | 1,776 | 1,395 |
| 2027 | – | 1,109 | 1,480 | 1,823 | 1,415 |
| 2028 | – | 1,116 | 1,505 | 1,869 | 1,435 |
| 2029 | – | 1,124 | 1,532 | 1,915 | 1,456 |
| 2030 | – | 1,134 | 1,559 | 1,959 | 1,477 |
| 2031 | – | 1,144 | 1,586 | 2,004 | 1,499 |
| 2032 | – | 1,156 | 1,615 | 2,052 | 1,522 |
| 2033 | – | 1,169 | 1,645 | 2,102 | 1,547 |

## *Maui Sales Forecast Data*

Table E-46: Maui Sales Forecast Data (GWh)

*Includes Underlying Economic, Renewable Self Generation, Non-PBFA EEPS Contribution, PBFA DSM Programs, and Electric Vehicle Forecasts*

| Year | Historical | Blazing a Bold Frontier | Stuck in the Middle | No Burning Desire | Moved by Passion |
|---|---|---|---|---|---|
| 1992 | 838 | – | – | – | – |
| 1993 | 861 | – | – | – | – |
| 1994 | 901 | – | – | – | – |
| 1995 | 937 | – | – | – | – |
| 1996 | 964 | – | – | – | – |
| 1997 | 969 | – | – | – | – |
| 1998 | 968 | – | – | – | – |
| 1999 | 1,003 | – | – | – | – |
| 2000 | 1,042 | – | – | – | – |
| 2001 | 1,071 | – | – | – | – |
| 2002 | 1,097 | – | – | – | – |
| 2003 | 1,143 | – | – | – | – |
| 2004 | 1,185 | – | – | – | – |
| 2005 | 1,188 | – | – | – | – |
| 2006 | 1,203 | – | – | – | – |
| 2007 | 1,214 | – | – | – | – |
| 2008 | 1,177 | – | – | – | – |
| 2009 | 1,134 | – | – | – | – |
| 2010 | 1,135 | – | – | – | – |
| 2011 | 1,126 | – | – | – | – |
| 2012 | 1,090 | 1,079 | 1,113 | 1,139 | 1,107 |
| 2013 | – | 1,034 | 1,107 | 1,167 | 1,088 |
| 2014 | – | 991 | 1,104 | 1,202 | 1,072 |
| 2015 | – | 945 | 1,093 | 1,241 | 1,047 |
| 2016 | – | 902 | 1,084 | 1,285 | 1,025 |
| 2017 | – | 858 | 1,074 | 1,327 | 1,002 |
| 2018 | – | 820 | 1,074 | 1,375 | 990 |
| 2019 | – | 788 | 1,073 | 1,419 | 979 |
| 2020 | – | 763 | 1,074 | 1,466 | 972 |
| 2021 | – | 736 | 1,074 | 1,505 | 964 |
| 2022 | – | 715 | 1,076 | 1,545 | 960 |
| 2023 | – | 697 | 1,078 | 1,584 | 956 |
| 2024 | – | 684 | 1,086 | 1,627 | 958 |
| 2025 | – | 668 | 1,086 | 1,658 | 952 |
| 2026 | – | 657 | 1,090 | 1,692 | 952 |
| 2027 | – | 646 | 1,097 | 1,726 | 953 |
| 2028 | – | 639 | 1,104 | 1,762 | 955 |
| 2029 | – | 627 | 1,106 | 1,789 | 952 |
| 2030 | – | 618 | 1,112 | 1,823 | 953 |
| 2031 | – | 610 | 1,118 | 1,858 | 954 |
| 2032 | – | 607 | 1,131 | 1,904 | 962 |
| 2033 | – | 598 | 1,138 | 1,939 | 965 |

Table E-47: Maui No PBFA DSM Sales Forecast Data (GWh)

*Includes Underlying Economic, Renewable Self Generation, Non-PBFA EEPS Contribution, and Electric Vehicle Forecasts*

| Year | Historical | Blazing a Bold Frontier | Stuck in the Middle | No Burning Desire | Moved by Passion |
|---|---|---|---|---|---|
| 1992 | 838 | – | – | – | – |
| 1993 | 861 | – | – | – | – |
| 1994 | 901 | – | – | – | – |
| 1995 | 937 | – | – | – | – |
| 1996 | 964 | – | – | – | – |
| 1997 | 969 | – | – | – | – |
| 1998 | 968 | – | – | – | – |
| 1999 | 1,003 | – | – | – | – |
| 2000 | 1,042 | – | – | – | – |
| 2001 | 1,071 | – | – | – | – |
| 2002 | 1,097 | – | – | – | – |
| 2003 | 1,143 | – | – | – | – |
| 2004 | 1,185 | – | – | – | – |
| 2005 | 1,188 | – | – | – | – |
| 2006 | 1,203 | – | – | – | – |
| 2007 | 1,214 | – | – | – | – |
| 2008 | 1,177 | – | – | – | – |
| 2009 | 1,134 | – | – | – | – |
| 2010 | 1,135 | – | – | – | – |
| 2011 | 1,126 | – | – | – | – |
| 2012 | 1,090 | 1,087 | 1,118 | 1,144 | 1,114 |
| 2013 | – | 1,057 | 1,122 | 1,183 | 1,108 |
| 2014 | – | 1,029 | 1,130 | 1,228 | 1,106 |
| 2015 | – | 998 | 1,129 | 1,277 | 1,095 |
| 2016 | – | 970 | 1,130 | 1,331 | 1,087 |
| 2017 | – | 940 | 1,131 | 1,383 | 1,078 |
| 2018 | – | 918 | 1,141 | 1,441 | 1,079 |
| 2019 | – | 901 | 1,150 | 1,496 | 1,081 |
| 2020 | – | 891 | 1,162 | 1,553 | 1,089 |
| 2021 | – | 879 | 1,171 | 1,602 | 1,095 |
| 2022 | – | 873 | 1,183 | 1,652 | 1,103 |
| 2023 | – | 871 | 1,196 | 1,702 | 1,114 |
| 2024 | – | 873 | 1,214 | 1,756 | 1,129 |
| 2025 | – | 871 | 1,224 | 1,796 | 1,137 |
| 2026 | – | 876 | 1,239 | 1,841 | 1,150 |
| 2027 | – | 880 | 1,256 | 1,885 | 1,165 |
| 2028 | – | 887 | 1,274 | 1,932 | 1,181 |
| 2029 | – | 891 | 1,285 | 1,969 | 1,191 |
| 2030 | – | 897 | 1,302 | 2,013 | 1,206 |
| 2031 | – | 904 | 1,318 | 2,059 | 1,221 |
| 2032 | – | 915 | 1,341 | 2,114 | 1,243 |
| 2033 | – | 922 | 1,358 | 2,160 | 1,259 |

## *Lanai Sales Forecast Data*

Table E-48: Lanai Sales Forecast Data (MWh)

*Includes Underlying Economic, Renewable Self Generation, Non-PBFA EEPS Contribution, PBFA DSM Programs, and Electric Vehicle Forecasts*

| Year | Historical | Blazing a Bold Frontier | Stuck in the Middle | No Burning Desire | Moved by Passion |
|---|---|---|---|---|---|
| 1992 | 23,327 | – | – | – | – |
| 1993 | 23,879 | – | – | – | – |
| 1994 | 25,818 | – | – | – | – |
| 1995 | 26,053 | – | – | – | – |
| 1996 | 26,365 | – | – | – | – |
| 1997 | 26,047 | – | – | – | – |
| 1998 | 26,085 | – | – | – | – |
| 1999 | 26,569 | – | – | – | – |
| 2000 | 27,108 | – | – | – | – |
| 2001 | 26,905 | – | – | – | – |
| 2002 | 27,036 | – | – | – | – |
| 2003 | 28,136 | – | – | – | – |
| 2004 | 27,802 | – | – | – | – |
| 2005 | 27,942 | – | – | – | – |
| 2006 | 28,691 | – | – | – | – |
| 2007 | 30,736 | – | – | – | – |
| 2008 | 29,138 | – | – | – | – |
| 2009 | 26,096 | – | – | – | – |
| 2010 | 24,967 | – | – | – | – |
| 2011 | 24,785 | – | – | – | – |
| 2012 | 24,712 | 24,279 | 24,526 | 25,428 | 24,463 |
| 2013 | – | 23,655 | 24,263 | 25,518 | 24,087 |
| 2014 | – | 23,111 | 24,056 | 25,683 | 23,771 |
| 2015 | – | 22,567 | 23,926 | 25,848 | 23,533 |
| 2016 | – | 22,089 | 23,830 | 26,087 | 23,328 |
| 2017 | – | 21,480 | 23,620 | 26,177 | 23,010 |
| 2018 | – | 20,936 | 23,490 | 26,342 | 22,771 |
| 2019 | – | 20,393 | 23,375 | 26,507 | 22,547 |
| 2020 | – | 19,913 | 23,341 | 26,751 | 22,404 |
| 2021 | – | 19,305 | 23,166 | 26,836 | 22,121 |
| 2022 | – | 18,762 | 23,064 | 27,001 | 21,910 |
| 2023 | – | 18,218 | 22,964 | 27,165 | 21,702 |
| 2024 | – | 17,737 | 22,927 | 27,415 | 21,556 |
| 2025 | – | 17,131 | 22,752 | 27,495 | 21,273 |
| 2026 | – | 16,587 | 22,652 | 27,659 | 21,064 |
| 2027 | – | 16,043 | 22,547 | 27,824 | 20,850 |
| 2028 | – | 15,561 | 22,515 | 28,079 | 20,709 |
| 2029 | – | 14,956 | 22,338 | 28,153 | 20,425 |
| 2030 | – | 14,412 | 22,232 | 28,318 | 20,209 |
| 2031 | – | 13,890 | 22,141 | 28,498 | 20,014 |
| 2032 | – | 13,450 | 22,144 | 28,787 | 19,918 |
| 2033 | – | 12,890 | 21,990 | 28,886 | 19,666 |

Table E-49: Lanai No PBFA DSM Sales Forecast Data (MWh)

*Includes Underlying Economic, Renewable Self Generation, Non-PBFA EEPS Contribution, and Electric Vehicle Forecasts*

| Year | Historical | Blazing a Bold Frontier | Stuck in the Middle | No Burning Desire | Moved by Passion |
|---|---|---|---|---|---|
| 1992 | 23,327 | – | – | – | – |
| 1993 | 23,879 | – | – | – | – |
| 1994 | 25,818 | – | – | – | – |
| 1995 | 26,053 | – | – | – | – |
| 1996 | 26,365 | – | – | – | – |
| 1997 | 26,047 | – | – | – | – |
| 1998 | 26,085 | – | – | – | – |
| 1999 | 26,569 | – | – | – | – |
| 2000 | 27,108 | – | – | – | – |
| 2001 | 26,905 | – | – | – | – |
| 2002 | 27,036 | – | – | – | – |
| 2003 | 28,136 | – | – | – | – |
| 2004 | 27,802 | – | – | – | – |
| 2005 | 27,942 | – | – | – | – |
| 2006 | 28,691 | – | – | – | – |
| 2007 | 30,736 | – | – | – | – |
| 2008 | 29,138 | – | – | – | – |
| 2009 | 26,096 | – | – | – | – |
| 2010 | 24,967 | – | – | – | – |
| 2011 | 24,785 | – | – | – | – |
| 2012 | 24,712 | 24,447 | 24,641 | 25,543 | 24,616 |
| 2013 | – | 24,159 | 24,607 | 25,862 | 24,546 |
| 2014 | – | 23,952 | 24,629 | 26,256 | 24,536 |
| 2015 | – | 23,745 | 24,729 | 26,650 | 24,603 |
| 2016 | – | 23,603 | 24,862 | 27,119 | 24,704 |
| 2017 | – | 23,330 | 24,881 | 27,439 | 24,691 |
| 2018 | – | 23,123 | 24,981 | 27,833 | 24,758 |
| 2019 | – | 22,915 | 25,095 | 28,227 | 24,841 |
| 2020 | – | 22,772 | 25,290 | 28,700 | 25,003 |
| 2021 | – | 22,501 | 25,345 | 29,015 | 25,026 |
| 2022 | – | 22,294 | 25,472 | 29,409 | 25,121 |
| 2023 | – | 22,086 | 25,602 | 29,803 | 25,219 |
| 2024 | – | 21,942 | 25,794 | 30,282 | 25,379 |
| 2025 | – | 21,672 | 25,848 | 30,591 | 25,401 |
| 2026 | – | 21,464 | 25,978 | 30,985 | 25,498 |
| 2027 | – | 21,257 | 26,102 | 31,379 | 25,590 |
| 2028 | – | 21,111 | 26,299 | 31,863 | 25,755 |
| 2029 | – | 20,843 | 26,352 | 32,167 | 25,776 |
| 2030 | – | 20,635 | 26,475 | 32,561 | 25,867 |
| 2031 | – | 20,450 | 26,613 | 32,970 | 25,977 |
| 2032 | – | 20,346 | 26,845 | 33,488 | 26,187 |
| 2033 | – | 20,122 | 26,920 | 33,817 | 26,240 |

## *Molokai Sales Forecast Data*

Table E-50: Molokai Sales Forecast Data (MWh)

*Includes Underlying Economic, Renewable Self Generation, Non-PBFA EEPS Contribution, PBFA DSM Programs, and Electric Vehicle Forecasts*

| Year | Historical | Blazing a Bold Frontier | Stuck in the Middle | No Burning Desire | Moved by Passion |
|---|---|---|---|---|---|
| 1992 | 29,841 | – | – | – | – |
| 1993 | 30,849 | – | – | – | – |
| 1994 | 33,064 | – | – | – | – |
| 1995 | 33,920 | – | – | – | – |
| 1996 | 34,341 | – | – | – | – |
| 1997 | 33,549 | – | – | – | – |
| 1998 | 34,710 | – | – | – | – |
| 1999 | 35,576 | – | – | – | – |
| 2000 | 36,349 | – | – | – | – |
| 2001 | 35,681 | – | – | – | – |
| 2002 | 34,942 | – | – | – | – |
| 2003 | 35,894 | – | – | – | – |
| 2004 | 35,344 | – | – | – | – |
| 2005 | 35,918 | – | – | – | – |
| 2006 | 35,273 | – | – | – | – |
| 2007 | 35,756 | – | – | – | – |
| 2008 | 33,586 | – | – | – | – |
| 2009 | 31,834 | – | – | – | – |
| 2010 | 31,451 | – | – | – | – |
| 2011 | 30,685 | – | – | – | – |
| 2012 | 29,942 | 29,477 | 30,238 | 30,848 | 30,136 |
| 2013 | – | 28,268 | 29,677 | 30,253 | 29,339 |
| 2014 | – | 27,149 | 29,200 | 29,831 | 28,630 |
| 2015 | – | 26,031 | 28,723 | 29,490 | 27,921 |
| 2016 | – | 24,986 | 28,329 | 29,303 | 27,293 |
| 2017 | – | 23,793 | 27,751 | 28,960 | 26,484 |
| 2018 | – | 22,675 | 27,323 | 28,762 | 25,824 |
| 2019 | – | 21,570 | 26,841 | 28,588 | 25,115 |
| 2020 | – | 20,575 | 26,480 | 28,484 | 24,539 |
| 2021 | – | 19,512 | 26,011 | 28,256 | 23,885 |
| 2022 | – | 18,566 | 25,581 | 28,143 | 23,286 |
| 2023 | – | 17,654 | 25,192 | 27,990 | 22,739 |
| 2024 | – | 16,829 | 24,906 | 27,939 | 22,302 |
| 2025 | – | 15,892 | 24,427 | 27,728 | 21,683 |
| 2026 | – | 15,031 | 24,055 | 27,563 | 21,172 |
| 2027 | – | 14,179 | 23,716 | 27,412 | 20,697 |
| 2028 | – | 13,392 | 23,410 | 27,373 | 20,254 |
| 2029 | – | 12,488 | 22,980 | 27,115 | 19,695 |
| 2030 | – | 11,648 | 22,647 | 26,973 | 19,232 |
| 2031 | – | 10,836 | 22,286 | 26,868 | 18,746 |
| 2032 | – | 10,110 | 22,051 | 26,830 | 18,390 |
| 2033 | – | 9,270 | 21,674 | 26,625 | 17,899 |

Table E-51: Molokai No PBFA DSM Sales Forecast Data (MWh)

*Includes Underlying Economic, Renewable Self Generation, Non-PBFA EEPS Contribution, and Electric Vehicle Forecasts*

| Year | Historical | Blazing a Bold Frontier | Stuck in the Middle | No Burning Desire | Moved by Passion |
|---|---|---|---|---|---|
| 1992 | 29,841 | – | – | – | – |
| 1993 | 30,849 | – | – | – | – |
| 1994 | 33,064 | – | – | – | – |
| 1995 | 33,920 | – | – | – | – |
| 1996 | 34,341 | – | – | – | – |
| 1997 | 33,549 | – | – | – | – |
| 1998 | 34,710 | – | – | – | – |
| 1999 | 35,576 | – | – | – | – |
| 2000 | 36,349 | – | – | – | – |
| 2001 | 35,681 | – | – | – | – |
| 2002 | 34,942 | – | – | – | – |
| 2003 | 35,894 | – | – | – | – |
| 2004 | 35,344 | – | – | – | – |
| 2005 | 35,918 | – | – | – | – |
| 2006 | 35,273 | – | – | – | – |
| 2007 | 35,756 | – | – | – | – |
| 2008 | 33,586 | – | – | – | – |
| 2009 | 31,834 | – | – | – | – |
| 2010 | 31,451 | – | – | – | – |
| 2011 | 30,685 | – | – | – | – |
| 2012 | 29,942 | 29,685 | 30,380 | 30,990 | 30,325 |
| 2013 | – | 28,893 | 30,103 | 30,680 | 29,908 |
| 2014 | – | 28,191 | 29,910 | 30,542 | 29,577 |
| 2015 | – | 27,489 | 29,718 | 30,485 | 29,247 |
| 2016 | – | 26,862 | 29,608 | 30,582 | 28,998 |
| 2017 | – | 26,085 | 29,314 | 30,523 | 28,567 |
| 2018 | – | 25,384 | 29,170 | 30,609 | 28,286 |
| 2019 | – | 24,696 | 28,973 | 30,719 | 27,956 |
| 2020 | – | 24,118 | 28,896 | 30,899 | 27,760 |
| 2021 | – | 23,472 | 28,711 | 30,956 | 27,485 |
| 2022 | – | 22,942 | 28,565 | 31,127 | 27,264 |
| 2023 | – | 22,446 | 28,460 | 31,258 | 27,096 |
| 2024 | – | 22,038 | 28,458 | 31,491 | 27,037 |
| 2025 | – | 21,519 | 28,263 | 31,564 | 26,798 |
| 2026 | – | 21,074 | 28,175 | 31,684 | 26,665 |
| 2027 | – | 20,638 | 28,120 | 31,816 | 26,570 |
| 2028 | – | 20,268 | 28,098 | 32,061 | 26,506 |
| 2029 | – | 19,782 | 27,952 | 32,087 | 26,325 |
| 2030 | – | 19,358 | 27,904 | 32,230 | 26,241 |
| 2031 | – | 18,963 | 27,827 | 32,409 | 26,134 |
| 2032 | – | 18,653 | 27,876 | 32,656 | 26,157 |
| 2033 | – | 18,231 | 27,783 | 32,734 | 26,045 |

# Appendix E-4: Peak Forecast Data

## *Hawaiian Electric Peak Forecast Data*

Table E-52: HECO Peak Forecast Data (MW)

*Includes Underlying Economic, Renewable Self Generation, Non-PBFA EEPS Contribution, PBFA DSM Programs, and Electric Vehicle Forecasts*

| Year | Historical | Blazing a Bold Frontier | Stuck in the Middle | No Burning Desire | Moved by Passion |
|---|---|---|---|---|---|
| 1992 | 1,129 | – | – | – | – |
| 1993 | 1,123 | – | – | – | – |
| 1994 | 1,140 | – | – | – | – |
| 1995 | 1,158 | – | – | – | – |
| 1996 | 1,166 | – | – | – | – |
| 1997 | 1,176 | – | – | – | – |
| 1998 | 1,131 | – | – | – | – |
| 1999 | 1,120 | – | – | – | – |
| 2000 | 1,164 | – | – | – | – |
| 2001 | 1,191 | – | – | – | – |
| 2002 | 1,204 | – | – | – | – |
| 2003 | 1,242 | – | – | – | – |
| 2004 | 1,281 | – | – | – | – |
| 2005 | 1,230 | – | – | – | – |
| 2006 | 1,265 | – | – | – | – |
| 2007 | 1,216 | – | – | – | – |
| 2008 | 1,186 | – | – | – | – |
| 2009 | 1,213 | – | – | – | – |
| 2010 | 1,162 | – | – | – | – |
| 2011 | 1,141 | – | – | – | – |
| 2012 | 1,141 | 1,149 | 1,171 | 1,196 | 1,167 |
| 2013 | – | 1,139 | 1,187 | 1,237 | 1,179 |
| 2014 | – | 1,126 | 1,203 | 1,278 | 1,190 |
| 2015 | – | 1,112 | 1,217 | 1,323 | 1,200 |
| 2016 | – | 1,096 | 1,234 | 1,369 | 1,213 |
| 2017 | – | 1,078 | 1,244 | 1,408 | 1,219 |
| 2018 | – | 1,051 | 1,250 | 1,441 | 1,220 |
| 2019 | – | 1,039 | 1,266 | 1,487 | 1,232 |
| 2020 | – | 1,026 | 1,279 | 1,525 | 1,241 |
| 2021 | – | 1,014 | 1,282 | 1,549 | 1,240 |
| 2022 | – | 1,002 | 1,287 | 1,571 | 1,240 |
| 2023 | – | 991 | 1,292 | 1,594 | 1,241 |
| 2024 | – | 985 | 1,301 | 1,617 | 1,246 |
| 2025 | – | 978 | 1,311 | 1,640 | 1,252 |
| 2026 | – | 966 | 1,314 | 1,655 | 1,250 |
| 2027 | – | 953 | 1,316 | 1,670 | 1,248 |
| 2028 | – | 940 | 1,318 | 1,686 | 1,246 |
| 2029 | – | 928 | 1,320 | 1,702 | 1,244 |
| 2030 | – | 915 | 1,322 | 1,719 | 1,241 |
| 2031 | – | 904 | 1,325 | 1,742 | 1,241 |
| 2032 | – | 893 | 1,330 | 1,766 | 1,241 |
| 2033 | – | 883 | 1,334 | 1,791 | 1,242 |

Table E-53: HECO No PBFA DSM Peak Forecast Data (MW)

*Includes Underlying Economic, Renewable Self Generation, Non-PBFA EEPS Contribution, and Electric Vehicle Forecasts*

| Year | Historical | Blazing a Bold Frontier | Stuck in the Middle | No Burning Desire | Moved by Passion |
|---|---|---|---|---|---|
| 1992 | 1,129 | – | – | – | – |
| 1993 | 1,123 | – | – | – | – |
| 1994 | 1,140 | – | – | – | – |
| 1995 | 1,158 | – | – | – | – |
| 1996 | 1,166 | – | – | – | – |
| 1997 | 1,176 | – | – | – | – |
| 1998 | 1,131 | – | – | – | – |
| 1999 | 1,120 | – | – | – | – |
| 2000 | 1,164 | – | – | – | – |
| 2001 | 1,191 | – | – | – | – |
| 2002 | 1,204 | – | – | – | – |
| 2003 | 1,242 | – | – | – | – |
| 2004 | 1,281 | – | – | – | – |
| 2005 | 1,230 | – | – | – | – |
| 2006 | 1,265 | – | – | – | – |
| 2007 | 1,216 | – | – | – | – |
| 2008 | 1,186 | – | – | – | – |
| 2009 | 1,213 | – | – | – | – |
| 2010 | 1,162 | – | – | – | – |
| 2011 | 1,141 | – | – | – | – |
| 2012 | 1,141 | 1,163 | 1,180 | 1,205 | 1,180 |
| 2013 | – | 1,167 | 1,207 | 1,257 | 1,205 |
| 2014 | – | 1,170 | 1,232 | 1,307 | 1,230 |
| 2015 | – | 1,170 | 1,257 | 1,363 | 1,253 |
| 2016 | – | 1,169 | 1,284 | 1,419 | 1,280 |
| 2017 | – | 1,166 | 1,305 | 1,469 | 1,300 |
| 2018 | – | 1,155 | 1,320 | 1,511 | 1,314 |
| 2019 | – | 1,157 | 1,347 | 1,568 | 1,340 |
| 2020 | – | 1,159 | 1,370 | 1,616 | 1,362 |
| 2021 | – | 1,162 | 1,383 | 1,650 | 1,375 |
| 2022 | – | 1,165 | 1,398 | 1,682 | 1,388 |
| 2023 | – | 1,169 | 1,413 | 1,715 | 1,403 |
| 2024 | – | 1,178 | 1,433 | 1,748 | 1,422 |
| 2025 | – | 1,186 | 1,453 | 1,782 | 1,441 |
| 2026 | – | 1,189 | 1,466 | 1,807 | 1,453 |
| 2027 | – | 1,191 | 1,478 | 1,833 | 1,464 |
| 2028 | – | 1,193 | 1,490 | 1,858 | 1,476 |
| 2029 | – | 1,195 | 1,503 | 1,885 | 1,488 |
| 2030 | – | 1,198 | 1,514 | 1,911 | 1,498 |
| 2031 | – | 1,202 | 1,528 | 1,945 | 1,511 |
| 2032 | – | 1,206 | 1,543 | 1,980 | 1,526 |
| 2033 | – | 1,210 | 1,557 | 2,015 | 1,540 |

## *HELCO Peak Forecast Data*

Table E-54: HELCO Peak Forecast Data (MW)

*Includes Underlying Economic, Renewable Self Generation, Non-PBFA EEPS Contribution, PBFA DSM Programs, and Electric Vehicle Forecasts*

| Year | Historical | Blazing a Bold Frontier | Stuck in the Middle | No Burning Desire | Moved by Passion |
|---|---|---|---|---|---|
| 1992 | 144 | – | – | – | – |
| 1993 | 149 | – | – | – | – |
| 1994 | 154 | – | – | – | – |
| 1995 | 159 | – | – | – | – |
| 1996 | 160 | – | – | – | – |
| 1997 | 162 | – | – | – | – |
| 1998 | 164 | – | – | – | – |
| 1999 | 170 | – | – | – | – |
| 2000 | 171 | – | – | – | – |
| 2001 | 174 | – | – | – | – |
| 2002 | 178 | – | – | – | – |
| 2003 | 187 | – | – | – | – |
| 2004 | 195 | – | – | – | – |
| 2005 | 197 | – | – | – | – |
| 2006 | 201 | – | – | – | – |
| 2007 | 203 | – | – | – | – |
| 2008 | 198 | – | – | – | – |
| 2009 | 195 | – | – | – | – |
| 2010 | 191 | – | – | – | – |
| 2011 | 189 | – | – | – | – |
| 2012 | 189 | 176 | 186 | 200 | 185 |
| 2013 | – | 172 | 187 | 206 | 185 |
| 2014 | – | 169 | 188 | 214 | 185 |
| 2015 | – | 163 | 190 | 212 | 187 |
| 2016 | – | 165 | 190 | 219 | 186 |
| 2017 | – | 165 | 193 | 216 | 189 |
| 2018 | – | 164 | 194 | 226 | 189 |
| 2019 | – | 163 | 196 | 231 | 190 |
| 2020 | – | 162 | 198 | 236 | 191 |
| 2021 | – | 161 | 201 | 241 | 193 |
| 2022 | – | 161 | 203 | 247 | 195 |
| 2023 | – | 160 | 205 | 253 | 196 |
| 2024 | – | 160 | 207 | 259 | 197 |
| 2025 | – | 160 | 208 | 265 | 198 |
| 2026 | – | 160 | 211 | 270 | 200 |
| 2027 | – | 159 | 213 | 276 | 202 |
| 2028 | – | 159 | 215 | 281 | 203 |
| 2029 | – | 158 | 218 | 287 | 205 |
| 2030 | – | 158 | 220 | 292 | 207 |
| 2031 | – | 158 | 223 | 298 | 209 |
| 2032 | – | 158 | 225 | 304 | 211 |
| 2033 | – | 158 | 228 | 309 | 213 |

Table E-55: HELCO No PBFA DSM Peak Forecast Data (MW)

*Includes Underlying Economic, Renewable Self Generation, Non-PBFA EEPS Contribution, and Electric Vehicle Forecasts*

| Year | Historical | Blazing a Bold Frontier | Stuck in the Middle | No Burning Desire | Moved by Passion |
|---|---|---|---|---|---|
| 1992 | 144.0 | – | – | – | – |
| 1993 | 148.7 | – | – | – | – |
| 1994 | 153.8 | – | – | – | – |
| 1995 | 158.5 | – | – | – | – |
| 1996 | 160.4 | – | – | – | – |
| 1997 | 161.5 | – | – | – | – |
| 1998 | 164.3 | – | – | – | – |
| 1999 | 170.2 | – | – | – | – |
| 2000 | 170.8 | – | – | – | – |
| 2001 | 174.1 | – | – | – | – |
| 2002 | 177.9 | – | – | – | – |
| 2003 | 186.7 | – | – | – | – |
| 2004 | 194.5 | – | – | – | – |
| 2005 | 197.0 | – | – | – | – |
| 2006 | 201.3 | – | – | – | – |
| 2007 | 203.3 | – | – | – | – |
| 2008 | 198.2 | – | – | – | – |
| 2009 | 194.6 | – | – | – | – |
| 2010 | 190.6 | – | – | – | – |
| 2011 | 189.2 | – | – | – | – |
| 2012 | 189.3 | 180.2 | 189.2 | 202.7 | 189.1 |
| 2013 | – | 178.9 | 191.4 | 210.8 | 191.1 |
| 2014 | – | 178.0 | 194.0 | 220.0 | 193.6 |
| 2015 | – | 174.6 | 197.7 | 219.9 | 197.1 |
| 2016 | – | 179.1 | 199.7 | 228.0 | 199.0 |
| 2017 | – | 180.8 | 204.6 | 227.4 | 203.8 |
| 2018 | – | 182.6 | 206.8 | 239.1 | 205.8 |
| 2019 | – | 184.1 | 210.7 | 245.6 | 209.6 |
| 2020 | – | 185.6 | 214.0 | 252.3 | 212.7 |
| 2021 | – | 187.0 | 218.2 | 258.8 | 216.8 |
| 2022 | – | 188.9 | 222.0 | 266.1 | 220.4 |
| 2023 | – | 190.9 | 225.8 | 273.7 | 224.1 |
| 2024 | – | 193.3 | 229.1 | 281.2 | 227.3 |
| 2025 | – | 195.7 | 232.5 | 288.8 | 230.5 |
| 2026 | – | 197.4 | 236.3 | 295.9 | 234.2 |
| 2027 | – | 199.3 | 240.3 | 302.9 | 238.0 |
| 2028 | – | 201.2 | 244.2 | 310.0 | 241.8 |
| 2029 | – | 203.1 | 248.1 | 317.1 | 245.6 |
| 2030 | – | 204.9 | 252.1 | 324.2 | 249.4 |
| 2031 | – | 207.2 | 256.4 | 331.5 | 253.6 |
| 2032 | – | 209.5 | 260.7 | 338.9 | 257.9 |
| 2033 | – | 211.8 | 265.0 | 346.3 | 262.1 |

## *Maui Peak Forecast Data*

Table E-56: Maui Peak Forecast Data (MW)

*Includes Underlying Economic, Renewable Self Generation, Non-PBFA EEPS Contribution, PBFA DSM Programs, and Electric Vehicle Forecasts*

| Year | Historical | Blazing a Bold Frontier | Stuck in the Middle | No Burning Desire | Moved by Passion |
|---|---|---|---|---|---|
| 1992 | 153 | – | – | – | – |
| 1993 | 150 | – | – | – | – |
| 1994 | 157 | – | – | – | – |
| 1995 | 164 | – | – | – | – |
| 1996 | 168 | – | – | – | – |
| 1997 | 168 | – | – | – | – |
| 1998 | 169 | – | – | – | – |
| 1999 | 173 | – | – | – | – |
| 2000 | 178 | – | – | – | – |
| 2001 | 183 | – | – | – | – |
| 2002 | 186 | – | – | – | – |
| 2003 | 194 | – | – | – | – |
| 2004 | 203 | – | – | – | – |
| 2005 | 198 | – | – | – | – |
| 2006 | 202 | – | – | – | – |
| 2007 | 201 | – | – | – | – |
| 2008 | 191 | – | – | – | – |
| 2009 | 196 | – | – | – | – |
| 2010 | 196 | – | – | – | – |
| 2011 | 186 | – | – | – | – |
| 2012 | 195 | 184 | 189 | 193 | 188 |
| 2013 | – | 181 | 191 | 200 | 190 |
| 2014 | – | 178 | 193 | 208 | 191 |
| 2015 | – | 174 | 194 | 216 | 191 |
| 2016 | – | 171 | 194 | 225 | 191 |
| 2017 | – | 168 | 195 | 234 | 191 |
| 2018 | – | 165 | 197 | 244 | 193 |
| 2019 | – | 162 | 199 | 253 | 194 |
| 2020 | – | 159 | 200 | 262 | 194 |
| 2021 | – | 156 | 201 | 270 | 195 |
| 2022 | – | 152 | 202 | 277 | 195 |
| 2023 | – | 150 | 204 | 285 | 196 |
| 2024 | – | 147 | 205 | 292 | 196 |
| 2025 | – | 145 | 207 | 299 | 197 |
| 2026 | – | 144 | 208 | 305 | 198 |
| 2027 | – | 142 | 210 | 311 | 199 |
| 2028 | – | 140 | 212 | 318 | 200 |
| 2029 | – | 138 | 213 | 324 | 201 |
| 2030 | – | 136 | 215 | 330 | 202 |
| 2031 | – | 132 | 215 | 337 | 202 |
| 2032 | – | 129 | 216 | 343 | 202 |
| 2033 | – | 125 | 216 | 350 | 202 |

Net peaks are estimated based on historical gross peaks; 2007–2011 average gross-to-net ratio is based on energy.

Table E-57: Maui No PBFA DSM Peak Forecast Data (MW)

*Includes Underlying Economic, Renewable Self Generation, Non-PBFA EEPS Contribution, and Electric Vehicle Forecasts*

| Year | Historical | Blazing a Bold Frontier | Stuck in the Middle | No Burning Desire | Moved by Passion |
|---|---|---|---|---|---|
| 1992 | 153 | – | – | – | – |
| 1993 | 150 | – | – | – | – |
| 1994 | 157 | – | – | – | – |
| 1995 | 164 | – | – | – | – |
| 1996 | 168 | – | – | – | – |
| 1997 | 168 | – | – | – | – |
| 1998 | 169 | – | – | – | – |
| 1999 | 173 | – | – | – | – |
| 2000 | 178 | – | – | – | – |
| 2001 | 183 | – | – | – | – |
| 2002 | 186 | – | – | – | – |
| 2003 | 194 | – | – | – | – |
| 2004 | 203 | – | – | – | – |
| 2005 | 198 | – | – | – | – |
| 2006 | 202 | – | – | – | – |
| 2007 | 201 | – | – | – | – |
| 2008 | 191 | – | – | – | – |
| 2009 | 196 | – | – | – | – |
| 2010 | 196 | – | – | – | – |
| 2011 | 186 | – | – | – | – |
| 2012 | 195 | 186 | 191 | 194 | 190 |
| 2013 | – | 185 | 194 | 203 | 194 |
| 2014 | – | 185 | 198 | 213 | 198 |
| 2015 | – | 184 | 200 | 223 | 200 |
| 2016 | – | 182 | 202 | 233 | 202 |
| 2017 | – | 181 | 205 | 244 | 204 |
| 2018 | – | 181 | 209 | 255 | 208 |
| 2019 | – | 180 | 212 | 266 | 211 |
| 2020 | – | 180 | 214 | 276 | 213 |
| 2021 | – | 179 | 217 | 286 | 216 |
| 2022 | – | 178 | 220 | 295 | 219 |
| 2023 | – | 178 | 223 | 304 | 221 |
| 2024 | – | 178 | 226 | 313 | 224 |
| 2025 | – | 178 | 229 | 322 | 227 |
| 2026 | – | 179 | 232 | 329 | 230 |
| 2027 | – | 179 | 236 | 337 | 234 |
| 2028 | – | 180 | 239 | 345 | 237 |
| 2029 | – | 180 | 242 | 353 | 240 |
| 2030 | – | 181 | 245 | 360 | 243 |
| 2031 | – | 179 | 247 | 369 | 245 |
| 2032 | – | 178 | 250 | 377 | 247 |
| 2033 | – | 177 | 252 | 385 | 249 |

Net peaks are estimated based on historical gross peaks; 2007–2011 average gross-to-net ratio is based on energy.

## *Lanai Peak Forecast Data*

Table E-58: Lanai Peak Forecast Data (MW)
*Includes Underlying Economic, Renewable Self Generation, Non-PBFA EEPS Contribution, PBFA DSM Programs, and Electric Vehicle Forecasts*

| Year | Historical | Blazing a Bold Frontier | Stuck in the Middle | No Burning Desire | Moved by Passion |
|---|---|---|---|---|---|
| 1992 | 4.5 | – | – | – | – |
| 1993 | 4.3 | – | – | – | – |
| 1994 | 4.6 | – | – | – | – |
| 1995 | 4.6 | – | – | – | – |
| 1996 | 4.9 | – | – | – | – |
| 1997 | 4.8 | – | – | – | – |
| 1998 | 5.0 | – | – | – | – |
| 1999 | 4.9 | – | – | – | – |
| 2000 | 4.8 | – | – | – | – |
| 2001 | 5.0 | – | – | – | – |
| 2002 | 4.7 | – | – | – | – |
| 2003 | 4.9 | – | – | – | – |
| 2004 | 4.7 | – | – | – | – |
| 2005 | 5.0 | – | – | – | – |
| 2006 | 5.4 | – | – | – | – |
| 2007 | 5.3 | – | – | – | – |
| 2008 | 5.1 | – | – | – | – |
| 2009 | 4.5 | – | – | – | – |
| 2010 | 4.7 | – | – | – | – |
| 2011 | 4.5 | – | – | – | – |
| 2012 | 4.5 | 4.2 | 4.3 | 4.5 | 4.2 |
| 2013 | – | 4.2 | 4.2 | 4.5 | 4.2 |
| 2014 | – | 4.1 | 4.3 | 4.6 | 4.2 |
| 2015 | – | 4.0 | 4.2 | 4.5 | 4.2 |
| 2016 | – | 4.0 | 4.2 | 4.6 | 4.1 |
| 2017 | – | 3.9 | 4.1 | 4.6 | 4.0 |
| 2018 | – | 3.8 | 4.2 | 4.7 | 4.1 |
| 2019 | – | 3.8 | 4.1 | 4.7 | 4.0 |
| 2020 | – | 3.7 | 4.2 | 4.8 | 4.1 |
| 2021 | – | 3.5 | 4.2 | 4.8 | 4.0 |
| 2022 | – | 3.5 | 4.1 | 4.8 | 3.9 |
| 2023 | – | 3.4 | 4.2 | 4.9 | 4.0 |
| 2024 | – | 3.3 | 4.1 | 4.9 | 3.9 |
| 2025 | – | 3.3 | 4.1 | 5.0 | 3.9 |
| 2026 | – | 3.2 | 4.1 | 5.0 | 3.9 |
| 2027 | – | 3.1 | 4.1 | 5.1 | 3.8 |
| 2028 | – | 3.0 | 4.1 | 5.0 | 3.9 |
| 2029 | – | 2.9 | 4.1 | 5.1 | 3.8 |
| 2030 | – | 2.8 | 4.0 | 5.1 | 3.8 |
| 2031 | – | 2.8 | 4.1 | 5.2 | 3.8 |
| 2032 | – | 2.7 | 4.1 | 5.3 | 3.8 |
| 2033 | – | 2.7 | 4.0 | 5.3 | 3.7 |

Net peaks are estimated based on historical gross peaks; 2007–2011 average gross-to-net ratio is based on energy.

Table E-59: Lanai No PBFA DSM Peak Forecast Data (MW)

*Includes Underlying Economic, Renewable Self Generation, Non-PBFA EEPS Contribution, and Electric Vehicle Forecasts*

| Year | Historical | Blazing a Bold Frontier | Stuck in the Middle | No Burning Desire | Moved by Passion |
|---|---|---|---|---|---|
| 1992 | 4.5 | – | – | – | – |
| 1993 | 4.3 | – | – | – | – |
| 1994 | 4.6 | – | – | – | – |
| 1995 | 4.6 | – | – | – | – |
| 1996 | 4.9 | – | – | – | – |
| 1997 | 4.8 | – | – | – | – |
| 1998 | 5.0 | – | – | – | – |
| 1999 | 4.9 | – | – | – | – |
| 2000 | 4.8 | – | – | – | – |
| 2001 | 5.0 | – | – | – | – |
| 2002 | 4.7 | – | – | – | – |
| 2003 | 4.9 | – | – | – | – |
| 2004 | 4.7 | – | – | – | – |
| 2005 | 5.0 | – | – | – | – |
| 2006 | 5.4 | – | – | – | – |
| 2007 | 5.3 | – | – | – | – |
| 2008 | 5.1 | – | – | – | – |
| 2009 | 4.5 | – | – | – | – |
| 2010 | 4.7 | – | – | – | – |
| 2011 | 4.5 | – | – | – | – |
| 2012 | 4.5 | 4.3 | 4.3 | 4.5 | 4.3 |
| 2013 | – | 4.3 | 4.3 | 4.6 | 4.3 |
| 2014 | – | 4.3 | 4.4 | 4.7 | 4.4 |
| 2015 | – | 4.2 | 4.4 | 4.7 | 4.4 |
| 2016 | – | 4.2 | 4.4 | 4.8 | 4.3 |
| 2017 | – | 4.2 | 4.3 | 4.8 | 4.3 |
| 2018 | – | 4.2 | 4.4 | 4.9 | 4.4 |
| 2019 | – | 4.2 | 4.4 | 5.0 | 4.4 |
| 2020 | – | 4.2 | 4.5 | 5.1 | 4.5 |
| 2021 | – | 4.1 | 4.5 | 5.1 | 4.5 |
| 2022 | – | 4.1 | 4.5 | 5.2 | 4.5 |
| 2023 | – | 4.0 | 4.6 | 5.3 | 4.6 |
| 2024 | – | 4.0 | 4.6 | 5.4 | 4.5 |
| 2025 | – | 4.0 | 4.6 | 5.5 | 4.5 |
| 2026 | – | 4.0 | 4.7 | 5.6 | 4.6 |
| 2027 | – | 4.0 | 4.7 | 5.7 | 4.6 |
| 2028 | – | 3.9 | 4.7 | 5.6 | 4.7 |
| 2029 | – | 3.9 | 4.7 | 5.7 | 4.7 |
| 2030 | – | 3.8 | 4.7 | 5.8 | 4.7 |
| 2031 | – | 3.8 | 4.8 | 5.9 | 4.8 |
| 2032 | – | 3.8 | 4.8 | 6.0 | 4.8 |
| 2033 | – | 3.8 | 4.8 | 6.1 | 4.8 |

Net peaks are estimated based on historical gross peaks; 2007–2011 average gross-to-net ratio is based on energy.

## *Molokai Peak Forecast Data*

Table E-60: Molokai Peak Forecast Data (MW)
*Includes Underlying Economic, Renewable Self Generation, Non-PBFA EEPS Contribution, PBFA DSM Programs, and Electric Vehicle Forecasts*

| Year | Historical | Blazing a Bold Frontier | Stuck in the Middle | No Burning Desire | Moved by Passion |
|---|---|---|---|---|---|
| 1992 | 5.8 | – | – | – | – |
| 1993 | 5.9 | – | – | – | – |
| 1994 | 6.1 | – | – | – | – |
| 1995 | 6.8 | – | – | – | – |
| 1996 | 6.5 | – | – | – | – |
| 1997 | 6.4 | – | – | – | – |
| 1998 | 6.4 | – | – | – | – |
| 1999 | 6.7 | – | – | – | – |
| 2000 | 6.3 | – | – | – | – |
| 2001 | 6.2 | – | – | – | – |
| 2002 | 6.4 | – | – | – | – |
| 2003 | 6.4 | – | – | – | – |
| 2004 | 6.6 | – | – | – | – |
| 2005 | 6.1 | – | – | – | – |
| 2006 | 6.1 | – | – | – | – |
| 2007 | 6.1 | – | – | – | – |
| 2008 | 5.8 | – | – | – | – |
| 2009 | 5.8 | – | – | – | – |
| 2010 | 5.5 | – | – | – | – |
| 2011 | 5.6 | – | – | – | – |
| 2012 | 5.4 | 5.1 | 5.3 | 5.4 | 5.3 |
| 2013 | – | 5.0 | 5.3 | 5.4 | 5.3 |
| 2014 | – | 4.9 | 5.2 | 5.3 | 5.2 |
| 2015 | – | 4.8 | 5.2 | 5.3 | 5.1 |
| 2016 | – | 4.6 | 5.1 | 5.2 | 5.0 |
| 2017 | – | 4.5 | 5.1 | 5.2 | 5.0 |
| 2018 | – | 4.3 | 5.0 | 5.2 | 4.9 |
| 2019 | – | 4.3 | 5.0 | 5.2 | 4.8 |
| 2020 | – | 4.1 | 4.9 | 5.2 | 4.7 |
| 2021 | – | 4.0 | 4.8 | 5.1 | 4.7 |
| 2022 | – | 3.8 | 4.8 | 5.2 | 4.6 |
| 2023 | – | 3.7 | 4.8 | 5.1 | 4.6 |
| 2024 | – | 3.5 | 4.8 | 5.2 | 4.5 |
| 2025 | – | 3.5 | 4.7 | 5.1 | 4.5 |
| 2026 | – | 3.3 | 4.7 | 5.2 | 4.4 |
| 2027 | – | 3.2 | 4.6 | 5.1 | 4.3 |
| 2028 | – | 3.1 | 4.6 | 5.2 | 4.2 |
| 2029 | – | 3.0 | 4.5 | 5.1 | 4.2 |
| 2030 | – | 2.9 | 4.4 | 5.0 | 4.1 |
| 2031 | – | 2.8 | 4.4 | 5.1 | 4.0 |
| 2032 | – | 2.6 | 4.3 | 5.0 | 4.0 |
| 2033 | – | 2.5 | 4.3 | 5.1 | 3.9 |

Net peaks are estimated based on historical gross peaks; 2007–2011 average gross-to-net ratio is based on energy.

Table E-61: Molokai No PBFA DSM Peak Forecast Data (MW)

*Includes Underlying Economic, Renewable Self Generation, Non-PBFA EEPS Contribution, and Electric Vehicle Forecasts*

| Year | Historical | Blazing a Bold Frontier | Stuck in the Middle | No Burning Desire | Moved by Passion |
|---|---|---|---|---|---|
| 1992 | 5.8 | – | – | – | – |
| 1993 | 5.9 | – | – | – | – |
| 1994 | 6.1 | – | – | – | – |
| 1995 | 6.8 | – | – | – | – |
| 1996 | 6.5 | – | – | – | – |
| 1997 | 6.4 | – | – | – | – |
| 1998 | 6.4 | – | – | – | – |
| 1999 | 6.7 | – | – | – | – |
| 2000 | 6.3 | – | – | – | – |
| 2001 | 6.2 | – | – | – | – |
| 2002 | 6.4 | – | – | – | – |
| 2003 | 6.4 | – | – | – | – |
| 2004 | 6.6 | – | – | – | – |
| 2005 | 6.1 | – | – | – | – |
| 2006 | 6.1 | – | – | – | – |
| 2007 | 6.1 | – | – | – | – |
| 2008 | 5.8 | – | – | – | – |
| 2009 | 5.8 | – | – | – | – |
| 2010 | 5.5 | – | – | – | – |
| 2011 | 5.6 | – | – | – | – |
| 2012 | 5.4 | 5.2 | 5.4 | 5.5 | 5.4 |
| 2013 | – | 5.2 | 5.4 | 5.5 | 5.4 |
| 2014 | – | 5.1 | 5.4 | 5.5 | 5.4 |
| 2015 | – | 5.0 | 5.4 | 5.5 | 5.3 |
| 2016 | – | 4.9 | 5.3 | 5.4 | 5.3 |
| 2017 | – | 4.9 | 5.3 | 5.4 | 5.3 |
| 2018 | – | 4.8 | 5.3 | 5.5 | 5.3 |
| 2019 | – | 4.8 | 5.3 | 5.5 | 5.3 |
| 2020 | – | 4.7 | 5.3 | 5.6 | 5.3 |
| 2021 | – | 4.6 | 5.3 | 5.6 | 5.3 |
| 2022 | – | 4.5 | 5.3 | 5.7 | 5.2 |
| 2023 | – | 4.5 | 5.4 | 5.7 | 5.3 |
| 2024 | – | 4.4 | 5.4 | 5.8 | 5.3 |
| 2025 | – | 4.4 | 5.3 | 5.7 | 5.3 |
| 2026 | – | 4.3 | 5.3 | 5.8 | 5.3 |
| 2027 | – | 4.2 | 5.3 | 5.8 | 5.3 |
| 2028 | – | 4.2 | 5.3 | 5.9 | 5.2 |
| 2029 | – | 4.2 | 5.3 | 5.9 | 5.2 |
| 2030 | – | 4.1 | 5.3 | 5.9 | 5.2 |
| 2031 | – | 4.1 | 5.3 | 6.0 | 5.2 |
| 2032 | – | 4.0 | 5.3 | 6.0 | 5.2 |
| 2033 | – | 4.0 | 5.3 | 6.1 | 5.2 |

Net peaks are estimated based on historical gross peaks; 2007–2011 average gross-to-net ratio is based on energy.

# Appendix E-5: Underlying Economic Forecast Data

## *Hawaiian Electric Underlying Economic Forecast Data*

Table E-62: HECO Underlying Economic Forecast Data (GWh)

| Year | Historical | Blazing a Bold Frontier | Stuck in the Middle | No Burning Desire | Moved by Passion |
|---|---|---|---|---|---|
| 1992 | 6,650 | – | – | – | – |
| 1993 | 6,607 | – | – | – | – |
| 1994 | 6,797 | – | – | – | – |
| 1995 | 6,963 | – | – | – | – |
| 1996 | 7,091 | – | – | – | – |
| 1997 | 7,040 | – | – | – | – |
| 1998 | 6,938 | – | – | – | – |
| 1999 | 6,998 | – | – | – | – |
| 2000 | 7,212 | – | – | – | – |
| 2001 | 7,277 | – | – | – | – |
| 2002 | 7,390 | – | – | – | – |
| 2003 | 7,522 | – | – | – | – |
| 2004 | 7,733 | – | – | – | – |
| 2005 | 7,721 | – | – | – | – |
| 2006 | 7,701 | – | – | – | – |
| 2007 | 7,675 | – | – | – | – |
| 2008 | 7,556 | – | – | – | – |
| 2009 | 7,378 | – | – | – | – |
| 2010 | 7,277 | – | – | – | – |
| 2011 | 7,242 | – | – | – | – |
| 2012 | 6,976 | 7,107 | 7,206 | 7,357 | 7,206 |
| 2013 | – | 7,115 | 7,349 | 7,653 | 7,349 |
| 2014 | – | 7,132 | 7,500 | 7,961 | 7,500 |
| 2015 | – | 7,157 | 7,669 | 8,312 | 7,669 |
| 2016 | – | 7,239 | 7,906 | 8,741 | 7,906 |
| 2017 | – | 7,224 | 8,029 | 9,035 | 8,029 |
| 2018 | – | 7,166 | 8,131 | 9,311 | 8,131 |
| 2019 | – | 7,187 | 8,285 | 9,634 | 8,285 |
| 2020 | – | 7,223 | 8,434 | 9,940 | 8,434 |
| 2021 | – | 7,253 | 8,538 | 10,173 | 8,538 |
| 2022 | – | 7,303 | 8,660 | 10,410 | 8,660 |
| 2023 | – | 7,355 | 8,778 | 10,629 | 8,778 |
| 2024 | – | 7,410 | 8,892 | 10,825 | 8,892 |
| 2025 | – | 7,466 | 9,007 | 11,025 | 9,007 |
| 2026 | – | 7,507 | 9,099 | 11,199 | 9,099 |
| 2027 | – | 7,547 | 9,192 | 11,375 | 9,192 |
| 2028 | – | 7,587 | 9,287 | 11,554 | 9,287 |
| 2029 | – | 7,628 | 9,382 | 11,736 | 9,382 |
| 2030 | – | 7,669 | 9,478 | 11,921 | 9,478 |
| 2031 | – | 7,709 | 9,577 | 12,130 | 9,577 |
| 2032 | – | 7,749 | 9,677 | 12,343 | 9,677 |
| 2033 | – | 7,789 | 9,777 | 12,559 | 9,777 |

## *HELCO Underlying Economic Forecast Data*

Table E-63: HELCO Underlying Economic Forecast Data (GWh)

| Year | Historical | Blazing a Bold Frontier | Stuck in the Middle | No Burning Desire | Moved by Passion |
|---|---|---|---|---|---|
| 1992 | 791 | – | – | – | – |
| 1993 | 802 | – | – | – | – |
| 1994 | 836 | – | – | – | – |
| 1995 | 847 | – | – | – | – |
| 1996 | 876 | – | – | – | – |
| 1997 | 894 | – | – | – | – |
| 1998 | 903 | – | – | – | – |
| 1999 | 922 | – | – | – | – |
| 2000 | 954 | – | – | – | – |
| 2001 | 960 | – | – | – | – |
| 2002 | 995 | – | – | – | – |
| 2003 | 1,046 | – | – | – | – |
| 2004 | 1,083 | – | – | – | – |
| 2005 | 1,116 | – | – | – | – |
| 2006 | 1,149 | – | – | – | – |
| 2007 | 1,163 | – | – | – | – |
| 2008 | 1,141 | – | – | – | – |
| 2009 | 1,120 | – | – | – | – |
| 2010 | 1,110 | – | – | – | – |
| 2011 | 1,104 | – | – | – | – |
| 2012 | 1,085 | 1,068 | 1,117 | 1,192 | 1,117 |
| 2013 | – | 1,066 | 1,142 | 1,247 | 1,142 |
| 2014 | – | 1,064 | 1,171 | 1,306 | 1,171 |
| 2015 | – | 1,068 | 1,197 | 1,339 | 1,197 |
| 2016 | – | 1,076 | 1,229 | 1,377 | 1,229 |
| 2017 | – | 1,087 | 1,261 | 1,408 | 1,261 |
| 2018 | – | 1,100 | 1,295 | 1,457 | 1,295 |
| 2019 | – | 1,113 | 1,328 | 1,503 | 1,328 |
| 2020 | – | 1,125 | 1,357 | 1,548 | 1,357 |
| 2021 | – | 1,138 | 1,386 | 1,594 | 1,386 |
| 2022 | – | 1,151 | 1,414 | 1,640 | 1,414 |
| 2023 | – | 1,164 | 1,441 | 1,687 | 1,441 |
| 2024 | – | 1,186 | 1,469 | 1,736 | 1,469 |
| 2025 | – | 1,197 | 1,494 | 1,785 | 1,494 |
| 2026 | – | 1,213 | 1,525 | 1,834 | 1,525 |
| 2027 | – | 1,224 | 1,552 | 1,883 | 1,552 |
| 2028 | – | 1,236 | 1,581 | 1,932 | 1,581 |
| 2029 | – | 1,247 | 1,609 | 1,981 | 1,609 |
| 2030 | – | 1,259 | 1,639 | 2,028 | 1,639 |
| 2031 | – | 1,271 | 1,668 | 2,075 | 1,668 |
| 2032 | – | 1,284 | 1,697 | 2,124 | 1,697 |
| 2033 | – | 1,296 | 1,728 | 2,175 | 1,728 |

## *Maui Underlying Economic Forecast Data*

Table E-64: Maui Underlying Economic Forecast Data (GWh)

| Year | Historical | Blazing a Bold Frontier | Stuck in the Middle | No Burning Desire | Moved by Passion |
|---|---|---|---|---|---|
| 1992 | 838 | – | – | – | – |
| 1993 | 861 | – | – | – | – |
| 1994 | 901 | – | – | – | – |
| 1995 | 937 | – | – | – | – |
| 1996 | 964 | – | – | – | – |
| 1997 | 973 | – | – | – | – |
| 1998 | 975 | – | – | – | – |
| 1999 | 1,013 | – | – | – | – |
| 2000 | 1,057 | – | – | – | – |
| 2001 | 1,093 | – | – | – | – |
| 2002 | 1,126 | – | – | – | – |
| 2003 | 1,177 | – | – | – | – |
| 2004 | 1,226 | – | – | – | – |
| 2005 | 1,235 | – | – | – | – |
| 2006 | 1,253 | – | – | – | – |
| 2007 | 1,269 | – | – | – | – |
| 2008 | 1,240 | – | – | – | – |
| 2009 | 1,208 | – | – | – | – |
| 2010 | 1,218 | – | – | – | – |
| 2011 | 1,222 | – | – | – | – |
| 2012 | 1,090 | 1,208 | 1,234 | 1,258 | 1,234 |
| 2013 | – | 1,206 | 1,254 | 1,307 | 1,254 |
| 2014 | – | 1,207 | 1,278 | 1,363 | 1,278 |
| 2015 | – | 1,203 | 1,292 | 1,422 | 1,292 |
| 2016 | – | 1,203 | 1,310 | 1,487 | 1,310 |
| 2017 | – | 1,201 | 1,326 | 1,549 | 1,326 |
| 2018 | – | 1,202 | 1,349 | 1,616 | 1,349 |
| 2019 | – | 1,201 | 1,368 | 1,677 | 1,368 |
| 2020 | – | 1,204 | 1,388 | 1,740 | 1,388 |
| 2021 | – | 1,201 | 1,403 | 1,794 | 1,403 |
| 2022 | – | 1,202 | 1,419 | 1,848 | 1,419 |
| 2023 | – | 1,204 | 1,435 | 1,901 | 1,435 |
| 2024 | – | 1,210 | 1,456 | 1,957 | 1,456 |
| 2025 | – | 1,210 | 1,468 | 2,000 | 1,468 |
| 2026 | – | 1,216 | 1,484 | 2,048 | 1,484 |
| 2027 | – | 1,221 | 1,502 | 2,094 | 1,502 |
| 2028 | – | 1,229 | 1,521 | 2,142 | 1,521 |
| 2029 | – | 1,231 | 1,533 | 2,181 | 1,533 |
| 2030 | – | 1,236 | 1,550 | 2,226 | 1,550 |
| 2031 | – | 1,241 | 1,565 | 2,273 | 1,565 |
| 2032 | – | 1,249 | 1,587 | 2,329 | 1,587 |
| 2033 | – | 1,250 | 1,602 | 2,374 | 1,602 |

## *Lanai Underlying Economic Forecast Data*

Table E-65: Lanai Underlying Economic Forecast Data (MWh)

| Year | Historical | Blazing a Bold Frontier | Stuck in the Middle | No Burning Desire | Moved by Passion |
|---|---|---|---|---|---|
| 1992 | 23,327 | – | – | – | – |
| 1993 | 23,879 | – | – | – | – |
| 1994 | 25,818 | – | – | – | – |
| 1995 | 26,053 | – | – | – | – |
| 1996 | 26,365 | – | – | – | – |
| 1997 | 26,094 | – | – | – | – |
| 1998 | 26,177 | – | – | – | – |
| 1999 | 26,790 | – | – | – | – |
| 2000 | 27,334 | – | – | – | – |
| 2001 | 27,141 | – | – | – | – |
| 2002 | 27,290 | – | – | – | – |
| 2003 | 28,426 | – | – | – | – |
| 2004 | 28,162 | – | – | – | – |
| 2005 | 28,345 | – | – | – | – |
| 2006 | 29,052 | – | – | – | – |
| 2007 | 31,102 | – | – | – | – |
| 2008 | 29,516 | – | – | – | – |
| 2009 | 26,492 | – | – | – | – |
| 2010 | 25,394 | – | – | – | – |
| 2011 | 25,260 | – | – | – | – |
| 2012 | 24,712 | 25,032 | 25,194 | 26,087 | 25,194 |
| 2013 | – | 24,880 | 25,247 | 26,482 | 25,247 |
| 2014 | – | 24,794 | 25,347 | 26,947 | 25,347 |
| 2015 | – | 24,708 | 25,525 | 27,412 | 25,525 |
| 2016 | – | 24,689 | 25,737 | 27,952 | 25,737 |
| 2017 | – | 24,537 | 25,834 | 28,342 | 25,834 |
| 2018 | – | 24,452 | 26,012 | 28,807 | 26,012 |
| 2019 | – | 24,366 | 26,205 | 29,272 | 26,205 |
| 2020 | – | 24,346 | 26,479 | 29,817 | 26,479 |
| 2021 | – | 24,195 | 26,612 | 30,202 | 26,612 |
| 2022 | – | 24,109 | 26,817 | 30,667 | 26,817 |
| 2023 | – | 24,024 | 27,026 | 31,132 | 27,026 |
| 2024 | – | 24,002 | 27,297 | 31,682 | 27,297 |
| 2025 | – | 23,852 | 27,429 | 32,062 | 27,429 |
| 2026 | – | 23,767 | 27,637 | 32,527 | 27,637 |
| 2027 | – | 23,681 | 27,839 | 32,992 | 27,839 |
| 2028 | – | 23,659 | 28,117 | 33,547 | 28,117 |
| 2029 | – | 23,510 | 28,247 | 33,922 | 28,247 |
| 2030 | – | 23,425 | 28,448 | 34,387 | 28,448 |
| 2031 | – | 23,339 | 28,650 | 34,852 | 28,650 |
| 2032 | – | 23,316 | 28,932 | 35,412 | 28,932 |
| 2033 | – | 23,168 | 29,055 | 35,782 | 29,055 |

## *Molokai Underlying Economic Forecast Data*

Table E-66: Molokai Underlying Economic Forecast Data (MWh)

| Year | Historical | Blazing a Bold Frontier | Stuck in the Middle | No Burning Desire | Moved by Passion |
|---|---|---|---|---|---|
| 1992 | 29,841 | – | – | – | – |
| 1993 | 30,849 | – | – | – | – |
| 1994 | 33,064 | – | – | – | – |
| 1995 | 33,920 | – | – | – | – |
| 1996 | 34,342 | – | – | – | – |
| 1997 | 33,650 | – | – | – | – |
| 1998 | 34,922 | – | – | – | – |
| 1999 | 35,894 | – | – | – | – |
| 2000 | 36,814 | – | – | – | – |
| 2001 | 36,239 | – | – | – | – |
| 2002 | 35,577 | – | – | – | – |
| 2003 | 36,615 | – | – | – | – |
| 2004 | 36,140 | – | – | – | – |
| 2005 | 36,844 | – | – | – | – |
| 2006 | 36,311 | – | – | – | – |
| 2007 | 36,907 | – | – | – | – |
| 2008 | 34,909 | – | – | – | – |
| 2009 | 33,373 | – | – | – | – |
| 2010 | 33,202 | – | – | – | – |
| 2011 | 33,000 | – | – | – | – |
| 2012 | 29,942 | 32,491 | 33,115 | 33,699 | 33,115 |
| 2013 | – | 32,127 | 33,086 | 33,565 | 33,086 |
| 2014 | – | 31,844 | 33,138 | 33,600 | 33,138 |
| 2015 | – | 31,562 | 33,189 | 33,717 | 33,189 |
| 2016 | – | 31,358 | 33,325 | 33,988 | 33,325 |
| 2017 | – | 30,998 | 33,273 | 34,102 | 33,273 |
| 2018 | – | 30,715 | 33,372 | 34,361 | 33,372 |
| 2019 | – | 30,433 | 33,412 | 34,640 | 33,412 |
| 2020 | – | 30,226 | 33,552 | 34,978 | 33,552 |
| 2021 | – | 29,869 | 33,540 | 35,167 | 33,540 |
| 2022 | – | 29,586 | 33,544 | 35,456 | 33,544 |
| 2023 | – | 29,304 | 33,570 | 35,695 | 33,570 |
| 2024 | – | 29,094 | 33,691 | 36,032 | 33,691 |
| 2025 | – | 28,739 | 33,602 | 36,197 | 33,602 |
| 2026 | – | 28,457 | 33,616 | 36,408 | 33,616 |
| 2027 | – | 28,175 | 33,661 | 36,629 | 33,661 |
| 2028 | – | 27,962 | 33,739 | 36,964 | 33,739 |
| 2029 | – | 27,610 | 33,682 | 37,073 | 33,682 |
| 2030 | – | 27,328 | 33,726 | 37,301 | 33,726 |
| 2031 | – | 27,046 | 33,722 | 37,546 | 33,722 |
| 2032 | – | 26,830 | 33,829 | 37,842 | 33,829 |
| 2033 | – | 26,481 | 33,784 | 37,965 | 33,784 |

# Appendix E-6: Renewable Self-Generation Forecast Data

## *HELCO Renewable Self-Generation Peak Forecast Data*

Table E-67: HELCO Renewable Self-Generation Peak Forecast Data (MWh)

| Year | Blazing a Bold Frontier | Stuck in the Middle | No Burning Desire | Moved by Passion |
|---|---|---|---|---|
| 2012 | – | – | – | – |
| 2013 | – | – | – | – |
| 2014 | – | – | – | – |
| 2015 | (0.1) | (0.1) | (0.0) | (0.1) |
| 2016 | (0.1) | (0.1) | (0.0) | (0.1) |
| 2017 | (0.1) | (0.1) | (0.0) | (0.1) |
| 2018 | (0.1) | (0.1) | (0.0) | (0.1) |
| 2019 | (0.1) | (0.1) | (0.0) | (0.1) |
| 2020 | (0.1) | (0.1) | (0.0) | (0.1) |
| 2021 | (0.1) | (0.1) | (0.0) | (0.1) |
| 2022 | (0.1) | (0.1) | (0.0) | (0.1) |
| 2023 | (0.1) | (0.1) | (0.0) | (0.1) |
| 2024 | (0.1) | (0.1) | (0.0) | (0.1) |
| 2025 | (0.1) | (0.1) | (0.0) | (0.1) |
| 2026 | (0.2) | (0.1) | (0.1) | (0.2) |
| 2027 | (0.2) | (0.1) | (0.1) | (0.2) |
| 2028 | (0.2) | (0.1) | (0.1) | (0.2) |
| 2029 | (0.2) | (0.1) | (0.1) | (0.2) |
| 2030 | (0.2) | (0.1) | (0.1) | (0.2) |
| 2031 | (0.2) | (0.1) | (0.1) | (0.2) |
| 2032 | (0.2) | (0.1) | (0.1) | (0.2) |
| 2033 | (0.2) | (0.1) | (0.1) | (0.2) |

## *Hawaiian Electric Renewable Self-Generation Forecast Data*

Table E-68: HECO Renewable Self-Generation Forecast Data (GWh)

| Year | Blazing a Bold Frontier | Stuck in the Middle | No Burning Desire | Moved by Passion |
|---|---|---|---|---|
| 2012 | (30) | (16) | (9) | (27) |
| 2013 | (109) | (60) | (35) | (99) |
| 2014 | (204) | (111) | (65) | (185) |
| 2015 | (302) | (165) | (96) | (274) |
| 2016 | (419) | (229) | (133) | (381) |
| 2017 | (516) | (282) | (164) | (469) |
| 2018 | (613) | (335) | (195) | (558) |
| 2019 | (710) | (387) | (226) | (645) |
| 2020 | (806) | (440) | (257) | (733) |
| 2021 | (903) | (492) | (287) | (821) |
| 2022 | (992) | (541) | (316) | (902) |
| 2023 | (1,069) | (583) | (340) | (972) |
| 2024 | (1,136) | (620) | (361) | (1,033) |
| 2025 | (1,194) | (651) | (380) | (1,085) |
| 2026 | (1,244) | (678) | (396) | (1,131) |
| 2027 | (1,288) | (702) | (410) | (1,171) |
| 2028 | (1,328) | (724) | (423) | (1,207) |
| 2029 | (1,365) | (745) | (434) | (1,241) |
| 2030 | (1,401) | (764) | (446) | (1,273) |
| 2031 | (1,435) | (783) | (456) | (1,304) |
| 2032 | (1,468) | (801) | (467) | (1,334) |
| 2033 | (1,499) | (818) | (477) | (1,363) |

## *HELCO Renewable Self-Generation Forecast Data*

Table E-69: HELCO Renewable Self-Generation Forecast Data (GWh)

| Year | Blazing a Bold Frontier | Stuck in the Middle | No Burning Desire | Moved by Passion |
|---|---|---|---|---|
| 2012 | (4) | (2) | (1) | (4) |
| 2013 | (14) | (8) | (5) | (14) |
| 2014 | (21) | (12) | (7) | (21) |
| 2015 | (26) | (14) | (8) | (26) |
| 2016 | (32) | (18) | (10) | (32) |
| 2017 | (38) | (21) | (12) | (38) |
| 2018 | (42) | (23) | (13) | (42) |
| 2019 | (47) | (26) | (15) | (47) |
| 2020 | (52) | (28) | (17) | (52) |
| 2021 | (56) | (31) | (18) | (56) |
| 2022 | (60) | (33) | (19) | (60) |
| 2023 | (64) | (35) | (21) | (64) |
| 2024 | (69) | (38) | (22) | (69) |
| 2025 | (73) | (40) | (23) | (73) |
| 2026 | (78) | (42) | (25) | (78) |
| 2027 | (82) | (45) | (26) | (82) |
| 2028 | (87) | (48) | (28) | (87) |
| 2029 | (91) | (50) | (29) | (91) |
| 2030 | (96) | (52) | (31) | (96) |
| 2031 | (100) | (55) | (32) | (100) |
| 2032 | (105) | (57) | (33) | (105) |
| 2033 | (109) | (60) | (35) | (109) |

## *Maui Renewable Self-Generation Forecast Data*

Table E-70: Maui Renewable Self-Generation Forecast Data (GWh)

| Year | Blazing a Bold Frontier | Stuck in the Middle | No Burning Desire | Moved by Passion |
|---|---|---|---|---|
| 2012 | (10) | (5) | (3) | (9) |
| 2013 | (35) | (19) | (11) | (31) |
| 2014 | (60) | (33) | (19) | (54) |
| 2015 | (83) | (46) | (27) | (76) |
| 2016 | (109) | (59) | (35) | (99) |
| 2017 | (133) | (73) | (42) | (121) |
| 2018 | (154) | (84) | (49) | (140) |
| 2019 | (169) | (92) | (54) | (153) |
| 2020 | (180) | (98) | (57) | (164) |
| 2021 | (188) | (102) | (60) | (171) |
| 2022 | (194) | (106) | (62) | (176) |
| 2023 | (199) | (109) | (63) | (181) |
| 2024 | (203) | (111) | (65) | (185) |
| 2025 | (206) | (112) | (66) | (187) |
| 2026 | (209) | (114) | (66) | (190) |
| 2027 | (211) | (115) | (67) | (192) |
| 2028 | (214) | (117) | (68) | (194) |
| 2029 | (215) | (117) | (69) | (196) |
| 2030 | (217) | (118) | (69) | (197) |
| 2031 | (219) | (119) | (70) | (199) |
| 2032 | (221) | (121) | (70) | (201) |
| 2033 | (223) | (121) | (71) | (202) |

## *Lanai Renewable Self-Generation Forecast Data*

Table E-71: Lanai Renewable Self-Generation Forecast Data (MWh)

| Year | Blazing a Bold Frontier | Stuck in the Middle | No Burning Desire | Moved by Passion |
|---|---|---|---|---|
| 2012 | (39) | (21) | (12) | (35) |
| 2013 | (86) | (47) | (27) | (78) |
| 2014 | (119) | (65) | (38) | (108) |
| 2015 | (152) | (83) | (48) | (138) |
| 2016 | (185) | (101) | (59) | (169) |
| 2017 | (218) | (119) | (69) | (198) |
| 2018 | (251) | (137) | (80) | (228) |
| 2019 | (284) | (155) | (90) | (258) |
| 2020 | (318) | (173) | (101) | (289) |
| 2021 | (350) | (191) | (111) | (318) |
| 2022 | (383) | (209) | (122) | (349) |
| 2023 | (416) | (227) | (133) | (379) |
| 2024 | (451) | (246) | (143) | (410) |
| 2025 | (483) | (263) | (154) | (439) |
| 2026 | (516) | (281) | (164) | (469) |
| 2027 | (549) | (299) | (175) | (499) |
| 2028 | (583) | (318) | (186) | (530) |
| 2029 | (615) | (335) | (196) | (559) |
| 2030 | (648) | (353) | (206) | (589) |
| 2031 | (681) | (372) | (217) | (619) |
| 2032 | (716) | (391) | (228) | (651) |
| 2033 | (747) | (408) | (238) | (679) |

## *Molokai Renewable Self-Generation Forecast Data*

Table E-72: Molokai Renewable Self-Generation Forecast Data (MWh)

| Year | Blazing a Bold Frontier | Stuck in the Middle | No Burning Desire | Moved by Passion |
|---|---|---|---|---|
| 2012 | (116) | (63) | (37) | (105) |
| 2013 | (434) | (237) | (138) | (395) |
| 2014 | (744) | (406) | (237) | (677) |
| 2015 | (1,054) | (575) | (335) | (958) |
| 2016 | (1,368) | (746) | (435) | (1,244) |
| 2017 | (1,674) | (913) | (533) | (1,522) |
| 2018 | (1,983) | (1,082) | (631) | (1,803) |
| 2019 | (2,280) | (1,243) | (725) | (2,072) |
| 2020 | (2,541) | (1,386) | (808) | (2,310) |
| 2021 | (2,719) | (1,483) | (865) | (2,472) |
| 2022 | (2,857) | (1,558) | (909) | (2,597) |
| 2023 | (2,961) | (1,615) | (942) | (2,691) |
| 2024 | (3,049) | (1,663) | (970) | (2,772) |
| 2025 | (3,104) | (1,693) | (988) | (2,822) |
| 2026 | (3,156) | (1,722) | (1,004) | (2,869) |
| 2027 | (3,200) | (1,746) | (1,018) | (2,909) |
| 2028 | (3,247) | (1,771) | (1,033) | (2,952) |
| 2029 | (3,273) | (1,785) | (1,041) | (2,975) |
| 2030 | (3,304) | (1,802) | (1,051) | (3,004) |
| 2031 | (3,334) | (1,819) | (1,061) | (3,031) |
| 2032 | (3,371) | (1,839) | (1,073) | (3,065) |
| 2033 | (3,390) | (1,849) | (1,078) | (3,081) |

# Appendix E-7: Energy Efficiency (EEPS) Forecast Data

## *The EM&V Contractor and PBFA EEPS Forecast*

*The Evaluation Measurement & Verification Contractor (EM&V Contractor) and the Public Benefits Fee Administrator (PBFA) EEPS Forecast*

Table E-73: EM&V and PBFA Base Level EEPS Forecast Data (GWh)

| Year | Non-PBFA EEPS Contributions [GWh] | PBFA DSM Programs Energy Savings [GWh] | Total EEPS Energy Savings [GWh] | PBFA DSM Programs | | |
|---|---|---|---|---|---|---|
| | | | | Program Costs (excluding incentives or rebates) [$ million] | "Incentives and Rebates" [$ million] | "Customer Costs" [$ million] |
| 2012 | (15.3) | (71.5) | (86.8) | 8.61 | 15.29 | 99.74 |
| 2013 | (45.9) | (187.6) | (233.5) | 8.61 | 15.29 | 99.74 |
| 2014 | (76.5) | (303.7) | (380.2) | 11.48 | 20.38 | 132.95 |
| 2015 | (107.1) | (419.8) | (526.9) | 11.48 | 20.38 | 132.95 |
| 2016 | (137.6) | (535.9) | (673.5) | 11.48 | 20.38 | 132.95 |
| 2017 | (168.2) | (652.0) | (820.2) | 11.48 | 20.38 | 132.95 |
| 2018 | (198.8) | (768.1) | (966.9) | 11.48 | 20.38 | 132.95 |
| 2019 | (229.4) | (884.2) | (1,113.6) | 11.48 | 20.38 | 132.95 |
| 2020 | (260.0) | (1,000.3) | (1,260.3) | 14.35 | 25.47 | 166.19 |
| 2021 | (290.6) | (1,116.4) | (1,407.0) | 14.35 | 33.96 | 221.58 |
| 2022 | (321.2) | (1,232.5) | (1,553.7) | 14.35 | 33.96 | 221.58 |
| 2023 | (351.7) | (1,348.6) | (1,700.4) | 14.35 | 33.96 | 221.58 |
| 2024 | (382.3) | (1,464.7) | (1,847.1) | 14.35 | 33.96 | 221.58 |
| 2025 | (412.9) | (1,580.8) | (1,993.8) | 14.35 | 33.96 | 221.58 |
| 2026 | (443.5) | (1,696.9) | (2,140.4) | 17.22 | 40.75 | 265.90 |
| 2027 | (474.1) | (1,813.0) | (2,287.1) | 17.22 | 40.75 | 265.90 |
| 2028 | (504.7) | (1,929.1) | (2,433.8) | 17.22 | 40.75 | 265.90 |
| 2029 | (535.3) | (2,045.2) | (2,580.5) | 17.22 | 40.75 | 265.90 |
| 2030 | (565.9) | (2,161.3) | (2,727.2) | 17.22 | 40.75 | 265.90 |
| 2031 | (589.0) | (2,277.4) | (2,866.4) | 17.22 | 40.75 | 265.90 |
| 2032 | (604.6) | (2,393.6) | (2,998.2) | 17.22 | 40.75 | 265.90 |
| 2033 | (620.3) | (2,509.7) | (3,129.9) | 17.22 | 40.75 | 265.90 |

## *Hawaiian Electric Energy Efficiency Forecast Data*

Table E-74: HECO Energy Efficiency Forecast Data (GWh)

| Year | Blazing a Bold Frontier | Stuck in the Middle | No Burning Desire | Moved by Passion |
|---|---|---|---|---|
| 2012 | (61) | (42) | (42) | (56) |
| 2013 | (184) | (125) | (125) | (167) |
| 2014 | (307) | (209) | (209) | (279) |
| 2015 | (429) | (293) | (293) | (390) |
| 2016 | (552) | (376) | (376) | (502) |
| 2017 | (675) | (460) | (460) | (614) |
| 2018 | (798) | (544) | (544) | (725) |
| 2019 | (920) | (627) | (627) | (837) |
| 2020 | (1,043) | (711) | (711) | (948) |
| 2021 | (1,166) | (795) | (795) | (1,060) |
| 2022 | (1,288) | (878) | (878) | (1,171) |
| 2023 | (1,411) | (962) | (962) | (1,283) |
| 2024 | (1,534) | (1,046) | (1,046) | (1,394) |
| 2025 | (1,656) | (1,129) | (1,129) | (1,506) |
| 2026 | (1,779) | (1,213) | (1,213) | (1,617) |
| 2027 | (1,902) | (1,297) | (1,297) | (1,729) |
| 2028 | (2,025) | (1,380) | (1,380) | (1,841) |
| 2029 | (2,147) | (1,464) | (1,464) | (1,952) |
| 2030 | (2,270) | (1,548) | (1,548) | (2,064) |
| 2031 | (2,386) | (1,627) | (1,627) | (2,170) |
| 2032 | (2,497) | (1,702) | (1,702) | (2,270) |
| 2033 | (2,607) | (1,777) | (1,777) | (2,370) |

## *HELCO Energy Efficiency Forecast Data*

Table E-75: HELCO Energy Efficiency Forecast Data (GWh)

| Year | Blazing a Bold Frontier | Stuck in the Middle | No Burning Desire | Moved by Passion |
|---|---|---|---|---|
| 2012 | (24) | (16) | (16) | (22) |
| 2013 | (43) | (29) | (29) | (39) |
| 2014 | (61) | (42) | (42) | (56) |
| 2015 | (80) | (55) | (55) | (73) |
| 2016 | (99) | (67) | (67) | (90) |
| 2017 | (118) | (80) | (80) | (107) |
| 2018 | (136) | (93) | (93) | (124) |
| 2019 | (155) | (106) | (106) | (141) |
| 2020 | (174) | (118) | (118) | (158) |
| 2021 | (192) | (131) | (131) | (175) |
| 2022 | (211) | (144) | (144) | (192) |
| 2023 | (230) | (157) | (157) | (209) |
| 2024 | (248) | (169) | (169) | (226) |
| 2025 | (267) | (182) | (182) | (243) |
| 2026 | (286) | (195) | (195) | (260) |
| 2027 | (304) | (207) | (207) | (277) |
| 2028 | (323) | (220) | (220) | (294) |
| 2029 | (342) | (233) | (233) | (311) |
| 2030 | (360) | (246) | (246) | (328) |
| 2031 | (378) | (258) | (258) | (344) |
| 2032 | (395) | (269) | (269) | (359) |
| 2033 | (412) | (281) | (281) | (374) |

## *Maui Energy Efficiency Forecast Data*

Table E-76: Maui Energy Efficiency Forecast Data (GWh)

| Year | Blazing a Bold Frontier | Stuck in the Middle | No Burning Desire | Moved by Passion |
|---|---|---|---|---|
| 2012 | (10) | (7) | (7) | (9) |
| 2013 | (29) | (19) | (19) | (26) |
| 2014 | (48) | (32) | (32) | (43) |
| 2015 | (67) | (45) | (45) | (61) |
| 2016 | (86) | (59) | (59) | (78) |
| 2017 | (105) | (71) | (71) | (95) |
| 2018 | (124) | (84) | (84) | (112) |
| 2019 | (143) | (97) | (97) | (130) |
| 2020 | (162) | (111) | (111) | (147) |
| 2021 | (181) | (123) | (123) | (164) |
| 2022 | (200) | (136) | (136) | (182) |
| 2023 | (219) | (149) | (149) | (199) |
| 2024 | (238) | (163) | (163) | (217) |
| 2025 | (257) | (175) | (175) | (233) |
| 2026 | (276) | (188) | (188) | (251) |
| 2027 | (295) | (201) | (201) | (268) |
| 2028 | (315) | (215) | (215) | (286) |
| 2029 | (333) | (227) | (227) | (303) |
| 2030 | (352) | (240) | (240) | (320) |
| 2031 | (370) | (252) | (252) | (336) |
| 2032 | (388) | (265) | (265) | (353) |
| 2033 | (404) | (276) | (276) | (367) |

## *Lanai Energy Efficiency Forecast Data*

Table E-77: Lanai Energy Efficiency Forecast Data (MWh)

| Year | Blazing a Bold Frontier | Stuck in the Middle | No Burning Desire | Moved by Passion |
|---|---|---|---|---|
| 2012 | (213) | (146) | (146) | (194) |
| 2013 | (638) | (435) | (435) | (580) |
| 2014 | (1,063) | (725) | (725) | (966) |
| 2015 | (1,488) | (1,014) | (1,014) | (1,353) |
| 2016 | (1,918) | (1,308) | (1,308) | (1,744) |
| 2017 | (2,338) | (1,594) | (1,594) | (2,125) |
| 2018 | (2,763) | (1,884) | (1,884) | (2,512) |
| 2019 | (3,188) | (2,173) | (2,173) | (2,898) |
| 2020 | (3,623) | (2,470) | (2,470) | (3,293) |
| 2021 | (4,038) | (2,753) | (2,753) | (3,671) |
| 2022 | (4,463) | (3,043) | (3,043) | (4,057) |
| 2023 | (4,888) | (3,332) | (3,332) | (4,443) |
| 2024 | (5,327) | (3,632) | (3,632) | (4,843) |
| 2025 | (5,738) | (3,912) | (3,912) | (5,216) |
| 2026 | (6,163) | (4,202) | (4,202) | (5,602) |
| 2027 | (6,587) | (4,491) | (4,491) | (5,989) |
| 2028 | (7,032) | (4,794) | (4,794) | (6,392) |
| 2029 | (7,437) | (5,071) | (5,071) | (6,761) |
| 2030 | (7,862) | (5,361) | (5,361) | (7,148) |
| 2031 | (8,266) | (5,636) | (5,636) | (7,514) |
| 2032 | (8,671) | (5,912) | (5,912) | (7,883) |
| 2033 | (9,029) | (6,156) | (6,156) | (8,208) |

## *Molokai Energy Efficiency Forecast Data*

Table E-78: Molokai Energy Efficiency Forecast Data (MWh)

| Year | Blazing a Bold Frontier | Stuck in the Middle | No Burning Desire | Moved by Passion |
|---|---|---|---|---|
| 2012 | (264) | (180) | (180) | (240) |
| 2013 | (790) | (539) | (539) | (718) |
| 2014 | (1,316) | (898) | (898) | (1,197) |
| 2015 | (1,843) | (1,257) | (1,257) | (1,676) |
| 2016 | (2,376) | (1,620) | (1,620) | (2,160) |
| 2017 | (2,896) | (1,975) | (1,975) | (2,633) |
| 2018 | (3,423) | (2,334) | (2,334) | (3,112) |
| 2019 | (3,949) | (2,693) | (2,693) | (3,590) |
| 2020 | (4,488) | (3,060) | (3,060) | (4,080) |
| 2021 | (5,002) | (3,411) | (3,411) | (4,548) |
| 2022 | (5,529) | (3,770) | (3,770) | (5,026) |
| 2023 | (6,055) | (4,129) | (4,129) | (5,505) |
| 2024 | (6,600) | (4,500) | (4,500) | (6,000) |
| 2025 | (7,109) | (4,847) | (4,847) | (6,462) |
| 2026 | (7,635) | (5,206) | (5,206) | (6,941) |
| 2027 | (8,162) | (5,565) | (5,565) | (7,420) |
| 2028 | (8,712) | (5,940) | (5,940) | (7,920) |
| 2029 | (9,215) | (6,283) | (6,283) | (8,377) |
| 2030 | (9,741) | (6,642) | (6,642) | (8,856) |
| 2031 | (10,241) | (6,982) | (6,982) | (9,310) |
| 2032 | (10,743) | (7,325) | (7,325) | (9,766) |
| 2033 | (11,186) | (7,627) | (7,627) | (10,170) |

# Appendix E-8: Energy Efficiency (EEPS) Peak Forecast Data

## *The EM&V Contractor and PBFA EEPS Peak Forecast*

*The Evaluation Measurement & Verification Contractor (EM&V Contractor) and the Public Benefits Fee Administrator (PBFA) EEPS Peak Forecast*

Table E-79: EM&V and PBFA Base Level EEPS Peak Impact Forecast Data (MW)

| Year | Non-PBFA EEPS Contributions [MW] | PBFA DSM Programs Peak Impact [MW] | Total EEPS Peak Impact [MW] |
|---|---|---|---|
| 2012 | (4.3) | (18.1) | (22.3) |
| 2013 | (8.5) | (34.4) | (42.9) |
| 2014 | (12.8) | (51.4) | (64.2) |
| 2015 | (17.1) | (68.4) | (85.5) |
| 2016 | (21.3) | (85.4) | (106.8) |
| 2017 | (25.6) | (102.4) | (128.0) |
| 2018 | (29.9) | (119.4) | (149.3) |
| 2019 | (34.2) | (136.4) | (170.6) |
| 2020 | (38.4) | (153.5) | (191.9) |
| 2021 | (42.7) | (170.5) | (213.2) |
| 2022 | (47.0) | (187.5) | (234.4) |
| 2023 | (51.2) | (204.5) | (255.7) |
| 2024 | (55.5) | (221.5) | (277.0) |
| 2025 | (59.8) | (238.5) | (298.3) |
| 2026 | (64.0) | (255.5) | (319.6) |
| 2027 | (68.3) | (272.5) | (340.8) |
| 2028 | (72.6) | (289.5) | (362.1) |
| 2029 | (76.8) | (306.5) | (383.4) |
| 2030 | (81.1) | (323.6) | (404.7) |
| 2031 | (83.3) | (340.6) | (423.9) |
| 2032 | (85.5) | (357.6) | (443.1) |
| 2033 | (87.7) | (374.5) | (462.2) |

## *Hawaiian Electric Energy Efficiency Peak Forecast Data*

Table E-80: HECO Energy Efficiency Peak Forecast Data (MW)

| Year | Blazing a Bold Frontier | Stuck in the Middle | No Burning Desire | Moved by Passion |
|---|---|---|---|---|
| 2012 | (18) | (12) | (12) | (16) |
| 2013 | (36) | (25) | (25) | (33) |
| 2014 | (55) | (37) | (37) | (50) |
| 2015 | (73) | (50) | (50) | (67) |
| 2016 | (92) | (63) | (63) | (84) |
| 2017 | (111) | (76) | (76) | (101) |
| 2018 | (130) | (88) | (88) | (118) |
| 2019 | (148) | (101) | (101) | (135) |
| 2020 | (167) | (114) | (114) | (152) |
| 2021 | (186) | (127) | (127) | (169) |
| 2022 | (204) | (139) | (139) | (186) |
| 2023 | (223) | (152) | (152) | (203) |
| 2024 | (242) | (165) | (165) | (220) |
| 2025 | (261) | (178) | (178) | (237) |
| 2026 | (279) | (190) | (190) | (254) |
| 2027 | (298) | (203) | (203) | (271) |
| 2028 | (317) | (216) | (216) | (288) |
| 2029 | (335) | (229) | (229) | (305) |
| 2030 | (354) | (241) | (241) | (322) |
| 2031 | (371) | (253) | (253) | (337) |
| 2032 | (388) | (264) | (264) | (353) |
| 2033 | (405) | (276) | (276) | (368) |

### *HELCO Energy Efficiency Peak Forecast Data*

Table E-81: HELCO Energy Efficiency Peak Forecast Data (MW)

| Year | Blazing a Bold Frontier | Stuck in the Middle | No Burning Desire | Moved by Passion |
|---|---|---|---|---|
| 2012 | (5.1) | (3.5) | (3.5) | (4.6) |
| 2013 | (7.9) | (5.4) | (5.4) | (7.2) |
| 2014 | (10.8) | (7.4) | (7.4) | (9.8) |
| 2015 | (13.8) | (9.4) | (9.4) | (12.5) |
| 2016 | (16.7) | (11.4) | (11.4) | (15.2) |
| 2017 | (19.6) | (13.4) | (13.4) | (17.9) |
| 2018 | (22.6) | (15.4) | (15.4) | (20.5) |
| 2019 | (25.5) | (17.4) | (17.4) | (23.2) |
| 2020 | (28.4) | (19.4) | (19.4) | (25.9) |
| 2021 | (31.4) | (21.4) | (21.4) | (28.5) |
| 2022 | (34.3) | (23.4) | (23.4) | (31.2) |
| 2023 | (37.3) | (25.4) | (25.4) | (33.9) |
| 2024 | (40.2) | (27.4) | (27.4) | (36.5) |
| 2025 | (43.1) | (29.4) | (29.4) | (39.2) |
| 2026 | (46.1) | (31.4) | (31.4) | (41.9) |
| 2027 | (49.0) | (33.4) | (33.4) | (44.6) |
| 2028 | (51.9) | (35.4) | (35.4) | (47.2) |
| 2029 | (54.9) | (37.4) | (37.4) | (49.9) |
| 2030 | (57.8) | (39.4) | (39.4) | (52.6) |
| 2031 | (60.5) | (41.2) | (41.2) | (55.0) |
| 2032 | (63.1) | (43.0) | (43.0) | (57.4) |
| 2033 | (65.8) | (44.8) | (44.8) | (59.8) |

## *Maui Energy Efficiency Peak Forecast Data*

Table E-82: Maui Energy Efficiency Peak Forecast Data (MW)

| Year | Blazing a Bold Frontier | Stuck in the Middle | No Burning Desire | Moved by Passion |
|---|---|---|---|---|
| 2012 | (2.8) | (1.9) | (1.9) | (2.6) |
| 2013 | (5.7) | (3.9) | (3.9) | (5.2) |
| 2014 | (8.6) | (5.9) | (5.9) | (7.9) |
| 2015 | (11.6) | (7.9) | (7.9) | (10.6) |
| 2016 | (14.6) | (9.9) | (9.9) | (13.2) |
| 2017 | (17.5) | (11.9) | (11.9) | (15.9) |
| 2018 | (20.5) | (14.0) | (14.0) | (18.6) |
| 2019 | (23.4) | (16.0) | (16.0) | (21.3) |
| 2020 | (26.4) | (18.0) | (18.0) | (24.0) |
| 2021 | (29.4) | (20.0) | (20.0) | (26.7) |
| 2022 | (32.3) | (22.0) | (22.0) | (29.4) |
| 2023 | (35.3) | (24.0) | (24.0) | (32.1) |
| 2024 | (38.2) | (26.1) | (26.1) | (34.8) |
| 2025 | (41.2) | (28.1) | (28.1) | (37.4) |
| 2026 | (44.1) | (30.1) | (30.1) | (40.1) |
| 2027 | (47.1) | (32.1) | (32.1) | (42.8) |
| 2028 | (50.1) | (34.1) | (34.1) | (45.5) |
| 2029 | (53.0) | (36.1) | (36.1) | (48.2) |
| 2030 | (56.0) | (38.2) | (38.2) | (50.9) |
| 2031 | (58.6) | (40.0) | (40.0) | (53.3) |
| 2032 | (61.3) | (41.8) | (41.8) | (55.7) |
| 2033 | (64.0) | (43.6) | (43.6) | (58.2) |

## *Lanai Energy Efficiency Peak Forecast Data*

Table E-83: Lanai Energy Efficiency Peak Forecast Data (MW)

| Year | Blazing a Bold Frontier | Stuck in the Middle | No Burning Desire | Moved by Passion |
|---|---|---|---|---|
| 2012 | (0.06) | (0.04) | (0.04) | (0.06) |
| 2013 | (0.13) | (0.09) | (0.09) | (0.12) |
| 2014 | (0.19) | (0.13) | (0.13) | (0.18) |
| 2015 | (0.26) | (0.18) | (0.18) | (0.24) |
| 2016 | (0.33) | (0.22) | (0.22) | (0.30) |
| 2017 | (0.39) | (0.27) | (0.27) | (0.36) |
| 2018 | (0.46) | (0.31) | (0.31) | (0.42) |
| 2019 | (0.52) | (0.36) | (0.36) | (0.48) |
| 2020 | (0.59) | (0.40) | (0.40) | (0.54) |
| 2021 | (0.66) | (0.45) | (0.45) | (0.60) |
| 2022 | (0.72) | (0.49) | (0.49) | (0.66) |
| 2023 | (0.79) | (0.54) | (0.54) | (0.72) |
| 2024 | (0.85) | (0.58) | (0.58) | (0.78) |
| 2025 | (0.92) | (0.63) | (0.63) | (0.84) |
| 2026 | (0.99) | (0.67) | (0.67) | (0.90) |
| 2027 | (1.05) | (0.72) | (0.72) | (0.96) |
| 2028 | (1.12) | (0.76) | (0.76) | (1.02) |
| 2029 | (1.18) | (0.81) | (0.81) | (1.08) |
| 2030 | (1.25) | (0.85) | (0.85) | (1.14) |
| 2031 | (1.31) | (0.89) | (0.89) | (1.19) |
| 2032 | (1.37) | (0.93) | (0.93) | (1.25) |
| 2033 | (1.43) | (0.97) | (0.97) | (1.30) |

## *Molokai Energy Efficiency Peak Forecast Data*

Table E-84: Molokai Energy Efficiency Peak Forecast Data (MW)

| Year | Blazing a Bold Frontier | Stuck in the Middle | No Burning Desire | Moved by Passion |
|---|---|---|---|---|
| 2012 | (0.08) | (0.05) | (0.05) | (0.07) |
| 2013 | (0.16) | (0.11) | (0.11) | (0.14) |
| 2014 | (0.24) | (0.16) | (0.16) | (0.22) |
| 2015 | (0.32) | (0.22) | (0.22) | (0.29) |
| 2016 | (0.40) | (0.27) | (0.27) | (0.37) |
| 2017 | (0.48) | (0.33) | (0.33) | (0.44) |
| 2018 | (0.57) | (0.39) | (0.39) | (0.52) |
| 2019 | (0.65) | (0.44) | (0.44) | (0.59) |
| 2020 | (0.73) | (0.50) | (0.50) | (0.66) |
| 2021 | (0.81) | (0.55) | (0.55) | (0.74) |
| 2022 | (0.89) | (0.61) | (0.61) | (0.81) |
| 2023 | (0.98) | (0.67) | (0.67) | (0.89) |
| 2024 | (1.06) | (0.72) | (0.72) | (0.96) |
| 2025 | (1.14) | (0.78) | (0.78) | (1.04) |
| 2026 | (1.22) | (0.83) | (0.83) | (1.11) |
| 2027 | (1.30) | (0.89) | (0.89) | (1.19) |
| 2028 | (1.39) | (0.94) | (0.94) | (1.26) |
| 2029 | (1.47) | (1.00) | (1.00) | (1.33) |
| 2030 | (1.55) | (1.06) | (1.06) | (1.41) |
| 2031 | (1.62) | (1.11) | (1.11) | (1.48) |
| 2032 | (1.70) | (1.16) | (1.16) | (1.54) |
| 2033 | (1.77) | (1.21) | (1.21) | (1.61) |

# Appendix E-9: Contribution Data for Energy Efficiency (EEPS) Forecasts

## *Hawaiian Electric Energy Efficiency Contribution Data for Each Scenario*

Table E-85: HECO Blazing a Bold Frontier Scenario Energy Efficiency Data

| Year | Energy Savings [GWh] | | | Peak Demand Impacts [MW] | | | PBFA DSM Program Cost ($ million) | | |
|---|---|---|---|---|---|---|---|---|---|
| | *Non-PBFA EEPS Contributions* | *PBFA DSM Programs Energy Savings* | *Total EEPS Energy Savings* | *Non-PBFA EEPS Contributions* | *PBFA DSM Programs Peak Demand* | *Total EEPS Peak Demand* | *Program Costs (excluding incentives or rebates)* | *Incentives and Rebates* | *Customer Costs* |
| 2012 | (12.8) | (48.6) | (61.4) | (3.8) | (14.2) | (18.0) | 7.20 | 12.79 | 83.43 |
| 2013 | (38.4) | (145.7) | (184.1) | (7.5) | (28.5) | (36.0) | 7.20 | 12.79 | 83.43 |
| 2014 | (64.0) | (242.8) | (306.8) | (11.3) | (43.5) | (54.7) | 9.60 | 17.04 | 111.21 |
| 2015 | (89.5) | (339.9) | (429.5) | (15.0) | (58.4) | (73.4) | 9.60 | 17.04 | 111.21 |
| 2016 | (115.1) | (437.0) | (552.2) | (18.8) | (73.4) | (92.1) | 9.60 | 17.04 | 111.21 |
| 2017 | (140.7) | (534.2) | (674.9) | (22.5) | (88.3) | (110.8) | 9.60 | 17.04 | 111.21 |
| 2018 | (166.3) | (631.3) | (797.6) | (26.3) | (103.3) | (129.6) | 9.60 | 17.04 | 111.21 |
| 2019 | (191.9) | (728.4) | (920.3) | (30.0) | (118.2) | (148.3) | 9.60 | 17.04 | 111.21 |
| 2020 | (217.5) | (825.5) | (1,043.0) | (33.8) | (133.2) | (167.0) | 12.00 | 21.31 | 139.02 |
| 2021 | (243.1) | (922.6) | (1,165.7) | (37.5) | (148.1) | (185.7) | 12.00 | 28.41 | 185.35 |
| 2022 | (268.6) | (1,019.7) | (1,288.4) | (41.3) | (163.1) | (204.4) | 12.00 | 28.41 | 185.35 |
| 2023 | (294.2) | (1,116.9) | (1,411.1) | (45.0) | (178.1) | (223.1) | 12.00 | 28.41 | 185.35 |
| 2024 | (319.8) | (1,214.0) | (1,533.8) | (48.8) | (193.0) | (241.8) | 12.00 | 28.41 | 185.35 |
| 2025 | (345.4) | (1,311.1) | (1,656.5) | (52.6) | (208.0) | (260.5) | 12.00 | 28.41 | 185.35 |
| 2026 | (371.0) | (1,408.2) | (1,779.2) | (56.3) | (222.9) | (279.2) | 14.40 | 34.09 | 222.42 |
| 2027 | (396.6) | (1,505.3) | (1,901.9) | (60.1) | (237.9) | (297.9) | 14.40 | 34.09 | 222.42 |
| 2028 | (422.2) | (1,602.5) | (2,024.6) | (63.8) | (252.8) | (316.7) | 14.40 | 34.09 | 222.42 |
| 2029 | (447.7) | (1,699.6) | (2,147.3) | (67.6) | (267.8) | (335.4) | 14.40 | 34.09 | 222.42 |
| 2030 | (473.3) | (1,796.7) | (2,270.0) | (71.3) | (282.8) | (354.1) | 14.40 | 34.09 | 222.42 |
| 2031 | (492.7) | (1,893.8) | (2,386.5) | (73.2) | (297.7) | (371.0) | 14.40 | 34.09 | 222.42 |
| 2032 | (505.8) | (1,990.9) | (2,496.7) | (75.2) | (312.7) | (387.8) | 14.40 | 34.09 | 222.42 |
| 2033 | (518.9) | (2,088.0) | (2,606.9) | (77.1) | (327.6) | (404.7) | 14.40 | 34.09 | 222.42 |

Table E-86: HECO Stuck in the Middle Scenario Energy Efficiency Data

| Year | Energy Savings [GWh] | | | Peak Demand Impacts [MW] | | | PBFA DSM Program Cost ($ million] | | |
|---|---|---|---|---|---|---|---|---|---|
| | *Non-PBFA EEPS Contributions* | *PBFA DSM Programs Energy Savings* | *Total EEPS Energy Savings* | *Non-PBFA EEPS Contributions* | *PBFA DSM Programs Peak Demand* | *Total EEPS Peak Demand* | *Program Costs (excluding incentives or rebates)* | *Incentives and Rebates* | *Customer Costs* |
| 2012 | (8.7) | (33.1) | (41.8) | (2.6) | (9.7) | (12.3) | 4.91 | 8.72 | 56.88 |
| 2013 | (26.2) | (99.3) | (125.5) | (5.1) | (19.4) | (24.5) | 4.91 | 8.72 | 56.88 |
| 2014 | (43.6) | (165.5) | (209.2) | (7.7) | (29.6) | (37.3) | 6.55 | 11.62 | 75.83 |
| 2015 | (61.1) | (231.8) | (292.8) | (10.2) | (39.8) | (50.1) | 6.55 | 11.62 | 75.83 |
| 2016 | (78.5) | (298.0) | (376.5) | (12.8) | (50.0) | (62.8) | 6.55 | 11.62 | 75.83 |
| 2017 | (95.9) | (364.2) | (460.1) | (15.4) | (60.2) | (75.6) | 6.55 | 11.62 | 75.83 |
| 2018 | (113.4) | (430.4) | (543.8) | (17.9) | (70.4) | (88.3) | 6.55 | 11.62 | 75.83 |
| 2019 | (130.8) | (496.6) | (627.5) | (20.5) | (80.6) | (101.1) | 6.55 | 11.62 | 75.83 |
| 2020 | (148.3) | (562.8) | (711.1) | (23.0) | (90.8) | (113.8) | 8.18 | 14.53 | 94.78 |
| 2021 | (165.7) | (629.1) | (794.8) | (25.6) | (101.0) | (126.6) | 8.18 | 19.37 | 126.38 |
| 2022 | (183.2) | (695.3) | (878.4) | (28.2) | (111.2) | (139.4) | 8.18 | 19.37 | 126.38 |
| 2023 | (200.6) | (761.5) | (962.1) | (30.7) | (121.4) | (152.1) | 8.18 | 19.37 | 126.38 |
| 2024 | (218.1) | (827.7) | (1,045.8) | (33.3) | (131.6) | (164.9) | 8.18 | 19.37 | 126.38 |
| 2025 | (235.5) | (893.9) | (1,129.4) | (35.8) | (141.8) | (177.6) | 8.18 | 19.37 | 126.38 |
| 2026 | (252.9) | (960.1) | (1,213.1) | (38.4) | (152.0) | (190.4) | 9.82 | 23.24 | 151.65 |
| 2027 | (270.4) | (1,026.4) | (1,296.8) | (40.9) | (162.2) | (203.1) | 9.82 | 23.24 | 151.65 |
| 2028 | (287.8) | (1,092.6) | (1,380.4) | (43.5) | (172.4) | (215.9) | 9.82 | 23.24 | 151.65 |
| 2029 | (305.3) | (1,158.8) | (1,464.1) | (46.1) | (182.6) | (228.7) | 9.82 | 23.24 | 151.65 |
| 2030 | (322.7) | (1,225.0) | (1,547.7) | (48.6) | (192.8) | (241.4) | 9.82 | 23.24 | 151.65 |
| 2031 | (335.9) | (1,291.2) | (1,627.1) | (49.9) | (203.0) | (252.9) | 9.82 | 23.24 | 151.65 |
| 2032 | (344.8) | (1,357.4) | (1,702.3) | (51.2) | (213.2) | (264.4) | 9.82 | 23.24 | 151.65 |
| 2033 | (353.8) | (1,423.7) | (1,777.4) | (52.6) | (223.4) | (275.9) | 9.82 | 23.24 | 151.65 |

Table E-87: HECO No Burning Desire Scenario Energy Efficiency Data

| Year | Energy Savings [GWh] | | | Peak Demand Impacts [MW] | | | PBFA DSM Program Cost ($ million) | | |
|---|---|---|---|---|---|---|---|---|---|
| | *Non-PBFA EEPS Contributions* | *PBFA DSM Programs Energy Savings* | *Total EEPS Energy Savings* | *Non-PBFA EEPS Contributions* | *PBFA DSM Programs Peak Demand* | *Total EEPS Peak Demand* | *Program Costs (excluding incentives or rebates)* | *Incentives and Rebates* | *Customer Costs* |
| 2012 | (8.7) | (33.1) | (41.8) | (2.6) | (9.7) | (12.3) | 4.91 | 8.72 | 56.88 |
| 2013 | (26.2) | (99.3) | (125.5) | (5.1) | (19.4) | (24.5) | 4.91 | 8.72 | 56.88 |
| 2014 | (43.6) | (165.5) | (209.2) | (7.7) | (29.6) | (37.3) | 6.55 | 11.62 | 75.83 |
| 2015 | (61.1) | (231.8) | (292.8) | (10.2) | (39.8) | (50.1) | 6.55 | 11.62 | 75.83 |
| 2016 | (78.5) | (298.0) | (376.5) | (12.8) | (50.0) | (62.8) | 6.55 | 11.62 | 75.83 |
| 2017 | (95.9) | (364.2) | (460.1) | (15.4) | (60.2) | (75.6) | 6.55 | 11.62 | 75.83 |
| 2018 | (113.4) | (430.4) | (543.8) | (17.9) | (70.4) | (88.3) | 6.55 | 11.62 | 75.83 |
| 2019 | (130.8) | (496.6) | (627.5) | (20.5) | (80.6) | (101.1) | 6.55 | 11.62 | 75.83 |
| 2020 | (148.3) | (562.8) | (711.1) | (23.0) | (90.8) | (113.8) | 8.18 | 14.53 | 94.78 |
| 2021 | (165.7) | (629.1) | (794.8) | (25.6) | (101.0) | (126.6) | 8.18 | 19.37 | 126.38 |
| 2022 | (183.2) | (695.3) | (878.4) | (28.2) | (111.2) | (139.4) | 8.18 | 19.37 | 126.38 |
| 2023 | (200.6) | (761.5) | (962.1) | (30.7) | (121.4) | (152.1) | 8.18 | 19.37 | 126.38 |
| 2024 | (218.1) | (827.7) | (1,045.8) | (33.3) | (131.6) | (164.9) | 8.18 | 19.37 | 126.38 |
| 2025 | (235.5) | (893.9) | (1,129.4) | (35.8) | (141.8) | (177.6) | 8.18 | 19.37 | 126.38 |
| 2026 | (252.9) | (960.1) | (1,213.1) | (38.4) | (152.0) | (190.4) | 9.82 | 23.24 | 151.65 |
| 2027 | (270.4) | (1,026.4) | (1,296.8) | (40.9) | (162.2) | (203.1) | 9.82 | 23.24 | 151.65 |
| 2028 | (287.8) | (1,092.6) | (1,380.4) | (43.5) | (172.4) | (215.9) | 9.82 | 23.24 | 151.65 |
| 2029 | (305.3) | (1,158.8) | (1,464.1) | (46.1) | (182.6) | (228.7) | 9.82 | 23.24 | 151.65 |
| 2030 | (322.7) | (1,225.0) | (1,547.7) | (48.6) | (192.8) | (241.4) | 9.82 | 23.24 | 151.65 |
| 2031 | (335.9) | (1,291.2) | (1,627.1) | (49.9) | (203.0) | (252.9) | 9.82 | 23.24 | 151.65 |
| 2032 | (344.8) | (1,357.4) | (1,702.3) | (51.2) | (213.2) | (264.4) | 9.82 | 23.24 | 151.65 |
| 2033 | (353.8) | (1,423.7) | (1,777.4) | (52.6) | (223.4) | (275.9) | 9.82 | 23.24 | 151.65 |

Table E-88: HECO Moved by Passion Scenario Energy Efficiency Data

| Year | Energy Savings [GWh] | | | Peak Demand Impacts [MW] | | | PBFA DSM Program Cost ($ million] | | |
|---|---|---|---|---|---|---|---|---|---|
| | *Non-PBFA EEPS Contributions* | *PBFA DSM Programs Energy Savings* | *Total EEPS Energy Savings* | *Non-PBFA EEPS Contributions* | *PBFA DSM Programs Peak Demand* | *Total EEPS Peak Demand* | *Program Costs (excluding incentives or rebates)* | *Incentives and Rebates* | *Customer Costs* |
| 2012 | (11.6) | (44.1) | (55.8) | (3.4) | (13.0) | (16.4) | 6.55 | 11.62 | 75.85 |
| 2013 | (34.9) | (132.4) | (167.3) | (6.8) | (25.9) | (32.7) | 6.55 | 11.62 | 75.85 |
| 2014 | (58.1) | (220.7) | (278.9) | (10.2) | (39.5) | (49.7) | 8.73 | 15.49 | 101.10 |
| 2015 | (81.4) | (309.0) | (390.4) | (13.6) | (53.1) | (66.7) | 8.73 | 15.49 | 101.10 |
| 2016 | (104.7) | (397.3) | (502.0) | (17.1) | (66.7) | (83.8) | 8.73 | 15.49 | 101.10 |
| 2017 | (127.9) | (485.6) | (613.5) | (20.5) | (80.3) | (100.8) | 8.73 | 15.49 | 101.10 |
| 2018 | (151.2) | (573.9) | (725.1) | (23.9) | (93.9) | (117.8) | 8.73 | 15.49 | 101.10 |
| 2019 | (174.4) | (662.2) | (836.6) | (27.3) | (107.5) | (134.8) | 8.73 | 15.49 | 101.10 |
| 2020 | (197.7) | (750.5) | (948.2) | (30.7) | (121.1) | (151.8) | 10.91 | 19.37 | 126.38 |
| 2021 | (221.0) | (838.7) | (1,059.7) | (34.1) | (134.7) | (168.8) | 10.91 | 25.82 | 168.50 |
| 2022 | (244.2) | (927.0) | (1,171.3) | (37.5) | (148.3) | (185.8) | 10.91 | 25.82 | 168.50 |
| 2023 | (267.5) | (1,015.3) | (1,282.8) | (40.9) | (161.9) | (202.8) | 10.91 | 25.82 | 168.50 |
| 2024 | (290.7) | (1,103.6) | (1,394.4) | (44.4) | (175.5) | (219.8) | 10.91 | 25.82 | 168.50 |
| 2025 | (314.0) | (1,191.9) | (1,505.9) | (47.8) | (189.1) | (236.8) | 10.91 | 25.82 | 168.50 |
| 2026 | (337.3) | (1,280.2) | (1,617.5) | (51.2) | (202.7) | (253.8) | 13.09 | 30.99 | 202.20 |
| 2027 | (360.5) | (1,368.5) | (1,729.0) | (54.6) | (216.3) | (270.9) | 13.09 | 30.99 | 202.20 |
| 2028 | (383.8) | (1,456.8) | (1,840.6) | (58.0) | (229.9) | (287.9) | 13.09 | 30.99 | 202.20 |
| 2029 | (407.0) | (1,545.1) | (1,952.1) | (61.4) | (243.5) | (304.9) | 13.09 | 30.99 | 202.20 |
| 2030 | (430.3) | (1,633.4) | (2,063.7) | (64.8) | (257.1) | (321.9) | 13.09 | 30.99 | 202.20 |
| 2031 | (447.9) | (1,721.6) | (2,169.5) | (66.6) | (270.6) | (337.2) | 13.09 | 30.99 | 202.20 |
| 2032 | (459.8) | (1,809.9) | (2,269.7) | (68.3) | (284.2) | (352.6) | 13.09 | 30.99 | 202.20 |
| 2033 | (471.7) | (1,898.2) | (2,369.9) | (70.1) | (297.8) | (367.9) | 13.09 | 30.99 | 202.20 |

## HELCO Energy Efficiency Contribution Data for Each Scenario

Table E-89: HELCO Blazing a Bold Frontier Scenario Energy Efficiency Data

| Year | Energy Savings [GWh] | | | Peak Demand Impacts [MW] | | | PBFA DSM Program Cost ($ million] | | |
|---|---|---|---|---|---|---|---|---|---|
| | *Non-PBFA EEPS Contributions* | *PBFA DSM Programs Energy Savings* | *Total EEPS Energy Savings* | *Non-PBFA EEPS Contributions* | *PBFA DSM Programs Peak Demand* | *Total EEPS Peak Demand* | *Program Costs (excluding incentives or rebates)* | *Incentives and Rebates* | *Customer Costs* |
| 2012 | (1.9) | (22.2) | (24.1) | (0.6) | (4.5) | (5.1) | 1.10 | 1.95 | 12.70 |
| 2013 | (5.8) | (37.0) | (42.8) | (1.2) | (6.9) | (8.1) | 1.10 | 1.95 | 12.70 |
| 2014 | (9.7) | (51.7) | (61.5) | (1.8) | (9.2) | (11.0) | 1.46 | 2.59 | 16.93 |
| 2015 | (13.6) | (66.5) | (80.2) | (2.4) | (11.6) | (14.0) | 1.46 | 2.59 | 16.93 |
| 2016 | (17.5) | (81.3) | (98.8) | (3.0) | (14.0) | (16.9) | 1.46 | 2.59 | 16.93 |
| 2017 | (21.4) | (96.1) | (117.5) | (3.6) | (16.3) | (19.9) | 1.46 | 2.59 | 16.93 |
| 2018 | (25.3) | (110.9) | (136.2) | (4.2) | (18.7) | (22.8) | 1.46 | 2.59 | 16.93 |
| 2019 | (29.2) | (125.7) | (154.9) | (4.7) | (21.1) | (25.8) | 1.46 | 2.59 | 16.93 |
| 2020 | (33.1) | (140.4) | (173.6) | (5.3) | (23.4) | (28.8) | 1.83 | 3.24 | 21.16 |
| 2021 | (37.0) | (155.2) | (192.2) | (5.9) | (25.8) | (31.7) | 1.83 | 4.32 | 28.22 |
| 2022 | (40.9) | (170.0) | (210.9) | (6.5) | (28.1) | (34.7) | 1.83 | 4.32 | 28.22 |
| 2023 | (44.8) | (184.8) | (229.6) | (7.1) | (30.5) | (37.6) | 1.83 | 4.32 | 28.22 |
| 2024 | (48.7) | (199.6) | (248.3) | (7.7) | (32.9) | (40.6) | 1.83 | 4.32 | 28.22 |
| 2025 | (52.6) | (214.4) | (266.9) | (8.3) | (35.2) | (43.5) | 1.83 | 4.32 | 28.22 |
| 2026 | (56.5) | (229.1) | (285.6) | (8.9) | (37.6) | (46.5) | 2.19 | 5.19 | 33.86 |
| 2027 | (60.4) | (243.9) | (304.3) | (9.5) | (40.0) | (49.5) | 2.19 | 5.19 | 33.86 |
| 2028 | (64.3) | (258.7) | (323.0) | (10.1) | (42.3) | (52.4) | 2.19 | 5.19 | 33.86 |
| 2029 | (68.2) | (273.5) | (341.7) | (10.7) | (44.7) | (55.4) | 2.19 | 5.19 | 33.86 |
| 2030 | (72.1) | (288.3) | (360.3) | (11.3) | (47.1) | (58.3) | 2.19 | 5.19 | 33.86 |
| 2031 | (75.0) | (303.1) | (378.1) | (11.6) | (49.4) | (61.0) | 2.19 | 5.19 | 33.86 |
| 2032 | (77.0) | (317.9) | (394.8) | (11.9) | (51.8) | (63.7) | 2.19 | 5.19 | 33.86 |
| 2033 | (79.0) | (332.6) | (411.6) | (12.2) | (54.0) | (66.2) | 2.19 | 5.19 | 33.86 |

Table E-90: HELCO Stuck in the Middle Scenario Energy Efficiency Data

| Year | Energy Savings [GWh] | | | Peak Demand Impacts [MW] | | | PBFA DSM Program Cost ($ million] | | |
|---|---|---|---|---|---|---|---|---|---|
| | *Non-PBFA EEPS Contributions* | *PBFA DSM Programs Energy Savings* | *Total EEPS Energy Savings* | *Non-PBFA EEPS Contributions* | *PBFA DSM Programs Peak Demand* | *Total EEPS Peak Demand* | *Program Costs (excluding incentives or rebates)* | *Incentives and Rebates* | *Customer Costs* |
| 2012 | (1.3) | (15.1) | (16.4) | (0.4) | (3.1) | (3.5) | 0.75 | 1.33 | 8.66 |
| 2013 | (4.0) | (25.2) | (29.2) | (0.8) | (4.7) | (5.5) | 0.75 | 1.33 | 8.66 |
| 2014 | (6.6) | (35.3) | (41.9) | (1.2) | (6.3) | (7.5) | 1.00 | 1.77 | 11.54 |
| 2015 | (9.3) | (45.4) | (54.7) | (1.6) | (7.9) | (9.5) | 1.00 | 1.77 | 11.54 |
| 2016 | (11.9) | (55.4) | (67.4) | (2.0) | (9.5) | (11.5) | 1.00 | 1.77 | 11.54 |
| 2017 | (14.6) | (65.5) | (80.1) | (2.4) | (11.1) | (13.6) | 1.00 | 1.77 | 11.54 |
| 2018 | (17.3) | (75.6) | (92.9) | (2.8) | (12.7) | (15.6) | 1.00 | 1.77 | 11.54 |
| 2019 | (19.9) | (85.7) | (105.6) | (3.2) | (14.4) | (17.6) | 1.00 | 1.77 | 11.54 |
| 2020 | (22.6) | (95.8) | (118.3) | (3.6) | (16.0) | (19.6) | 1.25 | 2.21 | 14.43 |
| 2021 | (25.2) | (105.8) | (131.1) | (4.0) | (17.6) | (21.6) | 1.25 | 2.95 | 19.24 |
| 2022 | (27.9) | (115.9) | (143.8) | (4.5) | (19.2) | (23.6) | 1.25 | 2.95 | 19.24 |
| 2023 | (30.5) | (126.0) | (156.5) | (4.9) | (20.8) | (25.7) | 1.25 | 2.95 | 19.24 |
| 2024 | (33.2) | (136.1) | (169.3) | (5.3) | (22.4) | (27.7) | 1.25 | 2.95 | 19.24 |
| 2025 | (35.8) | (146.2) | (182.0) | (5.7) | (24.0) | (29.7) | 1.25 | 2.95 | 19.24 |
| 2026 | (38.5) | (156.2) | (194.7) | (6.1) | (25.6) | (31.7) | 1.49 | 3.54 | 23.09 |
| 2027 | (41.2) | (166.3) | (207.5) | (6.5) | (27.3) | (33.7) | 1.49 | 3.54 | 23.09 |
| 2028 | (43.8) | (176.4) | (220.2) | (6.9) | (28.9) | (35.7) | 1.49 | 3.54 | 23.09 |
| 2029 | (46.5) | (186.5) | (232.9) | (7.3) | (30.5) | (37.8) | 1.49 | 3.54 | 23.09 |
| 2030 | (49.1) | (196.6) | (245.7) | (7.7) | (32.1) | (39.8) | 1.49 | 3.54 | 23.09 |
| 2031 | (51.1) | (206.6) | (257.8) | (7.9) | (33.7) | (41.6) | 1.49 | 3.54 | 23.09 |
| 2032 | (52.5) | (216.7) | (269.2) | (8.1) | (35.3) | (43.4) | 1.49 | 3.54 | 23.09 |
| 2033 | (53.9) | (226.8) | (280.6) | (8.3) | (36.8) | (45.2) | 1.49 | 3.54 | 23.09 |

Table E-91: HELCO No Burning Desire Scenario Energy Efficiency Data

| Year | Energy Savings [GWh] | | | Peak Demand Impacts [MW] | | | PBFA DSM Program Cost ($ million] | | |
|---|---|---|---|---|---|---|---|---|---|
| | *Non-PBFA EEPS Contributions* | *PBFA DSM Programs Energy Savings* | *Total EEPS Energy Savings* | *Non-PBFA EEPS Contributions* | *PBFA DSM Programs Peak Demand* | *Total EEPS Peak Demand* | *Program Costs (excluding incentives or rebates)* | *Incentives and Rebates* | *Customer Costs* |
| 2012 | (1.3) | (15.1) | (16.4) | (0.4) | (3.1) | (3.5) | 0.75 | 1.33 | 8.66 |
| 2013 | (4.0) | (25.2) | (29.2) | (0.8) | (4.7) | (5.5) | 0.75 | 1.33 | 8.66 |
| 2014 | (6.6) | (35.3) | (41.9) | (1.2) | (6.3) | (7.5) | 1.00 | 1.77 | 11.54 |
| 2015 | (9.3) | (45.4) | (54.7) | (1.6) | (7.9) | (9.5) | 1.00 | 1.77 | 11.54 |
| 2016 | (11.9) | (55.4) | (67.4) | (2.0) | (9.5) | (11.5) | 1.00 | 1.77 | 11.54 |
| 2017 | (14.6) | (65.5) | (80.1) | (2.4) | (11.1) | (13.6) | 1.00 | 1.77 | 11.54 |
| 2018 | (17.3) | (75.6) | (92.9) | (2.8) | (12.7) | (15.6) | 1.00 | 1.77 | 11.54 |
| 2019 | (19.9) | (85.7) | (105.6) | (3.2) | (14.4) | (17.6) | 1.00 | 1.77 | 11.54 |
| 2020 | (22.6) | (95.8) | (118.3) | (3.6) | (16.0) | (19.6) | 1.25 | 2.21 | 14.43 |
| 2021 | (25.2) | (105.8) | (131.1) | (4.0) | (17.6) | (21.6) | 1.25 | 2.95 | 19.24 |
| 2022 | (27.9) | (115.9) | (143.8) | (4.5) | (19.2) | (23.6) | 1.25 | 2.95 | 19.24 |
| 2023 | (30.5) | (126.0) | (156.5) | (4.9) | (20.8) | (25.7) | 1.25 | 2.95 | 19.24 |
| 2024 | (33.2) | (136.1) | (169.3) | (5.3) | (22.4) | (27.7) | 1.25 | 2.95 | 19.24 |
| 2025 | (35.8) | (146.2) | (182.0) | (5.7) | (24.0) | (29.7) | 1.25 | 2.95 | 19.24 |
| 2026 | (38.5) | (156.2) | (194.7) | (6.1) | (25.6) | (31.7) | 1.49 | 3.54 | 23.09 |
| 2027 | (41.2) | (166.3) | (207.5) | (6.5) | (27.3) | (33.7) | 1.49 | 3.54 | 23.09 |
| 2028 | (43.8) | (176.4) | (220.2) | (6.9) | (28.9) | (35.7) | 1.49 | 3.54 | 23.09 |
| 2029 | (46.5) | (186.5) | (232.9) | (7.3) | (30.5) | (37.8) | 1.49 | 3.54 | 23.09 |
| 2030 | (49.1) | (196.6) | (245.7) | (7.7) | (32.1) | (39.8) | 1.49 | 3.54 | 23.09 |
| 2031 | (51.1) | (206.6) | (257.8) | (7.9) | (33.7) | (41.6) | 1.49 | 3.54 | 23.09 |
| 2032 | (52.5) | (216.7) | (269.2) | (8.1) | (35.3) | (43.4) | 1.49 | 3.54 | 23.09 |
| 2033 | (53.9) | (226.8) | (280.6) | (8.3) | (36.8) | (45.2) | 1.49 | 3.54 | 23.09 |

Table E-92: HELCO Moved by Passion Scenario Energy Efficiency Data

| Year | Energy Savings [GWh] | | | Peak Demand Impacts [MW] | | | PBFA DSM Program Cost ($ million] | | |
|---|---|---|---|---|---|---|---|---|---|
| | *Non-PBFA EEPS Contributions* | *PBFA DSM Programs Energy Savings* | *Total EEPS Energy Savings* | *Non-PBFA EEPS Contributions* | *PBFA DSM Programs Peak Demand* | *Total EEPS Peak Demand* | *Program Costs (excluding incentives or rebates)* | *Incentives and Rebates* | *Customer Costs* |
| 2012 | (1.8) | (20.2) | (21.9) | (0.5) | (4.1) | (4.6) | 1.00 | 1.77 | 11.55 |
| 2013 | (5.3) | (33.6) | (38.9) | (1.1) | (6.2) | (7.3) | 1.00 | 1.77 | 11.55 |
| 2014 | (8.9) | (47.0) | (55.9) | (1.6) | (8.4) | (10.0) | 1.33 | 2.36 | 15.39 |
| 2015 | (12.4) | (60.5) | (72.9) | (2.2) | (10.5) | (12.7) | 1.33 | 2.36 | 15.39 |
| 2016 | (15.9) | (73.9) | (89.9) | (2.7) | (12.7) | (15.4) | 1.33 | 2.36 | 15.39 |
| 2017 | (19.5) | (87.4) | (106.8) | (3.2) | (14.8) | (18.1) | 1.33 | 2.36 | 15.39 |
| 2018 | (23.0) | (100.8) | (123.8) | (3.8) | (17.0) | (20.8) | 1.33 | 2.36 | 15.39 |
| 2019 | (26.6) | (114.2) | (140.8) | (4.3) | (19.1) | (23.5) | 1.33 | 2.36 | 15.39 |
| 2020 | (30.1) | (127.7) | (157.8) | (4.9) | (21.3) | (26.1) | 1.66 | 2.95 | 19.24 |
| 2021 | (33.6) | (141.1) | (174.8) | (5.4) | (23.4) | (28.8) | 1.66 | 3.93 | 25.65 |
| 2022 | (37.2) | (154.6) | (191.7) | (5.9) | (25.6) | (31.5) | 1.66 | 3.93 | 25.65 |
| 2023 | (40.7) | (168.0) | (208.7) | (6.5) | (27.7) | (34.2) | 1.66 | 3.93 | 25.65 |
| 2024 | (44.3) | (181.4) | (225.7) | (7.0) | (29.9) | (36.9) | 1.66 | 3.93 | 25.65 |
| 2025 | (47.8) | (194.9) | (242.7) | (7.6) | (32.0) | (39.6) | 1.66 | 3.93 | 25.65 |
| 2026 | (51.3) | (208.3) | (259.7) | (8.1) | (34.2) | (42.3) | 1.99 | 4.72 | 30.78 |
| 2027 | (54.9) | (221.8) | (276.6) | (8.6) | (36.3) | (45.0) | 1.99 | 4.72 | 30.78 |
| 2028 | (58.4) | (235.2) | (293.6) | (9.2) | (38.5) | (47.7) | 1.99 | 4.72 | 30.78 |
| 2029 | (62.0) | (248.6) | (310.6) | (9.7) | (40.6) | (50.3) | 1.99 | 4.72 | 30.78 |
| 2030 | (65.5) | (262.1) | (327.6) | (10.2) | (42.8) | (53.0) | 1.99 | 4.72 | 30.78 |
| 2031 | (68.2) | (275.5) | (343.7) | (10.5) | (44.9) | (55.5) | 1.99 | 4.72 | 30.78 |
| 2032 | (70.0) | (289.0) | (358.9) | (10.8) | (47.1) | (57.9) | 1.99 | 4.72 | 30.78 |
| 2033 | (71.8) | (302.4) | (374.2) | (11.1) | (49.1) | (60.2) | 1.99 | 4.72 | 30.78 |

## *Maui Energy Efficiency Contribution Data for Each Scenario*

Table E-93: Maui Blazing a Bold Frontier Scenario Energy Efficiency Data

| Year | Energy Savings [GWh] | | | Peak Demand Impacts [MW] | | | PBFA DSM Program Cost ($ million) | | |
|---|---|---|---|---|---|---|---|---|---|
| | *Non-PBFA EEPS Contributions* | *PBFA DSM Programs Energy Savings* | *Total EEPS Energy Savings* | *Non-PBFA EEPS Contributions* | *PBFA DSM Programs Peak Demand* | *Total EEPS Peak Demand* | *Program Costs (excluding incentives or rebates)* | *Incentives and Rebates* | *Customer Costs* |
| 2012 | (2.0) | (7.5) | (9.5) | (0.6) | (2.3) | (2.8) | 1.12 | 1.98 | 12.94 |
| 2013 | (6.0) | (22.6) | (28.5) | (1.2) | (4.5) | (5.7) | 1.12 | 1.98 | 12.94 |
| 2014 | (9.9) | (37.6) | (47.6) | (1.8) | (6.9) | (8.6) | 1.49 | 2.64 | 17.24 |
| 2015 | (13.9) | (52.7) | (66.6) | (2.4) | (9.2) | (11.6) | 1.49 | 2.64 | 17.24 |
| 2016 | (17.9) | (67.8) | (85.6) | (3.0) | (11.6) | (14.6) | 1.49 | 2.64 | 17.24 |
| 2017 | (21.8) | (82.8) | (104.6) | (3.6) | (14.0) | (17.5) | 1.49 | 2.64 | 17.24 |
| 2018 | (25.8) | (97.9) | (123.7) | (4.2) | (16.3) | (20.5) | 1.49 | 2.64 | 17.24 |
| 2019 | (29.8) | (112.9) | (142.7) | (4.7) | (18.7) | (23.4) | 1.49 | 2.64 | 17.24 |
| 2020 | (33.7) | (128.0) | (161.7) | (5.3) | (21.1) | (26.4) | 1.86 | 3.30 | 21.55 |
| 2021 | (37.7) | (143.1) | (180.7) | (5.9) | (23.4) | (29.4) | 1.86 | 4.40 | 28.74 |
| 2022 | (41.7) | (158.1) | (199.8) | (6.5) | (25.8) | (32.3) | 1.86 | 4.40 | 28.74 |
| 2023 | (45.6) | (173.2) | (218.8) | (7.1) | (28.1) | (35.3) | 1.86 | 4.40 | 28.74 |
| 2024 | (49.6) | (188.2) | (237.8) | (7.7) | (30.5) | (38.2) | 1.86 | 4.40 | 28.74 |
| 2025 | (53.6) | (203.3) | (256.8) | (8.3) | (32.9) | (41.2) | 1.86 | 4.40 | 28.74 |
| 2026 | (57.5) | (218.3) | (275.9) | (8.9) | (35.2) | (44.1) | 2.23 | 5.29 | 34.49 |
| 2027 | (61.5) | (233.4) | (294.9) | (9.5) | (37.6) | (47.1) | 2.23 | 5.29 | 34.49 |
| 2028 | (65.5) | (248.5) | (313.9) | (10.1) | (40.0) | (50.1) | 2.23 | 5.29 | 34.49 |
| 2029 | (69.4) | (263.5) | (332.9) | (10.7) | (42.3) | (53.0) | 2.23 | 5.29 | 34.49 |
| 2030 | (73.4) | (278.6) | (352.0) | (11.3) | (44.7) | (56.0) | 2.23 | 5.29 | 34.49 |
| 2031 | (76.4) | (293.6) | (370.0) | (11.6) | (47.1) | (58.6) | 2.23 | 5.29 | 34.49 |
| 2032 | (78.4) | (308.7) | (387.1) | (11.9) | (49.4) | (61.3) | 2.23 | 5.29 | 34.49 |
| 2033 | (80.4) | (323.8) | (404.2) | (12.2) | (51.8) | (64.0) | 2.23 | 5.29 | 34.49 |

Table E-94: Maui Stuck in the Middle Scenario Energy Efficiency Data

| Year | Energy Savings [GWh] | | | Peak Demand Impacts [MW] | | | PBFA DSM Program Cost ($ million] | | |
|---|---|---|---|---|---|---|---|---|---|
| | *Non-PBFA EEPS Contributions* | *PBFA DSM Programs Energy Savings* | *Total EEPS Energy Savings* | *Non-PBFA EEPS Contributions* | *PBFA DSM Programs Peak Demand* | *Total EEPS Peak Demand* | *Program Costs (excluding incentives or rebates)* | *Incentives and Rebates* | *Customer Costs* |
| 2012 | (1.4) | (5.1) | (6.5) | (0.4) | (1.5) | (1.9) | 0.76 | 1.35 | 8.82 |
| 2013 | (4.1) | (15.4) | (19.5) | (0.8) | (3.1) | (3.9) | 0.76 | 1.35 | 8.82 |
| 2014 | (6.8) | (25.7) | (32.4) | (1.2) | (4.7) | (5.9) | 1.02 | 1.80 | 11.76 |
| 2015 | (9.5) | (35.9) | (45.4) | (1.6) | (6.3) | (7.9) | 1.02 | 1.80 | 11.76 |
| 2016 | (12.2) | (46.2) | (58.4) | (2.0) | (7.9) | (9.9) | 1.02 | 1.80 | 11.76 |
| 2017 | (14.9) | (56.5) | (71.3) | (2.4) | (9.5) | (11.9) | 1.02 | 1.80 | 11.76 |
| 2018 | (17.6) | (66.7) | (84.3) | (2.8) | (11.1) | (14.0) | 1.02 | 1.80 | 11.76 |
| 2019 | (20.3) | (77.0) | (97.3) | (3.2) | (12.7) | (16.0) | 1.02 | 1.80 | 11.76 |
| 2020 | (23.0) | (87.3) | (110.3) | (3.6) | (14.4) | (18.0) | 1.27 | 2.25 | 14.70 |
| 2021 | (25.7) | (97.5) | (123.2) | (4.0) | (16.0) | (20.0) | 1.27 | 3.00 | 19.59 |
| 2022 | (28.4) | (107.8) | (136.2) | (4.5) | (17.6) | (22.0) | 1.27 | 3.00 | 19.59 |
| 2023 | (31.1) | (118.1) | (149.2) | (4.9) | (19.2) | (24.0) | 1.27 | 3.00 | 19.59 |
| 2024 | (33.8) | (128.3) | (162.1) | (5.3) | (20.8) | (26.1) | 1.27 | 3.00 | 19.59 |
| 2025 | (36.5) | (138.6) | (175.1) | (5.7) | (22.4) | (28.1) | 1.27 | 3.00 | 19.59 |
| 2026 | (39.2) | (148.9) | (188.1) | (6.1) | (24.0) | (30.1) | 1.52 | 3.60 | 23.51 |
| 2027 | (41.9) | (159.1) | (201.1) | (6.5) | (25.6) | (32.1) | 1.52 | 3.60 | 23.51 |
| 2028 | (44.6) | (169.4) | (214.0) | (6.9) | (27.3) | (34.1) | 1.52 | 3.60 | 23.51 |
| 2029 | (47.3) | (179.7) | (227.0) | (7.3) | (28.9) | (36.1) | 1.52 | 3.60 | 23.51 |
| 2030 | (50.0) | (189.9) | (240.0) | (7.7) | (30.5) | (38.2) | 1.52 | 3.60 | 23.51 |
| 2031 | (52.1) | (200.2) | (252.3) | (7.9) | (32.1) | (40.0) | 1.52 | 3.60 | 23.51 |
| 2032 | (53.5) | (210.5) | (263.9) | (8.1) | (33.7) | (41.8) | 1.52 | 3.60 | 23.51 |
| 2033 | (54.9) | (220.7) | (275.6) | (8.3) | (35.3) | (43.6) | 1.52 | 3.60 | 23.51 |

Table E-95: Maui No Burning Desire Scenario Energy Efficiency Data

| Year | Energy Savings [GWh] | | | Peak Demand Impacts [MW] | | | PBFA DSM Program Cost ($ million] | | |
|---|---|---|---|---|---|---|---|---|---|
| | *Non-PBFA EEPS Contributions* | *PBFA DSM Programs Energy Savings* | *Total EEPS Energy Savings* | *Non-PBFA EEPS Contributions* | *PBFA DSM Programs Peak Demand* | *Total EEPS Peak Demand* | *Program Costs (excluding incentives or rebates)* | *Incentives and Rebates* | *Customer Costs* |
| 2012 | (1.4) | (5.1) | (6.5) | (0.4) | (1.5) | (1.9) | 0.76 | 1.35 | 8.82 |
| 2013 | (4.1) | (15.4) | (19.5) | (0.8) | (3.1) | (3.9) | 0.76 | 1.35 | 8.82 |
| 2014 | (6.8) | (25.7) | (32.4) | (1.2) | (4.7) | (5.9) | 1.02 | 1.80 | 11.76 |
| 2015 | (9.5) | (35.9) | (45.4) | (1.6) | (6.3) | (7.9) | 1.02 | 1.80 | 11.76 |
| 2016 | (12.2) | (46.2) | (58.4) | (2.0) | (7.9) | (9.9) | 1.02 | 1.80 | 11.76 |
| 2017 | (14.9) | (56.5) | (71.3) | (2.4) | (9.5) | (11.9) | 1.02 | 1.80 | 11.76 |
| 2018 | (17.6) | (66.7) | (84.3) | (2.8) | (11.1) | (14.0) | 1.02 | 1.80 | 11.76 |
| 2019 | (20.3) | (77.0) | (97.3) | (3.2) | (12.7) | (16.0) | 1.02 | 1.80 | 11.76 |
| 2020 | (23.0) | (87.3) | (110.3) | (3.6) | (14.4) | (18.0) | 1.27 | 2.25 | 14.70 |
| 2021 | (25.7) | (97.5) | (123.2) | (4.0) | (16.0) | (20.0) | 1.27 | 3.00 | 19.59 |
| 2022 | (28.4) | (107.8) | (136.2) | (4.5) | (17.6) | (22.0) | 1.27 | 3.00 | 19.59 |
| 2023 | (31.1) | (118.1) | (149.2) | (4.9) | (19.2) | (24.0) | 1.27 | 3.00 | 19.59 |
| 2024 | (33.8) | (128.3) | (162.1) | (5.3) | (20.8) | (26.1) | 1.27 | 3.00 | 19.59 |
| 2025 | (36.5) | (138.6) | (175.1) | (5.7) | (22.4) | (28.1) | 1.27 | 3.00 | 19.59 |
| 2026 | (39.2) | (148.9) | (188.1) | (6.1) | (24.0) | (30.1) | 1.52 | 3.60 | 23.51 |
| 2027 | (41.9) | (159.1) | (201.1) | (6.5) | (25.6) | (32.1) | 1.52 | 3.60 | 23.51 |
| 2028 | (44.6) | (169.4) | (214.0) | (6.9) | (27.3) | (34.1) | 1.52 | 3.60 | 23.51 |
| 2029 | (47.3) | (179.7) | (227.0) | (7.3) | (28.9) | (36.1) | 1.52 | 3.60 | 23.51 |
| 2030 | (50.0) | (189.9) | (240.0) | (7.7) | (30.5) | (38.2) | 1.52 | 3.60 | 23.51 |
| 2031 | (52.1) | (200.2) | (252.3) | (7.9) | (32.1) | (40.0) | 1.52 | 3.60 | 23.51 |
| 2032 | (53.5) | (210.5) | (263.9) | (8.1) | (33.7) | (41.8) | 1.52 | 3.60 | 23.51 |
| 2033 | (54.9) | (220.7) | (275.6) | (8.3) | (35.3) | (43.6) | 1.52 | 3.60 | 23.51 |

Table E-96: Maui Moved by Passion Scenario Energy Efficiency Data

| Year | Energy Savings [GWh] | | | Peak Demand Impacts [MW] | | | PBFA DSM Program Cost ($ million] | | |
|---|---|---|---|---|---|---|---|---|---|
| | *Non-PBFA EEPS Contributions* | *PBFA DSM Programs Energy Savings* | *Total EEPS Energy Savings* | *Non-PBFA EEPS Contributions* | *PBFA DSM Programs Peak Demand* | *Total EEPS Peak Demand* | *Program Costs (excluding incentives or rebates)* | *Incentives and Rebates* | *Customer Costs* |
| 2012 | (1.8) | (6.8) | (8.6) | (0.5) | (2.0) | (2.6) | 1.02 | 1.80 | 11.76 |
| 2013 | (5.4) | (20.5) | (25.9) | (1.1) | (4.1) | (5.2) | 1.02 | 1.80 | 11.76 |
| 2014 | (9.0) | (34.2) | (43.2) | (1.6) | (6.2) | (7.9) | 1.35 | 2.40 | 15.68 |
| 2015 | (12.6) | (47.9) | (60.5) | (2.2) | (8.4) | (10.6) | 1.35 | 2.40 | 15.68 |
| 2016 | (16.2) | (61.6) | (77.8) | (2.7) | (10.5) | (13.2) | 1.35 | 2.40 | 15.68 |
| 2017 | (19.8) | (75.3) | (95.1) | (3.2) | (12.7) | (15.9) | 1.35 | 2.40 | 15.68 |
| 2018 | (23.4) | (89.0) | (112.4) | (3.8) | (14.8) | (18.6) | 1.35 | 2.40 | 15.68 |
| 2019 | (27.0) | (102.7) | (129.7) | (4.3) | (17.0) | (21.3) | 1.35 | 2.40 | 15.68 |
| 2020 | (30.7) | (116.4) | (147.0) | (4.9) | (19.1) | (24.0) | 1.69 | 3.00 | 19.60 |
| 2021 | (34.3) | (130.0) | (164.3) | (5.4) | (21.3) | (26.7) | 1.69 | 4.00 | 26.13 |
| 2022 | (37.9) | (143.7) | (181.6) | (5.9) | (23.4) | (29.4) | 1.69 | 4.00 | 26.13 |
| 2023 | (41.5) | (157.4) | (198.9) | (6.5) | (25.6) | (32.1) | 1.69 | 4.00 | 26.13 |
| 2024 | (45.1) | (171.1) | (216.2) | (7.0) | (27.7) | (34.8) | 1.69 | 4.00 | 26.13 |
| 2025 | (48.7) | (184.8) | (233.5) | (7.6) | (29.9) | (37.4) | 1.69 | 4.00 | 26.13 |
| 2026 | (52.3) | (198.5) | (250.8) | (8.1) | (32.0) | (40.1) | 2.03 | 4.80 | 31.35 |
| 2027 | (55.9) | (212.2) | (268.1) | (8.6) | (34.2) | (42.8) | 2.03 | 4.80 | 31.35 |
| 2028 | (59.5) | (225.9) | (285.4) | (9.2) | (36.3) | (45.5) | 2.03 | 4.80 | 31.35 |
| 2029 | (63.1) | (239.6) | (302.7) | (9.7) | (38.5) | (48.2) | 2.03 | 4.80 | 31.35 |
| 2030 | (66.7) | (253.3) | (320.0) | (10.2) | (40.6) | (50.9) | 2.03 | 4.80 | 31.35 |
| 2031 | (69.4) | (266.9) | (336.4) | (10.5) | (42.8) | (53.3) | 2.03 | 4.80 | 31.35 |
| 2032 | (71.3) | (280.6) | (351.9) | (10.8) | (44.9) | (55.7) | 2.03 | 4.80 | 31.35 |
| 2033 | (73.1) | (294.3) | (367.5) | (11.1) | (47.1) | (58.2) | 2.03 | 4.80 | 31.35 |

## *Lanai Energy Efficiency Contribution Data for Each Scenario*

Table E-97: Lanai Blazing a Bold Frontier Scenario Energy Efficiency Data

| Year | Energy Savings [GWh] | | | Peak Demand Impacts [MW] | | | PBFA DSM Program Cost ($ million) | | |
|---|---|---|---|---|---|---|---|---|---|
| | *Non-PBFA EEPS Contributions* | *PBFA DSM Programs Energy Savings* | *Total EEPS Energy Savings* | *Non-PBFA EEPS Contributions* | *PBFA DSM Programs Peak Demand* | *Total EEPS Peak Demand* | *Program Costs (excluding incentives or rebates)* | *Incentives and Rebates* | *Customer Costs* |
| 2012 | (0.044) | (0.168) | (0.212) | (0.013) | (0.050) | (0.064) | 0.025 | 0.044 | 0.289 |
| 2013 | (0.133) | (0.505) | (0.637) | (0.027) | (0.101) | (0.127) | 0.025 | 0.044 | 0.289 |
| 2014 | (0.222) | (0.841) | (1.062) | (0.040) | (0.153) | (0.193) | 0.025 | 0.044 | 0.289 |
| 2015 | (0.310) | (1.177) | (1.487) | (0.053) | (0.206) | (0.259) | 0.033 | 0.059 | 0.385 |
| 2016 | (0.399) | (1.514) | (1.912) | (0.066) | (0.259) | (0.325) | 0.033 | 0.059 | 0.385 |
| 2017 | (0.487) | (1.850) | (2.337) | (0.080) | (0.312) | (0.391) | 0.033 | 0.059 | 0.385 |
| 2018 | (0.576) | (2.186) | (2.762) | (0.093) | (0.365) | (0.457) | 0.033 | 0.059 | 0.385 |
| 2019 | (0.665) | (2.523) | (3.187) | (0.106) | (0.418) | (0.524) | 0.033 | 0.059 | 0.385 |
| 2020 | (0.753) | (2.859) | (3.612) | (0.119) | (0.470) | (0.590) | 0.033 | 0.059 | 0.385 |
| 2021 | (0.842) | (3.195) | (4.037) | (0.133) | (0.523) | (0.656) | 0.042 | 0.074 | 0.481 |
| 2022 | (0.930) | (3.532) | (4.462) | (0.146) | (0.576) | (0.722) | 0.042 | 0.098 | 0.642 |
| 2023 | (1.019) | (3.868) | (4.887) | (0.159) | (0.629) | (0.788) | 0.042 | 0.098 | 0.642 |
| 2024 | (1.108) | (4.205) | (5.312) | (0.172) | (0.682) | (0.854) | 0.042 | 0.098 | 0.642 |
| 2025 | (1.196) | (4.541) | (5.737) | (0.186) | (0.734) | (0.920) | 0.042 | 0.098 | 0.642 |
| 2026 | (1.285) | (4.877) | (6.162) | (0.199) | (0.787) | (0.986) | 0.042 | 0.098 | 0.642 |
| 2027 | (1.374) | (5.214) | (6.587) | (0.212) | (0.840) | (1.052) | 0.050 | 0.118 | 0.770 |
| 2028 | (1.462) | (5.550) | (7.012) | (0.225) | (0.893) | (1.118) | 0.050 | 0.118 | 0.770 |
| 2029 | (1.551) | (5.886) | (7.437) | (0.239) | (0.946) | (1.184) | 0.050 | 0.118 | 0.770 |
| 2030 | (1.639) | (6.223) | (7.862) | (0.252) | (0.998) | (1.250) | 0.050 | 0.118 | 0.770 |
| 2031 | (1.706) | (6.559) | (8.266) | (0.259) | (1.051) | (1.310) | 0.050 | 0.118 | 0.770 |
| 2032 | (1.752) | (6.896) | (8.647) | (0.265) | (1.104) | (1.370) | 0.050 | 0.118 | 0.770 |
| 2033 | (1.797) | (7.232) | (9.029) | (0.272) | (1.157) | (1.429) | 0.050 | 0.118 | 0.770 |

Table E-98: Lanai Stuck in the Middle Scenario Energy Efficiency Data

| Year | Energy Savings [GWh] | | | Peak Demand Impacts [MW] | | | PBFA DSM Program Cost ($ million] | | |
|---|---|---|---|---|---|---|---|---|---|
| | *Non-PBFA EEPS Contributions* | *PBFA DSM Programs Energy Savings* | *Total EEPS Energy Savings* | *Non-PBFA EEPS Contributions* | *PBFA DSM Programs Peak Demand* | *Total EEPS Peak Demand* | *Program Costs (excluding incentives or rebates)* | *Incentives and Rebates* | *Customer Costs* |
| 2012 | (0.030) | (0.115) | (0.145) | (0.009) | (0.034) | (0.043) | 0.017 | 0.030 | 0.197 |
| 2013 | (0.091) | (0.344) | (0.435) | (0.018) | (0.069) | (0.087) | 0.017 | 0.030 | 0.197 |
| 2014 | (0.151) | (0.573) | (0.724) | (0.027) | (0.105) | (0.132) | 0.017 | 0.030 | 0.197 |
| 2015 | (0.211) | (0.803) | (1.014) | (0.036) | (0.141) | (0.177) | 0.023 | 0.040 | 0.263 |
| 2016 | (0.272) | (1.032) | (1.304) | (0.045) | (0.177) | (0.222) | 0.023 | 0.040 | 0.263 |
| 2017 | (0.332) | (1.261) | (1.594) | (0.054) | (0.213) | (0.267) | 0.023 | 0.040 | 0.263 |
| 2018 | (0.393) | (1.491) | (1.883) | (0.063) | (0.249) | (0.312) | 0.023 | 0.040 | 0.263 |
| 2019 | (0.453) | (1.720) | (2.173) | (0.072) | (0.285) | (0.357) | 0.023 | 0.040 | 0.263 |
| 2020 | (0.514) | (1.949) | (2.463) | (0.081) | (0.321) | (0.402) | 0.023 | 0.040 | 0.263 |
| 2021 | (0.574) | (2.179) | (2.753) | (0.090) | (0.357) | (0.447) | 0.028 | 0.050 | 0.328 |
| 2022 | (0.634) | (2.408) | (3.042) | (0.099) | (0.393) | (0.492) | 0.028 | 0.067 | 0.438 |
| 2023 | (0.695) | (2.637) | (3.332) | (0.108) | (0.429) | (0.537) | 0.028 | 0.067 | 0.438 |
| 2024 | (0.755) | (2.867) | (3.622) | (0.117) | (0.465) | (0.582) | 0.028 | 0.067 | 0.438 |
| 2025 | (0.816) | (3.096) | (3.912) | (0.127) | (0.501) | (0.627) | 0.028 | 0.067 | 0.438 |
| 2026 | (0.876) | (3.325) | (4.202) | (0.136) | (0.537) | (0.672) | 0.028 | 0.067 | 0.438 |
| 2027 | (0.936) | (3.555) | (4.491) | (0.145) | (0.573) | (0.717) | 0.034 | 0.080 | 0.525 |
| 2028 | (0.997) | (3.784) | (4.781) | (0.154) | (0.609) | (0.762) | 0.034 | 0.080 | 0.525 |
| 2029 | (1.057) | (4.013) | (5.071) | (0.163) | (0.645) | (0.807) | 0.034 | 0.080 | 0.525 |
| 2030 | (1.118) | (4.243) | (5.361) | (0.172) | (0.681) | (0.852) | 0.034 | 0.080 | 0.525 |
| 2031 | (1.163) | (4.472) | (5.636) | (0.176) | (0.717) | (0.893) | 0.034 | 0.080 | 0.525 |
| 2032 | (1.194) | (4.701) | (5.896) | (0.181) | (0.753) | (0.934) | 0.034 | 0.080 | 0.525 |
| 2033 | (1.225) | (4.931) | (6.156) | (0.186) | (0.789) | (0.974) | 0.034 | 0.080 | 0.525 |

Table E-99: Lanai No Burning Desire Scenario Energy Efficiency Data

| Year | Energy Savings [GWh] | | | Peak Demand Impacts [MW] | | | PBFA DSM Program Cost ($ million] | | |
|---|---|---|---|---|---|---|---|---|---|
| | *Non-PBFA EEPS Contributions* | *PBFA DSM Programs Energy Savings* | *Total EEPS Energy Savings* | *Non-PBFA EEPS Contributions* | *PBFA DSM Programs Peak Demand* | *Total EEPS Peak Demand* | *Program Costs (excluding incentives or rebates)* | *Incentives and Rebates* | *Customer Costs* |
| 2012 | (0.030) | (0.115) | (0.145) | (0.009) | (0.034) | (0.043) | 0.017 | 0.030 | 0.197 |
| 2013 | (0.091) | (0.344) | (0.435) | (0.018) | (0.069) | (0.087) | 0.017 | 0.030 | 0.197 |
| 2014 | (0.151) | (0.573) | (0.724) | (0.027) | (0.105) | (0.132) | 0.017 | 0.030 | 0.197 |
| 2015 | (0.211) | (0.803) | (1.014) | (0.036) | (0.141) | (0.177) | 0.023 | 0.040 | 0.263 |
| 2016 | (0.272) | (1.032) | (1.304) | (0.045) | (0.177) | (0.222) | 0.023 | 0.040 | 0.263 |
| 2017 | (0.332) | (1.261) | (1.594) | (0.054) | (0.213) | (0.267) | 0.023 | 0.040 | 0.263 |
| 2018 | (0.393) | (1.491) | (1.883) | (0.063) | (0.249) | (0.312) | 0.023 | 0.040 | 0.263 |
| 2019 | (0.453) | (1.720) | (2.173) | (0.072) | (0.285) | (0.357) | 0.023 | 0.040 | 0.263 |
| 2020 | (0.514) | (1.949) | (2.463) | (0.081) | (0.321) | (0.402) | 0.023 | 0.040 | 0.263 |
| 2021 | (0.574) | (2.179) | (2.753) | (0.090) | (0.357) | (0.447) | 0.028 | 0.050 | 0.328 |
| 2022 | (0.634) | (2.408) | (3.042) | (0.099) | (0.393) | (0.492) | 0.028 | 0.067 | 0.438 |
| 2023 | (0.695) | (2.637) | (3.332) | (0.108) | (0.429) | (0.537) | 0.028 | 0.067 | 0.438 |
| 2024 | (0.755) | (2.867) | (3.622) | (0.117) | (0.465) | (0.582) | 0.028 | 0.067 | 0.438 |
| 2025 | (0.816) | (3.096) | (3.912) | (0.127) | (0.501) | (0.627) | 0.028 | 0.067 | 0.438 |
| 2026 | (0.876) | (3.325) | (4.202) | (0.136) | (0.537) | (0.672) | 0.028 | 0.067 | 0.438 |
| 2027 | (0.936) | (3.555) | (4.491) | (0.145) | (0.573) | (0.717) | 0.034 | 0.080 | 0.525 |
| 2028 | (0.997) | (3.784) | (4.781) | (0.154) | (0.609) | (0.762) | 0.034 | 0.080 | 0.525 |
| 2029 | (1.057) | (4.013) | (5.071) | (0.163) | (0.645) | (0.807) | 0.034 | 0.080 | 0.525 |
| 2030 | (1.118) | (4.243) | (5.361) | (0.172) | (0.681) | (0.852) | 0.034 | 0.080 | 0.525 |
| 2031 | (1.163) | (4.472) | (5.636) | (0.176) | (0.717) | (0.893) | 0.034 | 0.080 | 0.525 |
| 2032 | (1.194) | (4.701) | (5.896) | (0.181) | (0.753) | (0.934) | 0.034 | 0.080 | 0.525 |
| 2033 | (1.225) | (4.931) | (6.156) | (0.186) | (0.789) | (0.974) | 0.034 | 0.080 | 0.525 |

Table E-100: Lanai Moved by Passion Scenario Energy Efficiency Data

| Year | Energy Savings [GWh] | | | Peak Demand Impacts [MW] | | | PBFA DSM Program Cost ($ million] | | |
|---|---|---|---|---|---|---|---|---|---|
| | *Non-PBFA EEPS Contributions* | *PBFA DSM Programs Energy Savings* | *Total EEPS Energy Savings* | *Non-PBFA EEPS Contributions* | *PBFA DSM Programs Peak Demand* | *Total EEPS Peak Demand* | *Program Costs (excluding incentives or rebates)* | *Incentives and Rebates* | *Customer Costs* |
| 2012 | (0.040) | (0.153) | (0.193) | (0.012) | (0.046) | (0.058) | 0.023 | 0.040 | 0.263 |
| 2013 | (0.121) | (0.459) | (0.580) | (0.024) | (0.091) | (0.116) | 0.023 | 0.040 | 0.263 |
| 2014 | (0.201) | (0.764) | (0.966) | (0.036) | (0.139) | (0.176) | 0.023 | 0.040 | 0.263 |
| 2015 | (0.282) | (1.070) | (1.352) | (0.048) | (0.188) | (0.236) | 0.030 | 0.054 | 0.350 |
| 2016 | (0.363) | (1.376) | (1.739) | (0.060) | (0.236) | (0.296) | 0.030 | 0.054 | 0.350 |
| 2017 | (0.443) | (1.682) | (2.125) | (0.072) | (0.284) | (0.356) | 0.030 | 0.054 | 0.350 |
| 2018 | (0.524) | (1.988) | (2.511) | (0.084) | (0.332) | (0.416) | 0.030 | 0.054 | 0.350 |
| 2019 | (0.604) | (2.293) | (2.898) | (0.096) | (0.380) | (0.476) | 0.030 | 0.054 | 0.350 |
| 2020 | (0.685) | (2.599) | (3.284) | (0.108) | (0.428) | (0.536) | 0.030 | 0.054 | 0.350 |
| 2021 | (0.765) | (2.905) | (3.670) | (0.120) | (0.476) | (0.596) | 0.038 | 0.067 | 0.438 |
| 2022 | (0.846) | (3.211) | (4.057) | (0.133) | (0.524) | (0.656) | 0.038 | 0.089 | 0.584 |
| 2023 | (0.926) | (3.517) | (4.443) | (0.145) | (0.572) | (0.716) | 0.038 | 0.089 | 0.584 |
| 2024 | (1.007) | (3.822) | (4.829) | (0.157) | (0.620) | (0.776) | 0.038 | 0.089 | 0.584 |
| 2025 | (1.088) | (4.128) | (5.216) | (0.169) | (0.668) | (0.836) | 0.038 | 0.089 | 0.584 |
| 2026 | (1.168) | (4.434) | (5.602) | (0.181) | (0.716) | (0.896) | 0.038 | 0.089 | 0.584 |
| 2027 | (1.249) | (4.740) | (5.988) | (0.193) | (0.764) | (0.956) | 0.045 | 0.107 | 0.700 |
| 2028 | (1.329) | (5.046) | (6.375) | (0.205) | (0.812) | (1.017) | 0.045 | 0.107 | 0.700 |
| 2029 | (1.410) | (5.351) | (6.761) | (0.217) | (0.860) | (1.077) | 0.045 | 0.107 | 0.700 |
| 2030 | (1.490) | (5.657) | (7.147) | (0.229) | (0.908) | (1.137) | 0.045 | 0.107 | 0.700 |
| 2031 | (1.551) | (5.963) | (7.514) | (0.235) | (0.956) | (1.191) | 0.045 | 0.107 | 0.700 |
| 2032 | (1.592) | (6.269) | (7.861) | (0.241) | (1.004) | (1.245) | 0.045 | 0.107 | 0.700 |
| 2033 | (1.634) | (6.574) | (8.208) | (0.247) | (1.052) | (1.299) | 0.045 | 0.107 | 0.700 |

## *Molokai Energy Efficiency Contribution Data for Each Scenario*

Table E-101: Molokai Blazing a Bold Frontier Scenario Energy Efficiency Data

| Year | Energy Savings [GWh] | | | Peak Demand Impacts [MW] | | | PBFA DSM Program Cost ($ million) | | |
|---|---|---|---|---|---|---|---|---|---|
| | *Non-PBFA EEPS Contributions* | *PBFA DSM Programs Energy Savings* | *Total EEPS Energy Savings* | *Non-PBFA EEPS Contributions* | *PBFA DSM Programs Peak Demand* | *Total EEPS Peak Demand* | *Program Costs (excluding incentives or rebates)* | *Incentives and Rebates* | *Customer Costs* |
| 2012 | (0.055) | (0.208) | (0.263) | (0.016) | (0.062) | (0.079) | 0.031 | 0.055 | 0.358 |
| 2013 | (0.165) | (0.625) | (0.790) | (0.033) | (0.125) | (0.158) | 0.031 | 0.055 | 0.358 |
| 2014 | (0.274) | (1.042) | (1.316) | (0.049) | (0.190) | (0.239) | 0.041 | 0.073 | 0.477 |
| 2015 | (0.384) | (1.459) | (1.843) | (0.066) | (0.256) | (0.321) | 0.041 | 0.073 | 0.477 |
| 2016 | (0.494) | (1.875) | (2.369) | (0.082) | (0.321) | (0.403) | 0.041 | 0.073 | 0.477 |
| 2017 | (0.604) | (2.292) | (2.896) | (0.099) | (0.386) | (0.485) | 0.041 | 0.073 | 0.477 |
| 2018 | (0.714) | (2.709) | (3.423) | (0.115) | (0.452) | (0.567) | 0.041 | 0.073 | 0.477 |
| 2019 | (0.823) | (3.126) | (3.949) | (0.131) | (0.517) | (0.649) | 0.041 | 0.073 | 0.477 |
| 2020 | (0.933) | (3.542) | (4.476) | (0.148) | (0.583) | (0.731) | 0.052 | 0.091 | 0.597 |
| 2021 | (1.043) | (3.959) | (5.002) | (0.164) | (0.648) | (0.812) | 0.052 | 0.122 | 0.795 |
| 2022 | (1.153) | (4.376) | (5.529) | (0.181) | (0.714) | (0.894) | 0.052 | 0.122 | 0.795 |
| 2023 | (1.263) | (4.793) | (6.055) | (0.197) | (0.779) | (0.976) | 0.052 | 0.122 | 0.795 |
| 2024 | (1.372) | (5.209) | (6.582) | (0.213) | (0.844) | (1.058) | 0.052 | 0.122 | 0.795 |
| 2025 | (1.482) | (5.626) | (7.108) | (0.230) | (0.910) | (1.140) | 0.052 | 0.122 | 0.795 |
| 2026 | (1.592) | (6.043) | (7.635) | (0.246) | (0.975) | (1.222) | 0.062 | 0.146 | 0.954 |
| 2027 | (1.702) | (6.460) | (8.162) | (0.263) | (1.041) | (1.304) | 0.062 | 0.146 | 0.954 |
| 2028 | (1.812) | (6.877) | (8.688) | (0.279) | (1.106) | (1.385) | 0.062 | 0.146 | 0.954 |
| 2029 | (1.921) | (7.293) | (9.215) | (0.296) | (1.172) | (1.467) | 0.062 | 0.146 | 0.954 |
| 2030 | (2.031) | (7.710) | (9.741) | (0.312) | (1.237) | (1.549) | 0.062 | 0.146 | 0.954 |
| 2031 | (2.114) | (8.127) | (10.241) | (0.320) | (1.303) | (1.623) | 0.062 | 0.146 | 0.954 |
| 2032 | (2.170) | (8.544) | (10.714) | (0.329) | (1.368) | (1.697) | 0.062 | 0.146 | 0.954 |
| 2033 | (2.227) | (8.960) | (11.187) | (0.337) | (1.433) | (1.771) | 0.062 | 0.146 | 0.954 |

Table E-102: Molokai Stuck in the Middle Scenario Energy Efficiency Data

| Year | Energy Savings [GWh] | | | Peak Demand Impacts [MW] | | | PBFA DSM Program Cost ($ million] | | |
|---|---|---|---|---|---|---|---|---|---|
| | *Non-PBFA EEPS Contributions* | *PBFA DSM Programs Energy Savings* | *Total EEPS Energy Savings* | *Non-PBFA EEPS Contributions* | *PBFA DSM Programs Peak Demand* | *Total EEPS Peak Demand* | *Program Costs (excluding incentives or rebates)* | *Incentives and Rebates* | *Customer Costs* |
| 2012 | (0.037) | (0.142) | (0.180) | (0.011) | (0.043) | (0.054) | 0.021 | 0.037 | 0.244 |
| 2013 | (0.112) | (0.426) | (0.539) | (0.022) | (0.085) | (0.107) | 0.021 | 0.037 | 0.244 |
| 2014 | (0.187) | (0.710) | (0.898) | (0.034) | (0.130) | (0.163) | 0.028 | 0.050 | 0.325 |
| 2015 | (0.262) | (0.995) | (1.257) | (0.045) | (0.174) | (0.219) | 0.028 | 0.050 | 0.325 |
| 2016 | (0.337) | (1.279) | (1.616) | (0.056) | (0.219) | (0.275) | 0.028 | 0.050 | 0.325 |
| 2017 | (0.412) | (1.563) | (1.975) | (0.067) | (0.263) | (0.331) | 0.028 | 0.050 | 0.325 |
| 2018 | (0.487) | (1.847) | (2.334) | (0.078) | (0.308) | (0.386) | 0.028 | 0.050 | 0.325 |
| 2019 | (0.561) | (2.131) | (2.693) | (0.090) | (0.353) | (0.442) | 0.028 | 0.050 | 0.325 |
| 2020 | (0.636) | (2.415) | (3.052) | (0.101) | (0.397) | (0.498) | 0.035 | 0.062 | 0.407 |
| 2021 | (0.711) | (2.699) | (3.411) | (0.112) | (0.442) | (0.554) | 0.035 | 0.083 | 0.542 |
| 2022 | (0.786) | (2.984) | (3.770) | (0.123) | (0.487) | (0.610) | 0.035 | 0.083 | 0.542 |
| 2023 | (0.861) | (3.268) | (4.129) | (0.134) | (0.531) | (0.666) | 0.035 | 0.083 | 0.542 |
| 2024 | (0.936) | (3.552) | (4.488) | (0.146) | (0.576) | (0.721) | 0.035 | 0.083 | 0.542 |
| 2025 | (1.011) | (3.836) | (4.847) | (0.157) | (0.620) | (0.777) | 0.035 | 0.083 | 0.542 |
| 2026 | (1.085) | (4.120) | (5.206) | (0.168) | (0.665) | (0.833) | 0.042 | 0.100 | 0.651 |
| 2027 | (1.160) | (4.404) | (5.565) | (0.179) | (0.710) | (0.889) | 0.042 | 0.100 | 0.651 |
| 2028 | (1.235) | (4.689) | (5.924) | (0.190) | (0.754) | (0.945) | 0.042 | 0.100 | 0.651 |
| 2029 | (1.310) | (4.973) | (6.283) | (0.202) | (0.799) | (1.000) | 0.042 | 0.100 | 0.651 |
| 2030 | (1.385) | (5.257) | (6.642) | (0.213) | (0.843) | (1.056) | 0.042 | 0.100 | 0.651 |
| 2031 | (1.441) | (5.541) | (6.982) | (0.218) | (0.888) | (1.107) | 0.042 | 0.100 | 0.651 |
| 2032 | (1.480) | (5.825) | (7.305) | (0.224) | (0.933) | (1.157) | 0.042 | 0.100 | 0.651 |
| 2033 | (1.518) | (6.109) | (7.627) | (0.230) | (0.977) | (1.207) | 0.042 | 0.100 | 0.651 |

Table E-103: Molokai No Burning Desire Scenario Energy Efficiency Data

| Year | Energy Savings [GWh] | | | Peak Demand Impacts [MW] | | | PBFA DSM Program Cost ($ million] | | |
|---|---|---|---|---|---|---|---|---|---|
| | *Non-PBFA EEPS Contributions* | *PBFA DSM Programs Energy Savings* | *Total EEPS Energy Savings* | *Non-PBFA EEPS Contributions* | *PBFA DSM Programs Peak Demand* | *Total EEPS Peak Demand* | *Program Costs (excluding incentives or rebates)* | *Incentives and Rebates* | *Customer Costs* |
| 2012 | (0.037) | (0.142) | (0.180) | (0.011) | (0.043) | (0.054) | 0.021 | 0.037 | 0.244 |
| 2013 | (0.112) | (0.426) | (0.539) | (0.022) | (0.085) | (0.107) | 0.021 | 0.037 | 0.244 |
| 2014 | (0.187) | (0.710) | (0.898) | (0.034) | (0.130) | (0.163) | 0.028 | 0.050 | 0.325 |
| 2015 | (0.262) | (0.995) | (1.257) | (0.045) | (0.174) | (0.219) | 0.028 | 0.050 | 0.325 |
| 2016 | (0.337) | (1.279) | (1.616) | (0.056) | (0.219) | (0.275) | 0.028 | 0.050 | 0.325 |
| 2017 | (0.412) | (1.563) | (1.975) | (0.067) | (0.263) | (0.331) | 0.028 | 0.050 | 0.325 |
| 2018 | (0.487) | (1.847) | (2.334) | (0.078) | (0.308) | (0.386) | 0.028 | 0.050 | 0.325 |
| 2019 | (0.561) | (2.131) | (2.693) | (0.090) | (0.353) | (0.442) | 0.028 | 0.050 | 0.325 |
| 2020 | (0.636) | (2.415) | (3.052) | (0.101) | (0.397) | (0.498) | 0.035 | 0.062 | 0.407 |
| 2021 | (0.711) | (2.699) | (3.411) | (0.112) | (0.442) | (0.554) | 0.035 | 0.083 | 0.542 |
| 2022 | (0.786) | (2.984) | (3.770) | (0.123) | (0.487) | (0.610) | 0.035 | 0.083 | 0.542 |
| 2023 | (0.861) | (3.268) | (4.129) | (0.134) | (0.531) | (0.666) | 0.035 | 0.083 | 0.542 |
| 2024 | (0.936) | (3.552) | (4.488) | (0.146) | (0.576) | (0.721) | 0.035 | 0.083 | 0.542 |
| 2025 | (1.011) | (3.836) | (4.847) | (0.157) | (0.620) | (0.777) | 0.035 | 0.083 | 0.542 |
| 2026 | (1.085) | (4.120) | (5.206) | (0.168) | (0.665) | (0.833) | 0.042 | 0.100 | 0.651 |
| 2027 | (1.160) | (4.404) | (5.565) | (0.179) | (0.710) | (0.889) | 0.042 | 0.100 | 0.651 |
| 2028 | (1.235) | (4.689) | (5.924) | (0.190) | (0.754) | (0.945) | 0.042 | 0.100 | 0.651 |
| 2029 | (1.310) | (4.973) | (6.283) | (0.202) | (0.799) | (1.000) | 0.042 | 0.100 | 0.651 |
| 2030 | (1.385) | (5.257) | (6.642) | (0.213) | (0.843) | (1.056) | 0.042 | 0.100 | 0.651 |
| 2031 | (1.441) | (5.541) | (6.982) | (0.218) | (0.888) | (1.107) | 0.042 | 0.100 | 0.651 |
| 2032 | (1.480) | (5.825) | (7.305) | (0.224) | (0.933) | (1.157) | 0.042 | 0.100 | 0.651 |
| 2033 | (1.518) | (6.109) | (7.627) | (0.230) | (0.977) | (1.207) | 0.042 | 0.100 | 0.651 |

Table E-104: Molokai Moved by Passion Scenario Energy Efficiency Data

| Year | Energy Savings [GWh] | | | Peak Demand Impacts [MW] | | | PBFA DSM Program Cost ($ million] | | |
|---|---|---|---|---|---|---|---|---|---|
| | *Non-PBFA EEPS Contributions* | *PBFA DSM Programs Energy Savings* | *Total EEPS Energy Savings* | *Non-PBFA EEPS Contributions* | *PBFA DSM Programs Peak Demand* | *Total EEPS Peak Demand* | *Program Costs (excluding incentives or rebates)* | *Incentives and Rebates* | *Customer Costs* |
| 2012 | (0.050) | (0.189) | (0.239) | (0.015) | (0.057) | (0.072) | 0.028 | 0.050 | 0.325 |
| 2013 | (0.150) | (0.568) | (0.718) | (0.030) | (0.113) | (0.143) | 0.028 | 0.050 | 0.325 |
| 2014 | (0.250) | (0.947) | (1.197) | (0.045) | (0.173) | (0.218) | 0.037 | 0.066 | 0.434 |
| 2015 | (0.349) | (1.326) | (1.675) | (0.060) | (0.232) | (0.292) | 0.037 | 0.066 | 0.434 |
| 2016 | (0.449) | (1.705) | (2.154) | (0.075) | (0.292) | (0.366) | 0.037 | 0.066 | 0.434 |
| 2017 | (0.549) | (2.084) | (2.633) | (0.090) | (0.351) | (0.441) | 0.037 | 0.066 | 0.434 |
| 2018 | (0.649) | (2.463) | (3.111) | (0.105) | (0.411) | (0.515) | 0.037 | 0.066 | 0.434 |
| 2019 | (0.749) | (2.842) | (3.590) | (0.119) | (0.470) | (0.590) | 0.037 | 0.066 | 0.434 |
| 2020 | (0.848) | (3.220) | (4.069) | (0.134) | (0.530) | (0.664) | 0.047 | 0.083 | 0.542 |
| 2021 | (0.948) | (3.599) | (4.547) | (0.149) | (0.589) | (0.739) | 0.047 | 0.111 | 0.723 |
| 2022 | (1.048) | (3.978) | (5.026) | (0.164) | (0.649) | (0.813) | 0.047 | 0.111 | 0.723 |
| 2023 | (1.148) | (4.357) | (5.505) | (0.179) | (0.708) | (0.887) | 0.047 | 0.111 | 0.723 |
| 2024 | (1.248) | (4.736) | (5.984) | (0.194) | (0.768) | (0.962) | 0.047 | 0.111 | 0.723 |
| 2025 | (1.347) | (5.115) | (6.462) | (0.209) | (0.827) | (1.036) | 0.047 | 0.111 | 0.723 |
| 2026 | (1.447) | (5.494) | (6.941) | (0.224) | (0.887) | (1.111) | 0.056 | 0.133 | 0.868 |
| 2027 | (1.547) | (5.873) | (7.420) | (0.239) | (0.946) | (1.185) | 0.056 | 0.133 | 0.868 |
| 2028 | (1.647) | (6.251) | (7.898) | (0.254) | (1.006) | (1.259) | 0.056 | 0.133 | 0.868 |
| 2029 | (1.747) | (6.630) | (8.377) | (0.269) | (1.065) | (1.334) | 0.056 | 0.133 | 0.868 |
| 2030 | (1.847) | (7.009) | (8.856) | (0.284) | (1.125) | (1.408) | 0.056 | 0.133 | 0.868 |
| 2031 | (1.922) | (7.388) | (9.310) | (0.291) | (1.184) | (1.475) | 0.056 | 0.133 | 0.868 |
| 2032 | (1.973) | (7.767) | (9.740) | (0.299) | (1.244) | (1.543) | 0.056 | 0.133 | 0.868 |
| 2033 | (2.024) | (8.146) | (10.170) | (0.307) | (1.303) | (1.610) | 0.056 | 0.133 | 0.868 |

# Appendix E-10: Electric Vehicles Forecast Data

## *Hawaiian Electric Vehicles Forecast Data*

Table E-105: HECO Electric Vehicles Forecast Data (GWh)

| Year | Blazing a Bold Frontier | Stuck in the Middle | No Burning Desire | Moved by Passion |
|---|---|---|---|---|
| 2012 | 4 | 2 | 1 | 2 |
| 2013 | 7 | 4 | 2 | 4 |
| 2014 | 12 | 6 | 3 | 6 |
| 2015 | 17 | 9 | 4 | 9 |
| 2016 | 27 | 13 | 7 | 13 |
| 2017 | 39 | 20 | 10 | 20 |
| 2018 | 54 | 27 | 14 | 27 |
| 2019 | 71 | 36 | 18 | 36 |
| 2020 | 92 | 46 | 23 | 46 |
| 2021 | 117 | 58 | 29 | 58 |
| 2022 | 145 | 72 | 36 | 72 |
| 2023 | 176 | 88 | 44 | 88 |
| 2024 | 211 | 105 | 53 | 105 |
| 2025 | 248 | 124 | 62 | 124 |
| 2026 | 290 | 145 | 73 | 145 |
| 2027 | 333 | 167 | 83 | 167 |
| 2028 | 379 | 190 | 95 | 190 |
| 2029 | 428 | 214 | 107 | 214 |
| 2030 | 479 | 239 | 120 | 239 |
| 2031 | 532 | 266 | 133 | 266 |
| 2032 | 584 | 292 | 146 | 292 |
| 2033 | 637 | 319 | 159 | 319 |

## *HELCO Electric Vehicles Forecast Data*

Table E-106: HELCO Electric Vehicles Forecast Data (GWh)

| Year | Blazing a Bold Frontier | Stuck in the Middle | No Burning Desire | Moved by Passion |
|---|---|---|---|---|
| 2012 | – | – | – | – |
| 2013 | 0 | 0 | 0 | – |
| 2014 | 1 | 0 | 0 | – |
| 2015 | 1 | 0 | 0 | – |
| 2016 | 1 | 1 | 0 | – |
| 2017 | 2 | 1 | 0 | – |
| 2018 | 3 | 1 | 1 | – |
| 2019 | 4 | 2 | 1 | – |
| 2020 | 6 | 3 | 1 | – |
| 2021 | 8 | 4 | 2 | – |
| 2022 | 10 | 5 | 3 | – |
| 2023 | 13 | 6 | 3 | – |
| 2024 | 16 | 8 | 4 | – |
| 2025 | 19 | 10 | 5 | – |
| 2026 | 23 | 12 | 6 | – |
| 2027 | 28 | 14 | 7 | – |
| 2028 | 32 | 16 | 8 | – |
| 2029 | 37 | 19 | 9 | – |
| 2030 | 42 | 21 | 11 | – |
| 2031 | 48 | 24 | 12 | – |
| 2032 | 54 | 27 | 14 | – |
| 2033 | 61 | 31 | 15 | – |

### *Maui Electric Vehicles Forecast Data*

Table E-107: Maui Electric Vehicles Forecast Data (GWh)

| Year | Blazing a Bold Frontier | Stuck in the Middle | No Burning Desire | Moved by Passion |
|---|---|---|---|---|
| 2012 | 1 | 0 | 0 | 0 |
| 2013 | 1 | 0 | 0 | 0 |
| 2014 | 1 | 1 | 0 | 1 |
| 2015 | 2 | 1 | 0 | 1 |
| 2016 | 3 | 1 | 1 | 1 |
| 2017 | 4 | 2 | 1 | 2 |
| 2018 | 6 | 3 | 1 | 3 |
| 2019 | 8 | 4 | 2 | 4 |
| 2020 | 10 | 5 | 3 | 5 |
| 2021 | 13 | 7 | 3 | 7 |
| 2022 | 17 | 8 | 4 | 8 |
| 2023 | 21 | 10 | 5 | 10 |
| 2024 | 25 | 13 | 6 | 13 |
| 2025 | 30 | 15 | 8 | 15 |
| 2026 | 35 | 18 | 9 | 18 |
| 2027 | 41 | 20 | 10 | 20 |
| 2028 | 47 | 24 | 12 | 24 |
| 2029 | 54 | 27 | 13 | 27 |
| 2030 | 61 | 30 | 15 | 30 |
| 2031 | 68 | 34 | 17 | 34 |
| 2032 | 76 | 38 | 19 | 38 |
| 2033 | 84 | 42 | 21 | 42 |

## *Cumulative Electric Vehicle Count Base Forecast Data*

Table E-108: Cumulative Electric Vehicle Count Base Forecast[2]

| Year | HECO | MECO | HELCO |
|---|---|---|---|
| 2012 | 803 | 139 | 11 |
| 2013 | 1,481 | 193 | 38 |
| 2014 | 2,386 | 273 | 81 |
| 2015 | 3,577 | 386 | 143 |
| 2016 | 5,550 | 567 | 232 |
| 2017 | 8,067 | 824 | 374 |
| 2018 | 11,139 | 1,157 | 576 |
| 2019 | 14,802 | 1,574 | 837 |
| 2020 | 19,140 | 2,092 | 1,166 |
| 2021 | 24,192 | 2,714 | 1,572 |
| 2022 | 29,969 | 3,441 | 2,061 |
| 2023 | 36,465 | 4,269 | 2,631 |
| 2024 | 43,630 | 5,194 | 3,282 |
| 2025 | 51,445 | 6,211 | 4,009 |
| 2026 | 59,993 | 7,333 | 4,807 |
| 2027 | 68,964 | 8,455 | 5,688 |
| 2028 | 78,490 | 9,755 | 6,652 |
| 2029 | 88,563 | 11,140 | 7,700 |
| 2030 | 99,140 | 12,606 | 8,830 |
| 2031 | 110,099 | 14,145 | 10,044 |
| 2032 | 120,937 | 15,722 | 11,366 |
| 2033 | 131,889 | 17,331 | 12,861 |

[2] The base EV forecast corresponds to the EV forecast used in the Stuck in the Middle and Moved by Passion Scenario forecasts. EV lifetime assumed to be 16 years.

# Appendix E-11: Fuel Costs Forecast Data

## *Biodiesel Forecast Data*

Table E-109: HECO, Maui, and HELCO Biodiesel Forecast (Price per Gallon)

| $/Gallon | HECO | | Maui | | HELCO | |
|---|---|---|---|---|---|---|
| *Year* | *Low* | *High* | *Low* | *High* | *Low* | *High* |
| 2013 | $5.40 | $6.35 | $5.50 | $6.48 | $5.56 | $6.55 |
| 2014 | $4.74 | $6.42 | $4.84 | $6.54 | $4.88 | $6.61 |
| 2015 | $4.44 | $6.52 | $4.53 | $6.65 | $4.58 | $6.71 |
| 2016 | $4.34 | $6.53 | $4.43 | $6.66 | $4.47 | $6.72 |
| 2017 | $4.28 | $6.56 | $4.36 | $6.69 | $4.41 | $6.75 |
| 2018 | $4.20 | $6.56 | $4.28 | $6.69 | $4.32 | $6.76 |
| 2019 | $4.12 | $6.59 | $4.20 | $6.72 | $4.24 | $6.78 |
| 2020 | $4.04 | $6.59 | $4.12 | $6.73 | $4.16 | $6.79 |
| 2021 | $3.94 | $6.63 | $4.02 | $6.76 | $4.05 | $6.83 |
| 2022 | $3.87 | $6.67 | $3.95 | $6.81 | $3.99 | $6.87 |
| 2023 | $3.76 | $6.71 | $3.83 | $6.84 | $3.87 | $6.91 |
| 2024 | $3.67 | $6.74 | $3.74 | $6.87 | $3.78 | $6.94 |
| 2025 | $3.58 | $6.77 | $3.65 | $6.90 | $3.69 | $6.97 |
| 2026 | $3.49 | $6.80 | $3.56 | $6.93 | $3.59 | $7.00 |
| 2027 | $3.40 | $6.83 | $3.47 | $6.96 | $3.50 | $7.03 |
| 2028 | $3.31 | $6.85 | $3.38 | $6.99 | $3.41 | $7.06 |
| 2029 | $3.22 | $6.88 | $3.28 | $7.02 | $3.32 | $7.09 |
| 2030 | $3.13 | $6.91 | $3.19 | $7.05 | $3.22 | $7.12 |
| 2031 | $3.04 | $6.94 | $3.10 | $7.08 | $3.13 | $7.15 |
| 2032 | $2.95 | $6.97 | $3.01 | $7.11 | $3.04 | $7.18 |
| 2033 | $2.86 | $7.00 | $2.92 | $7.14 | $2.95 | $7.21 |

Table E-110: HECO, Maui, and HELCO Biodiesel Forecast (Price per MMBtu)

| $/MMBtu | HECO | | Maui | | HELCO | |
|---|---|---|---|---|---|---|
| *Year* | *Low* | *High* | *Low* | *High* | *Low* | *High* |
| 2013 | $43.17 | $50.84 | $44.03 | $51.86 | $44.46 | $52.36 |
| 2014 | $37.93 | $51.33 | $38.69 | $52.35 | $39.07 | $52.87 |
| 2015 | $35.56 | $52.14 | $36.27 | $53.19 | $36.63 | $53.71 |
| 2016 | $34.75 | $52.23 | $35.44 | $53.28 | $35.79 | $53.80 |
| 2017 | $34.22 | $52.46 | $34.90 | $53.51 | $35.24 | $54.03 |
| 2018 | $33.57 | $52.51 | $34.24 | $53.56 | $34.58 | $54.08 |
| 2019 | $32.95 | $52.70 | $33.61 | $53.75 | $33.94 | $54.28 |
| 2020 | $32.30 | $52.76 | $32.95 | $53.81 | $33.27 | $54.34 |
| 2021 | $31.49 | $53.04 | $32.12 | $54.10 | $32.44 | $54.63 |
| 2022 | $30.97 | $53.38 | $31.59 | $54.45 | $31.90 | $54.98 |
| 2023 | $30.07 | $53.65 | $30.67 | $54.72 | $30.97 | $55.26 |
| 2024 | $29.35 | $53.89 | $29.94 | $54.96 | $30.23 | $55.50 |
| 2025 | $28.63 | $54.12 | $29.21 | $55.21 | $29.49 | $55.75 |
| 2026 | $27.92 | $54.36 | $28.47 | $55.45 | $28.75 | $55.99 |
| 2027 | $27.20 | $54.60 | $27.74 | $55.69 | $28.01 | $56.24 |
| 2028 | $26.48 | $54.84 | $27.01 | $55.94 | $27.27 | $56.48 |
| 2029 | $25.76 | $55.08 | $26.28 | $56.18 | $26.53 | $56.73 |
| 2030 | $25.04 | $55.32 | $25.54 | $56.42 | $25.79 | $56.97 |
| 2031 | $24.32 | $55.55 | $24.81 | $56.66 | $25.05 | $57.22 |
| 2032 | $23.61 | $55.79 | $24.08 | $56.91 | $24.31 | $57.47 |
| 2033 | $22.89 | $56.03 | $23.35 | $57.15 | $23.57 | $57.71 |

## *Biocrude Forecast Data*

Table E-111: HECO, Maui, and HELCO Biocrude Forecast (Price per Gallon)

| $/Gallon | HECO | | Maui | | HELCO | |
|---|---|---|---|---|---|---|
| *Year* | *Low* | *High* | *Low* | *High* | *Low* | *High* |
| 2013 | $6.30 | $6.37 | $6.42 | $6.50 | $6.48 | $6.56 |
| 2014 | $5.77 | $6.55 | $5.89 | $6.68 | $5.94 | $6.74 |
| 2015 | $5.51 | $6.54 | $5.62 | $6.67 | $5.67 | $6.74 |
| 2016 | $5.48 | $6.57 | $5.59 | $6.70 | $5.65 | $6.76 |
| 2017 | $5.46 | $6.53 | $5.57 | $6.66 | $5.62 | $6.73 |
| 2018 | $5.43 | $6.54 | $5.54 | $6.67 | $5.59 | $6.73 |
| 2019 | $5.40 | $6.51 | $5.51 | $6.64 | $5.57 | $6.70 |
| 2020 | $5.38 | $6.52 | $5.49 | $6.65 | $5.54 | $6.72 |
| 2021 | $5.35 | $6.55 | $5.46 | $6.68 | $5.51 | $6.75 |
| 2022 | $5.33 | $6.56 | $5.43 | $6.70 | $5.49 | $6.76 |
| 2023 | $5.30 | $6.57 | $5.41 | $6.71 | $5.46 | $6.77 |
| 2024 | $5.27 | $6.58 | $5.38 | $6.71 | $5.43 | $6.78 |
| 2025 | $5.25 | $6.59 | $5.35 | $6.72 | $5.40 | $6.79 |
| 2026 | $5.22 | $6.60 | $5.32 | $6.73 | $5.38 | $6.80 |
| 2027 | $5.19 | $6.61 | $5.30 | $6.74 | $5.35 | $6.81 |
| 2028 | $5.17 | $6.62 | $5.27 | $6.75 | $5.32 | $6.82 |
| 2029 | $5.14 | $6.63 | $5.24 | $6.76 | $5.30 | $6.83 |
| 2030 | $5.12 | $6.64 | $5.22 | $6.77 | $5.27 | $6.84 |
| 2031 | $5.09 | $6.65 | $5.19 | $6.78 | $5.24 | $6.85 |
| 2032 | $5.06 | $6.66 | $5.16 | $6.79 | $5.22 | $6.86 |
| 2033 | $5.04 | $6.66 | $5.14 | $6.80 | $5.19 | $6.86 |

Table E-112: HECO, Maui, and HELCO Biocrude Forecast (Price per MMBtu)

| $/MMBtu | HECO | | Maui | | HELCO | |
|---|---|---|---|---|---|---|
| *Year* | *Low* | *High* | *Low* | *High* | *Low* | *High* |
| 2013 | $48.81 | $49.40 | $49.78 | $50.39 | $50.27 | $50.89 |
| 2014 | $44.74 | $50.75 | $45.63 | $51.76 | $46.08 | $52.27 |
| 2015 | $42.71 | $50.71 | $43.56 | $51.72 | $43.99 | $52.23 |
| 2016 | $42.50 | $50.90 | $43.35 | $51.92 | $43.78 | $52.43 |
| 2017 | $42.30 | $50.63 | $43.15 | $51.64 | $43.57 | $52.15 |
| 2018 | $42.10 | $50.68 | $42.94 | $51.69 | $43.36 | $52.20 |
| 2019 | $41.89 | $50.45 | $42.73 | $51.46 | $43.15 | $51.97 |
| 2020 | $41.69 | $50.54 | $42.52 | $51.55 | $42.94 | $52.06 |
| 2021 | $41.49 | $50.79 | $42.32 | $51.81 | $42.73 | $52.32 |
| 2022 | $41.28 | $50.89 | $42.11 | $51.91 | $42.52 | $52.42 |
| 2023 | $41.08 | $50.96 | $41.90 | $51.98 | $42.31 | $52.49 |
| 2024 | $40.88 | $51.03 | $41.69 | $52.05 | $42.10 | $52.56 |
| 2025 | $40.67 | $51.10 | $41.49 | $52.12 | $41.89 | $52.63 |
| 2026 | $40.47 | $51.17 | $41.28 | $52.20 | $41.68 | $52.71 |
| 2027 | $40.27 | $51.24 | $41.07 | $52.27 | $41.47 | $52.78 |
| 2028 | $40.06 | $51.31 | $40.86 | $52.34 | $41.26 | $52.85 |
| 2029 | $39.86 | $51.38 | $40.66 | $52.41 | $41.05 | $52.92 |
| 2030 | $39.66 | $51.45 | $40.45 | $52.48 | $40.85 | $53.00 |
| 2031 | $39.45 | $51.52 | $40.24 | $52.55 | $40.64 | $53.07 |
| 2032 | $39.25 | $51.59 | $40.03 | $52.62 | $40.43 | $53.14 |
| 2033 | $39.05 | $51.66 | $39.83 | $52.70 | $40.22 | $53.21 |

## High Sulfur Diesel Forecast Data

Table E-113: HECO, Maui, and HELCO High Sulfur Diesel Forecast (Price per Barrel)

| $/Barrel | HECO | | | Maui | | | HELCO | | |
|---|---|---|---|---|---|---|---|---|---|
| Year | Reference | High | Low | Reference | High | Low | Reference | High | Low |
| 2013 | $120.27 | $119.96 | $120.07 | $133.39 | $165.97 | $117.46 | $130.48 | $130.15 | $130.26 |
| 2014 | $122.18 | $150.52 | $108.31 | $134.02 | $182.62 | $111.58 | $132.56 | $163.72 | $117.31 |
| 2015 | $122.82 | $165.10 | $103.29 | $137.55 | $196.64 | $106.96 | $133.23 | $179.72 | $111.76 |
| 2016 | $125.99 | $177.37 | $99.38 | $142.42 | $203.05 | $102.57 | $136.69 | $193.19 | $107.44 |
| 2017 | $130.32 | $183.02 | $95.67 | $147.60 | $209.88 | $104.19 | $141.43 | $199.38 | $103.32 |
| 2018 | $134.93 | $189.06 | $97.20 | $152.93 | $217.08 | $106.02 | $146.47 | $205.99 | $104.97 |
| 2019 | $139.67 | $195.41 | $98.91 | $158.58 | $224.90 | $108.29 | $151.65 | $212.95 | $106.81 |
| 2020 | $144.70 | $202.32 | $101.02 | $164.56 | $233.19 | $110.75 | $157.14 | $220.51 | $109.09 |
| 2021 | $150.02 | $209.63 | $103.28 | $170.91 | $242.53 | $113.43 | $162.96 | $228.53 | $111.55 |
| 2022 | $155.67 | $217.89 | $105.75 | $177.49 | $252.05 | $115.99 | $169.13 | $237.57 | $114.22 |
| 2023 | $161.53 | $226.30 | $108.11 | $184.32 | $262.29 | $118.42 | $175.54 | $246.77 | $116.77 |
| 2024 | $167.59 | $235.35 | $110.34 | $191.41 | $273.15 | $121.07 | $182.17 | $256.69 | $119.20 |
| 2025 | $173.90 | $244.94 | $112.79 | $198.82 | $284.48 | $123.55 | $189.06 | $267.19 | $121.85 |
| 2026 | $180.48 | $254.95 | $115.07 | $206.51 | $296.25 | $126.07 | $196.26 | $278.16 | $124.32 |
| 2027 | $187.30 | $265.34 | $117.39 | $214.53 | $308.53 | $128.67 | $203.72 | $289.54 | $126.83 |
| 2028 | $194.42 | $276.18 | $119.78 | $222.92 | $321.15 | $131.27 | $211.51 | $301.41 | $129.42 |
| 2029 | $201.87 | $287.33 | $122.17 | $231.64 | $333.43 | $133.93 | $219.65 | $313.61 | $132.01 |
| 2030 | $209.60 | $298.14 | $124.61 | $240.75 | $346.05 | $136.59 | $228.11 | $325.47 | $134.66 |
| 2031 | $217.68 | $309.26 | $127.06 | $250.16 | $359.10 | $139.29 | $236.95 | $337.65 | $137.32 |
| 2032 | $226.02 | $320.75 | $129.54 | $259.91 | $373.94 | $142.54 | $246.07 | $350.24 | $140.00 |
| 2033 | $234.65 | $333.83 | $132.53 | $133.39 | $165.97 | $117.46 | $255.52 | $364.58 | $143.24 |

Table E-114: HECO, Maui, and HELCO High Sulfur Diesel Forecast (Price per MMBtu)

| $/MMBtu | HECO | | | Maui | | | HELCO | | |
|---|---|---|---|---|---|---|---|---|---|
| *Year* | *Reference* | *High* | *Low* | *Reference* | *High* | *Low* | *Reference* | *High* | *Low* |
| 2013 | $20.52 | $20.47 | $20.49 | $22.41 | $22.35 | $22.37 | $22.27 | $22.21 | $22.23 |
| 2014 | $20.85 | $25.69 | $18.48 | $22.76 | $28.32 | $20.04 | $22.62 | $27.94 | $20.02 |
| 2015 | $20.96 | $28.17 | $17.63 | $22.87 | $31.16 | $19.04 | $22.74 | $30.67 | $19.07 |
| 2016 | $21.50 | $30.27 | $16.96 | $23.47 | $33.56 | $18.25 | $23.33 | $32.97 | $18.33 |
| 2017 | $22.24 | $31.23 | $16.33 | $24.30 | $34.65 | $17.50 | $24.13 | $34.02 | $17.63 |
| 2018 | $23.03 | $32.26 | $16.59 | $25.19 | $35.82 | $17.78 | $24.99 | $35.15 | $17.91 |
| 2019 | $23.84 | $33.35 | $16.88 | $26.10 | $37.04 | $18.09 | $25.88 | $36.34 | $18.23 |
| 2020 | $24.69 | $34.52 | $17.24 | $27.06 | $38.38 | $18.48 | $26.82 | $37.63 | $18.62 |
| 2021 | $25.60 | $35.77 | $17.62 | $28.08 | $39.79 | $18.90 | $27.81 | $39.00 | $19.04 |
| 2022 | $26.56 | $37.18 | $18.05 | $29.16 | $41.39 | $19.36 | $28.86 | $40.54 | $19.49 |
| 2023 | $27.56 | $38.62 | $18.45 | $30.29 | $43.01 | $19.79 | $29.95 | $42.11 | $19.93 |
| 2024 | $28.60 | $40.16 | $18.83 | $31.45 | $44.76 | $20.21 | $31.09 | $43.80 | $20.34 |
| 2025 | $29.68 | $41.80 | $19.25 | $32.66 | $46.61 | $20.66 | $32.26 | $45.60 | $20.79 |
| 2026 | $30.80 | $43.51 | $19.64 | $33.93 | $48.55 | $21.08 | $33.49 | $47.47 | $21.21 |
| 2027 | $31.96 | $45.28 | $20.03 | $35.24 | $50.55 | $21.51 | $34.77 | $49.41 | $21.64 |
| 2028 | $33.18 | $47.13 | $20.44 | $36.61 | $52.65 | $21.96 | $36.09 | $51.43 | $22.09 |
| 2029 | $34.45 | $49.03 | $20.85 | $38.04 | $54.80 | $22.40 | $37.48 | $53.52 | $22.53 |
| 2030 | $35.77 | $50.88 | $21.26 | $39.53 | $56.90 | $22.85 | $38.93 | $55.54 | $22.98 |
| 2031 | $37.15 | $52.77 | $21.68 | $41.08 | $59.05 | $23.31 | $40.43 | $57.62 | $23.43 |
| 2032 | $38.57 | $54.74 | $22.11 | $42.69 | $61.28 | $23.77 | $41.99 | $59.77 | $23.89 |
| 2033 | $40.04 | $56.97 | $22.62 | $44.35 | $63.81 | $24.32 | $43.60 | $62.21 | $24.44 |

## *Ultra Low Sulfur Diesel (ULSD) Forecast Data*

Table E-115: HECO and HELCO Ultra Low Sulfur Diesel Forecast Data (Price per Barrel)

| $/Barrel | HECO | | | HELCO | | |
|---|---|---|---|---|---|---|
| *Year* | *Reference* | *High* | *Low* | *Reference* | *High* | *Low* |
| 2013 | $124.30 | $123.99 | $124.09 | $131.16 | $130.83 | $130.94 |
| 2014 | $126.26 | $154.61 | $112.39 | $133.24 | $164.40 | $117.99 |
| 2015 | $126.96 | $169.25 | $107.44 | $133.93 | $180.42 | $112.46 |
| 2016 | $130.20 | $181.57 | $103.61 | $137.40 | $193.90 | $108.14 |
| 2017 | $134.60 | $187.27 | $99.97 | $142.15 | $200.10 | $104.04 |
| 2018 | $139.28 | $193.36 | $101.58 | $147.20 | $206.72 | $105.70 |
| 2019 | $144.08 | $199.77 | $103.37 | $152.39 | $213.68 | $107.56 |
| 2020 | $149.19 | $206.74 | $105.56 | $157.90 | $221.26 | $109.86 |
| 2021 | $154.58 | $214.13 | $107.91 | $163.73 | $229.28 | $112.32 |
| 2022 | $160.31 | $222.47 | $110.47 | $169.91 | $238.33 | $115.01 |
| 2023 | $166.26 | $230.96 | $112.92 | $176.33 | $247.56 | $117.58 |
| 2024 | $172.41 | $240.11 | $115.24 | $182.98 | $257.49 | $120.02 |
| 2025 | $178.80 | $249.80 | $117.77 | $189.89 | $268.01 | $122.68 |
| 2026 | $185.47 | $259.91 | $120.13 | $197.10 | $278.99 | $125.16 |
| 2027 | $192.38 | $270.40 | $122.54 | $204.58 | $290.39 | $127.69 |
| 2028 | $199.60 | $281.35 | $125.01 | $212.38 | $302.27 | $130.30 |
| 2029 | $207.14 | $292.59 | $127.49 | $220.54 | $314.50 | $132.90 |
| 2030 | $214.97 | $303.50 | $130.02 | $229.01 | $326.36 | $135.57 |
| 2031 | $223.14 | $314.71 | $132.55 | $237.87 | $338.56 | $138.24 |
| 2032 | $231.59 | $326.29 | $135.12 | $247.01 | $351.17 | $140.94 |
| 2033 | $240.32 | $339.48 | $138.22 | $256.48 | $365.52 | $144.19 |

Table E-116: MECO Ultra Low Sulfur Diesel Forecast Data (Price per Barrel)

| $/Barrel | Maui | | | Lanai | | | Molokai | | |
|---|---|---|---|---|---|---|---|---|---|
| *Year* | *Reference* | *High* | *Low* | *Reference* | *High* | *Low* | *Reference* | *High* | *Low* |
| 2013 | $133.53 | $133.19 | $133.30 | $154.40 | $154.00 | $154.13 | $137.86 | $137.51 | $137.62 |
| 2014 | $135.65 | $168.23 | $119.72 | $156.81 | $188.56 | $141.22 | $140.05 | $172.21 | $124.29 |
| 2015 | $136.31 | $184.92 | $113.87 | $157.83 | $205.20 | $135.91 | $140.79 | $188.78 | $118.62 |
| 2016 | $139.89 | $198.96 | $109.30 | $161.71 | $219.21 | $131.89 | $144.42 | $202.72 | $114.21 |
| 2017 | $144.79 | $205.39 | $104.95 | $166.87 | $225.79 | $128.09 | $149.35 | $209.16 | $110.02 |
| 2018 | $150.01 | $212.26 | $106.61 | $172.38 | $232.83 | $130.19 | $154.61 | $216.02 | $111.79 |
| 2019 | $155.37 | $219.49 | $108.48 | $178.03 | $240.23 | $132.51 | $160.01 | $223.25 | $113.76 |
| 2020 | $161.07 | $227.35 | $110.81 | $184.02 | $248.30 | $135.28 | $165.74 | $231.11 | $116.18 |
| 2021 | $167.09 | $235.68 | $113.31 | $190.36 | $256.85 | $138.22 | $171.81 | $239.44 | $118.77 |
| 2022 | $173.48 | $245.06 | $116.04 | $197.10 | $266.52 | $141.45 | $178.24 | $248.84 | $121.61 |
| 2023 | $180.12 | $254.63 | $118.65 | $204.08 | $276.36 | $144.52 | $184.92 | $258.41 | $124.31 |
| 2024 | $186.99 | $264.92 | $121.12 | $211.29 | $286.96 | $147.42 | $191.83 | $268.71 | $126.88 |
| 2025 | $194.13 | $275.83 | $123.82 | $218.78 | $298.19 | $150.60 | $199.02 | $279.63 | $129.68 |
| 2026 | $201.59 | $287.22 | $126.35 | $226.60 | $309.90 | $153.55 | $206.52 | $291.03 | $132.30 |
| 2027 | $209.33 | $299.05 | $128.92 | $234.69 | $322.05 | $156.56 | $214.30 | $302.86 | $134.96 |
| 2028 | $217.40 | $311.38 | $131.56 | $243.12 | $334.70 | $159.65 | $222.41 | $315.19 | $137.70 |
| 2029 | $225.85 | $324.07 | $134.21 | $251.94 | $347.69 | $162.75 | $230.89 | $327.88 | $140.44 |
| 2030 | $234.62 | $336.39 | $136.92 | $261.08 | $360.26 | $165.91 | $239.70 | $340.18 | $143.25 |
| 2031 | $243.78 | $349.06 | $139.63 | $270.62 | $373.17 | $169.08 | $248.90 | $352.83 | $146.05 |
| 2032 | $253.25 | $362.16 | $142.38 | $280.47 | $386.50 | $172.28 | $258.40 | $365.90 | $148.90 |
| 2033 | $263.05 | $377.06 | $145.68 | $290.65 | $401.71 | $176.16 | $268.23 | $380.79 | $152.32 |

Table E-117: HECO and HELCO Ultra Low Sulfur Diesel Forecast Data (Price per MMBtu)

| $/MMBtu | HECO | | | HELCO | | |
|---|---|---|---|---|---|---|
| *Year* | *Reference* | *High* | *Low* | *Reference* | *High* | *Low* |
| 2013 | $21.69 | $21.64 | $21.66 | $22.89 | $22.83 | $22.85 |
| 2014 | $22.04 | $26.98 | $19.61 | $23.25 | $28.69 | $20.59 |
| 2015 | $22.16 | $29.54 | $18.75 | $23.37 | $31.49 | $19.63 |
| 2016 | $22.72 | $31.69 | $18.08 | $23.98 | $33.84 | $18.87 |
| 2017 | $23.49 | $32.68 | $17.45 | $24.81 | $34.92 | $18.16 |
| 2018 | $24.31 | $33.75 | $17.73 | $25.69 | $36.08 | $18.45 |
| 2019 | $25.15 | $34.86 | $18.04 | $26.59 | $37.29 | $18.77 |
| 2020 | $26.04 | $36.08 | $18.42 | $27.56 | $38.61 | $19.17 |
| 2021 | $26.98 | $37.37 | $18.83 | $28.57 | $40.01 | $19.60 |
| 2022 | $27.98 | $38.83 | $19.28 | $29.65 | $41.59 | $20.07 |
| 2023 | $29.01 | $40.31 | $19.71 | $30.77 | $43.20 | $20.52 |
| 2024 | $30.09 | $41.90 | $20.11 | $31.93 | $44.94 | $20.95 |
| 2025 | $31.20 | $43.59 | $20.55 | $33.14 | $46.77 | $21.41 |
| 2026 | $32.37 | $45.36 | $20.97 | $34.40 | $48.69 | $21.84 |
| 2027 | $33.58 | $47.19 | $21.38 | $35.70 | $50.68 | $22.29 |
| 2028 | $34.83 | $49.10 | $21.82 | $37.06 | $52.75 | $22.74 |
| 2029 | $36.15 | $51.06 | $22.25 | $38.49 | $54.89 | $23.19 |
| 2030 | $37.52 | $52.97 | $22.69 | $39.97 | $56.96 | $23.66 |
| 2031 | $38.94 | $54.92 | $23.13 | $41.51 | $59.09 | $24.13 |
| 2032 | $40.42 | $56.94 | $23.58 | $43.11 | $61.29 | $24.60 |
| 2033 | $41.94 | $59.25 | $24.12 | $44.76 | $63.79 | $25.16 |

Table E-118: MECO Ultra Low Sulfur Diesel Forecast Data (Price per MMBtu)

| $/MMBtu | Maui | | | Lanai | | | Molokai | | |
|---|---|---|---|---|---|---|---|---|---|
| *Year* | *Reference* | *High* | *Low* | *Reference* | *High* | *Low* | *Reference* | *High* | *Low* |
| 2013 | $23.30 | $23.24 | $23.26 | $26.95 | $26.88 | $26.90 | $24.06 | $24.00 | $24.02 |
| 2014 | $23.67 | $29.36 | $20.89 | $27.37 | $32.91 | $24.65 | $24.44 | $30.05 | $21.69 |
| 2015 | $23.79 | $32.27 | $19.87 | $27.54 | $35.81 | $23.72 | $24.57 | $32.95 | $20.70 |
| 2016 | $24.41 | $34.72 | $19.08 | $28.22 | $38.26 | $23.02 | $25.20 | $35.38 | $19.93 |
| 2017 | $25.27 | $35.85 | $18.32 | $29.12 | $39.41 | $22.35 | $26.07 | $36.50 | $19.20 |
| 2018 | $26.18 | $37.04 | $18.61 | $30.08 | $40.63 | $22.72 | $26.98 | $37.70 | $19.51 |
| 2019 | $27.12 | $38.31 | $18.93 | $31.07 | $41.93 | $23.13 | $27.93 | $38.96 | $19.85 |
| 2020 | $28.11 | $39.68 | $19.34 | $32.12 | $43.33 | $23.61 | $28.93 | $40.33 | $20.28 |
| 2021 | $29.16 | $41.13 | $19.77 | $33.22 | $44.82 | $24.12 | $29.98 | $41.79 | $20.73 |
| 2022 | $30.28 | $42.77 | $20.25 | $34.40 | $46.51 | $24.69 | $31.11 | $43.43 | $21.22 |
| 2023 | $31.43 | $44.44 | $20.71 | $35.62 | $48.23 | $25.22 | $32.27 | $45.10 | $21.70 |
| 2024 | $32.63 | $46.23 | $21.14 | $36.87 | $50.08 | $25.73 | $33.48 | $46.90 | $22.14 |
| 2025 | $33.88 | $48.14 | $21.61 | $38.18 | $52.04 | $26.28 | $34.73 | $48.80 | $22.63 |
| 2026 | $35.18 | $50.13 | $22.05 | $39.55 | $54.08 | $26.80 | $36.04 | $50.79 | $23.09 |
| 2027 | $36.53 | $52.19 | $22.50 | $40.96 | $56.20 | $27.32 | $37.40 | $52.86 | $23.55 |
| 2028 | $37.94 | $54.34 | $22.96 | $42.43 | $58.41 | $27.86 | $38.81 | $55.01 | $24.03 |
| 2029 | $39.41 | $56.56 | $23.42 | $43.97 | $60.68 | $28.40 | $40.29 | $57.22 | $24.51 |
| 2030 | $40.95 | $58.71 | $23.90 | $45.56 | $62.87 | $28.96 | $41.83 | $59.37 | $25.00 |
| 2031 | $42.54 | $60.92 | $24.37 | $47.23 | $65.13 | $29.51 | $43.44 | $61.58 | $25.49 |
| 2032 | $44.20 | $63.20 | $24.85 | $48.95 | $67.45 | $30.07 | $45.10 | $63.86 | $25.99 |
| 2033 | $45.91 | $65.80 | $25.42 | $50.72 | $70.11 | $30.74 | $46.81 | $66.46 | $26.58 |

## *Liquefied Natural Gas (LNG) Forecast Data*

Table E-119: HECO Liquefied Natural Gas Forecast Data

| $/MMBtu | HECO | |
|---|---|---|
| *Year* | *Reference* | *High* |
| 2013 | n/a | n/a |
| 2014 | n/a | n/a |
| 2015 | $13.70 | $21.11 |
| 2016 | $14.40 | $21.53 |
| 2017 | $14.60 | $22.12 |
| 2018 | $15.00 | $22.75 |
| 2019 | $15.20 | $23.40 |
| 2020 | $15.50 | $24.09 |
| 2021 | $15.70 | $24.82 |
| 2022 | $16.20 | $25.60 |
| 2023 | $16.60 | $26.42 |
| 2024 | $16.90 | $27.27 |
| 2025 | $17.20 | $28.16 |
| 2026 | $17.60 | $29.08 |
| 2027 | $17.90 | $30.04 |
| 2028 | $18.20 | $31.04 |
| 2029 | $18.50 | $32.09 |
| 2030 | $18.90 | $33.18 |
| 2031 | $24.50 | $39.51 |
| 2032 | $24.90 | $40.71 |
| 2033 | $25.40 | $41.96 |

## *Low Sulfur Fuel Oil (LSFO) Forecast Data*

Table E-120: HECO Low Sulfur Fuel Oil Forecast (Price per Barrel/per MMBtu)

| Price | HECO: $/Barrel | | | HECO: $/MMBtu | | |
|---|---|---|---|---|---|---|
| *Year* | *Reference* | *High* | *Low* | *Reference* | *High* | *Low* |
| 2013 | $109.36 | $109.08 | $109.18 | $17.64 | $17.59 | $17.61 |
| 2014 | $111.12 | $139.91 | $97.06 | $17.92 | $22.57 | $15.66 |
| 2015 | $111.57 | $154.52 | $91.76 | $18.00 | $24.92 | $14.80 |
| 2016 | $114.59 | $166.82 | $87.56 | $18.48 | $26.91 | $14.12 |
| 2017 | $118.78 | $172.40 | $83.56 | $19.16 | $27.81 | $13.48 |
| 2018 | $123.25 | $178.34 | $84.86 | $19.88 | $28.77 | $13.69 |
| 2019 | $127.84 | $184.61 | $86.33 | $20.62 | $29.78 | $13.92 |
| 2020 | $132.71 | $191.41 | $88.21 | $21.41 | $30.87 | $14.23 |
| 2021 | $137.87 | $198.61 | $90.24 | $22.24 | $32.03 | $14.55 |
| 2022 | $143.33 | $206.71 | $92.45 | $23.12 | $33.34 | $14.91 |
| 2023 | $149.02 | $214.98 | $94.57 | $24.03 | $34.67 | $15.25 |
| 2024 | $154.90 | $223.88 | $96.58 | $24.98 | $36.11 | $15.58 |
| 2025 | $161.03 | $233.31 | $98.78 | $25.97 | $37.63 | $15.93 |
| 2026 | $167.43 | $243.16 | $100.83 | $27.00 | $39.22 | $16.26 |
| 2027 | $174.07 | $253.39 | $102.92 | $28.08 | $40.87 | $16.60 |
| 2028 | $181.00 | $264.06 | $105.07 | $29.19 | $42.59 | $16.95 |
| 2029 | $188.26 | $275.05 | $107.23 | $30.36 | $44.36 | $17.30 |
| 2030 | $195.80 | $285.74 | $109.44 | $31.58 | $46.09 | $17.65 |
| 2031 | $203.68 | $296.74 | $111.65 | $32.85 | $47.86 | $18.01 |
| 2032 | $211.83 | $308.12 | $113.89 | $34.17 | $49.70 | $18.37 |
| 2033 | $220.27 | $321.04 | $116.58 | $35.53 | $51.78 | $18.80 |

## *Medium Sulfur Fuel Oil (MSFO) Forecast Data*

Table E-121: HELCO and Maui Medium Sulfur Fuel Oil Forecast Data (Price per Barrel)

| $/Barrel | HELCO | | | Maui | | |
|---|---|---|---|---|---|---|
| *Year* | *Reference* | *High* | *Low* | *Reference* | *High* | *Low* |
| 2013 | $98.01 | $97.76 | $97.84 | $95.93 | $95.69 | $95.77 |
| 2014 | $99.59 | $125.70 | $86.84 | $97.48 | $123.49 | $84.79 |
| 2015 | $99.98 | $138.94 | $82.01 | $97.84 | $136.64 | $79.95 |
| 2016 | $102.69 | $150.07 | $78.18 | $100.52 | $147.71 | $76.10 |
| 2017 | $106.48 | $155.12 | $74.52 | $104.27 | $152.71 | $72.44 |
| 2018 | $110.51 | $160.49 | $75.68 | $108.25 | $158.05 | $73.56 |
| 2019 | $114.65 | $166.16 | $77.00 | $112.35 | $163.66 | $74.83 |
| 2020 | $119.05 | $172.30 | $78.67 | $116.70 | $169.76 | $76.47 |
| 2021 | $123.70 | $178.81 | $80.49 | $121.30 | $176.21 | $78.24 |
| 2022 | $128.64 | $186.14 | $82.47 | $126.18 | $183.47 | $80.17 |
| 2023 | $133.77 | $193.62 | $84.36 | $131.25 | $190.88 | $82.02 |
| 2024 | $139.08 | $201.66 | $86.16 | $136.51 | $198.85 | $83.78 |
| 2025 | $144.61 | $210.19 | $88.13 | $141.98 | $207.30 | $85.70 |
| 2026 | $150.39 | $219.09 | $89.97 | $147.69 | $216.12 | $87.50 |
| 2027 | $156.39 | $228.34 | $91.84 | $153.63 | $225.29 | $89.33 |
| 2028 | $162.65 | $237.99 | $93.77 | $159.82 | $234.86 | $91.21 |
| 2029 | $169.20 | $247.92 | $95.70 | $166.31 | $244.71 | $93.10 |
| 2030 | $176.01 | $257.59 | $97.67 | $173.05 | $254.30 | $95.03 |
| 2031 | $183.13 | $267.54 | $99.65 | $180.10 | $264.17 | $96.97 |
| 2032 | $190.49 | $277.83 | $101.66 | $187.39 | $274.38 | $98.93 |
| 2033 | $198.11 | $289.52 | $104.07 | $194.94 | $285.98 | $101.28 |

Table E-122: HELCO and Maui Medium Sulfur Fuel Oil Forecast Data (Price per MMBtu)

| $/MMBtu | HELCO | | | Maui | | |
|---|---|---|---|---|---|---|
| *Year* | *Reference* | *High* | *Low* | *Reference* | *High* | *Low* |
| 2013 | $15.56 | $15.52 | $15.53 | $15.23 | $15.19 | $15.20 |
| 2014 | $15.81 | $19.95 | $13.78 | $15.47 | $19.60 | $13.46 |
| 2015 | $15.87 | $22.05 | $13.02 | $15.53 | $21.69 | $12.69 |
| 2016 | $16.30 | $23.82 | $12.41 | $15.96 | $23.45 | $12.08 |
| 2017 | $16.90 | $24.62 | $11.83 | $16.55 | $24.24 | $11.50 |
| 2018 | $17.54 | $25.48 | $12.01 | $17.18 | $25.09 | $11.68 |
| 2019 | $18.20 | $26.37 | $12.22 | $17.83 | $25.98 | $11.88 |
| 2020 | $18.90 | $27.35 | $12.49 | $18.52 | $26.95 | $12.14 |
| 2021 | $19.64 | $28.38 | $12.78 | $19.25 | $27.97 | $12.42 |
| 2022 | $20.42 | $29.55 | $13.09 | $20.03 | $29.12 | $12.73 |
| 2023 | $21.23 | $30.73 | $13.39 | $20.83 | $30.30 | $13.02 |
| 2024 | $22.08 | $32.01 | $13.68 | $21.67 | $31.56 | $13.30 |
| 2025 | $22.95 | $33.36 | $13.99 | $22.54 | $32.90 | $13.60 |
| 2026 | $23.87 | $34.78 | $14.28 | $23.44 | $34.31 | $13.89 |
| 2027 | $24.82 | $36.24 | $14.58 | $24.39 | $35.76 | $14.18 |
| 2028 | $25.82 | $37.78 | $14.88 | $25.37 | $37.28 | $14.48 |
| 2029 | $26.86 | $39.35 | $15.19 | $26.40 | $38.84 | $14.78 |
| 2030 | $27.94 | $40.89 | $15.50 | $27.47 | $40.37 | $15.08 |
| 2031 | $29.07 | $42.47 | $15.82 | $28.59 | $41.93 | $15.39 |
| 2032 | $30.24 | $44.10 | $16.14 | $29.74 | $43.55 | $15.70 |
| 2033 | $31.45 | $45.96 | $16.52 | $30.94 | $45.39 | $16.08 |

## *Low Sulfur Industrial Fuel Oil (LSIFO) Forecast Data*

Table E-123: HELCO and Maui Low Sulfur Industrial Fuel Oil Forecast (Price per Barrel)

| $/Barrel | HELCO | | | Maui | | |
|---|---|---|---|---|---|---|
| *Year* | *Reference* | *High* | *Low* | *Reference* | *High* | *Low* |
| 2013 | $112.77 | $112.49 | $112.59 | $111.27 | $110.99 | $111.09 |
| 2014 | $114.57 | $143.08 | $100.66 | $113.05 | $141.56 | $99.13 |
| 2015 | $115.09 | $157.61 | $95.48 | $113.54 | $156.07 | $93.93 |
| 2016 | $118.15 | $169.84 | $91.40 | $116.58 | $168.28 | $89.83 |
| 2017 | $122.37 | $175.42 | $87.52 | $120.78 | $173.84 | $85.92 |
| 2018 | $126.87 | $181.37 | $88.90 | $125.25 | $179.77 | $87.27 |
| 2019 | $131.49 | $187.63 | $90.46 | $129.85 | $186.01 | $88.79 |
| 2020 | $136.40 | $194.44 | $92.41 | $134.73 | $192.79 | $90.71 |
| 2021 | $141.59 | $201.65 | $94.51 | $139.89 | $199.97 | $92.79 |
| 2022 | $147.09 | $209.77 | $96.80 | $145.36 | $208.06 | $95.05 |
| 2023 | $152.81 | $218.05 | $99.00 | $151.05 | $216.31 | $97.21 |
| 2024 | $158.74 | $226.97 | $101.08 | $156.94 | $225.19 | $99.26 |
| 2025 | $164.90 | $236.41 | $103.36 | $163.07 | $234.60 | $101.50 |
| 2026 | $171.33 | $246.27 | $105.48 | $169.47 | $244.42 | $103.59 |
| 2027 | $178.01 | $256.51 | $107.65 | $176.12 | $254.63 | $105.73 |
| 2028 | $184.98 | $267.19 | $109.87 | $183.05 | $265.27 | $107.92 |
| 2029 | $192.26 | $278.19 | $112.11 | $190.30 | $276.22 | $110.12 |
| 2030 | $199.84 | $288.87 | $114.39 | $197.84 | $286.88 | $112.37 |
| 2031 | $207.75 | $299.86 | $116.67 | $205.71 | $297.83 | $114.63 |
| 2032 | $215.93 | $311.23 | $118.99 | $213.86 | $309.16 | $116.91 |
| 2033 | $224.40 | $324.15 | $121.77 | $222.29 | $322.04 | $119.65 |

Table E-124: HELCO and Maui Low Sulfur Industrial Fuel Oil Forecast (Price per MMBtu)

| $/MMBtu | HELCO | | | Maui | | |
|---|---|---|---|---|---|---|
| *Year* | *Reference* | *High* | *Low* | *Reference* | *High* | *Low* |
| 2013 | $18.19 | $18.14 | $18.16 | $17.95 | $17.90 | $17.92 |
| 2014 | $18.48 | $23.08 | $16.23 | $18.23 | $22.83 | $15.99 |
| 2015 | $18.56 | $25.42 | $15.40 | $18.31 | $25.17 | $15.15 |
| 2016 | $19.06 | $27.39 | $14.74 | $18.80 | $27.14 | $14.49 |
| 2017 | $19.74 | $28.29 | $14.12 | $19.48 | $28.04 | $13.86 |
| 2018 | $20.46 | $29.25 | $14.34 | $20.20 | $28.99 | $14.08 |
| 2019 | $21.21 | $30.26 | $14.59 | $20.94 | $30.00 | $14.32 |
| 2020 | $22.00 | $31.36 | $14.90 | $21.73 | $31.10 | $14.63 |
| 2021 | $22.84 | $32.52 | $15.24 | $22.56 | $32.25 | $14.97 |
| 2022 | $23.72 | $33.83 | $15.61 | $23.45 | $33.56 | $15.33 |
| 2023 | $24.65 | $35.17 | $15.97 | $24.36 | $34.89 | $15.68 |
| 2024 | $25.60 | $36.61 | $16.30 | $25.31 | $36.32 | $16.01 |
| 2025 | $26.60 | $38.13 | $16.67 | $26.30 | $37.84 | $16.37 |
| 2026 | $27.63 | $39.72 | $17.01 | $27.33 | $39.42 | $16.71 |
| 2027 | $28.71 | $41.37 | $17.36 | $28.41 | $41.07 | $17.05 |
| 2028 | $29.83 | $43.10 | $17.72 | $29.52 | $42.79 | $17.41 |
| 2029 | $31.01 | $44.87 | $18.08 | $30.69 | $44.55 | $17.76 |
| 2030 | $32.23 | $46.59 | $18.45 | $31.91 | $46.27 | $18.12 |
| 2031 | $33.51 | $48.37 | $18.82 | $33.18 | $48.04 | $18.49 |
| 2032 | $34.83 | $50.20 | $19.19 | $34.49 | $49.86 | $18.86 |
| 2033 | $36.19 | $52.28 | $19.64 | $35.85 | $51.94 | $19.30 |

# Appendix F:
# DR and DSM Program Data

This appendix contains tables of data derived from the Hawaiian Electric, MECO, and HELCO Demand Response (DR) programs, including:

- Residential Direct Load Control (RDLC) programs.
- Commercial and Industrial Direct Load Control (CIDLC) programs.
- Commercial and Industrial Dynamic Pricing (CIDP) programs.

It also includes the data tables from the Public Benefits Fee Administrator (PBFA) Demand-Side Management (DSM) programs.

# CONTENTS



# TABLES

## Hawaiian Electric Demand Response Program Data

Table F-1: HECO RDLC Program – Water Heating (Continue Existing)

| Year | Peak Impacts (Net MW) | Total Costs (thousands of real dollars) | | |
|---|---|---|---|---|
| | | *Incentives* | *Program Costs* | *Evaluation* |
| 2014 | 14.2 | 1,262.0 | 981.5 | 43.5 |
| 2015 | 14.2 | 1,262.0 | 981.5 | 43.5 |
| 2016 | 14.2 | 1,262.0 | 981.5 | 43.5 |
| 2017 | 14.2 | 1,262.0 | 981.5 | 43.5 |
| 2018 | 14.2 | 1,262.0 | 981.5 | 43.5 |
| 2019 | 14.2 | 1,262.0 | 981.5 | 43.5 |
| 2020 | 14.2 | 1,262.0 | 981.5 | 43.5 |
| 2021 | 14.2 | 1,262.0 | 981.5 | 43.5 |
| 2022 | 14.2 | 1,262.0 | 981.5 | 43.5 |
| 2023 | 14.2 | 1,262.0 | 981.5 | 43.5 |
| 2024 | 14.2 | 1,262.0 | 981.5 | 43.5 |
| 2025 | 14.2 | 1,262.0 | 981.5 | 43.5 |
| 2026 | 14.2 | 1,262.0 | 981.5 | 43.5 |
| 2027 | 14.2 | 1,262.0 | 981.5 | 43.5 |
| 2028 | 14.2 | 1,262.0 | 981.5 | 43.5 |
| 2029 | 14.2 | 1,262.0 | 981.5 | 43.5 |
| 2030 | 14.2 | 1,262.0 | 981.5 | 43.5 |
| 2031 | 14.2 | 1,262.0 | 981.5 | 43.5 |
| 2032 | 14.2 | 1,262.0 | 981.5 | 43.5 |
| 2033 | 14.2 | 1,262.0 | 981.5 | 43.5 |

*Notes*

1. Megawatt impacts are annualized non-coincident Peak Impacts (Net MW)
2. Total Costs = Incentives + Program Costs + Evaluation
3. Costs are listed in thousands of real 2012 dollars
4. Peak impacts are at the net-to-system level (net generation)

Table F-2: HECO RDLC Program – Water Heating (Expanded)

| Year | Peak Impacts (Net MW) | Total Costs (thousands of real dollars) | | |
|---|---|---|---|---|
| | | *Incentives* | *Program Costs* | *Evaluation* |
| 2014 | 15.4 | 1,277.2 | 2,846.3 | 233.5 |
| 2015 | 17.3 | 1,432.0 | 3,260.8 | 308.8 |
| 2016 | 19.0 | 1,576.0 | 3,146.1 | 212.5 |
| 2017 | 20.5 | 1,702.0 | 2,612.3 | 127.5 |
| 2018 | 21.7 | 1,795.6 | 1,950.4 | 37.4 |
| 2019 | 23.7 | 1,966.7 | 3,276.6 | 183.9 |
| 2020 | 25.8 | 2,137.8 | 3,558.7 | 183.9 |
| 2021 | 27.9 | 2,308.9 | 4,620.4 | 183.9 |
| 2022 | 29.9 | 2,480.0 | 2,378.8 | 183.9 |
| 2023 | 32.0 | 2,651.1 | 2,303.8 | 183.9 |
| 2024 | 34.1 | 2,822.3 | 2,242.1 | 183.9 |
| 2025 | 36.1 | 2,993.4 | 2,190.2 | 183.9 |
| 2026 | 38.2 | 3,164.5 | 2,145.9 | 183.9 |
| 2027 | 40.3 | 3,335.6 | 2,107.6 | 183.9 |
| 2028 | 42.3 | 3,506.7 | 2,074.2 | 183.9 |
| 2029 | 44.4 | 3,677.8 | 2,044.8 | 183.9 |
| 2030 | 46.4 | 3,848.9 | 2,018.8 | 183.9 |
| 2031 | 48.5 | 4,020.0 | 1,995.5 | 183.9 |
| 2032 | 50.6 | 4,191.1 | 1,974.6 | 183.9 |
| 2033 | 52.6 | 4,362.2 | 1,955.7 | 183.9 |

*Notes*

1. Megawatt impacts are annualized non-coincident Peak Impacts (Net MW)
2. Total Costs = Incentives + Program Costs + Evaluation
3. Costs are listed in thousands of real 2012 dollars
4. Peak impacts are at the net-to-system level (net generation)

Table F-3: HECO RDLC Programs – Air Conditioning (Continue Existing)

| Year | Peak Impacts (Net MW) | Total Costs (thousands of real dollars) | | |
|---|---|---|---|---|
| | | *Incentives* | *Program Costs* | *Evaluation* |
| 2014 | 3.2 | 218.0 | 169.5 | 7.5 |
| 2015 | 3.2 | 218.0 | 169.5 | 7.5 |
| 2016 | 3.2 | 218.0 | 169.5 | 7.5 |
| 2017 | 3.2 | 218.0 | 169.5 | 7.5 |
| 2018 | 3.2 | 218.0 | 169.5 | 7.5 |
| 2019 | 3.2 | 218.0 | 169.5 | 7.5 |
| 2020 | 3.2 | 218.0 | 169.5 | 7.5 |
| 2021 | 3.2 | 218.0 | 169.5 | 7.5 |
| 2022 | 3.2 | 218.0 | 169.5 | 7.5 |
| 2023 | 3.2 | 218.0 | 169.5 | 7.5 |
| 2024 | 3.2 | 218.0 | 169.5 | 7.5 |
| 2025 | 3.2 | 218.0 | 169.5 | 7.5 |
| 2026 | 3.2 | 218.0 | 169.5 | 7.5 |
| 2027 | 3.2 | 218.0 | 169.5 | 7.5 |
| 2028 | 3.2 | 218.0 | 169.5 | 7.5 |
| 2029 | 3.2 | 218.0 | 169.5 | 7.5 |
| 2030 | 3.2 | 218.0 | 169.5 | 7.5 |
| 2031 | 3.2 | 218.0 | 169.5 | 7.5 |
| 2032 | 3.2 | 218.0 | 169.5 | 7.5 |
| 2033 | 3.2 | 218.0 | 169.5 | 7.5 |

*Notes*

1. Megawatt impacts are annualized non-coincident Peak Impacts (Net MW)
2. Total Costs = Incentives + Program Costs + Evaluation
3. Costs are listed in thousands of real 2012 dollars
4. Peak impacts are at the net-to-system level (net generation)

Table F-4: HECO RDLC Programs – Air Conditioning (Expanded)

| Year | Peak Impacts (Net MW) | Total Costs (thousands of real dollars) | | |
|---|---|---|---|---|
| | | *Incentives* | *Program Costs* | *Evaluation* |
| 2014 | 5.7 | 407.7 | 810.7 | 66.5 |
| 2015 | 8.8 | 629.7 | 1,279.4 | 121.2 |
| 2016 | 12.5 | 893.7 | 1,591.9 | 10.8 |
| 2017 | 15.1 | 1,085.7 | 1,486.9 | 72.5 |
| 2018 | 17.0 | 1,217.7 | 1,180.2 | 22.6 |
| 2019 | 22.3 | 1,597.4 | 2,374.7 | 58.7 |
| 2020 | 27.5 | 1,976.6 | 2,936.0 | 58.7 |
| 2021 | 32.8 | 2,355.8 | 4,206.5 | 58.7 |
| 2022 | 38.1 | 2,735.0 | 2,340.9 | 58.7 |
| 2023 | 43.4 | 3,114.2 | 2,414.8 | 58.7 |
| 2024 | 48.7 | 3,493.4 | 2,476.5 | 58.7 |
| 2025 | 54.0 | 3,872.6 | 2,528.4 | 58.7 |
| 2026 | 59.3 | 4,251.8 | 2,572.7 | 58.7 |
| 2027 | 64.5 | 4,631.0 | 2,611.0 | 58.7 |
| 2028 | 69.8 | 5,010.2 | 2,644.4 | 58.7 |
| 2029 | 75.1 | 5,389.4 | 2,673.8 | 58.7 |
| 2030 | 80.4 | 5,768.6 | 2,699.8 | 58.7 |
| 2031 | 85.7 | 6,147.8 | 2,723.1 | 58.7 |
| 2032 | 91.0 | 6,527.0 | 2,744.0 | 58.7 |
| 2033 | 96.3 | 6,906.2 | 2,762.9 | 58.7 |

*Notes*

1. Megawatt impacts are annualized non-coincident Peak Impacts (Net MW)
2. Total Costs = Incentives + Program Costs + Evaluation
3. Costs are listed in thousands of real 2012 dollars
4. Peak impacts are at the net-to-system level (net generation)

Table F-5: HECO CIDLC Program (Continue Existing)

| Year | Peak Impacts (Net MW) | Total Costs (thousands of real dollars) | | |
|---|---|---|---|---|
| | | *Incentives* | *Program Costs* | *Evaluation* |
| 2014 | 24.9 | 3,420.0 | 1,033.0 | 110.0 |
| 2015 | 24.9 | 3,420.0 | 862.0 | 0.0 |
| 2016 | 24.9 | 3,420.0 | 862.0 | 0.0 |
| 2017 | 24.9 | 3,420.0 | 862.0 | 0.0 |
| 2018 | 24.9 | 3,420.0 | 862.0 | 0.0 |
| 2019 | 24.9 | 3,420.0 | 862.0 | 0.0 |
| 2020 | 24.9 | 3,420.0 | 862.0 | 0.0 |
| 2021 | 24.9 | 3,420.0 | 862.0 | 0.0 |
| 2022 | 24.9 | 3,420.0 | 862.0 | 0.0 |
| 2023 | 24.9 | 3,420.0 | 862.0 | 0.0 |
| 2024 | 24.9 | 3,420.0 | 862.0 | 0.0 |
| 2025 | 24.9 | 3,420.0 | 862.0 | 0.0 |
| 2026 | 24.9 | 3,420.0 | 862.0 | 0.0 |
| 2027 | 24.9 | 3,420.0 | 862.0 | 0.0 |
| 2028 | 24.9 | 3,420.0 | 862.0 | 0.0 |
| 2029 | 24.9 | 3,420.0 | 862.0 | 0.0 |
| 2030 | 24.9 | 3,420.0 | 862.0 | 0.0 |
| 2031 | 24.9 | 3,420.0 | 862.0 | 0.0 |
| 2032 | 24.9 | 3,420.0 | 862.0 | 0.0 |
| 2033 | 24.9 | 3,420.0 | 862.0 | 0.0 |

*Notes*

1. Megawatt impacts are annualized non-coincident Peak Impacts (Net MW)
2. Total Costs = Incentives + Program Costs + Evaluation
3. Costs are listed in thousands of real 2012 dollars
4. Peak impacts are at the net-to-system level (net generation)

Table F-6: HECO CIDLC Program (Expanded)

| Year | Peak Impacts (Net MW) | Total Costs (thousands of real dollars) | | |
|---|---|---|---|---|
| | | *Incentives* | *Program Costs* | *Evaluation* |
| 2014 | 26.0 | 3,600.0 | 2,113.0 | 250.0 |
| 2015 | 27.1 | 3,790.0 | 1,825.0 | 240.0 |
| 2016 | 27.5 | 3,970.0 | 1,656.0 | 0.0 |
| 2017 | 27.8 | 4,015.8 | 1,675.1 | 163.3 |
| 2018 | 28.1 | 4,061.6 | 1,694.2 | 163.3 |
| 2019 | 28.4 | 4,107.3 | 1,713.3 | 163.3 |
| 2020 | 28.7 | 4,153.1 | 1,732.4 | 163.3 |
| 2021 | 29.1 | 4,205.5 | 1,754.2 | 163.3 |
| 2022 | 29.5 | 4,257.8 | 1,776.0 | 163.3 |
| 2023 | 29.8 | 4,310.1 | 1,797.9 | 163.3 |
| 2024 | 30.2 | 4,362.4 | 1,819.7 | 163.3 |
| 2025 | 30.5 | 4,414.7 | 1,841.5 | 163.3 |
| 2026 | 30.9 | 4,467.1 | 1,863.3 | 163.3 |
| 2027 | 31.3 | 4,519.4 | 1,885.2 | 163.3 |
| 2028 | 31.6 | 4,571.7 | 1,907.0 | 163.3 |
| 2029 | 32.0 | 4,624.0 | 1,928.8 | 163.3 |
| 2030 | 32.3 | 4,676.4 | 1,950.6 | 163.3 |
| 2031 | 32.0 | 4,630.6 | 1,931.5 | 163.3 |
| 2032 | 31.7 | 4,584.8 | 1,912.4 | 163.3 |
| 2033 | 31.4 | 4,539.0 | 1,893.4 | 163.3 |

*Notes*

1. Megawatt impacts are annualized non-coincident Peak Impacts (Net MW)
2. Total Costs = Incentives + Program Costs + Evaluation
3. Costs are listed in thousands of real 2012 dollars
4. Peak impacts are at the net-to-system level (net generation)
5. The data includes impacts and costs from the continuation of the Fast Demand Response (DR) program

Table F-7: HECO Fast Demand Response Pilot

| Year | Peak Impacts (Net MW) | Total Costs (thousands of real dollars) | | |
|---|---|---|---|---|
| | | *Incentives* | *Program Costs* | *Evaluation* |
| 2012 | 1.5 | 300.0 | 1,513.3 | 211.2 |
| 2013 | 7.0 | 1,100.0 | 1,324.9 | 163.2 |
| 2014 | – | – | – | – |
| 2015 | – | – | – | – |
| 2016 | – | – | – | – |
| 2017 | – | – | – | – |
| 2018 | – | – | – | – |
| 2019 | – | – | – | – |
| 2020 | – | – | – | – |
| 2021 | – | – | – | – |
| 2022 | – | – | – | – |
| 2023 | – | – | – | – |
| 2024 | – | – | – | – |
| 2025 | – | – | – | – |
| 2026 | – | – | – | – |
| 2027 | – | – | – | – |
| 2028 | – | – | – | – |
| 2029 | – | – | – | – |
| 2030 | – | – | – | – |
| 2031 | – | – | – | – |
| 2032 | – | – | – | – |
| 2033 | – | – | – | – |

*Notes*

1. Megawatt impacts are annualized non-coincident Peak Impacts (Net MW)
2. Total Costs = Incentives + Program Costs + Evaluation
3. Costs are listed in thousands of real 2012 dollars
4. Peak impacts are at the net-to-system level (net generation)
5. Continuation of the Fast Demand Response (DR) Pilot program is included in Table F-6 as part of the Expanded CIDLC program

Table F-8: HECO CIDP Pilot

| Year | Peak Impacts (Net MW) | Total Costs (thousands of real dollars) | | |
|---|---|---|---|---|
| | | *Incentives* | *Program Costs* | *Evaluation* |
| 2012 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2013 | 1.9 | 1,200.0 | 1,716.0 | 160.0 |
| 2014 | 1.9 | 0.0 | 611.0 | 160.0 |
| 2015 | – | – | – | – |
| 2016 | – | – | – | – |
| 2017 | – | – | – | – |
| 2018 | – | – | – | – |
| 2019 | – | – | – | – |
| 2020 | – | – | – | – |
| 2021 | – | – | – | – |
| 2022 | – | – | – | – |
| 2023 | – | – | – | – |
| 2024 | – | – | – | – |
| 2025 | – | – | – | – |
| 2026 | – | – | – | – |
| 2027 | – | – | – | – |
| 2028 | – | – | – | – |
| 2029 | – | – | – | – |
| 2030 | – | – | – | – |
| 2031 | – | – | – | – |
| 2032 | – | – | – | – |
| 2033 | – | – | – | – |

*Notes*

1. Megawatt impacts are annualized non-coincident Peak Impacts (Net MW)
2. Total Costs = Incentives + Program Costs + Evaluation
3. Costs are listed in thousands of real 2012 dollars
4. Peak impacts are at the net-to-system level (net generation)

Table F-9: HECO CIDP Program (Expand Pilot)

| Year | Peak Impacts (Net MW) | Total Costs (thousands of real dollars) | | |
|---|---|---|---|---|
| | | *Incentives* | *Program Costs* | *Evaluation* |
| 2014 | 1.9 | 0.0 | 611.0 | 160.0 |
| 2015 | 3.9 | 1,300.0 | 1,163.5 | 160.0 |
| 2016 | 5.9 | 1,300.0 | 1,163.5 | 160.0 |
| 2017 | 7.9 | 1,300.0 | 1,163.5 | 160.0 |
| 2018 | 10.0 | 1,300.0 | 1,163.5 | 160.0 |
| 2019 | 12.0 | 1,300.0 | 1,163.5 | 160.0 |
| 2020 | 14.0 | 1,300.0 | 1,163.5 | 160.0 |
| 2021 | 16.3 | 1,440.0 | 1,163.5 | 160.0 |
| 2022 | 18.5 | 1,440.0 | 1,163.5 | 160.0 |
| 2023 | 20.7 | 1,440.0 | 1,163.5 | 160.0 |
| 2024 | 23.0 | 1,440.0 | 1,163.5 | 160.0 |
| 2025 | 25.2 | 1,440.0 | 1,163.5 | 160.0 |
| 2026 | 27.5 | 1,440.0 | 1,163.5 | 160.0 |
| 2027 | 29.7 | 1,440.0 | 1,163.5 | 160.0 |
| 2028 | 32.0 | 1,440.0 | 1,163.5 | 160.0 |
| 2029 | 34.2 | 1,440.0 | 1,163.5 | 160.0 |
| 2030 | 36.4 | 1,440.0 | 1,163.5 | 160.0 |
| 2031 | 37.2 | 480.0 | 1,163.5 | 160.0 |
| 2032 | 37.9 | 480.0 | 1,163.5 | 160.0 |
| 2033 | 38.7 | 480.0 | 1,163.5 | 160.0 |

*Notes*

1. Megawatt impacts are annualized non-coincident Peak Impacts (Net MW)
2. Total Costs = Incentives + Program Costs + Evaluation
3. Costs are listed in thousands of real 2012 dollars
4. Peak impacts are at the net-to-system level (net generation)

## MECO Demand Response Program Data

Table F-10: MECO RDLC Program – Water Heating

| Year | Peak Impacts (Net MW) | Total Costs (thousands of real dollars) | | |
|---|---|---|---|---|
| | | *Incentives* | *Program Costs* | *Evaluation* |
| 2014 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2015 | 0.3 | 27.8 | 1,663.3 | 2.8 |
| 2016 | 0.6 | 57.5 | 1,098.0 | 113.2 |
| 2017 | 1.1 | 92.8 | 1,292.6 | 2.8 |
| 2018 | 1.4 | 125.2 | 1,292.1 | 137.3 |
| 2019 | 1.8 | 158.6 | 1,359.8 | 69.6 |
| 2020 | 2.2 | 191.2 | 1,318.6 | 2.7 |
| 2021 | 2.5 | 224.8 | 1,315.2 | 2.7 |
| 2022 | 2.9 | 257.4 | 1,313.2 | 67.5 |
| 2023 | 3.3 | 290.0 | 1,314.2 | 2.7 |
| 2024 | 3.7 | 323.6 | 1,316.6 | 2.7 |
| 2025 | 4.0 | 356.2 | 1,320.0 | 66.6 |
| 2026 | 4.4 | 389.7 | 1,324.2 | 2.7 |
| 2027 | 4.8 | 422.4 | 1,328.9 | 2.7 |
| 2028 | 5.2 | 455.0 | 1,334.1 | 66.1 |
| 2029 | 5.5 | 488.5 | 1,339.7 | 2.6 |
| 2030 | 5.9 | 521.1 | 1,345.5 | 2.6 |
| 2031 | 6.2 | 549.8 | 1,245.7 | 66.0 |
| 2032 | 6.2 | 549.8 | 703.8 | 2.6 |
| 2033 | 6.2 | 549.8 | 703.8 | 2.6 |

*Notes*

1. Megawatt impacts are annualized non-coincident Peak Impacts (Net MW)
2. Total Costs = Incentives + Program Costs + Evaluation
3. Costs are listed in thousands of real 2012 dollars
4. Peak impacts are at the net-to-system level (net generation)

Table F-11: MECO RDLC Program – Air Conditioning

| Year | Peak Impacts (Net MW) | Total Costs (thousands of real dollars) | | |
|---|---|---|---|---|
| | | *Incentives* | *Program Costs* | *Evaluation* |
| 2014 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2015 | 0.0 | 2.2 | 130.7 | 0.2 |
| 2016 | 0.1 | 4.5 | 85.0 | 8.8 |
| 2017 | 0.1 | 7.2 | 100.4 | 0.2 |
| 2018 | 0.1 | 9.8 | 100.9 | 10.7 |
| 2019 | 0.1 | 12.4 | 106.2 | 5.4 |
| 2020 | 0.2 | 17.8 | 122.4 | 0.3 |
| 2021 | 0.3 | 23.2 | 135.8 | 0.3 |
| 2022 | 0.3 | 28.6 | 145.8 | 7.5 |
| 2023 | 0.4 | 34.0 | 153.8 | 0.3 |
| 2024 | 0.4 | 39.4 | 160.4 | 0.3 |
| 2025 | 0.5 | 44.8 | 166.0 | 8.4 |
| 2026 | 0.6 | 50.3 | 170.8 | 0.3 |
| 2027 | 0.6 | 55.6 | 175.1 | 0.3 |
| 2028 | 0.7 | 61.0 | 178.9 | 8.9 |
| 2029 | 0.8 | 66.5 | 182.3 | 0.4 |
| 2030 | 0.8 | 71.9 | 185.5 | 0.4 |
| 2031 | 0.9 | 75.2 | 170.3 | 9.0 |
| 2032 | 0.9 | 75.2 | 96.2 | 0.4 |
| 2033 | 0.9 | 75.2 | 96.2 | 0.4 |

*Notes*

1. Megawatt impacts are annualized non-coincident Peak Impacts (Net MW)
2. Total Costs = Incentives + Program Costs + Evaluation
3. Costs are listed in thousands of real 2012 dollars
4. Peak impacts are at the net-to-system level (net generation)

Table F-12: MECO CIDLC Program

| Year | Peak Impacts (Net MW) | Total Costs (thousands of real dollars) | | |
|---|---|---|---|---|
| | | *Incentives* | *Program Costs* | *Evaluation* |
| 2014 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2015 | 0.5 | 105.0 | 1,120.0 | 3.0 |
| 2016 | 1.6 | 315.0 | 670.0 | 17.0 |
| 2017 | 2.7 | 536.0 | 705.0 | 3.0 |
| 2018 | 3.1 | 609.0 | 657.0 | 51.0 |
| 2019 | 3.2 | 630.0 | 666.0 | 44.0 |
| 2020 | 3.2 | 630.0 | 568.0 | 3.0 |
| 2021 | 3.2 | 630.0 | 568.0 | 3.0 |
| 2022 | 3.2 | 630.0 | 568.0 | 40.0 |
| 2023 | 3.2 | 630.0 | 568.0 | 3.0 |
| 2024 | 3.2 | 630.0 | 568.0 | 3.0 |
| 2025 | 3.2 | 630.0 | 568.0 | 40.0 |
| 2026 | 3.2 | 630.0 | 568.0 | 3.0 |
| 2027 | 3.2 | 630.0 | 568.0 | 3.0 |
| 2028 | 3.2 | 630.0 | 568.0 | 40.0 |
| 2029 | 3.2 | 630.0 | 568.0 | 3.0 |
| 2030 | 3.2 | 630.0 | 568.0 | 3.0 |
| 2031 | 3.2 | 630.0 | 568.0 | 3.0 |
| 2032 | 3.2 | 630.0 | 568.0 | 3.0 |
| 2033 | 3.2 | 630.0 | 568.0 | 40.0 |

*Notes*

1. Megawatt impacts are annualized non-coincident Peak Impacts (Net MW)
2. Total Costs = Incentives + Program Costs + Evaluation
3. Costs are listed in thousands of real 2012 dollars
4. Peak impacts are at the net-to-system level (net generation)

Table F-13: MECO Fast Demand Response Pilot

| Year | Peak Impacts (Net MW) | Total Costs (thousands of real dollars) | | |
|---|---|---|---|---|
| | | *Incentives* | *Program Costs* | *Evaluation* |
| 2014 | 0.2 | 36.6 | 57.1 | 5.7 |
| 2015 | 0.2 | 36.6 | 57.1 | 5.7 |
| 2016 | 0.2 | 36.6 | 57.1 | 5.7 |
| 2017 | 0.2 | 36.6 | 57.1 | 5.7 |
| 2018 | 0.2 | 36.6 | 57.1 | 5.7 |
| 2019 | 0.2 | 36.6 | 57.1 | 5.7 |
| 2020 | 0.2 | 36.6 | 57.1 | 5.7 |
| 2021 | 0.2 | 36.6 | 57.1 | 5.7 |
| 2022 | 0.2 | 36.6 | 57.1 | 5.7 |
| 2023 | 0.2 | 36.6 | 57.1 | 5.7 |
| 2024 | 0.2 | 36.6 | 57.1 | 5.7 |
| 2025 | 0.2 | 36.6 | 57.1 | 5.7 |
| 2026 | 0.2 | 36.6 | 57.1 | 5.7 |
| 2027 | 0.2 | 36.6 | 57.1 | 5.7 |
| 2028 | 0.2 | 36.6 | 57.1 | 5.7 |
| 2029 | 0.2 | 36.6 | 57.1 | 5.7 |
| 2030 | 0.2 | 36.6 | 57.1 | 5.7 |
| 2031 | 0.2 | 36.6 | 57.1 | 5.7 |
| 2032 | 0.2 | 36.6 | 57.1 | 5.7 |
| 2033 | 0.2 | 36.6 | 57.1 | 5.7 |

*Notes*

1. Megawatt impacts are annualized non-coincident Peak Impacts (Net MW)
2. Total Costs = Incentives + Program Costs + Evaluation
3. Costs are listed in thousands of real 2012 dollars
4. Peak impacts are at the net-to-system level (net generation)

## HELCO Demand Response Program Data

Table F-14: HELCO RDLC Program – Water Heating

| Year | Peak Impacts (Net MW) | Total Costs (thousands of real dollars) | | |
|---|---|---|---|---|
| | | *Incentives* | *Program Costs* | *Evaluation* |
| 2014 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2015 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2016 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2017 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2018 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2019 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2020 | 0.3 | 27.8 | 1,663.3 | 2.8 |
| 2021 | 0.7 | 57.5 | 1,098.0 | 113.2 |
| 2022 | 1.1 | 92.8 | 1,292.6 | 2.8 |
| 2023 | 1.5 | 125.2 | 1,292.1 | 137.3 |
| 2024 | 1.8 | 158.6 | 1,359.8 | 69.6 |
| 2025 | 2.2 | 191.2 | 1,318.6 | 2.7 |
| 2026 | 2.6 | 224.8 | 1,315.2 | 2.7 |
| 2027 | 3.0 | 257.4 | 1,313.2 | 67.5 |
| 2028 | 3.4 | 290.0 | 1,314.2 | 2.7 |
| 2029 | 3.7 | 323.6 | 1,316.6 | 2.7 |
| 2030 | 4.1 | 356.2 | 1,320.0 | 66.6 |
| 2031 | 4.5 | 389.7 | 1,324.2 | 2.7 |
| 2032 | 4.9 | 422.4 | 1,328.9 | 2.7 |
| 2033 | 5.3 | 455.0 | 1,334.1 | 66.1 |

*Notes*

1. Megawatt impacts are annualized non-coincident Peak Impacts (Net MW)
2. Total Costs = Incentives + Program Costs + Evaluation
3. Costs are listed in thousands of real 2012 dollars
4. Peak impacts are at the net-to-system level (net generation)

Table F-15: HELCO RDLC Program – Air Conditioning

| Year | Peak Impacts (Net MW) | Total Costs (thousands of real dollars) | | |
|---|---|---|---|---|
| | | *Incentives* | *Program Costs* | *Evaluation* |
| 2014 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2015 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2016 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2017 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2018 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2019 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2020 | 0.0 | 2.2 | 130.7 | 0.2 |
| 2021 | 0.1 | 4.5 | 85.0 | 8.8 |
| 2022 | 0.1 | 7.2 | 100.4 | 0.2 |
| 2023 | 0.1 | 9.8 | 100.9 | 10.7 |
| 2024 | 0.1 | 12.4 | 106.2 | 5.4 |
| 2025 | 0.2 | 17.8 | 122.4 | 0.3 |
| 2026 | 0.3 | 23.2 | 135.8 | 0.3 |
| 2027 | 0.3 | 28.6 | 145.8 | 7.5 |
| 2028 | 0.4 | 34.0 | 153.8 | 0.3 |
| 2029 | 0.5 | 39.4 | 160.4 | 0.3 |
| 2030 | 0.5 | 44.8 | 166.0 | 8.4 |
| 2031 | 0.6 | 50.3 | 170.8 | 0.3 |
| 2032 | 0.6 | 55.6 | 175.1 | 0.3 |
| 2033 | 0.7 | 61.0 | 178.9 | 8.9 |

*Notes*

1. Megawatt impacts are annualized non-coincident Peak Impacts (Net MW)
2. Total Costs = Incentives + Program Costs + Evaluation
3. Costs are listed in thousands of real 2012 dollars
4. Peak impacts are at the net-to-system level (net generation)

Table F-16: HELCO CIDLC Program

| Year | Peak Impacts (Net MW) | Total Costs (thousands of real dollars) | | |
|---|---|---|---|---|
| | | *Incentives* | *Program Costs* | *Evaluation* |
| 2014 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2015 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2016 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2017 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2018 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2019 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2020 | 0.5 | 105.0 | 1,120.0 | 3.0 |
| 2021 | 1.6 | 315.0 | 670.0 | 17.0 |
| 2022 | 2.8 | 536.0 | 705.0 | 3.0 |
| 2023 | 3.1 | 609.0 | 657.0 | 51.0 |
| 2024 | 3.2 | 630.0 | 666.0 | 44.0 |
| 2025 | 3.2 | 630.0 | 568.0 | 3.0 |
| 2026 | 3.2 | 630.0 | 568.0 | 3.0 |
| 2027 | 3.2 | 630.0 | 568.0 | 40.0 |
| 2028 | 3.2 | 630.0 | 568.0 | 3.0 |
| 2029 | 3.2 | 630.0 | 568.0 | 3.0 |
| 2030 | 3.2 | 630.0 | 568.0 | 40.0 |
| 2031 | 3.2 | 630.0 | 568.0 | 3.0 |
| 2032 | 3.2 | 630.0 | 568.0 | 3.0 |
| 2033 | 3.2 | 630.0 | 568.0 | 40.0 |

*Notes*

1. Megawatt impacts are annualized non-coincident Peak Impacts (Net MW)
2. Total Costs = Incentives + Program Costs + Evaluation
3. Costs are listed in thousands of real 2012 dollars
4. Peak impacts are at the net-to-system level (net generation)

Table F-17: HELCO Fast DR Pilot

| Year | Peak Impacts (Net MW) | Total Costs (thousands of real dollars) | | |
|---|---|---|---|---|
| | | *Incentives* | *Program Costs* | *Evaluation* |
| 2014 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2015 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2016 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2017 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2018 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2019 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2020 | 0.2 | 36.6 | 149.2 | 5.6 |
| 2021 | 0.2 | 36.6 | 149.2 | 5.7 |
| 2022 | 0.2 | 36.6 | 57.1 | 5.7 |
| 2023 | 0.2 | 36.6 | 57.1 | 5.7 |
| 2024 | 0.2 | 36.6 | 57.1 | 5.7 |
| 2025 | 0.2 | 36.6 | 57.1 | 5.7 |
| 2026 | 0.2 | 36.6 | 57.1 | 5.7 |
| 2027 | 0.2 | 36.6 | 57.1 | 5.7 |
| 2028 | 0.2 | 36.6 | 57.1 | 5.7 |
| 2029 | 0.2 | 36.6 | 57.1 | 5.7 |
| 2030 | 0.2 | 36.6 | 57.1 | 5.7 |
| 2031 | 0.2 | 36.6 | 57.1 | 5.7 |
| 2032 | 0.2 | 36.6 | 57.1 | 5.7 |
| 2033 | 0.2 | 36.6 | 57.1 | 5.7 |

*Notes*

1. Megawatt impacts are annualized non-coincident Peak Impacts (Net MW)
2. Total Costs = Incentives + Program Costs + Evaluation
3. Costs are listed in thousands of real 2012 dollars
4. Peak impacts are at the net-to-system level (net generation)

# PBFA Demand-Side Management (DSM) Program Data

Table F-18: HECO PBFA DSM Program for 75% Achievement Level (PPBFA75)

| Year | PBFA DSM Programs Energy Savings (GWhs) | PBFA DSM Programs Peak Impact (MW) | Costs (millions of nominal dollars) | | |
|---|---|---|---|---|---|
| | | | *Program Costs* | *Incentives & Rebates* | *Customer Costs* |
| 2012 | (33.1) | (9.7) | 4.91 | 8.72 | 56.88 |
| 2013 | (99.3) | (19.4) | 4.91 | 8.72 | 56.88 |
| 2014 | (165.5) | (29.6) | 6.55 | 11.62 | 75.83 |
| 2015 | (231.8) | (39.8) | 6.55 | 11.62 | 75.83 |
| 2016 | (298.0) | (50.0) | 6.55 | 11.62 | 75.83 |
| 2017 | (364.2) | (60.2) | 6.55 | 11.62 | 75.83 |
| 2018 | (430.4) | (70.4) | 6.55 | 11.62 | 75.83 |
| 2019 | (496.6) | (80.6) | 6.55 | 11.62 | 75.83 |
| 2020 | (562.8) | (90.8) | 8.18 | 14.53 | 94.78 |
| 2021 | (629.1) | (101.0) | 8.18 | 19.37 | 126.38 |
| 2022 | (695.3) | (111.2) | 8.18 | 19.37 | 126.38 |
| 2023 | (761.5) | (121.4) | 8.18 | 19.37 | 126.38 |
| 2024 | (827.7) | (131.6) | 8.18 | 19.37 | 126.38 |
| 2025 | (893.9) | (141.8) | 8.18 | 19.37 | 126.38 |
| 2026 | (960.1) | (152.0) | 9.82 | 23.24 | 151.65 |
| 2027 | (1,026.4) | (162.2) | 9.82 | 23.24 | 151.65 |
| 2028 | (1,092.6) | (172.4) | 9.82 | 23.24 | 151.65 |
| 2029 | (1,158.8) | (182.6) | 9.82 | 23.24 | 151.65 |
| 2030 | (1,225.0) | (192.8) | 9.82 | 23.24 | 151.65 |
| 2031 | (1,291.2) | (203.0) | 9.82 | 23.24 | 151.65 |
| 2032 | (1,357.4) | (213.2) | 9.82 | 23.24 | 151.65 |
| 2033 | (1,423.7) | (223.4) | 9.82 | 23.24 | 151.65 |

Table F-19: HECO PBFA DSM Program for 25% Achievement Level (PPBFA25)

| Year | PBFA DSM Programs Energy Savings (GWhs) | PBFA DSM Programs Peak Impact (MW) | Costs (millions of nominal dollars) | | |
|---|---|---|---|---|---|
| | | | *Program Costs* | *Incentives & Rebates* | *Customer Costs* |
| 2012 | (11.0) | (3.2) | 1.64 | 2.91 | 18.96 |
| 2013 | (33.1) | (6.5) | 1.64 | 2.91 | 18.96 |
| 2014 | (55.2) | (9.9) | 2.18 | 3.87 | 25.28 |
| 2015 | (77.3) | (13.3) | 2.18 | 3.87 | 25.28 |
| 2016 | (99.3) | (16.7) | 2.18 | 3.87 | 25.28 |
| 2017 | (121.4) | (20.1) | 2.18 | 3.87 | 25.28 |
| 2018 | (143.5) | (23.5) | 2.18 | 3.87 | 25.28 |
| 2019 | (165.5) | (26.9) | 2.18 | 3.87 | 25.28 |
| 2020 | (187.6) | (30.3) | 2.73 | 4.84 | 31.59 |
| 2021 | (209.7) | (33.7) | 2.73 | 6.46 | 42.13 |
| 2022 | (231.8) | (37.1) | 2.73 | 6.46 | 42.13 |
| 2023 | (253.8) | (40.5) | 2.73 | 6.46 | 42.13 |
| 2024 | (275.9) | (43.9) | 2.73 | 6.46 | 42.13 |
| 2025 | (298.0) | (47.3) | 2.73 | 6.46 | 42.13 |
| 2026 | (320.0) | (50.7) | 3.27 | 7.75 | 50.55 |
| 2027 | (342.1) | (54.1) | 3.27 | 7.75 | 50.55 |
| 2028 | (364.2) | (57.5) | 3.27 | 7.75 | 50.55 |
| 2029 | (386.3) | (60.9) | 3.27 | 7.75 | 50.55 |
| 2030 | (408.3) | (64.3) | 3.27 | 7.75 | 50.55 |
| 2031 | (430.4) | (67.7) | 3.27 | 7.75 | 50.55 |
| 2032 | (452.5) | (71.1) | 3.27 | 7.75 | 50.55 |
| 2033 | (474.6) | (74.5) | 3.27 | 7.75 | 50.55 |

Table F-20: HECO PBFA DSM Program for 10% Achievement Level (PPBFA10)

| Year | PBFA DSM Programs Energy Savings (GWhs) | PBFA DSM Programs Peak Impact (MW) | Costs (millions of nominal dollars) | | |
|---|---|---|---|---|---|
| | | | *Program Costs* | *Incentives & Rebates* | *Customer Costs* |
| 2012 | (4.4) | (1.3) | 0.65 | 1.16 | 7.58 |
| 2013 | (13.2) | (2.6) | 0.65 | 1.16 | 7.58 |
| 2014 | (22.1) | (4.0) | 0.87 | 1.55 | 10.11 |
| 2015 | (30.9) | (5.3) | 0.87 | 1.55 | 10.11 |
| 2016 | (39.7) | (6.7) | 0.87 | 1.55 | 10.11 |
| 2017 | (48.6) | (8.0) | 0.87 | 1.55 | 10.11 |
| 2018 | (57.4) | (9.4) | 0.87 | 1.55 | 10.11 |
| 2019 | (66.2) | (10.7) | 0.87 | 1.55 | 10.11 |
| 2020 | (75.0) | (12.1) | 1.09 | 1.94 | 12.64 |
| 2021 | (83.9) | (13.5) | 1.09 | 2.58 | 16.85 |
| 2022 | (92.7) | (14.8) | 1.09 | 2.58 | 16.85 |
| 2023 | (101.5) | (16.2) | 1.09 | 2.58 | 16.85 |
| 2024 | (110.4) | (17.5) | 1.09 | 2.58 | 16.85 |
| 2025 | (119.2) | (18.9) | 1.09 | 2.58 | 16.85 |
| 2026 | (128.0) | (20.3) | 1.31 | 3.10 | 20.22 |
| 2027 | (136.8) | (21.6) | 1.31 | 3.10 | 20.22 |
| 2028 | (145.7) | (23.0) | 1.31 | 3.10 | 20.22 |
| 2029 | (154.5) | (24.3) | 1.31 | 3.10 | 20.22 |
| 2030 | (163.3) | (25.7) | 1.31 | 3.10 | 20.22 |
| 2031 | (172.2) | (27.1) | 1.31 | 3.10 | 20.22 |
| 2032 | (181.0) | (28.4) | 1.31 | 3.10 | 20.22 |
| 2033 | (189.8) | (29.8) | 1.31 | 3.10 | 20.22 |

Table F-21: Maui PBFA DSM Program for 75% Achievement Level (MPBFA75)

| Year | PBFA DSM Programs Energy Savings (GWhs) | PBFA DSM Programs Peak Impact (MW) | Costs (millions of nominal dollars) | | |
|---|---|---|---|---|---|
| | | | *Program Costs* | *Incentives & Rebates* | *Customer Costs* |
| 2012 | (5.1) | (1.5) | 0.76 | 1.35 | 8.82 |
| 2013 | (15.4) | (3.1) | 0.76 | 1.35 | 8.82 |
| 2014 | (25.7) | (4.7) | 1.02 | 1.80 | 11.76 |
| 2015 | (35.9) | (6.3) | 1.02 | 1.80 | 11.76 |
| 2016 | (46.2) | (7.9) | 1.02 | 1.80 | 11.76 |
| 2017 | (56.5) | (9.5) | 1.02 | 1.80 | 11.76 |
| 2018 | (66.7) | (11.1) | 1.02 | 1.80 | 11.76 |
| 2019 | (77.0) | (12.7) | 1.02 | 1.80 | 11.76 |
| 2020 | (87.3) | (14.4) | 1.27 | 2.25 | 14.70 |
| 2021 | (97.5) | (16.0) | 1.27 | 3.00 | 19.59 |
| 2022 | (107.8) | (17.6) | 1.27 | 3.00 | 19.59 |
| 2023 | (118.1) | (19.2) | 1.27 | 3.00 | 19.59 |
| 2024 | (128.3) | (20.8) | 1.27 | 3.00 | 19.59 |
| 2025 | (138.6) | (22.4) | 1.27 | 3.00 | 19.59 |
| 2026 | (148.9) | (24.0) | 1.52 | 3.60 | 23.51 |
| 2027 | (159.1) | (25.6) | 1.52 | 3.60 | 23.51 |
| 2028 | (169.4) | (27.3) | 1.52 | 3.60 | 23.51 |
| 2029 | (179.7) | (28.9) | 1.52 | 3.60 | 23.51 |
| 2030 | (189.9) | (30.5) | 1.52 | 3.60 | 23.51 |
| 2031 | (200.2) | (32.1) | 1.52 | 3.60 | 23.51 |
| 2032 | (210.5) | (33.7) | 1.52 | 3.60 | 23.51 |
| 2033 | (220.7) | (35.3) | 1.52 | 3.60 | 23.51 |

Table F-22: Maui PBFA DSM Program for 25% Achievement Level (MPBFA25)

| Year | PBFA DSM Programs Energy Savings (GWhs) | PBFA DSM Programs Peak Impact (MW) | Costs (millions of nominal dollars) | | |
|---|---|---|---|---|---|
| | | | *Program Costs* | *Incentives & Rebates* | *Customer Costs* |
| 2012 | (1.7) | (0.5) | 0.25 | 0.45 | 2.94 |
| 2013 | (5.1) | (1.0) | 0.25 | 0.45 | 2.94 |
| 2014 | (8.6) | (1.6) | 0.34 | 0.60 | 3.92 |
| 2015 | (12.0) | (2.1) | 0.34 | 0.60 | 3.92 |
| 2016 | (15.4) | (2.6) | 0.34 | 0.60 | 3.92 |
| 2017 | (18.8) | (3.2) | 0.34 | 0.60 | 3.92 |
| 2018 | (22.2) | (3.7) | 0.34 | 0.60 | 3.92 |
| 2019 | (25.7) | (4.2) | 0.34 | 0.60 | 3.92 |
| 2020 | (29.1) | (4.8) | 0.42 | 0.75 | 4.90 |
| 2021 | (32.5) | (5.3) | 0.42 | 1.00 | 6.53 |
| 2022 | (35.9) | (5.9) | 0.42 | 1.00 | 6.53 |
| 2023 | (39.4) | (6.4) | 0.42 | 1.00 | 6.53 |
| 2024 | (42.8) | (6.9) | 0.42 | 1.00 | 6.53 |
| 2025 | (46.2) | (7.5) | 0.42 | 1.00 | 6.53 |
| 2026 | (49.6) | (8.0) | 0.51 | 1.20 | 7.84 |
| 2027 | (53.0) | (8.5) | 0.51 | 1.20 | 7.84 |
| 2028 | (56.5) | (9.1) | 0.51 | 1.20 | 7.84 |
| 2029 | (59.9) | (9.6) | 0.51 | 1.20 | 7.84 |
| 2030 | (63.3) | (10.2) | 0.51 | 1.20 | 7.84 |
| 2031 | (66.7) | (10.7) | 0.51 | 1.20 | 7.84 |
| 2032 | (70.2) | (11.2) | 0.51 | 1.20 | 7.84 |
| 2033 | (73.6) | (11.8) | 0.51 | 1.20 | 7.84 |

Table F-23: Maui PBFA DSM Program for 10% Achievement Level (MPBFA10)

| Year | PBFA DSM Programs Energy Savings (GWhs) | PBFA DSM Programs Peak Impact (MW) | Costs (millions of nominal dollars) | | |
|---|---|---|---|---|---|
| | | | *Program Costs* | *Incentives & Rebates* | *Customer Costs* |
| 2012 | (0.7) | (0.2) | 0.10 | 0.18 | 1.18 |
| 2013 | (2.1) | (0.4) | 0.10 | 0.18 | 1.18 |
| 2014 | (3.4) | (0.6) | 0.14 | 0.24 | 1.57 |
| 2015 | (4.8) | (0.8) | 0.14 | 0.24 | 1.57 |
| 2016 | (6.2) | (1.1) | 0.14 | 0.24 | 1.57 |
| 2017 | (7.5) | (1.3) | 0.14 | 0.24 | 1.57 |
| 2018 | (8.9) | (1.5) | 0.14 | 0.24 | 1.57 |
| 2019 | (10.3) | (1.7) | 0.14 | 0.24 | 1.57 |
| 2020 | (11.6) | (1.9) | 0.17 | 0.30 | 1.96 |
| 2021 | (13.0) | (2.1) | 0.17 | 0.40 | 2.61 |
| 2022 | (14.4) | (2.3) | 0.17 | 0.40 | 2.61 |
| 2023 | (15.7) | (2.6) | 0.17 | 0.40 | 2.61 |
| 2024 | (17.1) | (2.8) | 0.17 | 0.40 | 2.61 |
| 2025 | (18.5) | (3.0) | 0.17 | 0.40 | 2.61 |
| 2026 | (19.8) | (3.2) | 0.20 | 0.48 | 3.14 |
| 2027 | (21.2) | (3.4) | 0.20 | 0.48 | 3.14 |
| 2028 | (22.6) | (3.6) | 0.20 | 0.48 | 3.14 |
| 2029 | (24.0) | (3.8) | 0.20 | 0.48 | 3.14 |
| 2030 | (25.3) | (4.1) | 0.20 | 0.48 | 3.14 |
| 2031 | (26.7) | (4.3) | 0.20 | 0.48 | 3.14 |
| 2032 | (28.1) | (4.5) | 0.20 | 0.48 | 3.14 |
| 2033 | (29.4) | (4.7) | 0.20 | 0.48 | 3.14 |

Table F-24: Lanai PBFA DSM Program for 75% Achievement Level (LPBFA75)

| Year | PBFA DSM Programs Energy Savings (GWhs) | PBFA DSM Programs Peak Impact (MW) | Costs (millions of nominal dollars) | | |
|---|---|---|---|---|---|
| | | | *Program Costs* | *Incentives & Rebates* | *Customer Costs* |
| 2012 | (0.115) | (0.03) | 0.02 | 0.03 | 0.20 |
| 2013 | (0.344) | (0.07) | 0.02 | 0.03 | 0.20 |
| 2014 | (0.573) | (0.10) | 0.02 | 0.03 | 0.20 |
| 2015 | (0.803) | (0.14) | 0.02 | 0.04 | 0.26 |
| 2016 | (1.032) | (0.18) | 0.02 | 0.04 | 0.26 |
| 2017 | (1.261) | (0.21) | 0.02 | 0.04 | 0.26 |
| 2018 | (1.491) | (0.25) | 0.02 | 0.04 | 0.26 |
| 2019 | (1.720) | (0.28) | 0.02 | 0.04 | 0.26 |
| 2020 | (1.949) | (0.32) | 0.02 | 0.04 | 0.26 |
| 2021 | (2.179) | (0.36) | 0.03 | 0.05 | 0.33 |
| 2022 | (2.408) | (0.39) | 0.03 | 0.07 | 0.44 |
| 2023 | (2.637) | (0.43) | 0.03 | 0.07 | 0.44 |
| 2024 | (2.867) | (0.46) | 0.03 | 0.07 | 0.44 |
| 2025 | (3.096) | (0.50) | 0.03 | 0.07 | 0.44 |
| 2026 | (3.325) | (0.54) | 0.03 | 0.07 | 0.44 |
| 2027 | (3.555) | (0.57) | 0.03 | 0.08 | 0.53 |
| 2028 | (3.784) | (0.61) | 0.03 | 0.08 | 0.53 |
| 2029 | (4.013) | (0.64) | 0.03 | 0.08 | 0.53 |
| 2030 | (4.243) | (0.68) | 0.03 | 0.08 | 0.53 |
| 2031 | (4.472) | (0.72) | 0.03 | 0.08 | 0.53 |
| 2032 | (4.701) | (0.75) | 0.03 | 0.08 | 0.53 |
| 2033 | (4.931) | (0.79) | 0.03 | 0.08 | 0.53 |

Table F-25: Lanai PBFA DSM Program for 25% Achievement Level (LPBFA25)

| Year | PBFA DSM Programs Energy Savings (GWhs) | PBFA DSM Programs Peak Impact (MW) | Costs (millions of nominal dollars) | | |
|---|---|---|---|---|---|
| | | | *Program Costs* | *Incentives & Rebates* | *Customer Costs* |
| 2012 | (0.038) | (0.01) | 0.01 | 0.01 | 0.07 |
| 2013 | (0.115) | (0.02) | 0.01 | 0.01 | 0.07 |
| 2014 | (0.191) | (0.03) | 0.01 | 0.01 | 0.07 |
| 2015 | (0.268) | (0.05) | 0.01 | 0.01 | 0.09 |
| 2016 | (0.344) | (0.06) | 0.01 | 0.01 | 0.09 |
| 2017 | (0.420) | (0.07) | 0.01 | 0.01 | 0.09 |
| 2018 | (0.497) | (0.08) | 0.01 | 0.01 | 0.09 |
| 2019 | (0.573) | (0.09) | 0.01 | 0.01 | 0.09 |
| 2020 | (0.650) | (0.11) | 0.01 | 0.01 | 0.09 |
| 2021 | (0.726) | (0.12) | 0.01 | 0.02 | 0.11 |
| 2022 | (0.803) | (0.13) | 0.01 | 0.02 | 0.15 |
| 2023 | (0.879) | (0.14) | 0.01 | 0.02 | 0.15 |
| 2024 | (0.956) | (0.15) | 0.01 | 0.02 | 0.15 |
| 2025 | (1.032) | (0.17) | 0.01 | 0.02 | 0.15 |
| 2026 | (1.108) | (0.18) | 0.01 | 0.02 | 0.15 |
| 2027 | (1.185) | (0.19) | 0.01 | 0.03 | 0.18 |
| 2028 | (1.261) | (0.20) | 0.01 | 0.03 | 0.18 |
| 2029 | (1.338) | (0.21) | 0.01 | 0.03 | 0.18 |
| 2030 | (1.414) | (0.23) | 0.01 | 0.03 | 0.18 |
| 2031 | (1.491) | (0.24) | 0.01 | 0.03 | 0.18 |
| 2032 | (1.567) | (0.25) | 0.01 | 0.03 | 0.18 |
| 2033 | (1.644) | (0.26) | 0.01 | 0.03 | 0.18 |

Table F-26: Lanai PBFA DSM Program for 10% Achievement Level (LPBFA10)

| Year | PBFA DSM Programs Energy Savings (GWhs) | PBFA DSM Programs Peak Impact (MW) | Costs (millions of nominal dollars) | | |
|---|---|---|---|---|---|
| | | | *Program Costs* | *Incentives & Rebates* | *Customer Costs* |
| 2012 | (0.015) | (0.00) | 0.00 | 0.00 | 0.03 |
| 2013 | (0.046) | (0.01) | 0.00 | 0.00 | 0.03 |
| 2014 | (0.076) | (0.01) | 0.00 | 0.00 | 0.03 |
| 2015 | (0.107) | (0.02) | 0.00 | 0.01 | 0.04 |
| 2016 | (0.138) | (0.02) | 0.00 | 0.01 | 0.04 |
| 2017 | (0.168) | (0.03) | 0.00 | 0.01 | 0.04 |
| 2018 | (0.199) | (0.03) | 0.00 | 0.01 | 0.04 |
| 2019 | (0.229) | (0.04) | 0.00 | 0.01 | 0.04 |
| 2020 | (0.260) | (0.04) | 0.00 | 0.01 | 0.04 |
| 2021 | (0.290) | (0.05) | 0.00 | 0.01 | 0.04 |
| 2022 | (0.321) | (0.05) | 0.00 | 0.01 | 0.06 |
| 2023 | (0.352) | (0.06) | 0.00 | 0.01 | 0.06 |
| 2024 | (0.382) | (0.06) | 0.00 | 0.01 | 0.06 |
| 2025 | (0.413) | (0.07) | 0.00 | 0.01 | 0.06 |
| 2026 | (0.443) | (0.07) | 0.00 | 0.01 | 0.06 |
| 2027 | (0.474) | (0.08) | 0.00 | 0.01 | 0.07 |
| 2028 | (0.505) | (0.08) | 0.00 | 0.01 | 0.07 |
| 2029 | (0.535) | (0.09) | 0.00 | 0.01 | 0.07 |
| 2030 | (0.566) | (0.09) | 0.00 | 0.01 | 0.07 |
| 2031 | (0.596) | (0.10) | 0.00 | 0.01 | 0.07 |
| 2032 | (0.627) | (0.10) | 0.00 | 0.01 | 0.07 |
| 2033 | (0.657) | (0.11) | 0.00 | 0.01 | 0.07 |

Table F-27: Molokai PBFA DSM Program for 75% Achievement Level (KPBFA75)

| Year | PBFA DSM Programs Energy Savings (GWhs) | PBFA DSM Programs Peak Impact (MW) | Costs (millions of nominal dollars) | | |
|---|---|---|---|---|---|
| | | | *Program Costs* | *Incentives & Rebates* | *Customer Costs* |
| 2012 | (0.142) | (0.04) | 0.02 | 0.04 | 0.24 |
| 2013 | (0.426) | (0.09) | 0.02 | 0.04 | 0.24 |
| 2014 | (0.710) | (0.13) | 0.03 | 0.05 | 0.33 |
| 2015 | (0.995) | (0.17) | 0.03 | 0.05 | 0.33 |
| 2016 | (1.279) | (0.22) | 0.03 | 0.05 | 0.33 |
| 2017 | (1.563) | (0.26) | 0.03 | 0.05 | 0.33 |
| 2018 | (1.847) | (0.31) | 0.03 | 0.05 | 0.33 |
| 2019 | (2.131) | (0.35) | 0.03 | 0.05 | 0.33 |
| 2020 | (2.415) | (0.40) | 0.04 | 0.06 | 0.41 |
| 2021 | (2.699) | (0.44) | 0.04 | 0.08 | 0.54 |
| 2022 | (2.984) | (0.49) | 0.04 | 0.08 | 0.54 |
| 2023 | (3.268) | (0.53) | 0.04 | 0.08 | 0.54 |
| 2024 | (3.552) | (0.58) | 0.04 | 0.08 | 0.54 |
| 2025 | (3.836) | (0.62) | 0.04 | 0.08 | 0.54 |
| 2026 | (4.120) | (0.67) | 0.04 | 0.10 | 0.65 |
| 2027 | (4.404) | (0.71) | 0.04 | 0.10 | 0.65 |
| 2028 | (4.689) | (0.75) | 0.04 | 0.10 | 0.65 |
| 2029 | (4.973) | (0.80) | 0.04 | 0.10 | 0.65 |
| 2030 | (5.257) | (0.84) | 0.04 | 0.10 | 0.65 |
| 2031 | (5.541) | (0.89) | 0.04 | 0.10 | 0.65 |
| 2032 | (5.825) | (0.93) | 0.04 | 0.10 | 0.65 |
| 2033 | (6.109) | (0.98) | 0.04 | 0.10 | 0.65 |

Table F-28: Molokai PBFA DSM Program for 25% Achievement Level (KPBFA25)

| Year | PBFA DSM Programs Energy Savings (GWhs) | PBFA DSM Programs Peak Impact (MW) | Costs (millions of nominal dollars) | | |
|---|---|---|---|---|---|
| | | | *Program Costs* | *Incentives & Rebates* | *Customer Costs* |
| 2012 | (0.047) | (0.01) | 0.01 | 0.01 | 0.08 |
| 2013 | (0.142) | (0.03) | 0.01 | 0.01 | 0.08 |
| 2014 | (0.237) | (0.04) | 0.01 | 0.02 | 0.11 |
| 2015 | (0.332) | (0.06) | 0.01 | 0.02 | 0.11 |
| 2016 | (0.426) | (0.07) | 0.01 | 0.02 | 0.11 |
| 2017 | (0.521) | (0.09) | 0.01 | 0.02 | 0.11 |
| 2018 | (0.616) | (0.10) | 0.01 | 0.02 | 0.11 |
| 2019 | (0.710) | (0.12) | 0.01 | 0.02 | 0.11 |
| 2020 | (0.805) | (0.13) | 0.01 | 0.02 | 0.14 |
| 2021 | (0.900) | (0.15) | 0.01 | 0.03 | 0.18 |
| 2022 | (0.995) | (0.16) | 0.01 | 0.03 | 0.18 |
| 2023 | (1.089) | (0.18) | 0.01 | 0.03 | 0.18 |
| 2024 | (1.184) | (0.19) | 0.01 | 0.03 | 0.18 |
| 2025 | (1.279) | (0.21) | 0.01 | 0.03 | 0.18 |
| 2026 | (1.373) | (0.22) | 0.01 | 0.03 | 0.22 |
| 2027 | (1.468) | (0.24) | 0.01 | 0.03 | 0.22 |
| 2028 | (1.563) | (0.25) | 0.01 | 0.03 | 0.22 |
| 2029 | (1.658) | (0.27) | 0.01 | 0.03 | 0.22 |
| 2030 | (1.752) | (0.28) | 0.01 | 0.03 | 0.22 |
| 2031 | (1.847) | (0.30) | 0.01 | 0.03 | 0.22 |
| 2032 | (1.942) | (0.31) | 0.01 | 0.03 | 0.22 |
| 2033 | (2.036) | (0.33) | 0.01 | 0.03 | 0.22 |

Table F-29: Molokai PBFA DSM Program for 10% Achievement Level (KPBFA10)

| Year | PBFA DSM Programs Energy Savings (GWhs) | PBFA DSM Programs Peak Impact (MW) | Costs (millions of nominal dollars) | | |
|---|---|---|---|---|---|
| | | | *Program Costs* | *Incentives & Rebates* | *Customer Costs* |
| 2012 | (0.019) | (0.01) | 0.00 | 0.00 | 0.03 |
| 2013 | (0.057) | (0.01) | 0.00 | 0.00 | 0.03 |
| 2014 | (0.095) | (0.02) | 0.00 | 0.01 | 0.04 |
| 2015 | (0.133) | (0.02) | 0.00 | 0.01 | 0.04 |
| 2016 | (0.170) | (0.03) | 0.00 | 0.01 | 0.04 |
| 2017 | (0.208) | (0.04) | 0.00 | 0.01 | 0.04 |
| 2018 | (0.246) | (0.04) | 0.00 | 0.01 | 0.04 |
| 2019 | (0.284) | (0.05) | 0.00 | 0.01 | 0.04 |
| 2020 | (0.322) | (0.05) | 0.00 | 0.01 | 0.05 |
| 2021 | (0.360) | (0.06) | 0.00 | 0.01 | 0.07 |
| 2022 | (0.398) | (0.06) | 0.00 | 0.01 | 0.07 |
| 2023 | (0.436) | (0.07) | 0.00 | 0.01 | 0.07 |
| 2024 | (0.474) | (0.08) | 0.00 | 0.01 | 0.07 |
| 2025 | (0.511) | (0.08) | 0.00 | 0.01 | 0.07 |
| 2026 | (0.549) | (0.09) | 0.01 | 0.01 | 0.09 |
| 2027 | (0.587) | (0.09) | 0.01 | 0.01 | 0.09 |
| 2028 | (0.625) | (0.10) | 0.01 | 0.01 | 0.09 |
| 2029 | (0.663) | (0.11) | 0.01 | 0.01 | 0.09 |
| 2030 | (0.701) | (0.11) | 0.01 | 0.01 | 0.09 |
| 2031 | (0.739) | (0.12) | 0.01 | 0.01 | 0.09 |
| 2032 | (0.777) | (0.12) | 0.01 | 0.01 | 0.09 |
| 2033 | (0.815) | (0.13) | 0.01 | 0.01 | 0.09 |

Table F-30: HELCO PBFA DSM Program for 75% Achievement Level (HPBFA75)

| Year | PBFA DSM Programs Energy Savings (GWhs) | PBFA DSM Programs Peak Impact (MW) | Costs (millions of nominal dollars) | | |
|---|---|---|---|---|---|
| | | | *Program Costs* | *Incentives & Rebates* | *Customer Costs* |
| 2012 | (15.1) | (3.1) | 0.75 | 1.33 | 8.66 |
| 2013 | (25.2) | (4.7) | 0.75 | 1.33 | 8.66 |
| 2014 | (35.3) | (6.3) | 1.00 | 1.77 | 11.54 |
| 2015 | (45.4) | (7.9) | 1.00 | 1.77 | 11.54 |
| 2016 | (55.4) | (9.5) | 1.00 | 1.77 | 11.54 |
| 2017 | (65.5) | (11.1) | 1.00 | 1.77 | 11.54 |
| 2018 | (75.6) | (12.7) | 1.00 | 1.77 | 11.54 |
| 2019 | (85.7) | (14.4) | 1.00 | 1.77 | 11.54 |
| 2020 | (95.8) | (16.0) | 1.25 | 2.21 | 14.43 |
| 2021 | (105.8) | (17.6) | 1.25 | 2.95 | 19.24 |
| 2022 | (115.9) | (19.2) | 1.25 | 2.95 | 19.24 |
| 2023 | (126.0) | (20.8) | 1.25 | 2.95 | 19.24 |
| 2024 | (136.1) | (22.4) | 1.25 | 2.95 | 19.24 |
| 2025 | (146.2) | (24.0) | 1.25 | 2.95 | 19.24 |
| 2026 | (156.2) | (25.6) | 1.49 | 3.54 | 23.09 |
| 2027 | (166.3) | (27.3) | 1.49 | 3.54 | 23.09 |
| 2028 | (176.4) | (28.9) | 1.49 | 3.54 | 23.09 |
| 2029 | (186.5) | (30.5) | 1.49 | 3.54 | 23.09 |
| 2030 | (196.6) | (32.1) | 1.49 | 3.54 | 23.09 |
| 2031 | (206.6) | (33.7) | 1.49 | 3.54 | 23.09 |
| 2032 | (216.7) | (35.3) | 1.49 | 3.54 | 23.09 |
| 2033 | (226.8) | (36.8) | 1.49 | 3.54 | 23.09 |

Table F-31: HELCO PBFA DSM Program for 25% Achievement Level (HPBFA25)

| Year | PBFA DSM Programs Energy Savings (GWhs) | PBFA DSM Programs Peak Impact (MW) | Costs (millions of nominal dollars) | | |
|---|---|---|---|---|---|
| | | | *Program Costs* | *Incentives & Rebates* | *Customer Costs* |
| 2012 | (5.0) | (1.0) | 0.25 | 0.44 | 2.89 |
| 2013 | (8.4) | (1.6) | 0.25 | 0.44 | 2.89 |
| 2014 | (11.8) | (2.1) | 0.33 | 0.59 | 3.85 |
| 2015 | (15.1) | (2.6) | 0.33 | 0.59 | 3.85 |
| 2016 | (18.5) | (3.2) | 0.33 | 0.59 | 3.85 |
| 2017 | (21.8) | (3.7) | 0.33 | 0.59 | 3.85 |
| 2018 | (25.2) | (4.2) | 0.33 | 0.59 | 3.85 |
| 2019 | (28.6) | (4.8) | 0.33 | 0.59 | 3.85 |
| 2020 | (31.9) | (5.3) | 0.42 | 0.74 | 4.81 |
| 2021 | (35.3) | (5.9) | 0.42 | 0.98 | 6.41 |
| 2022 | (38.6) | (6.4) | 0.42 | 0.98 | 6.41 |
| 2023 | (42.0) | (6.9) | 0.42 | 0.98 | 6.41 |
| 2024 | (45.4) | (7.5) | 0.42 | 0.98 | 6.41 |
| 2025 | (48.7) | (8.0) | 0.42 | 0.98 | 6.41 |
| 2026 | (52.1) | (8.5) | 0.50 | 1.18 | 7.70 |
| 2027 | (55.4) | (9.1) | 0.50 | 1.18 | 7.70 |
| 2028 | (58.8) | (9.6) | 0.50 | 1.18 | 7.70 |
| 2029 | (62.2) | (10.2) | 0.50 | 1.18 | 7.70 |
| 2030 | (65.5) | (10.7) | 0.50 | 1.18 | 7.70 |
| 2031 | (68.9) | (11.2) | 0.50 | 1.18 | 7.70 |
| 2032 | (72.2) | (11.8) | 0.50 | 1.18 | 7.70 |
| 2033 | (75.6) | (12.3) | 0.50 | 1.18 | 7.70 |

Table F-32: HELCO PBFA DSM Program for 10% Achievement Level (HPBFA10)

| Year | PBFA DSM Programs Energy Savings (GWhs) | PBFA DSM Programs Peak Impact (MW) | Costs (millions of nominal dollars) | | |
|---|---|---|---|---|---|
| | | | *Program Costs* | *Incentives & Rebates* | *Customer Costs* |
| 2012 | (2.0) | (0.4) | 0.10 | 0.18 | 1.15 |
| 2013 | (3.4) | (0.6) | 0.10 | 0.18 | 1.15 |
| 2014 | (4.7) | (0.8) | 0.13 | 0.24 | 1.54 |
| 2015 | (6.0) | (1.1) | 0.13 | 0.24 | 1.54 |
| 2016 | (7.4) | (1.3) | 0.13 | 0.24 | 1.54 |
| 2017 | (8.7) | (1.5) | 0.13 | 0.24 | 1.54 |
| 2018 | (10.1) | (1.7) | 0.13 | 0.24 | 1.54 |
| 2019 | (11.4) | (1.9) | 0.13 | 0.24 | 1.54 |
| 2020 | (12.8) | (2.1) | 0.17 | 0.29 | 1.92 |
| 2021 | (14.1) | (2.3) | 0.17 | 0.39 | 2.57 |
| 2022 | (15.5) | (2.6) | 0.17 | 0.39 | 2.57 |
| 2023 | (16.8) | (2.8) | 0.17 | 0.39 | 2.57 |
| 2024 | (18.1) | (3.0) | 0.17 | 0.39 | 2.57 |
| 2025 | (19.5) | (3.2) | 0.17 | 0.39 | 2.57 |
| 2026 | (20.8) | (3.4) | 0.20 | 0.47 | 3.08 |
| 2027 | (22.2) | (3.6) | 0.20 | 0.47 | 3.08 |
| 2028 | (23.5) | (3.8) | 0.20 | 0.47 | 3.08 |
| 2029 | (24.9) | (4.1) | 0.20 | 0.47 | 3.08 |
| 2030 | (26.2) | (4.3) | 0.20 | 0.47 | 3.08 |
| 2031 | (27.6) | (4.5) | 0.20 | 0.47 | 3.08 |
| 2032 | (28.9) | (4.7) | 0.20 | 0.47 | 3.08 |
| 2033 | (30.2) | (4.9) | 0.20 | 0.47 | 3.08 |

# Appendix G: Public Commentary

During the planning and writing of the IRP Report, the Hawaiian Electric Companies held a series of public meetings on each of the five islands that they serve. What follows is an account of the proceedings from each of those meetings, including specific dialog between company representatives and individuals. There is also a list of the documents collected during those meetings.

# CONTENTS

# Schedule of Meetings: November–December 2012

Several pubic meetings were scheduled at the end of 2012 on each of the islands served by the Hawaiian Electric Companies. Because of its size, three meetings were help on the island of Hawaii.

### Hawaiian Electric Company (HECO)

November 27, 2012
McKinley High School
Honolulu, Oahu

### Hawaii Electric Light Company (HELCO)

December 4, 2012
Imiloa Center
Hilo, Hawaii

December 5, 2012
Waikoloa Elementary
Waikoloa Village, Hawaii

December 6, 2012
Pahala Community Center
Pahala, Hawaii

### Maui Electric Company (MECO)

December 10, 2012
Hale Kupuna
Lanai City, Lanai

December 11, 2012
Pomaikai Elementary School Cafeteria
Kahului, Maui

December 13, 2012
Mitchell Pauole Community Center
Kaunakakai, Molokai

## Hawaiian Electric, Honolulu, Oahu

Integrated Resource Planning Public Meeting
McKinley High School
November 27, 2012

Key audience members:

- Jeffrey T. Ono, Consumer Advocate
- Carl Freedman, IRP Independent Entity
- Henry Curtis, IRP Advisory Group member

Annelle Amaral, facilitator

Robbie Alm welcomed everyone, acknowledged Advisory Group members and special guests, and introduced the meeting facilitator, Annelle Amaral. Ms. Amaral shared the objectives of the meeting, some basic ground rules and introduced Colton Ching, Vice President of Corporate Planning to present the Integrated Resource Plan process and information. Hawaiian Electric presentations ended at 6:31.

### *Audience Comments*

Annelle Amaral, meeting facilitator, informed attendees that they could verbally provide comments which would be documented on flip charts, provide written comments this evening, or submit comments later via the IE website. She invited audience comments:

Wendell Lum: Can you discuss the fuel cell technology used in the IRP?
*Response by Ken Fong:* The fuel cells resources in IRP are 400kW and fueled by natural gas. In past IRPs, fuel cells were propane fueled.

Wendell Lum: 100 companies are using the Bloom Box. Bloom Energy, based in Sunnyvale, California, has sold fuel cells to companies such as Fedex and Google, who have received Federal tax subsidies. In March 2011, Bloom Energy began leasing Bloom Boxes with no upfront cost, which opened the door for non-profits.

Shannon Wood: Strongly against use of any fossil fuel including LNG. Why is the utility only talking about oil and coal, why LNG?
*Response by Colton Ching:* We are not limiting the resources to oil fired. We do have scenarios for LNG and will look at all forms of renewables, such as solar, wind, and geothermal.

Shannon Wood: A story in the Star Advertiser said that Gasco is pushing for LNG. We need to build coal units since coal is abundant in the continental USA.

Unidentified male: from Arizona, in California, they are using water conservation as a method to save energy. It requires a lot of energy to move and treat water. Has there been any research on this?
*Response by Colton Ching:* I am not aware of any but this is useful input for the IRP.

Jim Hayes: Are the scenarios moving at same level or is one selected as ultimate outcome? Are more opportunities to provide input?
*Response by Colton Ching:* with scenario planning, all four scenarios would move forward. We would not pick one scenario as the most probable. Through the analysis under the four scenarios, four resources plans would emerge that will be used to develop one action plan. This action plan would consider all four futures with no attempt to predict which one is the most probable.

Jim Hayes- Would the price of gas determines which scenario moves forward?
*Response by Colton Ching:* It's a one year process to develop the action plan, but this is not a one-time deal. We will do an IRP every three years. It is a continuous process and we will have an advisory group for each process. We will develop new plans every three years. To answer part 2 of your question, in all scenarios we will meet the requirements such as RPS. For some scenarios, the requirements may be higher. The resource plans developed will comply with statutory requirements.

Bill Milks: I don't see the company getting heavily involved in energy storage. In the 1990s, there were studies on pumped storage, but these projects have since fell off the table. Four years ago, the Secretary of Energy spoke about pumped storage and how it was suited for situations like Hawaii where we want to put more wind into grid. When there is more wind energy produced at night, we can use this energy to pump water off-peak for use during on-peak hours. In the Black & Veatch resources, there is no mention of pumped storage. Pump storage is the best, proven, economical option to store energy for on-peak use. The company needs to open its eyes and look at this.

Wendell Lum: Fuel cell technology is accepted. Bloom Energy produces the Bloom box. The fuel cell is stack of ceramic plates. Many companies in California have invested in this. The materials to produce the Bloom Box are cheap, like sand. The efficiency is high and it can use either renewable or fossil fuel sources. It varies in size, but not ready for residential use (approximate cost $3,000). It is more for commercial & industrial. Used by Google, Walmart, Fedex, Coke Ebay. Doesn't use grid, wireless. Leased to non profits. Mr Lum provided copies of his information.

Unidentified female: who's paying for this? Is it from bonds?
*Response by Colton Ching:* We haven't done resource plans yet, but we will calculate bill impact, which will be provided in the spring of next year.

Unidentified female: How much time to build these power generators? Wind is quick but OTEC will take years.

Erica Brooksby (senior from Mililani High): For a Civics class project on solar power in Hawaii, I interviewed a professional in solar power. He said that 99.9% of residential PV is designed to produce only enough for their own needs because under Hawaiian Electric's NEM program unused credits are forfeited at the end of year. I propose that the NEM program be changed so that Hawaiian Electric pays for all credits to encourage people to maximize

PV panels installed to produce extra energy. This would not cost Hawaiian Electric anything.

#### Closing

At 7:00, a 10 minute break was held to allow public to speak to Hawaiian Electric representatives.

The meeting was reconvened to ask if any attendees had additional questions; no questions were posed. Annelle Amaral asked the two recorders to summarize the comments that had been documented on flip charts during the meeting and for attendees to make corrections, if needed. She thanked the audience, reminding everyone that additional comments could be sent to the IE and that presentations and comments would be available, providing the website information.

### *Public Documents*

- Honolulu Sign-in Sheet (2 pages)
- Honolulu Public Comment: Bloom Energy Bloom Box (65 pages)

## HELCO, Hilo, Hawaii

Integrated Resource Planning Public Meeting
'Imiloa Center
December 4, 2012

Attending from Hawaii Electric Light Company: Jay Ignacio, President; Curt Beck, Manager, Energy Services; Norman Verbanic, Manager, Production; Debra Gomez Ota, Planning Engineer; Virginia Aragon-Barnes, Educational Services Administrator; Pat Moore, Energy Services Administrator; Amanda Lee, Commercial Services Administrator; Carla Chitwood, HR Team Director; Kristen Okinaka, Administrative Aide

Annelle Amaral, Facilitator

See attached sign-in sheet for attendees from outside Hawaii Electric Light Company.

Jay Ignacio opened the meeting. He welcomed the group and emphasized that we are here to listen.

Jay did introductions of some key audience members:

- Jeffrey T. Ono, Consumer Advocate
- David Mattice, PUC
- Carl Freedman, IRP Independent Entity
- Barry Mizuno, IRP Advisory Group member
- Jon Olson, past IRP Advisory Group member

Annelle Amaral: Thanked everyone for attending, explained her role as the facilitator, and then introduced Pat Moore.

Pat gave short presentation on IRP process which included a brief overview of the IRP process, scenario planning and the scenarios that have been developed, the IRP schedule and objectives, several examples of resource options that may be considered, and HELCO's resource mix.

Annelle Amaral informed attendees that they could verbally provide comments which would be documented on flip charts, provide written comments this evening, or submit comments later via the IE website. Annelle then facilitated audience questions and comments.

### Audience Comments

Julie Neal, Ka'u Calendar: Where does oil come from? Does it really come from the Middle East?
*Response by N. Verbanic*: All oil comes from refineries on Oahu, who in turn get crude oil generally from Indonesia.

John Ota: Stated that his comments are based on information received from Tribune Herald. Information left him with mixed feelings. This is fishing expedition from HELCO and PUC to gain information from the public on how to address energy concerns. Also to ensure customers will pay for future plans such as cable (interisland). Intent is to send energy from Big Island to Oahu without consent of BI populous. Goal of IRP is to develop action plans but four scenarios all contain oil prices, which tells him that HELCO will never get rid of oil prices. Nothing shown on board tonight and in newspapers states that consumers will save. Consumers will suffer and will pay for it. So he is really mad. PUC should be asking question why consumer is paying such high cost per kilowatt-hour. Nothing was stated as to how HELCO will reduce energy costs. Why is there difference in price from island to island? He referred to Tribune Herald advertisement from 20 Nov 2012 which states that costs are 29% for IPPs and 29% for fuel oil. Showed copies of full page ads from the Tribune Herald. Said that HELCO is lying to public and should be put to screeching halt. Said PUC and HELCO work in unison.

Cory Harden: When looking at oil and different energy sources, do we also look at environmental impacts? Do we think about centralized vs. decentralized power? Do we look at how vulnerable the system is to disasters, intentional or natural? In shipping oil, do we look at possible disruption in shipping? Are all of these being factored in?
*Response by P. Moore*: Environmental impacts are part of objectives. Vulnerability is a good concern.

Jon Olson: Are we going to monetize the externalities such as site pollution and environmental issues? Can we connect the dollar sign to these concerns?
*Response by P. Moore*: Yes, we will be looking at externalities. Not sure if externalities will be specifically monetized. Advisory Group reworked objectives.

Jon Olson: Considering costs of solar systems, how will utility address redlined areas, that is, 10% limit on NEM.

*Response by P. Moore*: Explained that it is a misconception that HELCO is limiting NEM. Patproceeded to explain the current process for FIT and NEM.

Jon Olson: With cost of solar going down, many people have decided not to connect at all. Understands people want to have the asset instead of liability. At what point does utility no longer have monopoly?

Carey Yost: In IRP presentations HELCO says it is doing renewables but majority of renewables are IPPs. Why isn't HELCO investing and why does HELCO have aversion to risk? Why haven't line capacities been updated? Does IRP include climate change plans?
*Response by J. Ignacio*: Yes, we started as a primarily renewable energy company with hydro plants, as well as generation from sugar plantations. Some of our future strategies include conversion of existing plants, possible wind plants, expansion of hydro, and option to purchase in geothermal RFP. Integration is a difficult technical challenge. Since he was hired in 1990, HELCO has done a lot of work to rebuild transmission system. Still working on Waikoloa-Kailua line, saddle line, as well as North Kohala. Climate change is included in objective on environmental concerns.

Roger Meeker: RFP indicates that HELCO is looking for geothermal. Does that include phasing out fossil generation or is that to add capacity? Why is HELCO not expanding wind? (Annelle takes a break to remind audience that they should make statements regarding their own best ideas.) What is being done about curtailment policy?
*Response by J. Ignacio*: Still need to balance reliability with resources. Trying to look at other technologies such as batteries or other storage technologies to be able to do more wind in future. Regarding curtailment, we are trying to work on ways to accept more renewables, such as lowering output of the conventional plants. Yes, adding geothermal could lead to removing existing fossil units.

Roger Meeker: How can Maui have 40% wind and we have only 13%?
*Response by J. Ignacio*: They are not much different in terms of generation resources. Wind farms do have some batteries. But they will also have to do curtailment. MECO IPPs were willing to accept the curtailments.

David Tarnas: Would like to strongly encourage HELCO to pursue firm, dispatchable, renewable power, such as geothermal and biomass. Added advantage is that biomass supports another industry (agriculture) on island.

Yen Chen: Question on Adequacy of Supply report: Why is reserve margin roughly 50%? What would be reasonable?
*Response by J. Ignacio*: We do not know exact percentage. We have to follow basic planning criteria to have contingency reserves. (Explained Loss of Load (LOL) unit criteria.) Currently we have more generation now than in the early 90s when we had rolling blackouts.

Yen Chen: Scope of IRP is 5 years. Geothermal RFP asks for production in 2018. Does that make consideration of geothermal outside the scope of IRP?
*Response by P. Moore*: IPR planning period is 20 years. Action plan is for 5 years.

Yen Chen: He is a conservation advocate. Knows DSM was taken away from utilities but Hawaii Energy doing terrible job. Tremendous amount of waste in residential sector.

Richard Ha, farmer: Agriculture and energy are intertwined. Attended tonight to represent Big Island Community Coalition. Their objective is to make energy cost the lowest in the state. Will end up having more jobs on the island if can be competitive with Oahu energy cost. Talked about energy return on investment. Suggested using EROI in analysis.

Michael Hisin: Stated he wants to give IRP process a context. Believes new systems will be here within 5-10 years. Many patents being held up, including 4000 related to energy. Includes free energy devices, cold fusion, sonofusion, and low energy nuclear reactions. As resident of Puna where growth is 10%, feels Oahu treats them as a colony. But many people living near geothermal have gotten ill but Department of Health ignores them. Resource is not green, not renewable, not safe, and not clean. It's called fracking.

Richard Bideman, on behalf of Russell Ruderman: Russell has testified in opposition to geothermal. He is a scientist by training and lives in Lava Zone 1. We have a geothermal plant in the most hazardous lava zone in islands, but that was easiest resource to tap. But if we have disaster, this will affect ratepayers who depend on that resource. Kauai utility owned by ratepayers and they are installing 6000 solar panels. Ratepayers have agreed to increased rates for next 10 years. People feel there is no balance between ratepayers and stockholders. PUC shouldn't be selecting advisory group. PUC are only state commissioners that are paid by the state. Consumers should have a voice in the PUC. We should be putting a lot of our effort into solar. Generating capacity should be taking care of needs of consumers when solar goes down at night.

Carrie Marks: Would like to disagree with folks pushing geothermal and biomass. Wave power is firm, dispatchable power and HELCO should consider this. Doesn't like AKP project.

Nelson Ho: Didn't see discussion about externalities relating to geothermal. Current IRP process will underestimate controversy of next 50 MW of geothermal, which result in delays in construction. Feels have over-reliance on geothermal.

Cory Harden: Agreed scientists should review plans for various power options. Should look at decentralizing, environmental regulations, LNG, smart grid. Also look at different economic drivers. Look at how energy needs will change. Look at new regulations such as transmission across property lines. Look at doing DC power. Look at utility ownership and control. Include provisions for allowing energy conversion in building codes. Better public transportation and street design for alternative transportation. Tiny energy sources like energy flags, paddle wheels in downspouts, exercise bikes.

David Tarnas: HELCO and MECO should consider waste-to-energy in IRPs, which has been said by current mayor and former mayor. This is a firm, renewable power source. Utilities should work closely with the counties, who are the ones putting out these RFPs.

Richard Ha: Wanted to mention that IMF (International Monetary Fund) had study with 5 scenarios. IRP should look at those scenarios. 5th scenario is doomsday scenario. Should consider worst case. Consider food security. Example: Pinky's (convenience store) bill is $3500/month. If oil prices double, she is out of business. IRP folks should consider economic effect. Cost is very important. Wanted to comment that they are not pushing against HELCO. They have immense respect for those of HELCO.

#### Closing

Annelle asked both flip chart recorders (Amanda and Virginia) to summarize comments they have written.

Jay closed meeting by expressing appreciation for attendance and manner of sharing comments. We all agree we love the island, state, and world.

### *Public Documents*

- Hilo Sign-in Sheet (3 pages)
- Hilo Public Comment Cards (6 pages)

## HELCO, Waikoloa Village, Hawaii

IRP Public Meeting
Waikoloa Elementary
December 5, 2012

Attending from Hawaii Electric Light Company: Jay Ignacio, President; Kevin Waltjen, Manager, Engineering; Roger Keller, Manager, Distribution; Rhea Lee, Manager, Administration; Don Evangelista, Assistant District Superintendent; Debra Gomez Ota, Planning Engineer; Virginia Aragon-Barnes, Educational Services Administrator; Pat Moore, Energy Services Administrator; Bernie Sabado, Administrative Aide

Annelle Amaral, Facilitator

See attached sign-in sheet for attendees from outside Hawaii Electric Light Company.

Jay Ignacio opened the meeting. He welcomed the group and emphasized that we are here to listen.

Jay did introductions of some key audience members:

- Jeffrey T. Ono, Consumer Advocate
- David Mattice, PUC, Big Island
- Carl Freedman, IRP Independent Entity

Annelle Amaral: Thanked everyone for attending, explained her role as the facilitator, and then introduced Pat Moore.

Pat gave short presentation on IRP process which included a brief overview of the IRP process, scenario planning and the scenarios that have been developed, the IRP schedule and objectives, several examples of resource options that may be considered, and HELCO's resource mix.

Annelle Amaral informed attendees that they could verbally provide comments which would be documented on flip charts, provide written comments this evening, or submit comments later via the IE website. Annelle then facilitated audience questions and comments.

### *Audience Comments*

Steve Holmes: Said he's the father of the Honolulu Energy Code. Said cheapest kilowatt is the one you don't produce so we should work on energy efficiency. We have a huge base of solar water heaters on this island and the rest of the islands and we should recognize that. But how do we go back and convert the remaining homes that don't have solar? We can increase the rebate amount. Or we can set up power purchase agreements by having investors install the solar heaters. Also said he was instrumental in having all traffic lights on Oahu changed to LEDs. Suggests changing the outdoor lighting code on all islands. We see growth of microgrids in Hawaii like at NELHA and the military. We can do this with wind farms. We can look at new battery technologies like the guy at Puuwaawaa. We want to look at pulling bigger loads off the grid and use microgrids rather than adding more power. Smart grids and smart meters are very cost effective. New subdivisions should have zero energy homes. Finally, wanted to discuss geothermal. Came to Hawaii 40 years to ago to study volcanoes. Worked as a geologist and park ranger. Feels politicians are talking about geothermal as a panacea to our energy situation. But we are in a period of high volcanic activity and great amounts of lava are in the rift. Cone next to existing power plants is from a fairly recent eruption and we won't be able to move the power plant. Also, the risk is not just on the surface. There are pockets of working geothermal fluids. So you can drill and ruin your resource. Does not think we should put all eggs in one basket. So ignore the politicians. His vision is to look at distributed energy resources, like solar. There are financing options. If there are problems on the grid, we should look for ways to resolve the issues. There is no burden on the ratepayers. He would be willing to give a tour of existing rift zone.

Question from audience (I. De Groote): Are solar water heaters required island-wide?
*Response by S. Holmes*: Yes, required for all new residential construction statewide.

Question from audience (I. De Groote): Will all lights be changed to LED?
*Response by S. Holmes*: Yes.

Question from audience (I. De Groote): Where can we read about this?
*Response by S. Holmes*: There has been coverage by the local newspapers on Mr. Thiel and the LEDs. Or you can Google search his name.

Question from audience (I. De Groote): Regarding geothermal and the dangers, what about other countries that have been using geothermal? Do you have any scientific studies?
*Response by S. Holmes*: Yes, can email to you.

Sharon Diamond: Wants to look at health issues. Volcanic issues getting worse. Health getting worse. People need to have affordable air filtration and air conditioning. One of the missions should be to not have one of the highest rates in country and to try to help people deal with stress of dealing with environmental issues. Has been to HELCO presentations since early 90s. Quality of engineering thinking has been less well developed as compared to other people. But time has come to have high-quality engineering thinking. Her personal current health situation is due to pesticides and hospital error so encourages HELCO to think about consequences of what they do. HELCO should seek out environmental and health researchers for input. The way we do things needs to be improved. There are big environmental health resources in the U.S. but not on the Big Island but people here should get better information. In 1995 there was HELCO proposal to put fossil fuel plant upwind of hospital and retirement community in North Kohala but community came together to fight against it. There were engineers in audience going over design. We need HELCO to be more sophisticated, better in engineering, and more health conscious. Wanted to raise something that may be too expensive. Said we have fabulous wave energy in the channel. Not looking enough at wave energy. It's tricky but it's clean.

Isabelle De Groote: Why do we have only 3 or 4 people from the public here? Wasn't it in HELCO's best interest to promote this meeting?
*Response by P. Moore*: We had two series of releases to normal media outlets. It was on Civil Beat. It was in newspapers. We also paid for 7500 inserts in Ka'u Calendar. We also had personal service announcements on the radio.

Isabelle De Groote: Reason she came is cost of electricity is important. She is single mom. First priority for HELCO should be lower rates. She's sure she's not alone in being able to pay her electric bill every month. In terms of planning, HELCO is taking great step in integration and storage and to take advantage of renewables. But feels that it's really late in the game and should have done this 10 years ago. We have to take risks. She sees HELCO expanding office and having record profits. But HELCO should bite the bullet too. Try to take best risk and lower the cost to the consumers.

Caroline Carl: Represents Hawaii Energy. Regarding solar water heating rebate, current rebate is $750. They also have an interest buy-down program. Looking at pushing rebate to $1000 for a limited time offer. LEDs are on the rise also. They are working to target hard-to-reach businesses like tenants who pay the bill but landlords own the facility. Also installing interactive metering systems in 2 large hotels in Waikoloa. Wanted to say that they (Hawaii Energy) are also listening.

Question from audience (I. De Groote): What is upfront cost of basic solar heating system?

*Response by C. Carl*: Around $6,000 but can be knocked down to around $2,000 with tax rebates.

Steve Holmes: Said he is also father of Oahu solar loan program for PV and solar water heating with 0-2% interest loans. Then program was expanded to allow homeowners to acquire energy star appliances. State legislature also looking at PACE program. Also wanted to mention fuel switching. Supports proposal to use biodiesel at existing combustion turbines in Kona. Would also help meeting environmental requirements. Idea of adding biodiesel jobs is wonderful. Also Pacific Biodiesel just opened in Keaau and their refinery has extra capacity. We need biodiesel education. Biofuel is a good thing, a good sustainable fuel.

Question from audience (I. De Groote): Are you aware that we are against the biodiesel because we don't want to be locked into long-term contract?
*Response by S. Holmes*: Explains power purchase agreement is to incentivize private companies to invest.

Sharon Diamond: Said she called HELCO recently to ask how to be more efficient and explained medical needs. Asked if on-demand electric water heaters save money but HELCO would not answer the question.
*Response by P. Moore*: Regular water heater has standby losses (heat losses). Instantaneous does not have those losses so may be more efficient. But from utility perspective we look at peak demand. Instantaneous water heaters would add to our peak demand.

Sharon Diamond: Has house that has 2 water heaters so was told would have to install 2 solar water heaters.
*Response by P. Moore*: Sounds like already doing what can be done with the water heaters to save electricity. Solar water heaters are typically not cost-effective for families of 2 or less.

Jim Tsuji: Heard on Oahu if you generate more than you use they buy it back but not here. Is that true?
*Response by P. Moore*: Explained NEM program and FIT program.

Comment by P. Moore: Described IRP schedule and stated we will be back in spring to gather additional public comments on the Action Plan.

Isabelle De Groote: Can you summarize and explain the four scenarios?
*Response by P. Moore:* Reviewed the four scenarios.

Sharon Diamond: What are implications of global warming and climate change on your planning?
*Response by P. Moore*: We are taking those into account.

Sharon Diamond: Global warming is likely to cause higher cooler demand. Does one of your scenarios take that into account?
*Response by P. Moore*: The scenarios have different sales levels to account for that.

### Closing

Annelle asked both flip chart recorders (Virginia and Don) to summarize comments they have written.

Jay closed meeting by thanking everyone for being here and for their comments. He heard several strong messages tonight. One is that our customers are concerned about pricing. He recognized comment about our engineering competency. He said he strongly believes in technology and in the competency of our engineers. Our model of dependency on oil will have to change. He recognized risks of geothermal and of locating all plants in the East Rift Zone.

### *Public Documents*

- Waikoloa Sign-in Sheet (2 pages)
- Waikoloa Public Comment Card (2 pages)

## HELCO, Pahala, Hawaii

IRP Public Meeting
Pahala Community Center
December 6, 2012

Attending from Hawaii Electric Light Company: Jay Ignacio, President; Kevin Waltjen, Manager, Engineering; Norman Verbanic, Manager, Production; Debra Gomez Ota, Planning Engineer; Sam Terry, Planning Engineer; Virginia Aragon-Barnes, Educational Services Administrator; Pat Moore, Energy Services Administrator; Bernie Sabado, Administrative Aide

Annelle Amaral, Facilitator

See attached sign-in sheet for attendees from outside Hawaii Electric Light Company.

Jay Ignacio opened the meeting. He welcomed the group and emphasized that we are here to listen.

Jay did introductions of some key audience members:

- Jon Itomura, Consumer Advocate
- David Mattice, PUC, Big Island
- Carl Freedman, IRP Independent Entity

Annelle Amaral: Thanked everyone for attending, explained her role as the facilitator, and then introduced Pat Moore.

Pat gave short presentation on IRP process which included a brief overview of the IRP process, scenario planning and the scenarios that have been developed, the IRP schedule and objectives, several examples of resource options that may be considered, and HELCO's resource mix.

Annelle Amaral informed attendees that they could verbally provide comments which would be documented on flip charts, provide written comments this evening, or submit comments later via the IE website. Annelle then facilitated audience questions and comments.

### *Audience Comments*

Dennis Elwell: Said he is a retired materials scientist. He is angry, mostly at the price of electricity. What we have to pay is really unreasonably high. He pays four times the national average. He would like to see an analysis that shows what HELCO does compared with other utilities. Has heard that generating plant is only half the efficiency of a modern one. Has also heard the CEO gets $5 million. This seems absurd. Renewable energy is an excellent idea but should be compatible with lowering cost to consumer.

Ronald Self: He lives in Wood Valley and is a farmer. First issue everyone should understand is that energy policies of this island and state require significant structural change. Hawaiian Electric companies must give up state-sanctioned monopoly. It pits Hawaiian Electric/HELCO against other energy producers. They get to purchase energy and also compete with them. When you have monopolies, you're probably paying the highest prices you can. This island is a special place with natural energy resources: sun, wind, mountains with water. Hydroelectric plays small role now in the energy of this island. In the future of Ka'u, old flume tunnels will be put into action and will produce a lot of water. But they could be used simultaneously for production of energy, which is one of cheapest forms of energy. Geothermal is also a cheap form of energy. Have personally operated farm, home, and business on solar. Biofuel is the worst possible energy source. You use energy to grow something and then burn it. If HELCO relinquishes monopoly, we can have public entity that could purchase and distribute the energy. This would drive down the price and he knows that's what everyone wants in this room. Need to make this structural change now. Finally, this island should be shifting to the electrification of transportation because we have all these alternative sources. All our rental cars should be electric. This would make our island one of the greatest places in the world.

Robert Gomes: Who do we represent (question addressed to Annelle)?
*Response by A. Amaral*: This meeting tonight is sponsored by HELCO. Jay Ignacio and other HELCO employees are here tonight.

Robert Gomes: Is there any sense in us being here? Because we have no say. We could be home watching TV because they already decided.
*Response by A. Amaral*: Not only are we listening to you, HELCO wants to take into consideration the comments and input from public.

Robert Gomes: They are going to shove this biofuel down our throats. You are going to walk all over us.
*Response by J. Ignacio*: We are here to give you an opportunity to speak. Traditional utility planning has the utility doing the planning, calculations, design and then they go before the PUC for approval. PUC has changed that. Utility no longer plans in a vacuum. We have to take into account the public input. We have an advisory group of 68. Tonight we have representatives present from the CA and PUC. We are a regulated monopoly with oversight. Someone gives us approval or disapproval of our actions. The CA is like

your attorney, arguing on your behalf. "I encourage you to speak." We are not required to have this public hearing but felt we should have one to give people an opportunity to give their opinions. As a regulated utility, we need to execute the plan that PUC tells us.

Robert Gomes: Said he wanted to state that this is nothing personal. He likes HELCO. He uses a lot of electricity but bill is too high.

Unidentified Woman: What is naphtha?
*Response by J. Dizon*: It is a lighter fuel oil similar to kerosene.

Unidentified Woman: Is it a by-product?
*Response by J. Ignacio*: It is a product of refining.

Unidentified Woman: Said she would like to hear something from CA. To explain what they do.
*Response by J. Itomura*: Jeff Ono is executive director of CA. Statutorily required to participate in all PUC matters. Position may vary from case to case. Have to take into account the public benefit, which includes the utility's role and survival. Gave example of small water utility. PUC has website where you can look at rate cases. These are boxes and boxes of documents. That's their job.

(Next several commenters also direct their questions to J. Itomura.)

Ron Self, talking to J. Itomura: Most people here are strongly opposed to biofuel project but your office approved the first application. Isn't the head of DCCA connected to AKP?
*Response by J. Itomura*: There is no connection in our office. We need to keep in mind the state policy to go towards renewables. Hawaiian Electric is being held to high standard to meet the renewable standards portfolio and fast. Tension can be seen in first docket. While we did not object in first docket, we did state concerns.

Unidentified Woman, talking to J. Itomura: What is CA position on biodiesel project?
*Response by J. Itomura*: This is still an active docket. We still have concerns. We'd like to see how this application is different. Many times the HECO companies are unfairly criticized. A lot of times the push comes from the IPP and not from the HECO companies.

Unidentified Woman: So are you for or against the biodiesel project?
*Response by J. Itomura*: Cannot provide position at this time until they file. Can say that they have strong concerns.

Unidentified Woman: Business model locks in rate for 20 years. Is that correct?
*Response by J. Itomura*: Concept is based on speculation.
*Response by J. Ignacio*: Explains that contract has a specific price for the fuel.

Unidentified Woman: Could you name 3 benefits to the community regarding biodiesel project?
*Response by J. Itomura*: Responded by saying he is trying to guard against taking his comments out of context.

Unidentified Man, talking to J. Itomura: AKP has based information on EIS. What is your position on that?
*Response by J. Itomura*: Cannot say PUC has to require EIS.
*Response by J. Ignacio*: We are not a regulating body. We do have a contract that says they must abide by all laws and regulations.

Larry Johnson: Hawaii is in unique position that of all states in country we use more petroleum-based electricity than any other state. He is an environmental scientist strongly in favor of renewables: wind, solar, and possibly biofuels. We haven't mentioned conservation tonight. This would help consumers and HELCO. Hawaii Energy has started to address that problem. Would like to see proposal for mass contracts to solar energy installers. Lower rates are key issue here. He is environmental scientist. He is in favor of biofuels but long-term contract should be given at rate lower than current rate. Biofuels from algae has had problems. Biofuels from biomass like AKP have had problems. The producer should get private grants and bring lower price proposals for long-term contracts. Biofuels should only be included if they produce more energy than they use. AKP promised 2 years ago to do wells-to-wheels analysis but have not done that. Finally, we should be encouraging redundancy. He would like to complement HELCO for going to renewables but not focusing on a single renewable. We should also consider redundancy in location. Hawaii has tremendous possibilities but have to get away from fossil fuel model that is driving prices sky high and not doing any favors to environment.

Julie Neal: During discussion of AKP, not fair to compare AKP diesel to barrel of oil at $200 per barrel because not comparing same thing.
*Response by J. Ignacio*: Acknowledged frustration with not knowing pricing. Cannot disclose because also negotiating with other producers. Looking at current oil prices today, AKP pricing is higher than prices today. Looking at surcharge to be charged to all Hawaiian Electric customers.

Unidentified Woman: Is there any other precedent for using the utility to fund a development?
*Response by J. Ignacio*: In this project, we are not funding the developer. We are making a commitment to purchase their product for 20 years. Note we are not giving them cash to do their project. They are taking our commitment to investors to find financing. Customers will not lose if they cannot deliver the fuel. But understand concern that if they fail what happens to removal of the facility.

Robert Gomes: Isn't AKP before the PUC now asking for rate increase?
*Response by J. Ignacio*: They need to get investors. There is misconception that we are increasing rates today to collect a pool of money to give them. We are only giving them a commitment to purchase the fuel at a certain price.

Ron Self: But aren't you providing security?
*Response by J. Ignacio*: We are providing the commitment to purchase. But if project fails, there is no loss of money from our customers.

Larry Johnson: So rates will not go up until they actually delivery fuel?
*Response by J. Ignacio*: Yes, that is correct.

Earl Louis: Wants to focus on geothermal. Thinks this is better method than biofuel.

Chris Manfirdi: Thanks to HELCO for coming out to be our punching bag. Really important you guys are listening. We all know we have highest energy costs in the country. Confusing that answer is even higher energy costs. Energy costs manifest themselves in everything. Discourages businesses. Asked if anyone here from Advisory Group. Unfair that prices are so high that people install PV and then HELCO raises rates on everyone else. Hurts people that cannot afford to convert. Also concerned that he heard talk about negotiating for other biofuels so may have 3 or 4 contracts. Addressed this to CA: They act as our attorney and represent us but in the last docket CA accused them of NIMBYism. Take what community is saying to heart. Doesn't think would approve it if were built anywhere.

Lynn Hamilton: Wants to tell background about Pahala so we know impact on community. We want lower rates. Population in 2010 was 1,479. Includes Pahala and Wood Valley. We have 276 0-15 year-olds. 823 15-59 year-olds. 380 60+ year-olds. Work force is 823. 486 housing units. 443 occupied. 339 owner-occupied. 12 miles from Naalehu. 25 miles from Volcano. 16 years ago plantation closed. Community has diversified. Not sure what criteria HELCO is using to evaluate impact. How will the hundreds of workers affect the town? Pahala is a place where people can afford to live. What assurances do they have that AKP will follow regulations? Concerns: Proposed refinery sits on aquifer. Possible water and air pollution. Result of moving non-native plants. 681 earthquakes in recent years. Environment and community will be affected. Long term plan is desirable. Months ago Jay Ignacio asked her concerns. Her answer was that her main concern was the health and safety of people. Now adds technical viability. Concerned for water, land use, lost job opportunities.

Jeremy Buhr: Said he believes one of fixes is conservation. Likes NEM. Sounds like a lot of power produced by other companies. Has never seen split. Where would AKP fuel be taken and the transportation route?
*Jay introduced Norman Verbanic.*
*Response by N. Verbanic*: Tanker trucks would probably mostly drive south route but AKP has not announced their proposed route. Split between HELCO power and IPP, power is generally about 60/40 IPP/HELCO. Trying to re-negotiate these contracts.

Unidentified Woman: How many tankers?
*Response by N. Verbanic:* Currently 6 tankers a day, 5 days a week to Keahole. Amount would be similar for fuel from AKP.

Moses Espaniola: Said that you (HELCO) only here because needed to be here. Sees no one here his age or younger (he's 19). Understands they are businessmen and main goal is to make money. Feels slighted because cannot do anything. But again no young people here so are you really concerned about the long term?
*Response by J. Ignacio*: We are here voluntarily. We are not required to be here. But we do feel it is important. Disappointing but not surprising there are not more youth here. But now we have opportunity to make a change. We are

not just concerned about bottom line profits. One of primary interests is for owners of the company. Need to ensure they get return on their investment. But have to balance that against interest of customer. Also have to worry about community in general, including environmentally, socially. Also have to worry about our employees. Very concerned about long term well-being of this community.

Unidentified Man: If individual can meet energy needs without fuel then HELCO can too. No fuel non-negotiable.

Lorie Obra: Please stay away from AKP when making decisions about renewable energy. Please consider the wishes of the residents.

Ron Self: You recognize most of comments are against biofuel.
*Response by J. Ignacio*: Have been using biodiesel in vehicles. Hawaiian Electric has been using biofuel in the same type of generating units as in Kona.

Ron Self: Yield is 50 gallons per year per acre. Doesn't add up for amount of contract and for available acreage in Ka'u.
*Response by J. Ignacio*: AKP will have to have expert consultants doing that analysis.

Unidentified Woman: Jay has expressed great deal of trust in due diligence. What about in 2008 when country got into trouble because we trusted people doing due diligence? Issue of trust needs to be explored. You have a beautiful presentation and expertise in communications. You are trying to sell idea without having facts. Appreciate you are here without having to be here. Speaks to bizarre relationship between PUC and CA.

### Closing

Annelle asked both flip chart recorders (Virginia and Sam) to summarize comments they have written.

Pat asked the audience for best method to get meeting notices out.

Jon Itomura said that CA office is always open. They only have a small office of 12. He gave contact info for Consumer Advocate, 586-2800. You can also go online or send emails. He was asked if they can come out to small communities like this to explain what they do. Can always call and email.

Jay closed meeting by thanking everyone for being here, showing interest, having passion to make a difference, and for letting us know how they feel. Also thanked attendees for manner of sharing comments. In all three meetings, not everyone agrees but everyone has been respectful.

## *Public Documents*

- Pahala Sign-in Sheet (4 pages)
- Pahala Public Comment Cards (9 pages)

## MECO, Lanai City, Lanai

Hale Kupuna
Lanai City, Lanai
December 10, 2012

Attending from Maui Electric Company: Sharon Suzuki, President; Mat McNeff, Manager, Renewable Energy Services; Ed Oyama, Power Supply Supervisor, Lanai; Mike Thomas, Transmission and Distribution Supervisor, Lanai; Ellen Nashiwa, Supervisor, Planning; Therese Klaty, Planning Analyst

Annelle Amaral, Facilitator

See attached sign-in sheet for attendees from outside Maui Electric.

Sharon Suzuki opened the meeting by welcoming the group and explaining that Maui Electric is here to listen to what the community wants to see on their island.

Sharon acknowledged:

- Jeffrey T. Ono, Consumer Advocate
- Carl Freedman, IRP Independent Entity
- Sally Kaye, IRP Advisory Group member
- Alberta DeJetley, IRP Advisory Group member
- Chris Lovvorn, IRP Advisory Group member

Annelle Amaral: Thanked everyone for joining the meeting. Explained her role as a facilitator. Introduced Mat McNeff.

Mat McNeff: Presented slides giving a brief overview of the IRP process, the scenarios that have been developed, the schedule, objectives, and several examples of resource options that may be considered. Turned back over to Annelle after the presentation was complete.

Annelle Amaral opened the floor for comments.

### *Audience Comments*

Pat Reilly: My perspective may be a little different. I'm glad the CA and HECO are here. I'm concerned with the cost to the consumer and I don't see that anywhere in the analysis. The other thing is the profit of the Hawaiian electric companies. As I understand it, HECO has to pay a fair return to its shareholders. So as a result, we pay the highest electricity costs in the nation. A recent article in Civil Beat said in this process HECO is not interested in efficiently producing energy for the islands and I think that's wrong. If you look at the generators we have on this island, to me, getting off imported oil doesn't make any sense. Hawaiian Electric must make a profit on the price of the oil that's used. They want to put in the cable to connect islands and it's the customers that are going to pay for it. We're paying for everything while you guys are guaranteeing a profit.
*Response by Sharon Suzuki:* I want to clarify that the utility does not make a profit off the fuel. It's a straight pass-through. Also, we are not guaranteed a return. In the rate proceeding where we go before the commission, what is

approved is almost like a cap on the profit we're allowed to make. We do understand that the prices of electricity are high. We are looking at efficiencies to help make electricity more affordable.

Jim Andrews: You buy your crude oil from Asia, which is one of the most expensive places to get it from. That's poho because you can get it cheaper from North America. That would be part of the reason our electricity is higher. That might be something you should look at. Using a source of oil that is lower cost. My dollar is being spent better buying that oil.

Beverly Zigmond: I've lived on Lanai for over 20 years. Thank you for coming to Lanai. I want this island and every island to be able to determine their own energy scenario. I believe Lanai can be energy independent. I believe we should look at reducing our use. I use less than 9 kwh per day. I reduce and do whatever I can. I was astounded comparing my bills, same amount of days in the month, same amount of energy used, and my bill was higher than the last month. I feel like I'm being penalized for trying to be a good citizen and reducing my consumption. I really have a problem with that. I don't want this island to be an industrial power plant for Oahu. I'm opposed to being connected by an undersea cable. It's going to destroy our reefs, it's going into the whale sanctuary which is a protected place. Each island should decide for themselves what goes on for their own island.

Susan Osako: I notice in all your ads when you show all your energy sources, you don't show one we're really interested in. It's a vertical axis turbine that's being researched at Cal Tech. This technology uses less space, is quiet, they do not hurt birds. I would love to see it in the advertising so people know that there is more than one kind of wind. (Ms. Osako provided several pages of information that are attached).

Warren Osako: I also am opposed to making Lanai an industrial power plant for Oahu or anywhere else. I think if you connect the grids, if there's a problem on the grid it will affect everyone like on the mainland where there are problems like blackouts. On Kauai, they are putting in a biomass plant where they are going to burn albizia. And I'm looking at Kauai and it's going to be sustainable. There are many invasive species on Lanai kiawe, Christmas berry, others, a plant that would burn these invasive species would be better than putting up all these windmills that are not going to help Lanai. They're saying our rates will go down, but I want to have a contract that says that. You can take out the invasives and replace with natives to kill two birds with one stone.

Donna Schaumburg: I'm questioning if we are all going to conserve, then it makes sense that our bill will go down. But it doesn't seem like that's going to happen because then how will Hawaiian Electric make money? How will they make money if we're all using all of these energy efficient things that are coming up?
*Response by Sharon Suzuki:* The mechanism recently approved by the PUC is called decoupling. It takes away the disincentive to the utility for customers to conserve or, for example, install rooftop solar which would lower your consumption. Anytime we want to raise rates, we have to go before the PUC, and the Consumer Advocate is involved. We are allowed to recover a certain

amount of revenue. If our sales go down, there's an adjustment mechanism so if sales go down, we can recover what we need to be made whole.

Annelle Amaral: Does the ratepayer see a reduction in their bill?
*Response by Sharon:* Not necessarily. If the price of oil goes up, that's a pass through. So unfortunately your bill will go up with that. We're passing it through without a profit.
*Response by Carl Freedman:* Just to be clear, if you have a car, you have to feed it fuel, but you also have to make payments on it. That's kind of how the rates are. Some are for the system and some are for the fuel. If you run it less, you're going to save on fuel. But if you figure it out, your cost per mile for payments and insurance are going to go up. But you're still going to pay less money if you use your car less. If you assume that oil prices are the same for a while and you use fewer kilowatt hours, your bill will go down. If you use more kilowatt hours, your bill will go up. If everybody uses less, everybody's bill will go down, but not as much. The problem is that the oil prices go up and down and nobody can help it. The utility passes that straight to you, they don't make a profit on it, but you pay for it. Since fuel prices just seem to be going up, that part of the bill is going up.

Alberta DeJetley: When we were going to all these IRP process meetings, one thing I couldn't understand is we have more and more people going net metering, going off grid, generating their own electricity. As these people move off the grid, that leaves fewer of us to pay for the generation. As more and more people go off grid, the pool of rate payers becomes smaller and smaller, and the pool of people who can't afford to pay more will end up paying for it.

Man in blue and orange shirt: As more and more people go off the grid, a few days of rain comes, it's cloudy, now they want to have power. The utility has to maintain the power supply. What is the utility's position on future credits or future encouragement of going off the grid and putting PV on you roof?
*Response by Mat McNeff:* For net energy metering, right now it's the law. We're just following the law. We don't offer any additional encouragement other than their bill will be lower. It is the state and the federal government that offers the tax credit.

Man in blue and orange shirt: When more people get off the grid and go on PV, that budget the state has to give people credits, that budget is shrinking. You folks require people to go through this process, spend $3000 and have a study done.
*Response by Mat McNeff:* Maui Electric is in no way involved in the state or federal credits. With respect to potential needs for a study, as circuit penetration gets higher, we have a responsibility to maintain reliability, and there's a screen. If you fail several of the screens, you may need to have a study.

Robin Kaye: I have two comments and one question. This island has an opportunity to become a world class model to be fully sustainable. The population is concentrated in a small area, there are 15,000 acres of unused pineapple land, unused agricultural land. This is something the new majority

land owner has an interest in. We could make our mark. We should absolutely not pursue big wind on this island to send energy to Oahu. There is no benefit to Lanai. It would be a terrible mistake and destroy a really beautiful part of the island. Please explain that the undersea cable has been grandfathered into the IRP process because it's assumed to be part of your future.
*Response by Sharon Suzuki:* It's happening in parallel and not necessarily "grandfathered".
*Response by Annelle Amaral:* We can record that as a question and get back to you.

Robin Kaye: Big wind should be included in the IRP analysis just like any of the other resources.
*Response by Carl Freedman:* Part of my job as the IE is to oversee the process in some ways. I'm determined that no particular project like big wind is grandfathered. The commission wants an analysis of anything that goes forward. The very purpose of it is to do the economic analysis of everything. The question has come up in the process, "OK HECO, we're doing this planning process, but the company is putting out RFPs, why should we be doing this planning process when the company is putting out these RFPs?" I think we're going to have results from the IRP before results of analysis of the RFPs. The intent is to include everything and analyze everything. I think the Lanai big wind project kind of has a step up in some ways because they already have a term sheet but that's a different process than the IRP process. There is another RFP coming up. I just want to be reassuring that as far as this IRP is concerned, we're not assuming any project is a given.

John Dela Cruz: The thing about the IRP process is the thing that drives it is money, not by Lanai residents. The lobbyists are pushing all these projects to make money, not Lanai residents. If we're not diligent, we may all be overrun, including Maui Electric. About Lanai rates, I thought so too, when I tried to save electricity, my rate stayed the same. I also think it's made up by the revenue thing where you're allowed to make money. Maui Electric is not going to lose money. Nobody goes off the grid. Even people with solar. Maui Electric has an obligation to produce the 15 kwh a day I need whether I have PV or not.

Alberta DeJetley: When you go back to the scenarios, one was "Stuck in the Middle." What I'm beginning to think it means is renewables are all well and good, but how much are consumers really willing to pay? It would be great if we could take this island and produce biodiesel. But biodiesel is really expensive. Are we willing to pay for biodiesel in order to go green?

Robin Kaye: What John said is important. What we need to come to grips with is right now our energy policy is being set by developers. HECO says they have no choice but to buy energy that is created. Big wind is driven by a developer. A state that is trying to get off oil should have a policy set not by developers but by tax payers and elected officials.

Diane Preza: I represent Kūpa`a no Lāna`i. How much are we willing to pay for renewables? The mission of our group is to protect and preserve Hawaiian values, culture, heritage on the island, the aina, in terms of cultural issues. Not everything is about money for us. Being native Hawaiian and from this island, that is our concern. You talked about protecting Hawaii's environment and our culture. I hope you are sensitive to that.

Pierce Meyers: There have been presentations here about the HCEI. The wind farm was couched in terms of HECO has to comply with the HCEI. When I read the legislation, it doesn't look like there's a reason why it has to be now. It doesn't appear to have penalties associated with the renewable energy targets. Are there penalties? Are they paid by the shareholders or ratepayers? Will penalties be assessed if the HCEI goals are not met?
*Response by Mat McNeff:* There is the Renewable Portfolio Standard. There are increments, one of which is 30% by 2020. There are penalties. I don't know how much per kilowatt hour.
*Response by Sally Kaye:* It's $20/MWh, shareholders pay, but it's discretionary. There are a lot of exemptions.

Pierce Meyers: Big wind is being sold to us as it has to be done to avoid penalties to the utility.

Susan Osaka: Hopefully it's in your best interest and our best interest if good, clean, sustainable resources that don't destroy the land are chosen so that you don't have to accept a huge mega project that will cost a lot of money and cause a lot of damage. It's to your benefit and our benefit if you don't just choose technologies that big business is pushing on you, but choose the best projects.
*Response by Mat McNeff:* Part of the scenarios involve analyzing the Renewable Portfolio Standards. In fact the some of the scenarios involve not meeting the current RPS.

Warren Osako: Maui has wind power, has there been a reduction in the consumption of imported oil?
*Response by Mat McNeff:* I don't have those figures with me.

Pat Reilly: In all those documents you have, you have a piece of paper that answers your question. Maybe you should read your documents. Here's what's happening, my opinion. The US government, congress, lobbyist, state legislature have decided that we will stop using oil. Renewable energies are more expensive than oil. Coal is cheaper. Sun is free, why do we pay so much? The utility makes their money getting it from the sun to us. There is a changing business model. They will buy electricity and sell it to us. When you read this, we're going to reduce our energy across the whole state, that's ridiculous. It doesn't make sense. What makes sense is to have a business model that charges the lowest possible prices.

Debbie Dela Cruz: One of my real concerns about big wind is the effect on the Lanai economy. Lanai has been a one horse town, tourism, since the pineapple shut down. The hotel business model was to bring in fewer high-end tourists. They don't want to come and look at big wind. They expect Lanai the way that God created it. Is this going to be taken into consideration?

Steven Lichter: I agree with a lot of what everyone's saying, it's futuristic. I'm wondering if there's something we can do as soon as possible to cut the

prices down a little bit. Through the years, cars have become more efficient. Is the Lanai system obsolete? Or do we have an upgraded system? Is it that Lanai is so small we can't make our money back on new more efficient generation? Since fuel is the big cost at the moment, I think we should look at it. I think new efficient generation cost for Lanai should be shared over the whole state, not just Lanai. You buy a lot of fuel, why is it that we pay more for bulk fuel than the big island, that they have to barge further?
*Response by Mat McNeff:* We always run our machines as efficiently as possible.

Steven Lichter: I've seen that on the big island they've put in jet turbines that are supposed to cut the fuel consumption. Where are we? Are we on old dinosaur, or is it the most efficient?
*Response by Sharon Suzuki:* On the big island, the new efficient generation was when they needed additional generation resources. On this island, we're making the best use of the resources we have. And we are investing to meet new EPA requirements to lessen emissions. I also wanted to address that in the sense of efficiency, thru the IRP process in the past, we looked at that by using energy efficiency, and programs that are now offered by Hawaii Energy. We see that in the long term with energy efficiency, we don't have to make a huge investment to add new generation. To the extent that we can use what we already invested in, upgrade and maintain, use the most cost-effective fuel we can. For renewable energy, we're entering long term contracts, the price is lower than what we'd pay to generate with the traditional generation. We know that we're seeing less fuel purchased as a result of the renewable generation. Technically, the residents on Maui pay for some of the cost of the Lanai system. It's not all paid for by people of Lanai.

David Embrey: I grew up on the Big Island. I've been on Lanai for a year. On the Big Island, even with geothermal, wind, biofuel, I just looked at my bill on Lanai, my bill was higher on the Big Island than here. I'm trying to do a business here. I went to MECO to ask them what's it gonna take to get my business into electric. It's gonna cost me $28k. They want me to buy the transformer and do everything even though the power lines are going right by my place. We the people of Hawaii made HELCO and MECO, and shareholders are all making money. The people are not making nothing as the electric bills are getting higher, windmills are federal grants, big money. They'll make money, you'll make money and we're not making anything. In the outlook of all the resources that you see, what is the main one you're looking at? Big windmills destroyed the land on south point on the big island. We're here trying to figure out how we're going to survive.

Donna Schaumburg: What percent when you make decisions, What percent is gonna be the archeological sites, economy, rate payers, shareholders? Of those 7 IRP objectives, what is your top priority? Who has the biggest say?

Mel C: We're not the land owner. The land owner has the last say.

Ron McOmber: We just came from a harbor advisory meeting. It was between the land owner and this state. It's all going on only with the permission of the land owner. They had to go to Castle & Cooke to get a

floating dock to improve the harbor and keep service. The land owner should be an integral part of this IRP. I hear rumored desalinization plants, taking Manele off grid, all the water, that's the land owner's decision. Not the state, not the people living here. At the harbor advisory meeting, the Lanai residents were not at the table for the decisions.
*Response by Annelle Amaral:* The perspective is that the decisions about what happens on the island are not in the hands of the community that lives on the island.

Pat Reilly: You're presenting as if MECO or the PUC is going to make these decisions. Mr. Ellison owns the solar farm. The land owner will make the decisions. But we have a community plan process starting and we have the opportunity to zone the island the way we want. The landowner should be here making their input.

Carole Starbird: I have a curiosity question. Provide electricity at a reasonable cost. Do you consider what we're paying right now reasonable? I'm serious because I think electricity is really expensive.
*Response by Annelle Amaral:* I don't think MECO, HECO, or HELCO can answer that. Cost has been an issue.

Carole Starbird: If it's an objective, someone needs to define that.

Woman: I have a solar water heater, gas stove, but I still pay high electricity.

Max K: is big wind still being considered? Logically, feasibly, financially, how is it going to work? Let's find a better way. It will mess up our island. We have ocean tides, pick a channel and use that. Have wave and wind in the channel. Big wind farms will get ruined by salt spray in that location.

John Dela Cruz: I don't think we're going to see a significant reduction in our electric bill. We need to have a voice in what happens and how it happens. We have a voice with our vote. Right now, it's all driven by money.

John Ornellas: Is this IRP going to look at all aspects of energy? I haven't heard anything about nuclear or coal.
*Response by Annelle Amaral*– Right now, the list is expanding, not exclusive. I've heard about liquefied natural gas.
*Response by Sally Kaye:* The Renewable Portfolio Standards are not set in stone. The PUC has to look at them every 5 years, this year is the year they will do that. One of the things we struggle with, outer island people, is that we want an island specific discussion. So tonight, you ask us what we want for our system, but we don't really understand our system. What we have right now, what our forecast is. I talked to Sharon before the meeting and she offered to come back in January and have an island-specific conversation.

Pierce Myers: What is the possibility of island self-sufficiency? Is that on the table for Lanai to be self-sufficient? Is it possible in Hawaii for each island to be energy self-sufficient? What are levelized rates?
*Response by Sharon Suzuki:* Yes, that's an option.

Pierce Myers: if it comes to an undersea cable, part of the proposal was to levelize rates?
*Response by Sharon Suzuki:* I don't have data and specifics. Right now the

rates are pretty much each island pays for their own. If Lanai was interconnected with Oahu, then Lanai and Oahu costs would be spread across Lanai and Oahu.

Pierce Myers: Is there data showing that we would pay the same rate as Oahu and our rates would go down, or would all our rates go up?
*Response by Sharon Suzuki:* It depends on the costs of the cable, the windfarm, etc.

Pierce Myers: What prevents an island from being energy self-sufficient? Why is that not the best model?

Pat Reilly: Rate is different than bill. Have to look at total cost of your bill. Have to look at the surcharges. That's what decoupling meant. We don't have to sell electricity, we'll still make money. With all the costs, levelized rates will be higher.

Lady in white shirt: What's the state presently versus the 2020 goal? Where is it by island?
*Response by Jeffrey Ono*: It's close to 15% statewide.

Debbie Dela Cruz: I'm in support of what was said, the island should be self-sufficient. There's no reason you can't have big wind on Oahu except Oahu people don't want that and they have a bigger voice. Big wind will take up a huge portion of Lanai; it would take up a small portion of Oahu.

Susan Osako: One of the assumptions was that oil price will come down. They are investing more and more in LNG. The price will go down and stay down. The problem is with fracking. There is terrible pollution, poisoning. Their scenario is that places like Hawaii will replace everything with LNG. That is not a pie in the sky scenario, it could be a very real, practical scenario. That will mean destroying huge amounts of our land on Lanai for an industrial wind farm when something better is coming along.

#### Closing

Annelle Amaral: Thanked everyone for coming, for their time and input. She asked the scribes to read what they had recorded on the flipcharts.

Ed Oyama and Ellen Nashiwa: Read flipchart notes.

Sharon Suzuki:Thanked everyone for input and closed the meeting.

### *Public Documents*

- Lanai City Sign-in Sheet (2 pages)
- Lanai Public Comment: Wind Energy (7 pages)

## MECO, Kahului, Maui

Pomaikai Elementary School Cafeteria
Kahului, Maui
December 11, 2012

Attending from Maui Electric Company: Sharon Suzuki, President; Mat McNeff, Manager, Renewable Energy Services; Lyle Matsunaga, Manager, Accounting; Dan Takahata, Manager, Engineering; Kaui Awai-Dickson, Director, Communication; Ellen Nashiwa, Supervisor, Planning; Therese Klaty, Planning Analyst

Key audience members:

- Jeffrey T. Ono, Consumer Advocate
- Carl Freedman, IRP Independent Entity
- Brian Kageyama, PUC, Maui
- Lee Jakeway, IRP Advisory Group member

Annelle Amaral, Facilitator

See attached sign-in sheet for attendees from outside Maui Electric.

Sharon Suzuki: I'd like to welcome everyone, thank you for your time and for being here tonight. Integrated Resource Planning is a long term planning process that Maui Electric goes through to make sure we have enough generation resources to meet future demand. It's a long term outlook in which we're also looking for actions to take to reduce use of fossil fuels. We're here to listen to your ideas and get your feedback to help us make a better plan for the future. This process is overseen by the Hawaii Public Utilities Commission. The commission has appointed an independent entity, Carl Freedman. As the independent entity, Carl is responsible for coordinating the IRPs for all three companies. I'd also like to recognize that the Consumer Advocate Jeff Ono is here tonight as well as Brian Kageyama, who represents the PUC on Maui. There is an advisory group for this process that is across the three service territories, Maui County, Oahu and the Big Island. I'd like to recognize that we have one of our advisory group members, Lee Jakeway from HC&S in attendance.

Annelle Amaral: Thank you for joining us this evening. A facilitator is different than a moderator. My responsibility is to ensure we have an environment where everyone can be heard and we treat each other with respect. I'm kind of like the traffic cop, making sure everyone has a chance to speak and making sure we're all respectful. I'd like to introduce Mat McNeff from Maui Electric. He's going to give a presentation that will take about 15 minutes. I ask that if you have a question, jot it down on your paper and allow Mat to go through his presentation uninterrupted. Then, once Mat is finished, you can give good information to help Maui Electric build a smarter process for the future. We have two scribes. They're not professional scribes. But, they will try to capture the comments and someone is also taking notes on the computer. There are also comment cards available on the table where you checked in. All of the comments collected in these meetings will be posted on the IRP website so everyone can see what's being said on the other islands. Now I'm going to turn it over to Mat for the presentation.

Mat McNeff: Presented slides giving a brief overview of the IRP process, the scenarios that have been developed, the schedule, objectives, and several examples of resource options that may be considered. Turned back over to Annelle after the presentation was complete.

Annelle Amaral opened the floor for comments.

### *Audience Comments*

Warren Shibuya: Mr. Shibuya read from a written statement. A copy of that statement is attached.

Jerry Wright: Mr. Write read from a written statement. A copy of that statement is attached.
*Response by Mat McNeff:* With regard to the 15%, the rule is Rule 14H and it's the same for HECO, MECO and HELCO. There are a series of screens. One of the first is the 15% of peak load screen. If it fails that, in other words the penetration of distributed generation on the circuit is higher than 15% of the peak load, then we go on to further analysis that the utility does, which is called a supplemental review. The next circuit penetration screen is 75% of the daytime minimum load (for PV). If it fails the first (15% of peak load), but the circuit penetration is less than 75% of the daytime minimum load, the project can still be installed. The minimum load time period for this evaluation is the time period the generation is producing. So for PV that is typically between 9:00 a.m. and 5:00 p.m. Last year on Maui, more PV net energy metering systems were installed than in the 10 previous years combined. And around September of this year, we surpassed last year. That can be part of the increase in processing time you mentioned. Additional staff has been added. The procedures we follow were revised based on the rules that were agreed to with input from PV industry representatives. Last year, Maui Electric Company was first in the nation for installed PV systems per customer.

Jerry Wright: Can you address how many circuits are now basically closed down, or when you go to the interconnection study, if you want to proceed will it cost $3000?
*Response by Mat McNeff:* For a small residential system, that is correct.

Jerry Wright: On Oahu, for under 10 kW systems, they have not performed any interconnection studies and they do not use the 15% criteria to close any circuits.
*Response by Mat McNeff:* I'm not sure about specific studies or circuits on Oahu, but we all follow Rule 14H. It could be their circuits haven't hit the 75% minimum load threshold yet, but I don't know.

Jerry Wright: Mr. Wright reiterated concerns that MECO's limits were too conservative and that MECO was only relaxing limits when forced to by the PUC. Mr. Write asked: What does MECO have in mind for increasing grid access? People on the mainland feel the limits are very conservative and that there is lots of room for more PV here.
*Response by Mat McNeff:* In a nationwide ranking of utilities by the Solar Electric Power Association, MECO was number 1 for cumulative number of systems per 1,000 customers and number 2 for cumulative solar watts per customer, so we're kind of up there. We're constantly looking for ways to increase availability. The press release you referenced that announced the change to 75% of minimum load was driven by us, not the PUC.

Annelle Amaral: Asked for more comments and paused for responses. There were no responses. Annelle asked: I wondered if you have ideas of what resources you think might work better for Maui? We've heard some communities speak with great ferocity about what they do not what to see done. So I wonder if you have some thoughts that you wanted to share.

Jim Hall: I'm retired from Maui Electric. I worked in the Communication Shop. There are some things I never hear at some of these meetings. When I worked at MECO, we went out on a lot of quality issues. We went out to places where the electric grid was disturbed and we had to track down the problems. When you add solar, add wind, add some of these technologies, they cause power quality issues in a variety of ways, which ultimately will affect electronics and high tech equipment and can cause damage. I don't hear anything about power quality. When I hear about limits, I think the system was designed to handle what was built 20 years ago. Now things have changed over time and the original design was not made to handle some of the changes going in there now. Another thing is when you move to alternative energy, it's great for those who can afford to do that, but you have a lot of stranded cost that is left behind and somebody has to pay for it and it's usually someone like me or people in my neighborhood. It's like a house that is getting older and has fewer people living in it, but still needs a lot of maintenance that those left in the house have to pay for. There are still a lot of people who are on the grid and have to pay to maintain it.

Bruce Burzina: We're residents, my wife has been on Maui for 3 years. I'm an Assistant Vice President for the Wisconsin Public Service Corporation. I look at the potential on Maui, wind, pumped storage hydro, which I don't believe Maui has looked into or is doing to levelize the spikes and take care of the power quality issues referred to earlier. My last assignment was coal and I also had responsibility for 100 MW of gas generation. In one case, we had duel fuel generation, gas and oil. It didn't really make sense for us to keep the oil because of the cost, so we went to natural gas. When I look on the mainland and I see the development of liquefied natural gas, I wonder why Hawaii isn't looking at going from expensive fuel oil to less expensive LNG. So when I look at the scenario plot it's interesting to see the energy policy and the price of oil, and I ask myself how do you take care of your infrastructure and give yourself the ability to reinvest back into the grid and yet don't inundate the rate payers who aren't able to afford PV? Liquefied natural gas is cleaner than fuel oil, it doesn't have the sulfur. If you use lower sulfur fuel oil, you'll pay more for that. So there's an infrastructure investment, but the offset of the energy cost can help. The excess generation of PV could be used for pumped storage hydro or hydrogen conversion, or ocean platform storage technology that is in use in Great Britain.
*Response by Mat McNeff:* Pumped storage hydro is something that we have evaluated and continue to evaluate going forward. The same is true for liquefied natural gas. The Governor has asked us to evaluate LNG.

Bruce Burzina: If you'd like a personal tour of a pumped hydro facility I would love to offer it at our facility in Wisconsin.

Walter Enomoto: I'm here speaking as an individual, all work associations aside. I'd like to point out that the most cost effective energy is the one you don't use in the first place. The message of efficiency and conservation gets lost. Case in point: we have natural trade winds that we can hear blowing outside right now and we're running how many fans in this room? Once you start to think about it you see areas where things can be done better. On page 3 of the handout, under "Electricity Demand", it says, [quoting from the handout] "High electricity prices motivate more customers to migrate off grid and self-generate all or part of their needs especially with the advent of storage batteries for the residential market." People I've heard from, residential and commercial entities, are telling me they're looking for ways to get a partial offer or full offer to use battery storage to take a part or all of their load completely off the grid. It's something that needs to be factored into scenario planning. It's outside the utility's purview if people decide to go completely off grid. It's an X-factor that's out there if a battery storage technology comes along that makes it a more palatable option for them. It may be hard to model in scenario planning because you don't know how many people would make that decision. But the technology isn't that hard. This is something outside the scenario planning, but would affect the system if people decide to take load off the grid.

Annelle Amaral: If you have some questions you want to ask Maui Electric, I think they would be open to answering some questions. I want to offer if you want to ask Maui Electric some questions, let's open it up to that.

Man in blue shirt: Do you plan on opening up the grid further in the next year for commercial and residential feeder penetration without going through the interconnection study?
*Response by Mat McNeff:* As we learn more, it is our goal to make it less burdensome for people to interconnect. It's a learning process. We've been developing models to support that effort. I don't know if I can commit to a change next year. The results could be mixed, but we're definitely taking steps to move in that direction.

Man in blue shirt: What is the main thing that would allow Maui Electric to open up the grid more? Better equipment or something else?
*Response by Mat McNeff:* It depends on the specifics of the circuit and what's being proposed. In many cases, studies show that no additional equipment is required. In some cases, it shows that some equipment is needed such as effectively grounding equipment. But it really depends on the specifics of the circuit and what is being proposed.

Jerry Wright: What defines one circuit and why would one circuit be able to support more PV than another one that's right next to it?
*Response by Mat McNeff:* Generally, the way power is distributed across the island is at the highest voltage because that equals the lowest losses. Then it goes into distribution that extends out into neighborhoods and individual circuits. That is where the voltage is stepped down. The circuits are laid out to serve a geographic area at that lower voltage. Some may interlace or be close because of how the subdivisions were built over time. One example would be a circuit with a lot of load can take more distributed generation

because it is a percentage of the load. The one next to it may have much lower load on it, so it wouldn't be able to take as much distributed generation. So that's one example of why one circuit may be able to take more DG than one right next to it.

Ted Grupenhoff: Looking a the process for getting a renewable system, especially solar system here, the frustration that many customers are going through here, I find it interesting that the area we're sitting in right now is saturated and when they opened up the limits on the process, it's an area that did not get opened up and there's a huge pent up demand and people are very frustrated that they can't participate. There's an incredible amount of demand for renewables. I find it interesting that Maui Electric operates under different parameters, that HECO is not adhering to the 15% and passing through any system under 10 kw because distributed generation is a good thing. I've heard rumors that some circuits on Oahu, the Big Island and Kauai are reaching 50, 60, 70% of peak load.
*Response by Annelle Amaral:* Didn't we already answer that?
*Response by Mat McNeff:* Yes.

Ted Grupenhoff: I understand Rule 14H, but why is MECO being more conservative than HECO and HELCO?
*Response by Mat McNeff:* Rule 14H is consistent over HECO, MECO and HELCO. You mentioned that this circuit didn't open up here. That's because the circuit was already over the 75% of minimum load. HELCO and HECO were included in those SEPA rankings I mentioned earlier and they were ranked lower than MECO. I don't know a lot of specifics about HECO. I know a little more about HELCO and I know that they have done interconnection studies. Some of the circuits on Maui are already over 100% of the daytime minimum load. These are cases where a study was done and the result was that the project was able to go forward.

Ted Grupenhoff: I applaud you for what you're doing and recognize that we're forerunners around the world for using renewables. Is it MECO's intention to use the 75% maps in the same way as the 15% maps were used? I am in the solar industry. One of the things customers find really frustrating, if they want to interconnect, it's great value for the customer to do so. It's very frustrating to customers to have the delays. It's helpful for customers to look on the web and see where they are. Now that we've gone to the 75%, are the maps going to be on the web so people can see? I've heard that on Oahu when they went to the 75%, they've also rolled out a computer application process and I've heard it's 10 minutes to get an answer. Isn't that a quicker more efficient way to accommodate customers and not drag it out and frustrate customers?
*Response by Mat McNeff:* the locational value maps that are available online show the 15%. Customers can still go and see if they're above or below that and there's some value to knowing that. As circuits reach 75% of minimum load, MECO sends out maps to the installers so they can advise customers. You mentioned online application process. I think that might be something called DG Central. MECO is currently starting to implement DG Central if that's what you're referring to. The rollout was phased, HECO first, now MECO.

Ted Grupenhoff: What's the timeframe for net metering application to approval on Oahu?
*Response by Mat McNeff:* I don't know the timeframes on Oahu. It (DG Central) will help with tracking and hopefully efficiency.
*Response by Annelle Amaral:* As you're looking at scenarios, clearly there are some implementation issues that you have to factor into your scenario planning as Ted has articulated.

Ted Grupenhoff: I commend you for your efforts. Thank you.
*Response by Mat McNeff:* Thank you.

### Closing

Annelle Amaral: Thanked everyone for coming, for their time and input. She asked the scribes to read what they had recorded on the flipcharts.

Kaui Awai-Dickson, Director Communication and Ellen Nashiwa, Planning Supervisor, Maui Electric: Read flipchart notes.

Sharon Suzuki:Thanked everyone for input. Recognized Kal Kobayashi as an advisory group member who was not there at the beginning during introductions, and closed the meeting.

### *Public Documents*

- Kahului Sign-in Sheet (1 page)
- Jerry Wright Public Comment (3 pages)
- Warren Shibuya Public Comment (2 pages)

## MECO, Kaunakakai, Molokai

Mitchell Pauole Community Center
Kaunakakai, Molokai
December 13, 2012

Attendees from Maui Electric: Sharon Suzuki, President; Mathew McNeff, Manager, Renewable Energy Services; Ellen Nashiwa, Supervisor, Planning; Therese Klaty, Planning Analyst; Damien Pires, Supervisor, Molokai Power Supply; Ron Vicens, Supervisor, Molokai Transmission and Distribution

Key audience members:

- Jon Itomura, Consumer Advocate
- Carl Freedman, IRP Independent Entity
- Karen Holt, IRP Advisory Group member
- Greg Kahn, IRP Advisory Group member

Annelle Amaral, Facilitator

Sharon Suzuki: Welcome and thank you for coming here tonight. Integrated Resource Planning is the process electric utilities go through to determine future resources to meet future demand for electricity. We're here tonight to get your input and feedback on what are some of the ideas you have for resources that make sense for the Molokai community. We will be putting together an action plan and will come back in April/May timeframe of next year to also get your input on the action plan. So there will be other opportunities for you to comment. The process is overseen by the Hawaii Public Utilities Commission, and the commission has hired an independent entity. I'd like to introduce Carl Freedman. Carl represents the Public Utilities Commission and oversees the process to make sure we gather objective input across the companies' service territories. That's for Hawaiian Electric, our parent company on Oahu, and our sister company Hawaiian Electric Light Company on the Big Island. We have a 68 member IRP Advisory Group with four members representing Molokai. I'd like to recognize two that are here tonight, Karen Holt and Greg Kahn. Thank you for your time and for representing Molokai. We also have Jon Itomura. Jon is with the Division of Consumer Advocacy or what we refer to as the Consumer Advocate's office, the State of Hawaii Department of Commerce and Consumer Affairs. Thank you Jon for joining us tonight. I'd like to turn program over to Annelle Amaral, who will be our facilitator tonight.

Annelle Amaral: Aloha. Thank you all very much for coming this evening. A facilitator is different from a moderator. My function is to assure all voices are heard, to create an environment where we feel comfortable to be able to share with one another. We will all speak respectfully to one another, won't interrupt each other, leave ourselves open to what others have to say, learn from each other. It's possible to disagree without being disagreeable. After the presentation, I'll start calling on you to speak if you want to speak. We will be recording or summarizing what you're saying on flip charts and on computer. They're not trained recorders, they are MECO employees. Be patient with them. We don't expect to get everything you have to say down. We will try to capture and summarize what you have to say. We'll take these comments and the comments caught on the computer as well as the comments you provide on comment cards and we will post them on the website that we'll show you later so everyone going to the website will be able to see what Molokai thinks, what Lanai thinks, by reading through the comments from each of our meetings. I'm looking to try to get everyone to be able to speak at least once before I come back to you to speak a second time. But I will come back to you. I'll turn the program over to Mat. Mat is going to do a PowerPoint presentation. He talks for about 15 minutes. If you have a question as he's talking, just jot a note down and allow him to get through his presentation. Then if you have questions we can deal with that when he's pau.

Mat McNeff: Presented slides giving a brief overview of the IRP process, the scenarios that have been developed, the schedule, objectives, and several examples of resource options that may be considered. Turned back over to Annelle after the presentation was complete.

Annelle Amaral: There is a camera man here from Akaku. As you make comments, I would encourage you to use the microphone so he can capture what it is you're saying. We'll pull Sharon and Mat forward if there are questions that need to be answered. Water is also at the back. Please sign in if you haven't. Purpose is to hear from you. To hear what your thoughts are, your experiences here on Molokai. What is unique to Molokai that drives then some particular selection for some particular alternative resource. What works well, what doesn't work well and any other comments you would like to provide. If your comments are inhibited because you have a question, then by all means, we want to try to provide you with as much information as you need. Who would like to speak first?

### *Audience Comments*

Cheryl Corbiell: I'm representing myself and I'm a member of I Aloha Molokai. The points I'd like to make tonight for MECO and HECO is: no underwater sea cable, no community benefits for something as ludicrous as that. Because I have no idea why you want to have a huge grid in a state that sits on top of an active volcanic plate. In one of the latest issues of Newsweek, one of the things they talk about is if the New York area had not been a huge grid, the power would not have been out as long as it was. Communities need to make smaller grids. No big grids, keep Molokai energy independent, it's safer, our power stayed on in the last big earthquake. No big wind. Stupid. We do not need it on this island. Oahu has to figure out how to control their own power usage. We need to focus on our power needs and what to do to lower our power needs. The IRP is not addressing that because the IRP focused on Oahu because they're 80% of the state. So I'm not trusting in the IRP process because focus is Oahu driven. Your utility participates in activities like putting 15% caps on solar photovoltaic residential use. If all homes on Molokai went with solar photovoltaic, all we would need to figure out is nighttime generation, which would put you out of business. This is a utility survival strategy that's getting built into IRP. You've admitted that 15% is a made-up figure. Even though you say you've lifted it, it's still in force and you have to go through special studies to feed energy to MECO. The IRP report is going to come out after when the request for proposals for projects. I think that's backwards and I can't figure out why that's happening except that you already know what you're going to do and the IRP process is not a good process. You're not going to listen to the IRP report if you're going to put out those RFPs before that report comes out. You put in the list cultural sensitivities on the list and cost at the bottom. When I read the minutes about the IRP process, cost is talked about and community and the environment is on the bottom, very low priority. On this island, those things are very important to us. Needs to be more of a say besides the four people from Molokai that are your committee. That does not represent the whole continuum of Molokai. Need to listen to us. I've had some bad experiences with MECO lately. So I have little trust that they're going to listen. Tried to turn my power off because my husband's name was on the bill. 19 years, paid every bill, that's not good enough. Way back in the 1990's and early 2000, MECO was brought into the 20th century kicking and screaming and that they didn't want to do demand side management. I think MECO's in exactly the same place again. I sat on the Advisory Committee then. The discussion was, what are they going to do as a utility if everyone reduced their energy. This is the same situation. You're doing protectionism. You need to reinvent yourselves, transform yourselves. I understand that in Lanai, you said that we're not really listening to the energy management the company is putting out. Instead of spending hundreds of thousands of dollars on TV adds, we don't need to be convinced to lower our energy consumptions. Our bills are high, highest in the state and nation. We aren't reluctant to save energy, we're doing a good job, but there are barriers like the 15% that we can't put PV on our house if you're on the wrong grid. Thank you.

Teri Waros: I am a small business owner here on Molokai. I have a store in town and my monthly bill is about $500. Second to rent that is my highest cost. I thought about how I could affect that. I was really interested in doing solar and at that time the 15% cap was enacted because the drug store, the hospital and the grocery store have solar on their roof. Robbie Alms was here a couple years ago and promised us that there was going to be a report on the Kaunakakai grid. It was going to address this 15% cap. I've never seen that report. I don't know if anyone else has. There is a little bit of distrust. We were told that they were going to look at it and some report was going to be done and made available to the community. And today, we don't believe that's so. Even though the 15% is arbitrary, we were told it's necessary because our grids were not capable of handling renewable energy. No conversation I've heard about how to get our grids up to par to accept renewable energy. Right after we're capped and as individuals we're not allowed to put solar on our homes or in our businesses, MECO turns around and signs huge contracts for solar with huge companies. Need to make sure we're doing this for the good of everybody. If our intention is to find answers for our energy needs for the next 20 years, that's a wonderful intention, but we need to make sure that's the direction we're headed in. The minute our intention becomes about profits, we've changed the direction. At the same meeting, Robbie Alms at one point threw up his arms and said, "I don't understand why we get such resistance to our big projects." He mentioned geothermal on the Big Island and we were talking about big wind on Molokai. Obviously, we don't need large impacts and footprints on our aina. On this island we are very sensitive to that. Need to make sure we're considering small impact decentralized generation. Of the 70% less dependency on fossil fuels, 30% of that is to come from conservation. On Molokai we have the least consumption per capita in the state. Of course, part of it is we don't have big hotels. To get people to conserve, 30% is a significant amount. I remember the mom who told me the biggest impact she had on her kids was when they went off the grid and went to solar, so her kids had to check their meter and see how much power was available before they could decide whether to turn on their video games. So if you're actually going to get 80% of our population being on Oahu to conserve, need to consider decentralized generation. They're responsible for producing their own power and they will be more conscious of conserving their power. Either that or send them to camp on Molokai and we'll teach them how to do it. As a ratepayer, there's a little anger, distrust, frustration as a ratepayer to watch my legislators pass a bill last May that guarantees Hawaiian Electric, no matter whether the project is completed, whether we've ever generated a kilowatt of power or whether we've ever transmitted a kilowatt of power, the ratepayers will be responsible for paying for the interisland cable. It's wrong, not financially responsible, not fair to ratepayers. There is a question about the timing of the IRP process and the RFP. It doesn't seem to be very transparent, can be regarded like a smokescreen if we're going through this process and there's another process going on for the RFPs prior to the output of the IRP which has the public input.

Seeing what was presented up on the screen, I'd like a definition of what MECO considers public policy on renewables. No windmills not good for us, our aina, our communities, for our Maunaloa folks, for wildlife. No interisland cable. Financially, it doesn't make sense, doesn't pencil out. Need more transparency with that.
*Response by Annelle Amaral:* Mat or Sharon, can you help us understand what you mean when you talk about public policy on renewables?
*Response by Mat McNeff:* I can definitely talk about a part of it. Some of that is what we're trying to gather here tonight. How does the public feel about renewables? What do people want for renewables?
*Response by Annelle Amaral:* At some point, there will be legislation created, a public policy will be created based on whatever the consensus is around renewables?
*Response by Mat McNeff:* Ideally, but that's really outside the purview of the utility. The utility can gather the public input and incorporate that into our planning process.

Natalie Wilson: What is a renewable?
*Response by Annelle Amaral:* Can you clarify what we mean when we say "renewable." There was a screen where you showed all of the alternatives, can you repeat what a renewable is?
*Response by Mat McNeff:* Generally something that's not fossil fuel, not imported oil, and preferably that uses a local resource to generate electricity. Even basic questions like that, we're trying to gather information tonight. Some places feel like waste to energy as renewable, is that something that the people in Hawaii feel? If not, is that something we should include in the resource plan or something we shouldn't? It's really about gathering information and not coming in with what the utility feels one way or the other.
*Response by Annelle Amaral:* Some of the examples were up on the screen like solar, wave, wind.
*Response by Mat McNeff:* Sure, I threw up some common things that are considered renewable to get everyone thinking about it, get the juices flowing. But, if there are other things I didn't mention, feel free to bring them up.

Nathalie Wilson: I was born on this island. I'm a little concerned cause when I was growing up, we had a dairy. We had an electric plant, which generated electricity for the island of Molokai. My father was the lineman that put all of the lines out everywhere. This is extremely close to my heart. When you talk about renewable, aren't you talking about sustainable? Doesn't it have to be something that can continue, not for 20 years, but for perpetuity? We have to look at the future for our children. I have seen wind power in California, in Arizona, lots of places all over the country. They don't all work. Maybe 30% of them are working, some of them aren't. They have their limitations also. But where they are put are very large areas of land, large areas of land.

Molokai is not that big. You need at least a 200 foot by 200 foot pad 100 feet deep to sustain a 420 foot tower. Where are you going to put the dirt that you dig out of that pad and fill with cement? The dirt's got to go somewhere. *Response by Annelle Amaral:* If wind doesn't work for Molokai, what does work for Molokai?

Nathalie Wilson: I think that has got to be up to the people of Molokai. There are some things that can be done. I'm starting to look into some of them. On this island, there's a lot of kiawe. Kiawe is a natural briquette that can be gathered and it can be used to help create energy. I think we need to look at what we have here before we take a look at what we have out there. Let's take a look at what we have here and make use of our land and protect it. *Response by Annelle Amaral:* And that is kind of the point. Then, what does work? What works for Molokai is what we're here to hear from you. Yes, you can say, "this does not work." Then in the alternative, what does.

Peggy Lucas Bond: Ms. Bond read from a written statement as well as two petitions. Hard copies were provided to the utility. Copies of each are attached.

Greg Kahn: As a Molokai member of IRP Advisory Group, I wanted to take some time to share some impressions and my experience with members of the community here. Despite language in the mission of the IRP, which encourages rigorous debate and minority viewpoints, there is never any discussion of energy philosophy and a future action plan. How can an IRP Advisory Group have any teeth when the utility has already decided it will pursue interisland connectivity and an undersea cable? How can an IRP Advisory Group give advice when the utility has already accepted big wind as a viable plan without any debate? Questions which are fundamental to Molokai's energy future are not on the utility's IRP agenda. For instance: What are the consequences of adopting industrial scale wind farms on Molokai? Will there be huge amounts of erosion and dust? Will reefs have to be dynamited? Will there be cutting off of access to hunting grounds and cultural sites? Will hundreds of miles of access roads be built to go to the turbines? Will they decimate native birds and plants? These questions are not being debated during the IRP process. For instance, should a rural island have to bear the cost for energy that it exports to an urban island? And not just the monetary costs of higher bills, but the cost of industrializing a rural island, the cost of adverse environmental impacts on a rural island, the cost of degrading a native culture on a rural island, the cost of altering the social fabric on that island, the cost of depressing an already fragile economy, and the cost of health concerns. These questions are not being addressed by the IRP. And what are the reasons for interisland connectivity via the undersea cable? Wouldn't linking all islands make us vulnerable to service interruptions? Since ratepayers are footing the bill for the multi-billion dollar cable, should the utility have access to a resource they didn't pay for? These questions are not being debated at the IRP. Another example, as the utility's profit motive is central to its decision making process, can we really expect them to act in the best interest of the community and ratepayers? We do not discuss these questions at all at the IRP. For instance, why wouldn't island energy independence, Molokai generating energy for Molokai be the preferred future for us? This question is not being considered as an action plan. What we're left with is an IRP process where the utility is mandated to listen to the Advisory Group, but not bound to follow its advice; an IRP process which allows the utility to create an illusion that it's incorporating the advice of communities such as Molokai in the energy decisions they are making; an IRP process which looks a lot like window dressing. What we are also left with is a Molokai process. It's a process where members of the community come to meetings, debate the issues, speak out for what they think is the best for the island. I'm confident that this process will render an energy action plan, in our best interests. That plan will not include undersea cable, big wind, corporate bribes disguised as community benefits.

Janeel Hew: You're asking what works for our island. Are these questions also being directed to Oahu? What can they do for their island that will work for their island? Not what we can do that will work for their island?
*Response by Annelle Amaral:* Yes, answers are multiple, they're being noted and comments from Oahu will be posted on that IRP website.

Janeel Hew: With the RFP already in progress prior to results of the PEIS, I'd like some of the questions answered that I submitted to the PEIS before the RFP. (Ms. Hew provided a document containing her questions. A copy of the document is attached) How much radiation will people be exposed to because of the smart grid? You have to have transmitters into homes on each of their appliances. I would like answers because the PEIS isn't going to be until later, but the PUC has already put in their request for proposals for the cable. Are these things being considered? People have a choice for hazardous items. If you choose to use a cell phone, you're choosing to put that radiation next to your head. If the smart grid takes place and you have transmitters for each of your appliances, a transmitter box outside of your house, and a centralized hub for this information, you don't have a choice. It's being imposed on you. Is the public going to be notified to the health hazards of these things prior to it? Are they going to have the option to opt out?
*Response by Mat McNeff:* I'm not really familiar with the PEIS. But Maui Electric has several smart grid projects going on Maui and those are all voluntary. We don't force a smart meter on anyone who doesn't want it. They have to let us know they do want it before we install that at their house. I don't know a lot about the radiation. I've heard it is similar to other things people use every day like cell phones that you mentioned.

Janeel Hew: Cell phones are just as dangerous.
*Response by Mat McNeff:* We're not enforcing it on anyone. If they want a smart meter and they want to experience it, they can volunteer for the program.

Janeel Hew: So when Hawaii builds this new smart grid that we're all supposed to pay for, with our ratepaying and our taxes, who's going to pay for the doctor bills when we all have radiation exposure? You guys are putting a smart grid in place, whether it's voluntary or involuntary, you still have the centralized hub that's gonna be exposing people and animals radiation. If something is put in place and you don't know, that's a big problem. You're putting risk, people don't know what they're being exposed

to.
*Response by Sharon Suzuki:* At least for Maui Electric and our service territory, which is Maui, Lanai and Molokai, we have not made a commitment to on a broad scale install the smart grid technology. We have received some funding through the U.S. Department of Energy, the federal agency, to do that project. I believe we have under 200 meters. These are volunteers that volunteered to be part of this demonstration project. We're just testing out the technology.

Janeel Hew: Were they made aware of the impacts of the radiation?
*Response by Sharon Suzuki:* Yes. I don't know the details, but it's not supposed to have much electromagnetic field impact, more like cell phones and baby monitors. We're trying to learn more about it to see if it's something that we should look into further and evaluate after we get information for around a year from the meters. So we have not made a commitment to do it broad scale. I just wanted to clarify that point. And we will take your concern into consideration as we evaluate the results of this demonstration project. Because we have heard that also from others in our Maui community.

Unidentified member of the audience: Are you monitoring the people for health impacts? Are you monitoring the site?
*Response by Sharon Suzuki:* I don't know if we're monitoring the site and I don't think we're monitoring the people. We accept your concern and what you're bringing up today. We're here to listen, accept and try to incorporate it into our planning processes even for the smart grid demonstration project.

Janeel Hew: The wind turbines. You are using wind turbines on Maui, is that for Maui Electric or is that going to be for power on Oahu?
*Response by Mat McNeff:* Currently all the wind farms being built on Maui are for Maui.

Janeel Hew: Are you aware of vibro acoustics disease?
*Response by Mat McNeff:* No
*Response by Annelle Amaral:* What is that?

Janeel Hew: Vibro Acoustics Disease is caused by infrasound and low frequency noise. Research into VAD has been going on since 1980, conducted by a team of scientists, led by a pathologist Dr. Castillo Bronco in Portugal. Initially, they were monitoring low frequency noise in occupation environments. More recently, this team obtained irrefutable acoustic measurement results from within homes near wind turbines that show proof that wind turbines in the proximity of residential areas can lead to the development of Vibro Acoustics Disease. It's not wind turbine syndrome. This is an actual disease and it can be tested for in a hospital environment. This is your body's way of trying to adapt to the constant vibration of low frequency noise. It thickens the cardiovascular walls, it causes lung fibrosis, neural muscular disorder, seizures, early onset of Alzheimers disease. Through communications via the internet, a researcher for one of the top researchers for VAD, communicated to me if you know someone living in a low frequency noise contaminated home, move, do not sleep in that home. If you cannot move, do not stay there for most of the day and do not sleep there. The onset of it is much stronger and faster than in an occupational environment. These things need to be taken into consideration for windmills here, which I'm totally against or windmills on Maui. Also, she noted and also stressed that the low frequency noise should be measured prior to and after development using the proper weighting. An A weighted measurement is insufficient for low frequency noise. In regards to our reefs, over 50% of cancer research now is found from the ocean and our reefs. If you had cancer, what would you rather have, a cure for cancer or a high voltage direct current cable? What if the one sure cure was irreversibly eradicated because of that cable? How would you sleep?

Turbines, you have them in Maui. Do you know where those magnets come from? China because that's where those rare minerals are. There's a lake in china that's toxic sludge. No farm can raise cattle or grow food around this toxic waste. People are dying of cancer. Their teeth are falling out because of this toxic waste. Babies are being born with soft bone disease. Two of these magnets the size of cars go into each wind turbine. How can we justify the death of these people and the death of their land? It doesn't make sense for something that doesn't work. What we do need to see is more solar. Keeping a business going is not as important as living.

Prisca Medieros: Aloha. I'm an advocate for clean energy and I've always been pleased with our Hawaiian electric system. Since Oahu is facing an energy crisis and I always feel that Lanai, Kauai, Oahu, if there is trouble, then we really should kokua. But in this case for Molokai, what can we give that we don't have? I hope that our electric company can work with solar. As far as me personally wanting the wind farms, no, it's not going to do us any good. We're just one dot on a map. As far as the cable that is also no for Molokai because our fishermen, you have to put a big sign that says danger no fishing no swimming. And our people, they fish. It will just change, we are not so rich over here, as a matter of fact, we're poor. No wind farm for Molokai.

Les Wiley: I'm a west end resident, also a member of I Aloha Molokai. One of my biggest problems with this whole process is a lack of information. We have 26 page hand out here, been talking about windmills for over a year. I never see any numbers. It's all just talk and pretty slides. This document right here was very expensive, but it doesn't talk about things like the future or give us any numbers with which to make decisions. How can we make decisions if we don't have the data to make those decisions. Feel like I've walked into an auto dealership. I walked up to the salesman and I say, "Salesman, I want a fast car." He asks how much money do you have and I say 3 billion dollars. He says "I'll get you a car that can go 100 miles per hour, can break the speed limit in every state and I'll have it at your house tomorrow. Just go home, I'll deliver the car and a month from now you'll get a bill and a statement of how much the car is gonna cost you." That's how I feel here. We don't have any numbers. How do we know how much any of this is going to cost? We never talk about the future. We never talk about how much it's going to cost.

There have been reports by Pao-Shin Chu, head of Hawaiian State Climate Office, talking about number of trade wind days we have here in the islands.

Between 1973 and 2009 a period of 36 years, the number of trade wind days has dropped by 80, that's 80 fewer days now than 1973. This dropping of the number of trade wind days is going to continue into the future. The northwest northeast trade wind days are dropping and the trade winds are switching to the east. There are two problems, we're going to build windmills that need wind, are we taking into account that there will be fewer days with wind in the future? We're dropping about 2.2 days a year. You add up the total amount of days when there's less wind, it adds up to a significant amount of money. Over the life of the project, 20 years, it would be 44 fewer days a year. That's not insignificant. It comes out of our pocket. Have we accounted for that, does anyone talk about it? We have no way of knowing if it's been taken in to account. There are consequences of this switch in the trade winds. One is that as the trade winds switch to come out of the east instead of the northeast, that's causing drought conditions in the islands. All you have to do is go to the Big Island, Rainbow Falls, one of the biggest draws on the islands for tourists, the falls aren't falling. There's no water. Molokai has been in drought for 8 years and more. One of the problems is gonna be water to build these windmills. If you are going to make concrete, you need pure water, nobody's talked about the water we need. One thing they talked about is desalinization plant. There's an article in the Washington Post today talking about the problems with water availability in the western United States. It says San Diego currently pays $800 an acre-foot for water. And as the Colorado River dries up, there's talk about doing desalinization. If they desalinize or recycle waste water, it's gonna cost $1800 an acre-foot. If they bring it up from just salt water, it's gonna be $2150 per acre-foot. Is this being taken into account? Both the cost of running this desalinzation plant, building it, the damming that's required on the island? These things are not being addressed. My main concern above all others is that we can't build infrastructure fast enough to keep up with demand. We talk about conservation, which is all well and good. We have to take a whole new route, like these people taking about going off the grid. We can't just keep on doing business as usual. As an engineer, I did some back of the envelope computations to prove my point. I'm using my own numbers because HECO isn't forthcoming their numbers. I have two reports here. One is the size of Hawaii's energy sector. The other is the potential of renewable energy to reduce dependence on the State of Hawaii on oil. In that report they say that currently, this was 2010, there's 2,414 megawatts of statewide electrical production. This other report says the electrical industry in Hawaii is growing at a rate of 9%. There's simple rule, if you want to know how fast something is growing, you take the rate of growth divided into the number 70. That tells you how long it will take to be twice as big. If you take 9% into 70, you get 8. That means that in 8 years, the demand for electricity will double. If it's 2,414 in 2010, in 8 years it will be 4,818 megawatts. In 16 years, the demand will be 9,656 megawatts. If you wait 24 years, 19,312 megawatts. We can't keep up with that growth. Right now, according to this report, if you used all the renewable energy sources in Hawaii, you build on top of peoples' houses, anywhere you wanted, you can create 2,133 megawatts of power. That's 88% of the energy demand of the state. At the end of 8 years, the energy demand is going to be twice as much and you've already used up all of your renewable energy. You can't build any more. There's no more available. You start out at 88%, then in 8 years you got 44%, 16 years 22 %, 24 years you got 11%. After 32 years, all of our renewable energy only creates 2% of the total energy demand. Our real problem is not keeping up with demand, it's changing the demand itself. We have to do something different. It's like Teri said a few minutes ago. If you walk in your house and there's a meter on the wall that says you have this much power today, you're gonna be more in tune with your energy needs. The state should be spending 3 billion dollars on making people buy smaller cars, solar PV on rooftops, solar hot water heaters. If they put this 3 billion dollars into that process, changing the way people live. I don't care if you want it or not, the numbers say it's gonna happen to you, it's inevitable. HECO's in the same boat. This is a problem that faces all of us, the energy companies and the citizens. The numbers don't lie. We design bridges, airplanes and cars using numbers. Anybody can sit down with a piece of paper and some numbers and come up with these answers. Nobody's given us any numbers, where are the numbers? We have to go a different way. Math doesn't lie.

Mike Bond: Mr. Bond read from a written statement. A copy of that statement is attached.

Larry Tool: Mr. Tool read from a written statement. A copy of that statement is attached.

Patricia Crandall: I reside on the west end of Molokai. I've never been to a public meeting, where I agreed with every person who came before me. I think it's indicative of the way we've come together as a community and the consensus on detriment to the island of an industrial wind energy plant, which is not to say we aren't very interested in renewables. Many of us use them, we want them. And given the opportunity, would like to participate meaningfully in the process. The problem is the process is so futile and you've done something so terrible to deceive us. Going to put the Consumer Advocate representative on the spot. This is the situation we're facing in the PUC. We have the RFP process and the IRP process going on two different tracks. One should be slowed down. And there is currently pending in the PUC RFP proceeding, a motion to stay that proceeding until the IRP process is completed. It was joined in by several other entities, it sits there, languishes there. The PUC refuses to act on it. My question to the Consumer Advocate who represents all of us is why haven't you filed that motion for us? Why don't you support the motion that's currently pending? Why don't we have a representative that takes our concerns directly to the PUC? Why do we have to appear meeting after meeting saying the same thing? We don't want this. It's not right. The scale is wrong; the devastation to the environment is horrendous. If we're going to look at renewables, we need to look at them on a site-specific basis. You've already mentioned that some other things that you're looking at now in the IRP process are the impacts on cultural resources, environmental resources and financial consequences. There are a whole range of financial costs for all of the meetings, all of the energy all of us spend every day to come here, to travel, our agencies go back and forth, back and forth for years on end spending taxpayer money. What are those costs? Are those costs included in the billions for the cable or the millions for the wind energy plant we may or may not have? Don't look at this in a practical, holistic, pragmatic fashion.

Jon Itomura: Jeffrey Ono has also been to many of the IRP meetings throughout the islands. Our main intention is to be present at these meetings, I was also present at the PEIS meeting that was here, to gather as much information as we can. As many of you are keenly aware, so many of the issues that come before the PUC, that come before us now are interrelated; very separate and distinct but becoming very interrelated. As a Consumer Advocate's office, we have to be very wary of the consumer interests as a whole, consumer interests as some people mentioned looking forward. That's not an easy task to do when you have so many distinct dockets yet very interrelated issues. So with respect to the question, we've looked at the motion, we understand. We're also intimately involved in the process. The idea of stopping the RFP has many ramifications. The RFP is a process that brings in a lot of information we may not readily would have access to otherwise. I'll leave you with that thought to draw your own conclusions about that. Our process going forward is really to get as much information as possible and one way to do that is to allow some of these processes to move forward. The fact that we're not doing one thing or another does not dictate what our position is in any particular docket.

Les Wiley: Doesn't the CA's office have to take an official position?

Jon Itomura: If you want to talk process, when a motion goes before the PUC, the Consumer Advocate can give its position, oppose, support or take no position. We have not taken a position on the RFP motion. There's a short time, about a five day window to respond to a motion and for an issue such as this, that's not enough time for us to make that type of a decision.

Question from woman in green shirt and black shorts: Is what we say tonight and on the other islands going to come in after the RFP?
*Response by Annelle Amaral:* The process is that MECO will be coming up with an action plan in mid 2013.
*Response by Mat McNeff:* The RFP stands for Request for Proposals. As I understand it there's a draft RFP out for something like 200 megawatts of energy to be provided to Oahu. It's not specific that it needs to be on Molokai or Lanai. It could be on Oahu. And no cable is inherent in the RFP. There could be, there could be not. If they could get 200 megawatts in Oahu, no cable is needed, no wind farm on Molokai. The RFP isn't for 200 megawatts of wind on Molokai. It's just for 200 megawatts of renewable energy for Oahu. Whatever comes in through that process will be evaluated. With regards to the timing of all these things, many of the utility projects take many years to complete. In fact that RFP has been out for months and months and months and it's still in draft form, it hasn't even been issued yet. Nobody can respond to it. So with the action plan coming out mid next year, I don't believe that anything would even be awarded from that RFP prior to that time.

Question from unidentified person in the audience: Who would it be issued to?
*Response by Mat McNeff:* A slight clarification, I work for MECO and it's

primarily HECO doing a lot of the RFP work. But, as I understand it, it would be to the public. Anyone that wants to propose a project that can meet the requirements of the RFP, again that's something like 200 megawatts to Oahu, however that may be. If it's solar farm on Oahu, fine, it can be that. Then there would be some period for people to come up with projects that could meet the requirements of the RFP and submit their proposal like, "we can it for so many dollars." And then there would be some time over which HECO would evaluate all those proposals. I think that's some of the information that the maybe the Consumer Advocate would like to see. How much would a solar farm on Oahu cost? How much would it cost if it was on Maui?

Nathalie Wilson: So for the RFP, will there be reports of the community needs and the community position on these various types of issues here tonight?
*Response by Mat McNeff:* I don't think that's part of the RFP process, but it's definitely part of the IRP process. And I know some questions have come up about why do those things happen in parallel? That's because the projects for this type of scale take many, many, many years and we all hear everyone's concern over the cost of electricity. We don't want to stop our planning for those things that take multiple years while we do this IRP process to gather more information that can hopefully inform our future decisions.

Unidentified man in light gray: How much work has been done or will be done laying the cable before the RFP?
*Response by Mat McNeff:* None. That's my understanding. There may not even be a cable involved in whatever is awarded from the RFP.

Kimo McPherson: So actually what we're talking about is hypothetical. Information for who, for what? We can sit here all night and talk about down the road all night. What are you gathering information for?
*Response by Mat McNeff:* For the IRP, the purpose of this meeting here tonight, it's to inform our planning, inform utility planning for meeting future energy needs.

Jon Itomura: The other answer to your question is ultimately, anything any utility does, whether it's water, gas, electricity, goes before the PUC. So that is who you're gathering information for. The PUC makes the ultimate decision. Whether their public policy is mandated by statute, mandated by the Governor's mandate in various forms, that's a different issue. But the information goes before the PUC. What comes from the RFP has to then take a different form and go through the process to get PUC approval. At that time, whatever information the Consumer Advocate gets, will be in that proceeding. We'll be there representing a lot of the comments we've heard here. You'll see your comments coming out in our information requests. You can see that on the PUC website, their document management system, their DMS.

Teri Waros: Mat, you mentioned that you're not familiar with the PEIS, and that is equally important and many of us have been involved in that. So again, it looks to us that the RFP process coming ahead of the final environmental impact study is like putting the cart before the horse. Sharon,

I hope you're familiar with what's going on with the PEIS process.
*Response by Annelle Amaral:* There is good reason for a community to feel frustrated, there are a number of agencies engaged in this very complex project. Perhaps we should pull everyone into the room when we do these kinds of community meetings so then we get a more informed perspective.

Women in green shirt, black shorts: It's very frustrating to know that nothing we've said in the past over all these years has made one bit of difference.
*Response by Annelle Amaral:* Is that possible? That can't be possible.

Patricia Crandall: This is another instance of it. The Bureau of Ocean Management has an advisory task force that none of us knew about last March. They brought a lot of agencies into one room, but they didn't invite us. We didn't know about it until last week. If you want to go to YouTube and listen to 4 hours, it's out there. It's another example of another meeting which is out there somewhere.

Nathalie Wilson: Perhaps we need to write our own energy future.

Cheryl Corbiell: Talking about carts before the horse, let's refresh minds about what we've been through. First Wind is going to build a wind farm. Then the homesteaders and others have to come out and say "no you're not." Because somebody out there has made a deal with First Wind. They wrote kind of an RFP but it fit First Wind. Molokai Ranch at that time said "No, we won't lease you any land. Go talk to the community." Finally the PUC said no. That's First Wind. So First Wind gets to go do another sweetheart deal over on Maui. Then we hear Pattern. Governor says to Molokai Ranch you will either lose all your land through imminent domain or lease the land to a wind turbine. So then we get into the PEIS process the first time. We all come to those meetings. We give them our manao and we talk about how we don't want wind turbines on Molokai. In fact there's all these Federal people and I'm going, "Go home. They already picked. What are you supposed to be doing?" They say they're supposed to be consulting to the State of Hawaii. Why? They picked wind. Why did they pick wind? Sweetheart deal.

Then somebody says no, that was a mistake, let's start the PEIS all over again. And so all over again, we've done it. Now tonight we're talking to MECO, which is really HECO and what are we talking about again? We don't want it. We are concerned about where it goes. We are very concerned about our electricity. And we know that the IRP process does not focus on Molokai. We can focus on Molokai. The IRP process is not going to solve our problem because the whole focus is on how to supply electricity to 80% of the state on Oahu. That's where they spend their time. So we spend all our time coming to these meetings time and time again. When does it stop? Because at that BOEM meeting, what did they talk about? Interisland cable. So we know that a deal's being made because Pattern was the only contractor in the room. Pattern, who formed Hawaii Interisland Cable. I do not trust anybody from any utility or anyone in government because we have been at this and at this and say the same thing. And all we see is the process being snowed through and going around corners. The PLDC. I have a very strong suspicion that the energy is buried in that PLDC because then the government can do whatever they please without doing any of the environmental or cultural review. All of it starts to make sense. It's a conspiracy from day one.

Michael Bond: It's clear from my 30 years in the energy business this was a done deal from years ago. All of these public meetings are whitewash. The whole purpose of this is to finally shove it down our throats. You're gonna take 17 square miles of Molokai and ruin it forever. You're gonna ruin our aina, our culture. We're only 7000 people and there's nothing we can do about it. Mark Glick is doing all of this behind the scenes. The Governor is talking to the Obama administration setting up the funding so that the Obama administration is looking at alternatives so the environmental impacts can't be considered. All of this is being done behind our backs while we're being told "we're taking notes." The CA is widely known as the Corporate Advocate. You've never stood up in this entire process for the people. It's always been what's good for big wind. Never once have you intervened on the side of the people of Hawaii and to try to keep their rates low. Need to take that home and stop trying to cover it up.

Lady in green shirt and black shorts: Did it ever occur to any of you that the technology might have changed as you're collecting information for years and years and years?
*Response by Annelle Amaral:* You can take home whatever you want to take home and believe whatever you want to believe. But I know what we intended to do this evening and I believe we have done it, was to take the comments of the community members that came to the meeting with respect to what are your priorities for alternative resources and what are those things that you feel strongly against.

Bill Leach: I'm one of the newest residents to the island although I've been coming to the island since 1981. I have in the last year since this issue of windmills came up spoken to hundreds of people. Only recently have I spoken to a single person who said they wanted to give it a chance to see what it could do for the island. That became apparent when they received a phone call about all the benefits like opening a hotel on the west end, movie theater, golf course. There are only about 40 or 50 people here and I want to go on record saying it wouldn't matter, in my opinion, if you got all 7,000 people in this room, there would hardly be anyone who would support the windmills coming to this island for many of the reasons that have been spoken tonight.

Kanohowailuku Helm: I represent I Aloha Molokai, these are our petitions, about 2,200 signatures here. Those who signed oppose the wind turbines and undersea cable coming to Molokai. Also have a sign-up online and there must be another few thousand signatures on there as well. This island is just very much opposed to the wind turbines coming and undersea cable. As far as solutions, the same sun that shines upon this island, it shines upon Oahu as well and I think they can create that 200 megawatts, 400, even more than that on the island itself. (Mr. Helm provided a hard copy of the petition. A copy is attached.)

Lailani Kahn: I understand you can't speak to the RFP process or to the PEIS process. For the IRP process, you said your stated goal for this evening is to gather information from everyone and community input so I'd like to know with the information that you've gathered from Molokai what you're going to do with this input. I'm guessing you've heard a resounding kind of message. I think the input has been crystal clear. Knowing that, how do you see this information going forward and how do you intend to use it in the IRP process directly to make some difference for everyone having come forth tonight?

Annelle Amaral: Seems to be a strong consensus that wind is not wanted; that there is interest in decentralized solar. So what will you do with that manao?
*Response by Mat McNeff:* Personally, I think we're going to incorporate it into the action plan and the resource plan. That's what I believe will happen with the input we received.

Anelle Amaral: Lanai had the same message, that each island should be able to count on its own resources. I think the reason we go to each island is because it affects the planning. It gives weight to the planning. I'll never convince you that there is no conspiracy or the decision hasn't been made, but in my experience, that's the process. The process is to take input from you and give weight to the planning and that's the process.
*Response by Sharon Suzuki:* I agree.

Janeel Hew: Mat mentioned that the IR, information request, that's going to come from our questions and comments that we brought up this evening, correct?
*Response by Sharon Suzuki:* Those are not issued by us. I think that was Jon Itomura's comment.

Jon Itomura: That was my comment. What I bring and what our office brings back from these meetings will be reflected in information requests when it gets to the docketed matters.

Janeel Hew: Greg, you mentioned that there wasn't enough or any debate in the IRP. I'm am going to submit my 30+ pages of questions and comments that I submitted in the PEIS and that should stimulate some debate.

Kimo McPherson: I've been here for ages. I disagree with anything you guys say. It's really a political move to snow the people over. We already know we're gonna pay for it. To come to a community and ask us for our information when you give us so many pages of information to read in a few seconds. You want to know what we know and what we don't know. You want to know how ignorant we are of the issue. You're looking at people who are so smart. We know that electric companies are in trouble. They are going to fail. If we put PV on our rooftops and don't have to pay a third party to provide our energy for us. Who's the guy that's insulting us, it's the governor. We can't give you any guarantees, this will take effect 20 years from now. For the money we're paying for electricity, when do we get the results? I don't see it.

Lailani Kahn: Your answer was that it was going to be integrated into the action plan, What does that mean, will you just say, that's what the people said? Does that mean your recommendation would be not to have wind or

undersea cable for Molokai?
*Response by Mat McNeff:* I can't say that.

Larry Tool: Where is HECO this evening since they're the parent company since it seems they are making decisions about this. Also wanted to extend a welcome to the gentleman from the CA office. I have to tell you that after attending some rate hike meetings, I was thinking you were an urban myth. I work differently, I don't complain about the staff. But what I've heard about your office is that they say the funding is limited, the staff is limited, the time is tight. I've asked the same question of the PUC members. It would be good for the public to know what do you need to be a more effective public advocate? We need a lion in your office, we need a dragon, if everyone knew where your resources come from and what you need to do your job, I think we'd all be better off.

Annelle Amaral: Sharon, do you want to answer the question, where is HECO tonight and why aren't they here.
*Response by Sharon Suzuki:* I'm here to represent the utility. My commitment to you is we will take the comments back. The comments will be posted to irpie.com. My commitment to you is I will take back the key points and tell me if I have it right:

- No big wind on Molokai
- No undersea cable connecting Oahu to Molokai
- Prefer resources like distributed photovoltaic systems and Biomass like kiawe wood being a source for a biomass plant potentially

Is that correct?

### Closing

Thank you for your input I really do appreciate the time you've put into multiple processes. I guess they're kind of driven by different agencies. So I guess that's why you've had to go through the process multiple times. I'm here to represent the utility in this Integrated Resource planning process and that is my commitment to you — that I'll take back that message and share it with my peers at Hawaiian Electric Company and Mat will share it with his peers also. That's our obligation and something I can commit to you the Molokai community and the people who are here tonight.

Annelle Amaral: Thanked everyone for coming and for their comments and closed the meeting.

## *Public Documents*

- Kaunakakai Sign-in Sheet (2 pages)
- Humpback Whale Sanctuary Petition (52 pages)
- I Aloha Molokai Petition (281 pages)
- Janeel Hew Public Comment Card (1 page)
- Janeel Hew Public Comment (31 pages)
- Larry Tool Public Comment (1 page)
- Michael Bond Public Comment (3 pages)
- Peggy Lucas Bond Public Comment (2 pages)
- West Molokai Association Petition (64 pages)

# Schedule of Meetings: May–June 2013

Several pubic meetings were scheduled at the end of 2012 on each of the islands served by the Hawaiian Electric Companies. Because of its size, three meetings were help on the island of Hawaii.

### Hawaiian Electric Company (HECO)

June 12, 2013
Farrington High School Cafeteria
Honolulu, Oahu

### Hawaii Electric Light Company (HELCO)

June 4, 2013
Aupuni Center
Hilo, Hawaii

June 5, 2013
Pahala Community Center
Pahala, Hawaii

June 6, 2013
King Kamehameha Hotel
Kailua-Kona, Hawaii

### Maui Electric Company (MECO)

June 13, 2013
Pomaikai Elementary School Cafeteria
Kahului, Maui

June 19, 2013
Mitchell Pauole Community Center
Kaunakakai, Molokai

June 20, 2013
Hale Kupuna O Lanai Hall
Lanai City, Lanai

## Hawaiian Electric, Honolulu, Oahu

Hawaiian Electric Company
IRP Public Meeting #2
June 12, 2013, 6:00pm
Farrington High School Cafeteria

In addition to Hawaiian Electric employees, the following people registered attendance: Ed Wagner, Christian Hackett (Pattern Energy), Jim Wood, Wendell Lum (Bloom Energy), Jack Shriver, Ka'ili Britos (IDG), Doug McClaflin (Castle & Cooke), Jay Griffin (PUC), Josh Strickler (Hawaii Gas), Dean Nishina (DCA), Catharine Lo (Blue Planet), David Jones (Sunetric), Sophie Cocke (Civil Beat), Patricia M. Talbert (Indigenous Consultants).

The meeting was started by Scott Seu at approximately 6:10pm. He thanked everyone for their interest, informed them that information on the full Integrated Resource Plan (IRP) process was posted on the irpie.com website, and that comments could be submitted to the IE on the Draft Action Plan. Scott Seu welcomed everyone and introduced Annelle Amaral .

Annelle Amaral explained her role as the facilitator for the evening. She explained that comments could be submitted on comment cards if someone did not want to speak. For those who were willing to stand and provide comments, notes from the meeting were to be documented electronically and written on flip charts. Two handouts were available, which included a summary of the Draft Action Plan and a list of the public Advisory Group appointed by the Public Utilities Commission to provide input to the IRP process.

### *Audience Comments*

Scott then gave the presentation on the Draft Action Plan and answered questions during the presentation.

- Slide 14, item 2.B., "If LNG assured, Competitive Bid for more efficient generation". Question by Ed Wagner: What does assured mean? What is the process for bringing LNG here?

  *Response by Scott Seu:* There are many complexities with permitting the LNG infrastructure. It requires PUC and federal approvals. Assured means we're are at point that we are confident that if we issue a bid for new generation, the developer will have a fuel supply.

- Wendell Lum: What's the difference between LNG and natural gas?

  *Response by Scott Seu:* Natural gas is produced in gaseous form which is liquefied for transport to Hawaii. When the LNG arrives in Hawaii, the fuel is re-gasified.

- Wendell Lum: It takes 5 years or more to get LNG, due to the time it takes to build a tanker and storage.

  *Response by Scott Seu:* You are correct. Infrastructure will take time.

- Wendell Lum: Solar farms take up too much land and produce very little power. This is not the right way to go.
- Wendell Lum: It's a waste of money for interisland transmission. In Sunnyvale California, there are 20 bloom boxes in businesses such as Walmart and Google.

  *Response by Scott Seu:* Mr Lum will provide information on bloom box technology to whoever is interested after the meeting.
- Ed Wagner: PV generation per land use is very inefficient.
- Ed Wagner: Lanai people are opposed to the Lanai wind project.

  *Response by Scott Seu:* yes, there are some people on Lanai opposed to the project
- Ed Wagner: Will you be using a smart meter better than the meter used by KIUC to avoid issues and concerns that they had with the meter on Kauai.

  *Response by Scott Seu:* We will procure the best smart meter available. Even at that, customers may disagree and not want a smart meter, and they will have the option to opt out of the program.
- Ed Wagner: I hope that the smart meter is not as intrusive as NSA.
- Ed Wagner: Regarding fairness, shouldn't everyone go through the competitive bidding process?

  *Response by Scott Seu:* Competitive bidding is the assumed process unless we can show value of not going through the process. PUC will make the determination if there is value.
- Wendell Lum: There is Bloom Energy on high rises which are not connected to the grid and it is self-sufficient.
- Jim Wood: Scenarios didn't come up in any part of the presentation. So you are not going to test the action plan against the scenarios?

  *Response by Scott Seu:* Yes, we are doing this. This presentation focused on the action plan and not how the scenarios were used in the analysis. But discussion of the scenarios will be a part of the IRP filing.
- Ed Wagner: Does deactivation of the units mean that they are idling?

  *Response by Scott Seu:* Deactivation means the units are not running, so they are not warm and idling.
- Ed Wagner: How quickly can they be brought back

  Response by Dean Arakawa: In an 8 to 10 week timeframe.
- Representative from IDG: Will you be integrating geothermal in the Action Plan?

  *Response by Scott Seu:* Geothermal is a part of the action plan for Hawaii Electric Light Company. We have issued an RFP for geothermal and have received proposals. We are now reviewing these proposals.

- Ed Wagner: Will the ships bringing LNG to Oahu be LNG powered?

  *Response by Scott Seu*: Unsure, we will take this as a comment.

- Wendell Lum: If LNG is available, fuel cells would be another option. Only 1 fuel cell that works and it's made from sand.

The formal presentation ended at approximately 7:00pm. Annelle Amaral welcomed comments from the audience at this time. The comments were documented on large sheets of paper for the audience to see and notes were taken.

### Comments and Questions from the Audience

- Jim Wood: The company's goal is to lower customers' bills. As a customer, this is a laudable goal. As a resource manager, lower energy cost will encourage customers to use more power. How does the company resolve these conflicting goals?

- Ed Wagner: Are you prepared to answer written questions that I submitted to the IE?

  *Response by Scott Seu:* Not tonight. We will attempt to address your comments in the IRP report.

- Wendell Lum: I can explain the Bloom Box, which is spreading on the mainland and worldwide.

- Jim Wood: Where is the cost analysis of the action plan? The PUC accuses HECO of not having a plan to sustain financial operations under the new system of decoupling. Having a business plan that will produce a viable business 20 years from now is important.

Annelle Amaral asked if anyone else had comments or questions. Upon receiving no further response from the audience, she invited the attendees to stay and talk on a one-to-one basis with Hawaiian Electric representatives if they had questions or wanted to discuss other items. Scott Seu closed the meeting by thanking all for coming and for providing feedback. He reminded the audience that the IRP report will be filed at the end of the month and that the PUC will provide further guidance. The IRP report will be available online at irpie.com. Meeting end ended at approximately 7:10pm.

## HELCO, Hilo, Oahu

Hawaii Electric Light Company (HELCO)
IRP Public Meeting
Aupuni Center, Hilo – June 4, 2013

In addition to the Hawaii Electric Light Company employees, approximately 38 audience members were present (see separate attendance list).

The meeting was started by Jay Ignacio, HELCO President, at approximately 6:10 p.m. Jay welcomed all the participants and introduced some of the key audience members including: Jeffrey Ono (Consumer Advocate), David Mattice (Public Utilities Commission), Senator Russell Ruderman, and Advisory Group members Mike Kaleikini (PGV) , and Will Rolston (Hawaii County Energy Office).

Annelle Amaral introduced herself and explained her role as a facilitator for the evening. She explained that comments could be submitted on comment cards if someone did not want to speak. For those who were willing to stand and provide comments, notes from the meeting were to be documented electronically and written on flip charts.

Pat Moore began the formal presentation with background information on the IRP process.

Annelle then welcomed audience questions and comments pertaining to the IRP process.

- Question: Is this the entire plan?

  *Response by Pat Moore*: Yes

- Question: Question about the process. The audience member was disappointed with the PUC in their selection of the Advisory Group in not getting cross-section of people to serve on committee. No ratepayers on committee. Feels heavy representation in business and government. So feels process is flawed.

  *Response by Pat Moore*: One of the processes includes going to the public to get input.

- Question: How do you get input when you already issued RFP for 50 MW on geothermal?

  *Response by Pat Moore*: IRP process works in parallel with planning. The geothermal initiative began before IRP process.

  Follow-up comment: Have a hard time believing you.

- Question: What is the number of people that are ratepayers out of the 68-member group?

  *Response by Pat Moore*: All AG members are also ratepayers themselves.

- Question: Are the IE and AG satisfied with the process as it stands?

*Response by Pat Moore*: IE has filed evaluations which have been posted on the website.

- Comment: Maybe you shouldn't call the AG a community group because they don't represent the community.

Jay opened his presentation with a brief statement about how this cycle of IRP is different from past IRPs and that the plan being presented is only a draft set of actions. Jay began the presentation on the Draft Action Plan and answered questions during his presentation. Below are questions/comments made during Jay's presentation.

- Comment: Did not see community opinion included as part of objectives.
- Comment: Feels that we are continuing with geothermal project despite community objections.
- Question on item 5B: What would be the incentive to export expensive renewable energy elsewhere?

  *Response by Jay Ignacio*: Those discussions would have to take place if that project proceeds.
- Question on item 5B, H Kim: Can you tell me where to find the state directive on exporting renewable energy?

  *Response by Jay Ignacio*: There is no state directive. We are saying that if the state adopts such directive and issues an RFP, we would support that.
- Question on item 5B: Would we have opportunity to comment?

  *Response by Jay Ignacio*: Yes.
- Question on item 5B: Would we have opportunity to comment on an RFP?

  *Response by Jay Ignacio*: Yes.
- Question: When PUC considers a geothermal RFP, are you saying it's relevant for PUC to consider public comments at that time?

  *Response by Jay Ignacio*: You can give comments as part of this IRP process.
- Question to Consumer Advocate: Is there a process for taking comments?

  *Response by Jeffrey Ono*: The PUC always accepts comments.
- Question: On Waste-to-Energy (WTE), does Hawaii Island have enough waste to feed such a plant? How feasible is WTE?

  *Response by Jay Ignacio*: Action states to evaluate WTE. We are willing to consider it as an option.
- Question: IE reports says WTE was not cost effective.

  *Response by Jay Ignacio*: That IE comment may not have been specific to HELCO. However, we are willing to evaluate options.

- Question: Why are you willing to create a new company? (Reference is to Aina Koa Pono.)

  *Response by Jay Ignacio*: We are not going to own this company. We made commitment to purchase fuel.

- Question: Isn't price going to be $200/barrel?

  *Response by Jay Ignacio*: Price was not disclosed.

- Question: So who will pay the $200/barrel?

  *Response by Jay Ignacio*: We anticipate cost of biofuel will be higher in early years of the contract. We have also proposed that these higher costs be shared with the other islands.

- Question: Will you consider cost of community opposition? Sounded like you are saying that public opinion is relevant.

  Annelle Amaral: That has already been asked and answered. We already stated that your comments are important.

  *Response by Jay Ignacio*: We understand that with respect to Aina Koa Pono (AKP), there is opposition in Pahala which is why we are having public meeting in Pahala.

- Question: Part of cable project includes building two 200-MW cables. Not clear where we can comment on that. Need to be clear that we are not having opportunity to comment on important parts to the PUC.

  *Response by Jay Ignacio*: We can take your feedback and forward to PUC.

- Question: Regarding AKP, they made outlandish claims about yields. Has anybody done independent study to verify their claims?

  *Response by Jay Ignacio*: Process was to issue RFP that specified fuel amounts, etc. Once AKP was selected we did hire independent consultant. AKP's financiers also hired independent consultant.

- Question: Did you ask Pacific Biodiesel? Is it too late for them to propose?

  *Response by Jay Ignacio*: We made a commitment and are going forward.

- Question on 5B: Is there any resolution on the state level?

  *Response by Jay Ignacio*: There are no firm commitments.

- Comment: Concerned about connection with IDG and Mililani Trask.

- Comment (Cory): Against AKP. What is status of PUC review?

  *Response by Will Rolston*: There is currently a PUC docket open on this issue. The County of Hawaii has intervened. The docket number is 2012-0185.

  *Response by Norman Verbanic*: Rebuttal testimony is being prepared to be filed. If AKP is approved, would probably be at least 4 years before we see fuel delivered to Keahole.

- Question (Russell Ruderman): Will we be paying a higher rate than we are paying now?

  *Response by Jay Ignacio*: Yes, higher than current prices now. Contract also includes price escalation.

- Comment: In light of today's earthquake, is it a dirty word to address safety of energy production? Not just geothermal, but distance.

- Comment (Russell Ruderman): Excited about 6C and 6F.

- Question: For geothermal plant, will you need to install two lines per plant for redundancy?

  *Response by Jay Ignacio*: This depends on the location of the project(s).

- Question: What happens to rates with Advanced Metering Infrastructure (AMI) and all of these other improvements?

  *Response by Jay Ignacio*: When we pick an energy option, we will look at all impacts.

- Question: Will you be changing all meters?

  *Response by Jay Ignacio*: That is one of the reasons we haven't pursued AMI yet.

- Question: When you spoke of options that would not require transmission line upgrades, does that include turning lower Puna into industrial center?

  *Response by Jay Ignacio*: In the Geothermal Working Group, we looked at what would be the options be if we added 50 MW. Another example is WTE.

- Question: Can you explain more about 6F? Mini grids?

  *Response by Jay Ignacio*: Right now focus is not to use storage to displace generation. Focus has been to use storage to mitigate impacts of variable energy. Example is battery project at wind farm.

  Will Rolston: Also added that County of Hawaii recommended better load match. The docket number is 2011-0206.

- Question: Is there a projection for power demand 10-20 years out?

  *Response by Sam Terry*: Explained 4 scenarios. Information is on irpie.com website.

  *Response by Jay Ignacio*: We are trying to come up with an action plan that will accommodate varying levels of future demand.

- Comment: He has 400 square feet of solar panels, drives two electric cars, exported energy. If Germany can do it, there should be some way of giving incentives to people like me to help get a sustainable system.

  *Response by Jay Ignacio*: We actually sent one of our engineers to Germany. They are interconnected to neighboring countries but we're not. Also, prices we offer to NEM customers are more attractive than what Germany offers. Is it fair to give one set of customers 40 cents/kWh for energy but turn away 20 cents/kWh from another power producer?

- Question: Is there a form for me to add my input?

  *Response by Jay Ignacio*: You can speak with Mr. Kevin Waltjen.

- Question: Are you saying our solar resources are better than Germany's?

  *Response by Jay Ignacio*: Yes.

- Question: Are you willing to get out of power generation business if everyone has solar and all you're doing is maintaining the grid?

  *Response by Jay Ignacio*: We are in the process of decommissioning 2 of our resources at Shipman. And we said if there are better resources we will consider decommissioning other resources. We have not solely committed to one single resource.

- Comment: I am paying you $2000 a year and in 3 years I could have a solar system fully paid.

  *Response by Jay Ignacio*: We have NEM for you to consider.

- Question: Could you give update on Hu Honua? Is there a legal holdup with SMA?

  *Response by Norman Verbanic*: Not aware of any legal proceeding impacting project.

- Question: How is HELCO going to promote conservation? So it limits expansion of generation?

  *Response by Jay Ignacio*: Mechanism for energy efficiency has gone to company called Hawaii Energy. They are the primary party to lead energy efficiency.

- Question: When did that happen?

  *Response by Curt Beck*: 2009

End of presentation and questions for Jay.

Following the conclusion of the presentation, Annelle welcomed comments from the audience.

### Audience Comments

- Comment 1(Barb Cousins, self): Is there an agenda at the state level whether geothermal is to be pursued at all costs? Is concerned about geothermal interests lobbying at state level, and having the same geothermal interests making bid to build plant.

- Comment 2 (Richard Bidlemen, self): Lives in Puna. Why are we doing geothermal in lava zone 1. This is the most hazardous in all of Hawaii. He said he went to Jim, head volcanologist at HVO, who said it was easy resource to get to. Also said when there is lava flow in zone 1, it will affect all ratepayers who are dependent on that energy. If plant goes down, we may all be without energy. But he is not opposed to geothermal.

- Comment 3 (Sara Steiner, self): Concern about replacing oil with LNG because they get it by fracking so we shouldn't support that. New geothermal technology may also consider fracking. We should test water and should do things for the plant that is there already. In Puna, don't want to ruin land and health to give power to rest of state.
- Comment 4 (Beverly Frederick, East Hawaii Center): Concerned about unstable land in lava zone 1. Using reinjection is insane. It is not safe to live where we live, next to existing plant. Making plant safe is too expensive. In awe that discussions continue. Concerned about conflict of interest with those pushing geothermal. Nothing about it is right yet it is still happening. Wants moratorium. Would love HELCO to support truly local, decentralized renewable projects.
- Comment 5 (Bob Ely, Puna Pono Alliance): Concerned about economics of geothermal. But newer technologies are coming down in price. My whole community lives off grid and quite a bit cheaper than HELCO. Before geothermal can be built, solar technology will be 50 cents/watt by the end of year. There are new battery technologies. Energy policy in Hawaii is dictated by special interests.
- Comment 6 (Tom Travis, self): Reads article from Edison Electric Institute. No sign in action plan that utility addressed problem of costs. Geothermal costs 12 cents. Petroleum costs 20 cents. If we did 100% geothermal we would save 8 cents. Assuming we didn't have to build additional transmission lines.
- Comment 7 (Avery Freed, self): Lives in Puna. Retired radiologist. In earlier years, no one thought there was danger to chronic low-level radiation. Later became obvious that people exposed to chronic low-level radiation were in danger. By the time left professions, standard were so much stricter. Reminds him of what is happened with second hand smoke. Concerned about health risks to people in his community which is not respected by those who don't live there. They will find out that hydrogen sulfide is toxic. Everything should be stopped until absolutely safety is determined.
- Comment 8 (Tim Rees, self): Begging HELCO to be open with any information on waste to energy. Would support it if it can be done properly. County Council is floundering. It doesn't know much about thermal efficiencies. Hasn't seen anything concrete. Locked into perpetual contract at Puuanahulu. Could recycle material already at Puuanahulu. Covered with dirt so could dig our way out of that contract.
- Comment 9 (Kerri Marks, Occupy Hilo, Occupy Hawaii, GMO Free Hawaii Island): Agree with most of what has been said. Really hates LNG. It's stupid. Slides all contradict themselves. LNG cheaper now but won't be in 5-6 years. Agree about AKP. Thought PUC denied contract and AKP doesn't need HELCO. WTE is stupid idea especially if want to build on east side. Should be on west side where they make more waste.

Distributed generation is the way of future. Will take grid from you and start revoking easements. No geothermal. No AKP. HELCO you have chance to be world leader in DG. Want democratic control of grid. No interisland cable. Each island needs to take care of their own needs. Only Oahu needs our power. Be a model for the world. DG. Take us seriously or time is up.

- Comment 10 (Harry Kim, self): Truly wish there was better relationship with business, government, and community. Please look at plan about working with community. Concerned about Act 97. Concerned about how we relate to each other, especially the government that represents us.
- Comment 11 (Jim Albertini, Center for Nonviolent Education): Stopped 500 MW export of geothermal from Puna rainforest. 1. Hope all comments will be posted on website. 2. No more geothermal. If talk about culture is true, we should respect Pele. 3. One example of absurdity is transporting biomass from Ka'u to Keahole, sunniest place on island. 4. HECO's CEO has multi-million dollar compensation package. 5. Off grid for 30 years. If he can do it, everyone can do it.
- Comment 12 (Yen Chin, self): Worked two decades for public utility. One thing neglected in scenarios is a catastrophe scenario. HELCO has obligation to provide energy we demand when we demand it. People are wasting electricity but almost nobody doing anything about it. Worked for HELCO for 3 months. Some paying more than $500 a month but not good and not necessary.
- Comment 13 (Larry Gering): Harry Kim had great proposal on WTE but was shut down. No one has ever proven that Pele disapproves geothermal. Has problem with HELCO and PGV. PUC already approved paying PGV 26.3 cents/kWh. Need broad base of energy proposals. Solar is good but not reliable all the time. Geothermal is good. But need a big mix.
- Comment 14 (Cory Harden): Thanks HELCO for having meeting. Heard lot of concerns about LNG. Biofuel need to evaluate every proposal. PGV – Hard to detect hydrogen sulfide levels where most needed. Supports having each island make their own energy. Concerned about undersea cable. Commends HELCO for comments about renewable energy.

Annelle apologized for going over time.

Jay closed meeting by thanking all for coming and giving honest, straightforward feedback.

Note: Occupy Hilo videotaped the meeting.

HELCO employees in attendance:

Jay Ignacio, Virginia Aragon-Barnes, Norman Verbanic, Debra Gomez Ota, Curt Beck, Kristen Okinaka, Pat Moore, Amanda Lee, Tony Prietto, Sam Terry, Don Johnson, Kevin Waltjen, Susan Akim Seu, David Kurohara

## HELCO, Pahala, Hawaii

Hawaii Electric Light Company (HELCO)
IRP Public Meeting
Pahala Community Center – June 5, 2013

In addition to the Hawaii Electric Light Company employees, approximately 12 audience members were present (see separate attendance list).

Jay Ignacio, HELCO President, began the meeting at 6:10 p.m. Jay started the meeting with an explanation that the purpose of this meeting is to present a draft action plan for energy, and to give the public an opportunity to provide their input before the filing of the final report on June 28. Jay welcomed all the audience members and introduced some of the key audience members including: David Mattice (Public Utilities Commission), Jeffrey Ono (Consumer Advocate) and IRP Advisory Group member Will Rolston (Hawaii County Energy Office).

Annelle Amaral introduced herself and explained her role as facilitator for the evening. She explained that comments could be submitted on comment cards if someone did not want to speak. For those who were willing to stand and provide comments, notes from the meeting were to be documented electronically and written on flip charts.

Pat Moore began the formal presentation with background on the IRP process. Below are clarifying questions asked during Pat's presentation:

- Question (Will Rolston): Was it also mentioned that Advisory Group would be informed of any changes to the Action Plan?

  *Response by Pat Moore*: Yes.

- Question: Are the Advisory Group members employees of HELCO?

  *Response by Pat Moore*: No, they were selected by the PUC.

- Question: Are they involved in the energy industry?

  *Response by Pat Moore*: They represented government, business, etc.

- Question: What happened to IRP-4?

  *Response by Pat Moore*: Explained difference in process and new IRP framework.

- Clarification (Will Rolston): County of Hawaii had questioned the Advisory Group process. County wanted AG to have more of an approving role, rather than an advisory role.

Kevin Waltjen gave the presentation on Draft Action Plan. Below are clarifying questions asked during Kevin's presentation.

- Question: How much do you anticipate that we would be able to lower costs in the next 5 years? In percent?

  *Response by Kevin Waltjen*: We do not have exact number.

*Response by Jay Ignacio*: This is only a summary. For example, our current avoided cost is around 20 cents. We are looking for something lower than that.

- Question: How much time do I have to review the plan after June 28 and submit comments?

  *Response by Pat Moore*: PUC will open it up for comments. We don't know the exact period of time.

- Question: What does it mean to "repower Waiau"?

  *Response by Norman Verbanic*: One unit is from 1910. Plan is to refurbish larger unit and replace the smaller, older unit to increase total output to 2.1 MW.

- Question: What is LNG?

  *Response by Kevin Waltjen*: LNG is liquefied natural gas. Cost is lower.

- Question: Does biomass refer to Aina Koa Pono (AKP)?

  *Response by Kevin Waltjen*: No. For Puna we are looking at using wood chips.

- Question: Where would it come from?

  *Response by Kevin Waltjen*: We don't know for sure.

- Question: Regarding biomass, is algae a product you can use?

  *Response by Kevin Waltjen*: We don't know that but we can include that as a comment.

  *Response by Nick Paslay*: Algae technology is still in early stages.

- Question: Are they doing that on Kauai?

  *Response by Nick Paslay*: They are doing a pilot project on Kauai.

- Question: Are they doing something like that at NELHA?

- Response by Will Rolston: Solana is doing some algae research.

  Comment (Will Rolston): LNG is a major investment so we need to collect more information on that.

- Question: Where would the biomass be used?

  *Response by Kevin Waltjen*: In our Puna plant where we are currently using oil. We are still evaluating.

- Question: Would you use Kamehameha eucalyptus?

  *Response by Kevin Waltjen and Norman Verbanic*: Kamehameha owns the land but not the trees. We don't have detailed pricing information on biomass. Part of evaluation would include what the fuel would cost.

- Question: Is there land nearby that can be used?

*Response by Norman Verbanic*: The amount of land needed to produce the material needed for the plant is not in proximity to plant.

- Question: What about trash?

  *Response by Norman Verbanic*: County is interested in Waste To Energy (WTE) and we have been in talks with them.

- Question: Having difficulty following your presentation. Your vocabulary is not understandable, like "reliability". Could you provide more detail? Who is this Reliability Group?

  *Response by Kevin Waltjen*: Explained "reliability".

- Comment by Will Rolston: Provided docket number from Renewable Standards Working Group. Approximately 30 members, including solar industry and government. Gave recommendations to match generation and load to get better pricing.

- Question: When will PUC finalize the AKP decision?

  *Response by Nick Paslay*: Final decision date on the docket is not set. The next step is to complete information requests. IRs due 8/02. Then there would be evidentiary hearings.

- Question: Where will this be done?

  *Response by Will Rolston*: Docket is 2012-0185. You can look at it on PUC website. County of Hawaii is an intervenor.

- Question: So the parties can request an evidentiary hearing?

  *Response by Nick Paslay*: The parties can work together to recommend how to handle and then PUC decides. But none of that is known at this time.

- Question: Who would be making the decision on Advanced Metering Infrastructure (AMI)?

  *Response by Kevin Waltjen*: We would probably have to submit docket and PUC will decide.

- Comment: AMI is a safety issue. Magnetic creates problem for human beings. You should take a look at that before you waste a lot of money buying those meters.

  *Response by Jay Ignacio*: We will take that as a comment.

- Question: When we had rolling blackouts was that due to aging equipment?

  *Response by Kevin Waltjen*: In the 90s, we had rolling blackouts due to lack of generation. In the future, if we don't take care of aging equipment we will have reliability issues.

- Question (Will Rolston): Jay mentioned last night that we sent someone to Germany. Do you have a report on that?

*Response by Jay Ignacio*: We are a member of SEPA. We got a scholarship to attend a SEPA conference there. One of the key differences is that Germany is interconnected to neighboring utilities while here we are not.

- Question: Has anyone from HELCO or PUC visited UC San Diego to see their smart grid system?

  *Response by Jay Ignacio*: No.

- Question: Why not?

  *Response by Jay Ignacio*: We can talk to you offline on that.

- Question: Is there ever an issue where NEM customers will not be able to push energy out to the grid? Would you take FIT energy before you take NEM energy?

  *Response by Kevin Waltjen*: What happens on system is that we back down other generation to accept PV energy. At a certain point we will not be able to back down generation. There is no differentiation between FIT and NEM energy.

- Question: Concerned about proposed FIT projects in HOVE preventing newer NEM projects from coming online.

  *Response by Kevin Waltjen*: Those larger FIT projects will be required to install additional protection devices.

  *Response by Jay Ignacio*: We need to continue to work on this fairness issue. There is also a concern between distributed renewable generation and central renewable energy. Most DG we don't have direct control or visibility.

- Question: When I put in PV system, you changed my meter. Before that you were reading it remotely but now someone comes out every month. Did we take a step backwards in terms of metering?

  *Response by Kevin Waltjen and Jay Ignacio*: The old meter was a turtle meter, which we could read remotely. The new meter keeps different registers that we have to manually read.

Kevin closed the meeting with a comment that that this is an Action Plan, a set of actions that we are taking so that we can decide on the right path.

Following the presentation Annelle welcomed comments from the audience.

### Audience Comments

- Comment 1 (Paul Komora): On planet over 7 decades. Taught technology at university level. Cold fusion has been proven. Bottom line is utility has to make money. Owners want money but how much should that be? What is holding it back from production? We know Big Oil probably owns lot of stock in HELCO. Good presentation tonight. Now I understand why no one reacted to my presentation to PUC. Heard through grapevine that someone in Maui is pursuing this. UC San Diego saved 2 million dollars. Grew up in San Diego. Went to San Diego State. Hawaii could be center for development for the world if we try it here.

- Comment 2 (Earl Louis): You should look at cleanest way to do it. Biofuel is bogus. Ka'u is as big as island of Oahu. Solar is a good thing. We have a lot of state land where you can put solar. Geothermal not a good idea because land is unstable. Think of a situation where you can generate in each district. In the past, the mills powered the district. Wants to know what will happen in Ka'u, not in Hilo. Maybe Ka'u can be good example for rest of state.

Jay closed the meeting by thanking everyone for being here and sharing comments. We are proceeding with the process. We are taking all of your input and will include them in the final report.

Note: Occupy Hilo videotaped the meeting.

HELCO employees in attendance:

Pat Moore, Kevin Waltjen, Sam Terry, Virginia Aragon-Barnes, Debra Gomez Ota, Jay Ignacio, Josie Kiyan, Sue Akim Seu, Norman Verbanic, Nick Paslay (HECO Fuels)

## HELCO, Kailua-Kona, Hawaii

Hawaii Electric Light Company (HELCO)
IRP Public Meeting
King Kamehameha Hotel – June 6, 2013

In addition to the Hawaii Electric Light Company employees, approximately 15 audience members were present (see separate attendance list).

The meeting was started by Pat Moore at 6:01 p.m. Pat welcomed all the audience members and introduced some of the key audience members inclu ding: David Mattice, (Public Utilities Commission), Dean Nishina (Department of Consumer Advocate), IRP Advisory Group member Will Rolston (Hawaii County Energy Office), and Marni Herkes (Past IRP Advisory Group Member).

Annelle Amaral introduced herself and explained her role as facilitator for the evening. She explained that comments could be submitted on comment cards if someone did not want to speak. For those who were willing to stand and provide comments, notes from the meeting were to be documented electronically and written on flip charts.

Pat Moore began the formal presentation with background on the IRP process. Below are clarifying questions asked during Pat's presentation:

- Question: On objectives, what does "indigenous" mean? Does that refer to businesses?

  *Response by Pat Moore*: It means resources that are found here. No, it refers to the energy resources only.

- Question: Was the Gas Company involved in this process also?

  *Response by Pat Moore*: No.

Kevin Waltjen gave the presentation on Draft Action Plan. Below are clarifying questions asked during Kevin's presentation.

- Question (Will Rolston): Could you step up through the process of renegotiating with IPPs.

  *Response by Norman Verbanic*: Named IPPs and explained avoided cost contracts. We have approached each of these entities and invited them to reopen their existing contracts. It is a long process. For example, the contract for PGV expansion took about 4 years to negotiate.

- Question (Will Rolston): Does HELCO carry a much higher cost of T&D compared to the other islands?

  *Response by Kevin Waltjen*: When you look at square footage of our island compared with the number of customers, the cost is large compared to the other islands.

- Question: What about transmission losses?

*Response by Kevin Waltjen*: Transmission losses involve the amount of power that flows through the lines and the size of the line. Our losses are high over the long distances.

- Question: In terms of how much energy you produce, how much gets to the user?

  *Response by Norman Verbanic*: It's a dynamic number that depends on generation, where generation is running, load levels, etc. On average it's less than 10%. It can be as low as 3-4%. It's variable and changes minute-to-minute.

- Question: In earlier IRPs, there was talk of islanding? Is that being considered here?

  *Response by Kevin Waltjen*: We will talk about this under fairness topic.

- Question: Have been here for 4 years. Spent a lot of time attending government meetings. I have heard comments about HELCO that are uniformly negative. There is a ranch that cut relationship with you and is using hydrogen and microgrids. Why do you think the sentiment is so negative?

  *Response by Kevin Waltjen*: We're not familiar with that specific situation. Sometimes protection issues can be expensive.

- Question: Are we talking about wireless smart meters? All over the island? And is there a charge? And does this involve radiation?

  *Response by Kevin Waltjen*: Yes. It includes an opt-out provision. We will include that as a comment.

- Question: Regarding upgrading aging equipment, can we emphasize less or no emissions?

  *Response by Kevin Waltjen*: We will include that as a comment.

- Question (Marni Herkes): I am fan of HELCO. I don't agree with the comment that everyone is negative. I don't think you have touted your accomplishments in renewable energy. Are you planning more investment in renewable energy or projects to take more renewable energy?

  *Response by Kevin Waltjen*: Yes, for example we are doing a current project on battery storage. Another example is the West Hawaii Civic Center battery project.

- Question: A number of actions say "evaluate." What exactly are you doing? Do you have scenarios that show what is in and what is not in?

  *Response by Pat Moore*: We ran Strategist models. Analysis results are available on the website.

- Question: Is there any government money involved to do any of this? Where is the money going to come from to do these grand plans?

*Response by Kevin Waltjen*: We are running parallel paths and will evaluate to look for the lower cost options.

End of presentation. Annelle facilitated comments from the audience. The comments were documented on large sheets of paper for the audience to see and notes were taken.

### Audience Comments

- Comment 1 (Susan Golden): This is in line with an earlier comment about lowering customer costs. This is probably better addressed to PUC for making you do all these requirements which results in higher costs. Financing has to be changed at a higher level, not at HELCO's level. Have to figure out how to make the utility be a utility for the public. PUC has the biggest job.
- Comment 2 (Ulrich Bonne): Chemical physicist, retired. What is preventing HELCO from renting roof space for PV? What is preventing you from partnering with solar contractors to offer 20 cents/kWh for all customers. I have not seen any cost milestones in your IRP report. We want secure, reliable, uninterruptible power. We want energy at less than half the cost we see today. We want to eliminate need for more central power. Some are reflected in your draft 2013 plan. Commit to one or more numeric, measurable low cost goals. Without this, IRP is unacceptable. Would like to see quantification of goals.
- Comment 3 (Ron Becker): Concerned about smart meters. All over world, utility companies are installing meters on people's homes. It's not a benign thing. It has power to turn off electricity or ration electricity. It involves health issues. They emit radio frequency, pulsed radiation. I used detection meters to check them. It goes through concrete. It goes through you. Just like cell phones. They cause changes to cellular makeup of your body. Standards are out of date. You can't turn them off. It'll be on 24/7 and your body can never get used to that pulse. Also, I don't think it's right. Also it's wireless so it can be hacked. They'll know when you're home, how much air conditioning you're using. This is not right. They can install other smart meters, like fiber optic.
- Comment 4 (Jeff Rich): I don't want comments to be negative but I have concerns. In the past HEI has drafted policies that have not been followed on this island. How will oversight work?
- Comment 5 (Will Rolston): Gave PUC website for docket information.
- Comment 6 (Sarah Medeiros): Fascinated that PUC wants to take statewide approach for IRP. Does that mean that PUC is considering allowing having all customers benefit and having costs spread out? I think many of us would want to have equitable rates.
- Comment 7 (Marni Herkes): Are we thinking about statewide electric grid and geothermal? And who would own that resource? Would we get paid for that? There's a lot of concern about that. Asked PUC and CA rep to

take these comments. We've got everything together and do we want to share with somebody that's behind us.

At the close of the comment period, Annelle gave the audience the opportunity to ask further questions.

- Question: What was the brand of software?

  *Response by Kevin Waltjen*: Ventyx

- Question (Shane Nelsen): Regarding statewide geothermal, how does it fit into keeping costs of electricity down? Would we get compensation for sharing the geothermal?

  *Response by Kevin Waltjen*: That would be determined at the time

- Question (Ulrich Bonne): With uncertainty of geothermal and biomass, why not go for something proven such as solar or batteries?

  *Response by Curt Beck*: Yes, third parties have looked at these options. But we are not able to take advantage of tax credits. We can purchase the power cheaper from third parties than we can do it ourselves.

- Question: Surprised at low turnout. Lived away from islands for 20 years and when lived away she had at least 10 options. Here we only have you guys. How does that work?

  *Response by Kevin Waltjen*: Explained difference between HECO, HELCO, MECO.

- Question: Concerning Automatic Meter Infrastructure, are you getting government money?

  *Response by Kevin Waltjen*: No we are not.

- Question: Why does government want to give money to state?

  *Response by Kevin Waltjen*: Cannot answer that question.

  Will Rolston: Says was part of US-Japan agreement. State received $40M to do smart grid programs.

- Question: Is this related to project where Japan came to Maui?

  *Response by Kevin Waltjen*: Yes, Maui did a pilot project.

Kevin closed by thanking audience for their time.

HELCO employees in attendance:

Pat Moore, Kevin Waltjen, Sam Terry, Virginia Aragon-Barnes, Debra Gomez Ota, Sue Akim Seu, Norman Verbanic, Curt Beck, Don Evangelista, Stan Kaneo, Tony Prietto, Dana Martins, Bernie Sabado

## MECO, Kahului, Maui

Maui Electric Company, Ltd.
IRP 2013 Public Meeting
June 13, 2013
Pomaikai Elementary School Cafeteria
Kahului, Maui

Attending from Maui Electric Company:
Sharon Suzuki, President
Mat McNeff, Manager, Renewable Energy Services
Lyle Matsunaga, Manager, Accounting
Dan Takahata, Manager, Engineering
John Mauri, Manager, Power Supply
Kaui Awai-Dickson, Director, Communication
Ellen Nashiwa, Supervisor, Planning
Therese Klaty, Planning Analyst.
Annelle Amaral, Facilitator

See attached sign-in sheet for attendees from outside Maui Electric.

### Meeting Minutes

Mat McNeff and Sharon Suzuki presented a PowerPoint summary of the IRP process and Maui IRP Action Plan.

Annelle Amaral opened the floor for comments.

### *Audience Comments*

Kal Kobayashi read testimony from Mayor Alan Arakawa and Maui County Council Chair Gladys Baisa. A copy of the testimony is attached.

Warren Shibuya:
(In addition to Mr. Shibuya's comments below, he provided written comments that are attached.)

I am a homeowner and I have a Tier 1 FIT system. When I started my FIT system, the difference between what MECO purchases from me versus what I purchase was about $0.05. Now the difference is much larger. I am proposing that the PUC take this back. I believe the difference in price between what I sell and what I purchase should be no more than $0.05–$0.06. I chose to invest my money in a PV system. That system is now bringing in a larger return that I planned.

What we see in the presentation are estimates. MECO needs to increase quantification and measured data instead of estimates. There is opportunity to save money with less spinning reserve if data was quantified. There is not enough quantification of the load balancing that is being done by transformers and other equipment due to the increased amount of PV. We don't know the impact on the lifespan of this equipment without measurement.

Maui is on the leading edge and learning as we go.

Dick Mayer, retired from UH Maui College:
I would like to see a deeper analysis of all islands, not just Maui. I would like to see a clear explanation of the role of other resources such as ocean wave and geothermal. I would like to see what would happen if wheeling was allowed, separating the grid from MECO, with the grid owned by the County of Maui or a private entity. Also smart grid, smart grids can be small scale like micro grids. I would like to see the dollars associated with the scenario runs and the resources. People should be able to see the dollars in the action plan translated into $/kilowatt-hour. I would like to see more demand side management on individual residences or large commercial facilities such as freezers, chillers. Time of day metering should be addressed – charging lower rates during off peak times. There is nothing in the plan regarding energy use of vehicles. The electric vehicles could provide a lot of storage for excess electricity.

Tim Botkin, UH Maui College:
I've worked with other utilities on this transition. It's good that retirement of Kahului Power Plant is in the plan. You should do it sooner if possible. I don't think we should renew the contract with HC&S. They use a lot of coal, which is not good for sustainability. Natural gas is a good source that could bring some benefits. MECO should look at inverting their baseload strategy. 80% of the wind power is not being used. MECO needs to find a way to use the wind power and be reliable when the wind dies down. Look at storage as one solution. It's not right to rely on trade winds to address emissions. Need to reduce emissions. The bottom line is when you have seen the way we have organized our electricity structure, it promotes monopolies. In a way that is fair, but we're also seeing the doors getting kicked open. What I'm talking about is leadership for what we do as a community. I think MECO is in a position to be a leader for this change. Maui is in a great position to show how integration of renewables can be done.

Dick Mayer:
Need to investigate who is paying for the electric system on this island. Wealthy people who are putting large PV systems are not paying for the island electric system. Poor people, renters, low income people can't afford PV and they are subsidizing the rich. The system that is evolving is a regressive system. There needs to be a fair way to allocate the costs.

Anne Ku, UH Maui College, Maui Electric Vehicle Alliance:
Something we've found puzzling was why aren't the time of use rates being adopted more here on Maui by EV owners? You could have 300 customers, but you don't. In California, it's almost a one-to-one adoption by EV owners using time of use rates. It works because they already have smart meters in place. Here, customers have to pay an electrician. Also, the peak rate is much higher here, so people will pay a high rate for their loads like refrigerators. And the pilot rates for EV will expire at the end of the year. They should be reviewed and adopted now in a way that incentivizes additional EV adoption.

## MECO, Kaunakakai, Molokai

Maui Electric Company, Ltd.
Integrated Resource Planning Public Meeting
June 19, 2013
Mitchell Pauole Community Center
Kaunakakai, Molokai

Attending from Maui Electric Company:
Sharon Suzuki, President
Mathew McNeff, Manager, Renewable Energy Services
Damien Pires, Supervisor, Molokai Power Supply
Ellen Nashiwa, Supervisor, Planning Division
Therese Klaty, Planning Analyst
Jeremy Attri, Planning Analyst
Annelle Amaral, Facilitator

See attached sign-in sheet for attendees from outside Maui Electric.

Sharon Suzuki and Mat McNeff presented a Powerpoint summary of the IRP Action Plan for Molokai.

Annelle Amaral opened the floor to comments.

### *Audience Comments*

Lori Buchannan:
I agree 100% with the report from the IE submitted on May 10. I felt it was accurate, transparent, conscientious, and very well written. What I am wondering is why we are having this meeting tonight after the report submitted by the IE. It's upsetting to me as a community member that the PUC and the state is allowing this process to continue.

It is apparent that HECO has not been transparent. They have not provided information timely and upon request many times. When information has been provided it has been "half". As a member of the public, if you want me to make meaningful comments I need HECO and companies to give me something to comment on. I'm here tonight to say I am disappointed. There is no real cost analysis in the information provided.

I haven't seen any report submitted, despite all talk about green energy, about how we will address the toxic cadmium in solar panels, or the old windmills no longer being used. There is no process to decommission wind turbines. I don't want the toxic chemicals used to enter into my body or those of my family.

Greg Kahn, IRP Advisory Group member:
Months ago we were promised details. Where are the details? The plan shown tonight is just an outline of goals. The public meetings are being held after the action plan is already final.

How does LNG, a fossil fuel, factor into clean energy? LNG is filthy and not environmentally sound.

How will rate payers pay for the 6 billion dollar undersea cable? The cable will increase bills.

Where are the details on the top three Advisory Group goals?

There are no details on how the utility is going to protect Hawaiian cultural values and sites

There are no details on how the utility is going to protect the environment, the reefs, migratory birds, ocean mammals

There are no details on what the utility is going to do to protect community lifestyles

We have dealt with this before. We have been told by other parties that if Molokai does not want it we won't do it. Why is the public not being included more? Why is the undersea cable not addressed?

A flaw in the IRP process is the utility is required to listen to the public but not required to incorporate that input.

Elaine Callinan:
I have been looking forward to listening to the action plan. I don't see any elements in this presentation that reflect an action plan. I'm disappointed in the level of detail. This is a summary statement, a list of opportunities, not a plan.

Larry Tool, I Aloha Molokai:
I'm a member with IAM. I associate myself with the previous speakers' comments. I must recognize MECO's effort and recognition to incorporate community efforts. There is a problem with inertia in Oahu. HECO doesn't want to change. We need to strengthen the ability of those who can make change, such as the PUC. The PUC is a good group of people. They need public support to strengthen the PUC. They have a good idea what's wrong. I think a new process done differently could be a good thing

Just today the utility filed a new docket 2011-0156 asking today they want to waive the permitting process for 5 projects whose locations will remain secret except for the PUC. It's a slap in the face to the IRP.

Steve from MECO came to a meeting here and started his presentation by saying "I work for the electric utility but I see myself as a public servant." If only more of that sentiment could work it's way up the chain.

Kathie Flynn, I Aloha Molokai:
As a footnote to the solar panels, the CLFs put out 400 times more radiation and contain mercury that spills out when they're broken.

Last night on front line they were talking about retirement and 401K. In 50 years from now, every $100 put in today will be worth $36. The old paradigm doesn't work. This mentality and understanding is seeping into peoples' attitudes.

Sir Richard Branson of Virgin Air developed Plan B. He said, "It's time for businesses to be a force for good. People and the planet come first. Plan A was to do things for profit alone." It's time for more Plan B approaches, including the electric companies. They just want to rip people off.

Carla Hanchett, resident:
I'm disappointed that his happened at the same time as the OHA meeting.

I'm a busy person, I'm bummed out that I cannot trust my electric company, my state, my businesses. I followed the advice of the state and installed CFLs and put solar panels now I have cadmium etc. See Lori Buchannen's testimony. I agree with her testimony.

Chick Hirayama, resident:
I have a Ph.D. in Chemistry. I'm a former Westinghouse chemist. I worked there for 30 years. I've been hearing about mercury and cadmium. We all know Molokai rates are the one of the highest. One thing that engineers don't do, that they should, is a cost analysis of projects before they do it. For example for LNG MECO is that propane or methane? It makes a difference. The price of natural gas is down and is going to stay down because of the new process for getting it out of the ground.

Cadmium should not be a concern. It's worked into the material and stable. Mercury may be more concerning, but still on a small scale. The amount of mercury in CFLs is very small. If you're concerned about CFLs, you can use LED lamps. They're non-toxic.

I don't really understand what this meeting is all about. But if you want input from local residents, the primary objective should be lower cost.

Megan Sanford:
The people are tired of talking and nothing happening. We appreciate your showing but it is a show. We do not see results, we do not see details. We need to see that MECO cares about the high rates.

Whatever we do to help ourselves gets stomped out by large organizations. Too often, corporations come to Molokai and take from Molokai, but do not contribute anything.

We are educated and informed people. We are tired of coming to empty meetings with no real action resulting. We want to see action, information, details.

John Wordin, I Aloha Molokai:
I have a masters degree in aerospace engineering. As of about 2010 the world has used about half the oil available. To switch to another fossil fuel such as LNG is not the right approach to be taken. Switching to LNG is unconscionable. Fracking causes damage. We are between a rock and a hard place. We should discontinue use of carbon fuel in the first place. This planning process has to get on track and really deal with the problems people are facing.

Lindy Helm, I Aloha Molokai:
I'm speaking on behalf of Kanohowailuku Helm and I Aloha Molokai. IAM continues to work hard to find energy solutions for Molokai. IAM continues to advocate for Lanai and is in opposition to the undersea cable. I want to

thank MECO, Sharon, Mat and Steven, for being a part of the Molokai Clean Initiative. We continue to advocate for no undersea cable and bottom up solutions.

Kimo McPherson:
Those of us on Molokai know what's up. We pay our bill. What we add to the fire? EMF can cause sickness. I know a cross guard who worked under 3 transformers for 22 years who is now sick and planning to sue the electric company.

Ellison just bought Lanai and now another airline. Lanai is announcing exciting news. MECO is not showing us anything exciting. I wanted to hear a plan from the utility. All people should put PV on and generate their own electricity. That will beat them. The utility is scared of PV. For them it's all about the money. If we all put on PV they will go out of business. I want to reiterate what everyone has said here tonight.

Walter Ritte:
Like all other commentators I have very little information to go on. My comment is if you are going to do something on an island you should do it island-specific. This should not be done across islands. Big corporations are too far removed from the community. When communities are involved they think about more than money. If electricity planning is going to occur it should be done at the community scale. Interconnecting the islands does not make sense.

I'm not sure that cost is the primary issue. Cheap electricity encourages waste. Similar things happen with water.

I propose all homes generate their own electricity. Centralized planning and generation does not achieve the lower cost goal.

We should have community based operations, not state wide operations. There should be incentives for people who use the least.
Rita Woods, I Aloha Molokai, Maui County Red Cross:

Red Cross had a drill. A category 5 storm came through and knocked out power. Bottoms up generation makes the most sense since centralized power will be knocked out anyway, whether Molokai is or is not grid tied to other islands.

There have been events where developers came in and there have been meetings. This is just a way to wear us down so we stop fighting.

I think HECO should have to show up and explain themselves, and MECO should not have to take the rap all the time. I feel bad for MECO, they have to make sense of HECO policies. They should show actions instead of just noise.

## MECO, Lanai City, Lanai

Maui Electric Company, Ltd.
Integrated Resource Planning 2013 Public Meeting
June 20, 2013
Hale Kupuna O Lanai Hall
Lanai City, Lanai

Attending from Maui Electric Company:
Sharon Suzuki, President
Mathew McNeff, Manager, Renewable Energy Services
Ed Oyama, Supervisor, Molokai Power Supply
Michael Thomas, Supervisor, Molokai Transmission and Distribution
Ellen Nashiwa, Supervisor, Planning Division
Therese Klaty, Planning Analyst
Jeremy Attri, Planning Analyst
Annelle Amaral, Facilitator

Attending from Hawaiian Electric Company:
Scott Seu, Vice President, Energy Resources and Operations
Rodney Chong, Manager, Renewable Acquisition

See attached sign-in sheet for attendees from outside Maui Electric.

Sharon Suzuki and Mat McNeff presented a Powerpoint summary of the IRP Action Plan for Lanai. Scott Seu presented the status of the Lanai Wind project. Clarifying questions were answered.

Annelle Amaral opened the floor to comments

### *Audience Comments*

Butch Gima, resident:
At the CPAC meetings we have been discussing the Big Wind issue and have been actively taking Big Wind language out. The CPAC would like all types of renewable energy explored but would like the energy to stay on Lanai. The community is not against wind power completely, but rather against giving it away to Oahu without seeing what Oahu people are willing to give up.

Woman seated in the back of room:
Robby Alm was on TV last year and was asked "what is the energy plan for next year" he answered there is none. What happens when wind is no longer the hot energy source? Will we then have a graveyard of windmills? No one has talked about that to date.

I came back from a trip to California where windmills are falling apart, obviously developers are leaving with no accountability. When it's no longer economical for the developer, they leave and that's usually when they're bankrupt.

Bruce, resident:
I think it would be a terrible idea to put windmills in the Kaa area. I came

across some surveyors taking measurements. They said they were working on the road for the windmills. We're not being told the truth, information is being kept from us. Windmills for Oahu should be put on Oahu.

John Min, representing County Council Member Riki Hokama

See attached written statement.

Pat Reilly, resident:
The plan for Lanai looks like a reasonable plan, but it's very vague. We need more detail. It is important to the community that there is community involvement. As a corporation you have an obligation to you investors. As residents we have an obligation to our island. Oahu needs power because they are growing. The President is pro wind, the governor is pro wind, etc. The community must be involved. We must have a seat at the table. My take is the loss of 16,000 acres is incalculable and not being taken into consideration.

Kathy Brindo, resident:
Even if you find out that windmills on Lanai is the cheapest source that still does not make it right. There are moral issues that need to be taken into consideration. ¼ of the island would be destroyed. Would you destroy ¼ of Oahu, of Maui? Archaeologists could spend years studying that area. The place is a treasure. I believe it's immoral. I believe it's a sin.

John Schaumburg, resident:
I like the idea of LNG. I noticed however there was no talk about geothermal. There is a good possible site for geothermal on Maui. A 9 mile cable is cheaper than a 70 mile cable. On the Big Island, geothermal is firm with at least 85% capacity factor. More geothermal could make that island self-sufficient. 45% capacity factor for Lanai Wind is too optimistic. I think for Lanai Wind, 25%–35% is about the best capacity factor that could be expected. 85% of our economy on Lanai is based on tourism. Tourists don't want to see windmills. My general opinion after looking at all of this for years is that renewable generation with a capacity factor less than 70% is a waste of time and is only being considered because of the RPS. Biogen is good because it's dependable. PV and Wind are not desirable because they are not reliable.

Donna Schaumburg, resident:
I notice that our comments are taken down at each meeting. I would ask that at the next meeting you are prepared to answer some of the questions that have been repeated over the years.

Wendy:
In 2000, there was a meeting with First Wind. I am against it. God will provide everything we need. You do need to drudge up the ocean. I have been living on this island for 50 years. You come and talk, but do you stay? When you go back to you office what do you do with these comments? We will have 170 windmills. How will that look? Like a graveyard. How are you going to get those big windmills and big trucks to the wind farm? There aren't permits for it. Mr. M sold his land to a new owner. He is not

communicating with the community, he did not have any community input. I'm not in favor of it, because it is ridiculous.

Debbie, resident:
When Ellison bought the island, that gutted the benefit package except the rate. Robbie Alm stated that there was "no energy plan" meaning you're always looking for the latest and greatest. What happens when the wind farm isn't the latest and greatest anymore?

Donna Stokes, resident:
Me and my family are against the development of wind in the Kaa ahupua`a. the Kaa ahupua`a is the most pristine place on the island. We need to preserve this place. This place has our nicest beaches. We do not want it ruined. This is where we take our families. Please raise your hands if you want windmills built at Kaa ahupua`a. I want the record to show that no hands are raised. No one in this community wants windmills at Kaa ahupua`a. Our families depend on these kinds of areas.

Robin Kaye, Friends of Lanai:
What's changed since Ellison bought the island? The intimidation factor is gone. There are no more threats that you'll lose your job or home or threats that the island will close if there isn't a wind farm. The "support the wind farm" signs have come down except for a few that are still on abandoned houses. Second point is Ellison has not provided any support, at least publicly, for Big Wind. Except for Chris and Alberta, who left, this island community is opposed to Big Wind.

Diane Preza, resident:
When I was little my dad would take us to the church. We would go to the altar. We found money there, it was Hawaiian money. We would look but not take it. This is common sense that a child has, why don't adults have the same sense with the wind projects. As a seven year old child, we knew it was not ours to take. It's not right. It's not yours to just take. Of course we want green energy, but this is not the way to do it.

Sally Kaye, Friends of Lanai:
I want to thank MECO staff for their responsiveness. The Action Plan will be filed with the PUC on June 28. That is when we must pay close attention. We have to be vigilant. There have not been many details, MECO has been forthcoming about their vision, but it is after the plan is filed that we must really pay attention. When the plan is filed with the PUC, we need to understand it and comment on the plan. Thank you to Scott for coming. We needed a HECO presence here.

Questions from Lanai community members answered by Scott Seu unless otherwise noted.

Q: Can we do a PPA with C&C prior to the RFP process?
A: It would be very difficult, in theory yes, but the PPA would have to be very creative without a cable.

Q: Do you have permits, archeologists and others, for a big wind project?
A: No, that would be the responsibility of the developer.

Q: Would electricity prices go up or down if big wind goes through?
A: When we are in negotiations with any developer, like Sharon said, we want clean energy but we also want to lower our customers' bills. The project in front of us is Oahu purchasing power produced on Lanai; for this to happen, it would have to meet the criteria of lowering bills The project in the past proposed a community benefit that in exchange, Lanai prices would be linked to Oahu prices.

Q: Is there any linkage with the gasoline station and the wind project?
A: There is no linkage between the two.

Q: Is the cheap prices you a quoting inclusive of the cable cost?
A: The prices we need to look at are all in costs, inclusive of the cable and other costs, delivered on Oahu.

Q: What is the difference between rate and bill?
A: (Not 100% sure how Scott answered this so I'm guessing). The PPA rate is what the utility pays the developer to purchase energy. Purchased power is a straight passed through to customer bills.

Q: When the IRP objectives were shown sensitivity to community, given the opposition how can you justify continuing with big wind?
A: It is not yet justified. We have to follow through on the RFP, the results of which will include the qualitative comments from the community.

Q: In the RFP is one of the options no Big Wind on Lanai?
A: Yes, if through the RFP process we find that the Big Wind project, inclusive of an undersea cable, is not the right solution then we would not go forward.

Q: Are we still holding to the representations from Robby Alm?
A: Yes, we are.

Q: Isn't it cheaper to put wind power on Oahu without the cost of a cable rather than on Lanai?
A: We don't know that. We have to look at what is the best way to lower prices on Oahu through the RFP process.

Q: With the PV cells there is a 15% circuit saturation limit. Is there a similar limit for wind?
A: There is a difference between local distribution circuit vs. higher voltage transmission lines. The 15% criteria applies to the distribution level circuits and only triggers additional review. The 15% criteria also applies to all technologies, wind and PV.

Q: What is the financial impact Kahuku wind farm being out of service?
A: Their battery system experienced a fire and caused the facility to be out of service. To the extent we could have bought cheaper energy from them compared to the cost of the replacement energy that filled the void, then yes we are paying higher costs for energy.

Q: Are the promises by Castle & Cook still on the table?
A: From the HECO perspective, their commitments for community benefits is still a requirement of the term sheet. We are not privy to the details of the

agreements between Castle & Cook and Mr. Ellison but their commitments to HECO and Lanai are still on the table.

[Scott gave an example of how power prices and supply and load can allow for savings, for example, if wind is cheaper than HECO's generation]

Q: Is the utility responsible for the upkeep of the wind farms?
A: No, the developer is responsible for the upkeep.

Q: I came back from a trip to California where windmills are falling apart, obviously developers are leaving with no accountability.
A: This past legislative session, Hawaii enacted a law requiring developers to restore sites at the end of the project.

Q: How do you manage fuel and fuel costs?
A: We contract to purchase fuel with Tesoro and Chevron. However we also try to manage fuel costs through improving efficiency.

Q: There is a rumor that Murdock has been offered a $100M tax credit for completion of the Lanai Big Wind. Is that true? Is HECO receiving any similar tax credits?
A: Any tax credits for Mr. Murdock would be imbedded in the Castle & Cook financial portfolio and we have not yet seen it.

Q: Do all the costs spent on big wind studies etc. get passed on to customers?
A: HECO must justify to the PUC that RFP funds were spent prudently and if the utility can recover the costs.

Sally Kaye: You're already collecting the surcharge. It would be more honest to tell her that you already have the approval from the PUC to collect the surcharge for the studies.

Q: [Sally Kaye] Can you make it a requirement to provide financial data in a PPA to the public even though the bill failed this past legislative session that would of required financial disclosure?
A: Although the bill failed, we intend to require that project financial data be shared. There may be instances where it is not shared broadly, but rather with the PUC and the Consumer Advocate, under protective order.

Q: Please explain the renewable energy credits vs. the tax credits you are receiving?
A: A renewable energy credit is recognition by the state of a qualified energy that counts towards the 40% RPS goal. There is a secondary market on mainland where REC can be sold; these are not tax credits.

Q: Where are we currently as a state for renewable energy?
A: We are currently around 18% for HECO service territories, not including Kauai.

Q: How much revenue would a 200 MW wind farm generate in a year?
A: [Mat showed an example of wind farm revenue calculation]

200MW x Capacity Factor (for example, 0.45) x $0.2/kwh x 8760 hours/year x 1000 kW/MW = $158 million/year

Q: How does a PPA compare to the revenue calculation?
A: A developer has to consider the cost to build and operate the wind farm. We do try to review the project financials to understand what the profit is because we have to show the PUC that the developer is not making windfall profit on the backs of our customers.

Q: What upgrades are happing on Lanai to address solar DG penetration?
A: [Mike Thomas, Lanai T&D Supervisor] The distribution upgrades we're doing currently aren't directly related to DG penetration. We're replacing aging equipment.

Q: Would HECO purchase big wind power when it leaves Lanai or arrives at Oahu?
A: [Rodney Chong] The PPA would be structured such that metering would occur on Oahu. So the developer bears the cost of the losses across the undersea cable.

Q: Would HECO still consider big wind viable if Castle & Cook was the only bidder for both the wind farm and the cable?
A: HECO would look at the results and evaluate whether the project was in the best interest of its customers.

Q: Since Hawaii is on track for our renewable goals, how much would Lanai big wind contribute to the RPS goals?
A: It would contribute around 600–800 GWH. I would have to run the math to see what the % impact would be.

Q: If we are ahead of the RPS law requirements, would HECO sell the renewable energy credits?
A: No, the PUC can instill penalties if the utility does not hit the targets. These are challenging targets to achieve and we are not in the market of selling any credits.

# Appendix

This appendix contains the handouts from the various meetings, sign-up sheets, public letters, comment cards, and presentations.

## Hawaiian Electric, Honolulu, Oahu

Hawaiian Electric Company
Maui Electric Company
Hawaii Electric Light Company

# Integrated Resource Planning Public Meeting

6PM – 8PM Wednesday, June 12, 2013
Farrington High School Cafeteria
Hawaii Public Utilities Commission Docket No. 2012-0036
Integrated Resource Planning (IRP) for Hawaiian Electric (HECO), Maui Electric (MECO) and
Hawaii Electric Light Company (HELCO)

The Hawaiian Electric Companies invite you to comment on the Draft Five-Year Action Plans. The Action Plans are part of the Integrated Resource Planning (IRP) process, which looks at how the utilities will meet future energy needs. The Hawaiian Electric Companies intend to file an Action Plan for each company with the Hawaii Public Utilities Commission (PUC) by June 28, 2013.

Information about IRP and the Draft Action Plans is available online at www.irpie.com, the website of the PUC's independent representative facilitating and monitoring the process. The PUC initiated the latest round of integrated resource planning process in March 2012 and named Carl Freedman of Maui-based Haiku Design & Analysis as the commission's "Independent Entity" to oversee the process. The PUC also named a 68-member IRP Advisory Group, composed of representatives from diverse locations and organizations in Hawaii, to provide public input to the Hawaiian Electric utilities in the planning process. Attached is a copy of the PUC's Order naming the Advisory Group members.

**Send your public comments to public@irpie.com.** Comments may be in the form of an email or in the form of a document attached to an email; include your name, the date, and your island of residency. The Independent Entity will then post all comments to the www.irpie.com website. The public comment period on this phase will end on June 21, 2013. However, public comments will continue to be accepted via the email address above beyond the stated deadline.

According to the PUC:

> "The goal of integrated resource planning is to develop an Action Plan that governs how the utility will meet energy objectives and customer energy needs consistent with state energy policies and goals, while providing safe and reliable utility service at reasonable cost, through the development of Resource Plans and Scenarios of possible futures that provide a broader long-term perspective."
>
> *–A Framework for Integrated Resource Planning, Revised March 14, 2011*

…more

1

Hawaiian Electric Company
Maui Electric Company
Hawaii Electric Light Company

The IRP 2013 Draft Action Plan for Hawaiian Electric is as follows:

**LOWER CUSTOMER BILLS**

1) Deactivate/Decommission Generation
    a. Deactivate Honolulu 8 & 9
    b. Deactivate Waiau 3 & 4
    c. Deactivate/Decommission additional units as peak load decreases
    d. Potential reactivation for emergencies and/or generation shortfalls
2) Lower Cost Generating Facilities
    a. Complete current invitation for "Waiver Projects" for fast track and low-cost renewable resources
    b. If LNG assured, Competitive Bid for more efficient generation
    c. Convert CIP CT-1 to combined cycle and potentially lower cost fuels
    d. Re-negotiate/Re-bid Kalaeloa PPA
3) Replace Oil with LNG
    a. Develop infrastructure (regulated) for bulk LNG import
    b. Procure low-cost LNG supply for generation
    c. Assure environmental compliance at low cost
    d. Add gas firing capability to existing generating units
4) Other
    a. Develop & deploy additional Demand Response
    b. Allows for the turning off or on of loads for system operational benefits
    c. Modify existing baseload generation for greater turndown and/or cycling operation
    d. Issue RFP for low-cost biofuels

**CLEAN ENERGY FUTURE**

5) Meet or Exceed Renewable Portfolio Standards (40% Renewable Energy by 2030)
    a. Implement approved Renewable Standards Working Group (RSWG) actions
    b. Issue RFP for renewable energy and/or interisland transmission lines, as directed by the Public Utilities Commission
    c. Complete current invitation for "Waiver Projects" for fast track and low-cost renewable resources
    d. Hawaii Bioenergy biofuels pending approval by the Public Utilities Commission
    e. Continue consideration of Lanai Wind
    f. Develop utility-scale PV facility at Kahe Power Plant
6) Improve Grid Operations
    a. Reciprocating engine facility at Schofield (biofuel) for Base energy security, grid stability, catastrophic event mitigation and black start
    b. T&D upgrades to address load flow and voltage constraints
    c. Deploy Advanced Metering Infrastructure (AMI) island-wide by 2018 with opt-out provisions
    d. Implement conservation voltage reductions
    e. Upgrade telecom infrastructure to facilitate AMI and Distribution Automation
    f. Expand Distribution Automation
    g. Upgrade aging equipment
    h. Continue to evaluate and pursue cost effective energy storage

**FAIRNESS**

7) Address Issues with Existing Distributed Generation Programs
    a. Standardize interconnection process and practices
    b. Study, develop, and implement technical solutions for high penetration of distributed generation
    c. Review policies, legislation, and rules for best interests of all customers

#230-1351
Freddy

Integrated Resource Planning Public Meeting
June 13, 2013
Farrington High School Cafeteria

| | NAME | AFFILIATION (optional) | EMAIL ADDRESS (optional) |
|---|---|---|---|
| 2 | ED WAGNER | SELF | |
| 3 | CHRISTIAN HACKETT | PATTERN ENERGY | |
| 4 | JIM WOOD | | jwood@hoken.com |
| 5 | WENDELL LUM | BLOOM Energy | wendellkaneohe@hotmail.com |
| 6 | Jack Shriver | HELCO | |
| 7 | Kaʻili Britos | IDG | idghioffice@gmail.com |
| 8 | Earle Ifuku | HECO | |
| 9 | DAVE MCCLAFLIN | CASTLE & COOKE | |
| 10 | Kurt Tsue | HECO | kurt.tsue@heco.com |
| 11 | Jay Griffin | PUC | james.p.griffin@hawaii.com |
| 12 | Josh Strickler | HI GAS | |
| 13 | DEAN NISHINA | DCA | |
| 14 | Catharine Lo | Blue Planet | catharine@blueplanetfoundation.org |
| 15 | David Jones | Sunetric | djones@sunetric.com |
| 16 | Sophie Cebe | Civil Beat | |
| 17 | Patricia H. Talbert | Indigenous Consultants | |

6/25/2013 7:02 AM

# Hawaii Electric Company

## Draft Action Plan

### Integrated Resource Planning (IRP) 2013

Public Meeting
Wednesday, June 12, 2013
Farrington High School Cafeteria

Hawaiian Electric Company
Maui Electric Company
Hawaii Electric Light Company

1

## IRP Website (IRPIE.com)


Submit comments to public@irpie.com

2

1

6/25/2013 7:02 AM

## The Goal of IRP

"The goal of integrated resource planning is to develop an **Action Plan** that governs how the utility will **meet energy objectives and customer energy needs consistent with state energy policies and goals**, while providing **safe and reliable utility service at reasonable cost**, through the development of **Resource Plans and Scenarios of possible futures** that provide a **broader long-term perspective**."

Reference: Docket No. 2009-0108, Decision and Order, A Framework for Integrated Resource Planning, Revised March 14, 2011, Section II.A, page 2

3

## Definition of Action Plan

"Action Plan means an **implementation plan and schedule** for the specific **actions, resource options, and programs** to be executed by the utility to serve its customers' future energy needs and requirements in a manner consistent with the framework. The Action Plan **covers the first five (5) years of the twenty (20) year horizon** on the Scenarios analyzed."

Reference: Docket No. 2009-0108, Decision and Order, A Framework for Integrated Resource Planning, Revised March 14, 2011, Section I, page 1

4

2

6/25/2013 7:02 AM

## IRP 2013 Process Steps

- PUC initiated the current IRP cycle on March 1, 2012.
- Independent Entity selected to oversee process
- 68 member Advisory Group formed June 29, 2012
- Numerous Advisory Group meetings held
- Public meetings held in December 2012
- The Hawaiian Electric Companies must file the IRP including the Action Plan with the Public Utilities Commission by June 29, 2013.

5

## An Ongoing Process
## Keeping the Action Plan current

- Every 3 years the IRP process is repeated and the Action Plan **fully re-analyzed**
- Evaluation Report required between IRP cycles
- Action Plan updated as circumstances change
  - Action Plan needs to be robust and flexible to adapt to an uncertain future

6

3

6/25/2013 7:02 AM

## IRP 2013 Objectives

**Developed in conjunction with the Advisory Group in no particular order**

1. Protect Hawaii's culture and communities
2. Protect Hawaii's environment
3. Reduce dependency on imported fossil fuels and improve price stability
4. Provide electricity at a reasonable cost
5. Increase the use of indigenous energy resources
6. Provide reliable service
7. Improve operating flexibility

7

## Hawaii Electric Company's Strategic Considerations

- Lower customer bills
- Clean energy future
- Modernize grid
- Fairness

8

4

6/25/2013 7:02 AM

## IRP Challenges

We don't have a crystal ball

We can't predict the future

**The IRP process is informative, not definitive**

9

## Overall Challenge

We need to develop and keep relevant an Action Plan that has the **flexibility** to accommodate an uncertain future.

10

6/25/2013 7:02 AM

## The Goal of the Public Meetings

- Receive your comments on the draft Action Plan
  - What you like or dislike
  - What is of importance to you and our community
  - What you think should be added or deleted
- Create broad-based awareness of the complex and sometimes conflicting objectives and issues the utility and the Commission must resolve.*

*Reference: Docket No. 2009-0108, Decision and Order, A Framework for Integrated Resource Planning, Revised March 14, 2011, Section II.B, page 3

11

## Hawaiian Electric Draft Action Plan

12

6

6/25/2013 7:02 AM

**Draft Action Plan – Hawaiian Electric Company**
**Lower Customer Bills**

1. Deactivate/Decommission Generation
   A. Deactivate Honolulu 8 & 9
   B. Deactivate Waiau 3 & 4
   C. Deactivate/Decommission additional units as peak load decreases
   D. Potential reactivation for emergencies and/or generation shortfalls

13

**Draft Action Plan – Hawaiian Electric Company**
**Lower Customer Bills (cont'd.)**

2. Lower Cost Generating Facilities
   A. Complete current invitation for "Waiver Projects" for fast track and low-cost renewable resources
   B. If LNG assured, Competitive Bid for more efficient generation
   C. Convert CT-1 to combined cycle and potentially lower cost fuels
   D. Re-negotiate / Re-bid Kalaeloa PPA

14

7

6/25/2013 7:02 AM

**Draft Action Plan – Hawaiian Electric Company**
**Lower Customer Bills (cont'd.)**

3. Replace Oil with LNG
   - A. Develop infrastructure (regulated) for bulk LNG import
   - B. Procure low-cost LNG supply for generation
   - C. Assure environmental compliance at low cost
   - D. Add gas firing capability to existing generating units


15

**Draft Action Plan – Hawaiian Electric Company**
**Lower Customer Bills (cont'd.)**

4. Other
   - A. Develop & deploy additional Demand Response
     - Allows for the turning off or on of loads for system operational benefits
   - B. Modify existing baseload generation for greater turndown and/or cycling operation
   - C. RFP for lower-cost biofuels

16

8

6/25/2013 7:02 AM

**Draft Action Plan – Hawaiian Electric Company**
**Clean Energy Future**

5. Meet or Exceed Renewable Portfolio Standards (40% Renewable Energy by 2030)
   A. Implement approved Reliability Standards Working Group (RSWG) actions
   B. RFP for renewable energy and/or interisland transmission lines, as directed by PUC
   C. Complete current invitation for "Waiver Projects" for fast track and low-cost renewable resources
   D. HBE biofuels pending PUC approval
   E. Continue consideration of Lanai Wind
   F. Develop utility-scale PV facility at Kahe Power Plant

17

**Draft Action Plan – Hawaiian Electric Company**
**Modernize Grid**

6. Improve Grid Operations
   A. Reciprocating engine facility at Schofield (biofuel) for Base energy security, grid stability, catastrophic event mitigation and black start
   B. T&D upgrades to address load flow and voltage constraints
   C. Deploy AMI island-wide by 2018 with opt-out provisions
   D. Implement conservation voltage reductions
   E. Upgrade telecom infrastructure to facilitate AMI and Distribution Automation
   F. Expand Distribution Automation
   G. Upgrade aging equipment
   H. Evaluate and pursue cost effective energy storage

18

9

6/25/2013 7:02 AM

**Draft Action Plan – Hawaiian Electric Company**
**Fairness**

7. Address Issues with Existing Distributed Generation Programs
   A. Standardize interconnection process and practices
   B. Study, develop, and implement technical solutions for high penetration of distributed generation
   C. Review policies, legislation, and rules for best interests of all customers

19

20

10

6/25/2013 7:02 AM

## Hawaii Electric Light, Hilo, Hawaii

### IRP PUBLIC MEETING

**Tuesday, June 4, 2013**

**County of Hawaii – Aupuni Center Conference Room (Hilo)**

*Notes and Comments*

What is the composition of the advisory group members?
- Process flawed because poor representation of the rate payers
- Heavily represented in business and government

How many from the community/rate payers are part of the 68?

Suggestion to remove advisory group title if it is not representing the community

What incentive is there to export Hawaii Island energy?

Will the IRP comments have an impact on the RFP?

Will the PUC consider the IRP comments when they negotiate a PPA?

How feasible is the waste to energy solution?

Cost of AKP fuels?

Very important to clarify where/how the opportunity to comment on important aspects such as the undersea cable

Is there any resolution at the state level for Item B (export of renewables)?

If AKP is a fixed rate with a long-term contract and is already higher than current rates, how is that beneficial?
- How will AMI infrastructure impact rates
- Explain geothermal upgrades
- Question on the need for a redundant line specific to geothermal

Explain 6F on energy storage

Is there a projection for power (load) demand (5/10 years)?

Would HELCO be willing to stop generating and only maintain and distribute if residents generate themselves (solar)?

How will HELCO promote the conservation of power?

Is there an agenda at the state level that geothermal is to be pursued at all costs?
- Concerned that there is a grave conflict of interest with geothermal process/parties (lobbying, state level)

When considering replacing oil with LNG – produced with fracking so believes we shouldn't support that
- Concerns with testing waters and lands for more geothermal

Economics: geothermal expensive, newer technologies coming down in price, amazing how fast technology is changing in solar

- Energy policy in Hawaii dictated by special interests

No sign in the action plan that the utility addressed (solar subsidy) fairness

Damage to chronic low-level radiation (cancer)

- Standards for what's considered safe radiation have changed a lot in his course of work, similar to secondary smoke
- Hydrogen sulfide (low levels) toxic, plans stopped until this is fixed

Hates LNG

- Slides contradict themselves
- AKP was misinformed on contract
- Waste-to-energy bad idea if lines are needed to transport
- Encourages an attitude change for HELCO
- No undersea cable for Hawaii island
- Be a model for the world; distributed generation; take us seriously or your (HELCO) time is up

Post minutes and comments on IRP website

- No geothermal, respect Pele
- Transporting biofuels to Keahole (sunniest place) is unacceptable
- Subsidizing C. Lau HEI is unacceptable
- If he can live off grid, others can

No one has proven that Pele disapproves of geothermal

- Problem with HELCO and PUC
- Scam, disgraceful – the relationship HELCO has with PUC
- We need a mix of resources

How are you going to take input when you already have geothermal RFP?

We don't want more geothermal in our area

Is the independent entity satisfied with the process?

The community objects to the geothermal RFP

There already are a lot of comments against but yet it is still going

Do we only get to comment on HELCO actions or is it possible for statewide actions?

When you do take it to PUC, the comments made considered by the PUC on the geothermal RFP?

I do not think it is a good step (geothermal)
Are our comments being filtered before they get to PUC?

Earlier why are you doing the RFP before the comments when a comment was made that you would consider our comments – it's after the fact

Why are you proposing a new company to compete with the existing company?

Comment made by Jay in a report talking about cost effectiveness

When you talked about underwater cable, you said you would support it. So why are we even here if our comments wouldn't be considered?

AKP-scared by their claims about their yields. Were there independent studies done by anyone on their projections? Were their results say that they were the best gamble?

AKP-Sierra Club and I don't support it. What hoops do they to go through?

Safety concern with energy generation. Dirty word – safety generation. Nature, upwind, other safety concerns taken into consideration?

Excited to see CSF move solar on the slide, in the plans

When you spoke of options that didn't require more upgraded transmission lines, what project were you referring to?

2011-0206 County of Hawaii document, answering the above comment

Ratepayer has already produced 5MW of power for HELCO. Has solar panels, hybrids, should be incentives for people like me to produce.

Germany has produced a majority of their energy from solar. Why can't we do the same as Germany>

Is there a form for me to add my input when you are doing those studies?

What is the status with Honua? There is a legal proceedings coming.

Geothermal – How come we are doing it in lava zone #1? Went to Jim K. and emailed it. Reason is it is the easiest resource to get to. If/when there are issues, it is not just going to affect the residents or the ratepayers. Warning everyone about the impending issues when lava flows in area.

Concerns: EQ an example of what happens in lava zone 1

Reinjecting deadly toxins is insane

Regulations shouldn't be adding new numbers to existing plant

Not looking at the loss of human life, health concern. People who have interest in geothermal are lobbying for it.

Should be moratorium until real research is done on that.

Would like to see us move on other renewable energy projects, not geothermal.

Reading January 2013 “Edison Institute Electric” paper prepared by Peter Kind, “Disruptive Challenges: Financial Implications Responses to a Changing Retail Electric Business”.

- Utility in same position, to maintain grid, increase rates but when everyone leaves the grid, rates go up.
- There is no answer to that action plan
- Geothermal cost 12 cents but to his calculations it doesn’t make sense

Solid waste processing:

- Evaluating: be open by whatever information you have
- Doesn’t like it
- Could support it if it could be done properly
- Not well understood in the community
- What BTU or raw material needs to be used? Hears 500 tons.
- Puuanahulu: locked in a rate, covered with soil. But we are locked in a contract.
- If we can do it properly it could be good for us. A great resource there if we can get out of that contract.
- Puuanahulu could be improved, it would help our community. Please tell the county or work with them to help us out.

Harry Kim concerns:

- Wishes better relationship by government, business, community
- Interviewed by reporter, wants to re-establish regulations of 1983
- Past session: government should be for community
- Why it’s government/business on one side and community on the other side
- He’s friends with Jay but he’s talking about how we relate to each other
- Resents where we’re going and how we’re doing it. Not for HELCO, government but our island

Worked for public utility

- Neglected in report was possible issues or trouble scenarios
- HELCO has capability to supply every need/power we might have
- If you want to have lower bills we less power
- Lots of people using lots of electricity
- Some people using/paying $500 a month bills not necessary

Thanks HELCO, meetings should be required

- Concerned about natural gas/fracking
- Biofuels some are possible some are not
- Geothermal: Hard to figure out the hydrogen sulfide impact in neighborhood
- Commends HELCO for looking into distributed energy

When final decisions are being made on geothermal, I hope “known resource” doesn’t triumph over geologic instability.

Integrated Resource Planning Public Meeting
June 4, 2013
Aupuni Center (Hilo)

| NAME | AFFILIATION (optional) | EMAIL ADDRESS (optional) |
|---|---|---|
| CORY HARDEN | — | mh@ interpac.net |
| Lukas Mattice | | |
| Robert Petricci | PUNA PONO ALLIANCE | nimo1767@GMAIL.com |
| Richard Bidleman | Home Owner | richard@bidleman.net |
| MAYOR HARRY KIM | | |
| WILL ROLSTON | COUNTY OF HAWAII | |
| Lance Duncan | | |
| Laura TRAVIS | Self | Lauratravis@me.com |
| | | |
| | | |
| | | |
| | | |
| | | |
| | | |
| | | |
| | | |

Integrated Resource Planning Public Meeting
June 4, 2013
Aupuni Center (Hilo)

| NAME | AFFILIATION (optional) | EMAIL ADDRESS (optional) |
| --- | --- | --- |
| Susan Blankenbecler | self | sooshib@yahoo.com |
| Derek Inaba | CoH | dyinaba@hawaiicounty.gov |
| IKE PAYNE | self | ikiatoi@live.com |
| Nelson Ho | Self | |
| Gregory Paul | self | punalilu@gmail.com |
| DOUG ORTON | PUNA Resident | |
| Beverly Frederick | Wisdom Way Center | beverlyfrederick76@gmail.com |
| | | |
| | | |
| | | |
| | | |
| | | |
| | | |
| | | |
| | | |
| | | |

Integrated Resource Planning Public Meeting
June 4, 2013
Aupuni Center (Hilo)

| NAME | AFFILIATION (optional) | EMAIL ADDRESS (optional) |
|---|---|---|
| David Tarnas | | dt@mericainternational.com |
| Noe Kalipi | TiLeaf Group | nkalipi@tileafgroup.com |
| DWAYNE YOSHINA | | mahassamotman27@gmail.com |
| Dwight J. Vicente | | 2608 Ainaola Dr, Hilo |
| Avery Freed | | averymfreed@gmail.com |
| Jeff Ono | Consumer Advocate | |
| KERRI MARKS | | OCCUPYHILOMEDIA@GMAIL.COM |
| TOMMY GOYA | | tommygoya@hawaii.rr.com |
| MIKE KALEIKINI | PGV | mkaleikini@ormat.com |
| BOB ELY | SELF | BOB@BIGISLANDGROWERS.COM |
| David Mattice | PUC | |
| LORI DOUGLAS | SELF | |
| YEN CHIN | SELF | saveenergy5@gmail.com |
| Jim Albertini | Malu 'Aina | ja@malu-aina.org |
| ~~Tim Rees~~ | Yes | timrees5023@aol.com |
| Tom Travis | | ttravis12@mac.com |

Integrated Resource Planning Public Meeting
June 4, 2013
Aupuni Center (Hilo)

| NAME | AFFILIATION (optional) | EMAIL ADDRESS (optional) |
|---|---|---|
| Andrea T Gill | DBEDT State Energy off. | agill@dbedt.hawaii.gov |
| Russell Ruderman | ~~[illegible]~~ | senruderman@capitol.hawaii.gov |
| Sara Steiner | self | saralegal@live.com |
| Kris Wilhelmsen | Self | kris@kimnkris.com |
| Kim Kombacher | self | kim@kimnkris.com |
| Michael Hollinger | self | hollingermike@yahoo.com |
| SATYA-JANSEN | PUNAPCNC. | regaftruth@gmail.com. |
| Barry Mark | self | barrymark@hawaiiantel.net |
| LARRY GERING | SELF | dktrg1@hotmail.com |
| | | |
| | | |
| | | |
| | | |
| | | |
| | | |
| | | |

Name: DOUGLAS ORTON

Organization (optional): PUNA RESIDENT

Email (optional):

Questions/Comments:

I DO NOT SUPPORT FURTHER
GEO THERMAL DEVELOPMENT
AS A PUNA RESIDENT THE
VENTING OF HYDROGEN SULFIDE
IN LEAGUE WITH THE VOG
IS ALREADY HEALTH DAMAGING
& CAN ONLY INCREASE!

Name: Julie Myhre

Organization (optional): Self

Email (optional): julie.3889@gmail.com

Questions/Comments:

1) No effort should be made to explore importing LNG because it is at odds with the goal of reducing fossil fuels. The permitting of the LNG import point will take 10+ years, and it does not increase the security of energy of Hawaii Island.

2) Add time-of-use rates to offer discounts so that people are encouraged to use off-peak energy - Easy ~~+ time~~ fix.

OVER→

3) Thanks for making this meeting happen + providing a forum.

4) Please do some education on the importance of a solid grid for water distribution. no electricity = no water! (but for Puna folks that are almost all on catchment).

Name: SATYA JANSEN.

Organization (optional): PUNAPONO ALLIANCE:

Email (optional):

Questions/Comments:

MY GREATEST 'CONCERN' IS WHAT THRU 'RESEARCH' & 'EXPERIENCE' CONTINUES TO BE A 'LACK' OF 'EMERGENCY' PROTOCAL - AND 'GENERAL' MEASUREMENTS OF 'TOXINS' IN AIR/LAND/SEA... THE 'LACK' OF COMMUNITY ACCESS TO 'MEASUREMENTS OF 'CHEM' IN AIR/LAND/SEA CREATES FEAR. ALSO, A HUGE LACK OF 'HIGHER - EDUCATED' SCIENTIFIC INTERACTION / INVOLVEMENT OF THE PUNA. GEOTHERMAL PLANT IS UN - EXCEPTABLE... THE PLANT LACKS THE PROFESSIONAL EDGE THAT FACILITIES, SUCH AS IN → ICELAND — HAVE EXHIBITED.

I ALSO HAVE GREAT SADNESS @ THE VERY CLEAR AND OBVIOUS LACK OF CONCERN FOR OUR AINA - ITS PRESERVATION, AND ITS CHOICE IN BEING USED AND ABUSED FOR HUMAN EXCESS.

LACK OF ENVIRONMENTAL PROTECTION IS UN - EXCEPTABLE IN AN AGE OF 'WITNESSING' THE RESULTS / EFFECTS OF ALL OUR PREVIOUS ABUSES.

Name: Lance Duncan

Organization (optional):

Email (optional):

Questions/Comments:

Ratepayers in Hawaii county are pulling off the grid as rates increase and the cost of decentralized power is cheaper. In what possible scenario does increasing the fixed costs of the utility (in the form of transmission lines) and adding waste (electrical resistance/impedance) by building an interisland transmission cable and the required plants to power the waste (energy loss of the cable) help us use less energy or provide it more cheaply? This is not wanted and will cause more to leave & costs to rise.

Name: YEN CHIN

Organization (optional): YEN CHIN INVESTIGATIONS

Email (optional): saveenergy5@gmail.com

Questions/Comments:

* YOU SHOULD HAVE CONSIDERED A SCENARIO IN WHICH PETROLEUM SUPPLY BECOMES UNRELIABLE. CONSEQUENTLY, HELCO LOSES ITS ABILITY TO RELIABLY SUPPLY THE EXISTING DEMAND

# Hawaii Electric Light, Pahala, Hawaii

## IRP PUBLIC MEETING
**Wednesday, June 5, 2013**
**Pahala Community Center**
*Notes and Comments*

How much do you anticipate it will lower our costs? What percentage?

What date do I get the information and how long for review?

Wants clarification on Waiau Hydro Plant

Clarification on LNG and biomass, referring to AKP? Where?

Biomass – is algae a cost effective method?
- Kaua`i small scale plant run on algae, were there results?
- Are they doing it here at NELHA?

Where is the plant owned by HELCO located?
- Who does the shipping?
- The chopping?
- Are Kamehameha Schools' eucalyptus trees and option?
- Is there land nearby that could be farmed?

Trash – Hilo landfill is close to plant. It's done on O`ahu.

Unclear wording; would like a less technical explanation. Please explain reliability.

When will the PUC finalize the AKP? *Wants to know the date and where the rebuttals will be held.

*County of Hawaii Docket 2012-0185 AKP2.

So can all parties (County, HELCO…) be able to start the hearings?

Who makes the decision? (Referring to slide on smart meters)

Take a look, the research done on the safety/health concerns on smart meters.

Would this be a solution to the rolling blackouts like in the past?

Jay mentioned someone to Germany.
- Was there a report?
- Can we see it?

Has anyone visited UC San Diego's smart grid system>

With too little load will there ever be a situation where there's FIT or NEM customers who would be drawn from first?
The majority of FIT was in Ocean View. Saturation a fraud, no one else on the island will have a chance to "plug in" to the grid as well.

Concerned about the new meter installed. Did they make a mistake or step back installing the meter? And with the possibility of new meters, will we get another meter?

So if more solar goes up and it goes back to you, will it overload your system or would it actually benefit you?

Jay, you said before you would rather buy the centralized FIT. Is it because you're contracted?

This could cause people to go off the grid completely.

Free energy is on the shelf. Feels like legislation is keeping it from them. Why is it being kept from us, "free energy"?

What she hears is HELCO is ready to do what it needs to do. HELCO is a monopoly. It is like it is your way on no way.

Are you taking into consideration the possible deregulation of this industry?

The solutions: biomass, solar, geothermal

You should look at the cleanest of the options.

So how are you going to energize Ka`u?

Suggest options:

- Geothermal
- Solar panels the cleanest
- Hydro plant

Power for each district's situation. Ka`u could be a good example for the state of Hawaii.

Why don't you use copper for IP communications?

Disruptive process

Seen a lot of technology, cold fusion. We understand the utility company needs to make money. How do we pay for new technology?

What keeps new technology from being no reaction to PUC?

US San Diego produces 90% of power and saves $2 million. Someone on Maui pursuing technology. Hawaii could be the center for this development.

Integrated Resource Planning Public Meeting
June 5, 2013
Pahala Community Center

| NAME | AFFILIATION (optional) | EMAIL ADDRESS (optional) |
|---|---|---|
| EARL LOUIS | Custumer | |
| KERRI MARKS | RATE-PAYER | |
| | | |
| | | |
| | | |
| | | |
| | | |
| | | |
| | | |
| | | |
| | | |
| | | |
| | | |
| | | |
| | | |
| | | |

Integrated Resource Planning Public Meeting
June 5, 2013
Pahala Community Center

| NAME | AFFILIATION (optional) | EMAIL ADDRESS (optional) |
|---|---|---|
| Jeff Ono | Consumer Advocate | jeffrey.t.ono@dcca.hawaii.gov |
| Sara Witt | citizen | SARAwitt12@gmail.com |
| [illegible] | human | |
| David Mattice | PUC | |
| Lukas Mattice | | |
| WILL ROLSTON | COUNTY OF HAWAII | wrolston@co.hawaii.hi.us |
| Julie Neal | The Kau Calendar | mahalo@aloha.net |
| | | |
| | | |
| | | |
| | | |
| | | |
| | | |
| | | |
| | | |
| | | |

Integrated Resource Planning Public Meeting
June 5, 2013
Pahala Community Center

| NAME | AFFILIATION (optional) | EMAIL ADDRESS (optional) |
|---|---|---|
| John Poetzel | Customer | poetzel@yahoo.com |
| | | |
| | | |
| | | |
| | | |
| | | |
| | | |
| | | |
| | | |
| | | |
| | | |
| | | |
| | | |
| | | |
| | | |
| | | |

# Hawaii Electric Light, Kailua-Kona, Hawaii

## IRP PUBLIC MEETING
**Thursday, June 6, 2013**
**King Kamehameha's Kona Beach Hotel**
*Notes and Comments*

Are HELCO's T&D costs larger than HECO and MECO by a factor comparable to rates?

What are HELCO's transmission losses?

Is islanding considered as part of this IRP?

Upgrading of aging equipment needs to consider the environmental impacts.

Does the plan include scenarios of all the various draft action items?

Are those outcomes of the above available to the public?

Is government money used in the implementation of action items used to lower customer costs?

Speaker: Susan Goldon
Action is needed at the highest level (PUC) to control and provide reasonable costs

Speaker: Rou Beckman
Smarts Meters:
- Installed nationally, utility has the power to turn off/ration power
- Health issues from pulse radiation, changes make-up of one's cellular composition
- Smart meters never turn off
- Expressed privacy issues
- It knows what you are doing

Speaker: Will Ralston – (Ralston provided info on where to find docket info at the PUC website)

Speaker: Marnie Herkes
Are we thinking statewide grid?
If Hawaii island sends power to Maui and Oah`u, how does Hawaii island benefit?
Hawaii island has the resources.

How are royalties allocated? How does Hawaii benefit?

How come a customer can choose only HELCO?

Why does government want to fund smart meters?

Please explain the smart grid at Maui which is funded by U.S. government and Japan?

How do you go about negotiating the IPP contracts?
How much energy gets out to the user after you send to it out? Transmission losses?

The feelings about HELCO are negative. Commenter heard about PV system put on large scale farm selling energy back to HELCO. After being cut off they went into stored hydrogen and microgrids. Could you address that or say anything on that?

Were you talking about smart meters?

Commenter is concerned there is a movement all over the country to use smart meters. They give off radiation and cause a health concern.

Likes HELCO and what it does. Doesn't think HELCO lets people know about the fact that HELCO is the leader in this.

Is there anywhere in the action plan that would address this?

Is there a document with all individual plans we can look at and where?

May 30th meeting #9 of the IRP meeting will show preferred plan.

What is preventing us to rent roof space to PV (residents) and storage? It would lower our rates and profits.

What is preventing us from partnering with Kumu Kit?

Have you submitted to the PUC?

We want reliable, safe and secure energy.

We want to have lower rates.

We want to go to wind, solar.

Last meeting shows nothing about how to lower bills. Not in slides.

There is no numeric measurable data.

Acceptable would list ranges (data), benchmarks, percentiles, rates.

Has not seen any quantifiable data in the plan and not acceptable.

Concerned that HEI looks over the companies; they draft plans that have not always been implemented here on Hawaii island.

Speaker: Sarah
PUC wants a statewide approach to plan. Does that mean that the other island if combined, that would lower our costs by sharing or spreading the cost to everyone?

What brand of software are you using or planning to use? Name please.

Assuming HELCO has our best interest, why go after something unproven? Why not team up with Solar City or Kumu Kit? Why aren't you pursuing that? They are running away with the business dollars. Why not? Would it take different regulations or legislation change to do that?

Re: AMI
- Are you getting government money?
- Was MECO's pilot program government money?

Will Ralston replied: Japan/US initiative, $40 million for studies

Integrated Resource Planning Public Meeting
June 6, 2013
King Kamehameha's Kona Beach Hotel

| NAME | AFFILIATION (optional) | EMAIL ADDRESS (optional) |
|---|---|---|
| Dan Purcell | | |
| HAZEL BECK | Hawaii SBDC | hazel.beck@hisbdc.org |
| Will Rolston | County of Hawaii | wrolston@co.hawaii |
| John Bansemer | RE | bansemer@hawaii.rr.com |
| Shane Nelsen | OHA | shanen@oha.org |
| Elizabeth Berger | Customer | berger.elizabeth@gmail.com |
| Merr anne Stone | Resident | mas356@gmail.com |
| Josephine Keliipio | Kona Consumer | j.lilinoe@gmail.com |

Integrated Resource Planning Public Meeting
June 6, 2013
King Kamehameha's Kona Beach Hotel

| NAME | AFFILIATION (optional) | EMAIL ADDRESS (optional) |
|---|---|---|
| Susan Golden | Customer | SSGOLDEN@WEBTV.NET |
| Mychelle Flint | Customer | KRAVFISH@Me.Com |
| Jeff Rich | Customer | JEFF. Rich4e Gmail Com |
| Erin Miller | West Hawaii Today | |
| Ulrich Bonne | Ratepayer | ulrichbonne@msn.com |
| Marni Harker | | marniharker a. gmail.com |
| David Mattice | PUC | |
| Alternate Energy | customer | nohea3@gmail.com |
| R Bucler | Customer | |
| Sara & Daniel Medeiros | Retirees (HECO/HELCO) | medeiros@aloha.net |
| Hush Baker | | hush@hdbaker.con |
| | | |
| | | |
| | | |
| | | |
| | | |

HELCO IRP 2013, Public Hearing, PUC Docket 2012-0036
Kamehameha Hotel, Kailua-Kona, Hawaii, 6 June 2013

**Title: Secure 20 ¢/kWh for 30 years for all, via roof PV with on-site storage**
**To:** HELCO and PUC and to hawaii.puc@hawaii.gov
**From:** Ulrich Bonne, representing myself (Chemical Physicist, retired, Kailua-Kona, Hawaii)
ulrich.bonne@msn.com, http://AlohaFuels.pbworks.com, 808-324-0108

**Questions to HELCO:**

1. What is preventing you from offering to rent roof-space on any willing home or business, to finance, install and maintain solar PVs (preferably **with on-site storage**), so that you can offer electricity rates below 20 ¢/kWh to the landlords, use the surplus low-cost electricity to reduce the rate to all ratepayers, and make a profit to boot -- as you did (with partners) at the West Hawaii Civic Center?
2. What is preventing you from partnering with "solar utilities" such as SolarCity, KumuKit, and P.A.Harris to accomplish some aspects of the above and move towards 20 ¢/kWh or less for all ratepayers?
3. Not having seen any electricity price (i.e. ¢/kWh, as a measure of utility performance) milestones or benchmarks in your draft 2013 5-year IRP report -- have you proposed any such milestones to the PUC, but which were omitted in your published IRP?

**Comments to HELCO regarding draft 2013 IRP[1]:**
I believe that we can all agree on the following goals:

- Secure reliable, affordable and uninterruptible electric energy for homes, businesses and transportation;
- Secure 30-year levelized electricity rates at less than half of today's rates;
- Eliminate the need for electricity generation via combustion of imported oil or LNG or bio-fuel, and their associated remediation costs due to air pollution, health impairments, global warming and ocean acidification and
- Eliminate the need for <u>more</u> central geothermal, wind farms PV farms or inter-island cable

Some of the above are reflected in your draft 2013 IRP report, but none of your four slides on how to "Lower Customer Bills" commit to one or more <u>numeric</u> low-cost electricity goals or milestones, as you complete the listed actions. Without such data I find the IRP unacceptable, as it surely would flunk in any business school test. Why not expand into predictable & distributed solar, as suggested before[2]?

An acceptable plan, in my view, would not only list the uncertainty factors, but also quantify the corresponding consequences in terms of estimated achievable electricity rates or range thereof. It would compare HELCO's present & planned performance with published benchmarks, e.g. NREL.[3]

[1] Draft Action Plans Integrated Resource Planning (IRP) 2013, Hawaiian Electric Companies (Hawaiian Electric, Maui Electric, Hawaii Electric Light Company), IRP Advisory Group Meeting #10 May 30, 2013, **Hawaii Electric Light Company Draft Action Plan,** www.IRPIE.com, https://docs.google.com/file/d/0BxvCvKr8bi94SHo4dFg3UXRzT1k/edit
[2] U. Bonne, "Request HELCO study a plan for support of **many small, individual PV + battery back-up systems**," Public's inputs to HELCO's 2013 IRP (PUC Docket 2012-0036), 5 Dec. 2012, http://dms.puc.hawaii.gov/dms/OpenDocServlet?RT=&document_id=91+3+ICM4+LSDB15+PC_DocketReport59+26+A1001001A12L06B20857F2108318+A12L06B20857F210831+14+1960
[3] NREL, "2012 Utility Green Power Leaders in terms of top MWh sales in 2012," 5 June 2013, http://www.nrel.gov/news/press/2013/2211.html

**HAWAII ELECTRIC LIGHT COMPANY**

**DRAFT ACTION PLAN for IRP 2013**

LOWER CUSTOMER BILLS

1) Deactivate/Decommission Generation
   a) Decommission Shipman 3 and Shipman 4
   b) Deactivate/Decommission additional units as peak load decreases
   c) Potential reactivation for emergencies and/or generation shortfalls
2) Lower Cost Generating Facilities
   a) Complete Geothermal RFP
   b) Repower Waiau Hydro units
   c) Evaluate Waste-to-Energy solutions
   d) Re-negotiate existing IPP contracts
3) Replace Oil with Biomass and/or LNG
   a) Evaluate biomass conversion of Puna boiler
   b) Evaluate LNG feasibility
      i) ISO containers from mainland for short-term
      ii) From bulk facility on Oahu for long-term
4) Other
   a) Develop & deploy additional Demand Response
      i) Allows for the turning off or on of loads for system operational benefits

**CLEAN ENERGY FUTURE**

5) Meet or Exceed Renewable Portfolio Standards (40% Renewable Energy by 2040)
   a) Implement approved Renewable Standards Working Group (RSWG) actions
   b) Support potential export of renewable energy from Hawaii Island to other islands
      i) Evaluate potential for geothermal export

        ii) Evaluate grid tie to other islands

    c) Biodiesel conversion of Keahole Combined Cycle - AKP biofuels pending PUC approval

6) Improve Grid Operations

    a) Transmission Line Improvements: 6200, 6800, 3300, 3400 lines

    b) T&D upgrades to address load flow and voltage constraints

    c) Deploy AMI island-wide by 2018 with opt-out provisions

    d) Upgrade telecom infrastructure to facilitate AMI

    e) Upgrade aging equipment

    f) Continue to evaluate and pursue energy storage

**FAIRNESS**

7) Address Issues with Existing Distributed Generation Programs

    a) Standardize interconnection process and practices

    b) Study, develop, and implement technical solutions for high penetration of distributed generation

    c) Review policies, legislation, and rules for best interests of <u>all</u> customers

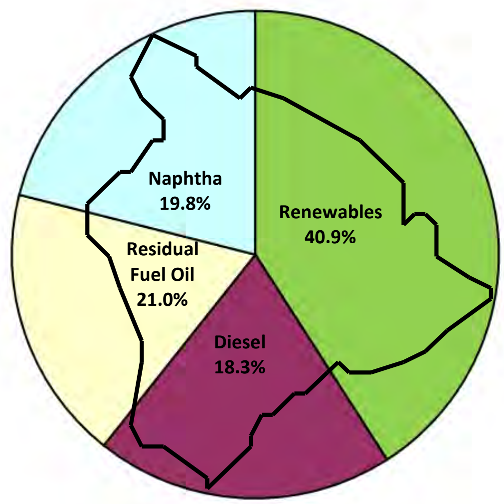
# HAWAII ELECTRIC LIGHT COMPANY, INC.
# ENERGY RESOURCES

ELECTRICITY provided by HELCO to its customers on the Big Island is produced from renewable and non-renewable energy sources. Renewables, which mean they can be replenished, are energy sources from nature such as solar, wind, hydro (water), biomass (plants), and geothermal (heat and steam from deep in the earth). Non-renewable energy resources, such as fossil fuels (oil and coal), cannot be replenished. Of the electricity provided to customers by HELCO in 2012, HELCO-owned generation produced 41.8% of the electricity while 58.2% was purchased from independent power producers (IPPs).

Renewable energy resources supplied approximately 40.9% of the Big Island's electricity generation needs in 2012 compared to 36.7% in 2011. Many renewable resources are affected by daily as well as seasonal changes. In the case of wind, these changes can occur instantaneously and fluctuate often. HELCO is a world leader in the amount and mix of renewable energy resources used and is working to increase this amount while taking into account reliability, cost, technology, and system constraints.

## ELECTRICITY PRODUCTION

## 2012




GEOTHERMAL supplied 22.8% of the electricity produced in 2012 compared to 19.6% in 2011. Puna Geothermal Venture (PGV), with an output capability of 34.6 MW is located in the lower Puna district.

HYDROELECTRIC supplied 4.9% compared to 3.8% in 2011. HELCO's Puueo and Waiau hydroelectric plants and the Wailuku River Hydroelectric Power Company's plant are all located on the Wailuku River near Hilo.

WIND supplied 13.2% compared to 13.3% in 2011. In 2006, HELCO began purchasing wind from Hawi Renewable Development's 10.6 MW wind farm located at Upolu Point in North Kohala and in early 2007, HELCO began purchasing wind power from the Pakini Nui 21 MW wind farm located at South Point. The Pakini Nui wind farm replaces the Apollo Energy Corporations wind farm which was decommissioned in August 2006.

SOLAR ENERGY increasingly benefits thousands of Big Island customers by providing electrical power through customer sited small-scale photovoltaic (PV) systems, and by reducing electrical loads through solar water heating. Photovoltaic installations by non-utility generators provided over 24 MW in 2012 of load reducing power compared to 13 MW in 2011 and 9 MW in 2010. HELCO promotes solar technologies through Net Energy Metering (NEM), Feed In Tariff (FIT), and the Sun Power for Schools program.

FOSSIL FUELS supplied 59.1% of the electricity produced in 2012, a decrease of 4.2% compared to 63.3% in 2011. Generation facilities included HELCO's Shipman and Hill Plants in Hilo, Puna Plant in Kea'au, Keahole Plant in Kona, and Waimea Plant in Waimea. In June 2009, HELCO completed an upgrade of the Keahole Plant, improving fuel efficiency and increasing its output to 78 MW. IPPs include Hamakua Energy Partners in Honokaa.

*Updated: 2/19/2013*

**HAWAII ELECTRIC LIGHT COMPANY, INC.**
**2012**
**ELECTRICITY PRODUCTION & PURCHASED POWER SUMMARY**

| RESOURCE | NET KWH/YR | % OF TOTAL | APPROXIMATE OUTPUT CAPABILITY (MW) * | |
|---|---|---|---|---|
| **HELCO Diesel Generation (Firm**)** | | | | |
| Waimea | 1,108,720 | | 7.50 | 3 units |
| Keahole | 2,090,880 | | 7.50 | 3 units |
| Keahole CT-2 | 628,410 | | 13.80 | |
| Keahole CT-4 | 88,296,840 | | 56.25 | (CT-4, CT-5, ST-7) |
| Keahole CT-5 | 75,898,080 | | | |
| Keahole ST-7 | 42,658,804 | | | |
| Kanoelehua | 369,310 | | 9.50 | 4 units |
| Kanoelehua CT-1 | 33,485 | | 11.50 | |
| Puna CT-3 | 2,567,740 | | 21.00 | |
| Dispersed Gen Sites | 51,550 | | 4.00 | 4 units |
| **TOTAL DIESEL** | **213,703,819** | **18.26%** | **131.05** | |
| **HELCO Steam Generation (Firm**)** | | | | |
| Shipman | 560,900 | | 14.40 | 2 units |
| Hill | 173,984,840 | | 33.70 | 2 units |
| Puna | 71,800,960 | | 15.70 | |
| **TOTAL STEAM** | **246,346,700** | **21.05%** | **63.80** | |
| **HELCO Hydropower (As-Available***)** | | | | |
| Waiau | 7,929,610 | | 1.10 | 2 units |
| Puueo | 21,010,460 | | 3.00 | 2 units |
| **TOTAL HYDROPOWER** | **28,940,070** | **2.47%** | **4.10** | * |
| **HELCO Wind (As-Available***)** | | | | |
| Lalamilo - Decommissioned 201C | 0 | | | |
| **TOTAL WIND** | **0** | **0.00%** | **0.00** | * |
| **TOTAL HELCO RESOURCES:** | **488,990,589** | **41.78%** | **198.95** | |
| **PURCHASE POWER (Firm**)** | | | | |
| Hamakua Energy Partners | 231,570,377 | | | |
| **TOTAL NAPTHA** | **231,570,377** | **19.79%** | **60.00** | |
| Puna Geothermal Venture | 266,234,200 | | | |
| **TOTAL GEOTHERMAL** | **266,234,200** | **22.75%** | **34.60** | |
| **PURCHASE POWER (As-Available***)** | | | | |
| Wailuku | 26,798,694 | | 12.10 | 2 units |
| Other Hydropower | 1,874,585 | | 0.30 | |
| **TOTAL HYDROPOWER** | **28,673,279** | **2.45%** | **12.40** | * |
| Pakini Nui (Kamaoa) | 111,902,578 | | 20.50 | 14 units |
| Hawi Renewable Development | 42,785,359 | | 10.56 | 16 units |
| Other Wind | 0 | | 0.00 | |
| **TOTAL WIND** | **154,687,937** | **13.22%** | **31.06** | * |
| Keahole Solar Power | 31,206 | | | |
| **TOTAL SOLAR POWER** | **31,206** | **0.00%** | **0.50** | * (100 kW currently installed) |
| **TOTAL Feed-In Tariff** | **213,400** | **0.02%** | **0.34** | |
| **TOTAL PURCHASED POWER:** | **681,410,399** | **58.22%** | **129.50** | |
| TOTAL ENERGY DELIVERED TO SYSTEM (2012): | 1,170,400,988 KWH | 100.00% | | |
| **FIRM RESOURCES OUTPUT CAPABILITY (including geothermal)** | | | **289.45** | **MW** |
| **AS-AVAILABLE RESOURCES OUTPUT CAPABILITY:** | | | **48.06** | **MW*** |

* Actual output varies depending on availability of as-available resources, and maintenance and operation status of all power plants. It is based on full operation of all generators originally installed at the site

** Firm resources are available 24 hours per day except when maintenance or repair operations are taking place

*** As-available resources produce electricity as the resource (i.e. wind, stream flow) is available

## Hawaiian Electric Light, Public Presentation

6/25/13



1

6/25/13

3

## The Goal of IRP

"The goal of integrated resource planning is to develop an **Action Plan** that governs how the utility will **meet energy objectives and customer energy needs consistent with state energy policies and goals**, while providing **safe and reliable utility service at reasonable cost**, through the development of **Resource Plans and Scenarios of possible futures** that provide a **broader long-term perspective**."

Reference: Docket No. 2009-0108, Decision and Order, A Framework for Integrated Resource Planning, Revised March 14, 2011, Section II.A, page 2

## Definition of Scenarios

"Scenarios means a **manageable range of possible future circumstances** or set of possible circumstances reflecting potential energy-related policy choices, **uncertain circumstances**, and **risks facing the utility and its customers**, which will be the **basis for the plans analyzed**. A Scenario may not consist of a particular project."

Reference: Reference Docket No. 2009-0108, D&O, A Framework for IRP, Revised March 14, 2011, Section I, page 1

2

6/25/13

5

## Definition of Resource Plan

"Resource Plan means a **set of resources, programs, or actions** over the twenty (20) year planning horizon **resulting from the analyses performed for the Scenarios** developed during the integrated resource planning process governed by this framework."

Reference: Reference Docket No. 2009-0108, D&O, A Framework for IRP, Revised March 14, 2011, Section I, page 1

6

## IRP 2013 Process Schedule

- IRP process for the 2013 filing started on March 1, 2012.
- Two public input opportunities:
  1. November 27 to December 13: Open comments related to the IRP process to date
  2. ~April/May 2013: Comments and input related to draft plan for action
- The Hawaiian Electric Companies must file the IRP with the Public Utilities Commission by June 29, 2013.

3

6/25/13

7

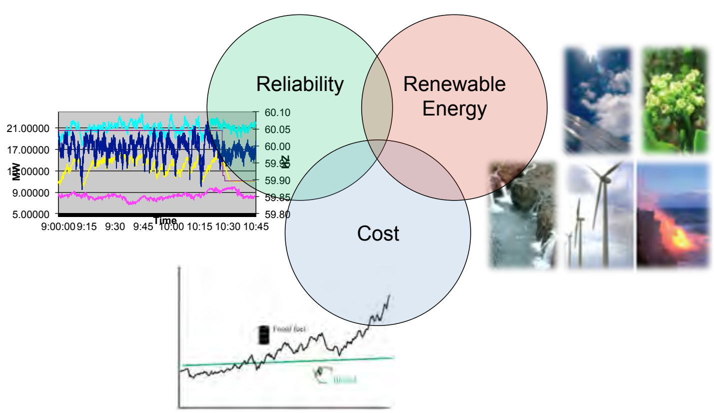
## IRP 2013 Objectives

**Developed in conjunction with the Advisory Group**
**in no particular order**

1. Protect Hawaii's culture and communities
2. Protect Hawaii's environment
3. Reduce dependency on imported fossil fuels and improve price stability
4. Provide electricity at a reasonable cost
5. Increase the use of indigenous energy resources
6. Provide reliable service
7. Improve operating flexibility

8

## A Balancing Act




4

6/25/13

9

## Scenario Planning

- Developing 20-year plans across multiple future possibilities
- Test plans for robustness and resiliency against uncertain future
- Develop an "Action Plan" that considers all scenarios and plans evaluated

10

## IRP 2013 Scenarios

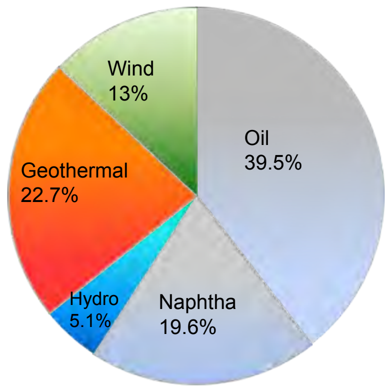
1. "Blazing a bold frontier" – high oil prices / aggressive clean energy goals
2. "Stuck in the middle" – elevated oil prices / middle of road clean energy goals
3. "No burning desire" – reduced oil prices / reduced clean energy goals
4. "Moved by passion" – elevated oil prices / aggressive clean energy goals

5

11

## YTD 2012 HELCO Resource Mix

41% RENEWABLE ENERGY
NEM ~2,900 systems, 16.7 MW

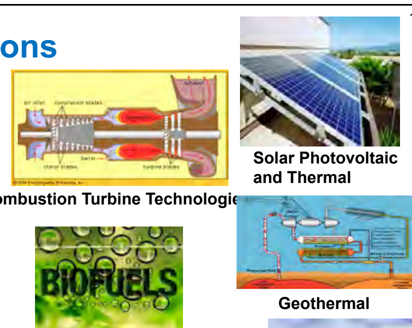


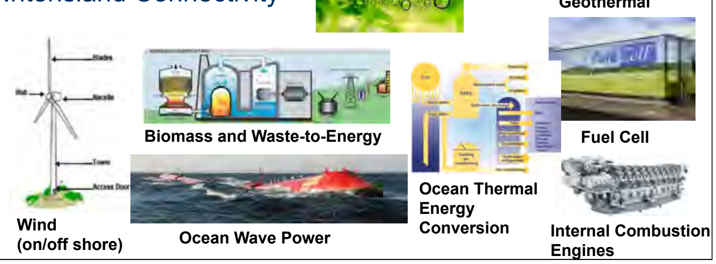

Source: Oct 2012, HELCO Generation Report

12

## IRP Resource Options

- Energy Efficiency
- Replace Existing Fossil Fuel Generating Plants
- Demand Response
- Energy Storage
- Interisland Connectivity



6/25/13


7

## Maui Electric, Kahului, Maui

Integrated Resource Planning Public Meeting
6PM - 8PM Thursday, June 13, 2013
Pomaikai Elementary, Kahului
Hawaii Public Utilities Commission Docket No. 2012-0036

| Name | Email (Optional) | Organization (Optional) |
|---|---|---|
| | | |
| Christian Hackett | | Pattern |
| Warren Shibuya | ob1Shibuya@hawaiiantel.net | self |
| Donald Mahoe JR | donaldmahoe@hotmail.com | Self |
| SEBASTIAN J. NOLA | BASHNOLA@AOL.COM | SELF |
| Gladys Baisa | | Cty |
| Eileen Chao | echao@mauinews.com | NEWS |
| LEILANI PULMANO | leilani@mhplanning.com | Munekiyo & Hiraga |
| DICK MAYER | DICKMAYER@EARTHLINK.NET | |
| KAL KOBAYASHI | ON FILE | |
| Anne Kil | anneku@hawaii.edu | UHMC EV |
| JON ITOMURA | jon.s.itomura@dcca.hawaii.gov | Consumer Advocate |
| TIM & BARB BOTKIN | tbbotkin@gmail.com | UH/MC |
| Stephan Jiran | sjiran@firstwind.com | First Wind |
| Tammy Cabral | | MECO |
| Ana Garcia | | MECO |
| Pam Farnsworth | | self |
| Kelly O'Brien | | FirstWind |
| Tom Blackburn-Rodriguez | tom@inmaui@me.com | |
| Ian Chan Hodges | ianch.h@mac.com | |
| TRICIA ROHLFING | | SOUTH MAUI RENEWABLES |
| | | |
| | | |
| | | |
| | | |
| | | |
| | | |
| | | |

ALAN M. ARAKAWA
MAYOR

200 South High Street
Wailuku, Hawai'i 96793-2155
Telephone (808) 270-7855
Fax (808) 270-7870
e-mail: mayors.office@mauicounty.gov

**OFFICE OF THE MAYOR**
Ke'ena O Ka Meia
COUNTY OF MAUI – Kalana O Maui

**TESTIMONY BY**

**MAYOR ALAN ARAKAWA AND COUNCIL CHAIR GLADYS C. BAISA**

**REGARDING MAUI ELECTRIC COMPANY'S IRP REPORT AND ACTION PLANS**

**JUNE 14, 2013**

Aloha to the staff of Maui Electric Company and to those of you here this evening. This testimony is based upon the participation on the IRP Advisory Group by Council Chair Gladys Baisa and the Mayor's representatives: Mr. Doug McLeod, Energy Commissioner, and Mr. Kal Kobayashi, Energy Coordinator.

We agree with the Public Utility Commission's observation in MECO's recent rate case Decision & Order, "that electric customers are increasingly frustrated because of high electric rates." We also share the concerns of the Commission about what appears to be a lack of movement by MECO "to a sustainable business model to address technological advancements and increasing customer expectations."

Like the Commission, we also question whether it's prudent for MECO's ratepayers to pay for the $806,000 budgeted for MECO's IRP expenses. Accordingly, we and other IRP Advisory Group Members have recommended, per a June 12, 2013 letter to Commission Chair Morita, that an initial review be conducted to determine the level and method for IRP expense cost recovery, before initiating a contested case proceeding.

On a more specific level, we also share the Commission's concerns about MECO's reluctance to retire the Kahului Power Plant and the need to eliminate the dumping of unused wind energy that could replace about six percent of MECO's fossil fuel generation load. We urge MECO to close the Kahului Power Plant soon and to implement system improvements, such as energy storage systems and smart grid/demand response systems, to eliminate the curtailment of low cost wind energy.

We also urge MECO to incorporate a long-term, sustainable business model within its IRP Report to address our previously voiced concerns on this matter.

Thank you for the opportunity to offer comments.

Alan Arakawa

ALAN M. ARAKAWA

Mayor, County of Maui

Gladys C. Baisa

GLADYS C. BAISA

Council Chair, County of Maui

Integrated Resource Planning, 13 June 2013
Pomaikai Elementary School, Kahului, Maui

Testimony: Fix FIT Tier 1 compensated and consumed rates not exceeding 5 or 6¢/kwh net price difference for fair and reasonable return on investment and power services and quantify to better manage renewable and grid distributed power.

At the 13 December 2012 IRP public meeting held at this same Pomaikai Elementary School, I asked this body, hoping the PUC fix the net price difference for Feed-in-Tariff (FIT) Tier 1 renewable power providers who are primarily grid power users. The FIT is fixed 20-year agreement, which needs ensuring a fair and reasonable return on investment (FRROI).

I offered a 5 to 6¢ maximum difference over the 20-year FIT agreement. Tier 2 and 3 power providers are power providers, not power users, while the homeowner Tier 1 produces and uses power. The homeowner continues paying rising prevailing rates for power used. The current "one-size fits all" description needs refining Tier 1 FIT provisions or these renewable contributors could stop sharing.

Tier 1 10kw capacity requires FIT homeowners conserve using electricity to ensure a FRROI. FIT power providers cannot expand their PV system to compensate for rate increases. As written, FIT power providers are stuck with diminishing return on investments and increasing risks from aged PV system.

As you know, electric rates increase regularly. A 10kw PV array will reasonably power two homes. The second home may not be able to participate due to site limitations or homeowner choosing not to invest in a renewable power generating system or energy sustain Hawaii.

Unless fixed net price difference is instituted immediately, Tier 1 FIT renewable power contributors will not get FRROI and could stop participating.

The next request is increasing the electric utility's ability to measure and quantify the amount of power and describe amounts of renewable power contributed on each circuit and throughout the grid. Fluctuating power characteristics can be attributed to unpredictable power user behaviors, high capacity air conditioners and less efficient switches in automatic transformer systems. Blaming power changes on the last contributor, renewable power provider, without any real-time circuit and distribution measurements, fails to isolate problem(s) and resolve varying power characteristics.

Example. I noticed an "unusual phenomenon" throughout my home. I talked and confirmed with engineers at MECO and inverter manufacturers, their equipment was providing quality 60-cycle frequency. I bought a frequency meter and isolated a loose intermitting arcing connection in my power box! A certified electrician corrected.

Renewable\\IRP 2012\IRP Pomaikai 13June13.docx

Integrated Resource Planning, 13 June 2013
Pomaikai Elementary School, Kahului, Maui

Without accurate real-time power measurements, how can anyone manage utility and renewable generated power, account each type contributions, including separated utility's meter-determined spinning reserves?

Utility services are reliable and appreciated. Can utility measure, determine and isolate distribution loss and demand? I believe, measuring, discriminating and quantifying various power resources needs attending.

Measure equipment performance on actual load, service profile and amounts of renewable power handled. How does utility measure life or failure risks of automatic switching transformers, besides length of time from installation or temperature of transformer and estimated load?

Mahalo for this opportunity to express my thoughts.

Respectfully,

Warren S. Shibuya
35 Kulamanu Circle
Kula, HI 96790

Renewable\\IRP 2012\IRP Pomaikai 13June13.docx

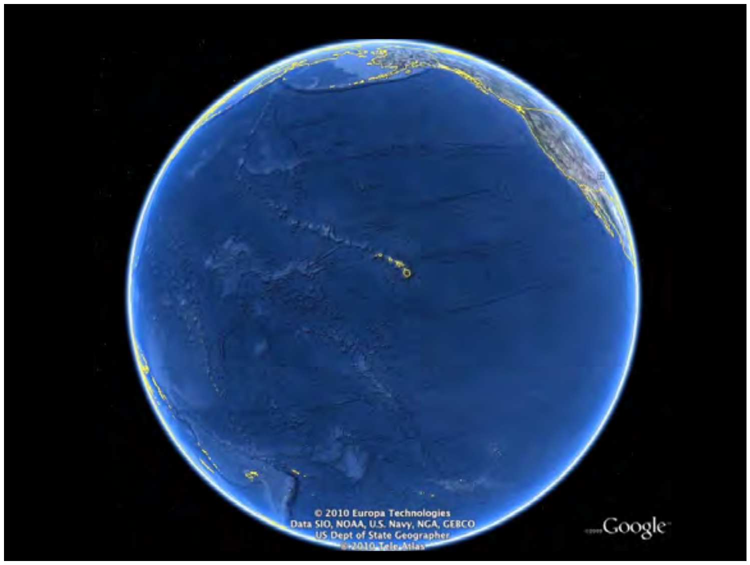
DICK MAYER

- MULTI-ISLAND ALTERNATIVES
- ALTERNATE GENERATORS (WIND, SOLAR, WAVE, OTEC, GEO-THERMAL
- WHEELING
- SMART GRIDS OF MAJOR USERS – NOT EVERY HOME
- $ + EXPECTED PROFIT MARGINS

ACTUAL COSTS TO CONSUMERS ¢/KWH

- INTEGRATE W/ POTENTIAL VEHICLE USE (ELECTRICITY)
- SEPARATION OF GRID FROM GENERATORS
- TIME OF DAY METERING

6/25/2013


© 2010 Europa Technologies
Data SIO, NOAA, U.S. Navy, NGA, GEBCO
US Dept of State Geographer
Google


Maui Electric Company
Draft Action Plan
Integrated Resource Planning 2013
Maui Public Meeting
June 13, 2013
Hawaiian Electric Company
Maui Electric Company
Hawaii Electric Light Company
Google

1

6/25/2013

## IRP Website (IRPIE.com)


Submit comments to [public@irpie.com](mailto:public@irpie.com)

3

## Goal of Integrated Resource Planning (IRP)

- Scenarios of Possible Futures
- Long-term Perspective
- Reliable Power
- Energy Objectives
- Reasonable Cost
- Resource Plans
- Action Plan

Reference: Docket No. 2009-0108, Decision and Order, A Framework for Integrated Resource Planning, Revised March 14, 2011, Section II.A, page 2

4

2

6/25/2013

## What is an action plan?

- Implementation plan and schedule
- Specific actions
- Resource options and programs
- 5 year horizon

5

## IRP 2013 Process Steps

| | |
|---|---|
| PUC initiated the current IRP cycle (Order No. 30233) | March 1, 2012 |
| Independent Entity selected to oversee process | May 1, 2012 |
| Advisory Group (68 members) formed | June 29, 2012 |
| Advisory Group Meetings | July 2012 – May 2013 |
| Public Meetings | December 2012 |
| Public Meetings | June 2013 |
| File the IRP report and Action Plan with the Public Utilities Commission | June 28, 2013 |

6

3

6/25/2013

## An Ongoing Process
## Keeping the Action Plan current

- Process repeated every 3 years
- Evaluation Report
- Action Plan Updates

7

## IRP 2013 Objectives

**Developed in conjunction with the Advisory Group in no particular order**

1. Protect Hawaii's culture and communities
2. Protect Hawaii's environment
3. Reduce dependency on imported fossil fuels and improve price stability
4. Increase the use of indigenous energy resources
5. Provide reliable service
6. Improve operating flexibility
7. Provide electricity at a reasonable cost

8

4

## The Goal of the Public Meetings

- Hear your comments on the draft Action Plan
- Create awareness of the complex and sometimes conflicting objectives

9

10

## Draft Action Plan for Maui

10

6/25/2013

## Overall Flexibility

We have developed an Action Plan that has the **flexibility** to accommodate an uncertain future

11

## Maui Electric Company's Strategic Considerations

- Lower customer bills
- Clean energy future
- Modernize grid
- Fairness

12

6

6/25/2013

## Lower Customer Bills

1. Lower Cost Generating Facilities
   A. Pursue firm generation Request for Proposal (RFP) in conjunction with customer and demand response programs
   B. Continue negotiations with Hawaiian Commercial & Sugar (HC&S)

13

## Lower Customer Bills *(cont.)*

2. Replace Oil with Liquefied Natural Gas (LNG)
   A. Evaluate LNG feasibility
      - From bulk facility on Oahu in 2021


14

6/25/2013

## Lower Customer Bills *(cont.)*

3. Other

   A. Develop & deploy Demand Response (DR) programs

   - Continue implementation of Fast DR Pilot Program
   - On-going evaluation of DR solutions
   - Residential and Commercial pilot programs to begin implementation in 2015



15

## Clean Energy Future

4. Meet or Exceed Renewable Portfolio Standards (RPS)

   A. Implement approved Reliability Standards Working Group (RSWG) actions

   B. Support potential grid tie system with other islands

   C. Work with partners on cost-effective renewable energy projects

16

8

## Modernize Grid

5. Improve Grid Operations
   A. Transmission & Distribution upgrades to address load flow and voltage constraints
      - Transmission line projects
        - MPP-Kamalii 69kV Line and substations in 2018
        - Waiinu-Kanaha 69kV Line in 2018

   B. Deploy Advanced Metering Infrastructure (AMI) island-wide by 2018 with opt-out provisions
   C. Implement conservation voltage reductions
   D. Upgrade telecom infrastructure to facilitate AMI

17

## Modernize Grid (*cont.*)

5. Improve Grid Operations (cont.)
   E. Upgrade aging equipment
   F. Continue to evaluate and pursue energy storage
      - Implement solution by end of 2017 if cost-effective

18

6/25/2013

## Modernize Grid *(cont.)*

6. Decommission Generation
   A. Kahului Power Plant in 2019

      Requires:
      - Completion of the Waiinu-Kanaha 69 kV line
      - Acquisition of replacement capacity through evaluation of:
        - Demand Response
        - Capacity value for wind
        - Energy Storage
        - Generation

   B. Evaluate Maalaea units 4 through 9 in 2022 for NAAQS compliance

      Requires:
      - Acquisition of replacement capacity as above

19

## Fairness

7. Address Issues with Existing Distributed Generation Programs
   A. Standardize interconnection process and practices
   B. Study, develop, and implement technical solutions for high penetration of distributed generation
   C. Review policies, legislation, and rules for best interests of all customers

20

10

6/25/2013

21


11

## Maui Electric, Kaunakakai, Molokai

Integrated Resource Planning Public Meeting
6PM - 8PM Wednesday, June 19, 2013
Mitchell Pauole Community Center, Kaunakakai
Hawaii Public Utilities Commission Docket No. 2012-0036

| Name | Email (Optional) | Organization (Optional) |
|---|---|---|
| C. Hirayama | chiki.hirayama@gmail.com | |
| David Kangas | bi2601200S@yahoo.com | |
| Rita Woods | rita.awoods@yahoo.com | IAM |
| [illegible] | emillia@pacificrr.com | Sustainable Molokai |
| Larry + Joann Tool | toolohana@hawaiiantel.net | IAM |
| Kimo McPherson | mcpherson.kimo@ | |
| " " | G.MAIL.com | I AM |
| M/M Cappy Capping | | |
| Emily Summers | | Molokai Dispatch (news) |
| Yvonne Eikhart | | |
| Keri Zacher | zacherk@hotmail.com | |
| Elaine Callinan | callinan.elaine@gmail | IAM |
| Sue Hoggins | | molokai |
| Teodora Madela | | |
| Jon Itomura | | Consumer Advocate |
| Lori Buchanan | lbuchanan@tnc.org | |
| Harmonee Williams | harmoneew@gmail.com | |
| Clare Gupta | claregupta@gmail.com | |
| Teri Waros | | IAM |
| Artice Swingle | | IAM |
| John Wordin | wordinjj@gmail.com | IAM |
| Kathie Flynn | | I AM |
| Megan Sanford | | |
| Walter Ritte | rittew@hotmail | |
| Carla Hanchett | critter@glcc.org | Resident etc |
| Lehua CH | | Resident |
| Kanoho/Lindy Helm | anahakirecords@gmail.com | IAM |
| Michael Rogan | | |
| Lindy Helm | - | IAM |

Name: Kanohowailuku & Lindy Helm

Organization (optional): IAM

Email (optional): anahakirecords@gmail.com

Questions/Comments

IAM continues to work hard in looking for energy solutions for Molokai & want to be an example for the rest of the world. We'd like to thank Matt McNeff, Stephen Rimshaw, Sharon Suzuki & MECO for being apart of the Molokai Clean energy initiative. We believe its the 1st step in bottom up planning. IAM continues to advocate and support Lanai as well; and no undersea cable! We believe there are better options and we continue to advocate for bottom up planning. Thank you!

Name: Keri Zacher

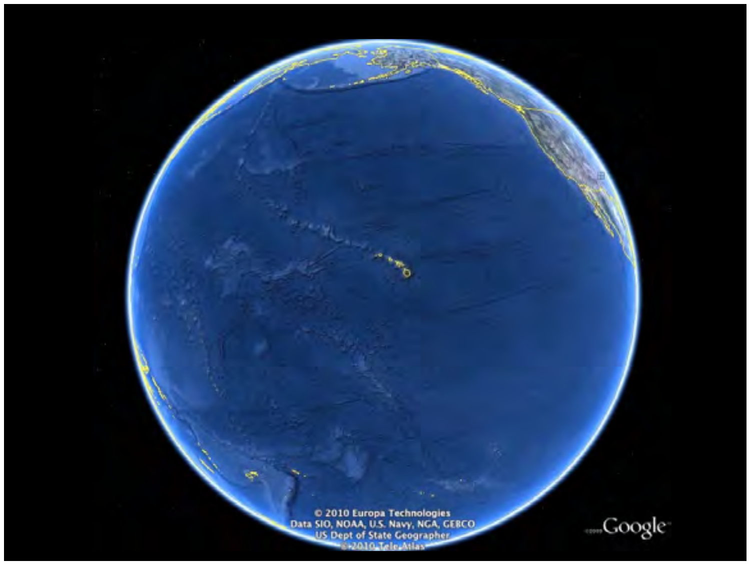
Organization (optional):

Email (optional): zacherk@hotmail.com

Questions/Comments

It's been said, but not yet heard.
It's an insult to claim an action plan without concrete information. How can you expect us to say okay. We want an honest solution and are willing to work to find one, but all that happened with a year's efforts from the advisory group is a waste of their time.

6/25/2013


© 2010 Europa Technologies
Data SIO, NOAA, U.S. Navy, NGA, GEBCO
US Dept of State Geographer
Google


Maui Electric Company
Draft Action Plan
Integrated Resource Planning 2013
Molokai Public Meeting
June 19, 2013
Hawaiian Electric Company
Maui Electric Company
Hawaii Electric Light Company
Google

1

6/25/2013

## IRP Website (IRPIE.com)


Submit comments to public@irpie.com

3

## Goal of Integrated Resource Planning (IRP)

- Scenarios of Possible Futures
- Long-term Perspective
- Reliable Power
- Energy Objectives
- Reasonable Cost
- Resource Plans
- Action Plan

Reference: Docket No. 2009-0108, Decision and Order, A Framework for Integrated Resource Planning, Revised March 14, 2011, Section II.A, page 2

4

2

6/25/2013

## What is an action plan?

- Implementation plan and schedule
- Specific actions
- Resource options and programs
- 5 year horizon

5

## IRP 2013 Process Steps

| | |
|---|---|
| PUC initiated the current IRP cycle (Order No. 30233) | March 1, 2012 |
| Independent Entity selected to oversee process | May 1, 2012 |
| Advisory Group (68 members) formed | June 29, 2012 |
| Advisory Group Meetings | July 2012 – May 2013 |
| Public Meetings | December 2012 |
| Public Meetings | June 2013 |
| File the IRP report and Action Plan with the Public Utilities Commission | June 28, 2013 |

6

3

6/25/2013

## An Ongoing Process
## Keeping the Action Plan current

- Process repeated every 3 years
- Evaluation Report
- Action Plan Updates

7

## IRP 2013 Objectives

**Developed in conjunction with the Advisory Group in no particular order**

1. Protect Hawaii's culture and communities
2. Protect Hawaii's environment
3. Reduce dependency on imported fossil fuels and improve price stability
4. Increase the use of indigenous energy resources
5. Provide reliable service
6. Improve operating flexibility
7. Provide electricity at a reasonable cost

8

4

## The Goal of the Public Meetings

- Hear your comments on the draft Action Plan
- Create awareness of the complex and sometimes conflicting objectives

9



## Draft Action Plan for Molokai

10

## Overall Flexibility

We have developed an Action Plan that has the **flexibility** to accommodate an uncertain future

11

## Maui Electric Company's Strategic Considerations

- Lower customer bills
- Clean energy future
- Modernize grid
- Fairness

12

6/25/2013

## Lower Customer Bills

1. Replace Oil with Liquefied Natural Gas (LNG)
   A. Evaluate LNG feasibility
      - From the mainland starting in 2018
      - From bulk facility on Oahu in 2021


13

## Clean Energy Future

2. Meet or Exceed Renewable Portfolio Standards (RPS)
   A. Assess utility-scale PV and biomass as potential generation resources in 2014
   B. Work with partners on cost-effective renewable energy projects

14

6/25/2013

## Modernize Grid

3. Improve Grid Operations
   - A. Transmission & Distribution upgrades to address load flow and voltage constraints
   - B. Deploy Advanced Metering Infrastructure (AMI) island-wide by 2018 with opt-out provisions
   - C. Upgrade telecom infrastructure to facilitate AMI starting in 2017
   - D. Upgrade aging equipment

15

## Modernize Grid *(cont.)*

3. Improve Grid Operations (cont.)
   - E. Continue to evaluate and pursue energy storage

16

8

6/25/2013

## Fairness

4. Address Issues with Existing Distributed Generation Programs
   - A. Standardize interconnection process and practices
   - B. Study, develop, and implement technical solutions for high penetration of distributed generation
   - C. Review policies, legislation, and rules for best interests of all customers

17

18

9

6/25/2013


10

## Maui Electric, Lanai City, Lanai

Integrated Resource Planning Public Meeting
5PM - 7PM Thursday, June 20, 2013
Hale Kupuna, Lanai City
Hawaii Public Utilities Commission Docket No. 2012-0036

| Name | Email (Optional) | Organization (Optional) |
|---|---|---|
| Jeff Ono | jeffrey.t.ono@dcca.hawaii.gov. | Consumer Advocate |
| Ron McOmber | RANDPMCOMBER@GMAIL.COM | RESIDENT |
| Diane Preza | preza@sandwichisles.net | resident |
| Debbie dela Cruz | yookom@gmail.com | " |
| Donna Schaumburg | | Resident |
| John Min | john.min@mauicounty.us. | Office of Councilmember Hokama |
| [illegible] | | |
| [illegible] SCHAUMBURG | schaumlny@gmail.com | RESIDENT |
| WARREN OSAKO | wosako@hawaiiantel.net | RESIDENT |
| Pat Reilly | kimchi745@gmail.com | " |
| Butch Gima | BG325@HOTMAIL.COM | " |
| Sally Kaye | SKAYE@RUNBOX.COM | FOL/IRP-AG |
| Mary Ellen Catiel | mcatiel@yahoo.com | Resident |
| Lorry Cornish | lorrycornish@hotmail.com | Retired Resident |
| Kathy Brindo | Kbrindo@hotmail.com | Resident-Teacher |
| Alberta deJetley | lanaitoday@yahoo.com | Lanai Today |
| Pierce Myers | piercem.myers@gmail.com | Resident |
| Sharah Myers | sharahkm@hawaii.edu | resident |
| Sunee Washom | cwashom@gmail | |
| emma grager | emmagrager@gmail | |
| [illegible] | | RES |
| JOHN ORNELLAS | JOHNORNELLAS@HOTMAIL.COM | |
| John dela Cruz | delacruz[illegible]@gmail.com | |
| [illegible] Catiel | [illegible] | Kupu o Lanai |
| Kaulana Kahoohalahala | Kahohalahala@gmail.com | Kupaa no Lanai |
| Roselani Kahoohalahala | K.mehana@gmail.com | Kūpa'a no Lāna'i |
| Kay Okamoto | Okamoto Realty@gmail.com | |
| Jessie Myers | jessiefmyers@gmail | personal |
| Donna Stokes | lanaiohana@hotmail.com | |

Integrated Resource Planning Public Meeting
5PM - 7PM Thursday, June 20, 2013
Hale Kupuna, Lanai City
Hawaii Public Utilities Commission Docket No. 2012-0036

| Name | Email (Optional) | Organization (Optional) |
|---|---|---|
| L. Castillo | lcticia@hawaiiantel.net | |
| B. Washom | sustainablelanai@gmail.com | |

**COUNTY COUNCIL**
COUNTY OF MAUI
200 S. HIGH STREET
WAILUKU, MAUI, HAWAII 96793
www.mauicounty.gov/council

June 19, 2013

Ms. Sharon Suzuki, CEO
Maui Electric Company, Ltd.
210 W. Kamehameha Avenue
Kahului, Hawaii 96732

Dear Ms. Suzuki:

SUBJECT: MECO Integrated Resource Planning (IRP) and Draft Action Plans Public Meeting of June 20, 2013 at Hale Kupuna, Lanai City, Lanai

Thank you for the opportunity to present comments on the MECO IRP and Draft Action Plan and to hear first-hand from Lanai residents on energy planning for the future. As you know, the Lanai community has been actively engaged in discussions and hearings related to the "Hawaii Interisland Renewable Energy Program—Wind" or "Big Wind" project.

As the Lanai member on the Maui County Council, I'd like to share my perspective for your consideration:

- Currently, a Citizen Advisory Committee of Lanai residents is assisting the County Planning Department in the update of the Lanai Community Plan. This 20-year plan sets forth goals, objectives and policies related to land use, the environment, the economy, social services, public services and infrastructure, cultural resources, energy and conservation, and other areas of community interest. I hope that the IRP and action plans will be sufficiently flexible to accommodate the goals, objectives and policies in the Lanai Community Plan. This plan update will eventually be reviewed and adopted into law by the Maui County Council.

- The IRP and action plans should promote expanded use of photovoltaic (PV) systems on Lanai, including implementing technical solutions and reducing obstacles for high penetration of distributed generation. For example, I understand that it may cost a residential customer interested in installing a PV system about $3,000 for an interconnection study, if this requirement is triggered by usage. The costs for businesses

June 19, 2013
Page 2

are much higher. These studies can be cost prohibitive and an obstacle to expanding PV usage on the island.

- As Chair of the Council's Policy and Intergovernmental Affairs Committee, I've introduced a resolution <u>in opposition</u> to the Big Wind Lanai project. In my view, the Big Wind project is <u>not</u> a viable alternative, in terms of community benefits, protection of the environment and cultural resources, and maintaining the rural character of the island. I'll wait for MECO's submittal of the final island action plan due on June 28, 2013, before making a decision to schedule this resolution for committee review.

In closing, thank you again for this opportunity to comment on the IRP and action plans.

Sincerely,

Riki Hokama

RIKI HOKAMA
Council Member

cc: Gladys, Baisa, Chair, Maui County Council

Name: Jason Gill

Organization (optional): Kupa'a no Lānā'i

Email (optional): jgill565@gmail.com

Questions/Comments

I do not support windmills on Lānā'i. It's not fair for residents of Lānā'i. We shouldn't have to sacrifice our cultural and natural resources just so Oahu can use more, and meet it's increasing demand for energy.

Name: KPK

Organization (optional):

Email (optional):

Questions/Comments

NO TO BIG WIND ON Lanai. all the people on Lanai
gotta give up all ther natural historical and cultural resources
for what OAHU.
I will fight against Big wind till
its GONE HECO, PUC

Name: Roselani Kaho'ohalahala

Organization (optional): 

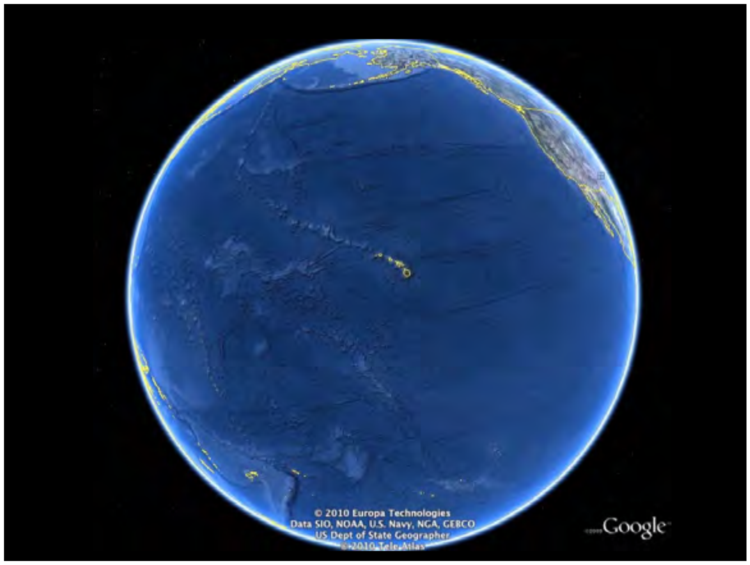
Email (optional): 

Questions/Comments

Smart meters = radiation, How much radiation?

"No way!" to Big wind on Lāna'i! It will negatively impact my life! It will decrease the quality of living. I will be extremely depressed if Big Wind happens. No to the desecration of Lāna'i and all of the archaeological sites. No undersea cable! Keep it out of the humpback whale sanctuary.

6/25/2013


© 2010 Europa Technologies
Data SIO, NOAA, U.S. Navy, NGA, GEBCO
US Dept of State Geographer
© 2010 Tele Atlas
Google


Maui Electric Company
Draft Action Plan Summary
Integrated Resource Planning 2013
Lanai Public Meeting
June 20, 2013
Hawaiian Electric Company
Maui Electric Company
Hawaii Electric Light Company
Google

1

## IRP Website (IRPIE.com)


Submit comments to public@irpie.com

3

## Goal of Integrated Resource Planning (IRP)

- Scenarios of Possible Futures
- Long-term Perspective
- Reliable Power
- Energy Objectives
- Reasonable Cost
- Resource Plans
- Action Plan

Reference: Docket No. 2009-0108, Decision and Order, A Framework for Integrated Resource Planning, Revised March 14, 2011, Section II.A, page 2

4

## What is an action plan?

- Implementation plan and schedule
- Specific actions
- Resource options and programs
- 5 year horizon

5

## IRP 2013 Process Steps

| | |
|---|---|
| PUC initiated the current IRP cycle (Order No. 30233) | March 1, 2012 |
| Independent Entity selected to oversee process | May 1, 2012 |
| Advisory Group (68 members) formed | June 29, 2012 |
| Advisory Group Meetings | July 2012 – May 2013 |
| Public Meetings | December 2012 |
| Public Meetings | June 2013 |
| File the IRP report and Action Plan with the Public Utilities Commission | June 28, 2013 |

6

6/25/2013

## An Ongoing Process
## Keeping the Action Plan current

- Process repeated every 3 years
- Evaluation Report
- Action Plan Updates

7

## IRP 2013 Objectives

**Developed in conjunction with the Advisory Group in no particular order**

1. Protect Hawaii's culture and communities
2. Protect Hawaii's environment
3. Reduce dependency on imported fossil fuels and improve price stability
4. Increase the use of indigenous energy resources
5. Provide reliable service
6. Improve operating flexibility
7. Provide electricity at a reasonable cost

8

4

## The Goal of the Public Meetings

- Hear your comments on the draft Action Plan
- Create awareness of the complex and sometimes conflicting objectives

9

10

## Draft Action Plan Summary for Lanai

10

## Overall Flexibility

We have developed an Action Plan that has the **flexibility** to accommodate an uncertain future

11

## Maui Electric Company's Strategic Considerations

- Lower customer bills
- Clean energy future
- Modernize grid
- Fairness

12

6/25/2013

## Lower Customer Bills

1. Replace Oil with Liquefied Natural Gas (LNG)
   A. Evaluate LNG feasibility
      - From the mainland starting in 2018
      - From bulk facility on Oahu in 2021


13

## Clean Energy Future

2. Meet or Exceed Renewable Portfolio Standards (RPS)
   A. Assess utility-scale PV and biomass as potential generation resources starting in 2014
   B. Work with partners on cost-effective renewable energy projects

14

7

## Modernize Grid

3. Improve Grid Operations
   A. Distribution upgrades to address load flow and voltage constraints
   B. Deploy Advanced Metering Infrastructure (AMI) island-wide by 2018 with opt-out provisions
   C. Upgrade telecom infrastructure to facilitate AMI starting in 2017
   D. Upgrade aging equipment

15

## Modernize Grid *(cont.)*

3. Improve Grid Operations (cont.)
   E. Continue to evaluate and pursue energy storage

16

6/25/2013

## Fairness

4. Address Issues with Existing Distributed Generation Programs
   - A. Standardize interconnection process and practices
   - B. Study, develop, and implement technical solutions for high penetration of distributed generation
   - C. Review policies, legislation, and rules for best interests of all customers

17

18

9

6/25/2013

## Lanai Wind

- What is in the Hawaiian Electric Action Plan?
  - Subject to PUC direction, proceed with Request for Proposals for Renewable Energy Delivered to Oahu and Undersea Cable
  - Power Purchase Agreement discussion with Castle & Cooke per 2010 PUC Waiver Order and 2011 Term Sheet
- Lanai Wind project depends on outcome of RFP, outcome of PPA negotiations, PUC approvals, permits, etc.

## RFP and PPA History and Status

- 2008 Hawaiian Electric RFP: non-conforming proposals received for wind farms on Lana'i and Moloka'i
- November 2010: PUC Waiver Order
- March 21, 2011: Term sheet for proposed Lana'i wind farm
- July 14, 2011: PUC directs HECO to submit RFP
- October 14, 2011: HECO files Draft RFP
- January 7, 2011: Received over 250 comments
- September 28, 2012: Posting of HECO's responses to comments and Revised Draft RFP
- Today: Awaiting PUC guidance on RFP; PPA discussions have been inactive since 2011 Term Sheet

10

6/25/2013


11

# 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.

---

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

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

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

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

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

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

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

Table H-1. Commercial Readiness Definitions

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

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

## EMERGING GENERATING TECHNOLOGIES

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

### Summary of CRIs for PSIP Resource Candidates

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

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

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

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

## Evaluation of Emerging Technologies

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

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

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

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

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

| 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.*

# Appendix I: Hawaiian Electric Companies Fuels Master Plan

The objective of the Fuels Master Plan (FMP) is to effectively plan for solutions that provide the fuel needed to meet the electricity demand for the customers of the Hawaiian Electric Companies in a reliable, environmentally compliant, and cost-effective manner.

This appendix contains the Fuels Master Plan as filed with the Public Utilities Commission on January 31, 2013, Docket No. 2009-0346.

# Hawaiian Electric Companies
# Fuels Master Plan

January 31, 2013

*Supported by*
*PA Consulting Group*
*Ten Canal Park*
*Cambridge, Massachusetts 02141*
*Tel: +1 617 225 2700*
*www.paconsulting.com*

## *1. EXECUTIVE SUMMARY*

The objective of this Fuels Master Plan ("FMP") is to effectively plan for solutions that provide the fuel needed to meet the electricity demand for the customers of Hawaiian Electric Company, Inc. ("Hawaiian Electric"), Hawaiian Electric Light Company, Inc. ("HELCO") and Maui Electric Company, Ltd. ("MECO") (collectively, "the Companies") in a reliable, environmentally compliant, and cost-effective manner. This FMP discusses the changes in strategies from those set forth in the February 2012 FMP.[1]

In the February 2012 FMP, liquid crude biofuels ("biocrude"), projected to contribute to Hawaiian Electric's renewable energy landscape, played a driving role in planning for segregation of biofuel and low sulfur fuel oil ("LSFO") storage. The revised fuel strategy has evolved as a result of new environmental regulations as well as developments in the Hawaii and global energy markets.

First, petroleum diesel is under consideration as a replacement to LSFO to enable Hawaiian Electric to comply with new environmental regulations. Switching from LSFO to diesel facilitates homogenous storage strategies on Oahu since biodiesel can be blended with diesel and stored in the same fuel tanks. In addition, whereas Hawaiian Electric's integration of biofuel previously centered around acquiring biocrude the current plan will focus more on biodiesel, which is more readily available in the market and has become cost competitive when compared to biocrude. Second, in response to the increased supply and low price levels seen in the mainland U.S. natural gas market, Hawaiian Electric is evaluating how to best acquire liquefied natural gas ("LNG") for regasification and integration of natural gas into its existing generating units. Such integration will reduce costs for Hawaiian Electric's customers and help the Companies meet air emissions mandates. With this change in drivers, the previous strategies for construction of additional liquid fuel storage tanks and Kahe Power Plant ("Kahe") unit conversion projects to enable co-firing of biocrude are no longer planned.

While planning for Renewable Portfolio Standards ("RPS") compliance and long-term LNG integration will continue, the more pressing fuels-related challenge and the primary focus of this FMP is developing and executing a near-term fuels strategy that enables the Companies to meet all environmental regulations in a reliable and cost-effective manner. The Companies now face a series of challenging fuels-related environmental regulations listed below:

- **The new National Ambient Air Quality Standards ("NAAQS") for Sulfur Dioxide ($SO_2$)** is driving conversion from LSFO to lower emissions fuels, including diesel and lower sulfur industrial fuel oil (IFO), at Hawaiian Electric, HELCO, and MECO in an effort to curb $SO_2$ emissions. While the EPA has stated that all jurisdictions should be compliant no later than 2017, specific compliance requirements and schedules have yet to be established at the statewide level.

- **The Mercury and Air Toxics Standards ("MATS")** require Hawaiian Electric to control emissions of particulate matter ("PM") and hazardous air pollutants ("HAPs"), including heavy metals and acid gases, from its oil-fired steam generating units by 2015.

[1] The February 22, 2012 FMP was filed as a Supplemental filing to the January 31, 2012 Status Report in Docket No. 2009-0346.

- **National Emission Standards for Hazardous Air Pollutants for Reciprocating Internal Combustion Engines ("RICE NESHAP")** require HELCO and MECO to control emissions of HAPs from their reciprocating internal combustion engines by 2013.

The MATS and NAAQS compliance requirements are driving Hawaiian Electric to explore the use of fuel additives, revised fuel formulations, and lower emissions fuel types coupled with capital investments that will accommodate the use of various diesel grades in place of LSFO, for example. RICE NESHAP requires reciprocating internal combustion engine generating units ("RICE") to operate on ultra-low sulfur diesel ("ULSD").

This FMP reflects a lower level of capital expenditures on infrastructure projects than did the February 2012 FMP. The previous FMP provided for approximately $300 million for additional liquid fuel storage tanks, land purchase for siting and operating new tanks and infrastructure, and conversion of Kahe's fuel systems for co-firing biocrude with LSFO. In this FMP, by contrast, the Companies have assumed no additional infrastructure investment for purposes of increased liquid fuel storage capacity. Instead, a total of $80 million in capital costs, which includes $50 million for meeting environmental compliance obligations, and $30 million for developing a Hawaiian Electric-owned pipeline, is projected. Therefore, the strategy outlined in this FMP presents a net overall cost reduction of approximately $220 million in capital costs compared to the February 2012 FMP.

The current projected capital costs include the following:

- Installing fuel tank berm liners on Oahu to accommodate diesel storage is estimated to cost $23 million.

- Generation-related retrofits on Hawaiian Electric's steam units to burn diesel are estimated to cost $27 million.

- Constructing a pipeline ("Kalaeloa Pipeline") from Kalaeloa Barbers Point Harbor ("KBPH") to Hawaiian Electric's Barbers Point Tank Farm ("BPTF") to facilitate the ability to directly import adequate fuel supplies will cost an estimated $30 million.

This FMP supports the strategy to be employed by the Companies in meeting environmental compliance obligations and, where appropriate, discusses the reasons behind the selected compliance path. There will be associated compliance costs, particularly in a case where the Companies must transition to purchasing, handling and consuming a different type of lower emissions fuel such as diesel. The market price of lower emissions fuels can be higher; diesel typically costs as much as 20% more per unit of energy than LSFO. Based on Hawaiian Electric's July 2012 fuel forecast, for example, the 2015 incremental diesel cost alone could be approximately $160 million per year.

Fuel procurement and delivery will be a primary focus for the next several years in line with converting to lower emissions fuels. Hawaiian Electric's potential demand for diesel will far outpace the supplies refined on-island, so sourcing options beyond the local refiners may need to be explored. The recent announcement that Tesoro Hawaii Corporation ("Tesoro") will be converting its Hawaii refinery to an import, storage, and distribution terminal[2] has escalated the Companies' concern over the uncertainty of on-island fuel sourcing and delivery options.

There are therefore uncertainties around the fuel supply options, contracts, and infrastructure implementation timeline necessary to achieve even near-term environmental compliance. In recognition of these uncertainties, the FMP will continue to be updated and filed with the Commission semi-annually to reflect new information and developments impacting the key factors driving fuel use and cost.

[2] On January 8, 2013, Tesoro announced that it will cease refining operations at its Kapolei Refinery during April of 2013, and begin the process of converting the refinery to an import, storage and distribution terminal.

## *2. INTRODUCTION*

This updated FMP addresses the most recent challenges faced by the Companies regarding evolving fuel markets and the environmental regulations that will be effective as early as May 2013. Compliance with these regulations will require infrastructure modifications, varying in complexity and cost. For example, fuel additives would require relatively modest modifications in comparison to the more significant switch to a lower emissions fuel as a replacement for LSFO, which would include accommodating changes to the fuel supply chain in sourcing increased amounts of the new fuel.

The high-level considerations regarding the Companies' fuel infrastructure and sourcing strategies are summarized in the following:

- Environmental Regulations – Compliance with emerging environmental regulations has become the principal driver of changes to the Companies' near- and intermediate-term fuel-related practices. A planned transition from LSFO to diesel drives the need for retrofits to the fuel systems to fire diesel, changes to fuel tank berms, and construction of Hawaiian Electric's new Kalaeloa Pipeline to support global fuel sourcing (to include increased volumes of diesel).
- RPS – RPS compliance strategies and biofuel used to generate renewable energy remain an important factor.
- LNG – Importation of LNG to provide natural gas for power generation represents access to a lower-cost fuel that will reduce costs, but will require significant infrastructure changes along with a new regulatory framework. LNG discussions in this document are preliminary; the Companies' plans surrounding use of natural gas will be available at a later time.

Innovation and flexibility will be needed for the Companies to adapt in this rapidly changing economic and regulatory environment.

Diesel fuel, as discussed in this document, represents a cleaner emitting, environmentally compliant type of liquid petroleum fuel. It is expected to play a vital role in bridging the gap to long-term LNG importation, and will remain as a secondary or contingency fuel even after the transition of Hawaiian Electric's generating units to consuming natural gas. Having both diesel and gas options will minimize the supply risk, commodity risk, and counterparty risk that could come from reliance on a remotely located single fuel type or contract source.

In addition to the planning already underway for executing a fuel switch to diesel in the intermediate term, Hawaiian Electric is also evaluating alternate fuel quality paths that could potentially address MATS and NAAQS compliance in separate phases, providing a simpler, lower-cost path to achieving MATS compliance while allowing adequate time to switch to diesel to meet the more stringent NAAQS compliance. Potential alternate paths to MATS compliance contemplates continued LSFO use, either with a modified LSFO composition through additional refining or in a blend with other fuels, and/or in combination with the application of fuel additives. The MATS compliance potential of such near-term options is worth exploring given the incremental cost and petroleum industry ramifications of a transition away from LSFO, but their feasibility remains uncertain until the testing is completed in 3Q 2013. Hawaiian Electric currently anticipates that achieving NAAQS compliance will require consumption of a lighter and higher quality fuel type having significantly lower sulfur content than LSFO in accordance with a

Confidential Information Deleted
Pursuant to Protective Order
filed on December 14, 2009.

schedule that allows for expeditious and timely compliance, based upon responsible planning and execution.

The switch from LSFO to diesel would also accommodate increased use of biofuels more readily, since biodiesel can be homogeneously blended with diesel and stored in the same fuel tanks. In addition, whereas Hawaiian Electric's integration of biofuel previously centered around acquiring biocrude, biodiesel is more readily available in the market and has become cost competitive when compared to biocrude.

When co-firing biocrude with LSFO was previously contemplated as the strategy for increasing biofuel powered generation, preparing Kahe's existing infrastructure for operational use of biocrude and adding separate biofuel storage tanks was estimated to cost $70 million to $80 million. Other actions that entailed significant costs in the previous FMP were the purchase of land for a fuel terminal in the Kalaeloa Harbor area estimated at $14 million to $20 million, and the site's build out of bulk fuel storage at a planned Hawaiian Electric Kalaeloa Fuel Terminal ("KFT") estimated to cost from $150 million to $200 million. Continued employment of existing fuel storage assets such as Hawaiian Electric's BPTF and generating station tank farms, suitably upgraded, obviates the need for the KFT land purchase. Elimination of these infrastructure projects, a result of the Companies' planned switch to diesel and avoidance of segregated biofuel storage, and the expected migration to consumption of LNG in the long-term, reduces potential capital expenditures for liquid fuel infrastructure by approximately $300 million.

As stated, fuel procurement and delivery will be a primary organizational focus for the next several years in line with converting to lower emissions fuels. Development of a Hawaiian Electric-owned Kalaeloa Pipeline from KBPH to BPTF is underway to expand delivery options to existing fuel storage facilities. This development will be essential to secure off-shore access to a supply of diesel fuel. The Kalaeloa Pipeline is estimated to cost $30 million. The Tesoro Throughput Agreement offers Hawaiian Electric its only current pipeline option for delivering fuel directly from an off-island supplier. [redacted] The Kalaeloa Pipeline will provide the Companies a direct harbor connection [redacted] and thereby enhances Hawaiian Electric's fuel security through access to off-shore sources. [redacted]

In addition to the planned capital expenditure for the development of the Kalaeloa Pipeline, other projects are planned to install fuel tank berm liners at BPTF, Kahe and Waiau Power Plant ("Waiau"), estimated at $23 million in aggregate; along with generating unit boiler retrofits at Kahe, Waiau, and Honolulu Power Plant ("HPP") to accommodate firing on diesel, estimated at $27 million. These capital expenditures, along with the Kalaeloa Pipeline at $30 million, result in a revised FMP estimated capital project cost of approximately $80 million.

Therefore, with the elimination of the $300 million in capital expenditures associated with the previous co-firing biocrude strategy, and the introduction of the $80 million in current capital expenditures, the result is a net reduction in overall capital expenditures for liquid fuel infrastructure of approximately $220 million.

Despite some uncertainties around the fuel supply options, contracts, and compliance deadlines, the current fuels strategy requires several actions to be executed in a timely manner. Table 1-1 introduces these near-term actions for Hawaiian Electric, HELCO and MECO.

**Table 2-1 – Key Fuels Activities**

| Summary of Key Fuel Actions for Hawaiian Electric, HELCO and MECO | | |
|---|---|---|
| **Hawaiian Electric** | **Anticipated PUC Application Date*** | **Anticipated Completion Date*** |
| MATS Early Notice of Compliance Plans submitted to the Commission (necessary for Administrative Order (AO) one year extension request) | Not applicable | 4/16/2013 |
| Evaluate alternate fuel options for MATS compliance | Not applicable | 3Q 2013 |
| MATS Broadly Available One Year Extension Request submitted to the State Department of Health | Not applicable | 12/18/2014 |
| Reliability Study submitted to Commission (necessary for MATS AO request) | Not applicable | 2015 |
| MATS AO Request submitted to EPA | Not applicable | 10/20/2015 |
| Installation of Hawaiian Electric-owned Kalaeloa Pipeline between KBPH and BPTF | 2013 | 2016 |
| Finalize low sulfur diesel contracts in time for MATS/NAAQS compliance | 2014-2015 | 2015-2016 |
| Prepare BPTF, and fuel storage tanks at Kahe and Waiau for storing and burning diesel | 2013-2014 | 2015-2016 |
| **HELCO** | | |
| Transition portion of plants' diesel receipt, storage and distribution system for consumption of ULSD for small RICE units in time for RICE NESHAP compliance | D&O issued, September 2012[3] | 1Q 2013 |
| Prepare select diesel units below 2.5 MW for switch to ULSD for RICE NESHAP compliance | Not applicable | 1Q 2013 |
| Procure low sulfur diesel and lower sulfur IFO for NAAQS compliance by non-RICE units | 2014-2015 | 2015-2016 |
| Switch Shipman, Hill, and Puna steam units to lower sulfur IFO for NAAQS compliance | Not applicable | 2Q 2017 or earlier |

[3] Tesoro Contract Amendment to supply ULSD was approved by Decision and Order No. 30661 on September 28, 2012, in Docket 2012-0031.

| HELCO (continued) | Anticipated PUC Application Date* | Anticipated Completion Date* |
|---|---|---|
| Switch Kanolehua, Puna and Keahole combustion turbine and non-RICE units to low sulfur diesel for NAAQS compliance | Not applicable | 2Q 2017 or earlier |
| **MECO** | | |
| New contract[4] for Aloha Petroleum's fuel storage at Kahului Harbor | 1Q 2013 | 2013 |
| Transition Molokai and Lanai and portion of Maui diesel receipt, storage and distribution system for consumption of for small RICE units in time for RICE NESHAP compliance | Completed 2012 | 1Q 2013 |
| Prepare all Molokai and Lanai and select Maalaea diesel units below 2.5 MW for switch to ULSD for RICE NESHAP compliance | Not applicable | 1Q 2013 |
| Procure low sulfur diesel and lower sulfur IFO for NAAQS compliance for non-RICE Maui units | 2014-2015 | 2015-2016 |
| Switch Kahului steam units to lower sulfur IFO for NAAQS compliance | Not applicable | 2Q 2017 or earlier |
| Switch Maalaea combustion turbine and non-RICE units to low sulfur diesel for NAAQS compliance | Not applicable | 2Q 2017 or earlier |

* Dates are subject to change.

The remainder of this document is organized as follows: Section 3, "Current State", details the environmental and RPS compliance obligations and outlines the current fuel operations related to these compliance requirements; Section 4, "Future State", delineates the desired future state of the fuel-related activities; Section 5, "Gap Analysis", summarizes the list of actions to be completed to reach the future state; and Section 6, "Conclusions", highlights the milestones associated with the FMP and its action items.

[4] Aloha Petroleum Terminalling Agreement with MECO was executed in December 2012.

## 3. CURRENT STATE

Designing the appropriate fuels strategy requires a clear understanding of driving environmental regulations, current and long-term power sector fuel demand, fuel procurement options and constraints, and security of supply and inventory policies. This section details the current state of each of these elements.

### 3.1 Compliance Obligations

#### 3.1.1 RPS

Meeting and exceeding state RPS goals remains a focus of the Companies. The Companies must achieve the following renewable portfolio targets:

- 15% of its net electricity sales by 2015
- 25% of its net electricity sales by 2020
- 40% of its net electricity sales by 2030

Hawaiian Electric is required to show compliance with the RPS by the dates given above. Prior to January 1, 2015, electrical energy savings can still be counted toward up to 50% of the RPS, but beginning January 1, 2015, the entire renewable portfolio standard must be met by electrical generation from renewable energy sources. In 2011, 24.5% RPS was achieved with energy efficiency savings. Without the inclusion of the energy efficiency programs, the RPS was 12%. The Companies are committed to meeting and exceeding the RPS goals and continue to increase their renewable energy portfolio. To that end, the Companies are actively seeking and incorporating a diverse portfolio of new renewable energy resources including wind, solar, hydro, geothermal, biomass, municipal solid waste, biofuel and other types of renewable generation that may emerge in the future. However, the only RPS-eligible generation source covered in this FMP is liquid biofuel for generating power in the Companies' existing generating units and potentially future select RICE and combustion turbine unit additions. Biofuel must be planned for, procured, stored, and delivered in much the same way as liquid petroleum fuels. Wind, solar, and geothermal power also play significant roles in RPS compliance but, because they do not have a traditional "fuel" component, they are outside the scope of this FMP.

#### 3.1.2 Environmental Compliance

Three key U.S. Environmental Protection Agency ("EPA") air emissions regulations are now in effect that are guiding the Companies' fuel plan. The Companies are preparing to make complex decisions soon as they strive for timely compliance without sacrificing reliability or incurring unnecessary cost. Compliance obligations require the Companies to re-evaluate their current fuel procurement strategies and bulk liquid petroleum storage and distribution infrastructure capabilities. Initial assessments indicate that none of the LSFO burning units at Hawaiian Electric will be compliant with MATS or NAAQS if current operating practices are maintained. Similarly, at HELCO and MECO certain diesel units and the medium-sulfur (maximum 2% sulfur) IFO burning units are not in compliance with RICE NESHAP and NAAQS respectively. These standards are briefly described below, followed by subsections detailing the implications on each company.

**NAAQS** – The Clean Air Act ("CAA") requires the EPA to set national ambient air quality standards for pollutants considered harmful to public health and the environment. The six "criteria" pollutants are carbon monoxide ("CO"), lead, nitrogen dioxide ("$NO_2$"), ozone, PM and $SO_2$. The CAA also requires the EPA to review the NAAQS every five years and to revise the NAAQS to reflect the latest scientific information on the impacts of air pollution on public health and the environment. In 2010, EPA revised the NAAQS for $SO_2$ and $NO_2$ and made them more stringent. Also, the compliance requirements for $PM_{2.5}$ were made more stringent. Based on Hawaiian Electric's preliminary modeling, $SO_2$ standard poses the greatest generating unit compliance challenge for the Company.

**MATS** – Under the 1990 CAA amendments, the objective of MATS is to reduce air pollution from coal and oil-fired power plants. The final rule from February 2012 sets standards for certain HAPs emitted by coal- and oil-fired electric generating units with a capacity of 25 MW or greater (meaning the rule will apply to Hawaiian Electric steam units only). Reducing filterable PM levels will be primary goal of Hawaiian Electric to comply with these new standards.

**RICE NESHAP** – Amendments to the RICE NESHAP, promulgated in 2010, will require reduced CO emissions for all non-emergency reciprocating diesel engines at MECO and HELCO and the adoption of additional work practices for some Hawaiian Electric diesel units. Compliance with RICE NESHAP is achieved by installing emission control equipment and switching to ULSD for select units.

Table 3-1 summarizes the compliance requirements in place for the Companies.

**Table 3-1 – Environmental Regulations and Compliance Requirements for the Companies**

| | Hawaiian Electric | HELCO | MECO |
|---|---|---|---|
| NAAQS | Need to reduce ambient pollutant concentration levels, particularly $SO_2$ | Need to reduce ambient pollutant concentration levels, particularly $SO_2$ | Need to reduce ambient pollutant concentration levels, particularly $SO_2$ |
| MATS | Need to reduce filterable PM emissions for oil-fired steam generating units | Does not apply | Does not apply |
| RICE NESHAP | Need to establish additional work practices for emergency RICE units | Need to reduce CO emissions for all reciprocating internal combustion engines | Need to reduce CO emissions for all reciprocating internal combustion engines |

The following sections provide more details on each company's required actions for compliance by the respective regulation.

**a. Hawaiian Electric**

**NAAQS** – All the Hawaiian Electric generating units excepting currently biofueled Campbell Industrial Park ("CIP") CT-1, steam units and Waiau combustion turbines, will need to reduce the 1 hour-$SO_2$ emission levels. In order to reach the required emission levels, a switch to a lower sulfur content fuel will be needed. While the EPA has stated that all jurisdictions should be compliant no later than August 2017, specific compliance requirements and schedules have yet to be established at the statewide level.

**MATS** - All Hawaiian Electric steam units are subject to the new MATS rule and will need to significantly reduce filterable PM emissions as a demonstration of compliance[5]. This PM emissions reduction will likely be accomplished through the least costly of several alternate fuel options as described later in Section 5.1.1. MATS compliance date is April 2015, with a possible one year extension available from the Department of Health ("DOH"), and a second one year extension that may be available by the EPA Administrative Order, subject to certain stringent criteria. Hawaiian Electric is actively seeking both extensions. *See* Table 2-1.

**RICE NESHAP –** Emergency RICE units of Hawaiian Electric will need to implement additional work practices for RICE NESHAP by May 2013.

**b. HELCO & MECO**

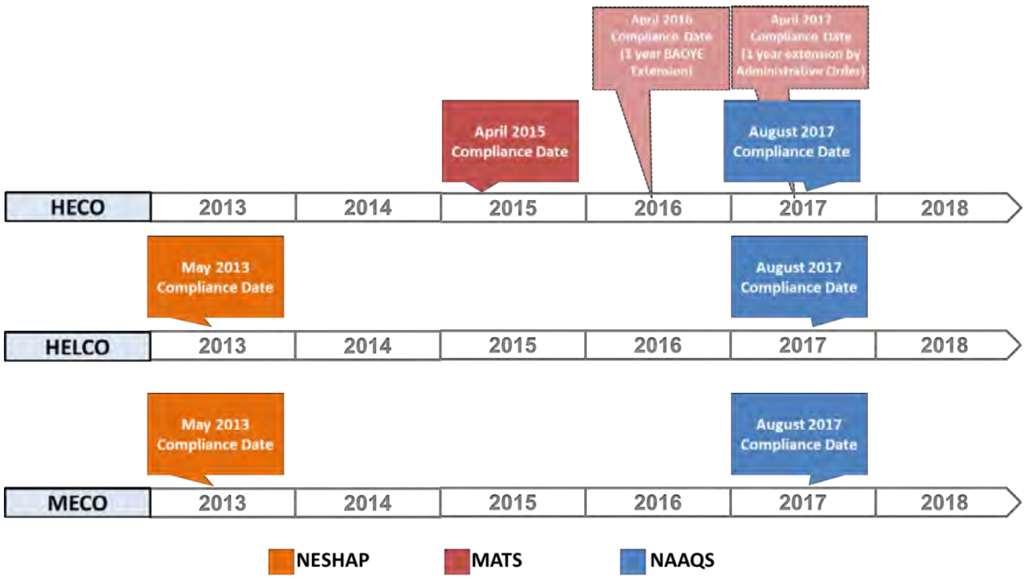
**NAAQS -** For HELCO, the boilers at the Hill, Puna and Shipman plants on the Big Island; and for MECO, the Kahului plant currently consume medium sulfur IFO and will need to switch to a lower sulfur content grade of fuel oil. The combustion turbine units at MECO and HELCO will need to switch to a lower sulfur content grade of diesel to comply with NAAQS. Several additional measures will need to be completed at the Maalaea Power Plant ("Maalaea") units. For M4-M9 units, selective catalytic converters for $NO_x$ reduction will be required. For M4-M7 units, diesel particulate filters will also need to be installed to reduce filterable PM emissions. Finally, for M1-M3 units, fuel injection timing retards will be needed to reduce $NO_x$ emissions.

**MATS -** HELCO and MECO units do not fall under the MATS rule because none of their individual units have capacity greater than the minimum threshold of 25 MW.

**RICE NESHAP -** To comply with the RICE NESHAP, HELCO and MECO RICE units will need to significantly reduce CO emissions. While the compliance date of May 2013 is around the corner, efforts to install oxidation catalysts on all the affected units and to switch from 0.4% diesel to 0.0015% ULSD, for units below 2.5 MW are in progress and both utilities are expected to comply on time. Transition of the HELCO and MECO-Maui, MECO-Lanai and MECO-Molokai plants' diesel receipt, storage and distribution piping from high sulfur diesel to ULSD commenced in 4Q 2012.

[5] The new MATS rule allows the use of filterable PM emissions as a "surrogate parameter" to demonstrate compliance with the MATS rule.

**Figure 3-1 – Environmental Compliance Timeline by Utility**




The combination of all three environmental regulations with compliance dates ranging from early 2013 through 2017[6] will drive a series of changes to the Companies' choice of fuels and infrastructure in the coming years. The following subsections outline the current state of fuel operations, or the foundation that will need to be built upon to ensure timely and cost-effective compliance.

## 3.2 Current Fuel Demand

### 3.2.1 Current Fuel Demand - Hawaiian Electric

On Oahu, petroleum fuel demand in the power sector is driven by maximum 0.5% sulfur content LSFO used at Hawaiian Electric's power plants (Kahe, Waiau, and HPP).

[6] The NAAQS compliance date of August 2017 is subject to specific compliance requirements and schedules that have yet to be established at the statewide level.

12

To maintain the current levels of generation going forward, Hawaiian Electric's Fuels Department must procure approximately 6.8 million barrels of liquid fuel per year. Roughly 99% of this fuel is currently LSFO and over 70% of it is delivered for use at Kahe. Modest quantities of maximum 0.4% sulfur diesel (15,600 barrels) fueled the combustion turbines, Waiau 9 and 10, while CIP CT-1 consumed 74,100 barrels of B99[7] biodiesel in 2012 from its supply contract with Renewable Energy Group, Inc. ("REG"). 2012 consumption by facility is shown in Table 3-2.

**Table 3-2 – Hawaiian Electric Liquid Fuel Demand in 2012**

| Fuel Type | Location | Quantity (million bbl/yr) |
|---|---|---|
| **LSFO** | | |
| | Kahe | 4.85 |
| | Waiau | 1.74 |
| | HPP | 0.11 |
| | ***Hawaiian Electric Total*** | ***6.70*** |
| **Diesel** | | |
| | Waiau | 0.02 |
| | ***Total*** | ***0.02*** |
| **Biodiesel** | | |
| | CIP CT-1 | 0.07 |
| | ***Total*** | ***0.07*** |
| **All Fuels Total** | | ***6.79*** |

CIP CT-1 is permitted to run on biodiesel[8] and is the only power sector driver for biofuel demand on Oahu. However, biofuel consumption is expected to increase over the coming years given Hawaiian Electric's commitment to pursuing renewable generation opportunities. This commitment aligns with the Hawaii State RPS law[9] which sets the minimum goals for using renewable energy resources to generate electricity across all the three companies.

### 3.2.2 Current Fuel Demand – HELCO

HELCO is the primary electricity provider to the Big Island of Hawaii. Its electricity is predominantly generated by three power plants – Puna, Hill and Keahole. Puna and Hill steam units burn maximum 2.0% sulfur IFO, whereas combustion turbine units at Puna and Keahole burn maximum 0.4% sulfur diesel. These three plants provide more than 90% of all the electricity HELCO generates. Two hydro units at Waiau and Puueo and a handful of additional steam and diesel units make up the remainder of HELCO's generation. However, approximately half of the island's generation need is met through IPPs, net energy metering (predominantly solar PV) and the feed-in-tariff ("FIT").

[7] B99 refers to 99% biodiesel.
[8] State of Hawaii Department of Health, 10-159E CAB File 0548, March 2, 2010.
[9] Hawaii Revised Statutes §269-91.

To maintain current levels of generation, HELCO must ensure a reliable supply of fuels. As shown in Table 3-3, in 2012 HELCO's steam and diesel generating units consumed approximately 371,000 barrels of diesel and 533,000 barrels of IFO. Total liquid fuel consumption exceeded 900,000 barrels.

**Table 3-3 – HELCO Liquid Fuel Demand in 2012**

| Fuel Type | Quantity ('000 bbl/yr) |
|---|---|
| Diesel | 370.6 |
| IFO | 533.4 |
| **All Fuels** | ***904.0*** |

### 3.2.3 Current Fuel Demand – MECO

MECO is the primary provider of electricity to Maui, Lanai, and Molokai. MECO-Maui's generation assets consist of a variety of maximum 0.4% sulfur diesel and ULSD fired combustion turbine and RICE units located at Maalaea, a maximum 2.0% sulfur IFO-fired steam plant at Kahului, and a small ULSD-fired RICE standby unit at Hana. Most of the MECO generation need is met by the diesel units at Maalaea while Kahului steam units provide the rest. Biodiesel is consumed by select RICE units at Maalaea during start up only. Generation purchased from IPPs and FITs constitutes the remaining portion of Maui's electricity consumption.

Table 3-4 shows the liquid fuel consumption at MECO-Maui in 2012 which was composed of approximately 75% diesel and 25% IFO.

**Table 3-4 – MECO Liquid Fuel Demand in 2012**

| Fuel Type | Quantity ('000 bbl/yr) |
|---|---|
| Diesel | 1,219.6 |
| Biodiesel | 2.6 |
| IFO | 374.8 |
| **All Fuels** | ***1,596.4*** |

All of MECO's generation on the islands of Molokai and Lanai are RICE units that will be consuming ULSD by May 2013 in compliance with RICE NESHAP fuel quality regulations.

## 3.3 Current Fuel Procurement

In 2012, the Companies' consolidated annual fuel purchases for electric generation totaled more than $1.3 billion, across a mix of liquid fuels that included the following:

- LSFO and IFO;
- high sulfur diesel;
- ULSD; and
- biodiesel

Historically, petroleum fuels have been procured under long-term (e.g., up to ten year) contracts with Tesoro and Chevron the two refiners operating on Oahu. These contracts have typically provided for "import parity" pricing through the use of market indices, such that the cost of fuel provided to the Companies is intended to be equivalent to the cost they could obtain in the global marketplace delivered to Oahu, with adders to cover quality and quantity adjustments, blending, storage, and transportation of fuels. Crude oil and petroleum products price volatility in global oil markets has put downward pressure on the earnings of these local refiners, causing

Confidential Information Deleted
Pursuant to Protective Order
filed on December 14, 2009.

them to be less willing to accept the risk of a supply obligation under a set of fixed terms and conditions in a long-term contract. Consequently, the term of future supply contracts is anticipated to be ever shorter.

Unlike many mainland utilities, Hawaiian Electric has limited fuel receiving alternatives, constraining the Company's ability to source fuel from suppliers other than Chevron and Tesoro whose facilities are located adjacent to or in close proximity to Hawaiian Electric's BPTF central fuel storage. In order to evaluate the effectiveness of the current "import parity" pricing model, suitable fuel receiving capabilities are needed to solicit price cost models for substantial volumes from potential offshore fuel suppliers. Having the ability to access offshore fuel supplies directly will be crucial to ensuring Hawaiian Electric's ability to switch to diesel due to environmental compliance obligations. Even at maximum crude oil processing rates, none of the fuel suppliers on Oahu can refine a sufficient volume of diesel in aggregate to supply Hawaiian Electric's total generation volume requirements.

The only current alternative to receiving fuel sourced from the local suppliers is made possible by use of Tesoro petroleum infrastructure under the terms of the Tesoro Throughput Agreement.[10] This agreement provides Hawaiian Electric with a right to use Tesoro's 20-inch black oil pipeline between KBPH and BPTF, and allows fuel types other than LSFO to be shipped. [redacted] The agreement expires December 31, 2017, with the potential for extensions thereafter.

Since the last FMP report was submitted, Hawaiian Electric has finalized two new LSFO contracts under the terms of which deliveries are to begin on May 1, 2013. The term of the agreement with Tesoro runs through December 2014; and though the contract includes an option to extend the term upon agreement of both parties, recent history suggests such simple extension may not be likely. The term of the corresponding supply contract with Chevron is through December 2016.[11] [redacted] There are also two inter-island fuel supply contracts with Chevron and Tesoro, which enable IFO, diesel and ULSD delivery to HELCO and MECO. Both of these contracts expire in December 2014. Lastly, Lanai Oil Company has been supplying ULSD since May 2010. Currently, there is no expiration date to this supply contract with Lanai Oil Company.

In addition to these petroleum fuel supply agreements, the Companies have a number of biofuel supply contracts in place. Under the current contract terms, Pacific Biodiesel, Inc ("PBI")[12] and

[10] Docket No. 2010-0113, approved on May 13, 2011.
[11] The new Tesoro and Chevron LSFO Supply Contracts received Interim Approval from the PUC on December 31, 2012 in Docket No.2012-0217
[12] Docket No. 2011-0368, approved on December 13, 2012.

Confidential Information Deleted
Pursuant to Protective Order
filed on December 14, 2009.

REG[13] will provide biodiesel for a three year term beginning in 2013 and through August 2015, respectively. Biodiesel supplied by REG is burned at CIP CT-1 and biodiesel supplied by PBI is to be burned at the new Honolulu International Airport Emergency Power Facility ("HIA Facility"). [redacted] In addition, PBI has a separate biodiesel contract with MECO, subject to renewal annually. This biodiesel is consumed at Maalaea for start-up of the units M12 and M13 to help reduce opacity. There are also proposed contracts with Aina Koa Pono-Ka'u ("AKP")[14], and Hawai'i BioEnergy, LLC ("HBE")[15]. These two contracts are for twenty (20) year terms and will support the Companies' strategy to increase renewable energy for compliance with RPS requirements.

A timeline of these supply and throughput contracts along with minimum and maximum fuel volumes are presented in Figure 3-2.

[13] Docket No. 2011-0337, approved on May 12, 2012.
[14] Docket No. 2012-0185.
[15] Docket No. 2011-0369.

Confidential Information Deleted
Pursuant to Protective Order
filed on December 14, 2009.

**Figure 3-2 – Existing Contract Timelines for the Companies**

| | | Fuel Type | [redacted] | Start | Finish | 2013 | 2014 | 2015 | 2016 | 2017 |
|---|---|---|---|---|---|---|---|---|---|---|
| Petroleum Fuels | **Tesoro** LSFO Supply | LSFO | [redacted] | May-13 | Dec-14 | | | | | |
| | **Tesoro** Inter-Island Supply | IFO; Diesel; ULSD | [redacted] | Jan-98 | Dec-14 | | | | | |
| | **Tesoro** Pipeline | Liquid Fuels | [redacted] | May-10 | Dec-17 | | | | | |
| | **Chevron** LSFO Supply | LSFO | [redacted] | May-13 | Dec-16 | | | | | |
| | **Chevron** Inter-Island Supply | IFO; Diesel | [redacted] | Jan-98 | Dec-14 | | | | | |
| | **Lanai Oil Company** Diesel Supply | ULSD | [redacted] | May-10 | None | | | EVERGREEN | | |
| Biofuels | **PBI** (Hawaiian Electric) | Biodiesel | [redacted] | 3Q 2013 | 3Q 2016 | | | | | |
| | **PBI** (MECO) | Biodiesel | [redacted] | Dec-12 | Dec-13 | | | | | |
| | **REG** | Biodiesel | [redacted] | Aug-12 | Aug-15 | | | | | |
| | **AKP** | Biodiesel | [redacted] | *Proposed* | | | | | | |
| | **HBE** | Biocrude | [redacted] | *Proposed* | | | | | | |

* Numbers are rounded off to the first decimal place.
** Includes both diesel and ULSD.
*** Average annual volume.

### 3.3.1 Fuel Supply Dependence

Although the acquisition of liquid fuel has historically been reliable with minimum delivery challenges, the Companies' continued dependence on the operations of local fuel suppliers is an increasing risk. In 2011, Hawaiian Electric [redacted]

- [redacted]
- [redacted]
- [redacted]

---

[redacted]

Confidential Information Deleted
Pursuant to Protective Order
filed on December 14, 2009.

[redacted] In January 2013, Tesoro announced the decision to close its Kapolei Refinery in April 2013, while continuing to operate the refinery infrastructure as an import, storage and distribution terminal. These import-related assets and Tesoro's multi-island retail and distribution terminal assets remain for sale. Tesoro's Kapolei Refinery is larger than Chevron's refinery in Hawaii with a capacity of 94,000 barrels per day (an output about 75% greater than the Chevron Oahu facility), and thus its closure further limits on-island fuel supply options normally available through local crude oil processing.

Although Tesoro has assured the Companies that all existing fuel supply commitments with Hawaiian Electric and subsidiaries will be fulfilled, closure of this refinery raises important fuel supply considerations for the Companies and highlights the need to explore offshore fuel sourcing options. Hawaiian Electric is aware that the execution of new offshore fuel supply contracts and construction of new supporting infrastructure have long lead times, and is developing strategies to secure capability to directly import adequate fuel supplies, particularly for diesel. Planning for Hawaiian Electric-owned infrastructure projects such as the Kalaeloa Pipeline enabling offshore fuel delivery to Hawaiian Electric's BPTF central storage facility are among the Company's intermediate-term strategies.

### 3.4 Current Fuel Delivery

The existing four paths of fuel imports into Oahu are described in Table 3-5. Hawaiian Electric is currently dependent on the local refineries receiving their petroleum and blending components through their respective offshore moorings to produce LSFO and other petroleum fuels in addition to Chevron's and Tesoro's ability to import refinery feedstocks, blending components and finished petroleum fuels through Tesoro's pipeline system from KBPH to their respective facilities. While some LSFO components are delivered by Chevron directly from its off-shore tanker mooring to Hawaiian Electric's BPTF, the great majority of Hawaiian Electric's LSFO supply is delivered to BPTF by Chevron (via refinery piping), and the remaining LSFO is delivered by Tesoro (via Tesoro's KBPH pipeline which interconnects with Hawaiian Electric's BPTF piping) to Hawaiian Electric's BPTF storage. Subsequently, LSFO is transported via Hawaiian Electric pipeline from BPTF to Kahe and Waiau. For delivery to HPP, LSFO is first trucked from BPTF to the Iwilei Tank Farm and subsequently to its intermediate storage there, it is delivered via a Hawaiian Electric pipeline from the Iwilei Tank Farm to HPP.

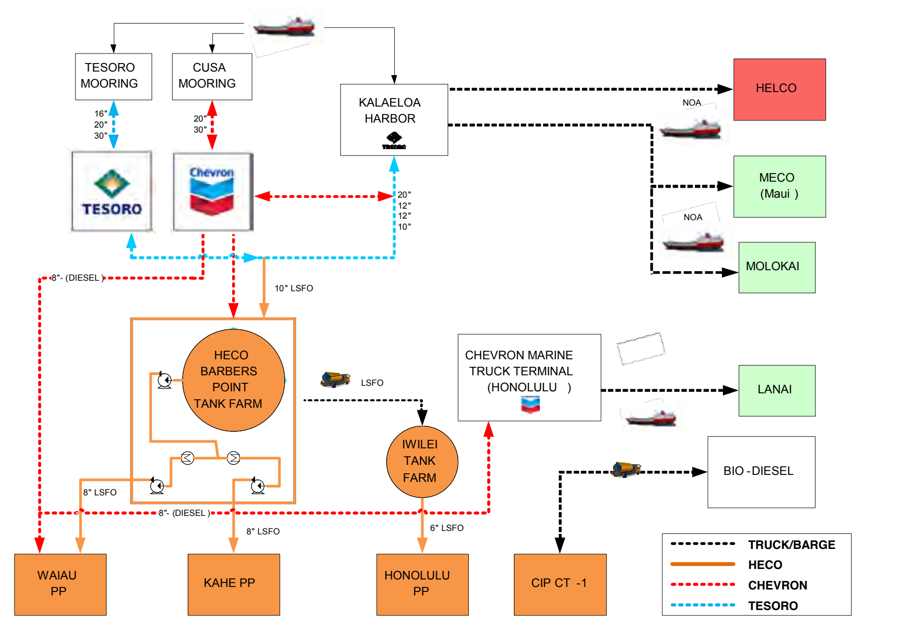
The biodiesel needed to run CIP CT-1 is currently imported from the U.S. mainland in ISO containers. The ISO containers are offloaded from a container ship at Honolulu Harbor and delivered to CIP via truck.

**Table 3-5 – Bulk Fuel Import Pathways**

| Import Path | Location | Delivery Size | Delivery Method |
|---|---|---|---|
| Chevron multi-buoy mooring | Offshore near Barbers Point to Chevron refinery | Tanker up to 150,000 deadweight tons (DWT) or capacities up to 1 million barrels | Import through 30" submarine pipeline<br>Export of naphtha and other refined products through 20" pipeline for export |
| Tesoro single point mooring | Offshore near Barbers Point to Tesoro refinery | Tanker up to 150,000 DWT or capacities up to 1 million barrels | Connected by 30", 20", 16" pipelines nominally in crude oil, black oil and white oil service, respectively |
| Tesoro Kalaeloa Harbor fuel hatches | Kalaeloa Harbor | Limited tankers due to 38' harbor depth including: Handysize tankers (35,000 DWT or ~250,000 bbl) or lightly loaded Panamax tankers (45,000 DWT or ~300,000 bbl) | Import and export via fuel hatches and four pipelines: 20" black oil, 12" diesel, 12" jet fuel, and 10" gasoline |
| Aloha Petroleum | Kalaeloa Harbor | | Import and export via fuel hatches and four 8" finished product pipelines |

Figure 3-3 is a schematic diagram which shows the current fuel paths used to deliver and distribute fuel on and from Oahu to Hawaiian Electric, MECO, and HELCO facilities. Fuel infrastructure facilities owned by Hawaiian Electric are identified as solid yellow lines, demonstrating that most of the fuel supply paths are not owned by Hawaiian Electric.

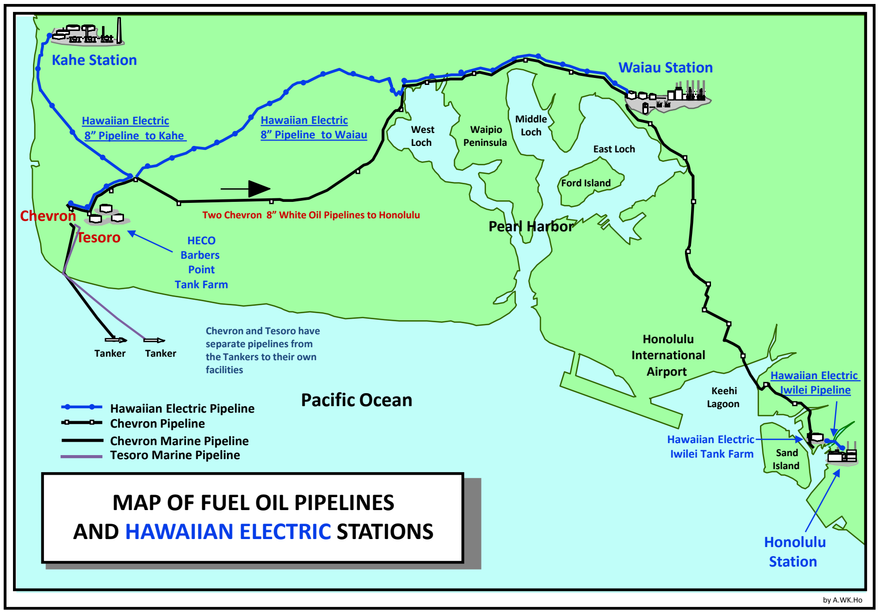
**Figure 3-3 – Existing Fuel Supply Paths**




20

Figure 3-4 provides a map showing the offshore mooring systems and connecting pipelines as they relate to BPTF and the primary Hawaiian Electric generation facilities.

**Figure 3-4 – Overview of Pipelines on Oahu**

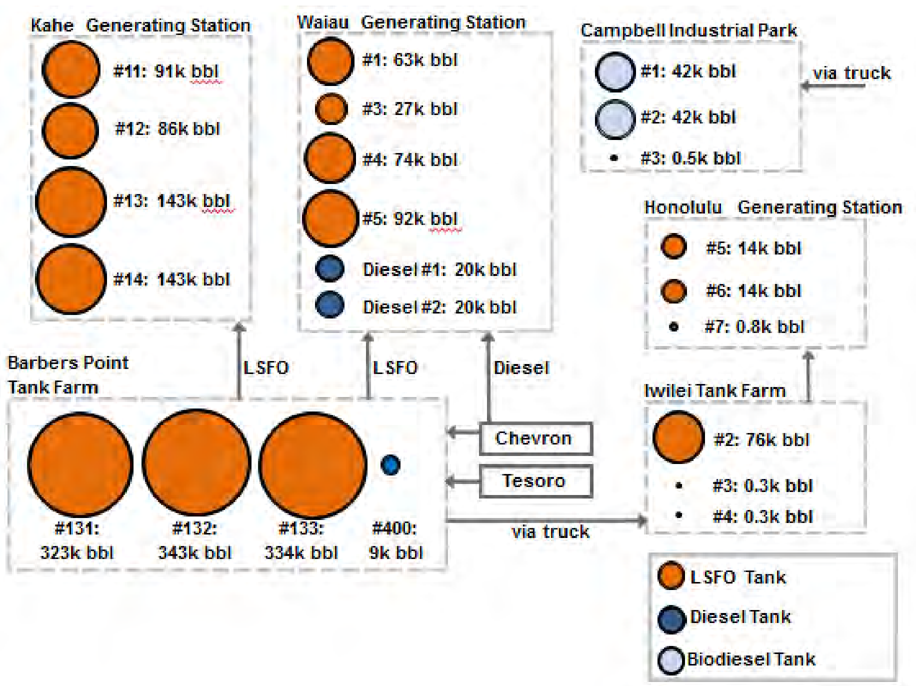



### 3.5 Current Fuel Storage

In addition to the fuel storage tanks owned and operated by Chevron and Tesoro, Hawaiian Electric maintains two bulk storage tank farms and fuel storage facilities at each of its generating stations. Hawaiian Electric's central bulk storage facility, BPTF, includes three large heated tanks which provide a total of 1 million barrels of bulk storage for LSFO from Chevron and Tesoro, with ultimate delivery to Kahe, Waiau, and HPP. Each of the power plants has on-site fuel storage for their working fuel inventories. Kahe has approximately 460,000 barrels of LSFO storage across four tanks. Waiau has approximately 260,000 barrels of LSFO storage across four tanks, plus two 20,000 barrel diesel tanks. HPP has two 14,000 barrel LSFO tanks on site, plus a 76,000 barrel tank at Iwilei Tank Farm bulk storage facility which is used to supply HPP with LSFO via pipeline. Two biodiesel tanks which hold up to 42,000 barrels are used to store supply for CIP CT-1.

A schematic of these storage units is presented in Figure 3-5.

Figure 3-5 – Hawaiian Electric Fuel Storage Tanks and Nominal Capacity




Current plant storage facility operations and quality control practices dictate that delivery occurs with one bulk storage tank being filled and then measured and tested before that fuel is available for consumption. A second tank is being filled while the first completes sampling and testing. A third tank is generally used to regulate the release of fuel to the power plant unit boilers, while a fourth tank allows redundancy for scheduled tank servicing and unplanned outages. External tank inspections occur every five years. Internal tank inspections can occur as frequently as ten years or sooner with the inspection cycle controlled by corrosion rate. When considerable work is needed, a tank can be out of service for up to a year.

Storage tanks owned by Chevron and Tesoro are used by the oil companies to store oil, blending components, refinery processing and refinery production products, and fuel oil prior to sale to the Companies. Dedicated refinery tanks provide product accumulation capacity prior to delivery of fuel to the Companies.

**a. Current Fuel Inventory Policies**

Current fuel inventory policies are described in detail in the inventory study completed by Black & Veatch.[17] This study performed a single contingency analysis to quantify the minimum inventories needed to cover a single failure event, as well as a stochastic analysis to consider the impact of a confluence of events. The findings showed that the recommended average LSFO operating volumes were 0.99 million barrels in 2010, (47.1 days of storage at average consumption rates) and 0.90 million barrels in 2015 (47.8 days of storage at average consumption rates). The worst case contingency proved to be a refinery outage at Chevron or a supply tanker disruption. The stochastic analysis demonstrated that at these inventory levels, Hawaiian Electric would typically fall below these minimum levels 1.85% of the time in 2015.

At present, Hawaiian Electric targets a 47 day inventory level for LSFO. Upon the introduction of additional fuel(s) to the system, the Company may need to revise fuel inventory targets according to varying delivery and lead times of new fuels, as well as the prevailing risk of supply complications.

### 3.6 Current Fuel On-Island Distribution

As shown in Figure 3-3, Hawaiian Electric facilities at the BPTF serve as the central point for receiving LSFO from Chevron and Tesoro for distribution to Kahe, Waiau, and HPP. LSFO stored at the BPTF is heated to upwards of 200 ºF and pumped to Kahe through a 5-mile long Hawaiian Electric-owned 8-inch pipeline, which connects to a 12-inch pipeline segment for delivery to fuel storage tanks at Kahe. Generally, LSFO is continuously pumped at flow rates that match the fuel consumption or burn rate of the power plant.

LSFO is also heated and pumped by equipment at the BPTF for delivery to Waiau through a 13-mile long insulated 8-inch pipeline owned by Hawaiian Electric. Diesel fuel is batch delivered to Waiau from the Chevron Refinery through a Chevron owned 8-inch pipeline that passes by Waiau and extends to Chevron's Honolulu Harbor Terminal facilities.

LSFO for HPP is trucked under contract from the BPTF to Hawaiian Electric's Iwilei Tank Farm and then pumped to HPP through a 1.1-mile long 6-inch pipeline owned by Hawaiian Electric.

Biodiesel distribution does not currently employ pipelines. ISO containers are unloaded from container vessels at Honolulu Harbor and then trucked to CIP for discharge directly into the fuel tanks at CIP CT-1.

[17] Black & Veatch, *Hawaiian Electric Oahu Fuel Inventory Study, Final Report*, June, 2010. Filed with Hawaiian Electric's Rate Case, Docket No. 2011-0080.

Confidential Information Deleted
Pursuant to Protective Order
filed on December 14, 2009.

## 4. FUTURE STATE

In order to have a clear vision of what fuel infrastructure and procurement approaches are needed, it is necessary to create a view of a preferred “future state”. Hawaiian Electric is pursuing LNG as a future fuel that’s cleaner and less costly than the petroleum fuel options currently employed. Although LNG is Hawaiian Electric’s long-term fuel choice goal, it will not be available in Hawaii in sufficiently large volumes and in time to meet the increasingly stringent environmental obligations. During the interim, Hawaiian Electric is planning for a transition to diesel to achieve environmental compliance. Even after the successful introduction of LNG, diesel related storage and distribution investments will continue to be used; diesel will serve as a secondary fuel that would need to be available for immediate use in the event of any disruption to LNG supply or distribution.

As with the previous FMP, the future state for this FMP builds on the findings of Hawaiian Electric’s “Scenario Analysis of the Renewable Portfolio Standards Strategy” (RPS Scenario Analysis) report.[18] In that report filed with the Commission in 2011, four scenarios were examined which vary the amount of renewable energy brought onto the system, as well as the sales forecast. A complete description of the related demand assumptions can be found in the report. Based on those target volumes for biofuel supply, production simulations were used to determine the quantity of LSFO needed in each of the four scenarios. The resulting volumes for both LSFO and biofuel were then used in the February 2012 FMP to provide planning for fuel procurement, delivery, storage, on-island distribution, and inventory policies. Those numbers remain the latest available, but it should be noted that updated projections are being prepared.

### 4.1 Future Fuel Demand

Based on the RPS Scenario Analysis, the Companies have established biofuel target volumes to help achieve the RPS goals, ensure reasonable costs, and position the Companies to have the flexibility to respond to the uncertainties associated with predicting the Companies’ RPS future. The biofuel target volumes determined in the RPS Scenario Analysis were 300,000 barrels (12.6 million gallons) for 2015 and 1.3 million barrels (54.6 million gallons) for 2020. Even though the RPS scenarios are the same as before, biofuel target volumes are likely to change when the new projections are released in June 2013. Based on these new projections, biofuel target volumes will be updated and incorporated in the next FMP.

### 4.2 Future Fuel Delivery to Oahu

Hawaiian Electric needs to increase its capability to take delivery of additional fuels directly from offshore sources to expand its options for maintaining a secure supply of petroleum fuels. Utility industry experience shows that the availability of alternative and independent fuel receiving, handling, and storage solutions is critical to negotiating economically reasonable fuel and fuel transportation contracts. The ultimate goal of Oahu fuel delivery has been to create the flexibility for timely, efficient, and cost effective supply of liquid fuels.

The two most promising near-term options for improving the delivery options for importation of liquid fuels to Oahu for Hawaiian Electric’s use are (1) [redacted]

[18] Docket No. 2011-0112, filed in response to CA-IR 18.

Confidential Information Deleted
Pursuant to Protective Order
filed on December 14, 2009.

[redacted] and (2) building Hawaiian Electric's Kalaeloa Pipeline, with access to an existing fuel hatch in KBPH. Further, with Tesoro's latest decision on closing the Kapolei Refinery and changing its business model to terminalling only, a long-term dependence on Tesoro creates additional uncertainty in relying on the first option alone. Therefore, Hawaiian Electric plans to secure its own harbor access which consists of its planned Kalaeloa Pipeline from KBPH to BPTF.

### 4.3 Future Fuel Storage

At present Hawaiian Electric has no anticipated need for additional storage facilities. The shift in primary generation fuel from LSFO to diesel is not expected to require new storage infrastructure, and biodiesel can be blended with diesel on site or burned at other dedicated facilities. This flexibility minimizes the need for segregated biodiesel storage at each node of the distribution system.

#### 4.3.1 No additional storage needed to support petroleum fuel

Hawaiian Electric does not expect any additional storage facility needs resulting from the transition to diesel; the current LSFO infrastructure can be retrofitted to store diesel. Hawaiian Electric's conversion to diesel, as detailed in Section 5, will take place in stages that allow sequential conversion from LSFO to diesel of the bulk fuel storage tanks at BPTF as well as the tanks at the plants.

#### 4.3.2 No additional storage needed to support biofuel

There are no additional storage needs anticipated for biofuel at this time. The switch from LSFO to diesel would also accommodate increased use of biofuels more readily, since biodiesel can be homogeneously blended with diesel and the blend will remain stable, obviating the need for additional segregated storage at BPTF or the plants. In addition, whereas Hawaiian Electric's integration of biofuel previously centered around acquiring biocrude, biodiesel is more readily available in the market and has become cost competitive when compared to biocrude.

Previously, when co-firing biocrude with LSFO was a primary renewable fuel generation strategy, the necessary preparation of Kahe for operational use of biocrude, including the addition of separate biofuel storage tanks, was estimated to cost $70 million to $80 million. The previous FMP and related strategy also envisioned the development of a greenfield bulk fuel storage facility, the planned KFT, capable of receiving and storing multiple types and grades of generation fuels on Oahu, having an estimated cost between $150 million and $200 million. Elimination of these infrastructure projects is the result of the Companies' current fuels strategy for the planned switch to diesel in the intermediate-term, the change from biocrude to biodiesel as the primary, future renewable fuel which avoids the need for segregated biofuel storage and firing, and the long-term planned use of LNG. The reduction of these previously expected capital expenditures coupled with the decision to forego purchase of land for the bulk fuel storage facility, discussed below and estimated at $14 million to $20 million, represents approximately $300 million that is no longer part of the current strategy.

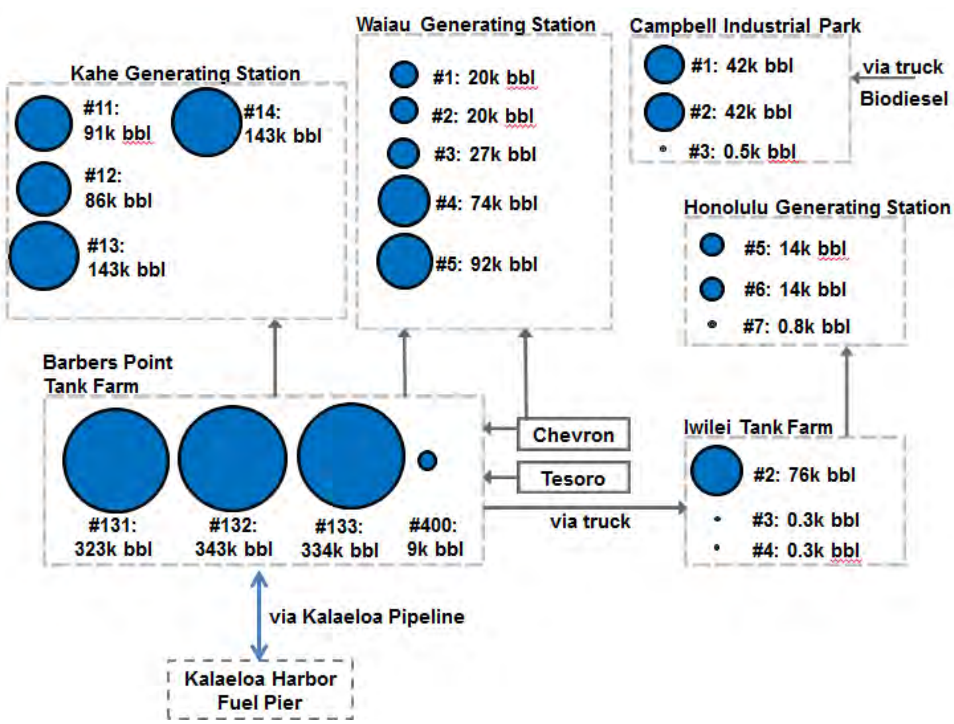
#### 4.3.3 Kalaeloa land no longer needed

To support Hawaiian Electric's previous fuel infrastructure expansion strategy, the Company sought to acquire a 26-acre parcel of land in the vicinity of KBPH. However, Hawaiian Electric no longer needs the land for additional liquid fuel storage tanks. Under current plans, the preferred biofuel is biodiesel, which can be blended and stored with diesel fuel. With Hawaiian Electric currently in the process of evaluating diesel as a replacement for LSFO to achieve environmental compliance, existing fuel storage infrastructure is expected to provide adequate storage capacity, such that acquiring the land is no longer necessary. Accordingly, Hawaiian Electric will not seek to purchase the parcel near KBPH.

#### 4.3.4 Future fuel storage infrastructure

Figure 4-1 shows a potential future state for the fuel storage infrastructure, which will primarily support diesel consumption and does not include additional storage tanks. Note that the current Waiau Tank 1 (63 kBbl capacity) used for storing LSFO, which is not shown on the figure, has been deemed unsuitable due to age and location; it is expected to be retired prior to the switch to diesel at Waiau.

**Figure 4-1 – Potential Future State for Fuel Storage after 2015 through 2019**




26

Confidential Information Deleted
Pursuant to Protective Order
filed on December 14, 2009.

### 4.4 Future On-Island Fuel Distribution

To support the Companies' fuel infrastructure future state shown in Figure 4-1, the primary unmet on-island fuel distribution system need becomes the ability to efficiently access imported bulk fuel delivered via tanker by the development of a delivery mechanism connecting such waterborne supply to Hawaiian Electric's existing BPTF storage facility. Hawaiian Electric plans to construct its Kalaeloa Pipeline from the Hawaiian Electric Pier 5 fuel hatch at KBPH to the BPTF for receipt and storage in existing tanks. This investment will primarily provide greater energy security that cannot be obtained with ongoing reliance on other companies' pipelines for essential fuel delivery, and will facilitate off-shore third-party supply options for acquiring the increase in imports which will be driven by the close of the Tesoro Kapolei Refinery and the switch to diesel.

### 4.5 Future Fuel Procurement

Fuel procurement and delivery will be a primary organizational focus for the next several years in line with converting Hawaiian Electric generation to the consumption of lower emissions fuels. Hawaiian Electric's demand for low emission fuels including biodiesel, ULSD, and lower sulfur diesel will far outpace the supplies refined on-island, a problem now affected by the closure of the Tesoro Kapolei Refinery, the only Hawaii producer of ULSD. Therefore, sourcing options based on off-shore supply are no longer simply a potentially optimal commercial strategy, but may be a necessity because a material part of the State's petroleum product demand, including the Companies', will be imported by Tesoro, Chevron, Aloha or others. By 4Q 2013, the Company will complete field emissions testing which will permit a full evaluation of alternate petroleum fuel paths for MATS and NAAQS compliance to permit a more precise definition of the type and quantity of its future fuel requirements. It is also anticipated that by that point [redacted]

Access to imported supplies of a variety of grades of liquid fuels in bulk at KBPH would be significantly enhanced by both obtaining from Tesoro provisions for larger volume, expanded fuel types and long-term use of their refinery-to-harbor pipeline system under an expanded throughput agreement and by installing the planned Kalaeloa Pipeline. Controlled direct entry of imported supplies into the Hawaiian Electric fuel system would allow not only expanded delivery options, but potentially could provide a means for the Companies to avoid commercial capture by a single or limited number of fuel suppliers. By increasing the number of potential suppliers, there is greater potential to ensure competitively procured fuel for the benefit of the Companies and its customers.

## 5. GAP ANALYSIS

The Companies need to achieve certain emission levels with regards to NAAQS, MATS, and RICE NESHAP. Table 5-1 revisits the compliance requirements presented in Section 3 and summarizes these emission limitations. The remainder of this section then introduces the changes that must be made, by each company, to meet its fuels-related objectives.

**Table 5-1 – Environmental Regulations and Compliance Requirements for the Companies**

| | Hawaiian Electric | HELCO | MECO |
|---|---|---|---|
| NAAQS | Need to reduce ambient pollutant concentration levels, particularly $SO_2$ | Need to reduce ambient pollutant concentration levels, particularly $SO_2$ | Need to reduce ambient pollutant concentration levels, particularly $SO_2$ |
| MATS | Need to reduce filterable PM emissions for oil-fired steam generating units | Does not apply | Does not apply |
| RICE NESHAP | Need to establish additional work practices for emergency RICE units | Need to reduce CO emissions for all reciprocating internal combustion engines | Need to reduce CO emissions for all reciprocating internal combustion engines |

### 5.1 Hawaiian Electric

#### 5.1.1 Environmental Compliance Strategy

With Hawaiian Electric's current fuel portfolio primarily composed of LSFO consuming steam units and the corresponding infrastructure which evolved to receive, store and distribute a heavy, high temperature and viscous type of fuel, compliance with MATS and NAAQS is challenging and requires an aggressive timeline of activities.

**MATS requires a switch to diesel by April 2015, barring extensions or alternative fuels success**

All the steam units at Hawaiian Electric are subject to MATS compliance requirements that impose filterable PM emission limits of 0.03lb/MMBtu. Hawaiian Electric's assessment indicates that switching to diesel would achieve this low emission level. However, there will be significant risk and challenge associated with transitioning the fuel storage and generation fleet in time to meet the April 2015 compliance date. There are two potential extensions which Hawaiian Electric is pursuing to ensure reliable electricity services to its customers during the compliance transition period.

- The first extension is the Broadly Available One Year Extension ("BAOYE") authorized by the CAA and can be granted by State of Hawaii permitting authorities. It is subject to the State's DOH approval with a 120 day advance notice. Hawaiian Electric plans to issue a BAOYE request to the DOH by December 2014.
- The second is also a one-year extension, which must be granted by EPA Administrative Order ("AO"). EPA has provided guidance for seeking such an AO, which includes stringent

criteria, including the filing (1) an Early Notice of Compliance Plan with the Commission by April 2013, (2) a Reliability Study with the Commission in 2015, and (3) an AO request with the EPA by October 2015.

Irrespective of whether Hawaiian Electric will need one or both extensions, Hawaiian Electric is developing an early notice of compliance plan for submittal to the Commission in April 2013, which will outline Hawaiian Electric's plans for compliance and estimated schedules based on the best information and analysis currently available. This April 2013 submittal is required by the EPA in order for Hawaiian Electric to consider requesting the second one-year extension through an AO.

Hawaiian Electric is also actively seeking lower-cost MATS-compliant alternatives to diesel that would fundamentally use the existing LSFO supply and distribution infrastructure, allowing for MATS compliance sooner than would be possible if a fuel switch to diesel was required; and thereby mitigating the cumulative risks, costs and disruptions that are associated with the various fuel transitions occurring statewide over the next five years. Among these alternatives are three alternate fuel paths that will be evaluated from 1Q through Q3 2013:

- A fuel additive, namely calcium nitrate, with LSFO to improve combustion conditions to achieve lower emissions.
- A LSFO with slightly modified quality specifications, such as lower ash content or lower density, for example, combustion of which would result in lower emissions.
- A blend of LSFO and diesel that would potentially lead to filterable PM emissions less than 0.03lb/MMBtu.

**Best option for meeting the schedule for NAAQS compliance will be switching to diesel**

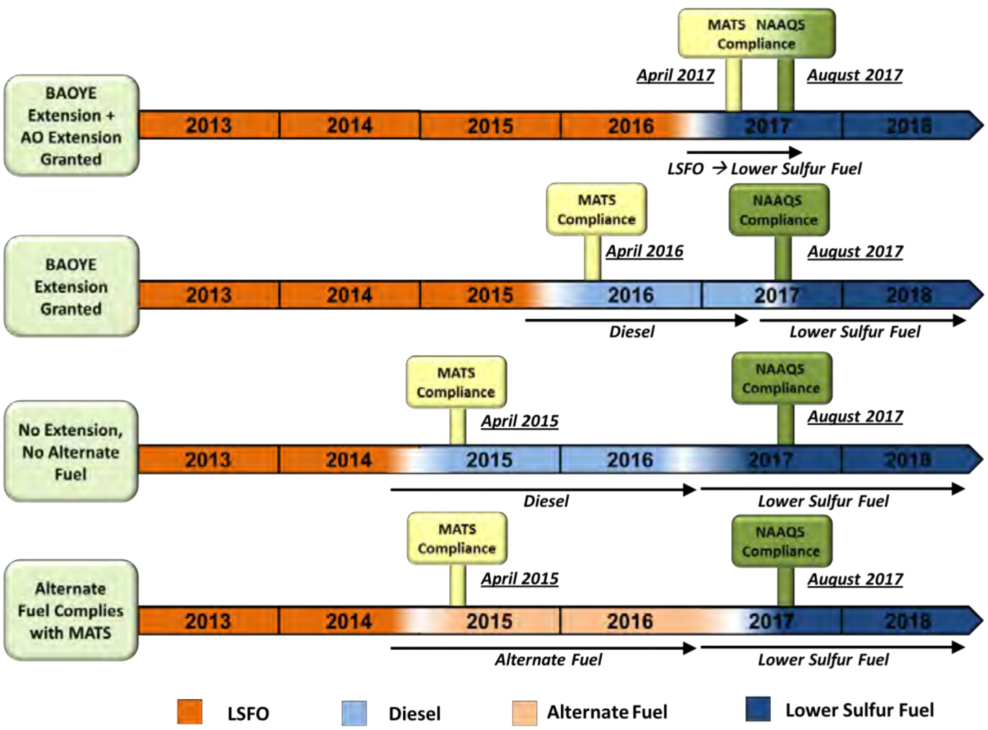
All Hawaiian Electric units are subject to NAAQS compliance requirements. Lowering sulfur emissions to desired levels can be achieved by one of two primary options: 1) by installing air quality control equipment (backend controls), or 2) by switching to lower sulfur fuel. As stated previously, LNG would also be a NAAQS compliant fuel, but the development of bulk importation, re-gasification and distribution infrastructure and generating unit modifications to permit a transition from a liquid fuel consuming generation system to LNG does not appear technically feasible by 2017.

Backend controls for Hawaiian Electric units are estimated to represent approximately $900 million in capital expenditures, and an investment of that magnitude needs to be evaluated in the context of the age of the units and the prospects for transitioning to LNG shortly thereafter (natural gas would likely burn clean enough to meet NAAQS on its own, rendering any major pollution control equipment unnecessary from a pure compliance perspective). Ultimately, however, backend controls is not a viable option because it would not allow Hawaiian Electric units to be NAAQS compliant by 2017, due to the time needed to install the equipment.

At this time, switching to lower sulfur fuels thus appears to be the best option for complying with NAAQS sulfur standards. For Hawaiian Electric's steam units, although switching from LSFO to a lower sulfur fuel, such as diesel, may represent approximately $160 million/year in additional fuel costs[19], fuel switching is a more flexible option than backend controls in regards to the compliance timeframes, and would serve as a secondary or contingency fuel to LNG in the future. The on-going Integrated Resource Planning ("IRP") process will further analyze this fuel switching strategy under various scenarios. The IRP process is scheduled for completion by the end of June 2013.

Figure 5-1 below illustrates potential changes to the MATS and NAAQS compliance timeline based on different scenarios. The color scheme distinguishing different fuel types indicates how costs might compare from one scenario to another depending on when the costly switch from LSFO to diesel is first made.

**Figure 5-1 – Hawaiian Electric MATS/NAAQS Compliance Schedule with Alternative Compliance Plans**




[19] $160 million/year is estimated based on Hawaiian Electric's fuel price and consumption forecast for 2015, as referenced in the new Chevron and Tesoro LSFO Supply Contracts application to the Commission in Docket No. 2012-0217.

30

Table 5-2 summarizes the options identified for MATS and NAAQS for Hawaiian Electric compliance along with their estimated costs, potential benefits, and risks.

**Table 5-2 – Compliance options for MATS and NAAQS with costs, benefits and risks**

| | Cost[1] | Benefits | Risks |
|---|---|---|---|
| **Alternate Fuel Options (for MATS only)** | Capital: Negligible<br><br>Change in fuel cost: less than $160 M/yr | Fuel cost savings; meeting compliance obligations in time | In demonstration stage; uncertainty in emission performance |
| **Switch to Diesel** | Capital[2]: $50 M<br><br>Change in fuel cost: approx. $160 M/yr | Cost-effective solution for short term given LNG as a future option | Inadequate supply on the islands; offshore supply constraints |

[1] All figures are approximate and subject to change upon further evaluation.
[2] Switch to diesel capital cost includes $23 million for installing berm liners and $27 million in generation retrofits (the $30 million Kalaeloa Pipeline project is not included here).

### 5.1.2 Fuel Storage

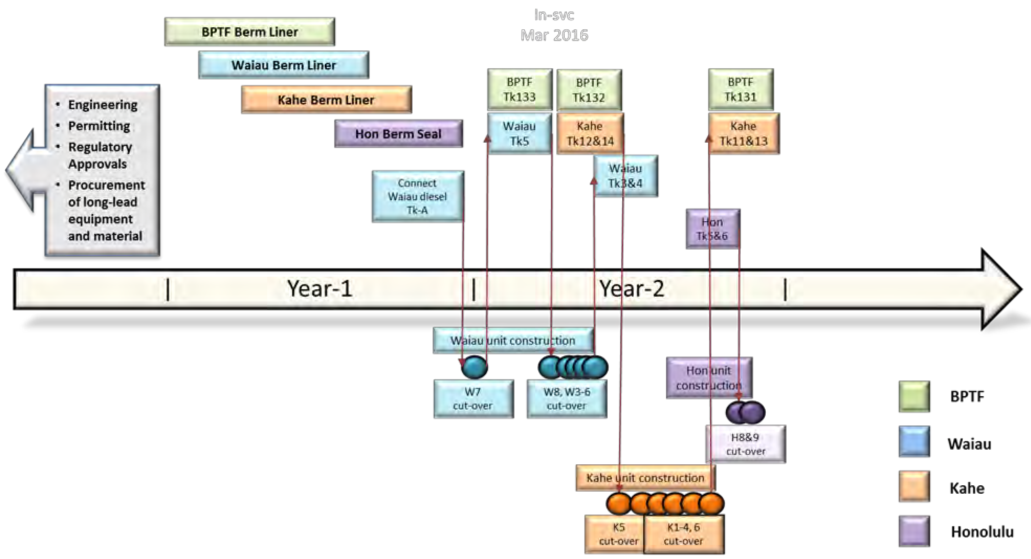
The conversion to diesel will require Hawaiian Electric to make preparations for proper storage of diesel at the tank farms, as follows:

**Install Berm Liners** – To prepare for the safe storage of diesel, Hawaiian Electric will need to install berm liners at Barbers Point, Kahe, and Waiau tank farms. Barbers Point Tanks 131, 132, and 133 will require one berm liner for the group. Kahe Tanks 11 and 12 will together require one berm liner, Kahe Tanks 13 and 14 will together require one berm liner, Waiau Tanks 3, 4 and 5 will together require one berm liner, and HPP Tanks 5 & 6 concrete berms will need to be sealed. Each berm liner installation will take up to four months to complete.

**Tank Cleaning –** Hawaiian Electric will need to strip and clean the fuel tanks of LSFO before replacing with diesel. High-pressure fuel recirculation will also be used to flush out and clean the fuel oil headers that run from each tank to the generating unit. The cleaning process has a turnaround of 6-8 weeks for each tank. After stripping and cleaning the tanks of LSFO, Hawaiian Electric will be able to store and run diesel to the generating units immediately.

Figure 5-2 illustrates a preliminary implementation timeline for diesel switch. The plan is still being developed, but the entire process to transition from LSFO to diesel (including tank berm liner installation) could take as long as two years. Sequencing and all other specifics are subject to change, and will be discussed further in the next FMP update.

**Figure 5-2: Preliminary Implementation Timeline for Diesel Switch**




### 5.1.3 Fuel Supply and Delivery

An essential piece of Hawaiian Electric's fuel switch plan is to ensure adequate supply of fuel in the coming years and to ensure reliable fuel delivery and distribution. In addition to Tesoro's cessation of refining in Hawaii, Chevron is limited in the amount of diesel it refines in Hawaii. With the current uncertainties surrounding the future landscape of Hawaii's fuel supply chain and Hawaiian Electric's plans to switch from LSFO to diesel, the ability to source adequate supplies of fuel, and moreover increased supplies of diesel, is uncertain without direct, if not also controlled, access to imported supplies. To decrease Hawaiian Electric's dependence upon local third parties and expand delivery capabilities for imported fuel, Hawaiian Electric is planning for construction of its Kalaeloa Pipeline.

**a. Fuel Procurement**

The current LSFO contracts with Tesoro and Chevron expire in 2014 and 2016, respectively, and do not guarantee transition of an adequate supply of diesel. Therefore, Hawaiian Electric currently does not have a supply contract(s) in place for the projected diesel volumes needed for the MATS/NAAQS compliance plan. Hawaiian Electric should have a better understanding of the timing and quantities of future diesel requirements, and be in a better position to solicit diesel supplies, in 3Q or 4Q 2013. By then, Hawaiian Electric should know whether any of the LSFO-based alternatives to MATS compliance are viable, the ramifications of the Tesoro refinery closure will be clearer, and there would still be sufficient time to secure adequate diesel supplies to accommodate unit conversion schedules.

With regards to supply of biofuel, current contracts with PBI and REG provide for up to 8 million gallons of biodiesel supply per year through 2016. Biodiesel supplied by the REG contract is consumed at CIP CT-1 at a minimum volume of 3 million gallons per year, but the contract allows up to 7 million gallons if there is additional need. Fuel supplied by PBI will be consumed

Confidential Information Deleted
Pursuant to Protective Order
filed on December 14, 2009.

at HIA Facility at a minimum volume of 250,000 gallons per year and the contract allows up to 1 million gallons. Future biofuel volumes will depend on the competitive market opportunities available as well as the biofuel consumption projections to be evaluated in the analysis of the IRP process.

REG Biodiesel is currently transported from the mainland in ISO containers with approximate capacity of 6,000 gallons each (PBI supplies will be imported from the Big Island). Bulk fuel shipping routes from the US mainland to Hawaii via either tank barge or tanker are not currently established due to lack of commercial demand in scale and biodiesel production is not connected to export facilities via the web of common carrier West Coast pipeline systems as are petroleum products. The limitation makes loading of bulk ships for relatively small volumes of biodiesel unlikely at this time.

**b. Kalaeloa Pipeline Project**

In terms of fuel supply, one of the main challenges facing Hawaiian Electric's future compliance with MATS and NAAQS will be securing adequate supplies of diesel. At this time, Hawaiian Electric is actively considering various options as it confirms its environmental compliance plan, including diesel volume and timing requirements. As mentioned in Section 4, a key concern is that Hawaiian Electric's current supply pathways and agreements are not sufficient for acquiring increased volumes of diesel and pose reliability risks since they are dependent on third parties. To help ensure the security to its fuel supply, Hawaiian Electric is planning to construct the Kalaeloa Pipeline to allow independent supplier marine delivery into KBPH for discharge to BPTF. As part of its planning, Hawaiian Electric is examining various liquid fuel delivery mechanisms including the following:

- [redacted]
- [redacted]
- Capacity of the Kalaeloa Pipeline may need to be as high as 6.5 million barrels per year between 2016 and 2020. To accommodate this amount of supply, Hawaiian Electric will examine the option of connecting the new pipeline to two piers (Pier 5 and Pier 6), instead of one (Pier 5) to allow greater availability.

The Kalaeloa Pipeline will cost the Company an estimated $30 million through the project's forecasted completion in 2016. Hawaiian Electric plans to file an application for this project with the Commission in 2013. This new pipeline will facilitate the import of adequate liquid fuel

Confidential Information Deleted
Pursuant to Protective Order
filed on December 14, 2009.

supplies to the BPTF whether it supplements or is a substitute for the pipeline throughput agreement with Tesoro expiring in 2017. It is important that this project is completed on time in order to support Hawaiian Electric's timely compliance with NAAQS regulations in the event it is the only viable option for acquiring increased volumes of imported diesel, and to establish leverage in fuel procurement negotiations as the Companies seek new supply agreements. The project schedule for completion in 2016 includes the time required to obtain necessary easements for the pipeline.

#### 5.1.4 Cost Estimate

Based on currently available information, Table 5-3 provides cost estimates for the significant projects included in the FMP.

**Table 5-3 – Estimated Project Costs**

| Project | Estimated Capital Costs |
|---|---|
| Prepare Kahe, Waiau, HPP for diesel conversion: | |
| • Berm Liner Installations | $23 million |
| • Unit Conversion Retrofits | $27 million |
| Hawaiian Electric Kalaeloa Pipeline | $30 million |
| **TOTAL:** | **$80 million** |

### 5.2 HELCO

#### 5.2.1 HELCO Environmental Compliance Plans

Currently, apart from the changes associated with switching to lower sulfur IFO for boilers to comply with NAAQS, no major fuel infrastructure changes are planned at HELCO. While the RICE NESHAP compliance date of May 2013 is around the corner, efforts to install oxidation catalysts on all oil-fired units and to switch units below 2.5 MW from 0.4% to 0.0015% sulfur diesel (ULSD) are in progress. Switching to lower sulfur fuels is expected to ensure compliance with NAAQS. Therefore, no additional investment will be required to comply with NAAQS.

#### 5.2.2 HELCO and MECO Inter-Island Fuel Supply Contracts

HELCO and MECO inter-island fuel supply contracts with Chevron and Tesoro, under which Hawaiian Electric also obtains diesel for consumption by its Waiau combustion turbine generating units and for other uses, expire on December 31, 2014. The scope of the contracts includes supplies of high sulfur and ultra-low sulfur diesel grades (the latter only with Tesoro) and IFO, as discussed in Section 3.3, as well as providing options for neighbor-island terminalling and other services. Accordingly, HELCO, MECO and Hawaiian Electric [redacted]

34

Confidential Information Deleted
Pursuant to Protective Order
filed on December 14, 2009.

## 5.3 MECO

### 5.3.1 MECO Environmental Compliance Plans

MECO will achieve RICE NESHAP requirements by switching to ULSD on Lanai and Molokai's diesel engines and on the Maalaea's quick start diesel generating units M1, M2, M3, and X1, and X2 no later than May 3, 2013. Currently, piping is being changed to convert the 7,300 barrel high sulfur Tank 1A to ULSD. [redacted][20].

For NAAQS compliance at MECO, several measures will have to be taken at the Kahului and Maalaea units:

- For steam units at the Kahului plant, a switch to lower sulfur IFO will be needed.
- For M1-M3 units at Maalaea, fuel injection timing retards will be needed to allow more complete combustion and less buildup of pollutants. These changes must be completed to comply with NAAQS.
- For M4-M9 units at Maalaea, catalytic converters will need to be installed to achieve selective catalytic reduction for $NO_x$ reduction.
- For M4-M7 units at Maalaea, diesel particulate filters will also need to be installed to reduce particulate matter emissions.

The Maalaea project applications are planned for submittal to the Commission in 2014. Preliminary engineering is underway.

### 5.3.2 MECO Aloha Petroleum Terminalling Contract

Hawaiian Electric, in conjunction with MECO, solicited interest from Aloha Petroleum, Chevron, and Tesoro to determine their capabilities to provide diesel fuel storage for MECO at Kahului Harbor. Hawaiian Electric received Aloha Petroleum's infrastructure proposal for storage at Kahului in January 2012 and has finalized a Terminalling Agreement with Aloha Petroleum in December 2012. An application requesting Commission approval of the Terminalling Agreement is being prepared and is expected to be filed with the Commission in 1Q 2013. The new Terminalling Agreement with Aloha Petroleum for storage at Kahului Harbor would replace an Aloha Petroleum letter agreement dated February 17, 2012. This letter agreement extended an existing 1998 terminalling contract for the same assets that transferred to Aloha Petroleum when they acquired the facility from Shell Oil in May 2010.

### 5.3.3 MECO Kahului Land Purchase

[redacted]

[20] ULSD has been secured to meet HELCO's and MECO's RICE NESHAP requirement under the Tesoro Second Amendment, as approved by the Commission in Docket No. 2012-0031.

Confidential Information Deleted
Pursuant to Protective Order
filed on December 14, 2009.

[redacted] Further, with the new Aloha Petroleum Terminalling Contract (pending submittal to the Commission), [redacted]

36

## *6. CONCLUSIONS*

The Companies developed this FMP in large part to map the activities that will enable the Companies to comply with new environmental regulations. This plan sets out the near-term fuels strategy that enables the Companies to meet environmental regulations in a reliable and cost-effective manner. Plans for RPS compliance and LNG integration will become the central areas of focus in future editions of the plan.

The FMP filed with the Commission in February 2012 outlined approximately $300M of fuels related infrastructure projects that are no longer included in the Companies' current strategy. Instead, a total of $80 million in capital costs, which includes $50 million for meeting environmental compliance obligations, and $30 million for developing a Hawaiian Electric-owned pipeline, is projected. Therefore, the strategy outlined in this FMP presents a net overall cost reduction of approximately $220 million in capital costs compared to the February 2012 FMP.

The current projected capital costs include the following:

- Installing fuel tank berm liners on Oahu to accommodate diesel storage is estimated to cost $23 million.
- Generation-related retrofits on Hawaiian Electric's steam units to burn diesel are estimated to cost $27 million.
- Constructing a pipeline from KBPH to Hawaiian Electric's BPTF to facilitate the ability to directly import adequate fuel supplies will cost an estimated $30 million.

Table 2-1 in Section 2 outlines these near-term actions for Hawaiian Electric, HELCO and MECO.

Fuels procurement strategies continue to evolve because of environmental compliance timeline uncertainties and dynamic changes underway to the local petroleum industry landscape. The Companies will continue to update fuel sourcing plans and activities through the Quarterly Reports and subsequent semi-annual updates to the FMP filed with the Commission.

# Appendix J: Scenario Planning Advisory Group Information

During the week of August 20–24, 2012, the Companies held a workshop with the Advisory Group to develop a set of scenarios to be used as a basis for analysis and planning for the Integrated Resource Plan report. Approximately half of the Advisory Group members attended the workshop.

Before the workshop, the Companies distributed four documents to Advisory Group members so that they could prepare for, and better participate in, the workshop. These documents were:

1. Welcome and Overview Cover Letter
2. Ten Tips for Successful Scenarios
3. Scenario Thinking Defined
4. Advisory Group Pre-Read Packet

On the final day of the workshop, the Companies distributed a document that summarized how the work of the Advisory Group was coalesced into four planning scenarios:

5. Advisory Group Meeting 3 Outputs

This appendix contains each of these five documents.

# CONTENTS

# FIGURES

# TABLES

# Welcome and Overview (Cover Letter)

Welcome to the pre-reading package for Advisory Group Meeting #3. Meeting #3, spread over a full week and requiring about 20 hours of your time, will provide the Advisory Group with an opportunity to draft the scenarios that the utility will then use to analyze our Resource Plans. I know that 20 hours represents a major demand on your time, and we will make every effort to make sure we use your time fully and meaningfully.

The scenarios created by the Advisory Group during Meeting #3 will become an essential input into all of the Integrated Resource Planning the utility does from that point forward. And they will address the core need of the Integrated Resource Planning process which the Public Utilities Commission's IRP Framework states:

> The goal of integrated resource planning is to develop an Action Plan that governs how the utility will meet energy objectives and customer energy needs consistent with state energy policies and goals, while providing safe and reliable utility service at reasonable cost, through the development of ***Resource Plans and Scenarios of possible futures that provide a broader long-term perspective***.

## What Are Scenarios?

"Scenarios are stories about how the future might unfold for our organizations, our issues, and even our world. Importantly, scenarios are not predictions. Rather, they are provocative and plausible stories about diverse ways in which relevant issues outside our organizations might evolve, such as the future political environment, social attitudes, regulation, and the strength of the economy.

"Because scenarios are hypotheses, not predictions, they are created and used in sets of multiple stories, usually three or four, which capture a range of future possibilities, good and bad, expected and surprising.

"And, finally, scenarios are designed to stretch our thinking about the opportunities and threats that the future might hold, and to weigh those opportunities and threats carefully when making both short-term and long-term strategic decisions."[1]

During Meeting #3, the Advisory Group will be lead by a professional scenario consultant to ensure that the scenarios created establish a broader long-term perspective on the future than the utility could create on its own. These scenarios will then be carefully analyzed for planning implications that will ultimately shape the IRP Action Plans.

By tapping the breadth of perspective and wide range of experiences possessed by the Advisory Group, the scenarios we create together will be broad, divergent, and well informed. They won't necessarily predict the future, but they should provide a clear and shared perspective *on the range of possible energy futures* that the utility, and the citizens of Hawaii, might face as we look out over the next 20 years.

---

[1] From *Scenario Thinking Defined*, by Eamonn Kelly, President of Global Business Network, the world's leading scenario planning organization

## Pre-Read Materials and Pre-Work

Attached with this cover letter is a set of Scenario Documents — pre-read materials that will help you prepare for our time together next week. There are two documents on scenario planning, and one somewhat longer Pre-Read Packet including a range of helpful materials.

### Scenario Thinking Defined

Scenario Document # 1 is an article titled ***Scenario Thinking Defined***. This provides an excellent primer on what scenario planning is and how it is widely used to help create strategies which consider future uncertainties that are well informed by a broad set of stakeholder perspectives.

### Ten Tips for Successful Scenarios

Scenario Document # 2 is a tip sheet titled ***Ten Tips for Successful Scenarios*** written by two of the world's leading authorities on scenario planning.

### Advisory Group Pre-Read Packet

Scenario Document #3 is the ***Pre-Read Packet***, which has three major sections:

- *Driving Forces Pre-Work* lists major factors and forces that are likely to shape the future of both energy supply and energy demand in Hawaii. **As you read through this list, please make any mental notes you might have about powerful shaping forces that are not specifically called out on this preliminary list.** The document includes a section for you to add your thoughts. Bring these with you on August 20.
- *Utility Reference Material* includes four sections of essential background information:
  - "Utility Cost of Capital and Financial Information"
  - "Forecasted Fuel Costs" for all three of the Hawaiian Electric Companies
  - "Overall Demand for Electricity and Electricity Sales" forecasts, again from all three of the Hawaiian Electric Companies
  - Information on major "Environmental Regulations"
- *Glossary of Energy Terms* with explanations of fundamental electric utility terms.

## Workshop Schedule

The scenario development work during Advisory Group Meeting # 3 will be spread out over a full week. Monday and Tuesday will be full days led by one of the world's leading scenario planning experts involving detailed Advisory Group conversations and time spent developing the scenarios.

Our final Meeting #3 session will be held on Friday where we will have an opportunity to test what was created earlier in the week, refine it, and improve it. In the intervening two days (Wednesday and Thursday), the work completed on Monday and Tuesday will be cleaned up and made ready for our final testing on Friday.

Here's a more detailed flow of our full schedule for the week, including the critical sessions on Monday, Tuesday, and Friday where we will have the full Advisory Group convened in Oahu:

### Monday, August 20, 2012: 9:00am–5:00pm

- Morning session – Introduction to Scenario Planning and Isolating Essential Driving Forces
- Afternoon session – Moving from Essential Drivers to Rough Scenario Frameworks

### Tuesday, August 21, 2012: 8:30am–4:30pm

- Morning session – Moving from Scenario Frameworks to Scenarios
- Afternoon session – Closing in on the Draft Scenarios

### Wednesday and Thursday

- Advisory Group in recess
- Monday and Tuesday materials being refined for final review on Friday

### Friday, August 24, 2012: 10:00am–3:00pm

- Morning session – Review of Emerging Refined Scenarios
- Afternoon Session – Discuss What the Scenarios Mean for IRP

## In Summary

Again, I want to welcome you to Advisory Group Meeting #3, where we will collaboratively create the energy scenarios for Hawaii till 2032 that will allow us to create wise and flexible IRP Action Plans for the State's evolving energy needs. I look forward to seeing you on Monday, August 20.

Respectfully,

Lisa K. K. Giang, P.E.
*Director, Corporate Energy Planning Division*

# Ten Tips for Successful Scenarios

*by Peter Schwartz and Jay Ogilvy, GBN Cofounders*

1. **Stay Focused.** Your scenarios should be developed within the context of a focal question: a specific decision to be made or a critical issue or uncertainty of great importance facing the organization. By keeping your sights on the raison d'être for the exercise, your scenarios will be both coherent and relevant.

2. **Emphasize Diversity and Interactivity.** Assembling a team that includes different functions, levels, and backgrounds will produce richer, more compelling scenarios. The scenario plots should be the unique product of this interactive, team effort. If they are off-the-shelf stories, reflect the prejudices of only the most powerful people, or do not incorporate insights from all levels of your management, they will be less relevant and less likely to capture the imagination of your organization's future leaders.

3. **Keep It Simple.** Although clever and creative plots that illuminate the interaction of key forces can help to make scenarios memorable, this is not primarily a creative writing project. Simple plots and a few characters enable managers to understand, use, and communicate the scenarios more effectively.

4. **Get Beyond "High, Medium, and Low" Scenarios.** Each scenario should be based on a fundamentally different logic, not a continuum. Although all your scenarios must be plausible, they shouldn't just be variations on a theme that express the same assumptions about the business environment.

5. **Avoid Probabilities or "Most Likely" Plots.** The future is unpredictable; don't just select the scenario plots that appear most likely to unfold. The most surprising scenarios may produce the most learning for your organization. Do not assign probabilities to the scenarios; instead, remain open to all possibilities. And don't fixate on one scenario that you want to achieve. Scenarios are meant to illuminate different futures, complete with negative and positive dimensions.

6. **Don't Draft Too Many Scenarios.** Choose scenarios whose differences really do make a difference. Three to four scenarios are usually all you need; more get confusing and hard to remember. Portraying a few, truly divergent futures is the best way to challenge the mental maps of the decision makers and suggest very different implications and strategic options. Continually emphasize that there are no right or wrong, good or bad scenarios, but a set of distinct and plausible futures that could unfold.

7. **Invent Catchy Names for the Scenarios.** Be creative in crafting evocative scenario names that quickly convey the crucial changes in the business environment that will affect your organization. When faced with a crisis—or unexpected opportunity—your managers should be able to recall the relevant scenario by name. Culturally referential titles—popular songs, movies, TV shows, sports, even countries—are often memorable. One set of our scenarios was named after Beatles' songs: A Hard Day's Night, Help, Magical Mystery Tour, and Imagine.

8. **Help the Decision Makers Own the Scenarios.** One of the most powerful contributions to a good scenario process is the direct and ongoing involvement of key decision makers. These are the people who will be responsible for using and communicating the scenarios throughout the organization. Engage them as much as possible in writing, editing, and reviewing the final scenarios. No matter who drafts the scenarios, he or she must thoughtfully and fairly solicit and welcome comments and suggestions from the rest of the team.

9. **Plan to Plan.** Allow enough time; a traditional scenario process takes several months. Before the first workshop, set aside at least a month to schedule and conduct stakeholder interviews and research. The initial workshop should run at least two days, with the first day focused on driving forces and uncertainties. Giving participants "time to sleep on it" often reveals new insights into the second day's tasks: developing the skeletal scenario logics and plots. After this session, allow 4-6 weeks for interim research and drafting scenarios. In the second, two-day workshop, you will refine the scenarios, explore the implications of each scenario individually, and answer the strategic question, "so what?" across all of the scenarios collectively. A third, optional workshop may cover strategic options and /or communication strategies.

10. **Dedicate Resources to Communicating the Scenarios.** Communicating the scenarios and their implications is a critical part of the scenario process, not an afterthought. Scenario planning will fail if its product is merely a handsome report, read once by a few executives. Instead, scenarios can and should drive your organization's ongoing strategic conversation and learning. Once the scenarios have been tested with a small group, finalize plans to engage many more people in the learning experience. Consider augmenting the written narratives with theater, video, improvisation, "war rooms"—whatever will help bring these futures to life. The show-biz component that enhances the communication of scenarios suggests one final axiom: If you're not having fun, you're not doing it right!


## Scenario Thinking Defined

WHAT ARE SCENARIOS?
WHAT IS SCENARIO THINKING?
THREE GUIDING PRINCIPLES
WHY DO SCENARIO THINKING?

### What Are Scenarios?

Scenarios are stories about how the future might unfold for our organizations, our issues, our nations, and even our world. Importantly, scenarios are not predictions. Rather, they are provocative and plausible stories about diverse ways in which relevant issues outside our organizations might evolve, such as the future political environment, social attitudes, regulation, and the strength of the economy. Because scenarios are hypotheses, not predictions, they are created and used in sets of multiple stories, usually three or four, that capture a range of future possibilities, good and bad, expected and surprising. And, finally, scenarios are designed to stretch our thinking about the opportunities and threats that the future might hold, and to weigh those opportunities and threats carefully when making both short-term and long-term strategic decisions.

Done well, scenarios are a medium through which great change can be envisioned and actualized. Perhaps the clearest illustration of the power of scenarios is the influential set of scenarios developed in South Africa in 1991, when a diverse group of South African leaders—community activists, politicians, unionists, academics, economists, and business leaders—used scenario thinking as a way to envision paths to democracy as the country transitioned out of apartheid. Each resulting scenario described a very different outcome of the political negotiations that were then underway. One scenario, which the group called *Ostrich*, told of what would happen if the negotiations were to break down between the apartheid government and Nelson Mandela's African National Congress. Another scenario, *Lame Duck*, foresaw a world in which a prolonged transition left the government weak and unable to satisfy all interests. A third scenario, *Icarus*, described a South Africa in which the ANC came to power and its massive public spending resulted in an economic crash. The fourth scenario, *Flight of the Flamingos*, described how the apartheid government, the ANC, and their respective constituencies might slowly and steadily rise together. These scenarios, known as the Mont Fleur scenarios, were subsequently shared widely throughout South Africa, and became an instrumental common language that helped facilitate public debate in the transition to democracy.

## What Is Scenario Thinking?

Scenario thinking is both a process and a posture. It is the process through which scenarios are developed and then used to inform strategy. After that process itself is internalized, scenario thinking becomes, for many practitioners, a posture toward the world—a way of thinking about and managing change, a way of exploring the future so that they might then greet it better prepared.

The scenario thinking process begins by identifying forces of change in the world, such as new technologies or the shifting role of government, that may have an impact on the people served by a nonprofit organization, as well as on the strategic direction of the nonprofit itself. These forces are combined in different ways to create a set of diverse stories about how the future could unfold. Once these futures have been created, the next step is to try to imagine what it would be like for an organization or community to live in each of these futures. The exercise may sound simple—and in many cases it is. But the results are often surprising and profound. In the process of adding detail and color to each future, new issues or strategic concerns rise to the surface, and old issues get reframed.

For example, Tides, a family of nonprofits in the U.S. and Canada that provides funding and capacity-building services to organizations promoting social change, used scenario thinking to explore how the progressive movement—the broad political and social context for their work—could play out over the coming decade. Tides's leaders brainstormed forces that could shape the future of the progressive movement, such as the relationship between government and business, the growth of networks, and the degree of convergence and fragmentation between progressive issues. Then, they created a set of scenarios that explored how the future could develop in very different ways. The scenarios focused on how two forces especially important and influential to the future of progressive social change—the nature of progressive leadership and the role of the government— might evolve.

Tides's leaders then tried "living" in each scenario. They considered what the environment for nonprofits and the state of philanthropy would be in each world. Next, they rehearsed what Tides might actually do if each scenario were reality: How would they need to adapt? Who might they partner with? What new opportunities and challenges would they face? By looking at the broader context framing their work, Tides's leaders were able to make important connections and surface new opportunities across their complex and wide reaching organization. In addition, the scenarios allowed them to see anew the potential cumulative power of the various parts of the organization.

This kind of strategic thinking, as the management thinker Henry Mintzberg describes it, is a combination of formal and informal learning that requires the powers of judgment and intuition to analyze shifts in the environment and produce new perspectives, insights, and catalysts for action. Ultimately, the point of scenario thinking is not to write stories of the future. Rather, it is to arrive at a deeper understanding of the world in which your organization operates, and to use that understanding to inform your strategy and improve your ability to make better decisions today and in the future. When used in complex multi-stakeholder environments, as it was in South Africa, scenario thinking stimulates rich conversations about future possibilities that can result in common ground for adversaries and push like-minded advocates to challenge their shared assumptions.

"Scenario thinking is a platform for structuring dialogue around a lot of loose ideas, making choices clearer," says GBN scenario practitioner Chris Ertel. "It rewrites the way you think about the future." At its most basic, scenario thinking helps people and organizations order and frame their thinking about the longer-term future while providing them with the tools and the confidence to take action soon. At its fi nest, scenario thinking helps people and organizations find strength of purpose and strategic direction in the face of daunting, chaotic, and even frightening circumstances.

## Three Guiding Principles

Pierre Wack, the originator of scenario thinking as it is commonly used today, described it as a discipline for encouraging creative and entrepreneurial thinking and action "in contexts of change, complexity, and uncertainty." Scenario thinking achieves this promise because of three fundamental principles: the long view, outside-in thinking, and multiple perspectives.

### *The Long View*

The day-to-day work of nonprofits is usually driven by near-term concerns and urgent needs: people are hungry, there are social injustices, funding must be secured. And as nonprofits are pushed to produce measurable outcomes in the short term, their planning horizons can become increasingly near-sighted. Scenario thinking requires looking beyond immediate demands and peering far enough into the future to see new possibilities, asking "What if?" For participants in the Mont Fleur scenarios, the long view meant stretching themselves to imagine a future of radical collaboration between the African National Congress and the apartheid government. For a U.S. nonprofit that relies on the work of volunteers, the long view might mean considering how the impending retirement of the Baby Boomers could affect their work and their reach. How might nonprofits tap the opportunity that this group represents? On the other hand, given rising healthcare costs, a sputtering Social Security system, and increasingly atomized families, will nonprofits be ready to respond to the needs of the growing aging population?

## THE ORIGINS OF SCENARIO THINKING

The idea of scenarios—telling stories of the future—is as old as humankind. Scenarios as a tool for strategy have their origins in military and corporate planning. After World War II, the U.S. military tried to imagine multiple scenarios for what its opponents might do. In the 1960s, Herman Kahn, who played an important role in the military effort, introduced scenarios to a corporate audience, including Royal Dutch/Shell. In the 1970s, Pierre Wack, a planner for Shell, brought the use of scenarios to a new level. Wack realized that he had to get inside the minds of decision-makers in order to affect strategic decisions—and scenarios could enable him to do so. Wack and his team used scenarios to paint vivid and diverse pictures of the future so that decision-makers at Shell could rehearse the implications for the company. As a result, Shell was able to anticipate the Arab oil embargo, and later to anticipate and prepare for the dramatic drop in oil prices in the 1980s. Since then, scenario thinking has become a popular tool for the development of corporate strategy in numerous industries.

The founding of Global Business Network in the late ‘80s helped accelerate the spread of scenario thinking. GBN is a network of organizations, scenario practitioners, and futurists from a variety of disciplines and industries. GBN codified the scenario thinking process and began to offer public training courses for strategists from across sectors. In the early ‘90s, there were successful experiments using scenarios as a tool for civic dialogue around large intractable issues, such as the future of South Africa at the end of apartheid. Around the same time, there were also public-sector efforts to use scenarios as an economic development tool, most notably by the Dutch and Scottish governments. Finally, with the growth of the nonprofit capacity-building movement in the 1990s, scenario thinking began to extend more rapidly into the U.S. nonprofit sector and into civil society organizations around the world. Today, the cumulative experience and innovation of scenario thinking is being applied and further evolved in the nonprofit context.

Such a long-term perspective may seem tangential to an organization's more immediate pressures. But for nonprofits that aspire to make fundamental change in the world, taking the long view is essential. Doing so enables you to take a more proactive and anticipatory approach to addressing deep-seated problems; see both challenges and opportunities more clearly; and consider the long-term effects and potential unintended consequences of actions that you might otherwise take.

### *Outside-In Thinking*

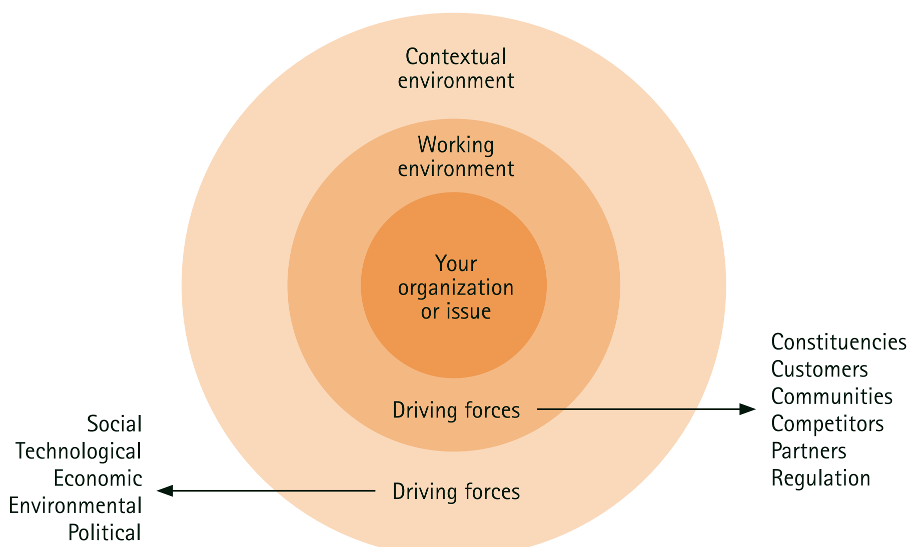
Most individuals and organizations are surprised by discontinuous events because they spend their time thinking about what they are most familiar with: their own field or organization. They think from the inside—the things they can control—out to the world they would like to shape. For a nonprofit that is caught in a cycle of responding to needs as they emerge, the realm of control is very narrow, as is the organization's peripheral vision—making it highly vulnerable to blindsiding.

Conversely, thinking from the outside-in begins with pondering external changes that might, over time, profoundly affect your work—a seemingly irrelevant technological development that could prove advantageous for service delivery, for example, or a geopolitical shift that could introduce unforeseen social needs. Thinking back to the late 1980s, most U.S. community foundations did not foresee financial service institutions, such as Fidelity, entering the business of donor-advised funds and becoming significant competitors. A decade ago, few U.S. public education administrators imagined that public schools would face such a wide range of competitors: charter schools, commercial players like Edison, vouchers. Outside-in thinking can help nonprofits anticipate and prepare for such "surprising" eventualities.

Figure J-1 illustrates a framework for outside-in thinking. The inner ring refers to your organization or the specific issue at stake. The middle ring is your immediate working environment, which includes forces of change such as your local community, partners, customers, and competitors. The outer ring is the contextual environment, which encompasses broad driving forces such as social values, geopolitics, governance, sustainability, and technology. These two outer rings—the contextual and the working environment—can easily blur into each other. But the distinction is helpful because it pushes you to consider not just immediate externalities, but also shifts in the contextual environment that are often overlooked when planning for the future. The scenario thinking process starts by exploring external developments, in both the broad contextual world and your working environment. Only after you've created scenarios about the external environment do you consider implications for your individual organization or issue.

Because most planning processes start by focusing on the organization and then move outward, the outside-in approach can feel uncomfortable or foreign at first. But once the concept is grasped, outside-in thinking can inspire more open and imaginative thoughts about a range of potential changes and strategies that may not have been visible otherwise. "Outside-in thinking is so important because it takes you out of your reality," said Ellen Friedman, managing director of the California Clinics Initiative, after leading her organization through a scenario thinking exercise. "Yes, it is threatening and challenging, but it is essential for moving forward."

Figure J-1: A Framework for Outside-In Thinking



### *Multiple Perspectives*

Introducing multiple perspectives is different from managing multiple stakeholders, which many nonprofits are very skilled at doing. The introduction of multiple perspectives—diverse voices that will shed new light on your strategic challenge—helps you better understand your own assumptions about the future, as well as the assumptions of others. When one is working with passionate convictions, it is easy to become deaf to voices you may not agree with. Yet consciously bringing these voices to the table exposes you to new ideas that will inform your own perspective and could prove extremely helpful in your effort to see the big picture of an issue or idea.

Consider, for example, the unusual coalition of Christian, Jewish, and environmental groups that launched the widely publicized anti-sports utility vehicle campaign "What Would Jesus Drive?" By integrating multiple perspectives that are not typically aligned or even associated with one another, the coalition was able to reframe the transportation and fuel efficiency debate as a "moral issue," resulting in an impressive national awareness campaign. In the first six months, the "What Would Jesus Drive?" campaign was the subject of over 4,000 media stories and garnered many front-page headlines.

The scenario thinking process creates a powerful platform for multiple (and often divergent) perspectives to come together. The result is an expansion of an organization's peripheral vision—you see new threats and opportunities that you otherwise may have missed. For the Schott Foundation, which used scenario thinking to develop strategy around the controversial issue of gender equity in education, multiple perspectives meant inviting a diverse group of people—including activists, corporate leaders, and policymakers representing different political ideologies—to enter into the scenario dialogue. "Before [the scenario experience] we only talked about what we wanted, and we assumed that the world was the world we envisioned inside our heads," said Schott's president, Rosa Smith. "[Now] we're much more willing to hear other voices."

# Pre-Read Packet

# Driving Forces Pre-Work

## What are Driving Forces and Why Do They Matter?

*Driving Forces* are the basic building blocks of scenario planning that are used to imagine how the future might unfold. Within the context of the IRP, driving forces are ***the key trends and developments*** shaping the ways in which energy will be both produced and consumed in Hawaii in the future. We at the Hawaiian Electric Companies have created a *preliminary* list of them for you below.

Because driving forces are so fundamental to creating scenarios for the IRP, we need to take special care in thinking about them as we launch this phase of the planning work. In particular, we need the Advisory Group's assistance to create the most comprehensive list of driving forces possible — a list that has been rigorously tested for blind spots. Your diversity of perspective and breadth of experience as a group are perfectly suited to this task.

These driving forces establish a foundation for creating scenarios to meet the stated goal of the Integrated Resource Planning process:

> The goal of integrated resource planning is to develop an Action Plan that governs how the utility will meet energy objectives and customer energy needs consistent with state energy policies and goals, while providing safe and reliable utility service at reasonable cost, through the development of Resource Plans and Scenarios of possible futures that provide a broader long-term perspective.

## Your Pre-work Assignment

Please read through the "Preliminary List of Driving Forces for Your Review" below. From your perspective, what is missing from it? Add what you feel is missing — as many drivers as you can think of — in the blank spaces that follow this preliminary list.

During the Advisory Group meeting #3, one of our first exercises together will be to share perspectives on the wide variety of driving forces that you see shaping the future of energy production and consumption in Hawaii. We'll say a lot more about doing that when we convene.

For now, please just review and think about this list. Then add any important trends and developments influencing the future of energy production and consumption in Hawaii between now and 2032 (the time horizon of the IRP) that you find to be missing.

## Preliminary List of Driving Forces for Your Review

- Cost of fossil fuels (especially oil as it is the primary form of fuel used by the utility's generating plants).
- Geopolitical factors influencing the availability of oil.
- Cost of alternative fuels like liquefied natural gas (a fossil fuel not presently used by the utility).
- Availability and feasibility of liquefied natural gas in Hawaii.
- Cost and availability of non-fossil fuels (like biofuels such as biodiesel.
- Availability of renewable energy (including solar, wind, geothermal, and hydro).
- Energy efficiency of individuals, households, and businesses.
- Overall effectiveness of Demand-Side Management (DSM) and the Energy Efficiency Portfolio Standards (EEPS).
- Amount of self-generation taking place (including the growth of small scale generating capacity owned by individuals, businesses, and private energy companies).
- Development of new technologies that could affect electricity use (such as electric vehicles) and breakthroughs in renewable energy technologies.
- Breakthroughs in other clean or cheap sources of power.
- Tax incentives for renewable energy technologies.
- Consumer demand for cleaner and more sustainable energy.
- Consumer willingness to pay for cleaner and more sustainable energy.
- Peak electricity demand for Hawaii as a whole and on individual islands.
- Scale and scope of new environmental laws.
- Enforcement of new environmental laws.
- Specific restrictions on greenhouse gas emissions.
- The broad effects of climate change.
- Weather patterns, specifically in Hawaii.
- Frequency and severity of natural disasters in Hawaii.
- Frequency and duration of power outages in Hawaii as a whole and on individual islands.
- Changes in overall population or population density across the islands.
- Impact of aging populations on energy consumption.
- Overall economic activity and growth across the islands.
- Overall economic activity and growth across the United States.

- Overall economic activity and growth around the world.
- New businesses creation across the islands.
- New job creation across the islands and the impacts of jobs on energy demand.
- The utility's ability to raise funds for infrastructure investments.
- Potential changes to the laws that govern the licensing of HECO, MECO, and HELCO as utilities.
- Ongoing costs of maintaining the utility's plants and infrastructure.

## Additional Driving Forces To Consider

Please add as many additional driving forces as you like, and bring this pre-work with you to the workshop on Monday, August 20.

- ______________________________
  ______________________________
- ______________________________
  ______________________________
- ______________________________
  ______________________________
- ______________________________
  ______________________________
- ______________________________
  ______________________________
- ______________________________
  ______________________________

# Utility Reference Material

Presented here are several sections of reference material about the Hawaiian Electric Companies.

## Utility Cost of Capital and Financial Assumptions

The Hawaiian Electric Companies finances its investments through two basic sources of capital (money): either debt (borrowed money) or equity (invested money). In both cases, the utility must pay for the certain rate of return for the use of this money. This rate of return is the utility's *Cost of Capital*.

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

Table J-1: Utility Cost of Capital

| Capital Source | Weight | Rate |
|---|---|---|
| Short Term Debt | 3.0% | 4.00% |
| Long Term Debt (Taxable Debt) | 39.0% | 7.00% |
| Hybrids | 0.0% | 6.50% |
| Preferred Stock | 1.0% | 6.50% |
| Common Stock | 57.0% | 11.00% |

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

Inflation annually raises the price for goods and services. This inflation affects how the utility operates, how we maintain costs, and how much we pay for new infrastructure to generate and transmit electricity. The utility's base assumptions are:

| | |
|---|---|
| Escalation Rate for O&M | 1.870% |
| Construction Escalation Rate for Capital | 3.000% |

## Forecasted Fuel Costs

To anticipate the potential cost of producing electricity, the Hawaiian Electric Companies project the cost of various fuels over the next twenty plus years. The utility burns several types of fuel.

- *Biodiesel* refers to a vegetable oil, animal fat, or other renewable liquid-based diesel fuel that can be used as a substitute for petroleum diesel.
- *Biocrude* is raw or unrefined plant oil, animal fat, or other renewable liquefied-based biofuel. This includes crude palm oil based blends.
- *Low Sulfur Fuel Oil* (LSFO) is HECO's primary fuel. It is a residual fuel oil similar to No. 6 fuel oil that contains less than 5,000 parts per million of sulfur; about 0.5% sulfur content.
- *High Sulfur Diesel* contains up to 4,000 parts per million of sulfur; or about 0.4% sulfur content.
- *Medium Sulfur Fuel Oil* (MSFO) or Industrial Fuel Oil (IFO) (also known as Bunker Fuel Oil) used by MECO and HELCO contains less than 20,000 parts per million of sulfur; or 2% sulfur content.
- *Ultra Low Sulfur Diesel* (ULSD) contains less that 15 parts per million of sulfur; or about 0.0015% sulfur content.
- *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.

## *Hawaiian Electric Company Fuel Forecasts*

The following figures depict the forecasts for these fuels for Hawaiian Electric Company for the island of Oahu.

Figure J-2: HECO Biodiesel Forecast: 2012–2035

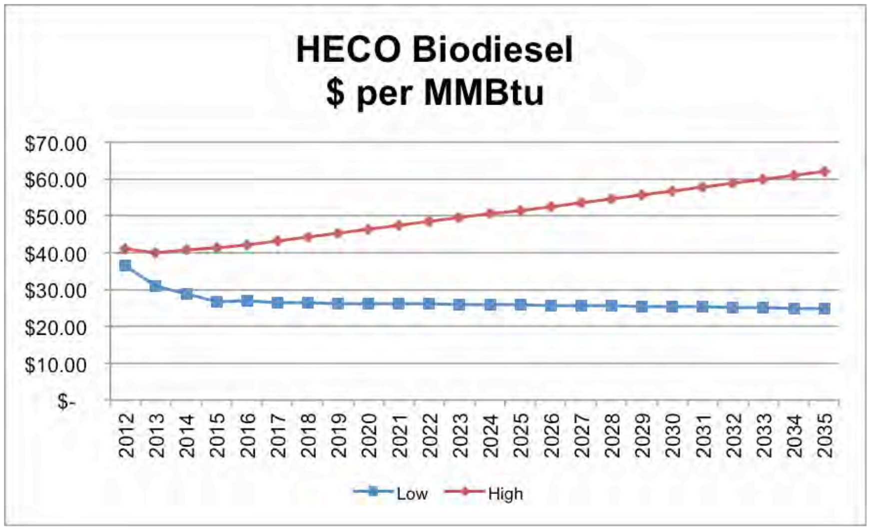



Figure J-3: HECO Biocrude Forecast: 2012–2035

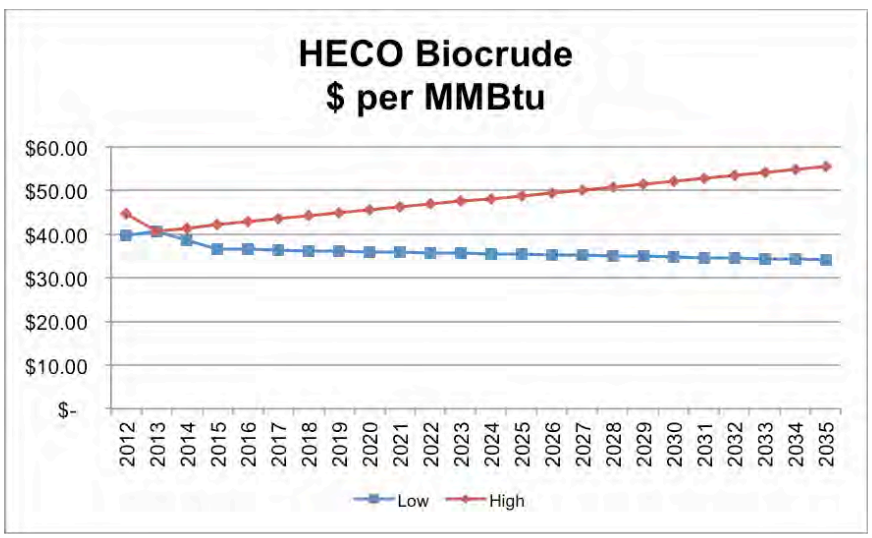


Figure J-4: HECO Low Sulfur Fuel Oil (LSFO) Forecast: 2012–2035

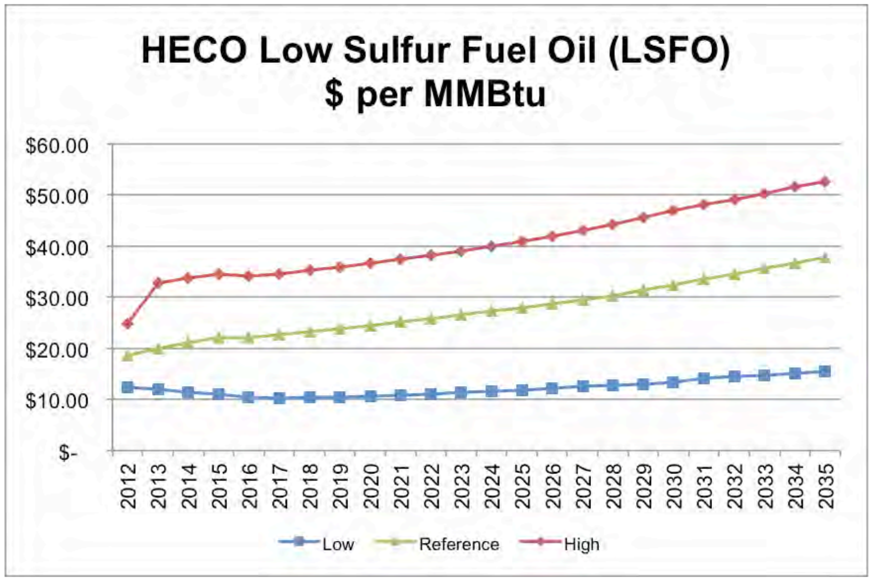



Figure J-5: HECO High Sulfur Diesel Forecast: 2012–2035

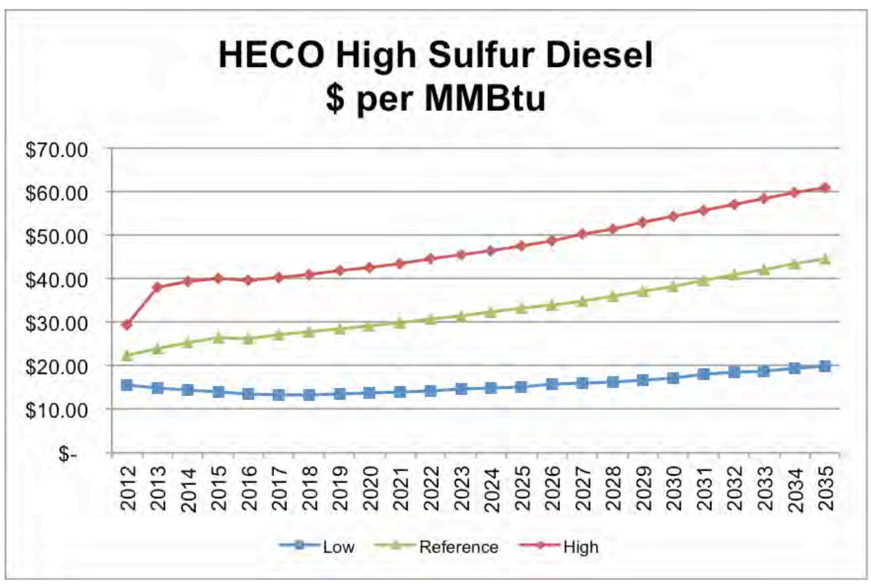


Figure J-6: HECO Ultra Low Sulfur Diesel (ULSD) Forecast: 2012–2035

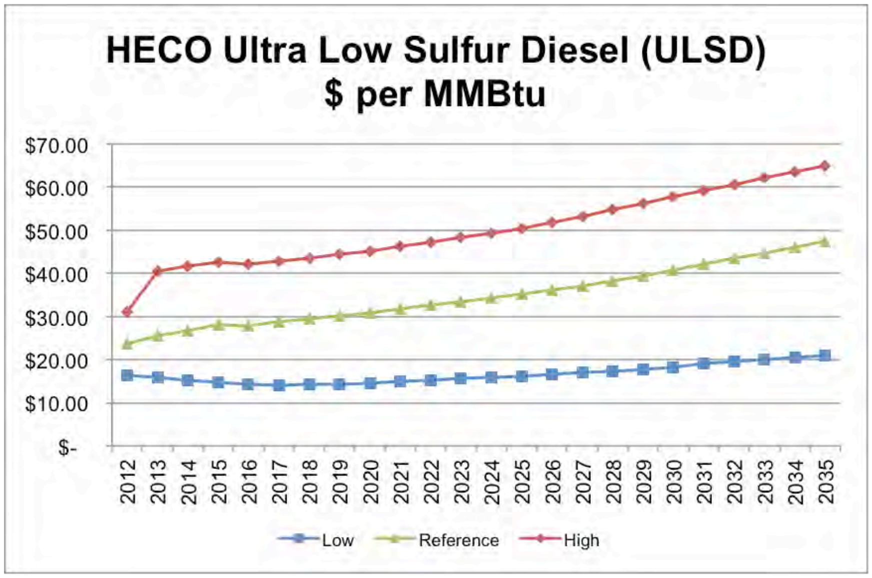



Figure J-7: HECO Liquefied Natural Gas (LNG) Forecast: 2018–2039

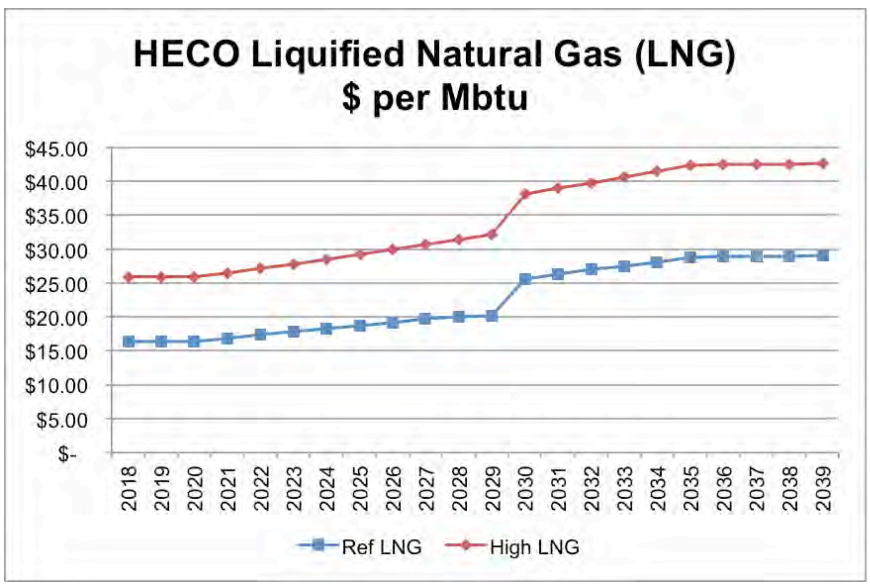
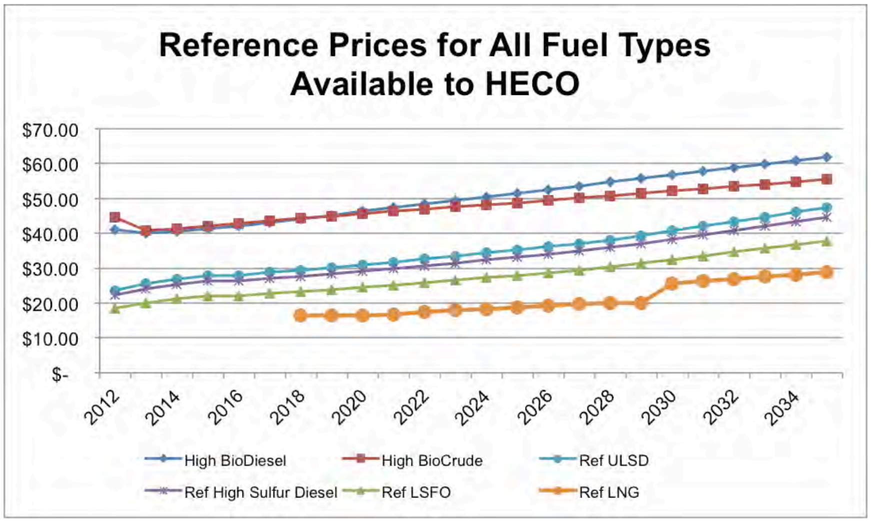


Figure J-8: HECO Reference Prices for All Available Fuel Types



## *Maui Electric Company Fuel Forecasts*

The following figures depict the forecasts for these fuels for Maui Electric Company for the islands of Maui, Lanai, and Molokai.

Figure J-9: MECO Biodiesel Forecast: 2012–2035

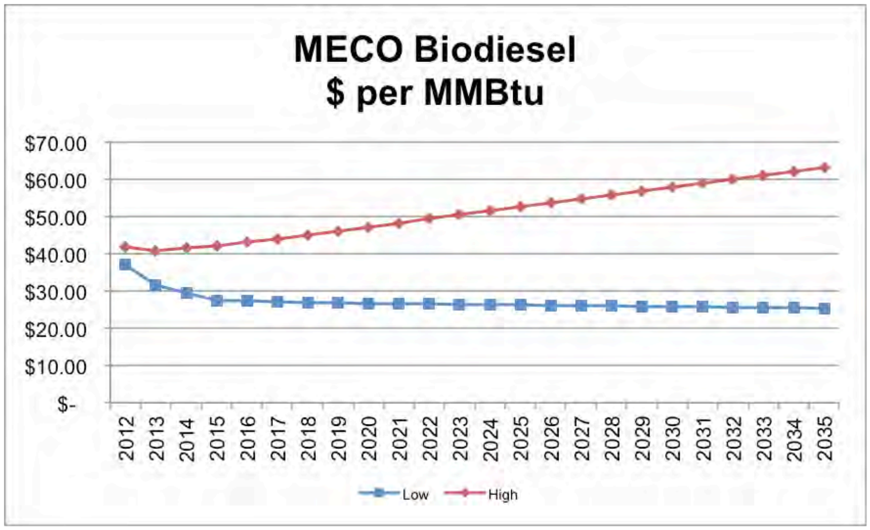



Figure J-10: MECO Biocrude Forecast: 2012–2035

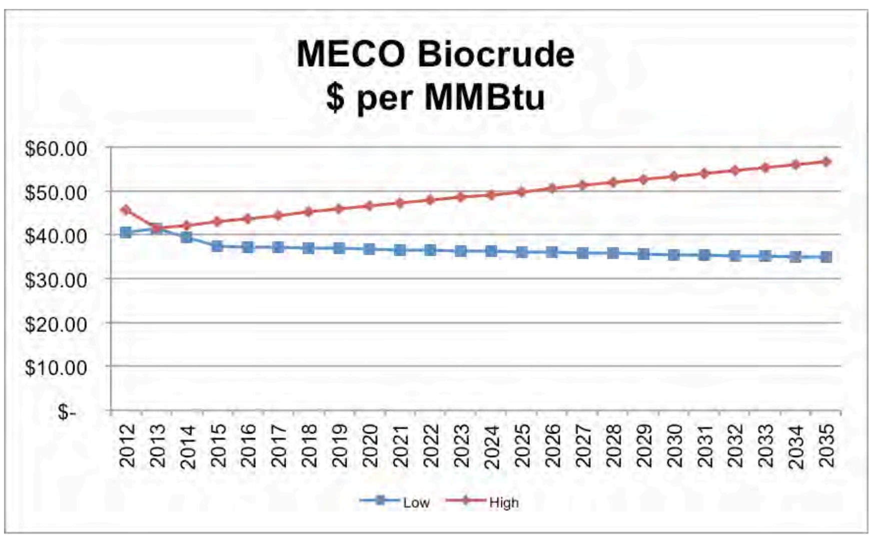


Figure J-11: Maui Medium Sulfur Fuel Oil (MSFO) Forecast: 2012–2035

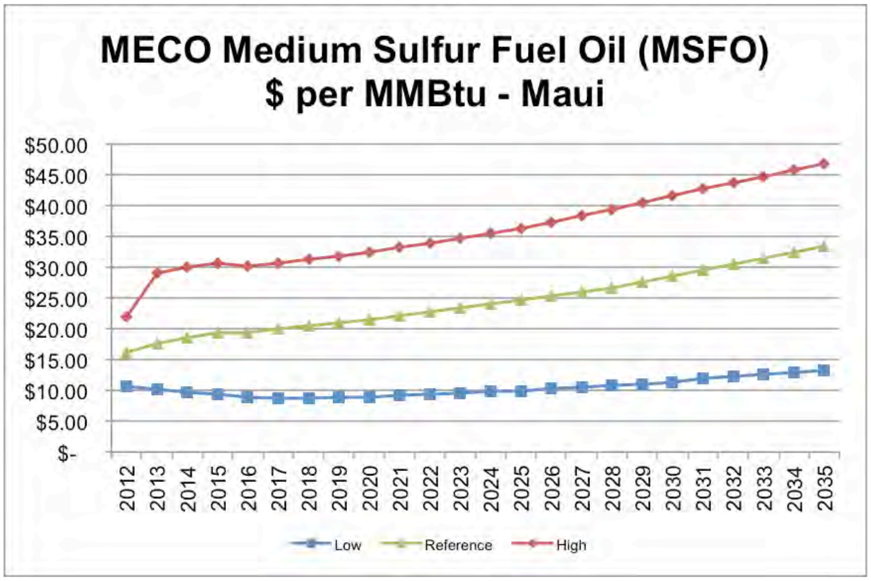



Figure J-12: Maui High Sulfur Diesel Forecast: 2012–2035

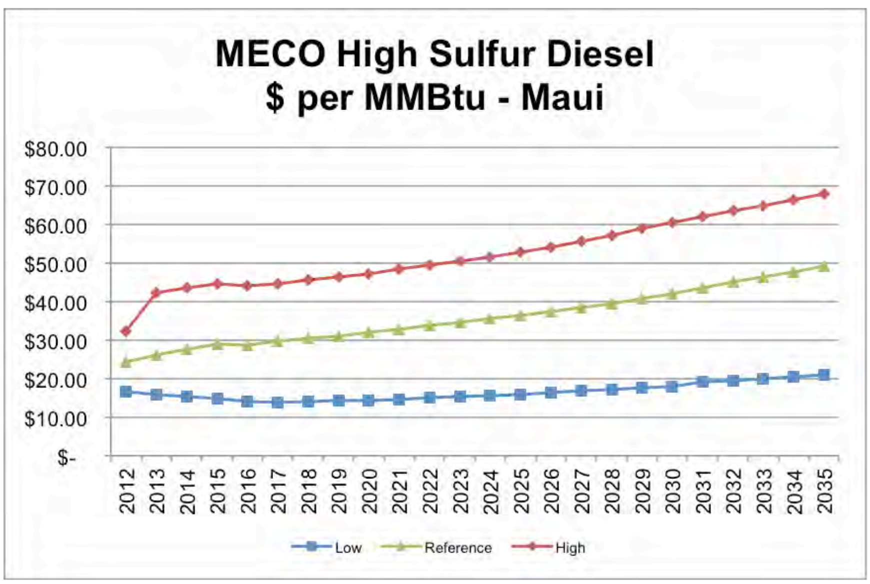


Figure J-13: Maui Ultra Low Sulfur Diesel (ULSD) Forecast: 2012–2035

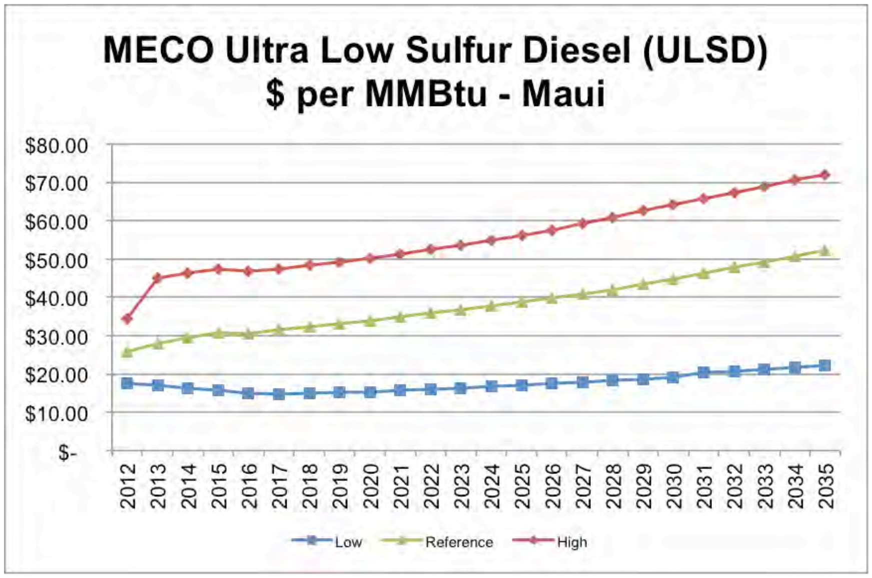



Figure J-14: Molokai High Sulfur Diesel Forecast: 2012–2035

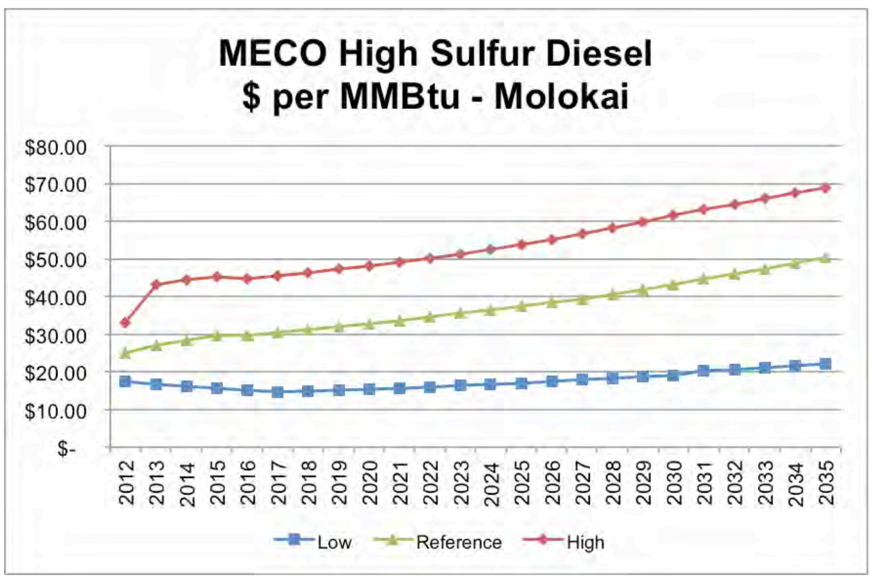


Figure J-15: Molokai Ultra Low Sulfur Diesel (ULSD) Forecast: 2012–2035

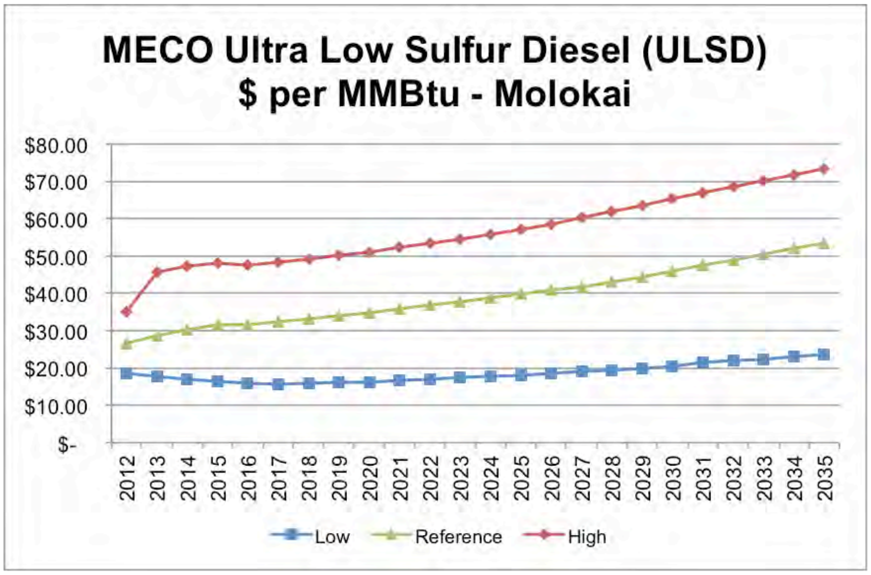



Figure J-16: Lanai High Sulfur Diesel Forecast: 2012–2035

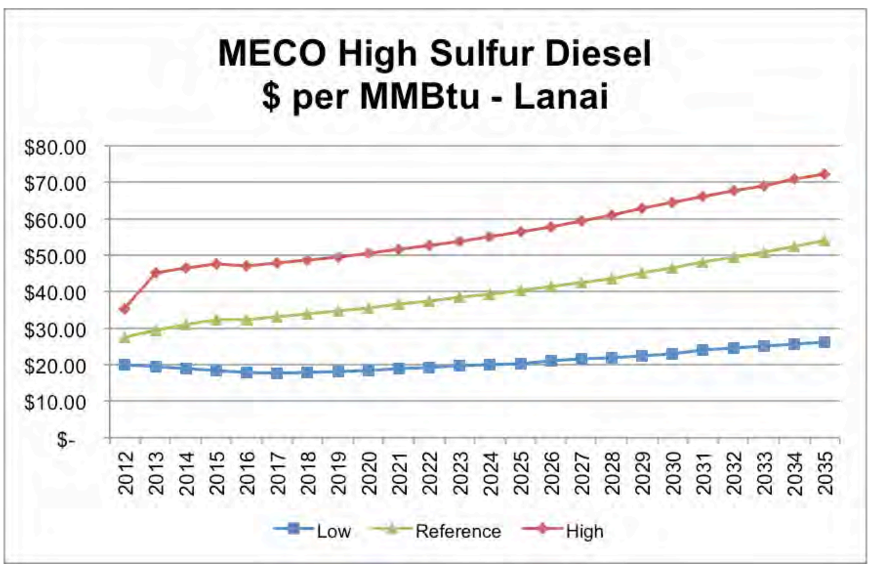


Figure J-17: Lanai Ultra Low Sulfur Diesel (ULSD) Forecast: 2012–2035

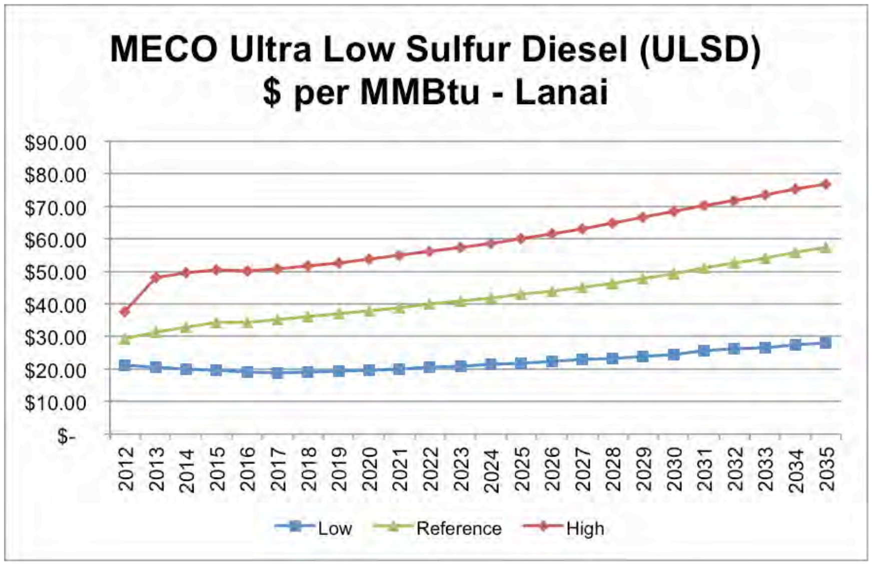
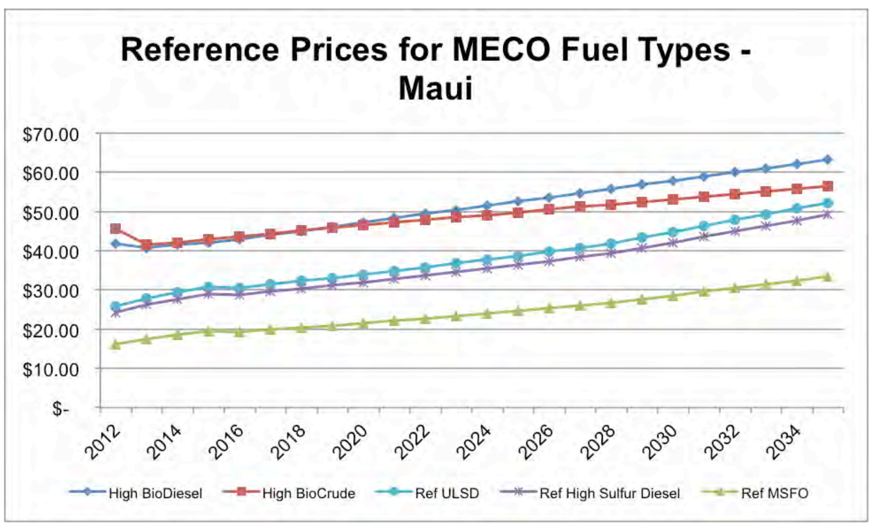



Figure J-18: MECO Reference Prices for All Available Fuel Types



## *Hawaii Electric Light Company Fuel Forecasts*

The following figures depict the forecasts for these fuels for Hawaii Electric Light Company for the island of Hawaii.

Figure J-19: HELCO Biodiesel Forecast: 2012–2035

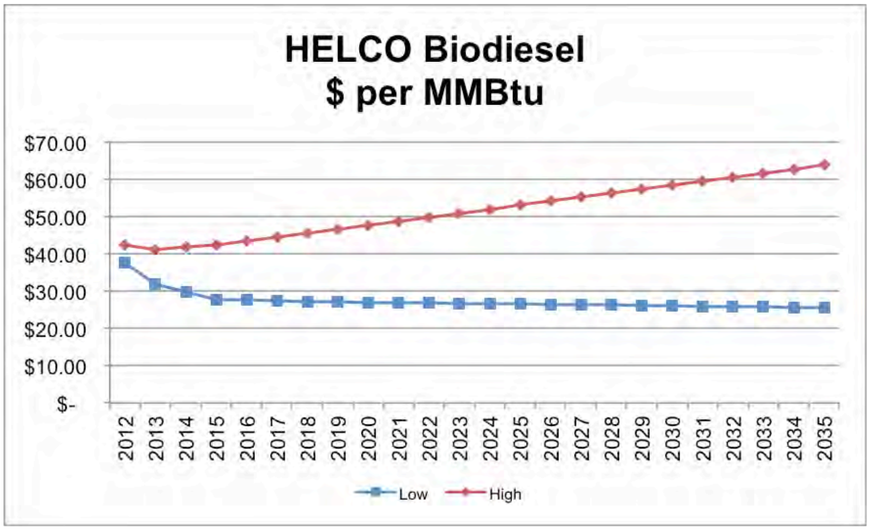



Figure J-20: HELCO Biocrude Forecast: 2012–2035

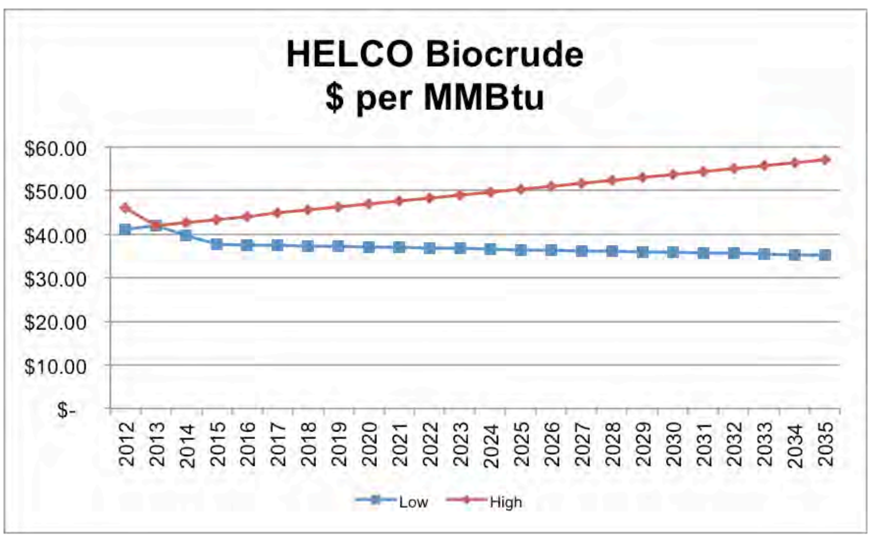


Figure J-21: HELCO Medium Sulfur Fuel Oil (MSFO) Forecast: 2012–2035

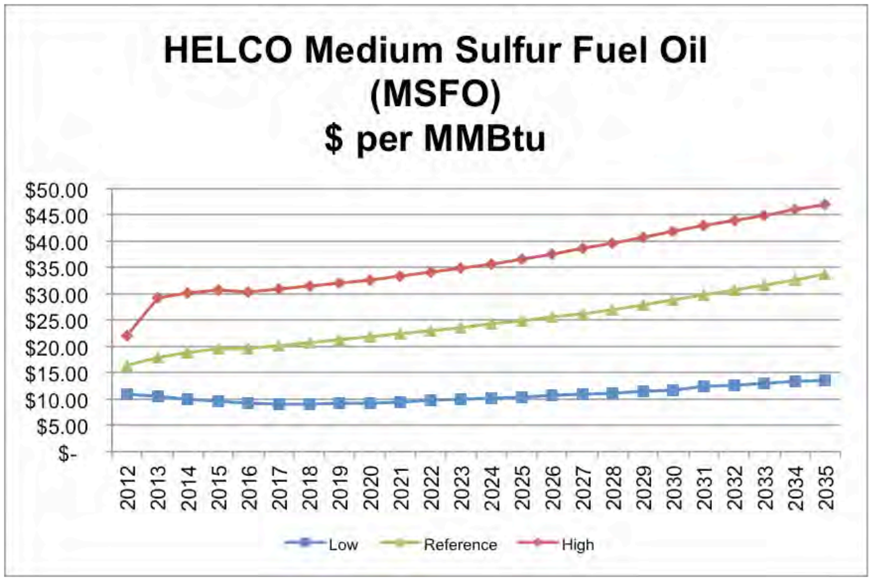



Figure J-22: HELCO High Sulfur Diesel Forecast: 2012–2035

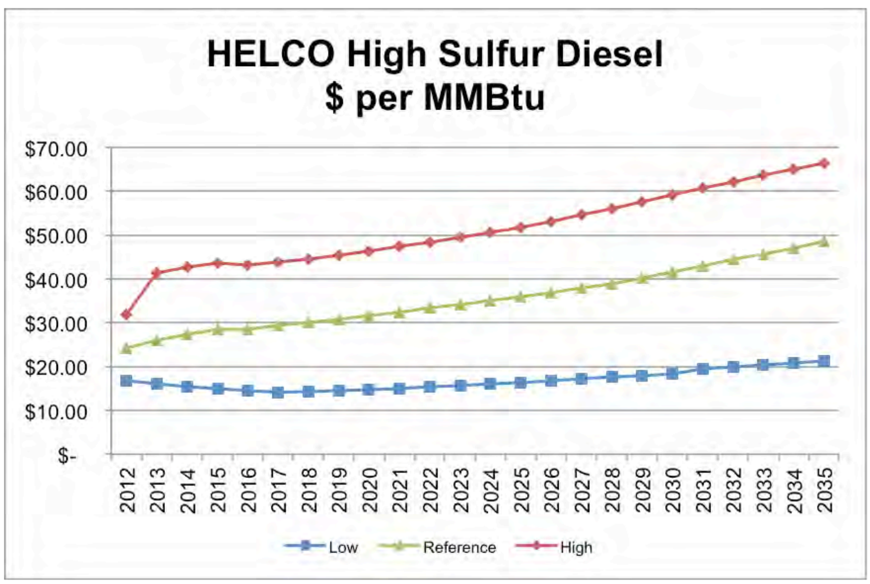


Figure J-23: HELCO Ultra Low Sulfur Diesel (ULSD) Forecast: 2012–2035

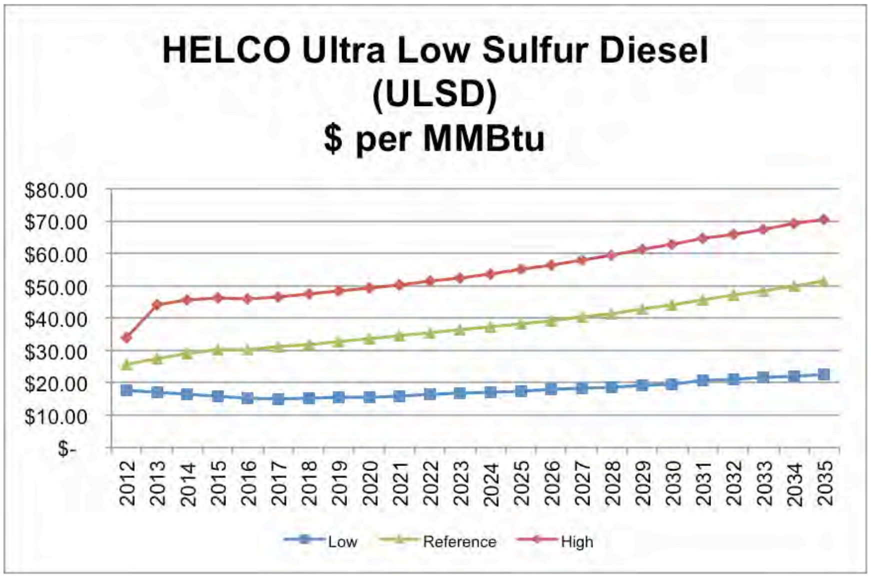
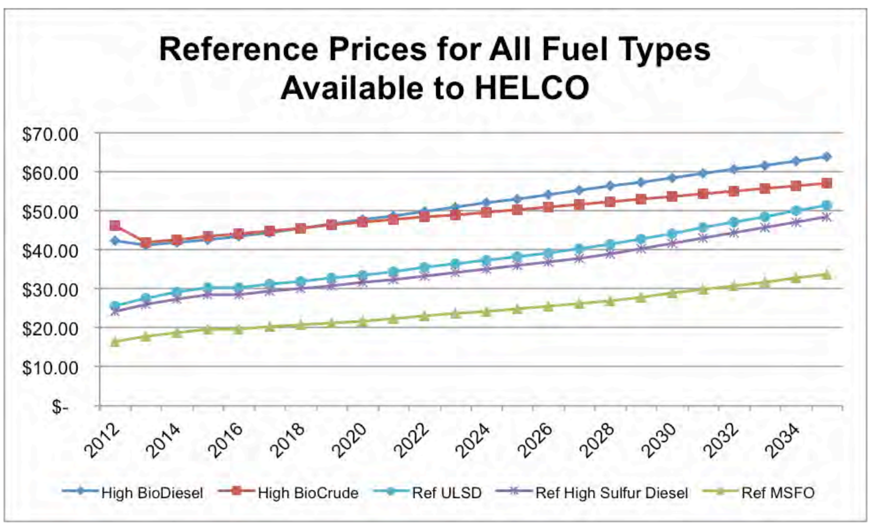



Figure J-24: HELCO Reference Prices for All Available Fuel Types



## Overall Demand for Electricity and Electricity Sales

The utility must determine the amount of electrical energy to generate to meet customer demand. To do this, the utility forecasts electricity sales and peak demand. Electricity demand continually fluctuates throughout the day. And, at a given instant during a year, this demand reaches its highest level: the peak demand. The utility must be able to generate enough megawatts during peak demand, when customer use is at its greatest.

Figure J-25 through Figure J-51 show the current utility sales and peak demand forecasts and some of the major factors that influenced the forecasts including:

- The forecasted impact of achieved Demand-Side Management or the level of Energy Efficiency Portfolio Standard (EEPS) that are expected.
- Sales growth due to electric vehicles.
- Sales and peak demand reduction due to amount of renewable self-generation.

### *Hawaiian Electric Company Forecasts*

Figure J-25: HECO Total Sales Forecast (Gigawatt Hours)

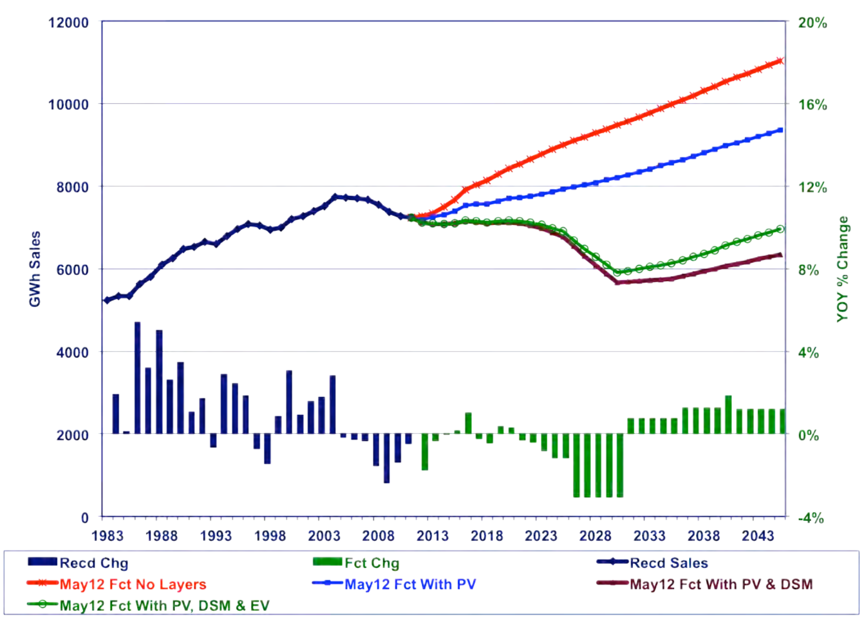


Figure J-26: HECO Peak Demand Forecast (Megawatts)

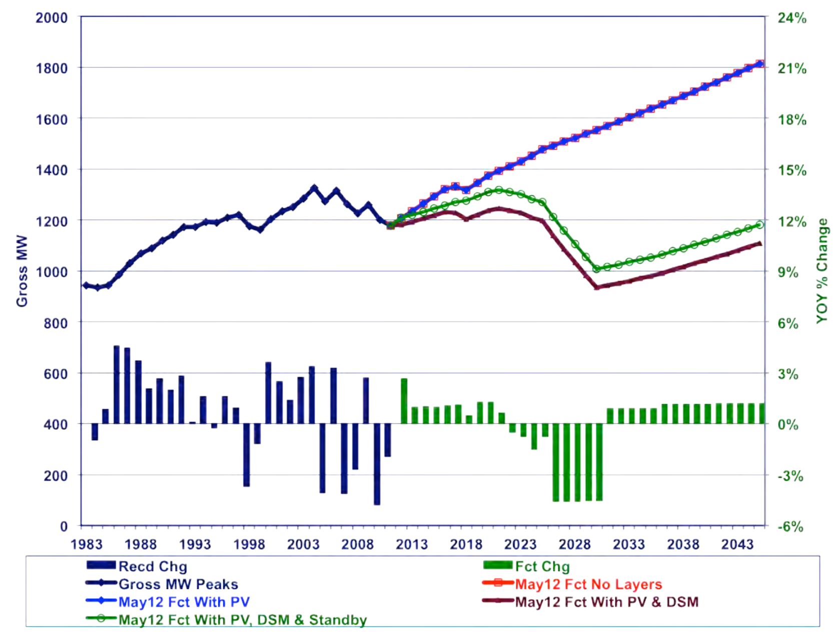



Figure J-27: HECO Energy Efficiency Estimate (Gigawatt Hours)

Figure J-28: HECO Energy Efficiency Estimate (Gross Megawatts)


Figure J-29: HECO Electric Vehicles Estimates (Gigawatt Hours)

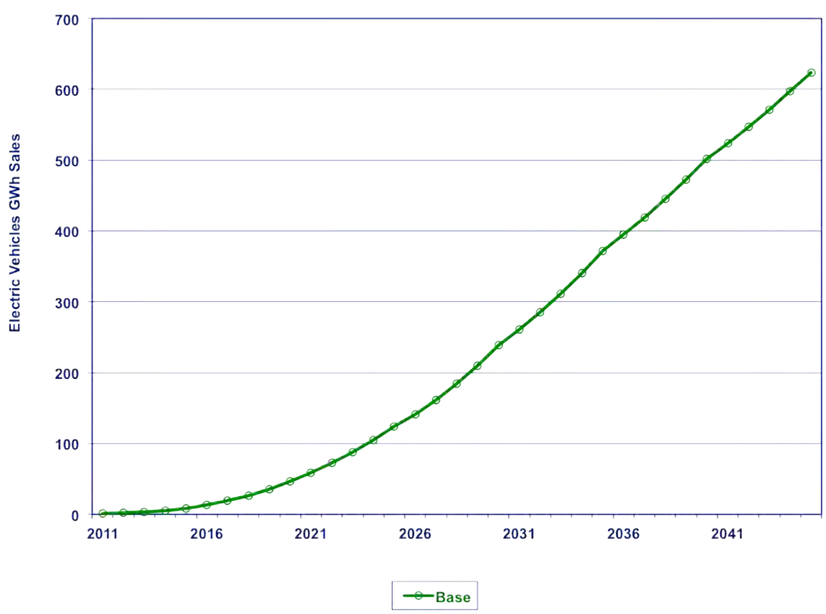


Figure J-30: HECO Renewable Self-Generation Estimate (Gigawatt Hours)

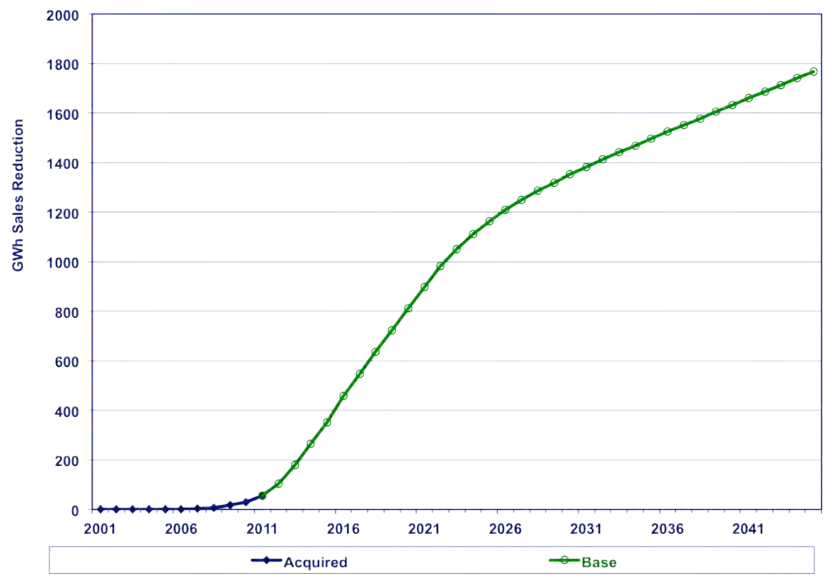
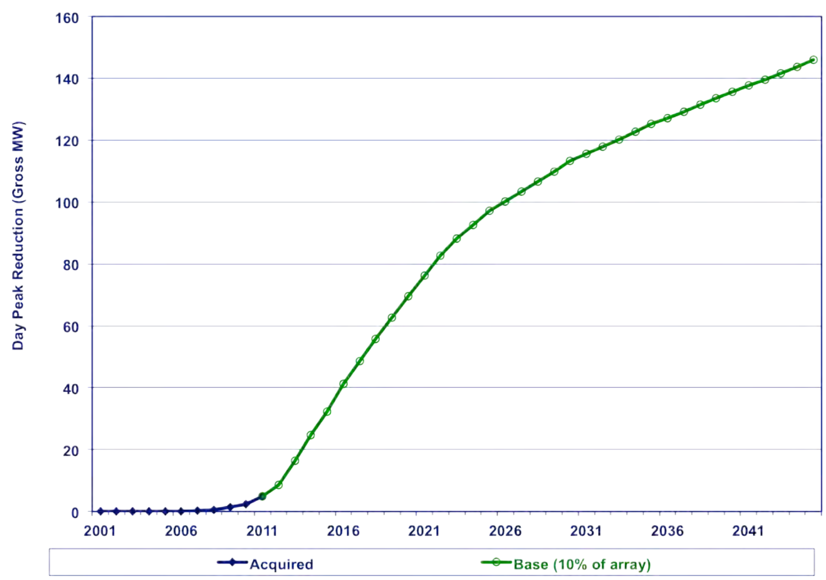



Figure J-31: HECO Renewable Self-Generation Estimate (Megawatts)



## *Maui Electric Company Forecasts*

These figures enable you to gain a better perspective of various conditions into the future facing MECO and the three islands it serves.

### Island of Maui

Figure J-32: Maui Total Sales Forecast (Megawatt Hours)

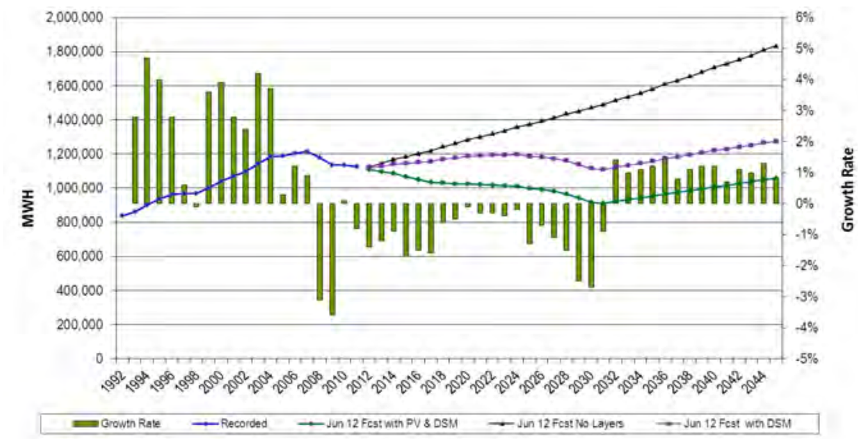



Figure J-33: Maui Annual System Peak Estimate (Megawatts)

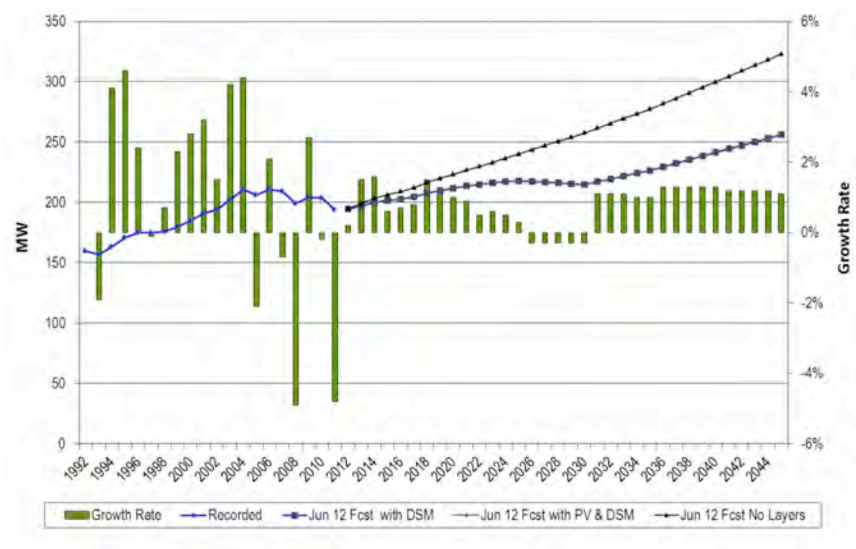


Figure J-34: Maui Energy Efficiency Estimate (Megawatt Hours)

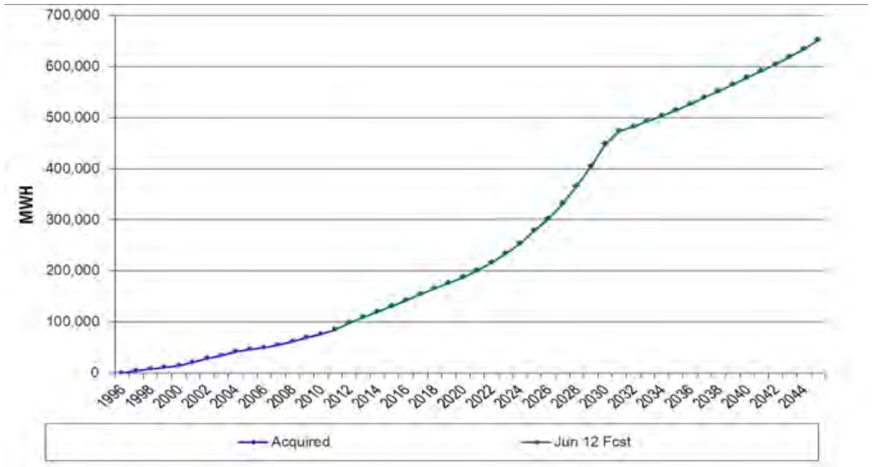



Figure J-35: Maui Energy Efficiency Estimate (Megawatts)

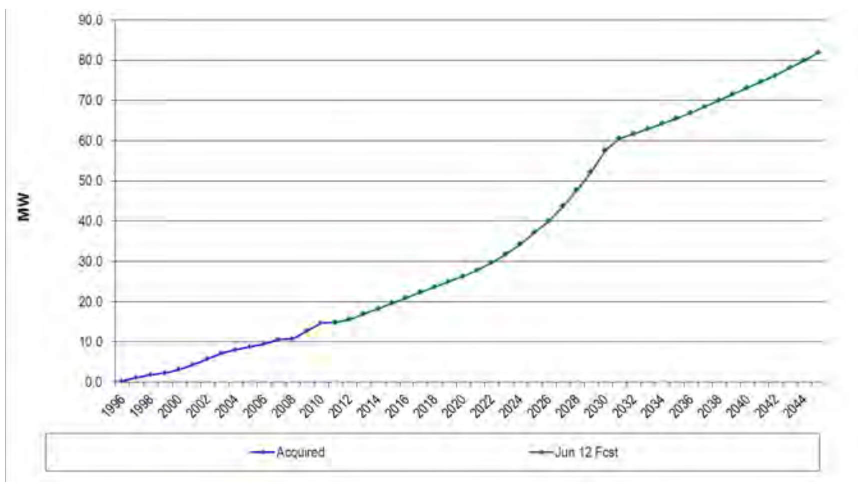


Figure J-36: Maui Electric Vehicles Estimate (Megawatt Hours)

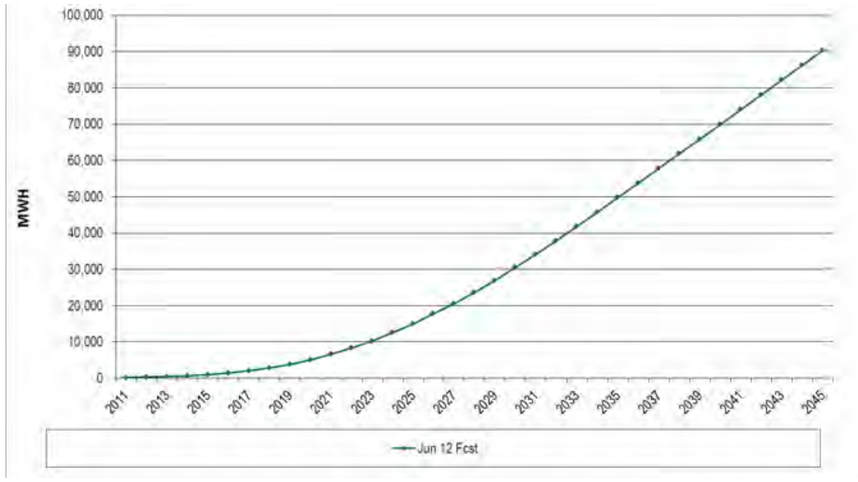
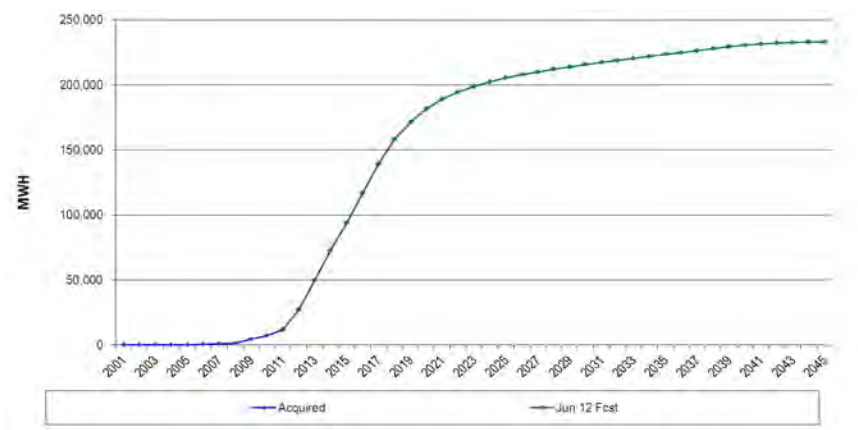



Figure J-37: Maui Renewable Self-Generation Estimate (Megawatt Hours)



## Island of Lanai

Figure J-38: Lanai Total Sales Forecast (Megawatt Hours)


Figure J-39: Lanai Annual System Peak Estimate (Megawatts)

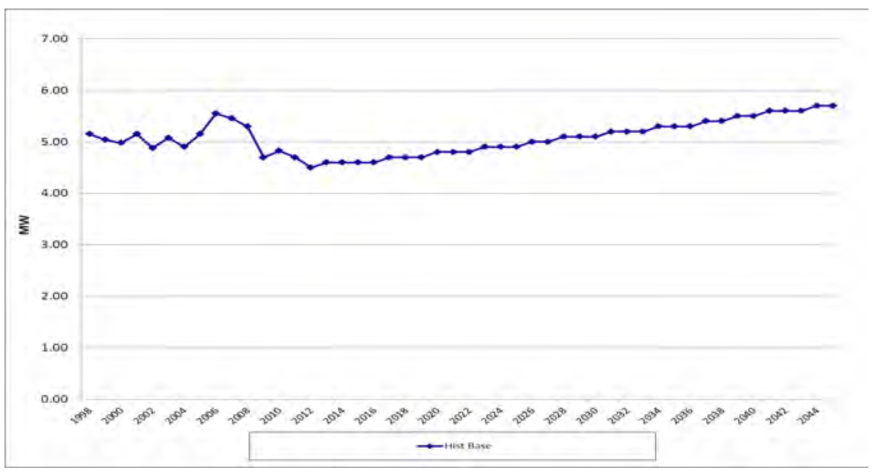


Figure J-40: Lanai Energy Efficiency Estimate (Megawatt Hours)

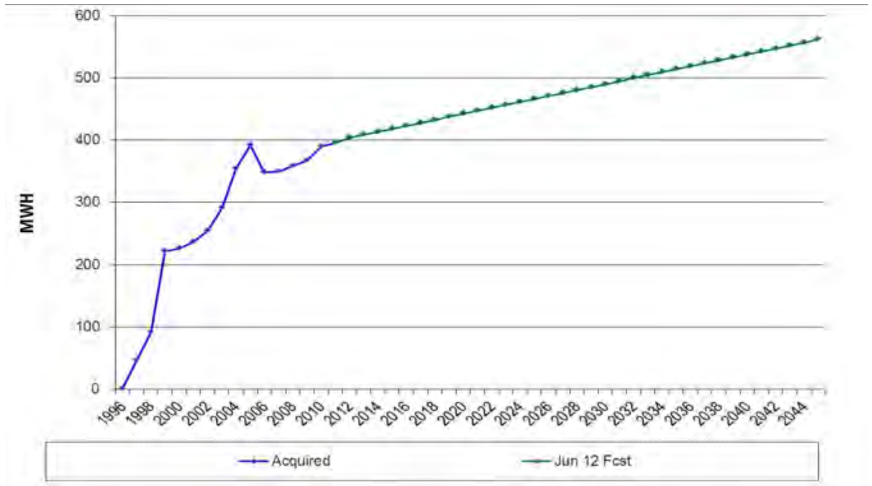
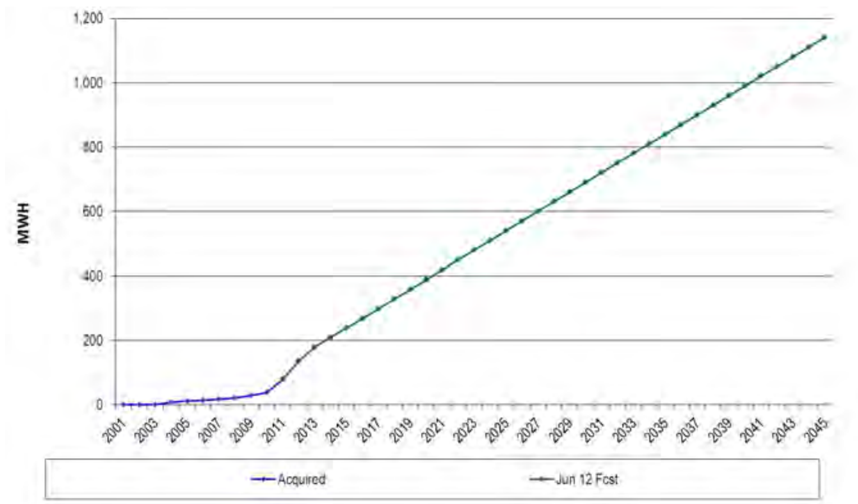



Figure J-41: Lanai Renewable Self-Generation Estimate (Megawatt Hours)



## Island of Molokai

Figure J-42: Molokai Total Sales Forecast (Megawatt Hours)

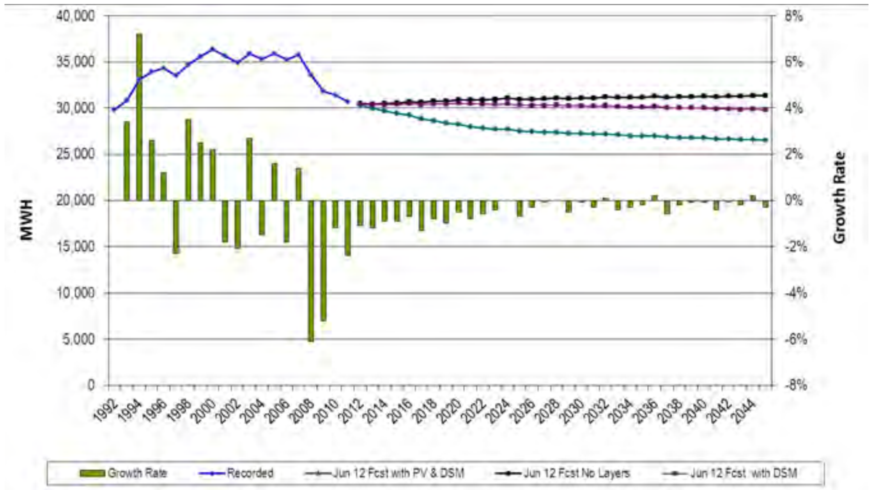



Figure J-43: Molokai Annual System Peak Estimate (Megawatts)

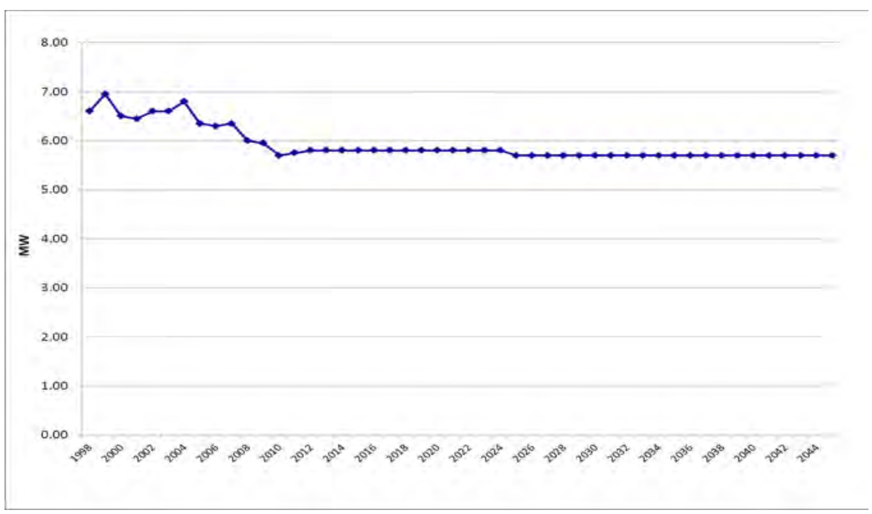


Figure J-44: Molokai Energy Efficiency Estimate (Megawatt Hours)

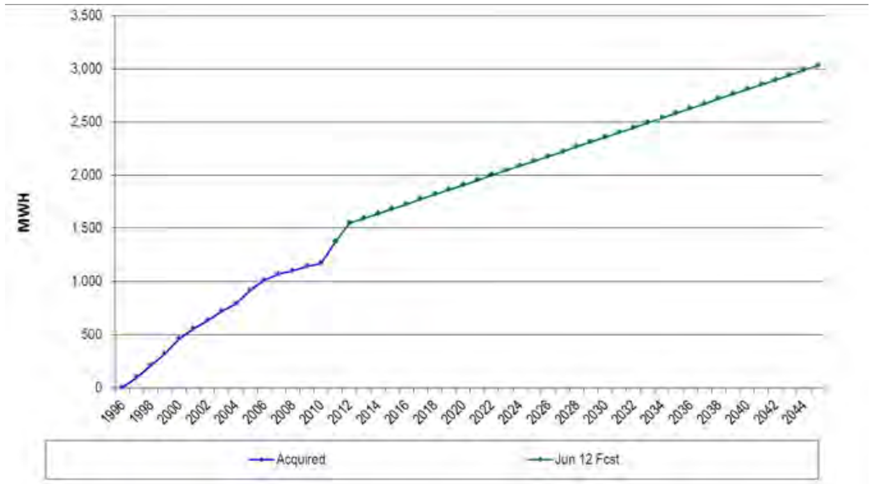
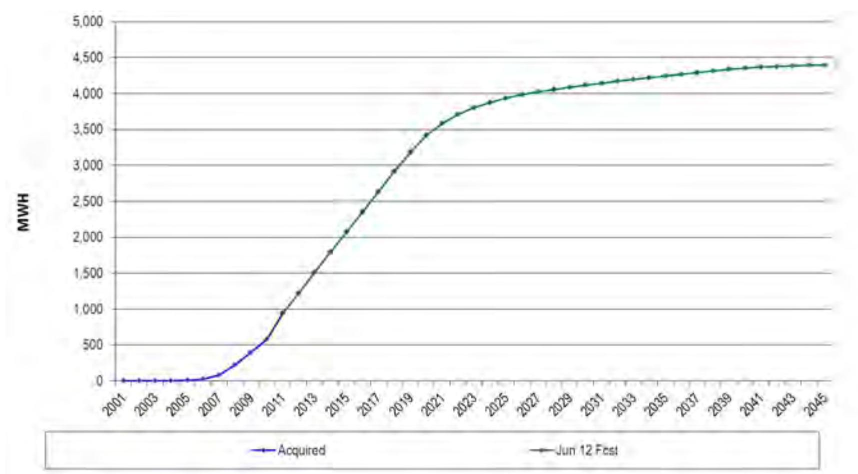



Figure J-45: Molokai Renewable Self-Generation Estimate (Megawatt Hours)



## *Hawaii Electric Light Company Forecasts*

Figure J-46: HELCO Total Sales Forecast (Gigawatt Hours)

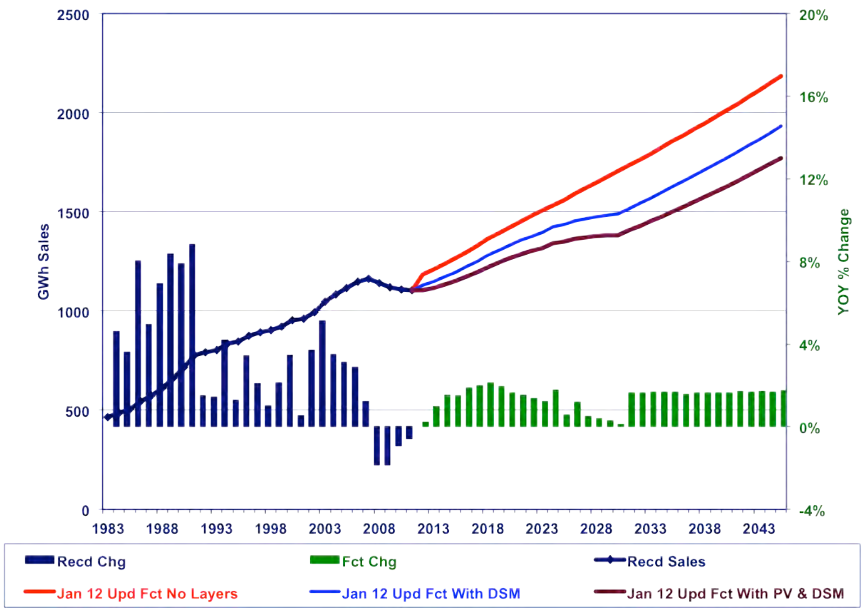



Figure J-47: HELCO Peak Forecast (Megawatts)

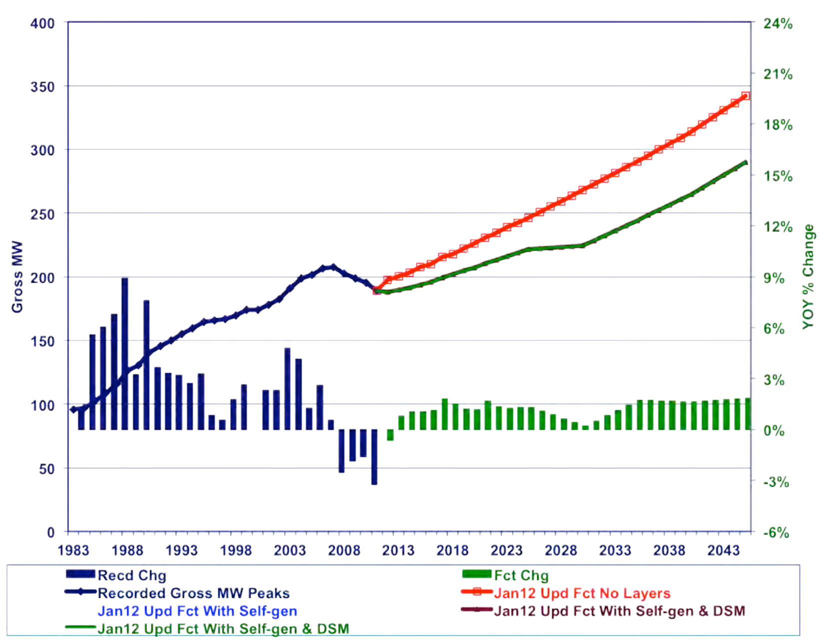


Figure J-48: HELCO Energy Efficiency Estimates (Gigawatt Hours)

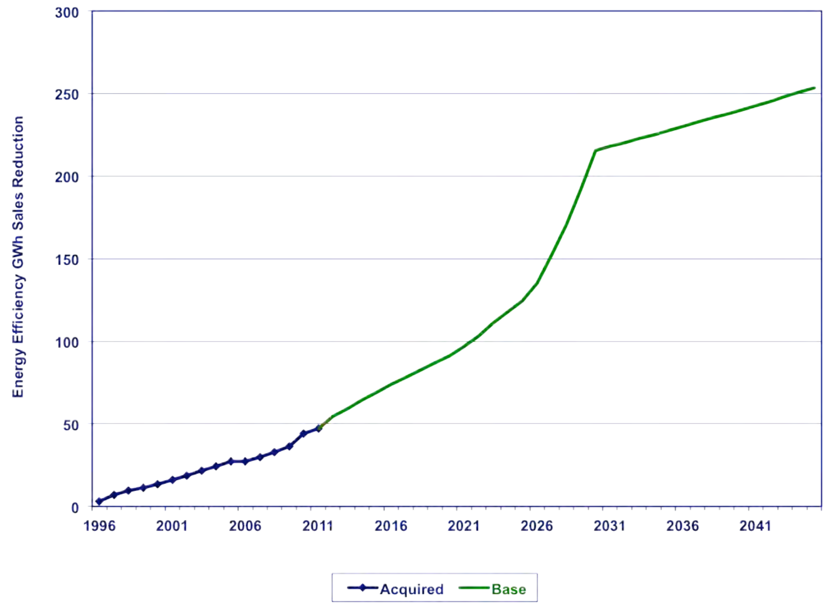



Figure J-49: HELCO Energy Efficiency Estimates (Gross Megawatts)

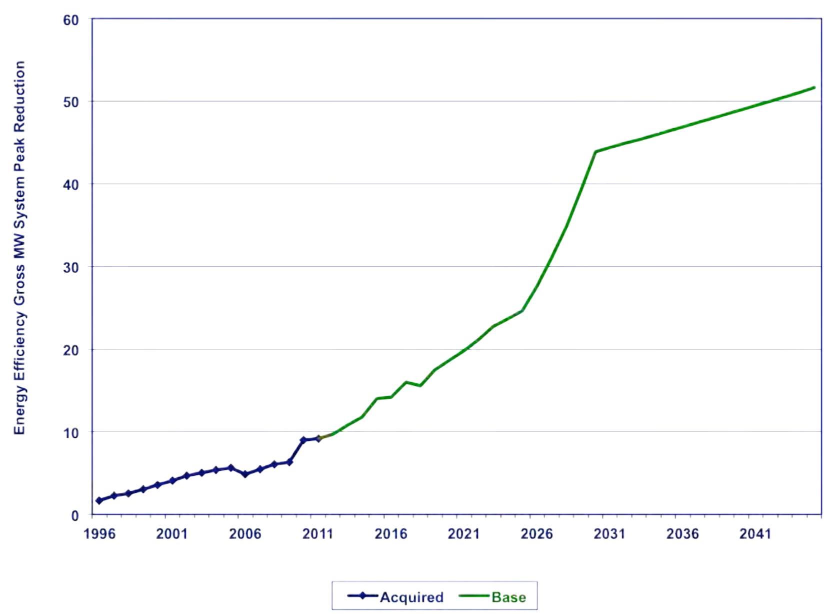


Figure J-50: HELCO Renewable Self-Generation Estimate (Gigawatt Hours)

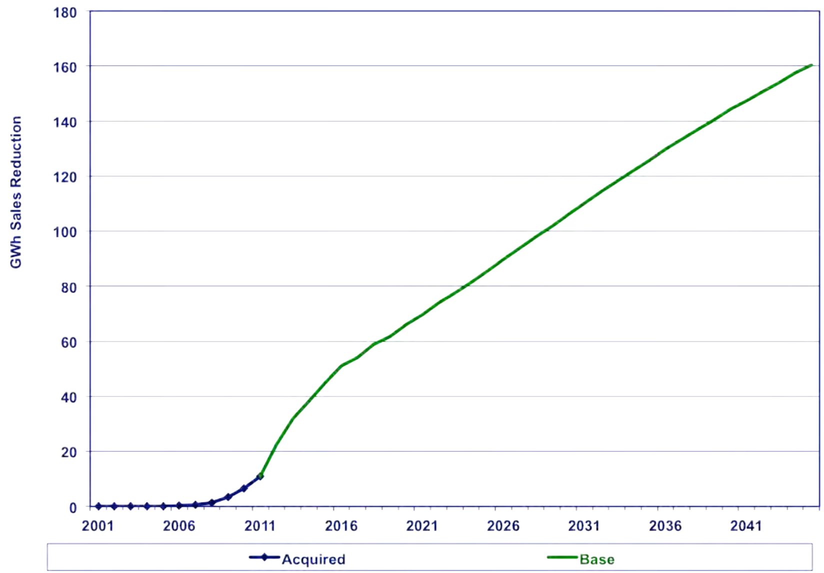
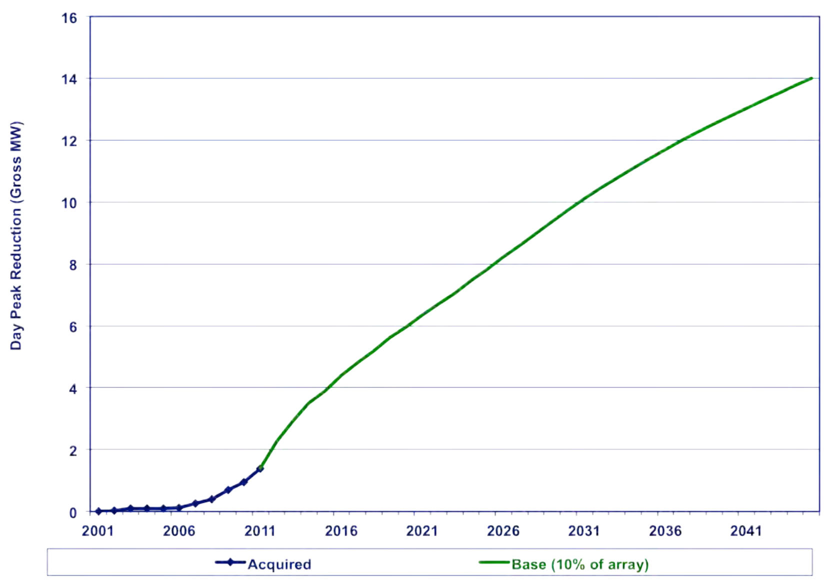



Figure J-51: HELCO Renewable Self-Generation Estimate (Megawatts)



## Environmental Regulations

Environmental regulations, mostly Federal laws, are meant to reduce or eliminate human impact on the natural environment.

### *Air Compliance*

Air compliance regulations (mainly through the Clean Air Act) seek to reduce or remove human-generated pollutants in the air that are known to be hazardous to human health.

#### 1. Mercury and Air Toxics Standards and National Ambient Air Quality Standards

*Mercury and Air Toxics Standards (MATS)*

On February 16, 2012, the Environmental Protection Agency (EPA) published the Mercury and Air Toxics Standards (MATS) final rule**.** The MATS rule established emissions limits for hazardous air pollutants for fossil-fuel fired steam electrical generating units (generating units).

Compliance is required by April 16, 2015. Facilities can be granted two one-year extensions to install emissions controls, effectively extending the compliance date to 2017. As a result of discussions between HECO and the EPA, the final MATS rule recognized the differences inherent in isolated, remote grids and established emissions limits for Non-Continental Liquid Oil-Fired Generating Units.

*National Ambient Air Quality Standards (NAAQS)*

In 2010, the EPA established two new one-hour air quality standards for Nitrogen Dioxide ($NO_2$) and Sulfur Dioxide ($SO_2$). Although these new one-hour standards are significantly more stringent than the previously existing standards, the $SO_2$ standard poses the greater challenge for HECO, MECO, and HELCO.

Although not yet final, HECO estimates the $SO_2$ NAAQS compliance date as August 2017. This estimate assumes the Hawaii Department of Health and the EPA meet their milestones for implementation of the NAAQS regulation.

#### 2. Regional Haze

Regional Haze is visibility impairment caused by human-made activities and natural processes over a wide geographic area. Since 1988, the EPA and other federal agencies have been monitoring visibility in national parks and wilderness areas. In 1999, the EPA announced a major effort to improve visibility in national parks and wilderness areas.

This major effort, The Regional Haze Rule, requires implementation of air quality control plans with a 2064 goal to restore national parks and wilderness areas to visibility levels that would exist if there were *no human-made emissions* (that is, return visibility to "natural" visibility). Because of the Haleakala and Hawaii Volcanoes National Parks, the Regional Haze Rule directly impacts MECO and HELCO power plants.

The EPA must develop a Federal Implementation Plan for Hawaii that outlines the EPA's strategy for making reasonable progress towards achieving natural visibility conditions in the national parks. A major issue is that EPA has taken the position that "natural visibility" conditions must assume that the Kilauea Volcano could stop erupting by 2064. Therefore, the EPA is requiring that reasonable progress be made to reduce human-made emissions now.

The EPA issued a pre-publication draft of the Hawaii Regional Haze FIP on May 16, 2012, and plans to issue the final plan by September 14, 2014.

#### 3. Reciprocating Internal Combustion Engines Maximum Available Control Technology

In March 2010, the EPA published its final rule establishing emissions standards for diesel generating units. The final rule became effective on May 3, 2010, with a compliance date of May 3, 2013.

### *Clean Water Act Compliance*

The Clean Water Act protects the country's waters, including lakes, rivers, and coastal areas by legislating standards for minimizing or eliminating the causes of water pollution and poor water quality.

#### 1. Section 316(b) Cooling Water Intake

In 2011, the EPA published the Clean Water Act (CWA) Section 316(b) proposed rule, also known as the "Cooling Water Intake Rule" or the "Fish Rule." The rule is designed to minimize the amount of marine aquatic organisms that are pinned against intake screens (impingement) or drawn into the equipment (entrainment).

The proposed rule outlines four compliance alternatives. The EPA prefers standards for impingement mortality control and entrainment mortality control.

The proposed rule does not mandate cooling towers (also known as "closed-cycle cooling") for entrainment control, but allows state agencies to make site-specific determinations that include cost-benefit considerations.

#### 2. Section 316(a) Thermal Discharge

The CWA Section 316(a) regulates thermal discharges from power plants. HECO has permits that allow thermal discharges from Kahe, Waiau, and Honolulu power plants. MECO (Kahului Power Plant) and HELCO (Shipman Power Plant) also have permits.

The EPA plans to revise its technical guidance for thermal discharges from power plants. The timeline for the revision is unknown, but is anticipated within the next few years. While the EPA works on the guidance update, several states are revising their discharge standards and fewer variances are being granted by State permitting authorities.

### 3. Effluent Limitation Guidelines

In 2009, the EPA announced plans to revise effluent limits for steam electric power industry wastewater discharges, including discharges from oil fired plants.

### 4. Storm Water Regulations

In 1992, storm water requirements were added to permits for HECO's Honolulu, Kahe, and Waiau generating stations; MECO's Kahului and Maalaea generating stations; and HELCO's Shipman Generating Station. The permits require a Storm Water Pollution Control Plan (storm water plan) with established discharge limits. A major component of the storm water plan is the implementation of Best Management Practices to eliminate or reduce storm water pollution.

HECO has conducted storm water runoff analyses. All generating stations have consistently exceeded the discharge limit for copper. Based on HECO studies, a significant amount of copper may be entering the waste stream from off-site sources (such as vehicular traffic or naturally occurring copper in sediment).

Nevertheless, the Hawaii Department of Health has taken the position that HECO is responsible for all pollutants mixed in the storm water runoff *irrespective of the source*. Our generating stations continue to be impacted by road grit from highways, neighboring properties' activities (that is, sediments from agriculture harvesting activities), and natural background conditions.

# Glossary of Energy Terms

A number of energy terms are frequently used during meetings and in discussions. Many of these terms are presented here to ensure that everyone understands them at their most basic level. These explanations are not exhaustive, but instead provide fundamental knowledge of some key industry terminology. Key terms are italicized.

### Capacity

*Capacity* is the maximum possible power that can be continuously generated or carried. It can be applied to generating plants, transmission lines, or any other type of electrical equipment. Capacity is generally expressed in megawatts.

There is a difference, however, between this maximum capacity that can be generated (*Generating Capacity*) and the amount that can actually be generated to meet demand (*Net Capacity*). This is because generating plants simply do not operate at maximum capacity and because some of the power generated is used to run the plant.

### Demand

*Demand* is the amount of electricity being consumed at a given moment. Over any given period of time, demand continually fluctuates. Thus, *Average Demand* is the total amount of electricity consumed over an interval of time divided by the units of time in that interval. *Peak Demand* is the highest amount of electricity consumed over an interval of time.

Both average demand and peak demand are typically calculated for several periods of time—hour, day, month, season, and year—and are used by a utility to plan generation and transmission capacity. A utility must have enough capacity to constantly meet demand, especially to meet peak demand.

### Demand-Side Management

Demand-Side Management (often referred to simply as DSM) are actions and programs planned, implemented, and monitored that influence utility customers to change how and when they use electricity (essentially changing demand patterns). For Hawaii, a law known as the Energy Efficiency Portfolio Standards (EEPS) has established a standard of electricity use reduction that DSM will achieve.

DSM programs include conservation measures, load management and strategic load growth, improvements in efficient electricity use, rate incentives and rebates, and education. These programs are designed to encourage customers to use electricity differently (such as using less electricity during peak hours or shifting electricity usage to off-peak hours during nights or weekends).

A sample DSM program would be rebates for purchasing energy efficient appliances or compact fluorescent lamp (CFL) light bulbs.

### Distributed Generation

*Distributed Generation* (DG) is electrical energy generated by small energy sources located at or near the end user of electricity sized to meet or enhance localized demand. These small-scale generators could be owned by the utility, small companies, customers, or groups of customers and are generally renewable energy resources.

### Fossil Fuels

*Fossil Fuels* — essentially coal, petroleum (oil), and natural gas — are naturally occurring fuels formed from the decomposition of buried organic matter.

Fossil fuels are non-renewable, taking millions of years to form. Current usage is depleting reserves much more quickly than new ones can be formed. Fossil fuels contain high percentages of carbon. Thus, the burning of fossil fuels produces about twice as much carbon dioxide (a greenhouse gas) as can be absorbed by natural processes.

### Generation

The term generation is used in two contexts. First, *Generation* refers to the process of producing electric energy (electricity) from other forms of energy (such as fossil fuels, wind, sun, and water). *Generation* also refers to the amount of electricity produced by a power plant.

### Load

*Load* is the amount of power being delivered on the transmission system, and is a direct result of customer demand.

### Outage

An *Outage* is the period of time when a generating plant, transmission line, or other resource is out of service. The reasons for an outage vary. A *Forced Outage* results from emergency situations, such as when a storm knocks down power lines or when equipment suddenly fails. A *Maintenance Outage* occurs when equipment must be worked on to ensure its continued viability. A *Planned Outage* is the scheduled removal of a resource, usually for inspection, overhaul, repair, or repowering.

### Renewable Energy

*Renewable Energy* is generated from resources that replenish naturally, are virtually inexhaustible. Renewable energy resources include biomass, hydro, geothermal, solar, and wind, and can also include ocean thermal, wave power, and tidal power.

- *Biomass* is an energy source derived from living or recently living organisms: garbage, wood, waste, landfill gases, and alcohol fuels. Biomass can be converted into a biofuel if necessary.
- *Hydro* (short for hydroelectricity) is electricity generated from falling or flowing water.
- *Geothermal* is electricity generated from heat (thermal) energy stored in the Earth's crust.
- *Solar* is energy generated from the light and heat of the sun.
- *Wind* energy is generated from turbines that harness the power of the wind.
- *Ocean Thermal* generates electricity from the temperature difference between deep (cooler) water and surface (warmer) water.
- *Wave Power* captures energy from surface waves in the ocean.
- *Tidal Power* converts the energy of tides into electricity.

### Wattage

A *Watt* is the basic, albeit small, measure for an electrical unit of power. It is used to rate any number of devices that require electricity to operate (such as the venerable light bulb). A *Kilowatt* equals 1,000 watts. In terms of demand, consider that a 100-watt light bulb that is continually on for 10 hours is equivalent to a kilowatt (100-watts times 10 hours equals 1,000 watts, or 1 kilowatt).

Because watts and kilowatts are small measures of electric energy, power needs are generally referred to in larger measures: a *Megawatt* is 1,000 kilowatts (or one million watts); a *Gigawatt* is 1,000 megawatts (1 million kilowatts, or 1 billion watts). A megawatt can power about 500 to 600 homes annually.

# Summary of the IRP
# Scenario Development Workshop

# Orientation

### From *Scenario Thinking Defined*, By Eamonn Kelly

> "Scenarios are stories about how the future might unfold for our organizations, our issues, our nations, and even our world. Importantly, scenarios are not predictions. Rather, they are provocative and plausible stories about diverse ways in which relevant issues outside our organizations might evolve, such as the future political environment, social attitudes, regulation, and the strength of the economy.
>
> "Because scenarios are hypotheses, not predictions, they are created and used in sets of multiple stories, usually three or four, that capture a range of future possibilities, good and bad, expected and surprising.
>
> "And, finally, scenarios are designed to stretch our thinking about the opportunities and threats that the future might hold, and to weigh those opportunities and threats carefully when making both short-term and long-term strategic decisions."

The scenario planning work being done by the Integrated Resource Planning (IRP) Advisory Group has been mandated by the Public Utilities Commission and is intended to advance the following goal:

> "The goal of integrated resource planning is to develop an Action Plan that governs how the utility will meet energy objectives and customer energy needs consistent with state energy policies and goals, while providing safe and reliable utility service at reasonable cost, through the development of Resource Plans and *Scenarios of possible futures that provide a broader long-term perspective.*"[2]

Importantly, the desired IRP scenarios need to describe a wide range of possible futures that the utilities' Resource Plans and Action Plan might need to address. They are intended to broaden the perspectives of planners, and are further intended to help planners test and refine critical modeling assumptions.

The scenarios *are not* a replacement for forecasting or econometric modeling. Those techniques are essential to good planning. The scenarios are vital supplements to those core planning techniques.

By providing a longer term perspective, and by intentionally stretching analytical thinking about critical modeling assumptions, the scenarios allow for more robust planning and decision making against a future energy landscape in Hawaii which has many fundamental uncertainties incorporated into it.

[2] *A Framework for Integrated Resource Planning*, Section II-A: Goals of Integrated Resource Planning; page 2.

The particular scenario planning approach adopted for the IRP process is widely considered to be best in class and was selected for the process after careful consideration of several other techniques. One of the primary advantages of the approach selected was that it has been repeatedly proven helpful when the perspectives of vested stakeholder groups are broad, divergent and often at odds.

Contributions made by the Advisory Group to the scenario planning process on August 20, 21, and 24 were, as expected, broad, divergent, and often at odds. Further advancing the work initiated on those three days now requires a period of synthesizing across those perspectives to produce a final set of scenarios which will be presented to the Advisory Group on September 24.

What follows is a summary of the many inputs provided by the Advisory Group while in session on August 20, 21, and 24. These inputs are clustered under five headers:

1. **Driving Forces** influencing the future evolution of the energy landscape in Hawaii between the present and 2032.
2. **Major Uncertainties** influencing future scenarios.
3. **Critical Uncertainties** which could substantially impact the future modeling assumptions.
4. The **Initial Scenario Set** encompassing the five individual team scenario frameworks and a final scenario set integrated from across all five frameworks.
5. **Feedback from the Advisory Group** on the initial scenarios.

# Driving Forces

## Driving Forces and Why They Matter

*Driving Forces* are the basic building blocks of scenario planning that are used to imagine how the future might unfold. Within the context of the IRP, driving forces are ***the key trends and developments*** shaping the ways in which energy will be both produced and consumed in Hawaii in the future.

Because driving forces are so fundamental to creating scenarios for the IRP, the process utilized took special care in thinking about them as broadly and expansively as possible. The diversity of perspective and breadth of experience represented within the Advisory Group was perfectly suited to this task. Working in five parallel teams to expand participation and allow for more constructive conversation and thinking, the Advisory Group identified 220 driving forces. The full list is attached below in alphabetical order.

## Master List of Driving Forces

These driving forces were identified by the IRP Advisory Group.

Table J-2: Master List of Driving Forces

| Driving Forces Identified by the Advisory Group |
|---|
| 1. “4-D” marketing/shift in economy ↓ tourism base |
| 2. “EDIN” involvement on Hawaii policy |
| 3. “Limping” is preferred |
| 4. “R” word |
| 5. “Super Grid” statewide |
| 6. Acceptance of Smart Grid technology |
| 7. Affordability of electricity |
| 8. Agricultural lifestyle versus Agriculture industry |
| 9. Aggressive curtailment |
| 10. Aging population |
| 11. Air service interruption |
| 12. Air travel cost |
| 13. Airline industry |
| 14. Algae biodiesel |
| 15. All Hawaii projects are halted because of SHIPD/NAFTA |
| 16. Ambient temperature rise |

**Driving Forces Identified by the Advisory Group**

17. Amount of self generation
18. Any and all related costs
19. Appropriate business model for HECO/utility
20. Availability and cost of money
21. Availability and feasibility of liquefied natural gas
22. Availability of rare metals
23. Availability of renewable energy
24. Battery storage
25. Biofuels
26. Catastrophic disease
27. Change in home/business technology
28. Change in RPS
29. Changes in climate patterns
30. Changes to ECAC
31. Changes to Internet — Web 3.0
32. Changes to law
33. Clean energy lifestyle versus clean energy industry
34. Climate change
35. Combined heat and power
36. Communication methods
37. Community benefits and detriments
38. Community opposition to placement of projects
39. Congress members representing Hawaii
40. Construction costs
41. Consumer ability to pay
42. Consumer activism
43. Consumer behavior
44. Consumer demand for clean energy
45. Consumer education
46. Consumer willingness to pay for clean energy
47. Consumer willingness to pay for secure energy
48. Consumer willingness, inability, or refusal to support
49. Cooperative model of rural models
50. Cost and availability of interstate shipping
51. Cost and availability of intrastate shipping
52. Cost of alternative fuels
53. Cost of capital

**Driving Forces Identified by the Advisory Group**

54. Cost of fossil fuels
55. Cost of renewable
56. Creation of new job centers
57. Creation of new population centers
58. Cultural values
59. Degrading infrastructure (sewer, electricity, water, rail, roads, air)
60. Demand response
61. Demographic shift /remote work shift
62. Desire to self-sustain
63. Difference between baseload and peak
64. Disconnect from source of "resource"
65. Disposable income
66. Disproving greenhouse gas
67. Driving forces that got us here ($/kWh, reliability)
68. Ease of access / energy
69. Economic disparities
70. Economy — US
71. Economy — World
72. Energy efficiency breakthrough
73. Energy efficiency failure
74. Energy efficiency organization structure
75. Effect on reliability of cabling
76. Effect/technology related to conservation
77. Effectiveness of energy efficiency portfolio standards and demand-side management
78. Electric vehicles
79. End use changes
80. Energy security
81. Energy storage costs and availability
82. Environmental degradation (for example, oil spill)
83. Environmental regulations
84. EPA mitigation measures
85. Electric vehicle penetration
86. Evolution of computer technology
87. Fairness of decoupling
88. Federal renewable portfolio standards (RPS)
89. Federal self generation/base security
90. Financial structure — individuals/generators/incentives

**Driving Forces Identified by the Advisory Group**

91. Finding alternative fossil fuel
92. Fission and micro fusion technology development
93. Flexible rate structure to achieve peak load leveling
94. Food security
95. Food versus fuel
96. Frequency and duration of outages
97. Fresh water resources
98. Fuel cells
99. Generation / wires / services model
100. Geopolitical factors influencing oil
101. Geographic concentration of generation capacity
102. Government policy on combined cycle
103. Government subsidies and tax policies
104. Governmental environment
105. Hawaii as "laboratory" perception
106. Hawaii as a "Space Flight Center"
107. Hawaii as a model
108. Hawaii Clean Energy Initiative
109. Hawaii counties policy
110. Hawaii dependence on discretionary income of potential visitors
111. HECO bond rating
112. Hawaii Legislative policy
113. How "clean" energy is defined
114. How "renewable" energy is defined
115. Hydrogen transportation and tech advances hydrogen conversion
116. Immigration
117. Impact of geothermal replacing fossil fuel
118. Impact of military build up/draw down
119. Industry mix
120. Industry size
121. Influence of Big Wind
122. Inouye
123. Insular drift
124. Integrating ground transportation into grid
125. Inter-island water
126. Interruptions in shipping
127. Investment risk / need to satisfy investors

**Driving Forces Identified by the Advisory Group**

128. Island by island cooperative option
129. IT infrastructure
130. KS loses its nonprofit status
131. Labor conflict / strikes
132. Land ownership
133. Land use decisions
134. Large volcanic eruption
135. Load shape changes
136. Load shifting technology
137. Maintenance cost
138. Mass transit
139. Microgrids / energy parks
140. Microwave energy
141. Migration of species
142. Military deployment changes
143. Military goes off grid
144. Mobile renewable energy units
145. Multiple public utilities
146. National / Federal policy
147. Natural disaster / disease
148. Natural resource depletion / protection
149. New business creation
150. New oil source discovered
151. New technology for electric vehicles and renewable energy
152. NIMBYism everywhere
153. NIMBYism on Oahu
154. Ocean energy
155. One grid connection — undersea cable
156. Overall economic activity and growth
157. Ownership of HECO
158. Peak electricity demand
159. Pensions (State, C&C)
160. Perceived value of energy conservation
161. Percentage of energy by IPPs
162. Permitting and time requirements
163. Plant retirement
164. Political change / climate

**Driving Forces Identified by the Advisory Group**

165. Population change
166. Population impact on demand/price
167. Preferred attributes of externalities
168. Preservation of institutional inertia or existing power structures
169. Private jet facilities
170. Production of waste
171. Public perception of cost
172. PUC framework, history, future
173. Rate signals/price signal
174. Re-emergence of inter-island transportation (that is, super ferry)
175. Refineries shutdown
176. Regulatory structure
177. Resurgence of native Hawaiian cultural concerns and values
178. Rise and fall of visitor numbers
179. Role and presence of consumer advocate
180. Role of State Energy Office
181. Role of utility companies
182. Royalty payments for use rights
183. Sea level rise
184. Security of Pacific Rim
185. Small/safe nuclear
186. Sovereignty
187. Specific shift of inter-island populations
188. System efficiency improvements
189. System reliability
190. Tariffs on energy equipment components
191. Telecommuting
192. Terrorism
193. Total sales
194. Tourism patterns and markets
195. Tradewind pattern altered
196. Transmission / Distribution lines
197. Transportation infrastructure
198. Transportation related issues
199. Travel
200. Trust
201. Tsunami

**Driving Forces Identified by the Advisory Group**

202. Unanticipated "demand" changes (that is, Gambling)
203. Unknown effects of fracking
204. Utilities become distributors only
205. Utility ability to absorb self generated energy
206. Utility financial structure — bankruptcy
207. Utility financial structure — co-op
208. Utility financial structure — municipal
209. Utility preservation
210. Utility tariff modification
211. Value system for immigrants
212. Vested utility interests / investments
213. Visa restrictions
214. Visions of HECO from inside
215. Visions of HECO from outside
216. Waste
217. Waste-to-energy development/advances
218. Weather patterns
219. Wheeling (regulatory changes)
220. Workforce development

# Major Uncertainties

## Major Uncertainties and Why They Matter

*Major Uncertainties* are a subset of the entire universe of driving forces. They share just two characteristics:

1. They are especially powerful factors or trends with the potential to *substantially alter* the core assumptions modelers and planners make about the future.
2. They are especially volatile factors or trends and thus resistant to traditional forecasting efforts.

In creating scenarios, **major uncertainties** are especially important elements precisely because of their combined impact and volatility: they really matter and they often defy the best efforts of forecasters. Scenario planning efforts therefore make a special effort to identify them in scenario planning work. Scenarios are then created which consider intentionally broad, yet still plausible, combinations of these factors producing test cases which allow modelers to think expansively about assumptions, without having to model an infinite number of permutations on those assumptions.

The Advisory Group was provided with a structured approach for identifying major uncertainties shaping possible futures (scenarios) providing a broader long-term perspective on the future conditions that the Resource Plans might need to respond to.

An emphasis was placed on identifying **major uncertainties related to the future conditions under which the utility might need to operate**. This was clearly distinguished from the future plans that the utility might make in response to these future conditions. The Advisory Group was reminded that the scenarios are about the future contexts in which the utility might need to operate. **The scenarios are not about the choices, or strategies, which the utility might ultimately exercise. That work is downstream from the scenario development workshop.**

With this guidance, and working in small groups, the Advisory Group identified twenty-four major uncertainties. The results are captured (in alphabetical order) below.

## Major Uncertainties Identified by the Advisory Group

Here is a list of the 24 major uncertainties that the Advisory Group identified.

1. Business Model for HECO
2. Climatic Effects and Natural Disasters
3. Consumer Activism
4. Consumer Dissatisfaction
5. Consumer Willingness to Pay
6. Cost and Availability of Fossil Fuel
7. Cost and Availability of Renewable Energy
8. Cost of Fuel Volatility
9. Cost of Oil
10. Desire to Protect Natural Environment
11. Electric Vehicle Technology
12. Environmental Regulation
13. Evolution of Breakthrough Energy Technologies
14. Government Policy
15. Grid Choice
16. Innovation in / Evolution of Generation Technology
17. Inter Island Connectivity / Inter-Island Cable
18. Level of Electricity Pricing
19. Overall Economic Health
20. Political Will
21. Relative Cost of Oil
22. Uniformity of Community Opinion
23. Visitor Industry
24. Volatility of Electricity Pricing

# Critical Uncertainties

## Critical Uncertainties and Why They Matter

*Critical Uncertainties* are a subset of the entire universe of major uncertainties. In addition to meeting the two conditions named above (the potential to substantially alter modeling assumptions about the future and innate volatility), they are also especially helpful in creating scenario sets which are intentionally broad and stretched to force the consideration of plausible and challenging scenarios that might otherwise avoid the attention of planners, potentially at their peril.

The Advisory Group, working in five teams, was asked to isolate a small number of these critical uncertainties. This proved especially difficult. And while each team did ultimately succeed in collapsing on two, the discomfort of the Advisory Group around that decision-making process was clear. **Pure consensus was not possible, even within each of the five teams. Strongly articulated dissenting opinions remained even after long and thoughtful deliberations. Across the five teams, the differences of opinion were often even further exacerbated.**

The list of critical uncertainties below highlights two that were directionally considered to be most central. We employed a simple voting technique to force closure on this list. That technique, however, produced only a modest advantage for the top two critical uncertainties. **The importance of the additional twelve were broadly acknowledged and the initial drafting of the scenarios proceeded with a mandate to incorporate the complexity suggested by the longer list.**

## List of Critical Uncertainties

This lists includes all 14 critical uncertainties identified across the five teams. The Advisory Group, using a simple weighted vote, selected the top two (highlighted) uncertainties. The remaining critical uncertainties are in no particular order.

1. **Public policy on renewables**
2. **Price of oil**
3. Community and citizen involvement in energy policy making
4. Technology developments
5. Economic factors shaping the energy debate
6. Environmental conditions and concerns
7. Shifting political realities
8. Changes in overall system resiliency
9. Infrastructure investment priorities
10. Relative attractiveness of fossil fuel stocks
11. Relative attractiveness of alternative fuels
12. Consumer choice
13. Changing environmental regulations and standards
14. Grid configurations and off-gridding

# Initial Scenario Set

## Team Scenario Frameworks and an Initial Scenario Set

In best-practice scenario planning, a scenario framework is created to help planners and advisors guard against the well known risks associated with group think and false confidence about future projections. A scenario framework is a tool—a forcing mechanism—to keep analytical thinking widely stretched.

Having stretched thinking with a scenario framework, the tests of scenario quality are the following:

1. Do the scenarios challenge conventional wisdom in helpful ways?
2. Are the scenarios plausible?
3. Do the scenarios capture a broad enough array of future outcomes to help planners do critical contingency planning and sensitivity analysis?
4. Do the scenarios help planners incorporate the broad range of perspectives and preferences held by citizens?

The five teams broken out from the Advisory Group were asked to juggle combinations of critical uncertainties to create scenario frameworks and scenarios that met these basic criteria, and ultimately decide on one framework per team. (All five team frameworks appear below.)

The results of these team deliberations were then compared and contrasted, and an effort was made to find a final framework that integrated the best of the five team frameworks. Note that several of the team frameworks use the top two critical uncertainties identified in the earlier voting exercise, although the frameworks make use of these uncertainties in distinctive ways. Other critical uncertainties were used by the teams as they saw fit.

### Five Team Frameworks

Figure J-52: Team Framework #1

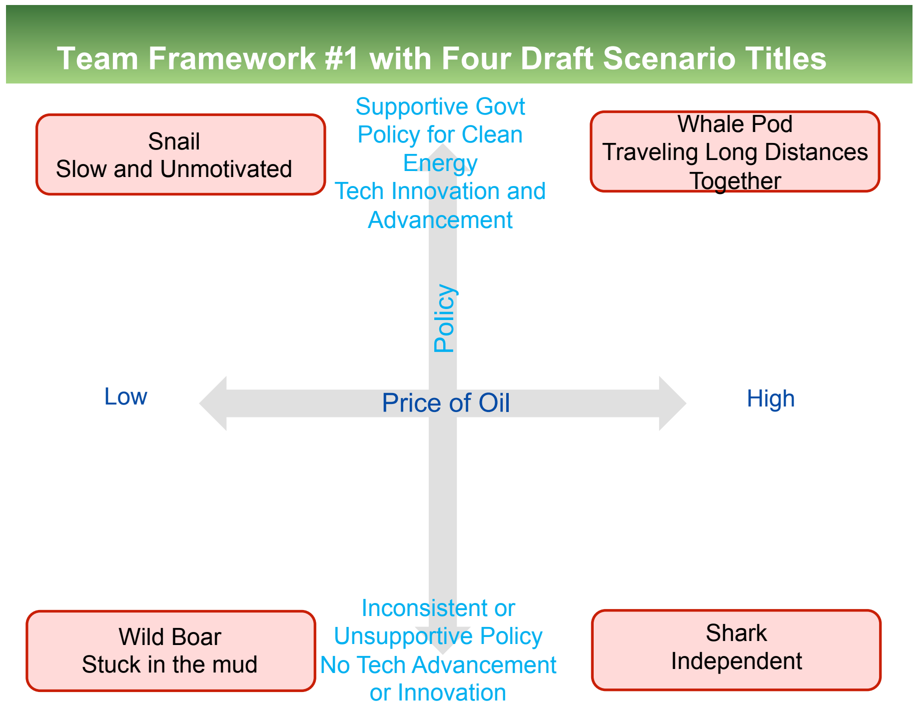



Figure J-53: Team Framework #2

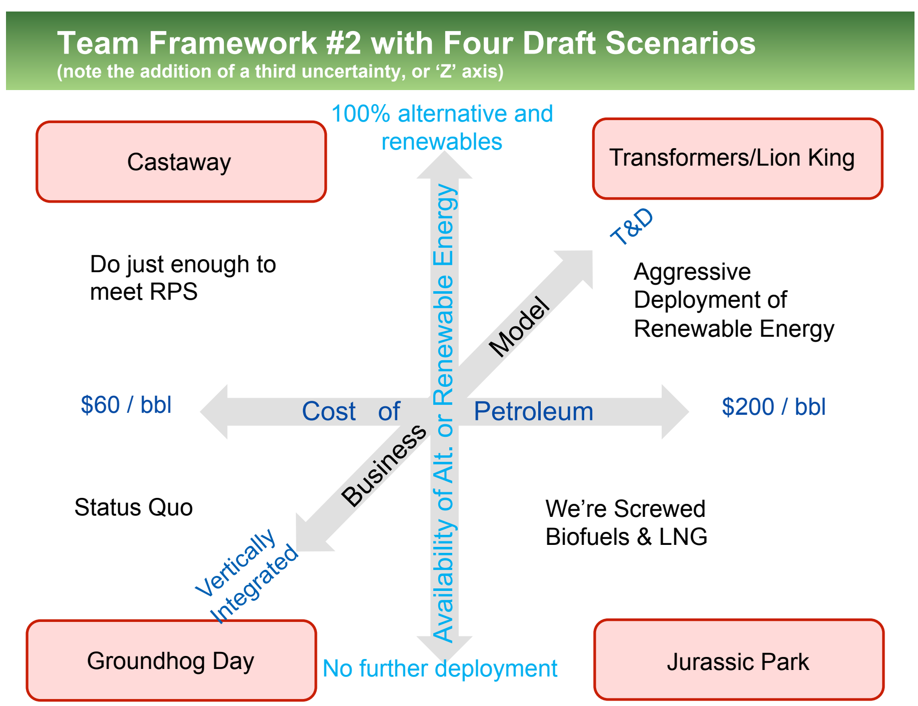


Figure J-54: Team Framework #3

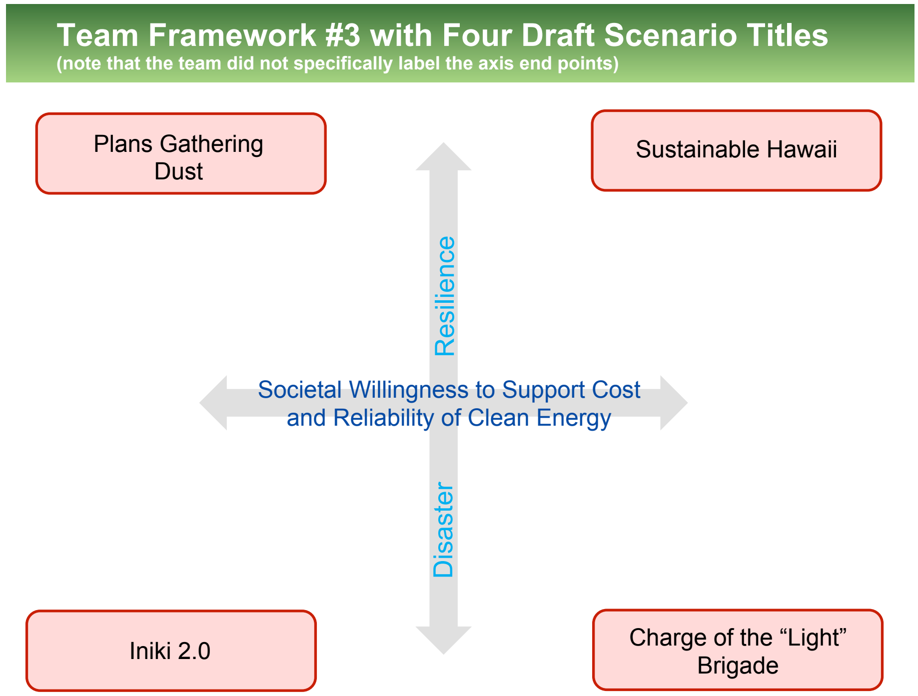



Figure J-55: Team Framework #4

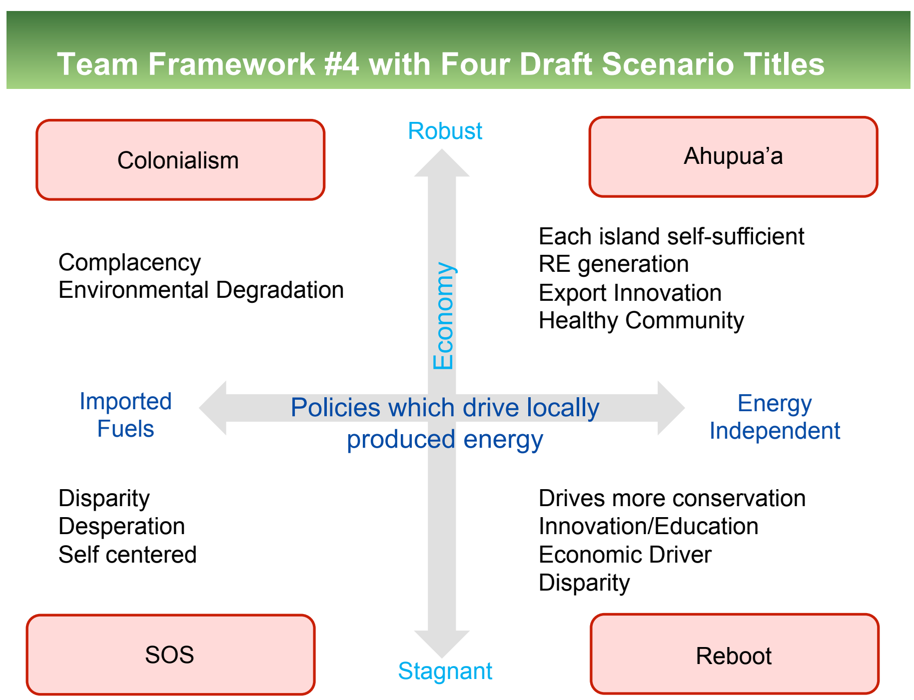
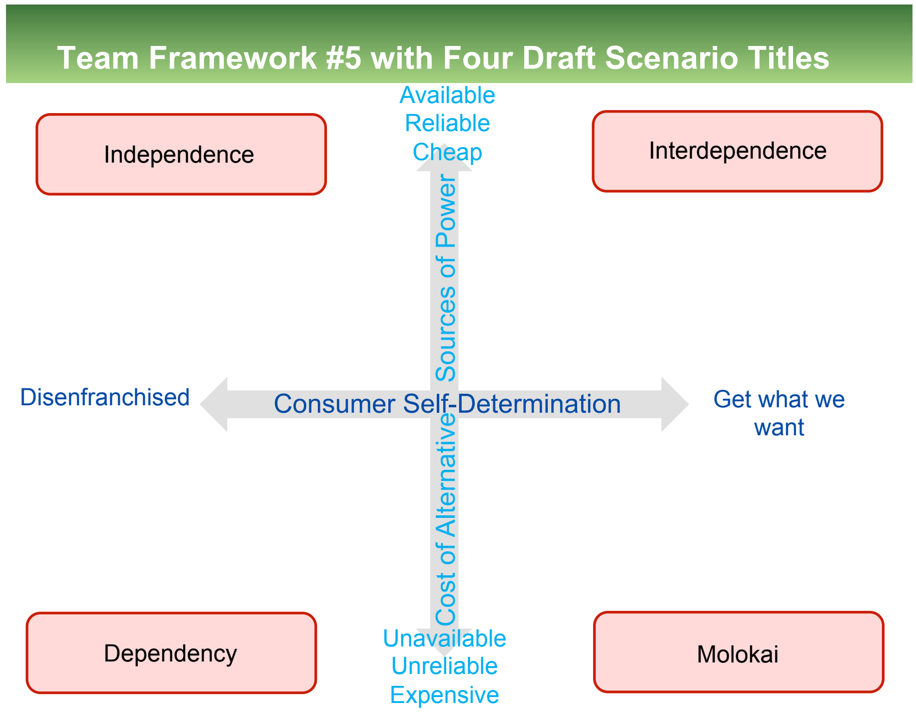


Figure J-56: Team Framework #5



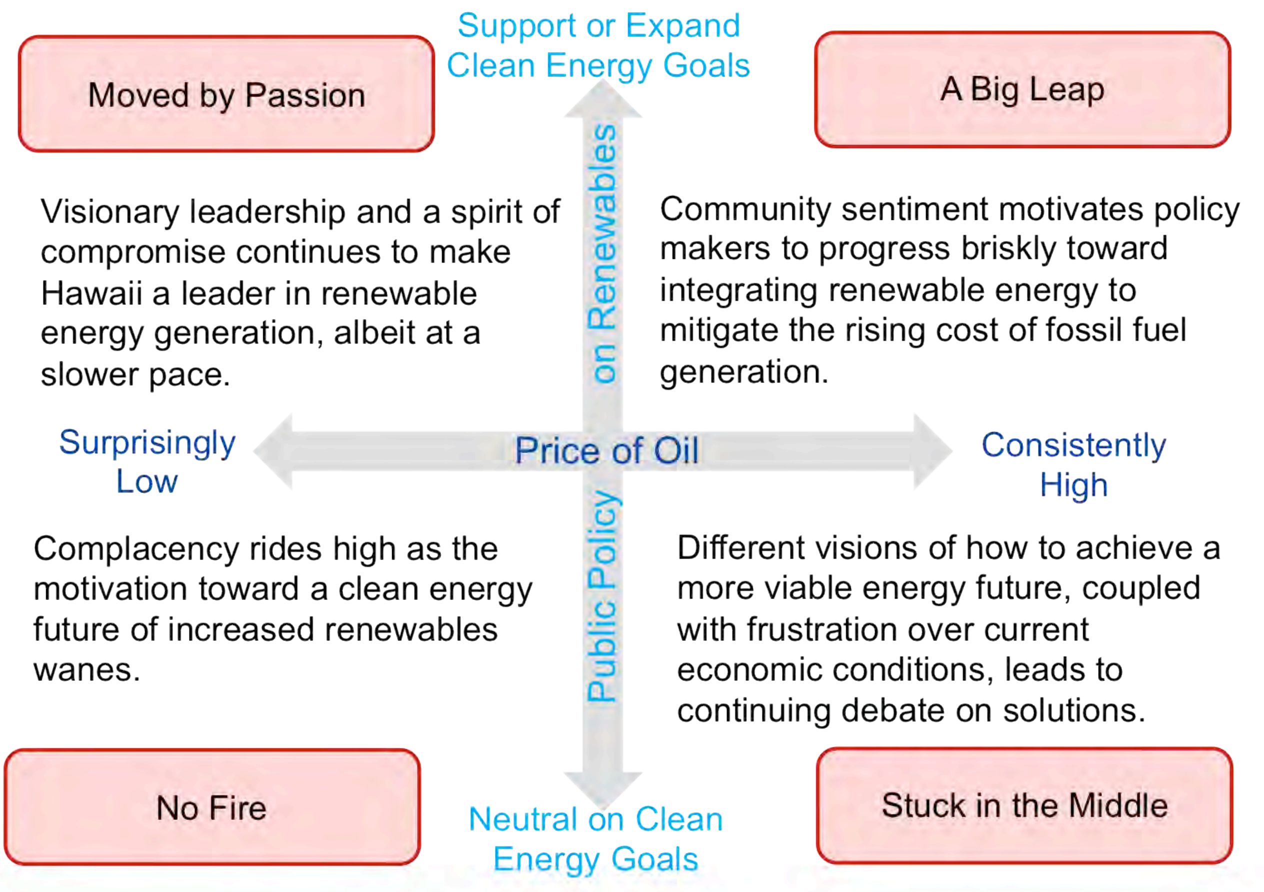

### Plenary Discussion

A plenary discussion was then held with the Advisory Group seeking to isolate the framework and scenarios that would be most useful for integrated resource planning. Again, while full consensus was not possible, the Advisory Group did reveal a slight preference for team frameworks #1 and #2. The Advisory Group decided that the utility team should integrate the strongest characteristics of those two frameworks and combine them into one. A further directive from the Advisory Group was to begin building some of the complexity found in energy conditions in Hawaii back into the scenarios themselves.

The graphic below depicts both the framework and the broadest outline of the implied scenarios that emerged as a result of the plenary discussions. This framework and outline were then further enriched to incorporate perspectives on the total set of fourteen critical uncertainties. Those scenario sketches are depicted below in bullet point format.

On August 24, over a five-hour session, the Advisory Group then offered detailed feedback on those sketches. That feedback is now being incorporated into the next draft of the scenarios, which will be shared at the September 24 Advisory Group meeting.

Figure J-57: Framework Scenarios Graphed Against Two Critical Uncertainties



## A Big Leap

- Skyrocketing oil prices force intense inspection of renewable alternatives.
- Skillful discussions by policy makers, energy entrepreneurs, and motivated citizens trigger a remarkable series of breakthrough events.
- Inspired action causes the renewable portfolio standards (RPS) and the energy efficiency portfolio standards (EEPS) to be increased beyond current legislative directives.
- Sustained, productive community engagement results in energy innovation, resourcefulness, and creativity.
- An entire raft of renewable, alternative, newer, and cleaner energy technologies emerge.
- Many new players create competitive alternatives while offering new service options.
- The increased choice for alternatives please customers, even though prices vary widely.
- High electricity prices lead to increased migration for customers to self-generate all or part of their needs.
- This rapid change for energy alternatives engenders many challenges, including increased expense.
- Electricity demand has fallen, resulting in upward pressure on pricing.
- In light of high fuel prices, investments look attractive, as financial burdens are spread across taxpayers and investors alike.
- Wide-spread community support exists for Hawaii to eliminate its oil addiction to ensure energy security and independence.

## Stuck in the Middle

- Skyrocketing oil prices force intense inspection of renewable alternatives.
- High oil prices slow economic growth.
- Customer sentiment toward the Utility has dipped to new lows.
- The renewable portfolio standards (RPS) directive remains in effect and the energy efficiency portfolio standards (EEPS) is not achieved.
- There is pressure to change the utility's energy mix yet progress toward that change is stagnated.
- While communities embrace a passion for a more sustainable energy mix, their visions for that future are conflicting and contradictory.
- Failure to innovate, combined with persistently high oil prices, pushes electricity prices even higher.

- Migration to self generation (to fulfill all or part of energy needs) continues.
- Policy-makers fervently debate energy possibilities, yet gridlock on solutions and methodologies.
- Alternative energy tax credits exists, but are either insufficient to coerce change or are sunsetting.
- Ideas arise, are explored, defined, and even planned, yet inaction ultimately prevails.
- Ardent activism is prevalent, but generally is unfocused and thus cannot be sustained.
- Residents agree the current situation is untenable, yet cannot concur of a clear path. Progress requires grim trade-offs that prove too difficult to make, or bold initiatives that lack courageous action because of perceived risks.

## No Fire

- Lower than expected oil prices neutralize serious discussions on alternate fuel sources to reduce Hawaii's addiction to oil.
- Lack of economic urgency due to economic recovery mutes potentially difficult policy discussions (such as an inter-island cable).
- The renewable portfolio standards (RPS) and energy efficiency portfolio standards (EEPS) are re-examined and the goals are lowered due to the low oil prices and lack of urgency to move towards renewables.
- Renewable energy incentives slowly end, causing investment in renewables to deteriorate and, with it, the slowing of new entrepreneurial activity.
- Current renewable energy projects progress slowly or are cancelled.
- Advancement and adoption of new technology stagnates.
- Demand for energy grows modestly as the economy grows and customers' desire to self-generate all or part of their needs slows.
- Aging infrastructure is ignored as public and governmental attention focuses on other issues.
- Important energy issues still exist, but conditions fail to motivate any meaningful attention.

## Moved by Passions

- Policy makers and the citizenry have facilitated substantial changes in energy generation despite more stable oil prices and electricity rates.
- Despite stable thoughtful and considered discussion about where and how energy is generated and transmitted.
- The RPS and EEPS 2030 targets remain unchanged, although interim goals are lowered to move at a slower pace.
- Electricity demand grows modestly due to a slower pace for achieving the RPS and EEPS.
- Historical volatility of oil prices spurs interest in renewables as a preferred energy source, even though renewable prices are more stable and continue to remain high.
- Carbon emission regulations are established and the overall commitment to environmental protection across the islands is high.
- Visionary forces for increased energy alternatives emerge as the theme for environmental sustainability and statewide prestige gains currency.
- Support for using the indigenous renewable energy resources grows as a method to secure stability for future generations.
- Citizens are more willing to compromise on the siting of energy facilities better facilitate statewide progress toward increased renewables.
- Because incentives for investing in renewables are few, consumers continue to leave the grid albeit at a slower pace.
- Economic conditions coupled with the growing appeal of Hawaii as an emerging leader in renewable energy strengthen tourism.
- Consumer interest in energy diversification and increases in renewables lead the discussion, although they sometimes struggle to attract attention due to lack of urgency.

# Feedback from the Advisory Group

This section describes comments by the Advisory Group on the initial draft scenarios.

## Takeaways

The Advisory Group offered vociferous feedback on the draft scenarios. That feedback fell in three broad groups:

1. Feedback directed at improving the quality of the scenarios as a planning tool.
2. Feedback focused on predicting which of the scenarios seemed more or less plausible.
3. Feedback focused on actions the utilities should take.

The range of opinions was diverse and Advisory Group member perspectives were often at odds. The task of the Companies will now be to take this feedback to create a richer and more defined set of scenarios which meet the goal of the IRP.

## Advisory Group Feedback

- Need the expected *future* in set too
- Need conventional wisdom in the text
- Dissatisfaction with framework, but okay with stories
- Y axis should include best projections on cost of oil
- ‘Cost of generation’ perhaps a better axis than cost of oil
- Y axis could be used by utility to migrate to “Moved By Passion”
- Y axis allows for proactive rather than reactive planning
- “Moved by Passion” does not feel plausible
- Need a bigger canvas
- Question assumption that renewables are/will be forever more expensive
- “All in” costs of renewable may be (much) lower than direct costs
- Wouldn’t it make sense to peg to forecasts
- “Big Leap” seems unlikely unless IRP is linked to community development plans

- Can't get to "Big Leap" with community linkages as storage
- Policy may not lead energy developments, it might actually follow
- "Big Leap" requires a formal plan that is more than just energy resource planning
- Remove "Oil"
- Regulatory issues need to be more fully developed across the scenarios
- How do we best capture community sentiment in the scenarios?
- Need to think about the big picture / beyond utility impacting task
- Consider overall interactions with state economy
- More speculation on game changers might be appropriate (for example, transport and evolution of electric vehicles)
- X axis might better be thought of as electricity utility rates rather than oil
- We were okay with the scenario concept; it generally worked for us
- "Big Leap" would require pushing past generation to include massive energy efficiency moves, widespread marked shifts, and a major re-think of the utilities' business model
- Scenarios do not cover utility interest in profitability/decision making /business model
- Need land use called out somewhere in the scenarios
- Need reliability called out somewhere in the scenarios
- Will the framework facilitate resource planning if statutory mandates are locked in?
- Need to acknowledge that policy is perhaps less mobile as a variable than framework suggests
- What we do know is that the system is bleeding now: ancient resources, high rates, and self-generation are rapidly expanding
- Scenario matrix has problems but it helped us talk
- Only one approach and not a new one
- Other possibilities include multi-attribute analysis, objective (modeling), and improved sensitivity analysis
- Need to focus on primary drivers and make specific for each island
- Scenario framework considers 100 pound gorillas; we need to be thinking about the 800 pound gorillas
- Need more market forces:
  - Cost of generation
  - Price as primary driver but certainly not only

- Hidden costs to environment need to come forward in the scenario analysis
- Scenarios that assume more renewable seem like 'official future'; scenarios that do not take renewable as given require more thinking
- Developments in self-generation are big; could be dominant planning factor in the future
- Nimby-ism not adequately reflected in the scenarios; needs to be amplified as an uncertainty or driver
- Using policy as axis does not seem like a great way to frame
- It is not just the existence of policy; it is also the rate at which policy is adopted and implemented
- Profitability and profit incentive of the utility are central motivations and has impact on propensity for change
- 'Relative price of renewable' is more critical than absolute price
- Quadrants would benefit from even more specificity; they need to be further stretched and tested for distinctiveness
- Switch to renewables does not necessarily mean lower prices
- Need to see a graphical demonstration of how scenarios impact load actual curves key; would be helpful to compare those graphics to base case forecasts
- Consumer is moved by more than just price; rate design is what moves the consumer
- Eventually being able to match generation and load across scenarios will be key to thinking through planning implications
- Must help utility match generation and load curves as a path to optimization
- High rates need to be dealt with in every scenario
- Need to deal with statutory requirements in every scenario
- Self-generation is the core driver of utility demand forecasts
- Alternative fuels are an important sensitivity in the Resource Plan
- Utility has got to look internally to profitability and viability
- Are the scenarios plausible?
- Only see two real paths forward:
  - Meet RPS and EEPS standards and stop
  - Or we go 'whole hog' on renewables
- I want a Resource Plan that reflects a total renewable strategy and retirement of *all* fossil
- Inter-island cable is an important uncertainty

- Alternate fuels is an important uncertainty
- What happens to Big Wind?
- Somewhere in the scenarios we need to assess probable system reliability and how much we are willing to pay for it
- Final Resource Plan will need to analyze current operating philosophies, especially the 'fossil mantra', and thinking about how the grid is operated
- Do the scenarios adequately allow for the extremes?
- One option would be for us to reduce the number of scenarios and apply that time to going deep on those
- Other important uncertainties include 'lesser attainment' and pace of the evolution of the Resource Plan
- Lower oil price scenarios all seem so much less plausible, liquified natural gas price notwithstanding
- Just have to get down to business… It feels like it is only two scenarios (really)
- Lower oil price scenarios do become plausible via liquefied natural gas or biofuels
- Need to make sure that 'Hawaiian values' are somehow captured across the scenario framework; we live on islands; insular in every sense; highly inter-reliant; this is *not* an engineering problem primarily
- Assumption that we all share the same values… and we don't
- 'Old guys think the young guys are renegades'
- Do we want to think about scenarios for the future or do we want to come up with a vision for what we really want?
- Need to think about the possibility of the Department of Defense (DOD) leaving system as an important driver
- Need to think about what happens to our refineries as an important wildcard
- Risk to the Advisory Group is that our perspectives are already obsolete before we even register them; the train is already out of the station on many important decisions
- Delivered electricity cost as essential
- The role of technology—both generation and efficiency generating technology—needs to be played up in the scenarios
- Any scenarios that soften the commitment to the renewable portfolio seem highly unlikely
- "Degrees of action" in southern hemisphere should be tracked carefully

- If the eventual Resource Plans 'hedge bets' in any way, that is likely to further lock us in to the status quo; half-way actions should be considered only with real caution
- RPS and EEPS targets should be kept out of the scenarios entirely, "they are arbitrary constructs"
- We are at risk of conforming back to expected case
- Thinking in two dimensions is dangerous
- What we do with the environment and with local culture are critical considerations; do we let these 'ride' or do we actively protect them?
- Renewable Portfolio Standard (RPS) as an artificial construct driving the entire process

# Next Steps

The next draft of the scenarios will be presented to the Advisory Group on September 24, 2012. That draft will be substantially more detailed than what was last shared. It will also include an initial translation of the scenarios into modeling assumptions to be utilized in the analysis that follows in the next phases of the IRP process.

# Appendix K: Supply-Side Resources

This appendix contains four documents that contain data and analysis that support Hawaiian Electric Company's supply-side resources.

- *Bus Bar Unit Information Form Costs* contains cost projections for the Blazing a Bold Frontier and Stuck in the Middle scenarios.
- *Future Capital Costs for Renewable Energy Options* dissected the issue of nominal versus real dollar costs, presenting both a historical perspective and estimating future costs of renewable energy.
- *Supply-Side Resource Assessment, IRP 2013, Executive Summary*, considered and evaluated all supply-side resource options appropriate for Hawaii that are available in the near term.
- *Consolidated Unit Information Forms (UIFs)* are the "generic" non-project-specific, supply-side resource option UIFs developed for the IRP process.

# CONTENTS

# FIGURES



# TABLES

# Bus Bar Costs

The Companies developed bus bar costs for many different Unit Information Forms (UIFs) for two scenarios: Blazing a Bold Frontier and Stuck in the Middle. Bus bar costs for the other two scenarios — No Burning Desire and Moved by Passion —were not developed because the resultant data would have been the same.

Bus bar data was developed for thirty UIFs (labeled in the column headings in the following tables) for six percentages, for three projected years: 2015, 2020, and 2030.

### About the Tables

The tables list the levelized cost (dollars per kWh) to run a unit at a percentage of the maximum capacity factor (% Max Cap).

Because photovoltaics (PV), wind, ocean wave, and ocean thermal have monthly profiles and thus have no capacity factor, the costs for each percentage are the same. The costs for all other UIFs is different from the various percentages.

## Bus Bar Costs: Blazing a Bold Frontier

### *2015 Blazing a Bold Frontier Costs*

The data in Table K-1 to Table K-5 is the levelized cost of dollars per kWh based on an installation in 2015.

Table K-1: Bus Bar Costs 2015, Blazing a Bold Frontier Scenario (1 of 5)

| % Max Cap | W01: Class 3 On Shore Wind (30 MW) | W02: Class 3 On Shore Wind (10 MW) | W03: Class 5 On Shore Wind (10 MW) | W04: Class 7 On Shore Wind (10 MW) | W05: Class 5 Off Shore Wind (100 MW) | P01: Rooftop PV (2kW) |
|---|---|---|---|---|---|---|
| 12% | 0.1933 | 0.2381 | 0.2056 | 0.1347 | 0.4316 | 0.5187 |
| 25% | 0.1933 | 0.2381 | 0.2056 | 0.1347 | 0.4316 | 0.5187 |
| 50% | 0.1933 | 0.2381 | 0.2056 | 0.1347 | 0.4316 | 0.5187 |
| 65% | 0.1933 | 0.2381 | 0.2056 | 0.1347 | 0.4316 | 0.5187 |
| 75% | 0.1933 | 0.2381 | 0.2056 | 0.1347 | 0.4316 | 0.5187 |
| 85% | 0.1933 | 0.2381 | 0.2056 | 0.1347 | 0.4316 | 0.5187 |

Table K-2: Bus Bar Costs 2015, Blazing a Bold Frontier Scenario (2 of 5)

| % Max Cap | P02: Rooftop PV (100kW) | P03: Single Axis Tracking PV (1MW) | P04: Parabolic Trough (50MW) | G01: Advanced Geothermal (25 MW) | G02: New Geothermal (25 MW) | V01: Ocean Wave (750kW) |
|---|---|---|---|---|---|---|
| 12% | 0.2933 | 0.2714 | 0.7399 | 1.4426 | 1.5151 | 2.8081 |
| 25% | 0.2933 | 0.2714 | 0.7399 | 0.7137 | 0.7492 | 2.8081 |
| 50% | 0.2933 | 0.2714 | 0.7399 | 0.3773 | 0.3957 | 2.8081 |
| 65% | 0.2933 | 0.2714 | 0.7399 | 0.2997 | 0.3141 | 2.8081 |
| 75% | 0.2933 | 0.2714 | 0.7399 | 0.2652 | 0.2778 | 2.8081 |
| 85% | 0.2933 | 0.2714 | 0.7399 | 0.2388 | 0.2501 | 2.8081 |

Table K-3: Bus Bar Costs 2015, Blazing a Bold Frontier Scenario (3 of 5)

| % Max Cap | V01: Ocean Wave (15MW) | OT1: Ocean Thermal (9.6MW) | A01: Biomass Combustion (25MW) | T01 w/: WTE w/ Tipping Fee (8MW) | T01 w/o: WTE No Tipping Fee (8MW) | F01: Fuel Cell (400kW) |
|---|---|---|---|---|---|---|
| 12% | 0.7731 | 1.4652 | 1.3647 | 3.4916 | 3.7285 | 1.7814 |
| 25% | 0.7731 | 1.4652 | 0.7265 | 1.5781 | 1.8150 | 1.0239 |
| 50% | 0.7731 | 1.4652 | 0.4320 | 0.6949 | 0.9318 | 0.6743 |
| 65% | 0.7731 | 1.4652 | 0.3640 | 0.4911 | 0.7280 | 0.5937 |
| 75% | 0.7731 | 1.4652 | 0.3338 | 0.4005 | 0.6374 | 0.5578 |
| 85% | 0.7731 | 1.4652 | 0.3107 | 0.3312 | 0.5681 | 0.5304 |

Table K-4: Bus Bar Costs 2015, Blazing a Bold Frontier Scenario (4 of 5)

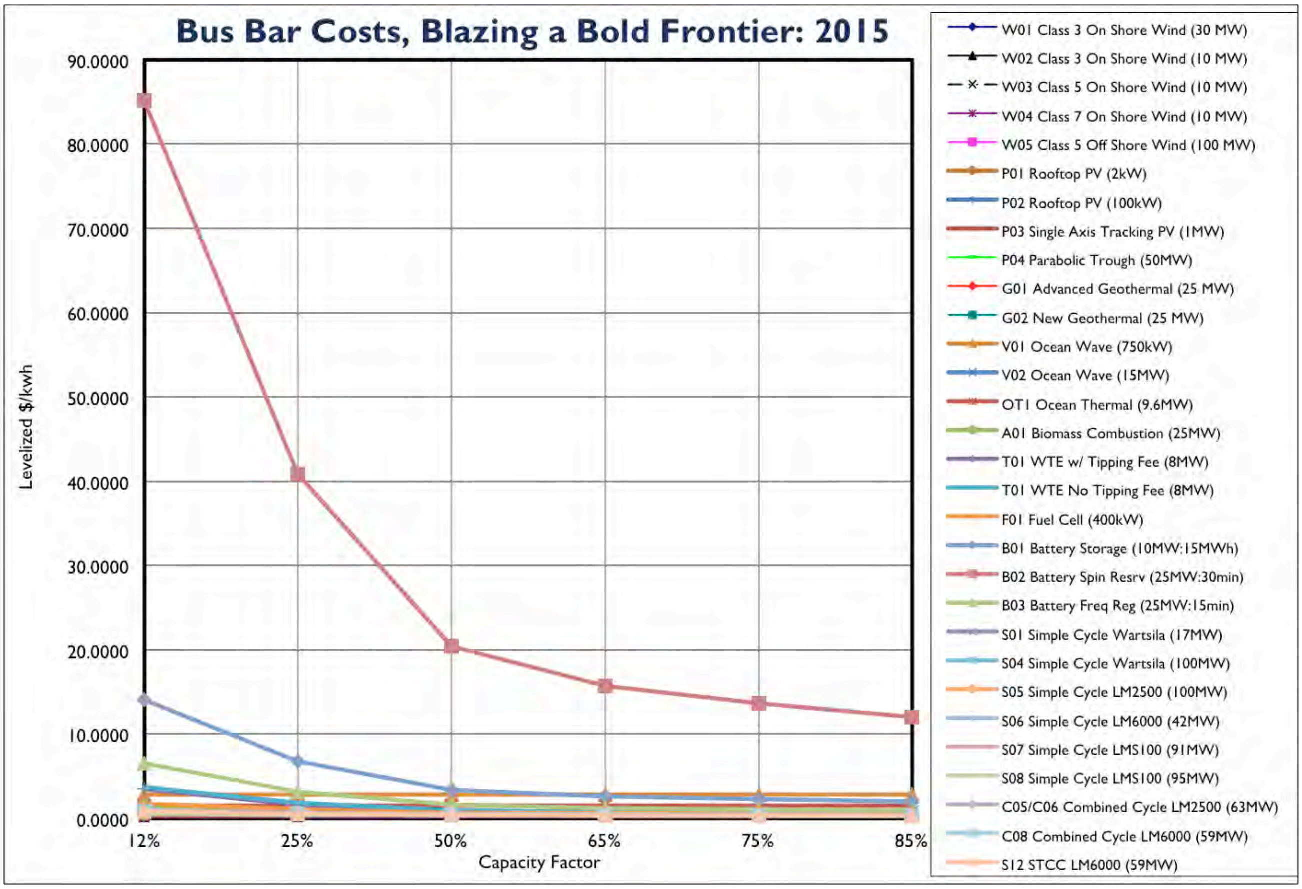
| % Max Cap | B01: Battery Storage (10MW:15MWh) | B02: Battery Spin Reserve (25MW:30min) | B03: Battery Frequency Regulation (25MW:15min) | S01: Simple Cycle Wärtsilä (17MW) | S04: Simple Cycle Wärtsilä (100MW) | S05: Simple Cycle LM2500 (100MW) |
|---|---|---|---|---|---|---|
| 12% | 14.1014 | 85.1364 | 6.5598 | 0.9472 | 0.6554 | 0.9831 |
| 25% | 6.7687 | 40.8654 | 3.1487 | 0.6109 | 0.4640 | 0.6706 |
| 50% | 3.3843 | 20.4327 | 1.5743 | 0.4558 | 0.3756 | 0.5263 |
| 65% | 2.6033 | 15.7175 | 1.2110 | 0.4199 | 0.3552 | 0.4930 |
| 75% | 2.2562 | 13.6218 | 1.0496 | 0.4040 | 0.3462 | 0.4783 |
| 85% | 1.9908 | 12.0192 | 0.9261 | 0.3919 | 0.3392 | 0.4669 |

Table K-5: Bus Bar Costs 2015, Blazing a Bold Frontier Scenario (5 of 5)

| % Max Cap | S06: Simple Cycle LM6000 (42MW) | S07: Simple Cycle LMS100 (91MW) | S08: Simple Cycle LMS100 (95MW) | C05/C06: Combined Cycle LM2500 (63MW) | C08: Combined Cycle LM6000 (59MW) | S12: STCC LM6000 (59MW) |
|---|---|---|---|---|---|---|
| 12% | 0.7429 | 0.6001 | 0.5789 | 0.9626 | 0.8418 | 0.8115 |
| 25% | 0.5357 | 0.4511 | 0.4391 | 0.5982 | 0.5405 | 0.5256 |
| 50% | 0.4401 | 0.3824 | 0.3745 | 0.4299 | 0.4015 | 0.3936 |
| 65% | 0.4180 | 0.3665 | 0.3596 | 0.3911 | 0.3694 | 0.3632 |
| 75% | 0.4082 | 0.3594 | 0.3530 | 0.3739 | 0.3551 | 0.3496 |
| 85% | 0.4007 | 0.3541 | 0.3480 | 0.3607 | 0.3442 | 0.3393 |

## *2015 Blazing a Bold Frontier Summary Chart*

Figure K-1: Blazing a Bold Frontier Summary Chart: 2015



### *2020 Blazing a Bold Frontier Costs*

The data in Table K-6 to Table K-10 is the levelized cost of dollars per kWh based on an installation in 2020.

Table K-6: Bus Bar Costs 2020, Blazing a Bold Frontier Scenario (1 of 5)

| % Max Cap | W01: Class 3 On Shore Wind (30 MW) | W02: Class 3 On Shore Wind (10 MW) | W03: Class 5 On Shore Wind (10 MW) | W04: Class 7 On Shore Wind (10 MW) | W05: Class 5 Off Shore Wind (100 MW) | P01: Rooftop PV (2kW) |
|---|---|---|---|---|---|---|
| 12% | 0.1982 | 0.2436 | 0.2103 | 0.1379 | 0.4359 | 0.5303 |
| 25% | 0.1982 | 0.2436 | 0.2103 | 0.1379 | 0.4359 | 0.5303 |
| 50% | 0.1982 | 0.2436 | 0.2103 | 0.1379 | 0.4359 | 0.5303 |
| 65% | 0.1982 | 0.2436 | 0.2103 | 0.1379 | 0.4359 | 0.5303 |
| 75% | 0.1982 | 0.2436 | 0.2103 | 0.1379 | 0.4359 | 0.5303 |
| 85% | 0.1982 | 0.2436 | 0.2103 | 0.1379 | 0.4359 | 0.5303 |

Table K-7: Bus Bar Costs 2020, Blazing a Bold Frontier Scenario (2 of 5)

| % Max Cap | P02: Rooftop PV (100kW) | P03: Single Axis Tracking PV (1MW) | P04: Parabolic Trough (50MW) | G01: Advanced Geothermal (25 MW) | G02: New Geothermal (25 MW) | V01: Ocean Wave (750kW) |
|---|---|---|---|---|---|---|
| 12% | 0.2971 | 0.2778 | 0.7577 | 1.4741 | 1.5468 | 2.9006 |
| 25% | 0.2971 | 0.2778 | 0.7577 | 0.7309 | 0.7665 | 2.9006 |
| 50% | 0.2971 | 0.2778 | 0.7577 | 0.3879 | 0.4064 | 2.9006 |
| 65% | 0.2971 | 0.2778 | 0.7577 | 0.3087 | 0.3233 | 2.9006 |
| 75% | 0.2971 | 0.2778 | 0.7577 | 0.2736 | 0.2863 | 2.9006 |
| 85% | 0.2971 | 0.2778 | 0.7577 | 0.2467 | 0.2581 | 2.9006 |

Table K-8: Bus Bar Costs 2020, Blazing a Bold Frontier Scenario (3 of 5)

| % Max Cap | V01: Ocean Wave (15MW) | OT1: Ocean Thermal (9.6MW) | A01: Biomass Combustion (25MW) | T01 w/: WTE w/ Tipping Fee (8MW) | T01 w/o: WTE No Tipping Fee (8MW) | F01: Fuel Cell (400kW) |
|---|---|---|---|---|---|---|
| 12% | 0.7952 | 1.4875 | 1.4277 | 3.6027 | 3.8773 | 1.8837 |
| 25% | 0.7952 | 1.4875 | 0.7637 | 1.6142 | 1.8889 | 1.1048 |
| 50% | 0.7952 | 1.4875 | 0.4573 | 0.6965 | 0.9711 | 0.7453 |
| 65% | 0.7952 | 1.4875 | 0.3866 | 0.4847 | 0.7593 | 0.6624 |
| 75% | 0.7952 | 1.4875 | 0.3551 | 0.3906 | 0.6652 | 0.6255 |
| 85% | 0.7952 | 1.4875 | 0.3311 | 0.3186 | 0.5932 | 0.5973 |

Table K-9: Bus Bar Costs 2020, Blazing a Bold Frontier Scenario (4 of 5)

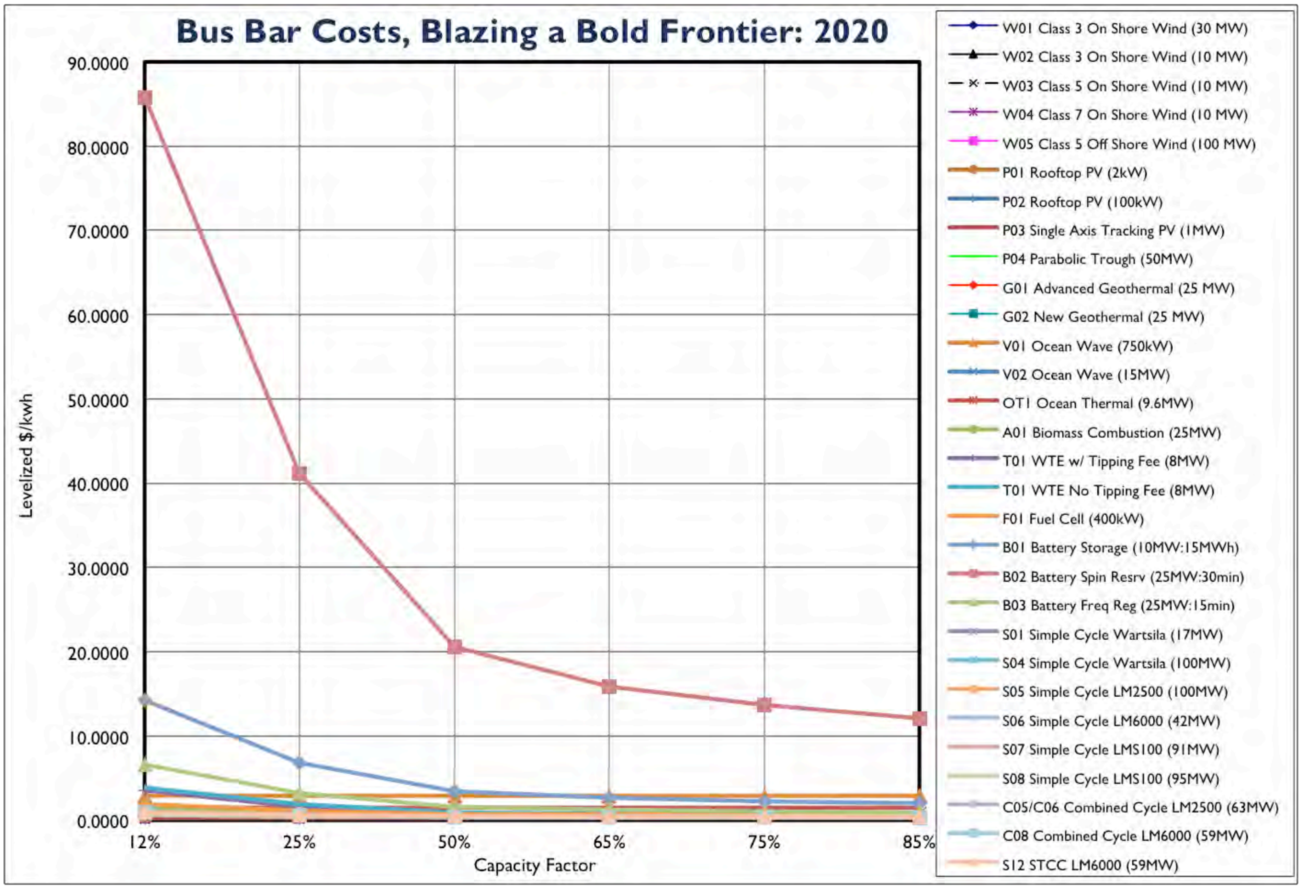
| % Max Cap | B01: Battery Storage (10MW:15MWh) | B02: Battery Spin Reserve (25MW:30min) | B03: Battery Frequency Regulation (25MW:15min) | S01: Simple Cycle Wärtsilä (17MW) | S04: Simple Cycle Wärtsilä (100MW) | S05: Simple Cycle LM2500 (100MW) |
|---|---|---|---|---|---|---|
| 12% | 14.2526 | 85.7032 | 6.6202 | 1.0167 | 0.6828 | 1.0362 |
| 25% | 6.8412 | 41.1376 | 3.1777 | 0.6292 | 0.4614 | 0.6758 |
| 50% | 3.4206 | 20.5688 | 1.5889 | 0.4504 | 0.3591 | 0.5094 |
| 65% | 2.6312 | 15.8221 | 1.2222 | 0.4091 | 0.3356 | 0.4710 |
| 75% | 2.2804 | 13.7125 | 1.0592 | 0.3908 | 0.3251 | 0.4539 |
| 85% | 2.0121 | 12.0993 | 0.9346 | 0.3767 | 0.3171 | 0.4409 |

Table K-10: Bus Bar Costs 2020, Blazing a Bold Frontier Scenario (5 of 5)

| % Max Cap | S06: Simple Cycle LM6000 (42MW) | S07: Simple Cycle LMS100 (91MW) | S08: Simple Cycle LMS100 (95MW) | C05/C06: Combined Cycle LM2500 (63MW) | C08: Combined Cycle LM6000 (59MW) | S12: STCC LM6000 (59MW) |
|---|---|---|---|---|---|---|
| 12% | 0.7682 | 0.6109 | 0.6809 | 1.0415 | 0.9016 | 0.9440 |
| 25% | 0.5290 | 0.4387 | 0.5192 | 0.6219 | 0.5551 | 0.6153 |
| 50% | 0.4186 | 0.3592 | 0.4446 | 0.4282 | 0.3952 | 0.4636 |
| 65% | 0.3931 | 0.3408 | 0.4274 | 0.3835 | 0.3583 | 0.4286 |
| 75% | 0.3818 | 0.3327 | 0.4198 | 0.3637 | 0.3419 | 0.4131 |
| 85% | 0.3732 | 0.3264 | 0.4139 | 0.3485 | 0.3294 | 0.4012 |

## *2020 Blazing a Bold Frontier Summary Chart*

Figure K-2: Blazing a Bold Frontier Summary Chart: 2020



## *2030 Blazing a Bold Frontier Costs*

The data in Table K-11 to Table K-15 is the levelized cost of dollars per kWh based on an installation in 2030.

Table K-11: Bus Bar Costs 2030, Blazing a Bold Frontier Scenario (1 of 5)

| % Max Cap | W01: Class 3 On Shore Wind (30 MW) | W02: Class 3 On Shore Wind (10 MW) | W03: Class 5 On Shore Wind (10 MW) | W04: Class 7 On Shore Wind (10 MW) | W05: Class 5 Off Shore Wind (100 MW) | P01: Rooftop PV (2kW) |
|---|---|---|---|---|---|---|
| 12% | 0.2092 | 0.2561 | 0.2212 | 0.1451 | 0.4457 | 0.5569 |
| 25% | 0.2092 | 0.2561 | 0.2212 | 0.1451 | 0.4457 | 0.5569 |
| 50% | 0.2092 | 0.2561 | 0.2212 | 0.1451 | 0.4457 | 0.5569 |
| 65% | 0.2092 | 0.2561 | 0.2212 | 0.1451 | 0.4457 | 0.5569 |
| 75% | 0.2092 | 0.2561 | 0.2212 | 0.1451 | 0.4457 | 0.5569 |
| 85% | 0.2092 | 0.2561 | 0.2212 | 0.1451 | 0.4457 | 0.5569 |

Table K-12: Bus Bar Costs 2030, Blazing a Bold Frontier Scenario (2 of 5)

| % Max Cap | P02: Rooftop PV (100kW) | P03: Single Axis Tracking PV (1MW) | P04: Parabolic Trough (50MW) | G01: Advanced Geothermal (25 MW) | G02: New Geothermal (25 MW) | V01: Ocean Wave (750kW) |
|---|---|---|---|---|---|---|
| 12% | 0.3058 | 0.2926 | 0.7986 | 1.5468 | 1.6198 | 3.1133 |
| 25% | 0.3058 | 0.2926 | 0.7986 | 0.7706 | 0.8065 | 3.1133 |
| 50% | 0.3058 | 0.2926 | 0.7986 | 0.4123 | 0.4311 | 3.1133 |
| 65% | 0.3058 | 0.2926 | 0.7986 | 0.3296 | 0.3444 | 3.1133 |
| 75% | 0.3058 | 0.2926 | 0.7986 | 0.2929 | 0.3059 | 3.1133 |
| 85% | 0.3058 | 0.2926 | 0.7986 | 0.2648 | 0.2765 | 3.1133 |

Table K-13: Bus Bar Costs 2030, Blazing a Bold Frontier Scenario (3 of 5)

| % Max Cap | V01: Ocean Wave (15MW) | OT1: Ocean Thermal (9.6MW) | A01: Biomass Combustion (25MW) | T01 w/: WTE w/ Tipping Fee (8MW) | T01 w/o: WTE No Tipping Fee (8MW) | F01: Fuel Cell (400kW) |
|---|---|---|---|---|---|---|
| 12% | 0.8461 | 1.5386 | 1.5728 | 3.8508 | 4.2199 | 2.1546 |
| 25% | 0.8461 | 1.5386 | 0.8493 | 1.6899 | 2.0589 | 1.3264 |
| 50% | 0.8461 | 1.5386 | 0.5154 | 0.6925 | 1.0616 | 0.9442 |
| 65% | 0.8461 | 1.5386 | 0.4384 | 0.4623 | 0.8314 | 0.8560 |
| 75% | 0.8461 | 1.5386 | 0.4041 | 0.3600 | 0.7291 | 0.8168 |
| 85% | 0.8461 | 1.5386 | 0.3779 | 0.2818 | 0.6509 | 0.7868 |

Table K-14: Bus Bar Costs 2030, Blazing a Bold Frontier Scenario (4 of 5)

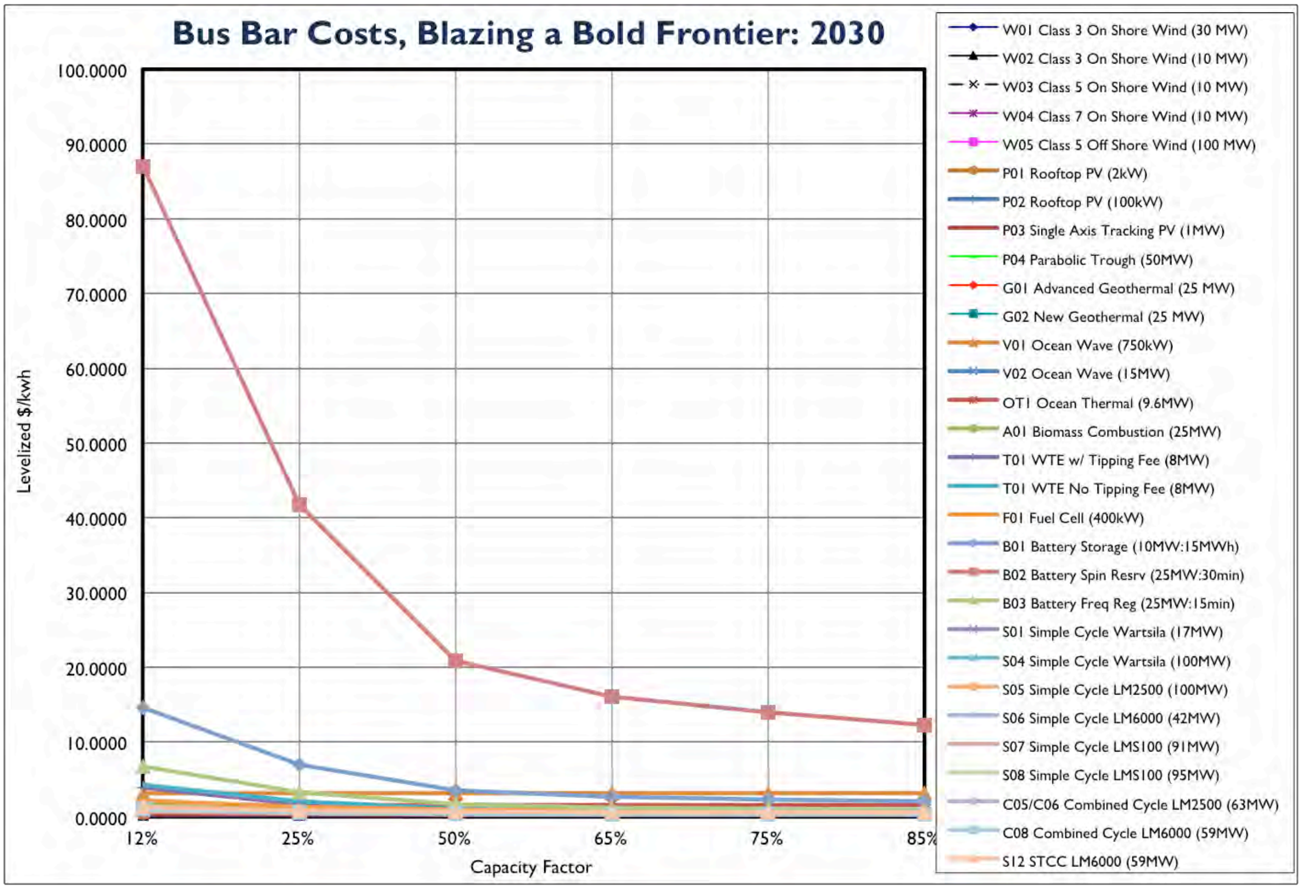
| % Max Cap | B01: Battery Storage (10MW:15MWh) | B02: Battery Spin Reserve (25MW:30min) | B03: Battery Frequency Regulation (25MW:15min) | S01: Simple Cycle Wärtsilä (17MW) | S04: Simple Cycle Wärtsilä (100MW) | S05: Simple Cycle LM2500 (100MW) |
|---|---|---|---|---|---|---|
| 12% | 14.6004 | 87.0074 | 6.7593 | 1.2069 | 0.7692 | 1.1913 |
| 25% | 7.0082 | 41.7636 | 3.2445 | 0.6919 | 0.4727 | 0.7115 |
| 50% | 3.5041 | 20.8818 | 1.6222 | 0.4542 | 0.3358 | 0.4900 |
| 65% | 2.6955 | 16.0629 | 1.2479 | 0.3994 | 0.3042 | 0.4389 |
| 75% | 2.3361 | 13.9212 | 1.0815 | 0.3750 | 0.2902 | 0.4162 |
| 85% | 2.0612 | 12.2834 | 0.9543 | 0.3563 | 0.2794 | 0.3989 |

Table K-15: Bus Bar Costs 2030, Blazing a Bold Frontier Scenario (5 of 5)

| % Max Cap | S06: Simple Cycle LM6000 (42MW) | S07: Simple Cycle LMS100 (91MW) | S08: Simple Cycle LMS100 (95MW) | C05/C06: Combined Cycle LM2500 (63MW) | C08: Combined Cycle LM6000 (59MW) | S12: STCC LM6000 (59MW) |
|---|---|---|---|---|---|---|
| 12% | 0.8525 | 0.6576 | 0.9566 | 1.2533 | 1.0659 | 1.2911 |
| 25% | 0.5334 | 0.4272 | 0.7405 | 0.6966 | 0.6070 | 0.8563 |
| 50% | 0.3861 | 0.3209 | 0.6407 | 0.4396 | 0.3953 | 0.6556 |
| 65% | 0.3521 | 0.2964 | 0.6177 | 0.3803 | 0.3464 | 0.6093 |
| 75% | 0.3370 | 0.2855 | 0.6074 | 0.3540 | 0.3247 | 0.5887 |
| 85% | 0.3255 | 0.2772 | 0.5996 | 0.3338 | 0.3081 | 0.5730 |

## *2030 Blazing a Bold Frontier Summary Chart*

Figure K-3: Blazing a Bold Frontier Summary Chart: 2030



## Bus Bar Costs: Stuck in the Middle

### *2015 Stuck in the Middle Costs*

The data in Table K-16 to Table K-20 is the levelized cost of dollars per kWh based on an installation in 2015.

Table K-16: Bus Bar Costs 2015, Stuck in the Middle Scenario (1 of 5)

| % Max Cap | W01: Class 3 On Shore Wind (30 MW) | W02: Class 3 On Shore Wind (10 MW) | W03: Class 5 On Shore Wind (10 MW) | W04: Class 7 On Shore Wind (10 MW) | W05: Class 5 Off Shore Wind (100 MW) | P01: Rooftop PV (2kW) |
|---|---|---|---|---|---|---|
| 12% | 0.2114 | 0.2610 | 0.2253 | 0.1475 | 0.4802 | 0.5689 |
| 25% | 0.2114 | 0.2610 | 0.2253 | 0.1475 | 0.4802 | 0.5689 |
| 50% | 0.2114 | 0.2610 | 0.2253 | 0.1475 | 0.4802 | 0.5689 |
| 65% | 0.2114 | 0.2610 | 0.2253 | 0.1475 | 0.4802 | 0.5689 |
| 75% | 0.2114 | 0.2610 | 0.2253 | 0.1475 | 0.4802 | 0.5689 |
| 85% | 0.2114 | 0.2610 | 0.2253 | 0.1475 | 0.4802 | 0.5689 |

Table K-17: Bus Bar Costs 2015, Stuck in the Middle Scenario (2 of 5)

| % Max Cap | P02: Rooftop PV (100kW) | P03: Single Axis Tracking PV (1MW) | P04: Parabolic Trough (50MW) | G01: Advanced Geothermal (25 MW) | G02: New Geothermal (25 MW) | V01: Ocean Wave (750kW) |
|---|---|---|---|---|---|---|
| 12% | 0.3252 | 0.2972 | 0.8098 | 1.5828 | 1.6643 | 3.0410 |
| 25% | 0.3252 | 0.2972 | 0.8098 | 0.7810 | 0.8208 | 3.0410 |
| 50% | 0.3252 | 0.2972 | 0.8098 | 0.4109 | 0.4315 | 3.0410 |
| 65% | 0.3252 | 0.2972 | 0.8098 | 0.3256 | 0.3416 | 3.0410 |
| 75% | 0.3252 | 0.2972 | 0.8098 | 0.2876 | 0.3017 | 3.0410 |
| 85% | 0.3252 | 0.2972 | 0.8098 | 0.2586 | 0.2712 | 3.0410 |

Table K-18: Bus Bar Costs 2015, Stuck in the Middle Scenario (3 of 5)

| % Max Cap | V01: Ocean Wave (15MW) | OT1: Ocean Thermal (9.6MW) | A01: Biomass Combustion (25MW) | T01 w/: WTE w/ Tipping Fee (8MW) | T01 w/o: WTE No Tipping Fee (8MW) | F01: Fuel Cell (400kW) |
|---|---|---|---|---|---|---|
| 12% | 0.8415 | 1.6204 | 1.4545 | 3.7670 | 4.0039 | 1.8066 |
| 25% | 0.8415 | 1.6204 | 0.7696 | 1.7103 | 1.9472 | 0.9818 |
| 50% | 0.8415 | 1.6204 | 0.4535 | 0.7610 | 0.9979 | 0.6011 |
| 65% | 0.8415 | 1.6204 | 0.3806 | 0.5419 | 0.7788 | 0.5133 |
| 75% | 0.8415 | 1.6204 | 0.3482 | 0.4446 | 0.6815 | 0.4742 |
| 85% | 0.8415 | 1.6204 | 0.3234 | 0.3701 | 0.6070 | 0.4444 |

Table K-19: Bus Bar Costs 2015, Stuck in the Middle Scenario (4 of 5)

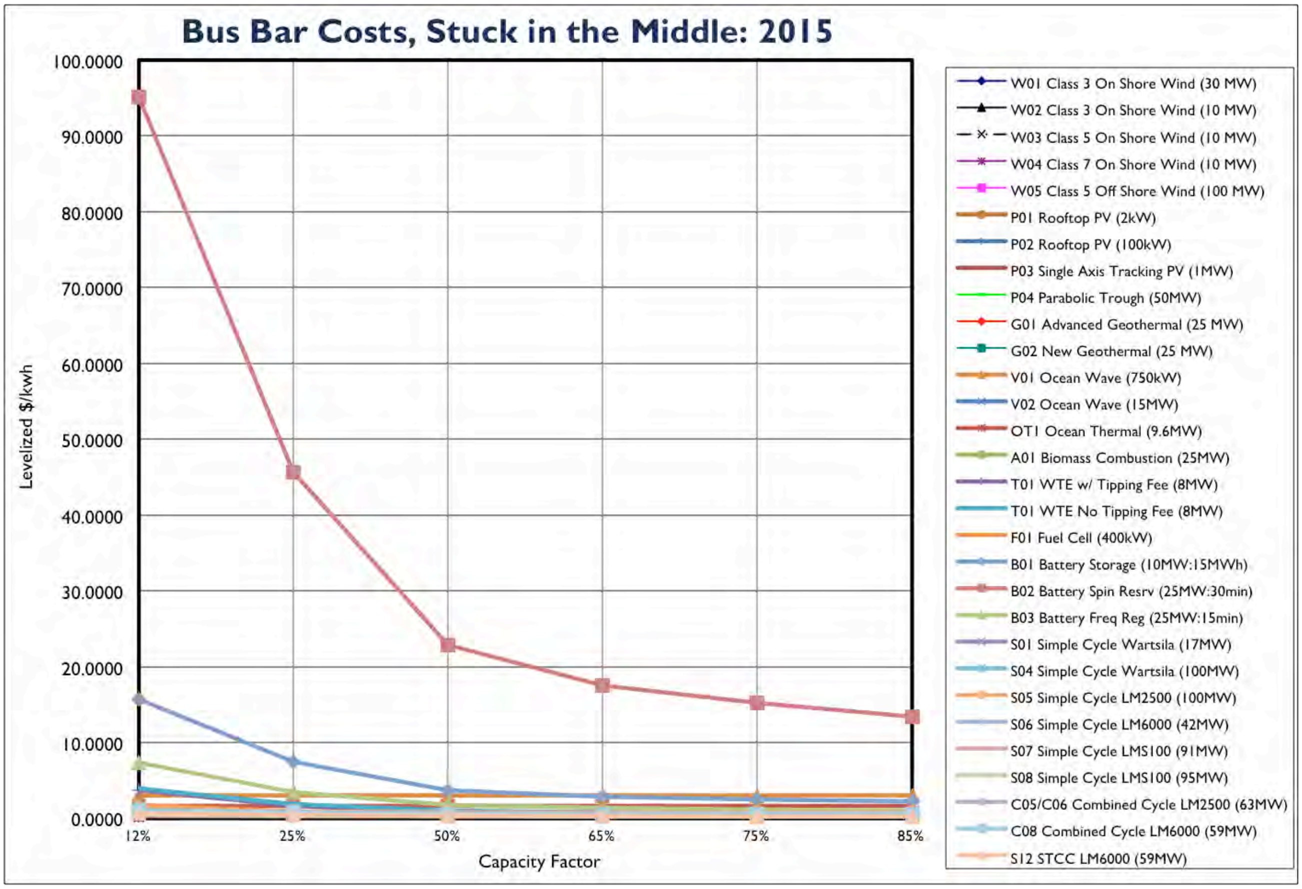
| % Max Cap | B01: Battery Storage (10MW:15MWh) | B02: Battery Spin Reserve (25MW:30min) | B03: Battery Frequency Regulation (25MW:15min) | S01: Simple Cycle Wärtsilä (17MW) | S04: Simple Cycle Wärtsilä (100MW) | S05: Simple Cycle LM2500 (100MW) |
|---|---|---|---|---|---|---|
| 12% | 15.6758 | 95.0887 | 7.3049 | 1.1767 | 0.8849 | 1.2833 |
| 25% | 7.5244 | 45.6426 | 3.5063 | 0.8405 | 0.6935 | 0.9708 |
| 50% | 3.7622 | 22.8213 | 1.7532 | 0.6853 | 0.6051 | 0.8266 |
| 65% | 2.8940 | 17.5548 | 1.3486 | 0.6495 | 0.5847 | 0.7933 |
| 75% | 2.5081 | 15.2142 | 1.1688 | 0.6336 | 0.5757 | 0.7785 |
| 85% | 2.2131 | 13.4243 | 1.0313 | 0.6214 | 0.5688 | 0.7672 |

Table K-20: Bus Bar Costs 2015, Stuck in the Middle Scenario (5 of 5)

| % Max Cap | S06: Simple Cycle LM6000 (42MW) | S07: Simple Cycle LMS100 (91MW) | S08: Simple Cycle LMS100 (95MW) | C05/C06: Combined Cycle LM2500 (63MW) | C08: Combined Cycle LM6000 (59MW) | S12: STCC LM6000 (59MW) |
|---|---|---|---|---|---|---|
| 12% | 1.0178 | 0.8539 | 0.4648 | 1.1700 | 1.0492 | 0.7167 |
| 25% | 0.8106 | 0.7049 | 0.3250 | 0.8055 | 0.7479 | 0.4308 |
| 50% | 0.7150 | 0.6362 | 0.2605 | 0.6373 | 0.6089 | 0.2988 |
| 65% | 0.6929 | 0.6203 | 0.2456 | 0.5985 | 0.5768 | 0.2683 |
| 75% | 0.6831 | 0.6133 | 0.2390 | 0.5812 | 0.5625 | 0.2548 |
| 85% | 0.6756 | 0.6079 | 0.2339 | 0.5680 | 0.5516 | 0.2444 |

## *2015 Stuck in the Middle Summary Chart*

Figure K-4: Stuck in the Middle Summary Chart: 2015



## *2020 Stuck in the Middle Costs*

The data in Table K-21 to Table K-25 is the levelized cost of dollars per kWh based on an installation in 2020.

Table K-21: Bus Bar Costs 2020, Stuck in the Middle Scenario (1 of 5)

| % Max Cap | W01: Class 3 On Shore Wind (30 MW) | W02: Class 3 On Shore Wind (10 MW) | W03: Class 5 On Shore Wind (10 MW) | W04: Class 7 On Shore Wind (10 MW) | W05: Class 5 Off Shore Wind (100 MW) | P01: Rooftop PV (2kW) |
|---|---|---|---|---|---|---|
| 12% | 0.2420 | 0.2990 | 0.2582 | 0.1689 | 0.5540 | 0.6521 |
| 25% | 0.2420 | 0.2990 | 0.2582 | 0.1689 | 0.5540 | 0.6521 |
| 50% | 0.2420 | 0.2990 | 0.2582 | 0.1689 | 0.5540 | 0.6521 |
| 65% | 0.2420 | 0.2990 | 0.2582 | 0.1689 | 0.5540 | 0.6521 |
| 75% | 0.2420 | 0.2990 | 0.2582 | 0.1689 | 0.5540 | 0.6521 |
| 85% | 0.2420 | 0.2990 | 0.2582 | 0.1689 | 0.5540 | 0.6521 |

Table K-22: Bus Bar Costs 2020, Stuck in the Middle Scenario (2 of 5)

| % Max Cap | P02: Rooftop PV (100kW) | P03: Single Axis Tracking PV (1MW) | P04: Parabolic Trough (50MW) | G01: Advanced Geothermal (25 MW) | G02: New Geothermal (25 MW) | V01: Ocean Wave (750kW) |
|---|---|---|---|---|---|---|
| 12% | 0.3746 | 0.3404 | 0.9275 | 1.8146 | 1.9090 | 3.4661 |
| 25% | 0.3746 | 0.3404 | 0.9275 | 0.8943 | 0.9404 | 3.4661 |
| 50% | 0.3746 | 0.3404 | 0.9275 | 0.4696 | 0.4933 | 3.4661 |
| 65% | 0.3746 | 0.3404 | 0.9275 | 0.3716 | 0.3902 | 3.4661 |
| 75% | 0.3746 | 0.3404 | 0.9275 | 0.3280 | 0.3443 | 3.4661 |
| 85% | 0.3746 | 0.3404 | 0.9275 | 0.2947 | 0.3092 | 3.4661 |

Table K-23: Bus Bar Costs 2020, Stuck in the Middle Scenario (3 of 5)

| % Max Cap | V01: Ocean Wave (15MW) | OT1: Ocean Thermal (9.6MW) | A01: Biomass Combustion (25MW) | T01 w/: WTE w/ Tipping Fee (8MW) | T01 w/o: WTE No Tipping Fee (8MW) | F01: Fuel Cell (400kW) |
|---|---|---|---|---|---|---|
| 12% | 0.9613 | 1.8643 | 1.6457 | 4.2716 | 4.5462 | 2.0669 |
| 25% | 0.9613 | 1.8643 | 0.8684 | 1.9353 | 2.2099 | 1.1244 |
| 50% | 0.9613 | 1.8643 | 0.5096 | 0.8570 | 1.1316 | 0.6895 |
| 65% | 0.9613 | 1.8643 | 0.4268 | 0.6082 | 0.8828 | 0.5891 |
| 75% | 0.9613 | 1.8643 | 0.3900 | 0.4976 | 0.7722 | 0.5445 |
| 85% | 0.9613 | 1.8643 | 0.3619 | 0.4130 | 0.6876 | 0.5104 |

Table K-24: Bus Bar Costs 2020, Stuck in the Middle Scenario (4 of 5)

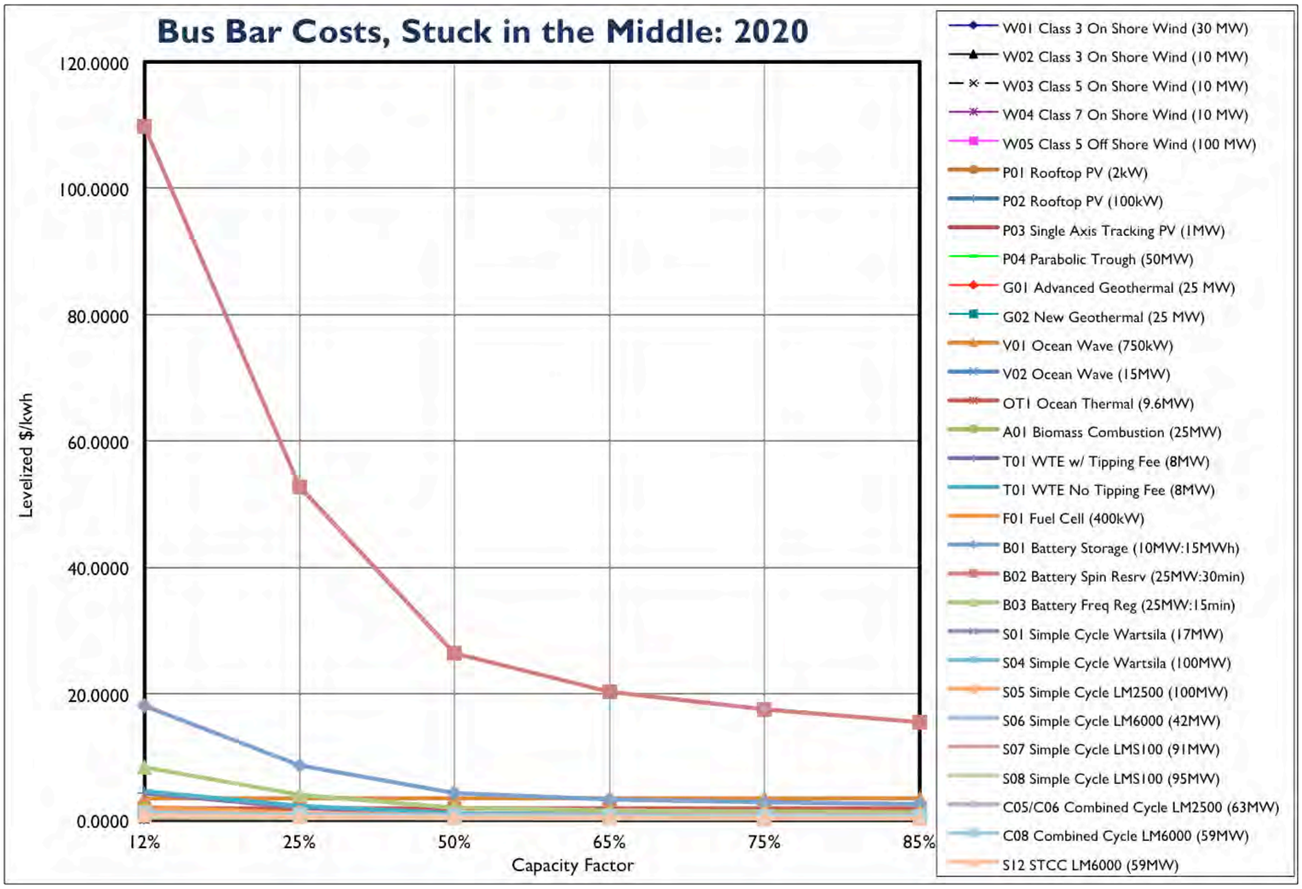
| % Max Cap | B01: Battery Storage (10MW:15MWh) | B02: Battery Spin Reserve (25MW:30min) | B03: Battery Frequency Regulation (25MW:15min) | S01: Simple Cycle Wärtsilä (17MW) | S04: Simple Cycle Wärtsilä (100MW) | S05: Simple Cycle LM2500 (100MW) |
|---|---|---|---|---|---|---|
| 12% | 18.0757 | 109.8705 | 8.4296 | 1.2885 | 0.9546 | 1.3917 |
| 25% | 8.6763 | 52.7379 | 4.0462 | 0.9010 | 0.7332 | 1.0313 |
| 50% | 4.3382 | 26.3689 | 2.0231 | 0.7222 | 0.6309 | 0.8649 |
| 65% | 3.3370 | 20.2838 | 1.5562 | 0.6809 | 0.6073 | 0.8265 |
| 75% | 2.8921 | 17.5793 | 1.3487 | 0.6625 | 0.5969 | 0.8095 |
| 85% | 2.5519 | 15.5111 | 1.1901 | 0.6485 | 0.5888 | 0.7964 |

Table K-25: Bus Bar Costs 2020, Stuck in the Middle Scenario (5 of 5)

| % Max Cap | S06: Simple Cycle LM6000 (42MW) | S07: Simple Cycle LMS100 (91MW) | S08: Simple Cycle LMS100 (95MW) | C05/C06: Combined Cycle LM2500 (63MW) | C08: Combined Cycle LM6000 (59MW) | S12: STCC LM6000 (59MW) |
|---|---|---|---|---|---|---|
| 12% | 1.0937 | 0.9114 | 0.5383 | 1.2870 | 1.1472 | 0.8255 |
| 25% | 0.8545 | 0.7392 | 0.3766 | 0.8674 | 0.8007 | 0.4967 |
| 50% | 0.7441 | 0.6597 | 0.3020 | 0.6737 | 0.6408 | 0.3450 |
| 65% | 0.7187 | 0.6414 | 0.2848 | 0.6290 | 0.6039 | 0.3100 |
| 75% | 0.7073 | 0.6332 | 0.2771 | 0.6092 | 0.5875 | 0.2945 |
| 85% | 0.6987 | 0.6270 | 0.2713 | 0.5940 | 0.5750 | 0.2826 |

## *2020 Stuck in the Middle Summary Chart*

Figure K-5: Stuck in the Middle Summary Chart: 2020



## *2030 Stuck in the Middle Costs*

The data in Table K-26 to Table K-30 is the levelized cost of dollars per kWh based on an installation in 2030.

Table K-26: Bus Bar Costs 2030, Stuck in the Middle Scenario (1 of 5)

| % Max Cap | W01: Class 3 On Shore Wind (30 MW) | W02: Class 3 On Shore Wind (10 MW) | W03: Class 5 On Shore Wind (10 MW) | W04: Class 7 On Shore Wind (10 MW) | W05: Class 5 Off Shore Wind (100 MW) | P01: Rooftop PV (2kW) |
|---|---|---|---|---|---|---|
| 12% | 0.3176 | 0.3932 | 0.3394 | 0.2220 | 0.7378 | 0.8580 |
| 25% | 0.3176 | 0.3932 | 0.3394 | 0.2220 | 0.7378 | 0.8580 |
| 50% | 0.3176 | 0.3932 | 0.3394 | 0.2220 | 0.7378 | 0.8580 |
| 65% | 0.3176 | 0.3932 | 0.3394 | 0.2220 | 0.7378 | 0.8580 |
| 75% | 0.3176 | 0.3932 | 0.3394 | 0.2220 | 0.7378 | 0.8580 |
| 85% | 0.3176 | 0.3932 | 0.3394 | 0.2220 | 0.7378 | 0.8580 |

Table K-27: Bus Bar Costs 2030, Stuck in the Middle Scenario (2 of 5)

| % Max Cap | P02: Rooftop PV (100kW) | P03: Single Axis Tracking PV (1MW) | P04: Parabolic Trough (50MW) | G01: Advanced Geothermal (25 MW) | G02: New Geothermal (25 MW) | V01: Ocean Wave (750kW) |
|---|---|---|---|---|---|---|
| 12% | 0.4975 | 0.4473 | 1.2182 | 2.3886 | 2.5153 | 4.5114 |
| 25% | 0.4975 | 0.4473 | 1.2182 | 1.1746 | 1.2363 | 4.5114 |
| 50% | 0.4975 | 0.4473 | 1.2182 | 0.6143 | 0.6460 | 4.5114 |
| 65% | 0.4975 | 0.4473 | 1.2182 | 0.4850 | 0.5097 | 4.5114 |
| 75% | 0.4975 | 0.4473 | 1.2182 | 0.4275 | 0.4492 | 4.5114 |
| 85% | 0.4975 | 0.4473 | 1.2182 | 0.3836 | 0.4029 | 4.5114 |

Table K-28: Bus Bar Costs 2030, Stuck in the Middle Scenario (3 of 5)

| % Max Cap | V01: Ocean Wave (15MW) | OT1: Ocean Thermal (9.6MW) | A01: Biomass Combustion (25MW) | T01 w/: WTE w/ Tipping Fee (8MW) | T01 w/o: WTE No Tipping Fee (8MW) | F01: Fuel Cell (400kW) |
|---|---|---|---|---|---|---|
| 12% | 1.2568 | 2.4701 | 2.1117 | 5.5044 | 5.8735 | 2.7277 |
| 25% | 1.2568 | 2.4701 | 1.1080 | 2.4836 | 2.8527 | 1.4952 |
| 50% | 1.2568 | 2.4701 | 0.6448 | 1.0894 | 1.4584 | 0.9263 |
| 65% | 1.2568 | 2.4701 | 0.5379 | 0.7676 | 1.1367 | 0.7950 |
| 75% | 1.2568 | 2.4701 | 0.4903 | 0.6246 | 0.9937 | 0.7367 |
| 85% | 1.2568 | 2.4701 | 0.4540 | 0.5153 | 0.8844 | 0.6921 |

Table K-29: Bus Bar Costs 2030, Stuck in the Middle Scenario (4 of 5)

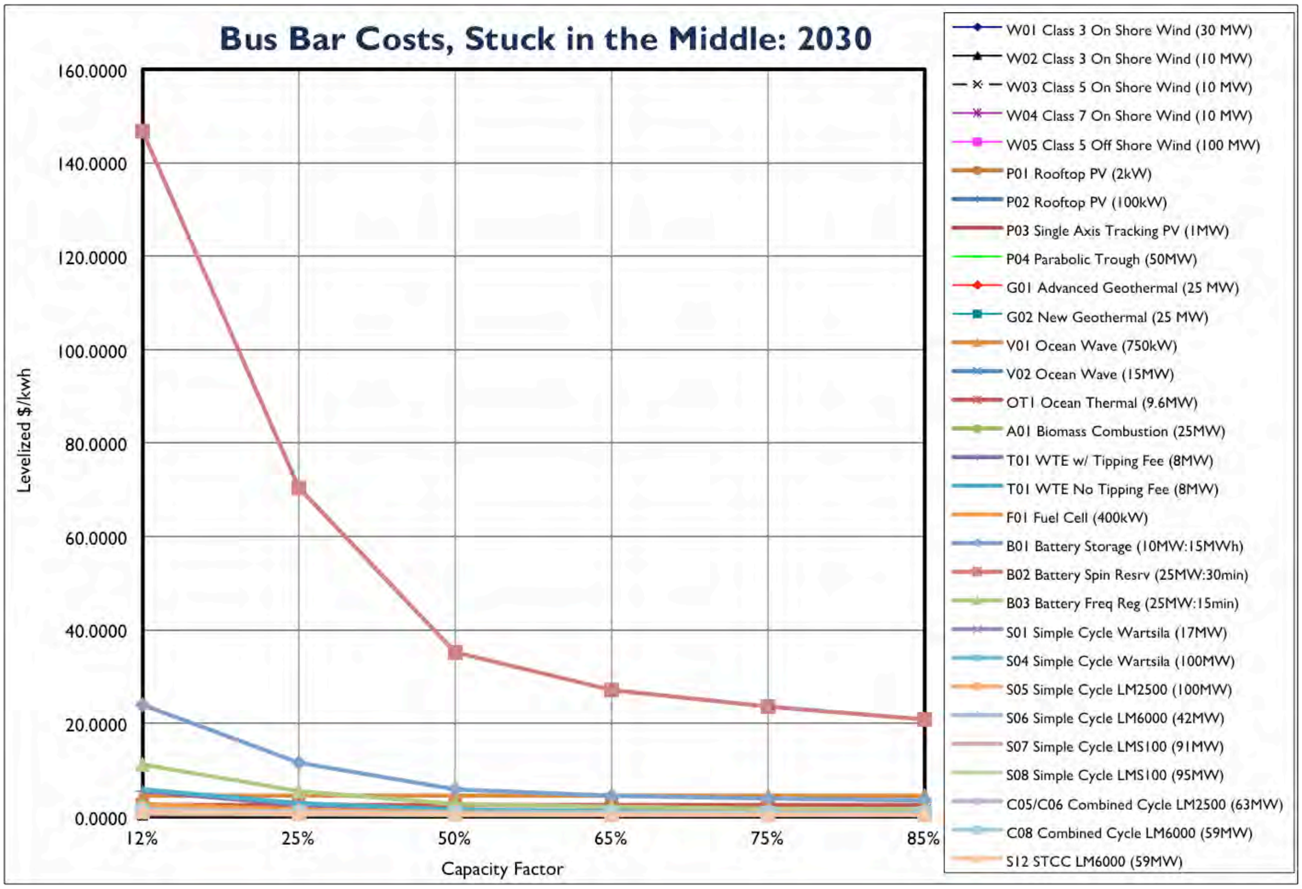
| % Max Cap | B01: Battery Storage (10MW:15MWh) | B02: Battery Spin Reserve (25MW:30min) | B03: Battery Frequency Regulation (25MW:15min) | S01: Simple Cycle Wärtsilä (17MW) | S04: Simple Cycle Wärtsilä (100MW) | S05: Simple Cycle LM2500 (100MW) |
|---|---|---|---|---|---|---|
| 12% | 24.0524 | 146.7574 | 11.2328 | 1.5630 | 1.1253 | 1.6571 |
| 25% | 11.5451 | 70.4436 | 5.3917 | 1.0480 | 0.8288 | 1.1773 |
| 50% | 5.7726 | 35.2218 | 2.6959 | 0.8103 | 0.6919 | 0.9559 |
| 65% | 4.4404 | 27.0937 | 2.0737 | 0.7555 | 0.6603 | 0.9048 |
| 75% | 3.8484 | 23.4812 | 1.7972 | 0.7311 | 0.6463 | 0.8820 |
| 85% | 3.3956 | 20.7187 | 1.5858 | 0.7125 | 0.6356 | 0.8647 |

Table K-30: Bus Bar Costs 2030, Stuck in the Middle Scenario (5 of 5)

| % Max Cap | S06: Simple Cycle LM6000 (42MW) | S07: Simple Cycle LMS100 (91MW) | S08: Simple Cycle LMS100 (95MW) | C05/C06: Combined Cycle LM2500 (63MW) | C08: Combined Cycle LM6000 (59MW) | S12: STCC LM6000 (59MW) |
|---|---|---|---|---|---|---|
| 12% | 1.2790 | 1.0514 | 0.7364 | 1.5750 | 1.3877 | 1.1081 |
| 25% | 0.9599 | 0.8211 | 0.5203 | 1.0183 | 0.9289 | 0.6732 |
| 50% | 0.8126 | 0.7148 | 0.4205 | 0.7613 | 0.7171 | 0.4725 |
| 65% | 0.7787 | 0.6902 | 0.3975 | 0.7020 | 0.6682 | 0.4262 |
| 75% | 0.7636 | 0.6793 | 0.3873 | 0.6757 | 0.6465 | 0.4056 |
| 85% | 0.7520 | 0.6710 | 0.3794 | 0.6555 | 0.6299 | 0.3899 |

## *2030 Stuck in the Middle Summary Chart*

Figure K-6: Stuck in the Middle Summary Chart: 2030



# Future Capital Costs for Renewable Energy Options

**MEMORANDUM**

| | |
|---|---|
| Hawaiian Electric Company | B&V Project 173322 |
| IRP 2013 | 22 May 2013 |

## Introduction

Black & Veatch provided HECO the capital and operating cost data that went into the Unit Information Forms (UIFs) as part of IRP 2013. Future changes in nominal technology costs have been estimated by HECO as entries into the Strategist model. Members of the Advisory Group (AG) have questioned some of the future cost assumptions made by HECO, with constant dollar cost estimates from the year 2000 from the National Renewable Energy Laboratory (NREL) presented by the AG that show future cost declines.

Black & Veatch reviewed the AG data and compared it to recent cost estimates performed by Black & Veatch in 2012 under contract to NREL for the purpose of updating NREL's estimates. This memo discusses the differences between the use of nominal versus real dollars in price forecasting, along with updating the data presented by the AG.

## Nominal versus Real Dollar Costs

When comparing costs over broad periods of time, variations are based in part on inflation and the corresponding change in the purchasing power of the dollar. Therefore, to understand variations due only to technology changes independent of inflation, costs are converted from nominal (or current) dollar values to real (or constant) dollar values. Nominal and real dollar values are defined as follows:

- **Nominal (or Current) Dollar Value** – the actual (unadjusted) dollar amount of money spent or earned within a given period of time.
- **Real (or Constant) Dollar Value** – value of money spent or earned within a given period of time, adjusted to remove the effects of price changes (that is, inflation). Real Dollar Value represents the value of money spent or earned, assuming the dollar had constant purchasing power over the given time period.

To convert nominal dollar values to real dollar values, a relevant price index is employed considering a specific base year. For example, based on data from United States Census Bureau,[1] the median income for all households in the United States in 2011 was $50,054, in year 2011 dollars. In 2000, the median household income for all households in the United States was $41,990, in year 2000 dollars. However, by adjusting year 2000 dollars by the Consumer Price Index for All Urban Consumers (CPI-U) to a 2011 basis, the median income in 2000 was $54,841 in year 2011 dollars. Therefore, while the *nominal* median household income increased by approximately 19 percent from 2000 to 2011, the *real* median household income decreased by almost 9 percent over that same time period.

Similarly, when examining variations in capital costs of renewable energy technologies over the mid-to long-term, it is useful to examine the trends in both nominal dollars and constant dollars. HECO uses nominal dollars in the Strategist model, while most technology forecasts (including NREL) use constant dollars. The differences in the two options make for very different forecasts, as shown in the next section.

## Historical Costs of Renewable Generation Options

Examinations of historical costs for specific renewable technologies offer some insight regarding changes in these technologies over time. Costs for on-shore wind and solar PV were reviewed as examples, given their prevalence in the market today.

To examine historical costs of wind and solar PV technologies, data from reports produced by Lawrence Berkeley National Laboratory (LBNL) were used:

- *2011 Wind Technologies Market Report* (2012), authored by Ryan Wiser and Mark Bolinger
- *Tracking the Sun V* (2012), authored by Galen Barbose, Naim Darghouth and Ryan Wiser

In each of these studies, the costs for all years are presented in 2011 constant dollars, which removes a number of economic effects. Presentation in this format is fairly standard in the energy industry in an attempt to demonstrate the impact of costs due largely to technical changes only. Black & Veatch does not encourage universal use solely of learning curve effects, which often predicts a cost reduction based on an assumed deployment level. Many factors influence rates of deployment and the resulting cost changes.

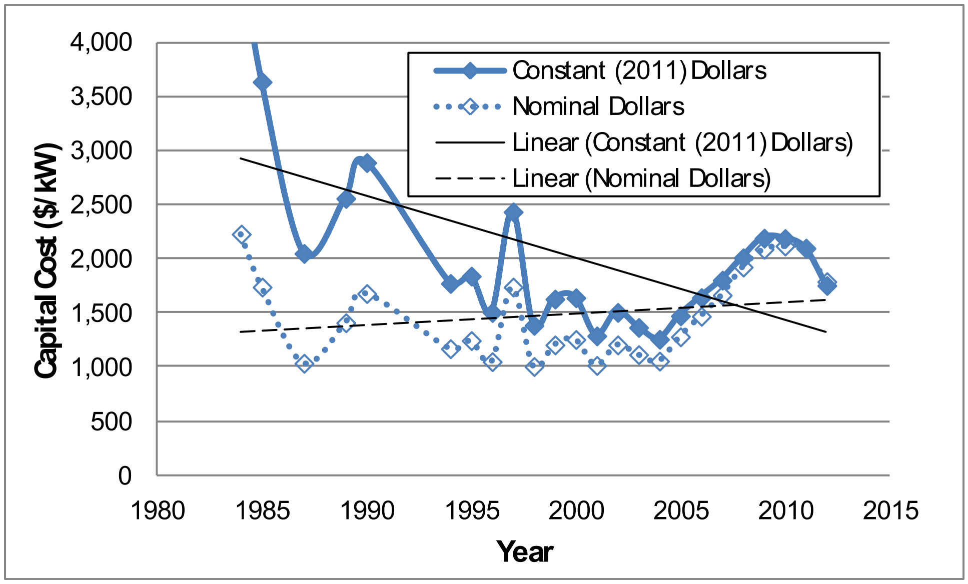
To illustrate the capital costs of wind projects, the 2011 constant dollar data presented by LBNL is presented alongside the same data in nominal dollars. To convert the data to nominal dollars, Black & Veatch utilized the (CPI-U).[2] Capital costs for wind projects, both in constant 2011 dollars and nominal dollars, are shown in Figure K-7. Note that because historical costs were escalated to 2011 dollars, the costs in constant 2011 dollars are higher than

[1] US Census Bureau, Historical Income Tables: Households – Table H-9. Accessed on May 8, 2013 at: http://www.census.gov/hhes/www/income/data/historical/household/.

[2] The Consumer Price Index for All Urban Consumers (CPI-U) is published by the Bureau of Labor Statistics (BLS). CPI-U data is available at: ftp://ftp.bls.gov/pub/special.requests/cpi/cpiai.txt.

the nominal dollars in each year because index adjustments increase the costs.

Figure K-7. Constant and Nominal-Dollar Capital Cost Trends for On-Shore Wind

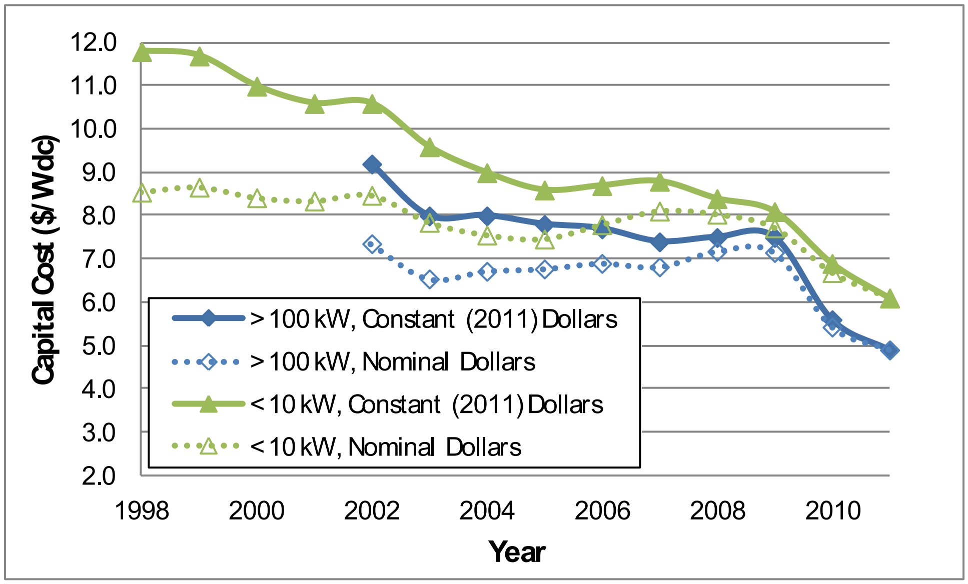



When considering capital costs for wind projects in terms of constant 2011 dollars, these costs appear to generally trend downward over the 30-year time period. However, when considering these costs in terms of nominal dollars, the cost trend over the 30-year period appears more flat. HECO uses nominal price escalations in the Strategist model that are relatively consistent with this cost trend.

Barbose et al. presented capital costs for solar PV projects in *Tracking the Sun V*. As with the wind data, this information is presented in constant 2011 dollars. In constant dollars, solar PV costs for residential-and commercial-scale systems clearly trend downward. The authors showed that utility-scale systems also trended downward, although the data sets were considerably smaller.

Employing the CPI-U index values, Black & Veatch developed capital cost trends for residential- and commercial-scale solar PV projects in nominal dollars, as shown in Figure K-8. Not shown are utility-scale costs as costs for these projects were not broken out by year.

Figure K-8. Constant-Dollar and Nominal-Dollar Capital Cost Trends for Solar PV Technologies




Throughout much of the 14-year period shown in Figure K-8, capital costs in constant 2011 dollars declined, while capital costs in nominal dollars were relatively flat. From 2009 through 2011, capital costs declined significantly in both constant and nominal dollars largely due to falling module prices. However, in the conclusions of the report, Barbose et al. note that "it is unclear how much lower module prices can go" and that non-module costs are the focus for future cost reductions. While future cost reductions on a constant dollar value are possible, they are unlikely to be as strong as what has recently been witnessed.

## Estimates of Future Capital Costs of Renewable Generation Options

Assumptions have changed significantly for future costs of renewable energy since the 2000 NREL report was released. In 2012, Black & Veatch, on behalf of NREL, developed estimates of cost and performance data for conventional, nuclear, and renewable power generation technologies.[3] The capital cost estimates were presented in constant 2009 dollars. Black & Veatch acknowledges that the magnitude of the cost projections may vary due to project-specific factors (for example, geographic location, project scale, market conditions, etc.); however, Black & Veatch considers the general cost trajectories presented in the 2012 report to remain valid for the technologies examined in the study.

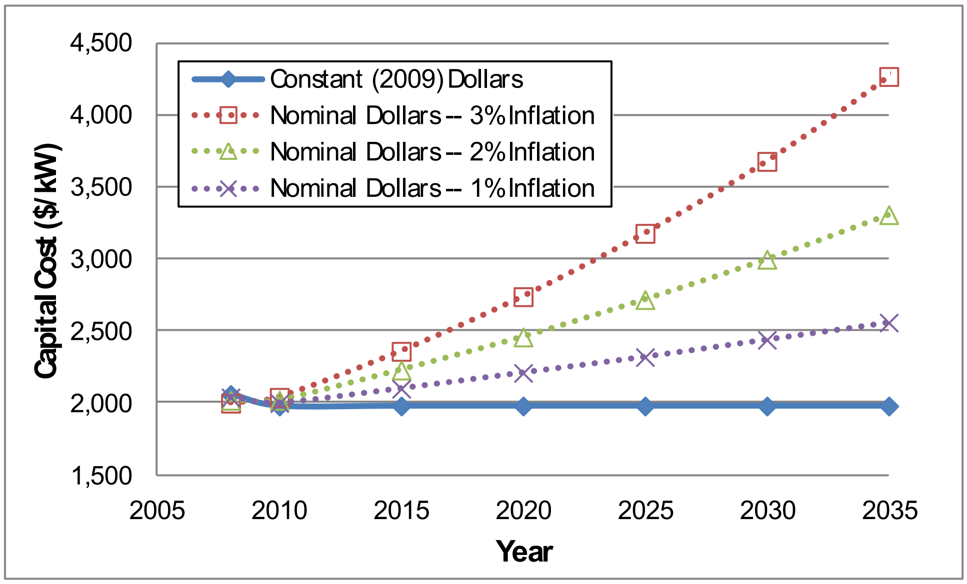
For renewable technologies, Black & Veatch projected that capital costs for certain technologies would remain flat (in constant 2009 dollars), while capital costs for other technologies would decrease (in constant 2009 dollars).

[3] *Cost and Performance Data for Power Generation Technologies* (2012), available online at: http://bv.com/docs/reports-studies/nrel-cost-report.pdf.

Renewable technologies for which capital costs are projected to remain relatively flat included the following: biomass, geothermal, on-shore wind and combustion turbine technologies.

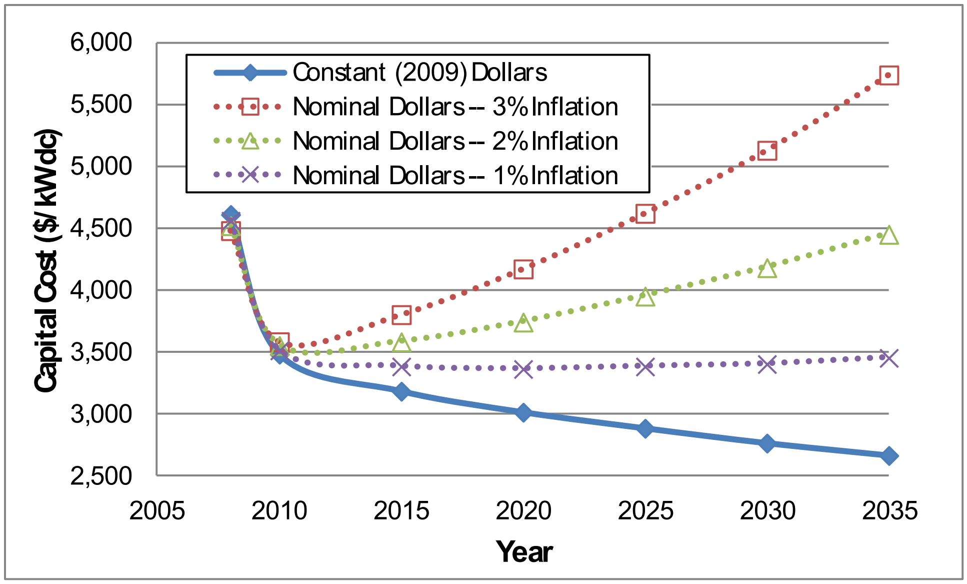
Capital costs for on-shore wind projects (in both constant 2009 dollars and nominal dollars) are shown in Figure K-9. Estimates of nominal-dollar costs in Figure K-9 are shown with general inflation rates ranging from 1 to 3 percent. While costs in 2009 dollars remain flat, costs in nominal dollars increase over the period from 2008 to 2035. If no technological improvements occur, the extent to which nominal dollar costs increase over this time period is largely dependent upon the inflation rate experienced during this time.

Figure K-9. Projected Future Cost Trends for On-Shore Wind Technologies




Renewable technologies for which capital costs (in constant 2009 dollars) are projected to decrease to some extent included the following: solar PV, solar thermal, off-shore wind, and battery energy storage. As an example of expected cost trend for these technologies, capital costs for large, utility-scale, fixed tilt solar PV projects (in both constant 2009 dollars and nominal dollars, assuming three different levels of inflation) are shown in Figure K-10. While costs in constant 2009 dollars decrease over the period from 2008 to 2035, the costs in nominal dollars increase over the same period (that is, real dollar costs decrease, but this decrease is less than the increase in nominal cost attributed to general inflation). Again, the extent to which nominal dollar costs increase is dependent upon the inflation rate used during the time period.

Figure K-10. Projected Future Cost Trends for Fixed Tilt Solar PV Technologies




It is the understanding of Black & Veatch that for modeling purposes within IRP 2013, HECO inputs costs in terms of nominal dollars, and for renewable energy technologies, the escalation value used to predict future costs were lower than those of fossil energy technologies. For the scenario where the escalation for renewable energy technologies was zero percent (that is, costs in nominal dollars are flat throughout the planning horizon of the model), the capital costs in terms of constant 2012 dollars decline throughout the planning horizon of the model. The cost of electricity ($/kWh or $/MWh) would follow a similar trend depending on the dollar basis used if the financial assumptions over the planning horizon do not change. Changes in financial inputs (debt and equity levels, along with interest rates and various project incentives) can greatly change the cost of electricity assumptions but are difficult to predict outside of the short-term.

**CONFIDENTIAL**

Executive Summary

# SUPPLY-SIDE RESOURCE ASSESSMENT, IRP 2013



**PREPARED FOR**

Hawaiian Electric Company

25 MARCH 2013

# Table of Contents



## LIST OF TABLES

# Acronym List

| | |
|---|---|
| BEFR | Battery Energy Frequency Regulation |
| BESR | Battery Energy Spinning Reserve |
| BESS | Battery Energy Storage System |
| CO | Carbon Monoxide |
| D&O | Decision and Order |
| DOD | Depth of Discharge |
| GE | General Electric |
| HECO | Hawaiian Electric Company |
| HELCO | Hawaii Electric Light Company |
| HINMREC | Hawaii National Marine Renewable Energy Center |
| IRP | Integrated Resource Planning |
| kW | Kilowatt |
| MECO | Maui Electric Company, Ltd. |
| MJ | Megajoule |
| MSW | Municipal Solid Waste |
| MVA | Megavolt-amp |
| MW | Megawatt |
| NASA | National Aeronautics and Space Administration |
| $NO_x$ | Nitrogen Oxides |
| NREL | National Renewable Energy Laboratory |
| O&M | Operations and Maintenance |
| OEM | Original Equipment Manufacturer |
| OTEC | Ocean Thermal Energy Conversion |
| PAFC | Phosphoric Acid Fuel Cell |
| Pelamis | Pelamis Wave Power |
| PTC | Performance Test Code |
| PV | Solar Photovoltaic |
| R&D | Research and Development |
| SAM | System Advisor Model |
| SAT | Single Axis Tracker |
| SCR | Selective Catalytic Reduction |
| SEIA | Solar Energy Industries Association |

| | |
|---|---|
| SME | Subject Matter Expert |
| SNCR | Selective Noncatalytic Reduction |
| $SO_x$ | Sulfur Oxides |
| SRO | Supply-Side Resource Option |
| TMY2 | Typical Meteorological Year Version 2 |
| TRL | Technology Readiness Level |
| UIF | Unit Information Form |
| UTC | UTC Power |
| WTE | Waste-to-Energy |

# 1.0 Objective

Hawaiian Electric Company's (HECO) Integrated Resource Planning (IRP) process was revised by the Decision and Order (D&O) for Docket No. 2009-0108 in March 2011. The goal of the revised IRP framework is to "develop an Action Plan that governs how the utility will meet energy objectives and customer energy needs consistent with state energy policies and goals, while providing safe and reliable utility service at reasonable cost, through the development of Resource Plans and Scenarios of possible futures that provide a broader long-term perspective." The IRP must evaluate a "range of possible future circumstances or set of possible circumstances reflecting potential energy-related policy choices, uncertain circumstances, and risks facing the utility and its customers, which will be the basis for the plans analyzed. A Scenario may not consist of a particular project."

To support the revised IRP framework and meet the scenario planning criteria, HECO developed supply-side resource option (SRO) Unit Information Forms (UIFs) that are "generic" and not project-specific. While no specific projects currently under consideration were modeled, location assumptions had to be made for some technologies (such as wind, solar, and ocean wave) to reflect typical or likely resource conditions. Data used to develop the SRO are based on past IRP data, vendor information and recent quotes, Hawaii resource data, consultant cost estimates from Black & Veatch, published data, and engineering judgment. The SRO technologies were sized to represent the types of facilities likely to be utilized to meet Hawaii Electric Light Company (HELCO), Maui Electric Company, Ltd. (MECO), and HECO requirements. Per the IRP Framework, the utility is required to consider all feasible supply-side resource options appropriate for Hawaii and available on the planning horizon.

# 2.0 Methodology

This section outlines how the technologies were chosen and the process involved in the development of the UIFs.

## 2.1 TECHNOLOGY SELECTION

The selection of commercial resources for IRP 2013 is built on the results of recent IRP cycles (primarily IRP-3 and IRP-4) with modifications to this list made by HECO as deemed appropriate. In addition, guidance from the Commission and Legislature on the technologies that should be included as part of the IRP process was also used in defining the appropriate technologies. Through discussion and planning meetings with HECO, MECO, and HELCO, a list of technologies and sizes was developed for SRO work. The intent is to model technologies that could conceivably be developed in the next 10 years to meet future energy requirements.

The technologies evaluated as part of IRP 2013 are as follows:

- Large Turbine Onshore Wind (30 and 10 megawatt [MW] blocks, 2.3 MW turbines)
- Small Scale Onshore Wind (600 kW turbines, phased development up to 6 MW)
- Offshore Wind (100 MW blocks)
- Solar Photovoltaic (PV):
  - Residential (2 kilowatts [kW])
  - Large Rooftop (100 kW)
  - Ground Mounted (1 MW blocks)
- Solar Thermal (Trough, 50 MW)
- Geothermal (new and existing sites [25 MW])
- Ocean Wave (2016 [750 kW] and 2020 [15 MW] systems)
- Ocean Thermal Energy Conversion (OTEC) (10 MW)
- Biomass Combustion (Banagrass, 25 MW)
- Biomass Conversion at Puna Generating Station (Eucalyptus, 13 MW)
- Waste-to-Energy (WTE) (municipal solid waste [MSW] mass burn, 8 MW)
- Fuel Cell (phosphoric acid using natural gas fuel, 400 kW)
- Battery Energy Storage:
  - Daily Peaking (10 MW:90 minute discharge duration)
  - Spinning Reserve (25 MW:30 minute discharge duration)
  - Frequency Regulation (25 MW:15 minute discharge duration)
- Reciprocating Engines, Biodiesel:
  - 1x0 Wartsila 18V46 (16.7 MW)
  - 1x0 Wartsila 12V32 (5 MW)
  - 6x0 Wartsila 18V46 (100.2 MW)

- Simple Cycle Combustion Turbines, Biodiesel:
  - 1x0 GE LM2500 (21.1 MW)
  - 1x0 GE LM6000 (41.9 MW)
  - 1x0 GE LMS100 PA (90.8 MW)
- Combined Cycle Combustion Turbines, Biodiesel:
  - 2x1 GE LM2500 (63.2 MW)
  - 1x1 GE LM6000 PG (58.8 MW)
- Simple Cycle Combustion Turbines, Natural Gas:
  - 1x1 GE LM6000 PG (58.3 MW)
  - 1x0 GE LMS100 PA (95.2 MW)

## 2.2 DATA SHEET DEVELOPMENT

### 2.2.1 General Development Approach

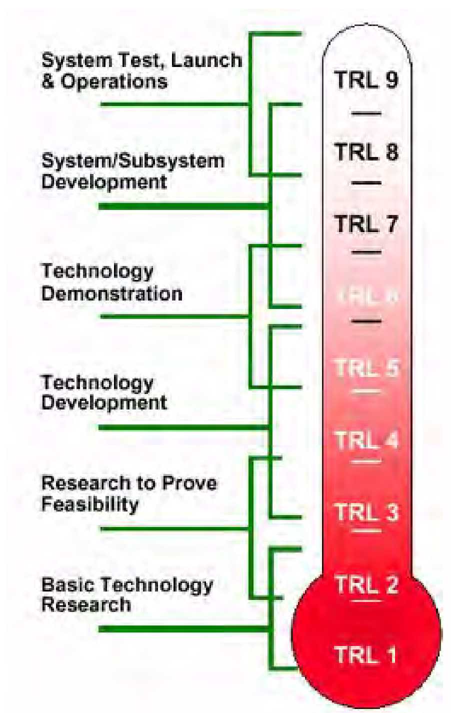
The general approach employed to develop the UIFs for IRP 2013 is summarized in the following steps. Rather than creating site-specific UIFs, Black & Veatch developed most UIFs based on generic site characteristics to better align with the scenario planning criteria. Exceptions were made for site-specific modifications, such as converting Puna Generating Station to biomass. Subsection 2.2.4 contains more information on the approach taken for each technology.

- Use of Previous IRP Basis: The team reviewed previous IRP information as a starting point for the development of UIFs for IRP 2013. Data was updated as necessary to reflect the latest available technologies or designs. The updates include technology, equipment performance, emissions, O&M or capital cost, etc.
- Design Assumptions for New Technologies: For technologies not included in the previous IRP efforts, new UIFs were developed consistent with the scenario planning criteria. For each technology, the team established a design basis and defined key assumptions, such as gross output, major equipment to be used, and a set of Hawaii-specific design factors to be included.
- Application of HECO Data: As much Hawaii-specific design and resource data were utilized as possible. If available, HECO provided relevant data and reports to be considered in the development of UIFs by Black & Veatch. For example, HECO provided wind resource data for developable locations to provide a realistic assessment of a typical power output profile.
- Use of Industry Standard Models, Data Sets, and Reports: Some UIFs used outside data analysis, models, and datasets where relevant. For example, solar resource datasets for Hawaii were obtained from satellite data, with modeling software employed to estimate performance for both solar PV and solar thermal technologies. The cost and performance of the technologies profiled in the UIFs were typically compared to those of recent installations.

- Discussions with Original Equipment Manufacturers (OEMs): Wherever possible, quotes and data from OEMs were obtained, with specific data gathered for projects to be developed in Hawaii. For example, data on cost and performance for fuel cells, ocean wave, battery energy, reciprocating engines, and combustion turbines were provided by the appropriate OEM.
- Use of Subject Matter Experts (SMEs): All IRP 2013 UIFs were developed and reviewed by Black & Veatch SMEs. These SMEs have direct experience with the respective technology under consideration as well as knowledge of industry standards and practices. SMEs provided input and review of typical design, performance, and cost parameters listed on the UIFs for each technology.

### 2.2.2 Technology Readiness Level

The commercial status of the technologies evaluated affected the level of detail and the accuracy of the cost and performance estimates. Black & Veatch scored technologies based on a "Technology Readiness Level" (TRL), as originally defined by the National Aeronautics and Space Administration (NASA) in evaluating space-related research and development (R&D) and since used by Electric Power Research Institute (EPRI)[1] when classifying the status of various types of electric generation equipment. TRLs range from 9 (commercially available operation) to 1 (basic technology research), as shown below:




[1] For more information on TRLs applied to electric generating equipment, refer to http://mydocs.epri.com/docs/publicmeetingmaterials/1103/7LNQEX3Z7D2/E236036_EPRI_Use_of_Technology_Readiness_Levels_03_2011.pdf.

In general, Black & Veatch was able to provide more rigorous and accurate detail when developing the UIFs for technologies that scored high on this scale. The technologies evaluated by Black & Veatch received the following scores:

- TRL 9: Onshore Wind (all sizes), Solar PV, Geothermal, WTE (MSW Mass Burn), Fuel Cell, Reciprocating Engines (Biodiesel), Combustion Turbines (Natural Gas), Biomass Conversion of Puna (Eucalyptus).
- TRL 8: Solar Thermal, Biomass (Banagrass), Battery (Peaking and Frequency Regulation), Combustion Turbines (Biodiesel).
- TRL 7: Ocean Wave (limited testing and optimization in Hawaiian wave conditions), Battery (Spinning Reserve).
- TRL 6: Offshore Wind (due to deepwater floating platforms).
- TRL 5: OTEC.

### 2.2.3 Development of Cost Estimates

For the majority of the UIFs, the base capital cost estimates assumes insurance and freight of all equipment at a typical mainland US facility. No sales tax or excise tax was included in the base estimate. Labor was assumed to be based on mainland rates. Cost estimates are based on the following:

- Experience Black & Veatch has gained through current project designs, proposals and contracts, vendor quotes, and from contacts made with equipment vendors.
- Fixed price contracts obtained through competitive bidding using comprehensive and complete specifications and drawings.
- Publicly available information on market conditions regarding the procurement of equipment and construction.

Adjustment factors specific to Hawaii were applied to the base capital cost estimates for shipping, local commodity pricing, taxes, and labor wage rates and productivity. These rates varied based on the technology; a typical range used is listed below:

- Shipping: A freight cost premium of between 5 to 20 percent was added to the mainland cost. The amount used could vary based on the nature of the material being shipped (for example, solar panels versus wind turbines versus combustion turbines).
- Commodity Premium: For commodities produced in Hawaii that would be used for site improvements (such as foundations and roads), prices were typically increased by 50 percent over mainland prices.
- Labor and Productivity: A labor wage rate and productivity premium of between 50 to 100 percent was added to the mainland costs. The amount applied to each technology could vary based on the estimate basis, the installation complexity, the availability of local craft labor, and other considerations.
- Excise Taxes: In general, the Oahu, Hawaii excise tax rate of 4.7122 percent was typically added to project direct and indirect costs.

In some cases, such as 2 kW solar PV, OTEC, and geothermal well development costs, Hawaii-specific cost estimates were obtained. No adjustments were necessary in these cases.

Nonfuel operations and maintenance (O&M) costs were developed for the various options. O&M costs were developed to include two components: fixed and variable O&M costs as follows:

- Fixed O&M costs are those costs associated with operation of the facility that are independent of the quantity of power produced by the plant. Fixed costs are primarily the costs associated with staffing the facility, including staff benefits. Other fixed costs include supplies, materials, and equipment to support the staff.
- Variable O&M costs are typically those costs directly associated with plant operation and are generally dependent upon the quantity of energy produced by the plant. This includes consumables, annual equipment inspections, major overhaul of equipment, and the routine maintenance of major power plant systems and balance-of-plant equipment.

As with capital costs, O&M costs were typically developed for mainland US projects, then adjusted in a similar fashion to reflect Hawaii-specific costs.

### 2.2.4 Technology-Specific Development Approach

A summary is provided below for the approach to development of cost and performance estimates for each technology. Additional detail can be found in the notes section of the UIFs:

- Large Turbine Onshore Wind: HECO provided Black & Veatch measured data from developable wind resource areas in Hawaii. Using an alpha value and the wind shear power law approximation, measured wind speeds were estimated at turbine hub heights. The energy production calculations were performed with Windographer, a widely used wind analysis tool. The wind turbine generator modeled in the UIFs was the Siemens SWT-2.3-101. There is significant experience with the operation of this turbine throughout the world; in addition, this is the same turbine being used at the First Wind Kawailoa wind project.

  The capital cost estimates were developed on the basis of Black & Veatch estimates for onshore wind projects built on ridgetops in mountainous terrain, with Hawaii-specific adjustments applied. Estimates are derived from bottom-up estimates developed for prior projects. These estimates were compared to recent Hawaii-specific cost estimates for wind projects of similar size. O&M cost estimates are based on previous experience as well as in-house information.
- Small Scale Onshore Wind: For applications on Molokai and Lanai, the use of small scale wind turbines was evaluated. The wind turbine modeled is the RRB PS-600, a 600 kW machine based on Vestas V47 technology. Wind data from the Molokai and Lanai airports were used as the initial performance basis, with shear factors and scaling applied to reflect likely wind speeds at the potential project sites. Windographer runs were performed to develop energy production profiles. Capital costs are based on Black & Veatch's database of project cost data for this size turbine, adjusted from mainland estimates to develop Hawaii specific data. Estimates are developed for Phase 1 (one turbine) through Phase 10 (10 turbines). Most infrastructure needed to support a 6 MW project (10 turbines) is included in the costs during Phase 1. Operations and maintenance costs are based on 1 to 3 full-time equivalent staff (depending on the Phase), necessary parts and materials for O&M, land lease, and warranty service.
- Offshore Wind: There are no reliable sources of offshore wind speed data appropriate for use in the development of offshore wind project performance and cost characteristics. Therefore, it was determined that onshore data would be used in a location near where a

potential offshore project would be sited, with adjustments made for likely offshore conditions. In accordance with direction provided by HECO, the offshore wind conditions should reflect an "average" condition likely to be encountered in a developable location. Using an alpha value and the wind shear power law approximation, measured wind speeds were sheared up to 90 meter hub-height wind speeds. As with the onshore wind UIF, the energy production calculations were performed with Windographer. The wind turbine generator modeled in this estimate was the Siemens SWT-3.6-107. This turbine type has been used for other offshore wind energy projects and is assumed to be reasonably representative of commercial offshore wind turbine technology available at this time.

The capital cost estimates were developed using two inputs: (1) Black & Veatch's review of publicly available offshore wind project cost estimates and (2) a bottom-up estimate based on scaling onshore costs to an offshore project. Additional cost items were added to the bottom-up estimate to reflect items that will be unique to an offshore wind project. Since the technology to develop offshore wind projects in deep water (greater than 200 feet) on floating platforms is not commercial,[2] there are no direct project comparisons that can be made. Therefore, the high end of projected cost estimates for new offshore projects was used. The bottoms-up cost estimate was built around achieving an installed mainland cost near this total figure; further adjustments were then applied to develop a Hawaii-specific cost estimate. Black & Veatch developed representative O&M cost estimates, which were based on scaling onshore costs to an offshore project and increasing costs to reflect the additional maintenance requirements likely to be required.

- Solar PV: Black & Veatch chose to use the Typical Meteorological Year version 2 (TMY2) dataset from the National Renewable Energy Laboratory (NREL) corresponding to the Honolulu station to represent the typical annual solar resource. The energy production calculations were performed with PVsyst software v.5.54, a photovoltaic system modeling tool developed by the University of Geneva. The models developed by Black & Veatch were based on commercially available polycrystalline modules and high efficiency inverters. Four models were built: a residential system (2 kW ac), a flat roof commercial system (100 kW ac), and a ground mounted system (1 MW ac) in two configurations: a fixed tilt structure and a single-axis tracker (SAT). Based on the levelized cost of electricity calculations, Black & Veatch found that the SAT system provides the best revenue for the project over its expected life. For this reason, the tracking system was used during datasheet development for the 1 MW-scale facility.

  The costs were estimated based on vendor quotes, literature sources, and Black & Veatch designs. Sources used were the California Energy Commission database for the Emerging Renewables Program, the quarterly US Solar Market Insight Report published by Solar Energy Industries Association (SEIA) and GTM Research, the Lawrence Berkeley National Laboratory's report *Tracking the Sun IV* (published September 2011), market index pricing published by *Solarbuzz*, and Black & Veatch's system pricing experience. After development of mainland costs, factors were applied to develop costs specific to Hawaii systems. A proprietary Black & Veatch model for estimating O&M costs was used. Model inputs include project size, location, PV module technology, design characteristics such as row spacing and inverter configuration, warranty, and the distance of the plant from service personnel.

- Solar Thermal: Black & Veatch used satellite solar data corresponding to a developable location previously identified by HECO on Oahu. Since the minimum size offered by vendors of commercial solar thermal facilities is 50 MW, it was assumed that this

[2] The commercial offshore projects in Europe and those planned in the Eastern United States are in shallow water, using a turbine mooring system that could not be used in Hawaii.

technology would be considered for Oahu only. The energy production calculations were performed with System Advisor Model (SAM) v.2011.12.2, an energy system modeling tool developed by NREL. Black & Veatch used the Physical Parabolic Trough Model in SAM, which characterizes the performance of the many system components from first principles of heat transfer and thermodynamics. The equipment modeled in SAM is representative of the size and technology installed at commercial parabolic trough plants.

The capital cost estimates were developed on the basis of existing Black & Veatch estimates for parabolic trough plants. Screening level estimates were derived from bottom-up estimates developed for prior projects. The capital costs were initially developed based on US mainland costs; these were then adjusted to be representative of a project located in Hawaii. O&M cost estimates are based on previous experience as well as in-house information.

- Geothermal: Two binary cycle projects were evaluated: one project in a location with a well-surveyed resource and previous exploration efforts (Advanced Geothermal) and another in a location with no previous development efforts and limited resource data (New Geothermal). Assumptions for both projects were largely the same with some exceptions pertaining to the number of wells required during development. Facility ratings were kept consistent with previous IRPs (25 MW net output). In accordance with the direction provided by HECO, dispatch capability was included in both designs. To model dispatch capability in the design, it was assumed that a greater number of heat exchangers would be used in the binary cycle, with heat exchangers bypassed in the event that turndown would be needed. While this increased the capital cost, it increases the level of grid services available.

  Capital cost estimates are based on both publicly available data as well as reports available by subscription. Public data from NREL, Geothermex, and the Geothermal Energy Association, as well as information provided by HECO, were used to develop the capital costs. Hawaii-specific costs for land, substation development, and wells were estimated separately for each plant. Since these are generic facilities, no additional new transmission costs were included. O&M costs were obtained from public data and HECO supplied information.

- Ocean Wave: Wave data for the ocean wave UIF was based on publicly available datasets from the University of Hawaii, Hawaii National Marine Renewable Energy Center (HINMREC), and EPRI, along with information provided by HECO. A representative location for project development was selected so that Hawaii-specific wave data could be applied. Selection of a location considered the quality of the wave resource, environmental restrictions, and locations previously considered for wave energy projects. This analysis selected wave data near Pauwela, Maui, to be a reasonable estimate. Wave data for Pauwela was obtained from HINMREC's SWAN model analysis.

  The cost and performance results for ocean wave technology presented in the UIF are derived from analysis performed by Pelamis Wave Power (Pelamis). The Pelamis cost model has been extensively validated by Black & Veatch in other work. Costs for performance of the current generation of technology (2016 deployment) and a projected advanced project better adapted to Hawaii wave resources (2020 deployment) were developed. The 2020 Pelamis cost models incorporate equipment-specific learning rates, based on identified potential cost reductions and performance improvements from engineering refinement.

- OTEC: Due to the current status of OTEC technology development, little reliable cost and performance data are available. The majority of the data used in the UIF are derived from a 2010 Lockheed Martin report completed for the US Navy for a project located 20 miles off the south coast of Oahu. This was supplemented with data presented in a presentation titled "OTEC Economics" given by University of Hawaii professor Dr. Luis Vega in 2007.
- Biomass Combustion: The technology option chosen is a 25 MW facility fueled with banagrass, which is assumed to be grown on the island where the project is located. Performance parameters developed for IRP 2013 were developed based on in-house Black & Veatch models. Black & Veatch employed the current version of its in-house boiler combustion model to estimate boiler performance parameters. The model employed by Black & Veatch is a spreadsheet-based model that utilizes American Society of Mechanical Engineers (ASME) Performance Test Codes (PTCs), industry standards, and stoichiometric combustion assumptions to calculate boiler efficiency, flue gas flow rates, fuel burn rates, and several other parameters. The updated combustion calculations assumed banagrass fuel properties (e.g., proximate and ultimate analyses) were consistent with IRP-3 efforts. To estimate steam cycle performance, Black & Veatch utilized a steam cycle model originally developed during IRP-3. Emissions data assume the use of Selective Noncatalytic Reduction (SNCR) for control of nitrogen oxides ($NO_x$); sorbent injection for the control of acid gases; and an electrostatic precipitator (ESP) for control of particulate matter (PM).

  Capital and O&M cost estimates were developed on the basis of existing Black & Veatch estimates for biomass combustion facilities with generating capacities in the range of 20 MW to 30 MW. Estimates were derived from bottom-up estimates developed for these prior projects. These estimates were adjusted to account for the use of banagrass fuel and to account for the construction and operation of the project at a Hawaiian location.
- Biomass Conversion: The Biomass Conversion option was developed assuming the conversion of an oil-fired unit to a suspension-fired boiler fueled with eucalyptus. Parameters for this option were based on two recent studies prepared by Black & Veatch on behalf of HELCO to evaluate options for conversion at Puna Generating Station: Puna Biomass Conversion Study (March 2009) and Puna Biomass Conversion Project (November 2012).

  Performance and emission parameters were estimated for the Biomass Conversion option based on these studies, which evaluated the feasibility of converting the Puna boiler to support solid fuel combustion in a suspension-fired boiler. Emission data assume the use of SNCR for control of $NO_x$ and the use of an ESP for control of PM.

  Capital cost estimates were developed based on the updated estimates prepared by Black & Veatch in these studies. O&M cost estimates were developed by Black & Veatch, assuming labor and commodity pricing consistent with that considered for other HECO IRP 2013 options and based on the facility operational parameters presented within the conversion studies.
- WTE: A UIF was developed for a WTE option fueled by MSW. This option was assumed to employ a mass burn boiler to consume 300 tons per day of MSW and provide a gross output of 8 MW. The design of this facility, including ratings and performance, was kept consistent with previous IRPs. Similar to the Biomass Combustion case, Black & Veatch utilized a steam cycle model developed for IRP-3 to estimate steam cycle performance. Emissions data assume the use of SNCR for control of $NO_x$ and sorbent injection for the control of sulfur oxides ($SO_x$) and acid gases.

Capital costs for the WTE option within IRP 2013 were scaled from capital cost estimates developed for IRP-3. This scaling was based on Black & Veatch estimates of cost variations for solid fueled steam cycle units (e.g., 25 MW biomass combustion facilities) during this same time period. To estimate O&M costs, Black & Veatch updated the O&M costs developed for IRP-3 based on current labor rates, scheduled maintenance cost factors, and unit prices for consumables.

- Fuel Cell: A Phosphoric Acid Fuel Cell (PAFC) system operating on natural gas is a commercially available technology manufactured and packaged by UTC Power (UTC) as a 400 kW unit. UTC is a world leader in PAFC installation, with over 300 units installed worldwide. Cost and performance information used to develop the UIF was obtained from UTC Power via technical documentation and telephone interviews. UTC configures the fuel cells to maintain a steady 400 kW output with the unit adjusting fuel intake as necessary to maintain that level of output. Fuel cells can be configured to follow load and can be ramped up or down by adjusting fuel consumption rates.

  Capital and operating costs were developed by UTC. Labor and materials were escalated to reflect Hawaii-specific labor costs, shipping, and taxes. In addition to the fixed O&M costs from UTC, HECO labor costs were added for operations, monitoring, and interaction with UTC personnel.

- Battery Energy Storage: In accordance with direction from HECO, three different battery operating modes were developed: a battery energy storage system (BESS), a battery energy spinning reserve (BESR), and a battery energy frequency regulation (BEFR). The BESS is employed in daily peaking cycle, with discharge cycles intended to average 1.5 hours in duration. The daily peak is expected to happen 5 days per week for 50 weeks per year. The BESR is based on four discharges to 80 percent depth of discharge (DOD) per month. Cycles are limited to 30 minutes, to reflect what would be needed to respond to a unit outage. The BEFR is based on 200 or more shallow DODs per month with discharge durations of less than 15 minutes. The batteries are assumed to be charged by renewable energy, and therefore, no air emissions are associated with the operation of the batteries. The batteries are sealed lead acid with no hydrogen emissions.

  The capital cost estimates were developed on the basis of existing Black & Veatch estimates for a BESS, BESR, and BEFR of a similar type and scale. Estimates were derived from proprietary vendor budgetary estimates developed for prior projects. This data was evaluated and modified with in-house information to better represent the scale and the location of the facility in Hawaii. O&M costs are based on previous experience as well as in-house information.

- Reciprocating Engines: Three cases were developed for reciprocating engine options: a 1x0 (i.e., one engine operating in simple cycle) Wartsila 18V46 reciprocating engine/generator facility; a 6x0 (i.e., 6 engines operating in simple cycle) Wartsila 18V46 reciprocating engine/generator facility; and a 1x0 Wartsila 12V32 reciprocating/engine facility.

  For the 6x0 Reciprocating Engine option, it was assumed the facility would be constructed in two phases:

  - Phase 1: Construction of a 1x0 Wartsila 18V46 facility, with space allocated for buildout to a 6x0 facility.
  - Phase 2: Installation of five remaining engine/generators and ancillary systems (e.g., additional tankage, electrical switchgear).

UIFs were developed for each individual phase, and an overall UIF was developed to summarize the relevant parameters for the facility as a whole.

For all Reciprocating Engine cases, the fuel is assumed to be biodiesel. Performance and emissions data for the Wartsila 18V46 and Wartsila 12V32 options were provided by Wartsila. Wartsila provided these data based on the biodiesel fuel specification provided by HECO. Emissions data assume the use of Selective Catalytic Reduction (SCR) for control of $NO_x$ and an oxidation catalyst for control of carbon monoxide (CO).

Capital cost estimates were developed on the basis of existing Black & Veatch estimates for reciprocating engine facilities of a similar type and scale. This existing in-house data, including previous vendor quotations for major equipment and current market pricing for commodities, were evaluated and adjusted to better represent the fuel used, the scale of the facility, and the location of the facility in Hawaii. Black & Veatch developed representative O&M cost estimates, which were based on in-house information and O&M cost information provided by Wartsila.

- Combustion Turbines: As shown in Section 2.1, seven cases were developed for the Combustion Turbine options: three simple cycle options operating on biodiesel, one simple cycle option on natural gas, two combined cycle options operating on biodiesel, and one combined cycle option on natural gas. For the combined cycle options, it was assumed that these facilities would be constructed in phases, similar to the approach employed for the 6x0 reciprocating engine option. For example, the 2x1 GE LM2500 option was assumed to occur in the following three phases:
  - Phase 1: Construction of a 1x0 LM2500 facility, with space allocated for buildout to a 2x1 facility.
  - Phase 2: Installation of a second LM2500 combustion turbine generator (CTG) and ancillary systems (e.g., additional tankage, electrical switchgear).
  - Phase 3: Installation of steam turbine cycle equipment and ancillary systems.

For cases fueled by biodiesel, performance and emission data were provided by the OEM, General Electric (GE). The biodiesel fuel specification was provided by HECO and forwarded to GE for consideration in the development of its performance estimates. For cases fueled by natural gas, performance and emission data were developed by Black & Veatch using combustion turbine performance and emission models developed by GE. For both cases, emissions data assume the use of SCR for control of $NO_x$ and an oxidation catalyst for control CO.

For combined cycle cases, Black & Veatch developed performance estimates built upon the CTG performance data for the respective simple cycle case. Steam cycle performance data were estimated using in-house Black & Veatch steam cycle models while taking into account the relevant CTG parameters (i.e., turbine back pressure, and exhaust flue gas temperatures and flow rates).

For all combustion turbine cases, capital and O&M cost estimates were developed on the basis of existing Black & Veatch estimates for combustion turbine facilities of a similar type and scale. Estimates were derived from bottom-up estimates developed for prior projects. These estimates were adjusted to account for the fuel to be used and to account for the siting of the project in Hawaii.

# 3.0 Supply-Side Data

## 3.1 COST AND PERFORMANCE SUMMARIES

The UIFs and notes that accompany the UIFs were the main deliverables provided to HECO in the development of the supply-side data by Black & Veatch. The attached tables summarize the salient performance and cost attributes of the technologies evaluated in support of IRP 2013. The five tables are as follows:

- Table 3-1: Capital Cost Summary.
- Table 3-2: O&M Cost Summary.
- Table 3-3: Technical Performance and Availability Summary.
- Table 3-4: Environmental Performance Summary.
- Table 3-5: Schedule and Resource Requirement Summary.

**Table 3-1 Capital Cost Summary**

| COMMERCIAL RESOURCE OPTIONS | FUEL | CAPITAL COST ESTIMATES (2011 $ MILLION) | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | | POWER BLOCK | SPECIAL SITING | SWITCHYARD | T&D | TOTAL DIRECT | INDIRECT | LAND | TOTAL CAPITAL | CAPITAL COST ($/KW)* |
| **Large Turbine Onshore Wind** | | | | | | | | | | |
| 10 MW (Class 7) | Wind | 32.9 | - | 2.8 | 3.5 | 39.2 | 5.2 | 0.5 | 44.8 | 4,874 |
| 10 MW (Class 5) | Wind | 32.9 | - | 2.8 | 3.5 | 39.2 | 5.2 | 0.5 | 44.8 | 4,874 |
| 10 MW (Class 3) | Wind | 32.9 | - | 2.8 | 3.5 | 39.2 | 5.2 | 0.5 | 44.8 | 4,874 |
| 30 MW (Class 3) | Wind | 93.5 | - | 4.0 | 6.2 | 103.6 | 11.0 | 0.5 | 115.1 | 3,849 |
| **Small Scale Onshore Wind** | | | | | | | | | | |
| 0.6 MW (Molokai, Class 6) | Wind | 7.8 | | 2.0 | 2.0 | 11.7 | 0.9 | 0.2 | 12.8 | 21,270 |
| 0.6 MW (Lanai, Class 6) | Wind | 7.8 | | 2.0 | 2.0 | 11.7 | 0.9 | 0.2 | 12.8 | 21,270 |
| 6 MW (Molokai, Class 6) | Wind | 26.9 | | 2.0 | 2.0 | 30.9 | 2.1 | 0.2 | 33.2 | 5,534 |
| 6 MW (Lanai, Class 6) | Wind | 26.9 | | 2.0 | 2.0 | 30.9 | 2.1 | 0.2 | 33.2 | 5,534 |
| **Offshore Wind** | | | | | | | | | | |
| 100 MW (Class 5) | Wind | 818.8 | - | 29.8 | 10.0 | 858.6 | 137.0 | 0.5 | 996.1 | 9,882 |
| **Solar Photovoltaic Resources** | | | | | | | | | | |
| 1 MW Single-Axis Tracking | Solar | 3.6 | - | - | 0.06 | 3.7 | 0.54 | - | 4.2 | 3,524 (DC) |
| 100 kW Rooftop | Solar | 0.4 | - | - | 0.01 | 0.36 | 0.08 | - | 0.44 | 3,605 (DC) |
| 2 kW Rooftop | Solar | 0.012 | - | - | - | 0.012 | 0.002 | - | 0.014 | 5,604 (DC) |
| **Solar Thermal Resources** | | | | | | | | | | |
| 50 MW Parabolic Trough | Solar | 334.2 | - | 3.0 | 2.5 | 339.7 | 95.1 | - | 434.8 | 8,695 |
| **Geothermal Resources** | | | | | | | | | | |

| COMMERCIAL RESOURCE OPTIONS | FUEL | CAPITAL COST ESTIMATES (2011 $ MILLION) | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | | POWER BLOCK | SPECIAL SITING | SWITCHYARD | T&D | TOTAL DIRECT | INDIRECT | LAND | TOTAL CAPITAL | CAPITAL COST ($/KW)* |
| 25 MW Geothermal (Advanced) | Geothermal | 217.1 | - | - | 4.4 | 221.5 | 37.8 | 5.4 | 264.8 | 9,130 |
| 25 MW Geothermal (New) | Geothermal | 234.0 | - | - | 4.4 | 238.4 | 37.8 | 5.4 | 281.7 | 9,712 |
| **Ocean Wave Resources** | | | | | | | | | | |
| Pelamis 750 kW (2016) | Ocean Wave | 10.3 | 5.5 | - | 1.0 | 16.7 | Not defined | - | 16.7 | 22,326 |
| Pelamis 15 MW (2020) | Ocean Wave | 107.6 | 8.4 | - | 5.0 | 121.0 | Not defined | - | 121.0 | 8,067 |
| **Ocean Thermal Resources** | | | | | | | | | | |
| 10 MW | Ocean Thermal | 286.8 | 83.0 | - | 20.8 | 390.7 | 50.4 | 0.05 | 441.2 | 45,956 |
| **Thermal Plant Resources** | | | | | | | | | | |
| Biomass Combustion (25 MW) | Banagrass | 127.2 | - | 3.8 | - | 131.0 | 49.7 | 3.1 | 183.7 | 6,541 |
| Biomass Conversion (13 MW) | Eucalyptus | 50.4 | - | - | - | 50.4 | 13.5 | - | 64.0 | 4,023 |
| Waste-to-Energy Mass Burn (8 MW) | MSW | 115.8 | 1.8 | 1.9 | - | 119.5 | 32.9 | 3.1 | 155.4 | 19,084 |
| **Fuel Cell Resources** | | | | | | | | | | |
| Phosphoric Acid, 400 kW | Natural Gas | 3.3 | - | - | - | 3.3 | 0.3 | - | 3.6 | 9,014 |
| **Battery Energy Resources** | | | | | | | | | | |
| Battery Energy Storage System (BESS) | - | 17.5 | - | - | - | 17.5 | 3.5 | - | 21.0 | 2,000 |
| Batt. Energy Spinning Reserve (BESR) | - | 29.5 | - | - | - | 29.5 | 5.9 | - | 35.4 | 1,349 |
| Batt. Energy Freq. Regulation (BEFR) | - | 21.8 | - | - | - | 21.8 | 3.1 | - | 24.9 | 947 |
| **Simple Cycle Resources** | | | | | | | | | | |

| COMMERCIAL RESOURCE OPTIONS | FUEL | CAPITAL COST ESTIMATES (2011 $ MILLION) | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | | POWER BLOCK | SPECIAL SITING | SWITCHYARD | T&D | TOTAL DIRECT | INDIRECT | LAND | TOTAL CAPITAL | CAPITAL COST ($/KW)* |
| 1 x 0 Wartsila 18V46 | Biodiesel | 45.6 | 0.7 | 3.0 | - | 49.3 | 24.4 | 2.4 | 76.1 | 4,459 |
| 6 x 0 Wartsila 18V46 | Biodiesel | 185.5 | 2.8 | 10.8 | - | 199.1 | 80.1 | 2.4 | 281.6 | 2,749 |
| 1 x 0 Wartsila 12V32 | Biodiesel | 20.8 | 0.3 | 1.5 | - | 22.6 | 11.1 | 0.9 | 34.6 | 6,633 |
| 1 x 0 GE LM2500 | Biodiesel | 55.7 | 0.8 | 3.4 | - | 60.0 | 28.7 | 2.4 | 91.0 | 4,248 |
| 1 x 0 GE LM6000 PG | Biodiesel | 77.6 | 1.2 | 5.2 | - | 83.9 | 36.1 | 2.4 | 122.4 | 2,890 |
| 1 x 0 GE LMS100 PA | Biodiesel | 137.1 | 2.1 | 8.2 | - | 147.4 | 46.2 | 2.4 | 196.0 | 2,128 |
| 1 x 0 GE LMS100 PA | Natural Gas | 134.7 | 2.0 | 8.2 | - | 144.9 | 45.6 | 2.4 | 192.9 | 1,997 |
| **Combined Cycle Resources** | | | | | | | | | | |
| 2 x 1 GE LM2500 | Biodiesel | 184.4 | 2.8 | 10.4 | - | 197.7 | 93.1 | 3.3 | 294.0 | 4,527 |
| 1 x 1 GE LM6000 PG | Biodiesel | 137.1 | 2.1 | 8.0 | - | 147.1 | 70.9 | 3.3 | 221.3 | 3,677 |
| 1 x 1 GE LM6000 PG | Natural Gas | 127.1 | 1.9 | 8.1 | - | 137.2 | 65.6 | 3.3 | 206.0 | 3,452 |

*Capital cost in $/kW rated for wind, solar PV (dc), solar thermal, ocean wave, ocean thermal, and fuel cell technologies. Costs are in $/kW gross for simple cycle turbines, combined cycle turbines, thermal plants (biomass and WTE), geothermal, and battery energy technologies. This reflects the industry standard for how capital costs are reported for each technology and does allow equivalent comparisons between technologies.

**Table 3-2 O&M Cost Summary**

| COMMERCIAL RESOURCE OPTIONS | FUEL | CAPACITY FACTOR (%) | FIXED O&M | | VARIABLE O&M | | LAND LEASE $\$10^6$/YEAR | STAFF NO. |
|---|---|---|---|---|---|---|---|---|
| | | | $\$10^6$/ YEAR | \$/KW-YEAR (NET) | $\$10^6$/ YEAR | \$/MWH (NET) | | |
| **Large Turbine Onshore Wind** | | | | | | | | |
| 10 MW (Class 7) | Wind | 56.2 | 0.87 | 168.2 | 0.09 | 2.0 | 0.26 | 2 |
| 10 MW (Class 5) | Wind | 41.4 | 0.87 | 228.6 | 0.06 | 2.0 | 0.26 | 2 |
| 10 MW (Class 3) | Wind | 35.6 | 0.87 | 265.3 | 0.06 | 2.0 | 0.26 | 2 |
| 30 MW (Class 3) | Wind | 35.6 | 2.4 | 223.1 | 0.19 | 2.0 | 0.86 | 4 |
| **Small Scale Onshore Wind** | | | | | | | | |
| 0.6 MW (Molokai, Class 6) | Wind | 40.7 | 0.26 | 1,076 | 0.005 | 2.28 | 0.005 | 1 |
| 0.6 MW (Lanai, Class 6) | Wind | 35.3 | 0.26 | 1,240 | 0.005 | 2.63 | 0.005 | 1 |
| 6 MW (Molokai, Class 6) | Wind | 37.8 | 1.37 | 602 | 0.05 | 2.46 | 0.26 | 3 |
| 6 MW (Lanai, Class 6) | Wind | 32.8 | 1.37 | 694 | 0.05 | 2.83 | 0.26 | 3 |
| **Offshore Wind** | | | | | | | | |
| 100 MW (Class 5) | Wind | 33.9 | 8.2 | 240.3 | 0.60 | 2.0 | 0.93 | 8 |
| **Photovoltaic Resources** | | | | | | | | |
| 1 MW Single-Axis Tracking | Solar | 27.4 (AC) | 0.041 | 41.3 | 0.007 | 3.0 | 0.07 | 1 |
| 100 kW Rooftop | Solar | 22.8 (AC) | 0.004 | 39.7 | 0.002 | 8.8 | 0 | 0 |
| 2 kW Rooftop | Solar | 22.8 (AC) | 0 | 0 | 0.0003 | 88.1 | 0 | 0 |
| **Solar Thermal Resources** | | | | | | | | |
| 50 MW Parabolic Trough | Solar | 20.8 | 7.18 | 691 | 1.59 | 17.4 | 3.58 | 31 |

| COMMERCIAL RESOURCE OPTIONS | FUEL | CAPACITY FACTOR (%) | FIXED O&M | | VARIABLE O&M | | LAND LEASE $\$10^6$/YEAR | STAFF NO. |
|---|---|---|---|---|---|---|---|---|
| | | | $\$10^6$/ YEAR | $/KW-YEAR (NET) | $\$10^6$/ YEAR | $/MWH (NET) | | |
| **Geothermal Resources** | | | | | | | | |
| 25 MW Geothermal (Advanced) | Water | 85 | 5.39 | 211 | 5.49 | 28.9 | n/a | 30 |
| 25 MW Geothermal (New) | Water | 85 | 5.39 | 211 | 5.69 | 29.8 | n/a | 30 |
| **Ocean Wave Resources** | | | | | | | | |
| Pelamis 750 kW (2016) | Wave | 16 | 0.72 | 6018 | 0 | 0 | 0.02 | 4 |
| Pelamis 15 MW (2020) | Wave | 20 | 4.34 | 1471 | 0 | 0 | 0.02 | 13 |
| **Ocean Thermal Resources** | | | | | | | | |
| 10 MW | Ocean | 52.1 | 3.41 | 683 | 3.24 | 78 | 0.38 | 19 |
| **Thermal Plant Resources** | | | | | | | | |
| Biomass Combustion (25 MW) | Banagrass | 83.0 | 8.02 | 321 | 1.68 | 9.3 | 1.49 | 37 |
| Biomass Conversion (13 MW) | Eucalyptus | 80.4 | 5.62 | 436 | 0.60 | 6.6 | - | 27 |
| Waste-to-Energy Mass Burn (8 MW) | MSW | 83.0 | 7.84 | 1,100 | 1.78 | 34.4 | - | 37 |
| **Fuel Cell Resources** | | | | | | | | |
| Phosphoric Acid, 400 kW | Natural Gas | 90 | 0.13 | 330 | 0.10 | 32.6 | 0.005 | 1 |
| **Battery Energy Resources** | | | | | | | | |
| Battery Energy Storage System (BESS) | - | N/A* | 0.26 | 25.9 | 0 | 0 | N/A | 1 |
| Batt. Energy Spinning Reserve (BESR) | - | N/A* | 0.26 | 10.4 | 0 | 0 | N/A | 1 |
| Batt. Energy Freq. Regulation (BEFR) | - | N/A* | 0.26 | 10.4 | 0 | 0 | N/A | 1 |
| **Simple Cycle Resources** | | | | | | | | |

| COMMERCIAL RESOURCE OPTIONS | FUEL | CAPACITY FACTOR (%) | FIXED O&M | | VARIABLE O&M | | LAND LEASE $10^6$/YEAR | STAFF NO. |
|---|---|---|---|---|---|---|---|---|
| | | | $10^6$/ YEAR | $/KW-YEAR (NET) | $10^6$/ YEAR | $/MWH (NET) | | |
| 1 x 0 Wartsila 18V46 | Biodiesel | 5.0 | 0.89 | 53.2 | 0.15 | 21.2 | - | 4 |
| 6 x 0 Wartsila 18V46 | Biodiesel | 5.0 | 1.0 | 10.1 | 0.52 | 11.7 | - | 4 |
| 1 x 0 Wartsila 12V32 | Biodiesel | 5.0 | 0.89 | 174 | 0.07 | 30.0 | - | 4 |
| 1 x 0 GE LM2500 | Biodiesel | 5.0 | 0.91 | 42.8 | 0.18 | 19.8 | - | 4 |
| 1 x 0 GE LM6000 PG | Biodiesel | 5.0 | 0.92 | 22.0 | 0.26 | 14.4 | - | 4 |
| 1 x 0 GE LMS100 PA | Biodiesel | 5.0 | 0.95 | 10.5 | 0.40 | 10.1 | - | 4 |
| 1 x 0 GE LMS100 PA | Natural Gas | 5.0 | 0.95 | 10.0 | 0.27 | 6.6 | - | 4 |
| **Combined Cycle Resources** | | | | | | | | |
| 2 x 1 GE LM2500 | Biodiesel | 60.0 | 4.22 | 66.8 | 4.04 | 12.2 | - | 19 |
| 1 x 1 GE LM6000 PG | Biodiesel | 60.0 | 3.74 | 63.5 | 3.89 | 12.6 | - | 17 |
| 1 x 1 GE LM6000 PG | Natural Gas | 60.0 | 3.74 | 64.0 | 2.51 | 8.2 | - | 17 |

*For Battery Energy Resources, capacity factor is not considered to be appropriate or meaningful to the characterization of these systems because it does not account for the charging and discharging of energy over the normal range of operating conditions. Therefore, capacity factor is listed as "N/A" for Battery Energy Resources.

**Table 3-3 Technical Performance and Availability Summary**

| COMMERCIAL RESOURCE OPTIONS | FUEL | CAPACITY AND HEAT RATE | | | | OPERATING DATA | | |
|---|---|---|---|---|---|---|---|---|
| | | GROSS CAPACITY (MW) | AUXILIARY POWER (MW) | NET CAPACITY (MW) | NET HEAT RATE (BTU/KWH) | ANNUAL PRODUCTION (GWH) | DUTY CYCLE | CAPACITY FACTOR (PERCENT) |
| **Large Turbine Onshore Wind** | | | | | | | | |
| 10 MW (Class 7) | Wind | 6.3 | N/A | 5.2 | N/A | 45.3 | Supplemental | 56.2 |
| 10 MW (Class 5) | Wind | 4.6 | N/A | 3.8 | N/A | 33.3 | Supplemental | 41.4 |
| 10 MW (Class 3) | Wind | 3.9 | N/A | 3.3 | N/A | 28.7 | Supplemental | 35.6 |
| 30 MW (Class 3) | Wind | 12.8 | N/A | 10.7 | N/A | 93.4 | Supplemental | 35.6 |
| **Small Scale Onshore Wind** | | | | | | | | |
| 0.6 MW (Molokai, Class 6) | Wind | 0.28 | N/A | 0.24 | N/A | 2.1 | Supplemental | 40.7 |
| 0.6 MW (Lanai, Class 6) | Wind | 0.24 | N/A | 0.21 | N/A | 1.9 | Supplemental | 35.3 |
| 6 MW (Molokai, Class 6) | Wind | 2.8 | N/A | 2.3 | N/A | 19.9 | Supplemental | 37.8 |
| 6 MW (Lanai, Class 6) | Wind | 2.4 | N/A | 2.0 | N/A | 17.2 | Supplemental | 32.8 |
| **Offshore Wind** | | | | | | | | |
| 100 MW (Class 5) | Wind | 42.0 | N/A | 34.2 | N/A | 299.7 | Supplemental | 33.9 |
| **Photovoltaic Resources** | | | | | | | | |
| 1 MW Single-Axis Tracking | Solar | 1.0 (AC) | N/A | 1.0 | N/A | 2.4 | Supplemental | 27.4 (AC) |
| 100 kW Rooftop | Solar | 0.1 (AC) | N/A | 0.1 | N/A | 0.2 | Supplemental | 22.8 (AC) |
| 2 kW Rooftop | Solar | 0.002 (AC) | N/A | 0.002 | N/A | 0.004 | Supplemental | 22.8 (AC) |
| **Solar Thermal Resources** | | | | | | | | |
| 50 MW Parabolic Trough | Solar | 11.9 | 1.5 | 10.4 | N/A | 91.0 | Supplemental | 20.8 |
| **Geothermal Resources** | | | | | | | | |

| COMMERCIAL RESOURCE OPTIONS | FUEL | CAPACITY AND HEAT RATE | | | | OPERATING DATA | | |
|---|---|---|---|---|---|---|---|---|
| | | GROSS CAPACITY (MW) | AUXILIARY POWER (MW) | NET CAPACITY (MW) | NET HEAT RATE (BTU/KWH) | ANNUAL PRODUCTION (GWH) | DUTY CYCLE | CAPACITY FACTOR (PERCENT) |
| 25 MW Geothermal (Advanced) | Water | 29.0 | 3.5 | 25.5 | N/A | 189.9 | Baseload/ Dispatchable | 85 |
| 25 MW Geothermal (New) | Water | 29.0 | 3.5 | 25.5 | N/A | 189.9 | Baseload/ Dispatchable | 85 |
| **Ocean Wave Resources** | | | | | | | | |
| Pelamis 750 kW (2016) | Wave | 0.12 | N/A | 0.12 | N/A | 1.05 | Supplemental | 16 |
| Pelamis 15 MW (2020) | Wave | 3.0 | N/A | 3.0 | N/A | 25.9 | Supplemental | 20 |
| **Ocean Thermal Resources** | | | | | | | | |
| 10 MW | Ocean | 5.2 | 0.2 | 5.0 | N/A | 41.6 | Baseload | 52.1 |
| **Thermal Plant Resources** | | | | | | | | |
| Biomass Combustion (25 MW) | Banagrass | 28.1 | 3.1 | 25.0 | 14,910 | 181.8 | Baseload | 83 |
| Biomass Conversion (13 MW) | Eucalyptus | 15.9 | 3.0 | 12.9 | 18,840 | 90.9 | Baseload | 80 |
| Waste-to-Energy Mass Burn (8 MW) | MSW | 8.1 | 1.0 | 7.1 | 19,300 | 51.6 | Baseload | 83 |
| **Fuel Cell Resources** | | | | | | | | |
| Phosphoric Acid, 400 kW | Natural Gas | 0.4 | N/A | 0.4 | 9,554 | 3.15 | Baseload/ Peaking | 90 |
| **Battery Energy Resources** | | | | | | | | |
| Battery Energy Storage System (BESS) | - | 10.5 | 0.5 | 10 | - | N/A* | Peaking/ Storage | N/A** |
| Batt. Energy Spinning Reserve (BESR) | - | 26.3 | 1.3 | 25 | - | N/A* | Spinning Reserve | N/A** |
| Batt. Energy Freq. Regulation (BEFR) | - | 26.3 | 1.3 | 25 | - | N/A* | Freq. Regulation | N/A** |

| COMMERCIAL RESOURCE OPTIONS | FUEL | CAPACITY AND HEAT RATE | | | | OPERATING DATA | | |
|---|---|---|---|---|---|---|---|---|
| | | GROSS CAPACITY (MW) | AUXILIARY POWER (MW) | NET CAPACITY (MW) | NET HEAT RATE (BTU/KWH) | ANNUAL PRODUCTION (GWH) | DUTY CYCLE | CAPACITY FACTOR (PERCENT) |
| **Simple Cycle Resources** | | | | | | | | |
| 1 x 0 Wartsila 18V46 | Biodiesel | 17.1 | 0.4 | 16.7 | 8,440 | 7.3 | Peaking | 5 |
| 6 x 0 Wartsila 18V46 | Biodiesel | 102.5 | 2.3 | 100.2 | 8,440 | 43.9 | Peaking | 5 |
| 1 x 0 Wartsila 12V32 | Biodiesel | 5.2 | 0.1 | 5.1 | 8,450 | 2.2 | Peaking | 5 |
| 1 x 0 GE LM2500 | Biodiesel | 21.4 | 0.3 | 21.1 | 11,040 | 9.2 | Peaking | 5 |
| 1 x 0 GE LM6000 PG | Biodiesel | 42.4 | 0.5 | 41.9 | 10,110 | 18.3 | Peaking | 5 |
| 1 x 0 GE LMS100 PA | Biodiesel | 92.1 | 1.3 | 90.8 | 9,340 | 39.8 | Peaking | 5 |
| 1 x 0 GE LMS100 PA | Natural Gas | 96.6 | 1.3 | 95.3 | 9,210 | 41.7 | Peaking | 5 |
| **Combined Cycle Resources** | | | | | | | | |
| 2 x 1 GE LM2500 | Biodiesel | 65.0 | 1.8 | 63.2 | 7,630 | 332 | Intermediate | 60 |
| 1 x 1 GE LM6000 PG | Biodiesel | 60.2 | 1.3 | 58.8 | 7,630 | 309 | Intermediate | 60 |
| 1 x 1 GE LM6000 PG | Natural Gas | 59.7 | 1.4 | 58.3 | 7,660 | 307 | Intermediate | 60 |

*For Battery Energy Resources, annual production (in terms of GWh) is listed as "N/A" because these Battery Resources do not independently generate energy; these resources only store energy produced by other generation assets connected to the electrical grid.

**For Battery Energy Resources, capacity factor is not considered to be appropriate or meaningful to the characterization of these systems because it does not account for the charging and discharging of energy over the normal range of operating conditions. Therefore, capacity factor is listed as "N/A" for Battery Energy Resources.

**Table 3-4 Environmental Performance Summary**

| COMMERCIAL RESOURCE OPTIONS | FUEL | FLUE GAS EMISSIONS, LB/MBTU | | | | | | WASTE STREAMS | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | | NITROGEN OXIDES | SULFUR OXIDES | CARBON DIOXIDE | CARBON MONOXIDE | VOLATILE ORGANIC COMP. | PARTICULATE MATTER | SOLID TPD | WATER MGD | THERMAL MBTU/D |
| **Large Turbine Onshore Wind** | | | | | | | | | | |
| 10 MW (Class 7) | Wind | - | - | - | - | - | - | - | - | - |
| 10 MW (Class 5) | Wind | - | - | - | - | - | - | - | - | - |
| 10 MW (Class 3) | Wind | - | - | - | - | - | - | - | - | - |
| 30 MW (Class 3) | Wind | - | - | - | - | - | - | - | - | - |
| **Small Scale Onshore Wind** | | | | | | | | | | |
| 0.6 MW (Molokai, Class 6) | Wind | - | - | - | - | - | - | - | - | - |
| 0.6 MW (Lanai, Class 6) | Wind | - | - | - | - | - | - | - | - | - |
| 6 MW (Molokai, Class 6) | Wind | - | - | - | - | - | - | - | - | - |
| 6 MW (Lanai, Class 6) | Wind | - | - | - | - | - | - | - | - | - |
| **Offshore Wind** | | | | | | | | | | |
| 100 MW (Class 5) | Wind | - | - | - | - | - | - | - | - | - |
| **Photovoltaic Resources** | | | | | | | | | | |
| 1 MW Single-Axis Tracking | Solar | - | - | - | - | - | - | - | - | - |
| 100 kW Rooftop | Solar | - | - | - | - | - | - | - | - | - |
| 2 kW Rooftop | Solar | - | - | - | - | - | - | - | - | - |
| **Solar Thermal Resources** | | | | | | | | | | |
| 50 MW Parabolic Trough | Solar | - | - | - | - | - | - | - | - | - |
| **Geothermal Resources** | | | | | | | | | | |

| COMMERCIAL RESOURCE OPTIONS | FUEL | FLUE GAS EMISSIONS, LB/MBTU | | | | | | WASTE STREAMS | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | | NITROGEN OXIDES | SULFUR OXIDES | CARBON DIOXIDE | CARBON MONOXIDE | VOLATILE ORGANIC COMP. | PARTICULATE MATTER | SOLID TPD | WATER MGD | THERMAL MBTU/D |
| 25 MW Geothermal (Advanced) | Water | - | - | - | - | 1.5 tpy | - | - | - | - |
| 25 MW Geothermal (New) | Water | - | - | - | - | 1.5 tpy | - | - | - | - |
| **Ocean Wave Resources** | | | | | | | | | | |
| Pelamis 750 kW (2016) | Wave | - | - | - | - | - | - | - | - | - |
| Pelamis 15 MW (2020) | Wave | - | - | - | - | - | - | - | - | - |
| **Ocean Thermal Resources** | | | | | | | | | | |
| 10 MW | Ocean | - | - | - | - | - | - | - | - | - |
| **Thermal Plant Resources** | | | | | | | | | | |
| Biomass Combustion (25 MW) | Banagrass | 0.18 | 0.124 | 222 | 0.35 | 0.02 | 0.015 | 15.1 | 1.03 | 94 |
| Biomass Conversion (13 MW) | Eucalyptus | 0.12 | 0.069 | 220 | ** | ** | 0.048 | 4.9 | 0.04‡ | 3 |
| Waste-to-Energy Mass Burn (8 MW) | MSW | 0.22 | 0.02 | 200 | 0.06 | 0.01 | 0.01 | 0.02 | 0.08 | 10 |
| **Fuel Cell Resources** | | | | | | | | | | |
| Phosphoric Acid, 400 kW | Natural Gas | 0.002 | 0 | 109 | 0.002 | 0.002 | 0 | - | - | - |
| **Battery Energy Resources*** | | | | | | | | | | |
| Battery Energy Storage System (BESS) | - | - | - | - | - | - | - | - | - | - |
| Batt. Energy Spinning Reserve (BESR) | - | - | - | - | - | - | - | - | - | - |
| Batt. Energy Freq. Regulation (BEFR) | - | - | - | - | - | - | - | - | - | - |
| **Simple Cycle Resources** | | | | | | | | | | |

| COMMERCIAL RESOURCE OPTIONS | FUEL | FLUE GAS EMISSIONS, LB/MBTU | | | | | | WASTE STREAMS | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | | NITROGEN OXIDES | SULFUR OXIDES | CARBON DIOXIDE | CARBON MONOXIDE | VOLATILE ORGANIC COMP. | PARTICULATE MATTER | SOLID TPD | WATER MGD | THERMAL MBTU/D |
| 1 x 0 Wartsila 18V46 | Biodiesel | 0.40 | 0.027 | 177 | 0.027 | 0.035 | 0.057 | - | 0.00 | 0 |
| 6 x 0 Wartsila 18V46 | Biodiesel | 0.40 | 0.027 | 177 | 0.027 | 0.035 | 0.057 | - | 0.00 | 0 |
| 1 x 0 Wartsila 12V32 | Biodiesel | 0.35 | 0.026 | 177 | 0.047 | 0.068 | 0.058 | - | 0.00 | 0 |
| 1 x 0 GE LM2500 | Biodiesel | 0.01 | 0.0005 | 177 | 0.006 | 0.001 | 0.010 | - | 0.05 | 4 |
| 1 x 0 GE LM6000 PG | Biodiesel | 0.01 | 0.0005 | 177 | 0.002 | 0.001 | 0.006 | - | 0.11 | 10 |
| 1 x 0 GE LMS100 PA | Biodiesel | 0.01 | 0.0005 | 177 | 0.005 | 0.001 | 0.004 | - | 0.10 | 9 |
| 1 x 0 GE LMS100 PA | Natural Gas | 0.01 | 0.0002 | 119 | 0.004 | 0.001 | 0.003 | - | 0.09 | 8 |
| **Combined Cycle Resources** | | | | | | | | | | |
| 2 x 1 GE LM2500 | Biodiesel | 0.01 | 0.0011 | 177 | 0.0063 | 0.0004 | 0.009 | - | 0.16 | 15 |
| 1 x 1 GE LM6000 PG | Biodiesel | 0.01 | 0.0011 | 177 | 0.0016 | 0.001 | 0.005 | - | 0.18 | 17 |
| 1 x 1 GE LM6000 PG | Natural Gas | 0.01 | 0.0004 | 119 | 0.0075 | 0.001 | 0.004 | - | 0.17 | 15 |

*Power for charging of Battery Energy Resources is assumed to come from zero emissions resources.
** Not estimated in the studies performed for this unit.
‡ Wastewater discharge for Biomass Conversion option does not include discharge of once-through cooling water (permitted for Puna Generating Station at a flow rate of 12.0 mgd).

**Table 3-5 Schedule and Resource Requirement Summary**

| COMMERCIAL RESOURCE OPTIONS | AVAILABILITY DATE* | | LEAD TIME MONTHS PRIOR TO COMMERCIAL OPERATION | | | | RESOURCE REQUIREMENTS | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2012 NTP | 2014 NTP | P | E | PR | C | SERVICE LIFE (YEARS) | LAND REQUIRED (ACRES) | FUEL (MBTU/H) | $NO_x$ CONTROL ADDITIVE (TPD) | $SO_2$ CONTROL ADDITIVE (TPD) | PLANT WATER (MGD) | COOLING TOWER MAKEUP (MGD) |
| **Large Turbine Onshore Wind** | | | | | | | | | | | | | |
| 10 MW (Class 7) | 2016 | 2018 | 36 | 24 | 14 | 9 | 20 | 24 | - | - | - | - | - |
| 10 MW (Class 5) | 2016 | 2018 | 36 | 24 | 14 | 9 | 20 | 24 | - | - | - | - | - |
| 10 MW (Class 3) | 2016 | 2018 | 36 | 24 | 14 | 9 | 20 | 24 | - | - | - | - | - |
| 30 MW (Class 3) | 2016 | 2018 | 36 | 24 | 14 | 9 | 20 | 79 | - | - | - | - | - |
| **Small Scale Onshore Wind** | | | | | | | | | | | | | |
| 0.6 MW (Molokai, Class 6) | 2014 | 2016 | 36 | 24 | 14 | 9 | 20 | 0.5 | - | - | - | - | - |
| 0.6 MW (Lanai, Class 6) | 2014 | 2016 | 36 | 24 | 14 | 9 | 20 | 0.5 | - | - | - | - | - |
| 6 MW (Molokai, Class 6) | 2015 | 2017 | 36 | 24 | 14 | 9 | 20 | 24 | - | - | - | - | - |
| 6 MW (Lanai, Class 6) | 2015 | 2017 | 36 | 24 | 14 | 9 | 20 | 24 | - | - | - | - | - |
| **Offshore Wind** | | | | | | | | | | | | | |
| 100 MW (Class 5) | 2020 | 2022 | 48 | 24 | 18 | 12 | 20 | N/A | - | - | - | - | - |
| **Photovoltaic Resources** | | | | | | | | | | | | | |
| 1 MW Single-Axis Tracking | 2014 | 2016 | 10 | 5 | 4 | 2 | 25 | 6.3 | - | - | - | - | - |
| 100 kW Rooftop | 2013 | 2015 | 5 | 3.5 | 2.5 | 1 | 25 | 0.3 | - | - | - | - | - |
| 2 kW Rooftop | 2013 | 2015 | 1.5 | 1 | .75 | .25 | 25 | 0.004 | - | - | - | - | - |
| **Solar Thermal Resources** | | | | | | | | | | | | | |
| 50 MW Parabolic Trough | 2017 | 2019 | 66 | 51 | 36 | 30 | 20 | 328 | - | - | - | 0.26 | 0.23 |

| COMMERCIAL RESOURCE OPTIONS | AVAILABILITY DATE* | | LEAD TIME MONTHS PRIOR TO COMMERCIAL OPERATION | | | | RESOURCE REQUIREMENTS | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2012 NTP | 2014 NTP | P | E | PR | C | SERVICE LIFE (YEARS) | LAND REQUIRED (ACRES) | FUEL (MBTU/H) | $NO_x$ CONTROL ADDITIVE (TPD) | $SO_2$ CONTROL ADDITIVE (TPD) | PLANT WATER (MGD) | COOLING TOWER MAKEUP (MGD) |
| **Geothermal Resources** | | | | | | | | | | | | | |
| 25 MW Geothermal (Advanced) | 2016 | 2018 | 45 | 36 | 30 | 18 | 30 | 25 | - | - | - | - | - |
| 25 MW Geothermal (New) | 2016 | 2018 | 51 | 42 | 30 | 18 | 30 | 25 | - | - | - | - | - |
| **Ocean Wave Resources** | | | | | | | | | | | | | |
| Pelamis 750 kW (2016) | 2016 | 2018 | 46 | 28 | 15 | 6 | 20 | - | - | - | - | - | - |
| Pelamis 15 MW (2020) | 2020 | 2022 | 46 | 28 | 15 | 6 | 20 | - | - | - | - | - | - |
| **Ocean Thermal Resources** | | | | | | | | | | | | | |
| 10 MW | 2018 | 2020 | 45 | 36 | 24 | 12 | 20 | - | - | - | - | - | - |
| **Thermal Plant Resources** | | | | | | | | | | | | | |
| Biomass Combustion (25 MW) | 2018 | 2020 | 79 | 54 | 39 | 36 | 30 | 14 | 373 | 2.6 | - | 1.26 | 0.47 |
| Biomass Conversion (13 MW) | 2018 | 2020 | 64 | 61 | 27 | 27 | 30 | 0 | 243 | 0.4 | - | 12.04 | N/A |
| Waste-to-Energy Mass Burn (8 MW) | 2018 | 2020 | 79 | 54 | 39 | 36 | 30 | 14 | 138 | 0.96 | 6.3 | 0.10 | - |
| **Fuel Cell Resources** | | | | | | | | | | | | | |
| Phosphoric Acid, 400 kW | 2013 | 2015 | 12 | 10 | 6 | 2 | 20 | 0.02 | 3.6 | - | - | 0 | 0 |
| **Battery Energy Resources** | | | | | | | | | | | | | |
| Battery Energy Storage (BESS) | 2013 | 2015 | 17 | 14 | 8 | 3 | 20 | 0.3 | - | - | - | - | - |
| Batt. Energy Spinning | 2013 | 2015 | 17 | 14 | 8 | 3 | 20 | 0.7 | - | - | - | - | - |

| COMMERCIAL RESOURCE OPTIONS | AVAILABILITY DATE* | | LEAD TIME MONTHS PRIOR TO COMMERCIAL OPERATION | | | | RESOURCE REQUIREMENTS | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2012 NTP | 2014 NTP | P | E | PR | C | SERVICE LIFE (YEARS) | LAND REQUIRED (ACRES) | FUEL (MBTU/H) | $NO_X$ CONTROL ADDITIVE (TPD) | $SO_2$ CONTROL ADDITIVE (TPD) | PLANT WATER (MGD) | COOLING TOWER MAKEUP (MGD) |
| Reserve (BESR) | | | | | | | | | | | | | |
| Batt. Energy Freq. Regulation (BEFR) | 2013 | 2015 | 17 | 14 | 8 | 3 | 20 | 0.7 | - | - | - | - | - |
| **Simple Cycle Resources** | | | | | | | | | | | | | |
| 1 x 0 Wartsila 18V46 | 2016 | 2018 | 62 | 26 | 20 | 14 | 30 | 11 | 141 | 0.51 | - | 0.003 | N/A |
| 6 x 0 Wartsila 18V46 | 2017 | 2019 | 68 | 32 | 26 | 20 | 30 | 11 | 846 | 3.06 | - | 0.017 | N/A |
| 1 x 0 Wartsila 12V32 | 2016 | 2018 | 62 | 26 | 20 | 14 | 30 | 4 | 43 | 0.16 | - | 0.002 | N/A |
| 1 x 0 GE LM2500 | 2016 | 2018 | 63 | 27 | 21 | 14 | 30 | 11 | 233 | 0.52 | - | 0.09 | N/A |
| 1 x 0 GE LM6000 PG | 2017 | 2019 | 72 | 36 | 28 | 20 | 30 | 11 | 423 | 0.86 | - | 0.20 | N/A |
| 1 x 0 GE LMS100 PA (Biodiesel) | 2016 | 2018 | 64 | 28 | 22 | 16 | 30 | 11 | 848 | 1.73 | - | 0.18 | N/A |
| 1 x 0 GE LMS100 PA (Natural Gas) | 2016 | 2018 | 64 | 28 | 22 | 16 | 30 | 11 | 877 | 0.93 | - | 0.16 | N/A |
| **Combined Cycle Resources** | | | | | | | | | | | | | |
| 2 x 1 GE LM2500 | 2018 | 2020 | 81 | 45 | 39 | 32 | 30 | 15 | 482 | 1.08 | - | 0.70 | 0.58 |
| 1 x 1 GE LM6000 PG (Biodiesel) | 2018 | 2020 | 78 | 42 | 34 | 26 | 30 | 15 | 449 | 0.99 | - | 0.59 | 0.36 |
| 1 x 1 GE LM6000 PG (Natural Gas) | 2018 | 2020 | 78 | 42 | 34 | 26 | 30 | 15 | 447 | 0.54 | - | 0.56 | 0.36 |

* 2012 Notice to Proceed (NTP) is assumed in the data sheets and forms.

## 3.2 GRID SERVICES

Greater attention was paid by HECO in IRP 2013 to the contribution that the various resources provide to grid electrical stability. As more and more intermittent, nondispatchable renewable energy resources are placed in service (such as solar and wind), the effect that they have on providing key grid stability services becomes more important, especially when traditional steam units that did provide these services are taken off-line. This is a critical factor that must be taken into account in Hawaii since each island grid is independent and must rely on a very limited set of units to provide these services. This is in contrast to most utilities on the mainland, which are tied into much larger electric grids.

Black & Veatch attempted to quantify some of these grid services for each technology evaluated in IRP 2013. This data will be used by HECO in the IRP process to help determine if the level of grid services being provided in the scenarios being run are acceptable. Much like with cost factors, resources chosen may change if the level of grid services provided is unacceptable to stable operation.

The main items reviewed by Black & Veatch and a brief description of each are shown below:

- Low Voltage Ride Through (LVRT): LVRT is the ability of a generator to remain connected to the grid for a specific period of time during a fault on the transmission system. A fault occurs when a power line disconnects from the grid, such as with lightning strikes or tree branch impacts. LVRT is beneficial for preventing many units from going off-line during a fault situation, which could exacerbate the situation. Currently, units connected to the distribution network (such as residential solar PV) do not allow LVRT for safety reasons.
- Ramping Capabilities: Ramping is the ability for generation to supply or reduce its output at a specified rate and in a controlled manner over a defined period of time.
- Droop Response: Droop response is the automatic, proportional control of a generator's output depending on machine speed for synchronous generators, or system frequency for power converters, and is required to stabilize the system in the event of a loss of generation or load. Droop response must occur within 1-second to alter the frequency rate-of-change and effectively stabilize the system.
- Frequency Regulation: Frequency regulation is the ability of a generator to increase or decrease power output to maintain system frequency. To provide frequency regulation, a plant must have energy reserves available to respond to a signal to increase its output in a matter of seconds.
- Voltage Regulation: A generator provides voltage regulation capability if the generator is able to control its excitation to maintain a specified terminal voltage, therefore supplying or absorbing reactive power to and from the system.
- Dispatchable: A dispatchable generator has stored energy that can be used at any time to meet system demand. A dispatchable generator has ramping capabilities that can be called upon to provide power to the grid within a specified time frame (usually 10 to 15 minutes). Dispatchable plants have a constant fuel source and can be relied upon to meet defined output requirements. Conventional generators are on line and peakers are dispatchable resources, since they can respond to a signal sent from the utility to generate power, or increase or decrease output.

- Inertia Constant (H-constant): The H-constant of a generator is defined as the ratio of the stored kinetic energy at rated speed to the rated apparent power of a machine (H= stored kinetic energy in MJ at synchronous speed / machine rating in MVA).
- Startup Time: Startup time is the amount of time it takes for a generator to achieve rated speed and power output from an "out-of-service" state. Generators that have short startup times can provide emergency reserves as opposed to carrying excess reserves online. For units with boilers, a hot start was assumed.

A summary of the main grid stability parameters is shown in Table 3-6.

**Table 3-6 Technology Grid Services Summary**

| TECHNOLOGY | LOW VOLTAGE RIDE THROUGH | RAMPING CAPABILITIES | UNDERFREQUENCY DROOP RESPONSE | OVERFREQUENCY DROOP RESPONSE | FREQUENCY REGULATION | DISPATCHABLE | RAMP RATE | INERTIA CONSTANT | STARTUP TIME |
|---|---|---|---|---|---|---|---|---|---|
| Wind - Onshore - Utility Scale | Yes | Limited | Yes | Yes | No | No | 10%/min. | N/A | <30 min. |
| Wind - Offshore - Utility Scale | Yes | Limited | Yes | Yes | No | No | 10%/min. | N/A | <30 min. |
| Solar PV - Rooftop | No | No | No | No | No | No | - | N/A | N/A |
| Solar PV - Utility Scale | Yes | Very Limited | No | Daylight Only | No | No | 10%/min. | N/A | N/A |
| Solar Thermal Without Storage | Yes | Limited | Daylight Only | Daylight Only | Daylight Only | No | 1-5%/min. | 3-4 MW-s/MVA | 30-60 min. |
| Geothermal | Yes | Yes | Yes | Yes | Yes | Limited | 1-5%/min. | 3-4 MW-s/MVA | 60-600 min. |
| Ocean Wave | Yes | Limited | No | Yes | No | No | 10%/min. | N/A | N/A |
| Ocean Thermal Energy Conversion | Yes | Yes | Yes | Yes | Yes | No | 10%/min. | 1-2 MW-s/MVA | <30 min. |
| Biomass Combustion (Banagrass/Eucalyptus) | Yes | Yes | Yes | Yes | Yes | Yes | 1-5%/min. | 3-4 MW-s/MVA | 120 min. |
| Simple Cycle Peaker or Recip Engine (Biodiesel) | Yes | Yes | Yes | Yes | Yes | Yes | 30-40%/min. | 1.1 - 1.3 MW-s/MVA | 10 min. |
| Combined Cycle (Biodiesel/Natural Gas) | Yes | Yes | Yes | Yes | Yes | Yes | 5%-10%/min. | 3-5 MW-s/MVA | 270 min. |
| Battery Storage (All Types) | Yes | Yes | Yes | Yes | Yes | Yes | 100%< 1 min. | N/A | <1 min. |
| Municipal Solid Waste (Mass Burn) | Yes | Yes | Yes | Yes | Yes | Yes | 1-5%/min. | 3-4 MW-s/MVA | 60 min. |
| Fuel Cell (Phosphoric Acid) | No | Yes | Yes | Yes | Yes | Yes | 100%< 1 min. | N/A | 180-360 min. |

# Consolidated Unit Information Forms (UIFs)

The Hawaiian Electric Companies developed supply-side resource option (SRO) consolidated Unit Information Forms (UIFs) that, except for site-specific modifications, are based on generic site information characteristics to better align with the scenario planning criteria.

These UIFs, with associated comments, follow.

Table A-1
30 MW On-Shore Class 3 Wind Unit Information Form

| | |
|---|---|
| **Utility:** | ***HECO*** |
| **Unit Type:** | ***30 MW Wind Energy - 13 2.3 MW Wind Turbines*** |
| **Fuel Type:** | ***Wind*** |
| **Site:** | ***Unspecified Class 3*** |

## UNIT INFORMATION FORM

## HECO IRP 2013

| | |
|---|---|
| **Date:** | ***February 27, 2013*** |
| **By:** | ***Black & Veatch*** |
| **Supersedes:** | ***February 12, 2013*** |

**Unit Ratings:**[A]

| | | Rated | Avg. Gross | Avg. Net |
|---|---|---|---|---|
| Normal Top Load | MW | 29.9 | 12.8 | 10.7 |
| Energy Production | MWh/yr | 261,924 | 112,353 | 93,365 |

**Ambient Conditions:**

| | | |
|---|---|---|
| Dry Bulb Temperature | F | 77 |
| Relative Humidity | percent | 70 |

**Operating Mode:**

| | | |
|---|---|---|
| Duty Cycle | | Supplemental |
| Capacity Factor | percent | 35.6 |

**Commercial Service:**

| | | | |
|---|---|---|---|
| Date Available | month/year | January | 2016 |
| Service Life | years | | 20 |

**Lead Time (Prior to Commercial Oper):**[B]

| | | Normal | Expedited |
|---|---|---|---|
| Permitting | months | 36 | -- |
| Engineering | months | 24 | -- |
| Procurement | months | 14 | -- |
| Construction | months | 9 | -- |

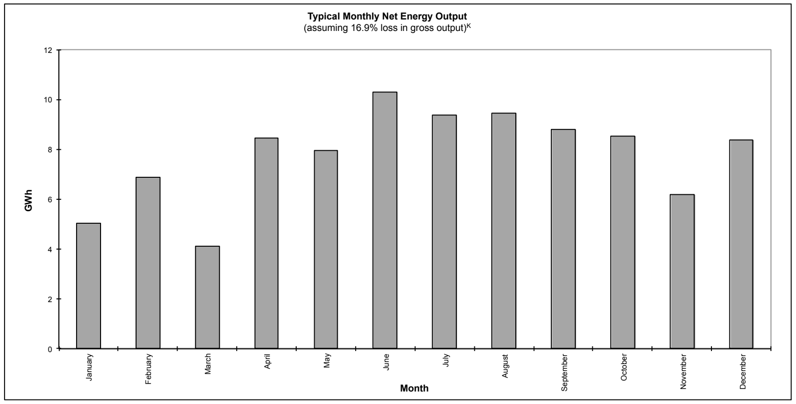
| | | |
|---|---|---|
| **Year Dollars:** | | December 2011 |
| **Capital Cost Uncertainty:** | plus/minus | +20%/-20% |

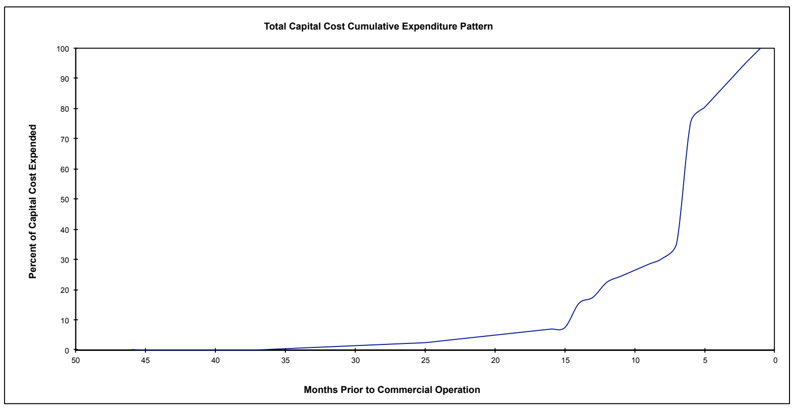
**Capital Cost (w/o AFUDC):**[C]

| | $million | $/kW$_{rated}$ | $/kW$_{net}$ |
|---|---|---|---|
| A. 30 MW Power Block Cost[D] | 93.45 | 3,125 | 8,768 |
| B. Special Siting Costs | - | - | - |
| C. Power Plant Switchyard[E] | 3.95 | 132 | 371 |
| D. T&D Interconnection[F] | 6.20 | 207 | 582 |
| E. Total Direct Cost (A+B+C+D) | 103.60 | 3,465 | 9,720 |
| F. Total Indirect Cost[H] | 11.00 | 368 | 1,032 |
| G. Land Cost[G] | 0.50 | 17 | 47 |
| H. Total Capital Cost (E+F) | 115.10 | 3,849 | 10,799 |

**Operations & Maintenance:**[I]

| | $/y | $/kW-y$_{rated}$ | $/kW-y$_{net}$ |
|---|---|---|---|
| Fixed Cost | 2,377,500 | 79.52 | 223.07 |
| | | $/MWh$_{rated}$ | $/MWh$_{net}$ |
| Variable Cost | 186,730 | 0.71 | 2.00 |
| Land Lease | 858,862 | | |
| Total First Year O&M | 3,423,092 | | |




**Grid Services**[M]

| | | | |
|---|---|---|---|
| Ramping Cap. (MW/min) | 3 | Dispatchable? | No |
| Inertia Constant (MW-s/MVA) | 0 | Voltage Regulation? | Yes |
| Start Time (min) | <30 min | LV Ride Through? | Yes |
| Underfreq. Droop? | Yes | Overfreq. Droop? | Yes |

**General Site/Technology Characteristics:**[J]

| | | |
|---|---|---|
| Average Annual Wind Speed at Hub Height | mph | 16.3 |
| Turbine Spacing Within Rows | feet | 994 |
| Min. Turbine Spacing Between Rows | feet | 2650 |
| Minimal Land Requirement | acres | 79 |
| Generator Type | | Squirrel Cage Induction Generator |

**Energy Losses:**[K]

| | | |
|---|---|---|
| Array | percent | 8.0 |
| Blade Soiling | percent | 1.0 |
| Control & Turbulence | percent | 2.0 |
| Downtime | percent | 5.0 |
| Line Losses | percent | 2.0 |
| Total | percent | 16.9 |

**Availability:**

| | | |
|---|---|---|
| Plant Maintenance Pattern | wk/y | 0-0-1-0-0-1 |
| Average Annual Maintenance | weeks | 0.50 |
| Immaturity Period | weeks | 16 |
| Immature Forced Outage Rate | percent | NA |
| Minimum Weeks Between Maintenance | weeks | 51 |
| Maintenance Requirement | weeks | 1 |
| Mature Forced Outage Rate | percent | 5 |
| Availability Factor | percent | 95 |

**Turbine/Tower Parameters:**

| | | |
|---|---|---|
| Turbine Rating | kW | 2300 |
| Power Factor | | 1 |
| Turbine Design | axis | Horizontal |
| Rotor Diameter | meters | 101 |
| Rotor Design | | Upwind |
| Number of Blades | | 3 |
| Tower Height | meters | 80 |
| Tower Design | | Tubular |

**Power Curve Data:**[L]

| Wind Speed mph | Power Output kW | Wind Speed mph | Power Output kW |
|---|---|---|---|
| 8.9 | 117 | 24.6 | 2257 |
| 11.2 | 267 | 26.8 | 2294 |
| 13.4 | 491 | 29.1 | 2299 |
| 15.7 | 802 | 31.3 | 2300 |
| 17.9 | 1211 | 33.6 | 2300 |
| 20.1 | 1697 | 35.8 | 2300 |
| 22.4 | 2095 | 38.0 | 2300 |

Table A-2
10 MW On-Shore Class 3 Wind Unit Information Form

## UNIT INFORMATION FORM

## HECO IRP 2013

| | |
|---|---|
| **Utility:** | *HECO* |
| **Unit Type:** | *10 MW Wind Energy - 4 2.3 MW Wind Turbines* |
| **Fuel Type:** | *Wind* |
| **Site:** | *Unspecified Class 3* |

| | |
|---|---|
| **Date:** | *March 23, 2013* |
| **By:** | *Black & Veatch* |
| **Supersedes:** | *February 27, 2013* |

**Unit Ratings:**[A]

| | | Rated | Avg. Gross | Avg. Net |
|---|---|---|---|---|
| Normal Top Load | MW | 9.2 | 3.9 | 3.3 |
| Energy Production | MWh/yr | 80,592 | 34,570 | 28,728 |

**Ambient Conditions:**

| | | |
|---|---|---|
| Dry Bulb Temperature | F | 77 |
| Relative Humidity | percent | 70 |

**Operating Mode:**

| | | |
|---|---|---|
| Duty Cycle | | Supplemental |
| Capacity Factor | percent | 35.6 |

**Commercial Service:**

| | | | |
|---|---|---|---|
| Date Available | month/year | January | 2016 |
| Service Life | years | | 20 |

**Lead Time (Prior to Commercial Oper):**[B]

| | | Normal | Expedited |
|---|---|---|---|
| Permitting | months | 36 | -- |
| Engineering | months | 24 | -- |
| Procurement | months | 14 | -- |
| Construction | months | 9 | -- |

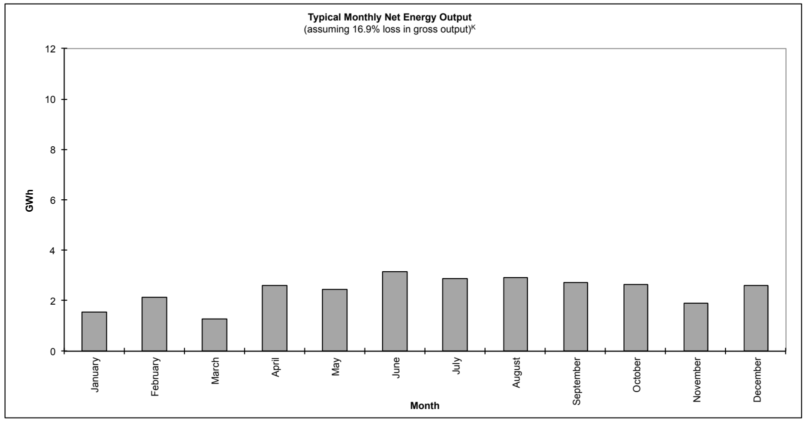
| | | |
|---|---|---|
| **Year Dollars:** | | December 2011 |
| **Capital Cost Uncertainty:** | plus/minus | +20%/-20% |

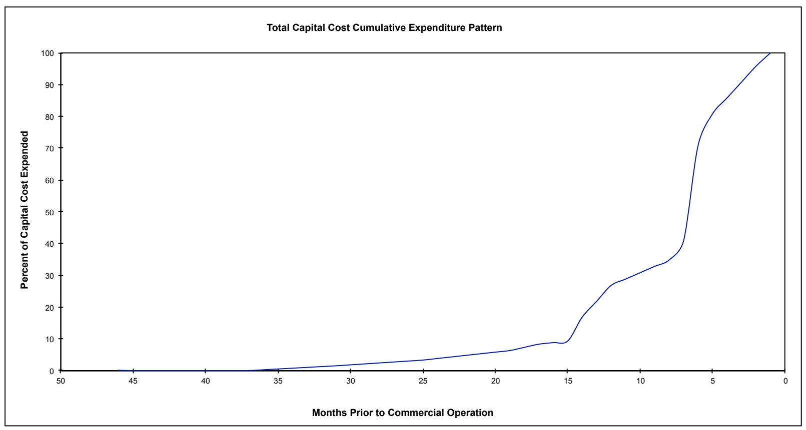
**Capital Cost (w/o AFUDC):**[C]

| | $million | $/kW$_{rated}$ | $/kW$_{net}$ |
|---|---|---|---|
| A. 10 MW Power Block Cost[D] | 32.92 | 3,578 | 10,038 |
| B. Special Siting Costs | - | - | - |
| C. Power Plant Switchyard[E] | 2.75 | 299 | 839 |
| D. T&D Interconnection[F] | 3.50 | 380 | 1,067 |
| E. Total Direct Cost (A+B+C+D) | 39.17 | 4,258 | 11,944 |
| F. Total Indirect Cost[H] | 5.17 | 562 | 1,577 |
| G. Land Cost[G] | 0.50 | 54 | 152 |
| H. Total Capital Cost (E+F) | 44.84 | 4,874 | 13,673 |

**Operations & Maintenance:**[I]

| | $/y | $/kW-y$_{rated}$ | $/kW-y$_{net}$ |
|---|---|---|---|
| Fixed Cost | 870,000 | 94.57 | 265.29 |
| | | $/MWh$_{rated}$ | $/MWh$_{net}$ |
| Variable Cost | 57,456 | 0.71 | 2.00 |
| Land Lease | 264,433 | | |
| Total First Year O&M | 1,191,889 | | |




**Grid Services**[M]

| | | | |
|---|---|---|---|
| Ramping Cap. (MW/min) | 1 | Dispatchable? | No |
| Inertia Constant (MW-s/MVA) | 0 | Voltage Regulation? | Yes |
| Start Time (min) | <30 min | LV Ride Through? | Yes |
| Underfreq. Droop? | Yes | Overfreq. Droop? | Yes |

**General Site/Technology Characteristics:**[J]

| | | |
|---|---|---|
| Average Annual Wind Speed at Hub Height | mph | 16.3 |
| Turbine Spacing Within Rows | feet | 994 |
| Min. Turbine Spacing Between Rows | feet | 2650 |
| Minimal Land Requirement | acres | 24 |
| Generator Type | | Squirrel Cage Induction Generator |

**Energy Losses:**[K]

| | | |
|---|---|---|
| Array | percent | 8.0 |
| Blade Soiling | percent | 1.0 |
| Control & Turbulence | percent | 2.0 |
| Downtime | percent | 5.0 |
| Line Losses | percent | 2.0 |
| Total | percent | 16.9 |

**Availability:**

| | | |
|---|---|---|
| Plant Maintenance Pattern | wk/y | 0-0-1-0-0-1 |
| Average Annual Maintenance | weeks | 0.50 |
| Immaturity Period | weeks | 16 |
| Immature Forced Outage Rate | percent | N/A |
| Minimum Weeks Between Maintenance | weeks | 51 |
| Maintenance Requirement | weeks | 1 |
| Mature Forced Outage Rate | percent | 5 |
| Availability Factor | percent | 95 |

**Turbine/Tower Parameters:**

| | | |
|---|---|---|
| Turbine Rating | kW | 2300 |
| Power Factor | | 1 |
| Turbine Design | axis | Horizontal |
| Rotor Diameter | meters | 101 |
| Rotor Design | | Upwind |
| Number of Blades | | 3 |
| Tower Height | meters | 80 |
| Tower Design | | Tubular |

**Power Curve Data:**[L]

| Wind Speed mph | Power Output kW | Wind Speed mph | Power Output kW |
|---|---|---|---|
| 8.9 | 117 | 24.6 | 2257 |
| 11.2 | 267 | 26.8 | 2294 |
| 13.4 | 491 | 29.1 | 2299 |
| 15.7 | 802 | 31.3 | 2300 |
| 17.9 | 1211 | 33.6 | 2300 |
| 20.1 | 1697 | 35.8 | 2300 |
| 22.4 | 2095 | 38.0 | 2300 |

Table A-3
10 MW On-Shore Class 5 Wind Unit Information Form

| | |
|---|---|
| **Utility:** | *HECO* |
| **Unit Type:** | *10 MW Wind Energy - 4 2.3 MW Wind Turbines* |
| **Fuel Type:** | *Wind* |
| **Site:** | *Unspecified Class 5* |

## UNIT INFORMATION FORM

## HECO IRP 2013

| | |
|---|---|
| **Date:** | *February 27, 2013* |
| **By:** | *Black & Veatch* |
| **Supersedes:** | *February 12, 2013* |

**Unit Ratings:**[A]

| | | Rated | Avg. Gross | Avg. Net |
|---|---|---|---|---|
| Normal Top Load | MW | **9.2** | **4.6** | **3.8** |
| Energy Production | MWh/yr | **80,592** | **40,109** | **33,331** |

**Ambient Conditions:**

| | | |
|---|---|---|
| Dry Bulb Temperature | F | **77** |
| Relative Humidity | percent | **70** |

**Operating Mode:**

| | | |
|---|---|---|
| Duty Cycle | | **Supplemental** |
| Capacity Factor | percent | **41.4** |

**Commercial Service:**

| | | | |
|---|---|---|---|
| Date Available | month/year | **January** | **2016** |
| Service Life | years | | **20** |

**Lead Time (Prior to Commercial Oper):**[B]

| | | Normal | Expedited |
|---|---|---|---|
| Permitting | months | **36** | **--** |
| Engineering | months | **24** | **--** |
| Procurement | months | **14** | **--** |
| Construction | months | **9** | **--** |

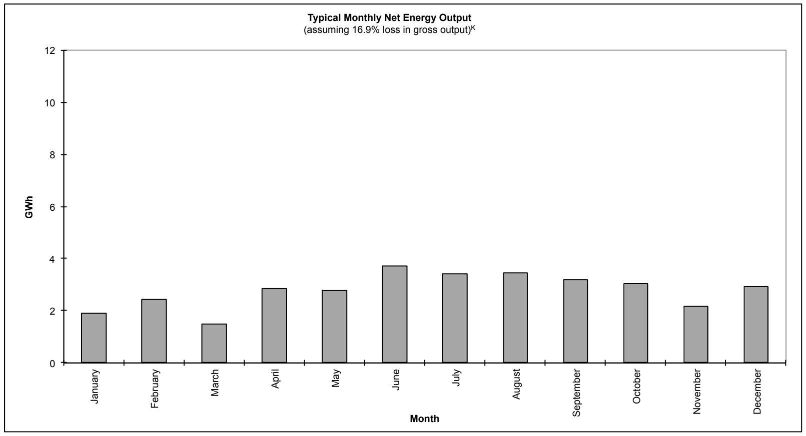
| | | |
|---|---|---|
| **Year Dollars:** | | **December 2011** |
| **Capital Cost Uncertainty:** | plus/minus | **+20%/-20%** |

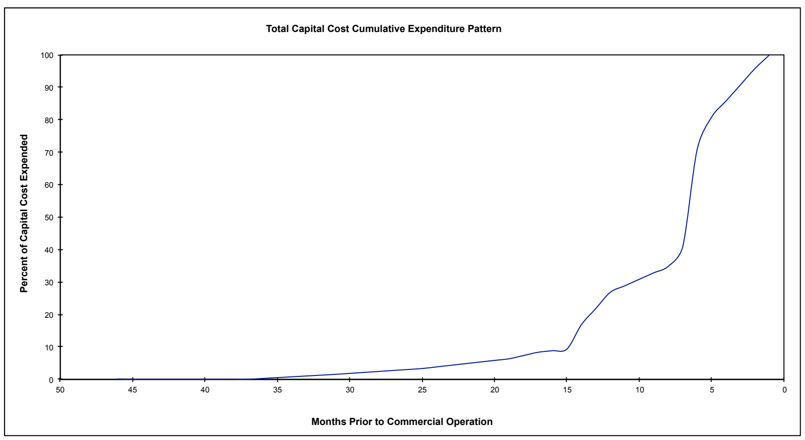
**Capital Cost (w/o AFUDC):**[C]

| | \$million | \$/kW$_{rated}$ | \$/kW$_{net}$ |
|---|---|---|---|
| A. 10 MW Power Block Cost[D] | 32.92 | 3,578 | 8,652 |
| B. Special Siting Costs | - | - | - |
| C. Power Plant Switchyard[E] | 2.75 | 299 | 723 |
| D. T&D Interconnection[F] | 3.50 | 380 | 920 |
| E. Total Direct Cost (A+B+C+D) | 39.17 | 4,258 | 10,295 |
| F. Total Indirect Cost[H] | 5.17 | 562 | 1,359 |
| G. Land Cost[G] | 0.50 | 54 | 131 |
| H. Total Capital Cost (E+F) | 44.84 | 4,874 | 11,785 |

**Operations & Maintenance:**[I]

| | \$/y | \$/kW-y$_{rated}$ | \$/kW-y$_{net}$ |
|---|---|---|---|
| Fixed Cost | **870,000** | **94.57** | **228.65** |
| | | \$/MWh$_{rated}$ | \$/MWh$_{net}$ |
| Variable Cost | **66,662** | **0.83** | **2.00** |
| Land Lease | **264,433** | | |
| Total First Year O&M | **1,201,095** | | |




**Grid Services**[M]

| | | | |
|---|---|---|---|
| Ramping Cap. (MW/min) | **1** | Dispatchable? | **No** |
| Inertia Constant (MW-s/MVA) | **0** | Voltage Regulation? | **Yes** |
| Start Time (min) | **<30 min** | LV Ride Through? | **Yes** |
| Underfreq. Droop? | **Yes** | Overfreq. Droop? | **Yes** |

**General Site/Technology Characteristics:**[J]

| | | |
|---|---|---|
| Average Annual Wind Speed at Hub Height | mph | **18.2** |
| Turbine Spacing Within Rows | feet | **994** |
| Min. Turbine Spacing Between Rows | feet | **2650** |
| Minimal Land Requirement | acres | **24** |
| Generator Type | | **Squirrel Cage Induction Generator** |

**Energy Losses:**[K]

| | | |
|---|---|---|
| Array | percent | **8.0** |
| Blade Soiling | percent | **1.0** |
| Control & Turbulence | percent | **2.0** |
| Downtime | percent | **5.0** |
| Line Losses | percent | **2.0** |
| Total | percent | **16.9** |

**Availability:**

| | | |
|---|---|---|
| Plant Maintenance Pattern | wk/y | **0-0-1-0-0-1** |
| Average Annual Maintenance | weeks | **0.50** |
| Immaturity Period | weeks | **16** |
| Immature Forced Outage Rate | percent | **N/A** |
| Minimum Weeks Between Maintenance | weeks | **51** |
| Maintenance Requirement | weeks | **1** |
| Mature Forced Outage Rate | percent | **5** |
| Availability Factor | percent | **95** |

**Turbine/Tower Parameters:**

| | | |
|---|---|---|
| Turbine Rating | kW | **2300** |
| Power Factor | | **1** |
| Turbine Design | axis | **Horizontal** |
| Rotor Diameter | meters | **101** |
| Rotor Design | | **Upwind** |
| Number of Blades | | **3** |
| Tower Height | meters | **80** |
| Tower Design | | **Tubular** |

**Power Curve Data:**[L]

| Wind Speed mph | Power Output kW | Wind Speed mph | Power Output kW |
|---|---|---|---|
| **8.9** | **117** | **24.6** | **2257** |
| **11.2** | **267** | **26.8** | **2294** |
| **13.4** | **491** | **29.1** | **2299** |
| **15.7** | **802** | **31.3** | **2300** |
| **17.9** | **1211** | **33.6** | **2300** |
| **20.1** | **1697** | **35.8** | **2300** |
| **22.4** | **2095** | **38.0** | **2300** |

Table A-4
10 MW On-Shore Class 7 Wind Unit Information Form

| | |
|---|---|
| **Utility:** | *HECO* |
| **Unit Type:** | *10 MW Wind Energy - 4 2.3 MW Wind Turbines* |
| **Fuel Type:** | *Wind* |
| **Site:** | *Unspecified Class 7* |

**UNIT INFORMATION FORM**

**HECO IRP 2013**

| | |
|---|---|
| **Date:** | *March 22, 2013* |
| **By:** | *Black & Veatch* |
| **Supersedes:** | *February 27, 2013* |

**Unit Ratings:**[A]

| | Units | Rated | Avg. Gross | Avg. Net |
|---|---|---|---|---|
| Normal Top Load | MW | 9.2 | 6.3 | 5.2 |
| Energy Production | MWh/yr | 80,592 | 55,073 | 45,308 |

**Ambient Conditions:**

| | | |
|---|---|---|
| Dry Bulb Temperature | F | 77 |
| Relative Humidity | percent | 70 |

**Operating Mode:**

| | | |
|---|---|---|
| Duty Cycle | | Supplemental |
| Capacity Factor | percent | 56.2 |

**Commercial Service:**

| | | | |
|---|---|---|---|
| Date Available | month/year | January | 2016 |
| Service Life | years | | 20 |

**Lead Time (Prior to Commercial Oper):**[B]

| | | Normal | Expedited |
|---|---|---|---|
| Permitting | months | 36 | -- |
| Engineering | months | 24 | -- |
| Procurement | months | 14 | -- |
| Construction | months | 9 | -- |

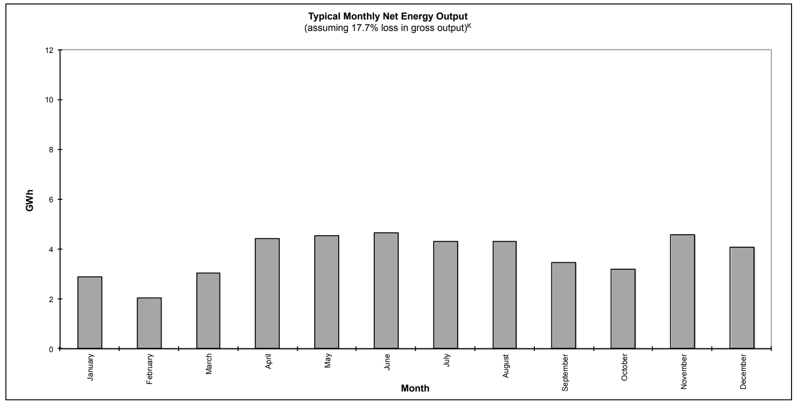
| | | |
|---|---|---|
| **Year Dollars:** | | December 2011 |
| **Capital Cost Uncertainty:** | plus/minus | +20%/-20% |

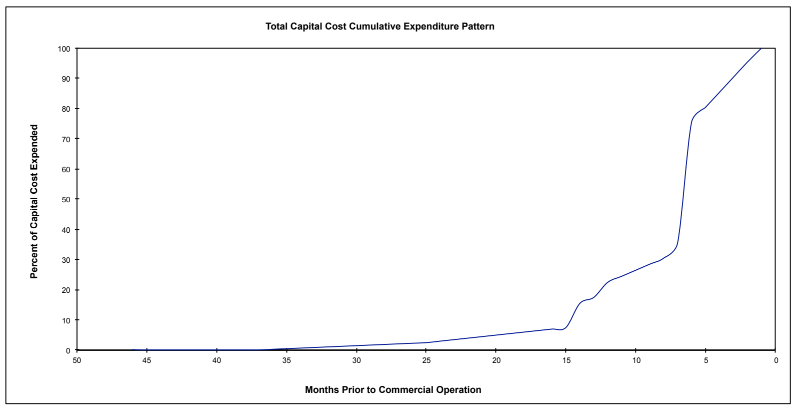
**Capital Cost (w/o AFUDC):**[C]

| | $million | $/kW$_{rated}$ | $/kW$_{net}$ |
|---|---|---|---|
| A. 10 MW Power Block Cost[D] | 32.92 | 3,578 | 6,365 |
| B. Special Siting Costs | - | - | - |
| C. Power Plant Switchyard[E] | 2.75 | 299 | 532 |
| D. T&D Interconnection[F] | 3.50 | 380 | 677 |
| E. Total Direct Cost (A+B+C+D) | 39.17 | 4,258 | 7,573 |
| F. Total Indirect Cost[H] | 5.17 | 562 | 1,000 |
| G. Land Cost[G] | 0.50 | 54 | 97 |
| H. Total Capital Cost (E+F) | 44.84 | 4,874 | 8,670 |

**Operations & Maintenance:**[I]

| | $/y | $/kW-y$_{rated}$ | $/kW-y$_{net}$ |
|---|---|---|---|
| Fixed Cost | 870,000 | 94.57 | 168.21 |
| | | $/MWh$_{rated}$ | $/MWh$_{net}$ |
| Variable Cost | 90,615 | 1.12 | 2.00 |
| Land Lease | 264,433 | | |
| Total First Year O&M | 1,225,048 | | |




**Grid Services**[M]

| | | | |
|---|---|---|---|
| Ramping Cap. (MW/min) | 1 | Dispatchable? | No |
| Inertia Constant (MW-s/MVA) | 0 | Voltage Regulation? | Yes |
| Start Time (min) | <30 min | LV Ride Through? | Yes |
| Underfreq. Droop? | Yes | Overfreq. Droop? | Yes |

**General Site/Technology Characteristics:**[J]

| | | |
|---|---|---|
| Average Annual Wind Speed at Hub Heightity | mph | 21.4 |
| Turbine Spacing Within Rows | feet | 994 |
| Min. Turbine Spacing Between Rows | feet | 2650 |
| Minimal Land Requirement | acres | 24 |
| Generator Type | | Squirrel Cage Induction Generator |

**Energy Losses:**[K]

| | | |
|---|---|---|
| Array | percent | 8.0 |
| Hysteresis | percent | 1.0 |
| Blade Soiling | percent | 1.0 |
| Control & Turbulence | percent | 2.0 |
| Downtime | percent | 5.0 |
| Line Losses | percent | 2.0 |
| Total | percent | 17.7 |

**Availability:**

| | | |
|---|---|---|
| Plant Maintenance Pattern | wk/y | 0-0-1-0-0-1 |
| Average Annual Maintenance | weeks | 0.50 |
| Immaturity Period | weeks | 16 |
| Immature Forced Outage Rate | percent | N/A |
| Minimum Weeks Between Maintenance | weeks | 51 |
| Maintenance Requirement | weeks | 1 |
| Mature Forced Outage Rate | percent | 5 |
| Availability Factor | percent | 95 |

**Turbine/Tower Parameters:**

| | | |
|---|---|---|
| Turbine Rating | kW | 2300 |
| Power Factor | | 1 |
| Turbine Design | axis | Horizontal |
| Rotor Diameter | meters | 101 |
| Rotor Design | | Upwind |
| Number of Blades | | 3 |
| Tower Height | meters | 80 |
| Tower Design | | Tubular |

**Power Curve Data:**[L]

| Wind Speed mph | Power Output kW | Wind Speed mph | Power Output kW |
|---|---|---|---|
| 8.9 | 117 | 24.6 | 2257 |
| 11.2 | 267 | 26.8 | 2294 |
| 13.4 | 491 | 29.1 | 2299 |
| 15.7 | 802 | 31.3 | 2300 |
| 17.9 | 1211 | 33.6 | 2300 |
| 20.1 | 1697 | 35.8 | 2300 |
| 22.4 | 2095 | 38.0 | 2300 |

### HECO IRP 2013 UIF Notes: Class 3 30 MW

Notes: (A) Unit ratings and energy production are based as follows:
Rated capacity at 2300 kW/turbine (Siemens SWT-2.3-101)
and 13 turbines.
Gross capacity based on April 2004 to March 2005 wind data
and turbine power curve. Avg. capacity information based in gross
capacity and assumed losses for the project site.
(B) Lead time for permitting assumes 36 months to
allow time for studies, monitoring, and community
outreach.
(C) Capital costs based on Black & Veatch database of
project cost data. Costs adjusted from mainland estimates to
develop Hawaii specific data. HI premium is roughly 25%.

(D) Values based on Black & Veatch internal cost database including recent WTG price data,
mainland US ridgetop project cost estimates, known Hawaii wind project cost data for 20 to 30 MW
projects. Costs adjusted for HI specific shipping, labor, taxes, and commodity values.
Power Block costs include:

| | | | |
|---|---|---|---|
| Civil/Structural Works = | $18,437,427 | Turbines and Transport = | $55,704,967 |
| Electrical Collection = | $19,312,427 | | |

(E) Switchyard cost based on 30MW design and is based on similar sized project in Maui.
(F) T&D Interconnection based on 30MW design and is based on similar sized project in Maui.
(G) Assumed 2 acres purchased for O&M facility and substation. All
other land for project leased from landowner (assumed as an O&M cost) .
(H) Indirects include construction mobilization/demobilization, security, health & safety,
site clean-up and support staff. Engineering and Construction Mgmt. included
under the Indirect Costs.
(I) Operations and maintenance costs based on 4 full-time equivalent staff,
necessary parts and materials for O&M, land lease, and warranty service.
Direct labor costs are fixed, which somewhat skew fixed/variable breakdown.
Variable costs for unscheduled maintenance and consumables.

Land lease costs are based on the assumption that only 10% of the net
acreage for the project is needed, since much of the land is not disturbed and can
be used for other purposes. Lease cost = $10,927/acre/year.
(J) Avg. wind speed at 80 meters in 2004 - 2005. Land requirement estimates
are only for the estimate of actual disturbed land (10% of net area)
(K) Total = 1-[(1-Loss1)(1-Loss2).......]
(L) Siemens SWT-2.3-101 Wind Turbine at sea level with 101m blade diameter
Cut-in wind speed = 9 mph and cut-out wind speed = 56 mph
(M) Ramping-up rates can be set within certain technology specific parameters using
control devices and SCADA. Requires intermittent resources to be set below
maximum output. Ramping-down cannot be easily controlled due to lack of resource
control; loss of resource will lead to loss of ramp-down capability. Some droop
response possible with proper controls in under and overfrequency situations.
Reactive capability can be achieved through inverters or converters and SCADA.

### HECO IRP 2013 UIF Notes: Class 3 10 MW

Notes: (A) Unit ratings and energy production are based as follows:
Rated capacity at 2300 kW/turbine (Siemens SWT-2.3-101)
and 4 turbines.
Gross capacity based on April 2004 to March 2005 wind data
and turbine power curve. Avg. capacity information based in gross
capacity and assumed losses for the project site.
(B) Lead time for permitting assumes 36 months to
allow time for studies, monitoring, and community
outreach.
(C) Capital costs based on Black & Veatch database of
project cost data. Costs adjusted from mainland estimates to
develop Hawaii specific data. HI premium is roughly 25%.

(D) Values based on Black & Veatch internal cost database including recent WTG price data,
mainland US ridgetop project cost estimates, known Hawaii wind project cost data for 20 to 30 MW
projects. Costs adjusted for HI specific shipping, labor, taxes, and commodity values.
Power Block costs include:

| | | | |
|---|---|---|---|
| Civil/Structural Works = | $7,665,311 | Turbines and Transport = | $17,669,213 |
| Electrical Collection = | $7,586,751 | | |

(E) Switchyard cost based on new 10MW design.
(F) T&D Interconnection based on new 10MW design.
(G) Assumed 2 acres purchased for O&M facility and substation. All
other land for project leased from landowner (assumed as an O&M cost) .
(H) Indirects include construction mobilization/demobilization, security, health & safety,
site clean-up and support staff. Engineering and Const. Mgmt. included
under the Indirect Costs.
(I) Operations and maintenance costs based on 2 full-time equivalent staff,
necessary parts and materials for O&M, land lease, and warranty service.
Direct labor costs are fixed, which somewhat skew fixed/variable breakdown.
Variable costs for unscheduled maintenance and consumables.

Land lease costs are based on the assumption that only 10% of the net
acreage for the project is needed, since much of the land is not disturbed and can
be used for other purposes. Lease cost = $10,927/acre/year.
(J) Avg. wind speed at 80 meters in 2004 - 2005. Land requirement estimates
are only for the estimate of actual disturbed land (10% of net area)
(K) Total = 1-[(1-Loss1)(1-Loss2).......]
(L) Siemens SWT-2.3-101 Wind Turbine at sea level with 101m blade diameter
Cut-in wind speed = 9 mph and cut-out wind speed = 56 mph
(M) Ramping-up rates can be set within certain technology specific parameters using
control devices and SCADA. Requires intermittent resources to be set below
maximum output. Ramping-down cannot be easily controlled due to lack of resource
control; loss of resource will lead to loss of ramp-down capability. Some droop
response possible with proper controls in under and overfrequency situations.
Reactive capability can be achieved through inverters or converters and SCADA.

### HECO IRP 2013 UIF Notes: Class 5 10 MW

Notes: (A) Unit ratings and energy production are based as follows:
Rated capacity at 2300 kW/turbine (Siemens SWT-2.3-101)
and 4 turbines.
Gross capacity based on April 2004 to March 2005 wind data
and turbine power curve. Avg. capacity information based in gross
capacity and assumed losses for the project site.
(B) Lead time for permitting assumes 36 months to
allow time for studies, monitoring, and community
outreach.
(C) Capital costs based on Black & Veatch database of
project cost data. Costs adjusted from mainland estimates to
develop Hawaii specific data. HI premium is roughly 25%.

(D) Values based on Black & Veatch internal cost database including recent WTG price data,
mainland US ridgetop project cost estimates, known Hawaii wind project cost data for 20 to 30 MW
projects. Costs adjusted for HI specific shipping, labor, taxes, and commodity values.
Power Block costs include:

| | | | |
|---|---|---|---|
| Civil/Structural Works = | $7,665,311 | Turbines and Transport = | $17,669,213 |
| Electrical Collection = | $7,586,751 | | |

(E) Switchyard cost based on new 10MW design.
(F) T&D Interconnection based on new 10MW design.
(G) Assumed 2 acres purchased for O&M facility and substation. All
other land for project leased from landowner (assumed as an O&M cost) .
(H) Indirects include construction mobilization/demobilization, security, health & safety,
site clean-up and support staff. Engineering and Const. Mgmt. included

Land lease costs are based on the assumption that only 10% of the net
acreage for the project is needed, since much of the land is not disturbed and can
be used for other purposes. Lease cost = $10,927/acre/year.
(J) Avg. wind speed at 80 meters in 2004 - 2005. Land requirement estimates
are only for the estimate of actual disturbed land (10% of net area)
(K) Total = 1-[(1-Loss1)(1-Loss2).......]
(L) Siemens SWT-2.3-101 Wind Turbine at sea level with 101m blade diameter
Cut-in wind speed = 9 mph and cut-out wind speed = 56 mph
(M) Ramping-up rates can be set within certain technology specific parameters using
control devices and SCADA. Requires intermittent resources to be set below
maximum output. Ramping-down cannot be easily controlled due to lack of resource
control; loss of resource will lead to loss of ramp-down capability. Some droop

under the Indirect Costs.
(I) Operations and maintenance costs based on 2 full-time equivalent staff, necessary parts and materials for O&M, land lease, and warranty service. Direct labor costs are fixed, which somewhat skew fixed/variable breakdown. Variable costs for unscheduled maintenance and consumables.

response possible with proper controls in under and overfrequency situations. Reactive capability can be achieved through inverters or converters and SCADA.

*HECO IRP 2013 UIF Notes: Class 7 10 MW*

Notes: (A) Unit ratings and energy production are based as follows:
Rated capacity at 2300 kW/turbine (Siemens SWT-2.3-101) and 4 turbines.
Gross capacity based on November 1993 to December 1994 wind data and turbine power curve. Avg. capacity information based in gross capacity and assumed losses for the project site.
(B) Lead time for permitting assumes 36 months to allow time for studies, monitoring, and community outreach.
(C) Capital costs based on Black & Veatch database of project cost data. Costs adjusted from mainland estimates to develop Hawaii specific data. HI premium is roughly 25%.

(D) Values based on Black & Veatch internal cost database including recent WTG price data, mainland US ridgetop project cost estimates, known Hawaii wind project cost data for 20 to 30 MW projects. Costs adjusted for HI specific shipping, labor, taxes, and commodity values.
Power Block costs include:

| | | | |
|---|---|---|---|
| Civil/Structural Works = | $7,665,311 | Turbines and Transport = | $17,669,213 |
| Electrical Collection = | $7,586,751 | | |

(E) Switchyard cost based on new 10MW design.
(F) T&D Interconnection based on new 10MW design.
(G) Assumed 2 acres purchased for O&M facility and substation. All other land for project leased from landowner (assumed as an O&M cost) .
(H) Indirects include construction mobilization/demobilization, security, health & safety, site clean-up and support staff. Engineering and Const. Mgmt. included under the Indirect Costs.
(I) Operations and maintenance costs based on 2 full-time equivalent staff, necessary parts and materials for O&M, land lease, and warranty service. Direct labor costs are fixed, which somewhat skew fixed/variable breakdown. Variable costs for unscheduled maintenance and consumables.

Land lease costs are based on the assumption that only 10% of the net acreage for the project is needed, since much of the land is not disturbed and can be used for other purposes. Lease cost = $10,927/acre/year.
(J) Avg. wind speed at 80 meters in 1993 - 1994. Land requirement estimates are only for the estimate of actual disturbed land (10% of net area)
(K) Total = 1-[(1-Loss1)(1-Loss2).......]. Lower wake losses expected versus other wind classes. Hysteresis losses due to expected high wind cut-out and lag to restart.
(L) Siemens SWT-2.3-101 Wind Turbine at sea level with 101m blade diameter
Cut-in wind speed = 9 mph and cut-out wind speed = 56 mph
(M) Ramping-up rates can be set within certain technology specific parameters using control devices and SCADA. Requires intermittent resources to be set below maximum output. Ramping-down cannot be easily controlled due to lack of resource control; loss of resource will lead to loss of ramp-down capability. Some droop response possible with proper controls in under and overfrequency situations. Reactive capability can be achieved through inverters or converters and SCADA.

Table A-5
100 MW Off-shore Wind Class 5 Unit Information Form

| | |
|---|---|
| Utility: | *HECO* |
| Unit Type: | *100 MW Wind Energy - 28 3.6 MW Wind Turbines* |
| Fuel Type: | *Wind* |
| Site: | *Undefined Class 5* |

**UNIT INFORMATION FORM**

**HECO IRP 2013**

| | |
|---|---|
| Date: | *February 27, 2013* |
| By: | *Black & Veatch* |
| Supersedes: | *February 12, 2013* |

**Unit Ratings:[A]**

| | | Rated | Avg. Gross | Avg. Net |
|---|---|---|---|---|
| Normal Top Load | MW | 100.8 | 42.0 | 34.2 |
| Energy Production | MWh/yr | 883,008 | 368,262 | 299,671 |

**Ambient Conditions:**

| | | |
|---|---|---|
| Dry Bulb Temperature | F | 77 |
| Relative Humidity | percent | 70 |

**Operating Mode:**

| | | |
|---|---|---|
| Duty Cycle | | Supplemental |
| Capacity Factor | percent | 33.9 |

**Commercial Service:**

| | | |
|---|---|---|
| Date Available | month/year | January 2020 |
| Service Life | years | 20 |

**Lead Time (Prior to Commercial Oper):[B]**

| | | |
|---|---|---|
| Permitting | months | 48 |
| Engineering | months | 24 |
| Procurement | months | 18 |
| Construction | months | 12 |

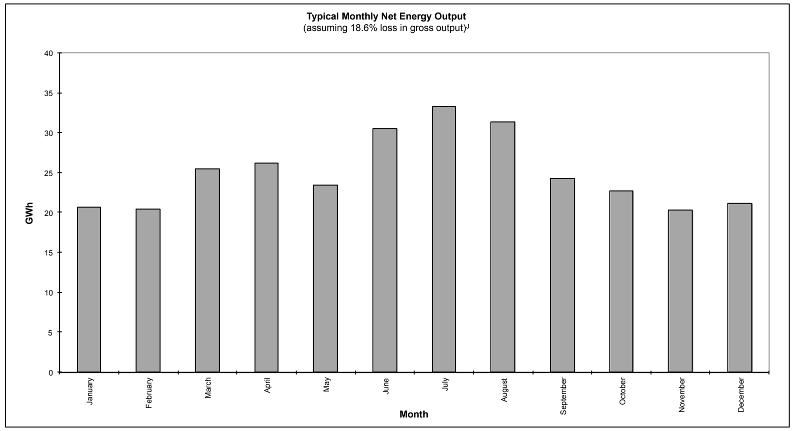
| | | |
|---|---|---|
| **Year Dollars:** | | December 2011 |
| **Capital Cost Uncertainty:** | plus/minus | +50%/-50% |

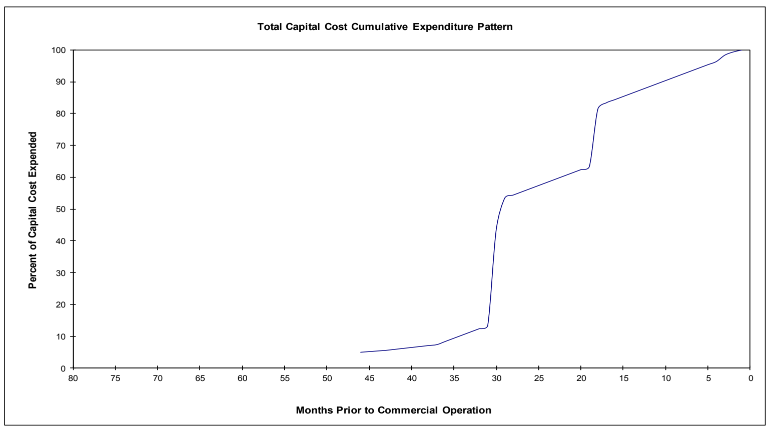
**Capital Cost (w/o AFUDC):[C]**

| | $million | $\$/\text{kW}_{\text{rated}}$ | $\$/\text{kW}_{\text{net}}$ |
|---|---|---|---|
| A1. 30 MW Power Block Cost[D] | 818.80 | 8,123 | 23,935 |
| B. Special Siting Costs | - | - | - |
| C. Power Plant Switchyard[E] | 29.80 | 296 | 871 |
| D. T&D Interconnection[F] | 10.00 | 99 | 292 |
| E. Total Direct Cost (A+B+C+D) | 858.60 | 8,518 | 25,099 |
| F. Total Indirect Cost[H] | 137.00 | 1,359 | 4,005 |
| G. Land Cost[G] | 0.50 | 5 | 15 |
| H. Total Capital Cost (E+F) | 996.10 | 9,882 | 29,118 |

**Operations & Maintenance:[I]**

| | $/y | $\$/\text{kW-y}_{\text{rated}}$ | $\$/\text{kW-y}_{\text{net}}$ |
|---|---|---|---|
| Fixed Cost | 8,220,000 | 81.55 | 240.29 |
| | | $\$/\text{MWh}_{\text{rated}}$ | $\$/\text{MWh}_{\text{net}}$ |
| Variable Cost | 599,342 | 0.68 | 2.00 |
| Land Lease | 932,659 | | |
| Total First Year O&M | 9,752,001 | | |




**Grid Services[N]**

| | | | |
|---|---|---|---|
| Ramping Cap. (MW/min) | 10 | Dispatchable? | No |
| Inertia Constant (MW-s/MVA) | 0 | Voltage Regulation? | Yes |
| Start Time (min) | <30 min | LV Ride Through? | Yes |
| Underfreq. Droop? | Yes | Overfreq. Droop? | Yes |

**General Site/Technology Characteristics:[K]**

| | | |
|---|---|---|
| Average Annual Wind Speed at Hub Height | mph | 18.5 |
| Turbine Spacing Within Rows | feet | 2457 |
| Min. Turbine Spacing Between Rows | feet | 3510 |
| Distance from Shore | miles | 5 |
| Water Depth | feet | >200 |
| Generator Type | | Squirrel Cage Induction Generator |

**Energy Losses:[L]**

| | | |
|---|---|---|
| Array | percent | 8.0 |
| Blade Soiling | percent | 1.5 |
| Control & Turbulence | percent | 2.0 |
| Downtime | percent | 6.5 |
| Line Losses | percent | 2.0 |
| Total | percent | 18.6 |

**Availability:**

| | | |
|---|---|---|
| Average Annual Maintenance | weeks | 2.00 |
| Immaturity Period | weeks | 26 |
| Immature Forced Outage Rate | percent | N/A |
| Minimum Weeks Between Maintenance | weeks | 50 |
| Maintenance Requirement | weeks | 2 |
| Mature Forced Outage Rate | percent | 10 |
| Availability Factor | percent | 90 |

**Turbine/Tower Parameters:**

| | | |
|---|---|---|
| Turbine Rating | kW | 3600 |
| Power Factor | | 1 |
| Turbine Design | axis | Horizontal |
| Rotor Diameter | meters | 107 |
| Rotor Design | | Upwind |
| Number of Blades | | 3 |
| Tower Height | meters | 90 |
| Tower Design | | Tubular |

**Power Curve Data:[M]**

| Wind Speed m/s | Power Output kW | Wind Speed m/s | Power Output kW |
|---|---|---|---|
| 8.9 | 80 | 24.6 | 2948 |
| 11.2 | 238 | 26.8 | 3340 |
| 13.4 | 474 | 29.1 | 3515 |
| 15.7 | 802 | 31.3 | 3577 |
| 17.9 | 1234 | 33.6 | 3594 |
| 20.1 | 1773 | 35.8 | 3599 |
| 22.4 | 2379 | 38.0 | 3600 |

*HECO IRP 2013 UIF Notes: Off-shore Class 5 Wind*

Notes:

(A) Unit ratings and energy production are based as follows:
Rated capacity at 3600 kW/turbine (Siemens SWT-3.6-107)
and 28 turbines.
Gross capacity based on January 2002 to January 2012 wind data
adjusted by a factor of 1.23 to match the
NREL June 2010 Assessment of Offshore Wind Energy Resources,
and turbine power curve. Avg. capacity information based in gross
capacity and assumed losses for the project site.
(B) Lead time for permitting assumes relatively little political
opposition to project development, but significant permitting requirements;
48 months of time assumed to obtain necessary permits
(C) Capital costs based on Black & Veatch review of projected
and actual offshore wind cost information globally, with adjustments
for Hawaii construction and deepwater foundations.

(D) Power Block costs include:

| | | | |
|---|---|---|---|
| Civil/Structural Works = | $255,951,000 | Turbines and Transport = | $418,962,000 |
| Electrical Collection = | $144,146,000 | | |

(E) Switchyard cost for on-shore equipment, scaled from smaller substation designs on Maui.
(F) T&D Interconnection scaled from 30MW design and is based on similar sized project in Maui.
(G) Assumed 2 acres purchased for O&M facility and substation. Subsurface leases assumed for
undersea cable and any mooring required.
(H) Indirects include construction mobilization/demobilization, security, health & safety,
site clean-up and support staff. Engineering and construction management included
under the Indirect Costs.

(I) Operations and maintenance costs based on 8 full-time equivalent staff,
necessary parts and materials for O&M, subsurface land lease, and management fees.
Direct labor costs are fixed, which somewhat skew fixed/variable breakdown.
Subsurface fees based on $0.69/sf, 1 acre per turbine, and 5 miles of 5 foot wide
ROW for transmission line.
(J) Avg. hourly data based on approximately 10 years of data near shore, January 2002
to January 2012, scaled to hub height, and with all losses and outages applied.
Wind speed scaled to meet expected Class 5 output.
(K) Estimated avg. wind speed at 90 meters from NREL map and on-shore data
(L) Total = 1-[(1-Loss1)(1-Loss2).......]
(M) Siemens SWT-3.6-107 Wind Turbine at sea level with 101m blade diameter
Design assumes a floating platform with ballasted moorings to the ocean floor.
(N) Ramping-up rates can be set within certain technology specific parameters using
control devices and SCADA. Requires intermittent resources to be set below
maximum output. Ramping-down cannot be easily controlled due to lack of resource
control; loss of resource will lead to loss of ramp-down capability. Some droop
response possible with proper controls in under and overfrequency situations.
Reactive capability can be achieved through inverters or converters and SCADA.

Table A-6
6 MW Small Scale On-Shore Wind, Molokai, Phase 1 (600 kW) Unit Information Form

**UNIT INFORMATION FORM**

**HECO IRP 2013**

| | |
|---|---|
| **Utility:** | *MECO* |
| **Unit Type:** | *6 MW Wind Energy - Phase 1 (600 kW)* |
| **Fuel Type:** | *Wind* |
| **Site:** | *Molokai - Class 6* |

| | |
|---|---|
| **Date:** | *February 27, 2013* |
| **By:** | *Black & Veatch* |
| **Supersedes:** | *February 17, 2013* |

**Unit Ratings:**[A]

| | Unit | Rated | Avg. Gross | Avg. Net |
|---|---|---|---|---|
| Normal Top Load | MW | 0.60 | 0.28 | 0.24 |
| Energy Production | MWh/yr | 5,256 | 2,441 | 2,137 |

**Ambient Conditions:**

| | | |
|---|---|---|
| Dry Bulb Temperature | F | 74 |
| Relative Humidity | percent | 78 |

**Operating Mode:**

| | | |
|---|---|---|
| Duty Cycle | | Supplemental |
| Capacity Factor | percent | 40.7 |

**Commercial Service:**

| | | |
|---|---|---|
| Date Available | month/year | July 2014 |
| Service Life | years | 20 |

**Lead Time (Prior to Comm. Oper):**[B]

| | | Normal | Expedited |
|---|---|---|---|
| Permitting | months | 36 | -- |
| Engineering | months | 24 | -- |
| Procurement | months | 14 | -- |
| Construction | months | 9 | -- |

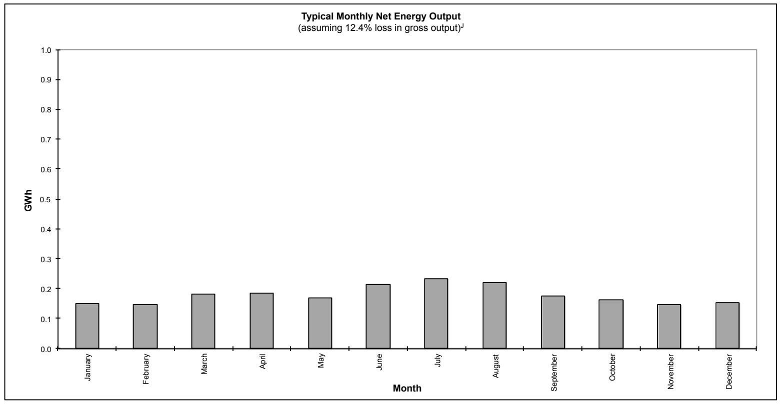
| | | |
|---|---|---|
| **Year Dollars:** | | December 2011 |
| **Capital Cost Uncertainty:** | plus/minus | +30%/-30% |

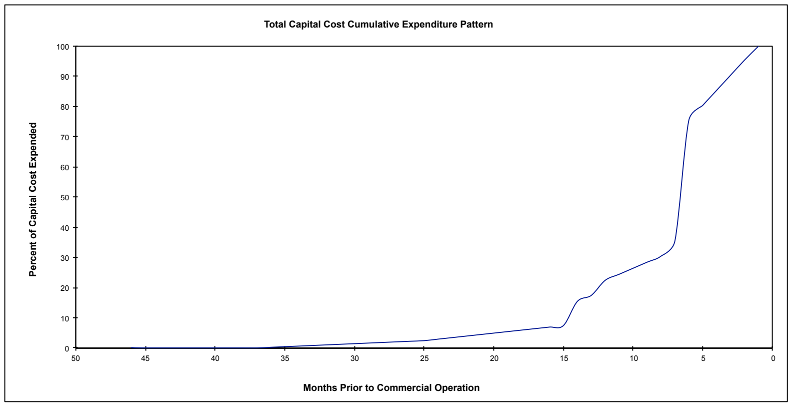
**Capital Cost (w/o AFUDC):**[C]

| | $million | $/kW$_{rated}$ | $/kW$_{net}$ |
|---|---|---|---|
| A. 0.6 MW Power Block Cost[D] | 7.75 | 12,925 | 31,782 |
| B. Special Siting Costs | - | - | - |
| C. Power Plant Switchyard[E] | 1.95 | 3,250 | 7,992 |
| D. T&D Interconnection[F] | 2.00 | 3,333 | 8,197 |
| E. Total Direct Cost (A+B+C+D) | 11.70 | 19,508 | 47,970 |
| F. Total Indirect Cost[H] | 0.85 | 1,425 | 3,503 |
| G. Land Cost[G] | 0.20 | 333 | 820 |
| H. Total Capital Cost (E+F) | 12.76 | 21,266 | 52,293 |

**Operations & Maintenance:**[I]

| | $/y | $/kW-y$_{rated}$ | $/kW-y$_{net}$ |
|---|---|---|---|
| Fixed Cost | 262,500 | 438 | 1076 |
| | | $/MWh$_{rated}$ | $/MWh$_{net}$ |
| Variable Cost | 4,882 | 0.93 | 2.28 |
| Land Lease | 5,464 | | |
| Total First Year O&M | 272,846 | | |




**Grid Services**[M]

| | | | |
|---|---|---|---|
| Ramping Cap. (MW/min) | 1 | Dispatchable? | No |
| Sys. Inertia (MW-s/MVA) | 0 | Voltage Regulation? | Yes |
| Start Time (min) | <30 min | LV Ride Through? | Yes |
| Underfreq. Droop? | Yes | Overfreq. Droop? | Yes |

**General Site/Technology Characteristics:**[K]

| | | |
|---|---|---|
| Average Ann. Wind Speed at Hub Height | mph | 19.8 |
| Turbine Spacing Within Rows | feet | NA |
| Min. Turbine Spacing Between Rows | feet | NA |
| Land Requirement | acres | 0.5 |
| Generator Type | | Doubly-Fed Induction Generator |

**Energy Losses:**[L]

| | | |
|---|---|---|
| Alignment | percent | 1.0 |
| Blade Soiling | percent | 1.5 |
| Control & Turbulence | percent | 2.0 |
| Downtime | percent | 6.5 |
| Line Losses | percent | 2.0 |
| Total | percent | 12.4 |

**Availability:**

| | | |
|---|---|---|
| Plant Maintenance Pattern | wk/y | 0-0-1-0-0-1 |
| Average Annual Maintenance | weeks | 1 |
| Immaturity Period | weeks | 16 |
| Immature Forced Outage Rate | percent | NA |
| Minimum Weeks Between Maintenance | weeks | 25 |
| Maintenance Requirement | weeks | 1 |
| Mature Forced Outage Rate | percent | 5 |
| Availability Factor | percent | 95 |

**Turbine/Tower Parameters:**

| | | |
|---|---|---|
| Turbine Rating | kW | 600 |
| Power Factor | | 1 |
| Turbine Design | axis | Horizontal |
| Rotor Diameter | meters | 47 |
| Rotor Design | | Upwind |
| Number of Blades | | 3 |
| Tower Height | meters | 50 |
| Tower Design | | Tubular |

**Power Curve Data:**[N]

| Wind Speed mph | Power Output kW | Wind Speed mph | Power Output kW |
|---|---|---|---|
| 8.9 | 21 | 24.6 | 473 |
| 11.2 | 42 | 26.8 | 532 |
| 13.4 | 80 | 29.1 | 564 |
| 15.7 | 142 | 31.3 | 582 |
| 17.9 | 218 | 33.6 | 597 |
| 20.1 | 303 | 35.8 | 600 |
| 22.4 | 401 | 38.0 | 602 |

Table A-7
6 MW Small Scale On-Shore Wind, Molokai, Net (6 MW) Unit Information Form

**UNIT INFORMATION FORM**

**HECO IRP 2013**

| | |
|---|---|
| **Utility:** | *MECO* |
| **Unit Type:** | *6.0 MW Wind Energy - Net (10 600 kW Turbines)* |
| **Fuel Type:** | *Wind* |
| **Site:** | *Molokai - Class 6* |

| | |
|---|---|
| **Date:** | *February 27, 2013* |
| **By:** | *Black & Veatch* |
| **Supersedes:** | *February 17, 2013* |

**Unit Ratings:[A]**

| | | Rated | Avg. Gross | Avg. Net |
|---|---|---|---|---|
| Normal Top Load | MW | 6.0 | 2.79 | 2.27 |
| Energy Production | MWh/yr | 52,560 | 24,410 | 19,863 |

**Ambient Conditions:**

| | | |
|---|---|---|
| Dry Bulb Temperature | F | 74 |
| Relative Humidity | percent | 78 |

**Operating Mode:**

| | | |
|---|---|---|
| Duty Cycle | | Supplemental |
| Capacity Factor | percent | 37.8 |

**Commercial Service:**

| | | | |
|---|---|---|---|
| Date Available | month/year | January | 2015 |
| Service Life | years | | 20 |

**Lead Time (Prior to Commercial Oper):[B]**

| | | Normal | Expedited |
|---|---|---|---|
| Permitting | months | 36 | -- |
| Engineering | months | 24 | -- |
| Procurement | months | 14 | -- |
| Construction | months | 9 | -- |

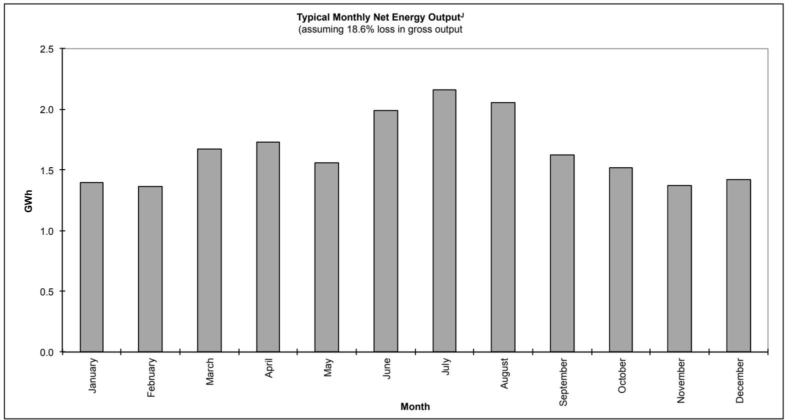
| | | |
|---|---|---|
| **Year Dollars:** | | December 2011 |
| **Capital Cost Uncertainty:** | plus/minus | +30%/-30% |

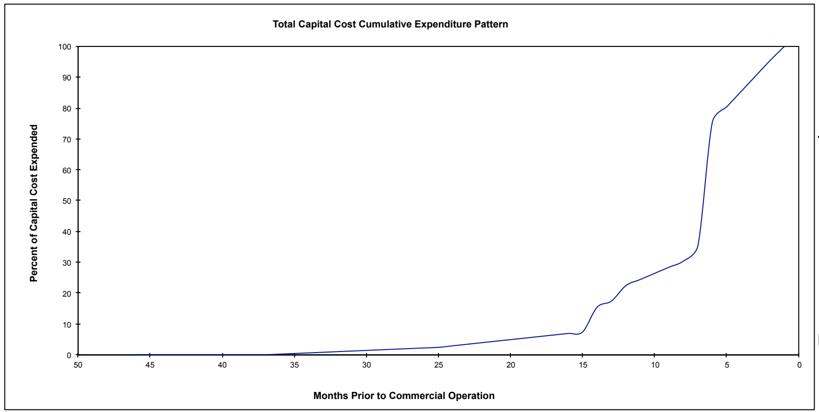
**Capital Cost (w/o AFUDC):[C]**

| | $million | $/kW$_{rated}$ | $/kW$_{net}$ |
|---|---|---|---|
| A. 6 MW Power Block Cost[D] | 26.94 | 4,490 | 11,882 |
| B. Special Siting Costs | - | - | - |
| C. Power Plant Switchyard[E] | 1.95 | 325 | 860 |
| D. T&D Interconnection[F] | 2.00 | 333 | 882 |
| E. Total Direct Cost (A+B+C+D) | 30.89 | 5,149 | 13,624 |
| F. Total Indirect Cost[H] | 2.11 | 352 | 930 |
| G. Land Cost[G] | 0.20 | 33 | 88 |
| H. Total Capital Cost (E+F) | 33.20 | 5,534 | 14,642 |

**Operations & Maintenance:[I]**

| | $/y | $/kW-y$_{rated}$ | $/kW-y$_{net}$ |
|---|---|---|---|
| Fixed Cost | 1,365,000 | 228 | 602 |
| | | $/MWh$_{rated}$ | $/MWh$_{net}$ |
| Variable Cost | 48,820 | 0.93 | 2.46 |
| Land Lease | 262,248 | | |
| Total First Year O&M | 1,676,068 | | |




**Grid Services[M]**

| | | | |
|---|---|---|---|
| Ramping Cap. (MW/min) | 1 | Dispatchable? | No |
| Sys. Inertia (MW-s/MVA) | 0 | Voltage Regulation? | Yes |
| Start Time (min) | <30 min | LV Ride Through? | Yes |
| Underfreq. Droop? | Yes | Overfreq. Droop? | Yes |

**General Site/Technology Characteristics:[K]**

| | | |
|---|---|---|
| Average Ann. Wind Speed at Hub Height | mph | 19.8 |
| Turbine Spacing Within Rows | feet | 500 |
| Min. Turbine Spacing Between Rows | feet | 1500 |
| Land Requirement | acres | 24 |
| Generator Type | | Doubly-Fed Induction Generator |

**Energy Losses:[L]**

| | | |
|---|---|---|
| Array | percent | 8.0 |
| Blade Soiling | percent | 1.5 |
| Control & Turbulence | percent | 2.0 |
| Downtime | percent | 6.5 |
| Line Losses | percent | 2.0 |
| Total | percent | 18.6 |

**Availability:**

| | | |
|---|---|---|
| Plant Maintenance Pattern | wk/y | 0-0-1-0-0-1 |
| Average Annual Maintenance | weeks | 1 |
| Immaturity Period | weeks | 16 |
| Immature Forced Outage Rate | percent | NA |
| Minimum Weeks Between Maintenance | weeks | 25 |
| Maintenance Requirement | weeks | 1 |
| Mature Forced Outage Rate | percent | 5 |
| Availability Factor | percent | 95 |

**Turbine/Tower Parameters:**

| | | |
|---|---|---|
| Turbine Rating | kW | 600 |
| Power Factor | | 1 |
| Turbine Design | axis | Horizontal |
| Rotor Diameter | meters | 47 |
| Rotor Design | | Upwind |
| Number of Blades | | 3 |
| Tower Height | meters | 50 |
| Tower Design | | Tubular |

**Power Curve Data:[N]**

| Wind Speed mph | Power Output kW | Wind Speed mph | Power Output kW |
|---|---|---|---|
| 8.9 | 21 | 24.6 | 473 |
| 11.2 | 42 | 26.8 | 532 |
| 13.4 | 80 | 29.1 | 564 |
| 15.7 | 142 | 31.3 | 582 |
| 17.9 | 218 | 33.6 | 597 |
| 20.1 | 303 | 35.8 | 600 |
| 22.4 | 401 | 38.0 | 602 |

Table A-8
6 MW Small Scale On-Shore Wind, Lanai, Phase 1 (600 kW) Unit Information Form

**UNIT INFORMATION FORM**

**HECO IRP 2013**

| | |
|---|---|
| **Utility:** | *MECO* |
| **Unit Type:** | *6 MW Wind Energy - Phase 1 (600 kW)* |
| **Fuel Type:** | *Wind* |
| **Site:** | *Lanai - Class 6* |

| | |
|---|---|
| **Date:** | *March 23, 2013* |
| **By:** | *Black & Veatch* |
| **Supersedes:** | *February 27, 2013* |

**Unit Ratings:[A]**

| | | Rated | Avg. Gross | Avg. Net |
|---|---|---|---|---|
| Normal Top Load | MW | **0.60** | **0.24** | **0.21** |
| Energy Production | MWh/yr | **5,256** | **2,116** | **1,854** |

**Ambient Conditions:**

| | | |
|---|---|---|
| Dry Bulb Temperature | F | **74** |
| Relative Humidity | percent | **78** |

**Operating Mode:**

| | | |
|---|---|---|
| Duty Cycle | | **Supplemental** |
| Capacity Factor | percent | **35.3** |

**Commercial Service:**

| | | | |
|---|---|---|---|
| Date Available | month/year | **July** | **2014** |
| Service Life | years | | **20** |

**Lead Time (Prior to Comm. Oper):[B]**

| | | Normal | Expedited |
|---|---|---|---|
| Permitting | months | **36** | **--** |
| Engineering | months | **24** | **--** |
| Procurement | months | **14** | **--** |
| Construction | months | **9** | **--** |

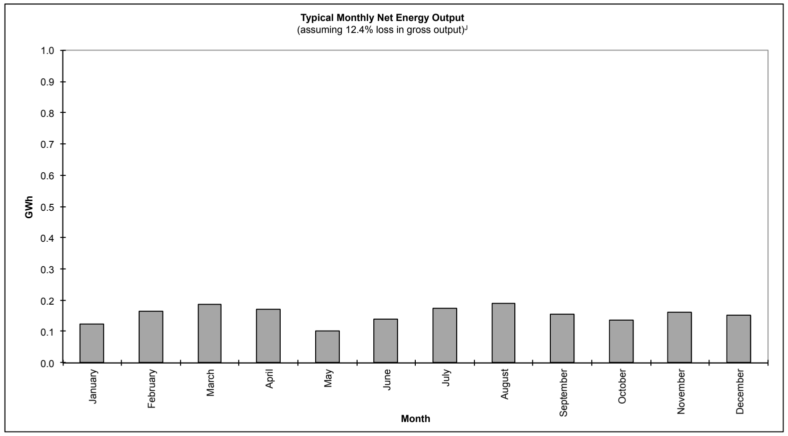
| | | |
|---|---|---|
| **Year Dollars:** | | **December 2011** |
| **Capital Cost Uncertainty:** | plus/minus | **+30%/-30%** |

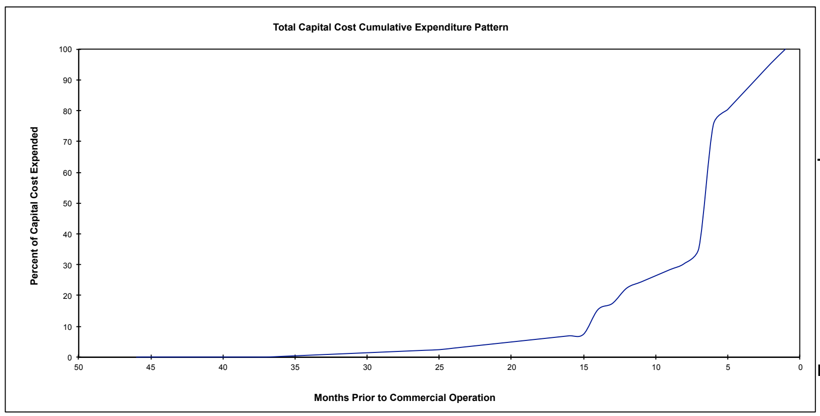
**Capital Cost (w/o AFUDC):[C]**

| | $million | $/kW$_{rated}$ | $/kW$_{net}$ |
|---|---|---|---|
| A. 0.6 MW Power Block Cost[D] | **7.75** | **12,925** | **36,647** |
| B. Special Siting Costs | **-** | **-** | **-** |
| C. Power Plant Switchyard[E] | **1.95** | **3,250** | **9,215** |
| D. T&D Interconnection[F] | **2.00** | **3,333** | **9,451** |
| E. Total Direct Cost (A+B+C+D) | **11.70** | **19,508** | **55,314** |
| F. Total Indirect Cost[H] | **0.85** | **1,425** | **4,039** |
| G. Land Cost[G] | **0.20** | **333** | **945** |
| H. Total Capital Cost (E+F) | **12.76** | **21,266** | **60,298** |

**Operations & Maintenance:[I]**

| | $/y | $/kW-y$_{rated}$ | $/kW-y$_{net}$ |
|---|---|---|---|
| Fixed Cost | **262,500** | **438** | **1240** |
| | | $/MWh$_{rated}$ | $/MWh$_{net}$ |
| Variable Cost | **4,882** | **0.93** | **2.63** |
| Land Lease | **5,464** | | |
| Total First Year O&M | **272,846** | | |




**Grid Services[M]**

| | | | |
|---|---|---|---|
| Ramping Cap. (MW/min) | **1** | Dispatchable? | **No** |
| Sys. Inertia (MW-s/MVA) | **0** | Voltage Regulation? | **Yes** |
| Start Time (min) | **<30 min** | LV Ride Through? | **Yes** |
| Underfreq. Droop? | **Yes** | Overfreq. Droop? | **Yes** |

**General Site/Technology Characteristics:[K]**

| | | |
|---|---|---|
| Average Ann. Wind Speed at Hub Height | mph | **20.1** |
| Turbine Spacing Within Rows | feet | **NA** |
| Min. Turbine Spacing Between Rows | feet | **NA** |
| Land Requirement | acres | **0.5** |
| Generator Type | | **Doubly-Fed Induction Generator** |

**Energy Losses:[L]**

| | | |
|---|---|---|
| Alignment | percent | **1.0** |
| Blade Soiling | percent | **1.5** |
| Control & Turbulence | percent | **2.0** |
| Downtime | percent | **6.5** |
| Line Losses | percent | **2.0** |
| Total | percent | **12.4** |

**Availability:**

| | | |
|---|---|---|
| Plant Maintenance Pattern | wk/y | **0-0-1-0-0-1** |
| Average Annual Maintenance | weeks | **1** |
| Immaturity Period | weeks | **16** |
| Immature Forced Outage Rate | percent | **NA** |
| Minimum Weeks Between Maintenance | weeks | **25** |
| Maintenance Requirement | weeks | **1** |
| Mature Forced Outage Rate | percent | **5** |
| Availability Factor | percent | **95** |

**Turbine/Tower Parameters:**

| | | |
|---|---|---|
| Turbine Rating | kW | **600** |
| Power Factor | | **1** |
| Turbine Design | axis | **Horizontal** |
| Rotor Diameter | meters | **47** |
| Rotor Design | | **Upwind** |
| Number of Blades | | **3** |
| Tower Height | meters | **50** |
| Tower Design | | **Tubular** |

**Power Curve Data:[N]**

| Wind Speed mph | Power Output kW | Wind Speed mph | Power Output kW |
|---|---|---|---|
| **8.9** | **21** | **24.6** | **473** |
| **11.2** | **42** | **26.8** | **532** |
| **13.4** | **80** | **29.1** | **564** |
| **15.7** | **142** | **31.3** | **582** |
| **17.9** | **218** | **33.6** | **597** |
| **20.1** | **303** | **35.8** | **600** |
| **22.4** | **401** | **38.0** | **602** |

Table A-9
6 MW Small Scale On-Shore Wind, Lanai, Net (6 MW) Unit Information Form

| | |
|---|---|
| Utility: | *MECO* |
| Unit Type: | *6.0 MW Wind Energy - Net (10 600 kW Turbines)* |
| Fuel Type: | *Wind* |
| Site: | *Lanai - Class 6* |

**UNIT INFORMATION FORM**

**HECO IRP 2013**

| | |
|---|---|
| Date: | *February 27, 2013* |
| By: | *Black & Veatch* |
| Supersedes: | *February 17, 2013* |

**Unit Ratings:[A]**

| | | Rated | Avg. Gross | Avg. Net |
|---|---|---|---|---|
| Normal Top Load | MW | 6.0 | 2.42 | 1.97 |
| Energy Production | MWh/yr | 52,560 | 21,169 | 17,226 |

**Ambient Conditions:**

| | | |
|---|---|---|
| Dry Bulb Temperature | F | 74 |
| Relative Humidity | percent | 78 |

**Operating Mode:**

| | | |
|---|---|---|
| Duty Cycle | | Supplemental |
| Capacity Factor | percent | 32.8 |

**Commercial Service:**

| | | | |
|---|---|---|---|
| Date Available | month/year | January | 2015 |
| Service Life | years | | 20 |

**Lead Time (Prior to Comm. Oper):[B]**

| | | Normal | Expedited |
|---|---|---|---|
| Permitting | months | 36 | -- |
| Engineering | months | 24 | -- |
| Procurement | months | 14 | -- |
| Construction | months | 9 | -- |

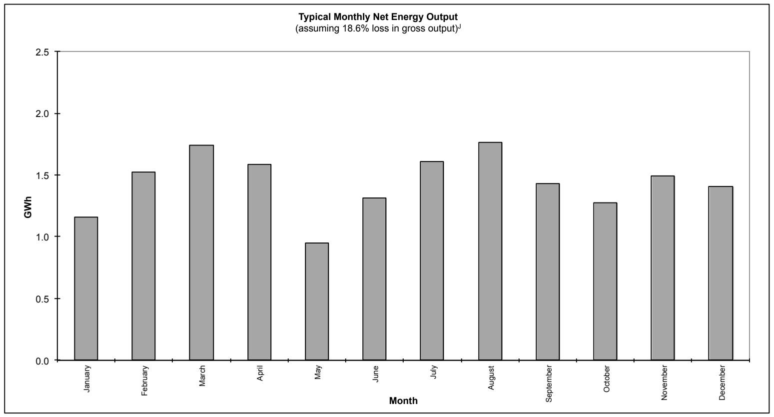
| | | |
|---|---|---|
| **Year Dollars:** | | December 2011 |
| **Capital Cost Uncertainty:** | plus/minus | +30%/-30% |

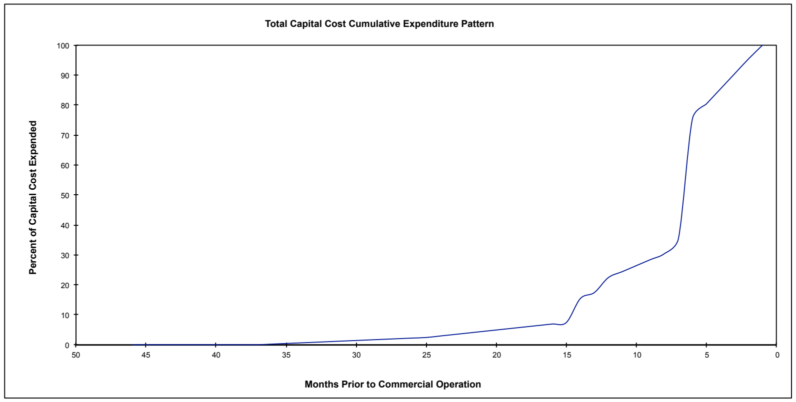
**Capital Cost (w/o AFUDC):[C]**

| | $million | $/kW$_{rated}$ | $/kW$_{net}$ |
|---|---|---|---|
| A. 6 MW Power Block Cost[D] | 26.94 | 4,490 | 13,701 |
| B. Special Siting Costs | - | - | - |
| C. Power Plant Switchyard[E] | 1.95 | 325 | 992 |
| D. T&D Interconnection[F] | 2.00 | 333 | 1,017 |
| E. Total Direct Cost (A+B+C+D) | 30.89 | 5,149 | 15,709 |
| F. Total Indirect Cost[H] | 2.11 | 352 | 1,073 |
| G. Land Cost[G] | 0.20 | 33 | 102 |
| H. Total Capital Cost (E+F) | 33.20 | 5,534 | 16,884 |

**Operations & Maintenance:[I]**

| | $/y | $/kW-y$_{rated}$ | $/kW-y$_{net}$ |
|---|---|---|---|
| Fixed Cost | 1,365,000 | 228 | 694 |
| | | $/MWh$_{rated}$ | $/MWh$_{net}$ |
| Variable Cost | 48,820 | 0.93 | 2.83 |
| Land Lease | 262,248 | | |
| Total First Year O&M | 1,676,068 | | |




**Grid Services[M]**

| | | | |
|---|---|---|---|
| Ramping Cap. (MW/min) | 1 | Dispatchable? | No |
| Sys. Inertia (MW-s/MVA) | 0 | Voltage Regulation? | Yes |
| Start Time (min) | <30 min | LV Ride Through? | Yes |
| Underfreq. Droop? | Yes | Overfreq. Droop? | Yes |

**General Site/Technology Characteristics:[K]**

| | | |
|---|---|---|
| Average Ann. Wind Speed at Hub Height | mph | 20.1 |
| Turbine Spacing Within Rows | feet | 500 |
| Min. Turbine Spacing Between Rows | feet | 1500 |
| Land Requirement | acres | 24 |
| Generator Type | | Doubly-Fed Induction Generator |

**Energy Losses:[L]**

| | | |
|---|---|---|
| Array | percent | 8.0 |
| Blade Soiling | percent | 1.5 |
| Control & Turbulence | percent | 2.0 |
| Downtime | percent | 6.5 |
| Line Losses | percent | 2.0 |
| Total | percent | 18.6 |

**Availability:**

| | | |
|---|---|---|
| Plant Maintenance Pattern | wk/y | 0-0-1-0-0-1 |
| Average Annual Maintenance | weeks | 1 |
| Immaturity Period | weeks | 16 |
| Immature Forced Outage Rate | percent | NA |
| Minimum Weeks Between Maintenance | weeks | 25 |
| Maintenance Requirement | weeks | 1 |
| Mature Forced Outage Rate | percent | 5 |
| Availability Factor | percent | 95 |

**Turbine/Tower Parameters:**

| | | |
|---|---|---|
| Turbine Rating | kW | 600 |
| Power Factor | | 1 |
| Turbine Design | axis | Horizontal |
| Rotor Diameter | meters | 47 |
| Rotor Design | | Upwind |
| Number of Blades | | 3 |
| Tower Height | meters | 50 |
| Tower Design | | Tubular |

**Power Curve Data:[N]**

| Wind Speed mph | Power Output kW | Wind Speed mph | Power Output kW |
|---|---|---|---|
| 8.9 | 21 | 24.6 | 473 |
| 11.2 | 42 | 26.8 | 532 |
| 13.4 | 80 | 29.1 | 564 |
| 15.7 | 142 | 31.3 | 582 |
| 17.9 | 218 | 33.6 | 597 |
| 20.1 | 303 | 35.8 | 600 |
| 22.4 | 401 | 38.0 | 602 |

*HECO IRP 2013 UIF Notes: Molokai 0.6 MW*

Notes: (A) Unit ratings and energy production are based as follows:
Rated capacity at 600 kW/turbine (RRB-PS 600, a Vestas V47 clone) and a single turbine case.
For Gross and Net production, the long-term adjusted wind speeds were estimated based on local data sources.
The Molokai Airport has 10 years of data at the 10 meter level from January 1st 2002 to January 1st 2012.
The Airport location was identified on the Utility-Scale Land-Based 80-Meter Wind Maps created by AWS Truepower and the National Renewable Energy Laboratory.
A shear factor of 0.26 was applied to the measured data at Molokai Airport to synthesize 80 meter data to match average wind speed on the AWS/NREL Wind Map output for that location (9.0 m/s).
A multiplication factor of 1.1025 was applied to the 10 meter and 80 meter wind speeds at the Airport to adjust wind speeds to the anticipated wind farm locations (10m/s). 50 meter wind speeds

(hub height) were synthesized based
and a shear factor of 0.26. The resul

Gross capacity based on long-term ac
Net production data was calculated by
(B) Lead time for permitting assumes
outreach. Assumes that permitting, er
Limited construction infrastructure on
(C) Capital costs based on Black & Ve
mainland estimates to develop Hawaii
High $/kW cost because of relative siz
Most infrastructure required for a 10 tu
O&M building, lighting, SCADA systen

(D) Values based on Black & Veatch internal cost data for this turbine in a small 2-turbine installation in the mainland US. Costs adjusted for HI specific shipping, labor, taxes, and commodity values.
Includes civil and most electrical infrastructure needed for a 6 MW (10 turbine) project.
Power Block costs include:

| | | | |
|---|---|---|---|
| Civil/Structural Works = | $5,077,223 | Turbines and Trans | $2,117,334 |
| Electrical Collection = | $560,379 | | |

(E) Switchyard cost based on a full 6 MW project design
(F) Interconnection assumed to include local substation, tie-line, and interconnection substation required for a 6 MW project.
(G) Land and dedicated O&M facility for a 6 MW project assumed.
(H) Indirects include construction mobilization/demobilization, security, health & safety, site clean-up and support staff. Engineering and Construction Mgmt. included under the Indirect Costs.
Geotechnical support and a large portion of the development costs for the 6 MW facility included.
(I) Operations and maintenance costs based on 1 full-time equivalent staff, necessary parts and materials for O&M, land lease, and warranty service. Direct labor costs are fixed, which somewhat skew fixed/variable breakdown. Variable costs for unscheduled maintenance and consumables, based on MWh. Land lease based on 10% of total land required.

*HECO IRP 2013 UIF Notes: Molokai 6 MW*

Notes: (A) Unit ratings and energy production are based as follows:
Rated capacity at 600 kW/turbine (RRB-PS 600, a Vestas V47 clone) and a ten turbine case.
For Gross and Net production, the long-term adjusted wind speeds were estimated based on local data sources.
The Molokai Airport has 10 years of data at the 10 meter level from January 1st 2002 to January 1st 2012.
The Airport location was identified on the Utility-Scale Land-Based 80-Meter Wind Maps created by AWS Truepower and the National Renewable Energy Laboratory.
A shear factor of 0.26 was applied to the measured data at Molokai Airport to synthesize 80 meter data to match average wind speed on the AWS/NREL Wind Map output for that location (9.0 m/s).
A multiplication factor of 1.1025 was applied to the 10 meter and 80 meter wind speeds at the Airport to adjust wind speeds to the anticipated wind farm locations (10m/s). 50 meter wind speeds

(hub height) were synthesized based on these shifted 80 and 10 meter wind speeds
and a shear factor of 0.26. The resul

Gross capacity based on long-term ac
Net production data was calculated by
(B) Lead time for permitting assumes
outreach. Limited construction infrastı
other islands.
(C) Capital costs based on Black & Ve
mainland estimates to develop Hawaii
Uses the same infrastructure develope
requires expenditures for electrical col
Costs reflect expenditures for all phas
the difference between final costs (6 N

(D) Values based on Black & Veatch internal cost data for this turbine in a small 2-turbine installation in the mainland US. Costs adjusted for HI specific shipping, labor, taxes, and commodity values.
Includes all infrastructure needed for a net 6 MW (10 turbine) project.
Power Block costs include:

| | | | |
|---|---|---|---|
| Civil/Structural Works = | $8,088,217 | Turbines and Trans | $14,922,931 |
| Electrical Collection = | $3,931,019 | | |

(E) Switchyard cost based on a full 6 MW project design
(F) Interconnection assumed to include local substation, tie-line, and interconnection substation required for a 6 MW project.
(G) Land and dedicated O&M facility for a 6 MW project assumed.
(H) Indirects include construction mobilization/demobilization, security, health & safety, site clean-up and support staff. Engineering and Construction Mgmt. included under the Indirect Costs.
Geotechnical support and all development costs for the full 6 MW facility are included.
(I) Operations and maintenance costs based on 3 full-time equivalent staff, necessary parts and materials for O&M, land lease, and warranty service. Direct labor costs are fixed, which somewhat skew fixed/variable breakdown. Variable costs for unscheduled maintenance and consumables, based on MWh. Land lease based on 10% of total land required.

## *HECO IRP 2013 UIF Notes: Lanai 0.6 MW*

Notes: (A) Unit ratings and energy production are based as follows:
Rated capacity at 600 kW/turbine (RRB-PS 600, a Vestas V47 clone) and a single turbine case.
Gross capacity based on long-term adjusted wind data and turbine power curve.
The Lanai Airport has 3.8 years of data from February 29, 2008 to December 31st, 2011. The Molokai Airport has 10 years of data at the 10 meter level from January 1st 2002 to January 1st 2012.
The correlation factor between these two sites on an annual basis is 0.93. Long-term to short-term annual ratios were calculated at Molokai Airport and applied to the data at Lanai Airport to create a long-term adjusted data set. Then the Lanai Airport location was identified on the Utility-Scale Land-Based 80-Meter Wind Maps created by AWS Truepower and the National Renewable Energy Laboratory to properly scale the wind speed.
A shear factor of 0.23 was applied to the data used for the Lanai Airport to synthesize 80 meter data with an average wind speed

similar to the AWS/NREL Wind Map output for that location (7.0 m/s). A multiplication factor of 1.4144
was applied to the 10 meter and 80 m
anticipated wind farm locations (10m/s
these shifted 80 and 10 meter wind sp
The resulting average wind speeds at

Net production data was calculated by
(B) Lead time for permitting assumes
outreach. Assumes that permitting, er
Limited construction infrastructure on
(C) Capital costs based on Black & Ve
mainland estimates to develop Hawaii
High $/kW cost because of relative siz
Most infrastructure required for a 10 tu
O&M building, lighting, SCADA system, and geotechnical studies, for example).

(D) Values based on Black & Veatch internal cost data for this turbine in a small 2-turbine installation in the mainland US. Costs adjusted for HI specific shipping, labor, taxes, and commodity values.
Includes civil and most electrical infrastructure needed for a 6 MW (10 turbine) project.
Power Block costs include:

| | | | |
|---|---|---|---|
| Civil/Structural Works = | $5,077,223 | Turbines and Trans | $2,117,334 |
| Electrical Collection = | $560,379 | | |

(E) Switchyard cost based on a full 6 MW project design
(F) Interconnection assumed to include local substation, tie-line, and interconnection substation required for a 6 MW project.
(G) Land and dedicated O&M facility for a 6 MW project assumed.
(H) Indirects include construction mobilization/demobilization, security, health & safety, site clean-up and support staff. Engineering and Construction Mgmt. included under the Indirect Costs.
Geotechnical support and a large portion of the development costs for the 6 MW facility included.
(I) Operations and maintenance costs based on 1 full-time equivalent staff, necessary parts and materials for O&M, land lease, and warranty service. Direct labor costs are fixed, which somewhat skew fixed/variable breakdown. Variable costs for unscheduled maintenance and consumables, based on MWh. Land lease based on 10% of total land required.

## *HECO IRP 2013 UIF Notes: Lanai 6 MW*

Notes: (A) Unit ratings and energy production are based as follows:
Rated capacity at 600 kW/turbine (RRB-PS 600, a Vestas V47 clone) and a ten turbine case.
Gross capacity based on long-term adjusted wind data and turbine power curve.
The Lanai Airport has 3.8 years of data from February 29, 2008 to December 31st, 2011. The Molokai Airport has 10 years of data at the 10 meter level from January 1st 2002 to January 1st 2012.
The correlation factor between these two sites on an annual basis is 0.93. Long-term to short-term annual ratios were calculated at Molokai Airport and applied to the data at Lanai Airport to create a long-term adjusted data set. Then the Lanai Airport location was identified on the Utility-Scale Land-Based 80-Meter Wind Maps created by AWS Truepower and the National Renewable Energy Laboratory to properly scale the wind speed.
A shear factor of 0.23 was applied to the data used for the Lanai Airport to synthesize 80 meter data with an average wind speed similar to the AWS/NREL Wind Map output for that location (7.0 m/s). A multiplication factor of 1.4144 was applied to the 10 meter and 80 meter wind speeds at the Airport to estimate wind patterns at the anticipated wind farm locations (10m/s). 50 meter wind speeds (hub height) were synthesized based on these shifted 80 and 10 meter wind speeds and a shear factor of 0.23.

(D) Values based on Black & Veatch internal cost data for this turbine in a small 2-turbine installation in the mainland US. Costs adjusted for HI specific shipping, labor, taxes, and commodity values.
Includes all infrastructure needed for a net 6 MW (10 turbine) project.
Power Block costs include:

| | | | |
|---|---|---|---|
| Civil/Structural Works = | $8,088,217 | Turbines and Trans | $14,922,931 |
| Electrical Collection = | $3,931,019 | | |

(E) Switchyard cost based on a full 6 MW project design
(F) Interconnection assumed to include local substation, tie-line, and interconnection substation required for a 6 MW project.
(G) Land and dedicated O&M facility for a 6 MW project assumed.
(H) Indirects include construction mobilization/demobilization, security, health & safety, site clean-up and support staff. Engineering and Construction Mgmt. included under the Indirect Costs.
Geotechnical support and all development costs for the full 6 MW facility are included.
(I) Operations and maintenance costs based on 3 full-time equivalent staff, necessary parts and materials for O&M, land lease, and warranty service. Direct labor costs are fixed, which somewhat skew fixed/variable breakdown. Variable costs for unscheduled maintenance and consumables, based on MWh. Land lease based on 10% of total land required.
(J) Avg. hourly data based on approximately 4 years of data collection at the Lanai Airport 2008-2011, scaled to hub height, with all losses and outages applied.
(K) Avg. wind speed estimated at 50 meter level, as described in note A. Land requirement estimates are based on generous turbine spacing within a compact area.

The resulting wind speeds at the anticipated wind farm location are:

| | | |
|---|---|---|
| 80 meter leve | = 10 m/s | (22.4 mph) |
| 50 meter leve | = 8.97 m/s | (20.1 mph) |
| 10 meter leve | = 6.20 m/s | (13.9 mph) |

Net production data was calculated by applying losses to the gross energy estimates for the project.
(B) Lead time for permitting assumes 36 months to allow time for studies, monitoring, and community outreach. Limited construction infrastructure on Molokai/Lanai likely requires longer lead time than other islands.
(C) Capital costs based on Black & Veatch database of project cost data. Costs adjusted from mainland estimates to develop Hawaii specific data. Net Hawaii premium is roughly 25%.
Uses the same infrastructure developed in Phase 1. Besides construction costs, each phase requires expenditures for electrical collection at each turbine, indirects, and engineering.
Costs reflect expenditures for all phases of the project; Phases 2 through 10 can be estimated by . the difference between final costs (6 MW) and Phase 1 (0.6 MW) costs, divided by 9.

Land lease costs are based on the assumption that only 10% of the net acreage for the project is needed, since much of the land is not disturbed and can be used for other purposes. Lease cost = $10,927/acre/year.
(L) Total = 1-[(1-Loss1)(1-Loss2).......]
(M) Ramping-up rates can be set within certain technology specific parameters using control devices and SCADA. Requires intermittent resources to be set below maximum output. Ramping-down cannot be easily controlled due to lack of resource control; loss of resource will lead to loss of ramp-down capability. Some droop response possible with proper controls in under and overfrequency situations. Reactive capability can be achieved through inverters or converters and SCADA.
(N) RRB-PS 600 kW Wind Turbine ( a Vestas V47 clone) at sea level with 47m blade diameter. Cut-in wind speed = 9 mph and cut-out wind speed = 56 mph

Table B-1
2 kW PV Unit Information Form

## UNIT INFORMATION FORM

## HECO IRP 2013

| | |
|---|---|
| **Utility:** | *HECO* |
| **Unit Type:** | *2.45 kWdc (2 kWac) PV System* |
| **Fuel Type:** | *Solar* |
| **Site:** | *Oahu Small Rooftop* |

| | |
|---|---|
| **Date:** | *October 11, 2012* |
| **By:** | *Black & Veatch* |
| **Supersedes:** | *August 6, 2012* |

**Unit Ratings:[A]**

| | | DC | AC |
|---|---|---|---|
| Normal Top Load (Nominal) | kW | 2.45 | 2 |
| Energy Production | kWh/yr | | 3,997 |

**Ambient Conditions:**

| | | |
|---|---|---|
| Dry Bulb Temperature | F | 77 |
| Relative Humidity | percent | 70 |

**Operating Mode:[B]**

| | | | |
|---|---|---|---|
| Duty Cycle | | | Supplemental |
| Capacity Factor (DC/AC) | percent | 18.6 | 22.8 |

**Commercial Service:**

| | | | |
|---|---|---|---|
| Date Available | month/year | January | 2013 |
| Service Life | years | | 25 |

**Lead Time (Prior to Commercial Oper):**

| | | Normal | Expedited |
|---|---|---|---|
| Permitting | weeks | 6 | 4 |
| Engineering | weeks | 4 | 3 |
| Procurement | weeks | 3 | 2 |
| Construction | weeks | 1 | 1 |

| | | |
|---|---|---|
| **Year Dollars:** | | December 2011 |
| **Capital Cost Uncertainty:** | plus/minus | +20%/-20% |

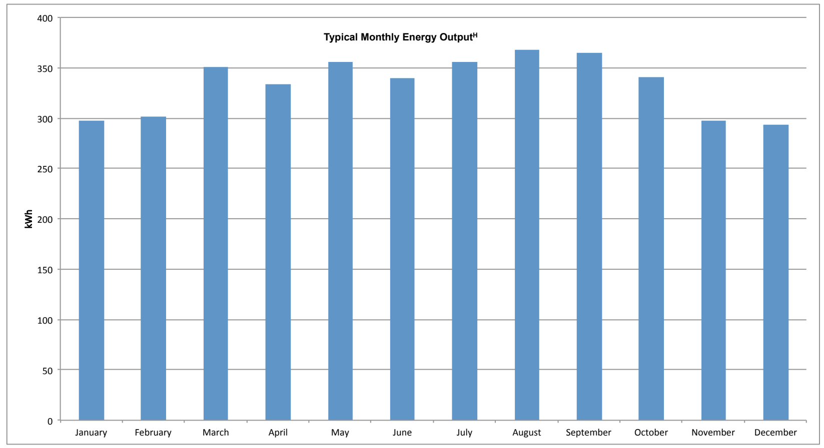
**Capital Cost (w/o AFUDC):[C]**

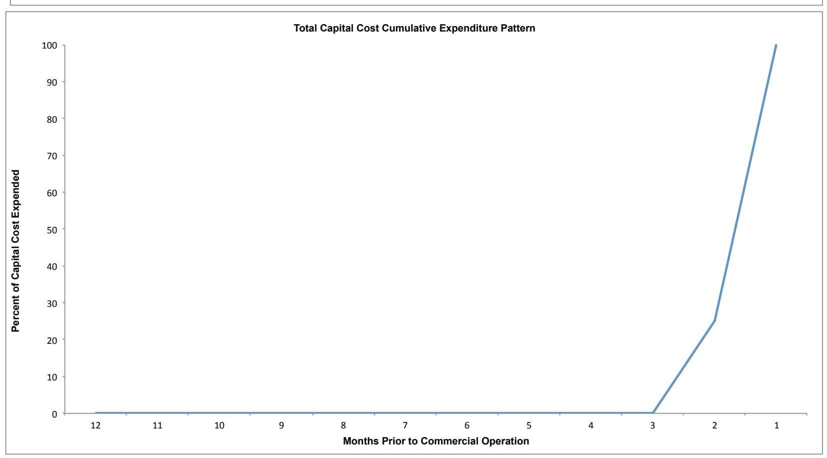
| | $thousand | $/kWdc | $/kWac |
|---|---|---|---|
| A. 2 kW Power Block Cost[D] | 11.9 | 4,869 | 5,965 |
| B. Special Siting Costs | 0.0 | 0 | 0 |
| C. Power Plant Switchyard | 0.0 | 0 | 0 |
| D. T&D Interconnection[D] | 0.0 | 0 | 0 |
| E. Total Direct Cost (A+B+C+D) | 11.9 | 4,869 | 5,965 |
| F. Total Indirect Cost[E] | 1.8 | 735 | 900 |
| G. Total Capital Cost (E+F) | 13.7 | 5,604 | 6,865 |

**Operations & Maintenance:[F]**

| | $/y | $/kW-$y_{rated (dc)}$ |
|---|---|---|
| Fixed Cost | 0 | 0 |

| | $/y | $/kWh$_{output (ac)}$ |
|---|---|---|
| Variable Cost | 352 | 0.088 |
| Land Lease Cost[G] | 0 | |
| Total Annual O&M | 352 | |




**Grid Services**

| | | | | |
|---|---|---|---|---|
| Ramping Capabilities | MW/min | No | Dispatchable? | No |
| Inertia Constant | MW-sec/MVA | No | Voltage Regulation? | No |
| Start Time (min) | | N/A | Disturbance Ride Through? | No |
| Underfreq. Droop Response? | | No | Overfreq. Droop Response? | No |

**General Site/Technology Characteristics[I]:**

| | | |
|---|---|---|
| Array Area | $ft^2$ | 177.5 |
| Site Latitude | degrees | 21.3 |
| Nominal Operating Cell Temperature | $^oF$ | 125.6 |
| Insolation (annual) | kWh/$m^2$ | 1985.4 |
| Ground Albedo | | 0.20 |
| Minimal Land Requirement | acres | 0.0041 |
| Generator | | Inverter |

**Energy Loss Factors:[J]**

| | | |
|---|---|---|
| PCU Efficiency | percent | 97.0 |
| Soiling | percent | 99.0 |
| Shading | percent | 98.0 |
| Availability | percent | 99.5 |
| Auxiliary Load | percent | 99.9 |
| DC Cabing | percent | 98.5 |
| Module Quality | percent | 100.0 |
| Mismatch | percent | 99.0 |
| Transformer (daytime) | percent | 100.0 |
| Transformer (night) | percent | 100.0 |
| AC Wiring | percent | 99.9 |
| **Total** | **percent** | 91.1 |

**Daily Resource Requirements at Normal Top Load:**

| | | |
|---|---|---|
| Fuel | bpd | 0 |
| Service & Plant Water | mgd | 0.000 |
| Cooling Tower Makeup | mgd | 0 |

**Availability:[K]**

| | | |
|---|---|---|
| Plant Maintenance Pattern | wk/y | N/A |
| Average Annual Maintenance | weeks | 0.24 |
| Immaturity Period | weeks | 4.00 |
| Immature Forced Outage Rate | percent | N/A |
| Minimum Weeks Between Maintenance | weeks | N/A |
| Mature Forced Outage Rate | percent | 1 |
| Equivalent Availability | percent | 49.0 |

**Module/Array Parameters:[L]**

| | | |
|---|---|---|
| Module Rating | W | 245 |
| Module Type | | p-crystalline |
| Module Efficiency | percent | 14.8 |
| Array Type | | fixed-tilt |
| Array Tilt | degrees | 20 |
| Array Azimuth | degrees | 180 (S) |
| Array Spacing (ground cover ratio) | | 1.00 |
| Panel Height | feet | 5.5 |
| Efficiency Reduction Coefficient | change/$^oF$ | -0.0022 |

*HECO IRP 2013 UIF Notes: Photovoltaic 2 kW*

**Notes:**

(A) The energy production was generated by PVsyst software version 5.54, with a minimum accuracy of 4%.

(B) Capacity factor based on nameplate nominal AC power of the inverter and 8760 operating hours per year, reported relative to both the DC and AC rating of the system.

(C) Capital costs are derived based on vendor quotes whenever possible. Other sources used were HECO, the California's Energy Commission database for the Emerging Renewables Program, the U.S Solar Market Insight Report published by SEIA and GTM research, the Lawrence Berkeley National Laboratory's report Tracking the Sun IV (published September 2011), market index pricing published by Solarbuzz and Black & Veatch's experience in system pricing. The cost of the system is for an individual owner, purchasing a system from a system integrator. Economies of scale are assumed, with costs expected to be similar to those on the mainland. The system is installed as a retrofit to the house with minimal roof work. Most current flush mounted systems have very little impact on the roof membrane.

(D) The system connects to the main entrance switch of the house with no upgrades.

(E) Indirect costs cover permitting fees, taxes, spare parts, profit, contingency, construction management, development costs and overhead.

(F) O&M costs were estimated based on vendor quotes whenever possible, as well as assumptions regarding maintenance requirements and costs based on Black & Veatch experience. Black & Veatch accounted for typical parameters such as inverter preventative maintenance and annual inspections. Several of these O&M activities are not typical for smaller systems, and therefore assumed to be zero for the 2 kW system.

(G) No land requirements; assumes space available from owner of the system.

(H) Total electrical energy production calculated with PVsyst software version 5.54. Reported in delivered energy (ac).

(I) The Array Area is the total photovoltaic module surface area and the Minimal Land Requirement is the minimal surface area required by the photovoltaic system, which includes inter-row distances only, no perimeter allowances. The Nominal Operating Cell Temperature is calculated by PVsyst considering the heat dissipation ability of the system. The insolation is the total yearly Global Horizontal Irradiance from the solar data set. The ground albedo is assumed to be constant year round at 0.2.

(J) Energy loss factors based on the following:
PCU Efficiency is the CEC efficiency of the inverters reported in the CEC data sheet.
Soiling and Shading are yearly totals calculated by PVsyst.
Availability is typical of similar installations.
Auxiliary Load based on standby consumption of the inverter at night.
DC and AC Cabling losses are typical of similar installations.
Module Quality calculated based on power tolerance, light induced degradation (LID) and first year degradation.
Mismatch is typical of similar installations and based on string size and number of strings per inverter.
No transformer losses due to system size.

(K) Availability values are provided as follows:
Plant maintenance pattern: No weekly maintenance pattern assumed for PV facilities as this is not typical.
Average annual maintenance: Accounts for planned and unplanned maintenance throughout a typical year.
Immaturity period: Reflects the initial start-up period for a plant while it is online but going through technical issues and therefore not producing energy at its full potential.
Immature forced outage rate: Not typically considered for PV facilities as the immaturity period is relatively short.
Minimal weeks between maintenance: Not typically considered for PV facilities.
Mature forced outage rate: Accounts for planned and unplanned maintenance through a typical year.

(L) Module rating and module efficiency from data sheet. The module type is poly-crystalline, typical of similar installations.
The tilt of the residential system was considered 20 degrees assuming this is a typical roof tilt for existing and newly built houses.
The array azimuth is 180 degrees or facing true south.
The ground cover ratio is determined by dividing the area covered by the modules by the area required by the system.
Panel height is the length of the module in meters.
Efficiency reduction coefficient is the temperature coefficient of power in %/°C (from data sheet).

# Appendix K: Consolidated Unit Information Forms

Table B-2
100 kW PV Unit Information Form

| | |
|---|---|
| **Utility:** | *HECO* |
| **Unit Type:** | *121 kWdc (100 kWac) PV System* |
| **Fuel Type:** | *Solar* |
| **Site:** | *Oahu Large Rooftop* |

**UNIT INFORMATION FORM**

**HECO IRP 2013**

| | |
|---|---|
| **Date:** | *October 11, 2012* |
| **By:** | *Black & Veatch* |
| **Supersedes:** | *September 27, 2012* |

**Unit Ratings:**[A]

| | Units | DC | AC |
|---|---|---|---|
| Normal Top Load (Nominal) | kW | 121 | 100 |
| Energy Production | kWh/yr | | 200,000 |

**Ambient Conditions:**

| | | |
|---|---|---|
| Dry Bulb Temperature | F | 77 |
| Relative Humidity | percent | 70 |

**Operating Mode:**[B]

| | | | |
|---|---|---|---|
| Duty Cycle | | | Supplemental |
| Capacity Factor (DC/AC) | percent | 18.9 | 22.8 |

**Commercial Service:**

| | | | |
|---|---|---|---|
| Date Available | month/year | January | 2013 |
| Service Life | years | | 25 |

**Lead Time (Prior to Commercial Oper):**

| | Units | Normal | Expedited |
|---|---|---|---|
| Permitting | months | 5 | 4 |
| Engineering | months | 3.5 | 2.5 |
| Procurement | months | 2.5 | 2 |
| Construction | months | 1 | 1 |

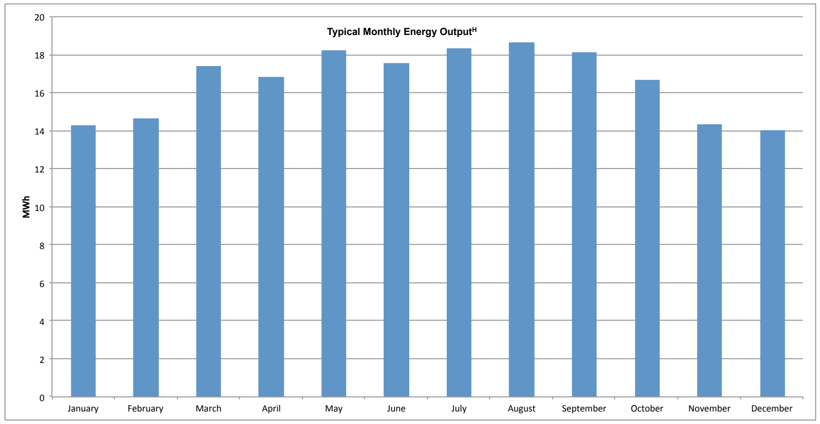
| | | |
|---|---|---|
| **Year Dollars:** | | December 2011 |
| **Capital Cost Uncertainty:** | plus/minus | +20%/-20% |

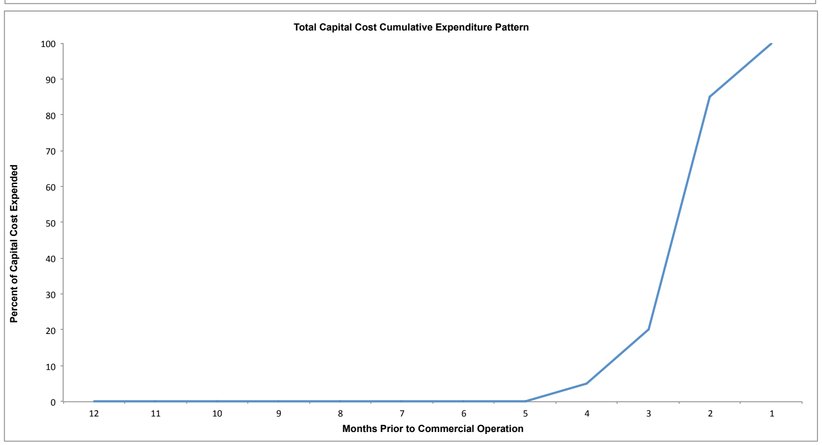
**Capital Cost (w/o AFUDC):**[C]

| | $thousand | $/kWdc | $/kWac |
|---|---|---|---|
| A. 100 kW Power Block Cost[D] | 349.9 | 2,892 | 3,499 |
| B. Special Siting Costs | 0.0 | 0 | 0 |
| C. Power Plant Switchyard | 0.0 | 0 | 0 |
| D. T&D Interconnection[D] | 10.5 | 87 | 105 |
| E. Total Direct Cost (A+B+C+D) | 360.4 | 2,979 | 3,604 |
| F. Total Indirect Cost[E] | 75.8 | 626 | 758 |
| G. Total Capital Cost (E+F) | 436.2 | 3,605 | 4,362 |

**Operations & Maintenance:**[F]

| | | |
|---|---|---|
| | $/y | $/kW-$y_{rated\ (dc)}$ |
| Fixed Cost | 3,969 | 32.80 |
| | $/y | $/kWh$_{output\ (ac)}$ |
| Variable Cost | 1,777 | 0.009 |
| Land Lease Cost[G] | 0 | 0.000 |
| Total Annual O&M | 5,746 | |




**Grid Services**

| | | | | |
|---|---|---|---|---|
| Ramping Capabilities | MW/min | No | Dispatchable? | No |
| Inertia Constant | MW-sec/MVA | No | Voltage Regulation? | No |
| Start Time (min) | minutes | N/A | Disturbance Ride Through? | No |
| Underfreq. Droop Response? | | No | Overfreq. Droop Response? | No |

**General Site/Technology Characteristics**[I]**:**

| | | |
|---|---|---|
| Array Area | $ft^2$ | 8725.1 |
| Site Latitude | degrees | 21.4 |
| Nominal Operating Cell Temperature | °F | 122.0 |
| Insolation (annual) | $kWh/m^2$ | 1985.4 |
| Ground Albedo | | 0.20 |
| Minimal Land Requirement | acres | 0.31 |
| Generator | | Inverter |

**Energy Loss Factors:**[J]

| | | |
|---|---|---|
| PCU Efficiency | percent | 97.5 |
| Soiling | percent | 99.0 |
| Shading | percent | 98.0 |
| Availability | percent | 99.0 |
| Auxiliary Load | percent | 99.9 |
| DC Cabing | percent | 98.0 |
| Diodes and Connections | percent | 100.0 |
| Mismatch | percent | 98.0 |
| Transformer (daytime) | percent | 100.0 |
| Transformer (night) | percent | 100.0 |
| AC Wiring | percent | 99.5 |
| **Total** | **percent** | 89.4 |

**Daily Resource Requirements at Normal Top Load:**

| | | |
|---|---|---|
| Fuel | bpd | 0 |
| Service & Plant Water | mgd | 0.000 |
| Cooling Tower Makeup | mgd | 0 |

**Availability:**[K]

| | | |
|---|---|---|
| Plant Maintenance Pattern | wk/y | N/A |
| Average Annual Maintenance | weeks | 0.24 |
| Immaturity Period | weeks | 4 |
| Immature Forced Outage Rate | percent | N/A |
| Minimum Weeks Between Maintenance | weeks | N/A |
| Mature Forced Outage Rate | percent | 1 |
| Equivalent Availability | percent | 49.0 |

**Module/Array Parameters:**[L]

| | | |
|---|---|---|
| Module Rating | W | 290 |
| Module Type | | crystalline |
| Module Efficiency | percent | 14.9 |
| Array Type | | fixed-tilt |
| Array Tilt | degrees | 15 |
| Array Azimuth | degrees | 180 (S) |
| Array Spacing (ground cover ratio) | | 0.64 |
| Panel Height | feet | 6.4 |
| Efficiency Reduction Coefficient | change/°F | -0.0024 |

*HECO IRP 2013 UIF Notes: Photovoltaic 100 kW*

**Notes:**

(A) The energy production was generated by PVsyst software version 5.54, with a minimum accuracy of 4%.

(B) Capacity factor based on nameplate nominal AC power of the inverter and 8760 operating hours per year, reported relative to both the DC and AC rating of the system.

(C) Capital costs are derived based on vendor quotes whenever possible. Other sources used were the California's Energy Commission database for the Emerging Renewables Program, the U.S Solar Market Insight Report published by SEIA pricing published by Solarbuzz and Black & Veatch's experience in system pricing. The cost of the system is for an individual owner, purchasing a system from a medium size integrator. The cost is not for a system under a Power Purchase portfolio of installations. Minimal economies of scale. The system is installed as a retrofit with minimal penetrations on the roof. The number of obstructions on the roof is also assumed to be minimal. Economy of scale lowers the installe

(D) The system is connected to the existing electric switchboard in the electrical room of the building with minimal upgrades required.

(E) Indirect costs cover permitting fees, taxes, spare parts, profit, contingency, construction management, development costs and overhead.

(F) O&M costs were estimated based on vendor quotes whenever possible, as well as assumptions regarding maintenance requirements and costs based on Black & Veatch experience. Black & Veatch accounted for typical parameters su maintenance and annual inspections.

(G) No land requirements. No roof lease requirements.

(H) Total electrical energy production calculated with PVsyst software version 5.54. Reported in delivered energy (ac).

(I) The Array Area is the total photovoltaic module surface area and the Minimal Land Requirement is the minimal surface area required by the photovoltaic system, which includes inter-row distances only, no perimeter allowances.
The Nominal Operating Cell Temperature is calculated by PVsyst considering the heat dissipation ability of the system. The insolation is the total yearly Global Horizontal Irradiance from the solar data set. The ground albedo is assumed to

(J) Energy loss factors based on the following. Higher losses than in the 2 kW case due to additional cabling, AC wiring losses, and panel mismatches (due to more strings and inverters)
PCU Efficiency is the CEC efficiency of the inverters reported in the CEC data sheet.
Soiling and Shading are yearly totals calculated by PVsyst.
Availability is typical of similar installations. Lower availability than in the 2 kW case due to number of panels and expected maintenance issues.
Auxiliary Load Based on standby consumption of the inverter at night.
DC and AC Cabling losses are typical of similar installations (more cabling leads to more losses than in the 2 kW case).
Module Quality Calculated based on power tolerance, light induced degradation (LID) and first year degradation.
Mismatch is typical of similar installations and based on string size and number of strings per inverter (more strings and inverters leads to more losses).
No transformer losses due to system size.

(K) Availability values are provided as follows:
Plant maintenance pattern: No weekly maintenance pattern assumed for PV facilities as this is not typical.
Average annual maintenance: Accounts for planned and unplanned maintenance throughout a typical year.
Immaturity period: Reflects the initial start-up period for a plant while it is online but going through technical issues and therefore not producing energy at its full potential.
Immature forced outage rate: Not typically considered for PV facilities as the immaturity period is relatively short.
Minimal weeks between maintenance: Not typically considered for PV facilities.
Mature forced outage rate: Accounts for planned and unplanned maintenance through a typical year.

(L) Module rating and module efficiency from data sheet. The module type is poly-crystalline, typical of similar installations.
The tilt of this system was considered 15 degrees assuming Sunlink mounting structures.
The array azimuth is 180 degrees or facing true south.
The ground cover ratio is determined by dividing the area covered by the modules by the area required by the system.
Panel height is the length of the module in meters.
Efficiency reduction coefficient is the temperature coefficient of power in %/°C (from data sheet).

# Appendix K: Consolidated Unit Information Forms

Table B-3
1 MW PV Unit Information Form

| | |
|---|---|
| Utility: | *HECO* |
| Unit Type: | *1.2 MWdc (1 MWac) PV System, Single Axis Tracking* |
| Fuel Type: | *Solar* |
| Site: | *Oahu Ground Mount* |

**UNIT INFORMATION FORM**

**HECO IRP 2013**

| | |
|---|---|
| Date: | *October 11, 2012* |
| By: | *Black & Veatch* |
| Supersedes: | *September 27, 2012* |

**Unit Ratings:**[A]

| | | DC | AC |
|---|---|---|---|
| Normal Top Load (Nominal) | kW | 1,199 | 1,000 |
| Energy Production | kWh/yr | | 2,400,000 |

**Ambient Conditions:**

| | | |
|---|---|---|
| Dry Bulb Temperature | F | 77 |
| Relative Humidity | percent | 70 |

**Operating Mode:**[B]

| | | | |
|---|---|---|---|
| Duty Cycle | | | Supplemental |
| Capacity Factor (DC/AC) | percent | 22.9 | 27.4 |

**Commercial Service:**

| | | | |
|---|---|---|---|
| Date Available | month/year | January | 2014 |
| Service Life | years | | 25 |

**Lead Time (Prior to Commercial Oper):**

| | | Normal | Expedited |
|---|---|---|---|
| Permitting | months | 10 | 8 |
| Engineering | months | 5 | 4 |
| Procurement | months | 4 | 3 |
| Construction | months | 2 | 2 |

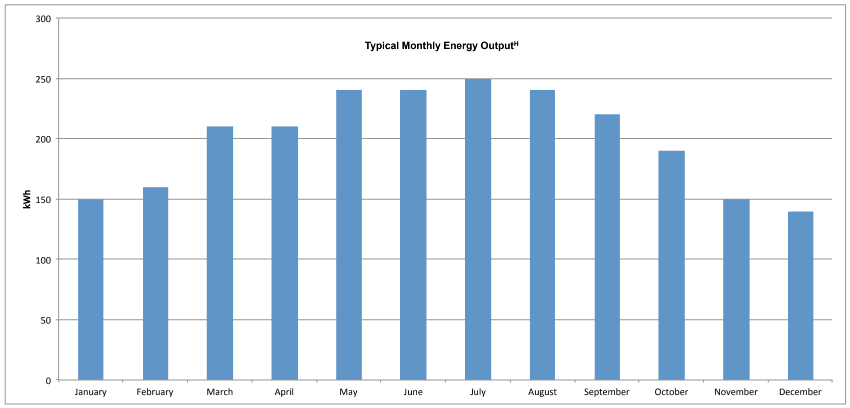
| | | |
|---|---|---|
| **Year Dollars:** | | December 2011 |
| **Capital Cost Uncertainty:** | plus/minus | +20%/-20% |

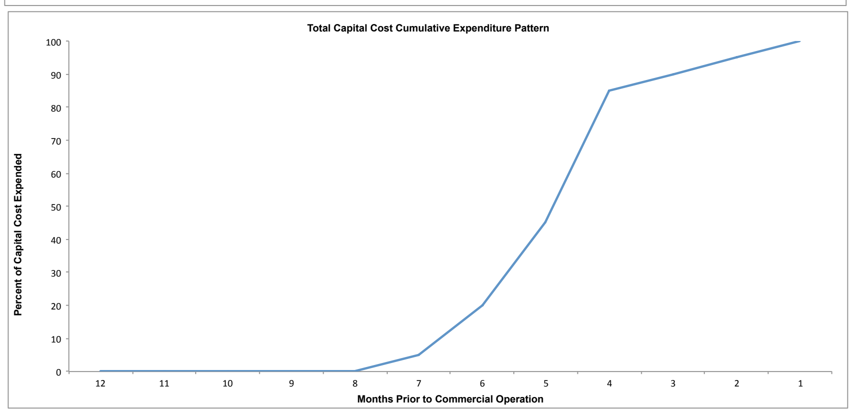
**Capital Cost (w/o AFUDC):**[C]

| | $thousand | $/kWdc | $/kWac |
|---|---|---|---|
| A. 1 MW Power Block Cost[D] | 3621.5 | 3,020 | 3,622 |
| B. Special Siting Costs | 0.0 | 0 | 0 |
| C. Power Plant Switchyard | 0.0 | 0 | 0 |
| D. T&D Interconnection[D] | 62.8 | 52 | 63 |
| E. Total Direct Cost (A+B+C+D) | 3684.3 | 3,073 | 3,684 |
| F. Total Indirect Cost[E] | 540.9 | 451 | 541 |
| G. Total Capital Cost (E+F) | 4225.2 | 3,524 | 4,225 |

**Operations & Maintenance:**[F]

| | | |
|---|---|---|
| | $/y | $/kW-$y_{rated\ (dc)}$ |
| Fixed Cost | 41,281 | 34.43 |
| | $/y | $/kWh$_{output\ (ac)}$ |
| Variable Cost | 7,158 | 0.003 |
| Land Lease Cost[G] | 68,840 | |
| | $/y | |
| Total Annual O&M | 117,279 | |




**Grid Services**[M]

| | | | | |
|---|---|---|---|---|
| Ramping Capabilities | MW/min | 0.1 | Dispatchable? | No |
| Inertia Constant | MW-sec/MVA | No | Voltage Regulation? | Yes |
| Start Time (min) | minutes | N/A | Disturbance Ride Through? | Yes |
| Underfreq. Droop Response? | | No | Overfreq. Droop Response? | Day Only |

**General Site/Technology Characteristics**[I]**:**

| | | |
|---|---|---|
| Array Area | $ft^2$ | 86336.2 |
| Site Latitude | degrees | 21.4 |
| Nominal Operating Cell Temperature | °F | 116.6 |
| Insolation (annual) | $kWh/m^2$ | 1985.4 |
| Ground Albedo | | 0.20 |
| Minimal Land Requirement | acres | 6.30 |
| Generator | | Inverter |

**Energy Loss Factors:**[J]

| | | |
|---|---|---|
| PCU Efficiency | percent | 98.0 |
| Soiling | percent | 99.0 |
| Shading | percent | 98.5 |
| Availability | percent | 99.0 |
| Auxiliary Load | percent | 99.6 |
| DC Cabing | percent | 98.0 |
| Diodes and Connections | percent | 100.0 |
| Mismatch | percent | 98.0 |
| Transformer (daytime) | percent | 99.0 |
| Transformer (night) | percent | 99.5 |
| AC Wiring | percent | 99.5 |
| **Total** | **percent** | **88.7** |

**Daily Resource Requirements at Normal Top Load:**

| | | |
|---|---|---|
| Fuel | bpd | 0 |
| Service & Plant Water | mgd | 0.000 |
| Cooling Tower Makeup | mgd | 0 |

**Availability:**[K]

| | | |
|---|---|---|
| Plant Maintenance Pattern | wk/y | N/A |
| Average Annual Maintenance | weeks | 0.24 |
| Immaturity Period | weeks | 8 |
| Immature Forced Outage Rate | percent | N/A |
| Minimum Weeks Between Maintenance | weeks | N/A |
| Mature Forced Outage Rate | percent | 1 |
| Equivalent Availability | percent | 49.0 |

**Module/Array Parameters:**[L]

| | | |
|---|---|---|
| Module Rating | W | 290 |
| Module Type | | crystalline |
| Module Efficiency | percent | 14.9 |
| Array Type | | tracker |
| Array tilt | degrees | +/- 45 |
| Array Azimuth | degrees | 180 (S) |
| Array Spacing (ground cover ratio) | | 0.49 |
| Panel Height | feet | 6.4 |
| Efficiency Reduction Coefficient | change/°F | -0.0024 |

*HECO IRP 2013 UIF Notes: Photovoltaic 1 MW Single Axis Tracking*

**Notes:**

(A) The energy production was generated by PVsyst software version 5.54, with a minimum accuracy of 4%.

(B) Capacity factor based on nameplate nominal AC power of the inverter and 8760 operating hours per year, reported relative to both the DC and AC rating of the system. Higher than other sizes due to the trackers.

(C) Capital costs are derived based on vendor quotes whenever possible. Other sources used were the California's Energy Commission database for the Emerging Renewables Program, the U.S Solar Market Insight Report published by SEIA and GTM research, market index pricing published by Solarbuzz and Black & Veatch's experience in system pricing. The cost of the system is for an individual owner, purchasing a system from a medium to large size integrator. Economies of scale apply to this system. The site preparation is assumed to be minimal, on a site with little vegetation, mostly flat and adequate drainage. The soil conditions are assumed to be adequate for one of the most economical driven pile foundation type.

(D) The system is connected to an existing substation or transformer of adequate capacity located next to the installation and with minimal upgrades required. No transmission line is assumed from the installation to the point of interconnection or very short and aerial.

(E) Indirect costs cover permitting fees, taxes, spare parts, profit, contingency, construction management, development costs and overhead.

(F) O&M costs were estimated based on vendor quotes whenever possible, as well as assumptions regarding maintenance requirements and costs based on Black & Veatch experience. Black & Veatch accounted for typical parameters such as inverter preventative maintenance and annual inspections. This system has the highest maintenance requirements due to size, ground mount configuration, and tracking.

(G) Land lease costs as per HECO are $10,927 per acre/year based on escalated Tier 3 FIT estimates for Oahu.

(H) Total electrical energy production calculated with PVsyst software version 5.54. Reported in delivered energy (ac).

(I) The Array Area is the total photovoltaic module surface area and the Minimal Land Requirement is the minimal surface area required by the photovoltaic system, which includes inter-row distances only, no perimeter allowances.
The Nominal Operating Cell Temperature is calculated by PVsyst considering the heat dissipation ability of the system. The insolation is the total yearly Global Horizontal Irradiance from the solar data set. The ground albedo is assumed to be constant year round at 0.2.

(J) Energy loss factors based on the following. Higher losses than the 2kW case due to use of transformers, lower availability due to panel maintenance, higher aux load (monitoring), more DC/AC wiring, and panel mismatch.
PCU Efficiency is the CEC efficiency of the inverters reported in the CEC data sheet.
Soiling and Shading are yearly totals calculated by PVsyst.
Availability is typical of similar installations. Lower availability than in the 2 kW case due to number of panels and expected maintenance issues.
Auxiliary Load based on standby consumption of the inverter at night.
DC and AC Cabling losses are typical of similar installations.
Module Quality calculated based on power tolerance, light induced degradation (LID) and first year degradation.
Mismatch is typical of similar installations and based on string size and number of strings per inverter.
Transformer losses (daytime and nightime) are typical of similar installations.

(K) Availability values are provided as follows:
Plant maintenance pattern: No weekly maintenance pattern assumed for PV facilities as this is not typical.
Average annual maintenance: Accounts for planned and unplanned maintenance throughout a typical year.
Immaturity period: Reflects the initial start-up period for a plant while it is online but going through technical issues and therefore not producing energy at its full potential.
Immature forced outage rate: Not typically considered for PV facilities as the immaturity period is relatively short.
Minimal weeks between maintenance: Not typically considered for PV facilities.
Mature forced outage rate: Accounts for planned and unplanned maintenance through a typical year.

(L) Module rating and module efficiency from data sheet. The module type is poly-crystalline, typical of similar installations.
The system considered was a horizontal, single-axis tracker with backtracking. The system is installed with driven piles as foundations.
The tracker is aligned true N-S with modules rotating every 10 minutes from east in the morning to west in the afternoon.
The ground cover ratio is determined by dividing the area covered by the modules by the area required by the system.
Panel height is the length of the module in meters.
Efficiency reduction coefficient is the temperature coefficient of power in %/°C (from data sheet).

(M) Ramping capabilities and overfrequency droop are available only if the system is at or near full output. The system can be ramped through a plant controller which essentially communicates with inverters to have them clip production to a desired level. Voltage Regulation and Disturbance Ride Through are possible assuming this is a system not regulated by the National Electrical Code but considered as a generator, with restricted access and under direct control of a utility. No underfrquency droop response is likely as plant typically will not be operating at reduced output.

Table C-1
50 MW Parabolic Trough Unit Information Form

| | |
|---|---|
| Utility: | *HECO* |
| Unit Type: | *50 MW Parabolic Trough System* |
| Fuel Type: | *Solar* |
| Site: | *Honolulu County* |

**UNIT INFORMATION FORM**

**HECO IRP 2013**

| | |
|---|---|
| Date: | *October 11, 2012* |
| By: | *Black & Veatch* |
| Supersedes: | *August 22, 2012* |

**Unit Ratings:**[A]

| | | Rated | Gross | Net |
|---|---|---|---|---|
| Normal Top Load | MW | 50 | 11.9 | 10.4 |
| Energy Production | MWh/yr | 438,000 | 104,539 | 91,017 |

**Ambient Conditions:**

| | | |
|---|---|---|
| Dry Bulb Temperature | ° F | 77 |
| Relative Humidity | percent | 70 |

**Operating Mode:**[B]

| | | |
|---|---|---|
| Duty Cycle | | Supplemental |
| Capacity Factor | percent | 20.8 |

**Commercial Service:**

| | | | |
|---|---|---|---|
| Date Available | month/year | January | 2017 |
| Service Life | years | | 20 |

**Lead Time (Prior to Commercial Oper):**

| | | Normal | Expedited |
|---|---|---|---|
| Permitting | months | 66 | 60 |
| Engineering | months | 51 | 48 |
| Procurement | months | 36 | 32 |
| Construction | months | 30 | 24 |

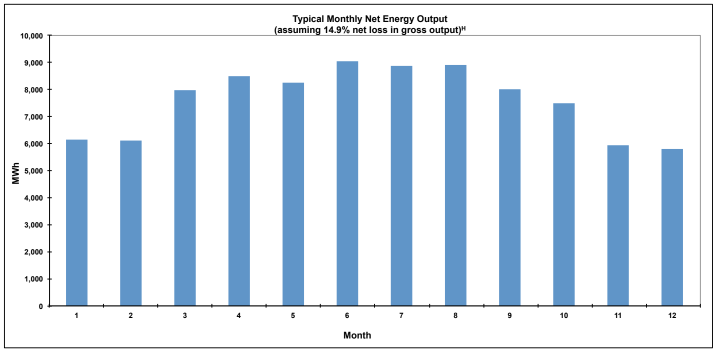
| | | |
|---|---|---|
| **Year Dollars:** | | December 2011 |
| **Capital Cost Uncertainty:** | plus/minus | +30%/-30% |

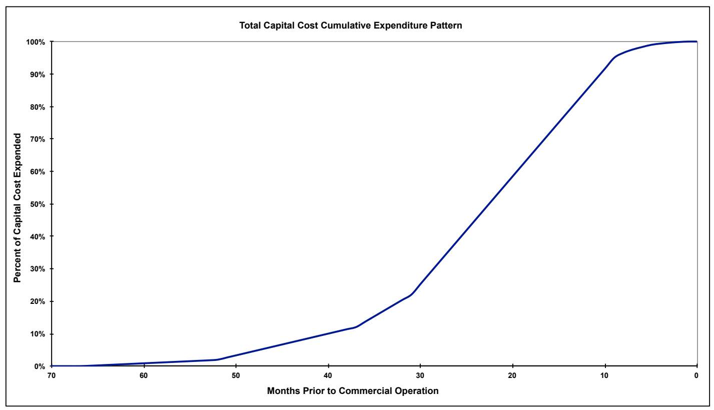
**Capital Cost (w/o AFUDC):**[C]

| | $thousand | $/kW$_{rated}$ | $/kW$_{net}$ |
|---|---|---|---|
| A. Power Block Cost | 107,489 | 2,150 | 10,345 |
| B1. HTF System Cost (incl steam generator) | 11,435 | 229 | 1,101 |
| B2. HTF System Cost (solar field) | 42,219 | 844 | 4,063 |
| C. Solar Field Cost | 139,915 | 2,798 | 13,466 |
| D. Civil Works Costs | 33,098 | 662 | 3,186 |
| E. Substation/Switchyard, T&D Interconnect[D] | 5,500 | 110 | 529 |
| F. Total Direct Cost (A+B+C+D+E) | 339,656 | 6,793 | 32,690 |
| G. Total Indirect Cost (E*0.28)[E] | 95,104 | 1,902 | 9,153 |
| H. Land Cost | 0 | 0 | 0 |
| I. Total Capital Cost (E+F) | 434,760 | 8,695 | 41,844 |

**Operations & Maintenance:**[F]

| | | | |
|---|---|---|---|
| | $/y | $/kW-y$_{rated}$ | $/kW-y$_{net}$ |
| Fixed Cost | 7,178,200 | 144 | 691 |
| | $/y | $/kWh$_{rated}$ | $/kWh$_{net}$ |
| Variable Cost | 1,587,700 | 0.004 | 0.017 |
| | $/y | $/acre | |
| Land Lease Cost[G] | 3,584,100 | 10,927 | |
| Total Annual O&M | 12,350,000 | | |




**Grid Services**[N]**:**

| | | | |
|---|---|---|---|
| Ramping Capabilities (MW/min) | 0.5 to 2.5 | Dispatchable? | No |
| Inertia Constant (MW-sec/MVA) | 3 to 4 | Voltage Regulation? | Limited |
| Start Time (min) | 30 to 60 | Disturbance Ride Through? | Yes |
| Underfreq. Droop Response? | Day Only | Overfreq. Droop Response? | Day Only |

**General Site/Technology Characteristics:**

| | | |
|---|---|---|
| Solar Multiple[I] | | 1.5 |
| Insolation at Design | W/m$^2$ | 950.0 |
| Rated Cycle Conversion Efficiency | % | 0.38 |
| Minimal Land Requirement | acres | 328 |
| Generator | | Synchronous |

**Collector Optical Parameters:**[J]

| | | |
|---|---|---|
| Tracking Error | percent | 99.0 |
| Geometry Effects | percent | 98.0 |
| Mirror Reflectance | percent | 93.5 |
| Mirror Soiling | percent | 95.0 |
| General Optical Error | percent | 99.0 |
| **Total Optical Efficiency** | percent | 85.3 |

**Daily Resource Requirements at Normal Top Load:**[K]

| | | |
|---|---|---|
| Fuel | bpd | 0 |
| Mirror Washing, Service & Plant Water | mgd | 0.26 |
| Cooling Tower Makeup | mgd | 0.23 |

**Availability:**

| | | |
|---|---|---|
| Average Annual Maintenance | weeks | 3.00 |
| Mature Forced Outage Rate | percent | 4.0 |
| Equivalent Availability[L] | percent | 96.0 |

**Collector/Loop Parameters:**[M]

| | | |
|---|---|---|
| Solar Field Area | ft$^2$ | 3,449,573 |
| Collector Aperture Area | ft$^2$ | 8795.0 |
| Collector Length | ft | 492.0 |
| Collector Aperture Width | ft | 18.93 |
| Row Spacing | ft | 56 |
| Collectors per Loop | | 8 |
| Total Number of Loops | | 49 |
| Design Loop Inlet Temp | ° F | 559 |
| Design Loop Outlet Temp | ° F | 736 |

*HECO IRP 2013 UIF Notes: Parabolic Trough 50 MW*

Notes:

(A) The ratings are based on estimates generated by System Advisory Model (SAM) software, Version 2011.12.2, from National Renewable Energy Laboratory (NREL).
(B) Capacity factor is based on 8760 operating hours, taking into account nighttime aux. load.
(C) Capital costs were developed on the basis of existing Black & Veatch estimates. Screening level estimates were derived from bottom-up estimates developed for previous projects. These existing in-house data were evaluated and modified to better represent the project considered in this analysis. The process was consistent with Black & Veatch experience reviewing third party cost estimates, and care was taken to ensure that total costs represent a market cost.
Black & Veatch also notes the following assumptions:
- Power Block Cost includes Balance of Plant Cost.
- HTF System Cost includes steam generator (on per kW basis), as well as piping, pumps and HTF volume (on per square meter of solar field basis).
- Civil Works Cost is for the solar field only. Power Block and HTF System Civil Works Cost is included in the Power Block and heat transfer fluid (HTF) system cost estimates.
- Solar Field Cost includes drilled piers; solar collectors; solar field control system, power cabling, data cabling and electrical buildings; swivel joints or flexible joints; solar collector element assembly lines; and solar field erection.

(D) Switchyard and T&D Interconnection costs from existing Black & Veatch estimates.
(E) Indirect cost includes engineering, insurance, bonds, contingency and EBIT.
(F) Black & Veatch developed representative O&M cost estimates based on previous experience and in-house information, categorized into fixed and variable components.
Fixed costs include the following:
- Labor, routine maintenance and expenses such as training, property taxes, insurance and office and administrative expenses.

Variable costs include the following:
- Outage maintenance, parts and materials, chemical usage (including water and partial replacement of HTF due to degradation) and equipment.

(G) Land lease cost as per HECO is $10,927/acre/year based on escalated Tier 3 FIT estimates for Oahu.
(H) Monthly and hourly energy data from SAM.
- Solar resource data from SolarAnywhere average DNI months for the selected Oahu location.
- Net energy does include an approximate 14.9% loss in gross-to-net output from parasitic losses when the plant is generating. These parasitic losses include power consumed by the collector tracker mechanisms, power required to pump HTF through the power cycle and balance of plant power requirements.
- Net energy does include the assumed availability factor for the plant.
- Plant auxiliary loads are included in the net generation estimate and do impact the capacity factor.

(I) The Solar Multiple, a solar field sizing parameter, is the ratio of the thermal power provided by the collector field at the design point to the thermal power required for rated capacity by the turbine.
(J) Collector Optical Parameters (from SAM) are included in the energy generation estimate.
- Tracking error accounts for reduction in absorbed radiation from poor sun sensor alignment, tracking algorithm error, tracker drive update rate error and twisting of the collector.
- Geometry effects account for errors from misaligned mirrors, mirror contour distortion from support structure mirror shape errors and receiver misalignment.
- Mirror reflectance is the fraction of incident solar radiation reflected onto the receiver from the mirror surface.
- Mirror soiling accounts for reduction in absorbed radiation cause by soiling of the mirror surface.
- General optical error accounts for reduction in absorbed radiation from general optical errors and error sources.

(K) Resource requirements at normal top load based on assumed water usage of 1,000 gal/MWh from SAM. Of this, approximately 90% is for cooling tower makeup and the remaining 10% for mirror washing, service and plant water.
(L) Equivalent availability factor accounts for facility downtime due to forced and scheduled outages.
(M) Collector/loop Parameters from SAM for representative parabolic trough system.
(N) Ramp rate of 3 percent per minute is typical for a system of this size. Voltage reg. requires appropriate SCADA controls. Droop response available during daylight hours only; amount limited by solar resource.

Table D-1
25 MW Advanced Development Geothermal Unit Information Form

| | |
|---|---|
| Utility: | *HECO* |
| Unit Type: | *Geothermal (25 MW)* |
| Fuel Type: | *--* |
| Site: | *Advanced Explored Location* |

## UNIT INFORMATION FORM

## HECO IRP 2013

| | |
|---|---|
| Date: | *March 23, 2013* |
| By: | *Black & Veatch* |
| Supersedes: | *October 11, 2012* |

**Unit Ratings at Average Conditions:[A]**

| | | Gross | Net |
|---|---|---|---|
| Normal Top Load | MW | 29.0 | 25.5 |
| Emergency | MW | 29.0 | 25.5 |
| Minimum | MW | 14.5 | 12.4 |

**Ambient Conditions:**

| | | |
|---|---|---|
| Dry Bulb Temperature | F | 77 |
| Relative Humidity | percent | 70 |
| CTG Inlet Air Temperature | F | N/A |

**Operating Mode:[B]**

| | | |
|---|---|---|
| Duty Cycle | | Baseload, with dispatch capability |
| Capacity Factor | percent | 85 |

**Commercial Service:**

| | | |
|---|---|---|
| Date Available | month/year | 2016 |
| Service Life | years | 30 |

**Lead Time (Prior to Commercial Oper):**

| | | Normal | Expedited |
|---|---|---|---|
| Permitting | months | 45 | -- |
| Engineering | months | 36 | -- |
| Procurement | months | 30 | -- |
| Construction | months | 18 | -- |

| | | |
|---|---|---|
| **Year Dollars** | | December 2011 |
| **Capital Cost Uncertainty:** | plus/minus | +30% / -30% |

**Capital Cost (without AFUDC)[C]:**

| | $million | $/kW$_{gross}$ | $/kW$_{net}$ |
|---|---|---|---|
| A. Total Power Block Cost (base)[D] | 217.09 | 7,486 | 8,513 |
| B. Special Siting Costs[E] | - | - | - |
| C. Power Plant Switchyard[E] | - | - | - |
| D. T&D Interconnection[F] | 4.40 | 152 | 173 |
| E. Total Direct Cost (A1+B+C+D) | 221.49 | 7,638 | 8,686 |
| F. Total Indirect Cost[D] | 37.82 | 1,304 | 1,483 |
| G. Land Cost[G] | 5.45 | 188 | 214 |
| H. Total Capital Cost (E+F+G) | 264.76 | 9,130 | 10,383 |

**Operations & Maintenance:[H]**

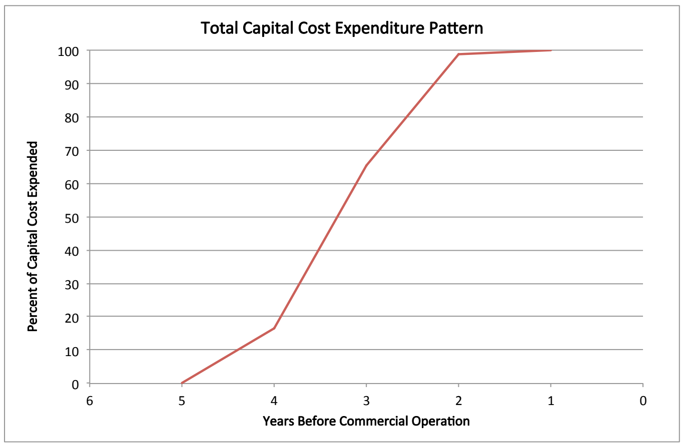
| | $/y | $/kW-y$_{gross}$ | $/kW-y$_{net}$ |
|---|---|---|---|
| Fixed Cost | 5,391,360 | 186 | 211 |
| | | $/MWh$_{gross}$ | $/MWh$_{net}$ |
| Variable Cost | 5,489,243 | 25.42 | 28.91 |
| Total First Year O&M | 10,880,603 | | |

**Capacity and Heat Rate Data:**

| Load Point | Gross Load | HHV Fuel Input | Gross Load Split CTG | Gross Load Split STG | Auxiliary Load Split CTG | Auxiliary Load Split BOP | Net Load | Net Plant Heat Rate | Quick Ld. Pickup |
|---|---|---|---|---|---|---|---|---|---|
| | MW | MBtu/h | MW | MW | MW | MW | MW | Btu/kWh | MW |
| Normal Top | 29.0 | -- | -- | 29.0 | -- | 3.50 | 25.5 | -- | -- |
| 75 percent | 21.8 | -- | -- | 21.8 | -- | 2.8 | 18.9 | -- | -- |
| 50 percent | 14.5 | -- | -- | 14.5 | -- | 2.1 | 12.4 | -- | -- |
| 25 percent | -- | -- | -- | -- | -- | -- | -- | -- | -- |
| Minimum | 14.5 | -- | -- | 14.5 | -- | 2.1 | 12.4 | -- | -- |

**Emissions:[I]**

| Load Point | Gross Load | Nitrogen Oxides | Sulfur Oxides | Hydrogen Sulfide | Carbon Monoxide | Isopentane | Particulate Matter |
|---|---|---|---|---|---|---|---|
| | MW | tons/year | tons/year | tons/year | tons/year | tons/year | tons/year |
| Normal Top | 25.00 | 0.00 | 0.00 | 0.00 | 0.00 | 1.50 | 0.00 |




**Grid Services**

| | | | | |
|---|---|---|---|---|
| Ramping Capabilities | MW/minute | 0.3-1.3 | Dispatchable (ORC only)? | Yes |
| Inertia Constant | MW-sec/MVA | 3-4 | Voltage Regulation? | Yes |
| Start Time (min) | minutes | 60-600 | Disturbance Ride Through? | Yes |
| Underfreq. Droop Response? | | Yes | Overfreq. Droop Response? | Yes |

**General Site/Technology Characteristics:**

| | | |
|---|---|---|
| Unit Type | | Binary |
| Working Fluid | | Isopentane |
| Total Operating Wells | | 10 |
| Production Wells | | 5 |
| Injection Wells | | 5 |
| Generator Type | | Synchronous |
| Minimum Land Requirement | acres | 25.0 |
| Cooling Type | | Air-Cooled |

**Daily Resource Requirements at Normal Top Load:**

| | | |
|---|---|---|
| Fuel | bpd | none |
| Service & Plant Water[J] | mgd | none |

**Waste Streams:**

| | | |
|---|---|---|
| Solid Waste | tpd | -- |
| Waste Water Discharge | mgd | -- |
| Water Discharge Temperature | F | -- |

**Availability:**

| | | |
|---|---|---|
| Plant Maintenance Pattern | wk/y | 3-3-3-3-3-8 |
| Average Annual Maintenance | weeks | 3.8 |
| Immaturity Period | weeks | 52 |
| Immature Forced Outage Rate | percent | 9 |
| Minimum Weeks Between Maintenance | weeks | 50 |
| Mature Forced Outage Rate | percent | 6 |
| Equivalent Availability | percent | 86.7 |

*IRP 2013 UIF Notes: Advanced Geothermal Development 25 MW*

Notes: **(A)** Unit ratings were based on previous IRP estimates for likely resource potential. Turndown reflects bypass of heat exchangers and recycle of geothermal fluid.

**(B)** Capacity factor based on 8,760 operating hours per year, assuming no required periods of turndown.

**(C)** The capital cost estimates were derived from design reports, with input from HECO and adjustments made for HI specific factors. The main public reports were:
**Black & Veatch,** "Cost And Performance Data For Power Generation Technologies", National Renewable Energy Laboratory, 2012.
**Hance, C.N.** "Factors Affecting Cost of Geothermal Power Development", Geothermal Energy Association, August 2005.
**GeothermEx, Inc.,** "Assessment of Energy Reserves and Costs of Geothermal Resources in Hawaii", Hawaii Department of Business, Economic Development, and Tourism, Honolulu, HI, 2005.
"Advanced" site assumes a known resource potential with previous development, reducing new development costs.

**(D)** Capital costs (excluding land, T&D, and wells) was estimated from published and proprietary data , averaged, adjusted for inflation per historic CE Plant Index rates and distributed across different development subcategories. This provided mainland costs; each factor was when adjusted for HI specific values taking into account labor, productivity, shipping, and taxes.
Well costs were estimated at $8.5MM per well ($6.5MM in 2005 dollars, adjusted to 2012$ per CE Plant Index rates). Well costs are Hawaii specific, and represent an average value of the expected range of $4-9MM per well ($2005) as indicated in the 2005 GeothermEx report. 10 operating wells and 2 dry wells assumed for the cost estimate. $3MM added to the capital cost for multiple heat exchangers and ancillary equipment (SCADA, VFDs, etc) to provide operational flexibility to run as low as 50 percent turbine output on a regular basis if needed.

**(E)** Special Siting Costs (i.e. wells and exploration) are accounted for in the capital cost estimate; switchyard costs included in T&D estimate.

**(F)** T&D Interconnection costs provided by Black & Veatch estimators based on current EPC work on T&D systems being performed in Hawaii by B&V.

**(G)** Land costs based on assumption that 1 acre per MW (net) of land is required at cost of $5 per sq. ft. Land requirements vary, and published values for binary plants range from 0.2 - 8.0 acres per MW. Land value estimated at $5/sq. ft. per HECO estimates, based on Waena assessed value of $4.71 and a total range of $1.2-$11/sq. ft. for 2012 assessed land value in Hawaii.

**(H)** Fixed O&M cost estimate based on 30 operators at burdened salary rate of $86.40/hour (rate provided by HECO). Hance (2005) indicated that operations staff requirements are not purely dependant on facility size and that plants from 15MW to 100MW typically require crews of 5-7 staff working 24 hr/7-day shifts, which amounts to 22-31 full time equivalents, assuming a 2 week vacation for each.
Variable O&M costs are comprised of (1) consumables (materials, chemicals, etc.), (2) well replacement costs, and (3) regular maintenance. Well replacement costs were estimated by assuming one new well would be needed every 5 years, and that one out of every five wells would be dry. Maintenance cost estimated at 1 percent of capital cost yearly.

**(I)** Binary geothermal plants are closed systems and therefore have no direct emissions since gases typically remain in solution and are injected back into the geothermal field. Air-cooled systems have no PM emissions. Fugitive emissions (e.g. from well drilling/testing) and emissions associated with ancillary systems (e.g. emergency backup generators) are considered to be negligible and are not included in this UDS. Fugitive emissions of working fluid (isopentane) are expected through valve leaks, etc. Assumptions: three 10 MW turbines with a capacity of 50 tons of isopentane each at a 1.0% annual leakage rate gives 1.5 tons/year of fugitive emissions of isopentane.

**(J)** Air cooled plant; no water required for cooling. No fresh water assumed needed for reservoir pressure maintenance. Remainder of plant needs very small.

Table D-2
25 MW New Development Geothermal Unit Information Form

| | |
|---|---|
| Utility: | *HECO* |
| Unit Type: | *Geothermal (25 MW)* |
| Fuel Type: | *--* |
| Site: | *New, Undeveloped Location* |

## UNIT INFORMATION FORM

## HECO IRP 2013

| | |
|---|---|
| Date: | *October 11, 2012* |
| By: | *Black & Veatch* |
| Supersedes: | *August 27, 2012* |

**Unit Ratings at Average Conditions:**[A]

| | | Gross | Net |
|---|---|---|---|
| Normal Top Load | MW | 29.0 | 25.5 |
| Emergency | MW | 29.0 | 25.5 |
| Minimum | MW | 14.5 | 12.4 |

**Ambient Conditions:**

| | | |
|---|---|---|
| Dry Bulb Temperature | F | 77 |
| Relative Humidity | percent | 70 |
| CTG Inlet Air Temperature | F | N/A |

**Operating Mode:**[B]

| | | |
|---|---|---|
| Duty Cycle | | Baseload, with dispatch capability |
| Capacity Factor | percent | 85 |

**Commercial Service:**

| | | |
|---|---|---|
| Date Available | month/year | 2016 |
| Service Life | years | 30 |

**Lead Time (Prior to Commercial Oper):**

| | | Normal | Expedited |
|---|---|---|---|
| Permitting | months | 51 | -- |
| Engineering | months | 42 | -- |
| Procurement | months | 30 | -- |
| Construction | months | 18 | -- |

| | | |
|---|---|---|
| **Year Dollars** | | December 2011 |
| **Capital Cost Uncertainty:** | plus/minus | +30% / -30% |

**Capital Cost (without AFUDC)**[C]**:**

| | $million | $/kW$_{gross}$ | $/kW$_{net}$ |
|---|---|---|---|
| A. Total Power Block Cost (base)[D] | 233.99 | 8,069 | 9,176 |
| B. Special Siting Costs[E] | - | - | - |
| C. Power Plant Switchyard[E] | - | - | - |
| D. T&D Interconnection[F] | 4.40 | 152 | 173 |
| E. Total Direct Cost (A1+B+C+D) | 238.39 | 8,220 | 9,349 |
| F. Total Indirect Cost[D] | 37.82 | 1,304 | 1,483 |
| G. Land Cost[G] | 5.45 | 188 | 214 |
| H. Total Capital Cost (E+F+G) | 281.66 | 9,712 | 11,045 |

**Operations & Maintenance:**[H]

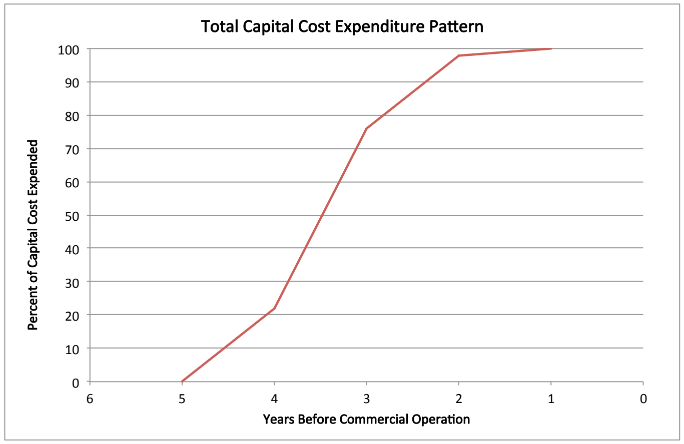
| | $/y | $/kW-y$_{gross}$ | $/kW-y$_{net}$ |
|---|---|---|---|
| Fixed Cost | 5,391,360 | 186 | 211 |
| | | $/MWh$_{gross}$ | $/MWh$_{net}$ |
| Variable Cost | 5,658,261 | 26.20 | 29.80 |
| Total First Year O&M | 11,049,621 | | |

**Capacity and Heat Rate Data:**

| Load Point | Gross Load | HHV Fuel Input | Gross Load Split CTG | Gross Load Split STG | Auxiliary Load Split CTG | Auxiliary Load Split BOP | Net Load | Net Plant Heat Rate | Quick Ld. Pickup |
|---|---|---|---|---|---|---|---|---|---|
| | MW | MBtu/h | MW | MW | MW | MW | MW | Btu/kWh | MW |
| Normal Top | 29.0 | -- | -- | 29.0 | -- | 3.5 | 25.5 | -- | -- |
| 75 percent | 21.8 | -- | -- | 21.8 | -- | 2.8 | 18.9 | -- | -- |
| 50 percent | 14.5 | -- | -- | 14.5 | -- | 2.1 | 12.4 | -- | -- |
| 25 percent | -- | -- | -- | -- | -- | -- | -- | -- | -- |
| Minimum | 14.5 | -- | -- | 14.5 | -- | 2.1 | 12.4 | -- | -- |

**Emissions:**[I]

| Load Point | Gross Load | Nitrogen Oxides | Sulfur Oxides | Hydrogen Sulfide | Carbon Monoxide | Isopentane | Particulate Matter |
|---|---|---|---|---|---|---|---|
| | MW | tons/year | tons/year | tons/year | tons/year | tons/year | tons/year |
| Normal Top | 25.00 | 0.00 | 0.00 | 0.00 | 0.00 | 1.50 | 0.00 |




**Grid Services**

| | | | | |
|---|---|---|---|---|
| Ramping Capabilities | MW/minute | 0.3-1.3 | Dispatchable (ORC only)? | Yes |
| Inertia Constant | MW-sec/MVA | 3-4 | Voltage Regulation? | Yes |
| Start Time (min) | minutes | 60-600 | Disturbance Ride Through? | Yes |
| Underfreq. Droop Response? | | Yes | Overfreq. Droop Response? | Yes |

**General Site/Technology Characteristics:**

| | | |
|---|---|---|
| Unit Type | | Binary |
| Working Fluid | | Isopentane |
| Total Operating Wells | | 12 |
| Production Wells | | 6 |
| Injection Wells | | 6 |
| Generator Type | | Synchronous |
| Minimum Land Requirement | acres | 25.0 |
| Cooling Type | | Air-Cooled |

**Daily Resource Requirements at Normal Top Load:**

| | | |
|---|---|---|
| Fuel | bpd | none |
| Service & Plant Water[J] | mgd | none |

**Waste Streams:**

| | | |
|---|---|---|
| Solid Waste | tpd | -- |
| Waste Water Discharge | mgd | -- |
| Water Discharge Temperature | F | -- |

**Availability:**

| | | |
|---|---|---|
| Plant Maintenance Pattern | wk/y | 3-3-3-3-3-8 |
| Average Annual Maintenance | weeks | 3.8 |
| Immaturity Period | weeks | 52 |
| Immature Forced Outage Rate | percent | 9 |
| Minimum Weeks Between Maintenance | weeks | 50 |
| Mature Forced Outage Rate | percent | 6 |
| Equivalent Availability | percent | 86.7 |

*IRP 2013 UIF Notes: New Geothermal Development 25 MW*

Notes:

**(A)** Unit ratings were based on previous IRP estimates for likely resource potential. Turndown reflects bypass of heat exchangers and recycle of geothermal fluid.

**(B)** Capacity factor based on 8,760 operating hours per year.

**(C)** The capital cost estimates were derived from design reports, with input from HECO and adjustments made for HI specific factors. The main public reports were:
**Black & Veatch,** "Cost And Performance Data For Power Generation Technologies", National Renewable Energy Laboratory, 2012.
**Hance, C.N.** "Factors Affecting Cost of Geothermal Power Development", Geothermal Energy Association, August 2005.
**GeothermEx, Inc.,** "Assessment of Energy Reserves and Costs of Geothermal Resources in Hawaii", Hawaii Department of Business, Economic Development, and Tourism, Honolulu, HI, 2005.
"New" site refers to greater uncertainty in resource potential and locations for geothermal fluid reservoirs, leading to higher development costs.

**(D)** Capital costs (excluding land, T&D, and wells) was estimated from published and proprietary data , averaged, adjusted for inflation per historic CE Plant Index rates and distributed across different development subcategories. This provided mainland costs; each factor was when adjusted for HI specific values taking into account labor, productivity, shipping, and taxes.
Well costs were estimated at $8.5MM per well ($6.5MM in 2005 dollars, adjusted to 2012$ per CE Plant Index rates). Well costs are Hawaii specific, and represent an average value of the expected range of $4-9MM per well ($2005) as indicated in the 2005 GeothermEx report. 12 operating wells and 2 dry wells assumed for the cost estimate. $3MM added to the capital cost for multiple heat exchangers and ancillary equipment (SCADA, VFDs, etc) to provide operational flexibility to run as low as 50 percent turbine output on a regular basis if needed.

**(E)** Special Siting Costs (i.e. wells and exploration) are accounted for in the capital cost estimate; switchyard costs included in T&D estimate.

**(F)** T&D Interconnection costs provided by Black & Veatch estimators based on current EPC work on T&D systems being performed in Hawaii by B&V.

**(G)** Land costs based on assumption that 1 acre per MW (net) of land is required at cost of $5 per sq. ft. Land requirements vary, and published values for binary plants range from 0.2 - 8.0 acres per MW. Land value estimated at $5/sq. ft. per HECO estimates, based on Waena assessed value of $4.71 and a total range of $1.2-$11/sq. ft. for 2012 assessed land value in Hawaii.

**(H)** Fixed O&M cost estimate based on 30 operators at burdened salary rate of $86.40/hour (rate provided by HECO). Hance (2005) indicated that operations staff requirements are not purely dependant on facility size and that plants from 15MW to 100MW typically require crews of 5-7 staff working 24 hr/7-day shifts, which amounts to 22-31 full time equivalents, assuming a 2 week vacation for each.
Variable O&M costs are comprised of (1) consumables (materials, chemicals, etc.), (2) well replacement costs, and (3) regular maintenance. Well replacement costs were estimated by assuming one new well would be needed every 5 years, and that one out of every five wells would be dry. Maintenance cost estimated at 1 percent of capital cost yearly.

**(I)** Binary geothermal plants are closed systems and therefore have no direct emissions since gases typically remain in solution and are injected back into the geothermal field. Air-cooled systems have no PM emissions. Fugitive emissions (e.g. from well drilling/testing) and emissions associated with ancillary systems (e.g. emergency backup generators) are considered to be negligible and are not included in this UDS. Fugitive emissions of working fluid (isopentane) are expected through valve leaks, etc. Assumptions: three 10 MW turbines with a capacity of 50 tons of isopentane each at a 1.0% annual leakage rate gives 1.5 tons/year of fugitive emissions of isopentane.

**(J)** Air cooled plant; no water required for cooling. No fresh water assumed needed for reservoir pressure maintenance. Remainder of plant needs very small.

Table E-1
750 kW Ocean Wave Unit Information Form

## UNIT INFORMATION FORM

## HECO IRP 2013

| | |
|---|---|
| **Utility:** | *HECO* |
| **Unit Type:** | *Ocean Wave - 750 kW* |
| **Fuel Type:** | *--* |
| **Site:** | *Pauwela, Maui, 1 mile from shore* |

| | |
|---|---|
| **Date:** | *March 23, 2013* |
| **By:** | *Black & Veatch* |
| **Supersedes:** | *October 11, 2012* |

**Unit Ratings:[A]**

| | | Rated | Gross | Net |
|---|---|---|---|---|
| Normal Top Load | MW | 0.75 | 0.12 | 0.12 |
| Energy Production | MWh/yr | 6,570 | 1,074 | 1,052 |

**Ambient Conditions:**

| | | |
|---|---|---|
| Dry Bulb Temperature | F | 77 |
| Relative Humidity | percent | 70 |

**Operating Mode:**

| | | |
|---|---|---|
| Duty cycle | | Supplemental |
| Capacity Factor | percent | 16 |

**Commercial Service:[B]**

| | | | |
|---|---|---|---|
| Date Available | month/year | June | 2016 |
| Service Life | years | | 20 |

**Lead Time (Prior to Commercial Oper):**

| | | Normal | Expedited |
|---|---|---|---|
| Permitting | months | 46 | -- |
| Engineering | months | 28 | -- |
| Procurement | months | 15 | -- |
| Construction | months | 6 | -- |

| | | |
|---|---|---|
| **Year Dollars:** | | December 2011 |
| **Capital Cost Uncertainty:** | plus/minus | +50%/-25% |

**Capital Cost (w/o AFUDC):[C]**

| | $million | $/kW rated | $/kW net |
|---|---|---|---|
| A. Machine installed cost[D] | 9.23 | 12,312 | 76,914 |
| B. Project development[E] | 1.05 | 1,400 | 8,746 |
| C. Balance of plant[F] | 5.5 | 7,280 | 45,478 |
| D. Onshore grid connection[G] | 1.0 | 1,333 | 8,329 |
| E. Total Direct Cost (A+B+C+D) | 16.74 | 22,326 | 139,467 |
| F. Total Indirect Cost[H] | - | - | - |
| H. Total Capital Cost (E+F) | 16.74 | 22,326 | 139,467 |

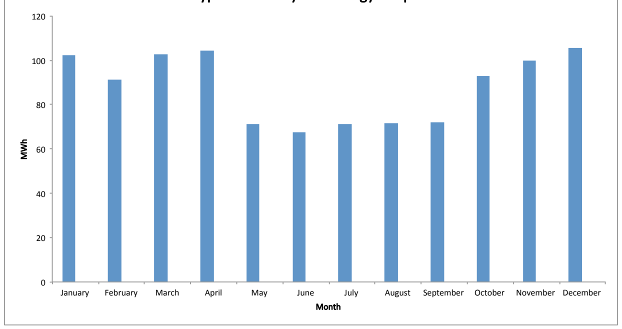
**Operations & Maintenance:[I]**

| | $/y | $/kW-y rated | $/kW-y net |
|---|---|---|---|
| Fixed Cost | 722,559 | 963 | 6018 |

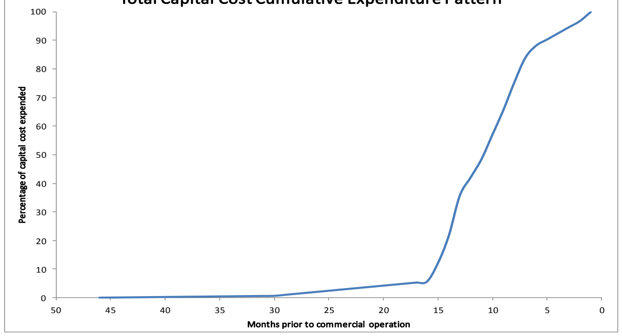
| | $/y | $/MWh rated | $/MWh net |
|---|---|---|---|
| Variable Cost | 0 | 0 | 0 |

| | |
|---|---|
| Subsurface Lease | 18,216 |
| Total First Year O&M | 740,775 |

Typical Monthly Net Energy Output[J]




Total Capital Cost Cumulative Expenditure Pattern




**General Site/Technology Characteristics:[K]**

| | | |
|---|---|---|
| Distance from Shore | miles | 1.0 |
| Average Wave Power Density | kW/m | 20.5 |
| Water Depth | ft | 239 |
| Latitude | | 20.958 |
| Longitude | | -156.322 |
| Generator | | Induction |

**Energy Losses:[L]**

| | | |
|---|---|---|
| Transmission Line Losses | percent | 2 |
| Total | percent | 2 |

**Availability:**

| | | |
|---|---|---|
| Immaturity Period | weeks | 8 |
| Immature Forced Out. Rate | percent | 3 |
| Mature Forced Out. Rate | percent | 5 |
| Availability Factor | percent | 92 |

**Equipment Parameters:**

| | | |
|---|---|---|
| Nominal Rating (per machine) | kW | 750 |

**Grid Services:[M]**

| | | |
|---|---|---|
| Ramping Capabilities | MW/min | 0.075 |
| Inertia Constant | MW-sec/MVA | NA |
| Start Time | minutes | NA |
| Dispatchable? | | No |
| Voltage Regulation? | | Yes |
| Disturbance Ride Through? | | Yes |
| Underfreq. Droop Response? | | No |
| Overfreq. Droop Response? | | Yes |

Table E-2
15 MW Ocean Wave Unit Information Form

| | | | |
|---|---|---|---|
| Utility: | HECO | Date: | March 23, 2013 |
| Unit Type: | Ocean Wave - 15 MW (20 750 kW Machines) | By: | Black & Veatch |
| Fuel Type: | -- | Supersedes: | October 11, 2012 |
| Site: | Pauwela, Maui, 1 mile from shore | | |

## UNIT INFORMATION FORM

## HECO IRP 2013

**Unit Ratings:[A]**

| | | Rated | Gross | Net |
|---|---|---|---|---|
| Normal Top Load | MW | 15.0 | 3.01 | 2.95 |
| Energy Production | MWh/yr | 131,400 | 26,410 | 25,882 |

**Ambient Conditions:**

| | | |
|---|---|---|
| Dry Bulb Temperature | F | 77 |
| Relative Humidity | percent | 70 |

**Operating Mode:**

| | | |
|---|---|---|
| Duty cycle | | Supplemental |
| Capacity Factor[A] | percent | 20 |

**Commercial Service:[B]**

| | | | |
|---|---|---|---|
| Date Available | month/year | June | 2020 |
| Service Life | years | | 20 |

**Lead Time (Prior to Commercial Oper):**

| | | Normal | Expedited |
|---|---|---|---|
| Permitting | months | 46 | -- |
| Engineering | months | 28 | -- |
| Procurement | months | 15 | -- |
| Construction | months | 6 | -- |

| | | |
|---|---|---|
| **Year Dollars:** | | December 2011 |
| **Capital Cost Uncertainty:** | plus/minus | +50%/-25% |

**Capital Cost (w/o AFUDC):[C]**

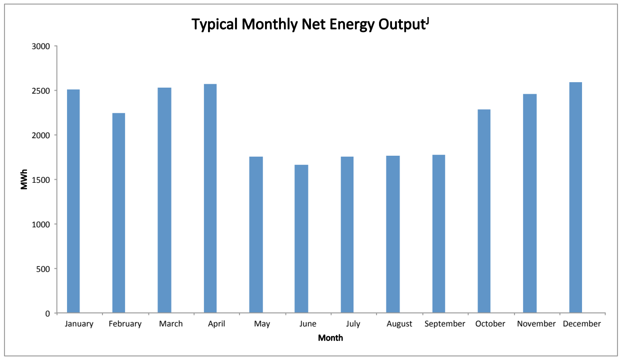
| | $million | $/kW$_{rated}$ | $/kW$_{net}$ |
|---|---|---|---|
| A. Machine installed cost[D] | 106.55 | 7,103 | 36,088 |
| B. Project development[E] | 1.05 | 70 | 356 |
| C. Balance of plant[F] | 8.4 | 560 | 2,845 |
| D. Onshore grid connection[G] | 5.0 | 333 | 1,693 |
| E. Total Direct Cost (A+B+C+D) | 121.00 | 8,067 | 40,982 |
| F. Total Indirect Cost[H] | - | - | - |
| H. Total Capital Cost (E+F) | 121.00 | 8,067 | 40,982 |

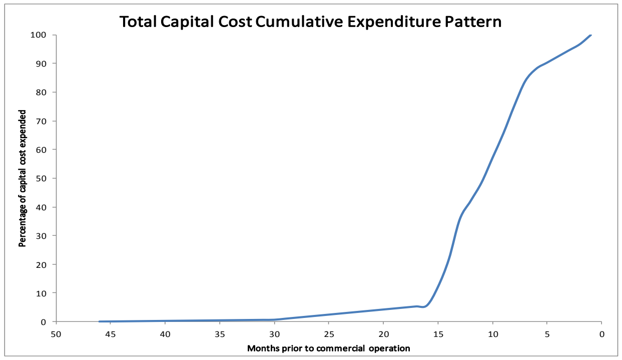
**Operations & Maintenance:[I]**

| | $/y | $/kW-y$_{rated}$ | $/kW-y$_{net}$ |
|---|---|---|---|
| Fixed Cost | 4,342,253 | 289 | 1471 |

| | $/y | $/MWh$_{rated}$ | $/MWh$_{net}$ |
|---|---|---|---|
| Variable Cost | 0 | 0 | 0 |

| | |
|---|---|
| Subsurface Lease | 18,216 |
| Total First Year O&M | 4,360,469 |




**General Site/Technology Characteristics:[K]**

| | | |
|---|---|---|
| Distance from Shore | miles | 1.0 |
| Average Wave Power Density | kW/m | 20.5 |
| Water Depth | ft | 239 |
| Latitude | | 20.958 |
| Longitude | | -156.322 |
| Generator | | Induction |

**Energy Losses:[L]**

| | | |
|---|---|---|
| Transmission Line Losses | percent | 2 |
| Total | percent | 2 |

**Availability:[M]**

| | | |
|---|---|---|
| Immaturity Period | weeks | 4 |
| Immature Forced Out. Rate | percent | 0 |
| Mature Forced Out. Rate | percent | 5 |
| Availability Factor | percent | 95 |

**Equipment Parameters:**

| | | |
|---|---|---|
| Nominal Rating (per machine) | kW | 750 |

**Grid Services:[N]**

| | | |
|---|---|---|
| Ramping Capabilities | MW/min | 0.075 |
| Inertia Constant | MW-sec/MVA | NA |
| Start Time | minutes | NA |
| Dispatchable? | | No |
| Voltage Regulation? | | Yes |
| Disturbance Ride Through? | | Yes |
| Underfreq. Droop Response? | | No |
| Overfreq. Droop Response? | | Yes |

## *HECO IRP 2013 UIF Notes: 750 kW Ocean Wave*

**Notes:**

(A) Unit ratings and energy production are based as follows:
Rated capacity at 750kW/machine (Pelamis)
in 2020. Adjusted from 500 kW per HECO direction.
Output based on energy output from the machine (note K), including
transmission losses and availability as specified.
Rating of machine reduced from standard to achieve sensible CF in the
relatively low wave energy resource in Hawaii.
(B) Commercial demonstrations on-going in UK, but not in HI.
(C) Capital costs based on a (future) cost model of Pelamis that has been
extensively validated by Black & Veatch in other work.
Parts manufactured in the US converted using £1:$1.4. Parts manufactured
in the UK converted using £1:$1.6 dollars. 5% added to all parts costs
for shipping to Hawaii (tubes shipped from mainland US and other materials
from the UK.) Pelamis is a leading wave energy developer, with one of the
best understood cost of energy for large scale deployments.
The industry is at a very early stage of development and the costs reflect this.
Machine is not optimized for Hawaii wave climate other than reduced rating.

Cost of energy could be improved by redesigning the machine for this climate,
which is different from NE Atlantic wave climate (lower intensity and longer
period waves). EPRI took a similar approach to reducing rating in 2005.
Optimization from machine geometry and advanced control at low sea states.
(D) Machine installed cost includes engineering, all manufacturing, and
installation (including moorings and spares).
(E) Project development includes permitting and site investigation.
(F) Balance of plant includes electrical costs to the point of shore connection
(not including any components on shore, just offshore cable to landfall).
(G) Onshore grid connection estimate based on data used for
wind energy interconnection cost.
(H) Indirect costs such as construction mob/demob, security, health & safety,
site clean-up, support staff, engineering and const. mgmt. are included in the
machine installed costs and not separately defined.
(I) Operations and maintenance costs are taken from the cost model of Pelamis
and converted using £1:$1.4. O&M costs include insurance and lease costs.
O&M costs do not vary with output due to early stage of the technology.
Subsurface lease for transmission line ROW, 1 mile long, 5 feet wide.

(J) Avg. monthly machine energy output data based on 10 years of wave data from HINMREC
SWAN model analysis at Pauwela and Pelamis power matrices with an uncertainty of +/-15%.
Includes transmission losses and availability. Output is estimated to be flat over an average day.
(K) Located at Pauwela using the site analysis in HINMREC report (73m depth).
(L) Energy losses shows transmission losses only; all other losses are included
in the Pelamis power matrices and hence directly in the energy calculations.
(M) Ramp-up only possible, provided that unit is not operating at full potential. Ramp down cannot be
controlled due to lack of resource certainty. Ramp-up rate ~10% of rated capacity/min.
Voltage regulation requires SCADA and proper control devices.
Overfrequency droop response only; plant unlikely to operate below available capacity to provide
underfrequency droop response.

**References**

Hawaii National Marine Renewable Energy Center (HINMREC) Wave Power Analysis for Selected Sites Around the Hawaiian Islands, August 2, 2011.

## *HECO IRP 2013 UIF Notes: 15 MW Ocean Wave*

**Notes:**

(A) Unit ratings and energy production are based as follows:
Rated capacity at 750kW/machine (Pelamis) and 20 machines for 15MW
in 2020. Adjusted from 500 kW per HECO direction.
Output based on energy output from the machine (note K), including
transmission losses and availability as specified.
Rating of machine reduced from standard to achieve sensible CF in the
relatively low wave energy resource in Hawaii. Higher CF than in the
750 kW (2016) UDS assuming designs optimized for HI wave resource.
(B) Commercial demonstrations on-going in UK, but not in HI.
(C) Capital costs based on a (future) cost model of Pelamis that has been
extensively validated by Black & Veatch in other work.
Parts manufactured in the US converted using £1:$1.4. Parts manufactured
in the UK converted using £1:$1.6 dollars. 5% added to all parts costs
for shipping to Hawaii (tubes shipped from mainland US and other materials
from the UK.) Pelamis is a leading wave energy developer, with one of the
best understood cost of energy for large scale deployments.
The industry is at a very early stage of development and the costs reflect this.
Costs will likely reduce significantly over time due to learning;
this is reflected in the 2016 to 2020 transition.
Machine is not optimized for Hawaii wave climate other than reduced rating.

Cost of energy could be improved by redesigning the machine for this climate,
which is different from NE Atlantic wave climate (lower intensity and longer
period waves). EPRI took a similar approach to reducing rating in 2005.
Optimization from machine geometry and advanced control at low sea states.
(D) Machine installed cost includes engineering, all manufacturing, and
installation (including moorings and spares).
(E) Project development includes permitting and site investigation.
(F) Balance of plant includes electrical costs to the point of shore connection
(not including any components on shore, just offshore cable to landfall).
(G) Onshore grid connection estimate based on data used for
wind energy interconnection cost.
(H) Indirect costs such as construction mob/demob, security, health & safety,
site clean-up, support staff, engineering and const. mgmt. are included in the
machine installed costs and not separately defined.
(I) Operations and maintenance costs are taken from the cost model of Pelamis
and converted using £1:$1.4. O&M costs include insurance and lease costs.
O&M costs do not vary with output due to early stage of the technology.
Subsurface lease for transmission line ROW, 1 mile long, 5 feet wide.

(J) Avg. monthly machine energy output data based on 10 years of wave data from HINMREC
SWAN model analysis at Pauwela and Pelamis power matrices with an uncertainty of +/-15%.
Includes transmission losses and availability. Output is estimated to be flat over an average day.
(K) Located at Pauwela using the site analysis in HINMREC report (73m depth).
(L) Energy losses shows transmission losses only; all other losses are included
in the Pelamis power matrices and hence directly in the energy calculations.
(M) Availability greater than in 750 kW (2016) case due to assumed improvements in technology
(N) Ramp-up only possible, provided that unit is not operating at full potential. Ramp down cannot be
controlled due to lack of resource certainty. Ramp-up rate ~10% of rated capacity/min.
Voltage regulation requires SCADA and proper control devices.
Overfrequency droop response only; plant unlikely to operate below available capacity to provide
underfrequency droop response.

**References**

Hawaii National Marine Renewable Energy Center (HINMREC) Wave Power Analysis for Selected Sites Around the Hawaiian Islands, August 2, 2011.

Table F-1
9.6 MW Ocean Thermal Energy Unit Data Sheet

## UNIT INFORMATION FORM

## HECO IRP 2013

| | |
|---|---|
| **Utility:** | *HECO* |
| **Unit Type:** | *9.6 MW Ocean Thermal* |
| **Fuel Type:** | *--* |
| **Site:** | *Oahu (South Coast), 20 miles from shore* |

| | |
|---|---|
| **Date:** | *March 23, 2013* |
| **By:** | *Black & Veatch* |
| **Supersedes:** | *October 11, 2012* |

**Unit Ratings:**[A]

| | | Rated | Avg. Gross | Avg. Net |
|---|---|---|---|---|
| Normal Top Load | MW | 9.6 | 5.2 | 5.0 |
| Minimum | MW | 9.6 | 0.0 | 0.0 |
| Energy Production | MWh/yr | 79,891 | 42,897 | 41,610 |

**Ambient Conditions:**

| | | |
|---|---|---|
| Dry Bulb Temperature | F | 77 |
| Relative Humidity | percent | 70 |

**Operating Mode:**

| | | |
|---|---|---|
| Duty Cycle | | Baseload |
| Capacity Factor | percent | 52.1 |

**Commercial Service:**

| | | | |
|---|---|---|---|
| Date Available | month/year | January | 2018 |
| Service Life | years | | 20 |

**Lead Time (Prior to Commercial Oper):**[B]

| | | |
|---|---|---|
| Permitting | months | 45 |
| Engineering | months | 36 |
| Procurement & Construction | months | 24 |
| Deployment, Startup, Commissioning | months | 12 |

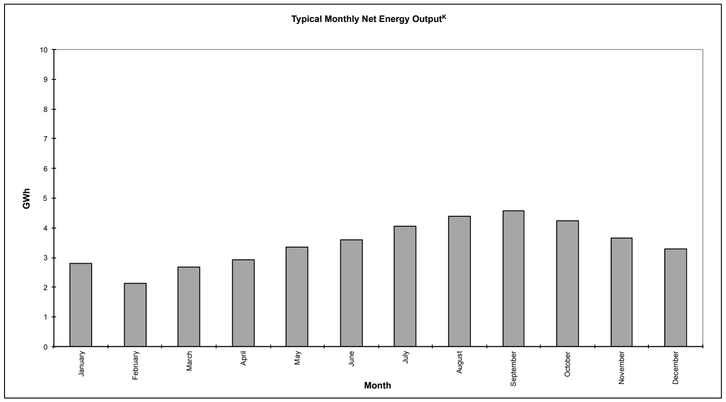
| | | |
|---|---|---|
| **Year Dollars**[C]**:** | | December 2011 |
| **Capital Cost Uncertainty:** | plus/minus | +100%/-50% |
| **Technology Readiness Level (1-9)** | | 5 |

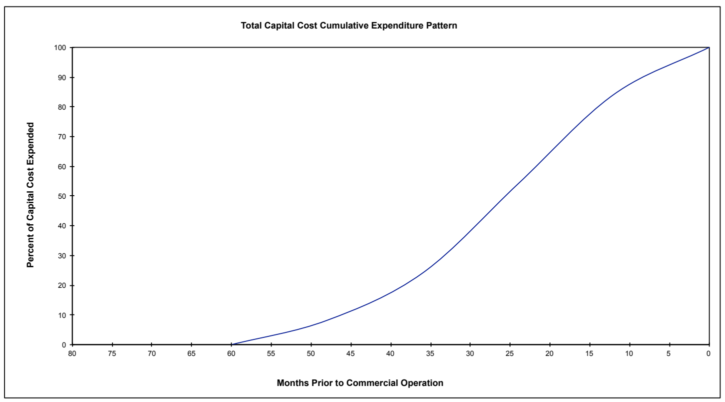
**Capital Cost (w/o AFUDC):**[C]

| | $million | $/kW$_{rated}$ | $/kW$_{net}$ |
|---|---|---|---|
| A. 9.6 MW Power Block Cost[D] | 286.83 | 29,878 | 57,365 |
| B. Special Siting Costs[E] | 83.04 | 8,650 | 16,609 |
| C. Power Plant Switchyard[F] | - | - | - |
| D. T&D Interconnection[G] | 20.81 | 2,168 | 4,163 |
| E. Total Direct Cost (A+B+C+D) | 390.68 | 40,696 | 78,137 |
| F. Total Indirect Cost[I] | 50.44 | 5,254 | 10,088 |
| G. Land Cost[H] | 0.05 | 5 | 10 |
| H. Total Capital Cost (E+F) | 441.18 | 45,956 | 88,235 |

**Operations & Maintenance:**[J]

| | $/y | $/kW-y$_{rated}$ | $/kW-y$_{net}$ |
|---|---|---|---|
| Fixed Cost | 3,414,528 | 355.68 | 682.91 |
| | | $/MWh$_{rated}$ | $/MWh$_{net}$ |
| Variable Cost | 3,235,563 | 40.50 | 77.76 |
| Submerged land Lease | 381,522 | | |
| Total First Year O&M | 7,031,613 | | |




**General Site/Technology Characteristics:**[L]

| | | |
|---|---|---|
| Average Cold Water Inlet Temperature | F | 39.4 |
| Average Warm Water Inlet Temperature | F | 78.3 |
| Cold Water Pipe Depth | ft | 3281 |
| Distance from Shore | miles | 20 |
| Generator | | Synchronous |

**Energy Losses:**[M]

| | | |
|---|---|---|
| Transmission Losses | percent | 3 |

**Availability:**

| | | |
|---|---|---|
| Immaturity Period | weeks | 3 |
| Immature Forced Outage Rate | percent | 33 |
| Minimum Weeks Between Maintenance | weeks | 51 |
| Maintenance Requirement | weeks | 1 |
| Mature Forced Outage Rate | percent | 5 |
| Availability Factor | percent | 95 |

**Equipment Parameters:**

| | | |
|---|---|---|
| Nominal Rating | MVA | 11.76 |
| Cycle Type | | Binary |
| Average Cold Water Flow Rate | gpm | 282,136 |
| Average Warm Water Flow Rate | gpm | 355,047 |
| Average Working Fluid (NH3) Flow Rate | lb/s | 447 |

**Grid Services:** [N]

| | | | |
|---|---|---|---|
| Ramping Capabilities (MW/min) | 0.5 | Dispatchable? | No |
| Inertia Constant (MW-sec/MVA) | 1-2 | Voltage Regulation? | Yes |
| Start Time (min) | <30 | Disturbance Ride Through? | Yes |
| Underfreq. Droop Response? | Yes | Overfreq. Droop Response? | Yes |

*HECO IRP 2013 UIF Notes: OTEC*

Notes:

(A) Unit ratings and energy production are based as follows:
Rated capacity at 11.76 MVA = 9.6 MW.
Gross capacity based on aux. load and mean annual output due to ocean temp. variations. Net takes into account trans. losses.
These and other assumptions are documented in this report:
*Cable, Brian (Lockheed Martin), "NAVFAC Ocean Thermal Energy Conversion (OTEC), Project N62583-09-C-0083, CDRL A003: OTEC System Design Report", Naval Facilities Engineering Services Center, Port Hueneme, CA, November 2010.*
Energy production estimate accounts for availability.

(B) Lead time is for permitting pilot plant. Additional permits needed for expansion to 10 MW. Includes EIS preparation NEPA, NPDES, DoD permits and obtaining land ROW (Lockheed report). Other durations reported by Vega, 2007 total 5 years for permitting, design, construction, startup.

(C) Capital costs based on Lockheed Martin/Navy report figures, adjusted to $2012 and with Black & Veatch assumptions applied.
Costs are Hawaii specific, assuming major components fabricated on the mainland and shipped to HI. Fabrication in Far East may reduce costs.
Cost estimate ranges per AACE 18R-97 for class 5 estimate (rev. Nov. 2011).
(D) Includes platform and power gen and I&C. Converted from 2010$ to 2012$.
(E) Special siting costs include ocean engineering: OTEC mooring installation and CWP fab system; added $18MM for permanent mooring.
(F) Switchyard costs are included in the T&D costs
(G) T&D Interconnection cost based on 10MW design to allow for expansion, and includes all power delivery, switches, transformers, and transmission line.
(H) Assumed onshore substation at Back Sub. at Hickam Airfield.
55' by 43', plus contingency for additional space needs at $5 per sq. ft.
(I) Indirects include includes program level expenses, permitting, platform engineering, and construction management.

(J) Operations and maintenance costs based on assumption of 12 full time operators on the platform (Lockheed report) and 7 land based personnel (adjusted from Vega presentation, 2007), using Hawaii labor costs. Variable costs assumed as midpoint of 5MW repair/replacement costs as reported by Vega 2007, adjusted to $2012 assuming 2.5% inflation per year. Labor costs assumed to be $86.40 per hour. Submerged land costs are based on the following assumptions:
From the shoreline (high tide) to 3 nautical miles is Hawaii territory; from Hawaii boundary to 200NM is federal territory. Assume 10ft wide by 20 mile long submerged land lease required. 2007 Hawaii rate of $0.60/sq. ft. escalated to $2012 at 2.5% per year. Assumes federal rate is the same.
(K) No diurnal patterns predicted; power fluctuates with seasonal variations in warm water temperature per LM OTEC report (81.7° high; 78.3° med; 73.6° F low). Cold water temperatures vary but are not seasonal: (38.9° low; 39.4° med; 39.8° F high). Seasonal variations were linearly interpolated between "summer" high (Sept.) and winter low (Feb.) values. Weather patterns obtained from: www.weatherbase.com.
(L) As described in Lockheed Martin/Navy 2010 report
(M) Losses and aux load based on median plant output (5MW) as reported in Lockheed OTEC Report.
Losses are 3% due to transmission; aux. load largely from seawater and working fluid pumps.
(N) Level of voltage regulation and droop response is dependent upon seasonal water temperatures

Dr. Vega's analysis used in this study can be seen at http://www.offinf.com/OTECEconomicsEnergyOcean2007Vega.pdf

Table G-1
25 MW Banagrass Combustion Unit Information Form

## UNIT INFORMATION FORM

## HECO IRP 2013

| | |
|---|---|
| **Utility:** | *HECO* |
| **Unit Type:** | *Biomass Combustion - 25 MW* |
| **Fuel Type:** | *Banagrass* |
| **Size:** | *Unspecified Island Site* |

| | |
|---|---|
| **Date:** | *March 25, 2013* |
| **By:** | *Black & Veatch* |
| **Supersedes:** | *October 11, 2012* |

**Unit Ratings:**

| | | Gross | Net |
|---|---|---|---|
| Normal Top Load | MW | 28.1 | 25.0 |
| Minimum | MW | 7.0 | 5.1 |

**Ambient Conditions:**

| | | |
|---|---|---|
| Dry Bulb Temperature | ° F | 77 |
| Relative Humidity | percent | 70 |

**Operating Mode:**

| | | |
|---|---|---|
| Duty Cycle | | Baseload |
| Capacity Factor | percent | 83 |

**Commercial Service:**

| | | | |
|---|---|---|---|
| Date Available[A] | month/year | January | 2018 |
| Service Life | years | | 30 |

**Lead Time (Prior to Comm. Operation):**

| | | Normal | Expedited |
|---|---|---|---|
| Permitting | months | 79 | 72 |
| Engineering | months | 54 | 50 |
| Procurement | months | 39 | 33 |
| Construction | months | 36 | 32 |

| | | |
|---|---|---|
| **Year Dollars:** | | December 2011 |
| **Capital Cost Uncertainty:** | plus/minus | +20%/-20% |

**Capital Cost (without AFUDC):**

| | $million | $/kW$_{gross}$ | $/kW$_{net}$ |
|---|---|---|---|
| A. Power Block Cost[B] | 127.18 | 4,528 | 5,087 |
| B. Special Siting Costs | 0.00 | - | - |
| C. Power Plant Switchyard | 3.80 | 135 | 152 |
| D. T&D Interconnection | 0.00 | - | - |
| E. Total Direct Cost (A+B+C+D) | 130.98 | 4,663 | 5,239 |
| F. Total Indirect Cost (E*0.38) | 49.71 | 1,770 | 1,988 |
| G. Land Cost[C] | 3.05 | 109 | 122 |
| H. Total Capital Cost (E+F+G) | 183.74 | 6,541 | 7,350 |

**Operations & Maintenance:**

| | | |
|---|---|---|
| | $ million/y | or $/kW-y$_{net}$ |
| Fixed Cost | 8.02 | 321 |
| | $ million/y | |
| Land Lease[D] | 1.490 | |
| | $/h run | or $/MWh$_{net}$ |
| Variable Cost | 232 | 9.26 |
| Staffing Requirements | 37 | |

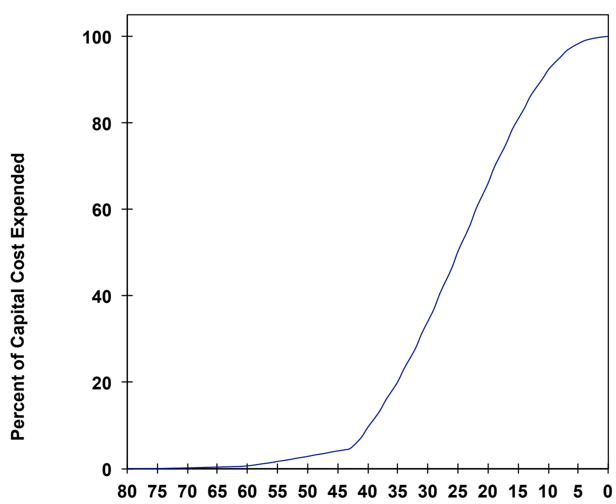
**Capacity and Heat Rate Data:[E]**

| Load Point | # STGs | Amb Cond | Gross Load | Net Load | Net Plant Heat Rate | Quick Load Pickup |
|---|---|---|---|---|---|---|
| | | ° F/RH | MW | MW | Btu/kWh | MW |
| Normal Top | 1 | 77/70 | 28.1 | 25.0 | 14,910 | -- |
| Minimum | 1 | 77/70 | 7.0 | 5.1 | 22,670 | -- |

**Flue Gas Emissions:[F]**

| | Normal Top Load at 77° F/70 %RH | Minimum Load at 77° F/70 %RH |
|---|---|---|
| | lb/MBtu | lb/MBtu |
| Nitrogen Oxides | 0.18 | 0.18 |
| Sulfur Oxides | 0.124 | 0.124 |
| Carbon Dioxide | 222 | 222 |
| Carbon Monoxide | 0.35 | 0.35 |
| Volatile Organic Compounds | 0.02 | 0.02 |
| Particulate Matter | 0.015 | 0.015 |

**Total Capital Cost Cumulative Expenditure Pattern**




**General Site/Technology Characteristics:**

| | | |
|---|---|---|
| Fuel Delivery | | Truck |
| Fuel Storage Onsite/Offsite | | 7 days/0 days |
| Water Supply Source | | Groundwater |
| Cycle Cooling | | Cooling Tower |
| Waste Water Disposal | | Field Irrigation |
| Solid Waste Disposal | | On-Island Landfill |
| Generator | | Synchronous |
| Banagrass Production Cost (FOB plant gate)[G] | $/dry ton | 95 |
| Banagrass Yield[G] | dry ton/acre-y | 21 |
| Banagrass Acreage Requirement[H] | acres | 7860 |
| Minimum Land Requirement | acres | 14.0 |

**Daily Resource Requirements at Normal Top Load:[I]**

| | | |
|---|---|---|
| Fuel (dry basis) | tpd | 555 |
| Urea (dry)[J] | tpd | 2.56 |
| Service & Plant Water | mgd | 1.255 |
| Leaching Process Wash Water[K] | mgd | 0.729 |
| Cooling Tower Makeup[L] | mgd | 0.472 |
| Supply Water Temperature | ° F | 79 |

**Waste Streams:**

| | | |
|---|---|---|
| Solid Waste | tpd | 15.10 |
| Waste Water Discharge | mgd | 1.03 |
| Water Discharge Temperature | ° F | 90 |
| Thermal Discharge[M] | MBtu/d | 94 |

**CTG/HRSG/STG Unit Startup Parameters:**

| | | |
|---|---|---|
| Cold Start Heat Input Requirement | MBtu | 620 |
| Hot Start Heat Input Requirement | MBtu | 195 |
| Hot Hours | hours | 2 |

**Availability:**

| | | |
|---|---|---|
| STG Maintenance Pattern | wk/y | 3-3-3-3-3-8 |
| Plant Maintenance Pattern | wk/y | 3-3-3-3-3-8 |
| Average Annual Maintenance | weeks | 4 |
| Immaturity Period | weeks | 9 |
| Immature Forced Outage Rate | percent | 12 |
| Minimum Weeks Between Maintenance | weeks | 48 |
| Mature Forced Outage Rate | percent | 9 |
| Equivalent Availability | percent | 83 |

**Grid Services:**

| | | |
|---|---|---|
| Ramping Capabilities[N] | MW/minute | 1.25 |
| Inertia Constant (STG only) | MW-sec/MVA | 3 - 4 |
| Start Time[O] (hot start) | minutes | 120 |
| Dispatchable? | | Yes |

| | |
|---|---|
| Voltage Regulation? | Yes |
| Disturbance Ride Through? | Yes |
| Underfrequency Droop Response? | Yes |
| Overfrequency Droop Response? | Yes |

*IRP 2013 UIF Notes: Biomass Combustion - 25 MW*

*Biomass Combustion (Unspecified Island Site) - 25 MW*

Notes:

(A) Date Available based on NTP of January 1, 2012 and expedited schedule.

(B) Thermal plant power block capital cost includes processing equipment to receive, store, crush, leach, and press the banagrass.

(C) Land cost based on $5/sq ft or $217,800/acre for plant facilities only.

(D) Banagrass land lease cost is based on 7,860 acres of land and an weighted estimate of land rent (on irrigated and unirrigated lands) of $190 per acre (2011$). This estimate is based upon land rent estimates presented in a 2009 paper, "The Economics of Cacao Production in Kona," by Kent Fleming, Virginia Easton Smith and H.C. "Skip" Bittenbinder of the University of Hawaii at Manoa.

(E) Performance is based on a feedstock moisture content of 50 percent, heating value of 4,028 Btu/lb (as introduced to boiler), and 11 percent auxiliary power requirement.

(F) Emissions are based on combustion of banagrass in stoker boiler. $NO_x$ emissions are reduced 50 percent with SNCR system. $SO_x$ emissions are based on banagrass sulfur content of 0.05 percent (dry basis). $CO_2$ emissions are based on fuel carbon content of 48.84 percent (dry basis). Particulate matter emissions are controlled with a fabric filter.

(G) Banagrass yield is a composite yield based on 22 tons/acre-year from irrigated land and 18 tons/acre-year from unirrigated land. Banagrass production cost is estimated based on a gross revenue of $1803 per acre (2007$) and an banagrass yield of 21.4 dry tons per acre-year (considering a composite of irrigated and unirrigated lands). This information is based upon information presented in a 2011 journal article, "Optimizing biofuel production: an economic analysis for selected biofuel feedstock production in Hawaii" authored by Tran, Illukpitiya, Yanagida and Ogoshi and published in Biomass and Bioenergy (35: 1756-1764). Values escalated assuming an annual rate of 3.2 percent, as recommended by Dr. John Yanagida of the University of Hawaii at Manoa.

(H) Total acreage was based on 6,690 acres of irrigated land and 1,165 acres of unirrigated land. Acreage for crop growth assumes heating value of 8,057 Btu/lb and a composite yield of 21.4 dry tons per acre-year.

(I) Based on 24 hour operation at normal top load. Feedstock requirements reported as dry weight, actual weight will be significantly higher because of moisture content. Ash content assumed to be 2.7 percent (by mass, dry basis).

(J) Urea is used as a reagent within the Selective Catalytic Reduction (SCR) system. No other reagents are required for operation of air quality control (AQC) systems.

(K) Leaching water requirements are based on a water to fiber ratio of 5:1.

(L) Cooling tower makeup water requirements are based on 5 cycles of concentration.

(M) Based on the difference between supply water temperature and waste water temperature.

(N) Boiler ramp rate (for a constant pressure system) is 5 percent of system capacity per minute (when unit load is in the range of 75 percent to 100 percent).

(O) Start time assumes a hot start (i.e., the boiler is shut down for 8 hours or less).

Table G-2
13 MW Biomass Conversion (Suspension Fired Boiler) Unit Information Form

## UNIT INFORMATION FORM

## HECO IRP 2013

| | |
|---|---|
| Utility: | *HELCO* |
| Unit Type: | *Biomass Conversion - 13 MW* |
| Fuel Type: | *Eucalyptus* |
| Site: | *Puna* |

| | |
|---|---|
| Date: | *March 25, 2013* |
| By: | *Black & Veatch* |
| Supersedes: | *February 13, 2013* |

### Unit Ratings:

| | | Gross | Net |
|---|---|---|---|
| Normal Top Load | MW | 15.9 | 12.9 |
| Minimum | MW | 8.0 | 5.7 |

### Ambient Conditions:

| | | |
|---|---|---|
| Dry Bulb Temperature | ° F | 80 |
| Relative Humidity | percent | 80 |

### Operating Mode:

| | | |
|---|---|---|
| Duty Cycle | | Baseload |
| Capacity Factor | percent | 80.4 |

### Commercial Service:

| | | | |
|---|---|---|---|
| Date Available[A] | month/year | April | 2018 |
| Service Life | years | | 30 |

### Lead Time (Prior to Comm. Operation):[B]

| | | Normal | Expedited |
|---|---|---|---|
| Permitting | months | 64 | - |
| Engineering | months | 61 | - |
| Procurement | months | 27 | - |
| Construction | months | 27 | - |

| | | |
|---|---|---|
| **Year Dollars:** | | December 2011 |
| **Capital Cost Uncertainty:** | plus/minus | +20%/-20% |

### Capital Cost (without AFUDC):

| | $million | $\$/kW_{gross}$ | $\$/kW_{net}$ |
|---|---|---|---|
| A. Power Block Cost[C] | 50.43 | 3,172 | 3,909 |
| B. Special Siting Costs | 0.00 | - | - |
| C. Power Plant Switchyard | 0.00 | - | - |
| D. T&D Interconnection | 0.00 | - | - |
| E. Total Direct Cost (A+B+C+D) | 50.43 | 3,172 | 3,909 |
| F. Total Indirect Cost (E*0.38) | 13.54 | 852 | 1,050 |
| G. Land Cost[D] | 0.00 | 0 | 0 |
| H. Total Capital Cost (E+F+G) | 63.97 | 4,023 | 4,959 |

### Operations & Maintenance:

| | | |
|---|---|---|
| | $ million/y | or $\$/kW\text{-}y_{net}$ |
| Fixed Cost | 5.62 | 436 |
| | $ million/y | |
| Land Lease[E] | - | |
| | $/h run | or $\$/MWh_{net}$ |
| Variable Cost | 85 | 6.61 |
| Staffing Requirements[F] | 27 | |

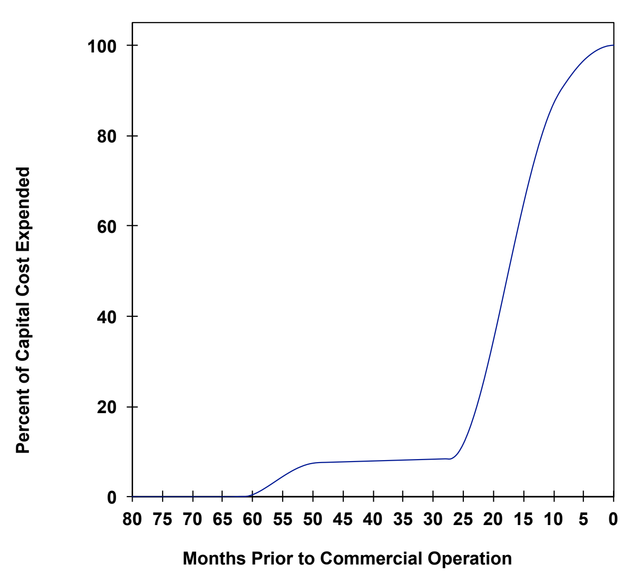
### Capacity and Heat Rate Data:[G]

| Load Point | # STGs | Amb Cond | Gross Load | Net Load | Net Plant Heat Rate | Quick Load Pickup |
|---|---|---|---|---|---|---|
| | | ° F/RH | MW | MW | Btu/kWh | MW |
| Normal Top | 1 | 80/80 | 15.9 | 12.9 | 18,840 | -- |
| Minimum | 1 | 80/80 | 8.0 | 5.7 | 22,330 | -- |

### Flue Gas Emissions:[H]

| | Normal Top Load at 77° F/70 %RH | Minimum Load at 77° F/70 %RH |
|---|---|---|
| | lb/MBtu | lb/MBtu |
| Nitrogen Oxides | 0.12 | - |
| Sulfur Oxides | 0.069 | - |
| Carbon Dioxide | 220 | - |
| Carbon Monoxide | not given | - |
| Volatile Organic Compounds | not given | - |
| Particulate Matter | 0.05 | - |

**Total Capital Cost Cumulative Expenditure Pattern**




### General Site/Technology Characteristics:

| | | |
|---|---|---|
| Fuel Delivery | | Truck |
| Fuel Storage Onsite/Offsite | | 14 days/0 days |
| Water Supply Source | | Groundwater |
| Cycle Cooling | | Cooling Pond |
| Waste Water Disposal | | Field Irrigation |
| Solid Waste Disposal | | On-Island Landfill |
| Generator | | Synchronous |
| Eucalyptus Production Cost (FOB plant gate)[I] | $/dry ton | 112 |
| Eucalyptus Yield[I] | dry ton/acre-y | 9.0 |
| Eucalyptus Acreage Requirement | acres | 11,410 |
| Minimum Power Plant Land Requirement | acres | 0.0 |

### Daily Resource Requirements at Normal Top Load:[J]

| | | |
|---|---|---|
| Fuel (dry basis) | dtpd | 350 |
| Urea (dry)[K] | tpd | 0.4 |
| Service & Plant Water | mgd | 12.035 |
| Cooling Water (once-through)[L] | mgd | 12.000 |
| Supply Water Temperature | ° F | 79 |

**Waste Streams:**

| | | |
|---|---|---|
| Solid Waste | tpd | 4.90 |
| Waste Water Discharge[M] | mgd | 0.04 |
| Water Discharge Temperature | ° F | 90 |
| Thermal Discharge[N] | MBtu/d | 3 |

### CTG/HRSG/STG Unit Startup Parameters:

| | | |
|---|---|---|
| Cold Start Heat Input Requirement | MBtu | 382 |
| Hot Start Heat Input Requirement | MBtu | 120 |
| Hot Hours | hours | 2 |

### Availability:

| | | |
|---|---|---|
| STG Maintenance Pattern | wk/y | 4-4-4-4-6 |
| Plant Maintenance Pattern | wk/y | 4-4-4-4-6 |
| Average Annual Maintenance | weeks | 4 |
| Immaturity Period | weeks | 9 |
| Immature Forced Outage Rate | percent | 12 |
| Minimum Weeks Between Maintenance | weeks | 48 |
| Mature Forced Outage Rate | percent | 2.8 |
| Equivalent Availability | percent | 90 |

**Grid Services:**

| | | |
|---|---|---|
| Ramping Capabilties[O] | MW/minute | 0.6 |
| System Inertia (STG only) | MW-sec/MVA | 3 - 4 |
| Start Time[P] (hot start) | minutes | 120 |
| Dispatchable? | | Yes |

| | |
|---|---|
| Voltage Regulation? | Yes |
| Disturbance Ride Through? | Yes |
| Underfrequency Droop Response? | Yes |
| Overfrequency Droop Response? | Yes |

*IRP 2013 UIF Notes: Biomass Conversion (Suspension-fired) - 13 MW*

*Biomass Conversion (Puna) - 13 MW*

Notes:

(A) Date Available based on NTP of January 1, 2012 and normal schedule.

(B) Lead Times based on schedule developed for 2012 Puna Biomass Conversion Study prepared by Black & Veatch.

(C) Thermal plant power block capital cost includes processing equipment to receive, store,and process the eucalyptus (fuel).

(D) Because the conversion project is a modification of an existing facility, no additional land is required, and no land cost is incurred.

(E) It is assumed that no land is leased by the utility for the production of eucalytus.

(F) Plant staffing requirements consist of the necessary operators for the converted biomass unit. It is assumed that maintenance, technical and administrative support will beprovided by centralized services (i.e., existing staff at the Puna facility). These existing maintenance, technical and administrative support staff are not included in this estimate.

(G) Performance is based on a feedstock moisture content of 40 percent and a heating value of 5,000 Btu/lb (as introduced to the suspension-fired boiler). These values correspond to a (dry-basis) heating value of 8,330 Btu/lb, or 16.67 MBtu/dry ton.

(H) Emissions are based on combustion of eucaplytus in a suspension-fired boiler. $NO_x$ emissions are reduced to permitted levels via an SNCR system. $SO_x$ emissions are based on eucalyptus sulfur content of 0.02 percent (dry basis). $CO_2$ emissions are based on fuel carbon content of 51.6 percent (dry basis). Particulate matter emissions are controlled with an electrostatic precipitator (ESP).

(I) Based on 2009 study conducted by Black & Veatch, the yield of eucaplytus grown in timber plantations on Hawaii Island typically range from 6 to 13 dry tons per acre-year, depending on soil temperature and moisture. It is assumed with selection of optimal eucalyptus species and sound management practices, sustainable yields would be 9 dry tons per acre-year. Considering timber grown in forests near Puna, delivered cost of eucalyptus was found to be approximately $105 per dry ton (2009$). This value was escalated to $112 per dry ton (2011$), assuming an escalation rate of 3.2 percent per year.

(J) Based on 24 hour operation at normal top load. Feedstock requirements reported as dry weight, actual weight will be significantly higher because of moisture content. Ash content assumed to be 2.0 percent (by mass, dry basis).

(K) Urea is used as a reagent within the Selective Non-Catalytic Reduction (SNCR) system. No other reagents are required for operation of air quality control (AQC) systems.

(L) Cooling water is drawn from groundwater wells, directed through the condenser and a cooling pond, then re-injected via a re-injection well. Full-load cooling water flow rate based on maximum permitted flow rate at the re-injection well.

(M) Assumed to be waste water from service water and potable water applications only.

(N) Based on the difference between supply water temperature and waste water temperature.

(O) Boiler ramp rate (for a constant pressure system) is 5 percent of system capacity per minute (when unit load is in the range of 75 percent to 100 percent).

(P) Start time assumes a hot start (i.e., the boiler is shut down for 8 hours or less).

Table H-1
8 MW Waste-to-Energy Unit Information Form

## UNIT INFORMATION FORM

## HECO IRP 2013

| | |
|---|---|
| Utility: | *HECO* |
| Unit Type: | *Waste-to-Energy - 8 MW* |
| Fuel Type: | *Municipal Solid Waste* |
| Site: | *Unspecified Island Location* |

| | |
|---|---|
| Date: | *March 25, 2013* |
| By: | *Black & Veatch* |
| Supersedes: | *October 11, 2012* |

### Unit Ratings:

| | | Gross | Net |
|---|---|---|---|
| Normal Top Load | MW | 8.1 | 7.1 |
| Minimum | MW | 3.9 | 3.4 |

### Ambient Conditions:

| | | |
|---|---|---|
| Dry Bulb Temperature | ° F | 77 |
| Relative Humidity | percent | 70 |

### Operating Mode:

| | | |
|---|---|---|
| Duty Cycle | | Base Load |
| Capacity Factor | percent | 83 |

### Commercial Service:

| | | |
|---|---|---|
| Date Available[A] | month/year | January 2018 |
| Service Life | years | 30 |

### Lead Time (Prior to Commercial Oper):

| | | Normal | Expedited |
|---|---|---|---|
| Permitting | months | 79 | 72 |
| Engineering | months | 54 | 50 |
| Procurement | months | 39 | 33 |
| Construction | months | 36 | 32 |

| | | |
|---|---|---|
| **Year Dollars:** | | December 2011 |
| **Capital Cost Uncertainty:** | plus/minus | +20%/-20% |

### Capital Cost (without AFUDC):

| | \$million | \$/kW$_{gross}$ | \$/kW$_{net}$ |
|---|---|---|---|
| A. Power Block Cost[B] | 115.78 | 14,218 | 16,254 |
| B. Special Siting Costs | 1.79 | 220 | 251 |
| C. Power Plant Switchyard[C] | 1.92 | 236 | 270 |
| D. T&D Interconnection | - | - | - |
| E. Total Direct Cost (A+B+C+D) | 119.49 | 14,674 | 16,775 |
| F. Total Indirect Cost (E*0.275) | 32.86 | 4,035 | 4,613 |
| G. Land Cost[D] | 3.05 | 374 | 428 |
| H. Total Capital Cost (E+F+G) | 155.40 | 19,084 | 21,816 |

### Operations & Maintenance:

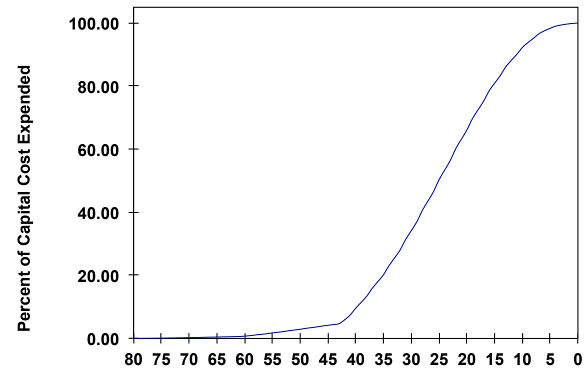
| | | |
|---|---|---|
| Fixed Cost | \$million/y | 7.835 |
| | or \$/kW-y$_{net}$ | 1,100 |
| Variable Cost | \$/h run | 245 |
| | or \$/MWh$_{net}$ | 34.38 |
| Staffing Requirements | | 37 |

### Capacity and Heat Rate Data:[E]

| Load Point | # STGs | Amb Cond ° F/RH | Gross Load MW | Net Load MW | Net Plant Heat Rate Btu/kWh | Quick Load Pickup MW |
|---|---|---|---|---|---|---|
| Normal Top | 1 | 77/70 | 8.1 | 7.1 | 19,300 | - |
| Minimum | 1 | 77/70 | 3.9 | 3.4 | 19,940 | - |

### Flue Gas Emissions:[F]

| | Normal Top Load at 77° F/70% RH lb/MBtu | Minimum Load at 77° F/70% RH lb/MBtu |
|---|---|---|
| Nitrogen Oxides | 0.22 | 0.22 |
| Sulfur Oxides | 0.0182 | 0.0182 |
| Carbon Dioxide | 200 | 200 |
| Carbon Monoxide | 0.057 | 0.057 |
| Vol. Organic Compounds | 0.007 | 0.007 |
| Particulate Matter | 0.01 | 0.01 |




### General Site/Technology Characteristics:

| | | |
|---|---|---|
| Fuel Delivery | | Truck |
| Fuel Storage Onsite | | 4 days |
| Water Supply Source | | Brackish Wells |
| Cycle Cooling | | Air Cooled Condenser |
| Waste Water Disposal | | Injection Wells |
| Solid Waste Disposal | | On-Island Landfill |
| Generator | | Synchronous |
| MSW Tipping Fee[G] | \$/ton | 91 |
| Minimum Plant Land Requirement | acres | 14.0 |

### Daily Resource Requirements at Normal Top Load:

| | | |
|---|---|---|
| Fuel (As-Received Basis)[H] | tpd | 300 |
| Urea (SNCR)[I] | tpd | 0.96 |
| Quicklime ($SO_2$ Additive)[I] | tpd | 6.30 |
| Service & Plant Water | mgd | 0.10 |
| Leaching Process Wash Water | mgd | NA |
| Cooling Tower Makeup | mgd | NA |
| Supply Water Temperature | ° F | 79 |

### Waste Streams:

| | | |
|---|---|---|
| Solid Waste | tpd | 0.02 |
| Waste Water Discharge | mgd | 0.08 |
| Water Discharge Temperature | ° F | 90 |
| Thermal Discharge[J] | MBtu/day | 10 |

### CTG/HRSG/STG Unit Startup Parameters:

| | | |
|---|---|---|
| Cold Start Heat Input Requirement | MBtu | 236 |
| Hot Start Heat Input Requirement | MBtu | 118 |
| Hot Hours | hours | 1 |

### Availability:

| | | |
|---|---|---|
| STG Maintenance Pattern | wk/y | 3-3-3-3-3-8 |
| Plant Maintenance Pattern | wk/y | 3-3-3-3-3-8 |
| Average Annual Maintenance | weeks | 4.0 |
| Immaturity Period | weeks | 9 |
| Immature Forced Outage Rate | percent | 12 |
| Minimum Weeks Between Maintenance | weeks | 26 |
| Mature Forced Outage Rate | percent | 9 |
| Equivalent Availability | percent | 83 |

### Grid Services:

| | | | | |
|---|---|---|---|---|
| Ramping Capabilties[K] | MW/minute | 0.35 | Voltage Regulation? | Yes |
| Inertia Constant (STG only) | MW-sec/MVA | 3 - 4 | Disturbance Ride Through? | Yes |
| Start Time[L] (hot start) | minutes | 60 | Underfrequency Droop Response? | Yes |
| Dispatchable? | | Yes | Overfrequency Droop Response? | Yes |

*HECO IRP 2013 UIF Notes: Waste-to-Energy (Mass Burn) - 8 MW*

*Waste-to-Energy (Mass Burn) - 8 MW*

Notes:

(A) Date Available based on NTP of January 1, 2012 and expedited schedule.
(B) Thermal plant power block capital cost includes 4 day pit for storage of MSW.
(C) Based on the HECO IRP 2013 25 MW Biomass Combustion option switchyard cost scaled according to a power law (employing an exponent of 0.6).
(D) Land cost based on $5/sq ft or $217,800/acre for plant facilities only.
(E) Performance is based on MSW heating value of 5,500 Btu/lb (as introduced to boiler), and 12.7 percent auxiliary power requirement.
"Clean " represents performance after furnace and boiler tube powerwashing.
Clean state will last about 3 to 4 weeks before moving towards the "Normal Top" performance. Powerwashing should be performed approximately every 6 months for each unit.
(F) Emissions are based on combustion of MSW in stoker boiler. $NO_x$ emissions are reduced 50 percent with SNCR system. Emissions are based on test data from a recent project of same size and fuel composition.
AQC equipment includes a spray dry absorber, using quicklime.
Activated Carbon injection is included for heavy metals emissions.
Particulate matter emissions are controlled with a fabric filter.

(G) Based on City and County of Honolulu tipping fee of $90.72 per ton reported in Report to the Twenty-fifth Legislature, State of Hawaii, 2010 - Solid Waste Management. Prepared by State of Hawaii, Department of Health, Office of Solid Waste Management, December 2009.
In same report, tipping fees for other Hawaiian counties were reported as follows:
Hawaii County - $85 per ton; Maui County - $63 per ton; Kauai County - $56 per ton.
(H) Based on 24 hour operation at normal top load. Ash content assumed to be 2.7 percent. The cost is based on one unit processing 300 tpd.
(I) Urea and quicklime are used for SCNR reagent and $SO_2$ additive, respectively. Flows based on past project test data.
(J) Based on the difference between supply water temperature and waste water temperature.
(K) Boiler ramp rate (for a constant pressure system) is 5 percent of system capacity per minute (when unit load is in the range of 75 percent to 100 percent).
(L) Start time assumes a hot start (i.e., the boiler is shut down for 8 hours or less).

Table I-1
400 kW Phosphoric Acid Fuel Cell Unit Information Form

## UNIT INFORMATION FORM

## HECO IRP 2013

| | |
|---|---|
| Utility: | *HECO* |
| Unit Type: | *Fuel Cell (400 kW)* |
| Fuel Type: | *Natural Gas* |
| Site: | *Unspecified* |

| | |
|---|---|
| Date: | *March 23, 2013* |
| By: | *Black & Veatch* |
| Supersedes: | *October 11, 2012* |

**Unit Ratings at Average Conditions:[A]**

| | | Net |
|---|---|---|
| Normal Top Load | MW | 0.4 |
| Emergency | MW | 0.4 |
| Minimum | MW | 0.1 |

**Ambient Conditions:**

| | | |
|---|---|---|
| Dry Bulb Temperature | F | 77 |
| Relative Humidity | percent | 70 |

**Operating Mode:[B]**

| | | |
|---|---|---|
| Duty Cycle | | Baseload / Peaking |
| Capacity Factor | percent | 90 |

**Commercial Service:**

| | | | |
|---|---|---|---|
| Date Available | month/year | June | 2013 |
| Service Life | years | | 20 |

**Lead Time (Prior to Commercial Oper):**

| | | Normal | Expedited |
|---|---|---|---|
| Permitting | months | 12 | -- |
| Engineering | months | 10 | -- |
| Procurement | months | 6 | -- |
| Construction | months | 2 | -- |

| | | |
|---|---|---|
| **Year Dollars** | | June 2012 |
| **Capital Cost Uncertainty:** | plus/minus | +30% / -30% |

**Capital Cost (without AFUDC)[C]:**

| | $million | $/kW$_{net}$ |
|---|---|---|
| A. Total Power Block Cost (base)[D] | 3.31 | 8,281 |
| B. Special Siting Costs[E] | - | - |
| C. Power Plant Switchyard[E] | - | - |
| D. T&D Interconnection[F] | - | - |
| E. Total Direct Cost (A1+B+C+D) | 3.31 | 8,281 |
| F. Total Indirect Cost | 0.29 | 733 |
| G. Land Cost[G] | - | - |
| H. Total Capital Cost (E+F+G) | 3.61 | 9,014 |

**Operations & Maintenance:[H]**

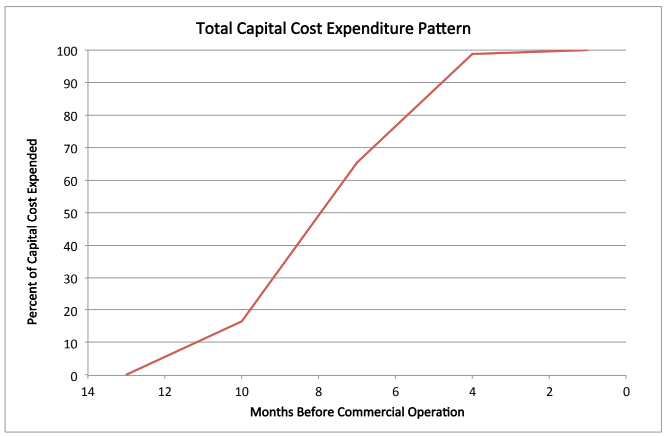
| | $/y | $/kW-y$_{net}$ |
|---|---|---|
| Fixed Cost | 131,970 | 330 |
| | | $/MWh$_{net}$ |
| Variable Cost | 102,750 | 33 |
| Total First Year O&M | 234,720 | |

**Capacity and Heat Rate Data at Average Conditions:[I]**

| Load Point | Gross Load | HHV Fuel Input | Auxiliary Load | Net Load | Net Plant Heat Rate | Quick Ld. Pickup |
|---|---|---|---|---|---|---|
| | MW | MBtu/h | MW | MW | Btu/kWh | MW |
| Normal Top | 0.4 | 3.8 | Undefined | 0.4 | 9,554 | 0.0 |
| 75 percent | 0.3 | 2.7 | Undefined | 0.3 | 9,089 | 0.1 |
| 50 percent | 0.2 | 1.8 | Undefined | 0.2 | 8,796 | 0.2 |
| 25 percent | 0.1 | 1.7 | Undefined | 0.1 | 16,528 | 0.3 |
| Minimum | 0.1 | 1.7 | Undefined | 0.1 | 16,528 | 0.3 |

**Flue Gas Emissions:[J]**

| Load Point | Gross Load | Nitrogen Oxides | Sulfur Oxides | Hydrogen Sulfide | Carbon Monoxide | Carbon Dioxide | VOCs | Particulate Matter |
|---|---|---|---|---|---|---|---|---|
| | MW | tons/year | tons/year | tons/year | tons/year | tons/year | tons/year | tons/year |
| Normal Top | 0.4 | 0.03 | n/a | n/a | 0.03 | 1563 | 0.03 | n/a |




**Grid Services[L]**

| | | | | |
|---|---|---|---|---|
| Ramping Capabilities | MW/min | 0.4 | Dispatchable? | Yes |
| Inertia Constant | MW-sec/MVA | none | Voltage Regulation? | No |
| Start Time (min) | minutes | 180-360 | Disturbance Ride Through? | No |
| Underfreq. Droop Response? | | Yes | Overfreq. Droop Response? | Yes |

**General Site/Technology Characteristics:**

| | | |
|---|---|---|
| Unit Type | | Phosphoric Acid |
| Year 1 Electrical Efficiency (percent) | | 40 |
| Year 10 Electrical Efficiency (percent) | | 38 |
| Fuel[K] | | Natural Gas |
| Fuel Source | | Pipeline |
| Cycle Cooling | | Air Cooled |
| Waste Water Disposal | | Sanitary Sewer |
| Minimum Land Requirement | sq. ft. | 894 |
| Generator | | Inverter |

**Daily Resource Requirements at Normal Top Load:**

| | | |
|---|---|---|
| Fuel (at 10 year average efficiency) | SCFD | 83,923 |
| Water Consumption at Amb. Temp < 85 F | gpm | 0 |
| Water Consumption at Amb. Temp = 110 F | gpm | 1 |
| Supply Gas Pressure | kPa | 3.5 |

**Waste Streams:**

| | | |
|---|---|---|
| Solid Waste | tpd | -- |
| Waste Water Discharge | mgd | -- |
| Water Discharge Temperature | F | -- |

**Availability:**

| | | |
|---|---|---|
| Average Annual Maintenance | weeks | 2.0 |
| Immaturity Period | weeks | 3 |
| Immature Forced Outage Rate | percent | 20 |
| Minimum Weeks Between Maintenance | weeks | 12 |
| Mature Forced Outage Rate | percent | 5 |
| Equivalent Availability | percent | 90 |

*HECO IRP 2013 UIF Notes: Fuel Cell 400 kW*

Notes:

**(A)** Unit ratings are based on information provided by UTC Power, a phosphoric acid fuel cell (PAFC) manufacturer. Internal auxiliary loads are considered proprietary and were not shared by the manufacturer.

**(B)** Capacity factor based on 8,760 operating hours per year.

**(C)** The capital cost estimate is based on a quote obtained from UTC Power during a conference call with Phong Nguyen and Derek Hildreth on 6/27/2012. UTC Power provided total mainland costs for the fuel cell equipment, and total mainland costs for installation. B&V assumptions were used to estimate the breakdown of total installation costs into labor, materials, and owner's costs for the purposes of applying Hawaii-specific scaling factors.

**(D)** Power Block costs include the fuel cell, air cooling unit, shipping, state taxes, and installation of equipment in Hawaii (labor and materials).

**(E)** No special siting costs are assumed to be required. Major equipment will be shipped in standard container vessels, with installation in a modular fashion.

**(F)** T&D interconnection is assumed to be negligible given the small size of the fuel cell facility.

**(G)** Land costs based on assumption that double the footprint of the fuel cell equipment is required at an annual lease cost of $5 per square foot. Land lease costs were therefore added to the fixed O&M costs and were excluded from capital costs.

**(H)** O&M costs are based on a quote from UTC Power and include one-half HECO FTE. UTC offers a full O&M service on a 10-year contract for $100,000 per year (mainland cost). This cost is roughly 75 percent variable (unscheduled maintenance) and 25 percent fixed (monitoring and scheduled maintenance). The fixed O&M costs are largely labor, adjusted with a Hawaii-specific multiplier of 1.5. Land lease costs (see note G) are also included as fixed O&M. Variable O&M costs are adjusted to Hawaii values assuming 50 percent materials and 50 percent labor. Reformer catalyst and stack replacement are included in these costs and assumed to occur in year 10.

**(I)** Heat rate and capacity figures were provided by UTC Power in published documentation supplemented with additional information provided via email. Auxiliary load not provided by manufacturer. Fuel requirements for 50 percent performance scaled from information provided for 225 kW output assuming a similar heat rate.

**(J)** Flue gas emissions were provided by UTC Power

**(K)** Natural gas composition requirements must meet the following requirements. Assuming 1090 BTU/SCF heat content for calculations.
Ethane: <10% (volume)
Propane: <5%
Butanes: <1.25%
C5 and Heavier: <0.5%
$CO_2$: <3%
$O_2$: <0.2%
$N_2$: <4% average, <15% peak
Total Sulfur: <6 ppm average, 30 ppm maximum
Ammonia: <0.5 ppm
Halides: <0.05 ppm
Olefins: <0.5%
LHV: 890 - 1090 BTU/scf

**(L)** Considered a distributed resource, so no voltage support/reactive capability per IEEE 1547. Distributed resources also assumed not to have LVRT for safety reasons.

Table J-1
Battery Energy Storage System (BESS) Unit Information Form

## UNIT INFORMATION FORM

## HECO IRP 2013

| | |
|---|---|
| Utility: | *HECO* |
| Unit Type: | *BESS (10 MW: 15 MWh) - Daily Peaking* |
| Fuel Type: | *None* |
| Site: | *Unspecified* |

| | |
|---|---|
| Date: | *March 23, 2013* |
| By: | *Black & Veatch* |
| Supersedes: | *October 11, 2012* |

**Unit Ratings:** [A]

| | Units | Gross | Net |
|---|---|---|---|
| Normal Top Load | MW | 10.50 | 10.00 |
| Minimum | MW | n/a | n/a |

**Ambient Conditions:**

| | | |
|---|---|---|
| Dry Bulb Temperature | ° F | 77 |
| Relative Humidity | percent | 70 |
| CTG Inlet Air Temperature | ° F | n/a |

**Operating Mode:** [B]

| | | |
|---|---|---|
| Duty Cycle | | Peaking/Storage |
| Annual Energy Discharge | MWh/yr | 1875 |

**Commercial Service:**

| | | |
|---|---|---|
| Date Available | month/year | January 2013 |
| Service Life | years | 20 |

**Lead Time (Prior to Comm. Operation):**

| | Units | Normal | Expedited |
|---|---|---|---|
| Permitting | months | 17 | 17 |
| Engineering | months | 14 | 14 |
| Procurement | months | 8 | 8 |
| Construction | months | 3 | 3 |

| | | |
|---|---|---|
| **Year Dollars:** | | December 2011 |
| **Capital Cost Uncertainty:** | plus/minus | +30%/-30% |

**Capital Cost (without AFUDC):** [C]

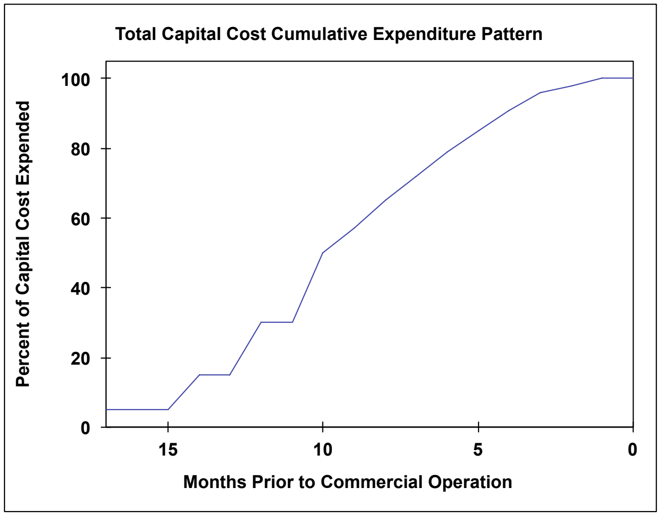
| | $million | $/kW$_{gross}$ | $/kW$_{net}$ |
|---|---|---|---|
| A. Power Block[D] | 17.50 | 1,667 | 1,750 |
| B. Special Siting Costs | - | - | - |
| C. Power Plant Switchyard[E] | - | - | - |
| D. T&D Interconnection[E] | - | - | - |
| E. Total Direct Cost (A+B+C+D) | 17.50 | 1,667 | 1,750 |
| F. Total Indirect Cost (E*0.20)[F] | 3.50 | 333 | 350 |
| G. Land Cost[G] | - | - | - |
| H. Total Capital Cost (E+F+G) | 21.00 | 2,000 | 2,100 |

**Operations & Maintenance:** [H]

| | | |
|---|---|---|
| Fixed Cost | $million/y | 0.259 |
| | or $/kW-y$_{net}$ | 25.93 |
| Variable Cost[I] | $/h run | 0 |
| | or $/MWh$_{net}$ | 0 |
| Staffing Requirements | | 1 |

**Capacity and Heat Rate Data:** [J]

| Load Point | | Comp Inlet | Gross Load | Net Load | Net Plant Heat Rate | Quick Load Pickup |
|---|---|---|---|---|---|---|
| | | ° F/RH | MW | MW | Btu/kWh | MW |
| Normal Top | | n/a | 10.50 | 10.00 | n/a | n/a |
| Minimum | | n/a | n/a | n/a | n/a | n/a |




**Grid Services:**

| | | |
|---|---|---|
| Ramping Capabilities | MW/minute | 10 |
| Inertia Constant | MW-sec/MVA | -- |
| Start Time[L] | minutes | <1 |
| Discharge Rate[M] | C | 0.66 |

| | |
|---|---|
| Dispatchable? | Yes |
| Voltage Regulation? | Yes |
| Disturbance Ride Through? | Yes |
| Underfreq. Droop Response? | Yes |
| Overfreq. Droop Response? | Yes |

**General Site/Technology Characteristics:**

| | | |
|---|---|---|
| Battery Type [K] | | Lead Acid |
| Expected Usage | cycles/yr | 250 |
| Battery Life | cycles | 20000 |
| Depth of Discharge | percent | 50 |
| Max. Charging Power Input | MW | 6.45 |
| Required Energy Input | MWh | 14.1 |
| Generator Type | | Power Converter |
| Minimum Land Requirement | acres | 0.3 |

**Availability:**

| | | |
|---|---|---|
| Average Annual Maintenance | wk/y | 2 |
| Immaturity Period | wk/y | -- |
| Immature Forced Outage Rate | weeks | -- |
| Minimum Weeks Between Maintenance | weeks | 50 |
| Mature Forced Outage Rate | percent | -- |
| Equivalent Availability | weeks | 95 |

**Efficiency:**

| | | |
|---|---|---|
| Roundtrip Efficiency | percent | 85 |

Table J-2
Battery Energy Spinning Reserve (BESR) Unit Information Form

## UNIT INFORMATION FORM

## HECO IRP 2013

| | |
|---|---|
| Utility: | *HECO* |
| Unit Type: | *BESR (25 MW: 30 min)* |
| Fuel Type: | *None* |
| Site: | *Unspecified* |

| | |
|---|---|
| Date: | *March 23, 2013* |
| By: | *Black & Veatch* |
| Supersedes: | *October 11, 2012* |

**Unit Ratings:** [A]

| | | Gross | Net |
|---|---|---|---|
| Normal Top Load | MW | 26.25 | 25.00 |
| Minimum | MW | n/a | n/a |

**Ambient Conditions:**

| | | |
|---|---|---|
| Dry Bulb Temperature | ° F | 77 |
| Relative Humidity | percent | 70 |
| CTG Inlet Air Temperature | ° F | n/a |

**Operating Mode:** [B]

| | | |
|---|---|---|
| Duty Cycle | | Spinning Reserve |
| Annual Energy Discharge | MWh/yr | 500 |

**Commercial Service:**

| | | |
|---|---|---|
| Date Available | month/year | January 2013 |
| Service Life | years | 20 |

**Lead Time (Prior to Comm. Operation):**

| | | Normal | Expedited |
|---|---|---|---|
| Permitting | months | 17 | 17 |
| Engineering | months | 14 | 14 |
| Procurement | months | 8 | 8 |
| Construction | months | 3 | 3 |

| | | |
|---|---|---|
| **Year Dollars:** | | December 2011 |
| **Capital Cost Uncertainty:** | plus/minus | +30%/-30% |

**Capital Cost (without AFUDC):** [C]

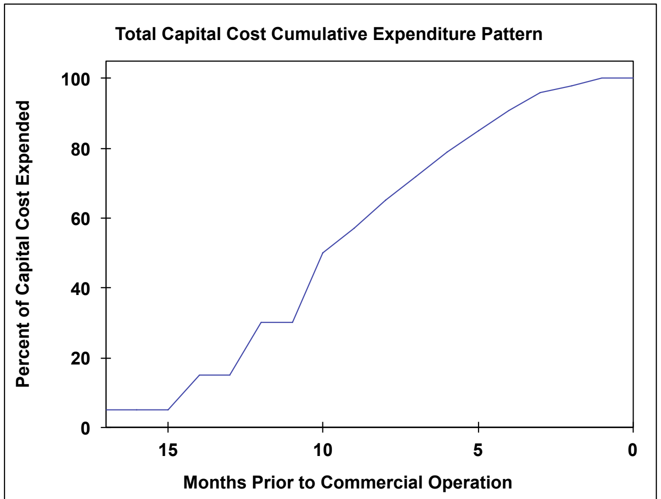
| | $million | $/kW$_{gross}$ | $/kW$_{net}$ |
|---|---|---|---|
| A. Power Block[D] | 29.50 | 1,124 | 1,180 |
| B. Special Siting Costs | - | - | - |
| C. Power Plant Switchyard[E] | - | - | - |
| D. T&D Interconnection[E] | - | - | - |
| E. Total Direct Cost (A+B+C+D) | 29.50 | 1,124 | 1,180 |
| F. Total Indirect Cost (E*0.20)[F] | 5.90 | 225 | 236 |
| G. Land Cost[G] | - | - | - |
| H. Total Capital Cost (E+F+G) | 35.40 | 1,349 | 1,416 |

**Operations & Maintenance:** [H]

| | | |
|---|---|---|
| Fixed Cost | $million/y | 0.259 |
| | or $/kW-y$_{net}$ | 10.37 |
| Variable Cost[I] | $/h run | 0 |
| | or $/MWh$_{net}$ | 0 |
| Staffing Requirements | | 1 |

**Capacity and Heat Rate Data:** [J]

| Load Point | | Comp Inlet | Gross Load | Net Load | Net Plant Heat Rate | Quick Load Pickup |
|---|---|---|---|---|---|---|
| | | ° F/RH | MW | MW | Btu/kWh | MW |
| Normal Top | | n/a | 26.25 | 25.00 | n/a | n/a |
| Minimum | | n/a | n/a | n/a | n/a | n/a |




**Grid Services:**

| | | |
|---|---|---|
| Ramping Capabilities | MW/minute | 10 |
| Inertia Constant | MW-sec/MVA | -- |
| Start Time[L] | minutes | <1 |
| Discharge Rate[M] | C | 2 |

| | |
|---|---|
| Dispatchable? | Yes |
| Voltage Regulation? | Yes |
| Disturbance Ride Through? | Yes |
| Underfreq. Droop Response? | Yes |
| Overfreq. Droop Response? | Yes |

**General Site/Technology Characteristics:**

| | | |
|---|---|---|
| Battery Type [K] | | Lead Acid |
| Expected Usage | cycles/yr | 50 |
| Battery Life | cycles | 3300 |
| Depth of Discharge | percent | 80 |
| Max. Charging Power Input | MW | 6.45 |
| Required Energy Input | MWh | 11.8 |
| Generator Type | | Power Converter |
| Minimum Land Requirement | acres | 0.7 |

**Availability:**

| | | |
|---|---|---|
| Average Annual Maintenance | wk/y | 2 |
| Immaturity Period | wk/y | -- |
| Immature Forced Outage Rate | weeks | -- |
| Minimum Weeks Between Maintenance | weeks | 50 |
| Mature Forced Outage Rate | percent | -- |
| Equivalent Availability | weeks | 95 |

**Efficiency:**

| | | |
|---|---|---|
| Roundtrip Efficiency | percent | 85 |

Table J-3
Battery Energy Frequency Regulation (BEFR) Unit Information Form

## UNIT INFORMATION FORM

## HECO IRP 2013

| | |
|---|---|
| Utility: | *HECO* |
| Unit Type: | *BEFR (25 MW:15 min)* |
| Fuel Type: | *None* |
| Site: | *Unspecified* |

| | |
|---|---|
| Date: | *March 23, 2013* |
| By: | *Black & Veatch* |
| Supersedes: | *October 11, 2012* |

**Unit Ratings:** [A]

| | | Gross | Net |
|---|---|---|---|
| Normal Top Load | MW | 26.25 | 25.00 |
| Minimum | MW | n/a | n/a |

**Ambient Conditions:**

| | | |
|---|---|---|
| Dry Bulb Temperature | ° F | 77 |
| Relative Humidity | percent | 70 |
| CTG Inlet Air Temperature | ° F | n/a |

**Operating Mode:** [B]

| | | |
|---|---|---|
| Duty Cycle | | Frequency Regulation |
| Annual Energy Discharge | MWh/yr | 4688 |

**Commercial Service:**

| | | |
|---|---|---|
| Date Available | month/year | January 2013 |
| Service Life | years | 20 |

| Lead Time (Prior to Comm. Operation): | | Normal | Expedited |
|---|---|---|---|
| Permitting | months | 17 | 17 |
| Engineering | months | 14 | 14 |
| Procurement | months | 8 | 8 |
| Construction | months | 3 | 3 |

| | | |
|---|---|---|
| **Year Dollars:** | | December 2011 |
| **Capital Cost Uncertainty:** | plus/minus | +30%/-30% |

**Capital Cost (without AFUDC):** [C]

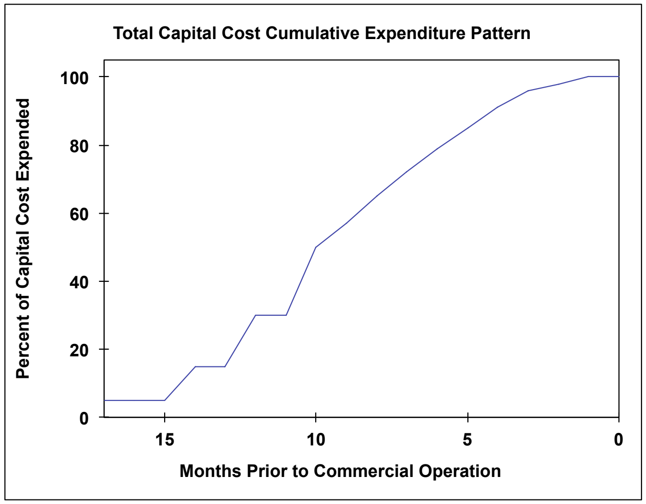
| | $million | $/kW$_{gross}$ | $/kW$_{net}$ |
|---|---|---|---|
| A. Power Block[D] | 21.80 | 830 | 872 |
| B. Special Siting Costs | - | - | - |
| C. Power Plant Switchyard[E] | - | - | - |
| D. T&D Interconnection[E] | - | - | - |
| E. Total Direct Cost (A+B+C+D) | 21.80 | 830 | 872 |
| F. Total Indirect Cost (E*0.20)[F] | 3.05 | 116 | 122 |
| G. Land Cost[G] | - | - | - |
| H. Total Capital Cost (E+F+G) | 24.85 | 947 | 994 |

**Operations & Maintenance:** [H]

| | | |
|---|---|---|
| Fixed Cost | $million/y | 0.259 |
| | or $/kW-y$_{net}$ | 10.37 |
| Variable Cost[I] | $/h run | 0 |
| | or $/MWh$_{net}$ | 0 |
| Staffing Requirements | | 1 |

**Capacity and Heat Rate Data:** [J]

| Load Point | Comp Inlet | Gross Load | Net Load | Net Plant Heat Rate | Quick Load Pickup |
|---|---|---|---|---|---|
| | ° F/RH | MW | MW | Btu/kWh | MW |
| Normal Top | n/a | 26.25 | 25.00 | n/a | n/a |
| Minimum | n/a | n/a | n/a | n/a | n/a |




**General Site/Technology Characteristics:**

| | | |
|---|---|---|
| Battery Type [K] | | Lead Acid |
| Expected Usage | cycles/yr | 2500 |
| Battery Life | cycles | 70,000 |
| Depth of Discharge | percent | 30 |
| Max. Charging Power Input | MW | 4.9 |
| Required Energy Input | MWh | 2.2 |
| Generator Type | | Power Converter |
| Minimum Land Requirement | acres | 0.7 |

**Availability:**

| | | |
|---|---|---|
| Average Annual Maintenance | wk/y | 2 |
| Immaturity Period | wk/y | -- |
| Immature Forced Outage Rate | weeks | -- |
| Minimum Weeks Between Maintenance | weeks | 50 |
| Mature Forced Outage Rate | percent | -- |
| Equivalent Availability | weeks | 95 |

**Efficiency:**

| | | |
|---|---|---|
| Roundtrip Efficiency | percent | 85 |

**Grid Services:**

| | | |
|---|---|---|
| Ramping Capabilities | MW/minute | 10 |
| Inertia Constant | MW-sec/MVA | -- |
| Start Time[L] | minutes | <1 |
| Discharge Rate[M] | C | 4 |

| | |
|---|---|
| Dispatchable? | Yes |
| Voltage Regulation? | Yes |
| Disturbance Ride Through? | Yes |
| Underfreq. Droop Response? | Yes |
| Overfreq. Droop Response? | Yes |

*IRP 2013 UIF Notes: Battery Energy Storage System*

*Battery Energy Storage System (10 MW : 15 MWh)*

Notes: (A) Net output is defined to be 10 MW. Auxiliary load is 5 percent. Aux loads are fed from the grid interconnection through aux transformer. Gross rating includes net output plus the auxiliary load.
(B) BESS intended to operate as a daily peaking resource in the evening to bridge between PV and load, for reserve use only. Annual discharge energy is the estimated total discharge to the grid in one year. For this resource, it is calculated as 50 percent of 15 MWh times 250 discharges per year. Emergency discharge energy is the same as normal operations because normal discharge is to 20 percent state-of-charge (SOC), which is the maximum.
(C) Capital costs in $/kW are based on nameplate net output.
(D) Adapted from confidential OEM quotes.
(E) Per HECO's instruction, the switchyard and T&D costs will not be included in the UDS. HECO will develop the switchyard and T&D costs separately.
(F) Total indirect cost is considered to be approximately 20 percent of total direct cost.
(G) Per HECO request, land is assumed to have already been purchased for resource option. Location is unspecified.
(H) $/kW-$y_{net}$ are based on net normal top output of 10 MW. Fixed O&M cost based on 1 staff at $194,270 burdened salary and facility maintenance at $65,000/year.
(I) Battery has life of 20,000 cycles at 50 percent depth of discharge (DOD), but life impacted if DOD varies. At 250 cycles/year, battery life is unconstrained. No battery replacement required.
(J) Aux load is combination of cooling, controls, and electrical losses with the system.
(K) Battery cost indicative of advanced lead acid technology. Li-ion is a viable alternative that should be considered for specific projects.
(L) Battery response time is on the order of seconds.
(M) Emergency discharge rating can be up to 200 percent of normal rating for a period of seconds.

*Battery Energy Spinning Reserve (25 MW : 30 min)*

Notes: (A) Net output is defined to be 25 MW. Auxiliary load is 5 percent. Aux loads are fed from the grid interconnection through aux transformer. Gross rating includes net output plus the auxiliary load.
(B) BESR intended to operate as spinning reserve. Annual discharge energy is the estimated total discharge to the grid in one year. For this resource, it is calculated as 80 percent of 12.5 MWh times 50 discharges per year Emergency discharge energy is the same as normal operations because normal discharge is to 20 percent state-of-charge (SOC), which is the maximum.
(C) Capital costs in $/kW are based on nameplate net output.
(D) Adapted from confidential OEM quotes.
(E) Per HECO's instruction, the switchyard and T&D costs will not be included in the UDS. HECO will develop the switchyard and T&D costs separately.
(F) Total indirect cost is considered to be approximately 20 percent of total direct cost.
(G) Per HECO request, land is assumed to have already been purchased for resource option. Location is unspecified.
(H) $/kW-$y_{net}$ are based on net normal top output of 25 MW. Fixed O&M cost based on 1 staff at $194,270 burdened salary and facility maintenance at $65,000/year.
(I) Battery should be capable of DOD up to 80 percent around 3300 times during operating life. No battery replacement should be required for 50 cycles/yr for 20 yrs.
(J) Aux load is combination of cooling, controls, and electrical losses with the system.
(K) Battery cost indicative of advanced lead acid technology. Li-ion is a viable alternative that should be considered for specific projects.
(L) Battery response time is on the order of seconds.
(M) Emergency discharge rating can be up to 200 percent of normal rating for a period of seconds.

*Battery Energy Frequency Regulation (25 MW:15 min)*

Notes: (A) Net output is defined to be 25 MW. Auxiliary load is 5 percent. Aux loads are fed from the grid interconnection through aux transformer. Gross rating includes net output plus the auxiliary load.
(B) BEFR intended to operate as frequency regulation. Annual discharge energy is the estimated total discharge to the grid in one year. For this resource, it is calculated as 30 percent of 6.25 MWh times 2500 discharges per year. emergency discharge energy provides capability to discharge to 20 percent state-of-charge (SOC) from 70 percent.
(C) Capital costs in $/kW are based on nameplate net output.
(D) Adapted from confidential OEM quotes.
(E) Per HECO's instruction, the switchyard and T&D costs will not be included in the UDS. HECO will develop the switchyard and T&D costs separately.
(F) Total indirect cost is considered to be approximately 20 percent of total direct cost.
(G) Per HECO request, land is assumed to have already been purchased for resource option. Location is unspecified.
(H) $/kW-$y_{net}$ are based on net normal top output of 25 MW. Fixed O&M cost based on 1 staff at $194,270 burdened salary and facility maintenance at $65,000/year.
(I) Battery has life of 70,000 cycles given depth of discharge (DOD) of 30 percent. DOD for frequency regulation will occur many times daily at DOD less than 30 percent. No battery replacement is expected to be required assuming 2500 cycles/year.
(J) Aux load is combination of cooling, controls, and electrical losses with the system.
(K) Battery cost indicative of advanced lead acid technology. Li-ion is a viable alternative that should be considered for specific projects.
(L) Battery response time is on the order of seconds.
(M) Emergency discharge rating can be up to 200 percent of normal rating for a period of seconds.

Table K-1
1x0 Wartsila 18V46 (Simple Cycle) Unit Information Form

**UNIT INFORMATION FORM**

**HECO IRP 2013**

| | |
|---|---|
| Utility: | *HECO* |
| Unit Type: | *Simple Cycle Wartsila 18V46* |
| Fuel Type: | *Biodiesel* |
| Site: | *Unspecified Island Location* |

| | |
|---|---|
| Date: | *March 25, 2013* |
| By: | *Black & Veatch* |
| Supersedes: | *December 20, 2012* |

**Unit Ratings:**

| | | Gross | Net |
|---|---|---|---|
| Normal Top Load | MW | 17.08 | 16.70 |
| Minimum[A] | MW | 6.83 | 6.68 |

**Ambient Conditions:**

| | | |
|---|---|---|
| Dry Bulb Temperature | ° F | 86 |
| Relative Humidity | percent | 70 |

**Operating Mode:**

| | | |
|---|---|---|
| Duty Cycle | | Peaking |
| Capacity Factor | percent | 5 |

**Commercial Service:**

| | | |
|---|---|---|
| Date Available[B] | month/year | August 2016 |
| Service Life | years | 30 |

| **Lead Time (Prior to Comm. Operation):** | | Normal | Expedited |
|---|---|---|---|
| Permitting | months | 62 | 56 |
| Engineering | months | 26 | 22 |
| Procurement | months | 20 | 18 |
| Construction | months | 14 | 13.0 |

| | | |
|---|---|---|
| **Year Dollars:** | | December 2011 |
| **Capital Cost Uncertainty:** | plus/minus | +20%/-20% |

**Capital Cost (without AFUDC):**

| | $million | $/kW$_{gross}$ | $/kW$_{net}$ |
|---|---|---|---|
| A. Power Block Cost | 45.64 | 2,673 | 2,733 |
| B. Special Siting Costs | 0.69 | 40 | 41 |
| C. Power Plant Switchyard | 3.00 | 176 | 180 |
| D. T&D Interconnection | - | - | - |
| E. Total Direct Cost (A+B+C+D) | 49.33 | 2,889 | 2,954 |
| F. Total Indirect Cost (E*0.495) | 24.42 | 1,430 | 1,462 |
| G. Land Cost[C] | 2.40 | 140 | 143 |
| H. Total Capital Cost (E+F+G) | 76.14 | 4,459 | 4,559 |

**Operations & Maintenance:**

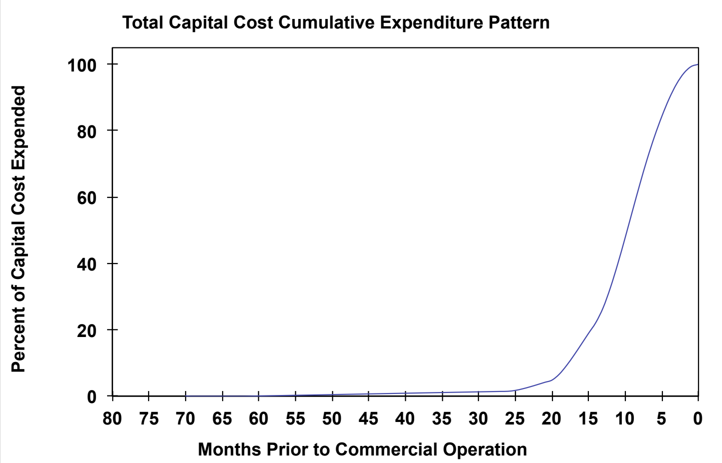
| | | |
|---|---|---|
| Fixed Cost | $million/y | 0.888 |
| | or $/kW-y$_{net}$ | 53.19 |
| Variable Cost | $/h run | 353 |
| | or $/MWh$_{net}$ | 21.15 |
| Staffing Requirements | | 4 |

**Capacity and Heat Rate Data:[D]**

| Load Point | # Engines | Comp Inlet | Gross Load | Net Load | Net Plant Heat Rate | Quick Load Pickup |
|---|---|---|---|---|---|---|
| | | ° F/RH | MW | MW | Btu/kWh | MW |
| Normal Top | 1 | 86/70 | 17.08 | 16.70 | 8,443 | - |
| 75% Load | 1 | 86/70 | 12.79 | 12.51 | 8,519 | 4.28 |
| 50% Load | 1 | 86/70 | 8.49 | 8.31 | 8,898 | 8.58 |
| Minimum[A] | 1 | 86/70 | 6.83 | 6.68 | not given | 10.25 |

**Flue Gas Emissions:[D]**

| | Normal Top Load at 59° F/70% RH | Minimum Load at 59° F/70% RH |
|---|---|---|
| | lb/MBtu | lb/MBtu |
| Nitrogen Oxides | 0.40 | not given |
| Sulfur Oxides | 0.0272 | not given |
| Carbon Dioxide | 177 | not given |
| Carbon Monoxide | 0.027 | not given |
| Volatile Organic Compounds | 0.035 | not given |
| Particulate Matter | 0.06 | not given |




**Grid Services:**

| | | |
|---|---|---|
| Ramping Capabilties[G] | MW/minute | 5.5 |
| Inertia Constant[H] | MW-sec/MVA | 1.2 |
| Start Time | minutes | 10 |
| Dispatchable? | | Yes |

| | |
|---|---|
| Voltage Regulation? | Yes |
| Disturbance Ride Through? | Yes |
| Underfrequency Droop Response? | Yes |
| Overfrequency Droop Response? | Yes |

**General Site/Technology Characteristics:**

| | | |
|---|---|---|
| Fuel Delivery | | Truck |
| Fuel Storage Onsite | | 15 days |
| Water Supply Source | | Truck |
| CTG Inlet Air Cooling | | No |
| Cycle Cooling | | NA |
| Waste Water Disposal | | Injection Wells |
| Solid Waste Disposal | | NA |
| Generator | | Synchronous |
| Minimum Land Requirement | acres | 11.0 |

**Daily Resource Requirements at Normal Top Load:[E]**

| | | |
|---|---|---|
| Fuel | gallons/day | 27,100 |
| Urea (dry)[F] | tpd | 0.51 |
| Service & Plant Water | mgd | 0.003 |
| Cooling Tower Makeup | mgd | NA |
| Supply Water Temperature | ° F | 79 |

**Waste Streams:**

| | | |
|---|---|---|
| Solid Waste | tpd | 0 |
| Waste Water Discharge | mgd | 0 |
| Water Discharge Temperature | ° F | 90 |
| Thermal Discharge | MBtu/d | 0 |

**CTG/HRSG/STG Unit Startup Parameters:**

| | | |
|---|---|---|
| Cold Start Heat Input Requirement | MBtu | 11 |
| Hot Start Heat Input Requirement | MBtu | 11 |
| Hot Hours | hours | 0.2 |

**Availability:**

| | | |
|---|---|---|
| CTG Maintenance Pattern | wk/y | 0-2-0-4-0-2-0-8 |
| STG Maintenance Pattern | wk/y | NA |
| Plant Maintenance Pattern | wk/y | 0-2-0-4-0-2-0-8 |
| Average Annual Maintenance | weeks | 2.0 |
| Immaturity Period | weeks | 5 |
| Immature Forced Outage Rate | percent | 6 |
| Minimum Weeks Between Maint. | weeks | 50 |
| Mature Forced Outage Rate | percent | 4 |
| Equivalent Availability | percent | 92 |

*IRP 2013 UIF Notes: Wartsila 18V46 (1x0 Simple Cycle)*

*Wartsila 18V46 (1x0 Simple Cycle)*

Notes:

(A) Wartsila does not provide performance data at loads below 50 percent. However, based on previous communications with Wartsila, engine load can be reduced to approximately 40 percent while maintaining emission compliance. Neglecting emission compliance, engine load can be reduced to as low as 20 percent. For modeling purposes, the minimum load is assumed to be 40 percent of normal top load.

(B) Date Available based on NTP of January 1, 2012 and expedited schedule.

(C) Land cost based on $5/sq ft or $217,800/acre for plant facilities only.

(D) Wartsila does not publish performance below 50 percent load.

(E) Based on 24 hour operation at normal top load. Fuel requirements reported as gallons per day, assuming a higher heating value of 16,800 Btu/lb and a density of 7.33 lb/gallon.

(F) Urea is used as a reagent within the Selective Catalytic Reduction (SCR) system. No other reagents are required for operation of air quality control (AQC) systems.

(G) The ramp rate of 5.5 MW/min is applicable when the engine is at loads greater than 50 percent and on AGC control.
The ramp rate during the start up sequence is 2.1 MW/min.

(H) System Inertia value based on previous Black & Veatch study (KIUC GenX Option Screening Study, November 2008).

Table K-2a
6x0 Wartsila 18V46 (Simple Cycle - Phase 1) Unit Information Form

## UNIT INFORMATION FORM

## HECO IRP 2013

| | |
|---|---|
| Utility: | *HECO* |
| Unit Type: | *Simple Cycle Wartsila 18V46* |
| Fuel Type: | *Biodiesel* |
| Site: | *Unspecified Island Location* |

| | |
|---|---|
| Date: | *March 25, 2013* |
| By: | *Black & Veatch* |
| Supersedes: | *December 20, 2012* |

**Unit Ratings:**

| | | Gross | Net |
|---|---|---|---|
| Normal Top Load | MW | 17.08 | 16.70 |
| Minimum[A] | MW | 6.83 | 6.68 |

**Ambient Conditions:**

| | | |
|---|---|---|
| Dry Bulb Temperature | ° F | 86 |
| Relative Humidity | percent | 70 |

**Operating Mode:**

| | | |
|---|---|---|
| Duty Cycle | | Peaking |
| Capacity Factor | percent | 5 |

**Commercial Service:**

| | | |
|---|---|---|
| Date Available[B] | month/year | February 2017 |
| Service Life | years | 30 |

**Lead Time (Prior to Commercial Operation):[C]**

| | | Normal | Expedited |
|---|---|---|---|
| Permitting | months | 68 | 62 |
| Engineering | months | 32 | 28 |
| Procurement | months | 26 | 24 |
| Construction | months | 20 | 19 |

| | | |
|---|---|---|
| **Year Dollars:** | | December 2011 |
| **Capital Cost Uncertainty:** | plus/minus | +20%/-20% |

**Capital Cost (without AFUDC):**

| | $million | $/kW$_{gross}$ | $/kW$_{net}$ |
|---|---|---|---|
| A1. Ph 1 (1x0) Power Block | 45.64 | 2,673 | 2,733 |
| A2. Ph 2 (5x0) Power Block | - | - | - |
| A. Total Power Block Cost | 45.64 | 2,673 | 2,733 |
| B. Special Siting Costs | 0.69 | 40 | 41 |
| C. Power Plant Switchyard | 3.00 | 176 | 180 |
| D. T&D Interconnection | - | - | - |
| E. Total Direct Cost (A+B+C+D) | 49.33 | 2,889 | 2,954 |
| F. Total Indirect Cost (E*0.495) | 24.42 | 1,430 | 1,462 |
| G. Land Cost[C] | 2.40 | 140 | 143 |
| H. Total Capital Cost (E+F+G) | 76.14 | 4,459 | 4,559 |

**Operations & Maintenance:**

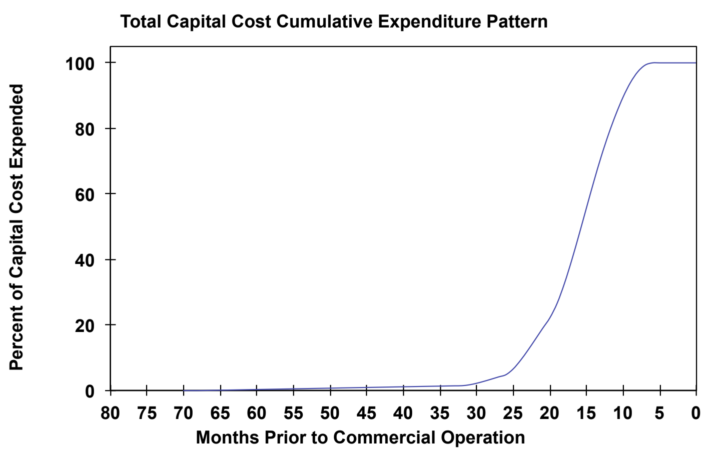
| | | 1x0 |
|---|---|---|
| Fixed Cost | $million/y | 0.888 |
| | or $/kW-y$_{net}$ | 53.19 |
| Variable Cost | $/h run | 353 |
| | or $/MWh$_{net}$ | 21.15 |
| Staffing Requirements | | 4 |

**Capacity and Heat Rate Data:[D,E]**

| Load Point | # Engines | Comp Inlet | Gross Load | Net Load | Net Plant Heat Rate | Quick Load Pickup |
|---|---|---|---|---|---|---|
| | | ° F/RH | MW | MW | Btu/kWh | MW |
| Normal Top | 1 | 86/70 | 17.08 | 16.70 | 8,443 | - |
| 75% Load | 1 | 86/70 | 12.79 | 12.51 | 8,519 | 4.28 |
| 50% Load | 1 | 86/70 | 8.49 | 8.31 | 8,898 | 8.58 |
| Minimum[A] | 1 | 86/70 | 6.83 | 6.68 | not given | 10.25 |

**Flue Gas Emissions:[D,F]**

| | Normal Top Load at 59° F/70% RH | Minimum Load at 59° F/70% RH |
|---|---|---|
| | lb/MBtu | lb/MBtu |
| Nitrogen Oxides | 0.40 | not given |
| Sulfur Oxides | 0.0272 | not given |
| Carbon Dioxide | 177 | not given |
| Carbon Monoxide | 0.027 | not given |
| Volatile Organic Compounds | 0.035 | not given |
| Particulate Matter | 0.06 | not given |




**Grid Services:**

| | | |
|---|---|---|
| Ramping Capabilities[I] | MW/minute | 5.5 |
| Inertia Constant[J] | MW-sec/MVA | 1.2 |
| Start Time | minutes | 10 |
| Dispatchable? | | Yes |

| | |
|---|---|
| Voltage Regulation? | Yes |
| Disturbance Ride Through? | Yes |
| Underfrequency Droop Response? | Yes |
| Overfrequency Droop Response? | Yes |

**General Site/Technology Characteristics:**

| | | |
|---|---|---|
| Fuel Delivery | | Truck |
| Fuel Storage Onsite | | 15 days |
| Water Supply Source | | Truck |
| CTG Inlet Air Cooling | | No |
| Cycle Cooling | | NA |
| Waste Water Disposal | | Injection Wells |
| Solid Waste Disposal | | NA |
| Generator | | Synchronous |
| Minimum Land Requirement | acres | 11.0 |

**Daily Resource Requirements at Normal Top Load:[G]**

| | | |
|---|---|---|
| Fuel | gallons/day | 27,100 |
| Urea (dry)[H] | tpd | 0.51 |
| Service & Plant Water | mgd | 0.003 |
| Cooling Tower Makeup | mgd | NA |
| Supply Water Temperature | ° F | 79 |

**Waste Streams:**

| | | |
|---|---|---|
| Solid Waste | tpd | 0 |
| Waste Water Discharge | mgd | 0 |
| Water Discharge Temperature | ° F | 90 |
| Thermal Discharge | MBtu/d | 0 |

**CTG/HRSG/STG Unit Startup Parameters:**

| | | |
|---|---|---|
| Cold Start Heat Input Requirement | MBtu | 11 |
| Hot Start Heat Input Requirement | MBtu | 11 |
| Hot Hours | hours | 0.2 |

**Availability:**

| | | |
|---|---|---|
| CTG Maintenance Pattern | wk/y | 0-2-0-4-0-2-0-8 |
| STG Maintenance Pattern | wk/y | NA |
| Plant Maintenance Pattern | wk/y | 0-2-0-4-0-2-0-8 |
| Average Annual Maintenance | weeks | 2.0 |
| Immaturity Period | weeks | 5 |
| Immature Forced Outage Rate | percent | 6 |
| Minimum Weeks Between Maint. | weeks | 50 |
| Mature Forced Outage Rate | percent | 4 |
| Equivalent Availability | percent | 92 |

Table K-2b
6x0 Wartsila 18V46 (Simple Cycle - Phase 2) Unit Information Form

## UNIT INFORMATION FORM

## HECO IRP 2013

| | |
|---|---|
| Utility: | *HECO* |
| Unit Type: | *Simple Cycle Wartsila 18V46* |
| Fuel Type: | *Biodiesel* |
| Site: | *Unspecified Island Location* |

| | |
|---|---|
| Date: | *March 25, 2013* |
| By: | *Black & Veatch* |
| Supersedes: | *December 20, 2012* |

**Unit Ratings:**

| | | Gross | Net |
|---|---|---|---|
| Normal Top Load | MW | **102.46** | **100.20** |
| Minimum[A] | MW | **40.98** | **40.08** |

**Ambient Conditions:**

| | | |
|---|---|---|
| Dry Bulb Temperature | ° F | **86** |
| Relative Humidity | percent | **70** |

**Operating Mode:**

| | | |
|---|---|---|
| Duty Cycle | | **Peaking** |
| Capacity Factor | percent | **5** |

**Commercial Service:**

| | | |
|---|---|---|
| Date Available[B] | month/year | **February 2017** |
| Service Life | years | **30** |

**Lead Time (Prior to Commercial Operation):[C]**

| | | Normal | Expedited |
|---|---|---|---|
| Permitting | months | **62** | **56** |
| Engineering | months | **26** | **22** |
| Procurement | months | **20** | **18** |
| Construction | months | **14** | **13** |

| | | |
|---|---|---|
| **Year Dollars:** | | **December 2011** |
| **Capital Cost Uncertainty:** | plus/minus | **+20%/-20%** |

**Capital Cost (without AFUDC):**

| | $million | $/kW$_{gross}$ | $/kW$_{net}$ |
|---|---|---|---|
| A1. Ph 1 (1x0) Power Block | - | - | - |
| A2. Ph 2 (5x0) Power Block | 139.86 | 1,638 | 1,675 |
| A. Total Power Block Cost | 139.86 | 1,638 | 1,675 |
| B. Special Siting Costs | 2.10 | 25 | 25 |
| C. Power Plant Switchyard | 7.80 | 91 | 93 |
| D. T&D Interconnection | - | - | - |
| E. Total Direct Cost (A+B+C+D) | 149.76 | 1,754 | 1,793 |
| F. Total Indirect Cost (E*0.372) | 55.71 | 652 | 667 |
| G. Land Cost[C] | - | - | - |
| H. Total Capital Cost (E+F+G) | 205.47 | 2,407 | 2,461 |

**Operations & Maintenance:**

| | | 6x0 |
|---|---|---|
| Fixed Cost | $million/y | **1.016** |
| | or $/kW-y$_{net}$ | **10.14** |
| Variable Cost | $/h run | **1,176** |
| | or $/MWh$_{net}$ | **11.74** |
| Staffing Requirements | | **4** |

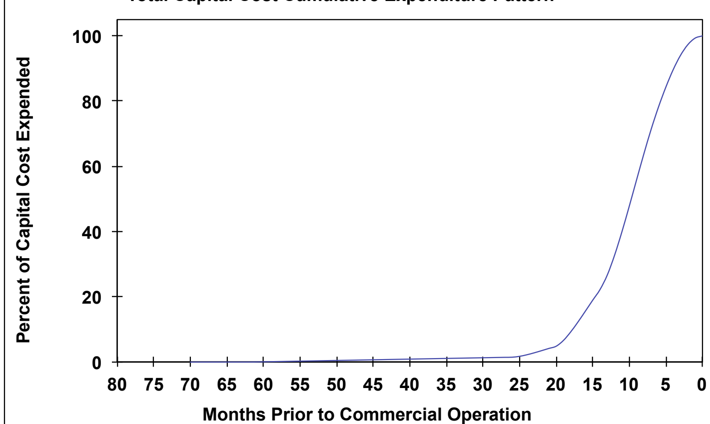
**Capacity and Heat Rate Data:[D,E]**

| Load Point | # Engines | Comp Inlet | Gross Load | Net Load | Net Plant Heat Rate | Quick Load Pickup |
|---|---|---|---|---|---|---|
| | | ° F/RH | MW | MW | Btu/kWh | MW |
| Normal Top | **6** | **86/70** | **102.46** | **100.20** | **8,443** | **-** |
| 75% Load | **6** | **86/70** | **76.76** | **75.08** | **8,519** | **25.69** |
| 50% Load | **6** | **86/70** | **50.96** | **49.84** | **8,898** | **51.49** |
| Minimum[A] | **6** | **86/70** | **40.98** | **40.08** | not given | **61.47** |

**Flue Gas Emissions:[D,F]**

| | Normal Top Load at 59° F/70% RH | Minimum Load at 59° F/70% RH |
|---|---|---|
| | lb/MBtu | lb/MBtu |
| Nitrogen Oxides | **0.40** | not given |
| Sulfur Oxides | **0.0272** | not given |
| Carbon Dioxide | **177** | not given |
| Carbon Monoxide | **0.027** | not given |
| Volatile Organic Compounds | **0.035** | not given |
| Particulate Matter | **0.06** | not given |

**Total Capital Cost Cumulative Expenditure Pattern**




**Grid Services:**

| | | |
|---|---|---|
| Ramping Capabilties[I] | MW/minute | **33** |
| Inertia Constant[J] | MW-sec/MVA | **1.2** |
| Start Time | minutes | **10** |
| Dispatchable? | | **Yes** |

| | |
|---|---|
| Voltage Regulation? | **Yes** |
| Disturbance Ride Through? | **Yes** |
| Underfrequency Droop Response? | **Yes** |
| Overfrequency Droop Response? | **Yes** |

**General Site/Technology Characteristics:**

| | | |
|---|---|---|
| Fuel Delivery | | **Truck** |
| Fuel Storage Onsite | | **15 days** |
| Water Supply Source | | **Truck** |
| CTG Inlet Air Cooling | | **No** |
| Cycle Cooling | | **NA** |
| Waste Water Disposal | | **Injection Wells** |
| Solid Waste Disposal | | **NA** |
| Generator | | **Synchronous** |
| Minimum Land Requirement | acres | **0.0** |

**Daily Resource Requirements at Normal Top Load:[G]**

| | | |
|---|---|---|
| Fuel | gallons/day | **162,800** |
| Urea (dry)[H] | tpd | **3.06** |
| Service & Plant Water | mgd | **0.017** |
| Cooling Tower Makeup | mgd | **NA** |
| Supply Water Temperature | ° F | **79** |

**Waste Streams:**

| | | |
|---|---|---|
| Solid Waste | tpd | **0** |
| Waste Water Discharge | mgd | **0** |
| Water Discharge Temperature | ° F | **90** |
| Thermal Discharge | MBtu/d | **0** |

**CTG/HRSG/STG Unit Startup Parameters:**

| | | |
|---|---|---|
| Cold Start Heat Input Requirement | MBtu | **66** |
| Hot Start Heat Input Requirement | MBtu | **66** |
| Hot Hours | hours | **0.2** |

**Availability:**

| | | |
|---|---|---|
| CTG Maintenance Pattern | wk/y | **0-2-0-4-0-2-0-8** |
| STG Maintenance Pattern | wk/y | **NA** |
| Plant Maintenance Pattern | wk/y | **0-2-0-4-0-2-0-8** |
| Average Annual Maintenance | weeks | **2.0** |
| Immaturity Period | weeks | **5** |
| Immature Forced Outage Rate | percent | **6** |
| Minimum Weeks Between Maint. | weeks | **50** |
| Mature Forced Outage Rate | percent | **4** |
| Equivalent Availability | percent | **92** |

Table K-2c
6x0 Wartsila 18V46 (Simple Cycle - Overall) Unit Information Form

| | |
|---|---|
| Utility: | *HECO* |
| Unit Type: | *Simple Cycle Wartsila 18V46* |
| Fuel Type: | *Biodiesel* |
| Site: | *Unspecified Island Location* |

## UNIT INFORMATION FORM

## HECO IRP 2013

| | |
|---|---|
| Date: | *March 25, 2013* |
| By: | *Black & Veatch* |
| Supersedes: | *December 20, 2012* |

**Unit Ratings:**

| | | Gross | Net |
|---|---|---|---|
| Normal Top Load | MW | 102.46 | 100.20 |
| Minimum[A] | MW | 40.98 | 40.08 |

**Ambient Conditions:**

| | | |
|---|---|---|
| Dry Bulb Temperature | ° F | 86 |
| Relative Humidity | percent | 70 |

**Operating Mode:**

| | | |
|---|---|---|
| Duty Cycle | | Peaking |
| Capacity Factor | percent | 5 |

**Commercial Service:**

| | | |
|---|---|---|
| Date Available[B] | month/year | February 2017 |
| Service Life | years | 30 |

**Lead Time (Prior to Commercial Operation):[C]**

| | | Normal | Expedited |
|---|---|---|---|
| Permitting | months | 68 | 62 |
| Engineering | months | 32 | 28 |
| Procurement | months | 26 | 24 |
| Construction | months | 20 | 19 |

| | | |
|---|---|---|
| **Year Dollars:** | | December 2011 |
| **Capital Cost Uncertainty:** | plus/minus | +20%/-20% |

**Capital Cost (without AFUDC):**

| | $million | $/kW$_{gross}$ | $/kW$_{net}$ |
|---|---|---|---|
| A1. Ph 1 (1x0) Power Block | 45.64 | - | - |
| A2. Ph 2 (5x0) Power Block | 139.86 | - | - |
| A. Total Power Block Cost | 185.50 | 1,811 | 1,851 |
| B. Special Siting Costs | 2.78 | 27 | 28 |
| C. Power Plant Switchyard | 10.80 | 105 | 108 |
| D. T&D Interconnection | - | - | - |
| E. Total Direct Cost (A+B+C+D) | 199.08 | 1,943 | 1,987 |
| F. Total Indirect Cost (E*0.403) | 80.13 | 782 | 800 |
| G. Land Cost[C] | 2.40 | 23 | 24 |
| H. Total Capital Cost (E+F+G) | 281.61 | 2,749 | 2,810 |

**Operations & Maintenance:**

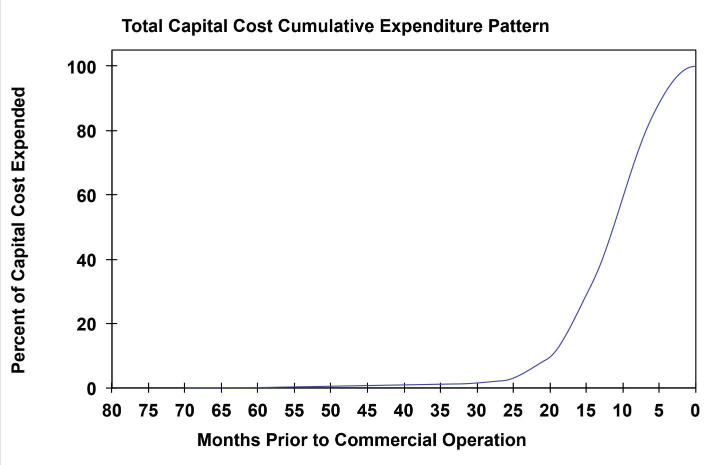
| | | 1x0 | 6x0 |
|---|---|---|---|
| Fixed Cost | $million/y | 0.888 | 1.016 |
| | or $/kW-y$_{net}$ | 53.19 | 10.14 |
| Variable Cost | $/h run | 353 | 1,176 |
| | or $/MWh$_{net}$ | 21.15 | 11.74 |
| Staffing Requirements | | 4 | 4 |

**Capacity and Heat Rate Data:[D,E]**

| Load Point | # Engines | Comp Inlet | Gross Load | Net Load | Net Plant Heat Rate | Quick Load Pickup |
|---|---|---|---|---|---|---|
| | | ° F/RH | MW | MW | Btu/kWh | MW |
| Normal Top | 6 | 86/70 | 102.46 | 100.20 | 8,443 | - |
| 75% Load | 6 | 86/70 | 76.76 | 75.08 | 8,519 | 25.69 |
| 50% Load | 6 | 86/70 | 50.96 | 49.84 | 8,898 | 51.49 |
| Minimum[A] | 6 | 86/70 | 40.98 | 40.08 | not given | 61.47 |

**Flue Gas Emissions:[D,F]**

| | Normal Top Load at 59° F/70% RH | Minimum Load at 59° F/70% RH |
|---|---|---|
| | lb/MBtu | lb/MBtu |
| Nitrogen Oxides | 0.40 | not given |
| Sulfur Oxides | 0.0272 | not given |
| Carbon Dioxide | 177 | not given |
| Carbon Monoxide | 0.027 | not given |
| Volatile Organic Compounds | 0.035 | not given |
| Particulate Matter | 0.06 | not given |




**Grid Services:**

| | | |
|---|---|---|
| Ramping Capabilities[I] | MW/minute | 33 |
| Inertia Constant[J] | MW-sec/MVA | 1.2 |
| Start Time | minutes | 10 |
| Dispatchable? | | Yes |

| | |
|---|---|
| Voltage Regulation? | Yes |
| Disturbance Ride Through? | Yes |
| Underfrequency Droop Response? | Yes |
| Overfrequency Droop Response? | Yes |

**General Site/Technology Characteristics:**

| | | |
|---|---|---|
| Fuel Delivery | | Truck |
| Fuel Storage Onsite | | 15 days |
| Water Supply Source | | Truck |
| CTG Inlet Air Cooling | | No |
| Cycle Cooling | | NA |
| Waste Water Disposal | | Injection Wells |
| Solid Waste Disposal | | NA |
| Generator | | Synchronous |
| Minimum Land Requirement | acres | 11.0 |

**Daily Resource Requirements at Normal Top Load:[G]**

| | | |
|---|---|---|
| Fuel | gallons/day | 162,800 |
| Urea (dry)[H] | tpd | 3.06 |
| Service & Plant Water | mgd | 0.017 |
| Cooling Tower Makeup | mgd | NA |
| Supply Water Temperature | ° F | 79 |

**Waste Streams:**

| | | |
|---|---|---|
| Solid Waste | tpd | 0 |
| Waste Water Discharge | mgd | 0 |
| Water Discharge Temperature | ° F | 90 |
| Thermal Discharge | MBtu/d | 0 |

**CTG/HRSG/STG Unit Startup Parameters:**

| | | |
|---|---|---|
| Cold Start Heat Input Requirement | MBtu | 66 |
| Hot Start Heat Input Requirement | MBtu | 66 |
| Hot Hours | hours | 0.2 |

**Availability:**

| | | |
|---|---|---|
| CTG Maintenance Pattern | wk/y | 0-2-0-4-0-2-0-8 |
| STG Maintenance Pattern | wk/y | NA |
| Plant Maintenance Pattern | wk/y | 0-2-0-4-0-2-0-8 |
| Average Annual Maintenance | weeks | 2.0 |
| Immaturity Period | weeks | 5 |
| Immature Forced Outage Rate | percent | 6 |
| Minimum Weeks Between Maint. | weeks | 50 |
| Mature Forced Outage Rate | percent | 4 |
| Equivalent Availability | percent | 92 |

*IRP 2013 UIF Notes:  Wartsila 18V46 (6x0 Simple Cycle)*

*Wartsila 18V46 (6x0 Simple Cycle)*

Notes: (A)  Wartsila does not provide performance data at loads below 50 percent.  However, based on previous communications with Wartsila, engine load can be reduced to approximately 40 percent while maintaining emission compliance.  Neglecting emission compliance, engine load can be reduced to as low as 20 percent.  For modeling purposes, the minimum load is assumed to be 40 percent of normal top load.

(B) Date Available represents Commercial Operation Date (COD) of all (6x0) engine systems.  Date Available is based on on NTP of January 1, 2012 and expedited schedule.

(C)  Land cost based on $5/sq ft or $217,800/acre for plant facilities only.

(D)  Wartsila does not publish performance below 50 percent load.

(E)  Performance is based on combustion of biodiesel. Combustion turbine performance and emissions were determined by OEM performance models, considering a bio-diesel fuel specification provided by HECO.

(F) Emissions of NOx are controlled via Selective Catalytic Reduction (SCR) system, and emissions of CO are controlled via CO catalyst.

(G)  Based on 24 hour operation at normal top load.  Fuel requirements reported as gallons per day, assuming a higher heating value of 16,800 Btu/lb and a density of 7.33 lb/gallon.

(H)  Urea is used as a reagent within the Selective Catalytic Reduction (SCR) system.  No other reagents are required for operation of air quality control (AQC) systems.

(I)  The ramp rate of 5.5 MW/min is applicable when the engine is at loads greater than 50 percent and on AGC control.
For the 6x0 scenario, the ramp rate is 5.5 MW/min per engine, or 33 MW/min for the entire facility.
The ramp rate during the start up sequence is 2.1 MW/min (per engine).

(J)  System Inertia value based on previous  Black & Veatch study (KIUC GenX Option Screening Study, November 2008).

# Appendix K: Consolidated Unit Information Forms

Table K-3
1x0 Wartsila 12V32 (Simple Cycle) Unit Information Form

## UNIT INFORMATION FORM

## HECO IRP 2013

| | |
|---|---|
| Utility: | *MECO* |
| Unit Type: | *Simple Cycle Wartsila 12V32* |
| Fuel Type: | *Biodiesel* |
| Site: | *Unspecified Island Location* |

| | |
|---|---|
| Date: | *March 25, 2013* |
| By: | *Black & Veatch* |
| Supersedes: | *February 19, 2013* |

**Unit Ratings:**

| | | Gross | Net |
|---|---|---|---|
| Normal Top Load | MW | 5.21 | 5.10 |
| Minimum[A] | MW | 2.08 | 2.04 |

**Ambient Conditions:**

| | | |
|---|---|---|
| Dry Bulb Temperature | ° F | 86 |
| Relative Humidity | percent | 70 |

**Operating Mode:**

| | | |
|---|---|---|
| Duty Cycle | | Peaking |
| Capacity Factor | percent | 5 |

**Commercial Service:**

| | | |
|---|---|---|
| Date Available[B] | month/year | August 2016 |
| Service Life | years | 30 |

**Lead Time (Prior to Comm. Operation):**

| | | Normal | Expedited |
|---|---|---|---|
| Permitting | months | 62 | 56 |
| Engineering | months | 26 | 22 |
| Procurement | months | 20 | 18 |
| Construction | months | 14 | 13.0 |

| | | |
|---|---|---|
| **Year Dollars:** | | December 2011 |
| **Capital Cost Uncertainty:** | plus/minus | +20%/-20% |

**Capital Cost (without AFUDC):**

| | $million | $/kW$_{gross}$ | $/kW$_{net}$ |
|---|---|---|---|
| A. Power Block Cost | 20.82 | 3,996 | 4,086 |
| B. Special Siting Costs | 0.31 | 60 | 61 |
| C. Power Plant Switchyard | 1.45 | 278 | 284 |
| D. T&D Interconnection | - | - | - |
| E. Total Direct Cost (A+B+C+D) | 22.58 | 4,334 | 4,431 |
| F. Total Indirect Cost (E*0.495) | 11.11 | 2,132 | 2,180 |
| G. Land Cost[C] | 0.87 | 167 | 171 |
| H. Total Capital Cost (E+F+G) | 34.57 | 6,633 | 6,783 |

**Operations & Maintenance:**

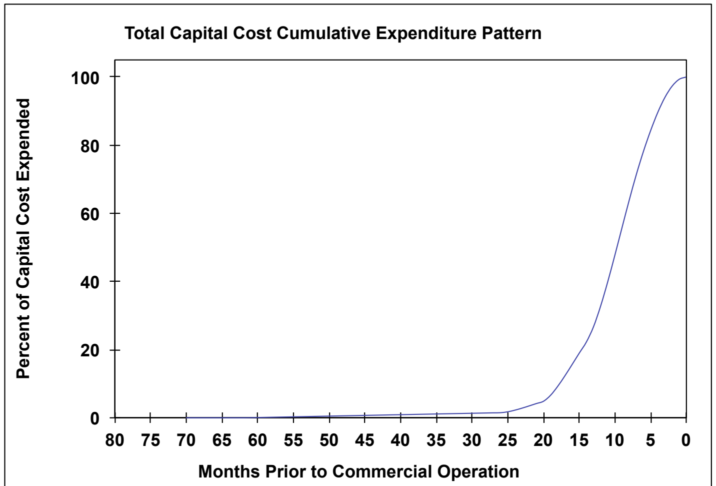
| | | |
|---|---|---|
| Fixed Cost | $million/y | 0.888 |
| | or $/kW-y$_{net}$ | 174.30 |
| Variable Cost | $/h run | 153 |
| | or $/MWh$_{net}$ | 29.99 |
| Staffing Requirements | | 4 |

**Capacity and Heat Rate Data:[D]**

| Load Point | # Engines | Comp Inlet | Gross Load | Net Load | Net Plant Heat Rate | Quick Load Pickup |
|---|---|---|---|---|---|---|
| | | ° F/RH | MW | MW | Btu/kWh | MW |
| Normal Top | 1 | 86/70 | 5.21 | 5.10 | 8,560 | - |
| Minimum[A] | 1 | 86/70 | 2.08 | 2.04 | not given | 3.13 |

**Flue Gas Emissions:[D]**

| | Normal Top Load at 59° F/70% RH | Minimum Load at 59° F/70% RH |
|---|---|---|
| | lb/MBtu | lb/MBtu |
| Nitrogen Oxides | 0.35 | not given |
| Sulfur Oxides | 0.0263 | not given |
| Carbon Dioxide | 177 | not given |
| Carbon Monoxide | 0.047 | not given |
| Volatile Organic Compounds | 0.068 | not given |
| Particulate Matter | 0.06 | not given |




**Grid Services:**

| | | |
|---|---|---|
| Ramping Capabilities[G] | MW/minute | 1.6 |
| System Inertia[H] | MW-sec/MVA | 1.2 |
| Start Time | minutes | 10 |
| Dispatchable? | | Yes |

| | |
|---|---|
| Voltage Regulation? | Yes |
| Disturbance Ride Through? | Yes |
| Underfrequency Droop Response? | Yes |
| Overfrequency Droop Response? | Yes |

**General Site/Technology Characteristics:**

| | | |
|---|---|---|
| Fuel Delivery | | Truck |
| Fuel Storage Onsite | | 15 days |
| Water Supply Source | | Truck |
| CTG Inlet Air Cooling | | No |
| Cycle Cooling | | NA |
| Waste Water Disposal | | Injection Wells |
| Solid Waste Disposal | | NA |
| Generator | | Synchronous |
| Minimum Land Requirement | acres | 4.0 |

**Daily Resource Requirements at Normal Top Load:[E]**

| | | |
|---|---|---|
| Fuel | gallons/day | 8,400 |
| Urea (dry)[F] | tpd | 0.16 |
| Service & Plant Water | mgd | 0.002 |
| Cooling Tower Makeup | mgd | NA |
| Supply Water Temperature | ° F | 79 |

**Waste Streams:**

| | | |
|---|---|---|
| Solid Waste | tpd | 0 |
| Waste Water Discharge | mgd | 0 |
| Water Discharge Temperature | ° F | 90 |
| Thermal Discharge | MBtu/d | - |

**CTG/HRSG/STG Unit Startup Parameters:**

| | | |
|---|---|---|
| Cold Start Heat Input Requirement | MBtu | 3 |
| Hot Start Heat Input Requirement | MBtu | 3 |
| Hot Hours | hours | 0.2 |

**Availability:**

| | | |
|---|---|---|
| CTG Maintenance Pattern | wk/y | 0-2-0-4-0-2-0-8 |
| STG Maintenance Pattern | wk/y | NA |
| Plant Maintenance Pattern | wk/y | 0-2-0-4-0-2-0-8 |
| Average Annual Maintenance | weeks | 2.0 |
| Immaturity Period | weeks | 5 |
| Immature Forced Outage Rate | percent | 6 |
| Minimum Weeks Between Maint. | weeks | 50 |
| Mature Forced Outage Rate | percent | 4 |
| Equivalent Availability | percent | 92 |

*IRP 2013 UIF Notes: Wartsila 12V32 (1x0 Simple Cycle)*

*Wartsila 12V32 (1x0 Simple Cycle)*

Notes:

(A) Wartsila does not provide performance data at loads below 50 percent. However, based on previous communications with Wartsila, engine load can be reduced to approximately 40 percent while maintaining emission compliance. Neglecting emission compliance, engine load can be reduced to as low as 20 percent. For modeling purposes, the minimum load is assumed to be 40 percent of normal top load.

(B) Date Available based on NTP of January 1, 2012 and expedited schedule.

(C) Land cost based on $5/sq ft or $217,800/acre for plant facilities only.

(D) Wartsila does not publish performance below 50 percent load.

(E) Based on 24 hour operation at normal top load. Fuel requirements reported as gallons per day, assuming a higher heating value of 16,800 Btu/lb and a density of 7.33 lb/gallon.

(F) Urea is used as a reagent within the Selective Catalytic Reduction (SCR) system. No other reagents are required for operation of air quality control (AQC) systems.

(G) The ramp rate of 1.6 MW/min is applicable when the engine is at loads greater than 50 percent and on AGC control.
The ramp rate during the start up sequence is 0.5 MW/min.

(H) System Inertia value based on previous Black & Veatch study (KIUC GenX Option Screening Study, November 2008).

Table L-1
GE LM2500 (Simple Cycle) Unit Information Form

## UNIT INFORMATION FORM

## HECO IRP 2013

| | |
|---|---|
| Utility: | *HECO* |
| Unit Type: | *Simple Cycle GE LM2500* |
| Fuel Type: | *Biodiesel* |
| Size: | *Unspecified Island Location* |

| | |
|---|---|
| Date: | *March 25, 2013* |
| By: | *Black & Veatch* |
| Supersedes: | *October 11, 2012* |

**Unit Ratings:**

| | | Gross | Net |
|---|---|---|---|
| Normal Top Load | MW | 21.43 | 21.13 |
| Minimum | MW | 5.39 | 5.13 |

**Ambient Conditions:**

| | | |
|---|---|---|
| Dry Bulb Temperature | °F | 86 |
| Relative Humidity | percent | 70 |
| CTG Inlet Air Temperature | °F | 86 |

**Operating Mode:**

| | | |
|---|---|---|
| Duty Cycle | | Peaking |
| Capacity Factor | percent | 5 |

**Commercial Service:**

| | | |
|---|---|---|
| Date Available[A] | month/year | November 2016 |
| Service Life | years | 30 |

**Lead Time (Prior to Commercial Oper):**

| | | Normal | Expedited |
|---|---|---|---|
| Permitting | months | 63 | 58 |
| Engineering | months | 27 | 24 |
| Procurement | months | 21 | 20 |
| Construction | months | 14 | 13 |

| | | |
|---|---|---|
| **Year Dollars:** | | December 2011 |
| **Capital Cost Uncertainty:** | plus/minus | +20%/-20% |

**Capital Cost (without AFUDC):**

| | $million | $/kW$_{gross}$ | $/kW$_{net}$ |
|---|---|---|---|
| A. Power Block Cost | 55.70 | 2,599 | 2,636 |
| B. Special Siting Costs | 0.84 | 39 | 40 |
| C. Power Plant Switchyard | 3.43 | 160 | 162 |
| D. T&D Interconnection | - | - | - |
| E. Total Direct Cost (A+B+C+D) | 59.96 | 2,798 | 2,838 |
| F. Total Indirect Cost (E*0.474) | 28.67 | 1,338 | 1,357 |
| G. Land Cost[B] | 2.40 | 112 | 113 |
| H. Total Capital Cost (E+F+G) | 91.03 | 4,248 | 4,308 |

**Operations & Maintenance:**

| | | |
|---|---|---|
| Fixed Cost | $million/y | 0.905 |
| | or $/kW-y$_{net}$ | 42.85 |
| Variable Cost | $/h run | 419 |
| | or $/MWh$_{net}$ | 19.84 |
| Staffing Requirements[C] | | 4 |

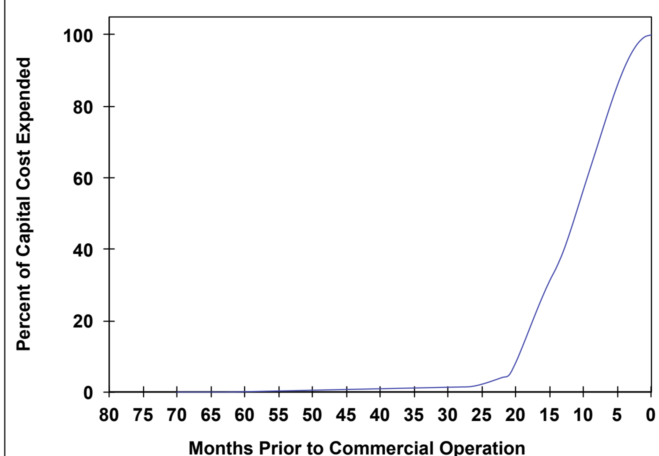
**Capacity and Heat Rate Data:[D]**

| Load Point | # CTGs | Comp Inlet | Gross Load | Net Load | Net Plant Heat Rate | Quick Load Pickup |
|---|---|---|---|---|---|---|
| | | °F/RH | MW | MW | Btu/kWh | MW |
| Normal Top | 1 | 86/70 | 21.43 | 21.13 | 11,044 | - |
| Minimum | 1 | 86/70 | 5.39 | 5.13 | 17,541 | 16.04 |

**Flue Gas Emissions:[E]**

| | Normal Top Load at 59° F/70% RH | Minimum Load at 59° F/70% RH |
|---|---|---|
| | lb/MBtu | lb/MBtu |
| Nitrogen Oxides | 0.01 | 0.01 |
| Sulfur Oxides | 0.0005 | 0.0005 |
| Carbon Dioxide | 177 | 177 |
| Carbon Monoxide | 0.006 | 0.060 |
| Volatile Organic Compounds | 0.000 | 0.005 |
| Particulate Matter | 0.01 | 0.02 |

**Total Capital Cost Cumulative Expenditure Pattern**




**General Site/Technology Characteristics:**

| | | |
|---|---|---|
| Fuel Delivery | | Truck |
| Fuel Storage Onsite | | 15 days |
| Water Supply Source | | Sea/Groundwater |
| CTG Inlet Air Cooling | | No |
| Cycle Cooling | | NA |
| Waste Water Disposal | | Injection Wells |
| Solid Waste Disposal | | NA |
| Generator | | Synchronous |
| Minimum Land Requirement | acres | 11.0 |

**Daily Resource Requirements at Normal Top Load:[F]**

| | | |
|---|---|---|
| Fuel | gallons/day | 46,200 |
| Urea (dry)[G] | tpd | 0.52 |
| Service & Plant Water | mgd | 0.09 |
| Cooling Tower Makeup | mgd | NA |
| Supply Water Temperature | °F | 79 |

**Waste Streams:**

| | | |
|---|---|---|
| Solid Waste | tpd | 0 |
| Waste Water Discharge | mgd | 0.05 |
| Water Discharge Temperature | °F | 90 |
| Thermal Discharge | MBtu/day | 4 |

**CTG/HRSG/STG Unit Startup Parameters:**

| | | |
|---|---|---|
| Cold Start Heat Input Requirement | MBtu | 27 |
| Hot Start Heat Input Requirement | MBtu | 27 |
| Hot Hours | hours | 0.2 |

**Availability:**

| | | |
|---|---|---|
| CTG Maintenance Pattern | wk/y | 0-0-1-0-0-6-0-0-1-0-0-12 |
| STG Maintenance Pattern | wk/y | NA |
| Plant Maintenance Pattern | wk/y | 0-0-1-0-0-6-0-0-1-0-0-12 |
| Average Annual Maintenance | weeks | 2 |
| Immaturity Period | weeks | 5 |
| Immature Forced Outage Rate | percent | 6 |
| Minimum Weeks Between Maintenance | weeks | 50 |
| Mature Forced Outage Rate | percent | 4 |
| Equivalent Availability | percent | 92 |

**Grid Services:**

| | | | | |
|---|---|---|---|---|
| Ramping Capabilties[H] | MW/minute | 10 | Voltage Regulation? | Yes |
| Inertia Constant[I] | MW-sec/MVA | 1.1 | Disturbance Ride Through? | Yes |
| Start Time | minutes | 10 | Underfrequency Droop Response? | Yes |
| Dispatchable? | | Yes | Overfrequency Droop Response? | Yes |

*IRP 2013 UIF Notes: LM2500 (Simple Cycle)*

*LM2500 (Simple Cycle)*

Notes:

(A) Date Available based on NTP of January 1, 2012 and expedited schedule.

(B) Land cost based on $5/sq ft or $217,800/acre for plant facilities only.

(C) For simple cycle facilities with very low (< 10 percent) capacity factors, it assumed that the staff would consist of 4 full-time operators, and these operators would be capable of providing minor, day-to-day maintenance for the combustion turbines.

(D) Performance is based on combustion of biodiesel. Combustion turbine performance and emissions were determined by OEM performance models, considering a bio-diesel fuel specification provided by HECO.

(E) Emissions of NOx are controlled via Selective Catalytic Reduction (SCR) system, and emissions of CO are controlled via CO catalyst.

(F) Based on 24 hour operation at normal top load. Fuel requirements reported as gallons per day, assuming a higher heating value of 16,800 Btu/lb and a density of 7.33 lb/gallon.

(G) Urea is used as a reagent within the Selective Catalytic Reduction (SCR) system. No other reagents are required for operation of air quality control (AQC) systems.

(H) The ramp rate of 14 MW/min is applicable following completion of required system purges during standard startup process. Complete startup period (including purges and ramping of unit) is 10 minutes, as noted.

(I) System Inertia value provided by OEM.

Table L-2
GE LM6000 PG (Simple Cycle) Unit Information Form

**UNIT INFORMATION FORM**

**HECO IRP 2013**

| | |
|---|---|
| Utility: | *HECO* |
| Unit Type: | *Simple Cycle GE LM6000 PG* |
| Fuel Type: | *Biodiesel* |
| Site: | *Unspecified Island Location* |

| | |
|---|---|
| Date: | *March 25, 2013* |
| By: | *Black & Veatch* |
| Supersedes: | *October 11, 2012* |

**Unit Ratings:**

| | | Gross | Net |
|---|---|---|---|
| Normal Top Load | MW | 42.36 | 41.87 |
| Minimum | MW | 10.62 | 10.23 |

**Ambient Conditions:**

| | | |
|---|---|---|
| Dry Bulb Temperature | ° F | 86 |
| Relative Humidity | percent | 70 |
| CTG Inlet Air Temperature | ° F | 86 |

**Operating Mode:**

| | | |
|---|---|---|
| Duty Cycle | | Peaking |
| Capacity Factor | percent | 5 |

**Commercial Service:**

| | | |
|---|---|---|
| Date Available[A] | month/year | June 2017 |
| Service Life | years | 30 |

**Lead Time (Prior to Comm. Operation):**

| | | Normal | Expedited |
|---|---|---|---|
| Permitting | months | 72 | 66 |
| Engineering | months | 36 | 32 |
| Procurement | months | 28 | 26 |
| Construction | months | 20 | 19 |

| | | |
|---|---|---|
| **Year Dollars:** | | December 2011 |
| **Capital Cost Uncertainty:** | plus/minus | +20%/-20% |

**Capital Cost (without AFUDC):**

| | $million | $/kW$_{gross}$ | $/kW$_{net}$ |
|---|---|---|---|
| A. Power Block Cost | 77.56 | 1,831 | 1,852 |
| B. Special Siting Costs | 1.16 | 27 | 28 |
| C. Power Plant Switchyard | 5.18 | 122 | 124 |
| D. T&D Interconnection | - | - | - |
| E. Total Direct Cost (A+B+C+D) | 83.90 | 1,981 | 2,004 |
| F. Total Indirect Cost (E*0.430) | 36.11 | 853 | 862 |
| G. Land Cost[B] | 2.40 | 57 | 57 |
| H. Total Capital Cost (E+F+G) | 122.41 | 2,890 | 2,924 |

**Operations & Maintenance:**

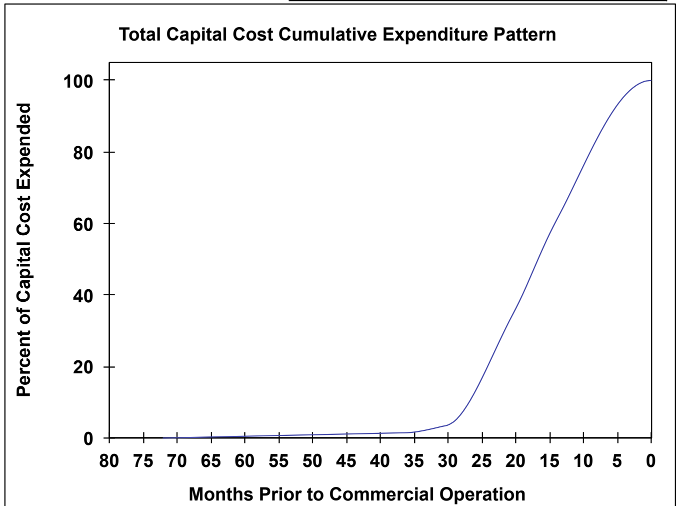
| | | |
|---|---|---|
| Fixed Cost | $million/y | 0.922 |
| | or $/kW-y$_{net}$ | 22.02 |
| Variable Cost | $/h run | 602 |
| | or $/MWh$_{net}$ | 14.38 |
| Staffing Requirements[C] | | 4 |

**Capacity and Heat Rate Data:[D]**

| Load Point | # CTGs | Comp Inlet | Gross Load | Net Load | Net Plant Heat Rate | Quick Load Pickup |
|---|---|---|---|---|---|---|
| | | ° F/RH | MW | MW | Btu/kWh | MW |
| Normal Top | 1 | 86/70 | 42.36 | 41.87 | 10,112 | - |
| Minimum | 1 | 86/70 | 10.62 | 10.23 | 17,689 | 31.74 |

**Flue Gas Emissions:[E]**

| | Normal Top Load at 59° F/70% RH | Minimum Load at 59° F/70% RH |
|---|---|---|
| | lb/MBtu | lb/MBtu |
| Nitrogen Oxides | 0.01 | 0.01 |
| Sulfur Oxides | 0.0005 | 0.0005 |
| Carbon Dioxide | 177 | 177 |
| Carbon Monoxide | 0.002 | 0.001 |
| Volatile Organic Compounds | 0.001 | 0.000 |
| Particulate Matter | 0.01 | 0.01 |




**Grid Services:**

| | | |
|---|---|---|
| Ramping Capabilities[H] | MW/minute | 14 |
| Inertia Constant[I] | MW-sec/MVA | 1.3 |
| Start Time | minutes | 10 |
| Dispatchable? | | Yes |

| | |
|---|---|
| Voltage Regulation? | Yes |
| Disturbance Ride Through? | Yes |
| Underfrequency Droop Response? | Yes |
| Overfrequency Droop Response? | Yes |

**General Site/Technology Characteristics:**

| | | |
|---|---|---|
| Fuel Delivery | | Truck |
| Fuel Storage Onsite | | 15 days |
| Water Supply Source | | Sea/Groundwater |
| CTG Inlet Air Cooling | | No |
| Cycle Cooling | | NA |
| Waste Water Disposal | | Injection Wells |
| Solid Waste Disposal | | NA |
| Generator | | Synchronous |
| Minimum Land Requirement | acres | 11.0 |

**Daily Resource Requirements at Normal Top Load:[F]**

| | | |
|---|---|---|
| Fuel | gallons/day | 83,800 |
| Urea (dry)[G] | tpd | 0.86 |
| Service & Plant Water | mgd | 0.20 |
| Cooling Tower Makeup | mgd | NA |
| Supply Water Temperature | ° F | 79 |

**Waste Streams:**

| | | |
|---|---|---|
| Solid Waste | tpd | 0 |
| Waste Water Discharge | mgd | 0.11 |
| Water Discharge Temperature | ° F | 90 |
| Thermal Discharge | MBtu/day | 10 |

**CTG/HRSG/STG Unit Startup Parameters:**

| | | |
|---|---|---|
| Cold Start Heat Input Requirement | MBtu | 36 |
| Hot Start Heat Input Requirement | MBtu | 36 |
| Hot Hours | hours | 0.2 |

**Availability:**

| | | |
|---|---|---|
| CTG Maintenance Pattern | wk/y | 0-0-1-0-0-6-0-0-1-0-0-12 |
| STG Maintenance Pattern | wk/y | NA |
| Plant Maintenance Pattern | wk/y | 0-0-1-0-0-6-0-0-1-0-0-12 |
| Average Annual Maintenance | weeks | 2 |
| Immaturity Period | weeks | 5 |
| Immature Forced Outage Rate | percent | 6 |
| Minimum Weeks Between Maint. | weeks | 50 |
| Mature Forced Outage Rate | percent | 4 |
| Equivalent Availability | percent | 92 |

*IRP 2013 UIF Notes: LM6000 PG (Simple Cycle)*

*LM6000 PG (Simple Cycle)*

Notes:

(A) Date Available based on NTP of January 1, 2012 and expedited schedule.

(B) Land cost based on $5/sq ft or $217,800/acre for plant facilities only.

(C) For simple cycle facilities with very low (< 10 percent) capacity factors, it assumed that the staff would consist of 4 full-time operators, and these operators would be capable of providing minor, day-to-day maintenance for the combustion turbines.

(D) Performance is based on combustion of biodiesel. Combustion turbine performance and emissions were determined by OEM performance models, considering a bio-diesel fuel specification provided by HECO.

(E) Emissions of NOx are controlled via Selective Catalytic Reduction (SCR) system, and emissions of CO are controlled via CO catalyst.

(F) Based on 24 hour operation at normal top load. Fuel requirements reported as gallons per day, assuming a higher heating value of 16,800 Btu/lb and a density of 7.33 lb/gallon.

(G) Urea is used as a reagent within the Selective Catalytic Reduction (SCR) system. No other reagents are required for operation of air quality control (AQC) systems.

(H) The ramp rate of 14 MW/min is applicable following completion of required system purges during standard startup process. Complete startup period (including purges and ramping of unit) is 10 minutes, as noted.

(I) System Inertia value provided by OEM.

# Appendix K: Consolidated Unit Information Forms

Table L-3
GE LMS100 PA (Simple Cycle) Unit Information Form

| | |
|---|---|
| Utility: | *HECO* |
| Unit Type: | *Simple Cycle GE LMS100 PA* |
| Fuel Type: | *Biodiesel* |
| Site: | *Unspecified Island Location* |

## UNIT INFORMATION FORM

## HECO IRP 2013

| | |
|---|---|
| Date: | *March 25, 2013* |
| By: | *Black & Veatch* |
| Supersedes: | *October 11, 2012* |

**Unit Ratings:**

| | | Gross | Net |
|---|---|---|---|
| Normal Top Load | MW | 92.12 | 90.79 |
| Minimum | MW | 23.08 | 21.96 |

**Ambient Conditions:**

| | | |
|---|---|---|
| Dry Bulb Temperature | ° F | 86 |
| Relative Humidity | percent | 70 |
| CTG Inlet Air Temperature | ° F | 86 |

**Operating Mode:**

| | | |
|---|---|---|
| Duty Cycle | | Peaking |
| Capacity Factor | percent | 5 |

**Commercial Service:**

| | | |
|---|---|---|
| Date Available[A] | month/year | November 2016 |
| Service Life | years | 30 |

**Lead Time (Prior to Commercial Oper):**

| | | Normal | Expedited |
|---|---|---|---|
| Permitting | months | 64 | 58 |
| Engineering | months | 28 | 24 |
| Procurement | months | 22 | 20 |
| Construction | months | 16 | 15 |

| | | |
|---|---|---|
| **Year Dollars:** | | December 2011 |
| **Capital Cost Uncertainty:** | plus/minus | +20%/-20% |

**Capital Cost (without AFUDC):**

| | $million | $/kW$_{gross}$ | $/kW$_{net}$ |
|---|---|---|---|
| A. Power Block Cost | 137.13 | 1,489 | 1,510 |
| B. Special Siting Costs | 2.06 | 22 | 23 |
| C. Power Plant Switchyard | 8.23 | 89 | 91 |
| D. T&D Interconnection | - | - | - |
| E. Total Direct Cost (A+B+C+D) | 147.42 | 1,600 | 1,624 |
| F. Total Indirect Cost (E*0.313) | 46.20 | 502 | 509 |
| G. Land Cost[B] | 2.40 | 26 | 26 |
| H. Total Capital Cost (E+F+G) | 196.01 | 2,128 | 2,159 |

**Operations & Maintenance:**

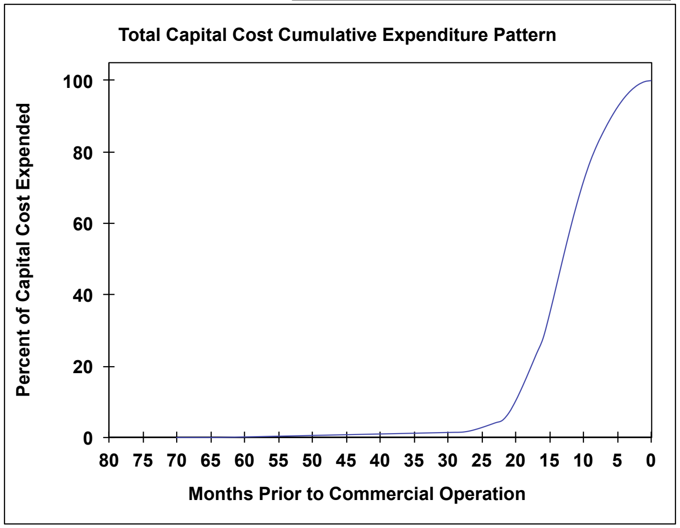
| | | |
|---|---|---|
| Fixed Cost | $million/y | 0.954 |
| | or $/kW-y$_{net}$ | 10.51 |
| Variable Cost | $/h run | 919 |
| | or $/MWh$_{net}$ | 10.12 |
| Staffing Requirements[C] | | 4 |

**Capacity and Heat Rate Data:[D]**

| Load Point | # CTGs | Comp Inlet | Gross Load | Net Load | Net Plant Heat Rate | Quick Load Pickup |
|---|---|---|---|---|---|---|
| | | ° F/RH | MW | MW | Btu/kWh | MW |
| Normal Top | 1 | 86/70 | 92.12 | 90.79 | 9,337 | - |
| Minimum | 1 | 86/70 | 23.08 | 21.96 | 14,921 | 69.04 |

**Flue Gas Emissions:[E]**

| | Normal Top Load at 59° F/70% RH | Minimum Load at 59° F/70% RH |
|---|---|---|
| | lb/MBtu | lb/MBtu |
| Nitrogen Oxides | 0.01 | 0.01 |
| Sulfur Oxides | 0.0005 | 0.0003 |
| Carbon Dioxide | 177 | 177 |
| Carbon Monoxide | 0.005 | 0.011 |
| Volatile Organic Compounds | 0.001 | 0.001 |
| Particulate Matter | 0.00 | 0.01 |




**Grid Services:**

| | | |
|---|---|---|
| Ramping Capabilties[H] | MW/minute | 50 |
| Inertia Constant[I] | MW-sec/MVA | 1.4 |
| Start Time | minutes | 10 |
| Dispatchable? | | Yes |

| | |
|---|---|
| Voltage Regulation? | Yes |
| Disturbance Ride Through? | Yes |
| Underfrequency Droop Response? | Yes |
| Ovderfrequency Droop Response? | Yes |

**General Site/Technology Characteristics:**

| | | |
|---|---|---|
| Fuel Delivery | | Truck |
| Fuel Storage Onsite | | 15 days |
| Water Supply Source | | Sea/Groundwater |
| CTG Inlet Air Cooling | | No |
| Cycle Cooling | | NA |
| Waste Water Disposal | | Injection Wells |
| Solid Waste Disposal | | NA |
| Generator | | Synchronous |
| Minimum Land Requirement | acres | 11.0 |

**Daily Resource Requirements at Normal Top Load:[F]**

| | | |
|---|---|---|
| Fuel | gallons/day | 168,300 |
| Urea (dry)[G] | tpd | 1.73 |
| Service & Plant Water | mgd | 0.18 |
| Cooling Tower Makeup | mgd | NA |
| Supply Water Temperature | ° F | 79 |

**Waste Streams:**

| | | |
|---|---|---|
| Solid Waste | tpd | 0 |
| Waste Water Discharge | mgd | 0.10 |
| Water Discharge Temperature | ° F | 90 |
| Thermal Discharge | MBtu/day | 9 |

**CTG/HRSG/STG Unit Startup Parameters:**

| | | |
|---|---|---|
| Cold Start Heat Input Requirement | MBtu | 72 |
| Hot Start Heat Input Requirement | MBtu | 72 |
| Hot Hours | hours | 0.2 |

**Availability:**

| | | |
|---|---|---|
| CTG Maintenance Pattern | wk/y | 0-0-1-0-0-6-0-0-1-0-0-12 |
| STG Maintenance Pattern | wk/y | NA |
| Plant Maintenance Pattern | wk/y | 0-0-1-0-0-6-0-0-1-0-0-12 |
| Average Annual Maintenance | weeks | 2.0 |
| Immaturity Period | weeks | 5 |
| Immature Forced Outage Rate | percent | 6 |
| Minimum Weeks Between Maintenance | weeks | 50 |
| Mature Forced Outage Rate | percent | 4 |
| Equivalent Availability | percent | 92 |

*IRP 2013 UIF Notes: LMS100 PA (Simple Cycle)*

*LMS100 PA (Simple Cycle)*

Notes:

(A) Date Available based on NTP of January 1, 2012 and expedited schedule.

(B) Land cost based on $5/sq ft or $217,800/acre for plant facilities only.

(C) For simple cycle facilities with very low (< 10 percent) capacity factors, it assumed that the staff would consist of 4 full-time operators, and these operators would be capable of providing minor, day-to-day maintenance for the combustion turbines.

(D) Performance is based on combustion of biodiesel. Combustion turbine performance and emissions were determined by OEM performance models, considering a bio-diesel fuel specification provided by HECO.

(E) Emissions of NOx are controlled via Selective Catalytic Reduction (SCR) system, and emissions of CO are controlled via CO catalyst.

(F) Based on 24 hour operation at normal top load. Fuel requirements reported as gallons per day, assuming a higher heating value of 16,800 Btu/lb and a density of 7.33 lb/gallon.

(G) Urea is used as a reagent within the Selective Catalytic Reduction (SCR) system. No other reagents are required for operation of air quality control (AQC) systems.

(H) The ramp rate of 50 MW/min is applicable following completion of required system purges during standard startup process. Complete startup period (including purges and ramping of unit) is 10 minutes, as noted.

(I) System Inertia value provided by OEM.

Table L-4
GE LMS100 PA (Simple Cycle) Unit Information Form

## UNIT INFORMATION FORM

## HECO IRP 2013

| | |
|---|---|
| Utility: | *HECO* |
| Unit Type: | *Simple Cycle GE LMS100 PA* |
| Fuel Type: | *Natural Gas* |
| Site: | *Unspecified Island Location* |

| | |
|---|---|
| Date: | *March 25, 2013* |
| By: | *Black & Veatch* |
| Supersedes: | *October 11, 2012* |

**Unit Ratings:**

| | | Gross | Net |
|---|---|---|---|
| Normal Top Load | MW | 96.59 | 95.25 |
| Minimum | MW | 24.19 | 23.07 |

**Ambient Conditions:**

| | | |
|---|---|---|
| Dry Bulb Temperature | ° F | 86 |
| Relative Humidity | percent | 70 |
| CTG Inlet Air Temperature | ° F | 86 |

**Operating Mode:**

| | | |
|---|---|---|
| Duty Cycle | | Peaking |
| Capacity Factor | percent | 5 |

**Commercial Service:**

| | | |
|---|---|---|
| Date Available[A] | month/year | November 2016 |
| Service Life | years | 30 |

**Lead Time (Prior to Commercial Oper):**

| | | Normal | Expedited |
|---|---|---|---|
| Permitting | months | 64 | 58 |
| Engineering | months | 28 | 24 |
| Procurement | months | 22 | 20 |
| Construction | months | 16 | 15 |

| | | |
|---|---|---|
| **Year Dollars:** | | December 2011 |
| **Capital Cost Uncertainty:** | plus/minus | +20%/-20% |

**Capital Cost (without AFUDC):**

| | $million | $/kW$_{gross}$ | $/kW$_{net}$ |
|---|---|---|---|
| A. Power Block Cost[B] | 134.66 | 1,394 | 1,414 |
| B. Special Siting Costs | 2.02 | 21 | 21 |
| C. Power Plant Switchyard | 8.23 | 85 | 86 |
| D. T&D Interconnection | - | - | - |
| E. Total Direct Cost (A+B+C+D) | 144.91 | 1,500 | 1,521 |
| F. Total Indirect Cost (E*0.314) | 45.56 | 472 | 478 |
| G. Land Cost[C] | 2.40 | 25 | 25 |
| H. Total Capital Cost (E+F+G) | 192.86 | 1,997 | 2,025 |

**Operations & Maintenance:**

| | | |
|---|---|---|
| Fixed Cost | $million/y | 0.954 |
| | or $/kW-y$_{net}$ | 10.02 |
| Variable Cost[D] | $/h run | 627 |
| | or $/MWh$_{net}$ | 6.58 |
| Staffing Requirements[E] | | 4 |

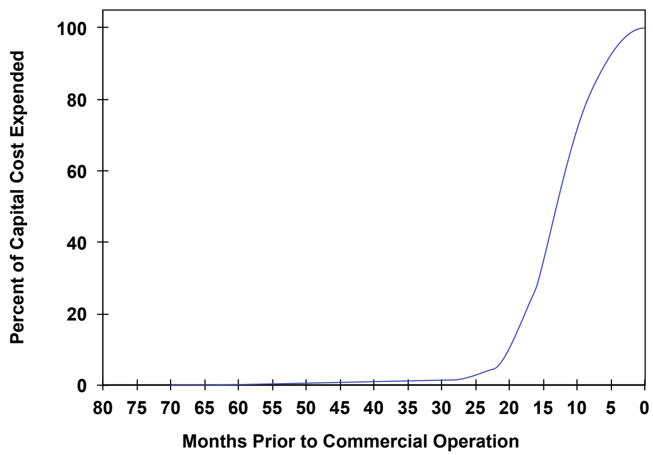
**Capacity and Heat Rate Data:[F]**

| Load Point | # CTGs | Comp Inlet ° F/RH | Gross Load MW | Net Load MW | Net Plant Heat Rate Btu/kWh | Quick Load Pickup MW |
|---|---|---|---|---|---|---|
| Normal Top | 1 | 86/70 | 96.59 | 95.25 | 9,208 | - |
| Minimum | 1 | 86/70 | 24.19 | 23.07 | 14,948 | 72.40 |

**Flue Gas Emissions:[G]**

| | Normal Top Load at 59° F/70% RH lb/MBtu | Minimum Load at 59° F/70% RH lb/MBtu |
|---|---|---|
| Nitrogen Oxides | 0.01 | 0.01 |
| Sulfur Oxides | 0.0002 | 0.0001 |
| Carbon Dioxide | 119 | 119 |
| Carbon Monoxide | 0.004 | 0.006 |
| Volatile Organic Compounds | 0.001 | 0.001 |
| Particulate Matter | 0.00 | 0.01 |

**Total Capital Cost Cumulative Expenditure Pattern**




**Grid Services:**

| | | |
|---|---|---|
| Ramping Capabilties[J] | MW/minute | 50 |
| Inertia Constant[K] | MW-sec/MVA | 1.4 |
| Start Time | minutes | 10 |
| Dispatchable? | | Yes |

| | |
|---|---|
| Voltage Regulation? | Yes |
| Disturbance Ride Through? | Yes |
| Undervoltage Droop Response? | Yes |
| Overvoltage Droop Response? | Yes |

**General Site/Technology Characteristics:**

| | | |
|---|---|---|
| Fuel Delivery | | Pipleine |
| Fuel Storage Onsite | | 0 days |
| Water Supply Source | | Sea/Groundwater |
| CTG Inlet Air Cooling | | No |
| Cycle Cooling | | NA |
| Waste Water Disposal | | Injection Wells |
| Solid Waste Disposal | | NA |
| Generator | | Synchronous |
| Minimum Land Requirement | acres | 11.0 |

**Daily Resource Requirements at Normal Top Load:[H]**

| | | |
|---|---|---|
| Fuel | mmscfd | 21.4 |
| Urea (dry)[I] | tpd | 0.93 |
| Service & Plant Water | mgd | 0.16 |
| Cooling Tower Makeup | mgd | NA |
| Supply Water Temperature | ° F | 79 |

**Waste Streams:**

| | | |
|---|---|---|
| Solid Waste | tpd | 0 |
| Waste Water Discharge | mgd | 0.09 |
| Water Discharge Temperature | ° F | 90 |
| Thermal Discharge | MBtu/day | 8 |

**CTG/HRSG/STG Unit Startup Parameters:**

| | | |
|---|---|---|
| Cold Start Heat Input Requirement | MBtu | 72 |
| Hot Start Heat Input Requirement | MBtu | 72 |
| Hot Hours | hours | 0.2 |

**Availability:**

| | | |
|---|---|---|
| CTG Maintenance Pattern | wk/y | 0-0-1-0-0-6-0-0-1-0-0-12 |
| STG Maintenance Pattern | wk/y | NA |
| Plant Maintenance Pattern | wk/y | 0-0-1-0-0-6-0-0-1-0-0-12 |
| Average Annual Maintenance | weeks | 2.0 |
| Immaturity Period | weeks | 5 |
| Immature Forced Outage Rate | percent | 6 |
| Minimum Weeks Between Maintenance | weeks | 50 |
| Mature Forced Outage Rate | percent | 4 |
| Equivalent Availability | percent | 92 |

*IRP 2013 UIF Notes: LMS100 PA (Simple Cycle)*

*LMS100 PA (Simple Cycle)*

Notes:

(A) Date Available based on NTP of January 1, 2012 and expedited schedule.

(B) Power Block capital costs include only equipment required for firing of natural gas. Capital costs do not include equipment required for firing biodiesel.

(C) Land cost based on $5/sq ft or $217,800/acre for plant facilities only.

(D) Combustion of natural gas within combustion turbines reduces variable O&M requirements relative to firing biodiesel in the same combustion turbine. When firing natural gas, Black & Veatch estimates that variable O&M costs are reduced approx. 30 percent relative to variable O&M costs when firing biodiesel.

(E) For simple cycle facilities with very low (< 10 percent) capacity factors, it assumed that the staff would consist of 4 full-time operators, and these operators would be capable of providing minor, day-to-day maintenance for the combustion turbines.

(F) Performance is based on combustion of natural gas. Combustion turbine performance and emissions were determined by OEM performance models.

(G) Emissions of NOx are controlled via Selective Catalytic Reduction (SCR) system, and emissions of CO are controlled via CO catalyst.

(H) Based on 24 hour operation at normal top load. Fuel requirements reported as million standard cubic feet per day (mmscfd), assuming a higher heating value of 1,000 Btu/scf.

(I) Urea is used as a reagent within the Selective Catalytic Reduction (SCR) system. No other reagents are required for operation of air quality control (AQC) systems.

(J) The ramp rate of 50 MW/min is applicable following completion of required system purges during standard startup process. Complete startup period (including purges and ramping of unit) is 10 minutes, as noted.

(K) System Inertia value provided by OEM.

Table L-5a
GE LM2500 (Combined Cycle - Ph 1) Unit Information Form

## UNIT INFORMATION FORM

## HECO IRP 2013

| | |
|---|---|
| Utility: | *HECO* |
| Unit Type: | *GE LM2500 - Combined Cycle (2x1)* |
| Fuel Type: | *Biodiesel* |
| Site: | *Unspecified Island Location* |

| | |
|---|---|
| Date: | *March 25, 2013* |
| By: | *Black & Veatch* |
| Supersedes: | *October 11, 2012* |

**Unit Ratings:**

| | | Gross | Net |
|---|---|---|---|
| Normal Top Load | MW | 21.43 | 21.13 |
| Minimum | MW | 5.39 | 5.13 |

**Ambient Conditions:**

| | | |
|---|---|---|
| Dry Bulb Temperature | ° F | 86 |
| Relative Humidity | percent | 70 |
| CTG Inlet Air Temperature | ° F | 86 |

**Operating Mode:**

| | | |
|---|---|---|
| Duty Cycle | | Peaking |
| Capacity Factor | percent | 5 |

**Commercial Service:**

| | | |
|---|---|---|
| Date Available[A] | month/year | November 2016 |
| Service Life | years | 30 |

**Lead Time (Prior to Commercial Operation):[B]**

| | | Normal | Expedited |
|---|---|---|---|
| Permitting | months | 81 | 75 |
| Engineering | months | 45 | 39 |
| Procurement | months | 39 | 37 |
| Construction | months | 32 | 30 |

| | | |
|---|---|---|
| **Year Dollars:** | | December 2011 |
| **Capital Cost Uncertainty:** | plus/minus | +20%/-20% |

**Capital Cost (without AFUDC):**

| | $million | $/kW$_{gross}$ | $/kW$_{net}$ |
|---|---|---|---|
| A1. CTG 1 Power Block, Ph 1 | 55.70 | 2,599 | 2,636 |
| A2. CTG 2 Power Block, Ph 2 | - | - | - |
| A3. STG Power Block, Ph 3 | - | - | - |
| A. Total Power Block Cost (A1+A2+A3) | 55.70 | 2,599 | 2,636 |
| B. Special Siting Costs | 0.84 | 39 | 40 |
| C. Power Plant Switchyard | 3.43 | 160 | 162 |
| D. T&D Interconnection | - | - | - |
| E. Total Direct Cost (A+B+C+D) | 59.96 | 2,798 | 2,838 |
| F. Total Indirect Cost (E*0.478) | 28.67 | 1,338 | 1,357 |
| G. Land Cost[C] | 2.40 | 112 | 113 |
| H. Total Capital Cost (E+F+G) | 91.03 | 4,248 | 4,308 |

**Operations & Maintenance:**

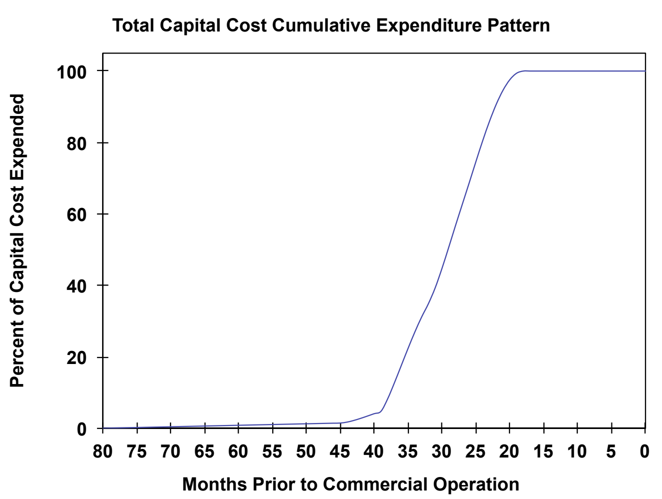
| | | Ph 1 SC |
|---|---|---|
| Fixed Cost | $million/y | 0.905 |
| | or $/kW-y$_{net}$ | 42.85 |
| Variable Cost | $/h run | 419 |
| | or $/MWh$_{net}$ | 19.84 |
| Staffing Requirements[D] | | 4 |

**Capacity and Heat Rate Data:[E]**

| Load Point | # CTGs | Comp Inlet | Gross Load | Net Load | Net Plant Heat Rate | Quick Load Pickup |
|---|---|---|---|---|---|---|
| | | ° F/RH | MW | MW | Btu/kWh | MW |
| Normal Top | 1 | 86/70 | 21.43 | 21.13 | 11,044 | - |
| Minimum | 1 | 86/70 | 5.39 | 5.13 | 17,541 | 16.04 |

**Flue Gas Emissions:[F]**

| | Normal Top Load at 59° F/70% RH | Minimum Load at 59° F/70% RH |
|---|---|---|
| | lb/MBtu | lb/MBtu |
| Nitrogen Oxides | 0.01 | 0.01 |
| Sulfur Oxides | 0.0005 | 0.0005 |
| Carbon Dioxide | 177 | 177 |
| Carbon Monoxide | 0.01 | 0.06 |
| Volatile Organic Compounds | 0.000 | 0.005 |
| Particulate Matter | 0.01 | 0.02 |




**Grid Services:**

| | | |
|---|---|---|
| Ramping Capabilties[I] | MW/minute | 10 |
| Inertia Constant[J] | MW-sec/MVA | 1.1 |
| Start Time | minutes | 10 |
| Dispatchable? | | Yes |

| | |
|---|---|
| Voltage Regulation? | Yes |
| Disturbance Ride Through? | Yes |
| Underfrequency Droop Response? | Yes |
| Overfrequency Droop Response? | Yes |

**General Site/Technology Characteristics:**

| | | |
|---|---|---|
| Fuel Delivery | | Truck |
| Fuel Storage Onsite | | 15 days |
| Water Supply Source | | Sea/Groundwater |
| CTG Inlet Air Cooling | | No |
| Cycle Cooling | | NA |
| Waste Water Disposal | | NA |
| Solid Waste Disposal | | NA |
| Generator | | Synchronous |
| Minimum Land Requirement | acres | 11.0 |

**Daily Resource Requirements at Normal Top Load:[G]**

| | | |
|---|---|---|
| Fuel | gallons/day | 46,200 |
| Urea (dry)[H] | tpd | 0.52 |
| Service & Plant Water | mgd | 0.09 |
| Cooling Tower Makeup | mgd | NA |
| Supply Water Temperature | ° F | 79 |

**Waste Streams:**

| | | |
|---|---|---|
| Solid Waste | tpd | 0 |
| Waste Water Discharge | mgd | 0.05 |
| Water Discharge Temperature | ° F | 90 |
| Thermal Discharge | MBtu/day | 4 |

**CTG/HRSG/STG Unit Startup Parameters:**

| | | |
|---|---|---|
| Cold Start Heat Input Requirement | MBtu | 27 |
| Hot Start Heat Input Requirement | MBtu | 27 |
| Hot Hours | hours | 0 |

**Availability:**

| | | |
|---|---|---|
| CTG Maintenance Pattern | wk/y | 0-0-1-0-0-6-0-0-1-0-0-12 |
| STG Maintenance Pattern | wk/y | NA |
| Plant Maintenance Pattern | wk/y | 0-0-1-0-0-6-0-0-1-0-0-12 |
| Average Annual Maintenance | weeks | 2 |
| Immaturity Period | weeks | 5 |
| Immature Forced Outage Rate | percent | 6 |
| Minimum Weeks Between Maintenance | weeks | 50 |
| Mature Forced Outage Rate | percent | 4 |
| Equivalent Availability | percent | 92 |

Table L-5b
GE LM2500 (Combined Cycle - Ph 2) Unit Information Form

**UNIT INFORMATION FORM**

**HECO IRP 2013**

| | |
|---|---|
| Utility: | *HECO* |
| Unit Type: | *GE LM2500 - Combined Cycle (2x1)* |
| Fuel Type: | *Biodiesel* |
| Site: | *Unspecified Island Location* |

| | |
|---|---|
| Date: | *March 25, 2013* |
| By: | *Black & Veatch* |
| Supersedes: | *October 11, 2012* |

**Unit Ratings:**

| | | Gross | Net |
|---|---|---|---|
| Normal Top Load | MW | 42.86 | 42.25 |
| Minimum | MW | 10.77 | 10.27 |

**Ambient Conditions:**

| | | |
|---|---|---|
| Dry Bulb Temperature | °F | 86 |
| Relative Humidity | percent | 70 |
| CTG Inlet Air Temperature | °F | 86 |

**Operating Mode:**

| | | |
|---|---|---|
| Duty Cycle | | Peaking |
| Capacity Factor | percent | 5 |

**Commercial Service:**

| | | |
|---|---|---|
| Date Available[A] | month/year | November 2016 |
| Service Life | years | 30 |

**Lead Time (Prior to Commercial Operation):[B]**

| | | Normal | Expedited |
|---|---|---|---|
| Permitting | months | 78 | 72 |
| Engineering | months | 42 | 38 |
| Procurement | months | 36 | 34 |
| Construction | months | 29 | 28 |

| | | |
|---|---|---|
| **Year Dollars:** | | December 2011 |
| **Capital Cost Uncertainty:** | plus/minus | +20%/-20% |

**Capital Cost (without AFUDC):**

| | $million | $/kW$_{gross}$ | $/kW$_{net}$ |
|---|---|---|---|
| A1. CTG 1 Power Block, Ph 1 | - | - | - |
| A2. CTG 2 Power Block, Ph 2 | 38.20 | 1,782 | 1,808 |
| A3. STG Power Block, Ph 3 | - | - | - |
| A. Total Power Block Cost (A1+A2+A3) | 38.20 | 1,782 | 1,808 |
| B. Special Siting Costs | 0.57 | 27 | 27 |
| C. Power Plant Switchyard | 3.43 | 160 | 162 |
| D. T&D Interconnection | - | - | - |
| E. Total Direct Cost (A+B+C+D) | 42.20 | 1,969 | 1,997 |
| F. Total Indirect Cost (E*0.417) | 17.61 | 822 | 833 |
| G. Land Cost[C] | - | - | - |
| H. Total Capital Cost (E+F+G) | 59.80 | 2,791 | 2,831 |

**Operations & Maintenance:**

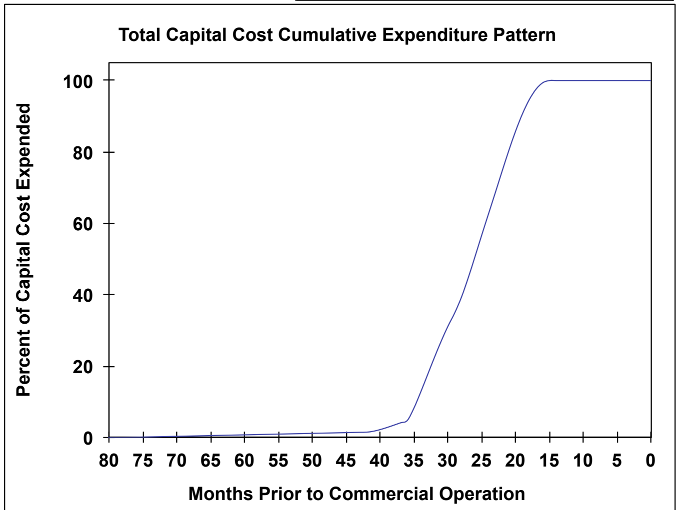
| | | Ph 2 SC |
|---|---|---|
| Fixed Cost | $million/y | 0.905 |
| | or $/kW-y$_{net}$ | 21.42 |
| Variable Cost | $/h run | 838 |
| | or $/MWh$_{net}$ | 19.84 |
| Staffing Requirements[D] | | 4 |

**Capacity and Heat Rate Data:[E]**

| Load Point | # CTGs | Comp Inlet °F/RH | Gross Load MW | Net Load MW | Net Plant Heat Rate Btu/kWh | Quick Load Pickup MW |
|---|---|---|---|---|---|---|
| Normal Top | 2 | 86/70 | 42.86 | 42.25 | 11,044 | - |
| Minimum | 2 | 86/70 | 10.77 | 10.27 | 17,541 | 32.09 |

**Flue Gas Emissions:[F]**

| | Normal Top Load at 59° F/70% RH lb/MBtu | Minimum Load at 59° F/70% RH lb/MBtu |
|---|---|---|
| Nitrogen Oxides | 0.01 | 0.01 |
| Sulfur Oxides | 0.0005 | 0.0005 |
| Carbon Dioxide | 177 | 177 |
| Carbon Monoxide | 0.01 | 0.06 |
| Volatile Organic Compounds | 0.000 | 0.005 |
| Particulate Matter | 0.01 | 0.02 |




**General Site/Technology Characteristics:**

| | | |
|---|---|---|
| Fuel Delivery | | Truck |
| Fuel Storage Onsite | | 15 days |
| Water Supply Source | | Sea/Groundwater |
| CTG Inlet Air Cooling | | No |
| Cycle Cooling | | NA |
| Waste Water Disposal | | NA |
| Solid Waste Disposal | | NA |
| Generator | | Synchronous |
| Minimum Land Requirement | acres | 0.0 |

**Daily Resource Requirements at Normal Top Load:[G]**

| | | |
|---|---|---|
| Fuel | gallons/day | 92,400 |
| Urea (dry)[H] | tpd | 1.04 |
| Service & Plant Water | mgd | 0.17 |
| Cooling Tower Makeup | mgd | NA |
| Supply Water Temperature | °F | 79 |

**Waste Streams:**

| | | |
|---|---|---|
| Solid Waste | tpd | 0 |
| Waste Water Discharge | mgd | 0.09 |
| Water Discharge Temperature | °F | 90 |
| Thermal Discharge | MBtu/day | 9 |

**CTG/HRSG/STG Unit Startup Parameters:**

| | | |
|---|---|---|
| Cold Start Heat Input Requirement | MBtu | 54 |
| Hot Start Heat Input Requirement | MBtu | 54 |
| Hot Hours | hours | 0 |

**Availability:**

| | | |
|---|---|---|
| CTG Maintenance Pattern | wk/y | 0-0-1-0-0-6-0-0-1-0-0-12 |
| STG Maintenance Pattern | wk/y | NA |
| Plant Maintenance Pattern | wk/y | 0-0-1-0-0-6-0-0-1-0-0-12 |
| Average Annual Maintenance | weeks | 2 |
| Immaturity Period | weeks | 5 |
| Immature Forced Outage Rate | percent | 6 |
| Minimum Weeks Between Maintenance | weeks | 50 |
| Mature Forced Outage Rate | percent | 4 |
| Equivalent Availability | percent | 92 |

**Grid Services:**

| | | |
|---|---|---|
| Ramping Capabilties[I] | MW/minute | 20 |
| Inertia Constant[J] | MW-sec/MVA | 1.1 |
| Start Time | minutes | 10 |
| Dispatchable? | | Yes |

| | |
|---|---|
| Voltage Regulation? | Yes |
| Disturbance Ride Through? | Yes |
| Underfrequency Droop Response? | Yes |
| Overfrequency Droop Response? | Yes |

Table L-5c
GE LM2500 (Combined Cycle - Ph 3) Unit Information Form

| | |
|---|---|
| Utility: | *HECO* |
| Unit Type: | *GE LM2500 - Combined Cycle (2x1)* |
| Fuel Type: | *Biodiesel* |
| Site: | *Unspecified Island Location* |

## UNIT INFORMATION FORM

## HECO IRP 2013

| | |
|---|---|
| Date: | *March 25, 2013* |
| By: | *Black & Veatch* |
| Supersedes: | *October 11, 2012* |

**Unit Ratings:**

| | | Gross | Net |
|---|---|---|---|
| Normal Top Load | MW | 64.96 | 63.17 |
| Minimum | MW | 19.56 | 18.16 |

**Ambient Conditions:**

| | | |
|---|---|---|
| Dry Bulb Temperature | °F | 77 |
| Relative Humidity | percent | 70 |
| CTG Inlet Air Temperature | °F | 77 |

**Operating Mode:**

| | | |
|---|---|---|
| Duty Cycle | | Intermediate |
| Capacity Factor | percent | 60 |

**Commercial Service:**

| | | |
|---|---|---|
| Date Available[A] | month/year | June 2017 |
| Service Life | years | 30 |

**Lead Time (Prior to Commercial Operation):[B]**

| | | Normal | Expedited |
|---|---|---|---|
| Permitting | months | 72 | 66 |
| Engineering | months | 36 | 32 |
| Procurement | months | 30 | 28 |
| Construction | months | 18 | 17 |

| | | |
|---|---|---|
| **Year Dollars:** | | December 2011 |
| **Capital Cost Uncertainty:** | plus/minus | +20%/-20% |

**Capital Cost (without AFUDC):**

| | $million | $/kW$_{gross}$ | $/kW$_{net}$ |
|---|---|---|---|
| A1. CTG 1 Power Block, Ph 1 | - | - | - |
| A2. CTG 2 Power Block, Ph 2 | - | - | - |
| A3. STG Power Block, Ph 3 | 90.55 | 4,306 | 4,563 |
| A. Total Power Block Cost (A1+A2+A3) | 90.55 | 4,306 | 4,563 |
| B. Special Siting Costs | 1.36 | 65 | 68 |
| C. Power Plant Switchyard | 3.59 | 171 | 181 |
| D. T&D Interconnection | - | - | - |
| E. Total Direct Cost (A+B+C+D) | 95.50 | 4,541 | 4,812 |
| F. Total Indirect Cost (E*0.491) | 46.84 | 2,227 | 2,360 |
| G. Land Cost[C] | 0.87 | 41 | 44 |
| H. Total Capital Cost (E+F+G) | 143.21 | 6,810 | 7,217 |

**Operations & Maintenance:**

| | | Ph 3 CC |
|---|---|---|
| Fixed Cost | $million/y | 4.220 |
| | or $/kW-y$_{net}$ | 66.80 |
| Variable Cost | $/h run | 769 |
| | or $/MWh$_{net}$ | 12.18 |
| Staffing Requirements[D] | | 19 |

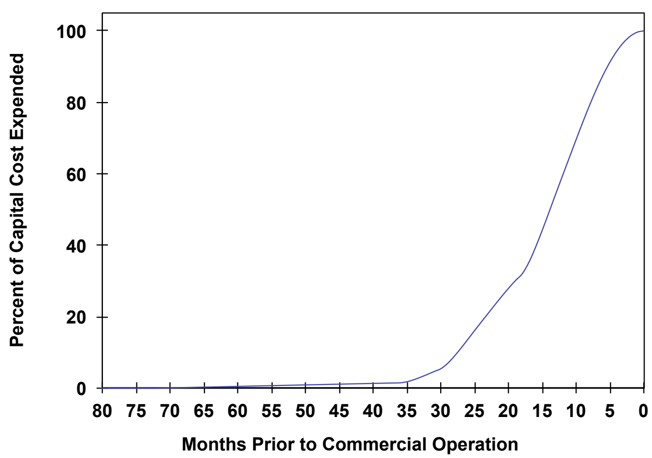
**Capacity and Heat Rate Data:[E]**

| Load Point | # CTGs | Comp Inlet | Gross Load | Net Load | Net Plant Heat Rate | Quick Load Pickup |
|---|---|---|---|---|---|---|
| | | °F/RH | MW | MW | Btu/kWh | MW |
| Normal Top | 2 | 77/70 | 64.96 | 63.17 | 7,627 | - |
| Minimum | 2 | 77/70 | 19.56 | 18.16 | 10,179 | 32.89 |

**Flue Gas Emissions:[F]**

| | Normal Top Load at 59° F/70% RH | Minimum Load at 59° F/70% RH |
|---|---|---|
| | lb/MBtu | lb/MBtu |
| Nitrogen Oxides | 0.01 | 0.01 |
| Sulfur Oxides | 0.0011 | 0.0012 |
| Carbon Dioxide | 177 | 177 |
| Carbon Monoxide | 0.01 | 0.06 |
| Volatile Organic Compounds | 0.000 | 0.005 |
| Particulate Matter | 0.01 | 0.02 |

Total Capital Cost Cumulative Expenditure Pattern




**Grid Services:**

| | | |
|---|---|---|
| Ramping Capabilties[I] | MW/minute | 3.3 |
| Inertia Constant[J] | MW-sec/MVA | 3 - 5 |
| Start Time (cold start) | minutes | 270 |
| Dispatchable? | | Yes |

| | |
|---|---|
| Voltage Regulation? | Yes |
| Disturbance Ride Through? | Yes |
| Underfrequency Droop Response? | Yes |
| Overfrequency Droop Response? | Yes |

**General Site/Technology Characteristics:**

| | | |
|---|---|---|
| Fuel Delivery | | Truck |
| Fuel Storage Onsite | | 15 days |
| Water Supply Source | | Sea/Groundwater |
| CTG Inlet Air Cooling | | No |
| Cycle Cooling | | Cooling Tower |
| Waste Water Disposal | | Injection Wells |
| Solid Waste Disposal | | NA |
| Generator | | Synchronous |
| Minimum Land Requirement | acres | 4.0 |

**Daily Resource Requirements at Normal Top Load:[G]**

| | | |
|---|---|---|
| Fuel | gallons/day | 95,000 |
| Urea (dry)[H] | tpd | 1.08 |
| Service & Plant Water | mgd | 0.70 |
| Cooling Tower Makeup | mgd | 0.58 |
| Supply Water Temperature | °F | 79 |

**Waste Streams:**

| | | |
|---|---|---|
| Solid Waste | tpd | 0 |
| Waste Water Discharge | mgd | 0.16 |
| Water Discharge Temperature | °F | 90 |
| Thermal Discharge | MBtu/day | 15 |

**CTG/HRSG/STG Unit Startup Parameters:**

| | | |
|---|---|---|
| Cold Start Heat Input Requirement | MBtu | 409 |
| Hot Start Heat Input Requirement | MBtu | 255 |
| Hot Hours | hours | 2 |

**Availability:**

| | | |
|---|---|---|
| CTG Maintenance Pattern | wk/y | 0-0-1-0-6-0-0-1-0-12 |
| STG Maintenance Pattern | wk/y | 0-0-1-0-3-0-0-1-0-6 |
| Plant Maintenance Pattern | wk/y | 0-0-1-0-6-0-0-1-0-12 |
| Average Annual Maintenance | weeks | 2 |
| Immaturity Period | weeks | 5 |
| Immature Forced Outage Rate | percent | 6 |
| Minimum Weeks Between Maintenance | weeks | 50 |
| Mature Forced Outage Rate | percent | 4 |
| Equivalent Availability | percent | 92 |

Table L-5d

GE LM2500 (Combined Cycle - Overall) Unit Information Form

## UNIT INFORMATION FORM

## HECO IRP 2013

| | |
|---|---|
| Utility: | *HECO* |
| Unit Type: | *GE LM2500 - Combined Cycle (2x1)* |
| Fuel Type: | *Biodiesel* |
| Site: | *Unspecified Island Location* |

| | |
|---|---|
| Date: | *March 25, 2013* |
| By: | *Black & Veatch* |
| Supersedes: | *October 11, 2012* |

**Unit Ratings:**

| | | Gross | Net |
|---|---|---|---|
| Normal Top Load | MW | 64.96 | 63.17 |
| Minimum | MW | 19.56 | 18.16 |

**Ambient Conditions:**

| | | |
|---|---|---|
| Dry Bulb Temperature | ° F | 77 |
| Relative Humidity | percent | 70 |
| CTG Inlet Air Temperature | ° F | 77 |

**Operating Mode:**

| | | |
|---|---|---|
| Duty Cycle | | Intermediate |
| Capacity Factor | percent | 60 |

**Commercial Service:**

| | | |
|---|---|---|
| Date Available[A] | month/year | March 2018 |
| Service Life | years | 30 |

**Lead Time (Prior to Commercial Operation):[B]**

| | | Normal | Expedited |
|---|---|---|---|
| Permitting | months | 81 | 75 |
| Engineering | months | 45 | 39 |
| Procurement | months | 39 | 37 |
| Construction | months | 32 | 30 |

| | | |
|---|---|---|
| **Year Dollars:** | | December 2011 |
| **Capital Cost Uncertainty:** | plus/minus | +20%/-20% |

**Capital Cost (without AFUDC):**

| | \$million | \$/kW$_{gross}$ | \$/kW$_{net}$ |
|---|---|---|---|
| A1. CTG 1 Power Block, Ph 1 | 55.70 | - | - |
| A2. CTG 2 Power Block, Ph 2 | 38.20 | - | - |
| A3. STG Power Block, Ph 3 | 90.55 | - | - |
| A. Total Power Block Cost (A1+A2+A3) | 184.44 | 2,839 | 2,920 |
| B. Special Siting Costs | 2.77 | 43 | 44 |
| C. Power Plant Switchyard | 10.45 | 161 | 165 |
| D. T&D Interconnection | - | - | - |
| E. Total Direct Cost (A+B+C+D) | 197.66 | 3,043 | 3,129 |
| F. Total Indirect Cost (E*0.471) | 93.11 | 1,433 | 1,474 |
| G. Land Cost[C] | 3.27 | 50 | 52 |
| H. Total Capital Cost (E+F+G) | 294.04 | 4,527 | 4,655 |

**Operations & Maintenance:**

| | | Ph 1 SC | Ph 2 SC | Ph 3 CC |
|---|---|---|---|---|
| Fixed Cost | \$million/y | 0.905 | 0.905 | 4.220 |
| | or \$/kW-y$_{net}$ | 42.85 | 21.42 | 66.80 |
| Variable Cost | \$/h run | 419 | 838 | 769 |
| | or \$/MWh$_{net}$ | 19.84 | 19.84 | 12.18 |
| Staffing Requirements[D] | | 4 | 4 | 19 |

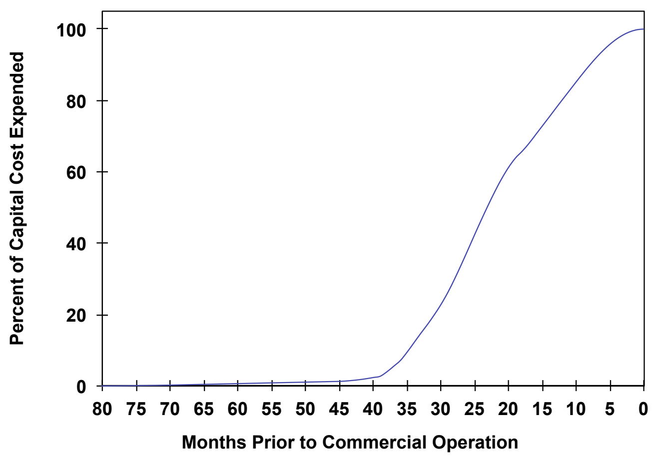
**Capacity and Heat Rate Data:[E]**

| Load Point | # CTGs | Comp Inlet | Gross Load | Net Load | Net Plant Heat Rate | Quick Load Pickup |
|---|---|---|---|---|---|---|
| | | ° F/RH | MW | MW | Btu/kWh | MW |
| Normal Top | 2 | 77/70 | 64.96 | 63.17 | 7,627 | - |
| Minimum | 2 | 77/70 | 19.56 | 18.16 | 10,179 | 32.89 |

**Flue Gas Emissions:[F]**

| | Normal Top Load at 59° F/70% RH | Minimum Load at 59° F/70% RH |
|---|---|---|
| | lb/MBtu | lb/MBtu |
| Nitrogen Oxides | 0.01 | 0.01 |
| Sulfur Oxides | 0.0011 | 0.0012 |
| Carbon Dioxide | 177 | 177 |
| Carbon Monoxide | 0.01 | 0.06 |
| Volatile Organic Compounds | 0.000 | 0.005 |
| Particulate Matter | 0.01 | 0.02 |

**Total Capital Cost Cumulative Expenditure Pattern**




**Grid Services:**

| | | |
|---|---|---|
| Ramping Capabilties[I] | MW/minute | 3.3 |
| Inertia Constant[J] | MW-sec/MVA | 3 - 5 |
| Start Time (cold start) | minutes | 270 |
| Dispatchable? | | Yes |

| | |
|---|---|
| Voltage Regulation? | Yes |
| Disturbance Ride Through? | Yes |
| Underfrequency Droop Response? | Yes |
| Overfrequency Droop Response? | Yes |

**General Site/Technology Characteristics:**

| | | |
|---|---|---|
| Fuel Delivery | | Truck |
| Fuel Storage Onsite | | 15 days |
| Water Supply Source | | Sea/Groundwater |
| CTG Inlet Air Cooling | | No |
| Cycle Cooling | | Cooling Tower |
| Waste Water Disposal | | Injection Wells |
| Solid Waste Disposal | | NA |
| Generator | | Synchronous |
| Minimum Land Requirement | acres | 15.0 |

**Daily Resource Requirements at Normal Top Load:[G]**

| | | |
|---|---|---|
| Fuel | gallons/day | 95,000 |
| Urea (dry)[H] | tpd | 1.08 |
| Service & Plant Water | mgd | 0.70 |
| Cooling Tower Makeup | mgd | 0.58 |
| Supply Water Temperature | ° F | 79 |

**Waste Streams:**

| | | |
|---|---|---|
| Solid Waste | tpd | 0 |
| Waste Water Discharge | mgd | 0.16 |
| Water Discharge Temperature | ° F | 90 |
| Thermal Discharge | MBtu/day | 15 |

**CTG/HRSG/STG Unit Startup Parameters:**

| | | |
|---|---|---|
| Cold Start Heat Input Requirement | MBtu | 409 |
| Hot Start Heat Input Requirement | MBtu | 255 |
| Hot Hours | hours | 2 |

**Availability:**

| | | |
|---|---|---|
| CTG Maintenance Pattern | wk/y | 0-0-1-0-6-0-0-1-0-12 |
| STG Maintenance Pattern | wk/y | 0-0-1-0-3-0-0-1-0-6 |
| Plant Maintenance Pattern | wk/y | 0-0-1-0-6-0-0-1-0-12 |
| Average Annual Maintenance | weeks | 2 |
| Immaturity Period | weeks | 5 |
| Immature Forced Outage Rate | percent | 6 |
| Minimum Weeks Between Maintenance | weeks | 50 |
| Mature Forced Outage Rate | percent | 4 |
| Equivalent Availability | percent | 92 |

*IRP 2013 UIF Notes: LM2500 (2x1 Combined Cycle)*

*LM2500 (2x1 Combined Cycle)*

Notes:

(A) Date Available represents Commercial Operation Date (COD) of all combined cycle systems. Date Available is based on on NTP of January 1, 2012 and expedited schedule.

(B) Lead Times represent months required for development of all (Phase 1, Phase 2 and Phase 3) materials and equipment. Lead Times assume development activities for Ph. 2 commence 3 months following the commencement of Ph. 1 activities. Lead Times assumed development activities for Ph. 3 commence 6 months following the commencement of Ph. 2 activiites. Lead Times presented for Overall installation do not account for CTG outage period required during Phase 3 construction.

(C) Land cost based on $5/sq ft or $217,800/acre for plant facilities only.

(D) For simple cycle facilities with very low (< 10 percent) capacity factors, it assumed that the staff would consist of 4 full-time operators, and these operators would be capable of providing minor, day-to-day maintenance for the combustion turbines. For combined cycle facilities with capacity factors greater than 40 percent, it is assumed that the facility would employ operators and a dedicated maintenance staff for maintenance of both combustion turbines and steam cycle equipment.

(E) Performance is based on combustion of biodiesel. Combustion turbine performance and emissions were determined by OEM performance models, considering a bio-diesel fuel specification provided by HECO.

(F) Emissions of NOx are controlled via Selective Catalytic Reduction (SCR) system, and emissions of CO are controlled via CO catalyst.

(G) Based on 24 hour operation at normal top load. Fuel requirements reported as gallons per day, assuming a higher heating value of 16,800 Btu/lb and a density of 7.33 lb/gallon.

(H) Urea is used as a reagent within the Selective Catalytic Reduction (SCR) system. No other reagents are required for operation of air quality control (AQC) systems.

(I) When operating in simple cycle, the ramp rate of 14 MW/min is applicable following completion of required system purges during of required system purges during standard startup process. Complete startup period (including purges and ramping of unit) is 10 minutes, as noted.
When operating in combined cycle, the unit ramp rate is limited by the capabilities of the heat recovery steam generator (HRSG) and steam turbine generator (STG). It is assumed that ramp rate is 5 percent of unit output. Because the combined cycle unit does not include a HRSG bypass system, it is assumed the this ramp rate applies to the combined cycle as a whole.

(J) System Inertia value provided by OEM.

Table L-6a
GE LM6000 PG (Combined Cycle - Phase 1) Unit Information Form

## UNIT INFORMATION FORM

## HECO IRP 2013

| | |
|---|---|
| Utility: | *HECO* |
| Unit Type: | *Simple Cycle GE LM6000 PG* |
| Fuel Type: | *Biodiesel* |
| Site: | *Unspecified Island Location* |

| | |
|---|---|
| Date: | *March 25, 2013* |
| By: | *Black & Veatch* |
| Supersedes: | *October 11, 2012* |

**Unit Ratings:**

| | | Gross | Net |
|---|---|---|---|
| Normal Top Load | MW | **42.36** | **41.87** |
| Minimum | MW | **10.62** | **10.23** |

**Ambient Conditions:**

| | | |
|---|---|---|
| Dry Bulb Temperature | ° F | **86** |
| Relative Humidity | percent | **70** |
| CTG Inlet Air Temperature | ° F | **86** |

**Operating Mode:**

| | | |
|---|---|---|
| Duty Cycle | | **Peaking** |
| Capacity Factor | percent | **5** |

**Commercial Service:**

| | | |
|---|---|---|
| Date Available[A] | month/year | **March 2018** |
| Service Life | years | **30** |

**Lead Time (Prior to Comm. Operation):[B]**

| | | Normal | Expedited |
|---|---|---|---|
| Permitting | months | **78** | **74** |
| Engineering | months | **42** | **38** |
| Procurement | months | **34** | **32** |
| Construction | months | **26** | **24** |

| | | |
|---|---|---|
| **Year Dollars:** | | **December 2011** |
| **Capital Cost Uncertainty:** | plus/minus | **+20%/-20%** |

**Capital Cost (without AFUDC):**

| | $million | $/kW$_{gross}$ | $/kW$_{net}$ |
|---|---|---|---|
| A1. CTG Power Block, Ph 1 | **77.56** | **1,831** | **1,852** |
| A2. STG Power Block, Ph 2 | **-** | **-** | **-** |
| A. Total Power Block Cost (A1+A2) | **77.56** | **1,831** | **1,852** |
| B. Special Siting Costs | **1.16** | **27** | **28** |
| C. Power Plant Switchyard | **5.18** | **122** | **124** |
| D. T&D Interconnection | **-** | **-** | **-** |
| E. Total Direct Cost (A+B+C+D) | **83.90** | **1,981** | **2,004** |
| F. Total Indirect Cost (E*0.430) | **36.11** | **853** | **862** |
| G. Land Cost[C] | **2.40** | **57** | **57** |
| H. Total Capital Cost (E+F+G) | **122.41** | **2,890** | **2,924** |

**Operations & Maintenance:**

| | | SC |
|---|---|---|
| Fixed Cost | $million/y | **0.922** |
| | or $/kW-y$_{net}$ | **22.02** |
| Variable Cost | $/h run | **602** |
| | or $/MWh$_{net}$ | **14.38** |
| Staffing Requirements[D] | | **4** |

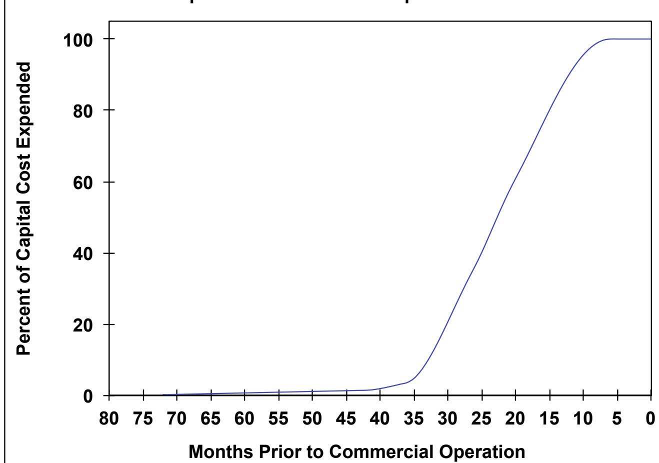
**Capacity and Heat Rate Data:[E]**

| Load Point | # CTGs | Comp Inlet | Gross Load | Net Load | Net Plant Heat Rate | Quick Load Pickup |
|---|---|---|---|---|---|---|
| | | ° F/RH | MW | MW | Btu/kWh | MW |
| Normal Top | **1** | **86/70** | **42.36** | **41.87** | **10,112** | **-** |
| Minimum | **1** | **86/70** | **10.62** | **10.23** | **17,688** | **31.74** |

**Flue Gas Emissions:[F]**

| | Normal Top Load at 59° F/70% RH | Minimum Load at 59° F/70% RH |
|---|---|---|
| | lb/MBtu | lb/MBtu |
| Nitrogen Oxides | **0.01** | **0.01** |
| Sulfur Oxides | **0.0005** | **0.0005** |
| Carbon Dioxide | **177** | **177** |
| Carbon Monoxide | **0.002** | **0.001** |
| Volatile Organic Compounds | **0.001** | **0.000** |
| Particulate Matter | **0.01** | **0.01** |

**Total Capital Cost Cumulative Expenditure Pattern**




**General Site/Technology Characteristics:**

| | | |
|---|---|---|
| Fuel Delivery | | **Truck** |
| Fuel Storage Onsite | | **15 days** |
| Water Supply Source | | **Sea/Groundwater** |
| CTG Inlet Air Cooling | | **No** |
| Cycle Cooling | | **NA** |
| Waste Water Disposal | | **Injection Wells** |
| Solid Waste Disposal | | **NA** |
| Generator | | **Synchronous** |
| Minimum Land Requirement | acres | **11.0** |

**Daily Resource Requirements at Normal Top Load:[G]**

| | | |
|---|---|---|
| Fuel | gallons/day | **83,800** |
| Urea (dry)[H] | tpd | **0.86** |
| Service & Plant Water | mgd | **0.20** |
| Cooling Tower Makeup | mgd | **NA** |
| Supply Water Temperature | ° F | **79** |

**Waste Streams:**

| | | |
|---|---|---|
| Solid Waste | tpd | **0** |
| Waste Water Discharge | mgd | **0.11** |
| Water Discharge Temperature | ° F | **90** |
| Thermal Discharge | MBtu/day | **10** |

**CTG/HRSG/STG Unit Startup Parameters:**

| | | |
|---|---|---|
| Cold Start Heat Input Requirement | MBtu | **36** |
| Hot Start Heat Input Requirement | MBtu | **36** |
| Hot Hours | hours | **0** |

**Availability:**

| | | |
|---|---|---|
| CTG Maintenance Pattern | wk/y | **0-0-1-0-0-6-0-0-1-0-0-12** |
| STG Maintenance Pattern | wk/y | **NA** |
| Plant Maintenance Pattern | wk/y | **0-0-1-0-0-6-0-0-1-0-0-12** |
| Average Annual Maintenance | weeks | **2.0** |
| Immaturity Period | weeks | **5** |
| Immature Forced Outage Rate | percent | **6** |
| Minimum Weeks Between Maintenance | weeks | **50** |
| Mature Forced Outage Rate | percent | **4** |
| Equivalent Availability | percent | **92** |

**Grid Services:**

| | | |
|---|---|---|
| Ramping Capabilties[I] | MW/minute | **14** |
| Inertia Constant[J] | MW-sec/MVA | **1.3** |
| Start Time[K] | minutes | **10** |
| Dispatchable? | | **Yes** |

| | |
|---|---|
| Voltage Regulation? | **Yes** |
| Disturbance Ride Through? | **Yes** |
| Underfrequency Droop Response? | **Yes** |
| Overfrequency Droop Response? | **Yes** |

Table L-6b
GE LM6000 PG (Combined Cycle - Phase 2) Unit Information Form

| | |
|---|---|
| Utility: | *HECO* |
| Unit Type: | *Combined Cycle GE LM6000 PG* |
| Fuel Type: | *Biodiesel* |
| Site: | *Unspecified Island Location* |

**UNIT INFORMATION FORM**

**HECO IRP 2013**

| | |
|---|---|
| Date: | *March 25, 2013* |
| By: | *Black & Veatch* |
| Supersedes: | *October 11, 2012* |

**Unit Ratings:**

| | | Gross | Net |
|---|---|---|---|
| Normal Top Load | MW | 60.18 | 58.81 |
| Minimum | MW | 19.40 | 18.37 |

**Ambient Conditions:**

| | | |
|---|---|---|
| Dry Bulb Temperature | ° F | 77 |
| Relative Humidity | percent | 70 |
| CTG Inlet Air Temperature | ° F | 77 |

**Operating Mode:**

| | | |
|---|---|---|
| Duty Cycle | | Intermediate |
| Capacity Factor | percent | 60 |

**Commercial Service:**

| | | |
|---|---|---|
| Date Available[A] | month/year | March 2018 |
| Service Life | years | 30 |

**Lead Time (Prior to Comm. Operation):[B]**

| | | Normal | Expedited |
|---|---|---|---|
| Permitting | months | 72 | 66 |
| Engineering | months | 36 | 32 |
| Procurement | months | 30 | 28 |
| Construction | months | 20 | 19 |

| | | |
|---|---|---|
| **Year Dollars:** | | December 2011 |
| **Capital Cost Uncertainty:** | plus/minus | +20%/-20% |

**Capital Cost (without AFUDC):**

| | $million | $/kW$_{gross}$ | $/kW$_{net}$ |
|---|---|---|---|
| A1. CTG Power Block, Ph 1 | - | - | - |
| A2. STG Power Block, Ph 2 | 59.50 | 3,985 | 4,233 |
| A. Total Power Block Cost (A1+A2) | 59.50 | 3,985 | 4,233 |
| B. Special Siting Costs | 0.90 | 60 | 64 |
| C. Power Plant Switchyard | 2.79 | 187 | 198 |
| D. T&D Interconnection | - | - | - |
| E. Total Direct Cost (A+B+C+D) | 63.19 | 4,231 | 4,495 |
| F. Total Indirect Cost (E*0.551) | 34.82 | 2,331 | 2,477 |
| G. Land Cost[C] | 0.87 | 58 | 62 |
| H. Total Capital Cost (E+F+G) | 98.87 | 6,621 | 7,034 |

**Operations & Maintenance:**

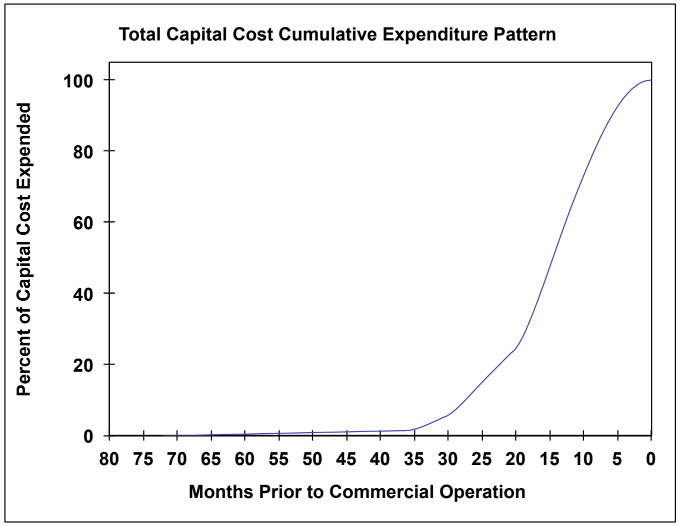
| | | CC |
|---|---|---|
| Fixed Cost | $million/y | 3.735 |
| | or $/kW-y$_{net}$ | 63.51 |
| Variable Cost | $/h run | 741 |
| | or $/MWh$_{net}$ | 12.60 |
| Staffing Requirements[D] | | 17 |

**Capacity and Heat Rate Data:[E]**

| Load Point | # CTGs | Comp Inlet | Gross Load | Net Load | Net Plant Heat Rate | Quick Load Pickup |
|---|---|---|---|---|---|---|
| | | ° F/RH | MW | MW | Btu/kWh | MW |
| Normal Top | 1 | 77/70 | 60.18 | 58.81 | 7,630 | - |
| Minimum | 1 | 77/70 | 19.40 | 18.37 | 10,264 | 33.91 |

**Flue Gas Emissions:[F]**

| | Normal Top Load at 59° F/70% RH | Minimum Load at 59° F/70% RH |
|---|---|---|
| | lb/MBtu | lb/MBtu |
| Nitrogen Oxides | 0.01 | 0.01 |
| Sulfur Oxides | 0.0011 | 0.0011 |
| Carbon Dioxide | 177 | 177 |
| Carbon Monoxide | 0.002 | 0.001 |
| Volatile Organic Compounds | 0.001 | 0.000 |
| Particulate Matter | 0.01 | 0.01 |




**Grid Services:**

| | | |
|---|---|---|
| Ramping Capabilties[I] | MW/minute | 3.0 |
| Inertia Constant[J] | MW-sec/MVA | 3 - 5 |
| Start Time[K] (cold start) | minutes | 270 |
| Dispatchable? | | Yes |

| | |
|---|---|
| Voltage Regulation? | Yes |
| Disturbance Ride Through? | Yes |
| Underfrequency Droop Response? | Yes |
| Overfrequency Droop Response? | Yes |

**General Site/Technology Characteristics:**

| | | |
|---|---|---|
| Fuel Delivery | | Truck |
| Fuel Storage Onsite | | 15 days |
| Water Supply Source | | Sea/Groundwater |
| CTG Inlet Air Cooling | | No |
| Cycle Cooling | | Cooling Tower |
| Waste Water Disposal | | Injection Wells |
| Solid Waste Disposal | | On-Island Landfill |
| Generator | | Synchronous |
| Minimum Land Requirement | acres | 4.0 |

**Daily Resource Requirements at Normal Top Load:[G]**

| | | |
|---|---|---|
| Fuel | gallons/day | 88,500 |
| Urea (dry)[H] | tpd | 0.99 |
| Service & Plant Water | mgd | 0.59 |
| Cooling Tower Makeup | mgd | 0.36 |
| Supply Water Temperature | ° F | 79 |

**Waste Streams:**

| | | |
|---|---|---|
| Solid Waste | tpd | 0 |
| Waste Water Discharge | mgd | 0.18 |
| Water Discharge Temperature | ° F | 90 |
| Thermal Discharge | MBtu/day | 17 |

**CTG/HRSG/STG Unit Startup Parameters:**

| | | |
|---|---|---|
| Cold Start Heat Input Requirement | MBtu | 382 |
| Hot Start Heat Input Requirement | MBtu | 238 |
| Hot Hours | hours | 2 |

**Availability:**

| | | |
|---|---|---|
| CTG Maintenance Pattern | wk/y | 0-0-1-0-6-0-0-1-0-12 |
| STG Maintenance Pattern | wk/y | 0-0-0-0-3-0-0-0-0-6 |
| Plant Maintenance Pattern | wk/y | 0-0-1-0-6-0-0-1-0-12 |
| Average Annual Maintenance | weeks | 2.0 |
| Immaturity Period | weeks | 5 |
| Immature Forced Outage Rate | percent | 6 |
| Minimum Weeks Between Maintenance | weeks | 50 |
| Mature Forced Outage Rate | percent | 4 |
| Equivalent Availability | percent | 92 |

# Appendix K: Consolidated Unit Information Forms

Table L-6c
GE LM6000 PG (Combined Cycle - Overall) Unit Information Form

## UNIT INFORMATION FORM

## HECO IRP 2013

| | |
|---|---|
| Utility: | *HECO* |
| Unit Type: | *Combined Cycle GE LM6000 PG* |
| Fuel Type: | *Biodiesel* |
| Site: | *Unspecified Island Location* |

| | |
|---|---|
| Date: | *March 25, 2013* |
| By: | *Black & Veatch* |
| Supersedes: | *October 11, 2012* |

**Unit Ratings:**

| | | Gross | Net |
|---|---|---|---|
| Normal Top Load | MW | 60.18 | 58.81 |
| Minimum | MW | 19.40 | 18.37 |

**Ambient Conditions:**

| | | |
|---|---|---|
| Dry Bulb Temperature | °F | 77 |
| Relative Humidity | percent | 70 |
| CTG Inlet Air Temperature | °F | 77 |

**Operating Mode:**

| | | |
|---|---|---|
| Duty Cycle | | Intermediate |
| Capacity Factor | percent | 60 |

**Commercial Service:**

| | | |
|---|---|---|
| Date Available[A] | month/year | March 2018 |
| Service Life | years | 30 |

**Lead Time (Prior to Comm. Operation):[B]**

| | | Normal | Expedited |
|---|---|---|---|
| Permitting | months | 78 | 74 |
| Engineering | months | 42 | 38 |
| Procurement | months | 34 | 32 |
| Construction | months | 26 | 24 |

| | | |
|---|---|---|
| **Year Dollars:** | | December 2011 |
| **Capital Cost Uncertainty:** | plus/minus | +20%/-20% |

**Capital Cost (without AFUDC):**

| | $million | $/kW$_{gross}$ | $/kW$_{net}$ |
|---|---|---|---|
| A1. CTG Power Block, Ph 1 | 77.56 | 1,289 | 1,319 |
| A2. STG Power Block, Ph 2 | 59.50 | 989 | 1,012 |
| A. Total Power Block Cost (A1+A2) | 137.06 | 2,278 | 2,331 |
| B. Special Siting Costs | 2.06 | 34 | 35 |
| C. Power Plant Switchyard | 7.97 | 132 | 136 |
| D. T&D Interconnection | - | - | - |
| E. Total Direct Cost (A+B+C+D) | 147.09 | 2,444 | 2,501 |
| F. Total Indirect Cost (E*0.482) | 70.93 | 1,179 | 1,206 |
| G. Land Cost[C] | 3.27 | 54 | 56 |
| H. Total Capital Cost (E+F+G) | 221.28 | 3,677 | 3,763 |

**Operations & Maintenance:**

| | | SC | CC |
|---|---|---|---|
| Fixed Cost | $million/y | 0.922 | 3.735 |
| | or $/kW-y$_{net}$ | 22.02 | 63.51 |
| Variable Cost | $/h run | 602 | 741 |
| | or $/MWh$_{net}$ | 14.38 | 12.60 |
| Staffing Requirements[D] | | 4 | 17 |

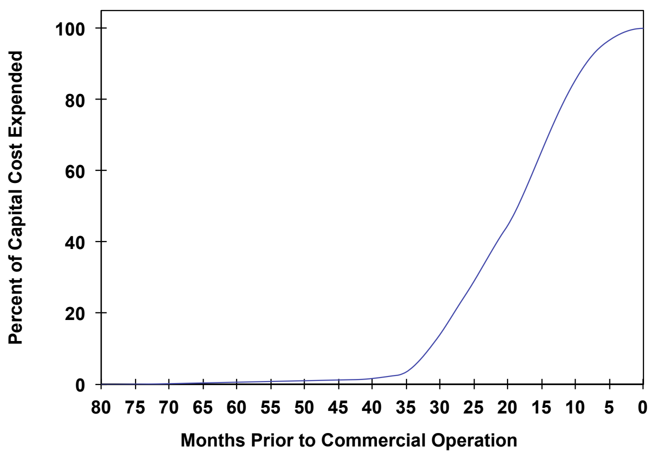
**Capacity and Heat Rate Data:[E]**

| Load Point | # CTGs | Comp Inlet | Gross Load | Net Load | Net Plant Heat Rate | Quick Load Pickup |
|---|---|---|---|---|---|---|
| | | °F/RH | MW | MW | Btu/kWh | MW |
| Normal Top | 1 | 77/70 | 60.18 | 58.81 | 7,630 | - |
| Minimum | 1 | 77/70 | 19.40 | 18.37 | 10,264 | 33.91 |

**Flue Gas Emissions:[F]**

| | Normal Top Load at 59° F/70% RH | Minimum Load at 59° F/70% RH |
|---|---|---|
| | lb/MBtu | lb/MBtu |
| Nitrogen Oxides | 0.01 | 0.01 |
| Sulfur Oxides | 0.0011 | 0.0011 |
| Carbon Dioxide | 177 | 177 |
| Carbon Monoxide | 0.00 | 0.00 |
| Volatile Organic Compounds | 0.001 | 0.000 |
| Particulate Matter | 0.01 | 0.01 |

Total Capital Cost Cumulative Expenditure Pattern




**Grid Services:**

| | | |
|---|---|---|
| Ramping Capabilties[I] | MW/minute | 3.0 |
| Inertia Constant[J] | MW-sec/MVA | 3 - 5 |
| Start Time[K] (cold start) | minutes | 270 |
| Dispatchable? | | Yes |

| | |
|---|---|
| Voltage Regulation? | Yes |
| Disturbance Ride Through? | Yes |
| Underfrequency Droop Response? | Yes |
| Overfrequency Droop Response? | Yes |

**General Site/Technology Characteristics:**

| | | |
|---|---|---|
| Fuel Delivery | | Truck |
| Fuel Storage Onsite | | 15 days |
| Water Supply Source | | Sea/Groundwater |
| CTG Inlet Air Cooling | | No |
| Cycle Cooling | | Cooling Tower |
| Waste Water Disposal | | Injection Wells |
| Solid Waste Disposal | | On-Island Landfill |
| Generator | | Synchronous |
| Minimum Land Requirement | acres | 15.0 |

**Daily Resource Requirements at Normal Top Load:[G]**

| | | |
|---|---|---|
| Fuel | gallons/day | 88,500 |
| Urea (dry)[H] | tpd | 0.99 |
| Service & Plant Water | mgd | 0.59 |
| Cooling Tower Makeup | mgd | 0.36 |
| Supply Water Temperature | °F | 79 |

**Waste Streams:**

| | | |
|---|---|---|
| Solid Waste | tpd | 0 |
| Waste Water Discharge | mgd | 0.18 |
| Water Discharge Temperature | °F | 90 |
| Thermal Discharge | MBtu/day | 17 |

**CTG/HRSG/STG Unit Startup Parameters:**

| | | |
|---|---|---|
| Cold Start Heat Input Requirement | MBtu | 382 |
| Hot Start Heat Input Requirement | MBtu | 238 |
| Hot Hours | hours | 2 |

**Availability:**

| | | |
|---|---|---|
| CTG Maintenance Pattern | wk/y | 0-0-1-0-6-0-0-1-0-12 |
| STG Maintenance Pattern | wk/y | 0-0-0-0-3-0-0-0-0-6 |
| Plant Maintenance Pattern | wk/y | 0-0-1-0-6-0-0-1-0-12 |
| Average Annual Maintenance | weeks | 2 |
| Immaturity Period | weeks | 5 |
| Immature Forced Outage Rate | percent | 6 |
| Minimum Weeks Between Maintenance | weeks | 50 |
| Mature Forced Outage Rate | percent | 4 |
| Equivalent Availability | percent | 92 |

*IRP 2013 UIF Notes: LM6000 PG (1x1 Combined Cycle)*

*LM6000 PG (1x1 Combined Cycle)*

Notes:

(A) Date Available represents Commercial Operation Date (COD) of all combined cycle systems. Date Available is based on on NTP of January 1, 2012 and expedited schedule.

(B) Lead Times represent months required for development of both Phase 1 and Phase 2 materials and equipment. Lead Times assume development activities for Phase 2 commence 6 months following the commencement of Phase 1 activities. Lead Times presented for Overall installation do not account for CTG outage period required during Phase 2 construction.

(C) Land cost based on $5/sq ft or $217,800/acre for plant facilities only.

(D) For simple cycle facilities with very low (< 10 percent) capacity factors, it assumed that the staff would consist of 4 full-time operators, and these operators would be capable of providing minor, day-to-day maintenance for the combustion turbines. For combined cycle facilities with capacity factors greater than 40 percent, it is assumed that the facility would employ operators and a dedicated maintenance staff for maintenance of both combustion turbines and steam cycle equipment.

(E) Performance is based on combustion of biodiesel. Combustion turbine performance and emissions were determined by OEM performance models, considering a bio-diesel fuel specification provided by HECO.

(F) Emissions of NOx are controlled via Selective Catalytic Reduction (SCR) system, and emissions of CO are controlled via CO catalyst.

(G) Based on 24 hour operation at normal top load. Fuel requirements reported as gallons per day, assuming a higher heating value of 16,800 Btu/lb and a density of 7.33 lb/gallon.

(H) Urea is used as a reagent within the Selective Catalytic Reduction (SCR) system. No other reagents are required for operation of air quality control (AQC) systems.

(I) When operating in simple cycle, the ramp rate of 14 MW/min is applicable following completion of required system purges during standard startup process.
Complete startup period (including purges and ramping of unit) is 10 minutes, as noted.
When operating in combined cycle, the unit ramp rate is limited by the capabilities of the heat recovery steam generator (HRSG) and steam turbine generator (STG). It is assumed that ramp rate is 5 percent of unit output. Because the combined cycle unit does not include a HRSG bypass system, it is assumed the this ramp rate applies to the combined cycle as a whole.

(J) System Inertia value provided by OEM.

(K) Start time assumes use of a conventional HRSG. Cold start time for a conventional HRSG is approximately 4-5 hours. Hot start time for a conventional HRSG is approximately 2 hours.
Based on lessons learned on previous Black & Veatch projects, once-through HRSGs (supplied by Innovative Steam Technologies [IST]) require 45 minutes for a cold start.

Table L-7a
GE LM6000 PG (Combined Cycle - Phase 1) Unit Information Form

## UNIT INFORMATION FORM

## HECO IRP 2013

| | |
|---|---|
| Utility: | *HECO* |
| Unit Type: | *Simple Cycle GE LM6000 PG* |
| Fuel Type: | *Natural Gas* |
| Site: | *Unspecified Island Location* |

| | |
|---|---|
| Date: | *March 25, 2013* |
| By: | *Black & Veatch* |
| Supersedes: | *October 11, 2012* |

**Unit Ratings:**

| | | Gross | Net |
|---|---|---|---|
| Normal Top Load | MW | 42.38 | 41.89 |
| Minimum | MW | 10.62 | 10.24 |

**Ambient Conditions:**

| | | |
|---|---|---|
| Dry Bulb Temperature | ° F | 86 |
| Relative Humidity | percent | 70 |
| CTG Inlet Air Temperature | ° F | 86 |

**Operating Mode:**

| | | |
|---|---|---|
| Duty Cycle | | Peaking |
| Capacity Factor | percent | 5 |

**Commercial Service:**

| | | |
|---|---|---|
| Date Available[A] | month/year | March 2018 |
| Service Life | years | 30 |

**Lead Time (Prior to Comm. Operation):[B]**

| | | Normal | Expedited |
|---|---|---|---|
| Permitting | months | 78 | 74 |
| Engineering | months | 42 | 38 |
| Procurement | months | 34 | 32 |
| Construction | months | 26 | 24 |

| | | |
|---|---|---|
| **Year Dollars:** | | December 2011 |
| **Capital Cost Uncertainty:** | plus/minus | +20%/-20% |

**Capital Cost (without AFUDC):**

| | $million | $/kW$_{gross}$ | $/kW$_{net}$ |
|---|---|---|---|
| A1. CTG Power Block, Ph 1[C] | 67.66 | 1,596 | 1,615 |
| A2. STG Power Block, Ph 2 | - | - | - |
| A. Total Power Block Cost (A1+A2) | 67.66 | 1,596 | 1,615 |
| B. Special Siting Costs | 1.02 | 24 | 24 |
| C. Power Plant Switchyard | 5.17 | 122 | 123 |
| D. T&D Interconnection | - | - | - |
| E. Total Direct Cost (A+B+C+D) | 73.85 | 1,742 | 1,763 |
| F. Total Indirect Cost (E*0.428) | 31.58 | 745 | 754 |
| G. Land Cost[D] | 2.40 | 57 | 57 |
| H. Total Capital Cost (E+F+G) | 107.82 | 2,544 | 2,574 |

**Operations & Maintenance:**

| | | SC |
|---|---|---|
| Fixed Cost | $million/y | 0.922 |
| | or $/kW-y$_{net}$ | 22.01 |
| Variable Cost[E] | $/h run | 421 |
| | or $/MWh$_{net}$ | 10.06 |
| Staffing Requirements[F] | | 4 |

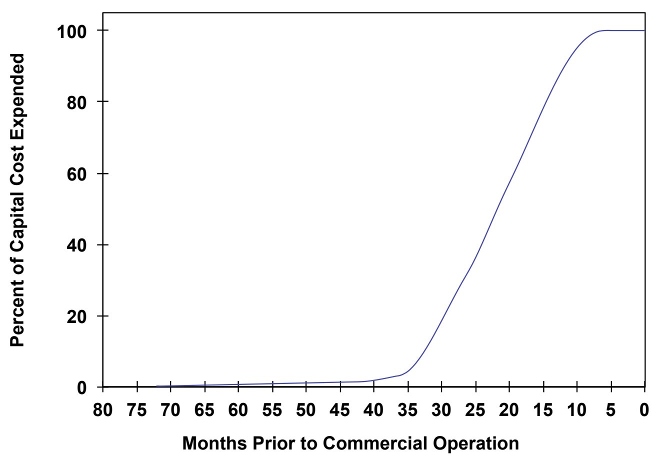
**Capacity and Heat Rate Data:[G]**

| Load Point | # CTGs | Comp Inlet | Gross Load | Net Load | Net Plant Heat Rate | Quick Load Pickup |
|---|---|---|---|---|---|---|
| | | ° F/RH | MW | MW | Btu/kWh | MW |
| Normal Top | 1 | 86/70 | 42.38 | 41.89 | 10,031 | - |
| Minimum | 1 | 86/70 | 10.62 | 10.24 | 17,912 | 31.76 |

**Flue Gas Emissions:[H]**

| | Normal Top Load at 59° F/70% RH | Minimum Load at 59° F/70% RH |
|---|---|---|
| | lb/MBtu | lb/MBtu |
| Nitrogen Oxides | 0.01 | 0.01 |
| Sulfur Oxides | 0.0002 | 0.0001 |
| Carbon Dioxide | 119 | 119 |
| Carbon Monoxide | 0.007 | 0.004 |
| Volatile Organic Compounds | 0.001 | 0.000 |
| Particulate Matter | 0.00 | 0.01 |

**Total Capital Cost Cumulative Expenditure Pattern**




**Grid Services:**

| | | |
|---|---|---|
| Ramping Capabilties[K] | MW/minute | 14 |
| Inertia Constant[L] | MW-sec/MVA | 1.3 |
| Start Time[M] | minutes | 10 |
| Dispatchable? | | Yes |

| | |
|---|---|
| Voltage Regulation? | Yes |
| Disturbance Ride Through? | Yes |
| Underfrequency Droop Response? | Yes |
| Overfrequency Droop Response? | Yes |

**General Site/Technology Characteristics:**

| | | |
|---|---|---|
| Fuel Delivery | | Pipeline |
| Fuel Storage Onsite | | 0 days |
| Water Supply Source | | Sea/Groundwater |
| CTG Inlet Air Cooling | | No |
| Cycle Cooling | | NA |
| Waste Water Disposal | | Injection Wells |
| Solid Waste Disposal | | NA |
| Generator | | Synchronous |
| Minimum Land Requirement | acres | 11.0 |

**Daily Resource Requirements at Normal Top Load:[I]**

| | | |
|---|---|---|
| Fuel | mmscfd | 10.2 |
| Urea (dry)[J] | tpd | 0.52 |
| Service & Plant Water | mgd | 0.17 |
| Cooling Tower Makeup | mgd | NA |
| Supply Water Temperature | ° F | 79 |

**Waste Streams:**

| | | |
|---|---|---|
| Solid Waste | tpd | 0 |
| Waste Water Discharge | mgd | 0.10 |
| Water Discharge Temperature | ° F | 90 |
| Thermal Discharge | MBtu/day | 9 |

**CTG/HRSG/STG Unit Startup Parameters:**

| | | |
|---|---|---|
| Cold Start Heat Input Requirement | MBtu | 36 |
| Hot Start Heat Input Requirement | MBtu | 36 |
| Hot Hours | hours | 0 |

**Availability:**

| | | |
|---|---|---|
| CTG Maintenance Pattern | wk/y | 0-0-1-0-0-6-0-0-1-0-0-12 |
| STG Maintenance Pattern | wk/y | NA |
| Plant Maintenance Pattern | wk/y | 0-0-1-0-0-6-0-0-1-0-0-12 |
| Average Annual Maintenance | weeks | 2.0 |
| Immaturity Period | weeks | 5 |
| Immature Forced Outage Rate | percent | 6 |
| Minimum Weeks Between Maintenance | weeks | 50 |
| Mature Forced Outage Rate | percent | 4 |
| Equivalent Availability | percent | 92 |

Table L-7b
GE LM6000 PG (Combined Cycle - Phase 2) Unit Information Form

| | |
|---|---|
| Utility: | *HECO* |
| Unit Type: | *Combined Cycle GE LM6000 PG* |
| Fuel Type: | *Natural Gas* |
| Site: | *Unspecified Island Location* |

## UNIT INFORMATION FORM

## HECO IRP 2013

| | |
|---|---|
| Date: | *March 25, 2013* |
| By: | *Black & Veatch* |
| Supersedes: | *October 11, 2012* |

**Unit Ratings:**

| | | Gross | Net |
|---|---|---|---|
| Normal Top Load | MW | 59.69 | 58.33 |
| Minimum | MW | 19.21 | 18.19 |

**Ambient Conditions:**

| | | |
|---|---|---|
| Dry Bulb Temperature | ° F | 77 |
| Relative Humidity | percent | 70 |
| CTG Inlet Air Temperature | ° F | 77 |

**Operating Mode:**

| | | |
|---|---|---|
| Duty Cycle | | Intermediate |
| Capacity Factor | percent | 60 |

**Commercial Service:**

| | | |
|---|---|---|
| Date Available[A] | month/year | March 2018 |
| Service Life | years | 30 |

**Lead Time (Prior to Comm. Operation):[B]**

| | | Normal | Expedited |
|---|---|---|---|
| Permitting | months | 72 | 66 |
| Engineering | months | 36 | 32 |
| Procurement | months | 30 | 28 |
| Construction | months | 20 | 19 |

| | | |
|---|---|---|
| **Year Dollars:** | | December 2011 |
| **Capital Cost Uncertainty:** | plus/minus | +20%/-20% |

**Capital Cost (without AFUDC):**

| | $million | $/kW$_{gross}$ | $/kW$_{net}$ |
|---|---|---|---|
| A1. CTG Power Block, Ph 1[C] | - | - | - |
| A2. STG Power Block, Ph 2 | 59.45 | 4,131 | 4,398 |
| A. Total Power Block Cost (A1+A2) | 59.45 | 4,131 | 4,398 |
| B. Special Siting Costs | 0.89 | 62 | 66 |
| C. Power Plant Switchyard | 2.96 | 206 | 219 |
| D. T&D Interconnection | - | - | - |
| E. Total Direct Cost (A+B+C+D) | 63.30 | 4,399 | 4,683 |
| F. Total Indirect Cost (E*0.537) | 34.02 | 2,364 | 2,517 |
| G. Land Cost[D] | 0.87 | 61 | 64 |
| H. Total Capital Cost (E+F+G) | 98.20 | 6,824 | 7,265 |

**Operations & Maintenance:**

| | | CC |
|---|---|---|
| Fixed Cost | $million/y | 3.735 |
| | or $/kW-y$_{net}$ | 64.04 |
| Variable Cost[E] | $/h run | 478 |
| | or $/MWh$_{net}$ | 8.19 |
| Staffing Requirements[F] | | 17 |

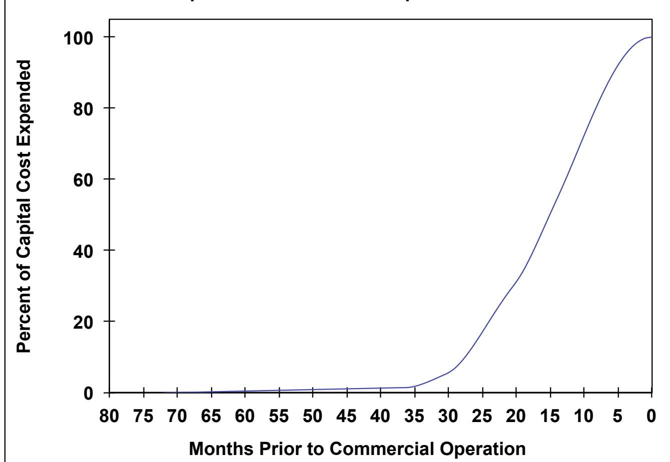
**Capacity and Heat Rate Data:[G]**

| Load Point | # CTGs | Comp Inlet | Gross Load | Net Load | Net Plant Heat Rate | Quick Load Pickup |
|---|---|---|---|---|---|---|
| | | ° F/RH | MW | MW | Btu/kWh | MW |
| Normal Top | 1 | 77/70 | 59.69 | 58.33 | 7,656 | - |
| Minimum | 1 | 77/70 | 19.21 | 18.19 | 10,540 | 33.95 |

**Flue Gas Emissions:[H]**

| | Normal Top Load at 59° F/70% RH | Minimum Load at 59° F/70% RH |
|---|---|---|
| | lb/MBtu | lb/MBtu |
| Nitrogen Oxides | 0.01 | 0.01 |
| Sulfur Oxides | 0.0004 | 0.0004 |
| Carbon Dioxide | 119 | 119 |
| Carbon Monoxide | 0.007 | 0.004 |
| Volatile Organic Compounds | 0.001 | 0.000 |
| Particulate Matter | 0.00 | 0.01 |

**Total Capital Cost Cumulative Expenditure Pattern**




**General Site/Technology Characteristics:**

| | | |
|---|---|---|
| Fuel Delivery | | Pipeline |
| Fuel Storage Onsite | | 0 days |
| Water Supply Source | | Sea/Groundwater |
| CTG Inlet Air Cooling | | No |
| Cycle Cooling | | Cooling Tower |
| Waste Water Disposal | | Injection Wells |
| Solid Waste Disposal | | On-Island Landfill |
| Generator | | Synchronous |
| Minimum Land Requirement | acres | 4.0 |

**Daily Resource Requirements at Normal Top Load:[I]**

| | | |
|---|---|---|
| Fuel | mmscfd | 10.9 |
| Urea (dry)[J] | tpd | 0.54 |
| Service & Plant Water | mgd | 0.56 |
| Cooling Tower Makeup | mgd | 0.36 |
| Supply Water Temperature | ° F | 79 |

**Waste Streams:**

| | | |
|---|---|---|
| Solid Waste | tpd | 0 |
| Waste Water Discharge | mgd | 0.17 |
| Water Discharge Temperature | ° F | 90 |
| Thermal Discharge | MBtu/day | 15 |

**CTG/HRSG/STG Unit Startup Parameters:**

| | | |
|---|---|---|
| Cold Start Heat Input Requirement | MBtu | 380 |
| Hot Start Heat Input Requirement | MBtu | 237 |
| Hot Hours | hours | 2 |

**Availability:**

| | | |
|---|---|---|
| CTG Maintenance Pattern | wk/y | 0-0-1-0-6-0-0-1-0-12 |
| STG Maintenance Pattern | wk/y | 0-0-0-0-3-0-0-0-0-6 |
| Plant Maintenance Pattern | wk/y | 0-0-1-0-6-0-0-1-0-12 |
| Average Annual Maintenance | weeks | 2.0 |
| Immaturity Period | weeks | 5 |
| Immature Forced Outage Rate | percent | 6 |
| Minimum Weeks Between Maintenance | weeks | 50 |
| Mature Forced Outage Rate | percent | 4 |
| Equivalent Availability | percent | 92 |

**Grid Services:**

| | | |
|---|---|---|
| Ramping Capabilties[K] | MW/minute | 3.0 |
| Inertia Constant[L] | MW-sec/MVA | 3 - 4 |
| Start Time[M] (cold start) | minutes | 270 |
| Dispatchable? | | Yes |

| | |
|---|---|
| Voltage Regulation? | Yes |
| Disturbance Ride Through? | Yes |
| Underfrequency Droop Response? | Yes |
| Overfrequency Droop Response? | Yes |

# Appendix K: Consolidated Unit Information Forms

Table L-7c
GE LM6000 PG (Combined Cycle - Overall) Unit Information Form

## UNIT INFORMATION FORM

## HECO IRP 2013

| | |
|---|---|
| Utility: | *HECO* |
| Unit Type: | *Combined Cycle GE LM6000 PG* |
| Fuel Type: | *Natural Gas* |
| Site: | *Unspecified Island Location* |

| | |
|---|---|
| Date: | *March 25, 2013* |
| By: | *Black & Veatch* |
| Supersedes: | *October 11, 2012* |

**Unit Ratings:**

| | | Gross | Net |
|---|---|---|---|
| Normal Top Load | MW | **59.69** | **58.32** |
| Minimum | MW | **19.21** | **18.18** |

**Ambient Conditions:**

| | | |
|---|---|---|
| Dry Bulb Temperature | ° F | **77** |
| Relative Humidity | percent | **70** |
| CTG Inlet Air Temperature | ° F | **77** |

**Operating Mode:**

| | | |
|---|---|---|
| Duty Cycle | | **Intermediate** |
| Capacity Factor | percent | **60** |

**Commercial Service:**

| | | |
|---|---|---|
| Date Available[A] | month/year | **March 2018** |
| Service Life | years | **30** |

**Lead Time (Prior to Comm. Operation):[B]**

| | | Normal | Expedited |
|---|---|---|---|
| Permitting | months | **78** | **74** |
| Engineering | months | **42** | **38** |
| Procurement | months | **34** | **32** |
| Construction | months | **26** | **24** |

| | | |
|---|---|---|
| **Year Dollars:** | | **December 2011** |
| **Capital Cost Uncertainty:** | plus/minus | **+20%/-20%** |

**Capital Cost (without AFUDC):**

| | $million | $/kW$_{gross}$ | $/kW$_{net}$ |
|---|---|---|---|
| A1. CTG Power Block, Ph 1[C] | **67.66** | **1,134** | **1,160** |
| A2. STG Power Block, Ph 2 | **59.45** | **996** | **1,019** |
| A. Total Power Block Cost (A1+A2) | **127.11** | **2,130** | **2,179** |
| B. Special Siting Costs | **1.91** | **32** | **33** |
| C. Power Plant Switchyard | **8.13** | **136** | **139** |
| D. T&D Interconnection | **-** | **-** | **-** |
| E. Total Direct Cost (A+B+C+D) | **137.15** | **2,298** | **2,352** |
| F. Total Indirect Cost (E*0.478) | **65.61** | **1,099** | **1,125** |
| G. Land Cost[D] | **3.27** | **55** | **56** |
| H. Total Capital Cost (E+F+G) | **206.02** | **3,452** | **3,532** |

**Operations & Maintenance:**

| | | SC | CC |
|---|---|---|---|
| Fixed Cost | $million/y | **0.922** | **3.735** |
| | or $/kW-y$_{net}$ | **22.01** | **64.04** |
| Variable Cost[E] | $/h run | **421** | **478** |
| | or $/MWh$_{net}$ | **10.06** | **8.19** |
| Staffing Requirements[F] | | **4** | **17** |

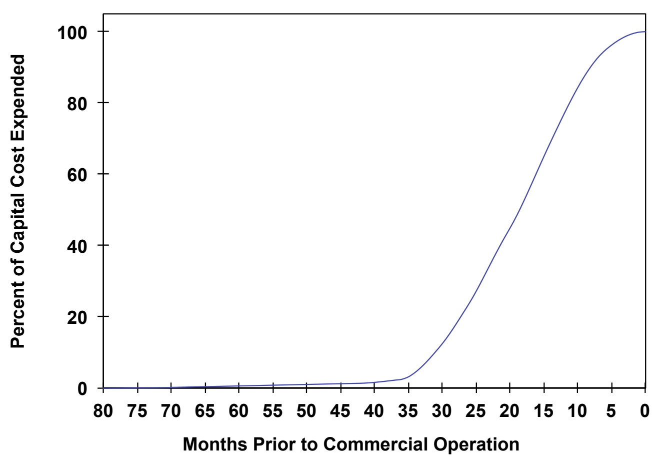
**Capacity and Heat Rate Data:[G]**

| Load Point | # CTGs | Comp Inlet | Gross Load | Net Load | Net Plant Heat Rate | Quick Load Pickup |
|---|---|---|---|---|---|---|
| | | ° F/RH | MW | MW | Btu/kWh | MW |
| Normal Top | **1** | **77/70** | **59.69** | **58.32** | **7,657** | **-** |
| Minimum | **1** | **77/70** | **19.21** | **18.18** | **10,542** | **33.95** |

**Flue Gas Emissions:[H]**

| | Normal Top Load at 59° F/70% RH | Minimum Load at 59° F/70% RH |
|---|---|---|
| | lb/MBtu | lb/MBtu |
| Nitrogen Oxides | **0.01** | **0.01** |
| Sulfur Oxides | **0.0004** | **0.0004** |
| Carbon Dioxide | **119** | **119** |
| Carbon Monoxide | **0.01** | **0.00** |
| Volatile Organic Compounds | **0.001** | **0.000** |
| Particulate Matter | **0.00** | **0.01** |

**Total Capital Cost Cumulative Expenditure Pattern**




**Grid Services:**

| | | |
|---|---|---|
| Ramping Capabilties[K] | MW/minute | **3.0** |
| Inertia Constant[L] | MW-sec/MVA | **3 - 4** |
| Start Time[M] (cold start) | minutes | **270** |
| Dispatchable? | | **Yes** |

| | |
|---|---|
| Voltage Regulation? | **Yes** |
| Disturbance Ride Through? | **Yes** |
| Underfrequency Droop Response? | **Yes** |
| Overfrequency Droop Response? | **Yes** |

**General Site/Technology Characteristics:**

| | | |
|---|---|---|
| Fuel Delivery | | **Pipeline** |
| Fuel Storage Onsite | | **0 days** |
| Water Supply Source | | **Sea/Groundwater** |
| CTG Inlet Air Cooling | | **No** |
| Cycle Cooling | | **Cooling Tower** |
| Waste Water Disposal | | **Injection Wells** |
| Solid Waste Disposal | | **On-Island Landfill** |
| Generator | | **Synchronous** |
| Minimum Land Requirement | acres | **15.0** |

**Daily Resource Requirements at Normal Top Load:[I]**

| | | |
|---|---|---|
| Fuel | mmscfd | **10.9** |
| Urea (dry)[J] | tpd | **0.54** |
| Service & Plant Water | mgd | **0.56** |
| Cooling Tower Makeup | mgd | **0.36** |
| Supply Water Temperature | ° F | **79** |

**Waste Streams:**

| | | |
|---|---|---|
| Solid Waste | tpd | **0** |
| Waste Water Discharge | mgd | **0.17** |
| Water Discharge Temperature | ° F | **90** |
| Thermal Discharge | MBtu/day | **15** |

**CTG/HRSG/STG Unit Startup Parameters:**

| | | |
|---|---|---|
| Cold Start Heat Input Requirement | MBtu | **380** |
| Hot Start Heat Input Requirement | MBtu | **237** |
| Hot Hours | hours | **2** |

**Availability:**

| | | |
|---|---|---|
| CTG Maintenance Pattern | wk/y | **0-0-1-0-6-0-0-1-0-12** |
| STG Maintenance Pattern | wk/y | **0-0-0-0-3-0-0-0-0-6** |
| Plant Maintenance Pattern | wk/y | **0-0-1-0-6-0-0-1-0-12** |
| Average Annual Maintenance | weeks | **2** |
| Immaturity Period | weeks | **5** |
| Immature Forced Outage Rate | percent | **6** |
| Minimum Weeks Between Maintenance | weeks | **50** |
| Mature Forced Outage Rate | percent | **4** |
| Equivalent Availability | percent | **92** |

*IRP 2013 UIF Notes: LM6000 PG (1x1 Combined Cycle)*

*LM6000 PG (1x1 Combined Cycle)*

Notes:

(A) Date Available represents Commercial Operation Date (COD) of all combined cycle systems. Date Available is based on on NTP of January 1, 2012 and expedited schedule.
(B) Lead Times represent months required for development of both Phase 1 and Phase 2 materials and equipment. Lead Times assume development activities for Phase 2 commence 6 months following the commencement of Phase 1 activities. Lead Times presented for Overall installation do not account for CTG outage period required during Phase 2 construction.
(C) Power Block capital costs include only equipment required for firing of natural gas. Capital costs do not include equipment required for firing biodiesel.
(D) Land cost based on $5/sq ft or $217,800/acre for plant facilities only.
(E) Combustion of natural gas within combustion turbines reduces variable O&M requirements relative to firing biodiesel in the same combustion turbine. When firing natural gas, Black & Veatch estimates that variable O&M costs are reduced approx. 30 percent relative to variable O&M costs when firing biodiesel.
(F) For simple cycle facilities with very low (< 10 percent) capacity factors, it assumed that the staff would consist of 4 full-time operators, and these operators would be capable of providing minor, day-to-day maintenance for the combustion turbines. For combined cycle facilities with capacity factors greater than 40 percent, it is assumed that the facility would employ operators and a dedicated maintenance staff for maintenance of both combustion turbines and steam cycle equipment.
(G) Performance is based on combustion of natural gas. Combustion turbine performance and emissions were determined by OEM performance models.
(H) Emissions of NOx are controlled via Selective Catalytic Reduction (SCR) system, and emissions of CO are controlled via CO catalyst.
(I) Based on 24 hour operation at normal top load. Fuel requirements reported as million standard cubic feet per day (mmscfd), assuming a higher heating value of 1,000 Btu/scf.
(J) Urea is used as a reagent within the Selective Catalytic Reduction (SCR) system. No other reagents are required for operation of air quality control (AQC) systems.
(K) When operating in simple cycle, the ramp rate of 14 MW/min is applicable following completion of required system purges during standard startup process.
Complete startup period (including purges and ramping of unit) is 10 minutes, as noted.
When operating in combined cycle, the unit ramp rate is limited by the capabilities of the heat recovery steam generator (HRSG) and steam turbine generator (STG). It is assumed that ramp rate is 5 percent of unit output. Because the combined cycle unit does not include a HRSG bypass system, it is assumed the this ramp rate applies to the combined cycle as a whole.
(L) System Inertia value provided by OEM.
(M) Start time assumes use of a conventional HRSG. Cold start time for a conventional HRSG is approximately 4-5 hours. Hot start time for a conventional HRSG is approximately 2 hours.
Based on lessons learned on previous Black & Veatch projects, once-through HRSGs (supplied by Innovative Steam Technologies [IST]) require 45 minutes for a cold start.

# Appendix L:
# Hawaiian Electric Capacity Planning Reliability Criteria

This report was prepared for the Hawaiian Electric Company by Robert Zeles, Associate Director of Consulting Services, at Shaw Power Technologies on 13 December 2004, as part of the HECO IRP-3 process. The Capacity Planning Reliability Criteria is used to evaluate generation adequacy, to establish the need for additional resources to meet future demand and energy requirements, and to evaluate the impacts that different portfolios of new resources will have on the reliability of the overall electric system.

# CONTENTS

# TABLES

# Legal Notice

This document was prepared by Shaw Power Technologies, Inc. ™ (PTI) solely for the benefit of Hawaiian Electric Company, Inc. Neither PTI, nor parent corporation or its or their affiliates, nor Hawaiian Electric Company. Inc., nor any person acting in their behalf (a) makes any warranty, expressed or implied. with respect to the use of any information or methods disclosed in this document; or (b) assumes any liability with respect to the use of any information or methods disclosed in this document.

Any recipient of this document, by their acceptance or use of this document, releases PTI, its parent corporation and its and their affiliates, and Hawaiian Electric Company, Inc. from any liability for direct. indirect, consequential or special loss or damage whether arising in contract, warranty, express or implied, tort or otherwise, and irrespective of fault, negligence, and strict liability.

# 1. Introduction

As part of the integrated resource planning (IRP) process, the various key criteria, factors, assumptions, and methodology need to be reviewed and documented at the start of the effort. One of the key items that should be reviewed early in this process is the capacity planning reliability criteria. These criteria will be used to evaluate generation adequacy, to establish the need for additional resources to meet future demand and energy requirements, and to evaluate the impacts that different portfolios of new resources will have on the reliability of the overall electric system. The criteria should be reviewed to ensure that they are both reasonable and appropriate for the current and future conditions.

Shaw Power Technologies, Inc.™ (PTI) was asked by Hawaiian Electric Company, Inc. (HECO) to review its capacity planning reliability criteria and consider whether these criteria are appropriate for continued use in its integrated resource planning process.

## 1.1 Current HECO Capacity Planning Reliability criteria

At the present time, there are three criteria that HECO uses to determine when additional generating facilities need to be added. HECO's planning reliability criteria indicates that new generation would be added to prevent the violation of any one of the rules. The first rule states that:

> "The sum of the amount net capability ratings of all available units minus the normal net capability rating of the largest available unit must be equal to or greater than the system peak load (as measured at the high-voltage side of the generator step-up transformers, that is, before T&D losses) to be supplied at 60Hz. minus the total amount of underfrequency relay-controlled interruptible loads."

The second rule is an operational criterion:

> "There must be enough net generation running in economic dispatch so that the sum of the three second quick load pickup power available from all running units, not including the most heavily loaded unit, plus the net loads of all other running units must equal or exceed 95 percent of the hourly system net load (which excludes power plant auxiliary loads but includes T&D losses). This is based on a minimum allowable system frequency of 58.5 Hz and assumes a 2 percent reduction in load for each 1 percent reduction m frequency."

A third element in HECO's capacity planning reliability criteria includes a reliability guideline. This guideline indicates that:

> "Capacity planning analysis will include a calculation of risk (Loss of Load Probability-LOLP) in years per day for each plan of the long-range expansion study In cases where risk is calculated to be less than 4.5 years per day the plan will be reviewed by the Vice President of Power Supply and the President for approval of use of the plan in the study. Calculations of risk will utilize normal net capability ratings ($N_1$, $N_2$, $N_3$, …$N_n$)."

## 1.2 Defining Reliability

Reliability is a measure that indicates how well a system performs its intended function. Adequacy is a related concept that is associated with reliability. A system is considered adequate if there are sufficient resources to perform its function. To apply these terms to electric systems, the North American Electric Reliability Council (NERC) has defined power system reliability as:

> "[T]he 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 must 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 and security.
>
> Adequacy: 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.
>
> Security: The ability of the electric system to withstand sudden disturbances such as electric short circuits or unanticipated loss of system elements."

These definitions apply to both the generation and transmission systems, and in using these definitions, an electric system would be considered unreliable if either the generation or transmission system were inadequate. For this specific review, the focus is on the generation aspect of the HECO electric system, while recognizing that transmission system constraints could impact the amount of generating capacity that could be deliverable to meet load.

## 1.3 Generation Adequacy

The function of the capacity planning reliability criteria is to establish a consistent basis for evaluating the current system and proposed expansion plans in terms of whether there will be adequate generation to meet load. Generation adequacy can be defined as the ability of all generating resources to supply the total system demand, with appropriate consideration of both scheduled arid unscheduled outages of the generating facilities. It does not consider reliability issues or limits associated with the transmission system, outside of constraints on importing power through ties to other systems.

System operators can predict hourly loads for the next day with reasonable accuracy given that some of the factors associated with load variability will have minimal effect in the short term, while others such as weather can be estimated with reasonable certainty. However, especially beyond one or two days, demand levels on a daily or hourly basis cannot be exactly predicted into the future. Therefore, it is not possible to precisely determine the amount of generating capacity that would be required to meet load levels at various points in time in the future. Similarly, sudden equipment failures can occur randomly, and repairs of outaged equipment can take longer than expected. Since there is a finite non-zero probability that each operating generation resource on the system could fail at a particular point in time, an infinite amount of generating capacity would be required to "guarantee" that the total load would always be met. As this is unrealistic and unfeasible, a probabilistic approach has often been used to evaluate generation adequacy.

As zero risk is approached, the marginal costs of incremental risk reduction (additional resources) become very large and there is no evidence to indicate a willingness of consumers to pay very high premiums for slightly higher reliability. In addition, unexpected or unpredictable events, such as exceptionally severe weather or acts of terrorism, occasionally cause electric systems to fail, either locally or wide spread, and these events may not be preventable at all. The logical conclusion of this issue from an economic perspective is that the process of setting an adequate level for reliability needs to balance the costs associated with disruption of supply against the costs of reducing that risk.

## 1.4 Changing Environment

Both in the United States and in numerous countries throughout the world, the electric industry is undergoing a structural change that is altering the responsibility for maintaining adequate resources to meet load. Previously, utilities were generally vertically integrated and had monopoly franchises. In that environment, utilities had an obligation to serve and to provide reliable service to all customer classes at the lowest reasonable cost. To conform to those requirements, utilities added resources to meet their projected load requirements, with the timing and, to some extent, sizing of new supply-side resources based upon the generation adequacy evaluations. This process and the resulting approval procedure from regulatory bodies were meant to ensure that reliability was being maintained at a reasonable level while at the same time limiting the ability of utilities to add too much generating capacity that would result in higher rates to consumers than may be considered reasonable.

As portions of the electric industry move towards a competitive generation market, this process is no longer directly applicable. For a deregulated generation supply industry, market forces should guide the addition of new generating facilities, while generation adequacy studies would be a guide to the likely level of future reliability. In this new environment, individual power producers are focused on producing power at the lowest cost possible to maximize profits, while the issues such as reliability, the environment, and demand-side control, previously considered in a regulatory environment especially in the IRP process, need to be addressed in other arenas.

Especially from an international perspective, governments have traditionally taken a strong interest in reliability of utility supply. Some of the factors behind such an interest in security of supply include:

- The essential nature of electricity and the associated high costs of interruptions.
- The difficulty in obtaining alternative supplies other than through monopoly-based transmission line networks.
- The difficulty of storing energy for most consumers.

Thus, it has generally been recognized that interruptions to energy supply can be both sudden and have serious consequences. At the same time that the structure of the electric utility industry is changing, there is no consistent approach being used to deal with generating resource adequacy. In certain competitive markets, capacity reserve margins have been required for customers, while other markets have taken a hands-off approach and are letting prices and resource additions be entirely market driven.

# 2. Capacity Planning Reliability Criteria

The evaluation process that was used for this study was to review the planning reliability criteria used by other electric utilities, reliability organizations, and regulatory bodies in the United States operating in an interconnected basis, and utilities operating in other countries that are either isolated or interconnected and to compare those criteria with the planning reliability criteria used by HECO. The purpose of this effort was to provide benchmarks for the evaluation of HECO criteria. The information that has been gathered for this process has been extracted from various public sources.

## 2.1 General

In attempting to express the reliability of an electric system, there is no single index that is universally used. The types of criteria that historically have been used by utilities for capacity planning include:

- Specified percentage reserve margin
- Loss of largest unit
- Loss of load expectation (LOLE)
- Dependence upon interconnections
- Expected unserved energy (EUE)

Of these, the percentage reserve margin and the LOLE criteria have generally been the criteria most often used.

The list of reliability indices can be broadly categorized as either deterministic or probabilistic. Deterministic indices, such as reserve margin and loss of largest unit, can be readily calculated with easily documented system parameters and can provide a snapshot of the system. These deterministic measures can be used for evaluating system adequacy for many years into the future. While they can be easily calculated, they have a deficiency in that they do not take unforeseen events into account and, hence, do not directly consider the various aspects of the system that affect overall system reliability.

The dynamic and variable nature of a power system is better analyzed through probabilistic measures. These approaches will take into account the future uncertainties in system components through statistical analyses. The resulting indices will provide a better indication of system reliability, with the tradeoff being that they are more difficult and time consuming to compute and evaluate.

## 2.2 Reserve Margin

The main reason for the prevalent use of a reserve margin as a reliability standard is a function of its ease of calculation and understanding. The reserve margin is a deterministic measure and represents the relative amount that installed generating resources are greater than the annual peak load. If the calculated reserve margin is above the criterion, then the system would be considered to be within the standard for the period evaluated.

The reserve margin is generally expressed as a percentage and is calculated by taking the difference between total generating system capacity and the system annual peak load and then dividing by the system annual peak load. This calculation can be readily performed for numerous years, utilizing projected annual peak loads and expected resources that would be available to meet those loads. The calculated reserve margins can then be compared with reliability criterion to determine the need to add resources. This process can be refined to consider seasonal peaks for regional analyses where diversity of loads or seasonal differences in generating capacity needs to be considered. Interruptible loads can be reflected in the analysis by either Including the interruptible load as a resource, or by using system firm load in the calculations.

The capacity margin is another reliability measure that has also been used and one which is very similar to the reserve margin. It shares all of the advantages and disadvantages of the reserve margin. The capacity margin would be calculated in a comparable manner to reserve margin, with the excess capacity above annual peak demand divided by the total generating system capacity.

## 2.3 Loss of Largest Unit

Unlike the reserve margin criteria, this criterion recognizes the potential reliability issue if the largest resource fails or is otherwise unavailable to serve load. For systems where a large unit, relative to the other generating units and, more importantly system load is added, the loss of that unit could result in the inability to meet peak load even if the reserve margin criterion were otherwise met.

This criterion is also a deterministic measure that is easy to evaluate and interpret. The net capacity of all available resources except for the largest unit are summed and compared to the system peak load. As long as that net capacity is larger than the peak load, the criterion is satisfied. For relatively large systems where the largest unit is a small percentage of the system peak, the use of this criterion without any other indices will result in insufficient capacity available to meet load when one or more units are unexpectedly tripped while other generation is out for scheduled maintenance.

## 2.4 Loss of Load Expectation (LOLE)

Loss of load expectation (LOLE) is a reliability index that indicates the expected number of periods in a year when the peak demand would exceed the available supply resources. While it can be calculated hourly, it is typically calculated and expressed in terms of the number of days per year.

In its more common presentation, LOLE is the expected number of days in a year the available generating capacity and other resources would be less than the daily peak demand, resulting in the inability to serve some portion of the load. It is obtained by calculating the probability that the daily peak demand would exceed the available capacity for each day, under the assumption that each day is independent of all others. These daily values are then summed for all the days in a year and multiplied by the number of days in the year. The calculation for hourly LOLE is similar, with the calculations done for each hour in the year. again under the assumption that each hour is independent of all others.

Of the various methods to assess system adequacy that have been discussed thus far, LOLE provides a mere complete evaluation of the expected system behavior. Unlike other measures, such as reserve margin, LOLE takes the following factors into account:

1. The peak load of every day (or the load of every hour for hourly calculations) of the year is considered to have an influence on system adequacy, not just the hour(s) of peak demand. Systems with a high load factor will tend to have a lower level of reliability, all other factors being equal.
2. Plant availability is taken into account. Generating resources with a high availability are of mere benefit than generating units with low availability, from the system reliability point of view.
3. The number and relative sizes of generating units impact the LOLE calculations. A small number of large units will provide less security than a large number of small units, all other factors being equal.

The reserve margin method does not take these factors into account. Its calculation is based on an annual peak or two seasonal peaks. The number and relative sizes of the units are not considered, nor are their availability levels. The loss of the largest unit approach has usefulness for small systems such as Hawaii Electric Light Company and Maui Electric Company where the unit size is large compared to peak load and for short-term operational planning, but otherwise suffers from the same limitations as the reserve margin.

While LOLE is typically expressed in terms of days per year or hours per year, it can also be expressed in terms of the number of years per one day loss of load. To illustrate by way of an example, a LOLE criterion of 1 day in 10 years is identical to 0.1 days per year. It is synonymous with 10 years per one day loss of load terminology used by HECO. HECO's reliability guideline is a LOLE calculation with a threshold of 4.5 years par day, or equivalently 0.22 days per year.

The LOLE values are sometimes referred to as loss of load probability (LOLP). However, the proper use of the term LOLP refers to the probability of not meeting load in any hour and thus is a unitless value. In contrast, the LOLE calculation is the result of a mathematical operation known as expected value. Because of this, the term LOLE is the proper name for this calculated value. The calculation procedure for hourly LOLP is the same as for hourly LOLE, with the result being the probability of not serving load in any hour in the year. Multiplying the hourly LOLP value by the number of hours in a year will result in the LOLE in hours per year.

There is no fixed relationship between an LOLE expressed in days per year and one expressed in hours per year. In the LOLE calculated on a daily basis, as is used in HECO's reliability guideline, only the peak demand for each day of the year is considered. For the hourly LOLP calculation, each hour of the year is considered. For systems with a high load factor on a daily basis, there would be more contribution to the LOLE value than if the daily load shape were more peaked. Similarly, energy-limited resources can contribute to a skewing of hourly LOLE values compared to da1ly calculations. For a "typical" utility, calculated LOLE values of 0.4–0.7 hours per year have been found to be comparable to 0.1 days per year for the same system and assumptions.

As previously indicated, the annual LOLE is the sum of the contributions from each day, or each hour if the analysis is so structured. In general, the daily expectations consider the peak load level for the day, the variability of that load, the units that are out on scheduled maintenance, and the probability that each of the remaining plants will be available. Typically, a plant availability distribution table is prepared, from which the probability of the available generation being less than any given load level can be found directly. These tables would then be modified for scheduled maintenance.

The calculated adequacy level is then compared to the reliability criteria standard to assess the adequacy of the system. If the calculated LOLE is greater than the standard, then the system fails to meet the adequacy standard and additional resources are needed. If the LOLE is less than or equal to the standard, then the system is within the standard. A very low LOLE value compared to the criterion is indicative of a system that has excess capacity strictly from the reliability planning reliability criteria; this result could be expected for systems with significant amounts of hydro generation.

### 2.4.1 Issues Relevant to LOLE Criteria Levels

The impact on overall system reliability associated with the addition of a large generating unit is a function of the number and sizes of generators on a system, the system demand, and the availability of the generator to be added. As an example, adding one 500 MW unit to a 1,000 MW system would result in a noticeably less reliable system than adding five 100 MW units. If this system after either of these additions has a 15% reserve margin (150 MW), then the loss of the 500 MW unit would result in less supply capability than the daily peak loads for a significant portion of the year. The greater the number of generators installed, the lower the probability that all of those units will be out at the same time. If the forced outage rate for each of these units was 10% and ignoring maintenance, the probability of having a total of 0 MW from these five units is 0.001%, compared to the 10% chance of not having any output from the single 500 MW unit

Annual LOLE values can be volatile from year to year, and are a non-linear parameter. During peak periods, the LOLE value can be many times greater than the value during minimum loads. The results of most studies will generally indicate that the majority of the yearly LOLE is accrued over a relatively small percentage of the year. In addition, it has been observed that the LOLE values tend to rise exponentially as reserve margins decline.

LOLE as a reliability measure can be used as a proxy for a more rigorous economic analysis that will recognize the tradeoff where the investment costs that are incurred to improve reliability are offset by the reduction in service interruption costs that are experienced by customers. The target LOLE value to select and use as a criterion is one that will produce an optimum balance where the sum of those costs is minimized.

Interruption cost surveys have generally indicated that there is a wide variation in interruption costs perceived by customers. Factors such as frequency, duration, time of occurrence, season, warning, and types of customers influence these costs. The LOLE level that balances these interruption costs against resource addition costs will vary by utility, especially in the international arena. A more stringent LOLE criterion will generally reflect higher interruption costs; these could be associated with an increased dependence on electricity for production, and societal costs associated with widespread power outages.

Some economists that are advocating for market prices to drive resource additions have argued that the industry standard of 1 day in 10 years implies a much higher customer interruption cost than their studies have shown. Their argument suggests that the current LOLE standard may be too high. Certainly it can be argued that the interruption costs for regions that are heavily dependent on electricity would be much greater than for underdeveloped countries where electric energy use is minimal by comparison.

## 2.5 Dependence Upon Interconnections

A similar reliability index is the dependence on supplemental capacity resources. One approach for this index is the determination of the number of days when the system under study would have to depend upon interconnections with other systems, curtailment of service to interruptible customers, and direct-controlled load management. Alternatively, the MW magnitude of dependence on interconnected systems can be used as the calculation approach, with the criterion being the import capability of the existing interconnections. In either of these approaches, the data requirements include forced outage rates, scheduled maintenance, and load forecasts as in the LOLE analyses.

The fundamental premise for this reliability index is that there are resources outside the utility system or planning area that could provide emergency power through one or more transmission interconnections. Thus. the utility will be dependent upon that external capability to avoid the shedding of load during supply emergencies. If there is no capacity that is available or deliverable during the emergency from the remote systems, the result would be load shedding. Since only one utility serves an island and none of the islands are interconnected, the dependence upon interconnections is not relevant for Hawaii.

## 2.6 Expected Unserved Energy

While LOLE is an important index in terms of identifying whether the generation system is reliable, it provides an incomplete picture. It does not identify whether there are single or multiple occurrences of load shedding in the period under study. It also does not give an indication of the size of the problem. The magnitude of the insufficiency as well as the duration are important in order to develop and evaluate corrective measures.

Expected Unserved Energy (EUE) is the expected amount of energy that would be curtailed due to demand exceeding available capacity. Generally expressed in MWh per year, this reliability index is a probabilistic index that uses many of the same parameters as used for LOLE. Additional factors are failure rates and repair rates for generating resources. The criterion for the EUE index is generally expressed as a percentage of annual energy.

While EUE could be used in Hawaii, this reliability index has generally not been used as a standard within the United States mainland and has been referenced only by Seminole Electric Cooperative (Florida) and Australia, and by Italy as their criterion prior to the European deregulation process. Therefore, attempting to compare a EUE criterion level established for HECO with other utilities would not produce meaningful results.

# 3. Review Process

## 3.1 General

The review process that was used for this report was to examine the planning reliability criteria used by other electric utilities, reliability organizations, and regulatory bodies in the United States operating in an interconnected basis, and utilities operating in other countries that are either isolated or interconnected. The purpose of this effort was to provide benchmarks for the evaluation of HECO criteria. The information that has been gathered has been extracted from various public sources.

## 3.2 Isolated Systems

The transmission systems of most electric utilities in the United States are interconnected with other systems. The interconnected networks allow the utilities to call upon the resources of neighboring systems to help in meeting load during emergency conditions. In contrast, HECO operates an electric system that is isolated from other utilities or sources of power not located on the island of Oahu. As a result, HECO must depend on its own generating resources plus the resources of independent power producers located on the island to meet customer load requirements. Recognizing that in general terms electric power cannot be stored but must be generated at the time that it is demanded, there is a probability that equipment failures, scheduled maintenance, and other factors may prevent generating facilities from operating. Therefore, while the criteria of interconnected utilities can be compared with isolated systems such as HECO's, the additional resources to meet the same criteria would need to be provided by local generation or load modification, rather than transmission lines to neighboring utilities.

## 3.3 Market Pricing Issues

As the electricity supply industry moves from the vertically integrated regulated monopolistic structure to a competitive commodity market, volatility in prices should be expected that reflect market forces. Developers of resources will install new capacity when they perceive that the market prices will provide them with sufficient revenue to result in a profitable venture. In periods of excess capacity, prices will remain low and provide little incentive to build new capacity. In commodity markets other than electric energy, marketers, retailers, and large customers will typically use long-term bilateral contracts that limit their exposure to price volatility as well as price hedging instruments. Unlike price volatility responses in some commodity markets, the issue of inadequate investment in generation and conservation may lead to actual electricity supply shortages, with resultant interruptions and the consequential economic disruptions. This risk stems from the instantaneous balancing of supply and demand in the electricity markets, the limited storage capability for electricity, and the transition time from when demand side issues appear to the time when supply side facilities can be developed and implemented.

Electricity has become a vital element of economic activity throughout most of the world, such that shortfalls of generating capacity can have significant economic and political ramifications. Since the development time for generating plants can be relatively long, it is important to consider the impacts that may result from the various options available to moderate the price volatility and the potential demand and supply imbalances. Some of the options that have been suggested include:

- A regulatory requirement on Load Serving Entities (LSEs) to maintain certain capacity margins.
- Require some entity to construct resources to maintain certain capacity margins.
- Provide some form of capacity payment from LSEs to give added incentive for a greater level of development of new generation. This would require some entity with sufficient market presence to implement the billing and collection from electricity users and direct the financial resources to the appropriate developers.
- Let the market mechanisms develop for hedging the risk of volatility. The premiums collected could be used to support the development of resources to boost supplies, thereby moderating the price volatility.

The current approach that has been implemented in the eastern United States has focused on requiring LSEs to have, in some manner, sufficient capacity to meet peak load plus a specified level of reserves. There are several approaches being developed that would provide for capacity payments, but these are in a state of flux at this time. While economists advocate that the market can provide mechanisms for addressing price risk, there has been limited movement in this direction given the political response to significant spikes in prices.

Theoretically, generation adequacy can be evaluated without concern as to whether the electricity market is competitive or not. While the market will influence the price of electricity during periods of supply shortage. it should not constrain the quantity of available capacity that will be available to meet demand. This assumes that the market conditions in the future will be sufficient to attract investment for future required capacity in a timely manner and that commercial operation of the market discourages poor availability levels. However, insufficient revenue to support costly or inefficient generating resources could lead to the early retirement of those units, thereby reducing total system generating capability.

In most commodity markets, the consumers' responses to price changes serve as a mechanism to restrain price swings. As prices get too high, consumers use the product more efficiently. curtail use of the product, find substitutes, or shift use to periods when it is less expensive. In certain regards, electricity is different in that it is a relative necessity of modern life and there are few substitutes for it, although there are ways in which to reduce the use of electricity, implement efficiency improvements or change the periods of use.

Another impact associated with the movement towards competitive markets is the focus of oversight parties. In the past. the focal point was on long-term resource needs. Now the state and regional bodies are focused on the shorter -term adequacy and reliability assessments and on the performance of electricity markets. In addition, data requirements for these efforts and the availability of that data are issues that have impeded the review process.

Market-based pricing as a means to signal the need for additional capacity is not an applicable consideration in Hawaii, as there is no competitive retail market and a limited wholesale market.

## 3.4 Planning Reliability Criteria in Current Practice

The discussions in the following sections present the basis and rationale of the planning reliability criteria used in various regions of the United States and in a number of countries.

### *3.4.1 Mid-Atlantic Area Council*

The Mid-Atlantic Area Council (MAAC) is a reliability council that covers the states of New Jersey, Delaware, Maryland, and the majority of Pennsylvania. This reliability council, like others throughout the United States, has maintained its reliability principles and standards as the generation market has undergone varying aspects of deregulation and re-regulation. Initially adopted in 1968, and most recently revised in March 1990, MAAC's reliability standards provide that the installation of generating capacity needs to be sufficient in each year to ensure that the probability of load exceeding the available generating capacity shall not be greater than one day in ten years. They have indicated a number of factors that should be reflected in the reliability analysis. These include the scheduled and unscheduled outages of generating units, limited energy capability from supply-side resources, the transmission network capabilities within the individual systems within MAAC, the connections to parties outside MAAC, and the nature of the connected load. The underlying principle for these standards is that they only apply to facilities that impact the reliability of the overall MAAC system, as opposed to facilities that only affect the reliability to supply local system loads.

MAAC' s focus is to ensure that the bulk electric system is planned and built so that the more likely contingencies will not result in loss of load. This allows individual participants in MAAC to adopt different criteria for their own systems where cost or other factors may limit the ability to attain the specified reliability. MAAC also recognizes that a diversity of types, sizes, and locations of all electric system facilities is needed to maintain reliability, by minimizing common mode outages. With respect to supply side resources. this means that different fuel types, fuel supply sources, or equipment types should be encouraged. If adequate diversity is not possible, then common mode outages should be considered in evaluating the overall system reliability level.

To ensure that all systems within MAAC contributed to the overall reliability, consistent with an LOLE of 1 day in 10 years, the Reliability Council of Pennsylvania New Jersey Maryland Interconnection LLC (PJM) established a 19.0% required reserve for the 2001–2003 planning periods. This obligatory reserve must be met by all load-serving entities in PJM as signatories to the Reliability Assurance Agreement (RAA). This reserve margin is the amount of generation that the LSE must maintain above their peak demand. Total P JM load is met through generating resources within PJM coupled with purchases from other regional markets. While generating resources can be energy-only or installed capacity resources, only the latter can be used by LSEs to meet their load and reserve responsibility.

The installed capacity resources used by a LSE within PJM can be called upon to support PJM during system emergencies. However, their output can be removed by their owner or marketer from the PJM market with as little as one day's notice, allowing their output to serve more lucrative markets. Since the installed capacity resources are important in evaluating and maintaining reliability levels, PJM is considering what approaches might be used to address this issue. An alternative to the reserve obligation would be to implement a market-based adequacy model. In this environment, a market that relies on price signals must also be designed with adequate safeguards in place to ensure that should there be a conflict between market price signals and system adequacy, that the reliability issues should not be jeopardized.

### 3.4.2 New York State

The New York State Reliability Council (NYSRC) was formed in 1997 to promote and preserve the reliability of electric service. The NYSRC is responsible for developing and updating reliability rules that shall be complied with by the New York Independent System Operator (NY ISO) and all entities engaged in electric power transactions in the New York State power system.

The NYSRC reliability rules as used in the December 2003 report on installed capacity requirement for 2004–2005 indicates that adequate resource capacity shall exist such that "…the probability of disconnecting firm load due to a resource deficiency will be. on the average, not more that once in ten (10) years". This NYSRC reliability rule is consistent with the Northeast Power Coordination Council (NPCC) resource adequacy standard. In this NYSRC report, the installed reserve margin for the New York Control Area (NYCA) has been set at 18% of forecasted peak load, based upon study results structured to ensure that the LOLE reliability criteria of 1 day in 10 years is met. In addition, LSEs are required to acquire sufficient capacity to meet their assigned installed capacity requirement. These capacity requirements may reflect local transmission constraints and other issues. LSEs within the

NY CA can meet their installed capacity requirements through the purchase of qualified capacity from resources within the NYCA or from resources that are located in neighboring control areas directly interconnected to the NYCA. The recall provisions for external resources will impact whether those resources will be qualified to meet the capacity requirements for LSEs.

### 3.4.3 ISO New England

The New England market is another that has undergone transformation due to power supply deregulation. The region was previously a tight pool where utility generation was dispatched to meet load at least cost. Since then, the New England Power Pool (NEPOOL) has opened participation to include independent power producers and the purchasers of utility generation.

The resource planning criterion for NEPOOL in NEPOOL's Planning Procedure directs that

> "Resources will be planned and installed in such a manner that, after due allowance for the factors enumerated below, the probability of disconnecting non-interruptible customers due to resource deficiency, an average, will be no more than once in ten years.
>
> **a.** The possibility that load forecasts may be exceeded due to weather variations.
>
> **b.** Immature and mature equivalent forced outage rates appropriate for generating units of various sizes and types, recognizing partial and full outages.
>
> **c.** Seasonal adjustment of resource capability.
>
> **d.** Proper maintenance requirements.
>
> **e.** Available operating procedures.
>
> **f.** The reliability benefits of interconnections with systems that are not NEPOOL Participants.
>
> **g.** Such other factors as may from time-to-time be appropriate."

As documented in a recently completed report on the NEPOOL installed capacity requirement for the 2004–2005 power year, the system operator, ISO New England (ISO-NE), is required to calculate the total installed capacity that must be available to meet projected daily loads and meet the annual LOLE reliability criterion of 1 day in 10 years. This is the capacity that must be purchased from the capacity market. The procedure utilizes current forced outage rates, maintenance schedules, and incorporates seasonal capacity changes as well as the benefits of ties to Canada and New York.

In using market prices to support a capacity market, ISO-NE has observed that the installed capacity market as currently structured may not provide sufficient capacity when needed. The market structure has not produced sufficient revenue for some of the regional generator owners who have had to turn over assets to lenders or file for bankruptcy. In addition, some of the new generation has been installed where transmission constraints limit the ability to deliver power where needed. This situation has resulted from both inadequate locational price signals and changes in the FERC minimum interconnection standards. As a result, ISO-NE is considering a location-based installed capacity market to address deficiencies in the existing capacity market.

### 3.4.4 Florida

Most of the members of the Florida Reliability Coordinating Council (FRCC) use a deterministic reliability criterion, namely reserve margin. As part of its overall assessment of resource adequacy, FRCC determines reserve margins for both summer and winter, based on system conditions expected at the time of the system peaks for each season. In their calculations of reserve margin, non-firm demand resources (interruptible loads and load management programs) plus supply side resources are compared to firm peak demand.

Progress Energy Florida and Florida Power & Light Company also use LOLE, with a criterion of 0.1 days per year. Effective in 2004, these two utilities and Tampa Electric Company have raised the reserve margin criterion from 15 to 20%. In addition, Seminole Electric Cooperative uses two reliability criteria, a 15% reserve margin and a 1% EUE.

### 3.4.5 Western Electricity Coordinating Council

The Western Electricity Coordinating Council (WECC) is the largest reliability council in the United States in geographical terms, covering essentially all of the western 13 contiguous states plus two Canadian provinces. While reliability criteria are prescribed by many states and regional reliability councils, neither the WECC nor the state of Washington specify an adequacy standard for resource planning. In its 2003 integrated resource plan, Puget Sound Energy, Inc. (PSE) indicated that it considered a range of planning levels for meeting both energy and capacity. With a substantial portion of their existing energy resources based on hydro generation, their planning process needs to consider economic evaluation of both the constraints during prolonged drought periods as well as periods of above average precipitation. If PSE focused only on capacity margin or LOLP, this would likely result in a shortage of energy during low water periods even though there was sufficient installed hydro generating capacity.

In their planning process and IRP analysis, PSE has considered the economic tradeoffs and risks by considering a number of planning levels. In addition, their analysis reflected the need to evaluate resource options from both a capacity and energy perspective.

In contrast, Xcel Energy Inc. (Xcel) had historically utilized WECC Power Supply Design Criteria No. 1 to establish the level of planning reserves for its system. Those criteria indicated that the needed reserve margin was equal to the largest risk (generating unit) plus 5 percent of load. Subsequent to Xcel's 1999 IRP filing, a reserve margin was determined and stipulated to by the Colorado Public Utility Commission that would equate to a LOLE of 1 day in 10 years. In this stipulation, a reserve margin of 13% to 17% was deemed appropriate, with the range designed to take into account load forecast uncertainty and resource development risks. These factors had not been reflected in the analysis to develop a basic reserve margin that would produce the target LOLE of 1 day in 10 years. In its 2004 IRP filing, Xcel has further refined its analysis of the reserve margin necessary to maintain the target LOLE and determined the appropriate value to be in the 16% to 17% range and is using this as the basis for identifying resource needs.

### 3.4.6 Australia

With the establishment of a national market, the National Electricity Code Administrator established the Reliability Panel to determine the appropriate reliability standards. The current structure of this market is an energy-only market. It appears the market has been successful to date, including the development of new investment in generating facilities. At the same time, the reserve trader arrangements that consider reliability levels have been continued as a backstop in the event that future market responses have the potential to reduce power system reliability.

With these standards, the National Electricity Market Management Company could intervene in the market to contract for additional resources to ensure an adequate reliability of supply in the event that there was a failure of the market to meet customer expectations. In this market, the reliability standard has been based upon unserved energy rather than capacity shortage expressed in either reserve margins or LOLE. Their rationale behind this approach is that the reliability standards in a market environment should be focused more towards individual customer reliability. While LOLE measures the number of days (or hours) of load shedding, it does not reflect the magnitude or duration of the deficiency. In contrast, unserved energy indicates the amount of overall customer energy requirements that would not be met over a period of time.

### 3.4.7 Ireland

Ireland has been moving to a fully competitive market and there have been concerns related to whether there would be sufficient generation added to meet demand under changing market structures. As a result, the Transmission System Operator Ireland (TSOI) is required to analyze and prepare a generation adequacy report covering the upcoming 7-year period. The reliability standard is 8 hours loss of load per year as indicated in the latest report, covering the 2004–2010 period. This means that in 8 hours during each year, the available capacity is expected to be less than unrestricted demand. The LOLE calculations used by TSOI do not reflect emergency operational procedures that are used to avoid loss of firm load, such as importing extra power from Northern Ireland or interruptible load shedding. The peak demand estimated for the winter 2004 season is 4,468 MW with available generation of 5,892 MW Their system is relatively isolated, with ties to Northern Ireland capable of delivering about 300 MW in emergencies and contractually providing 167 MW under current normal conditions.

### 3.4.8 Israel

The utility in Israel, the Israel Electric Corporation (IEC), is a vertically integrated utility owned by the government. In 2003, installed capacity of 10,117 MW was available to meet the peak demand of 8,570 MW for an 18.1% reserve margin. With no ties to other countries, IEC's reliability criterion is indicative of the desire to have a reliable supply-side system, with a planning criterion of 2.0 hours per year, with long term intention to increase reliability by reducing the LOLE criterion to 0. 7 hours per year.

### 3.4.9 Italy

The Italian power industry has been gradually restructuring since 1999. Prior to that time, ENEL, the utility that had the responsibility to maintain supply resources, used a ratio of Expected Energy Not Supplied to Demand with the criteria set at $10^{-5}$. Since 1999, several approaches have been taken to provide incentives for maintaining adequate capacity, including a reserve margin payment and an operational reserve. The issue of resource adequacy appears to have played an important role in the nation-wide blackout in the fall of 2003. The European Union (EU) Commission is also concerned with security of supply and the adequacy margin of each generating system. The EU Commission issued a proposal late in 2003 that, among other things, required member states to have a published approach for ensuring a balance between supply and demand including targets for reserve generation capacity.

### 3.4.10 Puerto Rico

The Puerto Rico Electric Power Authority (Authority) is a government owned utility providing service to the entire island. At the present time, there is no pressure for deregulation. Currently the Authority has 5,359 MW of resources to meet a peak load of 3,376 MW, yielding a reserve margin of nearly 59%. Of the Authority-owned generating facilities, there are four units with net capacity over 400 MW each, which in total supplied about 51% of the 2003 system peak. In addition, there are two cogeneration facilities, a coal-fired plant with about 450 MW net capability and a 507 MW net combined cycle plant. In recent years the Authority has made significant capital expenditures to improve reliability of its existing generating facilities. Ten years ago, the equivalent availability ratio was about 60%; with the recent improvements, it is now approaching 80%. Due to its isolated service area and minimal seasonal demand variations coupled with generating units that are large compared to system load, the Authority needs a large reserve margin to maintain reliability. The Authority's current target reserve margin is 45%, down from the 70% maintained in the early 1990s when there were more frequent forced outages.

### 3.4.11 Thailand

The Electricity Generating Authority of Thailand (EGAT) is the principal owner of generation and provides power to two distribution utilities and a number of large industrial sites. This government-owned utility had used reserve margin of 25-30%, but given the prolonged decline in economic activity, there are indications that this may have been reduced to 15%. Total generation in Thailand is over 21,000 MW and the transmission system has limited interconnections with neighboring countries. While there have been attempts by the government to privatize portions of EGAT, those attempts have been met with significant resistance.

### 3.4.12 Korea

As the Korean government has moved towards wholesale competition, the generation sector was removed from state-owned Korea Electric Power Corporation (KEPCO), which owned most of the generation, and divided into six generation subsidiaries. Shortly thereafter, the government prepared a study for an electricity resource baseline plan. In the resulting report prepared in 2002, the electric resource requirements for the 2002–2015 period were determined. These requirements were based on a LOLE of 0.5 days/year with an associated capacity reserve margin of 15–17%. Generation in South Korea currently totals about 56,000 MW. Demand for electricity over the past 30 years has increased at an average rate of about 12% per year, well over the 6.8% average annual growth in real GDP during the same period. Electric rates have risen minimally compared to the overall consumer price index and have contributed to the industrial competitiveness of Korea.

### 3.4.13 Singapore

The electricity wholesale market started operations in 2003, following years of transition from a vertically integrated government utility. The Energy Market Authority (EMA) replaced the Public utilities Board in regulating the electric industry. In its role, the EMA uses a reserve margin for assessing generation adequacy, comparing the projected margins against a 30% target index.

Operating reserves are determined by the power system operator (PSO), and are classified as either primary, secondary, and contingency, where response time is either 8 seconds, 30 seconds, or 10 minutes, respectively. The PSO will determine the reserve capacity needed, recognizing the need to consider the unexpected outage of a scheduled plant.

### 3.4.14 Jamaica

The total capacity of the generating resources on the island of Jamaica that was available to meet the 589 MW peak load in 2003 was 766 MW. These generating facilities include 16 small steam, diesel, and combustion turbine units (the largest of which has a nameplate capacity of 68.5 MW), 23 MW of hydro generation, 4 independent power producer (IPP) contracts and one 120-MW combined cycle plant. Generation expansion requirements are established within the guidelines of the mandated level of reliability to customers as stipulated by Jamaica Public Service's (JPS's) operating license. The reliability criterion for capacity planning purposes is measured as LOLP. Given the current system resource configuration, the 0.55% LOLP criteria will allow the two largest units to be out of service (one on normal maintenance and the second tripped off). For JPS, the reliability requirement will result in a reserve margin of about 25%.

### 3.4.15 United Kingdom

National Grid Company PLC (NGC) was established in 1999 as the owner and operator of the high voltage transmission system in England and Wales and is responsible for balancing supply with demand 24 hours a day. As part of their transmission license, NGC produces a seven-year forward looking statement that presents expected changes in the transmission system, projected loads and expected generating capacity. Within the competitive electricity supply industry in England and Wales, there is no set standard or requirement for planning margin, with the need for new resources determined by market forces. However, as part of the seven-year statement, NGC does determine a calculated reserve margin and compares it to a "notational" 20% reserve margin level that should be reasonable for discussion and presentation purposes. This is lower than the 24% that the Central Electricity Generating Board (CEGB) had previously been using as their capacity planning reserve margin.

NGC also has an operational planning margin requirement, whose purpose is a short term safety margin. This operational margin represents the amount of extra generation that must be available above the projected demand to meet a LOLE of one occasion per year.

### 3.4.16 Nordel

Nordel is an organization to facilitate communication and coordination between the individual transmission system operators (TSOs) in the Nordic countries of Denmark, Finland, Iceland, Norway, and Sweden. Its objective is to create, maintain and enhance an efficient competitive electric market Nordel also serves as a point of contact and forum between the individuals and representatives of the various market participants.

Sweden and Finland de not have any regulations concerning capacity reserves. In Norway there must be sufficient amount of regulating power available above load. Denmark's Electricity Supply Act requires that there must be enough production capacity to meet the estimated national demand plus additional capacity to offset the potential failures of production plants and transmission lines.

The current posture of Nordel is that the market should provide a credible price for electricity and thus the necessary signal for proper decision making by the market participants. The market prices should not be influenced or capped by any intervention that harms the market-oriented approach, even when prices are high. Adequacy should be provided by the market participants so that supply will meet demand and new facilities will be built by the market participants when it is needed. From this perspective, the TSO's responsibility should be limited to the operational hour and necessary operational reserves.

Nordel's position is that if society loses confidence in the participants' ability to provide adequacy, there will be a push towards centralized control and actions. The end result of this could be to create uncertainty among the market participants and potentially have a negative impact on the incentive to invest in new resources.

### 3.4.17 South Africa

South Africa is in the process of restructuring its electric supply industry, moving from a vertically integrated industry dominated by Eskom, the government-owned utility, to an unbundled supply industry with competition in the generation sector. The National Energy Regulator (NER) is the regulatory authority over the electricity supply industry in South Africa.

The NER recently completed a study for the National Integrated Resource Plan (IRP). The focus of this IRP was to optimize the supply-side and demand-side resource mix while ensuring a reliable electric supply and minimizing the cost of power to consumers. The intent of this effort by the NER is to provide an independent source of information and reference for the various decision-makers and stakeholders in order to help insure security of supply. The resulting reference plan presented in the IRP reflects two constraints, a 10% reserve margin, and a maximum EUE of 0.011% of total annual energy demand, based upon Eskom's LOLE criteria of 22 hours per year.

## 3.5 Discussion

Within the ten reliability councils of the United States, four of the councils, MAAC, East Central Area Reliability Coordination Agreement (ECAR), Mid-America Interconnected Network (MAIN), and Northeast Power Coordinating Council (NPCC), use LOLE as their stated planning reliability criteria and indicate that the standard is 1 day in 10 years (or its equivalent). While Electric Reliability Council of Texas (ERCOT), Mid-Continent Area Power Pool (MAPP), and Southwest Power Pool (SPP) use a reserve margin as their stated reliability criteria, they periodically use probability analyses to evaluate if changing conditions would require a revision to that deterministic criterion. This analytical process is generally structured to establish that the values used as the benchmark reserve margin would provide for a LOLE that was equivalent to 1 day in 10 years.

There are no specific criteria that have been prescribed by the WECC. In pert, this recognizes the wide diversity of resources throughout the region. With the large dependence upon hydro power in the northwest and large coal plants in other states in the western United States, the various utilities in the WECC have established their individual criteria appropriate for their situation that are designed to maintain reliability.

In the eastern United States where the wholesale markets are competitive, the general thrust has been to require the LSEs to have or purchase sufficient capacity from the market to maintain a reserve margin that would functionally sustain a LOLE of 1 day in 10 years. Specifically, the Midwest ISO (MISO) uses the 1 day in 10 years LOLE target to establish reserve margins for individual LSEs. The MISO approach considers the resources within each of the LSEs in setting the different reserve margins. In contrast. the PJM market currently uses the same reserve margin for all LSEs to maintain its target LOLE. Within New York State (part of NPCC), each LSE is required to maintain a reserve margin calculated from a study to ensure that the LOLE reliability criteria of 1 day in 10 years is met

As the wholesale markets in more regions of the United States become more competitive, the application of reliability criteria for long range planning will tend to become more difficult. In a competitive environment. there will be less sharing of data including the addition of new facilities and the retirement or mothballing of older units. This will introduce additional risk into the process since there will be less certainty as to the resources that will be available to meet future loads. As a result, there will be a shift to shorter-term planning perspectives, with the focus limited to perhaps three years into the future. With the general trend to requiring load serving entities to acquire sufficient reserves, there will likely be an increasing reliance on resources that can be developed quickly. The current emphasis on combined cycle units and combustion turbines with their short construction period gives the LSE's flexibility in responding to the dynamic marketplace with its changing and competitive aspects.

In summary, the industry standard for reliability criterion for the United States mainland has remained as a LOLE of 1 day in 10 years, even as the electric industry has transitioned from a vertically integrated and regulated environment to a competitive wholesale market. With the planning or evaluation horizon shortened due to reduced free sharing of data and other competitive factors, and the complexity associated with LOLE or other probabilistic methods, reserve margins will find increasing reference, as they are easy to understand and can be readily calculated. However, in the background, the probabilistic procedures will continue to be performed and used as the underpinning of the appropriate reserve margin. The planning reliability criteria for other countries were also reviewed. The results of this process are summarized in Table L-1.

Table L-1. Comparison of Generation Planning Reliability Criteria

| Country | Organization | Criteria Used | Target Index | Comments |
|---|---|---|---|---|
| Australia | National Electricity Code Administrator | Unserved Energy | 0.002% annual energy | |
| China | China Electric Power Institute | Reserve Margin | >20% | |
| England | NGC | Reserve Margin<br>LOLE | 20%<br>1 occasion/year | Reliability assessment<br>Operational planning |
| India | Central Electricity Authority | LOLP | 1% | |
| Ireland | TSO Ireland | LOLE | 8 hours/year | |
| Israel | IEG | LOLE | 2.0 hours/year<br>0.7 hours/year | Through 2010<br>After 2011 |
| Italy | ENEL | EUE | $10^{-5}$ | Pre-1999 industry reform |
| Jamaica | JPS | LOLP | 0.55% | Equivalent LOLE is 48 hours/year |
| Korea | KERI | LOLE | 0.5 days/year | Reserve margin of 15–17% |
| Malaysia | TNB | LOLE | 1 day/year | |
| Puerto Rico | Puerto Rico Electric Power Authority | Reserve Margin | 45% | |
| Saudi Arabia | SCECO East and West | LOLE | 0.2 days/year | |
| Singapore | Energy Market Authority | Reserve Margin | 30% Reliability assessment | |
| South Africa | Eskom | LOLE | 22 hours/year | |
| UAE | Sharjah Electric Company | LOLE | 5 hours/year | Reserve margin of 20% |
| United States | MAAC | LOLE | 1 day/10 years | |
| | ECAR | LOLE | 1 day/10 years | |
| | ERCOT | Reserve Margin | 15% | |
| | FRCC | Reserve Margin | 13.5–22% | Varies by utility |
| | MAIN | LOLE | 0.1 days/year | |
| | MAPP | Reserve Margin | 15% | |
| | NPCC | LOLE | 1 day/10 years | |
| | SPP | Capacity Margin | 16.75% | |
| | MISO | LOLE | 1 day/10 years | |
| | PJM | LOLE | 1 day/10 years | |

With the movement of the supply-side market to a competitive market, there has been a tendency to include some form of price mitigation in most markets during periods of power shortages. The potential impact of these price caps is to reduce the incentives for development of new investments in generation facilities. Therefore, some procedure to reflect resource adequacy is needed to ensure that sufficient resources are developed and available to meet future loads.

At this time, there is no standardized approach that fully addresses the resource adequacy requirement. There has been experience in capacity markets in the United States that suggests a general approach that would support the development of additional resources. This process involves the requirement that load serving entities procure sufficient capacity to meet both their peak load and a pre-determined reserve margin. Those LSEs that fail to procure adequate capacity from the market would be subject to a penalty.

Other approaches that are more market-based focus on (1) ensuring that the spot market clearing price rises in periods of tight supplies to a level that would be set by demand and no higher, (2) including an energy-only market that involves demand bidding and forward markets, and (3) setting rational price caps when the market can't. From pure economic theory, the inclusion of price cap represents an unpredictable intrusion into the market environment such that the economic demand and supply curves are distorted. Various aspects of these approaches have been tried in California as well as in Argentina and Australia.

The Nordel approach is to let the market price be unconstrained and allow the price rise to whatever level is necessary to balance supply and demand. In this environment, during periods of short supply, those facilities with available capacity can benefit from the capacity shortfall and potentially cover their fixed costs. Developers can respond to these predictable situations and make rational decisions on operation and expansion. If the prices that they can charge are limited or subject to unpredictable capping, this uncertainty will dampen their participation in the market. In one recent resource constraint in the Nordel market, prices jumped dramatically. From the economic sense, the market response was appropriate. However, there were numerous complaints on the price spikes, which may signal that there could be political pressure to constrain future price jumps.

As long as the wholesale power markets remain incomplete and imperfectly competitive as they are in most of the United States, there are some advantages to continuing with installed capacity obligations. One is that mandated installed capacity obligations are needed because generation adequacy and system security have public goods attributes. The positive externality associated with generation adequacy benefits not only the owners of the capacity but also society at large. These societal benefits may be large for electricity because of its crucial role in modem society, the difficulty in storing electricity, along with the necessity of balancing supply and loads in real time.

# 4. Planning Reliability Criteria for HECO

## 4.1 Loss of Largest Unit

The first rule used by HECO in evaluating the adequacy of existing resources is whether there is sufficient capacity without the largest unit to meet the system peak load including transmission and distribution system losses. The AES Barber Point facility is currently the largest generating resource on Oahu and has a net capability of 180 MW. This facility represents about 14 percent of the 2003 annual system peak of 1,284 MW. Total generating resources available to HECO in 2003 provided about 1,615 MW, as shown in the Table L-2, and resulted in a reserve margin of 25.8% assuming no interruptible loads.

Table L-2. HECO Resources

| Unit | Net Capacity (MW) |
|---|---|
| Honolulu 8 | 52.9 |
| Honolulu 9 | 54.4 |
| Waiau 3 | 46.2 |
| Waiau 4 | 46.4 |
| Waiau 5 | 54.6 |
| Waiau 6 | 55.6 |
| Waiau 7 | 88.1 |
| Waiau 8 | 88.1 |
| Waiau 9 | 51.9 |
| Waiau 10 | 49.9 |
| Kahe 1 | 88.2 |
| Kahe 2 | 86.3 |
| Kahe 3 | 88.2 |
| Kahe 4 | 89.2 |
| Kahe 5 | 134.7 |
| Kahe 6 | 133.9 |
| H-POWER | 46.0 |
| KPLP CT-1 | 90.0 |
| KPLP CT-2 | 90.0 |
| AES | 180.0 |
| *Total* | *1,614.6* |

Using the methodology of the first rule, and assuming for this discussion that relay-controlled interruptible load is zero, HECO had 1,435 MW of generating resources (excluding AES, the largest unit) to meet a peak load of 1,284 MW in 2003, indicating that the criterion was satisfied at least during the peak period.

If the largest unit was 340 MW (rather than 180 MW) and all of the generating resources still provided the same total net capacity of 1,615 MW, the loss of that largest unit during the peak period would have resulted in a capacity deficiency of about 10 MW. This rule has the effect of discouraging the installation of a single large generating unit (relative to the existing resources) that would serve a significant portion of HECO's system load.

In the months when peak demand is a little lower, maintenance is generally scheduled for all of the units. During February 2003, when the peak demand was 1,141 MW, if Kahe 5 or Kahe 6 were on scheduled maintenance and the AES unit failed, HECO would still have had 1,300 MW available to serve the peak load.

In applying the rule during lighter load months like February, the total available capacity would likely be reduced by units that are out for maintenance. This criterion can be readily used to determine the maximum capacity that can be scheduled out for maintenance at any point in time while allowing for the unscheduled outage of the largest available unit. Given the relatively constant monthly peak loads throughout the year, the use of this criterion on a monthly basis with the maintenance schedule will help to assure that there is sufficient capacity available to meet the expected peak loads.

During system emergencies where system frequency is starting to drop due to a mismatch between generation and load, there may be minimal time for system operators to respond to the situation. While all interruptible loads can be dropped, there may be significant delays between the time that a capacity shortfall is identified, notification to interruptible customers is made, and action is taken. For load disconnection to be effective in sudden system emergencies, only those interruptible loads that can be automatically disconnected can provide an immediate benefit to system stability. The use of under-frequency relays to disconnect these interruptible loads should result in immediate benefit to the system by reducing the load versus supply imbalance. Therefore, HECO's recognition of specific interruptible loads in evaluating resource adequacy is appropriate.

Of the utilities, reliability bodies and regulatory authorities surveyed, there was no mention of the loss of the largest unit as a specific criterion. In most cases, the utilities or regions in question have a much larger peak demand compared to the largest generating unit. Thus this reliability index would not be a limiting factor for them from the reliability perspective. Even in Jamaica, where the system load is less than HECO's, the largest unit represents only 11.6% of the peak load. With their criterion of 0.55% LOLP, JPS acknowledged that this will require sufficient capacity to be installed to allow the loss of the largest unit when the second largest is out for maintenance.

While this criterion does not reflect the relative reliabilities of the generating units 10 the system to indicate system security, it does indicate when the supply resources are not adequate to meet load under reasonably predictable circumstances.

## 4.2 Operational Criteria

The second rule requires that most of the generation from the most heavily loaded unit be able to be picked up within a three second period by all of the other operating resources. This rule is directed towards the operating procedures of HECO to minimize the loss of load due to a forced outage of an operating generator.

The issue of maintaining sufficient operating reserves and maintaining sufficient capacity reserves are closely related. Operating reserves are the first line of defense against major generation outages. Operating reserves are provided by generating units that can readily increase their output to restore balance to the system after a contingency such as the loss of a generator.

A mismatch between generation and load results in frequency deviation. To maintain nominal frequency and respond to sudden changes in supply or load, there needs to be sufficient generating capacity operating and available to meet those additional needs. The amounts of these reserves are related to the system's characteristics and frequency deviation limitations.

The specific parameters of this operational criterion are a function of the behavior of the system and the nature and capability of any interconnected utilities. While quick response reserves for some utilities or TSOs may be the capacity available 5 or 10 seconds after a system disturbance, the resources available to provide that reserve would be spread throughout the interconnected system. The review of the specific parameters, which are particular to the HECO environment. are beyond the scope of this review.

## 4.3 Loss of Load Probability (LOLP)

HECO's reliability guideline is currently at 4.5 years for one day loss of load. While the mainland United States has a higher level of reliability at 10 years for one day loss of load, a number of the island utilities that were reviewed indicate lower reliability levels in terms of LOLE. The National Grid Company which controls about 70 GW of generation in the competitive market of the United Kingdom uses a one occasion per year LOLE. Ireland's electric system, which has a peak demand about four times that of HECO, has a LOLE reliability standard of 8 hours per year. If this were calculated in terms of days per year, the equivalent LOLE value would be about 1.5 days per year. Both England and Ireland have established industry that is dependent on electric power for their economic viability. At the same time, these countries have transitioned to a competitive power supply sector, and, in the case of Ireland, do not recognize the benefit of interruptible load in this calculation.

In certain regards, the island of Jamaica is more comparable with HECO, both in terms of size and regulatory environment. Jamaica's reliability criterion of 0.55% LOLP is equivalent to 48 hours per year. As a result. without considering interruptible loads or load management benefits, the planning process for capacity planning for the electric supply system on Jamaica would appear to result in a system that would be less reliable than HECO's. In part, the lower level of reliability reflects the lower level of economic activity on Jamaica with the associated inability or unwillingness to pay for additional generating resources to improve reserve margins.

As previously discussed, the setting of a target LOLE should be based upon or recognize the cost of increasing capacity to improve reliability against the costs associated with interruption of service. In heavily developed countries with significant industrial load that is dependent on reliable service. the cost of interruptions is likely to be high. These costs include those expenses associated with lost production or the inability to serve customers. inconvenience, and societal costs like civil disorder. Adding resources to increase system reliability will increase electric costs that will be offset by reduced interruption costs. In contrast, in less developed countries with lower industrial activity and lower dependence on electricity for normal activities, there would be a much lower level of costs associated with interruption of electric service. Thus the difference in LOLE criterion levels between Jamaica and the United Kingdom or Ireland is reasonable.

After consideration of the sizes of the generating units relative to the demand levels, the next most critical factor influencing the LOLE calculation is the reliability levels of the various generating units. A system where the equivalent forced outage rates are over 20 percent (this excludes normal scheduled maintenance) for the large units will generally have a high LOLE value unless large reserve margins exist. In Puerto Rico, the equivalent availability for the generating resources in the 1990s had been about 60%; this means that each generating unit was out of service an average of 40% of the year due to forced outages or planned maintenance. While the LOLE values are not available, the utility recognized that a large reserve margin was necessary to maintain reliability and thus had a target reserve margin of 70%. Recently, as the results of significant increases in maintenance at its power plants have been realized through improving generating unit availability, the utility has been able to reduce the target reserve margin to about 45%. In contrast, based on the observed forced outage data for the past 10 years by unit type, HECO's equivalent forced outage rates are under 10% for most units, and for many of its larger units are under 2%. The benefit of these low failure rates is a high likelihood that the generating units will be available when needed. Thus, for a given LOLE level, a lower reserve margin will be appropriate for HECO compared to systems where generating units are less reliable.

While not an island, Israel's electric system is essentially isolated from the neighboring countries. Its current planning criterion is two hours per year LOLE, which is roughly equivalent to one day in three years. Israel's long term objective for capacity planning is to increase the level of reliability to 0.7 hours per year, equivalent to about 1 day in 10 years. Their goal to increase the criteria level over the next several years will improve their security of supply and also will raise costs associated with the increasing generating capacity requirements. The existing electric system in Korea is also isolated and their planning process uses a 0.5 days per year or 1 day in 2 years criterion. Since the growth rate of electric demand has been high and the Korean government has been focused on maintaining low energy costs to enhance its competitive position, the reliability criteria has been maintained at a lower level than other heavily industrialized nations. While both of these are developed countries with security and industrial activity that place a value on the reliability of supply, there is recognition that there are tradeoffs that have been explicitly or implicitly accepted in terms of cost and reliability.

In reviewing the LOLE reliability criterion indicated for other developed countries like UAE and Malaysia, the criteria is for a one day per year LOLE. In contrast, in less developed countries where electric service is not available throughout the country, the planning criterion reflects a LOLE of over four days per year.

## 4.4 Rationale for HECO's Reliability Guideline

The interconnected nature of the mainland United States utilities provides benefits in terms of reserve margins that must be maintained by any utility or ISO. Historically, the reliability criteria that have generally been used for the mainland utilities are based on a LOLE of 1 day in 10 years. Some of the reliability councils are indicating reserve margins as their planning reliability criteria, but acknowledge that the reserve levels should be adequate to provide a 1 day in 10 year LOLE level. As some supply markets, such as PJM, MISO, NE-ISO, and NY ISO, have moved to a competitive environment, the maintenance of supply reliability has been passed onto LSEs in the form of reserve margins that have been developed based on the LOLE criterion of 1 day in 10 years.

The Eastern Interconnected system in the United States has been planned using either directly or indirectly a LOLE of 1 day in 10 years. This standard was developed over time in a process that considered the consumers' costs of increasing reliability and the costs that interruption of service would cause. It can be argued that individual utilities would have different interruption costs, reflecting their industrial customers' needs, level of local economic activity, and other related factors. If this process was used and each individual utility was allowed to set its own LOLE criteria, then neighboring utilities could end up with significantly different reserve margins. The net result of this would be much greater dependence on neighboring utilities for systems with minimal reserves encountering the loss of a generator. With the interconnected nature of the system, this would result in uncompensated and unplanned sharing of other parties' resources; depending upon the state of the system it could also result in failures in adjacent systems or potentially cascading system failure. To ensure fairness and equitable sharing of costs, the reliability criterion is specified at the regional level and is functionally similar throughout the Eastern Interconnected system.

It is readily acknowledged that the reliability of transmission system circuits is much higher than for generating facilities. Recognizing that most United States mainland utilities are well interconnected with neighboring systems, there is access to spinning reserves on other generating resources throughout the interconnected system during an emergency situation. This process has a relatively high probability of success as long as critical transmission interfaces are not over-extended. This ability to share reserves through transmission system interconnections has helped to minimize the costs to any individual utility (through installed capacity reserves) associated with maintaining a high 1 day in 10 years level of supply-side reliability. Thus, while the United States mainland standard is a high level of reliability, a portion of this reliability is provided by the interconnected transmission grid.

Since there are no interconnections for HECO to utilize, its options to maintain high reliability are to increase capacity reserve margins, add small units relative to system load to minimize the impact of one or two unit outages, and minimize forced outage rates for each generating unit. With HECO's current low forced outage rates and the potential cost penalties associated with small units, increasing supply-side reliability on Oahu on a stricter LOLE basis (that is, 10 years for 1 day) would best be accomplished by adding generation sooner than otherwise planned, thereby raising the reserve margin. Since there are no interconnections with HECO, there are no other parties to share the additional reserve capacity costs. Therefore, attempting to attain the highest level of reliability will tend to cost the consumers on Oahu more than those on the mainland.

For relatively isolated systems, where there is little if any dependence upon and interconnection with others, the planning reliability criteria can be developed and established based on its operating environment and conditions. For most of the electric systems that were previously discussed, they are relatively isolated in terms of strong interconnections with neighboring systems. Therefore, they can specify criteria appropriate for their country or region and have little impact on other systems. As previously discussed, those countries that are less developed, have lower standards of living and are less dependent upon electricity for most activities have LOLE levels of more than 1 day per year. Issues such as the cost of power relative to available income, the need for basic necessities, and the way of life would all constrain the amount that consumers would pay for increasing reliability above any nominal level. Without rigorous calculations, the planning process with such low level of reliability would be similar to adding new generation when the load was greater than the installed capacity.

In developed countries with relatively isolated systems where security issues are important, economic activity is dependent on electricity and the standard of living is relatively high, the LOLE levels range from 1.0 to 5.0 years per one day loss of load. Saudi Arabia with relatively high income is at the more reliable end, with Korea and Israel in the mid range at 2.0 to 3.0 years per day, and the lower end including UAE and Ireland. As a state-owned utility, the planning reliability criteria for Israel's utility in the near term may be guided by other government financial issues, since the long range criteria is for a much higher reliability level. The Irish and Korean reliability levels may reflect the nature of the country where heavy industrial requirements am somewhat offset by significant population in rural areas with a lower dependence on reliability of electric power. Oahu can be considered to be urbanized with greater dependence on electricity than Ireland or UAE From this perspective, the reliability guideline used by HECO of 4.5 years per day is reasonable.

For a system that has a low load factor, the utility can strive to make all its capacity resources available during short peak period and easily perform preventative maintenance during the off-peak periods. In contrast, utilities with a high annual load factor, such as HECO's 2003 level of 73.4%, and small fluctuations in monthly peak demands can't concentrate all their maintenance to off-peak periods but must spread it throughout the year. With the relatively constant load levels, the probability of not meeting load on each day of the year would be comparable, whereas a system with a needle-peak would find most of the risk clustered around the peak with almost no chance of failure during the remainder of the year. Thus, as the reserve margin for HECO gets smaller, there is a more constant risk of failure throughout the year. In addition, the effect of the lower reserve margin is an exponential increase in the LOLP value. In order to have the equivalent level of reliability on the system peak day for a high and low load factor utility, the high load factor utility would have to maintain a more reliable system in terms of calculated LOLE per year. Thus HECO's 4.5 years per day guideline is not unreasonable when compered to the other relatively isolated developed countries.

In the 1960s, HECO had undertaken studies to review its planning reliability criteria. These studies recommended increasing the system reliability to a 7 to 10 year range for one day loss of load. The effect of implementing this recommendation would result in the need for additional resources above current plans. In the absence of a recent detailed study to evaluate total costs at varying reliability levels, it would be difficult to recommend that the current reliability guideline be changed. If island security costs increase significantly as a result of a less reliable power supply system, then a more in-depth review of the reliability guideline may be justifiable.

## 4.5 Other Criteria

While none of the surveyed organizations made reference to reliance on interconnections with other utilities, this approach is not appropriate for Hawaii. The expected unserved energy method recognizes the same factors as the LOLP method and also considers the amount of load that will be shed, but is a less utilized approach. While unserved energy does provide useful information and can be used in the IRP process to reflect dependence on other utilities or compare predicted unserved energy between resource portfolios, its use as a reliability measure has not been widely adopted.

# 5. Conclusions

The three elements of the current planning reliability criteria used by HECO reflect its operating environment on Oahu. The first rule is designed to ensure adequate supply in the event of a reasonably foreseeable event the loss of the largest generator. Similarly, the second rule is intended to ensure that the remaining generators can quickly supply the lost generation without severe system imbalance, loss of system frequency, system separation and system collapse. Both are appropriate elements that are needed to ensure that the supply side is adequate to meet the system's needs.

The current reliability guideline of 4.5 years to experience one loss of load day is reasonable for both a regulated vertically integrated utility on Oahu and for a competitive environment should one evolve. While the criterion is less stringent than United States mainland, it is higher than most of the surveyed systems outside the United States The LOLE level appropriate for HECO should be based on the local situation, considering its operating environment with high load factor balanced by the costs of improving reliability with more resources.

While the reliability criterion is lower than the mainland United States, it compares favorably with utilities and regulatory bodies internationally.

# Appendix: Engineering Standard Practice

Section V- Generation Planning
Subsection B. Part 11.1

Subject: Capacity Planning Reliability Criteria for Addition of Generation in HECO Long-Range Expansion Studies

Date: August 18, 1997
Cancels: December 11, 1990

### Summary of Changes from Previous Issue:

1. New capacity planning reliability criteria are based on the following policy statement regarding the treatment of interruptible loads in capacity planning:

   "Future power plant unit additions will not be planned or constructed to serve underfrequency relay-controlled interruptible loads. Such loads will be served by the reserve generating capacity that must be planned, constructed and dispatched in order to provide adequately reliable service for regular rate, firm customers."

2. Generating unit ratings were changed from gross unit capabilities to net unit capabilities.

3. Generating unit emergency ratings were eliminated.

### Definitions

1. Available Unit
   Unit which is capable of providing service, whether or not it is actually in service, regardless of the capacity level that can be provided.

   The following definitions specify how the generating unit kilowatt ratings shall be used in long-range generation expansion studies for determining the requirement dates for generation additions to the HECO system.

2. Normal Gross Capability Rating: ($G_1$, $G_2$, $G_3$, … $G_N$)
   These ratings shall not exceed the generator nameplate maximum KVA rating under any condition.

   a. For applicable steam turbines this is the maximum gross load the unit is capable of carrying continuously on a day-to-day basis with valves wide open, five percent overpressure, normal temperature, and all feed water heaters in service. This is the maximum gross load to which the unit is normally dispatched.

   b. For combustion turbines this is the gross output at the base temperature control capability.

3. Normal Net Capability Rating: ($N_1$, $N_2$, $N_3$, … $N_N$)

   a. For applicable steam turbines this is the maximum net load the unit is capable of carrying continuously on a day-to-day basis with valves wide open, five percent overpressure, normal temperature, and all feed water heaters in service. This is the maximum net load to which the unit is normally dispatched.

   b. For combustion turbines this is the net output at the base temperature control capability.

When purchases of firm capacity are made by HECO from other suppliers, these sources may be represented as generating units with normal gross and net capability ratings determined to be at reasonable levels which are consistent with the intent of these definitions.

### Generation Addition Rules

New generation will be added to prevent the violation of any one of the rules listed below. Available units include available HECO and firm capacity supplier units.

1. The sum of the normal net capability ratings of all available units minus the normal net capability rating of the largest available unit must be equal to or greater than the system peak load (as measured at the high-voltage side of the generator step-up transformers, that is, before T&D losses) to be supplied at 60 Hz, minus the total amount of underfrequency relay-controlled interruptible loads.

$$\sum_{i=1}^{n} N_i - N_L \geq \text{System Net Peak Load} - \text{Interruptible Load}$$

   where $N_L$ = normal net capability rating of largest available unit.

2. There must be enough net generation running in economic dispatch so that the sum of the three second quick load pickup power available from all running units, not including the most heavily loaded unit, plus the net loads of all other running units must equal or exceed 95 percent of the hourly system net load (which excludes power plant auxiliary loads but includes T&D losses). This is based on a minimum allowable system frequency of 58.5 Hz and assumes a 2 percent reduction in load for each 1 percent reduction in frequency.

The preceding rules apply to capacity planning in long-range generation expansion studies. The actual commercial operation date for the next unit to be added shall be determined using these rules as guides, with due consideration given to short-term operating conditions, equipment procurement, construction and financial constraints.

### Generation Reliability Guideline

Capacity planning analysis will include a calculation of risk (Loss of Load Probability) in years per day for each year of each plan of the long-range expansion study. In cases where risk is calculated to be less than 4.5 years per day, the plan will be reviewed by the Vice President of Power Supply and the President for approval of use of the plan in the study. Calculations of risk will utilize normal net capability ratings ($N_1$, $N_2$, $N_3$, … $N_N$)

Approved: Tom Joaquin, Vice President, Power Supply
Hawaiian Electric Company, Inc.

T. Michael May, President & Chief Executive Officer,
Hawaiian Electric Company, Inc

# Appendix M: Strategist Integrated Planning System

The Companies use the Strategist model the industry standard software for integrated resource planning for nearly 30 years, to perform the analysis required to produce the IRP report. The Strategist Dynamic Programming Algorithm described in this Appendix, generates and evaluates resource plans as well as the economics of resource alternatives.

# CONTENTS

# FIGURES

# Introduction

Strategist, a computer software system developed by NewEnergy Associates (since acquired by Ventyx), supports gas, water, and electric utility corporate strategic planning and utility decision analysis especially surrounding integrated resource planning.

The system combines quality planning software, a proven track record, Ventyx's commitment to ongoing maintenance and support, comprehensive user documentation (online help), and fast response to client needs. Strategist is available as a strategic marketing analysis system, as a least cost resource optimization system, as a comprehensive planning tool for quick evaluation of hundreds of alternatives, as a finance and rates planning system and as selected application modules that complement planning capabilities already in place. Strategist can also be used to screen demand and supply-side resources, develop candidate resource plans, and conduct sensitivity analyses.

Strategist incorporates several modules, each designed for a specific application.

- Load Forecast Adjustment (LFA)
- Differential Cost Effectiveness (DCE)
- Dynamic Marketing Program Design (DPD)
- Generation and Fuel (GAF)
  Available with "Multi Company" and Network Economy Interchange (NEI)
- Capital Expenditure and Recovery (CER)
- Class Revenue (CRM)
- Holding Company (HCM)
- Financial Reporting and Analysis (FIR)
- PROVIEW (PRV)

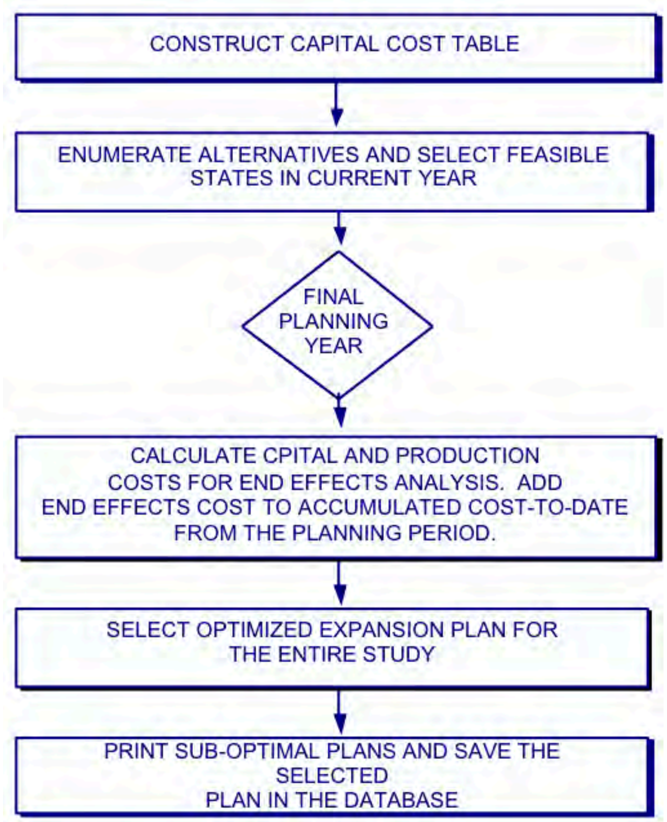
HECO utilized three Strategist modules:

- Load Forecast Adjustment (LFA
- Generation and Fuel (GAF)
- PROVIEW (PRV)

A flexible control system ties the application modules together and automates data transfer from one module to another. To interface with the Strategist database containing all inputs and outputs, a user may rely completely on the User Interface (UI) or utilize the control system batch command language. Strategist's UI adds full-screen spreadsheet data entry/edit capability, on-line documentation, graphic display of data, program execution, and reporting. With either the UI or the batch command language, it is easy to change selected inputs, run the application modules, and display results.

Figure M-1 outlines the structure of Strategist.

Figure M-1. Dynamic Programming Option




## Strategist: Evolution of the Industry Leader

Strategist is fully supported by the technical and consulting services of New Energy Associates, LLC. Strategist is an evolving product, enhanced and upgraded continuously. The Strategist system of today is not the PROSCREEN II system of just two years ago.

PROSCREEN II/Strategist's development since 1982 has proceeded in lockstep with that of the industry. In its earliest versions, PROSCREEN II was well suited for engineering, economic, and rudimentary financial analysis of central generating station alternatives. It was a major advance from then prevailing practices because financial consequences and constraints of resource decisions were an integral part of analysis. This advance allowed utilities to make the difficult decisions to cancel nuclear units or postpone base load additions on the basis of severe financial risk and strain.

In the early 1980s, PROSCREEN II added a comprehensive and integrated financial model, to represent the creative financing methods utilities required when faced with the period's record-high interest rates. PROSCREEN II's financial model was further enhanced to address the requirements of the 1986 Tax Reform Act.

In response to the competitive pressures many utilities faced in the 1980s, PROSCREEN II incorporated dynamic cost allocation and class-by-class revenue analysis capabilities.

In the late 1980s, Ventyx's optimization experts developed PROVIEW, adding the ability to simultaneously optimize supply and demand-side alternatives, a major step forward in integrated resource planning.

To address the industry need for fast, dynamic evaluation of demand-side management (DSM) measures, Ventyx added Differential Cost Effectiveness Module (DCE), a dynamic and detailed DSM analysis tool. Recent DCE enhancements have made it a powerful tool in the new, competitive utility environment. These include differential financial results, useful in customer profitability and retention analysis, and periodic avoided cost reporting, for determining how a utility's energy and capacity costs vary by time of day and season.

In 1990, PROSCREEN II's Generation and Fuel Module was enhanced by the addition of emissions reporting and dispatch, allowing full evaluation of compliance planning strategies to meet the Clean Air Act.

Ventyx added the Network Economy Interchange capability to PROSCREEN II to help utilities address the new issues related to competition brought about by the Energy Policy Act of 1992. And as utilities approach a competitive industry and consider restructuring options, PROSCREEN II's Holding Company Module simplifies and automates the evaluation of regulated and non-regulated Strategic Business Units (SBUs).

The PROSCREEN II User Interface (UI) was introduced to PC users in early 1992 addressing the industry need to evaluate and present the results of many options under numerous conditions in a quick and organized manner. The Strategist User Interface (UI) was unveiled in 1999 to provide for easier data input, organization, and reporting. The Windows-like feel of the interface allows users to quickly link data directly to Excel using Formula Service, organize and view data in Topics, and take advantage of customized reporting in Report Agent.

Currently, there are 10 full-time professionals dedicated to serving a growing Strategist client base of over 50 utilities. The Strategist system will continue to evolve and improve to meet the changing needs of a changing industry. The result will be continued unparalleled capability for utility planning.

## General Description

Strategist's advantage as an integrated planning system is its strength in all functional areas of utility planning. Strategist allows analysts to address all aspects of an integrated planning study at the depth and accuracy level required for informed decisions. Hourly chronological load patterns are recognized. Production cost simulations are comprehensive, yet fast. Financial analyses are accurate and thorough. Rate-level determinations reflect each utility's customer class definition and cost-of-service allocation factors. The system employs dynamic programming to develop optimal portfolios of resources. Sophisticated screening methodologies are available to develop and refine strategic marketing initiatives, identify market potential, and build portfolios of initiatives.

In Strategist, integrated resource screening and optimization is accomplished within a single system that handles strategic marketing programs, production costing, environmental reporting, capital budgeting, and financial, tax, and revenue forecasts on a rate class basis. Using a single, integrated software system for demand- and supply-side analysis of all resource types makes these studies much more manageable, ensures consistency in data assumptions, and provides credible, auditable results.

With Strategist, utility management can examine many more options in a shorter period of time. The system has been designed to streamline the many steps in a comprehensive integrated planning effort and to handle the mechanics. This minimizes human error, inconsistencies, and repetitive data entry. For instance, if a combustion turbine's in-service date is delayed in the optimization program, the new in-service date is automatically specified to the production costing module as well as the capital budgeting and financial modules. The module also performs year-by-year "round robin" processing in order to appropriately address price elasticity.

Strategist provides a wide variety of standard reports ranging from unit by unit generating statistics to construction project accounting reports to comprehensive pro forma financial results. The system includes full input summaries and detailed diagnostics.

## Diversity of Client Base and of Applications

Over 50 utilities now rely on Strategist for integrated corporate strategic planning. These utilities have diverse systems, demands, and organizational structures. Users include investor-owned, municipal, government and cooperative utilities and range in size from very large (24,000 MW) to very small (less than 50 MW) electric utilities, as well as gas and water utilities. The financial modules of Strategist have been specifically designed to address the need of public power organizations, municipals, and cooperatives.

These utilities rely on Strategist for a broad range of applications within the framework of integrated corporate strategic planning.

Selected applications include:

- Marketing Program Evaluation
- Promotional Rates Assessment
- Competitive Bid Evaluation
- Customer Retention Analysis
- Demand-Side Management Program Development and Evaluation
- Price Elasticity Impact
- Integrated Demand/Supply Least Cost Resource Planning
- Analysis of Environmental Regulations
- Environmental Compliance Planning
- Financial Feasibility of Construction Programs
- Capital Asset Repositioning
- Corporate Restructuring
- Diversification
- Merger and Acquisition Analysis
- Competitive Analysis
- Financial Forecasts
- Impact of New Legislation
- Scenario Risk Analysis
- Decision Analysis Risk Assessment

## Full Range of Evaluation Criteria

Strategist provides a full range of evaluation criteria so that every aspect of a plan can be assessed:

| | |
|---|---|
| Rates | Average Class Prices — Base and Fuel<br>Class Rate Increases — Base and Fuel |
| Economics | Present Worth of Revenue Requirements<br>Marginal Energy Costs<br>Marginal Capacity Costs |
| Reliability/Operations | Reserve Margin<br>Emergency Energy<br>Loss of Load Hours<br>Fuel and Capacity Mix<br>Load Diversity |

| | |
|---|---|
| Financial Integrity | External Financing<br>Interest Coverage Ratios<br>Quality of Earnings<br>Economic Value Added<br>Internal Generation of Funds<br>Capital Structure |
| Customer Impact | No Losers<br>Cross Subsidies<br>Program Participants |
| Societal Impact | Total Resource Cost<br>Customer Costs<br>Consumer Value<br>Environmental Externalties |
| Shareholder Impact | Return on Common Equity<br>Earnings Per Share<br>Common Dividends<br>Dividend Yield<br>Shareholder Value |

## Modular Structure

Analysts use the individual modules of Strategist to develop an understanding of specific areas of interest (for example, power system operation or rate level determination) as well as for complete integrated planning.

The configuration of a Strategist installation varies, depending on each user's applications, data availability, and staff resources. Many utilities rely on the entire system for strategic, corporate, and integrated planning. A common "subset" configuration is one designed for system planning without refined financial and rate capabilities. PROVIEW, DCE, the Load Forecast Adjustment Module, the Generation and Fuel Module, and PROVIEW Resource Optimization comprise this configuration. Other utilities utilize the financial components and rely on PROMOD IV for production costing. This configuration commonly includes the Capital Expenditure and Recovery Module, the Financial Reporting and Analysis Module, the Class Revenue Module, and Holding Company. Many utility companies which started with one or the other of these configurations have migrated to the full integrated system.

The modules comprising the entire Strategist system are discussed in detail in the following sections.

# Operating Environment

Strategist is available for PC installation with 32-bit versions for Windows 9x, Windows NT 4.0, Windows 2000, Windows XP, and later.

As a strategic planning tool designed to address top management issues, Strategist offers maximum ease of use. The system is meant to be used by an analyst whose expertise is in utility planning and not in software development or programming.

## User Interface (UI)

The Strategist User Interface (UI) allows the user to easily generate new or access old datasets, edit data, run the modules of Strategist, and report results. Data may be directly linked to a Strategist data grid using Formula Service; thus changes to data may be automatically updated in the model. In addition, with New Energy Report Agent, customized results may be quickly sent from Strategist to Excel, Access, Lotus, or an independent HTML page. These features allow the user to easily perform a complete study from beginning to end.

Additional User Interface features include:

- Record and Run Macro
- Standard and Customized Reporting
- Comments for Data Documentation
- Custom Topics
- Copy, Paste, and Undo
- Three Dimensional Data Viewing
- New Energy Pivot Cube
- ProNavigator to View File Structure

## Control System

The other option for interfacing with the modules and database, the Strategist Control System, is a flexible interface which uses a set of English-language line commands to access the system. The user can request output results on a year-by-year basis and change input data assumptions during any year within the study interval for which a Strategist module run is made.

An Execute Command Facility enables users to batch Strategist commands together and execute them with a single command in an interactive session.

The Operating System Bridge allows the user to issue operating system commands from within Strategist's interactive environment. The system allows the user to edit files on-line during the Strategist session without having to exit into the host operating system.

## Reporting

Strategist provides numerous standard output reports, an Input Summary for each application module and diagnostic reports.

## Strategist Data Transfer

Strategist modules automatically communicate with each other. This means that a user can run the entire system without manually transferring key outputs from one module (for example, production costs from Generation and Fuel) to another module (for example, Financial Reporting and Analysis). There are also built-in features that allow changes in prices for customer classes to be automatically fed back to the Load Forecast Adjustment Module for price elasticity calculations. Initial loading of data into Strategist is through a fixed format input file similar to that used by Ventyx PROMOD IV or the data spreadsheets.

Strategist operates with a single database for all modules. Once the database is set up, the user can load the data into Strategist with a single command. The data exists separately from the system so that a single session can include use of numerous databases or alternative versions of a single database.

Data is referred to by name through an easy-to-use hierarchy which substantially eases the user's access of data. The first order of the hierarchy is by module (FIR, CER, etc.), followed by data type (INPUT, OUTPUT), followed by an additional qualifier appropriate to the particular characteristics of each module. Each data item has a unique name which can be accessed by typing any unique abbreviation for the data name. Full descriptions of all data items are available in an on-line data directory.

Finally, Strategist provides complete documentation and support for user customization through a "User Subroutine" feature. All Strategist database variables are available for company specific logic within the code.

# Load Forecast Adjustment Module (LFA)

The Load Forecast Adjustment (LFA) Module is a multi-purpose tool for creating and modifying load forecasts and evaluating marketing and conservation programs. Using the LFA, a strategic planner may address key issues related to future electricity or gas demand and impacts attributed to each customer group. Results from this analysis can be automatically transferred to other Strategist modules to determine production costs, system reliability, cost-effectiveness of marketing initiatives, financing and revenue requirements, and a variety of other indicators affected by loads.

Because availability of load data is often limited, the LFA is designed to process data at the level of detail readily available. Load data is processed in the LFA by user-defined load groups. It is possible to define these load groups as very detailed or very summary in scope. The LFA categorizes group data based on availability of hourly load shapes. Customer groups for which shapes are not available are processed differently than those with shapes.

A key feature of the LFA is its ability to accommodate different levels of detail for different categories of load. If load shapes are unavailable or not needed for some customer groups, the user can easily organize the data to allow the LFA to approximate the missing information. For example, a study which analyzes the loss of a large industrial customer may need detailed modeling of only those rate classes affected by the reallocation of costs. Hourly load shapes could be entered for these classes, and the user need only enter peak, energy, and coincidence factors for any remaining classes.

The analysis of programs which lack historic data, such as new demand-side technologies, will also benefit from the LFA's unique features. For example, a relamping program may be quickly modeled with estimates of energy savings per customer and reductions in peak demand. The model then schedules the hourly impact of these programs based upon optional rules specified by the user. Conversely, the evaluation of programs such as direct control of end-use loads (DLC hardware) can be based on more detailed data such as estimated net changes in seasonal demand, energy, and hourly customer shapes.

The LFA Module calculates the impact of changing prices on the initial forecast. When processing in round robin mode, the modified load forecast is passed to the Generation and Fuel (GAF) Module for production costing and to the Financial Reporting and Analysis (FIR) Module for financial analysis. The new electric prices developed in the FIR are then used for further price impacts in subsequent years of the Strategist simulation.

The LFA Module may be used in conjunction with the Differential Cost Effectiveness (DCE) Module, PROVIEW and other Strategist modules to evaluate marketing and conservation programs. The recommended process for evaluating these programs includes three separate stages: screening, integrated demand/supply optimization, and detailed analysis. The process can be likened to a funnel, as depicted in Figure M-2. The LFA Module plays an important role in each of these stages.

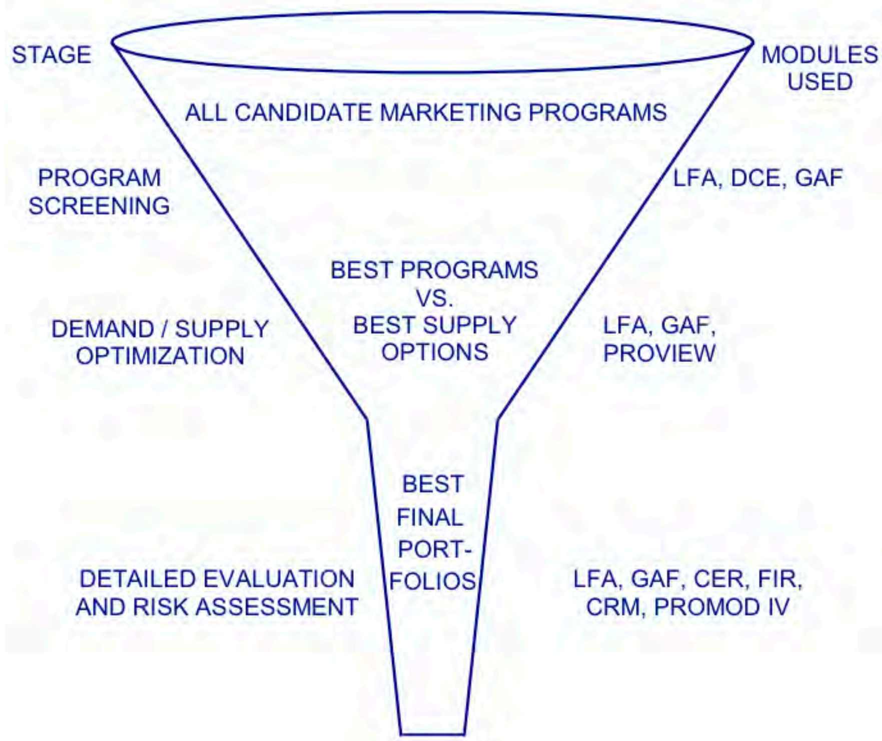
*Screening* of marketing initiatives is accomplished through use of the LFA Module in conjunction with the DCE and GAF Modules. Programs in the LFA Module database are evaluated one at a time and are ranked based on cost effectiveness measures from the following perspectives: utility, participant, community (total resource), society, typical consumer (RIM), and any user-defined benefit/cost measures. Capacity deferral costs or benefits are calculated using the capacity credit logic in the LFA and/or the reliability/reserve margin equalization logic in the GAF. Energy benefits or costs are calculated with a separate GAF production cost run for each program.

The cost effectiveness measures calculated in the initial screening of marketing alternatives will result in a multi-objective decision space. DCE pivots off this accumulated information and develops packages of alternatives which may be used as discrete levels of investment, energy, or peak demand impact that may compete against supply-side options in a fully integrated resource optimization.

Integrated *optimization* of marketing programs may be accomplished by the LFA Module in conjunction with the GAF Module and PROVIEW. LFA load groups representing marketing initiatives are identified as explicit options in PROVIEW along with supply options. The optimal mix of demand and supply options is developed using PROVIEW's dynamic programming capability. Several load groups may be easily combined into a single PROVIEW alternative if desired. In addition to the optimal plan, PROVIEW develops multiple suboptimal portfolios for further analysis.

The user also has available the same inputs to examine alternate marketing program penetrations. These "penetration factor" inputs make it easy to examine in detail the production, financial, and rate impacts of specific programs.

Figure M-2. Recommended Marketing Initiative Evaluation Methodology



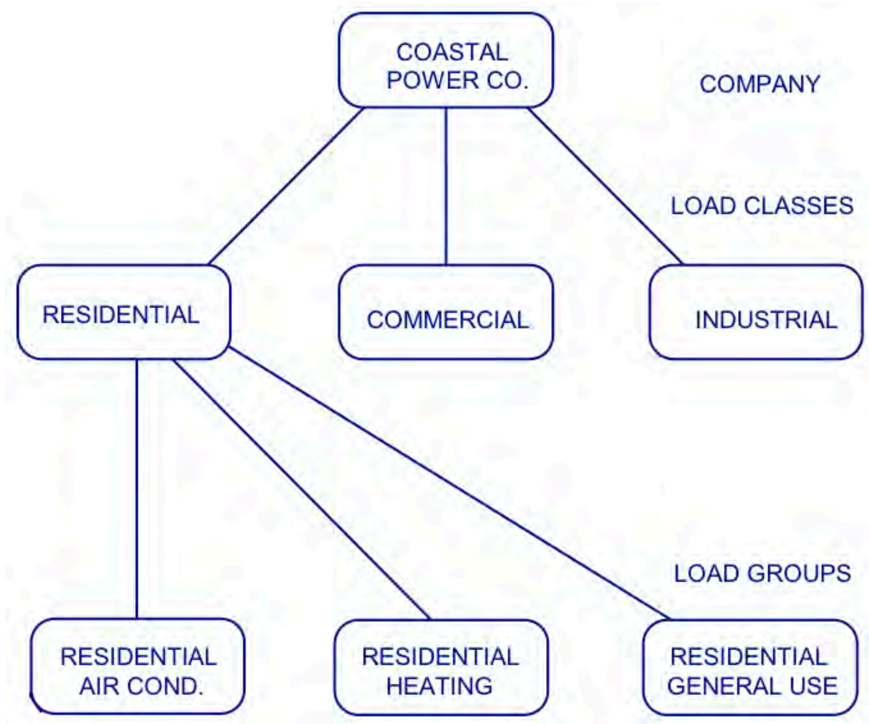

## General Capabilities

- The module provides a comprehensive demand-side program evaluation capability, with inputs for program cost, load impact, timing, and capital costs.
- Load impacts may be input chronologically for each program, or may be determined by the module based on inputs for peak, energy, and program type.
- The module, in conjunction with the GAF Module, provides for the dispatch of Direct Load Control (DLC). The module develops the data for DLC, including the characteristics of the underlying load to be controlled, the contribution of the DLC capacity to system reserves, the minimum savings required before DLC is dispatched economically, and the constraints to DLC operation. DLC is dispatched in the GAF according to an economic decision rule both to reduce peak and to maintain reliability.
- Load shape data may be supplied in detail if data is available or at an aggregate level for those groups which do not have adequate load shape data. The LFA Module thus allows the user to quickly develop a load shape projection for the company and system total, but gradually expand the detail of modeling as data availability increases.

- Load data can be defined in varying levels of detail. The degree of data aggregation is determined by the user. Any number of data groups may be specified. Data groups are summed to class totals. Class totals are summed to company totals. Data groups may correspond to end-uses, rate categories, customer categories, class totals, or even company totals.
- MWH data may be input seasonally or annually. If the user desires, the MWH for each season may be specified as a percent of the annual value. Peak load in MW or as a load factor may be input. If peak loads are not input for a group, peak is determined from input load profiles.
- End-use or DSM load shapes are determined from a variety of input formats. The user may enter a typical week profile directly for each season; enter typical daily load shapes and the frequency that each load shape occurs; or enter typical weekday, weekend day, and peak day load profiles. An EEI format preprocessor is part of the system. DSM programs can be specified as load impact "after" the program or as a combined "before and after" input.
- Class load profiles are computed to determine class peak and company load profile and peak demand.
- Load can also be calculated by region or area. This is used directly by PROMOD IV.
- Most calculations are performed seasonally, where seasons are defined by the number of seasons and number of days in each season.
- The module provides a mechanism to reconcile the electric price assumption underlying the load forecast and the electric price resulting from the Strategist simulation. This mechanism is intended to reflect a company's existing load forecasting process.
- Price response can be specified in a flexible manner. The LFA Module allows a variable lag structure input with lag coefficients specified for as many as ten prior years.
- Block energy rates, block demand rates, time of use rates, seasonal demand rates, and seasonal customer rates can be modeled to determine revenue by load class. These revenue values are passed to the DPD module and the FIR module.
- Results are reported by end-use group, by class, and by company.
- Numerous diagnostics supplement the standard reports.
- The LFA Module interfaces with PROMOD IV and therefore guarantees that load and DSM programs are treated in a manner consistent with Strategist.

Figure M-3 provides a general overview of the LFA Module.

Figure M-3. Sample Load Forecast Adjustment Module Database




## Module Methodology

The LFA Module allows the user to create electric company load forecasts to be transferred to the GAF Module for production costing purposes. The LFA processes the components of company load at a class and group level, where load groups sum to load classes and load classes sum to total company load. The contribution of class loads to company load also provides important transfer information for use in the Class Revenue Module (CRM) of Strategist. In addition to the company load and class transfers, the LFA provides estimates of total marketing program costs and customer costs for use in the CER, FIR, and PROVIEW Modules.

Company peak, energy, and load shape are developed for each season defined in the Strategist database. Seasons are identified by the number of days in each season. A user-defined number of seasons may be modeled, the maximum being defined at the time of the Strategist delivery. Each season's load shape is represented by a chronological 168-hour load profile called a typical weekly profile.

Data is entered at the group level and consists of a seasonal forecast of noncoincident peak, sales, and a typical weekly shape. This shape may be input as a typical week or the profile can be built from a library of typical daily load shapes; or the profile can be built from a library of typical weekdays, weekend days, and peak days; or this profile may be processed from EEI data.

Costs (benefits) associated with marketing initiatives may be provided explicitly for each program, including fixed, variable and one-time implementation costs (benefits) for both the utility as well as the customer. The following marketing program expenses, customer costs and benefits may be modeled:

- Customer Fixed Costs
- New Participants One-Time Costs
- Customer Variable Costs
- Utility Fixed Expense
- Utility New Participants Expense
- Utility Variable Expense
- New Participants Incentive Payment
- Variable Incentive Payment
- Fuel Switch Savings (Costs)
- New Participants External Costs (Benefits)
- Variable External Costs (Benefits)

The shape impacts of marketing programs may be specified or a variety of automated system load inputs may be specified. Automated inputs include:

- Peak Shave
- Unscheduled Reduction
- Peak Build
- Unscheduled Build
- Valley Build
- Valley Shave
- Percent Conservation
- Percent Growth

Dispatchable direct load control (DLC) programs may be evaluated in conjunction with the GAF Module. Strategist's DLC algorithm links the LFA and GAF Modules allowing dispatch decisions for DLC to benefit from the commitment, outage, and cost information available in the generating unit logic while retaining the chronology of load information. Loads available for control are developed in the LFA as well as a number of inputs associated with the description of payback and contractual use limitations (daily, monthly, and yearly for both hours and events). Each load group with load available for control is passed to the production costing module and evaluated against the expected marginal operating costs that would be experienced had no load control been available.

The LFA Module first develops energy sales and peak demand for each load group by multiplying the inputs by a user-defined penetration factor (less persistence) and by adjusting for price elasticity impacts. For groups which have shape data input, the LFA compares the load factor of the group shape to the implied load factor in the group peak and sales forecast. Any discrepancy is eliminated by modifying the load profile. Finally, the module develops the group requirements shape by scaling the sales shape by the user input group loss factor for the season.

Once each group has been processed, the hourly profiles are summed to create class load profiles and the class profiles are in turn summed to produce total company loads which are transferred to the GAF Module.

In many instances, peak, energy, and profile data requirements cannot be obtained for every load group represented in the database. In such cases the module will allow the following combinations of minimum data inputs:

1. *Load shape and sales forecast.*
   Noncoincident peak will be calculated by fitting the given energy under the given shape.

2. *Load shape and noncoincident peak.*
   Sales will be developed for each hour by multiplying the normalized shape against the input peak.

In the event that an hourly profile is unavailable for an input load group, the user has the ability to input peak, sales, and a coincidence factor for the load group. The user must also input an aggregate company shape representing the load profile of all groups for which hourly profile data is not entered, plus any other groups with hourly profile data which the user may wish to include in the aggregate shape. The module will first process all groups and classes which are included in the aggregate shape and which have a defined load shape. It will subtract the sum of these given load profiles from the input aggregate load profile. The resulting "residual" shape is assumed to be associated with all of the load groups for which shape information was not provided.

The LFA user also has the option of having the model calculate the impact of changing prices on the initial load forecast. This is accomplished by having the user input the base prices assumed in the initial load forecast, as well as the peak and energy elasticity coefficients for each load group modeled. Elasticity can be performed at either the average system price level or at the load class level with the alternate prices either being input directly by the user or being transferred from the FIR/CRM Module. The latter option requires the use of the round robin processing methodology.

When calculating the impacts of price elasticity, the LFA evaluates the impact of changing price on each individual load group before summing the modified profiles to the class and company level. Only the adjusted load is passed on to the GAF Module.

For combination electric and gas utilities that use Class Revenue, the gas sales forecast may be housed in the LFA Module for later use in the classification, allocation and revenue requirement calculations.

## Module Results

The LFA Module produces the following *Reports*:

- Input Summary by Data Qualifier
- Hourly Load Shape Report
- System Report
- Class Sales
- Class Requirements
- Class Detail
- Group Detail

In addition to standard output reports, diagnostics are provided to allow for detailed evaluation of LFA Module processing results. These *Diagnostics* include:

- Group, Class & Company Seasonal Peak and Energy Results
- Group Requirements Seasonal Shapes
- Class Requirements Seasonal Shapes
- Company Requirements Seasonal Shapes
- Group Seasonal Load Shape
- Block Rate Revenue Calculations
- Aggregation Table
- Adjustment Shape
- Aggregate Shape
- Residual Shape
- Change Commands for Coincidence Factors
- Write PROMOD IV LLIB and LDAT records to Interface File
- Weighted Average Price Calculations
- DSM Program Calculations
- Write Adjusted Load Group LLIB Cards
- Write Strategist LLIB, GRSL, GRYR Records
- DSM Program Summary

## The EEI Processor

As an alternative to creating load shapes and/or usage patterns outside the Strategist, users may use the built-in processor to process historical load data into a compressed format representing the original data.

The EEI processor develops either typical week representations for load shape modeling. For example, a user may wish to model an end-use load for water heaters in a particular segment of the market. The processor will automatically read a file in EEI format consisting of 8760 water heater load values for a particular year. The result of this processing is the creation of a typical week for each user-defined season. Another application of the processor is creation of typical weeks for a system load shape to transfer immediately to the LFA Module. The processor can either fill DPD use patterns or LFA load shapes.

# Generation And Fuel Module (GAF)

The Generation and Fuel (GAF) Module simulates power system operation using proven probabilistic methods. It provides production costs and generation reliability measures that are essential to supply and demand planning. The GAF Module fulfills a strategic planning role in that it requires less computer resources than more detailed production costing modules, without sacrificing overall accuracy.

## General Capabilities

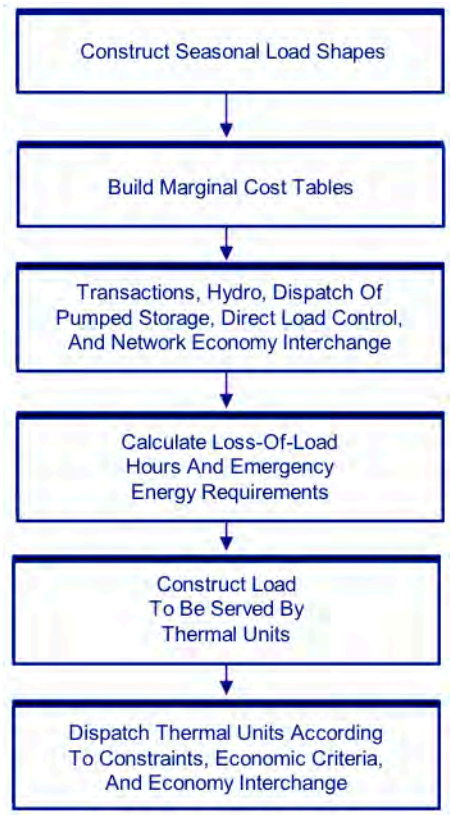
- The GAF Module uses probabilistic production costing techniques to simulate the effects of forced outages.
- Most module calculations are performed seasonally, where seasons are defined by number of seasons and by number of days per season.
- Sales, purchases, and hydro generation are accounted for on a seasonal basis.
- The user can explicitly define an hour-by-hour schedule for a transaction or simply specify when the transaction tends to occur (during peak load hours, low load hours, or randomly) and the GAF will schedule the transaction appropriately.
- Thermal generating units are represented by capacity segments; each segment may have a distinct heat rate, which may be input as average, incremental, or coefficients of a quadratic input/output equation. Availability is defined for the entire unit; a partial availability may also be input to represent times when a unit may only operate at minimum capacity. The units which are classified as must-run are committed first, followed by enough other units to satisfy a user-input commitment criterion. The remaining units are committed on an economic start-up and dispatch basis, subject to fuel limits and spinning reserve requirements.
- The dispatch of thermal units and economy energy may be performed on a seasonal or annual basis.
- Pumped hydro projects and direct load control programs are economically dispatched on a seasonal basis, based on marginal cost. (Direct load control programs may be modeled only if the LFA Module is licensed.)
- Units are dispatched to conform to upper and lower limitations on fuel usage.
- Unit dispatch is performed on an “as burned” or replacement cost of fuel basis.

- Unit, company and system emissions are calculated based on actual runtimes and fuel usage. Emissions allowances are purchased or sold on the basis of system performance and the inputs for allowance cost and allowance base for each effluent. The cost of allowances is reflected in the dispatch lambda used in dispatch order decisions.
- Environmental externalities are calculated for emissions, emergency energy, and direct load control.
- Multi-company dispatch with interchange accounting for holding companies or power pool simulation is provided.
- Numerous diagnostic reports which document detailed calculations are provided.

## Production Costing Methodology for the GAF Module

Figure M-4 presents the general design of the GAF Module. As shown, the production costing procedure consists of two stages. In the first stage, the operation of hydro generation and sale and purchase transactions are simulated. The pumped storage facilities and direct load control programs are then economically dispatched based on the constructed marginal cost curve of the system. The result of this first stage is the remaining annual or seasonal thermal load duration curve. In the second stage, the expected operation of the thermal generating units within the year is simulated by a probabilistic technique. The results are the production costs and system reliability indices.

Figure M-4. Overview of the Generation and Fuel Module




## Dispatch of Non-Thermal Resources

System load data is passed in the form of a typical 168-hour weekly load shape to the GAF from the LFA Module. Then, the dispatch of non-thermal resources is performed. The user may specify the order in which these resources are dispatched, or use the following default order:

1. The transactions (sales or purchases) that are input in the form of hourly values for each season are added to (in the case of sales) or subtracted from (in the case of purchases) the chronological load curves.

The transactions that are characterized by seasonal capacity and energy are scheduled. For each sale transaction, the user chooses whether the sale is a valley fill or peak build sale, or is to be applied uniformly to the load curves. For each purchase transaction, the user chooses whether the purchase is a peak shave or valley reduction purchase, or is to be applied uniformly to the load curves.

2. The hydro generating units are dispatched one at a time. Each hydro unit has a minimum (must-run) MW capacity, a maximum MW capacity, and a total energy (MWH) for the season. The remaining load, after steps 1 and 2, is first modified by subtracting from it the minimum hydro generation for every hour. The remaining hydro energy is used for peak shaving. This peak-shaving energy is calculated by subtracting the minimum hydro generation from the total hydro energy. The peak-shaving capacity is the difference between the maximum MW capacity and the minimum MW capacity of the unit.

3. Pumped storage hydro is scheduled. Storage dispatch is based on the expected generation cost at each hour before storage, pond storage limitations, cycle efficiency, and minimum savings. The storage algorithm works from highest cost hour down for generation and from lowest cost hour up for pumping, reducing the remaining load at high cost hours and increasing the load at low cost hours. This process is performed subject to the minimum savings and pond limit constraints. An option is available for the capacity of storage not used for economic reasons to be used for reliability purposes.

4. Direct load control devices are scheduled. The LFA Module provides information on underlying loads that are available for control and DLC dispatch parameters. All DLC devices are dispatched simultaneously so as to achieve the greatest possible savings and in such a way that a new peak is avoided. However, there is the added flexibility of defining a user-specified order in which the DLC devices will be dispatched. Payback is explicitly considered in addition to contractual constraints such as maximum number of interruptions and maximum hours of interruptions for each program.

If several companies are being modeled, non-thermal resources may be dispatched for a specified company or group of companies. This allows modeling of different types of systems such as a Genco and Disco where the generating company's non-thermal resources will be dispatched to meet the load of the distribution company. This type of logic is also useful for interconnected power systems where a resource should be scheduled based on market value in addition to native load requirements. After the dispatch of non-thermal resources is completed, the remaining load is served by thermal generating units. The thermal dispatch is performed on a seasonal or an annual basis as determined by the user for each water year. If annual dispatch is chosen, the modified seasonal load curves are combined into an annual load curve.

## Dispatch of Thermal Resources

Each generating unit may be represented with up to seven capacity segments. Each capacity segment may have a distinct heat rate. A unit may be designated as a must-run unit, in which case its minimum segment is dispatched before any upper segment in the system. Other thermal unit inputs include commission date, retirement date, immature forced outage rate, mature forced outage rate, and partial forced outage rate at the minimum capacity level.

Planned maintenance may be explicitly modeled for each generating unit by specifying the start and end dates for each maintenance, or by entering a start date and number of weeks of maintenance in each year. Optionally, only the annual number of weeks of maintenance may be specified, in which case maintenance is scheduled for the unit to levelize reserves or emergency energy across seasons. Maintenance may be handled as either a deration of the unit's capacity, or as an adjustment to its forced outage rate.

The widely accepted probabilistic production costing procedure is used to project the operation of each generating unit. The minimum segments of the must-run units are dispatched first, followed by enough other minimum segments to satisfy a user-defined dispatch commitment criterion. The remaining segments are dispatched in an economic order approximating the economic dispatch procedure of a system operator. Sufficient on-line capacity reserves are maintained to satisfy user-defined spinning reserve requirements. Fuel limits are monitored during the thermal unit dispatch. If fuel limits are exceeded, the system modifies the fuel mixtures and/or energy outputs of the generating units, resulting in a departure from economic dispatch. The impact of economy energy purchases and sales are determined on an economic basis.

After all available resources have been utilized, several reliability indices are determined. Among these are:

- Expected hours with negative margin (Loss of Load Hours, or LOLH)
- Expected emergency energy
- Reserve Margin

Alternatively, reliability measures, such as LOLH and expected emergency energy, may be fixed so that equivalent capacity benefits for DSM programs may be calculated. The GAF has the ability to calculate the equivalent capacity benefit of an incremental change in load based on a broad reliability measure. This relieves the user of the uncertain task of estimating a capacity benefit which for many DSM programs (for example, direct load control) may be difficult to measure. This is a significant improvement over the traditional calculation of the impact on the reserve margin (peak hour impact).

Emissions are calculated each season on a unit-by-unit basis. Removal efficiency characteristics of each unit are input. The individual unit results are then aggregated into company and system emissions totals and rates. The cost of emissions, whether such cost is in the form of allowance purchase price, emissions tax, or emissions externalities result from the thermal dispatch. Separate inputs allow these emissions costs to be included in a unit's dispatch lambda if desired.

## Network Economy Interchange (NEI) Modeling

The Network Economy Interchange (NEI) feature of the GAF helps reduce operating costs for a group of interconnected utilities by developing the most beneficial unit dispatch schedule for the group.

In a situation where there is unlimited transmission capacity between interconnected systems, the interchange process reaches economic equilibrium. At equilibrium, the marginal costs of all systems are virtually identical. To reach the point of equilibrium, the NEI feature performs interchange among interconnected systems in order to levelize the marginal costs. Interchange is economical as long as the difference in marginal cost is greater than the connection charges among systems.

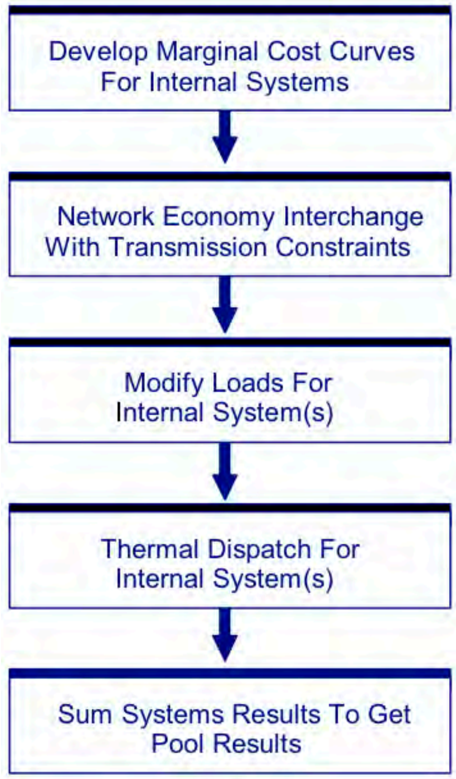
In power systems, particularly large systems covering major geographical areas, unlimited transmission capacities seldom exist, due to physical or contractual transmission limits. To neglect transmission capacity limits is to overestimate the benefit of economy interchange. This problem may not be severe if transmission constraints are not binding. However, in transmission-poor systems, overestimation of economy interchange benefits may distort overall system production costs.

The NEI feature provides a marginal cost-based algorithm for economy interchange among connected systems, while considering losses on transmission lines and enforcing transmissions limits for all hours. NEI accomplishes this by systematically matching potential buyers and sellers and incrementally equalizing their marginal costs.

The billing and accounting logic of the Network Economy Interchange reflects the market clearing price of the system. Therefore, if there are no losses, no connection charges, and no tie constraints, the marginal cost of the buyer will equal the marginal cost of the seller and the energy generated will equal the energy received. If there are differences between the buyer's cost and seller's revenue, the losses or surplus revenue is split between them based on the transfer point. If a third party is involved, then the losses and surplus revenue are allocated to the buyer, seller, and/or third parties based on their ownership.

Figure M-5 is a schematic flow diagram showing how NEI is incorporated into the overall GAF modeling structure. After all other load modifications are complete (transactions, hydro, pumped hydro, and direct load control), the GAF implements economy interchange. Interchange results are used to modify hourly loads of the internal companies. The GAF then executes the thermal dispatch for every internal company. If there is more than one internal company, the NEI feature sums company outputs to obtain the pool results.

Figure M-5. Generation And Fuel Schematic Diagram of the Network Economy Interchange




## Module Results

These *Reports* are provided by the GAF Module:

- System Report (includes company reports and multi-company interchange reports)
- Seasonal Summary Report
- Loads and Resources Report
- Unit Report
- Plant Report
- Hydro Unit Report
- Storage Unit Report
- Direct Load Control Report
- Fuel Data Report
- Fuel Class Report (included company reports)
- Input Summaries
- System Emissions Report
- Emission Report by Effluent

- Transaction Report
- Unit Profitability Report

In addition to standard output reports, numerous diagnostics are provided to allow for detailed evaluation of GAF Module processing and results. These *Diagnostics* include:

- Chronological Load at Each Stage of Dispatch
- Thermal Unit Dispatch
- Limited Fuel
- Company Fuel Type
- Dispatch Lambda
- Spinning Reserve Look Ahead
- Inflation/Escalation
- In-Dispatch Limited Fuel
- Externality Calculations
- Dispatch Lambda Emissions Adder
- Marginal Cost Curves
- Direct Load Control
- Chronological Marginal Costs at Each Stage of Dispatch
- Reliability
- Water Year Reports
- Multi-Company Interchange Accounting
- Energy Reserve Margin
- Daily Seasonal Definition
- Reserve Margin
- Seasonal Maintenance Week
- Seasonal Resource Diagnostics
- NEI Hourly Information by System and Transmission Link

All operating data necessary for specific project or overall system economic and financial calculations are automatically stored in Strategist's integrated data base during the execution of the GAF Module. In addition to standard output reports, numerous diagnostics detailing the operation of the GAF Module are available on an annual and seasonal basis.

# PROVIEW Module (PRV)

The PROVIEW (PRV) Module is a resource planning model which determines the least-cost balanced demand and supply plan for a utility system under prescribed sets of constraints and assumptions. PROVIEW incorporates a wide variety of expansion planning parameters including alternative technologies, unit conversions, cogenerators, unit capacity sizes, load management, marketing and conservation programs, fuel costs, reliability limits, emissions trading and environmental compliance options in order to develop a coordinated integrated plan which would be best suited for the utility. PROVIEW works in concert with the GAF Module to simulate the operation of a utility system. PROVIEW's optimization logic then determines the cost and reliability effects of adding resources to the system or modifying the load through demand-side management (DSM) or marketing programs.

The module allows modeling of emissions-related constraints, emissions allowance trading, and emissions reduction alternatives (for example, scrubbers, fuel switching). These capabilities are used both to develop optimal environmental compliance strategies and to incorporate resource planning.

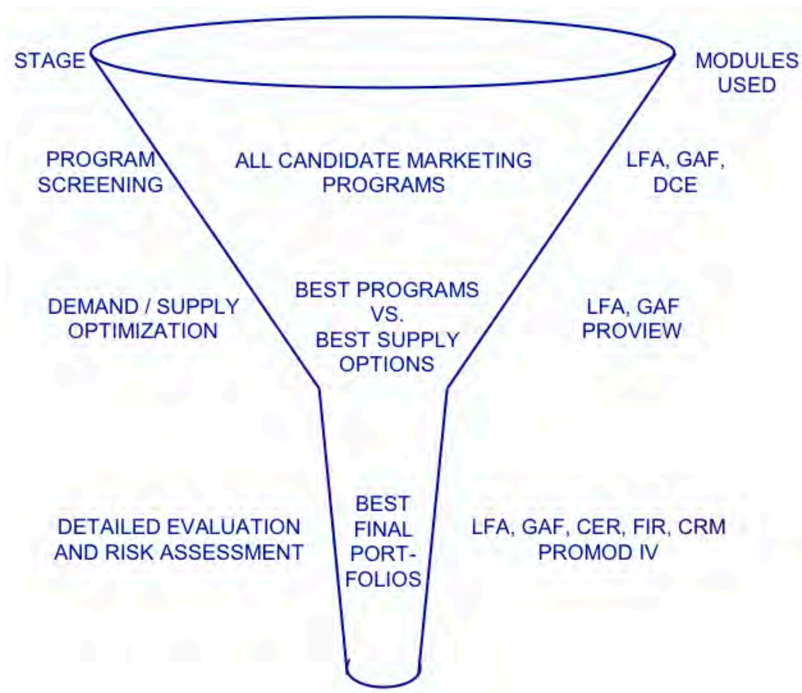
Figure M-6 graphically depicts the process by which PROVIEW works with other modules to evaluate DSM or marketing programs in three separate stages: screening, integrated supply/demand optimization, and detailed analysis.

Programs are screened by using the LFA Module in conjunction with DCE and the GAF Module. Programs in the LFA Module database are evaluated one at a time and are ranked based on industry standard cost effectiveness measures such as participant cost, utility cost, total resource cost, societal cost, and ratepayer impact measure (average rate). Groups of programs are then developed into portfolios based on the results of the ranking process. The LFA allows detailed treatment of system, class or end-use loads, enabling you to specify demand side or marketing programs on an hourly chronological basis. Capacity deferral benefits or costs are calculated using the capacity credit logic in the LFA and/or the reliability equalization logic in the GAF. Energy benefits or costs are calculated with a separate GAF production cost run for each program.

Once portfolios of programs have been developed, the LFA Module is used in conjunction with PROVIEW to perform integrated demand and supply optimization. LFA load groups representing DSM or marketing programs or portfolios of programs are specified as explicit PROVIEW alternatives. In this way, the programs compete on a "level playing field" with supply options. The optimal demand/supply plan is then developed using PROVIEW's dynamic programming capability. In addition to the optimal plan, PROVIEW retains multiple suboptimal demand/supply plans for further analysis.

The final step in evaluation of DSM or marketing programs involves use of the LFA Module in conjunction with all modules of Strategist and in conjunction with PROMOD IV, Ventyx's detailed production costing system. The CER Module provides the annual capital expenditure impacts of the programs and allows assessment of program costs which are capitalized. The FIR Module allows the evaluation of the impact of the programs on average rates, rate increase requirements and timing, and financial performance. The impact of programs on class rates and cross subsidy issues may be thoroughly evaluated in the CRM. Finally, detailed estimates of program impacts on production costs can be evaluated by passing the results of the LFA to PROMOD IV.

Figure M-6. Recommended Marketing Initiative Evaluation Methodology




## General Capabilities

- Data input is structured in a similar manner to Strategist GAF data.
- PROVIEW provides quick turn-around time by eliminating options that are not feasible and by eliminating unnecessary detail.
- PROVIEW allows for a full enumeration of all combinations of expansion options and/or demand-side management or marketing programs through its Dynamic Programming option. The system can thus be highly rigorous in its determination of a least-cost expansion plan for the entire planning period.

- Production cost calculations are performed for each alternative through the execution of the GAF Module. Demand side programs and associated sales impacts are computed through the execution of the LFA Module.
- PROVIEW uses the economic carrying charge as the capital cost representation during the study period optimization. After the study period rankings have been determined, the plans will be re-ranked over the planning period horizon using actual year by year revenue requirements. If these are not input, then levelized revenue requirements will be used.
- PROVIEW explicitly handles end effects in determination of the least cost plan. The end effects analysis approximates the capital and production cost of replacing the resulting utility system in kind over the user-input end effects period.
- PROVIEW provides for one of five objective functions to be used in the least-cost optimization: minimization of utility costs, minimization of average study period rates, minimization of total societal cost (total resource cost), minimization of total resource costs, or maximization of total unit profitability.
- PROVIEW will also evaluate any expansion plan optimized by one of the five objective functions mentioned above with regard to financial performance. The expansion plans may be re-ranked based on electric revenue, corporate value of the firm, economic value added, earnings per share, or value per share.
- PROVIEW provides numerous constraints for the user to reduce the number of options to consider. Minimum and maximum number to add, minimum and maximum reserve or loss of load hours, and first year available to add are but a few. PROVIEW can define alternatives as mutually exclusive or inclusive in a year. It can also restrict alternatives to be dependent upon certain other alternatives being in service (the second unit in a station is dependent upon the first unit having been constructed). PROVIEW also allows options such as phased construction of combined cycle units to be evaluated quickly. Maximum emissions levels can also be specified to reduce the alternatives considered.
- A PROVIEW optimization may be performed for the entire pool when multi-company summation logic is used. PROVIEW allows constraints to be entered at both the system level and for each company in the pool.
- When using Multi-Company, PROVIEW allows the addition of alternatives which are owned by a company other than the company (or pool) which is being optimized.
- PROVIEW allows complete evaluation of suboptimal plans. All plans are saved in PROVIEW's database for subsequent reporting and analysis. The user may specify the ranking of significantly different plans. Significantly different plans are developed as of a certain year of the analysis.
- Numerous diagnostics which explain in detail how PROVIEW reaches its optimal plan decision are available.

- PROVIEW results include a database that contains the results of all plans. The analyst can select any of these plans to be automatically set up in the LFA, GAF, CER, and FIR Modules for more extensive evaluation.

## Module Inputs

PROVIEW requires the data supplied by the user to be separated into two sections: the first section characterizes the existing utility system and the other section characterizes the potential expansion or marketing initiative options. The existing utility system data set is composed of the Strategist GAF and LFA Module data sets, which are fully described in the GAF Module online help and LFA Module online help. Briefly, data requirements for the existing system are grouped according to load, hydro unit, transaction, thermal unit, storage unit, fuel type, fuel class, and general parameter data. Data requirements for the existing load forecast are grouped according to load group, load shape, load class, and parameter data.

The data required for the planning alternative section contains information relating to alternative resources that may be added or marketing programs that may be implemented. Data in this section defines alternative unit characteristics, construction costs, resource addition limits, and resulting system reliability constraints. Alternative option information is specified in a general manner so that any proposed available option can be commissioned at any time during the study period.

## Module Methodology

PROVIEW's Dynamic Programming calculations are summarized as follows:

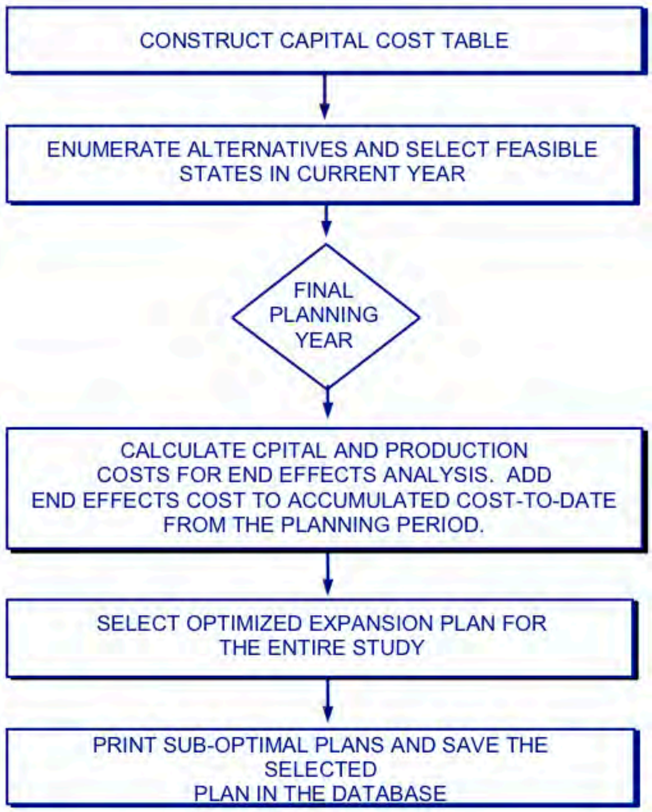
1. A capital cost table is constructed. This table contains the economic carrying for every alternative for each year of the study.
2. Feasible current-year states (combinations of alternatives) are determined by examining every combination of user-defined resource additions or marketing programs. Feasible states are those which meet reliability dependency and tunnel constraints. One-year capital and production costs are calculated and used to determine the accumulated cost-to-date. Each feasible state description is saved along with the associated accumulated cost-to-date.
3. The module repeatedly analyzes and saves feasible states for each year during the planning period. At the end of this planning period, a matrix of possible states for each year has been constructed. Note that each feasible state in the final year represents the end product of a different expansion plan.
4. Each potential expansion plan is subjected to end effects analysis. The end effects analysis adds to the accumulated cost-to-date of the capital and production cost of replacing the resulting utility system in kind, over a user-specified end effects period.

5. The module traces back through the matrix of feasible states to identify the components of the optimal plan and the components of each sub-optimal plan.

6. The optimal plan is set up in the LFA, GAF, CER, and FIR for subsequent analysis and reporting. All plans are saved in the database.

Figure M-7 shows the general logic flow of PROVIEW's Dynamic Programming option.

Figure M-7. Dynamic Programming Option



## Output Reports

The following *Reports* are produced by PROVIEW:

- Least Cost Plan Summary
- Demand Side Report
- Tunnel Report
- Significantly Different Plans
- System Cost Report
- Integrated Plan Report
- Study Period Plan Comparison
- Planning Period Plan Comparison
- Planning Period Emissions Analysis

PROVIEW produces the following *Diagnostics*:

- Reserve Analysis
- Levelized and Replacement Cost Tables
- Capital Cost Table
- Origin State Diagnostics
- State Analysis Summary
- State Analysis List
- Accepted State Diagnostics
- Levelization Calculations
- Dispatch of 1st End Effects State
- End Effects Period

# Appendix N: LNG Imports to Hawaii Study

The Companies contracted with Galway Energy Advisors to conduct a study as to the commercial and economic viability of importing liquefied natural gas (LNG) from the mainland. The report focuses on risk assessment, procurement options, regasification options, shipping considerations, and pricing analysis.

This appendix contains that study, plus revised forecast tables.

Galway Energy Advisors LLC

# LNG Imports to Hawaii:

# Commercial & Economic Viability Study

## Prepared for:

Hawaiian Electric Company

**October 5, 2012**

#1300, 3050 Post Oak Blvd, Houston, TX, USA 77056 www.galwaygroup.com #10-03A, 30 Robinson Road, Singapore, 048546

Galway Energy Advisors LLC

## Table of Contents

GALWAY ENERGY ADVISORS LLC



**Table of Figures**

GALWAY ENERGY ADVISORS LLC

## Glossary

Brent – A large oil field in the UK sector of the North Sea. Its name is used for blend of crudes widely used as a price marker or benchmark for the international oil industry.

Floating Storage and Regasification Unit (FSRU) – It is a floating storage and regasification system , which received LNG from offloading LNG carriers and the onboard regasification system provides natural gas send-out through pipelines to shore.

Henry Hub – The main gas pricing point in the US. It is a point on the natural gas pipeline system in Erath, Louisiana, close to the US' main production center on the Gulf Coast. Prices in most locations in the US are indexed at an expressed differential to the Henry Hub.

Japanese Crude Cocktail (JCC) – The nickname for Japan Customs–cleared Crude, it is the average price of customs cleared crude oil imports into Japan as reported in customs statistics. It is commonly used as an index in long term LNG contracts.

Japan/Korea Marker (JKM) – It is the benchmark daily assessment of the spot price for LNG cargoes delivered ex-ship into Japan or Korea. It is published by Platts.

Liquefaction – It is the process of converting natural gas from a vapor into a liquid by cooling it to -162$^{0}$C (-260$^{0}$F). The volume of gas is reduced by a factor of 600.

Liquefied Natural Gas (LNG) – It is natural gas (predominantly methane) that has been converted to liquid form for ease of storage or transport. LNG is formed by cooling natural gas to -162$^{0}$C (-260$^{0}$F) at which point the gas condenses into a liquid. The liquefaction process reduces the volume of gas by a factor of 600, which enables the transport of large volumes over great distances by ship. On arrival, it is unloaded and regasified before being injected into the gas transmission system.

Met-ocean - a contraction of the words 'meterology' and 'oceanology' referring to the waves, winds and currents conditions that affect offshore operations.

MMBtu – An acronym for Million Metric British Thermal Units. Btu is a unit of heat energy defined as the amount of heat required to raise the temperature of one pound of water by one degree Fahrenheit. One Btu equals 1,055 joules or 252 calories.

Mtpa – million tonnes per annum

National Balancing Point (NBP) – The main gas pricing point in the UK. It is a point of reference and not a physical location.

Netback price – The effective price for the supplier of the commodity (gas) at a defined point. It is calculated as market price less the cost of transportation.

Regasification – The process of converting LNG from a liquid to a vapor. This is achieved by heating the LNG in a regasification unit (vaporizer).

Sale and Purchase Agreement (SPA) – A definitive contract between a seller and buyer for the sale and purchase of a quantity of natural gas or LNG for delivery during a specified period at a specified price. Also known as GSPA wherein G stands for general.

Shale gas – It is natural gas formed from being trapped within shale formations. Shales are fine-grained sedimentary rocks that can be rich sources of petroleum and natural gas.

Third Party Access (TPA) – The right for a third party to use a specified pipeline or facility of another company.

# 1 Executive Summary

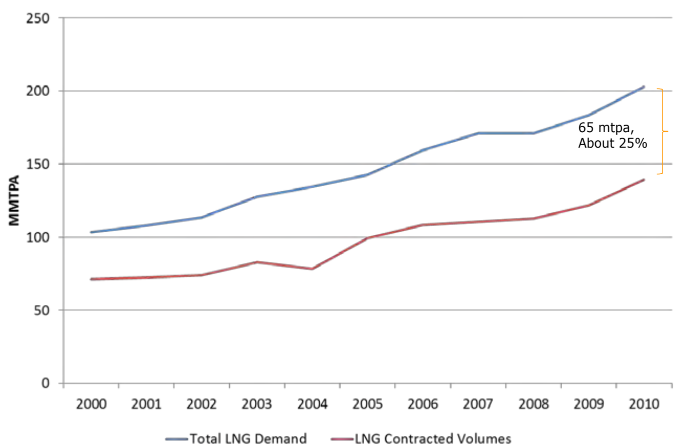
In March 2012, Hawaiian Electric Company (HECO) commissioned Galway Energy Advisors to examine the viability of LNG imports as an alternative to LSFO/ULSD. The study focused on the mid and long term supply situation and attendant supply risk; Procurement options for HECO, Regasification options for near and off-shore configurations, Shipping considerations and integrated pricing analysis.

## 2.1 Global LNG Context

Global LNG markets have evolved from being a regionally compartmentalized trade to being more globalized and liquid. Ten to fifteen years ago, global LNG markets were characterized by stable long term contracts, point to point deliveries, limited inter-regional trade, segmented pricing regimes and limited markets. However, as of 2012, the characteristics of the LNG market are quite different. Off takers now often have diversion rights and the liquid markets of the US and Europe allow for flexible volumes. There is two tier pricing on a regional basis and worldwide price linkage for short term trade. There are also many more markets and many more suppliers. There is, however, still no worldwide price linkage for long term trade.

A growing amount of LNG trade is flexible. The evolving characteristics of the global LNG market are most evident in the growth of short term/spot trade. This is now a trade in flexible volumes, which are not tied to specific destinations and are divertible. The goal of the suppliers of these volumes is to generate incremental profits from arbitrage opportunities. The popularity of these trades is evidenced by the fact that in 2010, 65 mtpa or 25% of LNG volumes were divertible. By 2020, short term/spot trade could account for over 90 mtpa as indicated in **Figure 1**.

**Figure 1: LNG Spot Market**



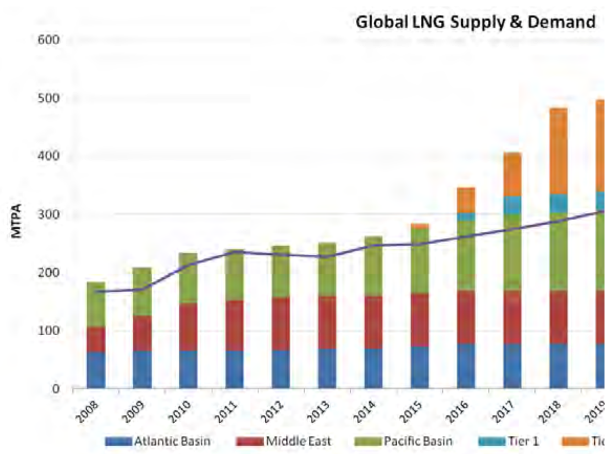

**Source: Galway**

The LNG industry has seen significant volatility in pricing, however, the general trend over the past decade has been increasing prices due to attendant increases in crude oil prices and to a lesser extent European gas pricing. This is because price formulae in long term LNG contracts from traditional suppliers are often oil indexed (or in Europe linked to regional gas pricing).

As global liquefaction capacity continues to rise, there is little supply risk in the 2020 timeframe. While price risk may be an issue, supply risk is not anticipated to be an issue. Global LNG liquefaction capacity is forecast to reach 363 mtpa by 2020 from the current level of 256 mtpa and the number of exporting countries is also forecast to increase from the present 18 to over 22 by 2020. It is expected that Qatar will be joined by Australia and North America as the leading LNG exporters by 2020. Global LNG supplies will increase significantly from the current 260 mtpa to 360 mtpa by 2020, with around 90 mtpa of LNG expected to be divertible volumes. Thus, supply will outstrip demand negating any concerns about supply risk (**Figure 2**).

GALWAY ENERGY ADVISORS LLC

**Figure 2: Global LNG Supply-Demand**




**Source: Galway**

HECO has supply options, however, it will not be viewed as an anchor customer for large scale liquefaction facilities; it will have to look at sourcing from US liquefaction capacity or purchase from the Spot Market in order to achieve preferential pricing. Given Hawaii's geographical location, HECO is well placed to buy from traditional Pacific Basin sellers and emerging North American sellers. However, purchasing from traditional sellers will not yield big price benefits due to their preference for oil indexed contracts and due to their greater bargaining position.

HECO's negotiating leverage may be limited by both the level of its demand and by the downward slope of demand profile. HECO's demand profiles[1] evaluated in this study were:

- Demand case 1: 0.85 → 0.55 mtpa
- Demand case 2: 0.65 → 0.40 mtpa
- Demand case 3: 0.575 → 0.275 mtpa

To obtain more assured long term price reductions, HECO should consider entering into an agreement to procure US liquefaction capacity. While this would allow HECO to procure natural gas directly from the US grid (and thus lower its root feed gas cost) it

[1] Addition of existing HawaiiGAS customers would add approximately 0.12 mtpa to the total demand. Other potential markets such as transportation could also increase this demand.

would also mean that HECO would then assume project development risk since all US liquefaction projects involve some level of greenfield activity.

There is a frenzy of activity around the US Gulf of Mexico liquefaction capacity. It is unlikely that HECO can participate in the current round. Current liquefaction tolling fee is in the range of US$3 per MMBtu for anchor customers. If HECO were to buy LNG from a capacity holder, it would likely have to pay market prices (as the capacity holder will seek to capture the pricing spread).

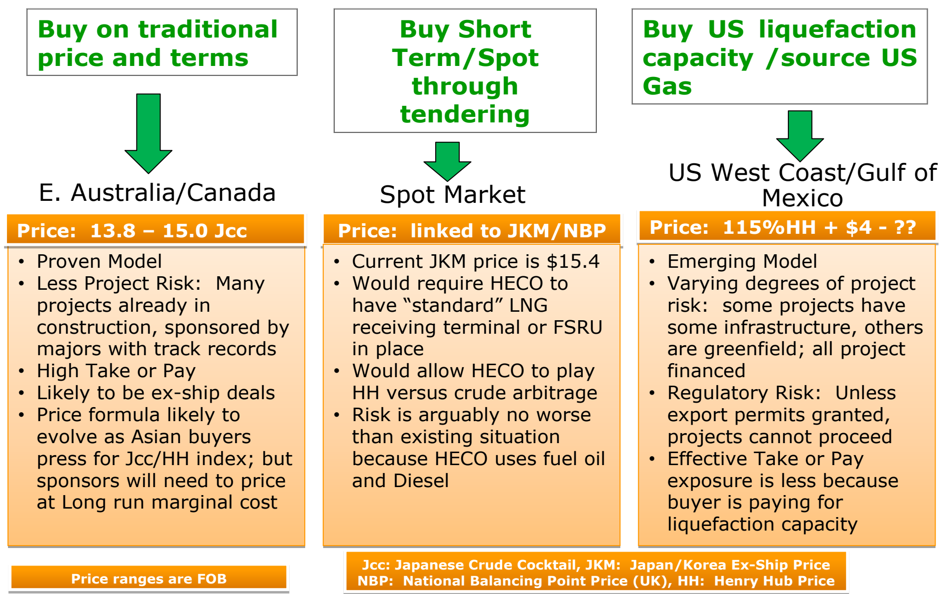
## 2.2 Procurement Options

Galway believes that HECO has the following 3 broad procurement options:

1. Traditional suppliers of LNG;
2. The emerging suppliers of LNG; and
3. The spot market.

Amongst the traditional suppliers, Eastern Australia and Canada emerge as potential contenders. Emerging suppliers would include the projects on the US West Coast and the projects in the US Gulf of Mexico. The characteristics of each procurement option in terms of risk and pricing are illustrated in **Figure 3**:

**Figure 3: Procurement Options**




**Source: Galway**

Regasification configuration will be an important consideration. The regasification configuration chosen will also play an important part in terms of LNG procurement. In order to support competitive procurement strategies, the regasification configuration should be acceptable to as many suppliers as possible.

## 2.3 Regas & Shipping Options

LNG import terminals can either be floating (near shore or offshore) or land-based. This study assumes that it will not be practical to site land-based facilities in Hawaii for the volumes anticipated. However, a more detailed siting analysis should be undertaken to evaluate both the floating and land-based LNG storage and regasification options.

### Floating Terminals

There are several floating LNG terminal configurations that have been implemented or proposed worldwide. There are 10 floating LNG terminals that have been successfully built while 5 are under construction or active development. LNG suppliers have grown increasingly comfortable with floating LNG terminal solutions but they will evaluate on a case by case basis and will conduct significant due diligence. Their focus will be on the LNG delivery ship to terminal interface in terms of safety and reliability. Suppliers have individual preferences and risk tolerances on both the terminal configuration and delivery ship interface. The terminal configuration impacts the floating terminal's reliability and availability because of met-ocean conditions. The impact is in terms of the availability to regasify LNG and send out natural gas and the availability to berth and unload the delivery ship.

The floating terminal choices for HECO include the following:

- Single berth near shore
- Double berth near shore
- Buoy based offshore

Galway's view is that suppliers are most comfortable with the double berth near shore configuration. Near shore floating terminal configurations include double berth and single berth solutions. Double berth solutions involve mooring an FSRU to a berth and connecting to a gas pipeline through a high pressure arm. The delivery ship moors to another berth. The LNG is transferred across the berth using hard arms. In single berth solutions, the FSRU is moored to a berth and connected to a gas pipeline through a high pressure arm. The delivery ship is moored to the FSRU. LNG is unloaded using ship to ship transfer (STS). Both of these configurations require calm waters and deep water access. The ship to ship transfer method for unloading LNG is a relatively new method to transfer LNG from a ship to an FSRU and can only be accomplished in calm waters. Of the two near shore configurations, the double berth solutions are generally well received by suppliers.

Offshore buoy based solutions are less popular with suppliers than berth based solutions due to concerns over STS at the buoy. The offshore buoy based solutions involve mooring the loaded FSRU to a buoy and connecting to the gas pipeline via a buoy connection in the hull. This configuration has a higher met-ocean condition threshold than berth based configurations, meaning the infrastructure can withstand more variation in ocean swells compared to other configurations. However, it is not popular since suppliers have not accepted STS while the FSRU is on buoy. Thus, these solutions have rarely been used.

Several small and mid-scale floating regasification concepts have been proposed but none have been implemented to date. The small and mid-scale floating configurations involve mooring a barge with LNG storage and regasification to a shore side berth or an offshore mooring point. Then a small scale LNG ship sails to and from the loading port to pick up LNG and transfer it to the regas barge. While this is a cheaper option than a full scale FSRU, it has not yet been implemented. The promoters of this concept provide only the infrastructure solution and not the supplies. Additionally, the traditional suppliers may not want to serve small scale ships due to berth capacity and schedule coordination concerns.

Siting constraints may impact the viability of near shore solutions. While near shore berth based solutions are better received by suppliers, it may be challenging for HECO to implement them. The siting of a berth based solution at Kalaeloa Harbor will need to be done in coordination with local, state authorities and other relevant stakeholders to ensure that the required dredging and construction of the new LNG berth can be undertaken and that the operation of an LNG terminal can be accomodated. Another option that HECO should seriously consider is Pearl Harbor as the site for the FSRU. In addition to this being a good functional site, the U.S. Navy may also realize some ancillary benefits. .

Siting constraints may also impact the viability of offshore solutions. HECO may also find it challenging to find a suitable location for a single or double buoy mooring system. Key issues identified are as follows:

- Water depth – Buoy system complexity and costs increase with depth (500 to 600 feet has been the deepest application so far). Also, at the 3 mile line, the water depth ranges from 2,100 feet to 2,700 feet. This is likely to be too deep to accommodate the buoy systems.
- Public acceptance – FSRUs have a relatively high volume above waterline and can be very visible from the shore. While this may generate some opposition, the presence of large crude oil carriers coming to the Barber's point area regularly to supply the Refineries in this area should help in mitigating concerns that this is something very new. .
- Restricted areas – The coastline near Barber's Point seems to include many restricted or prohibited areas.

Galway examined several floating terminal options as indicated below and believes that there are a few that may, subject to further study, be viable (**Figure 4**).

**Figure 4: Floating Regas/Shipping Options**

| | "Standard" Scale Solutions | S |
|---|---|---|
| Shore Side in Kalaeloa Harbor | • FSRU with Single Berth or Double Berth | • Mi Be • Re |
| Offshore Barbers Point or Kahe Point | • ~~FSRU with Single or Double Submerged Mooring Buoy with STS~~ • 2 FSRU's with Single or Double Submerged Mooring Buoy | • ~~Mi Su~~ • *Re Su* |

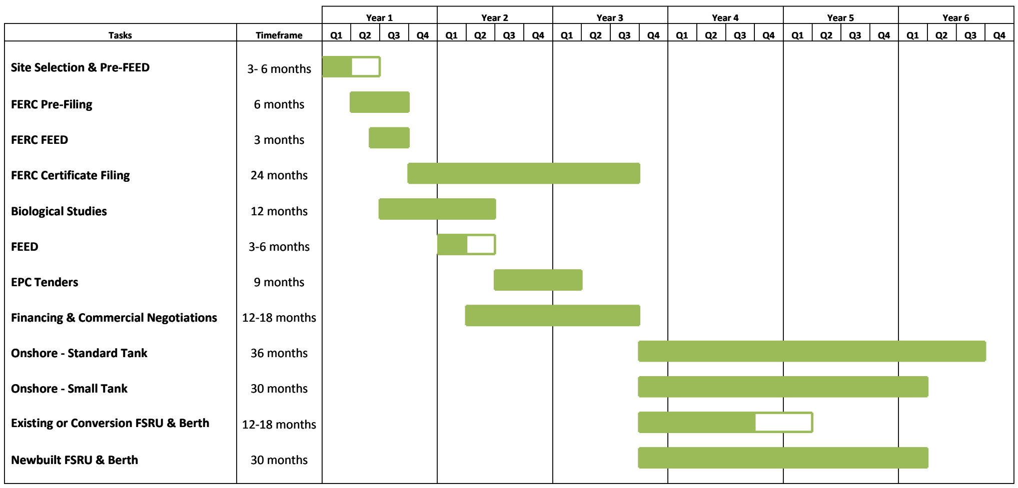
**Yellow:** Requires further studies - water depth & potential "Visual" pollution concerns
**Blue:** Harbor impact & proximity to public present siting challenges
***Blue*:*** Concerns about Metocean conditions for smaller FSRU's (never been done)
**Red:** Unlikely because of STS challenges & lack of supplier acceptance

**Source: Galway**

For a near shore configuration, a standard FSRU with a single or double berth configuration could be viable. A mid-scale or barge concept may also be viable although Galway has concerns about the economic viability of the ATB barges. For an off-shore configuration, a double FSRU arrangement (with one FSRU shuttling to pick up a cargo while the other is unloading at the discharge point) with a double buoy structure could be viable. An offshore regas barge could also be viable but again economics could be an issue.

The regasification terminal is the long lead item and will likely take 4 to 5 ½ years to implement, not including the time for local permitting and approvals. The time frame for the key project activities are shown in **Figure 5**:

**Figure 5: Development Timeline**




**Source: Galway**

The choice of shipping option will be determined by the regasification configuration and the source of supply. The key considerations in terms of shipping are as follows:

- Small buyers usually do not want or cannot mitigate the risks of shipping
- HECO will most likely need to be responsible for shipping if it procures tolling capacity in the US or elects to use small or mid-scale infrastructure.
- The Jones Act requires that ships delivering LNG from US port to US port be US owned, US built, US crewed and US flagged. It is likely that HECO can obtain a legislative waiver for the US built requirement (for standard size vessels, it may be more difficult for small or mid-scale vessels) but not for the other requirements. Compliance with the Act is also likely to result in higher shipping costs due to higher operating costs and less bargaining leverage with owners (since HECO and others will be competing for limited shipping options that are compliant to Jones Act).

## 2.4 Regas & Shipping Economics

Galway analyzed the combined economics of the shipping and regasification options. The results show that a near shore full-sized FSRU option is likely the most cost effective. However, the analysis also suggests that in view of the siting challenges constraining near shore options, offshore buoy based solutions may offer an acceptable alternative. The economic impact of the offshore options is seen to be in the range of a premium of US$1 per MMBtu (**Figure 6**).

Onshore options are likely to be the most expensive options even if they can be sited on Oahu.

**Figure 6: Regas and Shipping Economics**

| | | Annual Volumes (MTPA) | | | | | |
|---|---|---|---|---|---|---|---|
| **Terminal Configuration** | **Supplier** | **0.85** | **0.65** | **0.525** | **0.55** | **0.4** | **0.275** |
| **Onshore LNG Terminal** | **Kitimat** | 4.70 | 5.93 | 7.18 | 7.15 | 9.57 | 13.60 |
| | **US Gom** | 5.80 | 7.54 | 7.96 | 8.40 | 10.77 | 15.61 |
| | **Jordan Cove** | 4.84 | 6.33 | 7.84 | 7.75 | 10.66 | 15.49 |
| | **E. Australia** | 4.98 | 6.21 | 7.46 | 7.43 | 9.85 | 13.88 |
| **Small Scale Onshore** | **Kitimat** | 4.30 | 4.53 | 5.20 | 5.99 | 7.01 | 8.75 |
| | **Jordan Cove** | 4.15 | 4.41 | 4.91 | 6.54 | 6.98 | 8.38 |
| **2 x FSRU - Double Buoy** | **Kitimat** | 3.39 | 4.44 | 5.51 | 5.41 | 7.46 | 10.89 |
| | **US Gom** | 4.92 | 4.81 | 5.62 | 5.53 | 7.57 | 11.00 |
| | **Jordan Cove** | 3.43 | 4.48 | 5.56 | 5.47 | 7.50 | 10.94 |
| | **E. Australia** | 3.31 | 4.36 | 5.43 | 5.35 | 7.38 | 10.81 |
| **2 x FSRU - Single Buoy** | **Kitimat** | 3.19 | 4.19 | 5.20 | 5.11 | 7.07 | 10.29 |
| | **US Gom** | 4.72 | 4.56 | 5.31 | 5.23 | 7.18 | 10.40 |
| | **Jordan Cove** | 3.23 | 4.23 | 5.25 | 5.17 | 7.11 | 10.34 |
| | **E. Australia** | 3.11 | 4.11 | 5.12 | 5.05 | 6.99 | 10.21 |
| **Dockside Fullsize FSRU** | **Kitimat** | 2.56 | 3.13 | 3.71 | 3.69 | 4.81 | 6.68 |
| | **US Gom** | 3.66 | 4.74 | 4.49 | 4.94 | 6.01 | 8.69 |
| | **Jordan Cove** | 2.70 | 3.53 | 4.37 | 4.29 | 5.90 | 8.57 |
| | **E. Australia** | 2.84 | 3.41 | 3.99 | 3.97 | 5.09 | 6.96 |
| **Dockside Small/Mid FSRU** | **Kitimat** | 3.77 | 3.84 | 4.35 | 5.18 | 5.89 | 7.13 |
| | **Jordan Cove** | 3.62 | 3.72 | 4.06 | 5.73 | 5.86 | 6.76 |
| **ATB Regas Barges** | **Kitimat** | 4.30 | 5.86 | 5.28 | 7.05 | 7.46 | 10.13 |
| | **Jordan Cove** | 4.41 | 4.90 | 5.36 | 6.92 | 7.72 | 9.18 |

**Source: Galway**

## 2.5 Integrated Economics

Based on the LNG value chain options set forth earlier, an integrated economic analysis was performed to arrive at the delivered price of LNG for HECO. Several scenarios for analysis were created based on the various supply, regasification and shipping options. The scenarios under which the analysis was performed are shown in **Figure 7**.

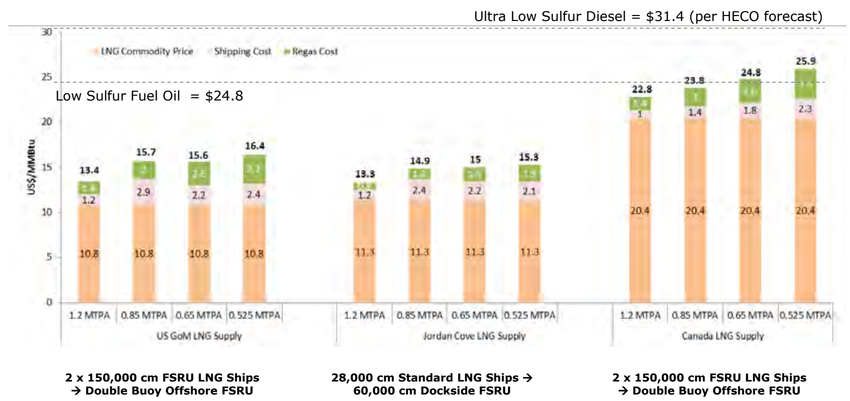
**Figure 7: Integrated Economics**

| | Supply Option | Regas Configuration | Shipping Configuration | Comment |
|---|---|---|---|---|
| 1 | Long/Short Term SPA from any source (no US restriction) | Docked 170,000 m3 FSRU | Likely Ex-ship (suppliers prefer DES for small buyers) | Commodity charge would be at oil indexed price (at today's prices, cost would be higher) |
| **2** | **Long/Short Term SPA from any source (no US restriction)** | **Offshore Double FSRU with double buoy** | **FOB (HECO needs to charter 2 Jones Act FSRUs)** | **Commodity charge would be at oil indexed price (at today's prices, cost would be higher)** |
| **3A** | **US HH Indexed supply: long term tolling for liquefaction** | **Offshore Double FSRU with double buoy** | **FOB (HECO needs to charter 2 Jones Act FSRU's)** | **US HH Indexed gas would partially offset higher supply chain costs** |
| 3B | US HH Indexed supply: long term tolling for liquefaction | Docked 170,000 m3 FSRU | FOB (HECO would need to charter FSRU's, Ship) | US HH Indexed gas would partially offset higher supply chain costs |
| **4** | **US HH Indexed supply: long term tolling for liquefaction** | **Docked small scale FSRU (60,000 m3)** | **FOB (HECO would need to charter Jones Act 25,000 m3 Ship)** | **HECO's options for sourcing gas from other LNG suppliers would be very limited** |

**Source: Galway**

Using these scenarios and the HECO demand profiles, the delivered price of regasified LNG was forecast. HECO's forecasts for crude oil and oil products were utilized in this analysis. The delivered price of regasified LNG for year 1 (2020) for the different demand throughputs and under different options is given **Figure 8**.

**Figure 8: Delivered Regasified LNG Prices**




Assumptions:
- LNG Price:
  - Canada: 14.84% JCC
  - US: 115% HH + 4(GoM) / 4.5(Jordan Cove)
- Brent Price ($/bbl):
  - Y1: 133.8
- HH Price ($/MMBtu):
  - Y1: 5.5

Source: Crude oil, LSFO, and ULSD prices (in nominal dollars) from HECO; Galway Energy Advisory Analysis

**Source: Galway[2]**

The analysis revealed that there are likely to be savings from the use of LNG whether sourced from the US or from traditional suppliers. Sourcing from the US could provide significant burner tip price reductions for HECO. However, the key questions (cost of US liquefaction capacity and spread between HH and fuel oil prices) relating to sourcing US LNG could undercut this as a supply option

Another interesting point is that even if HECO sources from traditional suppliers, there could still be a positive spread in burner tip pricing. At worst, it appears that prices of LNG and competing fuels would be roughly at parity. The degree of price spread is influenced by the volume throughputs, especially in light of a downward sloping demand profile.

## 2.6 Conclusions and Recommendations

- Supply risk is not anticipated to be an issue for HECO due to growing liquefaction capacity but managing price risk could be a key issue.

[2] Note that the price basis for Figure 8 is listed in the assumptions as a Brent price. Because Brent has a forward curve and JCC does not, the JCC projected price was calculated based on its correlation to Brent. So, the final calculated price for this chart was a JCC price.

- There are 3 procurement options:
  1. Buy long term supplies from a traditional supplier at oil indexation
  2. Buy from the spot market
  3. Contract for US liquefaction tolling capacity (and buy gas from US grid)

- HECO's demand for LNG is small, which may limit its negotiation leverage as well as procurement options.

- Near shore floating LNG terminal options are viable but may face significant permitting challenges.

- Although offshore floating options could be viable, additional study is required to confirm this.

- Shipping strategy is driven by supply strategy and regasification configuration. US sourced supplies are likely to necessitate HECO's entry into the shipping business due to Jones Act compliance requirements.

- There appears to be a significant positive burner tip price spread between HECO's LSFO/LSD and US LNG costs. There may be a positive price spread against global oil indexed LNG prices as well.

- Galway believes there to be sufficient viability to further investigate LNG as an alternative fuel.

Galway recommends that the next step should be to further define project scope and confirm technical and regulatory viability. This can be accomplished by undertaking the following tasks:

- Commission detailed siting studies to assess the viability of offshore buoy based options. This could take 3 to 6 months with costs ranging from $0.5 to $1 million.
- HECO should initiate discussions with the U.S. Navy to assess the viability of locating a FSRU based terminal in Pearl Harbor.

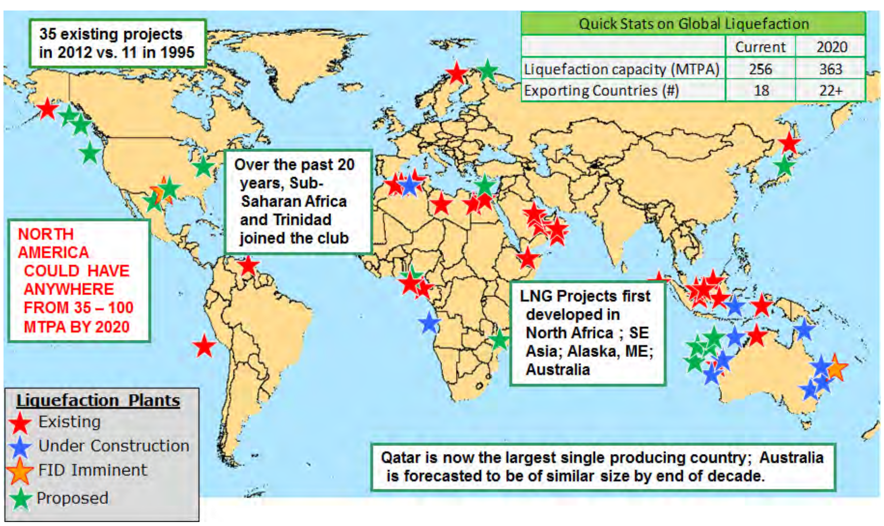
- Develop regulatory and permitting strategy through informal consultations with federal and state regulatory authorities.
- Develop detailed commercial and business structure for LNG importation.
- Hold informal consultations with vendors and suppliers.

## 2 Global LNG Overview

There has been significant growth in the LNG industry in the last 10-15 years both in terms of demand as well as liquefaction and regasification capacity. Major additions to global liquefaction capacity are forecast to result in a scenario where supply risk is not a big issue. However, US shale gas linked LNG is a major wildcard as there is uncertainty as to the amount of development that will occur. This has implications not just in terms of overall market balance but also in terms of supply options for HECO. The continuing growth of the spot market is another key factor with respect to supply sourcing. We examine these issues in detail in this section.

Liquefaction capacity has grown rapidly in the last 10-15 years with 35 existing projects in 2012 as opposed to 11 in 1995. The sources of LNG supplies have also diversified globally from the original group of North Africa, South East Asia, Alaska, the Middle East and Australia as several new regions, such as Sub-Saharan Africa and Trinidad, now host the sites of LNG projects. This growth is expected to continue with global liquefaction capacity reaching 363 MTPA by 2020, a rise of 41.8% from current levels. While Qatar is presently the single largest producer of LNG, Australia is forecast to usurp its position by 2020 (Figure 9).

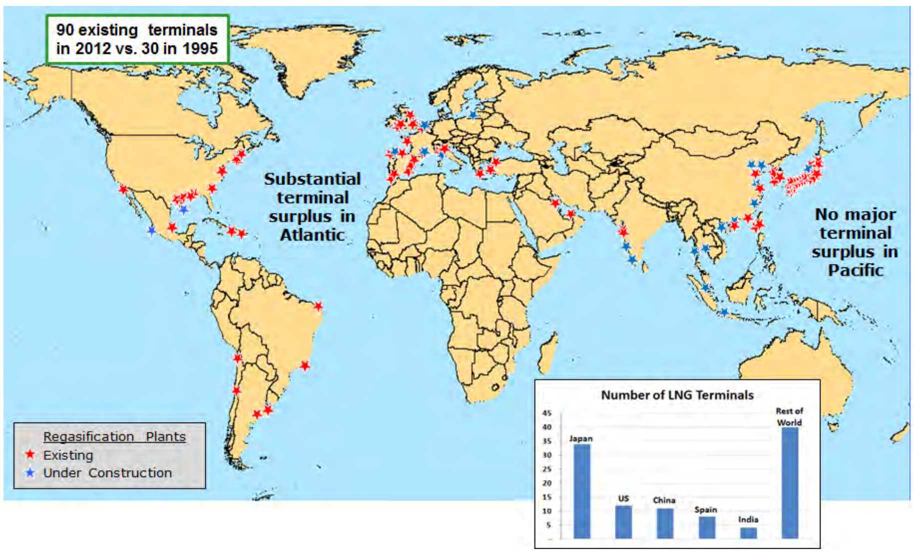
**Figure 9: Global LNG Supply**




*Source: Galway*

A similar growth has also been observed in the global regasification capacity, an increase of 200% from 177 MTPA in 1995 to 525 MTPA in 2012. Japan is the largest consumer of LNG, holding total regasification terminal capacity of 105 MTPA in 2012. There is no major surplus of regasification terminal capacity in the Pacific Basin (Figure 10).

**Figure 10: Global LNG regas Capacity**

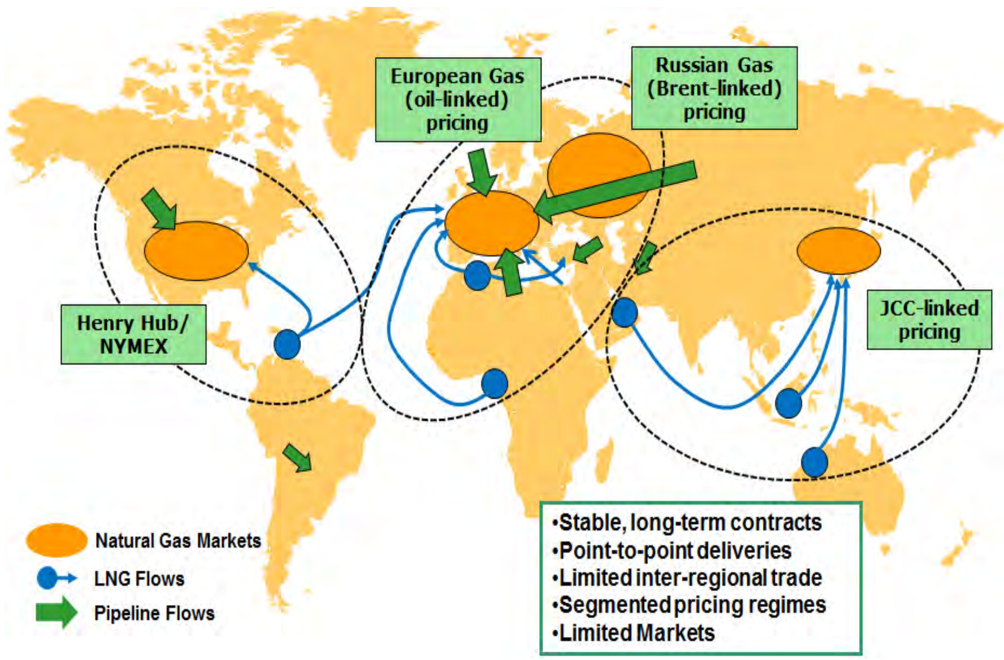



*Source: Galway*

## 2.1 Market Evolution

While the availability of LNG has grown on account of new project development, the very nature of LNG markets has also evolved from regionally compartmentalized to more globalized and liquid. Even 10 to 15 years ago, the market was characterized by stable long term contracts and point to point deliveries. As gas demand was still nascent, the markets for LNG were limited. There was limited inter-regional trade such as the export of Australian LNG to Japan. Pricing regimes were segmented with little interplay. For example, LNG trade in South East Asia was tied to Japanese Crude Cocktail (JCC) linked pricing whereas in the U.S, the Henry Hub/ NYMEX prices formed the basis for LNG prices. These factors meant that the spot market was not viable (**Figure 11**).

**Figure 11: LNG Markets 10-15 Years Ago**



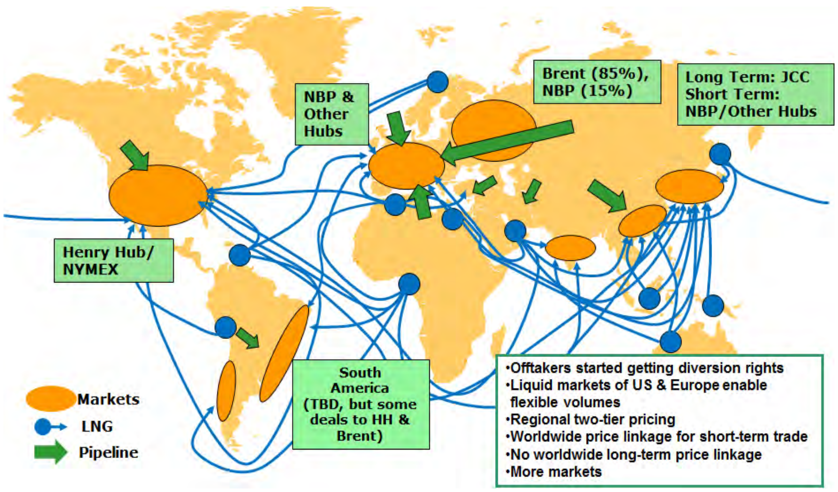

**Source: Galway**

However, the rapid growth of liquefaction capacity as well as the entry of new regions into the LNG trade (both as markets and suppliers) has resulted in an entirely altered scenario. As buyers of LNG were presented with multiple viable supply options, they began to negotiate diversion rights (the ability to divert volumes to other markets to take advantage of arbitrage opportunities). (**Figure 12**)

The liquid markets of the U.S and Europe also emerged as a market for flexible volumes. Both these factors led to the development of the LNG spot market, which resulted in a worldwide price linkage for short term trade (for example, short term LNG prices could be linked to the Henry Hub or the National Balancing Point (NBP)). However, no worldwide long term price linkage mechanism has emerged with oil indexation, JCC linked pricing and linkages to the NBP and Henry Hub still in place. Thus a regional two tier pricing architecture is in existence.

GALWAY ENERGY ADVISORS LLC

Figure 12: LNG Markets in 2012




Source: Galway

## 2.2 Markets and Participants

The current LNG industry has three types of market participants:

- Suppliers – Typical suppliers in the LNG industry fall into two groups:
    - Oil and gas companies – These include upstream companies such as Shell, BG, BP, Chevron, Total, Repsol and Sonatrach (Algeria) whose main aim is to monetize their gas reserves.
    - Joint venture projects – For example Nigeria LNG, Qatargas, Rasgas, Angola LNG. These joint ventures are usually between international oil and gas companies and national oil and gas companies.
- Buyers – Typical buyers of LNG are as follows:
    - Power and gas utilities – EDF, Centrica, Tokyo Gas, Tokyo Electric
    - Suppliers' marketing affiliates – BG, BP, Shell, Total
    - Marketing companies non-affiliated with suppliers – For example, the marketing affiliate of GDF Suez
    - Other large end users (separately or in a group) with access to regasification capacity – industrial users
- Traders and aggregators – The increasing liquidity and globalization of the LNG market have contributed to the emergence of a burgeoning spot trade in LNG

volumes (discussed in further detail later in this section). The players who are engaged in spot trading fall into two categories:

- Traditional suppliers and buyers – Some of the traditional buyers and suppliers have developed marketing portfolios and networks (shipping and terminal access) in order to take advantage of arbitrage opportunities and maximize profits. This has led to the emergence of LNG trading – for example, BG, GDF Suez.
- Pure commodity trading companies, which are now aggregating and reselling LNG – for example, Citi, J.P Morgan, Morgan Stanley and Macquarie.

Despite the increasing interplay of the various LNG markets around the world, two key regional markets have emerged, which have rather different dynamics and drivers. These two are the Atlantic Basin and the Pacific Basin markets. The following comparison identifies the key differences in market dynamics between these two key regions (**Figure 13**):

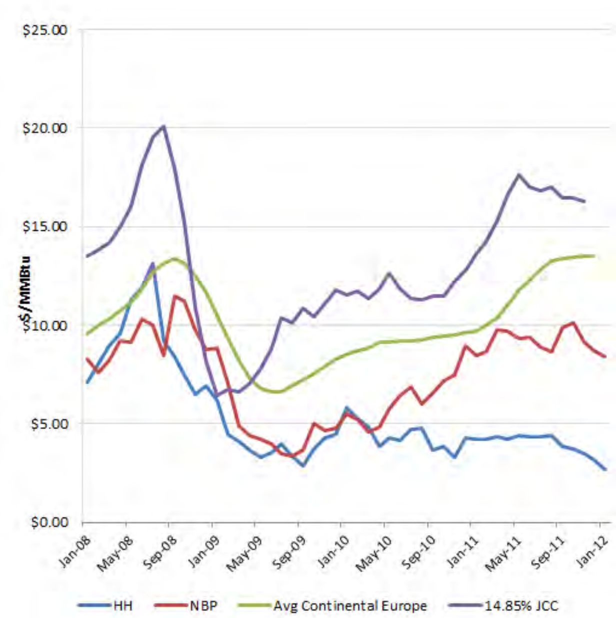
**Figure 13: Market Dynamics of the Atlantic and Pacific Basins**

| Atlantic Basin | Pacific Basin |
|---|---|
| ❖ This market is anchored by deep, very liquid, transparent gas markets.<br>➢ North America, UK, Europe<br><br>❖ North America and Europe have different supply drivers.<br>➢ The growth of shale gas in North America<br>➢ Competition between pipeline gas and LNG in Europe.<br><br>❖ The LNG supplies to this region are all effectively flexible.<br>➢ Few or no point to point contracts<br>➢ LNG portfolio players are vertically integrated and control shipping, terminals and marketing.<br>➢ Market participants choose to optimize position via diversion of volumes and management of their LNG portfolios. | ❖ Japan, Korea and Taiwan have tended to buy LNG at higher prices to lock in long term supply.<br>➢ However, since the tsunami that hit Japan in March 2011, traditional players have become more comfortable with supply risk and therefore, are willing to negotiate better pricing terms.<br><br>❖ Markets with expected high growth (India and China) are more reluctant to enter into high priced oil indexed contracts.<br>➢ These countries are currently pursuing more opportunistic purchases at prices below oil parity since these buyers know they have multiple alternatives.<br><br>❖ Growing trend from Asian buyers to become stakeholders in liquefaction projects and upstream reserves. |

**Source: Galway**

Before we can forecast the global demand supply balance for LNG, we must identify key drivers for these markets, which have been historically significant. The cost of alternative fuels and the netback price for suppliers will continue to be key drivers for LNG prices in these markets. A look at historical prices helps reveal these factors (**Figure 14**):

Figure 14: Market Dynamics of the Atlantic and Pacific Basins




Source: Galway

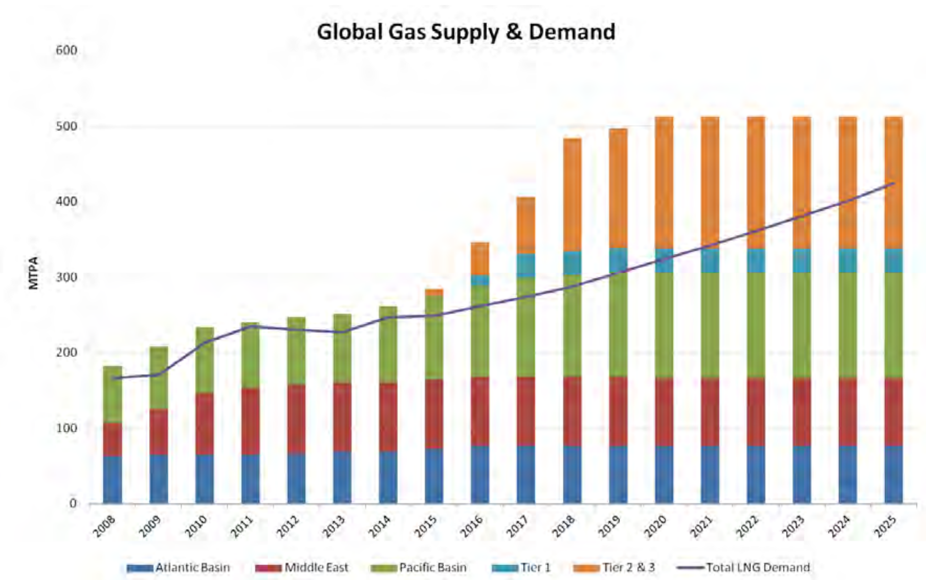
- Cost of alternative forms of energy – From the buyers' perspective, a primary factor is the cost of competing fuels. In the case of Hawaii, Chile and Argentina, the main competitor for LNG is fuel oil. In the case of the U.S and UK, the competition for LNG comes from the domestic natural gas market.
- Netback price – From the suppliers' perspective, the netback price, which is the value that they can realize in alternative markets, adjusted for shipping and LNG terminal costs, is key.
  - In the short term market, this would be the higher of the price of gas in the U.S (Henry Hub) or in the UK (NBP), or spot prices in Asia (JKM).
  - In the long term market, this would be the price of long term natural gas in Europe (around 11-12% Brent), or the price of long term LNG SPAs in Asia (12-15% of oil).

- Other factors – These include the creditworthiness of buyers, the risk of purchase disruption (the ability to consistently receive LNG), diversion rights (for buyer or seller) and logistical and strategic considerations (portfolio fit).

## 2.3 Supply-Demand Balance

Taking these key market drivers into account, Galway forecast demand for LNG on a global basis. Our analysis reveals that global demand for LNG will continue to rise by 81% from 235 MTPA in 2011 to 425 MTPA in 2025. We also forecast global LNG supply from existing, under construction and developing projects. Our analysis shows that global LNG supply will rise from 240 MTPA in 2011 to 512 MTPA in 2025, an increase of 113% (incl. Tier 2&3), provided that the projects taken into account in our forecasts materialize (**Figure 15**)

**Figure 15: Global LNG Supply-Demand Forecast**

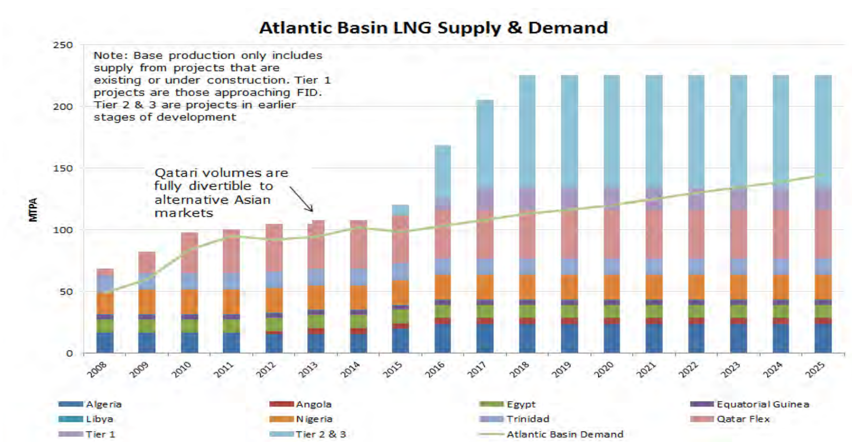



**Source: Galway**

Thus the overall global demand supply picture reveals that base production alone (i.e. production from projects that are existing or under construction) will be sufficient to meet global demand until the latter part of this decade. From 2019 onwards, additional supply will be required to the tune of 115 MTPA by 2025.

Galway further examined the demand supply scenario for the two key markets – the Atlantic Basin (**Figure 16**) and the Pacific Basin (**Figure 17**). LNG demand from the Atlantic Basin stood at 95 MTPA in 2011 and is forecast to grow to 145 MTPA by 2025, an increase of 53%. The supplies from existing projects, around 100 MTPA, were more than sufficient to meet demand in 2011. Base production, i.e. supplies from existing projects and those under construction, will be enough to meet demand until 2018. These supplies include flexible volumes from Qatar which are fully divertible to the Pacific Basin markets. From thereon, additional supplies will be required from projects currently approaching FID (Tier 1) and those in earlier stages of development (Tier 2 and 3) amounting to 110 MTPA by 2025.

**Figure 16: Atlantic Basin LNG Supply-Demand Forecast**

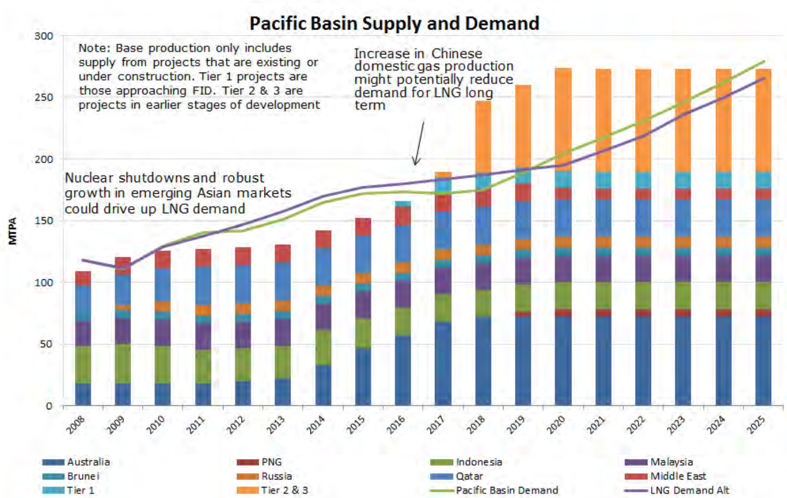



**Source: Galway**

The demand supply picture in the Pacific Basin, however, is quite different. As of 2011, available supply (around 130 MTPA in 2011) from existing facilities fell short of demand. This was largely on account of the nuclear power shutdowns in Japan owing to the Fukashima earthquake in March 2011.

Galway has developed two scenarios in order to forecast demand for LNG in the Pacific Basin. In the first scenario, shown as Pacific Basin demand in Figure 17, demand is projected to rise from around 140 MTPA in 2011 to around 275 MTPA in 2025. Further nuclear power shutdowns and robust growth in emerging Asian markets such as India and China could drive up LNG demand further. In the second scenario, shown as LNG demand alt in Figure 17, increase in Chinese domestic gas production might potentially reduce the demand for LNG in the long term. Thus, under the second scenario, overall LNG demand in the Pacific Basin would rise only to 260 MTPA by 2025.

**Figure 17: Pacific Basin LNG Supply-Demand Forecast**



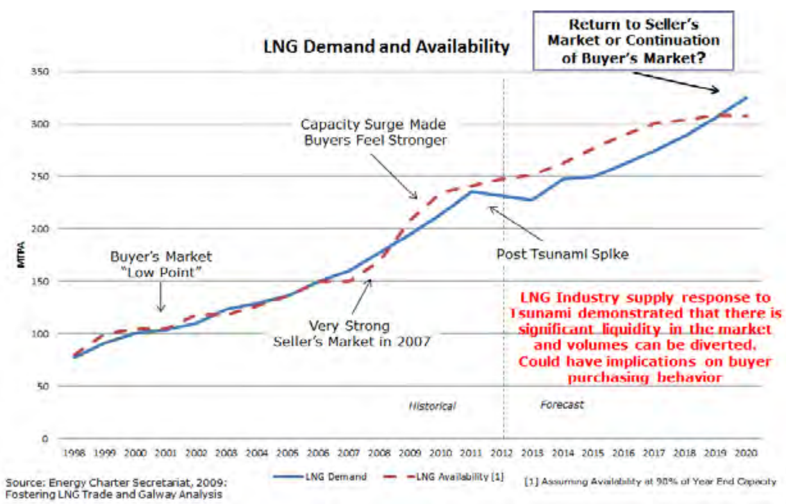

**Source: Galway**

Supply from existing production facilities and projects under construction (base production) are expected to increase to around 170 MTPA by 2018. In the interim, however, supplies are forecast to fall short of demand. In the long term also, additional supplies from Tier 1 and Tier 2 and 3 projects will be required amounting to 96.5 MTPA by 2025. Thus the overall supply demand forecasts imply that supplies will be sufficient to meet global demand. The supply situation is likely to be particularly favorable in the Atlantic Basin in the long term. However, market tightness in the Pacific Basin is possible, which might result in price risks for HECO.

A look at historical trends in the LNG industry reveals that the LNG industry experiences cyclicality (**Figure 18**). In the last 3 years, capacity additions have resulted in a stronger position for buyers. The industry's supply response to the post tsunami spike in demand has also demonstrated that there is significant liquidity in the market and that LNG volumes can be diverted. These could have implications for buyers' purchasing behavior as they become more willing to assume supply risk and less likely to pay higher prices to secure longer term supplies. As LNG availability is expected to continue to be in excess of demand until the end of this decade, this trend will likely continue.

However, it remains to be seen if there will be a continuation of the buyers' market or a return to the sellers' market post 2020. This has implications in terms of price risk for buyers.

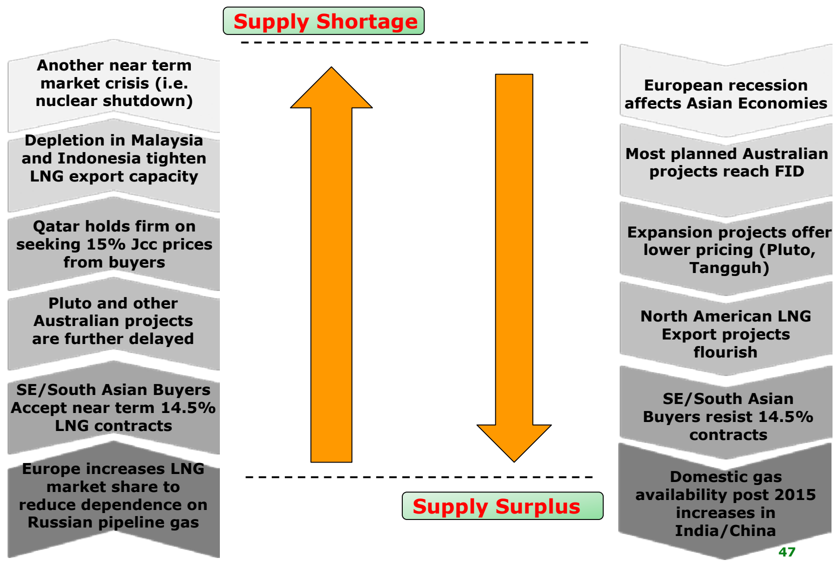
**Figure 18: Pacific Basin LNG Demand & Availability**




**Source: Galway**

Just as the tsunami in 2011 had a major impact on the global demand supply balance, several factors can result in alterations in the demand supply forecasts. These factors are identified in the following chart (**Figure 19**):

**Figure 19: Factors impacting global LNG supply demand balance**




**Source: Galway**

Of these factors, LNG export projects related to North American shale gas production are most likely the biggest unknown. The US shale gas industry has become increasingly important in the last decade. Not only is the potential reserve base of shale gas huge, being of the order of 862 TCF as of 2011**,** but it also continuing to grow rapidly. The primary drivers for this rapid growth are two-fold:

- Evolving technology: Improvements have been made in the technology used in fracturing and water management as well as in the drilling process (for example, multi-well pads).
- Improvements in exploitation of reserves: Over time, companies have learned to identify and focus on 'sweet spots' in the assets and on areas which are heavy with valuable liquids such as butane and pentane (for example, recent trends in the exploitation of the Eagle Ford and Marcellus reserves).

With the US shale gas industry gaining in importance, major oil companies such as Exxon, BP, Shell and BG are increasing their involvement. This trend can be viewed as a 'game changer'. Firstly, major oil companies often take a long term development perspective. Secondly, these companies have deep pockets and thus can follow a development schedule that is dictated by markets rather than by finances.

Galway expects that some liquefaction capacity will emerge in the US. However, the amount of development is uncertain. It could range from 20 to 80 MTPA. Furthermore, export permits from the Department of Energy and fracturing (the technology used for the extraction of shale gas) are both sensitive political issues. Thus there is a lot of uncertainty surrounding US LNG production and exports but it has the potential to have a major impact on the supply scenario.

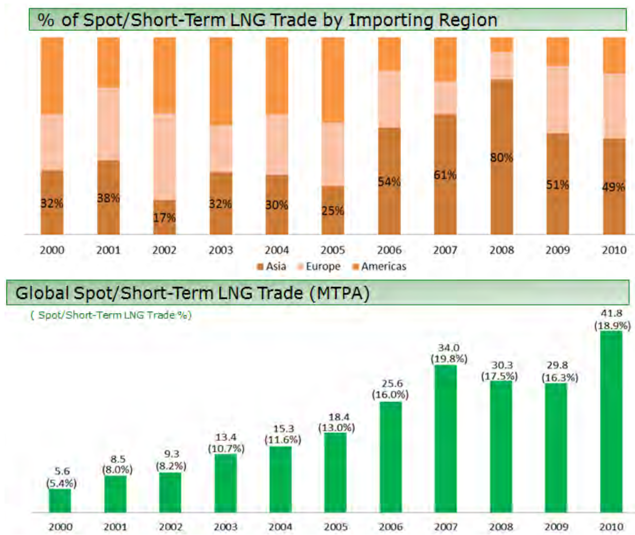
## 2.4 Short-Term/Spot LNG Trading

Short term trade is defined as a cargo or a series of cargoes traded with a 90 day to 2 or 3 year term. In the past, short term trade in LNG was driven by seasonal demand variations and availability name plate capacity (i.e. wedge volumes – the volumes available from liquefaction projects until contracted long term buyers could ramp up to take their full volume commitments). Nowadays, short term trade is driven by the following factors:

- 'Equity lifts' (i.e. the share of LNG that equity holders in a liquefaction plant are entitled to offtake) being sold into markets, not necessarily to end-users.
- Diversion of cargoes to higher value markets
- Expiry of long term SPAs

These factors have resulted in the continued growth of the short term LNG market to a point where spot/short term trade accounts for over 20% of the global LNG volume traded currently (**Figure 20**).

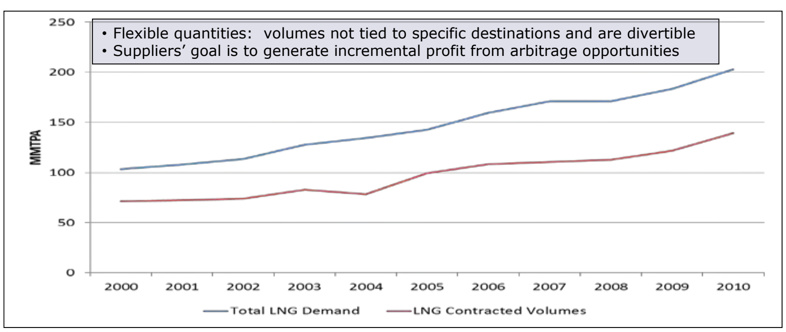
**Figure 20: Global Spot/short term LNG trade (MTPA)**




**Source: Galway**

In 2010, 65 MTPA (25% of LNG production) could be diverted to other markets. By 2020, this could easily be over 90 MTPA. Several 2 to 3 year term contracts have been done in Asia (for example, KOGAS, Chubu) for 0.5 to 0.8 MTPA. Given that HECO's needs are relatively small, the spot/short term market is an option to consider (**Figure 21**).

**Figure 21: Global Spot/short term LNG trade (MTPA)**




**Source: Galway**

Based on our analysis of the supply demand outlook and the overall outlook for the LNG industry, the following are the key takeaways for HECO:

- Supply will increase significantly by 2020 from 260 MTPA to 360 MTPA globally. Thus supply risk is not an issue for HECO. However, the management of price risk will be important.
- North America may become the 3rd major exporter of LNG joining Australia and Qatar. Africa will play a bigger role in LNG liquefaction following the startup of new projects in Mozambique and Tanzania.
- Galway expects over 90 MTPA of LNG will be divertible by 2020.
- Hawaii is well placed geographically to buy from the Atlantic and Pacific Basins.

# 3 LNG Procurement Options and Pricing

Hawaii is geographically well positioned to source LNG supplies from both the Atlantic Basin and Pacific Basin suppliers. However, an examination of contract portfolios of advanced Greenfield projects reveals availability of un-contracted capacity in the Eastern Australian and Canadian Greenfield projects. Other supply options include US LNG and the spot/short term market. But each of these options has its own implications especially in terms of pricing, reliability and bankability of HECO's LNG value chain. Galway believes that supply deals originating from either Australia or Canada projects, although more expensive may be most "bankable" given extensive LNG credentials as well as financial strength of the project sponsors (PETRONAS, Shell, Mitsubishi vis-à-vis Cheniere). HECO's relatively smaller demand requirements as well as its expected declining profile will limit its ability to anchor a Greenfield LNG project via a long-term supply deal. HECO will likely be viewed as an incremental customer by suppliers, a fact that will impact its bargaining position.

This section primarily focuses on feasible LNG supply sources, procurement options and associated pricing for HECO.

## 3.1 Potential Supply Sources

Galway analyzed four regions that could potentially supply HECO with long term LNG. These regions are Eastern Australia, Canada, South America and the US. Liquefaction projects. A comparison of these regions is as follows (**Figure 22**):

**Figure 22: Comparison of potential long term LNG supply sources**

| | Eastern Australia | Western Canada | West Coast US | Gulf of Mexico US | East Coast US | Peru | Trinidad |
|---|---|---|---|---|---|---|---|
| **Shipping Distance to Honolulu** | 3,995 nm Gladstone LNG | 2,409 nm Kitimat LNG | 2,164 nm Jordan Cove LNG | 6,209 nm Sabine Pass LNG | 6,593 nm Cove Point LNG | 5,232 nm Peru LNG | 5,934 nm Atlantic LNG |
| **LNG Production (MTPA)** | 18 | 5 to 13+ | 6 to 9 | 18 to 54 | 7 | 4.5 | 13.5 |
| **Fixed SPA Volumes (MTPA)** | 16.75 | Est. 10+ | -- | 18+ | 7+ | 4.5 | Flexible Volumes |
| **Available uncontracted Supply** | 1.2 | -- | -- | -- | -- | 0 | 13.5 |
| **Pricing Structure (for direct purchase)** | Crude Indexed plus a constant | Crude Indexed plus a constant | HH Indexed plus a constant | HH Indexed plus a constant | HH Indexed plus a constant | ~9% below HH | (HH, NBP) |

**Source: Galway**

Driven by higher project cost structures, LNG supply originating from Canada or Eastern Australia will likely be indexed to crude oil price to justify capital investments. The LNG sourced from these locations will therefore be significantly more expensive on a FOB basis, thus undermining HECO's desire to undercut Fuel Oil prices. Based on Galway research, approximately 1.2 mtpa of capacity at Gladstone LNG remains uncontracted while most of the capacity in the Canadian projects is being actively marketed.

While considering potential supply sources, Galway concluded potential LNG supply from Australia, Canada and the US. Australia has the capacity to supply Hawaii but the FOB/DES LNG price will be tied to crude oil which undermines downstream conversion economics for HECO. Australia is forecast to be largest producer of LNG by 2020 with production around 80-90 MTPA (**Figure 23**). LNG projects on the west coast are based on conventional gas whereas LNG projects on the east coast are based on unconventional coal bed methane. There are several projects planned on both the east and west coasts.

**Figure 23: Australian LNG projects**

| Project | Status | Predicted Start Date | Capacity (MTPA) | Source Gas | Oil/ Condensate (bpd) |
|---|---|---|---|---|---|
| Gorgon | Construction | 2014 | 15.0 | Conventional | 140,000 |
| Wheatstone | Construction | 2016 | 8.6 | Conventional | 80,000 |
| Pluto | Commissioning | 2012 | 4.8 | Conventional | 24,000 |
| Ichthys | FEED | 2017 | 8.4 | Conventional | 150,000 |
| GLNG | FID | 2015 | 7.8 | CBM | - |
| QCLNG | FID | 2015 | 8.6 | CBM | - |
| APLNG | FID | 2016 | 9.0 | CBM | - |
| Prelude | FID | 2017 | 3.6 | Conventional | 40,000 |

**Source: Galway**

Canada has several LNG projects, which could be potential sources.

- Kitimat LNG – The project sponsors are Apache, Encana and EOG. The project design capacity is 5 MTPA with a potential additional 5 MTPA train. This project has obtained its export licence. Its marketing objective is dedicated point to point contracts with Asian buyers. Train 1 startup is likely in 2018.

- Shell J.V. (Kitimat): The project is a Shell joint venture project with Mitsubishi, CNOOC and Kogas. Majority of supplies likely dedicated for joint venture partners' supply portfolios which implies HECO will have to buy directly from off takers' global LNG portfolio. The project consists of 8-20 mtpa of export capacity; still in the initial stages of planning.

- Other projects include: BC LNG (1.9 mtpa), Petronas/Progress LNG, and BG's LNG project, all in initial stages of development.

Several brownfield/greenfield projects are proposed in the US and expected to come online post 2020 (**Figure 24**). These terminals are in various stages of regulatory approval (with only Sabine Pass authorized to construct). Most of the proposed projects are conversions or retrofits of existing LNG regas facilities putting them at a significant cost and timing advantage compared the Greenfield projects. Sabine Pass (18 mtpa), Cameron (12 mtpa), Lake Charles, Cove Point (5 mtpa) and Freeport (15 mtpa) are brownfield expansions while Jordon Cove (6-9 mtpa), Oregon LNG, and Corpus Christi are Greenfield projects. Most of the brownfield LNG projects are well connected to the US pipeline grid and would require minimal investment in pipeline infrastructure to meet liquefaction needs.

Figure 24: US LNG projects


Source: Galway

LNG sourced from the US terminals will likely be sourced at prices indexed to local US hub prices such as the Henry, potentially providing significant fuel saving for HECO compared to Fuel Oil. With that said, we believe projects in US have either less bankable sponsors or sponsors that don't have prior liquefaction plant operational experience.

## 3.2 HECO Demand Scenarios

Galway analyzed HECO's future LNG requirements in light of its ability to secure liquefaction capacity/LNG supply as well as its negotiating leverage in securing this capacity at attractive pricing terms. Based on HECO's plans for power generation in the future, Galway developed 3 scenarios to forecast the demand for LNG as shown below (**Figure 25**).

The analysis revealed that only the high demand scenario potentially positions HECO as an anchor customer for a LNG project. Even then, however, the volume of LNG would not be viewed as material by most suppliers. The drop off in demand further complicates the situation for HECO. The annual volume commitments in the long-term LNG SPAs will need to be ratcheted down to match the declining consumption profile, possibly increasing LNG supply cost. This would also limit negotiation leverage for HECO and may even reduce supplier interest.

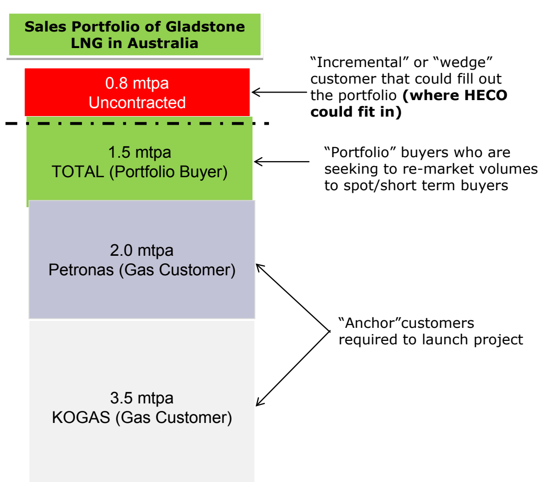
**Figure 25: HECO LNG demand scenarios – pros and cons**

| Case | Volume First 10 Years | Volume Next 10 years | Pros | Cons |
|---|---|---|---|---|
| Refuel Existing w/ LNG-No Big Wind | 0.85 | 0.55 | • Initial volume may be on the "cusp" of being an anchor customer for a LNG supply project.<br>• HECO may have some negotiating leverage to lower its liquefaction price | • HECO will need to wait on the liquefaction facility locking in other customers (to issue FID)<br>• Could be difficult to find alternative suppliers in case plant is down due to larger volume<br>• Need about 1.2 ships from GOM |
| Refuel Existing & Kalaeloa OR Retire W5-8, K1-6 & Replace with CCs + LNG Kalaelao | 0.65 | 0.4 | • Initial volume may be likely insufficient to position HECO as a major sale<br>• Best case for optimizing 1 LNG ship from GOM<br>• HECO could consider breaking purchases into 2 SPA's with different suppliers | • HECO will need to find wait on the liquefaction facility to lock up other customers (to issue FID)<br>• HECO would be considered an incremental sale by most LNG suppliers |
| Retire W5-8, K1-6 & Replace with CCs + Biocrude Kalaelao | 0.525 | 0.275 | • Volume is small enough that many spot options may be open to HECO<br>• HECO could consider breaking purchases into 2 SPA's with different suppliers | • HECO would be considered an incremental sale<br>• HECO has unused capacity on LNG ship (full ship is 0.65 mtpa from GOM) |

**Source: Galway**

Galway therefore believes that HECO will most likely act as a "wedge customer" and therefore need to wait on liquefaction projects to lock in other anchor tenants before a supply/liquefaction capacity deal can be finalized. The following graphic illustrates how HECO could potentially fit into the Gladstone LNG project (**Figure 26**)

**Figure 26: HECO's LNG Project Fit**

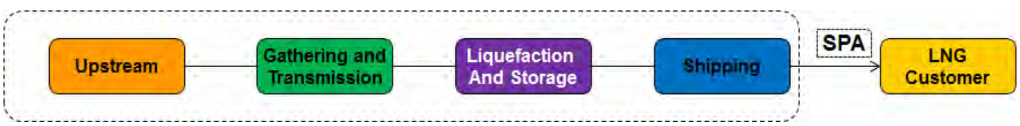



**Source: Galway**

## 3.3 Project Commercial Structures

There are significant differences in commercial structures of Canadian and E. Australian projects compared to their US counterparts. The Canadian/Australian projects follow more traditional LNG Mode where upstream resource owners drive project and sell LNG via an SPA. The primary driver is to monetize gas; and given the high cost structure of these projects, sellers want to sell at oil index. In many cases the upstream assets, LNG plant and shipping component are fully integrated from an ownership perspective as shown below (**Figure 27**):

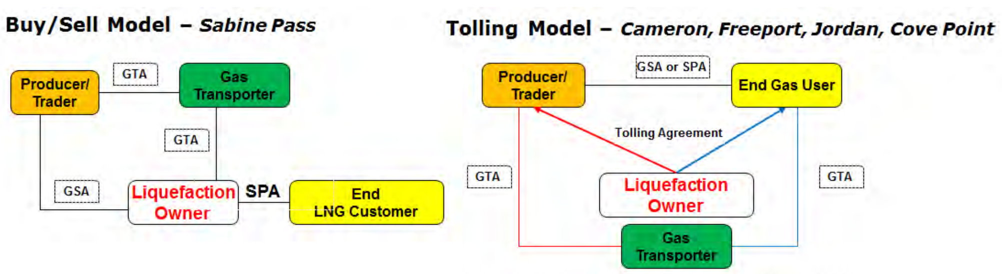
**Figure 27: Traditional LNG Commercial Structure**




**Source: Galway**

On the US side, two distinct models have emerged: the tolling model and the "buy/sell" model as shown below (**Figure 28**):

**Figure 28: US LNG Commercial Structure**




**Source: Galway**

The LNG SPAs for the Sabine Pass project are structured on a buy/sell model:

- LNG is being sold to customers
- Liquefaction owner is responsible for securing Gas
- They are a market maker and take risk/reward of this transaction

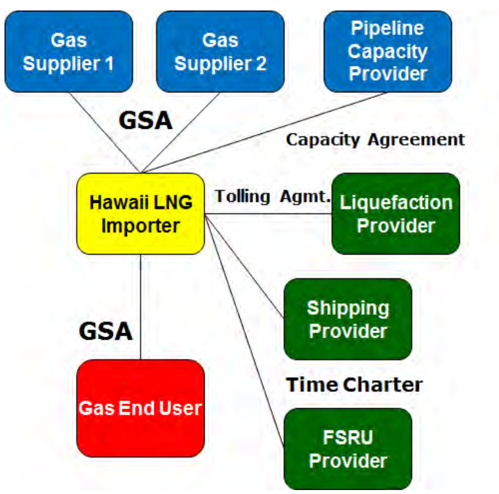
- Seeking more than a return on physical assets
- Customers have right to suspend gas offtakes and pay a minimum fee for liquefaction capacity
- Benefit for customers with large seasonality (e.g. KOGAS)

Freeport, Cameron, Jordon and Cove Point seem to follow the Tolling model:

- Liquefaction capacity being committed long term
- Could be driven by producer or gas customer
- Sponsor takes risk/reward of GSA transactions
- Liquefaction owner seeking return on physical assets

Since the capacity at Sabine Pass has been sold to multiple parties, HECO will now have to take up liquefaction capacity if it were to participate in US to souring Henry Hub index LNG. A typical commercial structure for HECO may be as follows (**Figure 29**):

**Figure 29: Potential Commercial Structure for HECO**




**Source: Galway**

## 3.4 Procurement Options

Galway believes HECO has three broad procurement options with various combinations of the three:

1. Buy on traditional price and terms: These projects are primarily monetizing stranded gas (such as in Canada/E. Australia) supported by majors with proven LNG terminal development and operational track record. Suppliers will require HECO commit to a take or pay ex-ship agreement with possibly minimal volume flexibility. The LNG pricing will most likely to be indexed to JCC, with potential for evolution of the pricing formula to include HH or other gas liquid trading hub. With that said, sponsors will need to price LNG at long-run marginal cost. Galway expects the FOB price for HECO under such structure to range between 13.8-15.0% of JCC depending on prevailing market conditions at time of executing the contract. HECO could contract with LNG tied to a project or buy directly from a portfolio supplier like BG, BP, Total or Gazprom.

2. Buy Short Term/Spot through tendering: Under this option HECO solely relies on spot purchases for its gas needs given the supply risk for spot volumes is minimal. HECO will essentially play the Henry Hub–FO arbitrage supported by downstream investment in LNG receiving terminal or FSRU. The investment in regas will potentially be stranded if price spreads go against HECO, but the risk is arguably no worse than the existing situation. HECO will be a price taker with prices linked to JKM or NBP. The current JKM LNG price is $15.4/MMBtu. HECO is well positioned to play short/spot market since the volume requirement is small enough that supply liquidity isn't an issue. Hawaii is also ideally located to access supply from both Atlantic (via Panama Canal) as well as Pacific basin.

3. Buy US Liquefaction capacity & source US gas: This is an emerging model in the US with varying degree of risks (financing risk, development risk, and regulatory risk). Unless export permits are granted by the DOE, projects cannot proceed. It remains to be seen how many projects eventually receive DOE export permits. As of today only Sabine Pass is fully permitted with all its capacity sold under long-term contracts. Galway expects LNG price under this option to range from 115% HH+3.50-4.00/MMBtu with higher tolls for customers with lower volumes.

Buyers use both competitive tenders and multi-party negotiations to procure LNG supplies. LNG Suppliers (particularly new projects) prefer the negotiation process. Given that HECO is new to the game and has small volumes, a tender process may not work for HECO. It generally takes, for a new buyer, 12-18 months to lock in LNG supply since the suppliers will undertake extensive due diligence to assess HECO's market potential. The process starts with meeting various suppliers and introducing HECO and vice versa (3-4 mos), entering into an MOU (perhaps with a term sheet) with the preferred supplier: 6 mos, entering into a HOA (with fully drafted key commercial terms): 9-12 mos, and completing negotiation of fully termed Sales and Purchase Agreement (SPA) 18 mos. While SPA negotiations are on-going, there may well be other negotiations HECO will be involved in such as Time charter party for Ship and FSRU or Tolling Agreement with the Liquefaction provider.

## *3.5* Pricing Structure

Typical LNG Price Structure in Pacific Basin: A typical pricing formula may look like:

**P($/**MMBtu**)=[slope(%)] x JCC + A**

Where,

JCC is "Japan Crude Cocktail" or "Japan Customs Clearance"

- Weighted average price of all crude oil imported into Japan
- Standard benchmark for all long-term Asian LNG contracts
- Reported monthly in arrears by Japan Custom Authorities

Slope is a multiplier to crude price (JCC)

- Traditional benchmark slope = 14.85% (crude parity = 17.2%)
- Highest known value = 17% (Short-term,Qatar,2007)
- Lowest known value = ~ 5% to 8% (Chinese, early 2000's)
    - Offset by high "A" factor to support financing

No standard benchmark for "A" factor

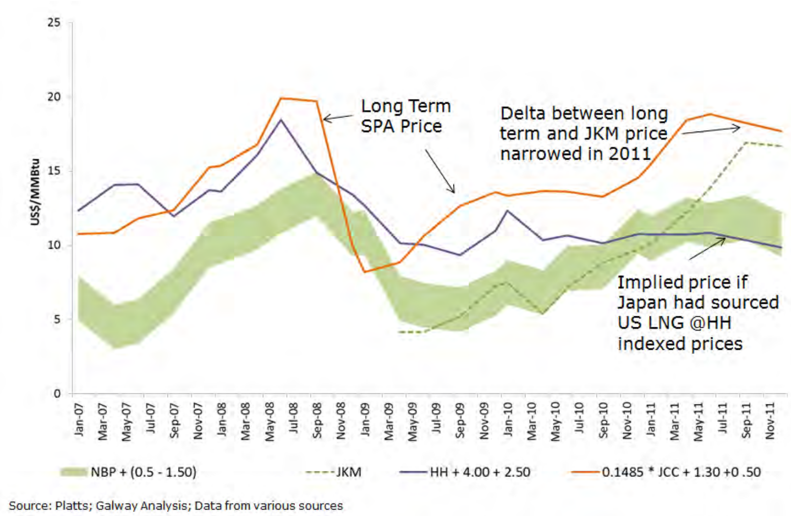
- In some SPA's, A = 0
- Sometimes used as a proxy for DES shipping costs
- In rare occasions, used as a floor price to support financing

Depending on market conditions (i.e. buyers/sellers' market), "S-Curves" are occasionally used to build in a collar

- A floor and ceiling price for JCC would establish a maximum and minimum price
- Sometimes, certain floor and ceiling JCC prices result in a different slope multiplier
- *Current crude price of $120/bbl would translate into a FOB price of almost $18.00*

**Figure 30** shows historical proxies for LNG spot deliveries to Japan under different pricing regimes. As seen, there is no global benchmark for spot LNG with prices ranging across a wide spectrum. Based on anecdotal evidence, Kogas once paid $22/MMBtu for a spot LNG cargo in 2008.

**Figure 30: Historical Proxy for LNG Spot Deliveries**




**Source: Galway**

Likely LNG Pricing Structure in US: A typical pricing formula in the US will likely take the following shape (**Figure 31**):

**Figure 31: LNG Pricing Structure in US**


**Source: Galway**

Where,

**A: Add on supplement to Henry Hub price** that may be required by a gas producer for a medium/long term sale. Galway has seen ranges of \$0.50 - \$2.00/MMBtu for **A**

**B: Pipeline/basis charge** from producing area to Liquefaction Terminal. Range of cost for B could be as high as \$1.90 for Jordan Cove to as low as \$0.20 near Gulf Coast.

**C: Liquefaction tolling charge** Lowest **C** to date is \$2.25 charged by Sabine Pass to BG, Later deals at Sabine pass raised C charge to \$3.00. *Galway believes that \$4.00 is a realistic number for HECO*

The Price Formula Ranges for HECO based on 0.8 mtpa (105 mmscfd) are as follows:

- High: P = HH + 2.00 + 1.90 + 4.00 --→ HH + 7.90/MMBtu (FOB)
- Low: P = HH + 0.50 + 0.20 + 3.00 ---> HH + 3.70/MMBtu (FOB)

**Figure 32** provides commercial terms and conditions for the Sabine Pass project:

**Figure 32: Sabine Pass LNG Current Liquefaction Customers**

| Customer | Quantity (mtpa) | Train | Commodity Charge ($/MMBtu) | Capacity Charge ($/MMBtu) |
|---|---|---|---|---|
| **British Gas** | 3.5 | 1 | 115% HH | 2.25 |
| | 2.0 | 2, 3, 4 | 115% HH | 2.50 |
| **Gas Natural Fenosa** | 3.5 | 2 | 115% HH | 2.50 |
| **KOGAS** | 3.5 | 3 | 115% HH | 3.00 |
| **GAIL** | 3.5 | 4 | 115% HH | 3.00 |

**Source: Galway**

Other commercial terms include:

- LNG Sales price is FOB; Term: 20 years
- Some portion of Liquefaction payment escalated @ US CPI
- Buyers can choose to cancel receipt of a cargo at beginning of year OR by giving notice in-year prior to 20th day of Month 2
- All Buyers, except Kogas, forfeit rights to any cancelled cargo
- CP's: Financing, approvals to build/operate plant, Seller FID, Export Authorizations, etc
- CP Target Date Dec 31, 2012 (then satisfied or waived)

Regardless of the commercial model, a key issue in sourcing LNG from US is that the buyer is exposed to HH vs. Oil price spread. HECO could need to rely on physical and financial risk management tools to mitigate cross commodity exposure to the balance sheet (HH vs. diesel). Few examples are as follows:

1. **Straight Swap (10 Years – Henry Hub): March 27, 2012**- $4.55/MMBTU. Add estimated liquefaction, shipping, re-gasification, and 15% pricing premium totaling about $8.00/MMBTU implies $12.55/MMBTU delivered price

2. **Costless Collars: March 27, 2012**: Call strike at $5.50/MMBTU and put strike at $3.75/MMBTU yielding delivered natural gas price capped at $13.50/MMBTU

(worst case scenario) and Contango case delivered natural gas price at $11.75/MMBTU (best case scenario)

3. **Fuel Switching Optionality**: Both the swap and cap amplify the option to switch to the cheapest fuel in a scenario with low oil price and high natural gas prices. Divert physical natural gas to highest priced markets while monetizing in-the-money swaps or call options and switch to fuel oil or diesel.

**Implications of supply disruptions to the Hawaiian economy and public safety**

The LNG industry has a strong track record of being a reliable and continuous supplier of long term volumes to their customers. However, there could be odd-instances of LNG supply disruption due to one of the following reasons;

1. **Force Majeure at the Liquefaction Facility:** This occurs when the supplier fails to supply due to issues which are not under their control. There have been instances like this in the past when the project was shut down for few days due to labor disputes, fire, local unrest or bad weather condition.

2. **Force Majeure due to LNG Shipping:** This occurs when the timer charter party fails to supply due to issues which are not under their control, like weather, labor disputes, etc.

3. **Gas Reserves Issue:** Historically, gas reserves were not much of an issue for LNG supply projects. However, new trends have started to emerge in places like Indonesia where the upstream reservoir is not producing to the expected level and hence the fall in LNG projection from Bontang. With more unconventional gas based LNG coming into the market, there are possibilities for issues due to uncertainty in the way the reservoir behaves.

4. **Project Start-up Delay:** This was not a major problem in the past; however there have been a number of cost related and man-power related issues with projects that are currently under construction, which might delay the project start-up date.

Contract terms and risk-management instruments might eventually address some of the financial risks associated with possible supply disruptions. Force Majeure risk is the most difficult one to manage as every LNG shipment has huge monetary value and it is hard for one entity to deal with all of that risk. However, the utility still needs to deal with the market issue, and therefore having a political-risk insurance or other financial instrument will only solve Hawaii's financial risk and not the supply risk.

However, the LNG requirement during a long-term supply disruption could be managed by one of the few options listed below;

1. LNG Storage: Having a FSU (Floating Storage Unit) or an onshore LNG storage tank will help manage any short term supply disruption, as the storage tank will act as the buffer volume to manage for the shortfall days or until finding an alternative supply source. Having a backup fuel supply could also mitigate risk.

2. Spot Trade: If the supply disruption is just for a few cargoes, then the growing spot trade will help to manage any immediate LNG requirements. Out of the total LNG trade in 2012, around 20% of the trade (around 45 MTPA) was on a spot basis. The actual volume of spot trades is expected to grow significantly with more and more new LNG supply projects coming online between now and 2017. With this increased liquidity in the system, any short term supply disruption could be well managed. The only risk involved with spot trade is that the price of spot LNG could be anything depending on the market fundamentals. Historically the price for spot LNG has been between $6 to $22/MMBtu.

3. Portfolio Players: If a supply disruption happens for a prolonged period of time (between a few months and a couple of years), then it is prudent to sign a short term supply deal with one of the portfolio player(BG, Shell, GDF Suez and etc) to limit the spot price risk. The portfolio suppliers have increasingly started to hold their equity volume from their projects on their balance sheet and to trade it on the sport market or open it for short term contracts.

# 4 Infrastructure Requirements

This section of the report provides a high-level overview of LNG regasification and shipping solutions available to HECO, evaluates solutions that may work better than others and identifies the most economic combined solution for regas and shipping.

In general, LNG supply sourcing strategies aim to establish a competitive environment amongst potential suppliers to obtain a competitive price and other fair terms and conditions. An “acceptable” infrastructure solution (regas and shipping) plays an important role in facilitating a high level of interest and competition amongst potential suppliers. Any buyer should expect that LNG suppliers will conduct significant financial (e.g. creditworthiness, etc.) and technical (e.g. off take reliability, regas infrastructure reliability etc.) due diligence. Therefore, having a proven and reliable LNG receiving infrastructure solution is an important component of establishing credibility with suppliers.

Galway has focused on the following dimensions to assess the various LNG regasification and shipping options that could be available to HECO to import LNG in Hawaii.

1. LNG import terminal infrastructure:
   - Onshore vs. Floating
   - FSRU at berth vs. FSRU at buoy
   - Standard scale vs. mid/small scale solutions
   - Business models for the terminal
   - Project development and permitting

2. LNG shipping infrastructure
   - Standard scale vs. mid/small scale
   - DES vs. FOB sales
   - Jones Act considerations
   - Panama Canal expansion’s impact on supply options

## 4.1 Regasification Options

As mentioned earlier, LNG infrastructure must be acceptable to as many potential suppliers as possible to enable the buyer to create a competitive LNG supply environment. Acceptability would be considered in terms of the following:

- The infrastructure should be designed, built and operated to safely and reliably accommodate LNG ships. Important factors would include berthing/docking (berth configurations, acceptable met-ocean conditions), LNG unloading (connectivity and rate), LNG storage (capacity), etc.
- The infrastructure should be compatible with potential suppliers' LNG shipping fleet.
- There should be focus on operational reliability of the LNG infrastructure and downstream markets to understand the risks of service disruptions at the terminal and the resulting impact on supply delivery schedule and shipping portfolio management (applies to both DES and FOB sales).

It is also important that the LNG infrastructure be based on proven and reliable solutions in order to support HECO's supply strategy. Use of novel liquefaction process, loading unloading techniques etc. may limit supplier interest and impact bankability of HECO's value chain. There are several choices to be made in terms of LNG infrastructure.

One of the key decisions is whether to go for onshore or a floating regas solution; each with its pros and cons. Onshore terminals include facilities such as berth, jetty, one or multiple steel and concrete storage tanks (160,000-200,000 cm), vaporizers and utilities. In a U.S. jurisdiction, the federal permitting process is overseen by the Federal Energy Regulatory Commission ("FERC") and usually takes about 3 years. It generally takes 3-4 years to build a Greenfield LNG regas facility once permits have been secured. The US Coast Guard which oversees offshore terminals has implemented a streamlined application process mandated by the Deepwater Port Act of 1974 that is designed to yield a decision within 1 year of receipt of an application for construction of an offshore LNG terminal.

Onshore regas terminals have been the industry standard for years with extensive history of reliable operations. Capital costs tend to be very high and can vary within the range of \$0.5-1.5 billion (based on size and siting characteristics). These terminals are generally most suitable for high volume baseload service to amortize the relatively high annual cost of service, operating expenses (which tend to be largely fixed), debt service, return of and on equity, taxes, etc., and achieve reasonable unit/throughput costs from economies of scale. Given HECO's smaller volume requirement, it may be very challenging to achieve economies of scale with a standard size onshore LNG terminal and therefore the throughput/unit costs may be significantly higher than alternative options.

Floating regas solutions, on the other hand, are an emerging concept but getting increased acceptance within the industry (with ~10 currently operating worldwide). Floating solutions include a mooring system, modified LNG ship with vaporizers and additional utilities ("FSRU") and a pipeline connection to end users/gas transmission infrastructure. Generally, floating LNG solutions can be implemented faster than onshore facilities and may result in lower up front capital costs for the customer. Just as with onshore terminals, the unit/throughput cost is driven by the volume of LNG being delivered. However because of the lower CAPEX costs, economies of scale can generally be achieved at lower volumes than onshore terminals.

The comparison between onshore and floating terminals is shown in **Figure 33**:

**Figure 33: Potential Commercial Structure for HECO**

| Onshore | Floating |
|---|---|
| • Marine facilities (berth, jetty)<br>• 1 or more steel & concrete tanks (typically 160,000 to 200,000 m3)<br>• Vaporizers (incl. heat source)<br>• Utilities | • Mooring system<br>• Modified LNG ship with vaporizers, additional utilities (FSRU)<br>• Pipeline Connection |
| • Industry "Standard"<br>• Extensive history of reliable operations<br>• Cost $0.5 - $1.5+ Billion<br>• Generally support larger loads<br>• Require deep water port (42 feet) & protected waters<br>• Compatible with multiple vaporization technologies (operating costs)<br>• Construction: 3-4 years<br>• US federal permitting: ~3 years (new terminal)<br>• Most suitable for base load service (economics)<br>• Expandable (site specific)<br>• "Stranded" | • Emerging, but increasingly accepted<br>• Cost: FSRU $100-$250+ MM (Conv. vs. New)<br>Infrastructure $50 - $200+ Million<br>• Unit costs can be higher depending on throughput<br>• Require deep water port (42 feet) & protected waters (for base load service)<br>• Limited vaporization technologies<br>• Construction: 3-12 months infrastructure<br>12-30 months FSRU<br>• US Federal Permitting: 2-3 years<br>• Increasingly used for base load service<br>• Limited/No expandability<br>• Multiple configurations have been implemented (shore side & offshore)<br>• Can be relocated |

**Source: Galway**

Floating LNG terminals are becoming more acceptable amongst the industry but their configuration (e.g. mooring system and interface with FSRU and LNG delivery ship) is very important to suppliers. As mentioned above, suppliers will conduct significant technical and operational due diligence and evaluate each floating LNG terminal on a case by case basis (just as they would for an onshore terminal). Suppliers will focus on LNG ship to FSRU/berth interface (in terms of safety and reliability). They each have individual preferences and risk tolerances on both the configuration of the mooring/berthing infrastructure and interface with the delivery ship. The choice of mooring configuration impacts the floating terminal's reliability and availability because of the impact of meteorological (wind) and ocean (waves and currents) conditions ("met-oceans conditions"). The interaction of the met-ocean conditions with the berth, FSRU and LNG delivery ship will impact the availability to regasify LNG and send out natural gas as well as the availability to berth and unload the delivery ship. As mentioned above, this reliability will be carefully scrutinized by LNG suppliers in their risk analysis to assess the potential impact on LNG supply delivery schedule and impact on shipping fleet portfolio.

Galway has identified several floating terminals options for HECO based on scale and possible location as shown in **Figure 34**:

**Figure 34: HECO's Options for Floating Terminals**

| | "Standard" Scale Solutions | Small/Mid Scale Solutions |
|---|---|---|
| **Shore Side in Kalaeloa Harbor** | • FSRU with Single Berth & "Ship-to-Ship" LNG transfer<br>• FSRU with Double Berth & "Across the berth" LNG Transfer | • Mid Scale FSRU with Single Berth & "Ship-to-Ship" LNG transfer<br>• Mid Scale FSRU with Double Berth & "Across the berth) LNG Transfer<br>• Regas ATB Barge with Single Berth |
| **Offshore Barbers Point or Kahe Point** | • FSRU with Single Submerged Mooring Buoy with STS<br>• FSRU with Above Water Single Point Mooring (fixed or floating) with STS<br>• 2 FSRU's with Single Submerged Mooring Buoy<br>• 2 FSRU's with Double Submerged Mooring Buoys | • Mid Scale FSRU with Single Submerged Mooring Buoy with STS<br>• Mid Scale FSRU with Above Water Single Point Mooring (fixed or floating)with STS<br>• Regas Barges with Single Submerged Mooring Buoy |

**Source: Galway**

Standard Scale Shore Side Options

Under a double berth configuration, the FSRU is moored to one of the berths and connected to a gas pipeline with a high pressure arm while the delivery ship moors to second berth. LNG is transferred from the delivery ship to the FSRU 'across the berth' using hard arm. Relatively benign met-ocean conditions are required to a) allow the FSRU to remain moored to the berth and maintain high regasification reliability, and b) allow the delivery ship to moor to the berth, and remain at the berth for the full unloading operation, to maintain high LNG unloading reliability. Deep water access (42+ feet) is also necessary to accommodate the typical draft requirements of the FSRU and to accommodate the typical draft requirements of the global LNG shipping fleet. With the right met-ocean conditions, this configuration is generally accepted by most suppliers.

Under a single berth configuration, the FSRU is moored to the single berth and connected to a gas pipeline with a high pressure arm. The delivery ship moors to the FSRU (instead of a berth). This is called “double banking”. LNG is unloaded from the delivery ship unto the FSRU using ship-to-ship transfer (STS) using either flexible hoses or hard arms. As with the double berth configuration, relatively benign met-ocean conditions are required to a) allow the FSRU to remain moored to the berth and maintain high regasification reliability, and b) allow the delivery ship to moor to the FSRU, and remain moored to the FSRU for the full unloading operation, and maintain high LNG unloading reliability. Again, deep water access (42+ feet) is necessary to accommodate the typical draft requirements of the FSRU and to accommodate the typical draft requirements of the global LNG shipping fleet. Although there are several existing floating LNG terminals using this single berth, double banking configuration, not all traditional LNG suppliers have yet fully embraced this solution, and most of those that have, have stated a preference for hard arms vs. flexible hoses (**Figure 35**).

The floating terminal configuration that is currently more favored amongst traditional LNG suppliers is the double berth configurations as it mimics typical LNG unloading operation at an onshore terminal more closely than the single berth/double banking configuration.

As mentioned above, suppliers will evaluate each floating LNG terminal on a case-by-case basis, and may not provide significant feedback about their acceptance of a floating LNG terminal until it is fully engineered (and permitted). Therefore, in jurisdictions, like the U.S., where the permitting process a) requires the scope and design of the project to be clearly defined at the beginning of the process, and b) requires some of the studies and agencies reviews to be revisited/redone if one or more material project scope and/or design changes are introduced once the permitting process has started, selecting a configuration that is expected to be most broadly accepted by suppliers (based on the industry’s track record and general feedback from suppliers) may be preferable. This should help to minimize the permitting timeline risks and the risks of limiting the pool of potential suppliers once the procurement process starts.

GALWAY ENERGY ADVISORS LLC

**Figure 35: Double Berth and Single Berth Operation**


Port Pecem – Brazil (Golar)


Bahia Blanca – Argentina (Excelerate)

**Source: Galway**

STS is a relatively new method to transfer LNG from a ship to an FSRU (**Figure 36**). In this method, the LNG ship moors to the FSRU 'side by side' using fenders and mooring lines. Flexible cryogenic hoses (or hard arms) are connected between the FSRU and the delivery ship, which are used to transfer the LNG from the ship onto the FSRU. The FSRU can either be moored at a berth, at anchor, or underway in calm waters. As with any LNG transfer method, this can only be accomplished in calm waters where cross-ship movement remains within the stress tolerance of the mooring lines and the hoses/hard arms. The vast majority, over 95%, of STSs that have been done to date have been performed when the FSRU was docked at a berth.

**Figure 36: Ship-to-Ship Operations**

**Source: Galway**

Standard Scale Offshore Options

The most common mooring option for offshore floating LNG terminals involves using either one or two submerged mooring buoys. With a submerged mooring buoy, a loaded FSRU moors to the buoy and is connected to an underwater gas pipeline via the buoy connection located in the bow of the hull. Using a buoy configuration, an FSRU can tolerate much higher met-ocean conditions than the berth configurations and can therefore maintain regasification reliability in “rough” sea states. Deeper water is required to accommodate the buoy, around 200 feet, but as water depth increases the engineering requirements for the buoy system increase thereby increasing costs. Currently, the deepest installation is in ~280 feet of water. The economic limit for water depth may be 500 to 600 feet. It should be noted that buoy based systems have been used in very deep water (4,000 + feet) to support the production of oil using Floating Production Storage Offloading units (FPSO’s). So, although it may be technically feasible to locate an offshore floating LNG terminal in deeper water, the economics of a floating LNG terminal may not support the incremental capital expenditures associated with a deeper water installation (whereas the economics of producing a large offshore oil field may be much more accommodating to the incremental capital expenditure).

To reload an offshore FSRU that is moored to a buoy, the delivery ship could theoretically moor against the FSRU in a double bank configuration and unload the LNG onto the FSRU using STS with flexible hoses or hard arms. However, suppliers have not yet accepted STS while the FSRU is moored to the buoy. It has, in fact, never been attempted.

Therefore, to reload an FSRU using a single buoy mooring configuration, the FSRU must disconnect from the buoy, sail to calm waters to meet the delivery ship and load LNG using STS. Since the FSRU will be disconnecting from the buoy, service interruptions lasting three to four days for each reloading operation should be expected.

To maintain continuous regasification service and gas deliveries, the offshore floating LNG terminal needs to have two buoys and two FSRUs – one FSRU would be moored on one of the buoys and delivering regasified LNG while the other FSRU would be sailing to/ from the loading port. By timing the arrival and mooring of the reloaded FSRU from the loading port before the “on station” FSRU runs out of LNG inventory, continuous gas deliveries can be maintained.

Buoy-based solutions were conceptualized for seasonal and spot service. The only buoy-based systems were built offshore Boston and in the Gulf of Mexico, but have hardly been used (primarily because of the market conditions in North America).

An alternative to a buoy-based system is an above water single point mooring system (**Figure 37**). In this method, the FSRU moors to an above water single mooring point and connects to the gas pipeline and mooring system via a connection/turret in the bow of the FSRU. The FSRU would be supplied by delivery ships moored against the FSRU in a double-bank configuration and LNG transferred via STS transfer using hard arms. The FSRU hull must undergo modifications that would hinder the FSRU's shipping efficiency because it would be primarily meant for a more permanent installation. The only project using this configuration is under construction in Italy offshore the Tuscan coast (Offshore LNG Tuscana). There is no known LNG supply contract for this project and therefore the suppliers' comfort level with loading an FSRU at an above water single point mooring via STS is unknown. However, it should be expected that LNG suppliers will have the same issues as supplying a submerged buoy.

**Figure 37: Submerged Mooring Buoy Options**

Northeast Gateway – Boston, MA (Excelerate)

Rendition of Offshore LNG Toscana – Tuscany, Italy (Golar)

**Source: Galway**

Small/Mid-Scale Options

In addition to the aforementioned standard scale solutions, several small and mid-scale floating regasification concepts have been proposed. A comparison of the small and mid-scale floating regasification concepts proposed to HECO is presented below (**Figure 38**):

One of the floating concepts consists of a mid-scale FSRU, which is permanently moored to a shore side berth or offshore mooring point. (The concept proposed to HECO includes a mid-scale FSRU with a LNG storage capacity of 60,000 m$^3$). One or more small scale LNG ships, articulated tug/barges (AT/B) sail to and from the loading port to pick up LNG and transfer to the regasification barge via hard arms. The number of ships required depends on distance, load and ship storage volume.

The potential benefits of this option are as follows:

- The mid-scale FSRU is cheaper than a standard scale FSRU.
- It requires shallower water (i.e. 22 feet vs. 42 feet)
- A mid-Scale FSRU has a smaller footprint than a standard scale FSRU (180 m x 40 m vs. 290 m x 42 m), and so needs less space and smaller infrastructure (for example, berth).

The potential challenges involved include the following:

- A mid-scale FSRU has not yet been implemented, whereas small scale delivery ships are currently in use in specific trades in Japan and Scandinavia
- The concept promoters tend to only offer the infrastructure solution and no supplies.
- Traditional LNG production facilities may not want to serve small scale ships, or barges due to berth capacity and schedule coordination concerns.

**Figure 38: Fixed regas barge/ Sailing regas and storage ATB barge**


Rendition of Concept Proposed to HECO by GasFin

**Sailing Regas & Storage ATB Barge**

Concept Proposed to HECO by Veresen (Picture of a Petroleum Products

**Source: Galway**

Another concept involves the construction of a fleet of AT/B barges with LNG storage and on-board regasification ("regas AT/B"). One regas A/TB is temporarily moored to a shore side berth or an offshore mooring point, while one or more of the fleet's remaining regas AT/B's sails to and from the loading port to pick up LNG. Then they replace the moored barge when it is empty. The number of barges required depends on distance, load and AT/B storage volume.

The potential benefits of this concept are as follows:

- It is cheaper than a full scale FSRU.
- It can be located in shallower environments (20 feet vs. 42 feet).
- It has a smaller footprint than an FSRU (177 m x 28 m vs. 290 m x 42 m) and hence needs less space and smaller infrastructure (for example, berth).

The potential challenges of this concept are as follows:

- It is more capital intensive than using mid-scale FSRU/small scale ship combination because on-board regasification equipment is installed on all the barges.
- It is much slower than small scale ships (10 knots vs. 16 knots), therefore more barges and capital may be required.

Small and mid-scale onshore LNG storage and regasification terminals have been used in North America, Europe and Asia. These are mostly peak shaving LNG storage and regasification terminals serviced by trucks or co-located with small scale liquefaction. Some have been supplied via small or mid-scale ships from either small scale liquefaction (for example in Scandinavia) or transshipment from large onshore LNG terminals (for example, Japan). However, no floating small or mid-scale storage and regasification concept has as yet been implemented. There are no apparent technical reasons why a berth-based small/mid-scale floating solution would not work as these solutions use mostly proven equipment and technology. However, some 'teething' problems should be expected with the first project as, like as with most new implementations, unforeseen issues may arise. Detailed met-ocean studies must be completed on a case-by-case basis to determine whether offshore buoy-based or single point mooring solutions are feasible to ensure that such offshore solutions can be operated safely and to ensure that sufficient regasification and LNG unloading reliability can be maintained

The key impediment to the implementation of these solutions seems to be related to finding sources of LNG supply. On the one hand, concept promoters tend to only offer infrastructure solutions. On the other hand, traditional LNG production facilities may not want to serve small scale ships or barges because of concerns about loading berth capacity and loading schedule coordination (for example, Kitimat LNG may not have sufficient berthing slots to accommodate small ships). In addition, Galway does have some questions and concerns about the feasibility of using ATB barges in trans-oceanic service as opposed to inter-coastal service. A company with ATB barge engineering and operational experience has expressed concerns about whether ATB barges larger than 20,000 cubic meters could be used in trans-oceanic service (Veresen has proposed to HECO a concept using 30,000 cubic ATB barges). Further technical due diligence should be conducted to evaluate the suitability of using AT/B barges to serve Hawaii from North America.

As indicated earlier, ten floating LNG terminals have been successfully built, and another five are under construction or active development. All but one baseload floating LNG terminal are using berth-based configurations (**Figure 39**).

**Figure 39: Floating LNG terminals in existence/under construction/development**

| Country | Project | Developer/FSRU Provider | Configuration | Baseload or Spot Service | Status |
|---|---|---|---|---|---|
| U.S. | Gulf Gateway (Gulf of Mexico) | Excelerate Energy/ Excelerate Energy | Regasification ship, single buoy | Spot (only used a few times) | De-Commissioned 2011 |
| U.S. | Northeast Gateway (Boston) | Excelerate Energy/ Excelerate Energy | Regasification ship, double buoy | Spot (only used a few times) | In-Service 2008 |
| U.S. | Neptune (Boston) | GDF SUEZ/ Hoegh LNG | Regasification ship, double buoy | Spot (only used a few times) | In-Service 2009 |
| Argentina | Gas Port Bahia Blanca | Repsol YPF & ENARSA/ Excelerate Energy | Regasification ship, single berth, flexible hose STS Transfer | **Baseload** | In-Service 2008 |
| Argentina | Gas Port Escobar | Repsol YPF & ENARSA/ Excelerate Energy | Regasification ship, single berth, flexible Hose STS | **Baseload** | In-Service 2011 |
| Brazil | Pecem | Petrobras/ Golar LNG | Regasification ship, double berth, across-the-berth transfer | **Baseload** (seasonal) | In-Service 2008 |
| Brazil | Guanabara Bay | Petrobras/ Golar LNG | Regasification ship, double berth, across-the-berth transfer | **Baseload** (seasonal) | In-Service 2009 |
| Indonesia | Jakarta Bay | PGN & Pertamina/ Golar LNG | Regasification ship, single Berth, Hard arms STS | **Baseload** | Under Construction |
| Indonesia | North Sumatra | PGN/ Hoegh LNG | Regasification ship, single Berth, Hard arms STS | **Baseload** | Under Construction |
| Italy | Offshore LNG Toscana (OLT) | OLT/ Golar LNG | Regasification ship, turret mooring, Hard arms STS | **Baseload** | Under Construction |
| Kuwait | Mina Al-Ahmadi | Kuwait National Petroleum Company/ Excelerate Energy | Regasification ship, double berth, across-the-berth transfer | **Baseload** | In-Service 2009 |
| Lithuania | Klaipeda | Klaipedos Nafta/ Hoegh LNG | Regasification ship, single Berth, Hard arms STS | **Baseload** | Under Construction |
| UK | Gas Port Teeside | Excelerate Energy/ Excelerate Energy | Regasification ship, single berth | Spot (only used a few times) | In-Service 2007 |
| UAE | Dubai | Shell/ Golar LNG | Regasification ship, single berth, flexible hose STS Transfer | **Baseload** | In-Service 2010 |

**Source: Galway**

## 4.2 Galway's Assessment of Options for HECO

All currently operating baseload floating LNG terminals have been built near shore in calm and protected waters using one or two berths. This generally provides the most reliable solution in terms of availability and, so far, is the only configurations accepted by the traditional LNG suppliers. There are limited suitable locations in Oahu to accommodate berth based solutions. For berth-based floating terminal solutions, Kalaeloa Harbor and Pearl Harbor may be the only viable sites.

- Kalaeloa Harbor
  - It is a well protected harbor with relatively deep water (~38 feet), although depth will have to be increased to 42+ feet to accommodate an FSRU and LNG delivery ships.
  - It is close to HECO's plants and the hub of the fuel pipeline distribution infrastructure.
  - It may need to be expanded to accommodate standard scale FSRUs and/or LNG berth for delivery ships.
- Pearl Harbor
  - From a functional perspective, it is likely to be the best site as it is protected, in calm waters and closer to major power and gas load customer.
  - HECO should consider working with the U.S. Navy to establish the viability of deploying an FSRU based terminal at a under (or unused) site.
- Port of Honolulu
  - It is not likely suitable due to limited water depth, extensive security zones and proximity to active airport runways.
- Kane'Ohe Bay (southern part)
  - It is not likely suitable because of extensive prohibited areas in the harbor, proximity to population, and the need to construct a cross-island pipeline to HECO's plants, which would very likely be very challenging.

Met-ocean conditions are a key determinant of the feasibility of floating LNG solutions and STS (either 'across the berth' or 'side by side'). Although, met-ocean conditions in Kalaeloa Harbor are expected to be sufficiently mild because of the harbor protection, detailed met-ocean studies are required to fully vet the feasibility of near shore floating solutions. Pearl Harbor should pose no issues.

Detailed studies are also required to vet the feasibility of any offshore solution. Some of the small/mid-scale floating LNG terminal concepts contemplate either a small/mid-scale FSRU or regas AT/B to either be reloaded using STS or swapped. The rule of thumb is that STS should be feasible with wave heights less than 1.5 to 2 meters and dominant wave period of less than 8 seconds. Data obtained from PacIOOS's Barber Point station 51204 between October 13th, 2010 and January 31st, 2012 indicates that floating options using STS could be limited as seen below:

- Dominant wave period – 86% of observations exceeded 8 seconds (please see appendix for data graphs)
- Wave height – 5% of observations exceeded 2 meters and 24% of observations exceeded 1.5 meters (please see appendix for data graphs)

Based on this preliminary data, there is some uncertainty whether the offshore small/mid-scale FSRU or regas AT/B concepts are suitable offshore either Barbers Point or Kahe Point assuming that continuous LNG supply is required. If occasional interruptions can be tolerated then there is more flexibility in finding a solution (as noted below).

To maintain continuous regasified LNG deliveries for an offshore floating LNG terminal, a double configuration is required and, as mentioned above, HECO would be required to use/charter two FSRU's. For this configuration, detailed met-ocean studies are required to assess the reliability of the "on-station" FSRU to remain moored to the buoy, and to assess the reliability of the "returning" FSRU to grab and connect to the second buoy.

In a single buoy configuration, reloading the FSRU while at a buoy using STS is very unlikely. LNG suppliers are yet to accept this process and met-ocean conditions offshore Barbers Point or Kahe Point appear to be unsuitable for STS. Therefore the alternatives to reload the FSRU with a single buoy configuration are as follows:

- The FSRU suspends gas deliveries and sails to a meeting point with calm water conditions in order to conduct an STS with the delivery ship. Further met-ocean studies are required to find one or more locations in Hawaii where sufficiently calm conditions consistently prevail to assure reliable STS operations. Galway is, however, not aware of any such potential location(s) other than deep water protected bays or ports such as Pearl Harbor or Kalaeloa Harbor. In addition, it is not clear that traditional suppliers would become comfortable supplying a baseload supply of LNG using open-water STS operations. **Therefore, this option seems unlikely to be feasible**.
- Use 2 FSRUs (one on-station and one sailing to and from the loading port) and temporarily suspend gas deliveries to switch FSRUs at the buoy. This would result in some suspension of gas deliveries while the FSRU's swap positions at the buoy (estimated 12 hours for each swap). Therefore the reliability of this configuration is dependent on the swapping frequency and the required met-ocean conditions to effectuate the swap.

The above comments are offered in the context that all HECO power stations just use natural gas a fuel. Galway understands that HECO plans to employ dual fueled facilities on some of its power stations hence a generally continuous LNG supply with the occasional interruption may be feasible. In this case, less expensive options may be available to HECO.

All berth based floating solutions appear feasible; full scale offshore solutions are likely to require 2 FSRUs whereas no small or mid-scale offshore solution appears feasible. Based on this initial assessment screen, the regasification infrastructure options available to HECO can be summarized in **Figure 40**.

**Figure 40: Summary of options for regasification infrastructure**

| | "Standard" Scale Solutions | Small/Mid Scale Solutions |
|---|---|---|
| Shore Side in Kalaeloa Harbor | • FSRU with Single Berth & "Ship-to-Ship" LNG transfer<br>• FSRU with Double Berth & "Across the berth" LNG Transfer | • Mid Scale FSRU with Single Berth & "Ship-to-Ship" LNG transfer<br>• Mid Scale FSRU with Double Berth & "Across the berth) LNG Transfer<br>• Regas ATB Barge with Single Berth |
| Offshore Barbers Point or Kahe Point | • ~~FSRU with Single Submerged Mooring Buoy with STS~~<br>• ~~FSRU with Above Water Single Point Mooring (fixed or floating) with STS~~<br>• 2 FSRU's with Single Submerged Mooring Buoy<br>• 2 FSRU's with Double Submerged Mooring Buoys | • ~~Mid Scale FSRU with Single Submerged Mooring Buoy with STS~~<br>• ~~Mid Scale FSRU with Above Water Single Point Mooring (fixed or floating)with STS~~<br>• Regas Barges with Single Submerged Mooring Buoy |

**Source: Galway**

*Green: these solutions appear feasible pending further siting considerations

Orange: there are concerns about viability because of met-ocean conditions and lack of a track record (these have never been implemented)

Red: these are unlikely because of STS challenges and the lack of supplier acceptance

In addition to floating LNG terminal solutions, there could also be a couple of onshore alternatives near Kalaeloa harbor

- Single tank standard scale onshore LNG terminal – A site of over 100 acres is adjacent to the existing pier and could accommodate a single tank of 160,000 to 180,000 cubic meters, regasification equipment and other infrastructure such as buildings, utilities, etc. It will be necessary to dredge the harbor in order to accommodate LNG ships as the current depth is not sufficient to accommodate them (38 feet vs. required 42 feet). The existing pier is also likely to be too busy and not long enough to accommodate both coal deliveries and LNG deliveries (assuming that two berths must be maintained for the coal terminal). Therefore a new berth will also need to be added.

- Small scale onshore LNG terminal – Either the 100+ acres site adjacent to the existing pier or a site of approximately 25 acres in the northeast corner of the harbor could potentially accommodate a small scale LNG terminal with a 60,000 cubic meter tank, regasification equipment and other infrastructure such as building and utilities, etc. The current harbor depth is sufficient to accommodate small scale ships (38 feet vs. required 22 to 24 feet). The existing pier is likely to be too busy to accommodate small scale LNG ships; therefore a new berth is likely to be needed.

## 4.3 Regas Solution Economics

The economic analysis of HECO's regasification options seems to suggest that small or mid-scale options provide the lowest per unit costs (**Figure 41**). However shipping cost needs to factor in to evaluate and compare economics for the combined regas + shipping infrastructure. Lower shipping efficiencies, which are expected for small or mid-scale shipping, may offset any regasification cost advantages for small or mid-scale terminal infrastructure.

**Figure 41: Economic Analysis of HECO's Regasification Options**

| | HECO Regas Economic Analysis | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| Regas Options | Y1 2020 000$ | 0.85 MTPA 2020 US$/mmbtu | 0.65 MTPA 2020 US$/mmbtu | 0.525 MTPA 2020 US$/mmbtu | Y11 2030 000$ | 0.55 MTPA 2030 US$/mmbtu | 0.4 MTPA 2030 US$/mmbtu | 0.28 MTPA 2030 US$/mmbtu |
| Onshore LNG Terminal | 164,524 | 4.00 | 5.23 | 6.48 | 171,526 | 6.45 | 8.87 | 12.90 |
| Small Scale Onshore LNG | 70,142 | 1.71 | 2.23 | 2.76 | 73,419 | 2.76 | 3.80 | 5.52 |
| 2 X FSRU - Double Offshore Buoy | 82,473 | 2.01 | 2.62 | 3.25 | 86,907 | 3.27 | 4.49 | 6.54 |
| 2 X FSRU - Single Offshore Buoy | 74,588 | 1.81 | 2.37 | 2.94 | 79,022 | 2.97 | 4.09 | 5.94 |
| Dockside Fullsize FSRU | 76,374 | 1.86 | 2.43 | 3.01 | 79,539 | 2.99 | 4.11 | 5.98 |
| Dockside Small/Mid-Size FSRU | 48,451 | 1.18 | 1.54 | 1.91 | 51,868 | 1.95 | 2.68 | 3.90 |
| ATB Barges | 62,264 | 1.51 | 1.98 | 2.45 | 64,784 | 2.44 | 3.35 | 4.87 |

**Source: Galway**

### 4.4 Siting Considerations

Overall, Pearl Harbor seems to be the best site for a Hawaii LNG terminal. The site is protected is in calm water and would likely require little dredging. Further, it is close to major load centers for power HECO and local gas companies. Presumably, it could also provide ancillary benefits to the U.S. Navy Base.

Kalaeloa Harbor is seen as a viable fallback siting option, but obtaining the required permits and approvals will require stakeholder consulation and input. The following are the siting considerations for Kalaeloa Harbor (see **Figure 42** below):

- **Berth availability** - Kalaeloa Harbor is a busy commercial port with limited berth availability. The Hawaii Department of Transportation, Harbor Division, is evaluating options to add one or two berths at Site C (refer to picture below) to accommodate liquid fuel deliveries and transshipment to other islands. Site C would also be suitable to accommodate a standard or small/mid scale FSRU and related delivery ships. However, access to the existing adjacent berths may be limited when a standard ship is delivering LNG to the FSRU. Consultation with the Hawaii Department of Transportation, Harbor Division would be required to assess the impact of adding an LNG berth at Site C.

- **Harbor dredging** – As mentioned above, dredging would be required to accommodate standard LNG ships and berthed FSRUs (to the tune of around 1 million cubic yards, at a cost of $5 to $10 per yard). In addition, some dredging and land based excavation would be required to build a new LNG berth (of around 1.3 to 2 million cubic yards combined, with costs ranging from $6 to $20 million) at Site B (refer to picture below). Since Kalaeloa harbor is a busy industrial port in Oahu, dredging operations may cause disruptions in harbor operations. However, some mitigation measures may be possible such as dredging only those areas in the harbor needed to accommodate LNG ships and FSRU (new berth, channel, and turning basin), restricting dredging operations to the night time only, etc. A suitable dredged material disposal site would also be required. Dredging will be one of the environmental impacts considered under the NEPA process administered by the FERC during the permitting process. Dredging would, however, be minimized or eliminated with a small or mid-scale LNG solution (onshore or floating).

- **LNG ship and FSRU security zones** – The US Coast Guard mandates security zones around LNG ships when sailing and after it is berthed. This would also likely apply to a berthed FSRU. Security zones are established on a site by site basis during the permitting process for the facility and may be revised as needed. The LNG shipping traffic in and out of Kalaeloa harbor may impact other marine activities, both commercial and pleasure boats/ships, because of the security zones. Such limitations may result in opposition from other users of the harbor.

- **Proximity to Kalaeloa Airport** – The proximity of potential onshore LNG terminal sites and new LNG berth sites to the Kalaeloa Airport is not likely to be an issue as the distance from the runway exceeds the minimum requirement (i.e. the LNG storage tank cannot be located within 1 mile of the runway - 49 CFR 193.2155)

- **Proximity to residences, marina and other 'meeting places'** – The proximity of onshore storage tank, berth and unloading lines (around 1 mile for potential site A, around 0.25 miles for potential site B, around 0.4 miles for potential site C) **could potentially cause some issues with exclusion zones** (in terms of thermal radiation and vapor dispersion). Required exclusion zones are determined through modeling and are dependent on site specific characteristics such as prevailing temperatures, humidity, wind speed and direction, topography, etc.. **Detailed engineering studies are required to evaluate the impact of exclusion zones** and availability (and cost) of engineering mitigation measure (for example, tank size, spacing full containment tank, spill troughs, berms, etc.).

Despite being located near an industrial area, Kalaeloa Harbor is also located relatively near residences, hotels, marinas and other public spaces which could result in increased opposition to siting an LNG facility in the harbor. Other than Everett (which was built in Boston in the 1970s), most US LNG terminals tend to be sited in industrial zones or more remote locations.

Figure 42: Proximity considerations for siting in Kalaeloa Harbor


Source: Galway

Finding a suitable location for an offshore solution near Barbers Point or Kahe Point could also be challenging. The following are the siting considerations for a buoy based offshore solution near Barbers Point:

- Water depth – Submerged buoys typically require a minimum of 200 feet of water to accommodate the buoy, flexible riser, anchoring system, etc. As water depth increases, the buoy system costs increase because of additional engineering requirements. Beyond depths of 500 to 600 feet (the original estimated economic limit for buoy-based systems when first conceptualized), increased buoy systems costs may impact economic viability (subject to further technical evaluation).

  At the 3 mile line along the western coast from Barbers Point to Kahe Point, water depth ranges from 2,100 feet to 2,700 feet, which is most likely too deep to accommodate buoy systems[3]. The water depth may exceed the initial economic limitations (500 to 600 feet) 1 mile offshore. Along the southern coast from Barbers Point to Keahi Point, initial economically viable water depths are available within the 3 mile line, but there are many restricted areas and it may not possible to find an appropriate location for a buoy system. Thus, it may be very difficult to find a suitable location for an offshore FSRU near Barbers Point or Kahe Point.

- Requirement for public consultation – LNG ships and FSRUs are large vessels (44 m x 290-300 m x 50 m) and are therefore very visible objects when sailing or

[3] Refer to NOAA Chart 19357 (http://www.charts.noaa.gov/OnLineViewer/19357.shtml)

anchoring near shore. It should be expected that trying to locate an FSRU close to shore (in order to address water depth limitations) near populated areas may draw significant public protest and opposition over 'visual pollution'. However, the regular presence of large oil tankers to supply the Hawaii Refineries implies that there is also some acceptance of the need for these types of facilities by the public.

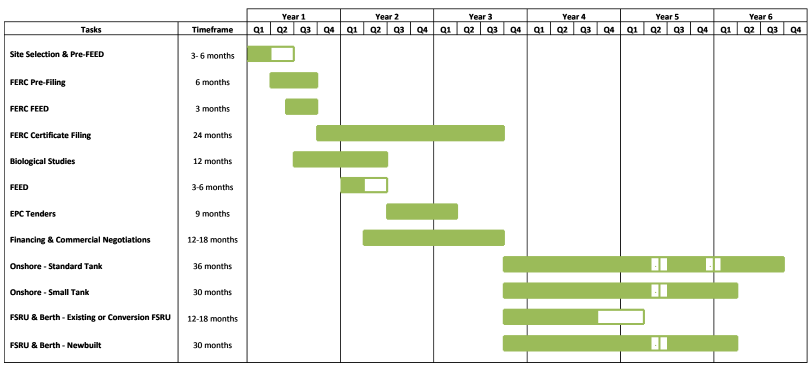
## 4.5 Permitting Considerations

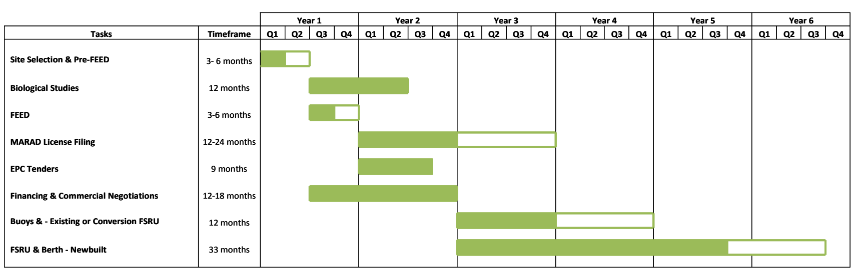
The FERC, MARAD and the US Coast Guard are key agencies in the federal permitting process. The following are the considerations for the federal permitting process:

- Onshore terminals and floating/offshore terminals within state waters
  - The Federal Energy Regulatory Commission (FERC) is the lead agency that manages and coordinates the environmental (National Environmental Policy Act) and permitting process with the other federal agencies.
  - The FERC process includes a mandatory pre-filing period (a minimum of 180 days) to facilitate the scoping of the project and permitting process with the federal agencies.
  - Following the pre-filing process, the project sponsor may proceed with filing for the certificate. The EIS and approval process is fairly situation specific and can be as short as 12 to 24 months but can also take significantly longer in more difficult cases.
  - The US Coast Guard (USGC) has jurisdiction over LNG shipping and terminal facilities up to the storage tank (berth and lines). USGC is one of the federal agencies involved in the FERC process.
- Offshore terminals outside state waters
  - The Department of Transportation's Maritime Administration (MARAD) is responsible for administering the licensing system established by the Deepwater Port Act (DWPA) and is responsible for preparing the Record of Decision for the project.
  - MARAD and the US Coast Guard share the duties for managing the National Environmental Policy Act and coordinating with other federal agencies.
  - MARAD and the US Coast Guard have 12 months to process a DWPA application, which can be extended to accommodate additional data requests to the applicant.

The anticipated project timeline for the FERC permitting process is shown in **Figure 43**. It shows that the project should take 4 to 5 ½ years to implement. The project should take 4 to 5 ½ years to implement by the MARAD permitting process as well. Local permitting and approvals would also need to be factored in and could add to this timeline.

**Figure 43: Anticipated project timeline – FERC & MARAD permitting**




**Source: Galway**

The following are the key takeaways for HECO from the analysis of regasification options:

- In order to support competitive procurement strategies, the regasification configuration should be acceptable to as many potential suppliers as possible.
- Suppliers are increasingly comfortable with delivering to floating LNG terminals, but the choice of configuration is important.
- Small or mid-scale berthed terminal solutions may offer better economics than standard size solutions.

- So far, no small or mid-scale floating terminal concept has been implemented.
- Kalaeloa Harbor appears to be the most viable site option to host berth based or an onshore LNG terminal solution, but obtaining siting approval may be difficult due to proximity to the public and required harbor modifications.
- Finding a suitable site for a buoy based offshore solution near Barbers Point may be challenging and will require further technical studies to assess met-ocean conditions, water depth limitations and potential 'visual pollution' concerns.

## 4.6 Shipping Options

Shipping is the most fungible element of the LNG value chain. It is usually driven by the need to satisfy both the liquefaction projects' needs (lower shipping costs while providing flexibility to market and delivering LNG to multiple markets) and the buyers' receiving facilities. LNG shipping is an enabler of supply strategy and must complement the terminal solution.

LNG ship classes tend to be designed to consistent specifications. Ship parameters include draught, form factor, loading/unloading manifolds, safety standards, etc. Compatibility with LNG terminals is a factor considered in the design. New ship classes tend to be introduced by new LNG supply projects. For example, the Q-Flex and Q-Max ships were introduced by the Qatari mega trains. Over time, receiving terminals may be modified to accommodate new major ship classes such as the Q-Flex and Q-Max.

For buyers and sellers, the procurement strategy and the receiving infrastructure drive the shipping strategy options. Broadly, the shipping strategies tend to be driven by the purchase contract type – Delivered Ex-Ship (DES) or Freight on Buyer (FOB)- and the ship size. The choice of DES vs. FOB is basically a choice of risk and flexibility allocation. Sellers and large buyers prefer to control shipping; smaller buyers usually do not want to undertake shipping risks. Under the DES structure, the seller charters the ship and owns the cargos on the water. By controlling the shipping, the seller can better optimize the shipping fleet to lower overall shipping cost and provide the marketing flexibility to sell LNG to the desired markets (to achieve better prices).

On the other hand, smaller buyers (like HECO) generally rely on DES since fleet optimization opportunities are limited and often do not outweigh the potential benefits of additional control. Like larger sellers, larger buyers have the ability to optimize fleets as well as capture higher value markets and therefore would prefer to enter into FOB contracts. Because of the commercial value of controlling shipping, the choice of DES vs. FOB is generally a point of negotiation between the buyers and sellers. New smaller buyers may not have the negotiation leverage, or the risk appetite, to obtain DES contracts and therefore would not normally be responsible for shipping activities.

HECO's LNG supply strategy and the outcome of the procurement process will determine DES or FOB options. The impacts of the three possible scenarios on the shipping options are discussed below:

- Long term supply agreement with a portfolio LNG seller or traditional LNG project
    - The most likely outcome will be **DES Sale and Purchase Agreement** since traditional sellers very strongly prefer to control shipping.
    - The traditional vessel size is 125,000 to 170,000 cubic meters (of which there are currently none that are Jones Act compliant).
    - The allocated fleet cost will be embedded in the delivered LNG price.
    - There is limited or no real transparency of shipping cost allocation but this not a big issue because the competitive procurement process focuses on delivered price.
    - For HECO, the risks and liabilities associated with shipping are very limited.
- Short term supply agreements with LNG portfolio seller or traditional LNG project
    - **There is no need for HECO to specify FOB purchases** as existing sellers are better equipped to manage fleet requirements in order to support short term sales. If it is important for HECO to include the US in the universe of potential short term supply sources, HECO may have to charter a Jones Act compliant ship, unless the US supplier has already done so in order to serve other markets (for example, Puerto Rico).
    - Generally, traditional sellers will prefer DES sales.
    - The traditional vessel size is 125,000 to 170,000 cubic meters (of which there are currently none that are Jones Act compliant).
    - Other buyers (Petrobras, Enarsa) have successfully procured short term LNG on DES basis.
- Tolling liquefaction capacity agreement with a US LNG export project
    - **The most likely outcome will be FOB sales** because the tolling projects only provide liquefaction capacity. LNG loading and sale risks are allocated to capacity holders. There are no lender concerns about FOB/DES because loans are based on capacity fee revenue, not LNG sale revenue.

- Most tolling projects are not or do not want to get involved in LNG shipping as it is not a core business activity for the project.
- Based on today's rules, LNG transportation to Hawaii will require Jones Act compliant LNG ships. This is likely to further limit the tolling projects' appetite for involvement in LNG shipping. The Jones Act compatible LNG ships would be less fungible than other vessels because of additional operating costs, which may impact the ability to find alternative employment for idle shipping capacity.

The combination of supply strategy and choice of LNG import terminal will drive HECO's shipping requirements as shown in **Figure 44**:

**Figure 44: HECO's shipping requirements by supply source/terminal options**

| | Berthed 170,000 $m^3$ FSRU at Kalaeloa Harbor | Offshore FSRU with Double Submerged Buoys Near Barbers Point | Mid/Small Scale FSRU at Kalaeloa Harbor |
|---|---|---|---|
| **Long-Term SPA with Traditional Seller(s)** | • **DES SPA** – Seller responsible for providing and managing shipping | • **FOB SPA** – HECO responsible for providing and managing shipping – **150,000 m3 class FSRU** (minimum term likely 10 years) | |
| **Short-Term Purchases from Traditional Seller(s)** | • **DES SPA** – Sellers responsible for providing and managing shipping | • **FOB SPA** – HECO responsible for providing and managing shipping –**150,000 m3 class FSRU** (minimum term likely 10 years) | |
| **Liquefaction Tolling Agreement with US Gulf Coast Project** | • **FOB LTA** - HECO responsible for providing and managing shipping - **1 or 2 145,000 – 150,000 $m^3$ Jones Act compliant ships** (term to match LTA term) | • **FOB LTA** – HECO responsible for providing and managing shipping –**150,000 m3 class Jones Act compliant FSRU** term to match LTA term) | |
| **Liquefaction Tolling Agreement with US West Coast Project** | • **FOB LTA** - HECO responsible for providing and managing shipping - **1 or 2 145,000 – 150,000 $m^3$ Jones Act compliant ships** (term to match LTA term) | • **FOB LTA** – HECO responsible for providing and managing shipping –**150,000 m3 class Jones Act compliant FSRU** term to match LTA term) | • **FOB LTA** – HECO responsible for providing and managing shipping - **Jones Act Compliant 25,000 m3 LNG ships, or 30,000 m3 ATB regas barges** (terms optimized to match expected LNG demand profile) |

**Source: Galway**

The key shipping issues for HECO are as follows:

1. One of the key issues for HECO is managing idle shipping capacity due to downward trending demand profile. In the case of DES contracts, the implications of the downward trending LNG consumption profile are addressed on the SPAs. It should generally be addressable because most sellers will be able to manage the reduced shipping requirements via fleet optimization. Under the FOB contract, it would be HECO's responsibility. HECO would have the following options:

- Structure shorter charter terms with options to renew which may result in a premium price depending on market conditions
- Try to find alternative employment for any idle capacity (via ship brokers) - however, for non-fungible ships (small scale ships, ATB barges, Jones Act compliant vessels), finding employment opportunities may be challenging because they may not fit world trades at the time.
- Reduce cost exposure by laying up idle capacity – This is Galway's assumption for small scale ships and barges. For Jones Act compliant vessels, we assume that the ship would be flagged out.

2. As a US destination, Hawaii may be subject to the Jones Act if the LNG supply is also loaded in a US port. The Merchant Marine Act of 1920 (also known as the Jones Act) imposes requirements on any ship involved in cabotage (from US port to US port). These requirements include the following:
   - The vessel must be US flagged
   - It must be constructed in a US yard
   - It must be owned by a US citizen
   - It must be crewed by US citizens (or permanent residents)

   At the moment, there are no Jones Act compliant LNG ships. The following options for compliance with the Jones Act are available:

   - Straight compliance
   - Obtain a Jones Act waiver for a specific ship via legislation
   - Obtain an amendment to the Jones Act for a broader waiver via legislation
   - Obtain an exemption to the Jones Act via legislation

   The requirement that the ship must be US built is the most challenging constraint for addressing the Jones Act. While a limited set of existing yards (two or three) with LNG shipbuilding experience could potentially ramp up production (the key issue here is dry dock size), the capital expenditures are expected to be 50 to 70 % higher compared to South Korean, Japanese or Chinese yards. Therefore, new US built vessels would not be competitive in the world fleet. One of these US yards, Newport News, evaluated building LNG ships again in the early 2000s but determined that they would be non-competitive. For small or mid-scale ships/barges, it is possible that several US yards will claim that they can produce those vessels, although the capital expenditures should be expected to remain 50 to 75% higher.

In relation to the requirement that vessels must be owned by a US citizen, some US shipping companies already have the required domain expertise required to manage and operate LNG ships and several other US shipping companies could relatively easily acquire that domain expertise.

As for the requirement regarding crew, there are experienced US officers and mariners to crew a limited number of ships which Galway estimates is between one to five ships.

The requirement that the vessel must be US flagged can be addressed by flagging in a foreign built vessel via legislation, typically attached to DOT/MARAD funding bill. Vessels have been flagged in (via legislation) if they met the US owned and US crewed requirements (since Mariner Unions hold more political clout than US yards).

There are several options available to HECO for complying with the Jones Act if it secured LNG supplies from a US port. Galway examined each of the options for complying with the Jones Act, which were presented earlier.

- Straight compliance – This is not likely for standard size ships because of the capital expenditure of the ship. It may be more feasible for small or mid-scale ships/barges, however, higher costs should be expected.
- Obtain a waiver for a specific vessel – Vessels have been flagged in via legislation as long as they met US owned and US crewed requirements. This may be more challenging for small or mid-scale ships/ barges as several US yards may claim that they can produce this vessel size.
- Obtain a Jones Act amendment for a broader waiver – This is a political issue and would require new legislation. An LNG ship waiver was included for Puerto Rico in the mid-1990s that allowed US built LNG ships to be reflagged in and foreign LNG ships built prior to 1996 to be flagged in if they met ownership and crew requirements.
- Obtain an exemption to the Jones Act – This is a highly political issue. Furthermore, the Jones Act benefits from strong support in Congress.

Complying with the Jones Act will most likely result in higher shipping costs

- **Higher operating expenditure** – There will be higher costs for a US crew and the use of US yards for maintenance. Galway's estimate is about $3 million per year in incremental costs (i.e. $8.8 million per year vs. $5.8 million per year).
- **Higher fleet management or optimization costs** – The Jones Act compliant ship may be less fungible in the broader LNG shipping market because of the higher costs. As a result, if there is idle shipping capacity to serve Hawaii from either the US Gulf Coast or West Coast, it may be more difficult and/or costly to find alternative employment for the idle capacity (this is one of the existing challenges to manage idle time with a small fleet).
- **Potential for higher charter rates because of lack of competition** – There is the possibility that only a limited number of US ship owners would want to enter into the LNG business and therefore HECO may not have a lot of bargaining leverage.

## 4.7 Shipping Economics

Galway analyzed the shipping costs for HECO based on the type of vessel, the supply sources and the volume of LNG (**Figure 45**). Galway concludes that standard ships provide significant economies of scale over small scale shipping options (but the trade-off is the higher cost for regasification). Second, shipping from the US Gulf Coast is most expensive due to the Jones Act compliance requirements (applied to US suppliers) and the FOB fleet management burden. And lastly, using FSRUs for shipping adds costs in terms of higher charter rates and poor shipping utilization.

**Figure 45: Shipping costs by vessel type, supply source and LNG volume**

| | | Price in $/MMBtu | | | | | |
|---|---|---|---|---|---|---|---|
| **SHIP TYPE** | **SUPPLIERS** | **0.85** | **0.65** | **0.525** | **0.55** | **0.4** | **0.275** |
| **Standard** | Kitimat | 0.70 | 0.70 | 0.70 | 0.70 | 0.70 | 0.70 |
| | US Gom | 1.80 | 2.31 | 1.48 | 1.95 | 1.90 | 2.71 |
| | Jordan Cove | 0.84 | 1.10 | 1.36 | 1.30 | 1.79 | 2.59 |
| | E. Australia | 0.98 | 0.98 | 0.98 | 0.98 | 0.98 | 0.98 |
| **FSRU** | Kitimat | 1.38 | 1.82 | 2.26 | 2.14 | 2.98 | 4.35 |
| | US Gom | 2.91 | 2.19 | 2.37 | 2.26 | 3.09 | 4.46 |
| | Jordan Cove | 1.42 | 1.86 | 2.31 | 2.20 | 3.02 | 4.40 |
| | E. Australia | 1.30 | 1.74 | 2.18 | 2.08 | 2.90 | 4.27 |
| **Small Scale** | Kitimat | 2.59 | 2.30 | 2.44 | 3.23 | 3.21 | 3.23 |
| | Jordan Cove | 2.44 | 2.18 | 2.15 | 3.78 | 3.18 | 2.86 |
| **ATB Barges** | Kitimat | 2.79 | 3.88 | 2.83 | 4.61 | 4.11 | 5.26 |
| | Jordan Cove | 2.90 | 2.92 | 2.91 | 4.48 | 4.37 | 4.31 |

*Jones Act adder applied to ships from the US Gom and Jordan Cove.

**Source: Galway**

Although regas options analyzed in isolation may point towards a small scale solution for HECO, the picture gets complicated when shipping economics are added to the regas economics. Galway's estimates of the combined cost of shipping and regasification are presented in **(Figure 46)**. Considering shipping economics along with regas, there is no clear advantage in favor of small scale solutions. In fact, a dockside small/mid FSRU solution may offer alternatives at an approximate $1 per MMBtu premium compared to dockside full scale FSRU. In terms of siting decision, an offshore buoy-based solution may offer alternatives at a ~$0.80-1.00/MMBtu premium over near shore options and may face lower siting challenges.

**Figure 46: Combined LNG regasification and shipping costs**

| | | Annual Volumes (MTPA) | | | | | |
|---|---|---|---|---|---|---|---|
| **Terminal Configuration** | **Supplier** | **0.85** | **0.65** | **0.525** | **0.55** | **0.4** | **0.275** |
| Onshore LNG Terminal | Kitimat | 4.70 | 7.15 | 5.93 | 9.57 | 7.18 | 13.60 |
| | US Gom | 5.80 | 6.31 | 5.48 | 5.95 | 5.90 | 6.71 |
| | Jordan Cove | 4.84 | 5.10 | 5.36 | 5.30 | 5.79 | 6.59 |
| | E. Australia | 4.98 | 4.98 | 4.98 | 4.98 | 4.98 | 4.98 |
| Small Scale Onshore | Kitimat | 4.30 | 5.06 | 4.67 | 7.03 | 5.97 | 8.75 |
| | Jordan Cove | 4.15 | 4.94 | 4.38 | 7.58 | 5.94 | 8.38 |
| 2 x FSRU - Double Buoy | Kitimat | 3.39 | 5.09 | 4.88 | 6.62 | 6.23 | 10.89 |
| | US Gom | 4.92 | 5.46 | 4.99 | 6.74 | 6.34 | 11.00 |
| | Jordan Cove | 3.43 | 5.13 | 4.93 | 6.68 | 6.27 | 10.94 |
| | E. Australia | 3.31 | 5.01 | 4.80 | 6.56 | 6.15 | 10.81 |
| 2 x FSRU - Single Buoy | Kitimat | 3.19 | 4.79 | 4.63 | 6.23 | 5.92 | 10.29 |
| | US Gom | 4.72 | 5.16 | 4.74 | 6.35 | 6.03 | 10.40 |
| | Jordan Cove | 3.23 | 4.83 | 4.68 | 6.29 | 5.96 | 10.34 |
| | E. Australia | 3.11 | 4.71 | 4.55 | 6.17 | 5.84 | 10.21 |
| Dockside Fullsize FSRU | Kitimat | 2.56 | 3.69 | 3.13 | 4.81 | 3.71 | 6.68 |
| | US Gom | 3.66 | 5.30 | 3.91 | 6.06 | 4.91 | 8.69 |
| | Jordan Cove | 2.70 | 4.09 | 3.79 | 5.41 | 4.80 | 8.57 |
| | E. Australia | 2.84 | 3.97 | 3.41 | 5.09 | 3.99 | 6.96 |
| Dockside Small/Mid FSRU | Kitimat | 3.77 | 4.25 | 3.98 | 5.91 | 6.12 | 7.13 |
| | Jordan Cove | 3.62 | 4.13 | 3.69 | 6.46 | 6.09 | 6.76 |
| ATB Regas Barges | Kitimat | 4.30 | 6.32 | 4.81 | 7.96 | 6.56 | 10.13 |
| | Jordan Cove | 4.41 | 5.36 | 4.89 | 7.83 | 6.82 | 9.18 |

**Source: Galway**

The following are the key takeaways for HECO from the analysis of shipping options:

- Shipping is an enabler of the supply strategy and must be compatible with the terminal solution.
- Small buyers usually do not want or cannot mitigate the risks of shipping.
- HECO will most likely need to be responsible for shipping if it procures tolling capacity in the US or elects to use small or mid-scale infrastructure.
- The Jones Act requires that ships delivering LNG from US port to US port be US owned, US built, US crewed and US flagged. It is likely that HECO can obtain a

legislative waiver for the US built requirement (for standard size ships) but not for the other requirements. It is also likely to result in higher shipping costs due to higher operating costs and less bargaining leverage with owners.[4]

- Standard size ships yield lower unit shipping costs as compared to small or mid-scale options (a saving of \$1.6 to \$1.8 per MMBtu).
- With greater siting challenges for near shore options, offshore buoy based solutions may offer alternatives at a premium of around \$1 per MMBtu for the combined shipping and regasification costs.

[4] Higher costs related to the Jones Act requirements could range from \$0.03 to \$0.42. Standard size ships moving large volumes benefit from the economies of scale, and generally make up the lower end of the range (< \$0.12). However, the small scale ships and ATB barges do not have the same size benefit. The Jones Act adder generally fell on the higher end of the spectrum (averaging ~\$0.30)

GALWAY ENERGY ADVISORS LLC

# 5 Integrated Commercial Economics

As previously mentioned, HECO has several options for each aspect of the LNG value chain-LNG supply source, shipping and regas infrastructure. Each choice will impact the delivered price of LNG for HECO. Since HECO's main motivation in considering LNG imports is to achieve savings by switching from oil products, Galway examines the price spread between LSFO and LNG. We analyze whether LNG would be a viable alternative for HECO and which value chain options would yield the most savings.

Based on the options identified for each step of the value chain in preceding sections, Galway has put together the scenarios in order to analyze the overall impact on delivered gas price for HECO (**Figure 47):**

**Figure 47: Integrated economic evaluation scenarios**

| | Supply Option | Regas Configuration | Shipping Configuration | Comment |
|---|---|---|---|---|
| 1 | Long/Short Term SPA from any source (no US restriction) | Docked 170,000 m3 FSRU | Likely Ex-ship (suppliers prefer DES for small buyers) | Commodity charge would be at oil indexed price (at today's prices, cost would be higher) |
| **2** | **Long/Short Term SPA from any source (no US restriction)** | **Offshore Double FSRU with double buoy** | **FOB (HECO needs to charter 2 Jones Act FSRUs)** | **Commodity charge would be at oil indexed price (at today's prices, cost would be higher)** |
| **3A** | **US HH Indexed supply: long term tolling for liquefaction** | **Offshore Double FSRU with double buoy** | **FOB (HECO needs to charter 2 Jones Act FSRU's)** | **US HH Indexed gas would partially offset higher supply chain costs** |
| 3B | US HH Indexed supply: long term tolling for liquefaction | Docked 170,000 m3 FSRU | FOB (HECO would need to charter FSRU's, Ship) | US HH Indexed gas would partially offset higher supply chain costs |
| **4** | **US HH Indexed supply: long term tolling for liquefaction** | **Docked small scale FSRU (60,000 m3)** | **FOB (HECO would need to charter Jones Act 25,000 m3 Ship)** | **HECO's options for sourcing gas from other LNG suppliers would be very limited** |

**Source: Galway**

The options identified for the economic analysis are as follows:

- LNG Supply (US Gulf Coast, US West Coast, Canada, Peru, T&T, E. Australia)
- LNG Shipping (Std. LNG ships, FSRU, ATB Barges, Small/Mid-size LNG ships)

- Regas Options (Std. Onshore, small scale onshore, offshore FSRU-double buoy, Offshore FSRU-single buoy, dockside FSRU, Dockside small/mid-size FSRU, ATB Barges)

The three strategies for supply sourcing were analyzed and three supply projects emerged as potential sources.

1. **Buy on traditional price and terms** – Eastern Australia and Canada are the two supply options based on this criterion. However, due to attractive shipping distance, Canada ranks higher than Eastern Australia. The Canadian LNG project identified is Kitimat LNG.

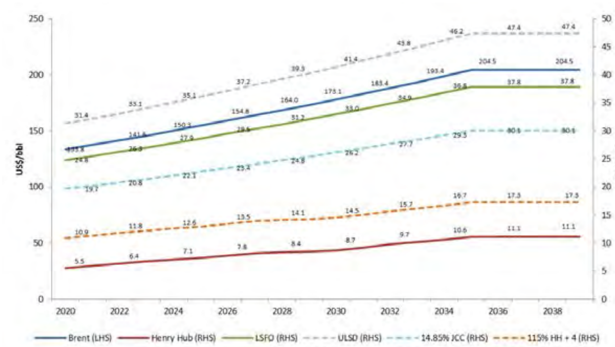
2. **Buy short term or spot through tendering** – Spot sales are DES supply and hence distance or supply project does not make much difference. The project identified is Kitimat LNG in Canada.

3. **Buy US liquefaction capacity or source US gas** – The only available LNG supplies on the Henry Hub index are from Jordan Cove on the US West Coast and US GoM LNG.

In undertaking this analysis, Galway's economic analysis is based on HECO/EIA's commodity price forecast as shown in **Figure 48**:

GALWAY ENERGY ADVISORS LLC

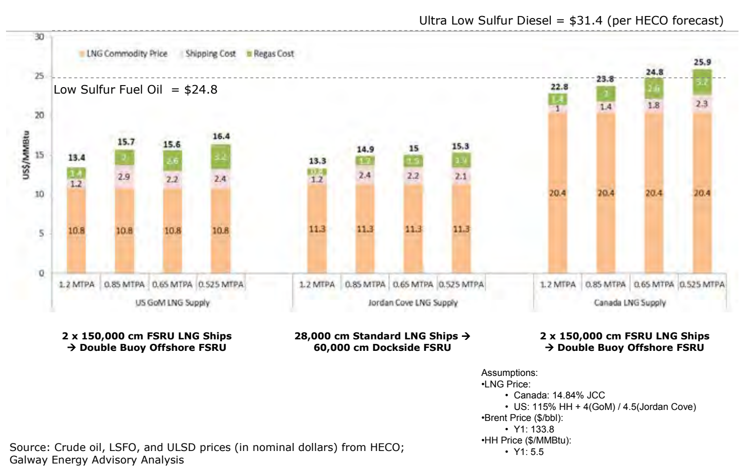
**Figure 48: Commodity price forecast in nominal dollars**




**Source: Galway, EIA (HH Forecast until 2035, flat thereafter, HECO forecast for LSFO/ULSD; JCC at 99% Brent**

Using the commodity forecast shown above, Galway forecast the delivered price of regasified LNG for year 1 (2020) for the different supply sources. Galway's analysis reveals that LNG will be an economically viable option to LSD and ULSD (**Figure 49**).

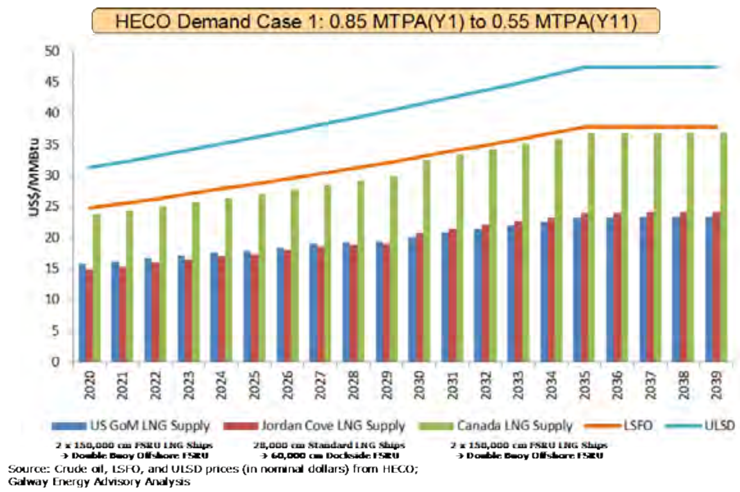
**Figure 49: Summary of the terminal tailgate gas price -Year 1 (2020)**




**Source: Galway**

Using the LNG demand scenarios presented earlier, a 20 year profile of the delivered price of LNG from the supply sources under consideration versus the delivered price of competing fuels was forecast (**Figure 50**). Under HECO demand case 1 (LNG demand of 0.85 mtpa (year 1) to 0.55 mtpa (year 11)), the delivered price of LNG from all three supply sources under consideration will be lower than that of competing fuels. However, LNG sourced from Canada will only be at a marginally lower price than that of LSFO in this scenario.

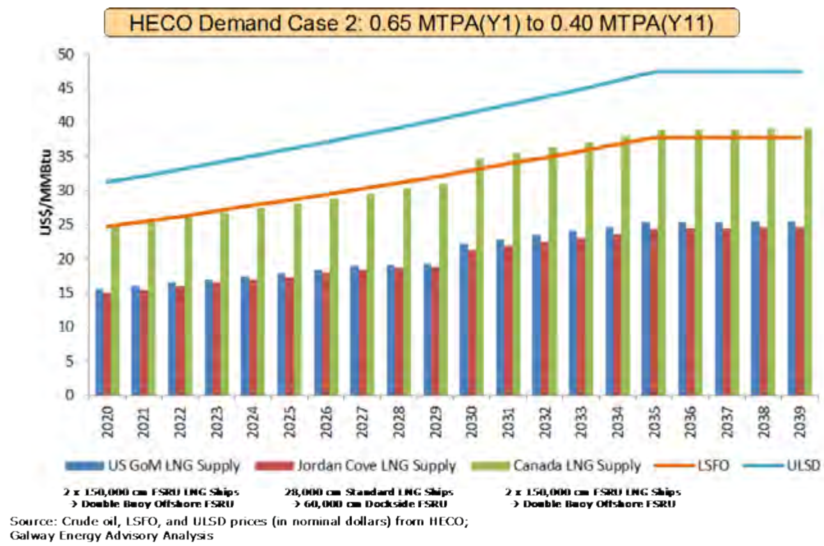
**Figure 50: HECO demand Case 1 delivered price of LNG vs. competing fuels**




**Source: Galway**

Under the HECO demand case 2 (LNG demand of 0.65 mtpa (year 1) to 0.40 mtpa (year 11)), the LNG supplies from the US Gulf of Mexico and Jordan Cove will have a distinct competitive advantage over competing fuels. However, LNG sourced from Canada will be undercut by LSFO in the second half of the forecast (**Figure 51**).

**Figure 51: HECO demand Case 2 delivered price of LNG vs. competing fuels**

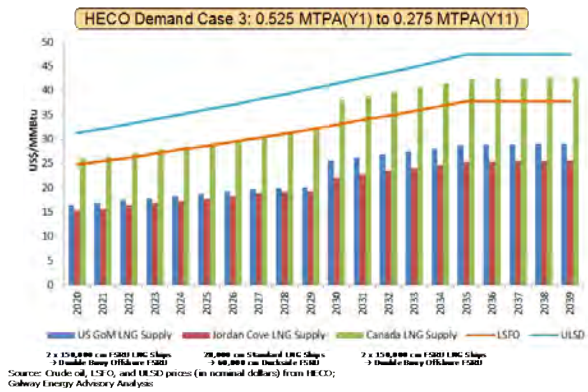



**Source: Galway**

Under HECO demand case 3 (LNG demand of 0.525 mtpa (year 1) to 0.275 mtpa (year 11)), the LNG supplies from Canada will not be able to compete with LSFO in the second half of the forecast period. LNG sourced from the US Gulf of Mexico and Jordan Cove will continue to be far more economical alternative than competing fuels. However, the margin between LNG supplies and competing fuels will reduce considerably **(Figure 52**).

Therefore, from the above analysis Galway can conclude that LNG will be an economically viable alternative to competing fuels in the 3 demand scenarios. Sourcing LNG from the US will yield the most economic benefit for HECO.

**Figure 52: HECO demand Case 3 delivered price of LNG vs. competing fuels**



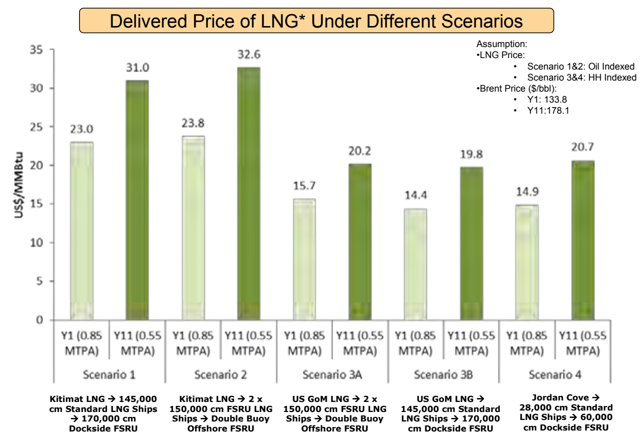

**Source: Galway**

A positive price spread exists in most scenarios between LSFO and LNG. However, volume throughputs will affect the magnitude of fuel savings. Based on the scenarios set forth above using a combination of supply options, regasification and shipping options, Galway forecast the delivered price of LNG into Hawaii using the three demand scenarios.

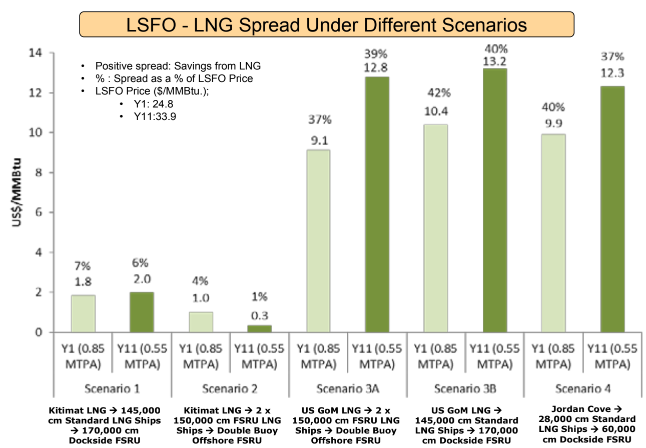
Under demand case 1 (**Figure 53**), the delivered price of LNG ranges between US $14.4 per MMBtu and US$ 23.8 per MMBtu for year 1 of the forecast period and between US$20.2 per MMBtu and US $32.6 per MMBtu for year 11 of the forecast period. Scenario 3B (LNG sourced from the US Gulf of Mexico, using 145,000 cubic meter standard LNG ships and using a 170,000 cubic meter dockside FSRU for regasification) yields the lowest delivered price of LNG into Hawaii under this demand scenario.

An analysis of the spread between LSFO and LNG was also conducted. Under demand case 1, there is a positive spread between LSFO and LNG at the burner tip in all the scenarios. The savings from LNG as percentage of LSFO price is highest under Scenario 3B amounting to 42% in the year 1 of the forecast period and 40% in year 11 of the forecast period.

**Figure 53: HECO demand Case 1 – delivered price of LNG into Hawaii under different scenarios**




Source: Galway Energy Advisory Analysis

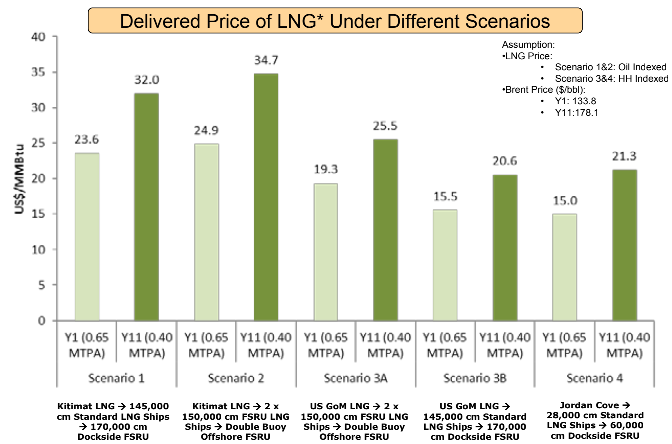



Source: Galway Energy Advisory Analysis

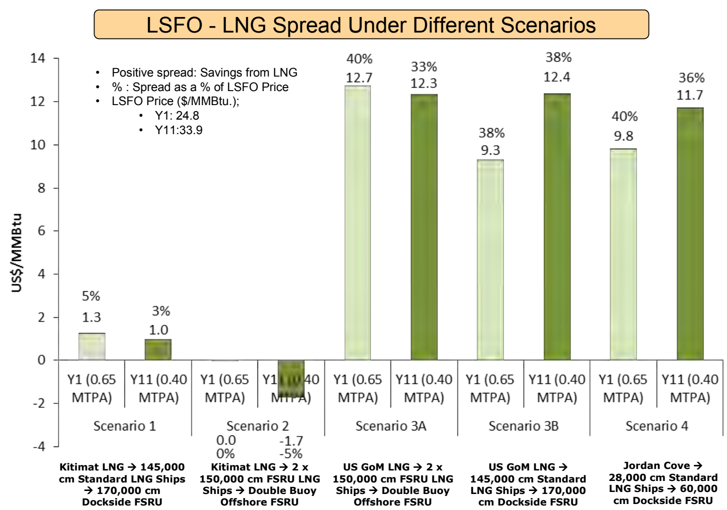
**Source: Galway**

Under demand case 2 (**Figure 54),** delivered price of LNG is between US $15 per MMBtu and US $24.9 per MMBtu for year 1 of the forecast period and between US$ 20.6 per MMBtu and US$ 34.7 per MMBtu for year 11 of the forecast period. Scenario 3B and Scenario 4 (LNG sourced from Jordan Cove using 28,000 cubic meter standard LNG ships and a 60,000 cubic meter dockside FSRU for regasification) yield the lowest delivered prices for LNG under this demand case.

**Figure 54: HECO demand Case 2 – delivered price of LNG into Hawaii under different scenarios**




Source: Galway Energy Advisory Analysis



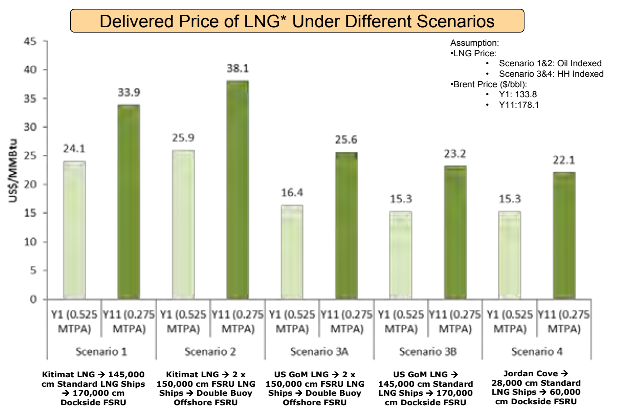

Source: Galway Energy Advisory Analysis

**Source: Galway**

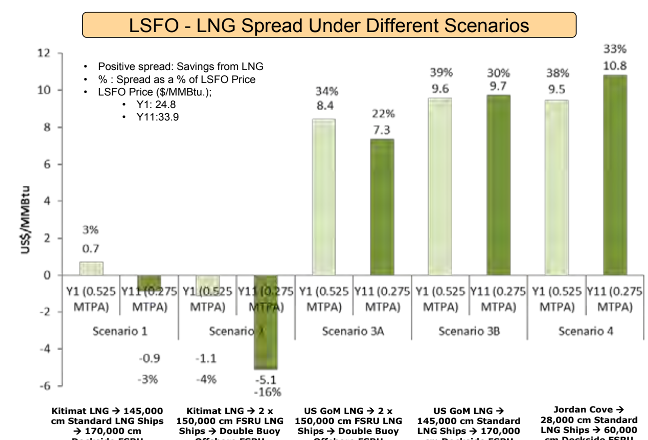
The analysis of the spread between LSFO and LNG under demand case 2 shows positive savings from LNG under all scenarios except Scenario 2. The spread between LSFO and LNG is in the range of 33% to 40% of the delivered price of LSFO under Scenarios 3A, 3B and 4.

Under demand case 3 (**Figure 55**), the delivered price of LNG ranges between US$ 15.3 per MMBtu and US$ 25.9 per MMBtu for year 1 of the forecast period and between US$ 22.1 per MMBtu and US$ 38.1 per MMBtu for year 11 of the forecast period. The lowest delivered prices are obtained in Scenario 4 (LNG sourced from Jordan Cove using 28,000 cubic meter standard LNG ships and a 60,000 cubic meter dockside FSRU for regasification).

**Figure 55: HECO demand Case 3 – delivered price of LNG into Hawaii under different scenarios**




Source: Galway Energy Advisory Analysis




Source: Galway Energy Advisory Analysis

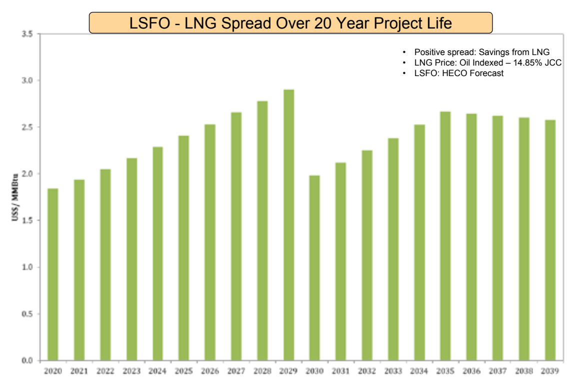
**Source: Galway**

Under demand case 3, both Scenarios 1 and 2 yield negative spreads. The spreads for Scenarios 3A, 3B and 4 are in the range of 22% to 39% of the delivered price of LSFO, which as a range is lower than in demand case 1.

Thus, demand case 1 yields the lowest delivered gas prices in all scenarios and the highest savings in using LNG over LSFO. The analysis also shows that the degree of price spread is influenced by the volume throughput of LNG, especially in the case of a downward sloping demand profile. Sourcing LNG from the US yields the highest savings for HECO but LNG from traditional suppliers can also yield savings although to a lesser extent

Using demand case 1, Galway forecast the LSFO-LNG price spread for the 20 year life of the project under each scenario. In Scenario 1 (**Figure 56**), the price spreads are positive throughout the forecast period. However, the savings from the use of LNG over LSFO are lower for the second half of the forecast period. The price spreads range from between US$ 1.5 to US$ 2 per MMBtu to $US 3 per MMBtu over the forecast period.

**Figure 56: HECO demand Case 1 Scenario 1**



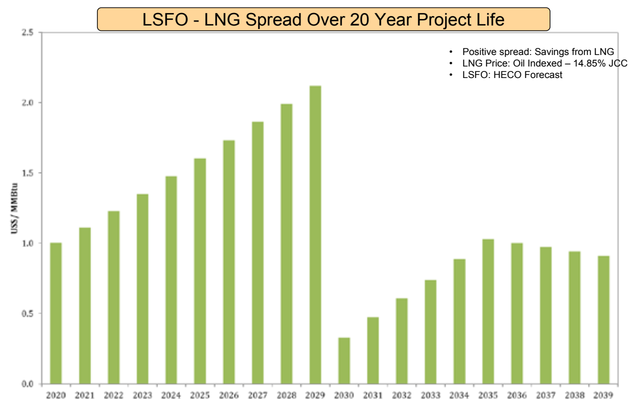

Source: Galway Energy Advisory Analysis

**Note:– Scenario 1: Kitimat LNG, 145,000 cubic meter standard LNG ships, 170,000 cubic meter dockside FSRU**

Under Scenario 2 (**Figure 57),** there is a sharp decline in the savings from use of LNG over LSFO from the first half of the forecast period to the second half. The price spreads range between less than US $0.5 per MMBtu to more than US$ 2 per MMBtu.

GALWAY ENERGY ADVISORS LLC

**Figure 57: HECO demand Case 1 Scenario 2**

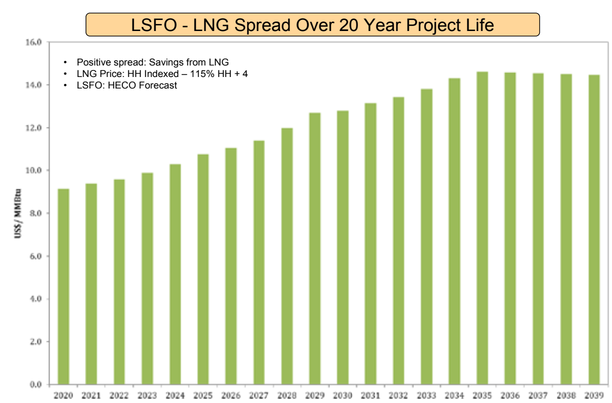



Source: Galway Energy Advisory Analysis

**Note:– Scenario 2: Kitimat LNG, 2 x 150,000 cubic meter FSRU LNG ships, double buoy offshore FSRU**

Under Scenario 3A (**Figure 58**), the LSFO-LNG price spread increases over the forecast period from around US$ 9 per MMBtu to around US$14 per MMBtu.

**Figure 58: HECO demand Case 1 Scenario 3A**

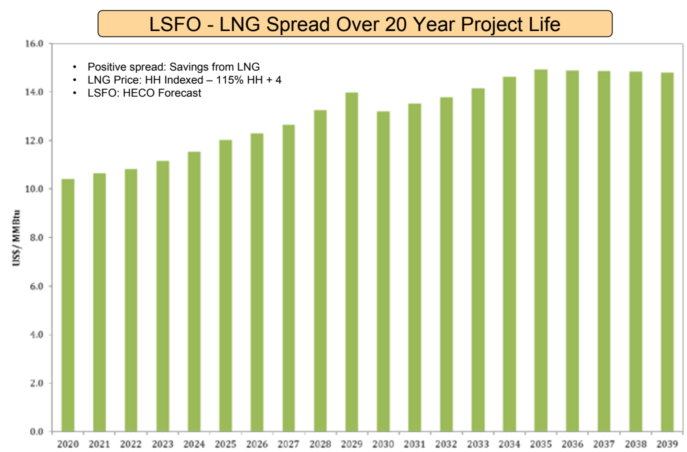



Source: Galway Energy Advisory Analysis

**Note: Scenario 3A: US GoM LNG, 2 x 150,000 cubic meter FSRU LNG ships, double buoy offshore FSRU**

Under Scenario 3B, the price spread rises over the forecast period from a little more than US $10 per MMBtu to over US$ 14 per MMBtu (**Figure 59**).

**Figure 59: HECO demand Case 1 Scenario 3B**



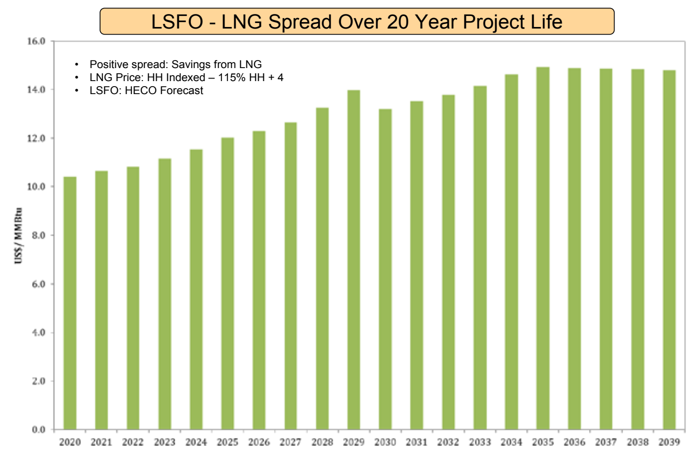

Source: Galway Energy Advisory Analysis

**Note: Scenario 3B: US GoM LNG, 2 x 150,000 cubic meter FSRU LNG ships, double buoy offshore FSRU**

Under Scenario 4 **(Figure 60**), there is again a positive spread between LSFO and LNG, which increases from around US$10 per MMBtu to US$14 per MMBtu. Thus, the supplies from the US yield the highest savings for HECO. However, traditional suppliers like Canada can also yield savings although to a lesser degree.

GALWAY ENERGY ADVISORS LLC

**Figure 60: HECO demand Case 1 Scenario 4**




Source: Galway Energy Advisory Analysis

**Note: Scenario 4: Jordan Cove, 28,000 cubic meter standard LNG ships, 60,000 cubic meter dockside FSRU**

The key takeaways for HECO from the analysis of the integrated economics of the various supply, regasification and shipping options are as follows:

- Sourcing LNG from the US could provide significant burner tip price reductions. However, the key issues for HECO in sourcing LNG from the US are as follows:
  - What will US liquefaction tolling cost?
  - What will be the spread between Henry Hub and alternative fuel oil prices?
- Even if HECO sources LNG from traditional suppliers, there could still be a spread between LSFO and LNG in burner tip pricing. At worst, it appears that the prices of LNG and competing fuels are roughly at parity.
- The degree of the LSFO-LNG price spread is impacted by the volume throughput, particularly in light of a downward sloping demand profile.

# 6 Conclusions

Galway believes that LNG could be a viable option for HECO.

Supply risk should not be an issue in the latter part of this decade given HECO's small demand requirements and the large number of projects in construction or in advanced development. The three broad procurement options are to buy long term from a traditional supplier at oil indexation; buy from the spot market or contract for US liquefaction tolling capacity (buy gas from grid). While all 3 options are viable in terms of providing a price equal to or less than projected costs of Fuel Oil or Low Sulfur Diesel, purchasing spot deliveries or contracting for US liquefaction capacity provide the largest price savings. Two factors limiting HECO's negotiating leverage are its small LNG demand and a declining offtake profile which is usually the reverse of what is typically seen in the industry. HECO would not be a major customer for any new US liquefaction project and it would be buying incremental or "wedge" capacity to fill out train sales. HECO does have two potential advantages over some Asian customers in terms of attracting US liquefaction developers. One is that any LNG sale to HECO would not require a Department of Energy export license and the second is that HECO credit is not an issue.

For the regas terminal, a near shore floating LNG terminal at Pearl Harbor is the best choice. It is in calm, protected water, near major load centers, would likely require less dredging and likely provide anciallary benefits to the U.S. Navy. The next best option would be an offshore floating option with shuttling FSRUs, but additional study is required to confirm this. This route becomes more viable if HECO could tolerate the occasional interruptions to LNG supply (perhaps by employing dual fueled power stations). A near shore floating option at Kalaeloa Harbor could also be viable provided the permitting challenges can be navigated and stakeholder issues can be satisfactorily addressed. The regasification concept ultimately selected by HECO will be important to LNG suppliers (particularly those that are selling under a long term sales agreement) so as to ensure that their product reaches its final destination. This will also be important to LNG shipping charterers. The Shipping strategy will be driven by supply strategy and regasification configuration. US sourced supplies will likely require HECO to charter its own ship due to Jones Act compliance requirements.

Pricing wise, there is a significant positive burner tip price spread between LSFO/LSD and US LNG price. There may be a positive price spread to oil indexed LNG prices.

In terms of next steps, Galway sees that further work needs to be done to further define project scope and confirm technical and regulatory viability. Specific steps should include the following:

- HECO should establish contact with the U.S. Navy to test the viability of using Pearl Harbor as a site for a floating LNG terminal.
- Commission detailed siting studies to assess viability of offshore buoy based options. Estimate cost $0.5 to $1 Million and timing is 3-6 months.
- Develop regulatory and permitting strategy through informal consultations with federal and state regulatory authorities.
- Develop detailed commercial and business structure for LNG importation.
- Hold informal consultations with vendors and supplier.

# 7 Appendix

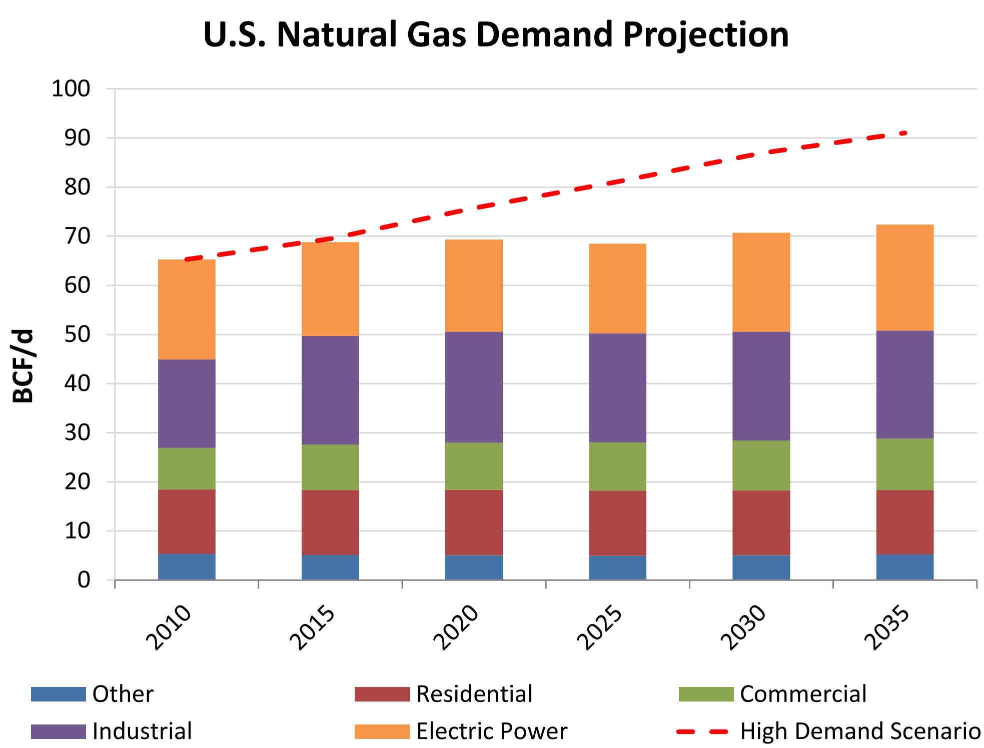
## 7.1 Follow-Up Questions and Response

**Question 1: How is the future demand for natural gas in the U.S. power generation sector likely to change as a result of greenhouse gas emission restrictions or costs, electricity demand growth, plant retirements, etc?**

Right now the natural gas sector is ripe for strong growth. The power sector in the US has been showing steady growth over the past decade, and that story will likely continue. There are a number of factors that will continue to push up the demand for natural gas. One big factor will be coal plant retirements due to aging infrastructure. With old plants slated to be shuttered over the next decade, natural gas plants – which are already in place with ample capacity – will be the alternative energy source for these coal plants. This one factor could account for an additional 5 Bcfd of natural gas demand. Regulatory policy on carbon emissions could add another 3 Bcfd to that number, as some other plants will be too costly to retrofit to emissions standards. Even without government incentives to switch to a cleaner fuel source, fuel switching is already occurring because of the low cost of natural gas.

Since natural gas is trading at a discount to fuel alternatives, there has been fuel switching across all sectors. Fuel switching could lead to about 5 Bcfd of increased demand over the next couple of decades. This ample supply of gas has both domestic and international developers looking to get involved in this market. One of the domestic sectors set up for growth is in the area of natural gas vehicles (NGVs). Low prices are providing an incentive for companies to convert their transportation fleets to NGVs. Over time, this could make up 1 Bcfd of demand. On an international level, the low pricing environment has sparked interest in LNG exports, which would ensure that an abundant stream of gas would continue to flow in from the production areas. LNG exports could account for 2 to 6 Bcfd of natural gas demand over the life of the liquefaction facilities. Summing up these projections, natural gas demand could be about 20 Bcfd (or 156

MTPA) higher than what the EIA predicted for 2035. All of these factors together mean that over time natural gas will take on a larger role in the energy mix.[5]




**2. What future restrictions on new gas supply might result from political pressures like Vermont's policy of banning fracking in that state (none existed anyway) and new EPA regulations?**

Tighter regulation of hydraulic fracking and the disposal of flow back waters remain one of the key risks towards the growth of shale gas in North America, and in particular LNG export project potential. Apart from the hydraulic fracking, additional concerns have surfaced such as air quality impacts in Wyoming/Texas, water disposal in

[5] These demand numbers are used to create a high case scenario. They are not included in reference scenarios throughout this presentation, specifically Figure 15.

the Marcellus, and the potential for seismic activity resulting from Class II disposal well injection in shale.

We believe that the environmental concerns are unlikely to impact the shale drilling to a significant level; stricter regulations would most likely increase costs. However, our view is that regulations will trend toward more disclosure or follow a similar approach to measures undertaken by the Pennsylvania DEP in 2010 to tighten cementing standards. In addition, any large-scale disruptions or cost increases are unlikely unless there are several high-profile incidents of documented water contamination from hydraulic fracturing. The EPA is expected to conclude its study on hydraulic fracturing toward the end of 2012, and it is very tough to guess the impact this study will have on regulation.

We don't have a clear standing in whether the political pressure will prevail or not, but clearly more regulation will increase cost and that would impact the LNG export projects. US LNG exports have a huge economic benefit to the country, and hence we don't foresee any issues at this point and the department of energy will likely issue several permits in the coming years and in general policy makers seem to support LNG exports.[6]

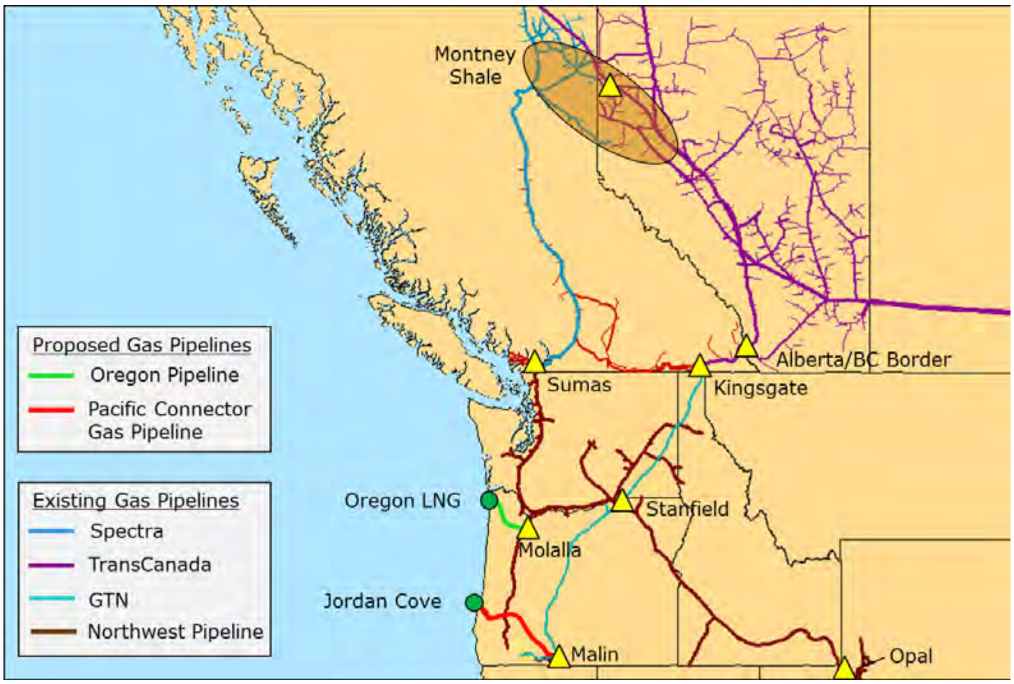
3**. How might new interstate gas pipeline networks change gas supply options on west coast and what would the implications be for supplying Hawaii?**

There are some pipeline expansions that are newly in place or under consideration in the West Coast that could have implications on LNG exports to Hawaii. The Ruby Pipeline was completed in 2011, and it runs from Opal to Malin. Ruby Pipeline has the capacity to carry 1.5 Bcfd to gas to Malin, with the intention to then flow gas down to California. Ruby has the potential to displace Canadian gas that typically supplies that area, which could create available capacity on the GTN line. Depending on the demand for Ruby gas, and the requirements for the Oregon export projects, this displacement may provide adequate support for an export project. Along with this, Jordan Cove has proposed that their feed gas line flow from Malin to Coos Bay. This line could pick up the displaced Canadian gas to feed their export project. However, this may also require expansions in the Canadian pipeline network, specifically on the TransCanada system.

The new pipeline networks create interesting opportunities on the West Coast given the proximity to Hawaii. However, having gas available does not necessarily help

[6] Even if US regulations squeeze LNG exports, there are foreign suppliers in the market that could help mitigate some of this risk. See Figure 2 which shows sufficient LNG volume in the market in the 2020 timeframe.

the LNG export approval process. Also, new pipelines and expansions will still be required to connect into the export plants.




**4. What is the likelihood of Alaskan natural gas pipelines and export terminal and what will the impact be on the US market? What would the timing of such developments be?**

The increased production growth from Lower-48 and western Canadian sources under the current low price environment pushes the Henry Hub prices to remain sub $5-6/MMBtu until 2020. Under this low price scenario it is highly unlikely that an expensive pipeline from Alaska to the Lower 48 or the LNG project will be developed. The major oil and gas companies operating in Alaska (BP, COP, and XOM) haven't prioritized gas development on the North Slope. Also, the cost of developing a pipeline from the North Slope to the anchorage area is expected to be around $20 Billion for a 1300 KM pipeline. If any such project comes in it probably won't be until after 2025. The impact of this pipeline is very hard to determine because the timing is so uncertain.

**5. Discuss LNG safety and homeland security issues/risks/myths.**

"The LNG industry has spent a vast amount of time analyzing and assessing the hazards and has either eliminated or developed mitigation techniques to reduce potential risks. As a result, in more than 50 years of commercial LNG use, no major accidents or safety or security problems have occurred, either in port or at sea.

The LNG industry carefully follows requirements set forth by the International Maritime Organization, Federal Energy Regulatory Commission, Department of Transportation, and the U.S. Coast Guard and works closely with the Department of Homeland Security to ensure its operations are safe and secure.

The LNG Industry provides the appropriate security, planning, prevention and mitigation in close coordination with local, state, and federal authorities, including the United States Coast Guard. These measures significantly reduce risks from intentional events such as terrorist attacks.

DISPELLING LNG SAFETY MYTHS

•Contrary to some misconceptions, LNG is NOT EXPLOSIVE in an uncontained environment.

•Natural gas needs to be in its gaseous state and mixed with a specific ratio of oxygen in the air to burn and is only combustible in the range of 5% to 15% volume concentrations in air.

•LNG (liquid) is not flammable and does not burn.

•LNG in its gaseous state is lighter than the surrounding air and will rise and dissipate.

•Should LNG spill or leak into water, the LNG will vaporize rapidly in water into gas and dissipate into the atmosphere.

•In more than 50 years of commercial LNG use, no major accidents or safety or security problems have occurred, either in port or at sea.

•Methane (the primary component of natural gas) is relatively insensitive to combustion as compared to heavier hydrocarbons.

•From a homeland security concern studies indicate that it is not possible to detonate LNG vapors, even with the use of an explosive charge (that is large enough) on a storage tank, unless the LNG vapors contain high fractions of ethane and propane (more than 20%). (Odds of occurrence is similar to winning the power ball or mega million lottery several times, simultaneously).

•LNG is not an attractive terrorist target given its non explosive nature.

•Not a single general public fatality has occurred anywhere in the world because of LNG operations.

•In the past thirty years, Japan has received nearly all of its natural gas in the form of LNG transported by ship. Once every 20 hours an LNG ship arrives at the busy Tokyo bay, unloads its LNG cargo, and leaves safely. In the last three decades and with more than 40,000 voyages by sea worldwide, there has not been a single reported LNG release from a ship's cargo tank.

•Natural gas in vehicles is a safer fuel than gasoline. Unlike gasoline that can pool on the ground in the event of an accident or leak, CNG dissipates harmlessly into the air. With a very narrow range of flammability to be combustible and nearly twice the ignition temperature of gasoline, it's also less likely to cause a fire"

**6. What options may be possible to decouple supply from delivery so that gas supply could be resold into mainland or world market if Hawaii's demand drops or cheaper renewable technologies become available?**

The options for this depend upon the contracting/procurement strategy HECO would choose to implement. If the LNG supply is procured on a Short Term/Spot basis then there will not be any issues due to limited liability for offtake. However, if the LNG is procured on a long term contract then it's important for HECO to negotiate destination flexibility in to their LNG SPA. With the destination flexibility, HECO could re-market the LNG into other markets on Spot, Short-term or Long-term basis. However, the risk will be on the pricing as there could be a scenario where the re-market volume could well be sold lower than what HECO has to pay.

## 7.2 Projected startup of liquefaction projects by tier (*all units in MTPA)

**Figure 61: Projected startup of liquefaction projects by tier**

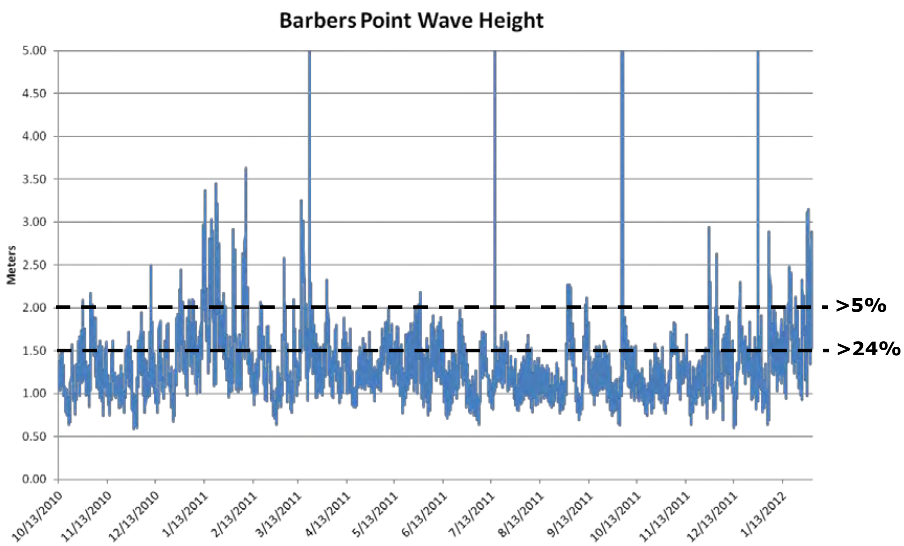
| Atlantic Basin | | | |
|---|---|---|---|
| **Potential & Possible** | | **Start-Up** | **Rank** |
| US (Sabine Pass T1-2 Cheniere) | 9.0 | 2016 | 1 |
| US (Sabine Pass T3-4 Cheniere) | 9.0 | 2017 | 1 |
| Columbia (Puerto Bahia) | 0.5 | 2017 | 2 |
| US (Freeport T1 Macquarie) | 4.0 | 2017 | 2 |
| US (Freeport T2 Macquarie) | 4.0 | 2017 | 2 |
| US (Freeport T3 Macquarie) | 4.0 | 2017 | 2 |
| | | | |
| **Intentional & Probable** | | **Start-Up** | **Rank** |
| Cameroon FLNG GdF Suez | 3.5 | 2016 | 3 |
| Nigeria (Brass T1-2) | 10.0 | 2017 | 3 |
| Nigeria (NLNG T7) | 8.5 | 2014 | 3 |
| Russia (Yamal LNG T1) | 5.0 | 2017 | 3 |
| Russia (Shtokman T1-2) | 15.0 | 2018 | 3 |
| Russia (Yamal LNG T2) | 5.0 | 2018 | 3 |
| US (Cove Point - Dominion ) | 7.8 | 2016 | 3 |
| US (Lake Charles - BG) | 12.0 | 2016 | 3 |
| US (Cameron - Sempra) | 12.0 | 2016 | 3 |

| Pacific Basin | | | |
|---|---|---|---|
| **Potential & Possible** | | **Start-Up** | **Rank** |
| Australia (APLNG-COP Train 2) | 4.5 | 2016 | 1 |
| Australia (Ichthys LNG T1) | 4.2 | 2017 | 1 |
| Australia (Ichthys LNG T2) | 4.2 | 2017 | 1 |
| Australia (Pluto LNG T2) | 4.3 | 2017 | 2 |
| Australia (Arrow LNG T1) | 4.0 | 2018 | 2 |
| Australia (Arrow LNG T2) | 4.0 | 2018 | 2 |
| Canada (Kitimat LNG) | 5.0 | 2017 | 2 |
| | | | |
| **Intentional & Probable** | | **Start-Up** | **Rank** |
| Australia (Browse LNG T1,2,3) | 12.0 | 2018 | 3 |
| Australia (Gorgon LNG T4) | 5.0 | 2019 | 3 |
| Australia (APLNG - COP T3-T4) | 9.0 | 2018 | 3 |
| Australia (Gladstone- Santos T3) | 3.9 | 2020 | 3 |
| Australia (Wheatstone LNG T3, T4) | 8.6 | 2020 | 3 |
| Australia (Bonepart FLNG) | 2.0 | 2019 | 3 |
| Canada (BC LNG) | 8.0 | 2018 | 3 |
| Indonesia (Tangguh Train 3) | 3.8 | 2020 | 3 |
| Indonesia (Abadi FLNG) | 2.5 | 2018 | 3 |
| Malaysia Tiga (Unnamed FLNG) | 1.2 | 2018 | 3 |
| PNG (PNG LNG T3) | 3.2 | 2018 | 3 |
| PNG (Gulf LNG Interoil T1) | 2.0 | 2019 | 3 |
| Russia (Sakhalin II T3) | 4.8 | 2018 | 3 |
| US (Jordan Cove) | 6.0 | 2018 | 3 |

**Source: Galway**

## 7.3 Barbers Point Metocean Data – Wave Height

**Figure 62: Barbers Point metocean data – wave height**




Source: NOAA PacIOOS's Barbers Point Station – 51204

**Source: NOAA PacIOOS's Barbers Point Station – 51204**

## 7.4 LNG Regasification economics

Methodology

- Galway has used its LNG regasification model to assess the economics for regasifying the delivered LNG based on the cost of service to meet the project financing.
- Galway assessed 7 different regasification options for 1 year based on the 3 given volume scenarios.
- After determining which scenarios were most feasible, Galway created a model to expand the selected cases out for 20 years at a volume of 0.85 MTPA for the first 10 years, and 0.55 MTPA for the remaining 10 years. The same methodology is being used for the other two demand cases.

Assumptions for the analysis of regasification economics

**Figure 63: Detailed assumptions – regasification economic analysis (1)**

| Parameters | Full Scale Onshore LNG Terminal | Small Scale Onshore LNG Terminal | FSRU Single Buoy | FSRU Double Buoy | Dockside FSRU | Dockside Small/Mid-Size FSRU | ATB Barges |
|---|---|---|---|---|---|---|---|
| Capex ($ Mn - Onshore; $K/d - FSRU) | 840 | 295 | 110,000 | 110,000 | 120,000 | 150 | 138 |
| Opex ($ Mn - Onshore; $K/d - FSRU) | 25 | 11.7 | 20,000 | 20,000 | 20,000 | 10.2 | 7 |
| Annual Opex Escalation | 2.50% | 2.50% | 2.50% | 2.50% | 2.50% | 2.50% | 2.50% |
| Debt %( to Equity Ratio) | 70% | 70% | 70% | 70% | 70% | 70% | 70% |
| Loan Tenor (years) | 18 | 18 | 18 | 18 | 18 | 18 | 18 |
| Financing Cost (BPS) | 300 | 300 | 300 | 300 | 300 | 300 | 300 |
| Loan Amortization | Straight Line | Straight Line | Straight Line | Straight Line | Straight Line | Straight Line | Straight Line |
| Debt Cost | 7.50% | 7.50% | 7.50% | 7.50% | 7.50% | 7.50% | 7.50% |
| Min DSCR | 1.7 | 1.7 | 1.7 | 1.7 | 1.7 | 1.7 | 1.7 |
| Equity Cost | 15% | 15% | 15% | 15% | 15% | 15% | 15% |
| Fed Income Tax | 35% | 35% | 35% | 35% | 35% | 35% | 35% |

**Source: Galway**

**Figure 64: Detailed assumptions – regasification economic analysis (2)**

| Parameters | Full Scale Onshore LNG Terminal | Small Scale Onshore LNG Terminal | FSRU Single Buoy | FSRU Double Buoy | Dockside FSRU | Dockside Small/Mid-Size FSRU | ATB Barges |
|---|---|---|---|---|---|---|---|
| Hawaii State Income Tax ($0-25K) | 4.40% | 4.40% | 4.40% | 4.40% | 4.40% | 4.40% | 4.40% |
| >$25k & <$100k | 5.40% | 5.40% | 5.40% | 5.40% | 5.40% | 5.40% | 5.40% |
| >100k | 6.40% | 6.40% | 6.40% | 6.40% | 6.40% | 6.40% | 6.40% |
| | | | | | | | |
| Design Speed (knots) | | | 18 | 18 | | | |
| | | | | | | | |
| Unloading (Days) (Shipping Cost) | 2 | 2 | 1 | 0 | 3.5 | 2 | 0 |
| | | | | | | | |
| Fuel Consumption/Retain | 0.50% | 0.50% | 2.50% | 2.50% | 2.50% | 2.50% | 2.50% |
| | | | | | | | |
| Buoy/Berth Capex ($ Mn) | | | 150 | 200 | 135 | 80 | 200 |
| | | | | | | | |
| Buoy/Berth Opex ($ Mn) | | | 3.5 | 3.5 | 4 | 2 | 2 |
| | | | | | | | |
| Buoy Opex Escalation Factor | | | 3.50% | 3.50% | 2.50% | 2.50% | 2.50% |
| | | | | | | | |
| Permitting (Years) | 1 | 1 | 1 | 1 | 1 | 1 | 1 |
| | | | | | | | |
| Construction (Years) | 4 | 3 | 2 | 2 | 2 | 2 | 2 |
| | | | | | | | |
| Project Life (Years) | 20 | 20 | 20 | 20 | 20 | 20 | 20 |

**Source: Galway**

Results of regasification economic analysis

**Figure 65: Results of regasification economic analysis**

| HECO Regas Economic Analysis | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| Regas Options | Y1 2020 000$ | 0.85 MTPA 2020 US$/mmbtu | 0.65 MTPA 2020 US$/mmbtu | 0.525 MTPA 2020 US$/mmbtu | Y11 2030 000$ | 0.55 MTPA 2030 US$/mmbtu | 0.4 MTPA 2030 US$/mmbtu | 0.28 MTPA 2030 US$/mmbtu |
| Onshore LNG Terminal | 164,524 | 4.00 | 5.23 | 6.48 | 171,526 | 6.45 | 8.87 | 12.90 |
| Small Scale Onshore LNG | 70,142 | 1.71 | 2.23 | 2.76 | 73,419 | 2.76 | 3.80 | 5.52 |
| 2 X FSRU - Double Offshore Buoy | 82,473 | 2.01 | 2.62 | 3.25 | 86,907 | 3.27 | 4.49 | 6.54 |
| 2 X FSRU - Single Offshore Buoy | 74,588 | 1.81 | 2.37 | 2.94 | 79,022 | 2.97 | 4.09 | 5.94 |
| Dockside Fullsize FSRU | 76,374 | 1.86 | 2.43 | 3.01 | 79,539 | 2.99 | 4.11 | 5.98 |
| Dockside Small/Mid-Size FSRU | 48,451 | 1.18 | 1.54 | 1.91 | 51,868 | 1.95 | 2.68 | 3.90 |
| ATB Barges | 62,264 | 1.51 | 1.98 | 2.45 | 64,784 | 2.44 | 3.35 | 4.87 |

**Source: Galway**

## 7.5 LNG storage considerations

- The regasification LNG sendout rate must be proactively managed to ensure that the inventory level is:
    - Sufficiently high to ensure that LNG will be available to maintain the desired sendout profile and 'keep the tank cold' until the next LNG delivery (i.e. it should not run out of gas).

  - Yet, sufficiently low to allow the full unloading of an LNG ship within in its scheduled delivered window
    - The consequences for a) forcing the delivery window to be extended would be demurrage charges, or for b) cancelling a cargo would be cancellation liabilities as per the terms of the contract.
- Inventory and sendout management can be challenging when:
  - The LNG delivery schedule is rateable and set around 6 months prior to the beginning of the contract year (typical SPA term).
  - Storage capacity is limited and is very close to the expected unloaded LNG quantities. There must always be a cushion to accommodate delivery schedule variations. This is a key design consideration for FSRU and onshore tank capacity and a key logistical/commercial point in supply agreements.
  - The ability to ramp up sendout (create sufficient space in the tank) or ramp down sendout (manage inventory cushion) is limited due to limited additional burn capacity or limited alternative fuel options.

## 7.6 Suppliers of FSRUs

The three proven suppliers of FSRUs are Excelerate Energy, Golar LNG and Hoegh LNG. Several other companies have actively participated in tender processes to supply FSRUs. These include the following:

- Japanese shipping companies with LNG ships: MOL, K-Line, NYK Line
- Other shipping companies: Exmar (Operator/manager of Excelerate Energy's FSRUs and co-owner of some of Excelerate's FSRUs), Teekay LNG Partners
- Marine infrastructure companies: SAIPEM, SBM Offshore, BW Gas

## 7.7 FSRU sourcing

FSRUs are either new built vessels that are specifically designed as FSRU ships or converted FSRUs (i.e. conventional LNG ships with the appropriate LNG storage technology (spherical or reinforced membrane) that are converted by adding vaporizers and additional utilities).

<u>Converted FSRUs</u>

Golar's fleet of 5 FSRUs are all conversions chartered under long term contracts to its customers. The advantages of these are that they can be cheaper based on the cost of the conversion candidate ($80 to $100 million plus the cost of the ship) and they can be converted quickly (in around 12 months). The disadvantage is that the availability of future suitable conversion candidates is limited (based on factors such as suitable storage capacity and technology, age, current market conditions and cost of ship).

Newbuilt FSRUs

Both Hoegh LNG and Excelerate have implemented projects using newbuilt FSRUs. The advantages of these are that they tend to be larger (and have more storage capacity) and can be more customized to the needs of specific projects. The disadvantages are that they are more expensive (around $260 million) and take longer to build (around 30 months).

Despite the disadvantages, newbuilt FSRUs are decidedly popular. Excelerate built a fleet of 8 FSRUs 'on spec' and has successfully placed 5 to long term charters (10 to 15 years). It is actively marketing 3 others. Hoegh LNG recently ordered 3 additional FSRUs and has committed 2 to new projects. It is also actively participating in tenders. Golar has options for 2 to 4 more FSRUs in the 2013 to 2015 timeframe.

The charter rates for FSRUs, both newbuilt and converted, depend on many factors, including the cost of the ships and the level of competition for FSRU customers. According to current estimates, long term (10 to 20 year) charter rates are in the $120,000 to $140,000 range.

It is difficult to assess what the FSRU market might look like in HECO's timeframe of 2018 to 2020. However, the demand for FSRUs is growing and providers are actively pursuing those opportunities. It is reasonable that HECO would be able to procure an FSRU, either newbuilt, an off-hire/charter existing FSRU or conversion. The key question is what terms will exist at that time. Using current charter rates ($120,000 to $140,000 per day) is a conservative assumption.

## 7.8 LNG terminal commercial and operational considerations

Ownership of the LNG terminal is not necessary. It is sufficient to control the LNG import capacity via a long term capacity contract (Terminal Use Agreement). This is the prevalent business model for merchant LNG terminals in North America. Third party developers permit, finance, build and operate the terminal under long term TUAs with capacity holders. A long term contract is required to finance the facilities. Capacity holders pay a 'use it or lose it' fee for their capacity and have specific volumetric capacity rights at the terminal.

The number of capacity holders in terminals tends to be relatively small because the operational complexity for scheduling deliveries of LNG, managing inventory and managing redeliveries increases with the number of users. Multi user complexity is further increased when there is limited storage capacity (as in the case of an FSRU or single tank terminal). **In Hawaii, it may be advantageous to have a single capacity holder or aggregator to ease operational issues at the terminal.**

### 7.9 Participants in LNG regasification terminals

In the Pacific Basin, the LNG end-users tend to build and operate the regasification terminals. These include regulated electric and power utilities (Japan), state owned utilities (Taiwan) and domestic oil companies either as end users (India) or as sponsors of the downstream gas infrastructure and markets (China, Thailand, India).

In the Atlantic Basin, ownership of regasification terminals is much more varied than in the Pacific Basin. Owners include private and state owned pipeline and gas companies, international oil companies holding interests in LNG projects, LNG buyers and end users, independent terminal developers and operators as well as integrated LNG projects.

Overview of LNG regasification commercial models – North America

Gas market regulatory regimes tend to dictate the commercial models undertaken by LNG regasification terminals. The regimes address whether the usage fees are set by regulated tariff or negotiated between the users and the terminal. They also decree whether access to the terminal by 3rd parties is mandated or optional. The regulatory regimes also develop permitting requirements, including safety, environmental protection, and marine traffic.

In North America, most LNG terminals follow a merchant model, wherein users and the terminal company negotiate access rights, usage costs and other terms and conditions. The original phases of 3 terminals in US are regulated under a tariff, which dictates user rights and usage costs. However, subsequent expansions and all subsequent new terminals followed a merchant model. Furthermore, in the US merchant regime, access rights for unaffiliated 3rd parties are not mandated by regulation. In Mexico, 2 existing terminals operate under merchant models. Regulations in Mexico mandate that uncommitted capacity (i.e. capacity not under contract) in LNG terminals be made available to 3rd parties.

Overview of LNG regasification commercial models – South America

In South America, LNG terminals tend to be end-user controlled with the costs of the terminals being rolled into the end-users infrastructure. South America does not offer third party access to the terminal infrastructure. In Brazil, the two seasonal LNG terminals are owned and controlled by Petrobras who buys and imports LNG directly. In Argentina, the two floating LNG terminals were developed by Repsol's affiliate YPF and are owned by government agency (ENARSA) who is also the LNG buyer. In Chile, two onshore LNG terminals are owned by a project company that is controlled by the downstream gas and electric utilities.

Overview of LNG regasification commercial models – Europe

In Europe, most LNG terminals are structured to operate under the merchant model. The EU mandates that third parties be offered unused capacity (under "use it or lose it" rules). Each country has implemented different standards to offer unused capacity to third parties by stipulating the timeframe within which capacity is deemed unused. In some cases, the timeframe, which defines unused capacity is practically too short to be claimed by a third party in time to arrange for an LNG delivery, unless they already have LNG and are diverting it from another European destination. In some cases, regulators mandate that a percentage of the terminal capacity be reserved to third party short-term users (15-20% of capacity). Spain currently provides the most third party user-friendly mandates in Europe.

Overview of LNG regasification commercial models – Asia

In Asia, the LNG terminals tend to be owned and controlled by single end-users with the cost of the terminals being rolled into the end-user's infrastructure. There is typically no third party access to the terminals, which means that LNG sales need to be made on ex-ship, or FOB, basis to the end-users directly. In Japan, all the terminals are owned by individual electric and gas utilities. In Korea, the terminals are owned by the gas monopoly Kogas. One terminal is owned by a large industrial user. In Taiwan, the two terminals are owned by the government owned oil company. In China, the terminals are controlled by JVs, which include one of the 3 major Chinese oil companies, end-user gas/power companies, and sometimes international partners. In India, one of the terminals is owned and controlled by a consortium of Indian oil and energy companies, which also imports and markets LNG under long-term SPAs. The other terminal is owned by 2 international oil companies and operated under a merchant model.

## 7.10 Overview of Excelerate Energy

Excelerate is one of the floating LNG terminal industry leaders and developed the concept of the FSRU (when owned by El Paso LNG). Owned by RWE (large German utility) and George Kaiser (US billionaire oilman and banker), it has a fleet of 8 FSRUs – 5 are currently uncommitted (this is the largest FSRU fleet). Its original strategy was to trade LNG using FSRUs and proprietary floating terminals - Northeast Gateway (Boston, MA), Gulf Gateway (Gulf of Mexico) using buoys, Teeside Gas port (UK) using single berth. It is also experienced with US permitting processes. Excelerate has expanded its business model to develop floating LNG terminals for third parties, provide and operate FSRUs. Some examples include Bahia Blanca Gasport and Port Escobar Gasport in Argentina for ENARSA, Mina Al-Ahmadi Gasport in Kuwait for Kuwait National Petroleum Company and it is also developing the Aguirre Gasport in Puerto Rico.

## 7.11 Overview of Golar LNG

Golar LNG is a mid-stream LNG company focused primarily on the transportation, regasification, liquefaction and trading of LNG. The company includes 2 divisions - Vessel Operations, which deals with the acquisition, ownership, operation and chartering of LNG carriers and FSRUs and LNG Trading, which deals with the trading of LNG cargos and providing physical and financial risk management in LNG for its customers. Golar developed the world's first Floating Storage and Regasification Unit (FSRU) based on the conversion of an existing LNG ship. It is the only company in the world that has done this It has 9 LNG ships, 5 committed FSRUs and options to build up to 5 additional ships/FSRUs.

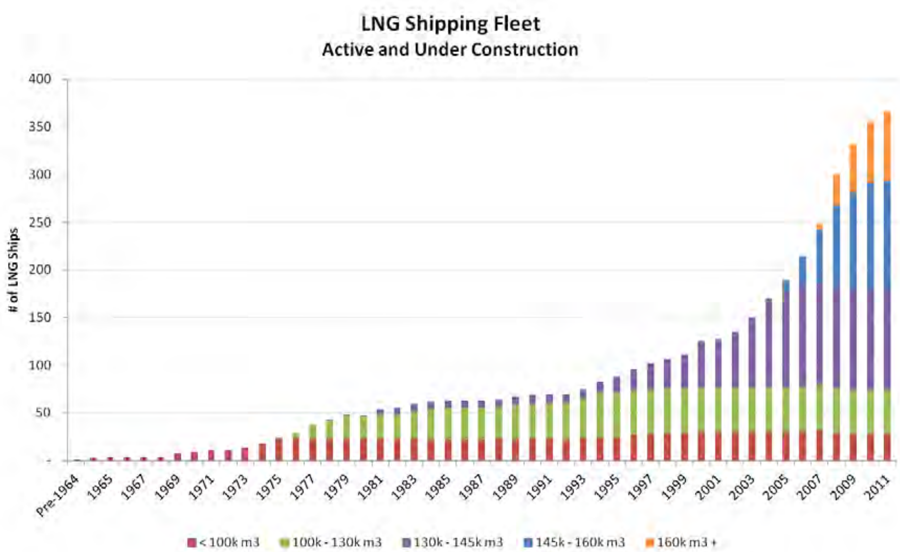
7.12 Overview of Hoegh LNG

Hoegh LNG is an LNG shipping company involved in both LNG ships and FSRUs. It operates two regasification vessels (GdF Suez Neptune and GdF Suez Cape Ann) and five LNG carriers (Norman Lady, Arctic Princess, Arctic Lady, Matthew and STX Frontier). It has ordered 3 new FSRUs, 2 of which are committed to new projects (Indonesia and Lithuania).

7.13 Growth of LNG shipping fleet

**Figure 66** shows the growth of LNG shipping in order keep pace with the growth in liquefaction capacity:

**Figure 66: LNG shipping fleet – active and under construction**




**Source: Galway**

Some key points to note with regard to the LNG shipping fleet are as follows:

- Ship size is trending higher to generate additional economies of scale.
- Smaller ships tend to be much older when reaching the end of their useful life (30-40 yrs).

- 11 ships of 19,000 to 40,000 cubic metres capacity are in use in Europe and Japan.
- 8 small scale ships (<12,000 cubic metres) have been built, all in the last 3 years.
- No LNG barges are in use (only 1 built in 1974 and is sparsely used).

### 7.14 Chartering of LNG ships

Ships are typically owned by 'single ship asset' companies. They are controlled and operated by experienced LNG shipping companies (Golar, Hoegh, Moeller, MOL, K-Line, NYK, etc.). Ships are time chartered (for terms that match SPA terms) by the following:

- Projects – Qatar, Rasgas, NWS, etc.
- Buyers – Tokyo Gas, Gas Natural, etc.
- Portfolio Marketers – Shell, BG, GDFSuez, etc.
- Equity Sellers – Chevron, ExxonMobil, etc.
- National Oil Companies – Gazprom, Sonatrach, etc.

The market for surplus ships available for spot/ short-term charters is cyclical and is now much tighter with generally no availability of newer high-efficiency vessels.

The following are the top 15 LNG carrier fleet owners/operators:

1. MISC (Malaysia)
2. NYK Shipping
3. Mitsui OSK Line
4. K Line
5. Nakilat (Qatar)
6. Teekay
7. BW Gas
8. Bonny Gas Transport (Nigeria)
9. BG Group
10. Shell Group
11. Exmar
12. A P Moller
13. Knutsen
14. National Gas Shipping
15. BP Shipping

### 7.15 Role of brokers in LNG shipping

Most of the LNG ships are under long-term charters, therefore brokers have a very limited role with charters. They have some level of involvement in the short-term charter market. Brokers are also involved in the resale and newbuilt markets. They are sometimes used as consultants to assist with ship tenders.

### 7.16 LNG shipyards

The shipyards (for ships larger than 50,000 cubic metre) active in last 10 years are as follows:

- China - Hundong
- Europe - CdA, Kvaerner, Izar
- Japan - Imabari, Kawasaki, Mitsubishi, Mitsui, Universal
- Korea - Daewoo, Hanjin, Hyundai, Samsung, STX

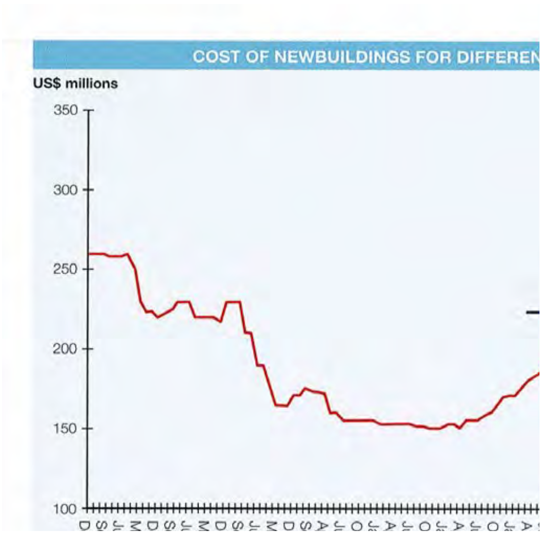
Total shipyard capacity is around 50 ships per year (as of 2008).

There are no US based ship builders anymore. This has an implication in terms of compliance with the Jones Act requirements. There are 15 ships built by yards in Quincy, Newport News, and Avondale from 1977 to 1980, of which 2 Avondale ships have been scrapped. There are 13 ships reaching the end of useful life and these, therefore, may not be good candidates to 're-flag' in the US for long-term trade. 2 have recently been re-flagged into the US for ethylene transportation.

### 7.17 Cost of LNG ships

LNG ships are expensive, fluctuating between $200 and $250 million per unit depending on market conditions and commodity (steel) prices. **Figure 67** shows the historical cost of LNG ships:

**Figure 67: Costs of newbuilds for different types of LNG carriers**




**Source: Galway and other sources**

### 7.18 Types of Charter Agreements

The various types of charter agreements are as follows:

- Time charter of named vessel
    - Owner retains control
    - Charterer instructs vessel where to proceed
- Bareboat (or Demise) charter of named vessel
    - Charterer effectively becomes the owner and is responsible for operating costs
- Voyage charter of named vessel

    - Usually fixed fee
    - No control by charterer
- Contract of Affreightment (COA)
    - BTU quantity is carried between specific points by various ships

### 7.19 Time charter rates

Time Charter hire rate is made up of capital and operating components. The following are its components:

- Capital component
    - Capital cost of vessel
    - Financing discount rate
    - Return expectations – most ship owners target over 20%  levered returns
    - Around $54,000 per day for a 145,000 – 150,000 cubic metre ship
- Operating component
    - Typically in the $15,000-$18,000 per day range
    - Normally adjusted each year of the time charter

Many other factors may impact the rates. These include the life of vessel, asset value after initial charter period, future new build costs, life extension costs, etc.

Generally, time charters are procured via tenders. Success and costs depend on the terms of the tender (e.g. length of charter, ship size, ship characteristics), and availability of ships meeting the tender requirements. Ship brokers are used from time to time but primarily to buy and sell ships or to advise on charter tender terms.

### 7.20 LNG shipping economics – Methodology

Galway has used its LNG shipping model to assess the economics for transporting LNG between the supply source and Hawaii. We assessed 12 different shipping economics cases for 1 year based on the 3 given volume scenarios. After determining which scenarios were most feasible, Galway created a model to expand the selected cases out for 20 years at a volume of 0.85 MTPA for the first 10 years, and 0.55 MTPA for the remaining 10 years. The same methodology is being used for the other two demand cases.

<u>Generic shipping economic analysis assumptions</u>

The following assumptions are applicable to all or most of the scenarios:

- Liquefaction cost: $1.75
- Maximum loading capacity at liquefaction plant: 98.5%
- Plant operating capacity: 95%
- Shipping days per year: 350

Certain variable costs were escalated at 2.5% annually over the 20 year timeframe of the project. The additional cost incurred by the stipulations of the Jones Act was assumed to be $3,000,000. Ship layup accounts for the cost of harboring ships that will not be needed after the volume requirements decrease.

Rates were calculated based on MMBtus delivered.

Specific assumptions – Standard LNG Ship

The specific assumptions used for a standard LNG ship are shown in **Figure 68**:

**Figure 68: Specific assumptions – standard LNG ship**

| Assumptions | |
|---|---|
| Size: | 145,000 cm |
| Hire Rate: | $70,000 |
| Insurance: | 0.06% of Loaded MMBtu's |
| Fuel Type: | MDO |
| Survey Fees: | $6,000 |
| Port Fees: | $250,000 |
| Fuel Consumption in Port: | 40 t/d |
| Fuel Consumption Laden: | 125 t/d |
| Fuel Consumption Ballast: | 120 t/d |
| Boil Off Laden: | 0.12% |
| Boil Off Ballast: | 0.10% |
| Average Speed: | 19 knots |
| Loading Time: | 1 Day |
| Unloading Time: | 2 Days |
| Panama Canal Time: | 1.5 Days |

**Source: Galway**

Specific assumptions – FSRU

The specific assumptions used for an FSRU are shown in **Figure 69**:

**Figure 69: Specific assumptions – FSRU**

| Assumptions | |
|---|---|
| Size: | 151,000 cm |
| Hire Rate: | $110,000 |
| Addition Hire Rate Opex: | $20,000 |
| Insurance: | 0.06% of Loaded MMBtu's |
| Fuel Type: | MDO |
| Survey Fees: | $6,000 |
| Port Fees: | $250,000 |
| Fuel Consumption in Port: | 40 t/d |
| Fuel Consumption Laden: | 125 t/d |
| Fuel Consumption Ballast: | 120 t/d |
| Boil Off Laden: | 0.12% |
| Boil Off Ballast: | 0.10% |
| Average Speed: | 18 knots |
| Loading Time: | 1 Day |
| Unloading Time: | 0 Days |
| Panama Canal Time: | 1.5 Days |

**Source: Galway**

Specific assumptions – Small scale 28,000 cubic metre ship

The assumptions used for a small scale 28,000 cubic metre ship are shown in **Figure 70**:

Figure 70: Specific assumptions – Small scale 28,000 cubic metre ship

| Assumptions | |
|---|---|
| Size: | 28,000 cm |
| Hire Rate: | $33,317 |
| Insurance: | 0.06% of Loaded MMBtu's |
| Fuel Type: | MDO |
| Survey Fees: | $6,000 |
| Port Fees: | $65,000 |
| Fuel Consumption in Port: | 3 t/d |
| Fuel Consumption Laden: | 48 t/d |
| Fuel Consumption Ballast: | 48 t/d |
| Boil Off Laden: | 0.00% |
| Boil Off Ballast: | 0.00% |
| Average Speed: | 16 knots |
| Loading Time: | 1 Day |
| Unloading Time: | 1 Days |
| Panama Canal Time: | 1.5 Days |

Source: Galway

## Specific assumptions – ATB Barges

The assumptions used for ATB barges are shown in **Figure 71**:

Figure 71: Specific assumptions – ATB barges

| Assumptions | |
|---|---|
| Size: | 30,000 cm |
| Hire Rate: | $35,199 |
| Insurance: | 0.06% of Loaded MMBtu's |
| Fuel Type: | MDO |
| Survey Fees: | $6,000 |
| Port Fees: | $65,000 |
| Fuel Consumption in Port: | 2 t/d |
| Fuel Consumption Laden: | 35 t/d |
| Fuel Consumption Ballast: | 35 t/d |
| Boil Off Laden: | 0.00% |
| Boil Off Ballast: | 0.00% |
| Average Speed: | 8 knots |
| Loading Time: | 1 Day |
| Unloading Time: | 1 Days |
| Panama Canal Time: | 1.5 Days |

Source: Galway

## 7.21 Panama Canal considerations and impact on shipping

The expansion of the Panama Canal is expected to be completed by 2015. The expansion will allow larger ships, like LNG ships, to cross from the Atlantic Basin to the Pacific Basin faster and, hopefully, cheaper. It should open up supply opportunities from the Atlantic Basin to markets along the west coast of the Americas that are currently quite far from the Pacific Basin options.

For Hawaii, US Gulf Coast liquefaction capacity becomes more accessible. However, there is still much uncertainty about costs and logistics. The Panama Canal Authority has not yet published a tariff for LNG ships. Galway has estimated potential tariff based on liquid bulk tariff at $700,000 for a round trip (around $0.22/MMBtu).

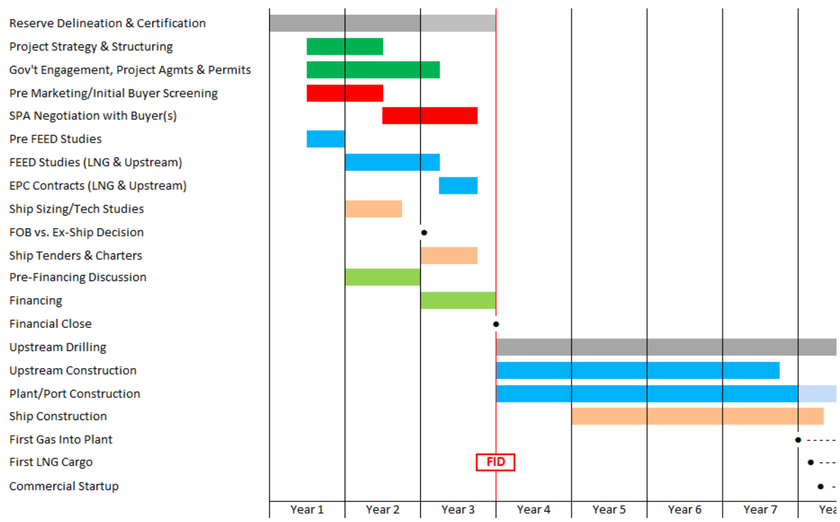
The Panama Canal Authority has not yet published operational requirements for LNG ships (priority handling, security, etc.). It is not uncommon for ships to have to wait days to pass through the Canal. It is not known yet if/how LNG ships will be prioritized through the expansion. LNG ships may be required to participate in the Canal's 'slot' reservation system (reserve and pre-pay slots months in advance), which may impact ship schedules if they miss the slot arranged months in advance.

## 7.22 Typical LNG project development timeline

The typical timeline for the development of an LNG project is shown in **Figure 72** :

GALWAY ENERGY ADVISORS LLC

**Figure 72: LNG project development timeline**

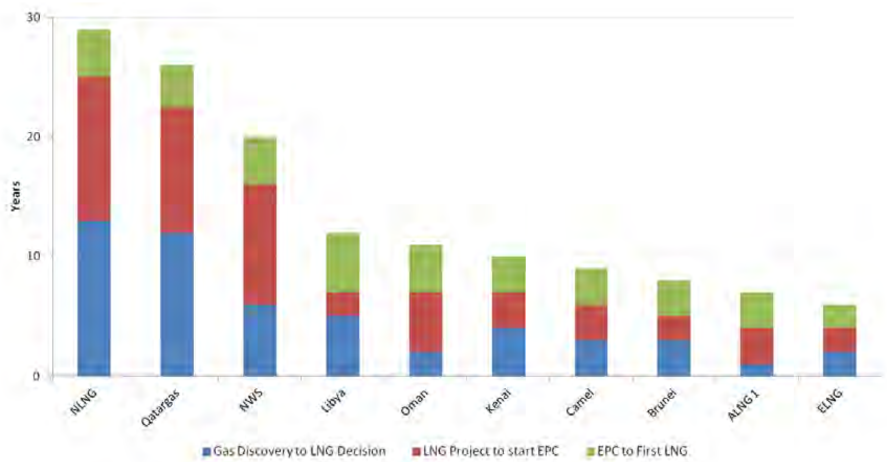



**Source: Galway**

A solid project structure is key to rapid project development. The development timeline for different liquefaction projects is shown in **Figure 73**:

GALWAY ENERGY ADVISORS LLC

Figure 73: Development timeline for liquefaction projects




Source: Galway

7.23 Conversion Factors

1 billion cubic meters of gas/year

= 0.74 million tons of LNG/year

= 96.7 million cubic feet of gas/day

1 million tons of LNG/year

= 1.35 billion cubic meters of gas/year

= 130.6 million cubic feet of gas/day

600 MW Base Load CCGT*

= 2.2 million cubic meters of gas/year

= 80,400 million Btu per day

~ 0.6 million tons of LNG/year

~ 9 cargoes of LNG (145,000 cubic meter ships)

*Heat Rate = 6,430 Btu/kW-hr; Dispatch = 87%

7.25 Detailed Economics

**Breakdown of Costs:**

For the final forecasts provided to HECO, the “Total Delivered to Hawaii” reflects the sum of the LNG FOB, Shipping, and Regas costs. The LNG FOB number is the price of the gas commodity from the seller including the liquefaction cost. For the US, this price was calculated using 115% of the Henry Hub commodity price, and then liquefaction added onto that. The commodity price was based on the forecast provided by the EIA out to 2035 (and then extended to 2039)[Table 1]. For GOM, the liquefaction was estimated at $4.00 (formula: 115%*HH+$4.00). For Jordan Cove the liquefaction was estimated at $4.50 (formula: 115%*HH+$4.50). Since the Canadian contracts will be oil linked, we calculated a price based on 14.85% * JCC, using the Brent forecast provided by the EIA out to 2035 (and then extended to 2039)[Table 1]. For both the HH-linked and oil-linked contracts, the LNG FOB price then took into account the energy required at burner tip in order to reach a final calculation.[7] The final LNG FOB pricing table is included below as Table 2.

[7] Burner Tip price is defined as the unit cost of gas (US$/mmbtu) at the power plant gate adjusted for all the energy lost in LNG transportation (boil off - 1.2%) and regasification (2.5%). The quantum of gas required at the power plant gate level is used to calculated the LNG quantity to be contracted by adding in the energy (3.7%) that is expected to be lost during the transportation and regasification process. Hence, the price of LNG at the burner tip price is 3.7% more than at the LNG FOB level.

GALWAY ENERGY ADVISORS LLC

Table 1: LNG FOB Commodity Price Basis:

| | | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| EIA Henry Hub Forecast | US$/mmbtu | 5.5 | 5.9 | 6.4 | 6.7 | 7.1 | 7.3 | 7.8 | 8.2 | 8.4 | 8.5 |
| EIA Brent Forecast | US$/bbl | 133.8 | 137.5 | 141.6 | 145.9 | 150.3 | 154.8 | 159.3 | 164.0 | 168.5 | 173.1 |
| Canada Oil Linked Contract | 14.85% JCC | 19.9 | 20.4 | 21.0 | 21.7 | 22.3 | 23.0 | 23.7 | 24.4 | 25.0 | 25.7 |

| | | 2030 | 2031 | 2032 | 2033 | 2034 | 2035 | 2036 | 2037 | 2038 | 2039 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| EIA Henry Hub Forecast | US$/mmbtu | 8.7 | 9.2 | 9.7 | 10.2 | 10.6 | 11.1 | 11.1 | 11.1 | 11.1 | 11.1 |
| EIA Brent Forecast | US$/bbl | 178.1 | 183.4 | 188.5 | 193.4 | 199.1 | 204.5 | 204.5 | 204.5 | 204.5 | 204.5 |
| Canada Oil Linked Contract | 14.85% JCC | 26.4 | 27.2 | 28.0 | 28.7 | 29.6 | 30.4 | 30.4 | 30.4 | 30.4 | 30.4 |

Table 2: Final LNG FOB Price (all numbers in $/MMBtu)

| | | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 | 2035 | 2036 | 2037 | 2038 | 2039 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Demand Case 1 | US GoM LNG Supply | 10.77 | 11.18 | 11.74 | 12.19 | 12.58 | 12.92 | 13.45 | 13.94 | 14.15 | 14.26 | 14.55 | 15.14 | 15.79 | 16.28 | 16.79 | 17.46 | 17.46 | 17.46 | 17.46 | 17.46 |
| | Jordan Cove LNG Supply | 11.28 | 11.7 | 12.26 | 12.71 | 13.1 | 13.43 | 13.97 | 14.46 | 14.66 | 14.78 | 15.07 | 15.66 | 16.3 | 16.8 | 17.31 | 17.98 | 17.98 | 17.98 | 17.98 | 17.98 |
| | Canada LNG Supply | 20.42 | 20.99 | 21.62 | 22.27 | 22.94 | 23.62 | 24.31 | 25.03 | 25.71 | 26.42 | 27.17 | 27.98 | 28.76 | 29.52 | 30.38 | 31.22 | 31.22 | 31.22 | 31.22 | 31.22 |
| Demand Case 2 | US GoM LNG Supply | 10.77 | 11.18 | 11.74 | 12.19 | 12.58 | 12.92 | 13.45 | 13.94 | 14.15 | 14.26 | 14.55 | 15.14 | 15.79 | 16.28 | 16.79 | 17.46 | 17.46 | 17.46 | 17.46 | 17.46 |
| | Jordan Cove LNG Supply | 11.28 | 11.7 | 12.26 | 12.71 | 13.1 | 13.43 | 13.97 | 14.46 | 14.66 | 14.78 | 15.07 | 15.66 | 16.3 | 16.8 | 17.31 | 17.98 | 17.98 | 17.98 | 17.98 | 17.98 |
| | Canada LNG Supply | 20.42 | 20.99 | 21.62 | 22.27 | 22.94 | 23.62 | 24.31 | 25.03 | 25.71 | 26.42 | 27.17 | 27.98 | 28.76 | 29.52 | 30.38 | 31.22 | 31.22 | 31.22 | 31.22 | 31.22 |
| Demand Case 3 | US GoM LNG Supply | 10.77 | 11.18 | 11.74 | 12.19 | 12.58 | 12.92 | 13.45 | 13.94 | 14.15 | 14.26 | 14.55 | 15.14 | 15.79 | 16.28 | 16.79 | 17.46 | 17.46 | 17.46 | 17.46 | 17.46 |
| | Jordan Cove LNG Supply | 11.28 | 11.7 | 12.26 | 12.71 | 13.1 | 13.43 | 13.97 | 14.46 | 14.66 | 14.78 | 15.07 | 15.66 | 16.3 | 16.8 | 17.31 | 17.98 | 17.98 | 17.98 | 17.98 | 17.98 |
| | Canada LNG Supply | 20.42 | 20.99 | 21.62 | 22.27 | 22.94 | 23.62 | 24.31 | 25.03 | 25.71 | 26.42 | 27.17 | 27.98 | 28.76 | 29.52 | 30.38 | 31.22 | 31.22 | 31.22 | 31.22 | 31.22 |

#1300, 3050 Post Oak Blvd, Houston, TX, USA 77056 www.galwaygroup.com #10-03A, 30 Robinson Road, Singapore, 048546

GALWAY ENERGY ADVISORS LLC

Final estimates were determined for the selected scenarios based on the LNG FOB price as well as the Shipping and Regas costs, which were calculated using the custom built integrated model that Galway built for the HECO project. The selected scenrios were as follows: US GoM exports using 2 x 150,000 cm FSRU with a double buoy FSRU; Jordan Cove exports using 28,000 LNG ship and 60,000 cm Dockside FSRU; and Canadian exports using 2 x 150,000 cm FSRU with a double buoy offshore FSRU. This data is provided in the tables below according to the demand requirements provided by HECO. The demand scenario providing for the largest volume of 0.85 MTPA to 0.55 MTPA is shown in Table 3. HECO Demand case 2 is shown below in Table 4. The final demand scenario is shown below in Table 5.

Table 3: HECO Demand 1

| | | | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 | 2035 | 2036 | 2037 | 2038 | 2039 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Volume | (MTPA) | 0.85 | 0.85 | 0.85 | 0.85 | 0.85 | 0.85 | 0.85 | 0.85 | 0.85 | 0.85 | 0.55 | 0.55 | 0.55 | 0.55 | 0.55 | 0.55 | 0.55 | 0.55 | 0.55 | 0.55 |
| HECO Demand 1 (0.85 MTPA to 0.55 MTPA) | US GoM LNG Supply | LNG FOB | 10.8 | 11.2 | 11.7 | 12.2 | 12.6 | 12.9 | 13.5 | 13.9 | 14.1 | 14.3 | 14.6 | 15.1 | 15.8 | 16.3 | 16.8 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 |
| | | Shipping | 2.9 | 2.9 | 2.9 | 2.9 | 2.9 | 3.0 | 3.0 | 3.0 | 3.0 | 3.0 | 2.4 | 2.4 | 2.4 | 2.4 | 2.4 | 2.4 | 2.4 | 2.4 | 2.4 | 2.5 |
| | | Regas | 2.0 | 2.0 | 2.0 | 2.0 | 2.0 | 2.1 | 2.1 | 2.1 | 2.1 | 2.1 | 3.3 | 3.3 | 3.3 | 3.3 | 3.4 | 3.4 | 3.4 | 3.4 | 3.4 | 3.5 |
| | | Total Delivered to HI | 15.7 | 16.1 | 16.7 | 17.2 | 17.6 | 17.9 | 18.5 | 19.0 | 19.2 | 19.3 | 20.2 | 20.8 | 21.5 | 22.0 | 22.5 | 23.2 | 23.3 | 23.3 | 23.3 | 23.4 |
| | Jordan Cove LNG Supply | LNG FOB | 11.3 | 11.7 | 12.3 | 12.7 | 13.1 | 13.4 | 14.0 | 14.5 | 14.7 | 14.8 | 15.1 | 15.7 | 16.3 | 16.8 | 17.3 | 18.0 | 18.0 | 18.0 | 18.0 | 18.0 |
| | | Shipping | 2.4 | 2.5 | 2.5 | 2.6 | 2.7 | 2.7 | 2.8 | 2.8 | 2.9 | 2.9 | 3.6 | 3.7 | 3.8 | 3.8 | 3.9 | 4.0 | 4.0 | 4.0 | 4.0 | 4.1 |
| | | Regas | 1.2 | 1.2 | 1.2 | 1.2 | 1.2 | 1.2 | 1.2 | 1.2 | 1.2 | 1.3 | 2.0 | 2.0 | 2.0 | 2.0 | 2.0 | 2.0 | 2.0 | 2.1 | 2.1 | 2.1 |
| | | Total Delivered to HI | 14.9 | 15.4 | 16.0 | 16.5 | 17.0 | 17.4 | 18.0 | 18.5 | 18.8 | 19.0 | 20.7 | 21.3 | 22.0 | 22.6 | 23.2 | 24.0 | 24.0 | 24.1 | 24.1 | 24.2 |
| | Canada LNG Supply | LNG FOB | 20.4 | 21.0 | 21.6 | 22.3 | 22.9 | 23.6 | 24.3 | 25.0 | 25.7 | 26.4 | 27.2 | 28.0 | 28.8 | 29.5 | 30.4 | 31.2 | 31.2 | 31.2 | 31.2 | 31.2 |
| | | Shipping | 1.4 | 1.4 | 1.4 | 1.4 | 1.4 | 1.4 | 1.4 | 1.4 | 1.4 | 1.4 | 2.2 | 2.2 | 2.2 | 2.2 | 2.2 | 2.2 | 2.2 | 2.2 | 2.2 | 2.2 |
| | | Regas | 2.0 | 2.0 | 2.0 | 2.0 | 2.0 | 2.1 | 2.1 | 2.1 | 2.1 | 2.1 | 3.3 | 3.3 | 3.3 | 3.3 | 3.4 | 3.4 | 3.4 | 3.4 | 3.4 | 3.5 |
| | | Total Delivered to HI | 23.8 | 24.4 | 25.0 | 25.7 | 26.4 | 27.1 | 27.8 | 28.5 | 29.2 | 29.9 | 32.6 | 33.5 | 34.3 | 35.1 | 36.0 | 36.8 | 36.8 | 36.9 | 36.9 | 36.9 |
| | LSFO | | 24.8 | 25.5 | 26.3 | 27.1 | 27.9 | 28.7 | 29.5 | 30.4 | 31.2 | 32.1 | 33.0 | 33.9 | 34.9 | 35.8 | 36.8 | 37.8 | 37.8 | 37.8 | 37.8 | 37.8 |
| | ULSD | | 31.4 | 32.2 | 33.1 | 34.1 | 35.1 | 36.1 | 37.2 | 38.2 | 39.3 | 40.3 | 41.4 | 42.6 | 43.8 | 44.9 | 46.2 | 47.4 | 47.4 | 47.4 | 47.4 | 47.4 |

GALWAY ENERGY ADVISORS LLC

Table 4: HECO Demand 2

| | | | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 | 2035 | 2036 | 2037 | 2038 | 2039 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Volume | (MTPA) | 0.65 | 0.65 | 0.65 | 0.65 | 0.65 | 0.65 | 0.65 | 0.65 | 0.65 | 0.65 | 0.4 | 0.4 | 0.4 | 0.4 | 0.4 | 0.4 | 0.4 | 0.4 | 0.4 | 0.4 |
| HECO Demand 2 (0.65 MTPA to 0.40 MTPA) | US GoM LNG Supply | LNG FOB | 10.8 | 11.2 | 11.7 | 12.2 | 12.6 | 12.9 | 13.5 | 13.9 | 14.1 | 14.3 | 14.6 | 15.1 | 15.8 | 16.3 | 16.8 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 |
| | | Shipping | 2.2 | 2.2 | 2.2 | 2.2 | 2.2 | 2.3 | 2.3 | 2.3 | 2.3 | 2.3 | 3.2 | 3.2 | 3.2 | 3.2 | 3.2 | 3.2 | 3.2 | 3.3 | 3.3 | 3.3 |
| | | Regas | 2.6 | 2.6 | 2.6 | 2.7 | 2.7 | 2.7 | 2.7 | 2.7 | 2.7 | 2.7 | 4.5 | 4.5 | 4.5 | 4.6 | 4.6 | 4.6 | 4.7 | 4.7 | 4.7 | 4.8 |
| | | Total Delivered to HI | 15.6 | 16.0 | 16.6 | 17.1 | 17.5 | 17.9 | 18.4 | 18.9 | 19.2 | 19.3 | 22.2 | 22.8 | 23.5 | 24.1 | 24.6 | 25.3 | 25.4 | 25.4 | 25.5 | 25.5 |
| | Jordan Cove LNG Supply | LNG FOB | 11.3 | 11.7 | 12.3 | 12.7 | 13.1 | 13.4 | 14.0 | 14.5 | 14.7 | 14.8 | 15.1 | 15.7 | 16.3 | 16.8 | 17.3 | 18.0 | 18.0 | 18.0 | 18.0 | 18.0 |
| | | Shipping | 2.2 | 2.2 | 2.2 | 2.3 | 2.3 | 2.3 | 2.4 | 2.4 | 2.4 | 2.5 | 3.5 | 3.5 | 3.6 | 3.6 | 3.6 | 3.7 | 3.7 | 3.7 | 3.8 | 3.8 |
| | | Regas | 1.5 | 1.6 | 1.6 | 1.6 | 1.6 | 1.6 | 1.6 | 1.6 | 1.6 | 1.6 | 2.7 | 2.7 | 2.7 | 2.7 | 2.8 | 2.8 | 2.8 | 2.8 | 2.9 | 2.9 |
| | | Total Delivered to HI | 15.0 | 15.5 | 16.1 | 16.6 | 17.0 | 17.4 | 17.9 | 18.5 | 18.7 | 18.9 | 21.3 | 21.9 | 22.6 | 23.1 | 23.7 | 24.4 | 24.5 | 24.5 | 24.6 | 24.7 |
| | Canada LNG Supply | LNG FOB | 20.4 | 21.0 | 21.6 | 22.3 | 22.9 | 23.6 | 24.3 | 25.0 | 25.7 | 26.4 | 27.2 | 28.0 | 28.8 | 29.5 | 30.4 | 31.2 | 31.2 | 31.2 | 31.2 | 31.2 |
| | | Shipping | 1.8 | 1.8 | 1.8 | 1.8 | 1.8 | 1.8 | 1.8 | 1.8 | 1.8 | 1.9 | 3.0 | 3.0 | 3.0 | 3.0 | 3.0 | 3.0 | 3.1 | 3.1 | 3.1 | 3.1 |
| | | Regas | 2.6 | 2.6 | 2.6 | 2.7 | 2.7 | 2.7 | 2.7 | 2.7 | 2.7 | 2.7 | 4.5 | 4.5 | 4.5 | 4.6 | 4.6 | 4.6 | 4.7 | 4.7 | 4.7 | 4.8 |
| | | Total Delivered to HI | 24.9 | 25.4 | 26.1 | 26.8 | 27.4 | 28.1 | 28.9 | 29.6 | 30.3 | 31.0 | 34.7 | 35.5 | 36.3 | 37.1 | 38.0 | 38.9 | 38.9 | 39.0 | 39.0 | 39.1 |
| | LSFO | | 24.8 | 25.5 | 26.3 | 27.1 | 27.9 | 28.7 | 29.5 | 30.4 | 31.2 | 32.1 | 33.0 | 33.9 | 34.9 | 35.8 | 36.8 | 37.8 | 37.8 | 37.8 | 37.8 | 37.8 |
| | ULSD | | 31.4 | 32.2 | 33.1 | 34.1 | 35.1 | 36.1 | 37.2 | 38.2 | 39.3 | 40.3 | 41.4 | 42.6 | 43.8 | 44.9 | 46.2 | 47.4 | 47.4 | 47.4 | 47.4 | 47.4 |

#1300, 3050 Post Oak Blvd, Houston, TX, USA 77056 www.galwaygroup.com #10-03A, 30 Robinson Road, Singapore, 048546

GALWAY ENERGY ADVISORS LLC

Table 5: HECO Demand 3

| | | | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 | 2035 | 2036 | 2037 | 2038 | 2039 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Volume | (MTPA) | 0.525 | 0.525 | 0.525 | 0.525 | 0.525 | 0.525 | 0.525 | 0.525 | 0.525 | 0.525 | 0.275 | 0.275 | 0.275 | 0.275 | 0.275 | 0.275 | 0.275 | 0.275 | 0.275 | 0.275 |
| HECO Demand 3 (0.525 MTPA to 0.275 MTPA) | **US GoM LNG Supply (Reference Forecast)** | LNG FOB | 10.8 | 11.2 | 11.7 | 12.2 | 12.6 | 12.9 | 13.5 | 13.9 | 14.1 | 14.3 | 14.6 | 15.1 | 15.8 | 16.3 | 16.8 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 |
| | | Shipping | 2.4 | 2.4 | 2.4 | 2.4 | 2.4 | 2.4 | 2.4 | 2.4 | 2.4 | 2.4 | 4.5 | 4.6 | 4.6 | 4.6 | 4.6 | 4.6 | 4.6 | 4.6 | 4.6 | 4.6 |
| | | Regas | 3.2 | 3.3 | 3.3 | 3.3 | 3.3 | 3.3 | 3.3 | 3.4 | 3.4 | 3.4 | 6.5 | 6.6 | 6.6 | 6.7 | 6.7 | 6.8 | 6.8 | 6.8 | 6.9 | 7.0 |
| | | Total Delivered to HI | 16.4 | 16.8 | 17.4 | 17.9 | 18.3 | 18.7 | 19.2 | 19.7 | 20.0 | 20.1 | 25.6 | 26.3 | 27.0 | 27.5 | 28.1 | 28.8 | 28.9 | 28.9 | 29.0 | 29.1 |
| | Jordan Cove LNG Supply | LNG FOB | 11.3 | 11.7 | 12.3 | 12.7 | 13.1 | 13.4 | 14.0 | 14.5 | 14.7 | 14.8 | 15.1 | 15.7 | 16.3 | 16.8 | 17.3 | 18.0 | 18.0 | 18.0 | 18.0 | 18.0 |
| | | Shipping | 2.1 | 2.2 | 2.2 | 2.2 | 2.3 | 2.3 | 2.3 | 2.4 | 2.4 | 2.4 | 3.2 | 3.2 | 3.2 | 3.3 | 3.3 | 3.3 | 3.3 | 3.4 | 3.4 | 3.4 |
| | | Regas | 1.9 | 1.9 | 1.9 | 1.9 | 2.0 | 2.0 | 2.0 | 2.0 | 2.0 | 2.0 | 3.9 | 3.9 | 4.0 | 4.0 | 4.0 | 4.1 | 4.1 | 4.1 | 4.2 | 4.2 |
| | | Total Delivered to HI | 15.3 | 15.8 | 16.4 | 16.9 | 17.3 | 17.7 | 18.3 | 18.8 | 19.1 | 19.2 | 22.1 | 22.8 | 23.5 | 24.0 | 24.6 | 25.3 | 25.4 | 25.5 | 25.5 | 25.6 |
| | **Canada LNG Supply (High Forecast)** | LNG FOB | 20.4 | 21.0 | 21.6 | 22.3 | 22.9 | 23.6 | 24.3 | 25.0 | 25.7 | 26.4 | 27.2 | 28.0 | 28.8 | 29.5 | 30.4 | 31.2 | 31.2 | 31.2 | 31.2 | 31.2 |
| | | Shipping | 2.3 | 2.3 | 2.3 | 2.3 | 2.3 | 2.3 | 2.3 | 2.3 | 2.3 | 2.3 | 4.4 | 4.4 | 4.4 | 4.4 | 4.4 | 4.4 | 4.4 | 4.5 | 4.5 | 4.5 |
| | | Regas | 3.2 | 3.3 | 3.3 | 3.3 | 3.3 | 3.3 | 3.3 | 3.4 | 3.4 | 3.4 | 6.5 | 6.6 | 6.6 | 6.7 | 6.7 | 6.8 | 6.8 | 6.8 | 6.9 | 7.0 |
| | | Total Delivered to HI | 25.9 | 26.5 | 27.2 | 27.8 | 28.5 | 29.2 | 29.9 | 30.7 | 31.4 | 32.1 | 38.1 | 39.0 | 39.8 | 40.6 | 41.5 | 42.4 | 42.5 | 42.5 | 42.6 | 42.6 |
| | LSFO | | 24.8 | 25.5 | 26.3 | 27.1 | 27.9 | 28.7 | 29.5 | 30.4 | 31.2 | 32.1 | 33.0 | 33.9 | 34.9 | 35.8 | 36.8 | 37.8 | 37.8 | 37.8 | 37.8 | 37.8 |
| | ULSD | | 31.4 | 32.2 | 33.1 | 34.1 | 35.1 | 36.1 | 37.2 | 38.2 | 39.3 | 40.3 | 41.4 | 42.6 | 43.8 | 44.9 | 46.2 | 47.4 | 47.4 | 47.4 | 47.4 | 47.4 |

*All numbers in US$/MMBt

Galway Energy Advisors LLC

GALWAY GROUP LP

ADVISORS AND INVESTMENT BANKERS TO THE ENERGY INDUSTRY

# HECO – Revised Forecasts for LNG Delivered Cost to Hawaii based on the EIA AEO Early Release 2013

**FEBRUARY 22, 2013**

GALWAY ENERGY ADVISORS
A MEMBER OF THE GALWAY GROUP LP
WWW.GALWAYGROUP.COM

# Table 3: Demand Case 1

| | | | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 | 2035 | 2036 | 2037 | 2038 | 2039 | 2040 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Volume | (MTPA) | 0.9 | 0.9 | 0.9 | 0.9 | 0.9 | 0.9 | 0.9 | 0.9 | 0.9 | 0.9 | 0.9 | 0.9 | 0.9 | 0.9 | 0.9 | 0.6 | 0.6 | 0.6 | 0.6 | 0.6 | 0.6 | 0.6 | 0.6 | 0.6 | 0.6 | 0.6 |
| HECO Demand 1 (0.85 MTPA to 0.55 MTPA) | US GoM LNG Supply | LNG FOB | 8.1 | 8.8 | 9.0 | 9.4 | 9.6 | 9.8 | 10.1 | 10.5 | 10.9 | 11.2 | 11.5 | 11.8 | 12.1 | 12.4 | 12.7 | 13.0 | 13.4 | 13.8 | 14.2 | 14.8 | 15.6 | 16.4 | 17.3 | 18.3 | 18.8 | 19.6 |
| | | Shipping | 2.9 | 2.9 | 2.9 | 2.9 | 2.9 | 2.9 | 2.9 | 2.9 | 2.9 | 2.9 | 2.9 | 3.0 | 3.0 | 3.0 | 3.0 | 3.0 | 2.4 | 2.4 | 2.4 | 2.4 | 2.4 | 2.4 | 2.4 | 2.4 | 2.4 | 2.5 |
| | | Regas | 2.0 | 2.0 | 2.0 | 2.0 | 2.0 | 2.0 | 2.0 | 2.0 | 2.0 | 2.0 | 2.0 | 2.1 | 2.1 | 2.1 | 2.1 | 2.1 | 3.3 | 3.3 | 3.3 | 3.3 | 3.4 | 3.4 | 3.4 | 3.4 | 3.4 | 3.5 |
| | | **Total Delivered to HI** | **13.0** | **13.7** | **13.9** | **14.3** | **14.5** | **14.8** | **15.0** | **15.5** | **15.9** | **16.2** | **16.5** | **16.8** | **17.1** | **17.5** | **17.8** | **18.1** | **19.1** | **19.4** | **19.9** | **20.6** | **21.3** | **22.2** | **23.1** | **24.1** | **24.7** | **25.5** |
| | Jordan Cove LNG Supply | LNG FOB | & | 9.3 | 9.5 | 9.9 | 10.2 | 10.4 | 10.6 | 11.1 | 11.5 | 11.7 | 12.0 | 12.4 | 12.6 | 13.0 | 13.2 | 13.6 | 14.0 | 14.3 | 14.7 | 15.4 | 16.1 | 17.0 | 17.8 | 18.8 | 19.4 | 20.1 |
| | | Shipping | 2.4 | 2.4 | 2.4 | 2.4 | 2.4 | 2.4 | 2.4 | 2.5 | 2.5 | 2.6 | 2.7 | 2.7 | 2.8 | 2.8 | 2.9 | 2.9 | 3.6 | 3.7 | 3.8 | 3.8 | 3.9 | 4.0 | 4.0 | 4.0 | 4.0 | 4.1 |
| | | Regas | 1.2 | 1.2 | 1.2 | 1.2 | 1.2 | 1.2 | 1.2 | 1.2 | 1.2 | 1.2 | 1.2 | 1.2 | 1.2 | 1.2 | 1.2 | 1.3 | 2.0 | 2.0 | 2.0 | 2.0 | 2.0 | 2.0 | 2.0 | 2.1 | 2.1 | 2.1 |
| | | **Total Delivered to HI** | **12.3** | **12.9** | **13.1** | **13.6** | **13.8** | **14.0** | **14.3** | **14.7** | **15.2** | **15.5** | **15.9** | **16.3** | **16.6** | **17.0** | **17.4** | **17.8** | **19.5** | **20.0** | **20.5** | **21.2** | **22.0** | **23.0** | **23.9** | **24.9** | **25.5** | **26.3** |
| | Canada LNG Supply | LNG FOB | 15.6 | 16.0 | 16.6 | 17.2 | 17.9 | 18.6 | 19.3 | 20.1 | 20.9 | 21.7 | 22.6 | 23.5 | 24.4 | 25.4 | 26.4 | 27.5 | 28.6 | 29.7 | 30.9 | 32.2 | 33.5 | 34.9 | 36.3 | 37.8 | 39.4 | 41.0 |
| | | Shipping | 1.4 | 1.4 | 1.4 | 1.4 | 1.4 | 1.4 | 1.4 | 1.4 | 1.4 | 1.4 | 1.4 | 1.4 | 1.4 | 1.4 | 1.4 | 1.4 | 2.2 | 2.2 | 2.2 | 2.2 | 2.2 | 2.2 | 2.2 | 2.2 | 2.2 | 2.2 |
| | | Regas | 2.0 | 2.0 | 2.0 | 2.0 | 2.0 | 2.1 | 2.0 | 2.0 | 2.0 | 2.0 | 2.0 | 2.1 | 2.1 | 2.1 | 2.1 | 2.1 | 3.3 | 3.3 | 3.3 | 3.3 | 3.4 | 3.4 | 3.4 | 3.4 | 3.4 | 3.5 |
| | | **Total Delivered to HI** | **19.0** | **19.4** | **20.0** | **20.7** | **21.3** | **22.0** | **22.7** | **23.5** | **24.3** | **25.1** | **26.0** | **26.9** | **27.9** | **28.9** | **29.9** | **31.0** | **34.1** | **35.2** | **36.5** | **37.8** | **39.1** | **40.5** | **42.0** | **43.5** | **45.1** | **46.7** |
| | LSFO | | 22.1 | 22.0 | 22.9 | 23.5 | 24.2 | 24.8 | 25.5 | 26.3 | 27.1 | 27.9 | 28.7 | 29.5 | 30.4 | 31.2 | 32.1 | 33.0 | 33.9 | 34.9 | 35.8 | 36.8 | 37.8 | 37.8 | 37.8 | 37.8 | 37.8 | 37.8 |
| | ULSD | | 27.9 | 27.9 | 28.9 | 29.7 | 30.5 | 31.4 | 32.2 | 33.1 | 34.1 | 35.1 | 36.1 | 37.2 | 38.2 | 39.3 | 40.3 | 41.4 | 42.6 | 43.8 | 44.9 | 46.2 | 47.4 | 47.4 | 47.4 | 47.4 | 47.4 | 47.4 |

GALWAY ENERGY ADVISORS 2

# Table 4: Demand Case 2

| | | | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 | 2035 | 2036 | 2037 | 2038 | 2039 | 2040 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Volume | (MTPA) | 0.65 | 0.65 | 0.65 | 0.65 | 0.65 | 0.65 | 0.65 | 0.65 | 0.65 | 0.65 | 0.65 | 0.65 | 0.65 | 0.65 | 0.65 | 0.4 | 0.4 | 0.4 | 0.4 | 0.4 | 0.4 | 0.4 | 0.4 | 0.4 | 0.4 | 0.4 |
| HECO Demand 2 (0.65 MTPA to 0.40 MTPA) | US GoM LNG Supply | LNG FOB | 8.1 | 8.8 | 9.0 | 9.4 | 9.6 | 9.8 | 10.1 | 10.5 | 10.9 | 11.2 | 11.5 | 11.8 | 12.1 | 12.4 | 12.7 | 13.0 | 13.4 | 13.8 | 14.2 | 14.8 | 15.6 | 16.4 | 17.3 | 18.3 | 18.8 | 19.6 |
| | | Shipping | 2.2 | 2.2 | 2.2 | 2.2 | 2.2 | 2.2 | 2.2 | 2.2 | 2.2 | 2.2 | 2.2 | 2.3 | 2.3 | 2.3 | 2.3 | 2.3 | 3.2 | 3.2 | 3.2 | 3.2 | 3.2 | 3.2 | 3.2 | 3.3 | 3.3 | 3.3 |
| | | Regas | 2.6 | 2.6 | 2.6 | 2.6 | 2.6 | 2.6 | 2.6 | 2.6 | 2.6 | 2.7 | 2.7 | 2.7 | 2.7 | 2.7 | 2.7 | 2.7 | 4.5 | 4.5 | 4.5 | 4.6 | 4.6 | 4.6 | 4.7 | 4.7 | 4.7 | 4.8 |
| | | **Total Delivered to HI** | **12.9** | **13.6** | **13.8** | **14.2** | **14.4** | **14.7** | **14.9** | **15.4** | **15.8** | **16.1** | **16.4** | **16.8** | **17.1** | **17.4** | **17.7** | **18.1** | **21.1** | **21.5** | **21.9** | **22.6** | **23.4** | **24.3** | **25.2** | **26.2** | **26.9** | **27.6** |
| | Jordan Cove LNG Supply | LNG FOB | 8.6 | 9.3 | 9.5 | 9.9 | 10.2 | 10.4 | 10.6 | 11.1 | 11.5 | 11.7 | 12.0 | 12.4 | 12.6 | 13.0 | 13.2 | 13.6 | 14.0 | 14.3 | 14.7 | 15.4 | 16.1 | 17.0 | 17.8 | 18.8 | 19.4 | 20.1 |
| | | Shipping | 2.2 | 2.2 | 2.2 | 2.2 | 2.2 | 2.2 | 2.2 | 2.2 | 2.2 | 2.3 | 2.3 | 2.3 | 2.4 | 2.4 | 2.4 | 2.5 | 3.5 | 3.5 | 3.6 | 3.6 | 3.6 | 3.7 | 3.7 | 3.7 | 3.8 | 3.8 |
| | | Regas | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 | 1.6 | 1.6 | 1.6 | 1.6 | 1.6 | 1.6 | 1.6 | 1.6 | 1.6 | 2.7 | 2.7 | 2.7 | 2.7 | 2.8 | 2.8 | 2.8 | 2.8 | 2.9 | 2.9 |
| | | **Total Delivered to HI** | **12.4** | **13.0** | **13.2** | **13.7** | **13.9** | **14.1** | **14.4** | **14.8** | **15.3** | **15.6** | **15.9** | **16.3** | **16.6** | **17.0** | **17.3** | **17.7** | **20.1** | **20.5** | **21.0** | **21.7** | **22.5** | **23.4** | **24.3** | **25.4** | **26.0** | **26.8** |
| | Canada LNG Supply | LNG FOB | 15.6 | 16.0 | 16.6 | 17.2 | 17.9 | 18.6 | 19.3 | 20.1 | 20.9 | 21.7 | 22.6 | 23.5 | 24.4 | 25.4 | 26.4 | 27.5 | 28.6 | 29.7 | 30.9 | 32.2 | 33.5 | 34.9 | 36.3 | 37.8 | 39.4 | 41.0 |
| | | Shipping | 1.8 | 1.8 | 1.8 | 1.8 | 1.8 | 1.8 | 1.8 | 1.8 | 1.8 | 1.8 | 1.8 | 1.8 | 1.8 | 1.8 | 1.8 | 1.9 | 3.0 | 3.0 | 3.0 | 3.0 | 3.0 | 3.0 | 3.1 | 3.1 | 3.1 | 3.1 |
| | | Regas | 2.6 | 2.6 | 2.6 | 2.6 | 2.6 | 2.6 | 2.6 | 2.6 | 2.6 | 2.7 | 2.7 | 2.7 | 2.7 | 2.7 | 2.7 | 2.7 | 4.5 | 4.5 | 4.5 | 4.6 | 4.6 | 4.6 | 4.7 | 4.7 | 4.7 | 4.8 |
| | | **Total Delivered to HI** | **20.0** | **20.5** | **21.1** | **21.7** | **22.3** | **23.0** | **23.7** | **24.5** | **25.4** | **26.2** | **27.1** | **28.0** | **29.0** | **30.0** | **31.0** | **32.1** | **36.1** | **37.3** | **38.5** | **39.8** | **41.2** | **42.6** | **44.1** | **45.6** | **47.2** | **48.8** |
| | LSFO | | 22.1 | 22.0 | 22.9 | 23.5 | 24.2 | 24.8 | 25.5 | 26.3 | 27.1 | 27.9 | 28.7 | 29.5 | 30.4 | 31.2 | 32.1 | 33.0 | 33.9 | 34.9 | 35.8 | 36.8 | 37.8 | 37.8 | 37.8 | 37.8 | 37.8 | 37.8 |
| | ULSD | | 27.9 | 27.9 | 28.9 | 29.7 | 30.5 | 31.4 | 32.2 | 33.1 | 34.1 | 35.1 | 36.1 | 37.2 | 38.2 | 39.3 | 40.3 | 41.4 | 42.6 | 43.8 | 44.9 | 46.2 | 47.4 | 47.4 | 47.4 | 47.4 | 47.4 | 47.4 |

# Table 5: Demand Case 3

| | | | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Volume | (MTPA) | 0.525 | 0.525 | 0.525 | 0.525 | 0.525 | 0.525 | 0.525 | 0.525 | 0.525 | 0.525 | 0.525 | 0.525 | 0.525 |
| HECO Demand 3 (0.525 MTPA to 0.275 MTPA) | **US GoM LNG Supply (Reference Forecast)** | LNG FOB | 8.1 | 8.8 | 9.0 | 9.4 | 9.6 | 9.8 | 10.1 | 10.5 | 10.9 | 11.2 | 11.5 | 11.8 | 12.1 |
| | | Shipping | 2.4 | 2.4 | 2.4 | 2.4 | 2.4 | 2.4 | 2.4 | 2.4 | 2.4 | 2.4 | 2.4 | 2.4 | 2.4 |
| | | Regas | 3.2 | 3.2 | 3.2 | 3.2 | 3.2 | 3.2 | 3.2 | 3.3 | 3.3 | 3.3 | 3.3 | 3.3 | 3.3 |
| | | **Total Delivered to HI** | **13.7** | **14.4** | **14.6** | **15.0** | **15.2** | **15.5** | **15.7** | **16.2** | **16.6** | **16.9** | **17.2** | **17.6** | **17.9** |
| | Jordan Cove LNG Supply | LNG FOB | 8.6 | 9.3 | 9.5 | 9.9 | 10.2 | 10.4 | 10.6 | 11.1 | 11.5 | 11.7 | 12.0 | 12.4 | 12.6 |
| | | Shipping | 2.1 | 2.1 | 2.1 | 2.1 | 2.1 | 2.1 | 2.1 | 2.2 | 2.2 | 2.2 | 2.3 | 2.3 | 2.3 |
| | | Regas | 1.9 | 1.9 | 1.9 | 1.9 | 1.9 | 1.9 | 1.9 | 1.9 | 1.9 | 1.9 | 2.0 | 2.0 | 2.0 |
| | | **Total Delivered to HI** | **12.7** | **13.3** | **13.6** | **14.0** | **14.2** | **14.4** | **14.7** | **15.2** | **15.6** | **15.9** | **16.2** | **16.6** | **16.9** |
| | **Canada LNG Supply (High Forecast)** | LNG FOB | 15.6 | 16.0 | 16.6 | 17.2 | 17.9 | 18.6 | 19.3 | 20.1 | 20.9 | 21.7 | 22.6 | 23.5 | 24.4 |
| | | Shipping | 2.3 | 2.3 | 2.3 | 2.3 | 2.3 | 2.3 | 2.3 | 2.3 | 2.3 | 2.3 | 2.3 | 2.3 | 2.3 |
| | | Regas | 3.2 | 3.2 | 3.2 | 3.2 | 3.2 | 3.2 | 3.2 | 3.3 | 3.3 | 3.3 | 3.3 | 3.3 | 3.3 |
| | | **Total Delivered to HI** | **21.1** | **21.5** | **22.1** | **22.8** | **23.4** | **24.1** | **24.8** | **25.6** | **26.4** | **27.3** | **28.2** | **29.1** | **30.0** |
| | LSFO | | 22.1 | 22.0 | 22.9 | 23.5 | 24.2 | 24.8 | 25.5 | 26.3 | 27.1 | 27.9 | 28.7 | 29.5 | 30.4 |
| | ULSD | | 27.9 | 27.9 | 28.9 | 29.7 | 30.5 | 31.4 | 32.2 | 33.1 | 34.1 | 35.1 | 36.1 | 37.2 | 38.2 |

| | | | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 | 2035 | 2036 | 2037 | 2038 | 2039 | 2040 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Volume | (MTPA) | 0.525 | 0.525 | 0.275 | 0.275 | 0.275 | 0.275 | 0.275 | 0.275 | 0.275 | 0.275 | 0.275 | 0.275 | 0.275 |
| HECO Demand 3 (0.525 MTPA to 0.275 MTPA) | **US GoM LNG Supply (Reference Forecast)** | LNG FOB | 12.4 | 12.7 | 13.0 | 13.4 | 13.8 | 14.2 | 14.8 | 15.6 | 16.4 | 17.3 | 18.3 | 18.8 | 19.6 |
| | | Shipping | 2.4 | 2.4 | 2.4 | 4.5 | 4.6 | 4.6 | 4.6 | 4.6 | 4.6 | 4.6 | 4.6 | 4.6 | 4.6 |
| | | Regas | 3.4 | 3.4 | 3.4 | 6.5 | 6.6 | 6.6 | 6.7 | 6.7 | 6.8 | 6.8 | 6.8 | 6.9 | 7.0 |
| | | **Total Delivered to HI** | **18.2** | **18.5** | **18.9** | **24.5** | **24.9** | **25.4** | **26.1** | **26.9** | **27.8** | **28.7** | **29.7** | **30.4** | **31.2** |
| | Jordan Cove LNG Supply | LNG FOB | 13.0 | 13.2 | 13.6 | 14.0 | 14.3 | 14.7 | 15.4 | 16.1 | 17.0 | 17.8 | 18.8 | 19.4 | 20.1 |
| | | Shipping | 2.4 | 2.4 | 2.4 | 3.2 | 3.2 | 3.2 | 3.3 | 3.3 | 3.3 | 3.3 | 3.4 | 3.4 | 3.4 |
| | | Regas | 2.0 | 2.0 | 2.0 | 3.9 | 3.9 | 4.0 | 4.0 | 4.0 | 4.1 | 4.1 | 4.1 | 4.2 | 4.2 |
| | | **Total Delivered to HI** | **17.3** | **17.7** | **18.0** | **21.0** | **21.4** | **21.9** | **22.6** | **23.4** | **24.3** | **25.3** | **26.3** | **26.9** | **27.7** |
| | **Canada LNG Supply (High Forecast)** | LNG FOB | 25.4 | 26.4 | 27.5 | 28.6 | 29.7 | 30.9 | 32.2 | 33.5 | 34.9 | 36.3 | 37.8 | 39.4 | 41.0 |
| | | Shipping | 2.3 | 2.3 | 2.3 | 4.4 | 4.4 | 4.4 | 4.4 | 4.4 | 4.4 | 4.4 | 4.5 | 4.5 | 4.5 |
| | | Regas | 3.4 | 3.4 | 3.4 | 6.5 | 6.6 | 6.6 | 6.7 | 6.7 | 6.8 | 6.8 | 6.8 | 6.9 | 7.0 |
| | | **Total Delivered to HI** | **31.0** | **32.1** | **33.2** | **39.5** | **40.7** | **42.0** | **43.3** | **44.7** | **46.1** | **47.6** | **49.1** | **50.7** | **52.4** |
| | LSFO | | 31.2 | 32.1 | 33.0 | 33.9 | 34.9 | 35.8 | 36.8 | 37.8 | 37.8 | 37.8 | 37.8 | 37.8 | 37.8 |
| | ULSD | | 39.3 | 40.3 | 41.4 | 42.6 | 43.8 | 44.9 | 46.2 | 47.4 | 47.4 | 47.4 | 47.4 | 47.4 | 47.4 |

GALWAY ENERGY ADVISORS

# Appendix O: Resource Plan Sheets

The Companies developed resource plans through its analysis to identify when and what type of resources should be added under the four scenarios to evaluate strategies to meet the Companies' planning criteria and objectives. This appendix shows the plans from the modeling runs.

All costs are present value amounts in thousands of dollars.

# CONTENTS

# TABLES

## HECO — Blazing a Bold Frontier



## HECO — Stuck in the Middle

## HELCO — Blazing a Bold Frontier



## HELCO — Stuck in the Middle



## HELCO — No Burning Desirve



## HELCO — Moved by Passion

## MECO — Moved by Passion



## Interconnect — Stuck in the Middle

# Hawaiian Electric Resource Plans

## Blazing a Bold Frontier

Table O-1. HECO Timing Run 1 (1 of 3)

| **Name** | **P1_2a1XRetire-1r0** | **P1_2a1XRetire-1r1** | **P1_2a1XRetire-1r2** | **P1_2a1NRetire-1r0** |
|---|---|---|---|---|
| *Plan* | Timing w/ H89 W34 Ret (ICE, SCCT) | Timing w/ H89 W34 Retire (ICE) | Required Timing (OTEC, Biomass) | Timing w H89 W34 Ret (ICE, SCCT) |
| *Notes* | | 0% RPS (Wind, PV, Wave, Biomass, CT, ICE) | 0% RPS (Wind, PV, Wave, Biomass, CT, ICE) | |
| *Resources Available* | ICE (17 MW)-Biodiesel (PS01)-2018<br>42 MW SCCT LM6000 - Biodiesel (PS06)-2018<br>100 MW SCCT LMS100 - Biodiesel (PS07)-2018<br>59 MW 1on1 LM6000 CC-Biodiesel (PC08)-2018<br>9.6 MW OTEC (PO01)-2018<br>25MW Banagrass Combustion (PA01)-2018 | ICE (17 MW)-Biodiesel (PS01)-2018 | 9.6 MW OTEC (PO01)-2018<br>25MW Banagrass Combustion (PA01)-2018 | ICE (17 MW)-Biodiesel (PS01)-2018<br>42 MW SCCT LM6000 - Biodiesel (PS06)-2018<br>100 MW SCCT LMS100 - Biodiesel (PS07)-2018 |
| *Reference* | P1_2a1XRetire-1r0.xlxs | P1_2a1XRetire-1r1.xlxs, ICEs Added | P1_2a1XRetire-1r2.xlxs | P1_2a1NRetire-1r0.xlxs |
| *2014* | Continue CIDLC, CIDP, RDLCWH, RDLCAC | Continue CIDLC, CIDP, RDLCWH, RDLCAC | Continue CIDLC, CIDP, RDLCWH, RDLCAC | Expanded CIDLC, CIDP, RDLCWH, RDLCAC |
| | 75%+25%+10% PBFA DSM | 75%+25%+10% PBFA DSM | 75%+25%+10% PBFA DSM | 75%+25%+10% PBFA DSM |
| *2015* | | | | |
| *2016* | Fuel Switch to Diesel (H8/9, Waiau 5-10/Kahe 1-6) | Fuel Switch to Diesel (H8/9, Waiau 5-10/Kahe 1-6) | Fuel Switch to Diesel (H8/9, Waiau 5-10/Kahe 1-6) | Fuel Switch to Diesel (H8/9, Waiau 5-10/Kahe 1-6) |
| *2017* | Deactivate W3 (-46MW)<br>Deactivate W4 (-46MW)<br>or H8/9 | Deactivate W3 (-46MW)<br>Deactivate W4 (-46MW)<br>or H8/9 | Deactivate W3 (-46MW)<br>Deactivate W4 (-46MW)<br>or H8/9 | Deactivate W3 (-46MW)<br>Deactivate W4 (-46MW)<br>or H8/9 |
| *2018* | | Add 34 MW ICE (PS01x2)-Biofueled | | |
| *2019* | Deactivate H8 (-53MW)<br>Deactivate H9 (-54MW)<br>or W3/4 | Deactivate H8 (-53MW)<br>Deactivate H9 (-54MW)<br>or W3/3 | Deactivate H8 (-53MW)<br>Deactivate H9 (-54MW)<br>or W3/4 | Deactivate H8 (-53MW)<br>Deactivate H9 (-54MW)<br>or W3/4 |
| *2020* | Add 91MW SCCT (PS07x1)-Biofueled | | | Add 91MW SCCT (PS07x1)-Biofueled |

| Name | P1_2a1XRetire-1r0 | P1_2a1XRetire-1r1 | P1_2a1XRetire-1r2 | P1_2a1NRetire-1r0 |
|---|---|---|---|---|
| *2021* | | | | |
| *2022* | | | | |
| *2023* | | | | |
| *2024* | | | | |
| *2025* | | | | |
| *2026* | | | | |
| *2027* | | | | |
| *2028* | | | | |
| *2029* | | | | |
| *2030* | | | | |
| *2031* | | | | |
| *2032* | | | | |
| *2033* | | | | |
| *Planning Period Total Cost* | 33, 130, 600 | 33, 220, 210 | 33, 213, 076 | 33, 217, 246 |
| *Study Period Total Cost* | 45, 362, 256 | 45, 570, 860 | 45, 607, 320 | 45, 480, 256 |
| *Planning Rank* | 1 | 3 | 2 | 1 |
| *Study Rank* | 1 | 2 | 3 | 1 |

Table O-2. HECO Timing Run 1 (2 of 3)

| **Name** | **P1_2a1X-1r0** | **P1_2a1X-1r1** | **P1_2a1X-1r2** | **P1_2a1X-1r3** |
|---|---|---|---|---|
| *Plan* | Timing, Least Cost no Retirements | Timing, ICEs Optimized | Scenario Required Timing | Timing, (OTEC added) |
| *Notes* | All ICE & CTs available, 2017 ULSD switch | Only 17 MW ICE available, 2022 ULSD fuel switch | | OTEC forced in 2020 |
| *Resources Available* | ICE (17 MW)-Biodiesel (PS01)-2018<br>42 MW SCCT LM6000 - Biodiesel (PS06)-2018<br>100 MW SCCT LMS100 - Biodiesel (PS07)-2018<br>59 MW 1on1 LM6000 CC-Biodiesel (PC08)-2018<br>9.6 MW OTEC (PO01)-2018<br>25MW Banagrass Combustion (PA01)-2018 | ICE (17 MW)-Biodiesel (PS01)-2018 | 9.6 MW OTEC (PO01)-2020<br>25MW Banagrass Combustion (PA01)-2020 | 9.6 MW OTEC (PO01)-2020<br>25MW Banagrass Combustion (PA01)-2020 |
| *Reference* | P1_2a1X-1r0.xlxs | P1_2a1X-1r1.xlxs | P1_2a1X-1r2.xlxs | P1_2a1X-1r3.xlxs |
| *2014* | Continue CIDLC, CIDP, RDLCWH, RDLCAC | Continue CIDLC, CIDP, RDLCWH, RDLCAC | Continue CIDLC, CIDP, RDLCWH, RDLCAC | Continue CIDLC, CIDP, RDLCWH, RDLCAC |
| | 75%+25%+10% PBFA DSM | 75%+25%+10% PBFA DSM | 75%+25%+10% PBFA DSM | 75%+25%+10% PBFA DSM |
| *2015* | | | | |
| *2017* | Deactivate W3 (-46MW)<br>Deactivate W4 (-46MW)<br>or H8/9 | | | |
| *2018* | | Add 34MW ICE (PS01x2)-Biofueled | | |
| *2019* | Deactivate H8 (-53MW)<br>Deactivate H9 (-54MW)<br>or W3/4 | | | |
| *2020* | Add 91MW SCCT (PS07x1)-Biofueled | | | Add 29MWr OTEC (POT1x3) |
| *2021* | | | | |
| *2022* | | | | |
| *2023* | | | | |
| *2024* | | | | |
| *2025* | | | | |
| *2026* | | | | |
| *2027* | | | | |
| *2028* | | | | |
| *2029* | | | | |

| Name | P1_2a1X-1r0 | P1_2a1X-1r1 | P1_2a1X-1r2 | P1_2a1X-1r3 |
|---|---|---|---|---|
| *2030* | | | | |
| *2031* | | | | |
| *2032* | | | | |
| *2033* | | | | |
| *Planning Period Total Cost* | 33, 264, 854 | 33, 355, 418 | 33, 347, 586 | 33, 949, 852 |
| *Study Period Total Cost* | 45, 569, 320 | 45, 782, 532 | 45, 815, 544 | 46, 719, 656 |
| *Planning Rank* | 1 | 3 | 2 | 4 |
| *Study Rank* | 1 | 2 | 3 | 4 |

Table O-3. HECO Timing Run 1 (3 of 3)

| **Name** | **P1_2a1N-1r0** | **P1B2a1xRetire-2r2** | **P1B2a1xRetire-2r3** | **P1B2a1xRetire-2r4** |
|---|---|---|---|---|
| *Plan* | Timing, Expanded DR, Least Cost | No Retirement, Convert all Exist to BF | Retire H8/H9/W3/W4, Convert Remaining Exist to BF | Retire All, Replace with BF, Timing Rule 1 |
| *Resources Available* | ICE (17 MW)-Biodiesel (PS01)-2018<br>42 MW SCCT LM6000 - Biodiesel (PS06)-2018<br>100 MW SCCT LMS100 - Biodiesel (PS07)-2018<br>59 MW 1on1 LM6000 CC-Biodiesel (PC08)-2018<br>9.6 MW OTEC (PO01)-2018<br>25MW Banagrass Combustion (PA01)-2018 | ICE (17 MW)-Biodiesel (PS01)-2017 | ICE (17 MW)-Biodiesel (PS01)-2017 | ICE (17 MW)-Biodiesel (PS01)-2017<br>100 MW SCCT LMS100 - Biodiesel (PS07)-2020 |
| *Reference* | P1_2a1N-1r0.xlxs | | | |
| *2014* | Expanded CIDLC, CIDP, RDLCWH, RDLCAC | Continue CIDLC, CIDP, RDLCWH, RDLCAC | Continue CIDLC, CIDP, RDLCWH, RDLCAC | Continue CIDLC, CIDP, RDLCWH, RDLCAC |
| | 75%+25%+10% PBFA DSM | 75%+25%+10% PBFA DSM | 75%+25%+10% PBFA DSM | 75%+25%+10% PBFA DSM |
| *2015* | | | | |
| *2016* | Fuel Switch to Diesel (H8/9, Waiau 5-10/Kahe 1-6) | Fuel Switch to Diesel (H8/9, Waiau 5-10/Kahe 1-6) | Fuel Switch to Diesel (H8/9, Waiau 5-10/Kahe 1-6) | Fuel Switch to Diesel (H8/9, Waiau 5-10/Kahe 1-6) |
| *2017* | | Add 51 MW ICE (PS01x3) | Add 51 MW ICE (PS01x3) | Add 51 MW ICE (PS01x3) |
| | | | Deactivate W3 (-46MW)<br>Deactivate W4 (-46MW)<br>or H8/9 | Deactivate W3 (-46MW)<br>Deactivate W4 (-46MW)<br>or H8/9 |
| *2018* | | | | |
| *2019* | | | Deactivate H8 (-53MW)<br>Deactivate H9 (-54MW)<br>or W3/4 | Deactivate H8 (-53MW)<br>Deactivate H9 (-54MW)<br>or W3/4 |
| *2020* | Add 91MW SCCT (PS07x1)-Biofueled | Convert all existing units to BF (H8/H9/W3-10/K1-6) | Convert all existing units to BF; (W5-10/K1-6) | Convert remaining units to BF (W9-10) |
| | | | | Add 380MW SCCT (PS07x2)-Biofueled |
| | | | | Retire W5 (-55MW)<br>Retire W6 (-56MW)<br>Retire W7 (-88MW)<br>Retire W8 (-88MW)<br>Retire K1 (-88MW)<br>Retire K2 (-86MW)<br>Retire K3 (-88MW)<br>Retire K4 (-89MW) |

| Name | P1_2a1N-1r0 | P1B2a1xRetire-2r2 | P1B2a1xRetire-2r3 | P1B2a1xRetire-2r4 |
|---|---|---|---|---|
| *2021* | | | | Add 182MW SCCT (PS07x2)-Biofueled<br>Retire K5 (-135MW) |
| *2022* | | | | Add 182MW SCCT (PS07x2)-Biofueled<br>Retire K6 (-134MW) |
| *2023* | | | | Add 91MW SCCT (PS07x1)-Biofueled |
| *2024* | | | | |
| *2025* | | | | |
| *2026* | | | | |
| *2027* | | | | |
| *2028* | | | | |
| *2029* | | | | |
| *2030* | | | | |
| *2031* | | | | |
| *2032* | | | | |
| *2033* | | | | |
| *Planning Period Total Cost* | 33, 350, 326 | 27, 456, 688 | 27, 322, 036 | 27, 704, 386 |
| *Study Period Total Cost* | 45, 688, 348 | 33, 180, 434 | 32, 967, 410 | 33, 520, 868 |
| *Planning Rank* | 1 | 2 | 1 | 3 |
| *Study Rank* | 1 | 2 | 1 | 3 |

Table O-4. HECO Timing Run 2 (1 of 2)

| **Name** | **Self Generation** | | **P1_2A1NRETIRE-1R2 TIMING EXPDR** | **P1_2A1XRETIRE-1R6Texp** | **P1_2A1XRETIRE-1R7 T4exp** | **P1_2A1XRETIRE-1R7 T1exp** |
|---|---|---|---|---|---|---|
| *Plan* | Annual | Cumulative | Deactivate H8/9-W3/4 | Deactivate H8/9-W3/4 | KPLP end | Deactivate H8/9-W3/4, KPLP end; Convert CT1 to CC & ICE |
| *Resources Available* | | | ICE (17 MW)-Biodiesel (PS01)-n/a<br>Convert CT-1 to CC 57MW (STC1)-n/a<br>30 MW Onshore Wind C3 (PW01)-n/a<br>5 MW of 1 MW Track PV (PP03)-n/a<br>200 MW Lanai Wind-n/a | ICE (17 MW)-Biodiesel (PS01)-n/a<br>Convert CT-1 to CC 57MW (STC1)-n/a<br>30 MW Onshore Wind C3 (PW01)-n/a<br>5 MW of 1 MW Track PV (PP03)-n/a<br>200 MW Lanai Wind-n/a | ICE (17 MW)-Biodiesel (PS01)-n/a<br>Convert CT-1 to CC ULSD (STC1)-2017<br>30 MW Onshore Wind C3 (PW01)-n/a<br>5 MW of 1 MW Track PV (PP03)-n/a<br>200 MW Lanai Wind-n/a | ICE (17 MW)-Biodiesel (PS01)-2018<br>Convert CT-1 to CC 57MW (STC1)-2018<br>30 MW Onshore Wind C3 (PW01)-n/a<br>5 MW of 1 MW Track PV (PP03)-n/a<br>200 MW Lanai Wind-n/a |
| *2014* | 64MW | 137MW | Expanded CIDLC, CIDP, RDLCWH, RDLCAC<br>75%+25%+10% PBFA DSM | Expanded CIDLC, CIDP, RDLCWH, RDLCAC<br>75%+25%+10% PBFA DSM<br>Deactivate H8 (-53MW)<br>Deactivate H9 (-54MW) | Expanded CIDLC, CIDP, RDLCWH, RDLCAC<br>75%+25%+10% PBFA DSM | Expanded CIDLC, CIDP, RDLCWH, RDLCAC<br>75%+25%+10% PBFA DSM<br>Deactivate H8 (-53MW)<br>Deactivate H9 (-54MW) |
| *2015* | 66MW | 203MW | | | | |
| *2016* | 79MW | 281MW | Fuel Switch to Diesel (H8/9, Waiau 5-10/Kahe 1-6) | Fuel Switch to Diesel (H8/9, Waiau 5-10/Kahe 1-6) | Fuel Switch to Diesel (H8/9, Waiau 5-10/Kahe 1-6) | Fuel Switch to Diesel (H8/9, Waiau 5-10/Kahe 1-6) |
| *2017* | 65MW | 347MW | Deactivate W3 (-46MW)<br>Deactivate W4 (-46MW) | Deactivate W3 (-46MW)<br>Deactivate W4 (-46MW) | KPLP Contract Ends (- 208MW) | Deactivate W3 (-46MW)<br>Deactivate W4 (-46MW)<br>KPLP Contract Ends (- 208MW) |
| *2018* | 65MW | 412MW | | | | Convert CT-1 to CC +57MW (STC1)<br>Add 51 MW ICE (PS01x3) |
| *2019* | 65MW | 477MW | Deactivate H8 (-53MW)<br>Deactivate H9 (-54MW) | | | |
| *2020* | 65MW | 541MW | | | | |
| *2021* | 65MW | 606MW | | | | |
| *2022* | 60MW | 666MW | Fuel Switch to ULSD (Waiau 5-10/Kahe 1-6) | Fuel Switch to ULSD (Waiau 5-10/Kahe 1-6) | Fuel Switch to ULSD (Waiau 5-10/Kahe 1-6) | Fuel Switch to ULSD (Waiau 5-10/Kahe 1-6) |
| *2023* | 51MW | 718MW | | | | |
| *2024* | 45MW | 763MW | | | | |
| *2025* | 39MW | 802MW | | | | |

| Name | Self Generation | | P1_2A1NRETIRE-1R2 TIMING EXPDR | P1_2A1XRETIRE-1R6Texp | P1_2A1XRETIRE-1R7 T4exp | P1_2A1XRETIRE-1R7 T1exp |
|---|---|---|---|---|---|---|
| *2026* | 34MW | 835MW | | | | |
| *2027* | 30MW | 865MW | | | | |
| *2028* | 27MW | 892MW | | | | |
| *2029* | 25MW | 917MW | | | | |
| *2030* | 24MW | 941MW | | | | |
| *2031* | 23MW | 963MW | | | | |
| *2032* | 22MW | 985MW | | | | |
| *2033* | 21MW | 1007MW | | | | |
| *Strategist Planning Period Total Cost* | | | 33, 254, 342 | 33, 208, 892 | 31, 813, 272 | 30, 355, 214 |
| *Strategist Study Period Total Cost* | | | 45, 639, 736 | 45, 594, 288 | 42, 652, 044 | 40, 530, 492 |
| *Planning Period Total Cost* | | | 35, 931, 718 | 35, 896, 912 | | |
| *Study Period Total Cost* | | | 48, 317, 113 | 48, 282, 307 | | |
| *Planning Rank* | | | 2 | 1 | | |
| *Study Rank* | | | 2 | 1 | | |

Table O-5. HECO Timing Run 2 (2 of 2)

| **Name** | **Self Generation** | | **P1_2A1XRETIRE-1R7 T2exp** | **P1_2A1XRETIRE-1R7 T3exp** | **P1B2A1NRetire-2R14 Timing** |
|---|---|---|---|---|---|
| *Plan* | | | Deactivate H8/9-W3/4, KPLP end; timing | Deactivate H8/9-W3/4, KPLP end; optimize additional deactivations | Deactivate H8/9-W3/4, KPLP end; optimize additional deactivations |
| *Resources Available* | Annual | Cumulative | ICE (17 MW)-Biodiesel (PS01)-2018<br>Convert CT-1 to CC 57MW (STC1)-n/a<br>30 MW Onshore Wind C3 (PW01)-n/a<br>5 MW of 1 MW Track PV (PP03)-n/a<br>200 MW Lanai Wind-n/a | ICE (17 MW)-Biodiesel (PS01)-2018<br>Convert CT-1 to CC 57MW (STC1)-2017<br>30 MW Onshore Wind C3 (PW01)-n/a<br>Deactivate W5-8 and Kahe 1-6 - 2018 | ICE (17 MW)-Biodiesel (PS01)-2018<br>Convert CT-1 to CC 57MW (STC1)-2017<br>30 MW Onshore Wind C3 (PW01)-n/a<br>Deactivate W5-8 and Kahe 1-6 - 2018 |
| *2014* | 64MW | 137MW | Expanded CIDLC, CIDP, RDLCWH, RDLCAC | Expanded CIDLC, CIDP, RDLCWH, RDLCAC | Expanded CIDLC, CIDP, RDLCWH, RDLCAC |
| | | | 75%+25%+10% PBFA DSM | 75%+25%+10% PBFA DSM | 75%+25%+10% PBFA DSM |
| | | | Deactivate H8 (-53MW)<br>Deactivate H9 (-54MW) | Deactivate H8 (-53MW)<br>Deactivate H9 (-54MW) | Deactivate H8 (-53MW)<br>Deactivate H9 (-54MW) |
| *2015* | 66MW | 203MW | | | |
| *2016* | 79MW | 281MW | Fuel Switch to Diesel (H8/9, Waiau 5-10/Kahe 1-6) | Fuel Switch to Diesel (H8/9, Waiau 5-10/Kahe 1-6) | Fuel Switch to Diesel (Waiau 5-8, Kahe 1-6) |
| *2017* | 65MW | 347MW | Deactivate W3 (-46MW)<br>Deactivate W4 (-46MW) | Deactivate W3 (-46MW)<br>Deactivate W4 (-46MW) | Add 51 MW ICE (PS01x3) |
| | | | KPLP Contract Ends (-208MW) | KPLP Contract Ends (-208MW) | KPLP Contract Ends (-208MW) |
| *2018* | 65MW | 412MW | | Convert CT-1 to CC +57MW (STC1) | Convert CT-1 to CC +57MW (STC1) |
| | | | Add 51 MW ICE (PS01x3) | Add 51 MW ICE (PS01x3) | |
| *2019* | 65MW | 477MW | | Deactivate K6 (-134MW) | Deactivate W3 (-46MW)<br>Deactivate W4 (-46MW) |
| *2020* | 65MW | 541MW | | | Add 285MW SCCT (PS08x3)-LNG |
| | | | | | Add 42MW SCCT (PS10x1)-LNG |
| | | | | | Retire W5 (-55MW)<br>Retire W6 (-56MW)<br>Retire W7 (-88MW)<br>Retire W8 (-88MW)<br>Retire K1 (-88MW)<br>Retire K2 (-86MW)<br>Retire K3 (-88MW)<br>Retire K4 (-89MW) |

| Name | Self Generation | | P1_2A1XRETIRE-1R7 T2exp | P1_2A1XRETIRE-1R7 T3exp | P1B2A1NRetire-2R14 Timing |
|---|---|---|---|---|---|
| *2021* | 65MW | 606MW | | | Add 177MW CC (PS12x3)-LNG |
| | | | | | Retire K5 (-135MW) |
| *2022* | 60MW | 666MW | Fuel Switch to ULSD (Waiau 5-10/Kahe 1-6) | Fuel Switch to ULSD (Waiau 5-10/Kahe 1-6) | Add 95MW SCCT (PS08x1)-LNG |
| | | | | | Retire K6 (-134MW) |
| *2023* | 51MW | 718MW | | Deactivate K1 (-88MW) | Add 59MW CC (PS12x1)-LNG |
| *2025* | 39MW | 802MW | | | |
| *2026* | 34MW | 835MW | | | |
| *2027* | 30MW | 865MW | | Deactivate K4 (-89MW) | |
| *2028* | 27MW | 892MW | | | |
| *2029* | 25MW | 917MW | | | |
| *2030* | 24MW | 941MW | | | |
| *2031* | 23MW | 963MW | | Deactivate K3 (-88MW) | |
| *2032* | 22MW | 985MW | | | |
| *2033* | 21MW | 1007MW | | Deactivate K5 (-134MW) | |
| | | | | Deactivate W5 (-55MW) | |
| *Strategist Planning Period Total Cost* | | | 31, 383, 886 | 29, 185, 878 | 29, 472, 974 |
| *Strategist Study Period Total Cost* | | | 41, 909, 096 | 36, 610, 480 | 38, 044, 448 |
| *Planning Period Total Cost* | | | | | |
| *Study Period Total Cost* | | | | | |
| *Planning Rank* | | | | | |
| *Study Rank* | | | | | |

Table O-6. HECO Screening Run (1 of 4)

| **Name** | **P1B2a1XRetire-2r0** | **P1B2a1xRetire-2r1** | **P1B2a1XRetire-2r2** | **P1B2b1XRetire-2r2** |
|---|---|---|---|---|
| *Plan* | 0% RPS (Wind, PV, Wave, Biomass, CT, ICE) | 0% RPS (Wind, PV, Wave, Biomass, CT, ICE) | Screen, (Wind, PV, Wave, CT91), Cycle K1-4 | Screen, (Wind, PV, Wave, CT91), Cycle K1-4 |
| *Notes* | Wind30, off-shore wind, PV5, & Wave15, CT91 avail, >20% curtail | Schofield (51MW ICE) forced in 2017. Wind30, off-shore wind, PV5, & Wave15, CT91 avail, >20% curtail | Wind30, off-shore wind, PV5, & Wave15, CT91 avail; Cycle Kahe 1-4 in 2020, >20% curtail | Add Lanai w, Wind30, off-shore wind, PV5, & Wave15, CT91 avail; Cycle Kahe 1-4 in 2020, >20% curtail |
| *Resources Available* | ICE (17 MW)-Biodiesel (PS01)-2017<br>100 MW SCCT - Biodiesel (PS07)-n/a<br>30 MW Onshore Wind Cl 3 (PW01)-2020<br>10 MW Onshore Wind Cl 5 (PW03)-2018<br>10 MW Onshore Wind Cl 7 (PW04)-2018<br>100 MW Offshore Wind (PW05)-2020<br>5 MW of 1 MW Tracking PV (PP03)-2015<br>50 MW Parabolic Trough PV (PP04)-n/a<br>9.6 MW OTEC (POT1)-n/a<br>15 MW Ocean Wave 5 MW (PV02)-2020 | ICE (17 MW)-Biodiesel (PS01)-2017<br>100 MW SCCT - Biodiesel (PS07)-2020<br>30 MW Onshore Wind Cl 3 (PW01)-2020<br>10 MW Onshore Wind Cl 5 (PW03)-2018<br>10 MW Onshore Wind Cl 7 (PW04)-2018<br>100 MW Offshore Wind (PW05)-2020<br>5 MW of 1 MW Tracking PV (PP03)-2015<br>50 MW Parabolic Trough PV (PP04)-n/a<br>9.6 MW OTEC (POT1)-n/a<br>15 MW Ocean Wave 5 MW (PV02)-2020 | ICE (17 MW)-Biodiesel (PS01)-n/a<br>100 MW SCCT - Biodiesel (PS07)-2020<br>30 MW Onshore Wind Cl 3 (PW01)-2018<br>10 MW Onshore Wind Cl 5 (PW03)-n/a<br>10 MW Onshore Wind Cl 7 (PW04)-n/a<br>100 MW Offshore Wind (PW05)-2020<br>5 MW of 1 MW Tracking PV (PP03)-2015<br>50 MW Parabolic Trough PV (PP04)-n/a<br>9.6 MW OTEC (POT1)-n/a<br>15 MW Ocean Wave (PV02)-2020 | ICE (17 MW)-Biodiesel (PS01)-n/a<br>100 MW SCCT - Biodiesel (PS07)-2020<br>30 MW Onshore Wind Cl 3 (PW01)-2018<br>10 MW Onshore Wind Cl 5 (PW03)-n/a<br>10 MW Onshore Wind Cl 7 (PW04)-n/a<br>100 MW Offshore Wind (PW05)-2020<br>5 MW of 1 MW Tracking PV (PP03)-2015<br>50 MW Parabolic Trough PV (PP04)-n/a<br>9.6 MW OTEC (POT1)-n/a<br>15 MW Ocean Wave (PV02)-2020 |
| *Reference* | P1B2a1XRetire-2r0.xlxs | | | |
| *2014* | Continue CIDLC, CIDP, RDLCWH, RDLCAC | Continue CIDLC, CIDP, RDLCWH, RDLCAC | Continue CIDLC, CIDP, RDLCWH, RDLCAC | Continue CIDLC, CIDP, RDLCWH, RDLCAC |
| | 75%+25%+10% PBFA DSM | 75%+25%+10% PBFA DSM | 75%+25%+10% PBFA DSM | 75%+25%+10% PBFA DSM |
| *2015* | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) |
| *2016* | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) |
| *2017* | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) |
| | | Add 51 MW ICE (PS01x3) | | |
| | Deactivate W3 (-46MW) Deactivate W4 (-46MW) or H8/9 | Deactivate W3 (-46MW) Deactivate W4 (-46MW) or H8/9 | Deactivate W3 (-46MW) Deactivate W4 (-46MW) or H8/9 | Deactivate W3 (-46MW) Deactivate W4 (-46MW) or H8/9 |
| *2018* | | Add 20 MW PV (PP03x4) | Add 60 MW Wind (PW01x2) | Add 60 MW Wind (PW01x2) |
| | | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) |

| Name | P1B2a1XRetire-2r0 | P1B2a1xRetire-2r1 | P1B2a1XRetire-2r2 | P1B2b1XRetire-2r2 |
|---|---|---|---|---|
| 2019 | | | Add 60 MW Wind (PW01x2) | Add 60 MW Wind (PW01x2) |
| | | | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) |
| | Deactivate H8 (-53MW)<br>Deactivate H9 (-54MW)<br>or W3/4 | Deactivate H8 (-53MW)<br>Deactivate H9 (-54MW)<br>or W3/4 | Deactivate H8 (-53MW)<br>Deactivate H9 (-54MW)<br>or W3/4 | Deactivate H8 (-53MW)<br>Deactivate H9 (-54MW)<br>or W3/4 |
| 2020 | | | Cycle Kahe 1 - 4 | Cycle Kahe 1 - 4 |
| | Add 100 MW Wind (PW05x1) | Add 100 MW Wind (PW05x1) | Add 20 MW PV (PP03x4) | Add 200MW Lanai Wind |
| | Add 150 MW Wind (PW01x5) | Add 120 MW Wind (PW01x4) | Add 180 MW Wind (PW01x6) | Add 180 MW Wind (PW01x2) |
| 2021 | | | Add 20 MW PV (PP03x4) | |
| 2022 | | | Add 20 MW PV (PP03x4) | |
| 2023 | | | | |
| 2024 | | | | |
| 2025 | | | | |
| 2026 | | | | Add 60 MW Wind (PW01x2) |
| 2027 | | | | Add 60 MW Wind (PW01x2) |
| | Add 30 MW Wind (PW01x1) | Add 60 MW Wind (PW01x2) | | |
| 2028 | | Add 60 MW Wind (PW01x2) | Add 60 MW Wind (PW01x2) | Add 60 MW Wind (PW01x2) |
| | Add 60 MW Wind (PW01x2) | | | |
| | Add 15 MW Wave (PV02x1) | | | |
| 2029 | | Add 60 MW Wind (PW01x2) | Add 60 MW Wind (PW01x2) | Add 60 MW Wind (PW01x2) |
| | Add 60 MW Wind (PW01x2) | | | |
| | Add 15 MW Wave (PV02x1) | | | |
| 2030 | | | | Add 60 MW Wind (PW01x2) |
| | Add 60 MW Wind (PW01x2) | Add 60 MW Wind (PW01x2) | Add 60 MW Wind (PW01x2) | |
| | Add 100 MW Wind (PW05x1) | Add 100 MW Wind (PW05x1) | Add 20 MW PV (PP03x4) | Add 100 MW Wind (PW05x1) |
| | Add 15 MW Wave (PV02x1) | Add 15 MW Wave (PV02x1) | | |
| | | | | Add 20 MW PV (PP03x4) |
| 2031 | Add 60 MW Wind (PW01x2) | Add 60 MW Wind (PW01x2) | | Add 60 MW Wind (PW01x2) |
| | | | | Add 20 MW PV (PP03x4) |
| 2032 | Add 30 MW Wind (PW01x1) | Add 30 MW Wind (PW01x1) | Add 30 MW Wind (PW01x2) | |
| | | | | Add 20 MW PV (PP03x4) |
| | | Add 15 MW Wave (PV02x1) | Add 100 MW Wind (PW05x1) | |

| **Name** | **P1B2a1XRetire-2r0** | **P1B2a1xRetire-2r1** | **P1B2a1XRetire-2r2** | **P1B2b1XRetire-2r2** |
|---|---|---|---|---|
| *2033* | | | | Add 60 MW Wind (PW01x2) |
| | | | Add 60 MW Wind (PW01x2) | Add 100 MW Wind (PW05x1) |
| | | Add 15 MW Wave (PV02x1) | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) |
| | | | Add 100 MW Wind (PW05x1) | |
| *Planning Period Total Cost* | 32, 584, 166 | 32, 336, 104 | 29, 078, 658 | 29, 030, 302 |
| *Study Period Total Cost* | 45, 142, 980 | 44, 678, 644 | 38, 170, 088 | 37, 300, 456 |
| *Planning Rank* | 4 | 3 | 2 | 1 |
| *Study Rank* | 5 | 4 | 2 | 1 |

Table O-7. HECO Screening Run (2 of 4)

| Name | P1B2b1xRetire-2r0 | P1B2a1xRetire-2r3 Screen | P1B2a1xRetire-2r3 Biof |
|---|---|---|---|
| *Plan* | Screen (Wind, PV, Wave CT91) | Retire H8/H9/W3/W4, Convert Remaining Exist to BF in 2020 | Retire H8/H9/W3/W4, Convert Remaining Exist to BF in 2020, Cycle K1&2 |
| *Notes* | Add Lanai Wind. Wind30, off-shore wind, PV5, & Wave15, CT91 avail, >20% curtail | Schofield (51MW ICE) forced in 2017, no non-firm, >20% curtail | Schofield (51MW ICE) forced in 2017, no non-firm, Cycle K1& 2 from 2023 |
| *Resources Available* | ICE (17 MW)-Biodiesel (PS01)-n/a<br>100 MW SCCT - Biodiesel (PS07)-2020<br>30 MW Onshore Wind Cl 3 (PW01)-2020<br>10 MW Onshore Wind Cl 5 (PW03)-n/a<br>10 MW Onshore Wind Cl 7 (PW04)-n/a<br>100 MW Offshore Wind (PW05)-n/a<br>5 MW of 1 MW Tracking PV (PP03)-2015<br>50 MW Parabolic Trough PV (PP04)-n/a<br>9.6 MW OTEC (POT1)-n/a<br>15 MW Ocean Wave 5 MW (PV02)-2020 | ICE (17 MW)-Biodiesel (PS01)-2017<br>100 MW SCCT - Biodiesel (PS07)-n/a<br>30 MW Onshore Wind Cl 3 (PW01)-n/a<br>10 MW Onshore Wind Cl 5 (PW03)-n/a<br>10 MW Onshore Wind Cl 7 (PW04)-n/a<br>100 MW Offshore Wind (PW05)-n/a<br>5 MW of 1 MW Tracking PV (PP03)-n/a<br>50 MW Parabolic Trough PV (PP04)-n/a<br>9.6 MW OTEC (POT1)-n/a<br>15 MW Ocean Wave 5 MW (PV02)-n/a | ICE (17 MW)-Biodiesel (PS01)-2017<br>100 MW SCCT - Biodiesel (PS07)-n/a<br>30 MW Onshore Wind Cl 3 (PW01)-n/a<br>10 MW Onshore Wind Cl 5 (PW03)-n/a<br>10 MW Onshore Wind Cl 7 (PW04)-n/a<br>100 MW Offshore Wind (PW05)-n/a<br>5 MW of 1 MW Tracking PV (PP03)-n/a<br>50 MW Parabolic Trough PV (PP04)-n/a<br>9.6 MW OTEC (POT1)-n/a<br>15 MW Ocean Wave 5 MW (PV02)-n/a |
| *2014* | Continue CIDLC, CIDP, RDLCWH, RDLCAC | Continue CIDLC, CIDP, RDLCWH, RDLCAC | Continue CIDLC, CIDP, RDLCWH, RDLCAC |
| | 75%+25%+10% PBFA DSM | 75%+25%+10% PBFA DSM | 75%+25%+10% PBFA DSM |
| *2015* | Add 20 MW PV (PP03x4) | | |
| *2016* | Add 20 MW PV (PP03x4) | | |
| *2017* | Add 20 MW PV (PP03x4) | | |
| | | Add 51 MW ICE (PS01x3) | Add 51 MW ICE (PS01x3) |
| | Deactivate W3 (-46MW)<br>Deactivate W4 (-46MW)<br>or H8/9 | Deactivate W3 (-46MW)<br>Deactivate W4 (-46MW)<br>or H8/9 | Deactivate W3 (-46MW)<br>Deactivate W4 (-46MW)<br>or H8/9 |
| *2018* | Add 20 MW PV (PP03x4) | | |
| *2019* | Deactivate H8 (-53MW)<br>Deactivate H9 (-54MW)<br>or W3/4 | Deactivate H8 (-53MW)<br>Deactivate H9 (-54MW)<br>or W3/4 | Deactivate H8 (-53MW)<br>Deactivate H9 (-54MW)<br>or W3/4 |
| *2020* | | Convert all existing units to BF (W5-10/K1-6) | Convert all existing units to BF (W5-10/K1-6) |
| | Add 200MW Lanai Wind | | |
| *2021* | | | |
| *2022* | | | |
| *2023* | | | Cycle Kahe 1 & 2 |
| *2024* | | | |
| *2025* | Add 60 MW Wind (PW01x2) | | |

| **Name** | **P1B2b1xRetire-2r0** | **P1B2a1xRetire-2r3 Screen** | **P1B2a1xRetire-2r3 Biof** |
|---|---|---|---|
| *2026* | Add 60 MW Wind (PW01x2) | | |
| | Add 20 MW PV (PP03x4) | | |
| *2027* | Add 60 MW Wind (PW01x2) | | |
| | Add 20 MW PV (PP03x4) | | |
| *2028* | Add 60 MW Wind (PW01x2) | | |
| | Add 20 MW PV (PP03x4) | | |
| *2029* | Add 60 MW Wind (PW01x2) | | |
| | Add 100 MW Wind (PW05x1) | | |
| | Add 20 MW PV (PP03x4) | | |
| | Add 15 MW Wave (PV02x1) | | |
| *2030* | Add 60 MW Wind (PW01x2) | | |
| | Add 100 MW Wind (PW05x1) | | |
| | Add 20 MW PV (PP03x4) | | |
| | Add 15 MW Wave (PV02x1) | | |
| *2031* | Add 60 MW Wind (PW01x2) | | |
| | Add 20 MW PV (PP03x4) | | |
| | Add 15 MW Wave (PV02x1) | | |
| *2032* | Add 30 MW Wind (PW01x1) | | |
| | Add 20 MW PV (PP03x4) | | |
| | Add 15 MW Wave (PV02x1) | | |
| *2033* | Add 20 MW PV (PP03x4) | | |
| | Add 15 MW Wave (PV02x1) | | |
| *Planning Period Total Cost* | 32, 684, 542 | 26, 979, 758 | 26, 680, 250 |
| *Study Period Total Cost* | 43, 650, 700 | 32, 855, 760 | 32, 420, 408 |
| *Planning Rank* | 5 | 6 | 3 |
| *Study Rank* | 3 | 6 | 2 |

Table O-8. HECO Screening Run (3 of 4)

| Name | P1B2a1xRetire-2r3 Biof_R | P1B2a1xRetire-2r5 Screen | P1B2b1xRetire-2r3 Screen |
|---|---|---|---|
| *Plan* | Retire H8/H9/W3/W4, Convert Remaining Exist to BF in 2020, Cycle K1&2 | Retire All, Replace with BF, Timing Rule1 | Retire H8/H9/W3/W4, Convert Remaining Exist to BF, Add Lanai Wind |
| *Notes* | Schofield (51MW ICE) forced in 2017, Cycle K1-4 from 2020, Wind30 & PV5 available | Schofield (51MW ICE) in 2017, 91MW CT added to replace Self Generation, no non-firm | Schofield (51MW ICE) forced in 2017, no non-firm, >20% curtail |
| *Resources Available* | ICE (17 MW)-Biodiesel (PS01)-2017<br>100 MW SCCT - Biodiesel (PS07)-n/a<br>30 MW Onshore Wind Cl 3 (PW01)-2018<br>10 MW Onshore Wind Cl 5 (PW03)-n/a<br>10 MW Onshore Wind Cl 7 (PW04)-n/a<br>100 MW Offshore Wind (PW05)-n/a<br>5 MW of 1 MW Tracking PV (PP03)-2020<br>50 MW Parabolic Trough PV (PP04)-n/a<br>9.6 MW OTEC (POT1)-n/a<br>15 MW Ocean Wave 5 MW (PV02)-n/a | | |
| *2014* | Continue CIDLC, CIDP, RDLCWH, RDLCAC | Continue CIDLC, CIDP, RDLCWH, RDLCAC | Continue CIDLC, CIDP, RDLCWH, RDLCAC |
| | 75%+25%+10% PBFA DSM | 75%+25%+10% PBFA DSM | 75%+25%+10% PBFA DSM |
| *2015* | | | |
| *2016* | | | |
| *2017* | Add 51 MW ICE (PS01x3) | Add 51 MW ICE (PS01x3) | Add 51 MW ICE (PS01x3) |
| | Deactivate W3 (-46MW)<br>Deactivate W4 (-46MW)<br>or H8/9 | Deactivate W3 (-46MW)<br>Deactivate W4 (-46MW)<br>or H8/9 | Deactivate W3 (-46MW)<br>Deactivate W4 (-46MW)<br>or H8/9 |
| *2018* | | | |
| *2019* | Deactivate H8 (-53MW)<br>Deactivate H9 (-54MW)<br>or W3/4 | Deactivate H8 (-53MW)<br>Deactivate H9 (-54MW)<br>or W3/4 | Deactivate H8 (-53MW)<br>Deactivate H9 (-54MW)<br>or W3/4 |
| *2020* | Convert all existing units to BF (W5-10/K1-6) | Convert remaining units to BF (W9-10) | Convert all existing units to BF (W5-10/K1-6) |
| | | Add 182MW SCCT (PS07x2)-Biofueled | Add 200MW Lanai Wind |
| | | Deactivate W5 (-55MW)<br>Deactivate W6 (-56MW)<br>Deactivate W7 (-88MW)<br>Deactivate W8 (-88MW)<br>Deactivate K1 (-88MW)<br>Deactivate K2 (-86MW)<br>Deactivate K3 (-88MW)<br>Deactivate K4 (-89MW) | |
| *2021* | | Add 182MW SCCT (PS07x2)-Biofueled | |
| | | Deactivate K5 (-135MW) | |

| Name | P1B2a1xRetire-2r3 Biof_R | P1B2a1xRetire-2r5 Screen | P1B2b1xRetire-2r3 Screen |
|---|---|---|---|
| *2022* | | Add 59MW CC (PC08x1)-Biofueled<br>Add 91MW SCCT (PS07x1)-Biofueled<br>Deactivate K6 (-134MW) | |
| *2023* | Cycle Kahe 1 & 2 | Add 59MW CC (PC08x1)-Biofueled | |
| *2024* | | | |
| *2025* | | | |
| *2026* | | | |
| *2027* | | | |
| *2028* | | | |
| *2029* | | | |
| *2030* | | | |
| *2031* | | | |
| *2032* | | | |
| *2033* | | | |
| *Planning Period Total Cost* | 26, 680, 250 | 27, 048, 904 | 27, 315, 910 |
| *Study Period Total Cost* | 32, 420, 408 | 33, 000, 280 | 33, 513, 280 |
| *Planning Rank* | 3 | 7 | 9 |
| *Study Rank* | 2 | 7 | 9 |

Table O-9. HECO Screening Run (4 of 4)

| **Name** | **P1B2a1xRetire-2r6** | **P1B2a1xRetire-2r6 Lanai** | **P1B2a1xRetire-2r6 LanH** |
|---|---|---|---|
| *Plan* | Retire H8/H9/W3/W4, Convert Remaining Exist to BF in 2020, Cycle K1&2 | Retire H8/H9/W3/W4, Convert Remaining Exist to BF in 2020, Cycle K1&2; Lanai | Retire H8/H9/W3/W4, Convert Remaining Exist to BF in 2020, Cycle K1&2; Lanai-higher cost |
| *Notes* | Cycle K1-2 from 2023, Wind30 & PV5 available | Cycle K1-2 from 2023, Wind30 & PV5 available, Lanai wind 2020 | Cycle K1-2 from 2023, Wind30 & PV5 available, Lanai wind 2020 |
| *Resources Available* | ICE (17 MW)-Biodiesel (PS01)-n/a<br>100 MW SCCT - Biodiesel (PS07)-n/a<br>30 MW Onshore Wind Cl 3 (PW01)-2018<br>10 MW Onshore Wind Cl 5 (PW03)-n/a<br>10 MW Onshore Wind Cl 7 (PW04)-n/a<br>100 MW Offshore Wind (PW05)-n/a<br>5 MW of 1 MW Tracking PV (PP03)-2020<br>50 MW Parabolic Trough PV (PP04)-n/a<br>9.6 MW OTEC (POT1)-n/a<br>15 MW Ocean Wave (PV02)-n/a | ICE (17 MW)-Biodiesel (PS01)-n/a<br>100 MW SCCT - Biodiesel (PS07)-n/a<br>30 MW Onshore Wind Cl 3 (PW01)-2018<br>10 MW Onshore Wind Cl 5 (PW03)-n/a<br>10 MW Onshore Wind Cl 7 (PW04)-n/a<br>100 MW Offshore Wind (PW05)-n/a<br>5 MW of 1 MW Tracking PV (PP03)-2020<br>50 MW Parabolic Trough PV (PP04)-n/a<br>9.6 MW OTEC (POT1)-n/a<br>15 MW Ocean Wave (PV02)-n/a | ICE (17 MW)-Biodiesel (PS01)-n/a<br>100 MW SCCT - Biodiesel (PS07)-n/a<br>30 MW Onshore Wind Cl 3 (PW01)-2018<br>10 MW Onshore Wind Cl 5 (PW03)-n/a<br>10 MW Onshore Wind Cl 7 (PW04)-n/a<br>100 MW Offshore Wind (PW05)-n/a<br>5 MW of 1 MW Tracking PV (PP03)-2020<br>50 MW Parabolic Trough PV (PP04)-n/a<br>9.6 MW OTEC (POT1)-n/a<br>15 MW Ocean Wave (PV02)-n/a |
| *2014* | Continue CIDLC, CIDP, RDLCWH, RDLCAC | Continue CIDLC, CIDP, RDLCWH, RDLCAC | Continue CIDLC, CIDP, RDLCWH, RDLCAC |
| | 75%+25%+10% PBFA DSM | 75%+25%+10% PBFA DSM | 75%+25%+10% PBFA DSM |
| *2015* | | | |
| *2016* | | | |
| *2017* | Deactivate W3 (-46MW)<br>Deactivate W4 (-46MW)<br>or H8/9 | Deactivate W3 (-46MW)<br>Deactivate W4 (-46MW)<br>or H8/9 | Deactivate W3 (-46MW)<br>Deactivate W4 (-46MW)<br>or H8/9 |
| *2018* | | | |
| *2019* | Deactivate H8 (-53MW)<br>Deactivate H9 (-54MW)<br>or W3/4 | Deactivate H8 (-53MW)<br>Deactivate H9 (-54MW)<br>or W3/4 | Deactivate H8 (-53MW)<br>Deactivate H9 (-54MW)<br>or W3/4 |
| *2020* | Convert all existing units to BF (W5-10/K1-6) | Convert all existing units to BF (W5-10/K1-6) | Convert all existing units to BF (W5-10/K1-6) |
| | | Add 200MW Lanai Wind | Add 200MW Lanai Wind |
| *2021* | | | |
| *2022* | | | |
| *2023* | Cycle Kahe 1 & 2 | Cycle Kahe 1 & 2 | Cycle Kahe 1 & 2 |
| *2024* | | | |
| *2025* | | | |
| *2026* | | | |
| *2027* | | | |
| *2028* | | | |

| Name | P1B2a1xRetire-2r6 | P1B2a1xRetire-2r6 Lanai | P1B2a1xRetire-2r6 LanH |
|---|---|---|---|
| *2029* | | | |
| *2030* | | | |
| *2031* | | | |
| *2032* | | | |
| *2033* | | | |
| *Planning Period Total Cost* | 26, 404, 916 | 26, 644, 042 | 26, 771, 064 |
| *Study Period Total Cost* | 32, 020, 054 | 32, 545, 570 | 32, 730, 858 |
| *Planning Rank* | 1 | 2 | 5 |
| *Study Rank* | 1 | 4 | 5 |

Table O-10. HECO Environmental Compliance 1 (1 of 2)

| Name | Self Generation | | P1B2a1XRetire-2r2 | P1B2a1XRetire-2r2 AQC | P1B2a1xRetire-2r6 |
|---|---|---|---|---|---|
| *Plan* | Annual | Cumulative | Fuel Switch to ULSD in 2022 | Install Air Quality Controls in 2022 | Fuel Switch to Biofuels in 2020 |
| *Notes* | | | Wind30, off-shore wind, PV5, & Wave15, CT91 avail; Cycle Kahe 1-4 in 2020, >20% curtail | Wind30, off-shore wind, PV5, & Wave15, CT91 avail; Cycle Kahe 1-4 in 2020, >20% curtail | Fuel switch applies to all Waiau 5-10 and Kahe 1-6, Cycle Kahe 1-2 to reduce dumped energy |
| *Resources Available* | | | ICE (17 MW)-Biodiesel (PS01)-n/a<br>100 MW SCCT - Biodiesel (PS07)-2020<br>30 MW Onshore Wind Cl 3 (PW01)-2018<br>10 MW Onshore Wind Cl 5 (PW03)-n/a<br>10 MW Onshore Wind Cl 7 (PW04)-n/a<br>100 MW Offshore Wind (PW05)-n/a<br>5 MW of 1 MW Tracking PV (PP03)-2015<br>50 MW Parabolic Trough PV (PP04)-n/a<br>9.6 MW OTEC (POT1)-n/a<br>15 MW Ocean Wave 5 MW (PV02)-2020 | ICE (17 MW)-Biodiesel (PS01)-n/a<br>100 MW SCCT - Biodiesel (PS07)-2020<br>30 MW Onshore Wind Cl 3 (PW01)-2018<br>10 MW Onshore Wind Cl 5 (PW03)-n/a<br>10 MW Onshore Wind Cl 7 (PW04)-n/a<br>100 MW Offshore Wind (PW05)-n/a<br>5 MW of 1 MW Tracking PV (PP03)-2015<br>50 MW Parabolic Trough PV (PP04)-n/a<br>9.6 MW OTEC (POT1)-n/a<br>15 MW Ocean Wave 5 MW (PV02)-2020 | ICE (17 MW)-Biodiesel (PS01)-n/a<br>100 MW SCCT - Biodiesel (PS07)-n/a<br>30 MW Onshore Wind Cl 3 (PW01)-2018<br>10 MW Onshore Wind Cl 5 (PW03)-n/a<br>10 MW Onshore Wind Cl 7 (PW04)-n/a<br>100 MW Offshore Wind (PW05)-n/a<br>5 MW of 1 MW Tracking PV (PP03)-2020<br>50 MW Parabolic Trough PV (PP04)-n/a<br>9.6 MW OTEC (POT1)-n/a<br>15 MW Ocean Wave 5 MW (PV02)-n/a |
| *2014* | 35MW | 75 MW | Continue CIDLC, CIDP, RDLCWH, RDLCAC | Continue CIDLC, CIDP, RDLCWH, RDLCAC | Continue CIDLC, CIDP, RDLCWH, RDLCAC |
| | | | 75%+25%+10% PBFA DSM | 75%+25%+10% PBFA DSM | 75%+25%+10% PBFA DSM |
| *2015* | 36MW | 111MW | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) | |
| *2016* | 43MW | 154MW | Fuel Switch to Diesel (H8/9, Waiau 5-10/Kahe 1-6) | Fuel Switch to Diesel (H8/9, Waiau 5-10/Kahe 1-6) | Fuel Switch to Diesel (H8/9, Waiau 5-10/Kahe 1-6) |
| | | | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) | |
| *2017* | 36MW | 189MW | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) | |
| | | | Deactivate W3 (-46MW)<br>Deactivate W4 (-46MW)<br>or H8/9 | Deactivate W3 (-46MW)<br>Deactivate W4 (-46MW)<br>or H8/9 | Deactivate W3 (-46MW)<br>Deactivate W4 (-46MW)<br>or H8/9 |
| *2018* | 36MW | 225MW | Add 60 MW Wind (PW01x2) | Add 60 MW Wind (PW01x2) | |
| | | | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) | |

| Name | Self Generation | | P1B2a1XRetire-2r2 | P1B2a1XRetire-2r2 AQC | P1B2a1xRetire-2r6 |
|---|---|---|---|---|---|
| *2019* | 35MW | 260MW | Add 60 MW Wind (PW01x2)<br>Add 20 MW PV (PP03x4)<br>Deactivate H8 (-53MW)<br>Deactivate H9 (-54MW)<br>or W3/4 | Add 60 MW Wind (PW01x2)<br>Add 20 MW PV (PP03x4)<br>Deactivate H8 (-53MW)<br>Deactivate H9 (-54MW)<br>or W3/4 | Deactivate H8 (-53MW)<br>Deactivate H9 (-54MW)<br>or W3/4 |
| *2020* | 35MW | 295MW | Fuel Switch to ULSD<br>(Waiau 5-10/Kahe 1-6)<br>Cycle Kahe 1 - 4<br>Add 20 MW PV (PP03x4)<br>Add 180 MW Wind (PW01x6) | Cycle Kahe 1 - 4<br>Add 20 MW PV (PP03x4)<br>Add 180 MW Wind (PW01x6) | Fuel Switch to BF<br>(Waiau 5-10/Kahe 1-6) |
| *2021* | 35MW | 331MW | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) | |
| *2022* | 28MW | 363MW | Add 20 MW PV (PP03x4) | AQC Waiau 5-8 & Kahe 1-6<br>Add 20 MW PV (PP03x4) | |
| *2023* | 28MW | 391MW | | | Cycle Kahe 1 & 2 |
| *2024* | 25MW | 416MW | | | |
| *2025* | 21MW | 437MW | | | |
| *2026* | 18MW | 456MW | | | |
| *2027* | 16MW | 472MW | | | |
| *2028* | 15MW | 486MW | Add 60 MW Wind (PW01x2) | Add 60 MW Wind (PW01x2) | |
| *2029* | 14MW | 500MW | Add 60 MW Wind (PW01x2) | Add 60 MW Wind (PW01x2) | |
| *2030* | 13MW | 513MW | Add 60 MW Wind (PW01x2)<br>Add 20 MW PV (PP03x4) | Add 60 MW Wind (PW01x2)<br>Add 20 MW PV (PP03x4) | |
| *2031* | 12MW | 525MW | | | |
| *2032* | 12MW | 538MW | Add 60 MW Wind (PW01x2)<br>Add 100 MW Wind (PW05x1) | Add 60 MW Wind (PW01x2)<br>Add 100 MW Wind (PW05x1) | |
| *2033* | 12MW | 549MW | Add 60 MW Wind (PW01x2)<br>Add 20 MW PV (PP03x4)<br>Add 100 MW Wind (PW05x1) | Add 60 MW Wind (PW01x2)<br>Add 20 MW PV (PP03x4)<br>Add 100 MW Wind (PW05x1) | |
| *Strategist Planning Period Total Cost* | | | 29, 078, 658 | 28, 827, 210 | 26, 404, 916 |
| *Strategist Study Period Total Cost* | | | 38, 170, 088 | 37, 763, 932 | 32, 020, 054 |
| *Planning Period Total Cost* | | | 30, 857, 503 | 32, 590, 956 | 29, 082, 294 |
| *Study Period Total Cost* | | | 40, 847, 465 | 41, 527, 673 | 34, 697, 431 |
| *Planning Rank* | | | 5 | 6 | 1 |
| *Study Rank* | | | 5 | 6 | 1 |

Table O-11. HECO Environmental Compliance 1 (2 of 2)

<table>
<tr><th>Name</th><th colspan="2">Self Generation</th><th>P1B2a1xRetire-4Dr6</th><th>P1B2a1xRetire-4Er0</th><th>P1B2a1xRetire-4Fr0</th></tr>
<tr><td>Plan</td><td rowspan="3">Annual</td><td rowspan="3">Cumulative</td><td>Fuel Switch to LNG in 2020</td><td>Deactivate Existing Replace with Conventional LNG Units</td><td>Deactivate Existing Replace with Conventional Biofueled Units</td></tr>
<tr><td>Notes</td><td>Fuel switch applies to all Waiau 5-8 and Kahe 1-6, Cycle Kahe 1-4 to reduce dumped energy</td><td>All units are deactivated by 2022</td><td>All units are deactivated by 2022</td></tr>
<tr><td>Resources Available</td><td>ICE (17 MW)-Biodiesel (PS01)-n/a<br>100 MW SCCT - Biodiesel (PS07)-n/a<br>30 MW Onshore Wind Cl 3 (PW01)-2018<br>10 MW Onshore Wind Cl 5 (PW03)-n/a<br>10 MW Onshore Wind Cl 7 (PW04)-n/a<br>100 MW Offshore Wind (PW05)-n/a<br>5 MW of 1 MW Tracking PV (PP03)-2020<br>50 MW Parabolic Trough PV (PP04)-n/a<br>9.6 MW OTEC (POT1)-n/a<br>15 MW Ocean Wave 5 MW (PV02)-n/a</td><td>95 MW SCCT LMS 100 - LNG (PS07)-2018<br>42 MW LM6000 SCCT LNG (PC08)-n/a<br>59 MW 1on1 LM6000 CC-LNG (PS12)-2020<br>25MW Banagrass (PA01)-n/a<br>400 kW Nat Gas Fuel Cell (FC40)-n/a<br>30 MW Onshore Wind Cl 3 (PW01)-2018<br>10 MW Onshore Wind Cl 5 (PW03)-n/a<br>5 MW of 1 MW Tracking PV (PP03)-2018</td><td>95 MW SCCT LMS 100 - Biodiesel (PS07)-2018<br>42 MW LM6000 SCCT Biodiesel (PC08)-n/a<br>59 MW 1on1 LM6000 CC-LNG (PS12)-2020<br>25MW Banagrass (PA01)-n/a<br>400 kW Nat Gas Fuel Cell (FC40)-n/a<br>30 MW Onshore Wind Cl 3 (PW01)-2018<br>10 MW Onshore Wind Cl 5 (PW03)-n/a<br>5 MW of 1 MW Tracking PV (PP03)-2018</td></tr>
<tr><td rowspan="2">2014</td><td rowspan="2">35MW</td><td rowspan="2">75 MW</td><td>Continue CIDLC, CIDP, RDLCWH, RDLCAC</td><td>Continue CIDLC, CIDP, RDLCWH, RDLCAC</td><td>Continue CIDLC, CIDP, RDLCWH, RDLCAC</td></tr>
<tr><td>75%+25%+10% PBFA DSM</td><td>75%+25%+10% PBFA DSM</td><td>75%+25%+10% PBFA DSM</td></tr>
<tr><td>2015</td><td>36MW</td><td>111MW</td><td></td><td></td><td></td></tr>
<tr><td>2016</td><td>43MW</td><td>154MW</td><td>Fuel Switch to Diesel (H8/9, Waiau 5-10/Kahe 1-6)</td><td>Fuel Switch to Diesel (H8/9, Waiau 5-10/Kahe 1-6)</td><td>Fuel Switch to Diesel (H8/9, Waiau 5-10/Kahe 1-6)</td></tr>
<tr><td>2017</td><td>36MW</td><td>189MW</td><td>Deactivate W3 (-46MW)<br>Deactivate W4 (-46MW)<br>or H8/9</td><td>Retire W3 (-46MW)<br>Retire W4 (-46MW)<br>or H8/9</td><td>Retire W3 (-46MW)<br>Retire W4 (-46MW)<br>or H8/9</td></tr>
<tr><td>2018</td><td>36MW</td><td>225MW</td><td>Add 60 MW Wind (PW01x2)</td><td>Add 20 MW PV (PP03x4)</td><td>Add 20 MW PV (PP03x4)</td></tr>
<tr><td rowspan="2">2019</td><td rowspan="2">35MW</td><td rowspan="2">260MW</td><td>Add 60 MW Wind (PW01x2)</td><td>Add 20 MW PV (PP03x4)</td><td></td></tr>
<tr><td>Deactivate H8 (-53MW)<br>Deactivate H9 (-54MW)<br>or W3/4</td><td>Retire H8 (-53MW)<br>Retire H9 (-54MW)<br>or W3/4</td><td>Retire H8 (-53MW)<br>Retire H9 (-54MW)<br>or W3/4</td></tr>
</table>

| Name | Self Generation | | P1B2a1xRetire-4Dr6 | P1B2a1xRetire-4Er0 | P1B2a1xRetire-4Fr0 |
|---|---|---|---|---|---|
| *2020* | 35MW | 295MW | Fuel switch to LNG (Waiau 5-10, Kahe 1-6) | | |
| | | | Add 150 MW Wind (PW01x5) | Add 20 MW PV (PP03x4) | Add 150 MW Wind (PW01x5) |
| | | | Add 20 MW PV (PP03x4) | Add 210 MW Wind (PW01x7) | |
| | | | | Retire W5 (-55MW)<br>Retire W6 (-56MW)<br>Retire W7 (-88MW)<br>Retire W8 (-88MW)<br>Retire K1 (-88MW)<br>Retire K2 (-86MW)<br>Retire K3 (-88MW)<br>Retire K4 (-89MW) | Retire W5 (-55MW)<br>Retire W6 (-56MW)<br>Retire W7 (-88MW)<br>Retire W8 (-88MW)<br>Retire K1 (-88MW)<br>Retire K2 (-86MW)<br>Retire K3 (-88MW)<br>Retire K4 (-89MW) |
| | | | | Add 182MW SCCT (PS07x2)-LNG | Add 182MW SCCT (PS07x2)-Biofueled |
| | | | | Add 59MW CC (PC08x1)-LNG | Add 59MW CC (PC08x1)-Biofueled |
| *2021* | 35MW | 331MW | Add 20 MW PV (PP03x4) | Add 90 MW Wind (PW01x3) | Add 60 MW Wind (PW01x2) |
| | | | | Add 20 MW PV (PP03x4) | |
| | | | | Add 182MW SCCT (PS07x2)-LNG | Add 182MW SCCT (PS07x2)-Biofueled |
| | | | | Retire K5 (-135MW) | Retire K5 (-135MW) |
| | | | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) | Add 60 MW Wind (PW01x2) |
| | | | | Add 59MW CC (PC08x1)-LNG | Add 59MW CC (PC08x1)-Biofueled |
| | | | | Add 91MW SCCT (PS07x1)-LNG | Add 91MW SCCT (PS07x1)-Biofueled |
| | | | | Retire K6 (-134MW) | Retire K6 (-134MW) |
| *2023* | 28MW | 391MW | Cycle Kahe 1 - 4 | | |
| | | | | Add 59MW CC (PC08x1)-LNG | Add 59MW CC (PC08x1)-Biofueled |
| | | | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) | Add 30 MW Wind (PW01x1) |
| *2024* | 25MW | 416MW | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) | |
| *2025* | 21MW | 437MW | Add 20 MW PV (PP03x4) | | |
| *2026* | 18MW | 456MW | | Add 60 MW Wind (PW01x2) | |
| *2027* | 16MW | 472MW | | Add 60 MW Wind (PW01x2) | |
| *2028* | 15MW | 486MW | | | |
| *2029* | 14MW | 500MW | Add 20 MW PV (PP03x4) | | |
| *2030* | 13MW | 513MW | Cycle Kahe 6 & Waiau 7 | | |
| | | | Add 180 MW Wind (PW01x6) | | |
| | | | Add 60 MW PV (PP03x12) | | |

| Name | Self Generation | | P1B2a1xRetire-4Dr6 | P1B2a1xRetire-4Er0 | P1B2a1xRetire-4Fr0 |
|---|---|---|---|---|---|
| *2031* | 12MW | 525MW | | | |
| *2032* | 12MW | 538MW | | | |
| *2033* | 12MW | 549MW | | | |
| *Strategist Planning Period Total Cost* | | | 27, 601, 824 | 27, 185, 884 | 26, 620, 508 |
| *Strategist Study Period Total Cost* | | | 34, 621, 540 | 33, 589, 848 | 32, 645, 724 |
| *Planning Period Total Cost* | | | 30, 571, 308 | 29, 759, 536 | 29, 111, 265 |
| *Study Period Total Cost* | | | 37, 591, 025 | 36, 163, 501 | 35, 136, 481 |
| *Planning Rank* | | | 4 | 3 | 2 |
| *Study Rank* | | | 4 | 3 | 2 |

Table O-12. HECO Environmental Compliance 2 (1 of 2)

| **Name** | **P1B2a1xRetire-2r6** | **P1B2a1xRetire-4Dr6** | **P1B2a1xRetire-4Er0** | **P1B2a1xRetire-4Fr0** |
|---|---|---|---|---|
| *Plan* | 0% RPS (Wind, PV, Wave, Biomass, CT, ICE) | 0% RPS (Wind, PV, Wave, Biomass, CT, ICE) | Retire All, Replace with LNG | Retire All, Replace |
| *Notes* | Cycle K1-2 from 2023, Wind30 & PV5 available | Cycle K1-4 from 2023 and K6 & W7 from 2030, Wind30 & PV5 available | 91MW CT & 59 MW CC added to replace Self Generation, LNG in 2020 | 91MW CT & 59 MW CC added to replace Self Generation |
| *Resources Available* | | | | |
| *2014* | Continue CIDLC, CIDP, RDLCWH, RDLCAC | Continue CIDLC, CIDP, RDLCWH, RDLCAC | Continue CIDLC, CIDP, RDLCWH, RDLCAC | Continue CIDLC, CIDP, RDLCWH, RDLCAC |
| | 75%+25%+10% PBFA DSM | 75%+25%+10% PBFA DSM | 75%+25%+10% PBFA DSM | 75%+25%+10% PBFA DSM |
| *2015* | | | | |
| *2016* | Fuel Switch to Diesel (H8/9, Waiau 5-10/Kahe 1-6) | Fuel Switch to Diesel (H8/9, Waiau 5-10/Kahe 1-6) | Fuel Switch to Diesel (H8/9, Waiau 5-10/Kahe 1-6) | Fuel Switch to Diesel (H8/9, Waiau 5-10/Kahe 1-6) |
| *2017* | Deactivate W3 (-46MW)<br>Deactivate W4 (-46MW)<br>or H8/9 | Deactivate W3 (-46MW)<br>Deactivate W4 (-46MW)<br>or H8/9 | Deactivate W3 (-46MW)<br>Deactivate W4 (-46MW)<br>or H8/9 | Deactivate W3 (-46MW)<br>Deactivate W4 (-46MW)<br>or H8/9 |
| *2018* | | | Add 20 MW PV (PP03x4) | |
| *2019* | | Add 60 MW Wind (PW01x2) | Add 20 MW PV (PP03x4) | |
| | Deactivate H8 (-53MW)<br>Deactivate H9 (-54MW)<br>or W3/4 | Deactivate H8 (-53MW)<br>Deactivate H9 (-54MW)<br>or W3/4 | Deactivate H8 (-53MW)<br>Deactivate H9 (-54MW)<br>or W3/4 | Deactivate H8 (-53MW)<br>Deactivate H9 (-54MW)<br>or W3/4 |
| *2020* | Fuel Switch to BF (Waiau 5-10/Kahe 1-6) | Fuel switch to LNG (Waiau 5-10, Kahe 1-6) | Add 20 MW PV (PP03x4) | |
| | | Add 150 MW Wind (PW01x5) | Add 210 MW Wind (PW01x7) | Add 150 MW Wind (PW01x5) |
| | | | Deactivate W5 (-55MW)<br>Deactivate W6 (-56MW)<br>Deactivate W7 (-88MW)<br>Deactivate W8 (-88MW)<br>Deactivate K1 (-88MW)<br>Deactivate K2 (-86MW)<br>Deactivate K3 (-88MW)<br>Deactivate K4 (-89MW) | Deactivate W5 (-55MW)<br>Deactivate W6 (-56MW)<br>Deactivate W7 (-88MW)<br>Deactivate W8 (-88MW)<br>Deactivate K1 (-88MW)<br>Deactivate K2 (-86MW)<br>Deactivate K3 (-88MW)<br>Deactivate K4 (-89MW) |
| | | | Add 182MW SCCT (PS07x2)-LNG | Add 182MW SCCT (PS07x2)-Biofueled |
| | | Add 20 MW PV (PP03x4) | Add 59MW CC (PC08x1)-LNG | Add 59MW CC (PC08x1)-Biofueled |

| Name | P1B2a1xRetire-2r6 | P1B2a1xRetire-4Dr6 | P1B2a1xRetire-4Er0 | P1B2a1xRetire-4Fr0 |
|---|---|---|---|---|
| *2021* | | | Add 182MW SCCT (PS07x2)-LNG | Add 182MW SCCT (PS07x2)-Biofueled |
| | | | Deactivate K5 (-135MW) | Deactivate K5 (-135MW) |
| | | | Add 90 MW Wind (PW01x3) | |
| | | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) | Add 60 MW Wind (PW01x2) |
| *2022* | | | Add 59MW CC (PC08x1)-LNG | Add 59MW CC (PC08x1)-Biofueled |
| | | | Add 91MW SCCT (PS07x1)-LNG | Add 91MW SCCT (PS07x1)-Biofueled |
| | | | Deactivate K6 (-134MW) | Deactivate K6 (-134MW) |
| | | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) | Add 60 MW Wind (PW01x2) |
| *2023* | Cycle Kahe 1 & 2 | Cycle Kahe 1 - 4 | Add 59MW CC (PC08x1)-LNG | Add 59MW CC (PC08x1)-Biofueled |
| | | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) | Add 30 MW Wind (PW01x1) |
| *2024* | | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) | |
| *2025* | | Add 20 MW PV (PP03x4) | | |
| *2026* | | | Add 60 MW Wind (PW01x2) | |
| *2027* | | | Add 60 MW Wind (PW01x2) | |
| *2028* | | | | |
| *2029* | | Add 20 MW PV (PP03x4) | | |
| *2030* | | Cycle Kahe 6 & Waiau 7 | | |
| | | Add 180 MW Wind (PW01x6) | | |
| | | Add 60 MW PV (PP03x12) | | |
| *2031* | | | | |
| *2032* | | | | |
| *2033* | | | | |
| *Planning Period Total Cost* | 26, 700, 347 | 27, 994, 588 | 27, 438, 090 | 26, 789, 820 |
| *Study Period Total Cost* | 32, 315, 484 | 35, 014, 306 | 33, 842, 056 | 32, 815, 036 |
| *Planning Rank* | 1 | 4 | 3 | 2 |
| *Study Rank* | 1 | 4 | 3 | 2 |

Table O-13. HECO Environmental Compliance 2 (2 of 2)

| **Name** | **P1B2a1xRetire-4Er1** | **P1B2a1XRetire-2r2** | **P1B2a1XRetire-2r2 AQC** |
|---|---|---|---|
| *Plan* | Retire All, Replace with LNG | Fuel Switch to ULSD in 2022 | Install Air Quality Controls in 2022 |
| *Notes* | 91MW CT & 59 MW CC added to replace Self Generation, LNG in 2020 | Wind30, off-shore wind, PV5, & Wave15, CT91 avail; Cycle Kahe 1-4 in 2020, >20% curtail | Wind30, off-shore wind, PV5, & Wave15, CT91 avail; Cycle Kahe 1-4 in 2020, >20% curtail |
| *Resources Available* | 95 MW SCCT LMS100 - LNG (PS08)-2018<br>42 MW LM6000 SCCT LNG (PS10)-2020<br>59 MW 1on1 LM6000 CC-LNG (PS12)-2020<br>25MW Banagrass (PA01)-2020<br>400 kW Nat Gas Fuel Cell (FC40)-2020<br>30 MW Onshore Wind Cl 3 (PW01)-n/a<br>10 MW Onshore Wind Cl 5 (PW03)-n/a<br>5 MW of 1 MW Tracking PV (PP03)-n/a | ICE (17 MW)-Biodiesel (PS01)-n/a<br>100 MW SCCT - Biodiesel (PS07)-2020<br>30 MW Onshore Wind Cl 3 (PW01)-2018<br>10 MW Onshore Wind Cl 5 (PW03)-n/a<br>10 MW Onshore Wind Cl 7 (PW04)-n/a<br>100 MW Offshore Wind (PW05)-n/a<br>5 MW of 1 MW Tracking PV (PP03)-2015<br>50 MW Parabolic Trough PV (PP04)-n/a<br>9.6 MW OTEC (POT1)-n/a<br>15 MW Ocean Wave 5 MW (PV02)-2020 | ICE (17 MW)-Biodiesel (PS01)-n/a<br>100 MW SCCT - Biodiesel (PS07)-2020<br>30 MW Onshore Wind Cl 3 (PW01)-2018<br>10 MW Onshore Wind Cl 5 (PW03)-n/a<br>10 MW Onshore Wind Cl 7 (PW04)-n/a<br>100 MW Offshore Wind (PW05)-n/a<br>5 MW of 1 MW Tracking PV (PP03)-2015<br>50 MW Parabolic Trough PV (PP04)-n/a<br>9.6 MW OTEC (POT1)-n/a<br>15 MW Ocean Wave 5 MW (PV02)-2020 |
| *2014* | Continue CIDLC, CIDP, RDLCWH, RDLCAC | Continue CIDLC, CIDP, RDLCWH, RDLCAC | Continue CIDLC, CIDP, RDLCWH, RDLCAC |
| | 75%+25%+10% PBFA DSM | 75%+25%+10% PBFA DSM | 75%+25%+10% PBFA DSM |
| *2015* | | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) |
| *2016* | Fuel Switch to Diesel<br>(H8/9, Waiau 5-10/Kahe 1-6) | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) |
| *2017* | | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) |
| | Deactivate W3 (-46MW)<br>Deactivate W4 (-46MW)<br>or H8/9 | Deactivate W3 (-46MW)<br>Deactivate W4 (-46MW)<br>or H8/9 | Deactivate W3 (-46MW)<br>Deactivate W4 (-46MW)<br>or H8/9 |
| *2018* | | Add 60 MW Wind (PW01x2) | Add 60 MW Wind (PW01x2) |
| | | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) |
| *2019* | Add 95MW SCCT (PS08x1)-LNG | Add 60 MW Wind (PW01x2) | Add 60 MW Wind (PW01x2) |
| | | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) |
| | Deactivate H8 (-53MW)<br>Deactivate H9 (-54MW)<br>or W3/4 | Deactivate H8 (-53MW)<br>Deactivate H9 (-54MW)<br>or W3/4 | Deactivate H8 (-53MW)<br>Deactivate H9 (-54MW)<br>or W3/4 |
| *2020* | Convert to Biodiesel<br>(W9-10) | Cycle Kahe 1 - 4 | Cycle Kahe 1 - 4 |
| | | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) |
| | Add 25MW Banagrass (PA01x1) | Add 180 MW Wind (PW01x6) | Add 180 MW Wind (PW01x6) |
| | Add 118MW CC (PS12x2)-LNG | | |

| Name | P1B2a1xRetire-4Er1 | P1B2a1XRetire-2r2 | P1B2a1XRetire-2r2 AQC |
|---|---|---|---|
| *2021* | Add 190MW SCCT (PS08x2)-LNG | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) |
| | Deactivate K5 (-135MW) | | |
| *2022* | Add 190MW SCCT (PS08x2)-LNG | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) |
| | | | AQC Waiau 5-8 & Kahe 1-6 |
| | Deactivate K6 (-134MW) | | |
| *2023* | Add 59MW CC (PS12x1)-LNG | | |
| *2024* | | | |
| *2025* | | | |
| *2026* | | | |
| *2027* | | | |
| *2028* | | Add 60 MW Wind (PW01x2) | Add 60 MW Wind (PW01x2) |
| 2029 | | Add 60 MW Wind (PW01x2) | Add 60 MW Wind (PW01x2) |
| 2030 | | Add 60 MW Wind (PW01x2) | Add 60 MW Wind (PW01x2) |
| | | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) |
| *2031* | | | |
| *2032* | | Add 30 MW Wind (PW01x1) | Add 30 MW Wind (PW01x1) |
| | | Add 100 MW Wind (PW05x1) | Add 100 MW Wind (PW05x1) |
| *2033* | | Add 60 MW Wind (PW01x2) | Add 60 MW Wind (PW01x2) |
| | | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) |
| | | Add 100 MW Wind (PW05x1) | Add 100 MW Wind (PW05x1) |
| *Planning Period Total Cost* | 28, 971, 188 | 29, 078, 658 | 28, 827, 210 |
| *Study Period Total Cost* | 36, 109, 260 | 38, 170, 088 | 37, 763, 932 |
| *Planning Rank* | 6 | 7 | 5 |
| *Study Rank* | 5 | 7 | 6 |

Table O-14. HECO Energy Efficiency Portfolio Standard (1 of 2)

| **Name** | **P1_2a1XRetire-7Ar0** | **P1_2a1XRetire-7Br0** | **P1_2a1XRetire-7Cr0** | **P1_2a1XRetire-7Dr0** |
|---|---|---|---|---|
| *Plan* | 35% EEPS H89 W34 Ret (ICE, SCCT) | 75% EEPS H89 W34 Ret (ICE, SCCT) | 100% EEPS H89 W34 Ret (ICE, SCCT) | 110% EEPS H89 W34 Ret (ICE, SCCT) |
| *Notes* | NO TRANSACTIONS | 0% RPS (Wind, PV, Wave, Biomass, CT, ICE) | 0% RPS (Wind, PV, Wave, Biomass, CT, ICE) | NO TRANSACTIONS |
| *Reference* | P1_2a1XRetire-7Ar0.xlxs | P1_2a1XRetire-7Br0.xlxs | P1_2a1XRetire-7Cr0.xlxs | P1_2a1XRetire-7Dr0.xlxs |
| *2014* | Continue CIDLC, CIDP, RDLCWH, RDLCAC | Continue CIDLC, CIDP, RDLCWH, RDLCAC | Continue CIDLC, CIDP, RDLCWH, RDLCAC | Continue CIDLC, CIDP, RDLCWH, RDLCAC |
| | 25%+10% PBFA DSM | 75% PBFA DSM | 75% +25% PBFA DSM | 75%+25%+10% PBFA DSM |
| *2015* | | | | |
| *2016* | | | | |
| *2017* | Retire W3 (-46MW)<br>Retire W4 (-46MW)<br>or H8/9 | Retire W3 (-46MW)<br>Retire W4 (-46MW)<br>or H8/9 | | Retire W3 (-46MW)<br>Retire W4 (-46MW)<br>or H8/9 |
| *2018* | | | | |
| *2019* | Retire H8 (-53MW)<br>Retire H9 (-54MW)<br>or W3/4 | Retire H8 (-53MW)<br>Retire H9 (-54MW)<br>or W3/4 | Retire H8 (-53MW)<br>Retire H9 (-54MW)<br>or W3/4 | Retire H8 (-53MW)<br>Retire H9 (-54MW)<br>or W3/4 |
| *2020* | | | | |
| *2021* | | | | |
| *2022* | | | | |
| *2023* | | | | |
| *2024* | | | | |
| *2025* | | | | |
| *2026* | | | | |
| *2027* | | | | |
| *2028* | | | | |
| *2029* | | | | |
| *2030* | | | | |
| *2031* | | | | |
| *2032* | | | | |
| *2033* | | | | |
| *Strategist Planning Period Total Cost* | | | | |
| *Strategist Study Period Total Cost* | | | | |

| Name | P1_2a1XRetire-7Ar0 | P1_2a1XRetire-7Br0 | P1_2a1XRetire-7Cr0 | P1_2a1XRetire-7Dr0 |
|---|---|---|---|---|
| *Planning Period Total Cost* | 34, 867, 496 | 33, 857, 728 | 33, 346, 900 | 33, 168, 224 |
| *Study Period Total Cost* | 48, 905, 832 | 46, 799, 032 | 45, 833, 056 | 45, 522, 056 |
| *Planning Rank* | 4 | 3 | 2 | 1 |
| *Study Rank* | 4 | 3 | 2 | 1 |

Table O-15. HECO Energy Efficiency Portfolio Standard (2 of 2)

| **Name** | **P1_2a1XRetire-7Ar1** | **P1_2a1XRetire-7Br1** | **P1_2a1XRetire-7Cr1** | **P1_2a1XRetire-7Dr1** |
|---|---|---|---|---|
| *Plan* | 35% EEPS H89 W34 Ret (ICE, SCCT) | 75% EEPS H89 W34 Ret (ICE, SCCT) | 100% EEPS H89 W34 Ret (ICE, SCCT) | 110% EEPS H89 W34 Ret (ICE, SCCT) |
| *Notes* | With transactions | With transactions | With transactions | With transactions |
| *Reference* | P1_2a1XRetire-7Ar1.xlxs | P1_2a1XRetire-7Br1.xlxs | P1_2a1XRetire-7Cr1.xlxs | P1_2a1XRetire-7Dr1.xlxs |
| *2014* | Continue CIDLC, CIDP, RDLCWH, RDLCAC | Continue CIDLC, CIDP, RDLCWH, RDLCAC | Continue CIDLC, CIDP, RDLCWH, RDLCAC | Continue CIDLC, CIDP, RDLCWH, RDLCAC |
| | 25%+10% PBFA DSM | 75% PBFA DSM | 75% +25% PBFA DSM | 75%+25%+10% PBFA DSM |
| *2015* | | | | |
| *2016* | | | | |
| *2017* | Retire W3 (-46MW) Retire W4 (-46MW) or H8/9 | Retire W3 (-46MW) Retire W4 (-46MW) or H8/9 | Retire W3 (-46MW) Retire W4 (-46MW) or H8/9 | Retire W3 (-46MW) Retire W4 (-46MW) or H8/9 |
| *2018* | | | | |
| *2019* | Retire H8 (-53MW) Retire H9 (-54MW) or W3/4 | Retire H8 (-53MW) Retire H9 (-54MW) or W3/4 | Retire H8 (-53MW) Retire H9 (-54MW) or W3/4 | Retire H8 (-53MW) Retire H9 (-54MW) or W3/4 |
| *2020* | | | | |
| *2021* | | | | |
| *2022* | | | | |
| *2023* | | | | |
| *2024* | | | | |
| *2025* | | | | |
| *2026* | | | | |
| *2027* | | | | |
| *2028* | | | | |
| *2029* | | | | |
| *2030* | | | | |
| *2031* | | | | |
| *2032* | | | | |
| *2033* | | | | |
| *Strategist Planning Period Total Cost* | | | | |
| *Strategist Study Period Total Cost* | | | | |
| *Planning Period Total Cost* | 36, 535, 686 | 35, 720, 084 | 35, 341, 592 | 35, 216, 274 |

| Name | P1_2a1XRetire-7Ar1 | P1_2a1XRetire-7Br1 | P1_2a1XRetire-7Cr1 | P1_2a1XRetire-7Dr1 |
|---|---|---|---|---|
| *Study Period Total Cost* | 49, 930, 625 | 48, 322, 849 | 47, 690, 437 | 47, 508, 641 |
| *Planning Rank* | 4 | 3 | 2 | 1 |
| *Study Rank* | 4 | 3 | 2 | 1 |

Table O-16. HECO 100% Renewable Energy

| **Name** | **P1B2B1XRETIRE-3CR0** | **P1B2A1XRETIRE-3CR0** |
|---|---|---|
| *Plan* | 100% RE by 2030 (Wind, PV, Wave, Biomass, CT, ICE) | 100% RE by 2030 (Wind, PV, Wave, Biomass, CT, ICE) |
| *Reference* | P1B2b1xRetire-2r0 | |
| *2014* | Continue CIDLC, CIDP, RDLCWH, RDLCAC | Continue CIDLC, CIDP, RDLCWH, RDLCAC |
| | 75%+25%+10% PBFA DSM | 75%+25%+10% PBFA DSM |
| *2015* | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) |
| *2016* | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) |
| *2017* | | Add 20 MW PV (PP03x4) |
| | Deactivate W3 (-46MW)<br>Deactivate W4 (-46MW)<br>or H8/9 | Deactivate W3 (-46MW)<br>Deactivate W4 (-46MW)<br>or H8/9 |
| *2018* | | Add 20 MW PV (PP03x4) |
| *2019* | | Add 20 MW PV (PP03x4) |
| | Deactivate H8 (-53MW)<br>Deactivate H9 (-54MW)<br>or W3/4 | Deactivate H8 (-53MW)<br>Deactivate H9 (-54MW)<br>or W3/4 |
| *2020* | Add 200MW Lanai Wind | Add 210 MW Wind (PW01x7) |
| *2021* | | |
| *2022* | Fuel Switch to ULSD<br>(Waiau 5-10/Kahe 1-6) | Fuel Switch to ULSD<br>(Waiau 5-10/Kahe 1-6) |
| *2023* | | |
| *2024* | | |
| *2025* | | |
| *2026* | | |
| *2027* | | |
| *2028* | | |
| *2029* | | |
| *2030* | Fuel Switch to BF<br>(Waiau 5-10/Kahe 1-6) | Fuel Switch to BF<br>(Waiau 5-10/Kahe 1-6) |
| *2031* | | |
| *2032* | | |
| *2033* | | |
| *Strategist Planning Period Total Cost* | 31, 122, 360 | 30, 977, 058 |
| *Strategist Study Period Total Cost* | 37, 244, 976 | 37, 059, 876 |
| *Planning Period Total Cost* | 33, 799, 739 | 33, 654, 432 |

| **Name** | **P1B2B1XRETIRE-3CR0** | **P1B2A1XRETIRE-3CR0** |
|---|---|---|
| *Study Period Total Cost* | 39, 922, 353 | 39, 737, 253 |
| *Planning Rank* | 2 | 1 |
| *Study Rank* | 2 | 1 |

Table O-17. HECO 0% Renewable Portfolio Standard

| Name | P1B2B1XRETIRE-3AR00%RPS | P1B2A1XRETIRE-3AR00%RPSNOLANAI | P1B2A1XRETIRE-3AR0 0%RPSNOLANAI_LNG | P1B2b1xRetire-2r0 |
|---|---|---|---|---|
| *Plan* | 0% RPS (Wind, PV, Wave, Biomass, CT, ICE) | 0% RPS (Wind, PV, Wave, Biomass, CT, ICE) | 0% RPS (Wind, PV, Wave, Biomass, CT, ICE) | Screen (Wind, PV, Wave CT91) |
| *Notes* | Lanai Wind in 2020, Wind30, off-shore wind, PV5, & Wave15, CT91 avail, >20% curtail | No Lanai Wind, Wind30, off-shore wind, PV5, & Wave15, CT91 avail, >20% curtail | No Lanai Wind, Wind30, off-shore wind, PV5, & Wave15, CT91 avail | Add Lanai Wind. Wind30, off-shore wind, PV5, & Wave15, CT91 avail, >20% curtail |
| *Resources Available* | | | | |
| *Reference* | P1B2b1xRetire-2r0 | | | |
| *2014* | Continue CIDLC, CIDP, RDLCWH, RDLCAC | Continue CIDLC, CIDP, RDLCWH, RDLCAC | Continue CIDLC, CIDP, RDLCWH, RDLCAC | Continue CIDLC, CIDP, RDLCWH, RDLCAC |
| | 75%+25%+10% PBFA DSM | 75%+25%+10% PBFA DSM | 75%+25%+10% PBFA DSM | 75%+25%+10% PBFA DSM |
| *2015* | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) |
| *2016* | | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) |
| *2017* | | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) |
| | Deactivate W3 (-46MW) Deactivate W4 (-46MW) or H8/9 | Deactivate W3 (-46MW) Deactivate W4 (-46MW) or H8/9 | Deactivate W3 (-46MW) Deactivate W4 (-46MW) or H8/9 | Deactivate W3 (-46MW) Deactivate W4 (-46MW) or H8/9 |
| *2018* | | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) |
| *2019* | Deactivate H8 (-53MW) Deactivate H9 (-54MW) or W3/4 | Deactivate H8 (-53MW) Deactivate H9 (-54MW) or W3/4 | Deactivate H8 (-53MW) Deactivate H9 (-54MW) or W3/4 | Deactivate H8 (-53MW) Deactivate H9 (-54MW) or W3/4 |
| *2020* | Add 200MW Lanai Wind | | | Add 200MW Lanai Wind |
| *2021* | | | | |
| *2022* | | | | |
| *2023* | | | | |
| *2024* | | | | |
| *2025* | | | | Add 60 MW Wind (PW01x2) |
| *2026* | | | | Add 60 MW Wind (PW01x2) |
| *2027* | | | | Add 60 MW Wind (PW01x2) |
| *2028* | | | | Add 60 MW Wind (PW01x2) |
| | | | | Add 20 MW PV (PP03x4) |

| Name | P1B2B1XRETIRE-3AR00%RPS | P1B2A1XRETIRE-3AR00%RPSNOLANAI | P1B2A1XRETIRE-3AR00%RPSNOLANAI_LNG | P1B2b1xRetire-2r0 |
|---|---|---|---|---|
| *2029* | | | | Add 60 MW Wind (PW01x2)<br>Add 100 MW Wind (PW05x1)<br>Add 20 MW PV (PP03x4)<br>Add 15 MW Wave (PV02x1) |
| *2030* | | | | Add 60 MW Wind (PW01x2)<br>Add 100 MW Wind (PW05x1)<br>Add 20 MW PV (PP03x4)<br>Add 15 MW Wave (PV02x1) |
| *2031* | | | | Add 60 MW Wind (PW01x2)<br>Add 20 MW PV (PP03x4)<br>Add 15 MW Wave (PV02x1) |
| *2032* | | | | Add 30 MW Wind (PW01x1)<br>Add 20 MW PV (PP03x4)<br>Add 15 MW Wave (PV02x1) |
| *2033* | | | | Add 20 MW PV (PP03x4)<br>Add 15 MW Wave (PV02x1) |
| *Strategist Planning Period Total Cost* | 32, 584, 166 | 32, 336, 104 | 29, 213, 356 | 32, 684, 542 |
| *Strategist Study Period Total Cost* | 45, 142, 980 | 44, 678, 644 | 38, 881, 456 | 43, 650, 700 |
| *Planning Period Total Cost,* | 35, 261, 538 | 35, 013, 481 | 31, 890, 730 | 34, 767, 314 |
| *Study Period Total Cost* | 47, 820, 357 | 47, 356, 021 | 41, 558, 833 | 46, 328, 077 |
| *Planning Rank* | 4 | 3 | 1 | 2 |
| *Study Rank* | 4 | 3 | 1 | 2 |

Table O-18. HECO Alternative Plan Development (1 of 3)

| **Name** | **Self Generation** | | **P1B2a1NRetire-2r8** | **P1B2a1NRetire-2r9** | **P1B2a1NRetire-2r10** | **P1B2a1NRetire-2r8_NoLan** |
|---|---|---|---|---|---|---|
| *Plan* | Annual | Cumulative | ULSD; KPLP end; Cycle K1-4 | LNG; KPLP continue; Cycle K1-4 | Biofuel; KPLP end; Cycle K1-4 | ULSD; KPLP end; Cycle K1-4; No Lanai Wind |
| *Notes* | | | Deactivate H8/9 at end of 2014, cycle K1-4 in 2018 | Deactivate H8/9 at end of 2014, cycle K1-4 in 2018 | Deactivate H8/9 at end of 2014, cycle K1-4 in 2018 | Deactivate H8/9 at end of 2014, cycle K1-4 in 2018 |
| *Resources Available* | | | ICE (17 MW)-Biodiesel (PS01)-Fixed<br>Convert CT-1 to CC 57MW (STC1)-Fixed<br>30 MW Onshore Wind C3 (PW01)-2020<br>5 MW of 1 MW Track PV (PP03)-2020<br>200 MW Lanai Wind-Fixed | ICE (17 MW)-Biodiesel (PS01)-Fixed<br>Convert CT-1 to CC 57MW (STC1)-Fixed<br>30 MW Onshore Wind C3 (PW01)-2020<br>5 MW of 1 MW Track PV (PP03)-2020<br>200 MW Lanai Wind-Fixed | ICE (17 MW)-Biodiesel (PS01)-Fixed<br>Convert CT-1 to CC 57MW (STC1)-Fixed<br>30 MW Onshore Wind C3 (PW01)-2020<br>5 MW of 1 MW Track PV (PP03)-2020<br>200 MW Lanai Wind-Fixed | ICE (17 MW)-Biodiesel (PS01)-Fixed<br>Convert CT-1 to CC 57MW (STC1)-Fixed<br>30 MW Onshore Wind C3 (PW01)-2020<br>5 MW of 1 MW Track PV (PP03)-2020<br>200 MW Lanai Wind-n/a |
| *2014* | 64MW | 137MW | Expanded CIDLC, CIDP, RDLCWH, RDLCAC | Expanded CIDLC, CIDP, RDLCWH, RDLCAC | Expanded CIDLC, CIDP, RDLCWH, RDLCAC | Expanded CIDLC, CIDP, RDLCWH, RDLCAC |
| | | | 75%+25%+10% PBFA DSM | 75%+25%+10% PBFA DSM | 75%+25%+10% PBFA DSM | 75%+25%+10% PBFA DSM |
| | | | Deactivate H8 (- 53MW)<br>Deactivate H9 (- 54MW) | Deactivate H8 (- 53MW)<br>Deactivate H9 (- 54MW) | Deactivate H8 (- 53MW)<br>Deactivate H9 (- 54MW) | Deactivate H8 (- 53MW)<br>Deactivate H9 (- 54MW) |
| *2015* | 66MW | 203MW | Add 20 MW Wind (PWWRx2) | Add 20 MW Wind (PWWRx2) | Add 20 MW Wind (PWWRx2) | Add 20 MW Wind (PWWRx2) |
| | | | Add 40 MW PV (PPWRx8) | Add 40 MW PV (PPWRx8) | Add 40 MW PV (PPWRx8) | Add 40 MW PV (PPWRx8) |

| Name | Self Generation | | P1B2a1NRetire-2r8 | P1B2a1NRetire-2r9 | P1B2a1NRetire-2r10 | P1B2a1NRetire-2r8_NoLan |
|---|---|---|---|---|---|---|
| 2016 | 79MW | 281MW | Fuel Switch to Diesel (Waiau 5-8//Kahe 1-6) | Fuel Switch to Diesel (Waiau 5-8//Kahe 1-6) | Fuel Switch to Diesel (Waiau 5-8//Kahe 1-6) | Fuel Switch to Diesel (Waiau 5-8//Kahe 1-6) |
| | | | Fuel Switch to ULSD (CIP-1) | Fuel Switch to ULSD (CIP-1) | Fuel Switch to ULSD (CIP-1) | Fuel Switch to ULSD (CIP-1) |
| | | | Add 20 MW Wind (PWWRx2) | Add 20 MW Wind (PWWRx2) | Add 20 MW Wind (PWWRx2) | Add 20 MW Wind (PWWRx2) |
| | | | Add 80 MW PV (PPWRx16) | Add 80 MW PV (PPWRx16) | Add 80 MW PV (PPWRx16) | Add 80 MW PV (PPWRx16) |
| 2017 | 65MW | 347MW | Add 60 MW Wind (PW01x2) | Add 60 MW Wind (PW01x2) | Add 60 MW Wind (PW01x2) | Add 60 MW Wind (PW01x2) |
| | | | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) |
| | | | KPLP Contract Ends (- 208MW) | KPLP Contract Ends (- 208MW) | KPLP Contract Ends (- 208MW) | KPLP Contract Ends (- 208MW) |
| | | | Deactivate W3 (- 46MW) Deactivate W4 (- 46MW) | Deactivate W3 (- 46MW) Deactivate W4 (- 46MW) | Deactivate W3 (- 46MW) Deactivate W4 (- 46MW) | Deactivate W3 (- 46MW) Deactivate W4 (- 46MW) |
| 2018 | 65MW | 412MW | Convert CT-1 to CC +57MW (STC1)-ULSD | Convert CT-1 to CC +57MW (STC1)-ULSD | Convert CT-1 to CC +57MW (STC1)-ULSD | Convert CT-1 to CC +57MW (STC1)-ULSD |
| | | | Add 51 MW ICE (PS01x3)-Biofuel | Add 51 MW ICE (PS01x3)-Biofuel | Add 51 MW ICE (PS01x3)-Biofuel | Add 51 MW ICE (PS01x3)-Biofuel |
| | | | Cycle Kahe 1 - 4 | Cycle Kahe 1 - 4 | Cycle Kahe 1 - 4 | Cycle Kahe 1 - 4 |
| | | | Add 60 MW Wind (PW01x2) | Add 60 MW Wind (PW01x2) | Add 60 MW Wind (PW01x2) | Add 60 MW Wind (PW01x2) |
| | | | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) |
| 2019 | 65MW | 477MW | Add 60 MW Wind (PW01x2) | Add 60 MW Wind (PW01x2) | Add 60 MW Wind (PW01x2) | Add 60 MW Wind (PW01x2) |
| | | | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) |

| Name | Self Generation | | P1B2a1NRetire-2r8 | P1B2a1NRetire-2r9 | P1B2a1NRetire-2r10 | P1B2a1NRetire-2r8_NoLan |
|---|---|---|---|---|---|---|
| *2020* | 65MW | 541MW | | Fuel Switch to LNG (Waiau 5-10, Kahe 1-6, CIP CC-1) | Fuel Switch to Biofuels (Waiau 5-10, Kahe 1-6, CIP CC-1) | Add 60 MW Wind (PW01x2) |
| | | | Add 200MW Lanai Wind | Add 200MW Lanai Wind | Add 200MW Lanai Wind | Add 20 MW PV (PP03x4) |
| | | | Add 60 MW Wind (PW01x2) | Add 60 MW Wind (PW01x2) | | |
| *2021* | 65MW | 606MW | | | | Add 60 MW Wind (PW01x2) |
| | | | Add 60 MW Wind (PW01x2) | Add 60 MW Wind (PW01x2) | | Add 20 MW PV (PP03x4) |
| *2022* | 60MW | 666MW | Fuel Switch to ULSD (Waiau 5-10/Kahe 1-6) | | | Fuel Switch to ULSD (Waiau 5-10/Kahe 1-6) |
| | | | Add 60 MW Wind (PW01x2) | Add 60 MW Wind (PW01x2) | | Add 60 MW Wind (PW01x2) |
| *2023* | 51MW | 718MW | Add 60 MW Wind (PW01x2) | Add 60 MW Wind (PW01x2) | | Add 60 MW Wind (PW01x2) |
| *2024* | 45MW | 763MW | Add 60 MW Wind (PW01x2) | Add 60 MW Wind (PW01x2) | | Add 30 MW Wind (PW01x1) |
| *2025* | 39MW | 802MW | Add 60 MW Wind (PW01x2) | Add 60 MW Wind (PW01x2) | | |
| *2026* | 34MW | 835MW | Add 60 MW Wind (PW01x2) | Add 60 MW Wind (PW01x2) | | |
| *2027* | 30MW | 865MW | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) | | Add 30 MW Wind (PW01x1) |
| *2028* | 27MW | 892MW | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) | | Add 60 MW Wind (PW01x2) |
| *2029* | 25MW | 917MW | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) | | Add 60 MW Wind (PW01x2) |
| | | | | | | Add 20 MW PV (PP03x4) |

| Name | Self Generation | | P1B2a1NRetire-2r8 | P1B2a1NRetire-2r9 | P1B2a1NRetire-2r10 | P1B2a1NRetire-2r8_NoLan |
|---|---|---|---|---|---|---|
| *2030* | 24MW | 941MW | Add 60 MW Wind (PW01x2) | Add 60 MW Wind (PW01x2) | | Add 60 MW Wind (PW01x2) |
| | | | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) | | Add 20 MW PV (PP03x4) |
| *2031* | 23MW | 963MW | Add 60 MW Wind (PW01x2) | Add 60 MW Wind (PW01x2) | | Add 60 MW Wind (PW01x2) |
| | | | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) | | Add 20 MW PV (PP03x4) |
| *2032* | 22MW | 985MW | Add 60 MW Wind (PW01x2) | Add 60 MW Wind (PW01x2) | | Add 60 MW Wind (PW01x2) |
| | | | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) | | Add 20 MW PV (PP03x4) |
| *2033* | 21MW | 1007MW | Add 60 MW Wind (PW01x2) | Add 60 MW Wind (PW01x2) | | Add 60 MW Wind (PW01x2) |
| | | | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) | | Add 20 MW PV (PP03x4) |
| *Strategist Planning Period Total Cost* | | | 25, 486, 970 | 23, 994, 680 | 22, 532, 936 | 25, 811, 284 |
| *Strategist Study Period Total Cost* | | | 31, 415, 750 | 29, 299, 898 | 31, 415, 750 | 32, 348, 226 |
| *Planning Period Total Cost* | | | 28, 174, 986 | 26, 974, 807 | 25, 220, 955 | 28, 499, 302 |
| *Study Period Total Cost* | | | 34, 103, 769 | 32, 280, 026 | 34, 103, 769 | 35, 036, 245 |
| *Planning Rank* | | | 7 | 3 | 1 | 8 |
| *Study Rank* | | | 4 | 1 | 4 | 7 |

Table O-19. HECO Alternative Plan Development (2 of 3)

| **Name** | **Self Generation** | | **P1B2a1NRetire-2r8_NoCy** | **P1B2a1NRetire-2r8NoHRet** | **P1B2a1NRetire-2r8KPLP_C** | **P1B2a1NRetire-2r11** |
|---|---|---|---|---|---|---|
| *Plan* | Annual | Cumulative | ULSD; KPLP end; No Cycle of Kahe | ULSD; Hon & Waiau continue, KPLP end; Cycle K1-4 | ULSD; KPLP continue; Cycle K1-4 | LNG; KPLP continue; Cycle K1-4 |
| *Notes* | | | Deactivate H8/9 at end of 2014 | Cycle K1-4 in 2018 | Deactivate H8/9 at end of 2014, cycle K1-4 in 2018 | Deactivate H8/9 at end of 2014, cycle K1-4 in 2018 |
| *Resources Available* | | | ICE (17 MW)-Biodiesel (PS01)-Fixed<br>Convert CT-1 to CC 57MW (STC1)-Fixed<br>30 MW Onshore Wind C3 (PW01)-2020<br>5 MW of 1 MW Track PV (PP03)-2020<br>200 MW Lanai Wind-Fixed | ICE (17 MW)-Biodiesel (PS01)-n/a<br>Convert CT-1 to CC 57MW (STC1)-n/a<br>30 MW Onshore Wind C3 (PW01)-2020<br>5 MW of 1 MW Track PV (PP03)-2020<br>200 MW Lanai Wind-Fixed | ICE (17 MW)-Biodiesel (PS01)-n/a<br>Convert CT-1 to CC 57MW (STC1)-n/a<br>30 MW Onshore Wind C3 (PW01)-2020<br>5 MW of 1 MW Track PV (PP03)-2020<br>200 MW Lanai Wind-Fixed | ICE (17 MW)-Biodiesel (PS01)-Fixed<br>Convert CT-1 to CC 57MW (STC1)-Fixed<br>Battery (15 MWH) - Fixed<br>30 MW Onshore Wind C3 (PW01)-2020<br>5 MW of 1 MW Track PV (PP03)-2020<br>200 MW Lanai Wind-n/a |
| *2014* | 64MW | 137MW | Expanded CIDLC, CIDP, RDLCWH, RDLCAC | Expanded CIDLC, CIDP, RDLCWH, RDLCAC | Expanded CIDLC, CIDP, RDLCWH, RDLCAC | Expanded CIDLC, CIDP, RDLCWH, RDLCAC |
| | | | 75%+25%+10% PBFA DSM | 75%+25%+10% PBFA DSM | 75%+25%+10% PBFA DSM | 75%+25%+10% PBFA DSM |
| | | | Deactivate H8 (- 53MW)<br>Deactivate H9 (- 54MW) | | Deactivate H8 (-53MW)<br>Deactivate H9 (-54MW) | Deactivate H8 (-53MW)<br>Deactivate H9 (-54MW) |
| *2015* | 66MW | 203MW | Add 20 MW Wind (PWWRx2) | Add 20 MW Wind (PWWRx2) | Add 20 MW Wind (PWWRx2) | Add 20 MW Wind (PWWRx2) |
| | | | Add 40 MW PV (PPWRx8) | Add 40 MW PV (PPWRx8) | Add 40 MW PV (PPWRx8) | Add 40 MW PV (PPWRx8) |
| *2016* | 79MW | 281MW | Fuel Switch to Diesel (Waiau 5-8//Kahe 1-6) | Fuel Switch to Diesel (Waiau 5-8//Kahe 1-6) | Fuel Switch to Diesel (Waiau 5-8//Kahe 1-6) | Fuel Switch to Diesel (Waiau 5-8//Kahe 1-6) |
| | | | Fuel Switch to ULSD (CIP-1) | Fuel Switch to ULSD (CIP-1) | Fuel Switch to ULSD (CIP-1) | Fuel Switch to ULSD (CIP-1) |
| | | | Add 20 MW Wind (PWWRx2) | Add 20 MW Wind (PWWRx2) | Add 20 MW Wind (PWWRx2) | Add 20 MW Wind (PWWRx2) |
| | | | Add 80 MW PV (PPWRx16) | Add 80 MW PV (PPWRx16) | Add 80 MW PV (PPWRx16) | Add 80 MW PV (PPWRx16) |

| Name | Self Generation | | P1B2a1NRetire-2r8_NoCy | P1B2a1NRetire-2r8NoHRet | P1B2a1NRetire-2r8KPLP_C | P1B2a1NRetire-2r11 |
|---|---|---|---|---|---|---|
| *2017* | 65MW | 347MW | Add 60 MW Wind (PW01x2) | Add 60 MW Wind (PW01x2) | Add 60 MW Wind (PW01x2) | Add 60 MW Wind (PW01x2) |
| | | | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) |
| | | | KPLP Contract Ends (- 208MW) | KPLP Contract Ends (- 208MW) | | Add 51 MW ICE (PS01x3)-Biofuel |
| | | | Deactivate W3 (- 46MW) Deactivate W4 (- 46MW) | | Deactivate W3 (-46MW) Deactivate W4 (-46MW) | Deactivate W3 (-46MW) Deactivate W4 (-46MW) |
| *2018* | 65MW | 412MW | Convert CT-1 to CC +57MW (STC1)-ULSD | | | Convert CT-1 to CC +57MW (STC1)-ULSD |
| | | | Add 51 MW ICE (PS01x3)-Biofuel | | | Add 15 MWH Battery (PB01x1) |
| | | | | Cycle Kahe 1 - 4 | Cycle Kahe 1 - 4 | Cycle Kahe 1 - 4 |
| | | | Add 60 MW Wind (PW01x2) | Add 60 MW Wind (PW01x2) | Add 60 MW Wind (PW01x2) | Add 60 MW Wind (PW01x2) |
| | | | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) |
| *2019* | 65MW | 477MW | Add 60 MW Wind (PW01x2) | Add 60 MW Wind (PW01x2) | Add 60 MW Wind (PW01x2) | Add 60 MW Wind (PW01x2) |
| | | | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) |
| *2020* | 65MW | 541MW | | Add 60 MW Wind (PW01x2) | | Fuel Switch to LNG (Waiau 5-8, Kahe 1-6, CIP CC-1, Kalaeloa) |
| | | | Add 200MW Lanai Wind | Add 200MW Lanai Wind | Add 200MW Lanai Wind | |
| | | | Add 60 MW Wind (PW01x2) | Add 20 MW PV (PP03x4) | Add 60 MW Wind (PW01x2) | |
| *2021* | 65MW | 606MW | Add 60 MW Wind (PW01x2) | Add 60 MW Wind (PW01x2) | Add 60 MW Wind (PW01x2) | |
| *2022* | 60MW | 666MW | Fuel Switch to ULSD (Waiau 5-10/Kahe 1-6) | Fuel Switch to ULSD (Waiau 5-10/Kahe 1-6) | Fuel Switch to ULSD (Waiau 5-10/Kahe 1-6) | |
| | | | Add 60 MW Wind (PW01x2) | Add 60 MW Wind (PW01x2) | Add 60 MW Wind (PW01x2) | |

| Name | Self Generation | | P1B2a1NRetire-2r8_NoCy | P1B2a1NRetire-2r8NoHRet | P1B2a1NRetire-2r8KPLP_C | P1B2a1NRetire-2r11 |
|---|---|---|---|---|---|---|
| *2023* | 51MW | 718MW | Add 60 MW Wind (PW01x2) | Add 60 MW Wind (PW01x2) | Add 60 MW Wind (PW01x2) | |
| *2024* | 45MW | 763MW | Add 60 MW Wind (PW01x2) | Add 60 MW Wind (PW01x2) | Add 60 MW Wind (PW01x2) | |
| *2025* | 39MW | 802MW | Add 60 MW Wind (PW01x2) | Add 60 MW Wind (PW01x2) | Add 60 MW Wind (PW01x2) | |
| | | | Add 20 MW PV (PP03x4) | | Add 20 MW PV (PP03x4) | |
| *2026* | 34MW | 835MW | Add 60 MW Wind (PW01x2) | Add 60 MW Wind (PW01x2) | Add 60 MW Wind (PW01x2) | |
| | | | Add 20 MW PV (PP03x4) | | Add 20 MW PV (PP03x4) | |
| *2027* | 30MW | 865MW | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) | |
| *2028* | 27MW | 892MW | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) | |
| *2029* | 25MW | 917MW | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) | |
| *2030* | 24MW | 941MW | Add 60 MW Wind (PW01x2) | Add 60 MW Wind (PW01x2) | Add 60 MW Wind (PW01x2) | |
| | | | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) | |
| *2031* | 23MW | 963MW | Add 60 MW Wind (PW01x2) | Add 60 MW Wind (PW01x2) | Add 60 MW Wind (PW01x2) | |
| | | | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) | |
| *2032* | 22MW | 985MW | Add 60 MW Wind (PW01x2) | Add 60 MW Wind (PW01x2) | Add 60 MW Wind (PW01x2) | |
| | | | | Add 20 MW PV (PP03x4) | | |
| *2033* | 21MW | 1007MW | Add 60 MW Wind (PW01x2) | Add 60 MW Wind (PW01x2) | Add 60 MW Wind (PW01x2) | |
| *Strategist Planning Period Total Cost* | | | 29, 027, 158 | 25, 420, 932 | 27, 659, 260 | 25, 845, 808 |
| *Strategist Study Period Total Cost* | | | 36, 250, 068 | 31, 271, 696 | 34, 463, 292 | 33, 343, 386 |

| Name | Self Generation | | P1B2a1NRetire-2r8_NoCy | P1B2a1NRetire-2r8NoHRet | P1B2a1NRetire-2r8KPLP_C | P1B2a1NRetire-2r11 |
|---|---|---|---|---|---|---|
| *Planning Period Total Cost* | | | 31, 715, 172 | 28, 070, 693 | 30, 347, 280 | 27, 394, 017 |
| *Study Period Total Cost* | | | 38, 938, 087 | 33, 921, 456 | 37, 151, 311 | 34, 891, 595 |
| *Planning Rank* | | | 11 | 6 | 10 | 2 |
| *Study Rank* | | | 10 | 3 | 9 | 2 |

Table O-20. HECO Alternative Plan Development (3 of 3)

| **Name** | **Self Generation** | | **P1B2a1NRetire-2r12** | **P1B2a1NRetire-2r13** | **P1B2a1NRetire-2r14** |
|---|---|---|---|---|---|
| *Plan* | Annual | Cumulative | ULSD; KPLP continue; Cycle K1-4 | LNG; KPLP continue; Cycle K1-4; Lanai Wind | LNG; KPLP continue; Cycle K1-4; Lanai Wind |
| *Notes* | | | Deactivate H8/9 at end of 2014, cycle K1-4 in 2018 | Deactivate H8/9 at end of 2014, cycle K1-4 in 2018 | Deactivate H8/9 at end of 2014, cycle K1-4 in 2018 |
| *Resources Available* | | | ICE (17 MW)-Biodiesel (PS01)-Fixed<br>Convert CT-1 to CC 57MW (STC1)-Fixed<br>Battery (15 MWH) - Fixed<br>30 MW Onshore Wind C3 (PW01)-2020<br>5 MW of 1 MW Track PV (PP03)-2020<br>200 MW Lanai Wind-n/a | ICE (17 MW)-Biodiesel (PS01)-Fixed<br>Convert CT-1 to CC 57MW (STC1)-Fixed<br>Battery (15 MWH) - Fixed<br>30 MW Onshore Wind C3 (PW01)-2020<br>5 MW of 1 MW Track PV (PP03)-2020<br>200 MW Lanai Wind-n/a | ICE (17 MW)-Biodiesel (PS01)-Fixed<br>Convert CT-1 to CC 57MW (STC1)-Fixed<br>Battery (15 MWH) - Fixed<br>30 MW Onshore Wind C3 (PW01)-2020<br>5 MW of 1 MW Track PV (PP03)-2020<br>200 MW Lanai Wind-n/a |
| *2014* | 64MW | 137MW | Expanded CIDLC, CIDP, RDLCWH, RDLCAC | Expanded CIDLC, CIDP, RDLCWH, RDLCAC | Expanded CIDLC, CIDP, RDLCWH, RDLCAC |
| | | | 75%+25%+10% PBFA DSM | 75%+25%+10% PBFA DSM | 75%+25%+10% PBFA DSM |
| | | | Deactivate H8 (-53MW)<br>Deactivate H9 (-54MW) | Deactivate H8 (-53MW)<br>Deactivate H9 (-54MW) | Deactivate H8 (-53MW)<br>Deactivate H9 (-54MW) |
| *2015* | 66MW | 203MW | Add 20 MW Wind (PWWRx2) | Add 20 MW Wind (PWWRx2) | Add 20 MW Wind (PWWRx2) |
| | | | Add 40 MW PV (PPWRx8) | Add 40 MW PV (PPWRx8) | Add 40 MW PV (PPWRx8) |
| *2016* | 79MW | 281MW | Fuel Switch to Diesel (Waiau 5-8//Kahe 1-6) | Fuel Switch to Diesel (Waiau 5-8//Kahe 1-6) | Fuel Switch to Diesel (Waiau 5-8//Kahe 1-6) |
| | | | Fuel Switch to ULSD (CIP-1) | Fuel Switch to ULSD (CIP-1) | Fuel Switch to ULSD (CIP-1) |
| | | | Add 20 MW Wind (PWWRx2) | Add 20 MW Wind (PWWRx2) | Add 20 MW Wind (PWWRx2) |
| | | | Add 80 MW PV (PPWRx16) | Add 80 MW PV (PPWRx16) | Add 80 MW PV (PPWRx16) |
| *2017* | 65MW | 347MW | Add 60 MW Wind (PW01x2) | Add 60 MW Wind (PW01x2) | Add 60 MW Wind (PW01x2) |
| | | | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) |
| | | | Add 51 MW ICE (PS01x3)-Biofuel | Add 51 MW ICE (PS01x3)-Biofuel | Add 51 MW ICE (PS01x3)-Biofuel |
| | | | Deactivate W3 (-46MW)<br>Deactivate W4 (-46MW) | Deactivate W3 (-46MW)<br>Deactivate W4 (-46MW) | KPLP Contract Ends (-208MW) |

| Name | Self Generation | | P1B2a1NRetire-2r12 | P1B2a1NRetire-2r13 | P1B2a1NRetire-2r14 |
|---|---|---|---|---|---|
| *2018* | 65MW | 412MW | Convert CT-1 to CC +57MW (STC1)-ULSD | Convert CT-1 to CC +57MW (STC1)-ULSD | Convert CT-1 to CC +57MW (STC1)-ULSD |
| | | | Add 15 MWH Battery (PB01x1) | Add 15 MWH Battery (PB01x1) | Add 15 MWH Battery (PB01x1) |
| | | | | | Fuel Switch to Kahe 3 to Biocrude Blend |
| | | | Cycle Kahe 1 - 4 | Cycle Kahe 1 - 4 | Cycle Kahe 1 - 4 |
| | | | Add 60 MW Wind (PW01x2) | Add 60 MW Wind (PW01x2) | Add 60 MW Wind (PW01x2) |
| | | | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) |
| *2019* | 65MW | 477MW | | | Deactivate W3 (-46MW)<br>Deactivate W4 (-46MW) |
| | | | Add 60 MW Wind (PW01x2) | Add 60 MW Wind (PW01x2) | Add 60 MW Wind (PW01x2) |
| | | | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) |
| *2020* | 65MW | 541MW | | Fuel Switch to LNG (Waiau 5-8,<br>Kahe 1-6, CIP CC-1, Kalaeloa) | Add 285MW SCCT (PS08x3)-LNG |
| | | | | | Add 42MW SCCT (PS10x1)-LNG |
| | | | | Add 200MW Lanai Wind | Retire W5 (-55MW)<br>Retire W6 (-56MW)<br>Retire W7 (-88MW)<br>Retire W8 (-88MW)<br>Retire K1 (-88MW)<br>Retire K2 (-86MW)<br>Retire K3 (-88MW)<br>Retire K4 (-89MW) |
| | | | | | Add 60 MW Wind (PW01x2) |
| | | | | | Add 20 MW PV (PP03x4) |
| *2021* | 65MW | 606MW | | | Add 177MW CC (PS12x3)-LNG |
| | | | | | Retire K5 (-135MW) |
| | | | | | Add 60 MW Wind (PW01x2) |
| | | | | | Add 20 MW PV (PP03x4) |
| *2022* | 60MW | 666MW | Fuel Switch to ULSD (Waiau 5-10/Kahe 1-6) | | Add 95MW SCCT (PS08x1)-LNG |
| | | | | | Retire K6 (-134MW) |
| | | | | | Add 60 MW Wind (PW01x2) |
| | | | | | Add 20 MW PV (PP03x4) |
| *2023* | 51MW | 718MW | | | Add 60 MW Wind (PW01x2) |
| | | | | | Add 59MW CC (PS12x1)-LNG |

| **Name** | **Self Generation** | | **P1B2a1NRetire-2r12** | **P1B2a1NRetire-2r13** | **P1B2a1NRetire-2r14** |
|---|---|---|---|---|---|
| *2024* | 45MW | 763MW | | | Add 60 MW Wind (PW01x2) |
| *2025* | 39MW | 802MW | | | Add 60 MW Wind (PW01x2) |
| *2026* | 34MW | 835MW | | | Add 60 MW Wind (PW01x2) |
| *2027* | 30MW | 865MW | | | |
| *2028* | 27MW | 892MW | | | |
| *2029* | 25MW | 917MW | | | |
| *2030* | 24MW | 941MW | | | Add 60 MW Wind (PW01x2) |
| *2031* | 23MW | 963MW | | | Add 60 MW Wind (PW01x2) |
| *2032* | 22MW | 985MW | | | Add 60 MW Wind (PW01x2) |
| *2033* | 21MW | 1007MW | | | Add 60 MW Wind (PW01x2) |
| *Strategist Planning Period Total Cost* | | | 28, 511, 744 | 26, 278, 714 | 26, 082, 882 |
| *Strategist Study Period Total Cost* | | | 38, 282, 500 | 34, 077, 944 | 32, 193, 226 |
| *Planning Period Total Cost* | | | 29, 767, 842 | 27, 826, 921 | 25, 291, 589 |
| *Study Period Total Cost* | | | 39, 538, 600 | 35, 626, 153 | 33, 238, 826 |
| *Planning Rank* | | | 4 | 3 | 1 |
| *Study Rank* | | | 4 | 3 | 1 |

Table O-21. HECO Preferred Plans

| **Name** | **Self Generation** | | **P1B2a1NRetire-2r11** | **P1B2a1NRetire-2r12** | **P1B2a1NRetire-2r13** | **P1B2a1NRetire-2r14** |
|---|---|---|---|---|---|---|
| *Plan* | Annual | Cumulative | LNG; KPLP continue; Cycle K1-4 | ULSD; KPLP continue; Cycle K1-4 | LNG; KPLP continue; Cycle K1-4; Lanai Wind | LNG; KPLP continue; Cycle K1-4; Lanai Wind |
| *Notes* | | | Deactivate H8/9 at end of 2014, cycle K1-4 in 2018 | Deactivate H8/9 at end of 2014, cycle K1-4 in 2018 | Deactivate H8/9 at end of 2014, cycle K1-4 in 2018 | Deactivate H8/9 at end of 2014, cycle K1-4 in 2018 |
| *Resources Available* | | | ICE (17 MW)-Biodiesel (PS01)-Fixed<br>Convert CT-1 to CC 57MW (STC1)-Fixed<br>Battery (15 MWH) - Fixed<br>30 MW Onshore Wind C3 (PW01)-2020<br>5 MW of 1 MW Track PV (PP03)-2020<br>200 MW Lanai Wind-n/a | ICE (17 MW)-Biodiesel (PS01)-Fixed<br>Convert CT-1 to CC 57MW (STC1)-Fixed<br>Battery (15 MWH) - Fixed<br>30 MW Onshore Wind C3 (PW01)-2020<br>5 MW of 1 MW Track PV (PP03)-2020<br>200 MW Lanai Wind-n/a | ICE (17 MW)-Biodiesel (PS01)-Fixed<br>Convert CT-1 to CC 57MW (STC1)-Fixed<br>Battery (15 MWH) - Fixed<br>30 MW Onshore Wind C3 (PW01)-2020<br>5 MW of 1 MW Track PV (PP03)-2020<br>200 MW Lanai Wind-n/a | ICE (17 MW)-Biodiesel (PS01)-Fixed<br>Convert CT-1 to CC 57MW (STC1)-Fixed<br>Battery (15 MWH) - Fixed<br>30 MW Onshore Wind C3 (PW01)-2020<br>5 MW of 1 MW Track PV (PP03)-2020<br>200 MW Lanai Wind-n/a |
| *2014* | 64MW | 137MW | Expanded CIDLC, CIDP, RDLCWH, RDLCAC | Expanded CIDLC, CIDP, RDLCWH, RDLCAC | Expanded CIDLC, CIDP, RDLCWH, RDLCAC | Expanded CIDLC, CIDP, RDLCWH, RDLCAC |
| | | | 75%+25%+10% PBFA DSM | 75%+25%+10% PBFA DSM | 75%+25%+10% PBFA DSM | 75%+25%+10% PBFA DSM |
| | | | Deactivate H8 (- 53MW)<br>Deactivate H9 (- 54MW) | Deactivate H8 (- 53MW)<br>Deactivate H9 (- 54MW) | Deactivate H8 (- 53MW)<br>Deactivate H9 (- 54MW) | Deactivate H8 (- 53MW)<br>Deactivate H9 (- 54MW) |
| *2015* | 66MW | 203MW | Add 20 MW Wind (PWWRx2) | Add 20 MW Wind (PWWRx2) | Add 20 MW Wind (PWWRx2) | Add 20 MW Wind (PWWRx2) |
| | | | Add 40 MW PV (PPWRx8) | Add 40 MW PV (PPWRx8) | Add 40 MW PV (PPWRx8) | Add 40 MW PV (PPWRx8) |
| *2016* | 79MW | 281MW | Fuel Switch to Diesel (Waiau 5-8//Kahe 1-6) | Fuel Switch to Diesel (Waiau 5-8//Kahe 1-6) | Fuel Switch to Diesel (Waiau 5-8//Kahe 1-6) | Fuel Switch to Diesel (Waiau 5-8//Kahe 1-6) |
| | | | Fuel Switch to ULSD (CIP-1) | Fuel Switch to ULSD (CIP-1) | Fuel Switch to ULSD (CIP-1) | Fuel Switch to ULSD (CIP-1) |
| | | | Add 20 MW Wind (PWWRx2) | Add 20 MW Wind (PWWRx2) | Add 20 MW Wind (PWWRx2) | Add 20 MW Wind (PWWRx2) |
| | | | Add 80 MW PV (PPWRx16) | Add 80 MW PV (PPWRx16) | Add 80 MW PV (PPWRx16) | Add 80 MW PV (PPWRx16) |

| Name | Self Generation | | P1B2a1NRetire-2r11 | P1B2a1NRetire-2r12 | P1B2a1NRetire-2r13 | P1B2a1NRetire-2r14 |
|---|---|---|---|---|---|---|
| *2017* | 65MW | 347MW | Add 60 MW Wind (PW01x2) | Add 60 MW Wind (PW01x2) | Add 60 MW Wind (PW01x2) | Add 60 MW Wind (PW01x2) |
| | | | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) |
| | | | Add 51 MW ICE (PS01x3)-Biofuel | Add 51 MW ICE (PS01x3)-Biofuel | Add 51 MW ICE (PS01x3)-Biofuel | Add 51 MW ICE (PS01x3)-Biofuel |
| | | | Deactivate W3 (- 46MW) Deactivate W4 (- 46MW) | Deactivate W3 (- 46MW) Deactivate W4 (- 46MW) | Deactivate W3 (- 46MW) Deactivate W4 (- 46MW) | KPLP Contract Ends (- 208MW) |
| *2018* | 65MW | 412MW | Convert CT-1 to CC +57MW (STC1)-ULSD | Convert CT-1 to CC +57MW (STC1)-ULSD | Convert CT-1 to CC +57MW (STC1)-ULSD | Convert CT-1 to CC +57MW (STC1)-ULSD |
| | | | Add 15 MWH Battery (PB01x1) | Add 15 MWH Battery (PB01x1) | Add 15 MWH Battery (PB01x1) | Add 15 MWH Battery (PB01x1) |
| | | | | | | Fuel Switch to Kahe 3 to Biocrude Blend |
| | | | Cycle Kahe 1 - 4 | Cycle Kahe 1 - 4 | Cycle Kahe 1 - 4 | Cycle Kahe 1 - 4 |
| | | | Add 60 MW Wind (PW01x2) | Add 60 MW Wind (PW01x2) | Add 60 MW Wind (PW01x2) | Add 60 MW Wind (PW01x2) |
| | | | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) |
| *2019* | 65MW | 477MW | | | | Deactivate W3 (- 46MW) Deactivate W4 (- 46MW) |
| | | | Add 60 MW Wind (PW01x2) | Add 60 MW Wind (PW01x2) | Add 60 MW Wind (PW01x2) | Add 60 MW Wind (PW01x2) |
| | | | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) |

| Name | Self Generation | | P1B2a1NRetire-2r11 | P1B2a1NRetire-2r12 | P1B2a1NRetire-2r13 | P1B2a1NRetire-2r14 |
|---|---|---|---|---|---|---|
| *2020* | 65MW | 541MW | Fuel Switch to LNG (Waiau 5-8, Kahe 1-6, CIP CC-1, Kalaeloa) | Add 60 MW Wind (PW01x2) | Fuel Switch to LNG (Waiau 5-8, Kahe 1-6, CIP CC-1, Kalaeloa)<br>Add 200MW Lanai Wind | Add 285MW SCCT (PS08x3)-LNG<br>Add 42MW SCCT (PS10x1)-LNG<br>Retire W5 (-55MW)<br>Retire W6 (-56MW)<br>Retire W7 (-88MW)<br>Retire W8 (-88MW)<br>Retire K1 (-88MW)<br>Retire K2 (-86MW)<br>Retire K3 (-88MW)<br>Retire K4 (-89MW)<br>Add 60 MW Wind (PW01x2)<br>Add 20 MW PV (PP03x4) |
| *2021* | 65MW | 606MW | | Add 60 MW Wind (PW01x2) | | Add 177MW CC (PS12x3)-LNG<br>Retire K5 (-135MW)<br>Add 60 MW Wind (PW01x2)<br>Add 20 MW PV (PP03x4) |
| *2022* | 60MW | 666MW | | Fuel Switch to ULSD (Waiau 5-10/Kahe 1-6) | | Add 95MW SCCT (PS08x1)-LNG<br>Retire K6 (-134MW)<br>Add 60 MW Wind (PW01x2)<br>Add 20 MW PV (PP03x4) |
| *2023* | 51MW | 718MW | | | | Add 60 MW Wind (PW01x2)<br>Add 59MW CC (PS12x1)-LNG |
| *2024* | 45MW | 763MW | | | | Add 60 MW Wind (PW01x2) |
| 2025 | 39MW | 802MW | | Add 60 MW Wind (PW01x2) | | Add 60 MW Wind (PW01x2) |

| **Name** | **Self Generation** | | **P1B2a1NRetire-2r11** | **P1B2a1NRetire-2r12** | **P1B2a1NRetire-2r13** | **P1B2a1NRetire-2r14** |
|---|---|---|---|---|---|---|
| *2026* | 34MW | 835MW | | Add 60 MW Wind (PW01x2) | | Add 60 MW Wind (PW01x2) |
| *2027* | 30MW | 865MW | | Add 60 MW Wind (PW01x2)<br>Add 20 MW PV (PP03x4) | | |
| *2028* | 27MW | 892MW | | Add 60 MW Wind (PW01x2)<br>Add 20 MW PV (PP03x4) | | |
| *2029* | 25MW | 917MW | | Add 60 MW Wind (PW01x2)<br>Add 20 MW PV (PP03x4) | | |
| *2030* | 24MW | 941MW | | Add 60 MW Wind (PW01x2)<br>Add 20 MW PV (PP03x4) | | Add 60 MW Wind (PW01x2) |
| *2031* | 23MW | 963MW | | Add 60 MW Wind (PW01x2)<br>Add 20 MW PV (PP03x4) | | Add 60 MW Wind (PW01x2) |
| *2032* | 22MW | 985MW | | Add 60 MW Wind (PW01x2)<br>Add 20 MW PV (PP03x4) | | Add 60 MW Wind (PW01x2) |
| *2033* | 21MW | 1007MW | | Add 60 MW Wind (PW01x2)<br>Add 20 MW PV (PP03x4) | | Add 60 MW Wind (PW01x2) |
| *Strategist Planning Period Total Cost* | | | 25, 845, 808 | 28, 466, 722 | 26, 278, 714 | 26, 082, 882 |
| *Strategist Study Period Total Cost* | | | 33, 343, 386 | 36, 562, 072 | 34, 077, 944 | 32, 193, 226 |
| *Planning Period Total Cost* | | | 27, 394, 017 | 29, 767, 842 | 27, 826, 921 | 25, 291, 589 |
| *Study Period Total Cost* | | | 34, 891, 595 | 39, 538, 600 | 35, 626, 153 | 33, 238, 826 |

| **Name** | **Self Generation** | | **P1B2a1NRetire-2r11** | **P1B2a1NRetire-2r12** | **P1B2a1NRetire-2r13** | **P1B2a1NRetire-2r14** |
|---|---|---|---|---|---|---|
| *Planning Rank* | | | 2 | 4 | 3 | 1 |
| *Study Rank* | | | 2 | 4 | 3 | 1 |

## Stuck in the Middle

Table O-22. HECO Timing Run 1 (1 of 3)

| **Name** | **Self Generation** | | **P2_2a1XRetire-1r0** | **P2_2a1XRetire-1r1** | **P2_2a1XRetire-1r2** | **P2_2a1NRetire-1r0** |
|---|---|---|---|---|---|---|
| *Plan* | Annual | Cumulative | Timing w H89 W34 Ret (ICE, SSCT) | Timing, (SCCT, OTEC, Biomass, CC) | Timing, 2017 ICE, (OTEC, Biomass, CC) | Timing w H89 W34 Ret (ICE, SSCT) |
| *Notes* | | | | | | |
| *Resources Available* | | | | | | |
| *2014* | 35MW | 75MW | Continue CIDLC, CIDP, RDLCWH, RDLCAC | Continue CIDLC, CIDP, RDLCWH, RDLCAC | Continue CIDLC, CIDP, RDLCWH, RDLCAC | Expanded CIDLC, CIDP, RDLCWH, RDLCAC |
| | | | 75% PBFA DSM | 75% PBFA DSM | 75% PBFA DSM | 75% PBFA DSM |
| *2015* | 36MW | 111MW | | | | |
| *2016* | 43MW | 154MW | Fuel Switch to Diesel (H8/9, Waiau 5-10/Kahe 1-6) | Fuel Switch to Diesel (H8/9, Waiau 5-10/Kahe 1-6) | Fuel Switch to Diesel (H8/9, Waiau 5-10/Kahe 1-6) | Fuel Switch to Diesel (H8/9, Waiau 5-10/Kahe 1-6) |
| *2017* | 36MW | 189MW | | | Add 51MW ICE (PS01x3)-Biofueled | |
| | | | Deactivate W3 (-46MW) Deactivate W4 (-46MW) or H8/9 | Deactivate W3 (-46MW) Deactivate W4 (-46MW) or H8/9 | Deactivate W3 (-46MW) Deactivate W4 (-46MW) or H8/9 | Deactivate W3 (-46MW) Deactivate W4 (-46MW) or H8/9 |
| *2018* | 36MW | 225MW | | | | |
| *2019* | 35MW | 260MW | Deactivate H8 (-53MW) Deactivate H9 (-54MW) or W3/4 | Deactivate H8 (-53MW) Deactivate H9 (-54MW) or W3/4 | Deactivate H8 (-53MW) Deactivate H9 (-54MW) or W3/4 | Deactivate H8 (-53MW) Deactivate H9 (-54MW) or W3/4 |
| *2020* | 35MW | 295MW | Add 91MW SCCT (PS07x1)-Biofueled | Add 91MW SCCT (PS07x1)-Biofueled | Add 91MW SCCT (PS07x1)-Biofueled | Add 91MW SCCT (PS07x1)-Biofueled |
| *2021* | 35MW | 331MW | Add 91MW SCCT (PS07x1)-Biofueled | Add 25MW (PA01x1)-Biomass | | |
| *2022* | 28MW | 363MW | | Add 59MW CC (PC08x1)-Biofueled | | |
| *2023* | 28MW | 391MW | | | | |
| *2024* | 25MW | 416MW | | | | |
| *2025* | 21MW | 437MW | | | | |
| *2026* | 18MW | 456MW | | | | |
| *2027* | 16MW | 472MW | | | Add 25MW (PA01x1)-Biomass | |
| *2028* | 15MW | 486MW | | | | |
| *2029* | 14MW | 500MW | | | | |

| Name | Self Generation | | P2_2a1XRetire-1r0 | P2_2a1XRetire-1r1 | P2_2a1XRetire-1r2 | P2_2a1NRetire-1r0 |
|---|---|---|---|---|---|---|
| *2030* | 13MW | 513MW | | | | |
| *2031* | 12MW | 525MW | | | | |
| *2032* | 12MW | 538MW | | | | |
| *2033* | 12MW | 549MW | | | | |
| *Planning Period Total Cost* | | | 22, 786, 490 | 22, 809, 202 | 22, 885, 620 | 22, 685, 522 |
| *Study Period Total Cost* | | | 34, 706, 916 | 34, 605, 832 | 34, 759, 692 | 34, 647, 932 |
| *Planning Rank* | | | 1 | 3 | 3 | 1 |
| *Study Rank* | | | 2 | 1 | 3 | 2 |

Table O-23. HECO Timing Run 1 (2 of 3)

| **Name** | **Self Generation** | | **P2_2a1NRetire-1r1** | **P2_2a1NRetire-1r2** | **P2_2a1NRetire-1r3** | **P2_2a1NRetire-1r4** |
|---|---|---|---|---|---|---|
| *Plan* | Annual | Cumulative | Timing, (SCCT, OTEC, Biomass, CC) | Timing, 2017 ICE, (OTEC, Biomass, CC) | Timing, (ICE, SCCT, Biomass) | Timing, (ICE, SCCT, Biomass) |
| *Notes* | | | | | Waiau3/4 and Honolulu 8/9 deactivated | Waiau3/4 and Honolulu 8/9 deactivated<br>KPLP contract ends |
| *Resources Available* | | | | | | |
| *2014* | 35MW | 75MW | Expanded CIDLC, CIDP, RDLCWH, RDLCAC | Expanded CIDLC, CIDP, RDLCWH, RDLCAC | Expanded CIDLC, CIDP, RDLCWH, RDLCAC | Expanded CIDLC, CIDP, RDLCWH, RDLCAC |
| | | | 75% PBFA DSM | 75% PBFA DSM | 75% PBFA DSM | 75% PBFA DSM |
| | | | | | Retire H8 (-53MW)<br>Retire H9 (-54MW)<br>or W3/4 | Retire H8 (-53MW)<br>Retire H9 (-54MW)<br>or W3/4 |
| *2015* | 36MW | 111MW | | | | |
| *2016* | 43MW | 154MW | Fuel Switch to Diesel (H8/9, Waiau 5-10/Kahe 1-6) | Fuel Switch to Diesel (H8/9, Waiau 5-10/Kahe 1-6) | Fuel Switch to Diesel (H8/9, Waiau 5-10/Kahe 1-6) | Fuel Switch to Diesel (H8/9, Waiau 5-10/Kahe 1-6) |
| *2017* | 36MW | 189MW | | Add 51MW ICE (PS01x3)-Biofueled | Add 17MW ICE (PS01x1)-Biofueled | Convert CT-1 to CC +57MW (STC1)-ULSD |
| | | | | | | Add 48MW SCCT (PS06x1)-Biofueled |
| | | | | | | Add 91MW SCCT (PS07x1)-Biofueled |
| | | | | | | KPLP Contract Ends-208MW) |
| | | | Deactivate W3 (-46MW)<br>Deactivate W4 (-46MW)<br>or H8/9 | Deactivate W3 (-46MW)<br>Deactivate W4 (-46MW)<br>or H8/9 | Retire W3 (-46MW)<br>Retire W4 (-46MW)<br>or H8/9 | Retire W3 (-46MW)<br>Retire W4 (-46MW)<br>or H8/9 |
| *2018* | 36MW | 225MW | | | Add 51MW ICE (PS01x3)-Biofueled | Add 17MW ICE (PS01x1)-Biofueled |
| | | | | | | Add 91MW SCCT (PS07x1)-Biofueled |
| *2019* | 35MW | 260MW | Deactivate H8 (-53MW)<br>Deactivate H9 (-54MW)<br>or W3/4 | Deactivate H8 (-53MW)<br>Deactivate H9 (-54MW)<br>or W3/4 | | |
| *2020* | 35MW | 295MW | Add 59MW CC (PC08x1)-Biofueled | | | Add 25MW (PA01x1)-Biomass |
| *2021* | 35MW | 331MW | | | | |
| *2022* | 28MW | 363MW | | Add 25MW (PA01x1)-Biomass | | |

| Name | Self Generation | | P2_2a1NRetire-1r1 | P2_2a1NRetire-1r2 | P2_2a1NRetire-1r3 | P2_2a1NRetire-1r4 |
|---|---|---|---|---|---|---|
| *2023* | 28MW | 391MW | | | | |
| *2024* | 25MW | 416MW | | | | |
| *2025* | 21MW | 437MW | | | | |
| *2026* | 18MW | 456MW | | | | |
| *2027* | 16MW | 472MW | Add 25MW (PA01x1)-Biomass | | Add 25MW (PA01x1)-Biomass | |
| *2028* | 15MW | 486MW | | | | |
| *2029* | 14MW | 500MW | | | | |
| *2030* | 13MW | 513MW | | | | |
| *2031* | 12MW | 525MW | | | | |
| *2032* | 12MW | 538MW | | | | |
| *2033* | 12MW | 549MW | | Add 59MW CC (PC08x1)-Biofueled | | |
| *Planning Period Total Cost* | | | 22, 722, 088 | 22, 793, 692 | 22, 835, 316 | 24, 526, 660 |
| *Study Period Total Cost* | | | 34, 572, 544 | 34, 697, 868 | 34, 738, 260 | 36, 369, 152 |
| *Planning Rank* | | | 2 | 3 | | |
| *Study Rank* | | | 1 | 3 | | |

Table O-24. HECO Timing Run 1 (3 of 3)

| **Name** | **Self Generation** | | **P2B2b1NRetire-4Er0 timing** | **P2B2b1NRetire-4Er1 timing** | **P2_2a1NRetire-1r9** | **P2B2b1NRetire-1r14** |
|---|---|---|---|---|---|---|
| *Plan* | Annual | Cumulative | Timing, (ICE, SCCT, Biomass), LNG | Timing, (ICE, SCCT, Biomass), LNG | Timing, (SCCT, OTEC, Biomass, CC) | Timing, (ICE, SCCT, Biomass), LNG |
| *Resources Available* | | | | | | |
| *2014* | 35MW | 75MW | Expanded CIDLC, CIDP, RDLCWH, RDLCAC<br>75% PBFA DSM | Expanded CIDLC, CIDP, RDLCWH, RDLCAC<br>75% PBFA DSM<br>Deactivate H8 (-53MW)<br>Deactivate H9 (-54MW) | Expanded CIDLC, CIDP, RDLCWH, RDLCAC<br>75% PBFA DSM | Expanded CIDLC, CIDP, RDLCWH, RDLCAC<br>75% PBFA DSM<br>Deactivate H8 (-53MW)<br>Deactivate H9 (-54MW) |
| *2015* | 36MW | 111MW | | | | |
| *2016* | 43MW | 154MW | Fuel Switch to Diesel (H8/9, Waiau 5-10/Kahe 1-6) | Fuel Switch to Diesel (H8/9, Waiau 5-10/Kahe 1-6) | Fuel Switch to Diesel (H8/9, Waiau 5-10/Kahe 1-6) | Fuel Switch to Diesel (H8/9, Waiau 5-10/Kahe 1-6) |
| *2017* | 36MW | 189MW | Deactivate W3 (-46MW)<br>Deactivate W4 (-46MW) | Deactivate W3 (-46MW)<br>Deactivate W4 (-46MW) | Convert CT-1 to CC on ULSD (SCC1)<br>Deactivate W3 (-46MW)<br>Deactivate W4 (-46MW) or H8/9 | Activate H8 (+53MW)<br>Activate H9 (+54MW)<br>Convert CT-1 to CC +57MW (STC1)-ULSD<br>Add 51MW ICE (PS01x3)-Biofueled<br>KPLP Contract Ends-208MW) |
| *2018* | 36MW | 225MW | | Add 68MW ICE (PS01x4)-Biofueled | | |
| *2019* | 35MW | 260MW | Deactivate H8 (-53MW)<br>Deactivate H9 (-54MW) or W3/4 | | Deactivate H8 (-53MW)<br>Deactivate H9 (-54MW) or W3/4 | Add 95MW SCCT (PS08x1)-Biodiesel/LNG<br>Deactivate W3 (-46MW)<br>Deactivate W4 (-46MW)<br>Deactivate H8 (-53MW)<br>Deactivate H9 (-54MW) |

| Name | Self Generation | | P2B2b1NRetire-4Er0 timing | P2B2b1NRetire-4Er1 timing | P2_2a1NRetire-1r9 | P2B2b1NRetire-1r14 |
|---|---|---|---|---|---|---|
| 2020 | 35MW | 295MW | Add 91MW SCCT (PS07x1)-Biofuel<br>Add 354MW CC (PC08x6)-Biofuel<br>Retire W5 (-55MW)<br>Retire W6 (-56MW)<br>Retire W7 (-88MW)<br>Retire W8 (-88MW)<br>Retire K1 (-88MW)<br>Retire K2 (-86MW)<br>Retire K3 (-88MW)<br>Retire K4 (-89MW) | Add 285MW SCCT (PS08x3)-LNG<br>Deactivate W5 (-55MW)<br>Deactivate W6 (-56MW) | | Add 285MW SCCT (PS08x3)-LNG<br>Add 177MW CC (PS12x3)-LNG<br>Retire W5 (-55MW)<br>Retire W6 (-56MW)<br>Retire W7 (-88MW)<br>Retire W8 (-88MW)<br>Retire K1 (-88MW)<br>Retire K2 (-86MW)<br>Retire K3 (-88MW)<br>Retire K4 (-89MW) |
| 2021 | 35MW | 331MW | Add 91MW SCCT (PS07x1)-Biofuel<br>Add 118MW CC (PC08x6)-Biofuel<br>Retire K5 (-135MW) | Add 95MW SCCT (PS08x1)-LNG<br>Deactivate W7 (-88MW)<br>Deactivate W8 (-88MW) | Add 25MW (PA01x1)-Biomass | Add 177MW CC (PS12x3)-LNG<br>Retire K5 (-135MW) |
| 2022 | 28MW | 363MW | Add 68MW ICE (PS01x4)-Biofueled<br>Add 91MW SCCT (PS07x1)-Biofuel<br>Retire K6 (-134MW) | Add 190MW SCCT (PS08x2)-LNG<br>Deactivate K1 (-88MW)<br>Deactivate K2 (-86MW) | | Add 190MW SCCT (PS08x2)-LNG<br>Retire K6 (-134MW) |
| 2023 | 28MW | 391MW | Add 91MW SCCT (PS07x1)-Biofuel | Add 59MW CC (PS12x1)-LNG<br>Deactivate K3 (-88MW)<br>Deactivate K4 (-89MW) | | Add 95MW SCCT (PS08x1)-LNG |
| 2024 | 25MW | 416MW | | Add 59MW CC (PS12x1)-LNG<br>Deactivate K5 (-135MW) | | |
| 2025 | 21MW | 437MW | | Add 177MW CC (PS12x3)-LNG<br>Deactivate K6 (-134MW) | | |
| 2026 | 18MW | 456MW | | | | |
| 2027 | 16MW | 472MW | | | | |
| 2028 | 15MW | 486MW | | | | |
| 2029 | 14MW | 500MW | | | | |
| 2030 | 13MW | 513MW | | | | |
| 2031 | 12MW | 525MW | | | | |

| **Name** | **Self Generation** | | **P2B2b1NRetire-4Er0 timing** | **P2B2b1NRetire-4Er1 timing** | **P2_2a1NRetire-1r9** | **P2B2b1NRetire-1r14** |
|---|---|---|---|---|---|---|
| *2032* | 12MW | 538MW | | | | |
| *2033* | 12MW | 549MW | | | | |
| *Planning Period Total Cost* | | | 27, 884, 710 | 21, 382, 862 | 22, 261, 448 | 21, 344, 112 |
| *Study Period Total Cost* | | | 39, 493, 300 | 29, 931, 952 | 33, 899, 532 | 29, 275, 540 |
| *Planning Rank* | | | | | | |
| *Study Rank* | | | | | | |

Table O-25. HECO Timing Run 2 (1 of 3)

| ***Name*** | **Self Generation** | | **P2_2a1NRetire-1r1** | **P2_2a1NRetire-1r3** | **P2_2a1NRetire-1r5** | **P2_2a1NRetire-1r4** |
|---|---|---|---|---|---|---|
| *Plan* | | | Timing, (SCCT, OTEC, Biomass, CC) | Timing, (ICE, SCCT, Biomass) | Timing, (ICE, SCCT, Biomass) | Timing, (ICE, SCCT, Biomass) |
| *Resources Available* | Annual | Cumulative | 17 MW ICE - Biodiesel (PS01)-2016<br>42 MW SCCT - Biodiesel (PS06)-2019<br>91 MW SCCT - Biodiesel (PS07)-2019<br>25MW Banagrass Combustion (PA01)-2020<br>9.6 MW OTEC (POT1)-n/a<br>15 MW Ocean Wave (PV02)-n/a | 17 MW ICE - Biodiesel (PS01)-2016<br>42 MW SCCT - Biodiesel (PS06)-2019<br>91 MW SCCT - Biodiesel (PS07)-2019<br>25MW Banagrass Combustion (PA01)-2020<br>9.6 MW OTEC (POT1)-n/a<br>15 MW Ocean Wave (PV02)-n/a | 17 MW ICE - Biodiesel (PS01)-2016<br>42 MW SCCT - Biodiesel (PS06)-2017<br>91 MW SCCT - Biodiesel (PS07)-2017<br>+57 MW Convert CT-1 to CC-ULSD (STC1)-2017<br>25MW Banagrass Combustion (PA01)-2020<br>9.6 MW OTEC (POT1)-n/a<br>15 MW Ocean Wave (PV02)-n/a | 17 MW ICE - Biodiesel (PS01)-2016<br>42 MW SCCT - Biodiesel (PS06)-2017<br>91 MW SCCT - Biodiesel (PS07)-2017<br>+57 MW Convert CT-1 to CC-ULSD (STC1)-2017<br>25MW Banagrass Combustion (PA01)-2020<br>9.6 MW OTEC (POT1)-n/a<br>15 MW Ocean Wave (PV02)-n/a |
| *2014* | 35MW | 75MW | Expanded CIDLC, CIDP, RDLCWH, RDLCAC<br>75% PBFA DSM | Expanded CIDLC, CIDP, RDLCWH, RDLCAC<br>75% PBFA DSM<br>Deactivate H8 (- 53MW)<br>Deactivate H9 (- 54MW) | Expanded CIDLC, CIDP, RDLCWH, RDLCAC<br>75% PBFA DSM<br>Deactivate H8 (- 53MW)<br>Deactivate H9 (- 54MW) | Expanded CIDLC, CIDP, RDLCWH, RDLCAC<br>75% PBFA DSM<br>Deactivate H8 (- 53MW)<br>Deactivate H9 (- 54MW) |
| *2015* | 36MW | 111MW | | | | |
| *2016* | 36MW | 189MW | Fuel Switch to Diesel (Hon 8-9Waiau 5-8, Kahe 1-6) | Fuel Switch to Diesel (Hon 8-9Waiau 5-8, Kahe 1-6) | Fuel Switch to Diesel (Hon 8-9Waiau 5-8, Kahe 1-6) | Fuel Switch to Diesel (Hon 8-9Waiau 5-8, Kahe 1-6) |

| *Name* | **Self Generation** | | **P2_2a1NRetire-1r1** | **P2_2a1NRetire-1r3** | **P2_2a1NRetire-1r5** | **P2_2a1NRetire-1r4** |
|---|---|---|---|---|---|---|
| *2017* | 36MW | 189MW | Deactivate W3 (- 46MW) Deactivate W4 (- 46MW) | Deactivate W3 (- 46MW) Deactivate W4 (- 46MW) | Convert CT-1 to CC +57MW (STC1)-ULSD<br>Deactivate W3 (- 46MW) Deactivate W4 (- 46MW) | Convert CT-1 to CC +57MW (STC1)-ULSD<br>Add 48MW SCCT (PS06x1)-Biofueled<br>Add 91MW SCCT (PS07x1)-Biofueled<br>KPLP Contract Ends-208MW)<br>Deactivate W3 (- 46MW) Deactivate W4 (- 46MW) |
| *2018* | 36MW | 225MW | | Add 68MW ICE (PS01x4)-Biofueled | Add 17MW ICE (PS01x1)-Biofueled | Add 17MW ICE (PS01x1)-Biofueled<br>Add 91MW SCCT (PS07x1)-Biofueled |
| *2019* | 35MW | 260MW | Deactivate H8 (- 53MW) Deactivate H9 (- 54MW) | | | |
| *2020* | 35MW | 295MW | Add 59MW CC (PC08x1)-Biofueled | | | |
| *2021* | 35MW | 331MW | | | | |
| *2022* | 28MW | 363MW | Fuel Switch to ULSD (Hon 8-9Waiau 5-8, Kahe 1-6) | Fuel Switch to ULSD (Hon 8-9Waiau 5-8, Kahe 1-6) | Fuel Switch to ULSD (Hon 8-9Waiau 5-8, Kahe 1-6) | Add 25MW (PA01x1)-Biomass<br>Fuel Switch to ULSD (Hon 8-9Waiau 5-8, Kahe 1-6) |
| *2023* | 28MW | 391MW | | | | |
| *2024* | 25MW | 416MW | | | | |
| *2025* | 21MW | 437MW | | | | |
| *2026* | 18MW | 456MW | | | | |
| *2027* | 16MW | 472MW | Add 25MW (PA01x1)-Biomass | Add 25MW (PA01x1)-Biomass | | |
| *2028* | 15MW | 486MW | | | | |
| *2029* | 14MW | 500MW | | | | |

| *Name* | **Self Generation** | | **P2_2a1NRetire-1r1** | **P2_2a1NRetire-1r3** | **P2_2a1NRetire-1r5** | **P2_2a1NRetire-1r4** |
|---|---|---|---|---|---|---|
| *2030* | 13MW | 513MW | | | | |
| *2031* | 12MW | 525MW | | | | |
| *2032* | 12MW | 538MW | | | | |
| *2033* | 12MW | 549MW | | | Add 25MW (PA01x1)-Biomass | |
| *Strategist Planning Period Total Cost* | | | 22, 722, 088 | 22, 828, 962 | 22, 337, 036 | 23, 466, 240 |
| *Strategist Study Period Total Cost,* | | | 34, 572, 544 | 34, 731, 560 | 34, 003, 256 | 35, 465, 772 |
| *Planning Period Total Cost* | | | 25, 399, 463 | 25, 516, 981 | | |
| *Study Period Total Cost* | | | 25, 399, 465 | 25, 516, 981 | | |
| *Planning Rank* | | | 1 | 2 | | |
| *Study Rank* | | | 1 | 2 | | |

Table O-26. HECO Timing Run 2 (2 of 3)

| **Name** | **Self Generation** | | **P2_2a1NRetire-1r6** | **P2_2a1NRetire-1r7** | **P2_2a1NRetire-1r8** | **P2_2a1NRetire-1r10** |
|---|---|---|---|---|---|---|
| *Plan* | Annual | Cumulative | Timing, (ICE, SCCT, Biomass) | Timing, (ICE, SCCT, Biomass) | Timing, (ICE, SCCT, Biomass) | Timing, (ICE, SCCT, Biomass) |
| *Notes* | | | | | | |
| *Resources Available* | | | 17 MW ICE - Biodiesel (PS01)-2016<br>42 MW SCCT - Biodiesel (PS06)-2017<br>91 MW SCCT - Biodiesel (PS07)-2017<br>+57 MW Convert CT-1 to CC-ULSD (STC1)-2017<br>25MW Banagrass Combustion (PA01)-2020<br>9.6 MW OTEC (POT1)-n/a<br>15 MW Ocean Wave (PV02)-n/a | 17 MW ICE - Biodiesel (PS01)-2016<br>42 MW SCCT - Biodiesel (PS06)-2017<br>91 MW SCCT - Biodiesel (PS07)-2017<br>+57 MW Convert CT-1 to CC-ULSD (STC1)-2017<br>25MW Banagrass Combustion (PA01)-2020<br>9.6 MW OTEC (POT1)-n/a<br>15 MW Ocean Wave (PV02)-n/a | 17 MW ICE - Biodiesel (PS01)-2016<br>42 MW SCCT - Biodiesel (PS06)-2017<br>91 MW SCCT - Biodiesel (PS07)-2017<br>+57 MW Convert CT-1 to CC-ULSD (STC1)-2018<br>25MW Banagrass Combustion (PA01)-2020<br>9.6 MW OTEC (POT1)-n/a<br>15 MW Ocean Wave (PV02)-n/a | 17 MW ICE - Biodiesel (PS01)-2016<br>42 MW SCCT - Biodiesel (PS06)-2017<br>91 MW SCCT - Biodiesel (PS07)-2017<br>+57 MW Convert CT-1 to CC-ULSD (STC1)-2018<br>25MW Banagrass Combustion (PA01)-2020<br>9.6 MW OTEC (POT1)-n/a<br>15 MW Ocean Wave (PV02)-n/a |
| *2014* | 35MW | 75MW | Expanded CIDLC, CIDP, RDLCWH, RDLCAC<br>75% PBFA DSM<br>Deactivate H8 (- 53MW)<br>Deactivate H9 (- 54MW) | Expanded CIDLC, CIDP, RDLCWH, RDLCAC<br>75% PBFA DSM<br>Deactivate H8 (- 53MW)<br>Deactivate H9 (- 54MW) | Expanded CIDLC, CIDP, RDLCWH, RDLCAC<br>75% PBFA DSM<br>Deactivate H8 (- 53MW)<br>Deactivate H9 (- 54MW) | Expanded CIDLC, CIDP, RDLCWH, RDLCAC<br>75% PBFA DSM |
| *2015* | 36MW | 111MW | | | | |
| *2016* | 43MW | 154MW | Fuel Switch to Diesel (Hon 8-9Waiau 5-8, Kahe 1-6) | Fuel Switch to Diesel (Hon 8-9Waiau 5-8, Kahe 1-6) | Fuel Switch to Diesel (Hon 8-9Waiau 5-8, Kahe 1-6) | Fuel Switch to Diesel (Hon 8-9Waiau 5-8, Kahe 1-6) |

| Name | Self Generation | | P2_2a1NRetire-1r6 | P2_2a1NRetire-1r7 | P2_2a1NRetire-1r8 | P2_2a1NRetire-1r10 |
|---|---|---|---|---|---|---|
| *2017* | 36MW | 189MW | Activate H8 (+53MW) Activate H9 (+54MW) | Activate H8 (+53MW) Activate H9 (+54MW) | Activate H8 (+53MW) Activate H9 (+54MW) | |
| | | | Convert CT-1 to CC +57MW (STC1)-ULSD | Convert CT-1 to CC +57MW (STC1)-ULSD | Add 91MW SCCT (PS07x1)-Biofueled | Convert CT-1 to CC +57MW (STC1)-ULSD |
| | | | Add 51MW ICE (PS01x3)-Biofueled | Add 51MW ICE (PS01x3)-Biofueled | Add 51MW ICE (PS01x3)-Biofueled | Add 51MW ICE (PS01x3)-Biofueled |
| | | | KPLP Contract Ends-208MW) | | KPLP Contract Ends-208MW) | KPLP Contract Ends-208MW) |
| | | | Deactivate W3 (- 46MW) Deactivate W4 (- 46MW) | Add 25MW (PA01x1)-Biomass | Deactivate W3 (- 46MW) Deactivate W4 (- 46MW) | |
| *2018* | 36MW | 225MW | Deactivate H8 (- 53MW) Deactivate H9 (- 54MW) | | Deactivate H8 (- 53MW) Deactivate H9 (- 54MW) | |
| | | | Add 91MW SCCT (PS07x1)-Biofueled | | Add 91MW SCCT (PS07x1)-Biofueled | |
| *2019* | 35MW | 260MW | Add 91MW SCCT (PS07x1)-Biofueled | | Convert CT-1 to CC +57MW (STC1)-ULSD | |
| *2020* | 35MW | 295MW | | | Add 25MW (PA01x1)-Biomass | |
| *2021* | 35MW | 331MW | | | | |
| *2022* | 28MW | 363MW | Add 25MW (PA01x1)-Biomass | | | |
| | | | Fuel Switch to ULSD (Hon 8-9Waiau 5-8, Kahe 1-6) | Fuel Switch to ULSD (Hon 8-9Waiau 5-8, Kahe 1-6) | Fuel Switch to ULSD (Hon 8-9Waiau 5-8, Kahe 1-6) | Fuel Switch to ULSD (Hon 8-9Waiau 5-8, Kahe 1-6) |
| *2023* | 28MW | 391MW | | | | |
| *2024* | 25MW | 416MW | | | | |
| *2025* | 21MW | 437MW | | | | |
| *2026* | 18MW | 456MW | | | | |
| *2027* | 16MW | 472MW | | | | |
| *2028* | 15MW | 486MW | | | | Add 25MW (PA01x1)-Biomass |
| *2029* | 14MW | 500MW | | | | |

| **Name** | **Self Generation** | | **P2_2a1NRetire-1r6** | **P2_2a1NRetire-1r7** | **P2_2a1NRetire-1r8** | **P2_2a1NRetire-1r10** |
|---|---|---|---|---|---|---|
| *2030* | 13MW | 513MW | | | | |
| *2031* | 12MW | 525MW | | | | |
| *2032* | 12MW | 538MW | | | | |
| *2033* | 12MW | 549MW | | | | |
| *Strategist Planning Period Total Cost* | | | 23, 480, 774 | 23, 806, 272 | 24, 492, 802 | 23, 015, 940 |
| *Strategist Study Period Total Cost* | | | 35, 475, 688 | 35, 672, 316 | 36, 317, 444 | 35, 057, 308 |
| *Planning Period Total Cost* | | | | | | |
| *Study Period Total Cost* | | | | | | |
| *Planning Rank* | | | | | | |
| *Study Rank* | | | | | | |

Table O-27. HECO Timing Run 2 (3 of 3)

| Name | Self Generation | | P2_2a1NRetire-1r11 | P2_2a1NRetire-1r12 | P2_2a1NRetire-1r13 |
|---|---|---|---|---|---|
| *Plan* | | | Timing, (ICE, SCCT, Biomass) | Required Timing, (ICE, SCCT, Biomass) | Timing, (ICE, SCCT, Biomass) |
| *Notes* | | | | | |
| *Resources Available* | Annual | Cumulative | 17 MW ICE - Biodiesel (PS01)-2016<br>42 MW SCCT - Biodiesel (PS06)-2017<br>91 MW SCCT - Biodiesel (PS07)-2017<br>+57 MW Convert CT-1 to CC-ULSD (STC1)-2017<br>25MW Banagrass Combustion (PA01)-2020<br>9.6 MW OTEC (POT1)-n/a<br>15 MW Ocean Wave (PV02)-n/a | 17 MW ICE - Biodiesel (PS01)-2016<br>42 MW SCCT - Biodiesel (PS06)-2017<br>91 MW SCCT - Biodiesel (PS07)-2017<br>+57 MW Convert CT-1 to CC-ULSD (STC1)-2018<br>25MW Banagrass Combustion (PA01)-2020<br>9.6 MW OTEC (POT1)-n/a<br>15 MW Ocean Wave (PV02)-n/a | 17 MW ICE - Biodiesel (PS01)-2016<br>42 MW SCCT - Biodiesel (PS06)-2017<br>91 MW SCCT - Biodiesel (PS07)-2017<br>+57 MW Convert CT-1 to CC-ULSD (STC1)-2018<br>25MW Banagrass Combustion (PA01)-2020<br>9.6 MW OTEC (POT1)-n/a<br>15 MW Ocean Wave (PV02)-n/a |
| *2014* | 35MW | 75MW | Expanded CIDLC, CIDP, RDLCWH, RDLCAC<br>75% PBFA DSM<br>Deactivate H8 (-53MW)<br>Deactivate H9 (-54MW) | Expanded CIDLC, CIDP, RDLCWH, RDLCAC<br>75% PBFA DSM | Expanded CIDLC, CIDP, RDLCWH, RDLCAC<br>75% PBFA DSM<br>Deactivate H8 (-53MW)<br>Deactivate H9 (-54MW) |
| *2015* | 36MW | 111MW | | | |
| *2016* | 43MW | 154MW | Fuel Switch to Diesel (Hon 8-9Waiau 5-8, Kahe 1-6) | Fuel Switch to Diesel (Hon 8-9Waiau 5-8, Kahe 1-6) | Fuel Switch to Diesel (Hon 8-9Waiau 5-8, Kahe 1-6) |
| *2017* | 36MW | 189MW | Activate H8 (+53MW)<br>Activate H9 (+54MW)<br>Convert CT-1 to CC +57MW (STC1)-ULSD<br>Add 51MW ICE (PS01x3)-Biofueled<br>Deactivate W3 (-46MW)<br>Deactivate W4 (-46MW) | | Activate H8 (+53MW)<br>Activate H9 (+54MW)<br>Convert CT-1 to CC +57MW (STC1)-ULSD<br>Add 51MW ICE (PS01x3)-Biofueled<br>KPLP Contract Ends-208MW) |
| *2018* | 36MW | 225MW | Deactivate H8 (-53MW)<br>Deactivate H9 (-54MW) | | |
| *2019* | 35MW | 260MW | | | Deactivate W3 (-46MW)<br>Deactivate W4 (-46MW)<br>Deactivate H8 (-53MW)<br>Deactivate H9 (-54MW) |

| Name | Self Generation | | P2_2a1NRetire-1r11 | P2_2a1NRetire-1r12 | P2_2a1NRetire-1r13 |
|---|---|---|---|---|---|
| *2020* | 35MW | 295MW | | | |
| *2021* | 35MW | 331MW | | | |
| *2022* | 28MW | 363MW | Fuel Switch to ULSD (Hon 8-9Waiau 5-8, Kahe 1-6) | Fuel Switch to ULSD (Hon 8-9Waiau 5-8, Kahe 1-6) | Fuel Switch to ULSD (Hon 8-9Waiau 5-8, Kahe 1-6) |
| *2023* | 28MW | 391MW | | | |
| *2024* | 25MW | 416MW | | | |
| *2025* | 21MW | 437MW | | | |
| *2026* | 18MW | 456MW | | | |
| *2027* | 16MW | 472MW | | | |
| *2028* | 15MW | 486MW | | | |
| *2029* | 14MW | 500MW | | | |
| *2030* | 13MW | 513MW | | | |
| *2031* | 12MW | 525MW | | | |
| *2032* | 12MW | 538MW | | | |
| *2033* | 12MW | 549MW | Add 25MW (PA01x1)-Biomass | | |
| *Strategist Planning Period Total Cost* | | | 22, 600, 396 | 22, 463, 170 | 24, 313, 600 |
| *Strategist Study Period Total Cost* | | | 34, 304, 124 | 34, 492, 704 | 36, 153, 064 |
| *Planning Period Total Cost,* | | | | | |
| *Study Period Total Cost,* | | | | | |
| *Planning Rank* | | | | | |
| *Study Rank* | | | | | |

Table O-28. HECO Screening Run (1 of 2)

| **Name** | **P2B2a1XRetire-2r0** | **P2B2a1NRetire-2r0** | **P2B2b1NRetire-2r0** |
|---|---|---|---|
| *Plan* | Meet RPS by Scenario<br>Without Lanai Wind and Continue Existing DR | Meet RPS by Scenario<br>Without Lanai Wind, Expand DR | Meet RPS by Scenario<br>With Lanai Wind and Expanded DR |
| *Resources Available* | | 59 MW 1on1 LM6000 CC- Biodiesel (PC08)-fixed<br>25MW Banagrass Combustion (PA01)-fixed<br>30 MW Onshore Wind Cl 3 (PW01)-2016<br>10 MW Onshore Wind Cl 5 (PW03)-n/a<br>10 MW Onshore Wind Cl 7 (PW04)-n/a<br>100 MW Offshore Wind (PW05)-n/a<br>5 MW of 1 MW Tracking PV (PP03)-2015<br>50 MW Parabolic Trough PV (PP04)-n/a<br>9.6 MW OTEC (POT1)-n/a<br>15 MW Ocean Wave (PV02)-n/a | 59 MW 1on1 LM6000 CC- Biodiesel (PC08)-fixed<br>25MW Banagrass Combustion (PA01)-fixed<br>30 MW Onshore Wind Cl 3 (PW01)-2016<br>10 MW Onshore Wind Cl 5 (PW03)-n/a<br>10 MW Onshore Wind Cl 7 (PW04)-n/a<br>100 MW Offshore Wind (PW05)-n/a<br>5 MW of 1 MW Tracking PV (PP03)-2015<br>50 MW Parabolic Trough PV (PP04)-n/a<br>9.6 MW OTEC (POT1)-n/a<br>15 MW Ocean Wave (PV02)-n/a |
| *2014* | Continue CIDLC, CIDP, RDLCWH, RDLCAC | Expanded CIDLC, CIDP, RDLCWH, RDLCAC | Expanded CIDLC, CIDP, RDLCWH, RDLCAC |
| | 75% PBFA DSM | 75% PBFA DSM | 75% PBFA DSM |
| *2015* | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) | |
| *2016* | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) |
| | Add 60 MW Wind (PW01x2) | Add 60 MW Wind (PW01x2) | Add 60 MW Wind (PW01x2) |
| | Fuel Switch to Diesel (Hon 8-9Waiau 5-8, Kahe 1-6) | Fuel Switch to Diesel (Hon 8-9Waiau 5-8, Kahe 1-6) | Fuel Switch to Diesel (Hon 8-9Waiau 5-8, Kahe 1-6) |
| *2017* | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) | |
| | Add 60 MW Wind (PW01x2) | Add 60 MW Wind (PW01x2) | Add 60 MW Wind (PW01x2) |
| | Deactivate W3 (-46MW)<br>Deactivate W4 (-46MW)<br>or H8/9 | Deactivate W3 (-46MW)<br>Deactivate W4 (-46MW)<br>or H8/9 | Deactivate W3 (-46MW)<br>Deactivate W4 (-46MW)<br>or H8/9 |
| *2018* | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) | |
| | Add 60 MW Wind (PW01x2) | Add 60 MW Wind (PW01x2) | Add 60 MW Wind (PW01x2) |
| *2019* | Add 60 MW Wind (PW01x2) | Add 60 MW Wind (PW01x2) | |
| | Deactivate H8 (-53MW)<br>Deactivate H9 (-54MW)<br>or W3/4 | Deactivate H8 (-53MW)<br>Deactivate H9 (-54MW)<br>or W3/4 | Deactivate H8 (-53MW)<br>Deactivate H9 (-54MW)<br>or W3/4 |
| *2020* | Add 91MW SCCT (PS07x1)-Biofueled | Add 59MW CC (PC08x1)-Biofueled | Add 59MW CC (PC08x1)-Biofueled |
| | Add 60 MW Wind (PW01x2) | Add 60 MW Wind (PW01x2) | Add 200 MW Lanai Wind |
| *2021* | Add 25MW (PA01x1)-Biomass | | |

| **Name** | **P2B2a1XRetire-2r0** | **P2B2a1NRetire-2r0** | **P2B2b1NRetire-2r0** |
|---|---|---|---|
| *2022* | Add 59MW CC (PC08x1)-Biofueled | | |
| | Fuel Switch to Diesel (Hon 8-9Waiau 5-8, Kahe 1-6) | Fuel Switch to ULSD (Hon 8-9Waiau 5-8, Kahe 1-6) | Fuel Switch to ULSD (Hon 8-9Waiau 5-8, Kahe 1-6) |
| *2023* | | | |
| *2024* | Add 30 MW Wind (PW01x1) | Add 60 MW Wind (PW01x2) | |
| *2025* | | | |
| *2026* | Add 20 MW PV (PP03x4) | | |
| *2027* | | Add 25MW (PA01x1)-Biomass | Add 25MW (PA01x1)-Biomass |
| | Add 20 MW PV (PP03x4) | | |
| *2028* | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) |
| *2029* | Add 60 MW Wind (PW01x2) | Add 60 MW Wind (PW01x2) | Add 30 MW Wind (PW01x1) |
| | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) |
| *2030* | Add 150 MW Wind (PW01x5) | Add 150 MW Wind (PW01x5) | Add 150 MW Wind (PW01x5) |
| | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) |
| *2031* | | | |
| *2032* | | | |
| *2033* | | | |
| *Planning Period Total Cost* | 22, 484, 032 | 22, 322, 938 | 22, 234, 112 |
| *Study Period Total Cost* | 33, 462, 598 | 33, 236, 766 | 32, 899, 972 |
| *Planning Rank* | 7 | 4 | 1 |
| *Study Rank* | 7 | 5 | 1 |

Table O-29. HECO Screening Run (2 of 2)

| **Name** | **P2B2b1NRetire-2r0_LanH** | **P2B2a1NRetire-2r3** | **P2B2a1NRetire-2r4** |
|---|---|---|---|
| *Plan* | Screen based on P2B2a1NRetire-2r0, w/ Lanai Wind revised cost | Screen 30 MW Wind, 5 MW PV, Lanai Wind | Screen 30 MW Wind, 5 MW PV, Lanai Wind |
| *Resources Available* | 59 MW 1on1 LM6000 CC- Biodiesel (PC08)-fixed<br>25MW Banagrass Combustion (PA01)-fixed<br>30 MW Onshore Wind Cl 3 (PW01)-2016<br>10 MW Onshore Wind Cl 5 (PW03)-n/a<br>10 MW Onshore Wind Cl 7 (PW04)-n/a<br>100 MW Offshore Wind (PW05)-n/a<br>5 MW of 1 MW Tracking PV (PP03)-2015<br>50 MW Parabolic Trough PV (PP04)-n/a<br>9.6 MW OTEC (POT1)-n/a<br>15 MW Ocean Wave (PV02)-n/a | 17 MW ICE - Biodiesel (PS01)-fixed n/a<br>25MW Banagrass Combustion (PA01)-fixed<br>30 MW Onshore Wind Cl 3 (PW01)-2016<br>Lanai Wind-2020A<br>10 MW Onshore Wind Cl 7 (PW04)-n/a<br>100 MW Offshore Wind (PW05)-n/a<br>5 MW of 1 MW Tracking PV (PP03)-2015<br>50 MW Parabolic Trough PV (PP04)-n/a<br>9.6 MW OTEC (POT1)-n/a<br>15 MW Ocean Wave (PV02)-n/a | 17 MW ICE - Biodiesel (PS01)-fixed n/a<br>25MW Banagrass Combustion (PA01)-fixed<br>30 MW Onshore Wind Cl 3 (PW01)-2016<br>Lanai Wind-2020A<br>10 MW Onshore Wind Cl 7 (PW04)-n/a<br>100 MW Offshore Wind (PW05)-n/a<br>5 MW of 1 MW Tracking PV (PP03)-2015<br>50 MW Parabolic Trough PV (PP04)-n/a<br>9.6 MW OTEC (POT1)-n/a<br>15 MW Ocean Wave (PV02)-n/a |
| *2014* | Expanded CIDLC, CIDP, RDLCWH, RDLCAC | Expanded CIDLC, CIDP, RDLCWH, RDLCAC | Expanded CIDLC, CIDP, RDLCWH, RDLCAC |
| | 75% PBFA DSM | 75% PBFA DSM | 75% PBFA DSM |
| | | Deactivate H8 (-53MW)<br>Deactivate H9 (-54MW)<br>or W3/4 | Deactivate H8 (-53MW)<br>Deactivate H9 (-54MW)<br>or W3/4 |
| *2015* | | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) |
| *2016* | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) |
| | Add 60 MW Wind (PW01x2) | Add 60 MW Wind (PW01x2) | Add 60 MW Wind (PW01x2) |
| | Fuel Switch to Diesel (Hon 8-9Waiau 5-8, Kahe 1-6) | Fuel Switch to Diesel (Hon 8-9Waiau 5-8, Kahe 1-6) | Fuel Switch to Diesel (Hon 8-9Waiau 5-8, Kahe 1-6) |
| *2017* | | Add 17MW ICE (PS01x1)-Biofueled | Add 17MW ICE (PS01x1)-Biofueled |
| | | Add 60 MW Wind (PW01x2) | Add 60 MW Wind (PW01x2) |
| | Add 60 MW Wind (PW01x2) | | |
| | Deactivate W3 (-46MW)<br>Deactivate W4 (-46MW)<br>or H8/9 | Deactivate W3 (-46MW)<br>Deactivate W4 (-46MW)<br>or H8/9 | Deactivate W3 (-46MW)<br>Deactivate W4 (-46MW)<br>or H8/9 |
| *2018* | | Add 60 MW Wind (PW01x2) | Add 60 MW Wind (PW01x2) |
| | Add 60 MW Wind (PW01x2) | Add 51MW ICE (PS01x3)-Biofueled | Add 51MW ICE (PS01x3)-Biofueled |
| *2019* | | Add 60 MW Wind (PW01x2) | Add 60 MW Wind (PW01x2) |
| | Deactivate H8 (-53MW)<br>Deactivate H9 (-54MW)<br>or W3/4 | | |

| Name | P2B2b1NRetire-2r0_LanH | P2B2a1NRetire-2r3 | P2B2a1NRetire-2r4 |
|---|---|---|---|
| *2020* | Add 59MW CC (PC08x1)-Biofueled | | |
| | Add 200 MW Lanai Wind | Add 90 MW Wind (PW01x3) | Add 200 MW Lanai Wind |
| *2021* | | | |
| *2022* | Fuel Switch to ULSD (Hon 8-9Waiau 5-8, Kahe 1-6) | Fuel Switch to ULSD (Hon 8-9Waiau 5-8, Kahe 1-6) | Fuel Switch to ULSD (Hon 8-9Waiau 5-8, Kahe 1-6) |
| *2023* | | | |
| *2024* | | Add 30 MW Wind (PW01x1) | Add 30 MW Wind (PW01x1) |
| *2025* | | | |
| *2026* | | | |
| *2027* | Add 25MW (PA01x1)-Biomass | Add 25MW (PA01x1)-Biomass | Add 25MW (PA01x1)-Biomass |
| *2028* | Add 20 MW PV (PP03x4) | | |
| *2029* | Add 30 MW Wind (PW01x1) | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) |
| | Add 20 MW PV (PP03x4) | | |
| *2030* | Add 150 MW Wind (PW01x5) | Add 200 MW Lanai Wind | Add 200 MW Lanai Wind |
| | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) |
| *2031* | | | |
| *2032* | | | |
| *2033* | | | |
| *Planning Period Total Cost* | 22, 361, 132 | 22, 302, 460 | 22, 324, 040 |
| *Study Period Total Cost* | 33, 085, 258 | 32, 999, 758 | 33, 041, 060 |
| *Planning Rank* | 6 | 2 | 5 |
| *Study Rank* | 4 | 2 | 3 |

Table O-30. HECO Environmental Compliance (1 of 2)

| Name | Self Generation | | P2B2b1NRetire-2r0 | P2B2b1NRetire-4Br0 | P2B2b1NRetire-4Dr0 |
|---|---|---|---|---|---|
| *Plan* | Annual | Cumulative | Fuel Switch to ULSD in 2022 | Install Air Quality Controls in 2022 | Fuel Switch to LNG in 2020 |
| *Notes* | | | Fuel switch applies to all Waiau 5-8 and Kahe 1-6 | Install AQC on Waiau 5-8 and Kahe 1-6 | Fuel switch applies to all Waiau 5-8 and Kahe 1-6 |
| *Resources Available* | | | ICE (17 MW)-Biodiesel (PS01)-n/a<br>100 MW SCCT - Biodiesel (PS07)-n/a<br>42 MW LM6000 SCCT LNG (PC08)-n/a<br>59 MW 1on1 LM6000 CC-LNG (PS12)-2020<br>25MW Banagrass (PA01)-2027<br>30 MW Onshore Wind Cl 3 (PW01)-2016<br>10 MW Onshore Wind Cl 5 (PW03)-n/a<br>10 MW Onshore Wind Cl 7 (PW04)-n/a<br>100 MW Offshore Wind (PW05)-n/a<br>5 MW of 1 MW Tracking PV (PP03)-2015<br>50 MW Parabolic Trough PV (PP04)-n/a<br>9.6 MW OTEC (POT1)-n/a<br>15 MW Ocean Wave 5 MW (PV02)-2020 | ICE (17 MW)-Biodiesel (PS01)-n/a<br>100 MW SCCT - Biodiesel (PS07)-n/a<br>42 MW LM6000 SCCT LNG (PC08)-n/a<br>59 MW 1on1 LM6000 CC-LNG (PS12)-2020<br>25MW Banagrass (PA01)-2027<br>30 MW Onshore Wind Cl 3 (PW01)-2016<br>10 MW Onshore Wind Cl 5 (PW03)-n/a<br>10 MW Onshore Wind Cl 7 (PW04)-n/a<br>100 MW Offshore Wind (PW05)-n/a<br>5 MW of 1 MW Tracking PV (PP03)-2016<br>50 MW Parabolic Trough PV (PP04)-n/a<br>9.6 MW OTEC (POT1)-n/a<br>15 MW Ocean Wave 5 MW (PV02)-2020 | ICE (17 MW)-Biodiesel (PS01)-n/a<br>100 MW SCCT - Biodiesel (PS07)-n/a<br>42 MW LM6000 SCCT LNG (PC08)-n/a<br>59 MW 1on1 LM6000 CC-LNG (PS12)-2020<br>25MW Banagrass (PA01)-2027<br>30 MW Onshore Wind Cl 3 (PW01)-2016<br>10 MW Onshore Wind Cl 5 (PW03)-n/a<br>10 MW Onshore Wind Cl 7 (PW04)-n/a<br>100 MW Offshore Wind (PW05)-n/a<br>5 MW of 1 MW Tracking PV (PP03)-2016<br>50 MW Parabolic Trough PV (PP04)-n/a<br>9.6 MW OTEC (POT1)-n/a<br>15 MW Ocean Wave 5 MW (PV02)-2020 |
| *2014* | 35MW | 75 MW | Expanded CIDLC, CIDP, RDLCWH, RDLCAC | Expanded CIDLC, CIDP, RDLCWH, RDLCAC | Expanded CIDLC, CIDP, RDLCWH, RDLCAC |
| | | | 75% PBFA DSM | 75% PBFA DSM | 75% PBFA DSM |
| *2015* | 36MW | 111MW | | | |
| *2016* | 43MW | 154MW | Fuel Switch to Diesel (H8/9, Waiau 5-10/Kahe 1-6) | Fuel Switch to Diesel (H8/9, Waiau 5-10/Kahe 1-6) | Fuel Switch to Diesel (H8/9, Waiau 5-10/Kahe 1-6) |
| | | | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) |
| | | | Add 60 MW Wind (PW01x2) | Add 60 MW Wind (PW01x2) | Add 60 MW Wind (PW01x2) |
| *2017* | 36MW | 189MW | Add 60 MW Wind (PW01x2) | Add 60 MW Wind (PW01x2) | Add 60 MW Wind (PW01x2) |
| | | | Deactivate W3 (-46MW)<br>Deactivate W4 (-46MW)<br>or H8/9 | Deactivate W3 (-46MW)<br>Deactivate W4 (-46MW)<br>or H8/9 | Deactivate W3 (-46MW)<br>Deactivate W4 (-46MW)<br>or H8/9 |
| *2018* | 36MW | 225MW | Add 60 MW Wind (PW01x2) | Add 60 MW Wind (PW01x2) | Add 60 MW Wind (PW01x2) |

| **Name** | **Self Generation** | | **P2B2b1NRetire-2r0** | **P2B2b1NRetire-4Br0** | **P2B2b1NRetire-4Dr0** |
|---|---|---|---|---|---|
| *2019* | 35MW | 260MW | Deactivate H8 (-53MW)<br>Deactivate H9 (-54MW)<br>or W3/4 | Deactivate H8 (-53MW)<br>Deactivate H9 (-54MW)<br>or W3/4 | Deactivate H8 (-53MW)<br>Deactivate H9 (-54MW)<br>or W3/4 |
| *2020* | 35MW | 295MW | | | Fuel switch to LNG (Waiau 5-8, Kahe 1-6) |
| | | | Add 59MW CC (PC08x1)-Biofueled | Add 59MW CC (PC08x1)-Biofueled | Add 59MW CC (PC08x1)-Biofueled |
| | | | Add 200 MW Lanai Wind | Add 200 MW Lanai Wind | Add 200 MW Lanai Wind |
| *2021* | 35MW | 331MW | | | |
| *2022* | 28MW | 363MW | Fuel Switch to ULSD (Waiau 5-8, Kahe 1-6) | AQC Waiau 5-8 & Kahe 1-6 | |
| *2023* | 28MW | 391MW | | | |
| *2024* | 25MW | 416MW | | | |
| *2025* | 21MW | 437MW | | | |
| *2026* | 18MW | 456MW | | | |
| *2027* | 16MW | 472MW | Add 25MW (PA01x1)-Biomass | Add 25MW (PA01x1)-Biomass | Add 25MW (PA01x1)-Biomass |
| *2028* | 15MW | 486MW | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) |
| *2029* | 14MW | 500MW | Add 30 MW Wind (PW01x1) | Add 30 MW Wind (PW01x1) | Add 30 MW Wind (PW01x1) |
| | | | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) |
| *2030* | 13MW | 513MW | Add 150 MW Wind (PW01x5) | Add 150 MW Wind (PW01x5) | Add 150 MW Wind (PW01x5) |
| | | | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) |
| *2031* | 12MW | 525MW | | | |
| *2032* | 12MW | 538MW | | | |
| *2033* | 12MW | 549MW | | | |
| *Strategist Planning Period Total Cost* | | | 22, 234, 112 | 22, 019, 958 | 19, 836, 616 |
| *Strategist Study Period Total Cost* | | | 32, 899, 972 | 32, 510, 080 | 28, 042, 346 |
| *Planning Period Total Cost* | | | 24, 911, 485 | 25, 756, 081 | 22, 778, 486 |
| *Study Period Total Cost* | | | 35, 577, 349 | 36, 246, 205 | 30, 984, 215 |
| *Planning Rank* | | | 3 | 5 | 1 |
| *Study Rank* | | | 4 | 5 | 1 |

Table O-31. HECO Environmental Compliance (2 of 2)

| **Name** | **Self Generation** | | **P2B2b1NRetire-4Er0** | **P2B2b1NRetire-4Er1** |
|---|---|---|---|---|
| *Plan* | Annual | Cumulative | Deactivate Existing Replace with Conventional LNG Units | Deactivate Existing Replace with Conventional LNG Units |
| *Notes* | | | All units are deactivated by 2022 | All units are deactivated by 2022 |
| *Resources Available* | | | ICE (17 MW)-Biodiesel (PS01)-2022<br>95 MW SCCT LMS 100 - LNG (PS07)-2020<br>42 MW LM6000 SCCT LNG (PC08)-n/a<br>59 MW 1on1 LM6000 CC-LNG (PS12)-2020<br>25MW Banagrass (PA01)-n/a<br>400 kW Nat Gas Fuel Cell (FC40)-n/a<br>30 MW Onshore Wind Cl 3 (PW01)-2016<br>10 MW Onshore Wind Cl 5 (PW03)-n/a<br>5 MW of 1 MW Tracking PV (PP03)-2016 | ICE (17 MW)-Biodiesel (PS01)-2022<br>95 MW SCCT LMS 100 - LNG (PS07)-2020<br>42 MW LM6000 SCCT LNG (PC08)-n/a<br>59 MW 1on1 LM6000 CC-LNG (PS12)-2020<br>25MW Banagrass (PA01)-n/a<br>400 kW Nat Gas Fuel Cell (FC40)-n/a<br>30 MW Onshore Wind Cl 3 (PW01)-2016<br>10 MW Onshore Wind Cl 5 (PW03)-n/a<br>5 MW of 1 MW Tracking PV (PP03)-2016 |
| *2014* | 35MW | 75 MW | Expanded CIDLC, CIDP, RDLCWH, RDLCAC | Expanded CIDLC, CIDP, RDLCWH, RDLCAC |
| | | | 75% PBFA DSM | 75% PBFA DSM |
| | | | | Retire H8 (-53MW)<br>Retire H9 (-54MW) |
| *2015* | 36MW | 111MW | | |
| *2016* | 43MW | 154MW | Fuel Switch to Diesel<br>(H8/9, Waiau 5-10/Kahe 1-6) | Fuel Switch to Diesel<br>(Waiau 5-10/Kahe 1-6) |
| | | | Add 20 MW PV (PP03x4) | |
| | | | Add 60 MW Wind (PW01x2) | Add 60 MW Wind (PW01x2) |
| *2017* | 36MW | 189MW | Add 60 MW Wind (PW01x2) | Add 60 MW Wind (PW01x2) |
| | | | Retire W3 (-46MW)<br>Retire W4 (-46MW)<br>or H8/9 | Retire W3 (-46MW)<br>Retire W4 (-46MW) |
| *2018* | 36MW | 225MW | Add 60 MW Wind (PW01x2) | Add 60 MW Wind (PW01x2) |
| | | | | Add 68MW ICE (PS01x4)-Biofueled |
| *2019* | 35MW | 260MW | Retire H8 (-53MW)<br>Retire H9 (-54MW)<br>or W3/4 | |

| Name | Self Generation | | P2B2b1NRetire-4Er0 | P2B2b1NRetire-4Er1 |
|---|---|---|---|---|
| *2020* | 35MW | 295MW | | Add 60 MW Wind (PW01x2) |
| | | | Add 91MW CT (PS07x1)-LNG | |
| | | | Add 354MW CC (PC08x6)-LNG | Add 285MW SCCT (PS08x3)-LNG |
| | | | Add 200 MW Lanai Wind | Add 200 MW Lanai Wind |
| | | | Retire W5 (-55MW)<br>Retire W6 (-56MW)<br>Retire W7 (-88MW)<br>Retire W8 (-88MW)<br>Retire K1 (-88MW)<br>Retire K2 (-86MW)<br>Retire K3 (-88MW)<br>Retire K4 (-89MW) | Retire W5 (-55MW)<br>Retire W6 (-56MW) |
| *2021* | 35MW | 331MW | Add 91MW CT (PS07x1)-LNG | Add 90 MW Wind (PW01x3) |
| | | | Add 118 MW CC (PC08x2)-LNG | Add 95MW SCCT (PS08x1)-LNG |
| | | | Retire K5 (-135MW) | Retire W7 (-88MW)<br>Retire W8 (-88MW) |
| *2022* | 28MW | 363MW | Add 68MW ICE (PS01x4)-Biofueled | Add 190MW SCCT (PS08x2)-LNG |
| | | | Add 91MW CT (PS07x1)-LNG | Retire K1 (-88MW)<br>Retire K2 (-86MW) |
| | | | Retire K6 (-134MW) | Retire K6 (-134MW) |
| *2023* | 28MW | 391MW | | |
| *2024* | 25MW | 416MW | | |
| *2025* | 21MW | 437MW | | |
| *2026* | 18MW | 456MW | | |
| *2027* | 16MW | 472MW | Add 25MW (PA01x1)-Biomass | |
| *2028* | 15MW | 486MW | Add 20 MW PV (PP03x4) | |
| *2029* | 14MW | 500MW | Add 30 MW Wind (PW01x1) | |
| | | | Add 20 MW PV (PP03x4) | |
| *2030* | 13MW | 513MW | Add 150 MW Wind (PW01x5) | |
| | | | Add 20 MW PV (PP03x4) | |
| *2031* | 12MW | 525MW | | |
| *2032* | 12MW | 538MW | | |
| *2033* | 12MW | 549MW | | |
| *Strategist Planning Period Total Cost* | | | 21, 965, 590 | 22, 672, 492 |
| *Strategist Study Period Total Cost* | | | 30, 506, 690 | 31, 544, 914 |

| Name | Self Generation | | P2B2b1NRetire-4Er0 | P2B2b1NRetire-4Er1 |
|---|---|---|---|---|
| *Planning Period Total Cost* | | | 24, 539, 245 | 25, 268, 402 |
| *Study Period Total Cost* | | | 33, 080, 343 | 34, 140, 824 |
| *Planning Rank* | | | 2 | 4 |
| *Study Rank* | | | 2 | 3 |

Table O-32. HECO Energy Efficiency Portfolio Standard (1 of 3)

| **Name** | **P2_2a1XRetire-7Ar0** | **P2_2a1XRetire-7Br0** | **P2_2a1XRetire-7Cr0** |
|---|---|---|---|
| *Plan* | 35%EEPS, w H89 W34 Ret (ICE) | 75%EEPS, w H89 W34 Ret (ICE) | 100%EEPS, w H89 W34 Ret (ICE) |
| *Notes* | No transactions | No transactions | No transactions |
| *Resources Available* | | | |
| *Reference* | P2_2a1XRetire-7Ar0.xlxs | P2_2a1XRetire-7Br0.xlxs | P2_2a1XRetire-7Cr0.xlxs |
| *2014* | Continue CIDLC, CIDP, RDLCWH, RDLCAC | Continue CIDLC, CIDP, RDLCWH, RDLCAC | Continue CIDLC, CIDP, RDLCWH, RDLCAC |
| | 10%+25% PBFA DSM | 75% PBFA DSM | 25%+75% PBFA DSM |
| *2015* | | | |
| *2016* | | | |
| *2017* | Retire W3 (-46MW)<br>Retire W4 (-46MW)<br>or H8/9 | Retire W3 (-46MW)<br>Retire W4 (-46MW)<br>or H8/9 | Retire W3 (-46MW)<br>Retire W4 (-46MW)<br>or H8/9 |
| *2018* | Add 34MW ICE (PS01x2)-Biofueled | | |
| *2019* | Add 17MW ICE (PS01x1)-Biofueled | | |
| | Retire H8 (-53MW)<br>Retire H9 (-54MW)<br>or W3/4 | Retire H8 (-53MW)<br>Retire H9 (-54MW)<br>or W3/4 | Retire H8 (-53MW)<br>Retire H9 (-54MW)<br>or W3/4 |
| *2020* | Add 85MW ICE (PS01x5)-Biofueled | Add 85MW ICE (PS01x5)-Biofueled | Add 68MW ICE (PS01x4)-Biofueled |
| *2021* | Add 17MW ICE (PS01x1)-Biofueled | Add 17MW ICE (PS01x1)-Biofueled | |
| *2022* | Add 34MW ICE (PS01x2)-Biofueled | Add 34MW ICE (PS01x2)-Biofueled | Add 17MW ICE (PS01x1)-Biofueled |
| *2023* | | | |
| *2024* | | | |
| *2025* | Add 17MW ICE (PS01x1)-Biofueled | Add 17MW ICE (PS01x1)-Biofueled | |
| *2026* | | | |
| *2027* | Add 17MW ICE (PS01x1)-Biofueled | | |
| *2028* | Add 17MW ICE (PS01x1)-Biofueled | Add 17MW ICE (PS01x1)-Biofueled | Add 17MW ICE (PS01x1)-Biofueled |
| *2029* | | | |
| *2030* | | | |
| *2031* | Add 17MW ICE (PS01x1)-Biofueled | | |
| *2032* | | | |
| *2033* | Add 17MW ICE (PS01x1)-Biofueled | | |
| *Planning Period Total Cost* | 24, 070, 834 | 22, 995, 576 | 22, 410, 728 |

| Name | P2_2a1XRetire-7Ar0 | P2_2a1XRetire-7Br0 | P2_2a1XRetire-7Cr0 |
|---|---|---|---|
| *Study Period Total Cost* | 37, 324, 700 | 34, 988, 088 | 33, 669, 264 |
| *Planning Rank* | 4 | 3 | 2 |
| *Study Rank* | 4 | 3 | 2 |

Table O-33. HECO Energy Efficiency Portfolio Standard (2 of 3)

| **Name** | **P2_2a1XRetire-7Dr0** | **P2_2a1XRetire-7Ar1** | **P2_2a1XRetire-7Br1** |
|---|---|---|---|
| *Plan* | 110%EEPS, w H89 W34 Ret (ICE) | 35%EEPS, w H89 W34 Ret (ICE) | 75%EEPS, w H89 W34 Ret (ICE) |
| *Notes* | No transactions | With transactions | With transactions |
| *Resources Available* | | | 17MW ICE (PS01) - 2016 |
| *Reference* | P2_2a1XRetire-7Dr0.xlxs | P2_2a1XRetire-7Ar1.xlxs | P2_2a1XRetire-7Br1.xlxs |
| *2014* | Continue CIDLC, CIDP, RDLCWH, RDLCAC | Continue CIDLC, CIDP, RDLCWH, RDLCAC | Continue CIDLC, CIDP, RDLCWH, RDLCAC |
| | 10%+25%+75% PBFA DSM | 10%+25% PBFA DSM | 75% PBFA DSM |
| *2015* | | | |
| *2016* | | | |
| *2017* | Retire W3 (-46MW)<br>Retire W4 (-46MW)<br>or H8/9 | Retire W3 (-46MW)<br>Retire W4 (-46MW)<br>or H8/9 | Retire W3 (-46MW)<br>Retire W4 (-46MW)<br>or H8/9 |
| *2018* | | Add 34MW ICE (PS01x2)-Biofueled | |
| *2019* | | Add 17MW ICE (PS01x1)-Biofueled | |
| | Retire H8 (-53MW)<br>Retire H9 (-54MW)<br>or W3/4 | Retire H8 (-53MW)<br>Retire H9 (-54MW)<br>or W3/4 | Retire H8 (-53MW)<br>Retire H9 (-54MW)<br>or W3/4 |
| *2020* | Add 51MW ICE (PS01x3)-Biofueled | Add 85MW ICE (PS01x5)-Biofueled | Add 85MW ICE (PS01x5)-Biofueled |
| *2021* | | Add 17MW ICE (PS01x1)-Biofueled | Add 17MW ICE (PS01x1)-Biofueled |
| *2022* | Add 17MW ICE (PS01x1)-Biofueled | Add 34MW ICE (PS01x2)-Biofueled | Add 34MW ICE (PS01x2)-Biofueled |
| *2023* | | | |
| *2024* | | | |
| *2025* | | Add 17MW ICE (PS01x1)-Biofueled | Add 17MW ICE (PS01x1)-Biofueled |
| *2026* | | | |
| *2027* | | Add 17MW ICE (PS01x1)-Biofueled | |
| *2028* | | Add 17MW ICE (PS01x1)-Biofueled | Add 17MW ICE (PS01x1)-Biofueled |
| *2029* | | | |
| *2030* | | | |
| *2031* | | Add 17MW ICE (PS01x1)-Biofueled | |
| *2032* | | | |
| *2033* | | Add 17MW ICE (PS01x1)-Biofueled | |
| *Planning Period Total Cost* | 22, 152, 938 | 26, 531, 824 | 25, 590, 375 |

| Name | P2_2a1XRetire-7Dr0 | P2_2a1XRetire-7Ar1 | P2_2a1XRetire-7Br1 |
|---|---|---|---|
| *Study Period Total Cost* | 33, 109, 626 | 39, 482, 477 | 37, 311, 593 |
| *Planning Rank* | 1 | 4 | 3 |
| *Study Rank* | 1 | 4 | 3 |

Table O-34. HECO Energy Efficiency Portfolio Standard (3 of 3)

| **Name** | **P2_2a1XRetire-7Cr1** | **P2_2a1XRetire-7Dr1** | **P2_2a1XRetire-7Er1** |
|---|---|---|---|
| *Plan* | 100%EEPS, w H89 W34 Ret (ICE) | 110%EEPS, w H89 W34 Ret (ICE) | 75%EEPS, w H89 W34, KPLP Ret (ICE) |
| *Notes* | With transactions | With transactions | With transactions |
| *Resources Available* | 17MW ICE (PS01) - 2016 | 17MW ICE (PS01) - 2016 | 17MW ICE (PS01) - 2016 |
| *Reference* | P2_2a1XRetire-7Cr1.xlxs | P2_2a1XRetire-7Dr1.xlxs | P2_2a1XRetire-7Br1.xlxs |
| *2014* | Continue CIDLC, CIDP, RDLCWH, RDLCAC | Continue CIDLC, CIDP, RDLCWH, RDLCAC | Continue CIDLC, CIDP, RDLCWH, RDLCAC |
| | 25%+75% PBFA DSM | 10%+25%+75% PBFA DSM | 75% PBFA DSM |
| *2015* | | | |
| *2016* | | | Add 102MW ICE (PS01x6)-Biofueled |
| | | | Retire KPLP1 (-104MW)<br>Retire KPLP1 (-104MW) |
| *2017* | Retire W3 (-46MW)<br>Retire W4 (-46MW)<br>or H8/9 | Retire W3 (-46MW)<br>Retire W4 (-46MW)<br>or H8/9 | Retire W3 (-46MW)<br>Retire W4 (-46MW)<br>or H8/9 |
| *2018* | | | Add 85MW ICE (PS01x5)-Biofueled |
| *2019* | | | Add 17MW ICE (PS01x1)-Biofueled |
| | Retire H8 (-53MW)<br>Retire H9 (-54MW)<br>or W3/4 | Retire H8 (-53MW)<br>Retire H9 (-54MW)<br>or W3/4 | Retire H8 (-53MW)<br>Retire H9 (-54MW)<br>or W3/4 |
| *2020* | Add 68MW ICE (PS01x4)-Biofueled | Add 51MW ICE (PS01x3)-Biofueled | Add 85MW ICE (PS01x5)-Biofueled |
| *2021* | | | |
| *2022* | Add 17MW ICE (PS01x1)-Biofueled | Add 17MW ICE (PS01x1)-Biofueled | Add 17MW ICE (PS01x1)-Biofueled |
| *2023* | | | |
| *2024* | | | |
| *2025* | | | Add 17MW ICE (PS01x1)-Biofueled |
| *2026* | | | |
| *2027* | | | |
| *2028* | Add 17MW ICE (PS01x1)-Biofueled | | Add 17MW ICE (PS01x1)-Biofueled |
| *2029* | | | |
| *2030* | | | |
| *2031* | | | |
| *2032* | | | |
| *2033* | | | |
| *Planning Period Total* | 24, 979, 776 | 24, 741, 929 | 24, 788, 598 |

| Name | P2_2a1XRetire-7Cr1 | P2_2a1XRetire-7Dr1 | P2_2a1XRetire-7Er1 |
|---|---|---|---|
| *Cost,* | | | |
| *Study Period Total Cost,* | 35, 970, 443 | 35, 436, 567 | 36, 997, 576 |
| *Planning Rank* | 2 | 1 | 2 |
| *Study Rank* | 2 | 1 | 3 |

Table O-35. HECO 100% Renewable Energy

| **Name** | **P2B2b1NRetire-3Cr0** | **P2B2a1NRetire-3Cr0** | **P2B2a1NRetire-3Cr1** |
|---|---|---|---|
| *Plan* | 100% RE by 2030, Lanai Wind in 2020 (Wind, PV, Wave)<br>Convert Existing to Biodiesel in 2030 | 100% RE by 2030, (Wind, PV, Wave)<br>Convert Existing to Biodiesel in 2030 | 100% RE by 2030, (Wind, PV, Wave)<br>Convert Existing to Biodiesel in 2030 |
| *Notes* | | Allowed to add PW01x10 in 2020 | Allowed to add PW01x5 in 2020 |
| *Resources Available* | | | |
| *Reference* | P2B2b1NRetire-2r0 | | |
| *2014* | Expanded CIDLC, CIDP, RDLCWH, RDLCAC | Expanded CIDLC, CIDP, RDLCWH, RDLCAC | Expanded CIDLC, CIDP, RDLCWH, RDLCAC |
| | 75% PBFA DSM | 75% PBFA DSM | 75% PBFA DSM |
| *2015* | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) |
| *2016* | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) |
| *2017* | | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) |
| | Deactivate W3 (-46MW)<br>Deactivate W4 (-46MW)<br>or H8/9 | Deactivate W3 (-46MW)<br>Deactivate W4 (-46MW)<br>or H8/9 | Deactivate W3 (-46MW)<br>Deactivate W4 (-46MW)<br>or H8/9 |
| *2018* | | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) |
| *2019* | | | Add 20 MW PV (PP03x4) |
| | Deactivate H8 (-53MW)<br>Deactivate H9 (-54MW)<br>or W3/4 | Deactivate H8 (-53MW)<br>Deactivate H9 (-54MW)<br>or W3/4 | Deactivate H8 (-53MW)<br>Deactivate H9 (-54MW)<br>or W3/4 |
| *2020* | Add 59MW CC (PC08x1)-Biofueled | Add 59MW CC (PC08x1)-Biofueled | Add 59MW CC (PC08x1)-Biofueled |
| | Add 200 MW Lanai Wind | Add 300 MW Wind (PW01x10) | Add 210 MW Wind (PW01x7) |
| | Add 60 MW Wind (PW01x2) | | Add 60 MW PV (PP03x12) |
| | | | Add 30 MW Wave (PV02x2) |
| *2021* | | | Add 30 MW Wind (PW01x1) |
| *2022* | Add 60 MW Wind (PW01x2) | | Add 30 MW Wind (PW01x1) |
| *2023* | | | |
| *2024* | Add 30 MW Wind (PW01x1) | Add 60 MW Wind (PW01x2) | Add 60 MW Wind (PW01x2) |
| *2025* | | | |
| *2026* | | | |
| *2027* | Add 25MW (PA01x1)-Biomass | Add 25MW (PA01x1)-Biomass | Add 25MW (PA01x1)-Biomass |
| *2028* | | | |
| *2029* | | | |

| **Name** | **P2B2b1NRetire-3Cr0** | **P2B2a1NRetire-3Cr0** | **P2B2a1NRetire-3Cr1** |
|---|---|---|---|
| *2030* | Fuel Switch to BF (Waiau 5-10/Kahe 1-6) | Fuel Switch to BF (Waiau 5-10/Kahe 1-6) | Fuel Switch to BF (Waiau 5-10/Kahe 1-6) |
| | Add 60 MW Wind (PW01x2) | Add 60 MW Wind (PW01x2) | Add 60 MW Wind (PW01x2) |
| | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) | |
| *2031* | | | |
| *2032* | | | |
| *2033* | | | |
| *Planning Period Total Cost* | 22, 754, 010 | 22, 831, 272 | 23, 100, 820 |
| *Study Period Total Cost* | 32, 988, 304 | 33, 317, 892 | 33, 705, 028 |
| *Planning Rank* | 1 | 2 | 3 |
| *Study Rank* | 1 | 2 | 3 |

Table O-36. HECO 0% Renewable Portfolio Standard

| **Name** | **P2B2b1NRetire-3Ar0 0%RPS** | **P2B2a1NRetire-3Ar0 0% RPS No Lanai** | **P2B2A1NRETIRE-3AR0 0%RPSNOLANAILNG** | **P2B2b1NRetire-2r0** |
|---|---|---|---|---|
| *Plan* | 0% RPS, Lanai Wind in 2020 (Wind, PV) | 0% RPS, (Wind, PV) | 0% RPS, (Wind, PV) | RPS Screen based on P2B2a1NRetire-2r0, w/ Lanai Wind |
| *Resources Available* | | | | |
| *Reference* | P2B2b1NRetire-2r0 | | | |
| *2014* | Expanded CIDLC, CIDP, RDLCWH, RDLCAC | Expanded CIDLC, CIDP, RDLCWH, RDLCAC | Expanded CIDLC, CIDP, RDLCWH, RDLCAC | Expanded CIDLC, CIDP, RDLCWH, RDLCAC |
| | 75% PBFA DSM | 75% PBFA DSM | 75% PBFA DSM | 75% PBFA DSM |
| *2015* | | Add 20 MW PV (PP03x4) | | |
| *2016* | Add 60 MW Wind (PW01x2) | Add 60 MW Wind (PW01x2) | Add 60 MW Wind (PW01x2) | Add 20 MW PV (PP03x4) |
| | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) | | Add 60 MW Wind (PW01x2) |
| *2017* | Add 60 MW Wind (PW01x2) | Add 60 MW Wind (PW01x2) | | |
| | | | | Add 60 MW Wind (PW01x2) |
| | Deactivate W3 (-46MW) Deactivate W4 (-46MW) or H8/9 | Deactivate W3 (-46MW) Deactivate W4 (-46MW) or H8/9 | Deactivate W3 (-46MW) Deactivate W4 (-46MW) or H8/9 | Deactivate W3 (-46MW) Deactivate W4 (-46MW) or H8/9 |
| *2018* | Add 60 MW Wind (PW01x2) | Add 60 MW Wind (PW01x2) | | |
| | | | | Add 60 MW Wind (PW01x2) |
| *2019* | | Add 60 MW Wind (PW01x2) | | |
| | Deactivate H8 (-53MW) Deactivate H9 (-54MW) or W3/4 | Deactivate H8 (-53MW) Deactivate H9 (-54MW) or W3/4 | Deactivate H8 (-53MW) Deactivate H9 (-54MW) or W3/4 | Deactivate H8 (-53MW) Deactivate H9 (-54MW) or W3/4 |
| *2020* | Add 59MW CC (PC08x1)-Biofueled | Add 59MW CC (PC08x1)-Biofueled | Add 59MW CC (PC08x1)-Biofueled | Add 59MW CC (PC08x1)-Biofueled |
| | Add 200 MW Lanai Wind | | | Add 200 MW Lanai Wind |
| | | Add 30 MW Wind (PW01x1) | | |
| *2021* | | Add 30 MW Wind (PW01x1) | | |
| *2022* | | Add 30 MW Wind (PW01x1) | | |
| *2023* | | | | |
| *2024* | | Add 60 MW Wind (PW01x2) | | |
| *2025* | | | | |
| *2026* | | | | |
| *2027* | Add 25MW (PA01x1)-Biomass | Add 25MW (PA01x1)-Biomass | Add 25MW (PA01x1)-Biomass | Add 25MW (PA01x1)-Biomass |
| | | Add 30 MW Wind (PW01x1) | | |
| *2028* | | | | Add 20 MW PV (PP03x4) |

| Name | P2B2b1NRetire-3Ar0 0%RPS | P2B2a1NRetire-3Ar0 0% RPS No Lanai | P2B2A1NRETIRE-3AR0 0%RPSNOLANAILNG | P2B2b1NRetire-2r0 |
|---|---|---|---|---|
| *2029* | | | | Add 30 MW Wind (PW01x1) |
| | | | | Add 20 MW PV (PP03x4) |
| *2030* | | Add 20 MW PV (PP03x4) | | Add 150 MW Wind (PW01x5) |
| | | | | Add 20 MW PV (PP03x4) |
| *2031* | | Add 20 MW PV (PP03x4) | | |
| *2032* | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) | | |
| *2033* | Add 30 MW Wind (PW01x1) | Add 30 MW Wind (PW01x1) | | |
| | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) | | |
| *Planning Period Total Cost* | 22, 252, 975 | 22, 318, 927 | 19, 459, 624 | 22, 234, 112 |
| *Study Period Total Cost* | 32, 910, 344 | 33, 229, 286 | 27, 553, 628 | 32, 899, 972 |
| *Planning Rank* | 3 | 4 | 1 | 2 |
| *Study Rank* | 3 | 4 | 1 | 2 |

Table O-37. HECO Demand Response with Spinning Reserve

| **Name** | **P2B2b1NRetire-9r0** | **P2B2b1NRetire-9r1** |
|---|---|---|
| *Plan* | DR no Spin, based on P2B2a1NRetire-2r0, w/ Lanai Wind | DR w/ Spin value, based on P2B2a1NRetire-2r0, w/ Lanai Wind |
| *Resources Available* | | |
| *Reference* | P2B2b1NRetire-2r0 | |
| *2014* | Expanded CIDLC, CIDP, RDLCWH, RDLCAC | Expanded CIDLC, CIDP, RDLCWH, RDLCAC |
| | 75% PBFA DSM | 75% PBFA DSM |
| *2015* | | |
| *2016* | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) |
| | Add 60 MW Wind (PW01x2) | Add 60 MW Wind (PW01x2) |
| *2017* | Add 60 MW Wind (PW01x2) | Add 60 MW Wind (PW01x2) |
| | Deactivate W3 (-46MW)<br>Deactivate W4 (-46MW)<br>or H8/9 | Deactivate W3 (-46MW)<br>Deactivate W4 (-46MW)<br>or H8/9 |
| *2018* | Add 60 MW Wind (PW01x2) | Add 60 MW Wind (PW01x2) |
| *2019* | Deactivate H8 (-53MW)<br>Deactivate H9 (-54MW)<br>or W3/4 | Deactivate H8 (-53MW)<br>Deactivate H9 (-54MW)<br>or W3/4 |
| *2020* | Add 59MW CC (PC08x1)-Biofueled | Add 59MW CC (PC08x1)-Biofueled |
| | Add 200 MW Lanai Wind | Add 200 MW Lanai Wind |
| *2021* | | |
| *2022* | | |
| *2023* | | |
| *2024* | | |
| *2025* | | |
| *2026* | | |
| *2027* | Add 25MW (PA01x1)-Biomass | Add 25MW (PA01x1)-Biomass |
| *2028* | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) |
| *2029* | Add 30 MW Wind (PW01x1) | Add 30 MW Wind (PW01x1) |
| | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) |
| *2030* | Add 150 MW Wind (PW01x5) | Add 150 MW Wind (PW01x5) |
| | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) |
| *2031* | | |
| *2032* | | |
| *2033* | | |

| **Name** | **P2B2b1NRetire-9r0** | **P2B2b1NRetire-9r1** |
|---|---|---|
| *Planning Period Total Cost* | 22, 369, 115 | 22, 354, 143 |
| *Study Period Total Cost* | 33, 034, 979 | 33, 017, 997 |
| *Planning Rank* | 2 | 1 |
| *Study Rank* | 2 | 1 |

Table O-38. HECO CT-1 (1 of 2)

| **Name** | **P2B2B1NRETIRE-5BR0** | **P2B2B1NRETIRE-5CR1** | **P2B2B1NRETIRE-2R0 BF CONTR** | **P2B2B1NRETIRE-5DR0** |
|---|---|---|---|---|
| *Plan* | CT-1 Fuel Switch to ULSD in 2016 | CT-1 Fuel Switch to ULSD in 2016 and then to LNG in 2020 | Continue Biofuel Contract | CT-1 Fuel Switch to ULSD in 2016 w/ PV providing renewable energy |
| *Resources Available* | All resources fixed | All resources fixed | All resources fixed | All resources fixed |
| *2014* | Expanded CIDLC, CIDP, RDLCWH, RDLCAC | Expanded CIDLC, CIDP, RDLCWH, RDLCAC | Expanded CIDLC, CIDP, RDLCWH, RDLCAC | Expanded CIDLC, CIDP, RDLCWH, RDLCAC |
| | 75% PBFA DSM | 75% PBFA DSM | 75% PBFA DSM | 75% PBFA DSM |
| *2015* | | | | Add 15 MW PV (PP03x3) |
| *2016* | Add 60 MW Wind (PW01x2) | Add 60 MW Wind (PW01x2) | Add 60 MW Wind (PW01x2) | Add 60 MW Wind (PW01x2) |
| | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) |
| | Fuel Switch to Diesel (Hon 8-9, Waiau 5-8, Kahe 1-6) | Fuel Switch to Diesel (Hon 8-9,<br>Waiau 5-8, Kahe 1-6) | Fuel Switch to Diesel (Hon 8-9,<br>Waiau 5-8, Kahe 1-6) | Fuel Switch to Diesel (Hon 8-9,<br>Waiau 5-8, Kahe 1-6) |
| | Fuel Switch to ULSD (CIP-1) | Fuel Switch to ULSD (CIP-1) | Continue Biofuel Contract | Fuel Switch to ULSD (CIP-1) |
| *2017* | Add 60 MW Wind (PW01x2) | Add 60 MW Wind (PW01x2) | Add 60 MW Wind (PW01x2) | Add 60 MW Wind (PW01x2) |
| | Deactivate W3 (-46MW)<br>Deactivate W4 (-46MW)<br>or H8/9 | Deactivate W3 (-46MW)<br>Deactivate W4 (-46MW)<br>or H8/9 | Deactivate W3 (-46MW)<br>Deactivate W4 (-46MW)<br>or H8/9 | Deactivate W3 (-46MW)<br>Deactivate W4 (-46MW)<br>or H8/9 |
| *2018* | Add 60 MW Wind (PW01x2) | Add 60 MW Wind (PW01x2) | Add 60 MW Wind (PW01x2) | Add 60 MW Wind (PW01x2) |
| *2019* | Deactivate H8 (-53MW)<br>Deactivate H9 (-54MW)<br>or W3/4 | Deactivate H8 (-53MW)<br>Deactivate H9 (-54MW)<br>or W3/4 | Deactivate H8 (-53MW)<br>Deactivate H9 (-54MW)<br>or W3/4 | Deactivate H8 (-53MW)<br>Deactivate H9 (-54MW)<br>or W3/4 |
| *2020* | Add 59MW CC (PC08x1)-Biofueled | Add 59MW CC (PC08x1)-Biofueled | Add 59MW CC (PC08x1)-Biofueled | Add 59MW CC (PC08x1)-Biofueled |
| | Add 200 MW Lanai Wind | Add 200 MW Lanai Wind | Add 200 MW Lanai Wind | Add 200 MW Lanai Wind |
| | | Fuel Switch to LNG (CIP-1) | | |
| *2021* | | | | |
| *2022* | Fuel Switch to ULSD (Hon 8-9, Waiau 5-8, Kahe 1-6) | Fuel Switch to ULSD (Hon 8-9,<br>Waiau 5-8, Kahe 1-6) | Fuel Switch to ULSD (Hon 8-9,<br>Waiau 5-8, Kahe 1-6) | Fuel Switch to ULSD (Hon 8-9,<br>Waiau 5-8, Kahe 1-6) |
| *2023* | | | | |
| *2024* | | | | |
| *2025* | | | | |
| *2026* | | | | |

| Name | P2B2B1NRETIRE-5BR0 | P2B2B1NRETIRE-5CR1 | P2B2B1NRETIRE-2R0 BF CONTR | P2B2B1NRETIRE-5DR0 |
|---|---|---|---|---|
| *2027* | Add 25MW (PA01x1)-Biomass | Add 25MW (PA01x1)-Biomass | Add 25MW (PA01x1)-Biomass | Add 25MW (PA01x1)-Biomass |
| *2028* | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) |
| *2029* | Add 30 MW Wind (PW01x1) | Add 30 MW Wind (PW01x1) | Add 30 MW Wind (PW01x1) | Add 30 MW Wind (PW01x1) |
| | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) |
| *2030* | Add 150 MW Wind (PW01x5) | Add 150 MW Wind (PW01x5) | Add 150 MW Wind (PW01x5) | Add 150 MW Wind (PW01x5) |
| | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) |
| *2031* | | | | |
| *2032* | | | | |
| *2033* | | | | |
| *Strategist Planning Period Total Cost,* | 22, 234, 348 | 22, 176, 212 | 22, 346, 532 | 22, 250, 292 |
| *Strategist Study Period Total Cost* | 32, 899, 064 | 32, 783, 078 | 33, 026, 042 | 32, 910, 116 |
| *Planning Period Total Cost* | 24, 911, 725 | 24, 936, 482 | 25, 023, 904 | 24, 927, 669 |
| *Study Period Total Cost,* | 35, 576, 441 | 35, 543, 350 | 35, 703, 419 | 35, 587, 493 |
| *Planning Rank* | 2 | 6 | 7 | 3 |
| *Study Rank* | 5 | 3 | 7 | 6 |

Table O-39. HECO CT-1 (2 of 2)

| **Name** | **P2B2B1NRETIRE-2R0_LBIO** | **P2B2B1NRETIRE-5BR1** | **P2B2B1NRETIRE-5BR2** |
|---|---|---|---|
| *Plan* | Continue Biofuel Contract (low biofuel price sensitivity) | Convert CT-1 to Combined Cycle and Fuel Switch to ULSD in 2016 | Convert CT-1 to Combined Cycle using Biodiesel in 2016 |
| *Resources Available* | All resources fixed | All resources fixed | All resources fixed |
| *2014* | Expanded CIDLC, CIDP, RDLCWH, RDLCAC | Expanded CIDLC, CIDP, RDLCWH, RDLCAC | Expanded CIDLC, CIDP, RDLCWH, RDLCAC |
| | 75% PBFA DSM | 75% PBFA DSM | 75% PBFA DSM |
| *2015* | | | |
| *2016* | Add 60 MW Wind (PW01x2) | Add 60 MW Wind (PW01x2) | Add 60 MW Wind (PW01x2) |
| | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) |
| | Fuel Switch to Diesel (Hon 8-9, Waiau 5-8, Kahe 1-6) | Fuel Switch to Diesel (Hon 8-9, Waiau 5-8, Kahe 1-6) | Fuel Switch to Diesel (Hon 8-9, Waiau 5-8, Kahe 1-6) |
| | Lower Priced Biofuel Contract | +57MW Convert CT-1 to CC on ULSD (SCC1) | +57MW Convert CT-1 to CC on Biodiesel (SCC1) |
| *2017* | Add 60 MW Wind (PW01x2) | Add 60 MW Wind (PW01x2) | Add 60 MW Wind (PW01x2) |
| | Deactivate W3 (-46MW)<br>Deactivate W4 (-46MW)<br>or H8/9 | Deactivate W3 (-46MW)<br>Deactivate W4 (-46MW)<br>or H8/9 | Deactivate W3 (-46MW)<br>Deactivate W4 (-46MW)<br>or H8/9 |
| *2018* | Add 60 MW Wind (PW01x2) | Add 60 MW Wind (PW01x2) | Add 60 MW Wind (PW01x2) |
| *2019* | Deactivate H8 (-53MW)<br>Deactivate H9 (-54MW)<br>or W3/4 | Deactivate H8 (-53MW)<br>Deactivate H9 (-54MW)<br>or W3/4 | Deactivate H8 (-53MW)<br>Deactivate H9 (-54MW)<br>or W3/4 |
| *2020* | Add 59MW CC (PC08x1)-Biofueled | | |
| | Add 200 MW Lanai Wind | Add 200 MW Lanai Wind | Add 200 MW Lanai Wind |
| *2021* | | Add 25MW (PA01x1)-Biomass | Add 25MW (PA01x1)-Biomass |
| *2022* | Fuel Switch to ULSD (Hon 8-9, Waiau 5-8, Kahe 1-6) | Fuel Switch to ULSD (Hon 8-9, Waiau 5-8, Kahe 1-6) | Fuel Switch to ULSD (Hon 8-9, Waiau 5-8, Kahe 1-6) |
| *2023* | | | |
| *2024* | | | |
| *2025* | | | |
| *2026* | | | |
| *2027* | Add 25MW (PA01x1)-Biomass | | |
| *2028* | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) |
| *2029* | Add 30 MW Wind (PW01x1) | Add 30 MW Wind (PW01x1) | Add 30 MW Wind (PW01x1) |
| | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) |

| Name | P2B2B1NRETIRE-2R0_LBIO | P2B2B1NRETIRE-5BR1 | P2B2B1NRETIRE-5BR2 |
|---|---|---|---|
| *2030* | Add 150 MW Wind (PW01x5) | Add 150 MW Wind (PW01x5) | Add 150 MW Wind (PW01x5) |
| | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) |
| *2031* | | | |
| *2032* | | | |
| *2033* | | | |
| *Strategist Planning Period Total Cost* | 22, 258, 338 | 22, 196, 516 | 22, 254, 092 |
| *Strategist Study Period Total Cost* | 32, 716, 918 | 32, 845, 660 | 32, 866, 598 |
| *Planning Period Total Cost* | 24, 935, 719 | 24, 873, 891 | 24, 931, 469 |
| *Study Period Total Cost* | 35, 394, 295 | 35, 523, 037 | 35, 543, 975 |
| *Planning Rank* | 5 | 1 | 4 |
| *Study Rank* | 1 | 2 | 4 |

Table O-40. HECO Alternative Plan Development (1 of 4)

| **Name** | **Self Generation** | | **P2B2a1NRetire-2r3** | **P2B2a1NRetire-2r4** | **P2B2a1NRetire-2r5** | **P2B2a1NRetire-2r6** |
|---|---|---|---|---|---|---|
| *Plan* | | | 30 MW Wind, 5 MW PV, Lanai Wind | 30 MW Wind, 5 MW PV, Lanai Wind in 2020 | 30 MW Wind, 5 MW PV, Lanai Wind in 2020<br>Cycle K1-4 | LNG, 30 MW Wind, 5 MW PV, Lanai Wind in 2020<br>Cycle K1-4 |
| *Notes* | | | | | CT-1 switch to ULSD in 2016 | CT-1 switch to ULSD in 2016 |
| *Resources Available* | Annual | Cumulative | 17 MW ICE - Biodiesel (PS01)-fixed-n/a<br>25MW Banagrass Combustion (PA01)-fixed<br>30 MW Onshore Wind Cl 3 (PW01)-2016<br>Lanai Wind-2020A<br>10 MW Onshore Wind Cl 7 (PW04)-n/a<br>100 MW Offshore Wind (PW05)-n/a<br>5 MW of 1 MW Tracking PV (PP03)-2015<br>50 MW Parabolic Trough PV (PP04)-n/a<br>9.6 MW OTEC (POT1)-n/a<br>15 MW Ocean Wave (PV02)-n/a | 17 MW ICE - Biodiesel (PS01)-fixed<br>25MW Banagrass Combustion (PA01)-fixed<br>30 MW Onshore Wind Cl 3 (PW01)-2016<br>Lanai Wind-2020<br>10 MW Onshore Wind Cl 7 (PW04)-n/a<br>100 MW Offshore Wind (PW05)-n/a<br>5 MW of 1 MW Tracking PV (PP03)-2015<br>50 MW Parabolic Trough PV (PP04)-n/a<br>9.6 MW OTEC (POT1)-n/a<br>15 MW Ocean Wave (PV02)-n/a | 17 MW ICE - Biodiesel (PS01)-fixed<br>25MW Banagrass Combustion (PA01)-fixed<br>30 MW Onshore Wind Cl 3 (PW01)-2016<br>Lanai Wind-2020A<br>10 MW Onshore Wind Cl 7 (PW04)-n/a<br>100 MW Offshore Wind (PW05)-n/a<br>5 MW of 1 MW Tracking PV (PP03)-2015<br>50 MW Parabolic Trough PV (PP04)-n/a<br>9.6 MW OTEC (POT1)-n/a<br>15 MW Ocean Wave (PV02)-n/a | 17 MW ICE - Biodiesel (PS01)-fixed<br>25MW Banagrass Combustion (PA01)-fixed<br>30 MW Onshore Wind Cl 3 (PW01)-2016<br>Lanai Wind-2020A<br>10 MW Onshore Wind Cl 7 (PW04)-n/a<br>100 MW Offshore Wind (PW05)-n/a<br>5 MW of 1 MW Tracking PV (PP03)-2015<br>50 MW Parabolic Trough PV (PP04)-n/a<br>9.6 MW OTEC (POT1)-n/a<br>15 MW Ocean Wave (PV02)-n/a |
| *2014* | 35MW | 75MW | Expanded CIDLC, CIDP, RDLCWH, RDLCAC | Expanded CIDLC, CIDP, RDLCWH, RDLCAC | Expanded CIDLC, CIDP, RDLCWH, RDLCAC | Expanded CIDLC, CIDP, RDLCWH, RDLCAC |
| | | | 75% PBFA DSM | 75% PBFA DSM | 75% PBFA DSM | 75% PBFA DSM |
| | | | Deactivate H8 (-53MW)<br>Deactivate H9 (-54MW) | Deactivate H8 (-53MW)<br>Deactivate H9 (-54MW) | Deactivate H8 (-53MW)<br>Deactivate H9 (-54MW) | Deactivate H8 (-53MW)<br>Deactivate H9 (-54MW) |
| *2015* | 36MW | 111MW | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) | |
| *2016* | 43MW | 154MW | | | Fuel Switch to ULSD (CIP-1) | Fuel Switch to ULSD (CIP-1) |
| | | | Add 20 MW PV (PP03x4) | | Add 20 MW PV (PP03x4) | |
| | | | Add 60 MW Wind (PW01x2) | Add 60 MW Wind (PW01x2) | Add 60 MW Wind (PW01x2) | Add 60 MW Wind (PW01x2) |
| | | | Fuel Switch to Diesel (Waiau 5-8, Kahe 1-6) | Fuel Switch to Diesel (Waiau 5-8, Kahe 1-6) | Fuel Switch to Diesel (Waiau 5-8, Kahe 1-6) | Fuel Switch to Diesel (Waiau 5-8, Kahe 1-6) |

| Name | Self Generation | | P2B2a1NRetire-2r3 | P2B2a1NRetire-2r4 | P2B2a1NRetire-2r5 | P2B2a1NRetire-2r6 |
|---|---|---|---|---|---|---|
| 2017 | 36MW | 189MW | Add 60 MW Wind (PW01x2) | Add 60 MW Wind (PW01x2) | Add 60 MW Wind (PW01x2) | Add 60 MW Wind (PW01x2) |
| | | | | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) | |
| | | | Deactivate W3 (-46MW) Deactivate W4 (-46MW) | Deactivate W3 (-46MW) Deactivate W4 (-46MW) | Deactivate W3 (-46MW) Deactivate W4 (-46MW) | Deactivate W3 (-46MW) Deactivate W4 (-46MW) |
| 2018 | 36MW | 225MW | Add 60 MW Wind (PW01x2) | Add 60 MW Wind (PW01x2) | Add 60 MW Wind (PW01x2) | Add 30 MW Wind (PW01x1) |
| | | | | | Cycle Kahe 1 - 4 | Cycle Kahe 1 - 4 |
| 2019 | 35MW | 260MW | Add 68MW ICE (PS01x4)-Biofueled | Add 68MW ICE (PS01x4)-Biofueled | Add 68MW ICE (PS01x4)-Biofueled | Add 68MW ICE (PS01x4)-Biofueled |
| | | | Add 60 MW Wind (PW01x2) | | Add 60 MW Wind (PW01x2) | |
| 2020 | 35MW | 295MW | | | Add 90 MW Wind (PW01x3) | Fuel Switch to LNG (Waiau 5-8, Kahe 1-6) |
| | | | Add 90 MW Wind (PW01x3) | Add 200 MW Lanai Wind | Add 200 MW Lanai Wind | Add 200 MW Lanai Wind |
| 2021 | 35MW | 331MW | | | | |
| 2022 | 28MW | 363MW | | | Add 60 MW Wind (PW01x2) | |
| | | | Fuel Switch to ULSD (Hon 8-9Waiau 5-8, Kahe 1-6) | Fuel Switch to ULSD (Hon 8-9Waiau 5-8, Kahe 1-6) | Fuel Switch to ULSD (Hon 8-9Waiau 5-8, Kahe 1-6) | |
| 2023 | 28MW | 391MW | | | | |
| 2024 | 25MW | 416MW | Add 30 MW Wind (PW01x1) | | Add 60 MW Wind (PW01x2) | |
| 2025 | 21MW | 437MW | | | | |
| 2026 | 18MW | 456MW | | | | |
| 2027 | 16MW | 472MW | Add 25MW (PA01x1)-Biomass | Add 25MW (PA01x1)-Biomass | Add 25MW (PA01x1)-Biomass | Add 25MW (PA01x1)-Biomass |
| 2028 | 15MW | 486MW | | Add 20 MW PV (PP03x4) | | |
| 2029 | 14MW | 500MW | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) | | |
| | | | | Add 30 MW Wind (PW01x1) | | Add 90 MW Wind (PW01x3) |
| 2030 | 13MW | 513MW | Add 200 MW Lanai Wind | Add 150 MW Wind (PW01x5) | | Add 150 MW Wind (PW01x5) |
| | | | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) | | |
| 2031 | 12MW | 525MW | | | Add 20 MW PV (PP03x4) | |
| 2032 | 12MW | 538MW | | | Add 20 MW PV (PP03x4) | |
| 2033 | 12MW | 549MW | | | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) |
| | | | | | Add 30 MW Wind (PW01x1) | |

| Name | Self Generation | | P2B2a1NRetire-2r3 | P2B2a1NRetire-2r4 | P2B2a1NRetire-2r5 | P2B2a1NRetire-2r6 |
|---|---|---|---|---|---|---|
| *Planning Period Total Cost* | | | 22, 302, 460 | 22, 324, 040 | 21, 543, 384 | 19, 599, 428 |
| *Study Period Total Cost,* | | | 32, 999, 758 | 33, 041, 060 | 31, 321, 152 | 27, 559, 742 |
| *Planning Period Total Cost,* | | | 24, 990, 477 | 25, 012, 060 | 24, 231, 405 | 22, 579, 557 |
| *Study Period Total Cost,* | | | 35, 687, 777 | 35, 729, 079 | 34, 025, 777 | 30, 539, 870 |
| *Planning Rank* | | | 14 | 15 | 9 | 5 |
| *Study Rank* | | | 14 | 15 | 9 | 5 |

Table O-41. HECO Alternative Plan Development (2 of 4)

| Name | Self Generation | | P2B2a1NRetire-2r7 | P2B2a1NRetire-2r8 | P2B2a1NRetire-2r9 | P2B2a1NRetire-2r10 |
|---|---|---|---|---|---|---|
| *Plan* | Annual | Cumulative | 30 MW Wind, 5 MW PV, Lanai Wind in 2020<br>Cycle K1-4 | 30 MW Wind, 5 MW PV, Lanai Wind in 2020<br>Cycle K1-4, Waiver Projects | 30 MW Wind, 5 MW PV, Lanai Wind in 2020<br>Cycle K1-4, Waiver Projects | LNG, 30 MW Wind, 5 MW PV, Lanai Wind in 2020<br>Cycle K1-4, Waiver Projects |
| *Notes* | | | CT-1 switch to ULSD in 2016 | CT-1 switch to ULSD in 2016 | CT-1 switch to ULSD in 2016 | CT-1 switch to ULSD in 2016 |
| *Resources Available* | | | 17 MW ICE - Biodiesel (PS01)-fixed<br>25MW Banagrass Combustion (PA01)-fixed<br>30 MW Onshore Wind Cl 3 (PW01)-2016<br>Lanai Wind-2020A<br>10 MW Onshore Wind Cl 7 (PW04)-n/a<br>100 MW Offshore Wind (PW05)-n/a<br>5 MW of 1 MW Tracking PV (PP03)-2015<br>50 MW Parabolic Trough PV (PP04)-n/a<br>9.6 MW OTEC (POT1)-n/a<br>15 MW Ocean Wave (PV02)-n/a | 17 MW ICE - Biodiesel (PS01)-fixed<br>25MW Banagrass Combustion (PA01)-fixed<br>30 MW Onshore Wind Cl 3 (PW01)-2016<br>Lanai Wind-2020A<br>10 MW Onshore Wind Cl 7 (PW04)-n/a<br>100 MW Offshore Wind (PW05)-n/a<br>5 MW of 1 MW Tracking PV (PP03)-2015<br>50 MW Parabolic Trough PV (PP04)-n/a<br>9.6 MW OTEC (POT1)-n/a<br>15 MW Ocean Wave (PV02)-n/a | 17 MW ICE - Biodiesel (PS01)-fixed<br>25MW Banagrass Combustion (PA01)-fixed<br>30 MW Onshore Wind Cl 3 (PW01)-2016<br>Lanai Wind-2020A<br>10 MW Onshore Wind Cl 7 (PW04)-n/a<br>100 MW Offshore Wind (PW05)-n/a<br>5 MW of 1 MW Tracking PV (PP03)-2015<br>50 MW Parabolic Trough PV (PP04)-n/a<br>9.6 MW OTEC (POT1)-n/a<br>15 MW Ocean Wave (PV02)-n/a | 17 MW ICE - Biodiesel (PS01)-fixed<br>25MW Banagrass Combustion (PA01)-fixed<br>30 MW Onshore Wind Cl 3 (PW01)-2016<br>Lanai Wind-2020A<br>10 MW Onshore Wind Cl 7 (PW04)-n/a<br>100 MW Offshore Wind (PW05)-n/a<br>5 MW of 1 MW Tracking PV (PP03)-2015<br>50 MW Parabolic Trough PV (PP04)-n/a<br>9.6 MW OTEC (POT1)-n/a<br>15 MW Ocean Wave (PV02)-n/a |
| *2014* | 35MW | 75MW | Expanded CIDLC, CIDP, RDLCWH, RDLCAC<br>75% PBFA DSM<br>Deactivate H8 (-53MW)<br>Deactivate H9 (-54MW) | Expanded CIDLC, CIDP, RDLCWH, RDLCAC<br>75% PBFA DSM<br>Deactivate H8 (-53MW)<br>Deactivate H9 (-54MW) | Expanded CIDLC, CIDP, RDLCWH, RDLCAC<br>75% PBFA DSM<br>Deactivate H8 (-53MW)<br>Deactivate H9 (-54MW) | Expanded CIDLC, CIDP, RDLCWH, RDLCAC<br>75% PBFA DSM<br>Deactivate H8 (-53MW)<br>Deactivate H9 (-54MW) |

| Name | Self Generation | | P2B2a1NRetire-2r7 | P2B2a1NRetire-2r8 | P2B2a1NRetire-2r9 | P2B2a1NRetire-2r10 |
|---|---|---|---|---|---|---|
| *2015* | 36MW | 111MW | Add 20 MW PV (PP03x4) | Add 20 MW Wind (PWWRx2) | Add 20 MW Wind (PWWRx2) | Add 20 MW Wind (PWWRx2) |
| | | | | Add 40 MW PV (PPWRx8) | Add 40 MW PV (PPWRx8) | Add 40 MW PV (PPWRx8) |
| *2016* | 43MW | 154MW | Fuel Switch to ULSD (CIP-1) | Fuel Switch to ULSD (CIP-1) | Fuel Switch to ULSD (CIP-1) | Fuel Switch to ULSD (CIP-1) |
| | | | Add 20 MW PV (PP03x4) | Add 20 MW Wind (PWWRx2) | Add 20 MW Wind (PWWRx2) | Add 20 MW Wind (PWWRx2) |
| | | | Add 60 MW Wind (PW01x2) | Add 80 MW PV (PPWRx16) | Add 80 MW PV (PPWRx16) | Add 80 MW PV (PPWRx16) |
| | | | Fuel Switch to Diesel (Waiau 5-8, Kahe 1-6) | Fuel Switch to Diesel (Waiau 5-8, Kahe 1-6) | Fuel Switch to Diesel (Waiau 5-8, Kahe 1-6) | Fuel Switch to Diesel (Waiau 5-8, Kahe 1-6) |
| *2017* | 36MW | 189MW | Activate H8 (+53MW) Activate H9 (+54MW) | Activate H8 (+53MW) Activate H9 (+54MW) | Activate H8 (+53MW) Activate H9 (+54MW) | Activate H8 (+53MW) Activate H9 (+54MW) |
| | | | Convert CT-1 to CC +57MW (STC1)-ULSD | Convert CT-1 to CC +57MW (STC1)-ULSD | Convert CT-1 to CC +57MW (STC1)-ULSD | Convert CT-1 to CC +57MW (STC1)-ULSD |
| | | | Add 51MW ICE (PS01x3)-Biofueled | Add 51MW ICE (PS01x3)-Biofueled | Add 51MW ICE (PS01x3)-Biofueled | Add 51MW ICE (PS01x3)-Biofueled |
| | | | Add 60 MW Wind (PW01x2) | Add 60 MW Wind (PW01x2) | Add 60 MW Wind (PW01x2) | Add 60 MW Wind (PW01x2) |
| | | | Add 20 MW PV (PP03x4) | | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) |
| | | | KPLP Contract Ends-208MW) | KPLP Contract Ends-208MW) | KPLP Contract Ends-208MW) | KPLP Contract Ends-208MW) |
| | | | Deactivate W3 (- 46MW) Deactivate W4 (- 46MW) | Deactivate W3 (- 46MW) Deactivate W4 (- 46MW) | Deactivate W3 (- 46MW) Deactivate W4 (- 46MW) | Deactivate W3 (- 46MW) Deactivate W4 (- 46MW) |

| Name | Self Generation | | P2B2a1NRetire-2r7 | P2B2a1NRetire-2r8 | P2B2a1NRetire-2r9 | P2B2a1NRetire-2r10 |
|---|---|---|---|---|---|---|
| 2018 | 36MW | 225MW | Deactivate H8 (- 53MW) Deactivate H9 (- 54MW) | Deactivate H8 (- 53MW) Deactivate H9 (- 54MW) | Deactivate H8 (- 53MW) Deactivate H9 (- 54MW) | Deactivate H8 (- 53MW) Deactivate H9 (- 54MW) |
| | | | Cycle Kahe 1 - 4 | Cycle Kahe 1 - 4 | Cycle Kahe 1 - 4 | Cycle Kahe 1 - 4 |
| | | | Add 60 MW Wind (PW01x2) | Add 60 MW Wind (PW01x2) | Add 60 MW Wind (PW01x2) | Add 60 MW Wind (PW01x2) |
| | | | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) |
| | | | | | Add 15 MWH Battery (PB01x1) | Add 15 MWH Battery (PB01x1) |
| 2019 | 35MW | 260MW | Add 91MW SCCT (PS07x1)-Biofueled | Add 91MW SCCT (PS07x1)-Biofueled | Add 91MW SCCT (PS07x1)-Biofueled | Add 91MW SCCT (PS07x1)-Biofueled |
| | | | Add 60 MW Wind (PW01x2) | Add 60 MW Wind (PW01x2) | Add 60 MW Wind (PW01x2) | Add 60 MW Wind (PW01x2) |
| | | | | | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) |
| | | | Add 91MW SCCT (PS07x1)-Biofueled | Add 91MW SCCT (PS07x1)-Biofueled | Add 91MW SCCT (PS07x1)-Biofueled | Add 91MW SCCT (PS07x1)-Biofueled |
| 2020 | 35MW | 295MW | Add 210 MW Wind (PW01x7) | Add 210 MW Wind (PW01x7) | Add 60 MW Wind (PW01x2) | Fuel Switch to LNG (Waiau 5-8, Kahe 1-6, CIP CC-1) |
| | | | Add 200 MW Lanai Wind | Add 200 MW Lanai Wind | Add 200 MW Lanai Wind | Add 200 MW Lanai Wind |
| 2021 | 35MW | 331MW | Add 120 MW Wind (PW01x4) | Add 120 MW Wind (PW01x4) | Add 60 MW Wind (PW01x2) | |
| 2022 | 28MW | 363MW | Add 25MW (PA01x1)-Biomass | Add 25MW (PA01x1)-Biomass | Add 25MW (PA01x1)-Biomass | Add 25MW (PA01x1)-Biomass |
| | | | | Add 30 MW Wind (PW01x1) | Add 60 MW Wind (PW01x2) | |
| | | | Fuel Switch to ULSD (Hon 8-9Waiau 5-8, Kahe 1-6) | Fuel Switch to ULSD (Hon 8-9Waiau 5-8, Kahe 1-6) | Fuel Switch to ULSD (Hon 8-9Waiau 5-8, Kahe 1-6) | |
| 2023 | 28MW | 391MW | | | Add 60 MW Wind (PW01x2) | |
| 2024 | 25MW | 416MW | Add 60 MW Wind (PW01x2) | Add 30 MW Wind (PW01x1) | Add 60 MW Wind (PW01x2) | |
| 2025 | 21MW | 437MW | Add 30 MW Wind (PW01x1) | Add 30 MW Wind (PW01x1) | Add 60 MW Wind (PW01x2) | |
| 2026 | 18MW | 456MW | | | Add 30 MW Wind (PW01x1) | |

| **Name** | **Self Generation** | | **P2B2a1NRetire-2r7** | **P2B2a1NRetire-2r8** | **P2B2a1NRetire-2r9** | **P2B2a1NRetire-2r10** |
|---|---|---|---|---|---|---|
| *2027* | 16MW | 472MW | | | | |
| *2028* | 15MW | 486MW | | Add 30 MW Wind (PW01x1) | Add 30 MW Wind (PW01x1) | |
| *2029* | 14MW | 500MW | | | | |
| *2030* | 13MW | 513MW | Add 20 MW PV (PP03x4) | | | |
| *2031* | 12MW | 525MW | Add 30 MW Wind (PW01x1) | Add 30 MW Wind (PW01x1) | Add 30 MW Wind (PW01x1) | |
| | | | Add 20 MW PV (PP03x4) | | | |
| *2032* | 12MW | 538MW | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) | | |
| *2033* | 12MW | 549MW | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) | Add 30 MW Wind (PW01x1) | |
| | | | | Add 30 MW Wind (PW01x1) | | |
| *Planning Period Total Cost* | | | 21, 767, 556 | 21, 418, 294 | 21, 529, 744 | 19, 166, 182 |
| *Study Period Total Cost* | | | 31, 207, 786 | 30, 619, 690 | 30, 702, 114 | 26, 058, 198 |
| *Planning Period Total Cost* | | | 24, 455, 571 | 24, 106, 312 | 24, 217, 761 | 22, 146, 310 |
| *Study Period Total Cost* | | | 34, 070, 227 | 33, 307, 709 | 33, 390, 133 | 29, 038, 326 |
| *Planning Rank* | | | 12 | 7 | 8 | 3 |
| *Study Rank* | | | 11 | 7 | 8 | 3 |

Table O-42. HECO Alternative Plan Development (3 of 4)

| Name | Self Generation | | P2B2a1NRetire-2r11 | P2B2a1NRetire-2r12 | P2B2a1NRetire-2r13 | P2B2a1NRetire-2r14 |
|---|---|---|---|---|---|---|
| *Plan* | Annual | Cumulative | LNG, 30 MW Wind, 5 MW PV,<br>Cycle K1-4, Waiver Projects | LNG, 30 MW Wind, 5 MW PV, Lanai Wind in 2022<br>Cycle K1-4, Waiver Projects | LNG, 30 MW Wind, 5 MW PV,<br>Cycle K1-4, Waiver Projects | LNG, 30 MW Wind, 5 MW PV,<br>Cycle K1-4, Waiver Projects |
| *Notes* | | | CT-1 switch to ULSD in 2016 | CT-1 switch to ULSD in 2016 | CT-1 switch to ULSD in 2016 | CT-1 switch to ULSD in 2016 |
| *Resources Available* | | | 17 MW ICE - Biodiesel (PS01)-fixed<br>25MW Banagrass Combustion (PA01)-fixed<br>30 MW Onshore Wind Cl 3 (PW01)-n/a<br>Lanai Wind-n/a<br>10 MW Onshore Wind Cl 7 (PW04)-n/a<br>100 MW Offshore Wind (PW05)-n/a<br>5 MW of 1 MW Tracking PV (PP03)-n/a<br>50 MW Parabolic Trough PV (PP04)-n/a<br>9.6 MW OTEC (POT1)-n/a<br>15 MW Ocean Wave (PV02)-n/a | 17 MW ICE - Biodiesel (PS01)-fixed<br>25MW Banagrass Combustion (PA01)-fixed<br>30 MW Onshore Wind Cl 3 (PW01)-n/a<br>Lanai Wind-n/a<br>10 MW Onshore Wind Cl 7 (PW04)-n/a<br>100 MW Offshore Wind (PW05)-n/a<br>5 MW of 1 MW Tracking PV (PP03)-n/a<br>50 MW Parabolic Trough PV (PP04)-n/a<br>9.6 MW OTEC (POT1)-n/a<br>15 MW Ocean Wave (PV02)-n/a | 17 MW ICE - Biodiesel (PS01)-fixed<br>25MW Banagrass Combustion (PA01)-2022<br>30 MW Onshore Wind Cl 3 (PW01)-2016<br>Lanai Wind-2020A<br>10 MW Onshore Wind Cl 7 (PW04)-n/a<br>100 MW Offshore Wind (PW05)-n/a<br>5 MW of 1 MW Tracking PV (PP03)-2015<br>50 MW Parabolic Trough PV (PP04)-n/a<br>9.6 MW OTEC (POT1)-n/a<br>15 MW Ocean Wave (PV02)-n/a | 17 MW ICE - Biodiesel (PS01)-fixed<br>25MW Banagrass Combustion (PA01)-2022<br>30 MW Onshore Wind Cl 3 (PW01)-2016<br>Lanai Wind-2020A<br>10 MW Onshore Wind Cl 7 (PW04)-n/a<br>100 MW Offshore Wind (PW05)-n/a<br>5 MW of 1 MW Tracking PV (PP03)-2015<br>50 MW Parabolic Trough PV (PP04)-n/a<br>9.6 MW OTEC (POT1)-n/a<br>15 MW Ocean Wave (PV02)-n/a |
| *2014* | 35MW | 75MW | Expanded CIDLC, CIDP, RDLCWH, RDLCAC | Expanded CIDLC, CIDP, RDLCWH, RDLCAC | Expanded CIDLC, CIDP, RDLCWH, RDLCAC | Expanded CIDLC, CIDP, RDLCWH, RDLCAC |
| | | | 75% PBFA DSM | 75% PBFA DSM | 75% PBFA DSM | 75% PBFA DSM |
| | | | Deactivate H8 (-53MW)<br>Deactivate H9 (-54MW) | Deactivate H8 (-53MW)<br>Deactivate H9 (-54MW) | Deactivate H8 (-53MW)<br>Deactivate H9 (-54MW) | Deactivate H8 (-53MW)<br>Deactivate H9 (-54MW) |
| *2015* | 36MW | 111MW | Add 20 MW Wind (PWWRx2) | Add 20 MW Wind (PWWRx2) | Add 20 MW Wind (PWWRx2) | Add 20 MW Wind (PWWRx2) |
| | | | Add 40 MW PV (PPWRx8) | Add 40 MW PV (PPWRx8) | Add 40 MW PV (PPWRx8) | Add 40 MW PV (PPWRx8) |

| Name | Self Generation | | P2B2a1NRetire-2r11 | P2B2a1NRetire-2r12 | P2B2a1NRetire-2r13 | P2B2a1NRetire-2r14 |
|---|---|---|---|---|---|---|
| *2016* | 43MW | 154MW | Fuel Switch to ULSD (CIP-1) | Fuel Switch to ULSD (CIP-1) | Fuel Switch to ULSD (CIP-1) | Fuel Switch to ULSD (CIP-1) |
| | | | | Add 20 MW Wind (PWWRx2) | Add 20 MW Wind (PWWRx2) | Add 20 MW Wind (PWWRx2) |
| | | | | Add 80 MW PV (PPWRx16) | Add 80 MW PV (PPWRx16) | Add 80 MW PV (PPWRx16) |
| | | | Fuel Switch to Diesel (Waiau 5-8, Kahe 1-6) | Fuel Switch to Diesel (Waiau 5-8, Kahe 1-6) | Fuel Switch to Diesel (Waiau 5-8, Kahe 1-6) | Fuel Switch to Diesel (Waiau 5-8, Kahe 1-6) |
| *2017* | 36MW | 189MW | Activate H8 (+53MW) Activate H9 (+54MW) | Activate H8 (+53MW) Activate H9 (+54MW) | Activate H8 (+53MW) Activate H9 (+54MW) | Activate H8 (+53MW) Activate H9 (+54MW) |
| | | | Convert CT-1 to CC +57MW (STC1)-ULSD | Convert CT-1 to CC +57MW (STC1)-ULSD | Convert CT-1 to CC +57MW (STC1)-ULSD | Convert CT-1 to CC +57MW (STC1)-ULSD |
| | | | Add 51MW ICE (PS01x3)-Biofueled | Add 51MW ICE (PS01x3)-Biofueled | Add 51MW ICE (PS01x3)-Biofueled | Add 51MW ICE (PS01x3)-Biofueled |
| | | | | | Add 60 MW Wind (PW01x2) | Add 60 MW Wind (PW01x2) |
| | | | | | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) |
| | | | KPLP Contract Ends-208MW) | KPLP Contract Ends-208MW) | | |
| | | | Deactivate W3 (-46MW) Deactivate W4 (-46MW) | Deactivate W3 (-46MW) Deactivate W4 (-46MW) | Deactivate W3 (-46MW) Deactivate W4 (-46MW) | Deactivate W3 (-46MW) Deactivate W4 (-46MW) |
| *2018* | 36MW | 225MW | Deactivate H8 (-53MW) Deactivate H9 (-54MW) | Deactivate H8 (-53MW) Deactivate H9 (-54MW) | Deactivate H8 (-53MW) Deactivate H9 (-54MW) | Deactivate H8 (-53MW) Deactivate H9 (-54MW) |
| | | | Cycle Kahe 1 - 4 | Cycle Kahe 1 - 4 | Cycle Kahe 1 - 4 | Cycle Kahe 1 - 4 |
| | | | | | Add 60 MW Wind (PW01x2) | Add 60 MW Wind (PW01x2) |
| | | | | | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) |
| | | | Add 15 MWH Battery (PB01x1) | Add 15 MWH Battery (PB01x1) | Add 15 MWH Battery (PB01x1) | Add 15 MWH Battery (PB01x1) |
| *2019* | 35MW | 260MW | Add 91MW SCCT (PS07x1)-Biofueled | Add 91MW SCCT (PS07x1)-Biofueled | | |
| | | | | | Add 60 MW Wind (PW01x2) | Add 60 MW Wind (PW01x2) |
| | | | | | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) |
| | | | Add 91MW SCCT (PS07x1)-Biofueled | Add 91MW SCCT (PS07x1)-Biofueled | | |

| Name | Self Generation | | P2B2a1NRetire-2r11 | P2B2a1NRetire-2r12 | P2B2a1NRetire-2r13 | P2B2a1NRetire-2r14 |
|---|---|---|---|---|---|---|
| *2020* | 35MW | 295MW | | Add 30 MW Wind (PW01x1) | Fuel Switch to LNG (Waiau 5-8, Kahe 1-6, CIP CC-1) | Add 60 MW Wind (PW01x2) |
| | | | | Add 5 MW PV (PP03x1) | | |
| *2021* | 35MW | 331MW | | | | Add 60 MW Wind (PW01x2) |
| *2022* | 28MW | 363MW | Add 25MW (PA01x1)-Biomass | Add 25MW (PA01x1)-Biomass | | Add 60 MW Wind (PW01x2) |
| | | | | Add 200 MW Lanai Wind | | |
| | | | Fuel Switch to ULSD (Hon 8-9Waiau 5-8, Kahe 1-6) | Fuel Switch to ULSD (Hon 8-9Waiau 5-8, Kahe 1-6) | | Fuel Switch to ULSD (Hon 8-9Waiau 5-8, Kahe 1-6) |
| *2023* | 28MW | 391MW | | | | Add 60 MW Wind (PW01x2) |
| *2024* | 25MW | 416MW | | | | Add 60 MW Wind (PW01x2) |
| *2025* | 21MW | 437MW | | | | Add 60 MW Wind (PW01x2) |
| *2026* | 18MW | 456MW | | | | |
| *2027* | 16MW | 472MW | | | | |
| *2028* | 15MW | 486MW | | | | |
| *2029* | 14MW | 500MW | | | Add 60 MW Wind (PW01x2) | |
| *2030* | 13MW | 513MW | | | Add 60 MW Wind (PW01x2) | |
| *2031* | 12MW | 525MW | | | Add 30 MW Wind (PW01x1) | Add 60 MW Wind (PW01x2) |
| *2032* | 12MW | 538MW | | | Add 30 MW Wind (PW01x1) | Add 60 MW Wind (PW01x2) |
| *2033* | 12MW | 549MW | | | | |
| *Planning Period Total Cost* | | | 22, 840, 420 | 22, 026, 212 | 19, 411, 464 | 21, 361, 752 |
| *Study Period Total Cost* | | | 34, 142, 728 | 32, 172, 264 | 27, 226, 032 | 31, 131, 474 |

| Name | Self Generation | | P2B2a1NRetire-2r11 | P2B2a1NRetire-2r12 | P2B2a1NRetire-2r13 | P2B2a1NRetire-2r14 |
|---|---|---|---|---|---|---|
| *Planning Period Total Cost* | | | 25, 517, 799 | 24, 703, 585 | 22, 391, 589 | 24, 341, 882 |
| *Study Period Total Cost* | | | 36, 820, 105 | 34, 849, 641 | 30, 206, 160 | 34, 111, 602 |
| *Planning Rank* | | | 16 | 13 | 4 | 11 |
| *Study Rank* | | | 16 | 13 | 4 | 12 |

Table O-43. HECO Alternative Plan Development (4 of 4)

| Name | Self Generation | | P2B2a1NRetire-2r15 | P2B2a1NRetire-2r16 | P2B2a1NRetire-2r17 | P2B2a1NRetire-2r18 |
|---|---|---|---|---|---|---|
| *Plan* | Annual | Cumulative | LNG, 30 MW Wind, 5 MW PV,<br>Cycle K1-4, Waiver Projects | No LNG, 30 MW Wind, 5 MW PV,<br>Cycle K1-4, Waiver Projects | LNG, 30 MW Wind, 5 MW PV, Lanai Wind in 2020<br>Cycle K1-4, Waiver Projects | LNG, 30 MW Wind, 5 MW PV, No Kalaeloa<br>Cycle K1-4, Waiver Projects |
| *Notes* | | | CT-1 Conversion to CC 2018 | CT-1 Conversion to CC 2018 | CT-1 Conversion to CC 2018 | CT-1 Conversion to CC 2018 |
| *Resources Available* | | | 17 MW ICE - Biodiesel (PS01)-fixed<br>25MW Banagrass Combustion (PA01)-2022<br>30 MW Onshore Wind Cl 3 (PW01)-2016<br>Lanai Wind-2020A<br>10 MW Onshore Wind Cl 7 (PW04)-n/a<br>100 MW Offshore Wind (PW05)-n/a<br>5 MW of 1 MW Tracking PV (PP03)-2015<br>50 MW Parabolic Trough PV (PP04)-n/a<br>9.6 MW OTEC (POT1)-n/a<br>15 MW Ocean Wave (PV02)-n/a | 17 MW ICE - Biodiesel (PS01)-fixed<br>25MW Banagrass Combustion (PA01)-2022<br>30 MW Onshore Wind Cl 3 (PW01)-2016<br>Lanai Wind-2020A<br>10 MW Onshore Wind Cl 7 (PW04)-n/a<br>100 MW Offshore Wind (PW05)-n/a<br>5 MW of 1 MW Tracking PV (PP03)-2015<br>50 MW Parabolic Trough PV (PP04)-n/a<br>9.6 MW OTEC (POT1)-n/a<br>15 MW Ocean Wave (PV02)-n/a | 17 MW ICE - Biodiesel (PS01)-fixed<br>25MW Banagrass Combustion (PA01)-2022<br>30 MW Onshore Wind Cl 3 (PW01)-2016<br>Lanai Wind-2020A<br>10 MW Onshore Wind Cl 7 (PW04)-n/a<br>100 MW Offshore Wind (PW05)-n/a<br>5 MW of 1 MW Tracking PV (PP03)-2015<br>50 MW Parabolic Trough PV (PP04)-n/a<br>9.6 MW OTEC (POT1)-n/a<br>15 MW Ocean Wave (PV02)-n/a | 17 MW ICE - Biodiesel (PS01)-fixed<br>25MW Banagrass Combustion (PA01)-2022<br>30 MW Onshore Wind Cl 3 (PW01)-2016<br>Lanai Wind-2020A<br>10 MW Onshore Wind Cl 7 (PW04)-n/a<br>100 MW Offshore Wind (PW05)-n/a<br>5 MW of 1 MW Tracking PV (PP03)-2015<br>50 MW Parabolic Trough PV (PP04)-n/a<br>9.6 MW OTEC (POT1)-n/a<br>15 MW Ocean Wave (PV02)-n/a |
| *2014* | 35MW | 75MW | Expanded CIDLC, CIDP, RDLCWH, RDLCAC | Expanded CIDLC, CIDP, RDLCWH, RDLCAC | Expanded CIDLC, CIDP, RDLCWH, RDLCAC | Expanded CIDLC, CIDP, RDLCWH, RDLCAC |
| | | | 75% PBFA DSM | 75% PBFA DSM | 75% PBFA DSM | 75% PBFA DSM |
| | | | Deactivate H8 (-53MW)<br>Deactivate H9 (-54MW) | Deactivate H8 (-53MW)<br>Deactivate H9 (-54MW) | Deactivate H8 (-53MW)<br>Deactivate H9 (-54MW) | Deactivate H8 (-53MW)<br>Deactivate H9 (-54MW) |
| *2015* | 36MW | 111MW | Add 20 MW Wind (PWWRx2) | Add 20 MW Wind (PWWRx2) | Add 20 MW Wind (PWWRx2) | Add 20 MW Wind (PWWRx2) |
| | | | Add 40 MW PV (PPWRx8) | Add 40 MW PV (PPWRx8) | Add 40 MW PV (PPWRx8) | Add 40 MW PV (PPWRx8) |

| Name | Self Generation | | P2B2a1NRetire-2r15 | P2B2a1NRetire-2r16 | P2B2a1NRetire-2r17 | P2B2a1NRetire-2r18 |
|---|---|---|---|---|---|---|
| *2016* | 43MW | 154MW | Fuel Switch to ULSD (CIP-1) | Fuel Switch to ULSD (CIP-1) | Fuel Switch to ULSD (CIP-1) | Fuel Switch to ULSD (CIP-1) |
| | | | Add 20 MW Wind (PWWRx2) | Add 20 MW Wind (PWWRx2) | Add 20 MW Wind (PWWRx2) | Add 20 MW Wind (PWWRx2) |
| | | | Add 80 MW PV (PPWRx16) | Add 80 MW PV (PPWRx16) | Add 80 MW PV (PPWRx16) | Add 80 MW PV (PPWRx16) |
| | | | Fuel Switch to Diesel (Waiau 5-8, Kahe 1-6) | Fuel Switch to Diesel (Waiau 5-8, Kahe 1-6) | Fuel Switch to Diesel (Waiau 5-8, Kahe 1-6) | Fuel Switch to Diesel (Waiau 5-8, Kahe 1-6) |
| *2017* | 36MW | 189MW | | | | Activate H8 (+53MW) Activate H9 (+54MW) |
| | | | | | | Convert CT-1 to CC +57MW (STC1)-ULSD |
| | | | Add 51MW ICE (PS01x3)-Biofueled | Add 51MW ICE (PS01x3)-Biofueled | Add 51MW ICE (PS01x3)-Biofueled | Add 51MW ICE (PS01x3)-Biofueled |
| | | | Add 60 MW Wind (PW01x2) | Add 60 MW Wind (PW01x2) | Add 60 MW Wind (PW01x2) | Add 60 MW Wind (PW01x2) |
| | | | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) |
| | | | | | | KPLP Contract Ends-208MW) |
| | | | Deactivate W3 (-46MW) Deactivate W4 (-46MW) | Deactivate W3 (-46MW) Deactivate W4 (-46MW) | Deactivate W3 (-46MW) Deactivate W4 (-46MW) | |
| *2018* | 36MW | 225MW | Convert CT-1 to CC +57MW (STC1)-ULSD | Convert CT-1 to CC +57MW (STC1)-ULSD | Convert CT-1 to CC +57MW (STC1)-ULSD | Fuel Switch to Kahe 3 to Biofuel Blend |
| | | | Cycle Kahe 1 - 4 | Cycle Kahe 1 - 4 | Cycle Kahe 1 - 4 | Cycle Kahe 1 - 4 |
| | | | Add 60 MW Wind (PW01x2) | Add 60 MW Wind (PW01x2) | Add 60 MW Wind (PW01x2) | Add 60 MW Wind (PW01x2) |
| | | | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) |
| | | | Add 15 MWH Battery (PB01x1) | Add 15 MWH Battery (PB01x1) | Add 15 MWH Battery (PB01x1) | Add 15 MWH Battery (PB01x1) |
| *2019* | 35MW | 260MW | | | | Add 95MW SCCT (PS08x1)-Biodiesel/LNG |
| | | | | | | Add 60 MW Wind (PW01x2) |
| | | | Add 60 MW Wind (PW01x2) | Add 60 MW Wind (PW01x2) | Add 60 MW Wind (PW01x2) | Add 20 MW PV (PP03x4) |
| | | | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) | Deactivate W3 (-46MW) Deactivate W4 (-46MW) |
| | | | | | | Deactivate H8 (-53MW) Deactivate H9 (-54MW) |

| Name | Self Generation | | P2B2a1NRetire-2r15 | P2B2a1NRetire-2r16 | P2B2a1NRetire-2r17 | P2B2a1NRetire-2r18 |
|---|---|---|---|---|---|---|
| *2020* | 35MW | 295MW | Fuel Switch to LNG (Waiau 5-8, Kahe 1-6, CIP CC-1, Kalaeloa) | Add 60 MW Wind (PW01x2) | Fuel Switch to LNG (Waiau 5-8, Kahe 1-6, CIP CC-1, Kalaeloa)<br>Add 200 MW Lanai Wind | Add 285MW SCCT (PS08x3)-LNG<br>Add 177MW CC (PS12x3)-LNG<br>Retire W5 (-55MW)<br>Retire W6 (-56MW)<br>Retire W7 (-88MW)<br>Retire W8 (-88MW)<br>Retire K1 (-88MW)<br>Retire K2 (-86MW)<br>Retire K3 (-88MW)<br>Retire K4 (-89MW) |
| *2021* | 35MW | 331MW | | Add 60 MW Wind (PW01x2) | | Add 177MW CC (PS12x3)-LNG<br>Retire K5 (-135MW) |
| *2022* | 28MW | 363MW | | Add 60 MW Wind (PW01x2)<br>Fuel Switch to ULSD (Hon 8-9Waiau 5-8, Kahe 1-6) | | Add 190MW SCCT (PS08x2)-LNG<br>Retire K6 (-134MW) |
| *2023* | 28MW | 391MW | | Add 60 MW Wind (PW01x2) | | Add 95MW SCCT (PS08x1)-LNG |
| *2024* | 25MW | 416MW | | Add 60 MW Wind (PW01x2) | | |
| *2025* | 21MW | 437MW | | Add 60 MW Wind (PW01x2) | | |
| *2026* | 18MW | 456MW | Add 60 MW Wind (PW01x2) | | | |
| *2027* | 16MW | 472MW | Add 60 MW Wind (PW01x2) | | | |
| *2028* | 15MW | 486MW | Add 60 MW Wind (PW01x2) | | | |
| *2029* | 14MW | 500MW | Add 60 MW Wind (PW01x2) | | | Add 60 MW Wind (PW01x2) |
| *2030* | 13MW | 513MW | Add 60 MW Wind (PW01x2) | | Add 30 MW Wind (PW01x1) | Add 60 MW Wind (PW01x2) |
| *2031* | 12MW | 525MW | | Add 60 MW Wind (PW01x2) | | |
| *2032* | 12MW | 538MW | | Add 60 MW Wind (PW01x2) | | Add 30 MW Wind (PW01x1) |

| Name | Self Generation | | P2B2a1NRetire-2r15 | P2B2a1NRetire-2r16 | P2B2a1NRetire-2r17 | P2B2a1NRetire-2r18 |
|---|---|---|---|---|---|---|
| *2033* | 12MW | 549MW | | | | |
| *Planning Period Total Cost* | | | 18, 729, 652 | 21, 314, 870 | 18, 874, 302 | 20, 821, 548 |
| *Study Period Total Cost* | | | 25, 817, 764 | 31, 084, 122 | 25, 714, 928 | 28, 555, 732 |
| *Planning Period Total Cost* | | | 21, 709, 780 | 24, 295, 002 | 21, 854, 431 | 23, 395, 202 |
| *Study Period Total Cost,* | | | 28, 797, 892 | 34, 064, 250 | 28, 695, 056 | 31, 129, 385 |
| *Planning Rank* | | | 1 | 10 | 2 | 6 |
| *Study Rank* | | | 2 | 10 | 1 | 6 |

Table O-44. HECO Preferred Plans

| Name | Self Generation | | P2B2a1NRetire-2r15 | P2B2a1NRetire-2r16 | P2B2a1NRetire-2r17 | P2B2a1NRetire-2r18 |
|---|---|---|---|---|---|---|
| *Plan* | Annual | Cumulative | LNG, 30 MW Wind, 5 MW PV, Cycle K1-4, Waiver Projects | No LNG, 30 MW Wind, 5 MW PV, Cycle K1-4, Waiver Projects | LNG, 30 MW Wind, 5 MW PV, Lanai Wind in 2020 Cycle K1-4, Waiver Projects | LNG, 30 MW Wind, 5 MW PV, No Kalaeloa Cycle K1-4, Waiver Projects |
| *Notes* | | | CT-1 Conversion to CC 2018 | CT-1 Conversion to CC 2018 | CT-1 Conversion to CC 2018 | CT-1 Conversion to CC 2018 |
| *Resources Available* | | | 17 MW ICE - Biodiesel (PS01)-fixed<br>25MW Banagrass Combustion (PA01)-2022<br>30 MW Onshore Wind Cl 3 (PW01)-2016<br>Lanai Wind-2020A<br>10 MW Onshore Wind Cl 7 (PW04)-n/a<br>100 MW Offshore Wind (PW05)-n/a<br>5 MW of 1 MW Tracking PV (PP03)-2015<br>50 MW Parabolic Trough PV (PP04)-n/a<br>9.6 MW OTEC (POT1)-n/a<br>15 MW Ocean Wave (PV02)-n/a | 17 MW ICE - Biodiesel (PS01)-fixed<br>25MW Banagrass Combustion (PA01)-2022<br>30 MW Onshore Wind Cl 3 (PW01)-2016<br>Lanai Wind-2020A<br>10 MW Onshore Wind Cl 7 (PW04)-n/a<br>100 MW Offshore Wind (PW05)-n/a<br>5 MW of 1 MW Tracking PV (PP03)-2015<br>50 MW Parabolic Trough PV (PP04)-n/a<br>9.6 MW OTEC (POT1)-n/a<br>15 MW Ocean Wave (PV02)-n/a | 17 MW ICE - Biodiesel (PS01)-fixed<br>25MW Banagrass Combustion (PA01)-2022<br>30 MW Onshore Wind Cl 3 (PW01)-2016<br>Lanai Wind-2020A<br>10 MW Onshore Wind Cl 7 (PW04)-n/a<br>100 MW Offshore Wind (PW05)-n/a<br>5 MW of 1 MW Tracking PV (PP03)-2015<br>50 MW Parabolic Trough PV (PP04)-n/a<br>9.6 MW OTEC (POT1)-n/a<br>15 MW Ocean Wave (PV02)-n/a | 17 MW ICE - Biodiesel (PS01)-fixed<br>25MW Banagrass Combustion (PA01)-n/a<br>30 MW Onshore Wind Cl 3 (PW01)-2016<br>Lanai Wind-2020A<br>10 MW Onshore Wind Cl 7 (PW04)-n/a<br>100 MW Offshore Wind (PW05)-n/a<br>5 MW of 1 MW Tracking PV (PP03)-2015<br>50 MW Parabolic Trough PV (PP04)-n/a<br>9.6 MW OTEC (POT1)-n/a<br>15 MW Ocean Wave (PV02)-n/a |
| *2014* | 35MW | 75MW | Expanded CIDLC, CIDP, RDLCWH, RDLCAC | Expanded CIDLC, CIDP, RDLCWH, RDLCAC | Expanded CIDLC, CIDP, RDLCWH, RDLCAC | Expanded CIDLC, CIDP, RDLCWH, RDLCAC |
| | | | 75% PBFA DSM | 75% PBFA DSM | 75% PBFA DSM | 75% PBFA DSM |
| | | | Deactivate H8 (- 53MW)<br>Deactivate H9 (- 54MW) | Deactivate H8 (-53MW)<br>Deactivate H9 (-54MW) | Deactivate H8 (-53MW)<br>Deactivate H9 (-54MW) | Deactivate H8 (-53MW)<br>Deactivate H9 (-54MW) |
| *2015* | 36MW | 111MW | Add 20 MW Wind (PWWRx2) | Add 20 MW Wind (PWWRx2) | Add 20 MW Wind (PWWRx2) | Add 20 MW Wind (PWWRx2) |
| | | | Add 40 MW PV (PPWRx8) | Add 40 MW PV (PPWRx8) | Add 40 MW PV (PPWRx8) | Add 40 MW PV (PPWRx8) |

| Name | Self Generation | | P2B2a1NRetire-2r15 | P2B2a1NRetire-2r16 | P2B2a1NRetire-2r17 | P2B2a1NRetire-2r18 |
|---|---|---|---|---|---|---|
| *2016* | 43MW | 154MW | Fuel Switch to ULSD (CIP-1) | Fuel Switch to ULSD (CIP-1) | Fuel Switch to ULSD (CIP-1) | Fuel Switch to ULSD (CIP-1) |
| | | | Add 20 MW Wind (PWWRx2) | Add 20 MW Wind (PWWRx2) | Add 20 MW Wind (PWWRx2) | Add 20 MW Wind (PWWRx2) |
| | | | Add 80 MW PV (PPWRx16) | Add 80 MW PV (PPWRx16) | Add 80 MW PV (PPWRx16) | Add 80 MW PV (PPWRx16) |
| | | | Fuel Switch to Diesel (Waiau 5-8, Kahe 1-6) | Fuel Switch to Diesel (Waiau 5-8, Kahe 1-6) | Fuel Switch to Diesel (Waiau 5-8, Kahe 1-6) | Fuel Switch to Diesel (Waiau 5-8, Kahe 1-6) |
| *2017* | 36MW | 189MW | | | | Activate H8 (+53MW) Activate H9 (+54MW) |
| | | | | | | Convert CT-1 to CC +57MW (STC1)-ULSD |
| | | | Add 51MW ICE (PS01x3)-Biofueled | Add 51MW ICE (PS01x3)-Biofueled | Add 51MW ICE (PS01x3)-Biofueled | Add 51MW ICE (PS01x3)-Biofueled |
| | | | Add 60 MW Wind (PW01x2) | Add 60 MW Wind (PW01x2) | Add 60 MW Wind (PW01x2) | Add 60 MW Wind (PW01x2) |
| | | | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) |
| | | | | | | KPLP Contract Ends-208MW) |
| | | | Deactivate W3 (- 46MW) Deactivate W4 (- 46MW) | Deactivate W3 (-46MW) Deactivate W4 (-46MW) | Deactivate W3 (-46MW) Deactivate W4 (-46MW) | |
| *2018* | 36MW | 225MW | Convert CT-1 to CC +57MW (STC1)-ULSD | Convert CT-1 to CC +57MW (STC1)-ULSD | Convert CT-1 to CC +57MW (STC1)-ULSD | Fuel Switch to Kahe 3 to Biofuel Blend |
| | | | Cycle Kahe 1 - 4 | Cycle Kahe 1 - 4 | Cycle Kahe 1 - 4 | Cycle Kahe 1 - 4 |
| | | | Add 60 MW Wind (PW01x2) | Add 60 MW Wind (PW01x2) | Add 60 MW Wind (PW01x2) | Add 60 MW Wind (PW01x2) |
| | | | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) |
| | | | Add 15 MWH Battery (PB01x1) | Add 15 MWH Battery (PB01x1) | Add 15 MWH Battery (PB01x1) | Add 15 MWH Battery (PB01x1) |

| Name | Self Generation | | P2B2a1NRetire-2r15 | P2B2a1NRetire-2r16 | P2B2a1NRetire-2r17 | P2B2a1NRetire-2r18 |
|---|---|---|---|---|---|---|
| *2019* | 35MW | 260MW | Add 60 MW Wind (PW01x2)<br>Add 20 MW PV (PP03x4) | Add 60 MW Wind (PW01x2)<br>Add 20 MW PV (PP03x4) | Add 60 MW Wind (PW01x2)<br>Add 20 MW PV (PP03x4) | Add 95MW SCCT (PS08x1)-Biodiesel/LNG<br>Add 60 MW Wind (PW01x2)<br>Add 20 MW PV (PP03x4)<br>Deactivate W3 (-46MW)<br>Deactivate W4 (-46MW)<br>Deactivate H8 (-53MW)<br>Deactivate H9 (-54MW) |
| *2020* | 35MW | 295MW | Fuel Switch to LNG (Waiau 5-8, Kahe 1-6, CIP CC-1, Kalaeloa) | Add 60 MW Wind (PW01x2) | Fuel Switch to LNG (Waiau 5-8, Kahe 1-6, CIP CC-1, Kalaeloa)<br>Add 200 MW Lanai Wind | Add 285MW SCCT (PS08x3)-LNG<br>Add 177MW CC (PS12x3)-LNG<br>Retire W5 (-55MW)<br>Retire W6 (-56MW)<br>Retire W7 (-88MW)<br>Retire W8 (-88MW)<br>Retire K1 (-88MW)<br>Retire K2 (-86MW)<br>Retire K3 (-88MW)<br>Retire K4 (-89MW) |
| *2021* | 35MW | 331MW | | Add 60 MW Wind (PW01x2) | | Add 177MW CC (PS12x3)-LNG<br>Retire K5 (-135MW) |
| *2022* | 28MW | 363MW | | Add 60 MW Wind (PW01x2)<br>Fuel Switch to ULSD (Waiau 5-8, Kahe 1-6) | | Add 190MW SCCT (PS08x2)-LNG<br>Retire K6 (-134MW) |
| *2023* | 28MW | 391MW | | Add 60 MW Wind (PW01x2) | | Add 95MW SCCT (PS08x1)-LNG |
| *2024* | 25MW | 416MW | | Add 60 MW Wind (PW01x2) | | |
| *2025* | 21MW | 437MW | | Add 60 MW Wind (PW01x2) | | |
| *2026* | 18MW | 456MW | Add 60 MW Wind (PW01x2) | | | |
| *2027* | 16MW | 472MW | Add 60 MW Wind (PW01x2) | | | |

| Name | Self Generation | | P2B2a1NRetire-2r15 | P2B2a1NRetire-2r16 | P2B2a1NRetire-2r17 | P2B2a1NRetire-2r18 |
|---|---|---|---|---|---|---|
| *2028* | 15MW | 486MW | Add 60 MW Wind (PW01x2) | | | |
| *2029* | 14MW | 500MW | Add 60 MW Wind (PW01x2) | | | Add 60 MW Wind (PW01x2) |
| *2030* | 13MW | 513MW | Add 60 MW Wind (PW01x2) | | Add 30 MW Wind (PW01x1) | Add 60 MW Wind (PW01x2) |
| *2031* | 12MW | 525MW | | Add 60 MW Wind (PW01x2) | | |
| *2032* | 12MW | 538MW | | Add 60 MW Wind (PW01x2) | | Add 30 MW Wind (PW01x1) |
| *2033* | 12MW | 549MW | | | | |
| *Planning Period Total Cost* | | | 18, 729, 652 | 21, 314, 870 | 18, 874, 302 | 20, 821, 548 |
| *Study Period Total Cost* | | | 25, 817, 764 | 31, 084, 122 | 25, 714, 928 | 28, 555, 732 |
| *Planning Period Total Cost* | | | 21, 709, 780 | 24, 295, 002 | 21, 854, 431 | 23, 395, 202 |
| *Study Period Total Cost* | | | 28, 797, 892 | 34, 064, 250 | 28, 695, 056 | 31, 129, 385 |
| *Planning Rank* | | | 1 | 4 | 2 | 3 |
| *Study Rank* | | | 2 | 4 | 1 | 3 |

Table O-45. HECO Loss of Sales

| Name | Self Generation | | P2B2a1NRetire-2r15 LossOfSales |
|---|---|---|---|
| *Plan* | Annual | Cumulative | LNG, 30 MW Wind, 5 MW PV,<br>Cycle K1-4, Waiver Projects |
| *Notes* | | | CT-1 Conversion to CC 2018 |
| *Resources Available* | | | 17 MW ICE - Biodiesel (PS01)-fixed<br>25MW Banagrass Combustion (PA01)-2022<br>30 MW Onshore Wind Cl 3 (PW01)-2016<br>Lanai Wind-2020A<br>10 MW Onshore Wind Cl 7 (PW04)-n/a<br>100 MW Offshore Wind (PW05)-n/a<br>5 MW of 1 MW Tracking PV (PP03)-2015<br>50 MW Parabolic Trough PV (PP04)-n/a<br>9.6 MW OTEC (POT1)-n/a<br>15 MW Ocean Wave (PV02)-n/a |
| *2014* | 35MW | 75MW | Expanded CIDLC, CIDP, RDLCWH, RDLCAC |
| | | | 75% PBFA DSM |
| | | | Deactivate H8 (-53MW)<br>Deactivate H9 (-54MW) |
| *2015* | 36MW | 111MW | Add 20 MW Wind (PWWRx2) |
| | | | Add 40 MW PV (PPWRx8) |
| *2016* | 43MW | 154MW | Fuel Switch to ULSD<br>(CIP-1) |
| | | | Add 20 MW Wind (PWWRx2) |
| | | | Add 80 MW PV (PPWRx16) |
| | | | Fuel Switch to Diesel (Waiau 5-8, Kahe 1-6) |
| *2017* | 36MW | 189MW | Add 51MW ICE (PS01x3)-Biofueled |
| | | | Add 60 MW Wind (PW01x2) |
| | | | Add 20 MW PV (PP03x4) |
| | | | Deactivate W3 (-46MW)<br>Deactivate W4 (-46MW) |
| *2018* | 36MW | 225MW | Convert CT-1 to CC +57MW (STC1)-ULSD |
| | | | Cycle Kahe 1 - 4 |
| | | | Add 60 MW Wind (PW01x2) |
| | | | Add 20 MW PV (PP03x4) |
| | | | Add 15 MWH Battery (PB01x1) |
| *2019* | 35MW | 260MW | Add 60 MW Wind (PW01x2) |
| | | | Add 20 MW PV (PP03x4) |

| Name | Self Generation | | P2B2a1NRetire-2r15 LossOfSales |
|---|---|---|---|
| *2020* | 35MW | 295MW | Fuel Switch to LNG (Waiau 5-8, Kahe 1-6, CIP CC-1, Kalaeloa) |
| *2021* | 35MW | 331MW | |
| *2022* | 28MW | 363MW | |
| *2023* | 28MW | 391MW | |
| *2024* | 25MW | 416MW | |
| *2025* | 21MW | 437MW | |
| *2026* | 18MW | 456MW | |
| *2027* | 16MW | 472MW | |
| *2028* | 15MW | 486MW | |
| *2029* | 14MW | 500MW | |
| *2030* | 13MW | 513MW | Add 60 MW Wind (PW01x2) |
| *2031* | 12MW | 525MW | |
| *2032* | 12MW | 538MW | |
| *2033* | 12MW | 549MW | |
| *Planning Period Total Cost* | | | 17, 839, 032 |
| *Study Period Total Cost* | | | 24, 010, 832 |
| *Planning Period Total Cost* | | | 20, 819, 161 |
| *Study Period Total Cost* | | | 26, 990, 960 |
| *Planning Rank* | | | 1 |
| *Study Rank* | | | 1 |

## No Burning Desire

Table O-46. HECO Timing Run (1 of 3)

| Name | P3_2a1NRetire-1r0 | P3_2a1NRetire-1r1 | P3_2a1NRetire-1r2 | P3_2a1NRetire-1r3 |
|---|---|---|---|---|
| *Plan* | Required Timing: ICE, SCCT, CC | Timing: SCCT, Biomass/OTEC Fixed | Timing: ICE Fixed, SCCT, CC | Timing–2016–2017: ICE Fixed, SCCT |
| *Resources Available* | | | | |
| *Reference* | P3_2a1NRetire-1r0 Timinng.xlxs | P3_2a1NRetire-1r1 Timinng.xlxs | P3_2a1NRetire-1r0 Timinng.xlxs | |
| *2014* | Expanded CIDLC, CIDP, RDLCWH, RDLCAC | Expanded CIDLC, CIDP, RDLCWH, RDLCAC | Expanded CIDLC, CIDP, RDLCWH, RDLCAC | Expanded CIDLC, CIDP, RDLCWH, RDLCAC |
| | 75% PBFA DSM | 75% PBFA DSM | 75% PBFA DSM | 75% PBFA DSM |
| *2015* | | | | |
| *2016* | Add 91MW SCCT (PS07x1)-Biofueled | Add 91MW SCCT (PS07x1)-Biofueled | Add 91MW SCCT (PS07x1)-Biofueled | Add 34MW ICE (PS01x2)-Biofueled |
| *2017* | | | Add 51MW ICE (PS01x3)-Biofueled | Add 51MW ICE (PS01x3)-Biofueled |
| | Deactivate W3 (-46MW)<br>Deactivate W4 (-46MW)<br>or H8/9 | Deactivate W3 (-46MW)<br>Deactivate W4 (-46MW)<br>or H8/9 | Deactivate W3 (-46MW)<br>Deactivate W4 (-46MW)<br>or H8/9 | Deactivate W3 (-46MW)<br>Deactivate W4 (-46MW)<br>or H8/9 |
| *2018* | Add 91MW SCCT (PS07x1)-Biofueled | Add 91MW SCCT (PS07x1)-Biofueled | Add 91MW SCCT (PS07x1)-Biofueled | Add 91MW SCCT (PS07x1)-Biofueled |
| *2019* | Add 17MW ICE (PS01x1)-Biofueled | Add 91MW SCCT (PS07x1)-Biofueled | | Add 91MW SCCT (PS07x1)-Biofueled |
| 2020 | Deactivate H8 (-53MW)<br>Deactivate H9 (-54MW)<br>or W3/4 | Deactivate H8 (-53MW)<br>Deactivate H9 (-54MW)<br>or W3/4 | Deactivate H8 (-53MW)<br>Deactivate H9 (-54MW)<br>or W3/4 | Deactivate H8 (-53MW)<br>Deactivate H9 (-54MW)<br>or W3/4 |
| | Add 182MW SCCT (PS07x2)-Biofueled | Add 25MW (PA01x1)-Biomass | Add 91MW SCCT (PS07x1)-Biofueled | Add 91MW SCCT (PS07x1)-Biofueled |
| | | Add 96MWr OTEC (POT1x10) | | |
| *2021* | | | Add 91MW SCCT (PS07x1)-Biofueled | |
| *2022* | | Add 91MW SCCT (PS07x1)-Biofueled | | Add 91MW SCCT (PS07x1)-Biofueled |
| *2023* | | | | |
| *2024* | Add 91MW SCCT (PS07x1)-Biofueled | | | |
| *2025* | | | | |
| *2026* | | | | |

| Name | P3_2a1NRetire-1r0 | P3_2a1NRetire-1r1 | P3_2a1NRetire-1r2 | P3_2a1NRetire-1r3 |
|---|---|---|---|---|
| *2027* | | | Add 91MW SCCT (PS07x1)-Biofueled | |
| *2028* | | | | |
| *2029* | | | | |
| *2030* | | | | |
| *2031* | | Add 91MW SCCT (PS07x1)-Biofueled | | Add 91MW SCCT (PS07x1)-Biofueled |
| *2032* | | | | |
| *2033* | Add 34MW ICE (PS01x2)-Biofueled | | | |
| *Planning Period Total Cost* | 23, 742, 016 | 26, 005, 020 | 23, 844, 766 | 23, 906, 382 |
| *Study Period Total Cost* | 34, 670, 908 | 38, 597, 956 | 34, 755, 276 | 34, 877, 196 |
| *Planning Rank* | 1 | 5 | 2 | 3 |
| *Study Rank* | 1 | 5 | 2 | 3 |

Table O-47. HECO Timing Run (2 of 3)

| Name | Required Timing- (ICE, SCCT, CC) | Req Timing, Least Cost (ICE, SCCT, CC) | Timing, (ICE, SCCT, Biomass/Fixed OTEC) | Req Timing, (ICE, SCCT) |
|---|---|---|---|---|
| *Resources Available* | | | | |
| *Reference* | P3_2a1NRetire-1r0 Timinng.xlxs | P3_2a1X-1r0 Timing.xlxs | P3_2a1X-1r1 Timing.xlxs | P3_2a1N-1r0 Timing.xlxs |
| *2014* | Continue CIDLC, CIDP, RDLCWH, RDLCAC | Continue CIDLC, CIDP, RDLCWH, RDLCAC | Continue CIDLC, CIDP, RDLCWH, RDLCAC | Expanded CIDLC, CIDP, RDLCWH, RDLCAC |
| | 75% PBFA DSM | 75% PBFA DSM | 75% PBFA DSM | 75% PBFA DSM |
| *2015* | | | | |
| *2016* | Add 91MW SCCT (PS07x1)-Biofueled | Add 91MW SCCT (PS07x1)-Biofueled | Add 91MW SCCT (PS07x1)-Biofueled | Add 91MW SCCT (PS07x1)-Biofueled |
| | Fuel Switch to Diesel (H8/9, Waiau 5-10/Kahe 1-6) | Fuel Switch to Diesel (H8/9, Waiau 5-10/Kahe 1-6) | Fuel Switch to Diesel (H8/9, Waiau 5-10/Kahe 1-6) | Fuel Switch to Diesel (H8/9, Waiau 5-10/Kahe 1-6) |
| *2017* | Deactivate W3 (-46MW)<br>Deactivate W4 (-46MW)<br>or H8/9 | | | |
| *2018* | Add 42MW SCCT (PS06x1)-Biofueled | Add 91MW SCCT (PS07x1)-Biofueled | Add 91MW SCCT (PS07x1)-Biofueled | |
| | Add 91MW SCCT (PS07x1)-Biofueled | | | |
| *2019* | Add 17MW ICE (PS01x1)-Biofueled | | | Add 91MW SCCT (PS07x1)-Biofueled |
| | Deactivate H8 (-53MW)<br>Deactivate H9 (-54MW)<br>or W3/4 | | | |
| *2020* | Add 91MW SCCT (PS07x1)-Biofueled | | | |
| *2021* | | Add 91MW SCCT (PS07x1)-Biofueled | Add 25MW (PA01x1)-Biomass | |
| | | | Add 96MWr OTEC (POT1x10) | |
| *2022* | Add 17MW ICE (PS01x1)-Biofueled | | | |
| *2023* | | | | |
| *2024* | | Add 42MW SCCT (PS06x1)-Biofueled | Add 91MW SCCT (PS07x1)-Biofueled | Add 91MW SCCT (PS07x1)-Biofueled |
| *2025* | | | | |
| *2026* | | | | |
| *2027* | | | | |

| **Name** | **Required Timing- (ICE, SCCT, CC)** | **Req Timing, Least Cost (ICE, SCCT, CC)** | **Timing, (ICE, SCCT, Biomass/Fixed OTEC)** | **Req Timing, (ICE, SCCT)** |
|---|---|---|---|---|
| *2028* | Add 42MW SCCT (PS06x1)-Biofueled | Add 17MW ICE (PS01x1)-Biofueled | Add 17MW ICE (PS01x1)-Biofueled | |
| *2029* | | | | |
| *2030* | | Add 91MW SCCT (PS07x1)-Biofueled | Add 91MW SCCT (PS07x1)-Biofueled | |
| *2032* | | | | Add 42MW SCCT (PS06x1)-Biofueled |
| *2033* | | Add 17MW ICE (PS01x1)-Biofueled | Add 91MW SCCT (PS07x1)-Biofueled | |
| *Planning Period Total Cost* | 23, 957, 504 | 22, 766, 858 | 24, 963, 080 | 22, 575, 388 |
| *Study Period Total Cost* | 35, 037, 888 | 33, 330, 108 | 37, 214, 140 | 32, 984, 460 |
| *Planning Rank* | 4 | 2 | 5 | 1 |
| *Study Rank* | 4 | 2 | 5 | 1 |

Table O-48. HECO Timing Run (3 of 3)

| **Name** | **P3_2a1N-1r1** | **P3B2b1NRetire-LOLH Off 2016** | **P3B2b1NRetire-4Er0** |
|---|---|---|---|
| *Plan* | Timing, (SCCT, CC, Bio & OTEC Fixed) | Use Schofield to defer, LoLH off 2014-2016 | Deactivate Existing Replace with Conventional LNG Units |
| *Notes* | | | All units are deactivated by 2022 |
| *Resources Available* | | | ICE (17 MW)-Biodiesel (PS01)-n/a<br>95 MW SCCT LMS 100 - LNG (PS07)-2016<br>42 MW LM6000 SCCT LNG (PC08)-n/a<br>59 MW 1on1 LM6000 CC-LNG (PS12)-2019<br>25MW Banagrass (PA01)-n/a<br>400 kW Nat Gas Fuel Cell (FC40)-n/a<br>30 MW Onshore Wind Cl 3 (PW01)-2020<br>10 MW Onshore Wind Cl 5 (PW03)-n/a<br>5 MW of 1 MW Tracking PV (PP03)-n/a |
| *Reference* | P3_2a1N-1r1 Timing.xlxs | | |
| *2014* | Expanded CIDLC, CIDP, RDLCWH, RDLCAC | Expanded CIDLC, CIDP, RDLCWH, RDLCAC | Expanded CIDLC, CIDP, RDLCWH, RDLCAC |
| | 75% PBFA DSM | 75% PBFA DSM | 75% PBFA DSM |
| *2015* | | | |
| *2016* | Add 91MW SCCT (PS07x1)-Biofueled | | Add 95MW SCCT (PS08x1)-LNG |
| | Fuel Switch to Diesel<br>(H8/9, Waiau 5-10/Kahe 1-6) | Fuel Switch to Diesel<br>(H8/9, Waiau 5-10/Kahe 1-6) | Fuel Switch to Diesel<br>(H8/9, Waiau 5-10/Kahe 1-6) |
| *2017* | | Add 51MW ICE (PS01x3)-Biofueled | Deactivate W3 (-46MW)<br>Deactivate W4 (-46MW)<br>or H8/9 |
| | | Add 91MW SCCT (PS07x1)-Biofueled | |
| | | Deactivate W3 (-46MW)<br>Deactivate W4 (-46MW)<br>or H8/9 | |
| *2018* | | Add 91MW SCCT (PS07x1)-Biofueled | Add 91MW SCCT (PS07x1)-Biofueled |
| *2019* | Add 91MW SCCT (PS07x1)-Biofueled | | Add 59MW SCCT (PC08x1)-Biofueled |
| | | Deactivate H8 (-53MW)<br>Deactivate H9 (-54MW)<br>or W3/4 | Deactivate H8 (-53MW)<br>Deactivate H9 (-54MW)<br>or W3/4 |

| Name | P3_2a1N-1r1 | P3B2b1NRetire-LOLH Off 2016 | P3B2b1NRetire-4Er0 |
|---|---|---|---|
| 2020 | | Add 91MW SCCT (PS07x1)-Biofueled | Add 182MW SCCT (PS07x2)-Biofueled |
| | | | Add 295MW SCCT (PC08x5)-Biofueled |
| | | | Deactivate W5 (-55MW)<br>Deactivate W6 (-56MW)<br>Deactivate W7 (-88MW)<br>Deactivate W8 (-88MW)<br>Deactivate K1 (-88MW)<br>Deactivate K2 (-86MW)<br>Deactivate K3 (-88MW)<br>Deactivate K4 (-89MW) |
| 2021 | Add 25MW (PA01x1)-Biomass | Add 91MW SCCT (PS07x1)-Biofueled | Deactivate K5 (-135MW) |
| | Add 96MWr OTEC (POT1x10) | | Add 236MW SCCT (PC08x4)-Biofueled |
| 2022 | | | Deactivate K6 (-134MW) |
| | | | Add 177MW SCCT (PC08x3)-Biofueled |
| 2023 | | | Add 118MW SCCT (PC08x2)-Biofueled |
| 2024 | | | |
| 2025 | | | |
| 2026 | | | |
| 2027 | | Add 91MW SCCT (PS07x1)-Biofueled | Add 59MW STCC (PS12x1)-LNG |
| 2028 | | | |
| 2029 | | | |
| 2030 | | | |
| 2031 | Add 91MW SCCT (PS07x1)-Biofueled | | |
| 2032 | | | |
| 2033 | | | |
| Planning Period Total Cost | 24, 841, 266 | 23, 825, 786 | 33, 181, 366 |
| Study Period Total Cost | 36, 964, 032 | 34, 734, 792 | 48, 243, 400 |
| Planning Rank | 4 | | |
| Study Rank | 4 | | |

Table O-49. HECO Screening Run

| **Name** | **P3B2a1NRetire-2r0** | **P3B2b1NRetire-2r0** | **P3B2b1NRetire-2r0LanHi** | **P3B2a1NRetire-2r2** | **P3B2b1NRetire-2r1** |
|---|---|---|---|---|---|
| *Plan* | Screen Based on P3_2a1NRetire-1r0 w/o Lanai Wind | Screen Based on P3_2a1NRetire-1r0 w Lanai Wind | Screen Based on P3_2a1NRetire-1r0 w Lanai Wind revised cost | Screen based on P3_2a1NRetire-1r2 from TIMING w/o Lanai Wind | Screen based on P3B2b1NRetire-LOLH Off 2016 from TIMING, w Lanai Wind |
| *Resources Available* | ICE (17 MW)-Biodiesel (PS01)-Fixed<br>42 MW SCCT LM6000 - Biodiesel (PS06)-2016<br>100 MW SCCT - Biodiesel (PS07)-Fixed<br>30 MW Onshore Wind Cl 3 (PW01)-2020<br>10 MW Onshore Wind Cl 5 (PW03)-n/a<br>10 MW Onshore Wind Cl 7 (PW04)-n/a<br>100 MW Offshore Wind (PW05)-n/a<br>5 MW of 1 MW Tracking PV (PP03)-2015<br>50 MW Parabolic Trough PV (PP04)-n/a<br>9.6 MW OTEC (POT1)-n/a<br>15 MW Ocean Wave (PV02)-n/a | ICE (17 MW)-Biodiesel (PS01)-Fixed<br>42 MW SCCT LM6000 - Biodiesel (PS06)-2016<br>100 MW SCCT - Biodiesel (PS07)-Fixed<br>30 MW Onshore Wind Cl 3 (PW01)-2020<br>10 MW Onshore Wind Cl 5 (PW03)-n/a<br>10 MW Onshore Wind Cl 7 (PW04)-n/a<br>100 MW Offshore Wind (PW05)-n/a<br>5 MW of 1 MW Tracking PV (PP03)-2015<br>50 MW Parabolic Trough PV (PP04)-n/a<br>9.6 MW OTEC (POT1)-n/a<br>15 MW Ocean Wave (PV02)-n/a | ICE (17 MW)-Biodiesel (PS01)-Fixed<br>42 MW SCCT LM6000 - Biodiesel (PS06)-2016<br>100 MW SCCT - Biodiesel (PS07)-Fixed<br>30 MW Onshore Wind Cl 3 (PW01)-2020<br>10 MW Onshore Wind Cl 5 (PW03)-n/a<br>10 MW Onshore Wind Cl 7 (PW04)-n/a<br>100 MW Offshore Wind (PW05)-n/a<br>5 MW of 1 MW Tracking PV (PP03)-2015<br>50 MW Parabolic Trough PV (PP04)-n/a<br>9.6 MW OTEC (POT1)-n/a<br>15 MW Ocean Wave (PV02)-n/a | | |
| *2014* | Expanded CIDLC, CIDP, RDLCWH, RDLCAC | Expanded CIDLC, CIDP, RDLCWH, RDLCAC | Expanded CIDLC, CIDP, RDLCWH, RDLCAC | Expanded CIDLC, CIDP, RDLCWH, RDLCAC | Expanded CIDLC, CIDP, RDLCWH, RDLCAC |
| *2015* | 75% PBFA DSM | 75% PBFA DSM | 75% PBFA DSM | 75% PBFA DSM | 75% PBFA DSM |
| | Add 20 MW PV (PP03x4) | | | Add 20 MW PV (PP03x4) | |
| *2016* | Add 91MW SCCT (PS07x1)-Biofueled | Add 91MW SCCT (PS07x1)-Biofueled | Add 91MW SCCT (PS07x1)-Biofueled | Add 91MW SCCT (PS07x1)-Biofueled | |
| | | | | | Add 91MW SCCT (PS07x1)-Biofueled |

| Name | P3B2a1NRetire-2r0 | P3B2b1NRetire-2r0 | P3B2b1NRetire-2r0LanHi | P3B2a1NRetire-2r2 | P3B2b1NRetire-2r1 |
|---|---|---|---|---|---|
| 2017 | | | | Add 51MW ICE (PS01x3)-Biofueled | Add 51MW ICE (PS01x3)-Biofueled |
| | Deactivate W3 (-46MW) Deactivate W4 (-46MW) or H8/9 | Deactivate W3 (-46MW) Deactivate W4 (-46MW) or H8/9 | Deactivate W3 (-46MW) Deactivate W4 (-46MW) or H8/9 | Deactivate W3 (-46MW) Deactivate W4 (-46MW) or H8/9 | Deactivate W3 (-46MW) Deactivate W4 (-46MW) or H8/9 |
| 2018 | Add 20 MW PV (PP03x4) | | | Add 20 MW PV (PP03x4) | |
| | Add 91MW SCCT (PS07x1)-Biofueled | Add 91MW SCCT (PS07x1)-Biofueled | Add 91MW SCCT (PS07x1)-Biofueled | Add 91MW SCCT (PS07x1)-Biofueled | Add 91MW SCCT (PS07x1)-Biofueled |
| 2019 | Add 17MW ICE (PS01x1)-Biofueled | Add 17MW ICE (PS01x1)-Biofueled | Add 17MW ICE (PS01x1)-Biofueled | | |
| | Deactivate H8 (-53MW) Deactivate H9 (-54MW) or W3/4 | Deactivate H8 (-53MW) Deactivate H9 (-54MW) or W3/4 | Deactivate H8 (-53MW) Deactivate H9 (-54MW) or W3/4 | Deactivate H8 (-53MW) Deactivate H9 (-54MW) or W3/4 | Deactivate H8 (-53MW) Deactivate H9 (-54MW) or W3/5 |
| 2020 | | Add 200 MW Lanai Wind | Add 200 MW Lanai Wind | | Add 200 MW Lanai Wind |
| | Add 300 MW Wind (PW01x10) | Add 150 MW Wind (PW01x5) | Add 150 MW Wind (PW01x5) | Add 300 MW Wind (PW01x10) | Add 150 MW Wind (PW01x5) |
| | Add 182MW SCCT (PS07x2)-Biofueled | Add 182MW SCCT (PS07x2)-Biofueled | Add 182MW SCCT (PS07x2)-Biofueled | Add 91MW SCCT (PS07x1)-Biofueled | Add 91MW SCCT (PS07x1)-Biofueled |
| 2021 | Add 150 MW Wind (PW01x5) | Add 120 MW Wind (PW01x4) | Add 120 MW Wind (PW01x4) | Add 150 MW Wind (PW01x5) | Add 120 MW Wind (PW01x4) |
| | | | | Add 91MW SCCT (PS07x1)-Biofueled | Add 91MW SCCT (PS07x1)-Biofueled |
| 2022 | Add 120 MW Wind (PW01x4) | Add 90 MW Wind (PW01x3) | Add 90 MW Wind (PW01x3) | Add 120 MW Wind (PW01x4) | Add 90 MW Wind (PW01x3) |
| 2023 | | | | | |
| 2024 | Add 91MW SCCT (PS07x1)-Biofueled | Add 91MW SCCT (PS07x1)-Biofueled | Add 91MW SCCT (PS07x1)-Biofueled | | |
| | Add 120 MW Wind (PW01x4) | Add 120 MW Wind (PW01x4) | Add 120 MW Wind (PW01x4) | Add 120 MW Wind (PW01x4) | Add 120 MW Wind (PW01x4) |
| 2025 | Add 30 MW Wind (PW01x1) | Add 30 MW Wind (PW01x1) | Add 30 MW Wind (PW01x1) | | |
| 2026 | | | | | |
| 2027 | | | | Add 91MW SCCT (PS07x1)-Biofueled | Add 91MW SCCT (PS07x1)-Biofueled |
| | | | | Add 30 MW Wind (PW01x1) | |

| Name | P3B2a1NRetire-2r0 | P3B2b1NRetire-2r0 | P3B2b1NRetire-2r0LanHi | P3B2a1NRetire-2r2 | P3B2b1NRetire-2r1 |
|---|---|---|---|---|---|
| *2028* | | | | | |
| *2029* | | | | | |
| *2030* | | | | | |
| *2031* | | | | | |
| *2032* | | | | | |
| *2033* | Add 34MW ICE (PS01x2)-Biofueled | Add 34MW ICE (PS01x2)-Biofueled | Add 34MW ICE (PS01x2)-Biofueled | | |
| *Planning Period Total Cost* | 22, 935, 722 | 22, 853, 624 | 22, 980, 648 | 23, 070, 376 | 22, 967, 294 |
| *Study Period Total Cost* | 33, 212, 384 | 32, 880, 474 | 33, 065, 764 | 33, 329, 764 | 32, 979, 732 |
| *Planning Rank* | 2 | 1 | 4 | 5 | 3 |
| *Study Rank* | 4 | 1 | 3 | 5 | 2 |

Table O-50. HECO Environmental Compliance (1 of 2)

| **Name** | **P3B2b1NRetire-2r0** | **P3B2b1NRetire-4Br0** | **P3B2b1NRetire-4Dr0** | **P3B2b1NRetire-4Er2** |
|---|---|---|---|---|
| *Plan* | Fuel Switch to ULSD in 2022 | Install Air Quality Controls in 2022 | Fuel Switch to LNG in 2020 | Deactivate Existing Replace with Conventional LNG Units |
| *Notes* | Fuel switch applies to all Waiau 5-8 and Kahe 1-6 | Install AQC on Waiau 5-8 and Kahe 1-6 | Fuel switch applies to all Waiau 5-8 and Kahe 1-6 | All units are deactivated by 2022 |
| *Resources Available* | ICE (17 MW)-Biodiesel (PS01)-2016<br>100 MW SCCT - Biodiesel (PS07)-2016<br>42 MW LM6000 SCCT LNG (PC08)-2016<br>59 MW 1on1 LM6000 CC-LNG (PS12)-2020<br>25MW Banagrass (PA01)-2027<br>30 MW Onshore Wind Cl 3 (PW01)-2020<br>10 MW Onshore Wind Cl 5 (PW03)-n/a<br>10 MW Onshore Wind Cl 7 (PW04)-n/a<br>100 MW Offshore Wind (PW05)-n/a<br>5 MW of 1 MW Tracking PV (PP03)-2015<br>50 MW Parabolic Trough PV (PP04)-n/a<br>9.6 MW OTEC (POT1)-n/a<br>15 MW Ocean Wave 5 MW (PV02)-n/a | ICE (17 MW)-Biodiesel (PS01)-2016<br>100 MW SCCT - Biodiesel (PS07)-2016<br>42 MW LM6000 SCCT LNG (PC08)-n/a<br>59 MW 1on1 LM6000 CC-LNG (PS12)-2020<br>25MW Banagrass (PA01)-2027<br>30 MW Onshore Wind Cl 3 (PW01)-2020<br>10 MW Onshore Wind Cl 5 (PW03)-n/a<br>10 MW Onshore Wind Cl 7 (PW04)-n/a<br>100 MW Offshore Wind (PW05)-n/a<br>5 MW of 1 MW Tracking PV (PP03)-2015<br>50 MW Parabolic Trough PV (PP04)-n/a<br>9.6 MW OTEC (POT1)-n/a<br>15 MW Ocean Wave 5 MW (PV02)-n/a | ICE (17 MW)-Biodiesel (PS01)-n/a<br>100 MW SCCT - Biodiesel (PS07)-n/a<br>42 MW LM6000 SCCT LNG (PC08)-n/a<br>59 MW 1on1 LM6000 CC-LNG (PS12)-2020<br>25MW Banagrass (PA01)-2027<br>30 MW Onshore Wind Cl 3 (PW01)-2020<br>10 MW Onshore Wind Cl 5 (PW03)-n/a<br>10 MW Onshore Wind Cl 7 (PW04)-n/a<br>100 MW Offshore Wind (PW05)-n/a<br>5 MW of 1 MW Tracking PV (PP03)-n/a<br>50 MW Parabolic Trough PV (PP04)-n/a<br>9.6 MW OTEC (POT1)-n/a<br>15 MW Ocean Wave 5 MW (PV02)-2020 | ICE (17 MW)-Biodiesel (PS01)-n/a<br>95 MW SCCT LMS 100 - LNG (PS07)-2016<br>42 MW LM6000 SCCT LNG (PC08)-n/a<br>59 MW 1on1 LM6000 CC-LNG (PS12)-2019<br>25MW Banagrass (PA01)-n/a<br>400 kW Nat Gas Fuel Cell (FC40)-n/a<br>30 MW Onshore Wind Cl 3 (PW01)-2020<br>10 MW Onshore Wind Cl 5 (PW03)-n/a<br>5 MW of 1 MW Tracking PV (PP03)-n/a |
| *2014* | Expanded CIDLC, CIDP, RDLCWH, RDLCAC | Expanded CIDLC, CIDP, RDLCWH, RDLCAC | Expanded CIDLC, CIDP, RDLCWH, RDLCAC | Expanded CIDLC, CIDP, RDLCWH, RDLCAC |
| | 75% PBFA DSM | 75% PBFA DSM | 75% PBFA DSM | 75% PBFA DSM |
| *2015* | | | | |
| *2016* | Add 91MW SCCT (PS07x1)-Biofueled | Add 91MW SCCT (PS07x1)-Biofueled | Add 91MW SCCT (PS07x1)-Biofueled | Add 95MW SCCT (PS08x1)-LNG |
| | Fuel Switch to Diesel (H8/9, Waiau 5-10/Kahe 1-6) | Fuel Switch to Diesel (H8/9, Waiau 5-10/Kahe 1-6) | Fuel Switch to Diesel (H8/9, Waiau 5-10/Kahe 1-6) | Fuel Switch to Diesel (H8/9, Waiau 5-10/Kahe 1-6) |
| *2017* | Deactivate W3 (-46MW)<br>Deactivate W4 (-46MW) or H8/9 | Deactivate W3 (-46MW)<br>Deactivate W4 (-46MW) or H8/9 | Deactivate W3 (-46MW)<br>Deactivate W4 (-46MW) or H8/9 | Deactivate W3 (-46MW)<br>Deactivate W4 (-46MW) or H8/9 |
| *2018* | Add 91MW SCCT (PS07x1)-Biofueled | Add 91MW SCCT (PS07x1)-Biofueled | Add 91MW SCCT (PS07x1)-Biofueled | Add 95MW SCCT (PS08x1)-LNG |

| Name | P3B2b1NRetire-2r0 | P3B2b1NRetire-4Br0 | P3B2b1NRetire-4Dr0 | P3B2b1NRetire-4Er2 |
|---|---|---|---|---|
| *2019* | Add 17MW ICE (PS01x1)-Biofueled | Add 17MW ICE (PS01x1)-Biofueled | Add 17MW ICE (PS01x1)-Biofueled | Add 95MW SCCT (PS08x1)-LNG |
| | Deactivate H8 (-53MW)<br>Deactivate H9 (-54MW)<br>or W3/4 | Deactivate H8 (-53MW)<br>Deactivate H9 (-54MW)<br>or W3/4 | Deactivate H8 (-53MW)<br>Deactivate H9 (-54MW)<br>or W3/4 | Deactivate H8 (-53MW)<br>Deactivate H9 (-54MW)<br>or W3/4 |
| *2020* | Add 200 MW Lanai Wind | Add 200 MW Lanai Wind | Add 200 MW Lanai Wind | Add 200 MW Lanai Wind |
| | | | Fuel switch to LNG (Waiau 5-8, Kahe 1-6) | |
| | | | | Deactivate W5 (-55MW)<br>Deactivate W6 (-56MW)<br>Deactivate W7 (-88MW)<br>Deactivate W8 (-88MW)<br>Deactivate K1 (-88MW)<br>Deactivate K2 (-86MW)<br>Deactivate K3 (-88MW)<br>Deactivate K4 (-89MW) |
| | Add 150 MW Wind (PW01x5) | Add 150 MW Wind (PW01x5) | Add 150 MW Wind (PW01x5) | Add 210 MW Wind (PW01x7) |
| | Add 182MW SCCT (PS07x2)-Biofueled | Add 182MW SCCT (PS07x2)-Biofueled | Add 182MW SCCT (PS07x2)-Biofueled | Add 475MW SCCT (PS08x5)-LNG |
| *2021* | | | | Add 285MW SCCT (PS08x3)-LNG |
| | Add 120 MW Wind (PW01x4) | Add 120 MW Wind (PW01x4) | Add 120 MW Wind (PW01x4) | Add 120 MW Wind (PW01x4) |
| | | | | Deactivate K5 (-135MW) |
| *2022* | Fuel Switch to ULSD (Waiau 5-8, Kahe 1-6) | AQC Waiau 5-8 & Kahe 1-6 | | |
| | Add 90 MW Wind (PW01x3) | Add 90 MW Wind (PW01x3) | Add 90 MW Wind (PW01x3) | Add 90 MW Wind (PW01x3) |
| | | | | Add 95MW SCCT (PS08x1)-LNG |
| *2023* | | | | Deactivate K6 (-134MW) |
| | | | | Add 190MW SCCT (PS08x2)-LNG |
| *2024* | Add 91MW SCCT (PS07x1)-Biofueled | Add 91MW SCCT (PS07x1)-Biofueled | Add 91MW SCCT (PS07x1)-Biofueled | |
| | Add 120 MW Wind (PW01x4) | Add 120 MW Wind (PW01x4) | Add 120 MW Wind (PW01x4) | Add 120 MW Wind (PW01x4) |
| *2025* | Add 30 MW Wind (PW01x1) | Add 30 MW Wind (PW01x1) | Add 30 MW Wind (PW01x1) | Add 30 MW Wind (PW01x1) |
| *2026* | | | | |
| *2027* | | | | |
| *2028* | | | | |

| Name | P3B2b1NRetire-2r0 | P3B2b1NRetire-4Br0 | P3B2b1NRetire-4Dr0 | P3B2b1NRetire-4Er2 |
|---|---|---|---|---|
| *2029* | | | | |
| *2030* | | | | Add 60 MW Wind (PW01x2) |
| *2031* | | | | Add 30 MW Wind (PW01x1) |
| *2032* | | | | Add 59MW STCC (PS12x1)-LNG |
| *2033* | Add 34MW ICE (PS01x2)-Biofueled | Add 34MW ICE (PS01x2)-Biofueled | Add 34MW ICE (PS01x2)-Biofueled | |
| *Strategist Planning Period Total Cost* | 22, 853, 624 | 22, 596, 620 | 22, 259, 566 | 24, 716, 448 |
| *Strategist Study Period Total Cost* | 32, 880, 474 | 32, 391, 618 | 32, 314, 676 | 35, 386, 196 |
| *Planning Period Total Cost* | 22, 935, 820 | 23, 775, 391 | 22, 633, 872 | 23, 274, 023 |
| *Study Period Total Cost* | 32, 962, 672 | 33, 570, 391 | 32, 688, 982 | 35, 588, 355 |
| *Planning Rank* | 2 | 4 | 1 | 3 |
| *Study Rank* | 2 | 3 | 1 | 4 |

Table O-51. HECO Environmental Compliance (2 of 2)

| **Name** | **P3B2b1NRetire-2r0** | **P3B2b1NRetire-4Br0** | **P3B2b1NRetire-4Dr0** | **P3B2b1NRetire-4Er2** |
|---|---|---|---|---|
| *Plan* | Screen Based on P3_2a1NRetire-1r0 w Lanai Wind | AQC Existing | LNG Existing | Retire Replace LNG |
| *Resources Available* | | | | |
| *2014* | Expanded CIDLC, CIDP, RDLCWH, RDLCAC | Expanded CIDLC, CIDP, RDLCWH, RDLCAC | Expanded CIDLC, CIDP, RDLCWH, RDLCAC | Expanded CIDLC, CIDP, RDLCWH, RDLCAC |
| | 75% PBFA DSM | 75% PBFA DSM | 75% PBFA DSM | 75% PBFA DSM |
| *2015* | | | | |
| *2016* | Add 91MW SCCT (PS07x1)-Biofueled | Add 91MW SCCT (PS07x1)-Biofueled | Add 91MW SCCT (PS07x1)-Biofueled | Add 95MW SCCT (PS08x1)-LNG |
| *2017* | Deactivate W3 (-46MW)<br>Deactivate W4 (-46MW)<br>or H8/9 | Deactivate W3 (-46MW)<br>Deactivate W4 (-46MW)<br>or H8/9 | Deactivate W3 (-46MW)<br>Deactivate W4 (-46MW)<br>or H8/9 | Deactivate W3 (-46MW)<br>Deactivate W4 (-46MW)<br>or H8/9 |
| *2018* | Add 91MW SCCT (PS07x1)-Biofueled | Add 91MW SCCT (PS07x1)-Biofueled | Add 91MW SCCT (PS07x1)-Biofueled | Add 95MW SCCT (PS08x1)-LNG |
| *2019* | Add 17MW ICE (PS01x1)-Biofueled | Add 17MW ICE (PS01x1)-Biofueled | Add 17MW ICE (PS01x1)-Biofueled | Add 95MW SCCT (PS08x1)-LNG |
| | Deactivate H8 (-53MW)<br>Deactivate H9 (-54MW)<br>or W3/4 | Deactivate H8 (-53MW)<br>Deactivate H9 (-54MW)<br>or W3/4 | Deactivate H8 (-53MW)<br>Deactivate H9 (-54MW)<br>or W3/4 | Deactivate H8 (-53MW)<br>Deactivate H9 (-54MW)<br>or W3/4 |
| | Add 200 MW Lanai Wind | Add 200 MW Lanai Wind | Add 200 MW Lanai Wind | Add 200 MW Lanai Wind |
| *2020* | | | Fuel switch to LNG (Waiau 5-8, Kahe 1-6) | |
| | | | | Deactivate W5 (-55MW)<br>Deactivate W6 (-56MW)<br>Deactivate W7 (-88MW)<br>Deactivate W8 (-88MW)<br>Deactivate K1 (-88MW)<br>Deactivate K2 (-86MW)<br>Deactivate K3 (-88MW)<br>Deactivate K4 (-89MW) |
| | Add 150 MW Wind (PW01x5) | Add 150 MW Wind (PW01x5) | Add 150 MW Wind (PW01x5) | Add 210 MW Wind (PW01x7) |
| | Add 182MW SCCT (PS07x2)-Biofueled | Add 182MW SCCT (PS07x2)-Biofueled | Add 182MW SCCT (PS07x2)-Biofueled | Add 475MW SCCT (PS08x5)-LNG |
| *2021* | | | | Add 285MW SCCT (PS08x3)-LNG |
| | Add 120 MW Wind (PW01x4) | Add 120 MW Wind (PW01x4) | Add 120 MW Wind (PW01x4) | Add 120 MW Wind (PW01x4) |
| | | | | Deactivate K5 (-135MW) |

| Name | P3B2b1NRetire-2r0 | P3B2b1NRetire-4Br0 | P3B2b1NRetire-4Dr0 | P3B2b1NRetire-4Er2 |
|---|---|---|---|---|
| *2022* | Fuel Switch to ULSD (Waiau 5-8, Kahe 1-6) | AQC Waiau 5-8 & Kahe 1-6 | | |
| | Add 90 MW Wind (PW01x3) | Add 90 MW Wind (PW01x3) | Add 90 MW Wind (PW01x3) | Add 90 MW Wind (PW01x3) |
| | | | | Add 95MW SCCT (PS08x1)-LNG |
| *2023* | | | | Deactivate K6 (-134MW) |
| | | | | Add 190MW SCCT (PS08x2)-LNG |
| *2024* | Add 91MW SCCT (PS07x1)-Biofueled | Add 91MW SCCT (PS07x1)-Biofueled | Add 91MW SCCT (PS07x1)-Biofueled | |
| | Add 120 MW Wind (PW01x4) | Add 120 MW Wind (PW01x4) | Add 120 MW Wind (PW01x4) | Add 120 MW Wind (PW01x4) |
| *2025* | Add 30 MW Wind (PW01x1) | Add 30 MW Wind (PW01x1) | Add 30 MW Wind (PW01x1) | Add 30 MW Wind (PW01x1) |
| *2026* | | | | |
| *2027* | | | | |
| *2028* | | | | |
| *2029* | | | | |
| *2030* | | | | Add 60 MW Wind (PW01x2) |
| *2031* | | | | Add 30 MW Wind (PW01x1) |
| *2032* | | | | Add 59MW STCC (PS12x1)-LNG |
| *2033* | Add 34MW ICE (PS01x2)-Biofueled | Add 34MW ICE (PS01x2)-Biofueled | Add 34MW ICE (PS01x2)-Biofueled | |
| *Planning Period Total Cost* | 22, 988, 629 | 23, 793, 850 | 22, 652, 331 | 23, 071, 862 |
| *Study Period Total Cost* | 33, 015, 481 | 33, 588, 851 | 32, 707, 442 | 33, 296, 676 |
| *Planning Rank* | 2 | 4 | 1 | 3 |
| *Study Rank* | 2 | 4 | 1 | 3 |

Table O-52. HECO Energy Efficiency Portfolio Standard

| **Name** | **P3_2a1XRetire-7Ar0 EEPS** | **P3_2a1XRetire-7Br0** | **P3_2a1XRetire-7Cr0** | **P3_2a1XRetire-7Dr0** | **P3_2a1XRetire-7Ar1** |
|---|---|---|---|---|---|
| *Plan* | EEPS Timing- (ICE) | EEPS Timing- (ICE) | EEPS Timing- (ICE) | EEPS Timing- (ICE) | EEPS Timing- (ICE) |
| *Notes* | No Transactions | No Transactions | No Transactions | No Transactions | With Transactions |
| *Resources Available* | | | | | |
| *Reference* | P3_2a1NRetire-7Ar0 EEPS.xlxs | P3_2a1NRetire-7Br0 EEPS.xlxs | P3_2a1NRetire-7Cr0 EEPS.xlxs | P3_2a1NRetire-7Dr0 EEPS.xlxs | P3_2a1NRetire-7Ar1 EEPS.xlxs |
| *2014* | Continue CIDLC, CIDP, RDLCWH, RDLCAC | Continue CIDLC, CIDP, RDLCWH, RDLCAC | Continue CIDLC, CIDP, RDLCWH, RDLCAC | Continue CIDLC, CIDP, RDLCWH, RDLCAC | Continue CIDLC, CIDP, RDLCWH, RDLCAC |
| | 10%+25% PBFA DSM | 75% PBFA DSM | 25%+75% PBFA DSM | 10%+25%+75% PBFA DSM | 10%+25% PBFA DSM |
| *2015* | | | | | |
| *2016* | Add 68MW ICE (PS01x4)-Biofueled | Add 51MW ICE (PS01x3)-Biofueled | Add 34MW ICE (PS01x2)-Biofueled | Add 17MW ICE (PS01x1)-Biofueled | Add 68MW ICE (PS01x4)-Biofueled |
| *2017* | Add 34MW ICE (PS01x2)-Biofueled | Add 17MW ICE (PS01x1)-Biofueled | Add 17MW ICE (PS01x1)-Biofueled | Add 17MW ICE (PS01x1)-Biofueled | Add 34MW ICE (PS01x2)-Biofueled |
| | Retire W3 (-46MW) Retire W4 (-46MW) or H8/9 | Retire W3 (-46MW) Retire W4 (-46MW) or H8/9 | Retire W3 (-46MW) Retire W4 (-46MW) or H8/9 | Retire W3 (-46MW) Retire W4 (-46MW) or H8/9 | Retire W3 (-46MW) Retire W4 (-46MW) or H8/9 |
| *2018* | Add 119MW ICE (PS01x7)-Biofueled | Add 119MW ICE (PS01x7)-Biofueled | Add 119MW ICE (PS01x7)-Biofueled | Add 119MW ICE (PS01x7)-Biofueled | Add 119MW ICE (PS01x7)-Biofueled |
| *2019* | Add 51MW ICE (PS01x3)-Biofueled | Add 34MW ICE (PS01x2)-Biofueled | Add 34MW ICE (PS01x2)-Biofueled | Add 34MW ICE (PS01x2)-Biofueled | Add 51MW ICE (PS01x3)-Biofueled |
| | Retire H8 (-53MW) Retire H9 (-54MW) or W3/4 | Retire H8 (-53MW) Retire H9 (-54MW) or W3/4 | Retire H8 (-53MW) Retire H9 (-54MW) or W3/4 | Retire H8 (-53MW) Retire H9 (-54MW) or W3/4 | Retire H8 (-53MW) Retire H9 (-54MW) or W3/4 |
| *2020* | Add 102MW ICE (PS01x6)-Biofueled | Add 119MW ICE (PS01x7)-Biofueled | Add 102MW ICE (PS01x6)-Biofueled | Add 102MW ICE (PS01x6)-Biofueled | Add 102MW ICE (PS01x6)-Biofueled |
| *2021* | Add 51MW ICE (PS01x3)-Biofueled | Add 34MW ICE (PS01x2)-Biofueled | Add 34MW ICE (PS01x2)-Biofueled | Add 34MW ICE (PS01x2)-Biofueled | Add 51MW ICE (PS01x3)-Biofueled |
| *2022* | Add 34MW ICE (PS01x2)-Biofueled | Add 34MW ICE (PS01x2)-Biofueled | Add 34MW ICE (PS01x2)-Biofueled | Add 34MW ICE (PS01x2)-Biofueled | Add 34MW ICE (PS01x2)-Biofueled |
| *2023* | | | | | |
| *2024* | Add 51MW ICE (PS01x3)-Biofueled | Add 17MW ICE (PS01x1)-Biofueled | Add 17MW ICE (PS01x1)-Biofueled | Add 17MW ICE (PS01x1)-Biofueled | Add 51MW ICE (PS01x3)-Biofueled |
| *2025* | Add 34MW ICE (PS01x2)-Biofueled | Add 34MW ICE (PS01x2)-Biofueled | Add 17MW ICE (PS01x1)-Biofueled | Add 17MW ICE (PS01x1)-Biofueled | Add 34MW ICE (PS01x2)-Biofueled |
| *2026* | | | | | |

| Name | P3_2a1XRetire-7Ar0 EEPS | P3_2a1XRetire-7Br0 | P3_2a1XRetire-7Cr0 | P3_2a1XRetire-7Dr0 | P3_2a1XRetire-7Ar1 |
|---|---|---|---|---|---|
| *2027* | Add 34MW ICE (PS01x2)-Biofueled | Add 17MW ICE (PS01x1)-Biofueled | Add 17MW ICE (PS01x1)-Biofueled | Add 17MW ICE (PS01x1)-Biofueled | Add 34MW ICE (PS01x2)-Biofueled |
| *2028* | Add 34MW ICE (PS01x2)-Biofueled | Add 34MW ICE (PS01x2)-Biofueled | Add 34MW ICE (PS01x2)-Biofueled | Add 34MW ICE (PS01x2)-Biofueled | Add 34MW ICE (PS01x2)-Biofueled |
| *2029* | | | | | |
| *2030* | Add 17MW ICE (PS01x1)-Biofueled | Add 17MW ICE (PS01x1)-Biofueled | | | Add 17MW ICE (PS01x1)-Biofueled |
| *2031* | Add 34MW ICE (PS01x2)-Biofueled | Add 34MW ICE (PS01x2)-Biofueled | Add 34MW ICE (PS01x2)-Biofueled | Add 17MW ICE (PS01x1)-Biofueled | Add 34MW ICE (PS01x2)-Biofueled |
| *2032* | Add 17MW ICE (PS01x1)-Biofueled | | | | Add 17MW ICE (PS01x1)-Biofueled |
| *2033* | Add 51MW ICE (PS01x3)-Biofueled | Add 51MW ICE (PS01x3)-Biofueled | Add 34MW ICE (PS01x2)-Biofueled | Add 34MW ICE (PS01x2)-Biofueled | Add 51MW ICE (PS01x3)-Biofueled |
| *Planning Period Total Cost* | 25, 765, 672 | 24, 670, 838 | 24, 050, 252 | 23, 794, 228 | 25, 706, 153 |
| *Study Period Total Cost* | 38, 342, 928 | 36, 158, 228 | 34, 853, 568 | 34, 331, 052 | 38, 156, 739 |
| *Planning Rank* | 4 | 3 | 2 | 1 | 4 |
| *Study Rank* | 4 | 3 | 2 | 1 | 4 |

Table O-53. HECO 100% Renewable Energy

| Name | P3B2b1NRetire-3Cr0 | P3B2a1NRetire-3Cr0 |
|---|---|---|
| *Plan* | 100% RE by 2030, Lanai Wind in 2020 (Wind, PV, Wave, biomass)<br>Convert Existing to Biodiesel in 2030 | 100% RE by 2030, (Wind, PV, Wave, biomass)<br>Convert Existing to Biodiesel in 2030 |
| *Resources Available* | | |
| *Reference* | P3B2b1NRetire-2r0 | |
| *2014* | Expanded CIDLC, CIDP, RDLCWH, RDLCAC | Expanded CIDLC, CIDP, RDLCWH, RDLCAC |
| | 75% PBFA DSM | 75% PBFA DSM |
| *2015* | | Add 20 MW PV (PP03x4) |
| *2016* | Add 91MW SCCT (PS07x1)-Biofueled | Add 91MW SCCT (PS07x1)-Biofueled |
| *2017* | Deactivate W3 (-46MW)<br>Deactivate W4 (-46MW)<br>or H8/9 | Deactivate W3 (-46MW)<br>Deactivate W4 (-46MW)<br>or H8/9 |
| *2018* | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) |
| | Add 91MW SCCT (PS07x1)-Biofueled | Add 91MW SCCT (PS07x1)-Biofueled |
| *2019* | Add 17MW ICE (PS01x1)-Biofueled | Add 17MW ICE (PS01x1)-Biofueled |
| | Deactivate H8 (-53MW)<br>Deactivate H9 (-54MW)<br>or W3/4 | Deactivate H8 (-53MW)<br>Deactivate H9 (-54MW)<br>or W3/4 |
| *2020* | Add 200 MW Lanai Wind | Add 300 MW Wind (PW01x10) |
| | Add 210 MW Wind (PW01x7) | |
| | Add 182MW SCCT (PS07x2)-Biofueled | Add 182MW SCCT (PS07x2)-Biofueled |
| *2021* | Add 60 MW Wind (PW01x2) | Add 150 MW Wind (PW01x5) |
| *2022* | Add 90 MW Wind (PW01x3) | Add 120 MW Wind (PW01x4) |
| *2023* | | |
| *2024* | Add 91MW SCCT (PS07x1)-Biofueled | Add 91MW SCCT (PS07x1)-Biofueled |
| | Add 90 MW Wind (PW01x3) | Add 120 MW Wind (PW01x4) |
| | Add 20 MW PV (PP03x4) | |
| *2025* | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) |
| *2026* | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) |
| *2027* | Add 30 MW Wind (PW01x1) | Add 30 MW Wind (PW01x1) |
| | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) |
| *2028* | Add 90 MW Wind (PW01x3) | Add 90 MW Wind (PW01x3) |
| | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) |
| *2029* | Add 150 MW Wind (PW01x5) | Add 150 MW Wind (PW01x5) |
| | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) |

| **Name** | **P3B2b1NRetire-3Cr0** | **P3B2a1NRetire-3Cr0** |
|---|---|---|
| *2030* | Fuel Switch to BF (Waiau 5-10/Kahe 1-6) | Fuel Switch to BF (Waiau 5-10/Kahe 1-6) |
| | Add 150 MW Wind (PW01x5) | Add 150 MW Wind (PW01x5) |
| | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) |
| *2031* | Add 90 MW Wind (PW01x3) | Add 60 MW Wind (PW01x2) |
| | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) |
| *2032* | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) |
| *2033* | Add 34MW ICE (PS01x2)-Biofueled | Add 34MW ICE (PS01x2)-Biofueled |
| *Planning Period Total Cost* | 24, 591, 443 | 24, 674, 844 |
| *Study Period Total Cost* | 37, 532, 722 | 37, 912, 234 |
| *Planning Rank* | 1 | 2 |
| *Study Rank* | 1 | 2 |

Table O-54. HECO 0% Renewable Portfolio Standard

| **Name** | **P3B2b1NRetire-3Ar0 0%RPS** | **P3B2a1NRetire-3Ar0 0%RPS NOLANAI** | **P3B2A1NRETIRE-3AR0 0%RPS NOLANAILNG** | **P3B2b1NRetire-2r0** |
|---|---|---|---|---|
| *Plan* | 0% RPS, Lanai Wind in 2020 (Wind, PV, Wave, CT, Biomass) | 0% RPS (Wind, PV, Wave, CT, Biomass) | 0% RPS (Wind, PV, Wave, CT, Biomass) | Screen Based on P3_2a1NRetire-1r0 w/ Lanai Wind |
| *Resources Available* | | | | |
| *Reference* | P3B2b1NRetire-2r0 | | | |
| *2014* | Expanded CIDLC, CIDP, RDLCWH, RDLCAC | Expanded CIDLC, CIDP, RDLCWH, RDLCAC | Expanded CIDLC, CIDP, RDLCWH, RDLCAC | Expanded CIDLC, CIDP, RDLCWH, RDLCAC |
| | 75% PBFA DSM | 75% PBFA DSM | 75% PBFA DSM | 75% PBFA DSM |
| *2015* | | | | |
| *2016* | Add 91MW SCCT (PS07x1)-Biofueled | Add 91MW SCCT (PS07x1)-Biofueled | Add 91MW SCCT (PS07x1)-Biofueled | Add 91MW SCCT (PS07x1)-Biofueled |
| *2017* | Deactivate W3 (-46MW) Deactivate W4 (-46MW) or H8/9 | Deactivate W3 (-46MW) Deactivate W4 (-46MW) or H8/9 | Deactivate W3 (-46MW) Deactivate W4 (-46MW) or H8/9 | Deactivate W3 (-46MW) Deactivate W4 (-46MW) or H8/9 |
| | Add 91MW SCCT (PS07x1)-Biofueled | Add 91MW SCCT (PS07x1)-Biofueled | Add 91MW SCCT (PS07x1)-Biofueled | Add 91MW SCCT (PS07x1)-Biofueled |
| *2019* | Add 17MW ICE (PS01x1)-Biofueled | Add 17MW ICE (PS01x1)-Biofueled | Add 17MW ICE (PS01x1)-Biofueled | Add 17MW ICE (PS01x1)-Biofueled |
| | Deactivate H8 (-53MW) Deactivate H9 (-54MW) or W3/4 | Deactivate H8 (-53MW) Deactivate H9 (-54MW) or W3/4 | Deactivate H8 (-53MW) Deactivate H9 (-54MW) or W3/4 | Deactivate H8 (-53MW) Deactivate H9 (-54MW) or W3/4 |
| *2020* | Add 200 MW Lanai Wind | | | Add 200 MW Lanai Wind |
| | Add 150 MW Wind (PW01x5) | Add 150 MW Wind (PW01x5) | Add 150 MW Wind (PW01x5) | Add 150 MW Wind (PW01x5) |
| | Add 182MW SCCT (PS07x2)-Biofueled | Add 182MW SCCT (PS07x2)-Biofueled | Add 182MW SCCT (PS07x2)-Biofueled | Add 182MW SCCT (PS07x2)-Biofueled |
| *2021* | Add 120 MW Wind (PW01x4) | Add 150 MW Wind (PW01x5) | Add 150 MW Wind (PW01x5) | |
| | | | | Add 120 MW Wind (PW01x4) |
| *2022* | Add 90 MW Wind (PW01x3) | Add 150 MW Wind (PW01x5) | Add 150 MW Wind (PW01x5) | |
| | | | | Add 90 MW Wind (PW01x3) |
| *2023* | | Add 150 MW Wind (PW01x5) | Add 30 MW Wind (PW01x1) | |
| *2024* | Add 91MW SCCT (PS07x1)-Biofueled | Add 91MW SCCT (PS07x1)-Biofueled | Add 91MW SCCT (PS07x1)-Biofueled | Add 91MW SCCT (PS07x1)-Biofueled |
| | Add 120 MW Wind (PW01x4) | Add 120 MW Wind (PW01x4) | Add 120 MW Wind (PW01x4) | Add 120 MW Wind (PW01x4) |
| *2025* | Add 30 MW Wind (PW01x1) | | | Add 30 MW Wind (PW01x1) |

| **Name** | **P3B2b1NRetire-3Ar0 0%RPS** | **P3B2a1NRetire-3Ar0 0%RPS NOLANAI** | **P3B2A1NRETIRE-3AR0 0%RPS NOLANAILNG** | **P3B2b1NRetire-2r0** |
|---|---|---|---|---|
| *2026* | | | | |
| *2027* | | | Add 30 MW Wind (PW01x1) | |
| *2028* | | | Add 30 MW Wind (PW01x1) | |
| *2029* | | | | |
| *2030* | | | | |
| *2031* | | | Add 60 MW Wind (PW01x2) | |
| *2032* | | | | |
| *2033* | Add 34MW ICE (PS01x2)-Biofueled | Add 34MW ICE (PS01x2)-Biofueled | Add 34MW ICE (PS01x2)-Biofueled | Add 34MW ICE (PS01x2)-Biofueled |
| *Planning Period Total Cost* | 22, 935, 820 | 23, 025, 101 | 22, 360, 421 | 22, 853, 624 |
| *Study Period Total Cost* | 32, 962, 672 | 33, 307, 392 | 32, 685, 678 | 32, 880, 474 |
| *Planning Rank* | 3 | 4 | 1 | 2 |
| *Study Rank* | 3 | 4 | 1 | 2 |

## Moved by Passion

Table O-55. HECO Timing Run (1 of 3)

| **Name** | **P4_2a1XRetire-1r0** | **P4_2a1XRetire-1r1** | **P4_2a1XRetire-1r2** | **P4_2a1NRetire-1r0** |
|---|---|---|---|---|
| *Plan* | Required Timing, H8/9W4/5 Ret (ICE, SCCT) | Timing, H8/9, W45Ret (SCCT, CC, Bio, OTEC) | Timing, H8/9, W45Ret (ICE, Bio, OTEC Fixed) | Timing, H8/9W4/5 Ret (ICE, SCCT) |
| *Resources Available* | | | | |
| *2014* | Continue CIDLC, CIDP, RDLCWH, RDLCAC | Continue CIDLC, CIDP, RDLCWH, RDLCAC | Continue CIDLC, CIDP, RDLCWH, RDLCAC | Expanded CIDLC, CIDP, RDLCWH, RDLCAC |
| | 75%+25% PBFA DSM | 75%+25% PBFA DSM | 75%+25% PBFA DSM | 75%+25% PBFA DSM |
| *2015* | | | | |
| *2016* | Fuel Switch to Diesel (H8/9, Waiau 5-10/Kahe 1-6) | Fuel Switch to Diesel (H8/9, Waiau 5-10/Kahe 1-6) | Fuel Switch to Diesel (H8/9, Waiau 5-10/Kahe 1-6) | Fuel Switch to Diesel (H8/9, Waiau 5-10/Kahe 1-6) |
| *2017* | | | Add 51MW ICE (PS01x3)-Biofueled | |
| | Deactivate W3 (-46MW) Deactivate W4 (-46MW) | Deactivate W3 (-46MW) Deactivate W4 (-46MW) | Deactivate W3 (-46MW) Deactivate W4 (-46MW) | Deactivate W3 (-46MW) Deactivate W4 (-46MW) |
| *2018* | | | | |
| *2019* | Deactivate H8 (-53MW) Deactivate H9 (-54MW) | Deactivate H8 (-53MW) Deactivate H9 (-54MW) | Deactivate H8 (-53MW) Deactivate H9 (-54MW) | Deactivate H8 (-53MW) Deactivate H9 (-54MW) |
| *2020* | Add 91MW SCCT (PS07x1)-Biofueled | Add 91MW SCCT (PS07x1)-Biofueled | Add 25MW ICE (PA01x1)-Biofueled | |
| | | | Add 96MWr OTEC (POT1x10) | |
| *2021* | | | | |
| *2022* | | | | |
| *2023* | | | | |
| *2024* | | | | |
| *2025* | | | | |
| *2026* | | | | |
| *2027* | | | | |
| *2028* | | | | |
| *2029* | | | | |
| *2030* | | | | |
| *2031* | | | | |
| *2032* | | | | |
| *2033* | | Add 25MW (PA01x1)-Biomass | | Add 25MW (PA01x1)-Biomass |

| **Name** | **P4_2a1XRetire-1r0** | **P4_2a1XRetire-1r1** | **P4_2a1XRetire-1r2** | **P4_2a1NRetire-1r0** |
|---|---|---|---|---|
| *Planning Period Total Cost* | 24, 442, 528 | 24, 443, 534 | 26, 899, 948 | 24, 329, 166 |
| *Study Period Total Cost* | 35, 363, 552 | 35, 331, 128 | 39, 132, 096 | 35, 280, 644 |
| *Planning Rank* | 3 | 4 | 7 | 2 |
| *Study Rank* | 4 | 3 | 7 | 1 |

Table O-56. HECO Timing Run (2 of 3)

| **Name** | **P4_2a1NRetire-1r1** | **P4_2a1XRetire-1r3** | **P4_2a1NRetire-1r2** | **P4_2a1X-1r0** |
|---|---|---|---|---|
| *Plan* | Required Timing, H8/9W4/5 Ret (ICE) | Timing, H8/9, W45Ret (2017ICE Fixed) | Required Timing, H8/9W4/5 Ret (ICE) | Required Timing (ICE, SCCT) |
| *Resources Available* | | | | |
| *2014* | Expanded CIDLC, CIDP, RDLCWH, RDLCAC | Continue CIDLC, CIDP, RDLCWH, RDLCAC | Expanded CIDLC, CIDP, RDLCWH, RDLCAC | Continue CIDLC, CIDP, RDLCWH, RDLCAC |
| | 75%+25% PBFA DSM | 75%+25% PBFA DSM | 75%+25% PBFA DSM | 75%+25% PBFA DSM |
| *2015* | | | | |
| *2016* | Fuel Switch to Diesel (H8/9, Waiau 5-10/Kahe 1-6) | Fuel Switch to Diesel (H8/9, Waiau 5-10/Kahe 1-6) | Fuel Switch to Diesel (H8/9, Waiau 5-10/Kahe 1-6) | Fuel Switch to Diesel (H8/9, Waiau 5-10/Kahe 1-6) |
| *2017* | | Add 51MW ICE (PS01x3)-Biofueled | Add 51MW ICE (PS01x3)-Biofueled | |
| | Deactivate W3 (-46MW) Deactivate W4 (-46MW) | Deactivate W3 (-46MW) Deactivate W4 (-46MW) | Deactivate W3 (-46MW) Deactivate W4 (-46MW) | |
| *2018* | | | | |
| *2019* | Deactivate H8 (-53MW) Deactivate H9 (-54MW) | Deactivate H8 (-53MW) Deactivate H9 (-54MW) | Deactivate H8 (-53MW) Deactivate H9 (-54MW) | |
| *2020* | | | | |
| *2021* | | | | |
| *2022* | | Add 91MW SCCT (PS07x1)-Biofueled | | |
| *2023* | | | | |
| *2024* | | | | |
| *2025* | | | | |
| *2026* | | | | |
| *2027* | | | | |
| *2028* | | | | |
| *2029* | | | | |
| *2030* | | | | |
| *2031* | | | | |
| *2032* | | | | |
| *2033* | | | Add 91MW SCCT (PS07x1)-Biofueled | |
| *Planning Period Total Cost* | 24, 328, 362 | 24, 552, 726 | 24, 624, 702 | 24, 301, 878 |
| *Study Period Total Cost* | 35, 323, 016 | 35, 479, 868 | 35, 592, 896 | 35, 338, 584 |
| *Planning Rank* | 1 | 5 | 6 | 1 |
| *Study Rank* | 2 | 5 | 6 | 2 |

Table O-57. HECO Timing Run (3 of 3)

| **Name** | **P4_2a1X-1r1** | **P4_2a1N-1r0** | **P4B2b1NRetire-4Er1** |
|---|---|---|---|
| *Plan* | Timing, Least Cost (CC, Biomass, OTEC) | Timing (All Firm Available) | Deactivate Existing Replace with Conventional LNG Units |
| *Notes* | | | All units are deactivated by 2022 |
| *Resources Available* | | | ICE (17 MW)-Biodiesel (PS01)-n/a<br>95 MW SCCT LMS 100 - LNG (PS07)-2020<br>42 MW LM6000 SCCT LNG (PC08)-n/a<br>59 MW 1on1 LM6000 CC-LNG (PS12)-2020<br>25MW Banagrass (PA01)-n/a<br>400 kW Nat Gas Fuel Cell (FC40)-n/a<br>30 MW Onshore Wind Cl 3 (PW01)-2016<br>10 MW Onshore Wind Cl 5 (PW03)-n/a<br>5 MW of 1 MW Tracking PV (PP03)-2016 |
| *2014* | Continue CIDLC, CIDP, RDLCWH, RDLCAC | Expanded CIDLC, CIDP, RDLCWH, RDLCAC | Expanded CIDLC, CIDP, RDLCWH, RDLCAC |
| | 75%+25% PBFA DSM | 75%+25% PBFA DSM | 75%+25% PBFA DSM |
| *2015* | | | |
| *2016* | Fuel Switch to Diesel<br>(H8/9, Waiau 5-10/Kahe 1-6) | Fuel Switch to Diesel<br>(H8/9, Waiau 5-10/Kahe 1-6) | Fuel Switch to Diesel<br>(H8/9, Waiau 5-10/Kahe 1-6) |
| *2017* | | | Deactivate W3 (-46MW)<br>Deactivate W4 (-46MW) |
| *2018* | | | |
| *2019* | | | Deactivate H8 (-53MW)<br>Deactivate H9 (-54MW) |
| *2020* | | | Deactivate W5 (-55MW)<br>Deactivate W6 (-56MW)<br>Deactivate W7 (-88MW)<br>Deactivate W8 (-88MW)<br>Deactivate K1 (-88MW)<br>Deactivate K2 (-86MW)<br>Deactivate K3 (-88MW)<br>Deactivate K4 (-89MW) |
| | | | Add 273MW CT (PS07x3)-Biofueled |
| | | | Add 118MW CC (PC08x2)-Biofueled |
| *2021* | | | Retire K5 (-135MW) |
| | | | Add 236MW CC (PC08x4)-Biofueled |
| *2022* | | | Retire K6 (-134MW) |
| | | | Add 118MW CC (PC08x2)-Biofueled |
| *2023* | | | Add 91MW CT (PS07x1)-Biofueled |
| *2024* | | | |

| **Name** | **P4_2a1X-1r1** | **P4_2a1N-1r0** | **P4B2b1NRetire-4Er1** |
|---|---|---|---|
| *2025* | | | |
| *2026* | | | |
| *2027* | | | |
| *2028* | | | |
| *2029* | | | |
| *2030* | | | |
| *2031* | | | |
| *2032* | | | |
| *2033* | Add 25MW (PA01x1)-Biomass | Add 25MW (PA01x1)-Biomass | |
| *Planning Period Total Cost* | 24, 303, 150 | 24, 390, 642 | 27, 936, 478 |
| *Study Period Total Cost* | 35, 295, 400 | 35, 415, 040 | 38, 062, 348 |
| *Planning Rank* | 2 | 3 | #REF! |
| *Study Rank* | 1 | 3 | #REF! |

Table O-58. HECO Screening Run (1 of 2)

| **Name** | **P4B2a1XRetire-2r0** | **P4B2b1XRetire-2r1** | **P4B2a1NRetire-2r0 screening** |
|---|---|---|---|
| *Plan* | Screen, Exist DR (PV, Wind, Wave, Biomass) | Screen, Exist DR, Lanai Wind (PV, Wind, Wave, Biomass) | Screen, Expand DR (PV, Wind, Wave, Biomass) |
| *Resources Available* | | | 25MW Banagrass Combust (PA01)-2019<br>30 MW Onshore Wind Cl 3 (PW01)-2018<br>10 MW Onshore Wind Cl 5 (PW03)-n/a<br>10 MW Onshore Wind Cl 7 (PW04)-n/a<br>100 MW Offshore Wind (PW05)-2020<br>5 MW of 1 MW Tracking PV (PP03)-2015<br>50 MW Parabolic Trough PV (PP04)-n/a<br>9.6 MW OTEC (POT1)-n/a<br>15 MW Ocean Wave (PV02)-2020 |
| *Reference* | P4_2a1XRetire-2r0.xlxs | P4B2b1XRetire-2r1.xlxs | |
| *2014* | Continue CIDLC, CIDP, RDLCWH, RDLCAC | Continue CIDLC, CIDP, RDLCWH, RDLCAC | Expanded CIDLC, CIDP, RDLCWH, RDLCAC |
| | 75%+25% PBFA DSM | 75%+25% PBFA DSM | 75%+25% PBFA DSM |
| *2015* | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) |
| *2016* | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) |
| *2017* | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) |
| | Deactivate W3 (-46MW)<br>Deactivate W4 (-46MW) | Deactivate W3 (-46MW)<br>Deactivate W4 (-46MW) | Deactivate W3 (-46MW)<br>Deactivate W4 (-46MW) |
| *2018* | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) |
| | | | Add 60 MW Wind (PW01x2) |
| *2019* | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) |
| | | | Add 60 MW Wind (PW01x2) |
| | Deactivate H8 (-53MW)<br>Deactivate H9 (-54MW) | Deactivate H8 (-53MW)<br>Deactivate H9 (-54MW) | Deactivate H8 (-53MW)<br>Deactivate H9 (-54MW) |
| *2020* | Add 240 MW Wind (PW01x8) | | Add 120 MW Wind (PW01x4) |
| | Add 91MW SCCT (PS07x1)-Biofueled | Add 91MW SCCT (PS07x1)-Biofueled | |
| | | Add 200 MW Lanai Wind | |
| *2021* | Add 20 MW PV (PP03x4) | | Add 20 MW PV (PP03x4) |
| *2022* | | | |
| *2023* | | | |
| *2024* | | | |
| *2025* | | | |
| *2026* | | | |
| *2027* | Add 20 MW PV (PP03x4) | Add 30 MW Wind (PW01x1) | Add 20 MW PV (PP03x4) |

| Name | P4B2a1XRetire-2r0 | P4B2b1XRetire-2r1 | P4B2a1NRetire-2r0 screening |
|---|---|---|---|
| *2028* | Add 60 MW Wind (PW01x2) | Add 60 MW Wind (PW01x2) | Add 60 MW Wind (PW01x2) |
| | Add 20 MW PV (PP03x4) | | Add 20 MW PV (PP03x4) |
| *2029* | Add 60 MW Wind (PW01x2) | Add 60 MW Wind (PW01x2) | Add 60 MW Wind (PW01x2) |
| | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) |
| *2030* | Add 60 MW Wind (PW01x2) | Add 60 MW Wind (PW01x2) | Add 60 MW Wind (PW01x2) |
| | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) |
| *2031* | | | |
| *2032* | | | |
| *2033* | | | |
| *Planning Period Total Cost* | 24, 045, 194 | 24, 033, 750 | 23, 889, 496 |
| *Study Period Total Cost* | 34, 355, 428 | 34, 198, 564 | 34, 151, 112 |
| *Planning Rank* | 5 | 4 | 2 |
| *Study Rank* | 5 | 4 | 2 |

Table O-59. HECO Screening Run (2 of 2)

| **Name** | **P4B2b1NRetire-2r1 screening** | **P4B2b1NRetire-2r1 screeN_LanH** | **P4B2b1NRetire-2r2** |
|---|---|---|---|
| *Plan* | Screen, Expand DR, Lanai Wind (PV, Wind, Wave, Biomass) | Screen, Expand DR, Lanai Wind revised cost | Screen, Expand DR, Lanai Wind (PV, Wind, Wave, Biomass) |
| *Notes* | | | ICE In 2017 |
| *Resources Available* | 25MW Banagrass Combust (PA01)-2019<br>30 MW Onshore Wind Cl 3 (PW01)-2018<br>10 MW Onshore Wind Cl 5 (PW03)-n/a<br>10 MW Onshore Wind Cl 7 (PW04)-n/a<br>100 MW Offshore Wind (PW05)-2020<br>5 MW of 1 MW Tracking PV (PP03)-2015<br>50 MW Parabolic Trough PV (PP04)-n/a<br>9.6 MW OTEC (POT1)-n/a<br>15 MW Ocean Wave (PV02)-2020 | 25MW Banagrass Combust (PA01)-2019<br>30 MW Onshore Wind Cl 3 (PW01)-2018<br>10 MW Onshore Wind Cl 5 (PW03)-n/a<br>10 MW Onshore Wind Cl 7 (PW04)-n/a<br>100 MW Offshore Wind (PW05)-2020<br>5 MW of 1 MW Tracking PV (PP03)-2015<br>50 MW Parabolic Trough PV (PP04)-n/a<br>9.6 MW OTEC (POT1)-n/a<br>15 MW Ocean Wave (PV02)-2020 | |
| *Reference* | | | P4B2b1NRetire-2r2.xlxs |
| *2014* | Expanded CIDLC, CIDP, RDLCWH, RDLCAC | Expanded CIDLC, CIDP, RDLCWH, RDLCAC | Expanded CIDLC, CIDP, RDLCWH, RDLCAC |
| | 75%+25% PBFA DSM | 75%+25% PBFA DSM | 75%+25% PBFA DSM |
| *2015* | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) |
| *2016* | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) |
| *2017* | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) |
| | | | Add 51MW ICE (PS01x3)-Biofueled |
| | Deactivate W3 (-46MW)<br>Deactivate W4 (-46MW) | Deactivate W3 (-46MW)<br>Deactivate W4 (-46MW) | Deactivate W3 (-46MW)<br>Deactivate W4 (-46MW) |
| *2018* | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) |
| | Add 60 MW Wind (PW01x2) | Add 60 MW Wind (PW01x2) | Add 60 MW Wind (PW01x2) |
| *2019* | Deactivate H8 (-53MW)<br>Deactivate H9 (-54MW) | Deactivate H8 (-53MW)<br>Deactivate H9 (-54MW) | Deactivate H8 (-53MW)<br>Deactivate H9 (-54MW) |
| *2020* | Add 200 MW Lanai Wind | Add 200 MW Lanai Wind | |
| | Add 200 MW Lanai Wind | Add 200 MW Lanai Wind | Add 200 MW Lanai Wind |
| *2021* | | | |
| *2022* | | | |
| *2023* | | | |
| *2024* | | | |
| *2025* | | | |
| *2026* | | | |
| *2027* | | | |
| *2028* | Add 30 MW Wind (PW01x1) | Add 30 MW Wind (PW01x1) | Add 60 MW Wind (PW01x2) |
| | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) | |

| Name | P4B2b1NRetire-2r1 screening | P4B2b1NRetire-2r1 screeN_LanH | P4B2b1NRetire-2r2 |
|---|---|---|---|
| *2029* | Add 60 MW Wind (PW01x2) | Add 60 MW Wind (PW01x2) | Add 91MW SCCT (PS07x1)-Biofueled |
| | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) | Add 60 MW Wind (PW01x2) |
| *2030* | Add 60 MW Wind (PW01x2) | Add 60 MW Wind (PW01x2) | Add 60 MW Wind (PW01x2) |
| | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) |
| *2031* | | | |
| *2032* | | | |
| *2033* | | | |
| *Planning Period Total Cost* | 23, 885, 070 | 24, 012, 092 | 24, 271, 968 |
| *Study Period Total Cost* | 34, 006, 408 | 34, 191, 696 | 34, 596, 352 |
| *Planning Rank* | 1 | 3 | 6 |
| *Study Rank* | 1 | 3 | 6 |

Table O-60. HECO Environmental Compliance (1 of 2)

| Name | P4B2b1NRetire-2r1 Screening | P4B2b1NRetire-4Br1 | P4B2b1NRetire-4Dr1 | P4B2b1NRetire-4Er1 |
|---|---|---|---|---|
| *Plan* | Fuel Switch to ULSD in 2022 | Install Air Quality Controls in 2022 | Fuel Switch to LNG in 2020 | Deactivate Existing Replace with Conventional LNG Units |
| *Notes* | Fuel switch applies to all Waiau 5-8 and Kahe 1-6 | Install AQC on Waiau 5-8 and Kahe 1-6 | Fuel switch applies to all Waiau 5-8 and Kahe 1-6 | All units are deactivated by 2022 |
| *Resources Available* | ICE (17 MW)-Biodiesel (PS01)-n/a<br>100 MW SCCT - Biodiesel (PS07)-n/a<br>42 MW LM6000 SCCT LNG (PC08)-n/a<br>59 MW 1on1 LM6000 CC-LNG (PS12)-n/a<br>25MW Banagrass (PA01)-2019<br>30 MW Onshore Wind Cl 3 (PW01)-2018<br>10 MW Onshore Wind Cl 5 (PW03)-n/a<br>10 MW Onshore Wind Cl 7 (PW04)-n/a<br>100 MW Offshore Wind (PW05)-n/a<br>5 MW of 1 MW Tracking PV (PP03)-2015<br>50 MW Parabolic Trough PV (PP04)-n/a<br>9.6 MW OTEC (POT1)-n/a<br>15 MW Ocean Wave 5 MW (PV02)-2020 | ICE (17 MW)-Biodiesel (PS01)-n/a<br>100 MW SCCT - Biodiesel (PS07)-n/a<br>42 MW LM6000 SCCT LNG (PC08)-n/a<br>59 MW 1on1 LM6000 CC-LNG (PS12)-n/a<br>25MW Banagrass (PA01)-2019<br>30 MW Onshore Wind Cl 3 (PW01)-2018<br>10 MW Onshore Wind Cl 5 (PW03)-n/a<br>10 MW Onshore Wind Cl 7 (PW04)-n/a<br>100 MW Offshore Wind (PW05)-n/a<br>5 MW of 1 MW Tracking PV (PP03)-2015<br>50 MW Parabolic Trough PV (PP04)-n/a<br>9.6 MW OTEC (POT1)-n/a<br>15 MW Ocean Wave 5 MW (PV02)-n/a | ICE (17 MW)-Biodiesel (PS01)-n/a<br>100 MW SCCT - Biodiesel (PS07)-n/a<br>42 MW LM6000 SCCT LNG (PC08)-n/a<br>59 MW 1on1 LM6000 CC-LNG (PS12)-2020<br>25MW Banagrass (PA01)-2027<br>30 MW Onshore Wind Cl 3 (PW01)-2016<br>10 MW Onshore Wind Cl 5 (PW03)-n/a<br>10 MW Onshore Wind Cl 7 (PW04)-n/a<br>100 MW Offshore Wind (PW05)-n/a<br>5 MW of 1 MW Tracking PV (PP03)-2015<br>50 MW Parabolic Trough PV (PP04)-n/a<br>9.6 MW OTEC (POT1)-n/a<br>15 MW Ocean Wave 5 MW (PV02)-n/a | ICE (17 MW)-Biodiesel (PS01)-n/a<br>95 MW SCCT LMS 100 - LNG (PS07)-2020<br>42 MW LM6000 SCCT LNG (PC08)-n/a<br>59 MW 1on1 LM6000 CC-LNG (PS12)-2020<br>25MW Banagrass (PA01)-n/a<br>400 kW Nat Gas Fuel Cell (FC40)-n/a<br>30 MW Onshore Wind Cl 3 (PW01)-2016<br>10 MW Onshore Wind Cl 5 (PW03)-n/a<br>5 MW of 1 MW Tracking PV (PP03)-2016 |
| *2014* | Expanded CIDLC, CIDP, RDLCWH, RDLCAC | Expanded CIDLC, CIDP, RDLCWH, RDLCAC | Expanded CIDLC, CIDP, RDLCWH, RDLCAC | Expanded CIDLC, CIDP, RDLCWH, RDLCAC |
| | 75%+25% PBFA DSM | 75%+25% PBFA DSM | 75%+25% PBFA DSM | 75%+25% PBFA DSM |
| *2015* | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) |
| *2016* | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) |
| | Fuel Switch to Diesel (H8/9, Waiau 5-10/Kahe 1-6) | Fuel Switch to Diesel (H8/9, Waiau 5-10/Kahe 1-6) | Fuel Switch to Diesel (H8/9, Waiau 5-10/Kahe 1-6) | Fuel Switch to Diesel (H8/9, Waiau 5-10/Kahe 1-6) |
| *2017* | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) |
| | Deactivate W3 (-46MW)<br>Deactivate W4 (-46MW) | Deactivate W3 (-46MW)<br>Deactivate W4 (-46MW) | Deactivate W3 (-46MW)<br>Deactivate W4 (-46MW) | Deactivate W3 (-46MW)<br>Deactivate W4 (-46MW) |
| *2018* | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) |
| | Add 60 MW Wind (PW01x2) | Add 60 MW Wind (PW01x2) | Add 60 MW Wind (PW01x2) | Add 60 MW Wind (PW01x2) |

| Name | P4B2b1NRetire-2r1 Screening | P4B2b1NRetire-4Br1 | P4B2b1NRetire-4Dr1 | P4B2b1NRetire-4Er1 |
|---|---|---|---|---|
| 2019 | | | | Add 91MW CT (PS07x1)-LNG |
| | Deactivate H8 (-53MW)<br>Deactivate H9 (-54MW) | Deactivate H8 (-53MW)<br>Deactivate H9 (-54MW) | Deactivate H8 (-53MW)<br>Deactivate H9 (-54MW) | Deactivate H8 (-53MW)<br>Deactivate H9 (-54MW) |
| 2020 | | | | Deactivate W5 (-55MW)<br>Deactivate W6 (-56MW)<br>Deactivate W7 (-88MW)<br>Deactivate W8 (-88MW)<br>Deactivate K1 (-88MW)<br>Deactivate K2 (-86MW)<br>Deactivate K3 (-88MW)<br>Deactivate K4 (-89MW) |
| | | | Fuel switch to LNG (Waiau 5-8, Kahe 1-6) | Add 91MW CT (PS07x1)-LNG |
| | | | | Add 236MW CC (PC08x4)-LNG |
| | Add 200 MW Lanai Wind | Add 200 MW Lanai Wind | Add 200 MW Lanai Wind | Add 200 MW Lanai Wind |
| 2021 | | | | Retire K5 (-135MW) |
| | | | | Add 91MW CT (PS07x1)-LNG |
| | | | | Add 118 MW CC (PC08x2)-LNG |
| 2022 | Fuel Switch to ULSD (Waiau 5-8, Kahe 1-6) | AQC Waiau 5-8 & Kahe 1-6 | | Retire K6 (-134MW) |
| | | | | Add 118 MW CC (PC08x2)-LNG |
| 2023 | | | | Add 91MW CT (PS07x1)-LNG |
| 2024 | | | | |
| 2025 | | | | |
| 2026 | | | | |
| 2027 | | | | |
| 2028 | Add 30 MW Wind (PW01x1) | Add 30 MW Wind (PW01x1) | Add 30 MW Wind (PW01x1) | Add 30 MW Wind (PW01x1) |
| | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) |
| 2029 | Add 60 MW Wind (PW01x2) | Add 60 MW Wind (PW01x2) | Add 60 MW Wind (PW01x2) | Add 60 MW Wind (PW01x2) |
| | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) |
| 2030 | Add 60 MW Wind (PW01x2) | Add 60 MW Wind (PW01x2) | Add 60 MW Wind (PW01x2) | Add 60 MW Wind (PW01x2) |
| | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) |
| 2031 | | | | |
| 2032 | | | | |
| 2033 | | | | |

| Name | P4B2b1NRetire-2r1 Screening | P4B2b1NRetire-4Br1 | P4B2b1NRetire-4Dr1 | P4B2b1NRetire-4Er1 |
|---|---|---|---|---|
| *Strategist Planning Period Total Cost* | 23, 885, 070 | 23, 686, 352 | 21, 400, 236 | 23, 187, 138 |
| *Strategist Study Period Total Cost* | 34, 006, 408 | 33, 634, 624 | 29, 089, 696 | 30, 941, 318 |
| *Planning Period Total Cost* | 23, 967, 266 | 24, 865, 128 | 21, 774, 544 | 23, 389, 300 |
| *Study Period Total Cost* | 34, 088, 606 | 34, 813, 397 | 29, 464, 002 | 31, 143, 477 |
| *Planning Rank* | 3 | 4 | 1 | 2 |
| *Study Rank* | 3 | 4 | 1 | 2 |

Table O-61. HECO Environmental Compliance (2 of 2)

| **Name** | **P4B2b1NRetire-2r1** | **P4B2b1NRetire-4Br1** | **P4B2b1NRetire-4Dr1** | **P4B2b1NRetire-4Er1** |
|---|---|---|---|---|
| *Plan* | Screen, Expand DR, Lanai Wind (PV, Wind, Wave, Biomass) | AQC Existing | LNG Existing | Retire/Replace w/ LNG |
| *Resources Available* | | | | |
| *Reference* | P4B2b1NRetire-2r1.xlxs | P4B2b1NRetire-4Br1.xlxs | P4B2b1NRetire-4Dr1.xlxs | P4B2b1NRetire-4Er1.xlxs |
| *2014* | Expanded CIDLC, CIDP, RDLCWH, RDLCAC | Expanded CIDLC, CIDP, RDLCWH, RDLCAC | Expanded CIDLC, CIDP, RDLCWH, RDLCAC | Expanded CIDLC, CIDP, RDLCWH, RDLCAC |
| | 75%+25% PBFA DSM | 75%+25% PBFA DSM | 75%+25% PBFA DSM | 75%+25% PBFA DSM |
| *2015* | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) |
| *2016* | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) |
| *2017* | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) |
| | Deactivate W3 (-46MW)<br>Deactivate W4 (-46MW) | Deactivate W3 (-46MW)<br>Deactivate W4 (-46MW) | Deactivate W3 (-46MW)<br>Deactivate W4 (-46MW) | Deactivate W3 (-46MW)<br>Deactivate W4 (-46MW) |
| *2018* | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) |
| | Add 60 MW Wind (PW01x2) | Add 60 MW Wind (PW01x2) | Add 60 MW Wind (PW01x2) | Add 60 MW Wind (PW01x2) |
| *2019* | Deactivate H8 (-53MW)<br>Deactivate H9 (-54MW) | Deactivate H8 (-53MW)<br>Deactivate H9 (-54MW) | Deactivate H8 (-53MW)<br>Deactivate H9 (-54MW) | Deactivate H8 (-53MW)<br>Deactivate H9 (-54MW) |
| *2020* | | | Fuel switch to LNG (Waiau 5-8, Kahe 1-6) | |
| | | | | Deactivate W5 (-55MW)<br>Deactivate W6 (-56MW)<br>Deactivate W7 (-88MW)<br>Deactivate W8 (-88MW)<br>Deactivate K1 (-88MW)<br>Deactivate K2 (-86MW)<br>Deactivate K3 (-88MW)<br>Deactivate K4 (-89MW) |
| | | | | Add 273MW CT (PS07x3)-LNG |
| | | | | Add 118MW CC (PC08x2)-LNG |
| | Add 200 MW Lanai Wind | Add 200 MW Lanai Wind | Add 200 MW Lanai Wind | Add 200 MW Lanai Wind |
| *2021* | | | | Retire K5 (-135MW) |
| | | | | Add 236 MW CC (PC08x4)-LNG |

| Name | P4B2b1NRetire-2r1 | P4B2b1NRetire-4Br1 | P4B2b1NRetire-4Dr1 | P4B2b1NRetire-4Er1 |
|---|---|---|---|---|
| *2022* | Fuel Switch to ULSD (Waiau 5-8, Kahe 1-6) | AQC Waiau 5-8 & Kahe 1-6 | | Retire K6 (-134MW) |
| | | | | Add 118 MW CC (PC08x2)-LNG |
| *2023* | | | | Add 91MW CT (PS07x1)-LNG |
| *2024* | | | | |
| *2025* | | | | |
| *2026* | | | | |
| *2027* | | | | |
| *2028* | Add 30 MW Wind (PW01x1) | Add 30 MW Wind (PW01x1) | Add 30 MW Wind (PW01x1) | Add 30 MW Wind (PW01x1) |
| | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) |
| *2029* | Add 60 MW Wind (PW01x2) | Add 60 MW Wind (PW01x2) | Add 60 MW Wind (PW01x2) | Add 60 MW Wind (PW01x2) |
| | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) |
| *2030* | Add 60 MW Wind (PW01x2) | Add 60 MW Wind (PW01x2) | Add 60 MW Wind (PW01x2) | Add 60 MW Wind (PW01x2) |
| | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) |
| *2031* | | | | |
| *2032* | | | | |
| *2033* | | | | |
| *Planning Period Total Cost* | 24, 020, 075 | 24, 883, 587 | 21, 793, 003 | 23, 439, 349 |
| *Study Period Total Cost* | 34, 141, 415 | 34, 831, 857 | 29, 482, 462 | 31, 193, 526 |
| *Planning Rank* | 3 | 4 | 1 | 2 |
| *Study Rank* | 3 | 4 | 1 | 2 |

Table O-62. HECO 100% Renewable Energy

| **Name** | **P4B2b1NRetire-3Cr0** | **P4B2a1NRetire-3Cr0** | **P4B2a1NRetire-3Cr1** |
|---|---|---|---|
| *Plan* | 100% RE by 2030, Lanai Wind in 2020 (Wind, PV, Wave, biomass)<br>Convert Existing to Biodiesel in 2030 | 100% RE by 2030, (Wind, PV, Wave, biomass)<br>Convert Existing to Biodiesel in 2030 | 100% RE by 2030, (Wind, PV, Wave, biomass)<br>Convert Existing to Biodiesel in 2030 |
| *Notes* | | Allowed to add PW01x10 in 2020<br>Allowed to add PP03x8 in 2020 | Allowed to add PW01x5 in 2020<br>Allowed to add PP03x4 in 2020 |
| *Resources Available* | | | |
| *Reference* | P4B2b1NRetire-2r1 | | |
| *2014* | Expanded CIDLC, CIDP, RDLCWH, RDLCAC | Expanded CIDLC, CIDP, RDLCWH, RDLCAC | Expanded CIDLC, CIDP, RDLCWH, RDLCAC |
| | 75%+25% PBFA DSM | 75%+25% PBFA DSM | 75%+25% PBFA DSM |
| *2015* | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) |
| *2016* | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) |
| *2017* | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) |
| | Deactivate W3 (-46MW)<br>Deactivate W4 (-46MW) | Deactivate W3 (-46MW)<br>Deactivate W4 (-46MW) | Deactivate W3 (-46MW)<br>Deactivate W4 (-46MW) |
| *2018* | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) |
| *2019* | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) |
| | Deactivate H8 (-53MW)<br>Deactivate H9 (-54MW) | Deactivate H8 (-53MW)<br>Deactivate H9 (-54MW) | Deactivate H8 (-53MW)<br>Deactivate H9 (-54MW) |
| *2020* | | | Add 25 MW Biomass (PA01x1) |
| | | Add 210 MW Wind (PW01x7) | Add 150 MW Wind (PW01x5) |
| | | Add 40 MW PV (PP03x8) | Add 20 MW PV (PP03x4) |
| | | | Add 30 MW Wave (PV02x2) |
| | Add 200 MW Lanai Wind | | |
| *2021* | | | Add 30 MW Wind (PW01x1) |
| *2022* | | | |
| *2023* | | | |
| *2024* | | | |
| *2025* | | | |
| *2026* | | | |
| *2027* | | | |
| *2028* | | | |
| *2029* | | | |

| **Name** | **P4B2b1NRetire-3Cr0** | **P4B2a1NRetire-3Cr0** | **P4B2a1NRetire-3Cr1** |
|---|---|---|---|
| *2030* | Fuel Switch to BF<br>(Waiau 5-10/Kahe 1-6) | Fuel Switch to BF<br>(Waiau 5-10/Kahe 1-6) | Fuel Switch to BF<br>(Waiau 5-10/Kahe 1-6) |
| | Add 30 MW Wind (PW01x1) | Add 30 MW Wind (PW01x1) | |
| | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) |
| *2031* | | | |
| *2032* | | | |
| *2033* | | | |
| *Planning Period Total Cost* | 24, 454, 595 | 24, 460, 722 | 24, 769, 162 |
| *Study Period Total Cost* | 33, 766, 112 | 33, 901, 562 | 34, 398, 818 |
| *Planning Rank* | 1 | 2 | 3 |
| *Study Rank* | 1 | 2 | 3 |

Table O-63. HECO 0% Renewable Portfolio Standard

| **Name** | **P4B2b1NRetire-3Ar0 0%RPS** | **P4B2A1NRETIRE-3AR0 0%RPS NO LANAI** | **P4B2A1NRETIRE-3AR0 0%RPS NO LANAI_LNG** | **P4B2b1NRetire-2r1** |
|---|---|---|---|---|
| *Plan* | 0% RPS, Lanai Wind in 2020 (Wind, PV, Wave, CT, Biomass) | 0% RPS, (Wind, PV, Wave, CT, Biomass) | 0% RPS, (Wind, PV, Wave, CT, Biomass) | Screen, Expand DR, Lanai Wind (PV, Wind, Wave, Biomass) |
| *Resources Available* | | | | |
| *Reference* | P4B2b1NRetire-2r1 | | | P4B2b1NRetire-2r1.xlxs |
| *2014* | Expanded CIDLC, CIDP, RDLCWH, RDLCAC | Expanded CIDLC, CIDP, RDLCWH, RDLCAC | Expanded CIDLC, CIDP, RDLCWH, RDLCAC | Expanded CIDLC, CIDP, RDLCWH, RDLCAC |
| | 75%+25% PBFA DSM | 75%+25% PBFA DSM | 75%+25% PBFA DSM | 75%+25% PBFA DSM |
| *2015* | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) | | Add 20 MW PV (PP03x4) |
| *2016* | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) | | Add 20 MW PV (PP03x4) |
| *2017* | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) | | Add 20 MW PV (PP03x4) |
| | Deactivate W3 (-46MW) Deactivate W4 (-46MW) | Deactivate W3 (-46MW) Deactivate W4 (-46MW) | Deactivate W3 (-46MW) Deactivate W4 (-46MW) | Deactivate W3 (-46MW) Deactivate W4 (-46MW) |
| *2018* | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) | | Add 20 MW PV (PP03x4) |
| | Add 60 MW Wind (PW01x2) | Add 60 MW Wind (PW01x2) | Add 60 MW Wind (PW01x2) | Add 60 MW Wind (PW01x2) |
| *2019* | | Add 20 MW PV (PP03x4) | | |
| | | Add 60 MW Wind (PW01x2) | | |
| | Deactivate H8 (-53MW) Deactivate H9 (-54MW) | Deactivate H8 (-53MW) Deactivate H9 (-54MW) | Deactivate H8 (-53MW) Deactivate H9 (-54MW) | Deactivate H8 (-53MW) Deactivate H9 (-54MW) |
| *2020* | | Add 30 MW Wind (PW01x3) | | |
| | | Add 20 MW PV (PP03x4) | | |
| | Add 200 MW Lanai Wind | | | Add 200 MW Lanai Wind |
| *2021* | | | | |
| *2022* | | Add 20 MW PV (PP03x4) | | |
| *2023* | | | | |
| *2024* | | | | |
| *2025* | | | | |
| *2026* | | | | |
| *2027* | | | | |
| *2028* | | | | Add 30 MW Wind (PW01x1) |
| | | | | Add 20 MW PV (PP03x4) |

| Name | P4B2b1NRetire-3Ar0 0%RPS | P4B2A1NRETIRE-3AR0 0%RPS NO LANAI | P4B2A1NRETIRE-3AR0 0%RPS NO LANAI_LNG | P4B2b1NRetire-2r1 |
|---|---|---|---|---|
| *2029* | | | | Add 60 MW Wind (PW01x2) |
| | | | | Add 20 MW PV (PP03x4) |
| *2030* | | | | Add 60 MW Wind (PW01x2) |
| | | | | Add 20 MW PV (PP03x4) |
| *2031* | Add 20 MW PV (PP03x4) | | | |
| *2032* | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) | | |
| | | | | |
| *2033* | Add 20 MW PV (PP03x4) | Add 20 MW PV (PP03x4) | | |
| | | Add 60 MW Wind (PW01x2) | | |
| *Planning Period Total Cost* | 23, 911, 377 | 23, 900, 295 | 21, 040, 828 | 23, 885, 070 |
| *Study Period Total Cost* | 34, 010, 010 | 34, 135, 402 | 28, 633, 620 | 34, 006, 408 |
| *Planning Rank* | 4 | 3 | 1 | 2 |
| *Study Rank* | 3 | 4 | 1 | 2 |

# HELCO Resource Plans

## Blazing a Bold Frontier

Table O-64. HELCO Alternative Plan Development (1 of 3)

| Name | Self Generation | | H1B2A_X-2Ar1 | H1B2A_X-4Ar6 | H1B2A_X-4Ar8 | H1B2A_X-4Ar9 |
|---|---|---|---|---|---|---|
| *Plan* | | | Year 2022 Fuel Switch to LSIFO | Year 2022 Fuel Switch to LSIFO, LNG | Year 2022 Fuel Switch to LSIFO<br>Biodiesel 2018<br>CT3 LNG in 2018<br>Puna Biomass Conversion 2017 | Year 2022 Fuel Switch to LSIFO<br>Biodiesel 2018<br>Puna Biomass Conversion 2017 |
| *Notes* | Annual | Cumulative | Fuel switch applies to Hill 5, Hill 6, and Puna Steam<br>Cycle Hill5-6, Puna Steam | Fuel switch to LSIFO for Hill 5, Hill 6, and Puna Steam<br>Fuel switch to LNG for Keahole CC<br>Cycle Hill5-6, Puna Steam | Fuel switch to LSIFO for Hill 5, Hill 6<br>Fuel switch to LNG for Puna CT-3<br>Cycle Hill5-6, Puna Steam | Fuel switch to LSIFO for Hill 5, Hill 6<br>Fuel switch to LNG for Puna CT-3<br>Cycle Hill5-6, Puna Steam |
| *Reference* | | | | | 10 MW Wind (HW04)-2017<br>5 MW PV (HP03)-2015<br>25 MW Geothermal (HG02)-2020 | 10 MW Wind (HW04)-2017<br>5 MW PV (HP03)-2015<br>25 MW Geothermal (HG02)-2020 |
| *2014* | | | *75%+25%+10% PBFA DSM* | 75%+25%+10% PBFA DSM | 75%+25%+10% PBFA DSM | 75%+25%+10% PBFA DSM |
| | | | Hu Honua (21.5MW) | Hu Honua (21.5MW) | Hu Honua (21.5MW) | Hu Honua (21.5MW) |
| *2015* | 4MW | 18MW | Decommission Shipman 3 (-6.8 MW) | Decommission Shipman 3 (-6.8 MW) | Decommission Shipman 3 (-6.8 MW) | Decommission Shipman 3 (-6.8 MW) |
| | | | Decommission Shipman 4 (-6.7 MW) | Decommission Shipman 4 (-6.7 MW) | Decommission Shipman 4 (-6.7 MW) | Decommission Shipman 4 (-6.7 MW) |
| | | | | | Add 5MW PV (HP03x5) | Add 5MW PV (HP03x5) |
| *2016* | 4MW | 22MW | | | | |
| *2017* | 4MW | 25MW | Add 10MW Wind (HW04x1) | Add 10MW Wind (HW04x1) | Add 10MW Wind (HW04x1) | Add 10MW Wind (HW04x1) |
| | | | Add 25MW Geothermal (HG01x1) | Add 25MW Geothermal (HG01x1) | | |
| | | | | | Convert Puna to Biomass (HRP1) | Convert Puna to Biomass (HRP1) |

| Name | Self Generation | | H1B2A_X-2Ar1 | H1B2A_X-4Ar6 | H1B2A_X-4Ar8 | H1B2A_X-4Ar9 |
|---|---|---|---|---|---|---|
| *2018* | 3MW | 28MW | | | Add 25MW Geothermal (HG01x1)<br>Biofuel Conversion of Keahole CC<br>Convert CT-3 to LNG | Add 25MW Geothermal (HG01x1)<br>Biofuel Conversion of Keahole CC |
| *2019* | 3MW | 32MW | | | | |
| *2020* | 3MW | 35MW | Add 10MW Wind (HW04x1) | Add 10MW Wind (HW04x1) | Add 10MW Wind (HW04x1) | Add 10MW Wind (HW04x1) |
| *2021* | 3MW | 38MW | | | | |
| *2022* | 3MW | 41MW | Fuel Switch to LSIFO (Hill 5/6, Puna Steam) | Fuel Switch to LSIFO (Hill 5/6, Puna Steam) Fuel Switch to LNG (Keahole CC) | Fuel Switch to LSIFO (Hill 5/6, Puna Steam) | Fuel Switch to LSIFO (Hill 5/6, Puna Steam) |
| *2023* | 3MW | 43MW | | | | |
| *2024* | 3MW | 46MW | | | | |
| *2025* | 3MW | 49MW | | | | |
| *2026* | 3MW | 52MW | | | | |
| *2027* | 3MW | 55MW | | | | |
| *2028* | 3MW | 59MW | | | | |
| *2029* | 3MW | 61MW | | | | |
| *2030* | 3MW | 64MW | Add 10MW Wind (HW04x1) | Add 10MW Wind (HW04x1) | | |
| *2031* | 3MW | 67MW | Add 10MW Wind (HW04x1) | Add 10MW Wind (HW04x1) | | |
| *2032* | 3MW | 71MW | | | | |
| *2033* | 3MW | 73MW | | | Add 10MW Wind (HW04x1) | Add 10MW Wind (HW04x1) |
| *Strategist Planning Period Total Cost* | | | 4, 157, 473 | 4, 046, 622 | 4, 186, 627 | 4, 195, 227 |
| *Strategist Study Period Total Cost* | | | 5, 657, 579 | 5, 432, 833 | 5, 711, 668 | 5, 724, 441 |
| *Planning Period Total Cost* | | | 4, 803, 647 | 4, 714, 896 | 4, 839, 118 | 4, 841, 401 |
| *Study Period Total Cost* | | | 6, 303, 754 | 6, 085, 324 | 6, 364, 159 | 6, 370, 615 |

| Name | Self Generation | | H1B2A_X-2Ar1 | H1B2A_X-4Ar6 | H1B2A_X-4Ar8 | H1B2A_X-4Ar9 |
|---|---|---|---|---|---|---|
| *Planning Rank* | | | 6 | 4 | 8 | 9 |
| *Study Rank* | | | 6 | 4 | 8 | 9 |

Table O-65. HELCO Alternative Plan Development (2 of 3)

| **Name** | **Self Generation** | | **H1B2A_X-4Ar10** | **H1B2A_N-9R1** | **H1B2A_N-9R2** | **H1B1A_N-9R1 Contingency - with LNG** |
|---|---|---|---|---|---|---|
| *Plan* | Annual | Cumulative | Year 2022 Fuel Switch to LSIFO<br>Biodiesel 2018 | Year 2022 Fuel Switch to LSIFO<br>Biodiesel 2018<br>No LNG | Year 2022 Fuel Switch to LSIFO<br>Biodiesel 2018<br>No LNG<br>Puna Biomass Conversion 2017 | Year 2022 Fuel Switch to LNG |
| *Notes* | | | Fuel Switch to LSIFO for Hill 5, Hill 6 Fuel Switch to LNG for Puna CT-3<br>Cycle Hill5-6, Puna Steam | Fuel Switch to LSIFO for Hill 5, Hill 6, Puna<br>Cycle Hill5-6, Puna Steam | Fuel Switch to LSIFO for Hill 5, Hill 6, Puna<br>Cycle Hill5-6, Puna Steam | Fuel Switch to LNG for Hill 5, Hill 6 , Puna, Keahole<br>Cycle Hill5-6, Puna Steam |
| *Reference* | | | 10 MW Wind (HW04)-2017<br>5 MW PV (HP03)-2015<br>25 MW Geothermal (HG02)-2020 | 10 MW Wind (HW04)-2020<br>5 MW PV (HP03)-2020<br>25 MW Geothermal (HG02)-2022 | 10 MW Wind (HW04)-2020<br>5 MW PV (HP03)-2020<br>25 MW Geothermal (HG02)-2022 | 10 MW Wind (HW04)-2020<br>5 MW PV (HP03)-2020<br>25 MW Geothermal (HG02)-2022 |
| *2014* | 4MW | 14MW | | New CIDLC, Fast DR, RDLCWH, RDLCAC | New CIDLC, Fast DR, RDLCWH, RDLCAC | New CIDLC, Fast DR, RDLCWH, RDLCAC |
| | | | 75%+25%+10% PBFA DSM | 75%+25%+10% PBFA DSM | 75%+25%+10% PBFA DSM | 75%+25%+10% PBFA DSM |
| | | | Hu Honua (21.5MW) | Hu Honua (21.5MW) | Hu Honua (21.5MW) | Hu Honua (21.5MW) |
| *2015* | 4MW | 18MW | Decommission Shipman 3 (-6.8 MW) | Decommission Shipman 3 (-6.8 MW) | Decommission Shipman 3 (-6.8 MW) | Decommission Shipman 3 (-6.8 MW) |
| | | | Decommission Shipman 4 (-6.7 MW) | Decommission Shipman 4 (-6.7 MW) | Decommission Shipman 4 (-6.7 MW) | Decommission Shipman 4 (-6.7 MW) |
| | | | Add 5MW PV (HP03x5) | | | |
| *2016* | 4MW | 22MW | | | | |
| *2017* | 4MW | 25MW | Add 10MW Wind (HW04x1) | | Convert Puna to Biomass (HRP1) | |
| *2018* | 3MW | 28MW | Add 25MW Geothermal (HG01x1) | Add 25MW Geothermal (HG01x1) | Add 25MW Geothermal (HG01x1) | Add 25MW Geothermal (HG01x1) |
| | | | Biofuel Conversion of Keahole CC | Biofuel Conversion of Keahole CC | Biofuel Conversion of Keahole CC | |
| *2019* | 3MW | 32MW | | | | |

| Name | Self Generation | | HIB2A_X-4Ar10 | HIB2A_N-9R1 | HIB2A_N-9R2 | HIB1A_N-9R1 Contingency - with LNG |
|---|---|---|---|---|---|---|
| *2020* | 3MW | 35MW | Add 10MW Wind (HW04x1) | Add 10MW Wind (HW04x1) | | Add 5MW PV (HP03x5) |
| | | | | | | Add 10MW Wind (HW04x1) |
| *2021* | 3MW | 38MW | | Add 10MW Wind (HW04x1) | | Add 10MW Wind (HW04x1) |
| *2022* | 3MW | 41MW | Fuel Switch to LSIFO (Hill 5/6, Puna Steam) | Fuel Switch to LSIFO (Hill 5/6, Puna Steam) | Fuel Switch to LSIFO (Hill 5/6, Puna Steam) | Fuel Switch to LNG (Hill 5/6, Puna Steam, Keahole CC) |
| *2023* | 3MW | 43MW | | | | |
| *2024* | 3MW | 46MW | | | | |
| *2025* | 3MW | 49MW | | | | |
| *2026* | 3MW | 52MW | | | | |
| *2027* | 3MW | 55MW | | | | |
| *2028* | 3MW | 59MW | | | | |
| *2029* | 3MW | 61MW | | | | |
| *2030* | 3MW | 64MW | | | | Add 10MW Wind (HW04x1) |
| *2031* | 3MW | 67MW | | | | Add 10MW Wind (HW04x1) |
| *2032* | 3MW | 71MW | Add 10MW Wind (HW04x1) | | | |
| *2033* | 3MW | 73MW | Add 10MW Wind (HW04x1) | Add 10MW Wind (HW04x1) | Add 10MW Wind (HW04x1) | |
| *Strategist Planning Period Total Cost* | | | 4, 180, 231 | 3, 947, 526 | 4, 052, 654 | 4, 129, 452 |
| *Strategist Study Period Total Cost* | | | 5, 680, 373 | 5, 193, 255 | 5, 361, 511 | 5, 522, 871 |
| *Planning Period Total Cost* | | | 4, 826, 406 | 4, 593, 701 | 4, 671, 053 | 4, 781, 942 |
| *Study Period Total Cost* | | | 6, 326, 547 | 5, 839, 429 | 6, 007, 685 | 6, 175, 361 |
| *Planning Rank* | | | 7 | 1 | 3 | 5 |
| *Study Rank* | | | 7 | 1 | 3 | 5 |

Table O-66. HELCO Alternative Plan Development (3 of 3)

| **Name** | **Self Generation** | | **H1B1A_N-9R2 Parallel Plan - with Biodiesel** | **H1B2A_N-9R3 Preferred Plan - LSIFO** | **H1B1B_N-9R1** | **H1B2B_N-9R1 Secondary Plan - Puna Biomass** |
|---|---|---|---|---|---|---|
| *Plan* | Annual | Cumulative | Year 2022 Fuel Switch to LNG | Year 2022 Fuel Switch to LSIFO No LNG | Year 2022 Fuel Switch to LNG No Hu Honua, No Biodiesel | Year 2022 Fuel Switch to LSIFO No Hu Honua, No Biodiesel Convert Puna to Biomass |
| *Notes* | | | Fuel Switch to LNG for Hill 5, Hill 6 , Puna Cycle Hill5-6, Puna Steam | Fuel Switch to LSIFO for Hill 5, Hill 6 , Puna Cycle Hill5-6, Puna Steam | Fuel Switch to LNG for Hill 5, Hill 6 , Keahole CC Cycle Hill5-6, Puna Steam | Fuel Switch to LSIFO for Hill 5 & 6; Puna biomass conversion Cycle Hill5-6, Puna Steam |
| *Reference* | | | 10 MW Wind (HW04)-2020 5 MW PV (HP03)-2020 25 MW Geothermal (HG02)-2022 | 10 MW Wind (HW04)-2020 5 MW PV (HP03)-2020 25 MW Geothermal (HG02)-2022 | 10 MW Wind (HW04)-2020 5 MW PV (HP03)-2020 25 MW Geothermal (HG02)-2022 | 10 MW Wind (HW04)-2020 5 MW PV (HP03)-2020 25 MW Geothermal (HG02)-2022 |
| *2014* | 4MW | 14MW | New CIDLC, Fast DR, RDLCWH, RDLCAC | New CIDLC, Fast DR, RDLCWH, RDLCAC | New CIDLC, Fast DR, RDLCWH, RDLCAC | New CIDLC, Fast DR, RDLCWH, RDLCAC |
| | | | 75%+25%+10% PBFA DSM | 75%+25%+10% PBFA DSM | 75%+25%+10% PBFA DSM | 75%+25%+10% PBFA DSM |
| | | | Hu Honua (21.5MW) | Hu Honua (21.5MW) | Baseload Hill 6 | Baseload Hill 6 |
| *2015* | 4MW | 18MW | Decommission Shipman 3 (-6.8 MW) | Decommission Shipman 3 (-6.8 MW) | | Decommission Shipman 3 (-6.8 MW) |
| | | | Decommission Shipman 4 (-6.7 MW) | Decommission Shipman 4 (-6.7 MW) | | Decommission Shipman 4 (-6.7 MW) |
| *2016* | 4MW | 22MW | | | | |
| *2017* | 4MW | 25MW | | | Convert Puna to Biomass (HRP1) | Convert Puna to Biomass (HRP1) |
| *2018* | 3MW | 28MW | Add 25MW Geothermal (HG01x1) | Add 25MW Geothermal (HG01x1) | Add 25MW Geothermal (HG01x1) | Add 25MW Geothermal (HG01x1) |
| | | | Biofuel Conversion of Keahole CC | | | |
| *2019* | 3MW | 32MW | | | | |

## Appendix O: Resource Plan Sheets

HELCO Resource Plans

| Name | Self Generation | | H1B1A_N-9R2 Parallel Plan - with Biodiesel | H1B2A_N-9R3 Preferred Plan - LSIFO | H1B1B_N-9R1 | H1B2B_N-9R1 Secondary Plan - Puna Biomass |
|---|---|---|---|---|---|---|
| *2020* | 3MW | 35MW | | Add 5MW PV (HP03x5) | Add 5MW PV (HP03x5) | Add 5MW PV (HP03x5) |
| | | | Add 10MW Wind (HW04x1) | Add 10MW Wind (HW04x1) | Add 10MW Wind (HW04x1) | Add 10MW Wind (HW04x1) |
| *2021* | 3MW | 38MW | Add 10MW Wind (HW04x1) | Add 10MW Wind (HW04x1) | Add 10MW Wind (HW04x1) | Add 10MW Wind (HW04x1) |
| *2022* | 3MW | 41MW | Fuel Switch to LNG (Hill 5/6, Puna Steam) | Fuel Switch to LSIFO (Hill 5/6, Puna Steam) | Fuel Switch to LNG (Hill 5/6, Keahole CC) | Fuel Switch to LSIFO (Hill 5/6) |
| | | | | Add 5MW PV (HP03x5) | Add 5MW PV (HP03x5) | Add 5MW PV (HP03x5) |
| *2023* | 3MW | 43MW | | | | Add 5MW PV (HP03x5) |
| *2024* | 3MW | 46MW | | | | |
| *2025* | 3MW | 49MW | | | | |
| *2026* | 3MW | 52MW | | | | |
| *2027* | 3MW | 55MW | | | | |
| *2028* | 3MW | 59MW | | | | |
| *2029* | 3MW | 61MW | | | | |
| *2030* | 3MW | 64MW | | Add 10MW Wind (HW04x1) | Add 10MW Wind (HW04x1) | Add 10MW Wind (HW04x1) |
| *2031* | 3MW | 67MW | | Add 10MW Wind (HW04x1) | Add 10MW Wind (HW04x1) | Add 10MW Wind (HW04x1) |
| *2032* | 3MW | 71MW | | | | |
| *2033* | 3MW | 73MW | Add 10MW Wind (HW04x1) | | | |
| *Strategist Planning Period Total Cost* | | | 3, 947, 167 | 4, 242, 743 | 4, 341, 007 | 4, 466, 290 |
| *Strategist Study Period Total Cost* | | | 5, 192, 676 | 5, 752, 597 | 5, 740, 350 | 5, 986, 669 |
| *Planning Period Total Cost* | | | 4, 599, 657 | 4, 888, 918 | 4, 987, 556 | 5, 112, 465 |
| *Study Period Total Cost* | | | 5, 845, 166 | 6, 398, 772 | 6, 386, 899 | 6, 632, 844 |
| *Planning Rank* | | | 2 | 10 | 11 | 12 |
| *Study Rank* | | | 2 | 11 | 10 | 12 |

Table O-67. HELCO Preferred Plan

| **Name** | **Self Generation** | | **H1B2A_N-9R3 Preferred Resource Plan Fuel Switch to LSIFO** | **H1B1A_N-9R1 Contingency Plan Fuel Switch to LNG** | **H1B1A_N-9R2 Parallel Plan With Biodiesel** | **H1B2B_N-9R1 Secondary Plan Puna Biomass** |
|---|---|---|---|---|---|---|
| *Plan* | Annual | Cumulative | Year 2022 Fuel Switch to LSIFO<br>No LNG | Year 2022 Fuel Switch to LNG | Year 2022 Fuel Switch to LNG | Year 2022 Fuel Switch to LSIFO<br>No Hu Honua, No Biofuels<br>Convert Puna to Biomass |
| *Notes* | | | Fuel Switch to LSIFO for Hill 5, Hill 6 , Puna; Cycle Hill5-6, Puna Steam; New CIDLC, Fast DR, RDLCWH, RDLCAC; 75%+25%+10% PBFA DSM | Fuel Switch to LNG for Hill 5, Hill 6 , Puna, Keahole; Cycle Hill5-6, Puna Steam; New CIDLC, Fast DR, RDLCWH, RDLCAC; 75%+25%+10% PBFA DSM | Fuel Switch to LNG for Hill 5, Hill 6 , Puna Cycle Hill5-6, Puna Steam New CIDLC, Fast DR, RDLCWH, RDLCAC; 75%+25%+10% PBFA DSM | Fuel Switch to LSIFO for Hill 5 & 6; Puna biomass Cycle Hill5-6, Puna Steam New CIDLC, Fast DR, RDLCWH, RDLCAC 75%+25%+10% PBFA DSM |
| *Reference* | | | 10 MW Wind (HW04)-2020<br>5 MW PV (HP03)-2020<br>25 MW Geothermal (HG02)-2022 | 10 MW Wind (HW04)-2020<br>5 MW PV (HP03)-2020<br>25 MW Geothermal (HG02)-2022 | 10 MW Wind (HW04)-2020<br>5 MW PV (HP03)-2020<br>25 MW Geothermal (HG02)-2022 | 10 MW Wind (HW04)-2020<br>5 MW PV (HP03)-2020<br>25 MW Geothermal (HG02)-2022 |
| *2014* | 4MW | 14MW | Hu Honua (21.5MW) | Hu Honua (21.5MW) | Hu Honua (21.5MW) | Baseload Hill 6 |
| *2015* | 4MW | 18MW | Decommission Shipman 3 (-6.8 MW)<br>Decommission Shipman 4 (-6.7 MW) | Decommission Shipman 3 (-6.8 MW)<br>Decommission Shipman 4 (-6.7 MW) | Decommission Shipman 3 (-6.8 MW)<br>Decommission Shipman 4 (-6.7 MW) | Decommission Shipman 3 (-6.8 MW)<br>Decommission Shipman 4 (-6.7 MW) |
| *2016* | 4MW | 22MW | | | | |
| *2017* | 4MW | 25MW | | | | Convert Puna to Biomass (HRP1) |
| *2018* | 3MW | 28MW | Add 25MW Geothermal (HG01x1) | Add 25MW Geothermal (HG01x1) | Add 25MW Geothermal (HG01x1)<br>Biofuel Conversion of Keahole CC | Add 25MW Geothermal (HG01x1) |
| *2019* | 3MW | 32MW | | | | |
| *2020* | 3MW | 35MW | Add 5MW PV (HP03x5)<br>Add 10MW Wind (HW04x1) | Add 5MW PV (HP03x5)<br>Add 10MW Wind (HW04x1) | Add 10MW Wind (HW04x1) | Add 5MW PV (HP03x5)<br>Add 10MW Wind (HW04x1) |
| *2021* | 3MW | 38MW | Add 10MW Wind (HW04x1) | Add 10MW Wind (HW04x1) | Add 10MW Wind (HW04x1) | Add 10MW Wind (HW04x1) |

| Name | Self Generation | | H1B2A_N-9R3 Preferred Resource Plan Fuel Switch to LSIFO | H1B1A_N-9R1 Contingency Plan Fuel Switch to LNG | H1B1A_N-9R2 Parallel Plan With Biodiesel | H1B2B_N-9R1 Secondary Plan Puna Biomass |
|---|---|---|---|---|---|---|
| 2022 | 3MW | 41MW | Fuel Switch to LSIFO (Hill 5/6, Puna Steam) | Fuel Switch to LNG (Hill 5/6, Puna Steam, Keahole CC) | Fuel Switch to LNG (Hill 5/6, Puna Steam) | Fuel Switch to LSIFO (Hill 5/6) |
| | | | Add 5MW PV (HP03x5) | | | Add 5MW PV (HP03x5) |
| 2023 | 3MW | 43MW | | | | Add 5MW PV (HP03x5) |
| 2024 | 3MW | 46MW | | | | |
| 2025 | 3MW | 49MW | | | | |
| 2026 | 3MW | 52MW | | | | |
| 2027 | 3MW | 55MW | | | | |
| 2028 | 3MW | 59MW | | | | |
| 2029 | 3MW | 61MW | | | | |
| 2030 | 3MW | 64MW | Add 10MW Wind (HW04x1) | Add 10MW Wind (HW04x1) | | Add 10MW Wind (HW04x1) |
| 2031 | 3MW | 67MW | Add 10MW Wind (HW04x1) | Add 10MW Wind (HW04x1) | | Add 10MW Wind (HW04x1) |
| 2032 | 3MW | 71MW | | | | |
| 2033 | 3MW | 73MW | | | Add 10MW Wind (HW04x1) | |
| Strategist Planning Period Total Cost | | | 4, 242, 743 | 4, 129, 452 | 3, 947, 167 | 4, 466, 290 |
| Strategist Study Period Total Cost | | | 5, 752, 597 | 5, 522, 871 | 5, 192, 676 | 5, 986, 669 |
| Planning Period Total Cost | | | 4, 888, 918 | 4, 781, 942 | 4, 599, 657 | 5, 112, 465 |
| Study Period Total Cost | | | 6, 398, 772 | 6, 175, 361 | 5, 845, 166 | 6, 632, 844 |
| Planning Rank | | | 3 | 2 | 1 | 4 |
| Study Rank | | | 3 | 2 | 1 | 4 |

## Stuck in the Middle

Table O-68. HELCO Timing Run (1 of 2)

| **Name** | **H2_2A_X-1Ar0** | **H2_2A_X-1Br0** | **H2_2A_X-1Ar0_Geo** | **H2_2A_X-1Ar0_Geo_No_Ret** |
|---|---|---|---|---|
| *Plan* | Hu Honua in, No DR, timing (LCP fossil) | Hu Honua in, No DR, LCP renew | Hu Honua in, No DR, Geo forced w/ retire | Hu Honua in, No DR, Geo forced, no Hill retire |
| *Notes* | Timing Run with Firm Conventional Units Available<br>No DR Programs<br>Shipman 3 & 4 Deactivation | Timing Run with Firm Geothermal, Biomass, and Waste to Energy Units Available<br>No DR Programs<br>Shipman 3 & 4 Deactivation | | |
| *Resources Available* | 17MW ICE (HS01) - Avail 2016<br>21MW LM2500 (HS05) - Avail 2017<br>42MW LM6000 (HS06) - Avail 2017 | 25MW Advanced Geothermal (HG01) - Avail 2017<br>25MW New Geothermal (HG02) - Avail 2017<br>25MW Banagrass Combustion (HA01) - Avail 2017<br>8MW Waste-to-Energy (HT01) - Avail 2017<br>400KW Fuel Cell (HF01) - Avail 2017 | 25MW Advanced Geothermal (HG01) - Avail 2017<br>25MW New Geothermal (HG02) - Avail 2017<br>25MW Banagrass Combustion (HA01) - Avail 2017 | 25MW Advanced Geothermal (HG01) - Avail 2017<br>25MW New Geothermal (HG02) - Avail 2017<br>25MW Banagrass Combustion (HA01) - Avail 2018 |
| *Reference* | H2_2A_X-1Ar0 | H2_2A_X-1Br0 | H2_2A_X-1Ar0_Geo | H2_2A_X-1Ar0_Geo_No_Ret |
| *2013* | | | | |
| *2014* | 75% PBFA DSM | 75% PBFA DSM | 75% PBFA DSM | 75% PBFA DSM |
| | Hu Honua (21.5MW) | Hu Honua (21.5MW) | Hu Honua (21.5MW) | Hu Honua (21.5MW) |
| *2015* | Deactivate Shipman 3 (-6.8 MW) | Deactivate Shipman 3 (-6.8 MW) | Deactivate Shipman 3 (-6.8 MW) | Deactivate Shipman 3 (-6.8 MW) |
| | Deactivate Shipman 4 (-6.7 MW) | Deactivate Shipman 4 (-6.7 MW) | Deactivate Shipman 4 (-6.7 MW) | Deactivate Shipman 4 (-6.7 MW) |
| *2016* | | | | |
| *2017* | | | Add 25 MW Adv Geothermal (HG01x1) | Add 25 MW Adv Geothermal (HG01x1) |
| *2018* | | | | |
| *2019* | | | Retire Hill 5 (-13.5 MW) | |
| *2020* | | | | |
| *2021* | | | | |
| *2022* | | | | |
| *2023* | | | | |

| Name | H2_2A_X-1Ar0 | H2_2A_X-1Br0 | H2_2A_X-1Ar0_Geo | H2_2A_X-1Ar0_Geo_No_Ret |
|---|---|---|---|---|
| *2024* | | Add 25 MW Adv Geothermal (HG01x1) | | |
| *2025* | | | | |
| *2026* | | | | |
| *2027* | | | | |
| *2028* | | | | |
| *2029* | | | | |
| *2030* | | | | |
| *2031* | | | | |
| *2032* | | | | |
| *2033* | | Add 25 MW New Dev Geothermal (HG02x1) | Add 25 MW New Dev Geothermal (HG02x1) | Add 25 MW New Dev Geothermal (HG02x1) |
| *Planning Period Total Cost* | 4, 071, 219 | 4, 145, 424 | 4, 112, 242 | 4, 160, 553 |
| *Study Period Total Cost* | 6, 415, 763 | 6, 369, 636 | 6, 282, 930 | 6, 381, 536 |
| *Planning Rank* | 1 | 3 | 2 | 4 |
| *Study Rank* | 4 | 2 | 1 | 3 |

Table O-69. HELCO Timing Run (2 of 2)

| **Name** | **H2_2B_X-1Ar1** | **H2_2B_X-1Br0** | **H2_2A_N-1r0** | **H2_2B_N-1R1 Timing** | **H2_2B_N-1R0** |
|---|---|---|---|---|---|
| *Plan* | No Retire, HH out, No DR, LCP fossil | No Retire, HH out, No DR, LCP renewable | No Retire, Hu Honua in, w/DR, timing | No Retire, HH out, w/DR, timing | No Retire, HH out, w/DR, timing |
| *Notes* | Timing Run with Firm Conventional Units Available<br>No DR Programs<br>Hu Honua Out | Timing Run with Firm Geothermal, Biomass, and Waste to Energy Units Available<br>No DR Programs<br>Hu Honua Out | Timing Run with Firm Conventional Units Available<br>New DR Programs Added | Timing Run with Firm Conventional Units Available<br>New DR Programs Added<br>Hu Honua Out | Timing Run with Firm Conventional Units Available<br>New DR Programs Added<br>Hu Honua Out |
| *Resources Available* | None | 25MW Advanced Geothermal (HG01) - Avail 2017<br>25MW New Geothermal (HG02) - Avail 2017<br>25MW Banagrass Combustion (HA01) - Avail 2017<br>8MW Waste-to-Energy (HT01) - Avail 2017<br>400KW Fuel Cell (HF01) - Avail 2017 | 17MW ICE (HS01) - Avail 2016<br>21MW LM2500 (HS05) - Avail 2017<br>42MW LM6000 (HS06) - Avail 2017 | None | None |
| *Reference* | H2_2B_X-1Ar0 | H2_2B_X-1Br0 | H2_2A_N-1r0 | H2_2B_N-1R1 | H2_2B_N-1R0 |
| *2013* | | | | | |
| *2014* | | | New CIDLC, Fast DR, RDLCWH, RDLCAC | New CIDLC, Fast DR, RDLCWH, RDLCAC | New CIDLC, Fast DR, RDLCWH, RDLCAC |
| | 75% PBFA DSM | 75% PBFA DSM | 75% PBFA DSM | 75% PBFA DSM | 75% PBFA DSM |
| | | | Hu Honua (21.5MW) | | |
| *2015* | | | Deactivate Shipman 3 (- 6.8 MW) | | |
| | | | Deactivate Shipman 4 (- 6.7 MW) | | |
| *2016* | | | | | |
| *2017* | | | | | |
| *2018* | | | | | |
| *2019* | | Add 25 MW Adv Geothermal (HG01x1) | | | |
| *2020* | | | | | |
| *2021* | | | | | |
| *2022* | | | | | |
| *2023* | | | | | |

| Name | H2_2B_X-1Ar1 | H2_2B_X-1Br0 | H2_2A_N-1r0 | H2_2B_N-1R1 Timing | H2_2B_N-1R0 |
|---|---|---|---|---|---|
| *2024* | | | | | |
| *2025* | | | | | |
| *2026* | | | | | |
| *2027* | | | | | |
| *2028* | | | | | |
| *2029* | | | | | |
| *2030* | | | | | |
| *2031* | | | | | |
| *2032* | | Add 25 MW New Dev Geothermal (HG02x1) | | | |
| *2033* | | Add 25 MW New Dev Geothermal (HG02x1) | | | Add 17MW ICE (HS01x1)-Biofuel |
| *Planning Period Total Cost* | 4, 137, 911 | 4, 168, 614 | 4, 154, 785 | 4, 155, 684 | 4, 160, 168 |
| *Study Period Total Cost* | 6, 627, 242 | 6, 431, 870 | 6, 537, 002 | 6, 654, 898 | 6, 649, 343 |
| *Planning Rank* | 1 | 2 | 1 | 1 | 1 |
| *Study Rank* | 2 | 1 | 1 | 1 | 1 |

Table O-70. HELCO Screening Run

| **Name** | **H2B2b_X-2Br0.xlxs** | **H2B2a_X-2Ar1** | **H2B2b_X-2Br1.xlxs** | **H2B2b_X-2Br2.xlxs** |
|---|---|---|---|---|
| *Plan* | Screen, Hu Honua out, No DR, No Ret (Geo, Wind, PV, Wave, ) | Hu Honua in, No DR, screen (Geo, Wind, PV, Wave) | Screen, Hu Honua out, No DR, No Ret (Geo, Wind, PV, Wave) | Screen, Hu Honua out, No DR, No Ret (Geo, Wind, PV, Wave, Puna) |
| *Notes* | | Add Geothermal, Wind, PV, Ocean Wave, and Solar Thermal resources as needed to meet scenario RPS<br>Cycle Hill 5, Hill 6, and Puna | | |
| *Resources Available* | 10MW Wind (HW04) - Avail 2017<br>1MW PV (HP03) - Avail 2015<br>50MW PV (HP04) - Avail 2020<br>15MW Ocean Wave (HV02) - Avail 2020<br>25MW Advanced Geothermal (HG01) - Avail 2017<br>25MW New Geothermal (HG02) - Avail 2020 | 10MW Wind (HW04) - Avail 2017<br>1MW PV (HP03) - Avail 2015<br>50MW PV (HP04) - Avail 2020<br>15MW Ocean Wave (HV02) - Avail 2020<br>25MW Advanced Geothermal (HG01) - Avail 2017<br>25MW New Geothermal (HG02) - Avail 2020 | 10MW Wind (HW04) - Avail 2017<br>1MW PV (HP03) - Avail 2015<br>50MW PV (HP04) - Avail 2020<br>15MW Ocean Wave (HV02) - Avail 2020<br>25MW Advanced Geothermal (HG01) - Avail 2017<br>25MW New Geothermal (HG02) - Avail 2020 | 10MW Wind (HW04) - Avail 2017<br>1MW PV (HP03) - Avail 2015<br>50MW PV (HP04) - Avail 2020<br>15MW Ocean Wave (HV02) - Avail 2020<br>25MW Advanced Geothermal (HG01) - Avail 2017<br>25MW New Geothermal (HG02) - Avail 2020<br>Repower Puna with Biomass (HRP1) - Avail 2018 |
| *Reference* | H2B2b_X-2Br0.xlxs | H2B2a_X-2Ar1.xlxs | H2B2b_X-2Br1.xlxs | H2B2b_X-2Br2.xlxs |
| *2013* | | | | |
| *2014* | | Cycle Hill 5/6, Puna | Cycle Hill 5/6, Puna | Cycle Hill 5/6, Puna |
| | 75% PBFA DSM | 75% PBFA DSM | 75% PBFA DSM | 75% PBFA DSM |
| | | Hu Honua (21.5MW) | | |
| *2015* | | Deactivate Shipman 3 (-6.8 MW) | | |
| | | Deactivate Shipman 4 (-6.7 MW) | | |
| | Add 5MW PV (HP03x5) | Add 5MW PV (HP03x5) | Add 5MW PV (HP03x5) | Add 5MW PV (HP03x5) |
| *2016* | | | | |
| *2017* | Add 10MW Wind (HW04x1) | Add 10MW Wind (HW04x1) | Add 25MW Geothermal (HG01x1) | Add 25MW Geothermal (HG01x1) |
| | | | Add 10MW Wind (HW04x1) | Add 10MW Wind (HW04x1) |
| *2018* | | | | |
| *2019* | | Add 25MW Geothermal (HG01x1) | | |
| *2020* | Add 5MW PV (HP03x5) | Add 10MW Wind (HW04x1) | Add 10MW Wind (HW04x1) | Add 10MW Wind (HW04x1) |
| | Add 10MW Wind (HW04x1) | | | |

| Name | H2B2b_X-2Br0.xlxs | H2B2a_X-2Ar1 | H2B2b_X-2Br1.xlxs | H2B2b_X-2Br2.xlxs |
|---|---|---|---|---|
| *2021* | Add 5MW PV (HP03x5) | | Add 5MW PV (HP03x5) | Add 5MW PV (HP03x5) |
| *2022* | | Add 5MW PV (HP03x5) | Add 5MW PV (HP03x5) | Add 5MW PV (HP03x5) |
| *2023* | Add 25MW Geothermal (HG01x1) | Add 5MW PV (HP03x5) | | |
| *2024* | | Add 5MW PV (HP03x5) | Add 5MW PV (HP03x5) | Add 5MW PV (HP03x5) |
| *2025* | | | | |
| *2026* | Add 5MW PV (HP03x5) | | | |
| *2027* | | | | |
| *2028* | Add 5MW PV (HP03x5) | Add 5MW PV (HP03x5) | Add 25MW Geothermal (HG02x1) | Add 25MW Geothermal (HG02x1) |
| *2029* | Add 5MW PV (HP03x5) | Add 5MW PV (HP03x5) | | |
| *2030* | Add 10MW Wind (HW04x1) | Add 10MW Wind (HW04x1) | Add 10MW Wind (HW04x1) | Add 10MW Wind (HW04x1) |
| *2031* | Add 10MW Wind (HW04x1) | Add 10MW Wind (HW04x1) | Add 10MW Wind (HW04x1) | Add 10MW Wind (HW04x1) |
| | | | | Add 5MW PV (HP03x5) |
| *2032* | | | Add 5MW PV (HP03x5) | Add 5MW PV (HP03x5) |
| *2033* | Add 25MW Geothermal (HG02x1) | Add 25MW Geothermal (HG02x1) | Add 25MW Geothermal (HG02x1) | Add 5MW PV (HP03x5) |
| | Add 5MW PV (HP03x5) | Add 5MW PV (HP03x5) | Add 5MW PV (HP03x5) | Repower Puna w/ Biomass (HRP1x1) |
| *Planning Period Total Cost* | 4, 103, 012 | 3, 981, 469 | 4, 029, 471 | 4, 026, 916 |
| *Study Period Total Cost* | 6, 260, 562 | 5, 936, 770 | 6, 035, 432 | 6, 032, 461 |
| *Planning Rank* | 4 | 1 | 3 | 2 |
| *Study Rank* | 4 | 1 | 3 | 2 |

Table O-71. HELCO Environmental Compliance (Self Generation)

| **Name** | **Self Generation** | | **H2B2a_X-2Ar1** | **H2B2a_X-4Ar1** | **H2B2a_X-4Ar2b** | **H2B2a_X-4Ar3b** | **H2B2a_X-4Ar4** |
|---|---|---|---|---|---|---|---|
| *Plan* | Annual | Cumulative | Year 2022 Fuel Switch to LSIFO | Year 2022 Install Air Quality Controls | Retire Existing Replace with Conventional Biofuel Units | Retire Existing Replace with Geothermal | Year 2022 Fuel Switch to LSIFO, LNG |
| *Notes* | | | Fuel Switch applies to Hill 5, Hill 6 and Puna Steam<br>Cycle Hill 5/6, Puna Steam | Cycle Hill 5/6, Puna Steam | All Units except Keahole CC are Retired by Dec 2020<br>Cycle Hill 5/6, Puna Steam | All Units except Keahole CC are Retired by Dec 2020<br>Cycle Hill 5/6, Puna Steam | Fuel Switch to LSIFO for Hill 5, Hill 6 and Puna Steam<br>Fuel Switch to LNG for Keahole CC<br>Cycle Hill5-6, Puna Steam |
| *Resources Available* | | | None | None | None | None | None |
| *Reference* | | | | | | | |
| *2014* | 2MW | 8MW | 75% PBFA DSM | 75% PBFA DSM | 75% PBFA DSM | 75% PBFA DSM | 75% PBFA DSM |
| | | | Hu Honua (21.5MW) | Hu Honua (21.5MW) | Hu Honua (21.5MW) | Hu Honua (21.5MW) | Hu Honua (21.5MW) |
| *2015* | 2MW | 10MW | Retire Shipman 3 (-6.8 MW) | Retire Shipman 3 (-6.8 MW) | Retire Shipman 3 (-6.8 MW) | Retire Shipman 3 (-6.8 MW) | Retire Shipman 3 (-6.8 MW) |
| | | | Retire Shipman 4 (-6.7 MW) | Retire Shipman 4 (-6.7 MW) | Retire Shipman 4 (-6.7 MW) | Retire Shipman 4 (-6.7 MW) | Retire Shipman 4 (-6.7 MW) |
| | | | Add 5MW PV (HP03x5) | Add 5MW PV (HP03x5) | Add 5MW PV (HP03x5) | Add 5MW PV (HP03x5) | Add 5MW PV (HP03x5) |
| *2016* | 2MW | 12MW | | | | | |
| *2017* | 2MW | 14MW | Add 10MW Wind (HW04x1) | Add 10MW Wind (HW04x1) | Add 10MW Wind (HW04x1) | Add 10MW Wind (HW04x1) | Add 10MW Wind (HW04x1) |
| *2018* | 2MW | 15MW | | | | | |
| *2019* | 2MW | 17MW | Add 25MW Geothermal (HG01x1) | Add 25MW Geothermal (HG01x1) | Retire Hill 5 (-13.5 MW) | Retire Hill 5 (-13.5 MW) | Add 25MW Geothermal (HG01x1) |

## Appendix O: Resource Plan Sheets

HELCO Resource Plans

| Name | Self Generation | | H2B2a_X-2Ar1 | H2B2a_X-4Ar1 | H2B2a_X-4Ar2b | H2B2a_X-4Ar3b | H2B2a_X-4Ar4 |
|---|---|---|---|---|---|---|---|
| 2020 | 2MW | 19MW | Add 10MW Wind (HW04x1) | Add 10MW Wind (HW04x1) | Add 10MW Wind (HW04x1) | Add 10MW Wind (HW04x1) | Add 10MW Wind (HW04x1) |
| | | | | | Retire Hill 6 (-20 MW)<br>Retire Puna Steam (-15.5 MW)<br>Retire KanoelD 11, 15-17 (-9.5 MW)<br>Retire WaimeaD 12-14 (-7.5 MW)<br>Retire KeaholD 21-23 (-7.5 MW)<br>Retire Kanoe CT1 (-10.25 MW)<br>Retire Keaho CT2 (-13.80 MW)<br>Retire Puna CT3 (-19 MW)<br>Retire PanaewD, OuliD, PunaluD, KapuaD (-4 MW) | Retire Hill 6 (-20 MW)<br>Retire Puna Steam (-15.5 MW)<br>Retire KanoelD 11, 15-17 (-9.5 MW)<br>Retire WaimeaD 12-14 (-7.5 MW)<br>Retire KeaholD 21-23 (-7.5 MW)<br>Retire Kanoe CT1 (-10.25 MW)<br>Retire Keaho CT2 (-13.80 MW)<br>Retire Puna CT3 (-19 MW)<br>Retire PanaewD, OuliD, PunaluD, KapuaD (-4 MW) | |
| 2021 | 2MW | 21MW | | | Add 21MW CT (HS05x1)-Biofuel | Add 25MW Geothermal (HG01x1) | |
| | | | | | Add 63MW Dual Train CC (HC05x1, HC06x1) | Add 75MW New Geothermal (HG02x3) | |
| 2022 | 2MW | 22MW | Fuel Switch to LSIFO (Hill 5/6, Puna Steam) | AQC for Hill5/6, Puna Steam | | | Fuel Switch to LSIFO (Hill 5/6, Puna Steam)<br>Fuel Switch to LNG (Keahole CC) |
| | | | Add 5MW PV (HP03x5) | Add 5MW PV (HP03x5) | Add 5MW PV (HP03x5) | Add 5MW PV (HP03x5) | Add 5MW PV (HP03x5) |
| 2023 | 1MW | 24MW | Add 5MW PV (HP03x5) | Add 5MW PV (HP03x5) | Add 5MW PV (HP03x5) | Add 5MW PV (HP03x5) | Add 5MW PV (HP03x5) |
| 2024 | 2MW | 25MW | | | | Add 25MW New Geothermal (HG02x1) | |
| | | | Add 5MW PV (HP03x5) | Add 5MW PV (HP03x5) | Add 5MW PV (HP03x5) | Add 5MW PV (HP03x5) | Add 5MW PV (HP03x5) |

| Name | Self Generation | | H2B2a_X-2Ar1 | H2B2a_X-4Ar1 | H2B2a_X-4Ar2b | H2B2a_X-4Ar3b | H2B2a_X-4Ar4 |
|---|---|---|---|---|---|---|---|
| *2025* | 2MW | 27MW | | | | | |
| *2026* | 2MW | 29MW | | | | | |
| *2027* | 2MW | 30MW | | | | | |
| *2028* | 2MW | 32MW | Add 5MW PV (HP03x5) | Add 5MW PV (HP03x5) | Add 5MW PV (HP03x5) | Add 5MW PV (HP03x5) | Add 5MW PV (HP03x5) |
| *2029* | 2MW | 33MW | Add 5MW PV (HP03x5) | Add 5MW PV (HP03x5) | Add 5MW PV (HP03x5) | Add 5MW PV (HP03x5) | Add 5MW PV (HP03x5) |
| *2030* | 2MW | 35MW | Add 10MW Wind (HW04x1) | Add 10MW Wind (HW04x1) | Add 10MW Wind (HW04x1) | Add 10MW Wind (HW04x1) | Add 10MW Wind (HW04x1) |
| *2031* | 2MW | 37MW | Add 10MW Wind (HW04x1) | Add 10MW Wind (HW04x1) | Add 10MW Wind (HW04x1) | Add 10MW Wind (HW04x1) | Add 10MW Wind (HW04x1) |
| *2032* | 2MW | 38MW | | | | | |
| *2033* | 1MW | 40MW | Add 25MW Geothermal (HG02x1) | Add 25MW Geothermal (HG02x1) | Add 21MW CT (HS05x1)-Biofuel | | Add 25MW Geothermal (HG02x1) |
| | | | Add 5MW PV (HP03x5) | Add 5MW PV (HP03x5) | Add 5MW PV (HP03x5) | Add 5MW PV (HP03x5) | Add 5MW PV (HP03x5) |
| *Strategist Planning Period Total Cost* | | | 3, 981, 469 | 3, 978, 168 | 4, 701, 498 | 4, 427, 969 | 3, 943, 474 |
| *Strategist Study Period Total Cost* | | | 5, 936, 770 | 5, 931, 892 | 7, 055, 464 | 6, 523, 213 | 5, 858, 365 |
| *Planning Period Total Cost* | | | 3, 994, 908 | 4, 156, 663 | 4, 627, 644 | 4, 624, 343 | 5, 348, 680 |
| *Study Period Total Cost* | | | 5, 950, 210 | 6, 110, 386 | 6, 582, 945 | 6, 578, 066 | 7, 702, 646 |
| *Planning Rank* | | | 1 | 2 | 4 | 3 | 6 |
| *Study Rank* | | | 1 | 2 | 4 | 3 | 6 |

Table O-72. HELCO Environmental Compliance (1 of 2)

| **Name** | **H2B2a_X-2Ar1** | **H2B2a_X-4Ar1** | **H2B2a_X-4Ar2** | **H2B2a_X-4Ar3** |
|---|---|---|---|---|
| *Plan* | Hu Honua in, No DR, screen (Geo, Wind, PV, Wave) | AQC 2022<br>Comm out fuel switch for Hill5/6, Puna1 in 2022 | Retire/Replace Rule 1Timing LM2500/Dual Train CC | Retire/Replace Rule 1 Timing Geothermal |
| *Notes* | Fuel Switch applies to Hill 5, Hill 6 and Puna Steam<br>Cycle Hill 5/6, Puna Steam | Cycle Hill 5/6, Puna Steam | | |
| *Resources Available* | Firm and Variable Resources are fixed | None | | |
| *Reference* | H2B2a_X-2Ar1.xlxs | | | |
| *2013* | | | | |
| *2014* | Cycle Hill 5/6, Puna | Cycle Hill 5/6, Puna | Cycle Hill 5/6, Puna | Cycle Hill 5/6, Puna |
| | 75% PBFA DSM | 75% PBFA DSM | 75% PBFA DSM | 75% PBFA DSM |
| | Hu Honua (21.5MW) | Hu Honua (21.5MW) | Hu Honua (21.5MW) | Hu Honua (21.5MW) |
| *2015* | Deactivate Shipman 3 (-6.8 MW) | Deactivate Shipman 3 (-6.8 MW) | Deactivate Shipman 3 (-6.8 MW) | Deactivate Shipman 3 (-6.8 MW) |
| | Deactivate Shipman 4 (-6.7 MW) | Deactivate Shipman 4 (-6.7 MW) | Deactivate Shipman 4 (-6.7 MW) | Deactivate Shipman 4 (-6.7 MW) |
| | Add 5MW PV (HP03x5) | Add 5MW PV (HP03x5) | | |
| *2016* | | | | |
| *2017* | Add 10MW Wind (HW04x1) | Add 10MW Wind (HW04x1) | | |
| *2018* | | | | |
| *2019* | Add 25MW Geothermal (HG01x1) | Add 25MW Geothermal (HG01x1) | Deactivate Hill 5 (-13.5 MW) | Deactivate Hill 5 (-13.5 MW) |

| Name | H2B2a_X-2Ar1 | H2B2a_X-4Ar1 | H2B2a_X-4Ar2 | H2B2a_X-4Ar3 |
|---|---|---|---|---|
| 2020 | Add 10MW Wind (HW04x1) | Add 10MW Wind (HW04x1) | | |
| | | | Deactivate Hill 6 (- 20 MW) Deactivate Puna 1 (- 15.5 MW) Deactivate KanoeID 11, 15-17 (- 9.5 MW) Deactivate WaimeaD 12-14 (- 7.5 MW) Deactivate KeahoID 18-23 (- 24.5 MW) Deactivate Kanoe CT1 (- 10.25 MW) Deactivate Keaho CT2 (- 13.80 MW) Deactivate Puna CT3 (- 19 MW) Deactivate PanaewD, OuliD, PunaluD, KapuaD (-4 MW) | Deactivate Hill 6 (-20 MW) Deactivate Puna 1 (-15.5 MW) Deactivate KanoeID 11, 15-17 (- 9.5 MW) Deactivate WaimeaD 12-14 (- 7.5 MW) Deactivate KeahoID 18-23 (- 24.5 MW) Deactivate Kanoe CT1 (- 10.25 MW) Deactivate Keaho CT2 (- 13.80 MW) Deactivate Puna CT3 (- 19 MW) Deactivate PanaewD, OuliD, PunaluD, KapuaD (-4 MW) |
| 2021 | | | Add 21MW CT (HS05x1)-Biofuel | Add 25MW Geothermal (HG01x1) |
| | | | Add 63MW Dual Train CC (HC05x1, HC06x1) | Add 75MW New Geothermal (HG02x3) |
| 2022 | Fuel Switch to LSIFO (Hill 5/6, Puna 1) | AQC for Hill5/6, Puna1 | | |
| | Add 5MW PV (HP03x5) | Add 5MW PV (HP03x5) | | |
| 2023 | Add 5MW PV (HP03x5) | Add 5MW PV (HP03x5) | | |
| 2024 | | | | Add 25MW New Geothermal (HG02x1) |
| | Add 5MW PV (HP03x5) | Add 5MW PV (HP03x5) | | |
| 2025 | | | | |
| 2026 | | | | |
| 2027 | | | | |
| 2028 | Add 5MW PV (HP03x5) | Add 5MW PV (HP03x5) | | |
| 2029 | Add 5MW PV (HP03x5) | Add 5MW PV (HP03x5) | | |
| 2030 | Add 10MW Wind (HW04x1) | Add 10MW Wind (HW04x1) | | |
| 2031 | Add 10MW Wind (HW04x1) | Add 10MW Wind (HW04x1) | | |
| 2032 | | | | |
| 2033 | Add 25MW Geothermal (HG02x1) | Add 25MW Geothermal (HG02x1) | Add 21MW CT (HS05x1)-Biofuel | |
| | Add 5MW PV (HP03x5) | Add 5MW PV (HP03x5) | | |

| Name | H2B2a_X-2Ar1 | H2B2a_X-4Ar1 | H2B2a_X-4Ar2 | H2B2a_X-4Ar3 |
|---|---|---|---|---|
| *Planning Period Total Cost* | 4, 007, 084 | 4, 168, 839 | 4, 771, 319 | 4, 262, 065 |
| *Study Period Total Cost* | 5, 962, 386 | 6, 122, 562 | 7, 250, 325 | 6, 256, 569 |
| *Planning Rank* | 2 | 3 | 7 | 4 |
| *Study Rank* | 2 | 3 | 7 | 4 |

Table O-73. HELCO Environmental Compliance (2 of 2)

| **Name** | **H2B2a_X-4Ar2b** | **H2B2a_X-4Ar3b** | **H2B2a_X-4Ar4** |
|---|---|---|---|
| *Plan* | Retire/Replace LM2500/Dual Train CC, Fixed Wind | Retire/Replace Geothermal, Fixed Wind | Year 2022 Fuel Switch to LSIFO, LNG<br>Fuel Switch to LSIFO for Hill 5, Hill 6 and Puna Steam<br>Fuel Switch to LNG for Keahole CC<br>Cycle Hill5-6, Puna Steam |
| *Notes* | All Units except Keahole CC are deactivated by Dec 2020<br>Cycle Hill 5/6, Puna Steam | All Units except Keahole CC are deactivated by Dec 2020<br>Cycle Hill 5/6, Puna Steam | Fuel Switch to LSIFO for Hill 5, Hill 6 and Puna Steam<br>Fuel Switch to LNG for Keahole CC<br>Cycle Hill5-6, Puna Steam |
| *Resources Available* | None | None | None |
| *2013* | | | |
| *2014* | Cycle Hill 5/6, Puna | Cycle Hill 5/6, Puna | |
| | 75% PBFA DSM | 75% PBFA DSM | 75% PBFA DSM |
| | Hu Honua (21.5MW) | Hu Honua (21.5MW) | Hu Honua (21.5MW) |
| *2015* | Deactivate Shipman 3 (-6.8 MW) | Deactivate Shipman 3 (-6.8 MW) | Deactivate Shipman 3 (-6.8 MW) |
| | Deactivate Shipman 4 (-6.7 MW) | Deactivate Shipman 4 (-6.7 MW) | Deactivate Shipman 4 (-6.7 MW) |
| | Add 5MW PV (HP03x5) | Add 5MW PV (HP03x5) | Add 5MW PV (HP03x5) |
| *2016* | | | |
| *2017* | Add 10MW Wind (HW04x1) | Add 10MW Wind (HW04x1) | Add 10MW Wind (HW04x1) |
| *2018* | | | |
| *2019* | Deactivate Hill 5 (-13.5 MW) | Deactivate Hill 5 (-13.5 MW) | Add 25MW Geothermal (HG01x1) |
| *2020* | Add 10MW Wind (HW04x1) | Add 10MW Wind (HW04x1) | Add 10MW Wind (HW04x1) |
| | Deactivate Hill 6 (-20 MW)<br>Deactivate Puna 1 (-15.5 MW)<br>Deactivate KanoeID 11, 15-17 (-9.5 MW)<br>Deactivate WaimeaD 12-14 (-7.5 MW)<br>Deactivate KeaholD 18-23 (-24.5 MW)<br>Deactivate Kanoe CT1 (-10.25 MW)<br>Deactivate Keaho CT2 (-13.80 MW)<br>Deactivate Puna CT3 (-19 MW)<br>Deactivate PanaewD, OuliD, PunaluD, KapuaD (-4 MW) | Deactivate Hill 6 (-20 MW)<br>Deactivate Puna 1 (-15.5 MW)<br>Deactivate KanoeID 11, 15-17 (-9.5 MW)<br>Deactivate WaimeaD 12-14 (-7.5 MW)<br>Deactivate KeaholD 18-23 (-24.5 MW)<br>Deactivate Kanoe CT1 (-10.25 MW)<br>Deactivate Keaho CT2 (-13.80 MW)<br>Deactivate Puna CT3 (-19 MW)<br>Deactivate PanaewD, OuliD, PunaluD, KapuaD (-4 MW) | |
| *2021* | Add 21MW CT (HS05x1)-Biofuel | Add 25MW Geothermal (HG01x1) | |
| | Add 63MW Dual Train CC (HC05x1, HC06x1) | Add 75MW New Geothermal (HG02x3) | |

| Name | H2B2a_X-4Ar2b | H2B2a_X-4Ar3b | H2B2a_X-4Ar4 |
|---|---|---|---|
| *2022* | | | Fuel Switch to LSIFO (Hill 5/6, Puna Steam)<br>Fuel Switch to LNG (Keahole CC) |
| | Add 5MW PV (HP03x5) | Add 5MW PV (HP03x5) | Add 5MW PV (HP03x5) |
| *2023* | Add 5MW PV (HP03x5) | Add 5MW PV (HP03x5) | Add 5MW PV (HP03x5) |
| *2024* | | Add 25MW New Geothermal (HG02x1) | |
| | Add 5MW PV (HP03x5) | Add 5MW PV (HP03x5) | Add 5MW PV (HP03x5) |
| *2025* | | | |
| *2026* | | | |
| *2027* | | | |
| *2028* | Add 5MW PV (HP03x5) | Add 5MW PV (HP03x5) | Add 5MW PV (HP03x5) |
| *2029* | Add 5MW PV (HP03x5) | Add 5MW PV (HP03x5) | Add 5MW PV (HP03x5) |
| *2030* | Add 10MW Wind (HW04x1) | Add 10MW Wind (HW04x1) | Add 10MW Wind (HW04x1) |
| *2031* | Add 10MW Wind (HW04x1) | Add 10MW Wind (HW04x1) | Add 10MW Wind (HW04x1) |
| *2032* | | | |
| *2033* | Add 21MW CT (HS05x1)-Biofuel | | Add 25MW Geothermal (HG02x1) |
| | Add 5MW PV (HP03x5) | Add 5MW PV (HP03x5) | Add 5MW PV (HP03x5) |
| *Planning Period Total Cost* | 4, 703, 027 | 4, 429, 497 | 3, 975, 405 |
| *Study Period Total Cost* | 7, 056, 993 | 6, 524, 742 | 5, 890, 297 |
| *Planning Rank* | 6 | 5 | 1 |
| *Study Rank* | 6 | 5 | 1 |

Table O-74. HELCO Energy Efficiency Portfolio Standard

| **Name** | **H2B2a_X-7AR0** | **H2B2a_X-7AR1** | **H2B2a_X-7AR2** | **H2B2a_X-7AR3** |
|---|---|---|---|---|
| *Plan* | 35% EEPS Timing | 75% EEPS Timing | 100% EEPS Timing | 110% EEPS Timing |
| *Notes* | Timing Run with 17MW ICE | Timing Run with 17MW ICE | Timing Run with 17MW ICE | Timing Run with 17MW ICE |
| *Resources Available* | None | None | None | None |
| *2013* | | | | |
| *2014* | 25%+10% PBFA DSM | 75% PBFA DSM | 75%+25% PBFA DSM | 75%+25%+10% PBFA DSM |
| | Hu Honua (21.5MW) | Hu Honua (21.5MW) | Hu Honua (21.5MW) | Hu Honua (21.5MW) |
| *2015* | Deactivate Shipman 3 (-6.8 MW) | Deactivate Shipman 3 (-6.8 MW) | Deactivate Shipman 3 (-6.8 MW) | Deactivate Shipman 3 (-6.8 MW) |
| | Deactivate Shipman 4 (-6.7 MW) | Deactivate Shipman 4 (-6.7 MW) | Deactivate Shipman 4 (-6.7 MW) | Deactivate Shipman 4 (-6.7 MW) |
| *2016* | | | | |
| *2017* | | | | |
| *2018* | | | | |
| *2019* | | | | |
| *2020* | | | | |
| *2021* | | | | |
| *2022* | | | | |
| *2023* | | | | |
| *2024* | | | | |
| *2025* | | | | |
| *2026* | | | | |
| *2027* | | | | |
| *2028* | | | | |
| *2029* | | | | |
| *2030* | | | | |
| *2031* | | | | |
| *2032* | | | | |
| *2033* | | | | |
| *Planning Period Total Cost* | 4, 833, 861 | 4, 717, 394 | 4, 648, 266 | 4, 621, 468 |
| *Study Period Total Cost* | 7, 427, 249 | 7, 061, 938 | 6, 842, 410 | 6, 756, 836 |
| *Planning Rank* | 4 | 3 | 2 | 1 |
| *Study Rank* | 4 | 3 | 2 | 1 |

Table O-75. HELCO 0% Renewable Portfolio Standard

| **Name** | **H2B2A_X-2AR1-NORPS** |
|---|---|
| *Plan* | Screen, Hu Honua out, NoDR, NoRet, (Geo, Wind, PV, Wave), No RPS |
| *Notes* | Renewable Resources added to lower cost, not meet RPS requirement |
| *Resources Available* | 10MW Wind (HW04) - Avail 2017<br>1MW PV (HP03) - Avail 2015<br>50MW PV (HP04) - Avail 2020<br>15MW Ocean Wave (HV02) - Avail 2020<br>25MW Advanced Geothermal (HG01) - Avail 2017<br>25MW New Geothermal (HG02) - Avail 2020<br>25MW Banagrass Combustion (HA01) - Avail 2017 |
| *Reference* | H2B2b_X-2Br0-noRPS.xlxs |
| *2013* | |
| *2014* | Cycle Hill 5/6, Puna |
| | 75% PBFA DSM |
| | Hu Honua (21.5MW) |
| *2015* | Deactivate Shipman 3 (-6.8 MW) |
| | Deactivate Shipman 4 (-6.7 MW) |
| | Add 5MW PV (HP03x5) |
| *2016* | |
| *2017* | Add 10MW Wind (HW04x1) |
| *2018* | |
| *2019* | Add 25MW Geothermal (HG01x1) |
| *2020* | Add 10MW Wind (HW04x1) |
| *2021* | |
| *2022* | Add 5MW PV (HP03x5) |
| *2023* | Add 5MW PV (HP03x5) |
| *2024* | Add 5MW PV (HP03x5) |
| *2025* | |
| *2026* | |
| *2027* | |
| *2028* | Add 5MW PV (HP03x5) |
| *2029* | Add 5MW PV (HP03x5) |
| *2030* | Add 10MW Wind (HW04x1) |
| *2031* | Add 10MW Wind (HW04x1) |
| *2032* | |
| *2033* | Add 5MW PV (HP03x5) |
| | Add 25MW Geothermal (HG02x1) |

| **Name** | **H2B2A_X-2AR1-NORPS** |
|---|---|
| *Planning Period Total Cost* | 4, 007, 084 |
| *Study Period Total Cost* | 5, 962, 386 |
| *Planning Rank* | 1 |
| *Study Rank* | 1 |

Table O-76. HELCO 100% Renewable Energy

| **Name** | **H2B2A_X-4AR6** | **H2B2A_X-4AR5** |
|---|---|---|
| *Plan* | 100% RE | 100% RE |
| *Notes* | Biofuel Switch for 100% Renewable Self Generation, Convert Puna to Biomass | Biofuel Switch for 100% Renewable Self Generation |
| *Resources Available* | None | None |
| *2013* | | |
| *2014* | Cycle Hill 5/6, Puna | Cycle Hill 5/6, Puna |
| | 75% PBFA DSM | 75% PBFA DSM |
| | Hu Honua (21.5MW) | Hu Honua (21.5MW) |
| *2015* | Deactivate Shipman 3 (-6.8 MW) | Deactivate Shipman 3 (-6.8 MW) |
| | Deactivate Shipman 4 (-6.7 MW) | Deactivate Shipman 4 (-6.7 MW) |
| | Add 5MW PV (HP03x5) | Add 5MW PV (HP03x5) |
| *2016* | | |
| *2017* | Add 10MW Wind (HW04x1) | Add 10MW Wind (HW04x1) |
| *2018* | | |
| *2019* | Add 25MW Geothermal (HG01x1) | Add 25MW Geothermal (HG01x1) |
| *2020* | Add 10MW Wind (HW04x1) | Add 10MW Wind (HW04x1) |
| | Convert all existing units to Biofuel<br>Hill 5-6<br>KanoelD 11, 15-17<br>WaimeaD 12-14<br>KeahoID 18-23<br>Kanoe CT1<br>Keaho CT2<br>Puna CT3<br>Keaho CC1, CC2<br>PanaewD, OuliD, PunaluD, KapuaD | Convert all existing units to Biofuel<br>Hill 5-6<br>Puna 1<br>KanoelD 11, 15-17<br>WaimeaD 12-14<br>KeahoID 18-23<br>Kanoe CT1<br>Keaho CT2<br>Puna CT3<br>Keaho CC1, CC2<br>PanaewD, OuliD, PunaluD, KapuaD |
| | Convert Puna Steam to Biomass (HRP1x1) | |
| *2021* | | |
| *2022* | Add 5MW PV (HP03x5) | Add 5MW PV (HP03x5) |
| *2023* | Add 5MW PV (HP03x5) | Add 5MW PV (HP03x5) |
| *2024* | Add 5MW PV (HP03x5) | Add 5MW PV (HP03x5) |
| *2025* | | |
| *2026* | | |
| *2027* | | |
| *2028* | Add 5MW PV (HP03x5) | Add 5MW PV (HP03x5) |
| *2029* | Add 5MW PV (HP03x5) | Add 5MW PV (HP03x5) |

| Name | H2B2A_X-4AR6 | H2B2A_X-4AR5 |
|---|---|---|
| *2030* | Add 10MW Wind (HW04x1) | Add 10MW Wind (HW04x1) |
| *2031* | Add 10MW Wind (HW04x1) | Add 10MW Wind (HW04x1) |
| *2032* | | |
| *2033* | Add 25MW Geothermal (HG02x1) | Add 25MW Geothermal (HG02x1) |
| | Add 5MW PV (HP03x5) | Add 5MW PV (HP03x5) |
| *Planning Period Total Cost* | 4, 186, 398 | 4, 197, 910 |
| *Study Period Total Cost* | 6, 120, 976 | 6, 093, 320 |
| *Planning Rank* | 1 | 2 |
| *Study Rank* | 2 | 1 |

Table O-77. HELCO Demand Response as Spinning Reserve

| **Name** | **H2B2a_X-2Ar3** | **H2B2a_X-2Ar2** |
|---|---|---|
| *Plan* | DR with No Spinning Reserve Contribution | DR with Spinning Reserve Contribution |
| *Notes* | Expanded DR added for baseline, Cycle H5/6, Puna | Cycle H5/6, Puna |
| *Resources Available* | None | None |
| *2013* | | |
| *2014* | New CIDLC, Fast DR, RDLCWH, RDLCAC | New CIDLC, Fast DR, RDLCWH, RDLCAC |
| | 75% PBFA DSM | 75% PBFA DSM |
| | Hu Honua (21.5MW) | Hu Honua (21.5MW) |
| *2015* | Deactivate Shipman 3 (-6.8 MW) | Deactivate Shipman 3 (-6.8 MW) |
| | Deactivate Shipman 4 (-6.7 MW) | Deactivate Shipman 4 (-6.7 MW) |
| | Add 5MW PV (HP03x5) | Add 5MW PV (HP03x5) |
| *2016* | | |
| *2017* | Add 10MW Wind (HW04x1) | Add 10MW Wind (HW04x1) |
| *2018* | | |
| *2019* | Add 25MW Geothermal (HG01x1) | Add 25MW Geothermal (HG01x1) |
| *2020* | Add 10MW Wind (HW04x1) | Add 10MW Wind (HW04x1) |
| *2021* | | |
| *2022* | Add 5MW PV (HP03x5) | Add 5MW PV (HP03x5) |
| *2023* | Add 5MW PV (HP03x5) | Add 5MW PV (HP03x5) |
| *2024* | Add 5MW PV (HP03x5) | Add 5MW PV (HP03x5) |
| *2025* | | |
| *2026* | | |
| *2027* | | |
| *2028* | Add 5MW PV (HP03x5) | Add 5MW PV (HP03x5) |
| *2029* | Add 5MW PV (HP03x5) | Add 5MW PV (HP03x5) |
| *2030* | Add 10MW Wind (HW04x1) | Add 10MW Wind (HW04x1) |
| *2031* | Add 10MW Wind (HW04x1) | Add 10MW Wind (HW04x1) |
| *2032* | | |
| *2033* | Add 25MW Geothermal (HG02x1) | Add 25MW Geothermal (HG02x1) |
| | Add 5MW PV (HP03x5) | Add 5MW PV (HP03x5) |
| *Planning Period Total Cost* | 4, 024, 851 | 4, 013, 741 |
| *Study Period Total Cost* | 5, 989, 501 | 5, 960, 461 |
| *Planning Rank* | 2 | 1 |
| *Study Rank* | 2 | 1 |

Table O-78. HELCO Alternative Plan Candidate (1 of 5)

| **Name** | **Self Generation** | | **H2B2a_X-2Ar1** | **H2B2a_X-4Ar4** | **H2B2a_X-4Ar7** | **H2B2a_X-4Ar8** |
|---|---|---|---|---|---|---|
| *Plan* | Annual | Cumulative | Year 2022 Fuel Switch to LSIFO | Year 2022 Fuel Switch to LSIFO, LNG | Year 2022 Fuel Switch to LSIFO<br>Biodiesel 2018<br>CT3 LNG in 2018<br>Puna Biomass Conversion 2017 | Year 2022 Fuel Switch to LSIFO<br>Biodiesel 2018<br>No LNG<br>Puna Biomass Conversion 2017 |
| *Notes* | | | Fuel Switch applies to Hill 5, Hill 6 and Puna Steam<br>Cycle Hill 5/6, Puna Steam | Fuel Switch to LSIFO for Hill 5, Hill 6 and Puna Steam<br>Fuel Switch to LNG for Keahole CC<br>Cycle Hill5-6, Puna Steam | Fuel Switch to LSIFO for Hill 5, Hill 6 Fuel Switch to LNG for Puna CT-3<br>Cycle Hill5-6, Puna Steam | Fuel Switch to LSIFO for Hill 5, Hill 6<br>Cycle Hill5-6, Puna Steam |
| *Resources Available* | | | None | None | 10 MW Wind (HW04)-2017<br>5 MW PV (HP03)-2015<br>25 MW Geothermal (HG02)-2020 | 10 MW Wind (HW04)-2017<br>5 MW PV (HP03)-2015<br>25 MW Geothermal (HG02)-2020 |
| *2014* | 2MW | 8MW | 75% PBFA DSM | 75% PBFA DSM | 75% PBFA DSM | 75% PBFA DSM |
| | | | Hu Honua (21.5MW) | Hu Honua (21.5MW) | Hu Honua (21.5MW) | Hu Honua (21.5MW) |
| *2015* | 2MW | 10MW | Decommission Shipman 3 (-6.8 MW) | Decommission Shipman 3 (-6.8 MW) | Decommission Shipman 3 (-6.8 MW) | Decommission Shipman 3 (-6.8 MW) |
| | | | Decommission Shipman 4 (-6.7 MW) | Decommission Shipman 4 (-6.7 MW) | Decommission Shipman 4 (-6.7 MW) | Decommission Shipman 4 (-6.7 MW) |
| | | | Add 5MW PV (HP03x5) | Add 5MW PV (HP03x5) | | |
| *2016* | 2MW | 12MW | | | | |
| *2017* | 2MW | 14MW | Add 10MW Wind (HW04x1) | Add 10MW Wind (HW04x1) | Add 10MW Wind (HW04x1) | Add 10MW Wind (HW04x1) |
| | | | | | Convert Puna to Biomass (HRP1) | Convert Puna to Biomass (HRP1) |
| *2018* | 2MW | 15MW | | | Add 25MW Geothermal (HG01x1) | Add 25MW Geothermal (HG01x1) |
| | | | | | Biofuel Conversion of Keahole CC | Biofuel Conversion of Keahole CC |
| | | | | | Convert CT-3 to LNG | |
| *2019* | 2MW | 17MW | Add 25MW Geothermal (HG01x1) | Add 25MW Geothermal (HG01x1) | | |
| *2020* | 2MW | 19MW | Add 10MW Wind (HW04x1) | Add 10MW Wind (HW04x1) | Add 10MW Wind (HW04x1) | Add 10MW Wind (HW04x1) |
| *2021* | 2MW | 21MW | | | | |

| Name | Self Generation | | H2B2a_X-2Ar1 | H2B2a_X-4Ar4 | H2B2a_X-4Ar7 | H2B2a_X-4Ar8 |
|---|---|---|---|---|---|---|
| *2022* | 2MW | 22MW | Fuel Switch to LSIFO (Hill 5/6, Puna Steam) | Fuel Switch to LSIFO (Hill 5/6, Puna Steam) Fuel Switch to LNG (Keahole CC) | Fuel Switch to LSIFO (Hill 5/6, Puna Steam) | Fuel Switch to LSIFO (Hill 5/6, Puna Steam) |
| | | | Add 5MW PV (HP03x5) | Add 5MW PV (HP03x5) | | |
| *2023* | 1MW | 24MW | | Add 5MW PV (HP03x5) | | |
| *2024* | 2MW | 25MW | Add 5MW PV (HP03x5) | Add 5MW PV (HP03x5) | | |
| *2025* | 2MW | 27MW | | | Add 5MW PV (HP03x5) | Add 5MW PV (HP03x5) |
| *2026* | 2MW | 29MW | | | Add 5MW PV (HP03x5) | Add 5MW PV (HP03x5) |
| *2027* | 2MW | 30MW | | | | |
| *2028* | 2MW | 32MW | Add 5MW PV (HP03x5) | Add 5MW PV (HP03x5) | Add 5MW PV (HP03x5) | |
| *2029* | 2MW | 33MW | Add 5MW PV (HP03x5) | Add 5MW PV (HP03x5) | | Add 5MW PV (HP03x5) |
| *2030* | 2MW | 35MW | Add 10MW Wind (HW04x1) | Add 10MW Wind (HW04x1) | Add 10MW Wind (HW04x1) | Add 10MW Wind (HW04x1) |
| | | | | | Add 10MW Wind (HW04x1) | Add 5MW PV (HP03x5) |
| *2031* | 2MW | 37MW | Add 10MW Wind (HW04x1) | Add 10MW Wind (HW04x1) | Add 10MW Wind (HW04x1) | Add 10MW Wind (HW04x1) |
| | | | | | Add 5MW PV (HP03x5) | Add 5MW PV (HP03x5) |
| *2032* | 2MW | 38MW | | | Add 5MW PV (HP03x5) | Add 5MW PV (HP03x5) |
| *2033* | 1MW | 40MW | Add 25MW Geothermal (HG02x1) | Add 25MW Geothermal (HG02x1) | | |
| | | | Add 5MW PV (HP03x5) | Add 5MW PV (HP03x5) | Add 5MW PV (HP03x5) | Add 5MW PV (HP03x5) |
| *Strategist Planning Period Total Cost* | | | 3, 981, 469 | 3, 943, 474 | 4, 364, 586 | 4, 364, 413 |
| *Strategist Study Period Total Cost* | | | 5, 936, 770 | 5, 858, 365 | 6, 273, 113 | 6, 272, 867 |
| *Planning Period Total Cost* | | | 4, 627, 644 | 4, 595, 964 | 5, 017, 076 | 5, 010, 587 |
| *Study Period Total Cost* | | | 6, 582, 945 | 6, 510, 856 | 6, 925, 604 | 6, 919, 041 |
| *Planning Rank* | | | 3 | 1 | 16 | 14 |
| *Study Rank* | | | 4 | 1 | 15 | 14 |

Table O-79. HELCO Alternative Plan Candidate (2 of 5)

| **Name** | **Self Generation** | | **H2B2a_X-4Ar9** | **H2B2a_N-9r1** | **H2B2a_N-9r2** | **H2B2b_N-9r3** |
|---|---|---|---|---|---|---|
| *Plan* | Annual | Cumulative | Year 2022 Fuel Switch to LSIFO<br>Biodiesel 2018<br>No LNG | Year 2022 Fuel Switch to LSIFO<br>Biodiesel 2018<br>No LNG | Year 2022 Fuel Switch to LSIFO<br>Biodiesel 2018<br>No LNG<br>Puna Biomass Conversion 2017 | Year 2022 Fuel Switch to LSIFO<br>No LNG |
| *Notes* | | | Fuel Switch to LSIFO for Hill 5, Hill 6 , Puna Cycle Hill5-6, Puna Steam | Fuel Switch to LSIFO for Hill 5, Hill 6 , Puna Cycle Hill5-6, Puna Steam | Fuel Switch to LSIFO for Hill 5, Hill 6 Cycle Hill5-6, Puna Steam | Fuel Switch to LSIFO for Hill 5, Hill 6 Cycle Hill5-6, Puna Steam |
| *Resources Available* | | | 10 MW Wind (HW04)-2017<br>5 MW PV (HP03)-2015<br>25 MW Geothermal (HG02)-2020 | 10 MW Wind (HW04)-2020<br>5 MW PV (HP03)-2020<br>25 MW Geothermal (HG02)-2020 | 10 MW Wind (HW04)-2020<br>5 MW PV (HP03)-2015<br>25 MW Geothermal (HG02)-2020 | 10 MW Wind (HW04)-2020<br>5 MW PV (HP03)-2015<br>25 MW Geothermal (HG02)-2020 |
| *Reference* | | | | | | |
| *2014* | 2MW | 8MW | | New CIDLC, Fast DR, RDLCWH, RDLCAC | New CIDLC, Fast DR, RDLCWH, RDLCAC | New CIDLC, Fast DR, RDLCWH, RDLCAC |
| | | | 75% PBFA DSM | 75% PBFA DSM | 75% PBFA DSM | 75% PBFA DSM |
| | | | Hu Honua (21.5MW) | Hu Honua (21.5MW) | Hu Honua (21.5MW) | Baseload Hill 6 |
| *2015* | 2MW | 10MW | Decommission Shipman 3 (-6.8 MW) | Decommission Shipman 3 (-6.8 MW) | Decommission Shipman 3 (-6.8 MW) | |
| | | | Decommission Shipman 4 (-6.7 MW) | Decommission Shipman 4 (-6.7 MW) | Decommission Shipman 4 (-6.7 MW) | |
| *2016* | 2MW | 12MW | | | | |
| *2017* | 2MW | 14MW | Add 10MW Wind (HW04x1) | | Convert Puna to Biomass (HRP1) | |
| *2018* | 2MW | 15MW | Add 25MW Geothermal (HG01x1) | Add 25MW Geothermal (HG01x1) | Add 25MW Geothermal (HG01x1) | Add 25MW Geothermal (HG01x1) |
| | | | Biofuel Conversion of Keahole CC | Biofuel Conversion of Keahole CC | Biofuel Conversion of Keahole CC | |
| *2019* | 2MW | 17MW | | | | |
| *2020* | 2MW | 19MW | Add 10MW Wind (HW04x1) | Add 10MW Wind (HW04x1) | Add 10MW Wind (HW04x1) | Add 10MW Wind (HW04x1) |
| *2021* | 2MW | 21MW | | Add 5MW PV (HP03x5) | | Add 5MW PV (HP03x5) |
| | | | | Add 10MW Wind (HW04x1) | Add 10MW Wind (HW04x1) | Add 10MW Wind (HW04x1) |

| Name | Self Generation | | H2B2a_X-4Ar9 | H2B2a_N-9r1 | H2B2a_N-9r2 | H2B2b_N-9r3 |
|---|---|---|---|---|---|---|
| *2022* | 2MW | 22MW | Fuel Switch to LSIFO (Hill 5/6, Puna Steam) | Fuel Switch to LSIFO (Hill 5/6, Puna Steam) | Fuel Switch to LSIFO (Hill 5/6, Puna Steam) | Fuel Switch to LSIFO (Hill 5/6, Puna Steam) |
| | | | Add 5MW PV (HP03x5) | Add 5MW PV (HP03x5) | | Add 5MW PV (HP03x5) |
| *2023* | 1MW | 24MW | Add 5MW PV (HP03x5) | Add 5MW PV (HP03x5) | | Add 5MW PV (HP03x5) |
| *2024* | 2MW | 25MW | Add 5MW PV (HP03x5) | Add 5MW PV (HP03x5) | | Add 5MW PV (HP03x5) |
| *2025* | 2MW | 27MW | | | Add 5MW PV (HP03x5) | |
| *2026* | 2MW | 29MW | | | Add 5MW PV (HP03x5) | |
| *2027* | 2MW | 30MW | | | | |
| *2028* | 2MW | 32MW | Add 5MW PV (HP03x5) | Add 5MW PV (HP03x5) | | Add 25MW Geothermal (HG02x1) |
| *2029* | 2MW | 33MW | Add 5MW PV (HP03x5) | | Add 5MW PV (HP03x5) | |
| *2030* | 2MW | 35MW | Add 10MW Wind (HW04x1) | Add 10MW Wind (HW04x1) | Add 10MW Wind (HW04x1) | Add 10MW Wind (HW04x1) |
| | | | | | Add 5MW PV (HP03x5) | |
| *2031* | 2MW | 37MW | Add 10MW Wind (HW04x1) | Add 10MW Wind (HW04x1) | Add 10MW Wind (HW04x1) | Add 10MW Wind (HW04x1) |
| | | | | | Add 5MW PV (HP03x5) | Add 5MW PV (HP03x5) |
| *2032* | 2MW | 38MW | | | Add 5MW PV (HP03x5) | Add 5MW PV (HP03x5) |
| *2033* | 1MW | 40MW | Add 25MW Geothermal (HG02x1) | Add 25MW Geothermal (HG02x1) | | |
| | | | | Add 5MW PV (HP03x5) | Add 5MW PV (HP03x5) | Add 5MW PV (HP03x5) |
| *Strategist Planning Period Total Cost* | | | 4, 339, 457 | 4, 368, 570 | 4, 420, 409 | 4, 055, 226 |
| *Strategist Study Period Total Cost* | | | 6, 268, 288 | 6, 306, 628 | 6, 347, 029 | 6, 077, 122 |
| *Planning Period Total Cost* | | | 4, 985, 631 | 5, 014, 745 | 5, 066, 583 | 4, 701, 401 |

| Name | Self Generation | | H2B2a_X-4Ar9 | H2B2a_N-9r1 | H2B2a_N-9r2 | H2B2b_N-9r3 |
|---|---|---|---|---|---|---|
| *Study Period Total Cost* | | | 6, 914, 463 | 6, 952, 802 | 6, 993, 204 | 6, 723, 296 |
| *Planning Rank* | | | 13 | 15 | 19 | 11 |
| *Study Rank* | | | 13 | 16 | 18 | 12 |
| | | | | 11 | 14 | 9 |
| | | | | 11 | 13 | 10 |

Table O-80. HELCO Alternative Plan Candidate (3 of 5)

| **Name** | **Self Generation** | | **H2B1a_N-9r4** | **H2B1a_N-9r5** | **H2B2b_N-9r6** | **H2B2a_N-9r7** |
|---|---|---|---|---|---|---|
| *Plan* | *Annual* | *Cumulative* | Year 2022 Fuel Switch to LNG | Year 2022 Fuel Switch to LNG | Year 2022 Fuel Switch to LNG; No Hu Honua, No Biodiesel | Year 2022 Fuel Switch to LSIFO<br>No LNG |
| *Notes* | | | Fuel Switch to LNG for Hill 5, Hill 6 , Puna, Keahole<br>Cycle Hill5-6, Puna Steam | Fuel Switch to LNG for Hill 5, Hill 6 , Puna<br>Cycle Hill5-6, Puna Steam | Fuel Switch to LNG for Hill 5, Hill 6 , Keahole CC<br>Cycle Hill5-6, Puna Steam | Fuel Switch to LSIFO for Hill 5, Hill 6 , Puna<br>Cycle Hill5-6, Puna Steam |
| *Resources Available* | | | 10 MW Wind (HW04)-2020<br>5 MW PV (HP03)-2015<br>25 MW Geothermal (HG02)-2020 | 10 MW Wind (HW04)-2020<br>5 MW PV (HP03)-2015<br>25 MW Geothermal (HG02)-2020 | 10 MW Wind (HW04)-2020<br>5 MW PV (HP03)-2015<br>25 MW Geothermal (HG02)-2020 | 10 MW Wind (HW04)-2020<br>5 MW PV (HP03)-2020<br>25 MW Geothermal (HG02)-2020 |
| *Reference* | | | | | | |
| *2014* | 2MW | 8MW | New CIDLC, Fast DR, RDLCWH, RDLCAC | New CIDLC, Fast DR, RDLCWH, RDLCAC | New CIDLC, Fast DR, RDLCWH, RDLCAC | New CIDLC, Fast DR, RDLCWH, RDLCAC |
| | | | 75% PBFA DSM | 75% PBFA DSM | 75% PBFA DSM | 75% PBFA DSM |
| | | | Hu Honua (21.5MW) | Hu Honua (21.5MW) | Baseload Hill 6 | Hu Honua (21.5MW) |
| *2015* | 2MW | 10MW | Decommission Shipman 3 (-6.8 MW) | Decommission Shipman 3 (-6.8 MW) | | Decommission Shipman 3 (-6.8 MW) |
| | | | Decommission Shipman 4 (-6.7 MW) | Decommission Shipman 4 (-6.7 MW) | | Decommission Shipman 4 (-6.7 MW) |
| *2016* | 2MW | 12MW | | | | |
| *2017* | 2MW | 14MW | | | | |
| *2018* | 2MW | 15MW | Add 25MW Geothermal (HG01x1) | Add 25MW Geothermal (HG01x1) | Add 25MW Geothermal (HG01x1) | Add 25MW Geothermal (HG01x1) |
| | | | | Biofuel Conversion of Keahole CC | | |
| *2019* | 2MW | 17MW | | | | |
| *2020* | 2MW | 19MW | Add 10MW Wind (HW04x1) | Add 10MW Wind (HW04x1) | Add 10MW Wind (HW04x1) | Add 10MW Wind (HW04x1) |
| *2021* | 2MW | 21MW | | | Add 5MW PV (HP03x5) | Add 5MW PV (HP03x5) |
| | | | Add 10MW Wind (HW04x1) | Add 10MW Wind (HW04x1) | Add 10MW Wind (HW04x1) | Add 10MW Wind (HW04x1) |
| *2022* | 2MW | 22MW | Fuel Switch to LNG (Hill 5/6, Puna Steam, Keahole CC) | Fuel Switch to LNG (Hill 5/6, Puna Steam) | Fuel Switch to LNG (Hill 5/6, Puna Steam, Keahole CC) | Fuel Switch to LSIFO (Hill 5/6, Puna Steam) |
| | | | Add 5MW PV (HP03x5) | Add 5MW PV (HP03x5) | Add 5MW PV (HP03x5) | Add 5MW PV (HP03x5) |

| Name | Self Generation | | H2B1a_N-9r4 | H2B1a_N-9r5 | H2B2b_N-9r6 | H2B2a_N-9r7 |
|---|---|---|---|---|---|---|
| *2023* | 1MW | 24MW | Add 5MW PV (HP03x5) | Add 5MW PV (HP03x5) | Add 5MW PV (HP03x5) | Add 5MW PV (HP03x5) |
| *2024* | 2MW | 25MW | Add 5MW PV (HP03x5) | Add 5MW PV (HP03x5) | Add 5MW PV (HP03x5) | Add 5MW PV (HP03x5) |
| *2025* | 2MW | 27MW | Add 5MW PV (HP03x5) | Add 5MW PV (HP03x5) | | |
| *2026* | 2MW | 29MW | | | | |
| *2027* | 2MW | 30MW | | | | |
| *2028* | 2MW | 32MW | Add 5MW PV (HP03x5) | Add 5MW PV (HP03x5) | Add 5MW PV (HP03x5) | Add 5MW PV (HP03x5) |
| *2029* | 2MW | 33MW | Add 5MW PV (HP03x5) | Add 5MW PV (HP03x5) | Add 5MW PV (HP03x5) | Add 5MW PV (HP03x5) |
| *2030* | 2MW | 35MW | Add 10MW Wind (HW04x1) | Add 10MW Wind (HW04x1) | Add 10MW Wind (HW04x1) | Add 10MW Wind (HW04x1) |
| *2031* | 2MW | 37MW | Add 10MW Wind (HW04x1) | Add 10MW Wind (HW04x1) | Add 10MW Wind (HW04x1) | Add 10MW Wind (HW04x1) |
| | | | | | Add 25MW Geothermal (HG02x1) | |
| *2032* | 2MW | 38MW | | | | |
| *2033* | 1MW | 40MW | Add 25MW Geothermal (HG02x1) | Add 25MW Geothermal (HG02x1) | | Add 25MW Geothermal (HG02x1) |
| | | | Add 5MW PV (HP03x5) | Add 5MW PV (HP03x5) | Add 5MW PV (HP03x5) | Add 5MW PV (HP03x5) |
| *Strategist Planning Period Total Cost* | | | 3, 974, 155 | 4, 370, 517 | 4, 004, 848 | 4, 010, 886 |
| *Strategist Study Period Total Cost* | | | 5, 899, 553 | 6, 309, 314 | 5, 980, 014 | 5, 975, 412 |
| *Planning Period Total Cost* | | | 4, 626, 644 | 5, 023, 007 | 4, 657, 338 | 4, 657, 060 |
| *Study Period Total Cost* | | | 6, 552, 043 | 6, 961, 805 | 6, 632, 504 | 6, 621, 586 |
| *Planning Rank* | | | 2 | 17 | 6 | 5 |
| *Study Rank* | | | 2 | 17 | 8 | 6 |
| | | | 1 | 12 | 4 | 3 |
| | | | 1 | 12 | 6 | 4 |

Table O-81. HELCO Alternative Plan Candidate (4 of 5)

| Name | Self Generation | | H2B2a_N-9r8 | H2B1a_N-9r9 | H2B2b_N-9r10 | H2B2a_N-9r11 |
|---|---|---|---|---|---|---|
| *Plan* | Annual | Cumulative | Year 2022 Fuel Switch to LSIFO<br>No LNG<br>Puna Biomass Conversion 2017 | Year 2022 Fuel Switch to LSIFO<br>Biodiesel 2018<br>No LNG | Year 2022 Fuel Switch to LNG<br>No Hu Honua, No Biofuels | Year 2022 Fuel Switch to LSIFO<br>Biodiesel 2018<br>No LNG |
| *Notes* | | | Fuel Switch to LSIFO for Hill 5, Hill 6<br>Cycle Hill5-6, Puna Steam | Fuel Switch to LSIFO for Hill 5, Hill 6 , Puna<br>Cycle Hill5-6, Puna Steam | Fuel Switch to LNG for Hill 5, Hill 6 , Keahole CC<br>Cycle Hill5-6, Puna Steam | Fuel Switch to LSIFO for Hill 5, Hill 6 , Puna<br>Cycle Hill5-6, Puna Steam |
| *Resources Available* | | | 10 MW Wind (HW04)-2020<br>5 MW PV (HP03)-2015<br>25 MW Geothermal (HG02)-2020 | 10 MW Wind (HW04)-2020<br>5 MW PV (HP03)-2015<br>25 MW Geothermal (HG02)-2020 | 10 MW Wind (HW04)-2020<br>5 MW PV (HP03)-2015<br>25 MW Geothermal (HG02)-2020 | 10 MW Wind (HW04)-2020<br>5 MW PV (HP03)-2020<br>25 MW Geothermal (HG02)-2020 |
| *Reference* | | | | | | |
| *2014* | 2MW | 8MW | New CIDLC, Fast DR, RDLCWH, RDLCAC | New CIDLC, Fast DR, RDLCWH, RDLCAC | New CIDLC, Fast DR, RDLCWH, RDLCAC | New CIDLC, Fast DR, RDLCWH, RDLCAC |
| | | | 75% PBFA DSM | 75% PBFA DSM | 75% PBFA DSM | 75% PBFA DSM |
| | | | Hu Honua (21.5MW) | Baseload Hill 6 | Baseload Hill 6 | Hu Honua (21.5MW) |
| *2015* | 2MW | 10MW | Decommission Shipman 3 (-6.8 MW) | | | Decommission Shipman 3 (-6.8 MW) |
| | | | Decommission Shipman 4 (-6.7 MW) | | | Decommission Shipman 4 (-6.7 MW) |
| *2016* | 2MW | 12MW | | | | |
| *2017* | 2MW | 14MW | Convert Puna to Biomass (HRP1) | | Convert Puna to Biomass (HRP1) | |
| *2018* | 2MW | 15MW | Add 25MW Geothermal (HG01x1) | Add 25MW Geothermal (HG01x1) | Add 25MW Geothermal (HG01x1) | Add 25MW Geothermal (HG01x1) |
| | | | | Biofuel Conversion of Keahole CC | | Biofuel Conversion of Keahole CC |
| *2019* | 2MW | 17MW | | | | |
| *2020* | 2MW | 19MW | Add 10MW Wind (HW04x1) | Add 10MW Wind (HW04x1) | Add 10MW Wind (HW04x1) | Add 10MW Wind (HW04x1) |
| | | | | Add 5MW PV (HP03x5) | | |
| *2021* | 2MW | 21MW | | | | Add 5MW PV (HP03x5) |
| | | | Add 10MW Wind (HW04x1) | Add 10MW Wind (HW04x1) | Add 10MW Wind (HW04x1) | Add 10MW Wind (HW04x1) |

| Name | Self Generation | | H2B2a_N-9r8 | H2B1a_N-9r9 | H2B2b_N-9r10 | H2B2a_N-9r11 |
|---|---|---|---|---|---|---|
| *2022* | 2MW | 22MW | Fuel Switch to LSIFO (Hill 5/6, Puna Steam) | Fuel Switch to LSIFO (Hill 5/6, Puna Steam) | Fuel Switch to LNG (Hill 5/6, Keahole CC) | Fuel Switch to LSIFO (Hill 5/6, Puna Steam) |
| | | | | Add 5MW PV (HP03x5) | Add 5MW PV (HP03x5) | Add 5MW PV (HP03x5) |
| *2023* | 1MW | 24MW | | Add 5MW PV (HP03x5) | Add 5MW PV (HP03x5) | Add 5MW PV (HP03x5) |
| *2024* | 2MW | 25MW | | Add 5MW PV (HP03x5) | Add 5MW PV (HP03x5) | Add 5MW PV (HP03x5) |
| *2025* | 2MW | 27MW | Add 5MW PV (HP03x5) | | Add 5MW PV (HP03x5) | |
| *2026* | 2MW | 29MW | Add 5MW PV (HP03x5) | | | |
| *2027* | 2MW | 30MW | Add 5MW PV (HP03x5) | | | |
| *2028* | 2MW | 32MW | Add 5MW PV (HP03x5) | Add 5MW PV (HP03x5) | Add 5MW PV (HP03x5) | Add 5MW PV (HP03x5) |
| *2029* | 2MW | 33MW | Add 5MW PV (HP03x5) | Add 5MW PV (HP03x5) | Add 5MW PV (HP03x5) | |
| *2030* | 2MW | 35MW | Add 10MW Wind (HW04x1) | Add 10MW Wind (HW04x1) | Add 10MW Wind (HW04x1) | Add 10MW Wind (HW04x1) |
| *2031* | 2MW | 37MW | Add 10MW Wind (HW04x1) | Add 10MW Wind (HW04x1) | Add 10MW Wind (HW04x1) | Add 10MW Wind (HW04x1) |
| *2032* | 2MW | 38MW | Add 5MW PV (HP03x5) | | | |
| *2033* | 1MW | 40MW | | Add 25MW Geothermal (HG02x1) | Add 25MW Geothermal (HG02x1) | Add 25MW Geothermal (HG02x1) |
| | | | Add 5MW PV (HP03x5) | Add 5MW PV (HP03x5) | Add 5MW PV (HP03x5) | |
| *Strategist Planning Period Total Cost* | | | 4, 036, 754 | 4, 402, 672 | 4, 026, 209 | 4, 108, 049 |
| *Strategist Study Period Total Cost* | | | 5, 989, 625 | 6, 396, 031 | 5, 971, 630 | 5, 990, 375 |
| *Planning Period Total Cost* | | | 4, 682, 929 | 5, 042, 905 | 4, 678, 700 | 4, 754, 223 |
| *Study Period Total Cost* | | | 6, 635, 800 | 7, 036, 264 | 6, 624, 121 | 6, 636, 549 |
| *Planning Rank* | | | 9 | 18 | 8 | 12 |

| Name | Self Generation | | H2B2a_N-9r8 | H2B1a_N-9r9 | H2B2b_N-9r10 | H2B2a_N-9r11 |
|---|---|---|---|---|---|---|
| *Study Rank* | | | 9 | 20 | 7 | 10 |
| | | | 7 | 13 | 6 | 10 |
| | | | 7 | 15 | 5 | 8 |

Table O-82. HELCO Alternative Plan Candidate (5 of 5)

| Name | Self Generation | | H2B2b_N-9r12 | H2B2a_N-9r13 | H2B2b_N-9r14 |
|---|---|---|---|---|---|
| *Plan* | Annual | Cumulative | Year 2022 Fuel Switch to LNG<br>No Hu Honua, No Biofuels | Year 2022 Fuel Switch to LSIFO<br>LNG Keahole CC<br>Puna Biomass Conversion 2017 | Year 2022 Fuel Switch to LSIFO<br>No Hu Honua, No Biofuels |
| *Notes* | | | Fuel Switch to LNG for Hill 5, Hill 6 , Keahole CC<br>Cycle Hill5-6, Puna Steam | Fuel Switch to LSIFO for Hill 5, Hill 6<br>Cycle Hill5-6, Puna Steam | Fuel Switch to LSIFO for Hill 5, Hill 6 , Puna<br>Cycle Hill5-6, Puna Steam |
| *Resources Available* | | | 10 MW Wind (HW04)-2020<br>5 MW PV (HP03)-2015<br>25 MW Geothermal (HG02)-2020 | 10 MW Wind (HW04)-2020<br>5 MW PV (HP03)-2015<br>25 MW Geothermal (HG02)-2020 | 10 MW Wind (HW04)-2020<br>5 MW PV (HP03)-2015<br>25 MW Geothermal (HG02)-2020 |
| *Reference* | | | | | |
| *2014* | 2MW | 8MW | New CIDLC, Fast DR, RDLCWH, RDLCAC<br>75% PBFA DSM<br>Baseload Hill 6 | New CIDLC, Fast DR, RDLCWH, RDLCAC<br>75% PBFA DSM<br>Hu Honua (21.5MW) | New CIDLC, Fast DR, RDLCWH, RDLCAC<br>75% PBFA DSM<br>Baseload Hill 6 |
| *2015* | 2MW | 10MW | | Decommission Shipman 3 (-6.8 MW)<br>Decommission Shipman 4 (-6.7 MW) | |
| *2016* | 2MW | 12MW | | | |
| *2017* | 2MW | 14MW | Convert Puna to Biomass (HRP1) | Convert Puna to Biomass (HRP1) | Convert Puna to Biomass (HRP1) |
| *2018* | 2MW | 15MW | Add 25MW Geothermal (HG01x1)<br>Decommission Shipman 3 (-6.8 MW)<br>Decommission Shipman 4 (-6.7 MW) | Add 25MW Geothermal (HG01x1) | Add 25MW Geothermal (HG01x1)<br>Decommission Shipman 3 (-6.8 MW)<br>Decommission Shipman 4 (-6.7 MW) |
| *2019* | 2MW | 17MW | | | |
| *2020* | 2MW | 19MW | Add 10MW Wind (HW04x1) | Add 10MW Wind (HW04x1) | Add 10MW Wind (HW04x1) |
| *2021* | 2MW | 21MW | Add 10MW Wind (HW04x1) | Add 10MW Wind (HW04x1) | Add 10MW Wind (HW04x1) |
| *2022* | 2MW | 22MW | Fuel Switch to LNG (Hill 5/6, Keahole CC)<br>Add 5MW PV (HP03x5) | Fuel Switch to LSIFO (Hill 5/6, Puna Steam)<br>LNG Keahole CC | Fuel Switch to LSIFO (Hill 5/6) |
| *2023* | 1MW | 24MW | Add 5MW PV (HP03x5) | | Add 5MW PV (HP03x5) |
| *2024* | 2MW | 25MW | Add 5MW PV (HP03x5) | | |
| *2025* | 2MW | 27MW | Add 5MW PV (HP03x5) | | Add 5MW PV (HP03x5) |

| Name | Self Generation | | H2B2b_N-9r12 | H2B2a_N-9r13 | H2B2b_N-9r14 |
|---|---|---|---|---|---|
| 2026 | 2MW | 29MW | | Add 5MW PV (HP03x5) | Add 5MW PV (HP03x5) |
| 2027 | 2MW | 30MW | | Add 5MW PV (HP03x5) | Add 5MW PV (HP03x5) |
| 2028 | 2MW | 32MW | Add 5MW PV (HP03x5) | | Add 5MW PV (HP03x5) |
| 2029 | 2MW | 33MW | Add 5MW PV (HP03x5) | Add 5MW PV (HP03x5) | |
| 2030 | 2MW | 35MW | Add 10MW Wind (HW04x1) | Add 10MW Wind (HW04x1) | Add 10MW Wind (HW04x1) |
| | | | | Add 5MW PV (HP03x5) | |
| 2031 | 2MW | 37MW | Add 10MW Wind (HW04x1) | Add 10MW Wind (HW04x1) | Add 10MW Wind (HW04x1) |
| | | | | Add 5MW PV (HP03x5) | |
| 2032 | 2MW | 38MW | | Add 5MW PV (HP03x5) | Add 5MW PV (HP03x5) |
| 2033 | 1MW | 40MW | Add 25MW Geothermal (HG02x1) | | Add 25MW Geothermal (HG02x1) |
| | | | Add 5MW PV (HP03x5) | Add 5MW PV (HP03x5) | Add 5MW PV (HP03x5) |
| Strategist Planning Period Total Cost | | | 4, 012, 220 | 4, 000, 419 | 4, 051, 957 |
| Strategist Study Period Total Cost | | | 5, 950, 275 | 5, 907, 675 | 6, 046, 157 |
| Planning Period Total Cost | | | 4, 664, 710 | 4, 652, 909 | 4, 698, 132 |
| Study Period Total Cost | | | 6, 602, 765 | 6, 560, 165 | 6, 692, 331 |
| Planning Rank | | | 7 | 4 | 10 |
| Study Rank | | | 5 | 3 | 11 |
| | | | 5 | 2 | 8 |
| | | | 3 | 2 | 9 |

Table O-83. HELCO Preferred Plan

| Name | Self Generation | | H2B2a_N-9r7 | H2B1a_N-9r4 | H2B1a_N-9r5 | H2B2b_N-9r14 |
|---|---|---|---|---|---|---|
| *Plan* | Annual | Cumulative | Year 2022 Fuel Switch to LSIFO<br>No LNG | Year 2022 Fuel Switch to LNG | Year 2022 Fuel Switch to LNG | Year 2022 Fuel Switch to LSIFO<br>No Hu Honua, No Biofuels<br>Convert Puna to Biomass |
| *Notes* | | | Fuel Switch to LSIFO for Hill 5, Hill 6 , Puna Cycle Hill5-6, Puna Steam<br>New CIDLC, Fast DR, RDLCWH, RDLCAC<br>75% PBFA DSM | Fuel Switch to LNG for Hill 5, Hill 6 , Puna, Keahole Cycle Hill5-6, Puna Steam<br>New CIDLC, Fast DR, RDLCWH, RDLCAC<br>75% PBFA DSM | Fuel Switch to LNG for Hill 5, Hill 6 , Puna Cycle Hill5-6, Puna Steam<br>New CIDLC, Fast DR, RDLCWH, RDLCAC<br>75% PBFA DSM | Fuel Switch to LSIFO for Hill 5, Hill 6 Cycle Hill5-6, Puna Steam<br>New CIDLC, Fast DR, RDLCWH, RDLCAC<br>75% PBFA DSM |
| *Resources Available* | | | 10 MW Wind (HW04)-2020<br>5 MW PV (HP03)-2020<br>25 MW Geothermal (HG02)-2020 | 10 MW Wind (HW04)-2020<br>5 MW PV (HP03)-2015<br>25 MW Geothermal (HG02)-2020 | 10 MW Wind (HW04)-2020<br>5 MW PV (HP03)-2015<br>25 MW Geothermal (HG02)-2020 | 10 MW Wind (HW04)-2020<br>5 MW PV (HP03)-2015<br>25 MW Geothermal (HG02)-2020 |
| *2014* | 2MW | 8MW | Hu Honua (21.5MW) | Hu Honua (21.5MW) | Hu Honua (21.5MW) | Baseload Hill 6 |
| *2015* | 2MW | 10MW | Decommission Shipman 3 (-6.8 MW)<br>Decommission Shipman 4 (-6.7 MW) | Decommission Shipman 3 (-6.8 MW)<br>Decommission Shipman 4 (-6.7 MW) | Decommission Shipman 3 (-6.8 MW)<br>Decommission Shipman 4 (-6.7 MW) | |
| *2016* | 2MW | 12MW | | | | |
| *2017* | 2MW | 14MW | | | | Convert Puna to Biomass (HRP1) |
| *2018* | 2MW | 15MW | Add 25MW Geothermal (HG01x1) | Add 25MW Geothermal (HG01x1) | Add 25MW Geothermal (HG01x1)<br>Biofuel Conversion of Keahole CC | Add 25MW Geothermal (HG01x1)<br>Decommission Shipman 3 (-6.8 MW)<br>Decommission Shipman 4 (-6.7 MW) |
| *2019* | 2MW | 17MW | | | | |
| *2020* | 2MW | 19MW | Add 10MW Wind (HW04x1) | Add 10MW Wind (HW04x1) | Add 10MW Wind (HW04x1) | Add 10MW Wind (HW04x1) |
| *2021* | 2MW | 21MW | Add 5MW PV (HP03x5)<br>Add 10MW Wind (HW04x1) | Add 10MW Wind (HW04x1) | Add 10MW Wind (HW04x1) | Add 10MW Wind (HW04x1) |

## Appendix O: Resource Plan Sheets

HELCO Resource Plans

| Name | Self Generation | | H2B2a_N-9r7 | H2B1a_N-9r4 | H2B1a_N-9r5 | H2B2b_N-9r14 |
|---|---|---|---|---|---|---|
| *2022* | 2MW | 22MW | Fuel Switch to LSIFO (Hill 5/6, Puna Steam) | Fuel Switch to LNG (Hill 5/6, Puna Steam, Keahole CC) | Fuel Switch to LNG (Hill 5/6, Puna Steam) | Fuel Switch to LSIFO (Hill 5/6) |
| | | | Add 5MW PV (HP03x5) | Add 5MW PV (HP03x5) | Add 5MW PV (HP03x5) | |
| *2023* | 1MW | 24MW | Add 5MW PV (HP03x5) | Add 5MW PV (HP03x5) | Add 5MW PV (HP03x5) | Add 5MW PV (HP03x5) |
| *2024* | 2MW | 25MW | Add 5MW PV (HP03x5) | Add 5MW PV (HP03x5) | Add 5MW PV (HP03x5) | |
| *2025* | 2MW | 27MW | | Add 5MW PV (HP03x5) | Add 5MW PV (HP03x5) | Add 5MW PV (HP03x5) |
| *2026* | 2MW | 29MW | | | | Add 5MW PV (HP03x5) |
| *2027* | 2MW | 30MW | | | | Add 5MW PV (HP03x5) |
| *2028* | 2MW | 32MW | Add 5MW PV (HP03x5) | Add 5MW PV (HP03x5) | Add 5MW PV (HP03x5) | Add 5MW PV (HP03x5) |
| *2029* | 2MW | 33MW | Add 5MW PV (HP03x5) | Add 5MW PV (HP03x5) | Add 5MW PV (HP03x5) | |
| *2030* | 2MW | 35MW | Add 10MW Wind (HW04x1) | Add 10MW Wind (HW04x1) | Add 10MW Wind (HW04x1) | Add 10MW Wind (HW04x1) |
| *2031* | 2MW | 37MW | Add 10MW Wind (HW04x1) | Add 10MW Wind (HW04x1) | Add 10MW Wind (HW04x1) | Add 10MW Wind (HW04x1) |
| *2032* | 2MW | 38MW | | | | Add 5MW PV (HP03x5) |
| *2033* | 1MW | 40MW | Add 25MW Geothermal (HG02x1) | Add 25MW Geothermal (HG02x1) | Add 25MW Geothermal (HG02x1) | Add 25MW Geothermal (HG02x1) |
| | | | Add 5MW PV (HP03x5) | Add 5MW PV (HP03x5) | Add 5MW PV (HP03x5) | Add 5MW PV (HP03x5) |
| *Strategist Planning Period Total Cost* | | | 4, 010, 886 | 3, 974, 155 | 4, 370, 517 | 4, 051, 957 |
| *Strategist Study Period Total Cost* | | | 5, 975, 412 | 5, 899, 553 | 6, 309, 314 | 6, 046, 157 |
| *Planning Period Total Cost* | | | 4, 657, 060 | 4, 626, 644 | 5, 023, 007 | 4, 698, 132 |
| *Study Period Total Cost* | | | 6, 621, 586 | 6, 552, 043 | 6, 961, 805 | 6, 692, 331 |
| *Planning Rank* | | | 2 | 1 | 4 | 3 |
| *Study Rank* | | | 2 | 1 | 4 | 3 |

## No Burning Desire

Table O-84. HELCO Firm Timing (1 of 4)

| **Name** | **H3_2A_X-1Ar0** | **H3_2A_X-1Br0** | **H3_2A_X-1r0** | **H3_2A_X-1Ar0_Geo** |
|---|---|---|---|---|
| *Plan* | Hu Honua in, No DR, conven timing, Rule 1 | Hu Honua in, No DR, renewables timing, Rule 1 | Hu Honua in, No DR, LCP timing | Hu Honua in, No DR, Geo forced w/ Deactivate |
| *Resources Available* | 17MW ICE (HS01) available 2016<br>21MW CT (HS05) available 2017<br>42MW CT (HS06) available 2017 | 25MW geo (HG01) available 2017<br>25MW geo (HG02) available 2017<br>25MW biomass (HA01) available 2017<br>8MW WTE (HT01) available 2017 | 17MW ICE (HS01) available 2016<br>21MW CT (HS05) available 2017<br>25MW geo (HG01) available 2017<br>25MW geo (HG02) available 2017 | 25MW geo (HG02) available 2017<br>25MW biomass (HA01) available 2017 |
| *Reference* | H3_2A_X-1Ar0 | H3_2A_X-1Br0 | H3_2A_X-1r0 | H3_2A_X-1Ar0_Geo |
| *2014* | 75%+25%+10% PBFA DSM | 75%+25%+10% PBFA DSM | 75%+25%+10% PBFA DSM | 75%+25%+10% PBFA DSM |
| | Hu Honua (21.5MW) | Hu Honua (21.5MW) | Hu Honua (21.5MW) | Hu Honua (21.5MW) |
| *2015* | Deactivate Shipman 3 (-6.8 MW) | Deactivate Shipman 3 (-6.8 MW) | Deactivate Shipman 3 (-6.8 MW) | Deactivate Shipman 3 (-6.8 MW) |
| | Deactivate Shipman 4 (-6.7 MW) | Deactivate Shipman 4 (-6.7 MW) | Deactivate Shipman 4 (-6.7 MW) | Deactivate Shipman 4 (-6.7 MW) |
| *2016* | | | | |
| *2017* | Add 17MW ICE (HS01x1) biofuel | Add 25 MW Adv geothermal (HG01x1) | Add 25 MW Adv geothermal (HG01x1) | Add 25 MW Adv geothermal (HG01x1) |
| *2018* | | | | |
| *2019* | | | | Deactivate Hill 5 (-13.5 MW) |
| *2020* | | | | |
| *2021* | | | | |
| *2022* | | | | |
| *2023* | | | | |
| *2024* | Add 17MW ICE (HS01x1) biofuel | Add 25 MW New Dev geothermal (HG02x1) | Add 25 MW New Dev geothermal (HG02x1) | Add 25 MW New Dev geothermal (HG02x1) |
| *2025* | | | | |
| *2026* | Add 17MW ICE (HS01x1) biofuel | | | |
| *2027* | | | | |
| *2028* | | | | |
| *2029* | | | | |

| **Name** | **H3_2A_X-1Ar0** | **H3_2A_X-1Br0** | **H3_2A_X-1r0** | **H3_2A_X-1Ar0_Geo** |
|---|---|---|---|---|
| *2030* | | | | |
| *2031* | | | | |
| *2032* | | | | Add 25 MW New Dev geothermal (HG02x1) |
| *2033* | | | | |
| Planning Period Total Cost | 3, 951, 266 | 3, 881, 274 | 3, 881, 274 | 3, 887, 208 |
| Study Period Total Cost | 5, 870, 947 | 5, 688, 489 | 5, 688, 489 | 5, 744, 564 |
| Planning Rank | 12 | 5 | 5 | 8 |
| Study Rank | 11 | 1 | 1 | 8 |

Table O-85. HELCO Firm Timing (2 of 4)

| **Name** | **H3_2A_X-1Ar0_Geo_No_Ret** | **H3_2A_N-1Ar0** | **H3_2A_N-1Br0** | **H3_2A_N-1r0** |
|---|---|---|---|---|
| *Plan* | Hu Honua in, No DR, Geo forced, no Hill Deactivate | No Deactivate, Hu Honua in, w/DR, Conven, Rule 1 | No Deactivate, Hu Honua in, w/DR, renew, Rule 1 | No Deactivate, Hu Honua in, w/DR, timing LCP, Rule 1 |
| *Resources Available* | 25MW geo (HG02) available 2017<br>25MW biomass (HA01) available 2017 | 17MW ICE (HS01) available 2016<br>21MW CT (HS05) available 2017<br>42MW CT (HS06) available 2017 | 25MW geo (HG01) available 2017<br>25MW geo (HG02) available 2017<br>25MW biomass (HA01) available 2017<br>8MW WTE (HT01) available 2017 | 17MW ICE (HS01) available 2016<br>21MW CT (HS05) available 2017<br>25MW geo (HG01) available 2017<br>25MW geo (HG02) available 2017 |
| *Reference* | H3_2A_X-1Ar0_Geo_No_Ret | H3_2A_N-1Ar0 | H3_2A_N-1Br0 | H3_2A_N-1r0 |
| *2014* | | New CIDLC, Fast DR, RDLCWH, RDLCAC | New CIDLC, Fast DR, RDLCWH, RDLCAC | New CIDLC, Fast DR, RDLCWH, RDLCAC |
| | 75%+25%+10% PBFA DSM | 75%+25%+10% PBFA DSM | 75%+25%+10% PBFA DSM | 75%+25%+10% PBFA DSM |
| | Hu Honua (21.5MW) | Hu Honua (21.5MW) | Hu Honua (21.5MW) | Hu Honua (21.5MW) |
| *2015* | Deactivate Shipman 3 (-6.8 MW) | Deactivate Shipman 3 (-6.8 MW) | Deactivate Shipman 3 (-6.8 MW) | Deactivate Shipman 3 (-6.8 MW) |
| | Deactivate Shipman 4 (-6.7 MW) | Deactivate Shipman 4 (-6.7 MW) | Deactivate Shipman 4 (-6.7 MW) | Deactivate Shipman 4 (-6.7 MW) |
| *2016* | | | | |
| *2017* | Add 25 MW Adv geothermal (HG01x1) | Add 17MW ICE (HS01x1) biofuel | Add 25 MW Adv geothermal (HG01x1) | Add 25 MW Adv geothermal (HG01x1) |
| *2018* | | | | |
| *2019* | | | | |
| *2020* | | | | |
| *2021* | | | | |
| *2022* | | | | |
| *2023* | | | | |
| *2024* | Add 25 MW New Dev geothermal (HG02x1) | Add 17MW ICE (HS01x1) biofuel | | |
| *2025* | | | Add 25 MW New Dev geothermal (HG02x1) | Add 17MW ICE (HS01x1) biofuel |
| *2026* | | | | |
| *2027* | | | | |
| *2028* | | | | |
| *2029* | | | | |
| *2030* | | | | |

| Name | H3_2A_X-1Ar0_Geo_No_Ret | H3_2A_N-1Ar0 | H3_2A_N-1Br0 | H3_2A_N-1r0 |
|---|---|---|---|---|
| *2031* | | | | |
| *2032* | | | | |
| *2033* | | Add 17MW ICE (HS01x1) biofuel | | |
| *Planning Period Total Cost* | 3, 881, 274 | 3, 948, 936 | 3, 933, 042 | 3, 918, 217 |
| *Study Period Total Cost* | 5, 688, 489 | 5, 896, 815 | 5, 765, 507 | 5, 761, 537 |
| *Planning Rank* | 5 | 11 | 10 | 9 |
| *Study Rank* | 1 | 12 | 10 | 9 |

Table O-86. HELCO Firm Timing (3 of 4)

| **Name** | **H3_2B_N-1AR0** | **H3_2B_N-1BR0** | **H3_2B_N-1R0** | **H3_2B_X-1Ar0** |
|---|---|---|---|---|
| *Plan* | No Deactivate, HH out, w/DR, Conven, Rule 1 | No Deactivate, HH out, w/DR, renew, Rule 1 | No Deactivate, HH out, w/DR, timing LCP, Rule 1 | No Deactivate, HH out, No DR, conven timing, Rule 1 |
| *Resources Available* | 17MW ICE (HS01) available 2016<br>21MW CT (HS05) available 2017<br>42MW CT (HS06) available 2017 | 25MW geo (HG01) available 2017<br>25MW geo (HG02) available 2017<br>25MW biomass (HA01) available 2017<br>8MW WTE (HT01) available 2017 | 17MW ICE (HS01) available 2016<br>21MW CT (HS05) available 2017<br>25MW geo (HG01) available 2017<br>25MW geo (HG02) available 2017 | 17MW ICE (HS01) available 2016<br>21MW CT (HS05) available 2017<br>42MW CT (HS06) available 2017 |
| *Reference* | H3_2B_N-1AR0 | H3_2B_N-1BR0 | H3_2B_N-1R0 | H3_2B_X-1Ar0 |
| *2014* | New CIDLC, Fast DR, RDLCWH, RDLCAC | New CIDLC, Fast DR, RDLCWH, RDLCAC | New CIDLC, Fast DR, RDLCWH, RDLCAC | |
| | 75%+25%+10% PBFA DSM | 75%+25%+10% PBFA DSM | 75%+25%+10% PBFA DSM | 75%+25%+10% PBFA DSM |
| *2015* | | | | |
| *2016* | | | | |
| *2017* | Add 17MW ICE (HS01x1) biofuel | Add 25 MW Adv geothermal (HG01x1) | Add 25 MW Adv geothermal (HG01x1) | Add 17MW ICE (HS01x1) biofuel |
| *2018* | | | | |
| *2019* | | | | |
| *2020* | | | | |
| *2021* | | | | |
| *2022* | | | | |
| *2023* | | | | Add 21MW CT (HS05x1) biofuel |
| *2024* | Add 17MW ICE (HS01x1) biofuel | Add 25 MW New Dev geothermal (HG02x1) | Add 25 MW New Dev geothermal (HG02x1) | |
| *2025* | Add 17MW ICE (HS01x1) biofuel | | | Add 17MW ICE (HS01x1) biofuel |
| *2026* | | | | |
| *2027* | | | | |
| *2028* | | | | |
| *2029* | | | | |
| *2030* | | | | |
| *2031* | | | | |
| *2032* | | | | |
| *2033* | | | | |

| Name | H3_2B_N-1AR0 | H3_2B_N-1BR0 | H3_2B_N-1R0 | H3_2B_X-1Ar0 |
|---|---|---|---|---|
| *Planning Period Total Cost* | 3, 989, 072 | 3, 877, 549 | 3, 877, 549 | 3, 990, 766 |
| *Study Period Total Cost* | 5, 949, 114 | 5, 702, 144 | 5, 702, 144 | 5, 963, 627 |
| *Planning Rank* | 13 | 3 | 3 | 14 |
| *Study Rank* | 13 | 4 | 4 | 14 |

Table O-87. HELCO Firm Timing (4 of 4)

| **Name** | **H3_2B_X-1Br0** | **H3_2B_X-1r0** |
|---|---|---|
| *Plan* | No Deactivate, HH out, No DR, renewable, Rule 1 | No Deactivate, HH out, No DR, timing LCP, Rule 1 |
| *Resources Available* | 25MW geo (HG01) available 2017<br>25MW geo (HG02) available 2017<br>25MW biomass (HA01) available 2017<br>8MW WTE (HT01) available 2017 | 17MW ICE (HS01) available 2016<br>21MW CT (HS05) available 2017<br>25MW geo (HG01) available 2017<br>25MW geo (HG02) available 2017 |
| *Reference* | H3_2B_X-1Br0 | H3_2B_X-1r0 |
| *2014* | 75%+25%+10% PBFA DSM | 75%+25%+10% PBFA DSM |
| *2015* | | |
| *2016* | | |
| *2017* | Add 25 MW Adv geothermal (HG01x1) | Add 25 MW Adv geothermal (HG01x1) |
| *2018* | | |
| *2019* | | |
| *2020* | | |
| *2021* | | |
| *2022* | | |
| *2023* | | |
| *2024* | Add 25 MW New Dev geothermal (HG02x1) | Add 25 MW New Dev geothermal (HG02x1) |
| *2025* | | |
| *2026* | | |
| *2027* | | |
| *2028* | | |
| *2029* | | |
| *2030* | | |
| *2031* | | |
| *2032* | | |
| *2033* | Add 25 MW New Dev geothermal (HG02x1) | Add 17MW ICE (HS01x1) biofuel |
| *Planning Period Total Cost* | 3, 867, 246 | 3, 865, 130 |
| *Study Period Total Cost* | 5, 739, 856 | 5, 735, 685 |
| *Planning Rank* | 2 | 1 |
| *Study Rank* | 7 | 6 |

Table O-88. HELCO 100% Renewable Portfolio Standard

| **Name** | **H3B2A_N-2r0** | **H3B2A_N-2r1** | **H3B2A_N-2r2** | **H3B2A_N-2r3** |
|---|---|---|---|---|
| *Plan* | Hu Honua in w/ DR Screen Firm Fixed, (All RE) | Hu Honua in w/ DR geo /ICE Float | Meet RPS by Scenario<br>Year 2020: 20%<br>Year 2030: 30% | Meet RPS by Scenario<br>Year 2020: 20%<br>Year 2030: 30% |
| *Notes* | | | Firm float. Add geothermal, wind, PV, ocean wave, solar thermal and Puna repowering to meet RPS<br>Cycle Hill 5, Hill 6, and Puna | Firm fixed. Add geothermal, wind, PV, ocean wave, solar thermal and Puna repowering to meet RPS<br>Cycle Hill 5, Hill 6, and Puna |
| *Resources Available* | 1 MW PV (HP03) available 2015<br>10MW wind (HW04) available 2017<br>50 MW trough PV (HP04) available 2020<br>15MW ocean wave (HV02) available 2020 | 1 MW PV (HP03) available 2015<br>17MW ICE (HS01) available 2016<br>25MW geo (HG01) available 2016<br>25MW geo (HG02) available 2016<br>10MW wind (HW04) available 2017<br>50 MW trough PV (HP04) available 2020<br>15MW ocean wave (HV02) available 2020 | 1 MW PV (HP03) available 2015<br>17MW ICE (HS01) available 2016<br>25MW geo (HG01) available 2016<br>25MW geo (HG02) available 2016<br>10MW wind (HW04) available 2017<br>50 MW trough PV (HP04) available 2020<br>15MW ocean wave (HV02) available 2020 | 1 MW PV (HP03) available 2015<br>10MW wind (HW04) available 2017<br>50 MW trough PV (HP04) available 2020<br>15MW ocean wave (HV02) available 2020 |
| *2014* | | | Cycle H5/6, Puna | Cycle H5/6, Puna |
| | New CIDLC, Fast DR, RDLCWH, RDLCAC | New CIDLC, Fast DR, RDLCWH, RDLCAC | New CIDLC, Fast DR, RDLCWH, RDLCAC | New CIDLC, Fast DR, RDLCWH, RDLCAC |
| | 75% PBFA DSM | 75% PBFA DSM | 75% PBFA DSM | 75% PBFA DSM |
| | Hu Honua (21.5MW) | Hu Honua (21.5MW) | Hu Honua (21.5MW) | Hu Honua (21.5MW) |
| *2015* | Deactivate Shipman 3 (-6.8 MW) | Deactivate Shipman 3 (-6.8 MW) | Deactivate Shipman 3 (-6.8 MW) | Deactivate Shipman 3 (-6.8 MW) |
| | Deactivate Shipman 4 (-6.7 MW) | Deactivate Shipman 4 (-6.7 MW) | Deactivate Shipman 4 (-6.7 MW) | Deactivate Shipman 4 (-6.7 MW) |
| *2016* | | | | |
| *2017* | Add 25 MW geothermal (HG01x1) | Add 17MW ICE (HS01x1) biofuel | Add 25 MW geothermal (HG01x1) | Add 25 MW geothermal (HG01x1) |
| | Add 10 MW wind (HW04x1) | Add 10 MW wind (HW04x1) | Add 10 MW wind (HW04x1) | Add 10 MW wind (HW04x1) |
| *2018* | | | | |
| *2019* | | | | |
| *2020* | Add 10 MW wind (HW04x1) | Add 10 MW wind (HW04x1) | Add 10 MW wind (HW04x1) | Add 10 MW wind (HW04x1) |
| *2021* | | | | |

| **Name** | **H3B2A_N-2r0** | **H3B2A_N-2r1** | **H3B2A_N-2r2** | **H3B2A_N-2r3** |
|---|---|---|---|---|
| *2022* | Fuel switch to LSIFO (Hill 5/6, Puna Steam) | Fuel switch to LSIFO (Hill 5/6, Puna Steam) | Fuel switch to LSIFO (Hill 5/6, Puna Steam) | Fuel switch to LSIFO (Hill 5/6, Puna Steam) |
| *2023* | | | | |
| *2024* | | Add 25 MW geothermal (HG01x1) | | |
| *2025* | Add 17MW ICE (HS01x1) biofuel | | Add 17MW ICE (HS01x1) biofuel | Add 17MW ICE (HS01x1) biofuel |
| *2026* | | | | |
| *2027* | | | | |
| *2028* | | | | |
| *2029* | | | | |
| *2030* | Add 10 MW wind (HW04x1) | Add 10 MW wind (HW04x1) | Add 10 MW wind (HW04x1) | Add 10 MW wind (HW04x1) |
| *2031* | Add 10 MW wind (HW04x1) | Add 10 MW wind (HW04x1) | Add 10 MW wind (HW04x1) | Add 10 MW wind (HW04x1) |
| *2032* | | | | |
| *2033* | | | | |
| *Planning Period Total Cost* | 3, 898, 481 | 3, 894, 367 | 3, 847, 810 | 3, 847, 810 |
| *Study Period Total Cost* | 5, 697, 431 | 5, 695, 333 | 5, 632, 636 | 5, 632, 636 |
| *Planning Rank* | 4 | 3 | 1 | 1 |
| *Study Rank* | 4 | 3 | 1 | 1 |

Table O-89. HELCO Environmental Compliance (1 of 2)

| **Name** | **H3B2A_N-2r2** | **H3B2A_N-4r1** | **H3B2A_N-4r2** | **H3B2A_N-4r3** |
|---|---|---|---|---|
| *Plan* | Year 2022 Fuel Switch to LSIFO | Year 2022 Install Air Quality Controls | Deactivate Existing Replace with Conventional Biofuel Units | Deactivate Existing Replace with geothermal |
| *Resources Available* | 1 MW PV (HP03) available 2015<br>17MW ICE (HS01) available 2016<br>25MW geo (HG01) available 2016<br>25MW geo (HG02) available 2016<br>10MW wind (HW04) available 2017<br>50 MW trough PV (HP04) available 2020<br>15MW ocean wave (HV02) available 2020 | All units are fixed | 21MW CT (HS05) available 2020<br>63MW DTCC (HC05/HC06) available 2020 | 25MW geo (HG01) available 2020<br>25MW geo (HG02) available 2020 |
| *Notes* | Fuel Switch applies to Hill 5, Hill 6, and Puna Steam<br>Cycle H5/6, Puna Steam | Cycle H5/6, Puna Steam | | |
| *2014* | Cycle H5/6, Puna | Cycle H5/6, Puna | Cycle H5/6, Puna | Cycle H5/6, Puna |
| | New CIDLC, Fast DR, RDLCWH, RDLCAC | New CIDLC, Fast DR, RDLCWH, RDLCAC | New CIDLC, Fast DR, RDLCWH, RDLCAC | New CIDLC, Fast DR, RDLCWH, RDLCAC |
| | 75% PBFA DSM | 75% PBFA DSM | 75% PBFA DSM | 75% PBFA DSM |
| | Hu Honua (21.5MW) | Hu Honua (21.5MW) | Hu Honua (21.5MW) | Hu Honua (21.5MW) |
| *2015* | Deactivate Shipman 3 (-6.8 MW) | Deactivate Shipman 3 (-6.8 MW) | Deactivate Shipman 3 (-6.8 MW) | Deactivate Shipman 3 (-6.8 MW) |
| | Deactivate Shipman 4 (-6.7 MW) | Deactivate Shipman 4 (-6.7 MW) | Deactivate Shipman 4 (-6.7 MW) | Deactivate Shipman 4 (-6.7 MW) |
| *2016* | | | | |
| *2017* | Add 25 MW geothermal (HG01x1) | Add 25 MW geothermal (HG01x1) | | |
| | Add 10 MW wind (HW04x1) | Add 10 MW wind (HW04x1) | | |
| *2018* | | | | |
| *2019* | | | Deactivate Hill 5 (-13.5 MW) | Deactivate Hill 5 (-13.5 MW) |

| Name | H3B2A_N-2r2 | H3B2A_N-4r1 | H3B2A_N-4r2 | H3B2A_N-4r3 |
|---|---|---|---|---|
| *2020* | Add 10 MW wind (HW04x1) | Add 10 MW wind (HW04x1) | | |
| | | | | Add 50MW new geothermal (HG02x2) |
| | | | Add 21MW CT (HS05x1)-biofuel | |
| | | | Deactivate Hill 6 (-20 MW)<br>Deactivate Puna 1 (- 15.5 MW)<br>Deactivate KanoelD 11, 15-17 (- 9.5 MW)<br>Deactivate WaimeaD 12-14 (- 7.5 MW)<br>Deactivate KeaholD 18-23 (- 24.5 MW)<br>Deactivate Kanoe CT1 (- 10.25 MW)<br>Deactivate Keaho CT2 (- 13.80 MW)<br>Deactivate Puna CT3 (- 19 MW)<br>Deactivate PanaewD, OuliD, PunaluD, KapuaD (- 4 MW) | Deactivate Hill 6 (- 20 MW)<br>Deactivate Puna 1 (- 15.5 MW)<br>Deactivate KanoelD 11, 15-17 (- 9.5 MW)<br>Deactivate WaimeaD 12-14 (- 7.5 MW)<br>Deactivate KeaholD 18-23 (- 24.5 MW)<br>Deactivate Kanoe CT1 (- 10.25 MW)<br>Deactivate Keaho CT2 (- 13.80 MW)<br>Deactivate Puna CT3 (- 19 MW)<br>Deactivate PanaewD, OuliD, PunaluD, KapuaD (- 4 MW) |
| *2021* | | | Add 21MW CT (HS05x1)-biofuel | Add 25MW geothermal (HG01x1) |
| | | | Add 63MW Dual Train CC (HC05x1, HC06x1) | Add 75MW new geothermal (HG02x3) |
| *2022* | Fuel Switch to LSIFO (Hill 5/6, Puna 1) | AQC for Hill5/6, Puna1 | | |
| *2023* | | | | |
| *2024* | | | Add 21MW CT (HS05x1)-biofuel | |
| *2025* | Add 17MW ICE (HS01x1)-biofuel | Add 17MW ICE (HS01x1)-biofuel | | |
| | | | | Add 50MW new geothermal (HG02x2) |
| *2026* | | | | |
| *2027* | | | | |
| *2028* | | | | |
| *2029* | | | Add 21MW CT (HS05x1)-biofuel | |

| Name | H3B2A_N-2r2 | H3B2A_N-4r1 | H3B2A_N-4r2 | H3B2A_N-4r3 |
|---|---|---|---|---|
| *2030* | Add 10 MW wind (HW04x1) | Add 10 MW wind (HW04x1) | | |
| *2031* | Add 10 MW wind (HW04x1) | Add 10 MW wind (HW04x1) | | |
| *2032* | | | | |
| *2033* | | | Add 21MW CT (HS05x1)-biofuel | |
| *Planning Period Total Cost* | 3, 847, 810.000 | 3, 986, 797.609 | 5, 017, 860.000 | 4, 564, 316.500 |
| *Study Period Total Cost* | 5, 632, 635.500 | 5, 745, 124.795 | 7, 547, 815.000 | 6, 685, 292.000 |
| *Planning Rank* | 1 | 3 | 7 | 4 |
| *Study Rank* | 1 | 2 | 7 | 4 |

Table O-90. HELCO Environmental Compliance. (2 of 2)

| **Name** | **H3B2A_N-4r2b** | **H3B2A_N-4r3b** | **H3B2A_N-4r4** |
|---|---|---|---|
| *Plan* | Deactivate Existing Replace with Conventional Biofuel Units | Deactivate Existing Replace with geothermal | Year 2022 Fuel Switch to LSIFO, LNG |
| *Resources Available* | All units except Keahole CC are deactivated by December 2020<br>Cycle H5/6, Puna Steam | All units except Keahole CC are deactivated by December 2020<br>Cycle H5/6, Puna Steam | Fuel switch to LSIFO for Hill 5, Hill 6, and Puna Steam<br>Fuel switch to LNG for Keahole CC<br>Cycle Hill5-6, Puna Steam |
| *Notes* | 21MW CT (HS05) available 2020<br>63MW DTCC (HC05/HC06) available 2020 | 25MW geo (HG01) available 2020<br>25MW geo (HG02) available 2020 | All resources are fixed |
| *2014* | Cycle H5/6, Puna | Cycle H5/6, Puna | Cycle H5/6, Puna |
| | New CIDLC, Fast DR, RDLCWH, RDLCAC | New CIDLC, Fast DR, RDLCWH, RDLCAC | New CIDLC, Fast DR, RDLCWH, RDLCAC |
| | 75% PBFA DSM | 75% PBFA DSM | 75% PBFA DSM |
| | Hu Honua (21.5MW) | Hu Honua (21.5MW) | Hu Honua (21.5MW) |
| *2015* | Deactivate Shipman 3 (-6.8 MW) | Deactivate Shipman 3 (-6.8 MW) | Deactivate Shipman 3 (-6.8 MW) |
| | Deactivate Shipman 4 (-6.7 MW) | Deactivate Shipman 4 (-6.7 MW) | Deactivate Shipman 4 (-6.7 MW) |
| *2016* | | | |
| *2017* | | | Add 25 MW geothermal (HG01x1) |
| | Add 10 MW wind (HW04x1) | Add 10 MW wind (HW04x1) | Add 10 MW wind (HW04x1) |
| *2018* | | | |
| *2019* | Deactivate Hill 5 (-13.5 MW) | Deactivate Hill 5 (-13.5 MW) | |
| *2020* | Add 10 MW wind (HW04x1) | Add 10 MW wind (HW04x1) | Add 10 MW wind (HW04x1) |
| | | Add 50MW new geothermal (HG02x2) | |
| | Add 21MW CT (HS05x1) biofuel | | |
| | Deactivate Hill 6 (-20 MW)<br>Deactivate Puna 1 (-15.5 MW)<br>Deactivate KanoeID 11, 15-17 (-9.5 MW)<br>Deactivate WaimeaD 12-14 (-7.5 MW)<br>Deactivate KeaholD 18-23 (-24.5 MW)<br>Deactivate Kanoe CT1 (-10.25 MW)<br>Deactivate Keaho CT2 (-13.80 MW)<br>Deactivate Puna CT3 (-19 MW)<br>Deactivate PanaewD, OuliD, PunaluD, KapuaD (-4 MW) | Deactivate Hill 6 (-20 MW)<br>Deactivate Puna 1 (-15.5 MW)<br>Deactivate KanoeID 11, 15-17 (-9.5 MW)<br>Deactivate WaimeaD 12-14 (-7.5 MW)<br>Deactivate KeaholD 18-23 (-24.5 MW)<br>Deactivate Kanoe CT1 (-10.25 MW)<br>Deactivate Keaho CT2 (-13.80 MW)<br>Deactivate Puna CT3 (-19 MW)<br>Deactivate PanaewD, OuliD, PunaluD, KapuaD (-4 MW) | |
| | Add 21MW CT (HS05x1) biofuel | Add 25MW geothermal (HG01x1) | |
| | Add 63MW Dual Train CC (HC05x1, HC06x1) | Add 75MW new geothermal (HG02x3) | |

| Name | H3B2A_N-4r2b | H3B2A_N-4r3b | H3B2A_N-4r4 |
|---|---|---|---|
| *2022* | | | Fuel switch to LSIFO (Hill 5/6, Puna Steam)<br>Fuel switch to LNG (Keahole CC) |
| *2023* | | | |
| *2024* | Add 21MW CT (HS05x1) biofuel | | |
| *2025* | | | Add 17MW ICE (HS01x1) biofuel |
| | | Add 50MW new geothermal (HG02x2) | |
| *2026* | | | |
| *2027* | | | |
| *2028* | | | |
| *2029* | Add 21MW CT (HS05x1) biofuel | | |
| *2030* | Add 10 MW wind (HW04x1) | Add 10 MW wind (HW04x1) | Add 10 MW wind (HW04x1) |
| *2031* | Add 10 MW wind (HW04x1) | Add 10 MW wind (HW04x1) | Add 10 MW wind (HW04x1) |
| *2032* | | | |
| *2033* | Add 21MW CT (HS05x1) biofuel | | |
| *Planning Period Total Cost* | 4, 885, 033.500 | 4, 611, 855.500 | 3, 979, 898.572 |
| *Study Period Total Cost* | 7, 302, 339.500 | 6, 782, 342.000 | 5, 902, 956.541 |
| *Planning Rank* | 6 | 5 | 2 |
| *Study Rank* | 6 | 5 | 3 |

Table O-91. HELCO Energy Efficiency Portfolio Standard

| **Name** | **H3B2a_N-7AR0** | **H3B2a_N-7Ar1** | **H3B2a_N-7Ar2** | **H3B2a_N-7Ar3** |
|---|---|---|---|---|
| *Plan* | 35% EEPS | 75% EEPS | 100% EEPS | 110% EEPS |
| *Notes* | Includes fuel switch to LSIFO (Hill5/6, Puna Steam) in 2022 | Includes fuel switch to LSIFO (Hill5/6, Puna Steam) in 2022 | Includes fuel switch to LSIFO (Hill5/6, Puna Steam) in 2022 | Includes fuel switch to LSIFO (Hill5/6, Puna Steam) in 2022 |
| *Resources Available* | 17MW ICE (HS01) available 2016 | 17MW ICE (HS01) available 2016 | 17MW ICE (HS01) available 2016 | 17MW ICE (HS01) available 2016 |
| *2014* | 25%+10% PBFA DSM | 75% PBFA DSM | 75% PBFA DSM | 75% PBFA DSM |
| | Hu Honua (21.5MW) | Hu Honua (21.5MW) | Hu Honua (21.5MW) | Hu Honua (21.5MW) |
| *2015* | Deactivate Shipman 3 (-6.8 MW) | Deactivate Shipman 3 (-6.8 MW) | Deactivate Shipman 3 (-6.8 MW) | Deactivate Shipman 3 (-6.8 MW) |
| | Deactivate Shipman 4 (-6.7 MW) | Deactivate Shipman 4 (-6.7 MW) | Deactivate Shipman 4 (-6.7 MW) | Deactivate Shipman 4 (-6.7 MW) |
| *2016* | | | | |
| *2017* | Add 17MW ICE (HS01x1) biofuel | Add 17MW ICE (HS01x1) biofuel | | |
| *2018* | | | | |
| *2019* | | | | |
| *2020* | | | | |
| *2021* | | | | |
| *2022* | Fuel switch to LSIFO (Hill 5/6, Puna Steam) | Fuel switch to LSIFO (Hill 5/6, Puna Steam) | Fuel switch to LSIFO (Hill 5/6, Puna Steam) | Fuel switch to LSIFO (Hill 5/6, Puna Steam) |
| *2023* | Add 17MW ICE (HS01x1) biofuel | | Add 17MW ICE (HS01x1) biofuel | Add 17MW ICE (HS01x1) biofuel |
| *2024* | Add 17MW ICE (HS01x1) biofuel | Add 17MW ICE (HS01x1) biofuel | Add 17MW ICE (HS01x1) biofuel | Add 17MW ICE (HS01x1) biofuel |
| *2025* | | | | |
| *2026* | | Add 17MW ICE (HS01x1) biofuel | | |
| *2027* | | | | |
| *2028* | | | | |
| *2029* | | | | |
| *2030* | | | | |
| *2031* | Add 17MW ICE (HS01x1) biofuel | | | |
| *2032* | | | | |
| *2033* | | | Add 17MW ICE (HS01x1) biofuel | |

| **Name** | **H3B2a_N-7AR0** | **H3B2a_N-7Ar1** | **H3B2a_N-7Ar2** | **H3B2a_N-7Ar3** |
|---|---|---|---|---|
| *Planning Period Total Cost* | 4, 070, 977 | 3, 951, 266 | 3, 820, 575 | 3, 797, 980 |
| *Study Period Total Cost* | 6, 196, 400 | 5, 870, 947 | 5, 658, 767 | 5, 545, 508 |
| *Planning Rank* | 4 | 3 | 2 | 1 |
| *Study Rank* | 4 | 3 | 2 | 1 |

Table O-92. HELCO 0% Renewable Portfolio Standard

| **Name** | **H3B2A_N-2r2** | **H3B2A_N-2r3-noRPS** |
|---|---|---|
| *Plan* | Hu Honua in, w/ DR, Screen, Firm Fixed, (All RE), Cycle H5/6 Puna | Hu Honua in, w/ DR, Screen, Firm Fixed, (All RE), no RPS, Cycle H5/6 Puna |
| *Notes* | Includes fuel switch to LSIFO (Hill5/6, Puna Steam) in 2022 | Includes fuel switch to LSIFO (Hill5/6, Puna Steam) in 2022 |
| *Resources Available* | 1 MW PV (HP03) available 2015<br>17MW ICE (HS01) available 2016<br>25MW geo (HG01) available 2016<br>25MW geo (HG02) available 2016<br>10MW wind (HW04) available 2017<br>50 MW trough PV (HP04) available 2020<br>15MW ocean wave (HV02) available 2020 | 1 MW PV (HP03) available 2015<br>10MW wind (HW04) available 2017<br>25MW biomass (HT01)-avail 2017<br>25MW geo (HG02) available 2020<br>50 MW trough PV (HP04) available 2020<br>15MW ocean wave (HV02) available 2020 |
| *2014* | New CIDLC, Fast DR, RDLCWH, RDLCAC | New CIDLC, Fast DR, RDLCWH, RDLCAC |
| | 75% PBFA DSM | 75% PBFA DSM |
| | Hu Honua (21.5MW) | Hu Honua (21.5MW) |
| *2015* | Deactivate Shipman 3 (-6.8 MW) | Deactivate Shipman 3 (-6.8 MW) |
| | Deactivate Shipman 4 (-6.7 MW) | Deactivate Shipman 4 (-6.7 MW) |
| *2016* | | |
| *2017* | Add 25 MW geothermal (HG01x1) | Add 25 MW geothermal (HG01x1) |
| | Add 10 MW wind (HW04x1) | Add 10 MW wind (HW04x1) |
| *2018* | | |
| *2019* | | |
| *2020* | Add 10 MW wind (HW04x1) | Add 10 MW wind (HW04x1) |
| *2021* | | |
| *2022* | Fuel switch to LSIFO (Hill 5/6, Puna Steam) | Fuel switch to LSIFO (Hill 5/6, Puna Steam) |
| *2023* | | |
| *2024* | | |
| *2025* | Add 17MW ICE (HS01x1) biofuel | Add 17MW ICE (HS01x1) biofuel |
| *2026* | | |
| *2027* | | |
| *2028* | | |
| *2029* | | |
| *2030* | Add 10 MW wind (HW04x1) | Add 10 MW wind (HW04x1) |
| *2031* | Add 10 MW wind (HW04x1) | Add 10 MW wind (HW04x1) |
| *2032* | | |
| *2033* | | |
| *Planning Period Total Cost* | 3, 847, 810 | 3, 847, 810 |
| *Study Period Total Cost* | 5, 632, 636 | 5, 632, 636 |

| Name | H3B2A_N-2r2 | H3B2A_N-2r3-noRPS |
|---|---|---|
| *Planning Rank* | 1 | 1 |
| *Study Rank* | 1 | 1 |

Table O-93. HELCO 100% Renewable Energy

| **Name** | **H3B2a_N-4r5** | **H3B2a_N-4r6** |
|---|---|---|
| *Plan* | Hu Honua in, Screen, No DR (Geo, Wind, PV, Wave) | Hu Honua in, Puna Repower in 2020, Screen, No DR (Geo, Wind, PV, Wave) |
| *Notes* | Fuel switch existing to biofuel in 2020 | Fuel switch existing to biofuel in 2020 |
| *Resources Available* | All resources are fixed | All resources are fixed |
| *2014* | New CIDLC, Fast DR, RDLCWH, RDLCAC | New CIDLC, Fast DR, RDLCWH, RDLCAC |
| | 75% PBFA DSM | 75% PBFA DSM |
| | Hu Honua (21.5MW) | Hu Honua (21.5MW) |
| *2015* | Deactivate Shipman 3 (-6.8 MW) | Deactivate Shipman 3 (-6.8 MW) |
| | Deactivate Shipman 4 (-6.7 MW) | Deactivate Shipman 4 (-6.7 MW) |
| *2016* | | |
| *2017* | Add 25 MW geothermal (HG01x1) | Add 25 MW geothermal (HG01x1) |
| | Add 10 MW wind (HW04x1) | Add 10 MW wind (HW04x1) |
| *2018* | | |
| *2019* | | |
| *2020* | Add 10 MW wind (HW04x1) | Add 10 MW wind (HW04x1) |
| | Convert all existing units to biofuel<br>Hill 5-6<br>Puna Steam<br>KanoelD 11, 15–17<br>WaimeaD 12–14<br>KeaholD 21–23<br>Kanoe CT1<br>Keaho CT2<br>Puna CT3<br>Keaho CC1, CC2<br>PanaewD, OuliD, PunaluD, KapuaD | Convert all existing units to biofuel<br>Hill 5–6<br>KanoelD 11, 15–17<br>WaimeaD 12–14<br>KeaholD 21–23<br>Kanoe CT1<br>Keaho CT2<br>Puna CT3<br>Keaho CC1, CC2<br>PanaewD, OuliD, PunaluD, KapuaD |
| | | Convert Puna Steam to biomass (HRP1x1) |
| *2021* | | |
| *2022* | | |
| *2023* | | |
| *2024* | | |
| *2025* | Add 17MW ICE (HS01x1) biofuel | Add 17MW ICE (HS01x1) biofuel |
| *2026* | | |
| *2027* | | |
| *2028* | | |
| *2029* | | |
| *2030* | Add 10 MW wind (HW04x1) | Add 10 MW wind (HW04x1) |

| **Name** | **H3B2a_N-4r5** | **H3B2a_N-4r6** |
|---|---|---|
| *2031* | Add 10 MW wind (HW04x1) | Add 10 MW wind (HW04x1) |
| *2032* | | |
| *2033* | | |
| *Planning Period Total Cost* | 4, 666, 169 | 4, 553, 689 |
| *Study Period Total Cost* | 6, 915, 995 | 6, 735, 673 |
| *Planning Rank* | 2 | 1 |
| *Study Rank* | 2 | 1 |

## Moved by Passion

Table O-94. HELCO Firm Timing (1 of 2)

| **Name** | **H4_2A_X-1ARr0** | **H4_2A_X-1Br0** | **H4_2A_N-1r0** | **H4_2B_N-1R0** |
|---|---|---|---|---|
| *Plan* | Firm Timing With Conventional | Firm Timing With Renewable | Firm Timing With Conventional | Firm Timing With Conventional |
| *Notes* | Timing fun with firm conventional units available<br>No DR programs<br>Shipman 3 & 4 deactivation | Timing run with firm geothermal, biomass, and waste to energy units available<br>No DR programs<br>Shipman 3 & 4 deactivation | Timing run with firm conventional units available<br>New DR programs added | Timing run with firm conventional units available<br>New DR programs added<br>Hu Honua out |
| *Resources Available* | 17MW ICE (HS01) available 2016<br>21MW CT (HS05) available 2017<br>42MW CT (HS06) available 2017 | 25MW geo (HG01 & HG02) available 2017<br>25MW biomass (HA01) available 2017<br>8MW WTE (HT01) available 2017<br>400 kW Fuel Cell (HB01) available 2017 | 17MW ICE (HS01) available 2016<br>21MW CT (HS05) available 2017<br>42MW CT (HS06) available 2017 | 17MW ICE (HS01) available 2016<br>21MW CT (HS05) available 2017<br>42MW CT (HS06) available 2017 |
| *Reference* | H4_2A_X-1Ar1 | H4_2A_X-1Br0 | H4_2A_N-1r0 | H4_2B_N-1R0 |
| *2014* | | | New CIDLC, Fast DR, RDLCWH, RDLCAC | New CIDLC, Fast DR, RDLCWH, RDLCAC |
| | 75%+25%PBFA DSM | 75%+25%+10% PBFA DSM | 75%+25%+10% PBFA DSM | 75%+25%+10% PBFA DSM |
| | Hu Honua (21.5MW) | Hu Honua (21.5MW) | Hu Honua (21.5MW) | |
| *2015* | Deactivate Shipman 3 (- 6.8 MW) | Deactivate Shipman 3 (- 6.8 MW) | Deactivate Shipman 3 (-6.8 MW) | |
| | Deactivate Shipman 4 (- 6.7 MW) | Deactivate Shipman 4 (- 6.7 MW) | Deactivate Shipman 4 (-6.7 MW) | |
| *2016* | | | | |
| *2017* | | Add 25 MW adv geothermal (HG01x1) | | |
| *2018* | | | | |
| *2019* | | | | |
| *2020* | | | | |
| *2021* | | Add 25 MW new dev geothermal (HG02x1) | | |
| *2022* | | | | |
| *2023* | | | | |

| **Name** | **H4_2A_X-1ARr0** | **H4_2A_X-1Br0** | **H4_2A_N-1r0** | **H4_2B_N-1R0** |
|---|---|---|---|---|
| *2024* | | | | |
| *2025* | | | | |
| *2026* | | | | |
| *2027* | | | | |
| *2028* | | | | |
| *2029* | | | | |
| *2030* | | | | |
| *2031* | | | | |
| *2032* | | | | |
| *2033* | | Add 25 MW new dev geothermal (HG02x1) | | Add 17 MW ICE (HS01x1) |
| *Planning Period Total Cost* | 4, 213, 327 | 4, 116, 714 | 4, 230, 988 | 4, 368, 915 |
| *Study Period Total Cost* | 6, 316, 247 | 5, 877, 937 | 6, 342, 842 | 6, 620, 038 |
| *Planning Rank* | 5 | 2 | 6 | 8 |
| *Study Rank* | 5 | 2 | 6 | 8 |

Table O-95. HELCO Firm Timing (2 of 2)

| **Name** | **H4_2B_X-1Ar0** | **H4_2B_X-1Br0** | **H4_2A_X-1Ar0_Geo** | **H4_2A_X-1Ar0_Geo_No_Ret** |
|---|---|---|---|---|
| *Plan* | Firm Timing with Conventional | Firm Timing with Renewable | Hu Honua in, No DR, Geo forced with Deactivate | Hu Honua in, No DR, Geo forced, no Hill Deactivation |
| *Notes* | Timing run with firm conventional units available<br>No DR programs<br>Hu Honua out | Timing run with firm geothermal, biomass, and waste to energy units available<br>No DR programs<br>Hu Honua out | | |
| *Resources Available* | 17MW ICE (HS01) available 2016<br>21MW CT (HS05) available 2017<br>42MW CT (HS06) available 2017 | 25MW geo (HG01 & HG02) available 2017<br>25MW Biomass (HA01) available 2017<br>8MW WTE (HT01) available 2017<br>400 kW Fuel Cell (HB01) available 2017 | 25MW geo (HG01 & HG02) available 2017<br>25MW Biomass (HA01) available 2017 | 25MW geo (HG01 & HG02) available 2017<br>25MW Biomass (HA01) available 2017 |
| *Reference* | H4_2B_X-1Ar0 | H4_2B_X-1Br0 | H4_2A_X-1Ar0_Geo | H4_2A_X-1Ar0_Geo_No_Ret |
| *2014* | 75%+25%+10% PBFA DSM | 75%+25%+10% PBFA DSM | 75%+25%+10% PBFA DSM | 75%+25%+10% PBFA DSM |
| | | | Hu Honua (21.5MW) | Hu Honua (21.5MW) |
| *2015* | | | Deactivate Shipman 3 (- 6.8 MW) | Deactivate Shipman 3 (- 6.8 MW) |
| | | | Deactivate Shipman 4 (- 6.7 MW) | Deactivate Shipman 4 (- 6.7 MW) |
| *2016* | | | | |
| *2017* | | Add 25 MW adv geothermal (HG01x1) | Add 25 MW adv geothermal (HG01x1) | Add 25 MW adv geothermal (HG01x1) |
| | | Add 25 MW new dev geothermal (HG02x1) | | |
| *2018* | | | | |
| *2019* | | | Deactivate Hill 5 (-13.5 MW) | |
| *2020* | | | | |
| *2021* | | | Add 25 MW new dev geothermal (HG02x1) | Add 25 MW new dev geothermal (HG02x1) |
| *2022* | | | | |
| *2023* | | | | |
| *2024* | | | | |
| *2025* | | | | |
| *2026* | | | | |

| Name | H4_2B_X-1Ar0 | H4_2B_X-1Br0 | H4_2A_X-1Ar0_Geo | H4_2A_X-1Ar0_Geo_No_Ret |
|---|---|---|---|---|
| *2027* | | Add 25 MW new dev geothermal (HG02x1) | | |
| *2028* | | | | |
| *2029* | | | | |
| *2030* | | | | |
| *2031* | | | | |
| *2032* | | | | |
| *2033* | Add 17 MW ICE (HS01x1) | Add 25 MW new dev geothermal (HG02x1) | Add 25 MW new dev geothermal (HG02x1) | Add 25 MW new dev geothermal (HG02x1) |
| *Planning Period Total Cost* | 4, 351, 189 | 4, 196, 233 | 4, 097, 853 | 4, 116, 714 |
| *Study Period Total Cost* | 6, 592, 928 | 5, 989, 043 | 5, 846, 874 | 5, 877, 937 |
| *Planning Rank* | 7 | 4 | 1 | 2 |
| *Study Rank* | 7 | 4 | 1 | 2 |

Table O-96. HELCO 100% Renewable Portfolio Standard (1 of 2)

| **Name** | **H4B2A_X-2Ar0** | **H4B2A_X-2Ar1** | **H4B2A_X-2Ar2** |
|---|---|---|---|
| *Plan* | Hu Honua in, Screen, No DR (Geo, Wind, PV, Wave) | Hu Honua in, Screen, No DR (Geo, Wind, PV, Wave) | Hu Honua in, Screen, No DR (Geo, Wind, PV, Wave, Puna) |
| *Resources Available* | 1 MW PV (HP03) available 2015<br>10MW wind (HW04) available 2017<br>25MW geo (HG01) available 2017<br>25MW geo (HG02) available 2020<br>50 MW trough PV (HP04) available 2020<br>15MW ocean wave (HV02) available 2020 | 1 MW PV (HP03) available 2015<br>10MW wind (HW04) available 2017<br>25MW geo (HG01) available 2017<br>25MW geo (HG02) available 2020<br>50 MW trough PV (HP04) available 2020<br>15MW ocean wave (HV02) available 2020 | 1 MW PV (HP03) available 2015<br>10MW wind (HW03) available 2017<br>25MW geo (HG01) available 2017<br>Puna Repower (HRP1) available 2018<br>25MW geo (HG02) available 2020<br>50 MW trough PV (HP04) available 2020<br>15MW ocean wave (HV02) available 2020 |
| *Reference* | H4B2A_X-2Ar0.xlxs | H4B2A_X-2Ar1.xlxs | |
| *2014* | | Cycle H5/6, Puna | Cycle H5/6, Puna |
| | 75%+25% PBFA DSM | 75%+25% PBFA DSM | 75%+25% PBFA DSM |
| | Hu Honua (21.5MW) | Hu Honua (21.5MW) | Hu Honua (21.5MW) |
| *2015* | Deactivate Shipman 3 (-6.8 MW) | Deactivate Shipman 3 (-6.8 MW) | Deactivate Shipman 3 (-6.8 MW) |
| | Deactivate Shipman 4 (-6.7 MW) | Deactivate Shipman 4 (-6.7 MW) | Deactivate Shipman 4 (-6.7 MW) |
| | Add 5MW PV (HP03x5) | Add 5MW PV (HP03x5) | Add 5MW PV (HP03x5) |
| *2016* | | | |
| *2017* | Add 10MW wind (HW04x1) | Add 25MW geothermal (HG01x1) | Add 25MW geothermal (HG01x1) |
| | | Add 10MW wind (HW04x1) | Add 10MW wind (HW03x1) |
| *2018* | | | |
| *2019* | | | |
| *2020* | Add 5MW PV (HP03x5) | Add 5MW PV (HP03x5) | Add 5MW PV (HP03x5) |
| | Add 10MW wind (HW04x1) | Add 10MW wind (HW04x1) | Add 10MW wind (HW03x1) |
| *2021* | Add 5MW PV (HP03x5) | Add 5MW PV (HP03x5) | Add 10MW wind (HW03x1) |
| *2022* | Fuel Switch to LSIFO (Hill 5/6, Puna 1) | Fuel Switch to LSIFO (Hill 5/6, Puna 1) | Fuel Switch to LSIFO (Hill 5/6, Puna 1) |
| *2023* | | | |
| *2024* | Add 5MW PV (HP03x5) | Add 5MW PV (HP03x5) | Add 5MW PV (HP03x5) |
| *2025* | | | |
| *2026* | | | |
| *2027* | | | |
| *2028* | Add 5MW PV (HP03x5) | Add 5MW PV (HP03x5) | Add 5MW PV (HP03x5) |
| *2029* | Add 5MW PV (HP03x5) | Add 5MW PV (HP03x5) | Add 5MW PV (HP03x5) |
| *2030* | Add 10MW wind (HW04x1) | Add 10MW wind (HW04x1) | Add 10MW wind (HW03x1) |
| *2031* | Add 10MW wind (HW04x1) | Add 10MW wind (HW04x1) | Add 10MW wind (HW03x1) |
| *2032* | | | |

| Name | H4B2A_X-2Ar0 | H4B2A_X-2Ar1 | H4B2A_X-2Ar2 |
|---|---|---|---|
| *2033* | Add 25MW geothermal (HG01x1) | Add 25MW geothermal (HG01x1) | Add 25MW geothermal (HG02x1) |
| | | Add 5MW PV (HP03x5) | Add 5MW PV (HP03x5) |
| *Planning Period Total Cost* | 4, 232, 406 | 4, 004, 242 | 4, 057, 557 |
| *Study Period Total Cost* | 6, 140, 019 | 5, 668, 898 | 5, 769, 374 |
| *Planning Rank* | 5 | 2 | 4 |
| *Study Rank* | 5 | 2 | 4 |

Table O-97. HELCO 100% Renewable Portfolio Standard (2 of 2)

| **Name** | **H4B2A_X-2Ar3** | **H4B2A_X-2Ar4** |
|---|---|---|
| *Plan* | Meet RPS by Scenario<br>Year 2020: 25%<br>Year 2030: 40% | Hu Honua in, Screen, No DR (Geo, Wind, PV, Wave, Puna) |
| *Notes* | Add geothermal, wind, PV, ocean wave, solar thermal, and Puna repowering resources as needed to meet scenario RPS<br>Cycle Hill 5, Hill 6, and Puna | |
| *Resources Available* | 1 MW PV (HP03) available 2015<br>10MW wind (HW04) available 2017<br>25MW geo (HG01) available 2017<br>Puna repower (HRP1) available 2018<br>25MW geo (HG02) available 2020<br>50 MW trough PV (HP04) available 2020<br>15MW ocean wave (HV02) available 2020 | 1 MW PV (HP03) available 2015<br>10MW wind (HW03) available 2017<br>25MW geo (HG01) available 2017<br>Puna repower (HRP1) available 2018<br>25MW geo (HG02) available 2020<br>50 MW trough PV (HP04) available 2020<br>15MW ocean wave (HV02) available 2020 |
| *2014* | Cycle H5/6, Puna | Cycle H5/6, Puna |
| | 75%+25% PBFA DSM | 75%+25% PBFA DSM |
| | Hu Honua (21.5MW) | Hu Honua (21.5MW) |
| *2015* | Deactivate Shipman 3 (-6.8 MW) | Deactivate Shipman 3 (-6.8 MW) |
| | Deactivate Shipman 4 (-6.7 MW) | Deactivate Shipman 4 (-6.7 MW) |
| | Add 5MW PV (HP03x5) | Add 5MW PV (HP03x5) |
| *2016* | | |
| *2017* | Add 25MW geothermal (HG01x1) | Add 25MW geothermal (HG01x1) |
| | Add 10MW wind (HW04x1) | Add 10MW wind (HW03x1) |
| *2018* | | |
| *2019* | | |
| *2020* | Add 5MW PV (HP03x5) | Add 5MW PV (HP03x5) |
| | Add 10MW wind (HW04x1) | Add 10MW wind (HW03x1) |
| *2021* | Add 5MW PV (HP03x5) | Add 5MW PV (HP03x5) |
| | Add 10MW wind (HW04x1) | Add 10MW wind (HW03x1) |
| *2022* | Fuel Switch to LSIFO (Hill 5/6, Puna 1) | Fuel Switch to LSIFO (Hill 5/6, Puna 1) |
| | Add 10MW wind (HW04x1) | Add 10MW wind (HW03x1) |
| *2023* | | |
| *2024* | Add 5MW PV (HP03x5) | Add 5MW PV (HP03x5) |
| *2025* | | |
| *2026* | | |
| *2027* | | |
| *2028* | Add 5MW PV (HP03x5) | Add 5MW PV (HP03x5) |

| **Name** | **H4B2A_X-2Ar3** | **H4B2A_X-2Ar4** |
|---|---|---|
| *2029* | Add 5MW PV (HP03x5) | Add 5MW PV (HP03x5) |
| *2030* | | Add 10MW wind (HW03x1) |
| *2031* | | Add 10MW wind (HW03x1) |
| *2032* | | |
| *2033* | Add 25MW geothermal (HG02x1) | Add 25MW geothermal (HG02x1) |
| | Add 5MW PV (HP03x5) | |
| *Planning Period Total Cost* | 3, 959, 051 | 4, 031, 601 |
| *Study Period Total Cost* | 5, 622, 139 | 5, 730, 151 |
| *Planning Rank* | 1 | 3 |
| *Study Rank* | 1 | 3 |

Table O-98. HELCO Environmental Compliance (1 of 2)

| **Name** | **Self Generation** | | **H4B2A_X-2Ar3** | **H4B2A_X-4Ar1** | **H4B2A_X-4Ar2b** |
|---|---|---|---|---|---|
| *Plan* | Annual | Cumulative | Year 2022 Fuel Switch to LSIFO | Year 2022 Install Air Quality Controls | Retire Existing Replace with Conventional Biofuel Units |
| *Notes* | | | Fuel Switch applies to Hill 5, Hill 6, and Puna Steam Cycle H5/6, Puna Steam | Cycle H5/6, Puna Steam | All units except Keahole CC are retired by December 2020 Cycle H5/6, Puna Steam |
| *Resources available* | | | 1 MW PV (HP03) available 2015<br>10MW wind (HW02) available 2017<br>25MW geo (HG01) available 2017<br>Puna Repower (HRP1) available 2018<br>25MW geo (HG02) available 2020<br>50 MW trough PV (HP04) available 2020<br>15MW ocean wave (HV02) available 2020 | Puna Repower (HRP1) available 2018 | 21MW CT (HS05) available 2021<br>63MW DTCC (HC05/HC06) - Avail 2021 |
| *2014* | 4MW | 14MW | 75%+25% PBFA DSM | 75%+25% PBFA DSM | 75%+25% PBFA DSM |
| | | | Hu Honua (21.5MW) | Hu Honua (21.5MW) | Hu Honua (21.5MW) |
| *2015* | 4MW | 18MW | Deactivate Shipman 3 (-6.8 MW) | Retire Shipman 3 (-6.8 MW) | Retire Shipman 3 (-6.8 MW) |
| | | | Deactivate Shipman 4 (-6.7 MW) | Retire Shipman 4 (-6.7 MW) | Retire Shipman 4 (-6.7 MW) |
| | | | Add 5MW PV (HP03x5) | Add 5MW PV (HP03x5) | Add 5MW PV (HP03x5) |
| *2016* | 4MW | 22MW | | | |
| *2017* | 4MW | 25MW | Add 25MW geothermal (HG01x1) | Add 25MW geothermal (HG01x1) | |
| | | | Add 10MW wind (HW04x1) | Add 10MW wind (HW04x1) | Add 10MW wind (HW04x1) |
| *2018* | 3MW | 28MW | | | |
| *2019* | 3MW | 32MW | | | Retire Hill 5 (-13.5 MW) |

**Appendix O: Resource Plan Sheets**

HELCO Resource Plans

| Name | Self Generation | | H4B2A_X-2Ar3 | H4B2A_X-4Ar1 | H4B2A_X-4Ar2b |
|---|---|---|---|---|---|
| *2020* | 3MW | 35MW | Add 10MW wind (HW04x1) | Add 10MW wind (HW04x1) | Add 10MW wind (HW04x1) |
| | | | | | Retire Hill 6 (-20 MW)<br>Retire Puna Steam (-15.5 MW)<br>Retire KanoelD 11, 15-17 (- 9.5 MW)<br>Retire WaimeaD 12-14 (- 7.5 MW)<br>Retire KeaholD 21-23 (- 7.5 MW)<br>Retire Kanoe CT1 (- 10.25 MW)<br>Retire Keaho CT2 (- 13.80 MW)<br>Retire Puna CT3 (- 19 MW)<br>Retire PanaewD, OuliD, PunaluD, KapuaD (- 4 MW) |
| | | | Add 5MW PV (HP03x5) | Add 5MW PV (HP03x5) | Add 5MW PV (HP03x5) |
| *2021* | 3MW | 38MW | Add 5MW PV (HP03x5) | Add 5MW PV (HP03x5) | Add 5MW PV (HP03x5) |
| | | | Add 10MW wind (HW04x1) | Add 10MW wind (HW04x1) | Add 21MW CT (HS05x1)-Biofuel |
| | | | | | Add 63MW Dual Train CC (HC05x1, HC06x1) |
| *2022* | 3MW | 41MW | Fuel Switch to LSIFO (Hill 5/6, Puna Steam) | AQC for Hill5/6, Puna Steam | |
| | | | Add 10MW wind (HW04x1) | Add 10MW wind (HW04x1) | Add 10MW wind (HW04x1) |
| *2023* | 3MW | 43MW | | | |
| *2024* | 3MW | 46MW | Add 5MW PV (HP03x5) | Add 5MW PV (HP03x5) | Add 5MW PV (HP03x5) |
| *2025* | 3MW | 49MW | | | |
| *2026* | 3MW | 52MW | | | |
| *2027* | 3MW | 55MW | | | |
| *2028* | 3MW | 59MW | Add 5MW PV (HP03x5) | Add 5MW PV (HP03x5) | Add 5MW PV (HP03x5) |
| *2029* | 3MW | 61MW | Add 5MW PV (HP03x5) | Add 5MW PV (HP03x5) | Add 5MW PV (HP03x5) |
| *2030* | 3MW | 64MW | | | |
| *2031* | 3MW | 67MW | | | |
| *2032* | 3MW | 71MW | | | |
| *2033* | 3MW | 73MW | Add 25MW geothermal (HG02x1) | Add 25MW geothermal (HG02x1) | |
| | | | Add 5MW PV (HP03x5) | Add 5MW PV (HP03x5) | Add 5MW PV (HP03x5) |
| *Strategist Planning Period Total Cost* | | | 3, 959, 051 | 3, 958, 532 | 4, 677, 479 |

| Name | Self Generation | | H4B2A_X-2Ar3 | H4B2A_X-4Ar1 | H4B2A_X-4Ar2b |
|---|---|---|---|---|---|
| *Strategist Study Period Total Cost* | | | 5, 622, 139 | 5, 621, 328 | 6, 689, 785 |
| *Planning Period Total Cost* | | | 4, 665, 916 | 4, 835, 576 | 5, 385, 351 |
| *Study Period Total Cost* | | | 6, 329, 003 | 6, 493, 106 | 7, 397, 656 |
| *Planning Rank* | | | 2 | 3 | 5 |
| *Study Rank* | | | 2 | 3 | 5 |

Table O-99. HELCO Environmental Compliance (2 of 2)

| **Name** | **Self Generation** | | **H4B2A_X-4Ar3b** | **H4B2A_X-4Ar4** |
|---|---|---|---|---|
| *Plan* | Annual | Cumulative | Retire Existing Replace with Geothermal | Year 2022 Fuel Switch to LSIFO, LNG |
| *Notes* | | | All Units except Keahole CC are retired by December 2020<br>Cycle H5/6, Puna Steam | Fuel Switch to LSIFO for Hill 5, Hill 6, and Puna Steam<br>Fuel Switch to LNG for Keahole CC<br>Cycle Hill5-6, Puna Steam |
| *Resources Available* | | | 25MW Geo (HG01) available 2021<br>25MW Geo (HG02) available 2021 | Puna Repower (HRP1) available 2018 |
| *2014* | 4MW | 14MW | 75%+25% PBFA DSM | 75%+25% PBFA DSM |
| | | | Hu Honua (21.5MW) | Hu Honua (21.5MW) |
| *2015* | 4MW | 18MW | Retire Shipman 3 (-6.8 MW) | Retire Shipman 3 (-6.8 MW) |
| | | | Retire Shipman 4 (-6.7 MW) | Retire Shipman 4 (-6.7 MW) |
| | | | Add 5MW PV (HP03x5) | Add 5MW PV (HP03x5) |
| *2016* | 4MW | 22MW | | |
| *2017* | 4MW | 25MW | | Add 25MW Geothermal (HG01x1) |
| | | | Add 10MW wind (HW04x1) | Add 10MW wind (HW04x1) |
| *2018* | 3MW | 28MW | | |
| *2019* | 3MW | 32MW | Retire Hill 5 (-13.5 MW) | |
| *2020* | 3MW | 35MW | Add 10MW wind (HW04x1) | Add 10MW wind (HW04x1) |
| | | | Retire Hill 6 (-20 MW)<br>Retire Puna Steam (-15.5 MW)<br>Retire KanoeID 11, 15-17 (-9.5 MW)<br>Retire WaimeaD 12-14 (-7.5 MW)<br>Retire KeaholD 21-23 (-7.5 MW)<br>Retire Kanoe CT1 (-10.25 MW)<br>Retire Keaho CT2 (-13.80 MW)<br>Retire Puna CT3 (-19 MW)<br>Retire PanaewD, OuliD, PunaluD, KapuaD (- 4 MW) | |
| | | | Add 5MW PV (HP03x5) | Add 5MW PV (HP03x5) |
| *2021* | 3MW | 38MW | Add 5MW PV (HP03x5) | Add 5MW PV (HP03x5) |
| | | | Add 25MW Geothermal (HG01x1) | Add 10MW wind (HW04x1) |
| | | | Add 75MW New Geothermal (HG02x3) | |
| *2022* | 3MW | 41MW | | Fuel Switch to LSIFO (Hill 5/6, Puna Steam)<br>Fuel Switch to LNG (Keahole CC) |
| | | | Add 10MW wind (HW04x1) | Add 10MW wind (HW04x1) |
| *2023* | 3MW | 43MW | | |
| *2024* | 3MW | 46MW | Add 5MW PV (HP03x5) | Add 5MW PV (HP03x5) |
| *2025* | 3MW | 49MW | | |

| Name | Self Generation | | H4B2A_X-4Ar3b | H4B2A_X-4Ar4 |
|---|---|---|---|---|
| *2026* | 3MW | 52MW | | |
| *2027* | 3MW | 55MW | | |
| *2028* | 3MW | 59MW | Add 5MW PV (HP03x5) | Add 5MW PV (HP03x5) |
| *2029* | 3MW | 61MW | Add 5MW PV (HP03x5) | Add 5MW PV (HP03x5) |
| *2030* | 3MW | 64MW | | |
| *2031* | 3MW | 67MW | | |
| *2032* | 3MW | 71MW | | |
| *2033* | 3MW | 73MW | | Add 25MW Geothermal (HG02x1) |
| | | | Add 5MW PV (HP03x5) | Add 5MW PV (HP03x5) |
| *Strategist Planning Period Total Cost* | | | 4, 344, 435 | 3, 921, 988 |
| *Strategist Study Period Total Cost* | | | 6, 097, 962 | 5, 550, 993 |
| *Planning Period Total Cost* | | | 5, 052, 306 | 4, 636, 276 |
| *Study Period Total Cost* | | | 6, 805, 833 | 6, 264, 173 |
| *Planning Rank* | | | 4 | 1 |
| *Study Rank* | | | 4 | 1 |

Table O-100. HELCO 0% Renewable Portfolio Standard

| Name | H4B2A_X-2Ar3 | H4B2A_X-2Ar3-noRPS |
|---|---|---|
| *Plan* | Hu Honua in, Screen, No DR (Geo, Wind, PV, Wave), Cycle H5/6, Puna | Hu Honua in, Screen, No DR (Geo, Wind, PV, Wave), no RPS<br>Cycle H5/6, Puna |
| *Notes* | Includes fuel switch to LSIFO (Hill5/6, Puna Steam) in 2022 | Includes fuel switch to LSIFO (Hill5/6, Puna Steam) in 2022 |
| *Resources Available* | 1 MW PV (HP03) available 2015<br>10MW wind (HW02) available 2017<br>25MW Geo (HG01) available 2017<br>Puna repower (HRP1) available 2018<br>25MW Geo (HG02) available 2020<br>50 MW trough PV (HP04) available 2020<br>15MW ocean wave (HV02) available 2020 | 1 MW PV (HP03) available 2015<br>10MW wind (HW02), 25MW geo (HG01), & 25MW biomass (HT01) available 2017<br>Puna Repower (HRP1) available 2018<br>25MW geo (HG02) available 2020<br>50 MW trough PV (HP04) available 2020<br>15MW ocean wave (HV02) available 2020 |
| *2014* | 75%+25% PBFA DSM | 75%+25% PBFA DSM |
| | Hu Honua (21.5MW) | Hu Honua (21.5MW) |
| *2015* | Deactivate Shipman 3 (-6.8 MW) | Deactivate Shipman 3 (-6.8 MW) |
| | Deactivate Shipman 4 (-6.7 MW) | Deactivate Shipman 4 (-6.7 MW) |
| | Add 5MW PV (HP03x5) | Add 5MW PV (HP03x5) |
| *2016* | | |
| *2017* | Add 25MW geothermal (HG01x1) | Add 25MW geothermal (HG01x1) |
| | Add 10MW wind (HW04x1) | Add 10MW wind (HW04x1) |
| *2018* | | |
| *2019* | | |
| *2020* | Add 5MW PV (HP03x5) | Add 5MW PV (HP03x5) |
| | Add 10MW wind (HW04x1) | Add 10MW wind (HW04x1) |
| *2021* | Add 5MW PV (HP03x5) | Add 1MW PV (HP03x5) |
| | Add 10MW wind (HW04x1) | Add 10MW wind (HW04x1) |
| *2022* | Fuel Switch to LSIFO (Hill 5/6, Puna Steam) | Fuel Switch to LSIFO (Hill 5/6, Puna Steam) |
| | Add 10MW wind (HW04x1) | Add 10MW wind (HW04x1) |
| *2023* | | |
| *2024* | Add 5MW PV (HP03x5) | Add 5MW PV (HP03x5) |
| *2025* | | |
| *2026* | | |
| *2027* | | |
| *2028* | Add 5MW PV (HP03x5) | Add 5MW PV (HP03x5) |
| *2029* | Add 5MW PV (HP03x5) | Add 5MW PV (HP03x5) |
| *2030* | | |
| *2031* | | |

| Name | H4B2A_X-2Ar3 | H4B2A_X-2Ar3-noRPS |
|---|---|---|
| *2032* | | |
| *2033* | Add 25MW geothermal (HG02x1) | Add 25MW geothermal (HG02x1) |
| | Add 5MW PV (HP03x5) | Add 5MW PV (HP03x5) |
| *Planning Period Total Cost* | 3, 959, 051 | 3, 959, 051 |
| *Study Period Total Cost* | 5, 622, 139 | 5, 622, 139 |
| *Planning Rank* | 2 | 1 |
| *Study Rank* | 1 | 1 |

Table O-101. HELCO 100% Renewable Energy

| **Name** | **H4B2a_X-4Ar5** | **H4B2A_X-2Ar6** |
|---|---|---|
| *Plan* | Hu Honua in, Screen, No DR (Geo, Wind, PV, Wave) | Hu Honua in, Puna Repower in 2020, Screen, No DR (Geo, Wind, PV, Wave) |
| *Notes* | Fuel switch existing to biofuel in 2020 | Fuel switch existing to biofuel in 2020 |
| *Resources Available* | All resources were fixed | All resources were fixed |
| *2014* | Cycle H5/6, Puna | Cycle H5/6, Puna |
| | 75%+25% PBFA DSM | 75%+25% PBFA DSM |
| | Hu Honua (21.5MW) | Hu Honua (21.5MW) |
| *2015* | Deactivate Shipman 3 (-6.8 MW) | Deactivate Shipman 3 (-6.8 MW) |
| | Deactivate Shipman 4 (-6.7 MW) | Deactivate Shipman 4 (-6.7 MW) |
| | Add 5MW PV (HP03x5) | Add 5MW PV (HP03x5) |
| *2016* | | |
| *2017* | Add 25MW geothermal (HG01x1) | Add 25MW geothermal (HG01x1) |
| | Add 10MW wind (HW04x1) | Add 10MW wind (HW04x1) |
| *2018* | | |
| *2019* | | |
| *2020* | Add 10MW wind (HW04x1) | Add 10MW wind (HW04x1) |
| | Add 5MW PV (HP03x5) | Add 5MW PV (HP03x5) |
| | Convert all existing units to biofuel<br>Hill 5–6<br>Puna Steam<br>KanoelD 11, 15–17<br>WaimeaD 12–14<br>KeaholD 21–23<br>Kanoe CT1<br>Keaho CT2<br>Puna CT3<br>Keaho CC1, CC2<br>PanaewD, OuliD, PunaluD, KapuaD | Convert all existing units to biofuel<br>Hill 5–6<br>KanoelD 11, 15–17<br>WaimeaD 12–14<br>KeaholD 21–23<br>Kanoe CT1<br>Keaho CT2<br>Puna CT3<br>Keaho CC1, CC2<br>PanaewD, OuliD, PunaluD, KapuaD |
| *2021* | | Convert Puna Steam to biomass (HRP1x1) |
| | Add 5MW PV (HP03x5) | Add 5MW PV (HP03x5) |
| | Add 10MW wind (HW04x1) | Add 10MW wind (HW04x1) |
| *2022* | Add 10MW wind (HW04x1) | Add 10MW wind (HW04x1) |
| *2023* | | |
| *2024* | Add 5MW PV (HP03x5) | Add 5MW PV (HP03x5) |
| *2025* | | |
| *2026* | | |
| *2027* | | |

| **Name** | **H4B2a_X-4Ar5** | **H4B2A_X-2Ar6** |
|---|---|---|
| *2028* | Add 5MW PV (HP03x5) | Add 5MW PV (HP03x5) |
| *2029* | Add 5MW PV (HP03x5) | Add 5MW PV (HP03x5) |
| *2030* | | |
| *2031* | | |
| *2032* | | |
| *2033* | Add 25MW geothermal (HG02x1) | Add 25MW geothermal (HG02x1) |
| | Add 5MW PV (HP03x5) | Add 5MW PV (HP03x5) |
| *Planning Period Total Cost* | 4, 059, 984 | 4, 079, 897 |
| *Study Period Total Cost* | 5, 680, 958 | 5, 714, 612 |
| *Planning Rank* | 1 | 2 |
| *Study Rank* | 1 | 2 |

# MECO Resource Plans

## Blazing a Bold Frontier

Table O-102. MECO Firm Timing (1 of 2)

| **Strategy** | **M1_2b_X-1r3** | **M1_2a_N-1r3** | **M1_2a_X-1r3** |
|---|---|---|---|
| *Plan* | HC&S contract continues | HC&S contract terminated 2014 | HC&S contract terminated 2014 |
| *Notes* | Unit Timing Rule 1<br>17MW ICE, 5MW ICE, LM2500, Geo, WTE, Biomass | Unit Timing Rule 1<br>17MW ICE, 5MW ICE, LM2500, Geo, WTE, Biomass | Unit Timing Rule 1<br>17MW ICE, 5MW ICE, LM2500, Geo, WTE, Biomass |
| *DR & DSM Assumptions* | 110% of Base EEPS<br>Fast DR Only | 110% of Base EEPS<br>All DR - CIDLC Exp, RDLC Exp, Fast DR | 110% of Base EEPS<br>Fast DR Only |
| *2011-2013* | Kaheawa Wind II (21 MW) | Kaheawa Wind II (21 MW) | Kaheawa Wind II (21 MW) |
| | Auwahi (21 MW) | Auwahi (21 MW) | Auwahi (21 MW) |
| *2014* | | | |
| *2015* | | | |
| *2016* | | | |
| *2017* | | | |
| *2018* | | | |
| *2019* | | | |
| *2020* | | | |
| *2021* | | | |
| *2022* | | | |
| *2023* | | | |
| *2024* | | | |
| *2025* | | | |
| *2026* | | | |
| *2027* | | | |
| *2028* | | | |
| *2029* | | | |
| *2030* | | | |
| *2031* | | | |
| *2032* | | | |
| *2033* | | | |

| **Strategy** | **M1_2b_X-1r3** | **M1_2a_N-1r3** | **M1_2a_X-1r3** |
|---|---|---|---|
| *Planning Total Cost* | 5, 848, 294.50 | 6, 022, 616.00 | 5, 995, 727.50 |
| *Study Total Cost* | 8, 130, 334.50 | 8, 349, 251.50 | 8, 316, 523.00 |
| *Planning Rank* | 1 | 2 | 2 |
| *Study Rank* | 1 | 2 | 2 |

Table O-103. MECO Firm Timing (2 of 2)

| **Strategy** | **M1_2a_X-1r3** | **M1_2a_X-1r3** | **M1_2b_N-1r3** |
|---|---|---|---|
| Plan | HC&S contract terminated 2014 | HC&S contract terminated 2014 | HC&S contract continues |
| Notes | Unit Timing Rule 1<br>17MW ICE, 5MW ICE, LM2500, Geo, WTE, Biomass | Unit Timing Rule 1<br>17MW ICE, 5MW ICE, LM2500, Geo, WTE, Biomass | Unit Timing Rule 1<br>17MW ICE, 5MW ICE, LM2500, Geo, WTE, Biomass |
| DR & DSM Assumptions | 110% of Base EEPS<br>Fast DR Only | 110% of Base EEPS<br>Fast DR Only | 110% of Base EEPS<br>All DR - CIDLC Exp, RDLC Exp, Fast DR |
| 2011-2013 | Kaheawa Wind II (21 MW)<br>Auwahi (21 MW) | Kaheawa Wind II (21 MW)<br>Auwahi (21 MW) | Kaheawa Wind II (21 MW)<br>Auwahi (21 MW) |
| 2014 | | | |
| 2015 | | | |
| 2016 | | | |
| 2017 | | | |
| 2018 | | | |
| 2019 | | | |
| 2020 | | | |
| 2021 | | | |
| 2022 | | | |
| 2023 | | | |
| 2024 | | | |
| 2025 | | | |
| 2026 | | | |
| 2027 | | | |
| 2028 | | | |
| 2029 | | | |
| 2030 | | | |
| 2031 | | | |
| 2032 | | | |
| 2033 | (1) 5 MW ICE - Biofuel [MS14] | (1) 8 MW WTE [MT01] | |
| Planning Total Cost | 5, 998, 245.50 | 6, 002, 272.50 | 5, 875, 152.50 |
| Study Total Cost | 8, 344, 327.50 | 8, 398, 879.00 | 8, 163, 032.00 |
| Planning Rank | 3 | 4 | 1 |
| Study Rank | 3 | 4 | 1 |

Table O-104. MECO Lanai Plans

| | Preferred Plan | Contingency | Parallel | Secondary |
|---|---|---|---|---|
| **Strategy** | **ML-1** | **ML-2** | **ML-3** | **ML-4** |
| *Plan* | LNG Short-term, Biomass | LNG Long-term, Biomass | 100% renewable, biomass, biodiesel | 100% renewable, PV, battery, biodiesel |
| *Resources Available* | 600 kW Wind - Avail 2018<br>750 kW Wave - Avail 2019<br>1.0 MW PV - Avail 2018<br>1.0 MW Biomass - Avail 2018 | 600 kW Wind - Avail 2018<br>750 kW Wave - Avail 2019<br>1.0 MW PV - Avail 2018<br>1.0 MW Biomass - Avail 2018 | 600 kW Wind - Avail 2018<br>750 kW Wave - Avail 2019<br>1.0 MW PV - Avail 2018<br>1.0 MW Biomass - Avail 2018 | 600 kW Wind - Avail 2018<br>750 kW Wave - Avail 2019<br>1.0 MW PV - Avail 2018<br>1.0 MW Biomass - Avail 2018 |
| *2014* | | | Fuel Switch to Biodiesel | Fuel Switch to Biodiesel |
| *2015* | | | | |
| *2016* | | | | |
| *2017* | | | | |
| *2018* | Fuel Switch to 50% LNG<br>Add 1 MW Biomass | Add 1 MW Biomass | Add 1 MW Biomass | Battery Storage<br>Add 2 MW PV |
| *2019* | | | | |
| *2020* | | | | |
| *2021* | | Fuel Switch to 50% LNG | | |
| *2022* | | | | |
| *2023* | | | | |
| *2024* | | | | |
| *2025* | | | | |
| *2026* | | | | |
| *2027* | | | | |
| *2028* | | | | |
| *2029* | | | | |
| *2030* | | | | |
| *2031* | | | | |
| *2032* | | | | |
| *2033* | | | | |
| *PV Total Cost* | $164, 620 | $166, 235 | $107, 155 | $107, 707 |
| *Planning Rank* | 3 | 4 | 1 | 2 |

Table O-105. MECO Molokai Plans

| | Preferred Plan | Contingency | Parallel | Secondary Plan |
|---|---|---|---|---|
| **Strategy** | **MM-1** | **MM-2** | **MM-3** | **MM-4** |
| *Plan* | LNG Short-term, Biomass | LNG Long-term, Biomass | 100% renewable, biomass, biodiesel | 100% renewable, PV, battery, biodiesel |
| *Resources Available* | 600 kW Wind - Avail 2018<br>750 kW Wave - Avail 2019<br>1.0 MW PV - Avail 2018<br>1.0 MW Biomass - Avail 2018 | 600 kW Wind - Avail 2018<br>750 kW Wave - Avail 2019<br>1.0 MW PV - Avail 2018<br>1.0 MW Biomass - Avail 2018 | 600 kW Wind - Avail 2018<br>750 kW Wave - Avail 2019<br>1.0 MW PV - Avail 2018<br>1.0 MW Biomass - Avail 2018 | 600 kW Wind - Avail 2018<br>750 kW Wave - Avail 2019<br>1.0 MW PV - Avail 2018<br>1.0 MW Biomass - Avail 2018 |
| *2014* | | | Fuel Switch to Biodiesel | Fuel Switch to Biodiesel |
| *2015* | | | | |
| *2016* | | | | |
| *2017* | | | | |
| *2018* | Fuel Switch to 50% LNG | | | Battery Storage |
| | Add 1 MW Biomass | Add 1 MW Biomass | Add 1 MW Biomass | Add 1 MW PV |
| *2019* | | | | |
| *2020* | | | | |
| *2021* | | Fuel Switch to 50% LNG | | |
| *2022* | | | | |
| *2023* | | | | |
| *2024* | | | | |
| *2025* | | | | |
| *2026* | | | | |
| *2027* | | | | |
| *2028* | | | | |
| *2029* | | | | |
| *2030* | | | | |
| *2031* | | | | |
| *2032* | | | | |
| *2033* | | | | |
| *PV Total Cost* | $159, 858 | $164, 439 | $105, 477 | $108, 157 |
| *Planning Rank* | 3 | 4 | 1 | 2 |

## Stuck in the Middle

Table O-106. MECO Firm Timing (1 of 4)

| **Name** | **M2_2__N-1r0** | **M2_2__N-1r1** | **M2_2__N-1r2** |
|---|---|---|---|
| *Plan* | SitM Timing SC | SitM Timing 17 MW ICE | SitM Timing 5 MW ICE |
| *Notes* | 21 MW LM2500 Timing on Rule 1 | 17 MW ICE Timing on Rule 1 | 5 MW ICE Timing on Rule 1 |
| *Resources Available* | | | |
| *DR & DSM Assumptions* | 75% of Base EEPS<br>All DR - CIDLC Exp, RDLC Exp, Fast DR | 75% of Base EEPS<br>All DR - CIDLC Exp, RDLC Exp, Fast DR | 75% of Base EEPS<br>All DR - CIDLC Exp, RDLC Exp, Fast DR |
| *2014* | | | |
| *2015* | | | |
| *2016* | | | |
| *2017* | | | |
| *2018* | | | |
| *2019* | | | |
| *2020* | | | |
| *2021* | | | |
| *2022* | | | |
| *2023* | | | |
| *2024* | | | |
| *2025* | | | |
| *2026* | | | |
| *2027* | | | |
| *2028* | | | |
| *2029* | (1) 21 MW SC LM2500 - Biofuel [MS05] | (1) 17 MW ICE - Biofuel [MS01] | (1) 5 MW ICE - Biofuel [MS14] |
| *2030* | | | |
| *2031* | | | |
| *2032* | | | |
| *2033* | | | |
| *Planning Total Cost* | 4, 215, 328.50 | 4, 209, 279.50 | 4, 193, 926.00 |
| *Study Total Cost* | 6, 431, 150.50 | 6, 396, 131.00 | 6, 379, 619.50 |
| *Planning Rank* | 10 | 8 | 3 |
| *Study Rank* | 12 | 11 | 9 |

Table O-107. MECO Firm Timing (2 of 4)

| **Name** | **M2_2__N-1r3** | **M2_2__N-1r4** | **M2_2__N-1r5** |
|---|---|---|---|
| *Plan* | SitM Timing Other Firm | SitM Timing All W Geo | SitM Timing All No Geo |
| *Notes* | Timing for Banagrass, WTE, New Geo on Rule 1 | All firm resources from timing Add on Rule 1 | All firm resources from timing excluding geothermal, Add on Rule 1 |
| *Resources Available* | | | |
| *DR & DSM Assumptions* | 75% of Base EEPS<br>All DR - CIDLC Exp, RDLC Exp, Fast DR | 75% of Base EEPS<br>All DR - CIDLC Exp, RDLC Exp, Fast DR | 75% of Base EEPS<br>All DR - CIDLC Exp, RDLC Exp, Fast DR |
| *2014* | | | |
| *2015* | | | |
| *2016* | | | |
| *2017* | | | |
| *2018* | | | |
| *2019* | | | |
| *2020* | | | |
| *2021* | | | |
| *2022* | | | |
| *2023* | | | |
| *2024* | | | |
| *2025* | | | |
| *2026* | | | |
| *2027* | | | |
| *2028* | | | |
| *2029* | (1) 25 MW New Geo [MG02] | (1) 25 MW New Geo [MG02] | (1) 25 MW Banagrass [MA01] |
| *2030* | | | |
| *2031* | | | |
| *2032* | | | |
| *2033* | | | |
| *Planning Total Cost* | 4, 205, 737.00 | 4, 205, 737.00 | 4, 200, 278.50 |
| *Study Total Cost* | 6, 320, 432.50 | 6, 320, 432.50 | 6, 329, 030.00 |
| *Planning Rank* | 6 | 6 | 4 |
| *Study Rank* | 2 | 2 | 5 |

Table O-108. MECO Firm Timing (3 of 4)

| **Name** | **M2_2__X-1r0** | **M2_2__X-1r1** | **M2_2__X-1r2** |
|---|---|---|---|
| *Plan* | SitM Timing 5 MW ICE No DR | SitM Timing 17 MW ICE No DR | SitM Timing All W Geo No DR |
| *Notes* | 5 MW ICE Timing on Rule 1, No DR except Fast DR | 17 MW ICE Timing on Rule 1, No DR except Fast DR | All firm resources from timing<br>No DR except Fast DR, Add on Rule 1 |
| *Resources Available* | | | |
| *DR & DSM Assumptions* | 75% of Base EEPS<br>Fast DR Only | 75% of Base EEPS<br>Fast DR Only | 75% of Base EEPS<br>Fast DR Only |
| *2014* | | | |
| *2015* | | | |
| *2016* | | | |
| *2017* | | | |
| *2018* | | | |
| *2019* | | | |
| *2020* | | | |
| *2021* | | | |
| *2022* | | | |
| *2023* | (1) 5 MW ICE - Biofuel [MS14] | (1) 17 MW ICE - Biofuel [MS01] | (1) 25 MW New Geo [MG02] |
| *2024* | | | |
| *2025* | | | |
| *2026* | | | |
| *2027* | (1) 5 MW ICE - Biofuel [MS14] | | |
| *2028* | | | |
| *2029* | | | |
| *2030* | (1) 5 MW ICE - Biofuel [MS14] | | |
| *2031* | | | |
| *2032* | | | |
| *2033* | | | |
| *Planning Total Cost* | 4, 217, 691.00 | 4, 219, 082.50 | 4, 215, 532.50 |
| *Study Total Cost* | 6, 438, 427.00 | 6, 394, 514.50 | 6, 313, 411.50 |
| *Planning Rank* | 12 | 13 | 11 |
| *Study Rank* | 13 | 10 | 1 |

Table O-109. MECO Firm Timing (4 of 4)

| **Name** | **M2_2__X-1r3** | **M2_2b_N-1r0** | **M2_2b_X-1r0** | **M2_2b_X-1r1** |
|---|---|---|---|---|
| *Plan* | SitM Timing All No Geo No DR | SitM Timing All W Geo HC&S Extd | SitM Timing All W Geo No DR | SitM Timing All W Geo No DR |
| *Notes* | All firm resources from timing excluding geothermal, No DR except Fast DR, Add on Rule 1 | All firm resources from timing<br>Add on Rule 1 and HC&S Extd. | All firm resources from timing<br>No DR except Fast DR, Add on Rule 1, HC&S Extd. | Retest All firm resources from timing<br>No DR except Fast DR, Add on Rule 1, HC&S Extd. |
| *Resources Available* | | | | |
| *DR & DSM Assumptions* | 75% of Base EEPS<br>Fast DR Only | 75% of Base EEPS<br>All DR - CIDLC Exp, RDLC Exp, Fast DR | 75% of Base EEPS<br>Fast DR Only | 75% of Base EEPS<br>Fast DR Only |
| *2014* | | | | |
| *2015* | | | | |
| *2016* | | | | |
| *2017* | | | | |
| *2018* | | | | |
| *2019* | | | | |
| *2020* | | | | |
| *2021* | | | | |
| *2022* | | | | |
| *2023* | (1) 25 MW Banagrass [MA01] | | | |
| *2024* | | | | |
| *2025* | | | | |
| *2026* | | | | |
| *2027* | | | | |
| *2028* | | | | |
| *2029* | | | | |
| *2030* | | | | |
| *2031* | | | | |
| *2032* | | | | |
| *2033* | | | | |
| *Planning Total Cost* | 4, 211, 663.50 | 4, 202, 488.50 | 4, 175, 646.20 | 4, 175, 646.20 |
| *Study Total Cost* | 6, 328, 911.50 | 6, 364, 362.00 | 6, 331, 684.00 | 6, 331, 684.00 |
| *Planning Rank* | 9 | 5 | 1 | 1 |
| *Study Rank* | 4 | 8 | 6 | 6 |

Table O-110. MECO As-Available Screening (1 of 3)

| **Name** | **M2_2__N-2r12** | **M2_2__N-2r13** | **M2_2__N-2r14** |
|---|---|---|---|
| *Plan* | SitM Screen Fix Geo in 2029 | SitM Screen Fix 5 MW ICE in 2029 | SitM Screen Fix 5 MW ICE in 2029 |
| *Notes* | New Geo (25 MW) 2029 fixed, allow limited Wind, PV, Wave **(OVER Curtailed)** | New Geo (25 MW) 2029 fixed, allow limited Wind, PV, Wave (Curtailed OK) | New ICE (5 MW) 2029 fixed, allow limited Wind, PV, Wave (Curtailed OK) |
| *Resources Available* | | | |
| *DR & DSM Assumptions* | 75% of Base EEPS<br>All DR - CIDLC Exp, RDLC Exp, Fast DR | 75% of Base EEPS<br>All DR - CIDLC Exp, RDLC Exp, Fast DR | 75% of Base EEPS<br>All DR - CIDLC Exp, RDLC Exp, Fast DR |
| *2014* | | | |
| *2015* | 3x Wind (10 MW) | 3x Wind (10 MW) | 3x Wind (10 MW) |
| *2016* | 3x Wind (10 MW) | | 3x Wind (10 MW) |
| *2017* | 3x Wind (10 MW) | | 3x Wind (10 MW) |
| *2018* | | | |
| *2019* | | | |
| *2020* | | | |
| *2021* | | | |
| *2022* | | | |
| *2023* | | | |
| *2024* | | | |
| *2025* | | | |
| *2026* | | | |
| *2027* | | | |
| *2028* | | | |
| *2029* | Geothermal (25 MW) | Geothermal (25 MW) | ICE Biofueled (5 MW) |
| *2030* | | | 5x PV (1 MW) |
| *2031* | | | |
| *2032* | | 1x Wind (10 MW) | |
| *2033* | | 1x Wind (10 MW) | |
| *Planning Total Cost* | 4, 021, 085.80 | 4, 141, 788.50 | 3, 972, 732.50 |
| *Study Total Cost* | 6, 037, 028.50 | 6, 199, 832.50 | 5, 931, 363.50 |
| *Planning Rank* | 4 | 5 | 1 |
| *Study Rank* | 4 | 6 | 2 |

Table O-111. MECO As-Available Screening (2 of 3)

| **Name** | **M2_2__N-2r15** | **M2_2__X-2r11** | **M2_2__X-2r12** |
|---|---|---|---|
| *Plan* | SitM Screen Fix 5 MW ICE in 2029 | StiM Screen allow 5 MW ICE | StiM Screen allow Geo |
| *Notes* | New ICE (5 MW) 2029 fixed, allow limited Wind, PV, Wave (Curtailed OK) | Allow new ICEs (5 MW), allow limited Wind, PV, Wave (Curtailed OK) | Allow new Geo (25 MW), allow limited Wind, PV, Wave (Curtailed OK) |
| *Resources Available* | | | |
| *DR & DSM Assumptions* | 75% of Base EEPS All DR - CIDLC Exp, RDLC Exp, Fast DR | 75% of Base EEPS Fast DR Only | 75% of Base EEPS Fast DR Only |
| *2014* | | | |
| *2015* | 3x Wind (10 MW) | 3x Wind (10 MW) | 3x Wind (10 MW) |
| *2016* | 3x Wind (10 MW) | 3x Wind (10 MW) | |
| *2017* | 3x Wind (10 MW) | 3x Wind (10 MW) | |
| *2018* | | | |
| *2019* | | | |
| *2020* | | | |
| *2021* | | | |
| *2022* | | | |
| *2023* | | ICE Biofueled (5 MW) | Geothermal (25 MW) |
| *2024* | | | |
| *2025* | | | |
| *2026* | | | |
| *2027* | | ICE Biofueled (5 MW) | |
| *2028* | | | |
| *2029* | ICE Biofueled (5 MW) | | |
| *2030* | 5x PV (1 MW) | ICE Biofueled (5 MW) | |
| | | 5x PV (1 MW) | |
| *2031* | | | 1x Wind (10 MW) |
| *2032* | | | |
| *2033* | 5x PV (1 MW) | 5x PV (1 MW) | 1x Wind (10 MW) |
| *Planning Total Cost* | 3, 973, 120.00 | 3, 996, 843.50 | 4, 171, 063.20 |
| *Study Total Cost* | 5, 930, 542.00 | 5, 989, 311.00 | 6, 211, 850.50 |
| *Planning Rank* | 2 | 3 | 7 |
| *Study Rank* | 1 | 3 | 9 |

Table O-112. MECO As-Available Screening (3 of 3)

| **Name** | **M2_2__X-2r13** | **M2_2__N-2r16** | **M2_2__X-2r14** |
|---|---|---|---|
| *Plan* | StiM Screen allow Geo | SitM Screen Fix 5 MW ICE in 2029 | StiM Screen allow Geo |
| *Notes* | Allow new Geo (25 MW), allow limited Wind, PV, Wave (Curtailed OK) | Allow Geo (25 MW) allow limited Wind, PV, Wave (Curtailed OK) | Allow new Geo (25 MW), allow limited Wind, PV, Wave (Curtailed OK) |
| *Resources Available* | | | |
| *DR & DSM Assumptions* | 75% of Base EEPS<br>Fast DR Only | 75% of Base EEPS<br>All DR - CIDLC Exp, RDLC Exp, Fast DR | 75% of Base EEPS<br>Fast DR Only |
| *2014* | | | |
| *2015* | 3x Wind (10 MW) | 3x Wind (10 MW) | 3x Wind (10 MW)<br>5x PV (1 MW) |
| *2016* | | | 5x PV (1 MW) |
| *2017* | | | |
| *2018* | | | |
| *2019* | | | |
| *2020* | | | |
| *2021* | | | |
| *2022* | | 5x PV (1 MW) | |
| *2023* | Geothermal (25 MW) | | Geothermal (25 MW) |
| *2024* | | | |
| *2025* | | | |
| *2026* | | | |
| *2027* | | | |
| *2028* | | | |
| *2029* | | Geothermal (25 MW) | |
| *2030* | | | |
| *2031* | 1x Wind (10 MW) | 1x Wind (10 MW) | 1x Wind (10 MW) |
| *2032* | 5x PV (1 MW) | | |
| *2033* | 1x Wind (10 MW)<br>5x PV (1 MW) | 1x Wind (10 MW)<br>5x PV (1 MW) | 1x Wind (10 MW) |
| *Planning Total Cost* | 4, 172, 124.80 | 4, 143, 818.50 | 4, 178, 033.20 |
| *Study Total Cost* | 6, 210, 304.50 | 6, 196, 855.00 | 6, 209, 654.00 |
| *Planning Rank* | 8 | 6 | 9 |
| *Study Rank* | 8 | 5 | 7 |

Table O-113. MECO Environmental Compliance (1 of 4)

| **Name** | **M2B2__X-4Ar0** | **M2B2__X-4Ar1** | **M2B2__X-4Br0** | **M2B2__X-4Ar2** |
|---|---|---|---|---|
| *Plan* | SitM Env Comp | SitM Env Comp | SitM Env Comp | SitM Env Comp |
| *Notes* | Fuel Switch<br>Allow ICE 17MW<br>Allow Wind, PV, Wave<br>(Curtailed OK) | NO KAHULUI Fuel Switch<br>Allow ICE 17MW<br>Allow Wind, PV, Wave<br>(Curtailed OK) | Deactivate for Environmental Compliance<br>Allow ICE 17MW<br>Allow Wind, PV, Wave<br>(Curtailed OK) | Fuel Switch<br>Allow Geo<br>Allow Wind, PV, Wave<br>(Curtailed OK) |
| *Resources Available* | | | | |
| *DR & DSM Assumptions* | 75% of Base EEPS<br>Fast DR Only | 75% of Base EEPS<br>Fast DR Only | 75% of Base EEPS<br>Fast DR Only | 75% of Base EEPS<br>Fast DR Only |
| *2014* | | | | |
| *2015* | 3x Wind (10 MW) | 3x Wind (10 MW) | 3x Wind (10 MW) | 3x Wind (10 MW)<br>PV (5MW) |
| *2016* | 3x Wind (10 MW) | 3x Wind (10 MW) | 3x Wind (10 MW) | PV (5MW) |
| *2017* | 3x Wind (10 MW) | 3x Wind (10 MW) | 3x Wind (10 MW) | |
| *2018* | | | | |
| *2019* | | | | |
| *2020* | | | | |
| *2021* | | | Deactivate K1-4, X1-2, M1-13 | |
| *2022* | Fuel Switch to LSIFO (Kahului1-4) | AQC for Kahului1-4 | **8x** ICE Biofueled (17 MW)<br>PV (5MW) | Fuel Switch to LSIFO (Kahului1-4) |
| *2023* | ICE Biofueled (17 MW) | ICE Biofueled (17 MW) | | Geothermal (25 MW) |
| *2024* | | | | |
| *2025* | | | | |
| *2026* | | | ICE Biofueled (17 MW) | |
| *2027* | | | | |
| *2028* | | | PV (5MW) | |
| *2029* | | | | |
| *2030* | PV (5MW) | | | |
| *2031* | | | | Wind (10 MW) |
| *2032* | | | | |
| *2033* | PV (5MW) | PV (5MW) | | Wind (10 MW) |
| *Planning Total Cost* | 3, 998, 183.72 | 4, 122, 985.79 | 4, 428, 919.70 | 4, 178, 033.47 |

| Name | M2B2__X-4Ar0 | M2B2__X-4Ar1 | M2B2__X-4Br0 | M2B2__X-4Ar2 |
|---|---|---|---|---|
| *Study Total Cost* | 5, 958, 626.00 | 6, 039, 317.27 | 6, 393, 136.90 | 6, 209, 654.00 |
| *Planning Rank* | 7 | 8 | 13 | 10 |
| *Study Rank* | 6 | 8 | 13 | 10 |

Table O-114. MECO Environmental Compliance (2 of 4)

| **Name** | **M2B2__X-4Ar3** | **M2B2__X-4Br2** | **M2B1a_X-4Cr0** | **M2B1a_X-4Cr1** |
|---|---|---|---|---|
| *Plan* | SitM Env Comp | SitM Env Comp | SitM Env Comp | SitM Env Comp |
| *Notes* | NO KAHULUI Fuel Switch<br>Allow Geo<br>Allow Wind, PV, Wave<br>(Curtailed OK) | Deactivate for Environmental Compliance except Maalaea DTCC<br>Fix 2x Geo, allow ICE 17MW<br>Allow Wind, PV, Wave<br>(Curtailed OK) | LNG Fuel Switch<br>Fix ICE 17MW in 2023<br>Fix 9x WindC7, 2x TrPV<br>(Curtailed OK) | LNG Fuel Switch<br>Fix Geo in 2029<br>Fix 5x WindC7, 2x TrPV<br>(Curtailed OK) |
| *Resources Available* | | | | |
| *DR & DSM Assumptions* | 75% of Base EEPS<br>Fast DR Only | 75% of Base EEPS<br>Fast DR Only | 75% of Base EEPS<br>Fast DR Only | 75% of Base EEPS<br>Fast DR Only |
| *2014* | | | | |
| *2015* | 3x Wind (10 MW) | 2x Wind (10 MW) | **3x** On-Shore Wind Class 7 (10 MW) | **3x** On-Shore Wind Class 7 (10 MW) |
| | | | | Tracking PV (5 MW) |
| *2016* | | | **3x** On-Shore Wind Class 7 (10 MW) | Tracking PV (5 MW) |
| *2017* | | | **3x** On-Shore Wind Class 7 (10 MW) | |
| *2018* | | | | |
| *2019* | | | | |
| *2020* | | | Fuel Switch to LNG (Maalaea DTCCs) | Fuel Switch to LNG (Maalaea DTCCs) |
| *2021* | | Geothermal (25 MW) | | |
| | | Deactivate K1-4, X1-2, M1-13 | | |
| *2022* | AQC for Kahului1-4 | Geothermal (25 MW) | Fuel Switch to LSIFO (Kahului1-4) | Fuel Switch to LSIFO (Kahului1-4) |
| | | **5x** ICE Biofueled (17 MW) | | |
| *2023* | Geothermal (25 MW) | | ICE Biofueled (17 MW) | Geothermal (25 MW) |
| *2024* | | ICE Biofueled (5 MW) | | |
| *2025* | | | | |
| *2026* | | | | |
| *2027* | | | | |
| *2028* | | ICE Biofueled (5 MW) | | |
| *2029* | | | | |
| *2030* | | | Tracking PV (5 MW) | |

| Name | M2B2__X-4Ar3 | M2B2__X-4Br2 | M2B1a_X-4Cr0 | M2B1a_X-4Cr1 |
|---|---|---|---|---|
| *2031* | Wind (10 MW) | | | On-Shore Wind Class 7 (10 MW) |
| *2033* | Wind (10 MW) | | Tracking PV (5 MW) | On-Shore Wind Class 7 (10 MW) |
| | PV (5MW) | | | |
| *Planning Total Cost* | 4, 290, 491.76 | 4, 598, 308.08 | 3, 886, 037.88 | 4, 142, 369.89 |
| *Study Total Cost* | 6, 283, 411.27 | 6, 616, 564.90 | 5, 707, 580.30 | 6, 129, 125.80 |
| *Planning Rank* | 11 | 14 | 4 | 9 |
| *Study Rank* | 11 | 14 | 3 | 9 |

Table O-115. MECO Environmental Compliance (3 of 4)

| **Name** | **M2B2__X-4Br3** | **M2B1a_X-4Cr2** | **M2B1a_X-4Cr3** | **M2B1a_N-4Cr0** |
|---|---|---|---|---|
| *Plan* | SitM Env Comp | SitM Env Comp | SitM Env Comp | SitM Env Comp |
| *Notes* | Deactivate for Environmental Compliance except Maalaea DTCC<br>Allow ICEs, CT, CC<br>allow limited WindC7, TrPV, Wave<br>(Curtailed OK) | LNG Fuel Switch<br>Allow ICE 5MW<br>Allow Limited WindC7, TrPV, Wave<br>(Curtailed OK) | LNG Fuel Switch<br>Allow ICE 17MW<br>Allow 9x WindC7, 2x TrPV<br>(Curtailed OK) | LNG Fuel Switch<br>Allow ICE 5MW<br>Allow 9x WindC7, 2x TrPV<br>(Curtailed OK) |
| *Resources Available* | | | | |
| *DR & DSM Assumptions* | 75% of Base EEPS<br>Fast DR Only | 75% of Base EEPS<br>Fast DR Only | 75% of Base EEPS<br>Fast DR Only | 75% of Base EEPS<br>All DR - CIDLC Exp, RDLC Exp, Fast DR |
| *2014* | | | | |
| *2015* | 3x Wind (10 MW) | 3x Wind (10 MW) | 3x Wind (10 MW) | 3x Wind (10 MW) |
| *2016* | 3x Wind (10 MW) | 3x Wind (10 MW) | 3x Wind (10 MW) | 3x Wind (10 MW) |
| *2017* | 3x Wind (10 MW) | 3x Wind (10 MW) | 3x Wind (10 MW) | 3x Wind (10 MW) |
| *2018* | | | | |
| *2019* | | | | |
| *2020* | | Fuel Switch to LNG (Maalaea DTCCs) | Fuel Switch to LNG (Maalaea DTCCs) | Fuel Switch to LNG (Maalaea DTCCs) |
| *2021* | Deactivate K1-4, X1-2, M1-13 | | | |
| *2022* | **6x** ICE Biofueled (17 MW)<br>**2x** Biofuel Combustion Turbine (21 MW)<br>PV (5 MW) | Fuel Switch to LSIFO (Kahului1-4) | Fuel Switch to LSIFO (Kahului1-4) | Fuel Switch to LSIFO (Kahului1-4) |
| *2023* | | ICE LNG (5 MW) | ICE Biofueled (17 MW) | |
| *2024* | | | | |
| *2025* | | | | |
| *2026* | | | | |
| *2027* | | ICE LNG (5 MW) | | |
| *2028* | | | | |
| *2029* | | | | ICE LNG (5 MW) |
| *2030* | | ICE LNG (5 MW) | | |
| *2031* | | | | |
| *2032* | | | | |

| **Name** | **M2B2__X-4Br3** | **M2B1a_X-4Cr2** | **M2B1a_X-4Cr3** | **M2B1a_N-4Cr0** |
|---|---|---|---|---|
| *2033* | | | | |
| *Planning Total Cost* | 4, 407, 234.08 | 3, 882, 801.55 | 3, 884, 155.22 | 3, 859, 079.06 |
| *Study Total Cost* | 6, 346, 073.90 | 5, 733, 030.30 | 5, 705, 513.30 | 5, 674, 278.80 |
| *Planning Rank* | 12 | 2 | 3 | 1 |
| *Study Rank* | 12 | 4 | 2 | 1 |

Table O-116. MECO Environmental Compliance (4 of 4)

| **Name** | **M2_2__N-2r14** | **M2_2__X-2r11** |
|---|---|---|
| *Plan* | SitM Screen Fix 5 MW ICE in 2029 | StiM Screen allow 5 MW ICE |
| *Notes* | Fuel Switch with ICE (5 MW), allow limited Wind, PV, Wave (Curtailed OK) | Fuel Switch with ICE (5 MW), allow limited Wind, PV, Wave (Curtailed OK) |
| *Resources Available* | | |
| *DR & DSM Assumptions* | 75% of Base EEPS<br>All DR - CIDLC Exp, RDLC Exp, Fast DR | 75% of Base EEPS<br>Fast DR Only |
| *2014* | | |
| *2015* | 3x Wind (10 MW) | 3x Wind (10 MW) |
| *2016* | 3x Wind (10 MW) | 3x Wind (10 MW) |
| *2017* | 3x Wind (10 MW) | 3x Wind (10 MW) |
| *2018* | | |
| *2019* | | |
| *2020* | | |
| *2021* | | |
| *2022* | Fuel Switch to LSIFO (Kahului1-4) | Fuel Switch to LSIFO (Kahului1-4) |
| *2023* | | ICE Biofueled (5 MW) |
| *2024* | | |
| *2025* | | |
| *2026* | | |
| *2027* | | ICE Biofueled (5 MW) |
| *2028* | | |
| *2029* | ICE Biofueled (5 MW) | |
| *2030* | 5x PV (1 MW) | ICE Biofueled (5 MW)<br>5x PV (1 MW) |
| *2031* | | |
| *2032* | | |
| *2033* | | 5x PV (1 MW) |
| *Planning Total Cost* | 3, 972, 732.50 | 3, 996, 843.50 |
| *Study Total Cost* | 5, 931, 363.50 | 5, 989, 311.00 |
| *Planning Rank* | 5 | 6 |
| *Study Rank* | 5 | 7 |

Table O-117. MECO Energy Efficiency Portfolio Standard

| **Name** | **M2B2a_X-7Ar1** | **M2B2a_X-7Br1** | **M2B2a_X-7Cr1** | **M2B2a_X-7Dr1** |
|---|---|---|---|---|
| *Plan* | SitM EEPS Impact | SitM EEPS Impact | SitM EEPS Impact | SitM EEPS Impact |
| *Notes* | 35% EEPS<br>Allow ICE 17MW<br>no new as-availables<br>(Curtailed OK) | 75% EEPS<br>Allow ICE 17MW<br>no new as-availables<br>(Curtailed OK) | 100% EEPS<br>Allow ICE 17MW<br>no new as-availables<br>(Curtailed OK) | 110% EEPS<br>Allow ICE 17MW<br>no new as-availables<br>(Curtailed OK) |
| *Resources Available* | | | | |
| *Reference* | | | | |
| *DR & DSM Assumptions* | 35% of Base EEPS<br>Fast DR Only | 75% of Base EEPS<br>Fast DR Only | 100% of Base EEPS<br>Fast DR Only | 110% of Base EEPS<br>Fast DR Only |
| *2014* | | | | |
| *2015* | | | | |
| *2016* | | | | |
| *2017* | | | | |
| *2018* | ICE Biofueled (17 MW) | | | |
| *2019* | | | | |
| *2020* | | | | |
| *2021* | | | | |
| *2022* | | | | |
| *2023* | | ICE Biofueled (17 MW) | | |
| *2024* | | | | |
| *2025* | | | | |
| *2026* | ICE Biofueled (17 MW) | | | |
| *2027* | | | | |
| *2028* | | | | |
| *2029* | | | ICE Biofueled (17 MW) | |
| *2030* | | | | |
| *2031* | | | | |
| *2032* | | | | |
| *2033* | | | | |
| *Planning Total Cost* | 4, 383, 485.50 | 4, 219, 082.50 | 4, 138, 237.50 | 4, 092, 610.20 |
| *Study Total Cost* | 6, 764, 382.50 | 6, 394, 514.50 | 6, 212, 482.50 | 6, 101, 313.00 |
| *Planning Rank* | 4 | 3 | 2 | 1 |
| *Study Rank* | 4 | 3 | 2 | 1 |

Table O-118. MECO 100% Renewable Energy (1 of 2)

| **Name** | **M2C2__N-3r2b** | **M2C2__X-3r3b** | **M2C2__N-3r3r** | **M2C2__N-3r4r** |
|---|---|---|---|---|
| *Plan* | SitM 100% Renewable | SitM 100% Renewable | SitM 100% Renewable | SitM 100% Renewable |
| *Notes* | Allow ICEs, Geo, Biomass, WTE, CT<br>Existing Firm Biofueled in 2030<br>Fixed Wind, Allow PV, Wave (Curtailed OK) | allow ICEs, Geo, Biomass, WTE, CT<br>Existing Firm Biofueled in 2030<br>Fixed Wind, Allow PV, Wave (Curtailed OK) | Allow ICEs, Geo, CT<br>Existing Firm Deactivated or Biofueled<br>allow Wind, Wave (Curtailed OK) | Allow ICEs, CT<br>Existing Firm Deactivated or Biofueled<br>allow Wind, Wave (Curtailed OK) |
| *Resources Available* | | | | |
| *DR & DSM Assumptions* | 75% of Base EEPS<br>All DR - CIDLC Exp, RDLC Exp, Fast DR | 75% of Base EEPS<br>Fast DR Only | 75% of Base EEPS<br>All DR - CIDLC Exp, RDLC Exp, Fast DR | 75% of Base EEPS<br>All DR - CIDLC Exp, RDLC Exp, Fast DR |
| *2014* | | | | |
| *2015* | 3x Wind (10 MW) | 3x Wind (10 MW) | 3x Wind (10 MW) | 3x Wind (10 MW) |
| *2016* | 3x Wind (10 MW) | 3x Wind (10 MW) | 3x Wind (10 MW) | 3x Wind (10 MW) |
| *2017* | 3x Wind (10 MW) | 3x Wind (10 MW) | 3x Wind (10 MW) | 3x Wind (10 MW) |
| *2018* | | | | |
| *2019* | | | | |
| *2020* | | | | |
| *2021* | | | | |
| *2022* | | | | |
| *2023* | | Biofueled ICE (17 MW) | | |
| | | | Deactivate M4, M5 | Deactivate M4, M5 |
| *2024* | | | Biofueled CT (21 MW) | Biofueled ICE (17 MW) |
| *2025* | | | Deactivate K1, K2, K3, K4, M6, M7 | Deactivate K1, K2, K3, K4, M6, M7 |
| *2026* | | | Biofueled ICE (17 MW) | 2x Biofueled ICE (17 MW) |
| | | | Biofueled CT (21 MW) | Biofueled CT (21 MW) |
| | | | Deactivate M1 | Deactivate M1 |
| *2027* | | | Biofueled ICE (17 MW) | |
| | | | Deactivate M2, M3, M8 | Deactivate M2, M3, M8 |
| *2028* | | | Deactivate M9 | Deactivate M9 |
| *2029* | Biofueled ICE (5 MW) | PV (5MW) | Biofueled ICE (17 MW) | Biofueled ICE (17 MW) |
| | PV (5MW) | | Deactivate M10 | Deactivate M10 |
| *2030* | PV (5MW) | PV (5MW) | | Biofueled ICE (17 MW) |
| | | | Deactivate M11 | Deactivate M11 |

| **Name** | **M2C2__N-3r2b** | **M2C2__X-3r3b** | **M2C2__N-3r3r** | **M2C2__N-3r4r** |
|---|---|---|---|---|
| *2031* | | | Biofueled ICE (17 MW) | |
| *2032* | | | Deactivate X1, X2 | Deactivate X1, X2 |
| *2033* | PV (5MW) | | | Biofueled ICE (5 MW) |
| *Planning Total Cost* | 4, 006, 959.00 | 4, 031, 364.50 | 4, 160, 613.44 | 4, 163, 616.56 |
| *Study Total Cost* | 5, 962, 908.00 | 5, 990, 801.50 | 6, 077, 642.94 | 6, 095, 603.94 |
| *Planning Rank* | 1 | 2 | 4 | 6 |
| *Study Rank* | 1 | 2 | 4 | 5 |

Table O-119. MECO 100% Renewable Energy (2 of 2)

| **Name** | **M2C2__N-3r5r** | **M2C2__X-3r3r** | **M2C2__X-3r4r** |
|---|---|---|---|
| *Plan* | SitM 100% Renewable | SitM 100% Renewable | SitM 100% Renewable |
| *Notes* | Allow more ICEs, CT<br>Existing Firm Deactivated or Biofueled<br>allow Wind, PV, Wave<br>(Curtailed OK) | Allow ICEs, Geo, Biomass, WTE, CT<br>Existing Firm Deactivated or Biofueled<br>allow Wind, Wave<br>(Curtailed OK) | Allow more ICEs, CT<br>Existing Firm Deactivated or Biofueled<br>Fixed Wind, allow PV, Wave<br>(Curtailed OK) |
| *Resources Available* | | | |
| *DR & DSM Assumptions* | 75% of Base EEPS<br>All DR - CIDLC Exp, RDLC Exp, Fast DR | 75% of Base EEPS<br>Fast DR Only | 75% of Base EEPS<br>Fast DR Only |
| *2014* | | | |
| *2015* | 3x Wind (10 MW) | 3x Wind (10 MW) | 3x Wind (10 MW) |
| *2016* | 3x Wind (10 MW) | 3x Wind (10 MW) | 3x Wind (10 MW) |
| *2017* | 3x Wind (10 MW) | 3x Wind (10 MW) | 3x Wind (10 MW) |
| *2018* | | | |
| *2019* | | | |
| *2020* | | | |
| *2021* | | | |
| *2022* | | | |
| *2023* | | Biofueled ICE (17 MW) | Biofueled ICE (17 MW) |
| | Deactivate M4, M5 | Deactivate M4, M5 | Deactivate M4, M5 |
| *2024* | Biofueled ICE (17 MW) | | |
| *2025* | | Biofueled ICE (17 MW) | |
| | Deactivate K1, K2, K3, K4, M6, M7 | Deactivate K1, K2, K3, K4, M6, M7 | Deactivate K1, K2, K3, K4, M6, M7 |
| *2026* | 2x Biofueled CT (21 MW) | Biofueled ICE (17 MW) | 3x Biofueled ICE (17 MW) |
| | | Biofueled CT (21 MW) | |
| | Deactivate M1 | Deactivate M1 | Deactivate M1 |
| *2027* | Biofueled ICE (17 MW) | | |
| | Deactivate M2, M3, M8 | Deactivate M2, M3, M8 | Deactivate M2, M3, M8 |
| *2028* | | Biofueled ICE (17 MW) | Biofueled CT (21 MW) |
| | Deactivate M9 | Deactivate M9 | Deactivate M9 |
| *2029* | Biofueled ICE (17 MW) | | |
| | Deactivate M10 | Deactivate M10 | Deactivate M10 |
| *2030* | PV (5MW) | Biofueled CT (21 MW) | Biofueled ICE (17 MW) |
| | | | PV (5MW) |
| | Deactivate M11 | Deactivate M11 | Deactivate M11 |

| Name | M2C2__N-3r5r | M2C2__X-3r3r | M2C2__X-3r4r |
|---|---|---|---|
| *2031* | Biofueled ICE (17 MW) | Biofueled ICE (5 MW) | Biofueled ICE (17 MW) |
| *2032* | Deactivate X1, X2 | Deactivate X1, X2 | Deactivate X1, X2 |
| *2033* | | Geothermal (25 MW) | |
| *Planning Total Cost* | 4, 158, 822.02 | 4, 168, 333.83 | 4, 162, 439.58 |
| *Study Total Cost* | 6, 074, 930.44 | 6, 203, 354.94 | 6, 106, 908.94 |
| *Planning Rank* | 3 | 7 | 5 |
| *Study Rank* | 3 | 7 | 6 |

Table O-120. MECO Demand Response as Spinning Reserve

| **Name** | **M2_2__X-2r14** | **M2_2__N-2r17** |
|---|---|---|
| *Plan* | StiM Screen allow Geo | SitM Screen Fix 5 MW ICE in 2029 |
| *Notes* | Allow new Geo (25 MW)<br>allow limited WindC7, TrPV, Wave<br>(Curtailed OK) RUN 3/27/2013 | Apply Spin to DR Programs<br>New ICE (5 MW) 2029 fixed,<br>Fix limited WindC7, TrPV |
| *Resources Available* | | |
| *DR & DSM Assumptions* | 75% of Base EEPS<br>Fast DR Only | 75% of Base EEPS<br>All DR - CIDLC Exp, RDLC Exp, Fast DR |
| *2014* | | |
| *2015* | 3x On-Shore Wind Class 7 (10 MW) | 3x On-Shore Wind Class 7 (10 MW) |
| | 5x Tracking PV (1 MW) | |
| *2016* | 5x Tracking PV (1 MW) | 3x On-Shore Wind Class 7 (10 MW) |
| *2017* | | 3x On-Shore Wind Class 7 (10 MW) |
| *2018* | | |
| *2019* | | |
| *2020* | | |
| *2021* | | |
| *2022* | | |
| *2023* | Geothermal (25 MW) | |
| *2024* | | |
| *2025* | | |
| *2026* | | |
| *2027* | | |
| *2028* | | |
| *2029* | | ICE Biofueled (5 MW) |
| *2030* | | 5x Tracking PV (1 MW) |
| *2031* | 1x On-Shore Wind Class 7 (10 MW) | |
| *2032* | | |
| *2033* | 1x On-Shore Wind Class 7 (10 MW) | |
| *Planning Total Cost* | 4, 178, 033.20 | 3, 968, 782.80 |
| *Study Total Cost* | 6, 209, 654.00 | 5, 923, 331.50 |
| *Planning Rank* | 2 | 1 |
| *Study Rank* | 2 | 1 |

Table O-121. MECO Wind Capacity Value

| **Name** | **M2_2__X-2r11** | **M2B2a_X-8r3** |
|---|---|---|
| *Plan* | StiM Screen allow 5 MW ICE | SitM Capacity Value of Wind |
| *Notes* | Allow new ICEs (5 MW)<br>allow limited Wind, PV, Wave<br>(Curtailed OK) | Allow ICEs, Geo, Biomass, WTE, CT<br>Allow Wind C7, TrPV, Wave<br>(Curtailed OK) |
| *Resources Available* | 10 MW Wind (MW04) - Avail 2015<br>1 MW PV (MP03) - Avail 2015<br>15 MW Ocean Wave (MV02) - Avail 2015<br>5 MW ICE (MS14) - Avail 2016 | 10 MW Wind (MW04) - Avail 2015<br>1 MW PV (MP03) - Avail 2015<br>15 MW Ocean Wave (MV02) - Avail 2015<br>17 MW ICE (MS01) - Avail 2016<br>5 MW ICE (MS14) - Avail 2016<br>21 MW CT (MS05) - Avail 2016<br>25 MW Geothermal (MG02) - Avail 2016<br>25 MW Biomass (MA01) - Avail 2017<br>8 MW WTE (MT01) - Avail 2017 |
| *DR & DSM Assumptions* | 75% of Base EEPS<br>Fast DR Only | 75% of Base EEPS<br>Fast DR Only |
| *2014* | | |
| *2015* | 3x Wind (10 MW) | 3x Wind (10 MW) |
| *2016* | 3x Wind (10 MW) | 3x Wind (10 MW) |
| *2017* | 3x Wind (10 MW) | 3x Wind (10 MW) |
| *2018* | | |
| *2019* | | |
| *2020* | | |
| *2021* | | |
| *2022* | | |
| *2023* | ICE Biofueled (5 MW) | |
| *2024* | | |
| *2025* | | |
| *2026* | | ICE Biofueled (5 MW) |
| *2027* | ICE Biofueled (5 MW) | |
| *2028* | | |
| *2029* | | |
| *2030* | ICE Biofueled (5 MW)<br>5x PV (1 MW) | ICE Biofueled (5 MW)<br>5x PV (1 MW) |
| *2031* | | |
| *2032* | | |
| *2033* | 5x PV (1 MW) | 5x PV (1 MW) |
| *Planning Total Cost* | 3, 996, 844 | 3, 966, 869 |

| **Name** | **M2_2__X-2r11** | **M2B2a_X-8r3** |
|---|---|---|
| *Study Total Cost* | 5, 989, 311 | 5, 939, 421 |
| *Planning Rank* | 2 | 1 |
| *Study Rank* | 2 | 1 |

Table O-122. MECO Battery Storage

| **Name** | **M2B2a_X-7Br1** | **M2B2a_X-7Br1_Batt** | **M2B2a_X-7Br1_PV** | **M2B2a_X-7Br1_Batt_Cap** |
|---|---|---|---|---|
| *Plan* | No Battery | Battery storage forced in 2020 | PV forced in 2020 | Battery storage (with capacity value) forced in 2020 |
| *Notes* | From EEPS run | | | |
| *Resources Available* | | All resources were fixed | All resources were fixed | 17 MW ICE (MS01) - 2016<br>All other resources fixed |
| *DR & DSM Assumptions* | 75% of Base EEPS<br>Fast DR Only | 75% of Base EEPS<br>Fast DR Only | 75% of Base EEPS<br>Fast DR Only | 75% of Base EEPS<br>Fast DR Only |
| *2014* | | | | |
| *2015* | | | | |
| *2016* | | | | |
| *2017* | | | | |
| *2018* | | | | |
| *2019* | | | | |
| *2020* | | Battery Storage (MB01) | PV (1 MW) | Battery Storage (MB01) |
| *2021* | | | | |
| *2022* | | | | |
| *2023* | ICE Biofueled (17 MW) | ICE Biofueled (17 MW) | ICE Biofueled (17 MW) | |
| *2024* | | | | |
| *2025* | | | | |
| *2026* | | | | |
| *2027* | | | | |
| *2028* | | | | |
| *2029* | | | | |
| *2030* | | | | ICE Biofueled (17 MW) |
| *2031* | | | | |
| *2032* | | | | |
| *2033* | | | | |
| *Planning Total Cost* | 4, 219, 083 | 4, 222, 622 | 4, 219, 248 | 4, 179, 847 |
| *Study Total Cost* | 6, 394, 515 | 6, 398, 245 | 6, 393, 094 | 6, 362, 600 |
| *Planning Rank* | 2 | 4 | 3 | 1 |
| *Study Rank* | 3 | 4 | 2 | 1 |

Table O-123. MECO Lanai Plans

| | Preferred Plan | Contingency | Parallel | Secondary |
|---|---|---|---|---|
| **Strategy** | **ML-1** | **ML-2** | **ML-3** | **ML-4** |
| *Plan* | LNG Short-term, Biomass | LNG Long-term, Biomass | 100% renewable, biomass, biodiesel | 100% renewable, PV, battery, biodiesel |
| *Resources Available* | 600 kW Wind - Avail 2018<br>750 kW Wave - Avail 2019<br>1.0 MW PV - Avail 2018<br>1.0 MW Biomass - Avail 2018 | 600 kW Wind - Avail 2018<br>750 kW Wave - Avail 2019<br>1.0 MW PV - Avail 2018<br>1.0 MW Biomass - Avail 2018 | 600 kW Wind - Avail 2018<br>750 kW Wave - Avail 2019<br>1.0 MW PV - Avail 2018<br>1.0 MW Biomass - Avail 2018 | 600 kW Wind - Avail 2018<br>750 kW Wave - Avail 2019<br>1.0 MW PV - Avail 2018<br>1.0 MW Biomass - Avail 2018 |
| *2014* | | | Fuel Switch to Biodiesel | Fuel Switch to Biodiesel |
| *2015* | | | | |
| *2016* | | | | |
| *2017* | | | | |
| *2018* | Fuel Switch to 50% LNG<br>Add 2 MW Biomass | Add 2 MW Biomass | Add 2 MW Biomass | Battery Storage<br>Add 4 MW PV |
| *2019* | | | | |
| *2020* | | | | |
| *2021* | | Fuel Switch to 50% LNG | | |
| *2022* | | | | |
| *2023* | | | | |
| *2024* | | | | |
| *2025* | | | | |
| *2026* | | | | |
| *2027* | | | | |
| *2028* | | | | |
| *2029* | | | | |
| *2030* | | | | |
| *2031* | | | | |
| *2032* | | | | |
| *2033* | | | | |
| *PV Total Cost* | $140, 095 | $140, 677 | $153, 070 | $155, 716 |
| *Planning Rank* | 1 | 2 | 3 | 4 |

Table O-124. MECO Molokai Plans

| | Preferred Plan | Contingency | Parallel | Secondary Plan |
|---|---|---|---|---|
| **Strategy** | **MM-1** | **MM-2** | **MM-3** | **MM-4** |
| *Plan* | LNG Short-term, Biomass | LNG Long-term, Biomass | 100% renewable, biomass, biodiesel | 100% renewable, PV, battery, biodiesel |
| *Resources Available* | 600 kW Wind - Avail 2018<br>750 kW Wave - Avail 2019<br>1.0 MW PV - Avail 2018<br>1.0 MW Biomass - Avail 2018 | 600 kW Wind - Avail 2018<br>750 kW Wave - Avail 2019<br>1.0 MW PV - Avail 2018<br>1.0 MW Biomass - Avail 2018 | 600 kW Wind - Avail 2018<br>750 kW Wave - Avail 2019<br>1.0 MW PV - Avail 2018<br>1.0 MW Biomass - Avail 2018 | 600 kW Wind - Avail 2018<br>750 kW Wave - Avail 2019<br>1.0 MW PV - Avail 2018<br>1.0 MW Biomass - Avail 2018 |
| *2014* | | | Fuel Switch to Biodiesel | Fuel Switch to Biodiesel |
| *2015* | | | | |
| *2016* | | | | |
| *2017* | | | | |
| *2018* | Fuel Switch to 50% LNG<br>Add 3 MW Biomass | Add 3 MW Biomass | Add 3 MW Biomass | Battery Storage<br>Add 7 MW PV |
| *2019* | | | | |
| *2020* | | | | |
| *2021* | | Fuel Switch to 50% LNG | | |
| *2022* | | | | |
| *2023* | | | | |
| *2024* | | | | |
| *2025* | | | | |
| *2026* | | | | |
| *2027* | | | | |
| *2028* | | | | |
| *2029* | | | | |
| *2030* | | | | |
| *2031* | | | | |
| *2032* | | | | |
| *2033* | | | | |
| *PV Total Cost* | $137, 975 | $138, 840 | $151, 902 | $166, 216 |
| *Planning Rank* | 1 | 2 | 3 | 4 |

## No Burning Desire

Table O-125. MECO Firm Timing (1 of 4)

| Name | M3_2__N-1r0 | M3_2__N-1r1 | M3_2__N-1r2 | M3_2__N-1r3 |
|---|---|---|---|---|
| *Plan* | NBD Timing SC | NBD Timing 17 MW ICE | NBD Timing 5 MW ICE | NBD Timing Other Firm |
| *Notes* | 21 MW SC Timing on Rule 1 | 17 MW ICE Timing on Rule 1 | 5 MW ICE Timing on Rule 1 | Timing for Banagrass, WTE, New Geo on Rule 1<br>MA01 Max: 75 MW, MT01 Max: 8 MW, MG02 Max: 50 MW |
| *Resources Available* | | | | |
| *DR & DSM Assumptions* | 75% of Base EEPS<br>All DR - CIDLC Exp, RDLC Exp, Fast DR | 75% of Base EEPS<br>All DR - CIDLC Exp, RDLC Exp, Fast DR | 75% of Base EEPS<br>All DR - CIDLC Exp, RDLC Exp, Fast DR | 75% of Base EEPS<br>All DR - CIDLC Exp, RDLC Exp, Fast DR |
| *2014* | | | | |
| *2015* | (3) 5 MW ICE - Biofuel [MS14] | (3) 5 MW ICE - Biofuel [MS14] | (3) 5 MW ICE - Biofuel [MS14] | (3) 5 MW ICE - Biofuel [MS14] |
| *2016* | (1) 21 MW SC LM2500 - Biofuel [MS05] | (1) 17 MW ICE - Biofuel [MS01] | (1) 5 MW ICE - Biofuel [MS14] | (1) 25 MW New Geo [MG02] |
| *2017* | | | (2) 5 MW ICE - Biofuel [MS14] | |
| *2018* | | (1) 17 MW ICE - Biofuel [MS01] | (1) 5 MW ICE - Biofuel [MS14] | |
| *2019* | (1) 21 MW SC LM2500 - Biofuel [MS05] | | (2) 5 MW ICE - Biofuel [MS14] | (1) 25 MW New Geo [MG02] |
| *2020* | | (1) 17 MW ICE - Biofuel [MS01] | (1) 5 MW ICE - Biofuel [MS14] | |
| *2021* | | | (2) 5 MW ICE - Biofuel [MS14] | |
| *2022* | (1) 21 MW SC LM2500 - Biofuel [MS05] | | (1) 5 MW ICE - Biofuel [MS14] | (1) 8 MW WTE [MT01] |
| *2023* | | (1) 17 MW ICE - Biofuel [MS01] | (1) 5 MW ICE - Biofuel [MS14] | (1) 25 MW Banagrass [MA01] |
| *2024* | | | (2) 5 MW ICE - Biofuel [MS14] | |
| *2025* | (1) 21 MW SC LM2500 - Biofuel [MS05] | | | |
| *2026* | | (1) 17 MW ICE - Biofuel [MS01] | (2) 5 MW ICE - Biofuel [MS14] | (1) 25 MW Banagrass [MA01] |
| 2027 | | | (1) 5 MW ICE - Biofuel [MS14] | |

| **Name** | **M3_2__N-1r0** | **M3_2__N-1r1** | **M3_2__N-1r2** | **M3_2__N-1r3** |
|---|---|---|---|---|
| *2028* | (1) 21 MW SC LM2500 - Biofuel [MS05] | (1) 17 MW ICE - Biofuel [MS01] | (1) 5 MW ICE - Biofuel [MS14] | |
| *2029* | | | (1) 5 MW ICE - Biofuel [MS14] | |
| *2030* | | | (1) 5 MW ICE - Biofuel [MS14] | |
| *2031* | | (1) 17 MW ICE - Biofuel [MS01] | (1) 5 MW ICE - Biofuel [MS14] | (1) 25 MW Banagrass [MA01] |
| *2032* | (1) 21 MW SC LM2500 - Biofuel [MS05] | | (1) 5 MW ICE - Biofuel [MS14] | |
| *2033* | | | (2) 5 MW ICE - Biofuel [MS14] | |
| *Planning Total Cost* | 5, 090, 985 | 5, 050, 648 | 5, 206, 059 | 5, 097, 928 |
| *Study Total Cost* | 7, 642, 226 | 7, 515, 389 | 7, 780, 160 | 7, 606, 700 |
| *Planning Rank* | 4 | 3 | 6 | 5 |
| *Study Rank* | 5 | 3 | 6 | 4 |

Table O-126. MECO Firm Timing (2 of 4)

| **Name** | **M3_2__N-1r4** | **M3_2__N-1r5** | **M3_2__X-1r0** | **M3_2__X-1r1** |
|---|---|---|---|---|
| *Plan* | NBD Timing All W Geo | NBD Timing All No Geo | NBD Timing 5 MW ICE No DR | NBD Timing 17 MW ICE No DR |
| *Notes* | All firm resources from timing Add on Rule 1 | All firm resources from timing excluding geothermal, Add on Rule 1 | 5 MW ICE Timing on Rule 1, No DR except Fast DR | 17 MW ICE Timing on Rule 1, No DR except Fast DR |
| *Resources Available* | | | | |
| *DR & DSM Assumptions* | 75% of Base EEPS<br>All DR - CIDLC Exp, RDLC Exp, Fast DR | 75% of Base EEPS<br>All DR - CIDLC Exp, RDLC Exp, Fast DR | 75% of Base EEPS<br>Fast DR Only | 75% of Base EEPS<br>Fast DR Only |
| *2014* | | | | |
| *2015* | (3) 5 MW ICE - Biofuel [MS14] | (3) 5 MW ICE - Biofuel [MS14] | (3) 5 MW ICE - Biofuel [MS14] | (3) 5 MW ICE - Biofuel [MS14] |
| *2016* | (1) 25 MW New Geo [MG02] | (1) 21 MW SC LM2500 - Biofuel [MS05] | (2) 5 MW ICE - Biofuel [MS14] | (1) 17 MW ICE - Biofuel [MS01] |
| *2017* | | | (1) 5 MW ICE - Biofuel [MS14] | |
| *2018* | | | (2) 5 MW ICE - Biofuel [MS14] | (1) 17 MW ICE - Biofuel [MS01] |
| *2019* | (1) 21 MW SC LM2500 - Biofuel [MS05] | (1) 17 MW ICE - Biofuel [MS01] | (2) 5 MW ICE - Biofuel [MS14] | |
| *2020* | | | (1) 5 MW ICE - Biofuel [MS14] | (1) 17 MW ICE - Biofuel [MS01] |
| *2021* | | (1) 25 MW Banagrass [MA01] | (2) 5 MW ICE - Biofuel [MS14] | |
| *2022* | (1) 25 MW New Geo [MG02] | | (1) 5 MW ICE - Biofuel [MS14] | (1) 17 MW ICE - Biofuel [MS01] |
| *2023* | | | (1) 5 MW ICE - Biofuel [MS14] | |
| *2024* | | (1) 25 MW Banagrass [MA01] | (2) 5 MW ICE - Biofuel [MS14] | (1) 17 MW ICE - Biofuel [MS01] |
| *2025* | | | (1) 5 MW ICE - Biofuel [MS14] | |
| *2026* | (1) 17 MW ICE - Biofuel [MS01] | | (1) 5 MW ICE - Biofuel [MS14] | |
| *2027* | | | (1) 5 MW ICE - Biofuel [MS14] | (1) 17 MW ICE - Biofuel [MS01] |
| *2028* | | | (1) 5 MW ICE - Biofuel [MS14] | |

| **Name** | **M3_2__N-1r4** | **M3_2__N-1r5** | **M3_2__X-1r0** | **M3_2__X-1r1** |
|---|---|---|---|---|
| *2029* | (1) 17 MW ICE - Biofuel [MS01] | (1) 17 MW ICE - Biofuel [MS01] | (2) 5 MW ICE - Biofuel [MS14] | (1) 17 MW ICE - Biofuel [MS01] |
| *2030* | | | (1) 5 MW ICE - Biofuel [MS14] | |
| *2031* | (1) 17 MW ICE - Biofuel [MS01] | (1) 17 MW ICE - Biofuel [MS01] | (1) 5 MW ICE - Biofuel [MS14] | |
| *2032* | | | (1) 5 MW ICE - Biofuel [MS14] | (1) 17 MW ICE - Biofuel [MS01] |
| *2033* | | | (1) 5 MW ICE - Biofuel [MS14] | |
| *Planning Total Cost* | 4, 925, 736 | 5, 000, 486 | 5, 240, 748 | 5, 071, 779 |
| *Study Total Cost* | 7, 292, 457 | 7, 436, 842 | 7, 804, 157 | 7, 572, 211 |
| *Planning Rank* | 1 | 2 | 4 | 3 |
| *Study Rank* | 1 | 2 | 4 | 3 |

Table O-127. MECO Firm Timing (3 of 4)

| **Name** | **M3_2__X-1r2** | **M3_2__X-1r3** | **M3_2b_N-1r0** | **M3_2b_N-1r1** |
|---|---|---|---|---|
| *Plan* | NBD Timing All W Geo No DR | NBD Timing All No Geo No DR | NBD Timing All W Geo | NBD Timing All No Geo |
| *Notes* | All firm resources from timing No DR except Fast DR, Add on Rule 1 | All firm resources from timing excluding geothermal, No DR except Fast DR, Add on Rule 1 | HC&S Contract Extended Indefinitely<br>All firm resources from timing Add on Rule 1 | HC&S Contract Extended Indefinitely<br>All firm resources from timing excluding geothermal, Add on Rule 1 |
| *Resources Available* | | | | |
| *DR & DSM Assumptions* | 75% of Base EEPS<br>Fast DR Only | 75% of Base EEPS<br>Fast DR Only | 75% of Base EEPS<br>All DR - CIDLC Exp, RDLC Exp, Fast DR | 75% of Base EEPS<br>All DR - CIDLC Exp, RDLC Exp, Fast DR |
| *2014* | | | | |
| *2015* | (3) 5 MW ICE - Biofuel [MS14] | (3) 5 MW ICE - Biofuel [MS14] | | |
| *2016* | (1) 17 MW ICE - Biofuel [MS01] | (1) 17 MW ICE - Biofuel [MS01] | (1) 21 MW SC LM2500 - Biofuel [MS05] | (1) 21 MW SC LM2500 - Biofuel [MS05] |
| *2017* | | | | |
| *2018* | (1) 25 MW New Geo [MG02] | (1) 21 MW SC LM2500 - Biofuel [MS05] | | |
| *2019* | | | (1) 25 MW New Geo [MG02] | (1) 17 MW ICE - Biofuel [MS01] |
| *2020* | | (1) 21 MW SC LM2500 - Biofuel [MS05] | | |
| *2021* | (1) 25 MW New Geo [MG02] | | | (1) 17 MW ICE - Biofuel [MS01] |
| *2022* | | | (1) 25 MW New Geo [MG02] | |
| *2023* | | (1) 25 MW Banagrass [MA01] | | |
| *2024* | (1) 21 MW SC LM2500 - Biofuel [MS05] | | | (1) 17 MW ICE - Biofuel [MS01] |
| *2025* | | | | |
| *2026* | | | (1) 17 MW ICE - Biofuel [MS01] | |
| *2027* | (1) 21 MW SC LM2500 - Biofuel [MS05] | (1) 25 MW Banagrass [MA01] | | (1) 17 MW ICE - Biofuel [MS01] |
| *2028* | | | | |
| *2029* | | | (1) 17 MW ICE - Biofuel [MS01] | |
| *2030* | | | | (1) 25 MW Banagrass [MA01] |

| **Name** | **M3_2__X-1r2** | **M3_2__X-1r3** | **M3_2b_N-1r0** | **M3_2b_N-1r1** |
|---|---|---|---|---|
| *2031* | (1) 25 MW Banagrass [MA01] | (1) 21 MW SC LM2500 - Biofuel [MS05] | (1) 17 MW ICE - Biofuel [MS01] | |
| *2032* | | | | |
| *2033* | | | | |
| *Planning Total Cost* | 4, 948, 714 | 5, 016, 723 | 4, 711, 478 | 4, 756, 715 |
| *Study Total Cost* | 7, 326, 759 | 7, 471, 953 | 6, 978, 243 | 7, 090, 725 |
| *Planning Rank* | 1 | 2 | 1 | 2 |
| *Study Rank* | 1 | 2 | 1 | 2 |

Table O-128. MECO Firm Timing (4 of 4)

| **Name** | **M3_2b_X-1r0** | **M3_2b_X-1r1** |
|---|---|---|
| *Plan* | NBD Timing All W Geo No DR | NBD Timing All No Geo No DR |
| *Notes* | HC&S Contract Extended Indefinitely<br>All firm resources from timing<br>No DR except Fast DR, Add on Rule 1 | HC&S Contract Extended Indefinitely<br>All firm resources from timing excluding geothermal, No DR except Fast DR, Add on Rule 1 |
| *Resources Available* | | |
| *DR & DSM Assumptions* | 75% of Base EEPS<br>Fast DR Only | 75% of Base EEPS<br>Fast DR Only |
| *2014* | | |
| *2015* | | |
| *2016* | (1) 17 MW ICE - Biofuel [MS01] | (1) 17 MW ICE - Biofuel [MS01] |
| *2017* | | |
| *2018* | (1) 25 MW New Geo [MG02] | (1) 21 MW SC LM2500 - Biofuel [MS05] |
| *2019* | | |
| *2020* | | (1) 21 MW SC LM2500 - Biofuel [MS05] |
| *2021* | (1) 21 MW SC LM2500 - Biofuel [MS05] | |
| *2022* | | |
| *2023* | | (1) 25 MW Banagrass [MA01] |
| *2024* | (1) 25 MW New Geo [MG02] | |
| *2025* | | |
| *2026* | | |
| *2027* | (1) 17 MW ICE - Biofuel [MS01] | (1) 25 MW Banagrass [MA01] |
| *2028* | | |
| *2029* | | |
| *2030* | (1) 25 MW Banagrass [MA01] | |
| *2031* | | (1) 21 MW SC LM2500 - Biofuel [MS05] |
| *2032* | | |
| *2033* | | |
| *Planning Total Cost* | 4, 727, 451 | 4, 768, 211 |
| *Study Total Cost* | 7, 009, 543 | 7, 119, 244 |
| *Planning Rank* | 1 | 2 |
| *Study Rank* | 1 | 2 |

Table O-129. MECO Non-Firm Timing

| **Name** | **M3_2a_N-2r4** |
|---|---|
| *Plan* | NBD Screen Wind, PV, Wave |
| *Notes* | Firm Resource Timing on Rule 1, fixed from Unit Timing Run M3_2a_N-2r3, All DR, HC&S contract expires 12/31/2014 |
| *Resources Available* | |
| *DR & DSM Assumptions* | 75% of Base EEPS<br>All DR - CIDLC Exp, RDLC Exp, Fast DR |
| *2014* | |
| *2015* | (3) 5 MW ICE - Biofuel [MS14]<br>(3) 10 MW Wind - [MW04] |
| *2016* | (1) 21 MW SC LM2500 - Biofuel [MS05]<br>(2) 10 MW Wind - [MW04] |
| *2017* | |
| *2018* | (1) 10 MW Wind - [MW04] |
| *2019* | (1) 21 MW SC LM2500 - Biofuel [MS05] |
| *2020* | (1) 10 MW Wind - [MW04] |
| *2021* | (1) 10 MW Wind - [MW04] |
| *2022* | (1) 17 MW ICE - Biofuel [MS01]<br>(1) 10 MW Wind - [MW04] |
| *2023* | |
| *2024* | (1) 17 MW ICE - Biofuel [MS01] |
| *2025* | |
| *2026* | |
| *2027* | (1) 25 MW New Geo [MG02] |
| *2028* | |
| *2029* | |
| *2030* | |
| *2031* | (1) 17 MW ICE - Biofuel [MS01] |
| *2032* | |
| *2033* | |
| *Planning Total Cost* | 4, 792, 560 |
| *Study Total Cost* | 7, 068, 077 |
| *Planning Rank* | 1 |
| *Study Rank* | 1 |

Table O-130. MECO Environmental Compliance (1 of 2)

| **Name** | **M3_2a_N-2r4** | **M3B2a_N-4Br0** | **M3B2a_N-4Br1** |
|---|---|---|---|
| *Plan* | NBD Kahului Fuel Switch to LSIFO and Fuel Switch at Maalaea to S500 Diesel 2022. | NBD Kahului continues to use MSFO Fuel Switch at Maalaea to S500 Diesel 2022 | NBD Kahului Fuel Switch to LSIFO and Fuel Switch at Maalaea to S500 Diesel 2022. Unit Deactivations |
| *Notes* | Firm Resource Timing on Rule 1, fixed from Unit Timing Run M3_2a_N-2r3, All DR, HC&S contract expires 12/31/2014<br>No Existing Unit Deactivations | Environmental Compliance Run<br>Unit Timing 17MW ICE, 5MW ICE, LM2500, LM2500 DTCC, Geo, Bio, WTE<br>Existing Units Continue to use Fossil Fuel (Kahului fuel continue MSFO, Maalaea fuel switch to S500 in 2022)<br>No Existing Unit Deactivations | Environmental Compliance Run<br>Unit Timing 17MW ICE, LM2500, LM2500 DTCC, Geo, Bio,<br>Existing Units Continue to use Fossil Fuel (Kahului fuel switch to LSIFO, Maalaea fuel switch to S500 in 2022)<br>Deactivate existing units (K1-K4, MX1-M13) December 2021 |
| *Resources Available* | | | |
| *DR & DSM Assumptions* | 75% of base EEPS<br>All DR - CIDLC Exp, RDLC Exp, Fast DR | 75% of base EEPS<br>All DR - CIDLC Exp, RDLC Exp, Fast DR | 75% of base EEPS<br>All DR - CIDLC Exp, RDLC Exp, Fast DR |
| *2014* | | | |
| *2015* | (3) 5 MW ICE - Biofuel [MS14] | (3) 5 MW ICE - Biofuel [MS14] | (3) 5 MW ICE - Biofuel [MS14] |
| | (3) 10 MW wind - [MW04] | (3) 10 MW wind - [MW04] | (3) 10 MW wind - [MW04] |
| *2016* | (1) 21 MW SC LM2500 - Biofuel [MS05] | (1) 21 MW SC LM2500 - Biofuel [MS05] | (1) 21 MW SC LM2500 - Biofuel [MS05] |
| | (2) 10 MW wind - [MW04] | (2) 10 MW wind - [MW04] | (2) 10 MW wind - [MW04] |
| *2017* | | | |
| *2018* | (1) 10 MW wind - [MW04] | (1) 10 MW wind - [MW04] | (1) 10 MW wind - [MW04] |
| *2019* | (1) 21 MW SC LM2500 - Biofuel [MS05] | (1) 21 MW SC LM2500 - Biofuel [MS05] | (1) 21 MW SC LM2500 - Biofuel [MS05] |
| *2020* | (1) 10 MW wind - [MW04] | (1) 10 MW wind - [MW04] | |
| *2021* | (1) 10 MW wind - [MW04] | (1) 10 MW wind - [MW04] | (1) 25 MW New Geo [MG02] |
| | | | Deactivate MX1, MX2, M1-M13, K1-K4 (end of year) |
| *2022* | (1) 17 MW ICE - Biofuel [MS01] | (1) 17 MW ICE - Biofuel [MS01] | (1) 25 MW New Geo [MG02] |
| | (1) 10 MW wind - [MW04] | (1) 10 MW wind - [MW04] | (1) 17 MW ICE - Biofuel [MS01] |
| | | AQC for Kahului 1-4 | (1) 21 MW SC LM2500 - Biofuel [MS05] |
| | | | (1) 1/2 LM2500 DTCC (63MW) -Biofuel [MC05] |
| | | | (1) 1/2 LM2500 DTCC (63MW) -Biofuel [MC06] |
| | | | (3) 10 MW wind - [MW04] |
| *2023* | | | (1) 17 MW ICE - Biofuel [MS01] |
| *2024* | (1) 17 MW ICE - Biofuel [MS01] | (1) 17 MW ICE - Biofuel [MS01] | |

| Name | M3_2a_N-2r4 | M3B2a_N-4Br0 | M3B2a_N-4Br1 |
|---|---|---|---|
| *2025* | | | |
| *2026* | | | |
| *2027* | (1) 25 MW New Geo [MG02] | (1) 25 MW New Geo [MG02] | |
| *2028* | | | |
| *2029* | | | (1) 25 MW Banagrass [MA01] |
| *2030* | | | |
| *2031* | (1) 17 MW ICE - Biofuel [MS01] | (1) 17 MW ICE - Biofuel [MS01] | |
| *2032* | | | |
| *2033* | | | (1) 21 MW SC LM2500 - Biofuel [MS05] |
| *Planning Total Cost* | 4, 792, 560 | 4, 914, 013 | 5, 519, 669 |
| *Study Total Cost* | 7, 068, 077 | 7, 149, 607 | 8, 110, 809 |
| *Planning Rank* | 1 | 2 | 5 |
| *Study Rank* | 1 | 2 | 6 |

Table O-131. MECO Environmental Compliance (2 of 2)

| Name | M3B2a_N-4Br7 | M3B2a_N-4Br8 | M3B1a_N-4Cr0 |
|---|---|---|---|
| *Plan* | NBD Kahului Fuel Switch to LSIFO and Fuel Switch at Maalaea to S500 Diesel 2022. Unit Deactivation | NBD Kahului Fuel Switch to LSIFO and Fuel Switch at Maalaea to S500 Diesel 2022. Unit Deactivation | NBD Existing DTCC units (M141516, M171819) switch to LNG 2020. Kahului Units Switch to LSIFO and Fuel Switch at Maalaea to S500 Diesel 2022. No Unit Deactivation |
| *Notes* | Environmental Compliance Run<br>Unit Timing LM2500, Geo, Bio<br>Existing Units Continue to use Fossil Fuel (Kahului fuel switch to LSIFO, Maalaea fuel switch to S500 in 2022)<br>Deactivate existing units (K1-K4, MX1-M13) December 2021 | Environmental Compliance Run<br>Unit Timing 17MW ICE, LM2500, Geo, Bio<br>Existing Units Continue to use Fossil Fuel (Kahului fuel switch to LSIFO, Maalaea fuel switch to S500 in 2022)<br>Deactivate existing units (K1-K4, MX1-M13) December 2021 | Environmental Compliance Run<br>Same unit timing as plan 'M3B2a_N-4Br0'<br>No Existing Unit Deactivations<br>New units use Biofuel |
| *Resources Available* | | | |
| *DR & DSM Assumptions* | 75% of base EEPS<br>All DR - CIDLC Exp, RDLC Exp, Fast DR | 75% of base EEPS<br>All DR - CIDLC Exp, RDLC Exp, Fast DR | 75% of base EEPS<br>All DR - CIDLC Exp, RDLC Exp, Fast DR |
| *2014* | | | |
| *2015* | (3) 5 MW ICE - Biofuel [MS14] | (3) 5 MW ICE - Biofuel [MS14] | (3) 5 MW ICE - Biofuel [MS14] |
| | (3) 10 MW wind - [MW04] | (3) 10 MW wind - [MW04] | (3) 10 MW wind - [MW04] |
| *2016* | (1) 21 MW SC LM2500 - Biofuel [MS05] | (1) 21 MW SC LM2500 - Biofuel [MS05] | (1) 21 MW SC LM2500 - Biofuel [MS05] |
| | (2) 10 MW wind - [MW04] | (2) 10 MW wind - [MW04] | (2) 10 MW wind - [MW04] |
| *2017* | | | |
| *2018* | (1) 10 MW wind - [MW04] | (1) 10 MW wind - [MW04] | (1) 10 MW wind - [MW04] |
| *2019* | (1) 21 MW SC LM2500 - Biofuel [MS05] | (1) 21 MW SC LM2500 - Biofuel [MS05] | (1) 21 MW SC LM2500 - Biofuel [MS05] |
| *2020* | (1) 10 MW wind - [MW04] | (1) 10 MW wind - [MW04] | (1) 10 MW wind - [MW04] |
| | | | Fuel Switch to LNG (Maalaea DTCCs) |
| *2021* | (1) 10 MW wind - [MW04] | (1) 10 MW wind - [MW04] | (1) 10 MW wind - [MW04] |
| | Deactivate MX1, MX2, M1-M13, K1-K4 (end of year) | Deactivate MX1, MX2, M1-M13, K1-K4 (end of year) | |
| *2022* | (1) 25 MW New Geo [MG02] | (1) 25 MW New Geo [MG02] | (1) 17 MW ICE - Biofuel [MS01] |
| | (3) 21 MW SC LM2500 - Biofuel [MS05] | (7) 17 MW ICE - Biofuel [MS01] | (1) 10 MW wind - [MW04] |
| | (1) 1/2 LM2500 DTCC (63MW) -Biofuel [MC05] | (1) 10 MW wind - [MW04] | |
| | (1) 1/2 LM2500 DTCC (63MW) -Biofuel [MC06] | | |
| | (1) 10 MW wind - [MW04] | | |

| **Name** | **M3B2a_N-4Br7** | **M3B2a_N-4Br8** | **M3B1a_N-4Cr0** |
|---|---|---|---|
| *2023* | (1) 25 MW New Geo [MG02] | (1) 25 MW New Geo [MG02] | |
| *2024* | | | (1) 17 MW ICE - Biofuel [MS01] |
| *2025* | | | |
| *2026* | | | |
| *2027* | (1) 25 MW Banagrass [MA01] | (1) 17 MW ICE - Biofuel [MS01] | (1) 25 MW New Geo [MG02] |
| *2028* | | | |
| *2029* | | | |
| *2030* | | (1) 25 MW Banagrass [MA01] | |
| *2031* | | | (1) 17 MW ICE - Biofuel [MS01] |
| *2032* | (1) 21 MW SC LM2500 - Biofuel [MS05] | | |
| *2033* | | | |
| *Planning Total Cost* | 5, 523, 241 | 5, 463, 215 | 5, 088, 994 |
| *Study Total Cost* | 8, 106, 542 | 7, 989, 779 | 7, 782, 747 |
| *Planning Rank* | 6 | 4 | 3 |
| *Study Rank* | 5 | 4 | 3 |

Table O-132. MECO Energy Efficiency Portfolio Standard

| **Name** | **M3_2a_X-7Ar0** | **M3_2a_X-7Br0** | **M3_2a_X-7Cr0** | **M3_2a_X-7Dr0** |
|---|---|---|---|---|
| *Plan* | NBD Timing 17 MW ICE | NBD Timing 17 MW ICE | NBD Timing 17 MW ICE | NBD Timing 17MW ICE |
| *Notes* | EEPS Impact<br>17 MW SC Timing on Rule 1<br>No Existing Unit Retirements | EEPS Impact<br>17 MW SC Timing on Rule 1<br>No Existing Unit Retirements | EEPS Impact<br>17 MW SC Timing on Rule 1<br>No Existing Unit Retirements | EEPS Impact<br>17 MW SC Timing on Rule 1<br>No Existing Unit Retirements |
| *Resources Available* | | | | |
| *DR & DSM Assumptions* | 35% of Base EEPS<br>Fast DR | 75% of Base EEPS<br>Fast DR | 100% of Base EEPS<br>Fast DR | 110% of Base EEPS<br>Fast DR |
| *2014* | | | | |
| *2015* | (3) 5 MW ICE - Biofuel [MS14] | (3) 5 MW ICE - Biofuel [MS14] | (3) 5 MW ICE - Biofuel [MS14] | (3) 5 MW ICE - Biofuel [MS14] |
| *2016* | (1) 17 MW ICE - Biofuel [MS01] | (1) 17 MW ICE - Biofuel [MS01] | (1) 17 MW ICE - Biofuel [MS01] | (1) 17 MW ICE - Biofuel [MS01] |
| *2017* | (1) 17 MW ICE - Biofuel [MS01] | | | |
| *2018* | | (1) 17 MW ICE - Biofuel [MS01] | (1) 17 MW ICE - Biofuel [MS01] | (1) 17 MW ICE - Biofuel [MS01] |
| *2019* | (1) 17 MW ICE - Biofuel [MS01] | | | |
| *2020* | | (1) 17 MW ICE - Biofuel [MS01] | (1) 17 MW ICE - Biofuel [MS01] | |
| *2021* | (1) 17 MW ICE - Biofuel [MS01] | | | (1) 17 MW ICE - Biofuel [MS01] |
| *2022* | | (1) 17 MW ICE - Biofuel [MS01] | | |
| *2023* | (1) 17 MW ICE - Biofuel [MS01] | | (1) 17 MW ICE - Biofuel [MS01] | (1) 17 MW ICE - Biofuel [MS01] |
| *2024* | | (1) 17 MW ICE - Biofuel [MS01] | | |
| *2025* | (1) 17 MW ICE - Biofuel [MS01] | | | |
| *2026* | | | (1) 17 MW ICE - Biofuel [MS01] | (1) 17 MW ICE - Biofuel [MS01] |
| *2027* | (1) 17 MW ICE - Biofuel [MS01] | (1) 17 MW ICE - Biofuel [MS01] | | |
| *2028* | | | (1) 17 MW ICE - Biofuel [MS01] | |
| *2029* | | (1) 17 MW ICE - Biofuel [MS01] | | (1) 17 MW ICE - Biofuel [MS01] |
| *2030* | (1) 17 MW ICE - Biofuel | | | |

| **Name** | **M3_2a_X-7Ar0** | **M3_2a_X-7Br0** | **M3_2a_X-7Cr0** | **M3_2a_X-7Dr0** |
|---|---|---|---|---|
| | [MS01] | | | |
| *2031* | | | | |
| *2032* | (1) 17 MW ICE - Biofuel [MS01] | (1) 17 MW ICE - Biofuel [MS01] | (1) 17 MW ICE - Biofuel [MS01] | (1) 17 MW ICE - Biofuel [MS01] |
| *2033* | | | | |
| *Planning Total Cost* | 5, 224, 178 | 5, 071, 779 | 4, 972, 936 | 4, 943, 363 |
| *Study Total Cost* | 7, 888, 225 | 7, 572, 211 | 7, 362, 362 | 7, 305, 047 |
| *Planning Rank* | 4 | 3 | 2 | 1 |
| *Study Rank* | 4 | 3 | 2 | 1 |

Table O-133. MECO 100% Renewable Energy

| **Name** | **M3C2a_N-3Cr0** | **M3C2a_N-3Cr1** |
|---|---|---|
| *Plan* | NBD | NBD |
| *Notes* | Unit Timing for years 2015-2022 from 'M3_2a_N-2r4'<br>17MW ICE, 5MW ICE, LM2500, Geo, Biomass, WTE<br>Wind, PV, Wave<br>100% RE<br>Existing Units Switch to Biofuel 2030 | Unit Timing 17MW ICE, 5MW ICE, LM2500, Geo, Biomass, Wind, PV<br>100% RE<br>Existing Units Switch to Biofuel 2030<br>Deactivate existing units (K1-K4, MX1-M11) on Remaining Useful Life |
| *Resources Available* | | |
| *DR & DSM Assumptions* | 75% of Base EEPS<br>All DR - CIDLC Exp, RDLC Exp, Fast DR | 75% of Base EEPS<br>All DR - CIDLC Exp, RDLC Exp, Fast DR |
| *2014* | | |
| *2015* | (3) 5 MW ICE - Biofuel [MS14] | (3) 5 MW ICE - Biofuel [MS14] |
| | (3) 10 MW Wind - [MW04] | (3) 10 MW Wind - [MW04] |
| *2016* | (1) 21 MW SC LM2500 - Biofuel [MS05] | (1) 21 MW SC LM2500 - Biofuel [MS05] |
| | (2) 10 MW Wind - [MW04] | (2) 10 MW Wind - [MW04] |
| *2017* | | |
| *2018* | (1) 10 MW Wind - [MW04] | (1) 10 MW Wind - [MW04] |
| *2019* | (1) 21 MW SC LM2500 - Biofuel [MS05] | (1) 21 MW SC LM2500 - Biofuel [MS05] |
| *2020* | (1) 10 MW Wind - [MW04] | (1) 10 MW Wind - [MW04] |
| *2021* | (1) 10 MW Wind - [MW04] | (1) 10 MW Wind - [MW04] |
| *2022* | (1) 17 MW ICE - Biofuel [MS01] | (1) 17 MW ICE - Biofuel [MS01] |
| | (1) 10 MW Wind - [MW04] | (1) 10 MW Wind - [MW04] |
| *2023* | | Deactivate M4, M5 (end of year) |
| *2024* | (1) 17 MW ICE - Biofuel [MS01] | (1) 17 MW ICE - Biofuel [MS01] |
| | (5) 1MW Tracking PV | |
| *2025* | (5) 1MW Tracking PV | (1) 17 MW ICE - Biofuel [MS01] |
| | | Deactivate K1, K2, K3, K4, M6, M7 (end of year) |
| *2026* | (5) 1MW Tracking PV | (1) 25 MW New Geo [MG02] |
| | | (1) 17 MW ICE - Biofuel [MS01] |
| | | Deactivate M1 (end of year) |
| *2027* | (1) 25 MW New Geo [MG02] | (1) 25 MW New Geo [MG02] |
| | (5) 1MW Tracking PV | Deactivate M2, M3, M8 (end of year) |
| *2028* | (5) 1MW Tracking PV | |
| | | Deactivate M9 (end of year) |

| Name | M3C2a_N-3Cr0 | M3C2a_N-3Cr1 |
|---|---|---|
| *2029* | (5) 1MW Tracking PV | (1) 25 MW Banagrass [MA01] |
| | | (5) 1MW Tracking PV |
| | | Deactivate M10 (end of year) |
| *2030* | (5) 1MW Tracking PV | (1) 25 MW Banagrass [MA01] |
| | | (5) 1MW Tracking PV |
| | | Deactivate M11 (end of year) |
| *2031* | (1) 17 MW ICE - Biofuel [MS01] | (5) 1MW Tracking PV |
| | (5) 1MW Tracking PV | |
| *2032* | (5) 1MW Tracking PV | (1) 21 MW SC LM2500 - Biofuel [MS05] |
| | | (5) 1MW Tracking PV |
| | | Deactivate MX1, MX2 (end of year) |
| *2033* | (5) 1MW Tracking PV | |
| *Planning Total Cost* | 5, 182, 281 | 5, 259, 284 |
| *Study Total Cost* | 8, 258, 992 | 8, 227, 970 |
| *Planning Rank* | 1 | 2 |
| *Study Rank* | 2 | 1 |

Table O-134. MECO Wind Capacity Value

| **Name** | **M3_2a_N-2r4** | **M3B2a_N-8r0** |
|---|---|---|
| *Plan* | NBD Kahului Fuel Switch to LSIFO and<br>Fuel Switch at Maalaea to S500 Diesel 2022 | NBD 5% Wind Capacity Value |
| *Notes* | Firm Resource Timing on Rule 1, fixed from Unit Timing Run M3_2a_N-2r3, All DR, HC&S contract expires 12/31/2014<br>No Existing Unit Deactivations | Firm Resource Timing on Rule 1, Unit Timing Run M3_2a_N-2r4 as a guide<br>All DR, HC&S contract expires 12/31/2014<br>Wind Resources Provide 5% Firm Capacity Value |
| *Resources Available* | 10 MW Wind (MW04) - Avail 2015<br>1 MW PV (MP03) - Avail 2030<br>15 MW Ocean Wave (MV02) - Avail 2030<br>17 MW ICE (MS01) - Avail 2016<br>21 MW CT (MS05) - Avail 2016<br>25 MW Geothermal (MG02) - Avail 2016<br>25 MW Biomass (MA01) - Avail 2017<br>8 MW WTE (MT01) - Avail 2017 | 10 MW Wind (MW04) - Avail 2015<br>1 MW PV (MP03) - Avail 2015<br>17 MW ICE (MS01) - Avail 2022<br>5 MW ICE (MS14) - Avail 2015<br>21 MW CT (MS05) - Avail 2016<br>25 MW Geothermal (MG02) - Avail 2023<br>25 MW Biomass (MA01) - Avail 2023 |
| *DR & DSM Assumptions* | 75% of Base EEPS<br>All DR - CIDLC Exp, RDLC Exp, Fast DR | 75% of Base EEPS<br>All DR - CIDLC Exp, RDLC Exp, Fast DR |
| *2014* | | |
| *2015* | (3) 5 MW ICE - Biofuel [MS14] | (2) 5 MW ICE - Biofuel [MS14] |
| | (3) 10 MW Wind - [MW04] | (3) 10 MW Wind - [MW04] |
| *2016* | (1) 21 MW SC LM2500 - Biofuel [MS05] | (1) 21 MW SC LM2500 - Biofuel [MS05] |
| | (2) 10 MW Wind - [MW04] | (2) 10 MW Wind - [MW04] |
| *2017* | | |
| *2018* | (1) 10 MW Wind - [MW04] | (1) 10 MW Wind - [MW04] |
| *2019* | (1) 21 MW SC LM2500 - Biofuel [MS05] | (1) 21 MW SC LM2500 - Biofuel [MS05] |
| | | (1) 10 MW Wind - [MW04] |
| *2020* | (1) 10 MW Wind - [MW04] | |
| *2021* | (1) 10 MW Wind - [MW04] | (2) 10 MW Wind - [MW04] |
| | | |
| *2022* | (1) 17 MW ICE - Biofuel [MS01] | (1) 17 MW ICE - Biofuel [MS01] |
| | (1) 10 MW Wind - [MW04] | |
| *2023* | | |
| *2024* | (1) 17 MW ICE - Biofuel [MS01] | (1) 17 MW ICE - Biofuel [MS01] |
| *2025* | | |
| *2026* | | |
| *2027* | (1) 25 MW New Geo [MG02] | (1) 25 MW New Geo [MG02] |
| *2028* | | |
| *2029* | | |

| **Name** | **M3_2a_N-2r4** | **M3B2a_N-8r0** |
|---|---|---|
| *2030* | | |
| *2031* | (1) 17 MW ICE - Biofuel [MS01] | (1) 17 MW ICE - Biofuel [MS01] |
| *2032* | | |
| *2033* | | |
| *Planning Total Cost* | 4, 792, 560 | 4, 734, 182 |
| *Study Total Cost* | 7, 068, 077 | 6, 998, 552 |
| *Planning Rank* | 2 | 1 |
| *Study Rank* | 2 | 1 |

## Moved by Passion

Table O-135. MECO Firm Timing

| **Name** | **M4_2a_N-1r0** | **M4_2a_X-1r0** | **M4_2b_X-1r0** |
|---|---|---|---|
| *Plan* | MBP all timing | MBP all timing | MBP all timing |
| *Notes* | All firm Timing on Rule 1, without HC&S, plan rank 1 | All firm Timing on Rule 1, without HC&S, plan rank 1 | All firm Timing on Rule 1, with HC&S, plan rank 1 |
| *Resources Available* | | | |
| *DR & DSM Assumptions* | 100% of Base EEPS<br>All DR - CIDLC Exp, RDLC Exp, Fast DR | 100% of Base EEPS<br>Fast DR Only | 100% of Base EEPS<br>Fast DR Only |
| *2014* | | | |
| *2015* | | | |
| *2016* | | | |
| *2017* | | | |
| *2018* | | | |
| *2019* | | | |
| *2020* | | | |
| *2021* | | | |
| *2022* | | | |
| *2023* | | | |
| *2024* | | | |
| *2025* | | | |
| *2026* | | | |
| *2027* | | | |
| *2028* | | | |
| *2029* | | | |
| *2030* | | | |
| *2031* | | | |
| *2032* | | | |
| *2033* | (1) 25 MW New Geo [MG02] | (1) 25 MW New Geo [MG02] | |
| *Planning Total Cost* | 4, 525, 174.50 | 4, 498, 311.50 | 4, 517, 772.50 |
| *Study Total Cost* | 6, 577, 468.50 | 6, 545, 153.50 | 6, 610, 207.00 |
| *Planning Rank* | 3 | 1 | 2 |
| *Study Rank* | 2 | 1 | 3 |

Table O-136. MECO As-Available Screening (1 of 2)

| **Name** | **M4_2a_X-2r0** | **M4_2a_X-2r1** | **M4_2a_X-2r10** |
|---|---|---|---|
| *Plan* | MBP Screening Wind | MBP Screening PV | MBP Screening Wind |
| *Notes* | With Geothermal, Plan Rank 1 | With Geothermal, Plan Rank 1 | With Geothermal, Plan Rank 1 |
| *Resources Available* | | | |
| *Max Dump* | 32% | 29% | 23% |
| *DR & DSM Assumptions* | 100% of Base EEPS<br>Fast DR Only | 100% of Base EEPS<br>Fast DR Only | 100% of Base EEPS<br>Fast DR Only |
| *2014* | | | |
| *2015* | (1) 10 MW Wind - [MW04] | (5) 1 MW PV - [MP03] | (1) 10 MW Wind - [MW04] |
| *2016* | | | |
| *2017* | | | |
| *2018* | | | |
| *2019* | | | |
| *2020* | | | |
| *2021* | | | |
| *2022* | | | |
| *2023* | | | |
| *2024* | | | |
| *2025* | | | |
| *2026* | | | |
| *2027* | | | |
| *2028* | | | |
| *2029* | | | |
| *2030* | | | |
| *2031* | | | |
| *2032* | | | |
| *2033* | (1) 25 MW New Geo [MG02] | (1) 25 MW New Geo [MG02] | |
| *Planning Total Cost* | 4, 469, 527.00 | 4, 491, 292.00 | 4, 464, 544.00 |
| *Study Total Cost* | 6, 500, 437.00 | 6, 528, 762.00 | 6, 501, 011.00 |
| *Planning Rank* | 3 | 5 | 2 |
| *Study Rank* | 2 | 4 | 3 |

Table O-137. MECO As-Available Screening (2 of 2)

| **Notes** | **M4_2a_X-2r11** | **M4_2a_X-2r12** |
|---|---|---|
| *Plan* | MBP Screening PV | MBP Screening PV |
| *Notes* | Without Geothermal, Plan Rank 1 | Without Geothermal, Plank Rank 1 |
| *Resources Available* | | |
| *Max Dump* | 20% | 19% |
| *DR & DSM Assumptions* | 100% of Base EEPS<br>Fast DR Only | 100% of Base EEPS<br>Fast DR Only |
| *2014* | | |
| *2015* | (5) 1 MW PV - [MP03] | (5) 1 MW PV - [MP03] |
| *2016* | | (5) 1 MW PV - [MP03] |
| *2017* | | (5) 1 MW PV - [MP03] |
| *2018* | | (5) 1 MW PV - [MP03] |
| *2019* | | (5) 1 MW PV - [MP03] |
| *2020* | | (5) 1 MW PV - [MP03] |
| *2021* | | (5) 1 MW PV - [MP03] |
| *2022* | | (5) 1 MW PV - [MP03] |
| *2023* | | (5) 1 MW PV - [MP03] |
| *2024* | | |
| *2025* | | |
| *2026* | | |
| *2027* | | |
| *2028* | | |
| *2029* | | |
| *2030* | | |
| *2031* | | |
| *2032* | | |
| *2033* | | (5) 1 MW PV - [MP03] |
| *Planning Total Cost* | 4, 486, 544.50 | 4, 459, 951.50 |
| *Study Total Cost* | 6, 533, 503.00 | 6, 418, 476.00 |
| *Planning Rank* | 4 | 1 |
| *Study Rank* | 5 | 1 |

Table O-138. MECO Environmental Compliance (1 of 2)

| **Notes** | **M4B2A_X-4Ar0** | **M4B2A_X-4Cr0** | **M4B2A_X-4Cr1** |
|---|---|---|---|
| *Plan* | MBP Environmental Compliance Run | MBP Consolidated, 100% Renewable | MBP Consolidated, 100% Renewable |
| *Notes* | Without Deactivations, No KPP fuel switch, Install Air Quality Controls | With Deactivations | With Deactivations |
| *Resources Available* | | | |
| *Max Dumped* | 19% | 22% | 17% |
| *DR & DSM Assumptions* | 100% of Base EEPS<br>Fast DR Only | 100% of Base EEPS<br>Fast DR Only | 100% of Base EEPS<br>Fast DR Only |
| *2014* | | | |
| *2015* | (5) 1 MW PV [MP03] | (5) 1 MW PV [MP03] | (5) 1 MW PV [MP03] |
| *2016* | (5) 1 MW PV [MP03] | (5) 1 MW PV [MP03] | (5) 1 MW PV [MP03] |
| *2017* | (5) 1 MW PV [MP03] | | (5) 1 MW PV [MP03] |
| *2018* | (5) 1 MW PV [MP03] | | (5) 1 MW PV [MP03] |
| *2019* | (5) 1 MW PV [MP03] | | (5) 1 MW PV [MP03] |
| *2020* | (5) 1 MW PV [MP03] | | (5) 1 MW PV [MP03] |
| *2021* | (5) 1 MW PV [MP03] | | |
| *2022* | (5) 1 MW PV [MP03] | Deactivate K1, K2, K3, K4, X1, X2, M1, M2, M3, M4, M5, M6, M7, M8, M9, M10, M11, M12, M13 | Deactivate K1, K2, K3, K4, X1, X2, M1, M2, M3, M4, M5, M6, M7, M8, M9, M10, M11, M12, M13 |
| | | (1) 25 MW New Geo [MG02] | (1) 25 MW New Geo [MG02] |
| | | (1) 25 MW Banagrass [MA01] | (6) 17 MW ICE [MS01] |
| | | (5) 17 MW ICE [MS01] | |
| | AQC for Kahului 1-4 | | |
| *2023* | | | |
| *2024* | | | (1) 17 MW ICE [MS01] |
| *2025* | | | |
| *2026* | | | |
| *2027* | | | |
| *2028* | | | |
| *2029* | | | |
| *2030* | (5) 1 MW PV [MP03] | | |
| *2031* | | | |
| *2032* | | | |
| *2033* | (5) 1 MW PV [MP03] | | |

| Notes | M4B2A_X-4Ar0 | M4B2A_X-4Cr0 | M4B2A_X-4Cr1 |
|---|---|---|---|
| *Planning Total Cost* | 4, 578, 902.79 | 4, 827, 087.29 | 4, 860, 836.77 |
| *Study Total Cost* | 6, 490, 809.27 | 6, 728, 064.90 | 6, 765, 237.90 |
| *Planning Rank* | 3 | 4 | 6 |
| *Study Rank* | 3 | 4 | 6 |

Table O-139. MECO Environmental Compliance (2 of 2)

| **Name** | **M4B2A_X-4Cr2** | **M4B1A_X-4Ar0** | **M4_2a_X-2r12** |
|---|---|---|---|
| *Plan* | MBP Consolidated, 100% Renewable | MBP Environmental Compliance Run, LNG DTCC | MBP Screening PV |
| *Notes* | With Deactivations | Without Retirements, LNG DTCC, plan 1 | Without Geothermal, Plank Rank 1 |
| *Resources Available* | | | |
| *Max Dumped* | 20% | | 19% |
| *DR & DSM Assumptions* | 100% of Base EEPS<br>Fast DR Only | 100% of Base EEPS<br>Fast DR Only | 100% of Base EEPS<br>Fast DR Only |
| *2014* | | | |
| *2015* | (5) 1 MW PV [MP03] | (5) 1 MW PV [MP03] | (5) 1 MW PV - [MP03] |
| | (1) 10 MW Wind [MW04] | | |
| *2016* | (5) 1 MW PV [MP03] | (5) 1 MW PV [MP03] | (5) 1 MW PV - [MP03] |
| *2017* | (5) 1 MW PV [MP03] | (5) 1 MW PV [MP03] | (5) 1 MW PV - [MP03] |
| *2018* | (5) 1 MW PV [MP03] | (5) 1 MW PV [MP03] | (5) 1 MW PV - [MP03] |
| *2019* | (5) 1 MW PV [MP03] | (5) 1 MW PV [MP03] | (5) 1 MW PV - [MP03] |
| *2020* | | (5) 1 MW PV [MP03] | (5) 1 MW PV - [MP03] |
| *2021* | | (5) 1 MW PV [MP03] | (5) 1 MW PV - [MP03] |
| *2022* | Deactivate K1, K2, K3, K4, X1, X2, M1, M2, M3, M4, M5, M6, M7, M8, M9, M10, M11, M12, M13 | | (5) 1 MW PV - [MP03] |
| | (1) 25 MW New Geo [MG02] | | |
| | (6) 17 MW ICE [MS01] | | |
| *2023* | | | (5) 1 MW PV - [MP03] |
| *2024* | (1) 17 MW ICE [MS01] | | |
| *2025* | | | |
| *2026* | | | |
| *2027* | | | |
| *2028* | | | |
| *2029* | | (5) 1 MW PV [MP03] | |
| *2030* | | | |
| *2031* | | (5) 1 MW PV [MP03] | |
| *2032* | | | |
| *2033* | | (5) 1 MW PV [MP03] | (5) 1 MW PV [MP03] |
| *Planning Total Cost* | 4, 841, 780.80 | 4, 278, 735.37 | 4, 459, 951.33 |

**Appendix O: Resource Plan Sheets**

MECO Resource Plans

| **Name** | **M4B2A_X-4Cr2** | **M4B1A_X-4Ar0** | **M4_2a_X-2r12** |
|---|---|---|---|
| *Study Total Cost* | 6, 743, 316.40 | 6, 062, 163.80 | 6, 418, 476.00 |
| *Planning Rank* | 5 | 1 | 2 |
| *Study Rank* | 5 | 1 | 2 |

Table O-140. MECO Energy Efficiency Portfolio Standard

| **Name** | **M4_2A_X-7Ar0** | **M4_2A_X-7Br0** | **M4_2A_X-7Cr0** | **M4_2A_X-7Dr0** |
|---|---|---|---|---|
| *Plan* | MBP 35% EEPS | MBP 75% EEPS | MBP 100% EEPS | MBP 110% EEPS |
| *Notes* | All 17MW ICE Timing on Rule 1, plan rank 1 | All 17MW ICE Timing on Rule 1, plan rank 1 | All 17MW ICE Timing on Rule 1, plan rank 1 | All 17MW ICE Timing on Rule 1, plan rank 1 |
| *Resources Available* | | | | |
| *DR & DSM Assumptions* | 35% of Base EEPS<br>Fast DR Only | 75% of Base EEPS<br>Fast DR Only | 100% of Base EEPS<br>Fast DR Only | 110% of Base EEPS<br>Fast DR Only |
| *2014* | | | | |
| *2015* | | | | |
| *2016* | | | | |
| *2017* | | | | |
| *2018* | | | | |
| *2019* | (1) 17 MW ICE [MS01] | | | |
| *2020* | | | | |
| *2021* | | | | |
| *2022* | | | | |
| *2023* | | | | |
| *2024* | | (1) 17 MW ICE [MS01] | | |
| *2025* | | | | |
| *2026* | | | | |
| *2027* | (1) 17 MW ICE [MS01] | | | |
| *2028* | | | | |
| *2029* | | | | |
| *2030* | | | | |
| *2031* | | | | |
| *2032* | | | | |
| *2033* | | | | |
| *Planning Total Cost* | 4, 749, 953.50 | 4, 596, 187.50 | 4, 493, 827.00 | 4, 478, 280.00 |
| *Study Total Cost* | 7, 097, 095.00 | 6, 763, 068.50 | 6, 554, 562.50 | 6, 504, 873.00 |
| *Planning Rank* | 4 | 3 | 2 | 1 |
| *Study Rank* | 4 | 3 | 2 | 1 |

Table O-141. MECO 100% Renewable Energy (1 of 2)

| **Name** | **M4C2a_X-3Cr0** | **M4C2a_X-3Cr10** | **M4C2a_X-3Cr11** |
|---|---|---|---|
| *Plan* | MBP Consolidated, 100% Renewable | MBP Consolidated, 100% Renewable | MBP Consolidated, 100% Renewable |
| *Notes* | Without Retirements, plan 1 | With Retirements, Remaining Useful Life plan, plan 1 | With Retirements, Remaining Useful Life plan, plan 1 |
| *Resources Available* | | | |
| *Max Dumped* | 20% | 31% | 19% |
| *DR & DSM Assumptions* | 100% of Base EEPS<br>Fast DR Only | 100% of Base EEPS<br>Fast DR Only | 100% of Base EEPS<br>Fast DR Only |
| *2014* | | | |
| *2015* | (5) 1 MW PV [MP03] | | |
| *2016* | (5) 1 MW PV [MP03] | | |
| *2017* | (5) 1 MW PV [MP03] | | |
| *2018* | (5) 1 MW PV [MP03] | | |
| *2019* | (5) 1 MW PV [MP03] | | |
| *2020* | (5) 1 MW PV [MP03] | | |
| *2021* | (5) 1 MW PV [MP03] | | |
| *2022* | (5) 1 MW PV [MP03] | | |
| *2023* | (5) 1 MW PV [MP03] | Deactivate M4, M5 | Deactivate M4, M5 |
| *2024* | | (1) 17 MW ICE [MS01] | (1) 17 MW ICE [MS01] |
| *2025* | | Deactivate K1, K2, K3, K4, M6, M7 | Deactivate K1, K2, K3, K4, M6, M7 |
| *2026* | | (1) 25 MW New Geo [MG02] | (1) 25 MW New Geo [MG02] |
| | | (1) 17 MW ICE [MS01] | (1) 17 MW ICE [MS01] |
| | | Deactivate M1 | Deactivate M1 |
| *2027* | | Deactivate M2, M3, M8 | Deactivate M2, M3, M8 |
| *2028* | | (1) 25 MW New Geo [MG02] | (1) 17 MW ICE [MS01] |
| | | Deactivate M9 | Deactivate M9 |
| *2029* | | Deactivate M10 | (1) 17 MW ICE [MS01] |
| | | | Deactivate M10 |
| *2030* | (5) 1 MW PV [MP03] | (1) 17 MW ICE [MS01] | |
| | | Deactivate M11 | Deactivate M11 |
| *2031* | | (1) 5 MW ICE [MS14] | (1) 17 MW ICE [MS01] |
| *2032* | | Deactivate X1, X2 | Deactivate X1, X2 |
| *2033* | | | |
| *Planning Total Cost* | 4, 535, 346.50 | 4, 563, 620.00 | 4, 569, 630.50 |

| Name | M4C2a_X-3Cr0 | M4C2a_X-3Cr10 | M4C2a_X-3Cr11 |
|---|---|---|---|
| *Study Total Cost* | 6, 227, 419.50 | 6, 450, 845.00 | 6, 472, 975.00 |
| *Planning Rank* | 1 | 3 | 5 |
| *Study Rank* | 1 | 3 | 5 |

Table O-142. MECO 100% Renewable Energy (2 of 2)

| **Name** | **M4C2a_X-3Cr12** | **M4C2a_X-3Cr13** |
|---|---|---|
| *Plan* | MBP Consolidated, 100% Renewable | MBP Consolidated, 100% Renewable |
| *Notes* | With Retirements, Remaining Useful Life plan, plan 1 | With Retirements, Remaining Useful Life plan, plan 1 |
| *Resources Available* | | |
| *Max Dumped* | 18% | 17% |
| *DR & DSM Assumptions* | 100% of Base EEPS<br>Fast DR Only | 100% of Base EEPS<br>Fast DR Only |
| *2014* | | |
| *2015* | (5) 1 MW PV [MP03] | (5) 1 MW PV [MP03] |
| *2016* | | (5) 1 MW PV [MP03] |
| *2017* | | (5) 1 MW PV [MP03] |
| *2018* | | (5) 1 MW PV [MP03] |
| *2019* | | (5) 1 MW PV [MP03] |
| *2020* | | (5) 1 MW PV [MP03] |
| *2021* | | |
| *2022* | | |
| *2023* | Deactivate M4, M5 | Deactivate M4, M5 |
| *2024* | (1) 17 MW ICE [MS01] | (1) 17 MW ICE [MS01] |
| *2025* | Deactivate K1, K2, K3, K4, M6, M7 | Deactivate K1, K2, K3, K4, M6, M7 |
| *2026* | (1) 25 MW New Geo [MG02] | (1) 25 MW New Geo [MG02] |
| | (1) 17 MW ICE [MS01] | (1) 17 MW ICE [MS01] |
| | Deactivate M1 | Deactivate M1 |
| *2027* | Deactivate M2, M3, M8 | Deactivate M2, M3, M8 |
| *2028* | (1) 17 MW ICE [MS01] | (1) 17 MW ICE [MS01] |
| | Deactivate M9 | Deactivate M9 |
| *2029* | (1) 17 MW ICE [MS01] | (1) 17 MW ICE [MS01] |
| | Deactivate M10 | Deactivate M10 |
| | Deactivate M11 | Deactivate M11 |
| *2031* | (1) 17 MW ICE [MS01] | (1) 17 MW ICE [MS01] |
| *2032* | Deactivate X1, X2 | Deactivate X1, X2 |
| *2033* | | |
| *Planning Total Cost* | 4, 564, 387.50 | 4, 552, 187.00 |
| *Study Total Cost* | 6, 460, 925.00 | 6, 426, 976.50 |
| *Planning Rank* | 4 | 2 |
| *Study Rank* | 4 | 2 |

Table O-143. MECO Wind Capacity Value

| **Name** | **M4_2a_X-1r0** | **M4B2a_X-8r0** |
|---|---|---|
| *Plan* | MBP all timing | MBP all timing |
| *Notes* | All firm Timing on Rule 1, without HC&S | All firm Timing on Rule 1, without HC&S |
| *Max Dumped* | 29% | 29% |
| *DR & DSM Assumptions* | 100% of Base EEPS<br>Fast DR Only | 100% of Base EEPS<br>Fast DR Only |
| *2014* | | |
| *2015* | | |
| *2016* | | |
| *2017* | | |
| *2018* | | |
| *2019* | | |
| *2020* | | |
| *2021* | | |
| *2022* | | |
| *2023* | | |
| *2024* | | |
| *2025* | | |
| *2026* | | |
| *2027* | | |
| *2028* | | |
| *2029* | | |
| *2030* | | |
| *2031* | | |
| *2032* | | |
| *2033* | (1) 25 MW New Geo [MG02] | (1) 25 MW New Geo [MG02] |
| *Planning Total Cost* | 4, 498, 311.50 | 4, 498, 218.00 |
| *Study Total Cost* | 6, 545, 153.50 | 6, 544, 616.00 |
| *Planning Rank* | 2 | 1 |
| *Study Rank* | 2 | 1 |

# Interconnection Resource Plans

## Stuck in the Middle

Table O-144. MECO Renewable Portfolio Standard

| **Name** | **PHM2B2B1NRETIRE-3BR0** | | |
|---|---|---|---|
| *Plan* | HECO Fuel Switch to ULSD in 2022 | HELCO Deactivate Existing Replace with Geothermal | MECO Fuel Switch to LSIFO in 2022 |
| *Notes* | Consolidated RPS Target Run | Consolidated RPS Target Run | Consolidated RPS Target Run |
| *Resources Available* | 30 MW Wind (PW01)-2017<br>5 MW PV (PP03)-2015 | 10 MW Wind (HW01)-2015<br>1 MW PV (HP03)-2015<br>25 MW Geothermal (HG01)-2017<br>25 MW New Site Geo (HG02)-2020 | 10 MW Wind (MW04)-2015<br>1 MW PV (MP03)-2015 |
| *2014* | Expanded CIDLC, CIDP, RDLCWH, RDLCAC | No DR | All DR - CIDLC Exp, RDLC Exp, Fast DR |
| | 75% PBFA DSM | 75% PBFA DSM | 75% PBFA DSM |
| | | Hu Honua (21.5MW) | |
| *2015* | | Add 5 MW PV (HP03x5) | Add 30MW Wind (MW04x3) |
| | | Deactivate Shipman 3 (-6.8 MW) | |
| | | Deactivate Shipman 4 (-6.7 MW) | |
| *2016* | Add 20 MW PV (PP03x4) | | Add 30MW Wind (MW04x3) |
| | Add 60 MW Wind (PW01x2) | | |
| | Fuel Switch to Diesel (Hon 8-9, Waiau 5-8, Kahe 1-6) | | |
| *2017* | Add 60 MW Wind (PW01x2) | Add 10MW Wind (HW04x1) | Add 30MW Wind (MW04x3) |
| | Deactivate W3 (-46MW)<br>Deactivate W4 (-46MW)<br>or H8/9 | | |
| *2018* | Add 60 MW Wind (PW01x2) | Add 10MW Wind (HW04x1) | Add 20MW Wind (MW04x2) |
| *2019* | Deactivate H8 (-53MW)<br>Deactivate H9 (-54MW)<br>or W3/4 | | |
| *2020* | Add 59MW CC (PC08x1)-Biofueled | | |
| | Add 200 MW Lanai Wind | | |
| *2021* | | Add 10MW Wind (HW04x1) | |

| **Name** | **PHM2B2B1NRETIRE-3BR0** | | |
|---|---|---|---|
| *2022* | | Add 25MW Geothermal (HG01x1) | |
| | Fuel Switch to ULSD (Waiau 5-8, Kahe 1-6) | Fuel Switch to LSIFO (Hill 5-6, Puna 1) | Fuel Switch to LSIFO (Kahului 1-4, ) Fuel Swith to ULSD (All Maalaea) |
| *2023* | | | |
| *2024* | | Add 5 MW PV (HP03x5) | |
| *2025* | | Add 5 MW PV (HP03x5) | |
| *2026* | | Add 5 MW PV (HP03x5) | Add 10MW Wind (MW04x1) |
| *2027* | Add 25MW (PA01x1)-Biomass | | |
| *2028* | | Add 5 MW PV (HP03x5) | |
| *2029* | | | Add 5MW ICE (MS14x1)-Biodiesel |
| *2030* | | Add 5 MW PV (HP03x5) | |
| *2031* | | Add 10MW Wind (HW04x1) | Add 10MW Wind (MW04x1) |
| *2032* | Add 20 MW PV (PP03x4) | Add 10MW Wind (HW04x1) | |
| *2033* | Add 30 MW Wind (PW01x1) | Add 5 MW PV (HP03x5) | Add 10MW Wind (MW04x1) |
| | Add 20 MW PV (PP03x4) | Add 25MW New Geothermal (HG02x1) | |
| *Planning Period Total Cost* | 29, 972, 196 | | |
| *Study Period Total Cost* | 44, 312, 256 | | |
| *Interconnection Energy* | | | |

Table O-145. HECO – HELCO 1

| **Name** | **PH2B2b1N-6Cr1x (No Interconnection)** | | **PH2B2b1N-6Cr1 (With Interconnection)** | |
|---|---|---|---|---|
| *Plan* | HECO Fuel Switch to LNG in 2020 | HELCO Deactivate Existing Replace with Geothermal | HECO Fuel Switch to LNG in 2020 | HELCO Deactivate Existing Replace with Geothermal |
| *Notes* | Fuel switch applies to all Waiau 5-8 and Kahe 1-6 | All Units except Keahole CC are deactivated by Dec 2020<br>Cycle Hill 5/6, Puna Steam | Fuel switch applies to all Waiau 5-8 and Kahe 1-6 | All Units except Keahole CC are deactivated by Dec 2020<br>Cycle Hill 5/6, Puna Steam |
| *Resources Available* | None | None | None | None |
| *Interconnection Charge* | n/a | | 0 ¢/kWh | |
| *2014* | Expanded CIDLC, CIDP, RDLCWH, RDLCAC | | Expanded CIDLC, CIDP, RDLCWH, RDLCAC | |
| | 75% PBFA DSM | 75% PBFA DSM | 75% PBFA DSM | 75% PBFA DSM |
| | | Hu Honua (21.5MW) | | Hu Honua (21.5MW) |
| *2015* | | Deactivate Shipman 3 (- 6.8 MW) | | Deactivate Shipman 3 (- 6.8 MW) |
| | | Deactivate Shipman 4 (- 6.7 MW) | | Deactivate Shipman 4 (- 6.7 MW) |
| *2016* | Add 20 MW PV (PP03x4) | | Add 20 MW PV (PP03x4) | |
| | Add 60 MW Wind (PW01x2) | | Add 60 MW Wind (PW01x2) | |
| | Fuel Switch to Diesel (Hon 8-9Waiau 5-8, Kahe 1-6) | | Fuel Switch to Diesel (Hon 8-9Waiau 5-8, Kahe 1-6) | |
| *2017* | | Add 10MW Wind (HW04x1) | | Add 10MW Wind (HW04x1) |
| | Add 60 MW Wind (PW01x2) | | Add 60 MW Wind (PW01x2) | |
| | Deactivate W3 (-46MW)<br>Deactivate W4 (-46MW)<br>or H8/9 | | Deactivate W3 (-46MW)<br>Deactivate W4 (-46MW)<br>or H8/9 | |
| *2018* | Add 60 MW Wind (PW01x2) | | Add 60 MW Wind (PW01x2) | |
| *2019* | | Deactivate Hill 5 (-13.5 MW) | | Deactivate Hill 5 (-13.5 MW) |
| | Deactivate H8 (-53MW)<br>Deactivate H9 (-54MW)<br>or W3/4 | | Deactivate H8 (-53MW)<br>Deactivate H9 (-54MW)<br>or W3/4 | |

| Name | PH2B2b1N-6Cr1x (No Interconnection) | | PH2B2b1N-6Cr1 (With Interconnection) | |
|---|---|---|---|---|
| *2020* | Add 59MW CC (PC08x1)-Biofueled | Add 10MW Wind (HW04x1) | Add 59MW CC (PC08x1)-Biofueled | Add 10MW Wind (HW04x1) |
| | Add 200 MW Lanai Wind | Deactivate Hill 6 (-20 MW)<br>Deactivate Puna Steam (- 15.5 MW)<br>Deactivate KanoelD 11, 15-17 (-9.5 MW)<br>Deactivate WaimeaD 12-14 (-7.5 MW)<br>Deactivate KeaholD 21-23 (-7.5 MW)<br>Deactivate Kanoe CT1 (- 10.25 MW)<br>Deactivate Keaho CT2 (- 13.80 MW)<br>Deactivate Puna CT3 (- 19 MW)<br>Deactivate PanaewD, OuliD, PunaluD, KapuaD (- 4 MW) | Add 200 MW Lanai Wind | Deactivate Hill 6 (-20 MW)<br>Deactivate Puna Steam (- 15.5 MW)<br>Deactivate KanoelD 11, 15-17 (- 9.5 MW)<br>Deactivate WaimeaD 12-14 (- 7.5 MW)<br>Deactivate KeaholD 21-23 (- 7.5 MW)<br>Deactivate Kanoe CT1 (- 10.25 MW)<br>Deactivate Keaho CT2 (- 13.80 MW)<br>Deactivate Puna CT3 (- 19 MW)<br>Deactivate PanaewD, OuliD, PunaluD, KapuaD (- 4 MW) |
| | Fuel switch to LNG (Waiau 5-8, Kahe 1-6) | | Fuel switch to LNG (Waiau 5-8, Kahe 1-6) | |
| *2021* | | Add 25MW Geothermal (HG01x1) | | Add 25MW Geothermal (HG01x1) |
| | | Add 75MW New Geothermal (HG02x3) | | Add 75MW New Geothermal (HG02x3) |
| *2022* | | | | |
| *2023* | | | | |
| *2024* | | Add 25MW New Geothermal (HG02x1) | | Add 25MW New Geothermal (HG02x1) |
| *2025* | | | | |
| *2026* | | | | |
| *2027* | Add 25MW (PA01x1)-Biomass | | Add 25MW (PA01x1)-Biomass | |
| *2028* | Add 20 MW PV (PP03x4) | | Add 20 MW PV (PP03x4) | |
| *2029* | Add 30 MW Wind (PW01x1) | | Add 30 MW Wind (PW01x1) | |
| | Add 20 MW PV (PP03x4) | | Add 20 MW PV (PP03x4) | |
| *2030* | Add 150 MW Wind (PW01x5) | Add 10MW Wind (HW04x1) | Add 150 MW Wind (PW01x5) | Add 10MW Wind (HW04x1) |
| | Add 20 MW PV (PP03x4) | | Add 20 MW PV (PP03x4) | |
| *2031* | | Add 10MW Wind (HW04x1) | | Add 10MW Wind (HW04x1) |
| *2032* | | | | |

| **Name** | **PH2B2b1N-6Cr1x (No Interconnection)** | | **PH2B2b1N-6Cr1 (With Interconnection)** | |
|---|---|---|---|---|
| *2033* | | | | |
| *Planning Period Total Cost [$000]* | 24, 119, 132 | | 24, 060, 082 | |
| *Study Period Total Cost [$000]* | 34, 342, 756 | | 34, 268, 360 | |
| *Interconnection Energy* | | | | ~150 GWH H->P |
| *Planning Rank* | 2 | | 1 | |
| *Study Rank* | 2 | | 1 | |

Table O-146. HECO – HELCO 2

| **Name** | **PH2B2b1N-6Cr2x (No Interconnection)** | | **PH2B2b1N-6Cr2 (With Interconnection)** | |
|---|---|---|---|---|
| *Plan* | HECO Fuel Switch to LNG in 2020 | HELCO Year 2022 Fuel Switch to LSIFO | HECO Fuel Switch to LNG in 2020 | HELCO Year 2022 Fuel Switch to LSIFO |
| *Notes* | Fuel switch applies to all Waiau 5-8 and Kahe 1-6 | Fuel Switch applies to Hill 5, Hill 6 and Puna Steam Cycle Hill 5/6, Puna Steam | Fuel switch applies to all Waiau 5-8 and Kahe 1-6 | Fuel Switch applies to Hill 5, Hill 6 and Puna Steam Cycle Hill 5/6, Puna Steam |
| *Resources Available* | None | None | None | None |
| *Interconnection Charge* | n/a | | 0 ¢/kWh | |
| *2014* | Expanded CIDLC, CIDP, RDLCWH, RDLCAC | | Expanded CIDLC, CIDP, RDLCWH, RDLCAC | |
| | 75% PBFA DSM | 75% PBFA DSM | 75% PBFA DSM | 75% PBFA DSM |
| | | Hu Honua (21.5MW) | | Hu Honua (21.5MW) |
| *2015* | | Deactivate Shipman 3 (-6.8 MW) | | Deactivate Shipman 3 (-6.8 MW) |
| | | Deactivate Shipman 4 (-6.7 MW) | | Deactivate Shipman 4 (-6.7 MW) |
| *2016* | Add 20 MW PV (PP03x4) | | Add 20 MW PV (PP03x4) | |
| | Add 60 MW Wind (PW01x2) | | Add 60 MW Wind (PW01x2) | |
| | Fuel Switch to Diesel (Hon 8-9Waiau 5-8, Kahe 1-6) | | Fuel Switch to Diesel (Hon 8-9Waiau 5-8, Kahe 1-6) | |
| *2017* | | Add 10MW Wind (HW04x1) | | Add 10MW Wind (HW04x1) |
| | Add 60 MW Wind (PW01x2) | | Add 60 MW Wind (PW01x2) | |
| | Deactivate W3 (-46MW) Deactivate W4 (-46MW) or H8/9 | | Deactivate W3 (-46MW) Deactivate W4 (-46MW) or H8/9 | |
| *2018* | Add 60 MW Wind (PW01x2) | | Add 60 MW Wind (PW01x2) | |
| *2019* | | Add 25MW Geothermal (HG01x1) | | Add 25MW Geothermal (HG01x1) |
| | Deactivate H8 (-53MW) Deactivate H9 (-54MW) or W3/4 | | Deactivate H8 (-53MW) Deactivate H9 (-54MW) or W3/4 | |
| *2020* | Add 59MW CC (PC08x1)-Biofueled | Add 10MW Wind (HW04x1) | Add 59MW CC (PC08x1)-Biofueled | Add 10MW Wind (HW04x1) |
| | Add 200 MW Lanai Wind | | Add 200 MW Lanai Wind | |
| | Fuel switch to LNG (Waiau 5-8, Kahe 1-6) | | Fuel switch to LNG (Waiau 5-8, Kahe 1-6) | |
| *2021* | | | | |

| Name | PH2B2b1N-6Cr2x (No Interconnection) | | PH2B2b1N-6Cr2 (With Interconnection) | |
|---|---|---|---|---|
| *2022* | | Fuel Switch to LSIFO (Hill 5/6, Puna Steam) | | Fuel Switch to LSIFO (Hill 5/6, Puna Steam) |
| *2023* | | | | |
| *2024* | | | | |
| *2025* | | | | |
| *2026* | | | | |
| *2027* | Add 25MW (PA01x1)-Biomass | | Add 25MW (PA01x1)-Biomass | |
| *2028* | Add 20 MW PV (PP03x4) | | Add 20 MW PV (PP03x4) | |
| *2029* | Add 30 MW Wind (PW01x1) | | Add 30 MW Wind (PW01x1) | |
| | Add 20 MW PV (PP03x4) | | Add 20 MW PV (PP03x4) | |
| *2030* | Add 150 MW Wind (PW01x5) | Add 10MW Wind (HW04x1) | Add 150 MW Wind (PW01x5) | Add 10MW Wind (HW04x1) |
| | Add 20 MW PV (PP03x4) | | Add 20 MW PV (PP03x4) | |
| *2031* | | Add 10MW Wind (HW04x1) | | Add 10MW Wind (HW04x1) |
| *2032* | | | | |
| *2033* | | Add 25MW Geothermal (HG02x1) | | Add 25MW Geothermal (HG02x1) |
| *Planning Period Total Cost* | 23, 801, 446 | | 23, 535, 840 | |
| *Study Period Total Cost* | 33, 988, 692 | | 33, 507, 604 | |
| *Interconnection Energy* | | | ~500 GWH P->H | |
| *Planning Rank* | 2 | | 1 | |
| *Study Rank* | 2 | | 1 | |

Table O-147. HECO – HELCO 3

| **Name** | **PH2B2b1N-6Cr3x (No Interconnection)** | | **PH2B2b1N-6Cr3 (With Interconnection)** | |
|---|---|---|---|---|
| *Plan* | Fuel Switch to ULSD in 2022 | HELCO Deactivate Existing Replace with Geothermal | Fuel Switch to ULSD in 2022 | HELCO Deactivate Existing Replace with Geothermal |
| *Notes* | Fuel switch applies to all Waiau 5-8 and Kahe 1-6 | All Units except Keahole CC are deactivated by Dec 2020 Cycle Hill 5/6, Puna Steam | Fuel switch applies to all Waiau 5-8 and Kahe 1-6 | All Units except Keahole CC are deactivated by Dec 2020 Cycle Hill 5/6, Puna Steam |
| *Resources Available* | None | None | None | None |
| *Interconnection Charge* | n/a | | 0 ¢/kWh | |
| *2014* | Expanded CIDLC, CIDP, RDLCWH, RDLCAC | | Expanded CIDLC, CIDP, RDLCWH, RDLCAC | |
| | 75% PBFA DSM | 75% PBFA DSM | 75% PBFA DSM | 75% PBFA DSM |
| | | Hu Honua (21.5MW) | | Hu Honua (21.5MW) |
| *2015* | | Deactivate Shipman 3 (-6.8 MW) | | Deactivate Shipman 3 (-6.8 MW) |
| | | Deactivate Shipman 4 (-6.7 MW) | | Deactivate Shipman 4 (-6.7 MW) |
| *2016* | Add 20 MW PV (PP03x4) | | Add 20 MW PV (PP03x4) | |
| | Add 60 MW Wind (PW01x2) | | Add 60 MW Wind (PW01x2) | |
| | Fuel Switch to Diesel (Hon 8-9Waiau 5-8, Kahe 1-6) | | Fuel Switch to Diesel (Hon 8-9Waiau 5-8, Kahe 1-6) | |
| *2017* | | Add 10MW Wind (HW04x1) | | Add 10MW Wind (HW04x1) |
| | Add 60 MW Wind (PW01x2) | | Add 60 MW Wind (PW01x2) | |
| | Deactivate W3 (-46MW) Deactivate W4 (-46MW) or H8/9 | | Deactivate W3 (-46MW) Deactivate W4 (-46MW) or H8/9 | |
| *2018* | Add 60 MW Wind (PW01x2) | | Add 60 MW Wind (PW01x2) | |
| *2019* | | Deactivate Hill 5 (-13.5 MW) | | Deactivate Hill 5 (-13.5 MW) |
| | Deactivate H8 (-53MW) Deactivate H9 (-54MW) or W3/4 | | Deactivate H8 (-53MW) Deactivate H9 (-54MW) or W3/4 | |

| Name | PH2B2b1N-6Cr3x (No Interconnection) | | PH2B2b1N-6Cr3 (With Interconnection) | |
|---|---|---|---|---|
| 2020 | Add 59MW CC (PC08x1)-Biofueled | Add 10MW Wind (HW04x1) | Add 59MW CC (PC08x1)-Biofueled | Add 10MW Wind (HW04x1) |
| | Add 200 MW Lanai Wind | Deactivate Hill 6 (-20 MW)<br>Deactivate Puna Steam (- 15.5 MW)<br>Deactivate KanoelD 11, 15-17 (- 9.5 MW)<br>Deactivate WaimeaD 12-14 (- 7.5 MW)<br>Deactivate KeaholD 21-23 (- 7.5 MW)<br>Deactivate Kanoe CT1 (- 10.25 MW)<br>Deactivate Keaho CT2 (- 13.80 MW)<br>Deactivate Puna CT3 (- 19 MW)<br>Deactivate PanaewD, OuliD, PunaluD, KapuaD (- 4 MW) | Add 200 MW Lanai Wind | Deactivate Hill 6 (- 20 MW)<br>Deactivate Puna Steam (- 15.5 MW)<br>Deactivate KanoelD 11, 15-17 (- 9.5 MW)<br>Deactivate WaimeaD 12-14 (- 7.5 MW)<br>Deactivate KeaholD 21-23 (- 7.5 MW)<br>Deactivate Kanoe CT1 (- 10.25 MW)<br>Deactivate Keaho CT2 (- 13.80 MW)<br>Deactivate Puna CT3 (- 19 MW)<br>Deactivate PanaewD, OuliD, PunaluD, KapuaD (- 4 MW) |
| | | | **Inter-island Connection** | **Inter-island Connection** |
| 2021 | | Add 25MW Geothermal (HG01x1) | | Add 25MW Geothermal (HG01x1) |
| | | Add 75MW New Geothermal (HG02x3) | | Add 75MW New Geothermal (HG02x3) |
| 2022 | Fuel Switch to ULSD (Waiau 5-8, Kahe 1-6) | | Fuel Switch to ULSD (Waiau 5-8, Kahe 1-6) | |
| 2023 | | | | |
| 2024 | | Add 25MW New Geothermal (HG02x1) | | Add 25MW New Geothermal (HG02x1) |
| 2025 | | | | |
| 2026 | | | | |
| 2027 | Add 25MW (PA01x1)-Biomass | | Add 25MW (PA01x1)-Biomass | |
| 2028 | Add 20 MW PV (PP03x4) | | Add 20 MW PV (PP03x4) | |
| 2029 | Add 30 MW Wind (PW01x1) | | Add 30 MW Wind (PW01x1) | |
| | Add 20 MW PV (PP03x4) | | Add 20 MW PV (PP03x4) | |
| 2030 | Add 150 MW Wind (PW01x5) | Add 10MW Wind (HW04x1) | Add 150 MW Wind (PW01x5) | Add 10MW Wind (HW04x1) |
| | Add 20 MW PV (PP03x4) | | Add 20 MW PV (PP03x4) | |
| 2031 | | Add 10MW Wind (HW04x1) | | Add 10MW Wind (HW04x1) |
| 2032 | | | | |
| 2033 | | | | |

| Name | PH2B2b1N-6Cr3x (No Interconnection) | | PH2B2b1N-6Cr3 (With Interconnection) | |
|---|---|---|---|---|
| *Planning Period Total Cost* | 26, 513, 252 | | 26, 414, 828 | |
| *Study Period Total Cost* | 39, 193, 968 | | 39, 042, 384 | |
| *Interconnection Energy* | | | | ~300 GWH H->P |
| *Planning Rank* | 2 | | 1 | |
| *Study Rank* | 2 | | 1 | |

Table O-148. HECO – HELCO 4+

| **Name** | **PH2B2b1N-6Cr3x (No Interconnection)** | | **PH2B2b1N-6Cr10 (With Interconnection)** | |
|---|---|---|---|---|
| *Plan* | Fuel Switch to ULSD in 2022 | HELCO Deactivate Existing Replace with Geothermal | Fuel Switch to ULSD in 2022 Cycle K1-4 Retire KPLP | HELCO Deactivate Existing Replace with Geothermal Fixed |
| *Notes* | Fuel switch applies to all Waiau 5-8 and Kahe 1-6 | All Units except Keahole CC are deactivated by Dec 2020 Cycle Hill 5/6, Puna Steam | Fuel switch applies to all Waiau 5-8 and Kahe 1-6 HELCO Geothermal in 2022 provides HECO Capacity Loss from KPLP retirement | All Units except Keahole CC are deactivated by Dec 2020 Cycle Hill 5/6, Puna Steam |
| *Resources Available* | None | None | None | None |
| *Interconnection Charge* | n/a | | 160 $/MWh | |
| *2014* | Expanded CIDLC, CIDP, RDLCWH, RDLCAC | | Expanded CIDLC, CIDP, RDLCWH, RDLCAC | |
| | 75% PBFA DSM | 75% PBFA DSM | 75% PBFA DSM | 75% PBFA DSM |
| | | Hu Honua (21.5MW) | | Hu Honua (21.5MW) |
| *2015* | | Retire Shipman 3 (-6.8 MW) | | Retire Shipman 3 (-6.8 MW) |
| | | Retire Shipman 4 (-6.7 MW) | | Retire Shipman 4 (-6.7 MW) |
| *2016* | Add 20 MW PV (PP03x4) | | Add 20 MW PV (PP03x4) | |
| | Add 60 MW Wind (PW01x2) | | Add 60 MW Wind (PW01x2) | |
| | Fuel Switch to Diesel (Hon 8-9Waiau 5-8, Kahe 1-6) | | Fuel Switch to Diesel (Hon 8-9Waiau 5-8, Kahe 1-6) | |
| *2017* | Add 60 MW Wind (PW01x2) | Add 10MW Wind (HW04x1) | Add 60 MW Wind (PW01x2) | Add 10MW Wind (HW04x1) |
| | Deactivate W3 (-46MW) Deactivate W4 (-46MW) or H8/9 | | Retire W3 (-46MW) Retire W4 (-46MW) or H8/9 | |
| *2018* | Add 60 MW Wind (PW01x2) | | Add 60 MW Wind (PW01x2) | |
| *2019* | Deactivate H8 (-53MW) Deactivate H9 (-54MW) or W3/4 | | Retire H8 (-53MW) Retire H9 (-54MW) or W3/4 | Retire Hill 5 (-13.5 MW) |

| Name | PH2B2b1N-6Cr3x (No Interconnection) | | PH2B2b1N-6Cr10 (With Interconnection) | |
|---|---|---|---|---|
| *2020* | Add 59MW CC (PC08x1)-Biofueled | Add 10MW Wind (HW04x1) | Add 59MW CC (PC08x1)-Biofueled | Add 10MW Wind (HW04x1) |
| | Add 200 MW Lanai Wind | Retire Hill 6 (- 20 MW)<br>Retire Puna Steam (-15.5 MW)<br>Retire KanoelD 11, 15-17 (- 9.5 MW)<br>Retire WaimeaD 12-14 (- 7.5 MW)<br>Retire KeaholD 21-23 (- 7.5 MW)<br>Retire Kanoe CT1 (- 10.25 MW)<br>Retire Keaho CT2 (- 13.80 MW)<br>Retire Puna CT3 (- 19 MW)<br>Retire PanaewD, OuliD, PunaluD, KapuaD (- 4 MW) | Add 200 MW Lanai Wind | Retire Hill 6 (- 20 MW)<br>Retire Puna Steam (-15.5 MW)<br>Retire KanoelD 11, 15-17 (- 9.5 MW)<br>Retire WaimeaD 12-14 (- 7.5 MW)<br>Retire KeaholD 21-23 (- 7.5 MW)<br>Retire Kanoe CT1 (- 10.25 MW)<br>Retire Keaho CT2 (- 13.80 MW)<br>Retire Puna CT3 (- 19 MW)<br>Retire PanaewD, OuliD, PunaluD, KapuaD (- 4 MW) |
| | | | **Inter-island Connection** | **Inter-island Connection** |
| *2021* | | Add 25MW Geothermal (HG01x1) | | Add 25MW Geothermal (HG01x1) |
| | | Add 75MW New Geothermal (HG02x3) | | Add 75MW New Geothermal (HG02x3) |
| *2022* | Fuel Switch to ULSD (Waiau 5-8, Kahe 1-6) | | Fuel Switch to ULSD (Waiau 5-8, Kahe 1-6) | Add 200MW New Geothermal (HG02x8) |
| | | | Cycle Kahe 1 - 4 | |
| | | | Retire KPLP (-208 MW) | |
| *2023* | | | | |
| *2024* | | Add 25MW New Geothermal (HG02x1) | | Add 25MW New Geothermal (HG02x1) |
| *2025* | | | | |
| *2026* | | | | |
| *2027* | Add 25MW (PA01x1)-Biomass | | Add 25MW (PA01x1)-Biomass | |
| *2028* | | | Retire W5 (- 55MW) | |
| | Add 20 MW PV (PP03x4) | | Add 20 MW PV (PP03x4) | |
| *2029* | Add 30 MW Wind (PW01x1) | | Add 30 MW Wind (PW01x1) | |
| | Add 20 MW PV (PP03x4) | | Add 20 MW PV (PP03x4) | |
| *2030* | Add 150 MW Wind (PW01x5) | Add 10MW Wind (HW04x1) | Add 150 MW Wind (PW01x5) | Add 10MW Wind (HW04x1) |
| | Add 20 MW PV (PP03x4) | | Add 20 MW PV (PP03x4) | |
| *2031* | | Add 10MW Wind (HW04x1) | | Add 10MW Wind (HW04x1) |
| *2032* | | | | |
| *2033* | | | Retire W6 (- 55MW) | |

| Name | PH2B2b1N-6Cr3x (No Interconnection) | | | PH2B2b1N-6Cr10 (With Interconnection) | |
|---|---|---|---|---|---|
| *Planning Period Total Cost* | 26, 513, 252 | | | | 26, 270, 086 |
| *Study Period Total Cost* | 39, 193, 968 | | | | 37, 317, 248 |
| *Interconnection Energy* | | | | | ~ 1450 GWH H->P |
| *Planning Rank* | 7 | | | 3 | |
| *Study Rank* | 8 | | | 3 | |

Table O-149. HECO – MECO 1

| **Name** | **PM2B2B1N-6BR1X (No Interconnection)** | | **PM2B2B1N-6BR0 LNG (With Interconnection)** | |
|---|---|---|---|---|
| *Plan* | HECO Fuel Switch to LNG in 2020 | MECO Year 2022 Fuel Switch to LSIFO | HECO Fuel Switch to LNG in 2020 | MECO Year 2022 Fuel Switch to LSIFO |
| *Notes* | Fuel switch applies to all Waiau 5-8 and Kahe 1-6 | Fuel Switch<br>Allow ICE 17MW<br>Allow Wind, PV, Wave | Fuel switch applies to all Waiau 5-8 and Kahe 1-6 | Fuel Switch<br>Allow ICE 17MW<br>Allow Wind, PV, Wave |
| *2014* | Expanded CIDLC, CIDP, RDLCWH, RDLCAC | Fast DR only | Expanded CIDLC, CIDP, RDLCWH, RDLCAC | Fast DR only |
| | 75% PBFA DSM | 75% PBFA DSM | 75% PBFA DSM | 75% PBFA DSM |
| *2015* | | Add 30MW Wind (MW04x3) | | Add 30MW Wind (MW04x3) |
| *2016* | Add 20 MW PV (PP03x4) | Add 30MW Wind (MW04x3) | Add 20 MW PV (PP03x4) | Add 30MW Wind (MW04x3) |
| | Add 60 MW Wind (PW01x2) | | Add 60 MW Wind (PW01x2) | |
| *2017* | | Add 30MW Wind (MW04x3) | | Add 30MW Wind (MW04x3) |
| | Add 60 MW Wind (PW01x2) | | Add 60 MW Wind (PW01x2) | |
| | Deactivate W3 (-46MW)<br>Deactivate W4 (-46MW)<br>or H8/9 | | Deactivate W3 (-46MW)<br>Deactivate W4 (-46MW)<br>or H8/9 | |
| *2018* | Add 60 MW Wind (PW01x2) | | Add 60 MW Wind (PW01x2) | |
| *2019* | Deactivate H8 (-53MW)<br>Deactivate H9 (-54MW)<br>or W3/4 | | Deactivate H8 (-53MW)<br>Deactivate H9 (-54MW)<br>or W3/4 | |
| *2020* | Add 59MW CC (PC08x1)-Biofueled | | Add 59MW CC (PC08x1)-Biofueled | |
| | Add 200 MW Lanai Wind | | Add 200 MW Lanai Wind | |
| | | | **Inter-island Connection** | **Inter-island Connection** |
| | Fuel switch to LNG (Waiau 5-8, Kahe 1-6) | | Fuel switch to LNG (Waiau 5-8, Kahe 1-6) | |
| *2021* | | | | |
| *2022* | | Fuel Switch to LSIFO (Kahului1-4) | | Fuel Switch to LSIFO (Kahului1-4) |
| *2023* | | ICE Biofueled (17 MW) | | ICE Biofueled (17 MW) |
| *2024* | | | | |
| *2025* | | | | |
| *2026* | | | | |
| *2027* | Add 25MW (PA01x1)-Biomass | | Add 25MW (PA01x1)-Biomass | |
| *2028* | Add 20 MW PV (PP03x4) | | Add 20 MW PV (PP03x4) | |
| *2029* | Add 30 MW Wind (PW01x1) | | Add 30 MW Wind (PW01x1) | |
| | Add 20 MW PV (PP03x4) | | Add 20 MW PV (PP03x4) | |

| Name | PM2B2B1N-6BR1X (No Interconnection) | | PM2B2B1N-6BR0 LNG (With Interconnection) | |
|---|---|---|---|---|
| *2030* | Add 150 MW Wind (PW01x5) | Add 5 MW PV (MP03x5) | Add 150 MW Wind (PW01x5) | Add 5 MW PV (MP03x5) |
| | Add 20 MW PV (PP03x4) | | Add 20 MW PV (PP03x4) | |
| *2031* | | | | |
| *2032* | | | | |
| *2033* | | Add 5 MW PV (MP03x5) | | Add 5 MW PV (MP03x5) |
| *Planning Period Total Cost* | 23, 829, 954 | | 23, 821, 372 | |
| *Study Period Total Cost* | 33, 994, 680 | | 33, 919, 120 | |
| *Interconnection Energy* | | | ~50 GWH P->M | ~190 GWH M->P |
| *Planning Rank* | 2 | | 1 | |
| *Study Rank* | 2 | | 1 | |

Table O-150. HECO – MECO 2

| **Name** | **PM2B2b1N-6Br0 Base (No Interconnection)** | | **PM2B2b1N-6Br0 (With Interconnection)** | |
|---|---|---|---|---|
| *Plan* | HECO Fuel Switch to ULSD in 2022 | MECO Year 2022 Fuel Switch to LSIFO | HECO Fuel Switch to ULSD in 2022 | MECO Year 2022 Fuel Switch to LSIFO |
| *Notes* | Fuel switch applies to all Waiau 5-8 and Kahe 1-6<br>No Lanai Wind | Fuel Switch | Fuel switch applies to all Waiau 5-8 and Kahe 1-6<br>No Lanai Wind | Fuel Switch<br>Allow up to 300 MW of Wind in 2022 |
| *Reference* | | | | |
| *2014* | Expanded CIDLC, CIDP, RDLCWH, RDLCAC | Fast DR only | Expanded CIDLC, CIDP, RDLCWH, RDLCAC | Fast DR only |
| | 75% PBFA DSM | 75% PBFA DSM | 75% PBFA DSM | 75% PBFA DSM |
| *2015* | | Add 30MW Wind (MW04x3) | | Add 30MW Wind (MW04x3) |
| *2016* | Add 20 MW PV (PP03x4) | Add 30MW Wind (MW04x3) | Add 20 MW PV (PP03x4) | Add 30MW Wind (MW04x3) |
| | Add 60 MW Wind (PW01x2) | | Add 60 MW Wind (PW01x2) | |
| *2017* | | Add 30MW Wind (MW04x3) | | Add 30MW Wind (MW04x3) |
| | Add 60 MW Wind (PW01x2) | | Add 60 MW Wind (PW01x2) | |
| | Deactivate W3 (-46MW)<br>Deactivate W4 (-46MW)<br>or H8/9 | | Deactivate W3 (-46MW)<br>Deactivate W4 (-46MW)<br>or H8/9 | |
| *2018* | Add 60 MW Wind (PW01x2) | | Add 60 MW Wind (PW01x2) | |
| *2019* | Deactivate H8 (-53MW)<br>Deactivate H9 (-54MW)<br>or W3/4 | | Deactivate H8 (-53MW)<br>Deactivate H9 (-54MW)<br>or W3/4 | |
| *2020* | Add 59MW CC (PC08x1)-Biofueled | | Add 59MW CC (PC08x1)-Biofueled | |
| | | | **Inter-island Connection** | **Inter-island Connection** |
| | | | | Add 170MW Wind (MW04x17) |
| *2021* | | | | |
| *2022* | Fuel switch to ULSD (Waiau 5-8, Kahe 1-6) | Fuel Switch to LSIFO (Kahului1-4) | Fuel switch to ULSD (Waiau 5-8, Kahe 1-6) | Fuel Switch to LSIFO (Kahului1-4) |
| *2023* | | Add 17MW ICE (MS01x1)-Biofueled | | Add 17MW ICE (MS01x1)-Biofueled |
| *2024* | | | | |
| *2025* | | | | |
| *2026* | | | | |
| *2027* | Add 25MW (PA01x1)-Biomass | | Add 25MW (PA01x1)-Biomass | |
| *2028* | Add 20 MW PV (PP03x4) | | Add 20 MW PV (PP03x4) | |
| *2029* | Add 30 MW Wind (PW01x1) | | Add 30 MW Wind (PW01x1) | |
| | Add 20 MW PV (PP03x4) | | Add 20 MW PV (PP03x4) | |

| Name | PM2B2b1N-6Br0 Base (No Interconnection) | | PM2B2b1N-6Br0 (With Interconnection) | |
|---|---|---|---|---|
| *2030* | Add 150 MW Wind (PW01x5) | Add 5 MW PV (MP03x5) | Add 150 MW Wind (PW01x5) | Add 5 MW PV (MP03x5) |
| | Add 20 MW PV (PP03x4) | | Add 20 MW PV (PP03x4) | |
| *2031* | | | | |
| *2032* | | | | |
| *2033* | | Add 5 MW PV (MP03x5) | | Add 5 MW PV (MP03x5) |
| *Planning Period Total Cost* | 26, 265, 266 | | 26, 208, 166 | |
| *Study Period Total Cost* | 39, 177, 940 | | 39, 019, 140 | |
| *Interconnection Energy* | | | | ~1100 GWh M->P |
| *Planning Rank* | 2 | | 1 | |
| *Study Rank* | 2 | | 1 | |

Table O-151. HECO – MECO 3

| **Name** | **PM2B2b1N-6Br0W Base (No Interconnection)** | | **PM2B2b1N-6Br0W (With Interconnection)** | |
|---|---|---|---|---|
| *Plan* | HECO Fuel Switch to ULSD in 2022 | MECO Year 2022 Fuel Switch to LSIFO | HECO Fuel Switch to ULSD in 2022 | MECO Year 2022 Fuel Switch to LSIFO |
| *Notes* | Fuel switch applies to all Waiau 5-8 and Kahe 1-6 | Fuel Switch | Fuel switch applies to all Waiau 5-8 and Kahe 1-6 | Fuel Switch: Allow up to 300 MW of Wind in 2022 |
| *2014* | Expanded CIDLC, CIDP, RDLCWH, RDLCAC | Fast DR only | Expanded CIDLC, CIDP, RDLCWH, RDLCAC | Fast DR only |
| | 75% PBFA DSM | 75% PBFA DSM | 75% PBFA DSM | 75% PBFA DSM |
| *2015* | | Add 30MW Wind (MW04x3) | | Add 30MW Wind (MW04x3) |
| *2016* | Add 20 MW PV (PP03x4) | Add 30MW Wind (MW04x3) | Add 20 MW PV (PP03x4) | Add 30MW Wind (MW04x3) |
| | Add 60 MW Wind (PW01x2) | | Add 60 MW Wind (PW01x2) | |
| *2017* | | Add 30MW Wind (MW04x3) | | Add 30MW Wind (MW04x3) |
| | Add 60 MW Wind (PW01x2) | | Add 60 MW Wind (PW01x2) | |
| | Deactivate W3 (-46MW) Deactivate W4 (-46MW) or H8/9 | | Deactivate W3 (-46MW) Deactivate W4 (-46MW) or H8/9 | |
| *2018* | Add 60 MW Wind (PW01x2) | | Add 60 MW Wind (PW01x2) | |
| *2019* | Deactivate H8 (-53MW) Deactivate H9 (-54MW) or W3/4 | | Deactivate H8 (-53MW) Deactivate H9 (-54MW) or W3/4 | |
| *2020* | Add 59MW CC (PC08x1)-Biofueled | | Add 59MW CC (PC08x1)-Biofueled | |
| | | | **Inter-island Connection** | **Inter-island Connection** |
| | Add 200 MW Lanai Wind | | Add 200 MW Lanai Wind | Add 20MW Wind (MW04x2) |
| *2021* | | | | |
| *2022* | Fuel switch to ULSD (Waiau 5-8, Kahe 1-6) | Fuel Switch to LSIFO (Kahului1-4) | Fuel switch to ULSD (Waiau 5-8, Kahe 1-6) | Fuel Switch to LSIFO (Kahului1-4) |
| *2023* | | Add 17MW ICE (MS01x1)-Biofueled | | Add 17MW ICE (MS01x1)-Biofueled |
| *2024* | | | | |
| *2025* | | | | |
| *2026* | | | | |
| *2027* | Add 25MW (PA01x1)-Biomass | | Add 25MW (PA01x1)-Biomass | |
| *2028* | Add 20 MW PV (PP03x4) | | Add 20 MW PV (PP03x4) | |
| *2029* | Add 30 MW Wind (PW01x1) | | Add 30 MW Wind (PW01x1) | |
| | Add 20 MW PV (PP03x4) | | Add 20 MW PV (PP03x4) | |

| Name | PM2B2b1N-6Br0W Base (No Interconnection) | | PM2B2b1N-6Br0W (With Interconnection) | |
|---|---|---|---|---|
| *2030* | Add 150 MW Wind (PW01x5) | Add 5 MW PV (MP03x5) | Add 150 MW Wind (PW01x5) | Add 5 MW PV (MP03x5) |
| | Add 20 MW PV (PP03x4) | | Add 20 MW PV (PP03x4) | |
| *2031* | | | | |
| *2032* | | | | |
| *2033* | | Add 5 MW PV (MP03x5) | | Add 5 MW PV (MP03x5) |
| *Planning Period Total Cost* | 26, 224, 080 | | 26, 308, 896 | |
| *Study Period Total Cost* | 38, 845, 900 | | 38, 960, 072 | |
| *Interconnection Energy* | | | | ~400 GWh M->P |
| *Planning Rank* | 1 | | 2 | |
| *Study Rank* | 1 | | 2 | |

Table O-152. HECO – MECO 4

| **Name** | **PM2B2b1N-6Br1 Base (No Interconnection)** | | **PM2B2b1N-6Br1 (With Interconnection)** | |
|---|---|---|---|---|
| *Plan* | HECO Fuel Switch to ULSD in 2022 | MECO Year 2022 Fuel Switch to LSIFO | HECO Fuel Switch to ULSD in 2022 | MECO Year 2022 Fuel Switch to LSIFO |
| *Notes* | Fuel switch applies to all Waiau 5-8 and Kahe 1-6<br>No Lanai Wind<br>Retire KPLP in 2022 | Fuel Switch | Fuel switch applies to all Waiau 5-8 and Kahe 1-6<br>No Lanai Wind<br>Retire KPLP in 2022 | Fuel Switch<br>Allow up to 300 MW of Wind in 2022 |
| *Reference* | | | | |
| *2014* | Expanded CIDLC, CIDP, RDLCWH, RDLCAC | Fast DR only | Expanded CIDLC, CIDP, RDLCWH, RDLCAC | Fast DR only |
| | 75% PBFA DSM | 75% PBFA DSM | 75% PBFA DSM | 75% PBFA DSM |
| *2015* | | Add 30MW Wind (MW04x3) | | Add 30MW Wind (MW04x3) |
| *2016* | Add 20 MW PV (PP03x4) | Add 30MW Wind (MW04x3) | Add 20 MW PV (PP03x4) | Add 30MW Wind (MW04x3) |
| | Add 60 MW Wind (PW01x2) | | Add 60 MW Wind (PW01x2) | |
| *2017* | | Add 30MW Wind (MW04x3) | | Add 30MW Wind (MW04x3) |
| | Add 60 MW Wind (PW01x2) | | Add 60 MW Wind (PW01x2) | |
| | Deactivate W3 (-46MW)<br>Deactivate W4 (-46MW)<br>or H8/9 | | Deactivate W3 (-46MW)<br>Deactivate W4 (-46MW)<br>or H8/9 | |
| *2018* | Add 60 MW Wind (PW01x2) | | Add 60 MW Wind (PW01x2) | |
| *2019* | Deactivate H8 (-53MW)<br>Deactivate H9 (-54MW)<br>or W3/4 | | Deactivate H8 (-53MW)<br>Deactivate H9 (-54MW)<br>or W3/4 | |
| *2020* | Add 59MW CC (PC08x1)-Biofueled | | Add 59MW CC (PC08x1)-Biofueled | |
| | | | **Inter-island Connection** | **Inter-island Connection** |
| | | | | Add 210MW Wind (MW04x21) |
| *2021* | | | | |
| *2022* | Fuel switch to ULSD (Waiau 5-8, Kahe 1-6) | Fuel Switch to LSIFO (Kahului1-4) | Fuel switch to ULSD (Waiau 5-8, Kahe 1-6) | Fuel Switch to LSIFO (Kahului1-4) |
| | Retire KPLP (-208MW) | | Retire KPLP (-208MW) | |
| | Add 25MW (PA01x1)-Biomass | | Add 25MW (PA01x1)-Biomass | |
| | Add 177MW CC (PC08x3)-Biofueled | | Add 177MW CC (PC08x3)-Biofueled | |
| *2023* | | Add 17MW ICE (MS01x1)-Biofueled | | Add 17MW ICE (MS01x1)-Biofueled |
| *2024* | | | | |

| Name | PM2B2b1N-6Br1 Base (No Interconnection) | | PM2B2b1N-6Br1 (With Interconnection) | |
|---|---|---|---|---|
| *2025* | | | | |
| *2026* | | | | |
| *2027* | | | | |
| *2028* | Add 20 MW PV (PP03x4) | | Add 20 MW PV (PP03x4) | |
| *2029* | Add 30 MW Wind (PW01x1) | | Add 30 MW Wind (PW01x1) | |
| | Add 20 MW PV (PP03x4) | | Add 20 MW PV (PP03x4) | |
| *2030* | Add 150 MW Wind (PW01x5) | Add 5 MW PV (MP03x5) | Add 150 MW Wind (PW01x5) | Add 5 MW PV (MP03x5) |
| | Add 20 MW PV (PP03x4) | | Add 20 MW PV (PP03x4) | |
| *2031* | | | | |
| *2032* | | | | |
| *2033* | | Add 5 MW PV (MP03x5) | | Add 5 MW PV (MP03x5) |
| *Planning Period Total Cost* | 27, 110, 320 | | 26, 615, 508 | |
| *Study Period Total Cost* | 39, 931, 616 | | 39, 057, 512 | |
| *Interconnection Energy* | | | | ~1350 GWh M->P |
| *Planning Rank* | 2 | | 1 | |
| *Study Rank* | 2 | | 1 | |

Table O-153. HECO – MECO 5

| **Name** | **PM2B2b1N-6Br1W Base (No Interconnection)** | | **PM2B2b1N-6Br1W (With Interconnection)** | |
|---|---|---|---|---|
| *Plan* | HECO Fuel Switch to ULSD in 2022 | MECO Year 2022 Fuel Switch to LSIFO | HECO Fuel Switch to ULSD in 2022 | MECO Year 2022 Fuel Switch to LSIFO |
| *Notes* | Fuel switch applies to all Waiau 5-8 and Kahe 1-6 Retire KPLP in 2022 | Fuel Switch | Fuel switch applies to all Waiau 5-8 and Kahe 1-6 Retire KPLP in 2022 | Fuel Switch Allow up to 300 MW of Wind in 2022 |
| *2014* | Expanded CIDLC, CIDP, RDLCWH, RDLCAC | Fast DR only | Expanded CIDLC, CIDP, RDLCWH, RDLCAC | Fast DR only |
| | 75% PBFA DSM | 75% PBFA DSM | 75% PBFA DSM | 75% PBFA DSM |
| *2015* | | Add 30MW Wind (MW04x3) | | Add 30MW Wind (MW04x3) |
| *2016* | Add 20 MW PV (PP03x4) | Add 30MW Wind (MW04x3) | Add 20 MW PV (PP03x4) | Add 30MW Wind (MW04x3) |
| | Add 60 MW Wind (PW01x2) | | Add 60 MW Wind (PW01x2) | |
| *2017* | | Add 30MW Wind (MW04x3) | | Add 30MW Wind (MW04x3) |
| | Add 60 MW Wind (PW01x2) | | Add 60 MW Wind (PW01x2) | |
| | Deactivate W3 (-46MW) Deactivate W4 (-46MW) or H8/9 | | Deactivate W3 (-46MW) Deactivate W4 (-46MW) or H8/9 | |
| *2018* | Add 60 MW Wind (PW01x2) | | Add 60 MW Wind (PW01x2) | |
| *2019* | Deactivate H8 (-53MW) Deactivate H9 (-54MW) or W3/4 | | Deactivate H8 (-53MW) Deactivate H9 (-54MW) or W3/4 | |
| *2020* | Add 59MW CC (PC08x1)-Biofueled | | Add 59MW CC (PC08x1)-Biofueled | |
| | | | **Inter-island Connection** | **Inter-island Connection** |
| | Add 200 MW Lanai Wind | | Add 200 MW Lanai Wind | Add 190MW Wind (MW04x19) |
| *2021* | | | | |
| *2022* | Fuel switch to ULSD (Waiau 5-8, Kahe 1-6) | Fuel Switch to LSIFO (Kahului1-4) | Fuel switch to ULSD (Waiau 5-8, Kahe 1-6) | Fuel Switch to LSIFO (Kahului1-4) |
| | Retire KPLP (-208MW) | | Retire KPLP (-208MW) | |
| | Add 25MW (PA01x1)-Biomass | | Add 25MW (PA01x1)-Biomass | |
| | Add 177MW CC (PC08x3)-Biofueled | | Add 177MW CC (PC08x3)-Biofueled | |
| *2023* | | Add 17MW ICE (MS01x1)-Biofueled | | Add 17MW ICE (MS01x1)-Biofueled |
| *2024* | | | | |
| *2025* | | | | |
| *2026* | | | | |

| Name | PM2B2b1N-6Br1W Base (No Interconnection) | | PM2B2b1N-6Br1W (With Interconnection) | |
|---|---|---|---|---|
| *2027* | | | | |
| *2028* | Add 20 MW PV (PP03x4) | | Add 20 MW PV (PP03x4) | |
| *2029* | Add 30 MW Wind (PW01x1) | | Add 30 MW Wind (PW01x1) | |
| | Add 20 MW PV (PP03x4) | | Add 20 MW PV (PP03x4) | |
| *2030* | Add 150 MW Wind (PW01x5) | Add 5 MW PV (MP03x5) | Add 150 MW Wind (PW01x5) | Add 5 MW PV (MP03x5) |
| | Add 20 MW PV (PP03x4) | | Add 20 MW PV (PP03x4) | |
| *2031* | | | | |
| *2032* | | | | |
| *2033* | | Add 5 MW PV (MP03x5) | | Add 5 MW PV (MP03x5) |
| *Planning Period Total Cost* | 26, 733, 654 | | 26, 644, 136 | |
| *Study Period Total Cost* | 39, 037, 092 | | 38, 843, 164 | |
| *Interconnection Energy* | | | | ~1100 GWh M->P |
| *Planning Rank* | 2 | | 1 | |
| *Study Rank* | 2 | | 1 | |

Table O-154. HECO – MECO 6

| **Name** | **PM2B2b1N-6Br1 Base (No Interconnection)** | | **PM2B2b1N-6Br2 (With Interconnection)** | |
|---|---|---|---|---|
| *Plan* | HECO Fuel Switch to ULSD in 2022 | MECO Year 2022 Fuel Switch to LSIFO | HECO Fuel Switch to ULSD in 2022 | MECO Year 2022 Fuel Switch to LSIFO |
| *Notes* | Fuel switch applies to all Waiau 5-8 and Kahe 1-6<br>Retire KPLP in 2022<br>No Lanai Wind | Fuel Switch | Fuel switch applies to all Waiau 5-8 and Kahe 1-6<br>Retire KPLP in 2022<br>Cycle Kahe 1-4<br>No Lanai Wind | Fuel Switch<br>Allow up to 300 MW of Wind in 2022 |
| *Interconnection Charge* | n/a | | $79/MWH | |
| *2014* | Expanded CIDLC, CIDP, RDLCWH, RDLCAC | Fast DR only | Expanded CIDLC, CIDP, RDLCWH, RDLCAC | Fast DR only |
| | 75% PBFA DSM | 75% PBFA DSM | 75% PBFA DSM | 75% PBFA DSM |
| *2015* | | Add 30MW Wind (MW04x3) | | Add 30MW Wind (MW04x3) |
| *2016* | Add 20 MW PV (PP03x4) | Add 30MW Wind (MW04x3) | Add 20 MW PV (PP03x4) | Add 30MW Wind (MW04x3) |
| | Add 60 MW Wind (PW01x2) | | Add 60 MW Wind (PW01x2) | |
| *2017* | | Add 30MW Wind (MW04x3) | | Add 30MW Wind (MW04x3) |
| | Add 60 MW Wind (PW01x2) | | Add 60 MW Wind (PW01x2) | |
| | Deactivate W3 (-46MW)<br>Deactivate W4 (-46MW)<br>or H8/9 | | Deactivate W3 (-46MW)<br>Deactivate W4 (-46MW)<br>or H8/9 | |
| *2018* | Add 60 MW Wind (PW01x2) | | Add 60 MW Wind (PW01x2) | |
| *2019* | Deactivate H8 (-53MW)<br>Deactivate H9 (-54MW)<br>or W3/4 | | Deactivate H8 (-53MW)<br>Deactivate H9 (-54MW)<br>or W3/4 | |
| *2020* | Add 59MW CC (PC08x1)-Biofueled | | Add 59MW CC (PC08x1)-Biofueled | |
| | | | **Inter-island Connection** | **Inter-island Connection** |
| | | | | Add 210MW Wind (MW04x21) |
| *2021* | | | | |
| *2022* | Fuel switch to ULSD (Waiau 5-8, Kahe 1-6) | Fuel Switch to LSIFO (Kahului1-4) | Fuel switch to ULSD (Waiau 5-8, Kahe 1-6) | Fuel Switch to LSIFO (Kahului1-4) |
| | Retire KPLP (-208MW) | | Retire KPLP (-208MW) | |
| | Add 25MW (PA01x1)-Biomass | | Add 25MW (PA01x1)-Biomass | |
| | Add 177MW CC (PC08x3)-Biofueled | | Add 177MW CC (PC08x3)-Biofueled | |
| *2023* | | Add 17MW ICE (MS01x1)-Biofueled | | Add 17MW ICE (MS01x1)-Biofueled |

| Name | PM2B2b1N-6Br1 Base (No Interconnection) | | PM2B2b1N-6Br2 (With Interconnection) | |
|---|---|---|---|---|
| *2024* | | | | |
| *2025* | | | | |
| *2026* | | | | |
| *2027* | | | | |
| *2028* | Add 20 MW PV (PP03x4) | | Add 20 MW PV (PP03x4) | |
| *2029* | Add 30 MW Wind (PW01x1) | | Add 30 MW Wind (PW01x1) | |
| | Add 20 MW PV (PP03x4) | | Add 20 MW PV (PP03x4) | |
| *2030* | Add 150 MW Wind (PW01x5) | Add 5 MW PV (MP03x5) | Add 150 MW Wind (PW01x5) | Add 5 MW PV (MP03x5) |
| | Add 20 MW PV (PP03x4) | | Add 20 MW PV (PP03x4) | |
| *2031* | | | | |
| *2032* | | | | |
| *2033* | | Add 5 MW PV (MP03x5) | | Add 5 MW PV (MP03x5) |
| *Planning Period Total Cost* | 27, 110, 320 | | 26, 138, 918 | |
| *Study Period Total Cost* | 39, 931, 616 | | 37, 821, 232 | |
| *Interconnection Energy* | | | | ~1160 GWh M->P |
| *Planning Rank* | 2 | | 1 | |
| *Study Rank* | 2 | | 1 | |

Table O-155. HECO – MECO 7

| **Name** | **PM2B2b1N-6Br1W Base (No Interconnection)** | | **PM2B2b1N-6Br2W (With Interconnection)** | |
|---|---|---|---|---|
| *Plan* | HECO Fuel Switch to ULSD in 2022 | MECO Year 2022 Fuel Switch to LSIFO | HECO Fuel Switch to ULSD in 2022 | MECO Year 2022 Fuel Switch to LSIFO |
| *Notes* | Fuel switch applies to all Waiau 5-8 and Kahe 1-6<br>Retire KPLP in 2022 | Fuel Switch | Fuel switch applies to all Waiau 5-8 and Kahe 1-6<br>Retire KPLP in 2022<br>Cycle Kahe 1-4 | Fuel Switch<br>Allow up to 300 MW of Wind in 2022 |
| *Interconnection Charge* | None | | $100/MWh | |
| *2014* | Expanded CIDLC, CIDP, RDLCWH, RDLCAC | Fast DR only | Expanded CIDLC, CIDP, RDLCWH, RDLCAC | Fast DR only |
| | 75% PBFA DSM | 75% PBFA DSM | 75% PBFA DSM | 75% PBFA DSM |
| *2015* | | Add 30MW Wind (MW04x3) | | Add 30MW Wind (MW04x3) |
| *2016* | Add 20 MW PV (PP03x4) | Add 30MW Wind (MW04x3) | Add 20 MW PV (PP03x4) | Add 30MW Wind (MW04x3) |
| | Add 60 MW Wind (PW01x2) | | Add 60 MW Wind (PW01x2) | |
| *2017* | | Add 30MW Wind (MW04x3) | | Add 30MW Wind (MW04x3) |
| | Add 60 MW Wind (PW01x2) | | Add 60 MW Wind (PW01x2) | |
| | Deactivate W3 (-46MW)<br>Deactivate W4 (-46MW)<br>or H8/9 | | Deactivate W3 (-46MW)<br>Deactivate W4 (-46MW)<br>or H8/9 | |
| *2018* | Add 60 MW Wind (PW01x2) | | Add 60 MW Wind (PW01x2) | |
| *2019* | Deactivate H8 (-53MW)<br>Deactivate H9 (-54MW)<br>or W3/4 | | Deactivate H8 (-53MW)<br>Deactivate H9 (-54MW)<br>or W3/4 | |
| *2020* | Add 59MW CC (PC08x1)-Biofueled | | Add 59MW CC (PC08x1)-Biofueled | |
| | | | **Inter-island Connection** | **Inter-island Connection** |
| | Add 200 MW Lanai Wind | | Add 200 MW Lanai Wind | Add 210MW Wind (MW04x21) |
| *2021* | | | | |
| *2022* | Fuel switch to ULSD (Waiau 5-8, Kahe 1-6) | Fuel Switch to LSIFO (Kahului1-4) | Fuel switch to ULSD (Waiau 5-8, Kahe 1-6) | Fuel Switch to LSIFO (Kahului1-4) |
| | Retire KPLP (-208MW) | | Retire KPLP (-208MW) | |
| | Add 25MW (PA01x1)-Biomass | | Add 25MW (PA01x1)-Biomass | |
| | Add 177MW CC (PC08x3)-Biofueled | | Add 177MW CC (PC08x3)-Biofueled | |

## Appendix O: Resource Plan Sheets

Interconnection Resource Plans

| Name | PM2B2b1N-6Br1W Base (No Interconnection) | | PM2B2b1N-6Br2W (With Interconnection) | |
|---|---|---|---|---|
| *2023* | | Add 17MW ICE (MS01x1)-Biofueled | | |
| | | | | Add 17MW ICE (MS01x1)-Biofueled |
| *2024* | | | | |
| *2025* | | | | |
| *2026* | | | | |
| *2027* | | | | |
| *2028* | Add 20 MW PV (PP03x4) | | Add 20 MW PV (PP03x4) | |
| *2029* | Add 30 MW Wind (PW01x1) | | Add 30 MW Wind (PW01x1) | |
| | Add 20 MW PV (PP03x4) | | Add 20 MW PV (PP03x4) | |
| *2030* | Add 150 MW Wind (PW01x5) | Add 5 MW PV (MP03x5) | Add 150 MW Wind (PW01x5) | |
| | Add 20 MW PV (PP03x4) | | Add 20 MW PV (PP03x4) | Add 5 MW PV (MP03x5) |
| *2031* | | | | |
| *2032* | | | | |
| *2033* | | Add 5 MW PV (MP03x5) | | Add 5 MW PV (MP03x5) |
| *Planning Period Total Cost* | 26, 733, 654 | | 25, 795, 274 | |
| *Study Period Total Cost* | 39, 037, 092 | | 36, 854, 568 | |
| *Interconnection Energy* | | | | ~960 GWh M->P |
| *Planning Rank* | 2 | | 1 | |
| *Study Rank* | 2 | | 1 | |

# Appendix P: Preferred, Contingency, Parallel, and Secondary Plan Metrics

This appendix contains graphs of the metrics for the preferred, contingency, parallel, and secondary plans, for each utility, for the Blazing a Bold Frontier and Stuck in the Middle Scenarios.

# CONTENTS



# TABLES

# Hawaiian Electric Plan Metrics

Hawaiian Electric's metrics of the Preferred Plan, Contingency Plan, Parallel Plan, and Secondary Plan in Blazing a Bold Frontier and Stuck in the Middle are presented side by side.

## Blazing a Bold Frontier

Table P-1. Hawaiian Electric Blazing a Bold Frontier Greenhouse Gas Emissions

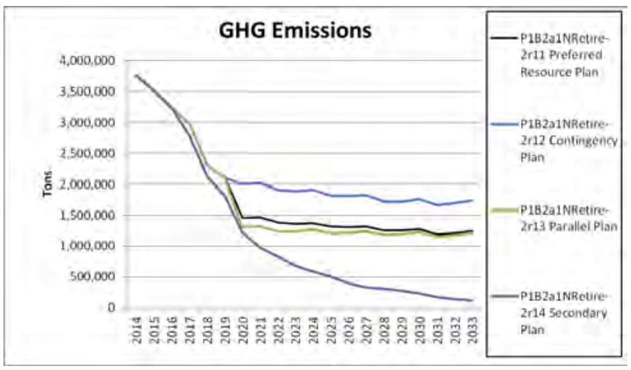
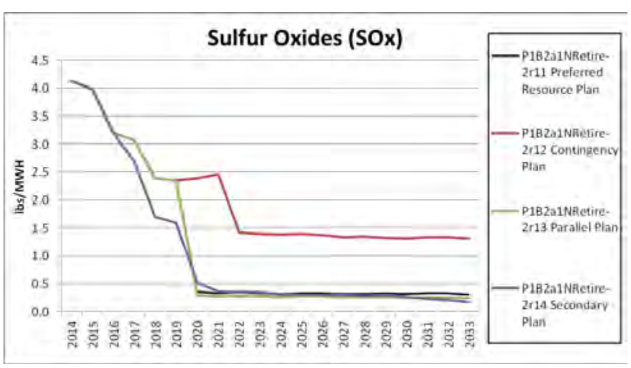



Table P-3. Hawaiian Electric Blazing a Bold Frontier Sulfur Oxides




## Stuck in the Middle

Table P-2. Hawaiian Electric Stuck in the Middle Greenhouse Gas Emissions

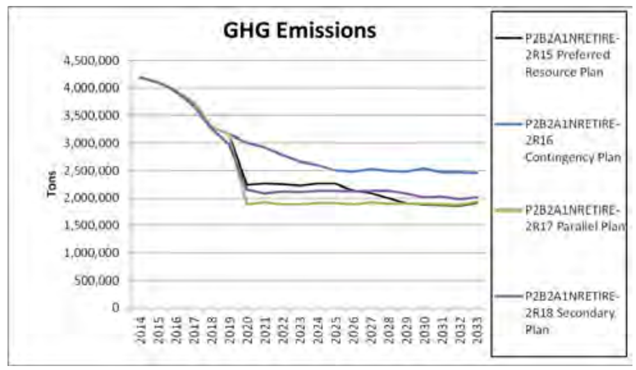



Table P-4. Hawaiian Electric Stuck in the Middle Sulfur Oxides

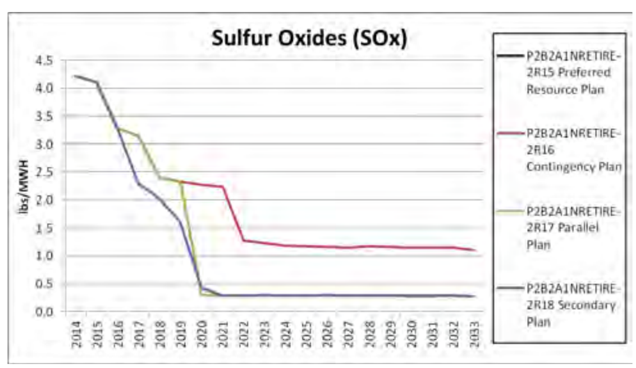


Table P-5. Hawaiian Electric Blazing a Bold Frontier Nitrous Oxides

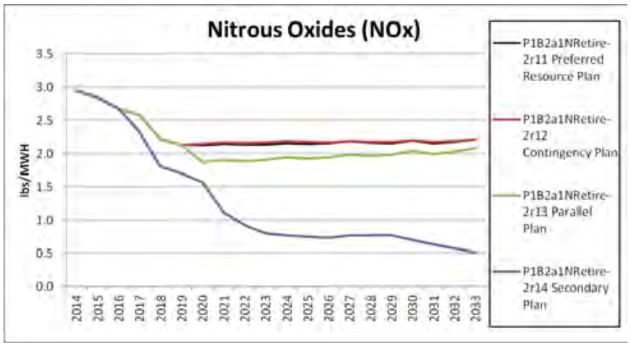



Table P-6. Hawaiian Electric Stuck in the Middle Nitrous Oxides

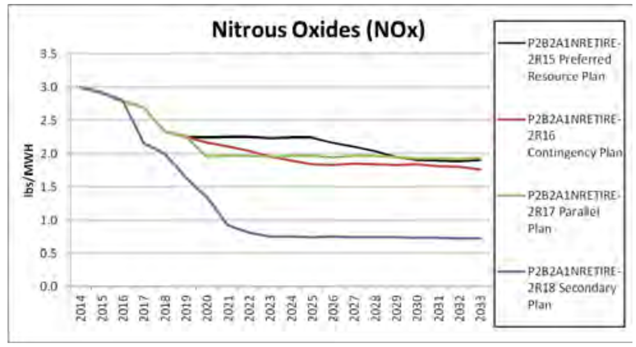



Table P-7. Hawaiian Electric Blazing a Bold Frontier Particulate Matter

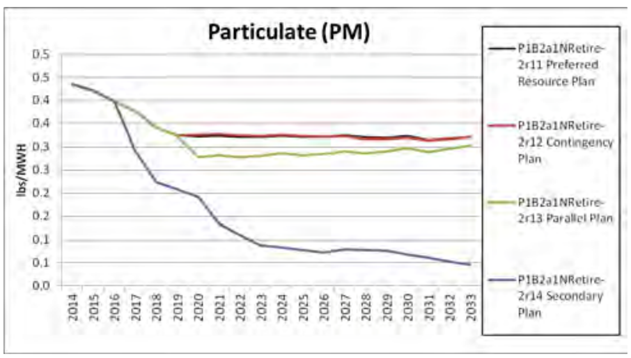



Table P-8. Hawaiian Electric Stuck in the Middle Particulate Matter

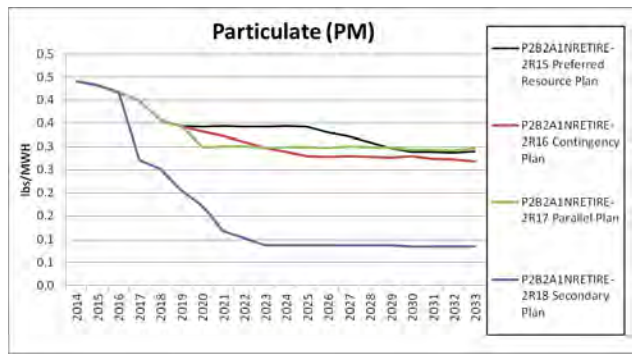



Table P-9. Hawaiian Electric Blazing a Bold Frontier Share of Delivered Energy from Imported Fossil Fuels

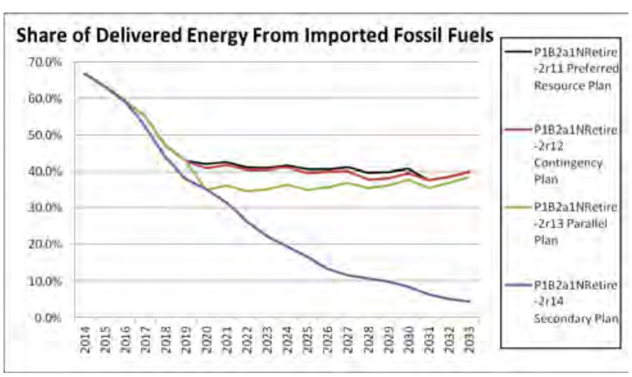



Table P-10. Hawaiian Electric Stuck in the Middle Share of Delivered Energy from Imported Fossil Fuels

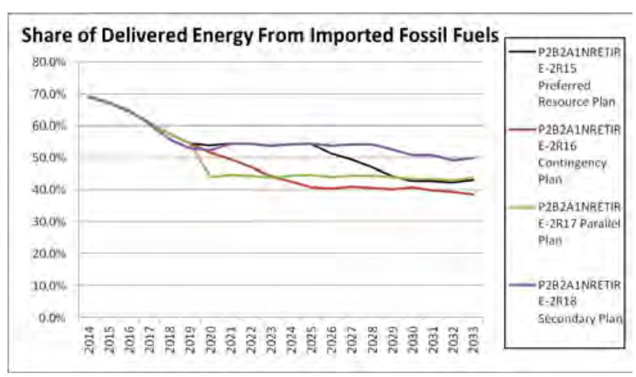


Table P-11. Hawaiian Electric Blazing a Bold Frontier Share of Resource Plan Costs Linked to Fossil Fuels

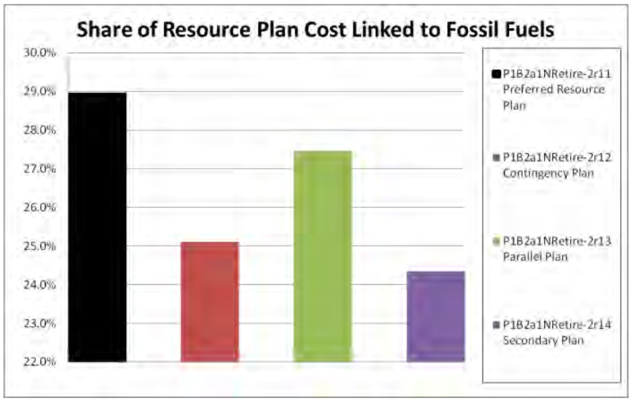



Table P-12. Hawaiian Electric Stuck in the Middle Share of Resource Plan Costs Linked to Fossil Fuels

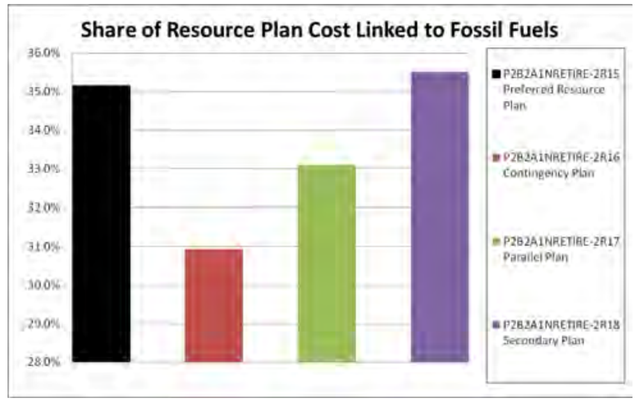



Table P-13. Hawaiian Electric Blazing a Bold Frontier Imported Fossil Fuel Oil Amount

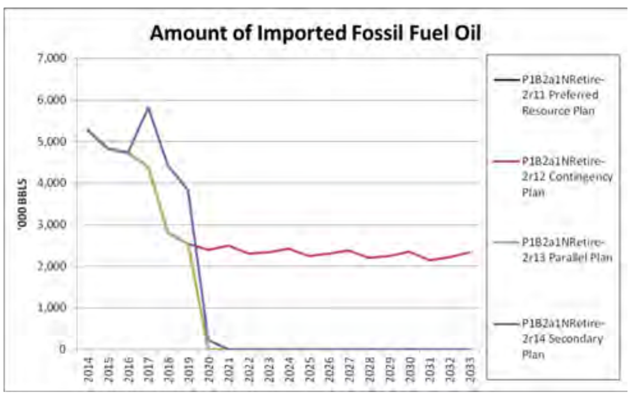



Table P-14. Hawaiian Electric Stuck in the Middle Imported Fossil Fuel Oil Amount

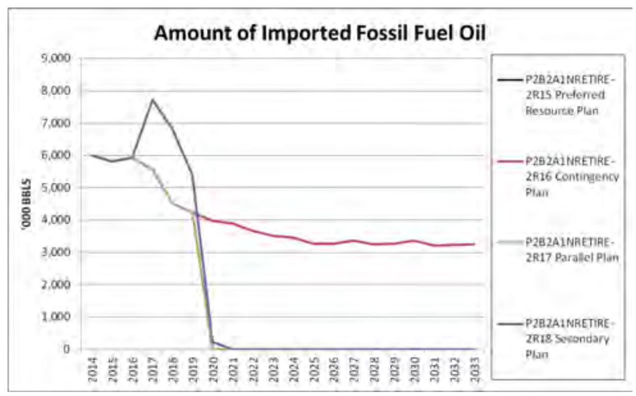



Table P-15. Hawaiian Electric Blazing a Bold Frontier Liquefied Natural Gas Amount

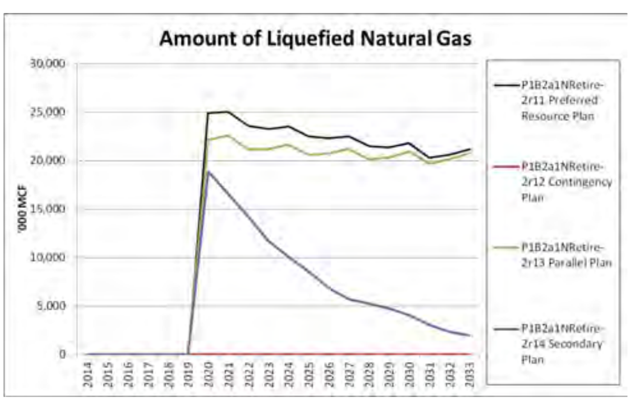



Table P-16. Hawaiian Electric Stuck in the Middle Liquefied Natural Gas Amount

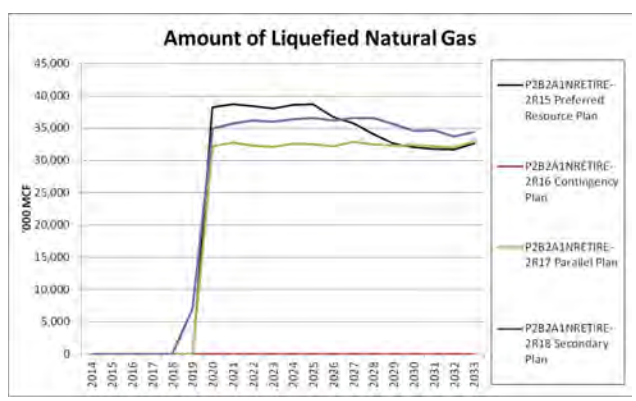


Table P-17. Hawaiian Electric Blazing a Bold Frontier Energy Efficiency Portfolio Standard

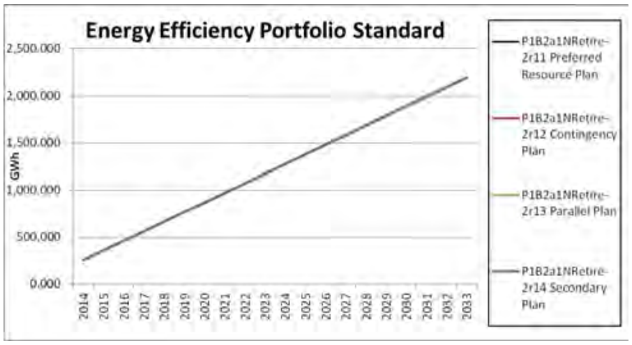



Table P-18. Hawaiian Electric Stuck in the Middle Energy Efficiency Portfolio Standard

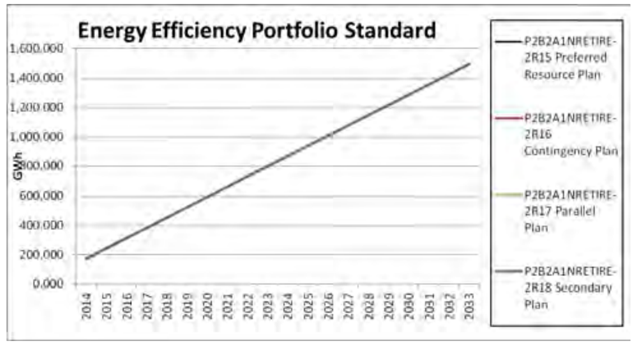



Table P-19. Hawaiian Electric Blazing a Bold Frontier Renewable Energy

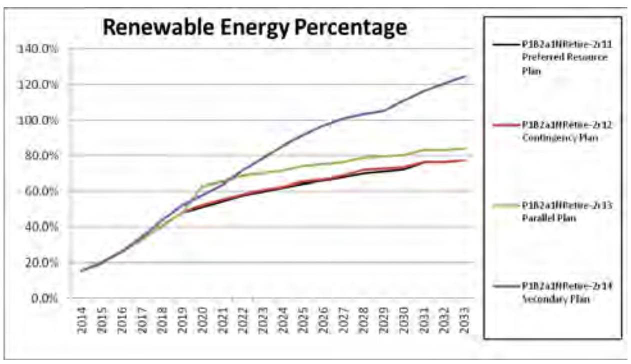



Table P-20. Hawaiian Electric Stuck in the Middle Renewable Energy

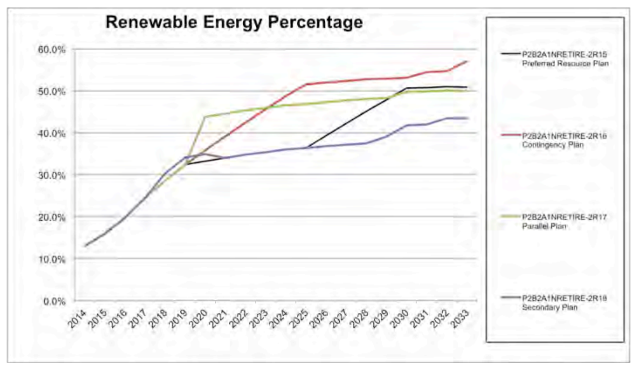



Table P-21. Hawaiian Electric Blazing a Bold Frontier Renewable Energy Curtailed

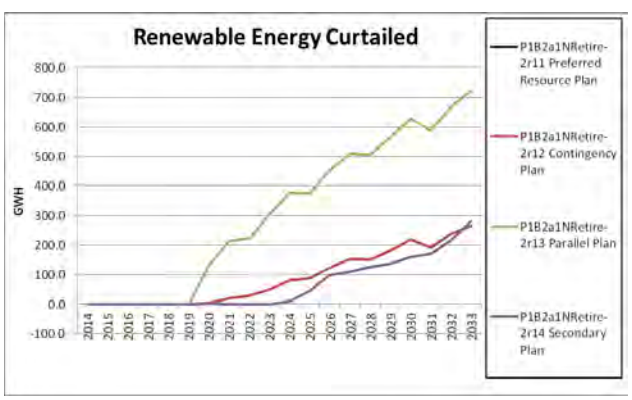



Table P-22. Hawaiian Electric Stuck in the Middle Renewable Energy Curtailed

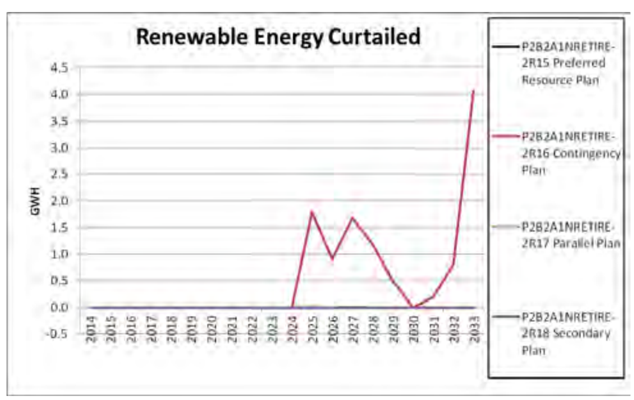


Table P-23. Hawaiian Electric Blazing a Bold Frontier Resource Diversity Index

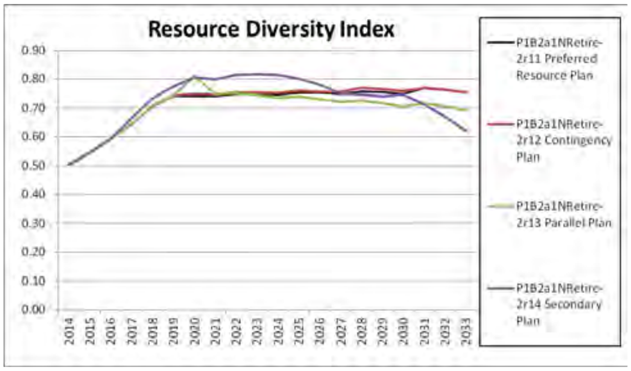



Table P-24. Hawaiian Electric Stuck in the Middle Resource Diversity Index

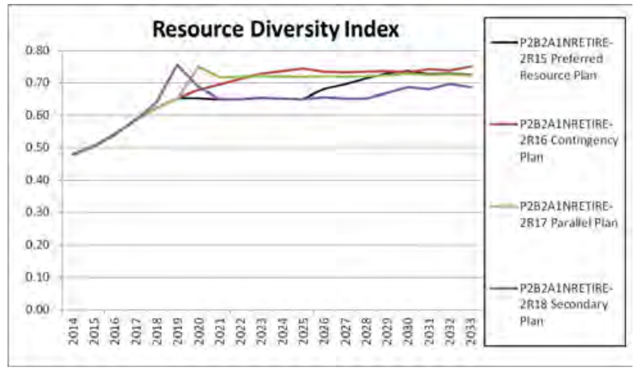



Table P-25. Hawaiian Electric Blazing a Bold Frontier Share of Generation from Local Resources

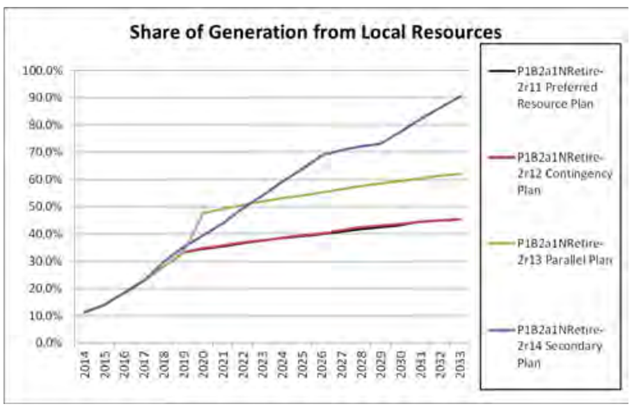



Table P-26. Hawaiian Electric Stuck in the Middle Share of Generation from Local Resources

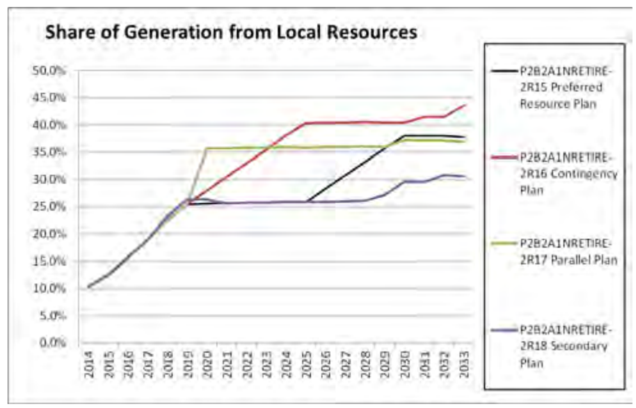



Table P-27. Hawaiian Electric Blazing a Bold Frontier Reserve Margin

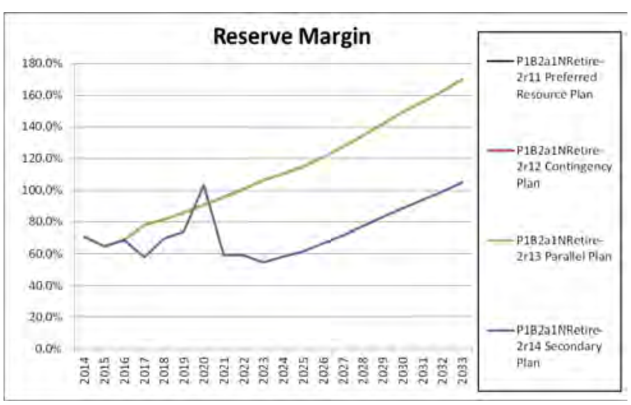



Table P-28. Hawaiian Electric Stuck in the Middle Reserve Margin

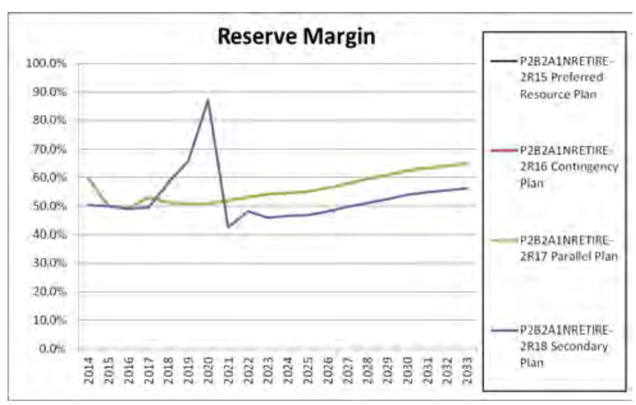


Table P-29. Hawaiian Electric Blazing a Bold Frontier Variable Energy Resource Penetration

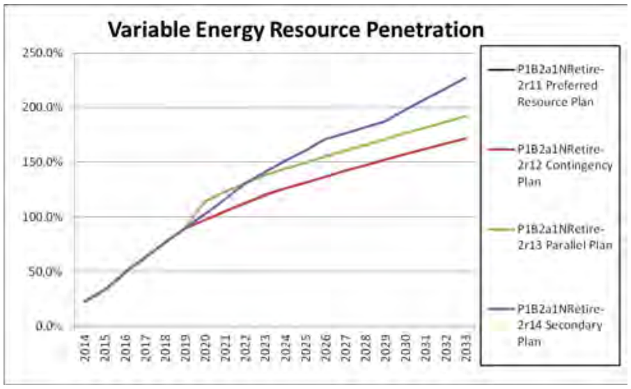



Table P-30. Hawaiian Electric Stuck in the Middle Variable Energy Resource Penetration

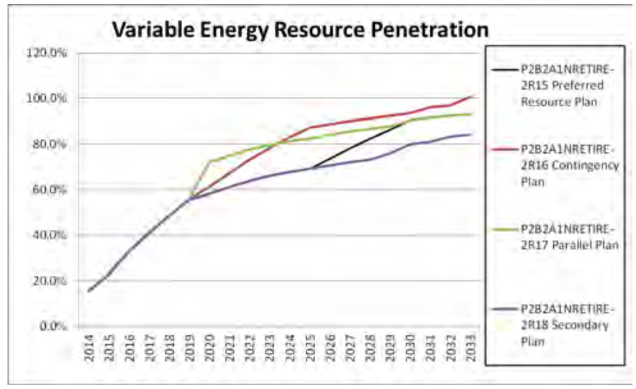



Table P-31. Hawaiian Electric Blazing a Bold Frontier Generation Efficiency

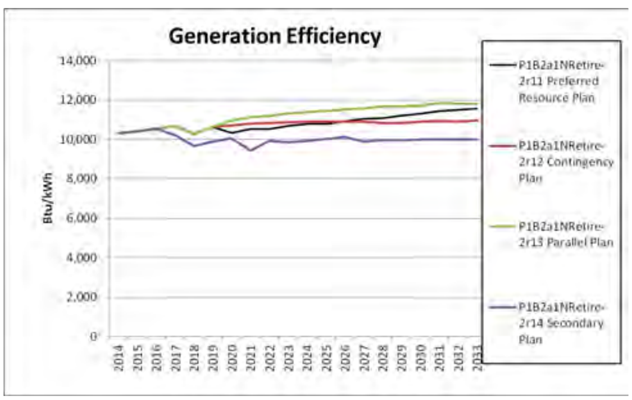



Table P-32. Hawaiian Electric Stuck in the Middle Generation Efficiency

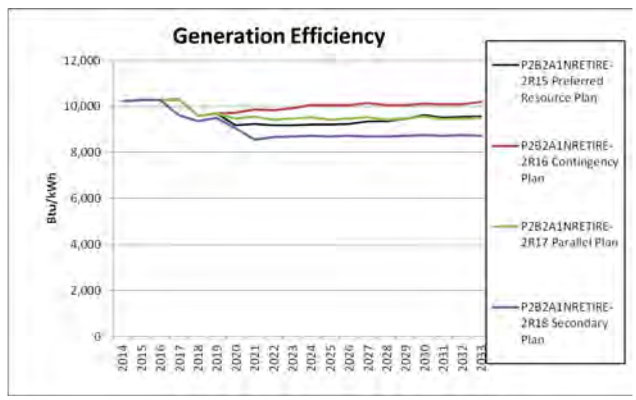



Table P-33. Hawaiian Electric Blazing a Bold Frontier System Regulating Capability

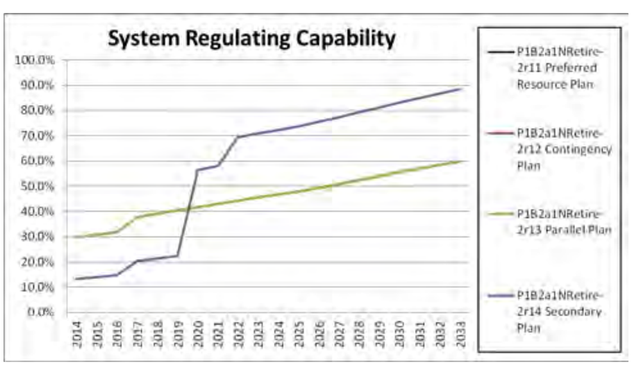



Table P-34. Hawaiian Electric Stuck in the Middle System Regulating Capability

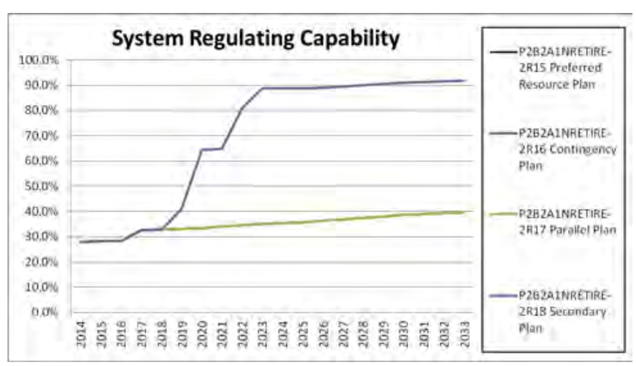


Table P-35. Hawaiian Electric Blazing a Bold Frontier Nominal Price of Electricity: Residential (2014$)

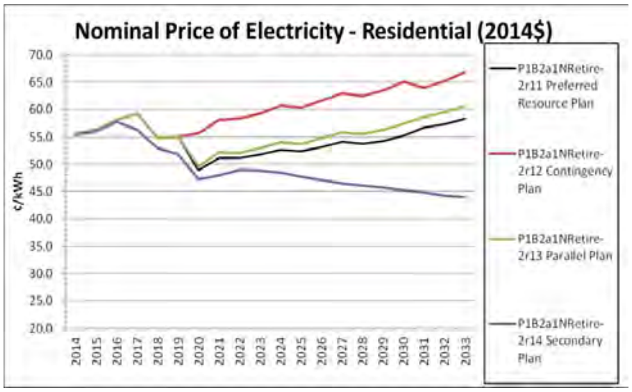



Table P-36. Hawaiian Electric Stuck in the Middle Nominal Price of Electricity: Residential (2014$)

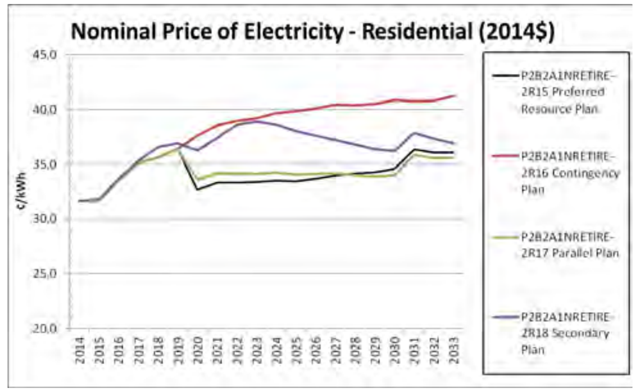



Table P-37. Hawaiian Electric Blazing a Bold Frontier Nominal Price of Electricity: Residential

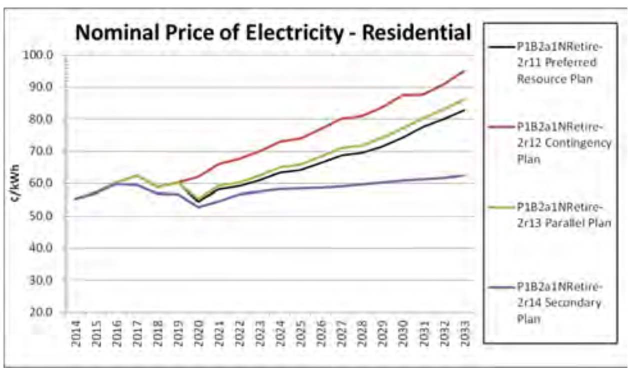



Table P-38. Hawaiian Electric Stuck in the Middle Nominal Price of Electricity: Residential

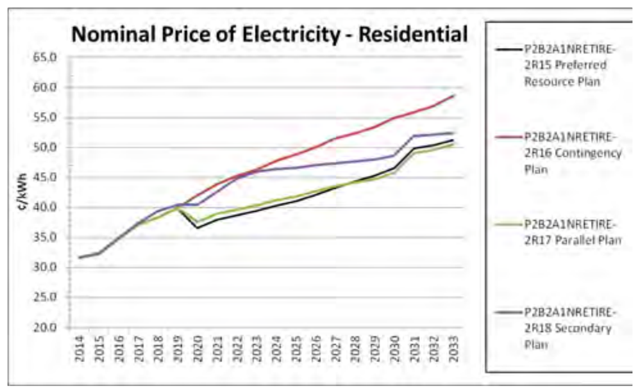



Table P-39. Hawaiian Electric Blazing a Bold Frontier Nominal Price of Electricity: Commercial (2014$)

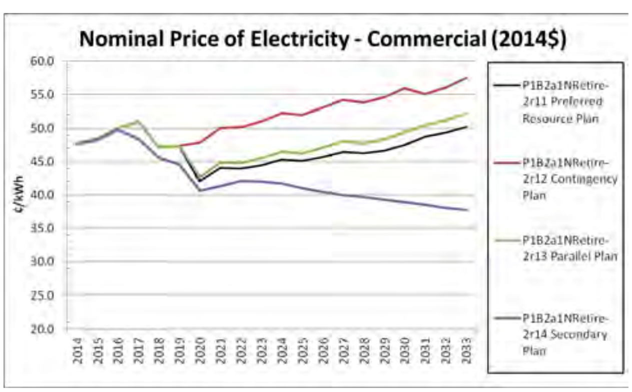



Table P-40. Hawaiian Electric Stuck in the Middle Nominal Price of Electricity: Commercial (2014$)

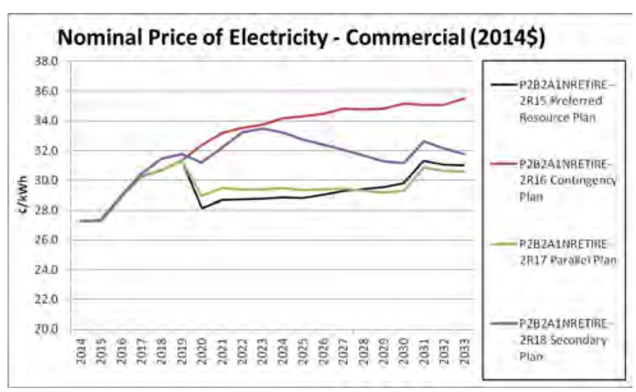


Table P-41. Hawaiian Electric Blazing a Bold Frontier Nominal Price of Electricity: Commercial

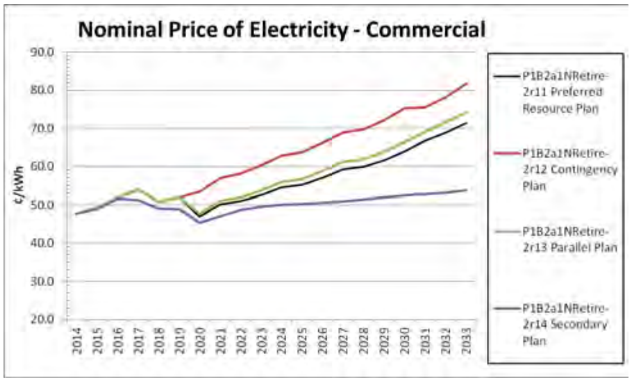



Table P-42. Hawaiian Electric Stuck in the Middle Nominal Price of Electricity: Commercial

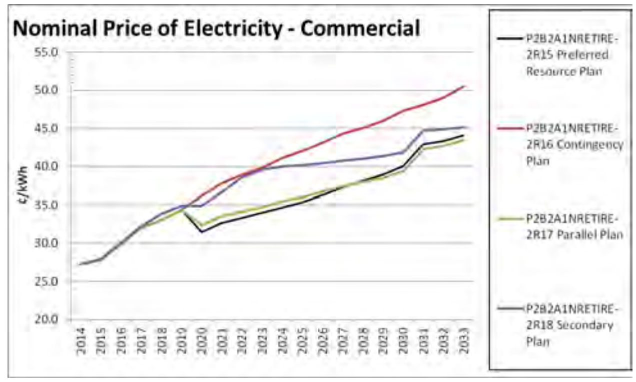



Table P-43. Hawaiian Electric Blazing a Bold Frontier Nominal Price of Electricity: Industrial (2014$)

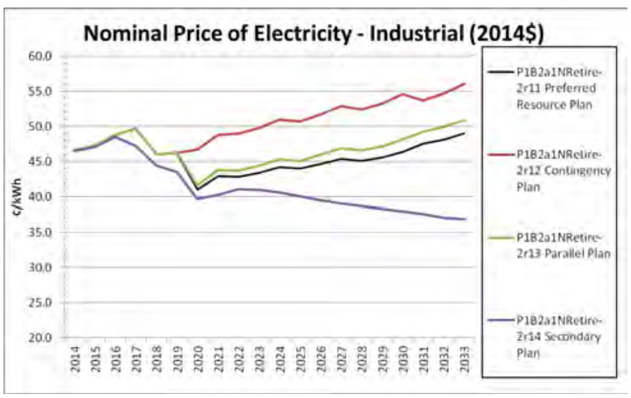



Table P-44. Hawaiian Electric Stuck in the Middle Nominal Price of Electricity: Industrial (2014$)

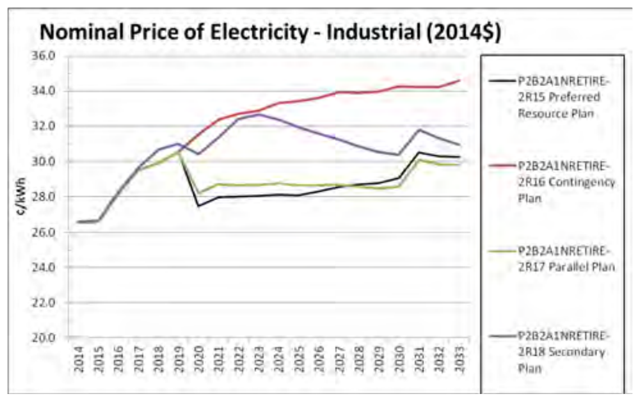



Table P-45. Hawaiian Electric Blazing a Bold Frontier Nominal Price of Electricity: Industrial

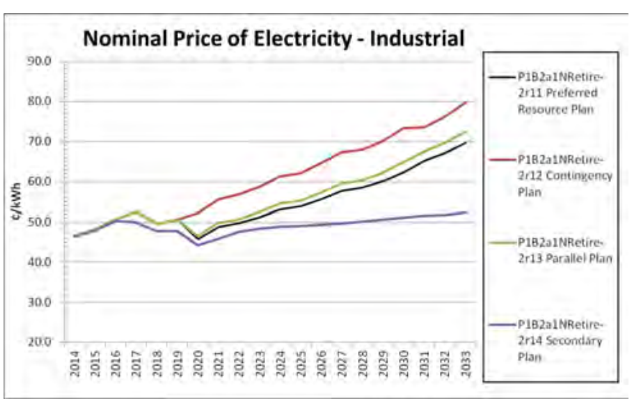



Table P-46. Hawaiian Electric Stuck in the Middle Nominal Price of Electricity: Industrial

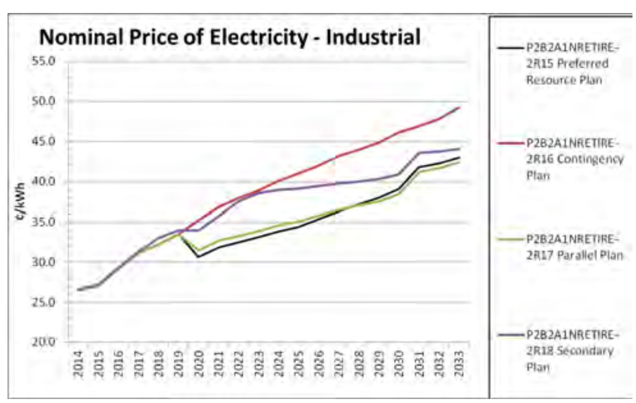


Table P-47. Hawaiian Electric Blazing a Bold Frontier Average Residential Bill (2014$)

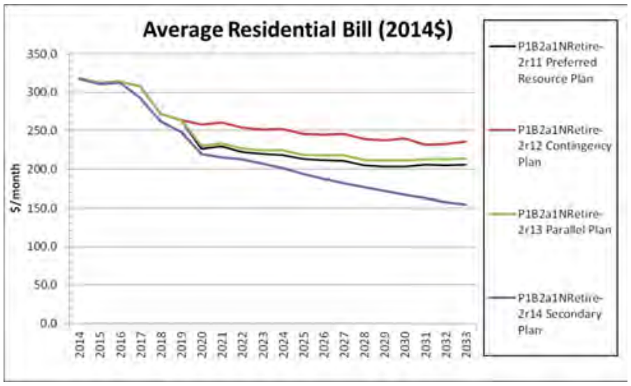



Table P-48. Hawaiian Electric Stuck in the Middle Average Residential Bill (2014$)

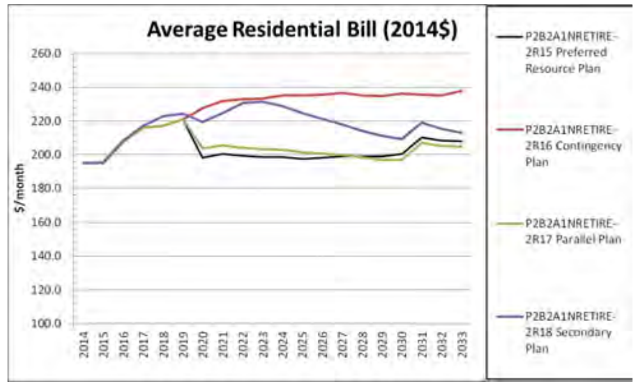



Table P-49. Hawaiian Electric Blazing a Bold Frontier Average Residential Bill

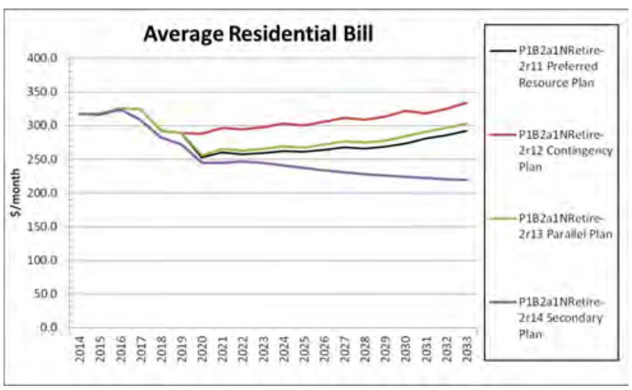



Table P-50. Hawaiian Electric Stuck in the Middle Average Residential Bill

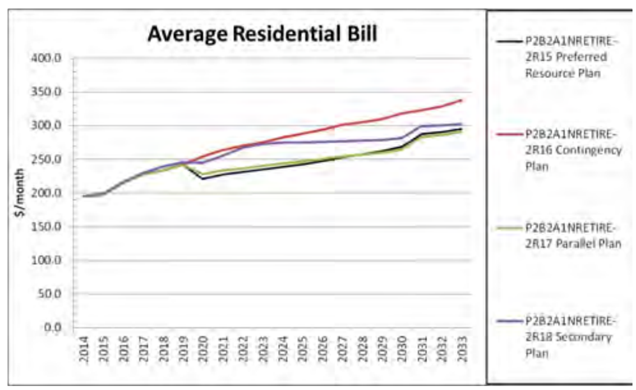



Table P-51. Hawaiian Electric Blazing a Bold Frontier Nominal Residential Bill

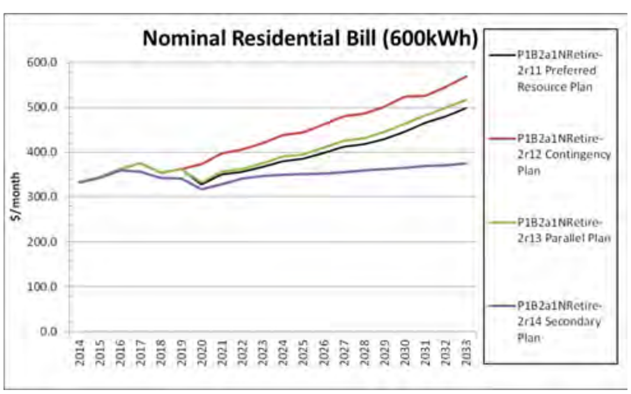



Table P-52. Hawaiian Electric Stuck in the Middle Nominal Residential Bill

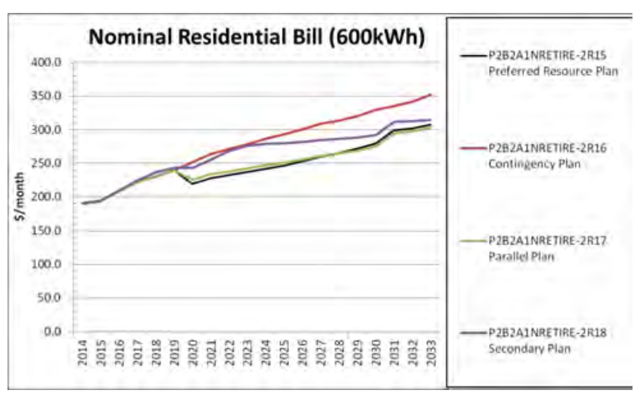


Table P-53. Hawaiian Electric Blazing a Bold Frontier Annual Revenue Requirements for Capital

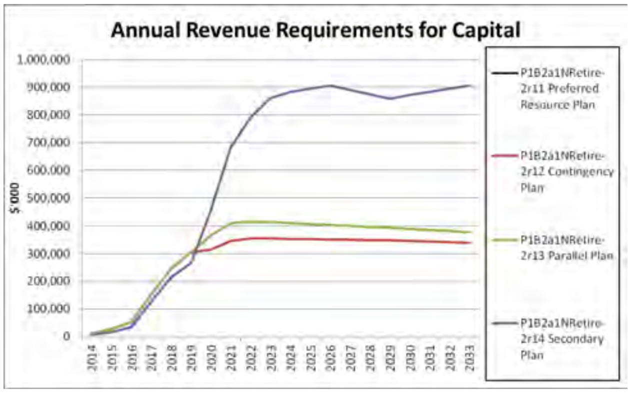



Table P-54. Hawaiian Electric Stuck in the Middle Annual Revenue Requirements for Capital

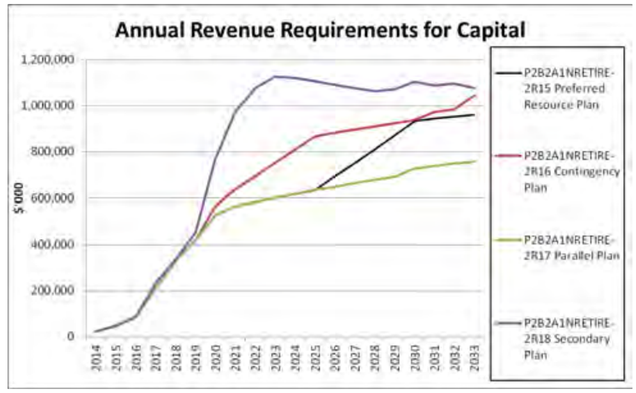



Table P-55. Hawaiian Electric Blazing a Bold Frontier Total Resource Cost: Planning Period

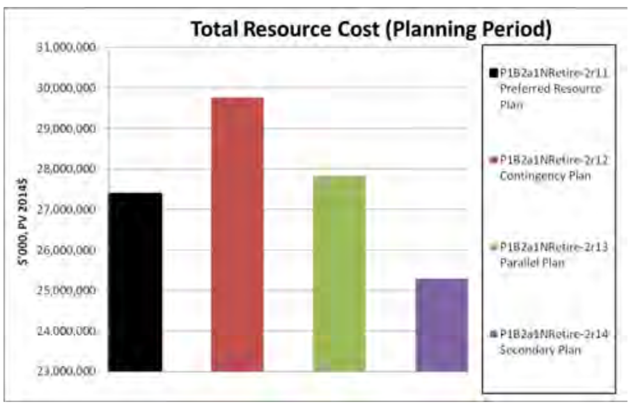



Table P-56. Hawaiian Electric Stuck in the Middle Total Resource Cost: Planning Period

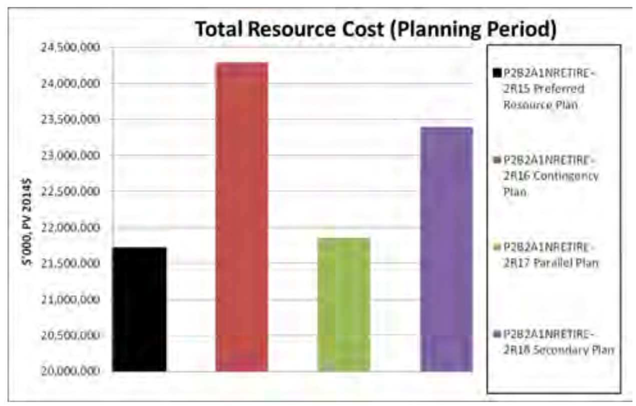



Table P-57. Hawaiian Electric Blazing a Bold Frontier Total Resource Cost: Study Period

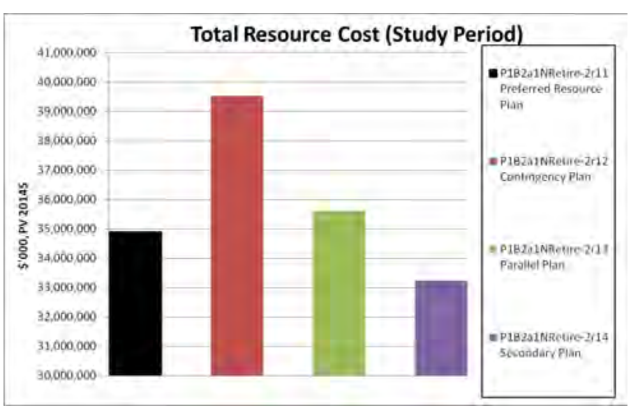
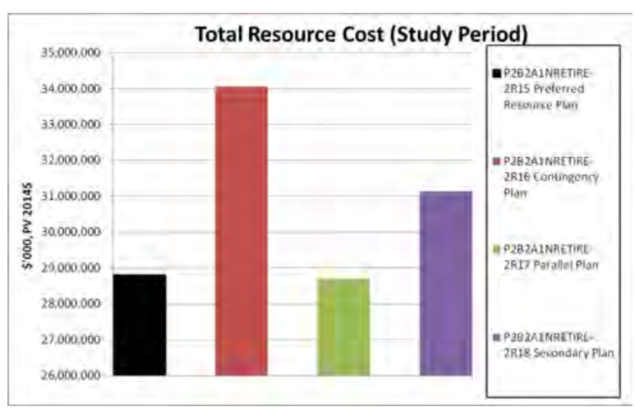



Table P-58. Hawaiian Electric Stuck in the Middle Total Resource Cost: Study Period



# HELCO Plan Metrics

HELCO's metrics of the Preferred Plan, Contingency Plan, Parallel Plan, and Secondary Plan in Blazing a Bold Frontier and Stuck in the Middle are presented side by side.

## Blazing a Bold Frontier

Table P-59. HELCO Blazing a Bold Frontier Greenhouse Gas Emissions

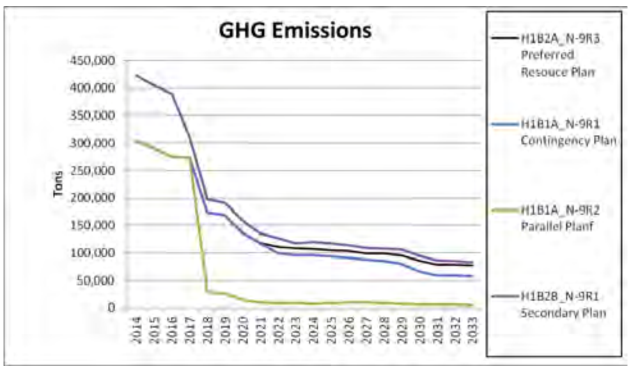
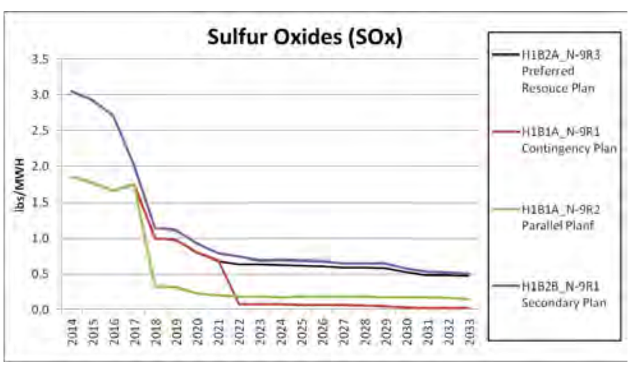



Table P-61. HELCO Blazing a Bold Frontier Sulfur Oxides




## Stuck in the Middle

Table P-60. HELCO Stuck in the Middle Greenhouse Gas Emissions

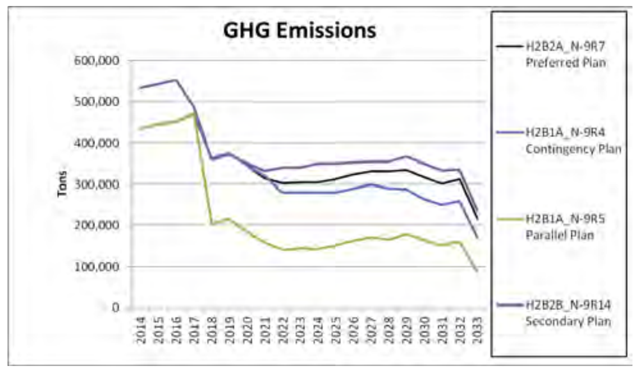



Table P-62. HELCO Stuck in the Middle Sulfur Oxides

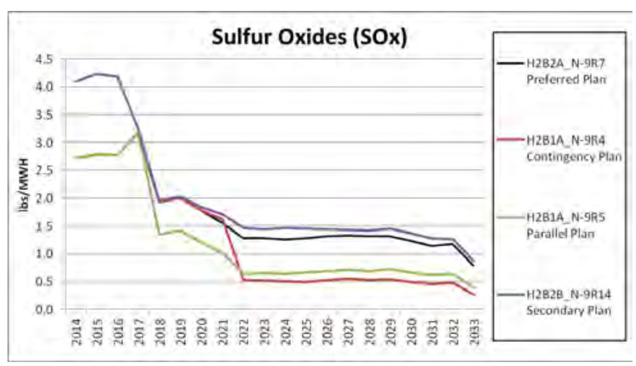


Table P-63. HELCO Blazing a Bold Frontier Nitrous Oxides

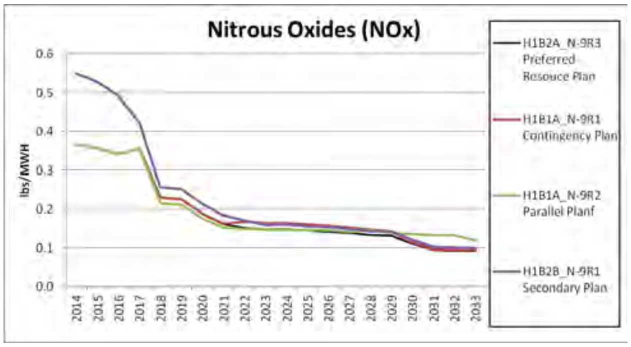



Table P-64. HELCO Stuck in the Middle Nitrous Oxides

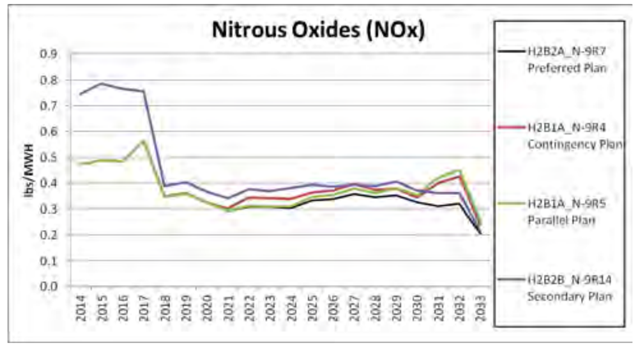



Table P-65. HELCO Blazing a Bold Frontier Particulate Matter

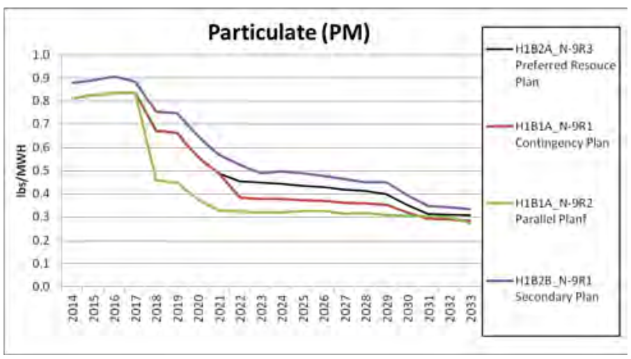



Table P-66. HELCO Stuck in the Middle Particulate Matter

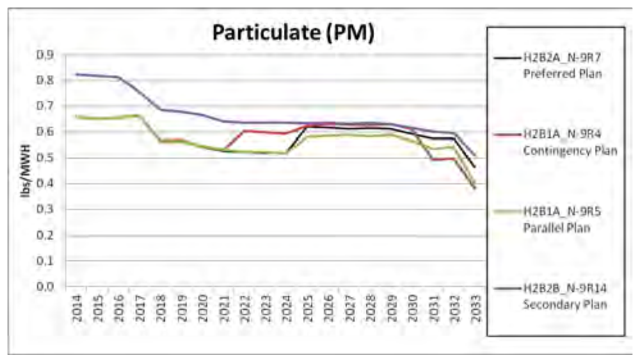



Table P-67. HELCO Blazing a Bold Frontier Share of Delivered Energy from Imported Fossil Fuels

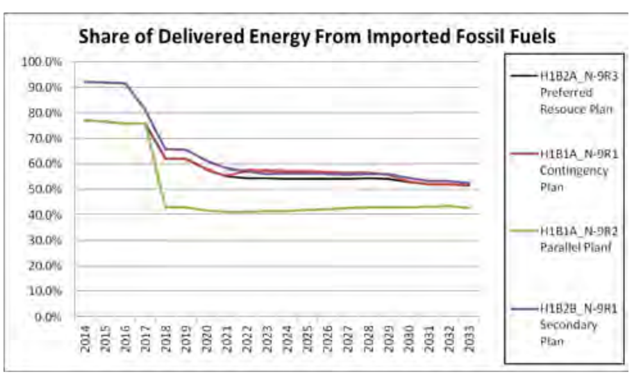



Table P-68. HELCO Stuck in the Middle Share of Delivered Energy from Imported Fossil Fuels

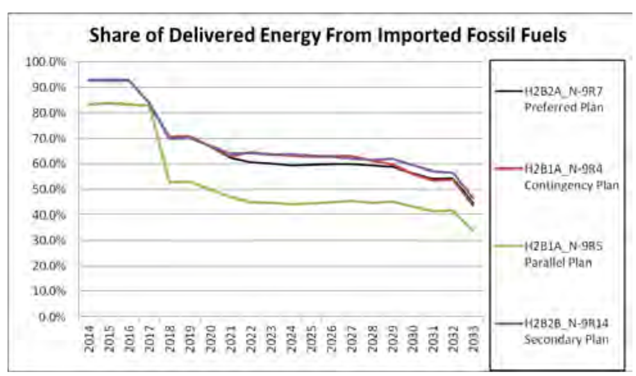


Table P-69. HELCO Blazing a Bold Frontier Share of Resource Plan Cost Linked to Fossil Fuels

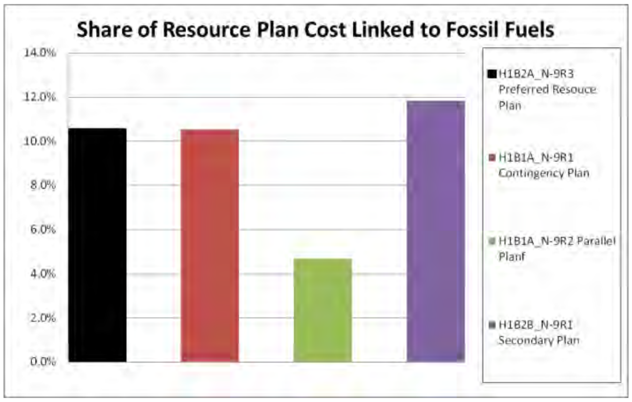



Table P-70. HELCO Stuck in the Middle Share of Resource Plan Cost Linked to Fossil Fuels

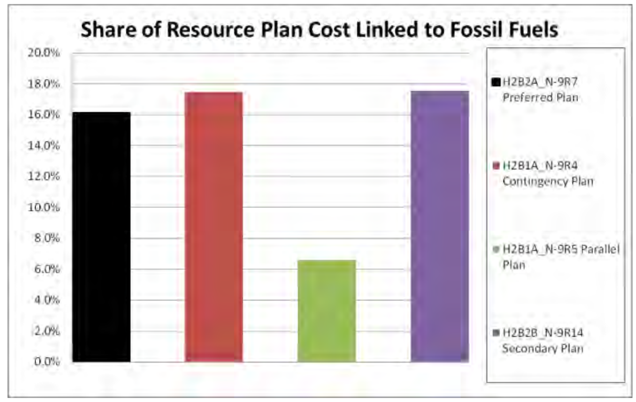



Table P-71. HELCO Blazing a Bold Frontier Imported Fossil Fuel Oil Amount

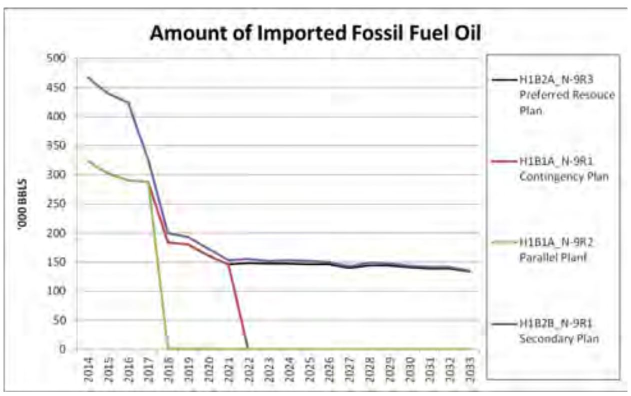



Table P-72. HELCO Stuck in the Middle Imported Fossil Fuel Oil Amount

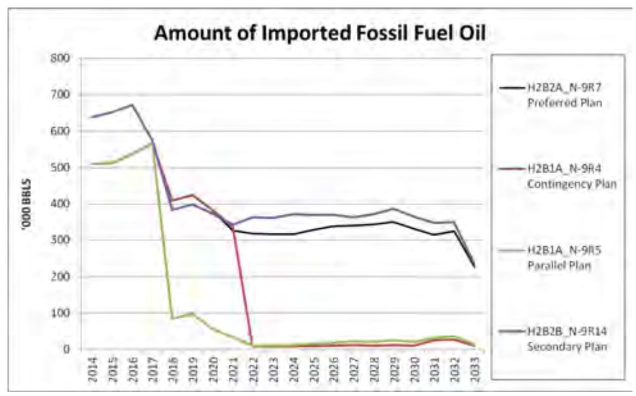



Table P-73. HELCO Blazing a Bold Frontier Liquefied Natural Gas Amount

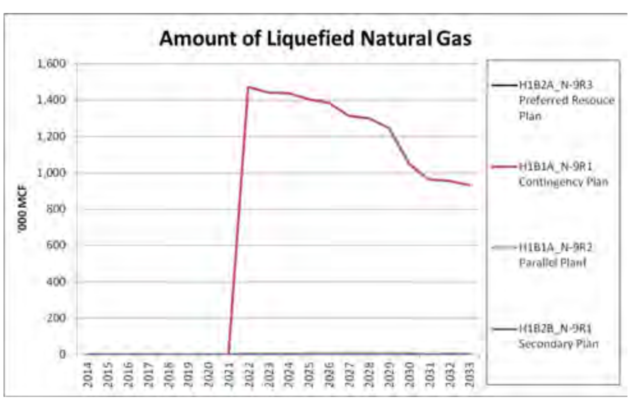



Table P-74. HELCO Stuck in the Middle Liquefied Natural Gas Amount

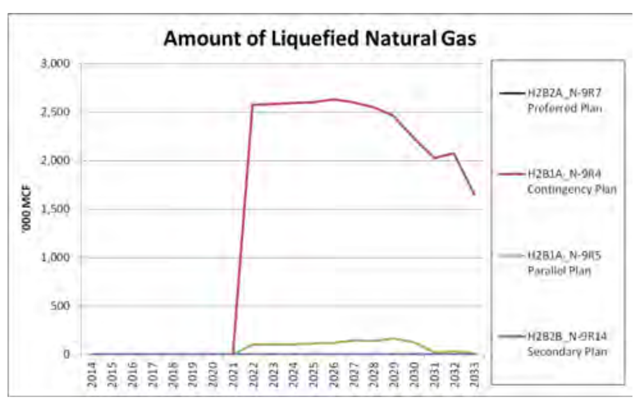


Table P-75. HELCO Blazing a Bold Frontier Energy Efficiency Portfolio Standard

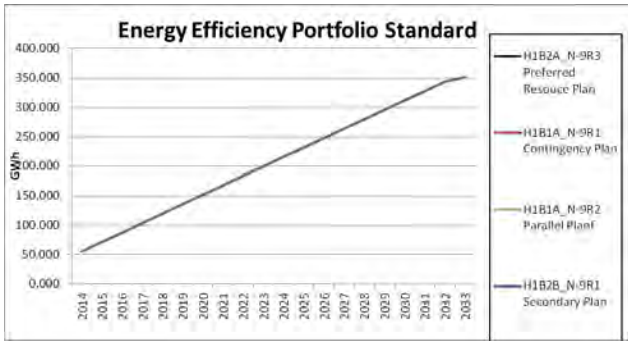



Table P-76. HELCO Stuck in the Middle Energy Efficiency Portfolio Standard

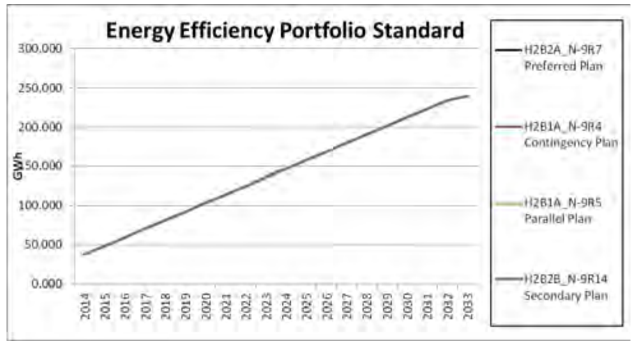



Table P-77. HELCO Blazing a Bold Frontier Renewable Energy

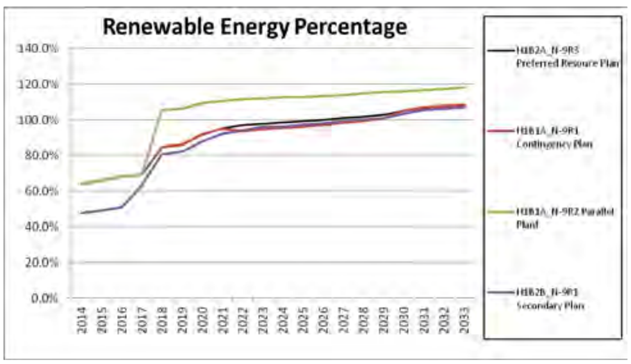



Table P-78. HELCO Stuck in the Middle Renewable Energy

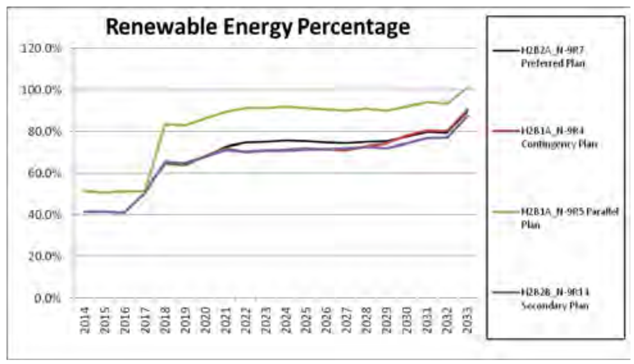



Table P-79. HELCO Blazing a Bold Frontier Renewable Energy Curtailed

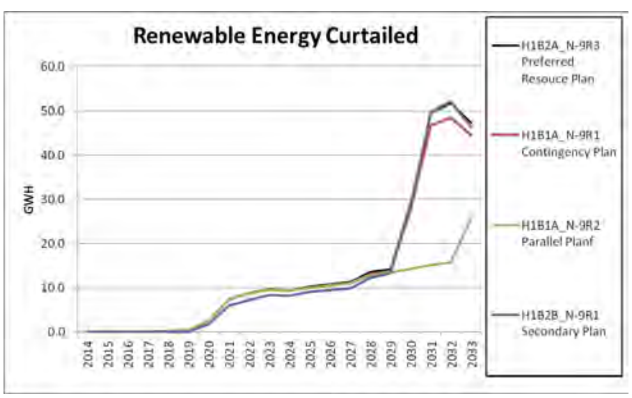



Table P-80. HELCO Stuck in the Middle Renewable Energy Curtailed

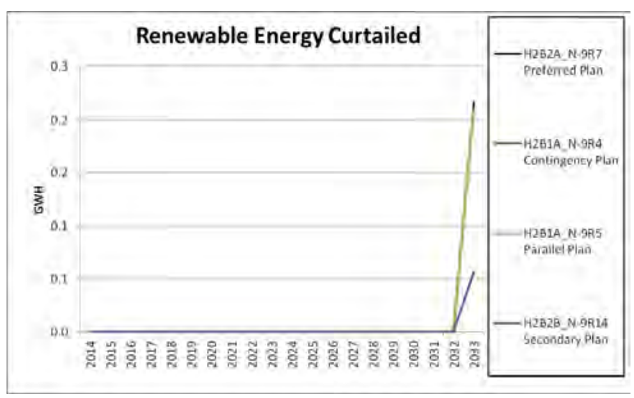


Table P-81. HELCO Blazing a Bold Frontier Resource Diversity Index

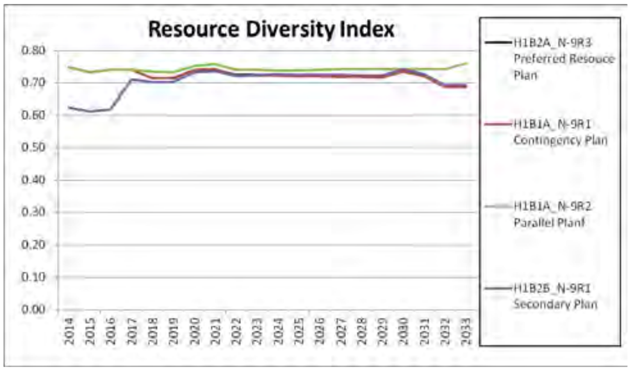



Table P-82. HELCO Stuck in the Middle Resource Diversity Index

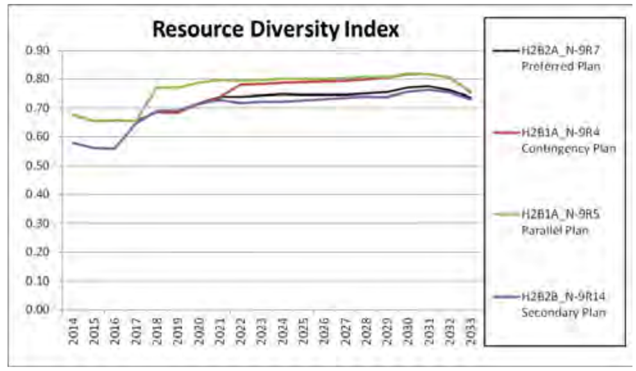



Table P-83. HELCO Blazing a Bold Frontier Share of Generation from Local Resources

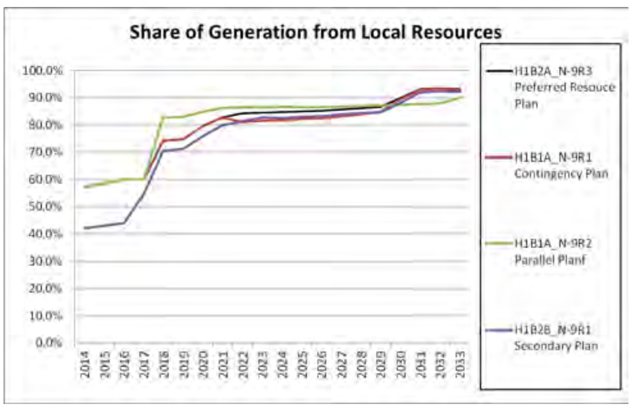



Table P-84. HELCO Stuck in the Middle Share of Generation from Local Resources

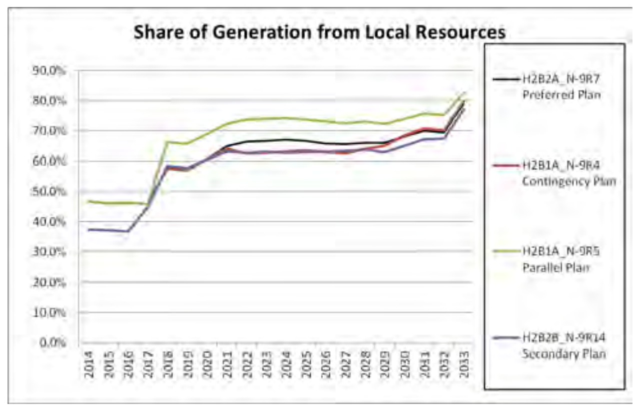



Table P-85. HELCO Blazing a Bold Frontier Reserve Margin

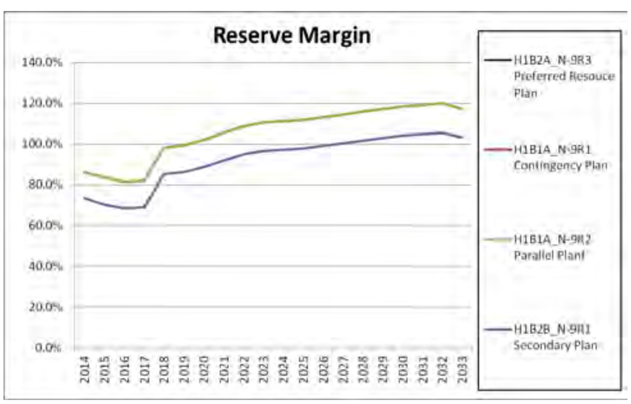



Table P-86. HELCO Stuck in the Middle Reserve Margin

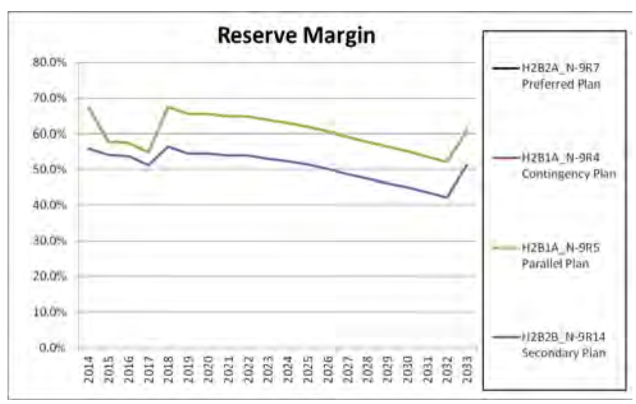


Table P-87. HELCO Blazing a Bold Frontier Variable Energy Resource Penetration

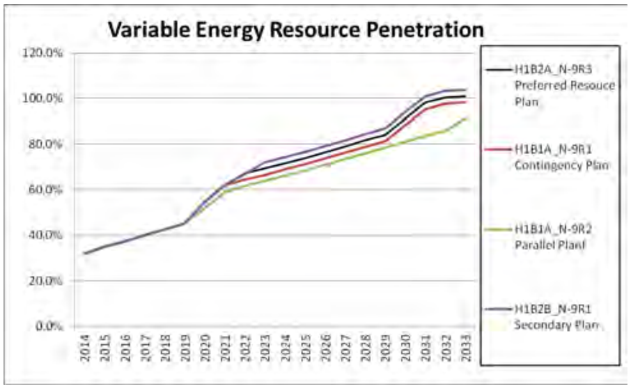



Table P-88. HELCO Stuck in the Middle Variable Energy Resource Penetration

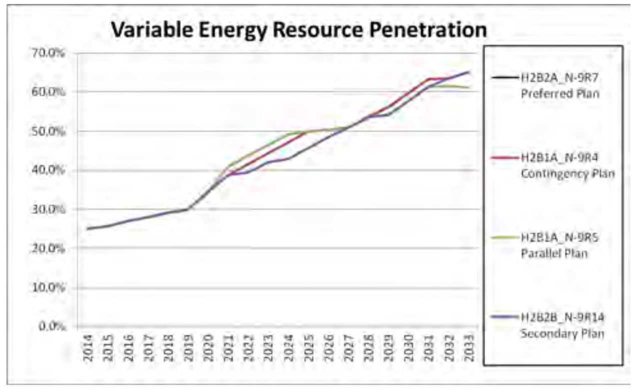



Table P-89. HELCO Blazing a Bold Frontier Generation Efficiency

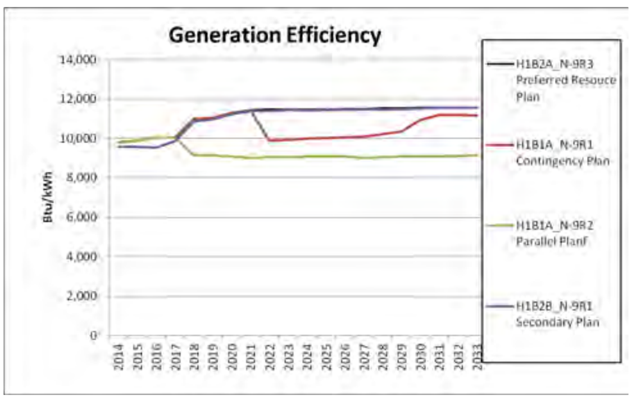



Table P-90. HELCO Stuck in the Middle Generation Efficiency

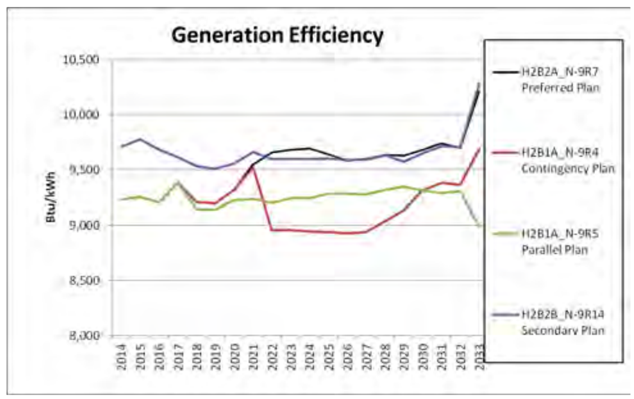



Table P-91. HELCO Blazing a Bold Frontier System Regulating Capability

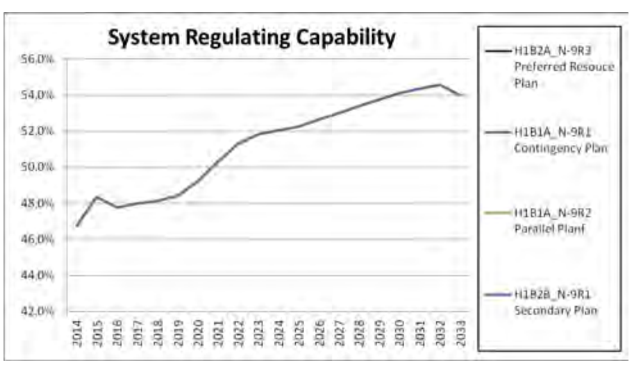



Table P-92. HELCO Stuck in the Middle System Regulating Capability

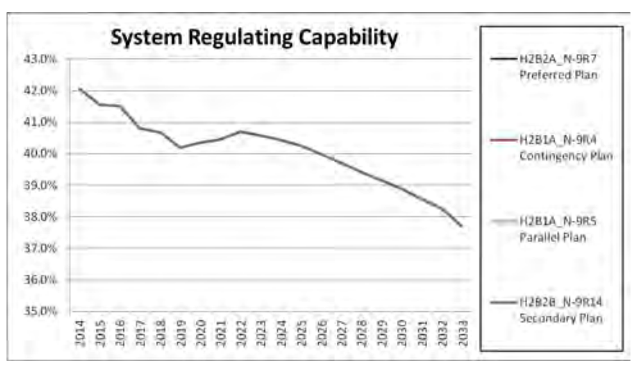


Table P-93. HELCO Blazing a Bold Frontier Nominal Price of Electricity: Residential (2014$)

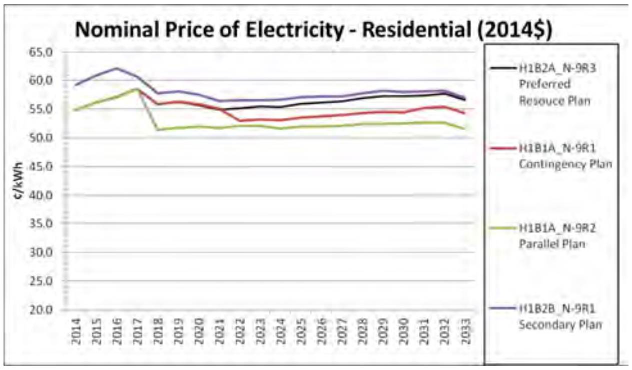



Table P-94. HELCO Stuck in the Middle Nominal Price of Electricity: Residential (2014$)

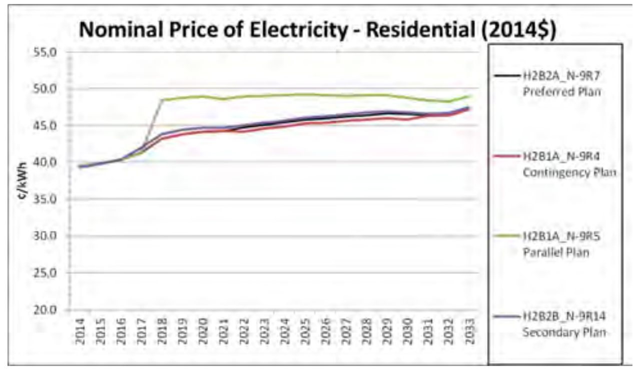



Table P-95. HELCO Blazing a Bold Frontier Nominal Price of Electricity: Residential

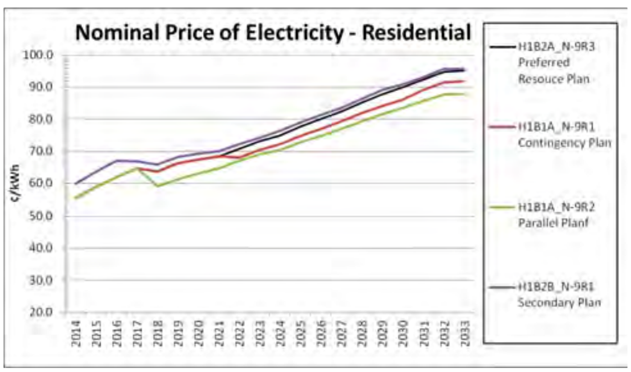



Table P-96. HELCO Stuck in the Middle Nominal Price of Electricity: Residential

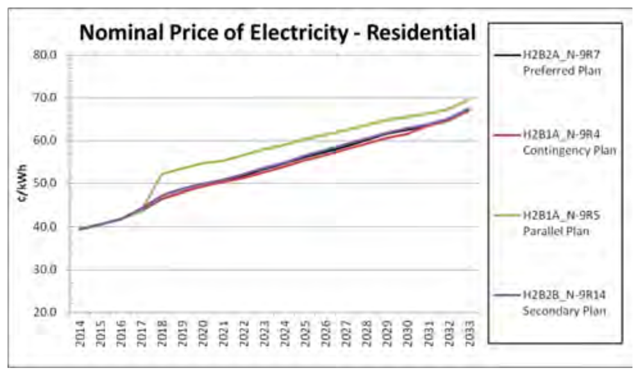



Table P-97. HELCO Blazing a Bold Frontier Nominal Price of Electricity: Commercial (2014$)

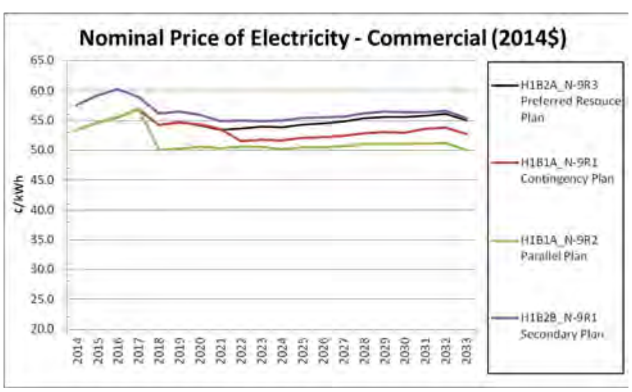



Table P-98. HELCO Stuck in the Middle Nominal Price of Electricity: Commercial (2014$)

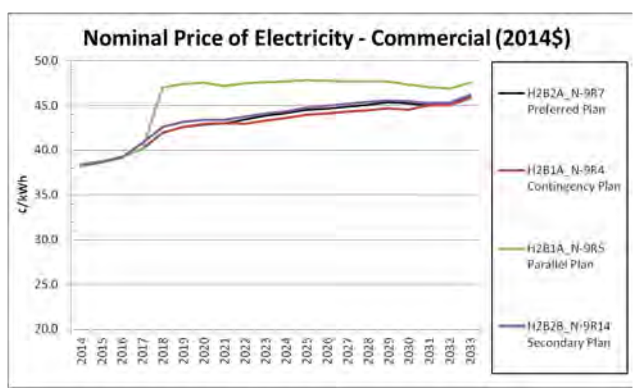


Table P-99. HELCO Blazing a Bold Frontier Nominal Price of Electricity: Commercial

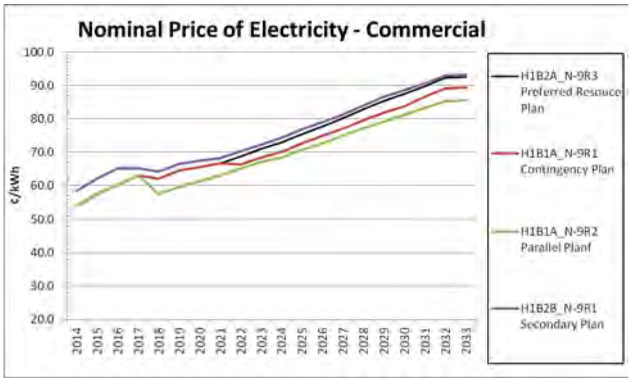



Table P-100. HELCO Stuck in the Middle Nominal Price of Electricity: Commercial

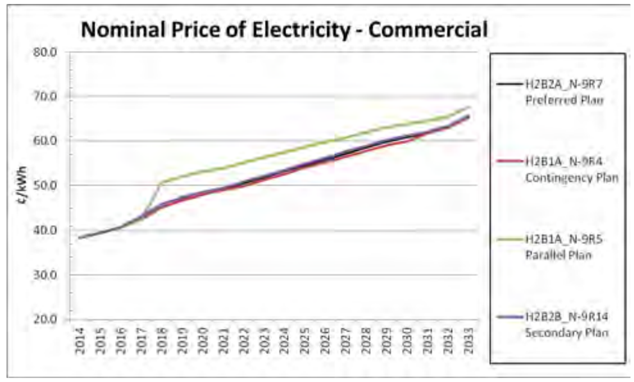



Table P-101. HELCO Blazing a Bold Frontier Nominal Price of Electricity: Industrial (2014$)

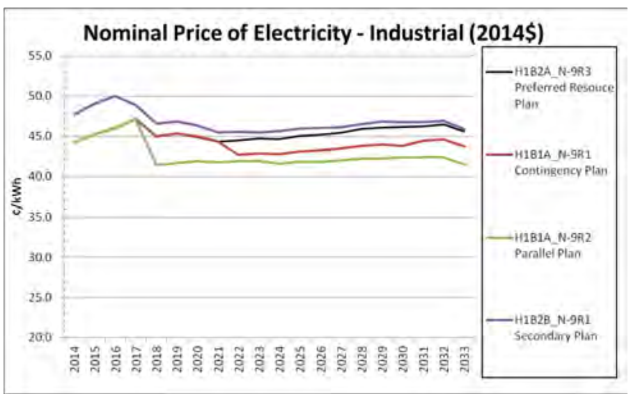



Table P-102. HELCO Stuck in the Middle Nominal Price of Electricity: Industrial (2014$)

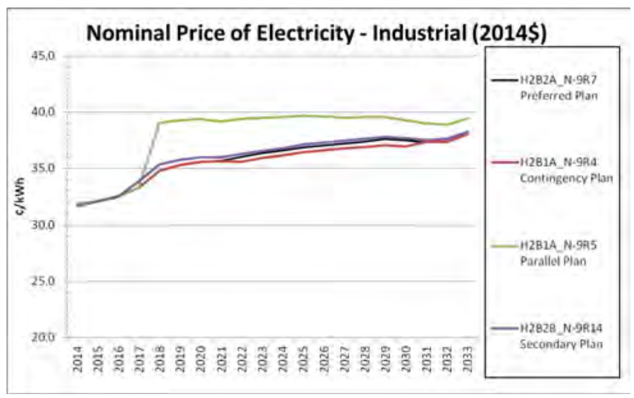



Table P-103. HELCO Blazing a Bold Frontier Nominal Price of Electricity: Industrial

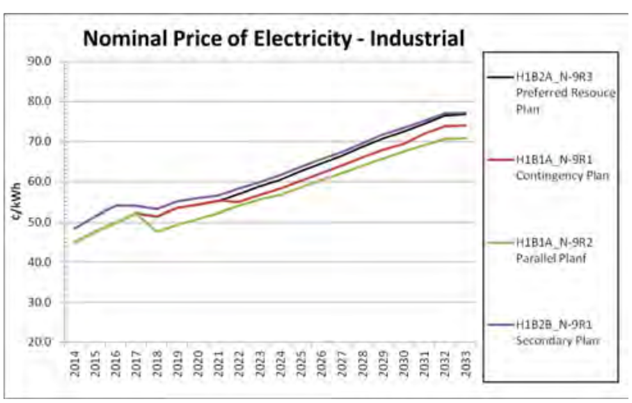



Table P-104. HELCO Stuck in the Middle Nominal Price of Electricity: Industrial

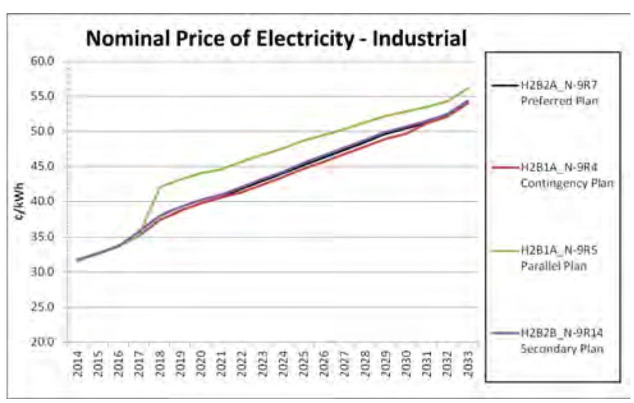


Table P-105. HELCO Blazing a Bold Frontier Average Residential Bill (2014$)

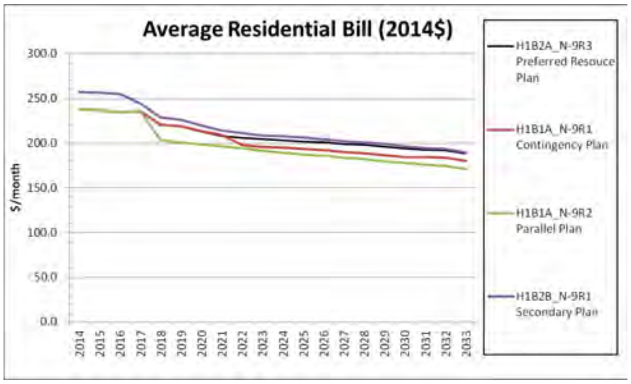



Table P-106. HELCO Stuck in the Middle Average Residential Bill (2014$)

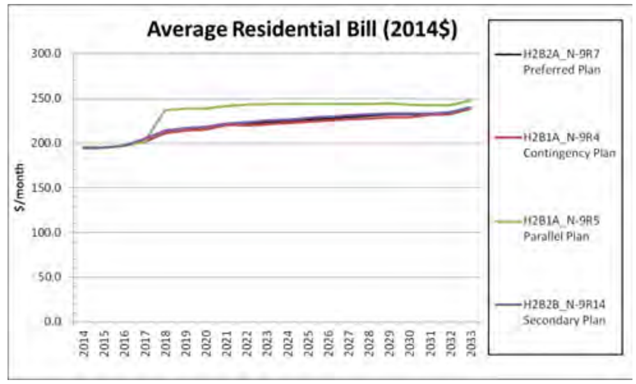



Table P-107. HELCO Blazing a Bold Frontier Average Residential Bill

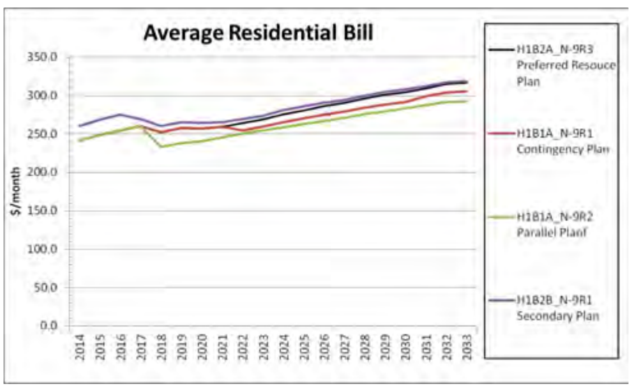



Table P-108. HELCO Stuck in the Middle Average Residential Bill

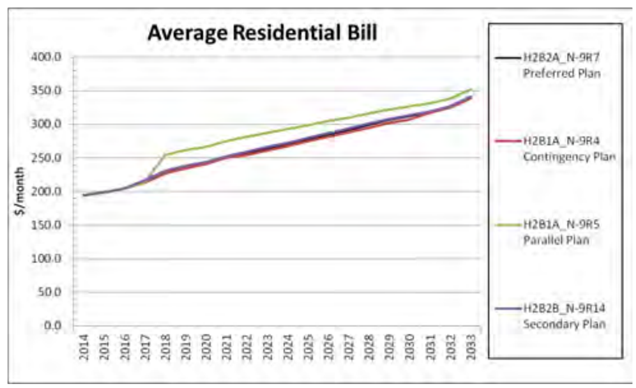



Table P-109. HELCO Blazing a Bold Frontier Nominal Residential Bill

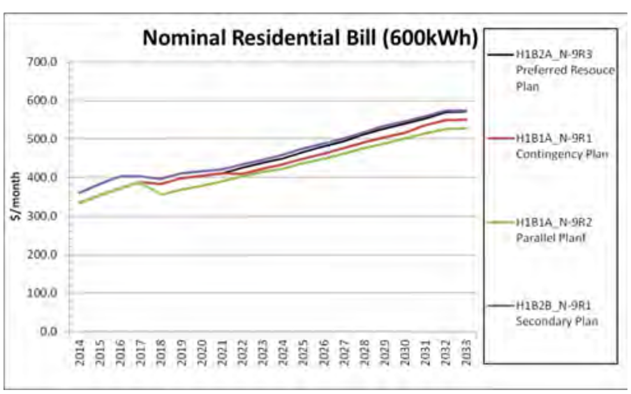



Table P-110. HELCO Stuck in the Middle Nominal Residential Bill

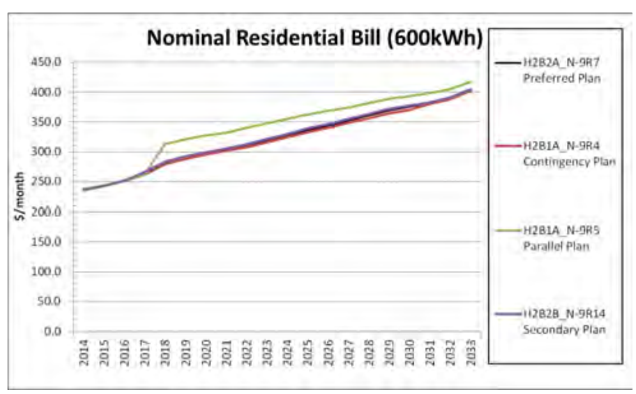


Table P-111. HELCO Blazing a Bold Frontier Annual Revenue Requirements for Capital

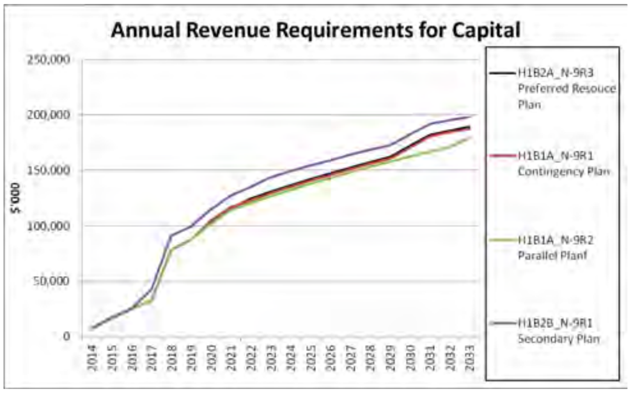



Table P-112. HELCO Stuck in the Middle Annual Revenue Requirements for Capital

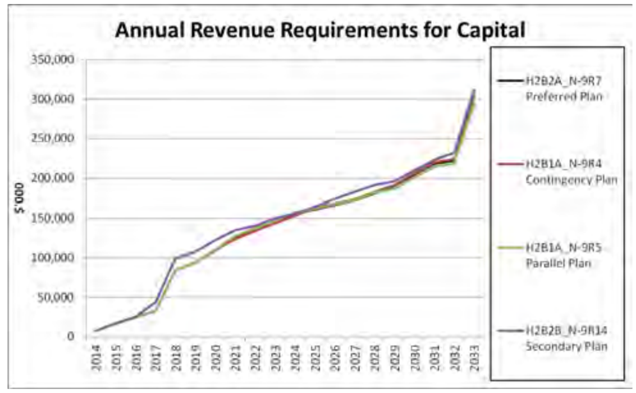



Table P-113. HELCO Blazing a Bold Frontier Total Resource Cost: Planning Period

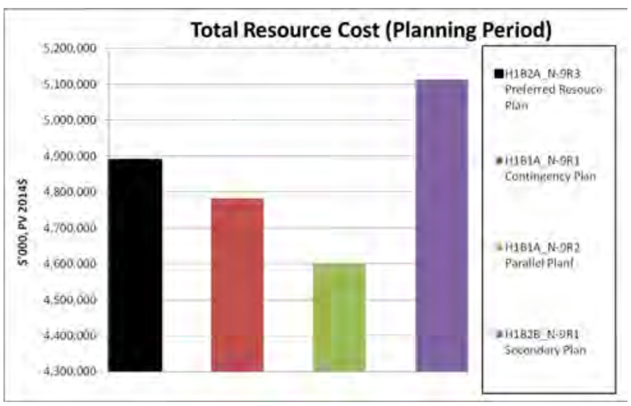



Table P-114. HELCO Stuck in the Middle Total Resource Cost: Planning Period

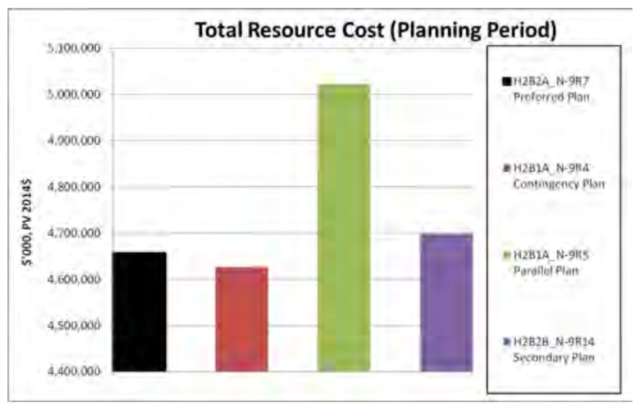



Table P-115. HELCO Blazing a Bold Frontier Total Resource Cost: Study Period

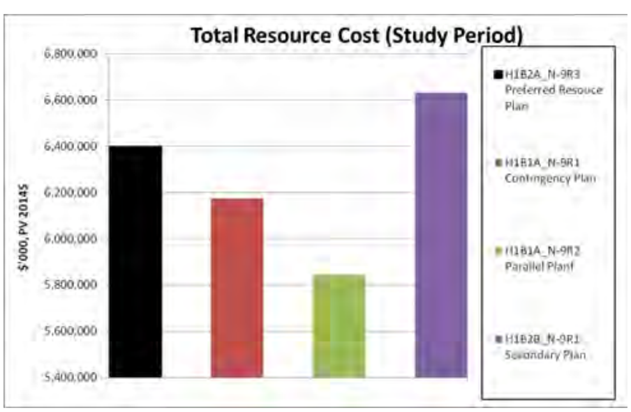
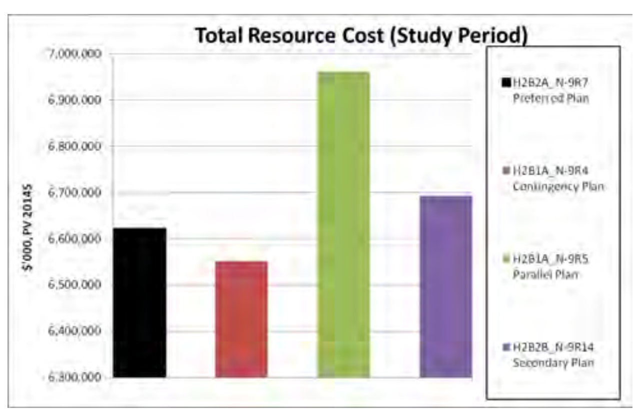



Table P-116. HELCO Stuck in the Middle Total Resource Cost: Study Period



# MECO Plan Metrics

MECO's metrics of the Preferred Plan, Contingency Plan, Parallel Plan, and Secondary Plan in Blazing a Bold Frontier and Stuck in the Middle are presented side by side, for Maui, Lanai, and Molokai.

## Maui Island

### Blazing a Bold Frontier

Table P-117. Maui Blazing a Bold Frontier Greenhouse Gas Emissions

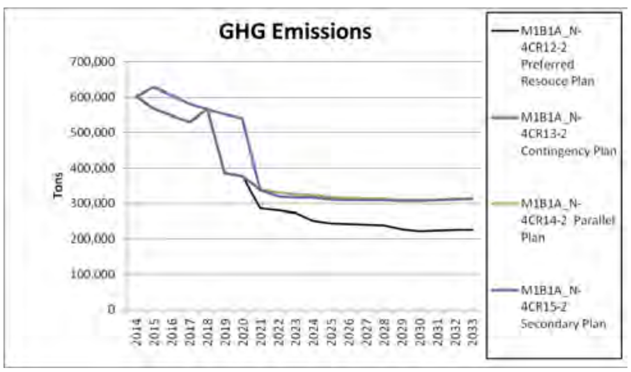
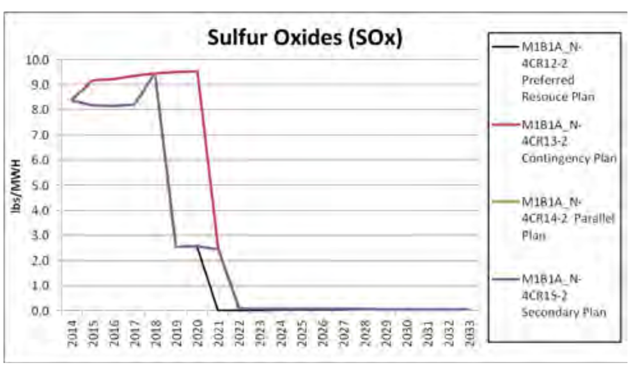



Table P-119. Maui Blazing a Bold Frontier Sulfur Oxides




### Stuck in the Middle

Table P-118. Maui Stuck in the Middle Greenhouse Gas Emissions

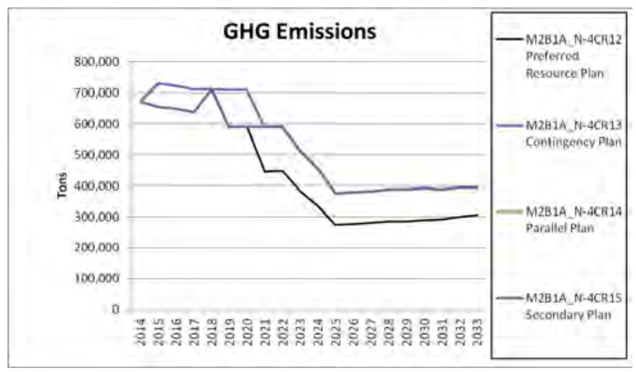



Table P-120. Maui Stuck in the Middle Sulfur Oxides

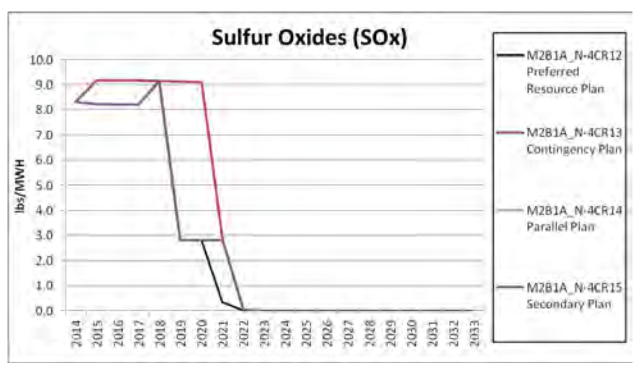


Table P-121. Maui Blazing a Bold Frontier Nitrous Oxides

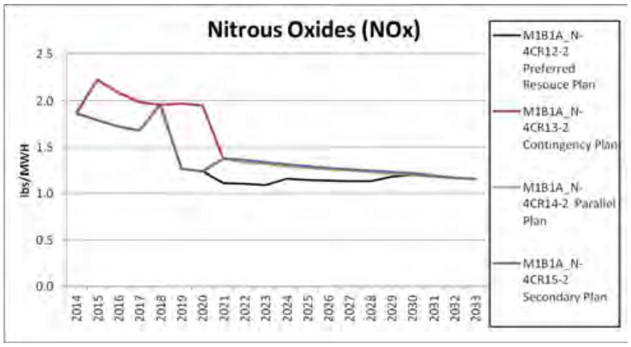



Table P-122. Maui Stuck in the Middle Nitrous Oxides

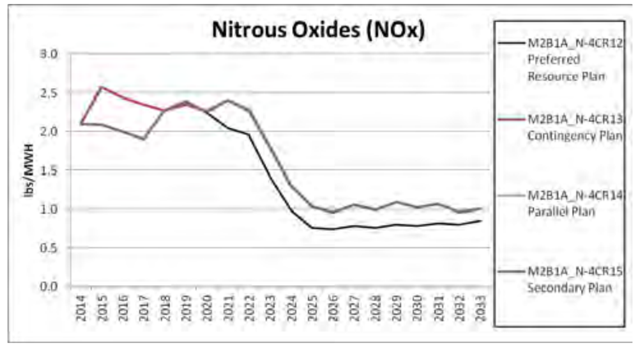



Table P-123. Maui Blazing a Bold Frontier Particulate Matter

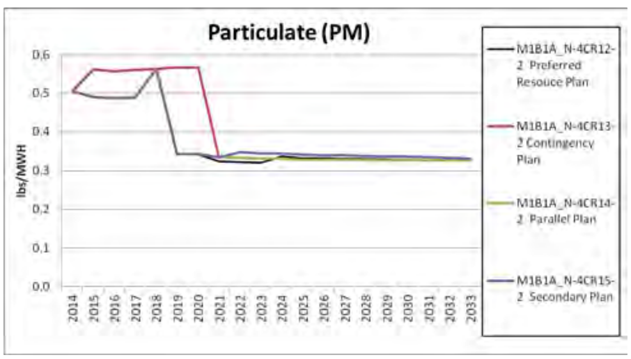



Table P-124. Maui Stuck in the Middle Particulate Matter

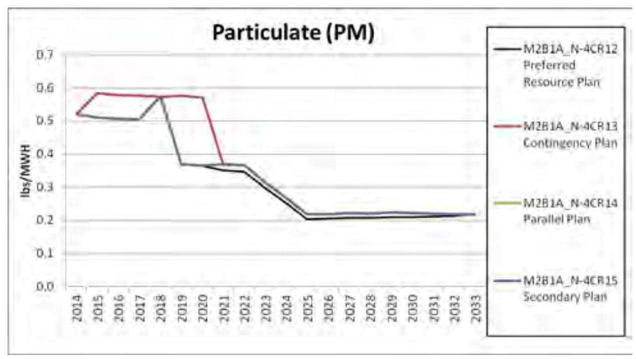



Table P-125. Maui Blazing a Bold Frontier Share of Delivered Energy from Imported Fossil Fuels

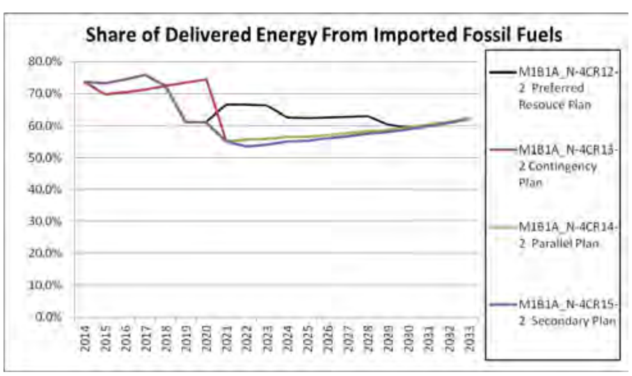



Table P-126. Maui Stuck in the Middle Share of Delivered Energy from Imported Fossil Fuels

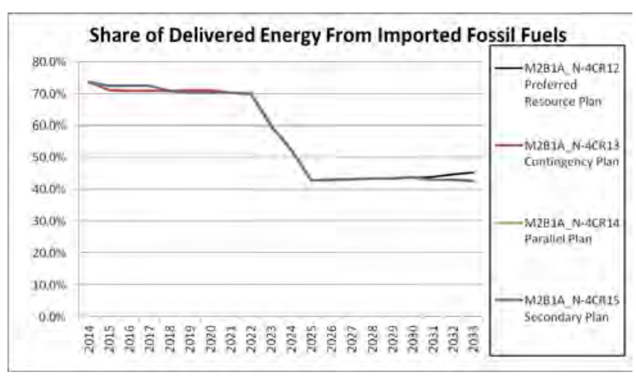


Table P-127. Maui Blazing a Bold Frontier Share of Resource Plan Cost Linked to Fossil Fuels

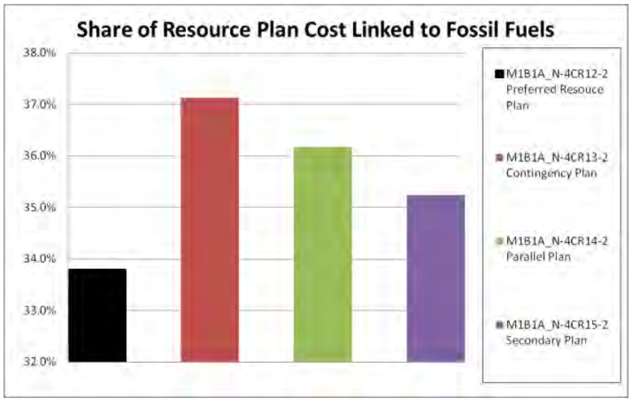



Table P-128. Maui Stuck in the Middle Share of Resource Plan Cost Linked to Fossil Fuels

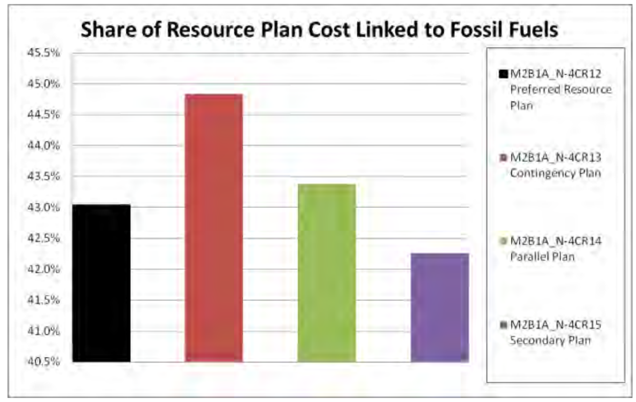



Table P-129. Maui Blazing a Bold Frontier Imported Fossil Fuel Oil Amount

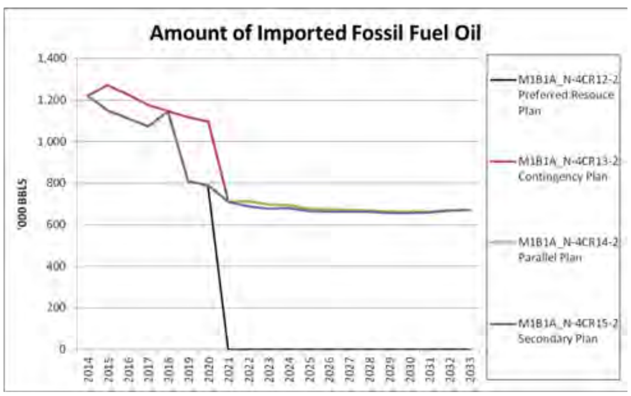



Table P-130. Maui Stuck in the Middle Imported Fossil Fuel Oil Amount

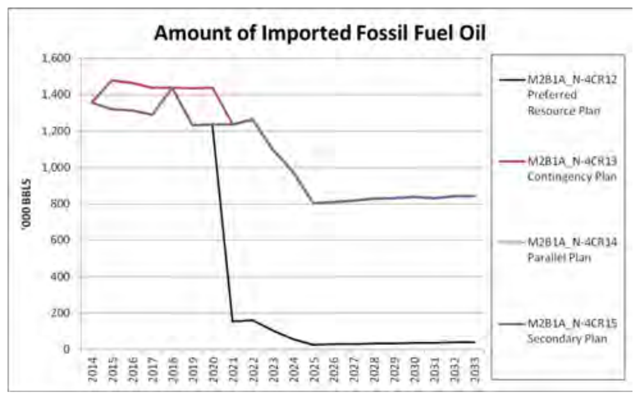



Table P-131. Maui Blazing a Bold Frontier Liquefied Natural Gas Amount

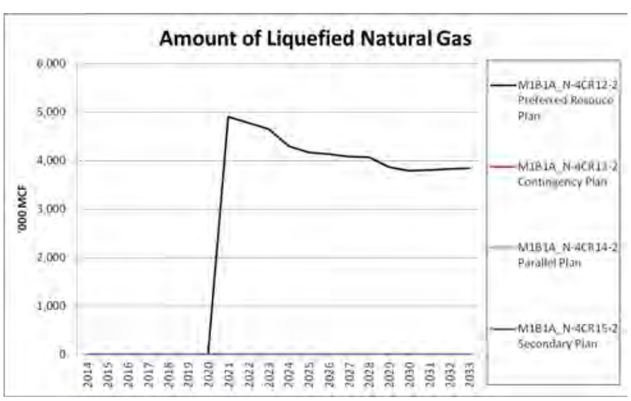



Table P-132. Maui Stuck in the Middle Liquefied Natural Gas Amount

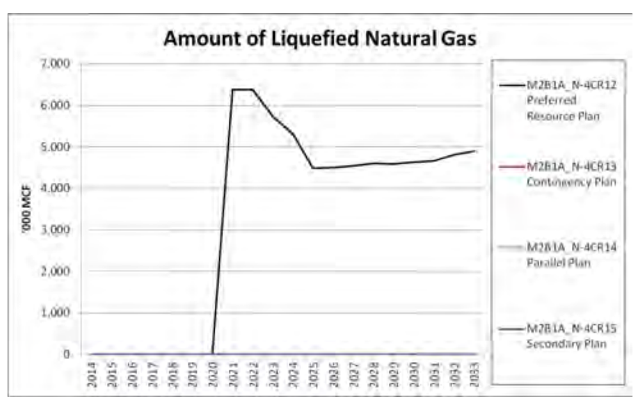


Table P-133. Maui Blazing a Bold Frontier Energy Efficiency Portfolio Standard

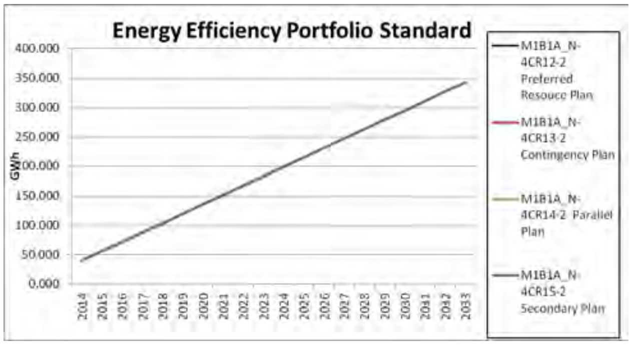



Table P-134. Maui Stuck in the Middle Energy Efficiency Portfolio Standard

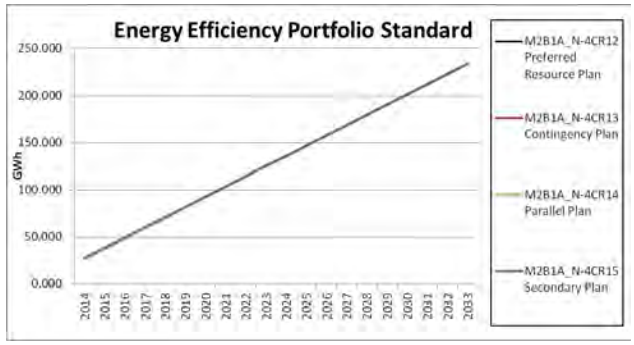



Table P-135. Maui Blazing a Bold Frontier Renewable Energy

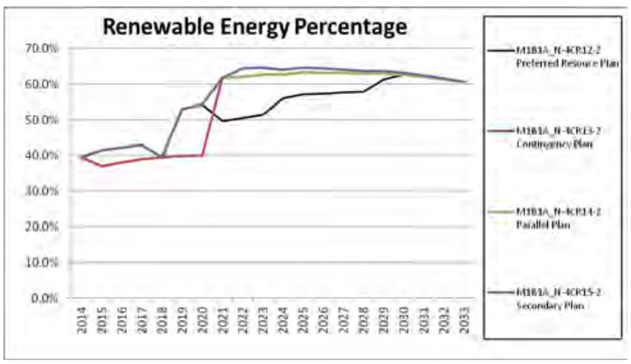



Table P-136. Maui Stuck in the Middle Renewable Energy

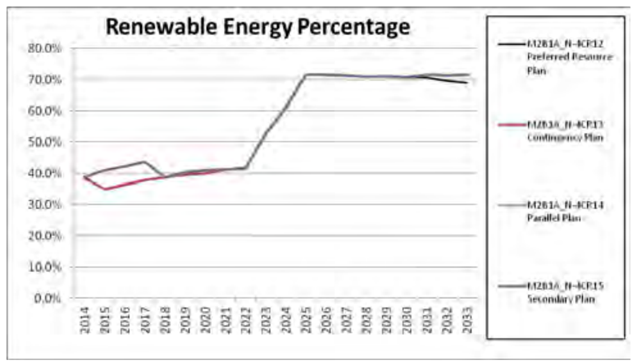



Table P-137. Maui Blazing a Bold Frontier Renewable Energy Curtailed

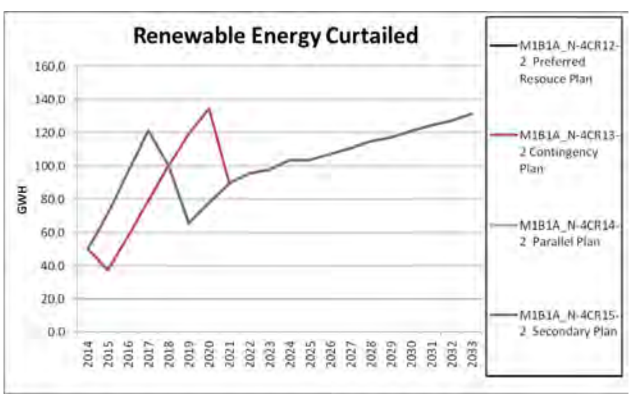



Table P-138. Maui Stuck in the Middle Renewable Energy Curtailed

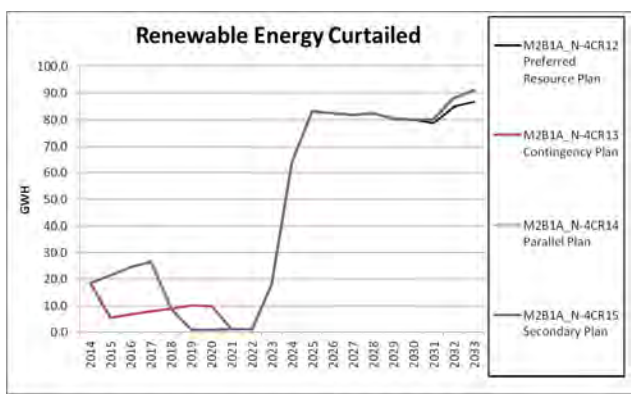


Table P-139. Maui Blazing a Bold Frontier Resource Diversity Index

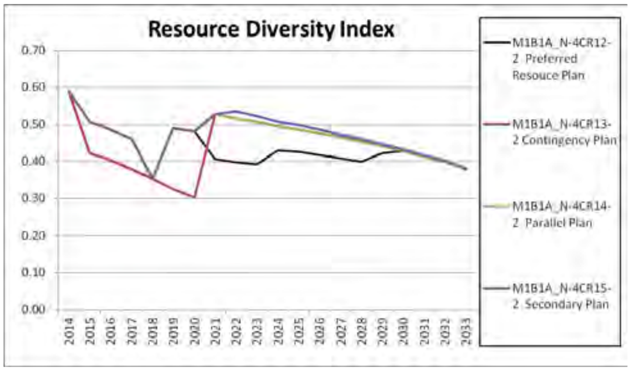



Table P-140. Maui Stuck in the Middle Resource Diversity Index

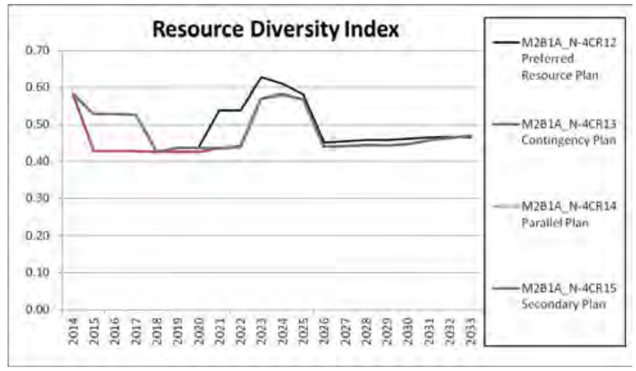



Table P-141. Maui Blazing a Bold Frontier Share of Generation from Local Resources

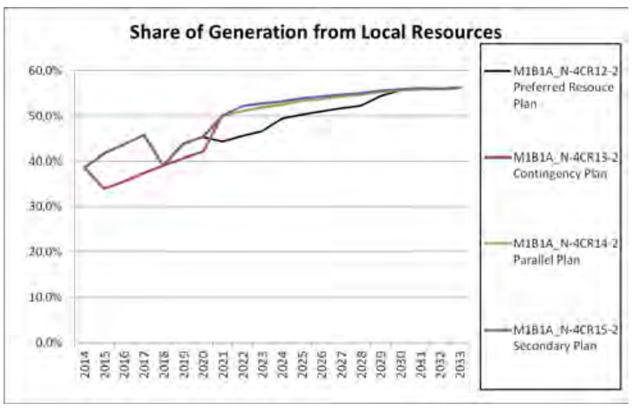



Table P-142. Maui Stuck in the Middle Share of Generation from Local Resources

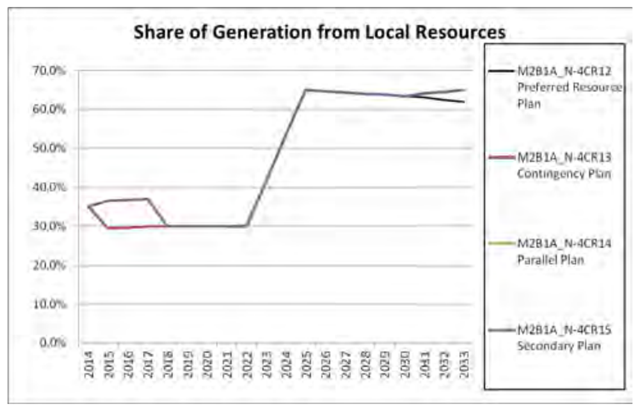



Table P-143. Maui Blazing a Bold Frontier Reserve Margin

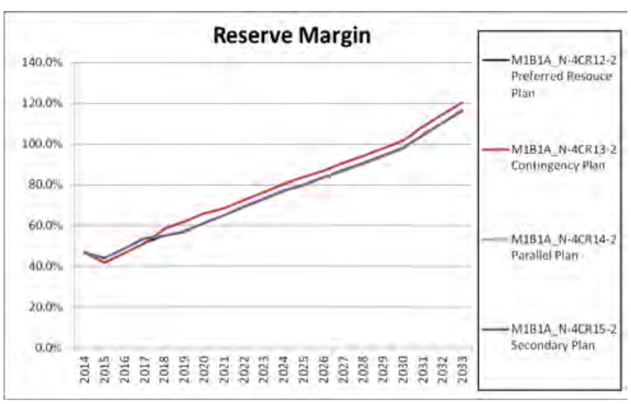



Table P-144. Maui Stuck in the Middle Reserve Margin

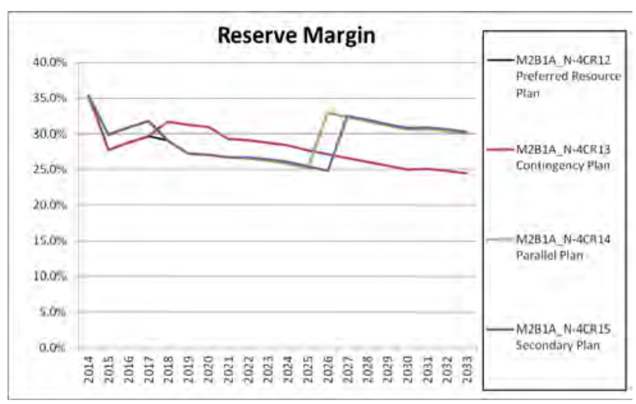


Table P-145. Maui Blazing a Bold Frontier Variable Energy Resource Penetration

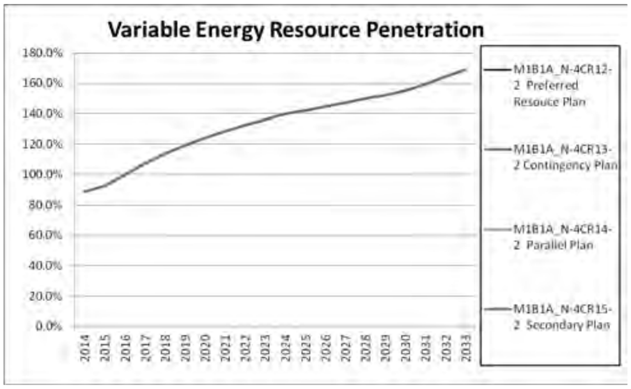



Table P-146. Maui Stuck in the Middle Variable Energy Resource Penetration

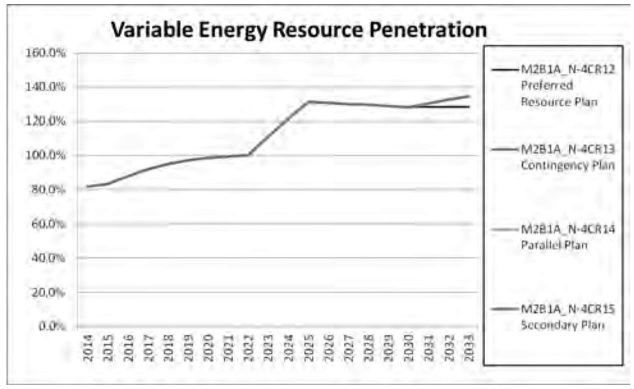



Table P-147. Maui Blazing a Bold Frontier Generation Efficiency

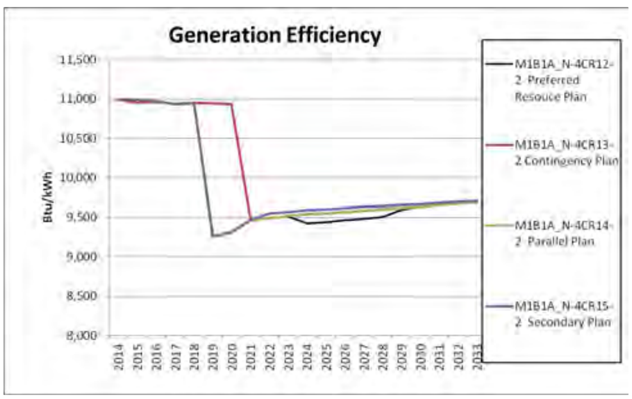



Table P-148. Maui Stuck in the Middle Generation Efficiency

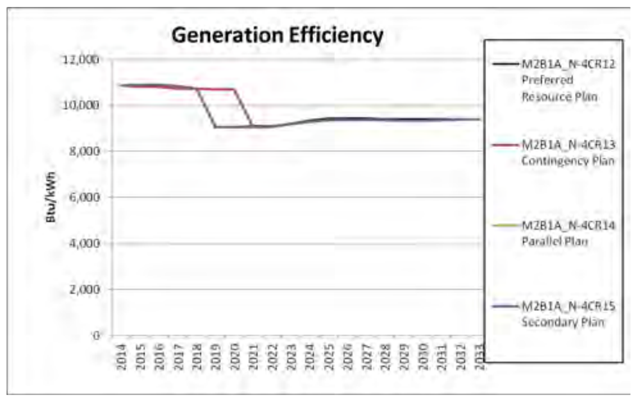



Table P-149. Maui Blazing a Bold Frontier System Regulating Capability

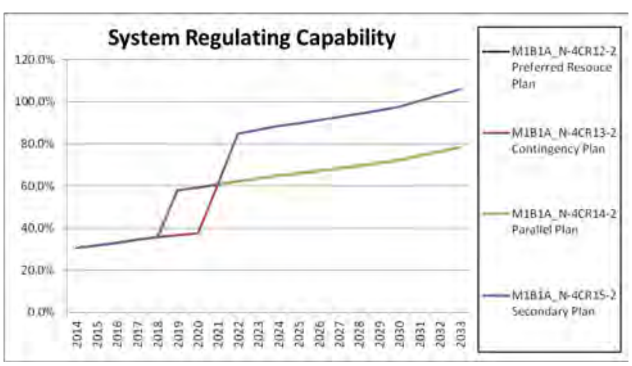



Table P-150. Maui Stuck in the Middle System Regulating Capability

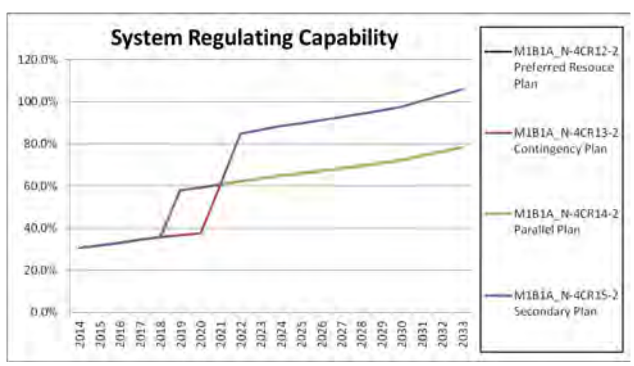


Table P-151. Maui Blazing a Bold Frontier Nominal Price of Electricity: Residential (2014$)

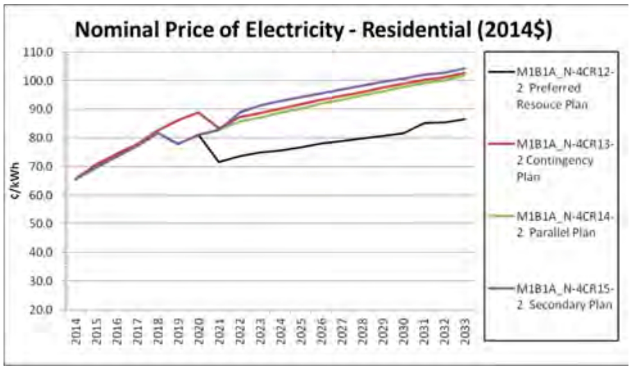



Table P-152. Maui Stuck in the Middle Nominal Price of Electricity: Residential (2014$)

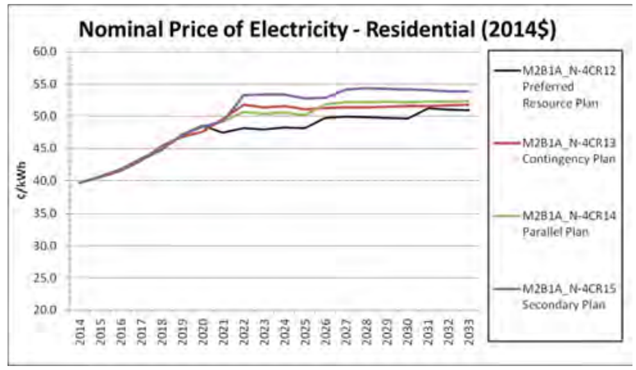



Table P-153. Maui Blazing a Bold Frontier Nominal Price of Electricity: Residential

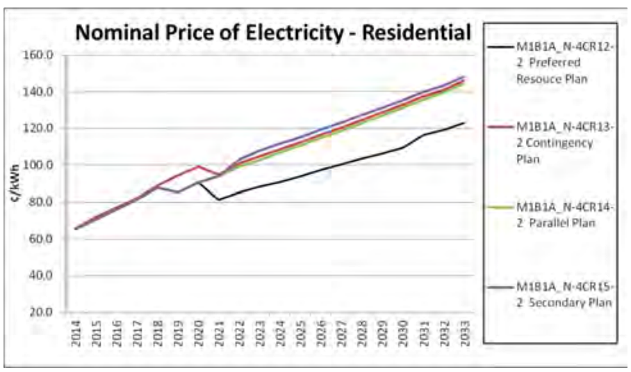



Table P-154. Maui Stuck in the Middle Nominal Price of Electricity: Residential

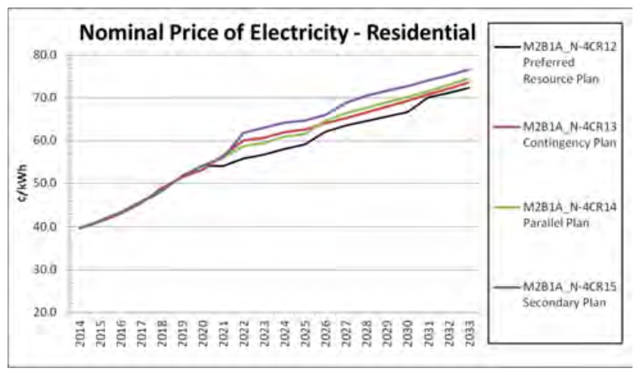



Table P-155. Maui Blazing a Bold Frontier Nominal Price of Electricity: Commercial (2014$)

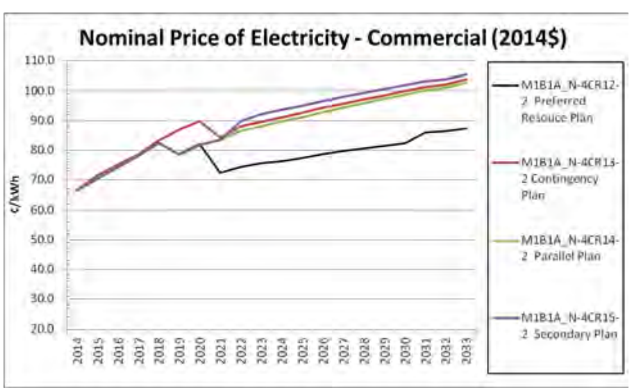



Table P-156. Maui Stuck in the Middle Nominal Price of Electricity: Commercial (2014$)

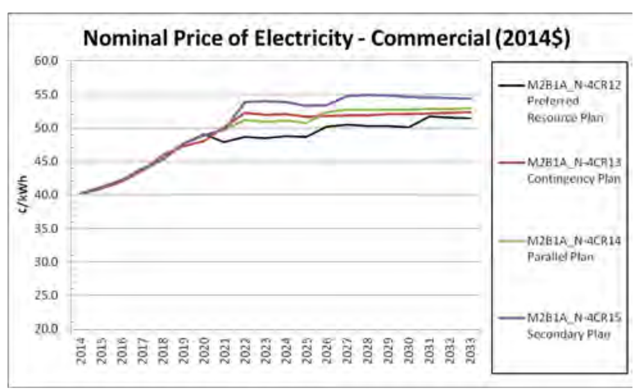


Table P-157. Maui Blazing a Bold Frontier Nominal Price of Electricity: Commercial

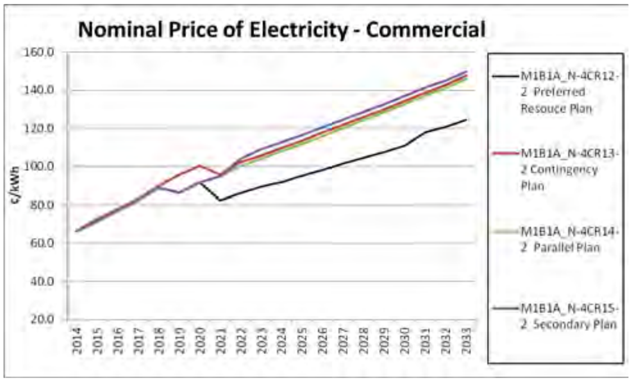



Table P-158. Maui Stuck in the Middle Nominal Price of Electricity: Commercial

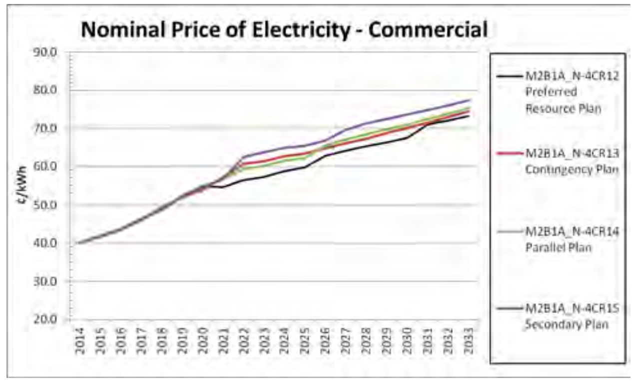



Table P-159. Maui Blazing a Bold Frontier Nominal Price of Electricity: Industrial (2014$)

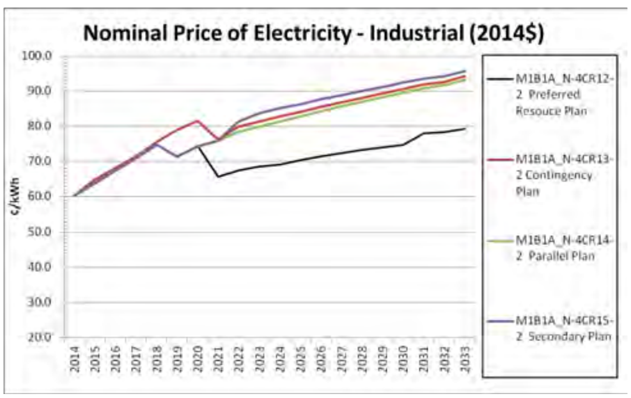



Table P-160. Maui Stuck in the Middle Nominal Price of Electricity: Industrial (2014$)

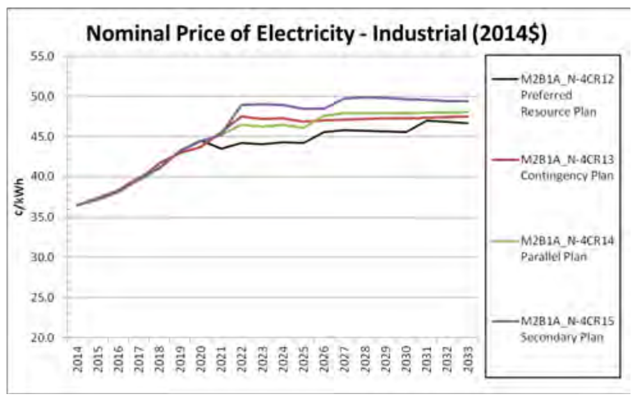



Table P-161. Maui Blazing a Bold Frontier Nominal Price of Electricity: Industrial

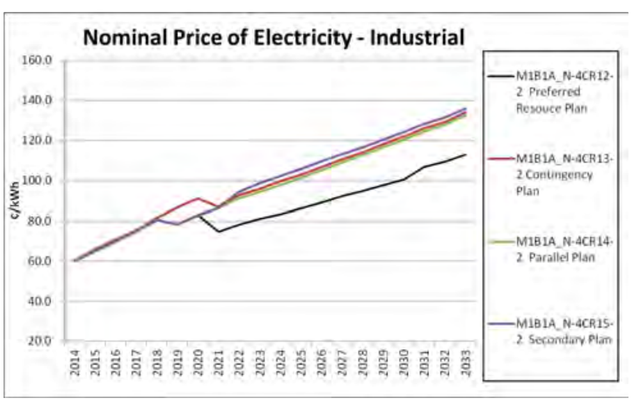



Table P-162. Maui Stuck in the Middle Nominal Price of Electricity: Industrial

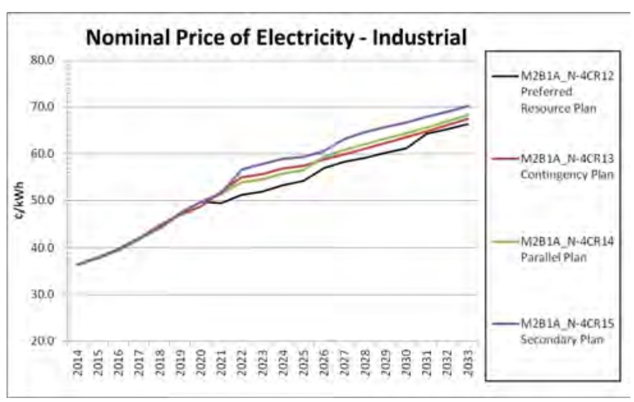


Table P-163. Maui Blazing a Bold Frontier Average Residential Bill (2014$)

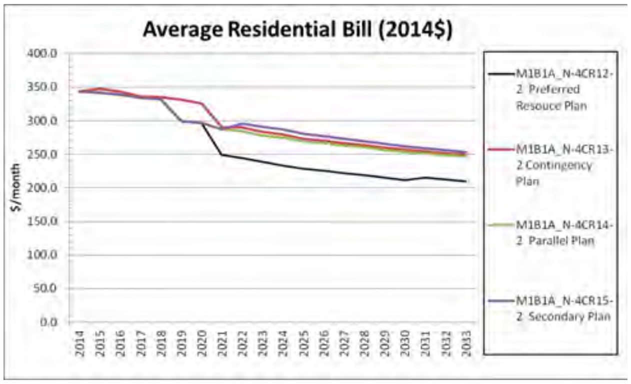



Table P-164. Maui Stuck in the Middle Average Residential Bill (2014$)

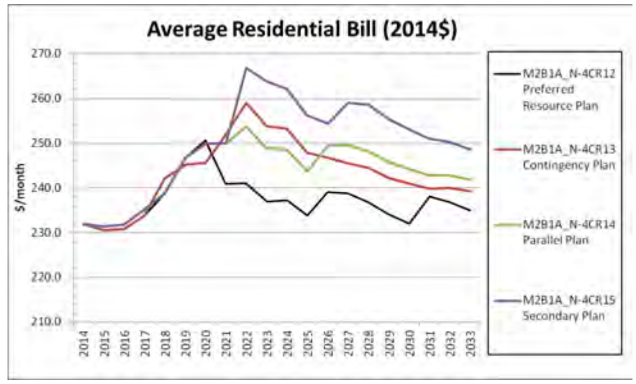



Table P-165. Maui Blazing a Bold Frontier Average Residential Bill

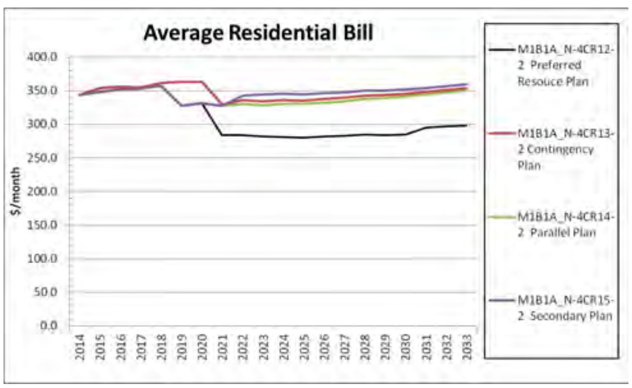



Table P-166. Maui Stuck in the Middle Average Residential Bill

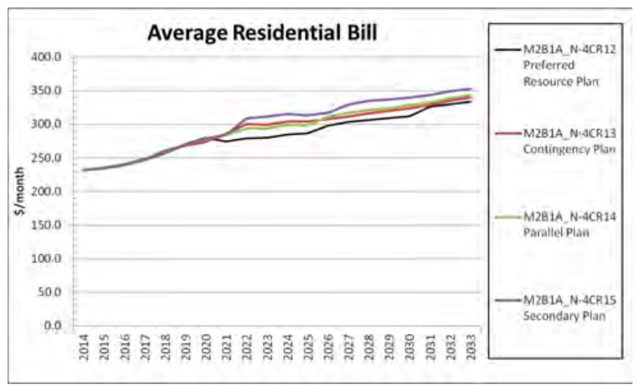



Table P-167. Maui Blazing a Bold Frontier Nominal Residential Bill

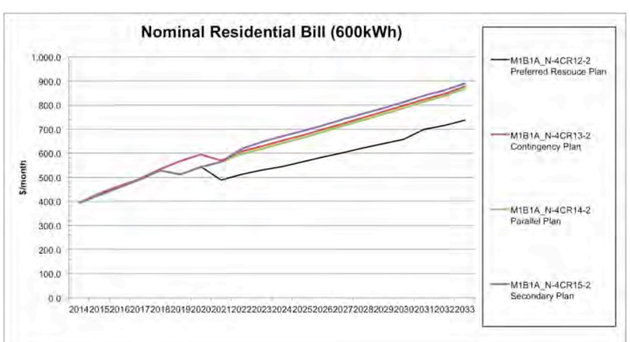



Table P-168. Maui Stuck in the Middle Nominal Residential Bill

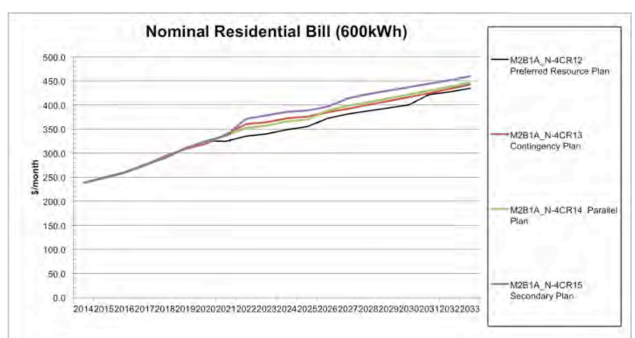


Table P-169. Maui Blazing a Bold Frontier Annual Revenue Requirements for Capital

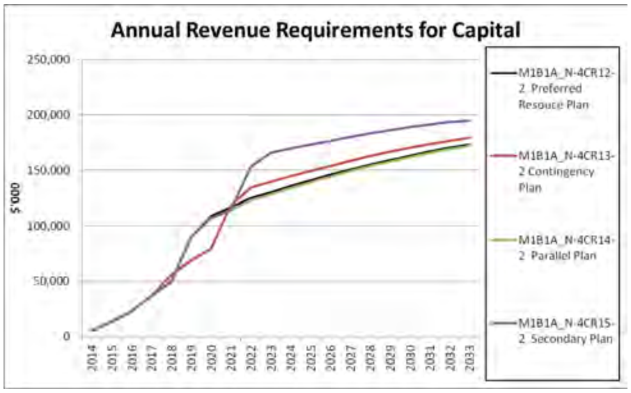



Table P-170. Maui Stuck in the Middle Annual Revenue Requirements for Capital

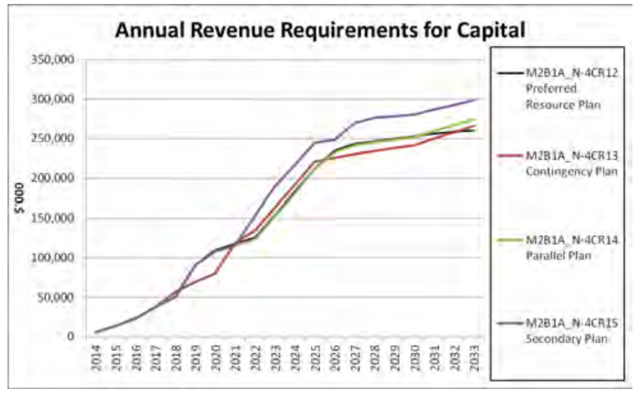



Table P-171. Maui Blazing a Bold Frontier Total Resource Cost: Planning Period

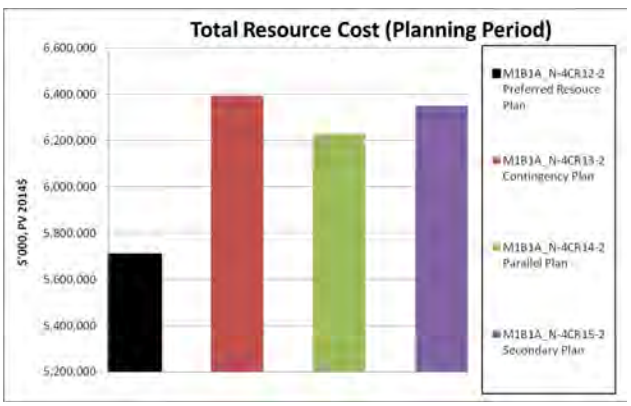



Table P-172. Maui Stuck in the Middle Resource Cost: Planning Period

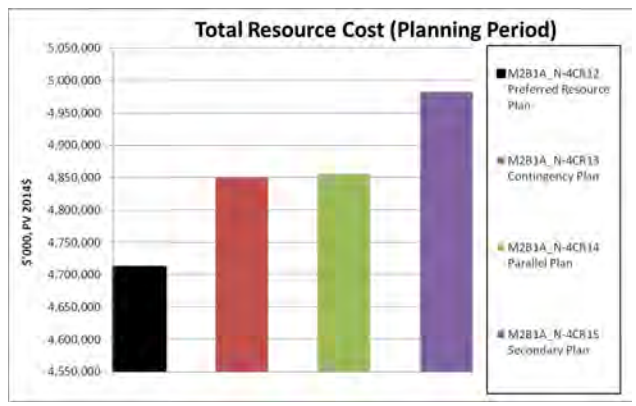



Table P-173. Maui Blazing a Bold Frontier Resource Cost: Study Period

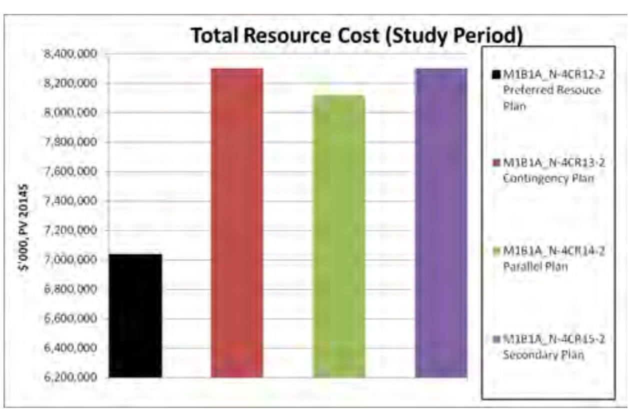
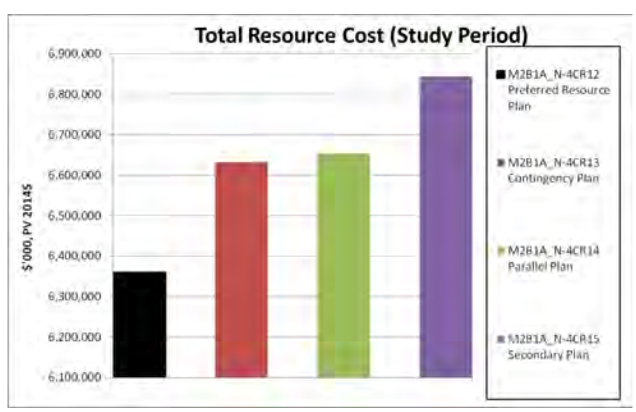



Table P-174. Maui Stuck in the Middle Resource Cost: Study Period



## Lanai Island

### Blazing a Bold Frontier

Table P-175. Lanai Blazing a Bold Frontier Greenhouse Gas Emissions

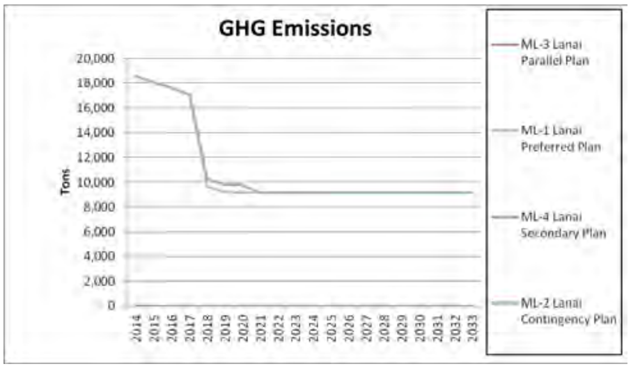



Table P-177. Lanai Blazing a Bold Frontier Sulfur Oxides

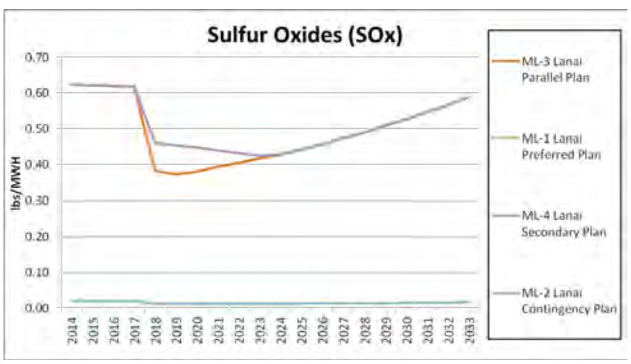
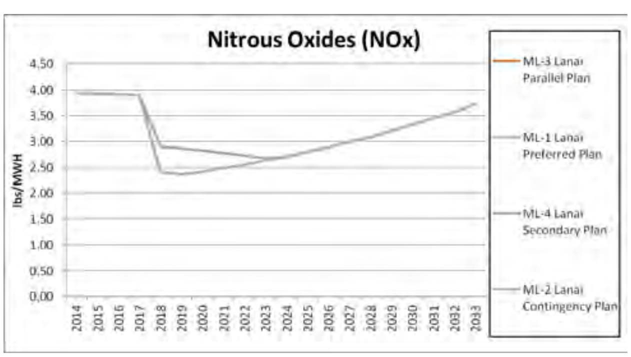



Table P-179. Lanai Blazing a Bold Frontier Nitrous Oxides




### Stuck in the Middle

Table P-176. Lanai Stuck in the Middle Greenhouse Gas Emissions

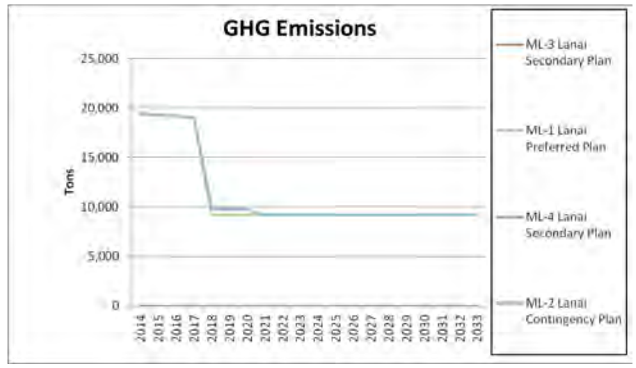



Table P-178. Lanai Stuck in the Middle Sulfur Oxides

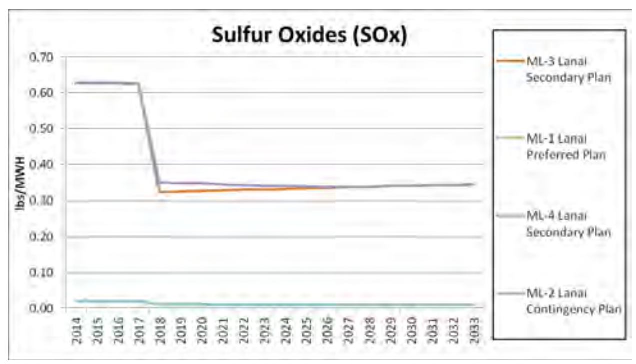



Table P-180. Lanai Stuck in the Middle Nitrous Oxides

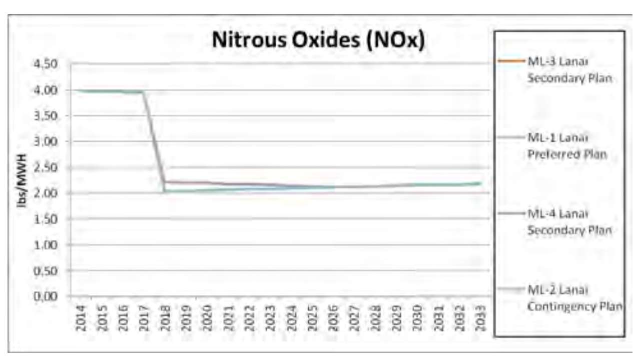


Table P-181. Lanai Blazing a Bold Frontier Particulate Matter

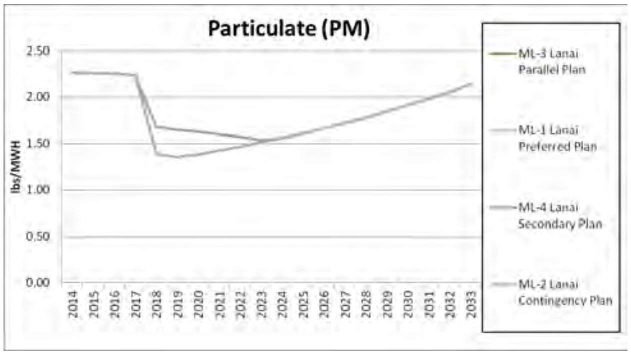



Table P-182. Lanai Stuck in the Middle Particulate Matter

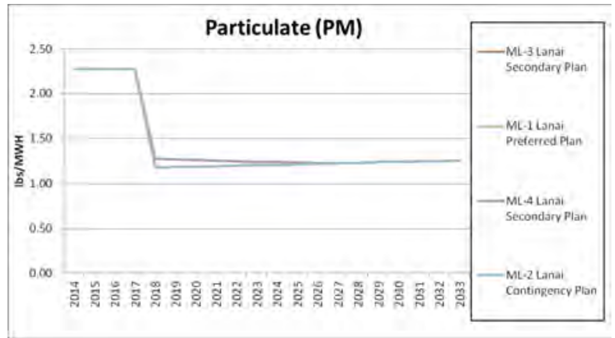



Table P-183. Lanai Blazing a Bold Frontier Share of Delivered Energy Linked to Oil Price

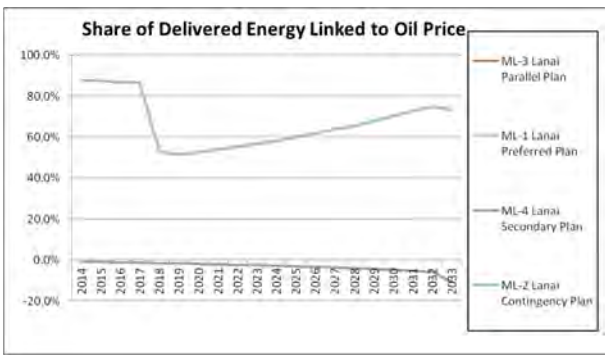



Table P-184. Lanai Stuck in the Middle Share of Delivered Energy Linked to Oil Price

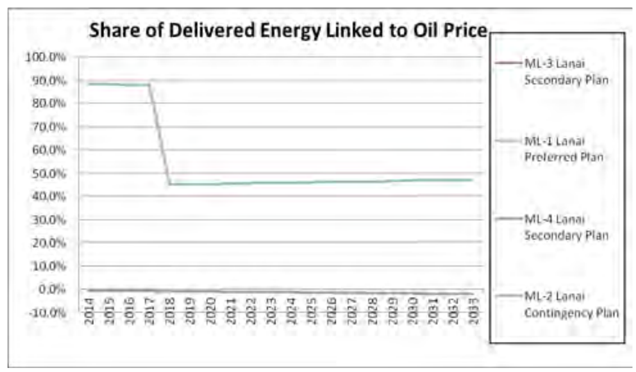



Table P-185. Lanai Blazing a Bold Frontier Share of Resource Plan Cost Linked to Fossil Fuels

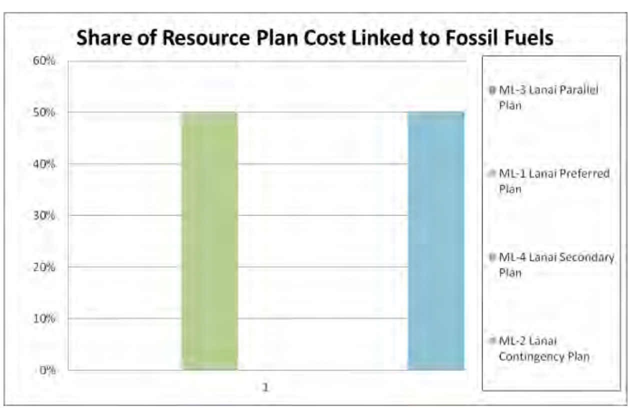



Table P-186. Lanai Stuck in the Middle Share of Resource Plan Cost Linked to Fossil Fuels

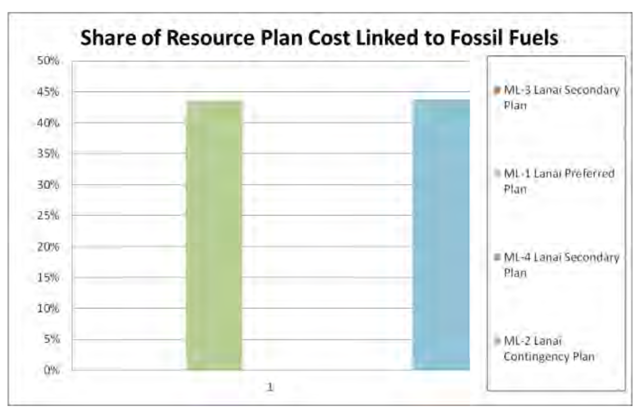


Table P-187. Lanai Blazing a Bold Frontier Imported Fuel Oil Amount

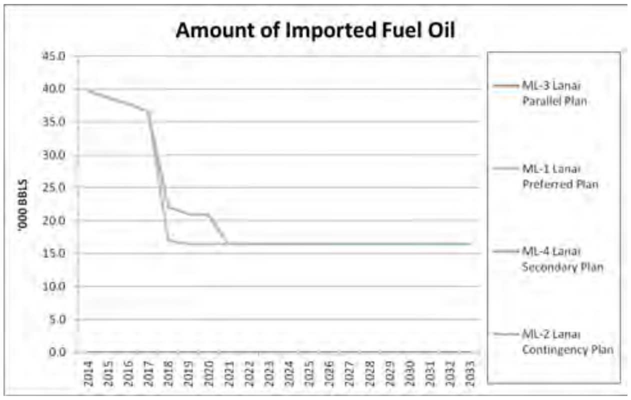



Table P-188. Lanai Stuck in the Middle Imported Fuel Oil Amount

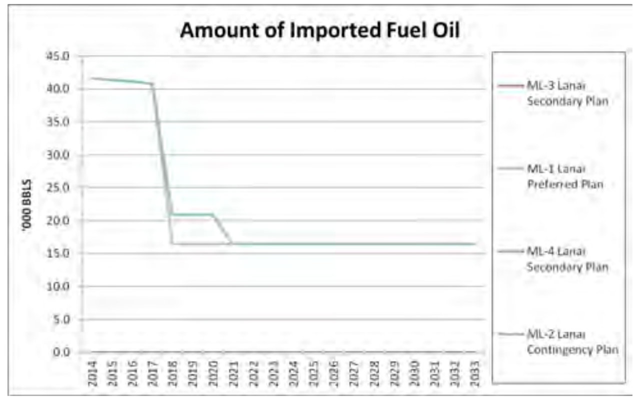



Table P-189. Lanai Blazing a Bold Frontier Imported LNG Amount

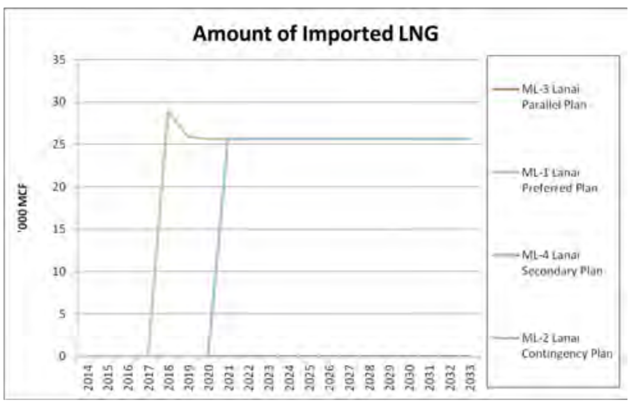



Table P-190. Lanai Stuck in the Middle Imported LNG Amount

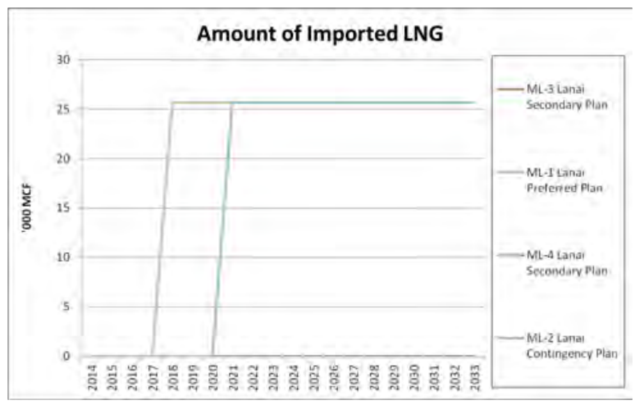



Table P-191. Lanai Blazing a Bold Frontier Energy Efficiency Portfolio Standard

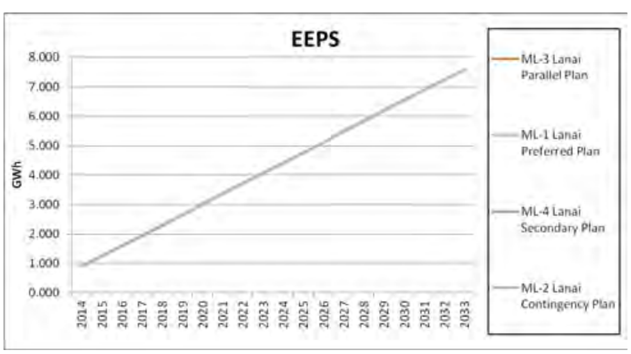



Table P-192. Lanai Stuck in the Middle Energy Efficiency Portfolio Standard

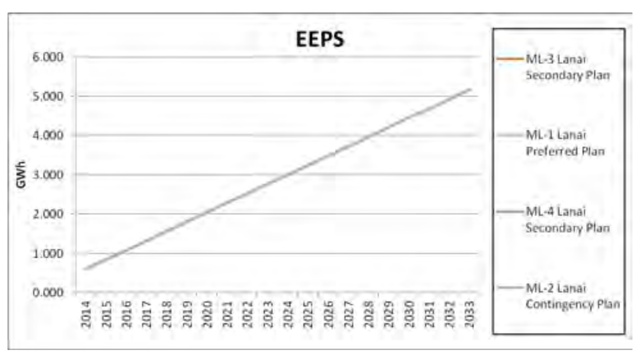


Table P-193. Lanai Blazing a Bold Frontier Renewable Energy

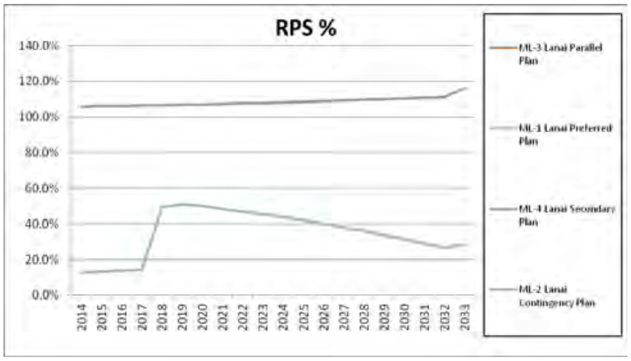



Table P-194. Lanai Stuck in the Middle Renewable Energy

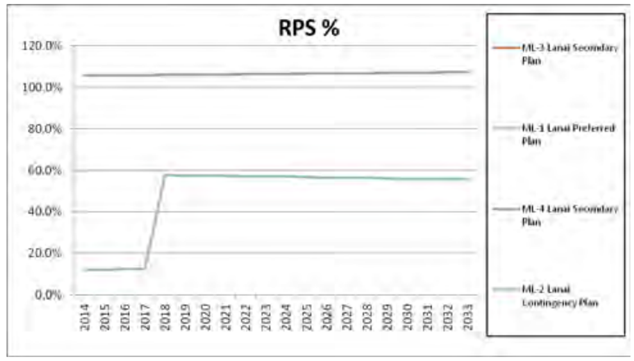



Table P-195. Lanai Blazing a Bold Frontier Renewable Energy Curtailed

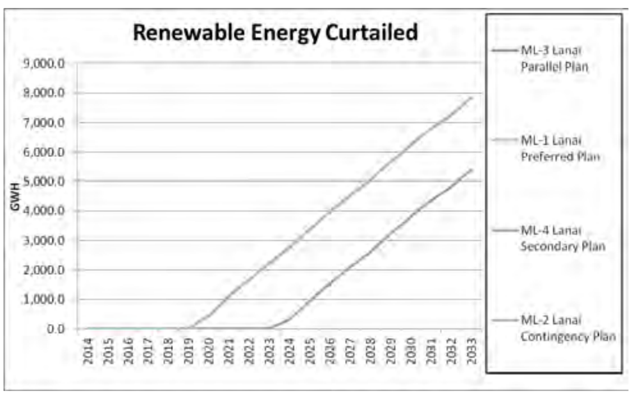



Table P-196. Lanai Stuck in the Middle Renewable Energy Curtailed

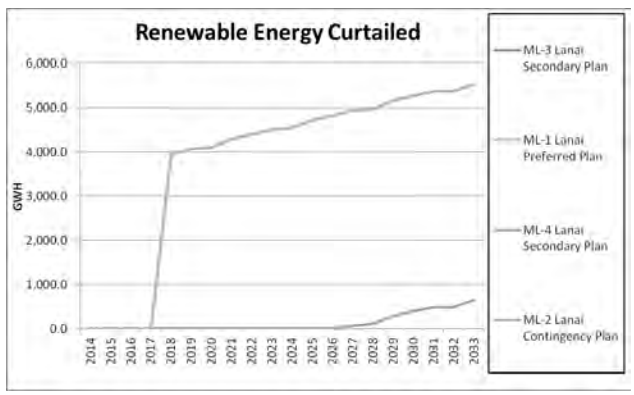



Table P-197. Lanai Blazing a Bold Frontier Resource Diversity Index

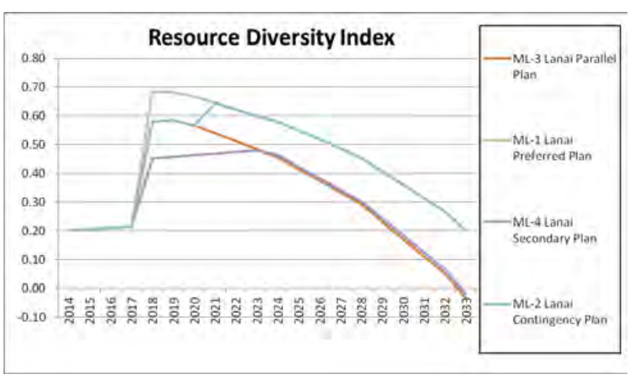



Table P-198. Lanai Stuck in the Middle Resource Diversity Index

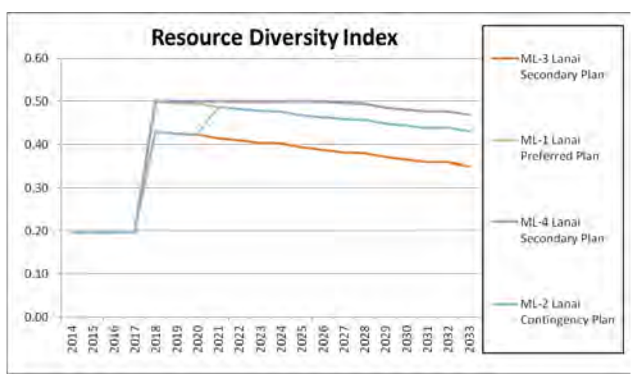


Table P-199. Lanai Blazing a Bold Frontier Share of Generation from Local Resources

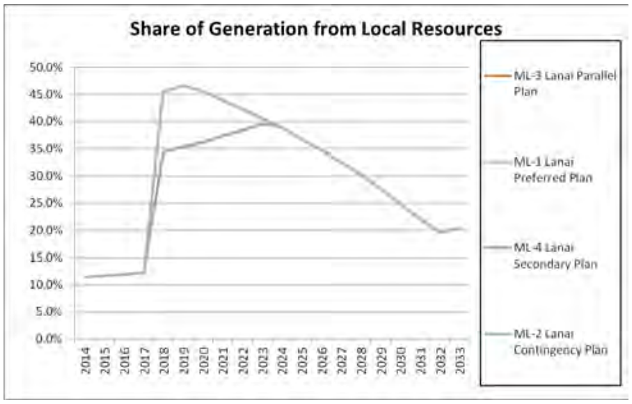



Table P-200. Lanai Stuck in the Middle Share of Generation from Local Resources

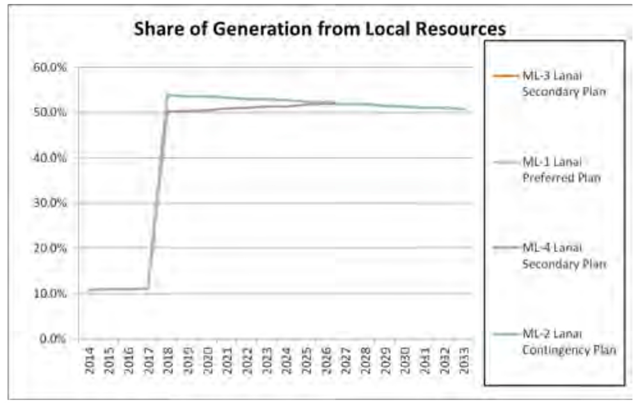



Table P-201. Lanai Blazing a Bold Frontier Reserve Margin

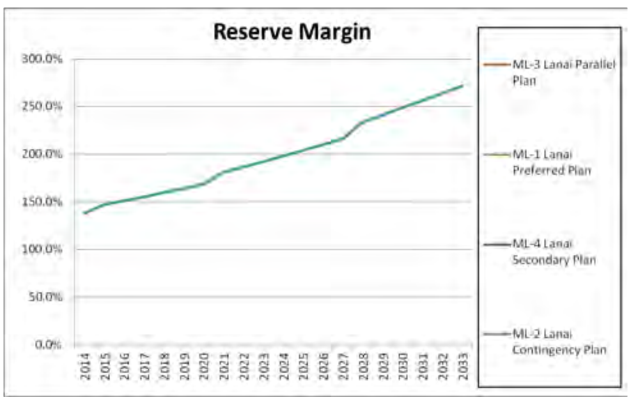



Table P-202. Lanai Stuck in the Middle Reserve Margin

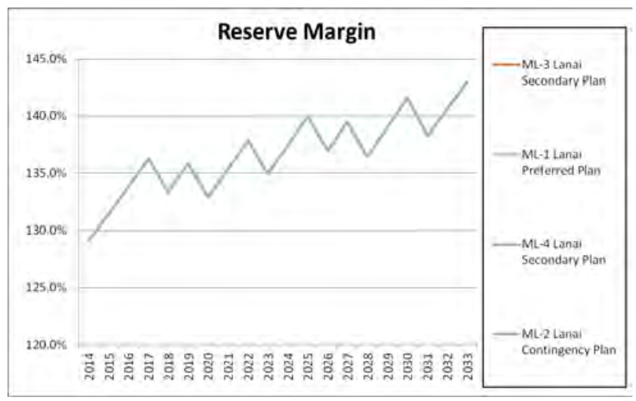



Table P-203. Lanai Blazing a Bold Frontier Intermittent As-Available Resource Penetration

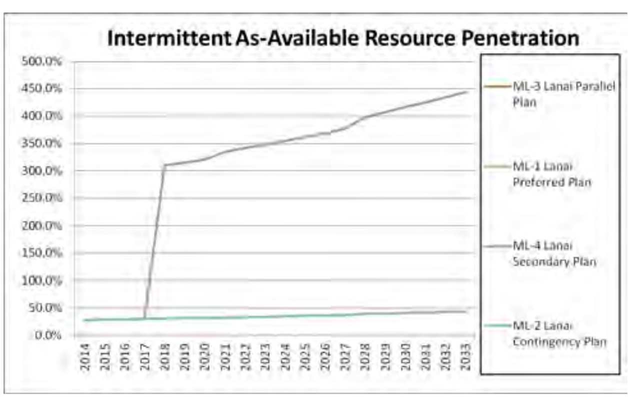



Table P-204. Lanai Stuck in the Middle Intermittent As-Available Resource Penetration

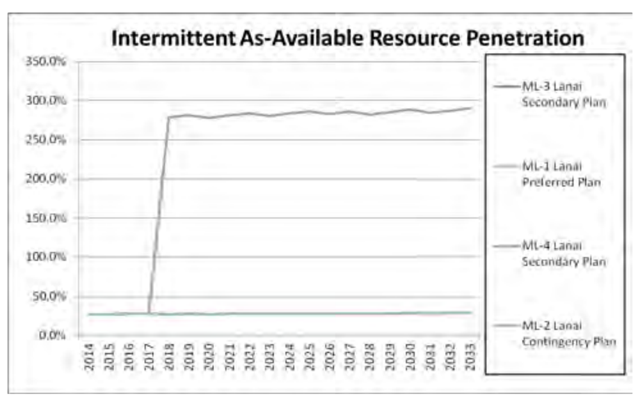


Table P-205. Lanai Blazing a Bold Frontier Generation Efficiency

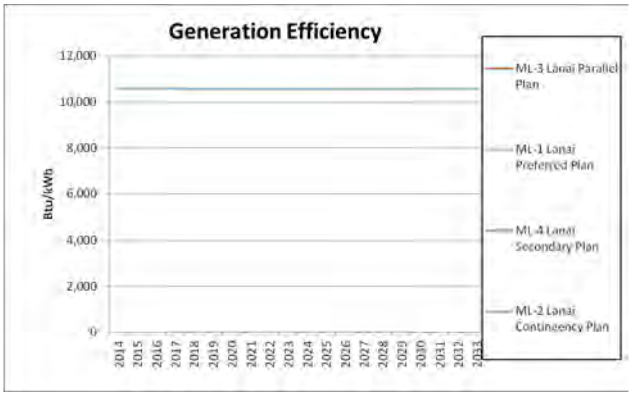



Table P-206. Lanai Stuck in the Middle Generation Efficiency

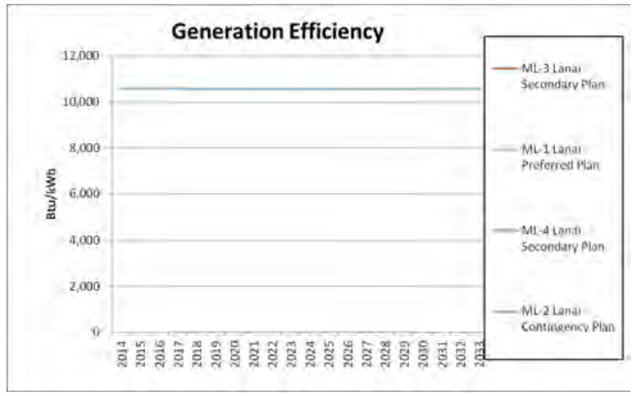



Table P-207. Lanai Blazing a Bold Frontier System Regulating Capability

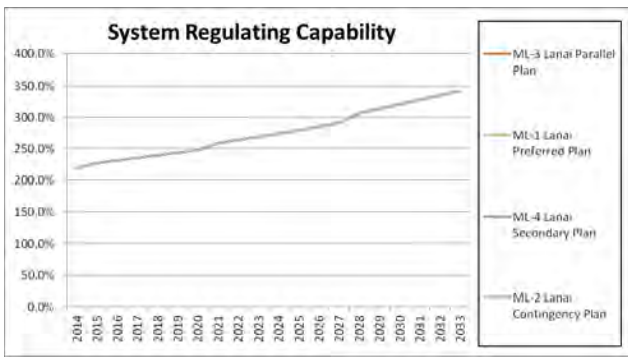



Table P-208. Lanai Stuck in the Middle System Regulating Capability

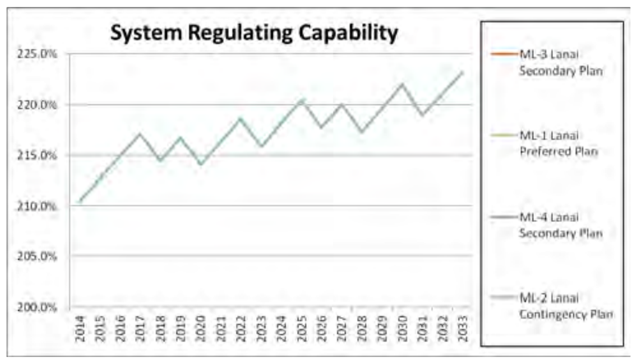



Table P-209. Lanai Blazing a Bold Frontier Nominal Price of Electricity: Residential

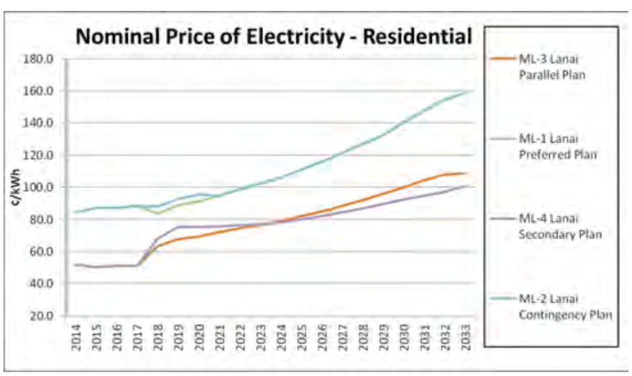



Table P-210. Lanai Stuck in the Middle Nominal Price of Electricity: Residential

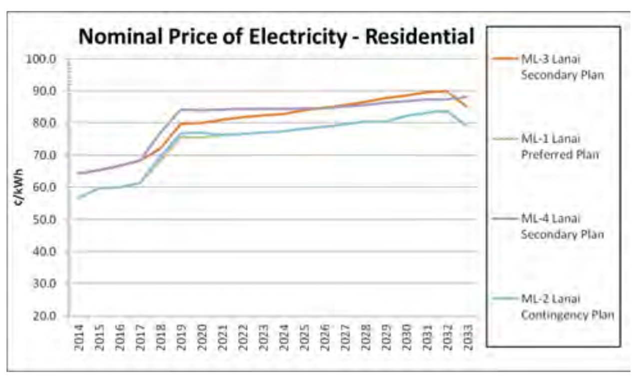


Table P-211. Lanai Blazing a Bold Frontier Nominal Price of Electricity: Commercial

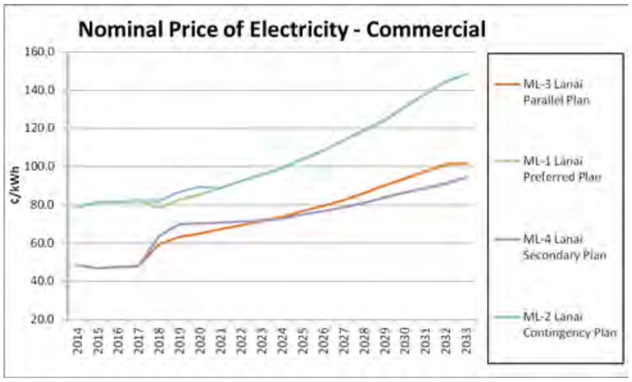



Table P-212. Lanai Stuck in the Middle Nominal Price of Electricity: Commercial

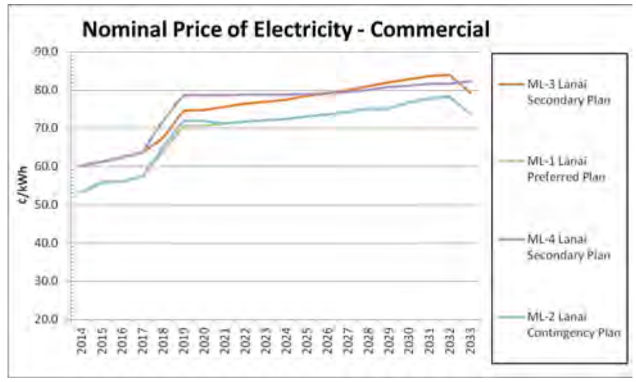



Table P-213. Lanai Blazing a Bold Frontier Nominal Price of Electricity: Industrial

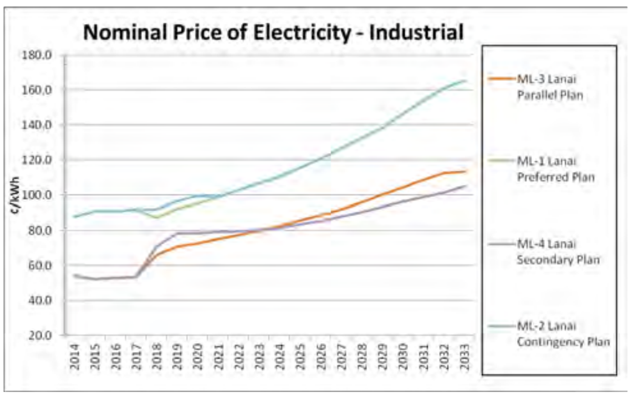



Table P-214. Lanai Stuck in the Middle Nominal Price of Electricity: Industrial

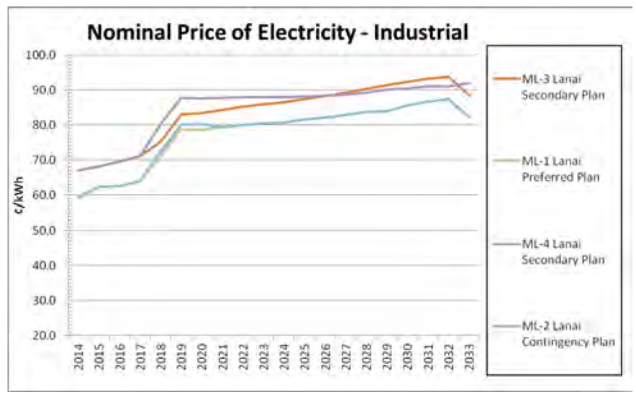



Table P-215. Lanai Blazing a Bold Frontier Nominal Residential Bill

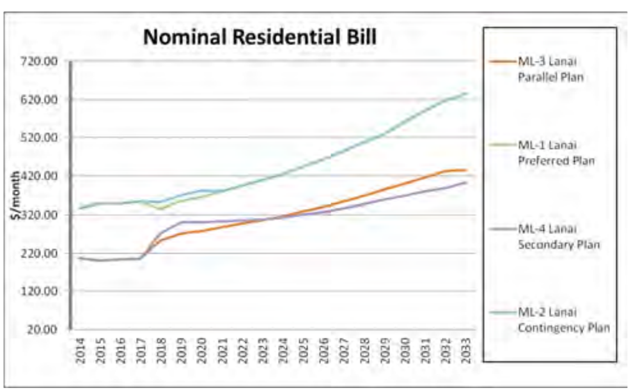



Table P-216. Lanai Stuck in the Middle Nominal Residential Bill

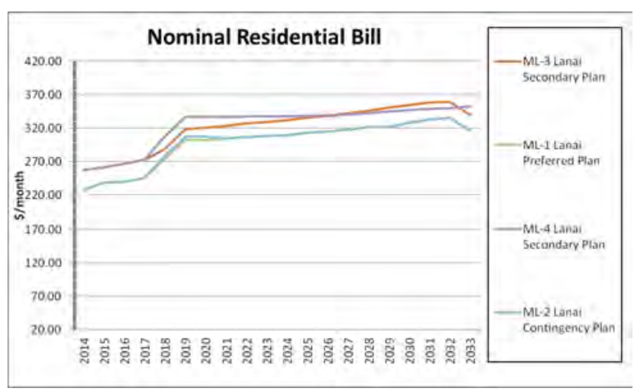


Table P-217. Lanai Blazing a Bold Frontier Annual Revenue Requirements for Capital

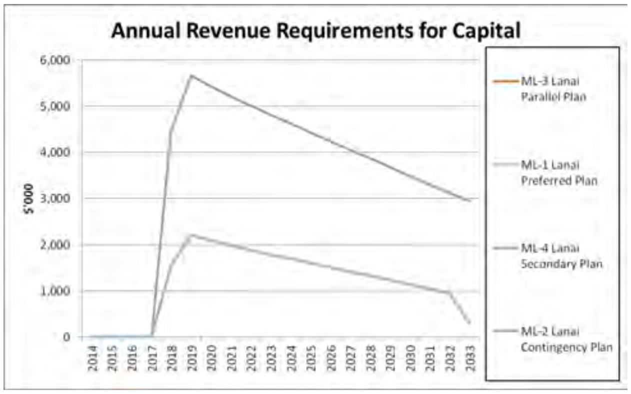



Table P-218. Lanai Stuck in the Middle Annual Revenue Requirements for Capital

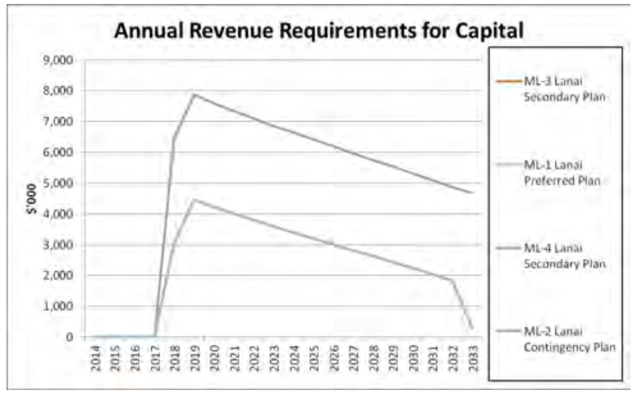



Table P-219. Lanai Blazing a Bold Frontier Total Resource Cost

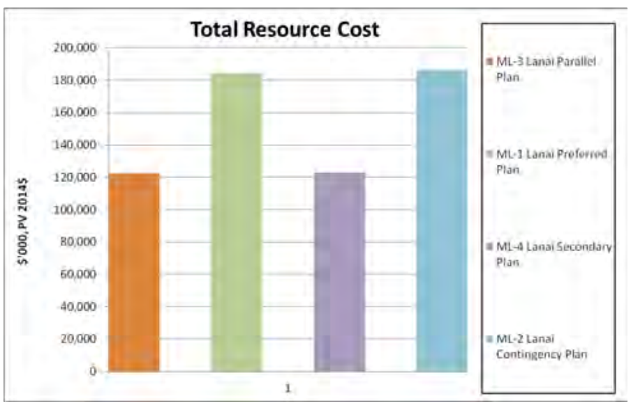
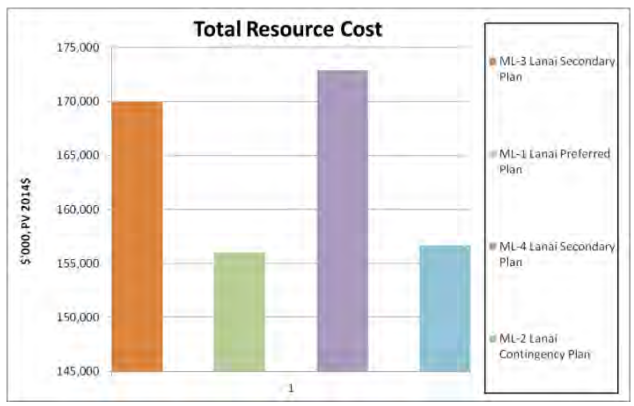



Table P-220. Lanai Stuck in the Middle Total Resource Cost



## Molokai Island

### Blazing a Bold Frontier

Table P-221. Molokai Blazing a Bold Frontier Greenhouse Gas Emissions

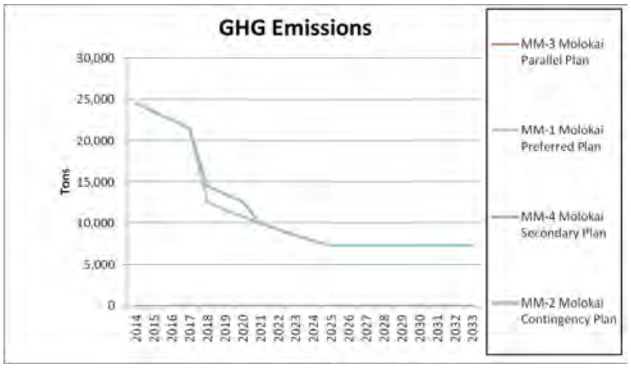
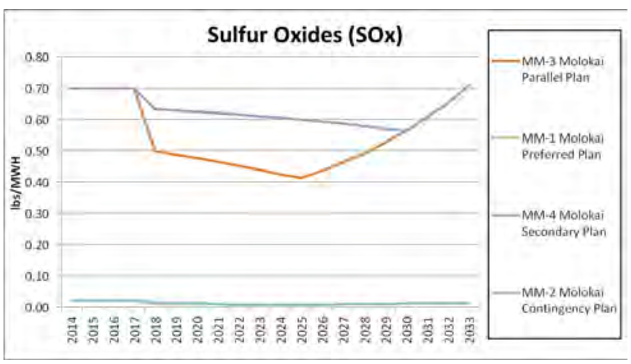



Table P-223. Molokai Blazing a Bold Frontier Sulfur Oxides




### Stuck in the Middle

Table P-222. Molokai Stuck in the Middle Greenhouse Gas Emissions

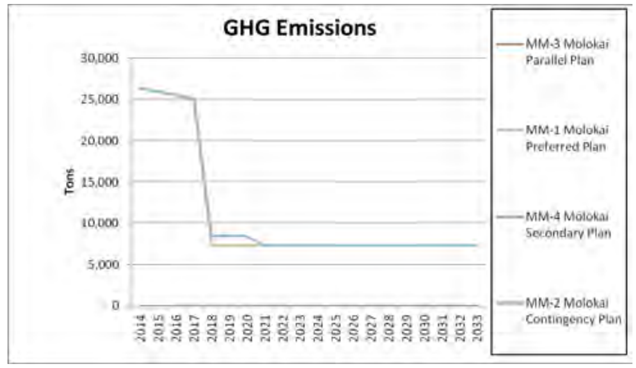



Table P-224. Molokai Stuck in the Middle Sulfur Oxides

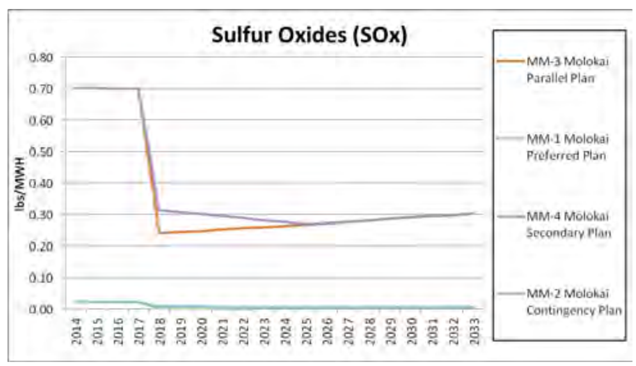


Table P-225. Molokai Blazing a Bold Frontier Nitrous Oxides

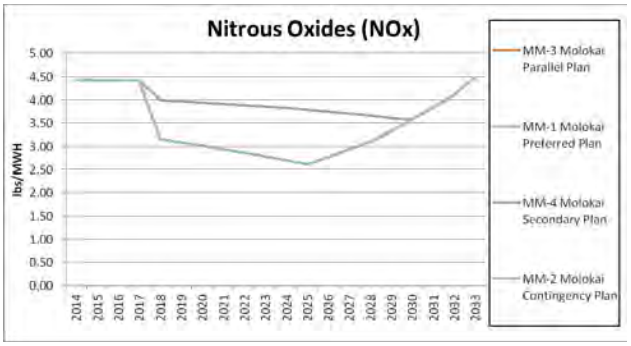



Table P-226. Molokai Stuck in the Middle Nitrous Oxides

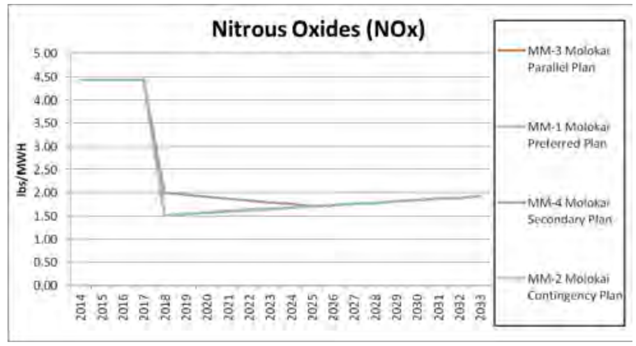



Table P-227. Molokai Blazing a Bold Frontier Particulate Matter

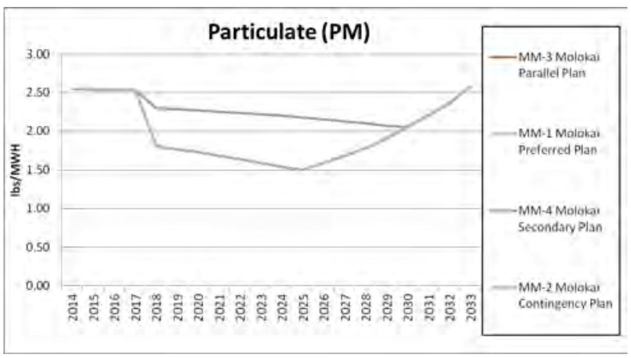



Table P-228. Molokai Stuck in the Middle Particulate Matter

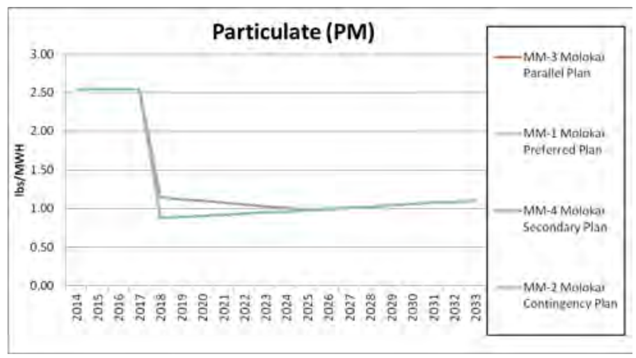



Table P-229. Molokai Blazing a Bold Frontier Share of Delivered Energy Linked to Oil Price

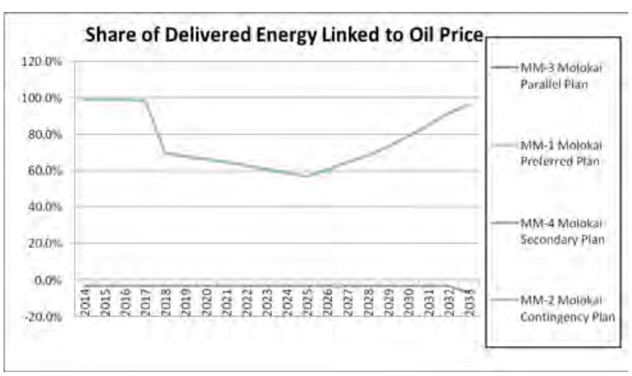



Table P-230. Molokai Stuck in the Middle Share of Delivered Energy Linked to Oil Price

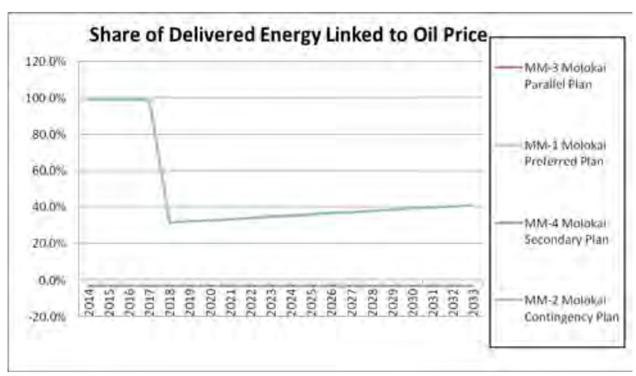


Table P-231. Molokai Blazing a Bold Frontier Share of Resource Plan Cost Linked to Fossil Fuels

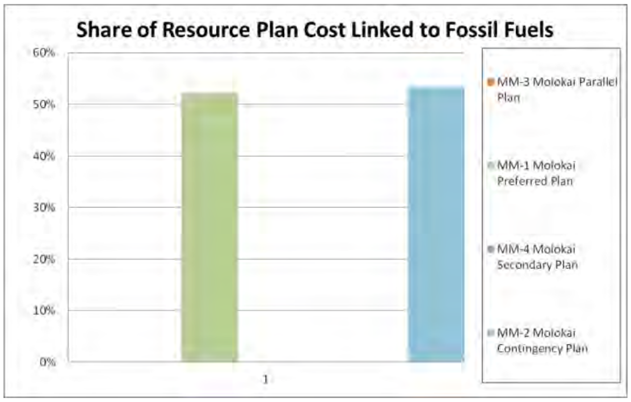



Table P-232. Molokai Stuck in the Middle Share of Resource Plan Cost Linked to Fossil Fuels

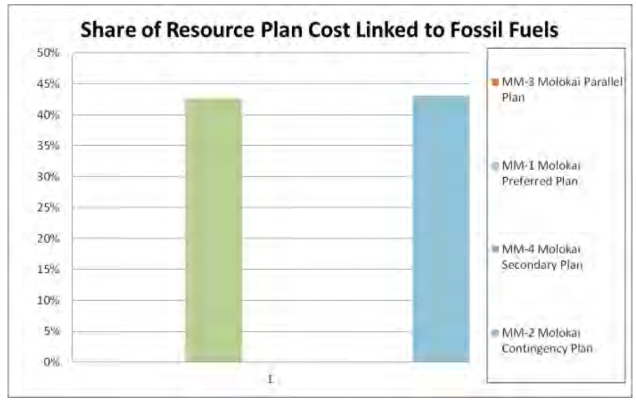



Table P-233. Molokai Blazing a Bold Frontier Imported Fuel Oil Amount

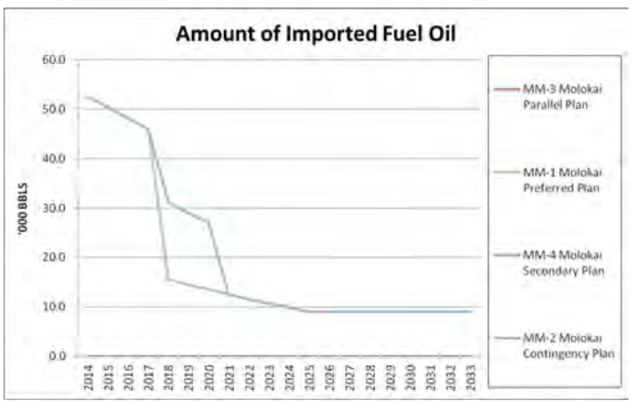



Table P-234. Molokai Stuck in the Middle Imported Fuel Oil Amount

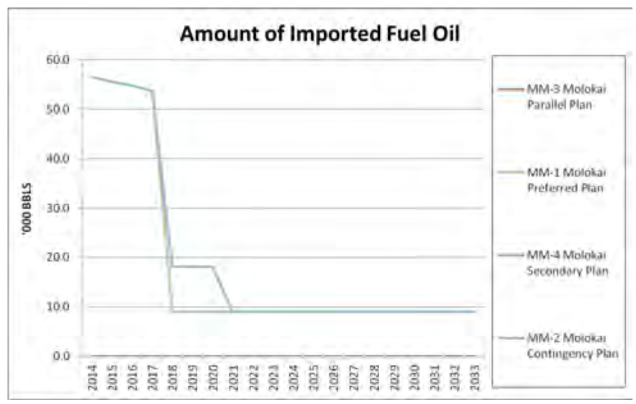



Table P-235. Molokai Blazing a Bold Frontier Imported LNG Amount

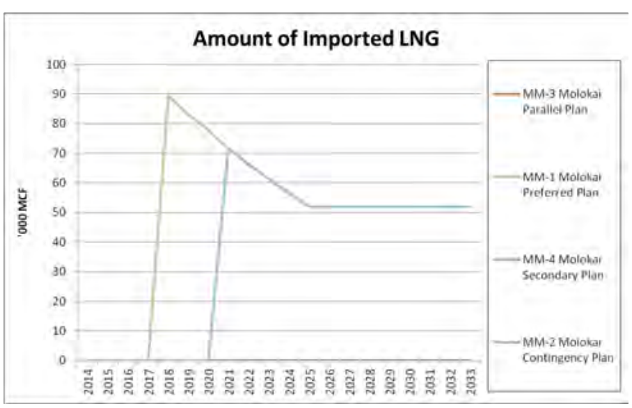



Table P-236. Molokai Stuck in the Middle Imported LNG Amount

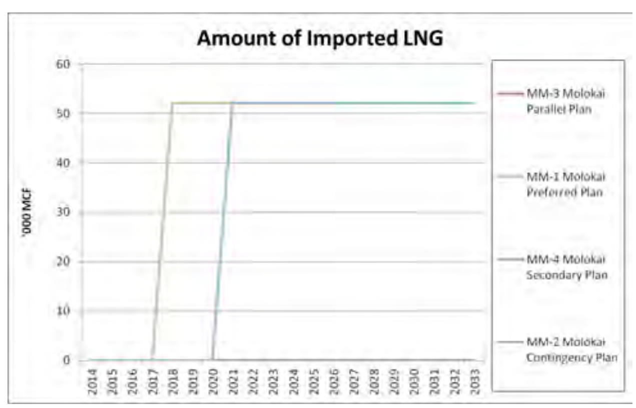


Table P-237. Molokai Blazing a Bold Frontier Energy Efficiency Portfolio Standard

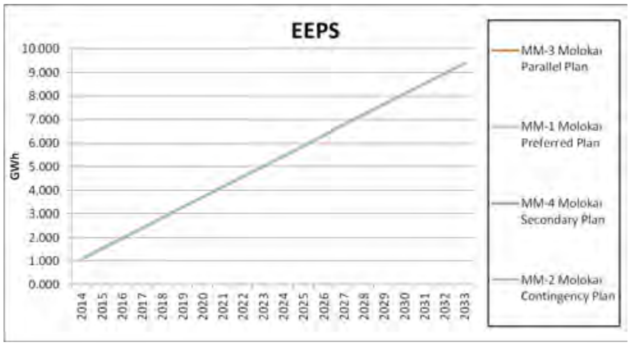



Table P-238. Molokai Stuck in the Middle Energy Efficiency Portfolio Standard

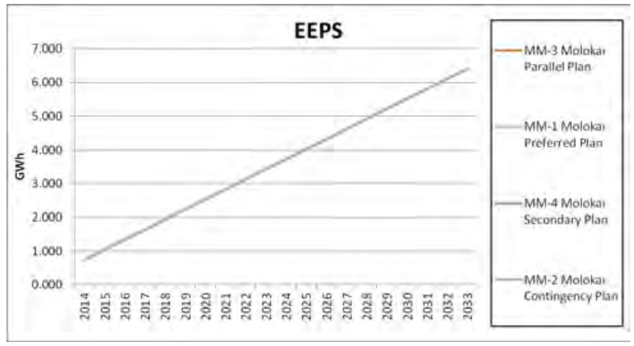



Table P-239. Molokai Blazing a Bold Frontier Renewable Energy

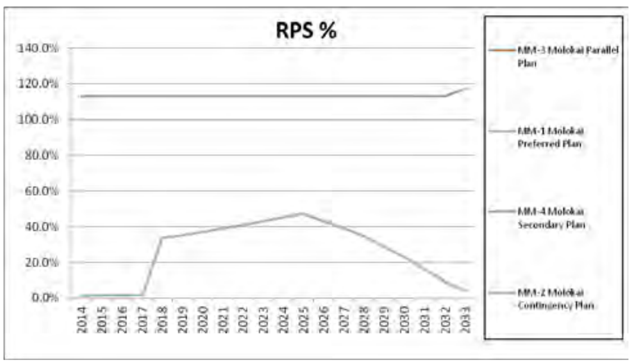



Table P-240. Molokai Stuck in the Middle Renewable Energy

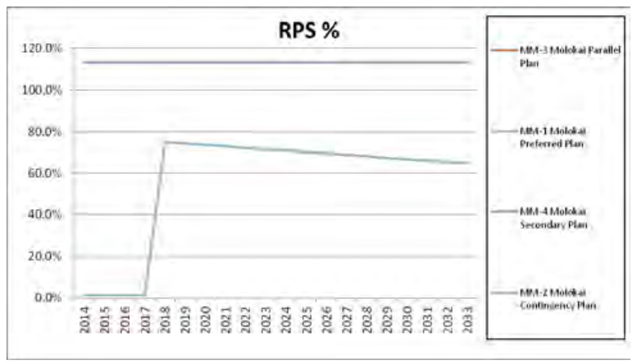



Table P-241. Molokai Blazing a Bold Frontier Renewable Energy Curtailed

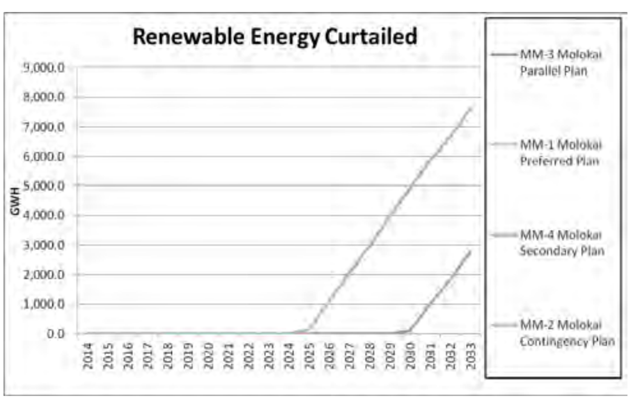



Table P-242. Molokai Stuck in the Middle Renewable Energy Curtailed

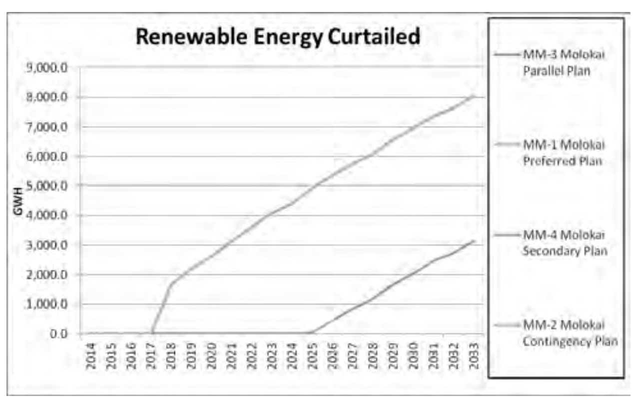


Table P-243. Molokai Blazing a Bold Frontier Resource Diversity Index

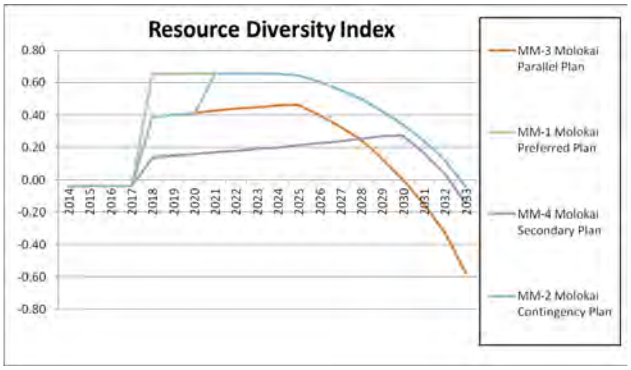



Table P-244. Molokai Stuck in the Middle Resource Diversity Index

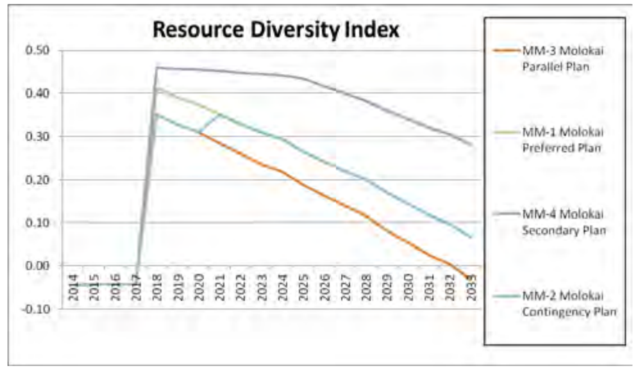



Table P-245. Molokai Blazing a Bold Frontier Share of Generation from Local Resources

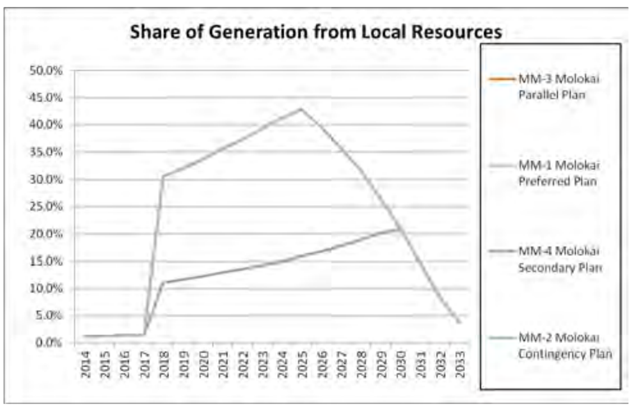



Table P-246. Molokai Stuck in the Middle Share of Generation from Local Resources

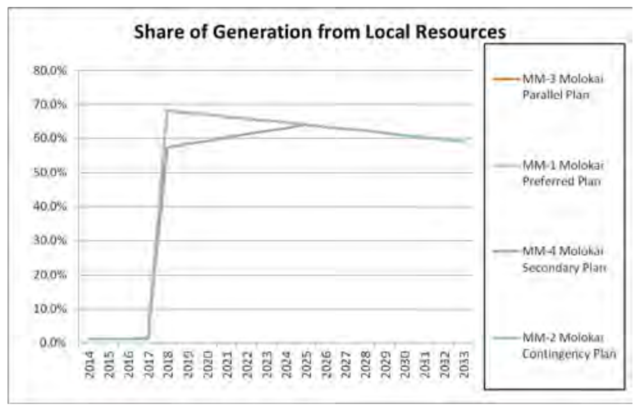



Table P-247. Molokai Blazing a Bold Frontier Reserve Margin

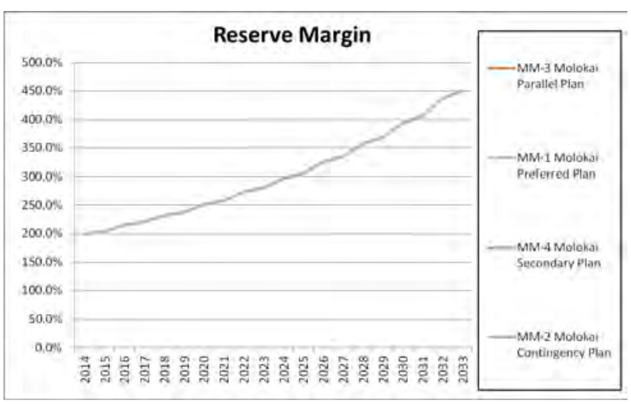



Table P-248. Molokai Stuck in the Middle Reserve Margin

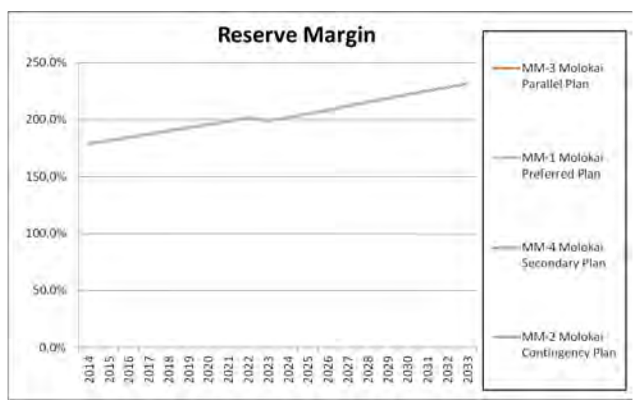


Table P-249. Molokai Blazing a Bold Frontier Intermittent As-Available Resource Penetration

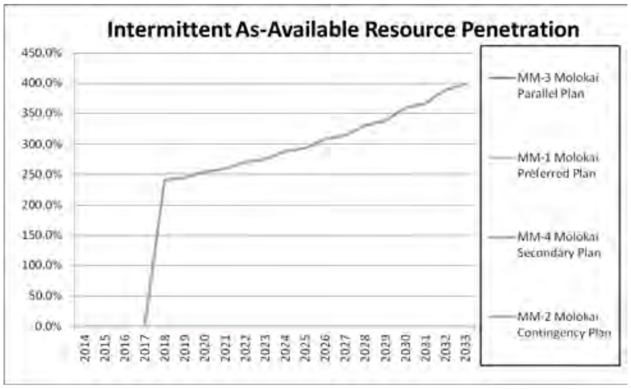



Table P-250. Molokai Stuck in the Middle Intermittent As-Available Resource Penetration

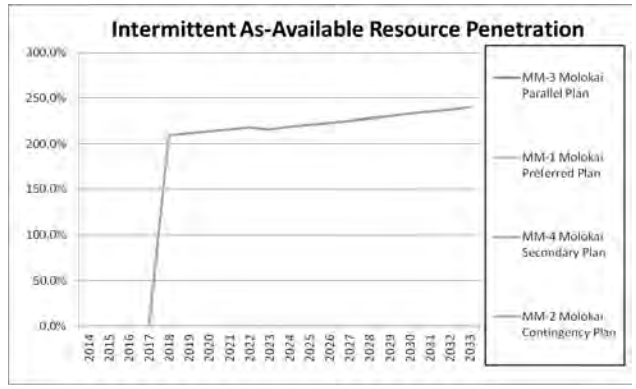



Table P-251. Molokai Blazing a Bold Frontier Generation Efficiency

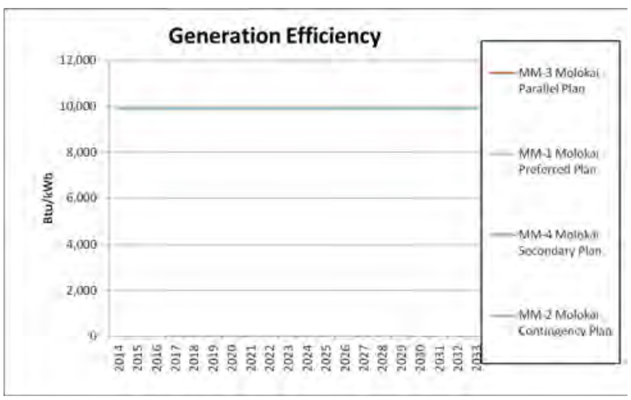



Table P-252. Molokai Stuck in the Middle Generation Efficiency

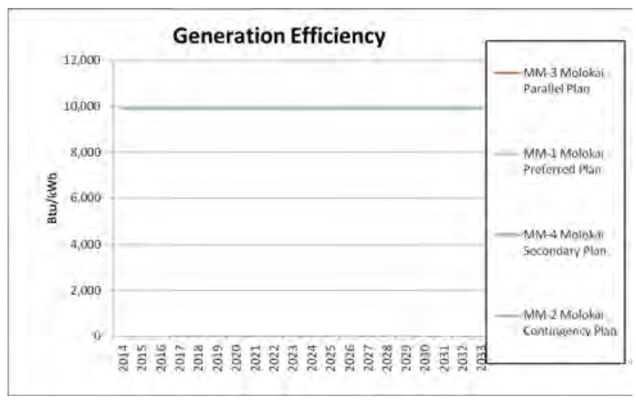



Table P-253. Molokai Blazing a Bold Frontier System Regulating Capability

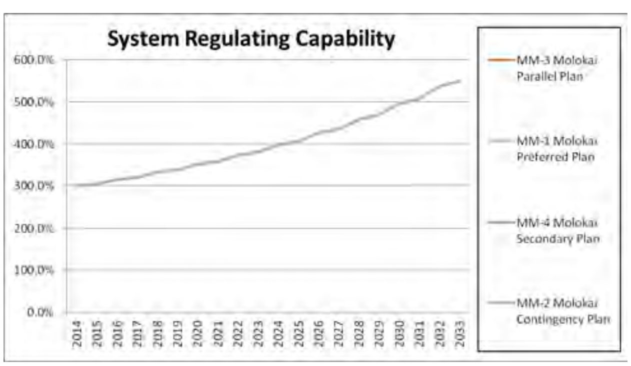



Table P-254. Molokai Stuck in the Middle System Regulating Capability

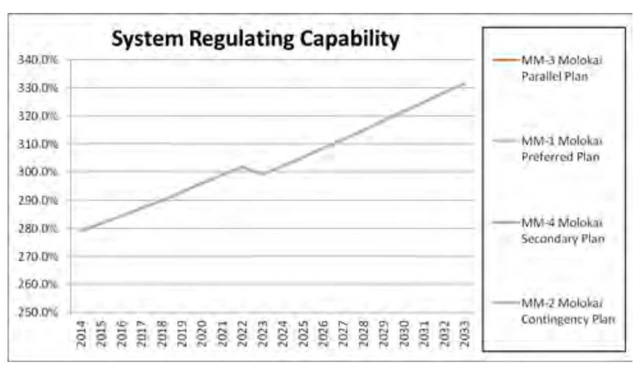


Table P-255. Molokai Blazing a Bold Frontier Nominal Price of Electricity: Residential

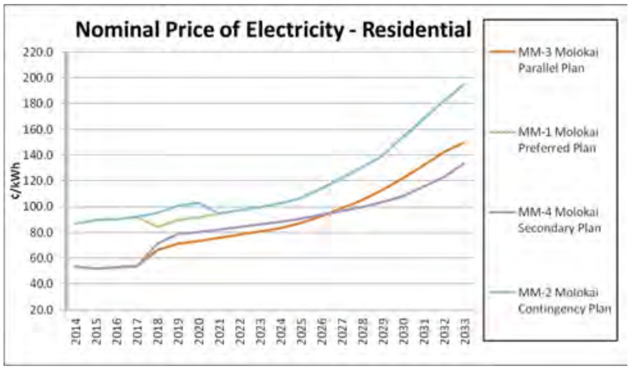



Table P-256. Molokai Stuck in the Middle Nominal Price of Electricity: Residential

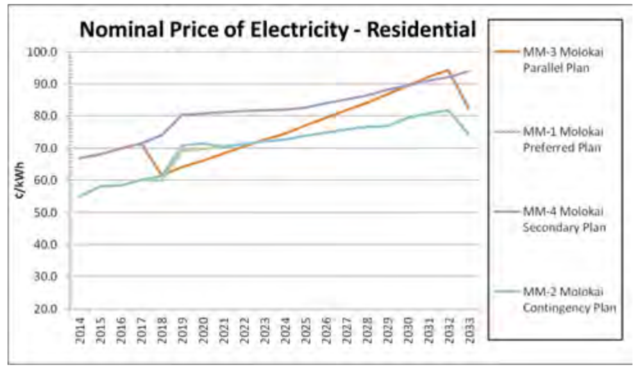



Table P-257. Molokai Blazing a Bold Frontier Nominal Price of Electricity: Commercial

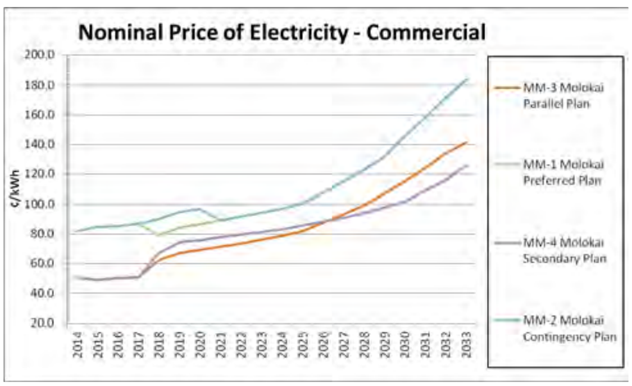



Table P-258. Molokai Stuck in the Middle Nominal Price of Electricity: Commercial

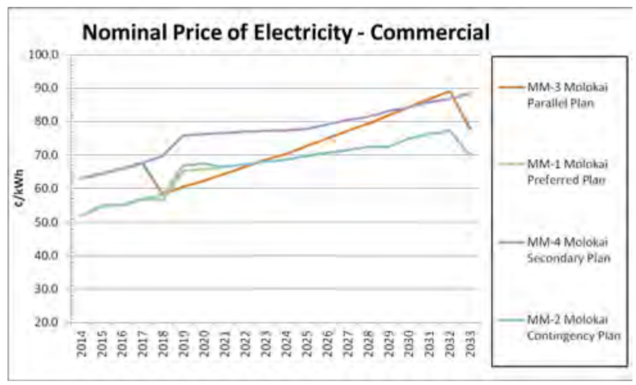



Table P-259. Molokai Blazing a Bold Frontier Nominal Price of Electricity: Industrial

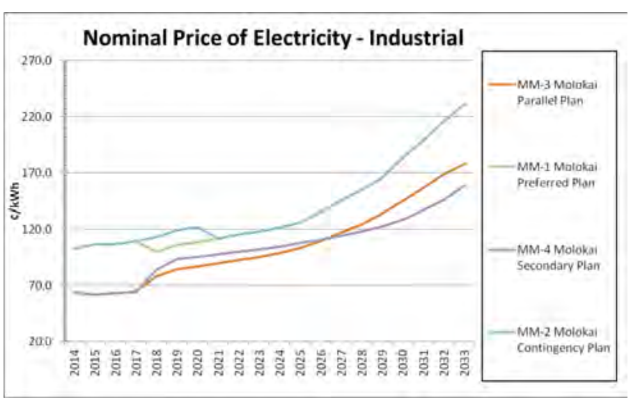



Table P-260. Molokai Stuck in the Middle Nominal Price of Electricity: Industrial

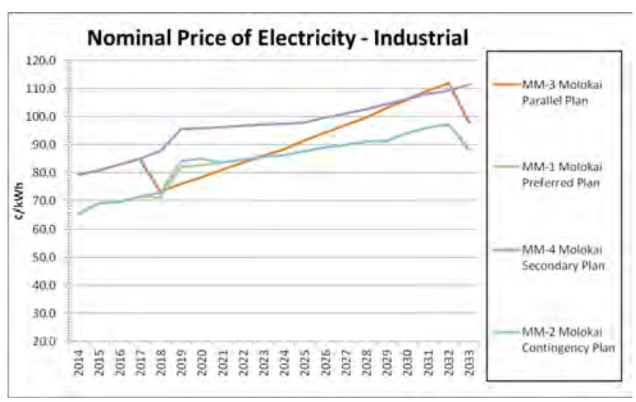


Table P-261. Molokai Blazing a Bold Frontier Nominal Residential Bill

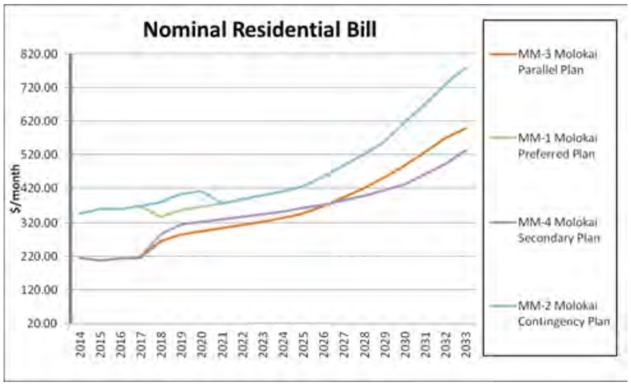



Table P-262. Molokai Stuck in the Middle Nominal Residential Bill

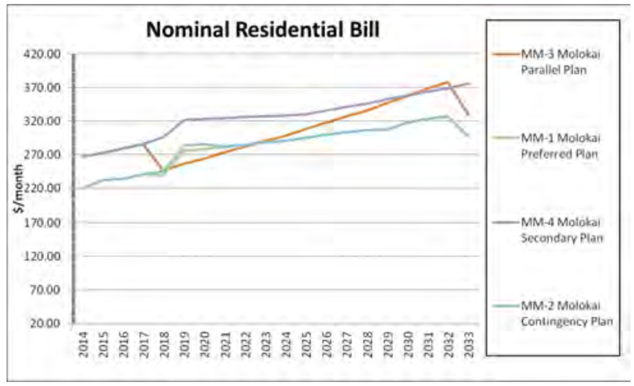



Table P-263. Molokai Blazing a Bold Frontier Annual Revenue Requirements for Capital

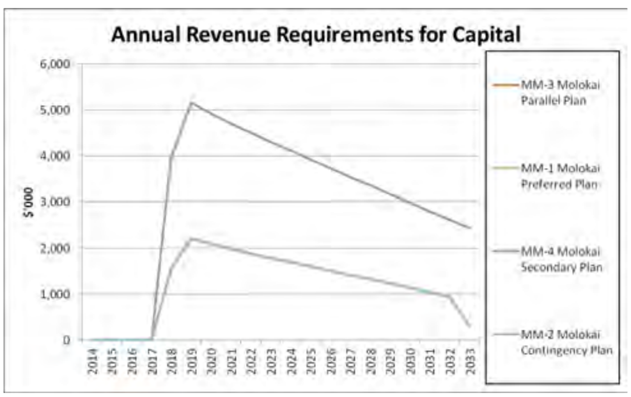



Table P-264. Molokai Stuck in the Middle Annual Revenue Requirements for Capital

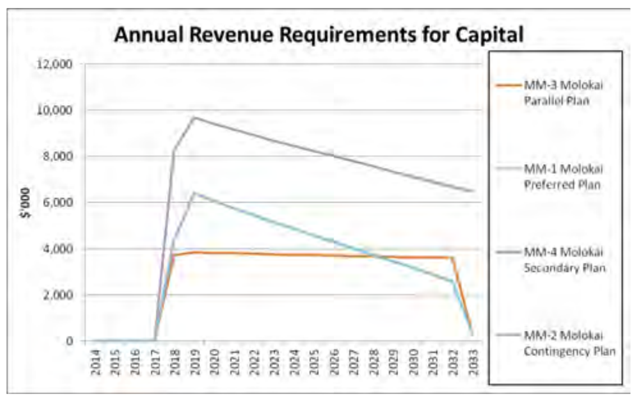



Table P-265. Molokai Blazing a Bold Frontier Total Resource Cost

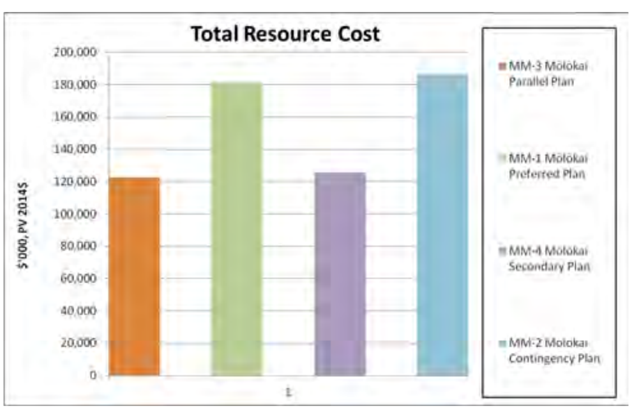
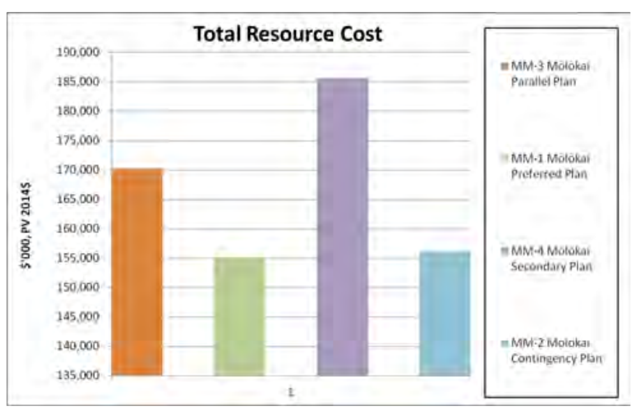



Table P-266. Molokai Stuck in the Middle Total Resource Cost



# Appendix Q:
# Action Plan Flowcharts

The Resource Plans developed during our analysis of the IRP process are oftentimes complex and present a planning challenge when developing our Action Plan. This appendix contains flowcharts for each utility that demonstrate the complexity of our challenge.

# CONTENTS



# TABLES

[This page intentionally left blank]

# Hawaiian Electric Action Plan Flowcharts

The Action Plan flowcharts for Hawaiian Electric demonstrate the complexity of its many resource plans for the island of Oahu.

Table Q-1. Overview of Hawaiian Electric's IRP Action Plan

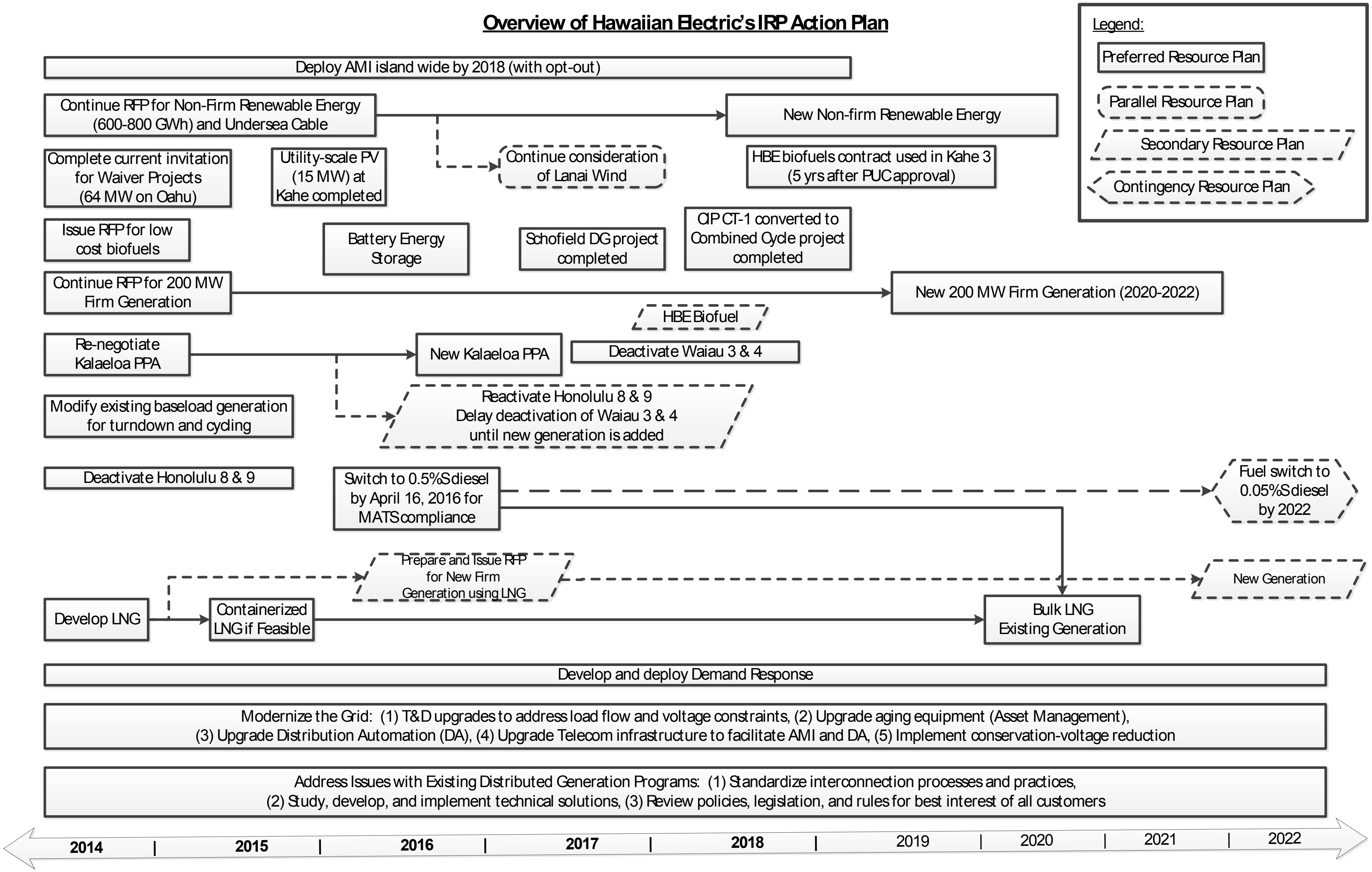


Table Q-2. Hawaiian Electric's Preferred Resource Plan (2014–2022) for Stuck in the Middle

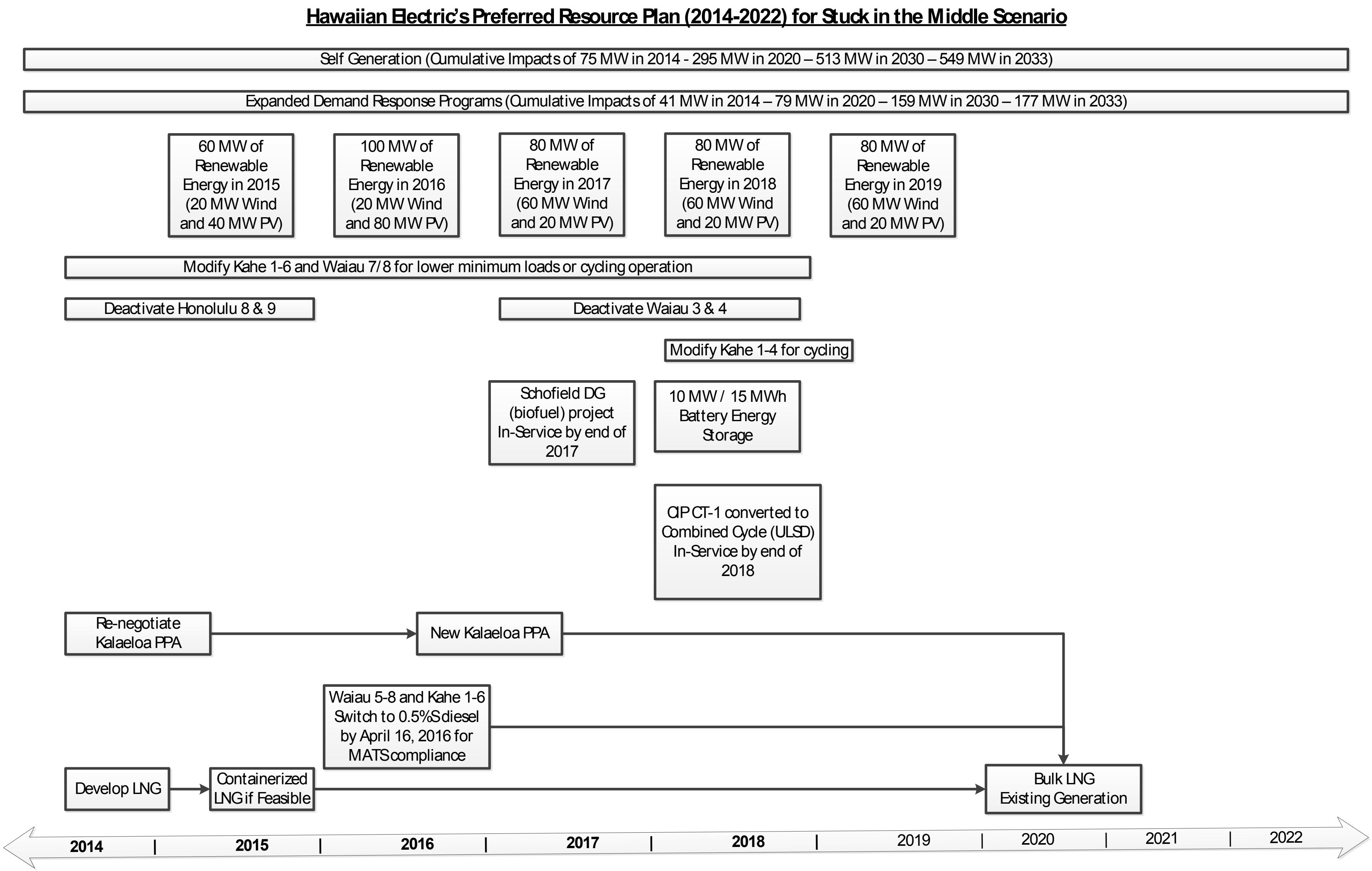


Table Q-3. Hawaiian Electric's Parallel Resource Plan (2014–2022) for Stuck in the Middle

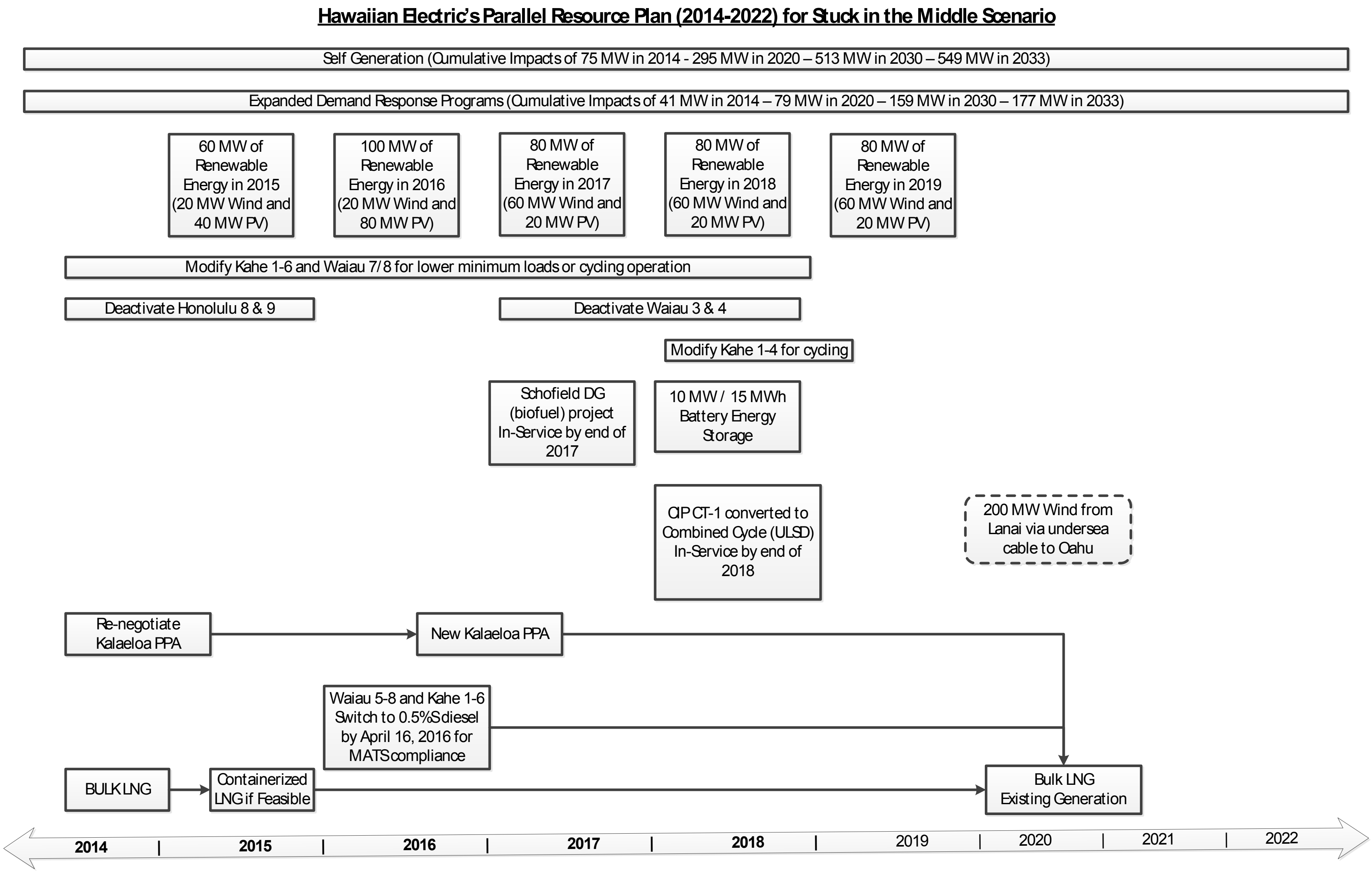


Table Q-4. Hawaiian Electric's Contingency Resource Plan (2014–2022) for Stuck in the Middle

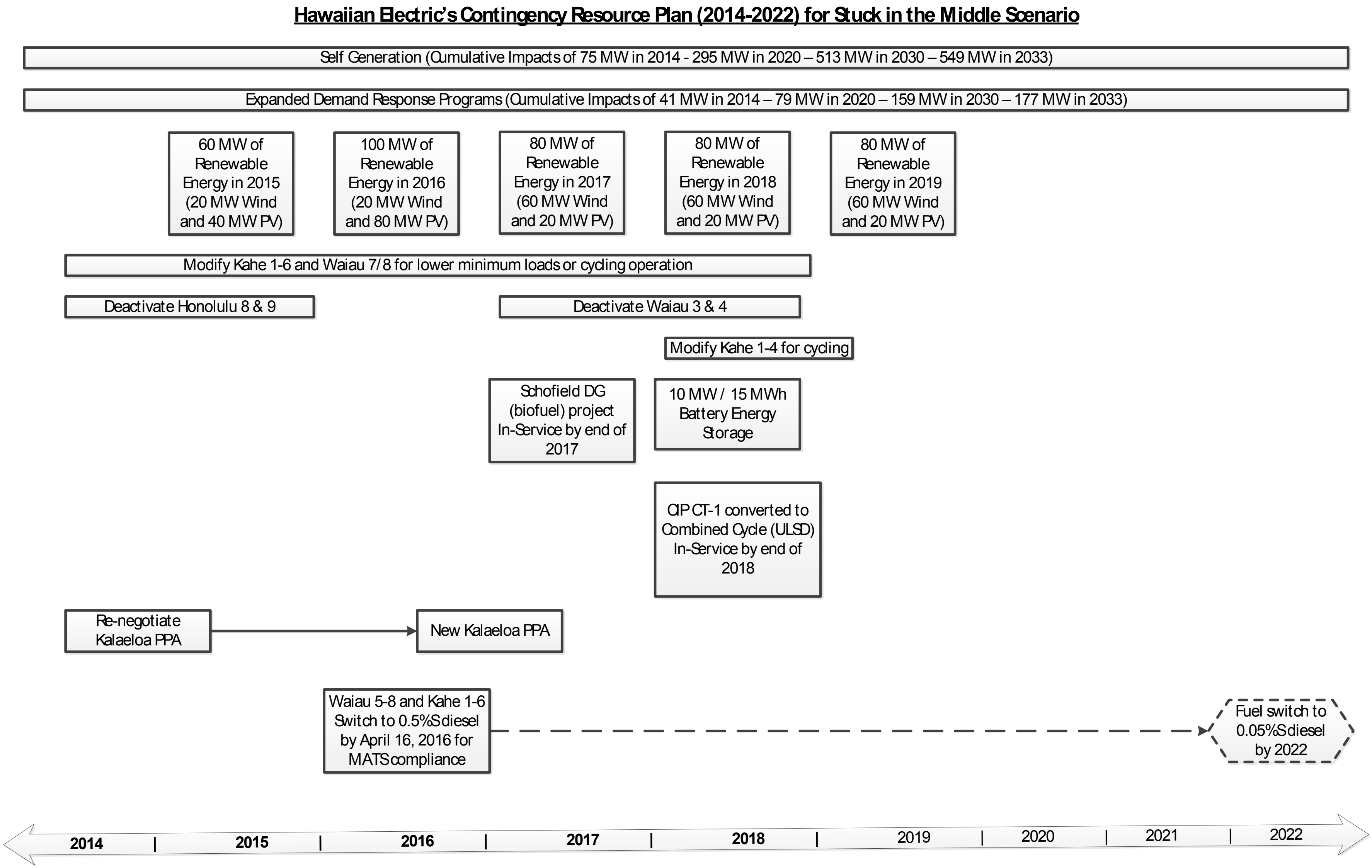


Table Q-5. Hawaiian Electric's Secondary Resource Plan (2014–2022) for Stuck in the Middle

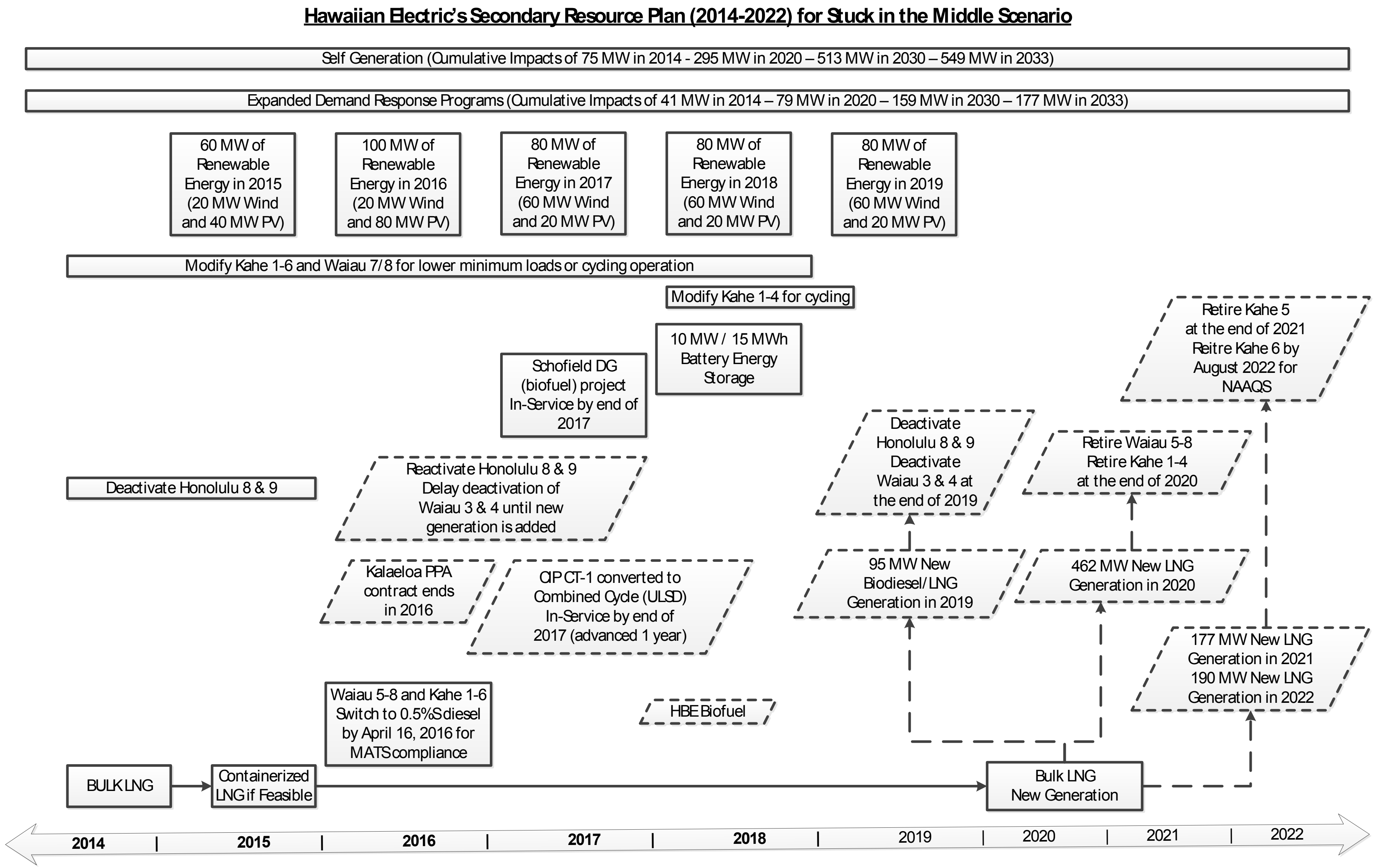


Table Q-6. Action Plan Complexities—LNG

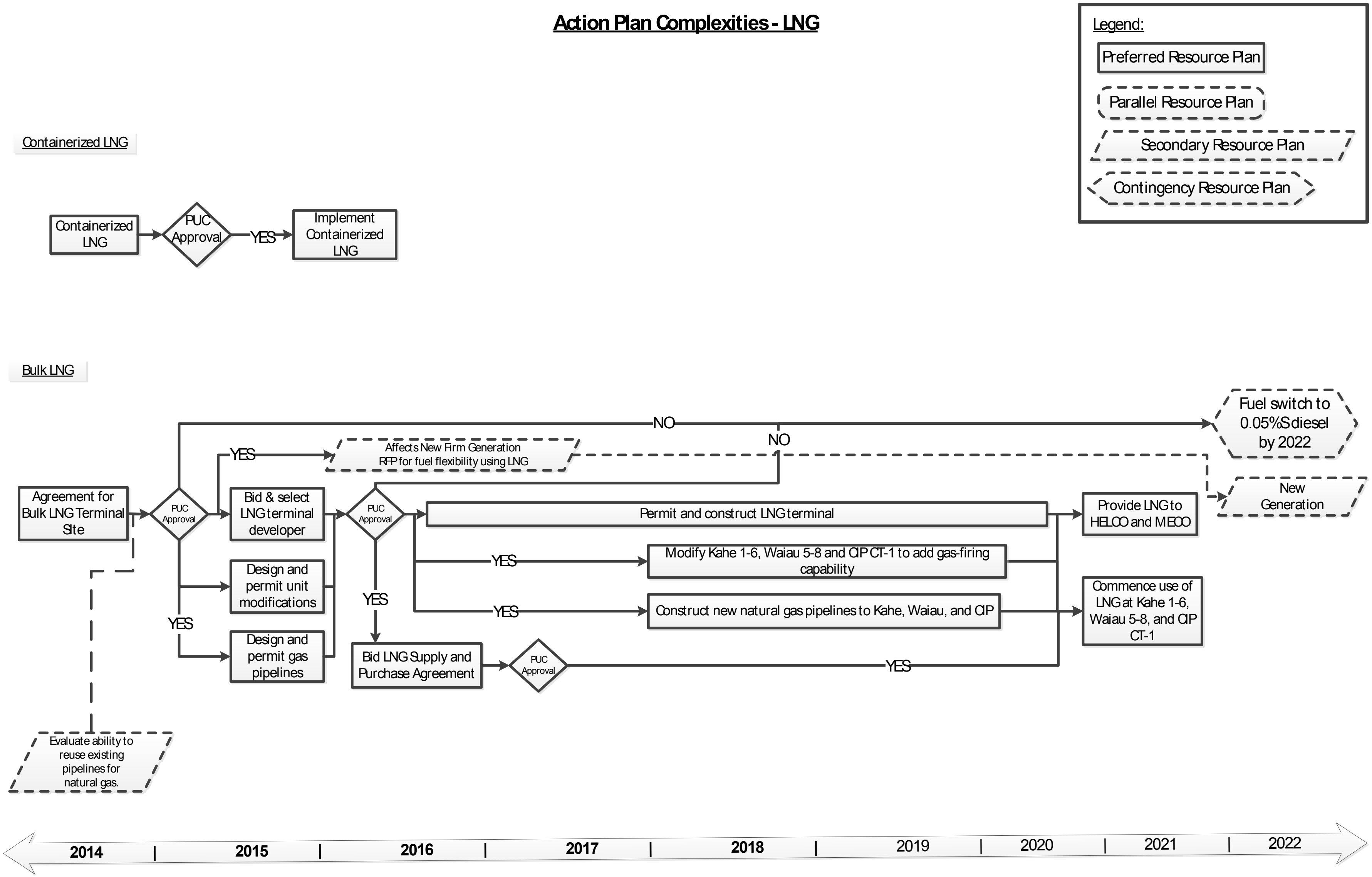


Table Q-7. Action Plan Complexities—Kalaeloa PPA and Firm Renewable RFP

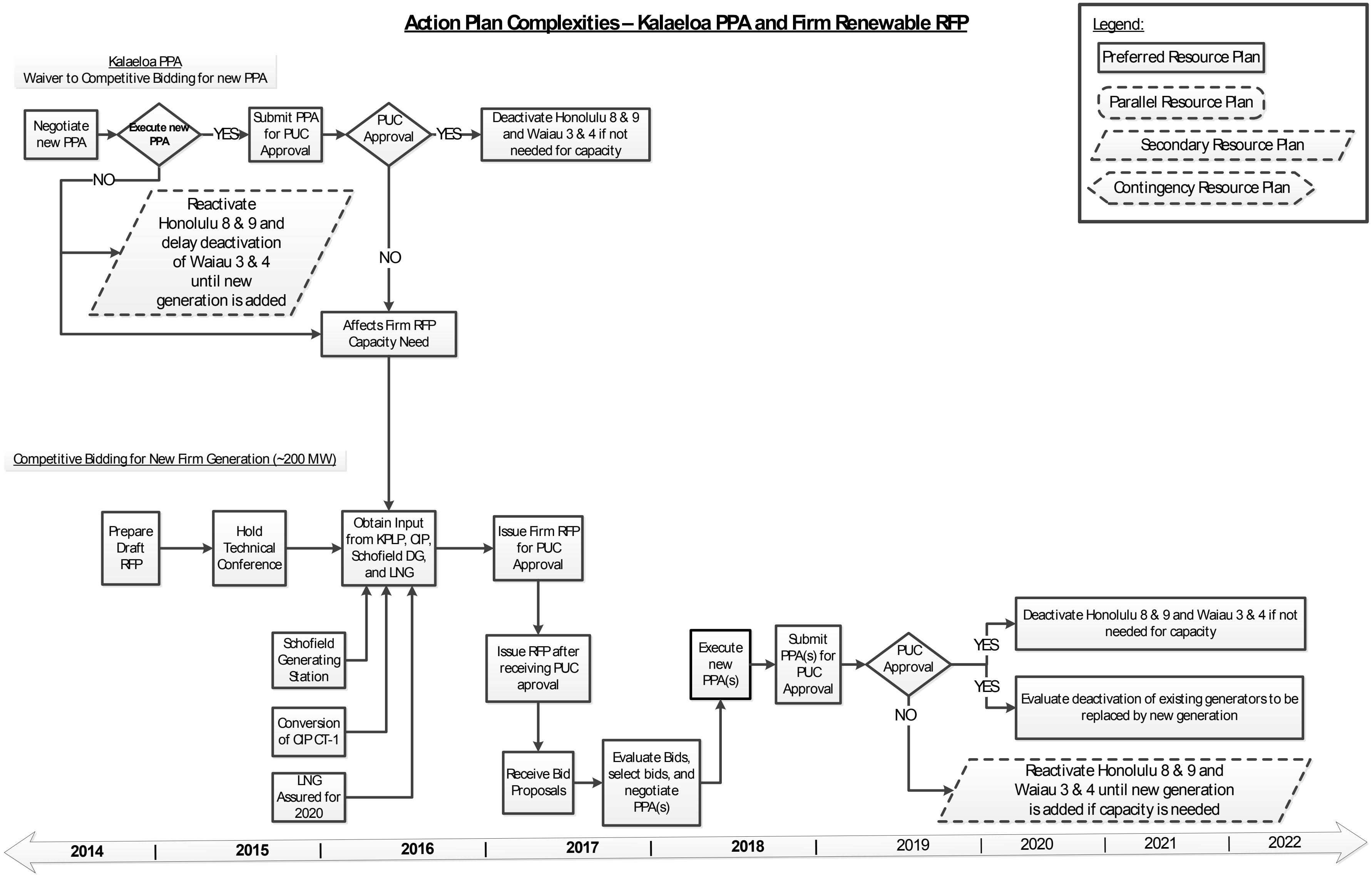


Table Q-8. Action Plan Complexities—Conversion of CIP CT-1 and Schofield Generation

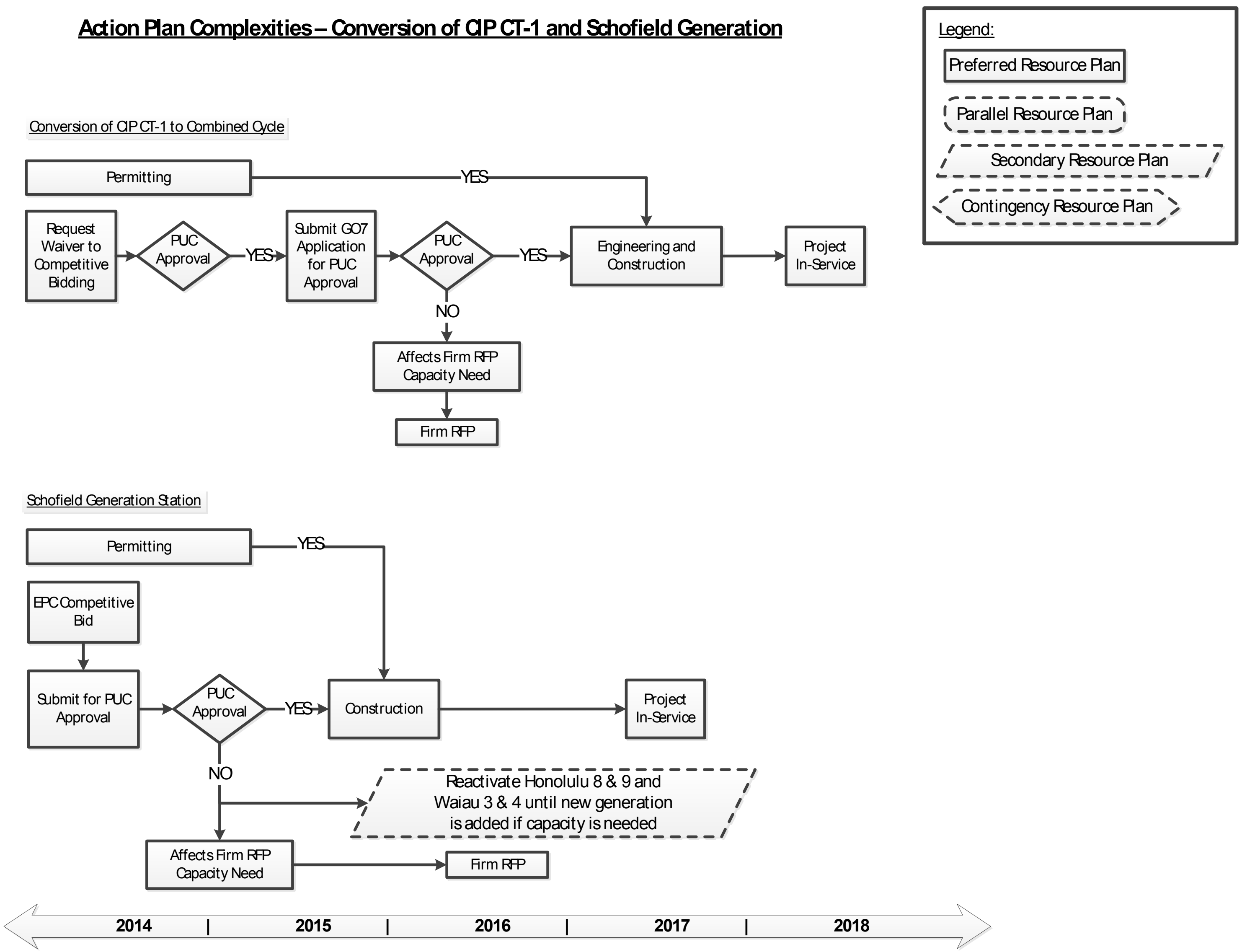
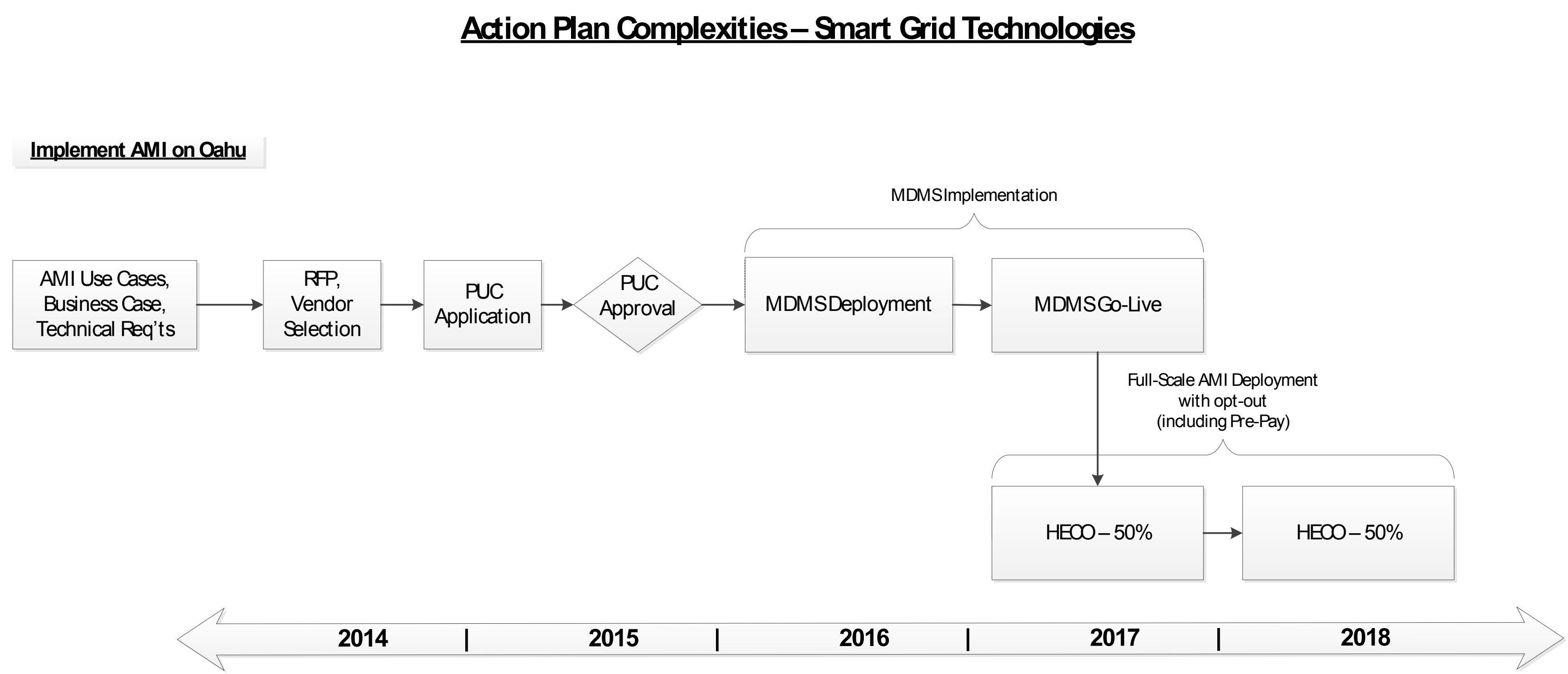


Table Q-9. Hawaiian Electric's Action Plan Complexities—Smart Grid Technologies



# HELCO Action Plan Flowcharts

The Action Plan flowcharts for Hawaii Electric Light demonstrate the complexity of its many resource plans for the island of Hawaii.

Table Q-10. Overview of HELCO's IRP Action Plan

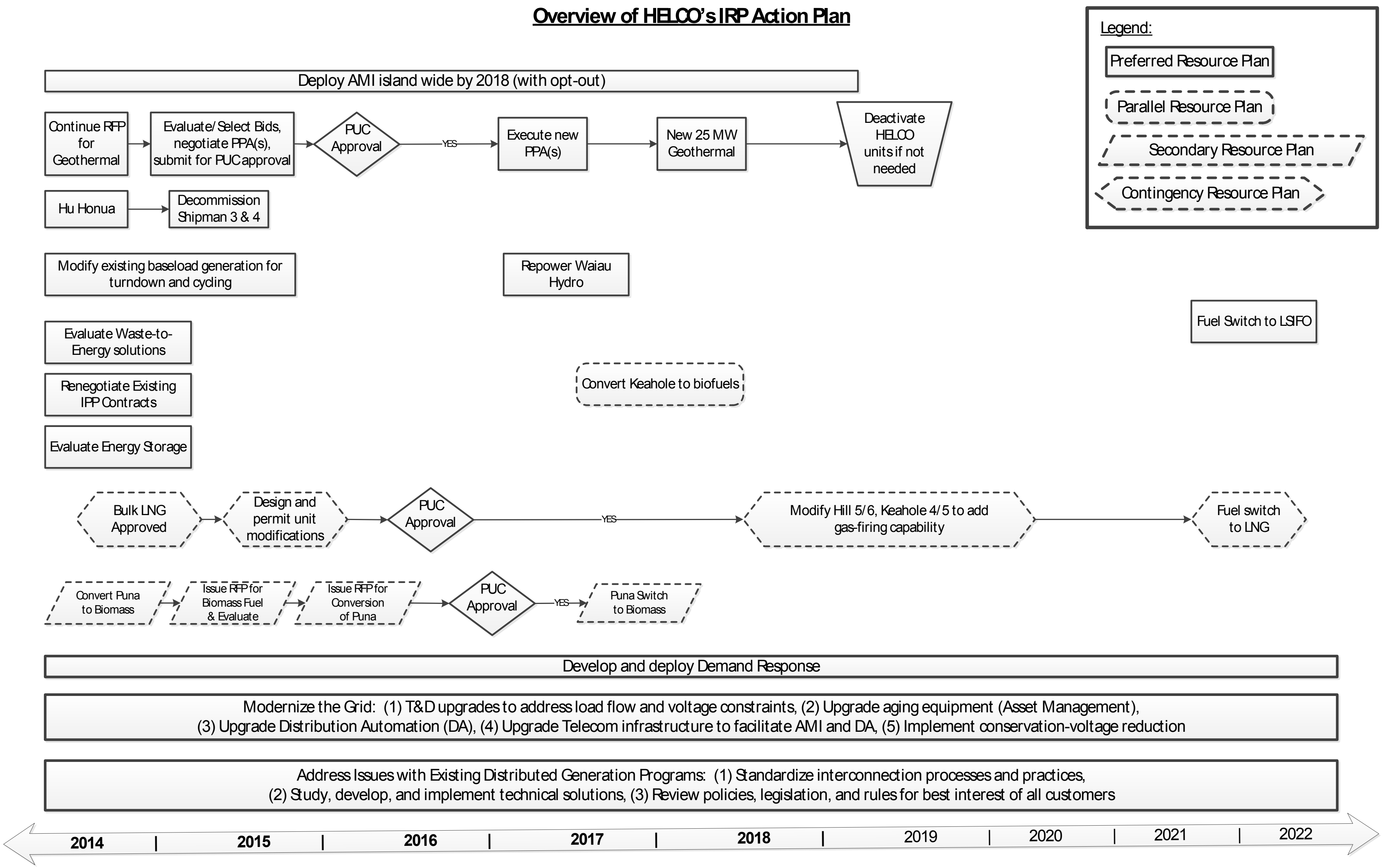


Table Q-11. HELCO's Preferred Resource Plan (2014–2022) for Stuck in the Middle

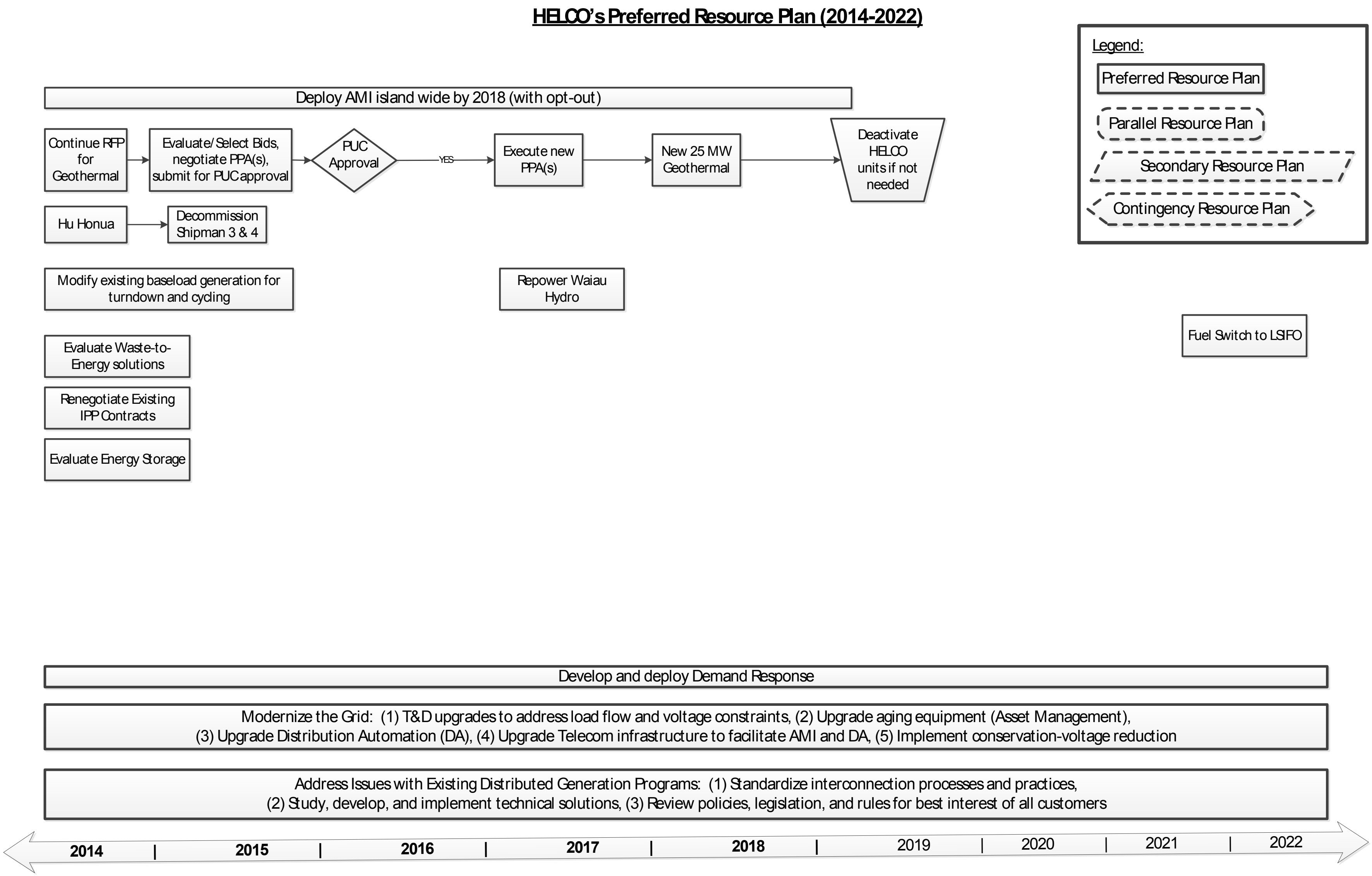


Table Q-12. HELCO's Parallel Resource Plan (2014–2022) for Stuck in the Middle

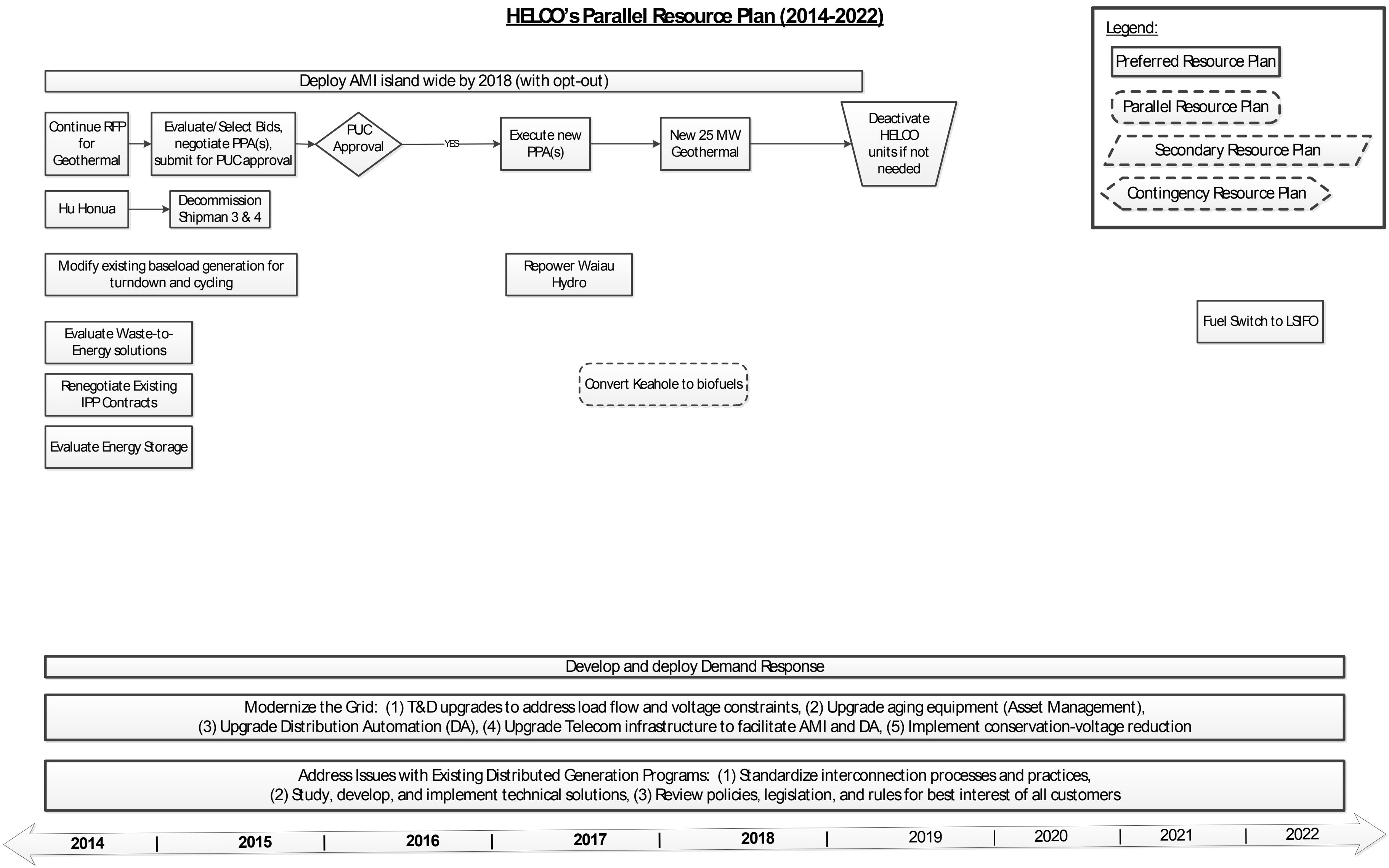


Table Q-13. HELCO's Contingency Resource Plan (2014–2022) for Stuck in the Middle

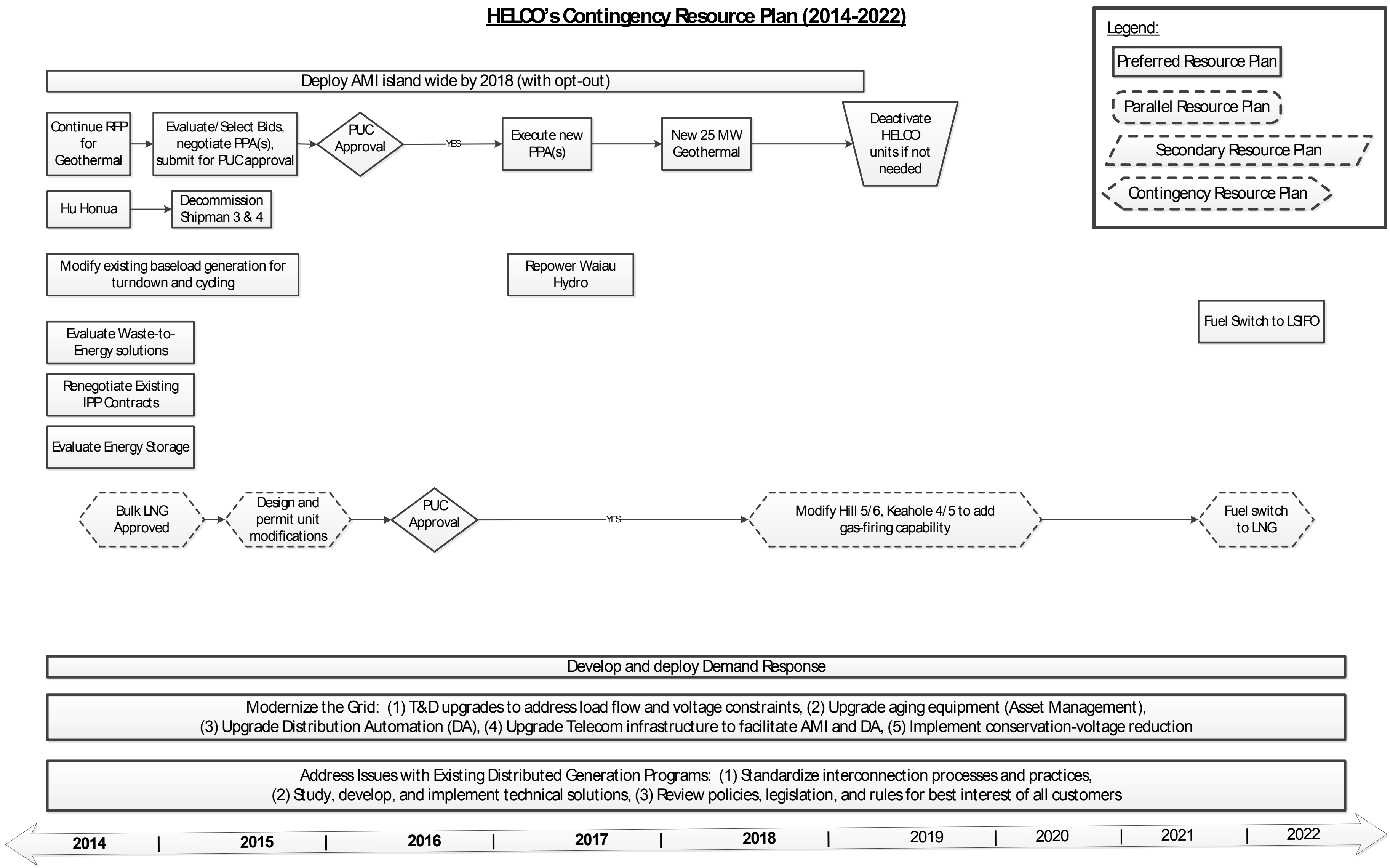


Table Q-14. HELCO's Secondary Resource Plan (2014–2022) for Stuck in the Middle

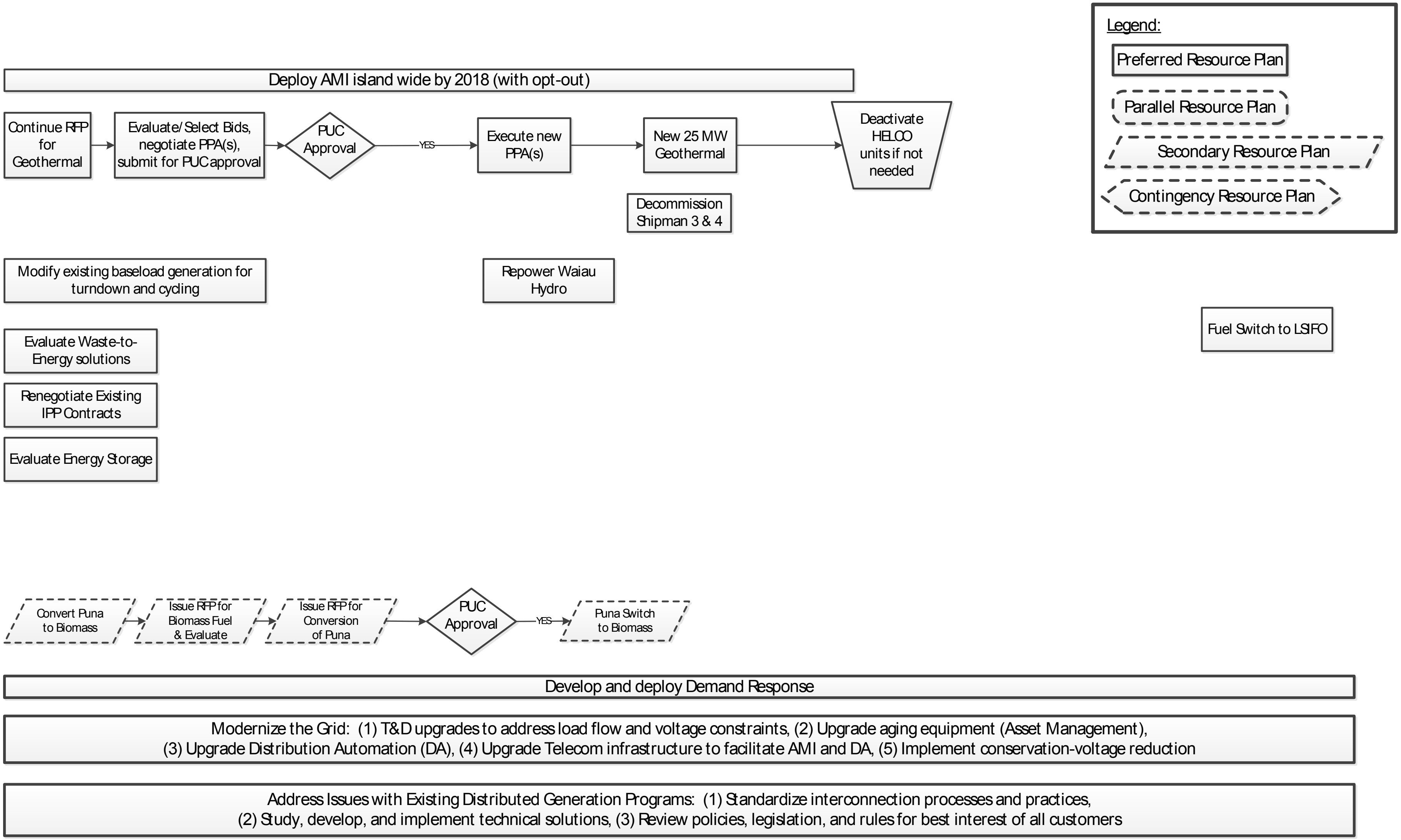
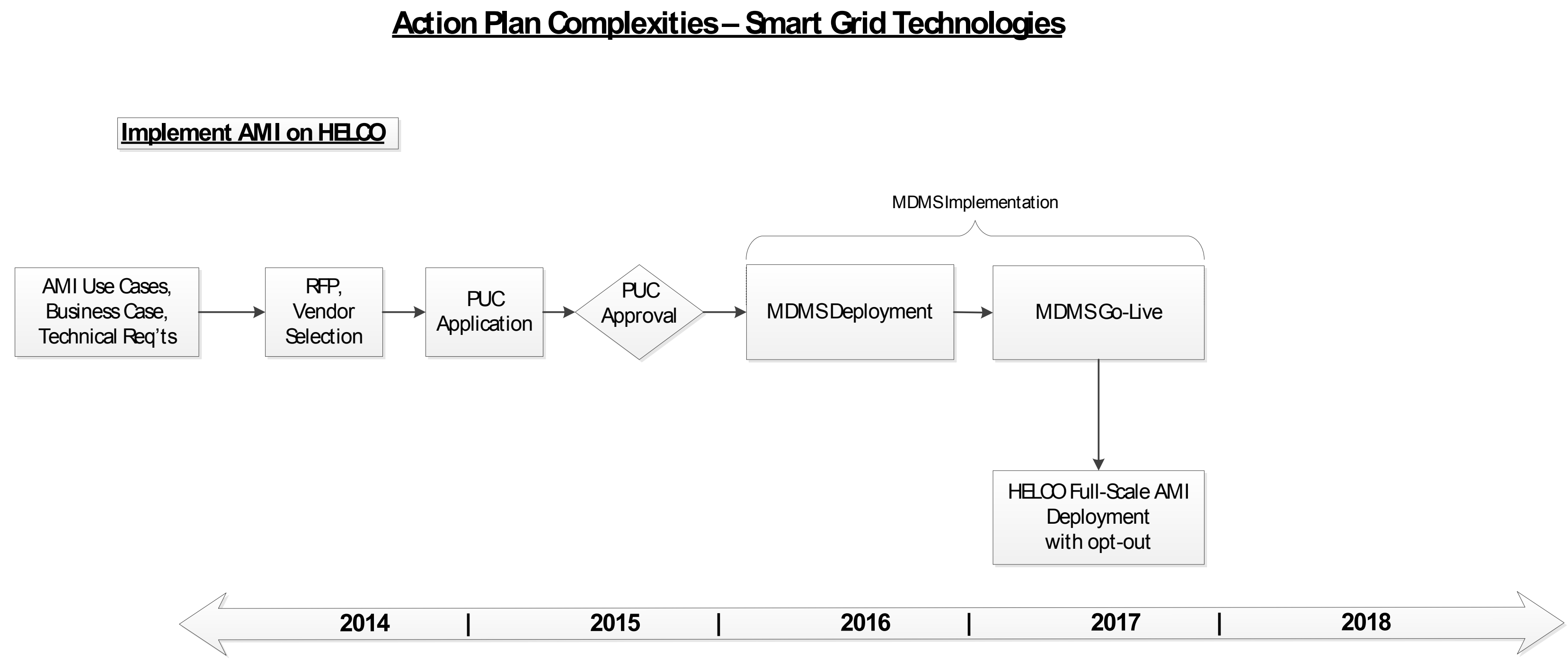


Table Q-15. HELCO's Action Plan Complexities—Smart Grid Technologies



# Maui Action Plan Flowcharts

The Action Plan flowcharts for Maui Electric demonstrate the complexity of its many resource plans for the island of Maui.

Table Q-16. Overview of Maui's IRP Action Plan

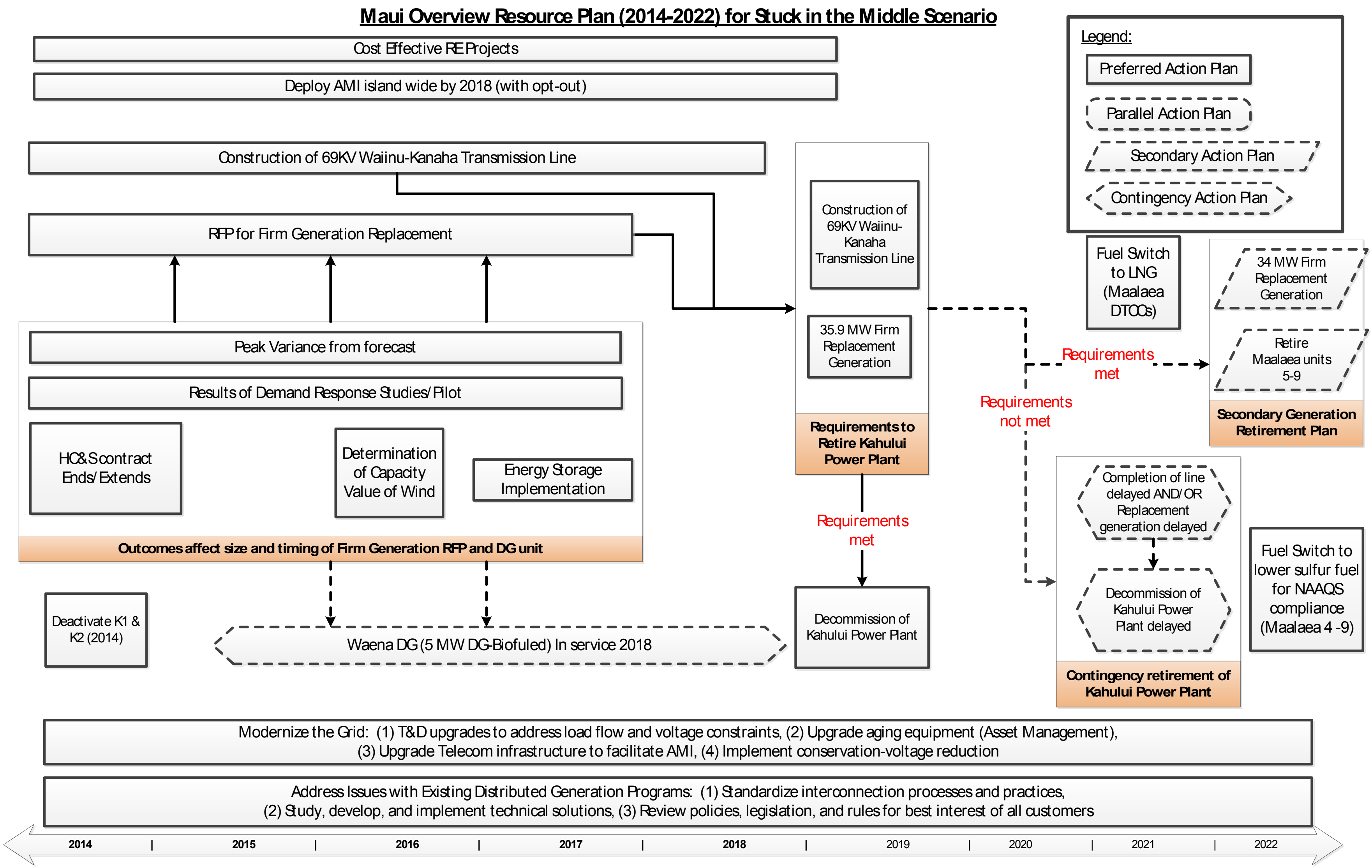


Table Q-17. Maui's Preferred Resource Plan (2014–2022) for Stuck in the Middle

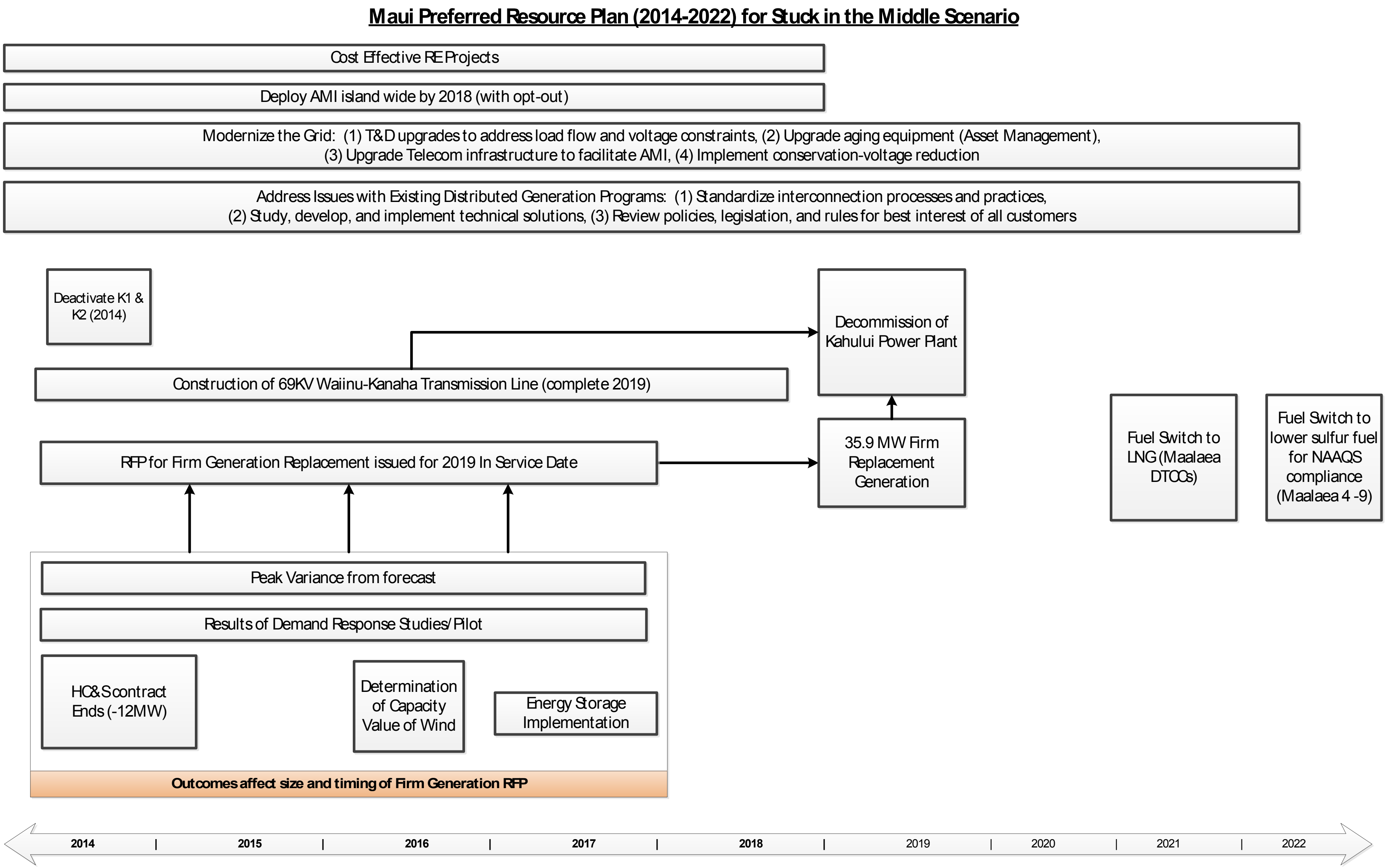


Table Q-18. Maui's Parallel Resource Plan (2014–2022) for Stuck in the Middle

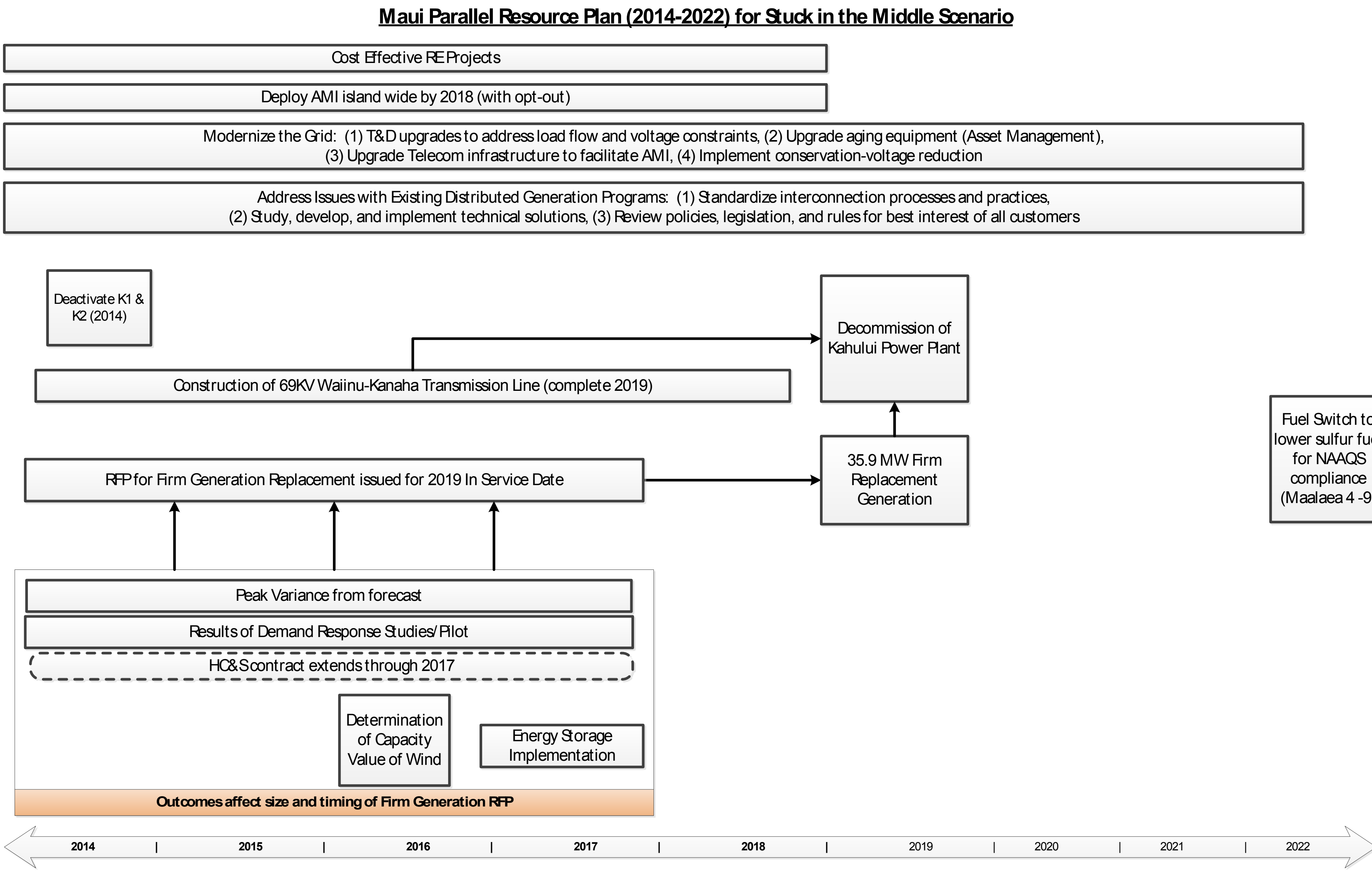


Table Q-19. Maui's Contingency Resource Plan (2014–2022) for Stuck in the Middle

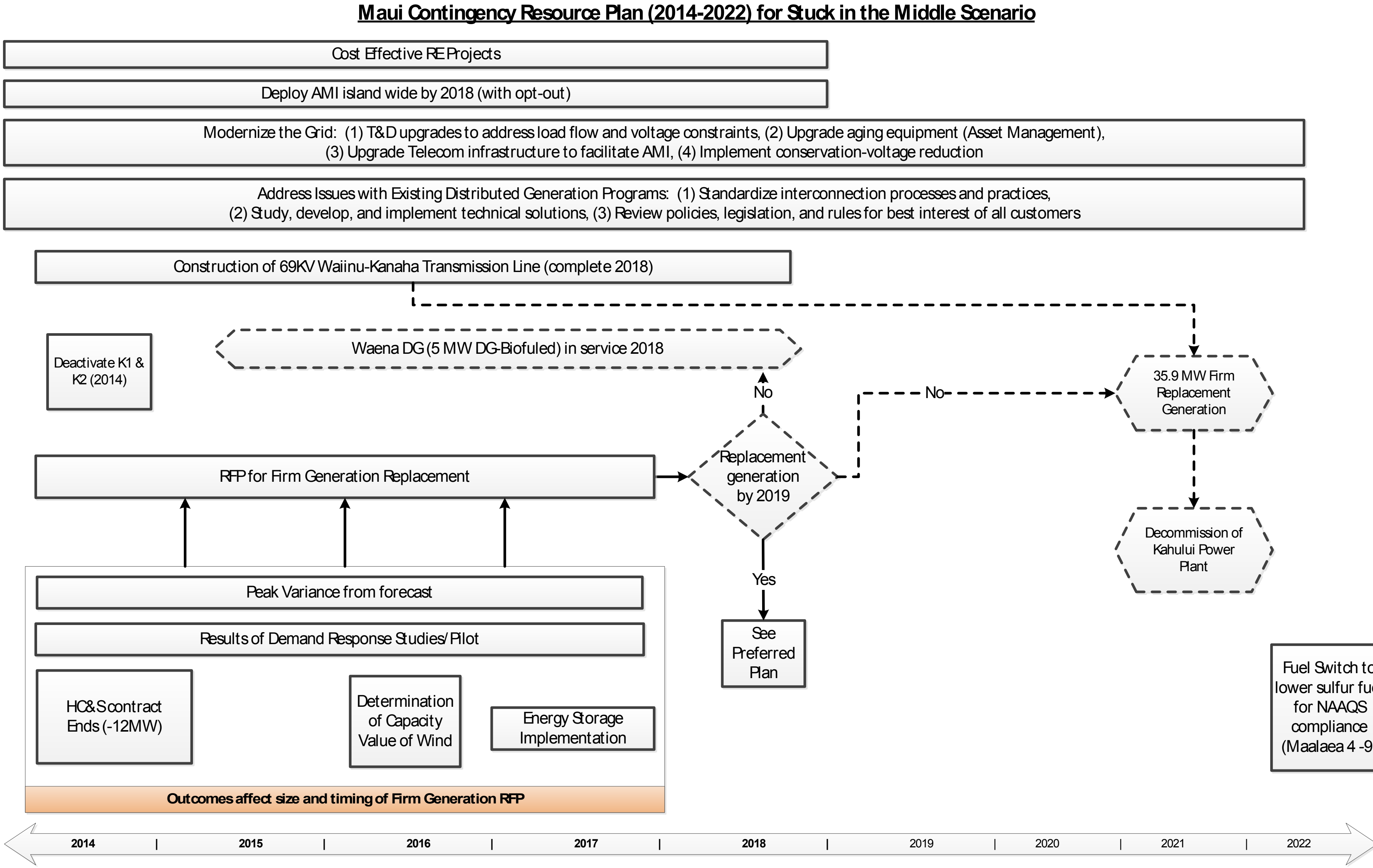
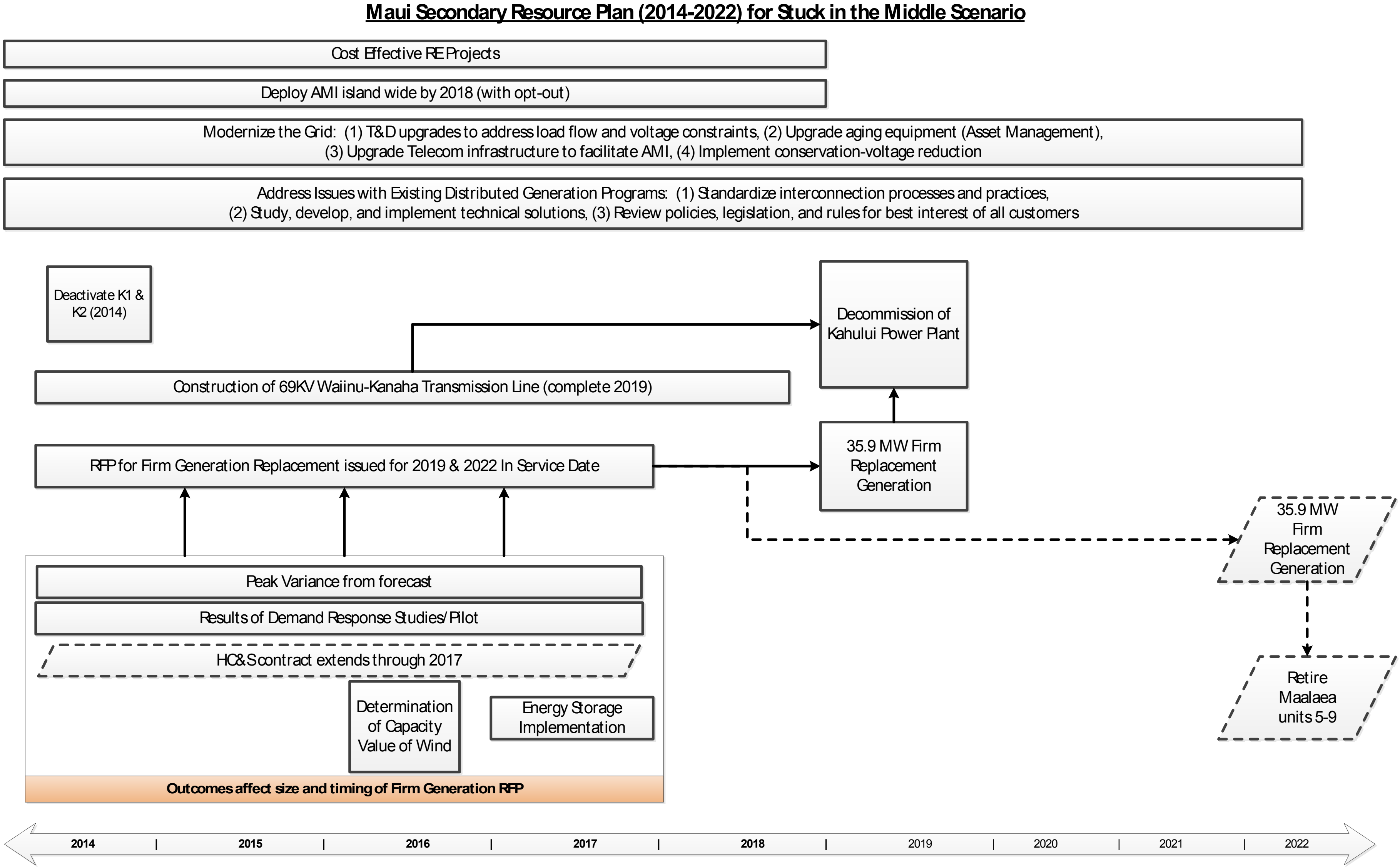


Table Q-20. Maui's Secondary Resource Plan (2014–2022) for Stuck in the Middle



## Appendix Q: Action Plan Flowcharts

Maui Action Plan Flowcharts

Table Q-21. Maui Action Plan Complexities—Utility-Scale BEsS

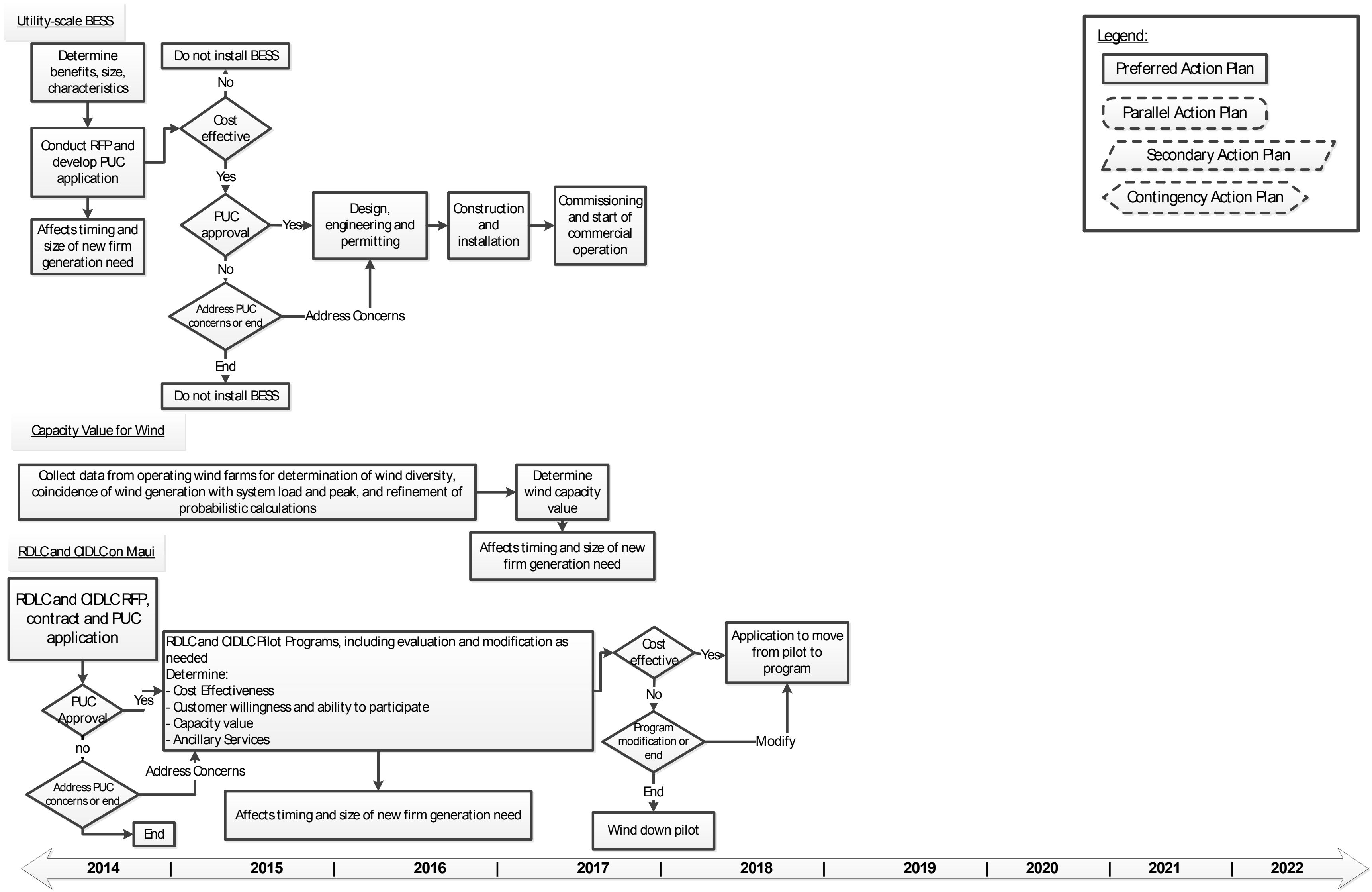
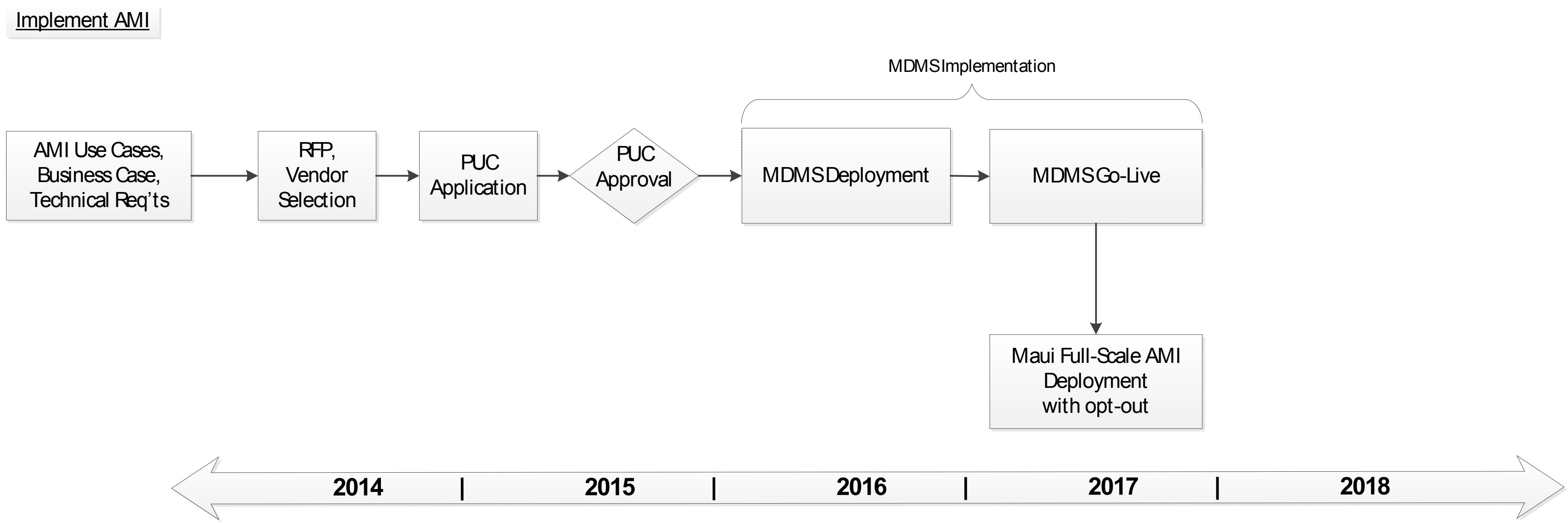


Table Q-22. Maui's Action Plan Complexities—Implement AMI



# Lanai Action Plan Flowcharts

The Action Plan flowcharts for Maui Electric demonstrate the complexity of its many resource plans for the island of Lanai.

Table Q-23. Overview of Lanai's IRP Action Plan

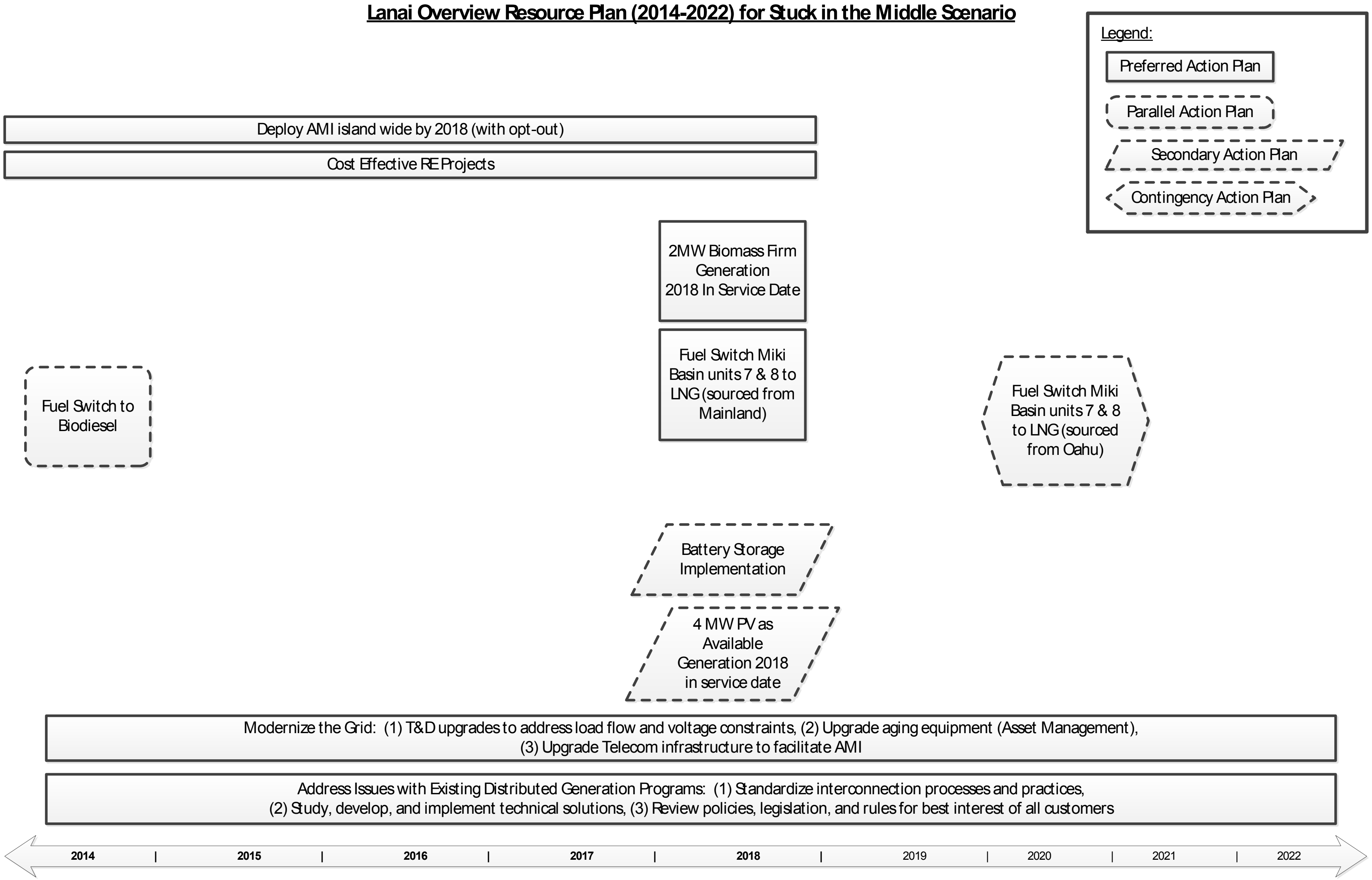


Table Q-24. Lanai's Preferred Resource Plan (2014–2022) for Stuck in the Middle

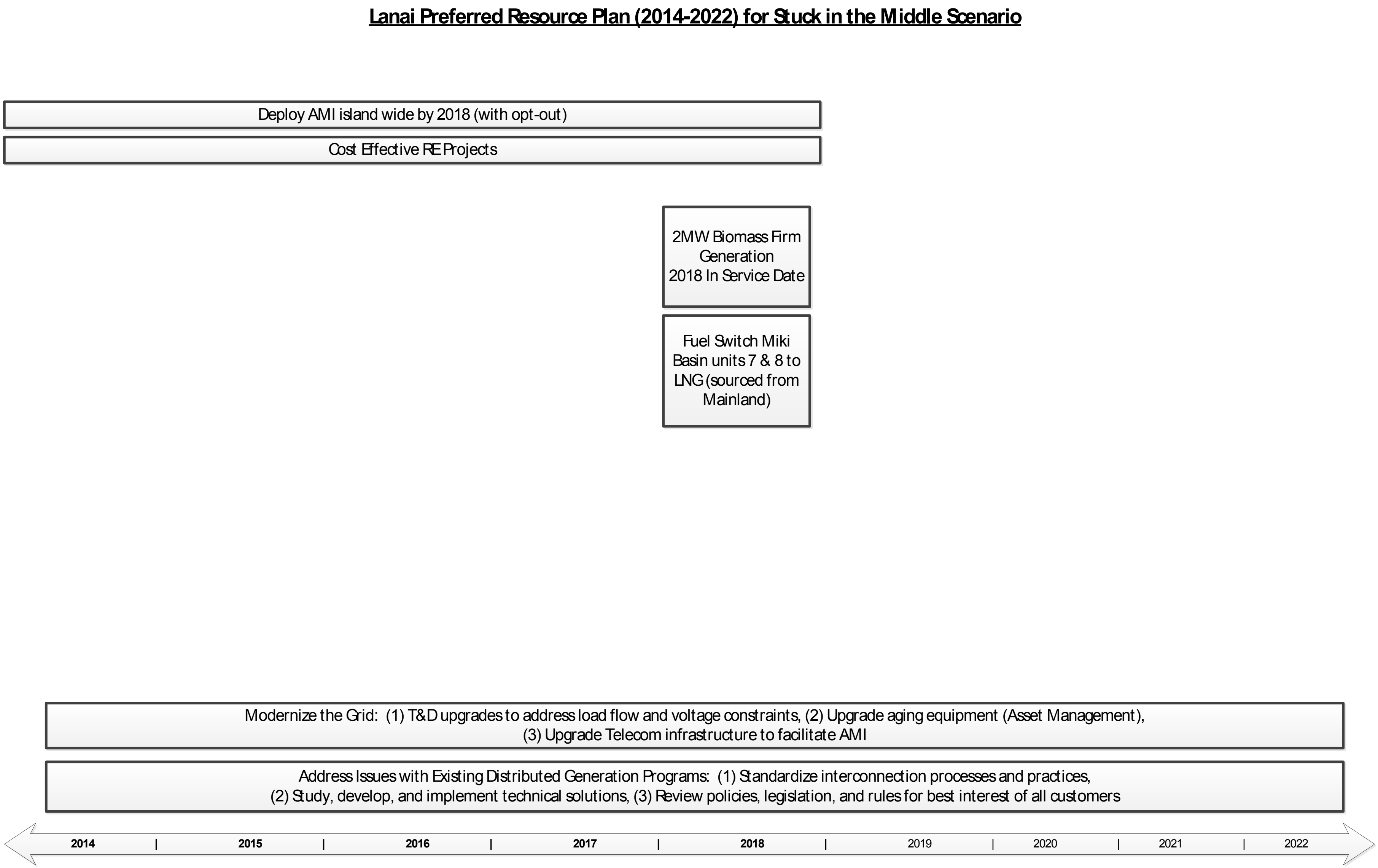


Table Q-25. Lanai's Parallel Resource Plan (2014–2022) for Stuck in the Middle

**Lanai Parallel Resource Plan (2014-2022) for Stuck in the Middle Scenario**

Table Q-26. Lanai's Contingency Resource Plan (2014–2022) for Stuck in the Middle

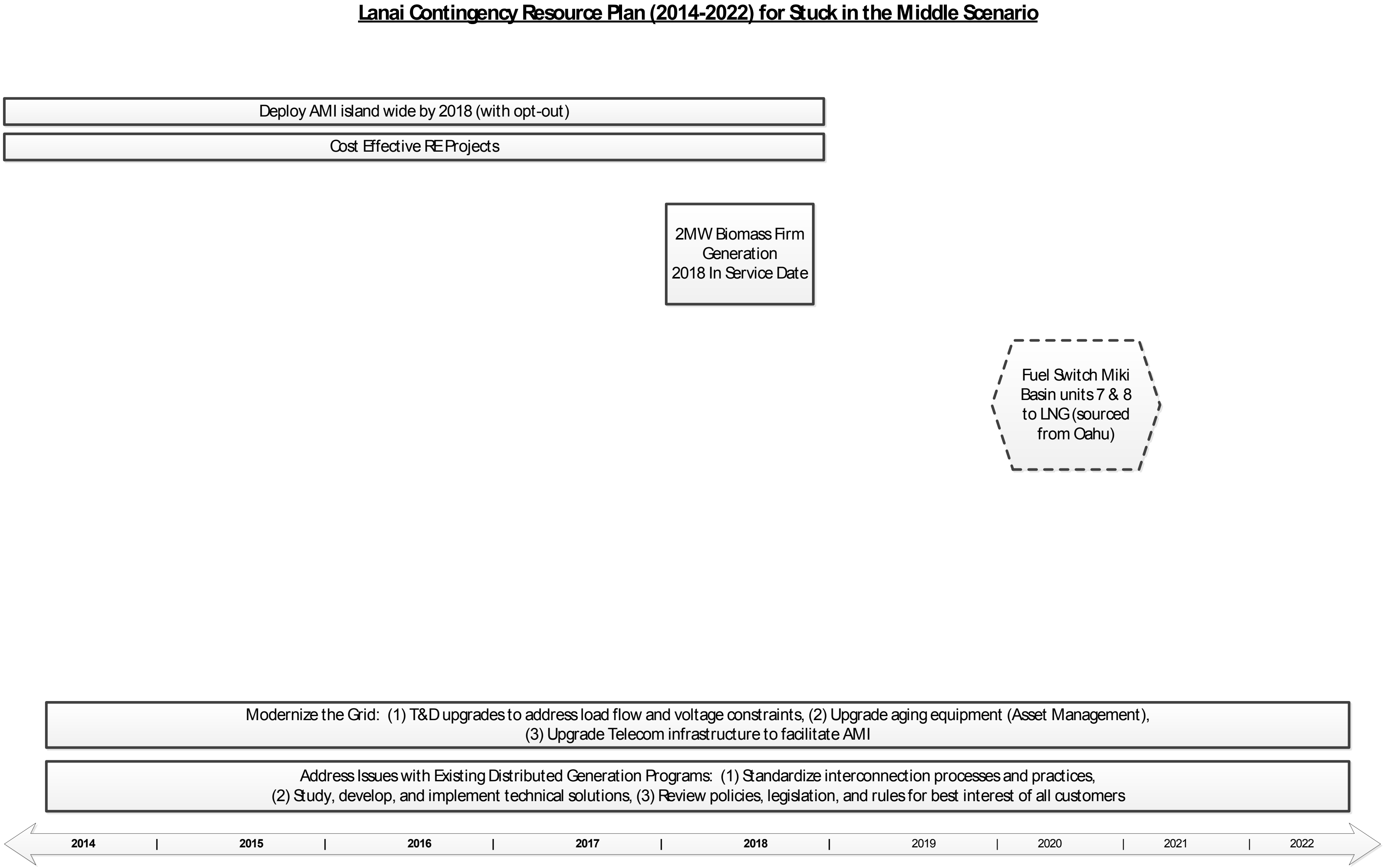


Table Q-27. Lanai's Secondary Resource Plan (2014–2022) for Stuck in the Middle

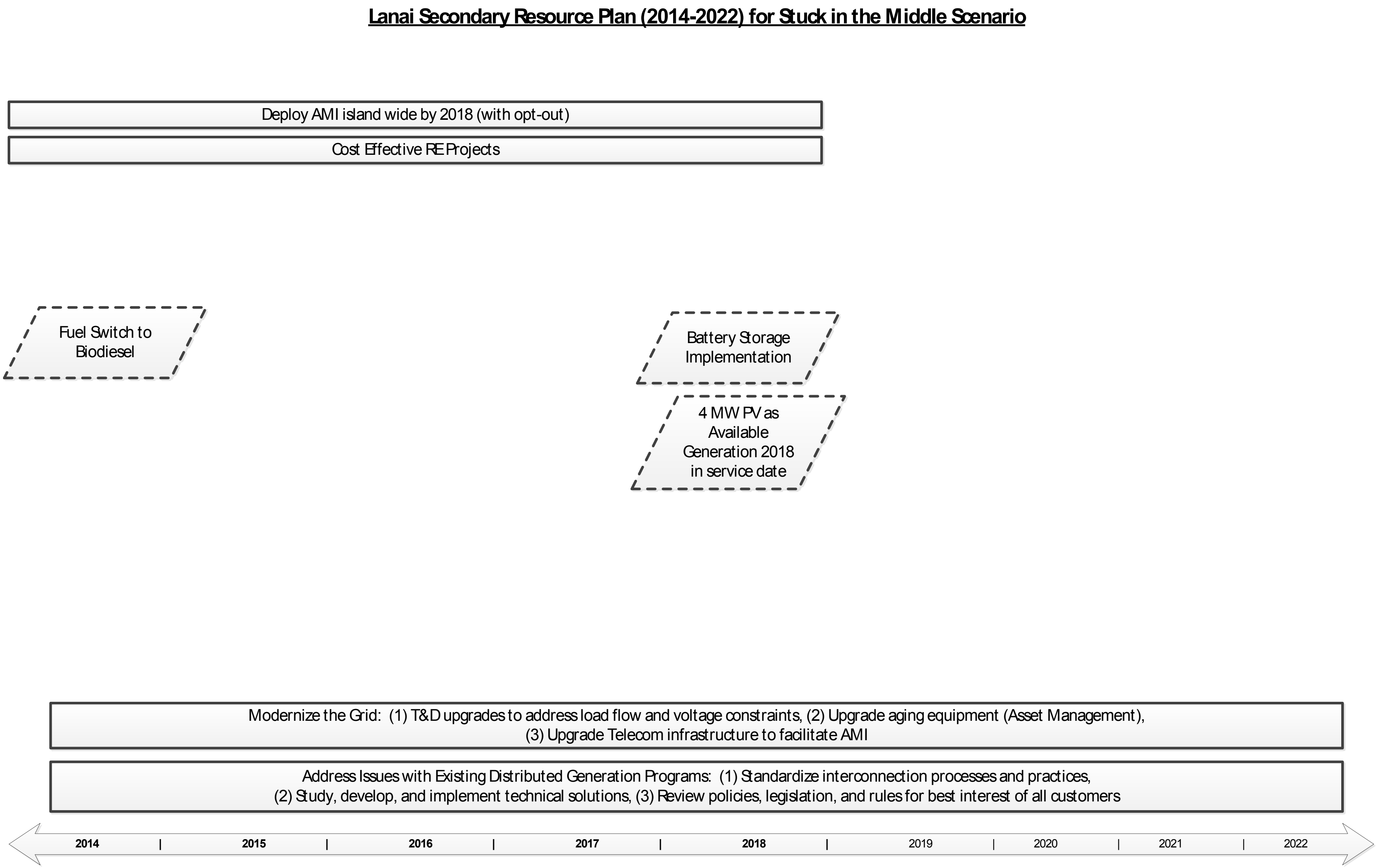


Table Q-28. Lanai's Action Plan Complexities—LNG

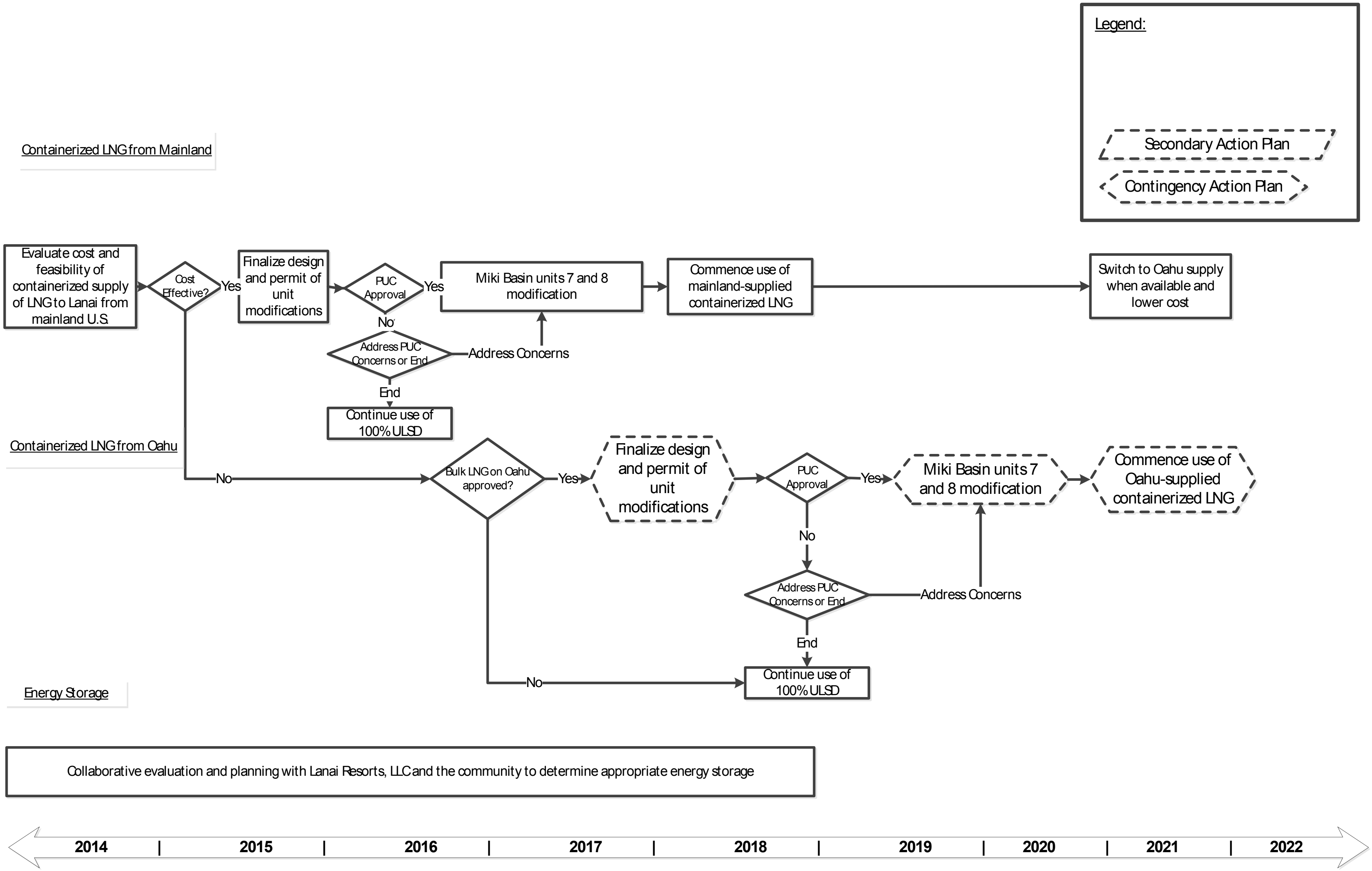
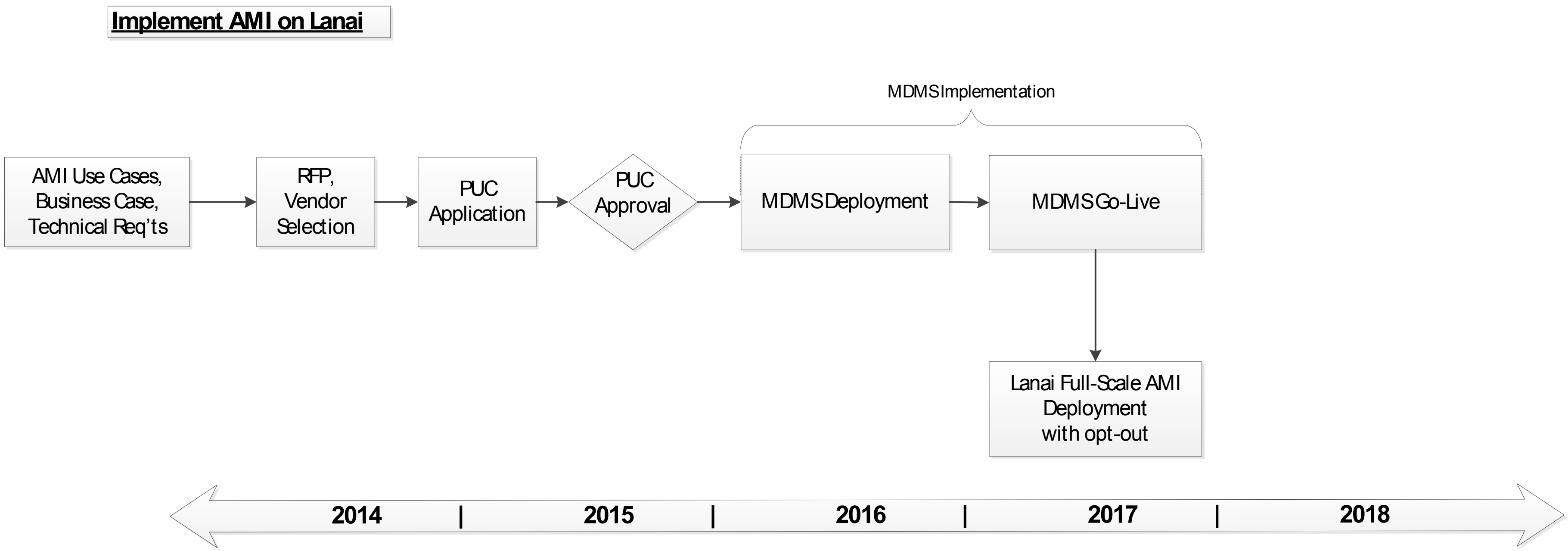


Table Q-29. Lanai's Action Plan Complexities—Implement AMI



# Molokai Action Plan Flowcharts

The Action Plan flowcharts for Maui Electric demonstrate the complexity of its many resource plans for the island of Molokai.

Table Q-30. Overview of Molokai's IRP Action Plan

**Molokai Overview Resource Plan (2014-2022) for Stuck in the Middle Scenario**

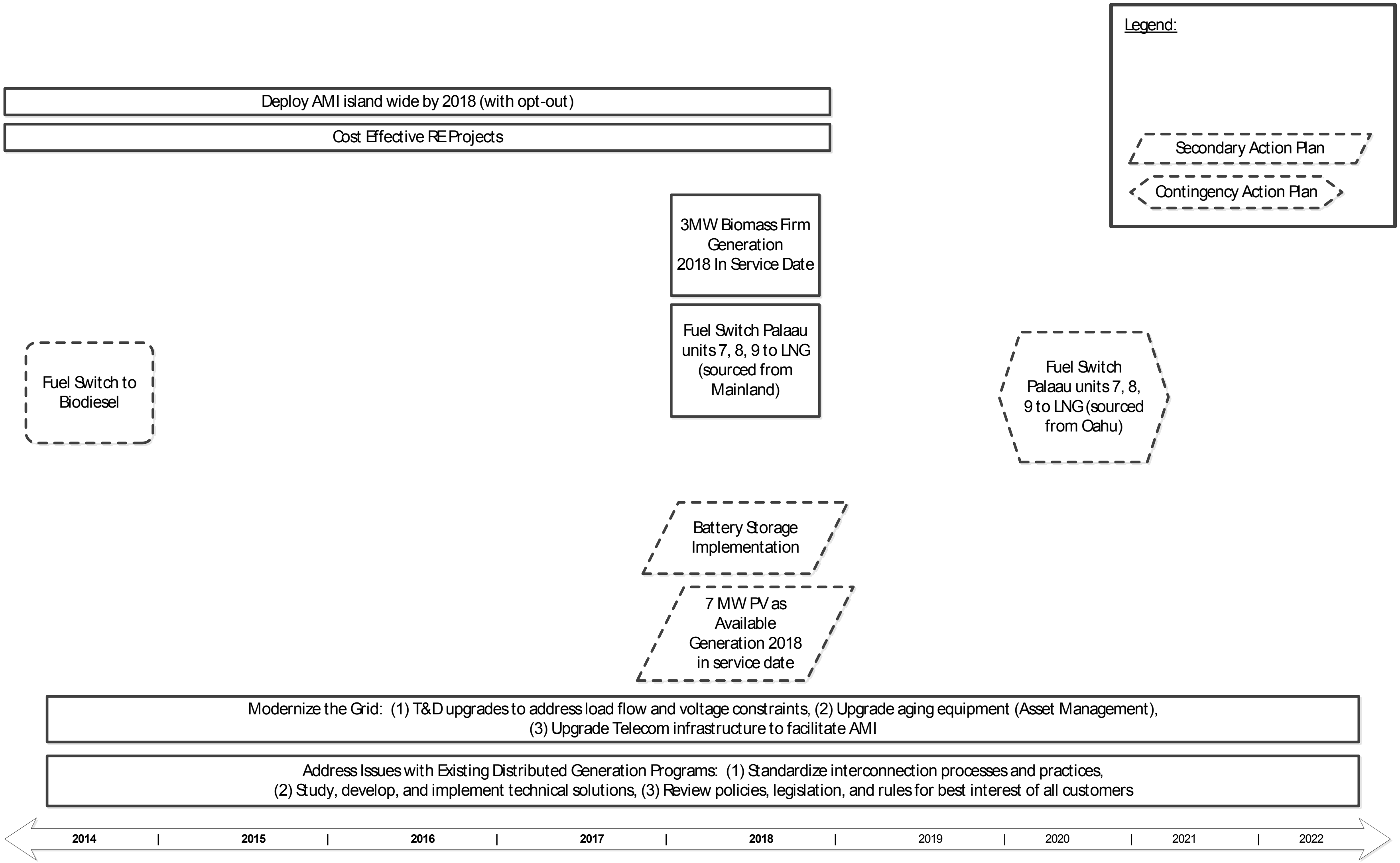


Table Q-31. Molokai's Preferred Resource Plan (2014–2022) for Stuck in the Middle

**Molokai Preferred Resource Plan (2014-2022) for Stuck in the Middle Scenario**

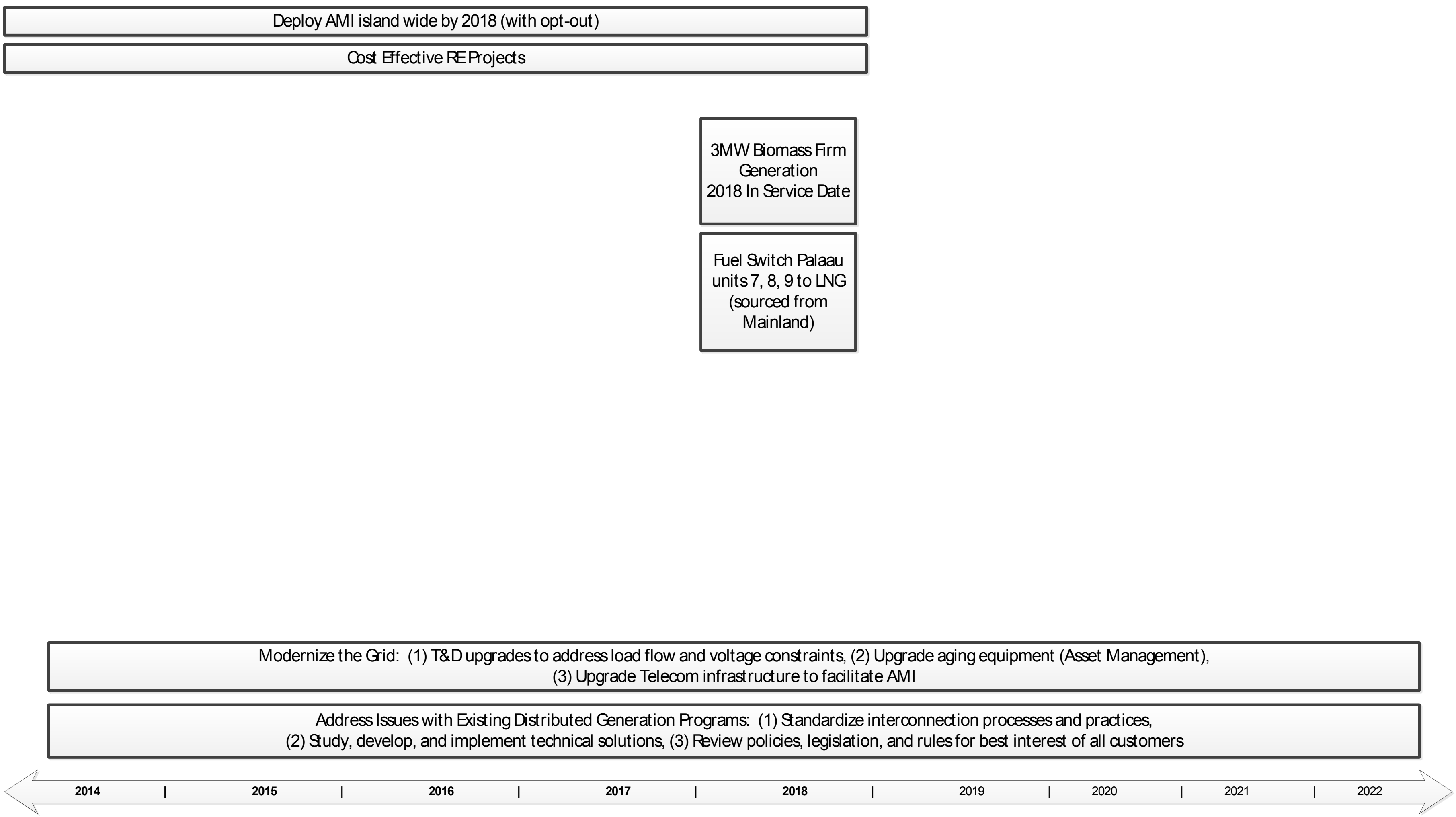


Table Q-32. Molokai's Parallel Resource Plan (2014–2022) for Stuck in the Middle

**Molokai Parallel Resource Plan (2014-2022) for Stuck in the Middle Scenario**

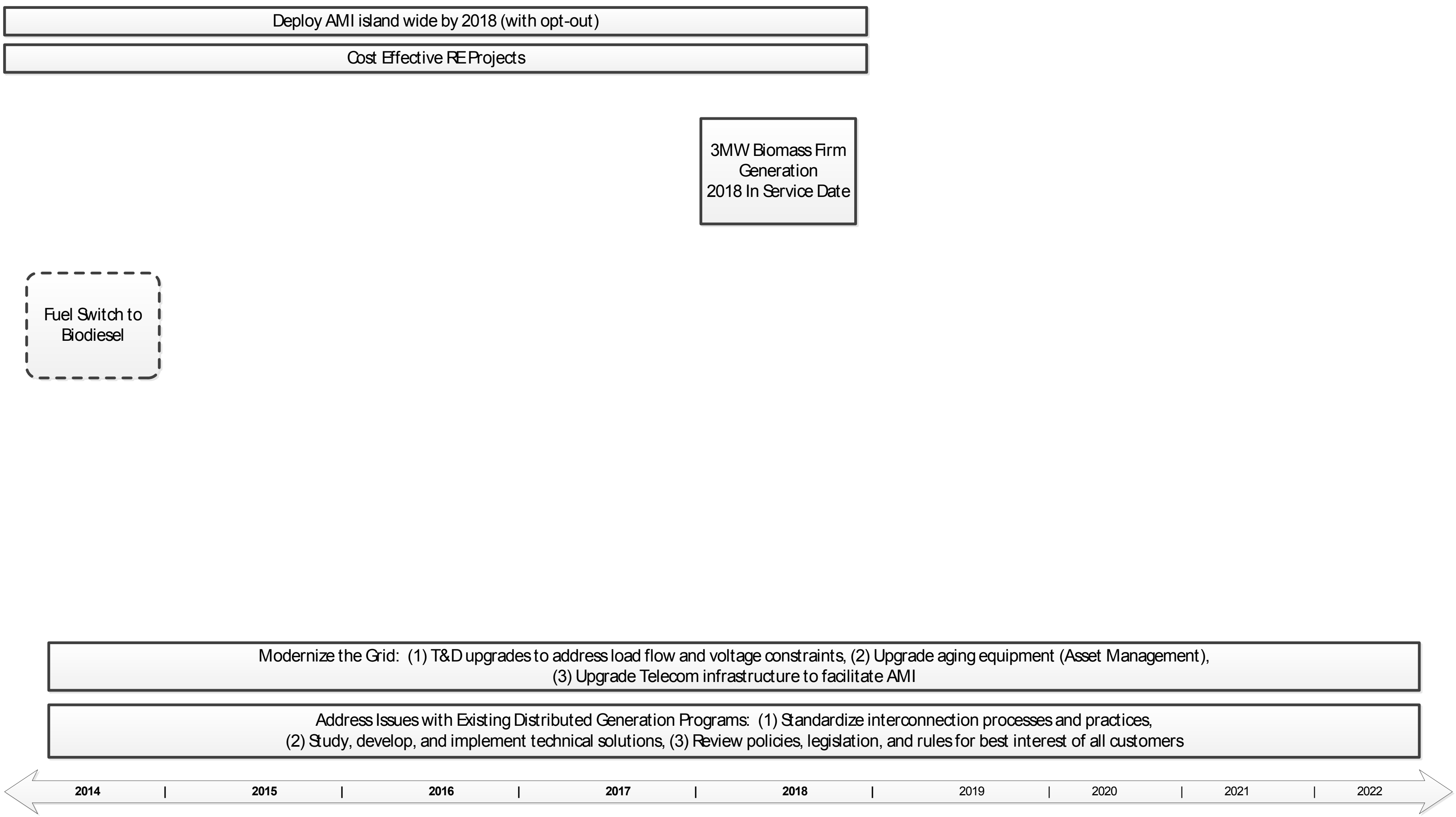


Table Q-33. Molokai's Contingency Resource Plan (2014–2022) for Stuck in the Middle

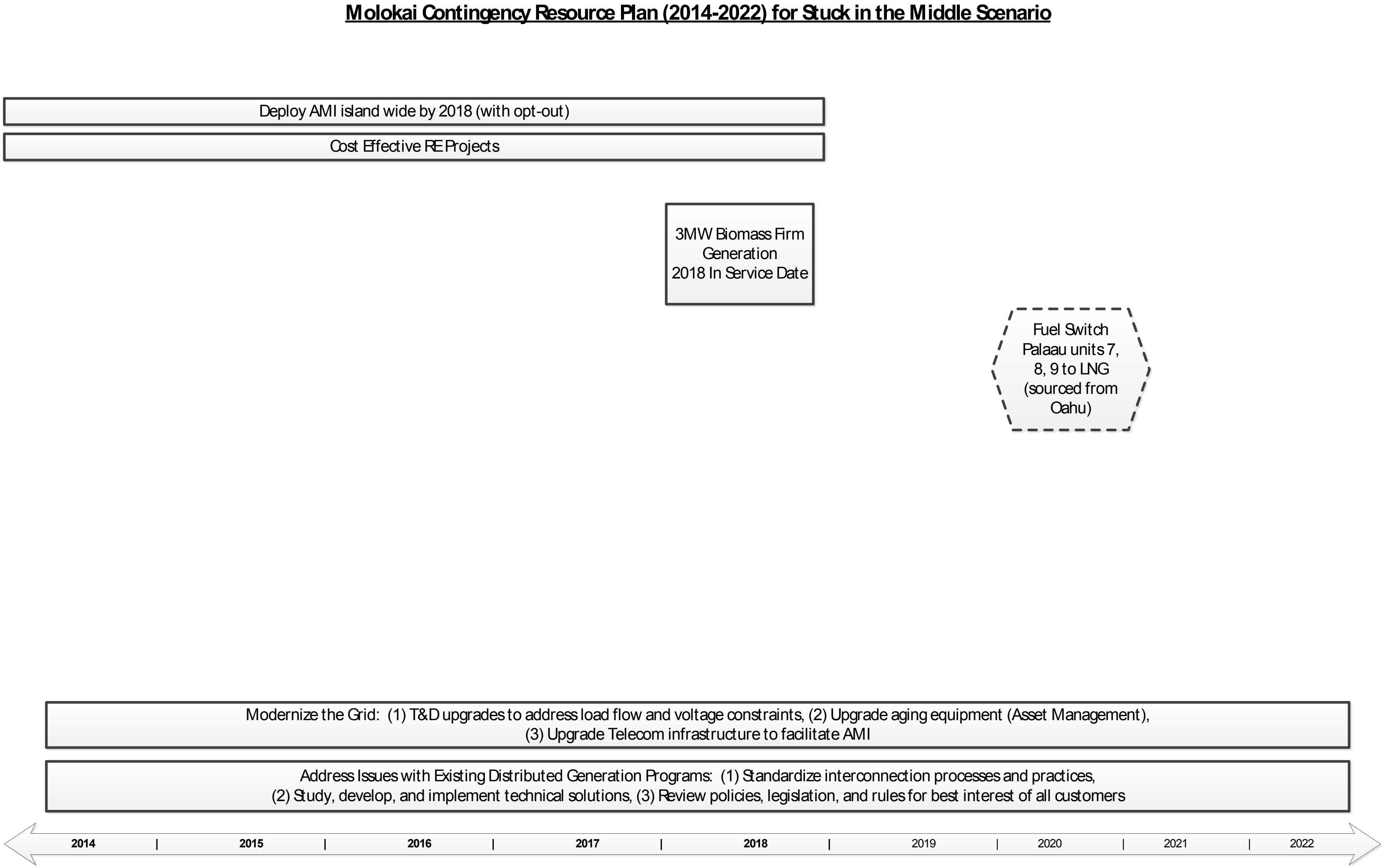


Table Q-34. Molokai's Secondary Resource Plan (2014–2022) for Stuck in the Middle

## Molokai Secondary Resource Plan (2014-2022) for Stuck in the Middle Scenario

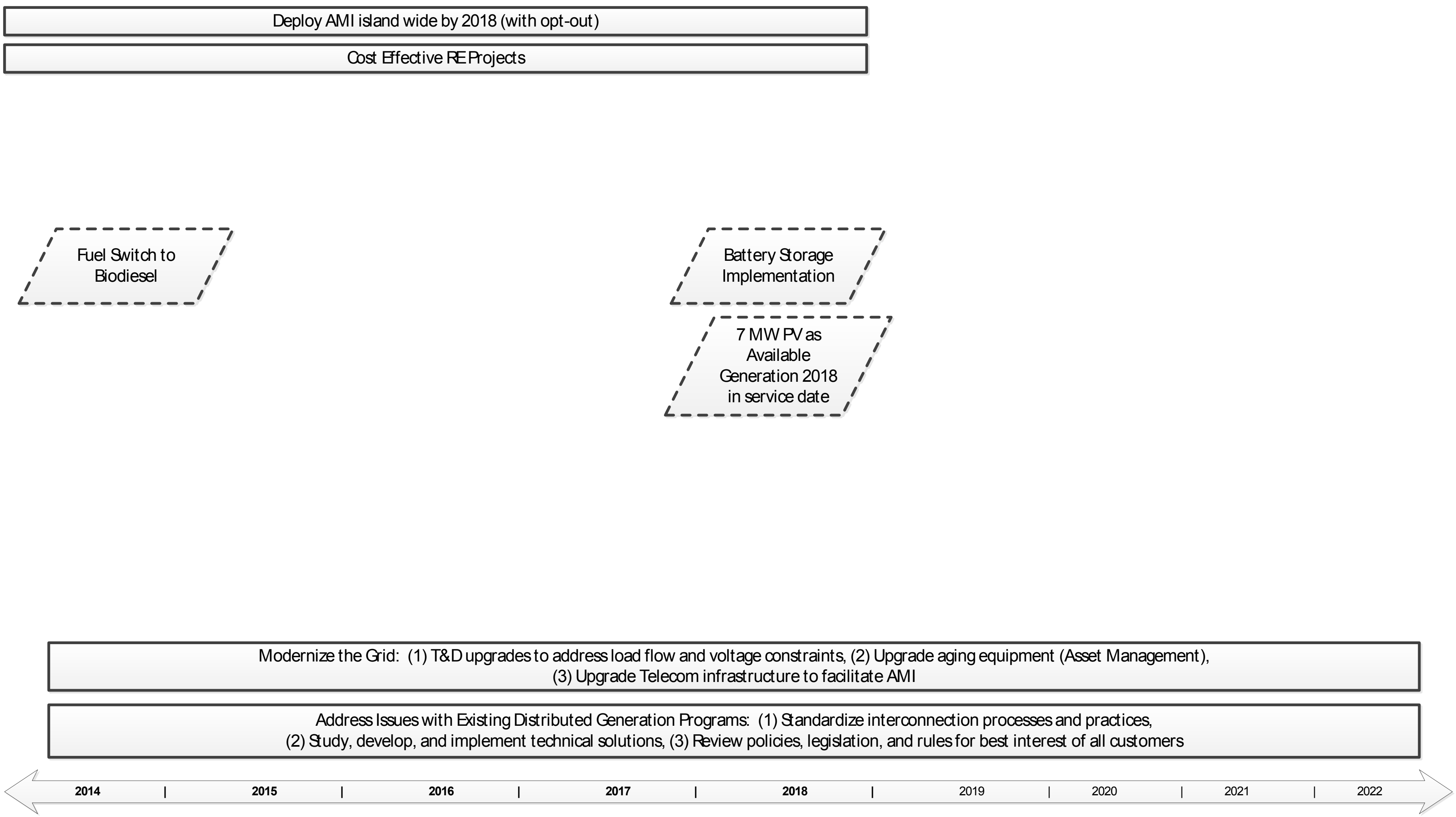


Table Q-35. Molokai's Action Plan Complexities—LNG

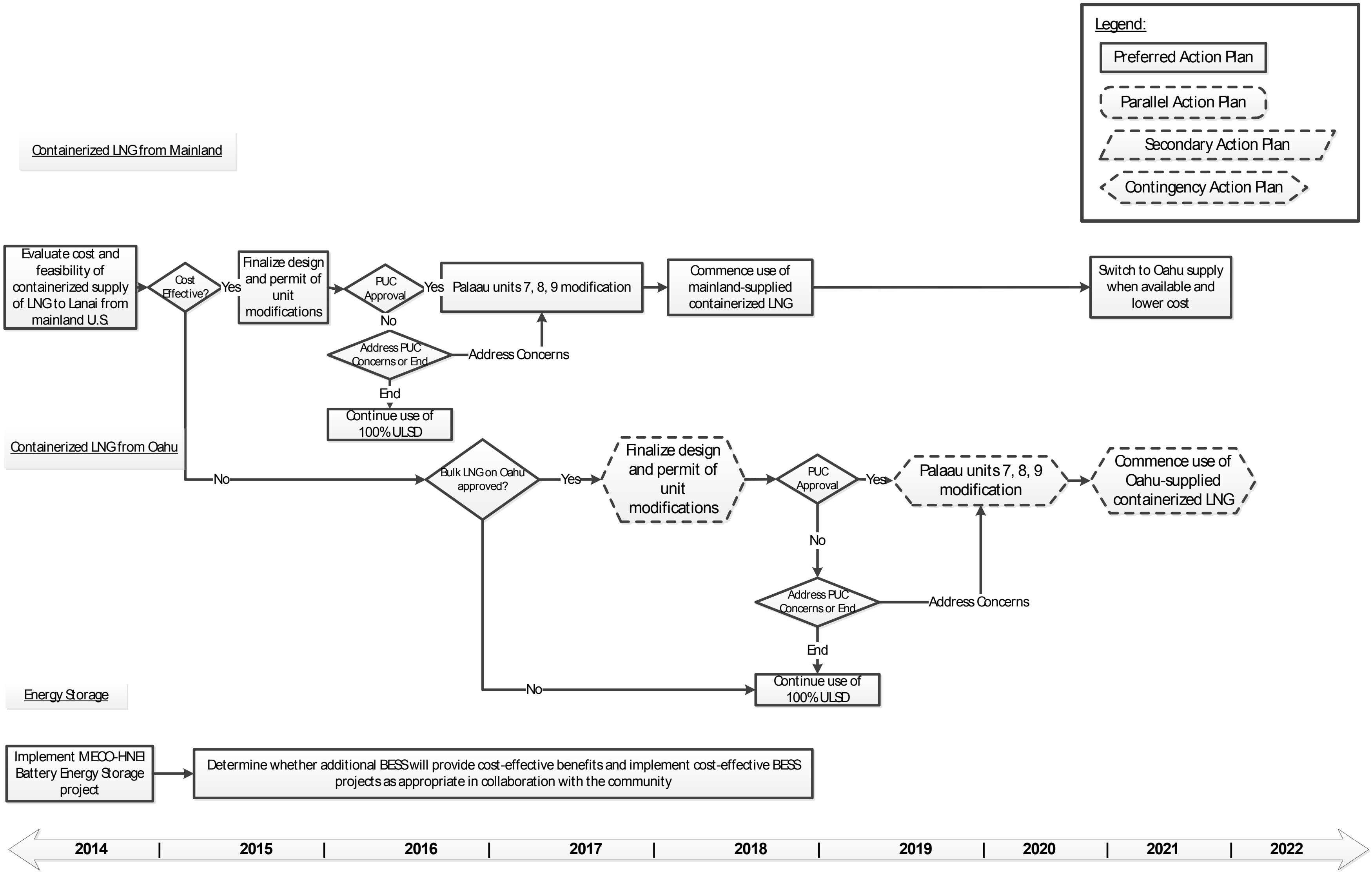
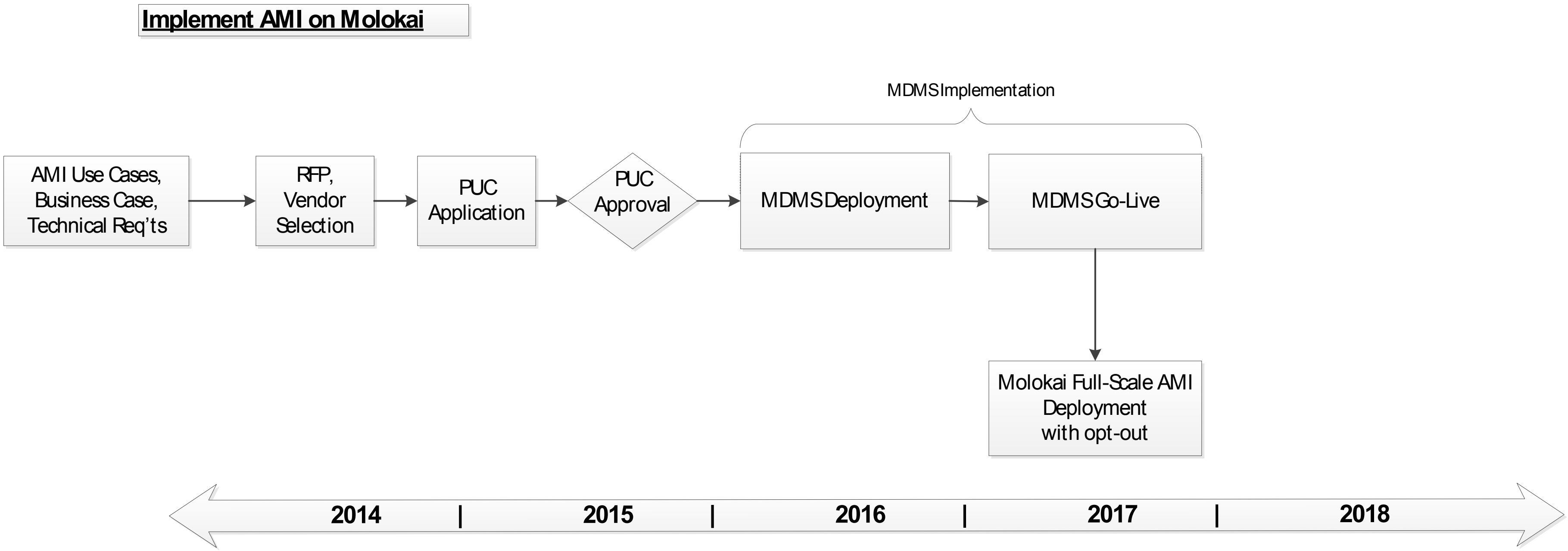


Table Q-36. Molokai's Action Plan Complexities—Implement LNG



[This page is intentionally left blank.]