Evaluation of Future Energy Technology Deployment Scenarios for the Big Island

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Evaluation of Future Energy Technology Deployment Scenarios for the Island of Hawaii

Executive Summary

ES 1: Project Overview

The State of Hawaii faces unique challenges in addressing its energy future. The State imports petroleum for the majority of the energy it consumes, making its economy vulnerable to oil supply disruptions and price volatility. This vulnerability, combined with a relatively small population, results in some of the highest electricity and gasoline prices in the nation. The Department of Energy, the Hawaii Natural Energy Institute, and the General Electric Company conducted a strategic energy analysis of the Big Island of Hawaii. The objective of this analysis was to inform State decision-makers on means to achieve clean, renewable, affordable, secure, and sustainable energy production. Since energy issues facing the state may eventually impact other parts of the country, this effort also provided information on resolving issues caused by the increased use of intermittent renewable resources in other parts of the nation. This effort assessed the economic, environmental and system performance impacts of three scenarios that incorporated increased renewable resources. In the effort's first phase, the electrical and transportation fuel infrastructures were modeled, calibrated, and validated against current conditions on the Big Island of Hawaii to establish an energy infrastructure baseline. In the second phase, a new baseline was established for the year 2018 consistent with the Hawaii Electric Light Company (HELCO) Integrated Resource Plan-3[1]. Three different electricity infrastructure scenarios were developed utilizing the IRP-3 as the baseline. The impact of each scenario was assessed and compared against the 2018 baseline using two modeling tools:
(1) GE MAPS™ Production Cost Simulation, used to assess unit commitment, unit dispatch, operating economics and the environmental impact for each scenario; and
(2) GE PSLF™ Dynamic Simulation, used to assess grid stability and dynamic performance in response to grid events and/or the variability of renewable energy.

These tools were used to assess the economics, environmental impact and performance of each electricity infrastructure scenario for various timescales of power system operation:

- Seconds-to-minutes (regulation and frequency control),
- Minutes-to-hours (load following, balancing), and
- Hours-to-days (unit commitment, day-ahead forecasting and schedules).

The types of analyses performed in this study were similar to other renewable energy studies performed for WECC, ERCOT and the NYISO. This study incorporated additional dynamic modeling to represent frequency control in the minute-to-hour time frame, in order to evaluate the impact of variable renewable energy resources on system frequency control and balancing.

[1] Hawaii Electric Light Company, Docket No. 04-0046, Integrated Resource Plan, May 31, 2007.

HELCO provided data on system operating rules and power plant characteristics, and high quality system data collected from their SCADA/EMS system. This information was used in the development, calibration, and validation of the initial power system models. The results of this validation exercise were presented in an earlier report[2]. Both the dynamic and production cost models provided a good representation of the Big Island grid. The production cost simulation results were within 1% of the actual historical 2006 energy production by fuel type. In the validation phase, dynamic model simulations accurately reproduced multiple one-hour traces of system frequency for a typical generation mix for three different load periods (minimum load, daytime load, and peak load). These results were used to evaluate the effectiveness of the model for various system response conditions. These analytical tools were used to assess the impacts of the technologies proposed in the scenarios on the electricity grid.

After developing a set of validated system models, three scenarios were analyzed using the simulation models. For analysis that involved annual production simulations using MAPS, the results of each simulation were compared against the 2018 baseline, titled the "Baseline Scenario" that includes a 220 MW average daily peak load, 32.5 MW of wind generation (9% of total energy production), and 30 MW of geothermal generation (14% of total energy generation). The study used assumed data for wind and hydro production in the analysis of future scenarios, based on observed data from the HELCO system. The analysis also required assumptions about how the system performed frequency control and dispatch with future generation additions. The calibrations were performed using year 2006 data.

ES 2: Scenario Overview

The following sub-sections provide an overview of each of the three scenarios. In the *Enhanced Energy Management* scenario the load profile was modified to reflect increased energy efficiency, combined heat and power, and plug-in hybrid electric vehicles (PHEVs) resulting in an aggregate reduction in peak load of around 24 MW. In the *Higher Wind Penetration* scenario, the wind energy penetration was augmented via expansions of the Apollo, Lalamilo and Hawi wind plants to a total capacity of 84.5 MW of wind power. In the *Higher Geothermal Penetration* scenario, the geothermal capability of the island was augmented with 12 MW of baseload capacity, and 16 MW of load-following capability.

ES 2.1: Enhanced Energy Management Scenario

The *Enhanced Energy Management* scenario leveraged energy efficiency, combined heat and power (CHP), and PHEVs to manage the load profile. The energy efficiency technologies included residential, commercial and resort components. Each component was represented by a specific MW reduction at peak, and scaled MW reductions (by the ratio of load / daily peak) for each hour across a given time period. In particular, the residential component achieved a 6 MW reduction at peak and scaled reductions between 6 AM and 1 AM. The commercial component projected a 4 MW reduction at peak and scaled reductions between 7 AM and 10 PM. The resort component projected a 7 MW reduction at peak and scaled reductions between 6 AM and 12 AM. The combined heat and power deployment was modeled as a uniform 7 MW reduction between 6 AM and 10 PM. The PHEV fleet (assumed to be 10% of the passenger cars) was capable of "smart-charging." These changes created the effect of filling the nighttime load

[2] Assessment of Electric and Transportation Infrastructure for the Big Island, Electrical Power System Performance Report, DOE Program DE-FC36-04G014248, March 30, 2006.

valley. The algorithm scheduled the vehicle charging based on the previous day's peak and average system load.

ES 2.2: Higher Wind Penetration Scenario

The *Higher Wind Penetration* scenario augmented the 2018 baseline scenario by expanding the three existing wind plants. The Apollo wind plant was increased from 20.5 MW to 42 MW, assuming a continuation of the same power purchase agreement (PPA) framework as the existing contract between Apollo and HELCO. The Hawi wind plant was increased from 10.5 MW to 20.6 MW, again assuming a continuation of the same PPA framework in place for the existing plant. The HELCO-owned wind plant at Lalamilo was expanded from 1.5 MW to 22.1 MW with modern wind turbines. The purpose of the proportional scaling was to model a proportional increase in system variability (second-to-second and minute-to-minute) in order to evaluate the impact on system balancing and frequency control. The impacts on transmission system loading were not evaluated, as it is known that there are transmission infrastructure limitations which could preclude the simple scaling identified here. The scenario studied the possibility of utilizing rapid-response storage to increase capabilities for frequency regulation and load balancing to offset the variability introduced by the wind energy.

ES 2.3: Higher Geothermal Penetration Scenario

The *Higher Geothermal Penetration* scenario assumed the development of a privately-owned geothermal facility at Hualalai with 10 MW of baseload capability and 10 MW of load following capability. In addition, the Puna Geothermal Venture geothermal facility was expanded with an additional 8 MW (2 MW of baseload and 6 MW of load following). The analysis assumed the same pricing terms were in place for the existing Puna Geothermal Venture contract, tied to the quarterly avoided cost. It should be noted that in a recent agreement between the state and the utility, future PPAs for geothermal electricity are unlikely to be tied to the utility's avoided cost. The dispatchable portion was assumed not to be must-take. While the existing geothermal plant is not controllable by the Automatic Generation Control (AGC) and does not exhibit droop response, the new geothermal units were assumed to provide inertial response, droop response, and governor response for the entire range similar to that of the existing oil-fired steam plants. This could potentially enable the relaxation of must-run rules presently being enforced for some of the oil-fired steam plants.

ES 3: Conclusions

The comparison between the projected IRP-3 2018 baseline scenario and the three future scenarios on imported petroleum, reduction in CO_2 emissions, and the amount of renewable electrical energy delivered are shown below, comparing the projected 2018 baseline with the scenario result. The results are for the electricity sector only. The three scenarios increased the renewable energy content relative to the base line scenario and reduced the amount of imported petroleum emissions in the electricity sector.

	Energy Security Imported Petroleum Reduction (%)	Environmental CO_2 Emissions Reduction (%)	Sustainability Renewable Energy Delivered (%)
Baseline	0%	0%	27%
Enhanced Energy Management	6%	6%	28%
Higher Wind Penetration	15%	14%	39%
Higher Geothermal Penetration	11%	10%	36%

It should be noted that the actual renewable energy delivered in 2006, the baseline year for model validation, to the utility was approximately 24% and grew to 32% by 2008. The baseline scenario developed in 2006 included limited growth in renewable energy as projected in HELCO's IRP-3 filing at the time. By 2008, renewable energy development exceeded the projected trend as the penetration level increased considerably. However, the analysis maintained assumptions consistent with HELCO's projections at the time of the IRP-3 filing. For more on recent trends, see the Appendix.

ES 3.1: Enhanced Energy Management Scenario

The *Enhanced Energy Management* scenario consisted of energy efficiency programs and combined heat and power to reduce system load, and plug-in hybrid electric vehicles to increase off-peak (nighttime) load.

ES 3.1.1: Energy Efficiency and Combined Heat & Power (CHP)

- *Variable cost:* Energy efficiency and CHP reduced peak load and overall electricity consumption. By displacing the most-expensive generation dispatched to meet peak load, the average system variable cost ($/MWh) decreased by 1%. Subsequent reductions in peak load (due to the various energy efficiency programs) further decreased the variable cost. However, the benefit of the variable cost reduction diminished. The estimated variable cost savings is sensitive to the assumptions about displaced peaking generation and fuel costs.

ES 3.1.2: Plug-in Hybrid Electric Vehicles (PHEVs)

- *Electricity generation:* 10% of the passenger car fleet translated into 73 GWh/yr of new electricity sales from combined cycle (~56 GWh), oil-fired steam (~10 GWh), and wind power (~5 GWh) plants. An additional 3% of wind energy was delivered to the system by reducing wind plant curtailment.
- *Integrating as-available renewables:* With no additional changes in HELCO's system, further expansions in wind power will increase the amount of wind curtailment, particularly during the off-peak nighttime hours. PHEVs that charge during those periods will decrease the amount of wind curtailment required. However, managing system stability would still remain as an operational constraint to integrating more as-available renewable resources.

- *Fossil fuel consumption:* In order to serve the additional load from PHEVs, the fossil fuel consumption in the electricity sector increased. However, switching from transportation fuel to electricity for PHEVs reduced the island-wide net fossil fuel consumption to serve these vehicles by 20%. Therefore, less fossil fuel is consumed in the production of electricity to serve PHEVs than the amount of transportation fuel consumed in similar gasoline-fueled vehicles. Gasoline prices were assumed to be $3.50 per gallon.
- *Variable cost*: Using a smart charging algorithm that charges PHEVs during the off-peak hours, the average variable cost to serve the additional load decreased by 12%. The utility incremental variable cost of serving the additional PHEV load is 54% lower than the cost of the gasoline borne by the owners of gasoline-fueled vehicles[3]. The benefits associated with PHEVs have the potential to cover the costs of the incremental charging infrastructure needed for the deployment of PHEVs and translate into savings for both the PHEV end user and HELCO. The magnitude of the variable cost savings is sensitive to the assumptions about generation dispatched to serve the increased off-peak demand and fuel cost.
- *Emissions:* PHEVs are nearly CO_2 neutral as a result of reducing transportation fuel consumption and increasing electricity consumption.
- *Dispatchable load:* Uncontrolled charging could pose significant operational challenges due to sudden increases in load. Utility control of the dispatchable load in the case of demand-side management and PHEVs provides system-operating benefits, especially if increased system flexibility is needed to enable higher penetrations of variable renewable energy. Demand response on the HELCO system would require new communications and controls infrastructure as well as system management capabilities by the utility control system.

ES 3.2: Higher Wind Penetration Scenario

The *Higher Wind Penetration* scenario consisted of substantial expansion of the wind plants at Hawi, Apollo and Lalamilo. Three primary impacts of increasing wind power penetration were observed:

1. *Fast-timescale wind variability:* Increasing wind penetration deteriorated the frequency performance due to sudden drops in wind power production.
2. *Slower-timescale wind variability:* Increasing wind penetration increased the need for flexible generation and fast-starting generation capable of increasing power production in response to sustained reductions in wind power production.
3. *Curtailment of wind power:* Wind power curtailment is a controlled reduction in power output at the wind plant, typically resulting from excess energy production. Increasing wind penetration increased wind power curtailment unless new technologies or operational practices were incorporated to reduce the excess energy situation.

ES 3.2.1: Fast-timescale Wind Variability

The Baseline scenario (BaU) simulated the largest wind-ramping-down event. This window may not be representative of the worst-case penetration observed, but was a reasonable variability case for comparisons between scenarios. HELCO provided historical data on a significant wind

[3] Gasoline price assumed to be $3.50/gallon.

power fluctuation event that was used for the baseline validation exercise. With limited data available, statistical analysis to determine severity of correction was not possible. The wind power reduction observed in the historical window was scaled up proportional to the size of the wind plant to reflect the expansion of the wind plants.

For the simulated one-hour window, the RMS frequency deviation nearly doubled between the Baseline scenario and the Higher Wind Penetration scenario. This indicates that significant frequency variability was observed when the wind power increased from 32.5 MW to 84.5 MW. In the simulation, the system frequency excursions associated with significant wind power variations were mitigated primarily by the steady-state droop response of the governors and the AGC regulation function. The simulation results suggest that system inertia was of secondary importance in addressing frequency deviations due to wind variability. The distribution of reserve among the regulating units that respond to the wind events had significant impact on the system frequency performance as did the degree of droop response (speed and droop setting) in mitigating the frequency impact of second-to-second variability.

In the simulations, stabilization devices (e.g., energy storage, other fast-reacting resources), flexible thermal generation with high ramp rates, and wind plant controls reduced the frequency performance issues associated with the fast-variability of the wind power. It should be noted that the mitigation measures that were evaluated use technologies that are commercially available today. However, these technologies are relatively new in their application in the electric utility industry. Thus, the model analysis used technical characteristics of the technologies and not empirical data. The following sections describe the results:

- *Stabilization Devices:* A simulation was performed with a stabilizing device with assumed fast-reacting, high-performance response characteristics. Stabilizing devices with assumed characteristics of 5 MW of power and less than 15 min of energy (i.e., 1 to 2 MWh of energy) reduced the variability of the system frequency for the Higher Wind Penetration scenario. The second-to-second performance was similar to or better than that of the Baseline scenario. Smaller stabilizing devices (e.g., 2 MW) also offered substantial improvements in frequency performance. Only stabilization devices using energy storage were evaluated. Other technologies that meet the power and energy requirements could also be suitable but were not studied.
- *Advanced Thermal Generator Controls*: Operating fast-reacting thermal generation units using information about wind power fluctuations (instead of responding to frequency droop) can result in better frequency performance. The thermal units can respond to the wind event before the loss of wind power production manifests itself in a frequency excursion.
- *Wind Controls for Up Regulation*: Some wind turbines can mitigate under frequency events (loss of generation) by increasing their power output. To achieve that, these turbines must initially operate below maximum available wind power. The use of this control option can increase the available up-regulation capability of the system.
- *Wind Controls for Down Regulation:* Some wind turbines can mitigate over frequency events (loss of load), by decreasing their power output. This control could potentially reduce the need for down-reserve allocation in thermal units under light load conditions and the associated curtailment in wind power production. This is particularly important for systems such as HELCO's where there are many hours of

- *Wind controls for smoothing*: Some wind turbines can use turbine controls to mitigate variability by smoothing electricity output to the system. This can reduce the second-to-second variability which is difficult to mitigate on the power system.

Improved system frequency performance achieved by these technologies could reduce incremental costs (e.g., poorer heat rate, wear and tear) to thermal units for the additional maneuvering required to meet fluctuations in wind power and result in improved system frequency control. These costs have not been quantified but exist due to the need for a greater number of generator controls for high wind penetrations due to frequency regulation, both from the droop response and supplemental frequency control through AGC. HELCO has found that the second-to-second variability of wind required an increase in the no-control deadband in order to avoid over-control by the supplement automatic generation controls for frequency correction. The addition of the wind plants significantly increased the frequency error on the system.

ES 3.2.2: Slower-timescale Wind Variability

The second timeframe of importance is the minute-to-hour timescale to address sustained wind power reductions. Increasing the penetration of variable generation, such as wind power, on the HELCO grid requires increased generation flexibility on this timescale. Spinning reserves can be maintained online to counter for loss of wind energy through sustained down-ramps. However, carrying additional spinning reserves contributes to minimum load requirements and excess energy problems. Another option, if available, is to utilize fast-starting generation. Both of these strategies for mitigating variability increase fuel and O&M costs and incur start up costs for the fast-starting generation.

Energy storage is another option for bridging the gap between a shortfall in up reserve caused by a sustained drop in wind power production and/or increase in load.

- *Energy Storage as Reserve*: With a 5 MW, 2 MWh energy storage system, the Higher Wind Penetration scenario achieved the same reserve performance as the Baseline scenario in the simulated events used for the analysis. Performance was measured in terms of the number of hours in which the up reserve of the committed generation was unable to meet the rise in load/decrease in wind power production, as well as the magnitude of the shortfall.
- *Energy Storage as Bridge to Fast-starting* Generation: One of the functions of the energy storage device is to allow time for operators to bring diesel or other fast-start generation on-line. The size of the energy storage device determines how much time a system operator has to decide whether or not to start additional generation in response to a potentially short-term drop in wind power. An additional issue in using these devices is a need for a mechanism to alert the system operator when the storage has completely discharged (or nearly so) and to start up standby generation.

The study concluded that incorporating wind power forecasting in the unit commitment strategy reduces fossil fuel consumption by the regulating units and minimizes wind plant curtailment. A wind power forecast was included in this scenario. It was based on the average daily wind power production for the prior year. This unrefined forecast offered benefits in terms of reducing fuel consumption and wind plant curtailment. Since the completion of this study, HELCO has implemented a forecasting strategy in its commitment decisions and methods for improving wind forecasts remains an area of significant research and development.

ES 3.3: Higher Geothermal Penetration Scenario

The *Higher Geothermal Penetration* scenario assumed the development of the Hualalai geothermal plant with 10 MW of baseload capability and 10 MW of load-following capability. Puna Geothermal Venture was expanded with an additional 8 MW (2 MW of baseload and 6 MW of load following). The new geothermal plants were assumed to be must-run at minimum load, to be under AGC control, and to provide similar droop response as existing oil-fired steam plants. Two sensitivity analyses were performed for this scenario.

- *Puna 2 Retirement:* The retirement of the Puna 2 steam plant and the addition of new geothermal energy reduced fuel consumption by 6% compared to the Baseline scenario. The retirement had no significant impact on variable cost because the PPAs were coupled to an avoided cost based on fuel price. A different PPA would result in a different variable cost impact.
- *Fuel Price Increase:* A 50% increase in fuel prices substantially increased variable costs for both the Baseline scenario and Higher Geothermal Penetration scenario. However, the increase in variable cost was more substantial for the Baseline scenario. If the PPA is decoupled from the fuel price, new geothermal power that displaces fossil fuel generation is a hedge against oil-price fluctuations.

ES 4: Recommendations

This study would not be possible without significant engagement from the utility project teams. The development and validation of the dynamic and production cost models were made possible by the recorded data provided by the utilities. The recommendations of this study are intended to provide HECO, HELCO, and the state with an independent perspective on some of the technology options, operating strategies, and regulatory measures needed to enable a clean, affordable, secure, and reliable energy supply. The implications of this study are also useful in informing DOE and other utilities in the country.

The following recommendations are summarized below.

- *System Heat Rate:* Degradation of the system heat rate is inevitable with an increased penetration of variable renewable energy due to the need to retain dispatchable resources on the system, which are operated at less economic and less efficient levels. The State of Hawaiʻi Public Utilities Commission (PUC) should recognize this inevitability and incorporate it into their evaluation of the utility's heat rate performance. Another option to avoid this is to select dispatchable renewable resources to minimize heat-rate impacts.
- *Unit Commitment and Dispatch:* Integrating additional variable renewable energy resources will require changes in HELCO system operating practices as well as changes to existing thermal generation assets to increase their flexibility. The PUC should allow for capital recovery of reasonable investments in existing thermal plants that provide the operational flexibility needed to enable higher penetrations of renewable energy. Furthermore, there will be times when fast-start generation is brought on-line due to a sustained loss of wind power

- *Must-Run Rules:* The simulations incorporated scenarios including HELCO's present system operating rules and scenarios removing some of the must-run rules. The analysis shows that the current must-run rules maintain a higher level of system reliability when more variable renewable energy is added to the system without additional mitigation efforts. However, the current rules also result in significant costs in terms of fuel consumption and curtailment of renewable energy. As HELCO's system evolves in the future, the utility should periodically review the need for the current operating rules. As technologies to mitigate the variability of renewable energy improve and HELCO incorporates new firm generation in its system, HELCO may have new options that maintain the same level of reliability but with lower fossil fuel consumption and/or lower operating costs.
- *Commitment and Wind Power Forecasting:* The analysis demonstrates that incorporating rudimentary forecasts of wind power in comparison to no forecast yields system level benefits. HELCO currently operates the system based on observing the recent trend in wind variability combined with forecasts from the National Oceanic and Atmospheric Administration. However, these methods still do not accurately predict ramp events and periods of sudden variability that pose the greatest challenge for HELCO's operation. Sub-hourly and sub-minute forecasting data would provide greater benefit. HELCO is pursuing studies to determine if near-term forecast improvements can be improved using targeted or other observational forecasting methods. It is noted that commercially available forecasts may be challenged in forecasting ramp events and periods of sudden variability that pose the greatest challenges for HELCO's operation.
- *Power Purchase Agreements (PPA):* PPAs with Independent Power Producers are important factors in HELCO's variable cost. These costs impact end-user rates. This study has shown that the addition of renewable generation results in significant overall advancement of the stakeholders' objectives of increased energy security, emissions reduction, and sustainability. New modes of system operation, new technologies, and new methods of using existing generation are required to reach substantially higher levels of renewable energy. Many of the existing PPAs are tied to oil prices. Thus, the customers see no economic benefit when oil prices rise, leading to an inequitable distribution of the economic costs and benefits. It is critical that the Hawaii State Legislature and Public Utilities Commission consider fair and equitable distribution of costs and benefits among all parties to help Hawaii meet its future energy needs.

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1.0 Background

Hawaii must make decisions about its energy future. Future energy resources should be reliable, affordable, environmentally friendly, emissions-free, and petroleum-independent. However, these characteristics represent trade-offs. For example, a highly reliable system costs more and a balance must be struck between the costs of increasing the reliability of energy supply versus the costs (economic, social, and public health and safety) versus not having energy when it is needed. Weighing this balance is a critical issue for public and private sector leaders on both a country and state level. Such analyses depend upon having accurate assessments of the choices that can be made.

New technologies in renewable energy, energy end use, energy conversion, transmission, distribution, and energy storage offer opportunities to provide clean, reliable, and secure energy for Hawaii and the country at less cost. This effort is part of a broader program to evaluate the options and opportunities in investing in Hawaii's energy infrastructure. The information gained as part of this effort will be useful for the rest of the nation in determining how to address climate change issues and to reduce petroleum consumption with new energy systems.

This study evaluated three future scenarios of the Big Island's electricity and transportation energy options. After this initial effort, similar validated models were developed for scenario analyses on Maui and Oahu. The US Department of Energy (DOE), the Hawaii Natural Energy Institute (HNEI), The General Electric Company (GE), and the Hawaiian Electric Company (HECO) and its subsidiary the Hawaii Electric Light Company (HELCO) have collectively provided about $1.5M to fund this effort.

2.0 Introduction

The objective of this project is to utilize validated analytical tools to quantify impacts of different scenarios of enhanced renewable energy, end-use efficiency, and integrated energy management on the Big Island and to assess the models' potential for use in other parts of the state and nation. In addition to informing state and utility leaders, the results of this effort can be used to consider the implications of substantially higher percentages of renewable resources on the electricity grid on a local, state, and national level.

The analytical tools quantify the effects under each scenario using economic, environmental, technical performance, and system stability measures. The study did not perform comprehensive benefit-cost analysis (BCA) of each scenario. However, the results of these analyses (and the models) could be used in future BCA to support decision-making. Key metrics developed by stakeholders were evaluated and compared against baseline results.

In Phase 1 of the program, baseline transportation and electricity models were developed, calibrated and validated against actual conditions. In Phase 2 of the program, stakeholders were engaged early in the process to identify key metrics, energy goals, technologies, and policies of interest. Stakeholder input was translated into themes, which guided the scenario selection process. Based on the results of these stakeholder interviews, four scenarios were chosen. On September 27, 2007 the stakeholders assembled in Hawaii to hear the results of the Phase 1 analysis and the results of the stakeholder interviews. The Phase 1 results were described in an earlier report[4] and the results of the stakeholder interviews were described in an earlier report[5]. At the summit, the four scenarios were outlined and stakeholder input was solicited. The process diagram is shown in Figure 1. There was agreement among the stakeholders with the overall objectives and technologies specified for each scenario.

[4] Assessment of Electric and Transportation Infrastructure for the Big Island, Electrical Power System Performance Report, DOE Program DE-FC36-04G014248, March 30, 2006.
[5] Strategic Energy Roadmap for the Big Island of Hawaii, A Presentation of the Transportation and Electricity Modeling Analysis and Results, and a Summary of the inputs and outcomes of the Stakeholder Summit, October 26, 2007.

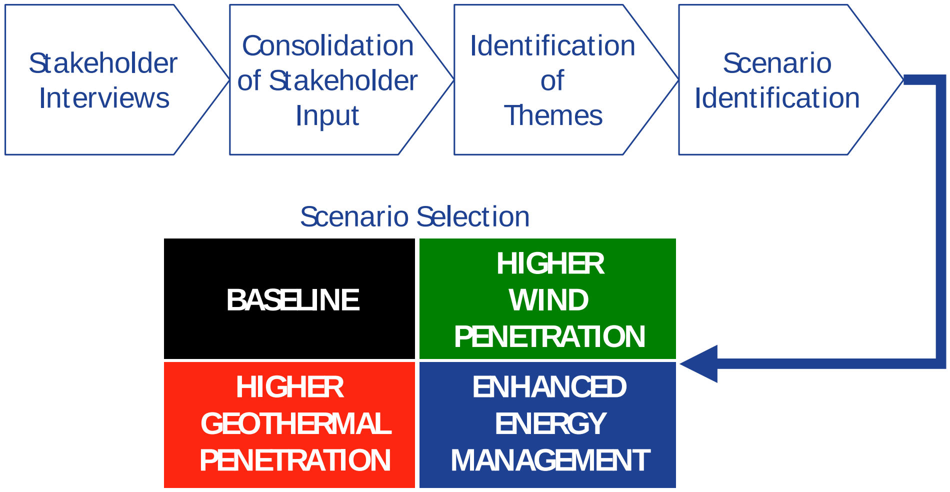

Figure 1. Scenario selection process diagram.

The Transportation Model was developed and validated against the data provided in the 2005 Hawaii Databook. Additional data were received from Bob Arrigoni at the Country of Hawaii Energy Office, from management at the airports on the Big Island, and from other organizations on the island and in the State. The transportation fleet, fuel type and vehicle type breakdown were used in conjunction with fuel demand forecasts, fuel price projections, emissions data, and land use information to evaluate economic, environmental, and sustainability metrics. In the scenario analysis phase of this project, the Transportation model was used to estimate the number of plug-in hybrid vehicles for the "Enhanced Energy Management" scenario.

The Electricity Model consisted of two specific simulation tools: the production cost modeling tool and the dynamic (or transient) modeling tool. The development of these high-resolution power system models required considerable interaction and support from HECO and HELCO management and staff. The production model considered the dispatch and constraints of all generation on an hourly basis and provided outputs such as the emissions, electricity production by unit, fossil fuel consumption, and variable cost of production. For example, if 10 MW of wind power were added and certain assumptions were made about the variability and availability of wind power, the spinning reserve needed to maintain system balancing and frequency control, the total variable cost of production, overall emissions and the MWh produced by fuel type could be evaluated. The dynamic model considered shorter timescale events (sub-hourly). The tool was necessary to determine the impact of decisions made in the longer timescales (production model) on the overall system operability, including stability in the shorter timescale. For example, if 10 MW of wind power were added, it would be necessary to determine the impact of alternative decisions for maintaining system stability (e.g., how much additional spinning reserve would be needed or how much energy storage would be needed). Both the production cost modeling tools and the transient modeling tools were augmented with statistical tools to identify wind variability events and load variability events to be analyzed in these tools.

The purpose of the modeling and analysis effort was to provide a baseline measure of electrical and transportation systems performance that would be used as a starting point for scenarios that explore alternative energy futures for the Big Island. The models were calibrated and validated against historical data from 2006. After the validation, the project team was confident in exercising the models to analyze forward-looking scenarios.

As noted above, the project team conducted stakeholder meetings during the project. These meetings included representatives from the organizations as indicated below in Table 1.

Table 1. List of stakeholders and organizations represented.

Organizations	**Representative(s)**
County of Hawaii Energy Office	Bob Arrigoni
Economic Development Alliance of Hawaii	Paula Helfrich
Enterprise Honolulu	Mike Fitzgerald and John Strom
Fairmont Orchid	Ed Andrews
Hamakua Energy Partners	Joe Clarkson
Hawaiʻi County Council	Pete Hoffmann
Hawaiʻi Island Economic Development Board	Mark McGuffie
Hawaiian Electric Company, Ltd.	Karl Stahlkopf
Hawaiʻi Electric Light Company, Inc.	Hal Kamigaki, Chengwu Chen, Art Russell, Lisa Dangelmaier
Hawi Renewable Development	Jim Nestman, Raymond Kanehaikua
Hilton Waikoloa Village	Rudy Habelt (Director of Property Operations)
Kohala Center	Betsy Cleary-Cole (Deputy Director)
Life of the Land	Henry Curtis (Executive Director)
Office of Hawaiian Affairs	Mark Glick, Yuko Chiba
Powerlight	Riley Saito
State of Hawaii, Department of Business, Economic Development & Tourism	John Tantlinger, Steve Alber, Priscilla Thompson
State of Hawaii, Public Service Commission, Division of Consumer Advocacy	Catherine Awakuni
Tesoro Hawaii Corporation	Carlos De Almeida
University of Hawaii at Manoa	Makena Coffman

2.1 The HELCO Electricity System

The HELCO system provides an unusual opportunity to assess the impact of a high percentage of renewable energy penetration on an electric power system. This system combines production from wind energy and a unique mix of generation resources, including fixed outputs from geothermal and run-of-river hydroelectric. Furthermore, the isolation of the Hawaii electrical grid presents the additional challenge that all power imbalances created by variable generation resources, such as wind and photovoltaic systems, result in a system imbalance and frequency error that must be corrected on a small grid. Three scenarios were analyzed that had higher renewable energy penetrations than is currently present on the Big Island. An additional facet of the study is analysis of different technological options to mitigate the frequency errors caused by higher penetration of intermittent renewable energy resources.

In 2006 (the year used for model validation), peak demand was 201 MW and the net energy produced was 1,255 million kwh. Electricity produced from refined petroleum products accounted for 76% of the electricity produced in the HELCO system. Renewable energy sources provided the remaining electricity with geothermal, hydroelectric, and wind producing approximately 17%, 5%, and 2% of the electricity, respectively. Electricity from solar photovoltaic sources accounted for less than 1% of the total supply[6].

HELCO operates their firm capacity in three modes of operation: baseload units that are online 24 hours a day, intermediate (cycling) units that generally start in the morning as demand increases and shut down in the evening, and peaking units that are only used to produce electricity for short time periods or an emergency. Baseload generation is provided by a geothermal plant run by Puna Geothermal Ventures (PGV) (27 MW off-peak and 30 MW on-peak), three steam units that operate on residual fuel oil (Hill 5-14 MW, Puna-15 MW, and Hill 6-20 MW), and one combined cycle unit run by Hamakua Energy Partners (HEP) that uses naphtha (HEP-28.5 MW). PGV is an Independent Power Producer (IPP) and provides its power on a must-run basis. HELCO's intermediate units include two small steam units (Shipman 3&4-7.5 MW each), the second train of the combined cycle plant (HEP-60 MW total), and three simple-cycle gas turbines (CT3, CT4, CT5-20 MW each). The peaking units include 14 small diesels (9 x 2.5 MW each, 4 x 1 MW each, 1 x 2 MW) and two simple-cycle gas turbines (CT1-11 MW and CT2-14 MW)[7].

The HELCO system also has a considerable amount of variable generation from renewable sources. Three wind power plants (Lalamilo - 2 MW, Apollo - 20.5 MW, and Hawi Renewable Development - 10.56 MW) and two hydroelectric projects (Wailuku River Hydro - 12.1 MW, Puueo and Waiau Hydro - 4 MW) operate on a must-take basis. However, generation from these sources is curtailed at times when available power supply exceeds demand.

HELCO has a flexible operation which, due to the short startup time for intermediate units, means that units are started in merit order with consideration of the available online resources. The merit order is established in advance, but decision to start units is based on the available reserves with consideration of the amount and volatility of the available variable generation production (wind, PV, hydro).

The HELCO system is unique in that a significant number of generators providing a large portion of the energy on the system are not dispatchable and do not participate in local frequency control or supplemental frequency control. This leaves relatively few units to perform load

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[6] State of Hawaii Department of Business, Economic Development, and Tourism, "Table 17.07: Electricity Production, By Source, By Island: 2006," *2007 State of Hawaii Data Book*, Online at http://hawaii.gov/dbedt/info/economic/databook/db2007/ .

[7] HELCO, "HELCO System Operations," Presentation at the HELCO IRP Advisory Group Orientation Session, August, 22, 2008, http://www.helcohi.com/vcmcontent/HELCO/RenewableEnergy/IRP/HELCO_IRP4_AG02_082208_07_Sys_Op.pdf, (accessed May 18, 2009).

balancing and frequency regulation, even as the balancing burden has increased due to the greater variability of apparent load as a result of wind energy and other as-available energy sources. This, combined with the lack of interconnections, places a large balancing burden on relatively few conventional units providing the balancing services.

2.2 Limitations of the Study

The models developed and presented here represent a mixture of standard electric power system engineering tools of the type regularly used by utilities and some novel simulations of types not typical within utility system planning. This study is not a standard system planning study nor is it meant to replace utility planning or the HELCO Integrated Resource Plan (IRP) exercise. Instead, the scenario analysis can provide those familiar with the HELCO system with directionally correct sensitivities, such as a change in the variable cost of production or emissions associated with a particular technology deployment decision. As much as it was possible to be technology-neutral, the project team examined technology deployments that achieve goals cited by the stakeholders during the interview process.

The system operating constraints outlined by HELCO operations were captured in the modeling results. It should be noted that present operating constraints could limit the potential benefit offered in each of the scenarios. This report notes the need for subsequent studies to evaluate the potential for new technological solutions that may allow greater system flexibility. The present operating constraints are in place to avoid system catastrophic failure.

An additional limitation, which is present in all scenario analyses, is that specifying a baseline scenario requires making assumptions about the future. At the time of the study, the project team used the projected trends in HELCO's IRP-3 filing with the PUC in developing the baseline scenario. Since that time, renewable energy development grew much faster than the recent historical trend. The baseline scenario, therefore, is not a prediction of the future but instead is a projection based on a certain set of assumptions.

3 Model Development and Validation

This aspect of the overall project led to the development of validated simulation models that can provide quantitative information useful for evaluating the electricity infrastructure. The models aimed at capturing challenges related to regulation, frequency control, load following and unit commitment considering intermittent resources such as wind generation. The quantitative analysis covered three timeframes, including:

- Seconds to minute (regulation and frequency control) – Dynamic simulation;
- Minutes to hour (load following, balancing) – Dynamic simulation; and
- Hours to days (unit commitment, day-ahead forecasting and schedules) – Production cost simulation.

The Big Island grid is a dynamic system, subject to continuously changing conditions, some of which can be anticipated and some of which cannot. Historically, from a control perspective, the demand of electricity (the load) is the primary independent variable – the driver to which all the short-term controllable elements in the power system must be positioned and to which it must respond. The performance of the power system is highly dependent on the ability of the system to accommodate changes and disturbances while maintaining quality and continuity of service to the customers.

There are several timeframes of variability, and each timeframe has corresponding planning requirements, operating practices, information requirements, economic implications, and technical challenges. Much of the analysis in the first phase of the project focused on developing models that evaluate system frequency control and balancing, including wind resources, in each of the timeframes relevant to the performance of HELCO power system. In the longest timeframe, planners look several years into the future to determine the requirements of the generation and balancing assets of the system based on capacity (or adequacy) needs. This timeframe includes the time required to permit and build new physical infrastructure. In the next smaller timeframe, day-to-day planning and operations must prepare the system for the upcoming diurnal load cycles. In this timeframe, decisions on unit commitment and dispatch of resources must be made. Operating practices must ensure reliable operation with the available resources. During the actual day of operation, the generation must change on an hour-to-hour and minute-to-minute basis. As an island, the system demand and balancing must be maintained solely by the generation on the system due to the lack of interconnections; and every imbalance is reflected in system frequency variations. This is the shortest timeframe in which economics and human decision-making play a substantial role. Unit commitment and scheduling decisions are implemented and refined to adjust for variations in both available generation and load.

In the shortest timeframe, cycle-to-cycle and second-to-second variations in the system are handled primarily by automated controls. The system's frequency control is implemented in a hierarchical scheme. In the shortest time frame, frequency control is affected by the local automatic governor response by the individual conventional generating facilities, which respond to changes in the system frequency. Under emergency conditions of very low frequency caused by excess demand relative to generation, under-frequency load shedding is automatically performed to bring the system into balance. In a longer time-scale of several seconds to minutes, a subset of generators provide supplemental regulation by following commands from the centralized AGC, to maintain the target system frequency.

The HELCO system is unique in that, for the validation year (2006) and baseline year (2018) scenarios, a significant number of generators providing a large portion of the energy on the system are not dispatchable and do not participate in local frequency control (through droop response) or supplemental frequency control (through AGC control). This leaves relatively few units to perform load balancing and frequency regulation, even as the balancing burden has increased due to the greater variability of apparent load as a result of wind energy and other as-available energy sources. This, combined with the lack of interconnections, places a large balancing burden on relatively few conventional units providing the balancing services.

With the addition of the two large wind plants at Apollo and Hawi wind farm (HRD), the AGC program was modified to reduce problems created by the second-to-second variability of the wind to minimize exacerbation of frequency error due to controls sent in response to the imbalance created by wind energy changes. The modifications dampened the control response due to frequency error created by changes in wind power output, and increased the no-control deadband for frequency error, allowing a greater frequency deviation before supplemental control is taken.

The project team modeled the system at different time scales:

- Transient modeling, in the seconds-to-minutes timescale, to determine frequency stability and transient performance of the island power system, and
- Production cost modeling, in the hours-to-days timescale, to determine the operating economics of the power system.

3.1 Transient and Long-term Dynamics Simulation

Transient and long-term dynamics simulations were used to estimate system performance during wind power fluctuations and system events through measures such as system frequency. This type of modeling is used to understand the impact of transient operation of different generators on system frequency in a seconds timeframe and is used by utilities to ensure that the system voltage and frequency do not become unstable during system disturbances, such as line faults, or contingencies, such as generator trips. Stability is necessary to ensure that the system is able to survive these transient conditions. In an unstable system, a fault or contingency can result in system failure. The dynamics tool was modified to include a longer-time frame than typically modeled with this tool, in order to model the dynamic system response to imbalances created by variable generation. For example, if wind power production suddenly decreases due to a sudden calming of wind in the area, to maintain balance and constant frequency, another generator or set of generators must increase electricity production at the same rate as the wind plant decreases its production. If the decrease in wind plant output is not exactly matched in rate and amount by an increase in other generation, the system frequency will deviate from 60Hz (it will be lower). The dynamic simulation tool can be used to model the frequency excursion associated with these types of events.

Short-term dynamic models of the HELCO grid were implemented in GE PSLF™. This tool is a widely used load flow and transient stability analysis package. This commercially available tool has a long history of application in the electric utility industry. The primary source of model uncertainty and error for short-term dynamic simulations comes from the inability to model with complete precision the various electric power assets in the HELCO power system (primarily the dynamic response characteristics of the generators, load, and governor models).

Long-term dynamic models of the HELCO grid were also developed in GE PSLF™. These simulations are two to three orders of magnitude longer than typical short-term stability simulations. The long-term simulations were performed with detailed representation of generator rotor flux dynamics and controls, typical of short-term dynamics. The models that were modified, or added, to capture long-term dynamics were AGC load and as-available generation variability. One function of AGC, as has been mentioned above, is supplemental frequency control to regulate frequency within targeted error bounds. This involves managing the balance between supply and demand on the power system by increasing or decreasing power production from the generators under AGC control to decrease any measured imbalance between real power supply and demand. The load demand and as-available generation are the two independent variables that affect the power balance.

The GE PSLF™ simulation outputs include estimations of:

- System frequency fluctuations due to load and wind variability,
- Voltages throughout the system,
- Active and Reactive power flows,
- Governor operations,
- Primary frequency regulation needs, and
- Load following regulation needs.

Other phenomena that can affect long-term dynamic behavior, such as long-duration power plant time constants (e.g., boiler thermal time constants), slow load dynamics (e.g., thermostatic effects), and human operator interventions (e.g., manual switching of system components) were not included in this model.

In order to validate the model, HELCO provided high-resolution two-second data for three one-hour windows, which included periods of wind variability and represented low, medium and high load cases to represent the different generating unit configurations. Three cases were chosen to represent typical system dispatch throughout the day, as at different load levels and with the intermediate generation coming online, there is a change the dynamic system frequency response, measured as the system frequency bias (MW/0.1 Hz). These three sets of high-resolution data included wind fluctuations that created significant frequency excursions. The actual wind power, during each of the windows, was used to drive the dynamic model. Once initiated, the following 3600 seconds were compared to the actual system frequency during the window. The model calibration with the three cases involved an iterative process. The team calibrated the model against the first set of data and then made further adjustments when analyzing the two additional events. After any subsequent changes, the team reran the models against the earlier events to check the accuracy of the calibration.

An example comparison is shown in Figure 2 below for a one-hour window on April 3, 2007.

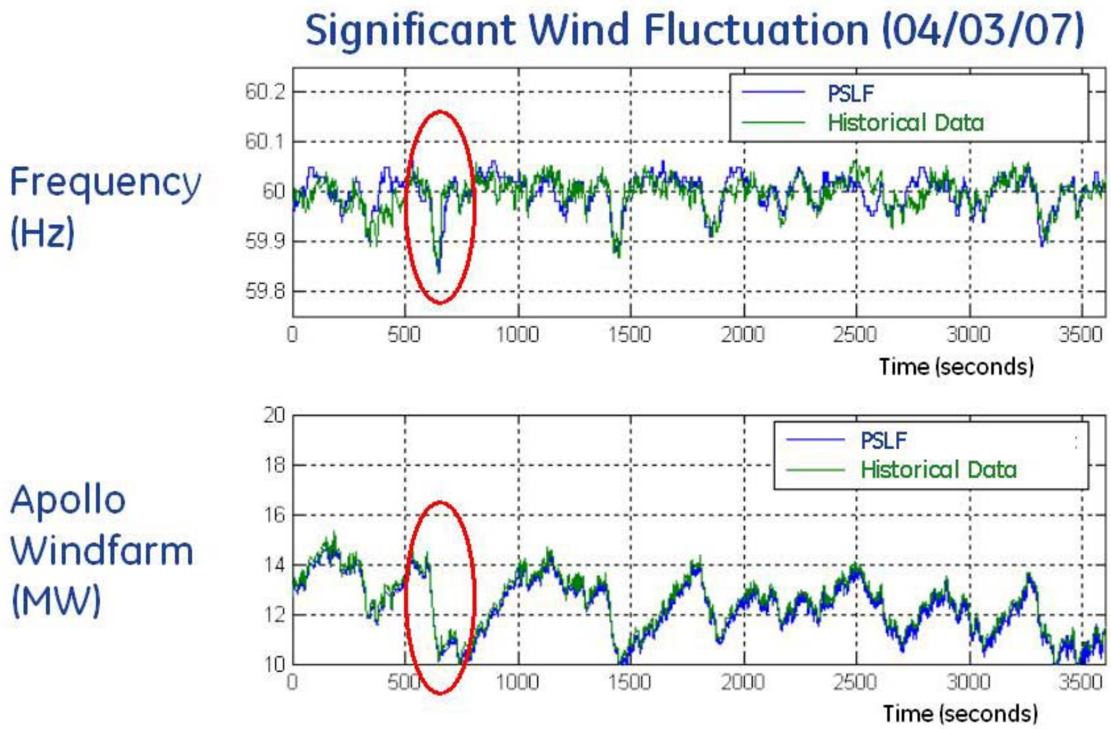

Figure 2. System frequency comparison between historical data and the dynamic model for a one-hour window on April 3, 2007.

At approximately 600 seconds, the Apollo wind plant decreased power output. This caused a frequency excursion of ~150 mHz. The model captured this frequency excursion. Additionally, the model captured other frequency deviations observed in this window. In order to ensure the model accurately represented reality, two additional one-hour windows were compared. The model accurately captured the system frequency performance for this window and the other two windows for normal operating conditions. The project team agreed that the model provides adequate fidelity for these scenario analyses. In fact, the degree of accuracy demonstrated in the back-casting runs displays considerably greater fidelity than is typically achieved for these types of forecasting models.

The approach to modeling the dynamic behavior of the HELCO grid has differing levels of model fidelity, depending on the timescale represented. The fidelity of the representation for short-term dynamics is affected by the dynamic generator models, system inertial characteristics, and frequency bias including effect of load as well as generation. The output of the wind plants in response to wind changes must be assumed and modeled. HELCO supplied the best available data for generator dynamics; however, accurate modeling of dynamic response remains a challenge for HELCO as it is for all utilities. It is of particular value to HELCO to model dynamics accurately simply because HELCO operates closer to stable boundaries, and much of the model data are based on actual physical measurements in the field.

In contrast to the short-term dynamics modeling, the representation of long-term dynamics can be expected to be of less fidelity because it is limited not only by the accuracy of the governor/power plant models, but also by the modeling of the AGC. Substantial improvements to the AGC model have been achieved throughout the second phase of the program due to additional information received from the HECO utilities about the AGC parameters and performance. Other phenomena that can affect long-term dynamic behavior, such as long duration power plant time constants (e.g., boiler thermal time constants), slow load dynamics (e.g., thermostatic effects), and human operator interventions (e.g., manual switching of system components) were not included in this model.

3.2 Production Cost Simulation

Throughout the year HELCO has to make decisions about which generators should be used to produce electricity in each hour of the day (commitment and dispatch). The commitment is the order in which units are started up and brought online. The dispatch of units is the determination of the allocation of power output among all the units. The commitment and dispatch decision depends on many constraints, including the cost of each generator, the capabilities of the transmission system, and rules about when each generator can be operated. The model includes representation of the HELCO transmission system and relevant characteristics of each generating unit, such as the maximum and minimum power output, heat rate (thermal efficiency) as a function of production level, emissions, minimum downtime between starts, start-up costs, operating constraints, and maintenance and forced outages. HELCO provided information on all the above parameters, except for emissions. The emissions assumptions were obtained from data used in HELCO utility fillings with the PUC.

Production cost modeling of the HELCO system was performed with the GE's Multi Area Production Simulation (MAPS™) software program. This commercially available modeling tool has a long history of use in utility applications. This tool was used to simulate the HELCO production for 2006. Ultimately, the production cost model provides the unit-by-unit production output (MW) on an hourly basis for an entire year of production (GWh of electricity production by each unit). The results also provide information about the variable cost of electricity production, emissions, fuel consumption, etc.

The overall simulation algorithm is based on economic dispatch according to the standard least marginal cost operating practice. That is, generating units that supply power at lower marginal cost of production are committed and dispatched before higher marginal cost generation. Commitment and dispatch are constrained by physical limitations of the system, such as transmission thermal limits, minimum spinning reserve, stability limits, as well as the physical limitations and characteristics of the power plants. The project team received significant input from HELCO and iterated through multiple refinements of the production cost simulation model.

The primary source of model uncertainty and error for production simulations, based on the model, consist of:

- Physical or operating constraints, such as stability limits, commitment and dispatch rules that apply under special conditions, etc. that are not currently in the model will result in errors.

[8]:

a. Operate with a minimum of two of the three base-load steam units online.
b. Must-run status of certain steam plants.
c. Restriction against operation of certain units during certain times of day.
d. Scheduled production each day and night from Puna Geothermal Venture.
e. As-available energy from the run-of-river hydro and wind power producers is on a must-take basis. This energy is curtailed according to a curtailment order only under conditions of excess energy, when the must-take conventional units are at minimum output with consideration for minimum regulation reserves.

- Minimum spinning reserve rules are included. Losses are considered in prioritizing dispatch. Each of these types of constraints in the model may be somewhat simpler than the precise situation dependent rules used by HELCO.
- Marginal production cost models consider heat rate and a variable O&M cost. However, the models do not include an explicit heat-rate penalty or an O&M penalty for increased maneuvering that may be a result of incremental system variability due to as-available renewables (especially wind).
- Production cost model includes fuel price as an input. Changes in fuel price significantly affect absolute cost calculations. Fuel price assumptions in this analysis followed the assumptions used in HELCO's IRP-3 submission to the PUC.
- The as-available energy levels and variability were based on assumptions for the future that were developed by the project team based on stakeholder input.
- Prices that HELCO pays to third parties for energy are not, in general, equal to the variable cost of production for the individual unit, nor are they equal to the systemic marginal cost of production. Rather, they are governed by power purchase agreements (PPAs). The price that HELCO pays third parties for energy production is reflected in the simulation results insofar as the conditions of the PPAs can be reproduced. The results are based on the avoided cost calculations from 2006.

The simulation assumes a day-ahead commitment of generating units and that variable generation is constant within each hour. Intra-hour variability of wind generation or other intermittent resources, and commitments made intra-hour are not modeled explicitly in this analysis. The simulation results provided insight into hour-to-hour operations, and how they may change subject to various changes in assumptions, including equipment or operating practice. Since the production cost model depends on fuel price as an input, relative costs and changes between alternative scenarios tend to produce better and more useful information than absolute costs.

The model results are presented in the report, but need to be caveated as described here:

- Approximate system dispatch and production, although these do not necessarily identically match system behavior,
- Do not necessarily accurately reproduce production costs on a unit-by-unit basis,
- Do not accurately reproduce every aspect of system operation,and

[8] Operational Requirements for Unit Commitment and Dispatch, System Operations Policies and Procedures, March 30, 2007.

- Reasonably quantify the incremental changes in marginal cost, emissions, fossil fuel consumption, and other operations metrics due to changes, such as higher levels of as-available generation penetration.

In order to validate the model, 2006 load, hydro and wind data were provided by HELCO for an entire year of production. An entire year was simulated in the production cost tool. The results for each unit in the HELCO grid included the number of starts, hours on-line, annual power production, fuel cost, capacity factor, variable O&M cost, fuel consumption, emissions (NO_x, SO_X, CO_2). Based on fuel type, the results of the simulation were compared to historical data (Figure 3). The results were separated into seven generator types: diesel units, Hamakua Energy Partner's combined cycle plant (HEP), combustion turbines (CT), wind power, oil-fired steam turbines (Oil), run-of-the-river hydro plants (hydro), and Puna Geothermal Venture's geothermal plant (GEO).

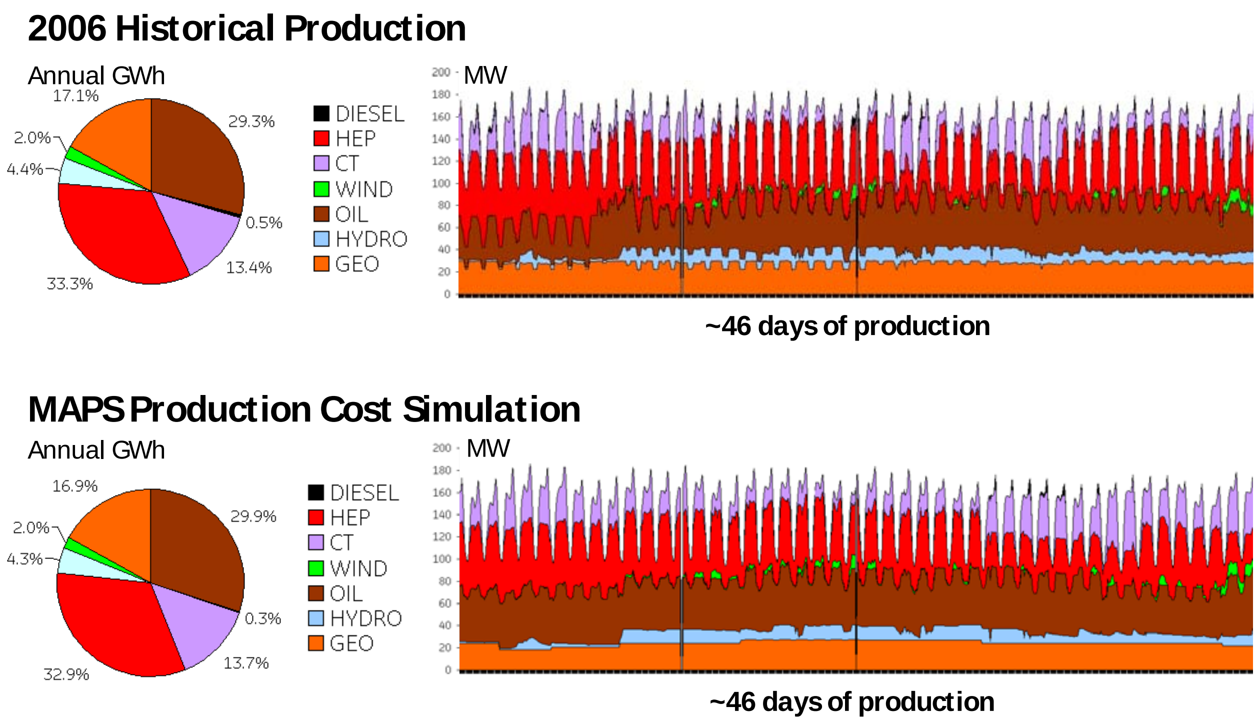

Figure 3. Electricity production on the Big Island, by unit type.

In Figure 3 the aggregate GWh of electricity production from the simulation was compared to historical data. The historical electricity production and GE MAPS™ simulation results compared within 1% by fuel type, and indicated that an accurate model had been developed. The system calibration factor calculated from the model was comparable to HELCO's calibration factor, 4-5% based on the modeled fuel efficiency (fuel use relative to system demand). The calibration factor is calculated as the ratio of the observed system heat rate to the simulated system heat rate. Despite the close calibration on aggregate energy production and fuel consumption, the model is unable to capture certain unique operating conditions such as changes to general commitment order and dispatch rules in order to address system conditions such as switching orders or other constraints and sub-hourly variations in intermittent generation, and is also unable to precisely reproduce the hourly dispatch of each unit throughout the entire year. Operating constraints and system operating rules were captured to the degree possible with the capabilities of the model.

Similar trends were observed between historical data and the simulation results; however, it should be noted that outages in GE MAPS™ (maintenance or forced) do not necessarily occur at the same time of year as the historical data. For example, the HEP production in the GE MAPS™ simulation decreases for nine days near the end of the window shown in Figure 3, while according to historical data the actual HEP outage occurred at a different time of the year. In addition to comparing the annual electricity production by fuel type, the hourly production, running hours, number of starts, and the heat rate curve for each unit were compared to HELCO data and actual historical performance. It should be noted that the production cost model considers heat rate and a variable O&M cost, but the models do not include an explicit heat-rate penalty or an O&M penalty for increased maneuvering that may be a result of incremental system variability due to as-available renewable resources (especially wind).

The annual operating results are summarized in Table 2 for one year of production. The units are aggregated by unit type. Unit types in red text represent Independent Power Producers (IPPs). The unit types in blue text represent HELCO-owned units. The energy production by type is shown in the second column. The fossil fuel consumption by type (MMBtu) is shown in the third column. The emissions by unit type are shown in the third, fourth and fifth columns of the table. Note that additional metrics were considered, but not reported here due to the proprietary content of the data. Fuel cost, variable O&M cost, start-up cost, Independent Power Producer purchase price and HELCO total variable cost have been removed at the request of HECO.

Table 2. Annual results from the production cost model for one year of production. Unit types in blue text represented HELCO-owned units. Unit types in red text represent IPP-owned units.

	EFFICIENCY		EMISSIONS		
TYPE	Total Energy (GWh)	Fuel Consumption (1000 x MMBTU	NOx (tons)	SOx (tons)	CO2 (tons)
Combustion Turbine (HELCO)	168	1991	151	279	161646
Diesel (HELCO)	3	32	6	5	2741
Steam Oil (HELCO)	381	5304	821	913	529301
Small Hydro (HELCO/IPP)	55	0	0	0	0
Combined Cycle (IPP)	418	3343	98	501	290684
Puna Geothermal (IPP)	215	5510	0	0	0
Wind (IPP)	26	0	0	0	0
Grand Total	**1265**	**16179**	**1076**	**1698**	**984372**

Based on the results of the validation exercise, the project team was satisfied with the accuracy of the production cost and dynamic models, and proceeded to the scenario analysis phase of the project. The degree of accuracy demonstrated for both the production cost and dynamic simulation models are considerably above the accuracy generally achieved for most forecasting models. The unit-by-unit hours on-line per year and number of starts per year were compared to 2006 historical data. The heat rate curve was compared on a unit-by-unit basis.

3.3 Sensitivity Analyses

The subsequent stage of the study considered small incremental changes in the supply and demand for electricity. The purpose of the sensitivity analysis was to provide insight to the project team of directional trends. For example, before the project team considered the impact of a 10 MW wind plant on the Big Island of Hawaii, a 1MW increment of wind power was added to the model to determine the per unit impact of an increment of wind power on emissions, energy production by type, and the variable cost of energy production. This exercise provided the project team with directionally correct trends for a variety of cases.

Some of the incremental changes considered were:

1. Supply-side: Generation & other technologies
    a. Geothermal power,
    b. Wind power,
    c. Solar power,
    d. Spinning reserve,
    e. Energy storage (scheduled charging), and
    f. Energy storage (market-rational/forecasting).
2. Demand-side: Load & other technologies
    a. Load,
    b. Nighttime trough filling,
    c. Peak load shaving, and
    d. Scaling of the load profile by load factor.

In each case, a very small change was made, providing a sense of which actions would have the largest incremental effect. These sensitivities, in turn, provide insight in determining directions for the stakeholders to consider. "Incremental" and "relative" are key qualifiers, as a power system is extremely complex and highly non-linear system. Directionally correct insight does not imply exactness or feasibility on a large scale. Nevertheless, the results suggest, for one example, that technology choices that reduce spinning reserve requirements had a significant beneficial impact on fossil fuel consumption and emissions. Addition of, for example, wind generation tended to displace fossil fuel consumption but added spinning reserve requirements. It is these types of approximate though quantitative measurements that provide insight for each of the scenarios that were considered.

As an example, if 1 MW of wind power was added to the HELCO grid at the Apollo wind plant (assuming the same capacity factor as existing at the plant), the production cost model reveals that 37,000 MMBtu of energy from fossil fuel generation were displaced by the wind energy on an annual basis. As a result, carbon emissions were reduced, as would the amount of fossil fuel imported to the island. The production cost model was used to quantify the variable cost of electricity production based on the power purchase agreements with each of the independent power producers and based on the fuel, operation, start-up, and maintenance costs of each generator. The results are shown in Table 3.

Table 3. The annual impact of adding 1 MW of wind power to the Apollo wind plant with respect to the baseline model.

		Fuel Use	Emissions (tons)		
	GWh	MMBtu	NOx	SOx	CO_2
Combined Cycle	-2.1	-15545	0	-2	-1352
Combustion Turbine	-1.3	-13905	-1	-2	-1245
Diesel	0.0	-341	0	0	-29
Puna Geothermal	0.0	0	0	0	0
Small Hydro	0.0	0	0	0	0
Steam Oil	-0.6	-7582	-1	-1	-726
Wind	4.1	0	0	0	0
Solar	0.0	0	0	0	0
Grand Total	0.1	-37374	-2	-6	-3352

The difference between a case where 1 MW of wind power was added to the Apollo wind plant and the baseline case is outlined in Table 3. Each unit type is broken out in the first column. In the second column, the difference in production by unit type is presented. For example, the addition of 1 MW of wind power at the Apollo wind plant results in an additional 4.1 GWh of wind power in one year. This resulted in the following reduction in energy production: combined-cycle decreased its production by 2.1 GWh, combustion turbines decreased their energy production by 1.3 GWh and Steam Oil plants decreased their energy production by 0.6 GWh. The reduction in production translated into a reduction in fuel use by these same units. Therefore, a total of 37,374 MMBtu of fuel consumption each year was avoided by the addition of 1 MW of wind power.

The interrelationship is much more complex than has been described thus far. The addition of wind power to the HELCO system could require additional regulation: generation that produces electricity at a sub-optimal, part-load, operating condition in order to address ramp up or down as a result of the wind power production. The existence of regulating reserve reduces the overall fossil fuel savings associated with increasing the penetration of wind power. New technologies, such as energy storage, may also be considered in order to address the impact of wind intermittency on the system frequency. Energy storage technologies could reduce HELCO's variable cost of production and reduce the amount of fossil fuel consumed on the island. However, there is a capital investment needed for such a technology as well as O&M costs associated with the operation of the technology and losses incurred in the charging/discharging cycle. From a technical perspective, the dynamic simulation (or transient simulation) tool can be used to illustrate the impact of various decisions (amount of spinning reserve, size of energy storage, etc.) on system stability. From an economic perspective, if wind power producers are contractually paid more than the costs of other generating assets that could generate electricity in its place, there is a cost adder associated with increased use of wind power.

This discussion reveals the economic and technical complexity of this type of power system modeling. However, by combining both production cost and dynamic modeling, much information can be provided to the Department of Energy (DOE), the utilities, and the State government about the impacts of technologies and policies on key metrics related to economics and sustainability. By using both production cost and transient simulation tools to analyze the three project scenarios, a more thorough analysis was performed. This provides greater insight into the technical and economic tradeoffs of these types of technology choices.

The models developed and presented here represent a mixture of standard electric power system engineering tools, of the type regularly used by utilities, and some novel simulations of types not typical within the utility system planning repertoire. The study was not a standard system planning study, nor was it meant to replace utility planning or the HELCO Integrated Resource Plan (IRP) exercise; instead, the scenario analyses provided those familiar with the HELCO system with directionally correct sensitivities, such as a change in the variable cost of production or emissions associated with a particular technology deployment decision. Insofar as it was possible to be technology-neutral, the project team examined technology deployments that achieve common themes or goals cited by the stakeholders during our interviews with them.

4 Scenario Analysis

In this section, results of the four scenarios will be presented. The scenario analyses are not meant to be exhaustive, nor are they meant to replace utility planning. Instead, the scenarios represent four specific cases that were evaluated in the model. These scenarios allowed the project team to observe if certain energy technology choices increased or decreased the outcomes of interest. A high level overview of each scenario is provided in Figure 4.

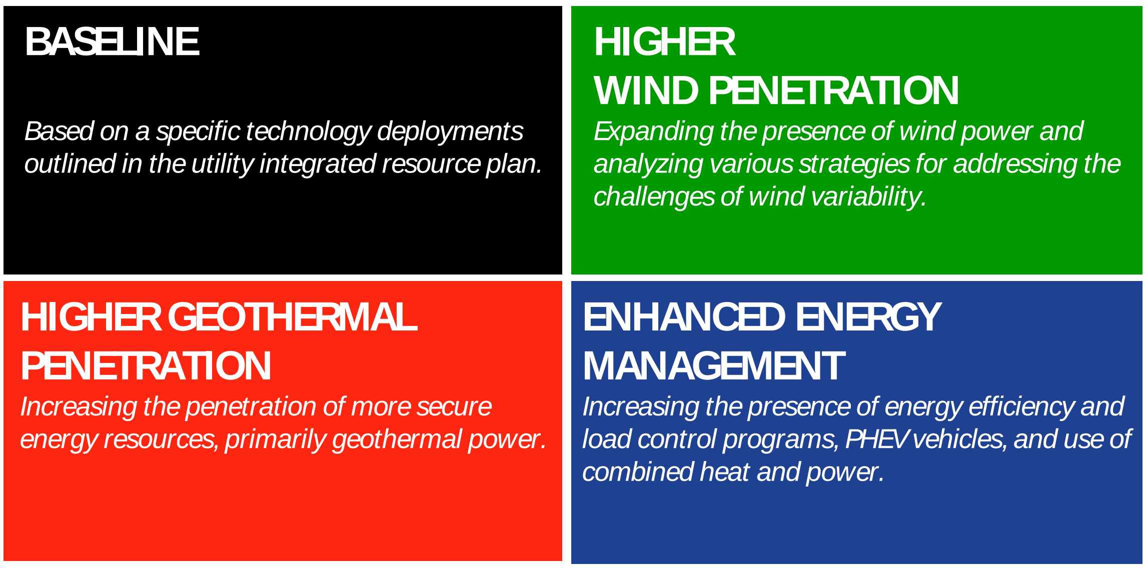

Figure 4. Scenarios of the Hawaii Energy Roadmap.

Considering both the production cost and dynamic performance offered a capability to postulate and evaluate scenarios in each of the timescales of interest. The results from the dynamic model were used to identify and specify additional technologies or operating practices needed to maintain satisfactory system performance in the sub-hourly timeframe. Two primary aspects of power system performance are: (1) maintaining satisfactory frequency and minimal excursions from 60 Hz, and (2) maintaining system stability synchronization with the grid and satisfactory voltages. The results from the production model were used to quantify the economic metrics associated with commitment and dispatch in the hour-to-hour timeframe. Together, these validated tools allowed the team to identify, evaluate, quantify, and compare forward-looking scenarios.

4.1 Baseline Scenario

The baseline scenario consisted of a minimalist approach to meeting the island's electricity needs in the 2018 study year. According to the HELCO Integrated Resource Plan it is expected that a 16 MW steam turbine (ST7) will be deployed at Keahole before 2018. This deployment will enable dual train combined cycle operation in conjunction with two existing combustion turbines (CT4 and CT5). According to HELCO's IRP, the deployment of ST-7 will allow HELCO to meet its capacity needs for the next several years[9]. The ramp rates, min power point and max power point for CT5 and CT4 were assumed the same as the initial baseline model, which was validated against historical data. ST7 was assumed to have similar performance as the HEP steam turbine, scaled to 16 MW.

It is important to note that HELCO's current plans now differ substantially from the IRP-3 filing and the 2018 Baseline scenario developed for this analysis. Several new renewable energy projects are moving forward and are summarized in the Appendix.

As a first step in developing the baseline model, the load curve for 2006 was projected to 2018 based on the IRP projections in peak demand and the 2006 historical load factor (Figure 5).

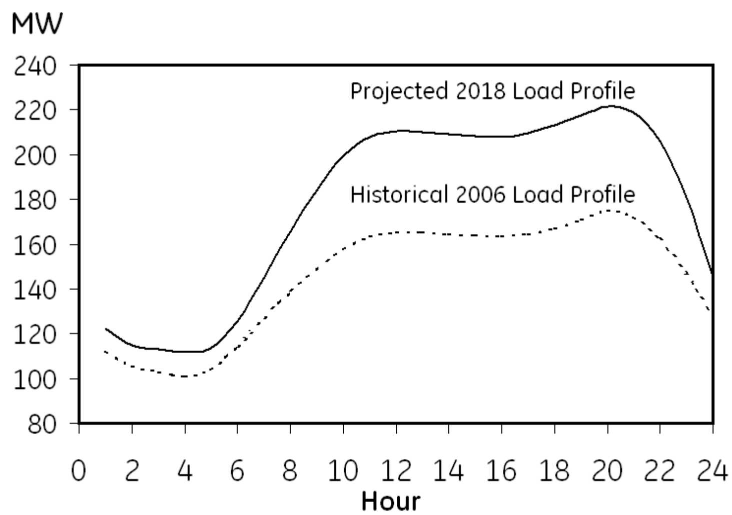

Figure 5. Average daily load profile in 2006 (historical) and 2018 (projected).

Using the validated 2006 model as a starting point, the baseline scenario was constructed in the production cost model (GE MAPS^{TM}). The results of the production cost model are shown in Figure 6. It should be noted that the production cost model uses a week-ahead commitment strategy. It was noted by HELCO that no such advanced commitment strategy is presently being used. Since the load assumptions were developed for the baseline scenario, the HELCO system experienced greater-than-expected growth in photovoltaic (PV) installations than anticipated in

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[9] *Ibid*, p.1-29

the IRP-3. The system "sees" PV generation as a reduction in load. Therefore, future load growth may deviate from recent trends if PV installations continue with rapid growth.

The annual GWh of electricity production by fuel type is shown on the left, and approximately forty days of hourly production are shown on the right for both the historical model (2006) and the new baseline scenario (2018). The results are separated into eight generator types: diesel units, wind power, run-of-the-river hydro plants (hydro), Hamakua Energy Partner's combined cycle plant (HEP), HELCO's Keahole combined cycle plant (CC), combustion turbines (CT), oil-fired steam turbines (Oil), and Puna Geothermal Venture's geothermal plant (PGV).

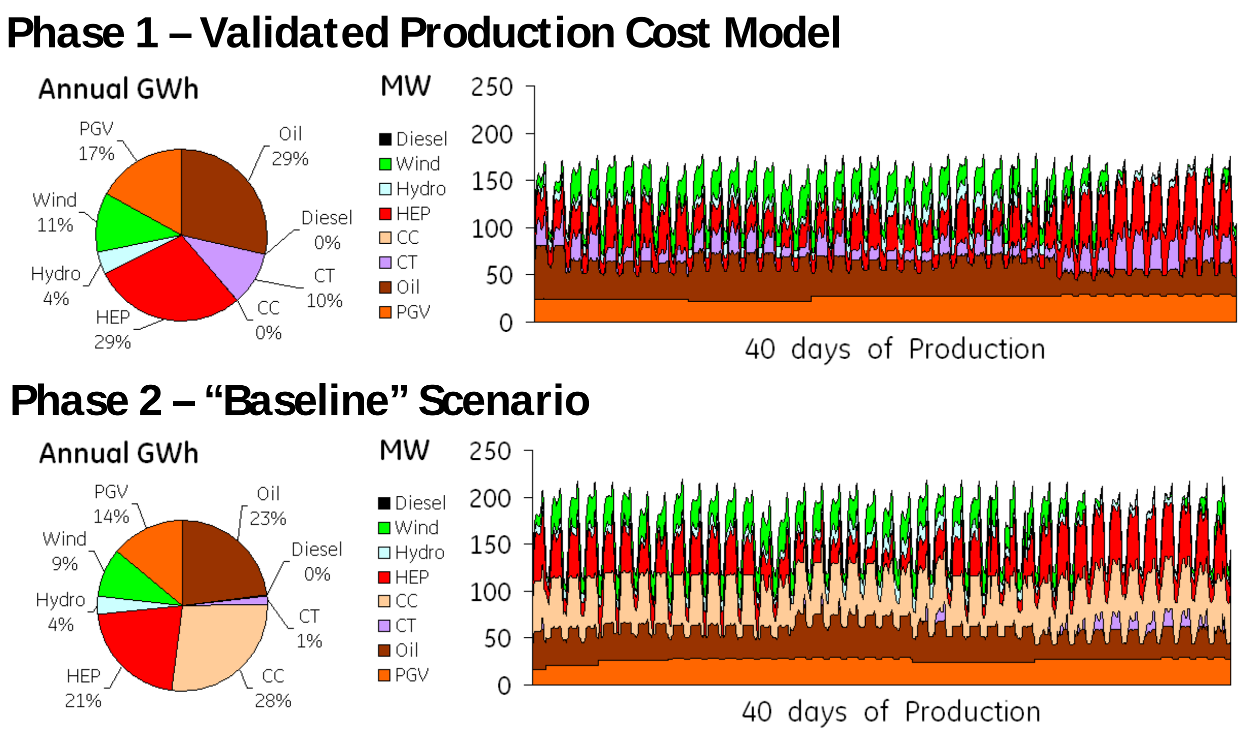

Figure 6. Simulation results for the 2006 historical model and the Baseline scenario.

The load curve expanded from the historical model to the Baseline scenario. As such, the percentage of total electricity produced by wind energy decreased because no new wind plants were developed. It should be noted that for the purpose of the baseline production simulation, all of the HELCO's must-run requirements were unchanged between the initial model developed in Phase 1 and this baseline scenario. As a comparison, production data for 2007 became available after this analysis. The share of generation by resource in 2007 was the following: steam (oil) 23.5%, PGV 19.9%, hydro 3.5%, wind 13.2%, CT 8.6%, CC 31.2%.

The tabular results of performance by unit type are presented in Table 4.

Table 4. Annual production cost results for the Baseline scenario.

	Capacity MW	Energy GWh	Fuel MMBtu	NOx tons	SOx tons	CO2 tons
Combined Cycle	117	738	5965673	174	895	518705
Combustion Turbine	43	46	593902	73	81	46969
Diesel	29	10	115766	21	16	9141
Puna Geothermal	30	215	0	0	0	0
Small Hydro	16	55	0	0	0	0
Steam Oil	61	350	4926321	762	847	490941
Wind	33	147	0	0	0	0
Grand Total	328	1561	11601662	1030	1839	1065756

The first column outlines the units by type. The second column contains the capacity available for each unit type. The third column contains the fuel consumption by unit type. The remaining columns contain the emissions by unit type. The fuel cost, O&M cost, start up cost, cost of the IPP contracts to HELCO and the total variable cost of HELCO have been removed from this table. Each scenario described later in this report will be compared with information in Table 4.

4.1.1 Dynamic Model

The long-term dynamic model was used to estimate frequency excursions and to assess system stability for a given scenario for a one-hour window. The baseline scenario was represented in the dynamic model (GE PSLF^{TM}) for various load conditions and wind power generation levels. Wind power variations from an historical window of 2-second data from May 23, 2007 were used to drive the 2018 baseline scenario simulations and all other scenarios where dynamic simulations were performed. This example was the most challenging of the samples provided by the utility for the analysis. Given the current limited data set, the project team did not assess how extreme this event was or assess a "worst case" scenario. The analytical methods do enable comparisons between the baseline scenario and historical data, and the results of this comparison are specific to the level of wind variability captured in the data set.

The dynamic simulation was initialized with the same load and generating units as dispatched by the production cost model for a similar load level. The individual loads were calculated to match total load (plus losses) and scaled proportionally to peak load flows provided for 2006. The dynamic performance of the combined cycle plant with ST7 at Keahole was assumed to be similar to the Hamakua Energy Partner (HEP) Combined Cycle plant. In the network model, HELCO lines 7200 and 7300 were modified from the 2006 calibration year system to represent re-conductoring to 556.5 AAC to reflect work completed in 2008. No pole replacement was assumed.

4.1.1.1 Second-to-second wind variability

The second-to-second variability simulations consisted of complete system time simulations (including generators, AVRs, governors, load behavior and AGC) where wind and load variability were used as the disturbances to the system. The analysis observes system frequency and generator power output. However, the simulation model produces many other output signals.

Of particular relevance is the wind power variability of all the wind plants in the system. The wind power variability is based on the largest wind-ramping-down event chosen by HELCO. This window may not be representative of the worst case observed, but was a reasonable variability case for comparisons between scenarios and was the most substantial wind fluctuation provided to the project team. In the three sets of high-resolution system data provided, the most variable wind power production occurred at the South Point wind plant. This wind plant will be referred to as the Apollo wind plant throughout this report. The wind power output varies at about 4 MW/min in a few occurrences. In the most severe variation in this data set (~2100 s), a ramp of 4 MW/min for 1 min was recorded.

In actual operational practice, the HELCO system has experienced wind plant power reductions due to wind speed changes that resulted in down-ramps from the amount of wind necessary for maximum output to minimum (zero) in approximately 3 minutes. Factors affecting the severity of the impact on the system frequency include not only the rate of change, but also the amount of sustained change, of the wind plant, as well as the available reserves and the allocation of reserves among the online units.

One-hour simulations were performed. The selected hours include intermediate wind power output, that is, hours where the power outputs of Apollo and Hawi were below rated power. These hours were chosen because they represent system conditions that would maximize the system disturbance from this specific wind event. The dispatch and commitment of other units in the system are based on GE MAPS™ results for the selected hour. The dispatch and commitment of other units were initialized in the dynamic model. The two cases are shown below.

Case	Scenario	Load Level	Wind Generation	Wind Penetration (%)
Low Load	Baseline	115 MW	21 MW	18 %
High Load	Baseline	214 MW	21 MW	10 %

The frequency responses are shown in Figures 7 and 8.

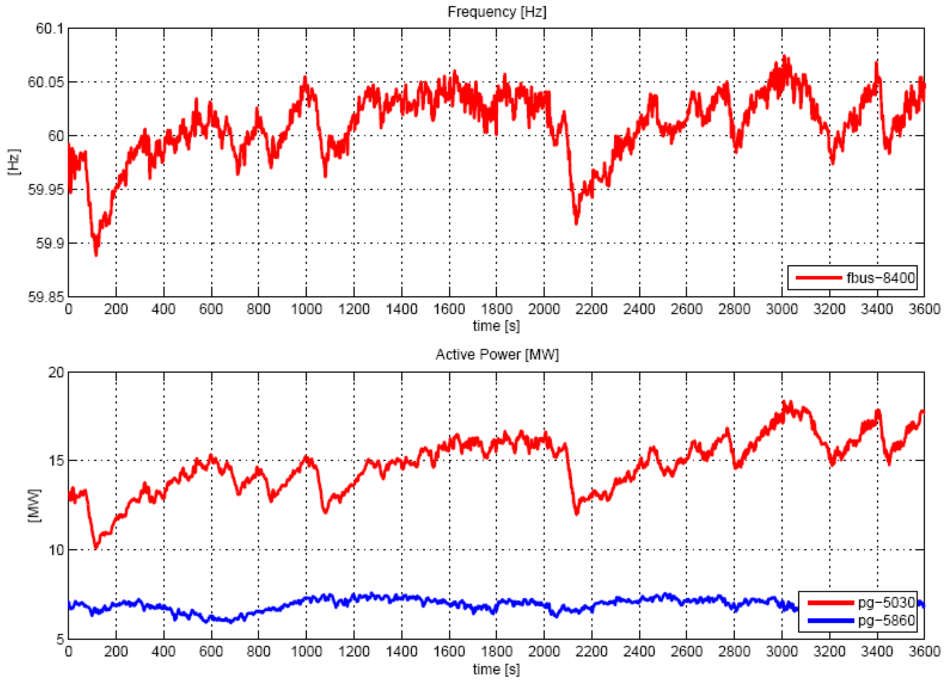

Figure 7. Baseline scenario: frequency response to wind power variations during a low load condition. System frequency (top figure, red curve), Apollo wind plant power output (bottom figure, red curve) and Hawi wind plant power output (bottom figure, blue curve).

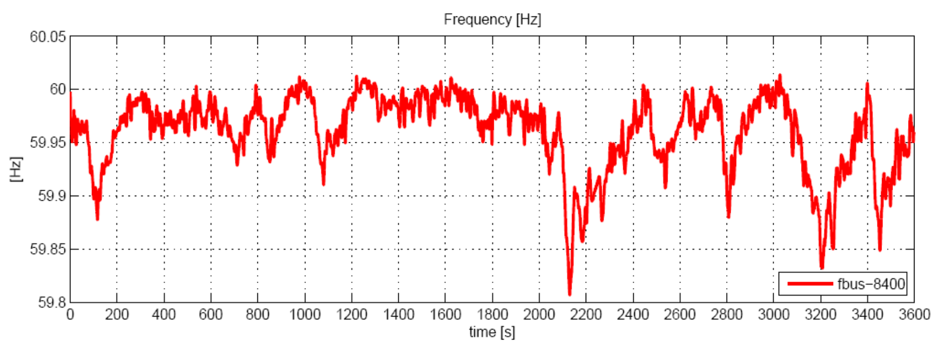

Figure 8. Baseline scenario: frequency response to wind power variations during a high load condition.

The up-regulating reserve is defined as the total additional power available from all of the online generators under AGC control (sum of the difference between the maximum dispatchable capacity of each online, dispatchable generator and the present production level of each generator). The up reserve is an important parameter to consider when analyzing the response of each generator to downward frequency excursions. Similarly, the down-regulating reserve, which is the difference between the minimum dispatchable limit of each regulating generator and the present output of each regulating generator, is important due to its impact on the system response to wind up-ramps. Based on these simulations, the frequency excursion at ~2100 s was larger in the high load case than in the low load case. Although the system inertia was greater at the high load condition (because more generation is dispatched), the available up reserve of all the thermal generation was lower than in the low load case. The units on AGC priority level 1 (operating under normal operation mode) had moderate up reserve available in the high load case. Since the up reserve is a key factor in the amplitude of the frequency excursion resulting from a wind down-ramp, the high load cases exhibited larger frequency excursions for the modeled wind down-ramp.

The lowest frequency measurement obtained during the simulated hour of operation is presented in Figure 9. Note that a lower frequency represents a more significant deviation from 60 Hz, and therefore a more significant imbalance between load and generation.

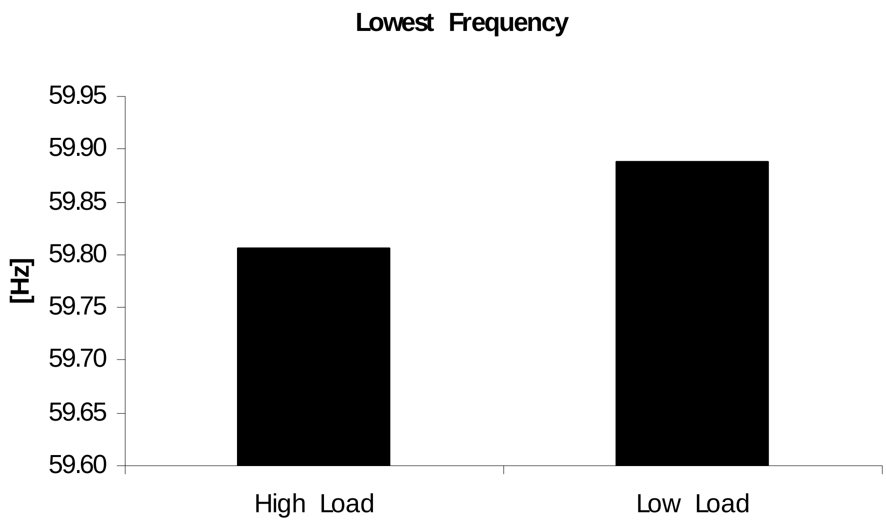

Figure 9. Baseline scenario: minimum frequency for a high load condition and low load condition.

The RMS value of the frequency deviation from nominal for the entire hour of simulation is presented in Figure 10. Note that a higher RMS value represents a more variable frequency signal. These values will be used as reference for analysis of other future scenarios.

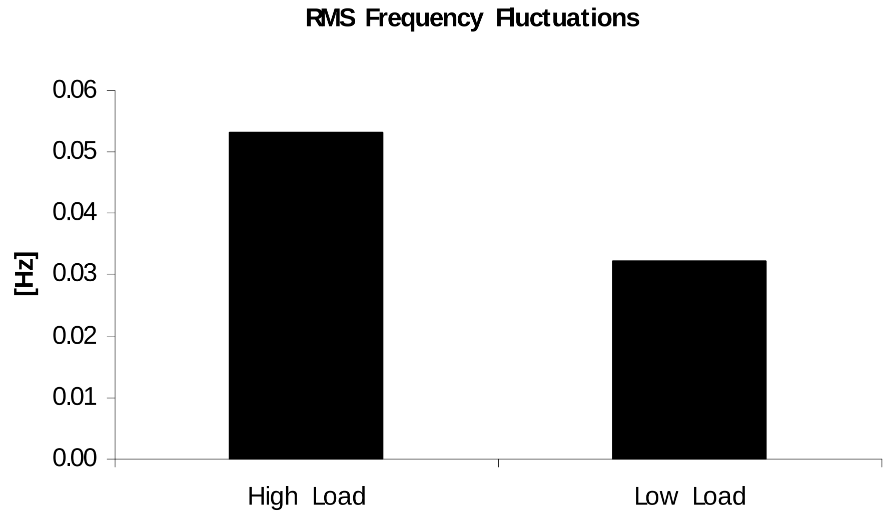

Figure 10. Baseline scenario: RMS frequency deviation for a high load condition and low load condition.

In order to confirm the relatively low impact of system inertia on system performance during these types of wind plant changes, the same cases were rerun with duplicate inertia (the inertia of each generating unit was duplicated). The results are summarized in Table 5. The maximum frequency change presented in this table was calculated over a period of 30 seconds.
It can be observed that the results are very similar between cases of same load level. It is assumed that this was because the wind power fluctuations last for tens to hundreds of seconds in the modeled scenarios – a time period which includes both local and supplemental frequency response; while the inertial response affects the system in shorter timeframes.

Table 5: Inertial sensitivity for the Baseline scenario.

Case	Description	System Inertia (sec)	Lowest Frequency (Hz)	RMS Frequency Fluctuations (Hz)	Max frequency change (Hz/sec)
BaU_2018_HL	High Load	2.3	59.81	0.053	0.14
BaU_2018_LL	Low Load	1.5	59.89	0.032	0.08
BaU_2018_HL_2xH	High Load, Duplicated Inertia	4.6	59.81	0.053	0.13
BaU_2018_LL_2xH	Low Load, Duplicated Inertia	3.0	59.88	0.032	0.08

Table 6 presents additional RMS indicators of frequency and output power of regulating units. The RMS slow frequency fluctuation was obtained by filtering the frequency with a 4th order filter with cutoff frequency of 1/250 sec. It can be observed that the RMS values for the slow frequency component were relatively close to the overall RMS, indicating that deep frequency fluctuations were relatively slow in nature.

Similarly, the RMS value of the fast variations in the power output of all regulating units was calculated over the sum of filtered power outputs with a 4^{th} order filter with 1/5 sec cutoff frequency. The RMS of the fast components was relatively low, showing that fast governor action was not as critical for system performance as governor droop and AGC operation for these types of system disturbances.

Table 6: Summary table of Baseline scenario variability results.

Case	Description	RMS frequency fluctuations (Hz)	RMS slow frequency fluctuations (Hz)	RMS power fluctuations regulating units (MW)	RMS fast power fluctuations regulating units (MW)
BaU_2018_HL	High Load	0.053	0.049	1.77	0.16
BaU_2018_LL	Low Load	0.032	0.029	1.42	0.17

4.1.1.2 Intra hour variability

The previous discussion was related to second-to-second wind and load variability. A second timescale of concern to the system operators is in the min-to-hour load following timeframe. In the minutes-to-hour timeframe, increases in load (demand for electricity) and decrease in wind power will require significant up reserve of the committed thermal generation. Essentially, an increasing load or decreasing wind power production will both demand additional power from the dispatched thermal generators. The up reserve is defined as the total additional power available from all of the dispatched generators, without having to start additional generators. The up reserve is the sum of the difference between the maximum capacity of each dispatched generator and the present production level of each generator. The up reserve represents the available MW of generation that is available to meet the increase in load or decrease in wind power production without needing to start a new generator. Similarly, down reserve represents the available MW to meet a decrease in load or increase in wind power production.

During events of sustained loss of wind power production and/or a sustained increase in load, the operator will need to decide whether or not to start a fast-starting generator, if insufficient up reserve is available on the committed thermal units. The available up reserve is a critical metric because as the amount of up reserve decreases due to rising load or decreasing wind power production, an operator will need to make a decision about starting a generator. The startup time for a generator can vary from one to a few minutes for small diesel units, to 20-30 min for intermediate gas turbines, and up to hours for steam units.

The production cost model is based on an hourly simulation of commitment and dispatch. At the beginning of an hour, the committed units are dispatched. The analysis assumes that the amount of wind power available over the hour is constant and based on the wind speed observed in the sampled data at the beginning of the hour. This assumption does not account for intra-hour variability of wind but attempts to limit the “smoothing” of wind variability. By representing the wind power over an hour using the value observed at the beginning of the hour, the data set maintains more of the variability in wind speed in comparison to alternatives to representing wind speed over an hour, such as the average.

Because the MAPS model calculates system dispatch by hour, the analysis does not directly model fast starts of generation caused by variability in load and wind generation within an hour. However, the analysis indirectly measures the number of fast starts required using the insufficient reserve metric. The insufficient reserve metric is based on the assumption that if the up reserve were insufficient to meet the load increase or wind power decrease over an hour, generation that could be started within the hour would be started. It should be noted that if the committed generation were unable to meet the increase in load and decrease in wind power, and sufficient fast-starting generation is available and could be dispatched with sufficient warning, the power system reliability would not be compromised.

In actual operation, the operator must know of this impending need created by the wind power output with sufficient advance notice to permit the time necessary to bring units online. At present, if the wind deviates from its present behavior by having a sudden down-ramp after a period of steady output, the operator will not have a means to anticipate the ramp and will not have carried the extra reserve. In this model, it is assumed that the reserve was maintained at a set value in the commitment logic and that the need for additional generation would be met by starting fast-start diesel units. In operational practice, the difficulty is predicting near-term ramps particularly when the ramp occurs following a prolonged period of steady production. The operator is not certain if a decline in wind is temporary or will be sustained until frequency is already affected. Therefore, it is speculated that the actual number of hours requiring units to be fast-started may be higher than calculated here because this analysis does not capture occasions where the operator may decide to fast start a unit because wind power is transiently decreasing, even if it recovers later that same hour.

The hourly production results were obtained from the production cost simulation for the Baseline Scenario in 2018. The hourly increase in load minus wind power was computed for each hour. The up reserve for each committed generator was computed at each hour. The difference between the available up reserve and the hourly increase in load minus wind power represents the shortfall in committed generation for any given hour. The number of hours when the up reserve was insufficient to meet the increase in load minus wind as well as the amount of the shortfall were identified and counted. The number of hours of insufficient reserve in the Baseline scenario was used as a reference indicator for future scenarios. The comparison of the number of hours with insufficient reserve between the Baseline scenario and other scenarios was used to indicate increments of required fast starts.

Figures 11 and 12 represent the probability density and cumulative distribution of available up reserve minus system hourly variability. The x-axis of both figures represents the difference between the available up reserve and the sum of the load increase and wind power decrease [Up reserve – (increase in load + decrease in wind power)]. Negative values on the x-axis represent hours in which the up reserve was not able to meet the increase in load and the decrease in wind power production. The spike at 58 MW may be a consequence of a discontinuity associated with must-run rules. The region that is lower than 0 MW is of primary importance for this analysis.

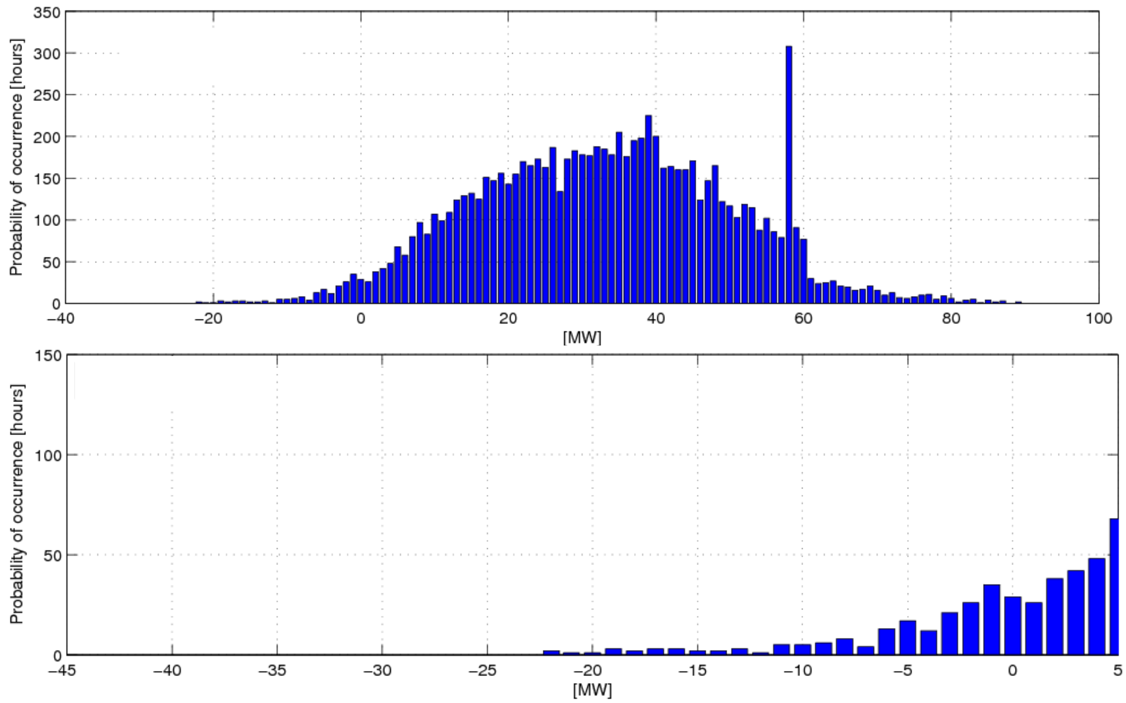

Figure 11. Baseline scenario: probability density function: available up reserve of thermal generation minus both the increase in load and reduction in wind power production.

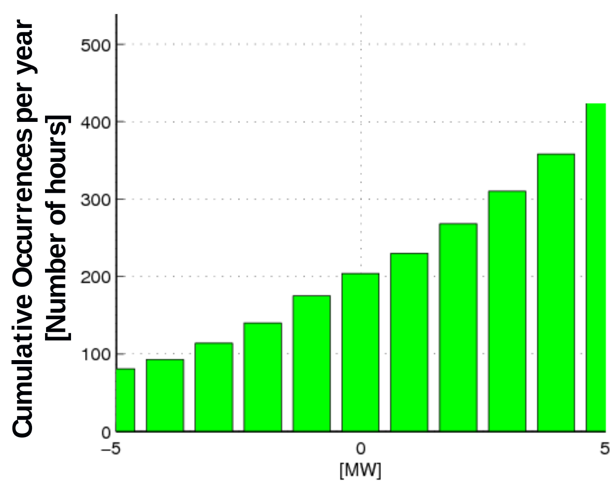

Figure12. Baseline scenario: cumulative distribution function: available up reverse of thermal generation minus both the increase in load and reduction in wind power production from –5 MW to +5 MW.

Based on the production cost simulation for the Baseline scenario, these results indicate that there were approximately 200 hours during the year in which insufficient up reserve were available to meet the increase in load and/or decrease in wind power production within a discrete hour. This is depicted in Figure 11 by the cumulative number of events that are less than zero on the x-axis. The x-axis in Figures 11 and 12 represents the magnitude of the shortfall. Negative values represent a shortfall, while positive values represent hours in which adequate up reserve were available.

4.1.1.3 System Faults and Generation Trips

In order to assess the impact of different scenarios on other aspects of system stability, transient stability simulation of events outlined in Table 7 were analyzed. Contingencies c1 and c2 result in a severe load unbalance in the system. These contingencies challenge the fast frequency regulation in the system and were used to help assess the risk of load shedding (sending end users offline) due to under-frequency load shedding. Contingency c2 is less severe than c1. Alternatively, contingencies c3 and c5 challenge the transient stability of the system during and after line faults and trips. These contingencies are associated with the system units maintaining synchronism and realistic levels of loading to avoid tripping off-line. These events were simulated for different initial conditions indicated in Table 8. The commitment and dispatch was obtained from the yearly GE MAPS™ results. These results represent severe contingencies and severe operating conditions in the system. The assessment covered several major contingencies reviewed by the project team. However, the analysis was not meant to be exhaustive.

Table 7: List of contingencies.

Contingency	Description
c1	Combined cycle trip at HEP
c2	Single unit trip at HEP
c3	7700 trip after fault (100 ms, solid fault)
c5	7700 trip (no fault)

Table 8: Initial conditions for Baseline scenario contingency cases.

Name	Load	Wind Speed	Hour
HW-HL	High	High	4120
NW-HL	High	Very Low	43
HW-LL	Low	High	1085
NW-LL	Low	Very Low	193

Table 9 presents the frequency metrics, up reserve of combustion and steam turbines and system inertia for contingencies c1 and c2. The c1 contingencies had significantly larger frequency excursions than the c2 contingencies. Contingency c1 resulted in significant load shedding for the high load cases. The high-load / no-wind case load shed down to the 58.2 Hz stage and the high-load / high-wind case shed down to the 58.4 Hz stage. The additional up reserve in the regulating units—as a result of the higher wind penetration—improved the frequency performance only slightly and prevented the operation of an additional stage of under frequency load shedding (58.2 Hz stage). The low-load cases did not result in frequency load shedding for contingency c1. Contingency c2 resulted in under-frequency load shedding for the high-load conditions of only the 59 Hz load-shedding stage.

Table 9: Summary contingencies c1 and c2 for Baseline scenario.

Contingency	Case	Max Frequency (Hz)	Min Frequency (Hz)	Steady State Frequency (Hz)	Initial Up reserve CTs (MW)	Initial Up reserve STs (MW)	System Inertia (sec)
c1	NW-HL	60.05	58.19	60.03	2	5	2.32
c1	NW-LL	60.00	59.05	59.57	20	33	1.71
c1	HW-HL	60.00	58.38	59.92	12	5	2.32
c1	HW-LL	60.00	59.01	59.50	16	39	1.49
c2	NW-HL	60.00	58.94	59.77	2	5	2.32
c2	NW-LL	60.00	59.75	59.89	20	33	1.71
c2	HW-HL	60.00	58.96	59.83	12	5	2.32
c2	HW-LL	60.00	59.75	59.89	16	39	1.49

Table 10 presents the results for contingencies c3 and c5. The c3 contingencies showed good voltage recovery (below 500 ms for all conditions).

Table 10: Summary contingencies c3 and c5 for Baseline scenario.

Cont	Case	Min Frequency (Hz)	HEP 69kV Min Voltage (pu)	HEP 69kV SS Voltage (pu)	HEP 69kV Recovery Time (sec)	Waimea Min Voltage (pu)	Waimea SS Voltage (pu)	Waimea Recovery Time (sec)
c3	NW-HL	59.18	0.00	1.03	0.38	0.33	0.98	0.48
c3	NW-LL	59.83	0.00	1.03	0.18	0.31	1.01	0.13
c3	HW-HL	59.48	0.00	1.03	0.35	0.35	0.97	0.15
c3	HW-LL	59.90	0.00	1.03	0.15	0.34	1.02	0.13
c5	NW-HL	59.34	1.00	1.03	0.00	0.88	0.98	0.15
c5	NW-LL	59.93	1.03	1.03	0.00	1.00	1.01	0.00
c5	HW-HL	59.53	1.01	1.03	0.00	0.90	0.97	0.00
c5	HW-LL	59.93	1.03	1.03	0.00	1.00	1.02	0.00

The system performance obtained in this assessment of the Baseline scenario was used as a reference for the analysis of other scenarios.

4.2 Higher Wind Penetration Scenario

The wind resource on the Big Island of Hawaii is excellent, as exhibited by very high capacity factors from the existing wind plants at Apollo, Hawi and Lalamilo. The Higher Wind Penetration scenario is motivated by the excellent wind resource on the island. At substantially higher penetrations of wind power, this analysis indicates that the HELCO system would need changes to the present system operation and/or technologies to address the variability. This scenario considers an expansion at each of three wind plant sites and assesses technologies and operating strategies to address the frequency impacts associated with wind variability.

According to the HELCO IRP3, high-resolution wind maps reveal that the offshore wind speeds are too low in regions having the shallow depths necessary for today's offshore wind technologies. Therefore, only a significant increase in land-based wind power, from 32.5 MW to 84.5 MW, was considered. The locations and amount of wind power added to the grid was based upon input by the project stakeholders who were interviewed as part of the project. The wind plant expansions are depicted in Figure 13.

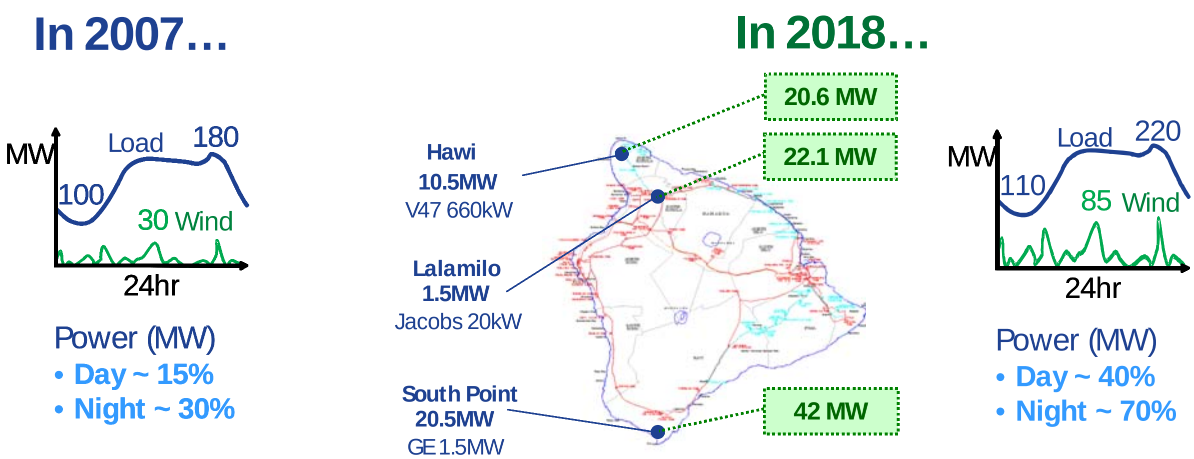

Figure 13. Present wind power installations and installed wind power for the Higher Wind Penetration scenario.

4.2.1 Production Cost Model

Production cost modeling of the HELCO system was performed with GE MAPS^{TM} described in a previous section. The model included representation of the HELCO transmission system and relevant characteristics of each generating unit. Unit models include maximum and minimum power output, heat rate as a function of load level, emissions, minimum downtime between starts, start-up costs, and operating constraints. Must-take as available generation was modeled as zero-marginal cost production, which can only be curtailed if the system is physically unable to accept the power. Operational constraints, as provided by HELCO are captured in the model. The results of this study are bound by those imposed constraints.

The overall simulation algorithm is based on standard least marginal cost operating practice. That is, generating units that can supply power for lower marginal cost of production are committed and dispatched before higher marginal cost generation. Commitment and dispatch are constrained by physical limitations of the system, such as transmission thermal limits, minimum spinning reserve, stability limits, as well as the physical limitations and characteristics of the power plants. The HELCO system cannot necessarily operate at the theoretical least-cost operating practice due to the operating criteria established to maintain system reliability and security constraints. Furthermore, the operational requirements of the available generating equipment impose additional constraints.

From the perspective of production costs, the incremental addition of 52 MW of wind power, at the three locations described earlier, reduced fuel consumption by 15%, and CO_2 emissions by 14%. The addition of the wind power to the Big Island displaced combined cycle plants, combustion turbines, and steam turbines as shown in Table 11.

Table 11. Comparing Higher Wind Penetration to the Baseline scenario.

HIGHER WIND PENETRATION

	Capacity MW	Energy GWh	Fuel MMBtu	NOx tons	SOx tons	CO2 tons
Combined Cycle	117	614	5007127	35	751	435364
Combustion Turbine	43	15	172454	57	27	15546
Diesel	29	14	115945	249	22	12608
Puna Geothermal	30	215	0	0	0	0
Small Hydro	16	55	0	0	0	0
Steam Oil	61	319	4547191	229	786	455420
Wind	85	335	0	0	0	0
Grand Total	**379**	**1567**	**9842717**	**569**	**1586**	**918939**

HIGHER WIND PENETRATION - BASELINE

	Capacity MW	Energy GWh	Fuel MMBtu	NOx tons	SOx tons	CO2 tons
Combined Cycle	0	-124	-958546	-140	-144	-83340
Combustion Turbine	0	-31	-421448	-16	-54	-31423
Diesel	0	4	179	228	6	3468
Puna Geothermal	0	0	0	0	0	0
Small Hydro	0	0	0	0	0	0
Steam Oil	0	-31	-379130	-533	-61	-35521
Wind	52	189	0	0	0	0
% Change	**16%**	**0%**	**-15%**	**-45%**	**-14%**	**-14%**

Wind power forecasting was incorporated in the hourly commitment strategy. Specifically, a wind power forecast based on the wind power profile for each hour of an average day was assumed in the commitment in this model. This is not the most accurate wind power production forecast available, but an assumed forecast method was needed in this analysis in order to have acceptable scenario performance with additional wind power on the grid.

4.2.1.1 Incorporating wind power production in the commitment strategy

In addition to the commitment strategy used, information about anticipated wind power production was incorporated into the commitment strategy. For the modeling in this scenario, a commitment strategy was superimposed on top of the production cost model to commit generation in anticipation that the wind power production would be the average level of production for the same hour throughout the previous year. This strategy may not necessarily be the most accurate method to forecast the wind power production, but even this strategy offered benefits in terms of reducing wind power curtailment when compared to a commitment strategy that uses no wind forecast.

The commitment strategy that included the wind forecast used several basic rules. If the wind power exceeded the forecasted, or anticipated, production generation in a specific hour, committed generation was backed down to accept the additional wind power. In contrast, if the wind power was less than the forecasted production, generation was ramped up. If insufficient up range was available, fast-starting generation would need to be committed. No attempt was made to optimize or significantly improve the forecast based on other trends, such as weather or time of year. The purpose of this exercise was to evaluate the impact of incorporating a rudimentary forecast of wind power production in the initial unit commitment. Incorporating wind forecasting in the commitment strategy could reduce the utilization of additional spinning reserve or stabilization devices (e.g., energy storage, battery, or other fast-reacting resources) to prevent utility frequency excursions.

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The must-run requirements of a certain number of conventional units, which resulted in the units backing down remaining online and thus increasing the online reserves, provided a buffer in the mismatch between the forecast and the actual wind production. Errors in the forecast in this analysis were addressed by increased use of the combustion turbines and diesels as shown in the GWh column in Table 12. The incorporation of a wind power production forecast in the commitment strategy resulted in a reduction in use of the combined cycle plants by 41 GWh/year. The net difference of 9 GWh is due to transmission losses.

Table 12. The impact of a wind power production forecast in the commitment strategy. NO_X, SO_X and CO_2 in units of tons.

	MW	GWh	MMBtu	NoX	SOX	CO2
Combined Cycle	0	-41	-436975	-124	-66	-37993
Combustion Turbine	0	6	64265	42	10	5801
Diesel	0	5	40274	230	8	4602
Puna Geothermal	0	0	0	0	0	0
Small Hydro	0	2	0	0	0	0
Steam Oil	0	8	84587	-467	13	7433
Wind	0	29	0	0	0	0
Grand Total	**0**	**9**	**-247849**	**-319**	**-35**	**-20157**

When knowledge about the expected wind power production is available, the overall unit commitment strategy can be improved. Even the incorporation of a crude forecast of the wind power production in the unit commitment significantly reduced wind power curtailment. According to Table 12, an additional 29 GWh/year was delivered to the system. When the wind power production is not incorporated in the commitment, unit over commitment was observed. This resulted in units being backed down when wind power was available or the curtailment of wind power when units were not backed down. But, as was described previously, if the forecast is inaccurate there is a need to be able to start generation to meet a shortfall caused by an inaccurate forecast. If increasing the amount of energy produced by renewable energy sources is an important objective for the Big Island, more accurate wind power forecasting should be developed along with fast responding stabilizing devices to maintain reliability and prevent nuisance utility under-frequency operation.

From an operational perspective, the most challenging incidences occur when the actual wind production was substantially lower than forecasted wind production and fast-start of generation was needed. One consequence of inaccuracies in the forecast will be nuisance load shedding if generation and load balance are not quickly restored before the first under-frequency block operates (within seconds). This has an implication on the availability of combustion turbines and diesel units capable of starting within minutes. The capacity of this type of generation and the availability of this type of generation (due to scheduled outages) is an important consideration when considering wind forecasting in the commitment. Direct load control programs, capable of disconnecting contracted loads could be one option to address these limited number of incidences in which load shedding may be required due to the unavailability of generation. The under-frequency nuisance tripping of the loads that is caused by intermittent generation must be minimized to maintain a reasonable level of reliability to the rate payers.

The Higher Wind Penetration scenario was constructed in both the production cost model (GE MAPS™) and the dynamic model (GE PSLF™). The electricity production, by type, is shown for an entire year of the production cost simulation (Figure 14). The hourly production, by type, is shown for forty days of the year. The same HELCO rules were imposed on the scenario shown here. An estimate of the wind power production based on the average annual wind power production for each hour of the previous year was included in the commitment strategy.

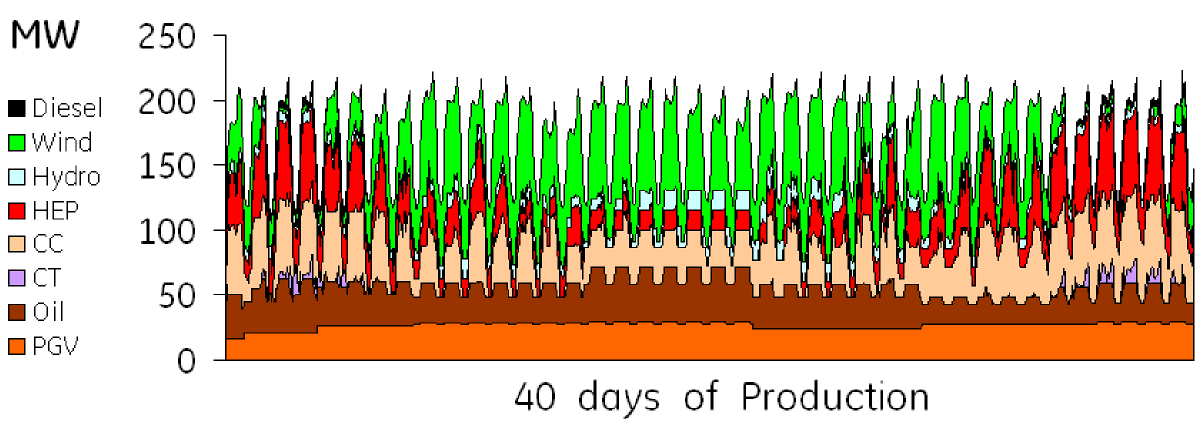

Figure 14. Energy production, by unit type, for the Higher Wind Penetration scenario.

The results will be discussed at the end of this section. The first step in the analysis process was to examine the dynamics of the grid for this scenario. The dynamic model was used to estimate the impact of the additional wind power, postulated in this scenario, on grid stability and frequency variations.

4.2.2 Dynamic Modeling

The same one-hour window as the baseline scenario was considered for the Higher Wind Penetration scenario. Since significantly more wind power capacity was present for this scenario, as compared to the Baseline scenario, the same decrease in wind speed results in a larger decrease in wind power production. In this case, the 34.5 kV radial line to Hawi was assumed re-conductored to accommodate additional wind generation. The expansion of the wind plant to this size on a radial transmission line would require additional study to determine its impact on system reliability during contingencies such as fault-clearing of the line. This level of detail was beyond the scope of the scenario analysis in this study.

4.2.2.1 Second-to-second wind variability

Similar to section 4.1.1.1, variability simulations were performed for the Higher Wind Penetration Scenario. The power production from the wind plant at Apollo and the wind plant at Hawi were scaled up based on the increase in installed power. Additional generation at these sites was conservatively assumed to be perfectly correlated to the production in the Baseline scenario. Since no high fidelity (2 second) data were available for the Lalamilo site, the Lalamilo wind plant was conservatively assumed to be coincident with the Hawi site.

The starting point for these simulations was based on the GE MAPS^{TM} results. The GE MAPS^{TM} results were used to define the unit commitment and dispatch for the initialization of the GE PSLF^{TM} model. The load and wind generation for the Higher Wind Penetration scenario and Baseline scenario are shown in Table 13.

Table 13: Higher Wind Penetration and Baseline scenario initial conditions.

Load	Scenario	Load Level	Wind Generation	Wind Penetration (%)
High Load	Baseline	214 MW	21 MW	10 %
Low Load	Baseline	115 MW	21 MW	18 %
High Load	Higher Wind	203 MW	61 MW	30 %
Low Load	Higher Wind	113 MW	56 MW	50 %

The frequency responses for the Higher Wind Penetration scenario with low and high load conditions are presented in Figure 15 and Figure 16.

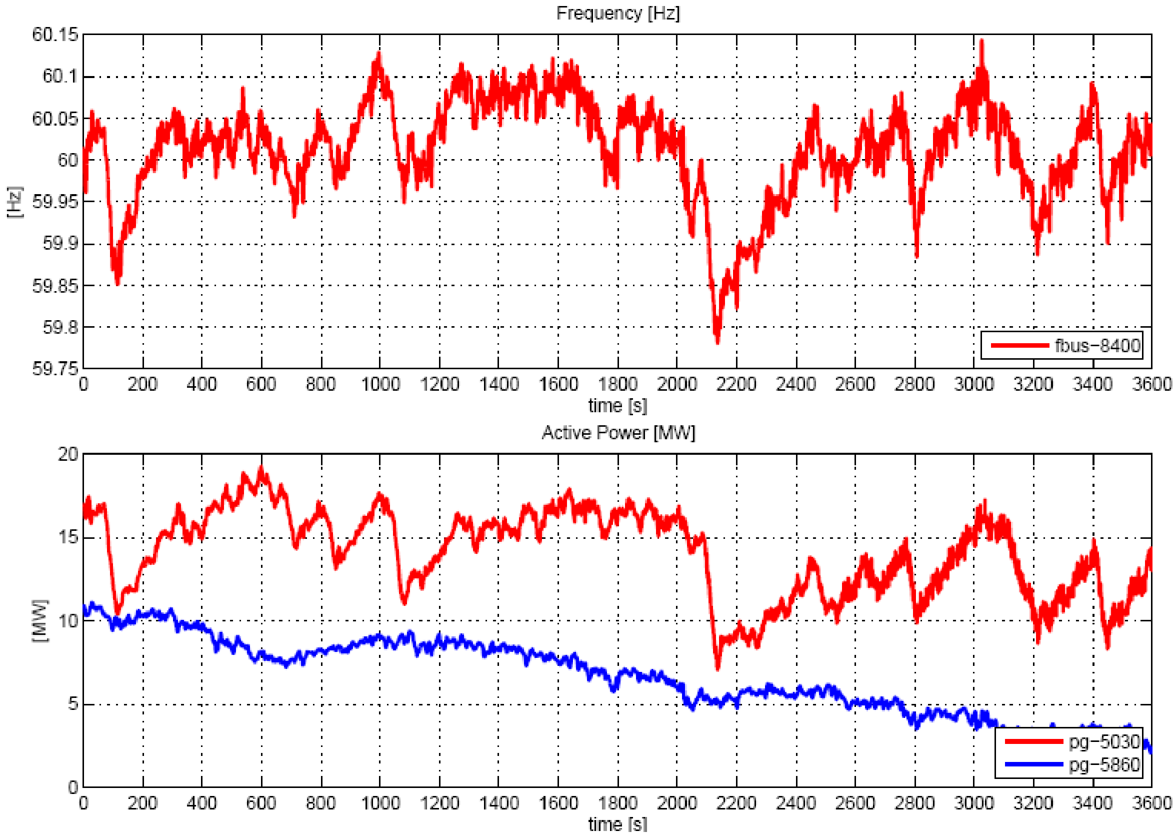

Figure 15. Higher Wind Penetration scenario: frequency response due to wind power variations during low load condition. System frequency (top figure, red curve), Apollo wind plant power output (bottom figure, red curve) and Hawi wind plant power output (bottom figure, blue curve).

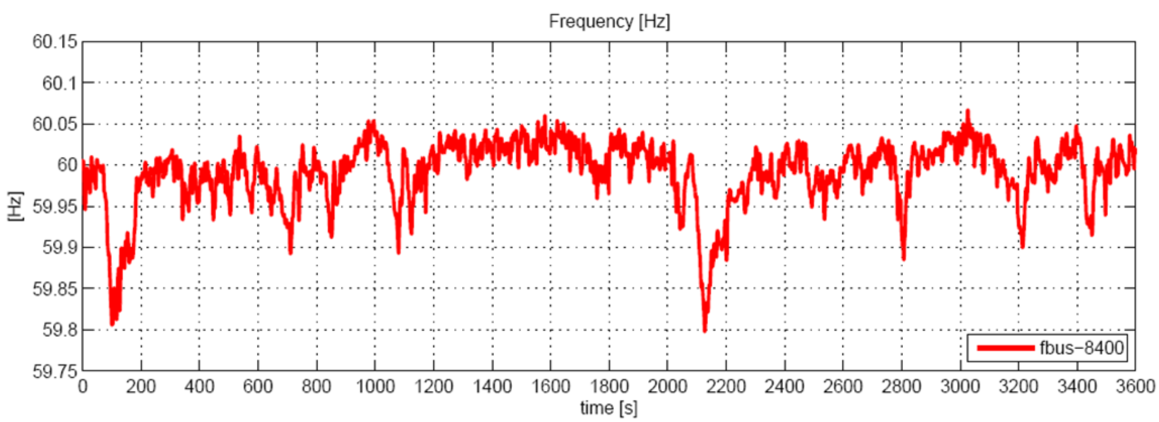

Figure 16. Higher Wind Penetration scenario: frequency response due to wind power variations during high load condition.

The results of the Higher Wind Penetration scenario cases are compared to the Baseline scenario cases in Table 14.

Table 14: Variability assessment of the Higher Wind Penetration (HW) & Baseline (BaU) scenarios.

Case	Description	Lowest Frequency (Hz)	RMS frequency fluctuations (Hz)	RMS slow frequency fluctuations (Hz)	Max frequency change (Hz/sec)	RMS power fluctuations regulating units (MW)	RMS fast power fluctuations regulating units (MW)
BaU_2018_LL	Business as Usual, year 2018, low load	59.89	0.032	0.029	0.019	1.415	0.173
HW_2018_LL	High Wind, year 2018, low load	59.78	0.060	0.051	0.016	2.293	0.316
HW2_2018_LL	High Wind, year 2018, low load, modified committment	59.82	0.050	0.041	0.014	2.768	0.311
BaU_2018_HL	Business as Usual, year 2018, high load	59.81	0.053	0.049	0.009	1.765	0.156
HW_2018_HL	High Wind, year 2018, high load	59.80	0.041	0.031	0.011	1.783	0.304
HW2_2018_HL	High Wind, year 2018, high load, modified committment	59.80	0.038	0.030	0.010	1.712	0.310

The low load cases show a worse frequency performance for the HW scenario. The lowest frequency was lower and the RMS frequency was higher for the HW scenario as compared to the Baseline scenario. In order to estimate the effect of commitment strategy on the system frequency performance during this wind event, a modified commitment that includes a rudimentary wind forecast (described earlier) was also considered for the HW scenario (HW2_2018_LL). The frequency performance is slightly better in the modified commitment because more flexible generation was committed. For high load conditions considered in the HW scenario, more available up reserve was present and a better frequency performance was observed. In fact, better RMS frequency performance was observed in the high load case for the Higher Wind Penetration scenario as compared to the high load case for the Baseline scenario, because the additional wind generation increased up reserve in the faster-response generation units on the HELCO system. However, the additional wind will generally result in worse performance on the minimum frequency measure.

HELCO's current operating experience with wind power confirms the results of the Higher Wind Penetration scenario. A private HELCO study confirmed that average frequency error increased with the addition of each wind plant. In response, HELCO made adjustments to their system operations to integrate wind power into the system. The next sections of this report describe some strategies for maintaining system stability with greater levels of wind power.

4.2.2.2 Mitigation of second-to-second wind variability

The Higher Wind Penetration scenario low load condition case was chosen for further analysis because this window exhibited the highest RMS frequency variation and the lowest minimum frequency observed in all of the cases. Potential changes in the power system, such as the addition of energy storage, were considered to investigate possible improvements in the overall system performance for this scenario.

4.2.2.2.1. Additional Rotating Reserve

The sensitivity of the higher wind scenarios to additional reserve was evaluated. Additional regulating reserve requires that generation be backed down to a lower, less efficient operating point. The fuel cost associated with increasing the regulating reserve is one reason for minimizing the amount of reserve in the HELCO system. The high load condition cases were repeated, increasing the up reserve at Keahole CT4 by 2MW (RR). Table 15 summarizes frequency performance. Note that two commitment strategies were considered (HW1 and HW2).

Table 15: Summary of Higher Wind Penetration scenario sensitivity to rotating reserve.

Case	Description	Lowest Frequency (Hz)	RMS frequency fluctuations (Hz)	RMS slow frequency fluctuations (Hz)	Max frequency change (Hz/sec)	RMS power fluctuations regulating units (MW)	RMS fast power fluctuations regulating units (MW)
HW_2018_HL	High Wind, year 2018, high load	59.80	0.041	0.031	0.011	1.783	0.304
HW_2018_HL+RR	High Wind, year 2018, high load, additional reserve	59.83	0.034	0.025	0.01	1.76	0.35
HW2_2018_HL	High Wind, year 2018, high load, modified committment	59.80	0.038	0.030	0.01	1.71	0.31
HW2_2018_HL+RR	High Wind, year 2018, high load, modified committment, additional reserve	59.84	0.035	0.028	0.13	1.73	0.31

The addition of 2 MW of additional up reserve at CT4 increased the minimum frequency deviation and decreased the RMS frequency as compared to the higher wind penetration, high load case without additional up reserve. Sensitivity analyses, performed in the first phase of this study, quantified the additional variable costs (fuel, start up and O&M) and emissions associated with increasing the regulating reserve requirement.

4.2.2.2.2. Frequency Stabilizing Devices

In the Higher Wind Penetration scenario, a significant frequency excursion was observed in the one-hour window. Stabilization devices in the form of energy storage or other fast-reacting resources could be used to improve system frequency performance. It is important to note that the dynamic stability results use a particular window of data and did not attempt to quantify the possible boundary conditions for wind performance.

Deviation of the frequency from 60 Hz results in increased maneuvering of the thermal generation to bring the frequency back to 60 Hz. The increased maneuvering results in heat rate impacts (lower efficiency) and it is assumed the increase in control actions and governor response will cause additional wear and tear of some of the thermal generators.

The character of the frequency excursions associated with significant wind power fluctuations required that stabilizing systems have a capability to delivery power and energy transiently. Those considered were energy storage, flywheels, fast reacting conventional generation, and pumped hydro. Different stabilizing sizes and control options were explored, assuming the devices were fully dedicated to frequency control. Pumped hydro was considered separately from the other stabilizing devices because it was assumed with a droop frequency control instead of fully dedicated to frequency control. This effort did not include an exhaustive control tuning of each stabilizing device; however, different settings were explored to use the proposed power ratings efficiently during the simulated operation. The tuning included transient and steady state gains, filtering, power rating, and the ramp-rate limit of power injection. The most relevant cases and settings are summarized in Table 16.

The table includes the Baseline (BaU) and the Higher Wind Penetration (HW) scenarios for reference. Stabilizing devices of 1 MW, 2 MW and 5 MW of rated power were considered. The control algorithms were fully dedicated to frequency control and more aggressive than typical governor droop controls. However, a washout characteristic was included to avoid continuous loading. Sensitivities to ramp rate were performed using fast (zero to full load in one second) in some cases and slow (2 MW/min) in others. Variations of ramp rate were considered for two reasons: (1) some technology options could be rate limited, and (2) it was important to understand the frequency performance implications of different rate limits. The performance characteristics for the stabilization devices could be met by current products that are commercially available. However, the operational experience with many of these technologies is currently limited.

Table 16: Higher Wind Penetration scenario: performance impact of stabilizing devices.

Description	Lowest Frequency (Hz)	RMS frequency fluctuations (Hz)	RMS slow frequency fluctuations (Hz)	Max Discharge Power (MW)	Max Charge Power (MW)	RMS power fluctuations regulating units (MW)	RMS fast power fluctuations regulating units (MW)
BaU 2018	59.89	0.03	0.03			1.42	0.17
HW 2018	59.78	0.06	0.05			2.29	0.32
1MW SD (gain 2)	59.82	0.05	0.04	1.12	-1.12	1.76	0.21
1MW SD (gain 2) rate limited	59.79	0.05	0.04	1.12	-1.12	1.96	0.16
1MW SD (gain 1)	59.82	0.05	0.04	1.12	-1.07	1.91	0.27
2MW SD (gain 1)	59.87	0.04	0.03	2.25	-2.24	1.35	0.17
2MW SD (gain 1) rate limited 2MW/min	59.84	0.04	0.03	2.25	-2.24	1.51	0.15
2MW SD (gain 2)	59.87	0.03	0.03	2.25	-2.24	1.20	0.07
2MW SD (gain 2) rate limited 2MW/min	59.85	0.04	0.03	2.25	-2.24	1.40	0.03
2MW SD (gain 3)	59.85	0.04	0.04	2.25	-1.86	1.63	0.24
5MW SD (gain 1)	59.95	0.02	0.02	4.74	-4.82	0.74	0.13
5MW SD (gain 1) rate limited 2MW/min	59.85	0.03	0.03	3.43	-4.15	1.25	0.04
5MW SD (gain 2)	59.98	0.01	0.01	4.94	-5.59	0.37	0.02
5MW SD (gain 2) rate limited 2MW/min	59.87	0.03	0.02	3.25	-5.26	1.09	0.01
30MW VSD PH	59.80	0.06	0.05	0.78	-0.84	2.19	0.36

The impact of different stabilizing devices is presented in Figures 17 to 19 with the best performing control settings obtained. Considering the lowest frequency observed (the largest excursion from 60 Hz) and the RMS frequency variation, the 2 MW stabilizing device substantially improved the frequency performance; to a similar performance as the Baseline scenario. The 5 MW stabilizing device provided better frequency performance as compared to the Baseline scenario. Figure 17 shows the lowest frequency measurement observed in the simulation window for various power-rated stabilizing devices. The lower values represent more substantial frequency excursions due to the sudden wind power reduction. The minimum frequency excursion (Figure 17) shows that all other stabilizing devices present better improvements than the pumped hydro storage due to the more aggressive control assumption. If pumped hydro response could respond faster than the controls analyzed here, similar performance may be observed. However, any device which responds directly to system frequency will need to be coordinated with the overall frequency management scheme of the HELCO system.

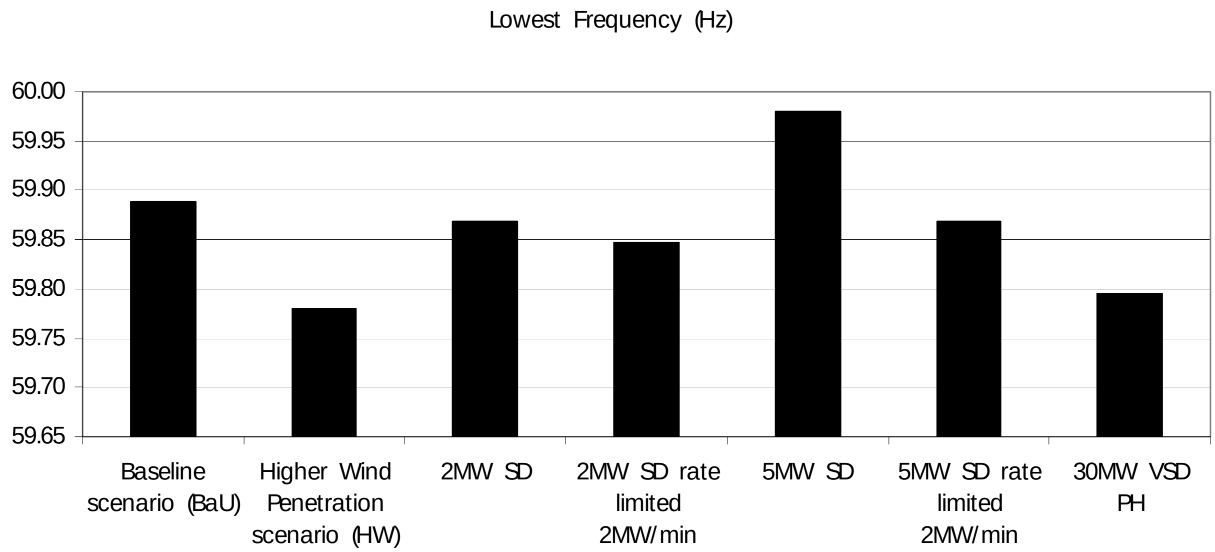

Figure 17. Minimum frequency (Hz) observed in the simulation window for various stabilizing devices.

Figure 18 shows the RMS value for the difference between the frequency signal and 60 Hz over the simulation window. Higher values represent more variable frequency signals.

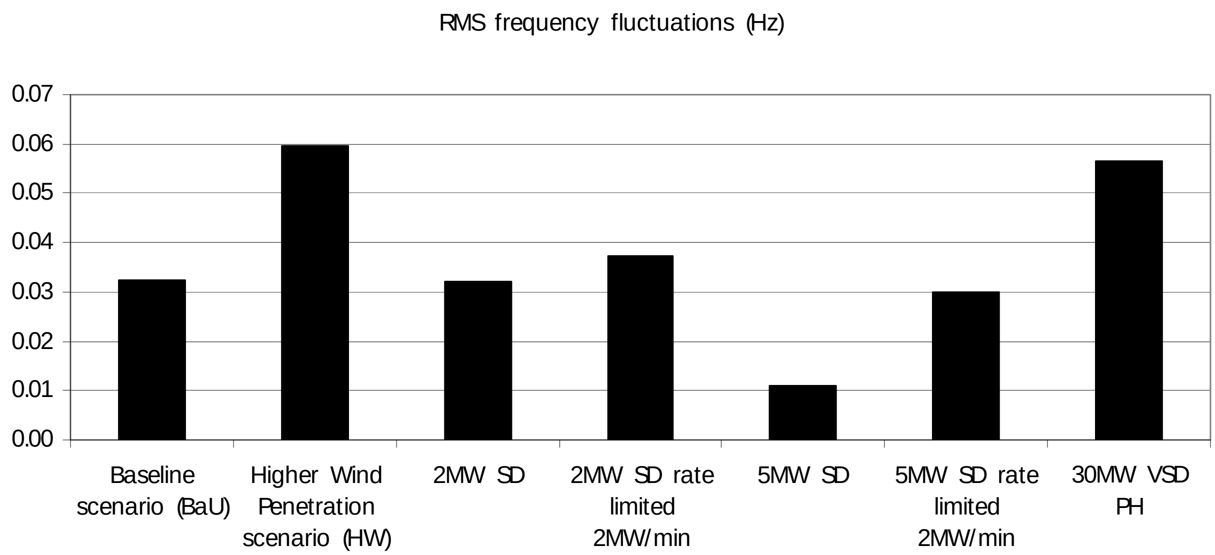

Figure 18. RMS frequency fluctuations (Hz) observed in the simulation window for various stabilizing devices.

Figure 19 shows the RMS value for the power excursions (in MW) from the set point over the simulation window. Higher values represent greater duty on the thermal generators that are increasing and decreasing power production to provide the necessary regulating functions. This has an impact on the heat rate and wear and tear of some units providing frequency regulation. This impact is not addressed in this study.

The stabilizing devices reduced the power fluctuations from the thermal generators. A 2 MW SD reduced the RMS in power fluctuations by 45% with respect to the Higher Wind Penetration scenario and was slightly better than Baseline scenario. A 5 MW device improved the RMS in power fluctuations by about 80% with respect to the Higher Wind Penetration s cenario. However, if the 5MW device was rate limited to 2 MW/min, the RMS power fluctuations were reduced by only 40% with respect to the Higher Wind Penetration scenario. Fast-responding stabilizing devices offer substantial reduction in the power fluctuation in the units. In Figure 19, the stabilizing device absorbs a significant part of the fluctuations. The thermal units served less of the fluctuations caused by the wind power variation than in the Baseline scenario.

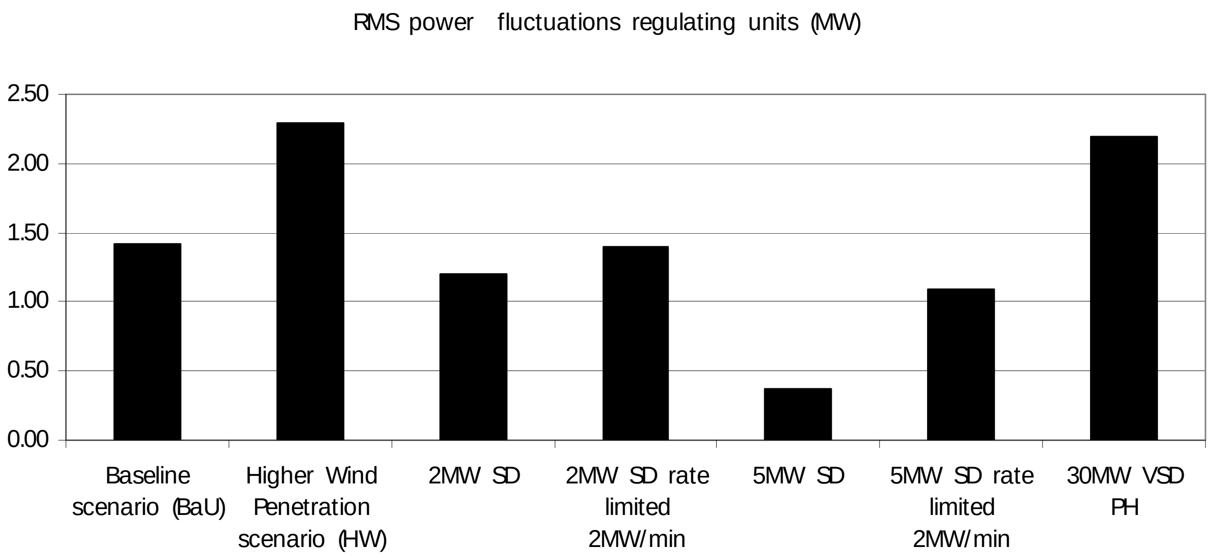

Figure 19. RMS power fluctuations (MW) of regulating units in the simulation window for various stabilizing devices.

4.2.2.3 Intra hour variability

In the Baseline and Higher Wind Penetration scenarios, there were hours during the year in which the up reserve of the generators was insufficient to meet the increase in load or decrease in wind power production in that hour. These events required a generator be started within the hour. These events occurred on the minutes-to-hour timeframe. The amount of up reserve was compared to the increase in load and decrease in wind power production for each hour of the year, similar to section 4.1.1.2 for the Baseline scenario.

Different commitment and dispatch criteria were considered to observe the attributes of a given commitment strategy. Two cases are presented here: Case 9 represents the commitment and dispatch criteria provided by HELCO, which include the must-run rules[10], and Case 7b represents commitment and dispatch criteria that deviate from the present HELCO strategy. In general, Case 7b did not include the must-run requirement for the steam generators on the HELCO system and required a CT unit at Keahole to come online when load exceeded 130 MW. Case 9 was used in all simulations, while Case 7b was only presented to be illustrative of

[10] Operational Requirements for Unit Commitment and Dispatch, System Operations Policies and Procedures, March 30, 2007.

alternate commitment strategies. These cases were compared to the Baseline scenario results presented earlier in the report.

A storage device was considered as one potential technology that could be used to bridge the shortfall between up reserve and the increasing load and/or decreasing wind power production over a specific timeframe. A storage device was sized for the Higher Wind Penetration scenario that would provide a similar number of these events each year as was observed in the Baseline scenario for the particular hours identified previously.

Similar to information shown in Figure 12, the number of hours during the year in which the up reserve was insufficient to meet the rise in load or decrease in wind power production was quantified. Additionally, the magnitude of the shortfall in energy was quantified. The amount of energy shortfall was estimated assuming a linear increase in load and a linear decrease in wind power production over the course of each hour of the year. Based on the linearization, the amount of energy shortfall could be calculated, but this method may underestimate the shortfall if within the hour the wind power drops significantly below level in the linear interpolation.

The y-axis of Figure 20 presents the cumulative number of events (hours per year). The x-axis represents the MW of available up reserve minus system hourly variability (load increase over the course of the hour + the decrease in wind power production). Therefore, positive values on the x-axis represent events in which sufficient up reserve was available. Negative values represent the amount of shortfall in that hour.

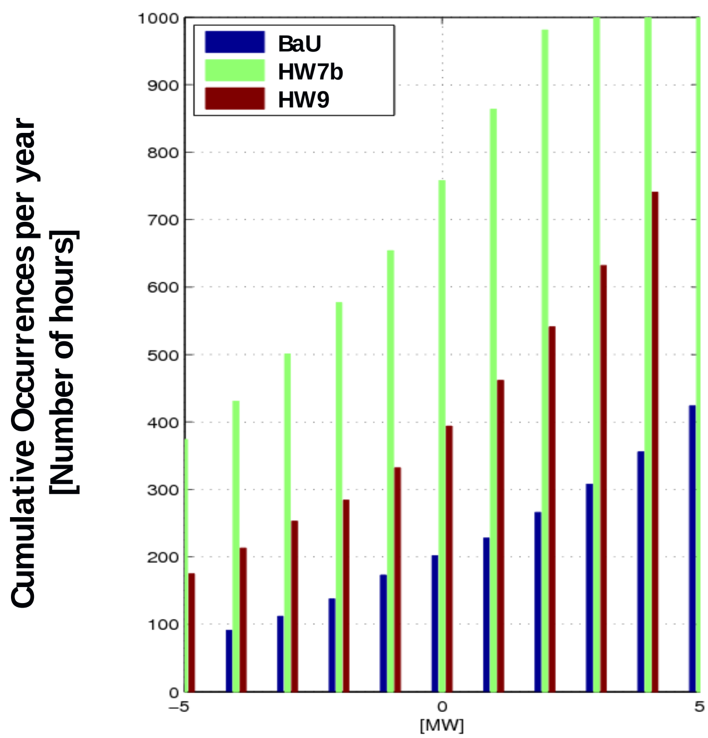

Figure 20. Cumulative distribution function from –5 MW to +5 MW. Up reserve minus hourly variability for the Baseline scenario (BaU), Higher Wind Penetration scenario (HW9) and Higher Wind Penetration with an alternate commitment strategy (HW7b).

Figure 20 shows that the Baseline scenario exhibited ~400 hours per year in which there was a shortfall in up reserve. This was discussed in section 4.1.1.2. The two Higher Wind Penetration scenario cases exhibit a greater number of hours in which there was a shortfall in up reserve. Figure 20 showed the cumulative number of events for the Baseline scenario and the two cases of the Higher Wind Penetration scenario (HW7b, HW9). Figure 21 shows the number of occurrences each year on the y-axis and the magnitude of each occurrence on the x-axis for the Baseline scenario, the Higher Wind Penetration scenario (HW9) and the Higher Wind Penetration scenario with a 5 MW (2 MWh) energy storage device used to bridge the shortfall in up reserve. The number of hours in which this occurred and the magnitude of each occurrence were calculated. The amount of energy shortfall was estimated assuming a linear increase in load and a linear decrease in wind power production over the course of each hour of the year. The energy shortfall was calculated based on the linearization.

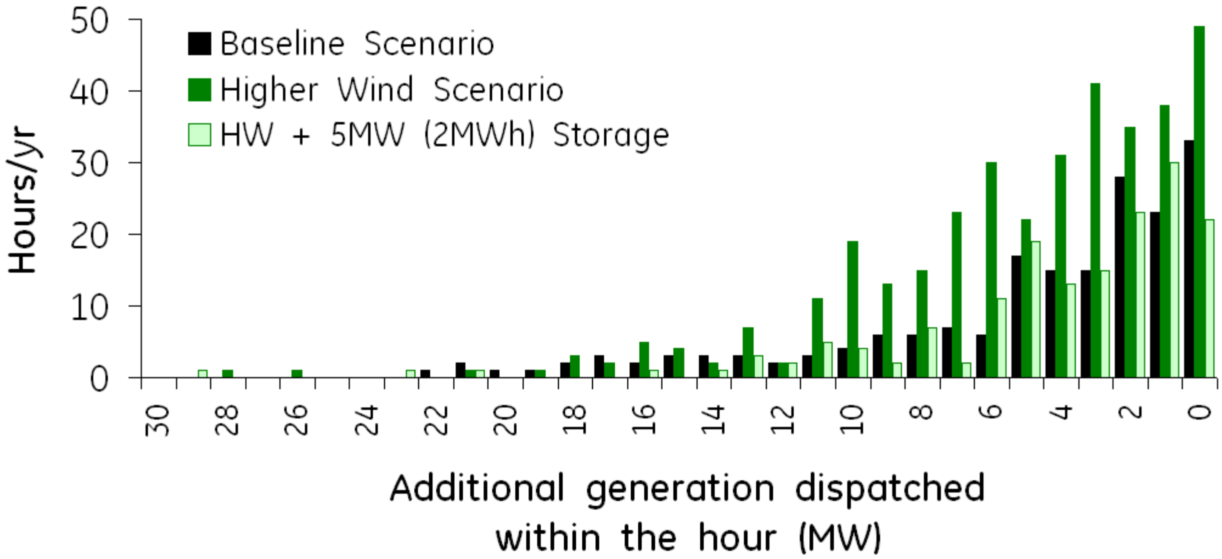

Figure 21. The shortfall of up reserve of the committed generation was quantified for the Baseline scenario, Higher Wind Penetration (HW) scenario, and the HW scenario with 5 MW (2 MWh) of energy storage.

Based on this analysis, approximately 2 MWh of energy storage (5 MW of power) provided sufficient power and energy to obtain a similar number and magnitude of shortfalls as was observed in the Baseline scenario.

It should be noted that the increase in load and decrease in wind power were considered on a discrete hourly basis only. Although significant inter-hour fluctuations, and the effect of this fluctuation on system frequency, could be addressed by the fast-reacting resource described earlier; sustained and rapid changes in load and wind power such as have been observed on the HELCO system from the existing wind plants may require additional energy and power than inferred by this analysis. Additionally, the primary objective of the storage device was to eliminate fast-starting diesels in response to changes in load and wind power or to provide a bridging strategy to reduce the number of starts associated with sustained changes in load and

- Identification of specific ramp or variability conditions which represent significant events and would be used as the boundary condition for sizing such a device.
- The specific time needed to start a diesel unit.
- The criteria the operator could use to conclude with a degree of confidence that a sustained event (load rise or wind power reduction) is occurring. (This is a significant challenge in real-time. At present, the trigger is the deviation of system frequency beyond 0.2 Hz). A refined method is necessary in order to provide the trigger for the discharge of energy, but to avoid false discharges. A combination of short-term forecasting and frequency error, along with real-time input of the MW change, might be necessary.
- The variable cost tradeoff with the capital and operating costs of a storage device, which include the capital investment and additional costs such as control systems and communications infrastructure for the necessary control inputs. For example, sizing an energy storage device to cover all of the power and energy shortfalls will result in a substantially larger storage device than one sized for 95% of the events. Relying on fast-starting diesel units for the extreme events is likely to be a more economic approach than sizing a storage device for all events.
- The influence of rated MWh on the life of battery components, if a battery is selected as the appropriate bridging device.
- A mechanism to alert the system operator that a device has discharged, and that it is necessary to start up the backup units.

4.2.2.4 System Faults and Generation Trips

The same contingencies considered in the Baseline scenario were considered for the Higher Wind Penetration scenario. Different load and wind generation levels were also considered. The uncontrolled trips of loads during a fault case and low load conditions were explored to assess risk of over frequency conditions. The initial conditions are outlined in Table 17. Similar to the Baseline scenario, the commitment and dispatch were obtained from the GE MAPS™ simulation results for the Higher Wind Penetration scenario. The c1 (combined cycle trip at HEP), c2 (single unit trip at HEP), c3 (transmission line trip with fault), and c5 (transmission line trip) contingencies examined in the Baseline scenario were also examined in the Higher Wind Penetration scenario.

Table 17: List of Higher Wind Penetration (HW) cases.

Scenario	Hour	Storage
HW-HL	7460	No
HW-HL	5637	No
HW-LL	3846	No
HW-LL	3795	No
HW-HL	7460	Yes
HW-HL	5637	Yes
HW-LL	3846	Yes
HW-LL	3795	Yes

4.2.2.4.1 Frequency performance during generation trips

The frequency response of the system for contingency c1 and c2 for high wind speed and high load conditions are presented in the figures below. The system frequency response with different scenarios and assumptions are shown for comparison. In the high load cases (Figure 22 and Figure 23), contingency c1 results in frequency load shedding for all cases. The rate of change of frequency is more substantial in the Higher Wind Penetration scenario (blue line) than the Baseline scenario (red line) as a result of the lower system inertia. In the Higher Wind Penetration scenario the under-frequency load shedding stages operated down to the 58.2 Hz stage. In the Baseline scenario, the under-frequency shedding reached the 58.4 Hz stage. The case with the stabilizing device (green line) showed small improvement (compared to blue line) because the power rating of the device was small compared to the unbalanced power.

Results for the high load case and contingency c2 are presented in Figure 23. System frequency performance was similar between the Baseline scenario (red line) and the Higher Wind Penetration scenario (blue line). In both cases, only the 59 Hz load-shedding scheme operated. A higher rate of change of frequency was observed in the Higher Wind Penetration scenario again because of the lower system inertia. The stabilizing device substantially improved the frequency performance because the storage device compensated for a considerable amount of the lost generation.

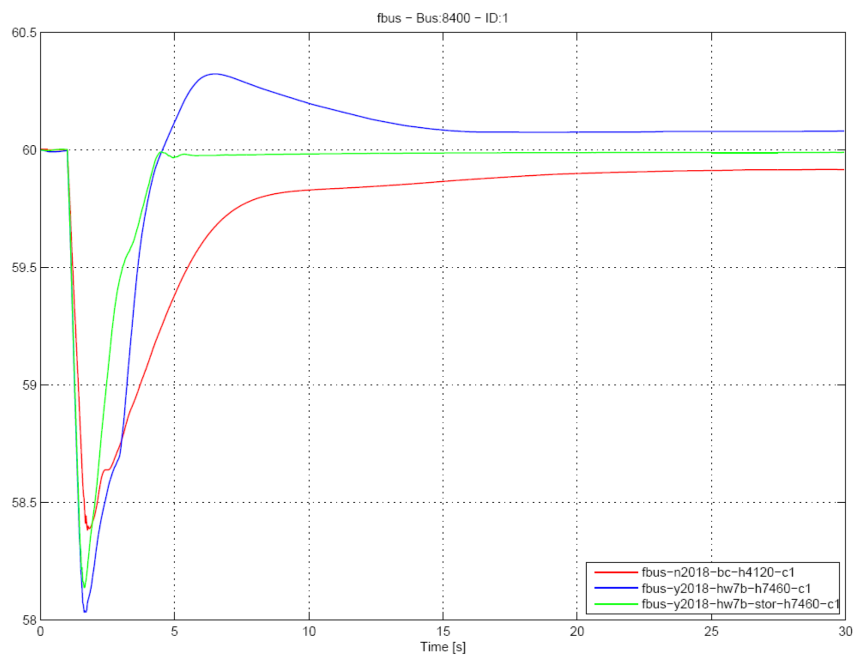

Figure 22. Frequency response for HW-HL scenario to contingency c1 for Baseline scenario case (red line), Higher Wind penetration (HW) case without storage (blue line) and HW case with storage (green line).

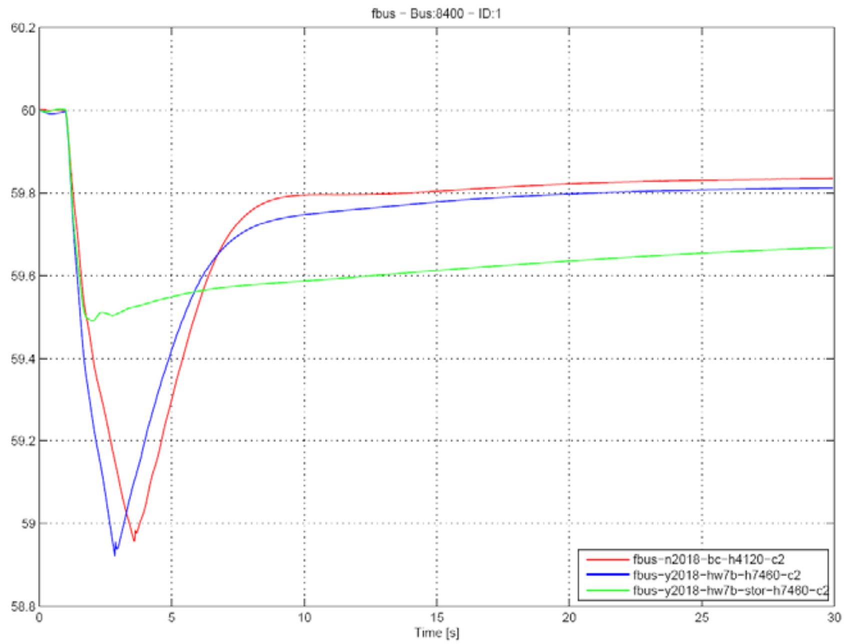

Figure 23. Frequency response during HW-HL scenarios to contingency c2 for Baseline scenario (BaU) case (red line), HW case without storage (blue line) and HW case with storage (green line).

A summary of frequency performance for conditions with high wind speed and low load is presented in Table 18 for the same scenarios.

Table 18. Frequency performance comparison for HW LL conditions after generation trips

Description	Contingency	Case	Min Frequency (Hz)	Steady State Frequency (Hz)
BaU	c1	HW-LL	59.01	59.50
HW	c1	HW-LL	58.97	59.83
HW modified commitment	c1	HW-LL	58.94	59.76
HW modified commitment	c1	HW-LL - Storage	59.45	59.93
BaU	c2	HW-LL	59.75	59.89
HW	c2	HW-LL	59.72	59.89
HW modified commitment	c2	HW-LL	59.68	59.88
HW modified commitment	c2	HW-LL - Storage	59.92	59.98

In the low load results (Figures 24 and 25), similar observations can be made regarding initial rate of change in frequency. Contingency c2 does not result in under-frequency load shedding for any of the cases considered (Figure 25). The commitment assumptions had an impact on the system performance. The HW case 9 (pink line) had slightly worse frequency performance as compared to the Baseline scenario. The HW case 7b with modified dispatch (blue line) showed a more significant difference in the frequency performance, although the installed wind capacity was same as in the HW case 9 (pink line). The unit commitment strategy had a major effect on the recovery of the system frequency. It is also important to mention that wind generation (and storage, when applicable) was assumed not to provide any response that could improve system inertial response. Some turbine manufacturers offer related capabilities.

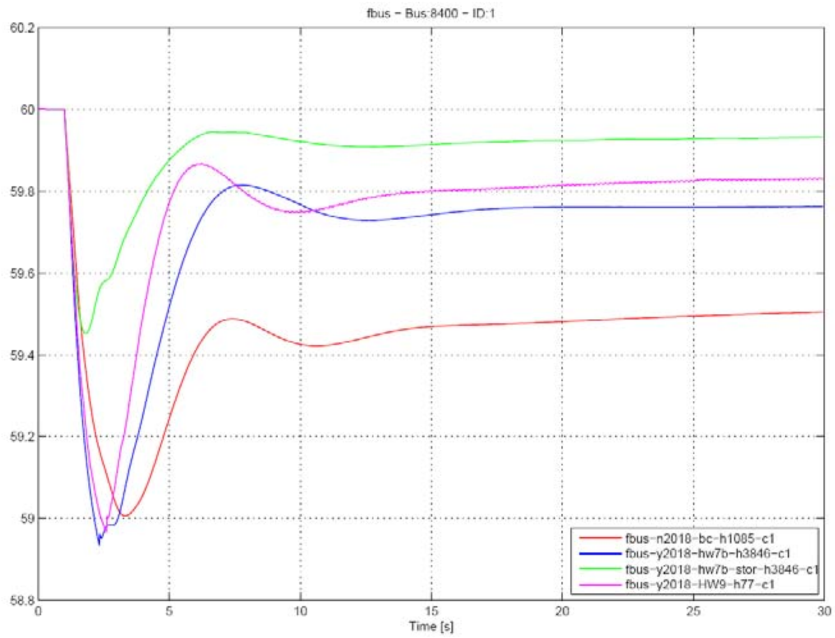

Figure 24. Frequency response during HW-LL scenarios to contingency c1 for Baseline scenario case (red line), HW case (pink line), HW case with modified dispatch (blue line) and HW case with modified dispatch and storage (green line).

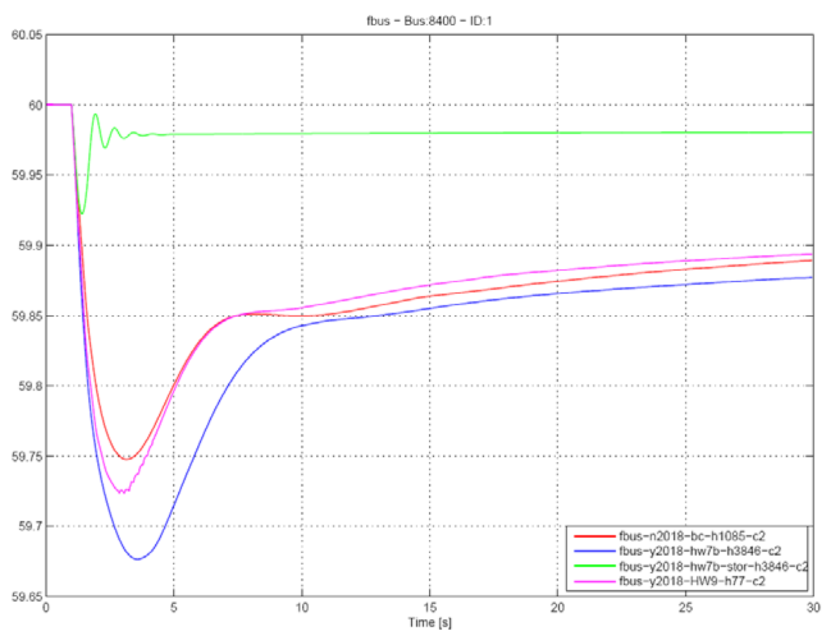

Figure 25. Frequency response during HW-LL scenarios to contingency c2 for BaU case (red line), HW case (pink line), HW case with modified dispatch (blue line) and HW case with modified dispatch and storage (green line).

4.2.2.4.2 Fault behavior

No significant differences were found with respect to voltage recovery for the considered event in this scenario with respect to the Baseline scenario. Table 19 presents results for comparison with Table 10. The c3 contingencies show good voltage recovery (below 500 ms for all conditions). Recovery times are slightly higher.

Table 19: Summary table: contingency c3 for HW scenario.

Cont	Case	Min Frequency (Hz)	HEP 69kV Min Voltage (pu)	HEP 69kV SS Voltage (pu)	HEP 69kV Recovery Time (sec)	Waimea Min Voltage (pu)	Waimea SS Voltage (pu)	Waimea Recovery Time (sec)
c3	NW-LL	59.92	0.00	1.03	0.18	0.33	1.02	0.13
c3	HW-LL	59.90	0.00	1.03	0.15	0.34	1.02	0.13
c3	NW-HL	59.48	0.00	1.03	0.40	0.38	1.00	0.13
c3	HW-HL	59.53	0.00	1.02	0.33	0.37	1.01	0.13
c3	/-LL - Stor	59.94	0.00	1.03	0.18	0.34	1.03	0.10
c3	/-LL - Stora	59.88	0.00	1.03	0.15	0.35	1.02	0.13
c3	/-HL - Stora	59.49	0.00	1.02	0.43	0.40	1.03	0.13
c3	/-HL - Stora	59.61	0.00	1.02	0.33	0.38	1.01	0.13

4.2.2.4.3 Enhanced Wind Variability Mitigation with Thermal Units

An alternative approach to mitigating the frequency effects of wind power intermittency is to coordinate the existing thermal generation in such a way that the generator is capable of responding sufficiently fast to changes in wind power production before the change in wind power production manifests itself in a system frequency excursion. In this simulation, a feed forward signal of wind power output change was provided to the AGC and adjusted the amount of power produced by the LM2500 combustion turbines at HEP. This addition of a "transient wind smoothing loop" (TWSL) improved frequency performance. This is shown in Figure 26.

Figure 26 shows the system frequency in the simulation plan under the Baseline scenario and then the same scenario with the TWSL mitigation.

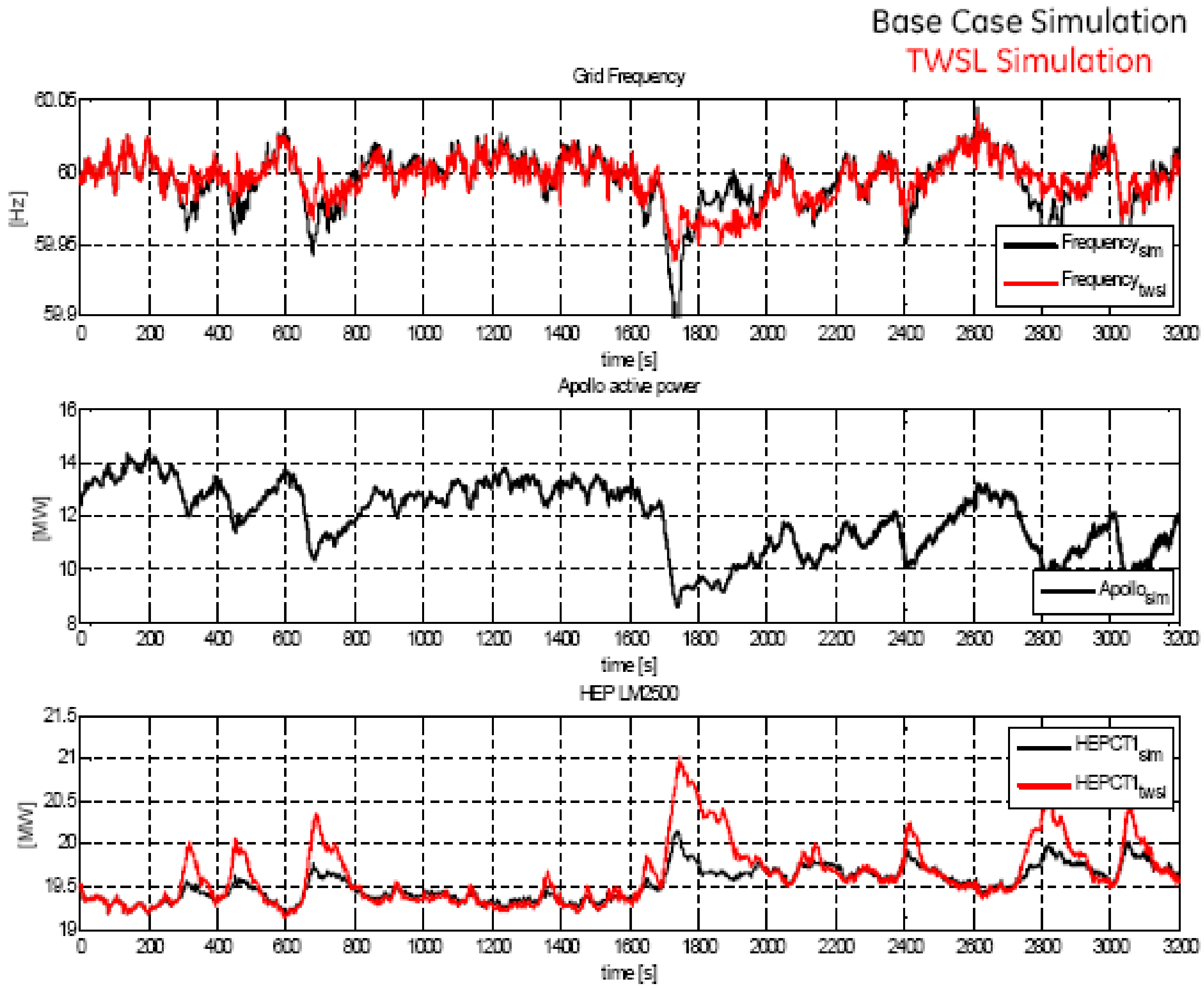

Figure 26. Top: Baseline scenario frequency trace (black) and the Transient Wind Smoothing Loop (TWSL) frequency trace (red). Middle: Wind power decrease at the Apollo wind plant. Bottom: Output of LM2500 (2 units) at HEP. Baseline scenario (black), TWSL implementation (red).

The modeling of this mitigation method may not represent a detailed or optimized design, but was intended to test the potential benefits from this control method. Other similar applications exist in the electric power industry, but pursuing this control method would require considerably greater detailed engineering.

4.2.2.4.4 Over frequency risk during low load operation

During low load operation with good wind conditions, thermal units tend to run close to the minimum limits due to the must-run requirements imposed by HELCO. The system is operated with a minimum of down reserve to reduce risk of over frequency in case of a loss of load. To illustrate this risk, contingency c3 was simulated assuming uncontrolled disconnection of some of the load due to low voltages during the fault (termed c8). Thirty percent of the load was assumed to be sensitive to low voltages (AC contactors, power converters, electronic loads, etc). The observed frequency response is shown in Figure 27. When the disconnected load exceeds available down reserve, the frequency increases (green line). In operation, this will cause generation disconnection. Given the risk of this over frequency conditions, it is recommended to coordinate over frequency/overspeed unit trips to ensure that critical units with regulation capability are the last to be disconnected during over frequency events.

The blue line shows the frequency obtained from assuming over-frequency control at the Apollo wind plant. The performance is significantly better that the case with load disconnection and no frequency control at the Apollo wind plant. This control option implemented at the Apollo wind plant provided down reserve equal to the power output of the wind plant. This type of control function is readily available in modern turbines. The over-frequency control function has the advantage of not requiring continuous operation below maximum available wind power. Consequently, this approach does not have any significant lost wind energy production penalty. The use of this function could reduce the need for down reserve in thermal units and hence reduce the amount and frequency of wind power curtailment. Furthermore, reducing wind power curtailment reduces the amount of fossil fuel consumed in thermal generation.

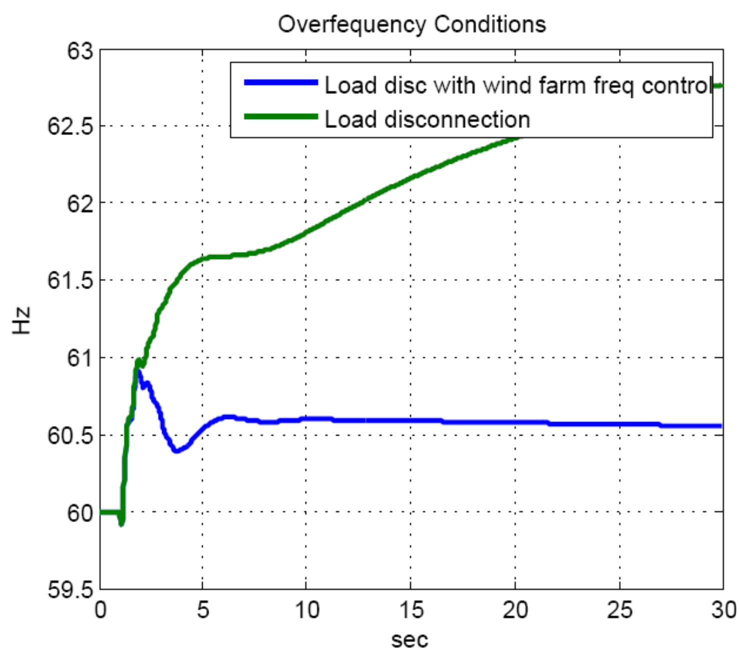

Figure 27. Load disconnection (contingency c8) under low load conditions and HW scenario (green line) and the same case assuming frequency control in Apollo wind plant (blue line).

Similarly, wind plants can perform frequency control for frequency excursions below nominal power, but are required to operate below maximum available wind power. In cases when wind plants are curtailed, it would be beneficial to the system to have wind plants performing this type of support function.

4.2.3 Conclusions for the Higher Wind Penetration Scenario

The analysis on the Higher Wind Penetration scenario showed that increasing wind power capacity substantially at three locations reduced fossil fuel consumption and CO_2 emissions on the HELCO system significantly. The results from this analysis show fuel consumption declined by 15% and CO_2 emissions by 14%. These reductions occurred as wind power displaced generation from combined cycle plants, combustion turbines and steam turbines as shown in Table 20. The results also show that this increase in variable power generation detrimentally affected the stability of the system if no additional operational measures were taken or no additional stabilization devices were incorporated into the system. When additional stabilization devices were incorporated into the system, the frequency performance of the system with high levels of wind power improved markedly. While this analysis simulates the HELCO system in a high level of detail, it uses a limited set of data to test the performance of wind power and storage technologies. This analysis is not meant as a detailed engineering design study. Furthermore, this is not a benefit-cost analysis as the full capital and operating costs of each scenario have not been quantified for comparison.

Energy storage for both second-to-minute variability and energy storage for minute-hour operational flexibility was modeled. Increasing the regulating (spinning) reserve requirement could be an alternative approach to energy storage over the longer minute-hour timeframe to help mitigate wind-ramping events. Additionally, the need to fast-start smaller diesel units to address the inter-hour wind and load variability was not quantified. It is expected that this would increase the overall fuel consumption. This amount was not quantified because substantial high fidelity wind data were not available for each of the three sites to perform the fast-start analysis.

Table 20. Comparing Higher Wind Penetration to the Baseline Scenario.

HIGHER WIND PENETRATION

	Capacity MW	Energy GWh	Fuel MMBtu	NOx tons	SOx tons	CO2 tons
Combined Cycle	117	614	5007127	35	751	435364
Combustion Turbine	43	15	172454	57	27	15546
Diesel	29	14	115945	249	22	12608
Puna Geothermal	30	215	0	0	0	0
Small Hydro	16	55	0	0	0	0
Steam Oil	61	319	4547191	229	786	455420
Wind	85	335	0	0	0	0
Grand Total	**379**	**1567**	**9842717**	**569**	**1586**	**918939**

HIGHER WIND PENETRATION - BASELINE

	Capacity MW	Energy GWh	Fuel MMBtu	NOx tons	SOx tons	CO2 tons
Combined Cycle	0	-124	-958546	-140	-144	-83340
Combustion Turbine	0	-31	-421448	-16	-54	-31423
Diesel	0	4	179	228	6	3468
Puna Geothermal	0	0	0	0	0	0
Small Hydro	0	0	0	0	0	0
Steam Oil	0	-31	-379130	-533	-61	-35521
Wind	52	189	0	0	0	0
% Change	**16%**	**0%**	**-15%**	**-45%**	**-14%**	**-14%**

The following conclusions can be drawn:

1. Increasing wind generation increases second-to-second system variability and impacts frequency performance (RMS frequency deviations for the Higher Wind Penetration scenario are nearly double the deviations observed in the Baseline scenario).
2. The system frequency excursions resulting from wind power variations are mostly improved by slow (steady-state) response of unit governors and the AGC regulation function. System inertia had little impact in the simulation windows observed in this study. The distribution of reserve (the types of units providing regulation) has significant impact on system performance. Generating units with poor droop response and slow AGC response do not provide good system support in addressing the second-to-second variability of wind power production.
3. The Higher Wind Penetration scenarios are characterized by lower system inertia. The system is then more prone to large frequency excursions and load shedding in the event of sudden loss of generation. Wind turbine manufacturer features to support the system in such events are relevant to HELCO system.
4. For the data sets analyzed, stabilizing devices of 5 MW and less than 10 min of energy improved system behavior in the Higher Wind Penetration scenario. It should be noted that the HELCO system has experienced larger deviations than that the events analyzed as part of this effort, and additional analysis is required to assess the sizing, control strategy, and cost feasibility of a storage device for the purpose of reducing frequency deviations from wind.
5. For the assumed variability study in the scenario, a 2 MW stabilizing device was effective at improving frequency performance to the same level as the Baseline scenario,

6. Another 5 MW (24min) of energy storage reduces the number of hours in which the expected starts of fast-starting generation is required as measured by the up reserve and the comparison between the up reserve of the Baseline scenario. This result is dependent on assumptions used in the modeling of the commitment orders.
7. Dynamic control of fast-reacting units in response to wind power fluctuations can result in a better frequency performance.
8. Wind plant frequency controls can prevent cascading events caused by over-frequency conditions. These controls automatically down-ramp wind plant output in response to over-frequency conditions. These conditions occur particularly during levels of low load and high wind generation if the system loses a significant level of load. The use of this control can reduce the need for down reserve in thermal units, which will reduce wind power curtailment.
9. Using frequency control for under frequency in wind plants during curtailed operation would improve system behavior. Furthermore, this could reduce the need for wind plant curtailment in some conditions as less reserve would remain on the system.

4.3 Enhanced Energy Management Scenario

Demand-side approaches, such as peak load reduction through the use of residential direct load control, enable load reduction during hours of expensive and challenging system operation. Multiple demand-side and supply-side approaches were considered in this scenario, including plug-in hybrid electric vehicles (PHEV), energy efficiency programs, distributed generation, combined heat and power, and residential and commercial load control programs.

The HELCO IRP proposes a number of demand-side programs. The impact on the peak load reduction and reduction in energy sales was estimated in the HELCO IRP and interpolated for 2018. The existing programs include:

- Residential Efficient Water Heating Program (REWH),
- Commercial and Industrial Energy Efficiency Program (CIEE),
- Commercial and Industrial New Construction Program (CINC),
- Commercial and Industrial Customized Rebate Program (CICR),

The new DSM energy efficiency programs include:

- Residential New Construction Program (RNC),
- Energy Solution for the Home Program (ESH),
- Residential Qualifying Income Program (RQI),

New Load control programs include:

- Residential Direct Load Control (RDLC),
- Commercial and Industrial Load Management (CILM).

The impact of these programs is summarized in Table 21.

Table 21. Demand reduction programs from HELCO IRP-3[11].

		2018	
	Energy Efficiency Program	Peak MW Reduction	GWh Reduction
Existing	REWH	2.4	8.5
	CIEE	3.7	25.6
	CINC	2.3	18.2
	CICR	3.2	16.6
New	ESH	1.9	5.7
	RQI	0.3	1.7
	RNC	1.7	5.0
Load Control	RDLC	2.7	0.0
	CILM	2.4	0.0
Rates	RTOU	0.3	0.0
	Sum	20.9	81.3

[11] HELCO IRP, Table 10.1-3

The following discussion is separated into two sections. The first section considers energy efficiency and combined heat and power. The second section considers the charging of PHEVs.

4.3.1 Energy Efficiency and Combined Heat and Power

Three programs that impact residential energy efficiency are the REWH, ESH, and RNC. These three programs provide ~6 MW of reduction at peak. A 6 MW reduction at peak was modeled in this scenario, scaled by the ratio of load / daily peak for each hour of the year, except the hours from 1am to 6am, daily. The early morning hours were excluded due to the lack of perceived impact of these programs during the early morning hours. For example, solar water heating reduces the electric water-heating load during the hours of sunlight. This reduction will not occur during the late evening and early morning hours. Additionally, the air conditioning load may be reduced by improved building envelope design, but this reduction in load should be less pronounced during the evening hours, when the air conditioning load is much lower. The IRP estimated ~20 GWh of energy reduction; however, the more aggressive approach used for this scenario resulted in ~30 GWh. A similar approach was taken for resort and commercial energy efficiency. The commercial IRP programs provide ~9 MW of reduction at peak and ~60 GWh reduction in energy use. For this scenario, the commercial energy efficiency program provides 4 MW of peak load reduction and the resort energy efficiency program provides 7 MW of peak load reduction. These two programs reduce energy consumption by ~60 GWh. The resort energy efficiency program reduces the load by the ratio of load / daily peak for each hour of the year, except the hours from 1am to 6am. The commercial energy efficiency program reduces load during the hours from 7am to 10pm by the ratio of load / daily peak for every day of the year.

Among a list of its attributes, Combined Heat and Power (CHP) increases the efficiency of distributed generation by using the exhaust heat to displace electricity consumption in applications such as absorption chilling or water heating. The State Legislature has included the use of waste heat from CHP in the definition of renewable energy technologies that count towards the State Renewable Portfolio Standard.[12] In this scenario, CHP installations will be distributed around the island. HELCO's updated CHP forecast[13] in the IRP indicates that there will be 5.5 MW of installed CHP capacity by 2018. CHP will reduce grid electricity consumption in two ways: (1) CHP produces electricity from on-site generation, and (2) avoids grid consumption from other equipment on-site, such as using absorption chillers instead of conventional chillers. CHP provides a uniform reduction in load of 7 MW. The reduction occurs during all hours, daily, except the hours from 10pm to 6am. The graphical representation is shown in Figure 28.

[12] *Ibid*, p. 6-30
[13] *Ibid*, Table 10.1-3

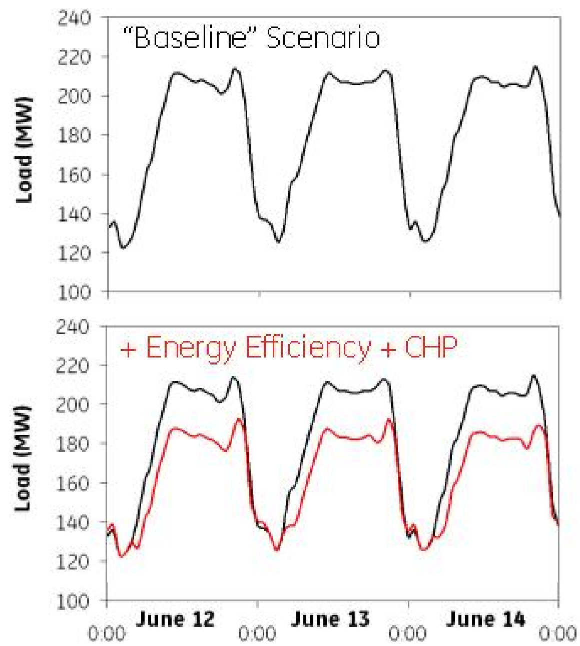

Figure 28. Baseline scenario load curve for three days of the year (black) was reduced to the red curve by the residential, resort and commercial energy efficiency programs, and the CHP deployment.

The energy efficiency and CHP reduced peak load and overall electricity consumption. By displacing the most expensive generation dispatched to meet peak load, the overall system average variable cost decreased by ~1% compared to the Baseline scenario. This means that in addition to the customers consuming less electrical energy from the grid, the energy provided by the HELCO system is produced more efficiently. With subsequent reductions in peak load (due to the various energy efficiency programs stacking upon one another), the variable cost decreased, but the incremental improvement in efficiency (as measured by dropping average variable cost) diminished.

4.3.2 Plug-in hybrid electric vehicle charging

The Big Island imports gasoline and diesel fuel refined on the island of Oahu. One of the objectives of this analysis was to evaluate the reduction of imported petroleum and increase energy production from indigenous resources. Plug-in hybrid electric vehicles (PHEV) will enable some of the overall energy consumption of a vehicle to be switched from conventional gasoline and diesel fuel to electricity produced from many power generation sources, including wind and solar power as well as conventional fossil fuel sources. Additionally, PHEVs that are charged during the nighttime hours will flatten the 24-hr load curve, which could reduce wind power curtailment.

The transportation model, developed in the first phase of this program, was used to simulate PHEV penetration levels. Based on data and projections from the 2005 Hawaii data book, light duty vehicle fleets (automobiles and light trucks) were assumed to increase by the rate of population growth and commercial fleets were assumed to increase by growth in the Gross

- 10% increase in average vehicle fuel economy from 2005 and 2018.
- Driving patterns (miles/day) similar in 2018 as 2005.
- Gasoline prices of $3.50/gallon.
- Ratio of 2007 average HELCO electricity prices to 2007 Big Island gasoline prices representative of the ratio in 2018.
- Average of 27-vehicle miles/day on the Big Island (Hawaii data book).
- PHEV driver reduces annual gasoline consumption by 85%.
- Entire car fleet is fueled by gasoline.

4.3.2.1 Smart Charging Algorithms

Unscheduled PHEV charging is expected to cause sub-economic commitment of generation, so smart charging algorithms present an opportunity to improve the commitment strategy. Further, incorporating smart charging algorithms is expected to reduce wind power curtailment at low load conditions. Better commitment and reduced wind curtailment will reduce the incremental fuel consumption required to provide PHEV charging power.

Two alternative charging algorithms were considered in the simulation. The first algorithm assumed a scheduled charge, whereby 12% of the total PHEV energy was charged from 11pm to 12am, 22% from 12am to 1am, 32% from 1am to 2am, 22% from 2am to 3am, and 12% from 3am to 4am.

A more advanced second algorithm considered the average daily load from the day prior and distributed the entire PHEV charging load over the hours less than the previous day's average load. The load was distributed throughout the hours less than the previous day's average load by the difference between the previous day's average load and the current load. This had the effect of smoothly filling the evening trough. Note that 200 MWh/day represents 10% of the passenger car fleet plugging in each evening (10 kWh battery). It should be noted that the power requirement for a battery will be greater at the start of charging and tapers off to near zero load as the charge completes. This is an important consideration in the development of a smart charging algorithm.

The average variable cost of the system operating with the two different smart charging algorithms was compared to the Baseline scenario and the energy efficiency programs and the CHP (see Figure 29). A reduction in average variable cost means the HELCO system is producing electric power more efficiently. The second charging algorithm (PHEV2) substantially reduced the average variable cost as compared to the energy efficiency programs and CHP alone and as compared to the first smart charging algorithm (PHEV1). It should be noted that PHEV1 increased the average variable cost of system operation as compared to the case where only the energy efficiency programs and CHP were incorporated without PHEV charging. This occurred when PHEV1 was included because the more expensive combustion turbine and diesel generators were dispatched more frequently than the less expensive steam plants to compensate for the more variable load resulting from the fixed charging schedule in PHEV1 as compared to the charging schedule based on the prior day's load curve in PHEV2.

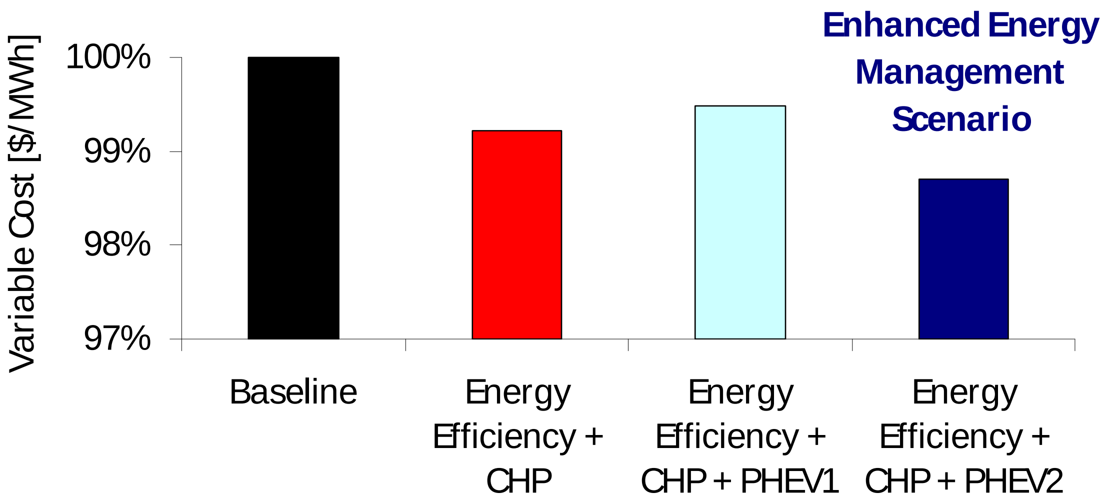

Figure 29. Average variable cost comparison between the Baseline scenario, the components of the Enhanced Energy Management scenario: (1) Energy Efficiency & CHP, and the two smart charging algorithms.

The PHEV2 charging algorithm was used in the further analyses. A visual representation of the PHEV2 charging algorithm is presented in Figure 30.

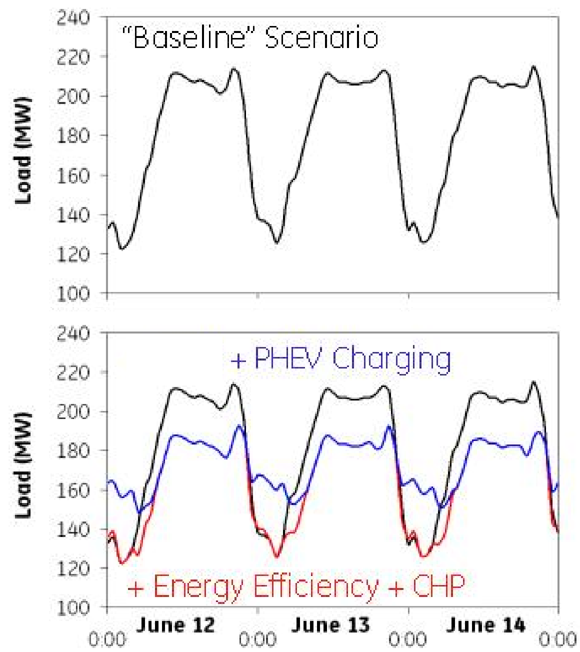

Figure 30. Baseline scenario load curve for three days of the year (black). The blue curve was obtained by adding the energy efficiency and CHP programs to the PHEV charging (PHEV2).

4.3.2.2 Results for Plug-in Hybrid Vehicles

If 10% of the passenger car fleet were PHEVs, this translates into 73 GWh/yr of new electricity sales from combined cycle plant (~56 GWh), oil-fired steam (~10 GWh), and wind power (~5 GWh). An additional 3% of available, but previously curtailed, wind energy was accepted by the system. Further expansions in wind power on the island will increase the amount of wind curtailment, particularly during the off-peak nighttime hours, making the potential benefits of PHEVs greater.

If the incremental variable cost of serving the additional load of the PHEVs is considered, charging during the off-peak hours, based on a smart charging algorithm, resulted in a 12% decrease in the average variable cost to serve the additional load as compared to the average variable cost of production without PHEVs. Therefore, serving the PHEV load during the hours of lower operating costs substantially reduced the average variable cost of energy production.

From an overall island perspective, the utility variable cost (mostly fuel costs) of serving the additional PHEV load is 54% lower than the cost of the gasoline purchased by the owners of gasoline-fueled vehicles. This variable cost saving, which only occurs with smart charging, represents an opportunity to cover the costs of the incremental charging infrastructure needed for the deployment of PHEVs and enable savings for both PHEV end users and HELCO. In order to serve the additional load from PHEVs, the fossil fuel consumption in the electricity sector increased. However, switching from transportation fuel to electricity for PHEVs reduces the island-wide net fossil fuel consumption by 20%. Therefore, less fossil fuel is consumed in the production of electricity to serve PHEVs than the amount of transportation fuel consumed in similar gasoline-fueled vehicles.

It should be noted that uncontrolled charging could pose significant operational challenges due to sudden increases in load. Conversely, utility control of the dispatchable load in the case of demand-side management and PHEVs provides system-operating benefits, especially if increased system flexibility is needed to enable higher penetrations of variable renewable energy. If demand-side management and PHEV charging can be made fast and flexible enough to provide needed ancillary services, substantial additional operating cost savings could be realized.

4.3.3 Conclusions for the Enhanced Energy Management Scenario

The reduction in peak load, associated with: (1) the energy efficiency programs and CHP, and (2) the increase in nighttime load due to PHEV charging reduces the use of the more flexible generation (diesels, combustion turbines) and increases the use of lower cost generation (steam plants). Approximately forty days of production is shown for each scenario in Figure 31.

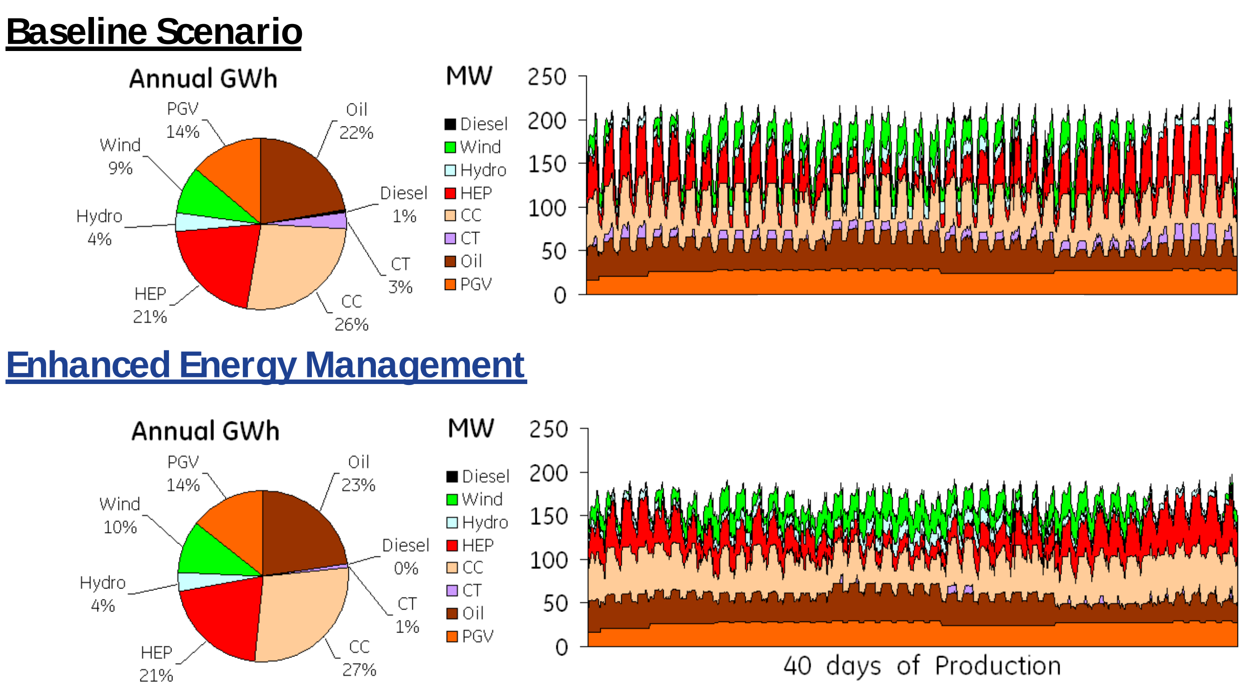

Figure 31. Production cost model results for the Baseline scenario and the Enhanced Energy Management scenario.

By d
isplacing more expensive, highly flexible generation with less expensive steam oil plants, the overall system variable cost decreased, as shown in Figure 29. The Enhanced Energy Management scenario decreased energy sales by 4%, but decreased the overall fuel consumption by 6% and CO_2 emissions by 6% (see Table 22).

Table 22. Comparing Enhanced Energy Management Scenario to the Baseline Scenario.

ENHANCED ENERGY MANAGEMENT

	Capacity MW	Energy GWh	Fuel MMBtu	NOx tons	SOx tons	CO2 tons
Combined Cycle	117	722	5898571	172	885	512870
Combustion Turbine	43	12	154604	19	21	11982
Diesel	29	2	22471	4	3	1805
Puna Geothermal	30	215	0	0	0	0
Small Hydro	16	55	0	0	0	0
Steam Oil	61	339	4791525	742	825	478203
Wind	33	150	0	0	0	0
Energy Mgmt reduction	0	67	0	0	0	0
Grand Total	**328**	**1562**	**10867171**	**937**	**1734**	**1004860**

ENHANCED ENERGY MANAGEMENT - BASELINE

	Capacity MW	Energy GWh	Fuel MMBtu	NOx tons	SOx tons	CO2 tons
Combined Cycle	0	-16	-67102	-2	-10	-5835
Combustion Turbine	0	-34	-439298	-54	-60	-34987
Diesel	0	-8	-93295	-17	-13	-7336
Puna Geothermal	0	0	0	0	0	0
Small Hydro	0	0	0	0	0	0
Steam Oil	0	-11	-134796	-20	-22	-12738
Wind	0	3	0	0	0	0
Energy Mgmt reduction	0	67	0	0	0	0
Grand Total (% Difference)	**0%**	**-4%**	**-6%**	**-9%**	**-6%**	**-6%**

By enabling the PHEV charging infrastructure and utility to vehicle communications for charging and implementing the CHP and energy efficiency programs outlined in this scenario, the overall system heat rate was improved. The load curve from the Baseline scenario was reduced by CHP and energy efficiency programs, and increased due to PHEV charging at nighttime hours. As shown in Table 22, this served to displace combined cycle, combustion turbine, diesel and steam oil plants, while slightly increasing wind power production (by reducing wind power curtailment observed in the Baseline scenario).

The impact of this scenario on operational flexibility in the minute-to-hour timeframe was positive, reducing the number of times fast-start generation was required compared to the Baseline scenario. This is measured by the count of hours where the generation committed at the beginning of an hour was unable to increase output sufficiently to meet the increase in load and/or decrease in wind power production in the hourly timeframe.

4.4 Higher Geothermal Penetration Scenario

This scenario was focused on increasing the penetration of flexible, load-following renewable energy in the form of geothermal at two locations on the island. Deploying technologies capable of being dispatched by the Automatic Generation Control (AGC) could enable the retirement of some generation capacity. The details of retiring thermal generation were not considered in this analysis. Each Independent Power Producer (IPP) was assumed to be paid $190/MWh at min load and $140/MWh at max load. A graphical representation of the deployment is shown in Figure 32.

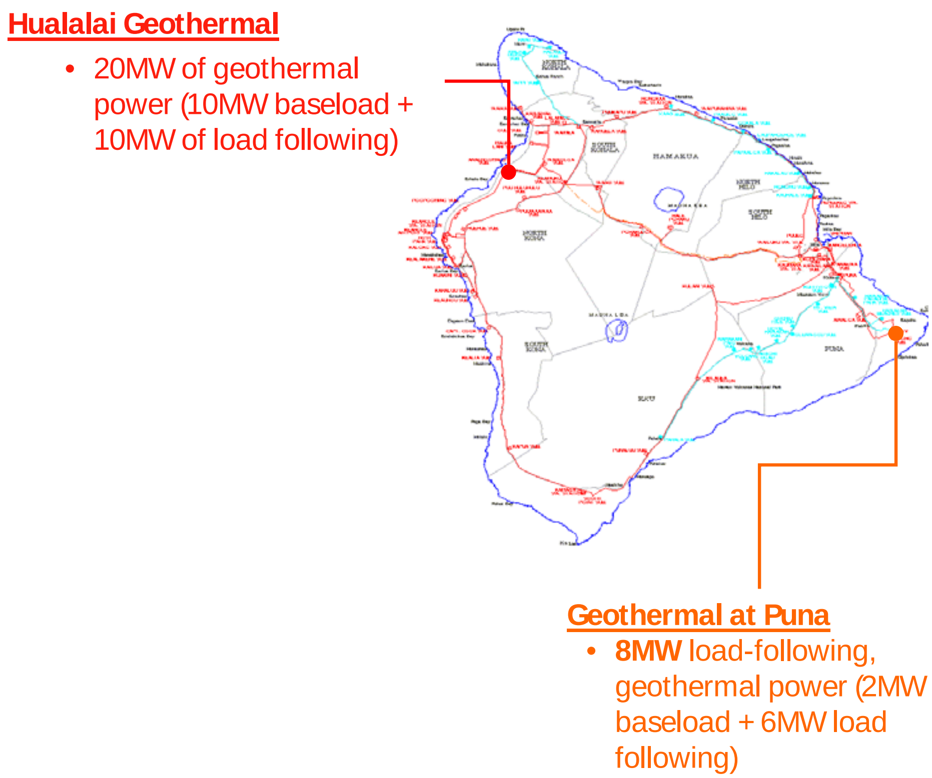

Figure 32. Geothermal plant deployments for the Higher Geothermal Penetration scenario.

The Higher Geothermal Penetration scenario offered an 11% decrease in fuel consumption and a 10% decrease in CO_2 emissions (Table 23).

Table 23. Higher Geothermal Penetration scenario compared to the Baseline scenario.

HIGHER GEOTHERMAL PENETRATION

	Capacity MW	Energy GWh	Fuel MMBtu	NOx tons	SOx tons	CO2 tons
Combined Cycle	117	651	5327603	156	799	463219
Combustion Turbine	43	14	179100	22	25	14214
Diesel	29	3	32325	6	5	2638
Puna Geothermal	38	240	0	0	0	0
Small Hydro	16	55	0	0	0	0
Steam Oil	61	337	4754651	736	819	474372
Wind	33	145	0	0	0	0
Hualalai Geothermal	20	128	0	0	0	0
Grand Total	**356**	**1573**	**10293679**	**920**	**1647**	**954442**

HIGHER GEOTHERMAL PENETRATION - BASELINE

	Capacity MW	Energy GWh	Fuel MMBtu	NOx tons	SOx tons	CO2 tons
Combined Cycle	0	-87	-638070	-19	-96	-55486
Combustion Turbine	0	-32	-414802	-51	-57	-32756
Diesel	0	-7	-83441	-15	-11	-6503
Puna Geothermal	8	25	0	0	0	0
Small Hydro	0	0	0	0	0	0
Steam Oil	0	-13	-171670	-26	-29	-16569
Wind	0	-1	0	0	0	0
Hualalai Geothermal	20	128	0	0	0	0
% Change	**9%**	**1%**	**-11%**	**-11%**	**-10%**	**-10%**

Since the variable cost of electricity on the Big Island is correlated to the oil price, deploying renewable energy, with a contract decoupled from avoided cost, offers a hedge against increasing oil price. A production cost simulation was performed for a 50% increase in fuel prices and a 50% increase in avoided cost power purchase agreements. The Higher Geothermal Penetration scenario offers a significant hedge against fuel price, increasing the variable cost by ~90% of the increase in variable cost associated with the same fuel price increase for the Baseline scenario. The result is shown in Figure 33.

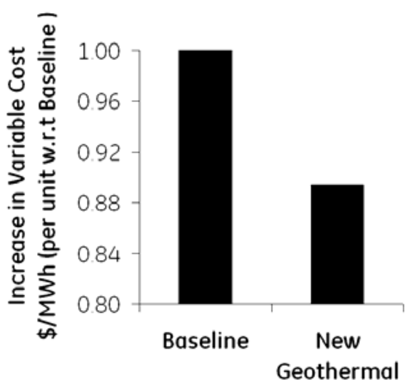

Figure 33. Increase in variable cost associated with a 50% fuel price increase.

A second variation was considered in this scenario. HELCO indicated that the deployment of load-following geothermal, with similar droop response as the HELCO steam plants could potentially enable the retirement of Shipman Power Plant or Puna 2 steam plant. The production cost simulation revealed an additional 6% maximum decrease in fuel consumption and emissions, while being nearly variable cost neutral to HELCO based on the PPA for the new geothermal plants outlined earlier.

4.4.1 Conclusions for the Higher Geothermal Penetration Scenario

The *Higher Geothermal Penetration* scenario assumed the development of Hualalai geothermal plant with 10 MW of baseload capability and 10 MW of load following capability. Puna Geothermal Venture was expanded with an additional 8 MW (2 MW of baseload and 6 MW of load following). The new geothermal plants were assumed must-run at minimum load, to provide similar droop response as existing oil-fired steam plants. Two independent sensitivities were performed for this scenario.

- The retirement of the Shipman Power Plant or Puna 2 oil-fired steam unit was considered, assuming the geothermal plants could provide similar droop response and frequency regulation on AGC. Retirement of the Shipman Power Plant or Puna 2 steam plant and the deployment of new geothermal energy reduced fuel consumption by maximum of 6% with respect to the Baseline scenario, while being nearly variable cost neutral (subject to the PPA between HELCO and the new geothermal plants). HELCO would determine the retirement of conventional units on the basis of the lowest cost.
- A 50% increase in fuel prices substantially increased variable costs for both the Baseline scenario and this scenario; however, the increase in variable cost was more substantial for the Baseline scenario. If the PPA is decoupled from the avoided cost, the deployment of geothermal power (that displaces fossil fuel generation) is a hedge against oil price fluctuations.

5.0.Recommendations

This study would not have been possible without significant engagement from the utility project teams. The development and validation of the dynamic and production cost models were made possible by the recorded data provided by the utilities. The recommendations of this study are intended to provide HECO, HELCO, the state, and the Department of Energy with a perspective on some of the technology options, operating strategies, and regulatory measures needed to enable a clean, affordable, secure, and reliable energy supply. These recommendations follow.

- *System Heat Rate:* Degradation of the system heat rate is inevitable with an increased penetration of variable renewable energy due to the need to retain dispatchable resources on the system, which are operated at less economic and less efficient levels. The Public Utilities Commission (PUC) should recognize this inevitability and incorporate it into their evaluation of the utility's heat rate performance. Another option to avoid this is to select dispatchable renewable resources to minimize heat-rate impacts.
- *Unit Commitment and Dispatch:* Integrating additional variable renewable energy resources will require changes in HELCO system operating practices as well as changes to existing thermal generation assets to increase their flexibility. The PUC should allow for capital recovery of reasonable investments in existing thermal plants that provide the operational flexibility needed to enable higher penetrations of renewable energy. Furthermore, there will be times when fast-start generation is brought on-line due to a sustained loss of wind power production, even though the wind might recover and make the fast-start of generation unnecessary. These false starts have operational costs. A study should be performed to assess the size of an energy storage device needed as a bridge to fast-starting generation during these types of events. There is an economic trade-off between the capital cost of energy storage and the operating cost of false starts. The statistical variability of wind power production should be used to identify a strategy for dispatching the energy storage device and thermal generator in response to these system conditions.
- *Must-Run Rules:* The simulations incorporated scenarios including HELCO's present system operating rules and scenarios removing some of the must-run rules. The analysis shows that the current must-run rules maintain a higher level of system reliability when more variable renewable energy is added to the system without additional mitigation efforts. However, the current rules also result in significant costs in terms of fuel consumption and curtailment of renewable energy. As HELCO's system evolves in the future, the utility should periodically review the need for the current operating rules. As technologies to mitigate the variability of renewable energy improve and HELCO incorporates new firm generation in its system, HELCO may have new options that maintain the same level of reliability but with lower fossil fuel consumption and/or lower operating costs.
- *Commitment and Wind Power Forecasting:* The analysis demonstrates that incorporating rudimentary forecasts of wind power in comparison to no forecast yields system level benefits. HELCO currently operates the system based on observing the recent trend in wind variability combined with forecasts from the National Oceanic and Atmospheric Administration. However, these methods still do not accurately predict ramp events and periods of sudden variability that pose the greatest challenge for HELCO's operation. Sub-hourly and sub-minute forecasting data would provide greater benefit. HELCO is pursuing studies to determine if near-term forecast improvements can be improved using targeted or

other observational forecasting methods. It is noted that commercially available forecasts may be challenged in forecasting ramp events and periods of sudden variability that pose the greatest challenges for HELCO's operation.

- *Power Purchase Agreements (PPAs):* PPAs with Independent Power Producers are important factors in HELCO's variable cost. These costs impact end-user rates. This study has shown that the addition of renewable generation results in significant overall advancement of the stakeholders' objectives of increased energy security, emissions reduction, and sustainability. New modes of system operation, new technologies, and new methods of using existing generation are required to reach substantially higher levels of renewable energy. Many of the existing PPAs are tied to oil prices. Thus, the customers see no economic benefit when oil prices rise, leading to an inequitable distribution of the economic costs and benefits. It is critical that the Hawaii State Legislature and Public Utilities Commission consider fair and equitable distribution of costs and benefits among all parties to help Hawaii meet its future energy needs.

Appendix

The HELCO system has changed since these analyses were performed. In addition, the State of Hawaii recently entered into an agreement with the HECO utilities, known as the Hawaii Clean Energy Initiative (HCEI), to substantially increase the amount of renewable energy through a mix of incentives and regulatory changes. With these changes, the current trend for renewable energy development on the HELCO system is increasing faster than projected in HELCO's IRP-3 filing, which was the primary basis for the assumptions used in this analysis. This appendix describes some of the recent changes at HELCO and includes operational experience that HELCO has gained through the management of already high levels of renewable energy on the utility's system.

In 2007, the Apollo wind plant became operational with 20.5 MW of capacity. The capacity factors of the two wind plants (HRD and Apollo) have been quite high. In 2008, the peak load was 196.6 MW, with 32.5 MW of wind generation (10.3% of total energy production), 30 MW of geothermal generation (18.8% of total energy production), and 15 MW of run-of-river hydroelectric generation (2.9% of total energy production). In sum, renewable energy accounted for 32% of total generation on the system. 2008 was a dry year with low hydro production.

Figure A-1 shows the percentage of each energy source, net-to-system, as recorded in 2008.

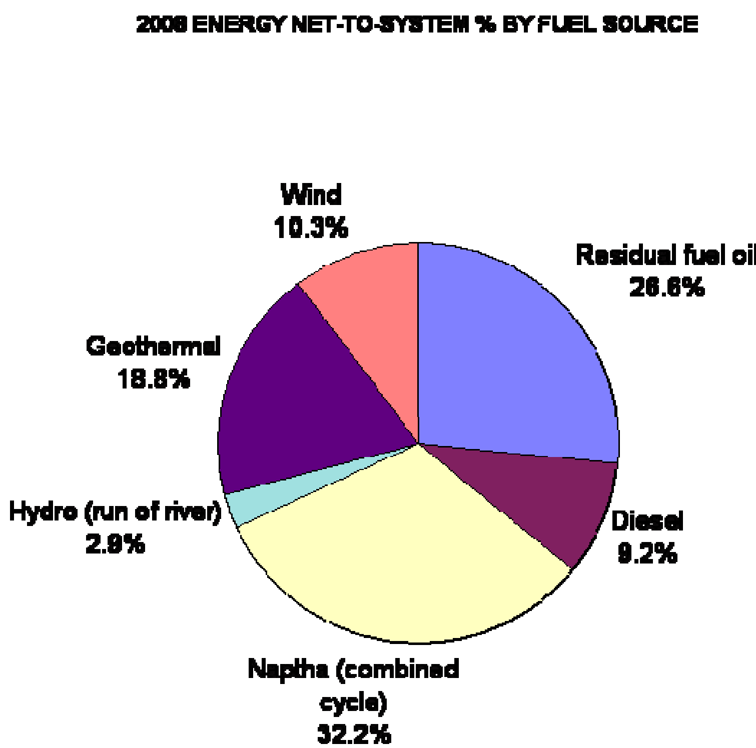

Figure A-1

These energy production numbers do not include distributed generation, which is not metered. There has been a significant amount of distributed photovoltaic (PV) generation installed in 2008, with additional projects anticipated in 2009. HELCO also anticipates new additions of renewable energy greater than the level assumed in the 2018 baseline scenario used in this analysis. HELCO has been in negotiations with potential suppliers of geothermal, wind, solar, or biomass energy. Specifically, HELCO has signed a contract with a small biomass project, is in negotiations with a 22.5 MW biomass project, and has already signed a contract for a 500 kW concentrated solar power (CSP) project. The 2018 baseline scenario also does not account for the recent trend of rapid growth in distributed PV.

At present, the HELCO system has approximately 33.5 MW of wind, which represents nearly 30% of the minimum peak load and 20% of on-peak load. Wind production through the first three months of 2009 was 12.8% of the total energy, and 14.3% of the energy generated in February 2009. The high production from wind energy, combined with the system size and a unique mix of generation resources including the fixed outputs from geothermal and run-of-river hydroelectric, has created a unique opportunity for HELCO to gain real operational data regarding the impact of high renewable energy penetrations on an electrical grid. The isolation of the Hawaii Island electric system presents the additional challenge that all power imbalances created by variable generation resources, such as wind, result in a system imbalance and frequency error.

Unlike interconnected facilities, which regulate to interchange schedules, HELCO's AGC operates in constant frequency control (CFC). This means that the objective is to balance load and demand at all times. In addition, the second function of AGC is to optimize costs (i.e., achieve lowest production cost). AGC operates on a longer time scale to reallocate the load served by dispatchable units among those units so as to minimize production costs (including consideration of losses). Controls issued for economic dispatch will also, in real-time, affect system frequency.

The HELCO system is unique in that, for the present and Baseline scenario, a significant number of generators providing a large portion of the energy on the system are not dispatchable and do not participate in local frequency control (through droop response) or supplemental frequency control (through AGC control). This leaves relatively few units to perform load balancing and frequency regulation, even as the balancing burden has increased due to the greater variability of apparent load as a result of wind energy and other as-available energy sources. This, combined with the lack of interconnections, places a large balancing burden on relatively few conventional units providing the balancing services.

In the actual operation of the HELCO power system, unit commitment times are not scheduled on a day-ahead basis. HELCO has the advantage of being able to maximize the flexibility and responsiveness of its operation due to the system operator having direct control of the intermediate and emergency generating assets. The system operator incorporates the real-time output of wind power plants and their behavior over the previous hour into dispatch decisions. Regulating reserves are modified depending on the stability of the wind output. High winds, which result in large amounts of wind power production with minimal variability, allow the system operator to delay or avoid starting intermediate and peaking units and carry the historical levels of minimal spinning reserves. HELCO also utilizes marine weather forecasts as consideration in hours-ahead scheduling.

However, at times, sudden ramps in wind output have depleted available reserves and resulted in significant deviations in frequency (see Figure A-2). HELCO has worked with wind forecasting entities to try and identify possible improvements in operation through use of wind forecasts. For wind power forecasting to improve the HELCO commitment decisions, intra-hour and near-term forecasts will need to improve the detection of wind events with significant effects on the grid, such as sustained ramps. Forecasting in these time frames and to predict certain events with accuracy is an area of research and development. HELCO is researching whether targeted forecasts may be employed, which may require additional telemetry data to capture the conditions that contribute to the most significant operational impacts. These targeted forecasts would assist by giving the operator advanced notice of variable conditions and/or wind ramp events.

In the absence of accurate forecasting, the utility needs to add significant amounts of spinning reserves and stabilization devices (e.g., energy storage, battery, or other fast-reacting resources) to prevent utility under-frequency operation and provide some means of very fast-acting second-to-second frequency control.

The following figures demonstrate some of the challenges of managing a small island electricity grid with increasing levels of as-available renewable energy. The first graph illustrates how a quick ramping event at wind power plants on the grid affects system frequency and the second shows how persistent variability in wind output affects the grid.

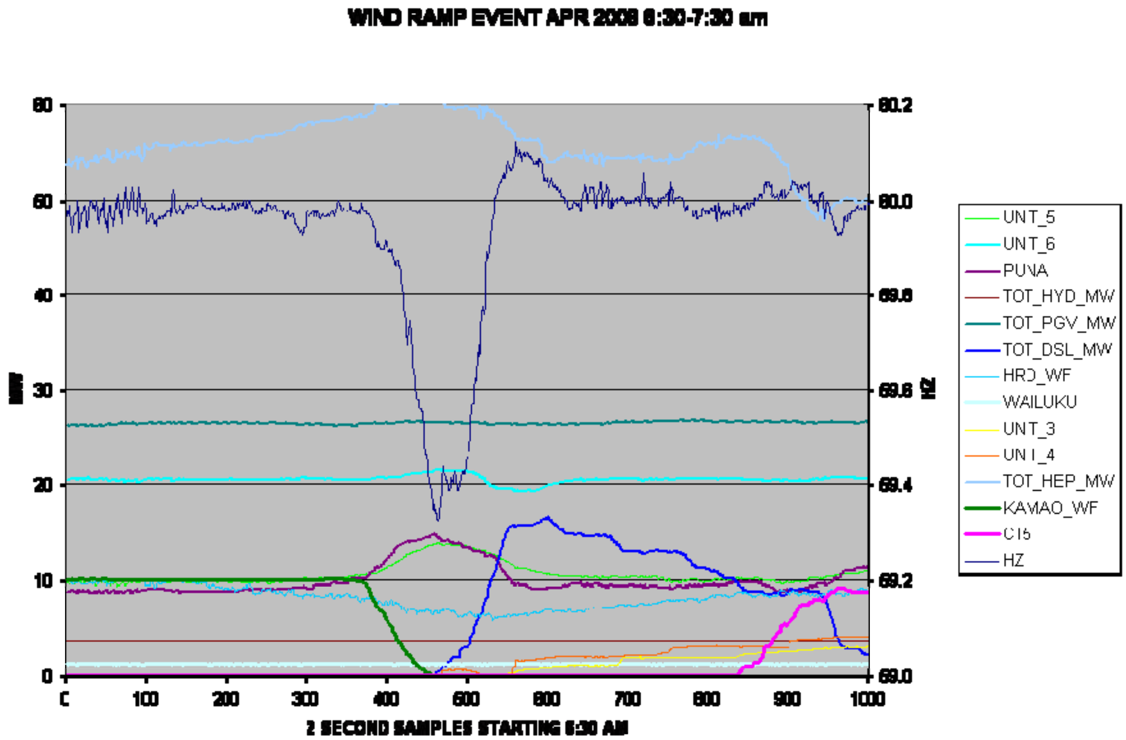

Figure A-2

This event occurred during the time of the load ramp. The time scale begins at 6:30 am. The output of the Apollo facility (labeled Kamao_WF) drops from 10 MW to zero within three minutes. At the same time, the output of HRD wind plant drops more gradually by 3 MW. The combined 13 MW decrease, occurring at a time of load increase resulted in frequency decline near 59.3 Hz (dark blue). The system operator recovers the system balance and frequency by starting diesel units (royal blue). The graph shows that HELCO could manage the quick drop in output from wind plants, but the variability in system frequency still poses significant risks for the system. For example, load shedding begins at 59.0 Hz and distributed generators connected with minimal IEEE 1547 protection settings disconnect at 59.3 Hz.

Variable wind power output poses another problem for system operators on a faster timescale, which is illustrated in Figure A-3.

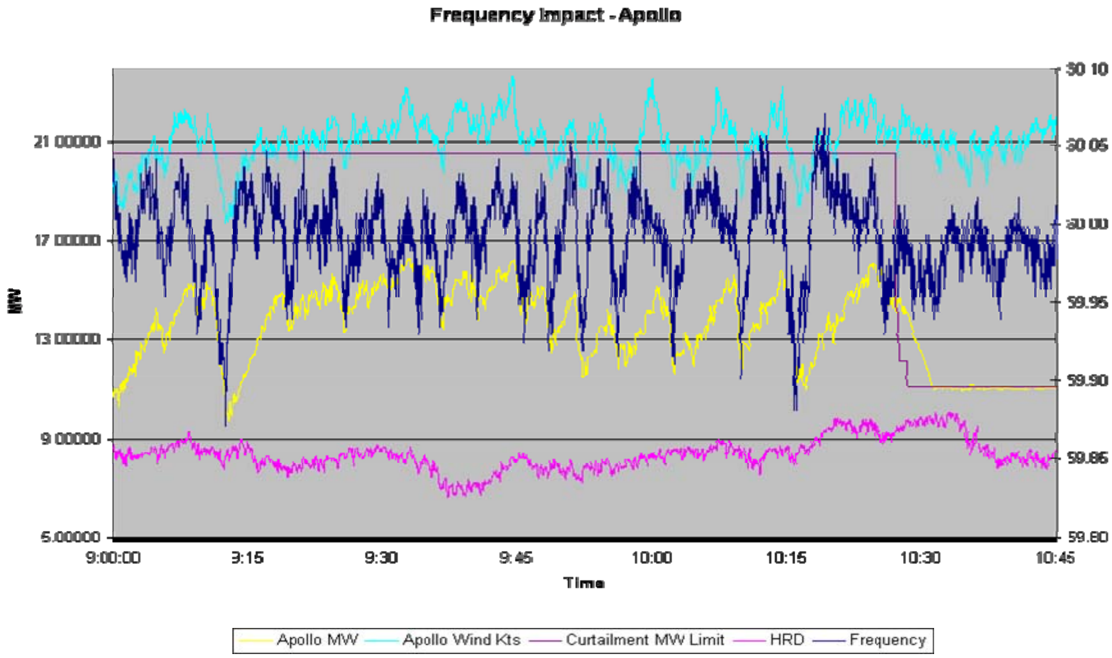

Figure A-3

In this example, the influence of the Apollo output (yellow) can be seen on the HELCO system frequency (dark blue). As output from the Apollo plant fluctuates rapidly, system frequency is difficult to maintain at 60 Hz. When the Apollo output is reduced and made steady through application of a curtailment control, after time 10:30, the system frequency becomes more stable. The curtailment is implemented through use of wind turbine controls.

HELCO has changed operating practices to accommodate greater levels of renewable energy and address the challenges illustrated in the previous figures. With the addition of the Apollo wind plant, HELCO modified the generation dispatch to force allocation among several generating units, rather than allowing the reserve allocation to be determined by the least-cost economic dispatch, in order to improve system frequency response. HELCO has also found that the amount of spinning reserve does not have a significant impact on second-to-second frequency control. This is dependent more upon the droop characteristics of the individual plants as well as the distribution of reserves across several units so that they may respond in unison. Reserves up and down must be considered to provide regulating capability in both directions.

Specifically, fast time frame (second-to-second, minute-to-minute) fluctuations of wind plant output create fast time frame variations in frequency (shown in Figure A-3). These variations occur in the time frame which is managed by the droop control of the regulating units. Attempting to resolve this fast time scale frequency variability by automatic generation controls only results in increasing the frequency error due to over-control. In order to avoid over-control, HELCO has had to de-tune the supplemental AGC control to ignore typical frequency error, so that controls are only issued once frequency error is large enough that over-correction is unlikely. This no-control dead band is as large as +/- 0.2 Hz (59.8 Hz – 60.2 Hz) during periods of low frequency bias (off-peak operation when fewer units operate and there is lower system demand). This is a degree of frequency error which constitutes an alarm level and makes the system less resilient to typical system disturbances and faults as the base condition is likely to be off-normal. In addition, variable frequency due to wind plant production changes can create combustion control problems at those generating units providing primary frequency control via droop response. At times, HELCO has had to curtail the wind plant during periods of variable wind plant output to reduce the degree of fluctuation in system frequency and resultant combustion control problems at regulating steam plants (as shown in Figure A-3).