2011

High Penetration PV Initiative

Base Line Modeling Report

Consultant Report

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BEW Engineering

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INTEGRATION OF RENEWABLE AND DISTRIBUTED ENERGY RESOURCES

HIGH PENETRATION PV INITIATIVE
Report on: Base Line Modeling on Sacramento Municipal Utilities District and Hawaiian Electric Companies Systems

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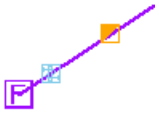
Table of Contents

Glossary of Terms 3
Introduction and Background 4
Locating of Monitors and Sensors 4
Base Line Modeling 5
1.1 Data Collection, Evaluation and Model Validation 6
Distribution Modeling and Analysis Process 7
1.1.1 Accounting for Load Displaced by Existing PV 9
1.1.2 Inverter Modeling in SynerGEE Electric for Fault Current Analysis 10
Analysis of Monitored PV Data 12
1.2 AC Smart Homes PV data 12
1.3 CT PV Data 14
1.4 Analysis of Monitored PV Data in the WA 3 Area 17
Analysis of Representative Demand Profiles 22
1.5 Introduction and Load Profiles for SMUD 25
1.5.1 SMUD Substation 1: CT 25
1.5.2 SMUD Substation 2: AC 26
1.5.3 SMUD Substation 3: EG Substation 30
1.5.4 SMUD Substation 4: L7 (69 kV) 32
1.5.5 SMUD Substation 5: EB 34
1.5.6 SMUD Substation 6: RF 35
1.6 Introduction of Load Profiles for HECO, MECO and HELCO 37
1.6.1 HECO Feeder: W1 3 38
1.6.2 HELCO: ML Substation 39
Conclusion 41
APPENDIX A 42

Glossary of Terms

TOOL: Any computational or software package that enables analysis
MODEL: A representation of an individual element that exists in a system
DATASET: A representation of a system which is composed of all the models existing in the system
DATA: Input variables to models or datasets
FEEDER: A distribution level circuit (e.g. 4kV, 12kV)
LINE: A transmission or sub-transmission level circuit (e.g. 138kV, 46kV)
NODE: A geographical or physical point joining one or more sections on a line or feeder where an element can be attached
SEGMENT: Section of a line or feeder connecting two nodes
GRID: The representation of all generation, lines and/or feeders supplying power to customers
MODELING: The process of developing one or more models
SIMULATING: The use of one or more tools to study the behavior of a model or dataset
SWING BUS: A swing bus can also be referred to as a slack bus. It is an element that must be defined in a power flow model as an infinite source or substation provided power. The Swing bus is often paired with a generator used to compute the power flow solution.
SPINNING RESERVES: The on-line reserve capacity that is ready to meet electric demand within a set amount of time of a dispatch by an electrical system operator

SynerGEE Model Key

	Fuse
	Transformer
	Open Switch
	Closed Switch
	Capacitor
	**Start of a Feeder + Breaker + Meter**
	Breaker

∅	**Recloser**
	Large Customer/Distributed Generator Model
Ⓖ	**Synchronous Generator Model**

Introduction and Background

The High PV Penetration Project (HIPV), implemented in June 2010, addresses common issues between the Sacramento Municipal Utility District (SMUD) and the Hawaiian Electric Utility (HECO). Both utilities adopted aggressive renewable energy targets with SMUD targeting 37% by 2020 and HECO targeting 40% by 2020 for the three Hawaiian utilities.

The three electric Hawaiian utilities are Hawaii Electric Company, Inc. (HECO), Maui Electric Company, Ltd. (MECO), and Hawaii Electric Light Company, Inc. (HELCO). The primary energy source (90%) in Hawaii is imported crude oil.

The Sacramento Municipal Utility District (SMUD) is the sixth largest publicly owned utility in the USA. The SMUD service area is over 900 square miles with over 578,000 residential, commercial and industrial customers. The record peak power demand is 3,299 MW recorded on July 24, 2006.

The three year project focuses on the potential impacts from high penetrations of distributed PV resources on distribution feeders located within the SMUD and HECO grids. This report summarizes the baseline modeling assumptions.

Locating of Monitors and Sensors

Historically, electric utility distribution planners were not too concerned about installing power quality meters, solar sensors and solar monitors on distribution feeders. There was not an urgent need to validate voltages, frequency and backfeed on the feeders since the power flows were from the distribution substation to the end of the feeder. Distribution feeders are normally radial lines so as long as the voltage at the end of the line were within voltage tolerances, everything was fine. Sometimes, there may be a customer that installs a cogeneration plant to self-generate but not to export to the utility.

Distributed customer owned renewable resources and new technologies have changed the distribution planning process and operational control of the transmission/distribution grids. Availability of low cost roof mounted solar panels, subsidies from state and local agencies, emission reduction requirements and Renewable Portfolio Standard (RPS) requirements have rapidly increased the penetration of distribution generation on the feeders. As these increase in magnitude, there are more voltage, frequency, power factor, reverse power flow and protection issues that must be addressed.

Historically, distribution planners would normally set the voltage regulation point at the distribution substation bus between 122 and 125 volts so that the end of the feeder would have a voltage ranging from 115 to 122 volts. If the voltage drops too low toward the end of the feeder, then the planner would install capacitor banks or regulators, depending on the length of the feeder. If there were multiple feeders served from the same substation bus, the transformer tap changer would be set to a regulation point that provides the same voltage on all the feeders.

More information on locating monitors and sensors can be found in Appendix A.

Base Line Modeling

There are twenty-five (25) feeders studied throughout the SMUD and HECO utility systems. There are eleven in SMUD, four in HECO, four in HELCO and six in MECO. The feeders selected for detailed analysis have distinctive characteristics that make them of particular interest as described in Table 1.

Feeder	**Utility**	**Voltage**	**Location**	**Existing PV**	**Other existing DG**
A-C (3 feeders)	SMUD	12.47 kV	Residential	Yes - 0.6 MVA	No
RF (1 feeder)	SMUD	12.47	Commercial/Industrial	Yes- .976 MW	No
EB (1 feeder)	SMUD	12.47 kV	Rural	None	Dairy Digester
CT (2 feeders)	SMUD	12.47 kV	Residential/Rural	Yes – 3 MVA	No
EG (3 feeders)	SMUD	69 kV	Residential/Commercial/Rural	No	No

L7 (1 Feeder)	SMUD	69 kV	Industrial	Yes - 2 MVA	No
W1 (4 feeders)	HECO	11.5 kV	Residential/Commercial	Yes – 1 MVA	No
ML (4 feeders)	HELCO	4.16 kV	Commercial	Yes – 0.04 MVA	Yes – possibly out of service
WA (6 feeders)	MECO	13.09 kV	Residential/Commercial	Yes	No

Table 1 Feeders selected for analysis

A preliminary list of the modeling, analytical and validation steps for SMUD and HECO is shown below:

- Identify high penetration analytical requirements (load flow, characteristics of the load, protection and coordination, voltage regulation, and islanding) for the distribution feeders being analyzed.
- Identify additional data parameters to be collected and locations of data collection along the high penetration distribution feeder to place additional high-fidelity monitoring equipment, if necessary.
- Record and collect a minimum of 6 to 12 months' worth of high-fidelity load data from the newly installed high-fidelity monitoring equipment.
- Collect the following electrical equipment nameplate data from the distribution system being analyzed: distributed generation on the feeder, inverters, any energy storage, feeder size, feeder length, feeder loading, switchgear, and transformers.
- Investigate varying incremental levels of PV penetration at the distribution capacity level and iterate with an existing system level model to understand to what degree higher PV levels will adversely affect the grids.
- Validate the models against the collected high fidelity load data.
- Develop a methodology for extending the findings using the simulation tools to inform and expedite interconnections studies at higher penetration levels.

1.1 Data Collection, Evaluation and Model Validation

This task is high fidelity load data collection, evaluation and model validation. Once the load data is collected, it is translated to the PV installations on the feeder and a validation analysis must be completed. The distribution model contains the existing and projected new PV installations. Since the utilities do not meter and record sub-hourly generation

from every PV installation, PV sites are assigned solar generation patterns based on historical data that may not have been directly related to the PV locations on the feeders. When the initial feeder analysis is completed, the most recent data available at that time is used. However, when the actual monitoring results are completed, the initial feeder data set can be updated and a new study completed to validate the distribution models ability to simulate the feeder operation.

Historical SCADA and Plant Information (PI) data from HECO and SMUD service areas contain both low fidelity intervals, as well as high fidelity, currently being collected at selected locations.

Distribution Modeling and Analysis Process

The typical distribution modeling and analytical processes used by developers and utilities is limited by the lack of detailed distribution modeling. Interconnection studies often use three phase models focusing on sub-transmission and substation impacts. The distribution system is often interpreted as an equivalent load, or simple impedance model. The highest level of existing detail is normally a three-phase aggregated load flow model. Most impact studies consider capacity and baseline generation. Impact of variable high PV penetrations is not generally quantified, due to a lack of accurately measured irradiance data for the PV.

BEW is using an enhanced distribution modeling and analysis process, and comparing it to the simplistic process to determine the level of detail required in future studies. This project will accurately quantify the effect of high penetrations of PV on the distribution and sub-transmission systems. The modeling detail includes detailed inverter, and PV modeling and performance.

The analysis determines the effect of variable resources and associated weather conditions on the distribution grid as a whole. The detailed distribution impacts are transferred into the sub-transmission and transmission system models to determine system impacts from the distribution system perspective. Value is added by incorporating single phase distribution modeling impacts. The following steps develop the feeder dataset for analysis:

- Extract (GIS) or build (when GIS not available) SynerGEE model
- Collect and apply detailed equipment information
    - Transformers, switches, fuses distributed loading, capacitors, inverters, PV panels etc.

- Collect PV data for area of interest if available
- Analyze PV performance
    - Associated weather data such as pyranometers and other sources
- Model inverters
    - Future detailed SynerGEE model, or
    - Existing equivalent impedance model, and
    - PSSE dynamic inverter model, when applicable

The load flow is considered at a single point in time and over a time sequential 24 hour period. The times of day selected for single point in time analysis are detailed in Figure 1. This example does not represent the specific time of interest for all utilities, but times of load behavior of interest.

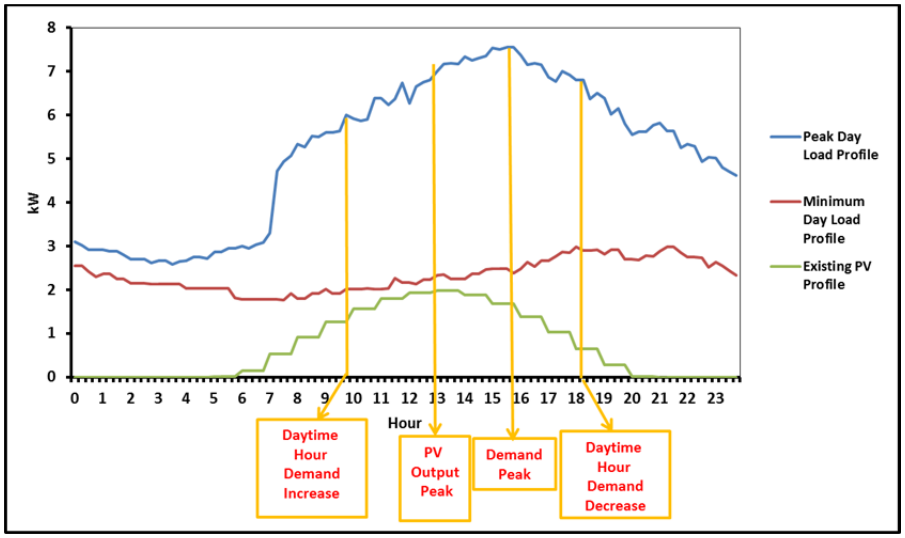


Figure 1: Times of day selected for analysis for AC

In Figure 1, looking at the Peak Day Load and Existing PV Profile, the four points of interest are (1) daytime hour when load is increasing, around 10am, (2) peak PV generation time, around 1 pm, (3) demand peak time, approximately 3 pm and (4) demand decrease in the evening, around 6pm. Each of these time periods has significant operational considerations. The minimum day load profile that is shown is informational.

During morning and evening ramp up and ramp down periods, conventional generation must increase or decrease output rapidly over time to meet demand. Increasing the distributed generation is expected to produce positive and negative impacts during these times. On the positive side, the additional generated power during daylight hours will reduce the amount by which conventional generators must ramp, the 24 hour demand curve is flattened.

Two peak times (3 and 4 above) are key focus areas for analysis, the PV peak time (around 1 pm) and the demand peak time (around 3 pm). It is expected at demand peak, there are little negative impacts to the system and the PV is a load reduction overall. This assumption is dependent on when the PV peak time occurs, and is considered on a feeder by feeder basis. If the demand peak occurs during evening or morning hours, there is possibly no negative or positive impact on operation at this time, instigated by PV. During the PV peak, issues including back-feed and voltage rise are expected. It is expected most of the steady state problems will occur at minimum load times versus maximum load times. When load is reduced voltage will increase.

Distribution lines are historically designed to move power from centralized substations to the end of long distribution feeders, the voltage drops are compensated for, either statically or dynamically, using tap changers. When PV generation is added on these feeders, active power is injected, usually not reactive. If a large PV unit is located somewhere along the length of the feeder and reverses the power flows on the line, an increase voltage occurs when power flows in the other direction.

1.1.1 Accounting for Load Displaced by Existing PV

The SCADA and Operations Measurement Systems (OPS) measure net demand at each substation and sub-transmission breaker. With approximately 2,000 existing residential and commercial PV units on the island of Oahu that are connected at the distribution feeder level, the demand allocation accounts for the PV displaced load at each location. Figure 2 depicts the SynerGEE Electric modeling.

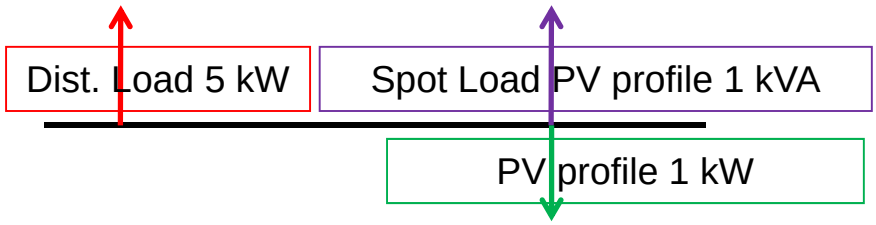


Figure 2: Explaining the addition of spot loads to account for displaced PV

In Figure 2, there is a 5 kW distributed load existing on the section in red. This distributed load is allocated based on SCADA numbers and therefore does not account for displaced load from PV. If for example, one (1) kVA of PV is located on the same section, a spot load (or load in a specific location, rather than distributed) equal to the PV size is added at the PV location. Effectively, this generation and load addition cancels out and the loading is the distributed load. However, in the case of analyzing the loss of

the entire 1 kVA of PV due to cloud coverage for example, the distribution load increases by 1 kW (assuming PV power factor of 100%). PV generating resources are added using measured profiles to simulate the peak day (Figure 3).

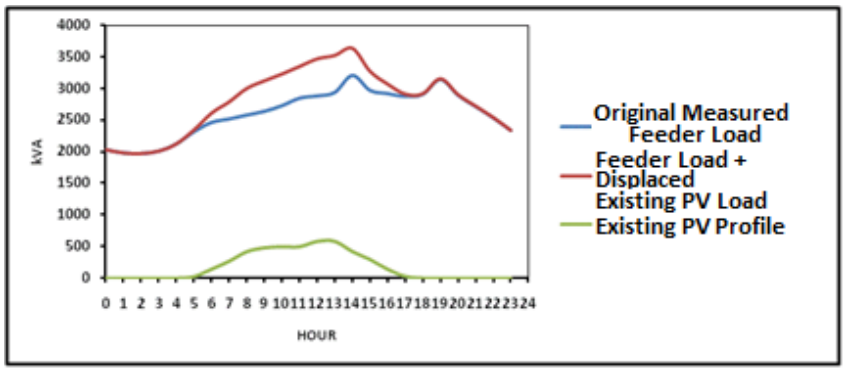


Figure 3: Example Feeder Load profile, with load displaced by PV added as spot loads

The process for adding load displaced by PV into an example feeder profile, results in a new demand peak at approximately 2 pm; shifted from the original feeder peak time of 7pm. The original late peak occurs when there is no PV offset to demand, as irradiance is very low during that evening period. By adding the projected displaced load that is served by PV resources, the revised feeder load profile shifts the peak load period to approximately midday.

1.1.2 Inverter Modeling in SynerGEE Electric for Fault Current Analysis

Each inverter has a pre-determined fault current contribution to the example feeder. Currently, there are no detailed inverter representations in SynerGEE Electric. Future versions of SynerGEE Electric are expected to include these advanced features. There are inverter specific characteristics used to calculate a fault current contribution from a specific inverter type. Specifications from the inverter data sheet of current and voltage ratings, allow the fault current to be calculated. The fault current is calculated using the following process.

Inverter information is collected for each existing PV installation on the feeders of interest and PV inverter datasheets are used to extract pertinent characteristics. Some examples of inverters installed on the feeders of interest include Solectria PVI 95, Xantrex GT250 and SMA Sunny Boy 7000.

The equivalent impedance inverter model in SynerGEE Electric, depicted in Figure 4 below, is constructed of a transformer (can be substituted for an equivalent generator model), an additional feeder simulating the low voltage side and contribution from this side of the inverter, and a large customer distributed generator. The transformer impedance is used to scale the high side contribution of fault current to the calculated size of the inverter. When the equivalent inverter model is connected to the feeder, by closing the open point, the contribution is now added to the main trunk current.

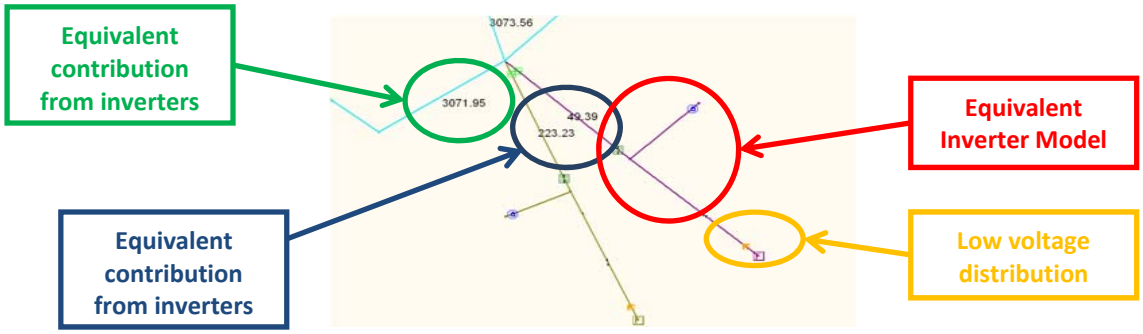


Figure 4: Equivalent Model of Inverter in SynerGEE

While the equivalent model is not specific to the inverter type, there are certain inverter characteristics that are common to calculate a fault current contribution from each inverter type. The expected fault current contribution of an inverter is calculated using data from the inverter spec sheet (i.e. rated power, nominal current rating, and maximum current rating) and the interconnection voltage. The current is calculated as follows:

$$I_{fault} = \frac{P_{inv} \cdot n_{inv} \cdot \alpha}{V_{conn}\sqrt{3}} \qquad (1)$$

Where

P_{inv}	is the rated power of a single inverter at a PV site in kW
n_{inv}	is the number of inverters at the PV site
α	is the ratio of maximum current rating to nominal current rating
A	is the area of the PV array in m^2
V_{conn}	is the interconnected line-to-line voltage

The output from Equation (1) for each inverter is a pre-determined fault current contribution, for which the model presented in Figure 4 is altered to represent.

Analysis of Monitored PV Data

To model the PV generation realistically, measured solar irradiance data is used to create generation profiles for PV units installed in the SMUD and HECO regions. Within SMUD there are two sensor types considered. Within HECO territory, there are a number of sensors installed.

In the SMUD AC feeder area, NREL installed a system within the substation to monitor and collect solar irradiance and ambient air temperature data. Data can be exported or plotted on-line for more accurately estimating PV generation. The second monitored existing PV location in the SMUD area is on the CT feeder. The existing PV installation is located in the RS area. The data monitored at this site is not overall irradiance, but actual kW output. Irradiance data is preferred, as the age and condition of the existing PV generation does not influence the irradiance, but does influence the kW output.

Finally in the HECO area, specifically on Oahu, there is a network of irradiance sensors. While there are not PV sensors located directly on WA 3, the feeder of interest on Oahu, the surrounding sensors can act as a proxy for this. The method to analyze each of the three locations is detailed in the following sections.

1.2 AC Smart Homes PV data

In SMUD, the solar monitoring system is approximately 2 miles northwest from the AC Solar Smart Homes and serves as a good representation of solar behavior in this community in Figure 5.

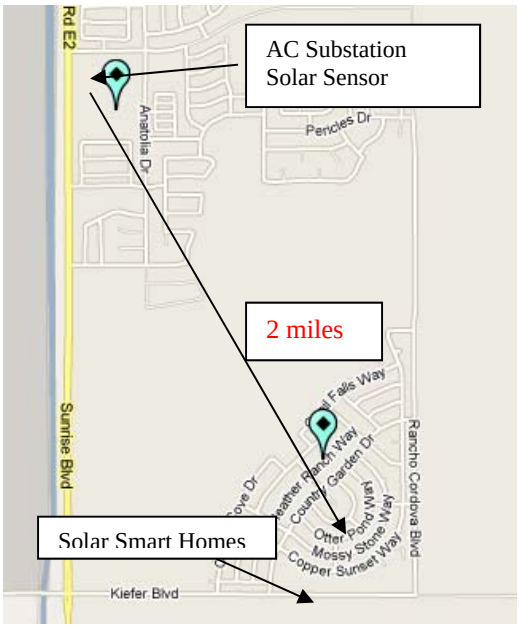


Figure 5: AC Sensor Location

The AC PV raw irradiance data obtained from NREL creates a profile for AC existing and potential PV with a resolution of one minute in Figure 6. July 15, 2009 is plotted in Figure 6 and is considered a good irradiance data profile since it follows the typical (bell curve) solar profile for a non-cloudy day. July 15th is the peak load profile day. The variation in irradiance at 9 am could be caused some type of atmospheric condition that can be only confirmed with detailed weather data which is not available for AC.

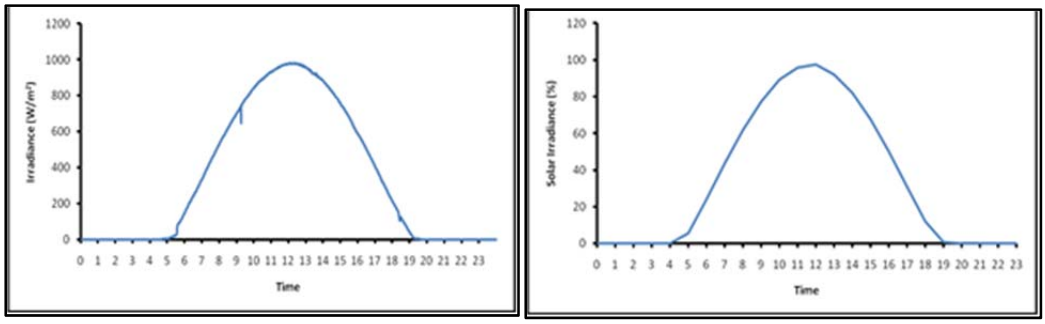


Figure 6: One Minute Solar Irradiance Data **Hourly Solar Irradiance Data for AC**

The one minute resolution data is aggregated to 1-hour format in SynerGEE for the time sequential simulation study in Figure 6. Solar irradiance is defined as "the amount of solar energy that arrives at a specific area of a surface during a specific time interval". Each PV generator is modeled with the same hourly profile from AC irradiance measurements in Figure 6 that shows the PV peak generation occurring at 1 pm on July 15, 2009.

1.3 CT PV Data

BEW developed power generation profiles for five PV generators installed at the SMUD RS property in Table 2. RS is the name of a subdivision connected to the CT 1 and is also the name of a SMUD property where a decommissioned nuclear power plant is located along with six large PV installations that are connected to the same feeder. Collectively, the PV installations at the SMUD RS property have over 3 MW of generating capacity, and compose the majority of PV generation on the CT 1 feeder.

#	Description	Power Rating (kVA)	PF (%)
1	RS PV1	1000	100
2	RS PV2	909	100
3	RS PV3&4	301	100
4	RS PV5	733	100
5	RS PV6	115	100
6	Other Distributed Generator	5	100
7	Other Distributed Generator	12	100
8	Other Distributed Generator	2	100
9	Other Distributed Generator	4	100

Table 2: Existing PV Customers on CT

The generator profiles shown in Figure 7 and Figure 8 depict actual generation profiles for the RS PV units for a typical summer day (August 1, 2009). The 15-minute profiles in Figure 7 are converted to hourly profiles (for this analysis). Each RS PV generator in Table 2 is modeled with its respective hourly profile from this data is not from the same day as the load data, but is the closest day for which all RS generators have complete power output data sets – August 1st.

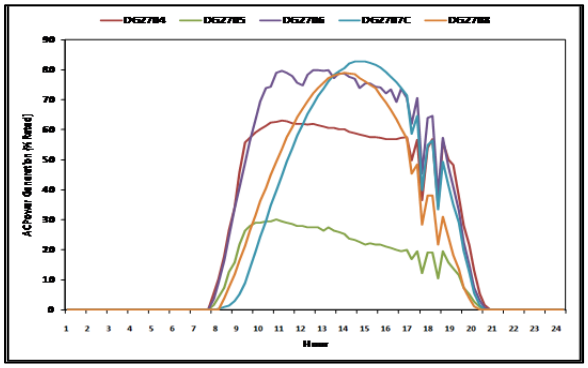


Figure 7: RS 15-Minute Generation Profiles

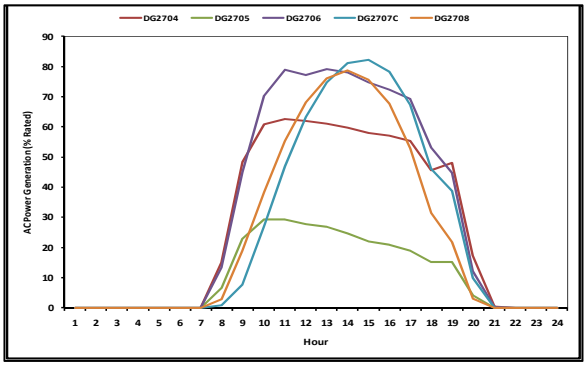


Figure 8: RS Hourly Generation Profiles

In addition to the PV generation at RS, there are four smaller PV generators located on C191201 (generators 6-9 in Table 2). Unlike the PV Systems at RS, historical power output data for these PV generators is not available. The RS power output profiles are not used for these additional four PV generators because the RS profiles contain idiosyncratic behavior specific to the different RS PV installations. Instead, the hourly profile for each additional generator is the irradiance measurements from AC (Figure 9) for the same day as the RS measurements. The AC irradiance sensor is roughly 15 miles away from CT and serves as a good representation of solar behavior. The power generation from these additional four PV generators is collectively much smaller than that of RS, so the lack of actual power output profiles is not crucial.

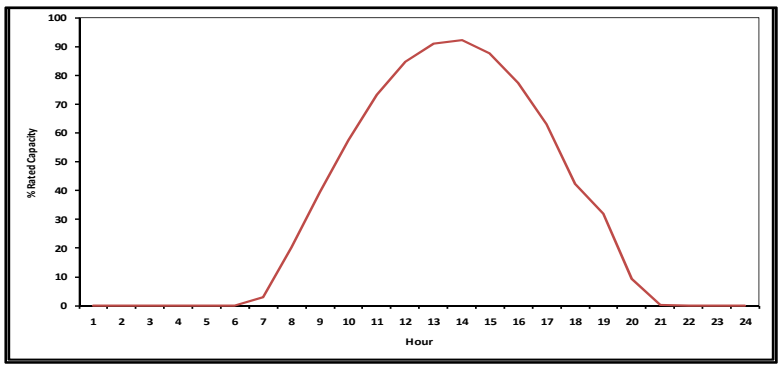


Figure 9: AC Hourly Irradiance Profile for 8/1/2009

A twenty-four hour load and PV profile is added as customer zones to SynerGEE and applied to CT 1 and 2. Each PV location profile is applied as a customer class/zone (Figure 10). Three different profiles can be applied to each month of the year. The three default day profile types are peak day, weekday, and weekend day. The two profile types are the peak day and minimum day (applied to the weekend day type).

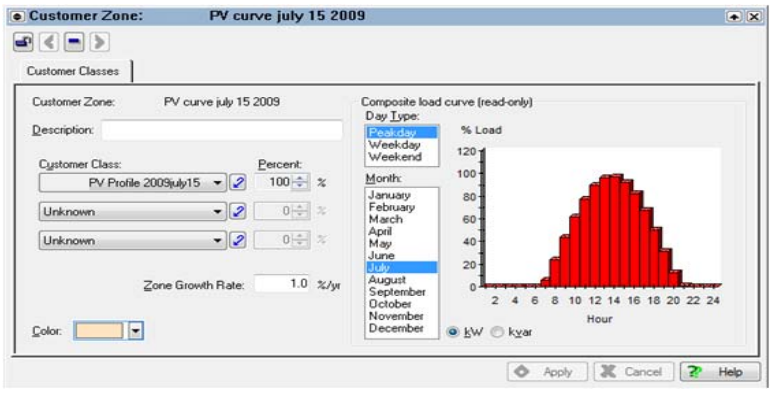
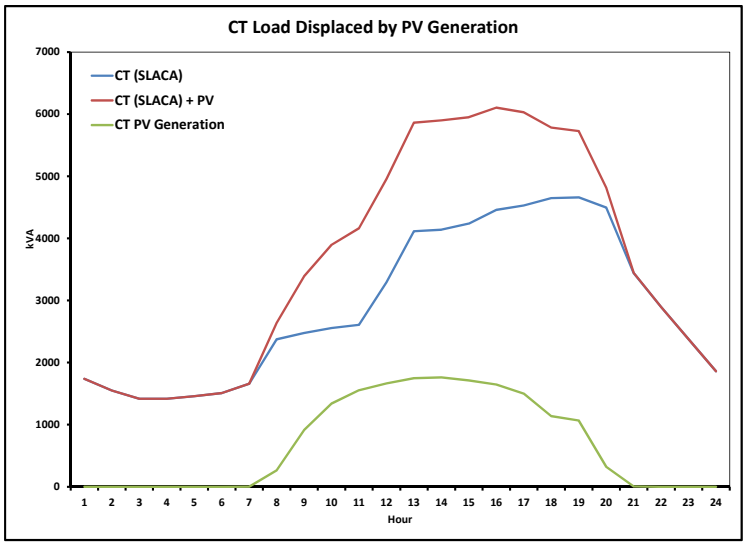


Figure 10: Hourly PV Customer Zone

PV generators are added to the SynerGEE model as a Large Customer with a constant PQ generator model. This means that the real and reactive powers generated by the PV do not change with voltage. The PV profile for the RS generators is applied as Scheduled Generation with Rated kVA reflected in Table 2. The total existing PV on CT is approximately 3,080 kVA. The power factor of each generator is set to its inverter specifications. Distributed feeder load is allocated as balanced, based on connected kVA. Sections of the model that have distributed load have a value of connected kVA. The fraction of the total demand (as measured by SCADA at the substation) allocated to a section is the fraction of that section's connected kVA to total connected kVA on the feeder.

The CT demand profile reflects total load minus PV generation at the substation. Since the demand profile includes the existing PV generation serving part of the load, it is not a true representation of the actual feeder load. Additional Spot Loads are added along with the PV Large Customers so that the PV generation is not counted twice in simulation. Each Spot Load is equal to the PV Large Customer and is added at the same section. Figure 11 below shows how the demand profile of the feeder changes when the additional Spot Loads are added.



Figu SLCA + PV **Displaced by PV Generation**

Figure 11 shows that the observed afternoon supra-peak of the demand shifts from 6pm (without additional Spot Loads, the blue plot) to approximately 3pm (with additional Spot Loads, the red plot). The high midda PV nand of the red plot (the true feeder demand) is supplied by the PV generation (green plot), and thus the peak demand observed by SCADA shifts to 6pm.

1.4 Analysis of Monitored PV Data in the WA 3 Area

For HECO, the impacts of high PV penetrations on WA 3 are quantified using PV data from actual locations across Oahu. Two sensors are operational on the W1 feeder, one at the north end and one at the south end. There are other sensors operational in Oahu with the most comprehensive being 17 “Oahu Grid” sensors located southwest of the feeder at the Barbers Point Naval Air Station (Figure 12). As no PV sensor is available in the exact WA area, we use the range of sensors on the island as a proxy for this area.

Figure 12: Oahu Map Showing Sensor Locations

When modeling PV generation from historical data, the analysis must consider multiple irradiance sensors distributed evenly across the geographic region containing the PV generation. A single sensor represents only a small point in space. It can exhibit much more frequent and dramatic changes in solar irradiance than a much larger PV module or array. Thus it is important to have a dispersion of sensors so that the average of the sensor set filters out the high frequency components and presumably approaches a more realistic PV generation profile. Figure 13 shows the averaging effect with the two sensors located on the W1 feeder. All sensor output raw data is 1-second time step, but shown here as averaged to a 5-minute time step. When compared to the individual sensors outputs, the average exhibits reduced peaks and valleys, but has similar frequent output swings. Blue line is the W1 sensor 1; Green line is W1 sensor 2; and Black line is average.

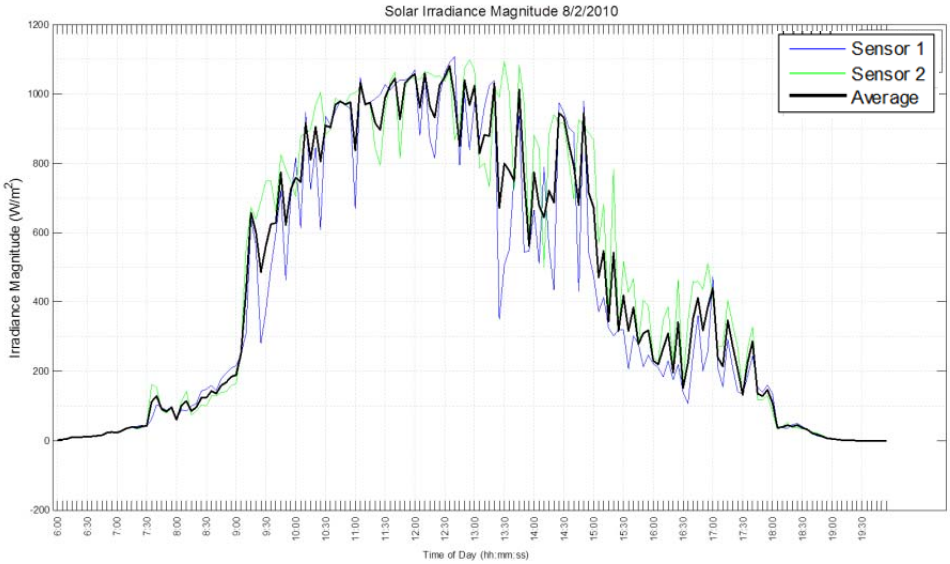


Figure 13: Example of W1 Irradiance Daily Output

Figure 14 shows the ramping, or change in irradiance for the same timestamp as the irradiance output, the magnitude of change in irradiance is significantly reduced when averaged.

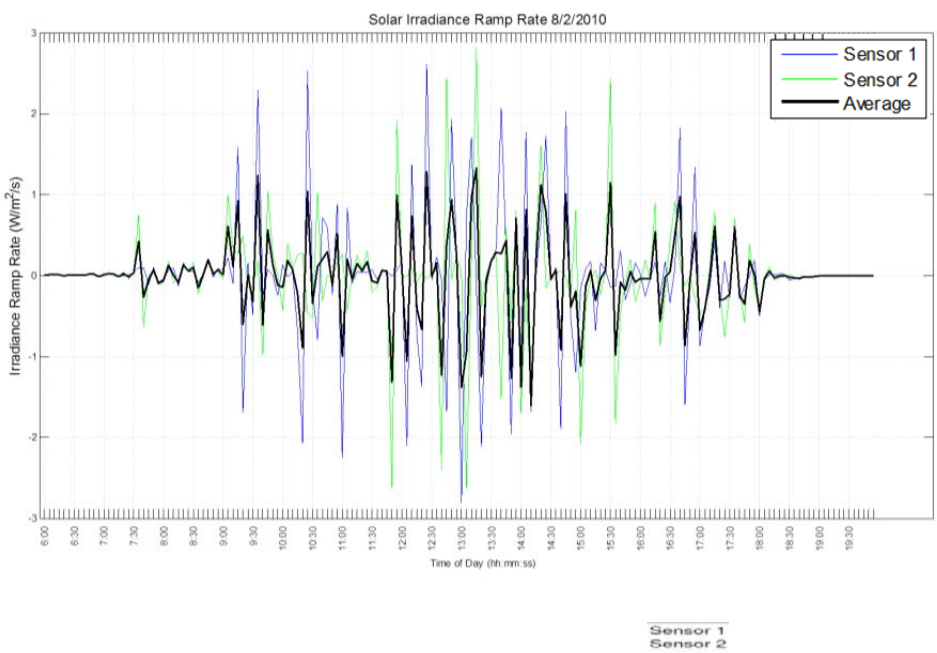


Figure 14: Example of Waiawa 1 Irradiance Ramping

These examples show a smoothing of the generation profile with only two point-size sensors. Increased smoothing is expected with an increased number of sensors, and the ultimate smoothness of the profile in the model can have significant impact on system performance in terms of controllable generation dispatching and ramping abilities. The irradiance data is updated every day. The data is imported into Matlab for automated plotting and computational analysis (e.g. use of many different statistical programs).

Observations and analysis are not conclusive but in the future will conclude if and how the Oahu Grid sensors can be combined with the feeder sensors to model PV generation. Two plots are shown (Figures 15 and 16), one of irradiance magnitude, and the other of irradiance ramp rate that contain data from the 17 Oahu grid sensors depicted in Figure 17.

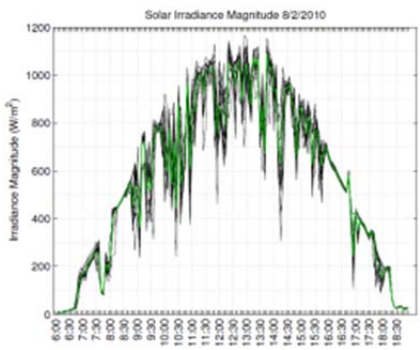


Figure 15: Example of All Oahu Grid Output

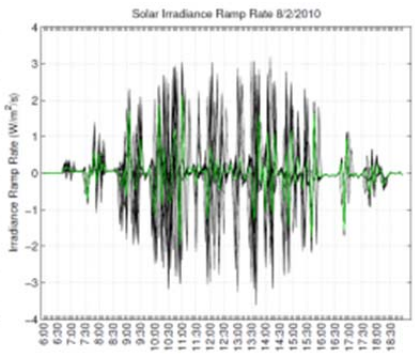


Figure 16: Example of All Oahu Grid Ramping

The effectiveness of averaging output is shown by combining different numbers of sensors on the Oahu Grid. In an effort to extrapolate the data from each pin-point sensor, and find an appropriate averaging technique to cover the entire land area in which sensors are located, the four outermost corner sensors are taken into consideration in the following analysis. These sensors are depicted below in Figure 17 in the smaller window with yellow flags. The underlying assumption necessary for this analysis is that each sensor must carry equal influence on the average.

Figure17: Map of Oahu Sensors with Distances, Selecting the Four Outer Corners

The data from these four sensors are graphed and analyzed in the same fashion as before to find appropriate averages in both the raw irradiance data and ramping rates (Figures 18 and 19).

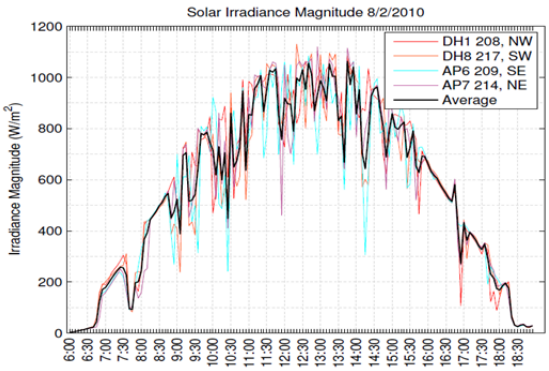


Figure 18: Example of 4 Corners of Oahu Grid Output

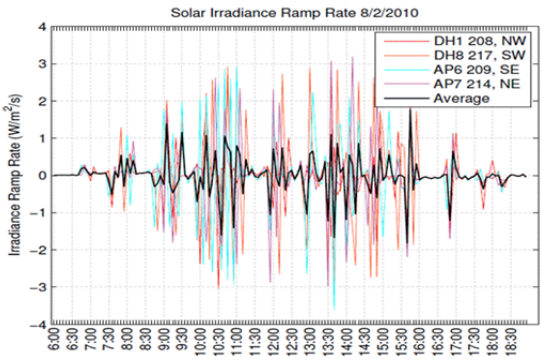
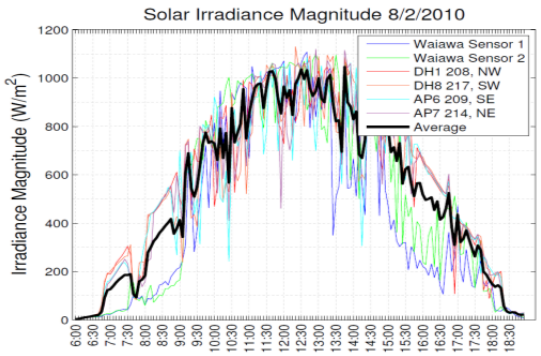


Figure 19: Example of 4 Corners of Oahu Grid Ramping

The next step combines the previous four corner locations with the data from W1 sensors 1 and 2 to determine if accurate averages can be found to cover the entire land area contained within these sensors. These sensors are depicted previously in Figure 20 in the large image with red lines drawn between the six sensors. Again, both irradiance and ramping rate are graphed.



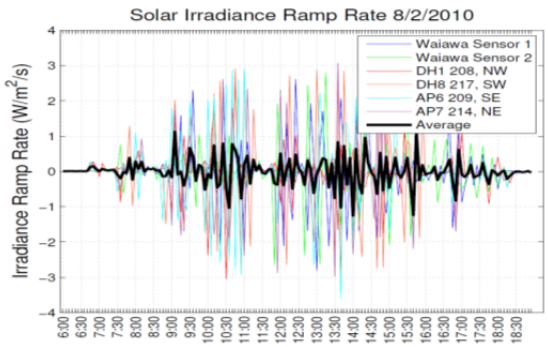


Figure 20A: Feeder and 4 Oahu Grid Sensors Output **Figure 20B: Feeder and 4 Oahu Grid Sensors Ramping**

Preliminary observations are made on the number of sensors to combine to accurately quantify PV ramping and cloud cover effects. Comparing Figure 20A to Figure 18 indicates the 4 corner sensors produce similar averages as all 17 sensors.

The Oahu Grid sensors are more correlated with each other than the W1 sensors 1 and 2 correlations. This is largely because the Oahu Grid sensors are closer to one another. When comparing the W1 and four corner sensor data in Figure 17, it is apparent that the cloud cover can be distinctly different between the two regions. Further work will be completed in this PV analysis section to make more accurate assessments and averaging techniques.

The hourly average plot is input to SynerGEE as a customer class, and used to model the generator outputs (Figure 21).

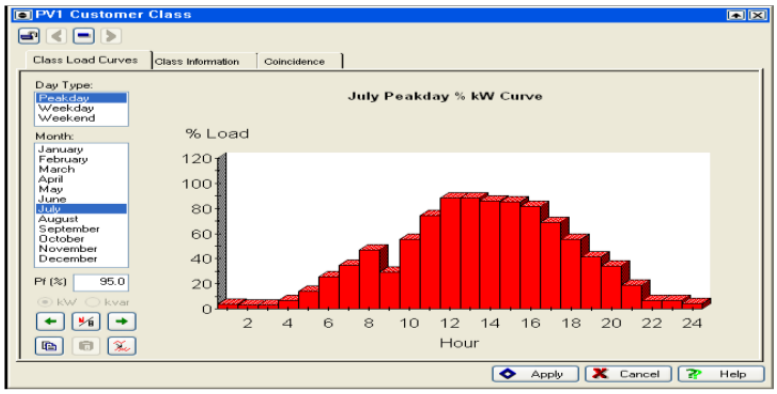


Figure 21: Input to SynerGEE for W 1 Sensor Data, creating power output profiles for each PV location on the W 1 feeder

Analysis of Representative Demand Profiles

For SMUD, the demand data is provided on the specific substations of interest with available SCADA for the entire year of 2009. (The RF substation is currently scheduled to have SCADA installed so high fidelity demand data is not yet available.) Data is excluded for 4 days in Table 3 because of missing or bad data.

The entire demand for any single day is excluded for all feeders even if only one record is missing or incorrect for any one feeder. For this initial study, the objective is to as consistent as possible between feeder data selection. The AC substation results are presented in the body of this report.

Date Excluded from Analysis	Reason
Tuesday, February 03, 2009	One or more MW values = "Bad"
Sunday, March 08, 2009	One or more 15-minute records missing
Wednesday, May 06, 2009	One or more MW values = "Not Connect"
Sunday, November 01, 2009	One or more 15-minute records missing

Table 3: Dates Excluded from Analysis

Figure 22, Figure 24, and Figure 26 show the day with the peak hour (June, July August) for each summer month of the year for AC 1, 2 and 3, respectively. Figure 23, Figure 25 and Figure 27 shows the minimum day for each summer month of the year for AC1, AC2, and AC3, respectively. The peak day for a month is the day with the highest instantaneous demand. The minimum day for a month is the day with the lowest instantaneous demand. This method allows the minimum day profile to vary more from month to month than for the peak day.

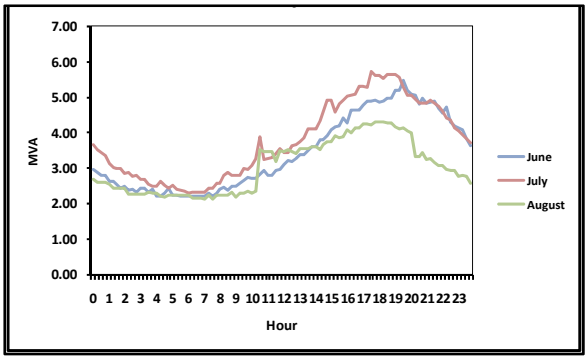


Figure 22: AC 1 Max Days, Summer

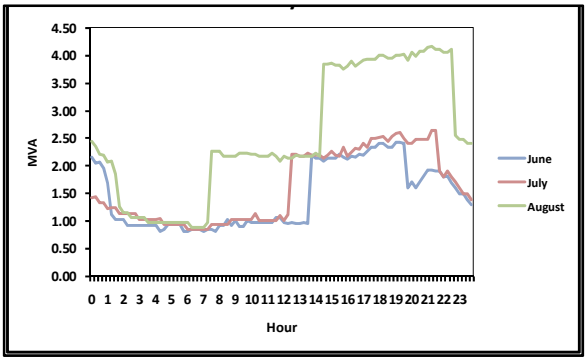


Figure 23: AC 1 Min Days, Summer

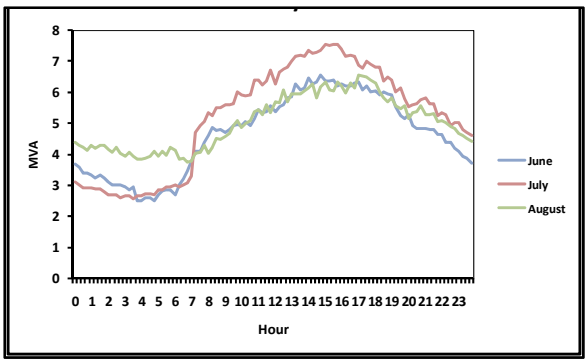


Figure 24: AC 2 Max Days, Summer

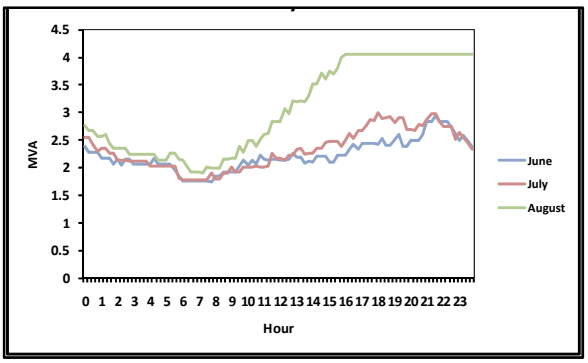


Figure 25: AC 2 Min Days, Summer

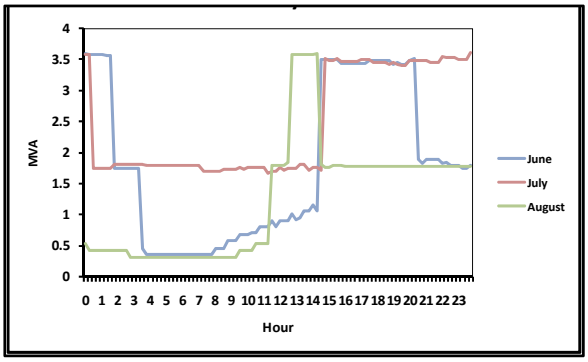


Figure 26: AC 3 Max Days, Summer

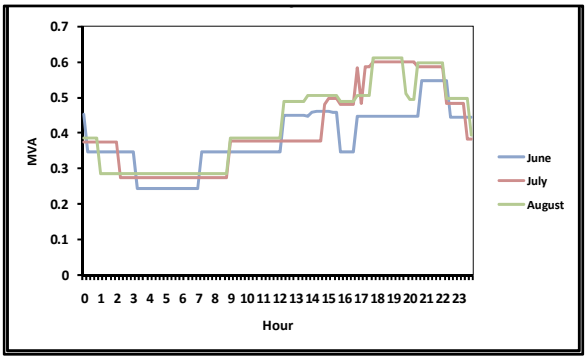


Figure 27: AC 3 Min Days, Summer

AC 1 is mostly residential with rooftop PV installations installed on approximately 300 homes. For the peak days, in January, February, March, and October, there is an unusual midday increase of load over a 1 hour period indicating there is a large commercial or residential load started or demand added to the feeder. This occurs on AC 3 for every month. In general, AC 1 demand peaks at approximately 6 pm. Displaced load from PV during the middle of the day can account for the shift in peak to late in the day. The minimum day profiles for AC 1 exhibit significant variation with months such as February, September, and December having evening peaks similar to those of the peak days. The spring and summer months are more closely grouped together exhibiting profiles more resembling a day with demand that is minimal on average. The minimum days for AC 1 are either a Sunday or a Monday.

AC 2 has a consistent peak day profile for each month. The demand peak occurs in January. As noted in the figure, the peak hour occurs earlier in the day from January through December. The minimum days for AC 2 are all either Sundays or weekdays, with the majority of the minimum days being Sundays.

The AC 3 peak day profiles indicate that the AC 3 loads could be commercial loads because they vary in a more linear way than the other AC feeders with no consistent

monthly profiles, and the load tends to change more rapidly. The AC 3 minimum day profiles are grouped together with low average-demand profiles, with September being the only exception. These low average-demand profiles could indicate many commercial customers being in an offline or standby state. The minimum days for AC 3 are all weekdays except for the January minimum day being a Saturday.

1.5 Introduction and Load Profiles for SMUD

1.5.1 SMUD Substation 1: CT

There are two 12kV distribution feeders connected to the CT Substation (Figure 28) with one feeder having exiting PV (CT 1).

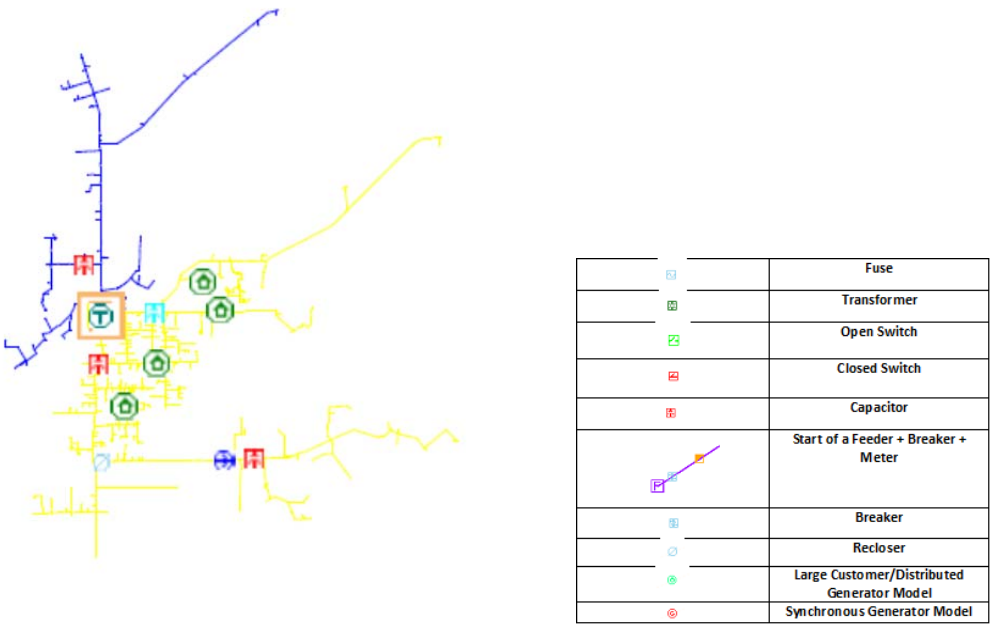


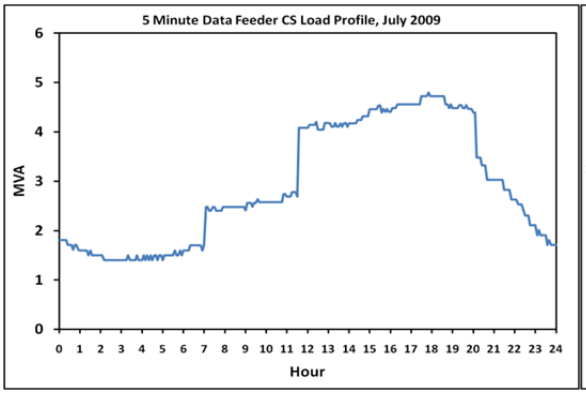
Figure 28: CT SynerGEE Model

There are five (5) capacitors on the two feeders providing potentially 6.6 MVAR. Table 4 shows the VAR capacity and control method for each capacitor.

Name	Fixed kVAR	Switched kVAR	Mode
1202A	0	3600	Time-Controlled
C-1479	0	600	Current-Controlled
C-1485	600	0	Normally OFF
C-1499	600	0	Fixed
C-1521	600	1200	VAR-Controlled

Table 4: Capacitor Controls for CT

The total peak feeder kW losses are 3.2% including the substation transformer and 2.6% for the two distribution feeders only. The minimum and maximum voltages on the feeder are 116.9V, and 125.1V, respectively. SMUD provides BEW with load data for the peak day of the year (July 15, 2009) in 5 minute increments, as plotted in Figure 29. The observed peak hour of the SCADA demand profile is 6 pm and excludes the demand displaced by existing PV units. The five minute load profile is converted to hourly for input to the SynerGEE time sequential simulation analysis (Figure 30).



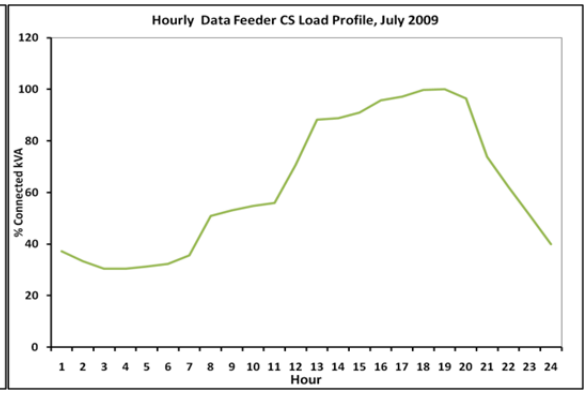


Figure 29:5-Minute Load Profile at Substation **Figure 30. Hourly Load Profile at Substation**

The maximum loading of any equipment on CT 1 and CT 2 is 54% and 96%, respectively, indicating no overloads on either feeder. The total distributed load i.e. the sum total of all the distributed transformers capacity is 7.5 MVA. The initial tap changer position at peak load is 2R for CT 1 and 3L for CT 2. The delta transformer tap change positions become greater as more PV is added to one feeder as compared to the other; there could be some circulating power flows and some reliability issues during feeder switching or outages.

1.5.2 SMUD Substation 2: AC

There are three 12 kV distribution feeders connected to the AC Substation with two feeders having existing PV (AC 1 and 2). There are six (6) capacitors on the three feeders with a total maximum rating of 13.8 MVAR. Each of the three feeders has one of the three capacitors with VAR control while the other three are fixed capacitors on AC 2 only. The VAR controlled capacitors do not normally operate during peak load hours.

The AC III residential community is in Rancho Cordova, CA[1]. Solar Smart Homes combine high-efficiency features along with rooftop-integrated 2.0kW$_{ac}$ PV systems. These have no energy storage. Ultimately, AC smart home community will have 795 homes, 600 of which will be solar smart with a potential PV generation capacity of 1.2 MW on AC 1.

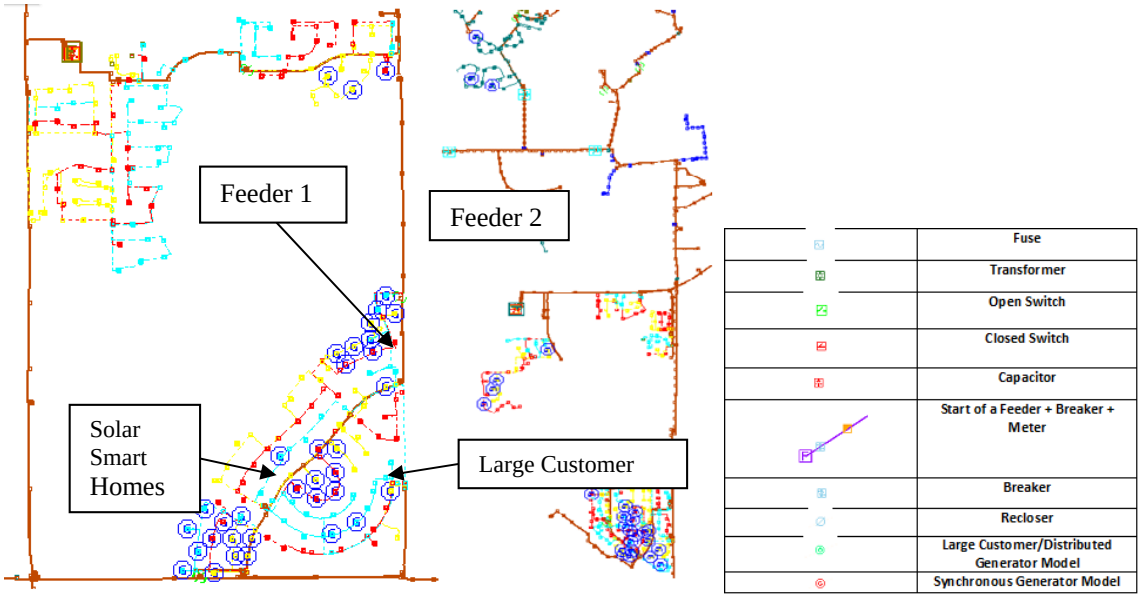


Figure 31: Locations of Existing PV within the AC

Within the SMUD distribution system, VAR support is provided to the sub-transmission system from distribution capacitor banks that are controlled by operations. The fixed capacitors are normally off. It is difficult to clearly identify the operation of the capacitors, thus all the capacitors are turned off during load allocation. Since the solar smart homes are on AC 1, the analysis mainly focuses on AC 1. SMUD provides load data to BEW for the peak day of the year (July 15, 2009) in 5 minute increments, as plotted in Figure 32. The 5 minute load profile is converted to hourly for input into the SynerGEE power flow model for time sequential simulation analysis (Figure 32). The initial observed feeder peaks from the SCADA demand profile occur at 6 pm, 3 pm, and 6 pm for AC 1, 2 and 3, respectively. The measured load profile does not account for demand displaced by existing PV units in both figures. Red is AC2; Blue is AC1; and Green is AC3.

[1] NREL Report: Impact of SolarSmart Subdivisions on SMUD's Distribution System

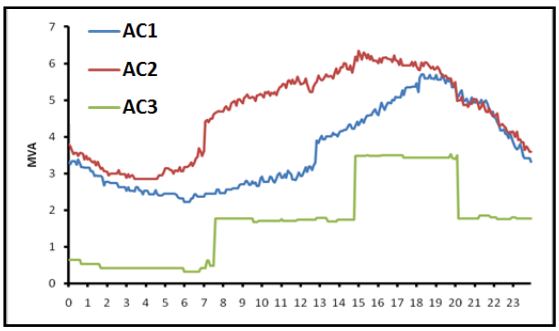


Figure 32: 5 minute Load Profile at substation

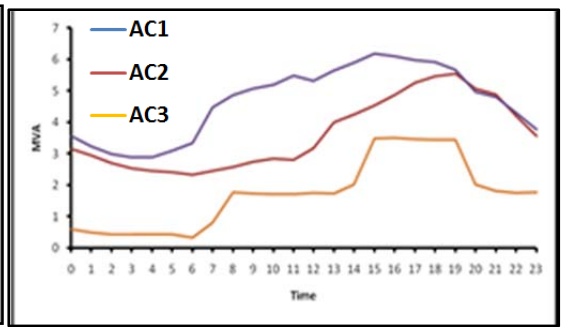


Figure 33: Hourly Load Profile at substation

Currently, there are 264 PV units on AC 1 with a total capacity of 642 kW and 103 PV units on AC 2 with a total capacity of 204 kW. The power factor of each PV unit is 100%. The potential additional PV on AC 1 is approximately 558 kW (1,200 – 642 = 558 kW). The potential PV is equally distributed across phases A, B, and C on three sections on AC 1. This potential analysis initially assumes the PV systems are balanced during the design stages. This is a reasonable assumption for AC, as it was designed as a solar community.

Based on a peak demand of 5100 kW, the PV capacity penetrations from the existing and potential PV levels are shown in Table 5. Capacity penetrations are the percent of PV generation capacity at the time of peak load.

PV Level	Installed PV MVA)	Capacity Penetration of Peak Load
Existing	3.1	60%
Existing + 1MW	4.1	80%
Existing + 2MW	5.1	99%

Table 5 Capacity Penetrations of PV Levels on CT

Potential PV is selected as the potential PV analysis point for CT as it represents a 30% and 60% increase in PV at the large existing location. 100% PV penetration on this feeder is not necessarily a realistic selection but represents a set point to work from.

Figure 34 shows how the demand profiles of the AC feeders change when the additional Spot Loads are added. The peak load time with displaced load added occurs at 6 pm, 3 pm, and 6 pm for AC 1, 2 and 3, respectively. The PV peak time occurs at 12 pm for AC 1 and AC 2 since the same solar irradiance profile is used. The existing PV units do not significantly impact the AC 1 and 2 peak times since the solar generation is minimal when the feeders peak.

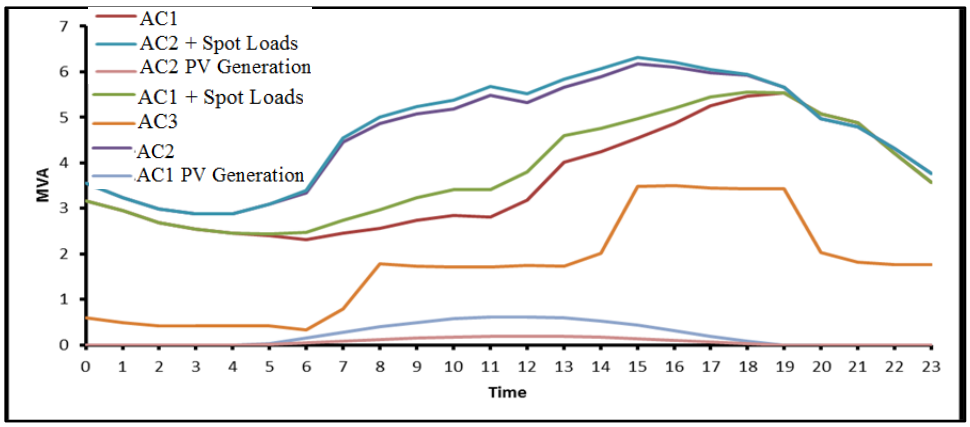


Figure 34: Hourly Load Profile plus Spot Loads for AC substation

The feeder load profiles above have capacitor banks operating to provide VAR support to the sub-transmission system. During the process of load allocation across the feeders, the capacitors are turned off and the calculated demand power factor for all three feeders is 93%. The new load profile with the calculated power factor is shown in Figure 35. The demand peaks are not shifted from the original feeder observed peaks, with displaced load added. The PV peak time occurs at 12 pm for AC.

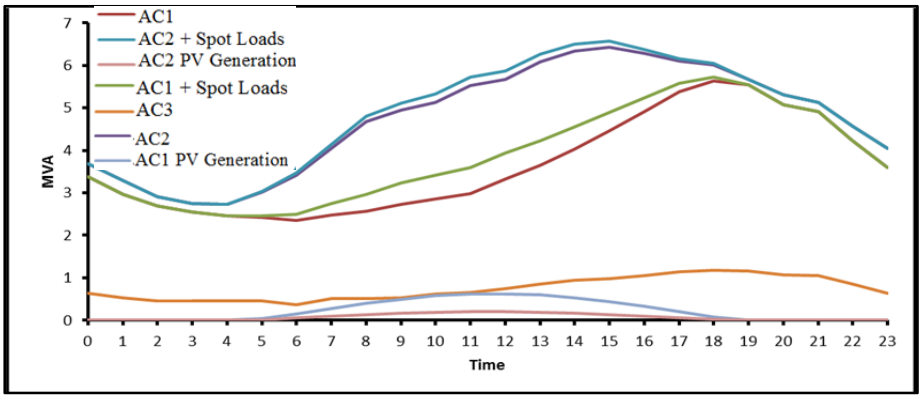


Figure 35: Hourly Load Profile plus Spot Loads for AC substation with assumed power factor of 93%

The smart home existing PV units are aggregated by section since the current version of SynerGEE only permits one Large Customer (DG) per modeled section. The PV units located on the same section in the SynerGEE model are aggregated to one equivalent PV unit on the same section. Originally, there are 367 PV units on the AC 1 and 2. After aggregating the PV units by section, there are 68 equivalent PV units in SynerGEE. Thirty-six (36) of the 68 PV units are on AC 1 with 34 PV units at the solar smart homes community. The other 32 PV units are on AC2 (Figure 31). The PV generators are added to specific sections in SynerGEE model as Large Customers with PV profile as scheduled generation and rated kVA. Load is allocated as balanced, based on connected kVA and peak load time. The aggregated PV unit has an inverter type which is the most commonly

used among the PV units. The modeled locations in SynerGEE for the smart homes community PV units were shown in Figure 31.

1.5.3 SMUD Substation 3: EG Substation

There are three 69 kV sub-transmission lines (EG 2, EG 3, and EG 4) serving the EG area. However, only EG 3 and EG 4 actually supply power to the more than 20 substations connected to these lines. Since SMUD has not provided the distribution feeder data, the distribution loads are modeled as an equivalent load on the low side of the transformers. The SynerGEE model for EG is shown in Figure 36. EG substation also supplies a distribution feeder of interest in this study, EB.

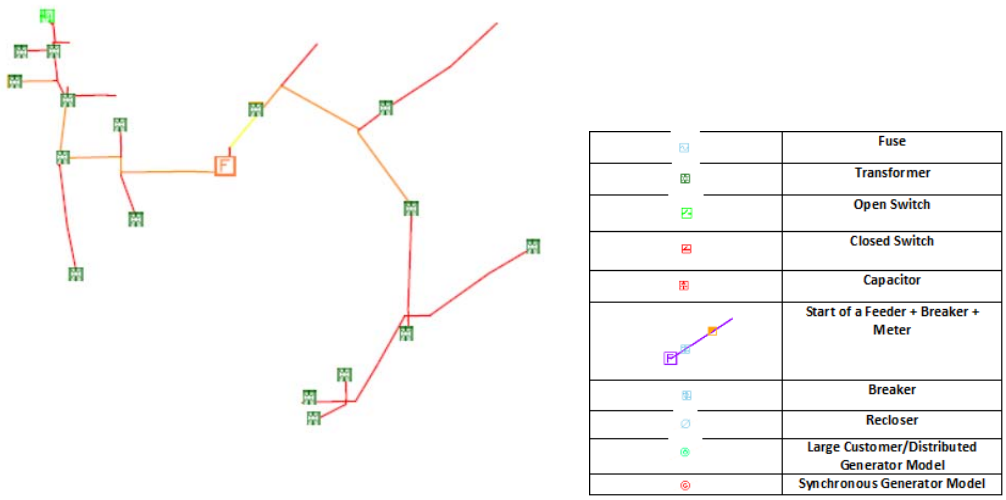
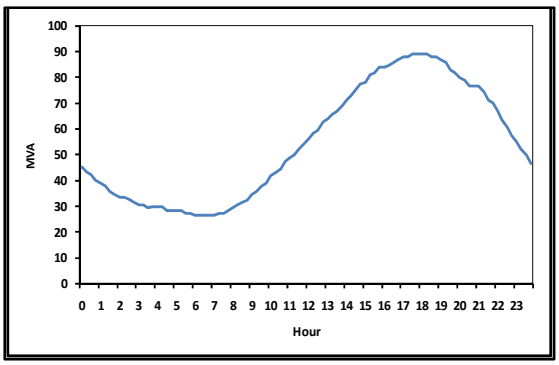


Figure 36. EG 69 kV SynerGEE Model for EG2,3, and 4

In the initial analysis it is assumed there are no PV installations, capacitors, or voltage regulators on these 69 kV lines. In Year Two of this project, larger PV installations connected at the 69 kV will be considered. The total peak line kW losses are 2.6% for the two 69 kV lines. The minimum and maximum voltages on the lines are 115.7V, and 127.1V, respectively. BEW is provided load data for the peak day of the year in 5 minute increments (Figure 37). The initial observed peak time occurs at 6 pm. The measured load profile does not account for demand displaced by existing PV units (3MVA capacity). The load profile is averaged to hourly for input to the time sequential analysis in Figure 38.



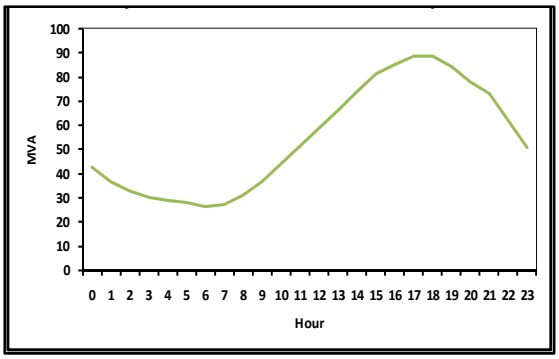


Figure 37: 15-Minute Profile for EG July 2009

Figure 38: Hourly Profile for EG for July 2009

Based on a peak demand of 126.5 MVA, the potential installed PV capacity for 15% and 30% penetrations levels are shown in Table 6. The percentages for potential penetration were selected based on discussions with SMUD, on points which trigger a detailed feeder study.

Table 6: Capacity Penetrations of PV Levels on EG

Installed PV (MW)	PV Capacity Penetration Level
19	15%
38	30%

There is no existing PV installed on EG substation, and no PV irradiance data in the area. The hourly profile for the potential PV is taken from irradiance measurements from AC in Figure 39 for the same day as the load profile. The AC irradiance sensors are approximately 12 miles from EG.

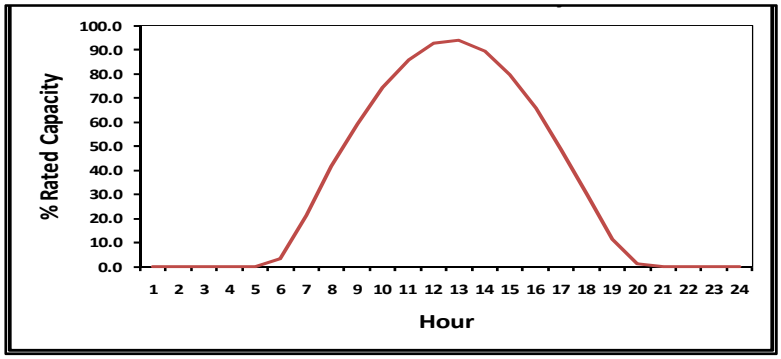


Figure 39: AC Hourly Irradiance Profile for July 2009

Twenty-four hour load and PV profiles are added as customer zones to SynerGEE and applied to EG 3 and 4. On the distribution side of each of the 20 distribution transformers

is a PV location representing an aggregate of potential PV for that distribution feeder. Potential PV penetrations of 15% and 30% of peak load are analyzed. The rated PV capacity placed at each distribution feeder equals 15% or 30% of the feeder total peak load, depending on the penetration level being analyzed. Since there are no existing PV exists on EG, no Spot Loads are added to account for displaced load not measured at the substation.

1.5.4 SMUD Substation 4: L7 (69 kV)

There is a 69 kV sub-transmission line connected to the L7 substation with existing PV but no capacitors or regulators. The SynerGEE model for the L7 feeder is shown in Figure 40.

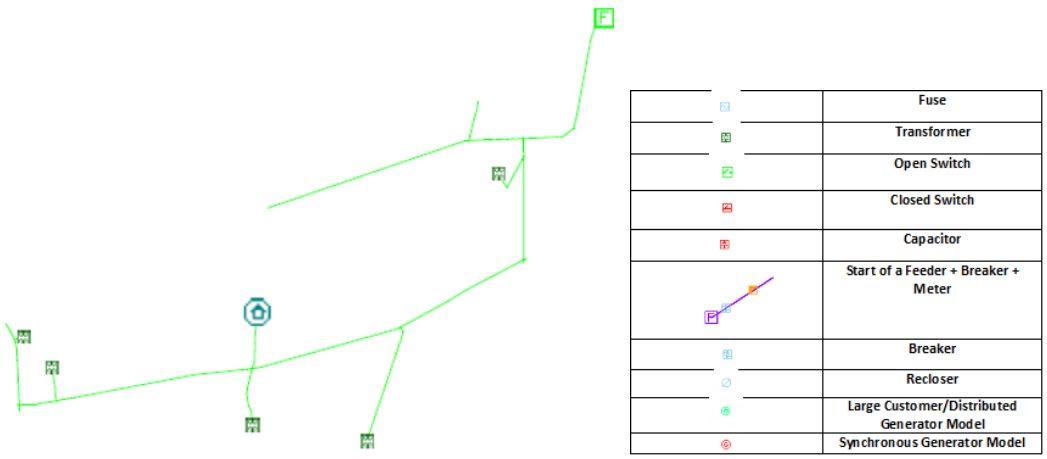
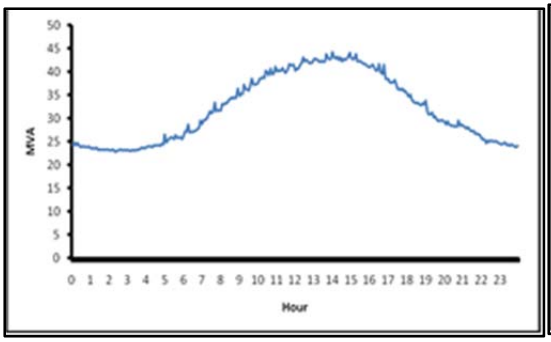


Figure 40: SynerGEE model for L7 Feeder

SMUD provided load data to BEW for the peak day of the year (July 15, 2009) in 5 minute increments, as plotted in Figure 41. The initial observed line peak from the SCADA demand profile occurs at 2 pm. The measured load profile does not account for demand displaced by existing PV units. The 5 minute load profile is converted to hourly for input into SynerGEE power flow model for time sequential simulation analysis (Figure 42).



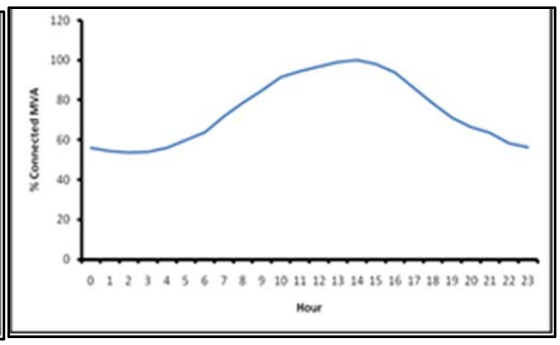


Figure 41: Minute Load Profile for L7 for July 2009 **Figure 42: Hourly Load Profile for L7 for July 2009**

The total existing PV on L7 is 2 MVA. The 2 MVA is located in the NA area of an L7 feeder. The power factor of each PV unit is 99%. The potential PV penetration level used for this analysis is 30% of the peak load or about 15.5 MVA. The potential PV is modeled at a section of the line that represents NA in SynerGEE. The percentages for potential penetration were selected based on discussions with SMUD, on points which trigger a detailed feeder study.

Figure 43 shows how the demand profiles of the line changes when the additional spot loads (load displaced by PV) are added. The peak load time with displaced load added occurs at 2 pm. The PV peak time occurs at 12 pm. The existing PV units do not significantly impact the L7 peak time since solar generation remains close to its peak load level.

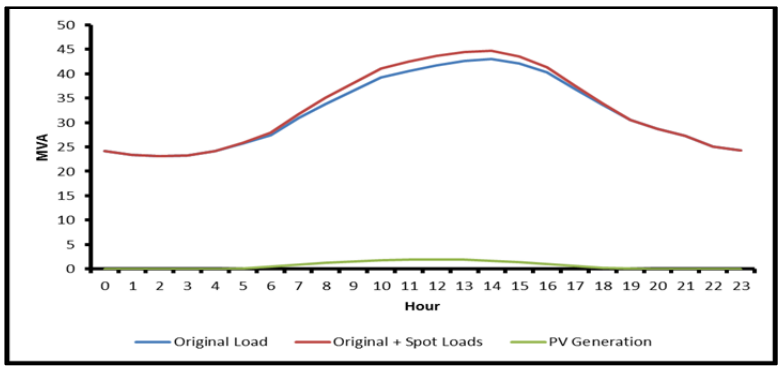


Figure 43: Hourly Load Profile plus Spot Loads for L 7

As with EG, no PV data are available therefore the AC PV raw irradiance data obtained from NREL is used to create a representative profile for the L7 existing and potential PV. The data is aggregated to 1-hour format in SynerGEE for the time sequential study. The existing PV unit is modeled on the NA section in SynerGEE (Table 7).

Table 7: Existing PV Customers and Spot Loads on L 7

#	Unique Device ID	Rated Generation (MVA)	PF (%)
1	LCustomer	2	99

1.5.5 SMUD Substation 5: EB

There is one 12 kV rural distribution feeder from the substation with no existing PV. One of the major loads is a dairy farm. Currently, EB has one 225 kW dairy digester generator located at the dairy farm. There is a second 225 kW dairy digester generator proposed. The dairy digester captures methane from cow waste. The methane then fuels a turbine, which provides power to the farm. The SynerGEE model for EB is shown in Figure 44. EB is fed from EG Bank 1.

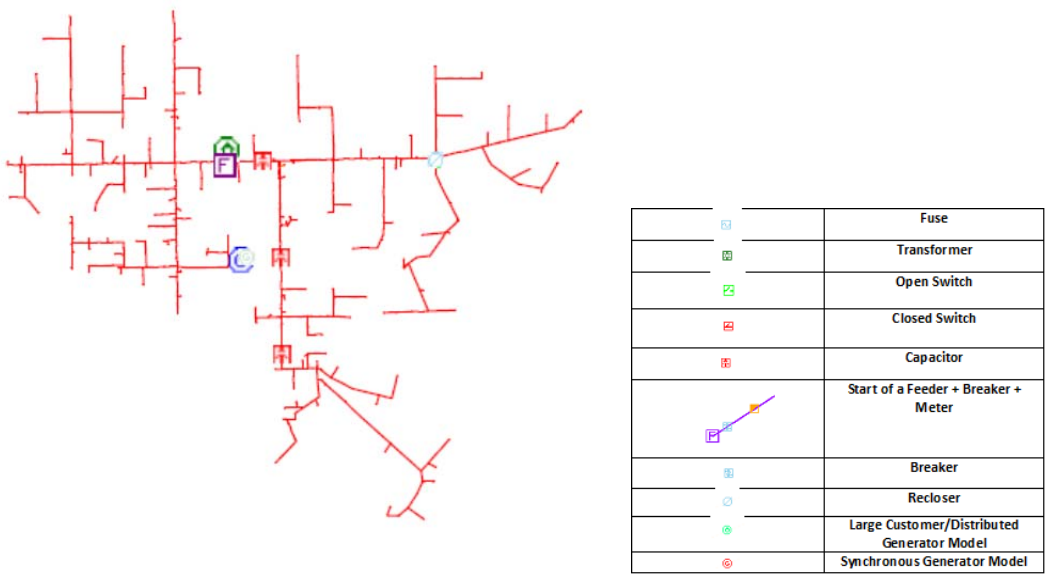
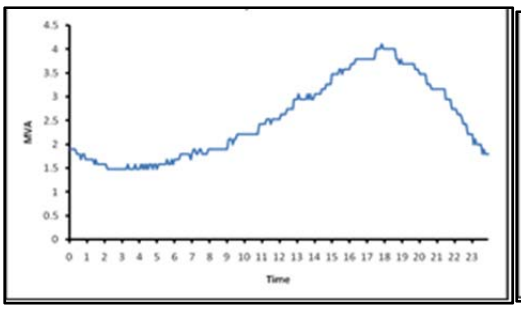


Figure 44: EB SynerGEE Model

EB Feeder contains two VAR control capacitor banks. Their maximum rating is 1.8 MVAR. A time-of-day controlled capacitor bank with a maximum rating of 1.2 MVAR also operates from 7 am to 11 pm. No feeder load data for this analysis was available, therefore a representative load from a feeder with similar characteristics with an assumed power factor of 95%. The 5 minute load profile is converted to hourly for input into SynerGEE time sequential simulation analysis Figure 45). The observed feeder peak from the measured demand profile occurs at 6 pm. EB is of interest to this analysis as there is a large PV site proposed at the same location as the digester in the near future.



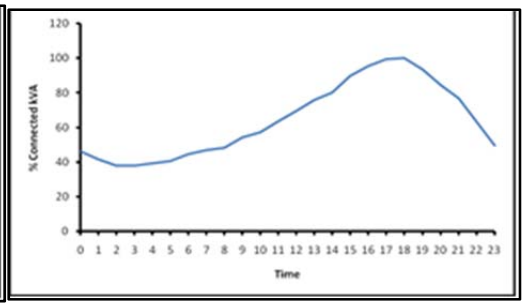


Figure 45: Five minute Load Profile at substation for July 2009 **Figure 46: Hourly Load Profile at substation for July 2009**

There is no existing PV on EB feeder. The potential PV penetration level assumed for the preliminary analysis is 20% of the peak load, 724 kVA. The PV is modeled at one section in SynerGEE. The power factor of the PV units is 99%. 724 kVA was selected as it was presented as a possible future penetration on this feeder in the first feeder review.

The dairy digester is still under pre-commercial testing. For this reason, two separate sets load flow analyses are completed. The first analysis excludes PV and compares one dairy digester generator in operation. In the second set of analysis, the generation from the dairy digester is the varying parameter, and 724 kVA of PV is added. The load profile as originally provided without PV and the PV generation profile are shown in Figure 47. The PV peak time occurs at 12 pm.

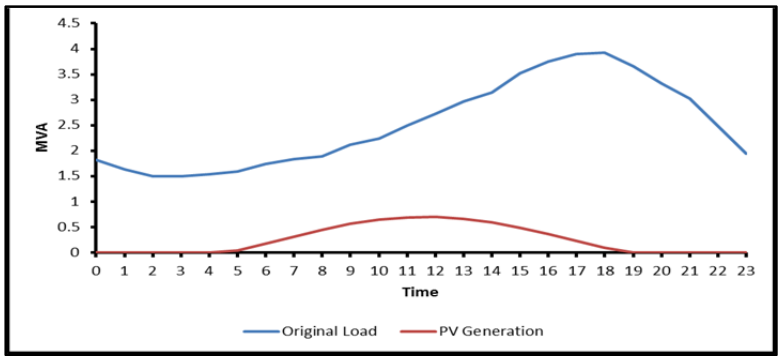


Figure 47: Hourly Load Profile plus PV generation for EB

The AC PV raw irradiance data obtained from NREL, presented in Section 1.2, is used to create a representative profile for the EB PV since there is no solar irradiance data available for EB feeder.

1.5.6 SMUD Substation 6: RF

The total existing PV on the RF feeder is two (2) PV units, with a total rated existing PV of 976 kVA at a power factor of 99%. The final potential PV penetration level assumed in this analysis is 30% of the peak load which is approximately 1,578 kVA. Figure 48 shows the SynerGEE Model for RF. RF is an industrial/commercial loaded feeder.

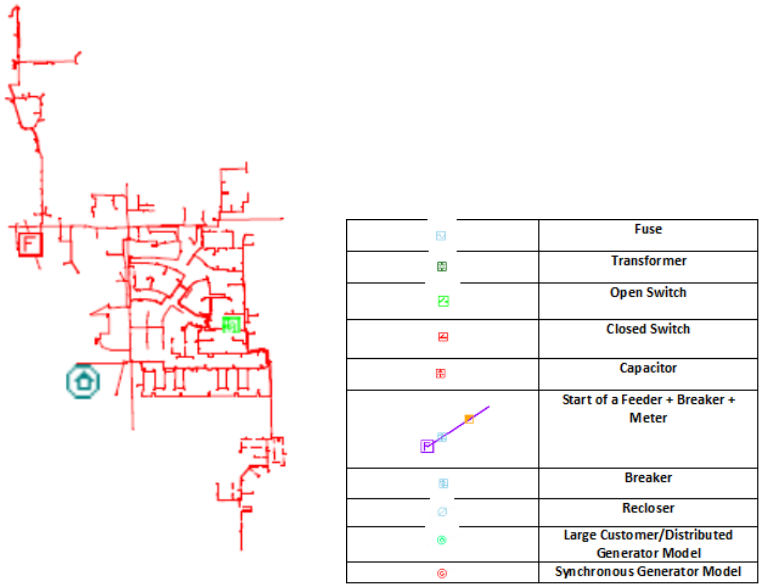


Figure 48: SynerGEE Model for RF

The potential additional PV is approximately 602 kVA. The potential is added at the section representing the manufacture's plant in SynerGEE.

RF substation, feeder 1 is a 12 kV distribution feeder, with existing PV at the manufacturing plant and one VAR controlled capacitor bank with a maximum rating of 3.6 MVAR. SMUD provides 2 days of peak load data (July 2009). The 15 minute load profile is converted to hourly for input into SynerGEE time sequential simulation analysis (Figures 49 and 50). The observed feeder peak occurs at 5pm. The measured load profile does not account for demand displaced by existing PV units.

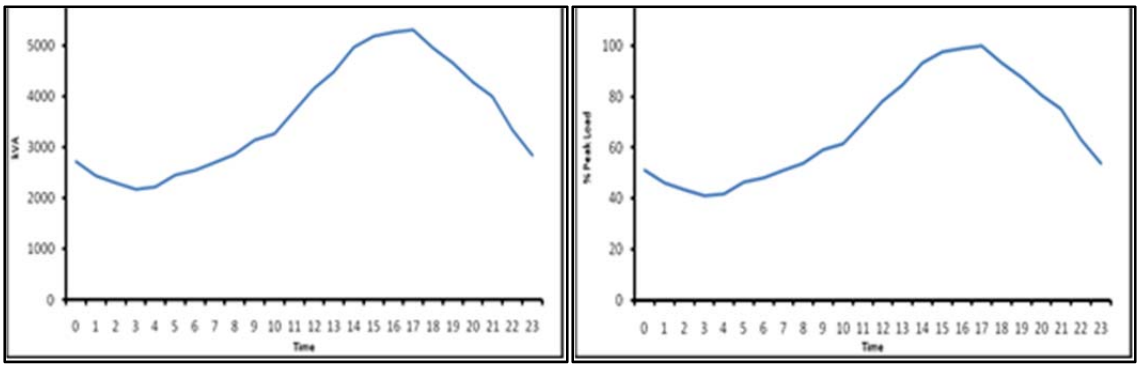


Figure 49: minute Load Profile at substation **Figure 50: Hourly Load Profile at substation.**

Figure 51 shows the demand profile of the feeder changing as the additional spot loads are added. The PV peak time occurs at 12 pm. The existing PV units significantly impact the RF peak time. The peak time changes from 5 pm at No PV to 3 pm with Existing PV.

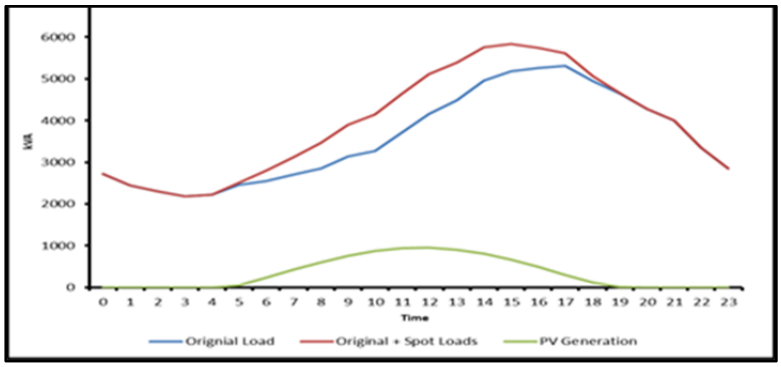


Figure 51: Hourly Load Profile plus Spot Loads for RF substation

The AC PV raw irradiance data from NREL is used to create a representative profile for the RF existing and potential PV. There is no solar irradiance data available for RF feeder. The data is aggregated to 1-hour format in SynerGEE.

1.6 Introduction of Load Profiles for HECO, MECO and HELCO

In this section, the results are presented for each feeder of study in Hawaii. An identical procedure is followed for each feeder and is described for SMUD. The assumptions vary based on existing PV penetrations, potential PV locations selected by HECO, existing distributed generation locations on the feeders and other pertinent feeder characteristics. The feeders are presented in the following order:

1. HECO Feeder: W1 3
2. HELCO Feeder: ML
3. MECO Feeder: WA

There currently no results for MECO and HELCO due to delay in receipt of data.

1.6.1 HECO Feeder: W1 3

W1 3 is an 11.5 kV distribution feeder connected to the W1 46 kV substation. Transformer 1 serves W1 1 and 2 feeders with power supplied by theWI 46 kV 2 line. Power to transformer 2 is supplied by the SK 46 kV line and serves the W1 3 feeder (the feeder of interest) and W1 4. Currently W1 3 has 9% PV penetration of peak feeder load, and 4.8 MVA peak demand. As in the SMUD feeder analyses BEW is provided 5 minute peak day (August mid-day) and minimum load day (Sunday afternoon in August) for the 2 substation transformers. The profiles are aggregated to the 11.5 kV level based on SLACA (HECO's Substation Load and Capacity Analysis system) loading information. Figure 52 shows the peak and minimum day.

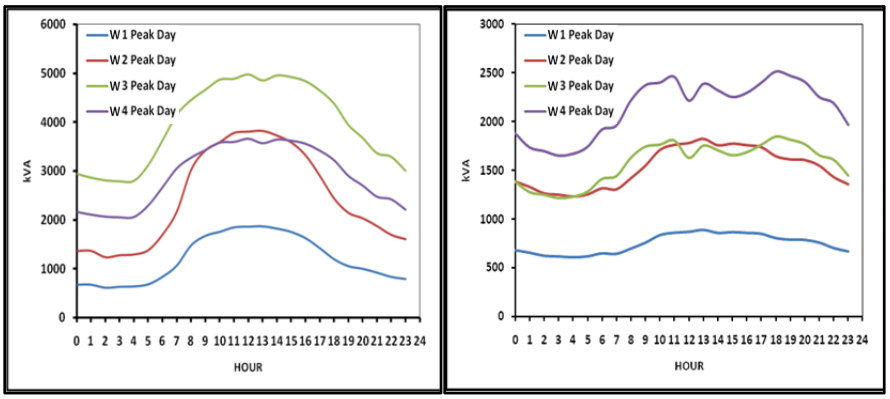


Figure 52: W1 Feeders load, maximum left hand side and minimum left hand side

Street addresses are provided for each of the PV locations on the feeder. An in-house address GIS locator tool gives the SynerGEE Electric model location for each PV site. Figure 53 shows how the PV locations are mapped and transferred to the model.

Figure 53: W1 3 Geography of PV Locations

The load displaced by PV is added to the load profile and plotted to show the actual peak time in Figure 54.

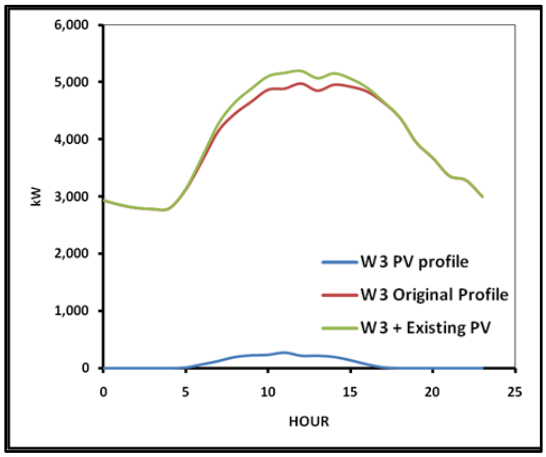


Figure 54: W1 3 PV profile added to normal load profile for replacement of displaced load.

1.6.2 HELCO: ML Substation

ML substation is selected by HELCO for detail high PV penetration analysis. ML Substation is located on the Big Island of Hawaii. ML substation supplies 4 distribution feeders, ML11, 12, 13 and 14. ML12 is a redundant feeder. The ML feeders supply mainly commercial load, hotel complexes and associated surrounding demands.

No distribution model exists for the ML substation. Data is received for the substation in hard copy switching diagram format. The hard copy is a background, and the line topology is traced to enter in to SynerGEE Electric. Line construction and type is entered manually from the switching diagram. Other information was provided on PV locations, PV inverter and panel type for existing locations, switch location and type, connected distribution transformers (used for load allocation), and other protection and switchgear information. Substation transformer datasheets are also provided. The ML Feeders modeled in SynerGEE Electric is shown in Figure 55.

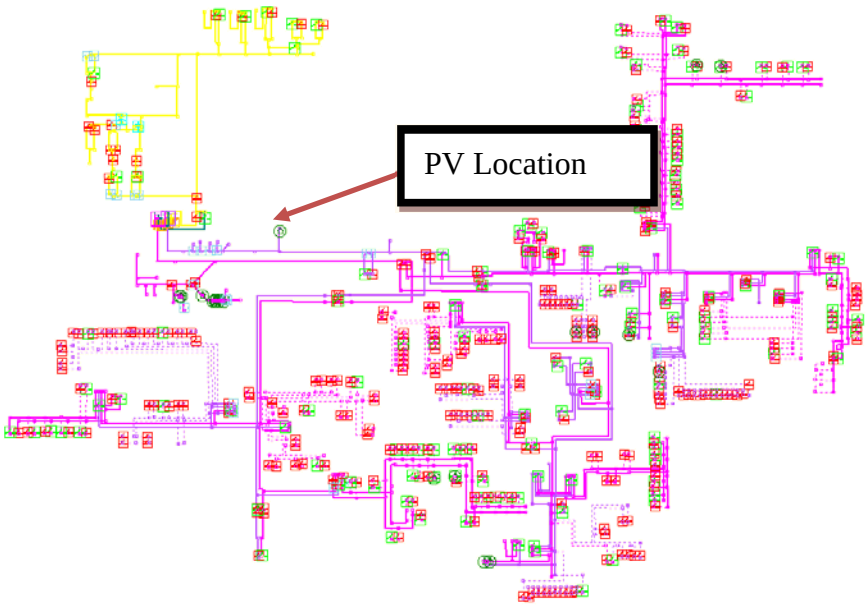


Figure 55: ML SynerGEE Model

Load information for a peak and minimum day of demand is provided. Load is allocated to the feeder on an hourly basis (Figure 56). Load profiles are provided specifically for large hotel loads, and allocated separately to the feeder. No measured PV data is available, but will be entered when received.

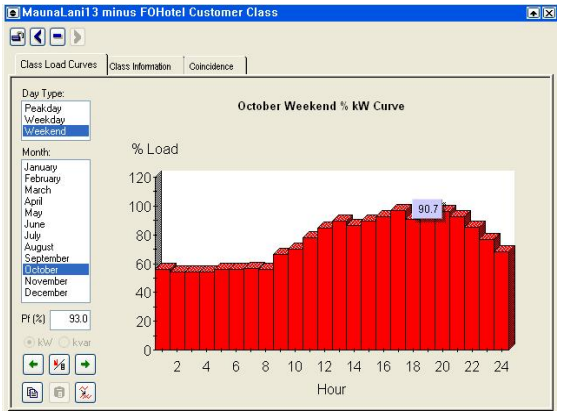


Figure 56 ML SynerGEE load profile

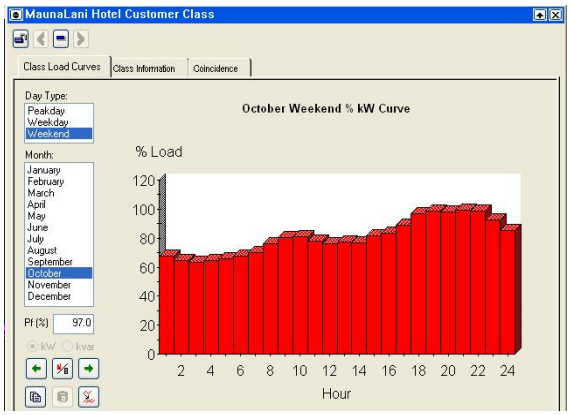


Figure 57 ML SynerGEE specific hotel load profile

ML 11, peaks at approximately 8pm, and has 2275 kVA demand. ML 12 is unloaded. ML 13 has approximately 3420 kVA demand and peaks approximately 5pm. ML 14 has approximately 2680 kVA demand and peaks approximately 11am.

Data is being reviewed by HELCO to date and following this the analysis will proceed in the same methodology used for the HECO feeder WA 3.

Conclusion

The baseline modeling included data collection, evaluation, modeling and analysis of the existing system with available data. This was implemented on the SMUD and HECO feeders of interest. The evaluation team also analyzed monitored PV data and representative load profiles for SMUD and the Hawaiian utilities. This report summarized the baseline modeling assumptions and characterized the feeders of interest. As monitoring equipment is deployed and more data is collected and evaluated, more analysis on the feeders of interest will be forthcoming, focusing on the impacts from current and increasing penetrations of distributed PV resources on these feeders.

APPENDIX A
EXAMPLES OF LOCATING MONITORS AND SENSORS ON DISTRIBUTION FEEDERS

Distribution planners normally set the voltage regulation point at the distribution substation bus between 122 and 125 volts so that the end of the feeder has a voltage ranging from 115 to 122 volts. If the voltage drops too low toward the end of the feeder, then the planner installs capacitor banks or regulators, depending on the length of the feeder. If there are multiple feeders served from the same substation bus, the transformer tap changer is set to a regulation point that provides the same voltage on all the feeders.

There are no mathematical equations or software that can determine where to install monitors and sensors on distribution feeders. There are too many variables that affect where these should be installed. Some of these variables include:

- Location and size of customer loads
- Location and size of projected and existing solar installations
- Size and type of conductors (overhead and underground)
- Size and location of capacitor banks and regulators
- Capability of the substation to provide voltage regulation

This is where the expertise of the utility distribution engineer comes into play. The engineer has an in-depth knowledge of the feeders in his planning area and where the potential areas for low or high voltage, frequency, line overloads and other factors could occur. The engineer also has knowledge on the capacitor bank operations and settings.

Combining this expertise with a base case run of the feeder provides insight into the condition of the feeder. By installing some potential solar installations on the feeder, the engineer can determine the "sensitivity" of the feeder to respond to distributed generation. "Sensitivity" is the reaction of capacitor banks, frequency, voltage and other factors to distributed generation and lower load as an end result. Distributed generation includes solar installation, customer installed cogeneration, demand-side management programs and electric vehicle impacts. By conducting some simple distribution feeder simulations and graphically displaying voltage, current and loads, the engineer can determine where to install monitors and sensors. A few examples are shown in the Discussion Section.

The engineer would pick some locations that show the potential for reverse power flow, voltage variations that occur along the feeder. Some of the interesting areas to install monitors include:

- At a large customer load point of delivery
- Near capacitor banks or regulators
- Near potential high distributed generation installations
- On the substation bus
- Before or after the substation transformer LTC

If the feeder with high distributed generation potential is connected to a substation bus that has multiple feeders connected, the impacts to the other feeders are as important as the feeder with distributed generation. The utility can not afford to install sensors and monitors on all of the feeders since the cost to install and maintain would be excessive. Instead, the utility's objective is the installation of monitoring equipment to be reallocated to different feeders and areas as data is collected and the feeder validated.

For those other feeders connected to the same substation bus, the engineer should request that the line crews obtain instantaneous and time stamped readings on the other feeders. For example, if the engineer is interested in the minimum daytime peak demand that usually occurs on a Sunday in March or April, the engineer may request that the line crews take a reading at the end of the feeders not monitored. If time stamped, the readings can be compared with the data being collected in one to five second increments. This would tell the engineer how the other feeders are reacting to high distributed generation on the other feeders. The instantaneous readings do not need to occur on the other feeders at the very exact time. For example, it there are five feeders connected to a bus with one having the high penetration of distributed generation, the other four feeders could have the instantaneous readings taken over several Sundays between the minimum daytime peak periods (noon to 2 pm for example). The data can be compared to determine the interaction of the feeders to high penetrations of distributed generation.

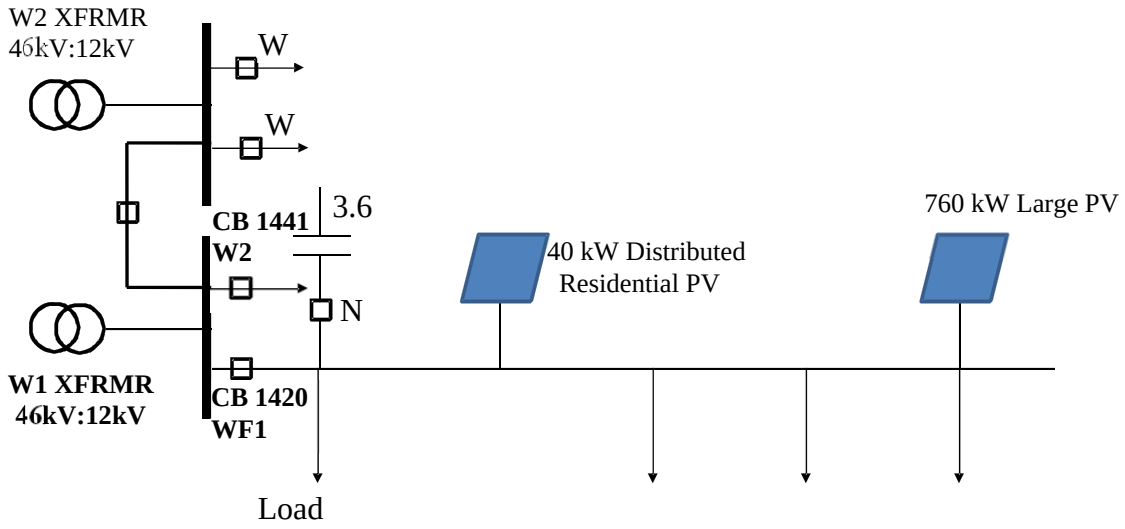
For example, after the equipment is installed on a feeder and data is collected for a year in one second to five second increments, the engineer has sufficient information to use to evaluate the potential impacts of high penetrations of distributed generation as long as the distribution planning model is capable of simulating feeder operation in those increments. The goal is to move the equipment around the distribution grid to obtain as much historical information as possible before high penetrations begin.

Today, the distribution of high PV generation and other demand-side technologies are not evenly distributed on all feeders or at the same locations on the feeders. It is difficult to

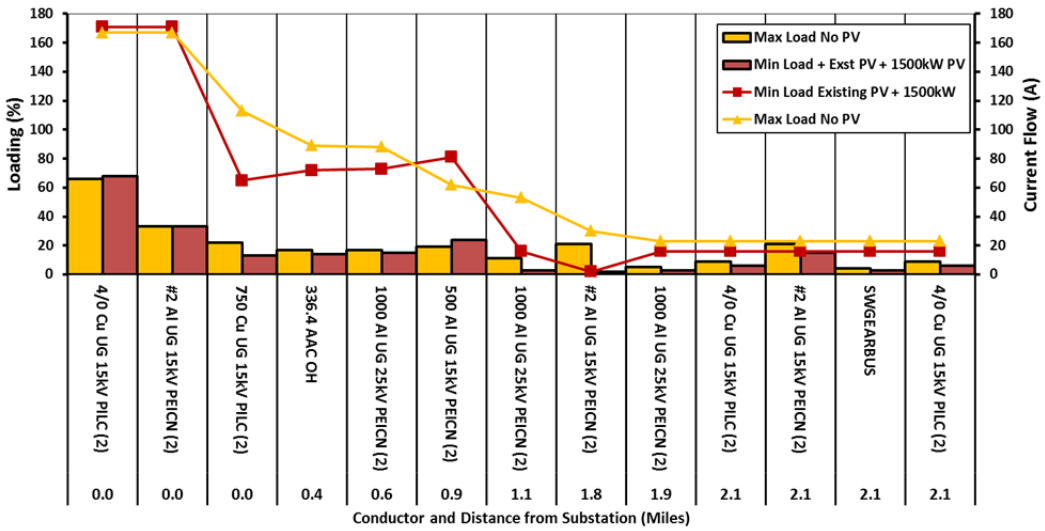
develop one common methodology for determining how or where to install monitors and sensors. A few examples for SMUD and HECO are shown below.

Shown below is a feeder layout for a HECO feeder. There are many feeder taps and the distributed solar is widely dispersed around the feeder.

It is not until the feeder layout is converted to a simple one line diagram as shown below. From the simple diagram, the large solar installations are located at the end of the feeder, there is a large capacity bank within the substation, and the other two feeders have very little solar installed.



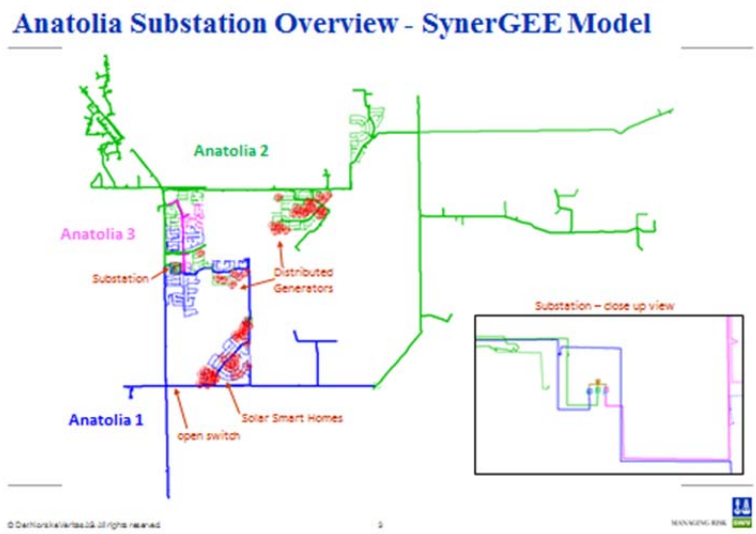
From this diagram, the initial decision would be to install monitors at the substation and at the end of the line where the large PV is located. The substation monitor would be recording the minimum volts, Vars, amps, power factor, tap changer position, frequency, cap bank status, and other attributes. The end of the feeder would have a monitor at the large customer location collecting the same data as at the substation, if the customer permits. The monitors would collect the customer net load and the solar generation on two different meters. If permission is not granted, then a line monitor and a solar sensor would have to be installed somewhere on the feeder but close to the large PV location. The type of installation varies by the type of distribution configuration, such as overhead or underground.



The figure above shows the loading and current flow on the various segments of the feeder. Depending on the penetration of solar on the feeder and its associated location, the location of distribution line monitors could change. Using the feeder flow diagram above, the high solar penetration is at the end of the feeder and the load is located close to the substation. By graphing a feeder energy flow diagram as shown above, there will be a shift in energy flows around the 1.8 miles from the substation. The exact location will depend on the feeder demand and solar penetration. However, the installation of field monitors near this location provides a central point to validate the directional change in the energy flows.

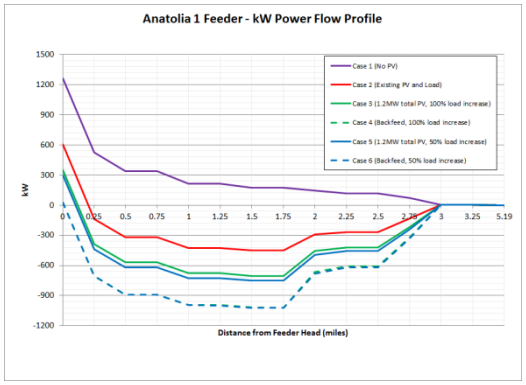
Another example is the Anatolia substation. The substation has three 12 kV feeders. Feeder 1 has high load close to the substation and high penetration at the end of the feeder at the smart solar residential community. Feeder 2 has a low demand and very little solar penetration. Feeder 3 is also a smart solar residential community with high

load but little solar penetration to date. Feeder 1 was only considered for the initial phase of analysis but monitors and sensors should be place on the three feeders.

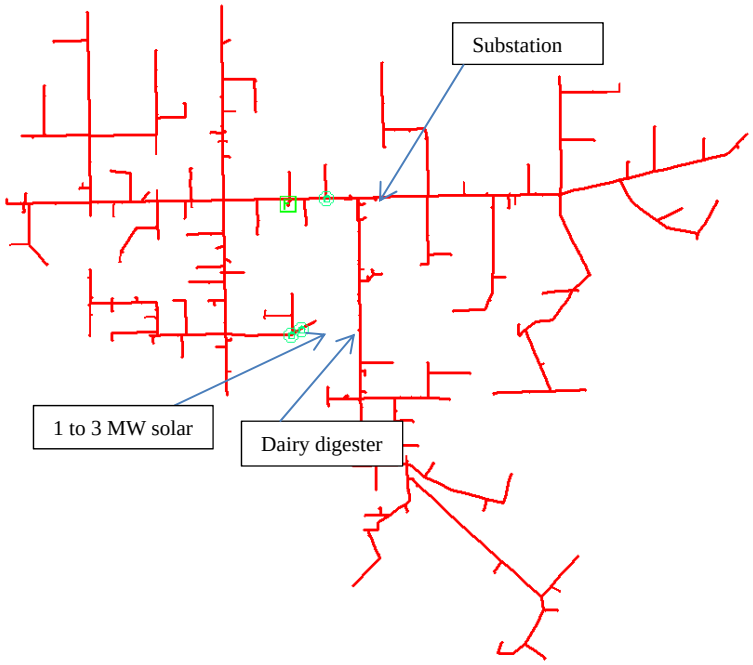
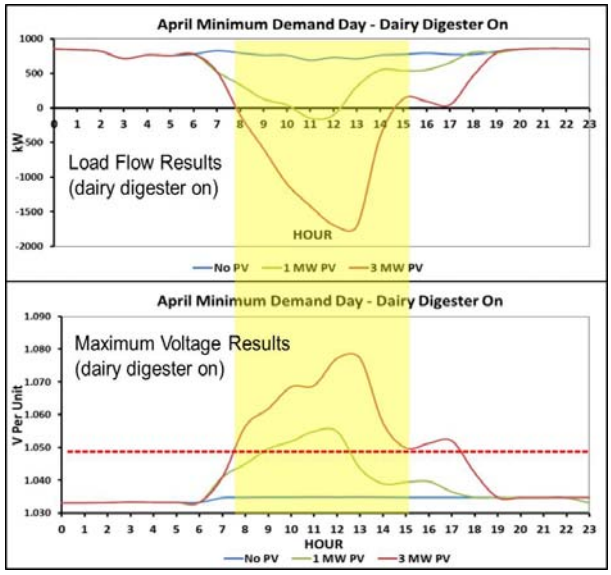


Feeder 1 had power quality meters installed at the feeder bus that is collecting feeder information such as volts, vars, amsp, power factor, frequency, and other parameters. In this case, the load for the smart home community was aggregated at the feeder entry point into the subdivision.

The graph shows the kilowatt flow on Feeder 1 from the substation to the entry point into the subdivision for various penetrations of roof top solar installations. These profiles indicate that solar sensors and power quality meters should be installed at the beginning and end of the modeled area for validating the feeder flows under base line conditions. Instead of installing another monitor in the middle of the feeder as was discussed in the previous example, the utility may want to take an instantaneous reading on a projected maximum and minimum daytime peak demand to validate the line flow and voltages on the line. Since the feeder demand is continuously recorded, the instantaneous readings in the middle of the feeder provide another level of validation.



The last example is shown below. This is a rural SMUD feeder with long lines and little load. There is a dairy farm digester and one or more central distribution solar farms toward the end of the feeder. Since the feeder separates right outside of the substation into two vary long lines, it is difficult to determine where the additional monitors and sensors should be placed. There needs to be equipment installed at the substation and near the solar/digest installations to verify the reverse power flows and voltages. However, there needs to be monitors at the end of the other line segment or at least some installation readings to verify the voltages.



The two figures below show the maximum voltage and maximum flows on the distribution line for a minimum daytime peak hour which is normally modeled as an April Sunday noon where the load is low but the solar generation is high. The substation bus voltage was set at 123 volts. The objectives were to determine where the highest voltage and the highest reverse power flow were recorded on the feeder and the potential durations of each occurrence.