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SAND2011-7541
Unlimited Release
Printed August 2011

Kauai Island Utility Co-op (KIUC) PV Integration Study

Tom Mousseau, EnerNex Corporation
Abraham Ellis, Sandia National Laboratories

Prepared by
Sandia National Laboratories
Albuquerque, New Mexico 87185 and Livermore, California 94550

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Kauai Island Utility Co-op (KIUC)
PV Integration Study

Abraham Ellis
Photovoltaics and Distributed Systems Integration
Sandia National Laboratories
P.O. Box 5800
Albuquerque, New Mexico 87185-1033

Tom Mousseau
620 Mabry Hood Road, Suite 300
Knoxville, TN 37922

Abstract

This report investigates the effects that increased distributed photovoltaic (PV) generation would have on the Kauai Island Utility Co-op (KIUC) system operating requirements. The study focused on determining reserve requirements needed to mitigate the impact of PV variability on system frequency, and the impact on operating costs. Scenarios of 5-MW, 10-MW, and 15-MW nameplate capacity of PV generation plants distributed across the Kauai Island were considered in this study. The analysis required synthesis of the PV solar resource data and modeling of the KIUC system inertia. Based on the results, some findings and conclusions could be drawn, including that the selection of units identified as marginal resources that are used for load following will change; PV penetration will displace energy generated by existing conventional units, thus reducing overall fuel consumption; PV penetration at any deployment level is not likely to reduce system peak load; and increasing PV penetration has little effect on load-following reserves. The study was performed by EnerNex under contract from Sandia National Laboratories with cooperation from KIUC.

Contents

Figures

Tables

Acronyms

AGC	Automatic Generation Control
DOE	Department of Energy
ETR	Extraterrestrial Radiation
ETRN	Extraterrestrial Normal Radiation
HCEI	Hawaii Clean Energy Initiative
HECO	Hawaiian Electric Company
KIUC	Kauai Island Utility Co-op
METSTAT Dir	Meteorological Statistical Model Direct Normal
NREL	National Renewable Energy Laboratory
PV	photovoltaic
SNL	Sandia National Laboratories
SUNY Glo	Global Solar Radiation
SUNY	State University of New York

Executive Summary

ES-1 Overview

This report investigates the effects that increased distributed photovoltaic (PV) generation would have on the Kauai Island Utility Co-op (KIUC) system operating requirements. The study focused on determining reserve requirements needed to mitigate the impact of PV variability on system frequency. The analysis was performed by examining the impact on system frequency and operating costs. Scenarios of 5-MW, 10-MW and 15-MW nameplate capacity of PV generation plants distributed across the Kauai Island were considered in this study. The study was performed by EnerNex under contract from Sandia National Laboratories with cooperation from KIUC.

ES-2 Approach

The study collected solar resource data and system operation data from readily available sources. Hourly solar resource data was acquired from the National Renewable Energy Laboratory solar database for years 2000–2005. Higher-resolution solar data provided by KIUC consisting of data for partial years was used to develop profiles and statistical representations of data. The statistical characterization of this data was applied to the NREL solar resource data to model intra-hour variability. In addition, KIUC provided a description of their operating system with UPLAN data depicting generation operation, operation costs, and projected load growth. KIUC also supplied high-resolution (15-second) system frequency data for December 1–21, 2009.

A system model was created, using the block diagram language VisSim, to mimic the KIUC system. KIUC provided data consisting of generation output, system load, and system frequency. The model input was generation and system load. The model output was system frequency response. A Base Case was defined that used the KIUC system generation output and system load. The model was tuned such that the output frequency response would closely match the provided KIUC system frequency.

Using the tuned model, a scenario of distributed PV generation was added to the Base Case configuration. The resulting output of frequency from the model showed degradation in system frequency. The model was tuned to the KIUC system frequency by adding regulating reserve capacity. The amount of generation output modification was captured and analyzed to demonstrate the PV effects on the system. KIUC provided UPLAN data that was used to approximate system production costs for the study period (2011) and to estimate the overall impact of the different PV penetration scenarios on system operations. The regulation reserve requirements established in the previous step were applied to the UPLAN production cost simulations.

ES-3 Findings and Conclusions

Through the analysis of the PV solar resource data and the modeling of the KIUC system with 5-MW, 10-MW, and 15-MW nameplate capacity of PV generation, the following findings and conclusions can be drawn:

- The selection of units identified as marginal resources that serve and follow system load will change. As PV generation increases, units identified as marginal resources will be units with lower operating costs. In general the cost of operations for marginal units will be reduced.
- The required spinning reserve to maintain system frequency increases with the penetration level of PV (see Figure ES-1).

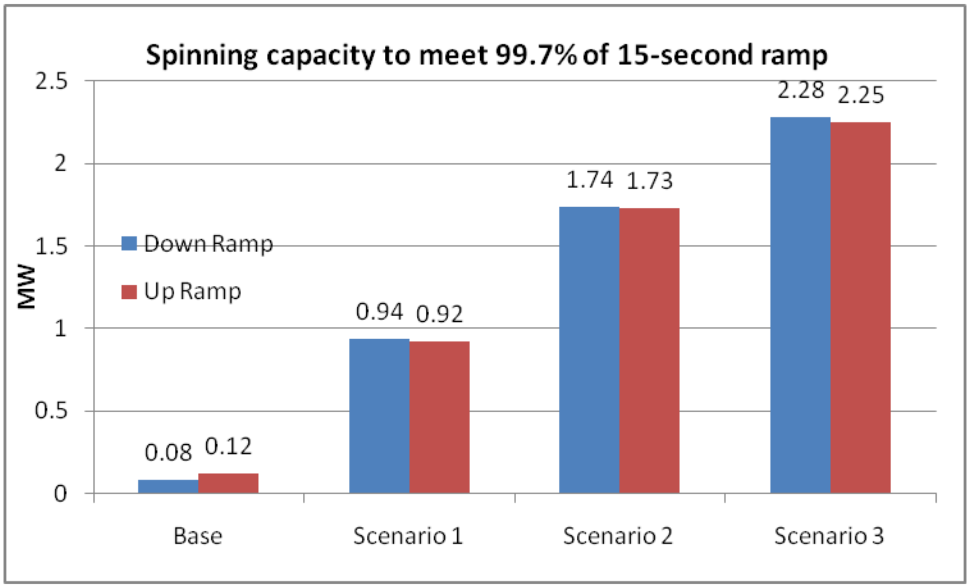

Figure ES-1. On-line spinning capacity requirement to meet 99.7% of 15-second changes in net load for study scenarios.

- PV penetration will displace existing system generation, thus reducing fuel consumption. The costs of conventional generation operations are reduced due to fuel savings. However, PV energy does not come at zero cost. (The production cost simulations did not take into account the PV cost.)
- PV generation installed at 5-MW, 10-MW, and 15-MW penetration levels will affect regulating reserves. The study showed that as PV penetration increases the required regulating reserve to control system frequency will increase (see Table ES-1). These additional reserve levels would result in a frequency performance that is similar to the existing system. This analysis is based on a limited amount of high-resolution system data, and did not consider system performance during contingencies.

- PV penetration at any penetration level is not likely to reduce system peak load. KIUC load patterns peak in the evening with a secondary peak in the morning. The peaks occur at times when PV generation is at low or zero level. PV has the best benefit for reducing system peak in the summer months when the solar day is longer.
- Increasing PV penetration has little effect on load-following reserves with negligible reduction as penetration increases (Table ES-1).

Table ES-1. Annual Incremental Reserve Range.

Range of monthly maximum load changes for study period in 2011	PV Penetration							
	Base Case		Scenario 1		Scenario 2		Scenario 3	
	From	To	From	To	From	To	From	To
Regulating (MW/15sec)	0.10	0.34	0.95	1.69	1.66	2.90	2.25	4.35
Load-Following (MW/h)	7.45	10.79	7.30	10.72	7.23	10.65	7.07	10.53

- PV generation studies require data with time resolution less than 1 hour, preferably in seconds.
  - Variability: High-resolution (1-second) solar resource data demonstrates greater variability of PV generation and can have a significant effect on system frequency. This impact may be obscured if PV generation is modeled with hourly resolution data.
  - Diversity: High-resolution (1-second) solar resource data yields improved diversity between geographically separated sites. Geographical diversity has a lesser impact on variability over longer time frames.

1 Introduction

1.1 Introduction

This report describes the potential effect of introducing different penetration levels of photovoltaic (PV) power into the Kauai Island Utility Co-op (KIUC) power system. The analysis was performed by EnerNex under contract to Sandia National Laboratories (SNL), and funded by the U.S Department of Energy (DOE).

In January 2008 the Hawaiian governor signed a Memorandum of Understanding with DOE to the Hawaiian-DOE Clean Energy Initiative (HCEI). This was an unprecedented effort to transform the entire Hawaii economy from receiving 95% of its energy, including most electricity, from imported oil today, to meeting the state's energy needs with 70% clean energy (primarily indigenous renewables and efficiency) by 2030.

To assist in meeting the goals of the HCEI, the KIUC is developing a renewable energy roadmap for the Hawaiian Island of Kauai. In providing support of the roadmap development, SNL has been tasked to supply KIUC with a preliminary solar integration impact study for the Kauai Island. EnerNex was contracted to work with SNL to assist in completing this task. This report provides description of the effort and its findings.

1.2 Scope

The scope of this study is to estimate potential operational and cost impacts of increasingly higher penetration of PV output on the KIUC system. The study relied upon the use of well-established tools and methodologies that have been used in the analysis of renewable resource integration studies for larger systems. Additional revisions to these methodologies were made to deal with the microgrid setting and higher time resolution needed to capture short-term PV power output impacts.

Early in the project it was determined the study would examine the impact of three scenarios of various PV integration. The first scenario totaling 5 MW of nameplate generation consists of one 3-MW and two 1-MW PV plants. The second scenario provides 10 MW of nameplate generation consisting of two 3-MW and four 1-MW plants. The third scenario consists of 15 MW of nameplate generation with four 3-MW and three 1-MW plants. This report provides details and analysis of data for each of the scenarios.

As an intermediate step in this study, there was an examination of the effect of PV on reserve requirements to maintain system reliability. To examine high-resolution time-domain simulations of the KIUC system, a commercially available modeling tool, VisSim, was used to take into account the impact of KIUC’s Automatic Generation Control (AGC) system.

It is not in the scope of this project to evaluate auxiliary costs of PV implementation such as the cost of construction, transmission and distribution lines, capital cost of plants, licensing, regulatory costs, permit costs, location siting, and PV integration or compatibility with the current KIUC generation system. For the purpose of the study the PV siting does not map to specific locations on the Kauai Island, nor is it the intent of this report to propose construction locations of PV sites on the island.

1.3 Requirements

An important aspect of the study involves the collection and identification of useful and accurate data from which results, analysis, findings, and recommendations are derived. The National Renewable Energy Laboratory (NREL) has several years of measured solar resource data for different sites on the Hawaiian Islands. One site from the database was on the Kauai Island at the Lihue airport. This was the only site for Kauai in the NREL database. To this end the project team identified early on that long range (year or more) periodically continuous solar resource PV data was limited to a single site on the island.

To incorporate diversity into the analysis, the NREL database provided solar resource data for other locations on the Hawaiian Islands. These locations were examined statistically and used in the study. In addition, KIUC provided measured solar data from various sites on the different islands. This data consisted of assorted time resolution PV data for different time periods less than a year in duration. A method for estimating solar plant output based on the irradiance data was provided by SNL. Details of the PV data used for the study can be found in Section 2.1.

Understanding the KIUC system and its response to large amounts of PV capacity penetration required building a model of the KIUC system including the effects of inertia and AGC. The KIUC system model representing in its present state with 3 MW of distributed PV penetration (Base Case) was validated and used as an operations baseline. Additional scenarios of the KIUC system for each PV penetration were analyzed for comparison against the Base Case.

KIUC provided UPLAN data for 2010 that was used in the study as a representative model of the KIUC generation system. The data consisted of generation resource configurations and system loads and was used as input for the system model. The UPLAN model allows for estimation of production cost and assessment of generation adequacy.

The study year was selected to be 2011. Load data for 2011 was derived by escalating the 2010 UPLAN load data at 1%. There were no generation fleet additions or retirements between 2010 and 2011.

2 Project Assumptions

2.1 Data Availability

2.1.1 KIUC Data

The data provided by KIUC consisted of generation information for supply, load data for demand, and selected PV metered data at different resolution and duration. The list of the received data included:

- KIUC Hourly – 2006 loads – grown from 2004/2005 actual load
- KIUC 15-second frequency 12/1/09 – 12/21/09
- KIUC 15-minute system load 2005, 2008, 2009
- KIUC Warehouse PV Project 1-second real power 5/27/10 – 6/22/10
- Ahukini PV Project 1-second real power 2/23/10 – 3/11/10, 5/20/10 – 5/27/10, 5/27/10 – 6/9/10, 5/27/10 – 6/14/10
- Koloa Sub T21 2-second frequency data 7/14/10 – 7/16/10, 7/14/10 – 7/19/10, 7/16/10 – 7/23/10, 7/23/10 – 7/30/10, 8/3/10 – 8/10/10
- Oahu 1-second normalized solar data (3 stations) 8/22/09 6 a.m. – 11:35 p.m.
- KIUC system data from UPLAN (input and output)
- Hana Kukui 2.5-minute solar irradiance 6/30/09 – 7/24/09
- Monthly marginal cost resources for 2010

From the UPLAN input data the generation mix of the KIUC generation resources are shown in Figure 1. BIO, PUR, WAT, and WND (what might be considered as energy coming from renewable resources) make up 20% of the KIUC generation mix with the balance 80%coming from FO_2, KNAP, and USED fuels and a total generation fleet nameplate of 120 MW. With the given nameplate capacity the KIUC system has high reliability to serve customer demand. Section 5.1 provides additional characteristics of system load used in the study.

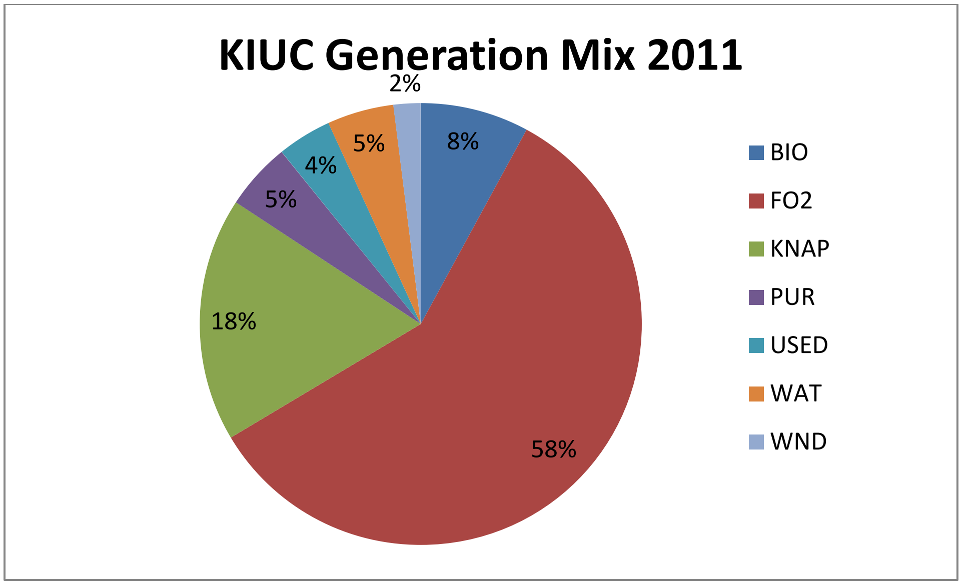

Figure 1. KUIC generation mix for 2011.

2.1.2 NREL Solar Data

The NREL National Solar Radiation Database was a primary source of solar resource data for the study. The database provided a single source of solar resource data for the island of Kauai representative of the Lihue airport. To consider the effects of geographical diversity on the performance of large PV systems it was decided to select additional sites from the NREL database representing other Hawaiian islands. Using solar patterns consistent with solar resource data on the Hawaiian Islands yet different enough to allow various PV plant output was intended to provide a degree of diversity for the study. It was assumed that the statistical correlation of hourly solar resource data among the selected sites would be reasonably similar to sites within the island of Kauai.

A sample of the NREL data from the Lihue airport is shown in Figure 2. The database includes four measurements of solar resource data:

- ETR: Extraterrestrial Radiation
- ETRN: Extraterrestrial Normal Radiation
- SUNY Glo: Global Solar Radiation
- METSTAT Dir: Meteorological Statistical Model Direct Normal

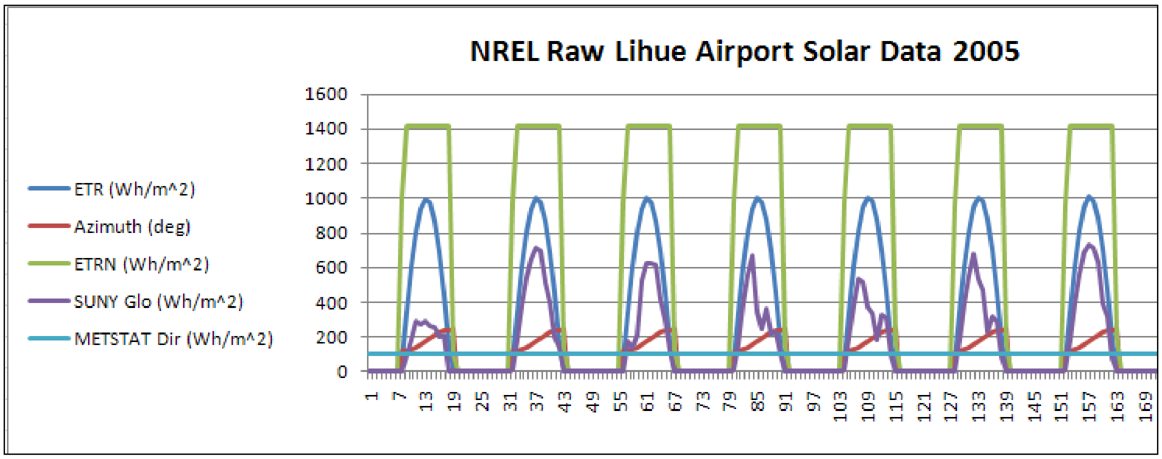

Figure 2. Sample of NREL 2005 Lihue Airport solar resource data.

The data used in the study was the SUNY Glo solar resource data that produces estimates of global and direct irradiance at hourly intervals for the United States using a 10-km gridded satellite cloud cover. It is derived from a solar model developed by The State University of New York (SUNY). The dataset for the SUNY model from the National Solar Database includes global irradiance, direct irradiance, diffuse irradiance, daily statistical data, and the hourly statistical data. The NREL data gives a 1-hour resolution of irradiance data. The sampling of irradiance hourly does not capture the intra-hourly changes that can occur with weather changes such as the movement of clouds. Thus the hourly data filters shorter time scale data variability that can be observed with data collected in 1-second intervals. In general, irradiance data changes over a 1-hour period can be of quite different than changes over a shorter time period.

KIUC provided a sample of high-resolution solar resource data from a collector on the Island of Oahu. This data represents the Hawaiian Electric Company (HECO) Campbell Ind. site. Figure 3 illustrates the variability of 1-second data for a selected day from 6:00 a.m. to 6:00 p.m. Also shown is the 60-minute average irradiance for each hour. It should be noted how much irradiance change occurs within the hour.

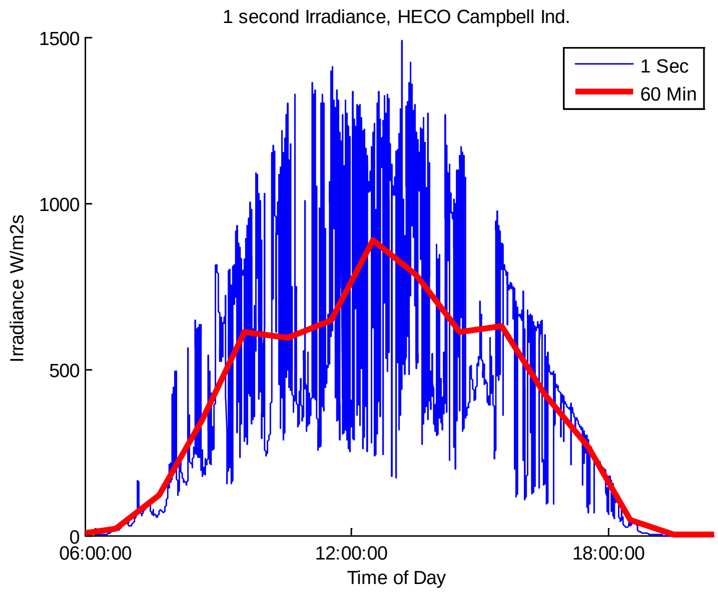

Figure 3. Comparison of 1-second and 60-minute average Global Horizontal irradiance for HECO Campbell on August 22, 2009.

Due to the significant intra-hour variability of the data, an analysis of the impact to the system frequency was included in the study. Solar data on a sub-hourly time scale was required to perform this analysis. To obtain higher-resolution irradiance data (1-second, 10-minute, etc.) an algorithm was developed to convert sites of hourly NREL data to a high-resolution data representative of the sites. This used actual irradiance patterns observed in measured KIUC data from the Kauai Island and then applied these patterns to the hourly NREL data.

For example, the nature of short-term variability at different sites on Kauai can be understood by considering the Oahu 1-second solar data. This data include 1-second irradiance data for August 22, 2009, from three sites – HECO Campbell, HECO Waiau, and HECO Ward St. Table 1 shows the 1-second ramp rate (RR) statistics for daytime irradiance. Very high ramp rates in irradiance are observed over a 1-second interval, with the maximum ramp rate of 609.57 W/m^2s at HECO Campbell. High ramp rates in irradiance over a short interval are largely due to the movement of clouds. Also, the ramp rate of irradiance data from HECO Ward St. has the least deviation but the most kurtosis of the three sites. This suggests that the increases variance at HECO Ward St. is a result of infrequent and extreme ramp rate deviations.

Table 1. 1-Second Ramp Rate Statistics for Daytime Irradiance Change Oahu Data.

Site	Mean(|RR|) W/m^2s	Max(|RR|) W/m^2s	STD(RR) W/m^2s	Kurtosis(RR)
HECO Campbell	9.66	609.57	32.90	57.69
HECO Waiau	10.57	444.98	31.11	36.99
HECO Ward St.	7.46	586.19	24.55	65.59

The cumulative probability distribution of the absolute value of the ramp rates for each site is shown in Figure 4. This represents the probability of the ramp rate occurring. The dotted line marks the 95th percentile of the ramp rates observed for each sites. From the chart, it can be interpreted that there is only a 5% chance that the ramp rate at HECO Waiau, HECO Campbell, and HECO Ward St. will be larger than 40 W/m^2, 55 W/m^2, and 60 W/m^2 respectively.

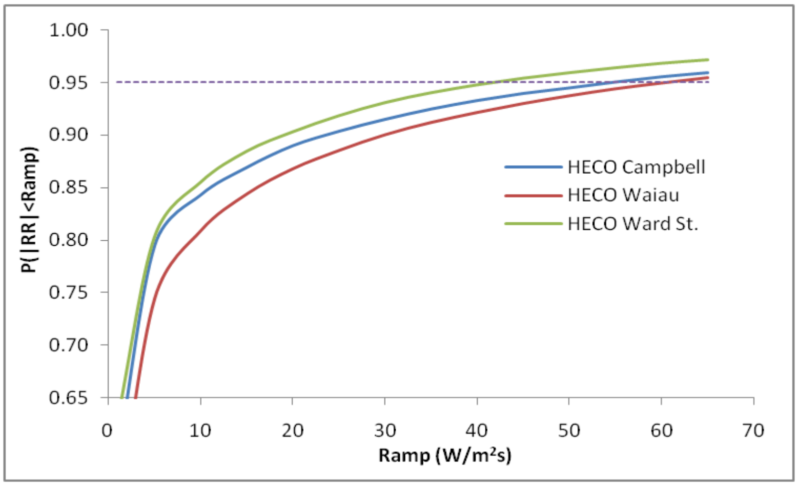

Figure 4. Cumulative probability distribution function of the absolute value of 1-second ramp rates for Oahu data.

To account for short-term variability in irradiance, the short-term variability pattern observed from the data provided by KIUC was mapped on the hourly average radiation data obtained from NREL database. It is necessary to account for the ramp rates because the majority of the variability in the PV power output is a result of variability in irradiance throughout the day.

2.2 Conversion from Irradiance to Power Output

The irradiance data provided by KIUC represents a single-sensor irradiance measurement; therefore, simply scaling up the single-sensor irradiance will result in exaggerated ramp rates of the actual PV plants. From previous studies, it is observed that the total energy flux of a PV plant can be calculated as a simple moving time average of the single-point irradiance output, where the averaging time is related to the dimensions of the solar field or size of the PV plant and to the cloud speed.[1] To account for the large solar fields and PV plant size modeled in this study, the irradiance data is processed as follows to approximate 95th percentile of short-term ramps:

- 1-MW systems: 20-second running average of single-sensor measurements
- 3-MW systems: 30-second running average of single-sensor measurements

[1] A. Longhetto et al., Effect of correlations in time and spatial extent on performance of very large solar conversion systems, *Solar Energy*, Vol. 43, No 2, pp. 77-84, 1989.

The delay parameters were provided by SNL based on analysis of PV irradiance and power output at the Lanai PV system and other sites. In a general sense, the delay parameters are related to cloud velocity, which should be similar in Kauai. The above approximation is based on the assumption that the plant output is the spatial average of irradiance over PV array footprint. In reality, the time average window that results in matching the 95^{th} percentile of ramps is a function of wind speed, which varies constantly. However, the approximations of the 1-MW and 3-MW systems give a good representation of the output characteristics of large PV systems.

A simple efficiency PV model was used to convert irradiance data to output power. The irradiance conversion model used a single, constant derate factor of 0.85 when converting solar energy from DC to AC electricity. The derate factor accounts for module mismatch, DC wiring losses, AC wiring losses, soiling, inverter efficiency, and inaccuracy in the PV module AC nameplate rating.

2.3 Other Assumptions

Assumptions made in this study are listed below:

- 1- and 3-MW plant sizes were used in this study. The required area and specific locations of the plants were assumed available and feasible to tie into the existing KIUC electric system.
- The PV generated will be a must take form of generation. System load will be adjusted by the amount of generation output provided by the PV plant.
- Plant sizes assumed for each scenario are assumed to be net AC output rating.
- PV plants are assumed to be flat plate PV, fixed axis, and southern azimuth.
- KIUC stated the impact of existing 3 MW of distributed PV generation has not been of concern to their operations dispatch because the PV generation is dispersed and short-term variability is mitigated. For this reason the base case for the analysis included the frequency effects caused by existing distributed PV generation.
- PV forecast data does not exist for equivalent actual PV generation. For this study, PV forecast error was assumed to be a persistence forecast.
- In the time frame of 2010 to 2011 there are no retirements or additions to the KIUC generation fleet. All generation performance, operating dispatch practices, and fuel costs are assumed same as in 2009 to 2010. From these assumptions it is concluded that the costs for operating the generation fleet in 2010 would be the same in 2011 if the system load in 2011 was identical to 2010.
- KIUC operates as an island system without interconnection to neighboring utilities. In this study only KIUC generation and loads will be modeled. The modeling of transmission is not considered necessary for this analysis.

3 Study Scenario

3.1 Scenario Description

This study analyzes three scenarios to evaluate integration cost for solar PV generation on the KIUC system. The scenarios represent a credible future installation of solar PV generation added to the KIUC electric generation system. KIUC currently has approximately 3 MW of existing distributed PV embedded in the KIUC load and not dispatched with the generation fleet. The operating characteristics of the 3-MW PV were not available for the study. The distribution locations, availability. and contribution to the KIUC grid are indicated only by the KIUC net load variation. Except for the diurnal generation cycle, the existing 3 MW of distributed PV penetration does not appear to significantly increase load ramps. The Base Case scenario includes the existing 3 MW of distributed PV while the three scenarios will provide additional PV capacity to the Base Case, assuming 1-MW and 3-MW central station plant sizes. The three PV generation scenarios identified would be central station PV plants having nameplate capacity totaling 5 MW for Scenario 1, 10 MW for Scenario 2, and 15 MW for Scenario 3. Each plant would consist of a combination of 1-MW and 3-MW distributed PV systems. The PV central systems distribution and capacity for each scenario is shown in Table 2.

Table 2. PV Central Systems Distribution and Capacity for Three Scenarios.

Location	Scenario 1 PV Capacity Installed (MW)	Scenario 2 PV Capacity Installed (MW)	Scenario 3 PV Capacity Installed (MW)
Site 1	3	3	3
Site 2	1	1	3
Site 3	1	1	3
Site 4	-	3	3
Site 5	-	1	1
Site 6	-	1	1
Site 7	-	-	1
Total MW	**5**	**10**	**15**

3.2 PV Data Modeling

As previously mentioned, the PV central station systems will be modeled in block sizes of 1 MW and 3 MW, and modeled as if distributed over the Kauai Island. To account for geographical diversity, hourly data from seven different sites on other islands were used as proxies to build the study scenarios shown in Table 2. High-resolution data from Oahu was used to derive intra-hour profiles.

Some of the considerations for proxy site selection include:

- The solar resource data at selected sites must be a close representation of the solar resource data patterns observed throughout the year on Kauai Island.
- The availability of a single site of solar resource data on Kauai correlated with the solar resource data at the selected sites. The need for selection of the other island solar resource data is recognized as being a less than conservative assumption; however, this solar resource data provided diversity at the intra-hour level.
- Sites selected should provide adequate spatial and temporal diversity in irradiance and hence diversity in the power generated at the sites for the different scenarios under consideration.

Statistical analysis was performed on data from Honolulu Airport, Kahului Airport, and Hilo International Airport to compare the hourly solar resource data pattern observed with that at Lihue Airport on Kauai Island. Table 3 gives the geographical locations and the selected years of the sites that were considered. Figure 5 shows a map of the selected sites.

Table 3. Site Locations.

Location	Latitude	Longitude	Resolution	Period
Lihue Airport	$21^{o}58'$	$159^{o}20'$	1 hr	2000-2005
Honolulu Airport	$21^{o}19'$	$157^{o}55'$	1 hr	2000-2005
Kahului Airport	$20^{o}53'$	$156^{o}26'$	1 hr	2000-2005
Hilo Airport	$19^{o}43'$	$155^{o}02'$	1 hr	2000-2005

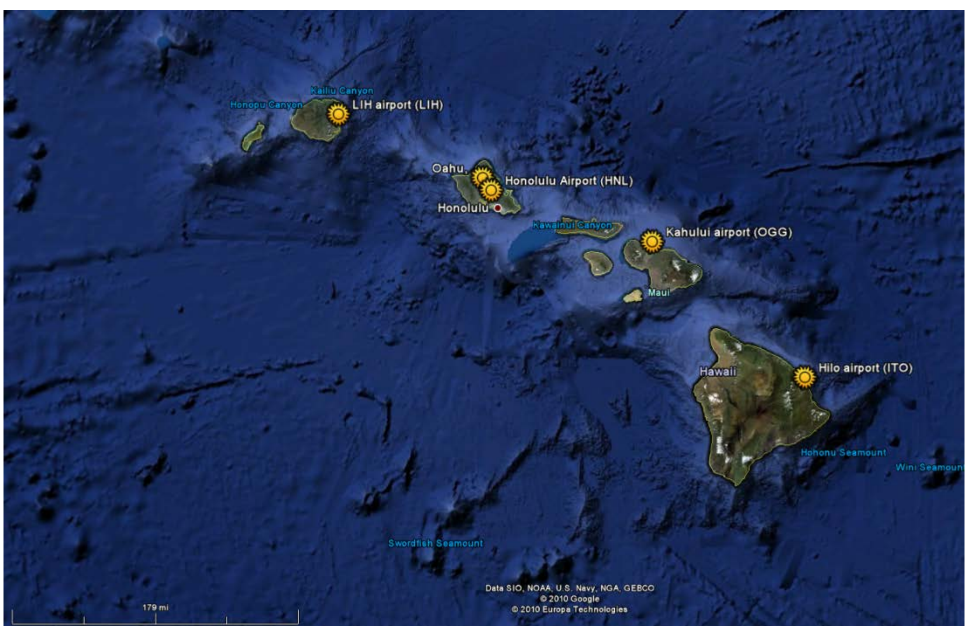

Figure 5. Map of site locations.

3.2.1 Year-to-Year Comparison

Site analysis was performed to compare the measured solar resource data from Lihue Airport, Honolulu Airport, Kahului Airport, and Hilo Airport over a six-year period (2000–2005).

Figures 6 through 13 show that slight monthly variation occurs over the years at the different sites, with the solar radiation at its highest from April through September and lowest from October through March, which corresponds to summer and winter seasons respectively. The result of the analysis also shows that the different sites are comparable in the amount of annual radiation received. For all the sites, a total annual solar radiation of about 2.0 MWh/m^2 is observed except at Hilo International Airport, where the annual solar radiation is slightly lower, 1.75 MWh/m^2. The sites show similarity in the monthly solar radiation and the annual solar radiation when compared to that observed at Lihue International Airport in Kauai.

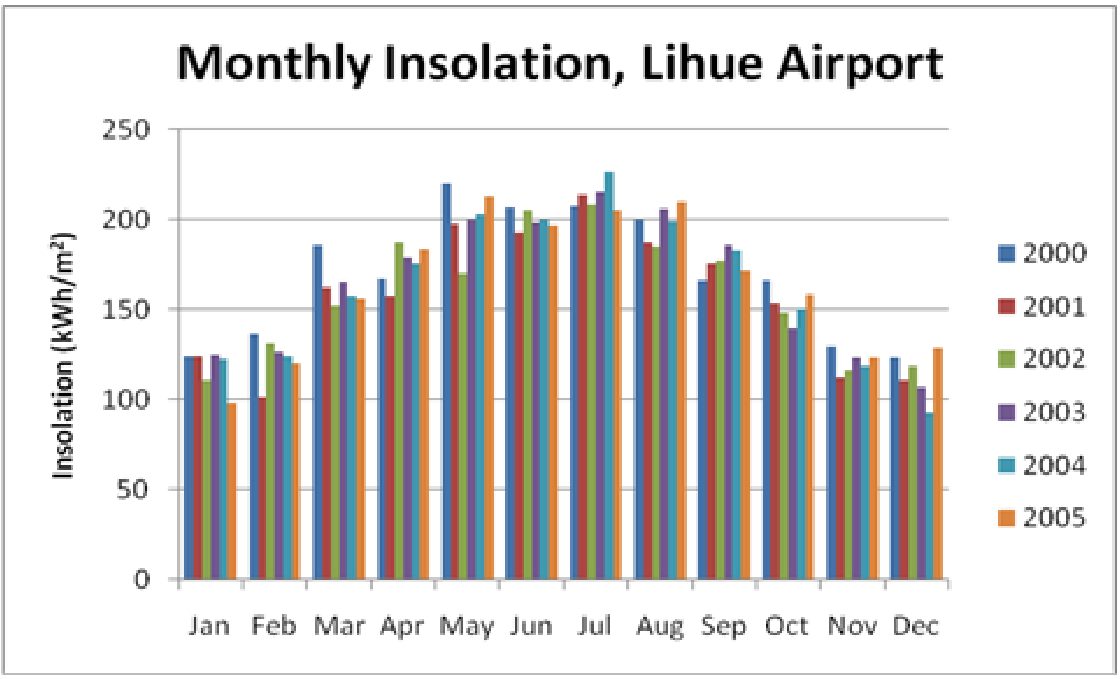

Figure 6. Monthly solar resource data at Lihue Airport, 2000–2005.

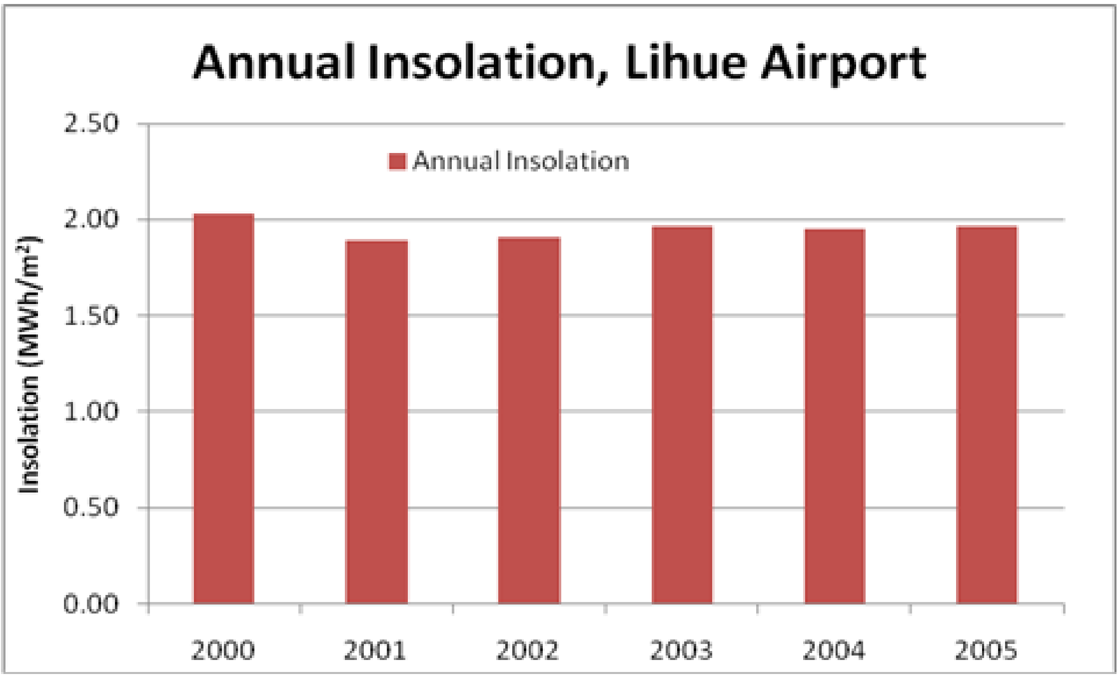

Figure 7. Annual solar resource data at Lihue Airport, 2000–2005.

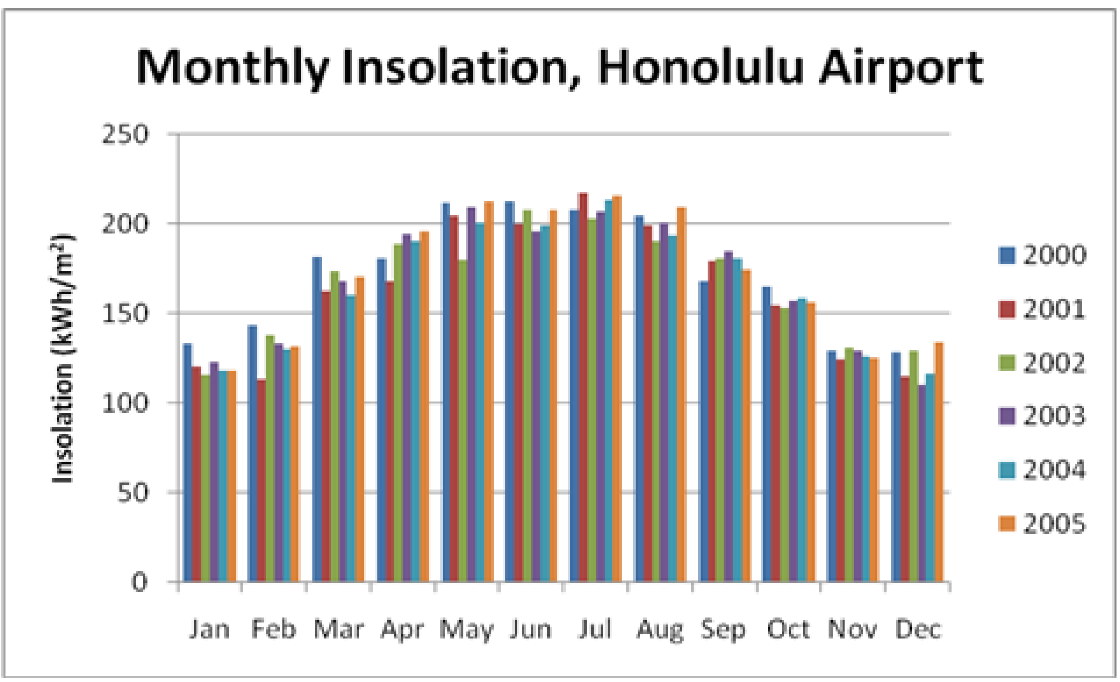

Figure 8. Monthly solar resource data at Honolulu Airport, 2000–2005.

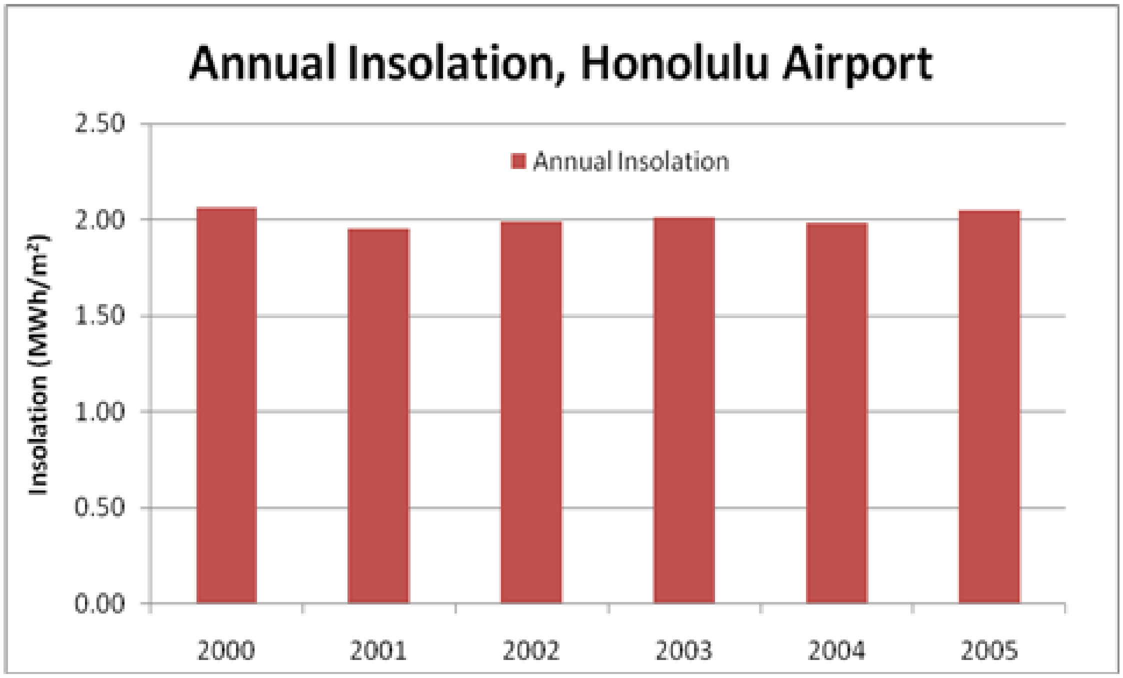

Figure 9. Annual solar resource data at Honolulu Airport, 2000–2005.

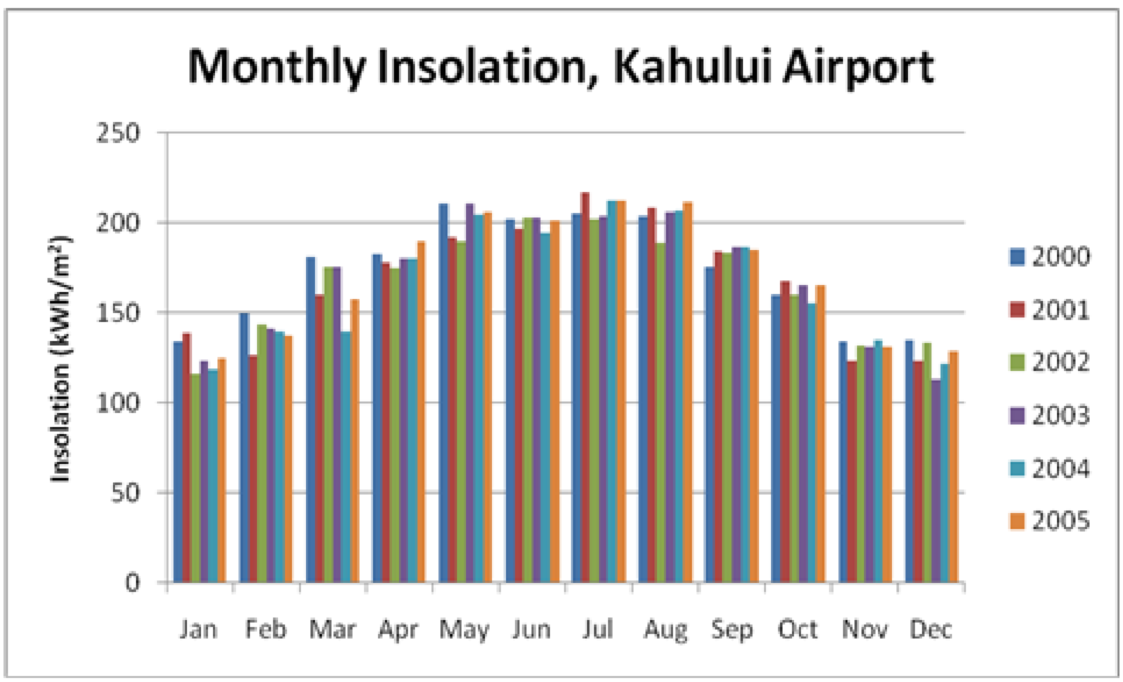

Figure 10. Monthly solar resource data at Kahului Airport, 2000–2005.

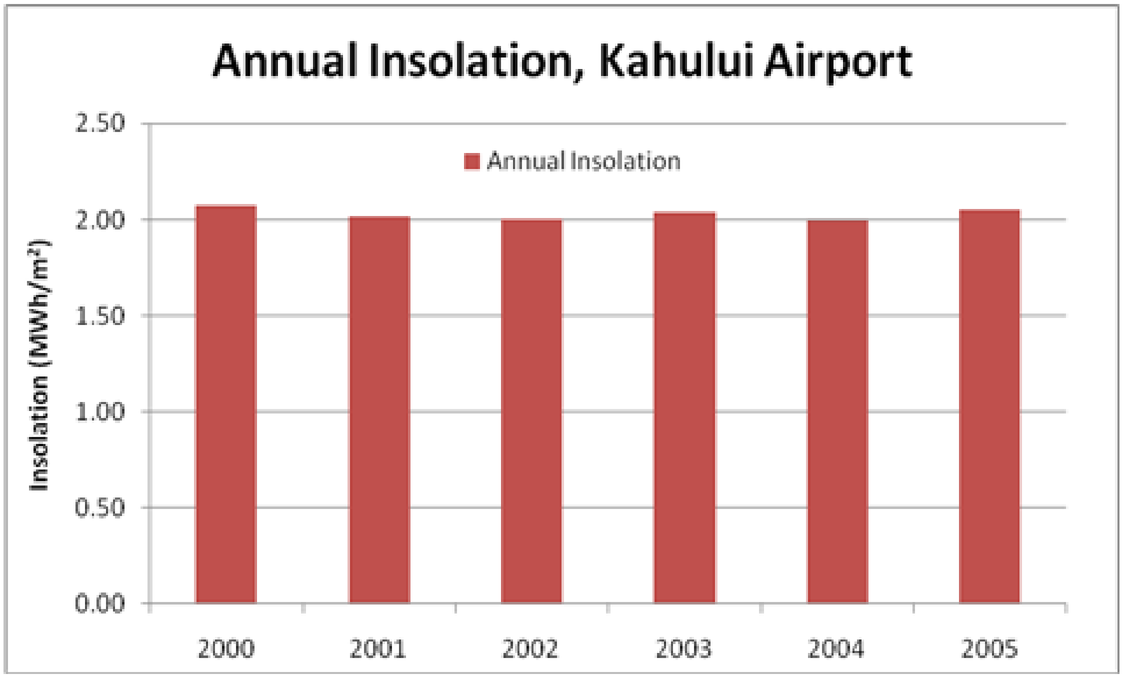

Figure 11. Annual solar resource data at Kahului Airport, 2000–2005.

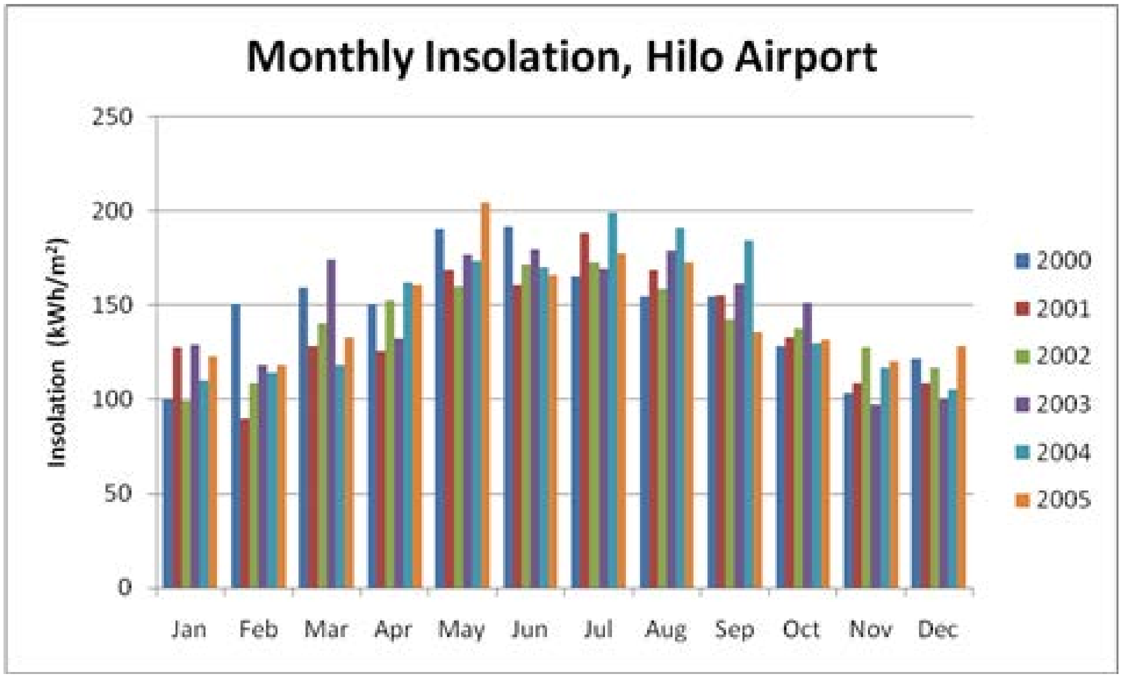

Figure 12. Monthly solar resource data at Hilo International Airport, 2000–2005.

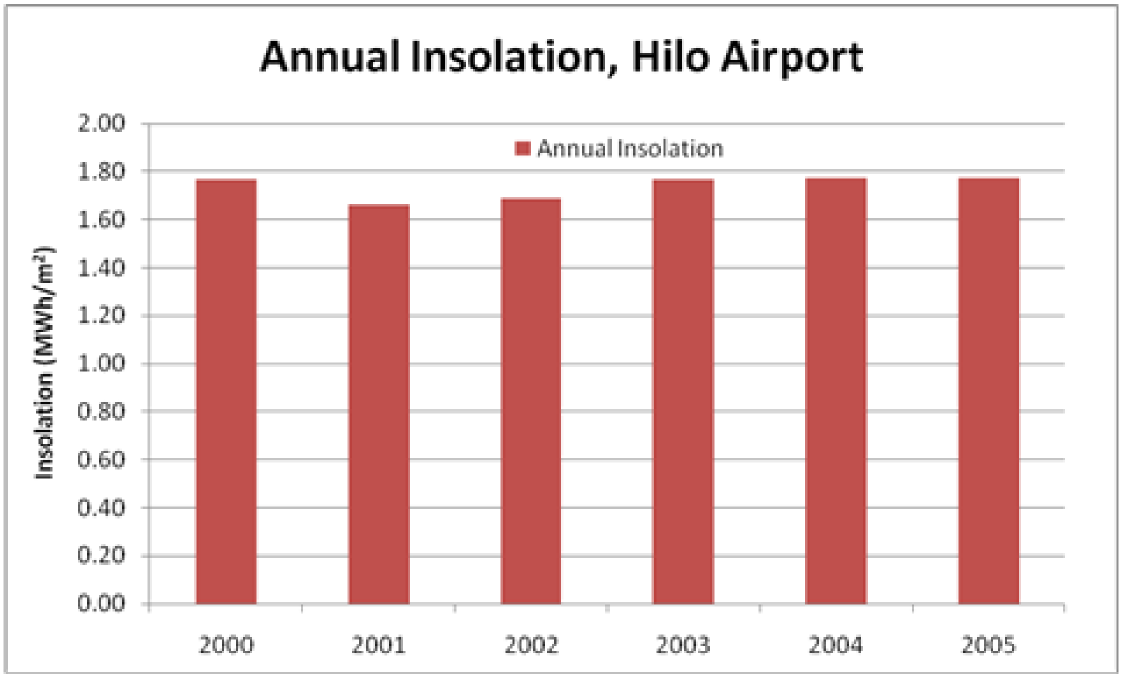

Figure 13. Annual solar resource data at Hilo International Airport, 2000–2005.

The results of the analysis suggest that the climate on Kauai Island is relatively constant and that the solar energy received by the neighboring islands is also relatively similar.

Since there is only slight variation in the amount of solar energy received on the other islands compared to Kauai, this study, although a less than conservative assumption, uses available solar resource data measurements from these sites as representative of the solar resource data that would be observed at different geographical areas on the Kauai Island.

It is recognized that this diversity may lend to increased variability on days when cloud cover is over the southern islands and not the Kauai Island, thus reducing PV benefit to the system. On the other hand, when there is cloud cover on the Kauai Island and not the southern islands there would be an increase in PV benefit to the system. The distribution of irradiance over the different sites is such that the special cases were not seen to be significant.

All central PV systems are modeled as if they were physically located on the Kauai Island. Figure 14 displays the solar resource data sites used to select PV data for analysis as the diurnal pattern observed on the actual sites on Kauai Island.

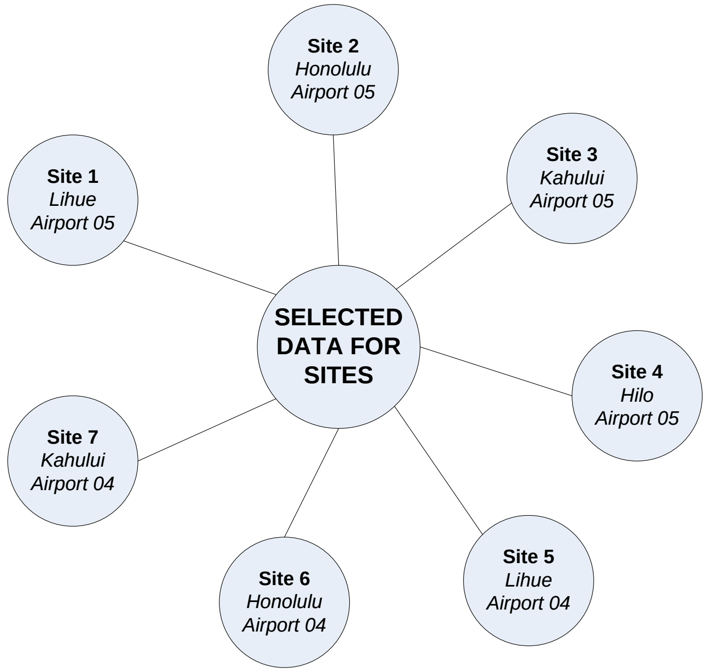

Figure 14. Selected sites and solar data representation.

The selection for the sites is based on the total monthly solar resource data observed at the sites (Figure 15), and not on the daily comparison of the solar resource data. The total monthly solar resource data observed at the selected sites are very comparable except for Site 4 (Hilo Airport), which shows a lower solar resource data. The solar resource data daily average of the sites may vary when compared with each other. For example, the variation of the hourly solar resource data may be more observable when a particular day in one year is compared to the same day in another year because of the daily weather differences between the two years. The justification in using the different sites from different islands is made based on the fact that the average solar resource data for the month will be close for the sites from one year to the other. The correlation of solar resource data between sites is discussed in Section 3.2.3. As described previously, in certain situations this diversity can reduce the net variability of PV and may be a less than conservative representation of the PV plants modeled on Kauai.

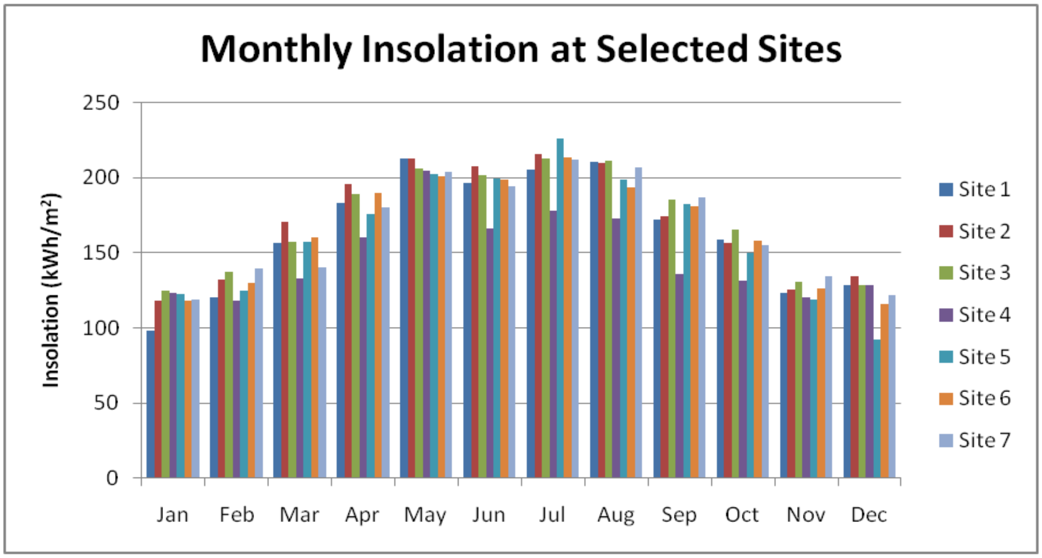

Figure 15. Monthly solar resource data at selected sites.

3.2.2 Analysis of Selected Sites

Figure 16 shows general statistics for montly solar resource data observed at Site 1. The montly maximum reaches over 1000 Wh/m^2 from April through August with minimum insolation in November, December, and January. The average high represents the average of the highest daily insolation observed throughout the month. The mean solar resource data represents the insolation observed throughout the month during daylight hours. For comparison, the same analysis was performed on the other sites in the study and can be found in Appendix A.

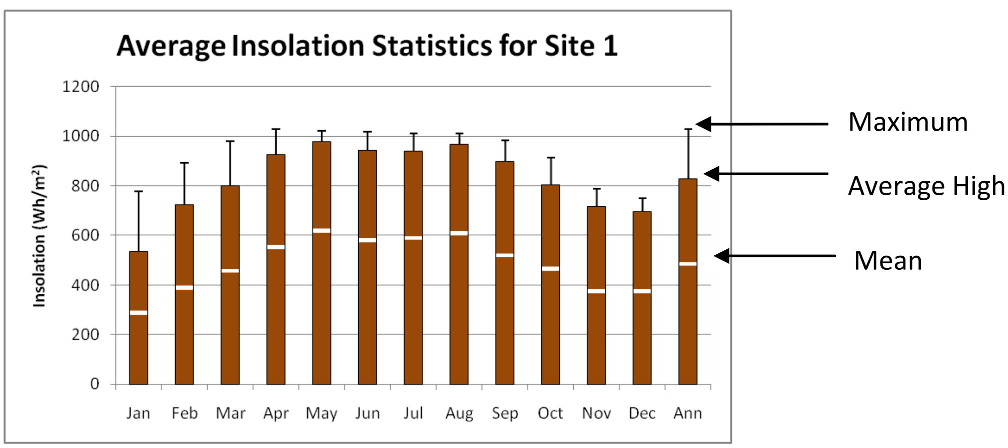

Figure 16. Average monthly and annual solar resource data statistics for Site 1.

Figure 17 presents a cumulative distribution plot of each site. The chart not only shows correlation in the distribution of the irradiance observed throughout the year, but also shows that there is diversity in the irradiance distribution of the sites. For example, about 80% of Hilo solar resource data is less than 450 Wh/m^2, whereas 80% of Kahului solar resource data is less than

600 Wh/m^2. From the graph, about 80% of the solar resource data observed at the sites is equal or less than 600 Wh/m^2.

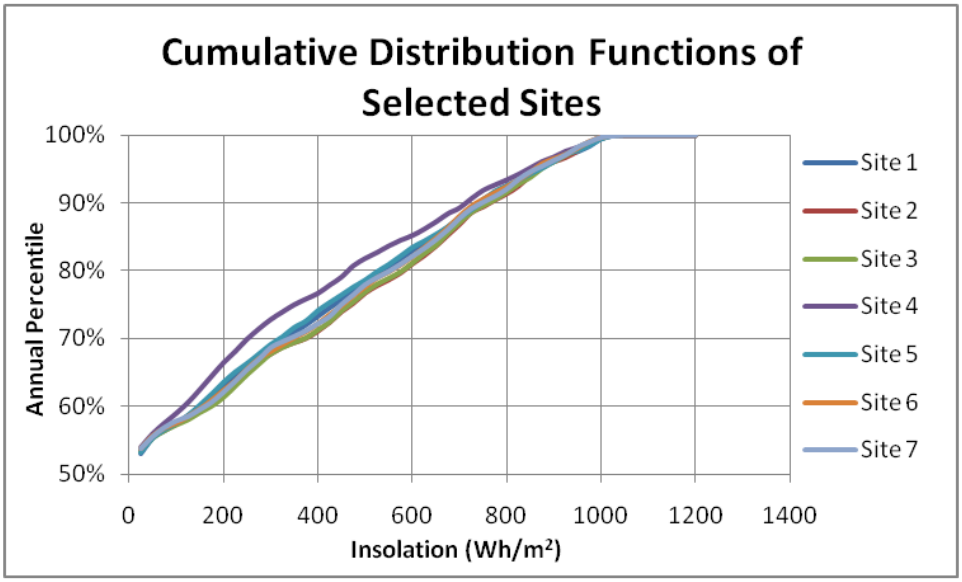

Figure 17. Cumulative distribution function of selected sites.

3.2.3 Correlation of Selected Sites

An analysis correlating the hourly irradiance data was performed. In the analysis a correlation of 1 is a perfect correlation between the two sets of data. This means that as the irradiance of one set increases/decreases the irradiance of the other set of data increases/decreases by the same amount. A correlation of -1 would mean that there is an opposite correlation of data between the two sites. In other words, when one site has an increase from one point to the next the other site decreases by the same amount. A correlation of 0 means there is no correlation between the data sets.

The correlation of solar resource data between the sites selected follows. A proposed ranking of the quality of site correlation is:

- 0 – 0.2: no or negligible correlation
- 0.2 – 0.4: low degree of correlation
- 0.4 – 0.6: moderate degree of correlation
- 0.6 – 0.8: marked degree of correlation
- 0.8 – 1.0: high correlation

Each site was examined during daylight hours. The correlation coefficients of each selected site for December are shown in Table 4.

Table 4. Solar Resource Data Correlation Coefficient in December for Selected Sites.

	Site 1	Site 2	Site 3	Site 4	Site5	Site 6	Site 7
Site 1	1.000						
Site 2	0.887	1.000					
Site 3	0.851	0.902	1.000				
Site 4	0.787	0.808	0.794	1.000			
Site 5	0.679	0.658	0.627	0.649	1.000		
Site 6	0.718	0.782	0.745	0.735	0.717	1.000	
Site 7	0.765	0.811	0.771	0.804	0.673	0.841	1.000

The 2005 data representative of Sites 1, 2, 3, and 4 are from different sites. The correlation between these sites varies between 0.787 and 0.902. The correlation coefficient of the hourly solar resource data is a marked degree of correlation showing that the diurnal variation of solar radiation throughout the day is similar.

Also, the 2004 data representative of Sites 5, 6, and 7 are from the same islands as 2, 3, and 4 respectively. The correlation between these sites varies between 0.679 and 0.841. Sites 5, 6, and 7 also show a marked degree of correlation with Sites 1, 2, 3, and 4. Additional months of correlation data can be found in Section A.7.

3.2.4 Correlation Data of High-Resolution Data

Due to the synchronized diurnal solar variation at the different sites, the hourly correlation coefficients of the solar resource data are usually close to one. But the diversity between sites is more evident when the correlation coefficient is found using solar resource data with a shorter time interval. This is illustrated by computing the correlation of measured data of Oahu 1-second solar resource data received from KIUC for three sites. Table 5 shows a high correlation of hourly average solar resource data between the sites. The high correlation is due to the diurnal pattern of the sun. A more moderate correlation is observed for the daylight hours when 1-second solar resource data is used, as shown in Table 6. The 1-second data results in a lower correlation between the sites due to the short-term variability in solar resource data, as a result of transient clouds.

Table 5. Correlation Coefficient of Average Hourly Solar Resource Data for Sites at Oahu on August 22, 2009.

	HECO Campbell	HECO Waiau	HECO Ward St.
HECO Campbell	1.00		
HECO Waiau	0.93	1.00	
HECO Ward St.	0.92	0.86	1.00

Table 6. Correlation Coefficient of 1–Second Solar Resource Data for Oahu Data on August 22, 2009.

	HECO Campbell	HECO Waiau	HECO Ward St.
HECO Campbell	1.00		
HECO Waiau	0.54	1.00	
HECO Ward St.	0.42	0.47	1.00

To show the diversity of the sites, a similar analysis is performed using the single-sensor irradiance measurements at the selected sites used to model the scenarios. The correlation coefficient of the average hourly irradiance of the sites during daylight hours is shown in Table 4. As expected, the correlation coefficient of the hourly solar resource data is very high. Using 1-second solar resource data, Table 7 results in a lower correlation coefficient due to differences in short-term solar variability between hours. On shorter time scales, a lower correlation indicates diversity between the sites, and the extent to which the aggregate variability of the sites will be dampened.

Table 7. Correlation Coefficients of 1–Second Irradiance for Selected Sites on December 9.

	Site 1	Site 2	Site 3	Site 4	Site 5	Site 6	Site 7
Site 1	1.00						
Site 2	0.56	1.00					
Site 3	0.96	0.59	1.00				
Site 4	0.94	0.58	0.98	1.00			
Site 5	0.53	0.98	0.55	0.55	1.00		
Site 6	0.53	0.65	0.58	0.56	0.59	1.00	
Site 7	0.32	0.47	0.39	0.37	0.40	0.63	1.00

3.3 Scenario Analysis

3.3.1 Capacity Factor and Energy from Solar

A performance characteristic for generation is the capacity factor. PV tends to have a low capacity factor considering high-level irradiance exists for only a few hours over the day. However, to provide a metric for the selected PV sites a summary of the capacity factor and annual PV energy for each scenario is shown in Tables 8 through 10. The capacity factor observed for the scenarios is about 19%, which is very good for a PV system when compared to the average capacity factor of about 15% in prime sites. The high capacity factor for PV is due to the Kauai Island receiving a considerable amount of solar radiation throughout the whole year.

Table 8. Summary of Capacity, Capacity Factor, and Annual Energy by Sites for Scenario 1.

Scenario 1			
Central Stations	**PV Capacity (MW)**	**Capacity Factor (%)**	**Annual PV Energy (MWh)**
Site 1	3	19.07%	5010.92
Site 2	1	19.90%	1743.17
Site 3	1	19.88%	1741.84
Total	5	19.40%	8495.93

Table 9. Summary of Capacity, Capacity Factor, and Annual Energy by Sites for Scenario 2.

Scenario 2			
Central Stations	**PV Capacity (MW)**	**Capacity Factor (%)**	**Annual PV Energy (MWh)**
Site 1		19.07%	5010.92
Site 2	1	19.90%	1743.17
Site 3	1	19.88%	1741.84
Site 4	3	17.19%	4518.55
Site 5	1	18.91%	1656.89
Site 6	1	19.27%	1687.62
Total	10	18.56%	16358.98

Table 10. Summary of Capacity, Capacity Factor, and Annual Energy by Sites for Scenario 3.

Scenario 3			
Central Stations	**PV Capacity (MW)**	**Capacity Factor (%)**	**Annual PV Energy (MWh)**
Site 1	3	19.07%	5010.92
Site 2	3	19.90%	5230.13
Site 3	3	19.89%	5226.15
Site 4	3	17.19%	4518.55
Site 5	1	18.91%	1656.89
Site 6	1	19.27%	1687.62
Site 7	1	19.51%	1709.40
Total	15	18.65%	25039.65

Figure 18 shows the seasonal variation of the PV energy produced, with the highest production during the summer and lowest during the winter season. The total energy from PV decreases by about 40% from summer to winter. The monthly PV energy as a percent of the load would vary throughout the year with its highest in the summer because of the seasonal variation of PV. Figure 19 shows the annual PV energy as a percent of the load energy. Note the PV resources installed for Scenario 1, Scenario 2, and Scenario 3 supply about 1.87%, 3.60%, and 5.51% of the annual load energy respectively. This is in addition to the existing 3 MW of distributed PV generation in the Base Case.

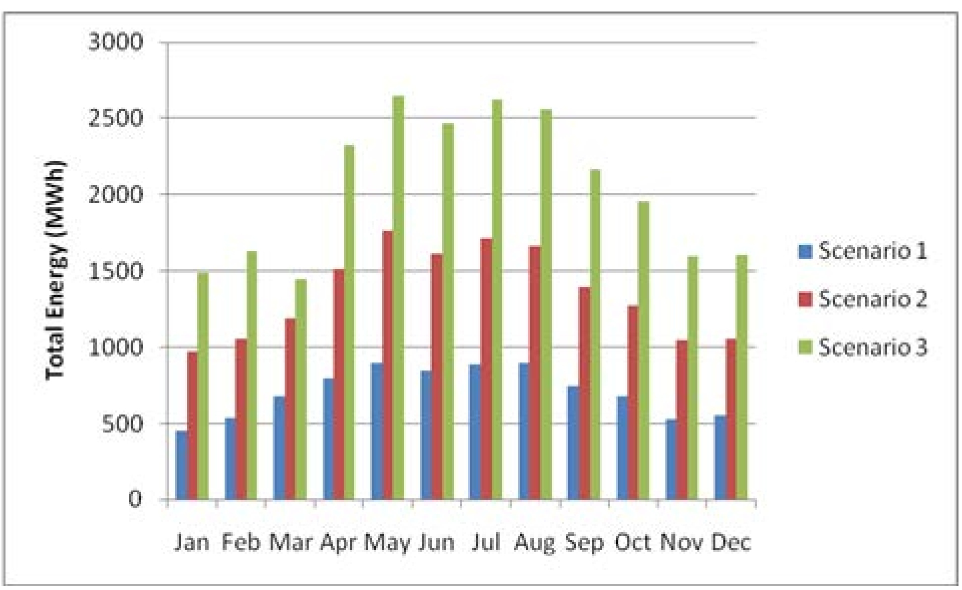

Figure 18. Total monthly energy from solar PV for each scenario.

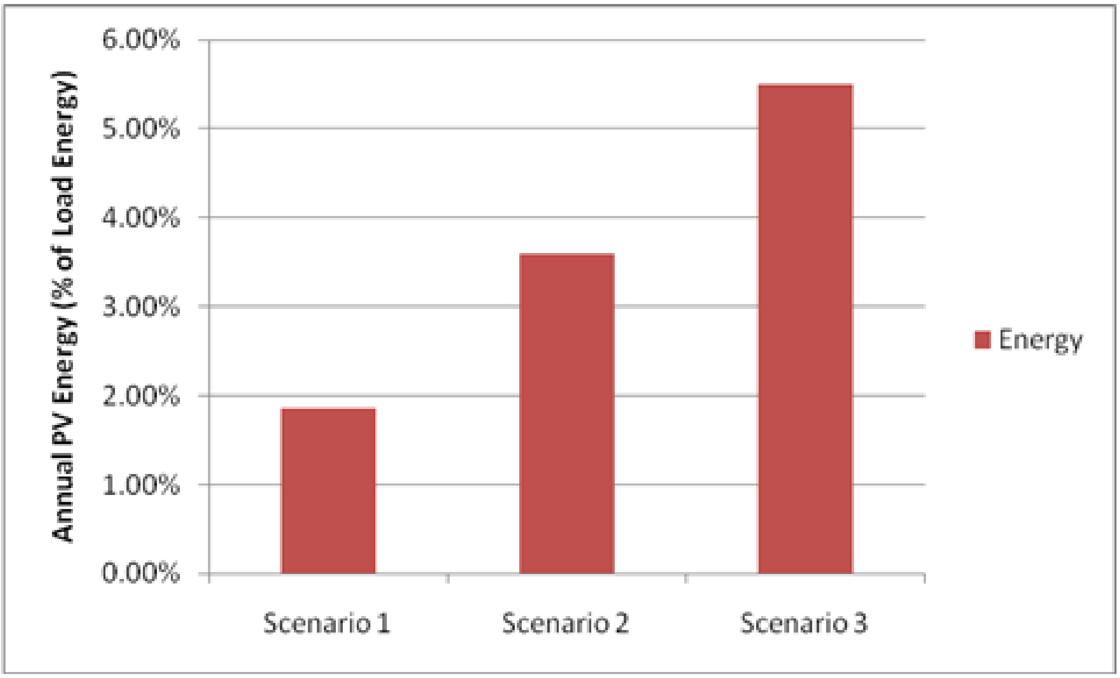

Figure 19. Annual energy as a percent of load energy.

3.3.2 PV Duration

Figures 20 and 21 show the PV duration curve and the PV penetration as a percent of the load throughout the year. The x-axis represents 8760 hours of the year. The PV duration curve is obtained by sorting the PV output for each scenario. The charts show as expected the availability of PV for 50% of the year when the sun is shining.

With increasing PV penetration level, regulation becomes more important because of the increased net load variability. Figure 21 shows the PV penetration of each scenario throughout the year. The PV penetration as percentage of load is calculated by expressing the chronological PV output as a percent of the corresponding hourly load for the year 2011. Even though PV resources are installed to supply about 1.87%, 3.60%, and 5.51% of the annual load energy for Scenario 1, Scenario 2, and Scenario 3 respectively, higher PV penetration can be observed for PV at different times during the year. For example, excluding the existing 3 MW of distributed PV generation that currently exists on the system, throughout the year peak PV output can reach 8%, 15%, and 23% of the instantaneous system load for Scenario 1, Scenario 2, and Scenario 3 respectively.

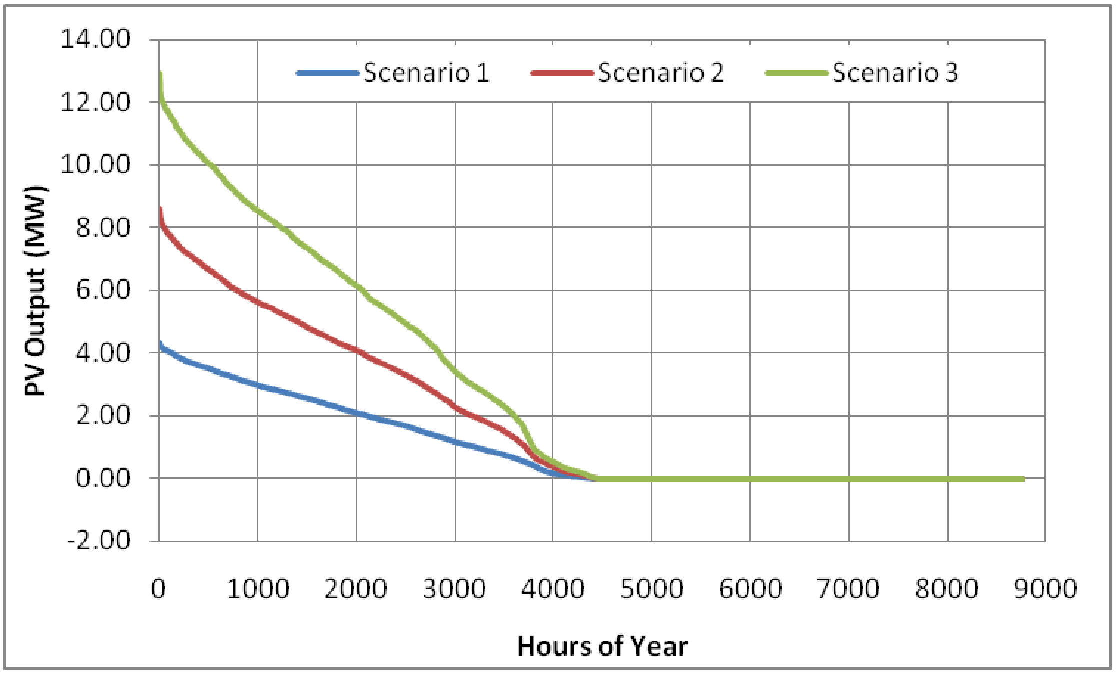

Figure 20. PV duration for scenarios.

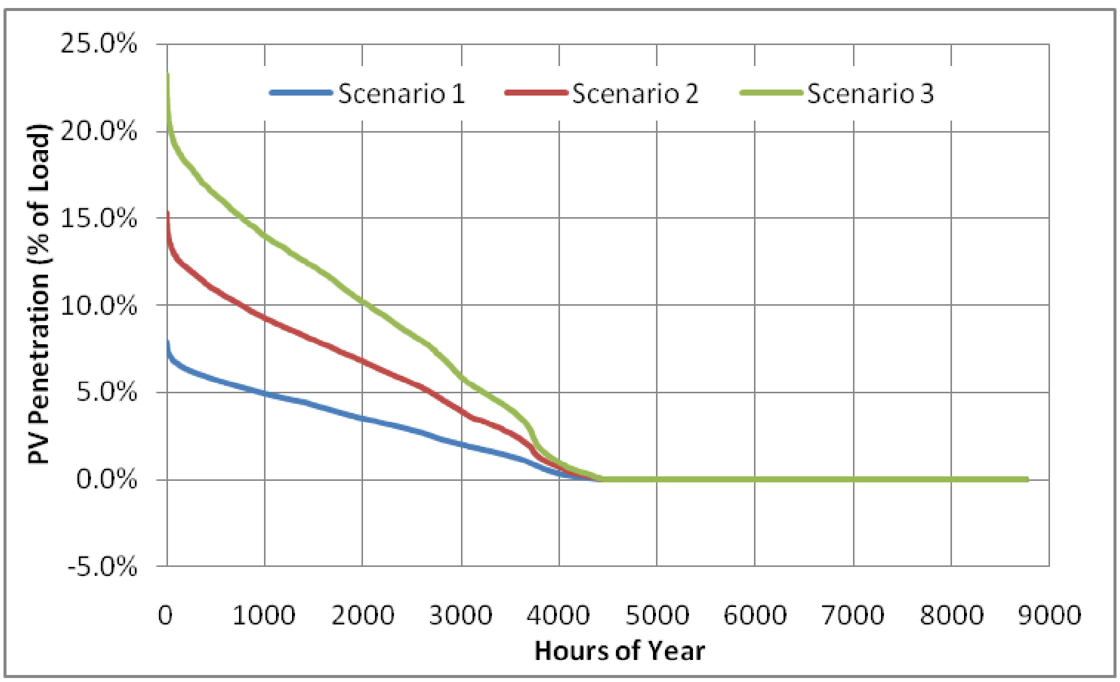

Figure 21. PV penetration for scenarios.

3.3.3 Net Load Duration

Load net PV is calculated by subtracting the chronological PV output from the corresponding hourly system load. A load duration curve for load net PV for each scenario demonstrates the impact of increasing PV penetration on the system. The impact is clearly visible as it helps offset the generation required to supply the load when the sun is shining. L-Sc1 represents the load net PV for Scenario 1, L-Sc2 represents the load net PV for Scenario 2, and L-Sc3 represents the load net PV for Scenario 3. The first division on the x-axis represents when the load is at its peak, usually between 7:00 p.m. and 9:00 p.m., while the last division on the x-axis represents when the load is at its minimum, and this usually occurs between 2 a.m. and 5:00 a.m. The nature of the load and the variability introduced by PV penetration will be discussed in detail in Section 5.

The minimum and maximum load net PV for each scenario is shown in Figure 22. It can be seen that installation of PV does not always reduce the effective capacity of the generating system needed at the peak load. This is due to the daily load patterns, as the peak load is usually observed around 8:00 p.m. when the PV is not producing. Low load conditions will not be affected by PV since the minimum load is usually observed very early in the morning when the PV is not producing. However, PV still contributes to serving load and the energy delivered displaces a significant amount of fuel.

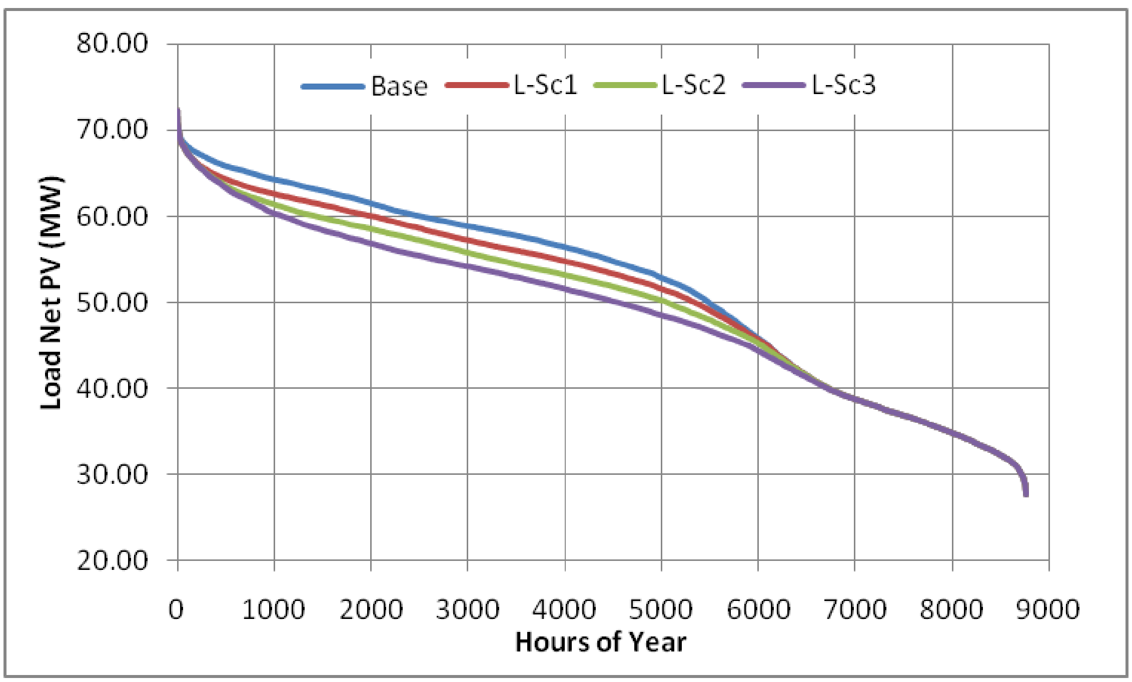

Figure 22. Load net PV duration curve for scenarios.

The effect of PV during peak load and minimum load is further illustrated in Figure 23. This figure displays the load and load net PV sorting only the load and keeping the time of the load net PV the same. In Figure 24, the effect of PV during the highest 100 hours of yearly load is displayed. It shows that PV does not reduce the highest 20 hourly peaks during the year. Some of the highest hourly loads occur in the winter when there are shorter daylight hours and the PV ceases generation before peak load occurrence. Closer observations show the variability of each scenario when PV is added. For example, near the 63rd hour Scenario 3 shows a dip where the other scenarios reduce load.

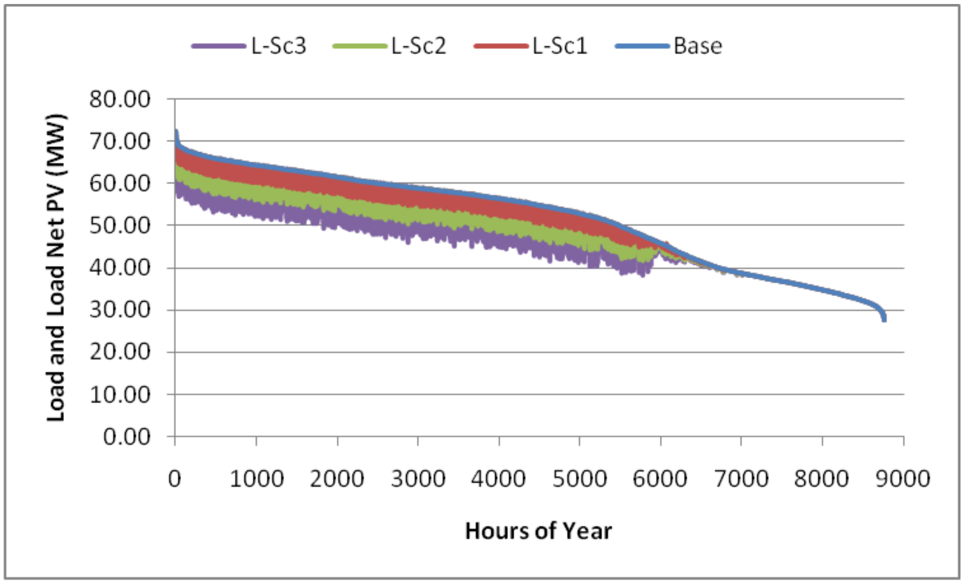

Figure 23. PV generation effect on peak and minimum load.

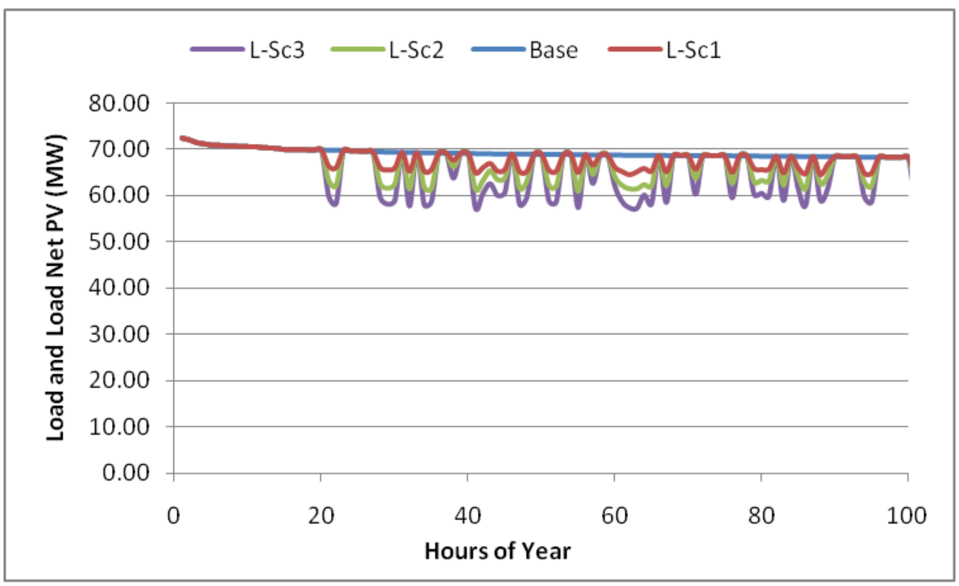

Figure 24. PV generation effect on peak and minimum load – zoomed.

4 Methodology

Electric power system operations control a diverse set of power generation that for the most part has been coordinating thermal and hydro resources with smaller (proportionally) amounts of renewable resources such as wind, solar PV, geothermal and bio gas, to list a few. PV generation has the potential to increase net load variability in the short time frame. For this reason an investigation was performed to examine the impact of PV variability on the existing KIUC system for each of the PV scenarios. This investigation focused on regulation to control system frequency.

In order to schedule generation and reserve resources in a control area that accommodates PV power, the time-varying patterns of the PV power production have to be taken into account. Overall, the additional system fluctuations that result from adding sizable PV plants are a function of the level of the PV penetration to the total system. PV generation output fluctuations principally drive the additional requirements and costs of balancing the host power system in the operational time scale (seconds to hours). Based on the varying production patterns of PV generation, a system operator may find that changes in scheduling and unit commitment of non-PV plants may result in a loss or a benefit to the system.

In general, PV power introduces varying production patterns and uncertainties that are different than what has been customary operation with hydro and thermal type generation. This difference can require an increase in use of additional resources to maintain balance. These resources include operational reserves to recover instantaneous changes in the balance between load and generation on the time scale of seconds (regulation reserves) and economic dispatch to adjust the output of units to follow longer trends in the net load (load-following reserves).

4.1 KIUC System Model

The purpose of modeling the KUIC AGC system is to analyze the sub-hour PV generation impacts in order to estimate the additional flexibility (regulation reserves) that would be required to manage the control area with significant PV generation. The analysis and simulation are based on 15-second system frequency data for the month of December (2011) and the 15-minute load data for the same period. The goal is to develop a model that uses load and load net PV variations as input while providing output of the required additional regulating capacity in order to maintain the balance of the system (i.e., keep the frequency close to the provided 15-second profile). KIUC provided samples of 15-second-frequency performance data that was used as a baseline for tuning the system model.

The procedure for determining the required generation variations is as follows:

1. Using the 15-minute load data, tune the control parameters (AGC gain, inertia) of the model. The simulation frequency output has to follow the actual system frequency on a 15-second base resulting in a 15-second load deviation profile.

2. Compute the load net PV data, based on the obtained 15-second load deviation data and 15-second solar resource data. Section A.2 provides information about the 15-second data.
3. Use the resulting 15-second load net PV data, from each PV penetration scenario, as simulation inputs.
4. The findings from the load-only and load net PV simulations (i.e., required generation variations) become inputs to later analytical processes; see Section 5.2 and Section 5.3.

4.1.1 System Model

The KIUC system is an electrical island operation with no ties to adjacent islands. Thus KIUC has sole responsibility to manage generation and afford their customers adequate reliability and system stability with minimum service interruptions. Because the system operates as an electrical island, the Kauai power system is modeled as an isolated power system consisting of a single generating unit that supplies a net load with specified frequency characteristics (see Figure 25). Note that the model excludes transmission and distribution lines, assuming they have no impact on the system behavior. Based on the magnitudes of the changes in the load, the droop characteristics of the governor, and a supplementary control responsible for keeping the system frequency close to the nominal frequency (i.e., 60 Hz), the simulation calculates the corresponding frequency changes. The model was configured and simulated using the visual block diagram language VisSim. Figure 25 shows the block diagram of the model. It consists of the following components and their tasks.[2]

- **Supplementary Control Model:** This component models adjustments of the load reference set point, in order to force the frequency deviations to zero.
- **Load Reference Set Point:** Reference unit output to force the frequency deviations to zero.
- **Governor Model:** This component models adjustment of the valve to change the mechanical power output to compensate for load changes.
- **Per Unit Change in Valve Position:** Position of the valve that controls emission of the steam into the turbine.
- **Governor Net Gain Model:** This component determines the change in the unit's output for a given change in frequency.
- **Prime–Mover Model:** This component models a turbine by relating the position of the valve that controls emission of steam into the turbine to the power output of the turbine.
- **Per Unit Load Change:** Net load drawn by the system (input).

[2] Allen J. Wood and Bruce F. Wollenberg, *Power Generation Operation and Control*, John Wiley & Sons, 1984.

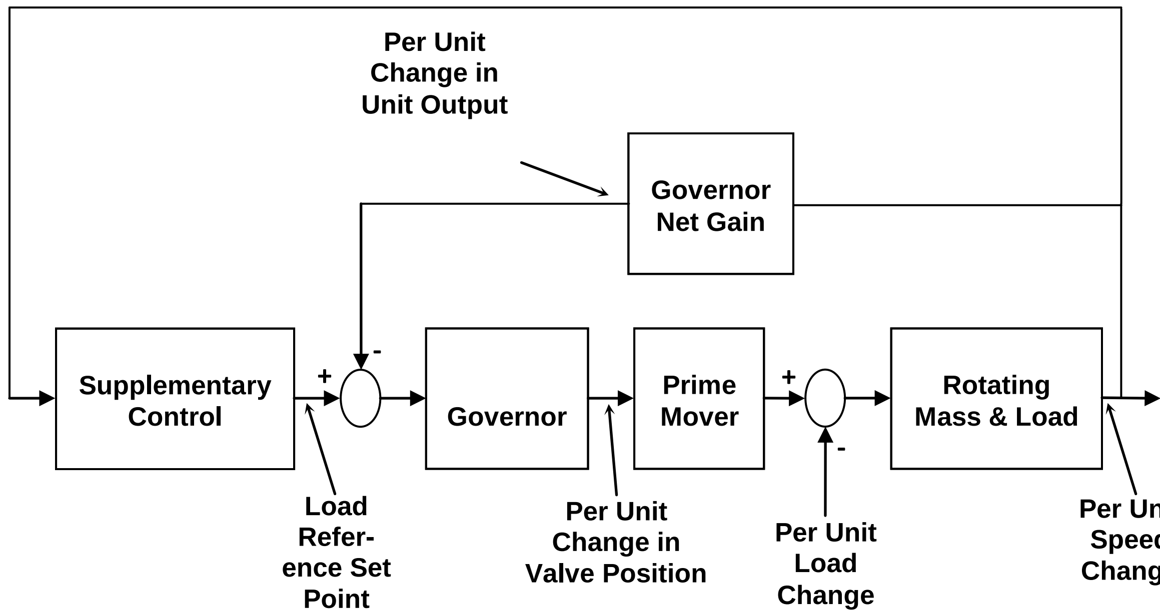

Figure 25. Block diagram of used system model with supplementary control.

- **Rotating Mass and Load:** A component that combines the following:
  - Generator Model: This component models positive and negative acceleration of the machine due to differences in mechanical and electrical torque, deviation of speed ($\Delta\omega$), and deviation of phase angle ($\Delta\delta$). Generation is ramped up and down while inertia is assumed to be the same across all scenarios.
  - Load Model: This component models the effect of a change in frequency on the net load drawn by the system at a given per unit base (i.e., 75 MW in this study).
- Per Unit Speed Change: Deviation of the frequency from the nominal 60 Hz (output).
- Per Unit Change in Unit Output: Changes in generation due to changes in frequency.

4.1.2 System Simulation of Base Case

As described in Section 4.1.1, the simulation implemented to represent the model of the control area uses load variability as input. The model accepts load as input and computes the system output frequency by matching a generation profile to the load. In a perfect world the generation would exactly match the load, resulting in a system frequency of 60 Hz. In reality the frequency varies about the 60 Hz target. KIUC provided corresponding load and frequency data for several days of real-time operations. The model required tuning to calculate an output frequency for the input load that closely matched the given frequency. To do this a profile of generator variability was used in the model. The profile was systematically adjusted until the resulting frequency output for the given load input closely represented the measured frequency of the system.

The following figures display the data representation of this process. The KIUC system load profile is shown in Figure 26. The system generation serves to produce the KIUC system frequency (Figure 27). The change in system load (Figure 28) must be followed by a comparable change in generation to maintain system frequency. The lead or lag of generation load following causes frequency variations as shown in the measured frequency (Figure 27). The model without a generation profile would operate perfectly at 60 Hz, so the generation profile was created and tuned (Figure 29) to cause the models output frequency to have behavior similar to the measured system frequency. Using the generator profile the modeled output frequency is shown super imposed on the system frequency in Figure 30. A sample hour is shown in Figure 31.

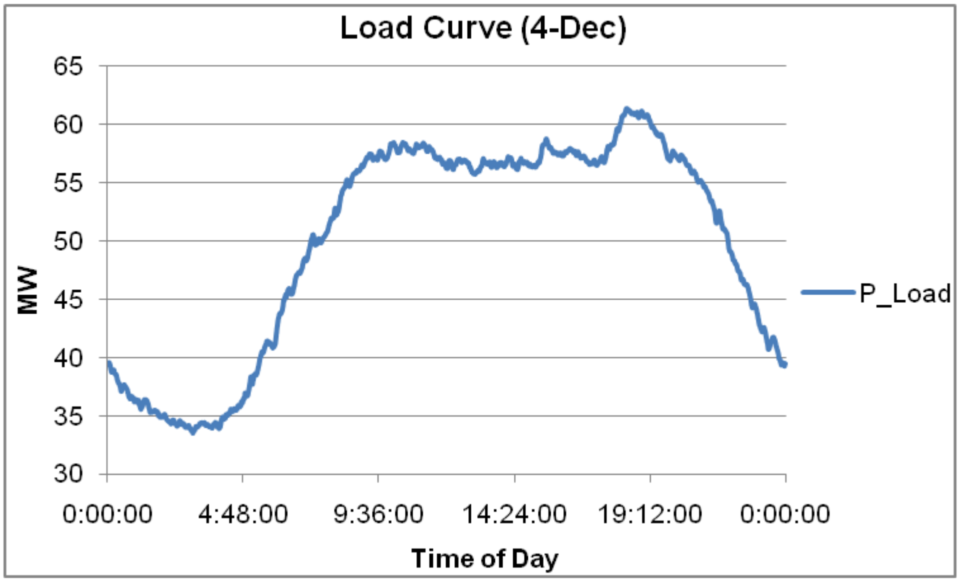

Figure 26. Load profile for a one-day period.

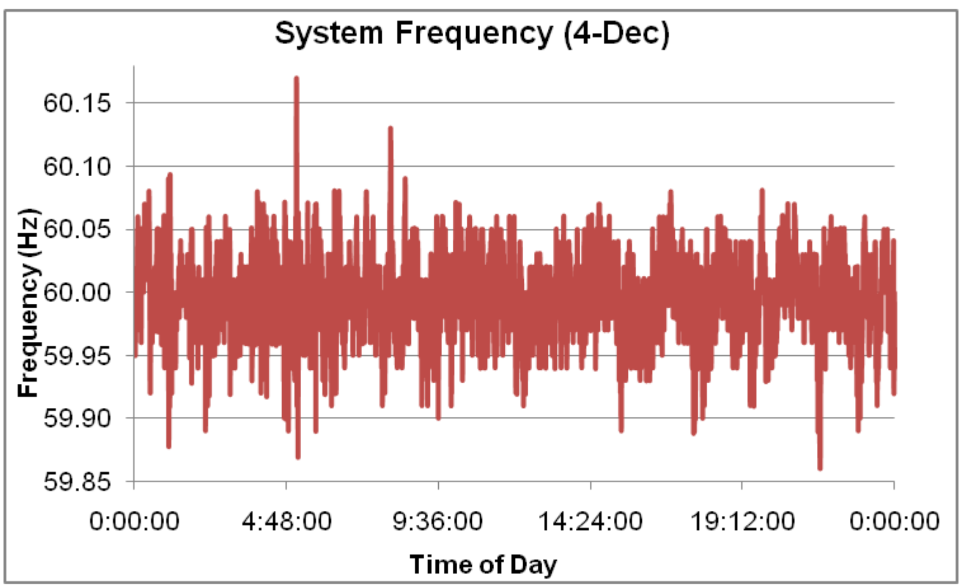

Figure 27. System frequency profile for a one-day period.

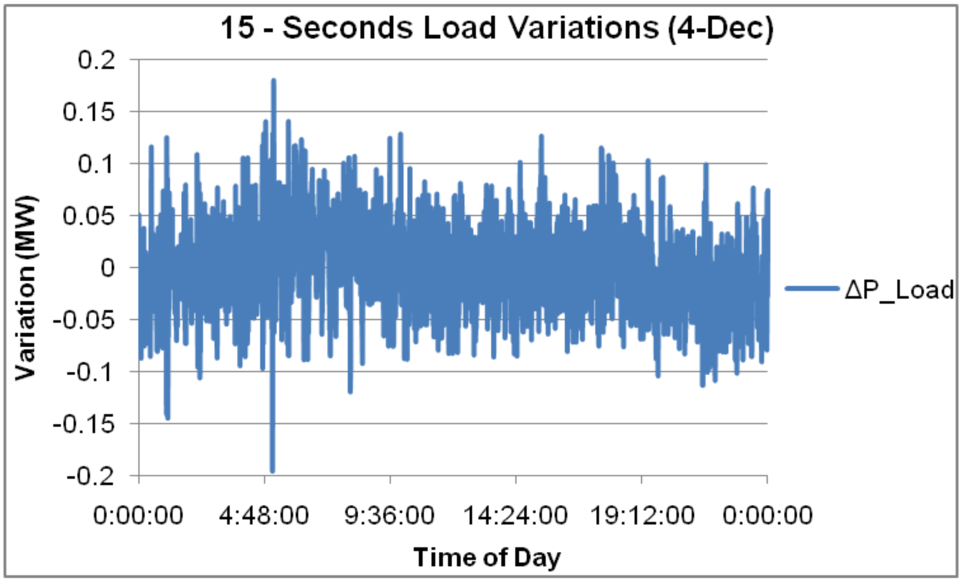

Figure 28. 15-second time-scale load variability.

Simulations were performed to obtain required power plant output variability for the dates December 1 through December 21, 2009. (Note that the frequency profile available for December 21 contains data from 12 a.m. to 4 p.m.). System inertia is assumed to stay the same, meaning that conventional units are assumed to be backed down rather than turned off.

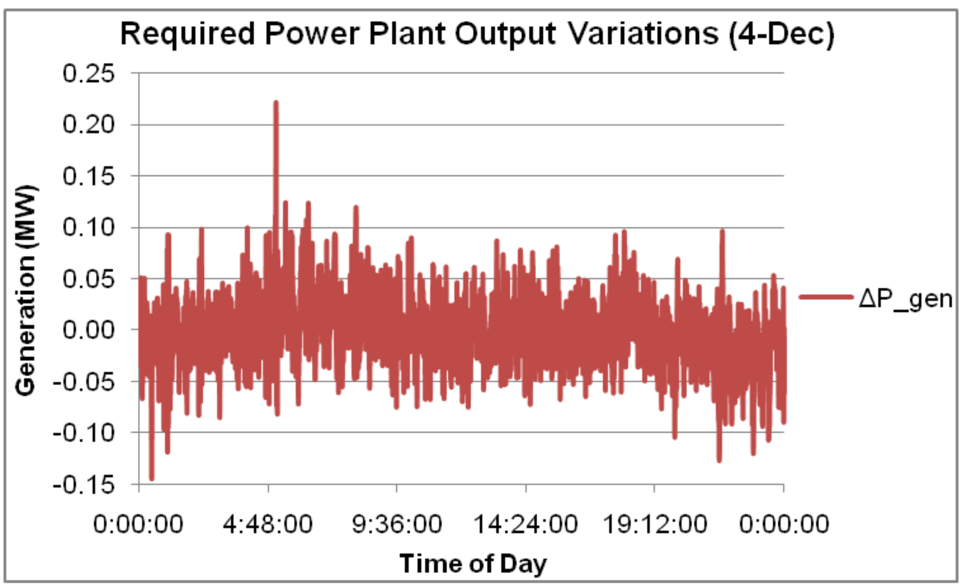

Figure 29. 15-second time-scale generation variability.

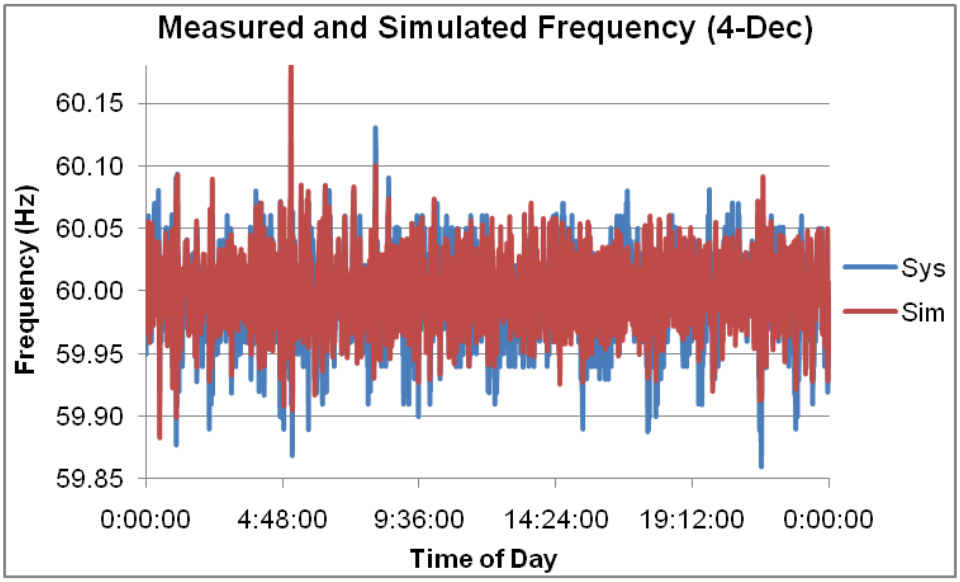

Figure 30. Simulated and measured (provided by KIUC) system frequency.

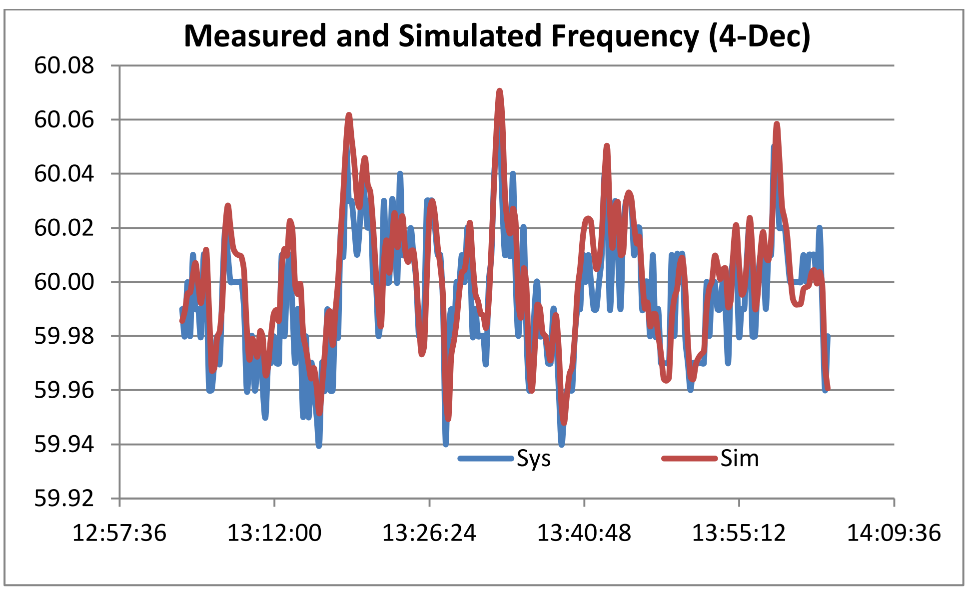

Figure 31. Measured and simulated frequency for sample hour.

4.1.3 System Simulation with PV

Modeling the system with PV requires the modification of system load by the amount of PV in the scenario. By definition, load net PV is the result of subtracting PV generation from the system load. This process implies that PV generation is a must take resource, thus requiring other generation resource adjustments to balance the system.

A sample day of load net PV curves for each scenario with 15-second resolution is shown in Figure 32. Zooming in on a section of the plot, one can observe the additional variability of the load net PV versus the relatively smooth shape of the system load.

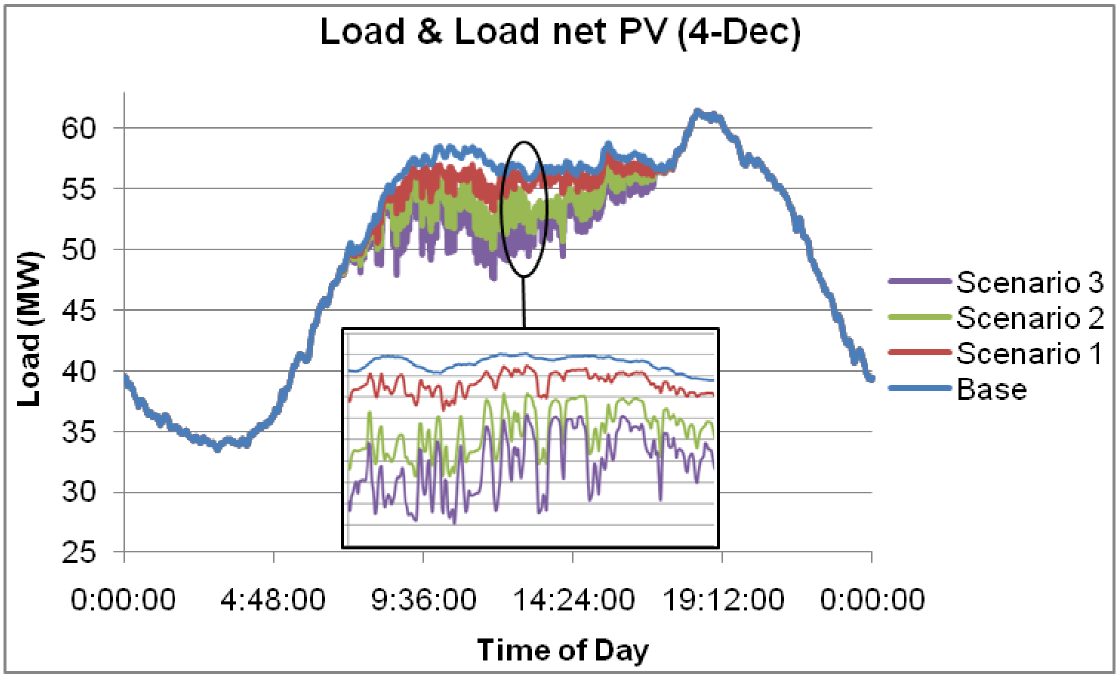

Figure 32. Load and load net PV 15-second profile for a one-day period.

When this data is examined for how much change occurs from period to period there is a well-defined band of variability for the Base Case. As PV is added to the system variability increases. For a single day in December the load net PV variability would look as depicted in Figure 33.

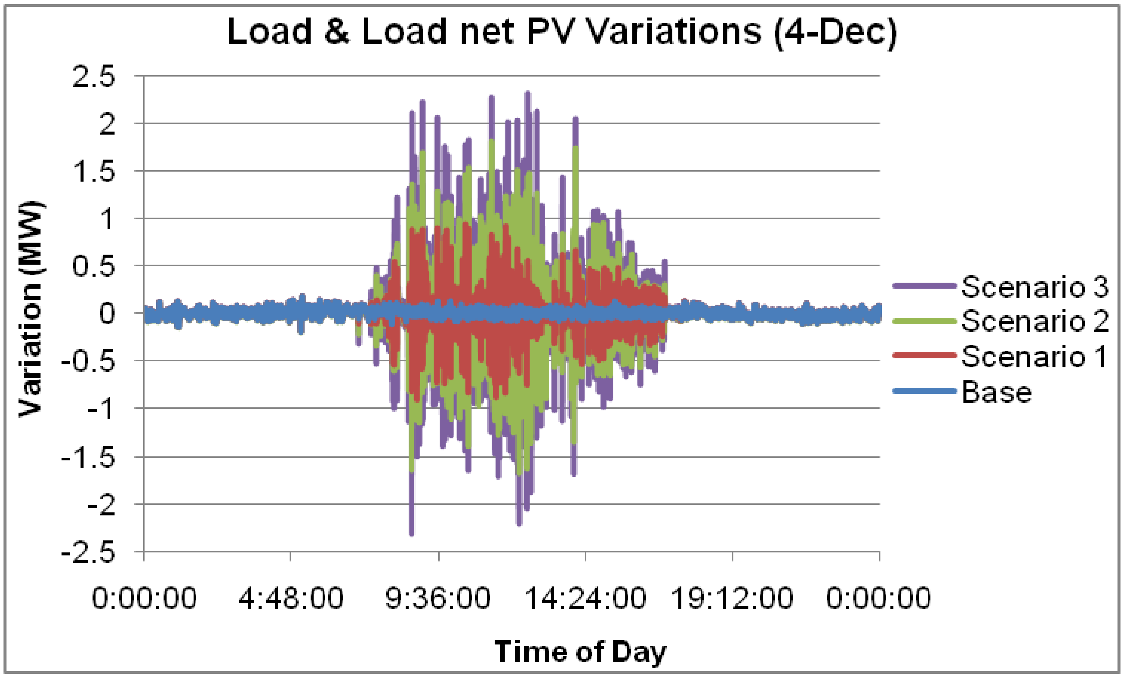

Figure 33. 15-second time-scale load and load net PV variability.

The simulation of Scenario 1 was performed by reducing system load by 5 MW of PV generation. Without changing the input generation level used for regulation in the Base Case, the model produced a change in system frequency that can be attributed to the variability of the PV generation. Figure 34 shows the composite plot of all scenarios and the frequency variations from the Base Case. It appears that during the daylight hours the frequency deviation increases with growing PV penetration. To mitigate the frequency change additional regulation units are required with generation profiles that complement the PV. After providing the simulation model with the generation profile (increase the number or variability of generation units [Figure 35]) the frequency of the system returned to a pattern similar to the frequency of the Base Case (Figure 36).

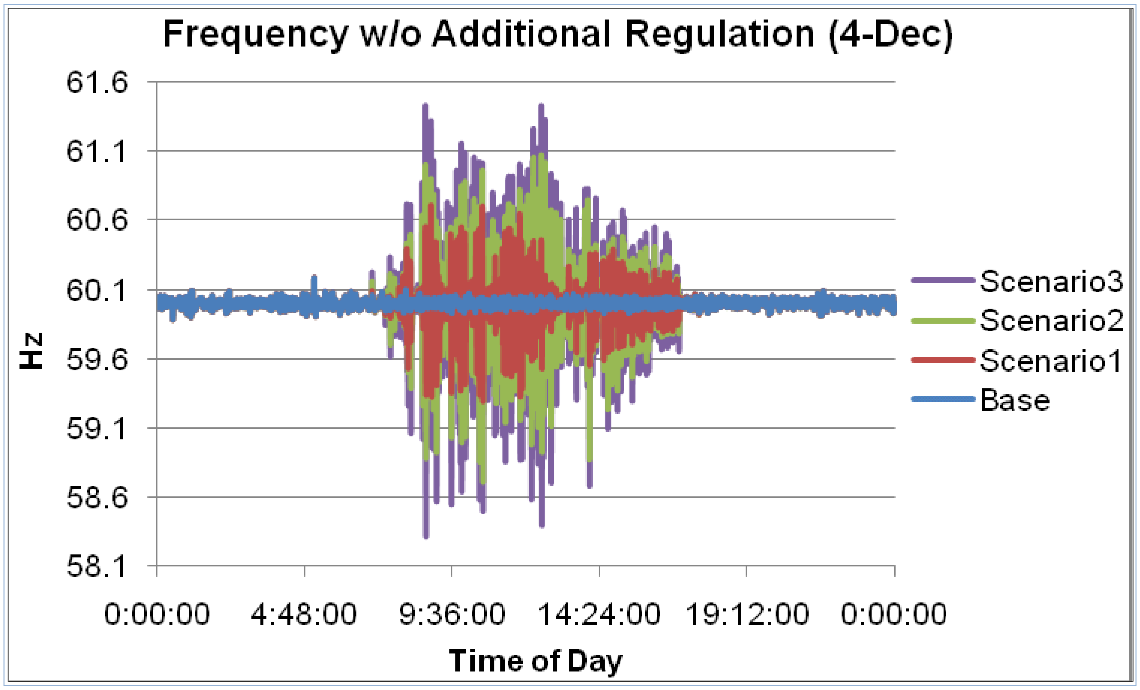

Figure 34. Simulated system frequency without additional regulation.

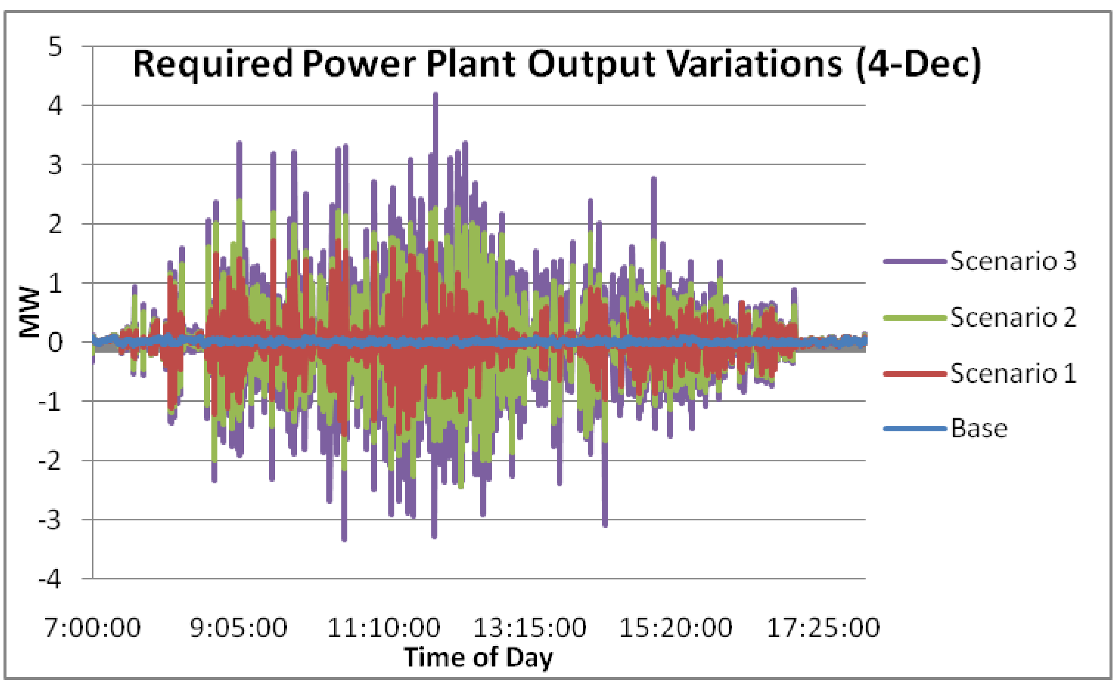

Figure 35. Required power plant output variability.

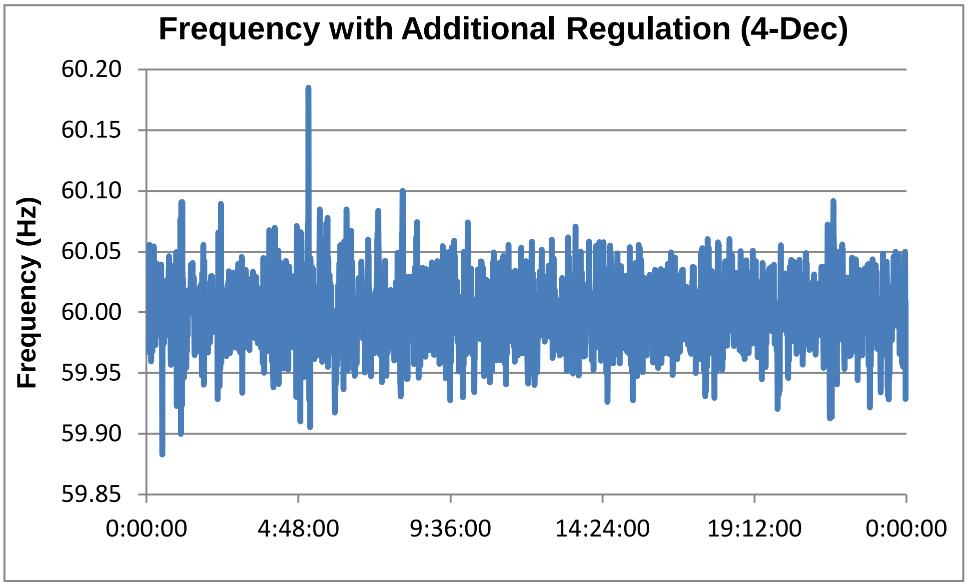

Figure 36. Simulated system frequency with additional regulation.

Table 11 shows the summary for power plant output with 15-second variations (load-only and three PV scenarios) required to maintain frequency deviations within the baseline envelope. It shows the highest and lowest point in positive variability and highest and lowest point in negative variability in the simulated data from December 1 to 21, 2011. In other words, the daily positive generation variability maxima, on the 15-second base for the month of December, rank between 0.10 MW and 0.35 MW without PV, 0.92 MW and 1.70 MW for Scenario 1, 1.53 MW and 2.91 MW for Scenario 2, and 2.26 MW and 4.37 MW for Scenario 3. On the other hand, the downward generation variability maxima, for the same period of time, lie between 0.07 MW and 0.29 MW without PV, 0.94 MW and 1.66 MW for Scenario 1, 1.45 MW and 2.85 MW for Scenario 2, and 2.06 MW and 4.14 MW for Scenario 3. Additional details of the generation requirements to support variability are included in Table A-6.

Table 11. Summary of 15-Second Generation Change Showing Maximum (Hi) and Minimum (Lo) Up-Ramp (Positive Variability) and Maximum (Lo) and Minimum (Hi) Down-Ramp (Negative Variability in MW for the Month of December.

		Base	Scenario 1	Scenario 2	Scenario 3
Positive Variability	Hi	0.349	1.699	2.910	4.370
	Lo	0.099	0.922	1.527	2.263
Negative Variability	Hi	-0.074	-0.939	-1.453	-2.063
	Lo	-0.291	-1.663	-2.854	-4.143

4.2 Marginal Unit Identification

When system generation is replaced by an alternative resource, be it load control or a renewable resource, the remaining generation committed to serve system load can commit and/or will dispatch differently. In general, the overall cost of operating the generation fleet decreases by the cost of the offset generation. The marginal unit in this study is considered to be the unit that would be used to either serve the next MW of load or the resource backed down to avoid over-generation.

Identifying the marginal units for the study year 2011 was based on results taken from UPLAN for the monthly marginal cost and the hourly load profile. The UPLAN data provided the marginal cost in $/MWh and unit occurrence in hours. For this analysis UPLAN operation output data for the year 2010 were used. The procedure for identifying the marginal units for the depicted scenarios is as follows:

1. Arrange monthly load data in descending order.
2. Apply marginal units in reversed merit order (high priced units first) based on the occurrence starting with the first hour.
3. Identify the minimum and maximum loads within which the particular unit is to be operated.
4. Calculate monthly load net PV profiles and arrange them in descending order.
5. Identify the load regions for the units based on load-only load boundaries.
6. Estimate the marginal unit occurrence for every unit depending on the depicted scenario.

Figure 37 shows the load and load net PV duration curves together with the marginal units operated at the depicted month (December). The occurrence of a marginal unit for a given load profile equals the length of the corresponding duration curve within the unit's marked area.

The marginal unit cost estimation is based on the identified monthly occurrence of every unit for a depicted scenario. Figure 38 shows the occurrence of the marginal units for a single month with respect to the scenarios (Marginal Unit Cost represent the corresponding marginal units – i.e., 316.71 $/MWh corresponds to unit S1-8MW-Block Loaded, 198.56 $/MWh to unit D3, 189.78 $/MWh to unit D5, etc.). With increasing PV penetration level the occurrence shifts to less-expensive units, reducing the overall marginal cost. This is described in more detail in Section 5.3.1.

Monthly marginal generation costs are summarized in Table A-7. Figure A-9 shows the monthly duration curves for the different scenarios in the study.

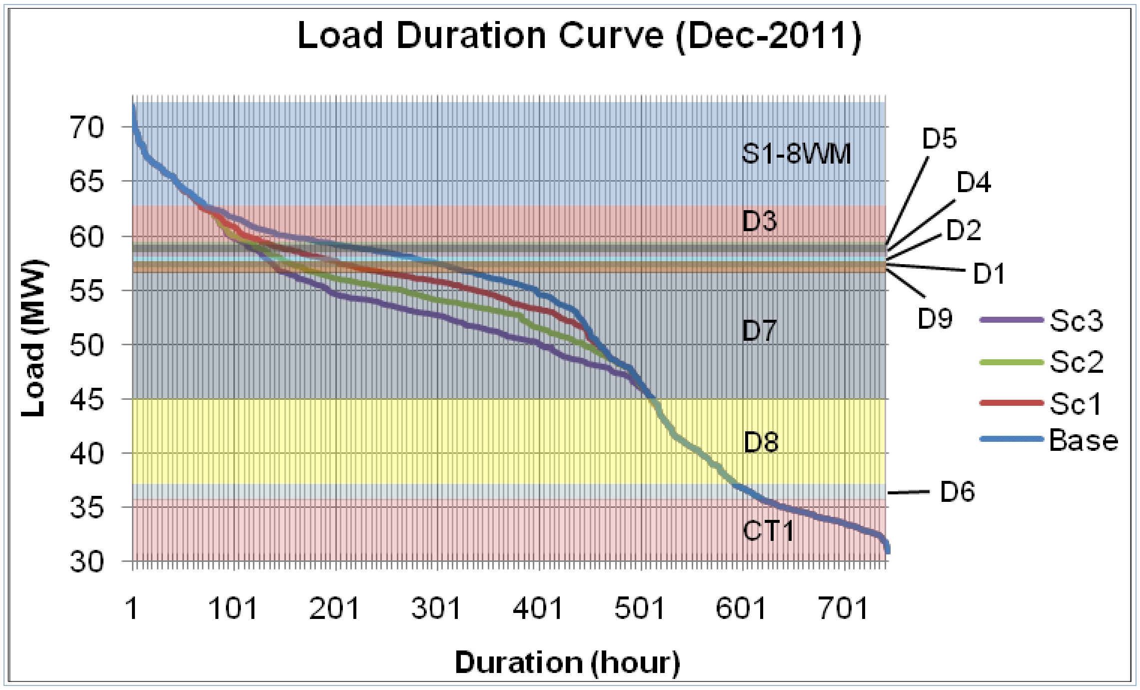

Figure 37. Load duration curve with marginal unit distribution.

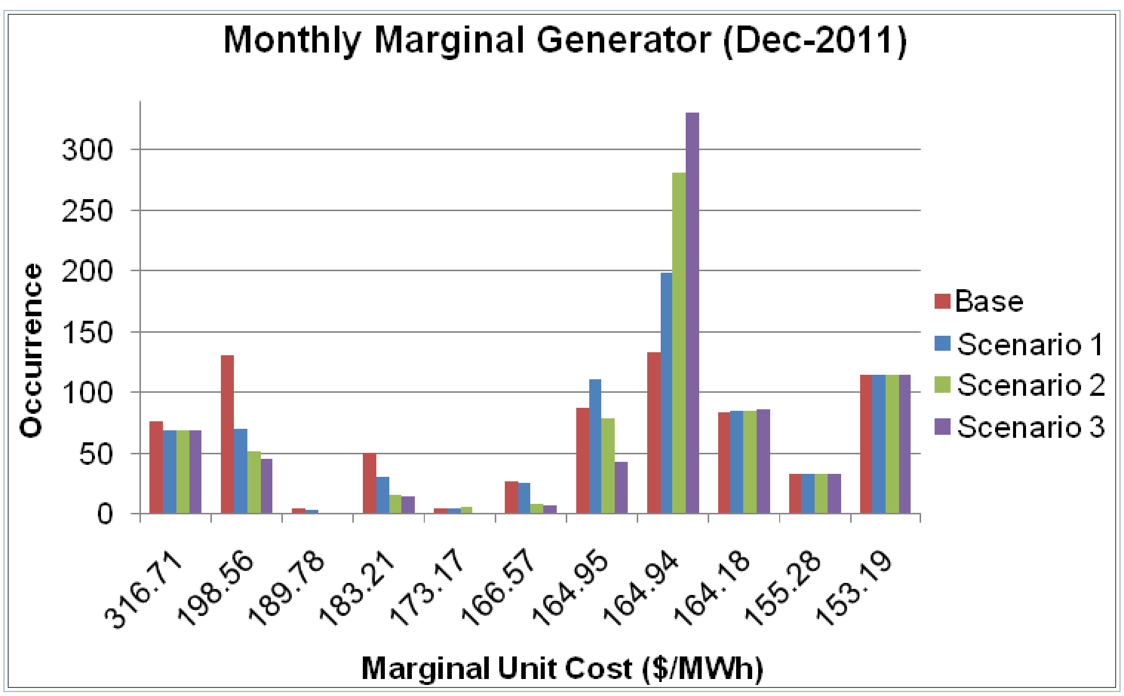

Figure 38. Monthly occurrence of identified marginal units.

4.3 Regulation Change Estimation

The regulation change estimation is based on the difference between the sub-hourly variability of the net load at the different penetration level of PV and the sub-hourly variability of the net load for the Base Case. In other words, we assume that the variability between maximum and minimum load within a given time period (1 hour) is supported by generation designated for regulation. This generation is typically comprised of one or more generating units running on the margin that is identified specifically for regulation support. When PV is added to the system the effect of PV variability on the system is measured by examining load net PV within the same time period and comparing the difference to the load only. Again the load net PV variability is supported by one or more generators on the margin. The introduction of PV to the system can impact load in three ways:

1. It can reduce the difference in net load change from one period to the next.
2. It can increase the amount of net load change from one period to the next.
3. It can have no change on net load from one period to the next.

The results of this study show that PV impacts load by increasing the amount of net load variability. Regulation required to support increased variability is necessary to maintain system frequency. The amount of additional regulation energy depends upon the penetration level of PV and the variability of the solar resource data. It was determined that as PV is added to the system the amount of regulation energy required to maintain system frequency will increase.

To capture the amount of generation required to support the inter-hour variability sub-hourly data was examined. The change in load and net load was examined with 15-second resolution data and it was noted that the change in load and change in load net PV showed greater variability than what was seen at the hourly resolution. Based on these findings the study identified the greatest change within the hour and identified this to be the amount of required regulation to support the additional PV. The amount of energy required within the hour can be supported by one or more generating units that typically would be operating on the margin. An example of sub-hourly load change is depicted in Figure 39. It can be seen that the range for the Base Case requires a set of generators to support 1.3 MW in load variability over the hour (Figure 40). The PV added in scenario 3 shows an increase in load net PV variability of 5 MW (Figure 39). This is an increase of 3.7 MW of variability over the Base Case. In other words, in order to maintain system frequency when 15 MW of PV are added to the system an additional 3.7 MW of on-line regulation generation would be required. Due to increased variability of load net PV the number of required regulating units will have an impact to the KIUC regulation cost.

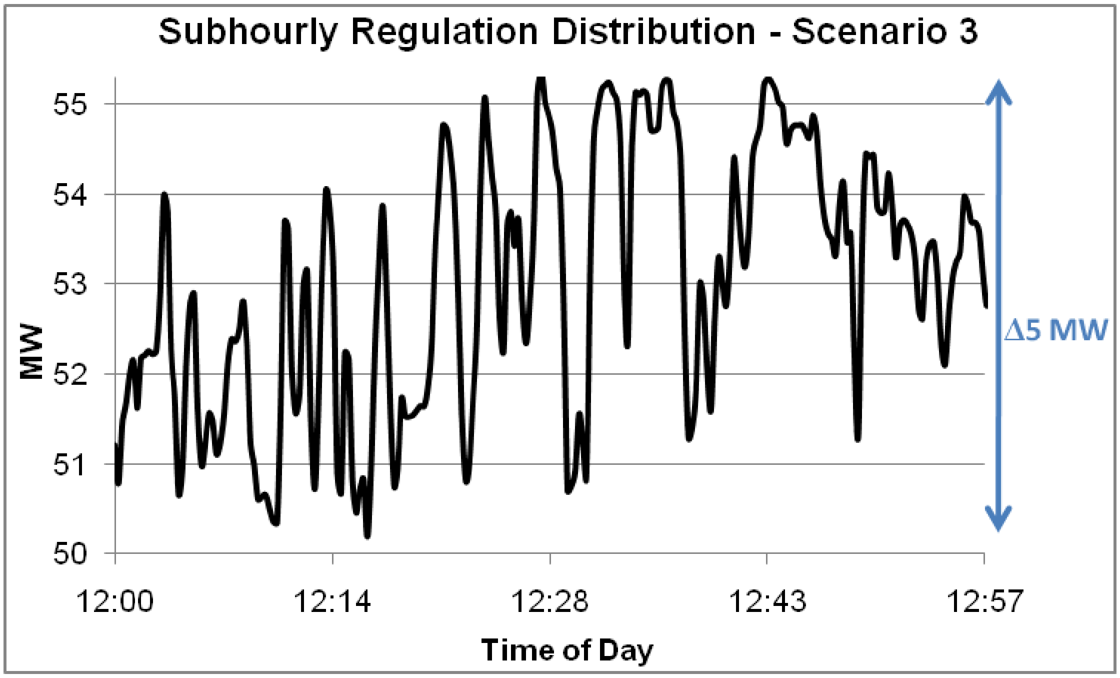

Figure 39. Scenario 3 sub-hourly load net PV variability.

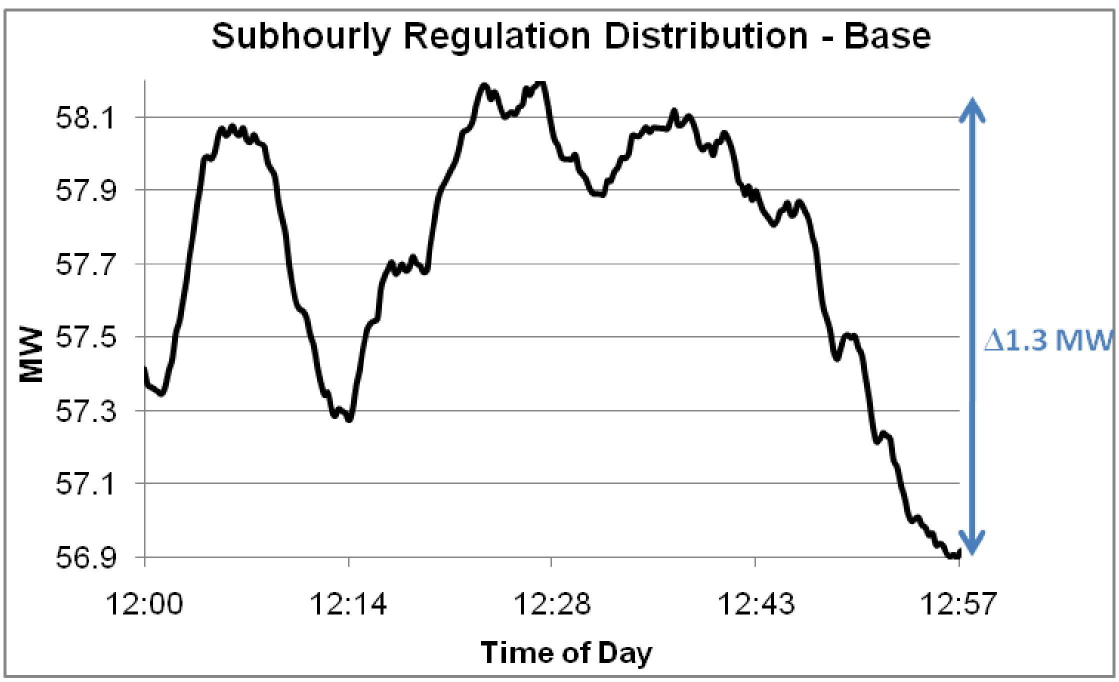

Figure 40. Sub-hourly load variability with no PV.

5 Analysis

5.1 Load Analysis

As previously mentioned, KIUC provided a 2010 system load profile that was escalated by 1% to obtain the 2011 load profile used in the study. The study load profile was examined by looking at a typical daily profile. Taking the average of the hourly load for each hour of the day in each month resulted in an average 24-hour daily load shape for each month. A graph of this is shown in Figure 41. One might observe the shift in the peak in November and December from the other months (hours 19 through 21).

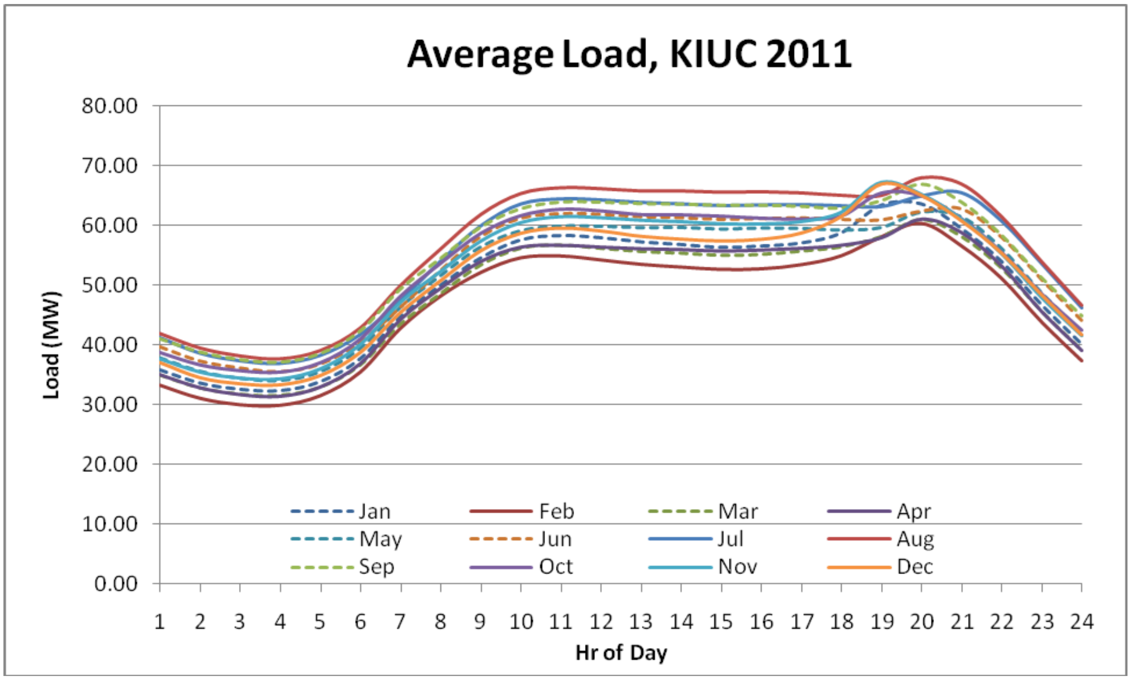

Figure 41. Average daily load shape for each month.

Figure 42 shows the monthly maximum and minimum load for the study load while Figure 43 shows the monthly energy and Table 12 provides a tabular summary of the information shown in these two figures.

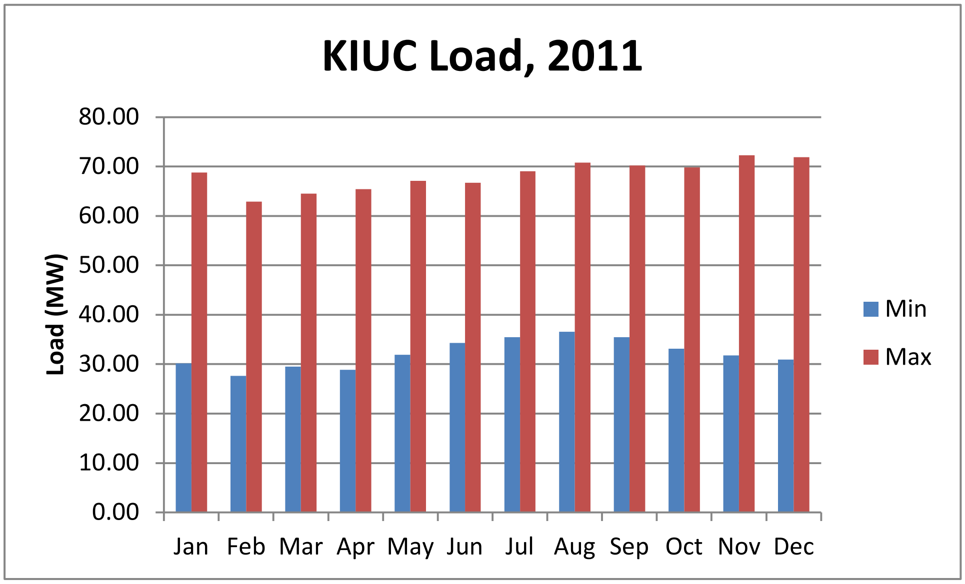

Figure 42. Monthly minimum and maximum load for study period.

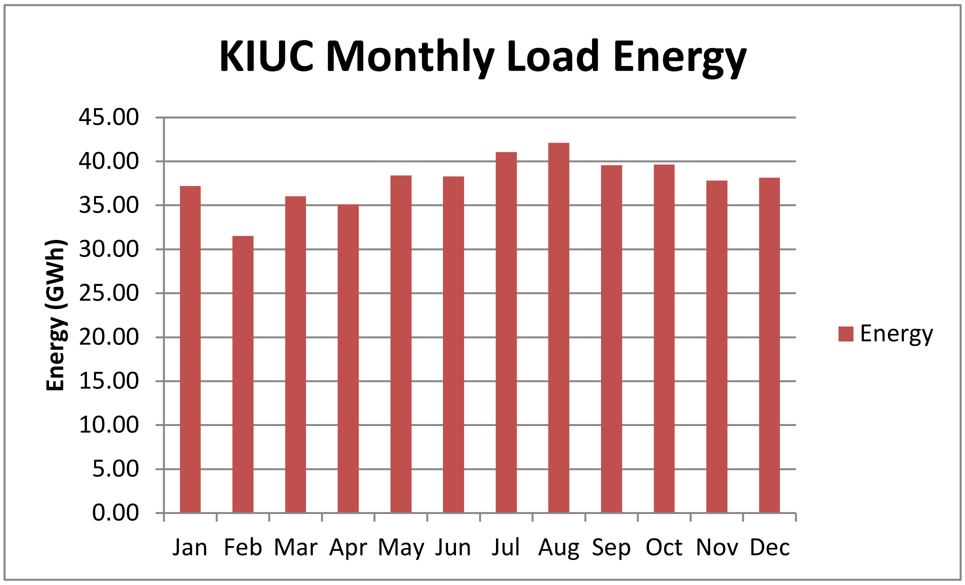

Figure 43. Monthly load energy for the study period.

Table 12. Summary of Monthly Load and Energy for the Study Period.

	Min (MW)	Max (MW)	Energy (GWh)
Jan	30.14	68.77	37.22
Feb	27.60	62.90	31.51
Mar	29.50	64.52	36.04
Apr	28.87	65.44	35.10
May	31.87	67.09	38.40
Jun	34.29	66.73	38.29
Jul	35.47	69.02	41.04
Aug	36.57	70.80	42.12
Sep	35.46	70.19	39.58
Oct	33.14	69.81	39.63
Nov	31.78	72.31	37.80
Dec	30.93	71.92	38.13
Annual	27.60	72.31	454.84

5.2 Load Net PV Analysis

The characterization of the PV plant's variability on the control area over different time scales (i.e., 15 seconds for regulation reserves and 1 hour for load-following reserves) can be accomplished by comparing the variability of load alone and load net PV. The variability refers to the difference in the given data set (i.e., load or load net PV) from one averaging interval to another:

$$\Delta L_i = L_i - L_{i-1} \quad (1)$$

where i depicts the step in the chosen time scale. Figures 44 and 45 show variations seen by the system, at considered time steps (i.e., hourly steps in Figure 45 for December 2011 and 15-second steps in Figure 45 for December 4, 2011), of the original load and load net PV based on each scenario.

The increase in the operating reserve capacity is the difference in the maximum values of the load only and load net PV duration curves. When planning and operating a power system the reserves are picked based on probabilities and risk. In general, the determined reserves have to cover variability within a certain probability (e.g., 99.7% of the variability). The 99.7th percentile is a common metric, which corresponds to three standard deviations (3σ) from the mean for a normally distributed random variable.

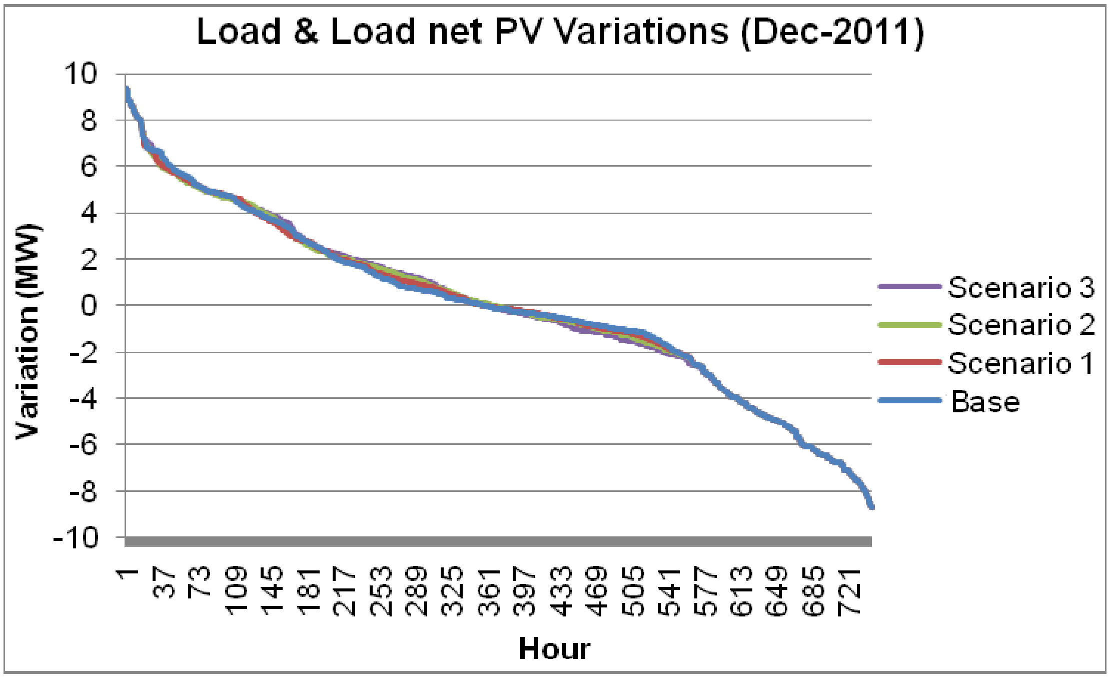

Figure 44. Load duration curve of monthly load and load net PV variations for one month.

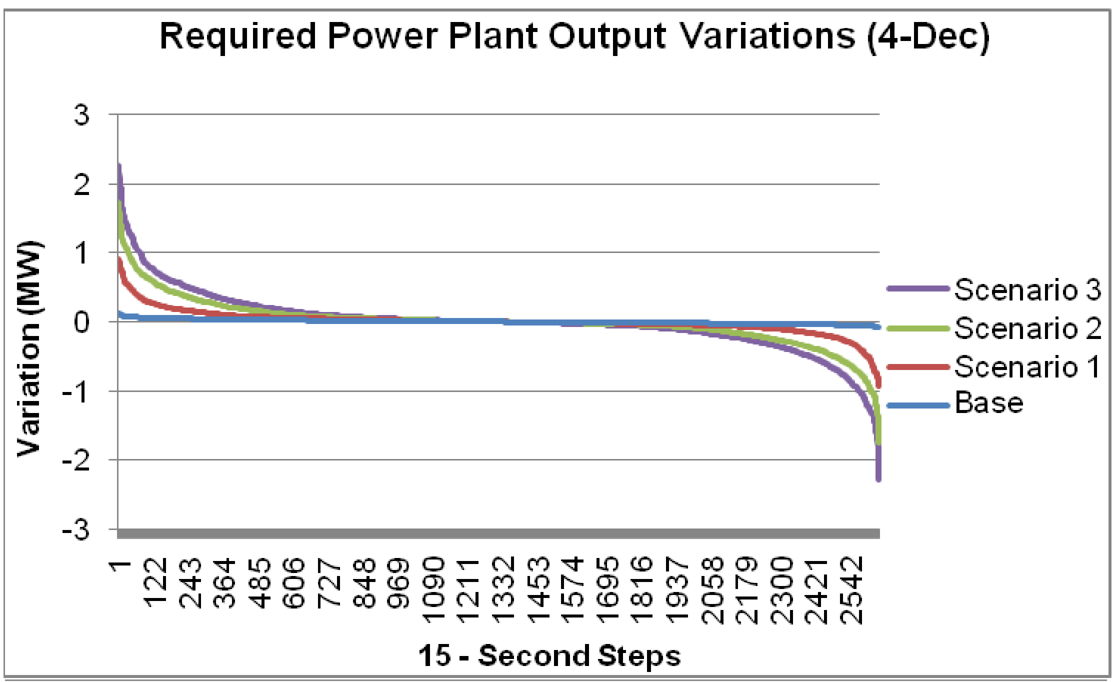

Figure 45. Load duration curve of load and load net PV 15-second variations for one day (5760 data samples).

The reserve impact of PV power is determined by following these three steps:

1. Calculate 99.7th percentile coverage for the original load.
2. Calculate 99.7th percentile coverage for the load net PV.
3. The operational integration impact on the reserves is the difference between percentile coverage of the net load PV and percentile coverage of the load.

Figures 46 and 47 show distribution curves of the original load and load net PV based on each scenario at hourly steps and 15-second steps, respectively. It should be noted that increased resolution of data, sub-hourly 15-second data, provides a more normal frequency distribution than the hourly data. Figures 46 and 47 show the 99.7th percentile reach of the hourly and 15-second datasets. For Scenario 3 the 15-second data for one day indicates a maximum variability of -2.28 MW to + 2.25 MW or a change in approximately 4.5 MW, whereas the hourly data for over a month for the same scenario has greater magnitude of variability with a range of -8.7 MW to 8.94 MW, or approximately 17.6 MW, over the hour.

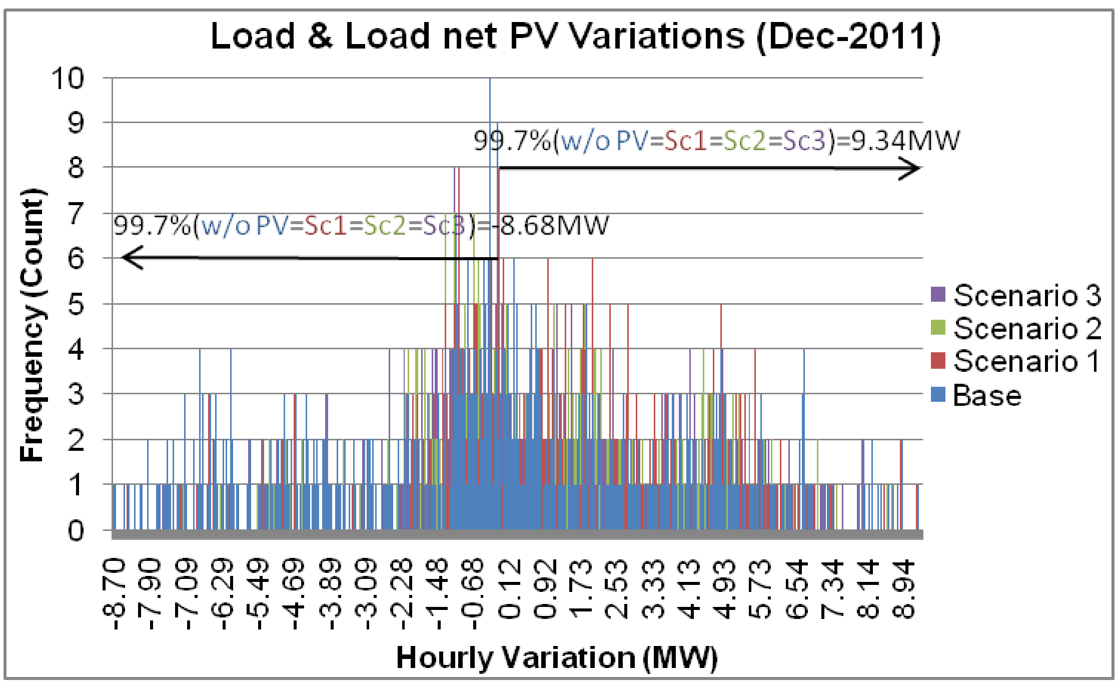

Figure 46. Histogram of load and load net PV hourly variations for one month.

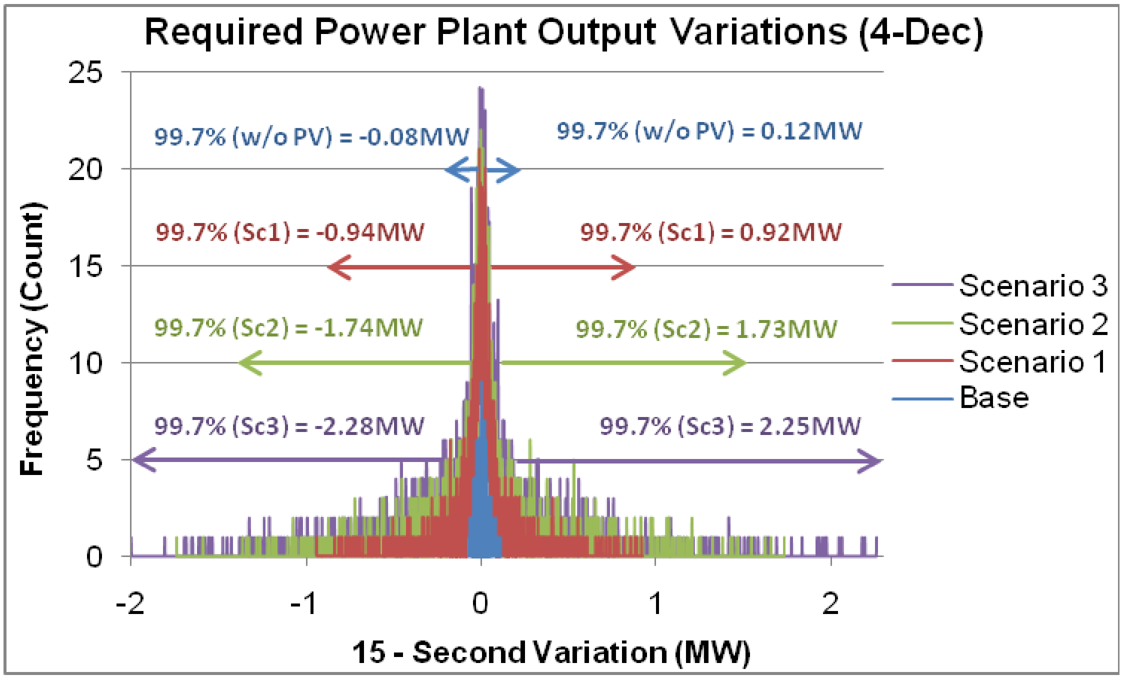

Figure 47. Histogram of load and load net PV 15-second variations for one day.

Table A-8 shows the details of the monthly 99.7th percentile coverage for the hourly load and load net PV positive variability and increase in variability for the study period. It is interesting to note while there is neither an increase nor a decrease in variability for the months November through March, there is a decrease in variability for the remaining months April through October. That means that when PV power is introduced to the control area no additional load-following reserves are required for the months November through March. However, during months April through October, due to increasing daylight hours, PV power output increasingly affects the peak variations in the load, which occur in early evening hours (7 p.m.–9 p.m.). Therefore, fewer load-following reserves are required for the months April through October, with the highest decrease during the month of May.

Table 13 shows the summary for the 99.7th percentile coverage for the month of May. In general, during this month 0.25 MW (≈5% of Nameplate), 0.60 MW (≈6% of nameplate). and 0.87 MW (≈5.8% of nameplate) less load-following reserves are required for Scenario 1, Scenario 2, and Scenario 3, respectively. The annual peaks in load-following reserves (≈ 99.7th percentile of the annual peak hourly variation) requirements with respect to the PV penetration level are 10.72 MW for Scenario 1, 10.65 MW for Scenario 2, and 10.53 MW for Scenario 3. The negative variability (down regulation) for the load-following reserves maintains unchanged. Tables A-8 through A-10 show details of the daily 99.7th percentile coverage for the 15-second load and load net PV positive (Table A-9) and negative (Table A-10) variability and increase in variability for the month of December (2011).

It becomes clear that for any size PV penetration additional regulation reserves are required (up and down regulation). The peaks in regulation reserve (≈ 99.7th percentile of the month of December peak 15-second variation) requirements for the different scenarios are 1.69 MW

(≈33.8% of nameplate) for Scenario 1, 2.90 MW (≈29.0% of nameplate) for Scenario 2, and 4.35 MW (≈29.0% of nameplate) for Scenario 3. Table 14 summarizes the peak and total reserve requirements for the depicted scenarios.

Table 13. Load-Following Reserve Assumption for May Based on the 99.7th Percentile Coverage.

Case	99.7th percentile (MW)	Increase (MW)	% of Nameplate
Base	8.94	--	--
Scenario 1	8.69	-0.25	5.0
Scenario 2	8.34	-0.60	6.0
Scenario 3	8.07	-0.87	5.8

Table 14. Incremental Reserve Assumption Based on the 99.7th Percentile Coverage.

Case	Regulation Increase (MW)	Load Follow (MW)
Scenario 1	1.69	10.72
Scenario 2	2.90	10.65
Scenario 3	4.35	10.53

Results shown in this section combined with the results from Section 3.3.3 suggest that PV generation increasingly affects the power system stability with increasing resolution of the solar resource data. In other words, the existing regulation at seconds to minutes range will be affected at a higher degree than the regulation at minutes to hours range.

Figure 48 shows scatter plots of the PV generation changes over the generation level. The data shown is based on the load and load net PV 15-second datasets averaged over the month of December. Of interest is the revelation that the maximum variability does not occur at maximum generation, but rather in the mid-range of the aggregated production curve.

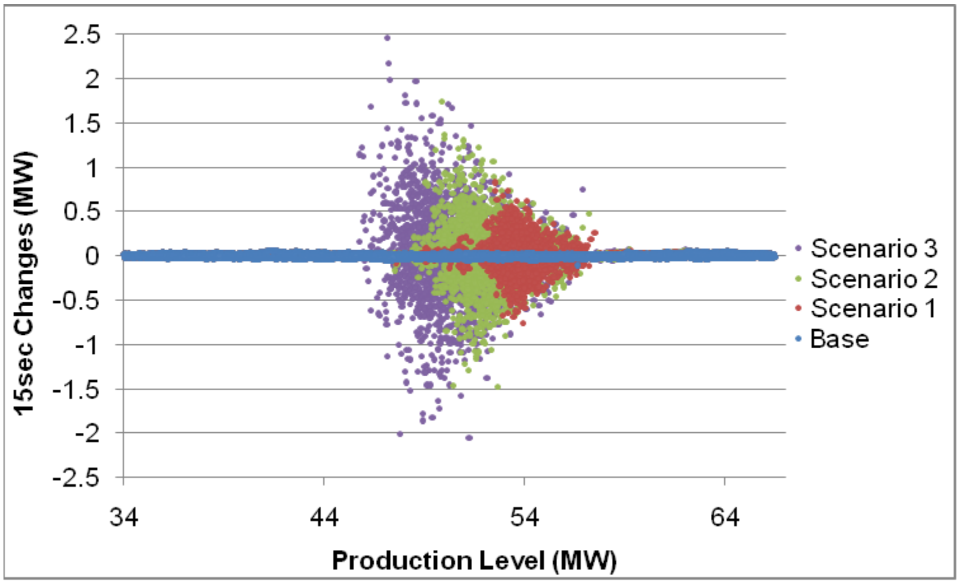

Figure 48. PV generation variability over load generation level.

5.3 Integration Analysis

5.3.1 Marginal Units

The total monthly marginal costs are based on identifying the marginal units operating cost ($/MWh) from UPLAN output and monthly occurrence of the individual marginal units, shown in Section 4.2. When PV generates, it will displace higher cost generation; thus there will be a corresponding reduction in fuel costs. Also, lower-priced units in the generation stack that have appropriate operating characteristics can become marginal resources and provide regulation support at a lower cost. Figure 49 shows the monthly cost for the identified marginal units.

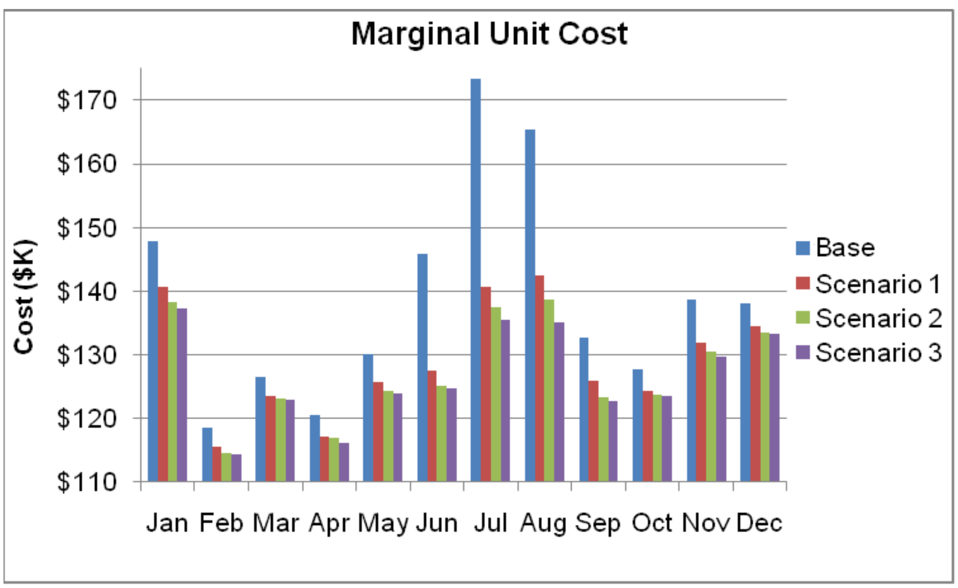

Figure 49. Monthly marginal units cost.

The highest percentage decrease in monthly marginal units cost compared to the Base Case occurs during the month of July (Scenario 1: 18.90%, Scenario 2: 20.70%, and Scenario 3: 21.89%) while the lowest percentage decrease occurs in March (Scenario 1: 2.24%, Scenario 2: 2.70%, and Scenario 3: 2.83%). The summary for the marginal unit costs and cost reduction for the months March and July is shown in Table 15, while Table 16 shows the summary of the annual marginal units cost and cost reduction. Based on the case with no PV the annual marginal unit cost reduction are 6.94% for Scenario 1, 8.17% for Scenario 2, and 8.78% for Scenario 3.

Table 15. Percent Reduction in Marginal Unit Costs for Each Scenario in March and July.

PV Capacity	March % Reduction	July % Reduction
Scenario 1	2.24%	18.90%
Scenario 2	2.70%	20.70%
Scenario 3	2.83%	21.89%

Table 16. Annual Percent Reduction in Marginal Unit Cost.

PV Capacity	% Reduction
Scenario 1	6.94%
Scenario 2	8.17%
Scenario 3	8.78%

Additional details for the marginal units cost reductions are shown in Table A-7.

5.3.2 Regulation Increase

Although from the previous section there is a reduction in cost for marginal units, the introduction of PV requires an increase in regulation that is supported by the marginal units. The additional regulation results from the increased sub-hourly load variability due to PV generation. When PV penetration increases so does the resulting load variability and subsequently the resources placed on margin must be responsive to the change and provide additional regulation. Table 17 compares the additional regulation for days with different insolation levels. Using the NREL data for December, days with different sun activity were selected such that the days with the greatest, smallest, and mean insolation were identified. The days were:

- 2-Dec shows the highest insolation;
- 10-Dec shows the medium insolation; and
- 4-Dec shows the lowest insolation.

By examining the low, medium, and high insolation days it was found that additional regulation for these days increased as the PV penetration increased. Also, additional regulation increased as the penetration of PV increased.

Table 17. Additional Regulation Energy Required for Each Day Based on Unit 15-Second Variability.

Case	Low Insolation Day	Med Insolation Day	High Insolation Day
Scenario 1 (MWh)	7.13	9.88	12.01
Scenario 2 (MWh)	19.87	22.23	22.86
Scenario 3 (MWh)	29.25	36.24	39.05

When looking the month of December the average daily additional regulation is shown in Table 18.

Table 18. Average Daily Additional Regulation for the Month of December.

	Scenario 1	Scenario 2	Scenario 3
Average daily additional regulation (MWh)	10.94	22.74	37.15

Additional details for the additional regulation summary are shown in Table A-8.

6 Conclusions and Findings

This section addresses findings and conclusions identified through the analysis of the PV solar resource data and the modeling of the KIUC system with 5-MW, 10-MW, and 15-MW nameplate capacity of PV generation.

- The selection of units identified as marginal resources that serve and follow system load will change. As PV generation increases, units identified as marginal resources will be units with lower operating costs. In general the cost of operations for marginal units will be reduced.
- The required spinning reserve to maintain system frequency increases with the penetration level of PV (Figure 50).

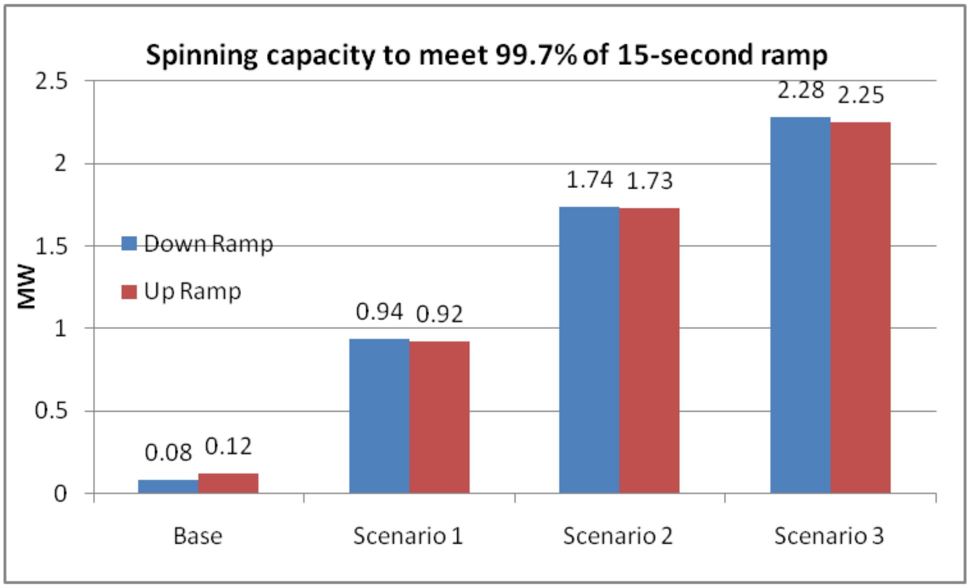

Figure 50. On-line spinning capacity requirement to meet 99.7% of 15-second changes in net load for study scenarios.

- PV penetration will displace existing system generation, thus reducing fuel consumption. The costs of conventional generation operations are reduced due to fuel savings. However, PV energy does not come at zero cost. (The production simulations did not take into account the PV cost.)
- PV generation installed at 5-MW, 10-MW, and 15-MW penetration levels will affect regulating reserves. The study showed that as PV penetration increases the required regulating reserve to control system frequency will increase (see Table 19). These additional reserve levels would result in a frequency performance that is similar to the existing system. This analysis is based on a limited amount of high-resolution system data, and did not consider system performance during contingencies.

- PV penetration at any penetration level is not likely to reduce net system load. KIUC load patterns peak in the evening with a secondary peak in the morning. The peaks occur at times when PV generation is at low or zero level. PV has the best benefit for reducing system peak in the summer months when the solar day is longer.
- Increasing PV penetration has little effect on load-following reserves with negligible reduction as penetration increases (see Table 19).

Table 19. Annual Incremental Reserve Range.

Range of monthly maximum load changes for study period in 2011	PV Penetration							
	Base Case		Scenario 1		Scenario 2		Scenario 3	
	From	To	From	To	From	To	From	To
Regulating (MW/15 sec)	0.10	0.34	0.95	1.69	1.66	2.90	2.25	4.35
Load-Following (MW/h)	7.45	10.79	7.30	10.72	7.23	10.65	7.07	10.53

- PV generation studies require data with time resolution less than 1 hour, preferably in seconds.
    - Variability: High-resolution (1-second) solar resource data demonstrates greater variability of PV generation and can have a significant effect on system frequency. This impact may be obscured if PV generation is modeled with hourly resolution data.
    - Diversity: High-resolution (1-second) solar resource data yields improved diversity between geographically separated sites. Geographical diversity has a lesser impact on variability over longer time frames.

Appendix A.

A.1 Site Analysis – Monthly and Annual Solar Pattern

This appendix shows a detailed examination of the analysis used for comparison of the sites. The monthly and annual minimum, maximum, and average solar resource data for each site is represented graphically in Figures A-1 through A-7.

The average high represents the average of the highest daily insolation observed throughout the month. The mean insolation represents the mean insolation observed throughout the whole month when the sun is shinning, usually between 8 a.m and 6:00 p.m. In this case, the mean does not account for those periods of the day when there is no sun since it is more important when PV is generating.

The results show that the solar resource data at selected sites exhibit the same monthly pattern, with the monthly mean insolation during the summer around 600 Wh/m^2, and the mean insolation during the winter around 400 Wh/m^2. Note that for mean insolation calculation, the solar resource data is only averaged over a period when the solar radiation is received and does not account for when the insolation is zero.

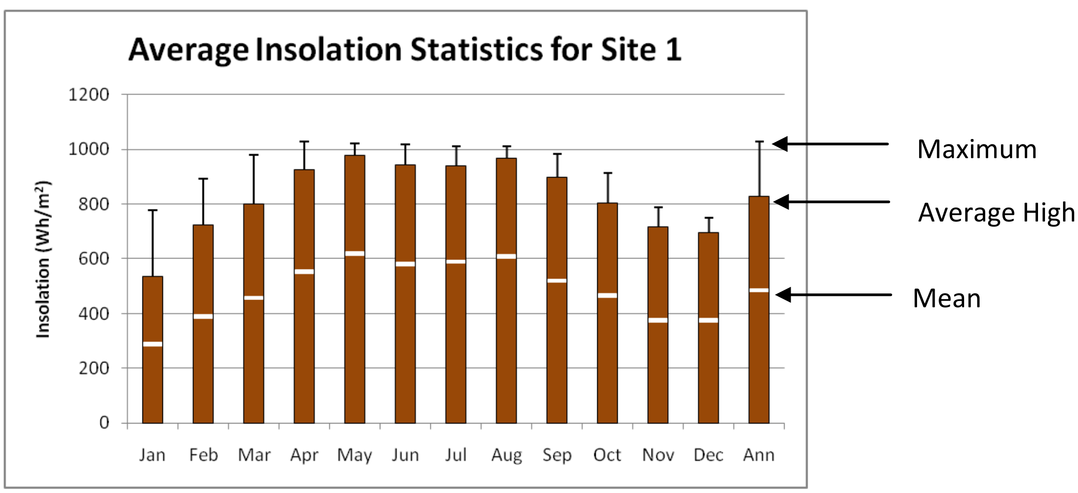

Figure A-1. Monthly solar resource data summary, Site 1.

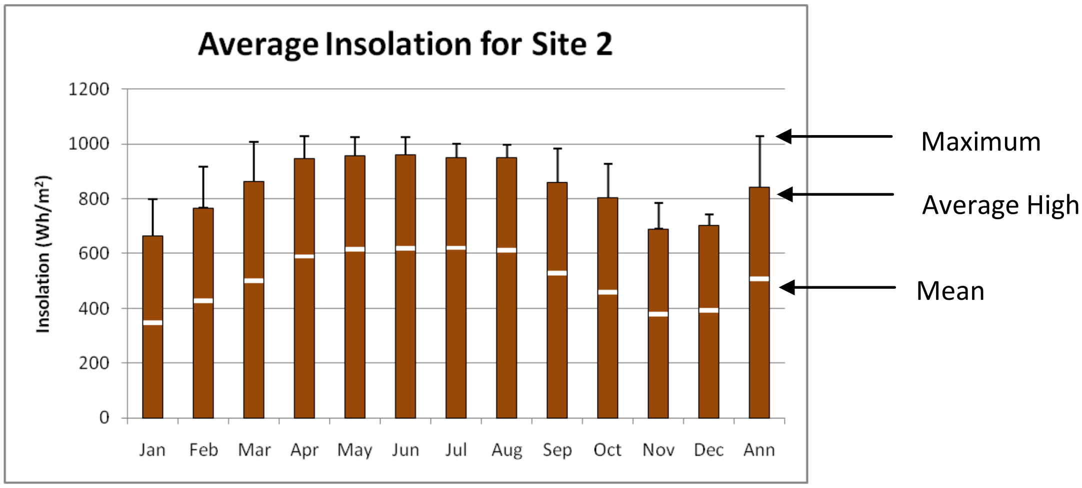

Figure A-2. Monthly solar resource data summary, Site 2.

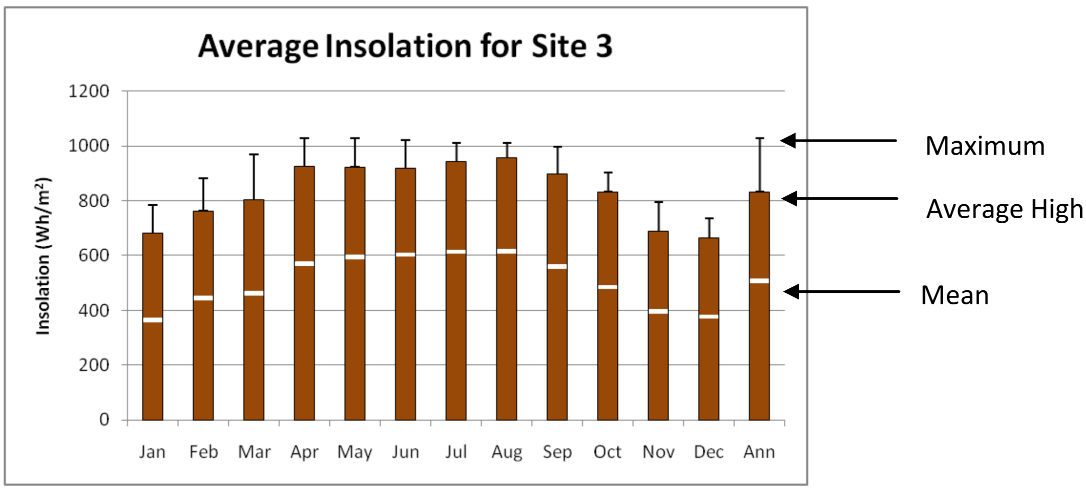

Figure A-3. Monthly solar resource data summary, Site 3.

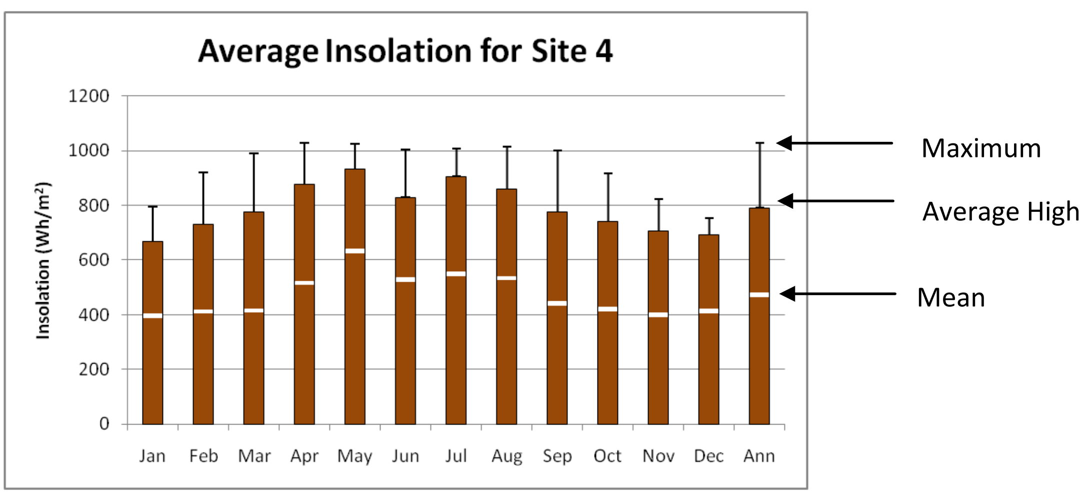

Figure A-4. Monthly solar resource data summary, Site 4.

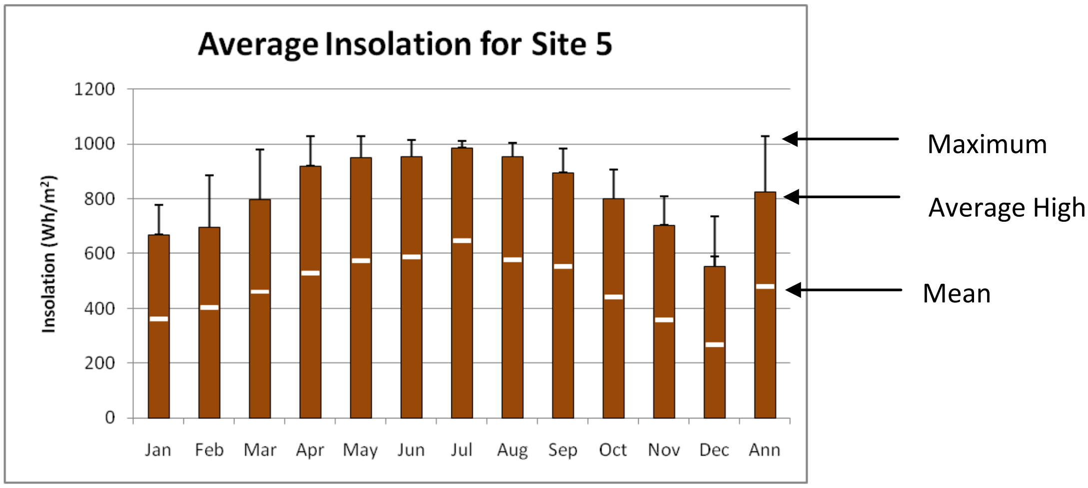

Figure A-5. Monthly solar resource data summary, Site 5.

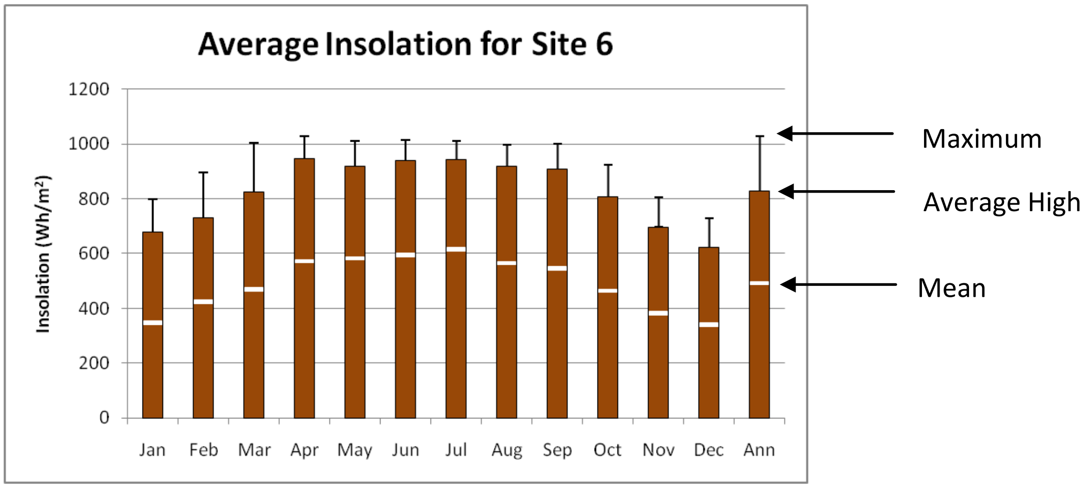

Figure A-6. Monthly solar resource data summary, Site 6.

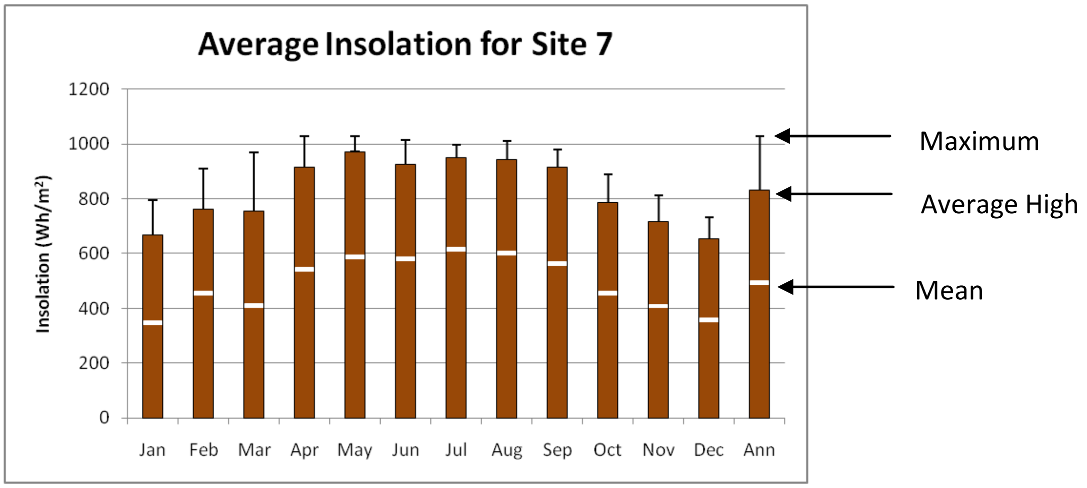

Figure A-7. Monthly solar resource data summary, Site 7.

A.2 High-Resolution Data Modeling

This section will describe the methodology used to model high-resolution solar resource data. KIUC provided 1-second solar resource data for three stations on Oahu and 2.5-minute solar resource data for Hana Kukui. The profiles provided in these data sets were used to create simulated high-resolution data from hourly profiles.

First, the daily total energy was calculated for the NREL solar resource data and the high-resolution solar resource data. Each set of data was classified into four categories, as shown below.

Overcast	Less than or equal to 2546 kWh/M^2/day
Slightly Sunny	Greater than Overcast and less than or equal to kWh/M^2/day
Moderately Sunny	Greater than Slightly Sunny and less than or equal to 5960 kWh/M^2/day
Very Sunny	Greater than Moderately Sunny

Next the group of hourly data in the overcast group was randomly mapped with higher resolution data in the overcast group. The other hourly data were randomly mapped with higher-resolution data in like groups.

Keeping the chronology of the data mapped with the solar resource data, the days were ranked from low to high power. The 2.5-minute data was ordered in the same way. From here the hourly data with lowest insolation day was mapped to the 2.5-minute data with lowest insolation day. Using the 2.5-minute data profile the algorithm computes the instantaneous values to obtain the variability between 2.5-minute periods while maintaining the correct hour ending average. Table A-1 shows a sample of hourly data and that data converted to 2.5-minute data.

Using the same approach, the 2.5-minute solar resource data was used to create 1-second solar resource data. The 1-second solar resource data was used to generate the 15-second data used in the model described in Section 4.1.1.

Table A-1. Sample Hour Solar Resource Data Converted to Higher Resolution.

Time	Kw		Kw	Time
0:00:00			285	9:00:00
1:00:00			305	9:02:30
2:00:00			555	9:05:00
3:00:00			497	9:07:30
4:00:00			518	9:10:00
5:00:00			355	9:12:30
6:00:00			177	9:15:00
7:00:00	1		175	9:17:30
8:00:00	83		182	9:20:00
9:00:00	66		266	9:22:30
10:00:00	269		245	9:25:00
11:00:00	208		256	9:27:30
12:00:00	154		400	9:30:00
13:00:00	161		409	9:32:30
13:00:00	157		293	9:35:00
15:00:00	204		264	9:37:30
16:00:00	277		237	9:40:00
17:00:00	170		163	9:42:30
18:00:00	11		165	9:45:00
19:00:00			138	9:47:30
20:00:00			138	9:50:00
21:00:00			153	9:52:30
22:00:00			130	9:55:00
23:00:00			148	9:57:30
0:00:00			195	10:00:00

The average Kw from 09:00:00 to 09:57:30 is **269**, which corresponds to the hour-ending

A.3 Monthly Load and PV Energy

The summary of the monthly load and PV energy for each scenario is shown in Tables A-2 through A-4. Figure A-9 shows the PV energy as a percentage of the load energy. More energy is obtained from PV during the summer months when compared to the winter months because of seasonal variation of solar radiation (Figure A-9).

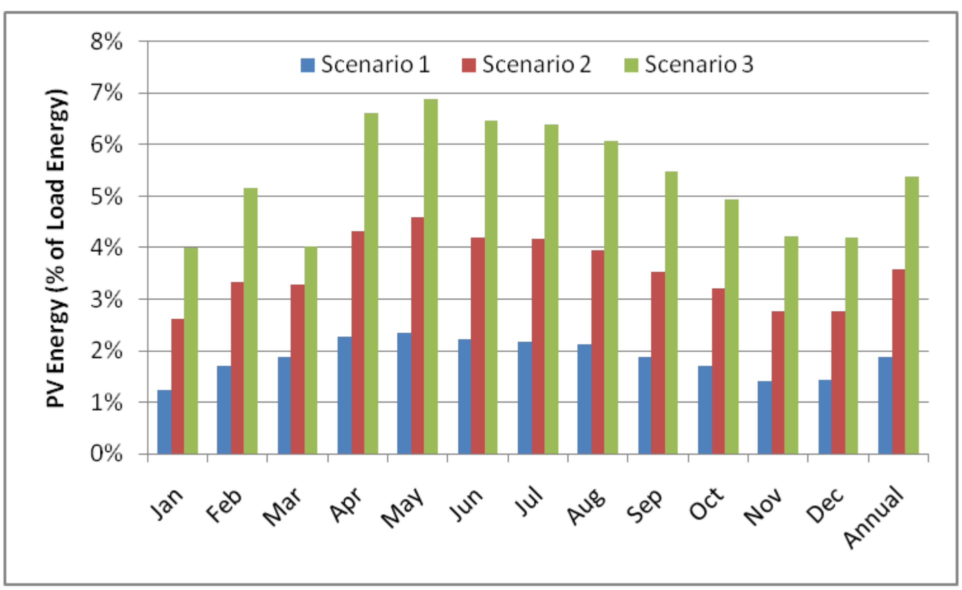

Figure A-8. PV energy as a percent of load energy.

Table A-2. Summary of Monthly Load and PV Energy for Scenario 1.

	Load			PV Scenario 1	
	Min (MW)	**Max (MW)**	**Energy (GWh)**	**Energy (GWh)**	**Energy % Load**
Jan	30.14	68.77	37.22	.456	1.23%
Feb	27.60	62.90	31.51	.535	1.70%
Mar	29.50	64.52	36.04	.677	1.88%
Apr	28.87	65.44	35.10	.795	2.26%
May	31.87	67.09	38.40	.898	2.34%
Jun	34.29	66.73	38.29	.849	2.22%
Jul	35.47	69.02	41.04	.888	2.16%
Aug	36.57	70.80	42.12	.894	2.12%
Sep	35.46	70.19	39.58	.744	1.88%
Oct	33.14	69.81	39.63	.678	1.71%
Nov	31.78	72.31	37.80	.532	1.41%
Dec	30.93	71.92	38.13	.550	1.44%
Annual	27.60	72.31	454.84	8.496	1.87%

Table A-3. Summary of Monthly Load and PV Energy for Scenario 2.

	Load			PV Scenario 2	
	Min (MW)	Max (MW)	Energy (GWh)	Energy (GWh)	Energy % Load
Jan	30.14	68.77	37.22	.974	2.62%
Feb	27.60	62.90	31.51	1.052	3.34%
Mar	29.50	64.52	36.04	1.186	3.29%
Apr	28.87	65.44	35.10	1.515	4.32%
May	31.87	67.09	38.40	1.762	4.59%
Jun	34.29	66.73	38.29	1.611	4.21%
Jul	35.47	69.02	41.04	1.714	4.18%
Aug	36.57	70.80	42.12	1.668	3.96%
Sep	35.46	70.19	39.58	1.399	3.54%
Oct	33.14	69.81	39.63	1.275	3.22%
Nov	31.78	72.31	37.80	1.047	2.77%
Dec	30.93	71.92	38.13	1.054	2.76%
Annual	27.60	72.31	454.84	16.258	3.57%

Table A-4. Summary of Monthly Load and PV Energy for Scenario 3.

	Load			PV Scenario 3	
	Min (MW)	Max (MW)	Energy (GWh)	Energy (GWh)	Energy % Load
Jan	30.14	68.77	37.22	1.488	4.00%
Feb	27.60	62.90	31.51	1.628	5.17%
Mar	29.50	64.52	36.04	1.446	4.01%
Apr	28.87	65.44	35.10	2.323	6.62%
May	31.87	67.09	38.40	2.647	6.89%
Jun	34.29	66.73	38.29	2.470	6.45%
Jul	35.47	69.02	41.04	2.621	6.39%
Aug	36.57	70.80	42.12	2.560	6.08%
Sep	35.46	70.19	39.58	2.170	5.48%
Oct	33.14	69.81	39.63	1.953	4.93%
Nov	31.78	72.31	37.80	1.597	4.23%
Dec	30.93	71.92	38.13	1.604	4.21%
Annual	27.60	72.31	454.84	24.507	5.39%

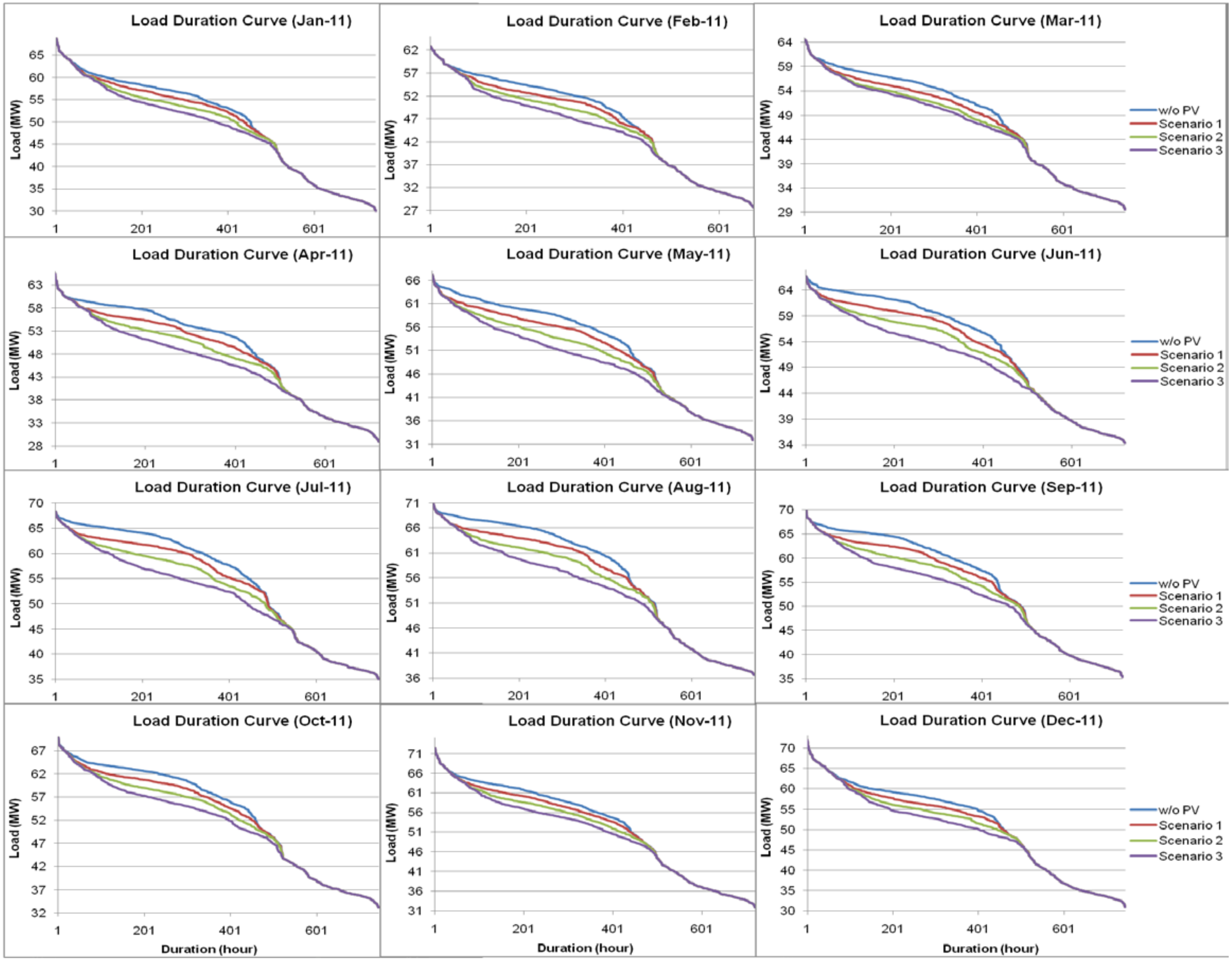

Figure A-9. Monthly load and load net PV duration curve summary.

A.4 High-Resolution Generation Statistics

It should be noted that Table A-5 is hourly variability while Table A-6 is 15-second variability and the greatest change in load from hour to hour occurs during the time of the day when the sun is rising, setting, or down.

Table A-6 shows how PV penetration changes variability in the sub-hourly period.

Table A-5. Monthly (2011) Load Variability and Load Net PV Variability for 1-Hour Data.

Month		Load	Load net PV Scenario 1	Load net PV Scenario 2	Load net PV Scenario 3	Month		Load	Load net PV Scenario 1	Load net PV Scenario 2	Load net PV Scenario 3
Jan	Average	-0.008	-0.008	-0.008	-0.008	Feb	Average	-0.001	-0.001	-0.001	-0.001
	Stdev	3.75	3.74	3.76	3.81		Stdev	3.64	3.65	3.69	3.77
	Max	9.57	9.57	9.57	9.57		Max	9.13	9.13	9.13	9.13
	Min	-8.45	-8.45	-8.45	-8.45		Min	-8.33	-8.33	-8.33	-8.33
Mar	Average	-0.001	-0.001	-0.001	-0.001	Apr	Average	0.003	0.003	0.003	0.003
	Stdev	3.52	3.49	3.49	3.50		Stdev	3.57	3.51	3.51	3.56
	Max	9.23	9.23	9.23	9.23		Max	10.83	10.76	10.69	10.57
	Min	-8.80	-8.80	-8.80	-8.80		Min	-8.92	-8.92	-8.92	-8.92
May	Average	0.009	0.009	0.009	0.009	Jun	Average	-0.003	-0.003	-0.003	-0.003
	Stdev	3.51	3.41	3.37	3.39		Stdev	3.46	3.36	3.31	3.31
	Max	8.97	8.72	8.37	8.10		Max	8.07	7.85	7.66	7.34
	Min	-13.91	-13.91	-13.91	-13.91		Min	-8.54	-8.54	-8.54	-8.54
Jul	Average	0.001	0.001	0.001	0.001	Aug	Average	0.002	0.002	0.002	0.002
	Stdev	3.58	3.47	3.41	3.40		Stdev	3.763	3.662	3.616	3.615
	Max	7.48	7.33	7.25	7.09		Max	8.888	8.817	8.703	8.593
	Min	-8.65	-8.65	-8.65	-8.65		Min	-8.600	-8.600	-8.600	-8.600
Sep	Average	-0.004	-0.004	-0.004	-0.004	Oct	Average	-0.002	-0.002	-0.002	-0.002
	Stdev	3.57	3.50	3.46	3.47		Stdev	3.63	3.57	3.56	3.57
	Max	9.46	9.43	9.40	9.35		Max	9.15	9.15	9.13	9.12
	Min	-8.52	-8.52	-8.52	-8.52		Min	-8.09	-8.09	-8.09	-8.09
Nov	Average	-0.001	-0.001	-0.001	-0.001	Dec	Average	0.006	0.006	0.006	0.006
	Stdev	3.79	3.76	3.74	3.76		Stdev	3.87	3.86	3.87	3.91
	Max	9.24	9.24	9.24	9.24		Max	9.38	9.38	9.38	9.38
	Min	-8.80	-8.80	-8.80	-8.80		Min	-8.70	-8.70	-8.70	-8.70

Table A-6. Daily (December) Load Variability and Load Net PV Variability for 15-Second Data.

Date		Load	Load Net PV Scenario 1	Load Net PV Scenario 2	Load Net PV Scenario 3	Date		Load	Load Net PV Scenario 1	Load Net PV Scenario 2	Load Net PV Scenario 3
1 Dec	Average	0.006	0.006	0.006	0.006	2 Dec	Average	0.005	0.005	0.005	0.005
	Stdev	0.03	0.20	0.34	0.50		Stdev	0.03	0.25	0.35	0.55
	Max	0.13	1.28	1.69	2.75		Max	0.16	1.24	1.77	3.22
	Min	-0.10	-1.21	-1.55	-2.40		Min	-0.10	-1.26	-1.60	-2.62
3 Dec	Average	0.004	0.004	0.004	0.004	4 Dec	Average	0.004	0.004	0.004	0.004
	Stdev	0.03	0.22	0.34	0.50		Stdev	0.03	0.17	0.33	0.44
	Max	0.13	1.21	2.25	3.01		Max	0.12	0.92	1.74	2.26
	Min	-0.14	-1.13	-1.85	-2.53		Min	-0.07	-0.94	-1.74	-2.28
5Dec	Average	0.000	0.000	0.000	0.000	6Dec	Average	0.009	0.009	0.009	0.009
	Stdev	0.03	0.26	0.33	0.54		Stdev	0.03	0.24	0.47	0.63
	Max	0.15	1.48	1.82	2.92		Max	0.18	1.34	2.50	3.68
	Min	-0.10	-1.36	-1.88	-2.61		Min	-0.11	-1.66	-2.61	-3.89
7 Dec	Average	0.006	0.006	0.006	0.006	8 Dec	Average	0.001	0.001	0.001	0.001
	Stdev	0.03	0.23	0.30	0.47		Stdev	0.02	0.26	0.38	0.56
	Max	0.18	1.13	1.53	2.40		Max	0.10	1.33	2.04	3.28
	Min	-0.11	-1.24	-1.67	-2.47		Min	-0.10	-1.66	-2.72	-3.89
9 Dec	Average	0.003	0.003	0.003	0.003	10 Dec	Average	0.011	0.011	0.011	0.011
	Stdev	0.03	0.23	0.42	0.59		Stdev	0.03	0.22	0.39	0.57
	Max	0.15	1.18	2.10	3.24		Max	0.24	1.16	2.23	3.18
	Min	-0.07	-1.41	-2.57	-3.71		Min	-0.12	-1.16	-2.26	-3.53
11 Dec	Average	0.009	0.009	0.009	0.009	12 Dec	Average	0.009	0.009	0.009	0.009
	Stdev	0.03	0.24	0.35	0.49		Stdev	0.03	0.19	0.35	0.52
	Max	0.13	1.26	2.44	3.20		Max	0.19	1.36	2.32	3.45
	Min	-0.08	-1.41	-2.14	-3.01		Min	-0.09	-1.21	-1.96	-2.70
13 Dec	Average	0.006	0.006	0.006	0.006	14 Dec	Average	0.0001	0.0001	0.0001	0.0001
	Stdev	0.03	0.23	0.45	0.60		Stdev	0.03	0.21	0.47	0.62
	Max	0.15	1.33	2.52	3.42		Max	0.12	1.21	2.73	3.72
	Min	-0.09	-1.43	-2.71	-3.43		Min	-0.16	-1.16	-2.53	-3.48
15Dec	Average	0.008	0.008	0.008	0.008	16Dec	Average	0.005	0.005	0.005	0.005
	Stdev	0.03	0.25	0.36	0.55		Stdev	0.03	0.22	0.35	0.53
	Max	0.12	1.49	2.26	3.27		Max	0.13	1.30	2.11	3.08
	Min	-0.09	-1.35	-2.29	-3.13		Min	-0.14	-1.44	-2.13	-3.01
17 Dec	Average	0.005	0.005	0.005	0.005	18 Dec	Average	0.004	0.004	0.004	0.004
	Stdev	0.03	0.21	0.34	0.48		Stdev	0.03	0.18	0.27	0.39
	Max	0.13	1.23	2.09	2.77		Max	0.11	0.95	1.67	2.36
	Min	-0.11	-1.15	-1.90	-2.55		Min	-0.10	-1.14	-1.45	-2.06
19 Dec	Average	0.005	0.005	0.005	0.005	20 Dec	Average	0.004	0.004	0.004	0.004
	Stdev	0.03	0.24	0.35	0.48		Stdev	0.03	0.32	0.55	0.84
	Max	0.35	1.30	2.14	2.84		Max	0.17	1.70	2.91	4.37
	Min	-0.29	-1.26	-2.37	-3.02		Min	-0.09	-1.66	-2.85	-4.14

A.5 Marginal Unit Summary

Table A-7. Monthly UPLAN Marginal Generator Summary and Estimated Scenario Operation.

Month	Unit	$/MWh	Base		Scenario 1		Scenario 2		Scenario 3	
			Hours on line	Unit Cost	Hours on line	Unit Cost	Hours on line	Unit Cost	Hours on line	Unit Cost
January	S1	366.22	128	$46,876	96	$35,157	89	$32,594	84	$30,762
	D5	232.83	8	$1,863	9	$2,095	3	$698	3	$698
	D4	192.9	31	$5,980	21	$4,051	13	$2,508	12	$2,315
	D3	186.55	45	$8,395	25	$4,664	14	$2,612	12	$2,239
	D2	173.17	1	$173	0	$0	0	$0	0	$0
	D9	164.58	126	$20,737	132	$21,725	93	$15,306	57	$9,381
	D7	164.46	116	$19,077	164	$26,971	214	$35,194	231	$37,990
	D8	163.16	84	$13,705	92	$15,011	113	$18,437	140	$22,842
	D1	162.37	6	$974	6	$974	6	$974	6	$974
	D6	155.28	21	$3,261	21	$3,261	21	$3,261	21	$3,261
	CT1	150.13	178	$26,723	178	$26,723	178	$26,723	178	$26,723

Month	Unit	$/MWh	Base		Scenario 1		Scenario 2		Scenario 3	
			Hours on line	Unit Cost	Hours on line	Unit Cost	Hours on line	Unit Cost	Hours on line	Unit Cost
February	S1	302.24	52	$15,716	47	$14,205	46	$13,903	46	$13,903
	D3	202.94	85	$17,250	43	$8,726	33	$6,697	30	$6,088
	D4	200.75	37	$7,428	16	$3,212	7	$1,405	6	$1,205
	D5	189.78	8	$1,518	4	$759	4	$759	2	$380
	GT2	183.4	1	$183	1	$183	0	$0	0	$0
	D1	167.77	18	$3,020	11	$1,845	3	$503	2	$336
	D7	164.74	136	$22,405	159	$26,194	112	$18,451	65	$10,708
	D9	164.69	115	$18,939	170	$27,997	236	$38,867	262	$43,149
	D8	163.77	24	$3,930	25	$4,094	35	$5,732	62	$10,154
	D6	155	21	$3,255	21	$3,255	21	$3,255	22	$3,410
	CT1	142.72	175	$24,976	175	$24,976	175	$24,976	175	$24,976

Month	Unit	$/MWh	Base		Scenario 1		Scenario 2		Scenario 3	
			Hours on line	Unit Cost	Hours on line	Unit Cost	Hours on line	Unit Cost	Hours on line	Unit Cost
March	S1	276.04	25	$6,901	23	$6,349	23	$6,349	23	$6,349
	D3	204.42	94	$19,215	44	$8,994	36	$7,359	36	$7,359
	D5	189.78	3	$569	0	$0	0	$0	0	$0
	D4	186.17	44	$8,191	24	$4,468	20	$3,723	18	$3,351
	D2	173.17	1	$173	0	$0	0	$0	0	$0
	D1	171.7	11	$1,889	11	$1,889	6	$1,030	6	$1,030
	D9	165.48	65	$10,756	42	$6,950	22	$3,641	18	$2,979
	D7	164.29	144	$23,658	201	$33,022	189	$31,051	164	$26,944
	D8	163.1	112	$18,267	153	$24,954	196	$31,968	216	$35,230
	D6	155.28	32	$4,969	33	$5,124	39	$6,056	50	$7,764
	CT1	149.56	213	$31,856	213	$31,856	213	$31,856	213	$31,856

Month	Unit	$/MWh	Base		Scenario 1		Scenario 2		Scenario 3	
			Hours on line	Unit Cost	Hours on line	Unit Cost	Hours on line	Unit Cost	Hours on line	Unit Cost
April	D3	197	118	$23,246	52	$10,244	49	$9,653	48	$9,456
	D5	189.78	9	$1,708	2	$380	4	$759	4	$759
	D4	188.1	45	$8,465	9	$1,693	9	$1,693	9	$1,693
	D2	173.17	2	$346	0	$0	0	$0	0	$0
	D1	169.93	20	$3,399	10	$1,699	7	$1,190	6	$1,020
	D9	164.2	61	$10,016	115	$18,883	39	$6,404	27	$4,433
	D7	164.01	146	$23,945	136	$22,305	169	$27,718	92	$15,089
	D8	163.22	73	$11,915	149	$24,320	173	$28,237	203	$33,134
	D6	155.28	23	$3,571	21	$3,261	38	$5,901	69	$10,714
	CT1	152.42	223	$33,990	226	$34,447	232	$35,361	262	$39,934

Month	Unit	$/MWh	Base		Scenario 1		Scenario 2		Scenario 3	
			Hours on line	Unit Cost	Hours on line	Unit Cost	Hours on line	Unit Cost	Hours on line	Unit Cost
May	S1	271.85	31	$8,427	14	$3,806	14	$3,806	14	$3,806
	D3	208.98	110	$22,988	59	$12,330	38	$7,941	34	$7,105
	D4	191.54	34	$6,512	23	$4,405	10	$1,915	9	$1,724
	D5	189.78	11	$2,088	11	$2,088	5	$949	6	$1,139
	D2	173.17	1	$173	0	$0	0	$0	0	$0
	D1	166.5	17	$2,831	12	$1,998	8	$1,332	3	$500
	D7	165.16	151	$24,939	164	$27,086	115	$18,993	68	$11,231
	D9	165.14	89	$14,697	118	$19,487	151	$24,936	114	$18,826
	D8	164.43	123	$20,225	166	$27,295	226	$37,161	319	$52,453
	D6	155.28	33	$5,124	33	$5,124	33	$5,124	33	$5,124
	CT1	153.19	144	$22,059	144	$22,059	144	$22,059	144	$22,059

Month	Unit	$/MWh	Base		Scenario 1		Scenario 2		Scenario 3	
			Hours on line	Unit Cost	Hours on line	Unit Cost	Hours on line	Unit Cost	Hours on line	Unit Cost
June	S1	448.69	79	$35,447	21	$9,422	20	$8,974	20	$8,974
	GT2	231.22	2	$462	2	$462	2	$462	2	$462
	D3	200.42	125	$25,053	41	$8,217	26	$5,211	24	$4,810
	D4	196.61	40	$7,864	54	$10,617	16	$3,146	12	$2,359
	D5	189.78	7	$1,328	25	$4,745	12	$2,277	9	$1,708
	D1	167.45	17	$2,847	40	$6,698	17	$2,847	11	$1,842
	D9	166.06	123	$20,425	164	$27,234	211	$35,039	102	$16,938
	D7	165.1	132	$21,793	177	$29,223	220	$36,322	342	$56,464
	D8	164.25	65	$10,676	66	$10,841	66	$10,841	68	$11,169
	D6	155.28	20	$3,106	20	$3,106	20	$3,106	20	$3,106
	CT1	153.19	110	$16,851	110	$16,851	110	$16,851	110	$16,851

Month	Unit	$/MWh	Base		Scenario 1		Scenario 2		Scenario 3	
			Hours on line	Unit Cost	Hours on line	Unit Cost	Hours on line	Unit Cost	Hours on line	Unit Cost
July	S1	521.92	127	$66,284	31	$16,180	30	$15,658	30	$15,658
	D5	196.95	16	$3,151	5	$985	3	$591	2	$394
	D3	194.93	151	$29,434	186	$36,257	73	$14,230	54	$10,526
	D4	186.17	66	$12,287	102	$18,989	124	$23,085	57	$10,612
	D1	172.16	16	$2,755	14	$2,410	35	$6,026	15	$2,582
	D2	171.14	8	$1,369	7	$1,198	12	$2,054	11	$1,883
	D9	166.6	100	$16,660	136	$22,658	169	$28,155	242	$40,317
	D7	164.46	87	$14,308	89	$14,637	123	$20,229	158	$25,985
	D8	164.11	57	$9,354	58	$9,518	59	$9,682	59	$9,682
	D6	155.28	25	$3,882	25	$3,882	25	$3,882	25	$3,882
	CT1	153.19	91	$13,940	91	$13,940	91	$13,940	91	$13,940

Month	Unit	$/MWh	Base		Scenario 1		Scenario 2		Scenario 3	
			Hours on line	Unit Cost	Hours on line	Unit Cost	Hours on line	Unit Cost	Hours on line	Unit Cost
August	S1	372.77	160	$59,643	39	$14,538	39	$14,538	38	$14,165
	GT1	331.21	12	$3,975	4	$1,325	3	$994	4	$1,325
	GT2	231.22	1	$231	1	$231	0	$0	0	$0
	D3	208.28	139	$28,951	197	$41,031	81	$16,871	49	$10,206
	D5	198.61	26	$5,164	43	$8,540	47	$9,335	23	$4,568
	D4	190.02	61	$11,591	74	$14,061	113	$21,472	59	$11,211
	D2	173.17	6	$1,039	3	$520	14	$2,424	9	$1,559
	D1	170.47	18	$3,068	11	$1,875	39	$6,648	36	$6,137
	D9	166.67	80	$13,334	128	$21,334	164	$27,334	250	$41,668
	D7	164.62	86	$14,157	89	$14,651	88	$14,487	120	$19,754
	D8	164.13	46	$7,550	46	$7,550	47	$7,714	47	$7,714
	D6	155.28	37	$5,745	37	$5,745	37	$5,745	37	$5,745
	CT1	153.19	72	$11,030	72	$11,030	72	$11,030	72	$11,030

Month	Unit	$/MWh	Base		Scenario 1		Scenario 2		Scenario 3	
			Hours on line	Unit Cost	Hours on line	Unit Cost	Hours on line	Unit Cost	Hours on line	Unit Cost
September	S1	291.54	61	$17,784	27	$7,872	27	$7,872	27	$7,872
	D3	206.17	136	$28,039	36	$7,422	27	$5,567	27	$5,567
	D4	192.85	56	$10,800	86	$16,585	34	$6,557	23	$4,436
	D5	189.78	9	$1,708	38	$7,212	11	$2,088	5	$949
	D2	173.17	1	$173	1	$173	0	$0	0	$0
	D1	169.76	19	$3,225	37	$6,281	17	$2,886	9	$1,528
	D9	166.69	129	$21,503	143	$23,837	218	$36,338	157	$26,170
	D7	164.87	112	$18,465	154	$25,390	188	$30,996	274	$45,174
	D8	164.64	58	$9,549	59	$9,714	59	$9,714	59	$9,714
	D6	155.19	38	$5,897	38	$5,897	38	$5,897	38	$5,897
	CT1	153.19	101	$15,472	101	$15,472	101	$15,472	101	$15,472

Month	Unit	$/MWh	Base		Scenario 1		Scenario 2		Scenario 3	
			Hours on line	Unit Cost	Hours on line	Unit Cost	Hours on line	Unit Cost	Hours on line	Unit Cost
October	S1	276.49	24	$6,636	21	$5,806	20	$5,530	20	$5,530
	D3	199.26	123	$24,509	48	$9,564	38	$7,572	36	$7,173
	D5	189.78	5	$949	1	$190	1	$190	1	$190
	D4	183.1	34	$6,225	14	$2,563	7	$1,282	7	$1,282
	D2	173.17	1	$173	0	$0	1	$173	0	$0
	D9	165.21	90	$14,869	88	$14,538	46	$7,600	35	$5,782
	D1	164.64	19	$3,128	35	$5,762	13	$2,140	4	$659
	D7	164.63	152	$25,024	217	$35,725	273	$44,944	256	$42,145
	D8	163.64	92	$15,055	116	$18,982	141	$23,073	181	$29,619
	D6	155.28	38	$5,901	38	$5,901	38	$5,901	38	$5,901
	CT1	152.5	166	$25,315	166	$25,315	166	$25,315	166	$25,315

Month	Unit	$/MWh	Base		Scenario 1		Scenario 2		Scenario 3	
			Hours on line	Unit Cost	Hours on line	Unit Cost	Hours on line	Unit Cost	Hours on line	Unit Cost
November	S1	392.04	79	$30,971	56	$21,954	54	$21,170	53	$20,778
	GT2	231.22	6	$1,387	4	$925	3	$694	3	$694
	D3	197.31	85	$16,771	42	$8,287	23	$4,538	22	$4,341
	D5	189.78	9	$1,708	6	$1,139	3	$569	2	$380
	D4	184.83	39	$7,208	40	$7,393	29	$5,360	17	$3,142
	D2	173.17	1	$173	0	$0	0	$0	0	$0
	D1	169.93	15	$2,549	31	$5,268	11	$1,869	7	$1,190
	D9	165.69	80	$13,255	86	$14,249	98	$16,238	47	$7,787
	D7	164.59	127	$20,903	174	$28,639	197	$32,424	238	$39,172
	D8	163.75	103	$16,866	105	$17,194	126	$20,633	155	$25,381
	D6	155.28	32	$4,969	32	$4,969	32	$4,969	32	$4,969
	CT1	152.39	144	$21,944	144	$21,944	144	$21,944	144	$21,944

Month	Unit	$/MWh	Base		Scenario 1		Scenario 2		Scenario 3	
			Hours on line	Unit Cost	Hours on line	Unit Cost	Hours on line	Unit Cost	Hours on line	Unit Cost
December	S1	316.71	76	$24,070	69	$21,853	69	$21,853	69	$21,853
	D3	198.56	131	$26,011	70	$13,899	52	$10,325	45	$8,935
	D5	189.78	5	$949	3	$569	0	$0	0	$0
	D4	183.21	50	$9,161	30	$5,496	16	$2,931	14	$2,565
	D2	173.17	4	$693	5	$866	6	$1,039	1	$173
	D1	166.57	27	$4,497	25	$4,164	8	$1,333	7	$1,166
	D9	164.95	87	$14,351	111	$18,309	79	$13,031	43	$7,093
	D7	164.94	133	$21,937	198	$32,658	281	$46,348	331	$54,595
	D8	164.18	83	$13,627	85	$13,955	85	$13,955	86	$14,119
	D6	155.28	33	$5,124	33	$5,124	33	$5,124	33	$5,124
	CT1	153.19	115	$17,617	115	$17,617	115	$17,617	115	$17,617

A.6 Reserve Analysis Summary

Table A-8. 99.7th Percentile Coverage for Hourly Load and Load Net PV Positive Variability and Increase in Variability.

Month	99.7th Percentile for Load and Load Net PV Variability in MW				Increase in Variability		
	Base	Scenario 1	Scenario 2	Scenario 3	Scenario 1	Scenario 2	Scenario 3
Jan-11	9.55	9.55	9.55	9.55	0.00	0.00	0.00
Feb-11	9.10	9.10	9.10	9.10	0.000	0.00	0.00
Mar-11	9.20	9.20	9.20	9.20	0.00	0.00	0.00
Apr-11	10.79	10.72	10.65	10.53	-0.07	-0.14	-0.26
May-11	8.93	8.68	8.33	8.06	-0.25	-0.60	-0.87
Jun-11	8.04	7.82	7.64	7.32	-0.22	-0.40	-0.72
Jul-11	7.45	7.30	7.22	7.06	-0.14	-0.22	-0.38
Aug-11	8.85	8.78	8.67	8.56	-0.07	-0.18	-0.29
Sep-11	9.43	9.41	9.37	9.32	-0.02	-0.05	-0.11
Oct-11	9.12	9.12	9.10	9.09	-0.003	-0.02	-0.03
Nov-11	9.20	9.20	9.20	9.20	0.00	0.00	0.00
Dec-11	9.34	9.34	9.34	9.34	0.00	0.00	0.00

Table A-9. 99.7th Percentile Coverage for 15-Second Load and Load Net PV Positive Variability and Increase in Variability.

Date	99.7th Percentile for Load and Load Net PV Variability in MW				Increase in Variability		
	Base	Scenario 1	Scenario 2	Scenario 3	Scenario 1	Scenario 2	Scenario 3
1-Dec	0.12	1.27	1.67	2.73	1.15	1.55	2.61
2-Dec	0.15	1.23	1.75	3.20	1.07	1.60	3.049
3-Dec	0.12	1.19	2.23	2.99	1.07	2.11	2.874
4-Dec	0.11	0.91	1.72	2.25	0.80	1.61	2.13
5-Dec	0.15	1.47	1.81	2.91	1.31	1.65	2.76
6-Dec	0.17	1.32	2.48	3.65	1.14	2.30	3.48
7-Dec	0.17	1.12	1.51	2.38	0.94	1.33	2.20
8-Dec	0.09	1.32	2.029	3.27	1.22	1.93	3.17
9-Dec	0.14	1.17	2.09	3.22	1.029	1.94	3.08
10-Dec	0.22	1.14	2.21	3.15	0.92	1.99	2.93
11-Dec	0.12	1.25	2.41	3.18	1.12	2.29	3.05
12-Dec	0.17	1.34	2.30	3.43	1.16	2.12	3.25
13-Dec	0.14	1.31	2.50	3.40	1.17	2.35	3.26
14-Dec	0.11	1.20	2.72	3.71	1.089	2.61	3.59
15-Dec	0.11	1.47	2.24	3.25	1.36	2.13	3.13
16-Dec	0.12	1.28	2.10	3.06	1.15	1.97	2.93
17-Dec	0.12	1.22	2.08	2.76	1.095	1.95	2.63
18-Dec	0.10	0.94	1.65	2.35	0.839	1.55	2.24
19-Dec	0.34	1.29	2.12	2.82	0.95	1.78	2.48
20-Dec	0.16	1.69	2.89	4.35	1.52	2.73	4.18
21-Dec	0.13	1.56	1.66	2.77	1.43	1.53	2.64

Table A-10. 99.7th Percentile Coverage for 15-Second Load and Load Net PV Negative Variability and Increase in Variability.

Date	-99.7th Percentile for Load and Load Net PV Variability in MW				Increase in Variability		
	Base	Scenario 1	Scenario 2	Scenario 3	Scenario 1	Scenario 2	Scenario 3
1-Dec	-0.11	-1.21	-1.54	-2.40	-1.111	-1.44	-2.29
2-Dec	-0.099	-1.26	-1.60	-2.61	-1.166	-1.50	-2.51
3-Dec	-0.14	-1.12	-1.85	-2.52	-0.97	-1.70	-2.38
4-Dec	-0.078	-0.94	-1.73	-2.27	-0.86	-1.65	-2.19
5-Dec	-0.095	-1.36	-1.87	-2.60	-1.26	-1.77	-2.50
6-Dec	-0.11	-1.66	-2.61	-3.88	-1.54	-2.49	-3.77
7-Dec	-0.11	-1.23	-1.67	-2.46	-1.11	-1.55	-2.34
8-Dec	-0.099	-1.65	-2.70	-3.87	-1.55	-2.60	-3.77
9-Dec	-0.077	-1.40	-2.56	-3.69	-1.32	-2.48	-3.61
10-Dec	-0.13	-1.16	-2.26	-3.53	-1.02	-2.13	-3.39
11-Dec	-0.088	-1.41	-2.13	-3.01	-1.32	-2.05	-2.92
12-Dec	-0.10	-1.21	-1.96	-2.70	-1.11	-1.86	-2.59
13-Dec	-0.097	-1.42	-2.71	-3.42	-1.33	-2.61	-3.32
14-Dec	-0.155	-1.15	-2.51	-3.46	-0.99	-2.36	-3.31
15-Dec	-0.09	-1.35	-2.28	-3.12	-1.26	-2.19	-3.03
16-Dec	-0.149	-1.44	-2.12	-3.009	-1.29	-1.97	-2.85
17-Dec	-0.11	-1.15	-1.89	-2.54	-1.04	-1.78	-2.43
18-Dec	-0.09	-1.14	-1.45	-2.06	-1.04	-1.35	-1.96
19-Dec	-0.29	-1.26	-2.36	-3.01	-0.96	-2.07	-2.72
20-Dec	-0.088	-1.66	-2.84	-4.13	-1.57	-2.76	-4.04
21-Dec	-0.11	-1.44	-1.59	-2.66	-1.33	-1.48	-2.55

A.7 Monthly Analysis Summary

Table A-11. Monthly Total Energy Summary.

Month	System Monthly Production in MWh				PV Production in MWh		
	Base	Scenario 1	Scenario 2	Scenario 3	Scenario 1	Scenario 2	Scenario 3
Jan	37,215.790	36,759.653	36,241.421	35,728.109	456.138	974.369	1,487.681
Feb	31,506.465	30,971.394	30,454.197	29,878.582	535.071	1,052.269	1,627.884
Mar	36,036.237	35,358.894	34,850.599	34,590.221	677.343	1,185.638	1,446.015
Apr	35,103.742	34,309.011	33,588.861	32,781.242	794.732	1,514.882	2,322.500
May	38,396.589	37,498.773	36,634.492	35,749.929	897.816	1,762.097	2,646.660
Jun	38,285.907	37,437.039	36,675.217	35,815.566	848.869	1,610.691	2,470.341
Jul	40,638.065	39,750.473	38,924.186	38,016.782	887.592	1,713.879	2,621.283
Aug	42,117.326	41,223.277	40,449.078	39,557.389	894.049	1,668.248	2,559.938
Sep	39,580.973	38,837.221	38,181.586	37,411.057	743.752	1,399.387	2,169.916
Oct	39,626.610	38,948.988	38,351.878	37,673.249	677.622	1,274.732	1,953.361
Nov	37,802.559	37,270.071	36,755.088	36,205.135	532.488	1,047.471	1,597.424
Dec	38,127.714	37,577.254	37,073.498	36,523.640	550.460	1,054.216	1,604.074
Annual	**454,437.978**	**445,942.048**	**438,180.101**	**429,930.901**	**8,495.930**	**16,257.877**	**24,507.077**
					1.87%	**3.58%**	**5.39%**

Table A-12. Correlation of January Hourly Data (7 a.m.–6 p.m.) for Selected Scenario Sites.

	Site 1	Site 2	Site 3	Site 4	Site5	Site 6	Site 7
Site 1	1.000						
Site 2	0.579	1.000					
Site 3	0.641	0.800	1.000				
Site 4	0.484	0.755	0.787	1.000			
Site 5	0.605	0.712	0.769	0.746	1.000		
Site 6	0.580	0.706	0.812	0.721	0.747	1.000	
Site 7	0.587	0.693	0.768	0.769	0.726	0.797	1.000

Table A-13. Correlation of February Hourly Data (7 a.m.–6 p.m.) for Selected Scenario Sites.

	Site 1	**Site 2**	**Site 3**	**Site 4**	**Site5**	**Site 6**	**Site 7**
Site 1	1.000						
Site 2	0.742	1.000					
Site 3	0.747	0.895	1.000				
Site 4	0.672	0.741	0.844	1.000			
Site 5	0.707	0.668	0.691	0.623	1.000		
Site 6	0.661	0.702	0.750	0.641	0.787	1.000	
Site 7	0.690	0.715	0.743	0.624	0.757	0.806	1.000

Table A-14. Correlation of March Hourly Data (7 a.m.–6 p.m.) for Selected Scenario Sites.

	Site 1	**Site 2**	**Site 3**	**Site 4**	**Site5**	**Site 6**	**Site 7**
Site 1	1.000						
Site 2	0.758	1.000					
Site 3	0.681	0.793	1.000				
Site 4	0.567	0.639	0.671	1.000			
Site 5	0.602	0.714	0.605	0.458	1.000		
Site 6	0.669	0.734	0.605	0.553	0.734	1.000	
Site 7	0.533	0.599	0.544	0.488	0.601	0.686	1.000

Table A-15. Correlation of April Hourly Data (7 a.m.–6 p.m.) for Selected Scenario Sites.

	Site 1	**Site 2**	**Site 3**	**Site 4**	**Site5**	**Site 6**	**Site 7**
Site 1	1.000						
Site 2	0.779	1.000					
Site 3	0.751	0.816	1.000				
Site 4	0.611	0.715	0.730	1.000			
Site 5	0.696	0.718	0.677	0.644	1.000		
Site 6	0.743	0.824	0.808	0.669	0.728	1.000	
Site 7	0.669	0.738	0.749	0.745	0.668	0.737	1.000

Table A-16. Correlation of May Hourly Data (7 a.m.–6 p.m.) for Selected Scenario Sites.

	Site 1	Site 2	Site 3	Site 4	Site5	Site 6	Site 7
Site 1	1.000						
Site 2	0.876	1.000					
Site 3	0.815	0.851	1.000				
Site 4	0.813	0.824	0.805	1.000			
Site 5	0.758	0.743	0.760	0.708	1.000		
Site 6	0.802	0.798	0.775	0.765	0.725	1.000	
Site 7	0.762	0.800	0.811	0.742	0.743	0.750	1.000

Table A-17. Correlation of June Hourly Data (7 a.m.–6 p.m.) for Selected Scenario Sites.

	Site 1	Site 2	Site 3	Site 4	Site5	Site 6	Site 7
Site 1	1.000						
Site 2	0.793	1.000					
Site 3	0.801	0.812	1.000				
Site 4	0.640	0.701	0.684	1.000			
Site 5	0.782	0.786	0.790	0.688	1.000		
Site 6	0.793	0.814	0.801	0.660	0.798	1.000	
Site 7	0.727	0.747	0.763	0.597	0.752	0.791	1.000

Table A-18. Correlation of July Hourly Data (7 a.m.–6 p.m.) for Selected Scenario Sites.

	Site 1	Site 2	Site 3	Site 4	Site5	Site 6	Site 7
Site 1	1.000						
Site 2	0.843	1.000					
Site 3	0.791	0.890	1.000				
Site 4	0.717	0.776	0.791	1.000			
Site 5	0.837	0.897	0.855	0.775	1.000		
Site 6	0.792	0.846	0.842	0.774	0.871	1.000	
Site 7	0.809	0.867	0.846	0.781	0.878	0.869	1.000

Table A-19. Correlation of August Hourly Data (7 a.m.–6 p.m.) for Selected Scenario Sites.

	Site 1	Site 2	Site 3	Site 4	Site5	Site 6	Site 7
Site 1	1.000						
Site 2	0.873	1.000					
Site 3	0.854	0.881	1.000				
Site 4	0.692	0.693	0.735	1.000			
Site 5	0.849	0.828	0.805	0.670	1.000		
Site 6	0.830	0.813	0.803	0.700	0.853	1.000	
Site 7	0.853	0.853	0.839	0.710	0.830	0.830	1.000

Table A-20. Correlation of September Hourly Data (7 a.m.–6 p.m.) for Selected Scenario Sites.

	Site 1	Site 2	Site 3	Site 4	Site5	Site 6	Site 7
Site 1	1.000						
Site 2	0.774	1.000					
Site 3	0.749	0.825	1.000				
Site 4	0.521	0.595	0.656	1.000			
Site 5	0.757	0.761	0.793	0.561	1.000		
Site 6	0.761	0.780	0.793	0.589	0.830	1.000	
Site 7	0.730	0.781	0.820	0.635	0.773	0.832	1.000

Table A-21. Correlation of October Hourly Data (7 a.m.–6 p.m.) for Selected Scenario Sites.

	Site 1	Site 2	Site 3	Site 4	Site5	Site 6	Site 7
Site 1	1.000						
Site 2	0.725	1.000					
Site 3	0.755	0.810	1.000				
Site 4	0.676	0.669	0.756	1.000			
Site 5	0.680	0.775	0.769	0.655	1.000		
Site 6	0.686	0.788	0.817	0.706	0.839	1.000	
Site 7	0.689	0.735	0.772	0.628	0.721	0.808	1.000

Table A-22. Correlation of November Hourly Data (7 a.m.–6 p.m.) for Selected Scenario Sites.

	Site 1	Site 2	Site 3	Site 4	Site5	Site 6	Site 7
Site 1	1.000						
Site 2	0.766	1.000					
Site 3	0.693	0.821	1.000				
Site 4	0.670	0.715	0.696	1.000			
Site 5	0.657	0.691	0.712	0.670	1.000		
Site 6	0.696	0.730	0.726	0.706	0.780	1.000	
Site 7	0.714	0.760	0.801	0.757	0.828	0.880	1.000

Table A-23. Correlation of December Hourly Data (7 a.m.–6 p.m.) for Selected Scenario Sites.

	Site 1	Site 2	Site 3	Site 4	Site5	Site 6	Site 7
Site 1	1.000						
Site 2	0.887	1.000					
Site 3	0.851	0.902	1.000				
Site 4	0.787	0.808	0.794	1.000			
Site 5	0.679	0.658	0.627	0.649	1.000		
Site 6	0.718	0.782	0.745	0.735	0.717	1.000	
Site 7	0.765	0.811	0.771	0.804	0.673	0.841	1.000

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Attn: Tom Key
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3 HECO
Attn: Leon Roose
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Honolulu, HI 96814

2 KIUC
Attn: Mike Yamane
John Cox
4463 Pahe's Street, Suite 1
Lihue, HI 96766-2000

1 New Mexico State University
Attn: Dr. Satish Ranade
Klipsh School of ECE, Box 3001, Dept. 3-O
Las Cruces, NM 88003

1 New Mexico State University
Attn: Andrew L. Rosenthal
Box 30001/Dept. 3SOL
Las Cruces, NM 88003-8001

1 NRECA Cooperative Research Network
Attn: Edward Torrero
301 Wilson Boulevard, SS9-204
Arlington, VA 22203-1860

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Attn: Paul C. Butler *(paper)*
3090 Defense Pentagon
Washington, DC 20301-3090

8 U.S. Department of Energy
Attn: Dr. Samuel F. Baldwin
Gil Bindewald
Tien Q. Duong
Richard J. King
Eric M. Lightner
Philip N. Overholt
Neil P. Rossmeissl
Dan T. Ton 1000 Independence Avenue SW
Washington, DC 20585-0121

1 U.S. Department of Energy
Attn: Dr. Imre Gyuk
OE-10/FORS
1000 Independence Ave. SW
Washington, DC 20585-0270

1 U.S. Department of Energy
Attn: William Parks
MS OE-1
1000 Independence Ave. SW
Washington, DC 20585-0270

1 U.S. Department of Energy
Attn: Steven Lindenberg
MS EE-20
1000 Independence Ave. SW
Washington, DC 20585-0270

1 U.S. Department of Energy - Albuquerque Operations Office
Attn: Dan Sanchez
Kirtland Air Force Base
Pennsylvania & H Street
Albuquerque, NM 87185

1 U.S. Department of Energy, Solar Systems Integration
Attn: Kevin Lynn
Alvin Razon
Solar Energy Technology Program
950 L'Enfant Plaza Washington, DC 20585

1 University of Hawaii
Attn: Dr. Bor Yann Liaw
1680 East West Road, Post 112A
Honolulu, HI 96822

1 UWIG
Attn: Charles Smith
Utility Wind Integration Group
PO Box 2787
Reston, Virginia 20195 USA

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