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Proactive Modeling Methodology

California Public Utilities Commission

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In 2012, DNVGL was awarded a two year contract from the California Public Utilities Commission (CPUC) under the California Solar Initiative (CSI) Research, Development and Deployment (RD&D) Solicitation 3. The title of the project is "Tools Development for Grid Integration of High PV Penetration". Itron is the CPUC RD&D Program Administrator. This project builds on the Sacramento Municipal Utility District (SMUD) Solicitation 1 titled "High Penetration PV Project (Hi-PV) Impacts to Transmission and Distribution Grids" to develop tools and methodologies to study distributed PV and central solar plants impacts on the utility grids.

Sacramento Municipal Utility District (SMUD), Hawaii Electric Company (HECO), Pacific Gas & Electric (PG&E), and City of Roseville are the participating electric utility member of the California Public Utilities Commission, California Solar Initiative Solicitation 3 project. The objectives of Solicitation 3 are to continue the studies on the potential impacts of distributed solar on the distribution grids, evaluation of software tools, and the development of a study methodology that any electric utility can incorporate into the planning process.

This report documents the methodology developed during this project.

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Reference to part of this report which may lead to misinterpretation is not permissible.

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List of abbreviations

Abbreviation	Meaning
BEW	Behnke, Erdman and Whitaker
CEC	California Energy Commission
CPUC	California Public Utilities Commission
CSI	California Solar Initiative
CT	Current Transformer
DG	Distributed Generation
DNV GL	Det Norske Veritas Germanischer Lloyd
FIT	Feed In Tariff
GIS	Geographical Information System
HCEI	Hawaii Clean Energy Initiative
HECO	Hawaiian Electric Company
HELCO	Hawaii Electric Light Company
Hi-PV	High Penetration Photovoltaic
IAP	Intermittency Analysis
IEEE	Institute of Electrical and Electronics Engineers
LDC	Line Drop Compensation
LLNL	Lawrence Livermore National Laboratory
LTC	Load Tap Changer
LVA	Locational Value Analysis
MECO	Maui Electric Company
OPS	Operations Measurement Systems
PG&E	Pacific Gas & Electric
PSLF	Positive Sequence Load Flow
PSS/E	Power System Simulation for Engineers
PT	Potential Transformer
PV	Photovoltaic
RD&D	Research, Development & Deployment
RPS	Renewable Portfolio Standard
SCADA	Supervisory Control and Data Acquisition
SMUD	Sacramento Municipal Utility District
SVA	Strategic Value Analysis

EXECUTIVE SUMMARY

In 2012, DNV GL was awarded a two year contract from the California Public Utilities Commission (CPUC) under the California Solar Initiative (CSI) Research, Development and Deployment (RD&D) Solicitation 3. The title of the project is "Tools Development for Grid Integration of High PV Penetration". Itron is the CPUC RD&D Program Administrator. This project builds on the Sacramento Municipal Utility District (SMUD) Solicitation 1 titled "High Penetration PV Project (Hi-PV) Impacts to Transmission and Distribution Grids" to develop tools and methodologies to study distributed PV and central solar plant impacts on the utility grids.

The team members are Hawaii Electric Company (HECO), SMUD, Pacific Gas & Electric (PG&E), and City of Roseville, California. The objectives of Solicitation 3 are to continue the studies on the potential impacts of distributed solar on the distribution grids and the development of a study methodology that any electric utility can incorporate into the planning process.

The research and demonstration on the impacts of high penetrations of renewable resources began in 2003 with the first California Energy Commission (CEC) sponsored Locational Value Analysis (LVA) of renewable resources on the transmission grid. BEW Engineering (BEW) developed the methodology and software tools under a CEC contract (CEC-2005-500-106) to integrate a transmission power flow model with a Geographical Information Systems (GIS) mapping tool to find optimal locations for renewable resources to reduce or eliminate transmission congestion. The project was expanded under another CEC project (CEC-500-2007) to study the impacts of high penetrations of California installed wind and solar projects.

In 2008 through 2010, BEW worked with Itron and Lawrence Livermore National Laboratory (LLNL) to expand the LVA to investigate the economic and operational value of high penetrations of distributed generation on the distribution grid. The Itron projects with BEW as a subcontractor (CPUC Self Generation Incentive Program-Sixth Year Impact Evaluation, August 2007 and CPUC Self Generation Incentive Program – Optimizing Dispatch and Location of Distributed Generation, July 2010) evaluated the benefits of existing distributed generation installed under the California Self Generation Incentive Project. The LLNL Project (CEC-500-2011-026) expanded the results of these two projects to study the economic and operational value of installing high penetrations of various types of distributed generation on the distribution grid such as cogeneration, solar, small wind, biomass, fuel cells, etc. All of these studies analyzed the major California electric utility systems.

Under the SMUD CPUC CSI RDD#1 contract and separate BEW contracts with HECO, BEW began developing detailed distribution feeder power flow simulation data sets for Synergi Electric, Power World Simulator, PSLF, PSS/E and potentially PSS/Sincal. The data sets are prepared for both unbalanced and balanced feeder representations. For each utility system, individual single-phase and three-phase PV inverters are modeled in the data sets. For HECO, the number of distributed PV inverters is over 4,000. There are 19 distribution feeders developed for Oahu, Maui and Big Island and 11 distribution feeders for SMUD that include a solar community, rural area with a long feeder and a digester, part of a large residential area and several other feeders. HECO has existing feeders with PV penetrations over 50%. BEW studied these feeders to determine the potential impacts from such high penetrations.

HECO has a mandate of 40% renewable penetration by 2025. SMUD and the other California electric utilities have mandates of 33% penetration of renewables by 2020. These renewable resources can be any combination of hydroelectric (under 30 MW generating capacity or smaller), biomass, wind, solar and geothermal. Initially, renewable resources could be located in-state and out-of-state. A revised state

mandate sets a percentage limit for in-state renewables. The construction of long high-voltage transmission lines to move power from remote areas to load centers is costly with long construction and permitting lead times. To counter this cost, the utilities began to facilitate the installation of distributed PV on the distribution feeders and behind the customer meters. While this reduces the need for costly transmission lines, it does create new problems for old distribution grids that are designed to move power from the substation to the customer load. The distribution system was never designed to move power from the customer to the transmission grid (reverse power flows) over the distribution feeder.

The CPUC CSI RDD Solicitation #3 is divided into distinct objectives: (1) Project Management; (2) Utility Interconnection: Nodal Approach for Strategically Locating PV; (3) Grid Operations: Case Studies of Evaluating Distributed PV on Distribution Grids.

The first objective is to expand upon previous California Energy Commission and California Public Utilities Commission Projects. Transmission simulation tools define both congestion zones and optimal locations for new generation through map overlays of renewable resource potentials across the transmission grid. This objective integrates the distribution grid with a visual mapping tool (i.e. GIS compatible platform specified by the utility) into an expanded locational value methodology. The approach assesses impacts across the system from a strategic development and grid enhancement perspective. California Rule 21 and Hawaii Rule 14H set guidelines and "triggers" in analyzing PV installations but not implementation. The methodology and process is used by utilities to facilitate distributed renewable resource expansion without negatively impacting system performance.

The second objective is to develop a validation approach to evaluate PV integration. Studies are carried out on potential impacts to individual feeders, substations, utility regions and utility grids from high DG PV penetrations. The participating utilities select different feeder configurations to demonstrate, evaluate and validate high PV penetrations under steady-state, contingency and dynamic scenarios. This objective is to document the ability of the software tools to study PV integration.

This report develops the basic steps that any utility can follow to produce consistent and repeatable studies on the potential impacts of high renewable penetrations on the utility distribution grids. To learn about each of the utility partner's application of this methodology and the results produced, please access the following website:

http://www.calsolarresearch.ca.gov/funded-projects/85-tools-development-for-grid-integration-of-high-pv-penetration

1 INTRODUCTION

In 2012, DNV GL was awarded a two year contract from the California Public Utilities Commission (CPUC) under the California Solar Initiative (CSI) Research, Development and Deployment (RD&D) Solicitation 3. The title of the project is "Tools Development for Grid Integration of High PV Penetration". Itron is the CPUC RD&D Program Administrator. This project builds on the Sacramento Municipal Utility District (SMUD) Solicitation 1 titled "High Penetration PV Project (Hi-PV) Impacts to Transmission and Distribution Grids" to develop tools and methodologies to study distributed PV and central solar plants impacts on the utility grids.

The team members are Hawaii Electric Company (HECO), SMUD, Pacific Gas & Electric (PG&E), and City of Roseville, California. The objectives of Solicitation 3 are to continue the studies on the potential impacts of distributed solar on the distribution grids and the development of a study methodology that any electric utility can incorporate into the planning process.

One of the objectives of the CSI3 study is the development of a methodology for the utility to use to evaluate the potential impacts and contributions of Distributed Generation (DG) PV to fault current, frequency, voltage, protection coordination, contingency outages, harmonics, flicker, etc. This methodology was developed through the CSI3 process and applied to the utility partners described above. Various regulatory agencies such as utility commissions, utility boards, other electric utilities, ratepayers and developers were given an opportunity to learn about this methodology and provide input. It is the intent of the methodology to provide a process that any electric utility of any size can apply to obtain consistent and reliable results and for ease of presentation to the regulatory agencies.

1.1 Objective and scope of review

This report describes a Proactive Planning Methodology for analyzing impacts on the transmission and distribution systems from high penetrations of central solar plants and/or distributed solar installations. Although the report concentrates on solar installations, the methodology is applied to any renewable technology, demand-side management, storage, and load shedding scheduling schemes. The report references specific studies on feeders in the Hawaii Electric Company, Sacramento Municipal Utility District (SMUD), Pacific Gas & Electric (PG&E), and the City of Roseville (Roseville) systems as examples. The Hawaiian electric utilities consist of Hawaii Electric Company (HECO), Maui Electric Company (MECO), and Hawaii Electric Light Company (HELCO). MECO has three islands (Maui, Molokai and Lanai).

Distribution feeders are selected for analysis based on the existing high feeder PV penetrations, projected high solar penetrations, diversity of customer types, available solar sensor locations, length of the feeder lines, and location/number of line regulators and capacitor banks. The study of individual feeders provides both a methodology for other electric utilities to follow and insight to the potential barriers and issues that restrict higher PV penetrations. Commonly followed DG standards such as IEEE 1547, (standard for interconnection of distributed resources with electric power systems) and IEEE 519 (recommended practices and requirements for harmonic control in electric power systems) are open to interpretation through the interconnection process. In-depth feeder analysis helps standardize and clarify the detail of measured data and analysis required.

Electric utilities have not historically installed power monitors and solar irradiance sensors on distribution feeders to collect real time data. This data is necessary for validating the feeder voltages, current, reactive power, frequency and other attributes that are impacted by high penetrations of distributed renewables resources. Distribution feeders are designed for power to flow from the substation transformer to the end of

the feeder. Transformer load-tap-changers, line capacitor banks and regulators, relay protection equipment and other feeder elements are designed to regulate and protect the feeder and its customers as power moves from the power source to the load. As high distributed renewable resources are installed, power moves in either direction depending on the customer load, environmental conditions and time of the year.

Lessons learned to date include:

- Availability of measured data is key to fully understanding impacts and sustainable development
- Software integration is essential for maintaining growing PV portfolios
- Preparation by utilities for high penetrations of variable resources in needed to get ahead and stay ahead of the curve
- Legacy and aging distribution equipment, such as load tap changers, are particularly impacted by variability of high PV penetrations
- Utilities need to plan in advance for upgrades and operational changes with informed and validated analysis
- Finding common ground with all stakeholders (i.e. operations, transmission and distribution planning, government agencies and developers) in necessary for continued sustainable PV development

The traditional distribution system is designed to deliver power from the transmission system through the distribution system to customer load so therefore the control and protection equipment on the system are designed to move electrical power in that direction. Now, local load centers can generate excess power to serve the local needs and export to the local utility grid.

Under feed-in-tariff ("FIT") programs, eligible renewable energy projects produce power to sell back to utilities. As more of the local, distributed generation is expected to come from variable, non-dispatchable PV resources, utilities must alter their planning process to account for power contributions from non-dispatchable local generation. Visibility and monitoring of non-dispatchable resources is an essential piece of the future proactive planning process.

The input data into power flow models is expanded, changed and modified due to the limitations of the existing software tools. Considerable time is spent evaluating the current modeling techniques, researching and collecting additional feeder and substation data, field verification of feeder elements and joint meetings with planners, operations, dispatchers, and managers to educate utility personnel on the expanded data requirements, field survey requirements and installation of additional recording equipment.

Installing power monitors and solar irradiance equipment requires planning and organization. Determination of where to place the equipment and the requirements for communication, data storage and data conversion are solved for each sensor and monitor. Communication links can be implemented through phone line, cell phone, on-site storage with manual reading, fiber optics or other. Safety, security and other factors are included in the decision process.

The implementation of research and development projects for testing and developing hardware and software for evaluating the impacts of distributed solar installations on distribution feeders and substations is slower and more complicated that envisioned. This is generally caused by insufficient historical data on solar

irradiance information; distribution feeder recorded operating data; and insufficient modeling of distribution feeders in existing software.

1.2 Background

In the California Strategic Value Analysis Project (SVA), California Intermittency Analysis (IAP) study and Hawaii's current Clean Energy Initiative (HCEI) renewable integration efforts, there is a lack of high quality, high resolution, field measured PV data to produce adequate modeling of high-penetration PV on the electrical system. This condition is a prevailing integration barrier not only for the solar community but also for wind, storage and other renewable efforts. Envisioned as part of this effort, DNV GL, SMUD and the Hawaiian Utilities collaborated in the development of a High-Penetration PV Initiative (Hi-PV) focused on development of distributed PV visualization tools supported by on-going field monitoring and data analysis at sites of interest; development and testing of hardware and software for enabling Hi-PV; and transfer of lessons learned.

SMUD, in partnership with DNV GL and HECO, implemented a research and development project that targets testing and development of hardware and software for evaluating the impacts from high PV penetrations on distribution feeders and substations. This effort addresses key grid integration and operational barriers that hinder larger-scale PV adoption into mainstream operations and onto the distribution grid.

The cooperation of the electric utilities in studying distribution feeder impacts from high PV penetrations, at first, appears inconsistent. SMUD is a load balancing authority and a land-based utility with many transmission interconnections to other utilities that provide backup power support. HECO consists of five islands (Oahu, Maui, Hawaii, Molokai, and Lanai) that lack interconnection capability with each other and serves as its own control and balancing authority. However, as different as the transmission and power sharing of resources are between the utilities, the distribution feeder configurations are very similar. SMUD currently has low PV penetration levels but is increasing while HECO has feeder penetration levels approaching 100% of feeder peak load on some feeders. HECO provides the perfect test bed for implementing cost effective measures to reduce barriers that can be incorporated into the SMUD system and any other utility grid.

SMUD and HECO are coordinating research efforts by studying specific distribution feeders to inject various PV penetration levels to determine potential impacts and develop a methodology for evaluating PV penetrations through software enhancements. This project received funding from the CSI RD&D Program first grant solicitation. The CSI RD&D Program is administered by Itron, on behalf of the CPUC.

As distributed PV and large-scale PV facilities continue to be planned and developed in both states, there is a need to implement quality field measurement campaigns and amass accurate data for improving electrical system models to include PV generators and integration control characteristics. Information developed can help inform PV manufacturers' development of new software, hardware, and communications approaches to respond to these needs.

With circuits throughout both California and Hawaii already experiencing high levels of PV penetration, and other feeders on the near horizon, immediate case studies are identified by SMUD and HECO for field monitoring; data collection and analysis; system modeling and simulation; and software and hardware development and testing. The sites focus on cases of immediate interest (e.g. existing high penetrations or

potential for high penetrations of PV), each requiring different monitoring and effort levels. These case studies provide the necessary data for the development and integration of the Hi-PV visualization tools (Planning, Operational and Forecasting) that assist SMUD and HECO to identify optimal locations that can benefit and accommodate more distributed resources (e.g. PV), visually track and trend changes within the respective distribution systems. These tools and research are useful to other utilities to better plan and utilize Hi-PV to improve the distribution systems.

Adequate modeling of the distribution circuits is an essential first step to investigate impacts on grid operation with an increasing content of variable renewable energy and to develop control and mitigation strategies. CSI RDD#1 was a three-year research project with the following objectives to demonstrate the application of modeling techniques to solve variable generating resource impacts on grid operation:

- Identify high penetration analysis needs (load flow, characteristics of the load, protection / coordination, voltage regulation, and islanding) for the distribution circuits being analyzed
- Identify additional data parameters to be collected and locations along the high penetration distribution circuits to place additional high-fidelity monitoring equipment, as necessary
- Record and collect at a minimum 6 months with a target of 12 months of high-fidelity load data from the newly installed high-fidelity monitoring equipment
- Collect electrical equipment nameplate data from the distribution systems being analyzed: distributed generation on the circuits, inverters, any energy storage, circuit size, circuit length, circuit loading, switchgear, and transformers to be used in the model development
- 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 adversely affect the grids
- Develop a methodology for extending the findings using the simulation tools to inform and expedite interconnection studies at higher penetration levels.

The collection of solar data from existing sites, installation of solar irradiance data at selected sites on the feeder, and collection of power data for the feeders either at the substation or at locations along the feeder have not been widely implemented. The first task in this project is the selection of locations to install equipment and begin collecting data for at least six months.

For some locations, equipment installation and monitoring proved to be problematic. Some of the problems discovered with the installation of data recording equipment are:

- Safety - Installations should not cause potential risk of injury
- Security – Equipment cannot be stolen easily
- Communication needs – Data transfer by cell phone, Supervisory Control and Data Acquisition (SCADA), fiber optics, etc.
- Equipment and budget availability – Type, cost, and utility available budget
- Data storage and management – Data can be one second or higher which creates large data files

Of the five items listed above, the installation of communication equipment (Item 3) and data storage (Item 5) created the most problems. Feeders can cover long distances creating potential issues with cell phone coverage, costs and availability of fiber options, and data storage limitations. Safety (Item 1) is a major issue when equipment is installed inside a substation. There are safety issues associated with locating measuring equipment to avoid personnel work space and operating equipment movement within the substation. The measuring equipment cannot be metal, must meet height restrictions while not placing equipment in shaded areas. For HECO, the measuring equipment had to be redesigned from a metal container to a plastic container and, unfortunately, is located where there is some potential shading from overhead lines.

The results of this first CPUC CSI RD&D project necessitated DNV GL, SMUD, HECO, PG&E, and the City of Roseville, CA to submit a proposal to continue this effort to expand the number of feeders studied and to develop a consistent and repeatable approach to study the impacts of high penetrations of variable generating renewable resources.

2 PROJECT OVERVIEW

2.1 Proactive planning analysis methodology overview

The Hi-PV analysis is separated into four major tasks as shown Figure 2.1. The first task is the gathering and monitoring of data. This includes the substation power measurements (real and reactive power, current, tap changer readings, voltage, power factor, etc.), measurements along the feeder (current, voltage, real and reactive power, etc.), customer PV output measurements and solar irradiance measurements at sites on the feeder. All the collected data is time stamped with readings in one second increments, where possible, otherwise the smallest increment possible. Data is encouraged to be collected for at least six months to cover the minimum and maximum feeder and substation demand periods. A full year of data is preferred for collection of cloud impacts and high generating unit maintenance periods.

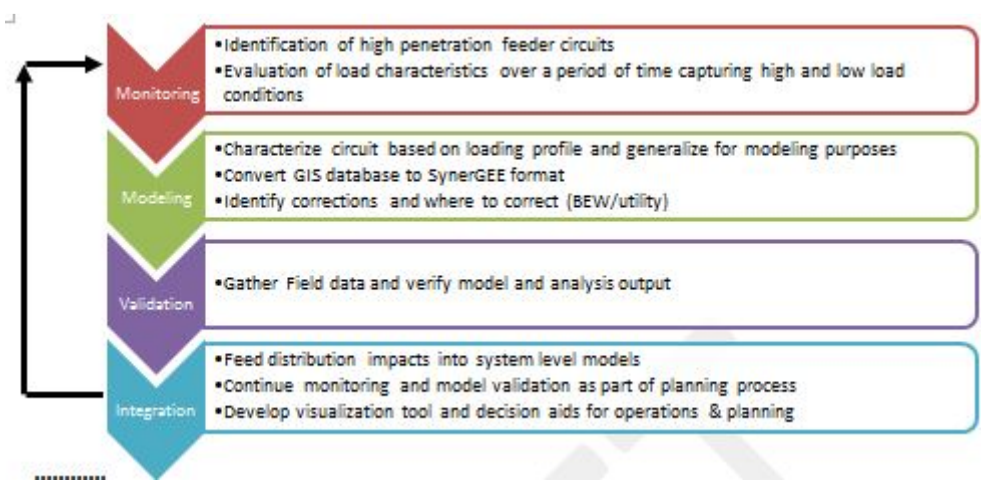

Figure 2.1 : Four Tasks of Hi-PV Study

The second task is "Modeling". The feeders and substation characteristics are input into distribution and transmission power flow tools to simulate the dispatch of generation (including PV) and power delivery to serve the customers. The distribution feeder is modeled in the unbalanced feeder mode meaning that the individual phases and associated connected line transformers; load and PV inverters are modeled. Each feeder element is associated with GIS coordinates for mapping of the feeder and the calculation of dispatch results. The data sets simulate different aspects of the power systems including electrical characteristics of the distribution circuits and relevant characteristics of PV inverters.

Typical distribution modeling tools include Synergi, CYME, ETAP, SINCAL, etc. for the distribution system analysis. Most of these distribution tools model various types of distribution circuits and distributed generation, but are limited to steady-state analysis (although recent upgrades are improving the dynamic capabilities). Potential high penetration effects from variable generating resources require transient or dynamic analysis. Power World, PSS/E, PSCAD and PSLF perform dynamic analyses for both distribution and transmission systems. This requires the distribution datasets be converted and transferred from the unbalanced feeder representation to the balanced three phase load used in transmission models.

The third task is "Validation". Before the power simulation results are used for operations and planning, the results are validated using the monitored data collected on the feeder in the first task. When the customers' load data on each line transformer, the line capacitor banks/line regulators, and existing PV installations are simulated in the power flow model, the results must be comparable to the actual data within an "acceptable" accuracy percentage. If the percentage differential is too high, then the application of the power flow tool to study high PV penetration impacts is limited. The selection of the "acceptable" accuracy percentage is not a pre-known value but determined after meeting with utility staff to review the data collected. The percentage may vary for each validation point.

The fourth task is "Integration". Integration studies determine the potential impacts of high PV penetrations on the distribution and transmission grids. Development of visualization tools and the integration of power flow tools are used in operations, transmission and distribution analyses. The results determine mitigation measures to solve distribution problems.

These tasks provide a validation of the model performance over several analytical time frames. Through data collection, modeling, and analysis, the detailed single circuit study identifies barriers (data gaps, as-built infrastructure limit) and informs system-level considerations and potential strategies for accommodating higher PV penetration levels.

2.2 Determining Project goals and objectives

2.2.1 Company goals

To attain future smart grid and clean energy targets for the utility operating environments, a utility goal is the development of a sustainable portfolio of energy supply (existing generation) and energy load management capabilities, including central plant and distributed variable generating resources, customer load management and other DSM programs. An advanced vision with enabling control technologies requires a strong understanding of solar resources and potential; tools to identify optimal siting locations and problem areas; predictive output tools; and strong communications and control approaches.

Over the next several years, utilities, such as PG&E, SMUD and HECO, expect that the high penetrations of PV and other technologies will reach levels requiring significant mitigation measures on the distribution system to maintain reliability, voltage control, and fault identification capabilities. An over-arching objective of the proactive planning methodology is to identify practical mitigation strategies for managing high penetrations of PV, which not only allows PV to reach higher penetrations, but ensure that it does so in a way that enhances grid reliability in the face of economic and environmental constraints. Meeting minute to minute demand with distributed intermittent resources providing a significant amount of the energy is a challenge. Doing it with a minimal amount of costly energy storage requires smart planning, much greater understanding of the solar resource, and a fundamental change in the communications and controls systems grid operators currently use to interact with generation resources. The proactive planning methodology aims to address each of these areas and enable electric utilities to demonstrate successful integration of very high penetrations of solar PV.

To achieve this effort, the utility develops a set of company goals covering all areas of the company operations and planning. There are specific goals developed by managers, planners, operators and field personnel, regulatory, finance, demand side management/load forecasting, and other departments on expanding renewable technologies. Before starting a proactive planning study and/or integrated resource planning study, the assigned responsible staff for developing these studies schedule meetings with company personnel to prepare a list of goals. From this list, the company prepares common targeted goals for the proactive study. These are shared with the regulatory agencies and stakeholders to obtain their respective goals.

For example, SMUD generates, transmits and distributes electricity to a 900-square-mile territory that includes California's capital city, Sacramento County, and a small portion of the Placer County. It is the sixth largest publicly owned utility in the US. SMUD has a regulatory Renewable Portfolio Standard (RPS) goal that requires 33% of its retail sales be supplied by eligible renewable resources. SMUD also has a Solar Initiative Incentive program goal of 125 MW of solar generation by 2016. These goals are the result of shared goal development.

2.2.2 Regulatory agency goals

Regulatory agencies can be city councils, public utility commissions, governments or others that monitor and regulate electric utilities. These groups have their own goals that may or may not agree with the utility goals and therefore must be reconciled to incorporate into the overall utility goals. The regulatory agencies may have electric rate requirements and renewable penetration levels, for example, that are not based on actual system reliability results. The utility may need to have meetings prior to beginning a study to ensure that the regulatory agencies are in agreement with the studies' objectives and that their goals are properly accounted for.

For example, SMUD is a municipal electric utility and governed by a seven-member Board of Directors (Board) selected by the voters to staggered four-year terms. The Board determines policy and establishes goals. In addition to the RPS goal of 33% renewables, the Board established a long term carbon reduction goal of 90% below 1990 levels by 2015. SMUD expects renewable energy, including solar, to play a substantial role in meeting its goals.

2.2.3 Stakeholder goals

The utility holds public meetings with electric customers, regulatory agencies, interest groups and others to hear the utility's upcoming studies and associated target goals and provide feedback to the utility. The utility must be prepared for a wide range of responses from residential and commercial rate payers interested in keeping electric rates down while special interest groups want high penetrations of renewables without regard to rates. These special interest groups may want to reduce fossil fuel usage, prevent wind turbine development, oppose off-shore development, reduction of carbon emissions, oppose new hydroelectric plants, and many other issues.

At these meetings, special interest groups may oppose each other to create "heated" debates. The utility may find little support for the utility's goals. The stakeholder meetings are necessary to obtain the positions of groups to ensure that the utility makes a concerted effort to recognize and address the different positions. These meetings may be held at one location or at various locations within the utility district, depending on the utility size and the concentration of customer load.

Once the utility staff obtains the responses from all parties, a revised utility goal and objective is developed.

In SMUD's case, SMUD's seven-member Board of Directors reflects stakeholder interests. Each director represents a different geographic area or "ward." During their four-year terms, their job is to establish policies and values about how SMUD serves its customers and to set the long-term direction SMUD will take moving forward in the 21st Century. In addition, Board and Committee meetings are held on a regular basis at SMUD's headquarters. The public can address the Board during these meetings and are given up to three minutes to provide comments to the Board.

2.3 Determining evaluation criteria for study objectives

The evaluation criteria (or Technical Criteria) identify conditions or issues impacting the grid that may preclude additional PV penetration onto the circuits. Technical Criteria are defined as a technical problem created on the electrical system with increasing levels of renewable technologies.

For steady-state analysis, Table 2-1 lists the Technical Criteria, associated limits and associated effects and impacts. Table 2-2 lists the Technical Criteria for dynamic modeling analysis conducted as part of this report.

Table 2-1 : Technical Criteria for Steady-State Analysis

Technical Criteria	Limit	Effects and Impacts
Backfeed	Reverse power flow as output of distributed generation exceeds feeder load	Existing distribution system equipment (such as transformers) have control systems that are set up to handle power flow in one direction only – from the transmission system through the distribution system to the customer. When power flow reverses at the transformer, the existing control systems may not recognize the change in direction and only sense the magnitude of the power. This can result in voltage regulation equipment moving in the wrong direction, causing increasing voltage problems.
Load Tap Changer (LTC) Position	Change in LTC position due to variation in PV output between 100% - clear conditions and 20% - cloudy conditions	The LTC is a voltage regulation device integrated into the transformer. In order to maintain the voltage on the distribution system within a specified band-width, it can increase or decrease the transformer voltage ratio incrementally when system load or generation conditions change. If the number of LTC position changes increases, this can cause a decrease in the service life of the equipment, and require more frequent maintenance or replacement.
Thermal Loading	Line loaded over 100% of specified capacity	If a line section is overloaded it can over-heat, causing potential damage to the equipment itself or surrounding structures.
Voltage	Voltage at any point on the distribution system is less than 95% or greater than 105% of nominal.	Customers would experience high or low voltage problems which can damage appliances and service may be lost if voltage remains outside nominal ±5%.
Fault Current	Short circuit contribution ratio of all generators connected to the distribution system is greater than 10% (California Rule 21 and Hawaii Rule 14H criterion)	Increases in fault current may require upgrading of protective equipment on the system. Circuit breakers at the sub-stations are rated for a maximum level of fault current, and if this value is exceeded the breakers may not function as required, causing damage to equipment and required replacement.

Table 2-2: Technical Criteria for Dynamic Analysis

Technical Criteria	Limit	Effects and Impacts
Under Frequency Inverter Trip	During an N-1 analysis, additional load shedding occurs compared to event occurring with no PV installed.	If PV inverters trip due to under-frequency during a transient event, this can lead to a cascading loss of generation, to which the electrical system responds by shedding load (blackouts) in order to balance the load with the reduced available generation.
Over Voltage Inverter Trip	During an N-1 analysis, additional load shedding occurs compared to event occurring with no PV installed.	As above, during a rapid reduction in generation due to inverters tripping, the voltage may vary, which again can be alleviated in the short term by the electrical system shedding load.

2.4 Determining time periods of interest

Transmission and distribution power flow studies are normally single points in time or short time intervals of less than a day. The renewable technologies determine the time periods of interest. For example, maximum wind generation normally occurs at night while solar maximum generation occurs during the daytime hours. There are two time periods of interest for solar studies. These are referred to as the "Minimum Daytime Peak" and the "Maximum Daytime Peak" periods. Minimum daytime peaks are the hours when solar generation is highest and utility load is at its lowest. Maximum daytime peak are the hours when solar generation is high and utility load is also high.

Wind generation usually does not peak during the same hours as solar so there could be one or two additional time periods of interest for wind. The wind periods can occur during the night; during the morning; or evening time periods. The last potential time periods of interest are maximum up and maximum down ramping. There are two ways for calculating maximum ramping: maximum ramping can be either up or down for wind and solar; or maximum ramp up or down for wind, solar and load. These ramp times normally occur during the morning when customer load and solar are increasing while wind is decreasing; or the evening when customer load is increasing while solar output is decreasing. During these time periods, the utility dispatchers are considering starting or shutting down conventional generation. If there is a sudden change in load or renewable generation, the dispatcher may not have sufficient spinning reserves or generating capacity to serve load.

Figure 2.2 below shows the recorded PV output for a single day, in 15-minute intervals. For this example, the PV output is at 100% between 10:00 am and 3 pm.

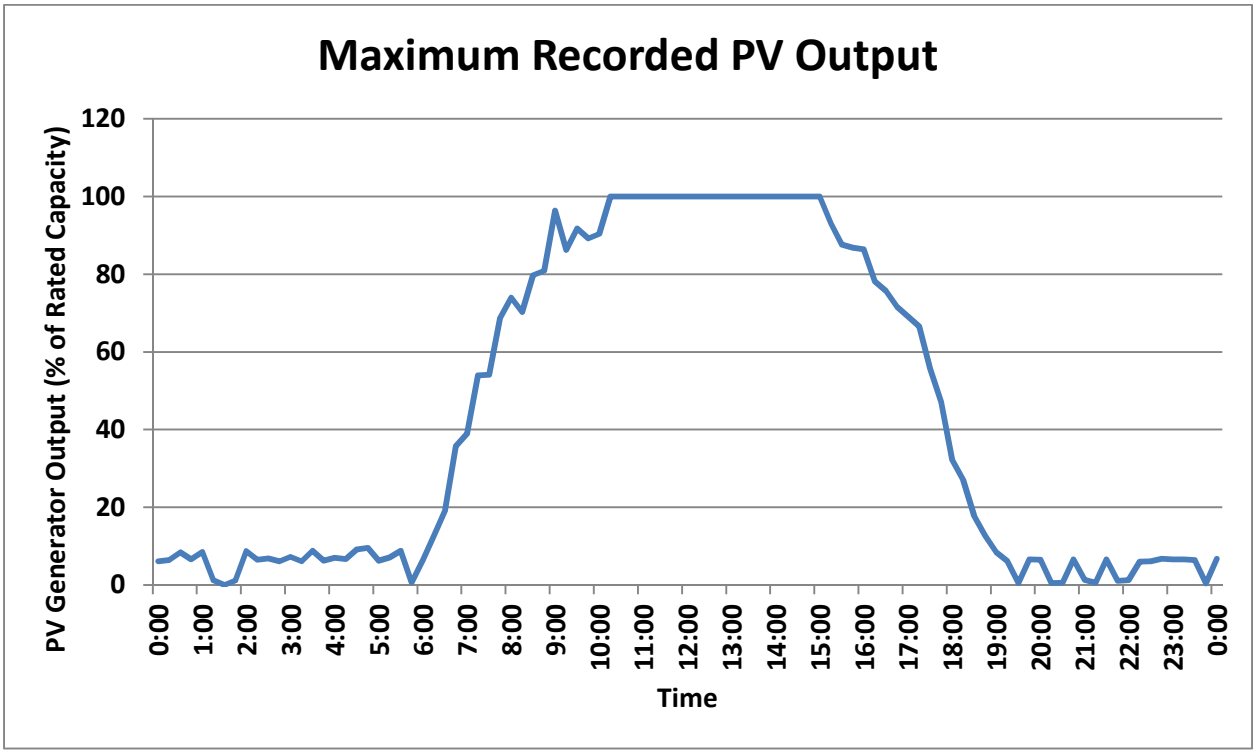

Figure 2.2 : Maximum recorded PV output

This example demonstrates the need by the utility planners to research and analyze the historical data to determine the time periods of interest, availability of data and the time increments for the study. There are certain questions to be answered such as:

- What is the purpose of the study?
- Who the study is for and what are the objectives to solve? (Operations, planning, regulatory, etc?)
- For the study selected, is 1 second, 1 minute, 5 minutes, 15 minutes or one hour needed?
- What are the duration and time increments of the study?

Once the utility planner determines the time period and time increment of interest, the next step is selecting the system demand requirements.

2.5 System peak, minimum daytime peak, maximum daytime peak

In solar analysis, there are three load definitions of interest that define the PV penetration and the loads analyzed. The load cases define the boundary limits on the system, such that the results of scenarios fall somewhere between these two cases. The load definitions are described further in the following paragraphs.

Peak Load refers to the peak recorded demand for the study system. This is normally measured at a sub-station, either at a circuit breaker or transformer. It is a measured value – rather than calculated – so it is considered net load for a feeder with installed PV generation. This value indicates the relative amount of

loading on a feeder, and also as a reference point when discussing PV penetration – PV penetration is often defined as '% of peak load'. The value of peak load is therefore defined two different ways. The "net" load is the measured peak value after the solar generation. The "gross" peak load is the summation of the net load plus the solar generation at the time of the measured load is read. The "% of peak load" is the percentage of the "gross" peak load.

Minimum Daytime Peak refers to the lowest load recorded during the hours of daytime – 10am to 4pm. This time period occurs at any minimum daytime period when solar is at its highest and load is at its lowest for the same time period. For most utilities, this is defined as an April Sunday noon time period when most business are closed, a spring period with mild temperatures requiring no air conditioning or heaters, and noon represents a clear day with no clouds.

Maximum Daytime Peak refers to the highest load recorded during the hours of daytime – 10am to 4pm. This time period occurs at any maximum daytime period when solar is at its highest and load is at its highest for the same time period. This could occur on any day of the year.

The utility planner uses recorded historical load data for the area studied to determine the three load points. The minimum and maximum daytime peaks can be between the hours of 10am and 4pm when solar generation is at its highest value. The peak load occurs at any time during the year and may even occur when solar is not generating, such as the evening period. Once these time periods of interest are determined, the planner uses this data in the solar penetration analysis studies described later in the report.

To determine these time periods, the planner develops a spreadsheet with some historical or projected hourly load for an entire year. For the year selected, the planner develops hourly solar generation profiles that correlate to the same load year and add to the spreadsheet. The planner then picks the daytime peak period of interest, which in this example is between 10am and 2pm. All hours outside of this time period are deleted leaving only those selected hours of interest. The data is then sorted using the solar data as reference, as shown below.

For this example, the solar size is 1 MW. The maximum daytime peak occurs on Wednesday, January 8 at noon. The minimum daytime peak occurs on Sunday, September 14 at 2pm. The same type of analysis is used for the selection of the wind maximum and minimum time periods.

Table 2- 3 : Determination of Maximum and Minimum Daytime Peak Periods

Month	Day	Hour	Load (MW)	Solar Output (MW)	Note
March	13	13	25.898	1.03	
September	14	13	23.978	1.02	
October	2	13	25.901	1.02	
March	23	13	25.907	1.02	
March	13	14	24.115	1.01	
February	19	13	24.677	1.01	
November	3	13	22.583	1	
October	2	12	26.699	1	
September	14	14	21.923	1	Minimum - Sunday
December	14	13	25.633	1	
March	19	13	26.154	1	
January	8	12	27.47	0.99	Peak - Wednesday
March	14	13	25.164	0.99	
September	14	12	24.228	0.99	
March	23	14	24.423	0.99	
March	21	13	25.907	0.99	
March	13	12	26.551	0.99	

2.6 Maximum ramping of renewable resources and load

In transient analyses, an important simulation is the maximum ramping scenario. There are several scenarios that are of interest:

- Maximum ramp up of PV output: This usually occurs in the morning as the PV turns on, but could also occur later in the day where clouds are involved. The most important scenarios are the maximum change in PV output that occurs within the time delay of the voltage regulation equipment – typically assumed to be 30 seconds if no data is available. This condition identifies voltage problems on the distribution circuits that occur when the voltage regulation equipment is not operating or responding to rapid changes in voltages due to the variability of solar generation.
- Maximum ramp down of PV output: This usually occurs in the late afternoon when PV output is reducing towards sunset. The load on the system may also be increasing, compounding the problem for generator dispatch (i.e. as PV output decreases and load increases, the amount of energy required from conventional generation increases rapidly). The maximum combined demand increase over different time intervals is investigated to identify the worst case for generator dispatch.
- Maximum ramp up of PV output and load: This usually occurs in the early morning when PV output is increasing at sunrise. The load on the system is increasing, compounding the problem for generator dispatch (i.e. as PV output increases and load increases, the amount of energy required from

conventional generation decreases rapidly). The maximum combined demand increase over different time intervals is investigated to identify the worst case for generator dispatch.

- Maximum ramping of solar generation over a 35 second time increment: This time period is a time period where solar generation experiences the largest change in generation due to environmental conditions or operational changes. Environmental changes may be large dense cloud formations moving over solar installations causing the solar systems to suddenly decrease or increase generation as the cloud passes overhead. Operational changes are the shut-down of solar generation due to feeder outages and start-up after the system is restored. The 35 second time period is normally the time delay of the transformer load tap changer. During this time period, the feeder voltage may increase or decrease outside of normal voltage limits.

The distribution planner uses the same historical load data to find the greatest ramp change over the interval of load data available. The interval of data may be 1 second, 1 minute, 5 minutes 15 minutes or hourly. The time increment depends on the type of study conducted and is determined by the distribution planner.

The same spreadsheet that is used to determine the maximum daytime peak and minimum daytime peak can be used to calculate the maximum ramping. In the example below, the maximum up ramp and maximum down ramp is calculated for a 59 MW load only and for a renewable system comprised of 10 MW of wind and 5 MW of solar plus load. For the load analysis only, the maximum ramp up and maximum ramp down are +11MW and -13MW, respectively. Adding the 25 MW of renewables, the maximum up and maximum down rates are +12MW and -14MW, respectively.

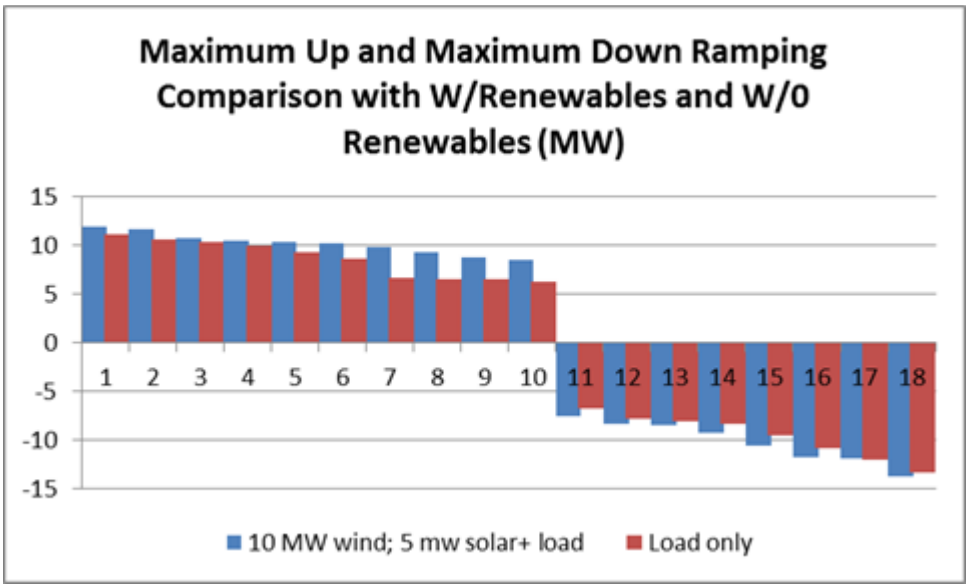

Figure 2.3 : Maximum Up and Maximum Down Ramps

In this example, the wind and solar penetration is not high enough to increase the up and down ramps of the system. There are several reasons for the lack of impacts of wind and solar on the ramp rates. The first reason is the percent penetration is not large enough to impact the load swings. The second reason is the

wind and solar energy profiles are too low to impact ramps. If the capacity factors are below average, wind and solar do not produce sufficient generation to operate at high outputs.

2.7 Selecting cluster areas and feeders of interest

The definition of a feeder cluster is specified according to the parameters of the overall system, and the most appropriate way of splitting the distribution system. The circuits included in a cluster are electrically connected at some voltage level, for example the cluster may include the distribution feeders connected to a single transmission line, or connected to a single sub-station transformer.

Prioritizing which feeders or clusters to analyze involves a combination of a few parameters:

- Existing and queued PV penetration: Feeders with high existing or queued PV penetrations are more likely to experience problems on the distribution system in the near term than the feeders with little or no currently installed or queued PV generators. Analysis of feeders with large amounts of existing PV generators have lower levels of uncertainty in the results as assumptions are not required on the placement of the new solar generators in the circuit.
- Available load data: Where load data is unavailable, there are high levels of uncertainty in the results of the analysis. Therefore, it is preferable to prioritize feeders with available data for study, while collecting data on those feeders without available load data.
- Feeders of particular interest: Other aspects may come into consideration when prioritizing the feeders to study. Examples include feeders where new line regulators are tested or systems where operational processes such as Conservation Voltage Regulation are tested. Where these exist, it may require studies be completed on these first.

The planning engineer must consider these factors in determining the priority of feeders and clusters to study. The planner must develop the criteria used to select feeders and clusters before proceeding in the study. The planner should schedule meetings with other planners, managers, operations staff, renewable technology experts and others to collect ideas and suggestions. From this information, the planner can prepare the method for reviewing feeders and determining the size of the clusters and the priority list for studies.

Definitions for the clusters are provided below and illustrated in Figure 2.4 and Figure 2.5.

1. ***A Distribution Circuit*** provides electricity to customers on various levels, including residential homes, commercial buildings and industrial parks, amongst other load types (Figure 2.4). On Oahu, the majority of PV installations are on the distribution circuit in the form of rooftop PV systems and ground mounted installations. A PV system may be connected at the subtransmission level depending on the size and interconnection requirements.
2. ***An Electrical Cluster*** is defined as a subtransmission feeder, down to the distribution substations and the associated distribution circuits that are fed from these substations (Figure 2.5). Electrical Clusters are identified to study a single subtransmission feeder and all electrically connected distribution circuits to study the effects of PV on each distribution circuit as well as the aggregate effects on the subtransmission feeder to obtain a complete picture of the aggregated impacts. A

subtransmission feeder provides a path to transmit electricity from the system level (138kV transmission line on Oahu) down to distribution level (distribution substations, distribution circuits 12kV and lower). For Oahu, the subtransmission feeders are rated at 46kV.

3. ***Regional Clusters*** are geographically organized areas grouping electrical clusters and may share similar terrain, solar availability and weather patterns. Twelve (12) Regional Clusters were identified for the island of Oahu. Creating Regional Clusters helps to organize the electrical clusters and distribution circuits for analysis.

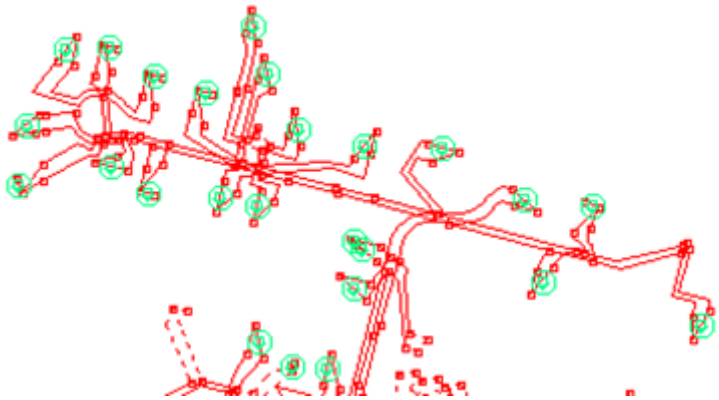

Figure 2.4 : Detailed Feeder Model representation of a single distribution circuit and associated distributed roof-top PV systems shown in green

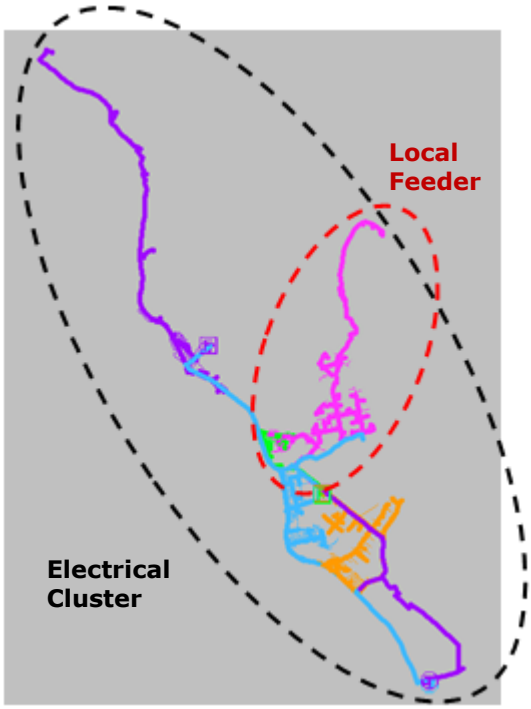

Figure 2.5 : Geographical representation of distribution feeders, comparison of the distribution feeder (electrical lines circled in red) and electrical cluster (all lines circled in black)

2.8 Setting power quality and solar sensor equipment

The selection of sensor and measuring equipment is determined by the utility staff. The type and number of sensors is dependent on the utility budget, data collection requirements and time increment of data. An example of data equipment is described below by Sacramento Municipal Utility.

Under a previously funded grant project, the High Penetration PV Initiative, SMUD installed solar sensor equipment to collect solar irradiance data and monitoring equipment, as necessary, to collect feeder data (i.e. voltage and current).

SMUD contracted with NEO Virtus Engineering to design, manufacture and deploy a solar monitoring network of five primary and sixty-six lower cost secondary irradiance monitoring stations. The network is deployed on a five kilometer grid using autonomous PV/battery powered data loggers installed in substations and on SMUD utility poles. The five primary stations used Rotating Shadowband Radiometers (RSRs) to collect and store irradiance measurements at the substations, while independent data loggers combined with global horizontal pyranometers made up the 66 secondary monitoring stations.

The primary RSR stations are an existing commercial product which NEO Virtus Engineering manufacturers for a client. The secondary stations, however, are designed "from scratch" for SMUD due to the unique requirement for mounting on utility poles. The exterior enclosure design includes a PV module and bracket, an adjustable pyranometer arm and support bracket for easy pole mount. The internal enclosure design houses a battery, data logger, cellular modem and associated electronics. The primary and secondary stations collected data in 1-minute resolution.

To collect feeder data, SMUD typically utilizes current transformers (CTs) and potential transformers (PTs), Remote Terminal Units (RTUs) and serial servers. Information is transmitted to SMUD via fiber, radio, cellular and communication lines depending on the site. Data collection intervals varied from 15 minutes to seconds.

Another example of equipment to collect customer data is from the City of Roseville, California.

The customer voltage data measured by Boomerang power quality analyzers in the field contain 240 V measurements at 1-second resolution for six locations on multiple feeders within the Westplan region. This data is used with the SCADA data to validate the Westplan model by comparing load flow simulation voltages to measured voltages at each hour in the minimum demand day.

2.8.1 Determining time increments of data collection

The time increments of data are determined by the type of studies being conducted and may be limited by the equipment deployed. Table 2-4 below displays a list of the analysis type and the associated time steps.

Table 2-4 : Time-steps required in data for different analysis types

Analysis Type	Time-Frame	Study Level (Cluster/Nodal/Large Individual/Small individual)	Validation Data Time-Step Required
Voltage Profile	Steady State	All	15 minute
Thermal Limits	Steady State	All	15 minute
Tap Changer Cycling/Inverter interactions	Steady State	All, evaluate with each interconnect	15 to 30 s irradiance data
Change existing Line Drop Compensation (LDC) settings	Steady State	All, evaluate with each interconnect	Time delay of LTC
Protection	Steady State	All	Sub-cycle
N-1 Generator Trip	Dynamic	Nodal/Cluster	1 second
N-1 Line Trip	Dynamic	Nodal/Cluster	1 second
All PV trip	Dynamic	Nodal, Cluster and large individual	1 second
Flicker	Dynamic	Nodal, Cluster and large individual	1 second
Harmonics	Dynamic and Steady State	Nodal, Cluster and Large Individual	Sub-cycle
Generator Dispatch	Dynamic and Steady State	Cluster	15 minute

2.9 Selecting simulation tools

The proactive planning methodology involves several types of analysis and subsequently different simulation tools or models. The requirements of the tools for each of the analysis types are discussed below.

Steady-State Analysis: Steady-state analysis is the simulation of the system under static conditions, an outage of a major distribution element or a major environmental condition. Steady state tools normally simulate a single point in time such as the minimum daytime peak. However, the newer tools are being updated to simulate short time periods up to one day. The simulation tool must be able to develop datasets of the distribution grid down to the distribution line transformer level. This requires the simulation tools to represent single-phase, two-phase and three-phase line taps. With the installations of large subdivisions with high solar rooftop penetrations, the simulation tools must now be able to represent secondary service

drops down to each residential home. Utilities are discovering that high concentrations of rooftop solar installations can create conditions of high voltage within a confined area.

Steady-state tools are used to evaluate scenarios of renewable technologies impacts on voltage, line loading, backfeed, current, and other factors.

When fault analysis studies are conducted, the steady state simulation tool must set the fault current for each of the inverters attached to the PV generators. The simulations involve varying the load and the output from the PV generators independently (and also varying independently the output of the existing generators and future generators). This must be considered when selecting the simulation tool. Finally, the tool must run load flow simulations and fault analysis simulations, producing output in terms of load, voltage, line section loading, Load Tap Changer (LTC) position and available fault current.

Transient Analysis: The transient studies considered in this proactive planning methodology should use the same model as the static analysis. These studies are intended to simulate changing environmental conditions, such as a change in irradiance due to a cloud passing over a system with some PV installations. In this case, the output of the generators may change within the time delay of the voltage regulation equipment, and at some PV penetrations this can result in voltage violations on the distribution system. The simulation tool must be capable of changing the control status of the voltage regulation equipment between time-steps while the generation output is ramped up or down.

Dynamic Analysis: In the dynamic analysis, a single-phase based dataset is not necessary, and load and generation are aggregated up to the three-phase level. In these analyses, the simulation tool must analyze the transmission model and calculate system frequency and voltage at a minimum. The tool must simulate inverter logic (such as frequency ride-through and voltage ride-through settings), and load-shedding schemes.

There are many commercially available simulation tools on the market that the distribution planner can license and in which they can receive training and support. Many utilities use their own internal developed tools that are customized for the specific utility. This report does not recommend specific tools but leaves that to the utility planner to determine.

2.9.1 Determining input data requirement

The required input data is determined based on the criteria to be analyzed. The system violations of the highest interest include:

- Reverse Power Flow;
- High/Low Voltage;
- Line Loading;
- Fault Current;
- LTC Cycling;
- Load-Shedding

The data required for each of these criteria are discussed in the following sections.

Reverse Power Flow: To determine when PV penetration levels could cause reverse power flow, the minimum daytime load is used to represent the feeder load. In theory, when the gross PV installed equals the minimum daytime load plus total feeder losses, there is the possibility of reverse power flow occurring at the substation bus.

However, a more accurate estimate is obtained using a feeder model that includes conductor and equipment impedances. Using this more detailed method, the line losses between the distributed generators, loads and the substation of the feeder are taken into account. This analysis may result in slightly higher PV penetration limits on the feeder given a more detailed representation of the feeder parameters.

Reverse power flows can occur along the feeder line segments. Reverse power flow along a feeder impacts protection equipment operation and coordination and creates negative effects during the implementation of switching routines and voltages.

High/Low Voltage: For voltage studies, the reverse power flow model is used and expanded to include distributed load, distributed generation, conductor impedances, equipment impedances, capacitor banks on the circuit, and voltage regulation equipment and settings. In addition to the feeder model, a load profile is required for the maximum daytime peak and minimum daytime load days, in terms of total feeder kW load. Finally, to ensure that the model used in the analysis accurately represents the real-life results, validation data is required. This includes a load profile for a given day on the circuit, along with associated voltage measured at the transformer. This allows a validation study to be performed where the load profile is input to the model, and the resultant voltage at the transformer is compared against the measured value.

Line Loading: For the line loading study, the feeder model is required, and includes rated continuous current carrying capacity of each line section on the feeder in addition to load and generation. Load profiles for the maximum daytime peak and minimum daytime load days are required, in terms of total feeder kW load.

Fault Current: For the fault current study, the same feeder model is required. Data includes the distributed load, distributed generation, conductor impedances and the available fault current from each inverter.

LTC Cycling: For the LTC cycling study, the steady state feeder model is required, as well as validation data and load profiles. The feeder model includes the sub-station transformer with Line Drop Compensation (LDC) settings, transformer CT rating and PT ratio, and LTC voltage set-point, along with the feeder configurations and impedances. The validation data includes the recorded LTC position, which is used similar to the voltage study above. The demand profile from the validation data is entered into the model, and the LTC position at each time-step checked against the recorded position. Finally, the load profiles include both the maximum daytime peak daytime and minimum daytime load profiles, in terms of total feeder kW load.

Load-Shedding: The load-shedding study requires a dynamic analysis including the transmission system. For this study, the transmission system model is required, along with dynamic data for the equipment on the system. The voltage and frequency ride-through settings for the PV generators are required, along with the load-shedding settings for any load-shedding schemes in the model.

Table 2-5 below presents a summary of the data requirements for each of the criteria:

Table 2-5: Summary of the data requirements for each of the criteria

Parameter	Data Required
Reverse Power Flow	Load Profiles, Feeder Model (for accuracy)
High or Low Voltage	Load Profiles, Feeder Model, Validation Data
Line Loading	Load Profiles, Feeder Model
Fault Current	Feeder Model
LTC Cycling	Load Profiles, Feeder Model, Validation Data
Load-Shedding	Transmission System Model, Dynamic Data, Inverter Settings, Load-Shedding Settings

2.10 Utility load forecasts

Since the distribution simulation tools normally simulate a single point in time or small time periods up to one day, short-term and long-term load forecasts are not required. However, since the utility planner must now expand from these single point periods of time over several years to hourly load forecasts over the years, it becomes necessary to properly account for utility load forecasts.

Examples of these multiple year analyses are on the minimum daytime peak load forecasts and on the hourly load forecasts. A utility planner must prepare renewable technology scenarios that require different renewable technologies to be commercially available into the future. The planner must be able to develop a "road map" on the various tracks that the utility can proceed to achieve the planned renewable penetration as cost effective as possible.

Figure 2.6 below demonstrates the changes that high solar penetrations create over time that need to be considered in long term planning. In this chart, the minimum daytime load forecast is presented for each year on one HECO distribution feeder. In just three years, HECO has experienced a significant drop in load during the midday time period. This creates a major problem for the utility to maintain system reliability and stability. The utility planner must alter the existing resource mix to provide spinning reserve margins, cycling unit capability and fast start generation to provide the reliability and stability during solar sudden generation patterns.

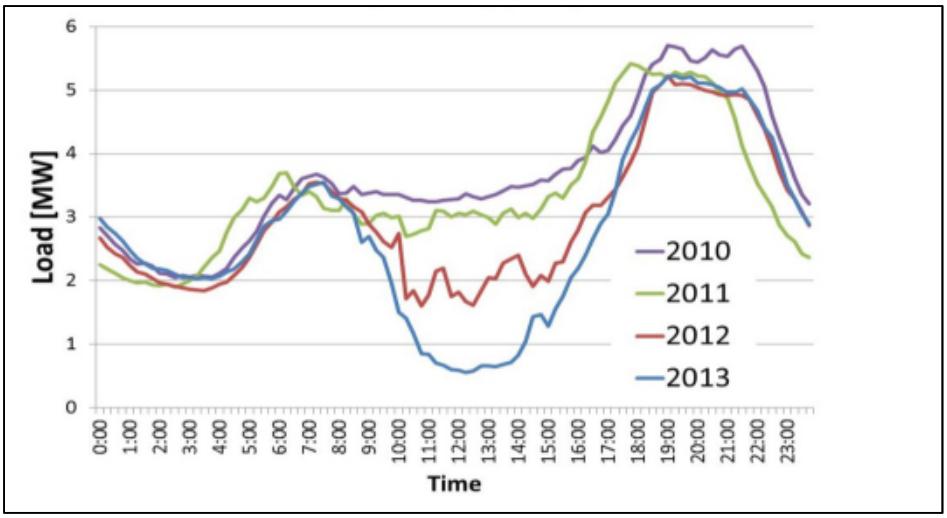

Figure 2.6 : Impacts of Renewables on HECO's Daily Load Forecasts

Analyzing Figure 2.6 above dramatically demonstrates the impacts of distributed solar on generating forecasting. The minimum load at noon in this figure dropped from 3.3 MW to 0.8 MW in just three years. The customer load at noon probability had some increase in energy consumption over the three year period but the net load at noon does not show any such occurrences. In fact, if the solar is suddenly removed for some reason, the utility must provide the load level that existed in 2010 at noon.

To conduct these types of studies, a short-term and long-term load forecast is developed. The forecast includes load growth rates for the various customer classes, demand side management forecasts, load shedding schemes, energy efficiency program impacts and other demand-reducing plans. The forecasts need to include risk factors for each of these demand-reducing plans. Some utilities are experiencing negative load growth as these demand-reducing programs are implemented that is requiring the utility to develop a long term load forecast strategy.

2.10.1 Customer loads

In addition to forecasting total load growth, the utility planner must also forecast changes in customer loads and mix. The planner must know the percentage make up between industrial, commercial and residential. A high percentage of residential load can make significant changes in load patterns since these can add solar, storage, electric vehicles and energy efficiency devices over a very short time period. A high percentage of industrial and commercial load tends to consume more power off peak which impacts wind generation. Another load group is the recreational or vacation load patterns that tend to be more seasonal and variable. These load patterns can quickly outpace generation mix that provides the stability and reliability to the grid.

2.10.2 Net vs gross loads

Many utility planners fail to recognize the impacts of not determining gross loads prior to conducting load forecasts and implementing energy efficiency programs or distributed generation studies. Gross load is the summation of metered customer load plus losses plus distributed renewable generation plus some demand-

reducing programs. In real time, the gross load changes every second, but for utility planning the gross load is aggregated into time increments such as hourly or 15 minute for each year of the study period.

All of the variables needed to calculate gross load change every hour. The SCADA and Operations Measurement Systems (OMS) measure net demand at each substation and sub-transmission breaker. The demand measured at this point includes the load used by the customers on the circuit (gross load), minus the effect of any PV generators on the circuit. This is shown in the figure below where the blue area represents the demand value measured at the substation, the green area represents the part of the gross load that has been served by the PV generators on the system downstream of the sub-station, and the red line represents the actual gross load on the circuit. Figure 2.7 shows that the gross load is the sum of the demand measured at the sub-station, and the output of the PV generators on the circuit. In order to determine the gross load, the PV output for the day in question is estimated, and added to the demand measured at the sub-station.

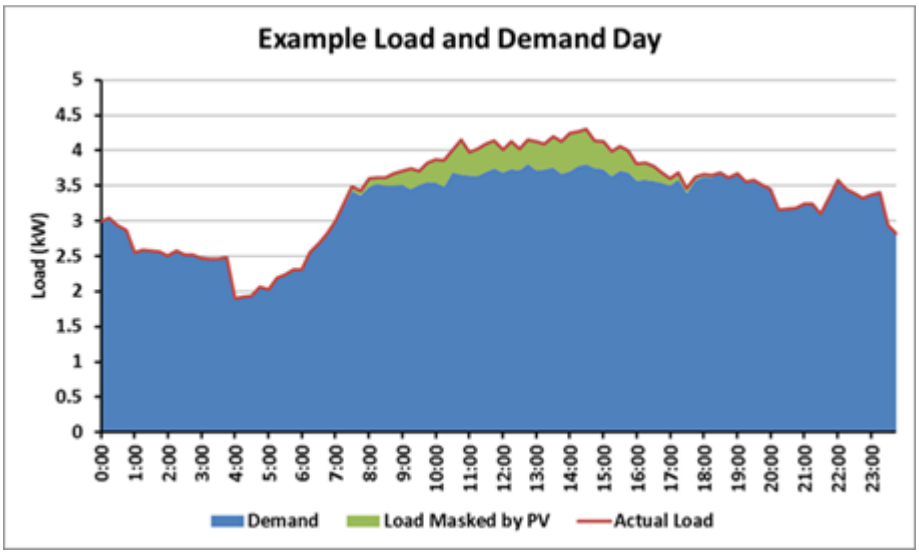

Figure 2.7: Gross load is the sum of the demand measured at the sub-station, and the output of the PV generators on the circuit

Why is it important to calculate a gross load?

- Customer load growth percentage is applied to the customer gross load as if solar generation was not there. If the customer turned off the solar, the utility would immediately see the full load appearing
- Without knowing the customer total gross load, the utility does not know how the customer is using their electricity, the load pattern changes that may be occurring, or the efficiency of the system
- Variable generating renewable resources are considered non-firm meaning that these types of resources can discontinue operation at any time

- As higher penetrations of distributed solar are installed, the overall net savings or value to the utility decreases. The utility must plan spinning reserves around the gross load to ensure adequate back-up power in case of the losing variable generation at any moment
- If the utility cannot recognize the gross load and the impacts that installed distributed generation and demand-reducing programs have on the load, then it becomes more difficult to forecast future cost effective programs.

Once the gross load profile is known for a given day, simulations can be performed using different PV penetrations and outputs with a common assumption on the variation in gross load throughout the day.

2.11 Existing, queued and projected solar

To identify potential solar-created problems, a range of different PV penetrations is simulated. Normally, the case with no PV is simulated first. This allows a baseline analysis to find existing problems on the feeder identified. If a loading or voltage issue exists in the baseline before PV is added, this should be checked and potentially corrected with the utility prior to continuing the study.

The PV penetration is then increased in steps (step size can be chosen based on time available to do the study and the level of detail required). Existing PV sites are added first and then the queued solar, as these represent the lowest level of uncertainty for commercial operation. Once these PV sites are modeled and at maximum solar output, higher PV penetrations are achieved by adding 'future' PV sites. The assumptions involved in the addition of this future solar are important for the results of the study. It is recommended that the following three scenarios are considered:

1. All future PV is placed in a single location near the substation. This has the potential to result in voltage violations near the end of the feeder furthest from the substation as the PV masks the actual load on the feeder from the voltage regulation equipment in the substation resulting in ineffective line drop compensation. See Figure 2.8 below.

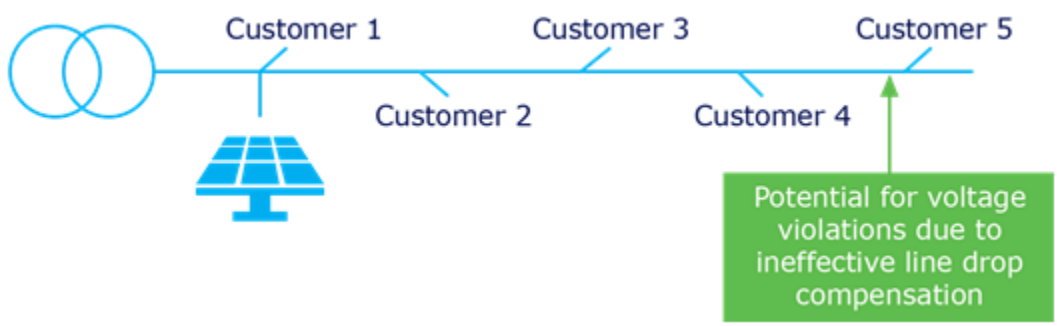

Figure 2.8 : Future PV located at substation

2. All future PV is placed in a single location near the end of the feeder furthest from the substation. This has the potential to result in thermal overloads and voltage violations near the PV site as the distribution circuit is generally weaker there as the power flow is normally the lowest on the circuit. See Figure 2.9 below.

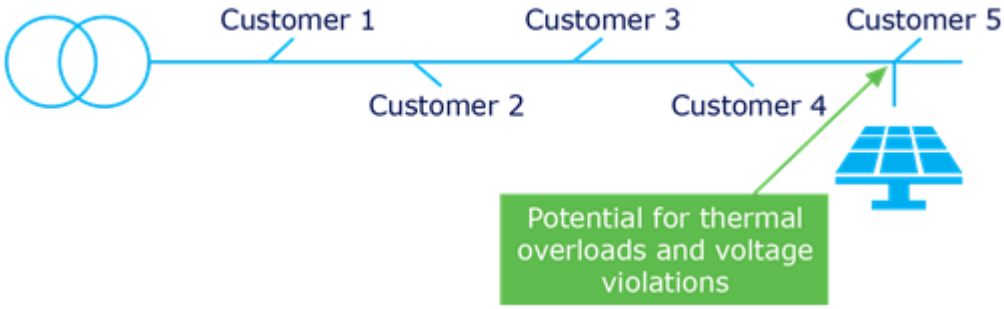

Figure 2.9 : Future PV located at the end of the feeder

3. All future PV is placed where there is connected load on the circuit, and in proportion to the connected load. This is analogous to having a large amount of rooftop solar on the circuit, with generators primarily serving existing loads. This can result in voltage and thermal overload violations on branches of the circuit not considered by scenarios 1 or 2. See Figure 2.10 below.

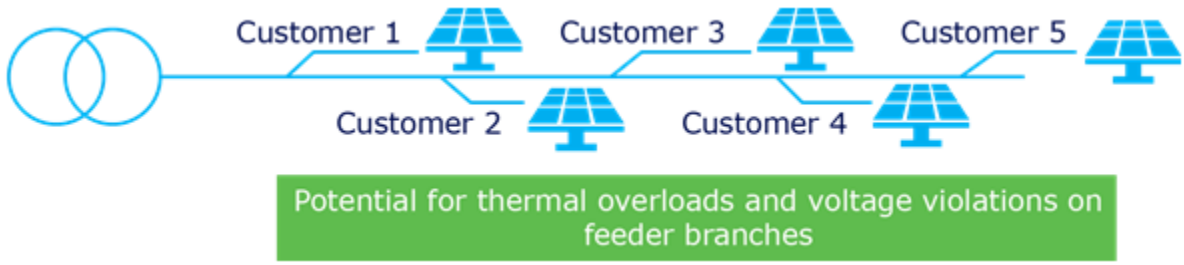

Figure 2.10 : Future PV located in proportion to connected load

For solar penetration studies for future solar installation, locating future solar is never 100% accurate, but these options represent a logical range of approximations. The capacity of future PV sites can be varied according to the required PV penetration on a given study, as shown in Figure 2.11 below.

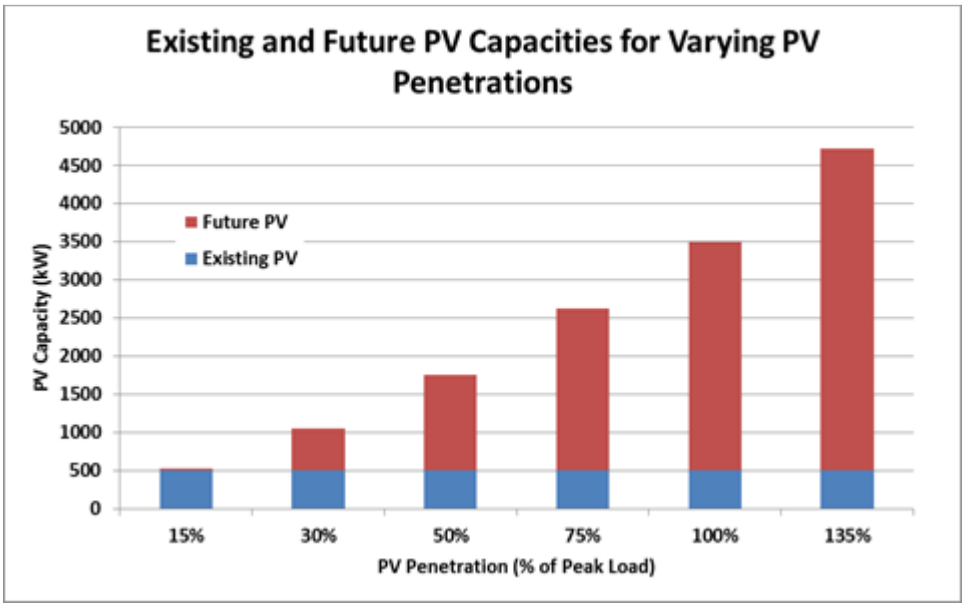

Figure 2.11: Existing and future PV capacities for varying PV penetrations

2.12 Feeder parameters

The following diagram represents a simplified version of the feeder model: See Figure 2.12 below.

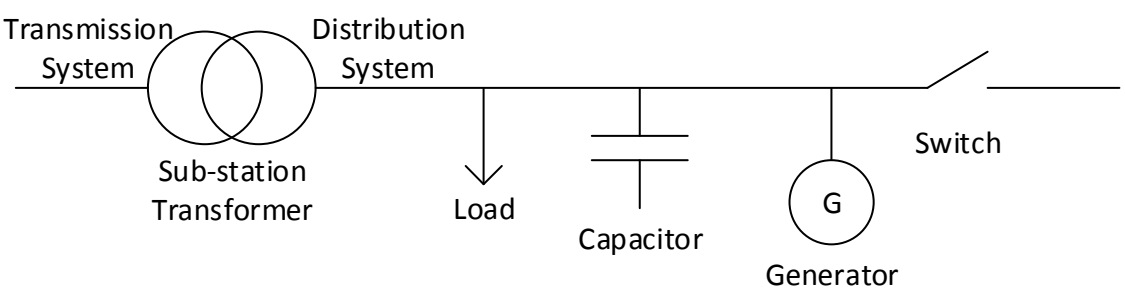

Figure 2.12: Feeder model

The following sections discuss the data requirements to model each item of equipment. In some cases, the data may not all be available, and a default value is used instead. This should be avoided where possible as it introduces uncertainty and error into the analysis.

2.12.1 Substation transformers

The sub-station transformer steps the voltage down from the transmission or sub-transmission system voltage to the voltage of the connected distribution feeders. The data required to model the sub-station transformer includes:

- High-side nominal voltage;

- Low-side nominal voltage;
- High-side connection arrangement (delta, wye, wye-ground, etc.);
- Low-side connection arrangement;
- Continuous and emergency kVA ratings;
- Rated kVA;
- Impedance;
- Resistance;
- No-load losses;
- Load Tap Changer PT ratio;
- Load Tap Changer CT rating;
- Load Tap Changer tap size;
- Load Tap Changer number of taps;
- Line Drop Compensation voltage set-point;
- Line Drop Compensation R value;
- Line Drop Compensation X value;
- Line Drop Compensation band-width;
- Tap control method (automatic or manual)

The transformer high-side nominal voltage is normally fixed at the system swing bus. The setting of this value varies between utilities and should be discussed internally before fixing the value. Depending on the type of analysis and the existing voltage value, the utility planner may conduct some sensitivity analysis to determine the most appropriate value since this setting impacts the operation of the LTC on the sub-station transformer

2.12.2 Distribution load

The individual customer load on the distribution system is normally aggregated at the same locations as the distribution line transformers. At each of these locations, the following information is required:

- Connected kVA or Transformer rated kVA;
- Any two of the following:
- Demand kW;
- Demand kVAR
- Demand power factor;

- Demand kVA.

When information about the instantaneous demand is not available, the total peak load for the feeder is distributed by the distribution simulation model in proportion to the connected kVA at the distribution transformer. If the simulation model cannot perform this function, the planner can create a spreadsheet to allocate the load and then import the data into the simulation model.

2.12.3 Capacitors

Capacitors are typically used in distribution systems to either boost the voltage where the voltage drop is excessive, or provide power factor correction (or both). For each capacitor bank the following information is required:

- Reactive power per phase (kVAR);
- Rated voltage;
- Connection type (delta, wye, wye-ground);
- Any control methods (such as time controls, voltage controls, etc.)

2.12.4 Generators

Generators located on the distribution system are, like load, aggregated at the distribution transformer. These represent the distributed PV, storage devices, EV or other devices on the system and are normally treated as negative load for steady-state analysis. The exceptions include:

- Fault analysis where the available fault current from the inverter is often higher than the rated current;
- Dynamic studies, where the inverter trip settings are included;
- Inverter options in mitigation studies, where power factor control is required.

For each generator located in the model, the following information is required:

- Generator rated kW output;
- Available fault current (assumed to be 120% of rated current if no information is available);
- Inverter trip settings for voltage ride-through and frequency ride-through

2.12.5 Switches and breakers

Line switches create open loops to maintain the radial nature of the feeder or to connect two feeder circuits together in case of planned or unplanned outages. For each switch, the only necessary information are the normal position of the switch (i.e. normally open or normally closed) and if the switch can be manually or automatically controlled.

The exception is the protection systems, such as sub-station circuit breakers. These protect the circuit from over-current in the case of a fault. The following data is required for sub-station breakers:

- Breaker rating;
- Interrupt rating;
- Phase relay cutoff amps;
- Ground relay cutoff amps

This information is for fault analysis, where the breaker rating must be capable of protecting the equipment on the system, while the interrupt rating must be above the available fault current on the system for the breaker to function in all scenarios.

2.13 Solar information

2.13.1 Methodology for locating sensors and monitoring equipment on distribution feeders

Historically, electric utility distribution planners were not too concerned about installing power quality meters, solar sensors and solar monitors on the distribution feeders. There was not an urgent need to validate voltages, frequency and back feed on the feeders since power flowed from the distribution substation to the end of the feeder. Distribution feeders are normally radial lines so if voltages at the end of the line are within voltage tolerances, everything is OK.

Sometimes, there may be a customer that installs a cogeneration plant to supply their own load but not to export to the utility. Distributed demand side resources and new technologies changed the distribution planning process and operational control of the transmission and distribution grids. High conventional plant fuel costs, availability of low cost roof mounted solar panels, subsidies from state and local agencies, emission reduction requirements and Renewable Portfolio Standards (RPS) requirements rapidly increased the penetration of distributed 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.

On a feeder without distributed generation, the voltage decreases with increasing distance from the substation. The magnitude of the total voltage drop depends on the impedance of the conductors and other equipment on the line, and the length of the feeder. Distribution planners therefore set the voltage regulation equipment at the sub-station to target a relatively high voltage – typically between 122 and 125 volts (on a 120 volt base) – so that the voltage at the end of the feeder remains within an acceptable range (i.e. between 115 and 122 volts on a 120 volt base). If the voltage drop along the feeder is too large for the voltage regulator, capacitor banks and line regulators are added to increase the voltage at critical points on the feeder.

There are no mathematical equations or software to 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 the planning area and where the potential areas for low or high voltage, frequency, line overloads and other factors can occur. The engineer has knowledge on the capacitor bank operations and settings.

Combining this expertise with a base analysis of the feeder provides insight into the feeder condition. By installing hypothetical solar installations on the feeder, the engineer determines 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. Distributed generation includes solar installations, customer installed cogeneration, demand-side management programs and electric vehicles. By conducting several distribution feeder simulations and graphically displaying voltage, current and distribution line transformer loads, the engineer determines where to install monitors and sensors.

The engineer picks locations that show the potential for reverse power flow, voltage variations and high equipment loading 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 large 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 with multiple feeders connected, the impacts to the other feeders are as important as the feeder with distributed generation. The utility may not be able to afford to install sensors and monitors on all of the feeders since the cost to install and maintain can be excessive. Instead, the utility objective is the installation of monitoring equipment which may be re-located to different feeders and areas as data is collected and the feeder simulation validated.

For the 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 can request that the line crews take a reading at the end of the feeders not monitored. If time stamped, the readings are compared with the data collected by the sensors and monitors. This informs the engineer on how the feeders are reacting to high distributed generation on the other feeders. The instantaneous readings do not occur on the feeders at the exact same time. For example, if there are five feeders connected to a bus with one having the high penetration of distributed generation, the other four feeders may have the instantaneous readings taken over several Sundays between the minimum daytime

peak periods (noon to 2 pm for example). The data can still 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, sufficient information is available to evaluate the potential impacts of high penetrations of distributed generation if the distribution planning model is capable of simulating feeder operation in these time 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 along the feeders or at the same feeder locations. 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.

Figure 2.13 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.

Figure 2.13: Feeder layout for a HECO feeder

When the feeder layout is converted to a simple one line diagram as shown in Figure 2.14 below, it can be seen that the large solar installations are located at the end of the feeder, the residential solar installations are located around the middle of the feeder and there is a large capacitor bank located within the substation with the other three feeders having little solar installed.

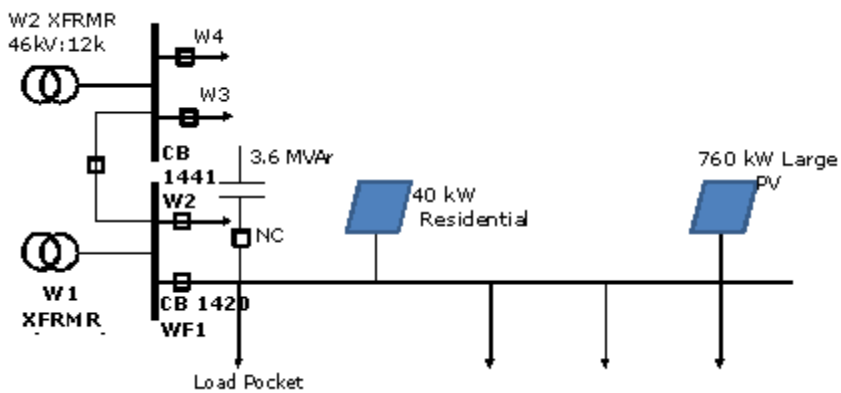

Figure 2.14: Feeder layout diagram

From this diagram, the initial decision is to install monitors at the substation and at the end of the line where the large PV is located. The substation monitor is recording the voltage, reactive power, current, power factor, tap changer position, frequency, capacitor bank status, and other attributes. The monitor at the large PV location is collecting the same data as at the substation, if the customer permits. The monitors collect the customer net load and the solar generation using two different meters. If permission is not granted, then a line monitor and a solar sensor are 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.

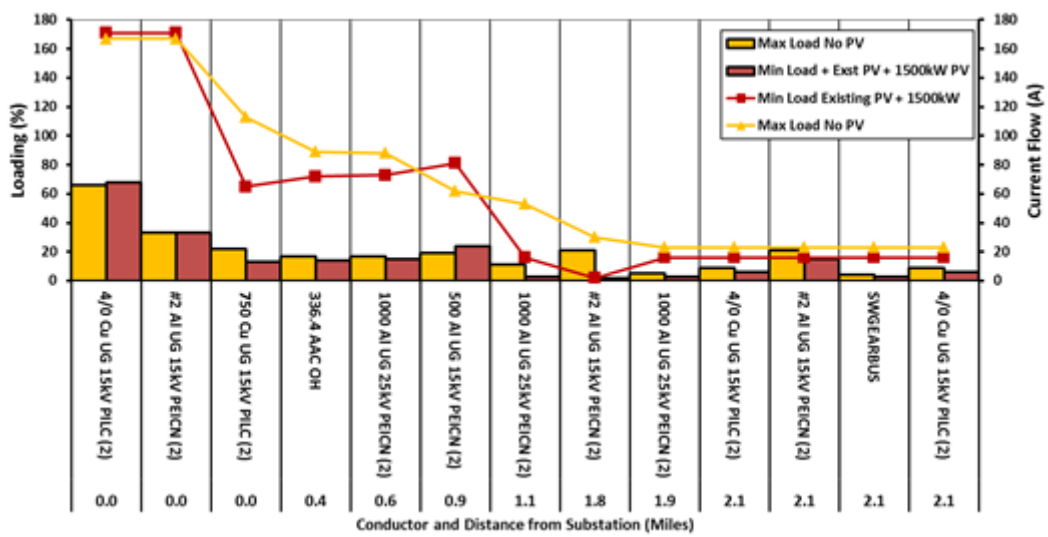

Figure 2.15: Loading and current flow on the feeder line segments

Figure 2.15 above shows the loading and current flow on the feeder line segments. Depending on the penetration and location of solar on the feeder, the locations of distribution line monitors 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 is a shift in

energy flows around the 1.8 miles from the substation. The exact location depends 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 a substation consisting of three 12 kV feeders. Feeder 1 has high load close to the substation and high penetration at the end of the feeder at a smart solar residential community. Feeder 2 has a low demand and some solar penetration. Feeder 3 is a residential community with high load but little existing solar penetration. While feeder 1 is considered for the initial analysis, monitors and sensors should be placed on the three feeders.

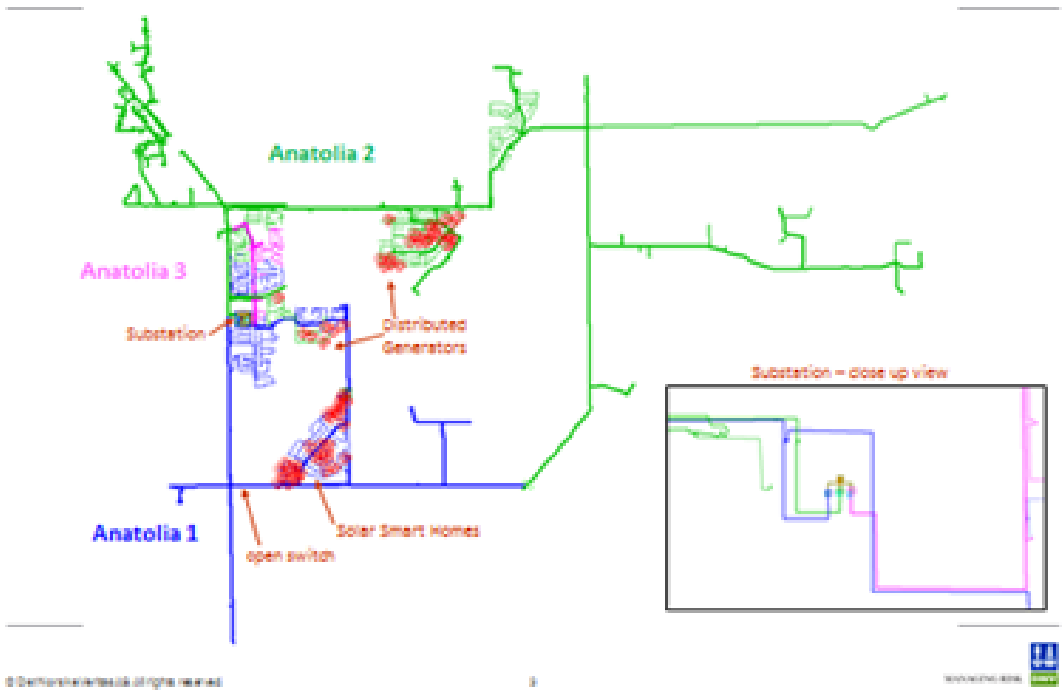

Figure 2.16 : Substation overview - Synergi Model

Feeder 1 in Figure 2.16 uses power quality meters installed at the substation feeder bus to collect feeder information such as voltage, reactive power, current, power factor, frequency, and other parameters. In this case, the load for the smart home community is aggregated at the feeder entry point into the subdivision.

Figure 2.17 below 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 feeder to validate the feeder flows under base line conditions. Instead of installing a monitor in the middle of the feeder as is discussed in the previous example, an instantaneous reading on a projected maximum and minimum daytime peak demand time is requested 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.

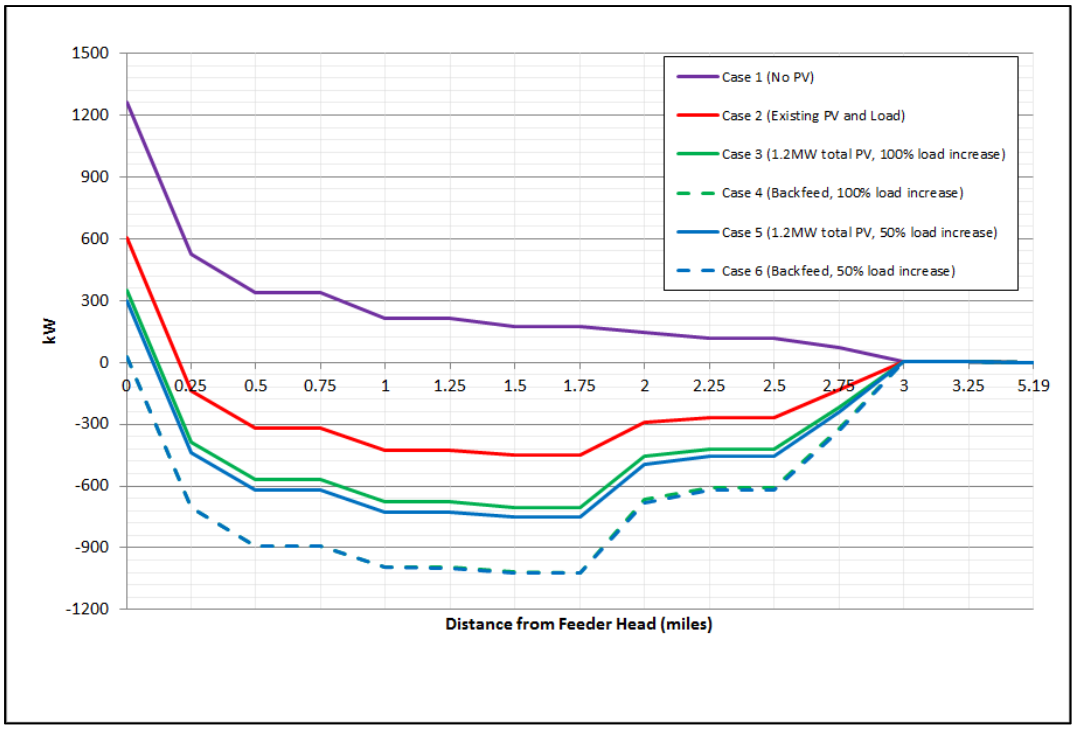

Figure 2.17: Kilowatt flow on Feeder 1 from the substation to the entry point into the subdivision

The last example is shown in Figure 2.18 below. This is a rural 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 very long lines, it is difficult to determine where the additional monitors and sensors should be placed. There should be equipment installed at the substation and near the solar/digester installations to verify the reverse power flows and voltages. However, there should also be monitors at the end of the other line segment or at least some installation readings to verify the voltages.

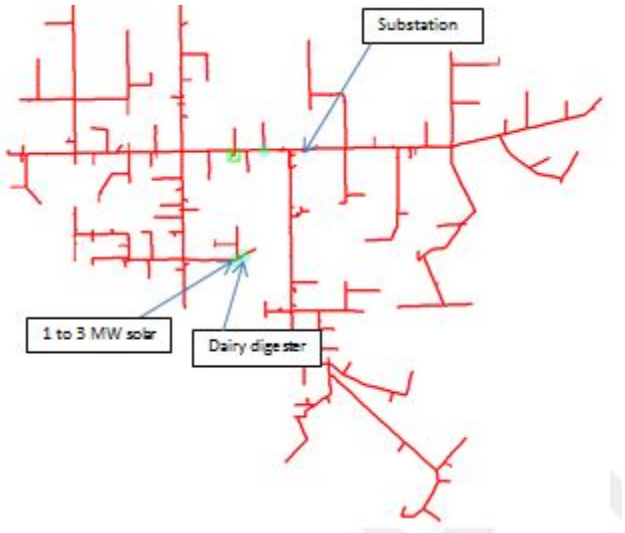

Figure 2.18: Rural feeder with long lines and little load

Figure 2.19 below shows the maximum voltage and maximum load flows on the distribution line for a minimum daytime peak hour when the load is low but the solar generation is high. The substation bus voltage is set at 123 volts (on a 120 volt base). The objectives are determining the location of the highest voltage and location of the highest reverse power flow.

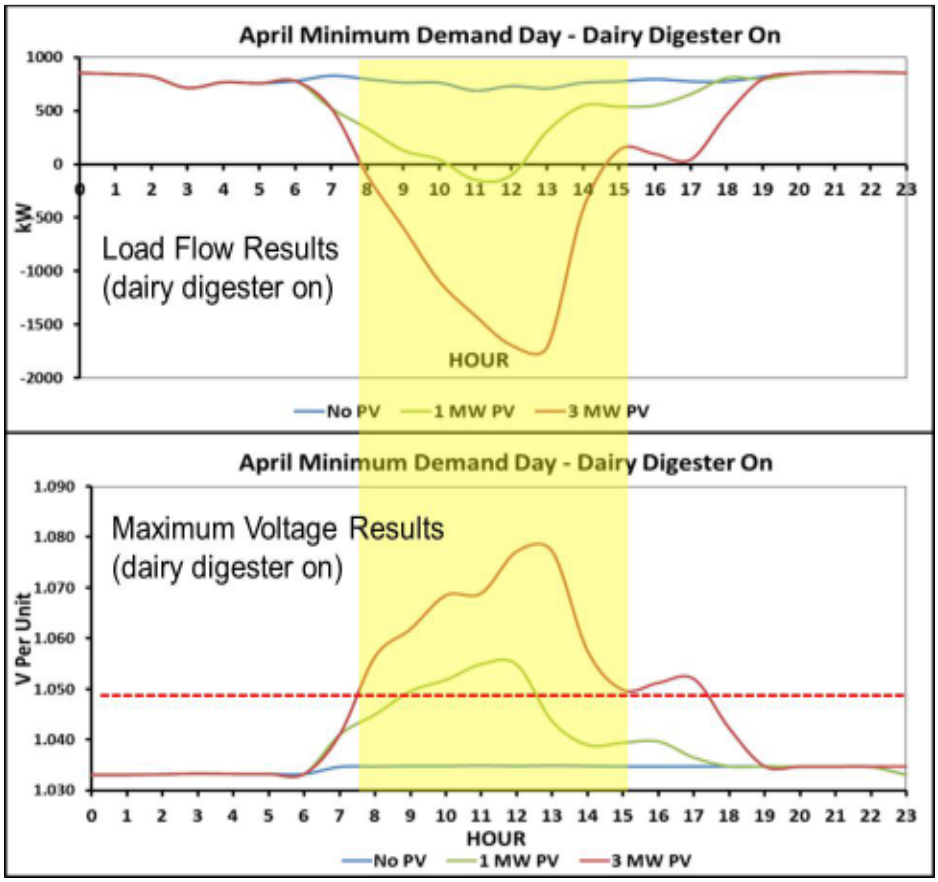

Figure 2.19: Maximum voltage and maximum load flows on the distribution line for a minimum daytime peak hour

The utility planner should consider these examples when considering where to place sensors and monitors. The planner selects one or more of these different methods to determine locations for equipment.

2.14 Creating and validating base case

A base case analysis is conducted for identifying system impacts due solely to the distribution system configuration without PV and then comparing to the case with existing PV. The base case study is conducted with the gross load profiles generated for the maximum daytime peak and minimum daytime load days and with the PV switched off. Gross load is defined as the sum of the net load recorded for the feeder and the displaced load served by the existing PV.

The base case results – in terms of voltage, line loading, power flow, etc. – are first checked to identify any technical criterion violations, which should not exist. The planner may decide if any existing violations need to be corrected for comparing future PV penetration scenarios. A clean base case without violations is important as higher PV penetrations can cause violations resulting in upgrades for which the utility may want the developer to pay. Having a clean base case avoids any conflicts in negotiating feeder upgrade payments.

The next task is to validate the base case with existing PV. This requires measurements of voltage and LTC position at the transformer that coincide with the given load profile. The voltage and LTC position produced in the model should be consistent with the given data, assuming the same demand is modeled at the transformer, in order to provide assurance that the results obtained from the model in future cases are consistent with reality.

After this is completed, any violations occurring in subsequent cases are due solely to the increases in PV installed on the system. In some cases, such as the fault analysis and the LTC cycling analysis, this base case provides the comparison case to check for rises in fault current, or changes in LTC position occurring due to PV operation.

The utility planner will conduct this same analysis for the entire distribution system. The planner may discover that existing data is unavailable that delays the start of the study. By beginning the study early, the planner can determine what data is and is not available and the best approach to obtaining the necessary data.

2.14.1 Validation points of interest

The dataset is validated at locations where load and voltage data is available. Typically, this is limited to the sub-station transformer or circuit breaker. The transformer operation is validated by inputting a given demand in terms of kW, kVAR and kVA, and comparing the voltage produced in the model with that measured. If the LDC R and X values are non-zero, the voltage produced in the model is unlikely to exactly equal the actual data as the LTC may not change positions exactly in-step with the real machine. An acceptable margin of error is half of the band-width setting of the transformer, which is the amount of voltage the LDC circuit is allowed to vary from the target voltage before the LTC changes position.

If the transformer voltage is validated, the next step is the validation of the LTC position and the change in LTC position. The absolute position of the LTC is not as important as this is dependent on the voltage of the sub-transmission system, which is typically fixed in the model and may not be consistent with the actual sub-transmission system voltage. The LTC position change is important for the LTC cycling study, where the change in the LTC position is recorded. It is important that the LTC changes position in the model under similar conditions to those recorded. It may be necessary to run several non-consecutive time-steps from a given demand profile where the LTC is in different positions, as a series of consecutive time-steps may not provide enough, or any, changes in LTC position.

After the transformer voltage and LTC behavior are validated, the rest of the data behaves in a manner consistent with actual. This is true if the model accurately represents the equipment that is installed, including conductor specifications, phasing, local loads and any other equipment installed on the distribution system.

2.15 Simulation options

2.15.1 Steady state

The steady state studies represent the extreme cases at each PV penetration and the assessment of the system against all technical criteria. It is impossible and unnecessary to run the analysis at every PV penetration from 0% to 135%. The range of PV penetrations analyzed is covered by a smaller number of analyses at discrete PV penetrations, with linear interpolation used to make more detailed estimations on where technical limitations lie. Figure 2.20 below shows an example of the options for load profile and PV penetrations analyzed.

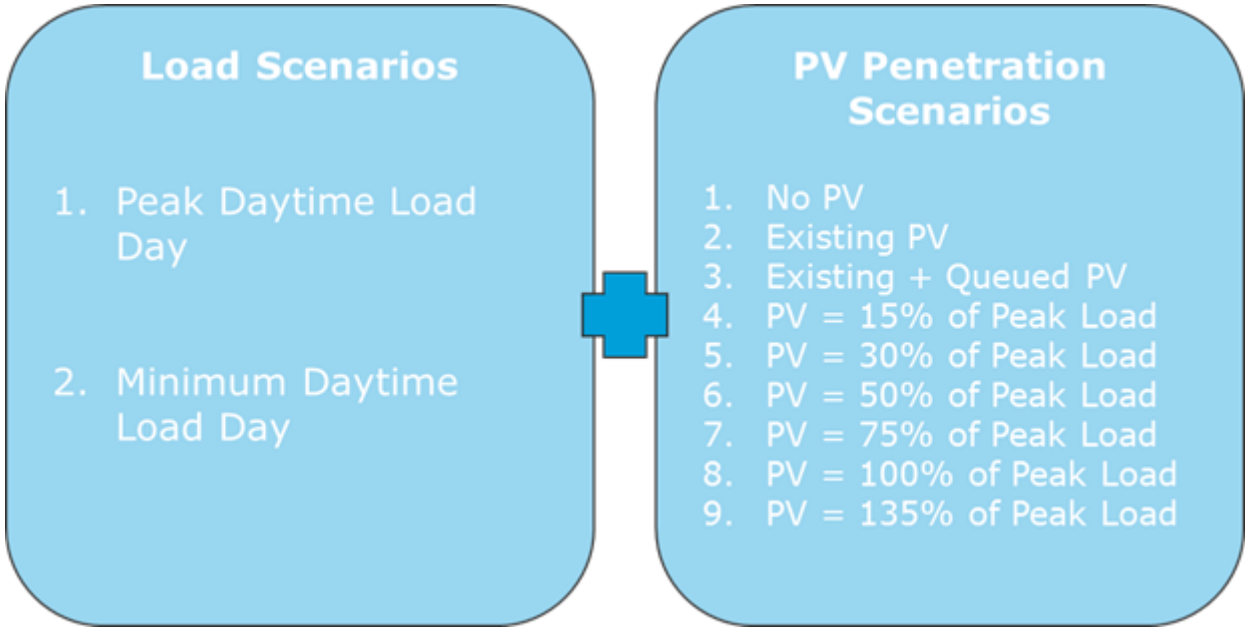

Figure 2.20: Options for load profile and PV penetrations analyzed

This combination of the two loading scenarios with the nine PV penetration scenarios produces 18 different cases for analysis. Each of these cases includes load flow analysis for 24 time-steps in the steady-state analysis. Running this number of analyses on each cluster is a time-consuming process if performed manually. It is therefore important that the simulation software includes a mechanism for automation of the running of consecutive analyses. This process is discussed for the Synergi Electric software in the following section.

2.15.2 Running automated sweeps for multiple simulations

The number of analyses to be performed for just the steady-state of a single cluster study using the example in Figure 2.20 is 432. Manually setting up, running and post-processing these studies is not feasible if to be completed within a reasonable time period. Some changes are required to the data between each study, whether changing the time-step within each case, or changing the PV penetration and load profile between cases. Manual operation also increases the possibility of mistakes, meaning further lost time re-running analyses.

In the software used in this example, Synergi Electric uses a feature to allow the user to program a large number of consecutive operations into the software. This allows for the creation of a 'recipe' that performs all of the necessary changes between cases (load profile changes, PV penetration changes, etc.), and runs each of the 24 time-steps in each case consecutively, while saving the results from each load flow to a specified folder. This reduces the time required from days for a manual operation to hours, while also removing the possibility of human error in the analysis.

Post-processing the results is also a laborious process if performed manually. Again, this can be automated, and the calculations performed are described in the following sections.

2.15.3 Line Segment voltage

For each load flow analysis performed, the maximum and minimum voltages on each feeder are identified. If these values are within the range 0.95 per unit to 1.05 per unit then there is no violation. If either the maximum or minimum voltage is outside this range, there is a violation. If the violation occurs in either of the cases without PV installed then the dataset is checked for inaccuracies as there normally should not be voltage violations in an existing condition.

If voltage violations occur outside of the first two cases, the location of the violation is identified and presented. The planner then chooses to fix the violation or to consider the violation as part of the reason for conducting a PV penetration study.

2.15.4 Line segment loading

For each load flow analysis conducted, the maximum continuous loading on each feeder is calculated. Again, two cases without PV are checked to ensure that the customer load is not causing load violations. After verification, the maximum continuous loading on the feeders for the other cases is calculated. If the continuous loading is above 100% on any section, this constitutes a violation. As with the voltage results, if a violation is found then the location and reason for the violation (if it is identifiable) is identified and presented. The planner then chooses to fix the violation or to consider the violation as part of the reason for conducting the PV penetration study.

2.15.5 Feeder backfeed

The backfeed study identifies the lowest PV penetration when there is no reverse power flow at the feeder head. Backfeed results are reported both at the feeder level and at the transformer level. Typically, each sub-station transformer has multiple distribution feeders connected. There may be situations where one or more of the feeders experience reverse power flow at the feeder head while the other feeders do not. There can be voltage control issues on the feeder with reverse power flow even if there is no reverse flow through the transformer. It is important to monitor the simulations to determine when this condition occurs. The case with reverse power flow at the transformer is a more obvious problem as the voltage regulation systems must recognize the direction of power flow and function accordingly.

The planner must choose to fix these problems or consider that these are part of the reason for conducting the study. These problems may not appear during the base case or the case with PV but may occur during the varying of PV penetrations.

2.15.6 Load tap changer cycling

LTC cycling analysis is slightly different from the other analyses. The single day load profiles analyzed alone cannot provide the PV penetration to analyze this potential problem. The changes in LTC position due solely to PV require a change in PV output. For example, this occurs due to clouds passing over the system that rapidly reduce solar irradiance. The analysis may find the first PV penetration level where changes in PV output cause a change in LTC position, but this effectively says that the PV output at this penetration requires a change from 100% to 0% (or the reverse) within a few minutes to affect the LTC position while maintaining constant load. In reality, the irradiance does not change so dramatically during a few minutes time interval, so this PV penetration is not a meaningful limit. However, the change in total PV output (in terms of kW) that causes the LTC to change position is meaningful. This is used in the analysis of a full year of load and irradiance data to determine the extra operations the LTC performs in a year at different PV penetrations. A limit on the increased number of operations is required to define the point that is a problem for the utility.

When investigating the effect of distributed PV over the LTC lifetime operation, the change in LTC current duty from the base case should also considered. This effect works in the opposite way from the increase in number of operations described above, up to the point of reverse power flow, as increasing PV penetration causes a reduction in current through the contacts, increasing the lifetime of the LTC. After the point of reverse power flow, increasing PV output causes an increase in current duty on the LTC contacts, and a decrease in LTC lifetime again. These two converse effects are analyzed together to identify the overall effect of distributed PV on the LTC lifetime. Figure 2.21 below shows the effect of the two impacts on LTC lifetime.

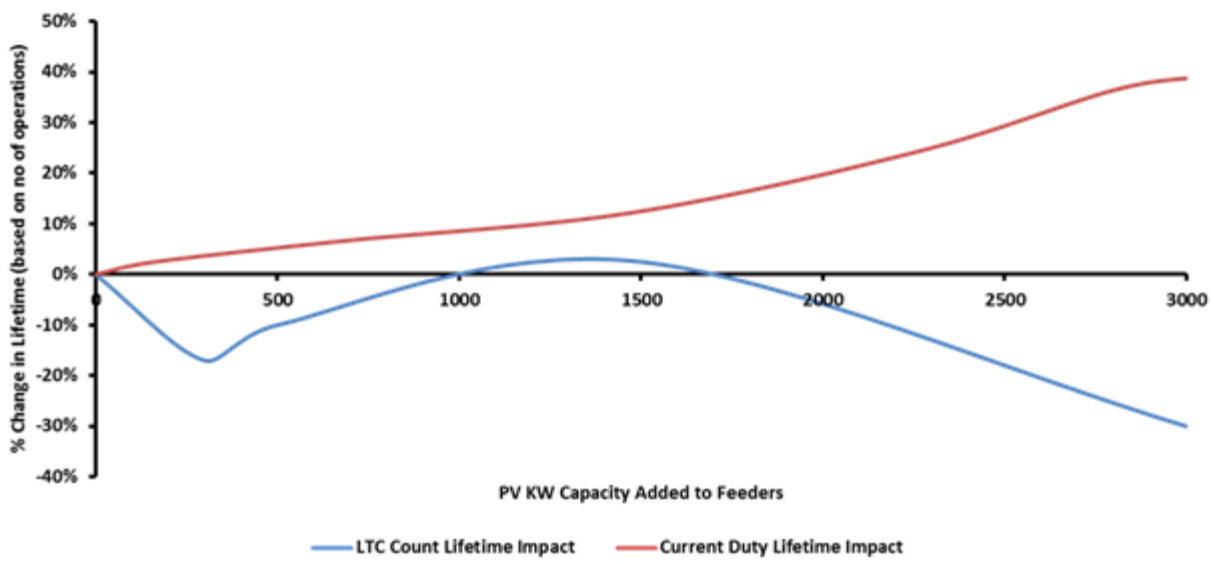

Figure 2.21: PV KW capacity added to feeders

The proper sequence of events to test the impact of LTC operation is setup prior to conducting the analysis. The first step for the planner is the documentation on the historical operation of the transmission LTC. Depending on the type of LTC and age, there may be a high number of LTC tap changes before adding PV. The transformer and LTC maintenance cycle must be considered to determine if the LTC operation is recorded. Finally, the planner needs to determine if this is a critical factor for consideration in the PV penetration study.

2.15.7 Fault current

Increasing the total PV capacity installed on the distribution system causes an associated increase in the available fault current on the system. The limit defined in Hawaii Rule 14H and California Rule 21 for a single PV installation is that the available fault current should not increase by more than 10% from the case without PV. However, this limit only triggers a more detailed analysis, and is not a barrier to further PV installations by itself. Another limit on fault current is the interrupt rating of the circuit breaker. A limit of 87.5% of the circuit breaker interrupt rating is defined in the interconnect rules.

The circuit breaker interrupt rating is not always available, and in these cases the default value is the 10% increase in fault current. Fault current analyses are conducted at each PV penetration, and the maximum available fault current in each case is compared to the case without PV. The PV penetration when the available fault current is 10% higher than the case without PV is identified.

2.16 Transient and dynamic simulations

An extreme case is where the PV output changes from 100% to 0% within the time-delay of the voltage regulation equipment, and then from 0% to 100% again within the time-delay of the voltage regulation equipment. The objective is the identification of short-term voltage violations not identified in the other steady-state analyses. This represents the maximum ramping condition.

The process for the transient simulations is:

1. Load flow with PV output at 100%;
2. Load flow with PV output at 0%, LTC fixed in the same position as at the end of step 1;
3. Load flow with PV output at 0%, LTC allowed to move freely;
4. Load flow with PV output at 100%, LTC fixed in the same position as at the end of step 3.

The voltages on each section in Step 2 are compared with Step 1, while the section voltages from Step 4 are compared with Step 3. A typical limit is a 3% change in the voltage in each case. The PV penetration that creates the 3% violation is identified. Voltage violations of ±5% from nominal, as in the steady-state simulations, should also be identified here.

2.16.1 Dynamic simulations

The goal of dynamic analysis is the identification of PV penetrations when additional load-shedding (blackouts) occurs in an N-1 contingency situation (i.e. when the largest generator on the transmission system is tripped). This analysis requires the full transmission system be modeled to calculate system frequency. In addition, the sub-station transformers between the transmission and sub-transmission system, and the distribution system are included. The load on each of the distribution feeders is aggregated to a distribution bus connected to the transformers. The PV on the distribution feeders is aggregated to the same bus, with one lumped generator to represent the existing PV systems, and the other to represent the future PV systems. These can be divided further if different voltage and frequency ride-through settings are used on different inverters in the system.

The following sequence is followed for the analysis:

1. System initialized and simulated for 10 seconds with no disturbances;
2. Largest generator tripped offline;
3. Simulation continues for another 60 seconds. Voltage and frequency are monitored, and any load-shedding is identified.

Tripping of PV units in the analysis is noted and the magnitude of load-shedding occurring in the 60 seconds after the generator is switched off is calculated. This load-shedding value is compared to the case without PV to determine additional load shedding due to the PV generators tripping. This analysis only covers problems occurring due to the PV inverters tripping offline during the disturbance. Further analysis identifies problems occurring due to the re-closing of the inverters, which can happen simultaneously if the re-closing times are the same for every inverter on the system..

The effect of different assumptions on accommodating the additional PV in high-penetration scenarios must be made. The transmission model is typically provided with a balance between load and generation so that the system is stable. However, as more PV is added to the high PV penetration scenarios, conventional generation is reduced to maintain the balance between generation and load. The simple method to reduce the conventional generation is the reduction on the output from each generator proportionally. This results in a system with a similar level of inertia to the case without PV; a similar reduction in frequency after the generator is tripped; and a higher level of flexibility as the conventional generation ramps up quickly using excess capacity. The results of a study using this method are therefore likely to be more favorable than the reality.

A more realistic method to accommodate the PV is turning off some conventional generators completely, while leaving the others at given output. This is more practical as conventional generators are less efficient when operated significantly below rated output. The system with higher PV penetrations has less inertia than the system without PV and the frequency drop increases resulting in more load-shedding. The generators to be turned off are discussed with the relevant planning departments at the utility to produce accurate results.

3 CONCLUSION

The Proactive Modeling Methodology was developed through funding from the California Public Utilities Commission, Hawaii Electric Company, Pacific Gas & Electric, Sacramento Municipal Utility District and the City of Roseville, California. The methodology provides a step-by-step approach to conduct a distribution study on the impacts of high penetrations of renewable technologies on the electric utility grid. The methodology also provides guidelines on the data requirements before even beginning to conduct a distribution study. The methodology has been tested and validated by the utility participants on feeders exhibiting different peak demands, feeder configurations and equipment, line conductor sizes, feeder lengths and customer mixes. These differences served to validate that the methodology can be adopted by any size utility and incorporated into the distribution planning process. The advantages of this methodology include:

- A repeatable and consistent methodology for evaluating the impacts and benefits of distributed renewable resources to the utility's distribution planning process
- A methodology that has been proven for any size utility grid with different load forecasts, system peak demands, service areas, lengths of distribution lines, customer mixes and distribution line conductor sizes
- The study provides a step-by-step approach to distributed renewable penetration studies.
- The methodology enables the utility planner to study one individual feeder, a cluster or regional group of feeders, an entire distribution system or secondary service drops to customer meters
- The study provides a list of necessary data requirements and time increments of data to complete detailed distribution steady state, dynamic and transient studies
- The output results can be presented to stakeholders, developers, regulatory agencies to support distributed renewable penetration recommendations
- The methodology can be completed using any detailed distribution planning software
- The methodology has been successfully used by the Hawaii Electric Utilities (HECO, MECO and HELCO), Sacramento Municipal Utility District, Pacific Gas & Electric, and City of Roseville
- The methodology has been applied by other utilities in the United States and the Caribbean to conduct distribution studies

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