Oahu Wind Integration Study

Final Report

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1.0 Executive Summary

Hawaii is an island state that relies heavily on imported fossil fuels to meet its energy needs. In 2008, Hawaii imported 42.6 million barrels of petroleum to meet 90% of its energy demand in all sectors, and was the most petroleum dependent state in the nation. In 2008 this cost the state approximately $8.4 billion each year, which was approximately 13% of the Gross State Product. Most of the imported oil is used for transportation fuel and approximately 30% is used to generate electricity.

Hawaii's dependence on oil makes the State vulnerable to disruptions in supply. Further, the volatility in oil prices translates into volatility in electricity prices. As oil prices increase, Hawaii consumers face increases in energy prices as well as the price of most basic goods and services that are imported into the state and shipped between islands. High-energy prices also challenge the competitiveness of Hawaii's tourism industry, which is a key sector in the State's economy.

In October 2008, the Hawaiian Electric Companies entered into an Energy Agreement with the State of Hawaii and the U.S. Department of Energy as part of the Hawaii Clean Energy Initiative. This initiative puts Hawaii on the path to generate 40% of its electricity from renewable resources by 2030. Hawaii is already near the top in the nation in the use of indigenous renewable energy resources relative to the State's total electricity production. As part of this agreement, aggressive renewable portfolio standard (RPS) goals were established that ultimately require 40% of Hawaiian Electric utilities' electricity to be generated from renewable sources by 2030 (10% by 2010, 15% by 2015, and 25% by 2020), which is one of the highest standards in the country. A cornerstone of this agreement is Hawaiian Electric's commitment to integrate 400 MW of wind power located on the islands of Molokai and/or Lanai that could be transmitted to the load center on Oahu through an undersea cable system, known as the "Big Wind" projects.

Integrating 400 MW of variable energy resources into the Oahu electrical system required an in-depth analysis to: 1) determine the viability of the Oahu system to accept the wind energy, 2) evaluate benefits of the project to the Oahu system, 3) identify potential impacts to the system reliability, and 4) evaluate strategies to improve system performance. Studies of this nature utilize sophisticated modeling tools to analyze performance of an electrical system through production cost and system dynamic simulations.

Results of this study suggest that 400 MW of off-island wind energy and 100 MW of on-island wind energy can be integrated into the Oahu electrical system while maintaining system reliability. Integrating this wind energy, along with 100 MW of solar PV, will eliminate the need to burn approximately 2.8 million barrels of low sulfur fuel oil and 132,000 tons of coal each year. The combined supply from the wind and solar PV plants will comprise just over 25% of Oahu's projected electricity demand.

1.1. Background

Hawaiian Electric Company (HECO) is an investor owned utility serving the energy needs for the island of Oahu with approximately 295,000 customers. Annual energy production is approximately 8000 GWh and system load typically ranges from a peak of 1200 MW to a minimum of 600 MW. The total generating capacity of the system is 1756 MW comprised of HECO owned generating units and independent power producers (IPPs), primarily fossil-fueled units.

Hawaiian Electric operates three power plants on the island of Oahu with a total of 17 generating units. These include (8) baseload steam units, (6) cycling steam units, and (3) three peaking combustion turbine (CTs) units. The steam units burn low sulfur fuel oil (LSFO); two CTs burn diesel fuel and one CT burns biofuel. The IPPs provide baseload energy, which includes: 1) a 46 MW city-owned waste-to-energy unit (HPower), 2) a 180 MW coal-fired unit (AES), and 3) a 208 MW LSFO-fired combined cycle unit (Kalaeloa). The baseload units operate continuously throughout the year except during maintenance outages. HECO-owned cycling units are committed daily to meet system demand and typically shut down following the evening peak. Peaking units are committed as required to meet system demand during system peaks and contingencies.

Starting in January 2009, the Hawaii Natural Energy Institute, the Hawaiian Electric Company, and the General Electric Company jointly developed and validated detailed, state-of-the-art power systems models of the Oahu electrical system to study the impacts of integrating the “Big Wind” projects. Different models were developed to analyze various time scales of system operation ranging from seconds, to hours, to weeks, over an entire year of operation. These models were used to assess specific high wind power scenarios, identify the potential challenges of integrating large amounts of wind power, and assess potential solutions to these challenges.

The Department of Energy (DOE), the Hawaii Natural Energy Institute (HNEI), and the Hawaiian Electric Company (HECO) provided funding for the Oahu Wind Integration Study. In addition to GE, HNEI and HECO, the project team included AWS Truepower, who provided wind power and wind forecast data, and the National Renewable Energy Laboratory, who provided wind and solar power data and validation of these data. The National Renewable Energy Laboratory also sponsored a Technical Review Committee (TRC), which was assembled five times during the project. The TRC consisted of technical experts from both industry and academia that brought experience from similar projects from around the world. The TRC provided oversight, guidance, and assessment of the work performed in this study.

Simulations of the Oahu system were performed for the year 2014. Inputs such as system load, unit heat rates, fuel prices, planned unit maintenance, forced outage rates, etc. were based on forecasts provided by HECO. The wind plants located on Molokai and Lanai were electrically connected to Oahu via a High Voltage Direct Current (HVDC) cable system (see Figure 1-1). These wind plants were not connected to the local island loads. New, on-island resources were also modeled including 100 MW of wind power and 100 MW of combined centralized and distributed solar photovoltaic (PV) power.

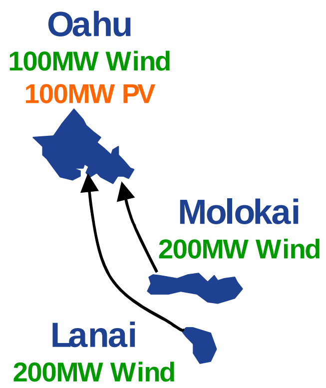

Figure 1-1. Illustrative schematic of the Oahu, Molokai, and Lanai interconnection.

Different wind power scenarios were developed by the project team and were analyzed using the modeling tools. For each scenario, these models were used to identify system performance and operating characteristics such as unit commitment and dispatch, wind energy delivered, fuel consumption, total variable cost, thermal unit ramping, system frequency performance during transient system events, and system frequency performance during variable wind events. Following these assessments a number of potential strategies were simulated to improve system performance (i.e., increase wind plant capacity factors, improve system reliability, and improve system efficiency).

Three primary wind scenarios were eventually considered; each examining a staged approach of integrating wind power on the Baseline 2014 Oahu system, as presented in Table 1-1. Scenarios #2 and #4 were removed from the study by combining resources and strategic planning and execution of the study. This allowed the project team to focus on the three scenarios below.

Table 1-1. Oahu Wind Integration Study Scenario

Scenario	Title	Wind			Solar PV
		Oahu	Lanai	Molokai	Oahu
Baseline	2014 Baseline	-	-	-	-
Scenario #1	"Big Wind" Oahu only	100MW	-	-	100MW
Scenario #3	"Big Wind" Oahu + Lanai only	100MW	400MW	-	100MW
Scenario #5	"Big Wind" Oahu + Lanai + Molokai	100MW	200MW	200MW	100MW

The study began with Scenario 5 to determine the effects of integrating 400 MW of total wind energy from the islands of Lanai and Molokai to Oahu. Scenario 5 was selected first because it would push the limits of both the simulated system as well as the modeling tools. In Scenario 3, 400 MW of wind energy from the island of Lanai was integrated into the Oahu system. Finally, Scenario 1 studied the Oahu system prior to the integration of any off-island wind energy.

The 100 MW of solar PV was deployed in each scenario primarily to evaluate its impact on wind energy delivered to the Oahu system. Many of the solar PV installations across the island will be much smaller in size relative to the wind plant resources evaluated. These smaller, distributed solar PV resources are interconnected to the distribution system whereas the analyses in this study focused exclusively on the transmission system to evaluate system-wide impacts associated with the balancing of generation and load. A comprehensive study of both the distribution and transmission system is required to analyze effectively the system-wide impacts of integrating high levels of solar PV resources on Oahu. Also, note that the historical data necessary to conduct a comprehensive solar integration study for the Oahu system does not exist, and must be developed.

In parallel with this effort, the Hawaiian Electric Company performed a number of internal studies to support the "Big Wind" projects. These include studies to improve generating unit capabilities, an assessment of the Energy Management System (EMS), assessments of its load control programs, and on-island transmission infrastructure studies. Other project teams undertook a number of large technical studies centered on the undersea cable system, including undersea topography and routing options, converter system configuration and technology assessments, and project cost estimates. The results presented in this report consider the conclusions and recommendations of many of these studies, where applicable.

1.2. Study Approach

Over the past decade, GE Energy Consulting has conducted wind and solar integration studies for electrical systems around North America. Most recently, these include the New England Wind Integration Study and the Western Wind and Solar Integration Study. A summary of the levels of renewable energy studied in each effort is provided in Figure 1-2. The wind integration studies for the islands of Hawaii posed challenges in addition to those associated with integrating high levels of wind power because of the unique characteristics of island electrical systems. The frequency of a North American power system will be maintained at exactly 60 Hz if the supply of and demand for electricity is perfectly matched in a region. If imbalanced, the frequency will begin to deviate from 60 Hz. Even without the integration of these renewable resources, frequency on an island electrical system tends to vary more than large electrical systems because the system is not interconnected with other power systems. With no electrical interconnection to neighboring systems, each island must manage its system frequency independently. To maintain adequate system performance during unexpected grid events, the spinning reserve requirement for the island of Oahu is 180 MW. This means that at least 180MW of power can be made available from the units already on-line (by increasing the production from these units) should an event take place. This provides sufficient power should the largest plant, AES, unexpectedly disconnects from the system.

	Wind	Solar	Peak Load	Energy
New York	3 GW		10%	4%
Ontario	15 GW		50%	30%
California	13 GW	3 GW	26%	15%
Texas	15 GW		25%	15%
Western U.S.	72 GW	15 GW	50%	27%
New England	12 GW		39%	24%
Hawaii	85 MW		48%	27%
Maui	70 MW		39%	25%
Oahu	500 MW	100 MW	55%	25%

Figure 1-2. Renewable Integration Studies conducted by GE

Another characteristic of an island system is the significance that each generating unit can have on overall system performance. Therefore, characteristics of the Oahu electrical system dictate the design criteria of the generating units. For example, it is common to see generating plants in North America in the 1000 MW size or larger, to leverage the economies of scale. This is possible because the size of the electrical system does not generally impose design constraints on generating units. In the western region of the continental United States, referred to as the Western Electricity Coordinating Council (WECC), the peak load is greater than 150,000 MW. This peak load is more than 100 times larger than the Oahu power system. The loss of a 1000 MW unit in the WECC region is a small percentage of this region's generation and has a small effect on the system frequency deviation. Now consider the Oahu system, where the single largest unit is the AES coal plant, rated at 180 MW. This single unit provides anywhere from 15 to 30% of the Oahu system load, and typically is the reason for system operating policies and maintenance scheduling. These unique system characteristics made it necessary to capture accurately, 1) the dynamic capabilities of each generating unit, 2) the unique operational characteristics of the system, and 3) performance of automatic generation controls (AGC), the controller that schedules and dispatches each unit to maintain system stability from seconds to minutes to hour timeframe.

The Oahu Wind Integration Study was conducted in two phases. In Phase 1, the system models were developed and simulation results were validated against historical data from 2007, for both production cost and dynamic simulations. In Phase 2, different wind energy scenarios were constructed and system operation was simulated for the study year. These scenarios included different configurations of wind resources (as listed in Table 1-1) and simulations of various strategies to; 1) increase wind energy delivered to the system, 2) reduce system operating cost, or 3) improve system reliability. The initial scenario analysis (Scenario 5) was quite extensive, requiring multiple iterations of production cost simulations, analyses of results, and modifications to assumptions to ensure reasonable operation of the system. Once production cost modeling results were deemed reasonable, dynamic modeling tools were used to identify hours of the year to simulate contingency events and conduct analyses of the impact of wind variability and uncertainty on the system.

1.3. Challenges of operating Oahu's system with high levels of wind power

Large-scale wind power presents several potential challenges for operating a power system, particularly small island grids like the Oahu electrical system. This section describes some of these challenges and begins by discussing operation of the baseline system without any substantial variable renewable energy generation. Figure 1-3 illustrates the system load profile for a typical week for the Oahu system in a future year without any large wind or solar PV projects.

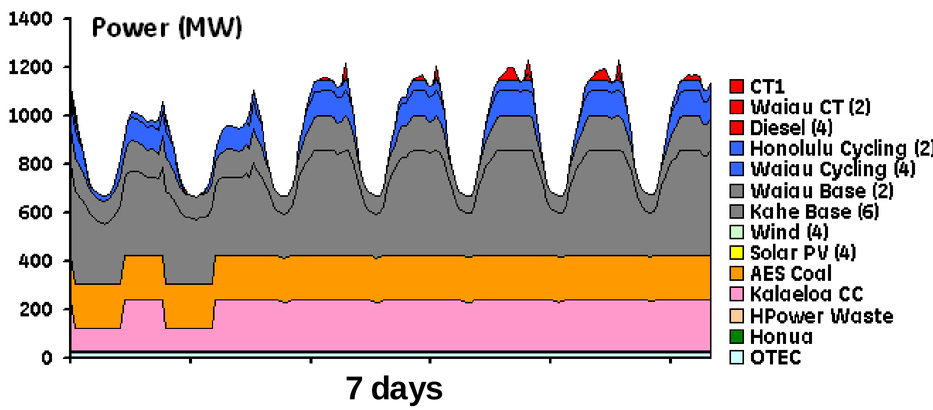

Figure 1-3. An example of operation for the Baseline 2014 Oahu power system

The graph shows the system load at a given point in time and the colors depict the dispatch of generating units to meet the load. The load profile of Oahu is characteristic of a residential customer base as tourism has a strong influence on the commercial sector. As such, system load does not deviate much from its profile. The system minimum load typically occurs from 10pm to 6am. The system day peak occurs between 12pm and 1pm and load remains relatively constant until the night peak between 6pm and 7pm.

Generating units are characterized by three modes of operation: baseload, cycling and peaking. The baseload units are generally the largest and least-cost units to operate and remain online continuously throughout the year. These units are economically dispatched to meet system load. In Figure 1-3 the baseload units are situated at the bottom of the figure and consist of the Kalaeloa Combined Cycle plant, AES steam plant, and Kahe and Waiau reheat steam units. A small amount of baseload energy is provided by HPower (waste to energy), Honua (gasification) and OTEC (Ocean Thermal Energy Conversion). Honua and OTEC are not presently in operation, but were assumed to be in this future study year.

Cycling units are smaller, non-reheat steam units. The cycling units are committed and shutdown daily to meet system demand and typically provide system up-reserves. The blue area represents cycling unit generation. The three peaking units are combustion turbines. These units are fueled by diesel fuel (Waiau 9 and Waiau 10) and biofuel (CIP-CT1). Four customer-owned diesel units can also provide peaking service. Peaking units are characterized as fast-start generation and are committed to meet peak demand and for system emergencies.

The baseload plants remain online consistently and respond to a reduction in demand (load) in the off-peak period by reducing their power output. Each unit has a limit on how low it can reduce its output, while remaining in a stable operating state. Similarly, each unit has limits on how quickly it can adjust output (up or down) to meet changes in the demand (known as ramp rate limits). In the baseline system without wind power, some of the power plants reach their minimum operating constraints during the off-peak period. The variation in load (demand) does not challenge the capability of the units to change output (ramp up or down). Figure 1-4 contrasts the situation with a large amount of wind power added to the system.

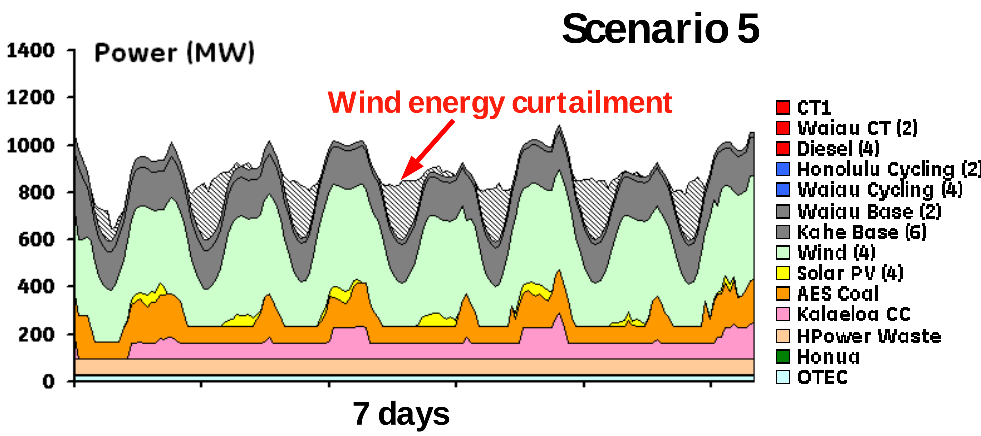

Figure 1-4. An example week of operation for the Oahu power system with 500 MW of wind power and 100 MW of solar power (Scenario 5)

Figure 1-4 shows a simulation for the same period of time as that shown in Figure 1-3 with the addition of 500 MW of wind and 100 MW of solar power. The light green area represents the wind energy delivered to the system and the yellow area represents the solar energy delivered to the system. In this simulation, the renewable resources were added to the baseline system without incorporating any strategies or modifications to system operation. The system cannot accept all available wind energy during the system minimum load periods so excess wind energy is curtailed as represented by the grey shaded area. During the periods of wind curtailment, the thermal units are operating at a very low power output. Later in the report, the study results will show that more wind energy can be accepted by the system if operational strategies are implemented.

The study also analyzed the variability of these renewable resources and its impact on the system. Figure 1-5 illustrates a significant change in wind power output on the third day of another week.

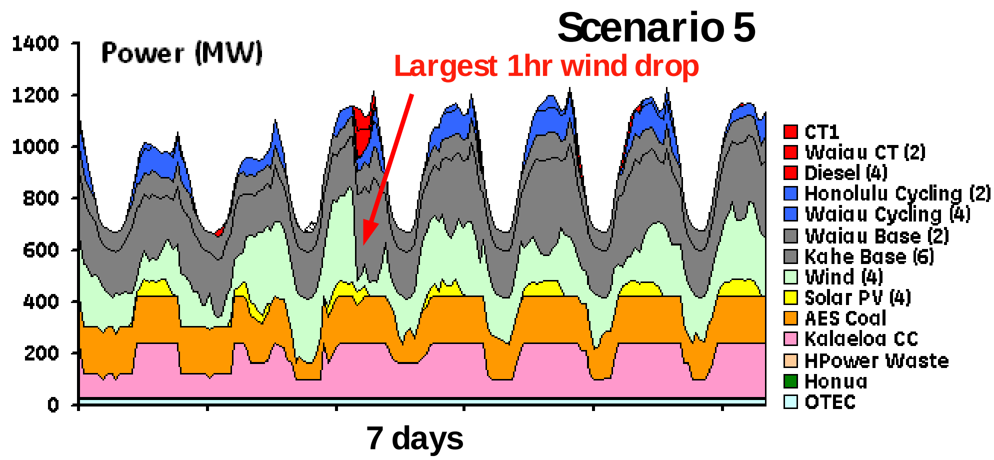

Figure 1-5. An example week of operation for the Oahu power system with 500 MW of wind power and 100 MW of solar power (Scenario 5)

This figure shows simulated operation during the week with the largest drop in wind power output over one hour, during the one-year study period. The magnitude of the wind power drop is over 300 MW. In this example, sufficient up-reserve capacity was available on-line and system operators would start peaking units (shown in red) to counter the loss of wind power. This particular event was a long, sustained drop in wind power that did not result in a system frequency deviation due to reserve capacity already online and generation that could be brought online quickly. The analysis will be described later in the Executive Summary.

The study also evaluated system performance for faster, short-term wind ramp events as well as contingency events that are more typical of classical power system analyses. The remaining sections of this summary describe the key results from this analysis and the technical report contains the full details of these assessments.

This section summarized some of the fundamental concepts in power system operation to help orient the reader with the challenges of operating a power system with a large amount of wind power. The examples described were intended to provide the reader with some background to help understand the technical and operating strategies selected by the study team to mitigate the challenges from wind power described above.

1.4. Wind energy can supply nearly 25% of Oahu's energy needs

The results from this study suggest feasible operation of the Oahu power system with high levels of wind and solar power (26% by energy, 50% nameplate relative to peak load), provided the strategies modeled in the study are implemented. This section will present system metrics, such as annual energy production, variable cost, and fuel consumption, which quantify the impact of the wind power additions to the mix of generation and operating costs. Subsequent sections will describe the proposed modifications in more detail.

Figure 1-6 shows the annual generation by unit and fuel type for each scenario with the full complement of operational modifications and strategies. The figures quantify how the addition of wind and solar PV to the Oahu system displaced generation from the fossil-fueled units.

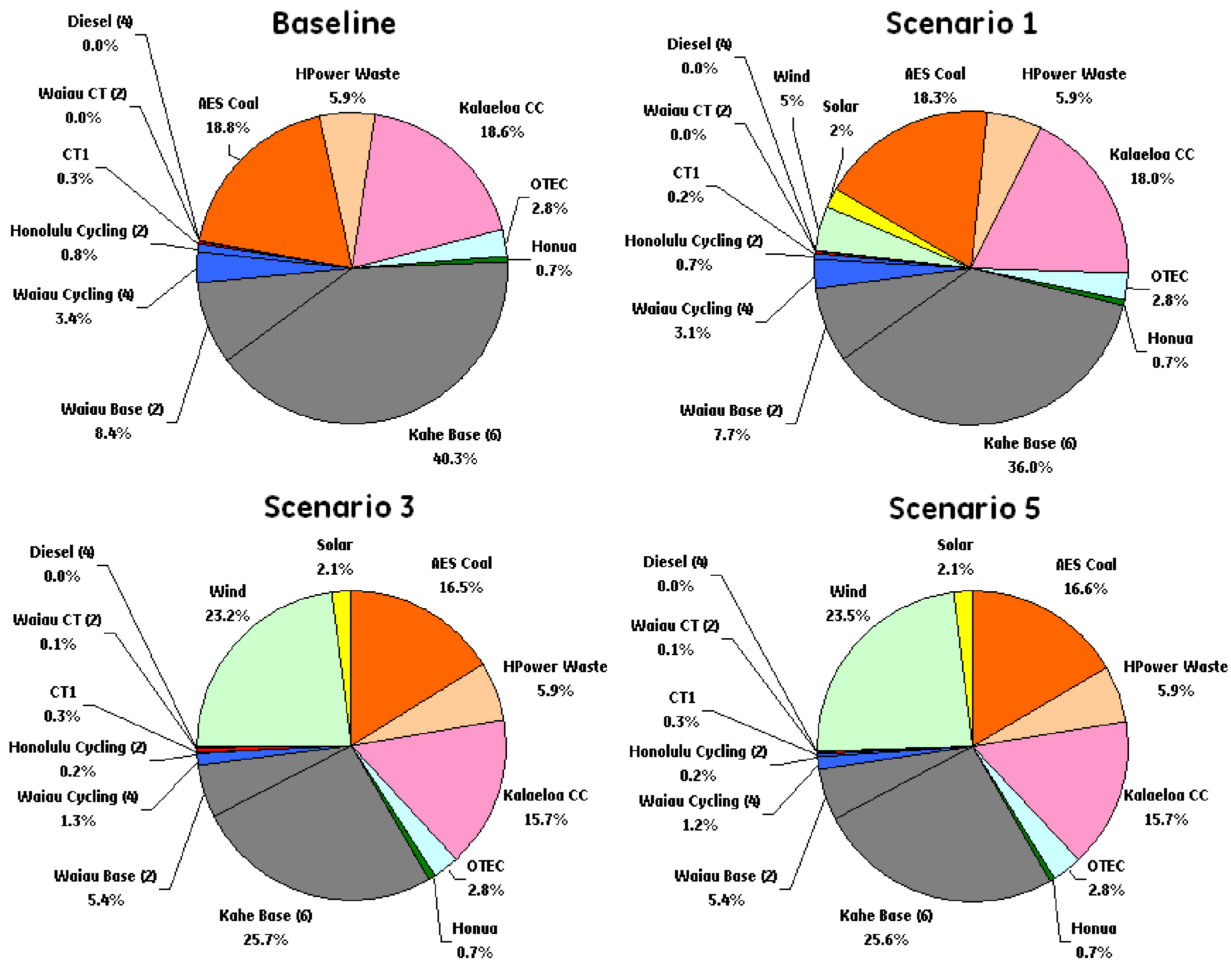

Figure 1-6. Share of annual energy production by fuel and unit type for each scenario.

Scenario 1 shows that adding 100 MW of wind and 100 MW of solar PV on Oahu can provide 7% of the annual energy and primarily displace generation from the Waiau and Kahe baseload units. The additional energy from wind and solar plants decreased the output from cycling units and IPP baseload units (AES coal plant and Kalaeloa Combined Cycle plant) but the relative decrease was smaller. The previous figures (Figure 1-3, Figure 1-4, and Figure 1-5) illustrate the displacement of thermal energy with wind and solar energy. During off peak hours, Kahe and Waiau baseload units, and the Kalaeloa and AES plants typically decrease their output, as wind energy is available. The units will continue to reduce their output until the units reach their minimum power level, respecting the down-reserve requirements of the system. The down-reserve is required to maintain unit stability during a loss-of-load contingency event. This will help to ensure that the unit does not operate below its stable operating power during typical loss-of-load events.

A similar pattern can occur during the daytime and peak hours. When wind and solar power is available, output from the thermal units will decrease until these units reach their minimum acceptable operating level, respective of the required down-reserve.

In Scenarios 3 and 5, the addition of off-island wind power increased the annual generation from wind and solar power to over 25%. The figures for these scenarios show that this new generation primarily offsets generation from the Kahe baseload units with smaller reductions in output from the Waiau units, cycling units, AES coal plant, and Kalaeloa CC plant. In aggregate, comparing Scenarios 3 and 5 to the baseline shows that the addition of 600 MW of new wind and solar PV generation primarily displaces oil-fired generation from the HECO-owned baseload and cycling units. Generation from AES and Kalaeloa decreases only slightly because these plants are typically the lower-cost plants on the Oahu grid. It is important to note that these results are sensitive to the fuel prices assumed in the study. It should also be noted that CO_2 pricing is not considered in these analyses. Changing fuel price assumptions and adding price associated with CO_2 emissions could affect the relative order of substituting thermal generation on the system.

The simulation also quantifies the amount of fossil fuel energy displaced by the wind and solar projects. The total fuel energy reduction between the Baseline 2014 case and the scenarios is shown in Figure 1-7. Note that the energy from HPower, Honua, and OTEC was assumed unchanged across all scenarios, and was therefore excluded from the comparison.

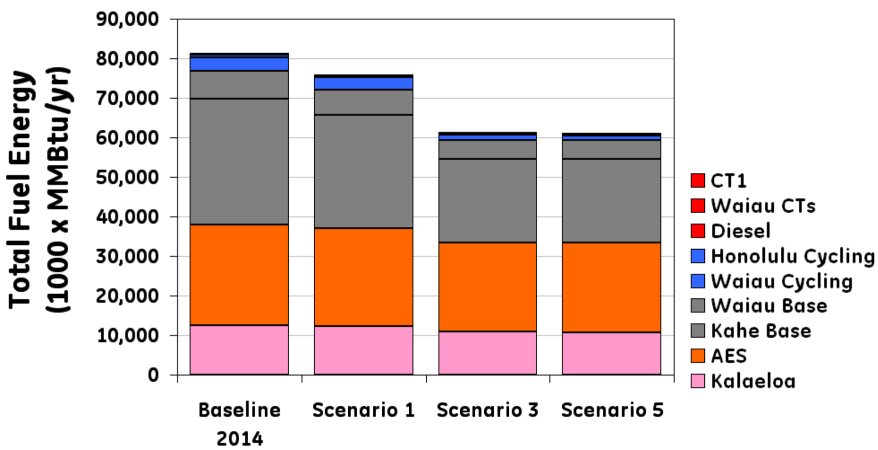

Figure 1-7. Total annual fuel consumption by Scenario.

Figure 1-7 represents the total fuel energy for each scenario. The difference in total fuel energy between the Baseline 2014 scenario and Scenario 5, with the suggested system modifications, is ~20 million MMBtu per year, which is comprised of nearly 2.8 million barrels of oil plus 132,000 tons of coal per year. The figure also shows most of the fuel savings is due to the reduction in fuel oil consumed by the Kahe and Waiau baseload units.

The reduction in annual variable cost is considered next. The total annual variable cost is primarily driven by fuel costs. Start-up and the Operations and Maintenance (O&M) expenses for each unit were also considered in this study, but were generally small in comparison to the fuel component. The variable costs used in this graph exclude the cost of the wind and solar energy supplied to the system. Figure 1-8 shows the results for total annual variable cost in different scenarios (relative to baseline).

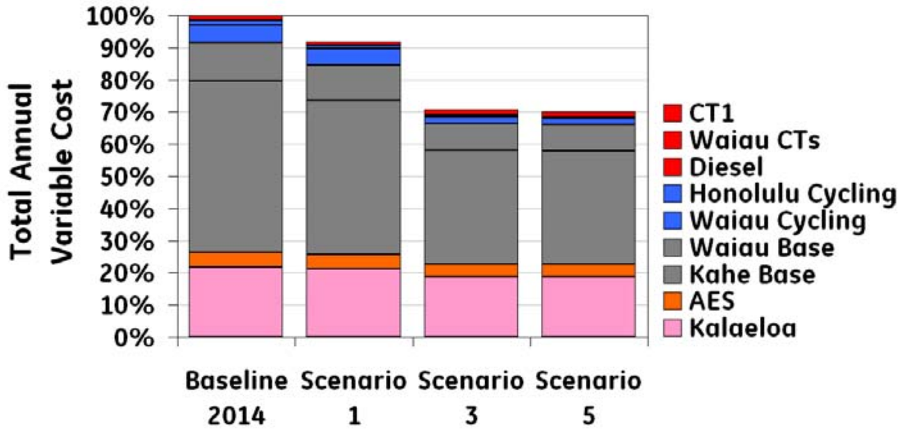

Figure 1-8. Total annual variable cost of operation.

The figure shows that the first 100 MW of wind and solar power on Oahu (Scenario 1) decreased total annual variable costs by approximately 10%. The addition of the off-island wind plants in Scenarios 3 and 5, and the associated strategies to enable the interconnection of the renewable energy projects, reduced total annual variable costs by nearly 30% as compared to the Baseline 2014 system.

The results in this section show the aggregate annual impact of adding wind and solar power to the Oahu system in different scenarios. During the course of the study, the team analyzed numerous strategies that would help Oahu integrate more renewable energy into the grid, while lowering the costs of each scenario, and improving the reliability of the system. The next subsection describes these strategies and quantifies their benefits.

1.5. Strategies to enable high levels of wind power on Oahu

A number of proposed strategies were simulated to observe the relative impact of each approach. The results are shown in Figure 1-9 for Scenario 5. The "Pre-modifications" condition represents a scenario with the addition of 500 MW of wind power and 100 MW of solar power with no modifications to the current operating strategies and generating unit capabilities of the Oahu system.

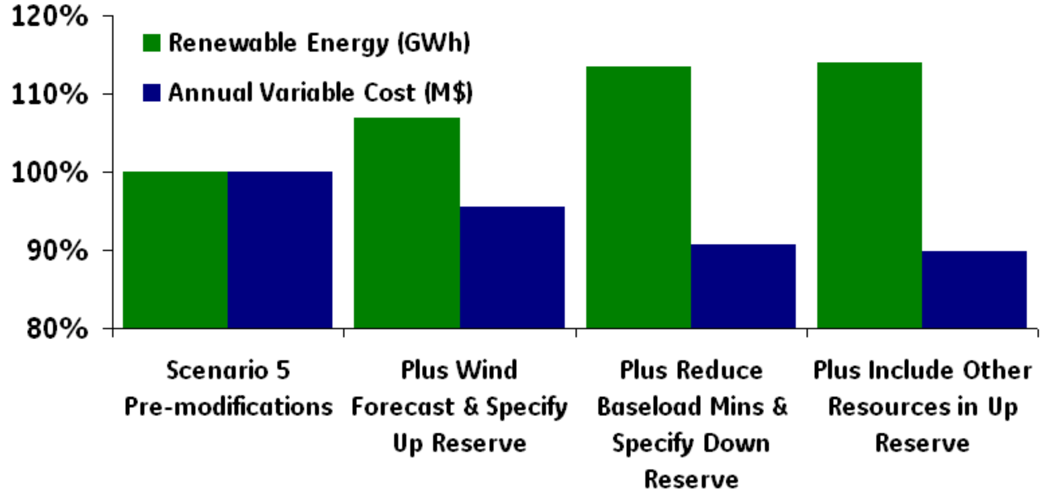

Figure 1-9. Scenario 5. Reduction in variable cost and increase in wind and solar energy delivered for staged strategies.

The figure shows that each of the strategies considered in the study increased the amount of renewable energy integrated into the system and lowered the annual variable cost relative to the "Pre-modification" condition. The proposed system modifications are summarized below:

Strategy #1: Wind power forecast and system up-reserve requirements

This strategy changed the rules for committing units to the system. Two changes were applied:

- Incorporate state-of-the-art wind power forecasting in the unit commitment and ensure cycling and fast-start units can be committed on a 4 hour ahead basis, and
- Increase the system up-reserve requirement to help manage sub-hourly wind variability and uncertainty in wind power forecasts

In the pre-modification condition, system operators planned to bring units online to meet forecasted load plus any reliability conditions. This operating practice neglected to plan for the expected amount of wind available on the system and often resulted in an excess of capacity on the system when large amounts of wind and solar power were available.

In this modified scenario, system operators committed units to meet the net load (forecasted load minus forecasted wind power output). This change in the unit commitment rule resulted in fewer cycling units being committed throughout the year, and thereby increased the amount of renewable energy accepted into the system. The adverse affect of this strategy occurred when the wind power forecast was inaccurate. For example, when wind power did not materialize as forecasted, the commitment of a fast-start peaking unit was required to quickly meet system demand.

The strategy also includes a modified up-reserve requirement to add regulating reserves to the 185 MW spinning reserve requirement to mitigate the adverse affects of wind power variability. The added regulating reserve would be a function of the forecasted wind power and its expected extreme downward variability over the 10-minute time frame. This additional regulating reserve is defined by the unit capacities and the combined ramping capability.

The results in Figure 1-9 show that with these two modifications wind energy delivered increased by 7% and annual variable cost decreased by 4.4% relative to the pre-modification condition.

Strategy #2: Reduce thermal unit minimum power and revise down-reserve requirement

The second modification to system considered in the study was:

- Reducing minimum stable operating power of seven HECO baseload units by a total of ~130 MW, and
- Implementing a down-reserve requirement (modeled as effectively 90 MW) to address plausible load rejection events.

Figure 1-4 showed that many of the thermal units operate at their minimum power levels during periods when a large amount of wind energy is being produced. The minimum power level of the thermal units limits the amount of wind energy that can be accepted by the system. Reducing the minimum operating point of the HECO baseload units lowers this constraint, allowing more wind energy to be accepted by the system.

Review of the initial results indicated that the majority of the HECO reheat units were dispatched at their minimum loads for many hours of the year including periods of higher system load. This significantly increased the system's exposure to a severe loss-of-load event. A loss-of-load event would request that the thermal units reduce their power output. In some instances, some units may already be operating at their minimum stable operating power. This could put the system at risk. To mitigate this risk, the system down-reserve requirement was assumed to be 90 MW to cover a plausible loss of load event.

The net effect of these modifications was a 14% increase in wind energy delivered to the system relative to the baseline simulation. Total variable cost decreased by 9%, mainly due to displacement of fossil fuel.

Another strategy was considered. This strategy included taking a baseload unit out of service for a total of 18-weeks during the year. This strategy only marginally increased the wind energy delivered to the system. This strategy also adversely affected the total variable cost of operation because higher cost cycling units were committed during these 18-weeks instead of a lower cost baseload unit.

Strategy #3: Refine the on-line regulating reserves to leverage other resources to meet system reserve requirements

In this strategy, the up-reserve requirement was reduced to account for “fast-responding” resources such as quick start generation and controllable loads available to the system operator. The net effect of this strategy reduced the number of units needed to meet the up-reserve requirement. The results in Figure 1-9 show that this strategy did not increase the amount of wind energy delivered, but did reduce the variable cost of operation beyond that observed in Strategy #2. Table 1-2 summarizes the results shown for each scenario in this section.

Table 1-2. Summary of Oahu Wind Integration Study Results

	Installed Wind (MW)			Installed Solar (MW)	Wind Energy (GWh)			Total Variable Cost ($M/yr)	Total Fuel Energy (1000xMMBtu/yr)	Avg HECO heatrate (Btu/kWh)	
	Oahu	Molokai	Lanai		Available[1]	Delivered	Curtailed			Simulated	Corrected[2]
Baseline 2014	0	0	0	0	0	0	0	100.0%	81,305	10,386	10,510
Scenario 1	100	0	0	100	358	358	0	91.7%	76,021	10,455	10,580
Scenario 3 + Strategies[3]	100	0	400	100	1,914	1,815	99	70.9%	61,317	10,795	10,924
Scenario 5 (Baseline)[4]	100	200	200	100	1,929	1,595	334	77.9%	62,193	10,704	10,832
Scenario 5 + Strategies[3]	100	200	200	100	1,929	1,839	90	70.0%	61,045	10,778	10,907

[1] Available refers to energy avialable on Oahu (after 5% loss of off-island energy over HVDC system)

[2] Corrected heat rate is 1.2% higher than simulated (calibrated based on 2007 baseline model validation)

[3] These cases represent Scenario 3F3 and Scenario 5F3 (all strategies are included)

[4] This case represents Scenario 5A

Table 1-2 shows that the strategies described above successively increased the amount of delivered wind energy. In fact, over 95% of the available wind energy was delivered when all of the strategies were utilized. As noted in the earlier discussion, the addition of wind and solar power significantly decreased total variable costs by nearly 30% (excluding costs of the renewable energy and required system modifications) and considerably reduced fossil fuel consumption.

The final column shows the average system heat rate for the HECO plants in units of Btus of energy consumed per kWh of energy produced. The results show that conventional generating units operate less efficiently with the addition of new wind and solar power on the system. This occurs because the thermal units are backed down to accept the as-available renewable energy being delivered to the Oahu system. When operating at lower output, the units consume more fuel per kWh of electricity generated (lower efficiency), which is reflected in the results when comparing the baseline and Scenario 1 to Scenarios 3 and 5. Further, there is a system cost associated with greater penetrations of wind and solar power. Results indicate the commitment of peaking (fast-start) units increases. This occurs due to the fact that additional capacity/reserve is needed during times when the wind forecast over-estimates the amount of wind power available. Fuel cost for these units are typically higher (diesel and biodiesel) than the LSFO used for the baseload and cycling units.

1.6. Short-timescale wind variability events and system contingency events considered for high levels of wind power on Oahu

In the previous sections, the analysis focused on longer timeframes (hour-to-hour, over one year). The above analysis was important to understand how the renewable energy displaced conventional generation on a daily, weekly, and annual basis. This section focuses on the shorter timescale impacts due to fast variability of the wind plants and new contingency events resulting from the undersea cable system in an environment of high wind energy penetration. The following analyses were performed:

1. Sustained wind power drops that reduce the thermal unit up-reserves,
2. Sustained wind power drops within an hour that could challenge the ramp rate capability of the thermal units.
3. Sustained wind power rises that could challenge the down-reserve capability of the thermal units.
4. Volatile wind power changes that could challenge the ramping capability of the thermal units.
5. The undersea cable trip contingency event that could cause a large under-frequency event.
6. High wind energy delivery forces thermal units to their minimum operating points, increasing exposure to large over-frequency events due to loss of load events.

The remaining subsections describe these events in greater detail and discuss the results of the analysis of each event.

1.6.1. Sustained wind power drops that reduce the thermal unit up-reserves

In general, the supply of electricity (generation) is managed to meet a variable but historically predictable demand for electricity (load). Integrating large variable wind resources to the electrical system increases the uncertainty in the amount of firm generation required to meet system demand (load and system up-reserves). In addition, wind power variability can challenge the system's ability to maintain system frequency. Therefore, it is imperative to analyze wind variability in different timescales (hours, minutes, and seconds) to assess the impacts on system performance. This is especially true for the Oahu electrical system where one wind plant (400 MW on Lanai in Scenario 3) can provide as much as 50% of the energy during moderate system load conditions, e.g. on weekends at light load. When wind plant production varies significantly, the conventional generation must respond proportionally, and at the same rate to maintain system frequency.

The number, size and geographic diversity of wind plants affect the variability of wind power as seen by the system accepting this power. Large wind plants that are spread over a vast area exhibit lower levels of sub-hourly variability on a per unit nameplate basis compared to smaller wind plants. Even in Scenario 5, the two wind plants were geographically close to one other so the variability of wind power delivered to the Oahu system was expected to be higher than that of a system that has more geographically diversity in wind plant locations.

In this study, the team first analyzed the modeled wind power output data to characterize the variability in the timescales noted above. The yearly data was screened to identify particularly challenging events when the system performance could be assessed. Figure 1-10 shows a histogram of hourly wind power changes (modeled wind data obtained from AWS Truepower), across the sum of the wind plants in Scenario 5 (200 MW Lanai, 200 MW Molokai, 100 MW Oahu) for the years 2007 and 2008. The largest 60-minute wind power change was observed to be 311 MW over one hour in Scenario 5. As a reference, in 99.9% of the events, the wind power dropped in Scenario 5 by less than 145 MW over one hour; and in 99.9% of the cases, wind power increased in Scenario 5 by less than 167 MW over one hour.

On a smaller time scale of 10 minutes, the largest total wind power reduction was 90 MW in Scenario 5 (and 127 MW in Scenario 3). A 5% loss of wind energy was assumed in the transport of power from Molokai and Lanai wind plants to Oahu through the HVDC cable system.

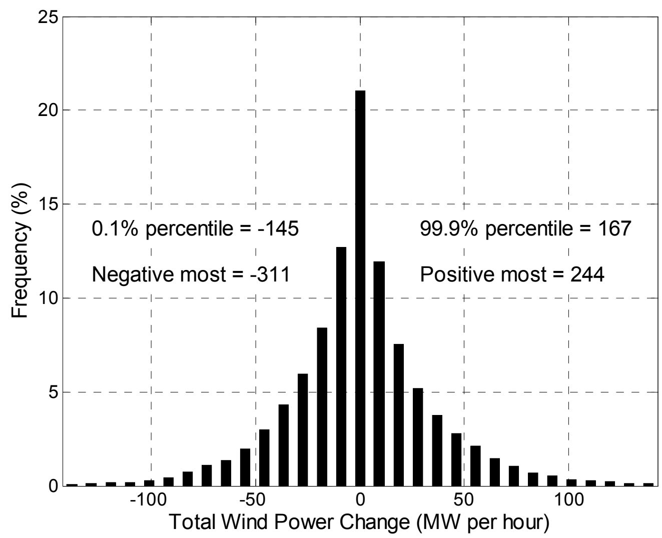

Figure 1-10. Histogram of total wind power changes over 60-minute for Scenario 5 for the wind energy delivered to the Oahu system (two years of simulated wind power data from AWS Truepower).

During the event of the largest drop in wind power (311 MW over a 60-minute interval, or 27% loss of generation), the system up-reserves were challenged. The system load was 1160 MW. At the completion of this one-hour event, only 5 MW of up-reserve capacity remained on the system if no additional units were committed. In the following hour, all fast-start units must be committed to restore system up-reserve.

Figure 1-11 shows the wind and solar power change over the one-hour period and shows the simulated system frequency during this event.

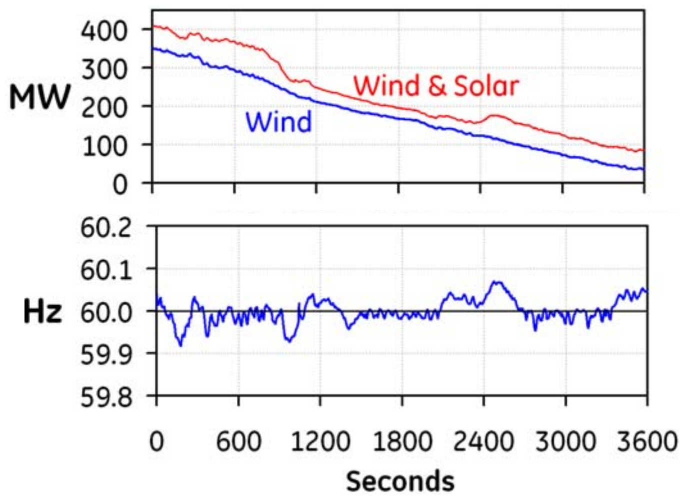

Figure 1-11. Frequency performance during largest 60-minute wind power drop

Figure 1-11 shows that the wind power dropped drastically over the one-hour period. This required conventional generators on the system to increase their output. The system frequency is a measure of the balance between supply and demand. When demand and supply match, the system frequency is 60 Hz. If the load (demand) increases more than the supply, the system frequency decreases and vice versa. As the frequency drops significantly below 60 Hz, the system may reach a frequency at which loads are disconnected (under-frequency load shedding schemes) in order to avoid a cascading blackout. As the frequency rises significantly above 60 Hz, the system may reach a frequency at which thermal units are disconnected to maintain system stability. In this event, the system frequency remains within an acceptable range, which indicates sufficient up-reserve capacity and ramp rate capability of the units to manage the loss of wind power. Note that a unit's capability to provide up-reserves is a function of its remaining capacity and its ramp rate. This analysis shows that wind plant variability in the 60-minute time frame did not adversely impact system performance provided sufficient up-reserve is maintained.

1.6.2. Wind power changes challenge ramp rate capability of thermal units

One of the strategies going into the study was to model the HECO generating fleet with increased ramping capability (nominal 5.5% per minute). The team again screened the wind power data to find a short-term ramp event over a 10-minute interval. A specific challenging event was identified. The load was 1108 MW at the start of the event. During the following 10-minute period, the wind dropped by 83 MW, the solar dropped by 16 MW, and the load increased by 6 MW. The analysis evaluated system performance for both the present and improved generating unit ramp rates. Figure 1-12 shows the performance of the system during this event, under the two different assumptions on the ramp rates of HECO units.

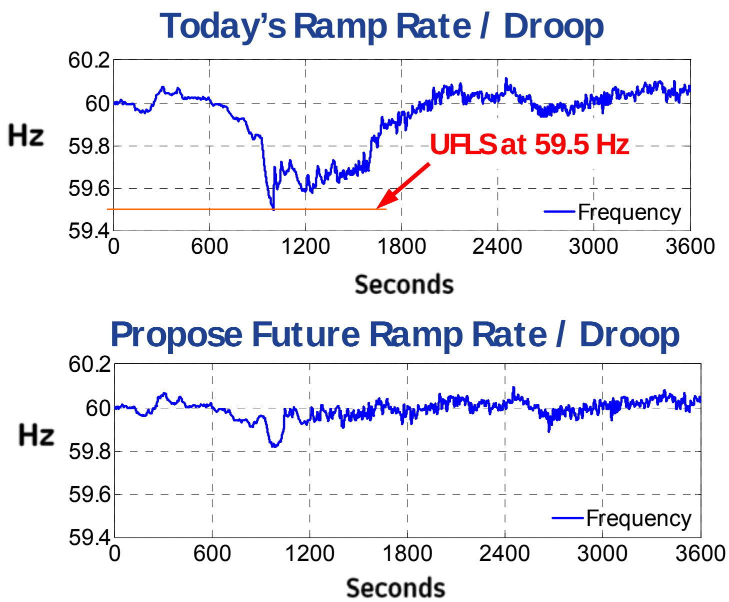

Figure 1-12. Large wind, solar, load change over 10 minute that challenged the system ramp rate capability

The graph on top shows the system frequency during this event with the present unit ramp rates. The sharp drop in frequency at the 10-minute mark is a result of a significant drop in wind power. System frequency dips to 59.5 Hz, initiating the first under-frequency load shedding (UFLS) scheme because the generating units are unable to match the rate of the drop in wind power output. Once the system frequency is stabilized, units increase power to restore system frequency to 60 Hz, approximately 15 minutes after the start of the event.

The lower graph shows the system frequency for the same event with the new, higher ramp rates for the HECO generating units. In this simulation, system frequency drops during the sharp wind power drop, but the magnitude and duration of the drop is significantly less. This analysis illustrates the benefits of improving unit ramping capability as it helps to stabilize system frequency during adverse wind power ramp events.

1.6.3. Wind power increase challenges system's down-reserve

As noted in Figure 1-4, the conventional thermal generating units operate at their minimum operating loads when a large amount of wind power is being delivered to the system. This condition is expected to occur for many hours of the year. If the wind power output suddenly increases, governor droop response of the thermal units could drive their outputs down below their dispatchable minimum load, and start consuming the system down-reserves. If this increase in wind power is large, the units may be forced to reduce output below their stable operating load, which could lead to unit trips. Unless appropriate strategies are implemented to manage these wind events, system reliability could be adversely affected.

A specific wind power event was observed. In this event, the wind power rose by 85 MW over a 10-minute interval. In order to manage the increase in wind power, fast-responding controls must be implemented to reduce the sudden increase in wind power. One option is to institute automatic wind plant curtailment control when thermal units are operating below or near the down-reserve requirement. Alternatively, the down-reserves could be increased, but this would reduce the total amount of wind energy accepted by the system. Another strategy is to use wind plants to provide down-reserve and contribute to this (reserve) requirement. All of these strategies should be considered by HECO for future operations with large amounts of wind power.

1.6.4. Large sub-hourly changes in wind power maneuvered thermal units

The team also analyzed generating unit and system impacts resulting from large variable wind events within an hour. Wind data was screened for hours of high wind and solar power volatility. An event was selected to determine whether the additional maneuvering of the thermal units caused by wind power changes would be acceptable over this interval. Additionally, this analysis intended to estimate the increased maneuvering on the thermal units due to the additional variability brought by the wind plants. The power output from each unit was observed for the hour.

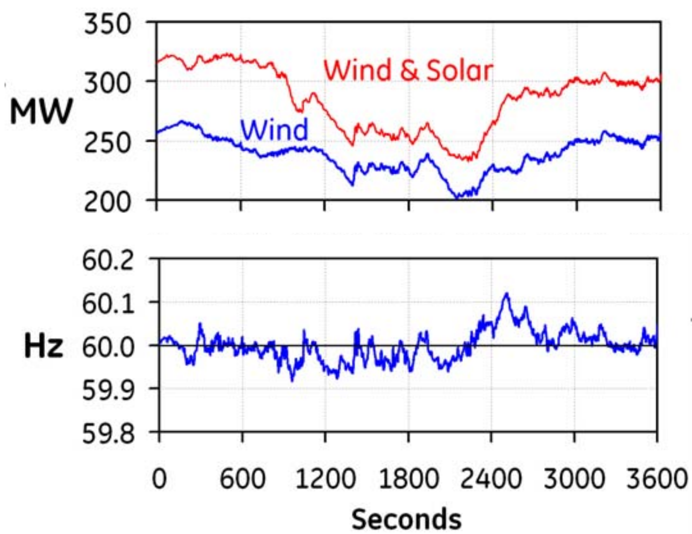

Figure 1-13. Impact of large swings in wind power on system frequency with the proposed thermal unit ramp rate capability and droop response (Scenario 5)

The figure illustrates system performance with the new ramp rates. For this event, the system load was 995 MW and the wind and solar power constituted a large portion of the generation. The system frequency remained within acceptable limits over this hour. As part of this assessment, the team determined the units on the system that were being dispatched to balance the variability from the wind plants. Of the eight HECO baseload units and two IPPs that are capable of providing regulation, it was observed that the HECO baseload units carried the burden of performing frequency regulation in response to these wind variability events, because the HECO units are backed down and typically more costly to operate than the IPP units. Additional sensitivity analyses were conducted to determine the benefits of the unit ramp rate improvements and imposing ramp rate limits on the wind plants.

1.6.5. Loss of cable delivering off-island wind energy causes large under-frequency events

In addition to looking at the impact of wind power variability events, traditional contingency events like instantaneous loss of generation were considered. With the installation of the undersea cable system, the largest single-contingency event for loss of generation on the Oahu system would be an undersea cable trip. Screening parameters included high wind plant output and low system up-reserves. For these criteria, an hour was selected in Scenario 5 when the system load was 1020 MW and the total wind power generation was at 363 MW, out of which 282 MW came from off-island plants. The system up-reserve capacity was relatively low at 267 MW, when a 200 MW cable trip was simulated. This was just prior to committing a unit to meet up-reserve requirements. Figure 1-14 shows the results for this event.

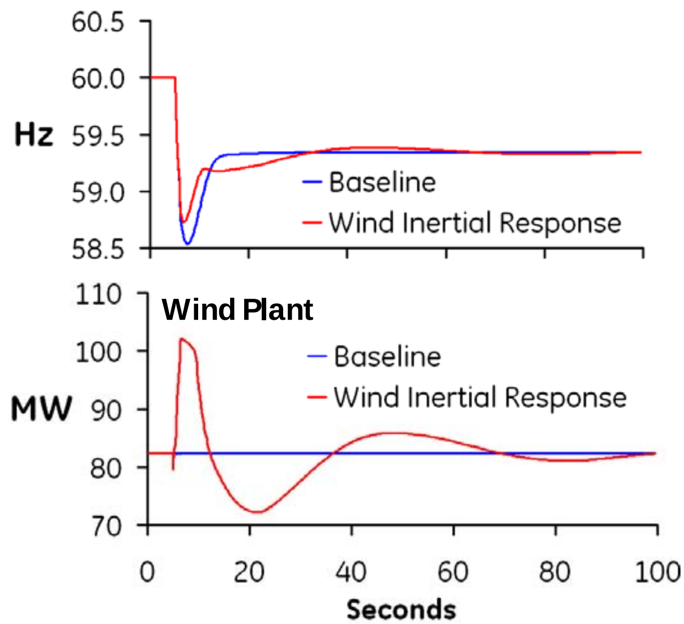

Figure 1-14. 200 MW cable trip event in Scenario 5 with future thermal unit droop characteristics, with and without wind turbine inertial-type response. Second figure shows response from remaining off-island wind plant.

The top graph shows the system frequency in the first 100 seconds after the undersea cable trip and the bottom graph shows the simulated wind plant output from the remaining off-island wind plant, after the cable trip event. The wind plant was supplying 82 MW of power at the beginning of this event. Since this is a transient event, no action of the Automatic Generation Control (AGC) is considered. The graph illustrates the results under two sets of assumptions. For the initial analysis (results shown in blue), the wind plant has no advanced capability to help the system respond to these events. Thus, power output from the wind plant remains constant throughout the event. The curve shown in red assumes the wind plant is capable of providing commercially available inertial-type response and can provide a short-term increase in power output. The second graph shows a rapid increase in power from the wind plant, by approximately 20 MW, in the first few seconds after the cable trip.

With no inertial-type response from the wind plants, the system frequency drops to 58.5 Hz, triggering ~55 MW of load shedding. By implementing wind plants with inertial-type response capability, the remaining 163 MW of wind power (82 MW from off-island and 81 MW from on-island) could briefly increase output, which helped reduce the under-frequency event by 0.13 Hz. The analysis shows the benefits of wind plants with advanced control features that are designed to assist the system during these types of events.

1.6.6. Load rejection events during high wind conditions causes large over-frequency events

Another contingency event that was considered in the study was a large loss-of-load during high wind conditions. As noted in previous sections, with the simulated wind plant projects, the thermal units were more frequently dispatched to much lower operating loads in order to accept large amounts of wind energy. If a significant loss of load event occurred, the system could be vulnerable if units were forced below their stable operating loads and units began to trip off-line.

To better understand these risks, the number of hours each unit operates at their minimum power was calculated, respecting the down-reserve requirement. Table 1-3 shows the results on a percentage basis, relative to the Baseline 2014 scenario.

Table 1-3. Per unit operation at minimum dispatchable power with respect to Baseline

Time at minimum dispatchable power	SCENARIO			
	Baseline	1	3	5
Kahe 1	100%	134%	153%	158%
Kahe 2	100%	143%	173%	173%
Kahe 3	100%	139%	225%	228%
Kahe 4	100%	134%	159%	160%
Kahe 5	100%	140%	261%	261%
Kahe 6	100%	131%	273%	272%
Waiau 7	100%	137%	93%	92%
Waiau 8	100%	129%	145%	146%

The results indicate that HECO reheat units operate at their minimum operating loads for a significant number of hours as compared to the Baseline scenario. This increases the number of hours the system could be at risk during transmission line faults. Modification to the down-reserve requirement was recommended to mitigate these system risks.

In this analysis, an hour was selected when the system load was 720 MW, the wind power was providing 50% of the generation (357 MW), the majority of the thermal units were dispatched at their minimum-operating load, and the system was carrying 89 MW of down-reserve. A down-reserve requirement of 90 MW was assumed in this study. At this instant, an event with a 140 MW loss of demand was simulated. The magnitude of this event was based on historical data from the Oahu system. The results are shown in Figure 1-15.

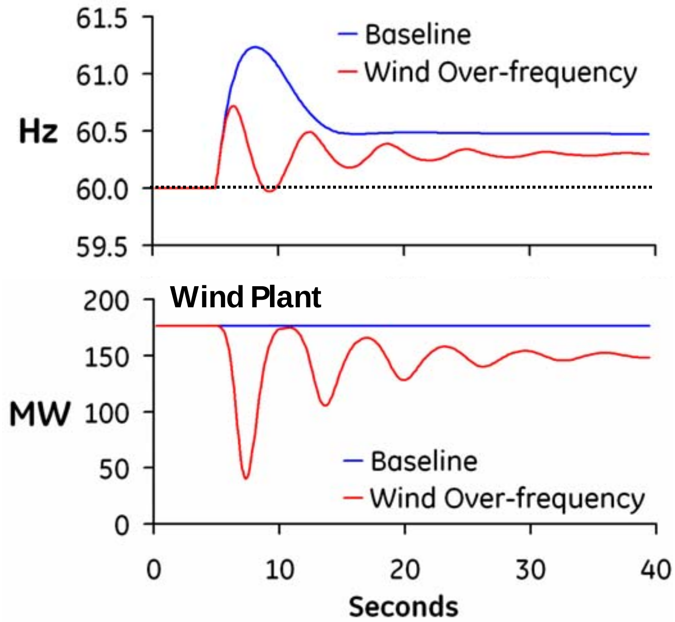

Figure 1-15. 140 MW load rejection event in Scenario 5 with future thermal unit droop characteristics, with and without wind turbine over-frequency control (3% droop / 30 mHz deadband).

The top graph shows the system frequency response immediately after the loss of load. The figures show results for two alternative options of wind turbine capabilities. The baseline case (shown in blue) considers wind turbines with no advanced features, while the alternate case (shown in red) considers wind turbines that are capable of providing commercially available over-frequency control, and can quickly reduce their output during system over-frequency events.

In the baseline system, frequency immediately rises above 61 Hz. In the “wind over-frequency” case, the magnitude of the frequency rise is lower and frequency settles down to a lower steady state value. The figure on the bottom illustrates the difference in wind plant output during these simulations. Again, no automatic generation control (AGC) response is considered for these types of simulations. In reality, after the event occurred, the AGC would send requests to the dispatchable thermal units to change their power output to bring the frequency back to 60 Hz.

The results show the magnitude of frequency excursion is substantially reduced when the wind plants participate during an over-frequency event. This wind turbine feature can help to maintain a more stable system frequency during these events and potentially reduce the down-reserve carried by the thermal plants.

1.7. Observations

This section of the summary highlights the observations and conclusions of the study.

- Limited wind energy curtailment occurred, primarily during light load (night-time) operation

    - Table 1-2 showed that nearly 95% of the available wind power could be accepted by the system with modifications to system operations and existing generating units.
- Thermal units are dispatched at their minimum operating loads, respecting the down reserve requirement, for a significant number of hours beyond the traditional system minimum load periods of 10pm to 6am. Thermal units operate less efficiently at these lower loads.
- The Oahu system is exposed to new contingencies and risks that could affect the system reliability, such as:
    - The possibility of a sudden loss of load (load rejection) when the thermal units are operating at low power output, and
    - The possibility of an undersea cable trip event that increases the loss of generation contingency from 180 MW (loss of AES) to 200 MW (loss of an off-island wind plant operating at full power).
- Sustained (60-minute) drops in wind and solar power do not impact system performance provided sufficient up-reserve is maintained.
- Variability in wind and solar power outputs, within an hour, could challenge the ramp rate capability of the thermal units and increase the severity and frequency of ramping events for the thermal units.

Based on these observations, the following approaches were considered and studied to reduce the variable cost of operation and increase the wind energy delivered to the Oahu system:

- Increasing the thermal unit ramp rate capability to manage the variability of wind power.
- Wind power forecasting to improve the commitment of the thermal units. Wind forecasts help the operator to schedule unit commitments to meet the net load (i.e. load minus forecasted wind power). This increases the amount of wind energy accepted by the system and reduces total variable costs.
- Defining the up-reserve requirements based on the wind power forecast and ramping capability. By establishing a new reserve requirement, the system can better respond to severe wind ramp events and system reliability can be maintained.
- Reducing minimum power of baseload units and refining the down-reserve. Reducing the minimum power of baseload units enables more wind energy to be accepted by the system. System performance is further improved with increased ramp rate capability. Refining the down-reserve requirement helps ensure system reliability during severe loss-of-load events.
- Seasonally cycling-off select baseload units. During periods of anticipated low load, cycling off selected baseload units reduced the number of units on-line and helped enable more wind energy to be accepted by the system. These benefits are offset by an increase in cycling unit run-hours as the more efficient baseload unit is unavailable during these periods.
- Reducing the up-reserve by relying on fast-start units and load control programs that can be dispatched quickly (to support generation) when the wind power drops.
- Considering advanced wind turbine technologies to provide inertial-type response, so wind plants can assist the system during system contingency events. Wind turbines with

advanced capabilities can contribute towards on-line reserve requirements and potentially increase total wind energy that can be accepted by the system.

This study did not perform extensive analysis on strategies to mitigate variability that utilize energy storage because of constraints on the study's resources and timeline. While energy storage can be used to help mitigate the variability and uncertainty of wind power in the HECO system, the cost and benefit of energy storage would need to be explicitly compared against alternate technologies and strategies that were considered in this study. This type of comparative benefit-cost analysis was beyond the scope of the current study.

Under the scenarios considered in this study, the team did conclude that energy storage is not necessary to manage the variability of the wind plants if the present ramp rate capabilities of the HECO thermal units are increased to the ramp rates proposed by HECO. This conclusion is sensitive to the underlying assumptions in the scenarios analyzed in the study. Each of the scenarios consists of a specific generation mix, wind plant sizes and locations, and assumed performance capabilities of the Energy Management System, thermal units, and wind plants. As the Oahu power system evolves, it may be necessary for HECO to reconsider the strategies and technologies to enable high levels of wind power, and/or consider alternate strategies to help enable the levels of wind power considered in this study.

1.8. Recommendations

This study shows that it is operationally feasible for the Oahu system to accommodate the wind projects and supply more than 25% of the island’s energy from the 500 MW of wind power and 100 MW of solar PV projects, if the following strategies are incorporated:

1.8.1. Operating Strategies

- Incorporate state-of-the-art wind power forecasting into the unit commitment process and account for the availability of wind plants in this forecast,
- Increase the up-reserve requirement to help manage sub-hourly wind variability and uncertainty in wind power forecasts,
- Continuously monitor wind power variability and wind power forecast accuracy to improve above estimates and operating strategies,
- Implement severe weather monitoring to ensure adequate unit commitment during periods of higher wind power variability,
- Evaluate the effectiveness of including other resources capable of contributing to up-reserve, such as fast-starting thermal units and load control programs,
- Continuously monitor and report fast-start capacity and load control available to enhance real-time system operation during wind variability, wind uncertainty, and other events,
- Implement a down-reserve requirement based on feasible loss-of-load events and the anticipated system response to the event,
- Once the wind plants are in operation, further refine the down-reserve requirement based on actual wind plant over-frequency performance during loss-of-load events,
- Integrate wind power measurements, automatic wind curtailment, and wind curtailment allocation in system operating practices.

1.8.2. Thermal Unit Modifications

- Reduce minimum stable operating power of baseload units, and
- Increase AGC response ramp rates and modify droop characteristics of HECO thermal units.

1.8.3. Wind Plants and HVDC Interconnection

- Deploy wind plants capable of providing: (1) inertial-type response for significant under-frequency events, (2) frequency control for significant over-frequency events, (3) less than 10-minute response to curtailment requests, and (4) wind plant under-frequency control during periods of curtailment due to other system needs only.
- Coordinate HVDC sending end converter and off-island wind plant to allow wind plant active power controls based on Oahu system frequency.

Based on the assumptions outlined in this study, the above system modifications, refinements in operating strategy, and wind plant requirements will help the Oahu power system to integrate the wind projects considered in this study.

1.9. Conclusions and Next Steps

This study was intended to provide the Hawaiian Electric Company with strategies to enable the integration of these wind projects. Further studies are required to implement these strategies to determine feasibility, cost benefit, and potential alternatives.

The technical analysis suggests that the Oahu system can accommodate the wind and solar projects examined in this study with the operational and equipment modifications as described above and with minimal curtailment of off-island wind energy. Reliable system operation under these projects will require investment in further studies, existing and new infrastructure, as well as specific requirements on the wind plants to be connected to the Oahu system.

Table of Contents

List of Figures

List of Tables

Nomenclature

ABC: The 2^{nd} order polynomial curve describing a thermal unit heat rate.
AGC: Automatic Generation Control
BESS: Battery Energy Storage System
CT: Combustion Turbine
DWP: Delivered Wind Power
FOR: Forced Outage Rates
GE: General Electric Company
GE MAPS^{TM}: GE Multi-Area Production Simulation; production cost modeling tool
GE PSLF^{TM}: GE Positive Sequence Load Flow; transient stability and dynamic modeling tool
HECO: Hawaiian Electric Company
HNEI: Hawaii Natural Energy Institute
IPP: Independent Power Producers
MOR: Maintenance Outage Rates
MR: Must-Run commitment requirement
OTEC: Ocean Thermal Energy Conversion
UFLS: Under frequency load shedding
WP: Wind plant

2.0 Acknowledgements

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- Debbie Lew, Dave Corbus, and Ray George from the National Renewable Energy Laboratory
- John Manobianco from AWS Truepower.
- The Technical Review Committee

This effort would not have been possible without support from the Hawaii Natural Energy Institute, the Hawaiian Electric Company, and Department of Energy.

3.0 Introduction

Over the past four years, the General Electric Company (GE), Hawaiian Electric Company (HECO) and the Hawaii Natural Energy Institute (HNEI) have collaborated on power systems studies on the islands of Hawaii, Maui and Oahu in order to assess the impacts of very high levels of renewable energy connected to each power system.

In January 2009 HECO, HNEI, and GE (collectively termed as the project team) developed, validated, and calibrated a baseline model of the Oahu power system for the year 2007. In the first phase of the effort, the project team established detailed production cost models, transient stability models, and an AGC (Automatic Generation Control) representation of the HECO system for the year of operation in 2007. In the second phase of this study, the model was updated to reflect the forecasted 2014 HECO system. The model was revised and utilized to assess wind penetration scenarios.

The results of this study suggest that 400 MW of off-island wind energy and 100 MW of on-island wind energy can be integrated into the Oahu electrical system while maintaining system reliability. Integrating this wind energy, along with 100 MW of solar PV, will eliminate the need to burn approximately 2.8 million barrels of low sulfur fuel oil and 132,000 tons of coal each year. The combined supply from the wind and solar PV plants will comprise just over 25% of Oahu's projected electricity demand. The following report will detail the results of the study, the model development, assumptions and limitations, strategies and recommendations.

Initially the project team determined that five scenarios would be considered. These included the following:

1. Scenario 1 – 100 MW wind on Oahu
2. Scenario 2 – 100 MW wind on Oahu and 200 MW wind on Molokai
3. Scenario 3 – 100 MW wind on Oahu and 400 MW wind on Lanai
4. Scenario 4 – 100 MW of Solar on Oahu
5. Scenario 5 – 100 MW wind and 100 MW solar on Oahu, 200 MW wind on Molokai and 200 MW wind on Lanai

In parallel with the data collection efforts for the scenario analysis, the project team held several meetings to develop a strategy to conduct the study. Several decisions allowed the team to reduce the list of scenarios from five to three. First, the team determined that Scenarios 1 and 2 should be combined to analyze all on-island renewable resources (a potential scenario prior to construction of the off-island wind plants and HVDC cable system). Second, the team determined that Scenario 5 should be the first scenario to be considered. It was anticipated that this scenario could potentially challenge the limits of the electrical system model as well as the modeling tools, enabling the team to identify constraints and resolve these constraints in the modeling tools. A successful simulation of Scenario 5 would help to eliminate other scenarios with smaller renewable energy penetration, such as Scenario 2. This allowed the project team to focus on analyzing strategies for Scenarios 5 and 3 that could address the challenges of integrating very high levels of wind power, while still meeting the study objectives. The project team agreed on the following scenarios:

1. Scenario 1 – 100 MW wind and 100 MW solar on Oahu
2. Scenario 3 – 100 MW wind and solar on Oahu, 400 MW wind on Lanai
3. Scenario 5 – 100 MW wind and 100 MW solar on Oahu, 200 MW wind on Molokai and 200 MW wind on Lanai

The contents of the report are described in the following paragraphs. In Section 4.0 the objectives of the study are outlined and information is provided about the modeling tools and study assumptions.

In Section 5.0 the details and limitations of each modeling tool is provided. In Section 5.1, the GE models used for this study are described. Five tools were assembled for this study; two of which are classical power system analysis tools, while the other three were developed or modified specifically for this study. This section of the report highlights the advancements to the GE models that were needed in order to capture the unique operating conditions of the Oahu power system, which is electrically smaller than systems that this GE team has analyzed in other studies. In Section 5.2, the baseline model development process and results are summarized. In Section 5.2.2 the results of the Baseline scenario and three high wind scenarios are presented. These high wind scenarios formed the basis for which the strategies to increase wind energy delivered were built upon.

In Sections 6.1 and 6.2, the preparation of all data for the models is described. This includes the wind power data, wind power forecasting data, and solar power data analysis efforts, as well as the analysis of wind power variability data as it pertained to defining system reserve requirements. In Section 6.3 a detailed overview of the model development, validation and calibration effort is provided. In Section 6.4 the results of Scenario 1 are presented. In Section 6.5 the results of Scenario 5 are presented, and in Section 6.6 the results of Scenario 3 are presented.

In Section 7.0, strategies to enhance system operation, reduce wind plant curtailment and reduce system-wide variable cost are examined. This section describes the results of the GE MAPS™ production cost simulations. The objectives of the study are outlined in Section 7.1. The results are presented in this section for Scenario 5. In Section 7.2 the impact of reducing the minimum power of the HECO thermal units is examined without changing the down-reserve requirement. In Section 7.3 the effect of increasing the down-reserve requirement to a more appropriate level is examined. In Section 7.4 the effect of seasonally cycling off HECO baseload units is considered. In Section 7.5 the effect of including other resources as part of the up-reserve is considered. The conclusions are provided in Section 7.6. In Sections 7.7, 7.8, and 7.9, the results of the above compilation of strategies are presented for Scenario 3. In Section 7.10, the results are summarized for both Scenario 3 and Scenario 5. The section concludes with a summary of all strategies that can help to enable the wind projects considered in this study.

In Section 8.0 the results of the Interhour screening process are described as well as the results of the dynamic simulation in GE PSLF™ (long-term dynamic and transient stability). This section highlights the simulations and results for all sub-hourly analysis.

In Section 9.0, observations and conclusions are provided. In Section 9.1, observations and conclusions are provided for the (steady-state) hour-to-hour production results. In Section 9.2, observations and conclusions are provided for the dynamic performance of the system.

In Section 10.0, the study recommendations are presented. The recommendations are separated into the following sub-sections:

- Wind plants (Section 10.1)
- Solar plants (Section 10.2)
- Data exchanged between wind/solar plants and operations (Section 10.3)
- Energy Management System (Section 10.4)
- Operating Strategies (Section 10.5)
- HVDC system (Section 10.6)
- Thermal unit modifications (Section 10.7)
- Additional studies and analyses (Section 10.8)

4.0 Background

In 2009 the General Electric Company, the Hawaiian Electric Company (HECO) and the Hawaii Natural Energy Institute (HNEI) jointly developed power system models of the Oahu system to assess forward-looking scenarios of plausible expansions to the generation mix on the island, with a primary focus on wind plant installations. These models were developed and results validated against 2007 historical data. The models were approved by the project team for the subsequent phase of the study. In this subsequent phase of the study, GE assembled a baseline model of the power system for 2014 (the future year of study) that included new generating units, updated operating rules and forecasted system load, unit maintenance schedule, fuel prices, etc. In this report, GE will highlight the results of the scenario analysis effort.

In Phase 1 of the study, models of the HECO system were developed, calibrated and validated against actual system conditions. The model consisted of three specific simulation tools: the production cost modeling tool, the transient stability dynamic model and a long-term dynamic model, which included a representation of HECO's Automatic Generation Control (AGC). The production cost model considered the dispatch and constraints of all generation on an hourly basis and provided outputs such as emissions, electricity production by unit, fossil fuel consumption, and variable cost of production. The transient stability dynamic model considered shorter timescale contingency events (sub-hourly) and characterized the system's ability to respond to these events. The long-term dynamic model considered critical wind variability event over less than one hour and characterized the system's ability to respond to these types of events. The dynamic modeling tools were necessary to determine the impact of decisions made in the longer timescales (production model) on the overall system operability. Statistical analyses tools were developed to identify wind and load variability events, which were examined in greater detail in this study.

The production cost model was developed to: (1) assess the variable cost of production (and its breakdown in terms of O&M, fuel, and start-up cost), (2) estimate the amount of wind and solar power curtailed, (3) quantify the overall system heat rate, and (4) describe the unit commitment and dispatch for each scenario. The production cost modeling tool (GE MAPS™) curtails wind and/or solar power when the units on-line cannot be backed down any further without violating their minimum power output and down-reserve requirement. Further, the production cost tool is used to initiate the dynamic model developed in GE PSLF™, which is a tool for assessing dynamic stability of the power system. A model of the HECO Automatic Generation Control (AGC) was developed for the project in GE PSLF™ and was used to assess the unit performance and system frequency impact of the wind variability for specific events on the system.

Significant interaction with the HECO and GE teams resulted in the development of a very high-resolution power system model for the island of Oahu. The purpose of this modeling and analysis effort was to provide a Baseline measure of power system performance. This Baseline model is used as a reference point for infrastructure evolution scenarios that explores alternative energy futures for HECO.

4.1. Study objectives

The General Electric Company (GE), the Hawaii Natural Energy Institute (HNEI) and the Hawaiian Electric Company (HECO) commenced a 16-month study effort to assess the impacts of integrating 400 MW of off-island wind energy to the Oahu electrical system. Study scenarios included wind and solar resources on Oahu as well as the off-island wind plants.

Objectives of the study include:

- Assess the amount of off-island wind energy delivered, fossil plant emissions, fuel consumption, and annual operating costs,
- Identify the operating characteristics (commitment/dispatch) of a system,
- Identify the impacts to reliable operation of a system,
- Assess the dynamic performance of the Oahu system,
- Identify strategies that facilitate high penetrations of wind power,
- Assess the impact of each strategy across many timescales of system operation, and
- Provide recommendations based on study results.

The study was conducted in two distinct phases. Phase 1 consisted of the development of the Oahu system model and validation of the model with historical data. Two existing software applications were used and three new tools developed to assess the impacts of integrating wind power across various timescales of system operation.

Phase 2 used the baseline model (from Phase I0 to simulate a future system with new on-island resources as well as 400 MW off-island wind plants. Three primary scenarios were analyzed:

1. Scenario 1 – 100 MW on-island wind power and 100 MW on-island solar power
2. Scenario 3 – Scenario 1 plus 400 MW of off-island wind power on Lanai
3. Scenario 5 - Scenario 1 plus 200 MW of off-island wind power on Molokai and 200 MW of off-island wind power on Lanai.

An integral component of the scenario analysis was the construction of specific strategies that were analyzed with the same tools. The results of these analyses provide the basis for conclusions and recommendations. Results of the study are based on simulations of the Oahu electrical system and are meant to inform HECO on the potential benefits of implementing these strategies to integrate high levels of as-available renewable energy onto the grid. As with any modeling study, additional work is required to assess feasibility, cost/benefit, and develop project plans necessary to implement these projects and strategies.

5.0 Model Development and Assumptions

This project was focused on providing a foundation from which simulations could be performed to develop quantitative information necessary for evaluating the electric infrastructure. The models developed in this study aimed to capture technical aspects of the challenges related to regulation, frequency control, load following and unit commitment, within the transmission system capabilities of the present and future infrastructure; particularly those associated with integration of high levels of wind power. The quantitative analysis covers a broad range of timeframes, including:

- Seconds to minutes (regulation and frequency control) – Dynamic simulation
- Minutes to hours (load following, balancing) – Dynamic simulation
- Hours to days (unit commitment, 24-hour forecasting and schedules) – Production cost simulation

Being an isolated electrical system, the Oahu grid is a very dynamic system subject to continuously changing conditions, some can be anticipated and some cannot. From a control perspective, the demand for electricity (the load) is the primary independent variable. All the short-term controllable resources in the power system must be positioned to respond to this. There are annual, seasonal, daily, minute-to-minute and second-to-second changes in the amount (and nature) of load required by the system. Unanticipated changes to the electrical system also affect the balance between generation and load demand. These occur in the second-to-second and minute-to-minute time frames and include contingency events such as sudden loss of generation or transmission/distribution infrastructure.

The addition of large amounts of variable wind power to the system adds another variable to an already dynamic electric grid. This variable generation resource together with the changing system load creates unique challenges that typical large electrical grids like those on the continental United States do not experience. The reliability of the electrical system is highly dependent on the ability of the system's resources to accommodate these changes and respond to system disturbances while maintaining power 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 was aimed at quantitatively evaluating the impact of existing HECO assets, in each of the timeframes relevant to the performance of Oahu power system. In the longest timeframe, planners look several years into the future to determine the infrastructure requirements 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, during day-to-day planning and operations, the system must prepare 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. This is the shortest timeframe in which economics and human decision-making play a substantial role. Unit commitment and scheduling decisions made for the day ahead are implemented and refined to meet the changing load.

In the shortest timeframe, cycle-to-cycle and second-to-second variations are characterized by the system's inertia and control response is automatic in the form of turbine governors and generator excitation systems. The system's automatic controls are hierarchical, with all individual generating facilities exhibiting specific behaviors in response to changes in the system that are locally observable (i.e., are detected at the generating plant or substation). In the second-to-second timescale, a subset of generators provide regulation by following commands from the centralized Automatic Generation Control (AGC), to meet overall system control objectives including system frequency.

These modeling studies are both sequential and iterative in nature. The process started with the development of a set of assumptions for the production cost model. A simulation was then performed to assess system performance over a year of operation. HECO engineering personnel assessed system performance, evaluated potential risks and performed validity checks for the results of production cost simulations. If unacceptable, assumptions were revised using good engineering judgment and the production cost simulation was repeated. When production cost simulation results were acceptable, dynamic simulations were performed to determine system stability during contingency events. The results may have warranted further modifications to the production cost assumptions.

A set of strategies were developed and simulated sequentially to evaluate their effectiveness, each requiring a separate production cost simulation and subsequent dynamic simulation and analysis. This process is repeated for every scenario.

5.1. GE Power Systems Modeling Tools

The GE modeling tools, described earlier in the report and used for this study, are a mix of classical utility power system analysis tools, including production cost modeling and transient stability modeling performed by the Generation and Transmission Planning teams, and tools developed specifically for this study.

The two classical power systems analysis tools used by the project team were:

1. GE MAPS™ production cost modeling to assess wind power curtailment, unit heat rates, variable cost of production, fuel consumption, etc., and
2. GE PSLF™ transient stability modeling to assess short-timescale planning contingencies associated with high penetration renewable integration.

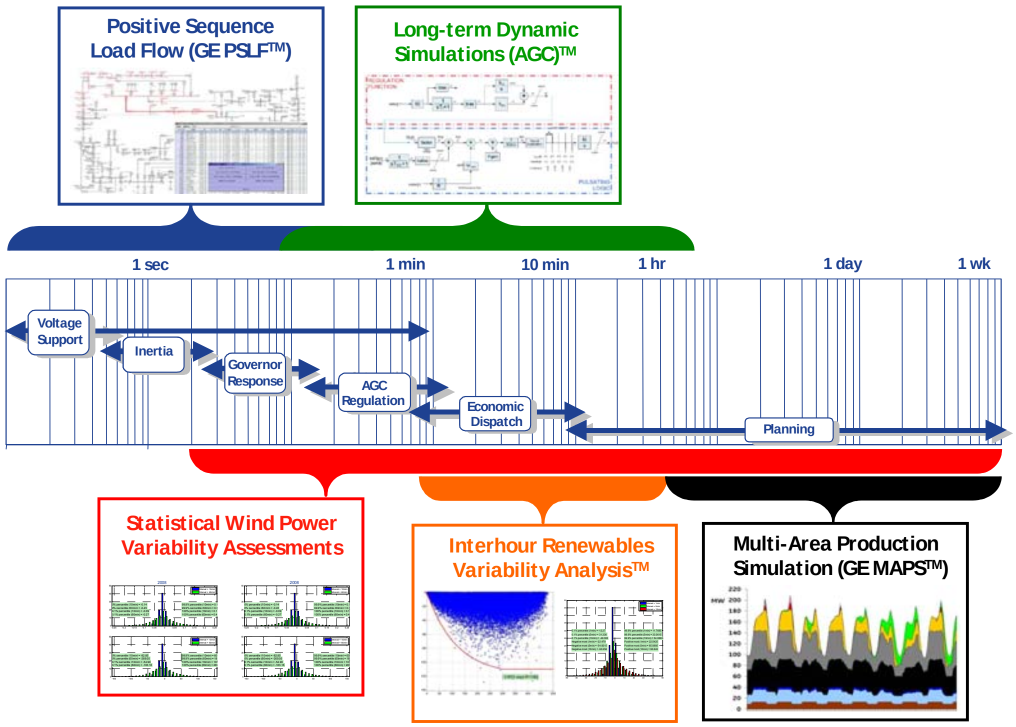
One of the tools was debuted in an earlier study on the Big Island of Hawaii and Maui, and the learning from those studies was leveraged in this project:

3. GE PSLF™ Long-term dynamic simulations to assess sustained and sudden renewable variability events capturing governor response and representative Automatic Generation Control response of the system.

The final two tools were developed and enhanced specifically for this assessment:

4. Statistical wind power variability assessments for system up-reserve estimates and selection of challenging system events, and
5. Interhour screening to identify the unit commitment during challenging system events associated with high penetrations of renewable energy and relatively low system up-reserves.

These five tools coupled together in a series of simulation efforts provided information over a range of timescales of interest to the project team. The range of timescales over which these tools work together is shown in Figure 5-1.



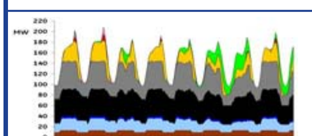
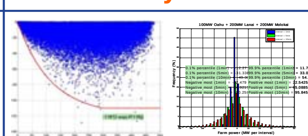
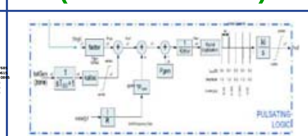
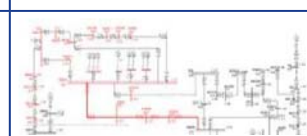
Multi-Area Production Simulation (GE MAPS)	Inter-hour Variability Analysis	Long-term Dynamic Simulations (Auto Gen Control)	Positive Sequence Load Flow (GE PSLF)
			
Unit commitment/ dispatch, representing operating rules, benchmarked against system operation.	Sub-hourly wind/solar/load changes with respect to reserve, based on commitment and dispatch.	Frequency analysis, including governors and AGC response. Initialized from MAPS and driven by major wind/solar events.	Full Transmission model for voltage & stability performance, governor response, contingency analysis.
Hourly results for 1yr	10min results for 1yr	1sec results for one 1hr	1ms results for 1min
Quantify energy production, variable cost, wind power curtailment, emissions, etc for each scenario to assess… • Wind/solar delivered • Unit commitment • Variable cost • Emissions, etc	Quantify reserve violations, fast starts & load shed events caused by sub-hourly wind/solar/load changes… • Assess reserve requirements • Assess fast-start events • Select windows for further analysis	Quantify frequency performance during wind/solar variability events and wind ramp events… • Reserve requirements • Types of regulating units, • Benefit of increasing ramp rates	Quantify system stability performance during contingencies… • Wind/solar plant requirements (freq control, LVRT, voltage control) • System contingencies • Generator trip • Load rejection • Other

Figure 5-1. GE power system modeling tools for the Oahu Wind Integration Study

5.1.1. GE MAPS™ production cost model

Throughout the year, system operators at HECO have to make decisions about which generators should be used to produce electricity in each hour of the day (i.e. commitment and dispatch decisions). The commitment of units is the selection of units, a day or week in advance, which must operate in the future hour of interest. The dispatch of units is the power output of these committed units in a given hour required to meet the load at that instant. The commitment and dispatch decision depends on many variables, including the cost of each generator, the capabilities of the transmission system, and startup constraints on cycling units, as an example. The model includes representation of the HECO 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.

Production cost modeling of the HECO system was performed with the GE's Multi Area Production Simulation (MAPS™) software program. This commercially available modeling tool has a long history of governmental, regulatory, independent system operator and investor-owned utility applications. This tool was used to simulate the HECO production for 2007 as part of the baseline model validation process. Later, the model was used to forecast the Oahu power system for the year 2014. 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 standard least marginal cost operating practice. That is, generating units that can supply power at lower marginal cost of production are committed and dispatched before units with higher marginal cost of 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. Significant input was received from HECO and multiple model refinement iterations were performed in order to capture the nuances of the HECO system.

The price that HECO pays to an independent power producer (IPP) for energy is not, in general, equal to the 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 HECO pays to IPPs for energy purchase was reflected in the simulation results insofar as the conditions of the PPAs can be reproduced. This was done in conjunction with the HECO team by modeling the AES and Kalaeloa units based on heat rate curves that reflect the cost of their production. The costs of purchasing power from HPower (today and in the future), Honua (future), and OTEC (future) were not captured in the model.

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

- 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 HECO.
- 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 renewable resources (in future scenarios).

- The production cost model requires input assumptions like forecasted fuel price, forecasted system load, estimated unit heat rates, maintenance and forced outage rates, etc. Variations from these assumptions could significantly alter the results of the study.
- Prices that HECO pays to IPPs 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 PPAs. The price that HECO pays to third parties is reflected in the simulation results insofar as the conditions can be reproduced.

The simulation results provide insight into hour-to-hour operations, and how the commitment and dispatch may change subject to various changes, including equipment or operating practices. Since the production cost model depends on fuel price as an input, relative costs and change in costs between alternative scenarios tend to produce better and more useful information than absolute costs. The results from the model approximate system dispatch and production, but do not necessarily identically match system behavior. The results do not necessarily reproduce accurate production costs on a unit-by-unit basis and do not accurately reproduce every aspect of system operation. However, the model reasonably quantifies the incremental changes in marginal cost, emissions, fossil fuel consumption, and other operations metrics due to changes, such as higher levels of wind power.

5.1.2. GE PSLF™ transient stability model

Transient stability simulations were used to estimate system behavior (such as frequency) during system events in the future year of study. This type of modeling can be used to understand the impact of transient operation of different generators on system frequency in a second's timeframe and is used by utilities to ensure that the system frequency remains relatively stable during critical operating practices. For example, if a thermal unit is unexpectedly disconnected from the grid when a large amount of power is being delivered to the system from wind plants, how does the system frequency and power output from the committed units change with different assumptions about wind plant performance, thermal unit governor characteristics, etc.? These types of simulations were performed in GE PSLF™.

The fidelity of short-term dynamics is limited primarily by the quality of governor model database provided. Short-term dynamic models of the HECO grid were implemented in GE PSLF™. This tool is widely used for load flow and transient stability analysis. The primary source of model uncertainty and error for short-term dynamic simulations is attributed to the difficulty in quantifying and populating component model parameters of various electric power assets in the HECO grid (primarily generators, load, and governor models).

5.1.3. GE PSLF™ long-term dynamic model

Long-Term Dynamic Simulations were performed for the Oahu grid using GE's Positive-Sequence Load Flow (PSLF™) software. Second-by-second load and wind variability was used to drive the full dynamic simulation of the HECO grid for several thousand seconds (approximately one hour). The model developed in Phase 1 of the program includes all of HECO-owned and IPP-owned generation assets in 2007. For the 2014 Baseline model, new plants (thermal, wind and solar) that will contribute to the governor response and AGC response in 2014 were added to the model.

Long-term dynamic models are two to three orders of magnitude longer (in run-time duration) than typical short-term stability simulations. The long-term simulations were performed with detailed representation of generator rotor flux dynamics and controls, which are typical of short-term dynamics. The models that were modified, or added, to capture long-term dynamics were Automatic Generation Control (AGC), load, and as-available generation variability. One responsibility of the AGC is frequency regulation, which involves managing the balance between supply and demand on the power system and correcting the imbalance by increasing or decreasing power production from a generator. The load and as-available generation are two other independent variables that affect the supply and demand on the short time-scale timescale of interest to the AGC.

In contrast to transient stability simulations, the representation of long-term dynamics can be expected to be of lower fidelity because it is limited not only by the accuracy of the governor/power plant models, but also by the modeling of AGC: the controller that dispatches generation to maintain system stability. 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.

The GE PSLF™ simulation outputs include estimations of the following:

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

5.1.4. GE Interhour screening tool

The fourth tool used in this study was the GE Interhour tool. This tool was developed specifically for the HECO system and provides two purposes: (1) screen results from GE MAPS™ production cost simulations to identify critical hours of interest for further analysis in the GE PSLF™ representation of the Oahu Automatic Generation Control, and (2) assess the sub-hourly performance by advancing the unit commitment/dispatch from GE MAPS™ 10-minute time steps for each hour of the year, respecting the reserve for each unit and the ramp rate capability of each unit. This tool was used to assess ramp rate and reserve adequacy of the Oahu system through wind power events.

The production cost model captures hourly performance of the system. The long-term dynamic model captures the second-to-second operation of the power system for selected hours of interest. The GE Interhour screening tool screens through the hourly GE MAPS™ results in 10-minute time steps to observe the impact of the changes in wind and solar power on the up-reserve of the system, respecting the ramp rate capability of thermal units and to highlight critical hours of operation that warrant further assessment in the second-to-second timeframe in the long-term dynamic simulation tool (GE PSLF^{TM} representation of the Oahu Automatic Generation Control).

5.1.5. Statistical analysis of wind, solar and load data

The wind power data, solar power data, load data, and wind power forecast data, were analyzed to determine their accuracy as compared to historical data from sites in Hawaii, and to provide information to the project team to help shape the next steps of the study. This process includes meaningful presentation of wind, solar and load data to make decisions about subsequent steps in the study, such as the level of up-reserve. For example, the 10-minute wind power variability data was presented to understand the statistical significance of the 10-minute changes in wind power production across the range of possible wind power production levels. This helped the project team to determine the additional reserves required by the system to accommodate the statistically significant 10-minute changes in wind power. The reserves were added to the minimum spinning reserve requirement to mitigate wind and solar power variability.

This tool was used to provide the team with an understanding of the following:

- The adequacy of the wind power data for the purposes of a high penetration wind power study (focus on wind variability as well as annual wind energy production),
- Wind variability across many timescales (seconds to hours) and relative to historical wind plant performance for plants already in operation in Hawaii,
- Wind power production correlated to load, time of day, solar production, etc., and
- Wind power forecasting accuracy relative to wind power data.

5.1.6. Model Refinements and New Model Developments

In order to accurately reflect the operation of the HECO system; the tools were modified to properly simulate unit and operating characteristics. In large power systems, a single generator provides a relatively small portion of the total power at a point in time. As such, the specifics of a single unit are less important as long as its general characteristics are captured (e.g., unit type, heat rate curve, maximum power, minimum power, fuel cost). This is not the case for relatively smaller power systems, such as the Oahu power system, where a single generator can provide 10 - 30% of the system load. On Oahu, the 180 MW AES coal plant can provide as much as 10-30% of the island's power at an instant. Accurately capturing the operation of each unit is critical in assessing the capability of the Oahu system to accept very high levels of wind power. Some of the specific unit constraints and operating rules that were reflected in the model include:

- CT (Combustion Turbine) and HRSG (Heat recovery steam generator) wash cycles for Kalaeloa combined cycle plant,
- A new model developed for the Kalaeloa Combined Cycle plant to capture three distinct operating states for the plant,
- Minimum up and down times for cycling and peaking units,
- Fast-starting units classification (e.g., units that can start within an hour). These units were available to cover any shortfall in generation and/or up-reserves for a subsequent operating hour.
- Up-reserves as a function of the wind power available to the system,

- Specification of CT-1 as the first fast-start unit to be committed,
- Waiau Station must have a minimum of (2) steam units committed at all times to provide voltage support. It was not possible to reflect this throughout the year; however, this was reflected for approximately 80% of the hours of the year.

It was necessary to model the fast-start units as committed (synchronized to the bus) 100% of the time (less their maintenance and forced outage rates) and dispatched to zero MW, but not contributing to up-reserve, in order to ensure they could be dispatched in the model to cover for a shortfall in up-reserve. The standard GE MAPS™ algorithm accounted for the full capability of these units as generating up-reserves, altering the normal unit commitment schedule by deferring more efficient cycling units. Hence, the algorithm was modified to properly simulate modeling of HECO's quick-start units and maintain the integrity of the unit commitment schedule. Some characteristics could not be modeled like the commitment schedule for cycling units.

In addition to modifying the traditional tools to simulate unit and system operation, it was necessary to develop tools to cover the range of timescales between GE MAPS™ and GE PSLF™. All the five tools are discussed in detail in Section 5.1. These tools were used together to assess the challenges of wind integration as well as assess the performance of potential solutions across many timescales of operation. Two of the five tools were refined to provide a more accurate representation of a smaller system, such as Oahu. The other three tools were enhanced to assess the timescales of power system operation not already captured in the other two tools.

5.1.7. Modeling limitations and study risks and uncertainties

Not all of the realities of operating a power system can be captured in models, and as such, the models are intended to provide directionally correct, non-exhaustive estimates of key metrics for a future system that contains high levels of wind energy. These estimates can provide those familiar with the Oahu power system insight on the system performance under high wind penetration scenarios and help those familiar with the system evaluate the effectiveness of operating strategies.

The models developed and presented here represent a mixture of standard electric power system engineering tools typically used by utilities and some novel simulation tools that are not within the utility planning repertoire. This study is not a standard system planning study, nor is it meant to replace HECO's utility planning process; instead, the scenario analysis study described here can provide those familiar with the Oahu power system with directionally correct sensitivities, such as a change in the variable cost of production or emissions associated with a particular technology deployment decision.

The recommendations section of the report highlights additional studies that should be performed before the integration of the large off-island wind projects. This study did not consider the following topics:

- The impact of capital cost expenditures to enable the benefits quantified in this study. This study provided the change in annual variable cost (fuel cost, start-up cost, operating and maintenance costs) based on assumed fuel prices and thermal unit performance characteristics. The cost side of the cost-benefit analysis should also be considered.

- Externalities, such as the cost of emissions for example, were not considered in this study.
- A system reliability assessment, of the sort necessary to determine resource adequacy, was not performed in this study.
- While this study did perform non-exhaustive dynamic assessments for specific scenarios and specific system events, other dynamic events and other system conditions could be of interest and should be examined, including a range of sensitivities for each dynamic event.

A fundamental assumption in this study is the use of a wind power forecast in the unit commitment process. If implemented, this allows system operators to reduce the commitment of oil-fired cycling units to meet system demand, thereby contributing to the increase in wind plant capacity factors. However, a wind power forecasting process for generation commitment has yet to be established in Hawaii. Furthermore, wind power forecasts for island system must be reliable and accurate as no interconnection exists to supply power in the event of a forecasting error. Benefits gained from accepting more wind energy will be off-set by running higher-cost fast-start generation to meet system demand when wind power forecasts are in error.

The wind data used in this study was based entirely on simulated data. No historical data from the wind plant sites simulated in this study was used. Furthermore, the wind data set was developed for two years (2007 and 2008), specifically for use in this wind integration study. Because variability is a major operational concern, validation efforts focused on capturing this aspect as accurately as possible—as opposed to matching the absolute wind power outputs at any specific site. Independent validation by AWS Truepower and NREL confirmed that the wind data reflected realistic averages, seasonal and diurnal patterns, and ramping behavior for wind speed and power output for Hawaii. However, the modeled data does not represent a long-term average and cannot replace actual onsite measurement. The level of wind power curtailment, total variable cost of operation, fuel consumption, and the system performance during dynamic events could all be impacted if different wind data were considered for this study. This poses a potential risk if actual wind power data or refinements to the modeled wind power data reveal substantially different wind power variability, wind power forecasting accuracy and annual wind power production levels. Changes to the wind data will impact some of the assumptions made in this study, particularly those related to system reserve. If actual wind data is provided in the future, it is recommended that studies be performed to assess the impact of the new wind data on the results described in this report.

AWS Truepower and NREL developed the initial solar data set for this study by using HECO Sun Power for Schools at a 15-minute level, which provided the historical solar trend profile. High-resolution variability was derived using an initial set of three months of 1-second solar irradiance data collected from four HECO sites in the southern portion of Oahu. These data were used to create the solar data set for the transient simulations. Potential solar projects were included in the modeling effort, primarily to assess the impact of these projects on the amount of wind energy delivered to the system. The study did not specifically assess the impact of solar power on the Oahu system.

The combined effect of these modeling limitations, risks and uncertainties could affect the actual system performance and the accuracy of the metrics reported. A schematic is presented in Figure 5-2 that illustrates the cumulative effect of some uncertainties reported in this study. The illustration refers to the annual fuel consumption on Oahu and the uncertainty in this metric due to a subset of the modeling assumptions. A similar diagram could be provided for other metrics, including the annual wind energy delivered to the system and the total variable cost of system operation.

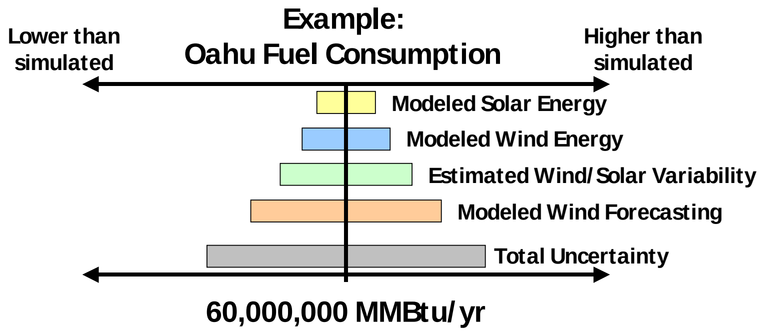


Figure 5-2. Illustration of the cumulative effect of modeling uncertainties and limitations on the annual fuel energy consumption on Oahu

Note that this study was neither a detailed engineering study of the wind projects and of the generation infrastructure nor a feasibility study for the HVDC interconnection and control strategy. The results of this effort were intended to help HECO perform further detailed assessments of each system modification in advance of accepting the wind projects considered in the study.

The results of the modeling tools utilized in this study are subject to the accuracy of the assumptions, model inputs and limitations of modeling tools, and the inherent differences attributed to simulation vs. reality. For example, in production cost simulations there is no knowledge of the sub-hourly wind variability to help determine unit commitment within the hour. In reality, operators may commit additional generation due to sudden drops in the wind power that challenge system up-reserves. If a unit has been committed, minimum run time requirements could force wind power curtailment due to excess generation. Wind variability will also increase the number of ramp events for the thermal units, potentially increasing the average system heat rate (resulting in lower average thermal efficiency and potentially higher maintenance costs and/or shorter intervals between maintenance).

In addition, to the abovementioned limitations of the production cost model, other factors may affect the accuracy of the results of this study:

- The wind production data used for the study corresponds to 2007. The study results are based on a single year of wind data.
- The production cost estimates do not account for any self-curtailment of the wind plants that may occur.
- The production cost model cannot account for operator intervention for environmental compliance, equipment malfunctions, safety concerns, etc.

Another factor for consideration is the degree of confidence in assumptions made throughout this study. For example, HECO has relatively high confidence that the thermal units will be capable of increasing their ramp rate capability, droop response, and operational flexibility. In contrast, there is a relatively lower confidence that an energy storage system can be designed to meet all system requirements served by the thermal units. Many of the uncertainties are a result of the issues stated above.

5.1.7.1. Solar PV modeling

At the start of this study, it was agreed that 100 MW of solar power would be considered in the study so the project team could better understand the wind integration challenges for a future Oahu system that is very likely to have some level of solar power penetration. Solar resources comprised of 15 MW of distributed PV and 85 MW of central station PV (rated at 60, 20, and 5 MW). These solar resources were included in the modeling effort to understand their impact on the amount of energy delivered by the wind plants. Thus, the solar PV modeling in the analysis helps define the boundary conditions necessary for the analysis of large amounts of wind power, but the data is not of sufficient fidelity to provide substantial insight into the ability of the Oahu system to accommodate these solar resources.

Similar to all modeling efforts, the value of the results relies heavily on the quality of the input data employed in the model. Close interaction between GE and HECO staff have made it possible to represent effectively key parameters in the models such as the AGC operation, unit governor response, and unit performance (heat rate, operating range, inertia, etc.). For long-term dynamic simulations, there is a need for development and use of high quality short-timescale, time synchronized wind power and solar power data, representative of the power output profile of the variable renewable resources under evaluation. There is a considerable time, work and expense involved in developing such data sets. For the larger-scale wind plant resources, representative data sets have been prepared using a variety of information. The data resources include recorded high resolution wind plant data (e.g., 2-second time interval samples of wind plant power output at the point of interconnection to the grid) from existing wind projects in operation on Maui and Hawaii island; and modeled wind plant resource data produced by complex computer programs using historical weather and climate data sets and measured wind speed, wind direction and other key data taken from meteorological towers erected at various locations across the state. With the operating experience and recorded data from wind plants operating in the state, and the industry-wide experience and maturity of wind technology and modeling tools, representative wind resource data sets have been developed and used in the models to date. Even with the relatively high quality wind resource data sets employed in the modeling work to date, it is critical for the project team to have an appreciation of the data limitations to effectively use and interpret modeled results of system operation and cost. Further information can be found in the final report provided by AWS Truepower[1].

The project team recognized at the outset that in contrast to development of the wind data sets described above, very little historical high-resolution PV power production data exists for the solar resources to be modeled in this study. Since an entire year of 2-sec solar power data was

[1] AWS Truepower, 2010, Development of Hawaiian Island Wind Resources, Wind Plant Output Datasets, and Forecast Observation Targeting. Submitted to National Renewable Energy Laboratory.

not available for each solar installation to be modeled (as was the case for the wind resources), it was not possible to obtain high fidelity solar power data for evaluation of specific windows of interest using the GE PSLF™ long-term dynamic tool. Time-synchronized, short-timescale (less than 10-second time interval samples) solar PV power production data is needed for system dynamics analysis of representative PV plants on the Oahu power system.

At the request of the evaluation team, the National Renewable Energy Laboratory (NREL) constructed and provided GE with 10-minute resolution solar power data for one year for the various solar deployments modeled. In addition to the 10-minute solar power data provided for one year, a single hour of 2-sec solar power data was constructed by NREL and provided to GE. With these limited solar resource data sets, the study focused on assessing the integration of large-scale wind plants.

In contrast to the high-penetration wind integration work conducted, focused analyses to evaluate the system level operation and cost impact of high penetrations of PV installations on the Oahu, Maui and Hawaii systems have not been performed to date. As noted above, a key requirement for meaningful evaluation is development of the representative resource data sets. In addition to the solar resource data described, there are also present limitations in the quality and capability of the PV inverter models in use and the operational controls and response capability of PV resources to be modeled. Continued work in these areas is necessary and is currently a key focus of utility industry and national laboratories. This continued work is necessary to enable effective modeling of high penetration PV scenarios using tools such as GE MAPS™ and GE PSLF™.

In addition, it is anticipated that much of the PV installations across the islands will be smaller in size relative to the wind plant resources. These distributed PV resources are often connected to the grid at the distribution system. As previously noted, the modeling tools and studies performed to date have focused exclusively on the transmission system to determine system-wide impacts associated with the balancing of generation and load, and therefore have not analyzed the potential challenges of integrating variable PV resources at the distribution-level. A comprehensive analysis of both distribution and transmission impacts is necessary to effectively study the impacts of integrating high penetrations of PV resources on the isolated island grids.

5.2. Baseline Model Development

In the first phase of the Oahu Wind Integration Study, the project team developed transient stability and production cost models of the HECO system. These models were used in the second phase of the study for high wind penetration scenario analyses. The sections below highlight the results of the baseline model development for the 2007 study year.

5.2.1. GE MAPS™ production cost model

In order to validate the model, data for 2007 was provided by HECO for an entire year of operation. An entire year was simulated in the production cost tool. The results for each unit in the HECO 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 5-3).

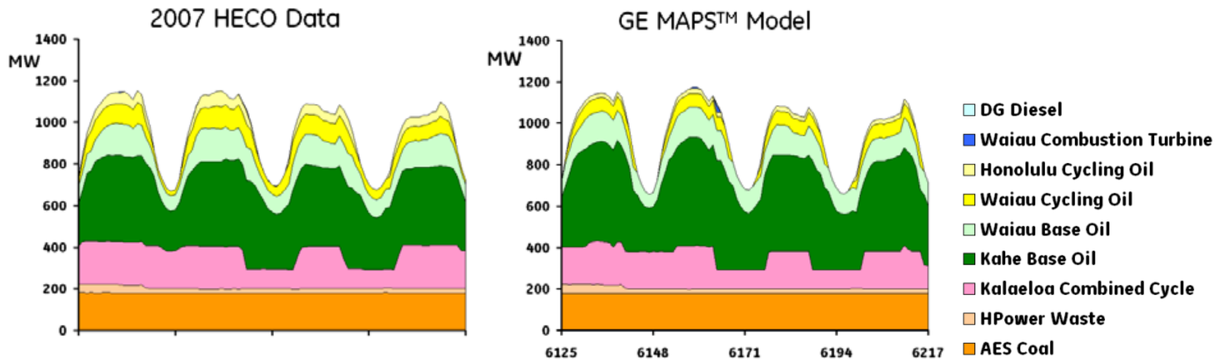


Figure 5-3 GE MAPS™ model results compared to historical hourly generation data for 4 days, starting September 13, 2007 and ending September 16, 2007

In Figure 5-4, the aggregate electricity production was compared to historical data. The historical electricity production and GE MAPS™ simulation results compared within 1% by fuel type. Although the model is unable to capture unique operating conditions, such as generator dispatch due to operator intervention, and the exact hourly dispatch of each unit throughout the year, the overall aggregate comparison of electricity production by fuel type indicates that a highly accurate model was developed.

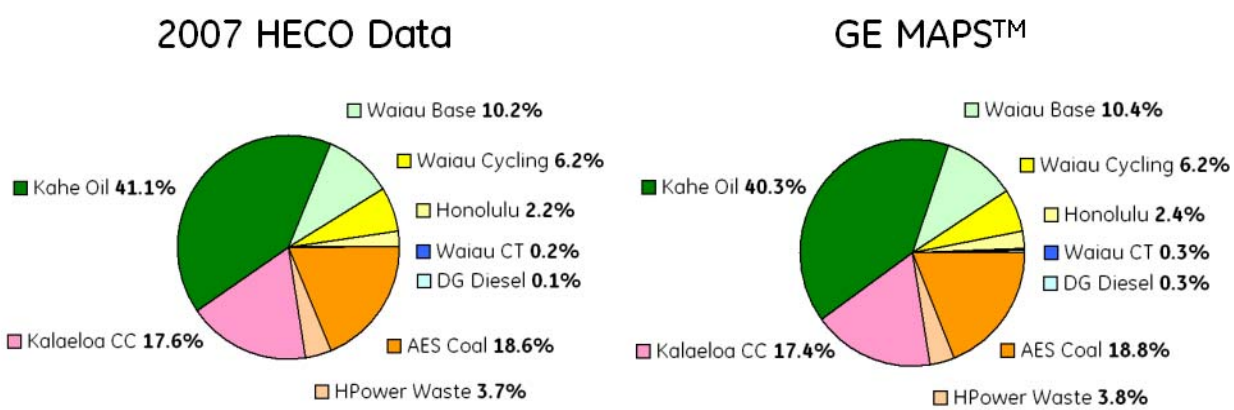


Figure 5-4 Electricity production, by unit type, for 2007.

In addition to comparing the annual energy production, fuel consumption and system heat rate were also compared to historical performance. These results are shown in Table 5-1. Based on the results of the GE MAPS™ simulation, the system heat rate was 1.2% less than the historical HECO system heat rate. This indicates that GE MAPS™ overestimates the overall system efficiency by ~1%. The total fuel consumption and total energy production was lower than historical 2007 values by ~3% and ~2% respectively.

Similar trends were observed between historical data and the simulation results; however, it should be noted that forced outages in GE MAPS™ do not necessarily occur at the same time of year as the historical data. In addition to the annual electricity production by fuel type, other statistical data like hourly production, run-hours, number of starts and average heat rates for each unit were compared to historical HECO data to validate the model.

Table 5-1 Comparison of the 2007 HECO historical and GE MAPS™ simulations of the fuel consumption, energy production and average thermal unit heat rate

	MMBtu		
	Actual	MAPS	% Diff
Honolulu	2,169,073	2,390,553	10.21%
Waiau	15,385,012	15,254,142	-0.85%
Kahe	33,989,502	32,425,301	-4.60%
Total	51,543,587	50,069,996	-2.86%

	MWH		
	Actual	MAPS	% Diff
Honolulu	174,000	195,163	12.16%
Waiau	1,345,000	1,350,073	0.38%
Kahe	3,324,000	3,217,064	-3.22%
AES	1,507,000	1,502,213.75	-0.32%
Kalaeloa	1,425,000	1,388,957.76	-2.53%
HPOWER	302,000	302,075.00	0.02%
Total	4,843,000	4,762,299	-1.67%

	Heat Rate (Btu/KWh)		
	Actual	MAPS	% Diff
Honolulu	12,466	12,249	-1.74%
Waiau	11,439	11,299	-1.22%
Kahe	10,225	10,079	-1.43%
Total	10,643	10,514	-1.21%

Some of the discrepancies between the model results and the historical 2007 results can be attributed to the following factors:

- Unique operating conditions could not be simulated due to the limitation of the model.
- Forward-looking heat rates and forced outage rates were used in the model, the values of which are different from those observed in 2007. This was addressed in the 2014 Baseline model.
- GE MAPS™ models the system to carry a minimum 180 MW of spinning reserve (185 MW in scenarios due to the increase in AES capacity in 2014) in every hour, but excess spinning reserve may be carried under light load conditions.
- During system outages, HECO may commit and dispatch units in a manner different from normal operating practices, which the model cannot capture.
- Temporary unit de-ratings occurred during 2007 historical operation. These de-ratings were not captured in the model.

Based on the results of the validation exercise, the Hawaiian Electric Company (HECO), the Hawaii Natural Energy Institute (HNEI), and the General Electric Company (GE) were satisfied with the accuracy of the production cost model, and were comfortable moving to the scenario analysis phase of the project. The degree of accuracy demonstrated is considerably above the accuracy generally achieved for forecasting models.

It should be noted that the results of the production model overstate the system-wide efficiency of the Oahu power system. This is primarily due to the optimistic performance simulated by the modeling tool. When heat rates are reported in this document, care is taken to specify the corrected heat rates based on the comparisons provided in this section. Therefore, the average heat rate provided by the production cost modeling tools is increased by 1.2% to better correct for this factor.

5.2.2. GE PSLF™ transient stability model

Transient simulations were performed using the dynamic model of the Oahu grid to assess the impact of severe system events, such as transmission faults resulting in cable trip events and generator trips. The extent of the associated simulation work is not intended to displace an interconnection study and is limited to explore implications relative to reserves or potential commitment constraints that could impact assumptions for other analysis in this study.

This section presents an overview of dynamic modeling of the various components of the power system assets on the Oahu grid. The model developed in Phase 1 of the study includes dynamic models of all of HECO-owned and IPP-owned generation assets (primarily generators, excitation systems and governors), loads, new renewable sources (new wind and solar plants) and protection schemes to maintain system stability (under frequency load shed scheme, etc.). PSS/E datasets provided by the Transmission Planning Division of HECO were converted to GE's Positive Sequence Load Flow (PSLF^{TM}) program format and transient stability assessments were performed in GE PSLF^{TM} model. This tool is widely used for load flow and transient stability analysis. This commercially available tool has a long history of application in the electric utility industry.

5.2.2.1. Baseline Load Flow Model

The load flow models (in PSS/E format) were provided for the year 2015. The baseline dynamic model of the power system was prepared for 2014 (the future year of study), which included new thermal units, new wind and solar power plants, new ramp rates of thermal units, new droop characteristics of the governors, new network data, etc.

Table 5-2 Load Flow Cases

File	**Load**	**Year 2015 Gen (MW)**	**Study Year 2014 Gen (MW)**
day2008nff-2015system (1298 MW).raw	day peak	1298	1279
eve2008nff-2015system (1315 MW).raw	evening peak	1315	1292
min2008nff-2015system (592 MW).raw	minimum	592	582

Table 5-2 shows the PSS/E load flow databases have been accordingly modified to reflect the generation for various scenarios of study year 2014. The following methodology was used for preparation of the baseline load flow cases for study year 2014:

- The total generation of the system is scheduled to be as in the last column of Table 5-2 based on the input provided by HECO for study year 2014,
- The total load has been scaled/adjusted using the scaling function available in GE PSLF^{TM} program so as to match the total generation while also considering the system losses,
- While the scaling of generation was done, it was ensured to respect the Pmax and Pmin limits of the units as given in Table 5-3,
- The maximum net capacity rating for AES has increased from 180 MW to 185 MW resulting in increase of gross MW from 201 MW to 206.3 MW
- The maximum capacity of HPOWER has been increased from 46 MW to 65 MW due to a planned installation of a third boiler, forecasted to be in service by about mid 2012
- GE PSLF^{TM} program used gross limits for AGC unit parameters and gross limits (max) for governor models in GE PSLF^{TM} as provided in Table 5-3 below.

Table 5-3 Gross Unit Ratings

Unit Name	Gross MW (Present)		Gross MW (3B/5B)		Gross MW (3F3/5F3)	
	Min	Max	Min	Max	Min	Max
HON-8 **(H8)**	24.0	56.4	24.0	56.4	24.0	56.4
HON-9 **(H9)**	24.0	57.1	24.0	57.1	24.0	57.1
KAHE-1 **(K1)**	34.8	85.8	38.8	85.8	25.1	85.8
KAHE-2 **(K2)**	35.0	85.9	39.0	85.9	25.3	85.9
KAHE-3 **(K3)**	35.0	90.0	39.0	90.0	25.6	90.0
KAHE-4 **(K4)**	35.2	89.0	39.2	89.0	25.7	89.0
KAHE-5 **(K5)**	55.3	141.7	59.4	141.7	41.4	141.7
KAHE-6 **(K6)**	55.1	142.2	59.2	142.2	61.7	142.2
WAI-3 **(W3)**	24.0	48.8	24.0	48.8	24.0	48.8
WAI-4 **(W4)**	23.7	49.1	23.7	49.1	23.7	49.1
WAI-5 **(W5)**	23.9	57.1	23.9	57.1	23.9	57.1
WAI-6 **(W6)**	24.1	56.1	24.1	56.1	24.1	56.1
WAI-7 **(W7)**	35.6	87.0	39.6	87.0	25.7	87.0
WAI-8 **(W8)**	35.0	89.9	39.0	89.9	25.1	89.9
WAI-9 **(W9)**	6.0	53.0	6.0	53.0	6.0	53.0
WAI-10 **(W10)**	6.0	50.0	6.0	50.0	6.0	50.0
AES-1 **(AES)**	76.0	206.3	80.3	206.3	86.7	206.3
KALAE-1 **(Kal1)**	28.5	86.0	29.5	86.0	29.0	86.0
KALAE-2 **(Kal2)**	28.5	86.0	29.5	86.0	29.0	86.0
KALAE-3 **(Kal3)**	11.0	40.0	11.0	40.0	11.0	40.0
CICT-1	39.5	114.0	41.5	114.0	41.5	114.0
HPOWER **(HPOWER)**	25.0	65.0	25.0	65.0	25.0	65.0

The following additions/modifications were made to the baseline model to reflect system resources in 2014:

- **OTEC**: Ocean thermal energy conversion plant, modeled as a reduction in load to provide a constant 25 MW throughout the year
- **Honua**: Gasification power plant, also modeled as a reduction in load to provide a constant 6 MW throughout the year.
- **CT1 Combustion Turbine**: Biofuel combustion turbine modeled as a quick start unit for peaking service.
- **Airport DG**: Four DG units modeled as quick-start units of 2 MW each, connected to the Airport substation at the 11.5kV level to Bus AIRP11B (Bus 11222 in dynamic model database).
- **Distributed Generators**: 30 MW of DGs located at various substations throughout Oahu were removed from the system.

5.2.2.2. Droop and Ramp Rate settings

HECO had initiated an internal program to validate and improve the performance of their turbine governor systems and controls. The database was modified to reflect the anticipated droop settings according to this HECO-internal program on the generating units.

Table 5-4 provides a summary of proposed governor droop settings that were used in the study. These droop settings were used for analytical purposes only and were not derived from testing and do not necessarily reflect actual governor response. Note that the proposed droop for K5, K6 and Kalaeloa were later modified to 5%, but were simulated in this study as reported in Table 5-4.

Table 5-4 Proposed thermal unit governor droop settings

NAME	DROOP % Proposed
AES	5.6%
Kalaeloa 1	3.5%
Kalaeloa 2	3.5%
HPower	-
Honua	-
OTEC	-
Kahe 1	5.0%
Kahe 2	5.0%
Kahe 3	5.0%
Kahe 4	5.0%
Kahe 5	4.5%
Kahe 6	4.5%
Waiau 7	5.0%
Waiau 8	5.0%
Honolulu 8	5.0%
Honolulu 9	5.0%
Waiau 3	5.0%
Waiau 4	5.0%
Waiau 5	5.0%
Waiau 6	5.0%
CIP-CT1	5.0%
Waiau 9	5.0%
Waiau 10	5.0%
Airport 1	-
Airport 2	-
Airport 3	-
Airport 4	-

AGC ramp rate values were also proposed by HECO for the purpose of the study and were based on attainable performance from the units once the modifications are applied. These settings are indicated as “Proposed” in the table below and later in the report. The ramp rates under “present” reflect the present settings on the AGC. These potential (future) thermal unit ramp rates were used as proposed ramp rates for the study year 2014 and are provided in Table 5-5.

Table 5-5 Present and Proposed Ramp Rate settings

	AGC RAMP RATES MW / min		
NAME	Present	Proposed	Once in a while
AES	2.5	2.5	-
Kalaeloa 1	1.3	2.5	-
Kalaeloa 2	1.3	1.8	-
HPower	-	-	-
Honua	-	-	-
OTEC	-	-	-
Kahe 1	1.6	5.0	7.0
Kahe 2	1.6	5.0	7.0
Kahe 3	2.0	5.0	7.0
Kahe 4	1.6	5.0	7.0
Kahe 5	2.5	7.0	10.0
Kahe 6	1.5	6.0	8.0
Waiau 7	1.9	5.0	7.0
Waiau 8	0.9	5.0	7.0
Honolulu 8	1.2	3.0	5.0
Honolulu 9	1.3	3.0	5.0
Waiau 3	0.9	2.5	4.0
Waiau 4	0.7	2.5	4.0
Waiau 5	1.4	3.0	5.0
Waiau 6	1.0	3.0	5.0
CIP-CT1	10.0	10.0	13.0
Waiau 9	2.6	5.0	10.0
Waiau 10	3.0	5.0	10.0
Airport 1	-	-	-
Airport 2	-	-	-
Airport 3	-	-	-
Airport 4	-	-	-

5.2.2.3. Baseline Dynamic Model Data

The dynamic model of Oahu system includes detailed dynamic models and respective parameters of generator units, turbine-governors, excitation systems, under frequency load shed scheme and dynamic load characteristics. Table 5-6 provides a summary of the models available in the PSS/E dynamic database. The dynamic database, provided by HECO in PSS/E format, was subsequently converted to GE PSLF™ format. Figure 5-5 provides a summary of the steps involved in the modeling effort to set up the dynamic model in PSLF.

The database did not include an AGC model (although related information was provided by HECO operations). Simulations to verify individual models against engineering practices were performed. Improvements made to the database are described in the following sections.

Table 5-6 Summary of various dynamic models in the PSS/E database for Oahu system

Bus No.	Bus Name	kV	Id	MBASE	GENS	EXCS	GOVS
1141	KAHE-1	14.4	1	96	GENROU	EXDC2	IEEEG1
1142	KAHE-2	14.4	2	96	GENROU	EXDC2	IEEEG1
1143	KAHE-3	14.4	3	101	GENROU	ESST4B	IEEEG1
1144	KAHE-4	14.4	4	101	GENROU	ESST4B	IEEEG1
1145	KAHE-5	16	5	158.8	GENROU	IEEX2A	IEEEG1
1146	KAHE-6	16	6	158.8	GENROU	IEEX2A	IEEEG1
1203	WAI-3	11	3	57.5	GENROU	ESST4B	IEEEG1
1204	WAI-4	11	4	57.5	GENROU	IEEEX4	IEEEG1
1205	WAI-5	11.5	5	64	GENROU	EXDC2	IEEEG1
1206	WAI-6	11.5	6	64	GENROU	EXDC2	IEEEG1
1207	WAI-7	14.4	7	96	GENROU	EXDC2	IEEEG1
1208	WAI-8	14.4	8	96	GENROU	EXDC2	IEEEG1
1209	WAI-9	13.8	9	57	GENROU	IEEEX3	GAST
1210	WAI-10	13.8	0	57	GENROU	IEEEX3	GAST
1311	KALAE-1	13.8	1	119.2	GENROU	IEEEX1	GAST
1312	KALAE-2	13.8	2	119.2	GENROU	IEEEX1	GAST
1313	KALAE-3	13.8	3	61.1	GENROU	IEEEX1	IEEEG1
1320	HRRP	13.8	1	75	GENROU	EXST1	IEEEG1
1331	AES-1	16	1	239	GENROU	EXAC1	TGOV3
1335	CICT-1	13.8	1	162	GENROU	UAC7B	WESGOV
4008	HON-8	11.5	8	62.5	GENROU	IEEEX1	IEEEG1
4009	HON-9	11.5	9	64	GENROU	IEEEX1	IEEEG1

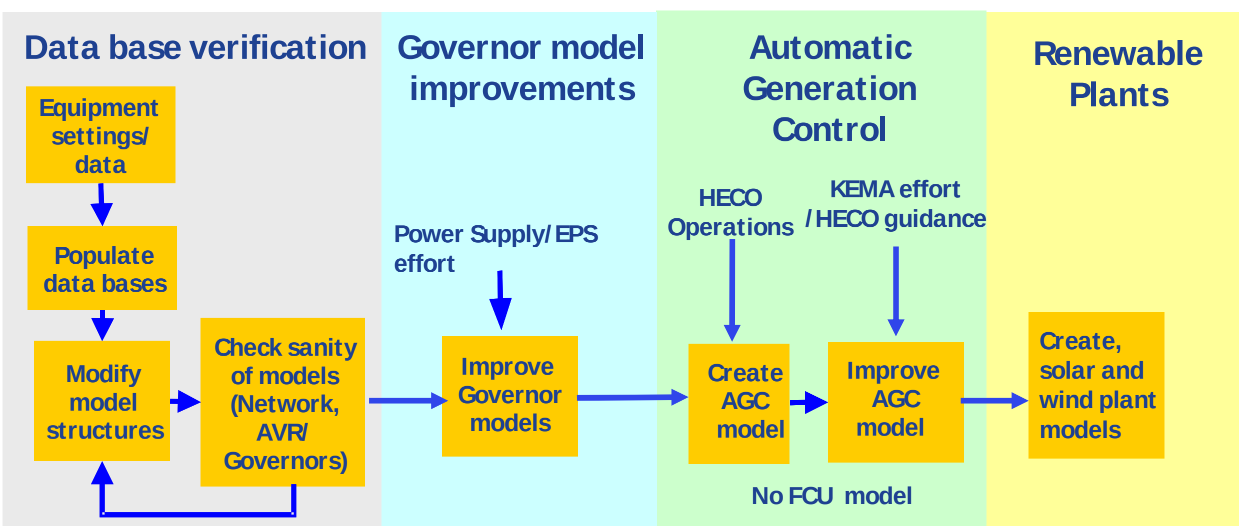


Figure 5-5 Baseline Model Database modeling in GE PSLF™

5.2.2.3.1. Turbine/Governor Models

Table 5-7 describes the governor model names in the PSS/E database provided by HECO and their respective models used in GE PSLF™.

Table 5-7 Dynamic Database - Governor Models

Type of Unit	PSS/E model provided	GE PSLF™ model used
Gas Turbine	GAST	gast
Steam Turbine	IEEEG1, TGOV3	ieeeg1, tgov3
Combustion Turbine	WESGOV	gpwscc

The following are the modifications made to the governor models dynamic database based on the input from HECO.

- Unit maximum power values from Table 5-3 were utilized to modify the respective parameters of the governor models,
- New droop settings provided in Table 5-4 were used to modify respective governor model parameters,
- As HRRP is run in turbine following mode and therefore a very slow and limited response during system transients is expected, no governor control is considered for HRRP unit. A conservative approach is followed wherein the governor model for HRRP is switched off.
- Governor ramp rates on HECO steam units were revised to reflect actual governor steam valve closing/opening times (3 sec from fully closed to fully open),
- Minimum valve position parameters were set to 10% of rated MW for all steam turbine models. Based on suggestions from HECO, the Pmin values of steam turbine models (ieeeg1 and tgov3) have been reset to a value of 0.1 times their turbine maximum rating. The Pmin parameters of the gas turbine (GT) model 'gast' are same as that from the original PSS/E model database. However, the current values of the gast models are unrealistically high values and may result in optimistic performance of the system in response to any transients. The Pmin values of gpwscc (another GT model) for CICT-1 and 2 units are presently set to zero, and
- ieeeg1 model of Kalaeloa ST unit (Kalae-3) was represented using a combined cycle ST governor model (ccst3) available in GE PSLF™.

5.2.2.3.2. Excitation System Models

Table 5-8 provides a summary of the AVR models used in PSLF when converted from PSS/E. AVR responses for all units were tested for a step change in voltage reference under non-synchronized conditions. The excitation system model parameters for the new CT unit (CICT-1) have been added to the dynamic database obtained from manufacturer datasheets provided by HECO.

Table 5-8. Dynamic Database – Excitation System Models

	PSS/E model provided	GE PSLF™ model used
1	ESST4B	exst4b
2	EXAC1	exac1
3	EXDC2	exdc2a
4	EXST1	exst1
5	IEEEX1	exdc1
6	IEEEX3	exst2
7	IEEEX4	exdc4
8	ÎEEX2A	exac1
9	UAC7B	esac7b

5.2.2.3.3. Load Characteristic

The loads in the load flow cases are represented as constant real and reactive power loads. For dynamic runs, loads were converted such that 100% of the real power load was constant current and 100% of the reactive power load was constant impedance. The dynamic load characteristic representation based on PSS/E data includes a quadratic frequency dependent load model. As suggested by HECO, Oahu's quadratic frequency dependent load model is changed to represent a linear dependence of real load power to frequency.

5.2.2.3.4. Under Frequency Load Shedding

New under frequency load shedding scheme (UFLS) models were provided by HECO in PSS/E format, which were then converted into GE PSLF™. The same models were used in the new scheme but with different parameters. The new UFLS was represented in PSS/E database by a under frequency load shedding relay model (lds3bl) with transfer trip acting at each load. In PSLF, this was represented as a definite-time under-frequency load shedding relay model (lsdt9), which does not include the transfer trip model. The GE PSLF™ lsdt9 UFLS model correctly captures the performance of the UFLS scheme provided by HECO.

5.2.2.4. New Solar and Wind Plants

The renewable resources that are anticipated to be connected to the Oahu Grid and to be studied for year 2014 include new solar and wind resources. This includes 100 MW of solar power on the island of Oahu, 100 MW of wind power on the island of Oahu and 40 MW of off-island wind on the islands of Lanai and/or Molokai. The wind and solar plant models were developed in GE PSLF™ based on the renewable resources to be considered for each scenario.

The 100 MW of solar power on Oahu is represented in PSLF as a combination of:

- 60 MW Centralized PV plant
- 15 MW Centralized PV plant
- 5 MW Centralized PV plant
- 5 MW Centralized PV plant, and

- 15 MW Distributed PV plants.

The centralized PV relate to the industrial plants while the distributed PV relate to the residential plants. Based on various discussions and data received from HECO, the above solar PV plants have been represented as new generation units at the following locations in the Baseline load flow model:

- **60 MW Centralized PV**: Modeled as a new PV plant on Kahe-Halawa Circuit #1 138kV transmission line and connected to a new substation created at 45% of the line distance from the Kahe AB 138kV bus (Bus 140)
- **15 MW Centralized PV**: Modeled as a new PV plant. The connection point is bus KAHE46B (Kahe 46kV Bus "B") at the end of the Kahe – Standard Oil Circuit #2.
- **5 MW Centralized PV**: Modeled as a new PV plant. The point of connection is the bus CEIP46B (CEIP 46kV Bus "B") that is ~10% from the beginning of the circuit CEIP 46.
- **5MW Centralized PV**: Modeled as a new PV plant. The point of connection is the bus KOOL46B (Koolau 46 kV Bus "B") at the end of the Koolau – Kailua circuit.
- **15 MW Residential PV**: Modeled as 1 MW load reduction at Makalapa substation and 2 MW load reductions at Halawa, Iwilei, School, Archer, Kewalo, Kamoku and Pukele substations respectively, for long-term dynamic simulations involving AGC. However, in this study, they are modeled as new individual PV generating plants at the respective substations.

The on-island and off-island wind power for the island of Oahu considered the following sites for specific scenarios in the study:

- 50 MW Oahu1 (North Shore Oahu wind)
- 50 MW Oahu2 (North Shore Oahu Wind)
- 200 MW or 400 MW of wind power on Lanai, and/or
- 200 MW of wind power on Molokai.

The 100 MW of wind power on North Shore of the island of Oahu consists of two 50 MW wind plant projects:

- **50 MW Oahu1**: This 50 MW of wind generation, originally on Waialua-Kahuku 46kV circuit (Wahiawa-Waialua 46kV circuit #2), consists of two wind plants, a 20 MW and a 30 MW wind plant in close proximity, but not located on one site. The 20 MW plant has since moved away from the 30 MW plant to a location between Waimea and Waialua substations. As the new site is electrically close to the previous location and it is anticipated that there should not be a significant change in the system response provided the wind data for these two sites is still the same, it was agreed with HECO to model the two 30 MW and 20 MW sites at the original location on Waialua-Kahuku 46kV circuit.

- **50 MW Oahu2**: Modeled as a 50 MW generating unit at the First Wind Interconnection point on the Wahiawa – Wailua #1 46kV feeder.
- **400 MW Off-island Wind**: Irrespective of the various scenarios considered in this study, the 400 MW of off-island wind is modeled as two wind plants of 200 MW each at the east and south shore landing sites of the Oahu Island. The two landing sites in east and south shares are located at Marine Corps Base Hawaii (MCBH) and Honolulu Harbor respectively. Each will receive 200 MW of wind power from Lanai and/or Molokai through HVDC cables depending on the scenario considered.

5.2.2.4.1. Network Data Modifications

The addition of new plants for wind and solar generation to the Baseline model of year 2014 was done through the addition of new transformation equipment at the various points of connections. This included adding new buses, circuits and transformers to the 2014 load flow model. The following assumptions were taken for modeling of the wind and solar plants for load flow analysis. Based on the scenario considered for each of the dynamic simulation, the wind and solar plants and related equipment are either switched on/off in the dynamic model.

100 MW Solar PV Plant Modeling

- New buses have been added to the Baseline load flow model at a scheduled voltage of 1 p.u.
- The PV plants, both centralized and residential, have been modeled as a single conventional unit connected to a 480V bus. The maximum generator real power output is the plant size at each location and reactive power capability is based on the number of converters used to meet the interconnection requirements. The capability of a single converter used to represent the solar plant is provided in Table 5-9. The solar plants have been configured based on the assumption to provide a +/- 0.9 power factor range at full power output.

Table 5-9 Single converter rating for solar plant model

Generator Rating	667 kVA
Pmax	600 kW
Pmin	0.0 kW
Qmax	291 kVAr
Qmin	- 291 kVAr
Terminal Voltage	480 V

- The residential solar plants with a point of interconnection (POI) at 25kV, namely at Iwilei, Kamoku and Kewalo constitute the distributed PV of 1-2 MW in size. These are modeled as PV aggregated generations with a 0.48/25kV unit-transformer of 6% impedance on the transformer MVA rating. The other residential PV plants with a POI of 46kV are connected using 0.48/15kV unit transformers and a substation transformer with 10% impedance on an MVA rating of 1.5 times peak load or 1.2 times PV power rating.

- The larger four industrial solar plants that constitute the Centralized PV are connected into their high voltage substations at 46kV or 138kV through a unit-transformer of 6% impedance on the transformer MVA rating, and a second substation transformer of 10% impedance on an MVA rating of 1.2 times PV power rating.

100 MW Onshore Oahu Wind Plant Modeling

- The 100 MW wind plant on the island of Oahu consisted of three wind plants: 50 MW, 20 MW and 30 MW. Each Oahu Wind plant model consists of an aggregated single wind turbine generator (WTG) and unit transformer with MVA ratings equal to N times the individual device ratings, where N is the number of WTGs in the wind plant that has been considered for the study.
    1. **50 MW plant** uses 34 turbines (1.5 MW GE); collector system voltage of 34.5kV; and unit terminal voltage of 575V
    2. **20 MW plant** uses 13 turbines (1.5 MW GE); collector system voltage of 34.5kV and unit terminal voltage of 575V
    3. **30 MW plant** uses 12 turbines (2.5 MW GE full converter model); collector system voltage of 23kV; and a unit terminal voltage of 690V.
- The aggregate WTG is modeled as a conventional generator connected to a (PV) bus and represents a doubly-fed asynchronous generator (DFAG) for 1.5 MW GE machines or a full converter model for 2.5 MW GE machines. The generator real power output (Pgen), maximum reactive power output (Qmax), and minimum reactive power output (Qmin) are modeled as N times the unit capabilities as shown in Table 5-10.
- Table 5-10 also provides unit transformer ratings and impedance data. The collector system voltages are at distribution levels of 34.5kV or 23kV and the substation transformers have been suitably rated for the number of WTGs, with an impedance of 10%.

Table 5-10 Individual WTG Power Flow Data

	1.5 MW Wind Turbine	**2.5 MW Wind Turbine**
Generator Rating	1.67 MVA	3 MVA
Pmax	1.5 MW	2.5 MW
Pmin	0.07 MW	0 MW
Qmax	0.726 MVAr	1.20 MVAr
Qmin	- 0.726 MVAr	- 1.20 MVAr
Terminal Voltage	575 V	690 V
Unit Transformer Rating	1.75 MVA	2.8 MVA
Unit Transformer Z	5.75%	6.0%
Unit Transformer X/R	7.5	7.5

400 MW Off-island Oahu Wind Plant Modeling (Lanai and Molokai)

- The 400 MW of wind from Lanai and Molokai is modeled as two WTGs of 200 MW each at the east and south shore landing sites of the Oahu Island. The east shore option considers a DC cable landing at MCBH with two 138kV circuits to Koolau Substation and a third 138kV circuit to Pukele Substation. The south shore option considers a DC cable landing at Honolulu harbor with one 138kV circuit each to Iwilei, Archer and Kamoku substations respectively.
- The two WTG plants of 200 MW each at the north and south shore landing sites for offshore wind from Lanai and Molokai are assumed to consist of 80 GE wind turbines each of 2.5 MW rated power rating. The parameters used in the load flow model are based on the individual WTG ratings of a 2.5 MW turbine as provided in Table 5-10.
- The generator model considered is full converter WTG in which the full converter machine is a conventional permanent magnet synchronous generator. The generator is connected to the power grid through a full converter. A full converter WTG model has been considered as it can be used to represent the characteristics of a HVDC station.

5.2.2.4.2. Dynamic Model Data modifications

Based on the scenario selected for simulation, modifications were made to the Baseline dynamic model data to include the dynamic data for the new wind and solar resources. These include:

Wind turbine generator model: The dynamic data of WTG model consists of the generator/converter model, electrical control model and the turbine and turbine control model.

- The generator/converter model injects real and reactive current into the network in response to control commands, and represents low and high voltage protective functions (e.g., low voltage ride through capability). The same generator/converter model, with different parameters, is used to represent both DFAG WTGs (1.5 MW GE WTG) and full converter WTGs (2.5 MW GE WTG).
- The electrical control model includes both closed and open loop reactive power controls, and voltage regulation with either a simplified emulator of GE's WindCONTROL system or a separate, detailed model. This model sends real and reactive commands to the generator/converter model. Different electrical control models are used to represent DFAG WTGs and full converter WTGs.
- The turbine and turbine control model represents the mechanical controls, including blade pitch control and power order (torque order in the actual equipment) to the converter; under speed trip; rotor inertia equation; wind power as a function of wind speed, blade pitch, rotor speed; and active power control. One model is used to represent both DFAG and full converter WTGs. However, more functions (e.g., dynamic braking resistor) are enabled for a full converter WTG than for a DFAG machine.

The transmission system being considered for transfer of wind power from Lanai and Molokai to Oahu is based on High Voltage Direct Current - Voltage Sourced Converter (HVDC-VSC) transmission technology. The HVDC-VSC model comprises of two voltage source converters

(VSC) linked together by a DC-link cable, their control systems and interfacing transformers. As detailed modeling of such a system is not yet available and as the primary objective of this model is to allow for analysis of the performance of a group of WTGs and how they interact with the Oahu power system, its representation has been made through a GE single full converter WTG model whose fundamental frequency electrical dynamic performance is completely dominated by the converter. The control of active and reactive power is handled by fast, high bandwidth regulators within the converter controls, and is greatly simplified for simulation of bulk power system dynamic performance. It is assumed for the offshore wind plant frequency control that the HVDC sending end converter replicates Oahu frequency in Lanai or Molokai or has some form of coordination with the wind plants.

For the full converter machines, the line-side of the converter corresponds to the WTG terminals. The electrical behavior on the variable frequency machine side of the converter is of no interest to the AC system. Further, operation (i.e., rotation) of the turbine is not required for the converter to continue reactive operation on the line-side. Near rated power, the GE full converter machines will normally operate at a speed selected to give optimum turbine performance. Control of the frequency converter allows the rotor speed to be completely decoupled from the grid frequency, and to be controlled over a wide range.

The 200 MW of wind at both north and south shores are therefore modeled as a single full converter WTG model that provide a rated power output of 200 MW at +/- 0.95 power factor or providing +/- 65MVAr of reactive power. This reactive power control corresponds to the HVDC-VSC converter ratings assumed in separate studies of the HVDC cable system.

Solar PV model: The dynamic performance of a solar plant is represented through two device models, a converter model and an electrical control model. The dynamic model for solar plant is similar to a wind plant that uses full converter turbine generators. The converter model is the equivalent of the converter, and represents the interface between the solar plant and the network. The fundamental frequency electrical dynamic performance of a solar plant is completely dominated by the converter.

5.2.3. GE PSLF™ long-term dynamic model

Long-term dynamic simulations were performed in GE PSLF™ based on the most recent database provided by the project stakeholders at the time of the study. The simulation of long-term dynamics is carried out through combination of short-term dynamic models of the HECO grid implemented in GE PSLF™ and the Automatic Generation Control (AGC) model. The AGC application in HECO's EMS was reflected in a model developed by GE in an earlier phase of the study and updated based on the most recent information provided at the time of the study. The AGC representation in GE PSLF™ was used to assess dynamic events on the system in timescales longer than transient stability events (less than one minute) and shorter than production cost modeling events (one hour). The long-term dynamic simulations assess the impact of system events, primarily related to changes in wind power production that rely upon the action of the AGC to correct for imbalances between the load and generation.

In transient events, the accuracy of short-term dynamics is determined primarily by the level of detailed representation of generators (transient or sub-transient), excitation systems and turbine/governor systems in the dynamic database provided. In contrast, the AGC model mostly drives the representation of system long-term dynamics; accuracy of the power plant models has lesser impact.

Long-term dynamic 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, which are 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 responsibility of the AGC is frequency regulation. This involves managing the balance between supply and demand on the power system and correcting the imbalance by increasing or decreasing power production from a generator. The load and as-available generation are two other independent variables that affect the supply and demand on the short time-scale timescale of interest to the AGC.

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.

5.2.3.1. AGC Model

AGC modeling for stability and long-term simulations is not standardized by the industry. The AGC for the Oahu grid was modeled based on information provided by HECO, engineering judgment and several related discussions with HECO operations. The proposed model is not intended to reproduce every detail of the actual AGC, but to capture behavior relevant for the objective of this study. The following are the salient points that have been considered for the development of the AGC model:

- Local Frequency Control (LFC), which is a legacy mode of operation external to the Energy Management System, has not been modeled in this study. It is anticipated that the LFC will be removed and its functionality incorporated into the AGC algorithm in the future.
- No EMS/AGC control for HPOWER,
- Unit and Area settings, and economic dispatch representation based according to information from HECO, and
- New ramp rates (Table 5-5) proposed as part of HECO's work to improve the dynamic responses of the generating units were used to modify the related AGC model parameters for use in the dynamic simulations.

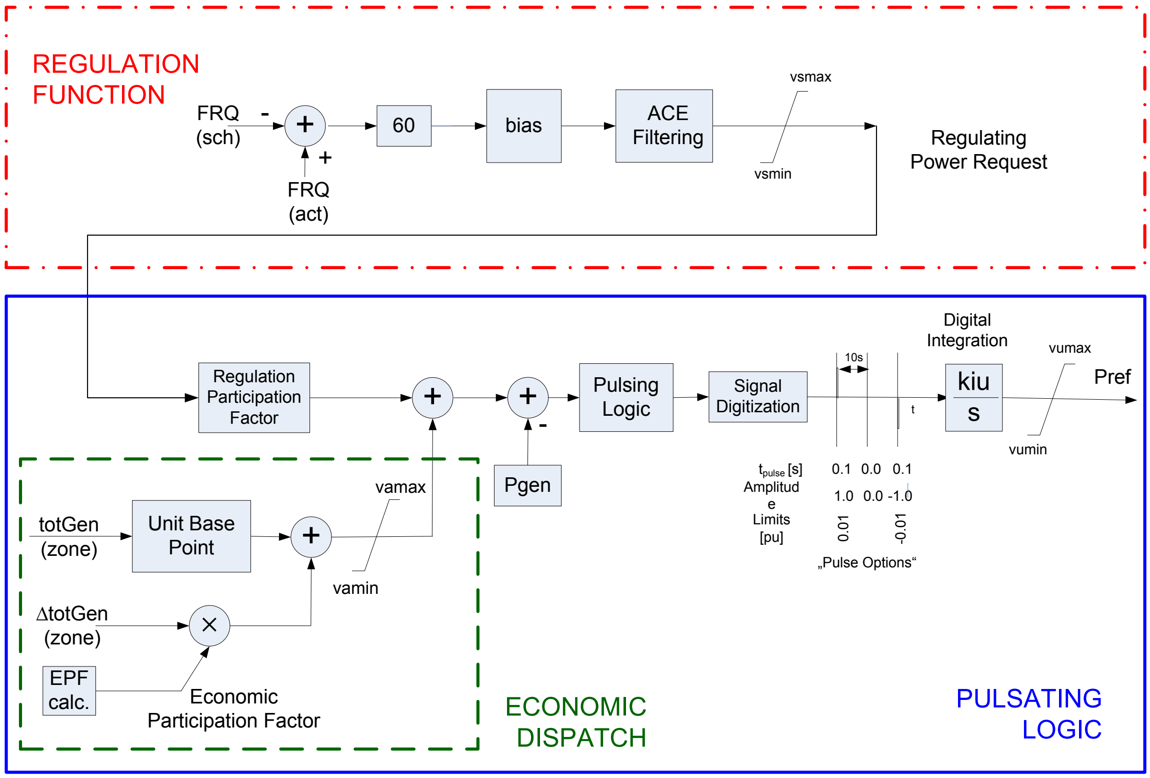


Figure 5-6 AGC model block diagram in normal operation mode

The block diagram of the AGC model is shown in Figure 5-6. The model is divided into three sections: regulation function, economic dispatch control and pulsating logic. A brief description of the settings and parameters of the model are presented in the next sections.

Regulation function:

- The bias is set to 15.0 MW/0.1 Hz. The bias is independent from the load level. Filtering of ACE is applied based on provided information.
- The inherent integral control action of the AGC model balances generation and demand, returning system frequency to 60 Hz following disturbances in the system.

Economic Dispatch Calculation:

- The economic dispatch calculation (EDC) program calculates the control base point for units under economic dispatch control. The EDC program also calculates the economic participation factor (EPF) based on an economic merit and the initial point of operation. Changes in total generation are distributed based on these participations factors.
- The EDC program is executed when one of the following conditions arises:
  - Total generation has shifted beyond the threshold power mismatch of 20 MW, with respect to the last EDC execution as specified based on the AGC data
  - Time elapsed since the last execution of EDC exceeds the threshold EDC run interval of 20 sec as specified based on the AGC data

Pulsating logic:

- All units under AGC share the ACE signal allocated (regulating power request) based on the unit Regulation Participation Factor (RPF). The relative magnitudes of the numbers determine their share of system ACE. The relative magnitudes of RPFs are normalized by the AGC system and determine the regulating units' share of system ACE.
- The level of control is determined by comparing the value of ACE against specified HECO's AGC ACE bands, which are Normal, Permissive, Assist, Warning and Trip. Based on the ACE value, all the units are placed on different levels of control with the following ACE limits: 0-1 MW (Deadband), 1-5 MW (Normal), 5-10 MW (Permissive), 10-30 MW (Assist), 30-150 MW (Warning) and >150 MW (Trip). There is a tolerance of 0.5 MW for transition between the various modes. The priority given to the economic dispatch and the ACE regulation changes depending on the level of control. The previous block diagram represents the Normal mode.

5.2.3.2. AGC Model Validation

With requested settings for the study (no LFC, new ramp rates and governor characteristics), the validation of the Oahu AGC model is performed by comparing a simulated event with the outcome of an EMS/AGC study carried out by KEMA[2].

The simulated event considered for the purpose of validation is a load rejection event. HECO provided GE with the data for this fault-induced event in which about 130 MW of load is rejected. The event has been simulated with the following base line pre-disturbance conditions:

- The total generation of the system is scheduled to be as according to 7/3/2008 1:41 PM historical data provided by HECO,
- The total load has been scaled such as to match the total generation while considering the system losses, and
- No FCUs and same AGC area level parameters.

Three different scenarios of simulations have been considered for the same load rejection event in order to understand properly the AGC behavior and system settings that influence the system response to disturbances. The three scenarios are discussed in the next sub-sections.

5.2.3.2.1. AGC Response without "Once In a While" ramp rates in AGC

For the purpose of validation, the system frequency response for the fault-induced 130 MW load rejection event as obtained by KEMA study has been reproduced here and is shown in Figure 5-7.

[2] "EMS Evaluation for High Penetration of Variable Generating Resources, Distributed Resources, Load Management Resources, and Energy Storage". KEMA – June 2009.

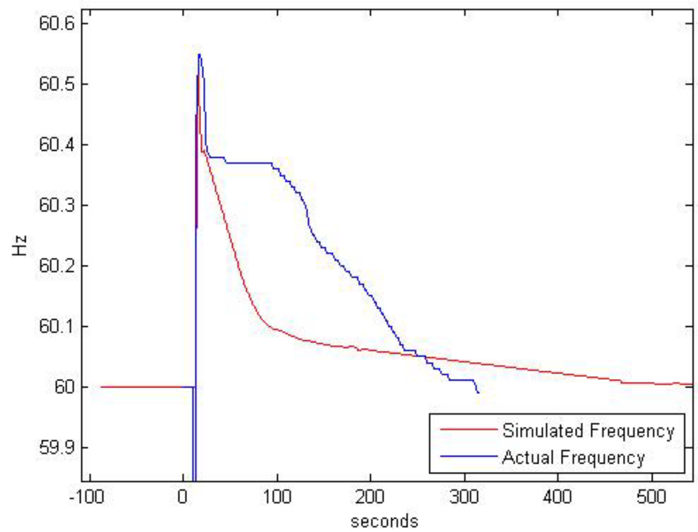


Figure 5-7 Exhibit 12, Scenario 3, Fast AGC Tuning, Simulated vs. Actual Frequency (wide scale)

The GE PSLF^{TM} study for Oahu AGC model validation for the load rejection event was simulated with the following considerations:

- 130 MW load rejection with system according to 7/3/2008 1:41 PM historical data.
- Droop and ramp rates according to expected improvements communicated by Power Supply (Table 5-4 and Table 5-5). Area Parameters are according to EMS info from HECO.
- Without "Once in a while" ramp rates in AGC
- The simulation is run for only 200 seconds in order to understand better the system's second-by-second behavior.

The emergency ramp rates are for events when ACE exceeds the Assist limit. Under such conditions, all the regulating units will be pulsed at their ramp rate to reduce ACE. The system frequency response for the GE PSLF^{TM} runs is shown in Figure 5-8.

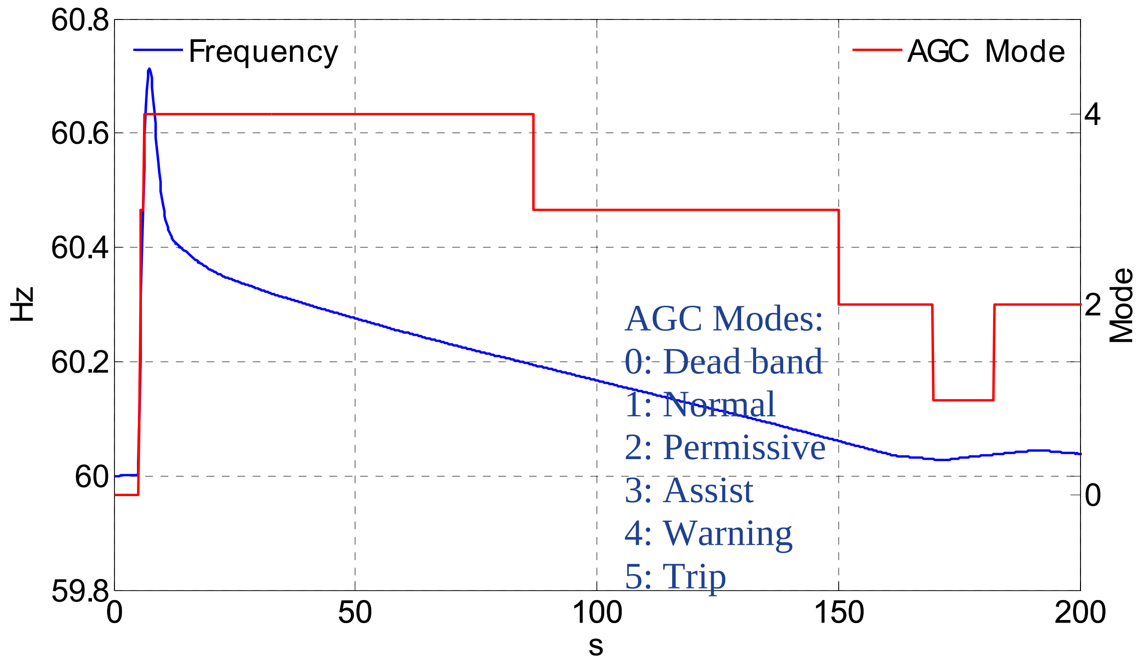


Figure 5-8 System Frequency Response without "Once in a while" ramp rates in AGC

The following observations were made:

- The maximum value of frequency deviation is higher than that of the actual event. This may be because 130 MW of load was rejected at once rather than in a sequence of load rejection events, which would have resulted in a slightly lower frequency deviation.
- System inertia and governor response of the units determine the peak frequency deviation and settling frequency immediately following the disturbance (20 seconds in the figure). This response is similar to the KEMA's modeled response.
- The AGC response in Assist and higher ACE modes is a little bit sluggish when compared to KEMA's response. It is estimated that this is because no "Once in a while" ramp rates were used.

5.2.3.2.2. AGC Response with "Once in a while" ramp rates in AGC

Based on the observation in the previous section, a second run was performed with "Once in a while" ramp rates (as given in Table 5-5) enabled in AGC.

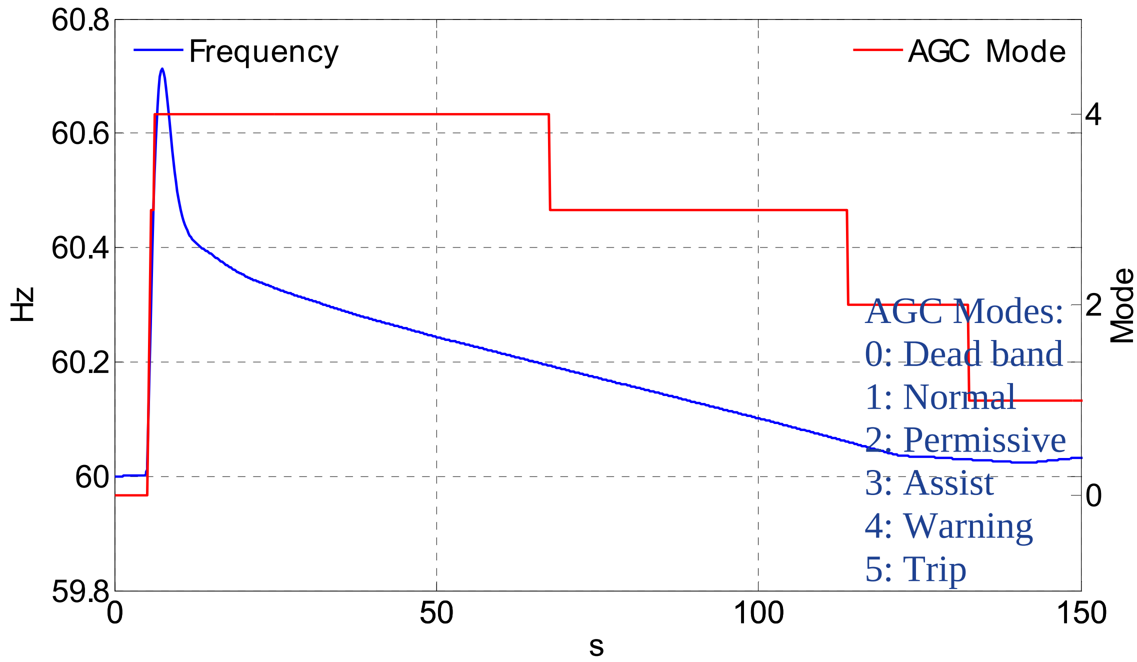


Figure 5-9 System Frequency Response with "Once in a while" ramp rates in AGC

The following are the observations made (see Figure 5-9):

- The maximum value of frequency deviation is still the same as in previous case.
- The system inertia and the governor action of the units play a significant role in bringing the system frequency close to the nominal as was observed in the previous case. The post-disturbance AGC response is similar to the KEMA's response.
- The AGC response in Assist and higher ACE modes behaves similarly when compared to KEMA's response in this scenario when "Once in a while" ramp rates were used as in AGC

5.2.4. Import of initial conditions from GE MAPS™ to GE PSLF™

The following methodology and assumptions were used to initialize the load flow model in GE PSLF™ using hourly dispatch of GE MAPS™:

Modeling of Kalaeloa Plant

- In GE MAPS™, Kalaeloa is modeled as three units. Unit 1 and 2 (each representing 1CT + ½ ST) rated for 67-90 MW and a third unit as a quick start rated at 28 MW, which operates only when Unit 1 and Unit 2 are operating at max capacity. This grouping was based on the pricing curve of Kalaeloa so as to capture the production cost economics
- However, in GE PSLF™ model, Kalaeloa is modeled as a combined cycle plant with two CTs and one ST, each represented by a generating unit. The PSLF database specifically represents the AVR/generator/governor of each CT and the ST. These units are set in/out of service depending upon the operation of the plant. At low outputs, Kalaeloa is

modeled as a single CT/ST and is based on the following operating modes as was mentioned by HECO.

1. Single Train Mode: 65-90 MW (1CT+ 1ST) – Kalaeloa plant is modeled as two generating units, 1 CT and 1 ST such that a minimum load of 11 MW for the ST is satisfied for the 65 MW net output case
2. No Operation Mode: 90-130 MW (empty dispatch zone)
3. Dual Train Mode: 130-180 MW (2 CTs + 1 ST) – Kalaeloa plant is modeled as three generating units
4. At maximum output: 208 MW – Kalaeloa plant is modeled with the two CTs at 84 MW each and ST at 40 MW to match the maximum limits of units as indicated in Table 5-3)

NET MW to GROSS MW:

- The NET MW hourly dispatch obtained from GE MAPS™ tool is converted to GROSS MW for initializing a GE PSLF™ simulation. This is because GE MAPS™ uses NET MW and GE PSLF™ uses GROSS MW in simulations (Governor and AGC models in PSLF also use GROSS MW limits for the unit parameters)
- The conversion is done through calculation of a generator auxiliary load, which is then added to the NET MW to obtain the GROSS MW for the unit to be dispatched.

The generator auxiliary load calculation is based on the data/information provided in a spreadsheet by HECO.

6.0 Scenario Analysis

In this Section, the results of the Baseline scenario and three high wind scenarios are presented. These high wind scenarios formed the basis on which the strategies to increase wind energy delivered were be built upon. In Section 6.1 an overview of the scenarios is provided. In Section 6.2 the preparation of all data for the models is described. This includes the wind power, wind power forecasting, and solar power data analysis effort as well as the analysis of wind power variability data as it pertains to the up-reserve requirements. In Section 6.3 a detailed overview of the model development, validation and calibration effort is provided. In Section 6.4 the results of Scenario 1 are presented. In Section 6.6, the results of Scenario 3 are presented, and in Section 6.5 the results of Scenario 5 are presented.

6.1. Overview of the scenarios

The results of the scenario analysis are presented for the following four scenarios specified by the project team (see Table 1-1; shown again in Table 6-1). The stakeholders of the study agreed that these four scenarios were the most critical scenarios to be examined in the study.

Table 6-1 Scenarios for the Oahu wind and solar integration study

Scenario	Title	Wind			Solar
		Oahu	Lanai	Molokai	Oahu
Baseline	2014 Baseline	-	-	-	-
Scenario #1	"Big Wind" Oahu only	100MW	-	-	100MW
Scenario #3	"Big Wind" Oahu + Lanai only	100MW	400MW	-	100MW
Scenario #5	"Big Wind" Oahu + Lanai + Molokai	100MW	200MW	200MW	100MW

The 200 or 400 wind plant on Lanai was modeled as a single wind plant on Lanai. The 200 wind plant on Molokai was specified as a single wind plant on Molokai. The 100 of solar power was added to the study to reflect a plausible solar installation scenario that consisted of a 60 centralized PV plant, a 20 centralized PV plant, a 5 centralized PV plant, and a 15 aggregation of distributed PV. The feasibility of integrating this level of solar power was not assessed in this study. The 100 of wind power was specified as multiple wind plants on the north shore of Oahu.

6.2. Preparation of data

Prior to commencing the scenario analysis and in parallel with the development of the baseline model for 2014, the project team compiled and statistically analyzed the wind power and wind power forecast data provided by AWS Truepower. These data were utilized to specify some of the requirements for system operation, such as the up-reserve requirements. These are discussed in this section.

6.2.1. Development of Wind and Solar data sets

In preparation for the scenarios, AWS Truepower provided the project team with 10 minute, 1 minute and 2 second wind plant output data for 27 sites. These sites were selected based on the screening criteria agreed upon by both the National Renewable Energy Laboratory (NREL) and the Hawaiian Electric Company (HECO). For the specific scenarios considered in this study, the following sites were modeled:

- 50 MW Oahu1
- 50 MW Oahu2
- 200 MW or 400 MW Lanai
- 200 MW Molokai

Per HECO's request, the 100 MW wind power on Oahu was modeled as two plants with capacities of 30 MW and 70 MW. The data was constructed by taking 30% and 70% of the total 100 MW of wind power.

For generating the wind power data, AWS Truepower used three classes of composite IEC power curves to model the turbines at different sites. These power curves are defined on the composite of three machines (GE, Vestas, and Gamesa) and are selected for a particular site based on the average wind speed at that location. For each of the four sites discussed above, the selected IEC classes were:

- IEC class 1: Lanai and Molokai
- IEC class 3: Oahu1 and Oahu2

In addition to wind power data, AWS Truepower provided wind power forecast data in the following timeframes for each of the sites described above:

- 1 hour
- 4 hour
- 6 hour
- 24 hour

The project team also received 10 minute, solar power data from NREL for the following four sites:

- 60 MW Oahu centralized (single-axis tracking)
- 20 MW Oahu centralized (single-axis tracking)
- 5 MW Oahu centralized (single-axis tracking)
- 15 MW Oahu distributed (aggregation of distributed solar power) (fixed)

The solar power data were constructed by NREL based on 10 years of 15 minute solar data from HECO's Sun Power for Schools program and several months of 1 second PV data from 4 sites in the southern portion of the Oahu. Select windows of data were provided with 2 second resolution of solar power production. It should be noted that the results of the study depend heavily on the quality of data provided, since historical power production data from these eight sites (four solar and four wind) does not exist, and models were used to develop the data (wind and solar power).

A number of tools were considered in the assessment of wind and solar data. These tools and techniques were developed in order to:

- Assess the accuracy of the wind power and wind speed data in relation to historical performance at wind plant sites in operation in Hawaii,
- Evaluate the magnitude of wind power changes for each scenario over different timescales,
- Evaluate the accuracy of wind variability over different timescales as they compare to other wind plant sites in Hawaii,
- Select the study year for wind data (out of the available two years),
- Identify the impact of wind power forecasting accuracy on system operation, and
- Develop a strategy for estimating the up-reserve needed to accommodate sub-hourly wind variability.

The following sections outline each of these techniques.

6.2.2. Wind data analysis

In order to assess the accuracy of the wind power data, the team provided a statistical analysis of these data. The objective of this effort was multifold:

- Assess the relationship between wind speed and wind power for each of the sites to see if the results are comparable to historical data from existing wind plant sites in Hawaii.
- Analyze these data in order to specify which year of wind power data should be included in the study,
- Assess the shorter timescale (10 minute) wind variability of each site and compare to historical variability data from existing wind plant sites in Hawaii.
- Develop a strategy for estimating the up-reserve requirement carried by the system to accommodate higher levels of wind power in the system without violating the present reserve requirement.

6.2.2.1. Wind turbine power curve (plant power vs. wind speed)

By comparing wind power and wind speed, the characteristics of the wind turbines at a given location could be analyzed. The turbine's power curve can be best estimated using an exponential function and least square error fitting. Figure 6-1 illustrates the relationship between power and wind speed for the 30 MW wind plant at Kaheawa (Maui wind plant) based on historical data. In this particular case, the bifurcation of power at high wind speed range indicates some tripping events of at least one turbine in the plant. This information was considered in the assessment of wind plants considered in this study.

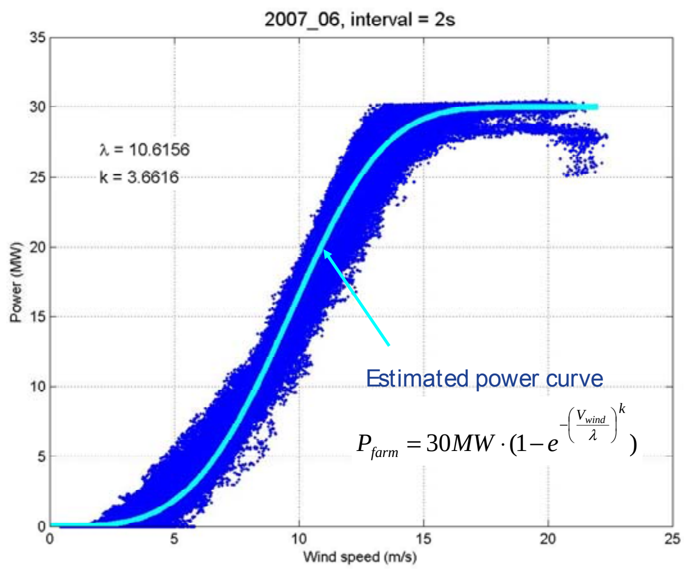


Figure 6-1 Kaheawa Wind Plant, Maui historical (2007 June) data Note that curtailment periods were removed from the historical data.

The wind plant power curve compared well to similar IEC class sites in Hawaii.

6.2.2.2. Wind variability at different power levels

One of the main purposes of studying wind variability is to inform HECO of potential changes in wind at different power levels. This analysis provides the information necessary to determine if sufficient levels of reserve are available to maintain system reliability and to understand the limits of a wind forecast. Reliance on a wind forecast is critical to increase energy production from wind plants and thereby help reduce operating costs. If no forecast of wind is included in the unit commitment, the thermal units on the system will back down (if free to back down) when wind is available in the actual hour resulting in a large amount of regulating reserves being carried. Eventually wind power must be curtailed when the thermal units reach their minimum power levels, respecting any down-reserve requirement. This reduces the amount of renewable energy that can be delivered and negatively impacts system heat rate as the thermal units operate at reduced efficiencies (higher heat rates).

Wind power changes were assessed over 10 minute and 60 minute intervals at different power levels. Figure 6-2 shows 10 minute power changes (downward power changes are shown only) as a function of the total wind power at the start of each 10 minute interval. The red curve is based on an exponential equation and is an estimation of the required on-line regulating reserves required to compensate for the majority of the 10 minute drops in wind power for the two years of data (2007 and 2008). This curve was used in conjunction with a wind forecast to estimate the regulating reserve requirement for the forecasted hour.

An interesting observation from Figure 6-2 is that the diversity of wind plants reduces the amount of additional up-reserve. Scenario 5 and Scenario 3 have equivalent installed wind plant capacities. In Scenario 5, wind power is dispersed in equal amounts on two islands while in Scenario 3 wind power is concentrated on one island. The diversity in the wind power variation on Lanai and Molokai provides a filtering effect to the total wind power fluctuation, resulting in lower amplitude of negative wind drops. This in turn helps in reducing regulating up-reserve requirement: a maximum of 82 MW in Scenario 5, compared to a maximum of 119 MW in Scenario 3.

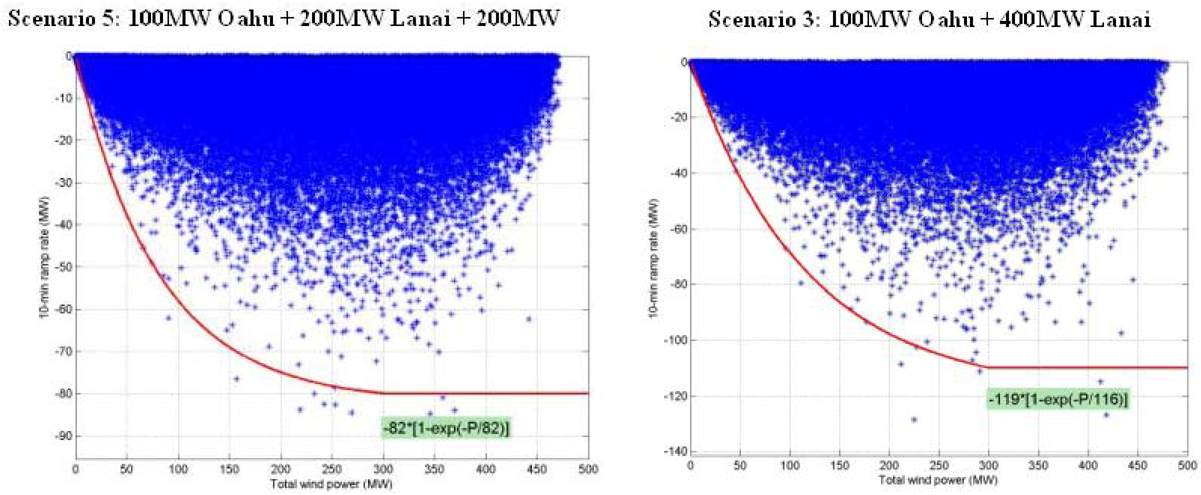


Figure 6-2 Ten minute wind power changes, based on two years of data, for Scenario 5 and Scenario 3

The figure highlights one of the important features of wind power variability. As the amount of wind power on the system increases from 0 MW to almost 300 MW, the magnitude of downward drops in wind power increase; however, beyond wind power of ~300 MW, the magnitude of downward drops starts to decrease. The shape of the power curve in Figure 6-1 can explain this behavior. The wind power variation is the greatest on the linear portion of the power curve (which is in the middle) at moderate wind speeds (specific wind speeds depend on the type of wind turbine and class of turbine). Therefore, the geographic diversity of the wind plants and their relative size with respect to the total installed wind plant base has a significant impact of the total wind power variations seen by the system.

6.2.2.3. Investigation of outlier events

The most rapid drops in wind power are of considerable interest in terms of establishing a boundary requirement for system operation. For this reason, the team analyzed the largest drops in wind power over a number of time intervals. Each event was extracted for further analysis. Such events can either be the largest drop in wind power for a single site, or largest drop in wind power for several sites combined. Figure 6-3 highlights a 1-hour window where the largest 1 minute drop in total wind power for Scenario 5 occurred. Note that this is based on the two years of wind data. It can be seen that all three sites exhibited a coincidental drop at this moment.

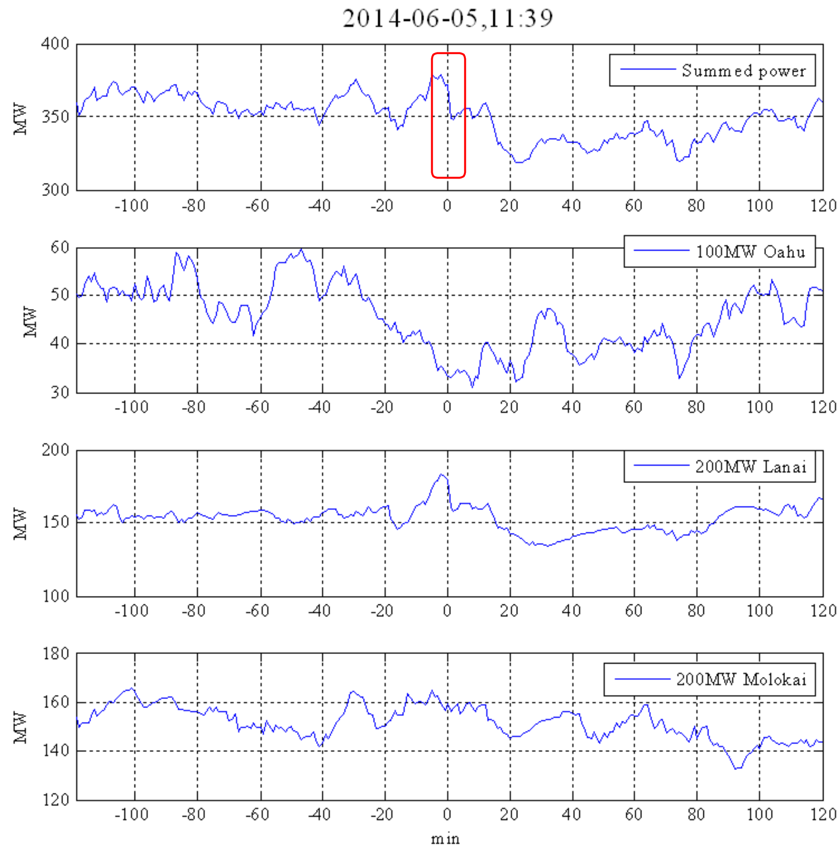


Figure 6-3 The largest 1 minute wind power drop for 100 MW Oahu + 200 MW Molokai + 200 MW Lanai (Scenario 5, excluding PV) from 2007 and 2008 modeled wind power data.

6.2.2.4. Selection of the wind data for the study year

In order to select one of the two years of wind and solar data for the single year of study, the variability of wind and solar power data on a 10-minute and 60 minute interval for Scenario 5 was assessed (see Figure 6-4). While the 0.1% percentile changes in power are similar for 2007 and 2008, the 0% percentile changes (largest downward change in power) are larger in the 2007 dataset, for both the 10 minute and the 60 minute analysis. Note that the 60 minute changes in wind and solar power are based on a calculation of the rolling 10 minute data.

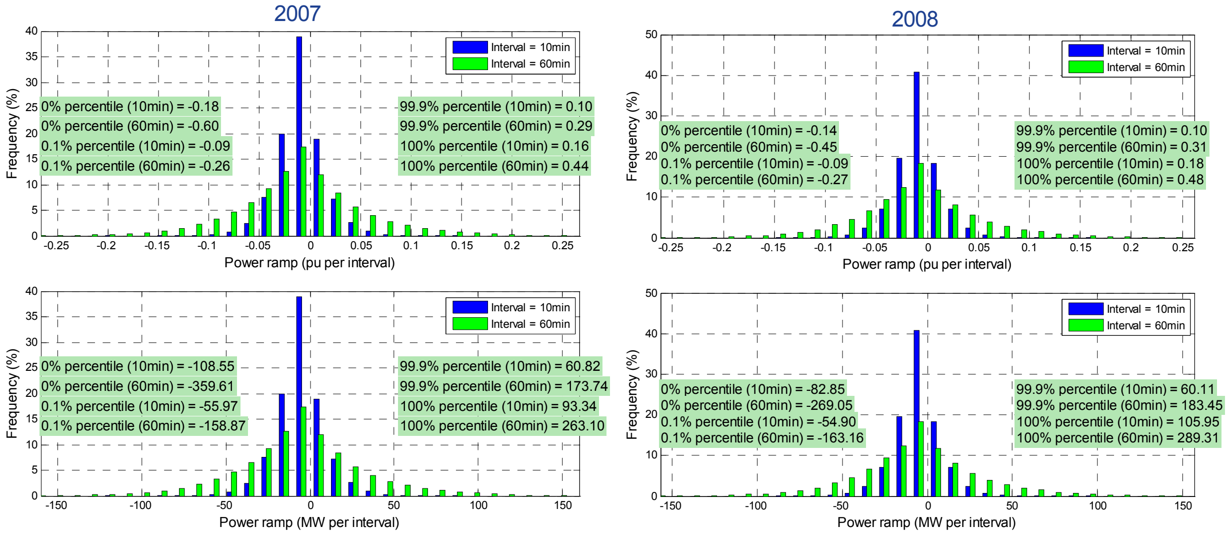


Figure 6-4. Wind and solar power variability for Scenario 5 (2007 on left, 2008 on right)

Based on these results, 2007 data were selected for the study year, as these data showed greater total wind and solar variability.

6.2.2.5. Histograms of wind power variability

The variability of wind power over different timescales is important to consider. An abrupt wind variation in a short period may cause a frequency deviation and therefore require a prompt governor response while a continuous, sustained wind drop over a long period requires an AGC response. A histogram of wind power variation at different time intervals provides a good statistical assessment of the severity of wind fluctuations. Figure 6-5 provides an example of a histogram of wind power variation at three different timescales for Scenario 5 without any solar data. The figure uses percentile values to describe the outlier events. Analyzing wind variability using a histogram is preferable over standard deviation metrics because wind power variations do not follow a normal distribution and therefore standard deviation does not directly correspond to a certain percentage probability.

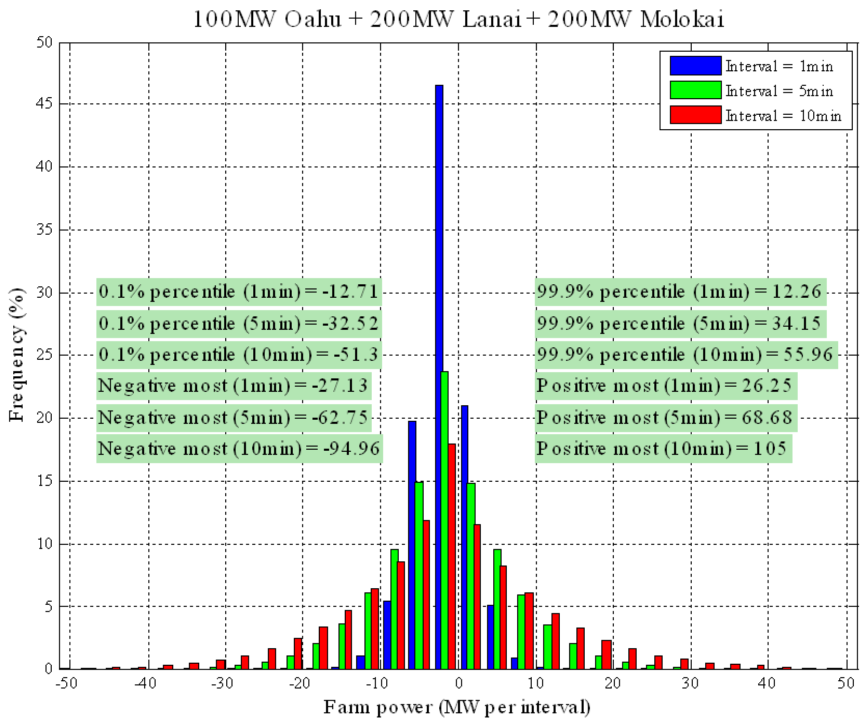


Figure 6-5. Histogram of wind power variation at 1 minute, 5 minute, and 10 minute interval for 2007 and 2008 wind power data.

The y-axis of the figure shows percentage of events and the corresponding wind power variation for these events is given on the x-axis. This analysis used two years (2007-08) of wind data and the wind power variation is aggregate variation of 100 MW Oahu, 200 MW Lanai, and 200 MW Molokai plants. The largest 1 minute, 5 minute and 10 minute total wind power drops are 27 MW, 63 MW and 95 MW, respectively.

It was also assumed that a continuous 5% of available wind power from the Molokai and Lanai wind plant sites are dissipated as losses in the HVDC system. Note that the results presented in Figure 6-5 do not include the assumed 5% losses of off-island wind energy delivered to Oahu over the HVDC cable. Therefore, the off-island wind power was reduced by 5% for the study year of 2007. The wind variability data is presented for each of the three high wind power scenarios in Figure 6-6.

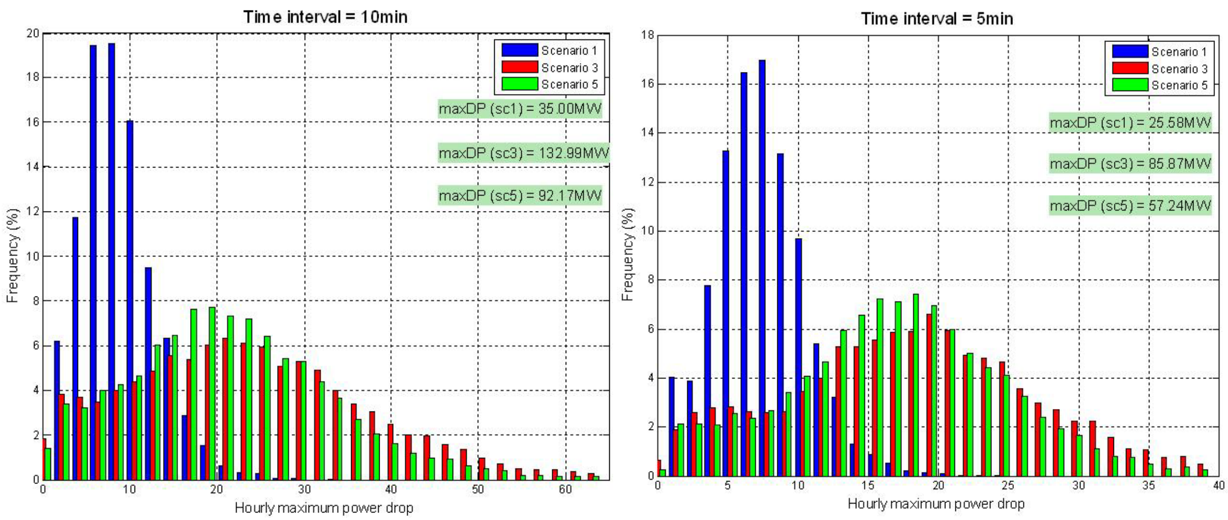


Figure 6-6. Histogram of wind power drops for each hour of the year (2007 wind data, reducing off-island wind power by 5% due to HVDC losses). No solar power changes are considered.

Based on these results, there is one 10-minute event in the study year when the wind power drops by 92 MW in Scenario 5 over a 10-minute interval. The second figure indicates there is one 5-minute event in the study year when the wind power drops in Scenario 5 by 57 MW over a 5-minute interval. In Scenario 3, the largest 5 minute and 10 minute wind power drops as seen on Oahu could be as high as 86 MW and 133 MW, respectively. It should be noted that no accounting for wind power curtailment that might be observed in the production cost simulation is made here.

6.2.3. Solar data analysis

The Oahu system already has a significant amount of distributed PV penetration at the distribution level and additional solar PV plants of various sizes are anticipated in the near future. HECO requested that the team consider, to the degree possible, a total of 100 MW of solar power on Oahu comprised of a combination of centralized and distributed PV installations in the analysis. The primary purpose of including these solar resources in the modeling was to determine the impact on the amount of wind energy that the off-island wind plants could deliver to the Oahu power system when other competing variable resources such as PV are present. Thus, PV modeling in the analysis done to date improves the boundary conditions necessary for analysis of these large amounts of wind power, but the fidelity of the solar data is not of sufficient to analyze impacts to the Oahu system.

GE and HECO staff recognized at the outset that in contrast to development of the wind data sets described above, very little historical high-resolution PV power production data exists for the solar resources to be modeled in this evaluation. Since an entire year of 2-second solar power data was not available for each solar installation to be modeled (as was the case for the wind resources), it was not possible to obtain high fidelity solar power data for evaluation of specific windows of interest using the GE PSLF^{TM} tool. Time-synchronized, short-timescale (less than 10 seconds time interval samples) solar PV power production data is needed for system dynamics analysis of representative PV plants on the Oahu power system.

At the request of the evaluation team, the National Renewable Energy Laboratory (NREL) constructed, and provided GE with, 10-minute resolution solar power data for one year for the various solar deployments modeled. In addition to the 10-minute solar power data provided for one year, a single hour of 2-sec solar power data was constructed by NREL and provided to GE. With these limited solar resource data sets used to the extent practicable, the focused assessment of the integration of large-scale wind plants were conducted.

As such, the 10-minute solar power data were sampled hourly, in a similar fashion as the wind data, to construct one year of hourly solar power production data to be used in the GE MAPS^{TM} simulations. The one-hour of 2-sec solar power data described above were used in some of the GE PSLF^{TM} dynamic simulations.

Considering both the time synchronized wind and solar power data for the 2014 study year, the total wind and solar variability was evaluated. The results are shown in Figure 6-7.

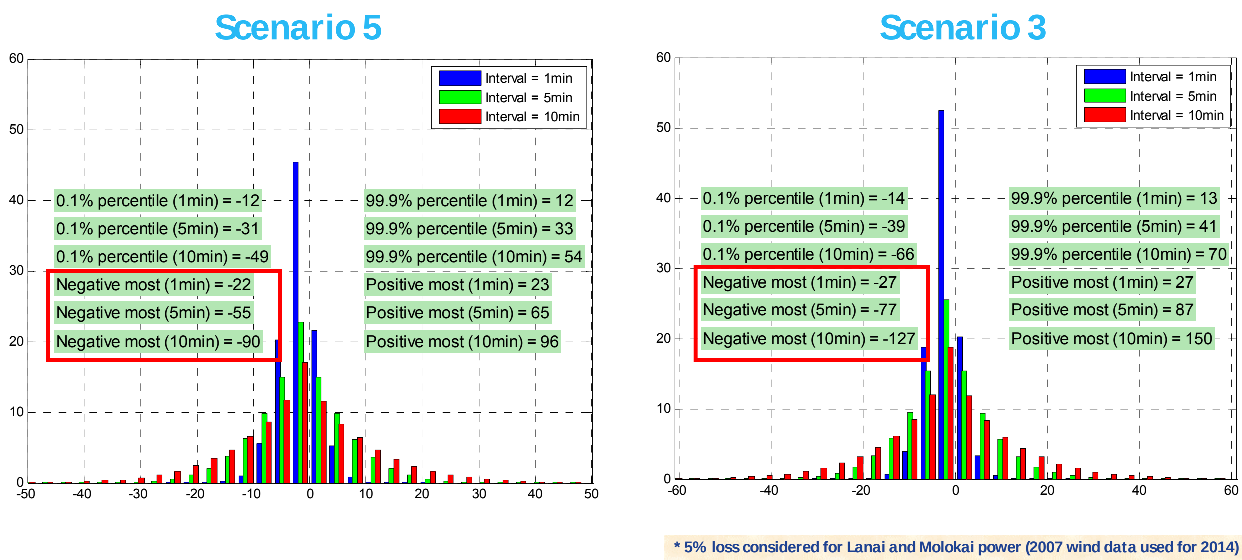


Figure 6-7. Histogram of wind and solar power changes for each hour of the year (2007 wind data, reducing off-island wind power by 5% due to HVDC losses).

The largest 10-minute wind and solar drop was 90 MW for Scenario 5 and 127 MW for Scenario 3. Both of these are marginally less than the largest 10-minute wind power change alone.

6.2.4. Wind power forecasting for unit commitment

Wind power forecasting can be used to improve system efficiency by including the information about wind power production in the unit commitment strategy. Without wind forecasting, the system would over-commit thermal generation to meet load. If wind power were available in the actual hour of dispatch, the thermal units would back down and operate at a higher heat rate. On the other hand, if the wind forecast is used in the unit commitment phase, there will be times when the forecast overestimates the amount of wind that would be available. During these instances, the wind power generation that is not realized is offset by the available regulating reserves. Quick-start units may be brought online to provide capacity and to restore regulating reserve requirement (if it is violated).

Using wind forecast in the commitment strategy necessitates the understanding of accuracy of these forecasts. Errors in wind power forecasting (either underestimation or overestimation) will influence the effectiveness of the unit commitment strategy, resulting in events when: (1) the wind forecast ***overestimates*** the wind being delivered to the system, so an insufficient number of units are committed. This would cause these units to ramp up to cover the shortfall in capacity and potentially require commitment of more expensive quick-start units to cover for the deficit of wind power, or (2) the wind forecast ***underestimates*** the wind being delivered to the system so extra units are committed and will be backed down to accept wind power. If the units are all backed down to their minimum loads, respecting the down-reserve, wind power will be curtailed. Figure 6-8 shows a histogram of the accuracy of wind forecast (actual wind power minus forecasted wind power) for the different forecast data provided by AWS Truepower.

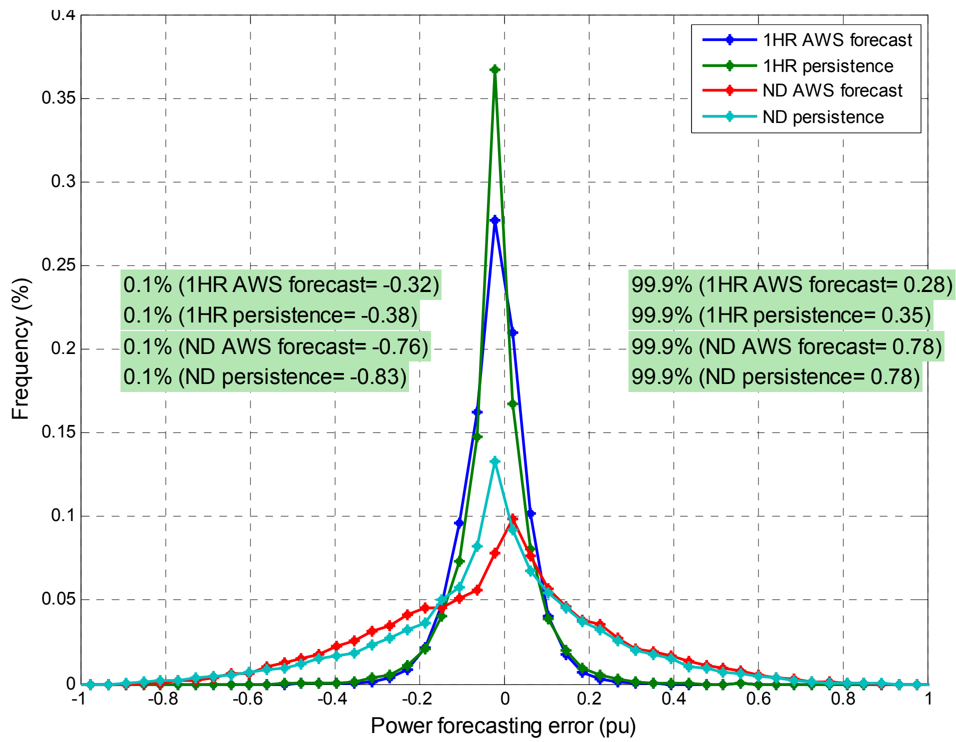


Figure 6-8. Histogram of wind forecasting error (actual power – forecasted power), for two years of data, for 100 MW Oahu + 400 MW Lanai (Scenario 3, excluding solar power). ND = next day.

Note that the accuracy is not based on actual wind power data from a site, but is based on the wind power data provided by AWS Truepower. Also note that a persistence forecasts is defined as a forecast of the future power output to be the same as the present power output. These are shown for comparison, but were not used in the study.

It was decided by the project team that a 4 hour wind forecast would be used in the unit commitment. The team selected this time period because it provides sufficient time for operators to commit and dispatch cycling units, which are the next units to be dispatched in the economic order after the must-run baseload units.

6.2.5. Reserve requirements

The Oahu system currently carries a minimum spinning reserve among all of its thermal units in the amount equal to the loss of the largest unit, the 180 MW AES coal plant (modeled as 185 MW for the expected increase in AES capacity). In the scenario analysis it was assumed that the spinning reserve would be complimented with an additional amount of regulating reserve to account for the sub-hourly wind variability. The regulating reserve is determined by the forecasted wind power and defined by reserve capacity and ramping capability. Therefore, in every hour of the year, the system carries spinning reserves (as a constant 185 MW) and regulating reserves (determined as a function of forecasted wind power). We will refer to the sum of spinning and regulating reserves as the up reserve of the system.

The project team utilized the results from Section 6.2.2.2 that described the relationship between 10-minute downward changes in wind power as a function of the available wind power in order to provide system operations with an expectation of the drop in wind power as a function of the amount of wind power available to the system. The 10 minute changes were selected in order to ensure that sufficient regulating reserve was available within the timeframe needed to fast-start the combustion turbines to cover for variations in wind power output, particularly downward changes, to avoid encroaching upon the 185 MW spinning reserve. Figure 6-9 highlights that as the wind power output increases from very low levels to approximately half of its installed capacity, the 10 minute downward changes increase. However, as the output increases beyond ~50% of the installed capacity, the 10 minute variability decreases.

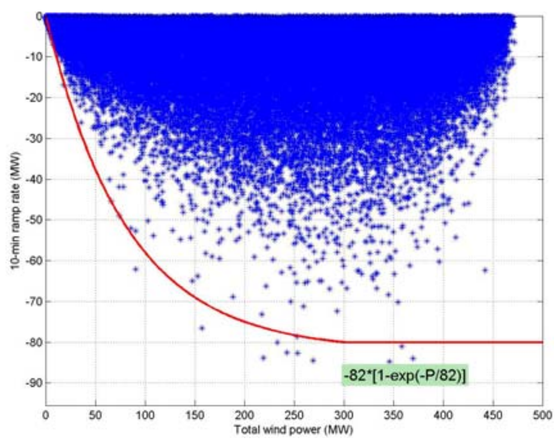


Figure 6-9. Scenario 5: 10 minute drops in wind power as a function of the wind power available at the start of the 10 minute interval. Results based on 2007 and 2008 modeled wind data from AWS Truepower.

The relationship between the 10-minute changes as a function of the available wind power is dependent on the size of the wind plants, the geographic diversity of the wind plant sites and the capacity factors of these plants. Therefore, it was necessary to analyze each scenario independently, based on the 2007 and 2008 historical data in order to estimate the amount of regulating reserve the system needs to cover the 10-minute changes in wind power.

In the scenarios considered in this study, the regulating reserve requirement was based on 10-minute downward wind variability statistics as a function of the 4-hour forecasted wind power level.

6.3. Baseline 2014 scenario

The Baseline scenario was constructed based on inputs from HECO. The project team forecasted the generation and operating strategies employed in 2014 for the HECO system. The Baseline scenario was developed for the year 2014 based on the expected changes to the present HECO system. This was done in order to compare the high wind scenarios to a benchmark without substantial wind and solar power in the system.

6.3.1. Overview of the GE MAPS™ Baseline 2014 scenario

The following section outlines the assumptions for the Baseline 2014 scenario. These assumptions were mostly unchanged for the scenario analysis described later in the report. Any changes made to the assumptions for the scenarios are specified. Note that MW values presented for the production cost tool are reported in net MW (not gross MW).

6.3.1.1. Oahu thermal generation

The Oahu generation consists of the following thermal units:

- Baseload units: AES, Kalaeloa, Kahe 1, 2, 3, 4, 5, and 6, and Waiau 7, and 8.
- Cycling units: Waiau 3, 4, 5, and 6, and Honolulu 8, and 9.
- Peaking units: CT1, Waiau 9, and 10, and Airport DG 1, 2, 3, and 4
- Scheduled energy from IPPs: HPower, OTEC, Honua

One modeling requirement specified by HECO was a minimum of two steam units must be on-line at Waiau Power Plant all times. This is required to maintain the system voltage at all times including the contingency of the loss of a Waiau steam unit. This is captured for ~80% of the year, but not the entire year because of the limitations of the GE MAPS™ model, whereby the unit commitment cannot be scheduled based on another units' unavailability. Therefore, the expected total minimum load of the committed generation will be underestimated for some of the hours of the year because this assumption was not captured in the tool.

Another modeling requirement specified by HECO is the cycling unit start-up order. Cycling unit pairs cannot be started simultaneously, so required on-line time of the second unit dictates scheduling of the first unit. As a result, cycling unit startup schedule is not based solely on lowest incremental cost. This is captured in some instances but has not been captured for all of the events due to limitations of the model.

6.3.1.2. Thermal unit heat rates

The heat rate curves were modeled based on the five-year average ABC heat rate constants provided by HECO. The heat rate curves are provided below.

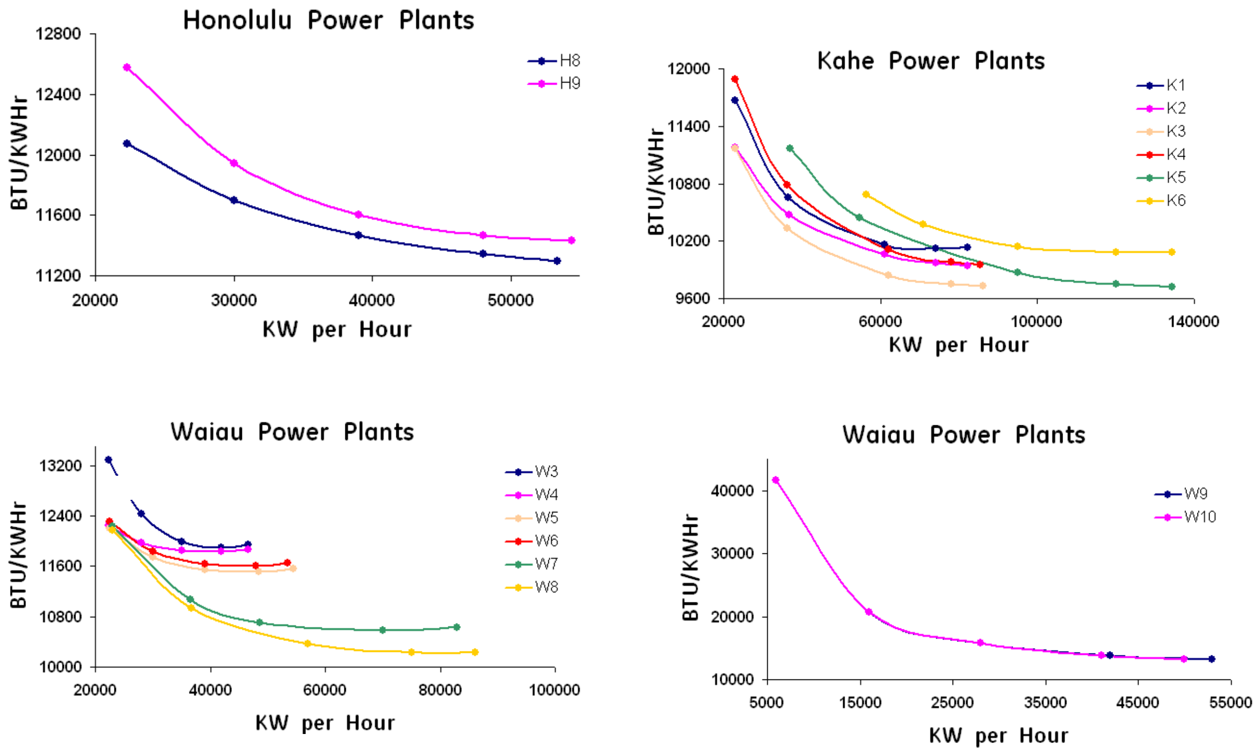


Figure 6-10. Thermal unit heat rates for Baseline 2014

6.3.1.3. Fuel prices and variable cost

The fuel prices modeled in all of the scenarios are summarized below in Table 6-2:

Table 6-2. Fuel cost ($/MMBtu)

Year	Honolulu	Waiau ST	Waiau CT	Kahe	AES	Kalaeloa	DGs	Bio-Diesel
2014	17.68	17.15	22.45	17.15	1.83	17.72	22.83	42.39

Note that the start-up cost is not included in unit commitment, but is included in the total variable cost for each unit. Total variable cost of a unit also comprises the O&M costs as specified by HECO.

6.3.1.4. Load forecasts

The 2014 peak and energy forecast were used to construct the 2014 load shape. The comparison between 2007 and 2014 load shape is shown in Figure 6-11. The load shapes for the two years are similar.

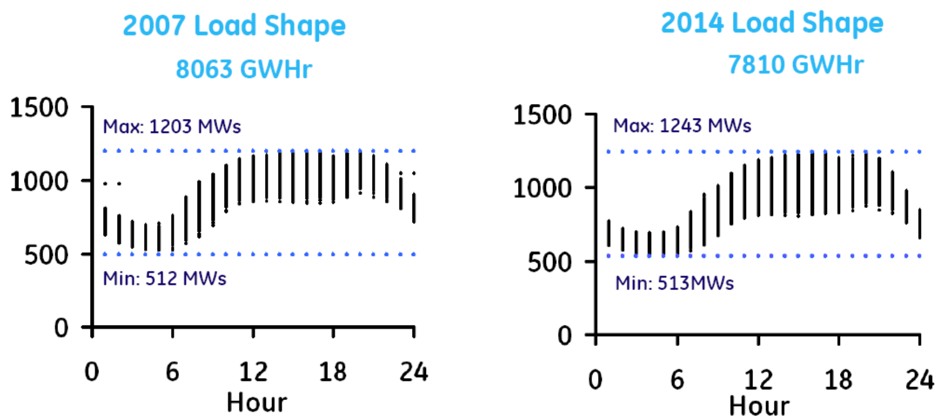


Figure 6-11. 2007 and 2014 load shapes

6.3.1.5. Independent Power Producers

The following decisions about how to implement the IPP hourly production in the models was made by the HECO project team during the weekly discussions. HPower's dispatch is modeled to follow a fixed schedule of 65 MW. It is not anticipated that HPower will operate in this exact fashion in 2014, but it is anticipated that HPower's capacity will increase from its present value, with the flexibility of increasing its production during peak system load hours and decrease its production during off-peak hours. This was not captured in the present Baseline model for 2014. The hourly production from AES and Kalaleloa units was established according to the economic dispatch. These units will be modeled in the same fashion as in the previous baseline model.

According to HECO, present curtailment protocol for IPPs specifies that firm capacity IPPs be economically dispatched to their contract minimum loads to accept as-available renewable energy from IPPs based on good engineering practice and maintaining system reliability. According to HECO, the as-available IPPs are curtailed in order based on Commission approval dates of the PPA contract, the last approved contract being the first unit curtailed. This was reflected in this study insofar as was possible.

6.3.1.5.1. Kalaeloa combined cycle plant

In order to capture the operation of Kalaeloa, the following assumptions were made:

- Kalaeloa was modeled as three separate units:
  - Unit 1 (CT + ½ ST) rated for 67-90 MW. Wash time from 9pm (Fri) to 9am (Sat)
  - Unit 2 (CT + ½ ST) rated for 67-90 MW. Wash time from 9pm (Sat) to 9am (Sun)
  - Unit 3 rated for 28 MW. Operates only when Unit 1 and Unit 2 are operating at max capacity.
- Kalaeloa operates in single train (67-90 MW) for at least five hours before entering dual train mode (134-180 MW)
- Note that the heat rate curve for two of the units (Unit 1 and 2) is based on the dual-train configuration efficiency. It was necessary to maintain the accuracy of this plant when these two "units" were both in operation (in dual train combined cycle configuration) so the heat rate during dual train operation was assumed. Actual heat rate is expected to be higher (less efficient operation).

6.3.1.5.2. AES coal-fired steam plant

The AES plant was modeled based on the representative ABC heat rate curve provided by HECO. AES was assumed to be capable of being backed down to 67 MW during off-peak hours (minimum net power + 4 MW of down-reserve).

6.3.1.5.3. HPower municipal solid waste plant

The HPower plant was assumed to follow a fixed schedule of 65 MW, continuously, outside of its outage schedule. According to HECO, HPower is not on AGC control and therefore is modeled without any governor response.

6.3.1.5.4. Ocean Thermal Energy Conversion (OTEC)

The ocean thermal energy conversion (OTEC) plant was modeled to provide a constant 25 MW throughout the year. It is not necessarily anticipated that the unit will be operated as such, but it was necessary to reflect the future contribution of such a unit to the overall energy production on Oahu.

6.3.1.5.5. Honua gasification plant

Gasification power plant, modeled to provide a constant 6 MW throughout the year. Similar to the OTEC plant it is not clear how this unit will specifically operate in the future, but it is necessary to capture the contribution of this plant to the future energy production on the island.

6.3.1.6. Down-reserve requirements

Note that the eight HECO baseload units (K1 K2, K3, K4, K5, K6, W7, W8) and two IPPs (Kalaeloa and AES) were modeled as maintaining an initial minimum of 40 MW of down-reserve by increasing the minimum dispatch power levels on the units by 4 MW each. This accounts for the contingency event of a failed transfer of a distribution circuit (maximum load). During instances when a baseload unit is on outage, less than 40 MW of down-reserve will be carried by the system. Due to limitations of the GE MAPS™ modeling tool, there was no way to ensure that exactly 40 MW of down-reserve was maintained in each hour of the year.

6.3.1.7. Overhaul, maintenance and forced outages

The actual planned and scheduled maintenance outages were modeled based on the intervals provided by HECO. Forced outages were modeled as a %/yr rounded to the nearest week. The outages are summarized in **Error! Reference source not found.**.

6.3.1.8. Fast-starting capability

Waiau 9, Waiau 10, CT1 and the Airport DGs were modeled as units being capable of starting within one hour to cover for a deficiency in spinning and/or regulating reserve. These units can be started if system load or reserve requirements are violated:

- Waiau 9 and Waiau 10 Combustion Turbines: Frame 7 CTs can be synchronized to the bus in 12 minutes.
- CT1 Combustion Turbine: This is a biodiesel combustion turbine commissioned in 2009. CT1 has environment permit restrictions that will constrain unit dispatch.
- Airport Distributed Generation (DG): Four DG units are modeled. Each unit can be dispatched to 2 MW (net).

CT1 was designated as the first unit to be committed before Waiau 9 or Waiau 10, but is restricted by provisions in the covered source permit such that it can be dispatched above minimum load only if the other steam units cannot meet system demand.

6.3.1.9. Reserve requirements

All units, except HPower, Honua, and OTEC are modeled to count 100% of their remaining capacity towards meeting system reserve requirements. Fast-start units (CT1, W9, W10, and Airport DG diesel units) are not counted towards meeting capacity or reserve requirements unless generation is not sufficient to meet system demands.

6.3.1.10. Run time requirements

In order to capture the minimum up or down time for some of the HECO units, the following assumptions were made:

- 5 hour downtime for W3, W4, W5, W6, H8, H9
- Minimum run time of 3 hours for cycling units
- Minimum run time of 1 hour and downtime of 1 hour for W9, W10
- Minimum run time of 1 hour for CT1

6.3.2. Overview of the GE PSLF™ Baseline 2014 scenario

Transient stability and long term assessments were performed in GE PSLF™ based on the most database described in sections 5.1.2 and 5.1.3. The load data was properly scaled to the 2014 scenario based on the load data used for MAPS at the specific hours of interest.

6.3.3. GE MAPS™ production cost model results

The annual electricity production by fuel type is shown in Figure 6-12 for the Baseline 2014 scenario. With the addition of two new scheduled-energy units (Honua and OTEC), and an increase in the energy output from HPower, less cycling and peaking units are committed and dispatched. Further, the total energy delivered in 2014 marginally decreased as compared to the original Baseline model for 2007.

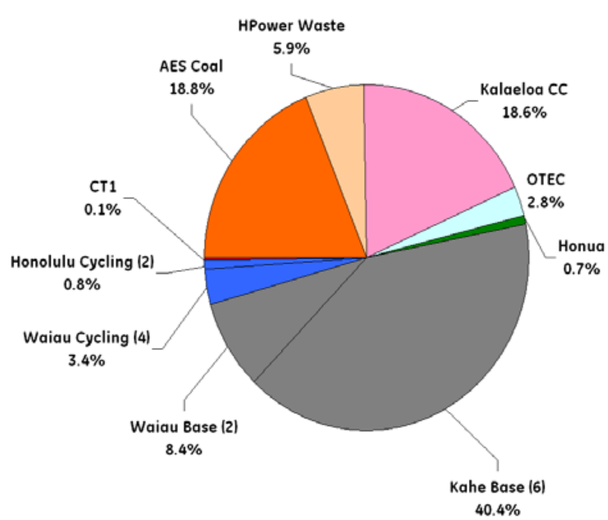


Figure 6-12. Baseline 2014 scenario. Annual energy production by unit type

A representative stack of generation is shown in Figure 6-13 from Friday December 19 to Friday December 26, 2014 and from Friday, October 10 to Friday, October 17. These weeks were of interest in the high wind scenarios, so were compared to these two weeks in the Baseline 2014 scenario.

The generation stack starts with the IPPs and the HECO baseload units and consists of cycling and peaking units near the top of the stack. Cycling units are committed to meet the system demand plus the reserve requirement. Cycling and peaking units may also be required when some of the baseload units are on outage. For example, cycling units are committed the first two days of this week, when Kalaeloa is available only in single train. No cycling units are committed on day four, until the later afternoon peak because the load is relatively low and Kalaeloa is available in dual-train.

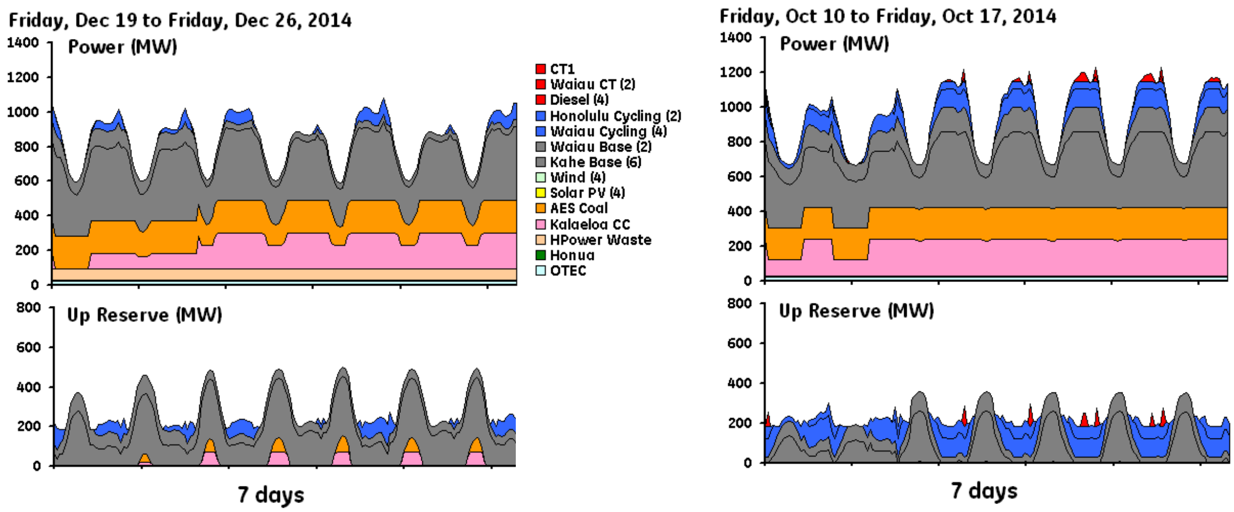


Figure 6-13. Baseline 2014 scenario. Hourly generation for two different weeks.

The Baseline 2014 scenario provides a reference to compare results of the other scenarios. In the following section, the high wind power scenarios will be presented in detail.

6.3.4. Conclusions

The Baseline scenario exhibits similar trends as presently observed today. During periods of the year when peak load is relatively high, the combustion turbines may be dispatched, while during periods of the year when the peak load is lower, cycling units may sufficiently meet the peak load. One of the significant changes from the present operating year to 2014 is the additional capacity of HPower and contributions from OTEC and Honua. The assumptions described for the Baseline 2014 scenario were unchanged in the future scenarios. For example, the load shape, thermal generation mix, and fuel prices were unchanged.

6.4. Scenario 1: 100 MW Oahu Wind + 100 MW Oahu Solar

6.4.1. Overview

This scenario considers the same generation mix as the Baseline 2014 scenario, plus the addition of 100 MW of wind on the island of Oahu and 100 MW of solar power on the island of Oahu.

The wind power on Oahu is a combination of two wind plants, located on the northern part of the island (70 MW and 30 MW). The 100 MW solar power is a combination of 60 MW centralized PV plant, 20 MW centralized PV plant, another 5 MW centralized PV plant, and 15 MW aggregation of distributed residential PV installations. Actual wind and solar power shapes were provided for each of these sites, at a time resolution of 10 minutes. In addition, four-hour wind forecast data was made available for the wind plant sites.

The four-hour wind forecast for the wind plant sites was used in establishing unit commitment. This allowed more wind energy to be accepted by the system because fewer cycling units were committed to meet system demand. System demand is defined as system load and up-reserve. Note that up-reserves are the sum of 180 MW (spinning reserves) and the regulating reserves required to mitigate wind power variability. The regulating reserve is a function of forecasted wind energy and is represented by the following equation.

Regulating reserve is represented by,

$$\text{Regulating Reserve} = func(\text{W})$$

Where, W is the total wind power production.

Up-reserve is represented by,

$$\text{Up Reserve} = \text{spinning reserve} + \text{regulating reserve}$$

$$\text{Up Reserve} = 185MW + func(\text{W})$$

The function is described in Figure 6-13.

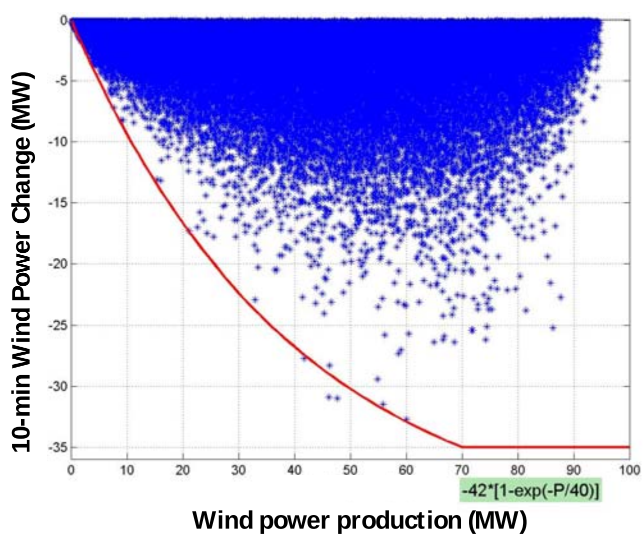


Figure 6-14. The regulating reserve requirement for Scenario 1 based on wind power production [*func*(W)]

Since the regulating reserve requirement must be established during the time of unit commitment, it was necessary to utilize a wind power forecast from four hours before the event. Four hours was selected because this was considered adequate time for HECO to commit a cycling unit to meet regulating reserve requirements.

Methods to forecast solar power were not available for this study. Therefore, forecast of solar power was not considered in the unit commitment, and the regulating reserve equation only includes forecasted wind power. In the actual hour of dispatch, if solar power is available then thermal units are dispatched down. As a result, up reserve (and accordingly regulating reserve) is increased proportionally for each MW of solar power. The same is true for wind power: if additional wind is available than was expected (forecast underestimated), the regulating reserve increases by one MW for each additional MW of wind accepted by the system. However, if the thermal units are already operating at their minimum power point, then excess wind power is curtailed. Some of the solar power is distributed residential PV connected to the distribution system and cannot be curtailed in this model.

When the sum of actual wind and solar power is less than the forecasted wind power, the committed thermal units are ramped up to meet system demand. If system reserve limits are encroached, wind power might be curtailed to maintain system reliability. Note that the up-reserve (spinning plus regulating) requirement is held constant in the commitment and dispatch phase. It should also be noted that fast-starting units are capable of being dispatched within 15 minutes if the committed thermal units cannot meet demand.

The curtailment order of the wind and solar sites is listed below:

- 60 MW Centralized PV Plant
- 20 MW Centralized PV Plant
- 70 MW Oahu Wind Plant
- 30 MW Oahu Wind Plant

The plant listed at the top of the list (60 MW Centralized PV Plant) is curtailed before of any other as-available renewable plant, while the 30 MW Oahu Wind Plant is the last to be curtailed. Curtailment policies apply to Scenarios 3 and 5 with these off-shore wind plants being the first units on the curtailment order.

Production cost simulations were performed in GE MAPS™ in order to observe the unit commitment and dispatch as well as the changes in variable cost of production (primarily fuel cost) associated with different scenarios of the wind plant deployments. This modeling approach was used to estimate the capacity factors of the wind plants and estimate the associated level of wind power curtailment. When the committed units reached their minimum operating level, respecting the down-reserve requirement of the system, no further wind energy could be accepted by the system. When this occurred any additional wind energy that was available to the system would be curtailed. Note that this methodology for estimating the level of wind energy curtailment excluded wind curtailment associated with violating any ramp rate requirements that may exist, any wind plant unavailability, and any other system conditions that may result in curtailment of wind energy.

The generation stack and annual energy by fuel type is shown in Figure 6-15.

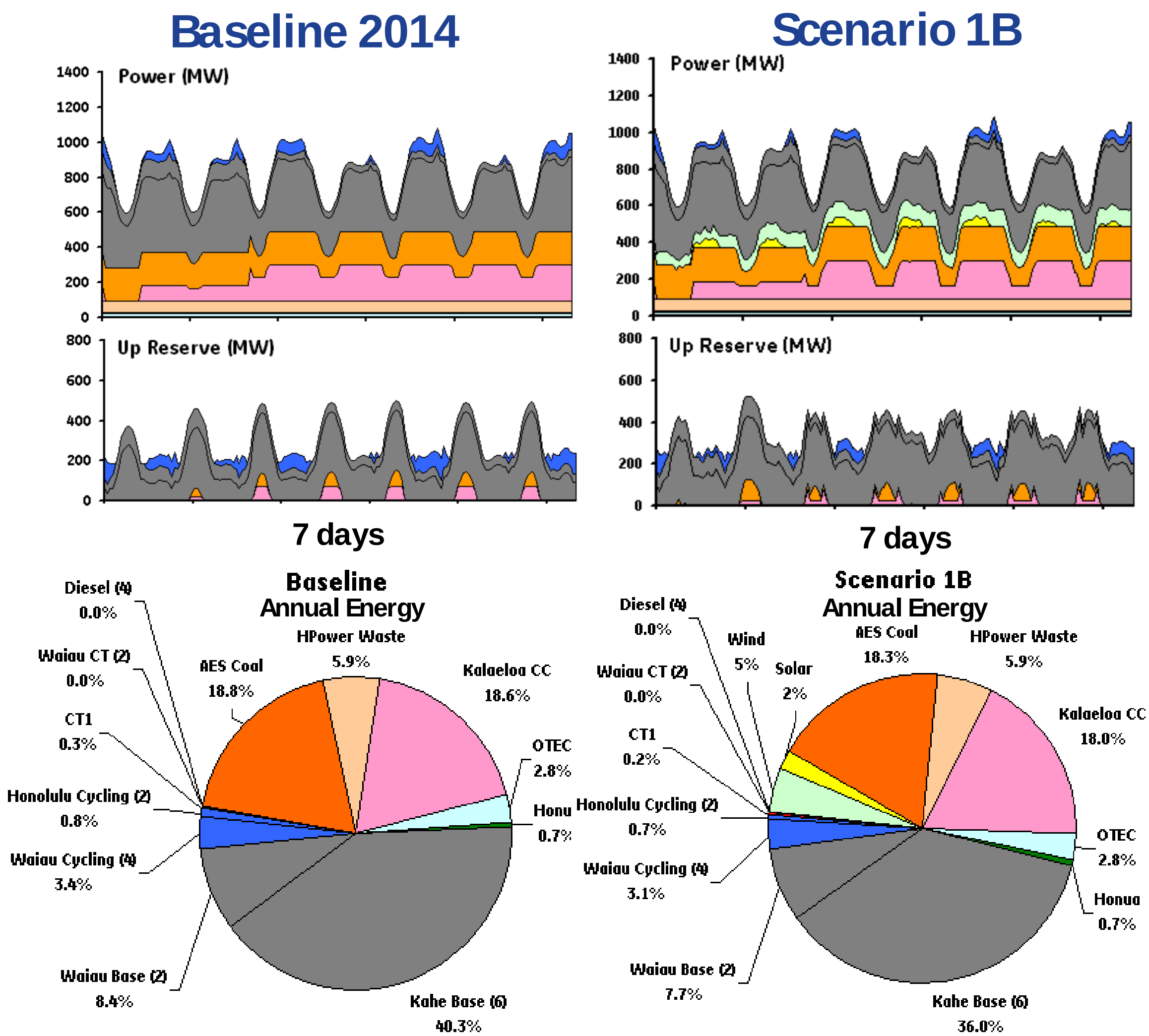


Figure 6-15. GE MAPS™ results for Scenario 1

The commitment and dispatch for Scenario 1 was similar to that of the Baseline 2014 scenario. No wind or solar energy curtailment was observed in Scenario 1. Note that the wind energy primarily displaces the Kahe and Waiau baseload units as these are more expensive baseload units as compared to the IPPs.

6.5. *Scenario 5: 100 MW Oahu + 200 MW Molokai + 200 MW Lanai Wind + 100 MW Oahu Solar*

6.5.1. Overview

This scenario considers Scenario 1 plus 400 MW of off-island wind (200 MW on Lanai and 200 MW on Molokai) for integration into the Baseline HECO system of 2014. This scenario has the highest available renewable energy: ≈ 50% of the peak load and posed the biggest challenge in terms of integration to the baseline model. Scenario 5 was selected as the first simulation in order to push the simulated system model to its limit, allowing the team to eliminate less challenging scenarios and focus on analyzing mitigating strategies.

Two sub-scenarios were considered:

1. <u>No forecast of wind and solar (Scenario 5A)</u>: This sub-scenario assumes that no knowledge of a wind forecast is available. GE MAPS™ performs unit commitment assuming that no solar or wind power is available. Spinning reserve is modeled as a constant 185 MW in the commitment phase. In the actual hour of dispatch, as wind and/or solar appears, the committed thermal units are backed down to accept the available renewable energy. As a result, the up-reserve increases by one MW for each MW of solar or wind power accommodated on the system. If the thermal units are already operating at their minimum power point, which is normally the case during low load hours and especially during nighttime, then renewable energy is curtailed.

2. <u>Four-hour forecast for wind and no forecast for solar (Scenario 5B)</u>: This sub-scenario assumes that a four-hour forecast is available for wind and no forecast is available for solar. GE MAPS™ performs unit commitment based on the wind forecast, such that thermal units can meet system demand (system load and system up-reserves). The regulating reserve requirement is a function of forecasted wind power and is represented by the following equation.

$$\text{Regulating reserve} = 82 \times \left(1 - \exp^{(-W/82)}\right)$$

Where, W is the sum of the forecasted wind power at Oahu, Molokai, and Lanai sites.

$$\text{Spinining reserve} = \text{reserve capacity for the largest generating unit} + \text{regulating reserve}$$
$$\text{Spinning reserve} = 185 + 82 \times \left(1 - \exp^{(-W/82)}\right)$$

The 10-minute wind drops are shown for Scenario 5 in Figure 6-9. Since the up- reserve must be established during the time of unit commitment, it was necessary to utilize a wind power forecast from four hours before the event. Four hours was selected because this was considered adequate time for HECO to commit a cycling unit to meet regulating reserve requirements.

Curtailment of the off-shore wind plants is equitably distributed between the two sites. No consideration for refining the reserve requirement based solar power was made.

6.5.2. GE MAPS™ production cost model results

The results for Scenario 5 are presented for both approaches:

- Scenario 5A: No wind forecasting and no modification to the spinning reserve requirement
- Scenario 5B: Wind forecasting and the addition of regulating reserve to the spinning reserve requirement

Figure 6-16 shows the annual energy generation from the renewable resources and the thermal units for Scenario 5. The energy delivered by the baseload units remains almost unchanged between Scenarios 5A and 5B. There is a slight decrease in the energy output of Kalaeloa and a small increase in the energy delivered from AES in Scenario 5B. This is because Kalaeloa is more frequently committed in dual train mode in Scenario 5A, as it has the lowest cost of operation, after AES, and is needed to meet the commitment without a wind forecast. In Scenario 5B, the wind forecast is included in the commitment and often results in Kalaeloa being committed in single train mode, so that the system is capable of accepting more wind energy. In the actual hour, any error in forecasting is adjusted by increasing the dispatch from the baseload units (AES, Kalaeloa, Kahe 1-6, and Waiau 7-8) and other cycling units committed for the hour. Since AES is the least expensive unit available, it is the first unit to increase its output. As a result, the output from AES increases between Scenario 5A and 5B. The energy from the cycling units decreases between Scenario 5A and 5B, again because of the fact that wind forecast reduces the net load of the system; thus reducing the need for committing additional units.

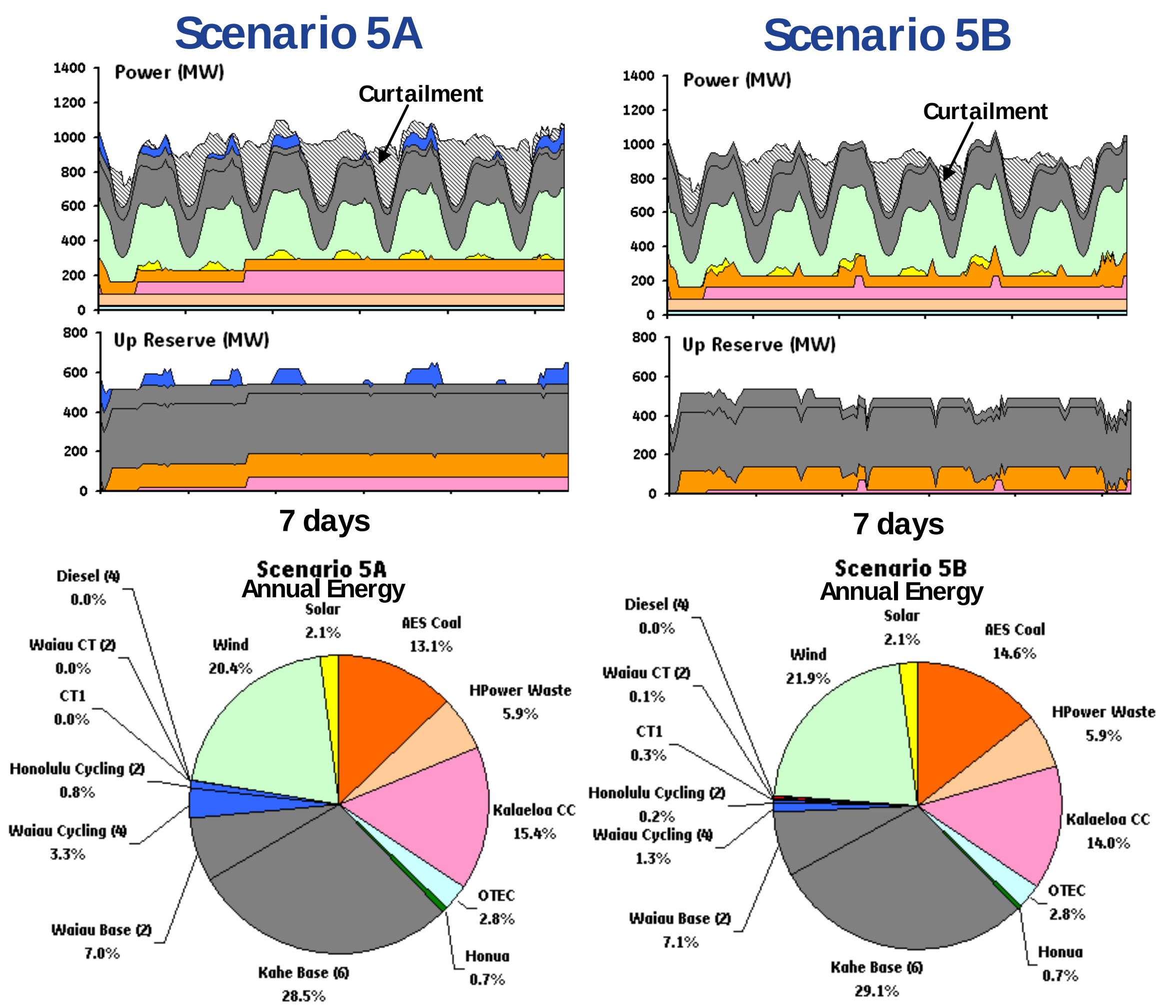


Figure 6-16. Scenario 5: One week of generation and annual energy production by unit type

The energy delivered from the wind installations and solar installations is shown in Table 6-3. The results shows that capacity factors of the Lanai and Molokai sites improve in scenario 5B, indicating that wind forecasts and up-reserve requirement can help accommodate more wind on the Oahu system. Most of the wind curtailment occurs at the Lanai and Molokai wind sites due to the curtailment order established by PPA contracts. No curtailment is seen at the solar and other wind sites. Note that "Available Energy" from Molokai and Lanai includes an assumed 5% loss of energy due to HVDC cable.

Table 6-3. Scenario 5: Wind and solar energy

	5A				5B			
	Solar (100MW)	On-shore Wind (100MW)	Molokai (200MW)	Lanai (200MW)	Solar (100MW)	On-shore Wind (100MW)	Molokai (200MW)	Lanai (200MW)
Available Energy (GWHr)	162	358	716	855	162	358	716	855
Curtailed Energy (GWHr)	0	0	162	172	0	0	106	109
Delivered Energy (GWHr)	162	358	554	684	162	358	611	747
Capacity Factor (Available)	18%	41%	41%	49%	18%	41%	41%	49%
Capacity Factor (Delivered)	18%	41%	32%	39%	18%	41%	35%	43%

Figure 6-17 compares the production cost simulation results between Scenario 5A and 5B for the week starting on October 10th. This is the week with the largest hourly drop in delivered wind and solar energy. The total drop in delivered renewable energy is 313 MW on October 13, in the future study year, between 2:00 pm and 3:00 pm. The wind power forecast is not able to predict accurately this sudden drop in wind power. As a result, the generating units are ramped up and the up-reserve decreases. In Scenario 5A, less wind energy was accepted by the system because cycling units were originally committed to meet system demand so the impact of the drop in wind power was less severe. In Scenario 5A, the system is carrying excess up-reserves and wind energy is being curtailed. For Scenario 5B, CT1, Waiau 9 and Waiau10 must be committed to meet system demand. In reality, committing these quick-start units is not as simple as it appears. System operators must determine if the wind ramp event will be a sustained event to the point of violating the reserve requirements. Once the decision is made to commit these units, their minimum operating times could cause more wind energy to be curtailed should the wind resources return. An accurate wind power forecast is essential to prevent excessive wind energy curtailment

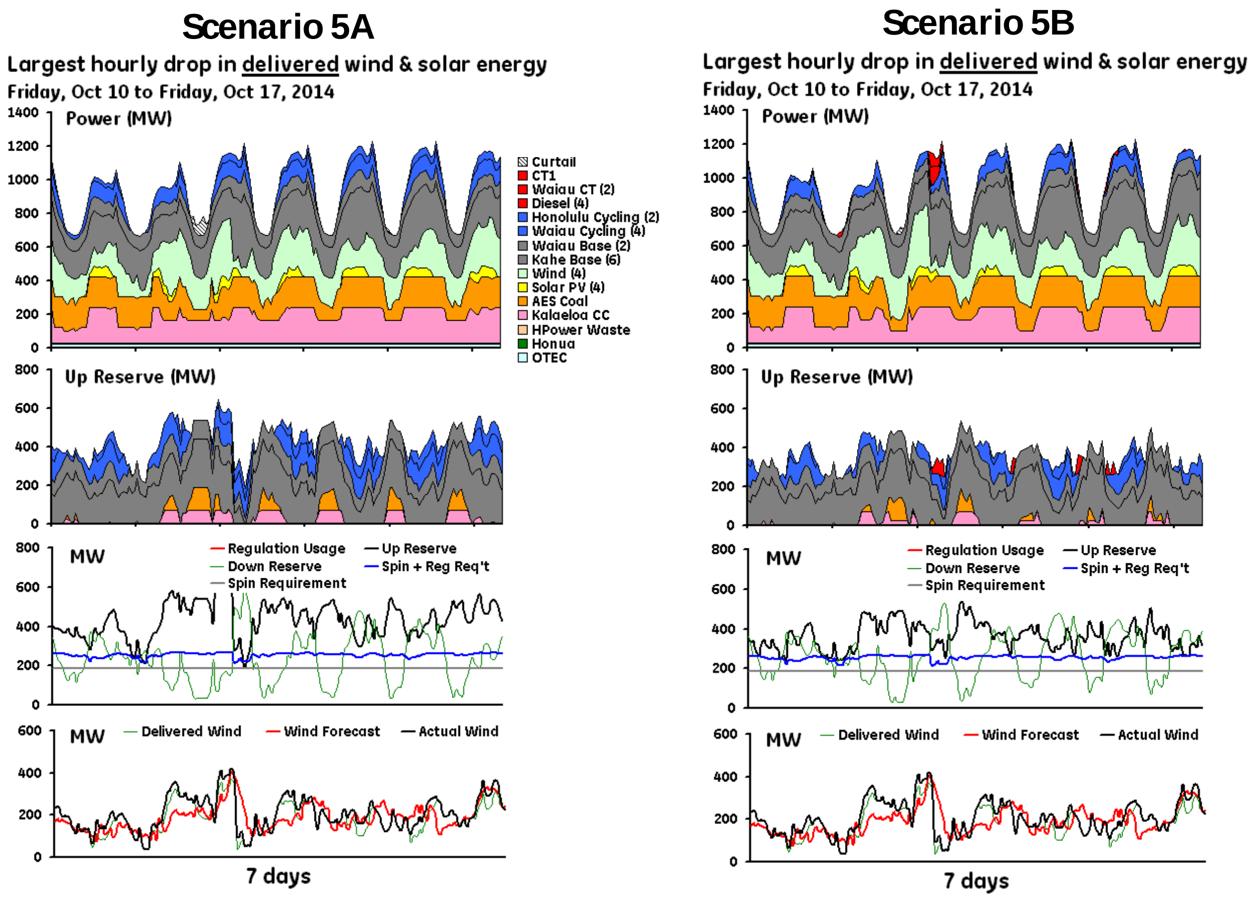


Figure 6-17. Scenario 5: Hourly generation, system reserves, and wind profile for 7 days, starting October 21, 2014.

The fuel consumption and total variable cost of operation in Scenarios 5A and 5B are presented in Figure 6-18. The fuel consumption drops by 1.4% (849,000 MMBtu) in Scenario 5B. The variable cost of operation shows a drop of 3.5% ($35M). This is attributed to using a wind forecasting strategy and a refined reserve requirement that helped avoid the commitment of thermal units.

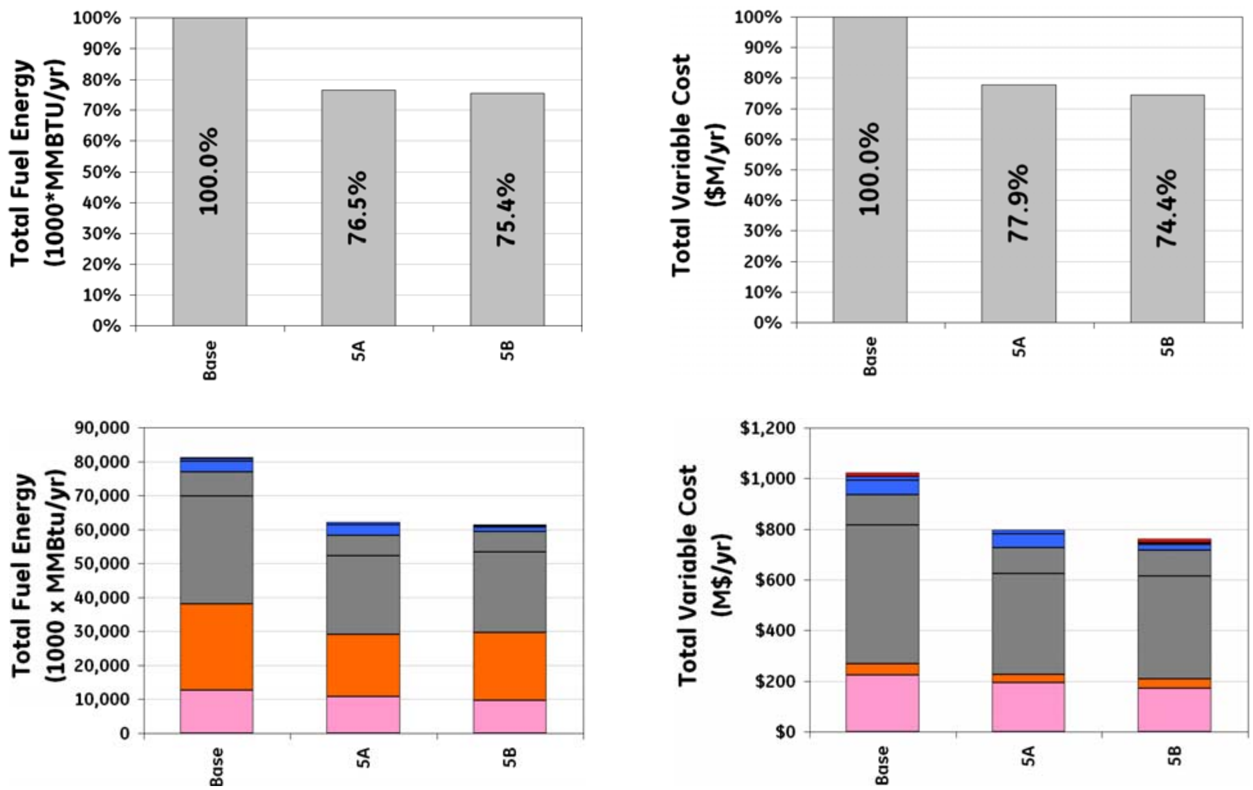


Figure 6-18. Scenario 5. Fuel energy and total variable cost of operation

For the purposes of comparison, Scenario 5A and 5B were presented in the above analysis. For all further analysis in this report Scenario 5B is considered as the Scenario 5 simulation.

6.6. Scenario 3: 100 MW Oahu + 400 MW Lanai Wind + 100 MW Oahu Solar

6.6.1. Overview

This scenario considers the same renewable resources as Scenario 1 with the addition of 400 MW of wind on the island of Lanai. The regulating reserve for Scenario 3 is higher than Scenario 5 because of the lack of wind resource diversity. Again regulating reserves is a function of forecasted wind power and is represented by the following equation discussed X.

Regulating reserve is represented by,

$$\text{Regulating reserve} = 119 \times \left(1 - \exp^{(-W/116)}\right)$$

Where, W is the total wind power production.

Total reserve is represented by,

$$\text{Spinning reserve} = \text{spinning reserves} + \text{regulating reserve}$$

$$\text{Spinning reserve} = 185 + 119 \times \left(1 - \exp^{(-W/116)}\right)$$

Since the reserve must be established during the time of unit commitment, it was necessary to utilize a wind power forecast from four hours before the event. As with Scenarios 1 and 5, a four hour forecast was selected because this was considered adequate time for HECO to commit a cycling unit to meet regulating reserve requirements.

6.6.2. GE MAPS™ production cost model results

Figure 6-19 shows the annual energy generation from renewable resources and thermal units in Scenario 3. As we compare Scenario 5B to Scenario 3B, the main difference is in the increased energy from cycling units. This is due to the higher regulating reserve requirement in Scenario 3B and as result for some hours, when the peak load is high, cycling units may be required to satisfy the reserve requirement. The amount of wind delivered to the system is the same.

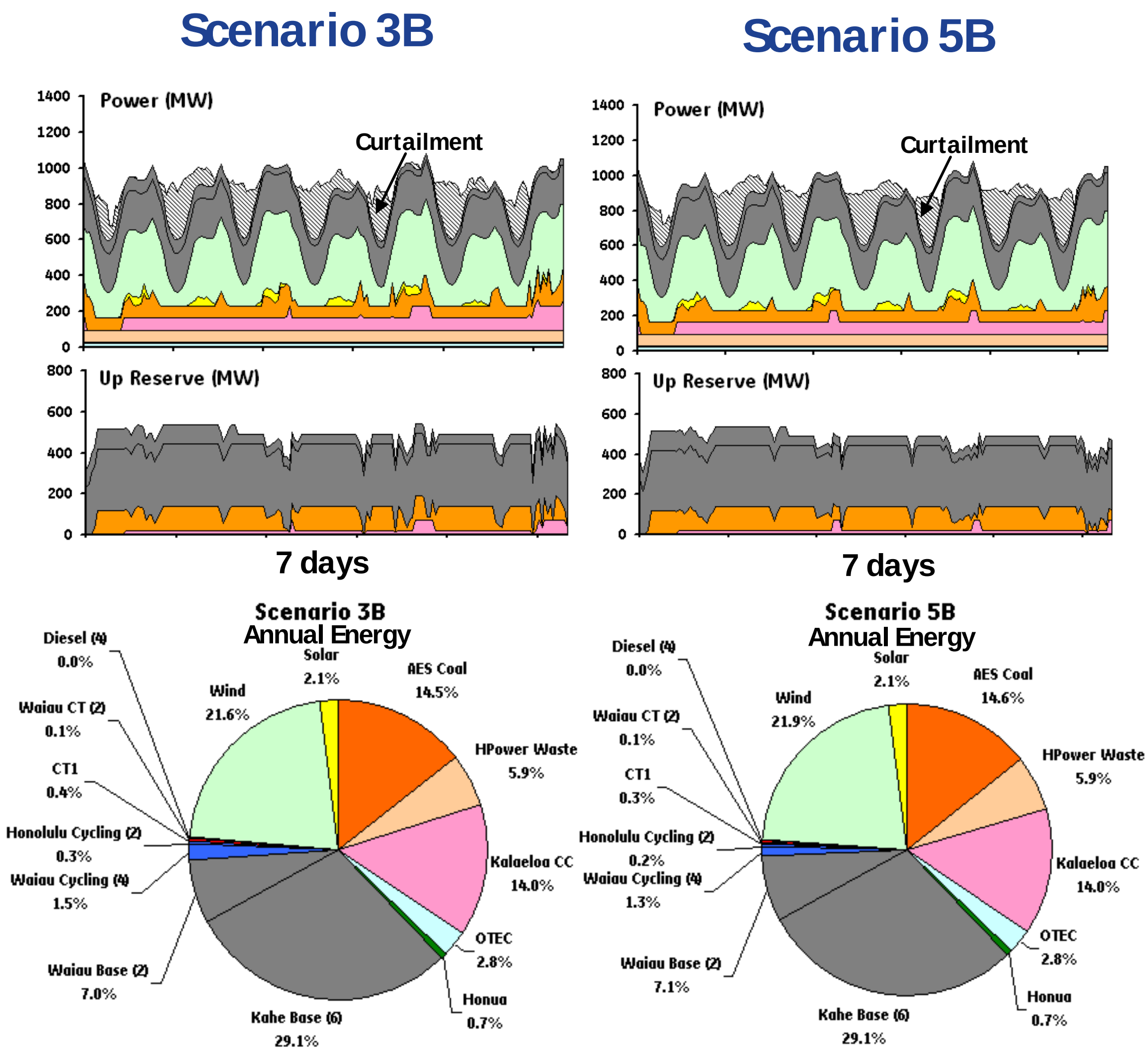


Figure 6-19. Scenario 3: Annual energy production by unit type

The energy delivered from the wind and solar installations is shown in Table 6-4. The vast majority of curtailment occurs at the 400 MW Lanai wind plant. This is because the Lanai plant ranks at the top in curtailment priority list. No curtailment is seen at the solar sites and only a small amount of wind curtailment occurs at the 70 MW Oahu wind plant (<1GWh). Note that available energy includes the assumed 5% wind energy lost in the HVDC cable and system.

Table 6-4. Scenario 3: Wind and solar energy

	1B				5B				3B			
	Solar (100MW)	On-shore Wind (100MW)	Molokai (200MW)	Lanai (200MW)	Solar (100MW)	On-shore Wind (100MW)	Molokai (200MW)	Lanai (200MW)	Solar (100MW)	On-shore Wind (100MW)	Molokai (200MW)	Lanai (400MW)
Available Energy (GWHr)	162	358	-	-	162	358	716	855	162	358	-	1,556
Curtailed Energy (GWHr)	0	0	-	-	0	0	106	109	0	0	-	226
Delivered Energy (GWHr)	162	358	-	-	162	358	611	747	162	358	-	1,331
Capacity Factor (Available)	18%	41%	-	-	18%	41%	41%	49%	18%	41%	-	44%
Capacity Factor (Delivered)	18%	41%	-	-	18%	41%	35%	43%	18%	41%	-	38%

Figure 6-20 shows the results of the production cost simulation for two different weeks in 2014. The week of October 10th contains the largest hourly drop in delivered wind and solar energy, which occurred on October 13 at 2:00pm Hawaii Time. The system operation is similar in Scenario 3B and 5B. The top-most figure illustrates that when this sudden drop in wind power is encountered, the Kahe and Waiau baseload units are ramped up to cover for the deficiency in generation. Fast-start CTs are also committed to meet system demand. The second figure from the top highlights the decrease in up-reserve after this event occurred. However, the reserve is restored in the succeeding hours, when the forecast is able to capture this large drop in wind power and additional thermal units are committed. The accuracy of the four-hour forecast is illustrated in the bottom-most figure, which shows that the forecasted wind is able to capture the trend in actual wind power in Scenario 3B, but was not able to do so in Scenario 5B.

The week of December 19th had the most potential wind power available. The operation of the system in Scenario 3B and 5B is similar. No clear differences were observed.

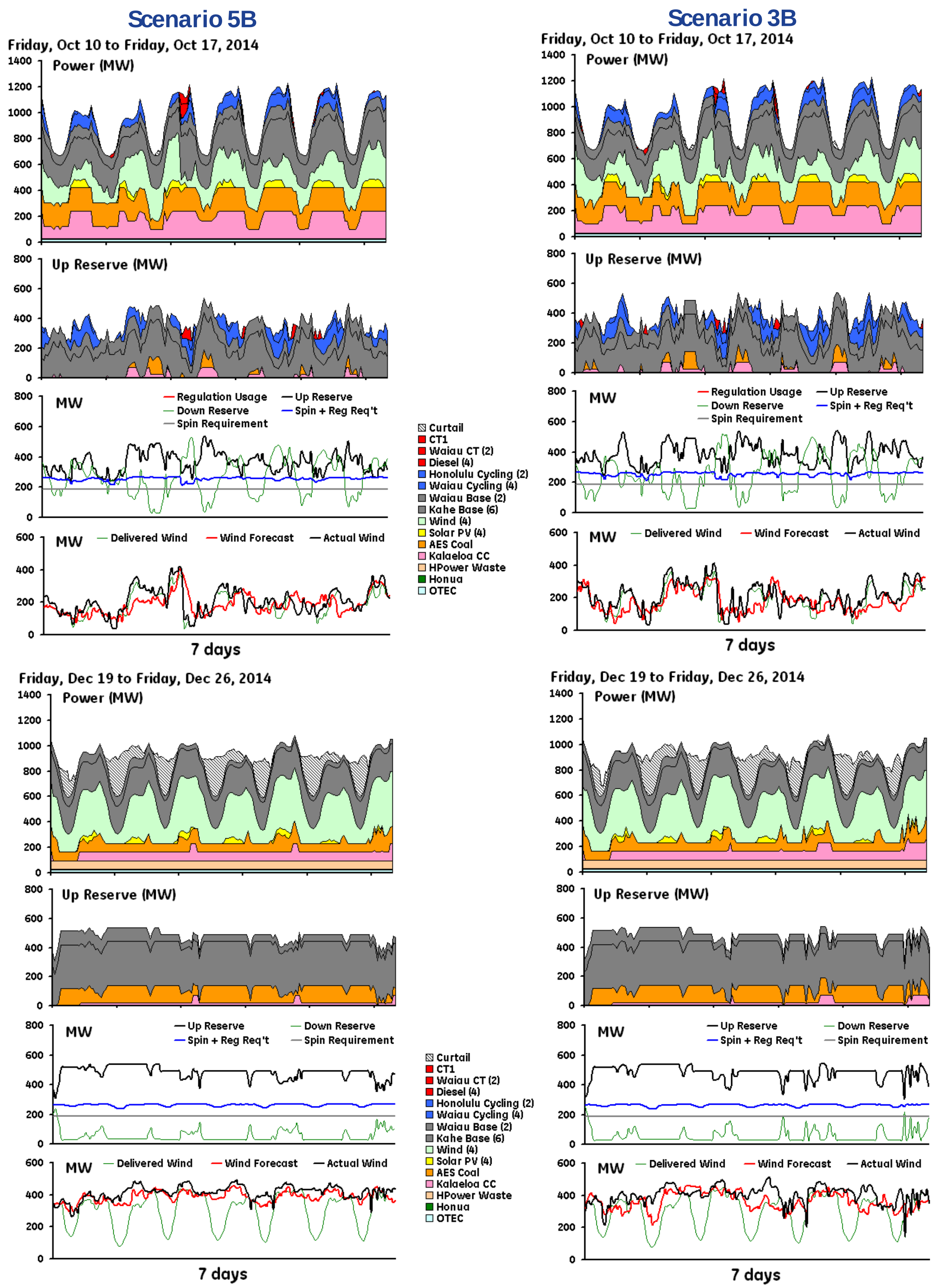


Figure 6-20. Scenario 5B and 3B. Hourly generation, system reserves, and wind profile for two different weeks in 2014, the future study year

6.7. *Conclusions*

As the wind energy delivery to the system increases, the committed thermal units spend more time at lower power points. The units can only be backed down to their lowest minimum power point, respecting the down-reserve requirement, after which all the available wind energy will be curtailed. Table 6-5 shows the number of hours of operation at this minimum power, respecting the down-reserve requirement, by different thermal units. In the high wind scenarios (Scenario 5B and 3B), Waiau and Kahe baseload units spend more than 50% of the time at their min power, respecting the down-reserve requirement. Such operation of the system entails a penalty on the heat rate of the system and also poses a challenge to operate the system under a load rejection event.

Table 6-5. Hours at min dispatchable power, respecting the down reserve requirement. The down-reserve requirement is shown in brackets

Hours at min dispatchable power	SCENARIO			
	Base (40MW)	1B (40MW)	5B (40MW)	3B (40MW)
AES Coal	2	23	1943	2004
KalaeloaCC	278	714	2603	2531
Kahe 1	2427	3247	5820	5849
Kahe 2	2982	4261	6578	6605
Kahe 3	1575	2182	4739	4717
Kahe 4	1758	2354	4938	4927
Kahe 5	1440	2016	4532	4509
Kahe 6	1904	2502	5125	5122
Waiau 7	4536	6215	6999	6982
Waiau 8	2027	2619	5246	5248

An important metric that captures the performance of the units is the average heat rate. This metric describes the average MMBtu of fuel required to generate a kWh of energy from the unit. The comparison of the three scenarios is shown in Table 6-6, where heat rate is shown by unit type. The heat rate of the baseload units increase from Baseline to Scenarios 3 and 5 because the thermal units are dispatched at lower power points, making the unit operation less efficient. The heat rate for the cycling and peaking units shows a moderate change. HPower, Honua, and OTEC are excluded from the heat rate calculations.

Table 6-6. Comparison of average heat rate of HECO thermal units

Average Heat Rate (Btu/kWh)	SCENARIO Base	1B	5B	3B
AES Coal	n/a	n/a	n/a	n/a
Kalaeloa CC	n/a	n/a	n/a	n/a
Kahe Base (6)	10,081	10,161	10,374	10,374
Waiau Base (2)	10,694	10,791	10,925	10,925
Waiau Cycling (4)	12,277	12,287	12,293	12,295
Honolulu Cycling (2)	12,261	12,253	12,254	12,242
CT1	16,084	16,329	15,750	15,875
Waiau CT (2)	13,016	12,982	12,983	13,010
Diesel (4)	10,209	10,209	10,209	10,209
HPower Waste	-	-	-	-
Honua	-	-	-	-
OTEC	-	-	-	-
Wind	-	-	-	-
Solar	-	-	-	-
Average (all Units)	11,469	11,576	11,777	11,784
Average (HECO Units)	10,386	10,455	10,601	10,631
Corrected Avg (HECO Units)	10,510	10,580	10,728	10,759

* Heat rate correction factor of 1.2% based on results of model validation effort with respect to baseline Oahu system

Two aggregate heat rates are shown in the Table 6-6. The heat rate for "all units" includes the HECO base load units, HECO cycling and peaking units, as well as AES and Kalaeloa. The heat rate for "all units" rises by 2.7% from Baseline to Scenario 3 and 5, implying that the system is 2.7% less efficient. The heat rate for "HECO units" includes HECO baseload units and HECO cycling and peaking units. This shows an increase of 2.3% and 2.0% in Scenario 3 and 5 respectively from the Baseline scenario.

The system heat rate has a direct impact on the total variable cost of operation. Variable cost of operation includes fuel cost, start-up cost, and the O&M cost. Figure 6-21 shows fuel consumption and total variable cost of operation across the different scenarios discussed. The fuel consumption increases by 0.6% (385,000 MMBtu) and the total variable cost of operation increases by 1.5% ($11.8M) from Scenario 5B to Scenario 3B. This is attributed to higher up-reserve requirement for Scenario 3B, which entails more frequency commitment of cycling units.

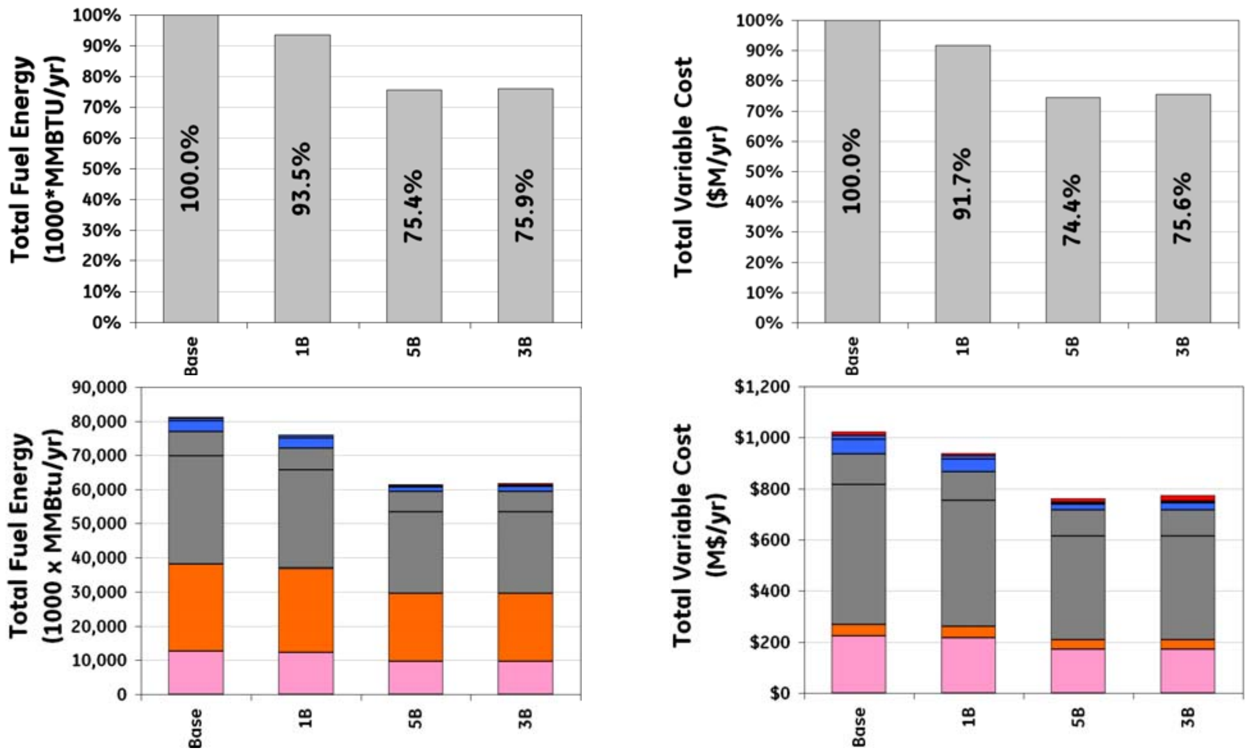


Figure 6-21. Scenario 3. Fuel energy and total annual variable cost of operation

It should be noted that the variable cost to HECO of AES and Kalaeloa is represented by the heat rate curves provided by HECO. Therefore, the actual variable cost to HECO based on the Power Purchase Agreements (PPAs) with AES and Kalaeloa may only be reflected accurately insofar as the modeled heat rate curves reflect the true cost of their operation to HECO. Further, the variable costs of Honua, HPower and OTEC are not captured in Figure 19 for the Baseline Scenario, Scenario 3 and Scenario 5. In Scenario 3 and Scenario 5, the variable cost to HECO associated with future PPAs with the wind and solar developers are not captured.

A summary of the renewable energy delivered is shown in Table 6-7.

Table 6-7. Summary of renewable energy delivered for select scenarios

		SCENARIO				
		Base	1B	5A	5B	3B
Solar (100MW)	Available Energy (GWh)	-	162	162	162	162
	Curtailed Energy (GWh)	-	0	0	0	0
	Delivered Energy (GWh)	-	162	162	162	162
	Capacity Factor (Available)	-	18%	18%	18%	18%
	Capacity Factor (Delivered)	-	18%	18%	18%	18%
On-shore Wind (100MW)	Available Energy (GWh)	-	358	358	358	358
	Curtailed Energy (GWh)	-	0	0	0	0
	Delivered Energy (GWh)	-	358	358	358	358
	Capacity Factor (Available)	-	41%	41%	41%	41%
	Capacity Factor (Delivered)	-	41%	41%	41%	41%
Molokai (200MW)	Available Energy (GWh)	-	-	716	716	-
	Curtailed Energy (GWh)	-	-	162	106	-
	Delivered Energy (GWh)	-	-	554	611	-
	Capacity Factor (Available)	-	-	41%	41%	-
	Capacity Factor (Delivered)	-	-	32%	35%	-
Lanai (200MW)	Available Energy (GWh)	-	-	855	855	-
	Curtailed Energy (GWh)	-	-	172	109	-
	Delivered Energy (GWh)	-	-	684	747	-
	Capacity Factor (Available)	-	-	49%	49%	-
	Capacity Factor (Delivered)	-	-	39%	43%	-
Lanai (400MW)	Available Energy (GWh)	-	-	-	-	1,556
	Curtailed Energy (GWh)	-	-	-	-	226
	Delivered Energy (GWh)	-	-	-	-	1,331
	Capacity Factor (Available)	-	-	-	-	44%
	Capacity Factor (Delivered)	-	-	-	-	38%

Available Energy includes an assumed 5% loss of energy due to HVDC cable

The results of the scenario analysis suggest that all of the onshore wind and solar power can be accepted by the system, while there is 334GWh of wind energy curtailment in Scenario 5A, 215GWh of wind energy curtailment in Scenario 5B and 226GWh of wind energy curtailment in Scenario 3B. The total variable cost of operation for the Scenario is shown in Table 6-8.

Table 6-8. Total variable cost of operation compared to the Baseline 2014 Scenario

Total Variable Cost	SCENARIO				
(per unit)	Base	1B	5A	5B	3B
AES Coal	5%	4%	3%	4%	4%
Kalaeloa CC	22%	21%	19%	17%	17%
Kahe Base (6)	53%	48%	39%	40%	40%
Waiau Base (2)	12%	11%	10%	10%	10%
Waiau Cycling (4)	6%	5%	5%	2%	3%
Honolulu Cycling (2)	1%	1%	1%	0%	0%
CT1	2%	1%	0%	2%	2%
Waiau CT (2)	0%	0%	0%	0%	0%
Diesel (4)	0%	0%	0%	0%	0%
HPower Waste					
Honua					
OTEC					
Wind					
Solar					
HECO Thermal Units	74%	66%	56%	54%	55%
Other IPPs	26%	26%	22%	20%	20%
Total Variable Cost ($M/yr)	100.0%	91.7%	77.9%	74.4%	75.6%

The results of the scenario analysis suggest that the total variable cost of operation for Scenario 5A, Scenario 5B, and Scenario 3B is 77.9%, 74.4% and 75.6% respectively, of the Baseline 2014 variable cost of operation.

The results of the Baseline 2014, Scenario 1B, Scenario 5B and Scenario 3B formed the basis for developing strategies to increase the wind energy delivered, enhance system operations and reliability, and improve system-wide economics of operation. The strategies will be considered in the next section of the report and compared to the wind energy curtailment levels presented in this section.

7.0 Renewable Resource Integration Strategies

This section describes the strategies considered to increase the amount of renewable energy delivered and improve the system economics while maintaining system reliability. Each strategy is outlined and the results of the GE MAPS^{TM} simulations are presented in this section for each strategy considered. The results of the dynamic simulations will be presented later for a subset of these simulations.

7.1. Objectives

This section will outline some of the potential strategies that were developed in this study to enable high penetration of wind power on the Oahu grid. Each of these strategies were designed to Reduce the State's dependence on fossil fuels for power generation to provide a hedge against fossil fuel price volatility and provide other environmental and societal benefits, while maintaining electrical system reliability. In this study, increasing the contribution from wind energy was achieved with system modifications that reduced wind energy curtailment and displaced fossil fuel based electricity generation.

In the latter sections, enabling technologies will be presented (e.g. inertial response of wind turbines, over-frequency control, etc.) that will support the system operation (in steady state and during transient conditions) as these strategies are put in place.

7.1.1. Overview of potential strategies

The following strategies were selected as potential modifications to the HECO system operation for the enabling high wind/solar integration:

Wind Power Forecasting

Incorporating a wind forecasting strategy to the unit commitment schedule helps in reducing the commitment of the more expensive cycling units. A 4-hour wind forecast strategy was used in Scenario 5B. The time interval of forecasting strategy depends upon the time needed to startup the cycling units to meet any shortfall in wind power. On the Oahu grid, four hours is considered sufficient time to make the decision to commit a cycling unit and bring this unit on-line.

Define Reserve Requirement

Adding regulating reserve to the spinning reserve requirement helps to mitigate the sub-hourly wind variability and also alleviates adverse impacts due to wind forecasting errors since spinning reserve is met by firm capacity thermal units.

Reduce Minimum Operating Load

By reducing the minimum power points of thermal units, more wind energy can be accepted during night-time/light-load operation. However, it must be ensured that sufficient down-reserve is present on the system to cover for load rejection events during this time.

Seasonally cycling baseload units

If wind energy is curtailed during light load conditions, by seasonally cycling a must-run baseload unit, additional wind energy could be accepted at these times.

Reduce On-line Regulating Reserves

Thermal units are committed to meet load plus up-reserve. If other resources can contribute to meet the regulating reserve requirement, commitment of thermal units is reduced. This could help to increase wind energy delivered to the system and reduce variable cost of operation. Table 7-1 highlights the wind integration strategy scenarios considered in this study.

Table 7-1. Summary of wind integration strategy scenarios

	Installed Wind Power on Oahu	Installed Solar Power on Oahu	Installed Wind Power on Molokai	Installed Wind Power on Lanai	Wind Forecast in Unit Commit ment	Up Reserve Req't (MW)	Effective Down Reserve (allocated per unit) (MW)	Reduced HECO Baseline Unit Min Power	Seasonal Cycling of Baseload Units
Baseline	0	0	0	0	N	185	40	N	N
Scenario 1B	100	100	0	0	Y	185 + A	40	N	N
Scenario 5A	100	100	200	200	Y	185	40	N	N
Scenario 5B	100	100	200	200	Y	185 + C	40	N	N
Scenario 3B	100	100	0	400	Y	185 + B	40	N	N
Scenario 5C	100	100	200	200	Y	185 + C	40	Y	N
Scenario 5D	100	100	200	200	Y	185 + C	40	N	Y
Scenario 5F1	100	100	200	200	Y	185 + C	90	Y	N
Scenario 5F2	100	100	200	200	Y	185 + C	90	Y	Y
Scenario 5F3	100	100	200	200	Y	185 + C - D	90	Y	Y
Scenario 3F1	100	100	0	400	Y	185 + B - D	90	Y	N
Scenario 3F2	100	100	0	400	Y	186 + B - D	90	Y	Y
Scenario 3F3	100	100	0	400	Y	187 + B - D	90	Y	Y

A,B,C = additional regulation based on 10-min wind variability
D = Load control capacity + W9 capacity (W10 if W9 not available)

The following sub-sections will describe the cases outlined in Table 7-1.

7.2. Scenario 5C: Reducing minimum power of baseload units

Since no fuel is consumed in the production of renewable energy, this resource can be characterized as "zero incremental cost", excluding its energy pricing. Therefore, as more renewable energy is accepted, the total variable system cost declines. However, the system has constraints in the amount of as-available energy that can be accepted. The primary constraints being the minimum load of the committed thermal units. Most of the curtailment happens during light load conditions (especially during night time) when the baseload thermal generation is backed down to the lowest operating power point, while respecting the down reserve requirement. One of the strategies to accept more wind energy is to reduce the minimum power points of the thermal units.

In the Oahu system, there are ten baseload thermal units that must be committed for all hours of the year, unless on maintenance or forced outage. Hence, a plausible strategy is to reduce the minimum power point of all or some of these baseload units.

In this scenario, the minimum stable operating power of seven HECO baseload units were reduced below their values in Scenario 5B. This reduction in power points is shown in Table 7-2. The minimum power points also reflect a down-reserve requirement of 4 MW on each unit (or effectively a 40 MW down-reserve provided by all ten baseload units). The minimum operating power of Kahe 6 was not reduced in this study due to potential operating limitations from emission control systems.

Table 7-2. Reduced minimum power points of seven HECO baseload units. Note that the minimum power points include the down-reserve already allocated to each unit.

Units	5B/3B (40MW down-reg)	5C (40MW down-reg)
W7	36.6	19.0
W8	36.8	19.0
K1	36.5	19.0
K2	36.7	19.0
K3	36.3	19.0
K4	36.3	19.0
K5	54.7	29.0

The heat rate at these new power points is obtained from the original ABC equation and the unit heat rate comparison between the two scenarios is shown in Table 7-3. Note that HECO anticipates unit to have higher thermal efficiency than modeled in this study due to capital improvement projects necessary to achieve the new minimum operating load. Therefore, HECO anticipates the heat rates used in this study are somewhat conservative.

Table 7-3. Comparison of heat rate of baseload units at min and max powers

Scenario 5B

	Min Power	Max Power	Heat Rate @Max Power	Heat Rate @Min Power
W7	36.6	82.9	10630	11068
W8	36.8	86.1	10233	10936
K1	36.5	82.1	10129	10659
K2	36.7	82.1	9943	10477
K3	36.3	86.1	9730	10331
K4	36.3	85.3	9956	10789
K5	54.7	134.3	9718	10444

Scenario 5C

	Min Power	Max Power	Heat Rate @Max Power	Heat Rate @Min Power
W7	19	82.9	10630	12956
W8	19	86.1	10233	12914
K1	19	82.1	10129	12287
K2	19	82.1	9943	11583
K3	19	86.1	9730	11663
K4	19	85.3	9956	12556
K5	29	134.3	9718	11813

By lowering the minimum power points to the values shown in Table 7-2, the thermal generation could be reduced by approximately 130 MW during light load hours, which ultimately helped in relieving curtailment of wind energy. Lower minimum operating loads also increases the reserve capacity of each unit; potentially increasing wind energy delivery by deferring the commitment of quick start generation during violations to system reserve requirements. However, it must be noted that the operation of the units at such low power points poses additional risk to system operation under load rejection scenarios. Sufficient down-reserve must be maintained to avoid multiple unit trips during severe loss of load events.

7.2.1. Benefits of reducing minimum power of baseload units

Figure 7-1 compares the annual energy production by different units between Scenario 5B and Scenario 5C. The baseload energy from Kahe and Waiau power plants (shown in grey) decreases (by ~6%) because the seven HECO baseload units at these locations operate at a lower power point during light load conditions. At the same time, the baseload energy from AES (shown in red) and Kalaeloa (shown in pink) increases by ~4%. This is because these are the least expensive thermal units on the Oahu grid. Therefore, after all the available wind and solar energy is accepted, these units are the first in the dispatch priority order. The wind energy delivered to the system increases by 2%. This is shown in

Table 7-4.

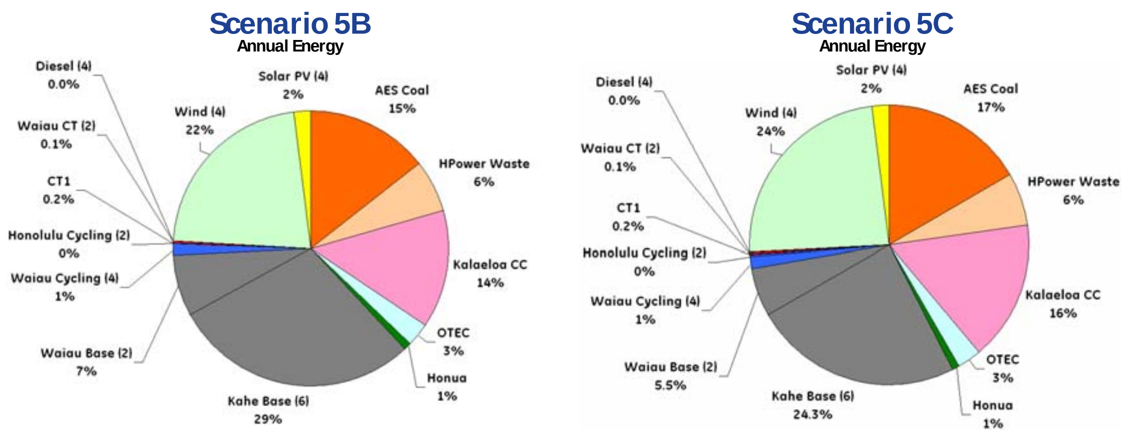


Figure 7-1. Scenario 5C: Annual energy production by unit type

By reducing the minimum power points of the seven HECO baseload units, the Oahu grid was able to accept 149GWh of additional offshore wind energy as compared to Scenario 5B. Figure 7-2 shows the generation stack for the week of the most available wind energy (December 19, 2014 in the future study year). It is clear from this figure that the reduced min power of the seven HECO baseload units substantially reduces the level of wind energy curtailment (shown as hatched area in Figure 7-2).

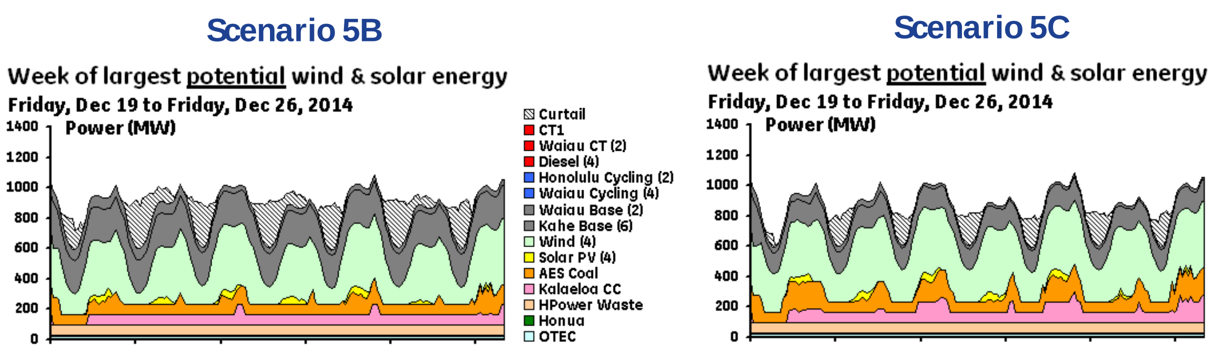


Figure 7-2. Scenario 5B and 5C. The week of Dec 19, 2014, in the future study year. This week exhibited the highest available wind energy.

However, there is still wind energy curtailment present in the system. There is no curtailment in the solar energy or on-shore wind energy. All the curtailment occurs at the offshore wind plants at Lanai and Molokai.

Table 7-4. Scenario 5C: Renewable energy delivered

	5B				5C			
	Solar (100MW)	On-shore Wind (100MW)	Molokai (200MW)	Lanai (200MW)	Solar (100MW)	On-shore Wind (100MW)	Molokai (200MW)	Lanai (200MW)
Available Energy (GWHr)	162	358	716	855	162	358	716	855
Curtailed Energy (GWHr)	0	0	106	109	0	0	33	33
Delivered Energy (GWHr)	162	358	611	747	162	358	683	822
Capacity Factor (Available)	18%	41%	41%	49%	18%	41%	41%	49%
Capacity Factor (Delivered)	18%	41%	35%	43%	18%	41%	39%	47%

As wind energy displaces thermal energy on the system, fuel consumption decreases and thus the total variable cost of operation also decreases. Figure 7-3 shows the trend in the fuel consumption and total variable cost of operation from the baseline system to the high wind scenarios. The incremental decrease in fuel energy by ~0.5% (279,000 MMBtu) and total variable cost by ~6.2% ($47M), from Scenario 5B to Scenario 5C, is attributed to the reduced power points of the seven baseload HECO units.

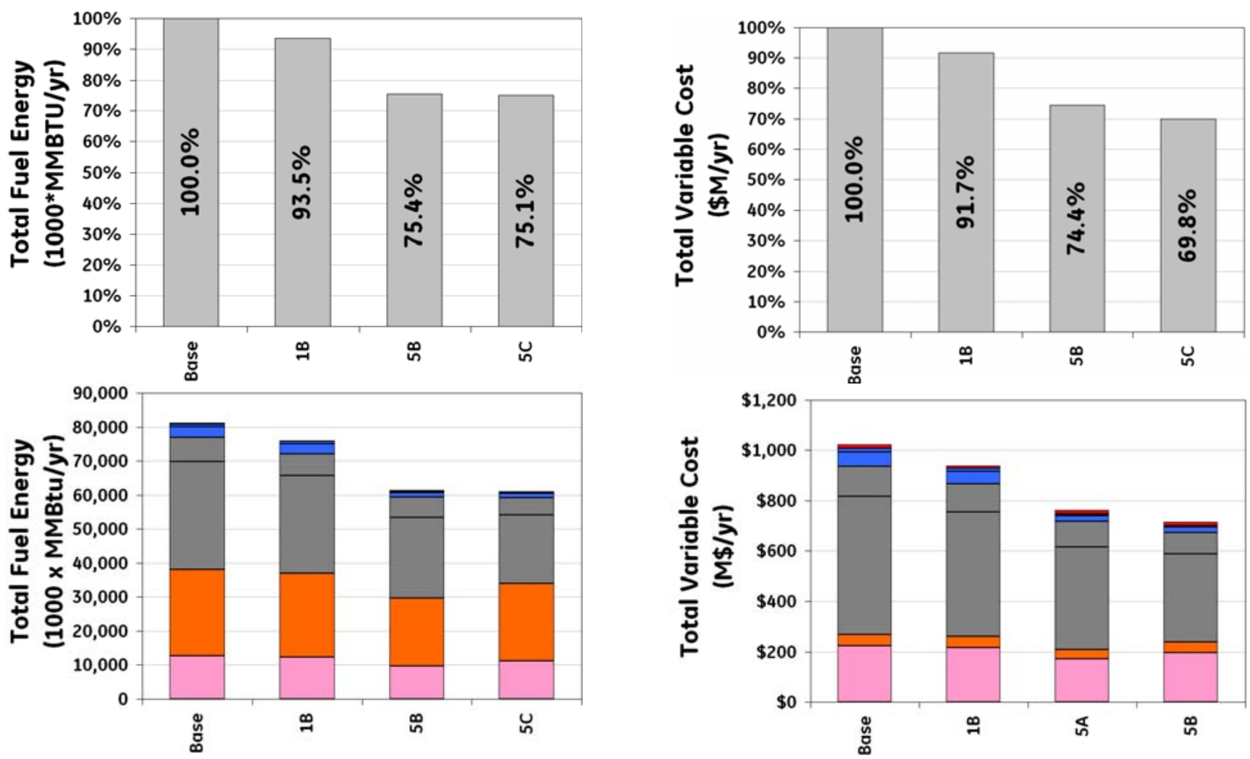


Figure 7-3. Scenario 5C: Fuel energy and total variable cost of operation

The breakdown of fuel energy by unit type is shown in Table 7-5. Again, it is emphasized that the operation of the system with such reduced minimum power points may not be acceptable from the system stability and reliability point of view. This issue is addressed in the next section (Scenario 5F1) with additional down-reserve carried on the system.

Table 7-5. Comparison of fuel energy per year by unit type

Fuel (MMBtu*1000 / yr)	Scenario 5B	Scenario 5C
AES Coal	20,067	22,840
Kalaeloa CC	9,704	11,157
Kahe Base (6)	23,616	20,222
Waiau Base (2)	6,023	4,923
Waiau Cycling (4)	1,281	1,281
Honolulu Cycling (2)	207	207
CT1	361	351
Waiau CT (2)	82	82
Diesel (4)	2	2
HPower Waste	-	-
Honua	-	-
OTEC	-	-
Wind	-	-
Solar	-	-
Total (All Units)	**61,344**	**61,065**
Total (HECO Units)	**31,573**	**27,069**

7.3. Scenario 5F1: Increasing the down-reserve requirement

In the previous section, the minimum power points of the units were reduced to a level that HECO considered as being too low to manage a typical load rejection event. At such low operating points, a load rejection scenario may result in a thermal unit tripping off, thus questioning the stability of the system under these conditions.

In this scenario, the minimum power points of the units are raised (compared to the last section) to reflect a higher down-reserve requirement carried by the system at all times. It was suggested that the effective down-reserve on the system be raised to 90 MW, which was deemed to be enough to counteract most of the load rejection conditions.

Table 7-6 shows the minimum power points of all the units in Scenario 5F1 and compares it to Scenarios 5B and 5C. The minimum power points include the down-reserve being carried by the units.

Table 7-6. Scenario 5F1. Minimum power points of the units changed to increase down-reserve to 90 MW

Units	5B/3B 40MW effective down-reg	5C 40MW effective down-reg	5F 90MW effective down-reg
H8	22.3	22.3	22.3
H9	22.3	22.3	22.3
W3	22.3	22.3	22.3
W4	22.3	22.3	22.3
W5	22.5	22.5	22.5
W6	22.5	22.5	22.5
W7	36.6	**19.0**	**23.0**
W8	36.8	**19.0**	**23.0**
W9	5.9	5.9	5.9
W10	5.9	5.9	5.9
K1	36.5	**19.0**	**23.0**
K2	36.7	**19.0**	**23.0**
K3	36.3	**19.0**	**23.0**
K4	36.3	**19.0**	**23.0**
K5	54.7	**29.0**	**37.0**
K6	54.0	54.0	**56.5**
Kal 1	67.0	67.0	**66.0**
Kal 2	67.0	67.0	**66.0**
Kal 3	0.0	0.0	0.0
AES	67.0	67.0	**73.0**
HPOWER	25.0	25.0	25.0
D1	0.0	0.0	0.0
D2	0.0	0.0	0.0
D3	0.0	0.0	0.0
D4	0.0	0.0	0.0
CIP-CT1	41.0	41.0	41.0

As the minimum power points of the baseload units (primarily Kahe and Waiau base load units) are raised, the energy from the HECO baseload units increases by 1.4%, as compared to Scenario 5C. This in turn displaces some energy production from the IPPs (AES and Kalaeloa output decreases by 0.2% and 0.8% respectively) as well as increases the wind curtailment by 0.4%. This is shown in Table 7-7.

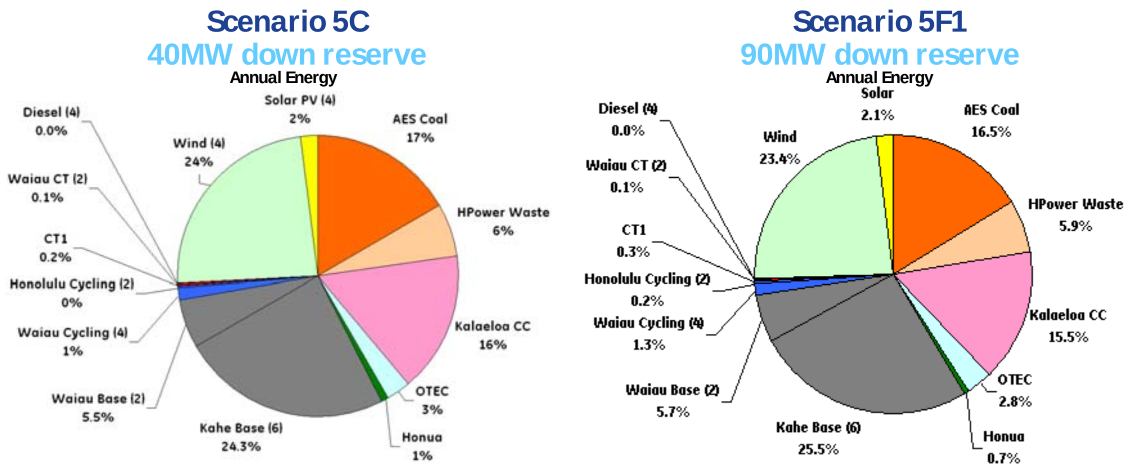


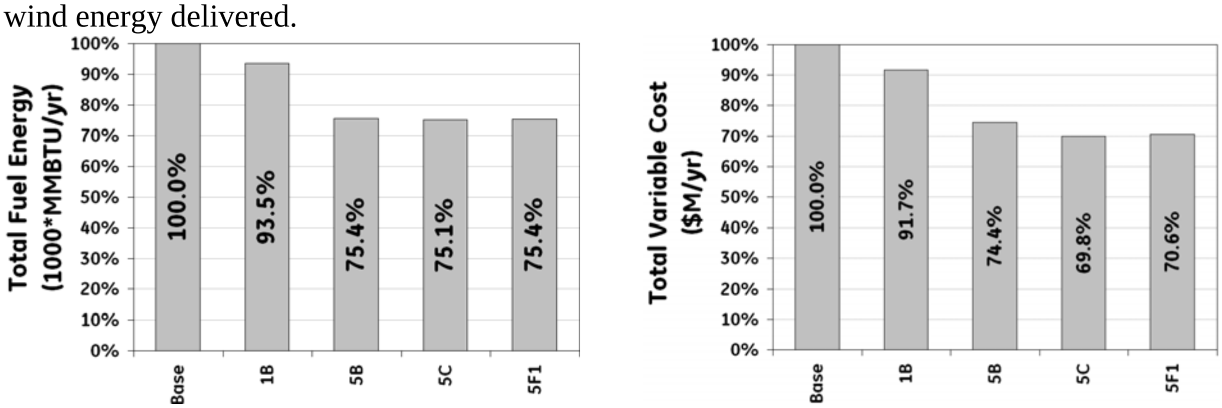
Figure 7-4. Scenario 5F1. Annual energy production by unit type

Wind curtailment primarily occurs during light load conditions (night-time hours) when the thermal units are operating at the minimum power points plus the down-reserve. The level of wind energy curtailment increased from Scenario 5C to Scenario 5F1 by 31GWh.

Table 7-7. Scenario 5F1: Renewable energy delivered

	5B				5C				5F1			
	Solar (100MW)	On-shore Wind (100MW)	Molokai (200MW)	Lanai (200MW)	Solar (100MW)	On-shore Wind (100MW)	Molokai (200MW)	Lanai (200MW)	Solar (100MW)	On-shore Wind (100MW)	Molokai (200MW)	Lanai (200MW)
Available Energy (GWHr)	162	358	716	855	162	358	716	855	162	358	716	855
Curtailed Energy (GWHr)	0	0	106	109	0	0	33	33	0	0	48	49
Delivered Energy (GWHr)	162	358	611	747	162	358	683	822	162	358	667	807
Capacity Factor (Available)	18%	41%	41%	49%	18%	41%	41%	49%	18%	41%	41%	49%
Capacity Factor (Delivered)	18%	41%	35%	43%	18%	41%	39%	47%	18%	41%	38%	46%

Increased energy from the baseload units results in increased fuel consumption and higher total variable cost of operation. This is highlighted in Figure 7-5. The fuel consumption shows a rise of 0.3% (202,000 MMBtu) and the total variable cost shows a rise of 1.1% ($8M) as compared to the previous scenario (Scenario 5C). However, this Scenario still shows benefits in terms of high wind energy delivered, lower fuel consumption, and lower total variable cost with respect to Scenario 5B, while still respecting transient stability of the system. The next section will investigate a strategy that is layered on top of this scenario, with the aim of further increasing the wind energy delivered.



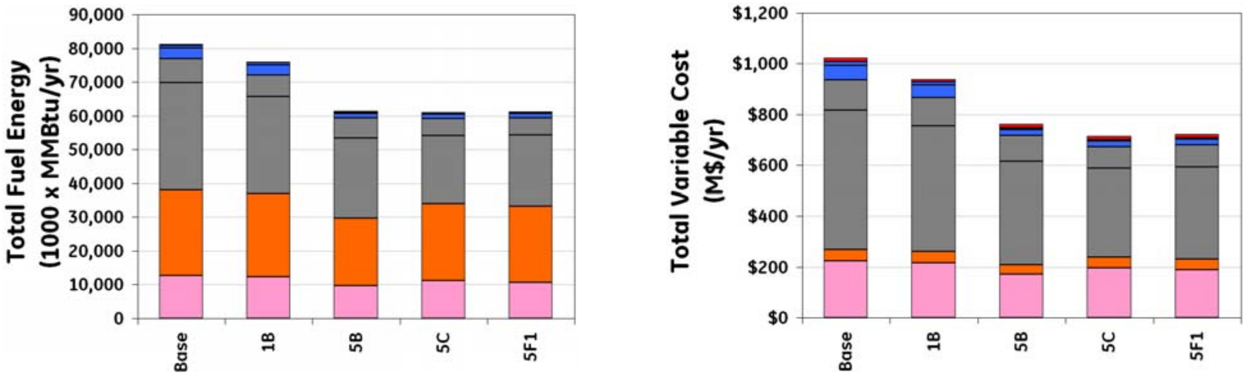


Figure 7-5. Scenario 5F1: Fuel energy and total variable cost of operation

7.4. Scenario 5F2: Reducing minimum power and seasonally cycling baseload units

This strategy reduces the number of baseload units committed, when the load is typically low to allow more wind energy to be delivered to the system. HECO's present practice in scheduling planned maintenance outages is to minimize periods of overlapping (simultaneous) baseload unit outages. Simulation of this strategy specifically schedules two baseload unit outages during traditional low load seasons to accept more wind energy.

The following schedule (Table 7-8) was provided by HECO for seasonally cycling three baseload units. This was modeled in GE MAPS™ by putting these units on outages for this period. This added 18 additional weeks of outages on the existing outage schedule. All the other modeling assumptions remained the same as in the previous scenario (Scenario 5F1).

Table 7-8. Scenario 5F2. Seasonal cycling dates of three baseload units

HECO Unit	Seasonal Cycling Period	
	Start	End
W7	11/1/2014	12/15/2014
K1	1/5/2014	2/6/2014
K2	2/17/2014	4/2/2014

With the above three baseload units on additional outage of 6 weeks each, less baseload thermal energy is produced from the Kahe and Waiau baseload units. This is shown in Figure 7-6, where the energy production from the Kahe and Waiau baseload units decreases by 0.8% on an annual basis. Interestingly, not all of this energy is displaced by the wind energy. The wind delivered to the system is seen to increase by only 0.1% or 9 GWh (as shown in. The decrease in the baseload thermal energy is compensated by an increase in energy production from cycling units (by 0.4%) because during certain periods, when a baseload unit is on seasonal cycling, the net load of the system may be high enough to require a cycling unit be committed. Net load refers to load minus available wind power. There may be cases when the available thermal units cannot meet system demand, which would also necessitate committing a cycling unit.

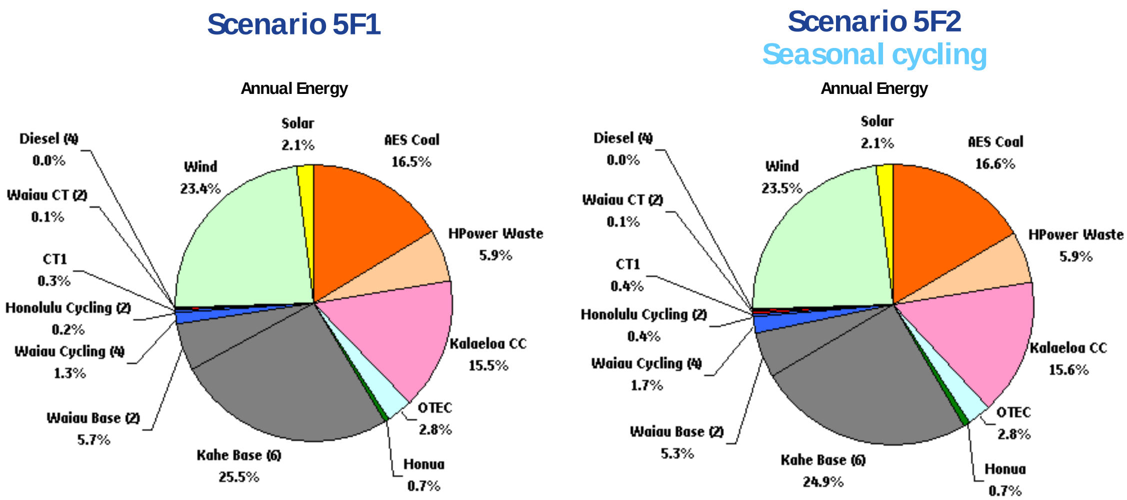


Figure 7-6. Scenario 5F2. Annual energy production by unit type

Table 7-9. Scenario 5F2. Renewable energy delivered

	5B				5F1				5F2			
	Solar (100MW)	On-shore Wind (100MW)	Molokai (200MW)	Lanai (200MW)	Solar (100MW)	On-shore Wind (100MW)	Molokai (200MW)	Lanai (200MW)	Solar (100MW)	On-shore Wind (100MW)	Molokai (200MW)	Lanai (200MW)
Available Energy (GWHr)	162	358	716	855	162	358	716	855	162	358	716	855
Curtailed Energy (GWHr)	0	0	106	109	0	0	48	49	0	0	45	45
Delivered Energy (GWHr)	162	358	611	747	162	358	667	807	162	358	671	810
Capacity Factor (Available)	18%	41%	41%	49%	18%	41%	41%	49%	18%	41%	41%	49%
Capacity Factor (Delivered)	18%	41%	35%	43%	18%	41%	38%	46%	18%	41%	38%	46%

In this study, wind output on a month-to-month basis and on a week-to-week basis was analyzed for the years 2007 and 2008 to determine if this data can assist in scheduling seasonal cycling. It can be inferred from Figure 7-7 and Figure 7-8 that the average monthly or weekly wind output does not show a high degree of correlation between the two years. Until more wind output data can be collected and analyzed, seasonal cycling should be scheduled based on historical system load data. Analysis should also be done on the impacts of seasonal cycling to system inertia and stability.

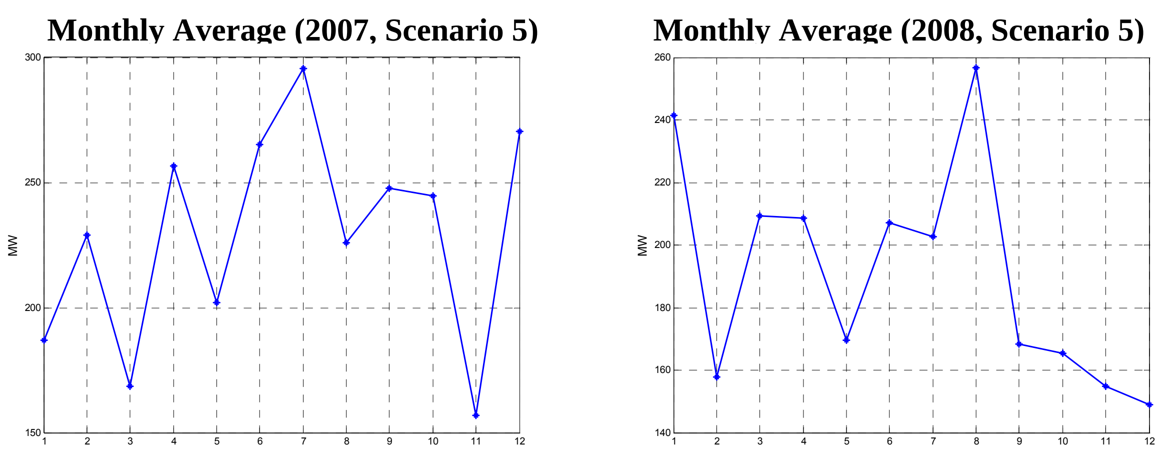


Figure 7-7. Average monthly wind data for 2007 and 2008

Weekly Average (2007, Scenario 5) **Weekly Average (2008, Scenario 5)**

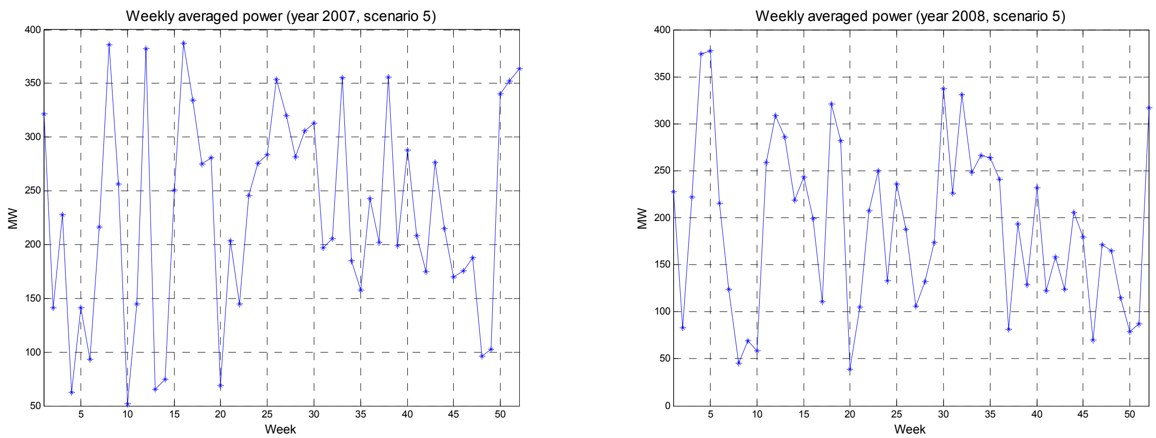


Figure 7-8. Average weekly wind data for 2007 and 2008

The fuel consumption is seen to decrease from Scenario 5F1 to Scenario 5F2 by 0.1% (33,000 MMBtu) and a marginal increase in delivered wind energy is realized. However, the total variable cost of operation increases by 0.5%, ($3.7M). This occurs because more expensive cycling units are dispatched to meet system demand when a baseload unit during the seasonal cycling of a baseload unit. The increase in cost depends on the relative fuel cost difference between the baseload units and the cycling units. This percentage may increase or decrease (on a percentage basis) as the fuel prices change. With this mitigation strategy, although additional wind energy is accepted, the total cost of operation increases. The next strategy (Scenario 5F3 in Section 7.5) will try to bring down the variable cost of operation, while helping the system to accommodate similar levels of wind power.

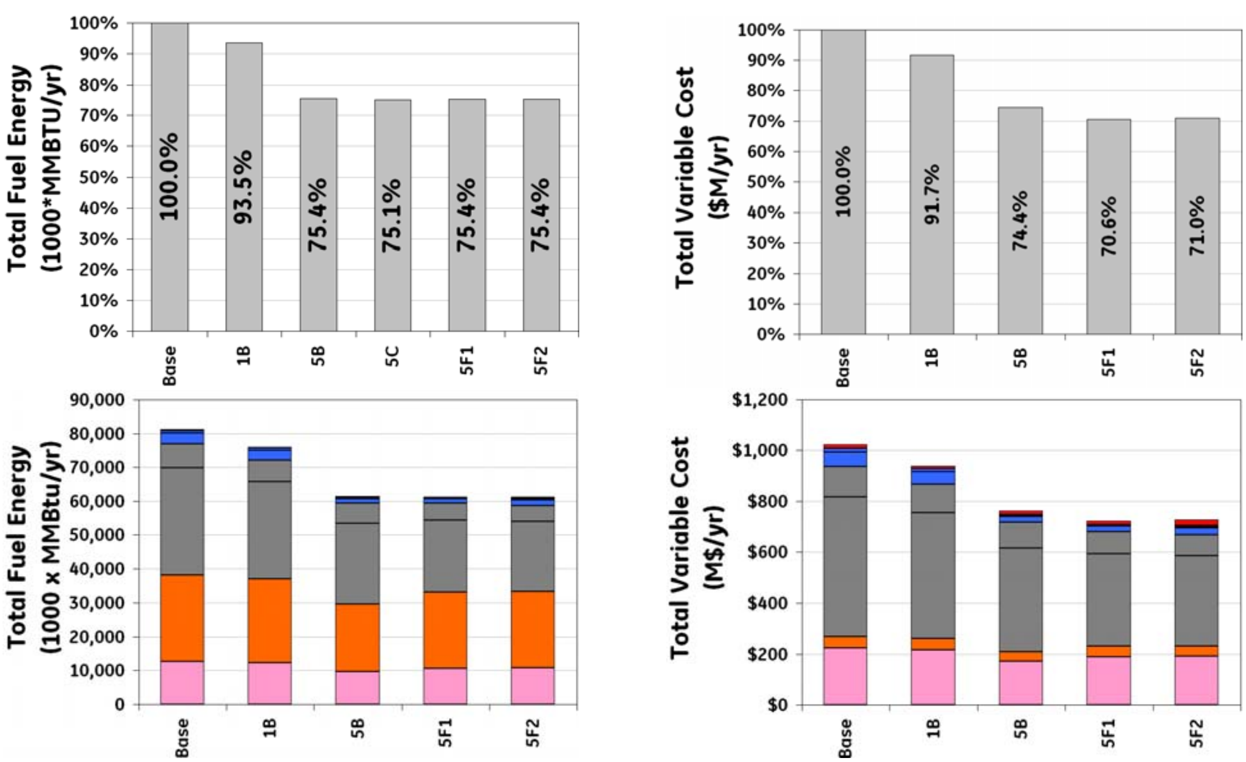


Figure 7-9. Scenario 5F2: Fuel energy and total variable cost of operation

7.4.1. Sensitivity to Solar Forecast

In this section, the incremental benefits of using a solar forecast are studied. So far, in all the scenarios, the unit commitment was based on meeting the load plus the up-reserve requirement minus the forecasted wind power. No forecast of solar was used. In the actual hour of dispatch, the units are backed down to accept available solar power not anticipated during the commitment stage. Thus, the system carries 1 MW of additional up-reserve for each 1 MW of solar power accepted as the thermal units back down to accept the solar power.

A perfect solar forecast is used to assess the entitlement of using a forecasting strategy for solar. As we include solar power in the forecast, the units will be committed to meet load minus forecasted wind minus forecasted solar plus the spinning reserve requirement. This will help in committing cycling units more optimally. Figure 7-10 shows the comparison between annual energy production by unit type. Less energy is dispatched from cycling units (by 0.3%) and an equal increase in energy is seen from the baseload units. However, the energy from fast-starting units increases as a result of more frequency violations of the reserve requirement. This occurs because fewer cycling units are committed, which provided a buffer between the reserve requirement and the reserve being carried on the system. The effects of a perfect solar forecast have the result of increasing the total variable cost of operation. Furthermore, the wind energy delivered remains the same because the curtailment of wind energy occurs primarily at night. Hence, using a solar forecast will not reduce wind curtailment during nighttime hours. In order for the variable cost to improve with a solar forecast it is recommended that an appropriate reserve requirement, including the variability of solar power be considered. This will serve to increase the up-reserve, and result in the commitment of cycling units, thereby reducing the number of expensive fast-starting events.

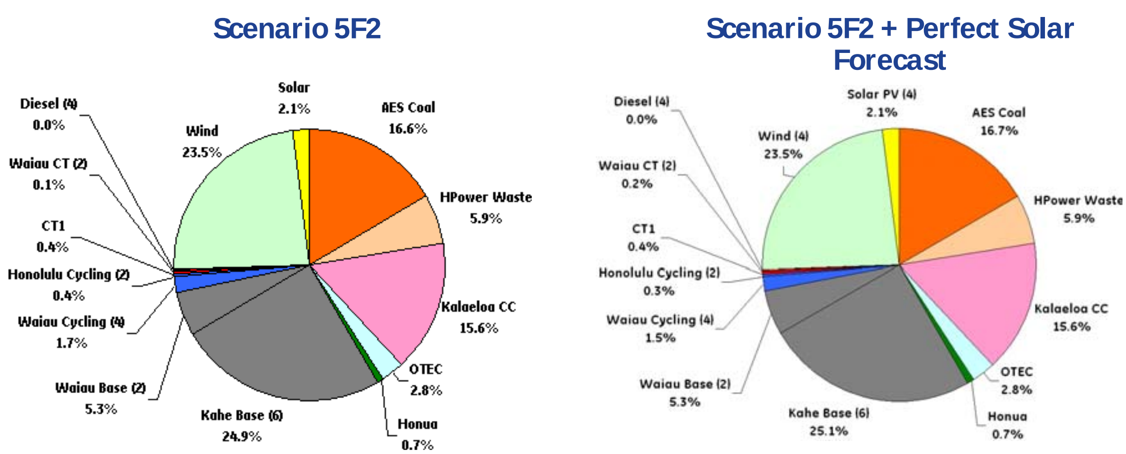


Figure 7-10. Scenario 5F2 with no solar forecast (left) and a perfect solar forecast (right). Annual energy production by unit type

Further, the regulating reserve function should be modified for the solar forecast, in a manner similar to estimating wind variability. Figure 7-11 shows that adding 100 MW of additional solar forecast did not significantly change the regulating reserve requirement. The maximum regulating reserve changes by only 2 MW (from a maximum of 82 MW to a maximum of 84 MW). On the other hand, adding on-island solar increases diversity and tends to flatten the variability curve.

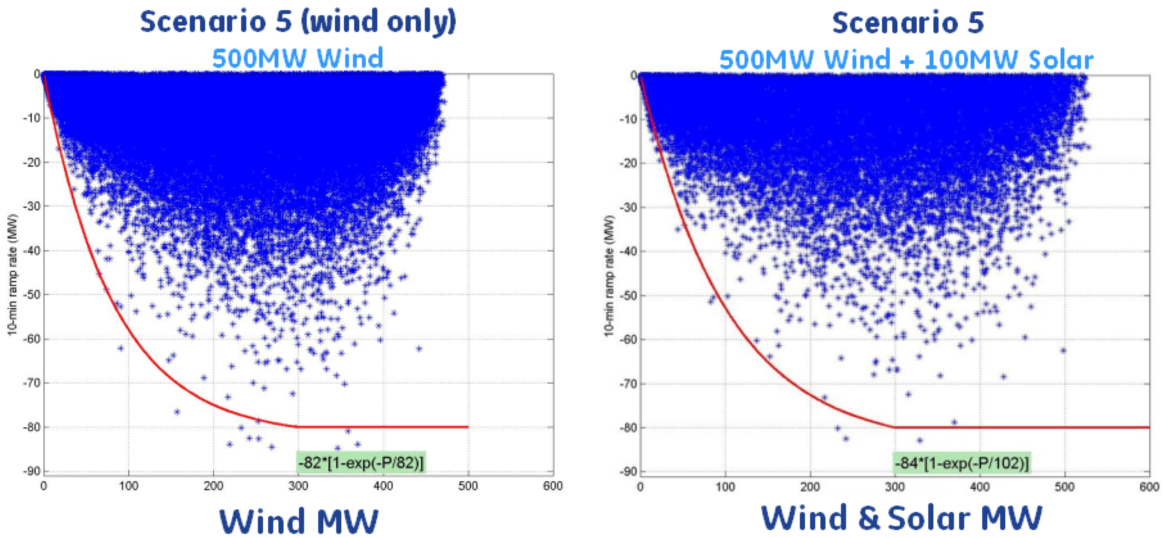


Figure 7-11. Regulating reserve function based on wind and solar forecast

With this small change in the regulating reserve function, the annual energy production by unit type remains the same (Figure 7-12). Wind energy delivered also does not show any change.

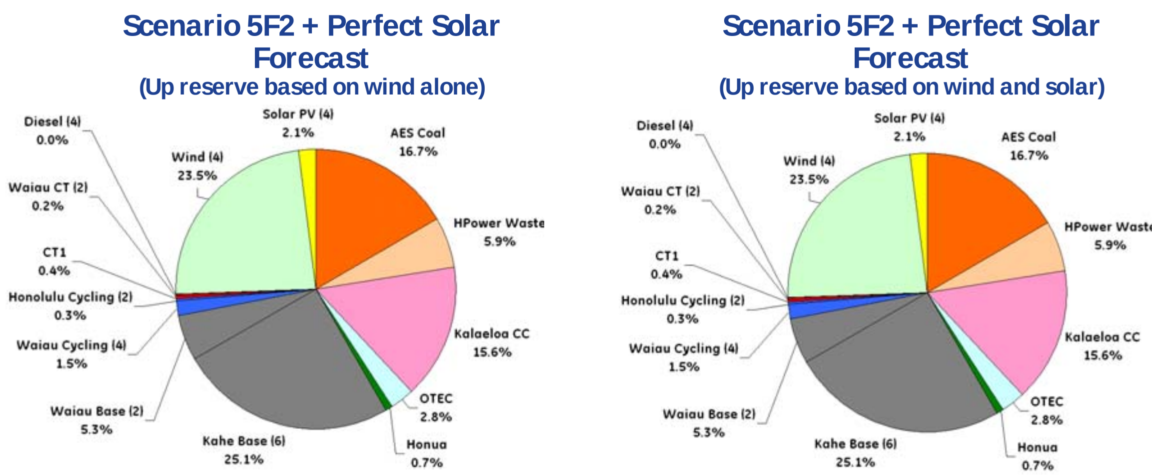


Figure 7-12. Scenario 5F2 with perfect solar forecast. The regulating reserve based on wind variability alone (left) and based on wind and solar variability (right). Annual energy production by unit type

7.5. Scenario 5F3: Reducing minimum power, seasonally cycling baseload units, and reducing the regulating reserve requirement

Thermal units are committed to meet net load and to satisfy the up-reserve requirement in an hour. The strategy presented in this section considers other resources that may be able to count towards the regulating reserve requirement so that the commitment from cycling units can be decreased and more wind energy can be delivered to the system.

HECO suggested that the existing water heater load control program might be able to contribute load relief for a short period, when triggered. The program that is currently in effect on the island of Oahu can allow for ~10 MW of load relief for ~ 15 minutes on an average, depending on the time of day and the load level. Therefore, this load management profile can contribute to the regulating reserve requirement and defer commitment of a thermal unit.

HECO also has ~220 MW of fast-starting generation capacity of which 108 MW can be online in 12 minutes. This generation is not counted during the commitment phase, when the other thermal units are reserved to provide up-reserve. It was suggested that capacity of one of the fast-starting generators (W9 or W10) could be counted towards the regulating reserves, if available during the hour. This would help to decrease the commitment of other thermal units (primarily the less efficient cycling units). It must be noted that CT-1 is the first fast-start unit to be committed to meet system demand but its startup is longer.

The residential water heater load control program (RDLC-WH) and a fast-starting generator were counted towards the up-reserve requirement in this scenario, decreasing the commitment of thermal units to meet system demand by their combined effects (load reduction and capacity). Figure 7-13 shows the modified regulating reserve requirement for this scenario.

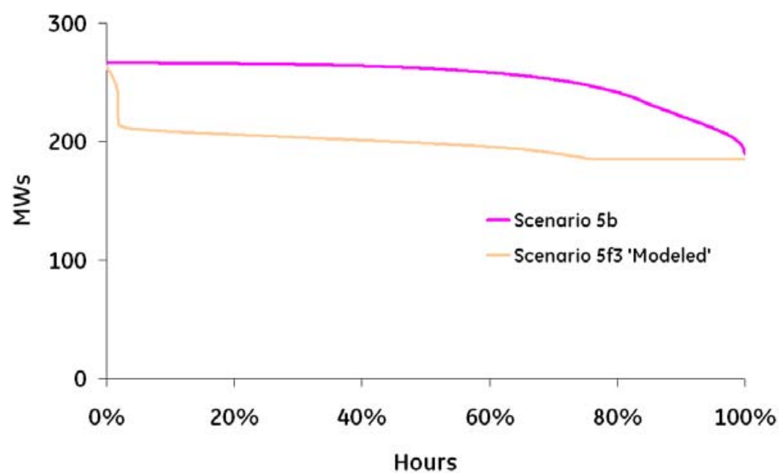


Figure 7-13. Scenario 5F3. Modified regulating reserve requirement in Scenario 5F3 compared to Scenario 5B

Figure 7-14 shows that the annual energy from the cycling units decrease by 0.7% as this strategy of reducing the regulating reserve is layered on the previous scenario (Scenario 5F2). The fast-starting energy from CT1 also moderately decreases (by 0.1%). This decrease in cycling and peaking energy is compensated by the increase in output from baseload units. The wind energy delivered remains unchanged because wind curtailment occurs primarily at night when the system carries excess reserve capacity despite only baseload units in operation. The energy delivered from different renewable energy plants shown in Table 7-10.

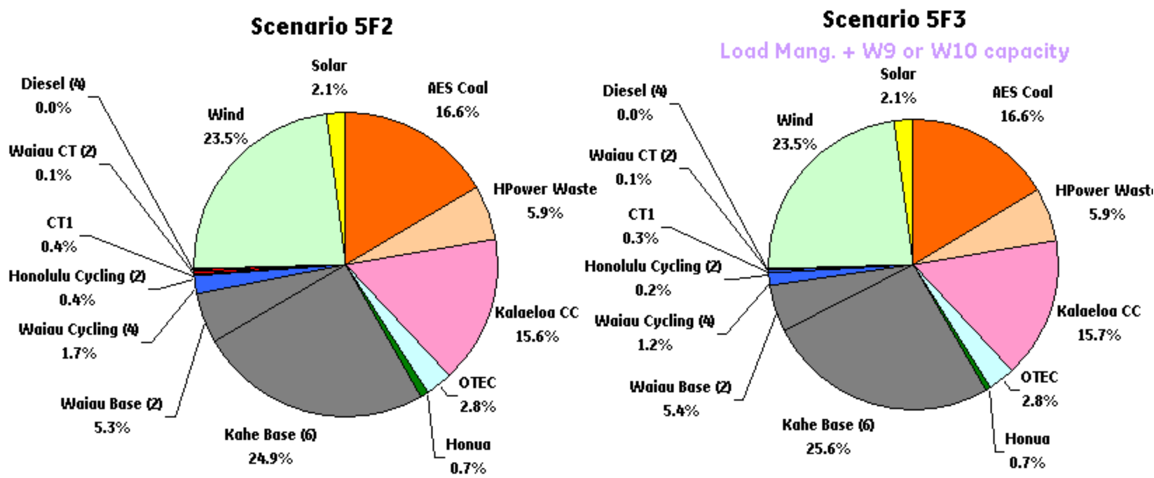


Figure 7-14. Scenario 5F3. Annual energy production by unit type

Table 7-10. Scenario 5F3. Renewable energy delivered

	5F1				5F2				5F3			
	Solar (100MW)	On-shore Wind (100MW)	Molokai (200MW)	Lanai (200MW)	Solar (100MW)	On-shore Wind (100MW)	Molokai (200MW)	Lanai (200MW)	Solar (100MW)	On-shore Wind (100MW)	Molokai (200MW)	Lanai (200MW)
Available Energy (GWHr)	162	358	716	855	162	358	716	855	162	358	716	855
Curtailed Energy (GWHr)	0	0	48	49	0	0	45	45	0	0	45	45
Delivered Energy (GWHr)	162	358	667	807	162	358	671	810	162	358	671	810
Capacity Factor (Available)	18%	41%	41%	49%	18%	41%	41%	49%	18%	41%	41%	49%
Capacity Factor (Delivered)	18%	41%	38%	46%	18%	41%	38%	46%	18%	41%	38%	46%

With a reduction in the regulating reserve requirement, the number of violations of this requirement is also seen to decrease. Violations are normally caused when the actual wind is lower than the forecast and a thermal unit must be committed to meet system demand. Violations of regulating reserve may also be observed when wind power suddenly drops within an hour. Under such conditions, fast-starting units are dispatched to maintain regulating reserve requirements.

As the regulating reserve requirement is reduced, the number of fast-start events is reduced as shown in Figure 7-15. The MW needed from the fast-starting units is also seen to decrease. The duration curve of dispatched fast-start MW is shown in Figure 7-16.

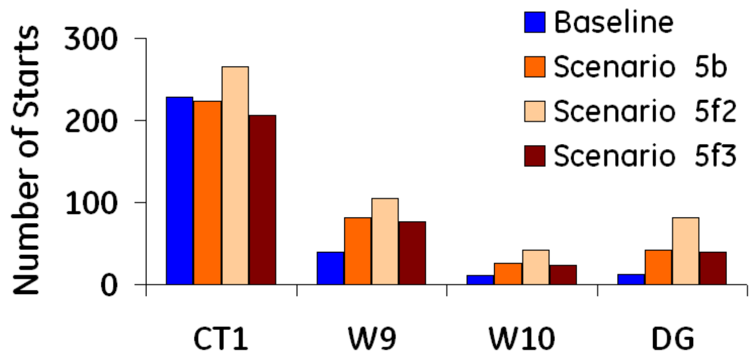


Figure 7-15. Scenario 5F3. Number of fast-start events by unit. Note that the number of fast-start events for the four Airport DGs are added together.

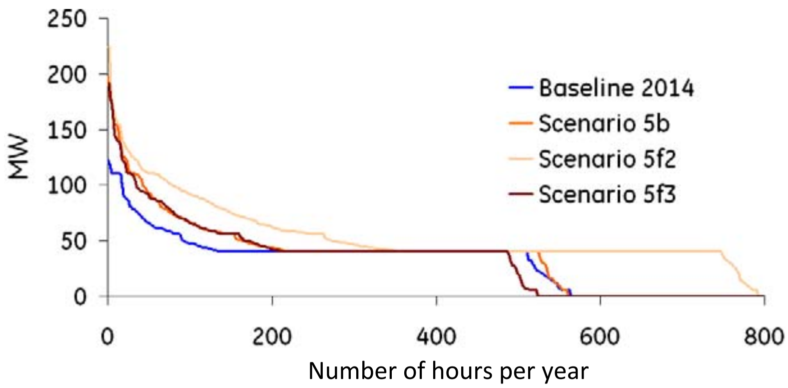


Figure 7-16. Scenario 5F3. Duration curve of fast-starting power from fast-starting units

Fuel consumption decreases from Scenario 5F2 to Scenario 5F3 by 0.4% (256,000 MMBtu) and the total variable cost of operation decreases by 1.4% ($10M). This is shown in Figure 7-17. This decrease occurs because expensive cycling and peaking energy is displaced by less expensive baseload energy.

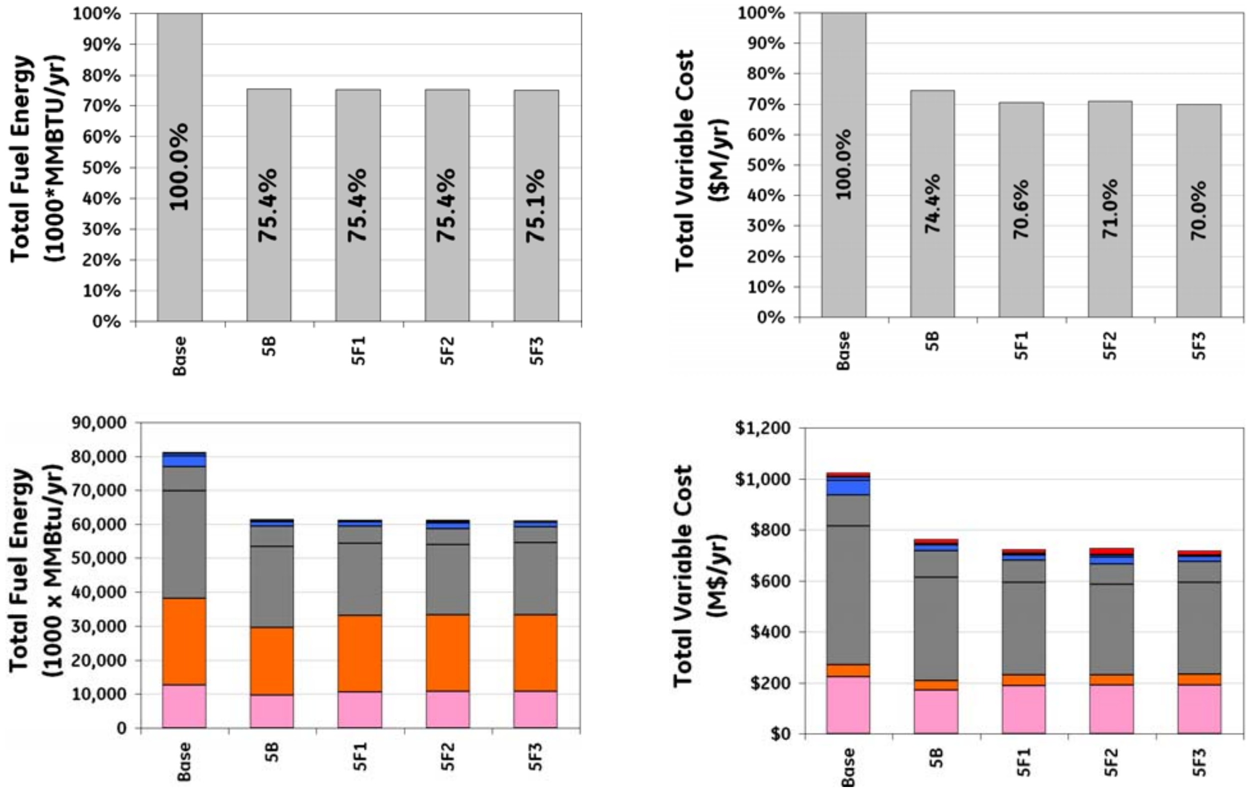


Figure 7-17. Scenario 5F3: Fuel energy and total variable cost of operation

7.6. Conclusions

As different strategies are layered on the baseline Oahu system of 2014, incremental benefits are observed in terms of:

- o Increased wind delivered to the system,
- o Reduced total variable cost of operation, and
- o Maintain system reliability.

These strategies were selected during weekly discussions with HECO on the basis that a feasible and reliable power system operation could be attained.

Figure 7-18 shows the incremental wind energy delivered to the Oahu grid as each strategy is layered on the previous strategy. All of the available solar energy is accepted in all scenarios.

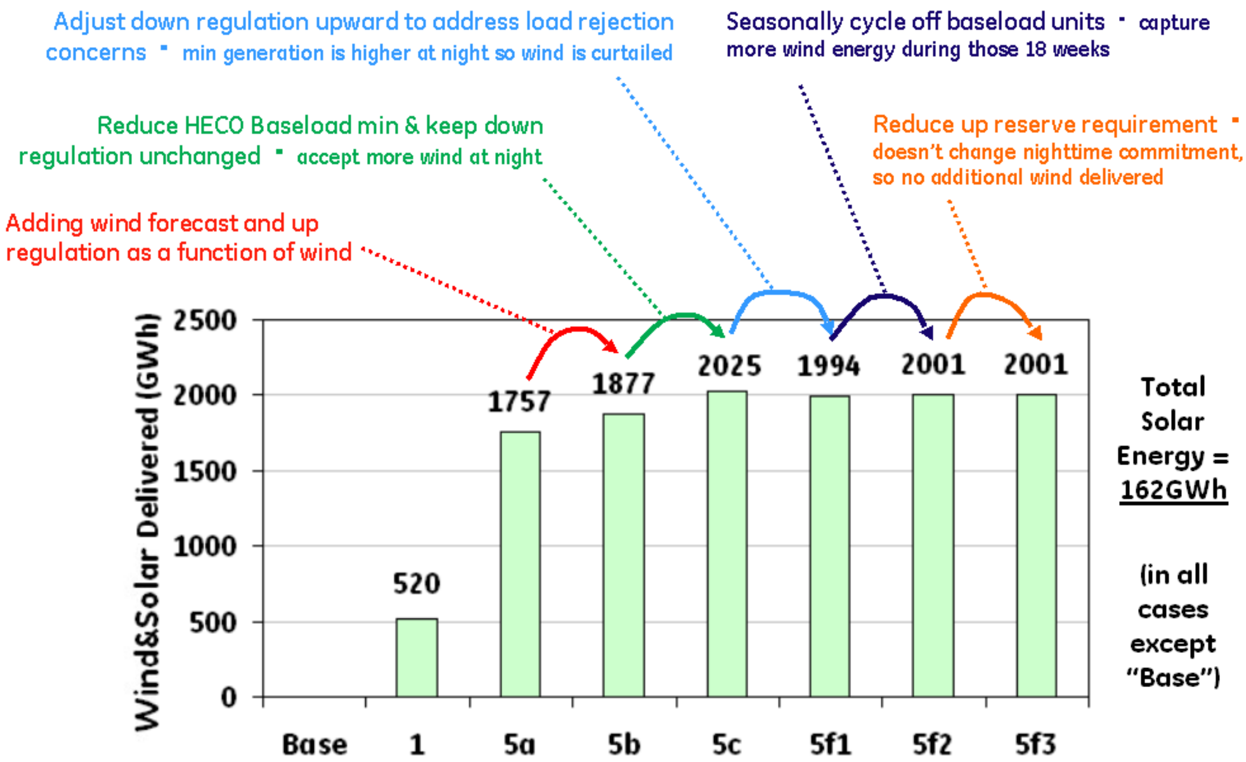


Figure 7-18. Renewable energy delivered under different scenarios

The high wind scenarios start with Scenario 5A, wherein the baseline system is subjected to 400 MW of off-island wind power, 100 MW of on-island wind power, and 100 MW of on-island solar power, without changing any operating rules. Thermal units are committed to meet load and no knowledge of wind/solar forecasting was included in the unit commitment. Therefore, in the actual hour, the committed thermal units are backed down to accept 1757 GWh of wind energy and 162 GWh of solar energy. When 4-hour wind forecasting technique and a modified regulating reserve requirement (as a function of 10 minute wind variability) is used in Scenario 5B, the system incrementally accepts 120GWhr of additional wind energy. As we move from Scenario 5B to Scenario 5C, the minimum power points of HECO baseload units are reduced, which further helps to increase wind energy delivered by 147 GWh. However, the down-reserve on the system was considered insufficient by HECO for reliable operation. This assumption was modified in Scenario 5F1, when the down-reserve was increased from 40 MW to 90 MW. This lead to a higher curtailment of wind during nighttime hours and therefore the wind energy delivered to the system decreased by 31GWhr. The next strategy (Scenario 5F2) was to seasonally cycle three baseload units, which helped relieve wind curtailment by 7 GWh during those 18 weeks. Finally, the regulating reserve requirement was reduced in Scenario 5F3 which helped to reduce the commitment of cycling units. Although this strategy did not help accept more wind energy, it did help to reduce the total variable cost of operation. In the end, wind curtailment energy was reduced to only 5% of available wind energy on Oahu.

Similarly, Figure 7-19 shows the effect on total variable cost of operation as different mitigation strategies are used in different scenarios. As more wind is accepted on the system, thermal energy is displaced by the zero incremental cost wind energy, which decreases the variable cost of operation. Fuel consumption across different units in different scenarios is also shown in the figure.

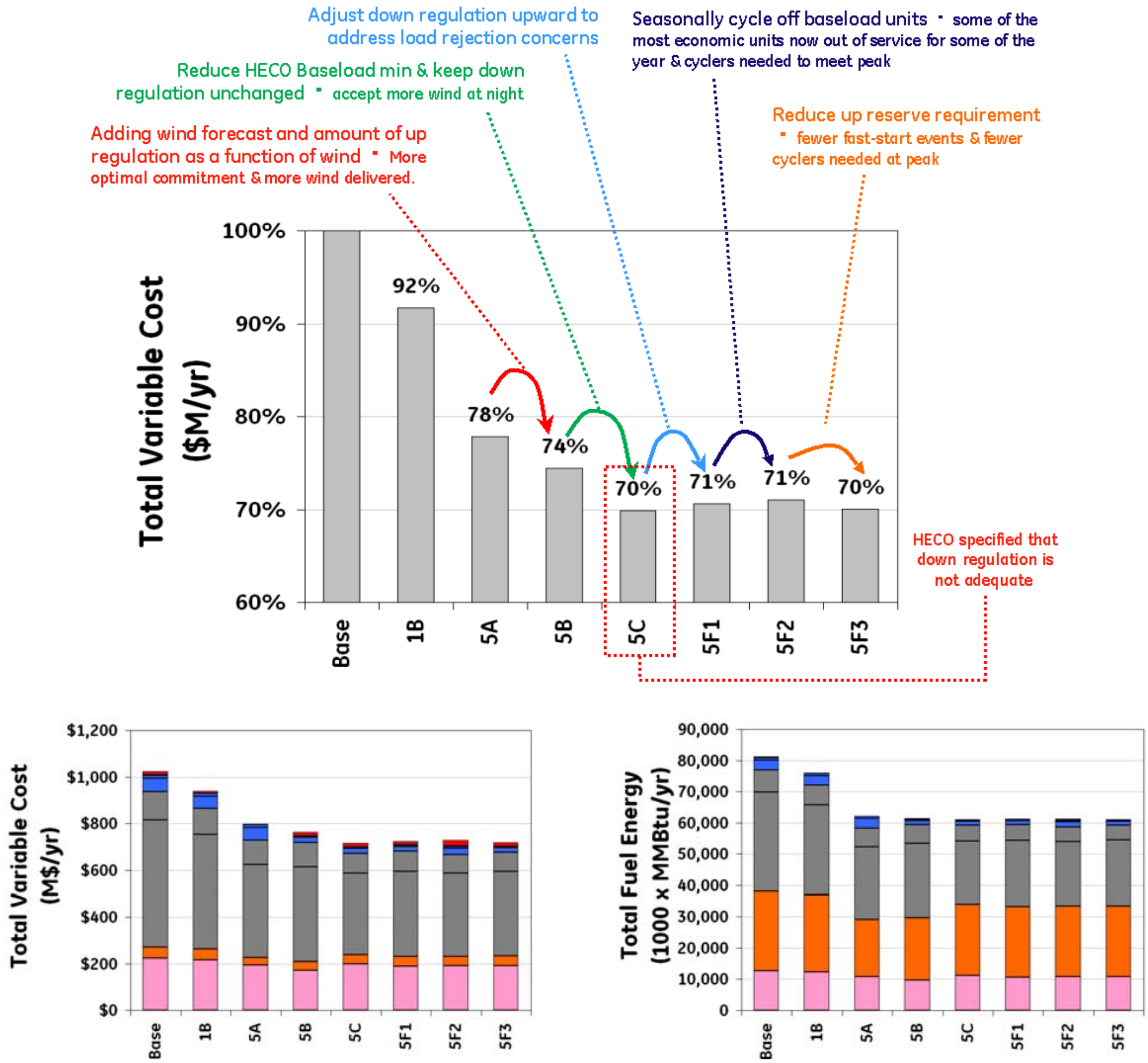


Figure 7-19. Total variable cost of operation and fuel consumption for each scenario

Starting with the high wind scenario (Scenario 5A), the total variable cost of operation decreased by 22% ($227M), as the thermal units back down to accept available wind and solar energy. Modeling a 4-hour wind forecast and with a modified regulating reserve requirement, the variable cost of operation decreased by another 4% ($41M). In Scenario 5C, minimum operating load for the reheat units was reduced, further decreasing the variable cost of operation by 4% ($41M). However, the specified down-reserve in this scenario was determined to be insufficient by HECO from a reliability standpoint. Therefore, in Scenario 5F1, the down-reserve was increased to 90 MW from 40 MW. With this, the variable cost of operation increased by 1% ($10M). In Scenario 5F2, seasonal cycling of baseload units helped to accept additional wind energy, but the cost of operation remained the same. The costs remain the same because zero variable cost wind energy displaces a portion of the baseload energy during seasonal cycling and more expensive cycling energy displaces the remaining portion. As a result the variable cost of operation exhibits marginal changes. In the last scenario (Scenario 5F3), the variable cost of operation is brought down to the level of Scenario 5C, although no additional wind was accepted. This was accomplished by counting other available resources to meet regulating reserve requirements, thus reducing the reliance on expensive cycling units. Scenario 3F considers off-island wind energy co-located on the island of Lanai. The strategies modeled are the same as in Scenario 5F.

7.7. *Scenario 3F1: Reducing minimum power of baseload units*

The minimum power points of the units were changed to the values presented earlier in Section 7.3. The heat rates at these new minimum power points were obtained from the original ABC equation. The minimum power points were changed to reflect a higher down-reserve requirement (90 MW), which is needed to sustain load rejection events. Figure 7-20 shows the comparison between Scenario 3B and Scenario 3F1 in terms of annual energy output from different thermal units as well as from the renewable energy plants. It should be noted that Scenario 3B is operated with a down-reserve of 40 MW, while the down-reserve in Scenario 3F1 is 90 MW. To enable the operation of thermal units with the aforementioned down-reserve requirement, capital expenditures will be required.

Figure 7-20 shows that baseload energy from the Waiau units decreased by 1.4% and by 3.6% at Kahe units, while AES and Kalaeloa increased their output by 1.9% and 1.5% respectively. The wind energy delivered increased by 1.5% (or 106GWh). The total wind energy delivered is 1808 GWh, which is similar to that observed in Scenario 5F1 (1832 GWh).

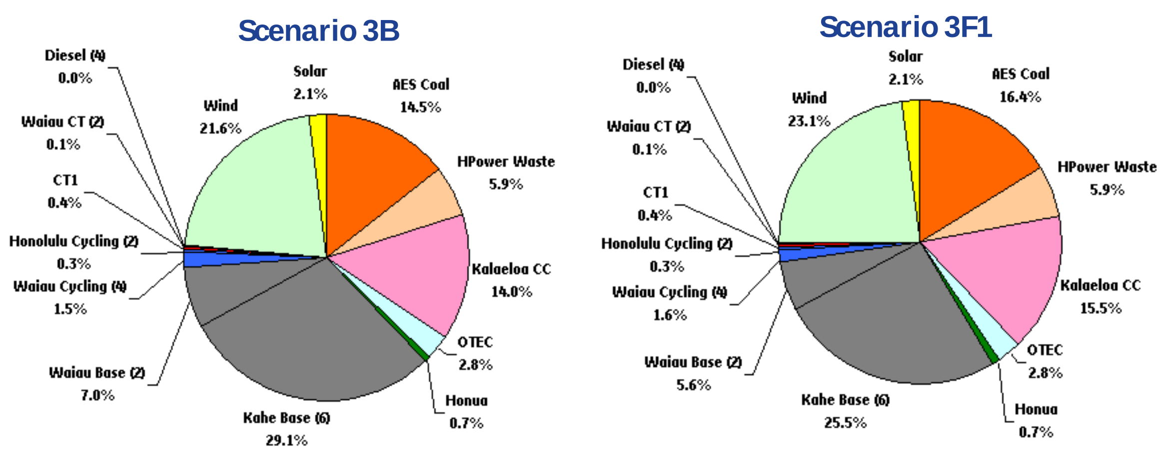


Figure 7-20. Scenario 3F1. Annual energy production by unit type

7.8. *Scenario 3F2: Reducing minimum power and seasonally cycling baseload units*

The scenario examined the impact of seasonally cycling baseload units. Three baseload units were seasonally cycled for 6 weeks each. The details were presented earlier in Section 7.4. Figure 7-21 shows that a moderately more wind energy was delivered in Scenario 3F2 as compared to Scenario 3F1. The cycling energy increased slightly because cyclers were needed to meet the load during periods of baseload cycling.

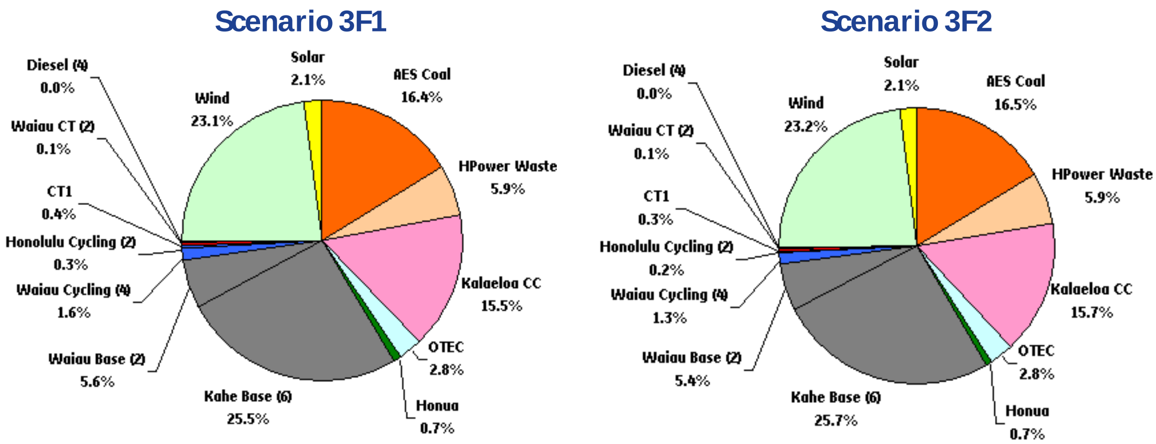


Figure 7-21. Scenario 3F2. Annual energy production by unit type

7.9. Scenario 3F3: Reducing minimum power and seasonally cycling baseload units, and reducing the regulating reserve requirement

This section considered the effect of reducing the regulating reserve requirement on the thermal units by utilizing available resources such as water heater load control program and a fast-starting unit capacity towards meeting this requirement. Figure 7-22 shows that although the amount of wind energy delivered remained the same, the thermal energy from cycling units decreased, which had the effect of reducing the variable cost of operation.

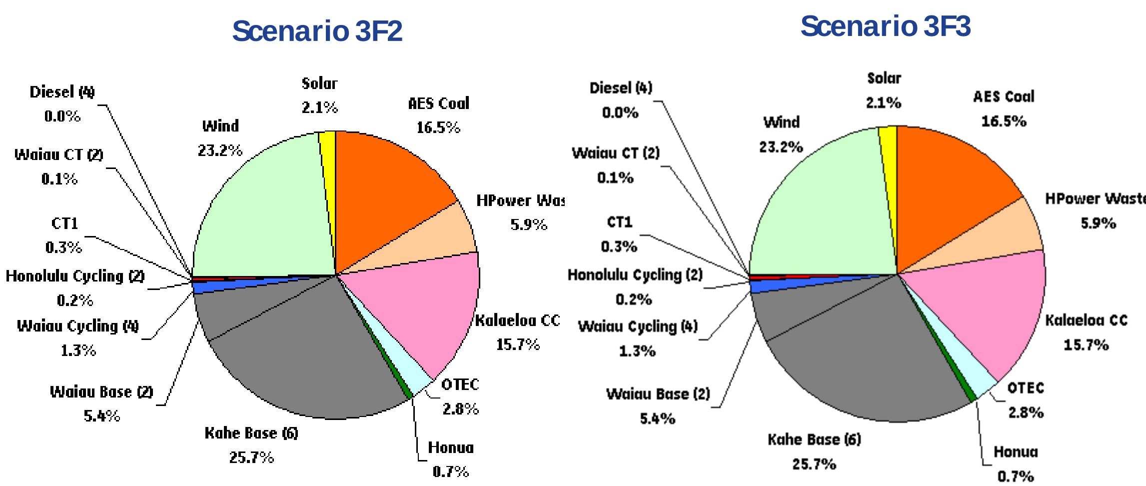


Figure 7-22. Scenario 3F3. Annual energy production by unit type

In summary, the level of wind energy delivered in Scenario 3F was similar to that of Scenario 5F, as shown in Figure 7-23. The total variable cost of operation was also similar. The small differences could be attributed to the wind resources and different levels of regulating reserves for the two scenarios. Recall that the regulating reserve for Scenario 3 is higher than that of Scenario 5 because of the greater variability observed when the wind plants were co-located on Lanai. The total variable cost and fuel consumption is shown in Figure 7-24.

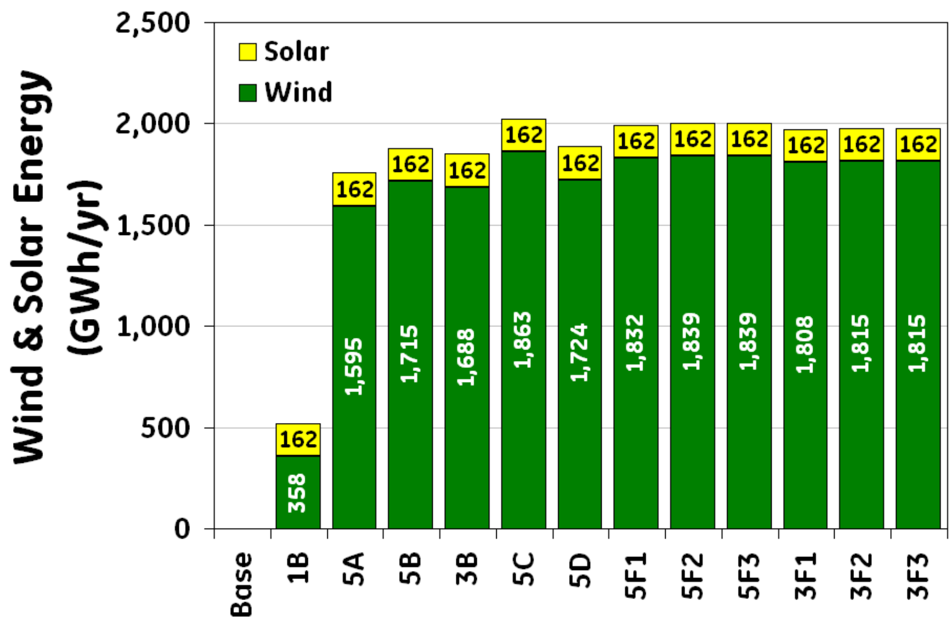


Figure 7-23. Delivered wind energy plus solar energy for each scenario

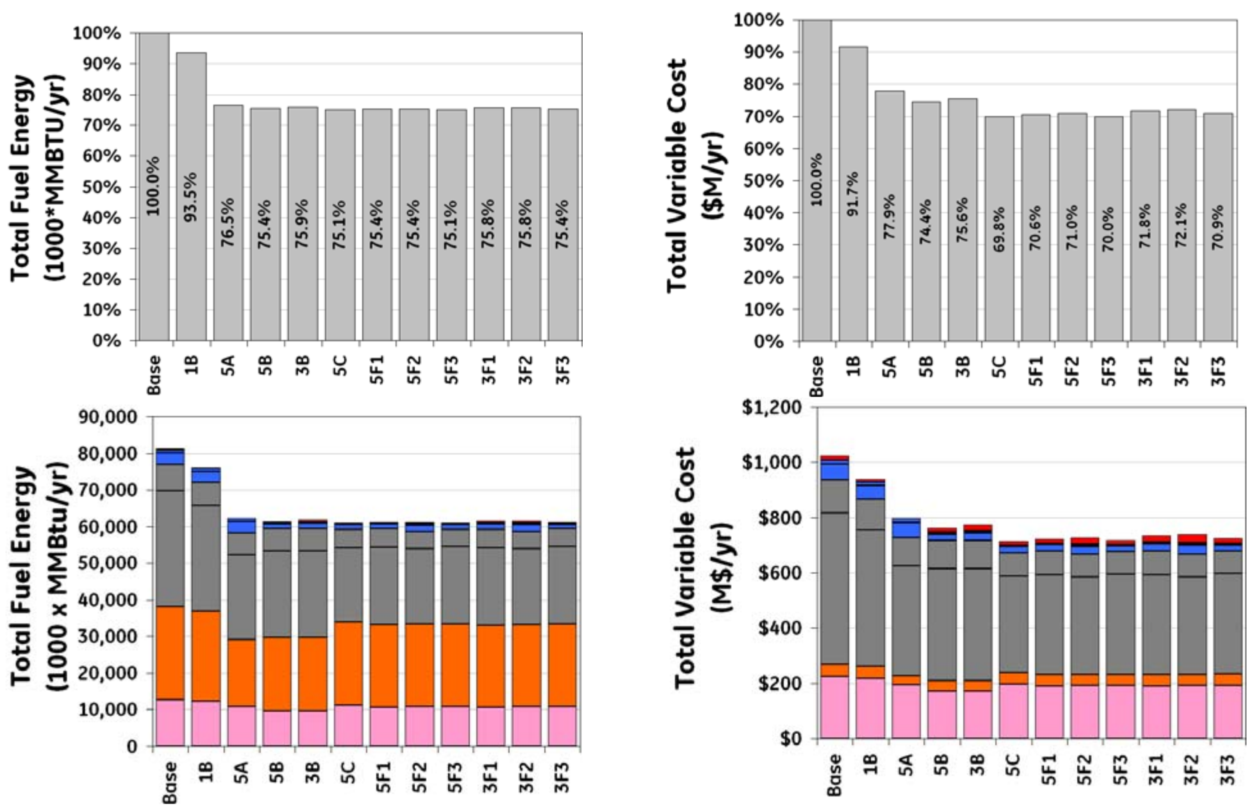


Figure 7-24. Total annual variable cost and fuel consumption for each scenario

7.10. Conclusions

A number of proposed system modifications were staged in series to observe the relative impact of each approach. The results are shown in Figure 7-25 for Scenario 5. Recall that Scenario 5 consists of 500 MW of wind power and 100 MW of solar power built upon the Baseline 2014 scenario without any modifications to the present Oahu system.

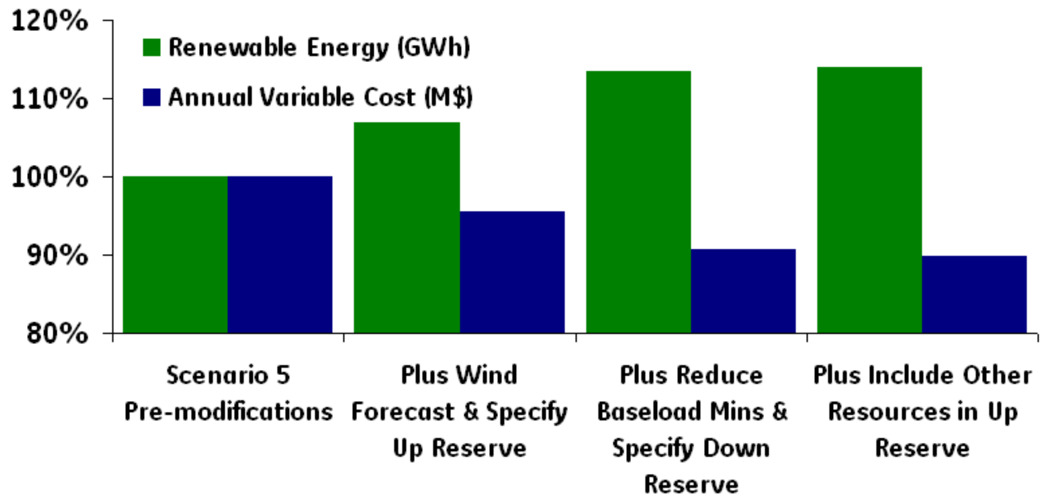


Figure 7-25. Scenario 5. Reduction in variable cost and increase in wind and solar energy delivered for staged strategies.

Results of the study indicate that, with all strategies implemented, LSFO displaced by the modeled renewable energy resources was 17,212,000 MMBtu per year for Scenario 3F3 and 17,509,000 MMBtu per year for Scenario 5F3; reducing LSFO consumption by 2.7 and 2.8 ***million*** barrels per year, respectively.

The proposed system modifications are summarized below:

Strategy #1: Wind power forecasting and specifying regulating reserve

- Incorporate state-of-the-art, 4-hour wind power forecasting in the unit commitment
- Increase the spinning reserve to add a regulating reserve requirement based on the strategy described in Figure 7-26 to help manage sub-hourly wind variability and uncertainty in wind power forecasts

These strategies increased the wind energy delivered to the system by 7% and reduced the annual variable cost by 4%.

Strategy #2: Reducing thermal unit minimum power and specifying down-reserve

- Reduce minimum stable operating power of seven HECO baseload units by a total of ~130 MW
- Implement a down-reserve requirement (modeled as effectively 90 MW) to address plausible load rejection events

These strategies further increased the wind energy delivered (to 14%) and further decreased the annual variable cost (to 9%). Note that cycling off a single baseload unit at a time for a total of

18-weeks during the year was included in this strategy, but only had a small effect on increasing the delivery of renewable energy and negatively affected the total variable cost of operation since more energy from the more expensive cycling units was needed during these 18-weeks.

Strategy #3: Refine regulating reserve to include other resources that can provide reserve capacity

- Reduce the previous regulating reserve requirement to include other resources, such as fast-start units as well as load control programs.

Modifying the regulating reserve requirement did not increase the wind energy delivered but reduced the variable cost of operation as compared to Strategy #2.

7.10.1.1. Strategy #1: Specifying reserve requirements and Wind power forecasting

The Oahu power system maintains 185 MW of spinning reserve to cover for a loss of the largest unit, the AES coal plant. It was assumed that the spinning reserve was unchanged when AES was not in operation. In addition to the spinning reserve, the study examined increasing the up-reserve by a regulating reserve to mitigate the sub-hourly wind variability events. This additional regulating reserve is a function of 10-minute wind power variability before another unit can be started. One approach considered all of the wind power drops over 10 minute intervals for two years of wind power data. All of these events are shown in Figure 7-26 as a function of the total wind power production at the start of each interval.

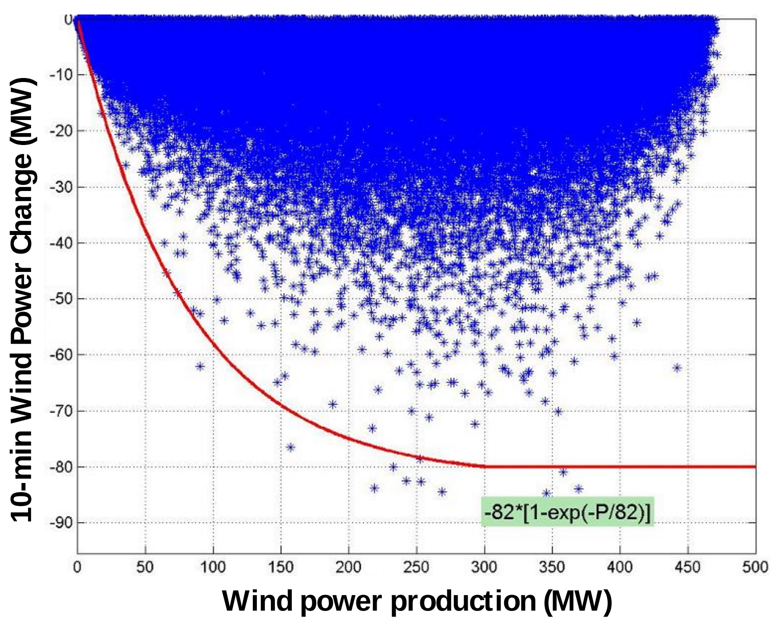


Figure 7-26. Total wind power changes over 10 minute intervals in Scenario 5 (two years of simulated wind power data from AWS Truepower).

The wind power drops are relatively modest at both high and low levels of wind power production. At these levels of wind power production, a change in wind speed has a moderate effect on overall wind power changes. In contrast, at mid-range wind power production levels, the same change in wind speed can result in larger changes in wind power as shown in Figure

7-26. It was decided by the team that in addition to the 185 MW of spinning reserve, the Oahu system would also carry a regulating reserve based on the red curve shown in Figure 7-26. The curve is an estimation of required on-line reserves to compensate for the majority of the 10-minute drops in wind power. Data for 10-minute intervals was analyzed as opposed to 60-minute interval data based on the startup times of the fast-starting units. The fast-starting generation could be brought on-line in less than an hour during relatively large wind power drop events that begin to consume the up-reserve. The 4-hour wind power forecast was used in both the unit commitment and in specifying the regulating reserve requirement based on the equation shown in Figure 7-26.

In addition to forecasting the load (net of any forecasted wind power), HECO must also commit units to ensure adequate up-reserve is available. By monitoring the wind power variability (10-minute changes) and correlating this to the level of wind power available on the system, the operators can refine the relationship between regulating reserve (based on 10-minute wind power changes) and the available wind power (per the wind power forecast) to ensure that adequate reserves are carried to cover for sub hourly wind variability.

Presently, cycling units are committed on a day-to-day basis to meet system demand, primarily to meet spinning reserve requirements. In the scenario analysis, wind power forecasting was modeled to refine the unit commitment strategy and reduce the commitment of cycling units. In this case, the thermal units would be committed to meet the load plus the up-reserve less the amount of forecasted wind power. On occasion, discrepancies between the wind power forecast and the available wind power could result in less efficient thermal unit operation. In general, wind power forecasts reduced the number of hours of operation of the cycling units on the HECO system, which improved the variable cost of operating the system. However, these benefits are partially offset by more frequent fast-starting events due to errors in forecasted wind power.

Wind power forecasting and refining the regulating reserve based on the expected wind power variability increased the wind energy delivered by 7.5% and reduced the total variable cost by 3.4%.

7.10.1.2. Strategy #2: Reducing thermal unit minimum power and specifying down reserve

A separate study effort by HECO evaluated the base loaded reheat units for various modes of off-line cycling duty and low load operation. As a result, improved unit turndown in the range of 5:1 and 6:1 was modeled for Kahe Units 1 through 5 and Waiau Units 7 and 8. A comparison between two cases (5B and 5C) was performed. In 5C, the minimum power of the Kahe Units 1 through 5 and Waiau Units 7 and 8 were reduced based on input from HECO. The results are shown in Figure 7-27. In 5B and 5C the impact of reducing the minimum power of the HECO thermal units was examined. The minimum power of seven out of the ten baseload thermal units were reduced by ~18 MW on each plant. These seven units provide, on average, about 36% of the island's energy. A 70% reduction in wind energy curtailment (149GWh/yr) was observed. In addition, by reducing the minimum power of the HECO baseload units, the energy production from the most economic thermal units could be increased during the hours of lower wind energy availability. These two factors results in a 4.6% variable cost savings (see Figure 7-28). It should be noted that the effective down-reserve was ~35 MW in these simulations; less than the effective down-reserve of ~90 MW later specified by HECO based on the results of dynamic performance assessments performed for this study.

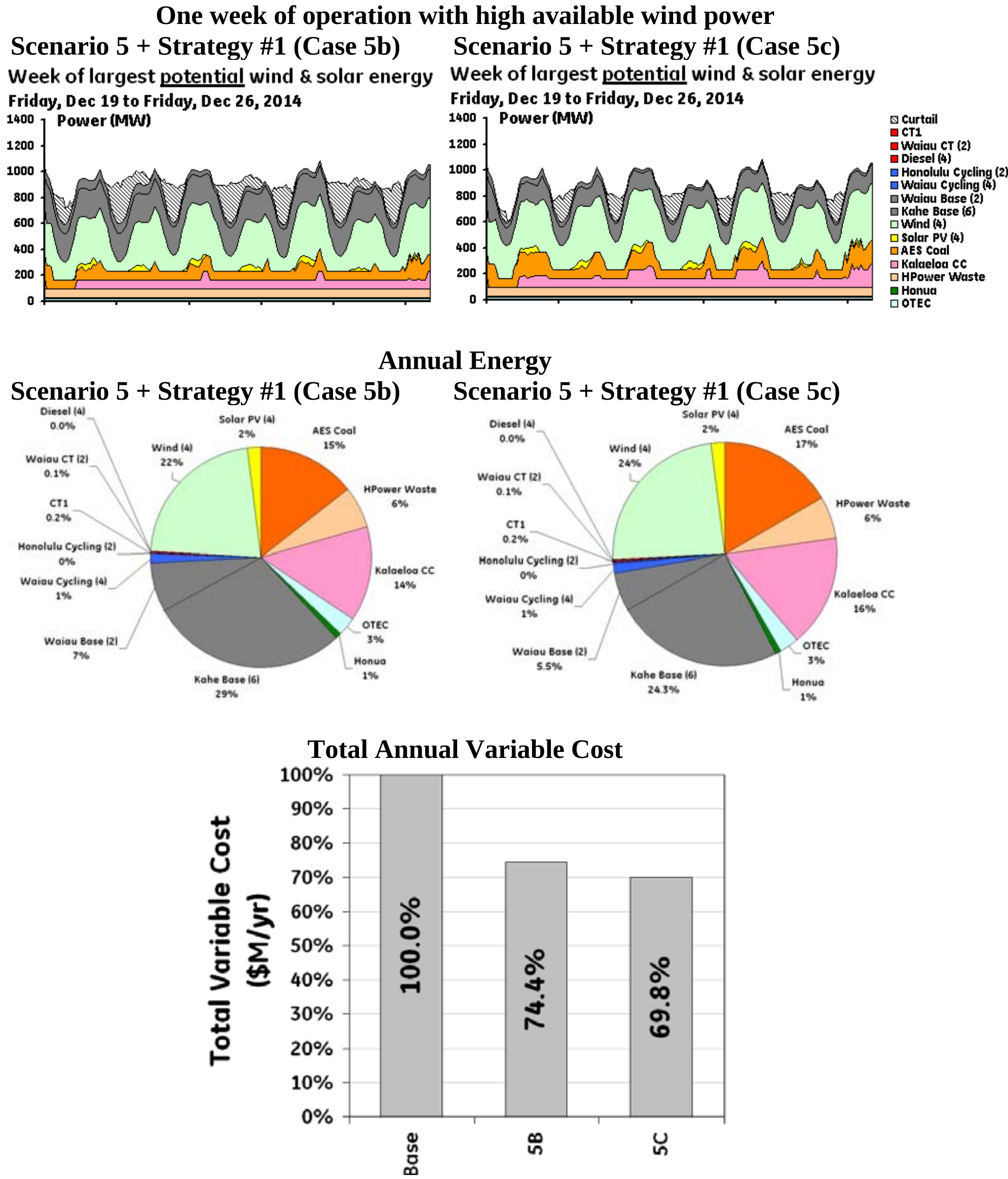


Figure 7-27. Summary of total variable cost savings and energy

Presently, HECO reheat units are dispatched to their minimum loads during the system minimum load periods when transmission lines are lightly loaded. As such, the impact of a loss-of-load event is minimal so the initial down-reserve requirement was set to ~40 MW to account for the contingency event on the loss of a 46KV distribution circuit. Following simulation of this scenario, results indicate that the majority of the reheat units operate at their minimum loads for significant hours of the year, thereby increasing the system's exposure to a severe loss-of-load event. As a result, the down-reserve requirement was increased to 90 MW for loss of a 138kV transmission circuit.

The Scenario 5 + Strategy #1, with ~40 MW of down reserve was compared to a second case (Scenario 5 + Strategy #1 and #2). Comparing these two cases provided the estimated impact of reducing the minimum power of some thermal units while increasing the down-reserve requirement to a more appropriate value. The results are shown in Figure 7-28 and in Table 7-11. The implementation of Strategy #2 increased the annual wind energy delivered by 6% beyond Scenario #5 + Strategy #1.

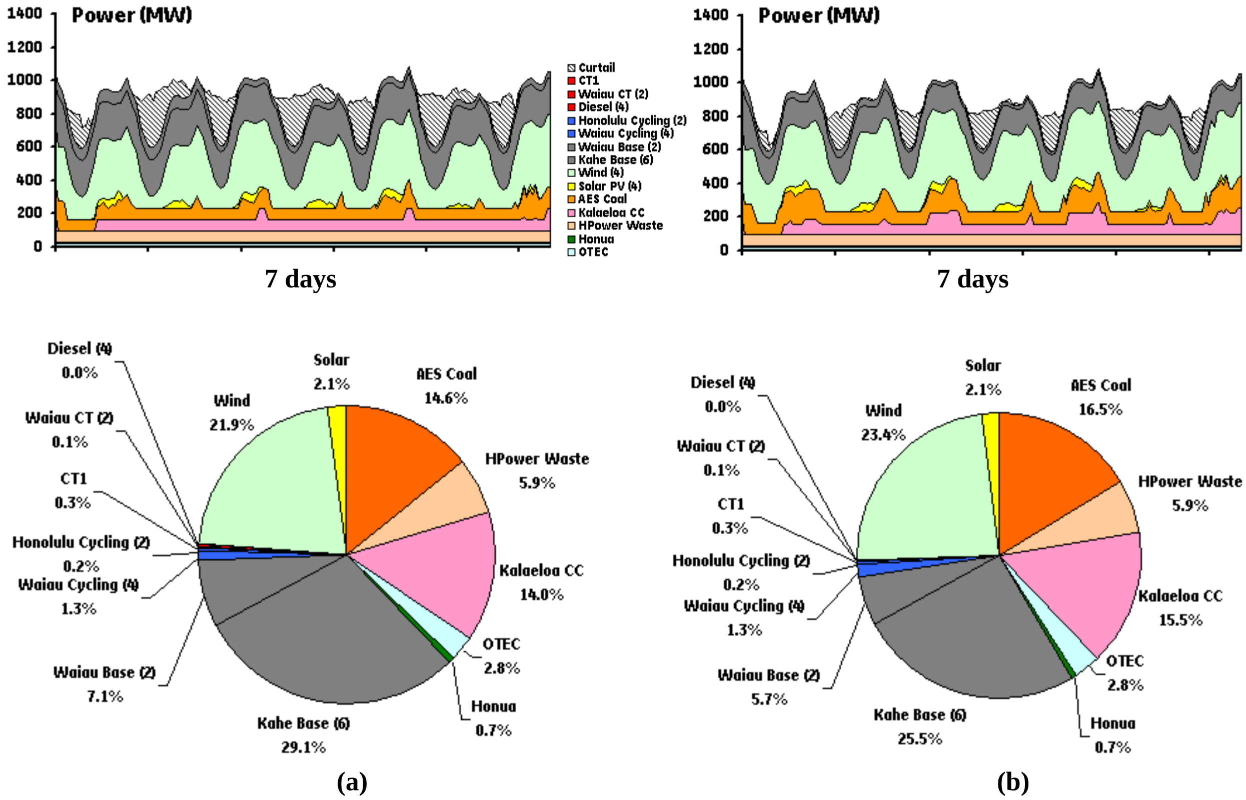


Figure 7-28. Impact of reducing the minimum operating power of 7 HECO baseload units and increasing the down-reserve requirement from ~40 MW to ~90 MW. Comparison of seven days of production during the week of highest available wind power and annual energy production for: (a) Scenario 5 + Strategy #1, and (b) Scenario + Strategy #1 and #2

Table 7-11. Summary of results for the cases showing reduced HECO thermal unit minimums and higher down-reserve requirement

	Effective Down Reserve (allocated per unit) (MW)	Reduced HECO Baseline Unit Min Power	Annual Fuel Energy (1000 x MMBtu/yr)	Total Annual Variable Cost w.r.t. Baseline 2014 Scenario	Average HECO Unit Heatrate (Btu/kWh)	Corrected Average HECO Unit Heatrate (Btu/kWh)[1]
Strategy 1 (Case 5B)	40	N	61,344	74%	10,601	10,728
Strategy 1 (Case 5C)	40	Y	61,065	70%	10,930	11,061
Strategy 1 + Strategy 2	90	Y	61,267	71%	10,839	10,969

[1] Corrected heat rate is 1.2% higher than simulated (calibrated based on 2007 baseline model validation)

Note that the average heat rate for HECO units is slightly higher than that of Scenario 5 because seven HECO baseload units are operating at a lower, less efficient operating load. For purposes of this study, the existing heat rate curves were extrapolated to these lower operating points to allow proper unit dispatch. It is anticipated by HECO that capital improvement projects required to obtain these lower minimum loads should provide heat rate improvements over the unit's entire operating range. As such, the results on fuel consumption and total variable cost savings may be conservative.

7.10.1.3. Strategy #3: Refine the regulating reserve to include other contributing resources

The current operating policy is to carry a minimum spinning reserve sufficient to cover for the loss of the largest generating unit at all times. This spinning reserve requirement was increased to add a regulating reserve component intended to cover the sub-hourly wind variability events. A number of different technologies and operating strategies can contribute to meet the regulating reserve requirements of the system. Two approaches considered in this study are: (1) HECO's residential direct load control program for water heaters (RDLC-WH), and (2) the fast-starting generating units like Waiau Units 9 and 10. Leveraging these resources, the system operator can reduce the amount of total reserve carried by the system resulting in a lower system-wide variable cost. Experience with actual wind variability, wind forecasting, expansion of load control programs, and additional quick-start resources will help HECO refine and optimize system reserve requirements over time.

In Scenario 5, the regulating reserve requirement was met by a combination of traditional thermal generation, the RDLC-WH program's load profile, and the nameplate capacity of Waiau 9 or 10 (approximately 50 MW). This reduced the number of commitments of additional cycling units to meet system reserve requirements resulting in fuel consumption and total variable cost savings of approximately 1% (see Figure 7-29).

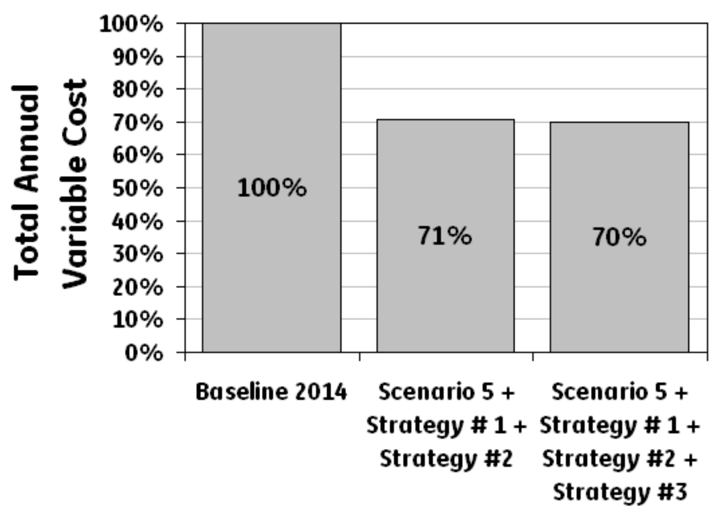


Figure 7-29. Total variable cost associated with reducing the regulating reserve to account for fast-starting generation and load control programs

On the Oahu system, wind energy curtailment occurred primarily when the system was at its minimum load and only the baseload units remained online, operating at their unit minimum loads. Therefore, Strategy #3 has no impact on the amount of wind energy that can be delivered to the system.

7.10.1.4. Summary of key results

Table 7-12 shows the energy from different thermal units and from renewable energy plants for each scenario. The energy from the cycling units decreased the most (with reference to the baseline case), followed by Kahe and Waiau baseload units, and then followed by AES and Kalaeloa. No solar energy is curtailed in any scenario.

Table 7-12. Annual energy by unit type under different scenarios

Energy	SCENARIO												
(GWh / yr)	Base	1B	5A	5B	3B	5C	5D	5F1	5F2	5F3	3F1	3F2	3F3
AES Coal	1,468	1,429	1,021	1,139	1,134	1,309	1,145	1,290	1,297	1,298	1,283	1,289	1,291
HPower Waste	460	460	460	460	460	460	460	460	460	460	460	460	460
Kalaeloa CC	1,456	1,409	1,206	1,092	1,093	1,275	1,104	1,213	1,223	1,225	1,216	1,225	1,230
OTEC	219	219	219	219	219	219	219	219	219	219	219	219	219
Honua	53	53	53	53	53	53	53	53	53	53	53	53	53
Kahe Base (6)	3,152	2,815	2,224	2,276	2,276	1,898	2,229	1,997	1,950	2,001	1,996	1,951	2,012
Waiau Base (2)	656	603	549	551	551	429	537	442	413	421	441	411	421
Waiau Cycling (4)	269	244	259	104	121	104	121	104	132	94	121	150	104
Honolulu Cycling (2)	62	52	62	17	21	17	24	17	27	17	21	31	18
CT1	22	13	1	23	32	22	32	22	33	22	31	41	26
Waiau CT (2)	4	2	1	6	9	6	10	6	11	6	9	14	8
Diesel (4)	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind	0	358	1,595	1,715	1,688	1,863	1,724	1,832	1,839	1,839	1,808	1,815	1,815
Solar	0	162	162	162	162	162	162	162	162	162	162	162	162
HECO Thermal Units	**4,165**	**3,729**	**3,097**	**2,978**	**3,011**	**2,477**	**2,952**	**2,589**	**2,567**	**2,561**	**2,620**	**2,599**	**2,590**
Wind & Solar	**0**	**520**	**1,757**	**1,877**	**1,850**	**2,025**	**1,886**	**1,994**	**2,001**	**2,001**	**1,970**	**1,977**	**1,977**
Other IPPs	**3,656**	**3,569**	**2,958**	**2,962**	**2,959**	**3,316**	**2,980**	**3,234**	**3,252**	**3,255**	**3,231**	**3,246**	**3,252**

The fuel consumption from different units is highlighted in Table 7-13. Fuel consumption follows a similar trend as the energy output from different thermal units.

Table 7-13. Annual fuel consumption by unit type in different scenarios

Fuel	SCENARIO											
(MMBtu*1000 / yr)	Base	1B	5A	5B	3B	5C	5F1	5F2	5F3	3F1	3F2	3F3
AES Coal	25,443	24,792	18,148	20,067	19,999	22,840	22,521	22,652	22,666	22,416	22,510	22,544
Kalaeloa CC	12,609	12,242	10,901	9,704	9,721	11,157	10,678	10,761	10,778	10,710	10,787	10,820
Kahe Base (6)	31,774	28,600	23,142	23,616	23,615	20,222	21,102	20,561	21,042	21,090	20,586	21,157
Waiau Base (2)	7,013	6,511	6,001	6,023	6,023	4,923	5,043	4,699	4,775	5,032	4,687	4,777
Waiau Cycling (4)	3,307	2,994	3,210	1,281	1,489	1,281	1,281	1,627	1,158	1,491	1,841	1,277
Honolulu Cycling (2)	765	639	765	207	257	207	207	337	206	257	386	225
CT1	346	216	18	361	501	351	351	522	340	490	641	412
Waiau CT (2)	47	26	9	82	121	82	82	139	79	119	182	104
Diesel (4)	1	0	0	2	2	2	2	3	1	2	3	1
HPower Waste	-	-	-	-	-	-	-	-	-	-	-	-
Honua	-	-	-	-	-	-	-	-	-	-	-	-
OTEC	-	-	-	-	-	-	-	-	-	-	-	-
Wind	-	-	-	-	-	-	-	-	-	-	-	-
Solar	-	-	-	-	-	-	-	-	-	-	-	-
Total (All Units)	**81,305**	**76,021**	**62,193**	**61,344**	**61,729**	**61,065**	**61,267**	**61,301**	**61,045**	**61,607**	**61,624**	**61,317**
Total (HECO Units)	**43,253**	**38,987**	**33,144**	**31,573**	**32,009**	**27,069**	**28,067**	**27,888**	**27,601**	**28,481**	**28,327**	**27,953**

The heat rate by unit type is shown in Table 7-14. The average heat rate of the thermal units tended to decrease as more and more wind energy is accepted. This occurs because the thermal units operate at lower (inefficient) power outputs for more hours of the year. This is confirmed in Table 7-15, which shows increased number of hours when the baseload units operate at minimum power levels. However, strategies such as wind forecasting and reducing the reserve requirement helped avoid the commitment of thermal units and tended to improve the heat rate of the system.

Table 7-14. Heat rate by unit type in different scenarios

Average Heat Rate (Btu/kWh)	SCENARIO											
	Base	1B	5A	5B	3B	5C	5F1	5F2	5F3	3F1	3F2	3F3
AES Coal	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Kalaeloa CC	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Kahe Base (6)	10,081	10,161	10,403	10,374	10,374	10,655	10,566	10,545	10,515	10,567	10,551	10,514
Waiau Base (2)	10,694	10,791	10,933	10,925	10,925	11,486	11,399	11,388	11,349	11,403	11,393	11,346
Waiau Cycling (4)	12,277	12,287	12,395	12,293	12,295	12,287	12,289	12,291	12,281	12,290	12,298	12,282
Honolulu Cycling (2)	12,261	12,253	12,261	12,254	12,242	12,254	12,254	12,282	12,285	12,242	12,270	12,274
CT1	16,084	16,329	15,691	15,750	15,875	15,738	15,738	15,614	15,743	15,865	15,688	15,902
Waiau CT (2)	13,016	12,982	13,011	12,983	13,010	12,981	12,981	13,002	13,006	13,009	13,018	13,030
Diesel (4)	10,209	10,209	n/a	10,209	10,209	10,209	10,209	10,209	10,209	10,209	10,209	10,209
HPower Waste	-	-	-	-	-	-	-	-	-	-	-	-
Honua	-	-	-	-	-	-	-	-	-	-	-	-
OTEC	-	-	-	-	-	-	-	-	-	-	-	-
Wind	-	-	-	-	-	-	-	-	-	-	-	-
Solar	-	-	-	-	-	-	-	-	-	-	-	-
Average (all Units)	11,469	11,576	11,684	11,777	11,784	12,068	12,033	12,050	12,006	12,036	12,053	11,999
Average (HECO Units)	10,386	10,455	10,704	10,601	10,631	10,930	10,839	10,866	10,778	10,872	10,900	10,795
Corrected Avg (HECO Units)	10,510	10,580	10,832	10,728	10,759	11,061	10,969	10,996	10,907	11,003	11,031	10,924

* Heat rate correction factor of 1.2% based on results of model validation effort with respect to baseline Oahu system

Table 7-15. Hours at minimum dispatchable power

Hours at min dispatchable power (respecting effective down	SCENARIO											
	Base (40MW)	1B (40MW)	5A (40MW)	5B (40MW)	3B (40MW)	5C (40MW)	5F1 (90MW)	5F1 (105MW)	5F2 (105MW)	5F3 (105MW)	3F1 (105MW)	3F2 (105MW)	3F3 (105MW)
AES Coal	2	23	2930	1943	2004	868	1023	1126	1064	1063	1199	1143	1142
KalaeloaCC	278	714	1217	2603	2531	1389	1525	1735	1657	1657	1721	1678	1677
Kahe 1	2427	3247	6100	5820	5849	3808	4239	4294	3763	3702	4314	3939	3841
Kahe 2	2982	4261	6741	6578	6605	5908	5944	6198	5333	5165	6236	5380	5145
Kahe 3	1575	2182	5256	4739	4717	3142	3351	3677	3596	3551	3731	3668	3595
Kahe 4	1758	2354	5477	4938	4927	2875	3091	2916	2829	2804	2918	2853	2812
Kahe 5	1440	2016	5178	4532	4509	3860	3826	3854	3802	3760	3893	3838	3756
Kahe 6	1904	2502	5629	5125	5122	5318	5360	5389	5307	5192	5398	5350	5187
Waiau 7	4536	6215	6964	6999	6982	4197	4270	4827	4291	4223	4812	4258	4168
Waiau 8	2027	2619	5616	5246	5248	2543	2780	3021	2975	2948	3048	3006	2955

Table 7-16 shows the number of hours of operation of different units. Baseload units that run continuously operated for the same number of hours in each scenario, except for scenarios where the baseload units are seasonally cycled (these are Scenarios 5F2/5F3 and Scenarios 3F2/3F3). The number of hours of operation for the cycling units tended to decrease as each strategy was considered. As expected, a decrease the number of starts is also observed, as shown in Table 7-17.

Table 7-16. Hours of operation for thermal units in different scenarios

	SCENARIO											
Hours Online	Base	1B	5A	5B	3B	5C	5F1	5F2	5F3	3F1	3F2	3F3
AES Coal	8,088	8,088	8,088	8,088	8,088	8,088	8,088	8,088	8,088	8,088	8,088	8,088
HPower Waste	-	-	-	-	-	-	-	-	-	-	-	-
KalaeloaCC	-	-	-	-	-	-	-	-	-	-	-	-
OTEC	-	-	-	-	-	-	-	-	-	-	-	-
Honua	-	-	-	-	-	-	-	-	-	-	-	-
Kahe 1	7,584	7,584	7,584	7,584	7,584	7,584	7,584	6,720	6,720	7,584	6,960	6,960
Kahe 2	7,920	7,920	7,920	7,920	7,920	7,920	7,920	7,008	7,008	7,920	7,008	7,008
Kahe 3	7,344	7,344	7,344	7,344	7,344	7,344	7,344	7,344	7,344	7,344	7,344	7,344
Kahe 4	7,608	7,608	7,608	7,608	7,608	7,608	7,608	7,608	7,608	7,608	7,608	7,608
Kahe 5	7,464	7,464	7,464	7,464	7,464	7,464	7,464	7,464	7,464	7,464	7,464	7,464
Kahe 6	7,752	7,752	7,752	7,752	7,752	7,752	7,752	7,752	7,752	7,752	7,752	7,752
Waiau 7	7,248	7,248	7,248	7,248	7,248	7,248	7,248	6,336	6,336	7,248	6,336	6,336
Waiau 8	7,080	7,080	7,080	7,080	7,080	7,248	7,248	7,248	7,248	7,080	7,080	7,080
Waiau 3	2,422	2,157	2,422	790	872	790	790	950	626	872	1,077	696
Waiau 4	3,170	2,965	3,170	1,453	1,739	1,453	1,453	1,771	1,332	1,739	2,041	1,478
Waiau 5	3,571	3,318	3,571	1,546	1,820	1,543	1,543	1,920	1,427	1,820	2,188	1,601
Waiau 6	2,216	1,932	2,216	732	839	729	729	1,097	711	839	1,195	747
Honolulu 7	1,742	1,490	1,742	483	623	483	483	715	431	623	852	489
Honolulu 8	1,057	847	1,057	276	320	276	276	515	320	320	559	332
CT1	489	311	24	497	696	482	482	710	467	680	878	574
Waiau 9	114	63	20	159	238	154	154	260	170	234	365	230
Waiau 10	28	14	4	61	76	61	61	92	51	76	109	63
Diesel (4)	44	24	0	82	113	82	82	145	56	113	171	71

Table 7-17. Number of starts for thermal units

	SCENARIO											
Number of Starts	Base	1B	5A	5B	3B	5C	5F1	5F2	5F3	3F1	3F2	3F3
AES Coal	2	2	2	2	2	2	2	2	2	2	2	2
HPower Waste	-	-	-	-	-	-	-	-	-	-	-	-
KalaeloaCC	-	-	-	-	-	-	-	-	-	-	-	-
OTEC	-	-	-	-	-	-	-	-	-	-	-	-
Honua	-	-	-	-	-	-	-	-	-	-	-	-
Kahe 1	2	2	2	2	2	2	2	2	2	2	2	2
Kahe 2	2	2	2	2	2	2	2	2	2	2	2	2
Kahe 3	2	2	2	2	2	2	2	2	2	2	2	2
Kahe 4	2	2	2	2	2	2	2	2	2	2	2	2
Kahe 5	3	3	3	3	3	3	3	3	3	3	3	3
Kahe 6	2	2	2	2	2	2	2	2	2	2	2	2
Waiau 7	4	4	4	4	4	4	4	4	4	4	4	4
Waiau 8	4	4	4	4	4	3	3	3	3	4	4	4
Waiau 3	221	213	221	94	107	94	94	103	75	107	123	90
Waiau 4	240	237	240	147	182	147	147	165	135	182	197	156
Waiau 5	304	294	304	159	197	159	159	191	148	197	223	166
Waiau 6	237	214	237	97	103	96	96	121	88	103	136	93
Honolulu 7	198	175	198	73	91	73	73	92	55	91	108	67
Honolulu 8	151	126	151	51	51	51	51	71	50	51	75	53
CT1	229	188	20	224	317	215	215	265	206	311	327	257
Waiau 9	40	27	7	82	125	79	79	106	76	123	161	117
Waiau 10	11	4	2	26	42	26	26	43	25	42	60	34
Diesel (4)	12	12	0	42	71	42	42	84	40	71	81	50

The capacity factors of the renewable energy plants and of the thermal plants are shown in Table 7-18 and Table 7-19. Scenarios 5F and 3F show very similar wind capacity factors.

Table 7-18. Capacity factors of renewable energy plants

		SCENARIO											
		Base	1B	5A	5B	3B	5C	5F1	5F2	5F3	3F1	3F2	3F3
Solar (100MW)	Available Energy (GWh)	-	162	162	162	162	162	162	162	162	162	162	162
	Curtailed Energy (GWh)	-	0	0	0	0	0	0	0	0	0	0	0
	Delivered Energy (GWh)	-	162	162	162	162	162	162	162	162	162	162	162
	Capacity Factor (Available)	-	18%	18%	18%	18%	18%	18%	18%	18%	18%	18%	18%
	Capacity Factor (Delivered)	-	18%	18%	18%	18%	18%	18%	18%	18%	18%	18%	18%
On-shore Wind (100MW)	Available Energy (GWh)	-	358	358	358	358	358	358	358	358	358	358	358
	Curtailed Energy (GWh)	-	0	0	0	0	0	0	0	0	0	0	0
	Delivered Energy (GWh)	-	358	358	358	358	358	358	358	358	358	358	358
	Capacity Factor (Available)	-	41%	41%	41%	41%	41%	41%	41%	41%	41%	41%	41%
	Capacity Factor (Delivered)	-	41%	41%	41%	41%	41%	41%	41%	41%	41%	41%	41%
Molokai (200MW)	Available Energy (GWh)	-	-	716	716	-	716	716	716	716	-	-	-
	Curtailed Energy (GWh)	-	-	162	106	-	33	48	45	45	-	-	-
	Delivered Energy (GWh)	-	-	554	611	-	683	667	671	671	-	-	-
	Capacity Factor (Available)	-	-	41%	41%	-	41%	41%	41%	41%	-	-	-
	Capacity Factor (Delivered)	-	-	32%	35%	-	39%	38%	38%	38%	-	-	-
Lanai (200MW)	Available Energy (GWh)	-	-	855	855	-	855	855	855	855	-	-	-
	Curtailed Energy (GWh)	-	-	172	109	-	33	49	45	45	-	-	-
	Delivered Energy (GWh)	-	-	684	747	-	822	807	810	810	-	-	-
	Capacity Factor (Available)	-	-	49%	49%	-	49%	49%	49%	49%	-	-	-
	Capacity Factor (Delivered)	-	-	39%	43%	-	47%	46%	46%	46%	-	-	-
Lanai (400MW)	Available Energy (GWh)	-	-	-	-	1,556	-	-	-	-	1,556	1,556	1,556
	Curtailed Energy (GWh)	-	-	-	-	226	-	-	-	-	106	100	100
	Delivered Energy (GWh)	-	-	-	-	1,331	-	-	-	-	1,450	1,457	1,457
	Capacity Factor (Available)	-	-	-	-	44%	-	-	-	-	44%	44%	44%
	Capacity Factor (Delivered)	-	-	-	-	38%	-	-	-	-	41%	42%	42%

Available Energy includes an assumed 5% loss of energy due to HVDC cable

Table 7-19. Capacity factors of thermal plants

	SCENARIO											
Capacity Factors	Base	1B	5A	5B	3B	5C	5F1	5F2	5F3	3F1	3F2	3F3
AES Coal	90.6%	88.2%	63.0%	70.3%	70.0%	80.8%	79.6%	80.1%	80.1%	79.2%	79.5%	79.6%
HPower Waste	-	-	-	-	-	-	-	-	-	-	-	-
KalaeloaCC	79.9%	77.3%	66.2%	59.9%	60.0%	70.0%	66.6%	67.1%	67.3%	66.7%	67.2%	67.5%
OTEC	-	-	-	-	-	-	-	-	-	-	-	-
Honua	-	-	-	-	-	-	-	-	-	-	-	-
Kahe 1	50.2%	45.5%	40.8%	41.0%	41.0%	31.7%	33.0%	28.5%	29.4%	33.0%	29.3%	30.3%
Kahe 2	58.7%	49.9%	43.2%	43.3%	43.3%	28.1%	30.9%	27.2%	28.6%	30.9%	27.1%	28.6%
Kahe 3	63.1%	56.6%	42.0%	43.3%	43.3%	36.6%	37.2%	37.6%	38.6%	37.2%	37.5%	38.7%
Kahe 4	62.3%	55.2%	43.3%	44.5%	44.4%	37.3%	38.7%	39.1%	40.1%	38.7%	39.0%	40.2%
Kahe 5	68.0%	61.6%	43.4%	45.3%	45.3%	37.8%	41.4%	41.6%	42.5%	41.3%	41.5%	42.7%
Kahe 6	53.3%	47.9%	39.9%	40.6%	40.6%	39.8%	40.9%	41.1%	41.8%	40.8%	41.0%	41.9%
Waiau 7	39.6%	37.6%	36.8%	36.7%	36.8%	26.2%	27.5%	23.3%	23.5%	27.5%	23.3%	23.6%
Waiau 8	48.8%	43.8%	37.3%	37.7%	37.7%	31.6%	32.2%	32.3%	33.2%	32.0%	32.1%	33.1%
Waiau 3	17.0%	14.9%	14.5%	5.3%	5.8%	5.4%	5.3%	6.4%	4.3%	5.9%	7.2%	4.7%
Waiau 4	17.0%	15.9%	17.0%	7.7%	9.2%	7.7%	7.7%	9.4%	7.1%	9.2%	10.8%	7.8%
Waiau 5	16.9%	15.6%	16.8%	7.3%	8.6%	7.3%	7.3%	9.0%	6.7%	8.6%	10.3%	7.5%
Waiau 6	10.6%	9.3%	10.6%	3.5%	4.0%	3.5%	3.5%	5.3%	3.4%	4.0%	5.7%	3.6%
Honolulu 7	8.3%	7.1%	8.3%	2.3%	3.0%	2.3%	2.3%	3.4%	2.1%	3.0%	4.1%	2.3%
Honolulu 8	4.9%	4.0%	4.9%	1.3%	1.5%	1.3%	1.3%	2.4%	1.5%	1.5%	2.6%	1.6%
CT1	1.1%	0.6%	0.1%	1.6%	2.2%	1.6%	1.6%	2.5%	1.5%	2.1%	3.0%	1.8%
Waiau 9	0.6%	0.3%	0.1%	1.0%	1.5%	1.0%	1.0%	1.8%	1.0%	1.5%	2.4%	1.4%
Waiau 10	0.2%	0.1%	0.0%	0.4%	0.5%	0.4%	0.4%	0.6%	0.3%	0.5%	0.7%	0.4%
Diesel (4)	0.2%	0.1%	0.0%	0.3%	0.4%	0.3%	0.3%	0.5%	0.2%	0.4%	0.6%	0.2%

Note that the dispatch of the cycling units (Waiau 3, 4, 5, 6 & Honolulu 8, 9) and their commitment order may not reflect actual operation

8.0 Sub-hourly Analysis

Earlier sections have focused on the hour-to-hour operation of the Oahu grid. This section of the report highlights the results and observations from all of the simulations performed in the sub-hourly timeframe. This includes dynamic simulations (transient stability and long-term dynamics) as well as the sub-hourly assessment of the GE MAPS^{TM} results in the Interhour tool.

8.1. Overview of critical sub-hourly events

The project team and stakeholders identified six dynamic events of interest for assessment in the sub-hourly tools. These events are:

1. Sustained wind power drops over one hour
   - These events could challenge the system's up-reserve
2. Sustained wind power drops within an hour
   - These events could challenge the up ramp rate capability of the thermal units
3. Sustained wind power rises
   - These events could challenge the system's down-reserve
4. Volatile wind power changes
   - These events could challenge the maneuvering capability of thermal units
5. Load rejection contingency event
   - These events could cause large over-frequency events
6. HVDC cable trip contingency event
   - These events could cause large under-frequency events

8.2. Sustained wind power drops over one hour

8.2.1. Overview

Wind and solar power can drop in a sustained fashion over an hour, which can challenge the available up-reserves on the system. Under such a condition, the dispatched thermal generators will have to be ramped up to meet the mismatch in generation and in the meantime fast-starting units may be committed to reduce the deficit of up-reserve. Wind and solar drops may in some cases increase the existing variability of system net load. The sustained wind/solar drop can also challenge the ramping potential of the system. If the maximum available MW/min rate of the committed thermal units becomes less than the MW/min drop from wind/solar, then system frequency drops and in extreme cases load shedding could occur. As a planning exercise, it is therefore essential to screen the system to identify worst-case conditions, and design strategies or operating rules that will help the system to sustain such events.

The GE Interhour Variability Analysis tool was enhanced for this study and used to screen the Oahu grid operation in order to understand the severity and frequency of increased variability in the system due to wind and solar power drops. The tool screens the hourly production results from GE MAPS^{TM} at a sub-hourly time step. The length of the screening window can extend from 10 min to 60 min, in 10-minute time steps, based on the available wind and solar data. We will refer to the 60 min (and 30 min) screening as Long-term analysis. Shorter-term analysis refers to 10 minute screening process. The objective of the long-term analysis is to identify the hours where sustained wind drops can pose a challenge to the available up-reserve on the system.

On the other hand, short-term analysis is more helpful to identify the events where a sudden wind drop can challenge the ramp rate of the system.

The wind and solar data was made available at a time resolution of 10 minutes, while the load was linearly interpolated between two hours. Aspects of the severity of the increased system variability are confirmed with finer resolution simulations, for select most severe hours in the year, with GE PSLF™.

8.2.2. Sustained wind power drops in Scenario 5B

As mentioned above, the Interhour tool is initialized by the GE MAPS™ commitment/dispatch for every hour of the year. It is further assumed that no units are committed within the hour to accommodate wind power drops, while in reality system operators may start the process of committing a fast-start unit when a sustained wind drop is observed. In this respect, the analysis is conservative in identifying worst-case operating condition. Further, the units committed in the next hour are only considered to meet the load rise from the beginning of this hour to the next. The unit commitment in the next hour is not considered towards meeting the wind power drops during the present hour.

The modifications of power output from the available thermal units are constrained by their maximum power and their ramp rates. That is, the units can provide up to their maximum power to the limit that their ramp rates allow in the time interval of interest. This is termed the up-range of the unit. This is described in equation (1)

$$\text{Up-range}_{\text{time-interval}} = \text{Minimum of (up-reserve, time-interval x ramp rate)} \quad (1)$$

where,

Up-range$_{time\text{-}interval}$ refers to the available up-reserve in the time-interval of interest, while up-reserve refers to the difference between the dispatch level and the maximum power of a unit at the beginning of the hour of interest

ramp rate refers to MW/min capability of the unit

time-interval is the time window of interest.

As an example, if a thermal unit with a maximum power output of 200 MW is dispatched at 120 MW, then the up-reserve from this unit is equal to 80 MW (200-120 MW). , Further, assume that the ramp rate of the unit is 1 MW/min, the effective up-reserves, or the up-range from this unit in a time period of 60 minute is 60 MW, not 80 MW.

$$\begin{aligned}\text{Up-range}_{60} &= \text{min(80 MW , 60 minute x 1 MW/min)} \\ &= \text{min(80 MW , 60 MW) = 60 MW}\end{aligned} \quad (2)$$

In this analysis, coherent with HECO operation practices, regulating reserve is added to the spinning (online) reserves. It is assumed that the complete up-reserve available at each unit can be used to counteract the system variability.

A metric is defined to prioritize the hours in terms of how severely the up-range is constrained under different wind power drop events. This is referred to as the up-range adequacy and is given by (3). This metric describes the MW of up-range are available on the system for each

MW of drop in wind plus drop in solar plus rise in load. If the up-range adequacy falls below 1, then the system's up-range is insufficient to counter the drop in wind/solar and the rise in load.

$$\text{Up-adequacy}_{60} = \text{Up-range}/(\text{Wind drop} + \text{Solar drop} + \text{Load rise}) \qquad (3)$$

Table 8-1 shows the long term screening results from Scenario 5B, using today's ramp rates at thermal units.

The first block of columns shows the time index for the events. The next two columns indicate the Scenario name and the time interval of interest. The next two blocks of columns indicate delivered wind/solar power and the 60-minute change in wind/solar power in this hour. The following block of columns shows initial load, hourly change in load, additional commitment in the following hour and then calculates load change net of commitment for this hour. The next block of columns shows the number of thermal units online in this hour and in the next hour to reflect how much additional commitment was made in the next hour. The second to last block shows the available up-range at the start of this hour, total change in wind and solar power in an hour, and the up-range at the end of this hour after accommodating for MW change in wind and solar power. The final column shows the up-range adequacy in this hour. The top ten hours are selected that show the lowest up-range adequacy. Most of the hours have up-range adequacy greater than 2, which implies that the system is able to handle sustained wind/solar drop and any rise in load over a period of 60 minutes. Hour 6855 shows up as the most critical hour, where the up-range adequacy is approaching 1.0.

Table 8-1. Long term screening results of Scenario 5B with today's ramp rates

Hour	Day	Date	Starting Hour	Scenario	Interval	Delivered Wind	Largest Wind Change	Delivered Solar	Largest Solar Change	Load (Start of Hour)	Largest Load Change	New Commit. (Next Hour)	Load Change (Net of Commit.)	Units Online (This Hour)	Units Online (Next Hour)	UpRange (Start)	WindChange+ SolarChange- LoadChange	UpRange (End)	UpRange Adequacy
6855	MON	13-Oct	15	5b	60	351	-311	54	-1	1160	-9	224	0	12	19	372	-312	59	1.2
6235	WED	17-Sep	19	5b	60	330	-62	34	-34	1101	76	0	76	10	12	320	-173	148	1.9
7170	SUN	26-Oct	18	5b	60	304	-105	32	-32	954	56	28	28	8	10	355	-165	189	2.1
3079	FRI	9-May	7	5b	60	143	-66	0	0	720	108	0	108	9	11	382	-174	209	2.2
6847	MON	13-Oct	7	5b	60	243	-75	0	0	765	118	28	90	8	10	386	-165	222	2.3
4962	SAT	26-Jul	18	5b	60	347	-176	54	-22	999	-19	28	0	9	9	464	-198	266	2.3
3690	TUE	3-Jun	18	5b	60	217	-78	50	-50	1139	-16	53	0	12	14	303	-128	175	2.4
694	WED	29-Jan	22	5b	60	202	-117	0	0	981	-117	113	0	9	9	282	-117	165	2.4
6571	WED	1-Oct	19	5b	60	319	-83	9	-9	1072	77	0	77	10	11	409	-169	240	2.4
8144	SAT	6-Dec	8	5b	60	167	-142	0	2	748	88	160	0	8	11	344	-140	204	2.5

The long-term analysis (60 minute time steps) is also repeated with the proposed, future, HECO thermal unit ramp rates and the results are shown in Table 8-2. It can be seen that no difference is observed between the two analyses and it can be said that the ramp rates of the units do not play a significant role in the 60 minute timeframe. This analysis is more affected by the available up-range at the beginning of the hour.

Table 8-2. Long term screening results of Scenario 5B with future ramp rates

Hour	Day	Date	Starting Hour	Scenario	Interval	Delivered Wind	Largest Wind Change	Delivered Solar	Largest Solar Change	Load (Start of Hour)	Largest Load Change	New Commit. (Next Hour)	Load Change (Net of Commit.)	Units Online (This Hour)	Units Online (Next Hour)	UpRange (Start)	WindChange+ SolarChange- LoadChange	UpRange (End)	UpRange Adequacy
6855	MON	13-Oct	15	5b	60	351	-311	54	-1	1160	-9	224	0	12	19	372	-312	59	1.2
6235	WED	17-Sep	19	5b	60	330	-62	34	-34	1101	76	0	76	10	12	320	-173	148	1.9
7170	SUN	26-Oct	18	5b	60	304	-105	32	-32	954	56	28	28	8	10	355	-165	189	2.1
3079	FRI	9-May	7	5b	60	143	-66	0	0	720	108	0	108	9	11	382	-174	209	2.2
6847	MON	13-Oct	7	5b	60	243	-75	0	0	765	118	28	90	8	10	386	-165	222	2.3
4962	SAT	26-Jul	18	5b	60	347	-176	54	-22	999	-19	28	0	9	9	464	-198	266	2.3
3690	TUE	3-Jun	18	5b	60	217	-78	50	-50	1139	-16	53	0	12	14	303	-128	175	2.4
694	WED	29-Jan	22	5b	60	202	-117	0	0	981	-117	113	0	9	9	282	-117	165	2.4
6571	WED	1-Oct	19	5b	60	319	-83	9	-9	1072	77	0	77	10	11	409	-169	240	2.4
8144	SAT	6-Dec	8	5b	60	167	-142	0	2	748	88	160	0	8	11	344	-140	204	2.5

Hour 6855 (Oct. 13, 2:00 pm, in the future study year) is shown in Figure 8-1. This hour exhibited the lowest up-range adequacy, as captured in the long-term analysis. In addition to the low up range, additional characteristics indicate this is an extremely challenging system event:

- Three large thermal units (HPOWER, K3, K4) were on outage. The production cost dispatch for this hour is shown in Figure 8-1.

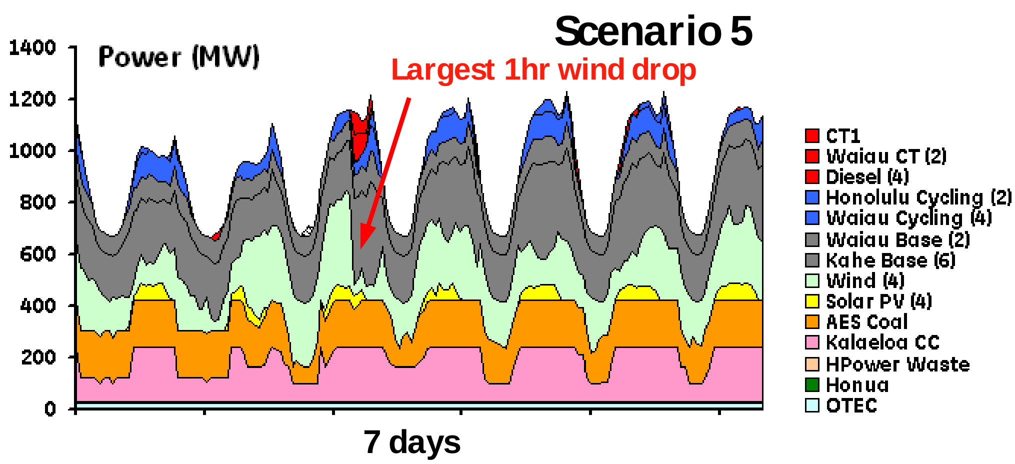


Figure 8-1. Hour 6855. Production cost dispatch and commitment for Scenario 5B

- This hour exhibits the largest hourly wind drop of 311 MW. Figure 8-2 shows the highest hourly wind power drops for the complete year of analysis. After Hour 6855, the next highest hourly drop in available wind power is 220 MW, while the delivered wind never sees a drop of greater than 180 MW.

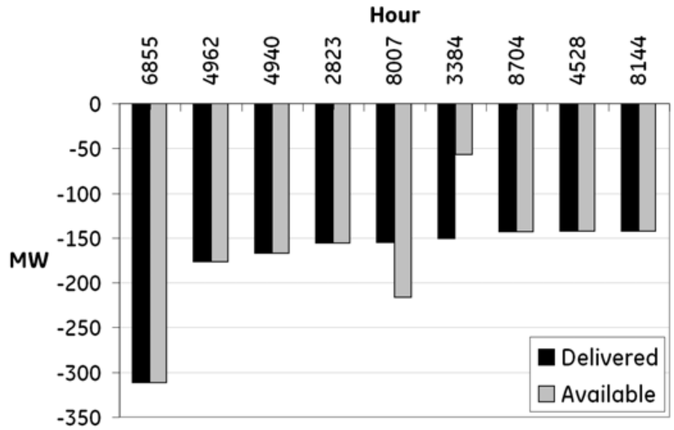


Figure 8-2. Highest drop in wind power for Scenario 5B (available and delivered)

- Large forecasting error (less than 0.1% percentile event) is observed for this hour. Figure 8-3 shows a forecasting error of 315 MW for this hour.

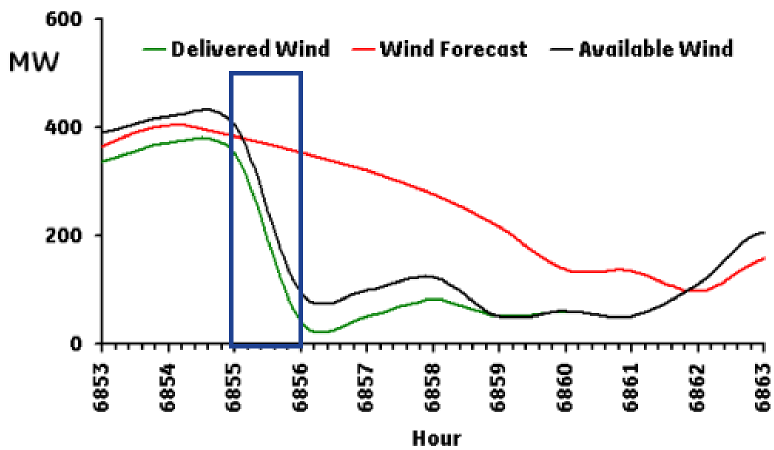


Figure 8-3. Forecasting error for the Hour 6855

- Sustained wind drop and a relatively large interhour solar drop are observed, as shown in Figure 8-4.

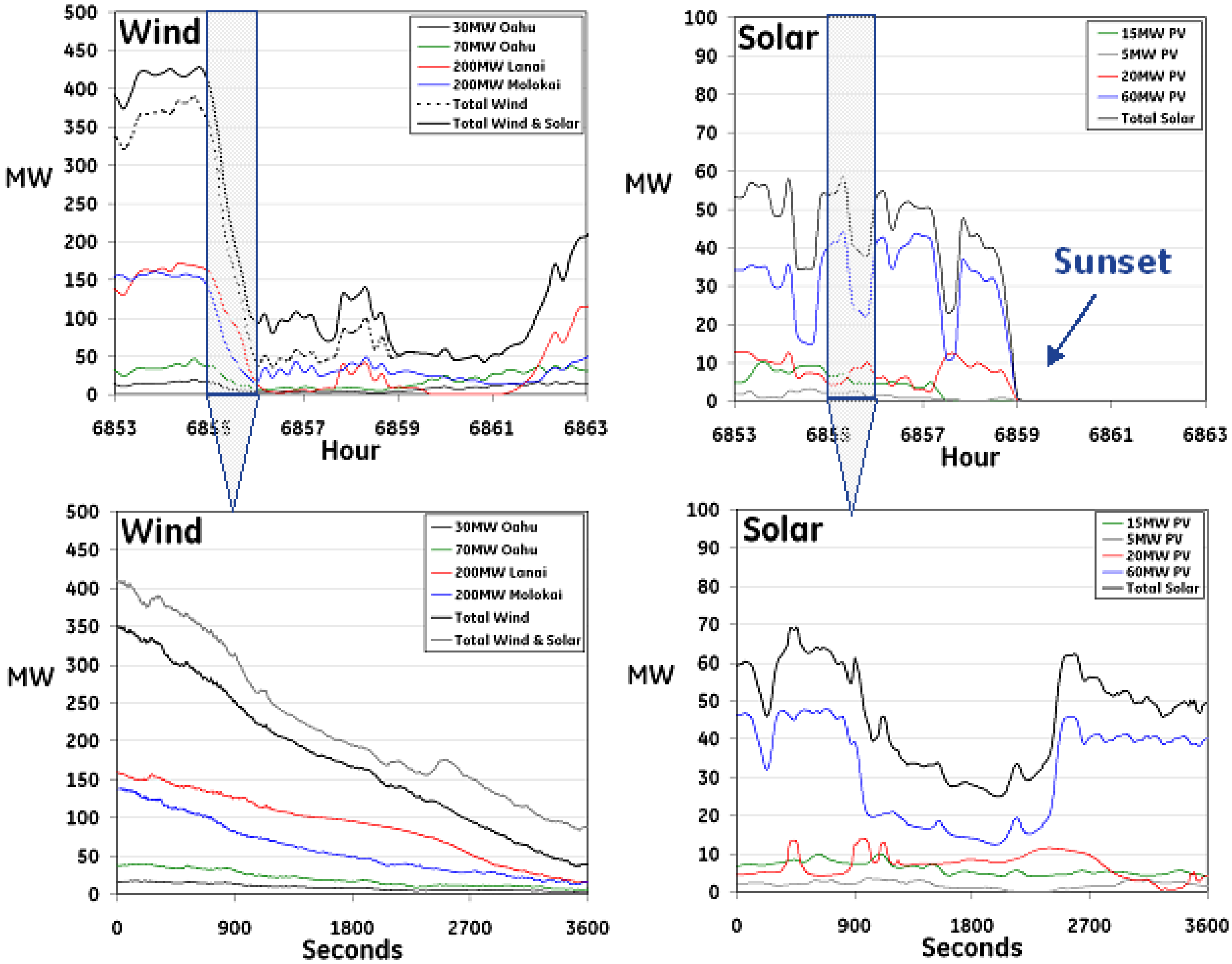


Figure 8-4. Drop in wind and solar power during the Hour 6855

In order to confirm that there were no dynamic aspects that would further limit the ability of the system to counteract hourly wind and solar power drops, this hour was simulated with GE PSLF™.

The team selected the 60-min interval that exhibited the largest drop in wind power from the year of wind power data (Hour 6855). The team performed long-term dynamic simulations in GE PSLF™ to assess the system frequency performance during this event based on the unit commitment at the start of the event. While in the process of simulating this event, the project team was notified that this significant wind power variability event might be a result of the way in which the wind power data were generated. In order to be certain, AWS Truepower would need to re-generate the wind power data. In order to maintain the schedule, the project team decided to move ahead with the analysis of this specific event, and decided that if the results indicated that the Oahu system was unable to accommodate this significant wind power event, the team would reconsider this decision. In addition, the magnitude of this wind drop event was on the order of wind power drops exhibited at other wind plants in Hawaii. Upon completion of the analysis, it was determined that the system frequency performance was manageable for this event, so the project team moved ahead to the next task.

8.2.3. GE PSLF™ long-term dynamic verification

As described in earlier sections, the GE MAPS™ production cost modeling involved commitment and dispatch of generation to meet the forecasted load for each hour of the year. The GE PSLF™ Dynamic model was developed to analyze the most challenging hours obtained from the GE MAPS™ tool. This model was developed in the first phase of the project and validated in that phase of the study. GE PSLF™ was used to develop a representation of the HECO Automatic Generation Control (AGC). The wind and solar plant models were developed in GE PSLF™ for each scenario.

Using the hourly units dispatch from GE MAPS™ simulation of Scenario 5B for the Hour 6855, the GE PSLF™ simulation was initialized. The model includes the equipment and controls described in 5.2.2 and 5.2.3. The disturbance to the system is the variability of wind and solar power plants. AWS Truepower provided the 2-sec data wind power data for each wind site and NREL provided 2-sec data solar power data for the solar sites.

8.2.3.1. Baseline

Based on the previous sections, Hour 6855 in Scenario 5B was selected as the hour for further analysis in the GE PSLF™.

The simulation was initialized based on gross MW hourly dispatch of units committed at the start of hour obtained from GE MAPS™ results. The following methodology was used to perform one-hour long-term dynamic simulations for Hour 6855:

- The load flow model was initialized for the Hour 6855 which starts on October 13, 2014 at 2:00pm HST,
- The Oahu power system was described by the electric network in the baseline load flow model,
- The dynamic modeling of the generators and other equipment connected in the network was provided through dynamic database,
- The variability used in this hour for long-term simulations is the wind and solar power changes over the hour. No load variability is considered in this simulation, since there was modest load change in the data. However, Oahu load was dynamically represented through a linear dependence of real power load to frequency, which may result in load variations due to changes in frequency, and
- The variability in wind and solar power affects the supply and demand on the timescale of interest to the AGC and is used as input to understand the frequency response of the Oahu system to the renewable power variations within that hour.

8.2.3.2. Sensitivities

Once the GE PSLF™ load flow model for Hour 6855 was initialized and the dynamic model was set up for wind and solar power variations, dynamic simulations were performed for various sensitivities.

Two different characteristics of solar variability time series were considered for Hour 6855. Figure 8-5 shows the original wind and solar power variability for Hour 6855 provided by AWS Truepower and NREL, respectively. The green bar in Figure 8-5 shows that between 10 and 20 minutes of Hour 6855, few solar plants (especially centralized PV 20 MW) actually increase or remain flat in their generation for few minutes even when there is sustained drop in wind power and centralized PV 60 MW (largest PV installation on Oahu).

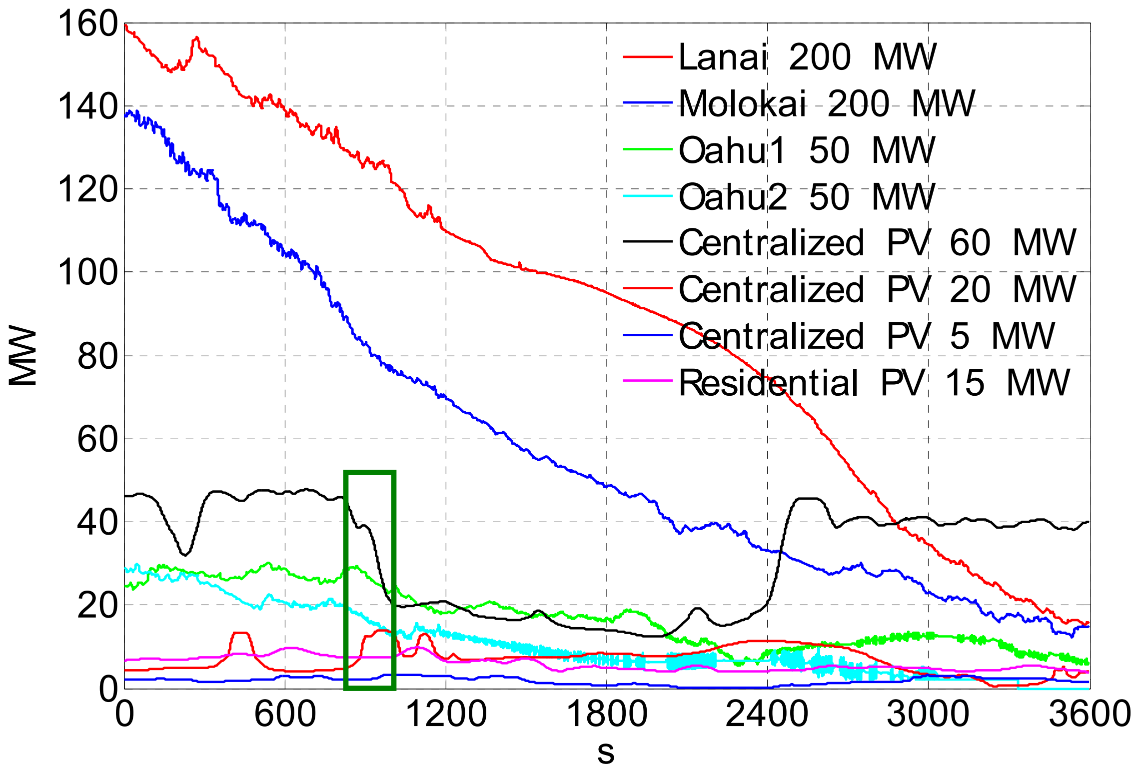


Figure 8-5. Wind and Solar Power Variability for Hour 6855

Modifying the solar data to get coherent solar and wind power drop between 10 and 20 minutes created a more pessimistic solar variability data set. This is shown in Figure 8-6. Dynamic simulations were performed with various sensitivities involving:

- Solar plant variability
  - Baseline solar plant variation
  - Modified solar (coherent solar and wind plant power drop)
- Thermal unit ramp rates
  - Proposed ramp rates
  - Today's ramp rates
- The gross MW AGC limits of all units under AGC are reduced by 5%
  - This was performed to understand whether the up-range of the system was approaching its limit

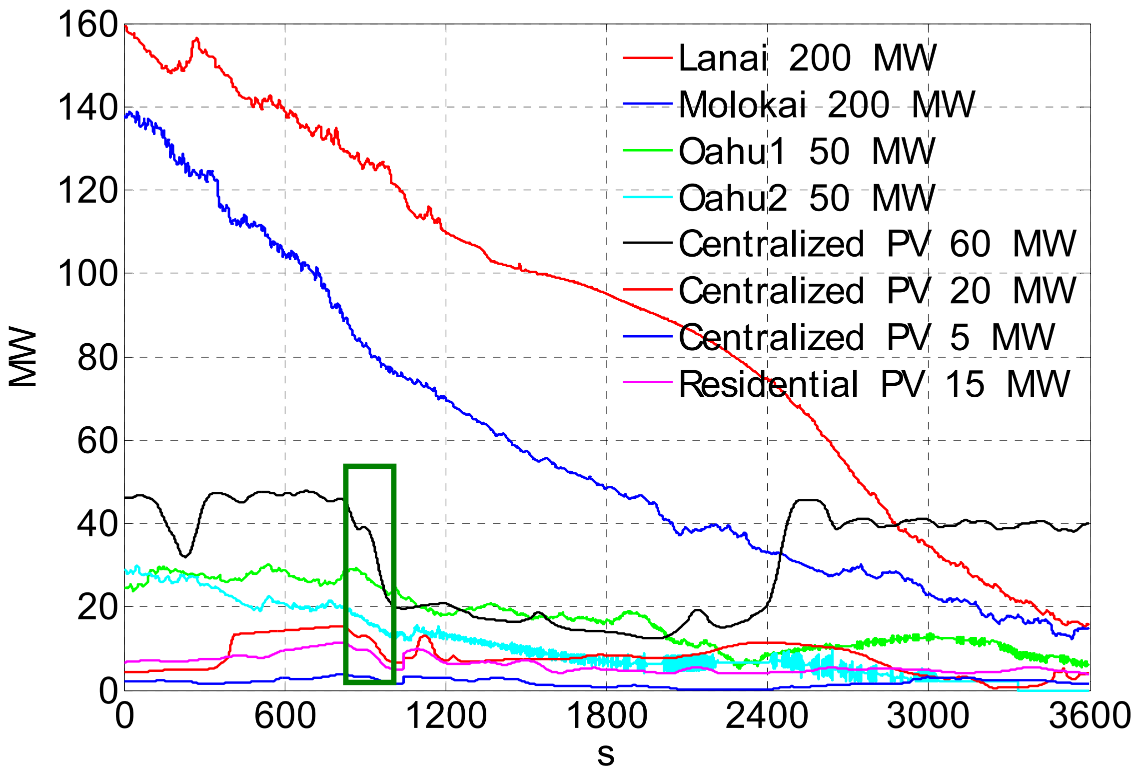
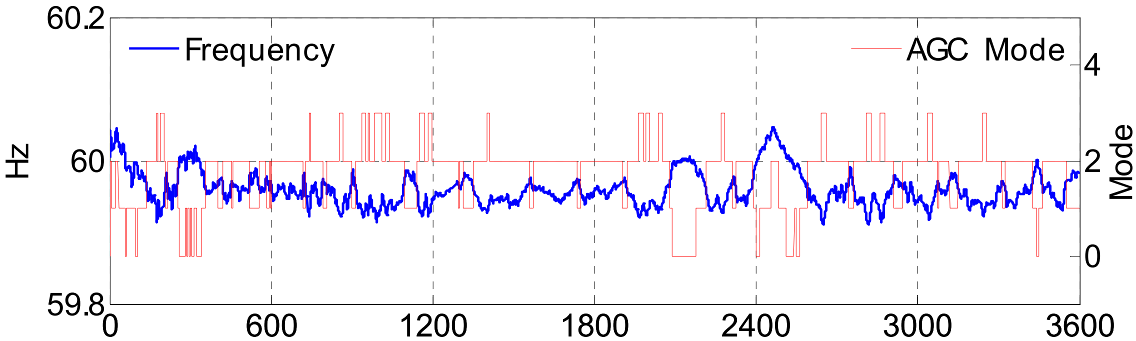


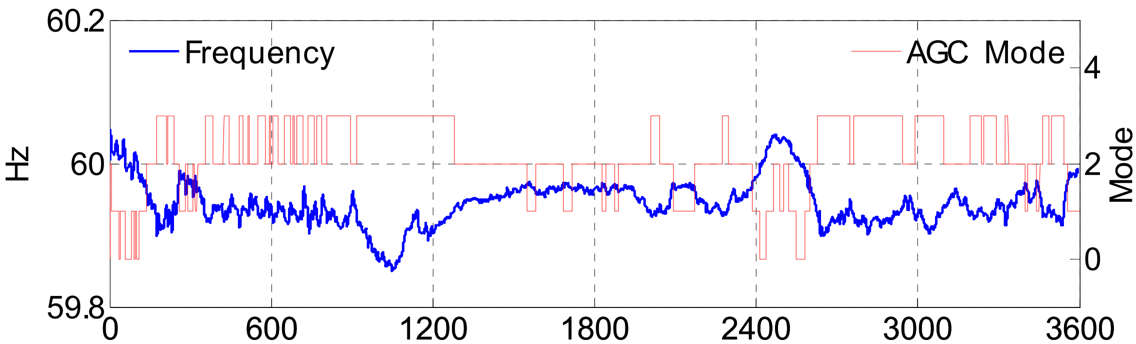
Figure 8-6. Wind power variability with modified solar for Hour 6855

8.2.3.3. Results

Figure 8-7 and Figure 8-8 show the results for the dynamic simulation with baseline solar variability and with no AES governor response considered. Figure 8-7(a) and Figure 8-7(b) shows analysis results for the unit ramp rates and Figure 8-8(a) and Figure 8-8(b) shows results for unit droop response.



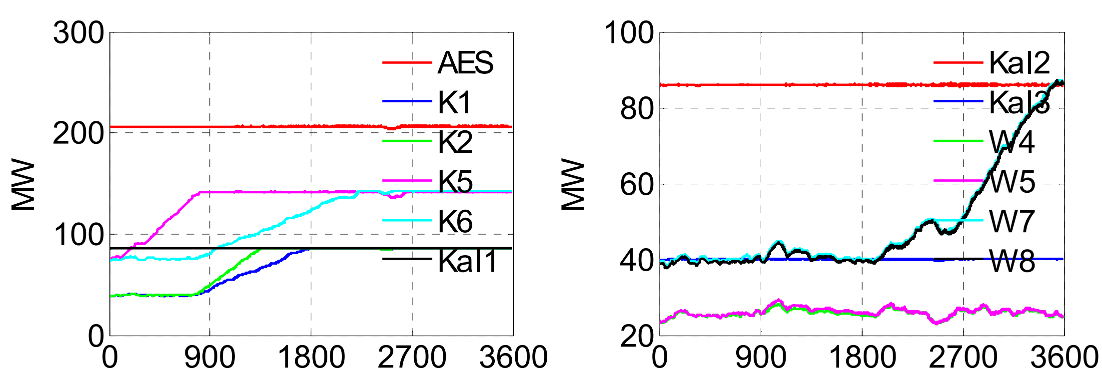
a). Proposed ramp rate settings



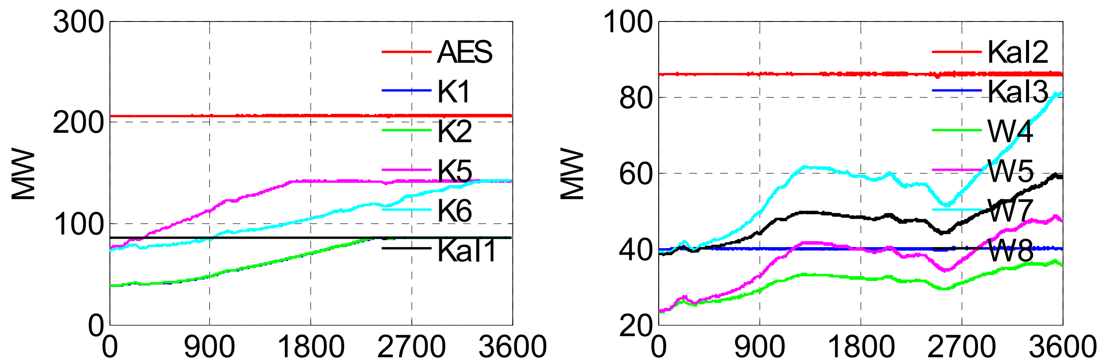
b). Today's ramp rate settings

Figure 8-7. Hour 6855 – Frequency response (x-axis in seconds)

The red curve shown in the above figure describes the various modes of the Automatic Generation Control (0: Dead band, 1: Normal, 2: Permissive, 3: Assist, 4: Warning, 5: Trip). During system events that cause large frequency deviations, the Automatic Generation Control could switch the system control to a different operating mode to correct more aggressively for the frequency deviation. For the simulated event shown above, the mode of operation reached the "Assist" mode (3). In "Assist" mode, the economic dispatch is ignored and all the controlled units are ramped up to quickly correct the frequency error. With the AGC ramp rates proposed by HECO, the AGC requires less time of operation in "Assist" mode to counteract the same wind power drop event.



a). Proposed ramp rate settings



b). Today's ramp rate settings (x-axis in seconds)

Figure 8-8. Hour 6855 - Generating unit response

Summary of results:

- The results show that the frequency excursions are fairly modest for the largest sustained hourly wind/solar generation drop in the year, even with moderate up-range
- Ramp rate of units do not limit the system's ability to counteract sustained 60-minute wind and solar power changes. With lower ramp-rate limits the system requires larger frequency deviations for the AGC to command sufficient units to react
- Available up-reserve dictates system ability to counteract sustained 60-minute wind and solar power changes.
- Screening analysis, based on up-range adequacy, gives a good indication of the ability of the system to survive 30/60-minute wind and solar power changes.
- Most of the generation correction is requested from the AGC economic dispatch algorithm (as opposed to the AGC ACE control). The economic dispatch requests few units to counteract the wind power drop at the time (based on economic participation factors).

8.2.4. Sustained wind power drops in other scenarios

Long-term screening was also performed for other scenarios. The unit commitment and dispatch changes as different strategies are employed to accept more wind power. Therefore, it was anticipated that more severe and frequent challenging events would be observed under these scenarios.

Figure 8-9 shows long-term analysis on scenario 5F3. Similar to scenario 5B, the lowest up-range adequacy was observed to be around one, again for the Hour 6855. The total wind/solar/load change in this hour was 311 MW. The next most severe hour had an up-range adequacy of 2

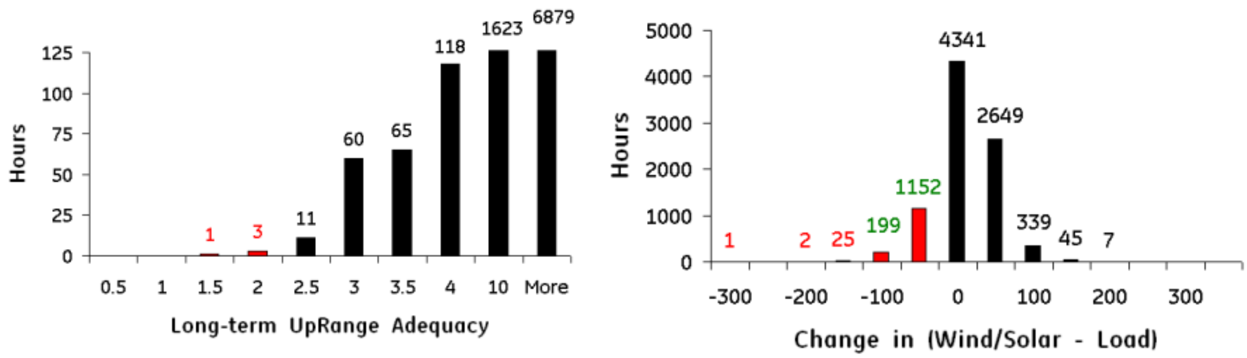


Figure 8-9. Long-term analysis for Scenario 5F3

A summary of results from long-term analysis on different scenarios is presented in Table 8-3. Sensitivity to today's and future (proposed) AGC ramp rates is included. The analysis shows the number of hours (for different scenarios) when the:

- Up-range adequacy is less than 4
- Up-range adequacy is less than 2
- Total up-reserve is less than 185 MW

Table 8-3. Summary of long-term analysis on different scenarios

Scenario	Unit Ramp Rates	Number of Hours when: UpRange Adequacy < 4	UpRange Adequacy < 2	UpReserves < 185MW
5b	Today's	188	2	15
5b	Future	188	2	15
5f3	Today's	258	4	273
5f3	Future	258	4	272
3b	Today's	256	5	15
3b	Future	256	5	15
3f3	Today's	376	13	261
3f3	Future	372	12	261

The ramp rates of the units do not affect the up-range adequacy in a 60-minute period. The total up-reserve (available at the beginning of the hour) determines the system ability to address changes in wind/solar/load over the hour. Scenario 3F3 shows largest number of hours with low up-range adequacy. Up-range adequacy limit of 4 and 2 were selected simply to highlight the number of hours that could be potentially challenging. Scenario 3 shows slightly higher wind variability than Scenario 5 and thus a slightly higher number of hours wherein the up-range is constrained. The last column shows the number of hours when the up-reserve at the end of the hour (after taking into account wind/solar/load change) drops below 185 MW. These can be potentially challenging hours if the largest system contingency, loss of 185 MW AES, also occurred during this time.

8.2.5. Conclusions

The Up-range adequacy metric was proposed to determine if a sustained wind/solar power drop could be handled by the system. An up-range adequacy of 1 would imply that wind/solar/load change in that hour could be managed by the up-range available in that hour. Any large wind/solar/load change would require a fast-start unit (there are three large fast-start units and four small fast-starting units, giving a total capacity of 222 MW) to be dispatched within 60 minutes. It seems that the up-reserve requirement is adequate because the up-range adequacy stays above 1 under all scenarios. As the up- reserve requirement increases (lowest to highest is 5F3, 5B, 3F3, 3B), additional units will be committed, which will further increase up-range adequacy to mitigate variability in wind and solar power and for contingency events.

The following are the overall conclusions for the impact of the sustained wind power drops over an hour:

- Screening analysis, based on up-range adequacy, gives a good indication of the ability of the system to survive 30/60-minute wind and solar power variability.
- Up-reserve used in production cost analysis (GE MAPS™) seems adequate for slow sustained wind/solar drops considering that up to 222 MW of fast start are available (W9, W10 ,CT1, Diesels)
- For long-term analyses (60-minute), an up-range adequacy of 1.0 would suggest that the up-reserve could manage the wind and solar power change over a 60-minute period. Any larger change would require a fast-start unit be dispatched within a 60-minute period.
- As the up-reserve requirement increases (lowest to highest is 5F3, 5B, 3F3, 3B), additional units will be committed, which will further increase the up-range adequacy.

8.3. Sustained wind power drops within an hour

8.3.1. Overview

This section presents interhour screening results at a more granular time scale of 10 minutes. We will refer to this as short-term interhour analysis. In the previous section, we looked at sustained wind and solar power changes over 60 minute period, which assessed whether enough up-range is available in every hour to manage safely the net load change across an hour. In the short-term analysis of this section, the assessment will be advanced within an hour, in 10 minute time steps, to assess whether enough up-range is available to address the wind and solar power variability.

8.3.2. Yearly screening of up-range and variability

Up-range adequacy is used to quantify the most challenging 10-minute intervals for every hour of the year. The interhour tool is again initialized from the hourly production cost results. The up-range of a unit in a 10-minute period is calculated using equation (4). The ramp rate values referred to the AGC ramp rate response. The up-range of all units is then obtained by adding together up the up-ranges of all units.

Additional commitment of thermal units in the next hour is not accounted towards load rise in the present hour, as opposed to the 60-minute analysis where thermal commitment in the next hour was considered to meet the increase in load.

$$\text{Up-range}_{\text{10-single unit}} = \text{Minimum of (up-reserve, 10 minute x ramp rate)} \qquad (4)$$

Then, for every hour of the year, the following is calculated with 10 minute wind and solar data:

- Largest 10 minute drop in wind power,
- Largest 10 minute drop in solar power,
- 10 minute load change (linearly interpolated across an hour)

The up-range adequacy of the system over this 10-minute period is calculated using (5). All of the hours of the year are assembled from the lowest to the highest up-range adequacy value.

It should be noted that a few key assumptions are made in this analysis:

1. The full ramp rate capability of each unit (today or future) is dispatched during a system event. In reality, there would be some time latency before AGC requests a unit to participate in managing wind and solar power variability.
2. The largest 10-minute wind change and largest 10-minute solar change were assumed coincident for each hour. In reality, these may not occur simultaneously.
3. New units committed for the subsequent hour do not provide any support in managing the wind and solar power changes.

$$\text{Up-range Adequacy}_{10} = \text{Up-range}_{10}/(\text{Wind drop} + \text{Solar drop} + \text{Load rise}) \qquad (5)$$

Before analyzing the results, some statistical analyses on wind variability (from Scenario 5 and Scenario 3) are presented in Figure 8-10. Wind power drops over 1 minute, 5 minute, and 10 minute are shown in different colored bars and all the hours of the year are binned into different levels of wind power drop. Important metrics include the 0.1% percentile and the negative most wind drop (0% percentile). The negative most 10-minute wind drop is 90 MW in Scenario 5 and 127 MW in Scenario 3.

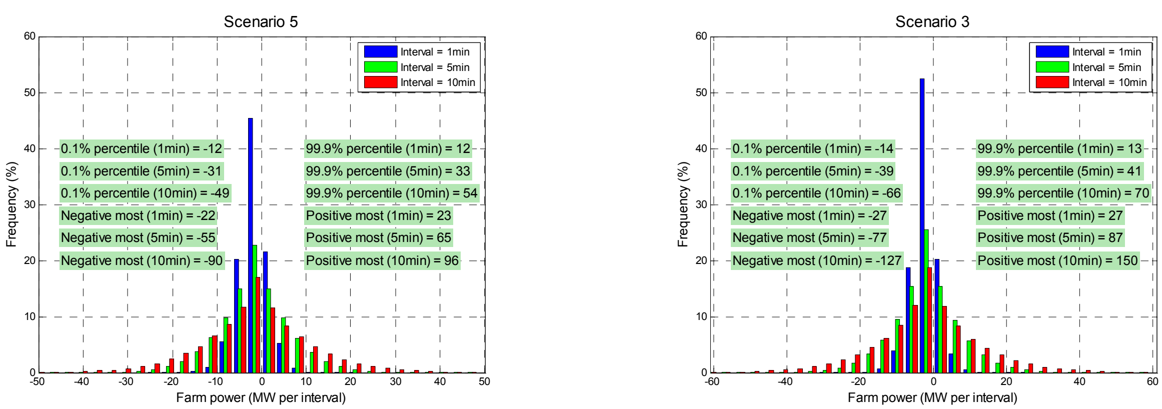


Figure 8-10. Short-timescale wind variability in Scenario 3 and Scenario 5

Table 8-4 shows the short-term screening results from Scenario 5B. In contrast to the long-term screening, more hours have up-range adequacy of less than 2. Hour 8008, in particular, is very close to exhausting its Up-range$_{10}$ at the end of a ten minutes time step. The picture improves when future AGC ramp rates are used, as shown in Table 8-5. All of the hours have up-range adequacy of at least 3. The up-range adequacy for Hour 8008 improves from 1.1 to 3.1, as the ramp rates of the units are improved from today's values to future (proposed) values. These results show that in a shorter time-scale, the ramp rate of the system can be a constraint, and the system could be better equipped to manage wind and solar power variability by increasing the ramp rates of the thermal units.

Table 8-4. Short term screening results of Scenario 5B with today's ramp rates

Hour	Day	Date	Starting Hour	Scenario	Interval	Delivered Wind	Largest Wind Change	Delivered Solar	Largest Solar Change	Load (Start of Hour)	Largest Load Change	Units Online (This Hour)	UpRange (Start)	WindChange+ SolarChange- LoadChange	UpRange (End)	UpRange Adequacy
8008	SUN	30-Nov	16	5b	10	210	-81	31	-23	994	0	10	111	-104	7	1.1
7497	SUN	9-Nov	9	5b	10	99	-56	1	-7	785	13	8	91	-76	15	1.2
6855	MON	13-Oct	15	5b	10	351	-83	54	-17	1160	-2	11	121	-99	22	1.2
8010	SUN	30-Nov	18	5b	10	61	-59	1	-15	1024	11	13	106	-85	21	1.3
8144	SAT	6-Dec	8	5b	10	167	-73	0	-3	748	15	8	117	-90	27	1.3
5106	FRI	1-Aug	18	5b	10	241	-80	55	-14	1136	-8	11	120	-87	33	1.4
7496	SUN	9-Nov	8	5b	10	109	-45	0	-10	710	12	7	98	-68	30	1.4
7170	SUN	26-Oct	18	5b	10	304	-50	32	-16	954	9	9	108	-75	33	1.4
7122	FRI	24-Oct	18	5b	10	366	-57	41	-12	1085	-1	10	101	-69	32	1.5
7570	WED	12-Nov	10	5b	10	303	-54	44	-18	1017	10	10	119	-81	38	1.5

Table 8-5. Short term screening results of Scenario 5B with future ramp rates

Hour	Day	Date	Starting Hour	Scenario	Interval	Delivered Wind	Largest Wind Change	Delivered Solar	Largest Solar Change	Load (Start of Hour)	Largest Load Change	Units Online (This Hour)	UpRange (Start)	WindChange+ SolarChange- LoadChange	UpRange (End)	UpRange Adequacy
8010	SUN	30-Nov	18	5b	10	61	-59	1	-15	1024	11	13	250	-85	166	3.0
8008	SUN	30-Nov	16	5b	10	210	-81	31	-23	994	0	10	327	-104	223	3.1
7497	SUN	9-Nov	9	5b	10	99	-56	1	-7	785	13	8	258	-76	182	3.4
8144	SAT	6-Dec	8	5b	10	167	-73	0	-3	748	15	8	313	-90	223	3.5
7720	TUE	18-Nov	16	5b	10	50	-44	52	-30	1037	-1	13	258	-73	185	3.5
6855	MON	13-Oct	15	5b	10	351	-83	54	-17	1160	-2	11	364	-99	265	3.7
5941	FRI	5-Sep	13	5b	10	203	-62	41	-8	1200	3	11	274	-73	201	3.7
5106	FRI	1-Aug	18	5b	10	241	-80	55	-14	1136	-8	11	337	-87	250	3.9
7570	WED	12-Nov	10	5b	10	303	-54	44	-18	1017	10	10	319	-81	238	3.9
7170	SUN	26-Oct	18	5b	10	304	-50	32	-16	954	9	9	325	-75	250	4.3

Short-term screening results are also presented for Scenario 5F3 in Table 8-6 (with today's ramp rates). For a few hours, the up-range adequacy becomes less than 1, which means the system is unable to match proportionally the MW/min of wind and solar power change in a 10-minute period. This could result in frequency excursion or load shedding. Hour 8008 has the lowest up-range adequacy of 0.9. The 10-minute interval in this hour starts with an up-range of 92 MW, as compared to Scenario 5B where the up-range is 111 MW. This is because a baseload unit is scheduled for seasonal cycling in this hour in Scenario 5F3. As a result, Kalaeloa is committed at full capacity to meet the load in Scenario 5F3. Although, the number of units online are the same, the up-range of the system is lower in Scenario 5F3.

Table 8-6. Short term screening results of Scenario 5F3 with today's ramp rates

Hour	Day	Date	Starting Hour	Scenario	Interval	Delivered Wind	Largest Wind Change	Delivered Solar	Largest Solar Change	Load (Start of Hour)	Largest Load Change	Units Online (This Hour)	UpRange (Start)	WindChange+ SolarChange- LoadChange	UpRange (End)	UpRange Adequacy
8008	SUN	30-Nov	16	5f3	10	210	-81	31	-23	994	0	10	92	-104	-12	0.9
7497	SUN	9-Nov	9	5f3	10	99	-56	1	-7	785	13	8	72	-76	-4	0.9
8144	SAT	6-Dec	8	5f3	10	167	-73	0	-3	748	15	8	90	-90	0	1.0
7496	SUN	9-Nov	8	5f3	10	109	-45	0	-10	710	12	7	72	-68	4	1.1
6855	MON	13-Oct	15	5f3	10	351	-83	54	-17	1160	-2	11	107	-99	8	1.1
7570	WED	12-Nov	10	5f3	10	303	-54	44	-18	1017	10	10	96	-81	15	1.2
5941	FRI	5-Sep	13	5f3	10	203	-62	41	-8	1200	3	11	92	-73	19	1.3
3489	MON	26-May	9	5f3	10	198	-37	14	-13	769	15	10	85	-64	21	1.3
7673	SUN	16-Nov	17	5f3	10	261	-23	56	-28	946	3	8	72	-54	18	1.3
5106	FRI	1-Aug	18	5f3	10	241	-80	55	-14	1136	-8	11	120	-87	33	1.4

Again, the situation improves with the proposed ramp rates. This is shown in Table 8-7. The increased ramp rates of the units help the system to provide more MW/min. As a result, all the hours of the year show an up-range adequacy of at least 2.5.

Table 8-7. Short term screening results of Scenario 5F3 with future ramp rates

Hour	Day	Date	Starting Hour	Scenario	Interval	Delivered Wind	Largest Wind Change	Delivered Solar	Largest Solar Change	Load (Start of Hour)	Largest Load Change	Units Online (This Hour)	UpRange (Start)	WindChange+ SolarChange- LoadChange	UpRange (End)	UpRange Adequacy
7497	SUN	9-Nov	9	5f3	10	99	-56	1	-7	785	13	8	193	-76	116	2.5
8008	SUN	30-Nov	16	5f3	10	210	-81	31	-23	994	0	10	278	-104	174	2.7
8010	SUN	30-Nov	18	5f3	10	61	-59	1	-15	1024	11	13	248	-85	163	2.9
3567	THU	29-May	15	5f3	10	151	-47	43	-14	1147	1	14	184	-63	121	2.9
5941	FRI	5-Sep	13	5f3	10	203	-62	41	-8	1200	3	11	221	-73	148	3.0
6855	MON	13-Oct	15	5f3	10	351	-83	54	-17	1160	-2	11	305	-99	205	3.1
7720	TUE	18-Nov	16	5f3	10	50	-44	52	-30	1037	-1	13	228	-73	155	3.1
8144	SAT	6-Dec	8	5f3	10	167	-73	0	-3	748	15	8	286	-90	196	3.2
7496	SUN	9-Nov	8	5f3	10	109	-45	0	-10	710	12	7	228	-68	160	3.4
8007	SUN	30-Nov	15	5f3	10	426	-81	56	-25	991	1	9	360	-106	254	3.4

The short-term screening results for Scenario 3F3 are also presented in Table 8-8 (with today's ramp rates) and in Table 8-9 (future ramp rates). The increased ramp rates of the units improve system ability to handle wind and solar power variability. Hour 6851 exhibits one of the lowest up-range adequacy values, both with current and with future ramp rates. This hour is examined more closely in the GE PSLF^{TM} tool to understand transient behavior of the system under short time-scale variability of wind/solar power. The results will be discussed below.

Table 8-8. Short term screening results of Scenario 3F3 with today's ramp rates

Hour	Day	Date	Starting Hour	Scenario	Interval	Delivered Wind	Largest Wind Change	Delivered Solar	Largest Solar Change	Load (Start of Hour)	Largest Load Change	Units Online (This Hour)	UpRange (Start)	WindChange+ SolarChange- LoadChange	UpRange (End)	UpRange Adequacy
1688	WED	12-Mar	8	3f3	10	214	-122	0	-1	881	4	10	106	-126	-20	0.8
8008	SUN	30-Nov	16	3f3	10	235	-85	31	-23	994	0	10	92	-108	-16	0.8
6851	MON	13-Oct	11	3f3	10	280	-83	55	-16	1108	6	10	89	-105	-16	0.9
7122	FRI	24-Oct	18	3f3	10	385	-89	41	-12	1085	-1	10	100	-101	-1	1.0
3559	THU	29-May	7	3f3	10	188	-59	0	-3	754	20	10	85	-82	3	1.0
7570	WED	12-Nov	10	3f3	10	294	-42	44	-18	1017	10	9	72	-69	3	1.0
7333	SUN	2-Nov	13	3f3	10	158	-74	5	0	914	0	10	79	-74	5	1.1
7321	SUN	2-Nov	1	3f3	10	76	-76	0	0	745	-8	8	72	-67	5	1.1
8010	SUN	30-Nov	18	3f3	10	21	-102	1	-15	1024	11	17	143	-128	15	1.1
7453	FRI	7-Nov	13	3f3	10	337	-79	50	-19	1107	1	12	112	-100	12	1.1

Table 8-9. Short term screening results of Scenario 3F3 with future ramp rates

Hour	Day	Date	Starting Hour	Scenario	Interval	Delivered Wind	Largest Wind Change	Delivered Solar	Largest Solar Change	Load (Start of Hour)	Largest Load Change	Units Online (This Hour)	UpRange (Start)	WindChange+ SolarChange- LoadChange	UpRange (End)	UpRange Adequacy
8010	SUN	30-Nov	18	3f3	10	21	-102	1	-15	1024	11	17	263	-128	135	2.1
6851	MON	13-Oct	11	3f3	10	280	-83	55	-16	1108	6	10	250	-105	145	2.4
1688	WED	12-Mar	8	3f3	10	214	-122	0	-1	881	4	10	304	-126	178	2.4
8011	SUN	30-Nov	19	3f3	10	167	-87	0	0	1091	3	12	217	-89	128	2.4
1720	THU	13-Mar	16	3f3	10	99	-89	10	0	1030	1	13	226	-89	137	2.5
8007	SUN	30-Nov	15	3f3	10	431	-110	56	-25	991	1	9	360	-135	225	2.7
8008	SUN	30-Nov	16	3f3	10	235	-85	31	-23	994	0	10	290	-108	181	2.7
5724	WED	27-Aug	12	3f3	10	180	-84	39	-4	1150	3	11	245	-91	154	2.7
6449	FRI	26-Sep	17	3f3	10	77	-67	50	-16	1161	-7	13	226	-76	150	3.0
7317	SAT	1-Nov	21	3f3	10	68	-71	0	0	1024	-10	12	183	-61	122	3.0

The results from the interhour short-term screening are summarized in Table 8-10. All of the scenarios show many hours when the up-range adequacy is less than 4 and less than 2. For short-term analyses (10 minute), an up-range adequacy of 2.0 would suggest that the systems up-range is capable of addressing two consecutive and identical 10 minute wind and solar power changes for a given commitment before all of the up range is consumed. It is assumed that no units can be started in the 10-minute period. This margin of up-range adequacy is required to cover for practical aspects of system operation and the fact that not all units will start ramping up at the beginning of the 10-minute period. The number of events when up-range is less than 2 is significantly reduced as today's AGC ramp rates are increased to future (proposed) ramp rates. The value of increasing ramp rates of the units is evident from this analysis and it is recommended that the future ramp rates be enabled to manage sub-hourly wind and solar variability.

Table 8-10. Summary of short-term analysis on different scenarios

Scenario	Unit Ramp Rates	Number of Hours when: UpRange Adequacy < 4	UpRange Adequacy < 2
5b	Today's	874	45
5b	Future	9	0
5f3	Today's	1516	96
5f3	Future	20	0
3b	Today's	1165	70
3b	Future	20	0
3f3	Today's	1851	207
3f3	Future	49	0

8.3.3. GE PSLF™ short-term dynamic analysis

8.3.3.1. Simulation window selection

The sub-hourly impacts of sustained wind and solar power drops within an hour that challenge the ramp rate capability of thermal units dispatched in the hour was considered next. The largest drops in wind and solar power over 1 minute, 5 minute and 10-minute periods were assessed for different scenarios.

However, the largest 1-minute wind and solar drops were not considered, as governors of thermal units operate during this time frame along with partial operation of AGC. It is expected that longer imbalances due to wind power changes in a time frame that does not allow operator reaction will have a more significant impact on frequency performance. For this reason the focus was on a timescale of 5-minute to 10-minute time periods.

Short-term analysis (10-minute screening) was performed to identify severe 10-minute wind and solar power drops. Based on this screening, Hour 6851 in Scenario 3F3 was selected for the following reasons:

- Largest drop in wind/solar power over an hour that consumed the up-spinning reserve and/or challenges the systems capability to ramp up before a unit can be started,
- Short timescale wind variability increases when 400 MW of wind power is co-located on Lanai (i.e., greater short-term variability for Scenario 3 than Scenario 5). Hence, Scenario 3 was considered
- Screening of Section 8.3.2 showed low up-range adequacy for this hour.
- Future ramp rates significantly improve system's ability to manage wind and solar power changes over 10 minute intervals.

Scenario 3F3 considers 100 MW of wind and 100 MW of solar on the island of Oahu and 400 MW of wind on the island of Lanai for integration into the Baseline HECO system of 2014. For the Hour 6851 in Scenario 3F3, the GE PSLF™ simulation was initialized with the gross MW hourly dispatch of units committed at the start of hour obtained from GE MAPS™ tool. The variability used in this hour for long-term simulations is the wind and solar power changes over the hour, provided with time resolution of two seconds. There was no solar data available with fast resolution for this hour. The solar power data used for Hour 6855 (Section 8.2.3) was used to represent solar variability.

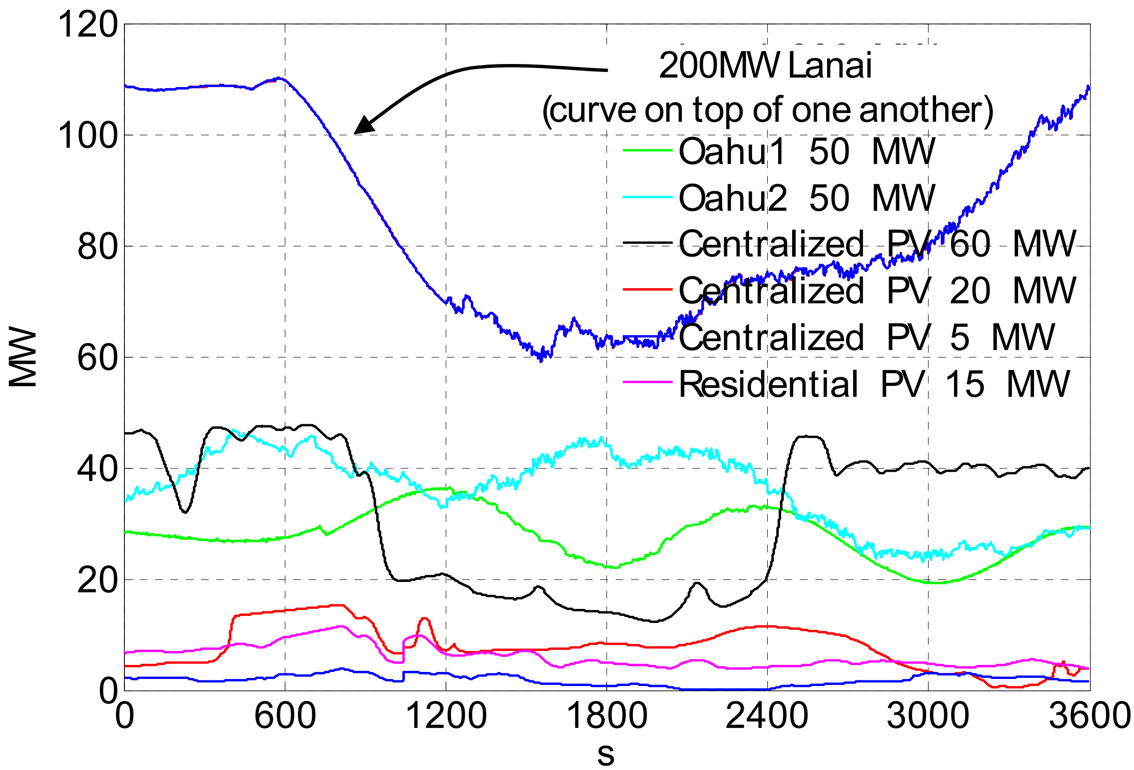


Figure 8-11. Hour 6851 wind and coherent solar power variability for Scenario 3F3

Figure 8-11 shows the wind and solar power variability and Figure 8-12 illustrates the total renewable generation variability for Hour 6851 in Scenario 3F3.

As can be observed from Figure 8-12, the largest 10-minute drop occurs between 10 minutes (600s) and 20 minutes (1200s) of the hour. Over a 10-minute period, the screening in Section 8.3.2 showed that the wind dropped 83 MW, the solar dropped 16 MW and the load increased by 6 MW.

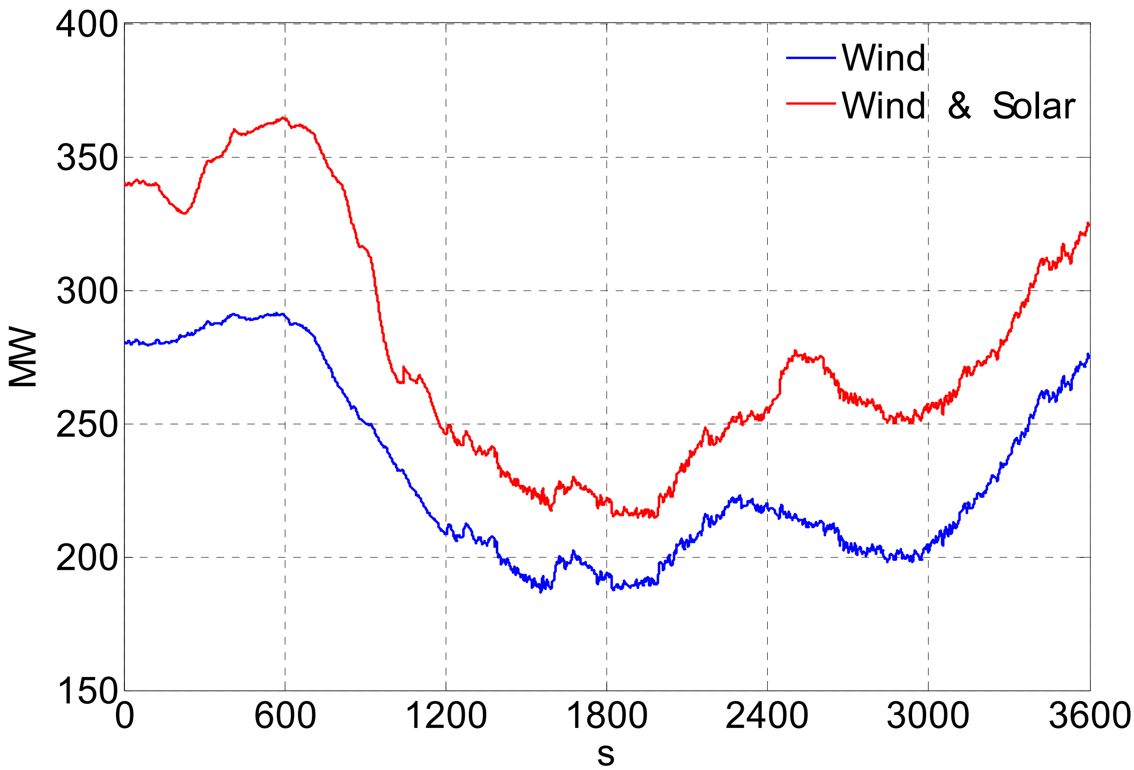


Figure 8-12. Hour 6851 Total Wind and Solar Power Variability

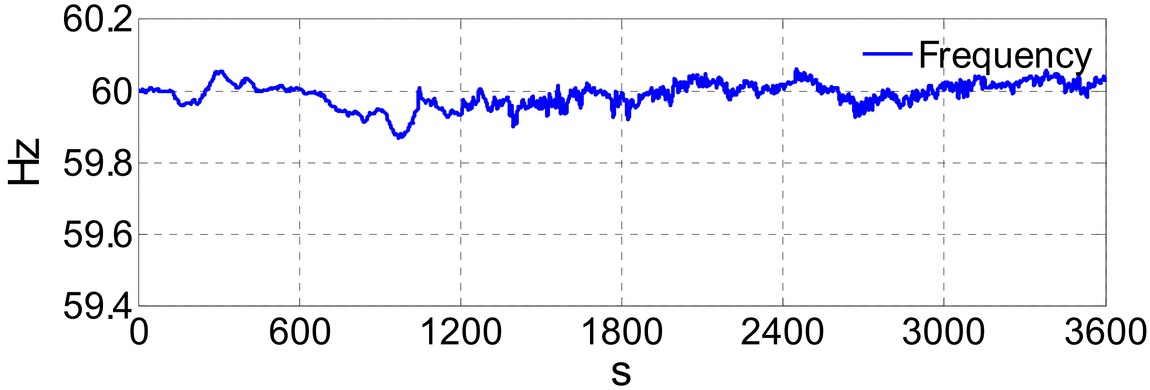
8.3.3.2. Sensitivities

Dynamic simulations were carried out for various sensitivities involving:

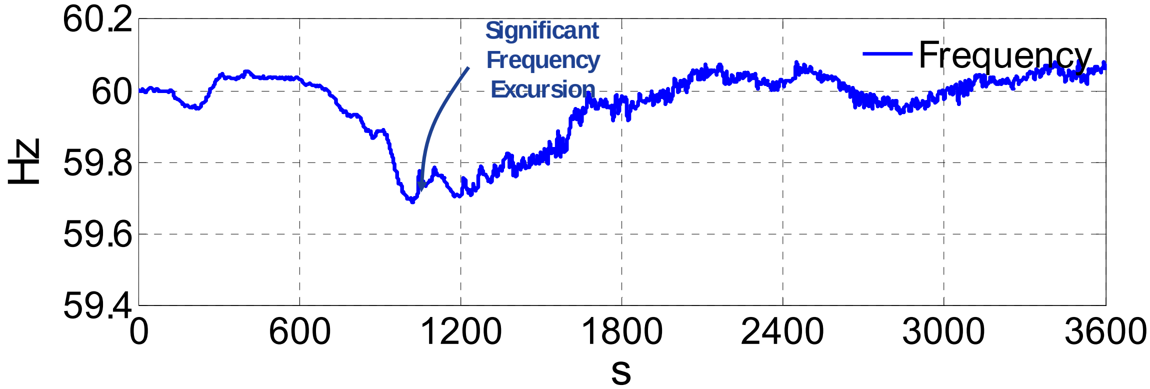
- Solar plant variability
  - Modified data (coherent solar plant output described in Section 8.2.3.2)
  - No solar plant variation
- Thermal unit ramp rates
  - Proposed ramp rates
  - Today's ramp rates
- Kahe 6 is assumed to be temporarily on manual control (the unit is not on AGC and no governor response is considered)

8.3.3.3. Results

Figure 8-13 shows the frequency response of the dynamic simulation for Hour 6851 with wind variability coherent with solar plant output. The top figure (a) illustrates that with proposed ramp rates, the system is able to manage significant wind and solar changes with acceptable frequency variation. The minimum frequency observed is ~59.9 Hz.



a). Proposed ramp rate settings and droop values

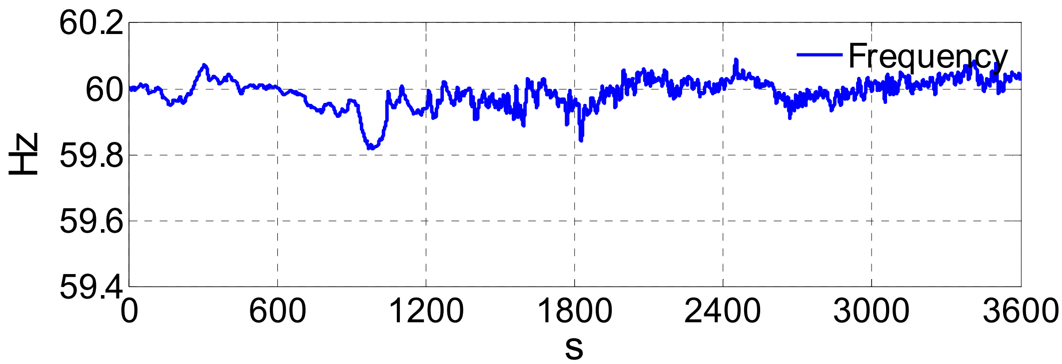


b). Today's ramp rate settings and droop values

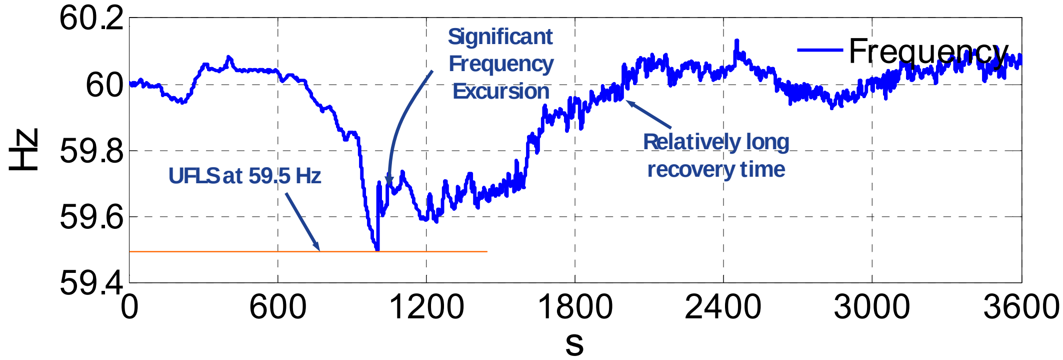
Figure 8-13. Hour 6851 – Frequency Response

However, with today's ramp rate settings (bottom figure b), there is a significant frequency excursion, as the system has insufficient up-range capability to manage the 10-minute wind and solar power change. The minimum frequency reached about 59.7 Hz due to the large 10-minute wind/solar drop.

To illustrate this behavior, two sensitivity simulations were performed with the additional assumption that Unit Kahe 6 is manually operated, implying that it is not responding to AGC pulses or governor droop (Figure 8-14). This can be the case if the unit is ramping up after coming on line or if the unit was controlled from the plant temporarily. It is observed from Figure 8-14 that with the proposed ramp rates the system managed to keep the frequency above 59.8 Hz but with today's ramp rates, bottom figure, the frequency dropped significantly resulting in an under frequency load shed at 59.5 Hz.



a). Proposed ramp rate settings



b). Today's ramp rate settings

Figure 8-14. Hour 6851 – Frequency Response with Kahe 6 manually operated (no droop or AGC response)

The short-term dynamic simulations for Hour 6851 also highlights that with today's ramp rate settings of the HECO thermal units, system frequency approaches the new under frequency load shed trigger.

8.3.4. Conclusions

The main conclusions for the assessment of sub-hourly impacts of sustained drops in wind and solar power within an hour are:

- Ramp rates of the HECO thermal units determine the system's ability to respond to wind and solar power changes.
- The 10-minute wind and solar power changes have demonstrated that today's thermal unit ramp rates are challenged.
- The proposed ramp rate improvements of the HECO thermal units are required to counteract severe 10-minute wind and solar power changes and maintain system reliability.

8.4. Sustained wind power rises

8.4.1. Overview

As different strategies are employed to enable high penetrations of wind power, the must run, baseload thermal units operate at minimum power point (respecting down-reserve requirement) for many more hours of the year. Under such conditions, if the wind power suddenly increases, these units would be forced to decrease their production further, thus consuming some of the system down-reserve. The down-reserve requirement HECO defined is based on load rejection events., which will be described later in the report. If a large increase in wind power is observed, the units may be forced to reduce production to their minimum level or lower, and if unaddressed through wind curtailment, this could lead to unit trips. Unless appropriate strategies are implemented, such operating conditions pose significant challenge to system performance in a severe load rejection event.

8.4.2. Yearly screening of down-range and variability

The Interhour tool was used to screen all hours of the year to identify challenging events when the system down-reserve was low and large sub-hourly increases in wind power were observed. The analysis is performed for 60-minute and 10-minute time periods. The system down-range for 60 minutes and 10 minutes is calculated, respecting the ramp rates of the units, as shown in equation (6). The de-commitment of the units in the next hour is not accounted for in the present hour, so as the wind increases the thermal units are backed down but not shutdown. The largest sub-hourly (60-minute or 10-minute) increase in wind power is subtracted from the down-range to identify the available down-range at the end of the 60-minute or 10-minute period.

$$\text{Down-range}_{\text{time-interval}} = \text{Minimum of (down-reserve, time-interval x ramp rate)} \qquad (6)$$

Figure 8-15 shows the down-range$_{60}$ at the beginning of every hour in Scenario 5F3. Most of the hours of the year start with a down-range of 90 MW (which is a system requirement). A few hours (~340) have down-rage of less than 80 MW. This occurs when multiple baseload units are on outage in that hour. Due to limitations of the GE MAPS^{TM} model, down-reserve was modeled by distributing down-reserve MWs among the baseload units by increasing their minimum power point. During planned or forced outages, there were some hours when the down-reserve may be less than 90 MW. The 60-minute wind power rise was determined from the hourly data points. If a wind plant was uncurtailed at the beginning of an hour, then it is left uncurtailed and the raw wind data were used to calculate the rise in wind power. Otherwise if a wind plant were curtailed at the beginning of the hour, it was assumed that the power could not go above the initial power level (in production cost results) during the period of analysis.

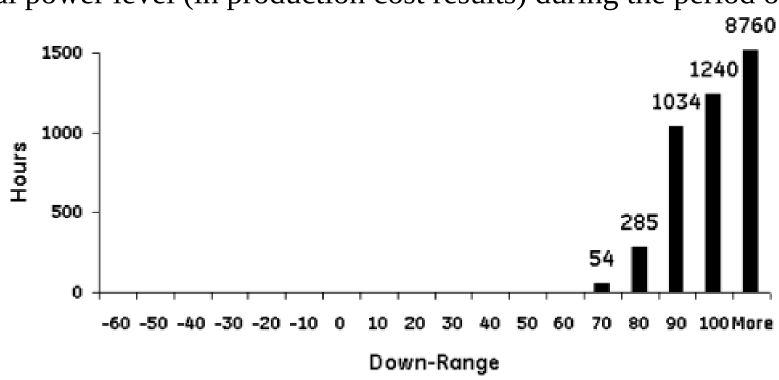


Figure 8-15. Down-range$_{60}$ at the beginning of the hour (Scenario 5F3)

Figure 8-16 shows the down-range at the end of the hour, as increased wind power was delivered to the system. For about 70 hours, the down-range of the system was fully consumed. Thermal units would be required to operate below acceptable minimum power levels and may encounter flame stability problems or trip for some of these hours unless the operator and/or automatic controls takes appropriate action. The system would be put at greater risk if there were a load rejection event in this hour.

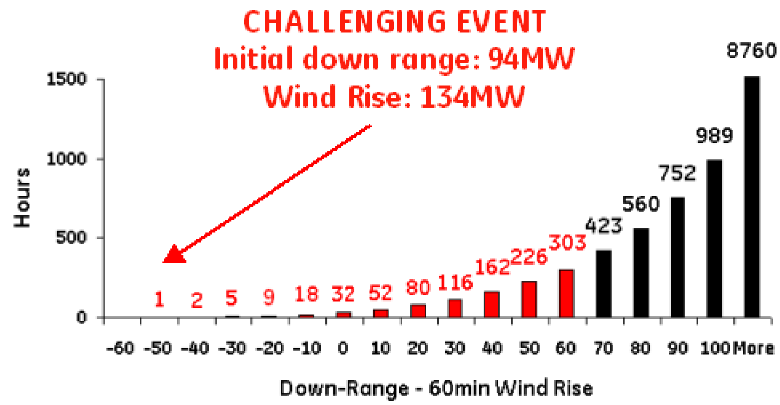


Figure 8-16. Challenging events in the 60 minute screening (Scenario 5F3)

The most challenging hour starts with a down-reserve of 94 MW and the wind increases by 134 MW in that hour shows the wind power and the system down-reserve available during this hour. It would be required that the operator curtails the off-island wind plants so that at least 90 MW of down-reserve could be maintained.

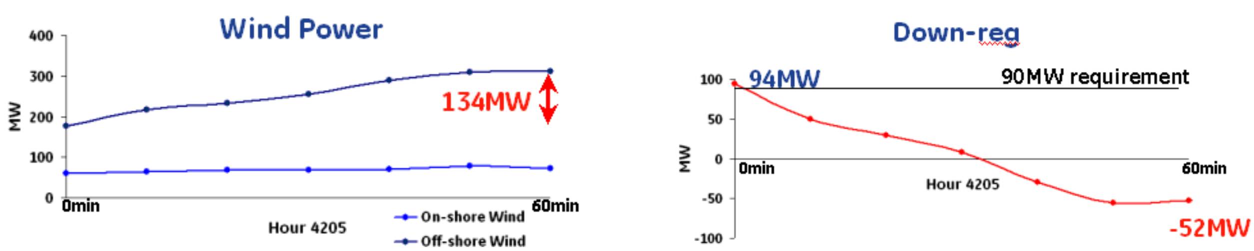


Figure 8-17. A challenging 60 minute event in Scenario 5F3

Shorter time-scale analysis (10 minute) was also performed to understand the impact of sudden increases in wind power on the operating down-reserve of the system. Figure 8-18 shows the down-range$_{10}$ at the beginning of every hour in Scenario 5F3. Most of the hours of the year start with a down-range of about 90 MW (which is a system requirement). Any hours with less than 90 MW are due to limitations of the model as described above. Figure 8-19 shows that for a few hours (~200), the down-range drops below 60 MW within a period of 10 minutes as the wind power picks up. For a particular challenging event, the wind power increased by 85 MW in 10 minutes. The system down-range$_{10}$ at the beginning of this hour was 85 MW, thus implying that the entire down-range will be consumed in this 10-minute period. This will pose operational risk if a consecutive load rejection event is experienced.

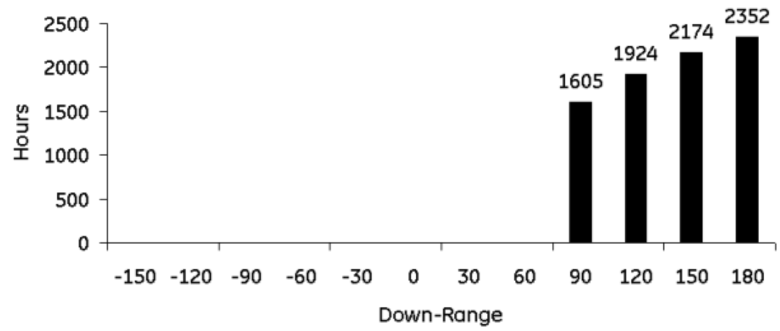


Figure 8-18. Down-range$_{10}$ at the beginning of the hour (Scenario 5F3)

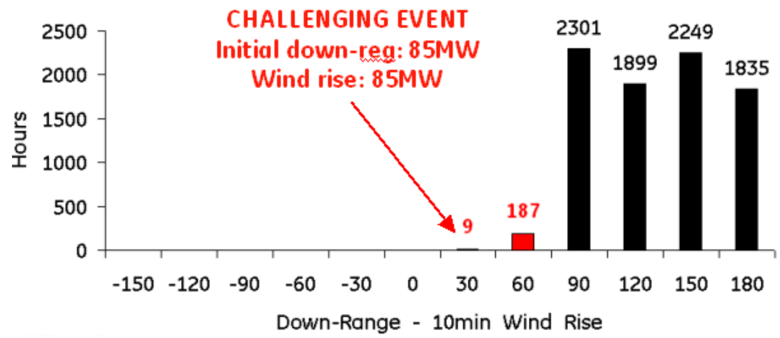


Figure 8-19. A challenging event in the 10 minute screening (Scenario 5F3)

Figure 8-20 shows the interhour variation of down-range and wind power for this critical hour. One approach to addressing this challenge is to curtail the off-island wind production to keep the desired down-reserve. A fast time response (less than 10 minute) is required from the operator if the wind plant is not automatically curtailed. In other events it may be that the on-island wind plants are increasing their power output. In that case, the operator will need to curtail the off-island plant to comply with the curtailment priority order.

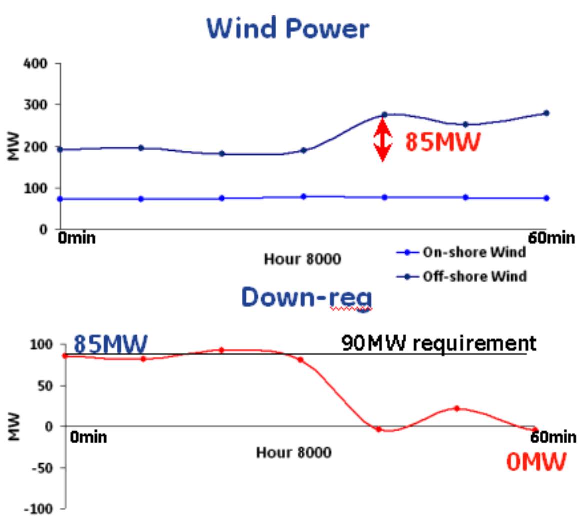


Figure 8-20. A challenging 10 minute event in Scenario 5F3

8.4.2.1. Mitigations

There are two alternatives to ensure wind power variability does not violate down-reserve requirements:

- Carry additional down-reserve on the system to account for wind power rises, or
- Automatically curtail wind power when the down-reserve requirement is violated.

Operating the system with additional down-reserve is expected to reduce the amount of wind energy that can be delivered to the system, and thereby increasing the total variable cost of operation. Automatic curtailment can prevent the need to increase the down-reserve.

Figure 8-10 shows that 99.9% of the wind rise events are less than 54 MW. If the system is operated to carry 54 MW of additional down-reserve, 99.9% of the 10-minute wind power increase events could be counteracted without compromising reserves for load-rejection events. Table 8-11 shows the additional curtailment in wind energy when the system down-reserve is increased from 90 MW to 144 MW.

Table 8-11. Additional wind curtailment when the system down-reserve is raised by 54 MW

	Wind Energy Curtailment
Scenario 5F3 (90 MW of down-reg)	90 GWhr
Scenario 5F3 (144 MW of down-reg)	163 GWhr

Automatically curtailing the wind plants when the down-reserve reduces below the level of 90 MW eliminates the need to carry additional downward regulating reserves.

8.4.3. Conclusions

The analysis show that wind rise events can lead to very low levels of down-reserve on the system, if wind power is not timely curtailed. Such events can have high wind power ramp rates (wind rise of 85 MW in 10 minutes) and therefore wind curtailment must be initiated at an equally fast response time. The automatic wind plant curtailment would operate when thermal units are operating below the down-reserve requirement. Alternatively, the down-reserve requirement could be increased. However, this option significantly increases the amount of wind curtailment.

8.5. Volatile wind power changes

8.5.1. Overview

Previous sections focused on sustained drops or rises in wind and solar power. In this section, screening of wind data was performed to identify significant wind power volatility events for each scenario. Once identified, these events would be analysed in the simulation tools to assess the impact of the volatile wind power changes on system performance. This was performed to understand the amount and allocation of additional maneuvering of thermal units needed to counteract wind and solar power variations.

The following topics are covered in this section:

- Description of the highly volatile hours as obtained from the screening process (Section 8.5.2)
- Results of the long-term dynamic simulation (Section 8.5.3)

    - Frequency performance (Section 8.5.3.1)
    - Thermal unit performance (Section 8.5.3.2)
    - Sharing of the wind power variability among thermal units (Section 8.5.3.3)
- Potential strategies to manage wind power variability (Section 8.5.4)
    - AGC modifications (Section 8.5.4.1)
    - Ramp rate control of wind plants (Section 8.5.4.2)
        - Wind plant control to limit up ramp rate
        - Energy storage to limit down ramp rate
    - Energy storage (Section 8.5.4.3)
- Conclusions (Section 8.5.5)

8.5.2. Identifying the significant wind power volatility events for each scenario

In addition to sustained wind power drops or rises, it is of interest to study the system response to high wind turbulence conditions. The available wind data was analyzed to identify highly volatile periods for different scenarios. The severity of the wind power variability was estimated based on the RMS calculation of the variations of wind power with respect to an average. The method is explained below.

First, depending on the specific scenario of interest, the total wind power output is calculated, at every time step of interest, as the summation of all existing wind plants. For example, the total wind power of Scenario 5 is calculated as:

$$P_{WIND}(k) = P_{100MW\_Oahu}(k) + P_{200MW\_Molokai}(k) + P_{200MW\_Lanai}(k)$$

Then, the 5 minute moving average power is obtained using the following equation:

$$P_{MA}(k) = \frac{1}{150} \sum_{m=-75}^{74} P_{WIND}(k+m)$$

That is, for each time stamp, the 5-minute average value equals the mean value of all the 2-sec data points that are in the sliding window centered at this time and with 2.5 minutes to both sides.

Next, the time series of wind power deviation is computed for each data point:

$$P_{DEV}(k) = P_{WIND}(k) - P_{MA}(k)$$

Lastly, for every hour of year 2014, the RMS value of wind turbulence is calculated as:

$$P_{DEV\_RMS} = \sqrt{\frac{1}{1800} \sum_{k\_in\_that\_hour} P_{DEV}^2(k)}$$

The larger the RMS value is, the more turbulent the wind is in this hour over the time interval examined. The length of the moving average window determines the bandwidth of the wind turbulence to which we are interested in. In this study wind variations with respect to 5 and 10 minute averages were considered. It was agreed by the stakeholders that this captured an important operating timeframe for the thermal units, longer than the immediate governor response and shorter than the timeframe to commit another unit. The nomenclature used in the remainder of the report calls RMSX to refer to the hourly RMS with respect to an X-minute (1, 5 and 10 minute) moving average. Same method and nomenclature was used to analyze results. Figure 8-21 depicts the RMS calculation of high frequency wind turbulence from the 2-sec simulated wind power data for year 2014.

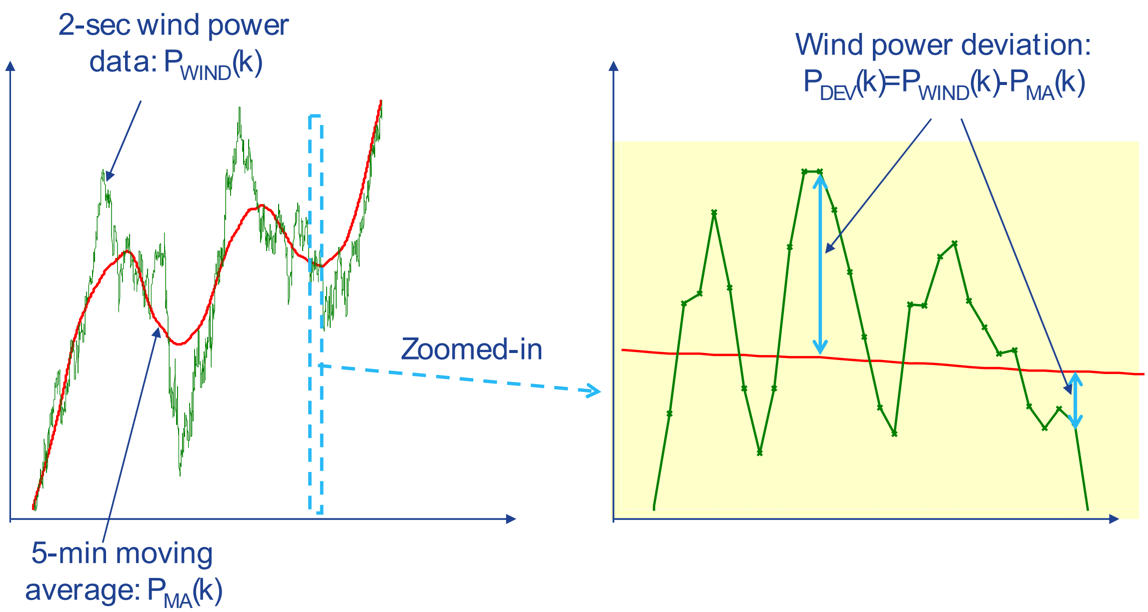


Figure 8-21. RMS calculation of high frequency wind turbulence

After the RMS value for each hour is calculated, all of the hours were sorted and the hours with highest RMS values were considered for GE PSLF^{TM} long-term simulations. Hours 5795, 5901 and 4990 in the year were identified as severe periods for Scenarios 5, 3 and 1 respectively. Figure 8-22 illustrates the total wind power trace for the most severe hours in both 5 minute and 10 minute screening for Scenario 5.

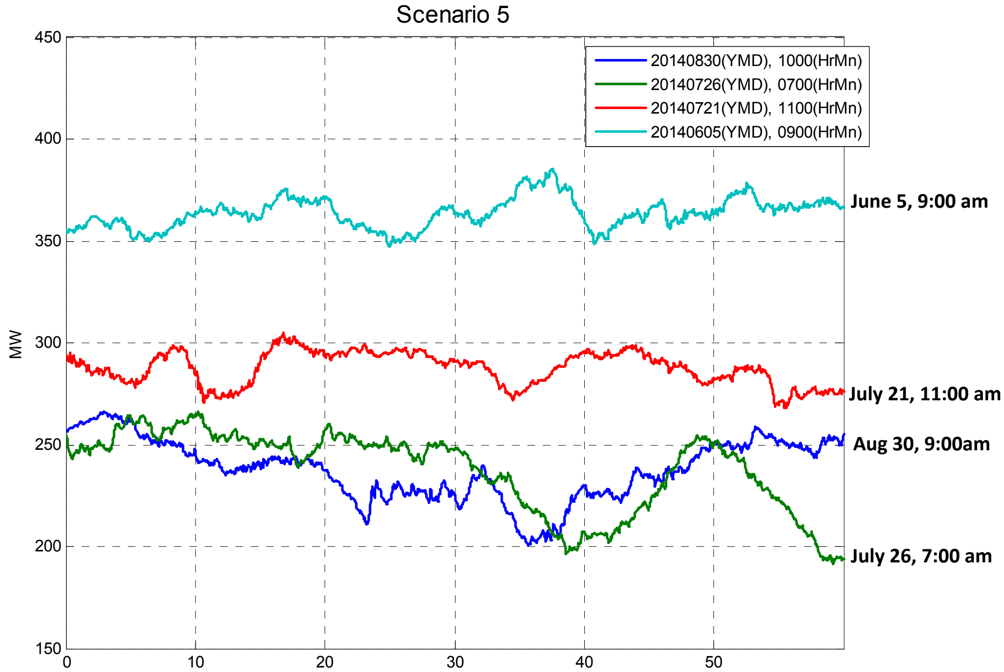
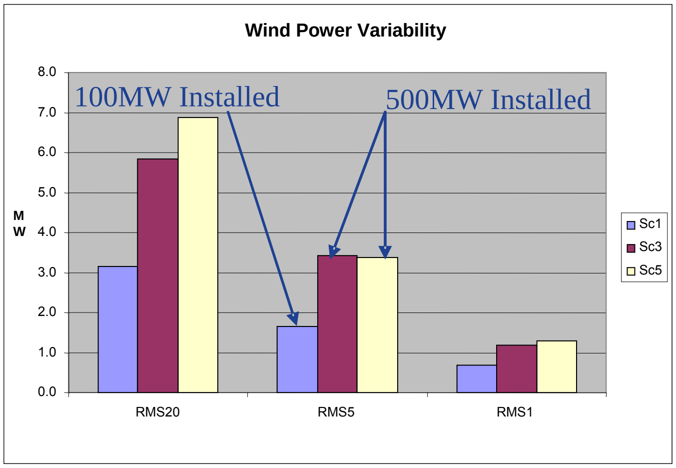


Figure 8-22. Total wind power trace for most severe hours in both 5 minute and 10 minute screening for Scenario 5 (x-axis in minutes for one hour)

The wind and solar data for selected volatile hours were analyzed to assess wind power variability changes for selected outliers in different scenarios. This is shown in Figure 8-23. The figure on the left indicates the wind power variability across all the scenarios. The figure on the right indicates wind variability with respect to its installed power. The installed power of Scenarios 3 and 5 is 500 MW and that of Scenario 1 is 100 MW. The values shown are RMS20, RMS5 and RMS1 corresponding to variability with respect to 20, 5 and 1 minute. The RMS1 values will approximately affect governor and AGC regulation; RMS5 will approximately affect regulation and partially affect AGC-economic dispatch; and RMS20 gives an indication of slower variability.



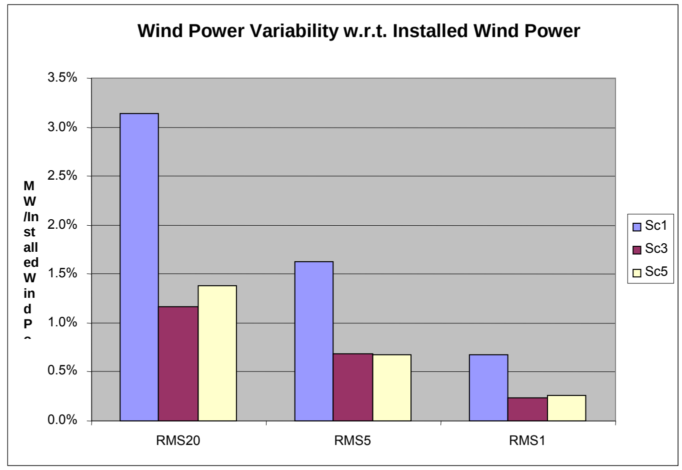


Figure 8-23. Wind variability increase for selected outliers between scenarios

Figure 8-23 illustrates that for Scenario 1 the variability of outliers is less than half with respect to Scenarios 3 or 5. Also, variability of outliers relative to the installed power is significantly higher for Scenario 1. In this case it is more than a twice of Scenario 3 or 5.

The impact of solar variability was also assessed based on limited available solar data for a different hour (Figure 8-24). There were no solar data available for these hours. The solar data of Hour 6855 was used for the analysis for all scenarios. The RMS1 value with and without solar data is similar. The available solar data for this study may not reflect the fast variability characteristics of this resource.

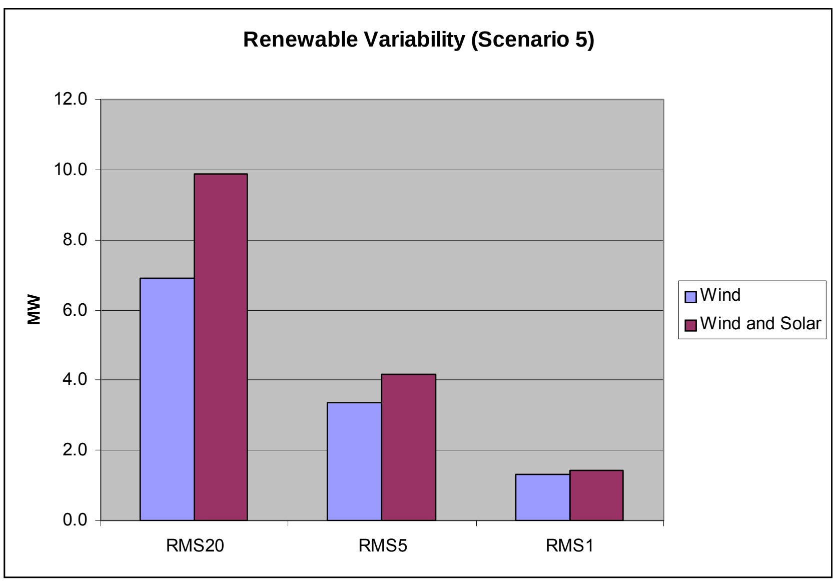


Figure 8-24. Wind and solar variability for selected outliers

8.5.3. Results

Using the volatile windows identified in the previous section for each scenario, PSLF simulations were performed. The severe hour of the year considered and the associated as-available production is presented in Table 8-12.

Table 8-12. Wind and solar generation data for PSLF runs of each scenario

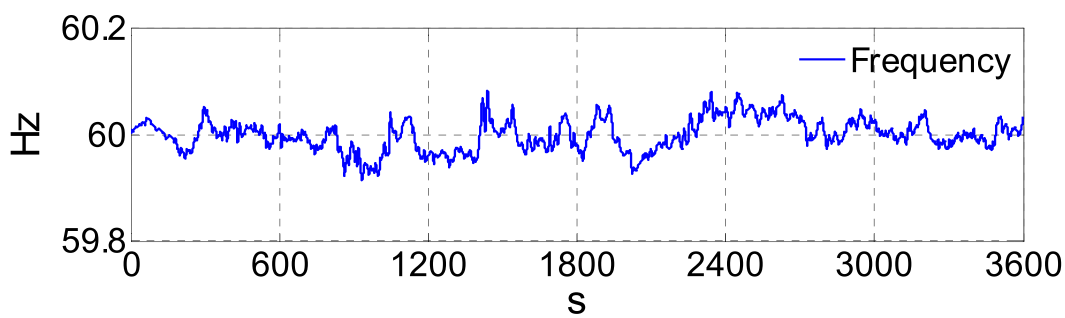
Renewables Generation at the start of hour for RMS Run	SCENARIO				
	5B	5F3	3B	3F3	1
	Hr 5795		Hr 5901		Hr 4990
15MW PV Ind	3	3	0	0	0
5MW PV Ind	1	1	0	0	0
15MW PV Res	7	7	0	0	0
5MW PV Res	2	2	0	0	0
60MW PV	46	46	0	0	0
50MW Oahu1	16	16	29	29	28
50MW Oahu2	21	21	12	12	24
200MW Lanai	83	83	197*	197*	-
200MW Molokai	136	136	-	-	-

* indicates wind power for 400MW Lanai

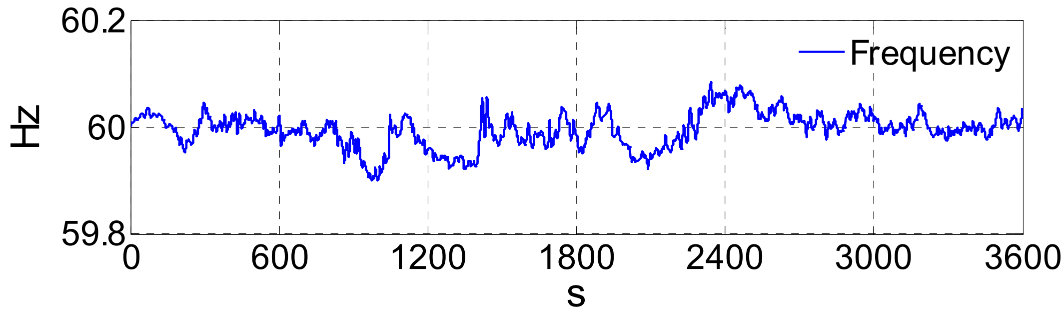
GE PSLF™ simulations were initialized with the gross MW hourly dispatch of units committed from MAPS™ in Hours 5795, 5901 and 4990 for Scenarios 5, 3 and 1 respectively. Solar data for these hours were not available; therefore the 2-sec solar data of Hour 6855 was used to eliminate the effect of solar power variability on these results. The intent of these simulations was to identify the impact of wind power variability.

8.5.3.1. Frequency performance during volatile wind power changes

In this section, the results for the long-term dynamic simulations of Hour 5795 in Scenario 5F3 are presented. The sensitivities discussed are with respect to proposed and present ramp rates and droop values. Figure 8-25 shows the system frequency response with coherent solar plant variability. It was assumed that the largest solar variability event during this window was experienced across all of the solar plants. The top figure (a) illustrates the frequency performance if the thermal units are capable of performing at their proposed ramp rates and droop characteristics and the bottom figure with the present ramp rates and droop characteristics. Different from fast sustained power reductions analyzed in section 8.3.3, this figure highlights that increasing the ramp rates and modifying the governor characteristics moderately reduced some of the faster frequency variations.



a). Proposed ramp rate settings and droop values

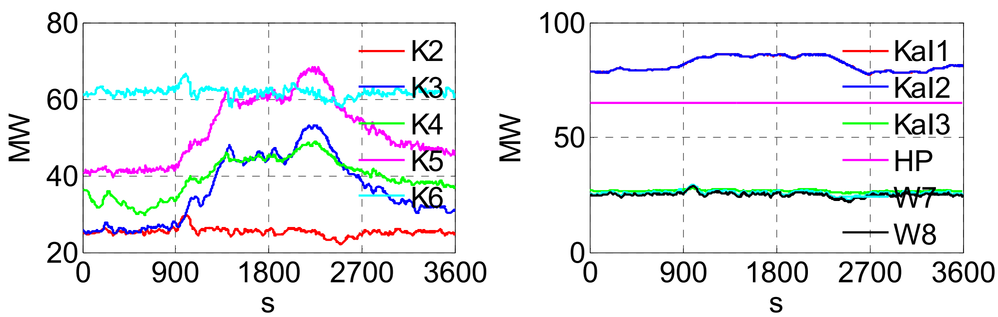


b). Today's ramp rate settings and droop values

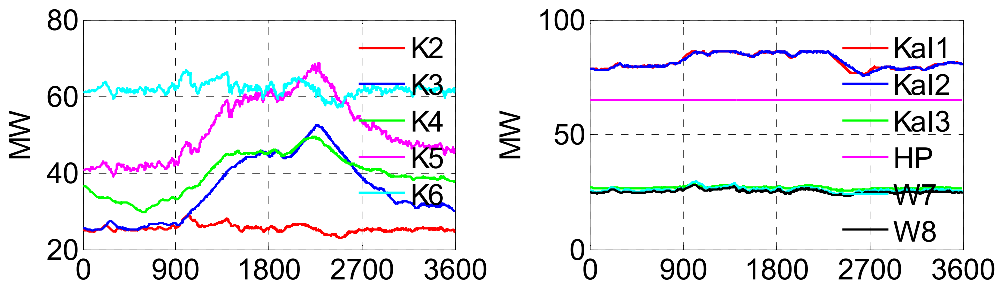
Figure 8-25. Hour 5795 Scenario 5F3 – Frequency Response

8.5.3.2. Thermal unit response during volatile wind power changes

Figure 8-26 shows the outputs of the individual generating units in response to variations of wind power in both directions. AES is not shown as it was at full power output for this event. It can be seen that not all units respond to the to the wind power fluctuations. Kalaeloa is initially operating close to top-load and hits maximum power early in the event, after wind power starts dropping (about 1000 seconds in the simulation). This occurs because Kalaeloa is operating in combined cycle mode, and is one of the more economic units not at top load. Therefore, the AGC economic dispatch instructed these units to pick up power. Even when the Kalaeloa units are not at full power, unit response is constrained because Kalaeloa cannot continuously ramp through its entire operating range. The Kahe units provide most of the maneuvering (K3, K4, and K5 in the figure). The AGC dispatches these units in response to wind variations because these are the next most economic units. Note that the HECO thermal units are all dispatched at or near their minimum operating loads. At approximately 900 seconds into the simulation, all units temporarily (for approximately 50 seconds) pick up power due to the AGC temporarily switching into the assist mode (all units are requested to ramp). After the frequency recovers and the AGC goes to normal AGC control mode, the less efficient and more expensive units are backed down to their original power levels and the more efficient and least expensive units are dispatched higher (mostly K5 and K3). That is, the economic dispatch tends to request fewer units to counteract the wind power variations.



a). Proposed Ramp Rate Settings and Droop values



b). Today's Ramp Rate Settings and Droop values

Figure 8-26. Hour 5795 Scenario 5F3 - Generating Unit Response

8.5.3.3. Thermal unit maneuvering during volatile wind power changes

As shown in Figure 8-27, the HECO units provide most of the maneuvering for the severe volatile hour in Scenario 5F3 and carry the burden of maintaining system frequency. Note that the RMS20 represents the RMS of the 20-min rolling average, the longest timescale shown in Figure 8-27. RMS1 represents the RMS of the 1-min rolling average, the shortest timescales shown in Figure 8-27. The IPPs (AES and Kalaeloa) typically do not provide much regulation support because:

- AES is the most efficient unit tends to operate at or near full load, and
- Kalaeloa is the second most efficient unit, and tends to operate at or near full load. In addition, Kalaeloa cannot continuously ramp through its entire operating range, which limits its participation.

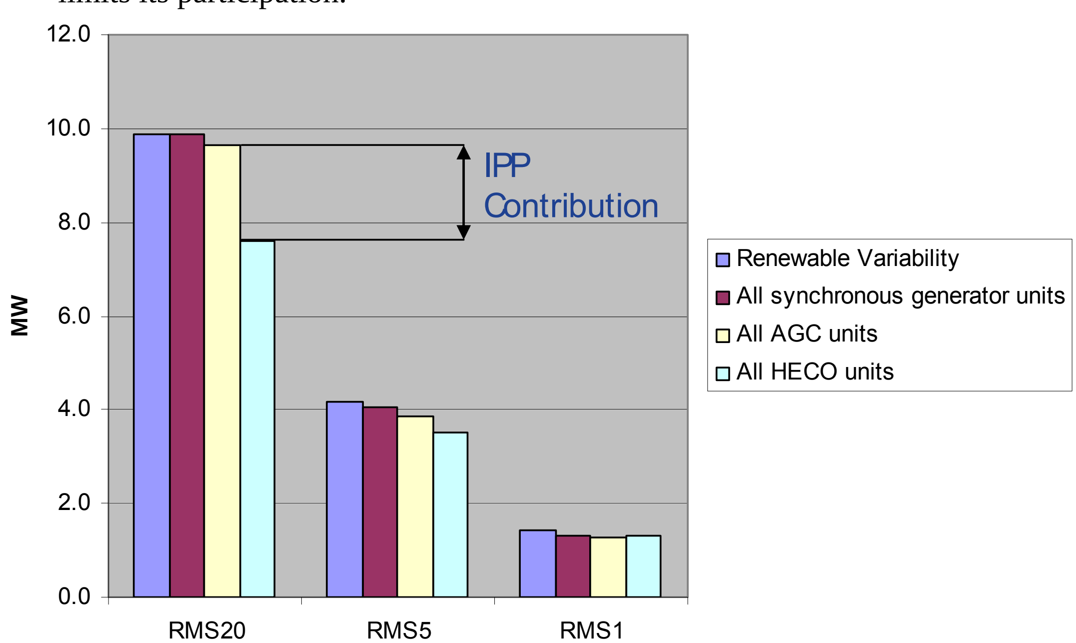


Figure 8-27. Hour 5795 Scenario 5F3 - Variability Sharing among Units (proposed ramp rates)

This is also illustrated in Figure 8-28. As conveyed from the figures, RMS5 and RMS20 are quite dependent on economic dispatch. Hence, HECO units do most of the maneuvering depending on the commitment and load level. In this case, it is Kahe 3 and Kahe 5. Similarly, AES and Kalaeloa do not contribute as much as the HECO units for faster variations (RMS1). In relation to the ratings of the units, the maneuvering of the Kahe 3 and 5 units are more significant compared than the other units (plot on the right).

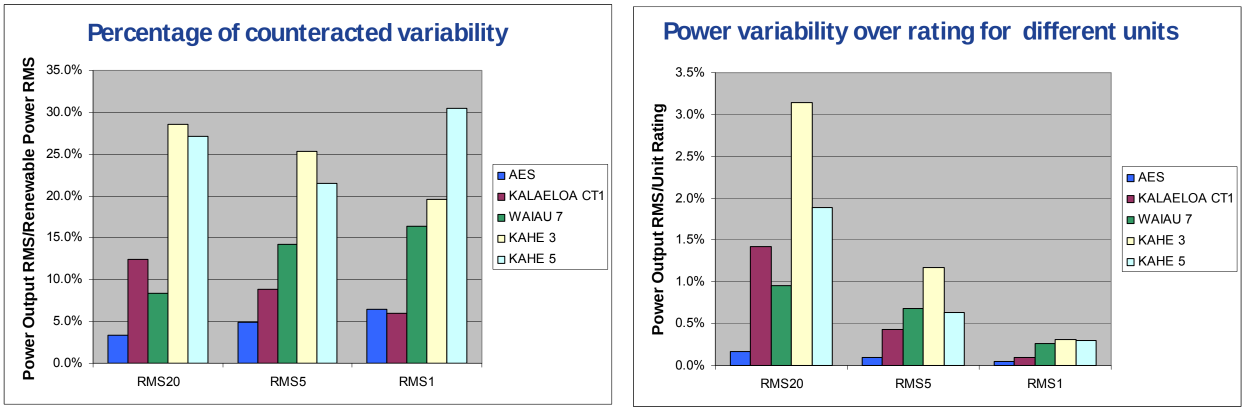


Figure 8-28. Hour 5795 Scenario 5F3 – Unit maneuvering. Left: figure: Percentage of variability counteracted by a specific unit. Right: figure: RMS power variability over the rating of each unit.

The frequency performance and wind power variability across all the scenarios is presented in Figure 8-29. As installed wind power and scenario assumptions are different, it was important to understand how these affect the frequency performance across the scenarios. The sensitivity analysis was performed for high-volatility hours across all the scenarios with no solar variability, and no governor response from AES. The wind power variability across Scenarios 5, 3 and 1 is shown in Figure 8-23 (left). Note that these data were used as an input to the simulation. Figure 8-29 shows the RMS value of the system frequency across all scenarios with proposed and present ramp rates and droop settings. The figures show that a good correlation exists between increased wind power variability and associated frequency performance. Scenarios 3B and 5B have better frequency performance than Scenarios 3F3 and 5F3 because 1) less wind energy is being delivered, 2) fewer units are against their limits, and 3) the system has more up reserve capacity in 3B and 5B as compared to 3F3 and 5F3. Figure 8-29 also highlights that the proposed AGC ramp-rate improvements to HECO units positively impact frequency mostly in the 5 minute and 20 minute time frames.

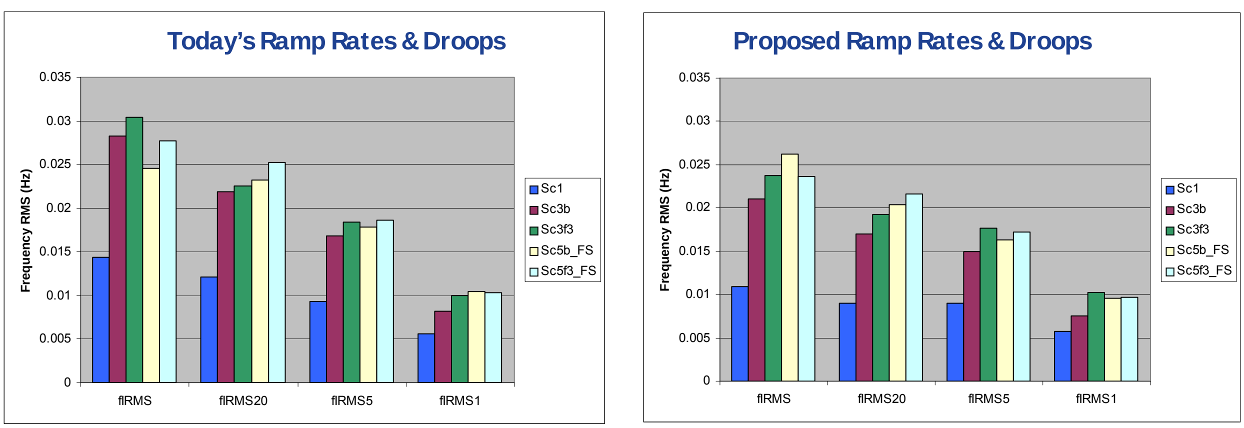
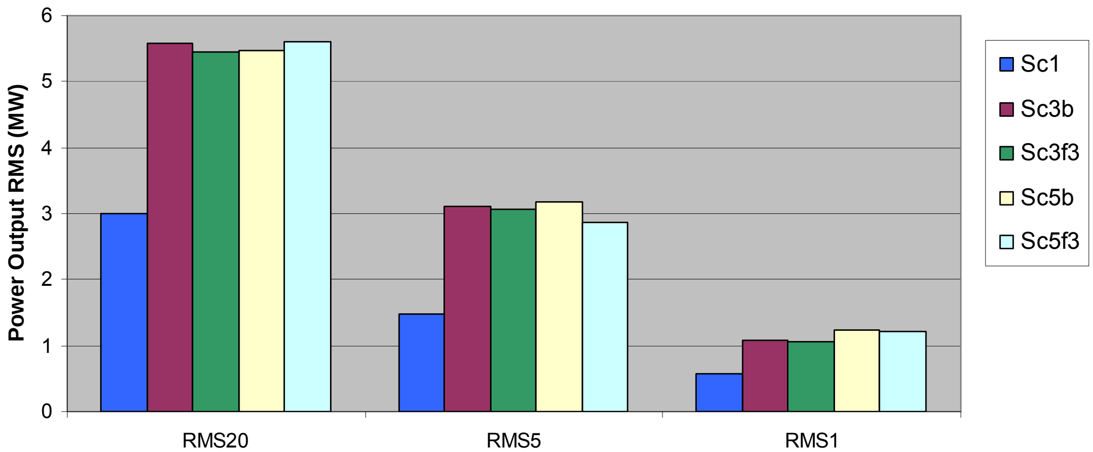
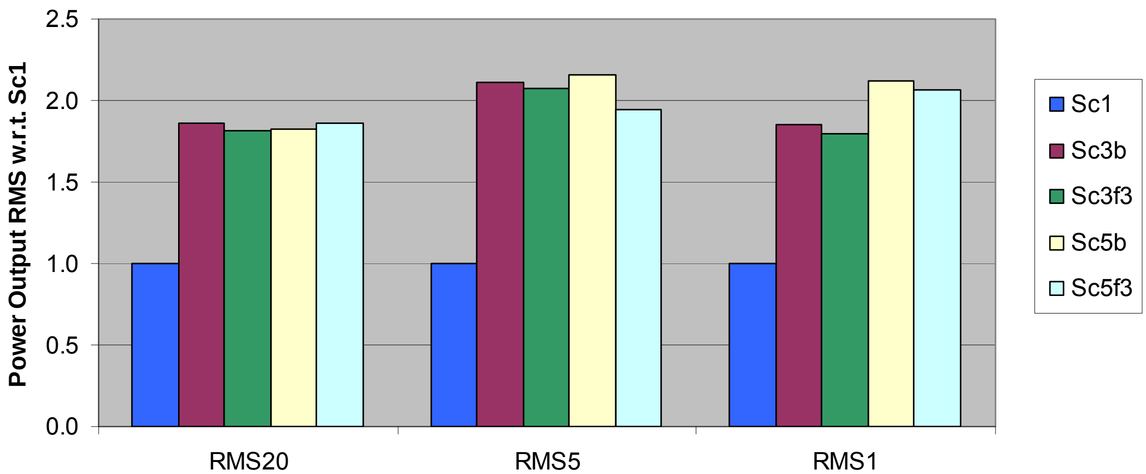


Figure 8-29. System frequency RMS across highly volatile wind events for each scenario. No solar variability and no governor response from AES were assumed.

Figure 8-30 shows that the maneuvering of HECO units increases in scenarios with more wind power. In this case only wind power variability was considered in the simulations. Note that the dynamic simulation cases assumed that no solar variability existed, and proposed ramp rates was in place for the HECO thermal units.





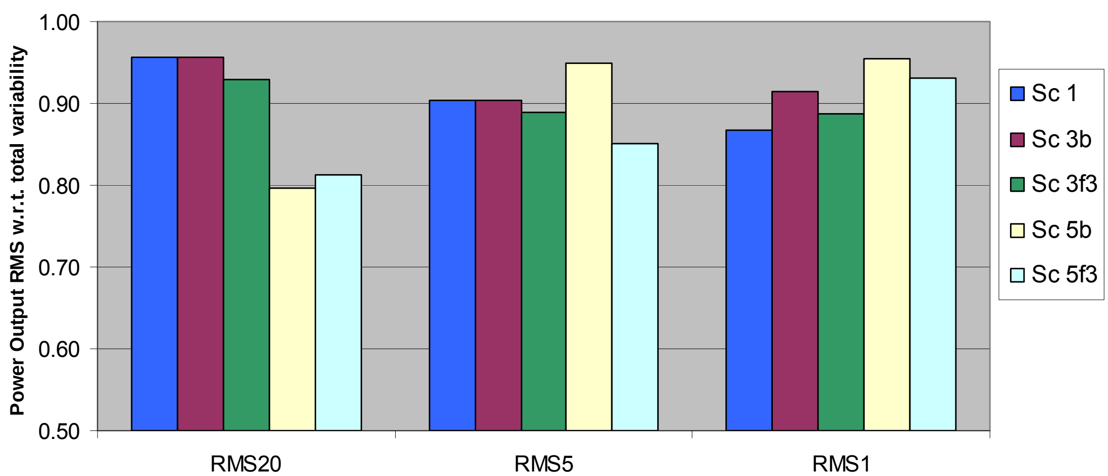


Figure 8-30. Maneuvering of HECO units across scenarios. No solar variability and proposed ramp rates for the HECO thermal units assumed.

The top figure shows the RMS power output for different timescales (1 minute, 5 minutes, 20 minutes). The RMS power output variability represents the power variations across the HECO units for each scenario and the respective volatile wind power event that was simulated.

The middle figure shows the variability on a per unit basis, with respect to Scenario 1. The maneuvering of HECO units doubled in Scenarios 5 and 3 as compared to Scenario 1.

The bottom figure shows the HECO units response with respect to total variability of the thermal units (all units). This figure highlights the respective contribution of the HECO units in response to the wind variability.

The following are the main observations from the analysis:

- HECO units provide most of the maneuvering and carry the majority of the burden of maintaining system frequency,
- A high percentage of total system variability (>80%) is counteracted by HECO units in all scenarios for both fast and slow variations
- Variability of system frequency is expected to increase if solar power is considered.

8.5.4. Strategies to manage highly volatile wind power events

Three strategies were considered to manage volatile wind power events:

- AGC cycle modifications,
- Wind plant ramp rate limits, and
- Energy storage.

Additional strategies may exist to help manage the volatility of the wind power

8.5.4.1. AGC cycle modifications

The project team considered other strategies to reduce the impact of volatile wind power events. One of these strategies is to reduce the AGC response cycle from 10 seconds to 4 seconds. The concept was to provide control action to the thermal units more quickly, thereby enabling the units to respond more quickly to volatile wind power events. A dynamic simulation sensitivity run was carried out in GE PSLF™ dynamic model to assess the effect of reducing the AGC control cycle from 10 seconds (present) to 4 seconds. The shorter control cycle enables the EMS to dispatch generation more frequently and reduces the amount of time a frequency error can develop (mismatch between generation and load).

This 4-sec AGC cycle run was performed for high-volatility hour of Scenario 5F3 (Hour 5795) with solar and wind variability. The dynamic simulation was performed with proposed ramp rates for the thermal units to understand if there is further significant contribution by reducing the response time of the AGC control.

The long-term dynamic simulation with 4-sec AGC cycle was performed using the following methodology:

- The load flow model in GE PSLF™ program is initialized for Hour 5795 of Scenario 5F3 using unit commitments obtained from GE MAPS™ tool,
- The simulated 2-sec wind and solar power data for the wind and solar sites are used for dynamic simulation in GE PSLF™ model (see Figure 8-31) to introduce variability.

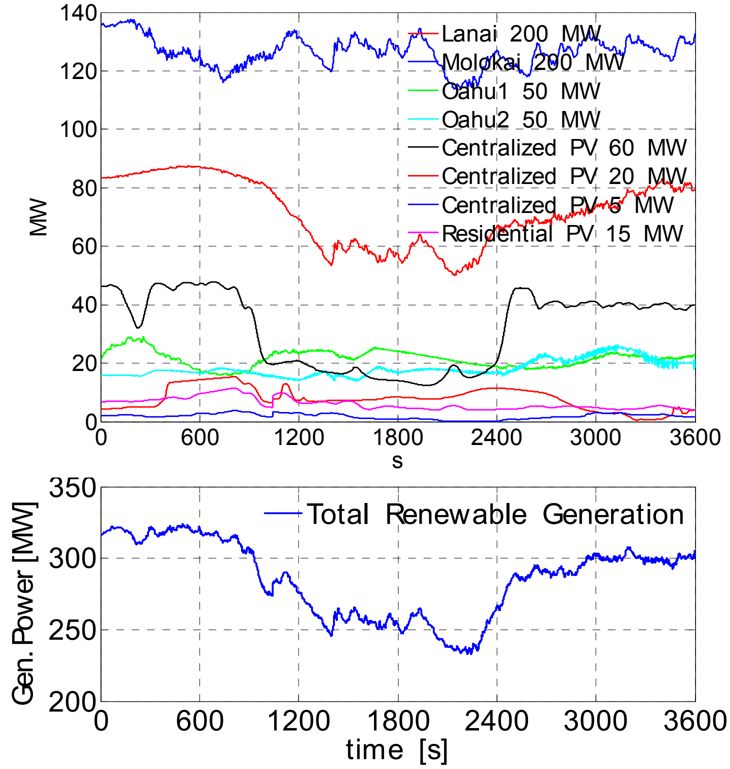
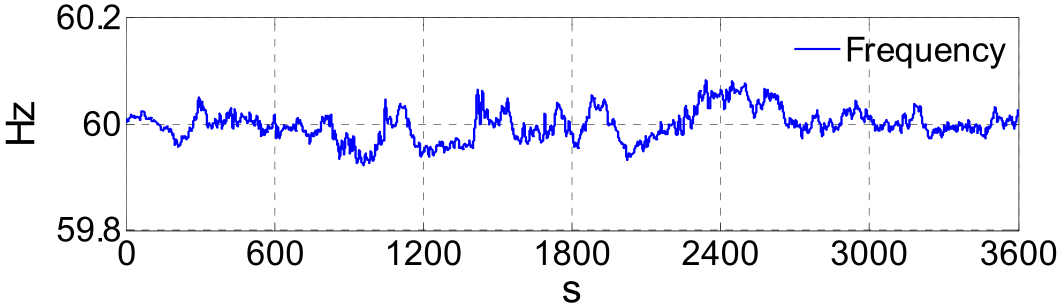
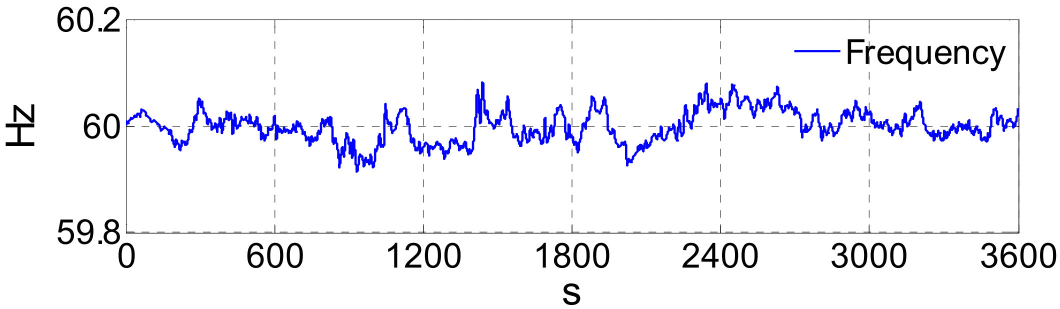


Figure 8-31. Wind and Solar Power variability – Hour 5795, Scenario 5F3

The results are shown in Figure 8-32 and Figure 8-33. A similar frequency response and HECO generator unit response is observed for both the cases. The figures highlight that only moderate improvement in system performance is achieved with the shorter AGC control cycle.

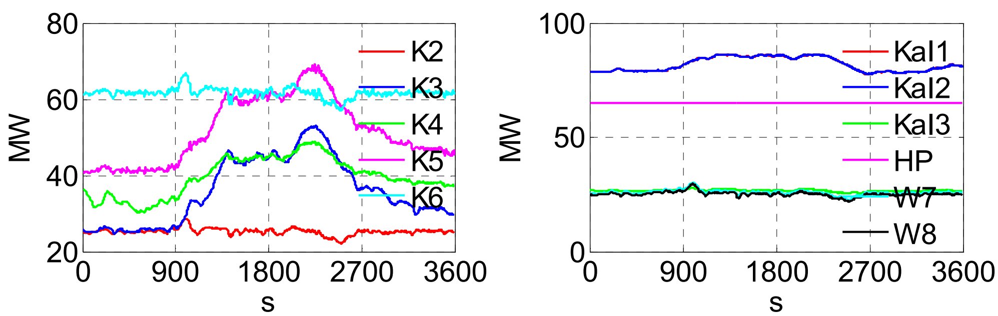


a). 4-sec AGC cycle

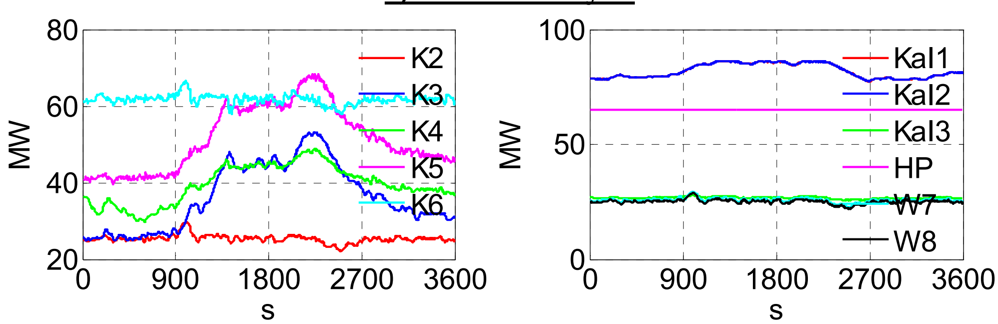


b). 10-sec AGC cycle

Figure 8-32. Hour 5795 Scenario 5F3 – Frequency Response



a). 4-sec AGC cycle



b). 10-sec AGC cycle

Figure 8-33. Hour 5795 Scenario 5F3 - Generating Unit Response

The results also highlight that by shortening the AGC control cycle to 4-sec from 10-sec, there is only a moderate improvement in frequency performance and smoother response of the HECO thermal units. Figure 8-34 shows that with 4-sec AGC cycle, there is a slight reduction in RMS value of the frequency in all the time frames (RMS1, RMS5 and RMS20).

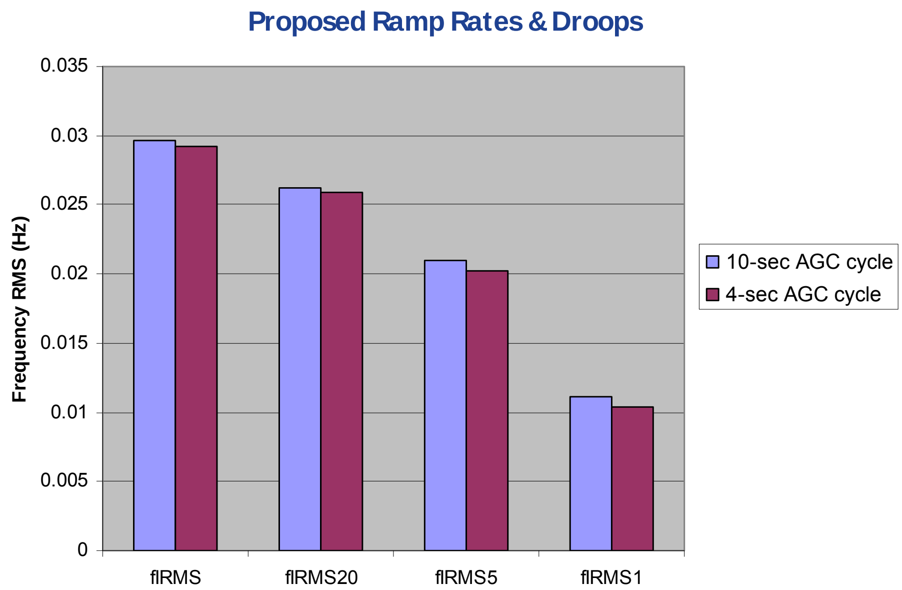
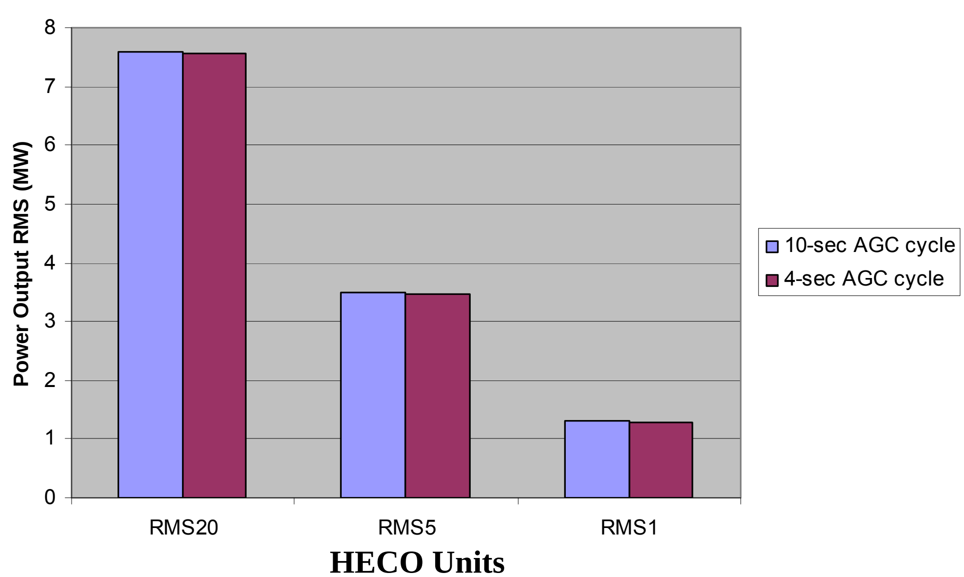
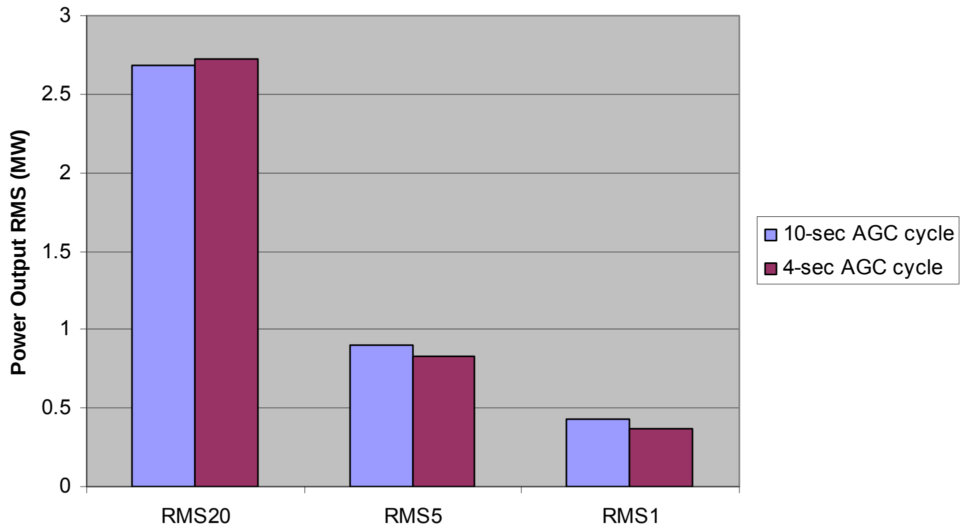


Figure 8-34. AGC cycle sensitivity - Hour 5795 Scenario 5F3

In Figure 8-35, it is observed that the RMS value of maneuvering of sum of all of the HECO units to the wind and solar variability has remained the same irrespective of the AGC control cycle (4-sec or 10-sec) considered. However, as shown for Kahe 5, the shorter AGC cycle of 4-sec has resulted in a smoother RMS value of power output of the Kahe 5 unit for a similar overall system response. That is for the same overall system response, the shorter AGC cycle results in lower maneuvering of the controlled units.





Kahe 5

Figure 8-35. AGC cycle sensitivity - maneuvering of HECO units

In summary, shortening the AGC control cycle to 4-sec from 10-sec only moderately improved the frequency performance.

8.5.4.2. Wind plant ramp rate controls

The variability of the wind power delivered to the HECO system can be reduced if the output from the wind plants is ramp rate limited. Modern wind turbines can automatically limit upward ramp events with sophisticated controls, by self-curtailing the wind energy delivered. Limiting the downward ramp events from the wind plant requires an energy storage system. Regulating wind power variation in such a way will reduce the maneuvering of thermal units.

The ramp rate limit control was modeled to limit the slower variability components (above about 30 sec) without significantly affecting faster variability. The rationale is that the relatively low frequency wind power variation is important to the system frequency transients and therefore should be ramp rate limited. The high frequency variations will mostly be attenuated by the inherent characteristic of the system's inertia. In addition, attempting to regulate high frequency variations will add stress on the turbine mechanical drive train and cause wear and tear. The same approach was used for representing ramp-rate limitation for wind power drops and rises.

Figure 8-36 shows the use of a low pass filter and a ramp rate limiter to limit the variability of low frequency components. This model captures the performance of modern wind turbine controls. Several ramp rate limits on the wind plants were simulated for the most volatile hours to understand the potential benefits and impacts to system frequency and delivered energy. Two-second wind power data was used in the simulation.

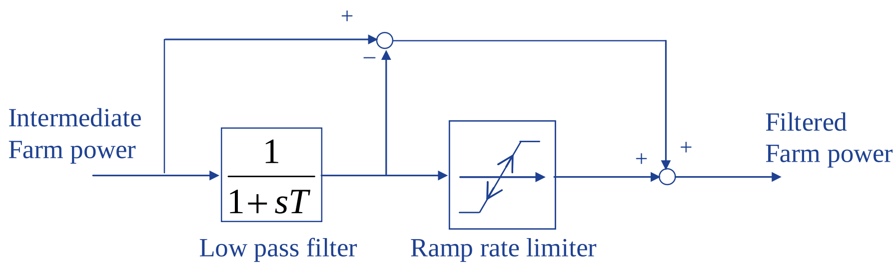


Figure 8-36. Processing filter for ramp rate control

8.5.4.2.1. Pitching the wind turbine blades to meet upward ramp limits

When upward ramp rate of a wind plant is controlled/limited, the output power from the wind plant is curtailed, by pitching the blades of the wind turbine, thereby reducing the available energy that could be captured from the wind. The difference between the delivered power and available power is the energy that is not captured. Table 8-13 presents the total energy lost in the year and the percentage of available energy lost. This analysis is for the entire study year of 2014.

The ramp rate limits shown at the top of the table are in per-unit of the wind plant rating and were applied to all wind plants in the system. The 1/120 per unit per minute means that a 200 MW plant would have a ramp-rate limitation of 1.67 MW/min (i.e. 200 divided by 120).

Table 8-13: Lost wind energy due to up ramp rate limits at each wind plant

Wind Farms	1/60 pu/min		1/120 pu/min	
	Lost Energy (GWh)	Lost Energy (%)	Lost Energy (GWh)	Lost Energy (%)
200MW Lanai	3.4	0.38%	13.7	1.53%
400MW Lanai	2.6	0.16%	13.1	0.81%
200MW Molokai	2.7	0.36%	9.0	1.20%
50MW North Oahu 1	3.7	2.21%	8.4	5.00%
50MW North Oahu 2	4.2	2.21%	9.6	5.08%

The lost energy (in units of energy and is units of lost energy with respect to total plant production) is shown for two upward ramp rate limits. The results indicate that a more aggressive ramp rate limit (1/120 pu/min) will cause higher levels of lost energy. The results also show that a larger wind plant (400 MW Lanai as compared to 50 MW North Oahu 1) will experience lower levels of lost wind energy (with respect to its annual energy production) because the plant is larger and more geographically diverse. This tends to reduce the variability of the plant on a per unit basis, thereby reducing the number of times the ramp rate limit would be exceeded. Conversely, the power output from smaller wind plants tend to be more variable due to less geographical diversity. This results in larger energy curtailment. Combining the results of the table above, the estimated lost energy per scenario is presented in Table 8-14.

Table 8-14: Lost wind energy due to up ramp rate limits per scenario

	1/60 pu/min		1/120 pu/min	
	Lost Energy (GWh)	Lost Energy (%)	Lost Energy (GWh)	Lost Energy (%)
Scenario 1	7.9	2.21%	18.0	5.04%
Scenario 3	10.5	0.53%	31.2	1.58%
Scenario 5	14.0	0.70%	40.7	2.02%

8.5.4.2.2. Wind plants integrated with energy storage to meet down ramp limits

Wind plants that must also meet a prescribed ramp rate limit in the down direction requires a storage system. During instances when the wind is calming and the power from the plant is dropping off faster than the prescribed downward ramp rate limit, and energy storage system can discharge its stored energy in order to slow the rate of power drop.

The following text describes the estimated size (power and energy rating) of a battery energy storage system (BESS) to meet: (1) a prescribed ramp rate limit at each wind plant, and (2) a prescribed ramp rate limit for each scenario. In the first case, it is assumed that each wind plant locally manages it ramp rate limit. In the second case, it is assumed that a system-wide BESS is deployed to manage the total aggregate wind plant ramp rate limit. It is anticipated that a smaller BESS (power and energy rating) would be needed to manage the system-wide ramp rate because the geographic diversity would cause relatively lower levels of variability as compared to the per unit variability at each wind plant. Two-second wind power data for the full year of 2014 was used to estimate the power and energy rating of the energy storage system, with some assumptions on battery performance parameters. This exercise was performed for each wind plant considered in the study and for various ramp rate requirements.

For the purposes of this example, a BESS will be sized to manage specific ramp rates at each wind plant. In a second task, the BESS will be sized to manage the ramp rate of the aggregate wind power delivered to the Oahu system.

The estimation of the BESS power rating is done in the following way:

Step 1: Calculate the needed BESS power for every 2-sec time step for the whole year

P_need(t) = P_raw(t) – P_filtered(t)

where positive *P_need* means power to be absorbed by the BESS while negative *P_need* means power to be supplied

Step 2: Find the 0.1% and 99.9% percentiles of the ascending sorted *P_need* data and pick the one with higher absolute value for determining the power rating of the BESS

P*_rating = max(|0.1% percentile of P_need|, |99.9% percentile of P_need|)*

In step 2 above, the 0.1% percentile of *P_need* means that there is 1/1000 chance that a wind-varying event will require higher discharging level than BESS rating. Similarly, the 99.9% percentile of *P_need* means that there is 1/1000 of chance that a wind-varying event will require higher charging level than BESS rating. Picking the higher value of these two means the designed BESS is capable of handling at least 998 out of 1000 events with fully compensated power.

Although it would be ideal if the BESS were able to meet the largest power requirement (i.e., to cover every *P_need* value), there is a compromise between the cost of the system and the benefit it brings. In addition, the statistical nature of the wind variability makes it impossible to know precisely what most severe *P_need* will be.

In order to estimate the energy rating of BESS, a number of assumptions related to BESS performance are made. In reality, these assumptions vary depending on the actual battery characteristics, actual BESS usage, etc. However, it is believed that this list of assumptions should provide an illustrative example for sizing a storage system.

- Assume that the BESS provides both ramp-up and ramp-down limiting functions. To best recover the available wind energy, the wind plant ramp-up limiting control is assumed over-ridden by BESS,
- Assume that BESS has to address at least 998 out of 1000 wind varying events,
- Assume that BESS has 90% one-way efficiency in power conversion (measured on high voltage side of transformer),
- Assume that BESS operates at 50% state of charge (SoC); ready for operating in either direction,
- Assume that BESS operates between 10% and 90% SoC, and
- Assume the BESS has a 30min re-charging (discharging) cycle time. To address those continuous rising or dropping events longer than 30min, a 20% margin is included for the BESS rating.

The estimation of the BESS energy rating is done in the following way:

Step 1: Take *P_need(t)* calculated from the power rating estimation and compute the integrated energy data

$$E\_intg(t) = E\_intg(t-\Delta t) + P\_need(t) * \Delta t$$

where Δt equals to 2 sec

Step 2: From the *E_intg* data series, compute for every time step the energy needed in a charging cycle as

$$E\_need(t) = E\_intg(t) – E\_intg(t-T\_cycle)$$

where *T_cycle* equals to 30min – the assumed re-charging/discharging cycle

Step 3: From the sorted *E_need(t)* in ascending order, we can again find out the 0.1% and 99.9% percentiles and set them as the required charging and discharging energy level for the BESS

E_discharge = - 0.1% percentile of E_need(t)
E_charge = 99.9% percentile of E_need(t)

Step 4: Finally, the estimated BESS energy rating is calculated using the assumptions mentioned previously:

E_rating = max(E_discharge, E_charge) / 50% / 90% / (90%-10%) / (1-20%)

Using the described method, one can estimate the power and energy rating of the BESS. The results are shown in Table 8-15.

Two ramp rate limits are shown here: 1/120 pu/min (top table) and 1/60 pu/min (bottom table). In the second column of each table the ramp rate limit (in units of MW/min) is described for each wind plant. The Power (MW) heading describe the maximum charge and discharge rating required to manage the up and down ramp rate limits at each wind plant, respectively. The Energy (MWh) heading describes the maximum charge and discharge energy required to manage the up and down ramp rate limits, respectively. The next column describes the estimated BESS Rating (MW, MWh). The BESS power rating is defined by the largest charge or discharge power required by the wind plant. The BESS energy rating is defined by the sum of the charge and discharge energy, plus the adders described above. The final column, titled BESS Rating estimates the size of the BESS with respect to the wind plant rating and in terms of minutes of energy at rated power (i.e., the total number of minutes the BESS could discharge energy at its rated power, if it were fully charged). The final four rows in red and blue text describe two different cases. The Distributed BESS scenario (red text) is simply the addition of all of the BESS' situated at each wind plant. Conversely, the Central BESS scenario (blue text) describes the size of the BESS if it were centrally located, managing the total wind plant ramp rate limit, as opposed to the ramp rate limit at each wind plant (Distributed BESS scenario).

Based on the constraints and assumptions summarized above, for a 1/120 pu/min ramp limit for Scenario 3, it is estimated that a total of 115 MW and 165 MWh of BESS would be needed to manage the ramp rate at each plant to meet this limit for the Oahu system (red text).

If the BESS is managing the total system-wide wind ramp rate limit (blue text), the results shown in the table below indicate that a smaller BESS, as measured in both MW and MWh was needed to manage the total production from all wind plants. In the case of the 1/120 pu/min ramp rate limit for Scenario 3, the size of the BESS decreases to 43 MW and 71 MWh based on the assumptions and constraints described earlier.

Table 8-15: Power and energy rating estimation for the BESS

1 / 120 per unit per min ramp rate	Ramp Rate (MW/min)	Power (MW) Charge	Power (MW) Discharge	Energy (MWh) Charge	Energy (MWh) Discharge	BESS Rating (est.) (MW / MWh)	BESS Rating (est.) % plant	BESS Rating (est.) Minutes
200MW Lanai	1.67	53	54	24	24	54 / 84	27%	94
400MW Lanai	3.33	69	66	31	29	69 / 107	17%	92
200MW Molokai	1.67	24	19	9	5	24 / 30	12%	75
50MW North Oahu 1	0.42	11	10	4	4	11 / 15	22%	80
50MW North Oahu 2	0.42	11	11	4	4	11 / 13	22%	72
Dist. BESS Scenario 3	4.17	-	-	-	-	115 / 165	23%	86
Dist. BESS Scenario 5	4.17	-	-	-	-	100 / 142	20%	85
Central BESS Scenario 3	4.17	37	43	20	20	43 / 71	9%	99
Central BESS Scenario 5	4.17	17	22	8	9	22 / 30	4%	82

1 / 60 per unit per min ramp rate	Ramp Rate (MW/min)	Power (MW) Charge	Power (MW) Discharge	Energy (MWh) Charge	Energy (MWh) Discharge	BESS Rating (est.) (MW / MWh)	BESS Rating (est.) % plant	BESS Rating (est.) Minutes
200MW Lanai	3.33	19	16	7	5	19 / 12	10%	37
400MW Lanai	6.67	17	16	6	4	17 / 10	4%	34
200MW Molokai	3.33	10	9	2	1	10 / 3	5%	21
50MW North Oahu 1	0.83	7	7	2	2	7 / 3	14%	28
50MW North Oahu 2	0.83	7	7	2	1	7 / 3	15%	25
Dist. BESS Scenario 3	8.33	-	-	-	-	41 / 19	8%	28
Dist. BESS Scenario 5	8.33	-	-	-	-	43 / 21	9%	30
Central BESS Scenario 3	8.33	8.8	9.3	3.1	2.2	9.3 / 10.8	1.9%	69
Central BESS Scenario 5	8.33	5.3	6.0	0.8	0.6	6.0 / 2.8	1.2%	28

It is worth noting that a centralized BESS configuration requires less total power and energy rating than a distributed BESS. From the tables above, the size of a centralized BESS is even smaller than a single BESS at a 200 MW Lanai plant. This is due to the wind smoothing benefits of geographic diversity.

8.5.4.2.3. Wind plant ramp rate limits and thermal unit maneuvering

Long-term dynamic simulations were performed for all scenarios with the following sensitivities for different wind plant ramp rate limits, in order to understand the reduction in power variability:

- No ramp rate limits
- 1/30 [pu/min] up/down
- 1/60 [pu/min] up/down
- 1/120 [pu/min] up/down
- 1/60 [pu/min] up
- 1/60 [pu/min] down

Figure 8-37 shows the up/down ramp rate limits applied to Molokai 200 MW for high-volatile hour of Scenario 5. The zoomed-in plot clearly illustrates that the wind power variability is reduced with the ramp rate limitations.

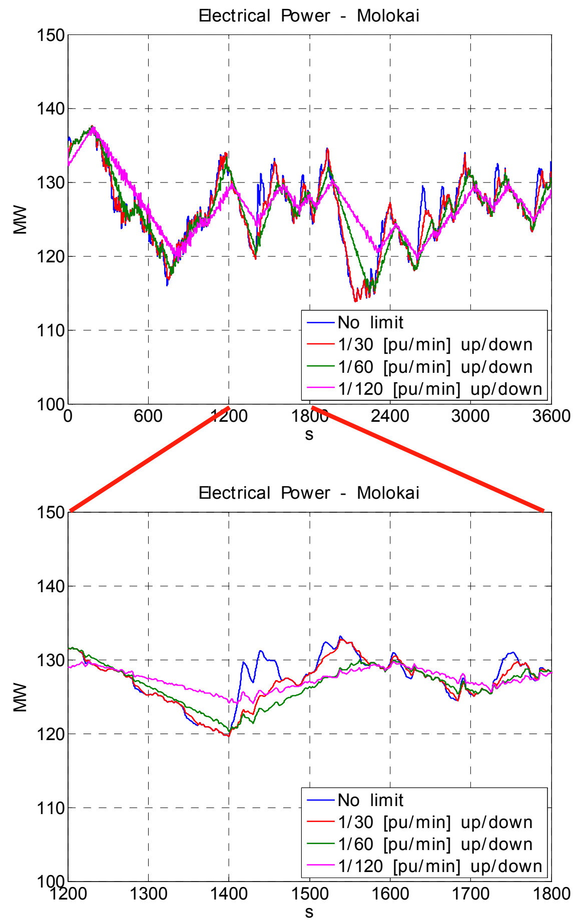


Figure 8-37. Ramp rate limits applied to 200 MW Molokai wind plant (top: one-hour, bottom: 10 minute zoom)

Figure 8-38 shows RMS estimations on total wind power variability for Scenario 5 and the effectiveness of ramp rate limits on the wind plants. The top figure shows the power RMS values for several ramp rate limits while the bottom plot shows the same magnitudes compared to the case without ramp rate limits. The bottom figure highlights that ramp rate limits are more effective in reducing shorter time frames (RMS1) as compared to RMS5 or RMS20. Also, the most constraining ramp rate limits (1/60 and 1/120 per unit per minute) produce sizable reduction of the RMS variability indexes as expected. RMS5 is 65% of base case for 1/60 per unit per minute and less than 40% of base case for 1/120 per unit per minute. Upward ramp rate limits have noticeable but more modest impact.

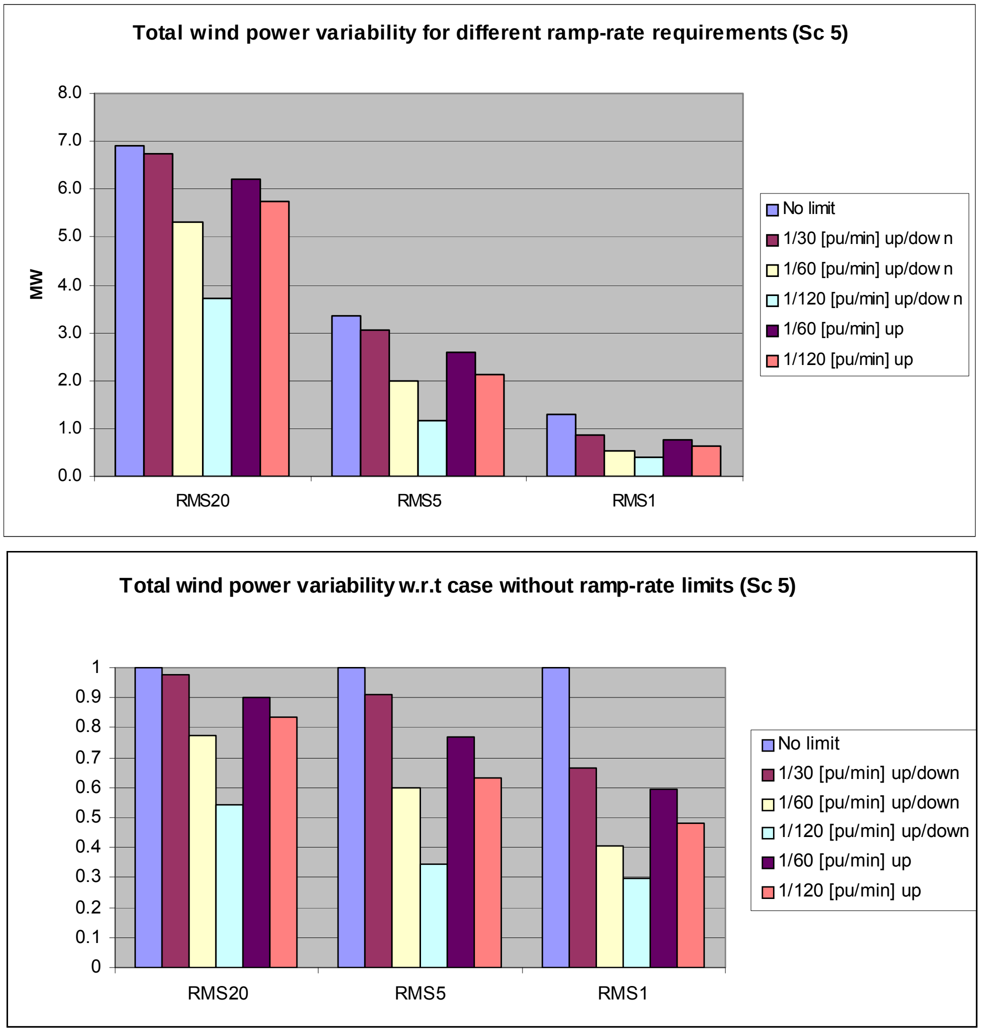


Figure 8-38. Effect of ramp rate limits at wind plants

With the objective of estimating the impact of these wind power variability reductions, GE PSLF™ dynamic simulations were performed for high-volatility hours of Scenarios 5, 3 and 1. The simulations were initialized from GE MAPS™ results and 2-second wind power data were used to simulate variability and perturb the system. Solar power was assumed constant to assess the impact of wind variability only.

The following results are for a high-volatility hour of Scenario 5F3 with proposed ramp rates. Figure 8-39 shows that constraining ramp rate limitations up/down (1/60 and 1/120 per unit per minute) caused a sizable reduction of the frequency RMS. The RMS5 frequency value for 1/120 per unit per minute was about 35% of the base case (fRMS). Ramp-rate limitation of 1/30 per unit per minute has RMS5 of about 90% of the base case. Limiting the ramp-rate for wind power pick up (the last two bars of each RMS value in Figure 8-39) results in RMS5 of less than 80% of the base case with 1/60 pu/min.

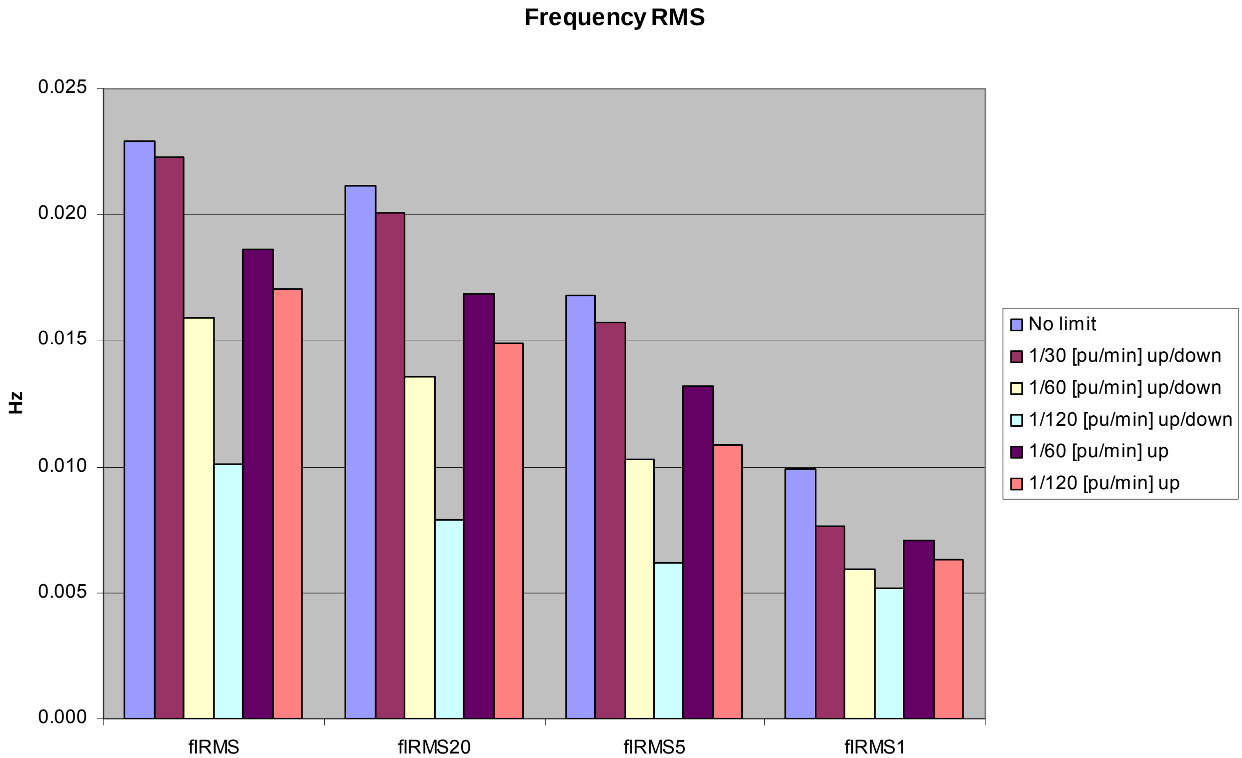


Figure 8-39. Effect of ramp rate limits on system frequency

The effect of ramp rate limitations on maneuvering of thermal units is shown in Figure 8-40. The results show that with very constraining ramp rate limitations (1/60 and 1/120 per unit per minute), a sizable reduction of thermal unit maneuvering is achieved. The RMS5 value for 1/120 per unit per minute is less than 50% of the base case; and for 1/60 per unit per minute, it is less than 70% of the base case at Kahe 4. A 1/30 ramp rate limit has moderate impact on the maneuvering of the units.

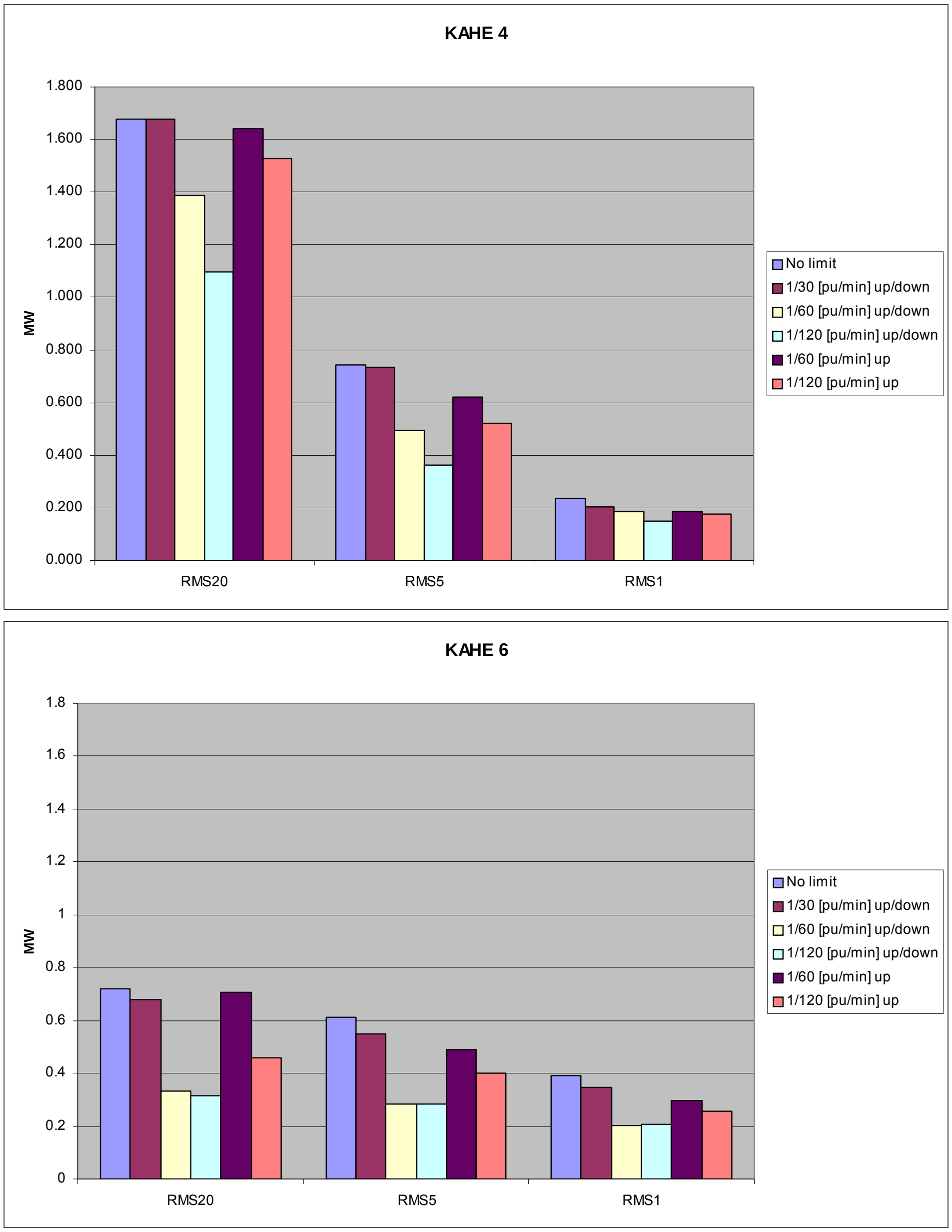


Figure 8-40. Effect of ramp rate limits on Kahe 4 and Kahe 6

Figure 8-41 illustrates the relationship of the power output of Kahe 3 as the constraints on wind plant ramp rates are increased.

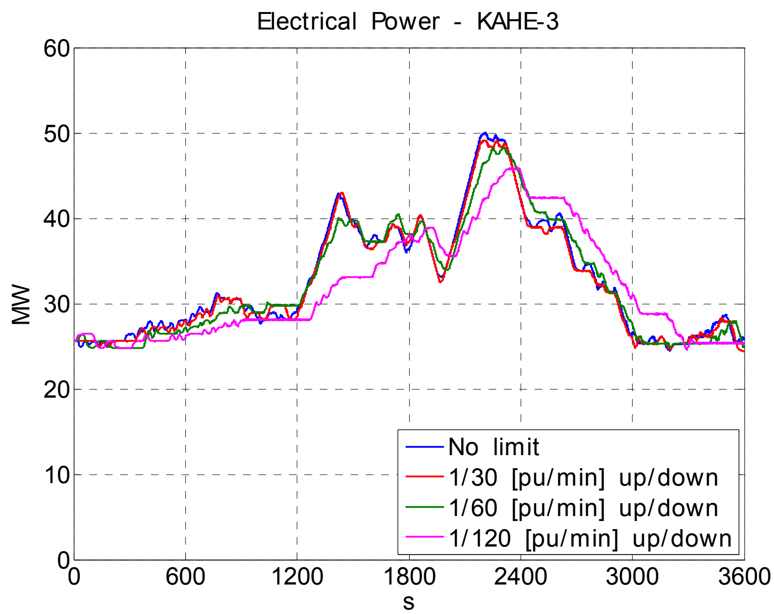


Figure 8-41. Kahe 3 Unit response for various ramp-rate limits

Limiting the upward and downward power changes from each wind plant reduces the variability of the thermal units that are balancing the power delivered from the wind plants. The cost of wind plant ramp rate limits in terms of lost energy due to wind energy curtailment to meet upward ramp rate limits and the capital and operating cost of an energy storage system to meet downward ramp rate limits were estimated for specific limits based on the assumptions described above. The benefit brought by wind plant ramp rate limits in terms of reduced thermal unit maneuvering is difficult to quantify, as the impact of greater thermal unit maneuvering on the heat rate (efficiency) and maintenance costs is not well known.

8.5.4.3. Energy Storage

In an earlier section, energy storage was described as a potential technology to help manage the down ramp rate limits at each wind plant. A comparison was made between managing the ramp rates at each wind plant and centrally managing the total wind power down ramp events. In addition to down ramp rate limits, energy storage could also be used as an additional resource to not only regulate the frequency events caused by wind variability events, but all events that might cause frequency excursions. A fast-responding energy storage system, such as a flywheel or battery energy storage system can quickly inject energy to the grid and absorb energy from the grid to help maintain the balance between load and generation.

This study did not perform extensive analysis on strategies to mitigate variability that utilize energy storage because of constraints on the study's resources and timeline. While energy storage can be used to help mitigate the variability and uncertainty of wind power in the HECO system, the cost and benefit of energy storage would need to be explicitly compared against alternate technologies and strategies that were considered in this study. This includes those mentioned above, including increasing the ramp rate capability and governor response of the HECO units. This type of analysis would also need to quantify the "cost" of thermal unit maneuvering in terms of unit efficiency penalty and maintenance. This type of comparative benefit-cost analysis was beyond the scope of the current study.

Under the scenarios considered in this study, the team did conclude that energy storage is not necessary to manage the variability of the wind plants if the present ramp rate capabilities of the HECO thermal units are increased to the ramp rates proposed by HECO. This conclusion is sensitive to the underlying assumptions in the scenarios analyzed in the study. Each of the scenarios consists of a specific generation mix, wind plant size and location, and assumed performance capabilities of the Energy Management System, thermal units, and wind plants. As the Oahu power system evolves, it may be necessary for HECO to reconsider the strategies and technologies to enable high levels of wind power, and/or consider alternate strategies to help enable the levels of wind power considered in this study.

8.5.5. Conclusions

The following are the overall conclusions and observations from the study of volatile wind power periods:

- Variability of severe volatile hours increases by a factor of approximately 2 when the offshore plants are added to the system (five times higher total installed wind plant rating in Scenario 3 and 5, as compared to Scenario 1). Variability here is measured in terms of the RMS indexes defined in Section 8.5.1.
- The RMS indexes of system frequency scale up nearly linearly with the increased wind power variability for the severe cases analyzed for each scenario.
- Sub-hourly slow variations (few minutes and slower) are mostly driven by AGC economic dispatch. Hence, only few units are dispatched to counteract the wind power variations based on the economic participation factors corresponding to the system operating condition.
- Scenarios 3B and 5B have better frequency performance than Scenarios 3F3 and 5F3 because less wind energy is being delivered to the system, fewer units are against their limits, and the system is carrying more online regulating reserves.
- HECO units tend to respond to fluctuations in wind and solar power more than the others units, thereby carrying the majority of the duty to maintain system frequency.
- Proposed ramp rate improvements to HECO units provide significant benefit in terms of maintaining system frequency and performance in the 5 minute and 20 minute time frames.

For the specific sensitivities with wind plant ramp rate limitations, some important conclusions are:

- Reducing the AGC cycle time from 10 seconds to 4 seconds moderately improved the frequency performance.
- Besides improving the ramp rates of the HECO units, wind plant ramp rate limits can be applied to mitigate the effects of fluctuating wind resources or limit excessive maneuvering of the thermal units.
- Modern wind turbine controls are capable of limiting upward ramp events. Energy curtailment increases as more constraining ramp rate limits are applied.
- Down ramp rate limits at each wind plant require energy storage be present to discharge its energy when the wind plant rapidly decreases its power output. The power and energy

rating of a BESS was estimated for the modeled wind plants for two different ramp rate requirements. The size and rating of the BESS for such applications is likely to be large. The size and rating of the BESS can be reduced if the BESS is centrally controlled to manage the system-wide wind plant ramp rate limit, as opposed to a single BESS at each wind plant locally managing the ramp rate of each wind plant.

- A fast-responding storage system can be used to address other system events, including those not related to wind plant variability that imbalance load and generation. The value of a storage system that provides system support in the form of frequency regulation or bridging to fast-starting thermal generation was not considered in this study; nor was the benefit the storage system could provide in terms of reducing thermal unit maneuvering. A detailed cost benefit analysis would be needed to determine the value proposition for the BESS on the Oahu system. This was beyond the scope of this study.
- The RMS5 frequency value for 1/120 per unit per minute was about 35% of the base case without ramp rate controls for Scenario 5F3 while a limit of 1/30 per unit per minute was 90% of the base case. Limiting the ramp rate for wind power pick up (the last two bars of each RMS value in Figure 8-39) results in RMS5 of less than 80% of the base case with 1/60 pu/min.

8.6. Loss of Load Contingency Event

The thermal units are expected to operate at minimum load for several hours in the year under high wind scenarios (Scenario 3 and 5) as discussed in sections 6.5 and 6.6. The simulations presented in this section analyze system performance during loss of load events during periods when the thermal units operate at low power level to assess down-reserve requirements and related sensitivities. The loss of load events of this magnitude are generally associated with faults on the transmission system.

8.6.1. Initial conditions and contingency

Transient stability simulations were performed for Scenario 5 during light load hours (720 MW load) with approximately 50% of the power being provided by wind plants (357 MW wind power). These conditions were observed in the production cost simulation on October 23rd at 12am. The thermal units were substantially backed down and the system was carrying 89 MW of down-reserve (1 MW below the specified limit). The unit commitment for this event was obtained from the production cost simulation. Table 8-16 below lists the generation dispatch for this hour. This hour was selected by HECO from a complete year of operation (high wind, low load).

Table 8-16: Generation dispatch on October 23rd at 12am for Scenario 5F3

AES	K1	K2	K5	K6	Kal	W7	W8	50 Wind	50 Wind	Lanai	Molokai	HON	OTEC
68.3	37.8	38.0	56.0	55.3	68.3	37.8	38.0	32.9	34.0	142.2	80.5	6.0	25.0

8.6.2. Sensitivities

The following sensitivities are considered in the GE PSLF^{TM} simulation:

- Load rejection amount (close to Kahe area)
  - 40 MW
  - 80 MW
  - 140 MW
- Wind farm over-frequency control

  - No response (base case)
  - Moderate response (6% droop and 240 mHz deadband)
  - Aggressive response (3% droop and 30 mHz deadband): GE is not proposing a 3% droop, this is a sensitivity performed to understand system performance with aggressive settings.
- Generator droop
  - Proposed future droop setting (base case)
  - Today's setting
- AES governor
  - With governor droop response (base case)
  - Without governor droop response

8.6.3. GE PSLF™ transient stability results

Figure 8-42 shows the simulation results from three different levels of load rejection (40, 80 and 140 MW). There is a rapid increase in frequency (upper-left in the figure) and then frequency recovers to a steady state value associated to the droop response of the thermal units. The AGC is not represented in these simulations and hence the frequency does not return back to nominal. The focus of these simulations is on the magnitude of the initial frequency deviation as opposed to recovery to 60 Hz. The mechanical power of AES (upper right) and Kahe 5 (lower left) show the governor responses for these units. The off-island wind plants power do not react to frequency and their output remains constant (as shown in the lower right figure).

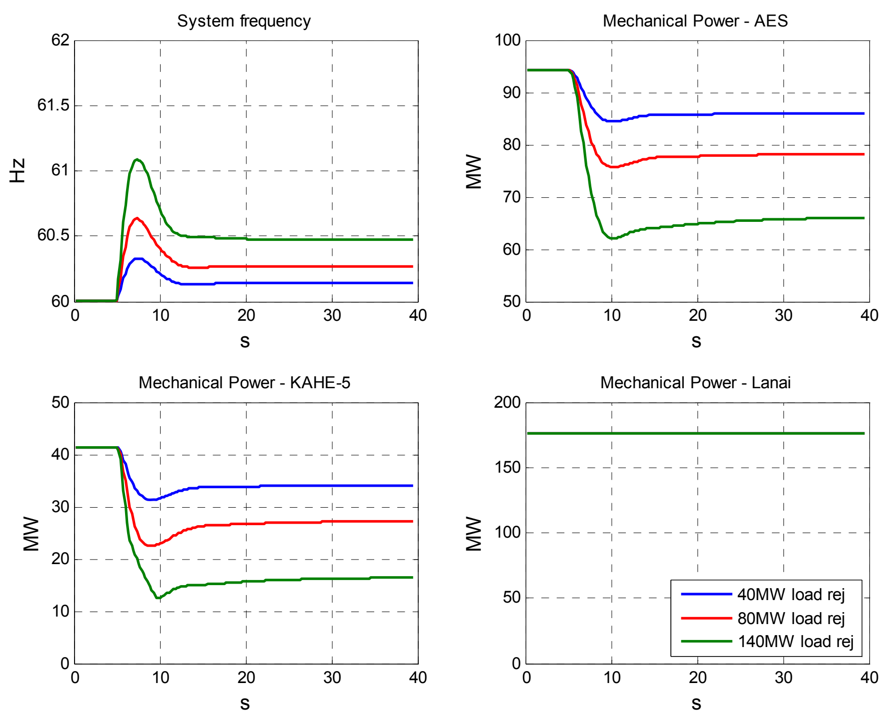


Figure 8-42: PSLF transient simulation result for load rejection (Sc 5F3, base case comparison while setting the minimum valve position of Kahe 5 governor to zero)

Figure 8-43 shows the system response with either proposed or current droop setting for the thermal units, when both experience an 80 MW load rejection. The more aggressive droop setting (as proposed) results in an improved transient performance (with less frequency excursion).

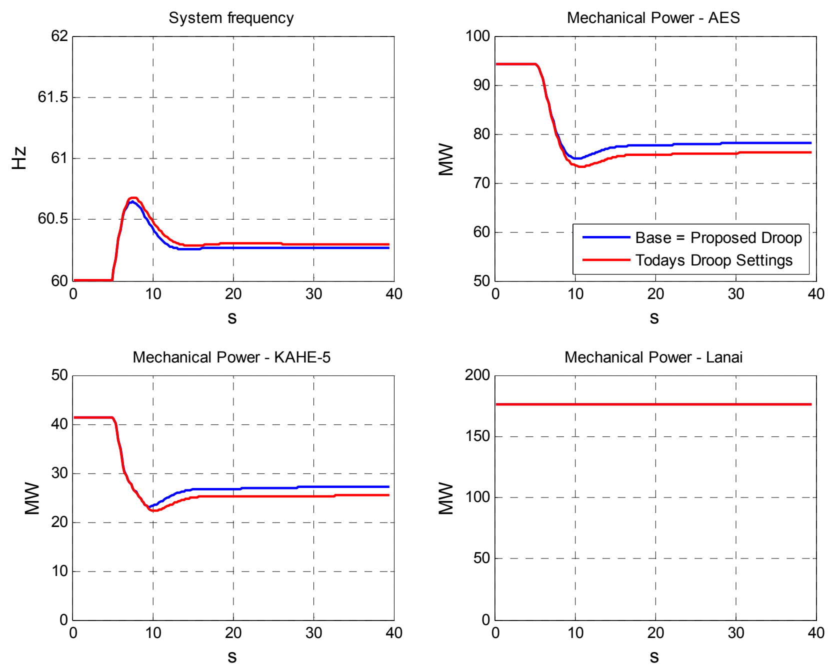


Figure 8-43: PSLF transient simulation result for 80 MW load rejection (Sc 5F3, thermal unit droop)

Figure 8-44 shows a sensitivity-run with no governor response in AES. As the AES governor does not participate in frequency regulation, other thermal units have to back down further and the system frequency runs higher both transiently and in steady state until the AGC can bring it back to nominal level. For an 80 MW load rejection event in Scenario 5F3 the maximum over-frequency increases by ~15% when AES does not contribute to the over-frequency event

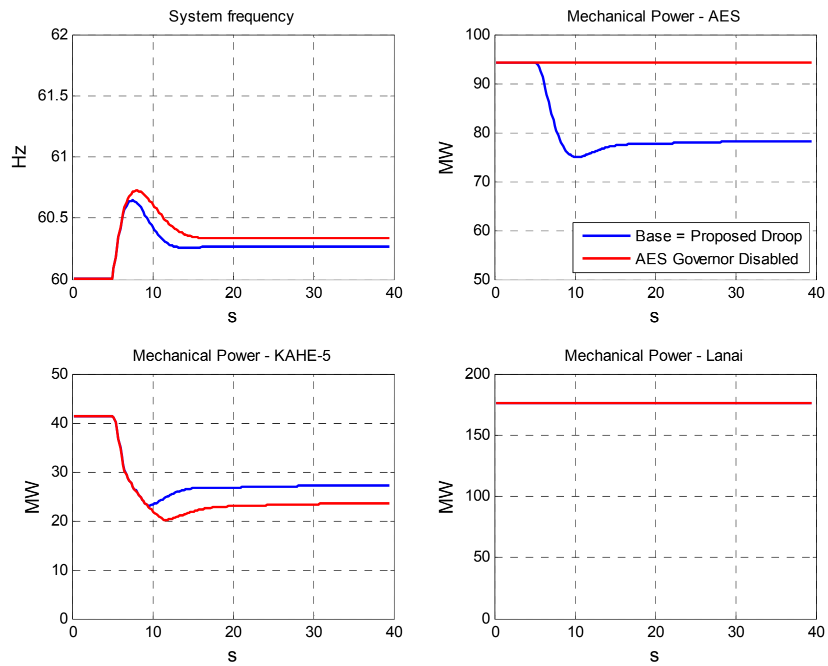


Figure 8-44: PSLF transient simulation result for 80 MW load rejection (Sc 5F3, AES governor sensitivity)

Figure 8-45 to Figure 8-46 show the effect of wind plants over-frequency control to the system performance. In Figure 8-45, the wind plant power is transiently reduced (red line in lower right plot). Once the frequency recovers within the deadband of frequency control, the wind plant returns to its initial power level. The frequency excursion (red line upper left plot) is reduced due to the wind plant control. With more aggressive frequency control (Figure 8-46), the maximum frequency excursion is reduced by about 30% from the base case.

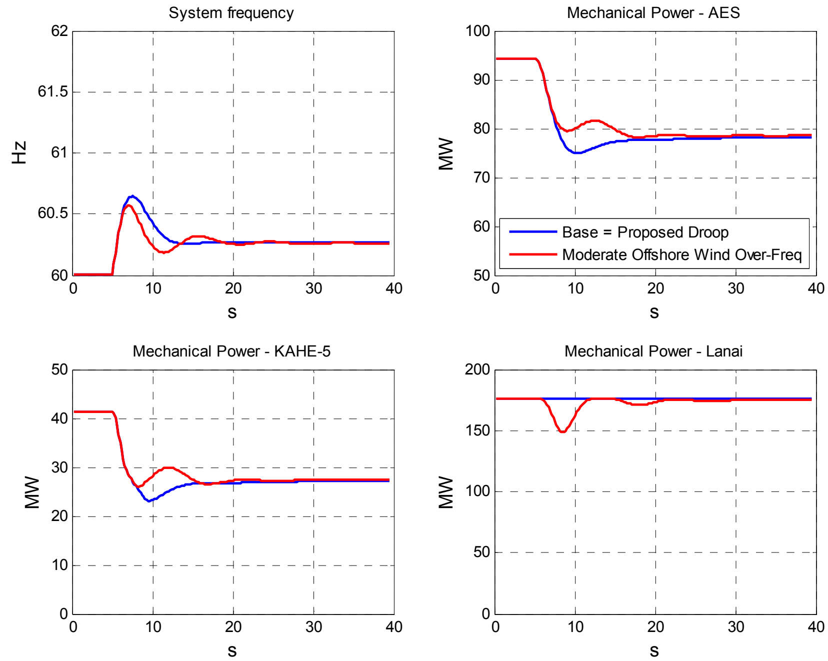


Figure 8-45: PSLF transient simulation result for 80 MW load rejection (Sc 5F3, moderate offshore wind plants over frequency control)

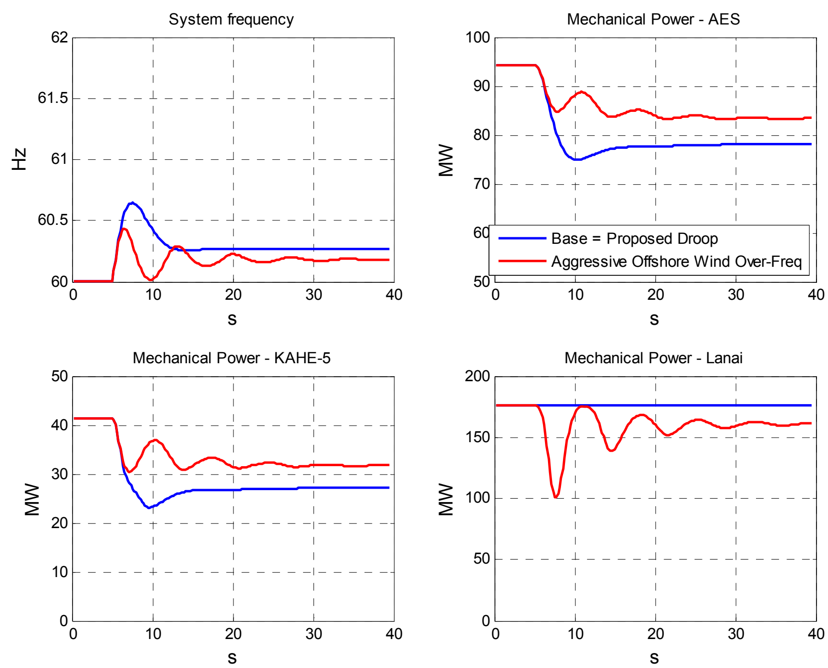


Figure 8-46: PSLF transient simulation result for 80 MW load rejection (Sc 5F3, aggressive offshore wind plants over frequency control)

Given the high power rating of the wind plants with respect to the conventional units committed, the power reduction from wind plants with droop settings similar to those of the thermal units resulted in noticeable improvements in system performance. The dead band on the wind plant droop response has an important impact on the system behavior. Considering a modest deadband (30 mHz) and a 3% droop (based on active power rating), the maximum frequency excursion and steady state difference for a 140 MW load rejection (with all plants participating in over-frequency control) is as much as 40% lower with respect to the base case with no wind plant over-frequency control. Consequently the power reduction of the HECO thermal units (no dead bands in their governors) with respect to their initial power before the loss of load is ~35%

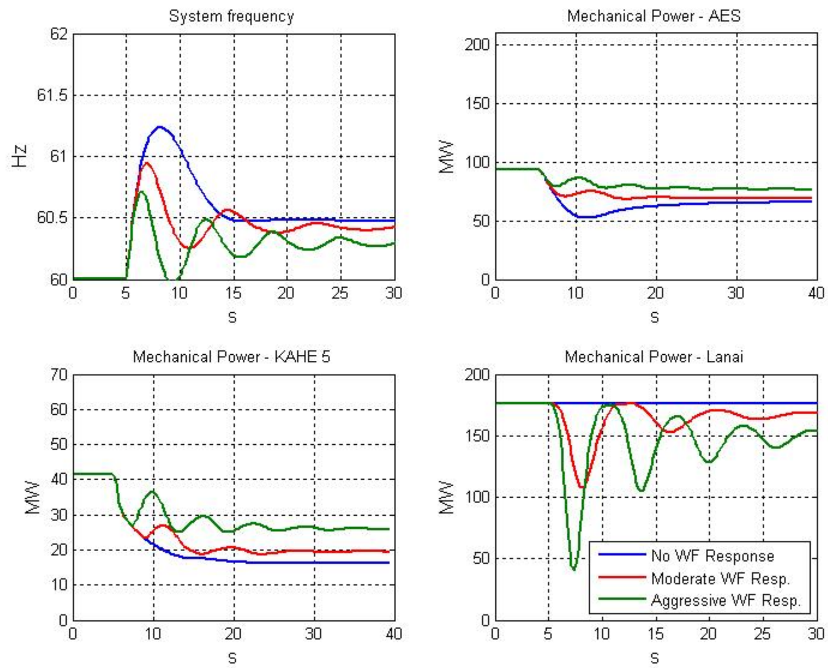


Figure 8-47. 140 MW load rejection event for all with plants in Scenario 5F3: No wind plant over-frequency control, moderate wind plant over-frequency control and aggressive wind plant over-frequency control. All cases assume future droop settings for thermal units.

The response of off-island wind plants to frequency excursions on the Oahu system requires coordination between the HVDC system controls and the wind plants. One control technique is altering power flow from the sending end of the HVDC system (Lanai and/or Molokai terminal) based on the system frequency on Oahu. In this simulation work, it was assumed that Oahu system frequency is available to wind plant controls or can be emulated at the AC side of HVDC sending end converter[3]. In this way, standard controls in the off-island wind plants can react to the frequency excursion. Other types of coordination between the HVDC controls and the off-island wind plants are possible but beyond the scope of this study.

[3] Parallel study addressing HVDC converter control concluded that the sending end HVDC converter(s) should impose frequency based on a clock signal. This is instead a more traditional control with a PLL following system frequency. The drivers for the control approach are related to the stability of fast current control loops of HVDC and wind turbine generators.

8.6.4. Conclusions

- The wind plant over-frequency control during loss of load events resulted in:
  - Improved system frequency response, and
  - Lower contribution of thermal units for power reduction
- Coordination between the HVDC controls and the off-island wind plants are required to provide over frequency control from these wind plants.
- Results are provided for consideration of potential reductions of down-reserve requirement from thermal units considering that wind plants can favorably contribute to mitigating over frequency events.
- Current and proposed droop settings. Results indicate modifications to the droop settings in the model provide moderate improvements to system performance. This could be attributed to increasing the governor ramp rates in the dynamic models for HECO steam units (3 seconds fully closed to fully open).
- There is no significant impact on performance in 40 and 80 MW load rejection cases. There is slightly higher power reduction from thermal units in 140 MW case with today's droop.
- AES' contribution to maintaining frequency is observable given the relative size of the unit on the system. The power reduction from the other thermal units is exacerbated if AES does not have a governor response. Even higher power reductions from thermal units will be observed if there are other units that do not have governor response.
- The results for scenario 5F3 are applicable to 3F3 since the relevant system operating conditions of thermal units are similar for both scenarios.

8.7. HVDC cable trip contingency event

The largest unit in the HECO system is AES steam unit. This unit has a net power of about 180 MW (projected to increase to 185 MW). The minimum spinning reserve is based on the trip of AES. HECO was interested in understanding the implications of HVDC cable trips, particularly considering that each HVDC cable is planned (at this point) for a 200 MW rating.

8.7.1. Initial conditions and contingency

Transient stability simulations of 200 MW cable trip contingencies were performed for Scenarios 3 and 5 during high wind conditions and moderate load. More specifically,

- Scenario 3 simulation consisted of 336 MW of wind power, 1041 MW of system load and 299 MW of up-reserves
- Scenario 5 simulation consisted of 363 MW of wind power and 1020 MW of load and 267 MW of up-reserves

These operating conditions marginally meet up-reserve requirements. In the MAPS results, CTs were committed to increase up-reserve in these hours. In the initialization of these simulations it was assumed that the CTs were not on-line at the beginning of this hour. The production cost results for October 24th at 8pm were used for the unit dispatch and commitment (except the CTs). Table 8-17 shows the units in service and the dispatch levels.

The contribution of off-island wind power for this hour was:

- Scenario 3 255 MW (400 MW wind plant on Lanai)
- Scenario 5 282 MW (200 MW plants on Lanai and Molokai)

In both scenarios none of the 200 MW rated plants were delivering full output (200 MW) to Oahu. Per request, it was assumed that 200 MW of off-island wind power was being delivered to Oahu through the tripped cable. The remainder of the total off-island wind power (55 MW for Scenario 3 and 82 MW for Scenario 5) was allocated to the other off-island wind plant.

Table 8-17: Generation dispatch for cable trip simulations

Scenario 5F3

AES	K1	K2	K5	K6	Kal	W7	W8	50 Wind	50 Wind	HON	Lanai + Molokai	OTEC
185.0	45.0	36.7	117.3	71.0	90.0	36.6	44.0	35.9	45.2	6.0	282.0	25.0

Scenario 3F3

AES	K1	K2	K5	K6	Kal	W7	W8	50 Wind	50 Wind	HON	Lanai + Molokai	OTEC
185.0	36.5	36.7	133.9	76.9	90.0	36.6	57.0	35.9	45.2	6.0	255.3	25.0

8.7.1.1. Sensitivities

The following sensitivities are considered in the simulations:

- Wind plant inertial response
- Wind plant under-frequency control
  - No response (base case)
  - Moderate response (6% droop and 240 mHz deadband)
  - Aggressive response (3% droop and 240 mHz deadband)
- Generator droop
  - Proposed future droop setting (base case)
  - Today's droop setting

8.7.2. GE PSLF™ transient stability results

In this section, the estimated system performance during 200 MW HVDC cable trips is presented. Selected simulation plots of Scenario 5F3 are presented in the report body. The base case for comparisons includes proposed droop setting on thermal units, no wind turbine inertial response and no wind plant under-frequency control. Selected parameters from each sensitivity simulation are plotted against the base case. Figure 8-48 compares the system transient response between today's droop (red line) and the base case (blue line) for Scenario 5F3. The frequency excursion (upper left) falls quickly and settles to the new system frequency. The power output of Kalaeloa CT 1 (upper right) picks up quickly. Kahe 6 (lower left) also picks up power. The off-island wind plant that is not disconnected with the trip cable is shown in the lower right. Except for the very fast transient at the time of the trip, the electrical power remains constant. The proposed droop settings (blue line) show a smaller frequency excursion and results in 18 MW less of under frequency load shedding.

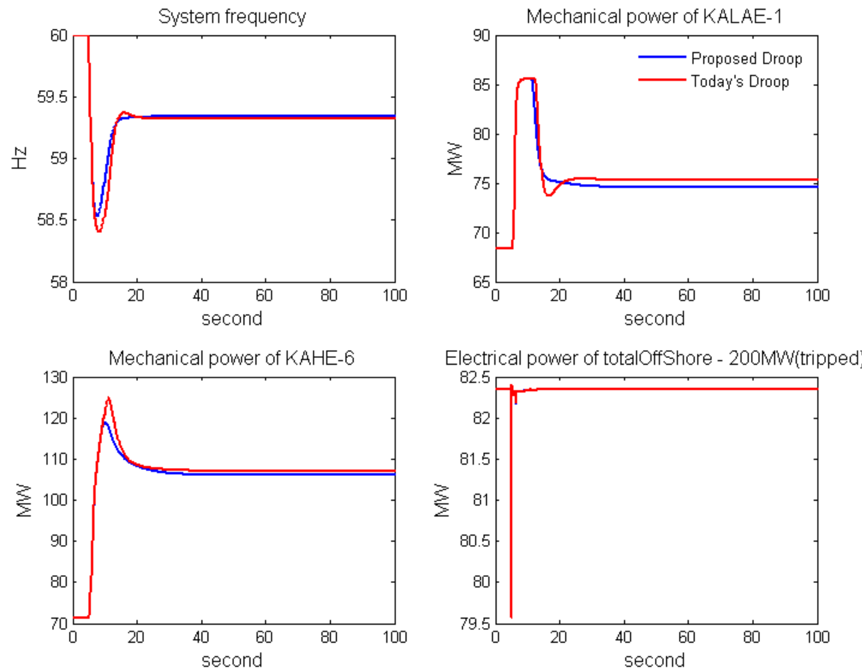


Figure 8-48: Transient simulation result for 200 MW cable trip for scenario 5F3. Sensitivity to thermal unit droop. Proposed droop (blue) and today's droop (red)

Figure 8-49 shows how wind plant inertial response can improve system performance during a frequency excursion due to loss of the HVDC cable or generation. As agreed with HECO, standard GE WindINERTIA settings were assumed in the wind turbines. The objective of the simulation is to analyze the benefits of modern OEM wind turbine controls that are readily available. By temporarily extracting 10% of rated power (200 MW) from the wind turbine mechanical drive train, the maximum frequency dip is reduced by 13%.

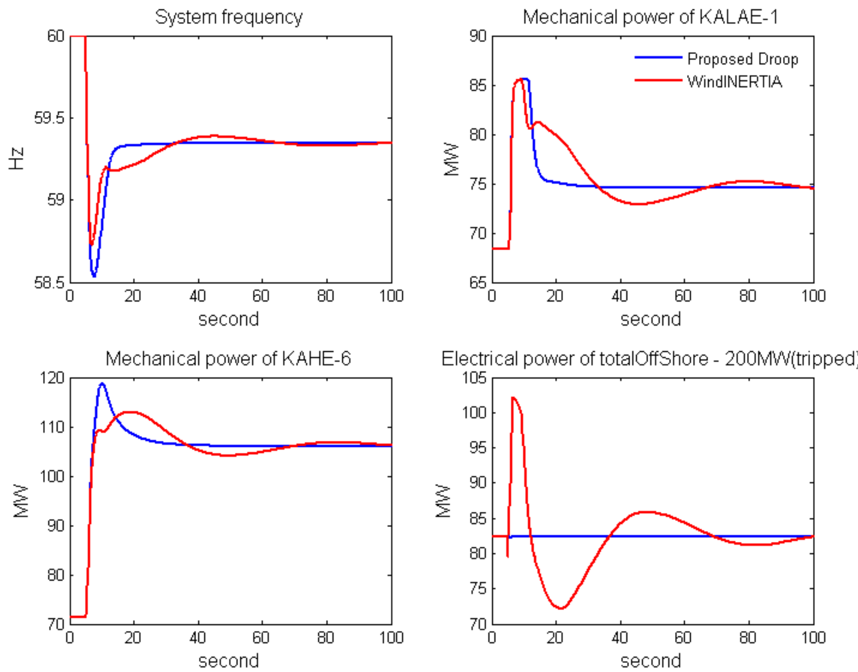


Figure 8-49: Transient simulation result for 200 MW cable trip for Scenario 5F3. Sensitivity to WindINERTIA. Base case (blue) and WindINERTIA case (red)

Figure 8-50 illustrates that no significant performance change is observed when operating the wind plant curtailed at a 95% of available power leaving 5% margin for under-frequency control. The reduced wind power production resulted in a proportional increase in power output at the thermal units (KAHE 5) to supply the same load. The spinning reserve carried by the system remains the same and the resulting system performance is not compromised.

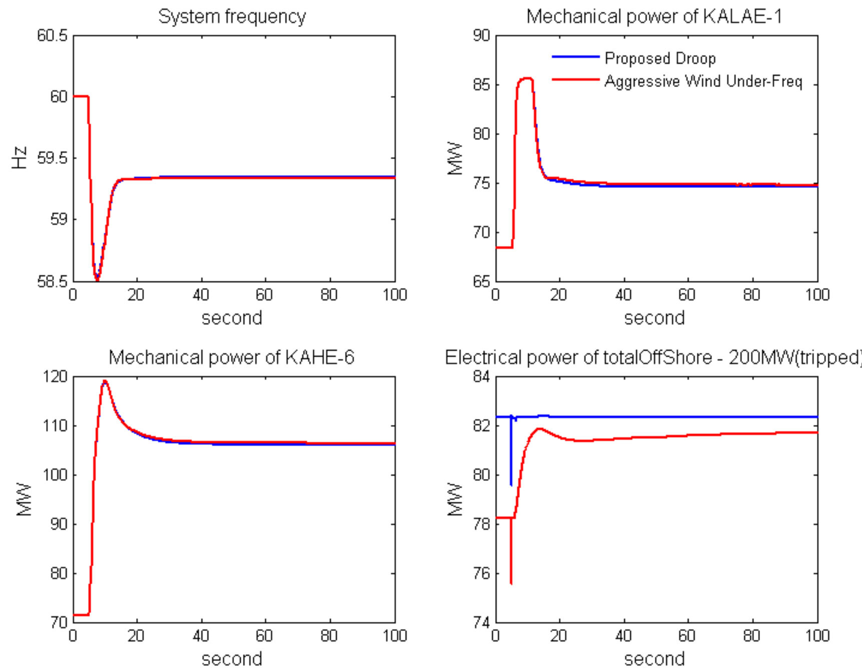


Figure 8-50: Transient simulation result for 200 MW cable trip for scenario 5F3. Aggressive wind under-frequency control. Base case (blue) and wind plant control case (red). The bottom right figure shows the un-tripped off-island wind plant carrying ~4 MW of up-reserve. All cases, including the base case, assume future droop settings for thermal units.

Figure 8-51 to Figure 8-53 show the same simulation result for scenario 3F3. The system in the two scenarios gives similar performance.

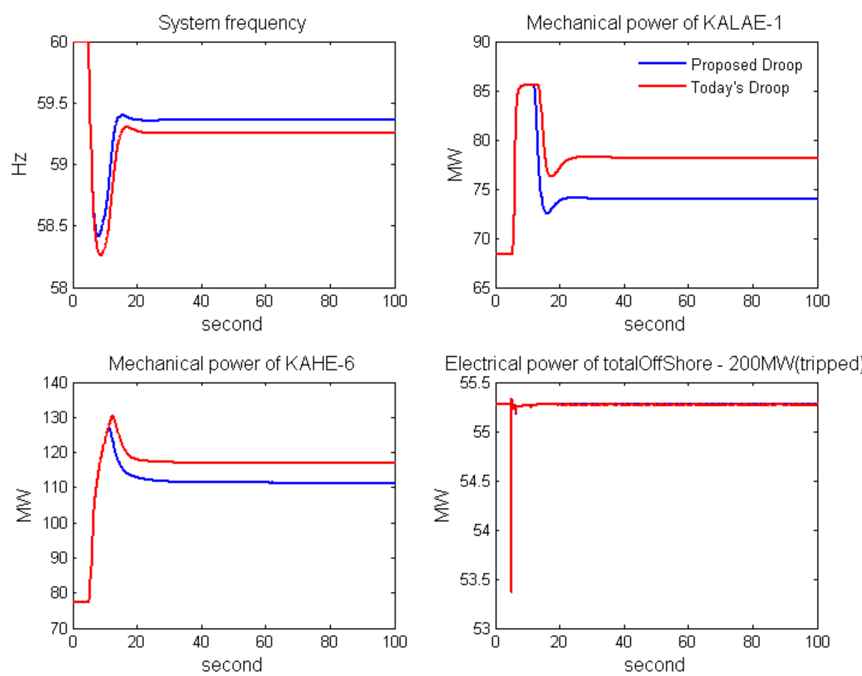


Figure 8-51: Transient simulation result for 200 MW cable trip for scenario 3F3. Sensitivity to thermal unit droop. Proposed droop (blue) and today's droop (red)

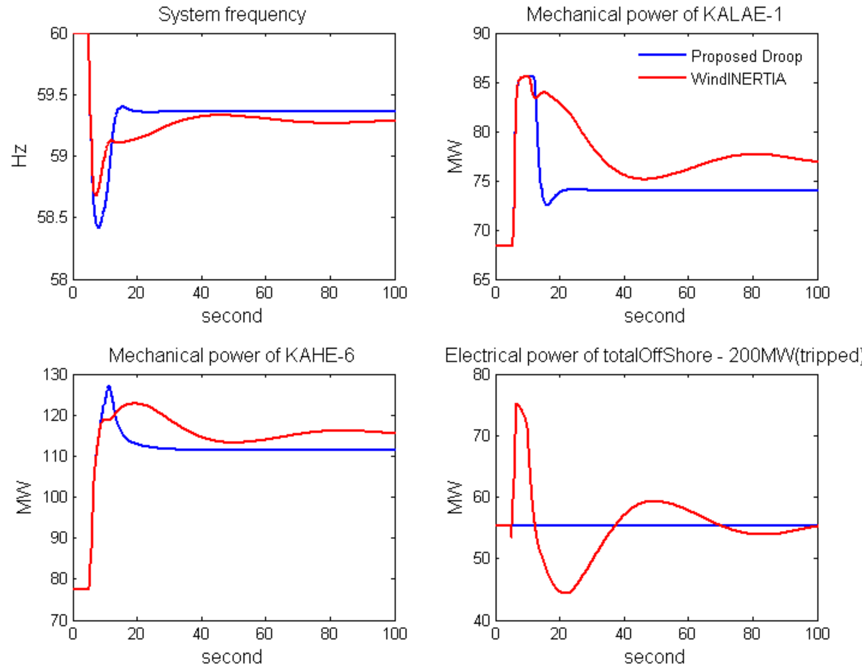


Figure 8-52: Transient simulation result for 200 MW cable trip for scenario 3F3. Sensitivity to WindINERTIA. Base case (blue) and WindINERTIA case (red)

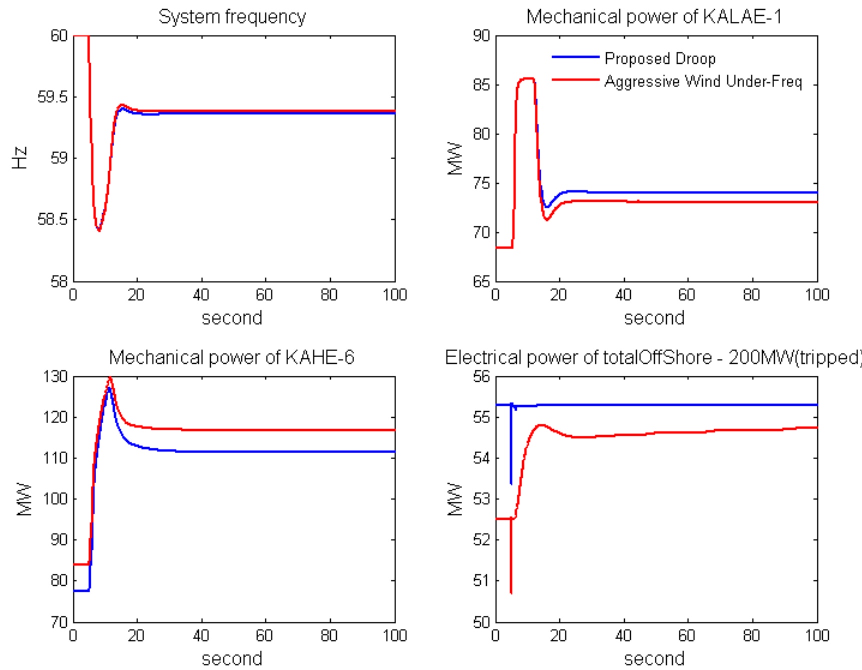


Figure 8-53: Transient simulation result for 200 MW cable trip for scenario 3F3. Aggressive wind under-frequency control. Base case (blue) and wind plant control case (red). The bottom right figure shows the un-tripped off-island wind plant carrying approximately 4 MW of up-reserve. All cases assume future droop settings.

The previous simulation work in this section includes off-island generation. As reference for comparison, a simulation of the system without off-island generation was performed. The simulated event is the loss of AES (185 MW). The system corresponds to Scenario 1 (100 MW of on-island wind power and 100 MW of on-island solar power) during light load conditions (664 MW) and 190 MW of up-reserve. The results are shown in Figure 8-54. In this case, five HECO baseload units were on-line (K1 and K2 were on forced outage, K6 on maintenance outage). Future thermal unit droop settings and under-frequency load shedding settings were assumed. 37 MW of load shedding was observed in this case.

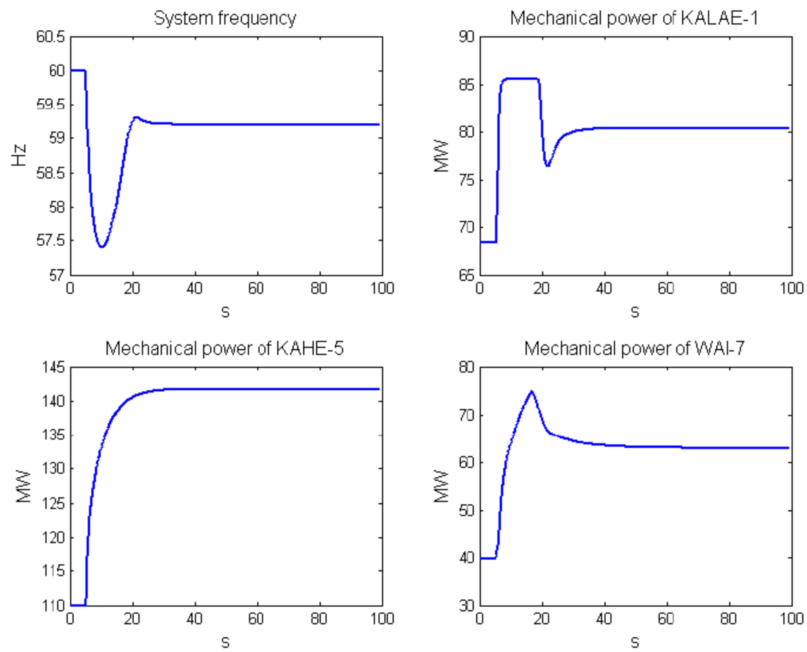


Figure 8-54. Trip of AES in Scenario 1 for future droop settings for thermal units

8.7.3. Conclusions

- The loss of HVDC cable case assumes larger loading on the cable than observed based on available wind data. It is assumed that the wind plant associated to the tripped cable does not remain connected to the system and cannot inject power through the remaining HVDC cable.
- 55 MW or more under frequency load shedding was observed in the 200 MW cable trip base case for scenarios 3F3 and 5F3
- The proposed thermal unit droop settings moderately improve system performance. This could be attributed to increasing the governor ramp rate in the dynamic models for HECO steam units (3 seconds fully closed to fully open).
- Wind turbine inertial response performance significantly improved frequency performance. Standard settings of GE WindINERTIA were used. The benefits of this function are:
  - 13-16% reduction in maximum under-frequency event.
  - In Scenario 3F3, wind turbine inertial response reduced load shedding by 18 MW (74 MW to 55 MW)

    - Wind turbine inertial response transiently increased the loading of the HVDC cable (for few tens of seconds). This should be verified with the specified loading cable characteristics
- Wind plant under-frequency control does not impact frequency performance if thermal units pick up the curtailed power. This function is recommended only when the wind plants are already curtailed due to other system requirements.
- Comparing the wind plant functions analyzed, modern wind turbines capable of providing inertial response without continuous curtailment improved system frequency without needing to curtail the wind energy.

9.0 Observations and Conclusions

A summary of observations and conclusions of the results described in Sections 7.0 and 8.0 is presented below.

9.1. Steady state system performance

9.1.1. Wind Curtailment

- Wind curtailment occurs typically at night during light load conditions when the thermal units are backed down to their minimum dispatchable operating point and wind energy was still available.
- If current operating practices do not evolve to include wind power forecasting and up-reserve requirement refinement, ~16% of wind energy available on Oahu (post cable losses) is estimated to be curtailed.

9.1.2. Down-Reserve Requirement

- Increasing the down reserve to 90 MW is necessary, based on the load rejection cases provided by HECO. Thermal units operate for significant hours of the year at their minimum operating points, increasing exposure to contingency event at the transmission level. Wind energy curtailment increased from 3% to 5%.

9.1.3. Seasonal Cycling of HECO Baseload Units

- Seasonally cycling three HECO baseload units (cycling off three baseload units; each for six different weeks) moderately reduced the wind energy curtailment, but increased the total variable cost of operation because the more expensive cycling units were needed to meet the peak load, and meet systems demands due to wind forecast errors, when the baseload unit was seasonally cycled.

9.1.4. Reducing Minimum Operating Power of Thermal Units

- Reducing the minimum power of seven HECO baseload units increased the amount of wind energy delivered by 7% (absolute). In conjunction with improved ramp rates, this strategy provides the additional benefit of increasing the upward regulating capacity for each unit.
- HECO thermal units operate more hours at their minimum operating load, approximately three times the number of hours for Scenarios 3 and 5 and two times the hours for Scenario 1.
- Thermal efficiency of the units decreases by 5-6% on average. However, equipment improvements necessary to obtain these new operating loads are expected to improve unit efficiency throughout the entire operating range. These were not modeled in this analysis.

9.1.5. Regulating Reserve Requirement

- The wind energy curtailment drops to 10% of the available energy when a 4 hour wind forecast is used to determine the regulating reserve component that is added to the system spinning reserve requirement.

- Reducing the on-line regulating reserve did not reduce wind energy curtailment (most curtailment is at light load when up-reserve is high), but did reduce variable cost because fewer fast-starting events were triggered (~30%).

9.1.6. Wind Energy Delivered

- Assumption of a wind power forecast protocol increased the amount of wind energy delivered to the system.
- Reducing the minimum operating loads of thermal units, seasonally cycling baseload units and increasing upward regulating reserve capacity all contribute to increasing the amount of wind energy delivered to the system while maintaining system reliability.

9.1.7. Fuel Consumption and Total Variable Cost of System Operation

- Reducing the minimum operating loads of thermal units, reducing the up-reserve requirement, and reducing the down-reserves carried by the thermal units reduced fuel consumption and the total variable cost.

9.2. Dynamic performance of the system

9.2.1. Co-located off-shore wind plants (400 MW Lanai)

- 400 MW of wind power situated on Lanai did not substantially change the level of wind energy delivered nor alter the dispatch/commitment of the thermal units, as compared to 200 MW of wind power situated on Lanai and 200 MW of wind power situated Molokai,
- Higher variability is observed when the wind plants are only located on Lanai, but this primarily affected sub-hourly operation and, as such, was considered in the sub-hourly analyses.

9.2.2. Sustained wind power drops over 60 minutes

- Today's unit ramp rates do not limit the system's ability to counteract sustained 60-minute wind and solar power changes provided sufficient up-reserve (in particular, regulating reserves) is carried by the system. With lower ramp rates the system requires larger frequency deviations for the AGC to command sufficient units to react.
- Regulating reserve determines the system's ability to counteract sustained 60-minute wind and solar power changes.
- Frequency excursions are modest during the largest sustained 60-minute wind and solar power change. Most of the generation correction is requested from the AGC economic dispatch algorithm (as opposed to the AGC ACE control). The economic dispatch requests few units to counteract the wind power drop at the time (based on economic participation factors).
- Reserve requirement seemed adequate for slow sustained wind/solar drops considering that up to 222 MW of fast start units are available (W9, W10, CT1, and 4 Airport Diesels)

9.2.3. Rapid wind power changes within an hour (10 minute)

- Thermal unit ramp rates determine the ability of the system to counteract wind power, solar power and load changes.

- The proposed ramp rates of HECO units significantly improves the ability of the system to counteract the estimated 10 minute wind and solar power change as compared to today's ramp rates.
- Sub-hourly up-range adequacy results for today's ramp rates indicate the system is ramp rate constrained for ~1-2% of the year. Increasing the ramp rates of the HECO baseload units by two to three times provides sufficient up-range capacity to manage sub-hourly changes in wind power, solar power and load based on the modeled wind and solar data used in this study.

9.2.4. Wind power increase during period of low down reserve

- There are instances when the system is operating at the minimum down reserve requirement and increasing wind power output could violate this requirement. These conditions can be addressed with automatic curtailment to ensure sufficient down reserves are maintained.

9.2.5. Fast and sudden wind power swings in both direction

9.2.5.1. Frequency Performance

- There is a good correlation between increased wind power variability and associated frequency performance.
- Scenarios 3B and 5B have better system frequency performance than Scenarios 3F3 and 5F3. This is because less wind energy is delivered to the system, fewer units are against their operating limits, and the system carries more regulating reserves.
- Proposed AGC ramp rate improvements provide significant benefits in terms of system performance, mostly in the 5 and 20-minute time frames where AGC is in control.
- Slower sub-hourly variations (few minutes and slower) are mostly driven by AGC economic dispatch. Hence, different units do most of the maneuvering depending on the commitment and load level.

9.2.5.2. HECO Unit Maneuvering

- The HECO units primarily carry the burden of managing the variability of wind and solar power and maintaining system frequency. The large IPPs (AES and Kalaeloa) are the most efficient units and typically operate at or near full operating load. In addition, Kalaeloa cannot be automatically dispatched throughout its entire operating range when not operating at full load.
- Slower sub-hourly variations (few minutes and slower) are mostly driven by AGC economic dispatch. Hence, different units do most of the maneuvering depending on the commitment and load level.
- The analyses performed highlight the benefits of the improved ramp rates of the HECO thermal units and their ability to maintain system frequency during severe wind and solar ramp events. This capability improves system performance but also could have O&M impacts to unit equipment depending on the severity and frequency of these events. Further analysis is required to quantify the O&M costs due to the increased maneuvering of the HECO units.

9.2.5.3. Wind Plant Ramp Rate Limits

- o Based on the modeled wind power data and the results of this study, ramp rate limits for the off-island wind plants are not required provided ramp rate improvement to the HECO units are implemented.
- o Variability of severe volatile hours increases by a factor of about two when the offshore plants are added to the system (five times higher wind plant rating).
- o Wind plant ramp rate limits were considered to reduce thermal unit maneuvering and improve frequency performance during wind variability events. Both were observed.
- o Modern wind turbine controls are capable of limiting upward ramp events, but downward ramp events require an energy storage system. The rating of a storage system would be relatively large (MW, MWh) to manage the ramp rates of the off-island wind plants.

9.2.6. Loss of load at high wind and light load

- o Some of the HECO thermal units hit their minimum operating load power limits for a 140 MW loss of load event.
- o Modest improvements were observed for proposed future thermal unit droop characteristics
- o AES contribution for reducing frequency excursion is observable. For an 80 MW loss of load rejection event in Scenario 5F3 the maximum over-frequency increases by ~15% when AES does not contribute to the over-frequency event.
- o Aggressive over-frequency wind power controls significantly reduced the magnitude of the over-frequency event, resulting in less contribution from thermal units. Further analyses are required to optimize the droop settings for the wind plants and to consider all reasonable contingency events.

9.2.7. Cable trip event at high wind conditions

- o Wind plant under-frequency control did not have an observable impact because thermal units of similar droop performance were displaced during this event. If wind plant was already curtailed, for other system needs, under-frequency control could offer additional under-frequency support.
- o In Scenario 5F3, proposed future thermal unit droop characteristics reduced under-frequency load shedding by 19 MW
- o In Scenario 5F3, wind plant inertial response reduced the magnitude of the under-frequency event (19 mHz; 13% reduction in minimum frequency).
- o In Scenario 3F3, wind plant inertial response reduced the amount of under-frequency load shedding by 18 MW as well as the magnitude of the under-frequency event (25 mHz; 16% reduction in minimum frequency).
- o Under-frequency and inertial response of the wind plants could enable the down reserve requirement to be reduced. Further analysis and/or actual operating experience is required.
- o Under-frequency load shedding was observed during Scenario 5F3 (55 MW of load shedding).

10.0 Recommendations

This section is intended to help define the requirements for the wind plants and propose changes to the HECO system as they pertain to the integration of high levels of wind power. The sections below do not elaborate on the conventional requirements for the interconnection of wind and solar plants, but rather focus on unique requirements beyond those of typical wind and solar plant installations, including operational strategies, thermal unit modifications and energy management system modifications. Recommendations are based on results of these modeling simulations for the given set of assumptions and stated limitations of the model and data.

10.1. Wind plants

The recommendations presented below are intended to help define the requirements for the off-island wind plants that were modeled in this study. The recommendations are intended to be functional and specific to the needs of the Oahu system for this, as assessed in this study. The associated operational information and operational strategies coupled with the wind plant requirements provided below are outlined in later sections of this document (Sections 10.4 and 10.5).

10.1.1. Recommend wind plants to continuously perform <u>over-frequency control</u> for significant over-frequency events

- Some wind plants are capable of decreasing active power to help maintain system frequency. It is expected that with the levels of wind and solar power assessed in this study, the baseload units on the Oahu system will operate at much lower power levels and the system will be operating at the minimum down-reserve requirement for many more hours of the year than has been historically observed. Over-frequency droop control for wind plants shows improved frequency performance during load rejection events (loss of load), i.e., at the times when thermal unit are backed down to lower operating levels. With wind plant over-frequency control, the thermal units experience less transient and steady state power reduction during the loss of load event, hence reducing the risk of undesired unit trips.
- A transient stability simulation was performed for Scenario 5F3 (200 MW Molokai wind plus 200 MW Lanai wind, plus 100 MW Oahu wind, plus 100 MW Oahu solar plus mitigating strategies) during light load hours (720 MW load) with approximately 50% of the power being provided by wind plants (357 MW wind power). These conditions were observed in the production cost simulation on October 23rd at 12am, in the future study year. The thermal units were substantially backed down and the system was carrying 89 MW of down-reserve (1 MW below the specified limit). The unit commitment for this event was obtained from the production cost simulation. The following sensitivities were performed:
  - Load rejection amounts (40 MW, 80 MW, and 140 MW)
  - Wind plant over-frequency settings
    - None
    - Moderate: 6% droop / 240 mHz deadband, and
    - Aggressive: 3% droop / 30 mHz deadband.

- Given the high power rating of the wind plants with respect to the conventional units committed, the power reduction from wind plants with droop settings similar to those of the thermal units, resulted in noticeable improvements in system performance. The dead band on the wind plant droop response has an important impact on the system behavior. Considering a modest deadband (30 mHz) and a 3% droop (based on active power rating), the maximum frequency excursion and steady state difference for a 140 MW load rejection (with all plants participating in over-frequency control) is as much as 40% lower with respect to the base case with no wind plant over-frequency control. Consequently the power reduction of the HECO thermal units (no dead bands in their governors) with respect to their initial power before the loss of load is ~35% lower. Further analyses are required to determine if aggressive wind plant droop settings improve system stability in all system contingency events. Note that HECO's objective is to achieve uniform (5%) droop response for all conventional units.
- The functional behavior that shows benefits to system performance is the reduction of power of the offshore wind plants when the frequency on Oahu is above nominal. In order to achieve this, it is required that the offshore wind plants detect a signal that represents the frequency on Oahu. In this simulation work, it was assumed that Oahu system frequency is available to the wind plant controls or emulated at the AC side of HVDC sending end converter. The more typical frequency control at the wind plants would then ensure the power reduction during over-frequency events. There are several variations of this such as scaling up the frequency excursions seen at the wind plants to increase their response or finding other ways of coordinating the HVDC controls and the wind plants to reduce power injection during over-frequency events.
- Sensitivity analyses were conducted with AES governor droop disabled (no governor response to frequency). When AES does not react to frequency, the severity of the over frequency event and the transient downward response of the thermal units are larger than reported earlier. For an 80 MW load rejection event in Scenario 5F3 the maximum over-frequency increases by ~15% when AES does not contribute to the over-frequency event.

10.1.2. Recommend wind plants to provide inertial response for significant <u>under-frequency</u> events

- Some wind plants can provide fast transient response to large drops in frequency. The details of the frequency response of wind plants to these events are different than those of conventional synchronous generation. The inertia of the system can be compromised as large synchronous thermal units are displaced by generation that does not provide inertia, reducing the amount of stored kinetic energy on the system. Any imbalance between generation and demand on a low inertia system results in frequency excursions with a higher rate of change and greater magnitude. The rate of change in frequency is critical because the faster the frequency change, the less time governors have to respond. A wind plant providing inertial response can help counteract this. During contingencies, such as a loss of generation due to an HVDC cable trip event, wind plants capable of providing inertial response reduced the power increase from thermal units responding to this event, but more importantly reduced the severity of the frequency excursion. Inertial response that is aggressive and potentially feasible further reduced the depth of the frequency excursion.

- A transient stability simulation was performed for a 200 MW cable trip contingency event for Scenario 5F3 during high wind conditions (363 MW), moderate load conditions (1020 MW) and a relatively low up-reserve capacity (267 MW). Note that the up-reserve requirement at this hour was 267 MW, so a new unit would be in the process of being committed. These conditions were observed in the production cost simulation on October 24th at 8pm. Less than 200 MW of wind power was being produced at each wind plant; the sum of the Lanai and Molokai wind plant production was 282 MW during this event. In order to postulate a worst-case condition, it was assumed that 200 MW of off-island wind power was being delivered to Oahu through the tripped cable. As such, 200 MW of wind power was allocated to one plant and the remainder (82 MW) was allocated to the other plant. The unit commitment for this event was obtained from the production cost simulation. The impact of wind plant inertial response was assessed under the following sensitivities:
    - Wind plant inertial response settings
        - None (base case)
        - With WindINERTIA. WindINERTIA is *GE's commercially available wind plant controls that provide inertial response. These models were used by the project team to represent a typical inertial response capability of a wind plant, as the models were readily available to the project team.*
- Scenario 3F3 considered all of the off-island wind power as being co-located on Lanai as opposed to being distributed equally on Molokai and Lanai (Scenario 5F3). The maximum under-frequency condition associated with the cable trip event improved from 58.3 Hz to 58.7 Hz depending on the scenario (3F3, 5F3) and the sensitivity (described above). Note that in Scenario 5F3, approximately 55 MW of load shedding was observed due to under-frequency load shedding in the base case (future thermal unit droop characteristics and no WindINERTIA). This increased to ~75 MW in Scenario 3F3.
- Another simulation was performed for the loss of AES in Scenario 1 during light load conditions. In this case, five HECO baseload units were on-line and future thermal unit droop settings and under-frequency load shedding settings were assumed. 37 MW of load shedding.
- Wind turbine inertial response reduced the maximum under-frequency event as compared to the baseline case by roughly 19 mHz (13% reduction in minimum frequency) for Scenario 5F3 and 25 mHz (16% reduction in minimum frequency) for Scenario 3F3. Furthermore, in Scenario 3F3, inertial response of wind plants reduced under-frequency load shedding from ~75 MW to 55 MW as compared to the case without inertial response of wind plants.
- During these cable trip simulations, AES was operating at maximum power and remained at maximum power during this under-frequency event. Historical performance indicates that AES will not respond to system frequency disturbances. To assess the possible impact of AES operating below maximum

power, thereby contributing to the up-reserve requirement, but not necessarily able to contribute to maintaining frequency during a cable trip event, the hourly production was analyzed to assess the probability of this occurrence. In Scenario 5F3, AES operates at maximum power for 5424 hours per year and operates at minimum power (respecting down-reserve) for 1730 hours per year. Of the 2664 hours when AES is not at maximum power and contributing to the up-reserve, the majority of the hours are at light load conditions, where up-reserve from all of the units on the system is generally in excess of the requirement. If AES did not participate in frequency control (exclude AES's contribution to up-spinning reserve), there would only be four hours in the year when a 200 MW wind trip (cable trip event) would fully consume the system reserve (not counting AES). Note that in these hours each off-island wind plant is producing less than 200 MW.

10.1.3. Recommend wind plants to provide <u>under-frequency control</u> only during periods of wind curtailment.

- Under-frequency control improves frequency performance by increasing the wind plants active power during load rises, drops in renewable energy or during loss of other generation. Some wind plants are capable of increasing their active power to the system to help maintain system frequency during under frequency events. However, the benefits may not outweigh the costs associated with the continuous wind plant curtailment needed to provide this service. Providing the inertial response with the wind plant operating at full power improves system response to a cable trip event without significantly reducing the energy yields at the wind plants. There is, however, value in enabling under-frequency control feature during specific periods of time when the HECO system would curtail wind energy due to other system constraints, such as minimum generation during light load hours**.**
- For the cable trip event described earlier, wind plant under-frequency control was assessed. In these simulations, the wind power was curtailed to enable under-frequency control in advance of the cable trip event, thereby increasing the output from thermal units in advance of the cable trip. Since total available up-reserve stayed the same, the frequency performance was essentially unchanged in these two cases. This occurred because of the similar frequency control performance from the thermal units as compared to the wind plants. As was stated earlier, the cost of continuously curtailing wind energy to enable under-frequency control could be relatively high. Therefore, since wind plants provide similar system performance benefit as thermal plants for such under-frequency events it is recommended that wind plants do ***not*** continuously curtail production to provide under-frequency control.

10.1.4. Recommend wind plants to be capable of responding to curtailment requests in less than 10 minutes, during system events, such as violation of down reserve requirement, and on a plant-by-plant basis.

- During light load hours with significant available wind energy, the thermal units will be backed down to accept wind energy. Any additional wind energy that becomes available will result in thermal units being further backed down to accept this wind energy. The thermal units will be backed down until the HECO down-reserve on the system becomes 90 MW. After this point, the thermal units should not be backed down further and any additional wind energy should be curtailed.

  - During these instances it is possible that an uncurtailed wind plant, situated lower in the curtailment order, increases its production. In this event, the governors would be requesting the thermal units to back down to accept more wind energy. As a result, the down-reserve requirement will be violated. The natural variability of wind, solar and load may result in partial or total consumption of the down-reserve and could put the system at risk during a contingency event, such as a load rejection. If the down-reserve is violated an operator should institute a curtailment request to adjust wind plant outputs to restore down-reserve and avoid thermal units operating below desired levels.

- Analysis of Scenario 5F3 indicated that there are approximately 300 hours of the year where the down-reserve requirement could be violated due to wind power and load variations unless actions (curtailment) were taken to reduce wind power production to restore down-reserve within an hour. There were also approximately 30 hours in the year, where rising wind power over a 60-minute interval—without considering the de-commitment of units in the sub-sequent hour—could completely consume the down-reserve if no actions were taken. For the same scenario, there were about 200 hours where the down-reserve requirement could be violated unless actions were taken to curtail wind power production to restore down-reserve within 10 minutes. There were no hours wherein 10-minute changes in wind power could entirely consume the down-reserve.
- Based on the results of Scenario 5F3, in a particular hour the system was carrying 94 MW of down-reserve and the wind power increased by 146 MW over the hour. In this case, the down-reserve would be entirely consumed if one or more of the wind plants were not curtailed and a thermal unit was not shutdown. Over a 60 minute interval, assuming no load decrease or solar power increase, the wind plant would need to reduce its production by ~140 MW over that period (~2.3 MW/min), or multiple wind plants could be simultaneously curtailed, reducing the ramp down requirement at a single plant. In the short-term analysis, an hour revealed a 10-minute interval where the down range capability (limited by the down ramp rate capability of the thermal units) was 98 MW and the wind power increased by 83 MW over 10 minute. In this instance, the down-reserve remaining on the system would be relatively low (15 MW) after this wind-rise event. The wind plant would need to reduce its production, on average, by 8.3 MW/min (or less if shared among multiple plants) over this 10-minute interval, excluding any changes from solar power and load during this interval and any contribution from other wind plants.

10.1.5. Recommend that HECO evaluate the costs and benefits of wind plant ramp rate controls and other approaches, such as centralized energy storage for frequency regulation, to reduce thermal unit maneuvering

- Limiting the rate by which a wind plant increases or decreases its production due to changes in wind speed can reduce the maneuvering of thermal units and limit frequency excursions associated with fast wind power changes. Both curtailing wind energy during periods of increasing wind speeds and managing down ramp rate requirements with energy storage during periods of decreasing wind speeds has an associated cost. This cost does not appear to justify the benefits of reduced maneuvering of thermal units, smaller frequency excursions—or other strategies that could offer similar benefits—such as centrally managed energy storage for frequency regulation. Note that the only additional cost of up ramp rate limits on the wind plants is the cost associated with curtailing wind energy during periods when wind speed is increasing faster than the wind power up ramp rate limit can accept. It is expected that this cost would be relatively small.
- The 2-sec total wind power production for an entire year was analyzed to find an hour that exhibited large upward and downward wind power changes over a 5 minute to 10-minute window. The screening process revealed an hour on August 30th (at 10am) that showed the highest wind variability in both 5 minute and 10-minute time intervals. Long-term dynamic simulations were performed for this hour to assess the thermal unit maneuvering and frequency impacts associated with the fast sub-hourly wind variability. The results suggested that the frequency performance and thermal unit maneuvering were manageable without ramp rate controls on the wind plants. Wind plant ramp rate controls helped reduce the thermal unit maneuvering and helped reduce frequency deviations, but there may be more cost-effective approaches to achieve these objectives. It is recommended that HECO evaluate other approaches, such as centrally managed energy storage for frequency regulation and modifications to the thermal units that could help enhance their ability to maneuver.
- The RMS of total wind power as seen by the Oahu system was calculated with respect to a 20-minute, 5 minute and 1 minute rolling average through this hour (in Scenario 5F3). No solar variability was considered. The only source of variability in the system was wind power. The following cases were examined:
  - No ramp rate limit
  - 1/30 per unit up and down ramp rate per minute at all wind plants (0.5 hr full ramp)
  - 1/60 per unit up and down ramp rate per minute at all wind plants (1hr full ramp)
  - 1/120 per unit up and down ramp rate per minute at all wind plants (2hr full ramp)
  - 1/60 per unit down ramp rate per minute at all wind plants (no up)
  - 1/120 per unit down ramp rate per minute at all wind plants (no up)
    - As an example, 1/120 per unit down ramp for a 200 MW wind plant equals 1.67 MW/min down ramp rate requirement.
- The RMS of system frequency and RMS of power for each thermal unit was calculated with respect to a 20 minute, 5 minute and 1 minute rolling average

10.1.6. Recommend wind plant ramp rate controls be controllable by the system operator

- Wind plant ramp rate controls limit the upward or downward changes in wind power being delivered to the system. During large rises in wind power production, the blades of the wind turbine can be pitched to limit the amount of energy being captured and consequently limit the wind power increase. In order to limit the rate of power decrease from a wind plant during sudden drops in wind power production, energy storage is needed to smooth the power reduction as seen by the system. In contrast to these types of wind plant ramp rate limits that reduce the wind power variability as seen by the HECO system, power ramp rate control for specific system events, such as requesting or relieving wind power curtailment or start-up/shut-down of a wind plant, is recommended. In order to meet ramp rates requested by the operator, the wind plant pitches the turbine blades to capture more or less energy than is available. When the plant is re-connected after maintenance or reconnected after tripping off-line, up ramp rate control can limit the rate at which the power increases at the plant. When a plant is to be taken off-line, down ramp rate limits can control the rate at which the wind plant power is reduced. Also, when curtailment is instituted or relieved, ramp rate control can maintain a more predictable and manageable wind plant power change.

10.2. Centralized Solar PV plants

10.2.1. Recommend monitoring of active power from utility-scale solar plants not embedded in the distribution system.

- By monitoring the active power from large solar plants, HECO can refine the net load forecast and refine the amount of up-reserve on the system to account for solar variability. This will help improve unit commitment and thereby reduce the average variable cost of operation as compared to operating without production information from embedded utility-scale solar plants. The benefits from such a forecasting strategy will increase as solar penetration on the HECO grid increases.

10.2.2. Recommend solar plants to provide grid support functions similar to those of wind plants.

- The following control functions are recommended, however specific requirements can be relieved on a project-by-project basis since not all manufacturers may offer these functions. It should be noted that some Solar PV OEMs do offer all of these functions.
  - Voltage regulation (or power factor control)
  - Low voltage, zero voltage, and high voltage ride-through
  - Frequency ride-through
  - Solar plant curtailment
  - Power ramp rate control (consistent with available sunlight)
  - Over-frequency control
  - Communications interface with HECO to receive and send data/commands.

10.3. Signals exchanged between wind/solar plants and system operations

The recommendations presented below are intended to help guide the requirements for wind and embedded utility-scale solar plants as they communicate and interface to systems operations on the HECO grid. The recommendations are intended to be functional as opposed to providing specific technology requirements and should be considered the minimum requirements for communication between system operator and solar/wind plants.

10.3.1. Recommend the following signals be sent from operations to the wind plants and large solar plants.

- Voltage set point (if regulating), maximum power limit (for curtailment), ramp up rate limiter on/off, frequency control on/off (n/a for solar), and order in the curtailment order.

10.3.2. Recommend the following signals be sent from wind and large solar plants to operations at typical SCADA sampling times.

- Active power, reactive power, wind speed (insolation, in the case of solar), voltage at point of interconnection, wind speed relative to turbine cut-out.
- Available wind power (equivalent to curtailed wind power plus delivered wind power)
- Wind power forecast
- Reserve capacity for inertial response

10.3.3. Recommend the following signals be sent from wind and solar plants to operations at slower sampling times.

- Wind plants
  - Number of turbines available (or MW rating of available turbines)
  - Number of turbines in operation (or MW rating of available turbines on-line)
  - Reason for turbine unavailability (e.g., high speed cutout, low wind speed, maintenance)
- Solar plants

    - Capacity available (with respect to total plant size)
    - Reason for unavailability
- Reactive power capability
- Available wind/solar power (equivalent to curtailed wind/solar power plus delivered wind/solar power)
- Status of breakers, voltage regulation, frequency regulation, curtailment, ramp rate limiter on/off

10.3.4. Recommend that if energy storage is integrated at a wind plant, the following information be provided to HECO operations.

- Status (on/off)
- Ramp up and ramp down rate performance limits, if applicable
- Max/min power and energy settings for the storage system
- State of charge limits for the storage system (high and low with respect to capacity)
- Recharge time (to full capacity)
- Duration of power available at full discharge power rating.
- Control mode setting (ramp rate control, frequency control, voltage regulation, if applicable)
- Reactive power capability
- Other characteristics, if applicable, such as inertial characteristics, frequency control dead band, voltage regulation settings
- Status of breakers, voltage regulation, curtailment, up ramp rate limiter on/off

10.4. Energy Management System (EMS)

The recommendations presented below are intended to help guide the requirements for the integration of new features in the EMS or at HECO's control room operation in another platform. The recommendations are intended to be functional as opposed to providing specific technology requirements.

10.4.1. Recommend development of automatic wind plant curtailment requests and the ability to allocate curtailment among multiple wind plants in the EMS or alternate platform

- When more than one wind plant is connected and a system event (caused by a change in load or wind power) requires curtailment of wind power, automated curtailment and curtailment allocation may ease the burden placed on the operator to set manually the new curtailment across the wind and solar fleet. The most likely event is related to violation of the down-reserve requirement and subsequent increased production from uncurtailed wind plants. This readjustment logic could be integrated into the Energy Management System (EMS) or another platform at the control room to allocate, monitor, and record curtailment among multiple wind plants. This control will fundamentally perform two functions:
    - Estimate the amount of total wind power curtailment in the system to avoid operation of thermal units below acceptable minimum power settings, and
    - Allocate the total wind power curtailment to generating wind and solar plants according to the curtailment order.

- This recommendation assumes that the requirement for wind plants to respond to curtailment requests is adopted. It is recommended that a real-time measurement of down-reserve and the ability to curtail wind energy and allocate the curtailment of wind energy among multiple plants on a sub-10 minute timeframe be implemented in the EMS or an alternate platform. This would avoid large increases in wind energy before a unit can be de-committed will help ensure sufficient down-reserve is maintained through continuous system operation. It should be noted that automatic wind curtailment should be coordinated with under-frequency control of wind plants, if adopted.

10.4.2. Recommend evaluating changes in the Automatic Generation Control (AGC) to improve sharing of thermal unit response to wind and solar variability events.

- Presently, the AGC commands few units to respond to slow system events, such as sustained wind power changes. This is because slow system unbalances are mostly counteracted by AGC economic dispatch. That is the ACE (Area Control Error) control in the AGC does not provide much support because the frequency does not significantly depart from nominal. The AGC economic dispatch tends to command few units based on variable cost merit. Hence few units are performing most of the maneuvering to counteract slow fluctuations in wind and solar power. In order to reduce the wear and tear on units that are often demanded to perform this maneuvering, a number of alternative approaches were qualitatively assessed:
  - ***Increase the number of thermal units responding to system events***
    - By setting the AGC economic dispatch limits narrower on some units, the AGC ACE control has power margin on more units to counteract wind power variations. Although this would improve the sharing of maneuvering duty for relatively fast and (to a lesser extent slow) wind power changes, this would also reduce the overall HECO system efficiency, as more economic units would be dispatched below base load.
  - ***Modify the Area Control Error (ACE) limits to transition Automatic Generation Control (AGC) to more aggressive operating mode***
    - Reducing the ACE threshold for AGC to operate in modes that request all units to counteract system events may help reducing the maneuvering on some units. In “Assist” mode the ACE control will command all units to balance the system event. This approach could result in greater duty on some of the thermal units or on over compensation, which could have an associated cost that does not outweigh the benefits.
- It is recommended that the above approaches be evaluated by HECO to determine the system performance benefits of each approach and the associated costs of each approach.

10.5. Operating Strategies

The recommendations presented below are intended to help provide guidance on future operating strategies for a system with high levels of wind and solar power. The recommendations are intended to be functional as opposed to providing specific technology requirements.

10.5.1. Unit Commitment

10.5.1.1. Recommend the implementation of a wind power forecast in the unit commitment in a timeframe similar to the time it takes to commit a cycling unit.

- In this study, the value of a wind power forecast for the unit commitment was assessed. By including the wind power forecast in the unit commitment, HECO thermal units were more accurately committed, on average, to meet load plus regulation. The time to commit a cycling unit includes the time required to observe the system conditions that may necessitate the commitment of a cycling unit, the time required to start that unit, the time required to bring that unit to minimum power, and the time that unit operates at minimum power before it can be considered to be capable of reliably regulating as defined by HECO. On occasion, discrepancies between the wind power forecast and the available wind power in a given hour resulted in up-reserve being consumed to address the shortfall in wind power or, alternatively, thermal units being backed down—if not in violation of the down-reserve requirement—to accommodate additional wind power that was available. In general, wind power forecasts reduced the number of hours of operation of the cycling units on the HECO system, which improved system-wide economics. However more frequent fast-starting events were observed on account of the error between forecasted wind power and the actual wind power. Quantification of the value of wind power forecasting was considered simultaneously with up-reserve requirements. This will be discussed in the next section (Section 10.5.1.2).

10.5.1.2. Recommend that the regulating reserve component of the up-reserve requirement be defined as a function of the wind power variability for a forecasted level wind power and refined once wind plants are in operation and data are available to assess the adequacy of these requirements

- By monitoring the wind power variability (10-minute changes) and correlating this to the level of wind power available on the system, the operators can refine the relationship between regulating reserve (based on 10 minute wind power changes) and the available wind power (as per the wind power forecast) to ensure that adequate up-reserve is carried to cover for sub hourly wind variability.
- In Scenario 5A and 5B, the impact of wind power forecasting and refinement of the up-reserve requirement, based on the anticipated level of 10-minute variability as a function of the 4-hour wind power forecast was assessed. In Scenario 5A, no wind power forecast was included in the unit commitment and the up-reserve was specified as 185 MW (today's requirement to cover for the loss of the largest unit, AES). In this scenario, wind power available in the actual hour would increase the amount of up-reserve on the system, in excess of the 185 MW requirement, by

backing down thermal units. In Scenario 5B the wind power forecast was used to develop up-reserve requirement and incorporated in the unit commitment scheduling process.. An additional 7% wind energy was delivered (120 GWh/yr) and a total of $35M/yr (3.4%) of total variable cost savings was achieved (contribution from additional wind energy at zero variable cost and improved unit commitment resulting in lower fuel costs). Wind power forecasting and refinement of the up- reserve offered the largest improvement in wind energy delivered and total variable cost savings of all strategies assessed in this study. It is recommended that HECO implement wind power forecasting and refinement of the up-reserve for unit commitment. It is also recommended that studies be performed by HECO to: 1) assess the accuracy of different wind power forecasting approaches over many timeframes (day ahead to one hour ahead), and 2) assess the amount of additional up-reserve that should be carried to address wind and solar variability based on additional information not available for this study, such as actual wind speed data from the wind plant sites and solar insolation data from potential solar plant sites.

10.5.1.3. Recommend the implementation of a solar power monitoring and forecasting in the unit commitment, where applicable.

- Today, the load observed on the HECO system is net of any embedded, unmonitored solar power production in the distribution system, and HECO commits thermal units to meet this load. For solar forecasting to be effective, an accurate account of the distributed solar resources is required.
- An analysis was performed based on Scenario 5F2 to examine the impact of including a perfect solar power forecast in the unit commitment (what is believed to be done by HECO today because embedded solar power is not being monitored). All of the simulations in this study assumed that units were committed to meet the system load (not the load net of embedded and unmonitored solar). In Scenario 5F2, thermal units were committed to meet the perfect load forecast. When solar power was available in the dispatch, thermal units were backed down, thereby increasing the up-reserve on the system. In the case when a perfect solar power forecast was included in the unit commitment, fewer cycling units were committed, because of the lower net load. In the actual hour of dispatch, the amount of up-reserve was lower and in some instances consumed by the lack of solar power available, resulting in more fast-start events. As a result, the improved commitment based on a perfect solar forecast resulted in lower reserve margin on the system and more fast-start events. This increased the total variable cost by $4M/yr. Therefore, the impact of solar power that is embedded in the distribution system, whose production is not known by systems operation will result in similar consequences as described here.

10.5.1.4. If changes to the present must-run requirements of the baseload units are made, it is recommended that the unit commitment strategy and level of up-reserve be re-examined by HECO, such that a discounted wind power forecast may be considered in the unit commitment.

- The present must-run status of the HECO baseload units resulted in additional up-reserve being carried by the system, at times well in excess of the reserve requirement. When the wind forecast over-estimates wind power, some of the up-reserve could be consumed to address the shortfall in wind power, leading to increase in fast-starting events. This is partially offset by the regulating reserve component of the up-reserve requirement that is based on the wind forecast, i.e. HECO would have to commit more thermal generation for regulating reserve based on the expected wind power. Discounting the wind forecast is one strategy to reduce the number of events when the up-reserve requirement is violated and the need to fast-start a unit. There is an economic penalty associated with discounting the wind forecast, but an economic benefit associated with reducing the number of fast-starting events.

10.5.2. Regulating reserve

10.5.2.1. Recommend that the regulating reserve requirement of the HECO system be based on the expected wind power variability and be revisited if the wind plant size or location changes from those modeled here.

- It is recommended that the regulating reserve component of the up-reserve requirement be a function of the wind power forecast and expected wind power variability over 10-minute timeframes. Variability is a function of wind power output. e.g. the variability is considerably higher in the mid power range compared to low or high power range. This should be considered when estimating regulating reserves. It is also recommended that this requirement in regulating reserves be refined over time.

10.5.2.2. Recommend that the regulating reserve requirement also be based on the expected solar power variability

- It is recommended that the regulating reserve component of the up-reserve requirement be a function of a solar forecast. For solar forecast to be effective, HECO must have a reasonable account of the distributed solar resources and monitoring capability. The proposed method to account for total wind power variability in the up-reserve requirement should be coordinated with a similar approach for total solar power variability, thereby including the total wind and solar power variability as a component in the up-reserve requirement.

10.5.2.3. Recommend contributions from other reliable resources, such as load control and fast-starting thermal units, in determining the regulating reserve requirement

- A number of different technologies and operating strategies can be considered part of the system operating reserve, which can contribute to the regulating reserve requirements of the system. Two approaches considered in this study are: 1) the HECO residential domestic hot water heater load control program, and 2)

- In Scenario 5F3 and 5F2 the regulating reserve component was reduced to account for residential hot water heater load control program and the availability of W9 (or W10, if W9 is on maintenance). As such, the up-reserve requirement was reduced. The results of the simulation revealed a total variable cost savings of $10M/yr (1%).

10.5.3. Down-reserve

10.5.3.1. Recommend that HECO adjust the down-reserve requirement based on system load and risk exposure

- Reducing the down-reserve on the system reduces wind energy curtailment. HECO requested that the down-reserve requirement for the simulation be 140 MW based on historical data. This was the conservative approach as a load rejection event occurred near peak conditions. During minimum system load periods, a 40 MW down-reserve would be sufficient in most cases. Note that due to model limitations only a single down-reserve capacity could be modeled. Actual down-reserves should be adjusted based on risk exposure and system load.
- In Scenario 5C and 5F1, two levels of effective down-reserve capacities were simulated (Scenario 5C = ~35 MW, Scenario 5F1 = ~90 MW). The effective down-reserve requirement was increased from ~35 MW to ~90 MW to accommodate contingency events, such as load rejection events during high wind output and high system load. Increasing the down-reserve requirement by ~55 MW resulted in curtailment of an additional 31 GWh of wind energy and the total variable cost increased by ~$8M/yr (0.8).

10.5.3.2. Recommend that HECO account for actual wind plant over-frequency performance when determining the down-reserve requirement.

- Wind energy curtailment occurs when the committed thermal units are at minimum power and the system is against the down-reserve requirement. Wind plants that have enabled over-frequency control can rapidly reduce their output and contribute to the down-reserve capability of the fleet. This, in conjunction with a control strategy implemented in the AGC that curtails the wind plant output immediately after this type of event could reduce the amount of down-reserve that needs to be carried by thermal units. Note that over-frequency control will need to be coordinated with the curtailment requests from the EMS or alternate platform.

10.5.4. Forecasting and Monitoring

10.5.4.1. Recommend a wind power forecast be developed and validated that accounts for the turbine availability at each wind plant.

- Establish a reliable wind power forecast procedure and incorporate it in the unit commitment scheduling process. The wind power forecast should be specific to the wind turbines, site topography, and turbine availability.

10.5.4.2. Recommend that HECO conduct a study to assess the accuracy of wind power forecasts, over a variety of time intervals, for each wind plant and for the total wind plant production.

- By studying the accuracy of wind power forecasts over a variety of time intervals, HECO can help establish the expected impact of wind forecast error for different commitment strategies, reserve requirements, system risks, etc.

10.5.4.3. Recommend that HECO determine the feasibility and accuracy of solar forecasting as part of the unit commitment strategy

- The methods, technologies and practices for integrating a solar power forecast for large embedded solar systems are in its infancy. The accuracy of different solar forecasting strategies is not well understood by the industry. It should be noted that the timescales of interest might vary in Hawaii from those of utilities that operate larger, well-interconnected power systems with lower levels of renewable energy. For example, HECO should have a heightened interest in shorter-term forecasting (hourly to sub-hourly), in addition to 24-hour solar forecasting. Also, monitoring of the existing solar resources is a fundamental requirement to implement a solar forecasting process.

10.5.4.4. Recommend HECO implement severe weather monitoring in the operations center that can predict weather patterns that could affect wind variability.

- Observable weather patterns, such as a Kona (southerly) weather patterns, can contribute to some of the substantial wind variability events on the system. Data for these events should be included in determining the regulating reserve requirement. It is recommended that weather be monitored to prepare the system operators for these challenging wind and solar-related system events, when possible. During weather events, additional wind/solar curtailment and increased commitment of thermal units will increase the operator’s ability to respond to sudden or sustained wind/solar events.

10.5.4.5. Recommend scheduling unit maintenance and seasonal cycling of baseload units to improve wind energy delivery and improve system economics.

- If HECO can schedule outages of baseload units during intervals when peak load is relatively low and wind curtailment during light load hours is high (relieve some curtailment by cycling off a baseload unit) this could offer value in terms of wind energy delivery and system economics. The ability to perform this will be improved over time as historical information about wind/solar energy profiles and load profiles by week (or month) can be used to influence the scheduling.

10.5.5. Additional Operator Information and Data Needs

The recommendations presented below are intended to help guide the requirements for the information to be provided for systems operation to enable integration of high levels of renewable energy. The recommendations are intended to be functional as opposed to providing specific technology requirements. The information described in this section will be required to enable the Operating Strategies recommended in the next section (10.5).

10.5.5.1. Implement monitoring and reporting of system up-reserve

- The EMS should calculate the available up-reserves on the system and report this to operations. This will enhance system operations decision making capability on unit commitments, fast start events, wind plant curtailment, etc.

10.5.5.2. Implement monitoring and reporting of system down-reserve

- The EMS should calculate the available down-reserve on the system and report this to system operators so system performance can be optimized. Furthermore, down-reserve contribution from the wind plants must be communicated to the system operators to ensure sufficient down-reserves are maintained at all times..

10.5.5.3. Implement monitoring and reporting of the availability of fast-starting generation that can be dispatched in 15 min to enable HECO to monitor the operating reserve

- The EMS should calculate the available fast-start capacity on the system within 15 minutes (cold-start to full power). This information will help operations in determining if sufficient up-reserve is available on the system.

10.5.5.4. Implement monitoring and reporting of high-resolution (sub minute) insolation and power data from solar plants and wind speed and power data from wind plants.

- The availability of data from the wind and solar plants will not only help HECO refine reserve requirements, but also help the planning department perform future system expansion scenario analyses with performance data for specific plant types, sizes and locations. By optimizing reserve requirements, potentially more wind energy can be accepted by the system. Furthermore, solar power data are critical for any future solar integration studies and critical in establishing solar power forecasting as part of the unit commitment (10.5.1.3) and expected solar power variability as part of the up-reserve requirement (Section 10.5.2.2).
- Limited sub 10-minute solar power data were provided for the study. Two-second solar power data were provided for select windows for each of the solar plants. The National Renewable Energy Laboratory (NREL) constructed the data for these large solar plants based on power data from small rooftop installations. This study did not adequately address the sub hourly impacts of solar power variability on system operation.

10.6. HVDC requirements

It was assumed in this study that the performance of the wind plants on the islands of Lanai and Molokai were replicated through the HVDC system on Oahu. Therefore, in order to capture the benefits of the active power control features by the wind plants, such as frequency control and inertia, the HVDC system needs to be coordinated with the response of the wind plants. The HVDC control should be coordinated in such a way as to realize the benefits on Oahu.

10.7. Thermal units

10.7.1. Recommend reducing the minimum stable operating power of the HECO thermal units

- Reducing the minimum power of the thermal units creates more room on the system to accept wind and solar energy. In conjunction with improved ramp rate, the capability of a unit to provide more up-reserves is increased.
- In Scenario 5B and 5C the impact of reducing the minimum power of the HECO thermal units was examined without changing the down-reserve requirement. The minimum power of seven out of the ten baseload thermal units were reduced by ~18 MW on each plant. These seven units provide, on average, about 36% of the island's energy. A 70% reduction in wind energy curtailment (149 GWh/yr) was observed. In addition, by reducing the minimum power of the HECO baseload units, the energy production from the most economic thermal units could be increased during the hours of lower wind energy availability. These two factors result in a $47M/yr (4.6%) variable cost savings (see Figure 7-28). It should be noted that the effective down-reserve was ~35 MW in these simulations, which is less than the ~90 MW down-reserve later specified by HECO based on the results of dynamic performance assessments performed for this study.
- Reducing the minimum operating power of the thermal units, while respecting the down-reserve, is critical to accepting wind energy during light load conditions, particularly at the high levels assessed in this study. The down reserve margin was specified by HECO based on historical load rejection events.

10.7.2. Recommend increasing the thermal unit ramp rates to those simulated in this study (base case).

- It was determined in this effort that the sub-hourly variability of wind and solar power may, on occasion, change (over a 10 minute) timeframe by amounts in excess of the present ramping capability of the thermal units. Therefore, it will be necessary to increase the ramp rates of the HECO thermal units to accommodate these changes in wind and solar power that may challenge the system's ramping capability.
- Sensitivity analyses were conducted on present and future thermal unit ramp rate capability. In Scenario 5F3, there were 3 hours in a year when the ramping capability of the committed thermal units (respective up-reserve limitations, if any) could not adequately cover a single occurrence of the largest 10-minute wind drop, largest 10 minute solar drop, and average 10-minute load rise in each hour, assuming these occurred simultaneously. If it were assumed that this same event happened twice in a row, there were a total of 14 hours when the ramping capability of the thermal units (respective up-reserve limitations, if any) could not adequately cover for simultaneous change in wind, solar, and load power in these consecutive 10-minute events. <u>With the proposed future ramp rates,</u> no hours that exhibited insufficient ramping capability of the thermal units in response to the

simultaneous occurrence of the largest 10-minute wind drop, largest 10-minute solar drop, an average 10 minute load change, for each hour of the year. Even if it were assumed that two of these events occurred subsequently, the proposed future ramp rates (higher than today) were adequate based on this simulation.

- Higher ramp rates than those considered here were provided by HECO. These ramp rates were considered "once-in-awhile" ramp rates that the units were capable of achieving for short durations and only infrequently. For the conditions and events considered in this study, these ramp rates were not considered necessary to manage the system performance.

10.7.3. Recommend improving the droop characteristics of the HECO units to improve performance during system contingencies

- The proposed droop response of the thermal units improves the system frequency performance during load rejection events (over-frequency) and cable trip events (under-frequency).
- For the cable trip event simulated in Scenario 5F3, the “base case” (including the proposed future droop characteristics) reduced the under-frequency excursion as compared to today’s droop characteristics.
- For the load rejection event simulated in Scenario 5F3, the proposed droop characteristics reduced the magnitude of the over-frequency excursion as compared to the existing droop settings.

10.8. Additional Study Work

It is recommended that the following efforts be pursued in advance of the interconnection of these large wind plants:

- Transmission planning and reliability analyses (e.g., transient stability, voltage stability, protection and control, etc.) for system with anticipated wind and solar power projects.
- Solar integration study based on representative solar power production data for anticipated solar plants and its impact to capacity factors of large off-island wind projects.
- Impact assessment on thermal unit heat rate performance based on expected maneuvering and dispatch for operation with the anticipated wind and solar power projects.
- Wind turbine controls studies and tuning for the HECO system to ensure adequate response of wind plants during system events.
- Wind and solar power forecasting feasibility and accuracy assessment.
- Assessment of potential impacts of torsional stresses on generating units due to higher penetrations of wind power and the interconnection of the HVDC system.
- Sensitivity analyses to fuel prices, wind energy production levels, unit retirement schedule, peak load and energy forecasts, potential emissions costs, etc.