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Russell Neal
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National Renewable Energy Laboratory
1617 Cole Boulevard
Golden, Colorado 80401
303-275-3000 • www.nrel.gov

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1 Introduction

The National Renewable Energy Laboratory (NREL), Southern California Edison (SCE), Quanta Technology, Satcon, Electrical Distribution Design (EDD), and Clean Power Research (CPR) have teamed together to analyze the impacts of high-penetration levels of photovoltaic (PV) resources interconnected onto the SCE distribution system. Specifically, SCE will be interconnecting a total of 500 MW of commercial scale PV by 2015 within their service territory through a program approved by the California Public Utility Commission (CPUC). Research efforts under this project include:

- Development of distribution and PV system models required to evaluate the impacts of high-penetration PV
- Identification and development of the necessary distribution system studies and analysis appropriate for determining the impacts of high-penetration PV
- Data collection on study distribution circuits to quantify the impacts of high-penetration PV
- Development of high-penetration PV impact mitigation strategies in the form of advanced inverter functions to enable high-penetration PV interconnection
- Lab testing of advanced PV inverter functions
- Field testing of advanced PV inverter functions.

In the first year of the project, research efforts have focused on (1) identifying the needed PV system models and distribution system analysis tool capability, (2) identifying prospective distribution circuits within the SCE service territory to be studied, (3) understanding the challenges of integrating high-penetration PV levels onto the SCE distribution system, (4) identifying appropriate data acquisition equipment, and (5) investigating the capability of PV inverters to realize advanced inverter functions that may be useful for mitigating high-penetration PV impacts on the SCE distribution system.

Section 2 of this report describes the need for investigating high-penetration PV scenarios on the SCE distribution system. A few of the expected impacts of high-penetration PV are described, and typical distribution system operation is explained. Two study distribution circuits are also identified in this chapter and discussed in terms of the expected PV penetration levels attained as SCE builds out the 500 MW of installed PV within their service territory.

The necessary PV system modeling and distribution system simulation advances are discussed in Section 3. To properly simulate high-penetration PV operation on a distribution circuit, the expected solar resource of a given PV installation needs to be determined. The first part of Section 3 outlines how solar resource data, collected through remote sensing satellites, can be processed and formatted for inclusion in a distribution system modeling tool such as Distributed Engineering Workstation (DEW), CYMDIST, or Synergee. The second part of Section 3 describes the additional functionality required of the distribution system modeling software package itself to properly and effectively evaluate high-penetration PV scenarios.

Section 4 describes the available distribution circuit data available for the two study distribution circuits identified in Section 2. Data acquisition on the study distribution circuits is required to quantify the impacts of high-penetration PV installations and to verify distribution system models of the study feeders developed during the course of this project. Locations of additional data acquisition systems, capable of measuring medium voltage (15 kV Class) line voltage and phase current, also are identified.

The PV inverter is the active control component within a single PV installation. As such, its characteristic operation determines the overall behavior of the PV system from the perspective of the distribution circuit to which it is connected. Section 5 discusses the additional inverter functionality that could be implemented in order to specifically mitigate some of the undesirable distribution system impacts caused by high-penetration PV installations.

2 Analysis of High Penetration Levels of PV into the Distribution Grid in California

This section provides supportive material and information required to facilitate various activities of the high-penetration PV project including (1) data requirements for modeling and simulation studies, (2) a summary and highlights of SCE distribution system design, operation methodologies, and interconnection requirements, and (3) a brief review of desired features for the next generation of PV inverters from the utility engineers' point of view.

Because only two or three distribution circuits (feeders) will be selected and studied under the limited scope of the project, this report also describes a generalization and classification method to characterize any distribution feeder in the SCE territory in terms of the level of similarity to the studied feeders. This approach can be used to identify expected PV integration impacts and mitigation solutions on other feeders with common attributes.

The information provided in this section presently is a work in progress and may include additional information as identified throughout the course of the project.

2.1 Selected Distribution Feeders for Study and Monitoring

Presently, two 12.0 kV distribution feeders that already include utility scale PV installations have been selected for inclusion in this project. Various feeder characteristics and existing/expected number of PV systems were considered as part of the selection criteria. The selected study feeders can also be defined as typical representations of 12.0 kV feeders for the SCE distribution systems, which have high PV penetration potential due to the type of commercial buildings with large roof-top areas suitable for PV installations.

The first study feeder, denoted as the Fontana, CA study feeder due to its approximate location, is a 12.0 kV feeder supplying an area with dominant commercial loads (Figure 2-1) fed from a 66 kV substation. The feeder includes three switched (automatic) capacitor banks. The Fontana 2.0 MW roof-top PV system is the first roof-top PV installation by SCE constructed under SCE's Solar Photovoltaic Program (SPVP). It is also expected that a total of 5.5 MW of PV generation will be added to the study feeder by the end of 2011. The Fontana PV system is electrically located close to the substation as it is at the end of an express feeder line section with a length of approximately one mile. The PV system is on the first part of the main feeder trunk before any branches and there are very few customers between the PV system location and the substation.

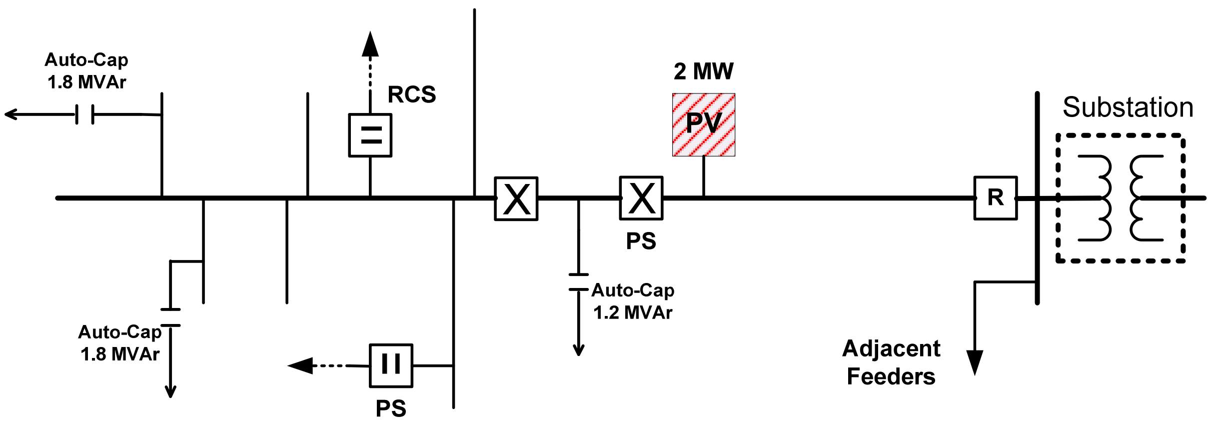

Figure 2-1. Schematic representation of the study feeder in Fontana, CA.

The second selected study feeder is located in Chino, CA and connects an existing 1.0 MW roof-top PV installation. This feeder is supplied from a 66 kV substation through a considerable length of the mainline feeder as shown in Figure 2-2. This feeder is expected to include an additional 3.0 MW of roof-top PV, partly based on current installations as part of the SPVP program (0.75 MW) and additional PV installations presently in the interconnection queue (2.25 MW) based on power purchase agreements with independent producers.

The PV system location for the Chino, CA feeder is toward the end of the feeder after some major customer loads. This feeder also includes four switched capacitor banks.

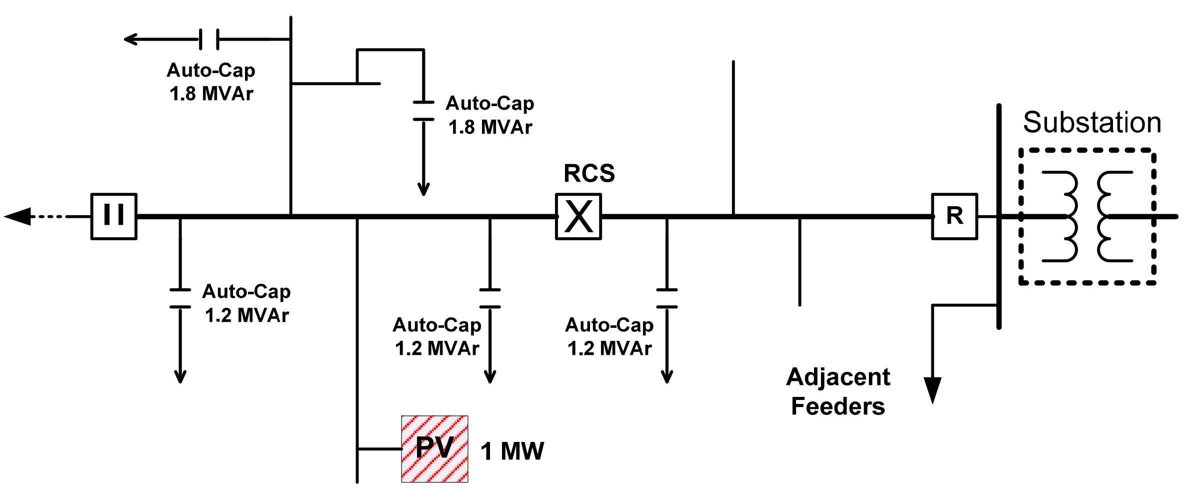

Figure 2-2. Schematic representation of the study feeder in Chino, CA.

The PV system specifications for each of the selected feeders are provided in Table 2-1 and Table 2-2 [1].

Table 2-1. PV Source Specifications.

		PV Module			
System	**Customer_ID**	**Manufacturer**	**Model**	**Quantity**	**Surface Area**
SPVP 1	Fontana	First Solar	FS272, Cadmium-Telluride Thin-Film	~33700	600000 sq ft
SPVP 2	Chino	First Solar	Thin-Film	TBD	458000 sq ft

TBD: To be determined

Table 2-2. PV System ac Specifications.

		Inverter			
System	**Customer_ID**	**Manufacturer**	**Rating**	**Model**	**Quantity**
SPVP 1	Fontana	Satcon Tech Group	500kVA, 600Vdc, 480Vac	#AE-500-60-PV-A	4
SPVP 2	Chino	Xantrex	250kVA, 300Vdc, 200Vac	TBD	4

TBD: To be determined

2.2 PV Interconnection Requirements

The SCE Interconnection Handbook [2] and California Rule 21 [3] provide the general design, interconnection, and operating requirements for connecting and operating a generation facility in parallel with SCE's distribution networks. Appendix A provides a summary of the requirements based on these references for a generation system with an aggregated size of 200 kVA or higher that is connected to systems with voltage levels of 34.5 kV or lower. The utility scale roof-top PV installations primarily fall into this category.

Table 2-3 outlines the main aspects of SCE design and interconnection requirements, which are applicable for large scale solar PV integration onto distribution feeders. The focus is on those requirements that may affect the operation and/or power quality of the distribution grid as a result of integrating a PV system to the conventionally designed feeders. In Table 2-3 the point on the distribution system at which the utility and the customer interface is referred to as the point of common coupling (PCC). The utility energy meter location and connection is often synonymous with the PCC of an interconnection.

Table 2-3. General Requirements for 200 kVA and Higher System (Plant) Connecting to 34.5 kV or Lower Voltage Level.

Requirements	Reference/Range/Solution	Comments
Standards and regulatory compliance	• SCE Interconnection Handbook • California Rule 21 • Joint NERC & WECC standards • CAISO & SCE reliability requirements	SCE Interconnection Handbook includes provision from IEEE 1547 & UL1741 and IEEE 929-1999 for utility interactive PV systems
Unity power factor	For generating units with P < 10 MW; at the interconnection point	Through the generation source and/or additional VAr control device
Interconnection equipment	Dedicated transformer	
Transformer configuration	• Delta high side • Ground band for 4 wire systems • Ground fault detector for 3-wire systems	Transformer should be equipped with no-load taps for ± 5% adjustment of ratio in 2.5% steps
Voltage range	± 5% of nominal feeder voltage	The plant should not cause voltage deviations beyond this level
Reactive power requirements	• Ability to deliver ± 0.95 power factor at the interconnection point • The maximum voltage rise ≤ 1% per step change in reactive power output of a generation facility	Except for the reactive power demand of facility load, inverter source should not impose any additional reactive power burden on the grid
Voltage imbalance	Less than 1% at PCC in steady-state	Worst case < 1.5%
Harmonics	IEEE 519-1992 & IEEE 1547-4.3.3.	
Flicker	IEEE 519-1992 & IEEE 1547 4.3.2	
Response to grid faults and/or loss of main (islanding)	Immediately cease operation (IEEE 1547)	Upon islanding or faults on the interconnecting feeder, single facility generation can separate its own load from the grid and continue supplying load

2.3 SCE Circuit Operating Methodology

SCE distribution feeders can be categorized in three voltage classes of 4.7 kV, 12 kV, and 21 kV. Most distribution substations are connected to either 66 kV or 115 kV high voltage systems. Among all distribution systems, the dominant category is 12 kV feeders supplied from 66 kV substations.

2.3.1 Transformer Load Tap Changers (LTC)

In a typical SCE distribution system, a load tap changer (LTC) is not used on substation transformers connecting to 66 kV systems. Substations connecting to 115 kV systems will be equipped with a LTC. Because all the distribution feeders of interest in this project are supplied from 66 kV substations, any effect of high-penetration PV installation on LTC operation may need to be investigated separately.

The 115 kV LTCs typically regulate the voltage at the distribution bus (LV side of substation transformer) without load drop compensation. The reference voltage is typically set at 122 Vac with a bandwidth of ±1.5 V. The tap changer delay may vary in the range of 30 to 90 seconds, depending on the application and the coordination requirement with any downstream voltage regulator.

2.3.2 Capacitor Banks

The SCE general practice is to install capacitor banks as required on distribution feeders as a preference to voltage regulators. In addition to substation-level capacitor banks (typically two banks), generally three or more capacitor banks may be found along the feeders to reduce the reactive power demand from high voltage systems (e.g. 66 and 115 kV systems).

SCE uses commercial capacitor bank controllers from Fisher Pierce, S&C, and Cooper Industries. The capacitor bank controllers operate based on voltage control with a time or a temperature offset to enhance daytime operation. The voltage control has override capability to disconnect or re-connect, respectively, on voltage increase or decrease beyond a pre-set range. Once disconnected on voltages beyond the high-level threshold, a pre-specified delay is applied to prevent instantaneous reconnection of a capacitor bank on possible voltage fluctuations. However, for disconnection on excessive voltage increase, typically no additional delay is applied beyond the capacitor bank internal measurement, filtering, and processing time.

The capacitor bank controller uses the voltage measurement from a single-phase voltage transformer (PT) to determine the feeder voltage. The phase connection of the capacitor bank PT is not generally identified on the drawings or in the records. These PTs are typically connected phase-to-phase. There may be some general practices suggested in the SCE distribution design guidelines (e.g. utilizing phase A&B connection always), but the practices are not routinely applied to all feeders and connections.

2.3.3 Remote Control Switches

A remote control switch (RCS) is an automated voltage controlled disconnect switch with the ability to open or close on a remote operator command. Typically, a RCS operates on loss of voltage with delay and uses single-phase voltage measurement for disconnection. Upon loss of voltage for a pre-specified period, an RCS operates and disconnects all three phases (three-phase gang-operated switching). The operating delay of RCSs is time coordinated with the recloser timer. The switch on/off position is communicated through the SCADA system. No phase voltage measurement is available from the RCSs via SCADA communication.

As shown in Figure 2-3, most average length feeders have one recloser located close to the substation and an RCS located about halfway (electrical load) on the backbone feeder or on any major laterals. Also, there will be additional RCSs with normal open (N.O) position at interconnection points with adjacent feeders to facilitate load transfer when required.

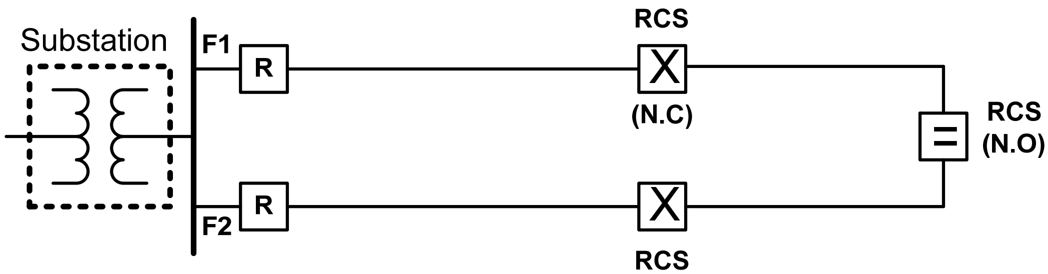

Figure 2-3. Utilization of reclosers and RCSs on distribution circuits.

Following a line fault and feeder clearing, typically a recloser utilizes two reclosing attempts (at 5 s and 55 s, approximately). After 30 s from time of voltage loss, about 25 s from the first reclosing shot and unsuccessful reclosing attempt, a downstream RCS disconnects the second half of a circuit. The second reclosing attempt tends to pick up the upstream load between the opened RCS and recloser location. If the reclosing is unsuccessful, a distribution operator can conclude that a fault is between the recloser and the RCS location. By observing the status of an RCS and a recloser, and based on the load level and available capacity of an adjacent feeder, the operator can decide whether to close or not close the intertie RCS to transfer the load downstream of the first RCS to an adjacent feeder.

2.3.4 Voltage Adjustment Levels

Presently, SCE does not use any active voltage control on their distribution feeders. The near-future plan is also to optimize the set points for voltage regulating devices (LTCs, capacitor banks, voltage regulators, etc.) off-line and set them once at pre-specified values based on reactive power and loss conservation criteria. The set points may be revisited occasionally if there is any planned maintenance or modification to a feeder.

In general, to achieve conservation voltage reduction (CVR), SCE practice is to set capacitor banks and/or transformer taps to operate the distribution circuits at the lowest permissible voltage range of 114 V to 120 V. The objective is to passively reduce load and losses by operating at the lowest permissible voltage level.

2.3.5 Demand Response Programs

SCE has many different types of demand response programs with customer engagements at various levels. The primary demand response programs that may be applicable to some customers on the selected study feeders are:

- Radio broadcast air-conditioning unit cycling (automatic)
- Customer initiated load curtailment—based on system operator phone calls to customer to apply previously negotiated level of load reduction to avoid complete power outage of the customer facility (applicable to commercial and industrial customers).

2.4 Future Circuit Configuration and Characteristics

SCE presently has no major upgrade plan or proposed changes in the general distribution feeder designs to address any potential enhancement that may facilitate high-penetration PV system integration. However, as part of SCE distribution Smart Grid initiatives, SCE has engaged in two projects involving advanced distribution automation and active voltage control that may provide some insight into future distribution system designs. The two projects are (1) Avanti circuit of the future [4], and (2) Irvine Smart Grid demonstration (ISGD) project [5].

Figure 2-4 shows a schematic diagram of the Avanti circuit. The circuit design includes a distribution level dynamic reactive power compensator to provide voltage and VAr support. The selected circuit is also equipped with solid-state fault current limiter, remote control switches, and fault interrupters to facilitate integration of distributed generation and protection coordination. The project objective was to demonstrate an integrated design, interoperability of various control devices, and operational features that can be achieved in distribution circuits equipped with intelligent devices, coordinated and operated through a SCADA system.

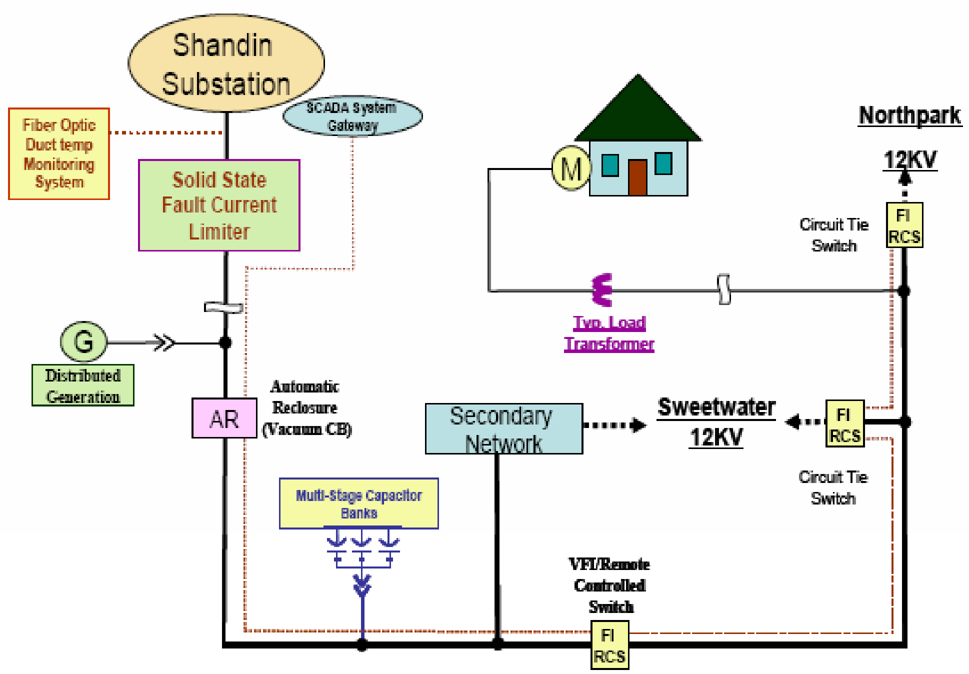

Figure 2-4. Schematic diagram of Avanti circuit of the future [5].

Figure 2-5 shows a schematic diagram of the ISGD project implemented on part of the UC Irvine campus. The customer loads are distributed on two adjacent feeders (Arnold and Rommel) that can be operated as a closed or an open loop. Universal remote control interruption devices (URCIs) with two-way communication infrastructure are provisioned to change circuit topology and transfer loads from one circuit to another during faults and contingency conditions. The project includes several subprojects targeting specific Smart Grid aspects such as (1) automatic volt/VAr control, (2) utilization of community-level energy storage for distribution constraint management, and (3) advanced control and protection strategies for self-healing circuits.

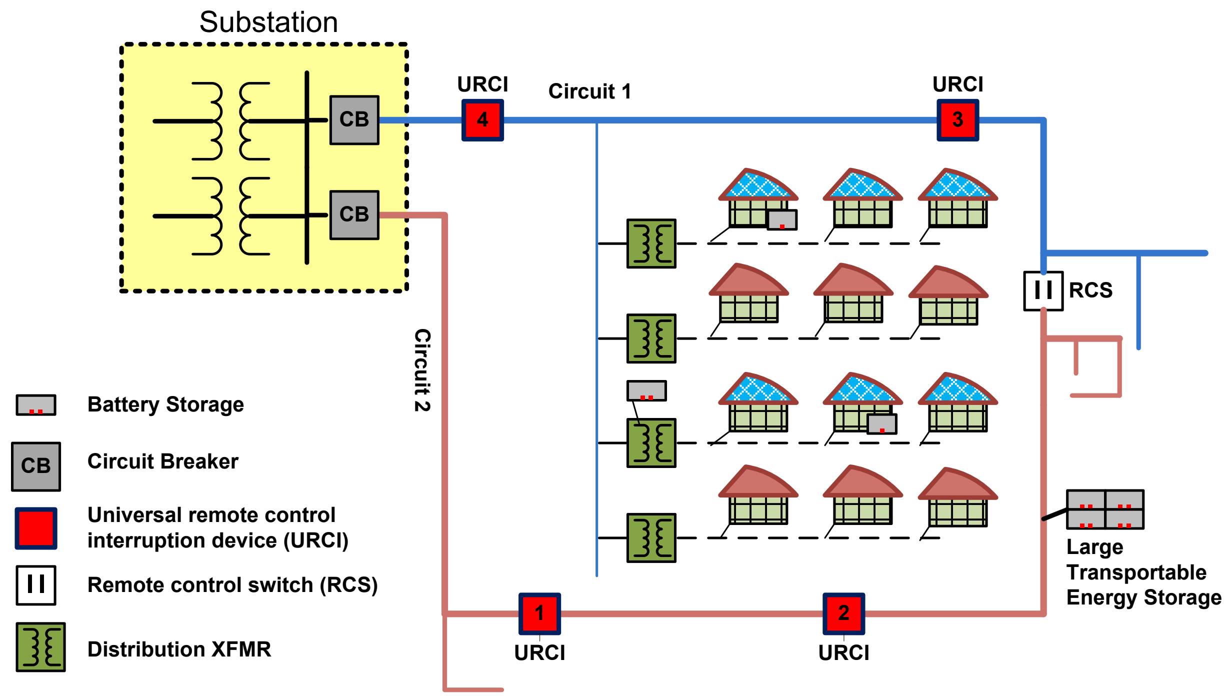

Figure 2-5. Schematic diagram of ISGD project [6].

2.5 Advanced PV Inverter Features

The following is a list of targeted and desired advanced features to be supported by intelligent PV inverters in order to reduce (or eliminate) adverse impact on power quality of the system as well as to enhance interaction with the grid. The recommended features are based on discussions with SCE distribution engineers and/or collected from review of relevant literature on the subject. For each feature, the control/operation objectives and expected impacts are described.

2.5.1 Target Feature: Voltage Regulation

Objective: To regulate the voltage at the point of common coupling during PV output fluctuations to maintain the voltage profile of the feeder within acceptable range.

Quantity(ies) involved: Inverter voltage and reactive power output; voltage at PCC.

Expected positive impact(s): Eliminate or reduce impact of a PV system on feeder voltage variations and support voltage quality at the customer site, especially for PV system installations toward the end of a feeder. The PV inverter can potentially act as an active filter to mitigate other power quality issues caused by non-linear loads, such as flicker and voltage sag/swell.

Potential adverse impact(s): Additional complexity in interconnection studies, higher degree of possible interactions with other voltage regulating devices, supervisory control and coordination requirements.

Inverter changes:

- Hardware changes: capacitor size or inverter topology to accommodate higher levels of reactive power support (common change aspect for any feature involving reactive power). Depending on the inverter topology and if it is not already oversized, the ratings of the power electronic switches may need to be increased to accommodate a reasonable amount of reactive power contribution at full active power.
- Software changes: addition of voltage control loops and user-selectable (or communicated) set points.
- Control schemes and requirements – reference control, voltage droop control, impedance measurement:
    - PV inverter may use control algorithms such as droop control or output impedance synthesis to determine voltage regulation needs.
    - The voltage control is primarily performed by an inverter supervisory control system to provide fast (sub-second) response.
    - A centralized dispatch of control modes and set points can be utilized in a multi-inverter situation, or to coordinate inverter voltage regulation effect with slow responses of other existing voltage-regulating devices on the same feeder (capacitor banks and line voltage regulators).
    - A slow-acting and narrow bandwidth communication system may be needed due to low priority of data communication and usage (to transmit dispatch set points or control modes only).

Other considerations and features: Communication with system operator or among devices to enable (1) status update of other voltage regulating devices and (2) regulating voltage at a selected point of the feeder rather than at the PCC.

2.5.2 Target Feature: VAr Control

Objective: To control reactive power output of a PV inverter to sink or source reactive power as a function of PV active power output variations, changes in the system, or by following pre-specified reactive power generation profiles.

Control modes and requirements: Based on applications, size of PV inverters, and operational desires, various VAr control modes can be defined.

- **Static VAr control** – This control mode primarily adjusts inverter power factor (pf). The power factor can be fixed, pre-scheduled or communicated set points. This control mode can be utilized when periodical (e.g. seasonal) adjustment of power factor based on variations in a feeder load or feeder configuration is desired. Distribution operators may use a supervisory controller to broadcast or multicast the power factor set points to several PV inverters. Note that inverter operation at unity power factor as currently prescribed by IEEE 1547.1 can be achieved with this control mode.

- **Dynamic VAr control** – This control mode automatically determines the reactive power output of a PV inverter based on pre-defined reactive power control algorithms and/or optimization strategies. The major application area desired by utility experts is to utilize dynamic VAr to cancel out or smooth out voltage fluctuations caused by power intermittency of PV inverters. Dynamic VAr control can also be utilized to compensate voltage drop on part of a feeder to achieve a flat voltage profile or reduce feeder losses. Dynamic VAr control mode may also be defined as a function of fast reactive power variations of a non-linear load to act as a distribution VAr compensator device.
- **Emergency (maximum) VAr control** – This is a control mode highly desired for utility operation during system contingency to provide maximum reactive power support and prevent voltage collapse. In this control mode, upon distribution operator request, each PV inverter supplies the maximum available reactive power output without reducing the active power output or violating the voltage limits. The target is to support transmission VAr emergency demand.

<u>Quantity(ies) involved:</u> Inverter active and reactive power output; indirect effect of system voltage, measured at PCC or load center (communicated).

<u>Expected positive impact(s):</u>

- Eliminating the adverse effect of PV inverters on feeder voltage increase.
- Reducing the number of tap-changer operations for LTCs and voltage regulators and/or capacitor bank operations.
- Actively contributing to and facilitating implementation of volt/VAr control strategies.

<u>Potential adverse impact(s):</u>

- Additional complexity in system design and interconnection studies.
- Details of control modes and inverter behavior may vary widely by inverter design from one manufacturer to another. This aspect would potentially affect real-world operation and coordination.
- Potential of dynamic interactions among multiple PV inverters with different control modes and responses.
- Complexity in calculating availability and reliability of reactive power capacity for emergency use. This is mainly because all control modes assign the priority to active power generation; hence, there may not be any tangible capacity available from PV inverters to supply reactive power when needed (unless inverters are oversized). On the other hand, the PV inverter owner or operator may also override the reactive power control capability to maximize production.

2.5.3 Target Feature: Power Curtailment

Objective: The main objective of this feature is to provide some degree of dispatchability in PV inverters in terms of active power output reduction. The primary application of this control feature is aimed at enabling utility operators to control the aggregated effect of total generation on distribution feeders during contingency conditions. A distribution operator can use this control mode to throttle back fast-acting generation to an aggregated reduced level rather than shutting down PV inverters or transmission connected systems.

Quantity(ies) involved: Inverter active power output, dc link voltage, and maximum point of power tracking schemes.

Expected positive impact(s):

- Additional degree of flexibility for utility operators.
- Reducing the voltage rise effect, as necessary, beyond the control limits achievable based on reactive power limits.
- Managing (preventing) unexpectedly large reverse power flow due to sudden loss of large loads.
- Loss reduction.

Potential adverse impact(s):

- Potential voltage drop and under-voltage issues on part of a feeder.
- Loss of a large amount of renewable energy generation if there is no provision for energy storage resulting in uncaptured revenue for PV system owner.

2.5.4 Target Feature: Ramp Rate Control (During Connection/ Disconnection or Sudden Output Variation)

Objective: This control feature can be used during fast power fluctuations caused by cloud effects or during start-up and shut-down of large PV inverters to balance the level of generation and load in the entire system. The maximum ramp rate of a system is typically determined by available spinning reserve and has to be oversized if there is no provision for power and load balancing by addition of PV systems. PV ramp rate control prevents change in spinning reserve requirements due to fast fluctuations of PV inverter outputs or sudden connection and disconnection of a large aggregated amount of PV generation.

Quantities and requirements: Active power output, dc link voltage, and active power controls.

- Implementing this feature requires a means of providing short-term storage based on the expected fluctuation rates for a PV system.
- Ramp rate control may be used by independent system operators (ISOs) to achieve frequency regulation for a system under stress.

- Reliable and accurate weather forecasting methods to determine cloud patterns and plan (coordinate) operation of various resources is also required and can enhance proper utilization of PV inverter ramp rate control.

Expected positive impact(s):

- Reducing the overall spinning reserve capacity requirements.
- Minimizing down-time of renewable energy sources.
- Contribution to frequency regulation of a system.

Some of the desirable (wishful) features for the PV inverter controls are:

- Low voltage and fault ride-through.
- Islanding and microgrid operation capability.

Characteristics of low voltage and fault ride-through for distribution applications are not well defined yet. The principal objective of these features is to prevent frequent disconnection of PV inverters during system transients that may cause significant voltage and frequency variations. The main target is to prevent adverse impact of transients originated from high voltage system to continue to support the load demand during such situations.

Intentional islanding and microgrid operation is a practice recommended by some utilities to enhance customer-based reliability during sustained power outages. Incorporating this feature in a PV inverter requires a means of frequency regulation and low following capability. Although the control feature already exists in stand-alone PV inverters with battery storage, it is not typically implemented on large scale PV inverters due to the cost of energy storage and the additional hardware to perform simultaneous voltage/frequency regulation. The inverter (and microgrid) protection methodology and fast/accurate islanding detection schemes are some other barriers that are not well established.

2.6 Classification and Generalization of Study Findings and Impacts

SCE's distribution system has more than 4,000 circuits. Given the fact that studying impacts of PV-based distributed generation (PV-DG) on all distribution feeders is neither practical nor economically feasible, the objective of the proposed classification methodology is to generalize the results of impact studies performed on a single feeder to a set of feeders with similar characteristics. The assumption is that impacts and mitigation measures for this set of feeders would be similar to those identified for the studied feeder.

The methodology uses geographic and statistical analysis to determine the similarity of a large set of non-studied feeders with respect to a small set of studied feeders. Then it ranks all non-studied feeders as a function of a similarity measure. Finally, for each studied feeder, it selects the group of most similar non-studied feeders on the basis of a customer-defined threshold. Study of the impact of PV-DG on each studied feeder, and appropriate weighting of the results, will provide an accurate picture of overall impacts on the utility system.

The distribution system's diversity of equipment, types of circuit configurations, voltages, and the study of the customers' geographic and demographic variations are used to determine and evaluate the similarity measure used in the classification method. The features of the summary data on SCE distribution systems and customer base are shown in Table 2-4.

Table 2-4. SCE T&D System Summary Features.[1]

OH Main Line Miles	OH Trans Count	2006 Peak Date
UG Main Line Miles	OH Trans kVA	2007 Peak Date
OH 3 Phase Miles	UG Trans Count	2008 Peak Date
UG 3 Phase Miles	UG Trans kVA	Automated kVAr
Voltage	OH Manual Switch	AR Count
Weather Zone	Tie Count	OH RCS
Customer Count	CI 2006	UG RCS
2006 Actual Peak	CI 2007	Substation Name
2007 Actual Peak	CI 2008	Switched kVAr
2008 Actual Peak	CMI 2006	Fixed kVAr
OH Miles	CMI 2007	Total kVAr
UG Miles	CMI 2008	Burd Switch
Total Miles		UG Manual Switch

2.6.1 Similarity Measure

The most commonly used similarity measure is Euclidean distance:

$$d(i,j)=\sqrt{\left|x_{i1}-x_{j1}\right|^2+\left|x_{i2}-x_{j2}\right|^2+\cdots\left|x_{ip}-x_{jp}\right|^2}$$

where $i=\left(x_{i1},x_{i2},\cdots,x_{ip}\right)$ and $j=\left(x_{j1},x_{j2},\cdots,x_{jp}\right)$ are two circuits with p attributes considered for comparison.

Euclidean distance is suitable for objects with all numerical information since it requires mathematical calculations. However, the summary data of SCE circuits contain not only numerical information but also categorical information. For instance, weather zone 2 doesn't mean that it is greater than weather zone 1.

To determine the similarity of two circuits with mixed numerical and categorical information, the similarity measure $d(i,j)$ is defined as[2]:

$$d(i,j)=\frac{\sum_{f=1}^{p} d_{ij}^{(f)}}{p}$$

[1] OH = Overhead, UG = Underground, CI = Customer Interruptions, CMI = Customer Minutes of Interruption, AR = Automatic Recloser, BURD = Buried Underground Residential Distribution.
[2] "Data Mining: Concepts and Techniques," Jiawei Han and Micheline Kamber, Morgan Kaufman, 2005.

If f is a numeric variable:

$$d_{ij}^{(f)} = \frac{\left| x_{if} - x_{jf} \right|}{\max_h x_{hf} - \min_h x_{hf}}$$

where h runs over all non-missing objects for variable f.

This equation shows the percentage of the distance between two specific numerical variables to the maximum possible distance between them.

If f is a categorical variable:

$$d_{ij}^{(f)} = \begin{cases} 0, & x_{if} = x_{jf} \\ 1, & \text{otherwise} \end{cases}$$

This equation indicates that if two categorical variables match with each other, the distance between them is 0; otherwise, the distance between them is 1.

With the similarity measure defined above, the differences of any circuit attribute between two feeders $d_{ij}^{(f)}$ are normalized. For categorical attributes, $d_{ij}^{(f)}$ is either 0 or 1. For numerical attributes, $d_{ij}^{(f)}$ ranges between 0 and 1. Therefore, it is not necessary to further implement a normalization process.

2.6.2 Data Pre-Processing

Weighting

Multiple circuit attributes representing the feeder characteristics have been used to evaluate the similarity measure. Not all of the attributes are equally important in presenting feeder characteristics, so appropriate weighting is required. The weighting strategy is closely related to the type of study to be carried out. For example, peak load and customer count are more important features for studying the impact of high penetration of photovoltaic-based distributed generation (PV-DG), but protective devices are more important for studying system reliability.

Four levels of importance have been defined for this type of study: most important, important, good to consider, and not necessary. The attributes included in each category are shown in Table 2-5, Table 2-6, Table 2-7, and Table 2-8, respectively.

Table 2-5. "Most Important" Data Fields.

Data Field	Weight Label
OH Main Line Miles	Most important
UG Main Line Miles	Most important
OH 3 Phase Miles	Most important
UG 3 Phase Miles	Most important
Voltage	Most important
Weather Zone	Most important
Customer Count	Most important
2006 Actual Peak	Most important
2007 Actual Peak	Most important
2008 Actual Peak	Most important

Table 2-6. "Important" Data Fields.

Data Field	Weight Label
OH Miles	Important
UG Miles	Important
Total Miles	Important
OH Trans Count	Important
OH Trans kVA	Important
UG Trans Count	Important
UG Trans kVA	Important

Table 2-7. "Good to Consider" Data Fields.

Data Field	Weight Label
OH Manual Switch	Good to consider
Tie Count	Good to consider
CI 2006	Good to consider
CI 2007	Good to consider
CI 2008	Good to consider
CMI 2006	Good to consider
CMI 2007	Good to consider
CMI 2008	Good to consider
2006 Peak Date	Good to consider
2007 Peak Date	Good to consider
2008 Peak Date	Good to consider
Automated kVAr	Good to consider

Table 2-8. "Not Necessary" Data Fields.

Data Field	Weight Label
AR Count	Not necessary
OH RCS	Not necessary
UG RCS	Not necessary
Substation Name	Not necessary
Switched kVAr	Not necessary
Fixed kVAr	Not necessary
Total kVAr	Not necessary
Burd Switch	Not necessary
UG Manual Switch	Not necessary

The circuit attributes are grouped into different categories according to their contribution to the feeder characteristics for this particular type of study. The "most important" group has the highest weight followed by the "important" group, then the "good to consider" group, and last the "not necessary" group. The attributes within one group are assigned the same weight. Higher-weight feeder features have more influence in determining the similarity of two circuits than lower-weight features do. In other words, the algorithm tends to group circuits into the same class if their high-weight attributes are closer.

2.6.3 Correlation Examination

Some circuit attributes are fully dependent on other attributes. For example, given any two of the overhead line mileage, underground line mileage, and total line mileage, the value of the third can be calculated. Therefore the total line miles and the percentage of overhead lines are used in the study.

Some circuit attributes are highly correlated with other attributes. For instance, the 2008 actual peak load of a feeder may be generally close to its peak load from 2007 and 2006. Table 2-9 shows the correlation among these three attributes. As a result, the 2006–2008 average peak load is used instead of individual year peak loads to indicate the electric usage of customers of this feeder.

Table 2-9. Correlation Matrix for 2006–2008 Actual Peak.

	2006 Actual Peak	2007 Actual Peak	2008 Actual Peak
2006 Actual Peak	1.0000	0.8008	0.7179
2007 Actual Peak	0.8008	1.0000	0.7906
2008 Actual Peak	0.7179	0.7906	1.0000

Excluding the feeder attributes that are closely related to other attributes can not only reduce the data dimension and expedite the computation process (because the dependent attributes are not providing more information) but it also can alleviate the potential impact of these dependent attributes on the weighting strategy (because redundant information is counted multiple times in measuring the similarity of two circuits).

The final feeder feature set used in the analysis is shown in Table 2-10 with variable type and corresponding importance shown as well. The fields shown in **bold** and *italic* are the ones that have been modified as described above.

Table 2-10. Data Fields Used in Cluster Analysis and Their Weights.

Data Field	Variable Type	Weight Label
OH Main Line Miles	Numerical	Most Important
UG Main Line Miles	Numerical	Most Important
OH 3 Phase Miles	Numerical	Most Important
UG 3 Phase Miles	Numerical	Most Important
Voltage	Categorical[3]	Most Important
Weather Zone	Categorical	Most Important
Customer Count	Numerical	Most Important
2006-2008 Average Peak	Numerical	Most Important
% of OH Miles	Numerical	Important
Total Miles	Numerical	Important
OH Trans Count	Numerical	Important
Average OH Trans kVA	Numerical	Important
UG Trans Count	Numerical	Important
Average UG Trans kVA	Numerical	Important
OH Manual Switch	Numerical	Good to consider
Tie Count	Numerical	Good to consider
2006-2008 Average CI	Numerical	Good to consider
2006-2008 Average CMI	Numerical	Good to consider
2006 Peak Month	Categorical	Good to consider
2007 Peak Month	Categorical	Good to consider
2008 Peak Month	Categorical	Good to consider
Automated kVAr	Numerical	Good to consider

Figure 2-6 shows the flow chart of the classification algorithm. It is worth mentioning that depending on how the studied feeders are selected, it is possible that a non-studied feeder ended up being classified as similar to more than one studied feeder. If this is the case, the highest similarity measure will be used to finalize the classification and assign the non-studied feeder to a single similarity set.

[3] It can be treated as numerical variable as well.

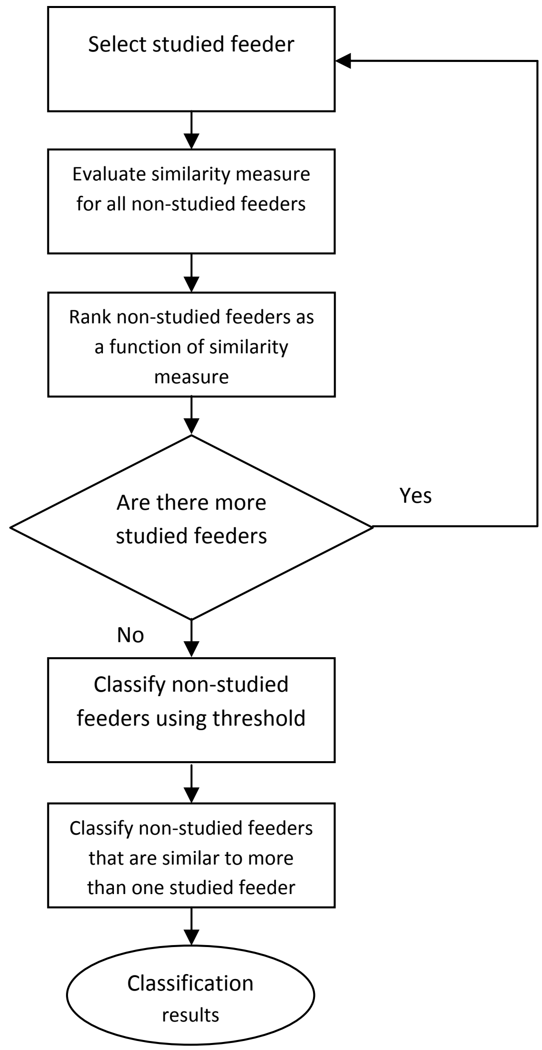

Figure 2-6. Flow chart of classification algorithm.

3 Distribution System Modeling and Simulation Tools for High-Penetration PV System Integration

As the penetration level of interconnected PV systems increases on a distribution system there is an increasing need for both accurate models of the solar resource and advanced distribution system analysis tools to evaluate high-penetration PV system impacts. This report provides initial assessments of solar resource data for use in distribution system studies and addresses the capability of existing distribution system modeling tools.

3.1 Part 1: Integration of PV into Distribution Modeling Tools

Software tools that model hourly production of PV systems have grown substantially in usage over the past decade, driven by the growth of the industry itself. These tools have supported the calculations of hourly and monthly PV energy production and the financial modeling necessary to determine cost-effectiveness. Tools have likewise evolved to support online processing of PV incentive programs, the incorporation of satellite-derived irradiance data (rather than ground-mounted measurements or Typical Meteorological Year [TMY] data), and features such as performance monitoring.

All of these advancements have been oriented around individual PV systems: the amount of energy produced by a system, economic payback of the system, etc. Until now, tools to model the behavior of multiple systems – or PV "fleets" – has been lacking. The work described in this report may therefore be considered as the introduction to a new class of PV software related to the behavior of PV fleets.

3.1.1 Background

Utility distribution engineers responsible for the design of safe, efficient, and cost-effective distribution systems have historically used tools that model lines and components (such as switches, capacitors, and transformers) under specific loading conditions, in particular the "peak" hour. In some cases, distributed generators have had to be modeled to adequately account for their impacts on load flows.

Distribution engineering tools, however, have generally not included support for PV modeling. The present work is intended to address this omission. With the continued growth of the PV market, and the increasing penetration of PV resources in the distribution grids, the modeling tools will have to begin to incorporate support for PV. The present work represents an initial attempt by Clean Power Research (CPR) to address the shortcoming.

3.1.1.1 PV Impacts on Distribution Studies

The following sections describe some of the important types of studies that are performed by utility distribution engineers using various modeling and analysis tools, and the impacts of PV generation that need to be considered in these studies.

3.1.1.2 Load Flows with Distributed Generation

Line loading is calculated in load flow studies – currents, voltages, and power factors – on different sections of the circuits at specific times (e.g. the time of peak loading). These are steady state calculations typically done to ensure that currents and voltages are within physical and regulatory limits.

PV in the distribution system can be considered a "negative load" like other distributed generation sources, but its output is more complicated because it varies every hour. Furthermore, PV output is dependent upon several factors, such as hourly solar irradiance, hourly ambient temperature, hourly sun angle, array azimuth and tilt, and PV module and inverter characteristics.

In high-penetration PV scenarios, the hours of maximum line loading do not necessarily correspond with maximum consumption. It will be necessary for engineers to consider other times in their load flow studies. For example, daytime consumption could be offset by PV and maximum line currents could be shifted from daytime to evening hours.

3.1.1.3 Protection Studies

Protection engineers need to determine settings and locations for protective devices such as reclosers and fuses. These settings are dependent upon stiffness of generation sources, impedances, and loadings.

PV will source current at the interconnection point, even causing current to flow in a reverse direction depending upon generation and local loads at the time. The magnitude of the PV contribution must be known in order to properly perform these studies. Utilities generally require compliance with UL 1741 in order to connect to the grid.

3.1.1.4 Fault Location

The tools may include the ability to determine probable locations of faults, given the line configuration and EMS readings at the time of the fault. These are presented as graphical locations on the circuit to facilitate dispatch of line crews.

PV will impact line currents during the time of the fault, so the outputs of PV systems need to be accounted for in the calculations of fault location.

3.1.1.5 Harmonic Analysis

Engineers need to determine the harmonic distortion (both individual harmonics as well as total harmonic distortion, THD) at selected locations on the line. This is historically caused by variable speed motor drives and other electronic loads.

PV inverters are electronic sources that also introduce harmonic content.

3.1.1.6 Conservation Voltage Reduction

There are potential energy-saving impacts associated with conservation voltage reduction (CVR). Distribution modeling tools are able to calculate energy savings that would be realized under different voltage scenarios.

In order to correctly model the voltages and energy use, PV generation must be considered during the critical low-voltage hours.

3.1.2 Data Requirements

Table 3-1. Data Requirements Table.

	Data Needed	**Notes**
Load Flow Studies	**Minimum, maximum, and average** PV output for all hours of interest.	
Protection Studies	**Minimum, maximum, and average** PV output for all hours of interest.	Grid-connected inverters are current-source devices (unlike synchronous generators). Inverters operate at the prevailing voltage and source current that corresponds with the maximum available power.
Fault Location	Estimated PV output at the **time of the fault**.	If actual PV output is measured (from EMS), then this data would be used. Real-time PV output estimation for fault location could be provided in the future as a web service.
Harmonic Analysis	**Average** PV output for all hours of interest. Inverter characteristics.	CPR does not have harmonic data on inverters but can provide expected output.
Conservation Voltage Reduction	**Minimum, maximum, and average** PV output for all hours of interest.	

3.1.3 Limitations of Existing Tools

Clean Power Research (CPR) has held a series of discussions with a software developer of a nationally recognized distribution engineering modeling tool. One approach used by this tool is to model PV as a negative load. That is, for a given hour, PV may be treated as a constant power source with a specified power factor (usually unity power factor). An example customer load editing tool is shown below in Figure 3-1. An apartment building load is presented.

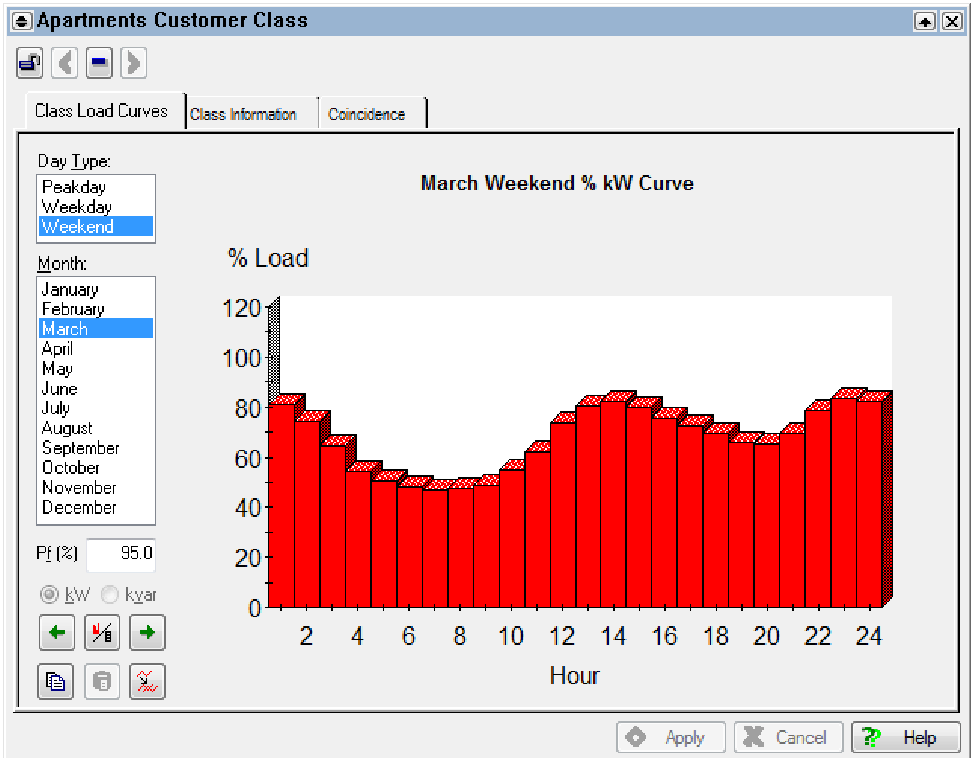

Figure 3-1. Customer load editing.

The same interface can be used to describe a PV output profile. As a result, distribution engineers are able to describe 12 month x 24 hour matrices for PV output under three scenarios: peakday, weekday, and weekend.

In practice, however, there are limitations with this approach:

- Modeling PV systems is complicated. Most utility distribution engineers are not familiar with hourly PV production models.
- Data input is time consuming. Even if hourly PV output values were known, the time to use editors such as the one presented above would not be practical.
- While customer demand may depend on whether it is a weekday or weekend, PV system generation does not.

3.1.4 Objective

CPR's objective was to produce a sample data set of PV output data that can be used by SCE distribution planners to analyze the effect of PV system output from a specific set of PV systems within the SCE distribution system and to conduct studies such as the ones described above.

3.1.5 Approach

Rather than entering PV production estimates for every PV system on the distribution system, hourly customized estimates could be generated automatically using existing PV system configuration data and existing PV modeling tools. The resulting output file could then be imported into the distribution tool in a suitable format.

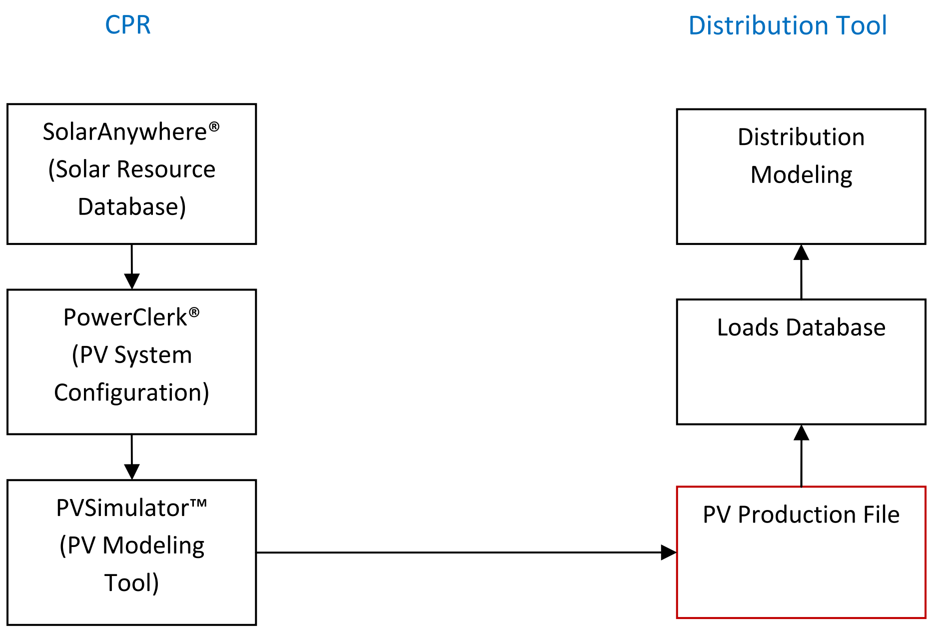

Figure 3-2. Process flow.

The approach includes the following:

- CPR software suite models the PV systems. PV system technical data is entered into PowerClerk for the SCE systems under consideration. Hourly modeling is performed using SolarAnywhere resource data, the PV systems as configured in PowerClerk, and the PVSimulator simulation engine.
- CPR creates the PV Production File. CPR developed the code necessary to create the output file.
- The process can be done for any number of systems as a batch process. To facilitate the data transfer, all of the PV systems for a given utility can be processed at one time. The service will create a single PV Production File for the entire utility system.
- The distribution tool associates PV output with a given distribution transformer. PowerClerk provides for Customer ID as a custom field. The output file will include Customer ID for location on the line.
- The distribution tool then models load flows using hourly PV output at the distribution transformer level.

3.1.6 Definition of Statistical Output Results

CPR produced three matrices for each PV system under study: one matrix for maximum power, one matrix for average power, and one matrix for standard deviation of power. Each matrix contains 12 months by 24 hours of data. Each matrix may be used by the engineering tool for different purposes or scenario analyses.

The maximum power, average power, and standard deviation of power arrays were created as follows:

- NREL supplied CPR with the system specifications (e.g. rating, orientation, shading, etc.) for each of the PV systems under consideration at SCE.
- PV system specification data was entered into the database and then combined with CPR’s time- and location-specific solar resource database (SolarAnywhere) and CPR’s PV simulation tool (PVSimulator) to calculate the hourly PV system output for each system for the past 10 years.
- The resulting data was used to calculate the maximum power, average power, and standard deviation of power for each system for each month and hour of the year. All values were in kW.
- The maximum power for a particular month and hour was defined as the maximum PV system output over the previous 10-year period for that specific month and hour for a specific PV system. For example, the maximum power for January at 10 a.m. was determined by examining PV output on every January day at 10 a.m. for the past 10 years. The maximum value from the 310 possible values (10 years x 31 days/year) was selected.
- The average power and standard deviation of power for a particular month and hour were similarly defined by calculating the average and standard deviation of PV system output over the previous 10-year period for that specific month and hour for a specific PV system.

A minimum power array is implicit in the data containing all zero values corresponding to system downtime. This data was not passed.

3.1.7 PV System Technical Data

Technical data (inverter make and model, PV make and model, quantities, orientation) was provided by NREL for two PV systems located in the service territory of Southern California Edison: a 2 MW ac system in Chino and a 1 MW ac system in Fontana. These two systems were used to create the sample data output file.

In Figure 3-3, the customer data is entered into the PowerClerk database. Since this system was not part of an incentive program, the incentive-related fields were ignored. However, the Utility Account Number field must be used to identify the location of the PV system on the distribution line. The distribution software includes the mapping to line location (or alternatively, a mapping of customer to distribution transformer).

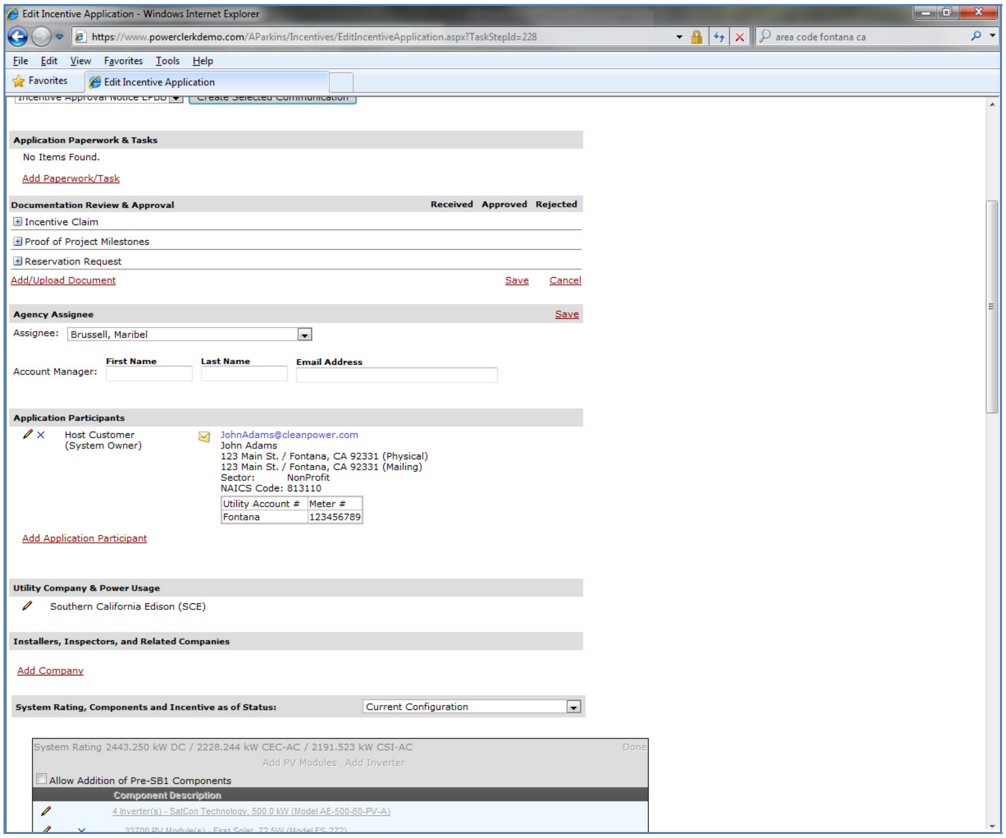

Figure 3-3. Customer editing and account linking.

Figure 3-4 and Figure 3-5 show the selection of inverter and PV module. PowerClerk provides the selection of manufacturers and models and other details such as the association of modules to specific inverters. Orientation and shading details were also entered.

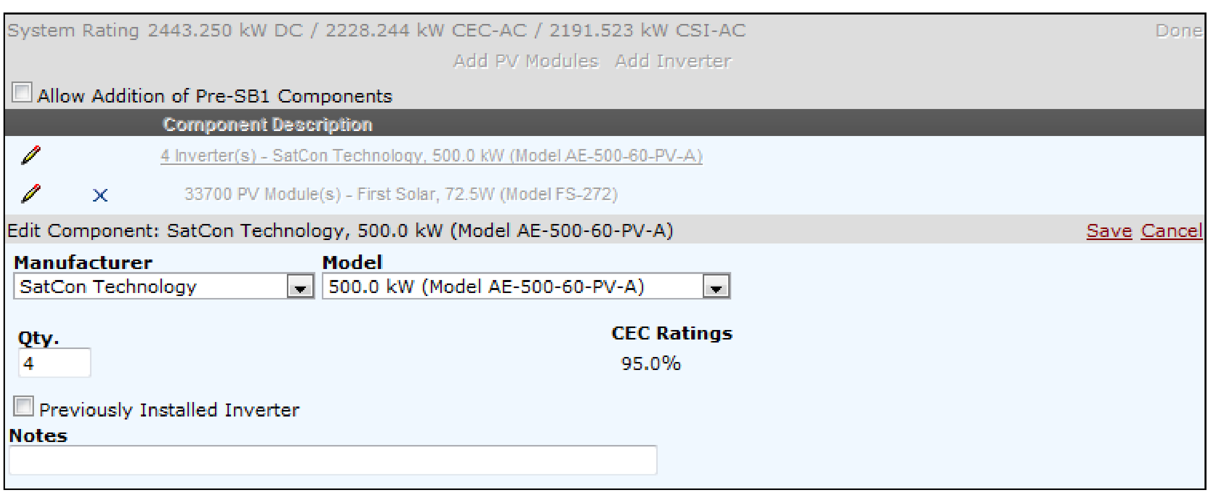

Figure 3-4. Inverter editing.

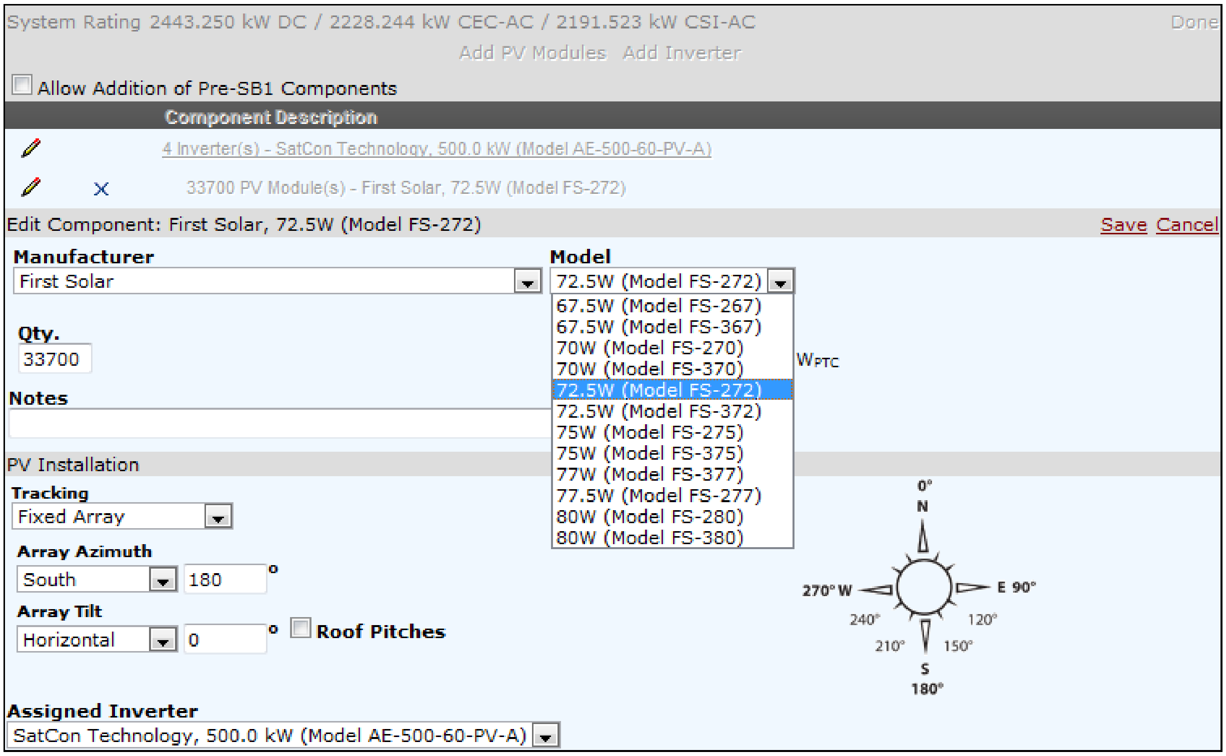

Figure 3-5. PV module editing.

3.1.8 Output Sample

The data file produced (as a deliverable to NREL) was in a format decided on and agreed to during the course of the project. It was to contain the following information:

- PV_System_1
    - **CustomerID**
    - **Maximum Power** in kW (matrix of 12 months x 24 hours)
    - **Average Power** in kW (matrix of 12 months x 24 hours)
    - **Standard Deviation** in kW (matrix of 12 months x 24 hours)
- PV_System_2
    - **CustomerID**
    - **Maximum Power** in kW (matrix of 12 months x 24 hours)
    - **Average Power** in kW (matrix of 12 months x 24 hours)
    - **Standard Deviation** in kW (matrix of 12 months x 24 hours)
- PV_System_3
    - Etc…

The delivered data file was in XML format and is shown in Appendix B.

3.1.9 Next Steps

The data file may be used for upload into a compatible engineering tool. This tool should be designed with an understanding of the unique characteristics of PV. For example, while conventional load flow studies are primarily concerned with the hour of greatest load (demand), this rule does not necessarily follow on circuits with high penetration of PV.

For example, during lightly loaded hours with high solar production (such as weekends), there may be significant back-feed on some sections of the line. The highest loading may actually occur in these "off-peak" hours.

3.2 Part 2: Distribution System Modeling and Simulation Requirements for Evaluating High-Penetration PV Integration

This section will be broken into three parts: background modeling applications, modeling needs for enabling high-penetration PV studies, and additional DEW capability needed to support the project goals.

3.2.1 Background

Solar cost reductions, increasing costs of traditional sources, and Renewable Portfolio Standards have created the possibility of significant levels of distributed solar generation being installed on distribution systems. This emerging situation could lead to high-penetration scenarios. To aid in evaluation and help with this expansion of solar resources, there needs to be significant changes in the way that the electric power infrastructure is designed and operated. In particular, new high-penetration software analysis tools need to be developed and integrated with existing software analysis tools such that utility planning and operation engineers can determine impacts as they do their normal work. This document outlines some analytical and software needs that will support expansion.

Modeling needs in support of the NREL/SCE high-penetration project will be broken into the following major headings:

1. Utility distribution modeling
2. Solar side modeling.

The following are general utility concerns or issues to be addressed with interconnecting a distributed resource (DR) to a utility system. These concerns are broken into the need for quantifying the impacts of DR on protection, operation, and planning and engineering studies.

From a **protection** point of view software capabilities need to address <u>*loadability*</u>, <u>*selectivity*</u>, and <u>*sensitivity*</u>, with the following definitions:

<u>*Loadability*</u> – ability to serve load without tripping.

<u>*Selectivity*</u> – the system protective devices nearest the fault isolate the fault before more remote device(s) operate to isolate the fault.

<u>*Sensitivity*</u> – the ability to sense faults.

The following are examples of study concerns:

- Improper coordination, nuisance fuse blowing, and upstream single phase faults resulting in fuse blowing
- Close-in faults causing voltage dips that trip DRs, isolating DRs from upstream faults
- DR stability during faults, islanding, reclosing out of synchronism, and transfer trip
- Equipment over-voltage, switchgear ratings, under-frequency relaying, and distribution automation studies.

From an **operational** point of view, software capabilities need to address the following examples of study concerns:

- Equipment over-voltage, resonant over-voltage
- LTC regulation affected by DRs, voltage regulation malfunctions, and line drop compensators fooled by DRs
- Substation load monitoring errors
- Loss of exciters causing low voltage, self excited induction generators, in-rush of induction machines causing voltage dips, voltage cancelled by forced commutated inverters, and capacitor switching causing inverter trips
- Cold load pickup with and without DRs, flicker, harmonics, stability during faults, and long feeder steady state stability
- Switching impacts resulting from large levels of solar generation
- Not allowing DRs to limit system operations during normal and emergency conditions including switching operations
- Protection and coordination with inverters, including sectionalizer miscounts
- Interoperability of multiple inverters from various manufacturers and voltage control with multiple sources on a distribution feeder
- Forecasting/planning for peak and light load
- Reliability impacts on both momentary and forced outage rates
- Economic impacts on operations energy and capacity
- Financial impact on capital and O&M.

From a **planning and engineering** point of view, software capabilities need to address the following examples of study concerns:

- Feeder loading criteria and forecasting
- Load forecasting that considers multiple generation sources
- The amount of generation that can be installed on a distribution feeder
- Feeder design that considers large levels of DR generation

- Distribution planning models that reflect actual system operation with high levels of DR generation
- Dynamics of small generators
- Economic analysis of losses
- Generation planning and operation for both capacity and energy, including production profile throughout the year and type of production.

In addition to new analysis tools, training for engineers that will use the new tools will be important to the overall success.

3.2.2 Modeling Needs for High-Penetration PV Studies

Modeling systems will need modifications in order to study impacts of high-penetration solar generation.

Detailed PV inverter models need to be developed for power flow, short circuit, and dynamic studies. Modeling should include programmable drag and drop solar inverter models that can accommodate solar input measurements to facilitate the study of high penetration of PV as part of the normal utility planning and operation process. This should include specific inverters, default inverters, and programmable inverter parts. The inverter models should be configured to emulate their control settings. The inverter models will also accept time sequence measurement data provided by Clean Power Research, the National Renewable Energy Laboratory, and others for load estimation and power flow.

The study system needs to be modeled across the entire load spectrum. Load modeling studies will need to be made across time-varying load curves, such as 8,760 hourly time points. The load modeling should be as close to customer load and generation as possible and represent all 8,760 annual-hourly load points. The modeling time points for analysis will need to be modified to accommodate the time sequence of the solar data stream.

Modeling systems needs to be capable of stepping through an operational time sequence that is granular enough to capture the operational movement of all active elements within the circuit, such as time delays for voltage regulation, protective device operation, etc. The step sizes should be programmable.

The following discussion goes into more specific modeling needs required for detailed studies.

3.2.2.1 Component Immittance

The component immittance type of analysis will need to be capable of calculating line and cable impedances and admittances as a function of construction, temperature, and frequency. This should include inverter impedances as well, particularly to facilitate harmonic analysis.

3.2.2.2 Load Estimation

The load estimation type of analysis is primarily a steady state analysis function. It needs to include time-sequenced analysis down to one-minute intervals or, in some analyses, features such as fault current analysis down to the millisecond. The load estimation function should be able to combine start of circuit measurements, interior circuit measurements, PV output, and the allocation of customer loading. Load modeling should be as close to customer load and generation as possible. Customer load estimation should be able to handle kWh measurements, load research statistics, single large customer (kW, kVAr, kVA) load measurements, special load measurements, and load growth factors (either for entire circuit or individual load) to estimate kW and kVAr loading as a function of time. Load forecasting should include weather dependent adjustments for both loads and solar generation.

3.2.2.3 Power Flow

The power flow type of analysis needs to solve large scale problems from transmission-level voltages down to secondary service points, including heavily meshed secondary systems. The power flow analysis should address both steady-state and quasi-dynamic overload, voltage, flicker, and control concerns. A power flow and voltage drop study should be performed to determine the steady-state loading profile of the system. The power flow should be capable of stepping through time-sequenced operations of the circuitry's active components, including rapid changes in loading such as system responses to changes in PV outputs and loading associated with rapid configuration changes.

3.2.2.4 Network Fault

The network fault type of analysis should be capable of calculating fault currents for radial and looped systems; work for multiple substations looped together; and analyze fault currents from distributed resource generators. It should be capable of running for loaded or unloaded systems as well as other model variations. Short circuit current studies are necessary to quantify the impacts on breaker duty, momentary interrupting capability, and protection/coordination needs to accommodate in-feed from multiple distributed resources and coordination for inverter fault performance. Inverter modeling and data inputs need to be developed. The characteristics of the inverter fault capability will need to be incorporated.

Analysis of multiple DR devices/technologies should be possible to determine the potential for oscillations and the effectiveness of anti-islanding controls.

3.2.2.5 Protection Coordination

The protection coordination type of analysis should locate protection and coordination problems within a circuit and should work with multiple sources of solar inverters and their protection systems. The protection coordination analysis should search protection databases to find lists of devices that will coordinate, display zones of protection, and update circuit protective devices. This analysis will aid in contingency analysis studies involving high-penetration PV.

3.2.2.6 Power Quality

The power quality type of analysis should address harmonic impacts, flicker, outages, momentary faults, and sag/swell concerns. Although many utilities have moved away from harmonic analysis of late with a focus on outage, we expect a renewed interest in harmonic analysis as the number of inverters increases. The need to quantify the harmonic impact on both the utility as well as on the individual inverter systems will be of increasing concern.

3.2.2.7 Harmonic Analysis

The harmonic type of analysis will require the study of harmonics generated by PV inverters and possible resonant interactions of inverters with the distribution system. In order to simulate harmonics on an ac distribution network, models for harmonic generating loads as well as system components must be developed. In general, the power electronics that generate harmonic currents can be modeled by using current source models. If the interactions between the ac and dc systems are needed, more complicated device-level models will be required that take into account the harmonic currents as a function of system reactance, delay angle, and commutation angle. Getting this information to support the latter may be a challenge.

3.2.2.8 Flicker Analysis

The flicker type of analysis should be capable of calculating voltage dip percentages resulting from loads cycling and capacitors switching, modeling the rapid fluctuations in PV output, and comparing the resulting voltage dips with the standard ANSI flicker curves.

3.2.2.9 Contingency Analysis

The contingency type of analysis, which typically runs first and second contingencies on a system of feeders to determine loss of load events, should be updated to include inverter response to contingencies. This function could be accomplished through updating existing power flow and short circuit analysis.

3.2.2.10 Reliability Analysis

The reliability type of analysis is used to predict changes in reliability as a result of circuit modifications. Reliability impacts of DRs, including intentional islanding, should be included in this analysis. In addition to normal feeder component reliability, inverter operational statistics will need to be developed. Note that some utilities may not have good reliability statistics on individual feeder components.

3.2.2.11 Feeder Performance

The feeder performance type of analysis should address time-varying load, such as all 8,760 annual-hourly load points. The efficiency should be examined and quantified across the entire load spectrum.

High penetration analysis modeling and the results should be managed through dashboard and visualization aids, providing a presentation layer to aid analyst understanding.

All of the above analysis methods are needed for planning, design, and operation. The modeling should be integrated with existing tools in a manner that imports field measurements. Quasi-dynamic modeling will provide detailed understanding of system response, which can offer guidance for system planning, design, and operation. In addition to new analysis tools, training for engineers who will use the new tools will be important to the overall success.

3.2.2.12 Power Flow Assessment – Study Example

The following is an example analysis of how to determine voltage and current effects of high-penetration solar.

Study 1. Run base case 1 at daylight peak load to develop normal circuit peak load baseline.

Study 2. Run base case 2 at daylight light load to develop normal circuit minimum load baseline.

Study 3. Run base case 1 again with a high penetration of solar generation and compare results with those from Study 1.

Study 4. Run base case 2 again with a high penetration of solar generation and compare the results with those from Study 2.

Study 5. Run base case 1 again with a high penetration of solar with the solar output varying from maximum to minimum with the circuit *regulation frozen* (remaining in its steady state condition before the solar variation occurred) to determine maximum circuit voltage variation. Compare results with those from studies 1 and 3.

Study 6. Run base case 2 again with a high penetration of solar with the solar output varying from maximum to minimum with *regulation frozen* (remaining in its steady state condition before the solar variation occurred) to determine maximum circuit voltage variation. Compare results with those from studies 2 and 4.

3.2.2.13 Network Fault Assessment – Study Example

The following is an example analysis of how to determine fault current impacts on a circuit with and without solar inverters present.

1. Run power flow applications and obtain results (voltages and currents) for the stabilized pre-fault system.

2. Run the network fault application to obtain short circuit current results at the time of the fault along with voltages to determine protective device operation along the circuit.

3. Run power flow applications on the post-fault system with the circuit *regulation frozen* (remaining in its steady state condition from the previous run), which may include configuration changes, to determine currents, voltages, and load loss without circuit regulation changes.

4. Rerun component immittance, load estimation, and power flow applications on the post-fault system, with circuit regulation performing its control function.

5. Rerun Step 4 above for a return of inverters that were outaged as a result of sags.

6. Rerun Step 5 with the return of the outaged area to quantify cold load pickup issues.

First obtain results on the circuitry without high penetrations of solar generation. Then repeat the study with the addition of high penetrations of solar. Each of the above should be run at daylight peak and light loads. The studies should be repeated for switching and contingency configurations that are normally studied in planning.

From these studies we expect to quantify the protection issues associated with the high penetration of solar on the SCE circuitry. These would include the issues such as loadability, selectivity, sensitivity, and cold load pickup issues.

3.2.2.14 Penetration Limits

From previous penetration studies, there are essentially three criterion dictating penetration limits, fault current sensitivity, reverse power, and voltage/overload restrictions. Typically at the beginning and middle of radial circuits, penetration limits are dictated by fault current sensitivity and reverse power. Near the end of the radial circuits, penetration limits are typically restricted by a combination of fault current sensitivity and voltage/overload.

We may want to examine the need to develop a high-penetration PV application. This could be done by modifying existing penetration/technology adoption analysis applications developed by EDD to determine initial high-penetration solar limits. The existing application criteria will need to be modified for reverse power, fault current sensitivity, and voltage/overload problems for high solar penetration. We recognize that problems may be resolved with additional circuit protection and control, but the application will be needed to help define those required circuit changes. In addition, the application may help to define new circuit configurations and operating characteristics (newly built circuits designed to accommodate high-penetration PV levels, microgrids, and Smart Grid implementation). See Section 3.2.3 for more information on DEW's Penetration Limits Application and Distributed Energy Resource (DER) Technology Adoption Analysis Application.

As a result of our previous DER penetration analysis experience, three main studies are proposed for assessing the penetration limit for a distribution circuit:

- Power flow results for highest penetrations of solar inverter-based generation, which corresponds to the maximum local area hourly solar output equal to circuit loading.
- Repeat of the above with a maximum short term solar variation, first with regulation not allowed to move and then again with regulation allowed to move.
- Power flow results for maximum penetration based on reverse power criterion.

The above procedure will be repeated through time-sequenced events with and without solar inverters present. The inverter output will be bracketed for output variations, including Volt/VAr operation and control possibilities.

3.2.3 Additional DEW Capability

3.2.3.1 Penetration Limits and DER Technology Adoption Analysis Application

Although not a part of our original proposal, we would like to recommend that DEW's Penetration Limits Application be modified for this project. We also recommend that this would best be done by merging this application with DEW's DER Technology Adoption Analysis Application. The following is a discussion of those existing applications.

3.2.3.2 Penetration Limits

A DER Penetration Limits Application has previously been created. Criteria for penetration limits were established, which include over-voltage, flicker, overload, reverse power, and fault sensitivity, both with and without active regulation. The penetration limits were calculated for circuit head, mid circuit, and end of circuit. The penetration application within DEW was established and supplemented with power flow and short circuit analysis applications.

The Penetration Limits Application determines the largest distributed generator that can be placed on a circuit without violating constraints, including flicker, component overload, customer level voltage, and reverse power at the substation transformer. Using either a bisection search method or a brute force method, the real power output of the generator is increased until one or more of these criteria are violated. The bisection search can greatly decrease the solution time by reducing the number of iterations the algorithm must perform to arrive at an acceptable solution. Solution parameters such as iteration size (for brute force) and acceptable real power window (for bisection search) can be adjusted to achieve the desired balance of solution time and accuracy. The user may also select which conditions to check for failure and specify failure points for flicker and customer level voltage.

The user may also choose to either actively control the reactive power output of the generator or simply hold the power factor constant at unity. Configurable parameters for active control include power factor as well as rated power factor for the generator.

The penetration limit reactive power control algorithm was adjusted to find the reactive power output for both maximum released capacity as well as minimum circuit losses. The algorithm no longer increases the real power output once any selected criteria are violated. Low customer voltage is a failure criterion.

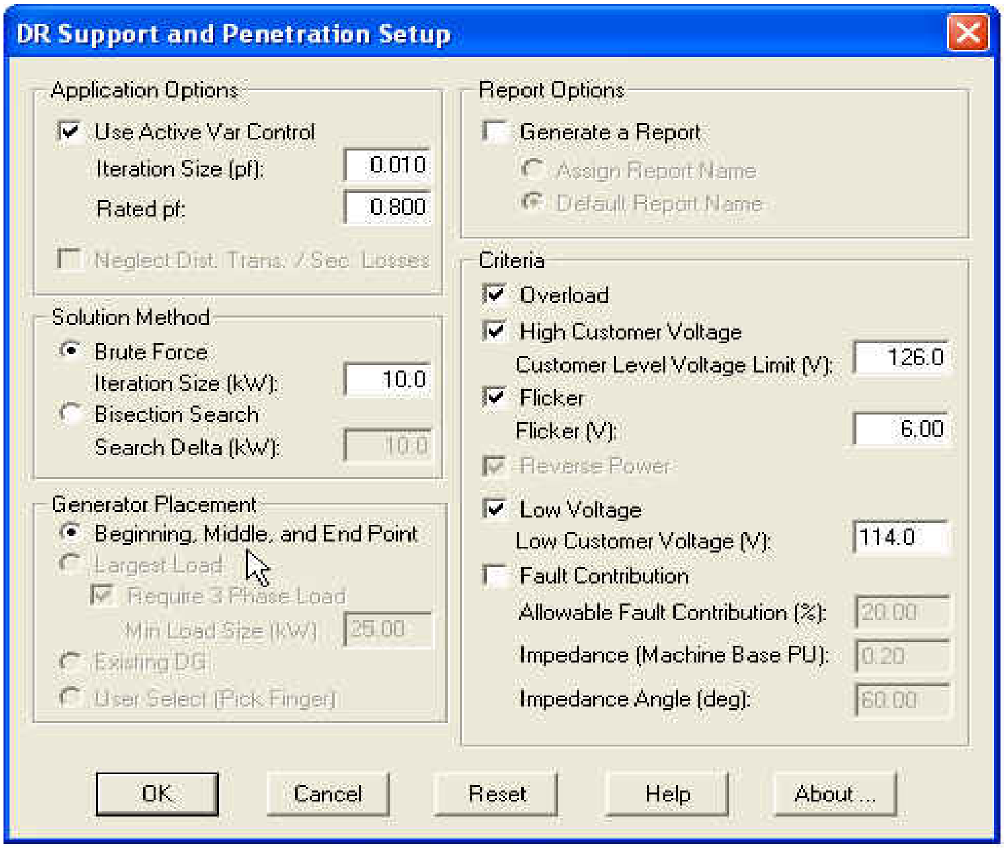

Figure 3-6. DEW's Penetration Limits Application dialog.

A protection sensitivity criterion is included. A rule of thumb is used such that the DR is not allowed to contribute more than 10% of the system's available fault current as a means of maintaining circuit protection selectivity and sensitivity. The maximum DR size is calculated for the points of interest as a means of maintaining the circuit protection.

3.2.3.3 DER Technology Adoption Analysis Application

Another potential addition to the project would be to combine the Penetration Limits Application with the DER Technology Adoption Analysis Application.

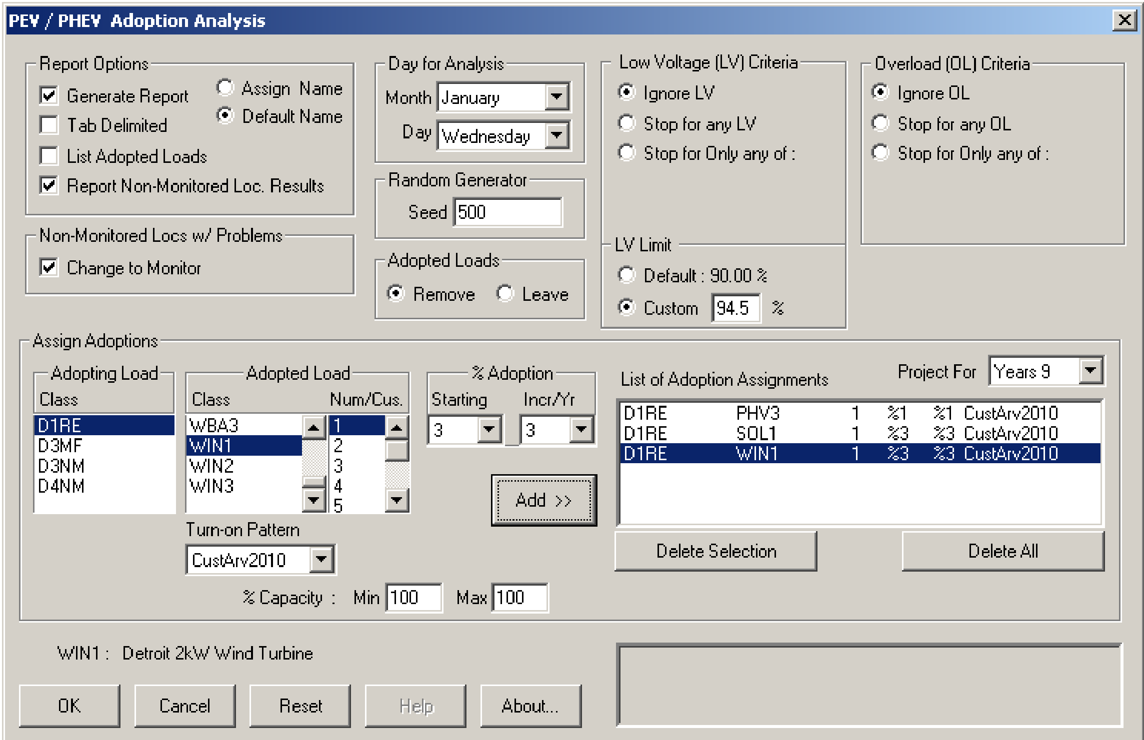

Figure 3-7. DEW's DER Technology Adoption Analysis Application dialog.

Electrical Distribution Design created an analysis program that runs with the DEW modeling system to aid DTE Energy in the analysis of the growth or adoption of electric vehicles. In particular, a DER Adoption Analysis Application was developed to study plug-in electric vehicles (PEV).

Monte Carlo simulation is used to randomly place PEV units at locations throughout the circuit. The simulation provides customer arrival home and plug-in time models, including automated charging during early morning hours.

After the PEV adoption program was completed, NREL funded the further development of the application. The PEV adoption program was expanded and renamed the DER Technology Adoption Analysis Application. The application was expanded to enable studies of simultaneous adoption of various technologies such as customer-owned solar generation, customer-owned wind generation, and utility-owned battery storage. An objective is to evaluate adoption levels of solar and wind generation supplemented with battery storage that will offset the adoption of electric vehicle loads.

The National Renewable Energy Laboratory’s solar data is utilized for the solar generator. For a given solar generation location and size, the NREL interface provides hourly generation data for an entire year, and thus 8,760 hours of generation are used in the analysis. For the wind generation, wind speed data is obtained using U.S local climatological data from the National Climatic Data Center (NCDC). The wind power used in this analysis is calculated by the wind turbine power equation. For each hour of analysis, customer loads are estimated from averaged hourly SCADA measurements, hourly customer kWh load data, and monthly kWh load data processed by load research statistics to create hourly loading estimates for each customer. Customer battery storage is also included.

The application, once modified by incorporating penetration limit analysis, would allow the analysis of any of SCE's distribution circuits.

4 Data Acquisition Requirements for Analysis of High Penetration Levels of PV into the Distribution Grid in California

4.1 Introduction

This section provides supportive material and information required to facilitate data acquisition requirements for evaluating the distribution system impacts of high-penetration PV integration. The collected data will be used to develop and verify models and simulations used to study the impacts of high-penetration PV integration and develop methods for mitigating these effects.

4.2 Distribution System Monitoring and Data Collection

This section describes measurement quantities and recording resolutions for data being periodically collected by SCE from their distribution substations and feeders as well as provisions in this project to install monitoring devices and collect feeder voltages and currents at pre-specified locations.

SCE utilizes a data streaming and historian tool entitled eDNA. Through this tool, it is possible to log rms voltages at the distribution substation as well as the rms current and reactive power of each feeder. The total substation current (in Arms) and reactive power of the transformer is also monitored. This information is typically logged at 10-second intervals as soon as a pre-specified level of variations in voltages or currents occurs. The data resolution at substation level also can be increased to 4-second intervals.

In addition to substation data, several voltage monitoring points along the feeder are available, mainly at capacitor bank locations. The capacitor bank voltage is captured for the only phase that has a connecting single-phase PT and used by the capacitor bank controller. The capacitor bank on/off status is also reported upon changes.

Table 4-1 provides a list of substation and feeder data available through eDNA that may be relevant to this project.

Table 4-1. Data Measurement Quantities from eDNA System.

Data	Data Availability	Resolution
Substation load data (Vrms, Irms, and Q)	Daily per feeder	4-second updates on changes*
Feeder load data (Vrms, Irms, and Q)	Daily per feeder	4-second updates on changes*
Capacitor bank status and voltage	Daily per feeder	5 minute
Voltage profile at capacitor bank locations	Daily per feeder	5 minute
Voltage profile at PV system location	Daily per PV system	Sensitive info **
PV system power output profile	Daily per PV system	Sensitive info**

The following aspects of data capturing and streaming of SCE's distribution SCADA system should be noted:

> * Data is only logged as soon as a specific level of change in the targeted quantity occurs. As a result, the captured data points for three-phase quantities are not synchronized in an output file. However, the recorded data is time stamped based on the eDNA time clock. In other words, numbers of data points are not the same per voltages and currents measured on different phases. Therefore, some post-processing work is needed to overlay data properly utilizing the time stamp. On the other hand, generating data profiles would be an easy and effective way of demonstrating daily variations.
>
> ** This information is considered very sensitive data about generation systems. SCE has some limitations on what information about PV systems can be published due to sensitivity of PV developers on PV performance analysis and the ability to calculate or compare system efficiencies.

The aforementioned data server (eDNA) has the ability to allow one-way streaming of pre-specified data to an external server without affecting SCE's cyber security. To set up a gateway, a mapping of required data from eDNA to the external database should be defined.

As part of the feeder monitoring plan for the project, it was also discussed that an independent (from SCE system) voltage and current monitoring apparatus should be installed at several points along each of the selected feeders. The measurement points of interest are generally:

- Voltage and current measurements immediately upstream of PV system interconnection point(s)
- Voltage and current measurements at the middle of a feeder (load center) or close to major load sites
- Voltage measurement toward the end of a backbone feeder or on the farthest point of long laterals and branches with major load flow.

4.2.1 Feeder Modeling

One of the applications of data monitoring and measurement is to verify feeder models, and typical phenomena may be observed during simulation studies. Appendix C provides a comprehensive list of data requirements for modeling a distribution feeder. SCE normally uses CYMDIST and PSCAD/EMTDC software tools, respectively, for steady-state and dynamic modeling of their distribution feeders.

Most of the feeder characteristic data can be extracted from the CYMDIST models. Examples are:

- Conductor types per line section
- Capacitor bank size and locations
- Load type (residential, commercial, single/three-phase) and locations
- Fuse and switch ratings and locations

- Rating and impedance for some of the three-phase transformers feeding large commercial/industrial loads.

It should be noted that generally the detailed load data (per customer) based on seasonal or daily variations is not incorporated in the CYMDIST. However, using the eDNA system, a load profile of a feeder for targeted days can be obtained. Available load measurements are for the entire feeder. A load allocation method should be used to perform load distribution for customers along the feeder for any specific load profile.

5 Advanced Inverter Technology for High Penetration Levels of PV Generation in Distribution Systems

5.1 Introduction

Practically all of the renewable energy sources, and most forms of energy storage, produce either dc or variable frequency output power. In many ways this is unfortunate because all power from these sources must pass through a frequency converter in order to feed the constant-frequency ac power grid. This extra stage of power conversion introduces additional equipment cost and power losses. On the plus side, however, this need for frequency conversion has resulted in a rapidly-growing class of electronically coupled generators (ECGs) connected to the grid, with control capabilities that are broadly superior to those of conventional rotating synchronous machine generators. Understandably, electric utilities have viewed the advent of these ECGs with a certain amount of fear, both because of their unfamiliar operating characteristics and because of their location in distribution systems where there traditionally has been minimal power generation. The level of concern has increased with the rapidly increasing size of proposed projects relative to the feeder rating and/or the minimum load levels. It is of course perfectly feasible to generate power in new or existing distribution circuits, and even to export power back into the transmission system, but in so doing we challenge some of the traditional assumptions that have been made in the design of protection and voltage regulation schemes for these circuits. This is especially true in the case of higher penetration levels for PV generation.

5.2 Utility Concerns about the Impact of High-Penetration PV on MV Feeders

As a leading supplier of inverters for large PV generating projects, Satcon has participated in industry forums and IEEE working groups for standards development, where electric utilities are also strongly represented. Satcon also provides support for project developers, in the United States and abroad, as they negotiate with utilities over interconnection impact assessments, connection rules, and similar issues that arise in regard to their requested grid connections. Because Satcon must comply with interconnection rules in the many countries where their inverters are installed, they also follow emerging regulations very closely and are aware of the world-wide trends in this area. Finally, they are called in to help solve real problems that occur in the field. As a result Satcon has a good overview of the main concerns of electric utilities in relation to the installation of large PV generating projects in distribution systems. These concerns can be roughly grouped into three categories as follows:

- What will be the effect of fluctuating real power output from renewable sources on the normal operation and power quality of the distribution system?
    - Increased switching operations for line regulators, tap changers, switched-capacitors.
    - Steady-state voltage regulation over the range of real power generation, especially on long feeders. Should PV generators be allowed/required to participate in voltage regulation automatically, or on the basis of reactive power dispatch or scheduling? If autonomous local automatic voltage control is allowed, can stable

operation be expected when multiple PV generators are involved on the same feeder? Will fast automatic voltage controllers "fight" with slower line regulators?

    - Flicker due to rapidly fluctuating voltage caused by sudden changes in real power generation.
    - Transient voltage changes on sudden trip of PV generation system, especially if the system is actively participating in voltage regulation.
    - Harmonics generated by the PV inverters, and possible resonant interactions of inverters with the distribution system.
    - Conductor and equipment loading due to new power flows resulting from the introduction of local power generation in the distribution system.

- How should the protection relay schemes be changed/designed for existing/new distribution feeders when large new generators are connected?
    - Reversible real and reactive power flows possible.
    - Protective relay settings and operation.
    - Contribution of new generators to short circuit levels.
    - Islanding of generators with residual load connected.
    - Auto-reclosing feeder breaker onto energized generators.
    - Appropriate grounding schemes for new generators to allow ground fault detection and prevent transient over-voltages.
- Additional concerns about providing real power management for frequency regulation in smaller grids (e.g. islands) with limited aggregate generator rotational inertia.
    - Rapid curtailment of real power sources on over-frequency.
    - Rapid load-shedding and/or "spinning reserve" deployment on under-frequency.
    - Ramping of real power from variable sources to minimize impact on the grid frequency.
    - Transient frequency excursion on sudden trip of generating system.

Many of these concerns can be addressed through a proper understanding of the capabilities and operating characteristics of the modern inverters that are used to couple PV systems to the grid. There is little doubt that the introduction of large-scale ECG into distribution systems will eventually force utilities to depart from some of the traditional practices that have been established over a century. This is bound to be a difficult process, and possibly risky at the outset, but should ultimately result in a better power system. Most of the issues listed as concerns do not in fact present fundamental obstacles to the implementation of high penetration levels of PV generation, and in many cases the presence of inverter-based PV generation can facilitate solutions rather than complicate the problems. This is especially true in regard to the area of system protection, because inverters are inherently fast acting and current-limited.

First we describe the basic output characteristics of inverters and the control capabilities that are relevant to their grid interconnection in a high-penetration scenario. This should serve to provide a basis for further consideration of system protection and circuit requirements from the utility perspective. Next we provide details of how the PV inverters can participate actively in the regulation of voltage in the distribution system. Because inverters bring to the table their unique ability to generate or absorb controlled reactive power, and there is little consensus on how this capability should be used in a distribution system, this is by far the most important topic that needs to be addressed.

5.3 Capabilities of Inverters

Inverters are electronic power converters that can be used to couple dc or variable-frequency power sources to the grid. Practically all renewable power generation systems depend on inverters for their grid connection. In these applications, the primary function of the inverter is simply to deliver the maximum possible generated real power (P) as efficiently as possible to the grid. The first generation of inverters for PV power was typically designed with only the basic controls necessary to perform this primary function, while complying with UL 1741 and IEEE 1547 requirements. For low power levels (less than 500 kW) and low levels of PV power penetration, certification of the equipment to these standards was sufficient for utilities to allow interconnection to the grid without much concern.

In addition to frequency conversion and basic real power delivery, inverters also have a number of other inherent control capabilities that are widely used elsewhere in power systems for power management and power quality improvement. As the penetration levels increase for PV generation, and as more sophisticated rules for interconnection emerge, it has become clear that harnessing these inverter control capabilities will be key to the successful implementation of large-scale PV generation in distribution systems. Consequently, a wide range of control functions have already been incorporated into newer PV inverter designs that will allow them to play an important role in the operation of the distribution system. In this section we will briefly describe the most relevant inverter capabilities and the ways in which they can facilitate the successful implementation of high penetration levels of PV generation.

5.3.1 Controlled Output Current

When connected to an established power grid (i.e. where the frequency and voltage are actively regulated), inverters typically operate as controlled current sources. This means that the high frequency switching of the inverter is controlled so that the output current from the inverter is actively forced to follow a reference signal. The design of the feedback control system that accomplishes this may differ from one manufacturer to another, but with an optimum design the output current control can be extremely fast (< 1 ms response) and accurate (< 1%). Furthermore, the control response can be practically unaffected by disturbances in the grid voltage.

The controlled output current of an inverter has several important implications:

- *As seen from the grid, the "impedance" of the inverter is very high.* As a result, the inverter output current continues to follow the internal reference signal, even when power system faults cause large changes in voltage. This is generally true for positive and negative sequence components. Most inverters provide a three-wire native output from their power electronics to an ungrounded winding on an isolation transformer, so they do not influence the zero sequence component of output current. Thus the apparent zero sequence impedance seen from the grid is a combination of the zero sequence impedance of the isolation transformer plus the effect of any neutral grounding impedance. With alternative inverter topologies, it is possible for the inverter to also control the zero sequence component, but the extra equipment expense is rarely justified. The high output impedance of an inverter is quite different from the case of a rotating synchronous machine generator, which can contribute relatively large transient output currents under fault conditions. It is important to note that although an inverter acts as a current source with high output impedance, it also has a limited maximum output voltage available. In other words, it will not present "infinite" voltage at its terminals if an upstream feeder breaker is suddenly opened while the inverter is running. The maximum output voltage is in fact determined by a combination of the inverter dc terminal voltage and the action of the control system.

- *The output current is limited.* The internally generated current reference signal takes account of prevailing voltage variations to maintain a required power output, but it is always subject to an over-riding current limit that corresponds to the level of current needed to output rated kVA at the minimum specified working voltage, usually 0.9 per-unit (pu). This means that with a properly designed control system, the output current from an inverter during a grid fault should not exceed 1.1 pu approximately. In most cases, a 1.1 pu fault contribution from distributed generators should be negligible in relation to the conventional fault contribution fed from the transmission system. Add to this the consideration that the inverter output currents are largely in phase with the system voltage, whereas the conventional fault currents are largely in quadrature, and it is safe to say that inverters contribute a negligible amount to the total fault level on a distribution feeder.
- *The output current can be reduced to zero in an extremely short time.* If necessary, the native output current from the inverter bridge can be stopped in a few microseconds (followed by some short-lived [< 1 cycle] decaying transients between the output filter and the grid). This can be very important for the protection and management of the distribution system. If the utility is concerned about circuit breaker capacity, provision can be made for the output current from an inverter-based generator to be stopped well before any mechanical switchgear starts to operate. In this situation, the inverter controls can autonomously initiate rapid shutdown when abnormal grid conditions are sensed, or the controls can respond to a signal from the utility (e.g. transfer trip)
- *The complex (apparent) output power ($S = P + jQ$) can be controlled in any of the four power quadrants.* Because the magnitude and the phase angle of the fundamental output current relative to the grid voltage can be arbitrarily selected, the real (P) and reactive (Q) components of S can be directly and independently controlled. The P output is typically controlled so as to regulate another internal quantity such as the dc voltage or power at the PV array. The active control of P also allows important over-riding real-power-limiting functions, such as power curtailment and power ramping, to be implemented in response to inputs received from a remotely located system operator (e.g. via SCADA). These real power management functions are expected to become essential tools for utilities under a high-penetration scenario, especially in smaller grids (e.g. islands) where the power system may not always be able to accept additional real power and where frequency regulation is a concern. Apart from the management of real power output, the inverter has unique capabilities to generate and strategically deploy reactive power (Q) output. This topic is especially important and warrants a separate in-depth discussion in the following sections.

The Q output that can be generated by inverters at a PV system is a valuable resource for utilities and is expected to be crucial for regulating the voltage in a distribution system with high penetration of PV.

- *The complex output power can be controlled with very high bandwidth.* In most cases it is not desirable to change real power output very rapidly because of the impact on system voltage (and frequency in weaker systems). Consequently, real power changes are usually made to follow slow time ramps whenever possible. The same consideration may often be true for reactive power. However, by means of the high bandwidth control of Q, the inverter can also act as a fast autonomous local voltage control system. Fast automatic response is essential for correction of the voltage deviations associated with voltage flicker, for example. This will be discussed in more detail in the following sections.
- *The inverter can absorb real power from the grid and deliver it to charge an energy storage device* connected to the dc-side collector bus (also fed by a PV array). This can facilitate the implementation of an energy management system where the inverter supplies real power to the grid from storage at times when PV power is not available. To achieve different objectives, the energy storage device might be relatively small (to facilitate power ramping) or very large (e.g. for frequency regulation or power output leveling).
- *The inverter output current can be controlled to correct pre-existing low-order voltage (or current) harmonics* on the grid. In order to do this, the inverter must deliberately produce corresponding harmonics in the output current. This rather specialized "active filter" function is sometimes performed by dedicated inverters installed specifically for this purpose. To facilitate the production of controlled harmonic output currents, an inverter would ideally switch at the highest practical frequency, and it would be designed with a small output filter inductor in order to minimize the inverter voltage needed to drive the harmonic currents. In addition, because the oscillating harmonic power produced at the ac terminals must be matched by an approximately equal harmonic power at the dc terminals, it is desirable to provide a larger-than-normal dc bus capacitance in order to minimize the corresponding harmonic voltage that develops on the dc bus. It would be relatively costly to produce a PV inverter designed to simultaneously deliver real power while also serving as an active filter. However, active-filter capability might be useful when normal PV power production is very low or zero, such as during the night.
- *The inverter can help to correct for unbalanced fundamental voltage* at the point of connection to the grid by controlling output current to include a negative sequence fundamental component. In this mode the inverter essentially acts as an active filter for the minus-one (-1) order harmonic. The negative sequence fundamental output current produces a second harmonic power pulsation at the ac terminals, matched by a similar power pulsation at the dc terminals. As in the case of the active filter, a large dc capacitance is needed to absorb this pulsating power with acceptably small dc voltage deviation. As mentioned previously, most inverters can only correct for the negative sequence fundamental. However, using a more costly alternative inverter topology (e.g. a four-leg inverter bridge), a similar correction could be provided for the zero-sequence components in an unbalanced system.

5.3.2 Grid-Smart Control Features

Under the DOE SEGIS program Satcon set out to develop an inverter design for the future grid that would have all of the capabilities needed to facilitate the integration of large-scale PV generation into distribution systems. To do this, it was necessary to define a new set of "Grid-Smart" control features for the inverter, which would make full use of the inherent capabilities listed in the previous section. The main inverter features that were selected are as follows:

- Local communication with site-level controller,* providing utility SCADA communications and multi-unit control through:
    - Control of <u>*real power limit*</u> (curtailment)
    - Controlled <u>*ramp rate for real power limit*</u>
    - Control of <u>*reactive power output OR power factor.*</u>

  * <u>NOTE</u>: The site-level controller is a shared local computer that complements the features of each inverter in a multi-inverter installation by providing aggregate output power management at the point of interconnection with the utility. The site controller is a communications hub that communicates with all inverters and the utility control center, and receives and processes real-time V, I measurements from POI. By issuing commands to the inverters it can provide:

- Aggregate power factor control – accounting for site transformers
    - Automatic voltage control if required
    - Long duration real power ramping by means of curtailment commands to inverters
        - Ride-through* capability for specified grid disturbances, requiring:
            - Adjustable tolerance for voltage and frequency deviation
            - Enhanced dynamic control to continue operating successfully with unbalanced or distorted grid voltages during faults
            - An un-interruptible power source for control and communications.

  * <u>NOTE</u>: "Ride-through" means that the generator must stay online and operate as specified during voltage disturbances caused by faults on the transmission system or an adjacent feeder. The ride-through requirement originated from experience in wind power generation, mainly at transmission level voltages, and has now become the most common new requirement for interconnection with medium voltage distribution systems. It is a contradiction of IEEE 1547, which requires generators to cease operating within specified maximum time periods when the grid voltage deviates from normal. New ride-through requirements differ considerably in regard to voltage levels and duration. In general they are intended to ensure that generators will be online and ready to carry their share of system load after the disturbance. In some cases the generator is required to generate reactive power according to a special schedule when voltage deviates beyond set limits. It is assumed that generators will use anti-islanding and other fault sensing methods to distinguish between a

voltage disturbance that requires ride-through and the occurrence of a fault within the feeder or the opening of the feeder breaker that requires operation to cease.

- *Bi-directional power flow* to support charging of a dc energy store using grid power.
- *Permissive signal* based on Power Line Carrier Communication (PLCC)* – an alternative to conventional transfer trip schemes.

  * NOTE: While it is generally understood that transfer trip schemes are needed for synchronous machine generators that cannot easily detect an island condition, there is considerable dispute over the need for these expensive schemes in the case of PV inverters that are usually certified to be compliant with the anti-islanding requirements of IEEE 1547. Often a utility will question the effectiveness of anti-islanding when there are multiple PV units connected on one feeder. Because there is, as yet, no definitive way to prove this point one way or another, the utility will usually choose to err on the safe side and insist on the provision of a transfer trip scheme. The PLCC carrier permissive signal provides an alternative approach, whereby all generators on a grid segment can rapidly and reliably detect when islanding has occurred and cease operating.

The SEGIS program work led to the development of Satcon's Solstice Inverter products that incorporate the Grid-Smart control features. These features provide a flexible basic control interface for the inverters, allowing higher-level power-management strategies to be implemented either from a remote control center or on site by means of a site-level control system.

Some of the Grid-Smart control features are illustrated in Figure 5-1 using waveforms generated from a transient simulation model. In this case the output currents to the grid are displayed together with the calculated associated instantaneous real and reactive power output. Real power curtailment, sudden change of irradiance at the PV array, and leading and lagging reactive power generation are all shown. For this illustration, fast internal ramp rates were set to speed up the transition between each operating state of interest. Note that there is no downward ramp of output power when the solar irradiance is suddenly dropped. The fall of power cannot be controlled in this situation without the addition of a suitable energy storage device.

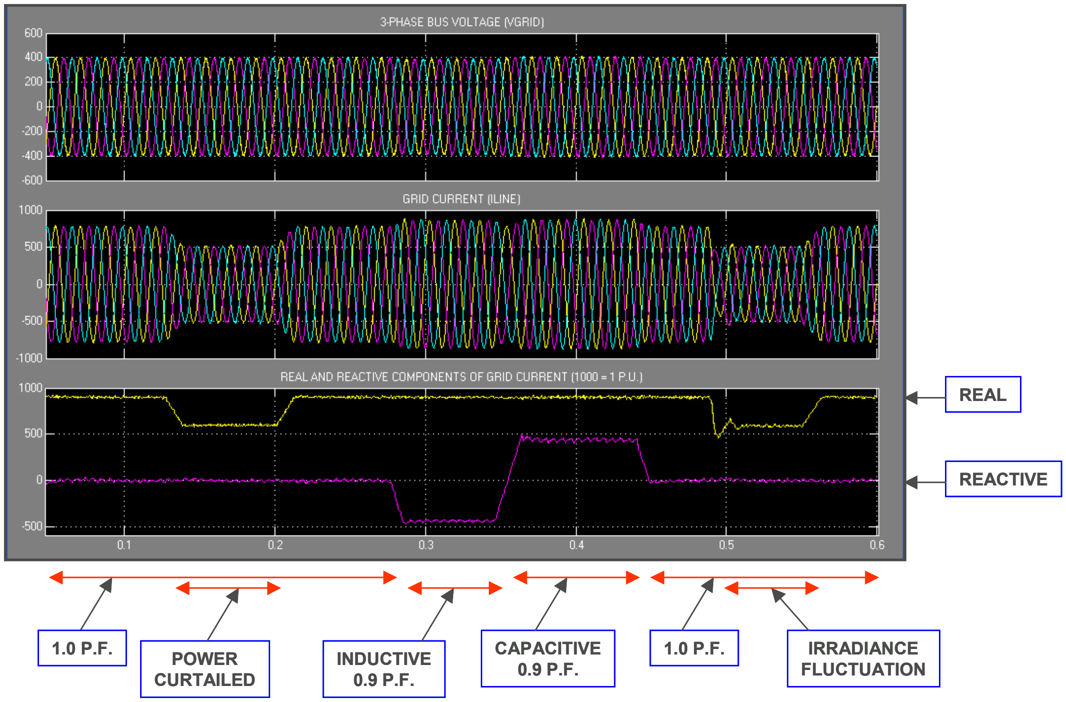

Figure 5-1. Illustration of some advanced grid support control features using a transient simulation model of a Grid-Smart inverter.

5.3.3 Reactive Power Generation

The name "reactive power" is really a misnomer, because the quantity it describes is actually the *redundant current* that flows at a given point in a power circuit in relation to the electrical power (watts) measured at that point. The notion of reactive power often causes confusion because it is an artifice created for circuit analysis, with no basis in physics. The concept of reactive power is also not uniformly applicable to three-phase and single-phase circuits.

In a three-phase circuit carrying positive and negative sequence currents only (i.e. where the sum of the three currents is zero), the *instantaneous reactive current* is defined at any given point in the circuit. It describes the part of the instantaneous three-phase current set that is redundant at that point (i.e. the part that could be discarded without changing the instantaneous electrical power calculated at that point). This redundant set of currents is *uniquely* defined using space vector theory. Specifically, it is the component of the current vector that is in space quadrature with the voltage vector. For convenience in circuit analysis, the instantaneous reactive current is multiplied by the voltage in order to define a quantity (VAr) with the same dimensions as power. Also a polarity is assigned to the product, depending on whether the current vector leads or lags the voltage vector spatially. This quantity is treated as the imaginary part of an instantaneous complex power quantity (S) for computation purposes. There is no universal rule for the polarity of reactive power, but if current is defined as positive in a certain direction, and the associated current vector *lags* the voltage vector, then reactive power is usually said to be flowing in that direction (i.e. positive). Because the reactive power in three-phase circuits is defined on an instantaneous basis, irrespective of the voltage and current waveforms, it can also be controlled on an instantaneous basis (i.e. in a time-frame that can be much shorter than one fundamental cycle). This means that instantaneous reactive power in three-phase circuits can be used to influence voltages in the circuit very rapidly, which can provide an important way for improving power quality.

Instantaneous reactive power is not defined for single-phase circuits. Instead, for single-phase circuits, the concept of reactive power is applied to *steady state behavior* with purely *sinusoidal voltage and current*, represented by sine-wave *phasors*. The reactive current phasor at a point in the circuit is defined as the component of the current phasor that is in quadrature with the voltage phasor at that point. This redundant component of current could be discarded without changing the *average* electrical power calculated at that point. Reactive current is once again multiplied by voltage to obtain reactive power. Of course, this steady-state phasor interpretation of reactive power can also be applied to three-phase circuits in the steady state, where it is entirely consistent with the instantaneous reactive power concept under steady state sinusoidal conditions. Phasor analysis also provides the only way of applying the reactive power concept to zero sequence currents flowing in three-phase circuits.

Reactive current occurs naturally in power circuits due to the presence of reactive circuit elements (inductance and capacitance) and various electrical loads (motors, etc.) that draw current at non-unity power factor. The reactive current passes through the circuit causing voltage drops and power losses and without contributing directly to the useful transfer of electrical energy. Reactive power is conserved (like electrical power) as it passes through an ideal transformer, but in a non-ideal transformer substantial reactive power may be absorbed by the leakage inductance. Passive reactive components (capacitors and reactors) are often strategically switched into or out of a power circuit to compensate for the natural reactive current flow. In the case of so-called "static VAr generators," electronic switches are used to regulate the reactive current drawn by these components.

Like electrical power, reactive power can be injected into a power circuit from a suitable generator. An ideal reactive power generator requires no electrical or mechanical power input, and no bulk reactive circuit elements, but instead uses a controlled source of voltage to drive the required reactive current output. The rotating synchronous machine is the traditional reactive power generator. The reactive power output from a synchronous generator is controlled by changing the field excitation, allowing reactive power generation up to rated kVA, as well as a more limited range of reactive power absorption. The ability to inject controlled reactive power into a power circuit is important because it provides a very effective means of regulating the voltage.

5.3.3.1 Inverter Reactive Power Generation Capability

Three-phase inverters are the ultimate reactive power generators, capable of generating or absorbing high quality reactive current that is controlled on an instantaneous basis. Modern inverters are unique in the world of VAr generators because they are able to change their reactive power output extremely rapidly. Response times of the order of 1 ms to full output are achievable (Figure 5-2), which is very fast compared to other devices such as rotating synchronous condensers and other switched devices using capacitors and inductors as the sources and sinks of reactive power. This fast response has allowed inverter-based VAr generators to be successfully applied for arc furnace flicker compensation and active power filtering, for example, where they operate in a sub-cycle control time frame.

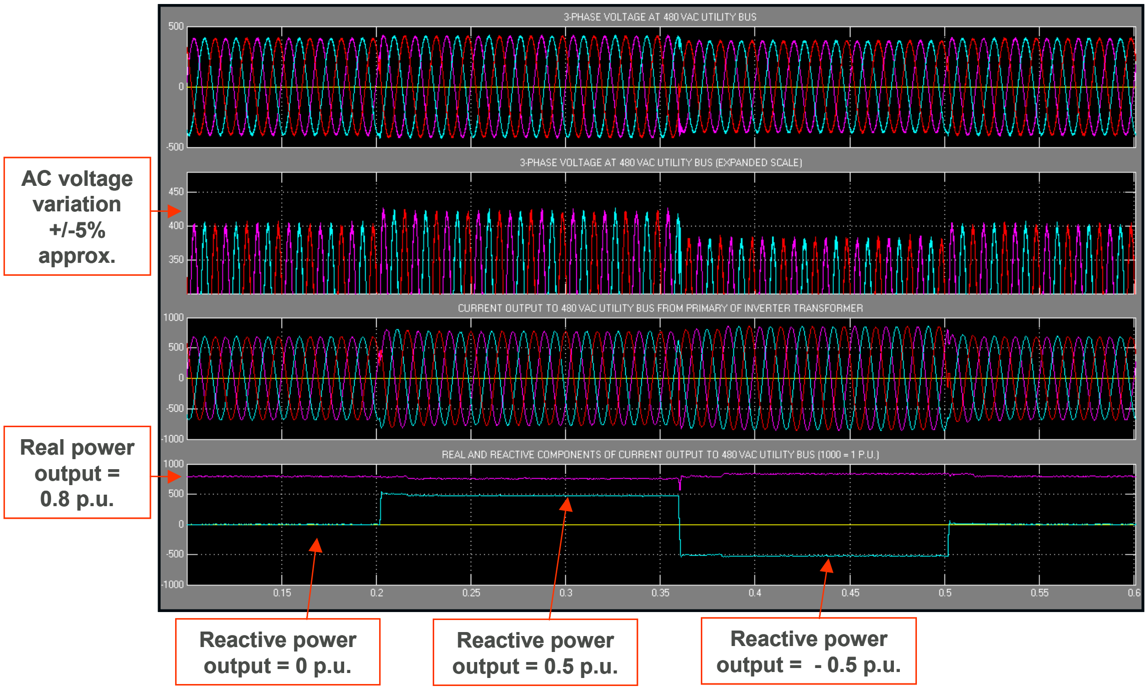

Figure 5-2. PV inverter simulation shows fast VAr step response capability and the effect on local bus voltage.

Inverters can provide real (P) and reactive (Q) output power simultaneously, with a corresponding complex power output, S = P + jQ. For safe operation of the solid-state switches in the inverter, there are strict limits on the maximum working current. Therefore inverters are typically designed for a specific maximum kVA output (S_{max}) that cannot be exceeded. Thus at any operating point, the P and Q output must be constrained so that $S_{max} > (P^2 + Q^2)^{1/2}$. Note that the Q output does not add linearly to the total prevailing kVA output. So, for example, with S_{max} = 1 pu, and a reactive power output of Q = 0.2 pu, an inverter can still pass real power up to P = 0.98 pu without exceeding S_{max}. This represents a very small impact on maximum real power production while generating a significant level of reactive power output. Some inverters are designed solely for the purpose of generating reactive power (i.e. P = 0). In that case the generated reactive power must account for the entire cost of the inverter. But if the cost of the inverter is already covered by its primary function (P delivery), then the incremental cost for simultaneous reactive power generation may be low. This is particularly true at times when the maximum real power capability of the inverter is not being used. This may occur, for example, in the case of PV power sources due to the daily cycle of solar irradiance.

While it is broadly accepted that the ability of inverters to generate controlled reactive power is a useful feature, there has been little consensus on how this capability should be deployed in a power distribution system. There are many ways in which the reactive power output of PV inverters might be managed for the benefit of the distribution system. Some of these schemes have already been arbitrarily defined and included in published interconnection rules and private power producer agreements, but there is not yet any uniformity apparent in these requirements. One trend is to provide a predetermined schedule of reactive power output versus voltage at the point of interconnection. The typical schedule would not require any reactive power output from the inverter until the voltage deviates outside of normal working limits. Supposedly, this approach circumvents the thorny issue of allowing a generator to perform automatic voltage control and avoids the anticipated problem of fast voltage controllers fighting with each other and with slower mechanically-switched line regulators. It is worth noting that automatic local voltage control is routine in transmission systems, where reactive power generators are always required to autonomously regulate the voltage at the bus where they are connected. Furthermore, there are many instances where fast-acting VAr generators are either connected to the same bus, or within a short distance of each other, and work together in a stable way thanks to the appropriate control system designs. There is no fundamental reason why PV inverters should not be used to continuously and autonomously regulate voltage in a similar way in distribution systems. This topic will be discussed in much more detail in Section 5.3.5.

5.3.3.2 Inverter Output Power Control

With regard to the PV inverter control system, the first consideration is how to make sure that the maximum inverter kVA is not exceeded while simultaneously supplying real and reactive power to the grid. Other manufacturers may use different design approaches, but Satcon provides a choice of two basic control modes, which make it possible to implement a variety of reactive power strategies.

The first control mode provides *independent reactive power control*. In this very flexible control mode, the maximum available reactive power at any time is calculated as a function of the prevailing real power curtailment level. Reactive power output follows a command (local or remote) up to the maximum available level. In a large utility-scale application, for example, the real power curtailment level is allowed to slowly track the prevailing real power output up to a pre-determined maximum, while the reactive power command is generated by a site-level controller following a specified algorithm in response to MV measurements at the point of interconnection. Figure 5-3 shows the available reactive power from the inverter versus the real power curtailment level. Note that available reactive power has been limited to 0.87 pu so that at least 0.50 pu real power is always achievable. This constraint is by design and does not represent an absolute limit.

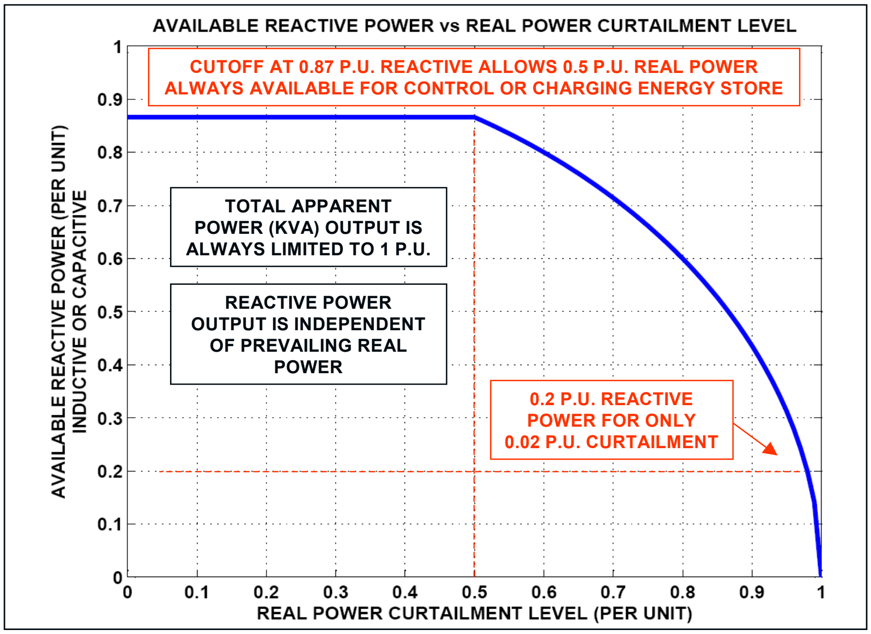

Figure 5-3. Independent reactive power control mode.

The second control mode provided for the inverter is a *power factor* mode. In this mode the reactive power output automatically tracks the real power output, maintaining the Q:P ratio that is consistent with the prevailing power factor command but always staying within the kVA rating, and observing the prevailing curtailment level for real power output. Figure 5-4 shows the maximum available real power as a function of power factor (assuming 1.0 pu real power curtailment) and the associated reactive power levels. This control mode can be used to set a constant power factor prescribed by the utility, or it can be used to follow a variable power factor command generated by the site controller or received from a remote operator at the utility control center.

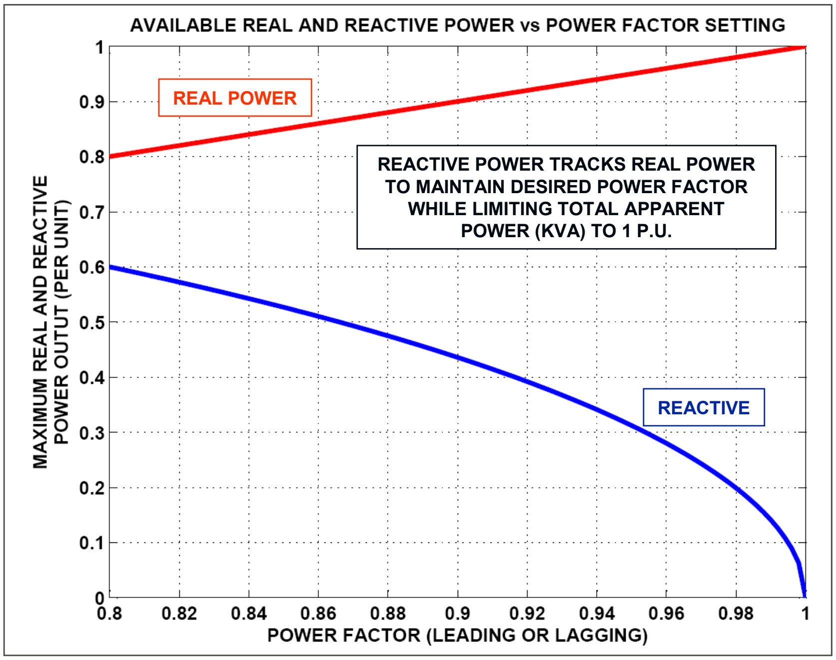

Figure 5-4. Power factor control mode.

The need for the site-level controller has emerged with the advent of larger PV projects that use multiple inverters to achieve the aggregate output power from the site. Multiple inverters are preferable to a single large inverter because of the physical layout of these projects over a large area and the logistics associated with providing the site-wide power collection circuits. The grid interconnection rules for these sites usually specify the required behavior at the point of interconnection (POI) with the utility MV feeder. Measurements at the POI are not usually available (or needed) in the individual inverter control systems, so the site controller provides a common local center of intelligence where higher-level power management algorithms can be executed. The site controller also serves as a communications hub for the site, exchanging commands and status information with the utility via SCADA and with the individual inverters via local serial communications. Figure 5-5 illustrates the role of the site controller.

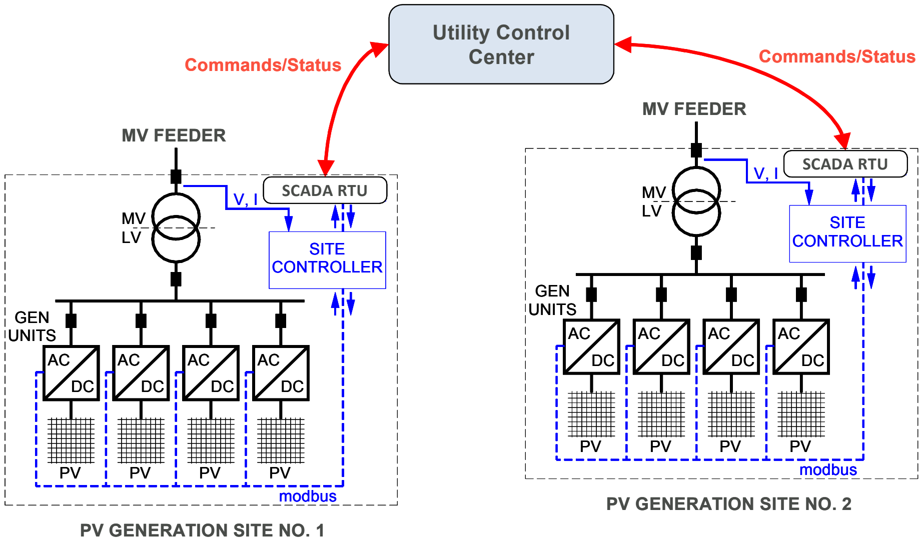

Figure 5-5. Site controller generates real and reactive power management commands for multiple inverters in utility-scale PV projects.

5.3.4 Effect of Inverter Output Power on Distribution Feeder Voltage

Voltage regulation on typical distribution feeders is achieved by switching taps on various kinds of transformers and also by means of reactive power injection from fixed or switched capacitor banks. In addition to the switching action associated with voltage regulation, the electrical loads connected to a typical feeder are constantly changing. A distribution system can thus be a rather complicated and very variable power circuit. However, it is instructive to consider a greatly simplified constant representation of a distribution feeder to illustrate the effect that might be expected from the connection of a PV generating system.

Viewed from the bus at the POI between the feeder and the PV system, the 60 Hz impedance of the feeder is essentially $Z = (R + jX)$ where X is mostly positive (i.e. inductive). Real power flowing away from the bus causes an increment in the local voltage magnitude mainly due to the drop across R. When reactive power is flowing away from the bus (i.e. when the current flowing away from the bus lags the voltage) it causes a local voltage magnitude increment due to the drop across X. The reactance, X, usually dominates over R in transmission and distribution circuits, especially in transformers. Reactive power injection (or absorption) at the PV bus therefore provides an effective means of increasing (or lowering) the voltage at the point of connection.

Medium voltage distribution feeders vary widely in terms of length of line from the transmission substation, voltage, type and physical disposition of conductors, grounding schemes, etc. Accordingly the expected problems from the addition of high penetration levels of PV also depend on the particular feeder that is being considered. In this section we will focus on the ways in which high-penetration PV can affect feeder voltage under different conditions and discuss the positive role that PV inverters can play in terms of steady state and dynamic voltage regulation.

Figure 5-6 shows the simplified representation of a PV system connected to a distribution feeder with 60 Hz impedance Z = (R + jX) pu. Obviously this model is highly simplistic, but it does capture the essence of the system captured at one point in time. The voltage at the utility substation is assumed to be constant with amplitude 1 pu, and the PV system output is S = (P + jQ) pu. All per-unit values are based on the PV system rating. Using this model, and assuming the PV system to be operating at unity power factor (Q = 0), the bus voltage at the system was calculated for the full range of real power output. The calculation was repeated for four different values of R, in each case assuming an X/R ratio of 4. The results, plotted in Figure 5-7, provide a quick overview of the different ways in which the bus voltage can be affected, depending on the feeder impedance. In each case, all of the reactive power absorbed by the feeder inductance is supplied from the substation. For the shorter line, with lower impedance, the resistance, R, dominates and the voltage rises approximately linearly with respect to output power. As the line length is increased (or the impedance is otherwise increased), the feeder inductance begins to dominate, causing the bus voltage to fall for generated power above a certain level. For a very long line the voltage at the PV bus can fall below the substation voltage, rapidly collapsing to the point where the inverter reaches its current limit. For a given X/R ratio in this scenario, the maximum bus voltage is the same, regardless of the total feeder impedance, but it occurs at different output power levels. The maximum bus voltage is higher for lower values of X/R, and it occurs at higher output power levels.

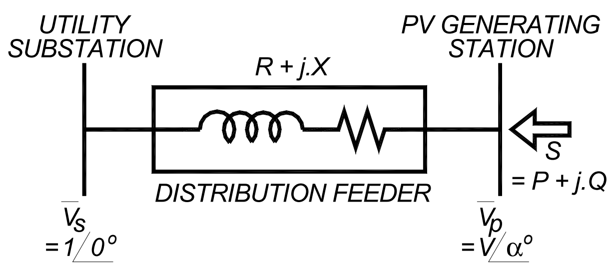

Figure 5-6. Simplified representation of a distribution feeder with PV generator connected.

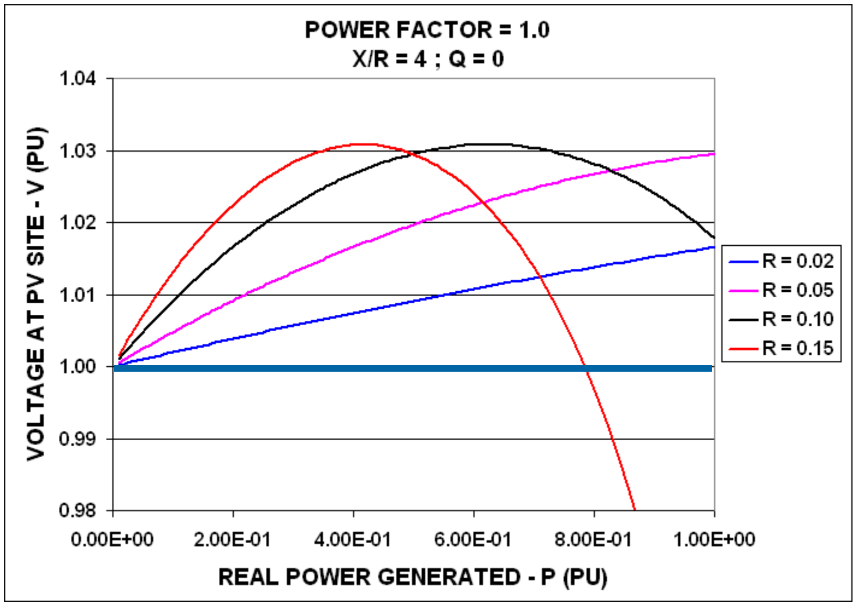

Figure 5-7. PV bus voltage versus real power generated. Inverter operates at power factor = 1.

A further set of calculations was performed for the same feeder impedances and the same range of real power output from the PV system, but now assuming that the PV bus is automatically regulated at 1 pu by means of reactive power output generated by the system. The results are plotted in Figure 5-8a. The output power factors corresponding to the operating points shown in Figure 5-8a are plotted in Figure 5-8b. Figure 5-8a shows that in every case considered a relatively small amount of reactive power generated or absorbed at the PV system (~ 0.2 pu or less) can completely compensate for any voltage variation at the PV bus that would otherwise be caused by the generated real power output. The required level of reactive power will be different for different feeder impedances and X/R ratios and will also depend on the reactive loads connected, but the same basic principle is valid in most practical cases. In this example, it was necessary for the PV system to absorb Q at most operating points in order to regulate the voltage to 1 pu. A further observation, from Figure 5-8b, is that a wide range of power factors would be needed to hold the voltage constant over the range of real power output. A constant power factor, selected for one operating point (say full output), would result in voltage deviations at other output power levels.

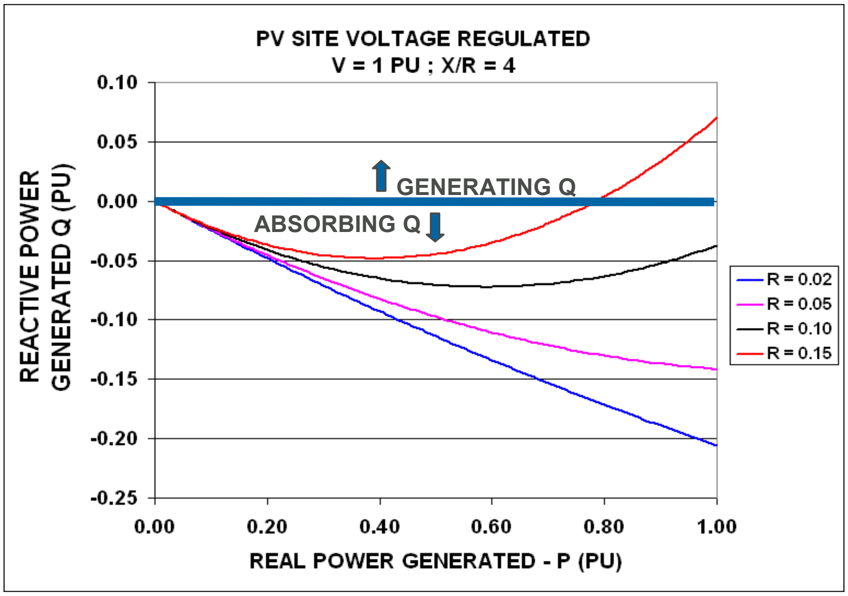

Figure 5-8a. PV reactive power output versus real power generated. PV inverter holds the bus voltage at 1 pu.

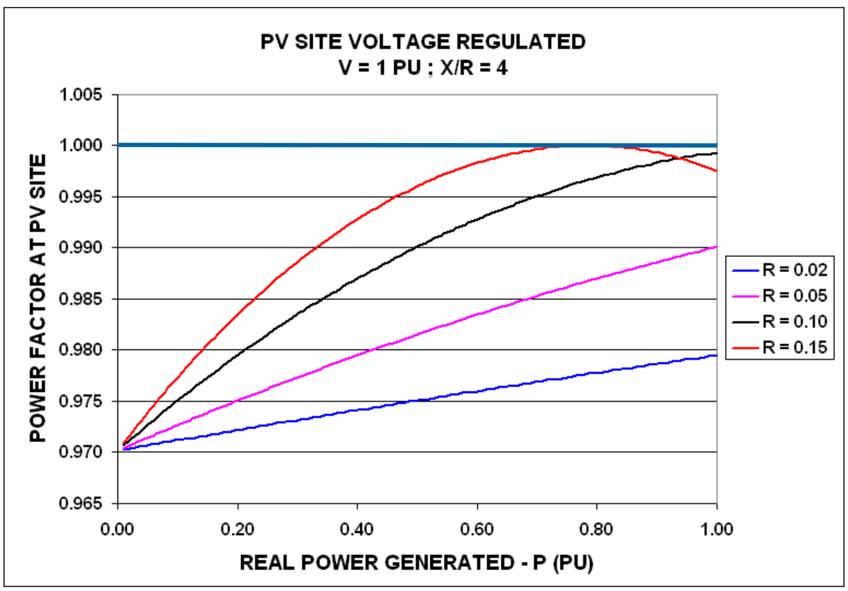

Figure 5-8b. PV inverter output power factors corresponding to Figure 5-8a.

These results illustrate the general effect that an inverter-based PV system may be expected to have on different types of distribution feeders. The necessary reactive power output from the PV system can be determined in a variety of different ways, requiring a variety of different response times ranging from very slow to very fast. As mentioned before, there is still no consensus as to the proper way to use reactive power generation. However, what is certain is that local injection of reactive power on a distribution feeder can be used for voltage regulation and can correct voltage deviations caused by generated real power, as well as correcting for "pre-existing" conditions on the feeder. One of the main benefits of regulating feeder voltage by local reactive power generation is that the local VAr source can supply the reactive power requirements of nearby loads, thus reducing the overall current loading at the substation and reducing the power losses on the feeder.

5.3.5 Simplified Distribution Feeder with Large PV System Connected

To illustrate some of the capabilities and potential benefits of an inverter-based PV system for voltage control, a simplified benchmark distribution feeder is defined in the one-line diagram in Figure 5-9. The layout of the feeder and the total loading is loosely based on a proposed project in Massachusetts, recently submitted to National Grid for approval. The simplified representation of the system does not include any conventional voltage regulating equipment, and the 69 kV sub-transmission bus has been assumed to be infinite. The bus designations and the load distribution are hypothetical, but the line impedances are consistent with tables. Essentially Figure 5-9 is a long 13.8 kV feeder with a 5 MVA PV system at the end. Load flow and detailed transient simulation studies have been used to illustrate the capability of the PV inverters to actively regulate the voltage at the point of connection.

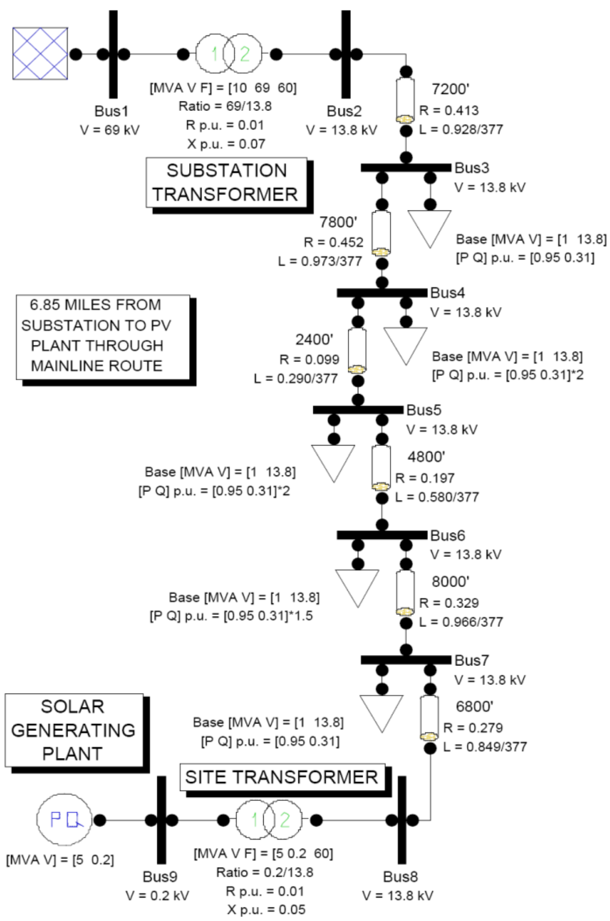

Figure 5-9. Simplified benchmark system with a 5 MVA PV system connected to a 13.8 kV feeder.

5.3.5.1 Steady State Analysis with Voltage Control at the PV System

Two simple scenarios are considered. In the first, the PV system is producing 4 MW with Q = 0 (i.e. pf = 1). The blue bars in Figure 5-10 show the feeder voltage profile for this case, and Figure 5-11a shows the corresponding values of P, Q generation, minus load, for each bus. Note the heavy reactive loading (2.949 MVAr) through the substation transformer at the transmission bus (No. 1) and the voltage sag on the line (well outside acceptable MV limits, but remember no taps, regulators, or capacitors are in use).

In the second scenario, the PV system is automatically generating VArs to keep the voltage at Bus No. 9 at 1 pu. The red bars in Figure 5-10 show the improved voltage profile. Figure 5-11b shows the corresponding P, Q profile. The PV system Q output is now 1.234 MVAr, while the substation reactive load has dropped to 1.595 MVAr. Feeder losses have also dropped by 38 kW.

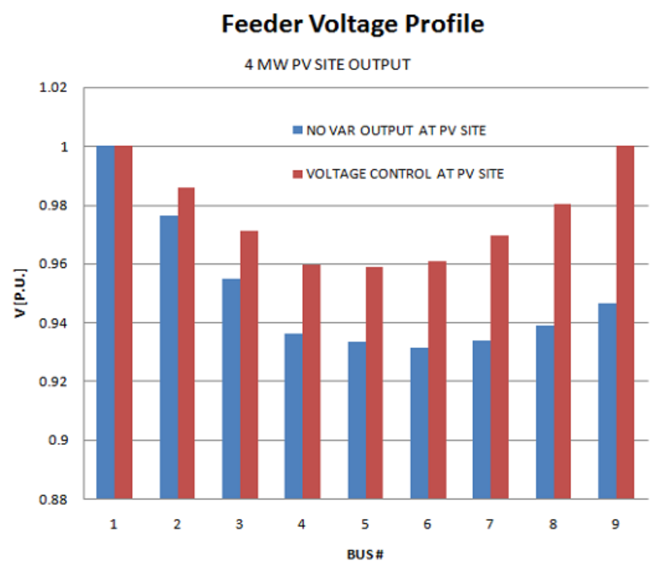

Figure 5-10. Feeder voltage profile with and without voltage control at the PV site. PV system output, P = 4 MW. No conventional compensation (regulators, capacitors, etc.).

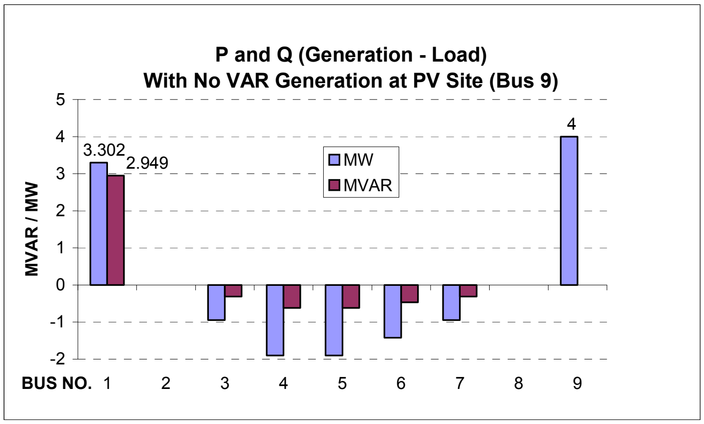

Figure 5-11a. Feeder bus P, Q (gen - load) with no reactive power generation at the PV site (corresponding to the blue bars in Figure 5-10).

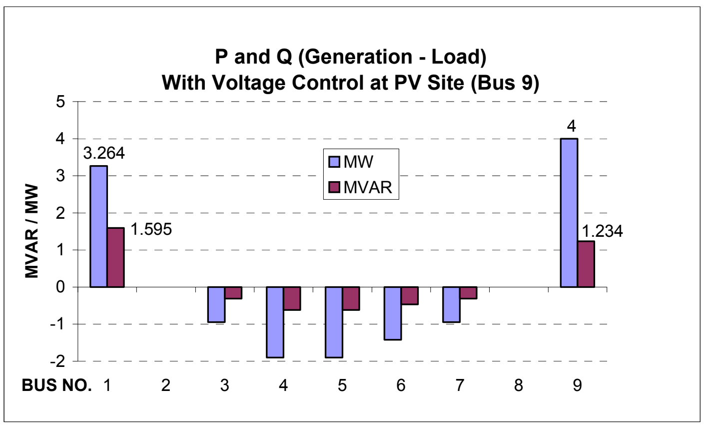

Figure 5-11b. Feeder bus P, Q (gen - load) with reactive power generation at the PV site used to maintain Bus No. 9 voltage at 1 pu (corresponding to the red bars in Figure 5-10).

The load flow analysis has also been used to produce a quasi-dynamic illustration of the effect on the feeder voltage profile as the real power production from the PV site changes. The same two scenarios are considered for the PV system, i.e. 1) Q = 0 and 2) automatic voltage control at the PV site. Figure 5-12a plots the bus voltages as the P output from the PV system is dropped from 4 MW to zero and back again, while Q = 0. Figure 5-12b shows the second case, which is similar but now with Q output generated by the PV system to keep the Bus No. 9 voltage at 1 pu. Note that these illustrations are simply a succession of load flow solutions showing the steady state locus for different P, Q output from the PV system, and not a true time-domain transient simulation.

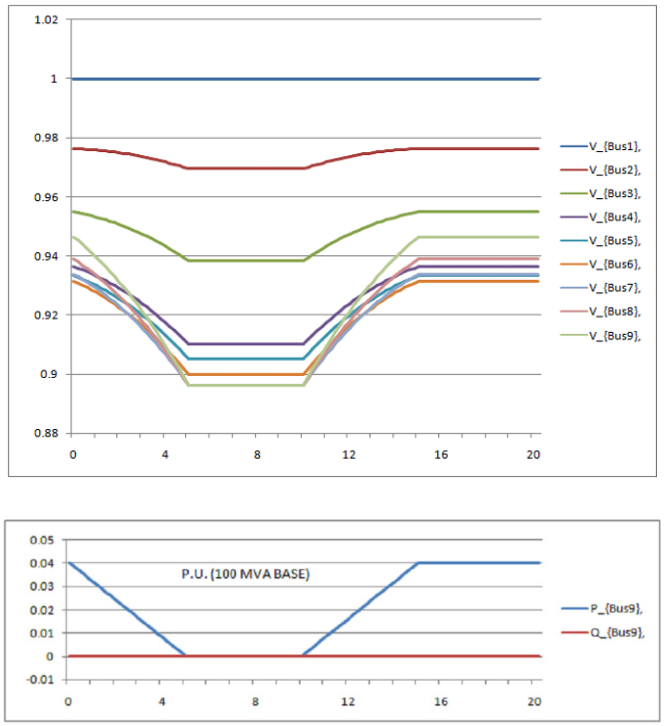

Figure 5-12a. Feeder voltage profile plotted as PV system real power drops from 4 MW to zero and back. Q output = 0. In this case the voltage at the PV system is not controlled.

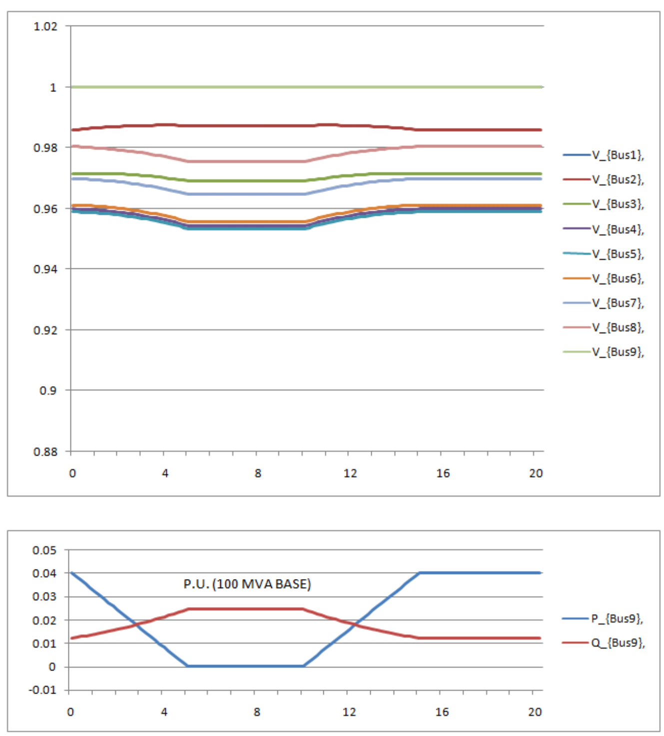

Figure 5-12b. Same P output as for Figure 5-12a, but here the PV system generates Q to keep the local (Bus 9) voltage at 1 pu.

5.3.5.2 Demonstration of Fast Automatic Voltage Control

The simplified benchmark feeder system shown in Figure 5-9 has been translated into a detailed transient simulation model of the three-phase system including the differential equations for all circuit elements. In particular, the PV system is modeled in great detail, including every aspect of the digital control system for the inverter. For this type of study, the involvement of the inverter manufacturer is essential because proprietary design details are usually needed. The physics equations governing the behavior of the PV array are also represented in detail, allowing basic input quantities such as solar irradiance to be varied as a function of time. The top-level model diagram is shown in Figure 5-13a, with more detail on the main elements of the PV unit subsystem shown in Figure 5-13b. Note that the loads are modeled differently in Figure 5-13a (constant impedance loads specified at base voltage and frequency) and Figure 5-9 (constant P, Q loads). Constant P, Q loads are difficult to implement in transient simulation. Note also that the 5 MW aggregate output of the site typically originates from, for example, 10 separate 500 kW inverter units with multiple coupling transformers, typically around 1 MVA each. To achieve a manageable transient model for grid interconnection studies, these multiple inverters and transformers are treated as a single lumped equivalent unit with 5 MVA rating.

The objective for creating this transient system model is to illustrate the ability of a PV inverter to autonomously perform fast automatic local voltage control at the point of connection to a distribution feeder. As discussed earlier, it is possible for the inverter to achieve voltage control in a sub-cycle time frame because both reactive power and three-phase voltage are defined on an instantaneous basis. In order to demonstrate this capability, the inverter controls in the model were modified to incorporate an automatic voltage control system. The controller commands rapid changes in reactive power in order to correct errors in the measured voltage feedback. Two cases were studied, one with the voltage controller disabled (and no reactive power generation) and one with the automatic voltage control enabled. In each case, the PV system is initially running under real power curtailment at 4 MW output (although the available solar power from the array is higher). At t = 0.2 the irradiance starts to drop from 1000 W/m^2 at a rate of 10^4 W/m^2/s. At t ≈ 0.225 it crosses the threshold for supporting the curtailed power output, and site output power starts to fall. After 80 ms the irradiance reaches 200 W/m^2 where it holds until t = 0.4, then rises again to 1000 W/m^2 at the same rate it dropped. This is a rather extreme interpretation of a passing cloud, although these fall and rise rates for irradiance might possibly occur.

Figure 5-14a shows the waveforms obtained for the case with voltage control disabled. As expected from the earlier steady state analysis, in this case we see a large voltage variation at each of the feeder buses due to the rapid transition of output power from the PV system. Figure 5-14b shows the case with fast automatic voltage control enabled. In this case the voltage control greatly reduces the voltage variations that occur over the length of the feeder.

In the earlier steady state load flow analysis, we assumed that the PV inverter would generate precisely the reactive power needed to maintain the voltage at 1 pu at Bus No. 9. What the transient case in Figure 5-14b serves to show is that a fast automatic voltage controller using a relatively small amount of locally generated reactive power can, in fact, hold the local bus voltage practically constant during short-lived transient disturbances. Note that the initial current output from the PV system in Figure 5-14b is roughly the same as in Figure 5-14a despite the higher Q output. This is due to the higher bus voltage in the Figure 5-14b case. It is reasonable to assume that this voltage control capability could also be used to reduce the voltage flicker that might otherwise be caused by such events. In the following section we investigate this hypothesis further, using the transient simulation model to show the improvement that could be achieved.

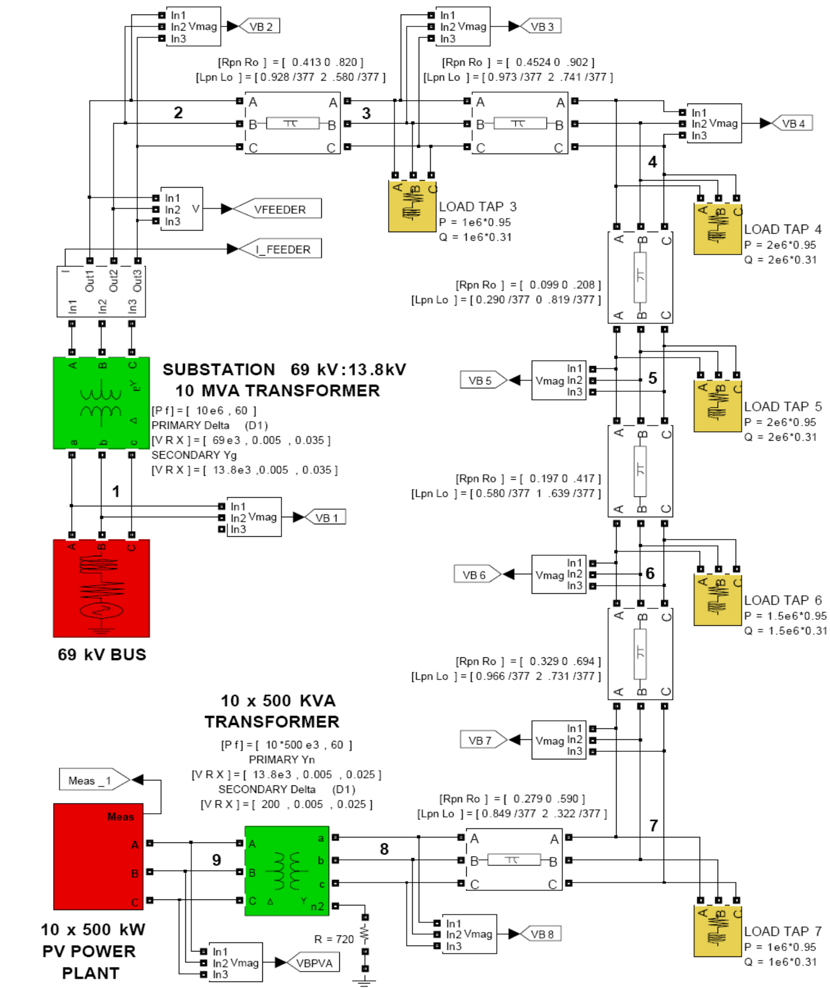

Figure 5-13a. Simulink transient model of the system in Figure 5-9.

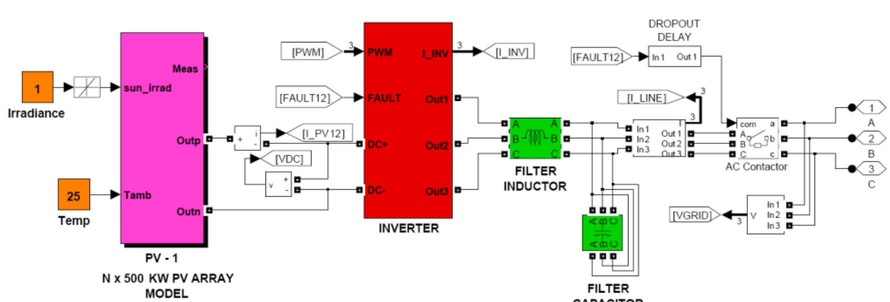

Figure 5-13b. PV unit subsystem in Figure 5-13a.

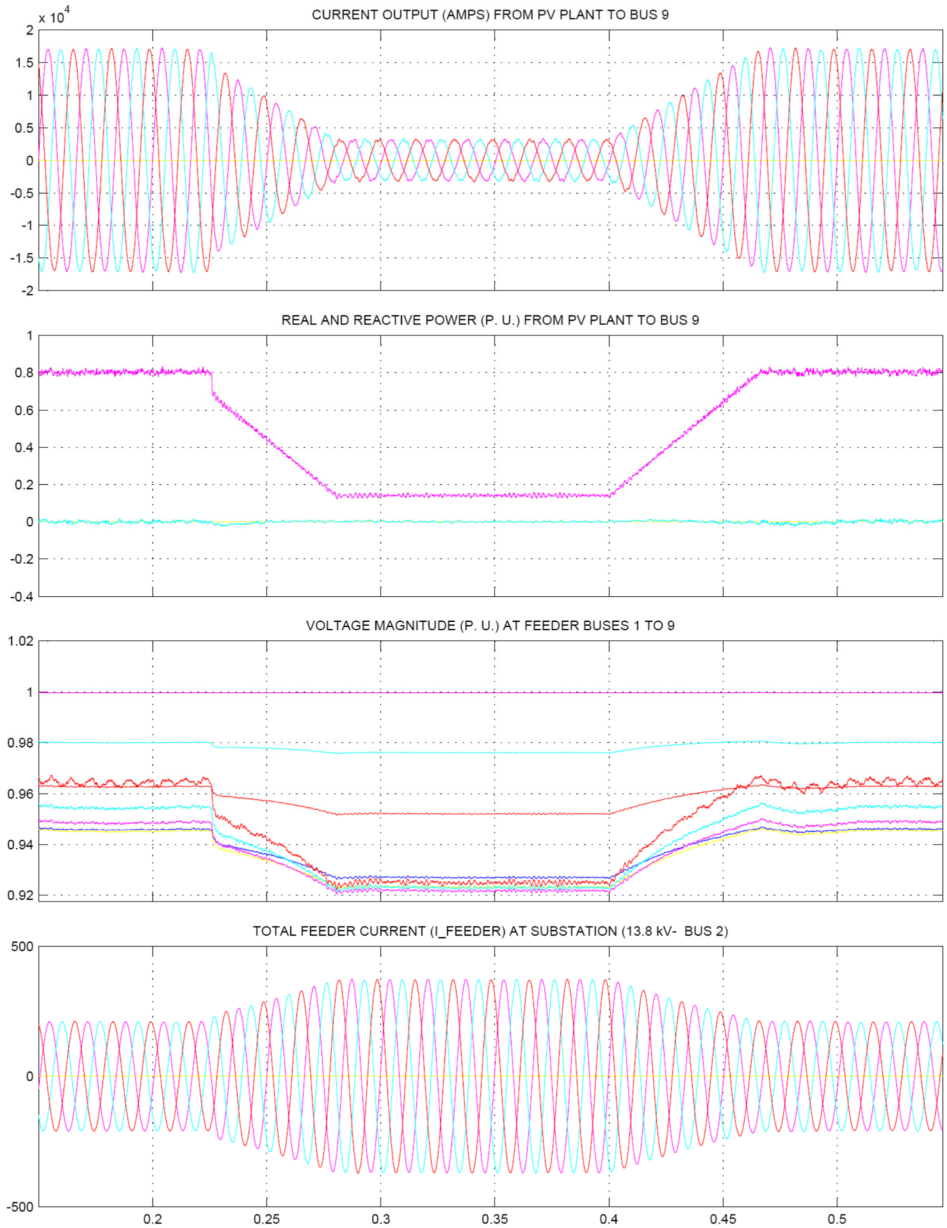

Figure 5-14a. No VAr output (pf = 1) at PV site during PV power dip. Bus No. 9 voltage is not controlled.

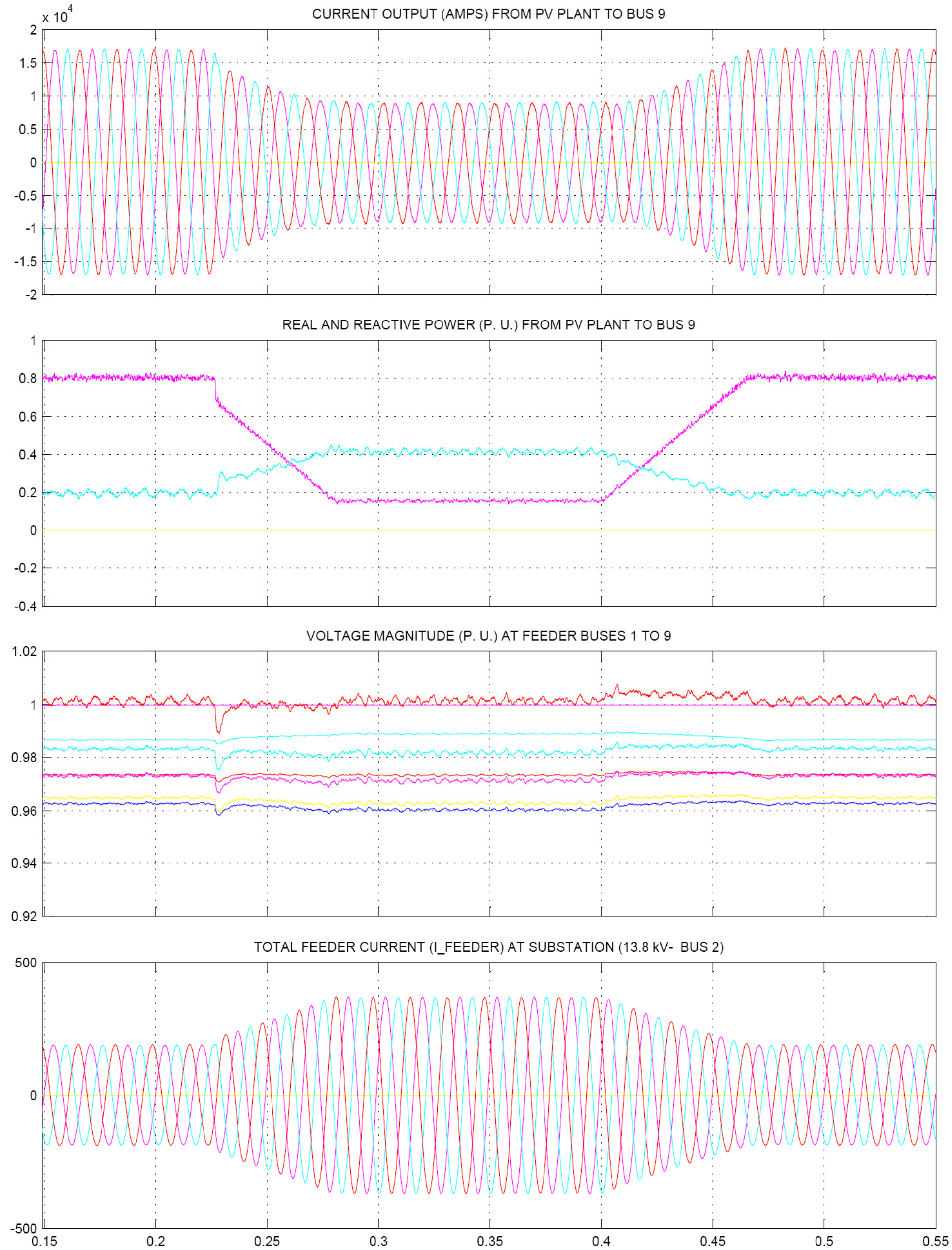

Figure 5-14b. PV system inverter actively controls the voltage at Bus No. 9 during PV power dip.

5.3.5.3 Fast Voltage Control for Flicker Reduction

The term "flicker" originates from the troublesome variation in light intensity, from incandescent lights in particular, as a result of even very small variations in voltage. Eye sensitivity, perception, and human tolerance play a large part in the assessment of flicker, which has made it difficult to define quantitatively in absolute engineering terms. Flicker sensitivity has been found to peak for voltage variations around 9 Hz, so flicker problems have traditionally been associated with industrial processes such as large electric arc furnaces and welding systems that draw fluctuating power at or around these frequencies. However, the concept of flicker has now been extended to cover all kinds of voltage fluctuations through the use of short-term (10 minutes) assessment (P_{st}) and long-term (a few hours) assessment (P_{lt}). The International Electrotechnical Commission (IEC) has developed standards for measuring voltage flicker. The IEC method for flicker measurement is defined in the IEC Std. 61000-4-15 (formerly the IEC 868). IEC Standard 61000-3-7 also provides target limits for P_{st} (0.9) and P_{lt} (0.7) as measured according to the standard. These standards have enabled consistent measurements to be made at existing locations, but it remains difficult to assess the possibility of excessive flicker at the planning stage because the result is critically dependent on the time-varying nature of the expected voltage variations. The issue is further complicated by the random nature of power fluctuations from a PV system, subject to passing cloud cover.

We have postulated that the fast automatic voltage control demonstrated by the results of Figure 5-14b can have a beneficial effect in reducing the flicker caused in a distribution system due to rapid fluctuation of output power from a PV generator. To test this hypothesis, we would like to use the detailed transient model of Figure 5-13 to generate the voltage waveform at one of the feeder buses in the benchmark system, and from this data calculate the level of flicker according to the IEC standard. By repeating the experiment with and without the fast voltage control enabled, we would obtain an absolute assessment of the improvement in the flicker level due to the voltage control. Unfortunately the transient model runs with a 1 μs time-step and it would be impractical (though not impossible) to simulate the 10 minutes of real-time voltage data required for P_{st} assessment. In order to facilitate the proposed experiment, a slightly simplified process was developed. The approach that was used is to simulate one "cloud cover cycle" such as that simulated in Figure 5-14a and Figure 5-14b and then to assume that the event is repeated continuously for 10 minutes. In this way, 10 minutes of voltage waveform data can rapidly be generated. This approach introduces an unrealistic periodicity for the cloud cycle into the experiment, but the response to each event is accurately simulated, thus allowing us to capture the changes in the voltage transitions due to the voltage control system. These voltage transitions are thought to account in large part for the flicker produced. If the same periodicity for the cloud cycle is consistently used, this method at least allows a comparative assessment to be obtained for the two different operating conditions.

An accurate, calibrated, discrete-time implementation of the IEC Flickermeter was then used to post-process the voltage measurement data and generate a value of P_{st}. Figure 5-15a shows a portion of the 10 minutes of data (4,000 Hz sampling) that was generated by repeating the Bus No. 7 A-phase voltage waveform for the event simulated in Figure 5-14a (i.e. with no VAr generation). This data was passed through the IEC Flickermeter and yielded a P_{st} measurement of 3.6492, which is well beyond the recommended limit of 0.9. Figure 5-15b shows the corresponding voltage data for the event in Figure 5-14b (i.e. with fast voltage control), which yielded a value of $P_{st} = 0.3833$, which is well inside the recommended limit. While these results may be open to interpretation, they do at least indicate the significant reduction of flicker that can be achieved by fast voltage control.

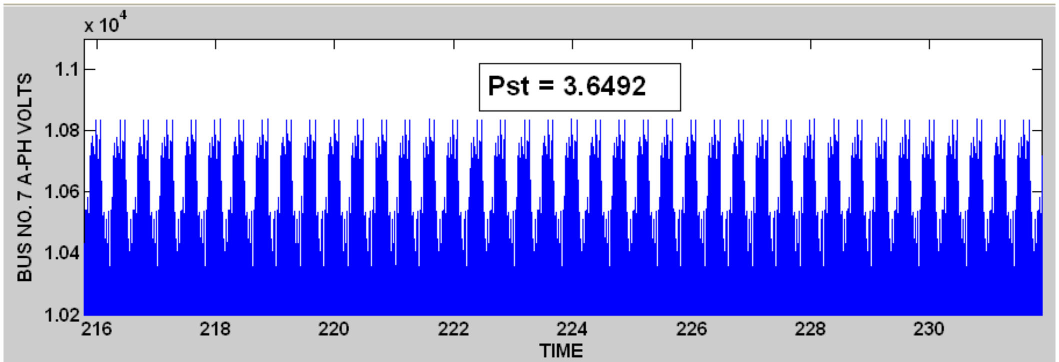

Figure 5-15a. Bus No. 7 A-phase voltage (scaled to show only the peak variation) – (Figure 5-14a event repeated over 10 minutes). P_{st} = 3.6492 (> 0.9 – unacceptable).

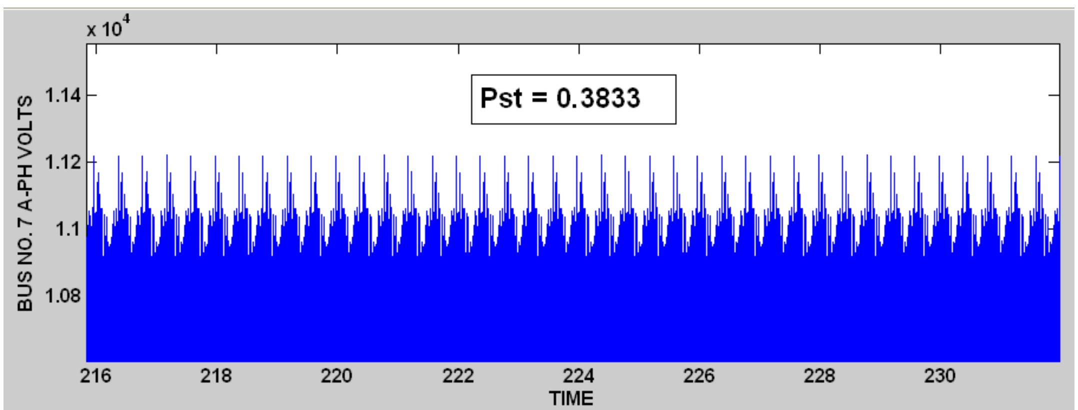

Figure 5-15b. Bus No. 7 A-phase voltage (scaled to show only the peak variation) – (Figure 5-14b event repeated over 10 minutes). P_{st} = 0.3833 (< 0.9 – acceptable).

5.4 Main Issues Delaying or Blocking the Connection of Large PV Projects

With the introduction of favorable feed-in tariff (FIT) rates and tax credits for renewable power, and the rapid decline in the cost of PV modules, there has been an unprecedented rush to install large PV projects in many parts of the world. Consequently, utilities have been inundated with requests for interconnection to the grid. In many cases the utilities have been unprepared to deal with this, especially in the case of large-scale projects (5 to 10 MW and even higher) requesting interconnection at distribution system voltage levels. In the United States the prevailing IEEE 1547 standard does not provide the answers needed to reassure utilities because these high-penetration scenarios were simply not anticipated when the standard was drawn up. So in some cases project approvals are on hold simply because the utility is waiting for clear guidelines to emerge that will allow them to determine what additional measures (if any) are needed for the project to proceed safely. In other cases, especially in other countries and in Hawaii, utilities and various regulatory bodies have been hastily drawing up their own rules and regulations for interconnection of DR. In many cases these new rules have had the effect of slowing the progress of PV projects as developers scramble to understand the requirements and their financial impacts. Examination of some of these rules is instructive because it highlights some of the utility concerns and shows some of the ways in which the advanced capabilities of inverters can be utilized to address them.

Some of the main issues and requirements currently affecting the interconnection of new PV systems are as follows:

- *Short circuit capacity limitation.* This applies in cases where the short circuit level has been assessed to be so close to the maximum capacity of existing circuit breakers that it would be unsafe to connect any additional local generation that would contribute in any way to increase the fault level. Surprisingly, this unlikely scenario apparently exists at many transformer stations in Ontario, Canada, where attractive feed-in tariffs (FIT) have been announced. As developers rush to take advantage of the FIT, interconnection of any new distributed generators through these transformer stations has been refused.
- *Power/distance limitation.* This applies especially in the case of the very long feeders encountered in Canada. These may be 44 kV feeders but are still classed as distribution level. The concern in this case is the regulation of voltage over a range of real power output from a PV system located far from the transformer station. Typically the utility allows connection of DR that falls within their acceptable power/distance rules and specifies remedies for those that are not acceptable. Such remedies are often expensive and include re-conductoring the feeder line, re-locating the system, or providing a separate reactive power generator to regulate voltage at the system location. The goal for many developers, whose projects are threatened by this rule, is to convince the utility to allow the PV inverters to participate in reactive power generation instead of using a separate VAr generator.
- *Transfer trip for PV system.* While it is generally understood that transfer trip schemes are needed for synchronous machine generators, there is considerable disagreement over the need for these expensive schemes in the case of PV inverters that are usually certified to be compliant with the anti-islanding requirements of IEEE 1547. Often the utility will require a transfer trip because they question the effectiveness of anti-islanding when there are multiple PV units connected on one feeder. The cost of providing a transfer trip scheme can sink the budget for a PV project.
- *Special custom requirements for reactive power deployment.* As the capability of inverters to generate reactive power becomes more widely understood, utilities are beginning to specify reactive power generation as a condition for interconnection. In some cases this calls for a fixed or adjustable power factor. In other cases a schedule is prescribed for reactive power output versus voltage or for reactive power output versus real power output. In general, rules for distribution feeders have stopped short of allowing generators to perform continuous autonomous local voltage control (as is commonly done in transmission systems).
- *Customized ride-through requirements.* Ride-through requirements differ considerably in regard to voltage levels and duration. In some cases the generator is required to generate reactive power according to a special schedule when voltage deviates beyond set limits.
- *Voltage quality requirements at the PV station.* This is an area where there is often disagreement about who is responsible for the grid voltage quality. It is impractical for a PV project developer to guarantee voltage quality at the point where the system is connected to the grid. Apart from any other consideration, the voltage quality depends on the impedance

of the grid and the presence of other harmonic sources throughout the system. It could be possible to fail to meet a voltage quality criterion without ever turning on the PV system. Undeterred by these facts, utilities still try to insert voltage quality requirements into power producer agreements and regulations.

- *PV system (ac output) grounding method.* In some cases utilities are insisting on the provision of a solidly-grounded primary neutral at the PV inverter isolation transformer. It is easy to demonstrate that this is bad practice, especially when the upstream transformer in the distribution system is also solidly grounded with low zero sequence impedance. However, it is difficult to persuade utilities to change their interpretations of their standard practice.
- *Transient over-voltage on islanding.* When impact studies show an unacceptable rise in inverter terminal voltage following sudden interruption of the grid connection, the utility will sometimes insist on the provision of special surge arrestors. This is a problem that is easily addressed through inverter control capabilities and need not be the cause for large additional equipment expense.
- *General uncertainty about impact of a high-penetration PV project on an existing feeder.* In these cases the utility may commission impact studies that will result in a number of special requirements being stipulated as the condition for approval. Sometimes the impact studies still leave room for doubts, and the approval may be further delayed. Main issues are usually the following:
    - Increased switching operations at line regulators, LTC, capacitor banks
    - Conductor and other equipment loading
    - Flicker
    - Protection relay settings with reverse power flow possible.

5.5 Conclusions

The advanced inverter capabilities we have discussed in this report could clearly facilitate high penetration levels of PV generation and also lead to potential savings for utilities by reducing line losses and drastically reducing regulator switching operations, thereby extending the life of equipment, reducing maintenance costs, and possibly deferring the cost of new capacitor banks and other equipment. In addition a new PV system on a feeder could improve the pre-existing power quality.

On the other hand, owner/operators who install inverters to interface their power plant to the grid would prefer that the inverters only be used to deliver revenue-producing real power. Providing ancillary services to the utility incurs a cost, either in terms of lost power production or power losses or other operating costs. The preferred business model for this relationship is not yet clear. It raises issues about who pays for what, as well as some more basic questions such as liability (who is responsible for maintaining system voltage) and how to measure lost production from variable sources for accounting purposes. These thorny issues have yet to be resolved before the benefits discussed here can be fully realized.

The report has shown that the advanced inverters in renewable power plants on distribution feeders can use their fast VAr generating capability to automatically regulate the voltage at the point of connection, thereby correcting for voltage swings due to their own real power fluctuations, reducing flicker that would otherwise occur, and improving power quality compared with the pre-existing conditions. Changes to existing regulations are needed if these potential benefits are to be fully realized.

The inverters that are used to connect PV power sources to the grid should be viewed as valuable resources for the management of the distribution system. Most of their unique control capabilities stem from the fact that inverters provide fast and flexible control of their output current (unparalleled by other power generators) and hence the real and reactive power injected into the grid.

The most important remaining questions for the integration of inverters into distribution systems lie in the area of voltage control. As we have seen, there are no fundamental technical barriers that would prevent PV inverters from actively and automatically controlling the voltage at their point of connection. Instead, the barriers lie in the unwillingness to adapt the existing infrastructure of the distribution system where necessary and to modify traditional practices to allow this to happen. This change will not come about quickly but, as with all innovation in the electric utility industry, will only start to happen after successful demonstration projects in the field have shown that the proposed new practices are safe, reliable, and beneficial.

6 References

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Appendix A. Summary of Interconnection Requirements for SCE Distribution Systems

This appendix summaries SCE's requirements as stated in the SCE interconnection handbook and California Rule 21 for interconnecting and operating a generation facility in parallel with SCE's distribution networks.

I. General Facility Design and Operation Requirements

It is required that the INTFAC (Interconnection Facility) complies with NERC Standards, Facility Connection Requirements (FAC-001), and ANSI/IEEE 1547-2003. The INTFAC is responsible for conforming to applicable joint NERC and Western Electricity Coordinating Council (WECC) standards, California Independent System Operator (CAISO) and SCE reliability criteria, Federal Energy Regulatory Commission (FERC) regulation, as well as good engineering and utility practice. INTFACs have the responsibility to ensure that they comply with the most recent version of the Interconnection Requirements. Requirements provided in this document are applicable to interconnecting generators intending to operate in parallel with SCE grid.

The parallel generator becomes a part of SCE's electrical system, and must, therefore, be considered in planning the protection of SCE's system. Prudent electrical practices require that certain protective devices (relays, circuit breakers, etc.) specified by SCE must be installed at any location where a Producer desires to operate its wholesale generating facilities in parallel with the SCE system. Other modifications to electrical system configuration or protective relays may also be required in order to accommodate parallel generation. SCE assumes no responsibility for determining protective equipment needed to protect Producer's facilities. SCE requires that such facilities also have adequate protective devices installed to react to abnormal electric system conditions and isolate from SCE's electric system.

- In case of fault in SCE system the INTFAC should stop producing.
- With SCE's approval, it is possible to use scheme for transferring Producer's loads from SCE's Distribution System to Producer's Generating Facility. The scheme may be used in lieu of the protective functions required for parallel operation.
- When islanding occurs, all generating facilities within the electrical island must be disconnected to prevent continued operation. The larger the installation, the greater the effect it may have on SCE's electrical system. SCE may require voltage and frequency protective functions or relays to detect islanding and shut down generation during islanding periods. Requirements are typically minimal for small installations, but increase in scope and/or complexity as the size of the generation installation increases. SCE may require voltage and frequency protective functions or relays to detect islanding and shut down generation during islanding periods.

II. Protection Requirements and Categories for Parallel Generators

SCE's requirements identify three different categories for Producer wholesale generating facilities connecting to the SCE system each with distinctive protection requirements. If multiple generation facilities are connected to the SCE system at a single point of interconnection, an aggregate capacity should be used to determine applicable categories. These categories are:

1. Interconnection voltage above 34.5 kV
2. 200 kVA and above capacity, interconnection voltage 34.5 kV or below
3. Less than 200 kVA capacity, interconnection voltage 34.5 kV or below

i. Protection Requirements for Category 1: Voltage Over 34.5 kV

The protection requirements for INTFAC in this category are:

1. Typically SCE-owned and controlled circuit breaker to disconnect generating facilities during SCE system trouble.
2. Synchronizing supervision relays (exception applies to inverter based generator) and telecommunications as required.
3. For non-inverter based (conventional) generators, either induction starting, automatic synchronizing or manual synchronizing supervised by a synchronizing relay must be provided by the Producer.
4. Manual synchronizing without a supervising relay is not permitted.
5. Protection related telecommunications may be required as determined by SCE Protection Engineering.

SCE-owned and maintained protective relays to provide protection functionality indicated above:

1. Short Circuit Protection (Devices 51V or 67V, 51N or 59G)
2. Islanding Protection (Devices 27/59, 81-0, 81-U)
3. Breaker Closing/Reclosing Control (Devices 25, 47, 79)
4. Loss of Synchronism (Device 78)

ii. Protection Requirements for Category 2: Total Generation 200 kVA and Above, Voltage at 34.5 kV or Below

The protection requirements for INTFAC in this category are:

1. Detect and clear the generator(s) from short circuits or grounds on the SCE system serving the Producer.
2. Detect the voltage and frequency changes in case of islanding.
3. Prevent re-paralleling the Producer's generation, after an incident of trouble.

Protection devices which may be required to satisfy the above requirements are:

1. Phase over-current trip devices (Device 51, 51V, or 67V)
2. Residual over-current or over-voltage relays to trip for ground faults on the SCE system (Devices 51N or 59G)
3. Under/over-voltage relays (Device 27/59)
4. Under/over-frequency relays (Device 81)
5. Phase sequence under-voltage relay (Device 47/27)
6. Automatic Separation: If the Producer desires to automatically separate from SCE and commence isolated operation upon loss of the SCE source, additional devices will be necessary to effect the separation.

Other specifications need to be taken into account for choosing the relays are:

1. Utility Quality Relays as opposed to industry quality relay should be selected.
2. Relay Operation Recorders are needed.
3. Relay Testing should be performed prior to applying the relay.
4. Four-wire Multi-grounded Neutral Distribution Circuits is required.

For INTFAC based on induction generators or ***static inverters*** the phase over-current protective devices may not be required, since these generation sources will not deliver sustained over-currents. All other specified protective devices are required.

iii. Protection Requirements for Category 3: Total Generation Less Than 200 kVA

1. Line Voltage Relay or Contactor
2. Relays to Detect Islanding
3. Fault Detection
4. Four-wire Multi-grounded Neutral Distribution Circuits
5. Dedicated Distribution Transformer
6. Harmonic Requirements for inverters
7. SCE Telecommunications
8. Exception to Protection Devices: These requirements include, but are not limited to, the provisions of IEEE Standard 929, IEEE Standard 1547, and UL Standard 1741.

III. Operating Requirements

SCE may also require additional operating requirements specific to an INTFAC. If so, these requirements will be documented in SCE's System Operating Bulletins (SOB), Substation Standard Instructions (SSI), and/or interconnection and power purchase agreements. SCE's SOBs and/or SSIs specific to the INTFAC and any subsequent revisions will be provided by

SCE to the INTFAC as they are made available. It is INTFAC's responsibility to comply with applicable operating requirements.

i. Voltage Variations

The INTFAC should have no adverse effect on the voltage regulation of that portion of the SCE system to which it is connected. Also, the INTFAC shall not cause the service voltage at other customers' location to go outside the requirements of ANSI C84.1-1995, Range A (IEEE 1547-4.1.1).

The step-up transformer ratio must be chosen such that the Producer can meet its voltage regulation obligation over the expected range of SCE system voltages. Step-up transformers must be equipped with no-load taps which provide ± 5% adjustment of the transformer ratio in 2.5% steps. The following voltage classifications apply to SCE distribution and sub-transmission systems:

- Primary distribution voltage 2.4 to 34.5 kV (± 5% variation)
- Subtransmission voltage 55 to 115 kV (± 5% variation)

SCE uses various voltage regulation techniques to raise or lower primary distribution and subtransmission voltages in order to maintain the customer's service voltage at the desired level. Producers interconnected at primary distribution or subtransmission voltage levels must be able to withstand such voltage changes and to respond with proper power factor adjustment in order not to oppose or interfere with SCE's or the CAISO's voltage regulation processes. The applicable voltage levels and response time of a generation facility to various levels of abnormal voltages are provided in the table below.

Voltage at the Point of Common Coupling		Maximum Trip Time # of Cycles	
120 V Base	% of Normal Voltage	60 Hz Nominal	Seconds
Less than 60 Volts	Less than 50%	10 Cycles	0.16 Seconds
>60 V or <106 V	>50% but <88%	120 Cycles	2 Seconds
>132 V or <144 V	>110% but <120%	Normal Operation	Normal Operation
>144 V	>120%	10%	0.16 Seconds

ii. VAr Correction

SCE shall not be obligated to supply or absorb reactive power for the INTFAC when it interferes with operation of the SCE transmission system. In subtransmission system an adequate VAr correction shall be provided for maximum coincident customer loads (one-in-five year heat storm conditions), after adjusting for dependable local generation and loss of the largest local bypass generator.

iii. Voltage Regulation/Reactive Power Supply Requirements

If power factor correction equipment is necessary, it may be installed by the INTFAC at the facility, or by SCE at SCE's facilities at the INTFAC's expense. For SCE controlled subtransmission and distribution systems, power factor should be in the range of 0.95 lagging to 0.95 leading at the point of delivery.

iv. Reactive Power Supply Requirements for Inverter Systems

The following requirements are applicable for the dominant inverter technology utilized in today's market (Forced-commutated Inverters). The requirements of Line-commutated Inverters (old technology) are not included:

- Supply reactive power so that the generating facility does not impose any additional reactive power demand upon SCE other than the demand of loads within the facility.
- It is not allowed that the producer delivers excess reactive power to SCE under normal operating conditions unless otherwise agreed to by SCE.
- Under emergency operation, producer can deliver excess reactive power to SCE for ensuring voltage schedule compliance.
- Producers connected to the subtransmission system or bulk power system (above 34.5 kV) must have the voltage regulation equipment and generator reactive power capability to maintain a voltage schedule or reactive power schedule prescribed.

The size of any discrete step change in reactive output shall be limited by the following criteria:

1. The maximum allowable voltage rise or drop (measured at the point of interconnection with the SCE system) associated with a step change in the output of the INTFAC's reactive power equipment must be less than or equal to 1%; and

2. The maximum allowable deviation from an INTFAC's reactive power schedule (measured at the point of interconnection with the SCE system) must be less than or equal to 10% of the INTFAC's maximum (boost) reactive capability.

Inverter systems 200 kVA or less, which conform to the recommended practices in IEEE Standard 929-19 and which have been tested and approved for conformance to UL Subject 1741, are considered to have met all SCE's reactive power supply requirements.

v. Off-Nominal Frequency Requirements

It is the Producer's responsibility to ensure conformance with the latest approved WECC Off-Nominal Generation Requirements. The CAISO is responsible for frequency control and therefore SCE can assume no responsibility for damage that occurs due to off nominal frequency operation.

The following table shows the value of tripping time (cycles) based on the rating and frequency range of the generation facility:

Under Frequency Limit	Over Frequency Limit	Minimum Time
> 59.4 Hz	60.0 to < 60.6 Hz	continuous operating range
≤ 59.4 Hz	≥ 60.6 Hz	3 minutes
≤ 58.4 Hz	≥ 61.6 Hz	30 seconds
≤ 57.8 Hz	N/A	7.5 seconds
≤ 57.3 Hz	N/A	45 cycles
≤ 57.0 Hz	> 61.7 Hz	instantaneous trip

vi. Voltage Imbalance and Abnormal Voltage or Current Waveforms (Harmonics)

SCE may require the facility to install equipment to eliminate the power quality problem.

- **Voltage Imbalance Criteria**
  - Unbalanced voltage level of an INTFAC should not exceed 1% at PCC at steady state condition.
  - Exceptions may be applied to the maximum range if it can be justified after a study conducted by SCE. In any case, the voltage imbalance should not reach higher than 1.5%.
  - INFACT responsibility to install mitigating devices.

- **Harmonics Criteria**
  INTFACs are required to limit harmonic voltage and current distortion produced by static power converters or similar equipment. When the Generating Facility is serving balanced linear loads, harmonic current injection into SCE's Distribution System at the PCC shall not exceed the limits stated in the table below. The harmonic current injections shall be exclusive of any harmonic currents due to harmonic voltage distortion present in SCE's distribution system without the Generating Facility connected (IEEE 1547-4.3.3.). The harmonic distortion of a Generating Facility located at a Customer's site shall be evaluated using the same criteria as for the Host Loads.

Individual harmonic order, h (odd harmonics)	h<11	11≤h<17	17≤h<23	23≤h<35	35≤h	Total demand distortion
Max. distortion (%)	4.0	2.0	1.5	0.6	0.3	5.0

- **Flicker Criteria**

  The Generating Facility shall not create objectionable flicker for other customers on SCE's Distribution System. To minimize the adverse voltage effects experienced by other customers (IEEE 1547 4.3.2), flicker at the PCC caused by the Generating Facility should not exceed the limits defined by the "Maximum Borderline of Irritation Curve" identified in IEEE 519-1992 (IEEE Recommended Practices and Requirements for Harmonic Control in Electric Power Systems, IEEE STD 519-1992). This requirement is necessary to minimize the adverse voltage effects experienced by other Customers on SCE's Distribution System. Generators may be connected and brought up to synchronous speed (as an induction motor) provided these flicker limits are not exceeded.

Photovoltaic Inverter Systems shall comply with IEEE 929-1999 and UL 1741. Utility-interactive inverters do not require separate synchronizing equipment. Non-utility interactive or "stand-alone" inverters shall not be used for Parallel Operation with SCE's Distribution System. The goal is providing high quality solar systems that promote highest energy production per ratepayer dollar, optimal system performance during peak demand periods, and appropriate energy efficiency (EE) improvement where solar systems are installed.

Appendix B. Example XML Schema of Delivered Solar Resource Datasets


```
- <PVOutputStatistics xmlns:xsi="http://www.w3.org/2001/XMLSchema-instance"
      xmlns:xsd="http://www.w3.org/2001/XMLSchema">
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- <Generator>
  <GeneratorId>Fontana</GeneratorId>
- <Months>
- <Month>
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- <Hours>
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</Hour>

Appendix C. Data Requirements for Distribution Feeder Model Development

The following table provides a comprehensive list of data requirements for modeling a distribution feeder for the purpose of steady-state and dynamic impact studies.

Data Category	Component	Required Data	Note
Distribution Network Modeling	**Distribution Feeder Configuration**	1- Schematic diagram of the feeder that shows the equipment along the feeder (all the devices are listed in the second column of this table.) 2- Power flow and short circuit model (CYMDIST, ASPEN, Synergy, etc.)	3 copies per feeder CYMDIST for SCE
	Substaion data and Equivalent Source Model for HV system	1- Rated Voltage (kV) 2- Operating voltage (kV) 3- Short circuit Capacity (MVA) 4- Voltage angel (degree or Radian) 5- Operating frequency (Hz) 6- Positive sequence impedance (HV side) 7- Zero sequence impedance (HV side) 8- Number of feeders	Can be extracted from CYMDIST model, if HV is modeled
	Transformer at substation	1- Rated Voltages (kV) for primary and secondary 2- Rated MVA 3- Series Impedance (Ω) 4- Winding configuration (primary/secondary) 5- Tap Setting for Manually adjusted seasonal tap, if applicable 6- LTC Settings for automatic tap adjustment, if applicable	Can be extracted from CYMDIST model, if HV is modeled May not be in CYME
	Load Data	1- Substation Load (P&Q for HV side of transformer) - 8760 hourly or monthly profiles 2- Feeder load (P&Q) - 8760 hours or monthly profiles 3- Neighbor feeders load (a lump sum can be calculated from 1 and 2, if not available individually) 4- Location and size of large (fixed) loads - to be excluded from load allocation	From SCADA Data Customer information
	Automatic switches and recloser	1- Number, location and operating modes of feeder reclosers 2- Number, location and operating mode of automatic feeder re-configuration switches	From CYMDIST May not be in CYME
	Voltage Regulators Data, if applicable	1- Rated MVA 2- Impedance 3- Single phase or three phase 4- Delay time for turn on and turn of 5- Operating voltage boundary (set points) 6- No. of taps 6- Control mode 7- Location or Pole number	Can be extracted from CYMDIST model
	Capacitor Banks data, if applicable	1- Rated kVAr 2- Control method (Manual or Voltage control) 3- Voltage boundary for turning off and on 4- Time delays 5- Location or Pole number 6- Cap bank status, if not fixed (manual)	Can be extracted from CYMDIST model May not be in CYME
	Line Data	1- Length of each section 2- Conductor type of each section	Can be extracted from CYMDIST model
PV Generator Modelling	**PV Inverter**	1- Manufacturer name and data sheets 2- Inverter model diagram from the manufacturer 3- Generation capacity of the PV plant 4- Control and protection scheme used in the inverter model	Manufacturer data (see next sheet)
	PV Transformer	1- MVA rating of the transformer associated with PV 2- Transformer configuration 3- Transformer impedance 4- Transformer rated voltages (kV)	Interconnection drawings and design data (see next sheet)
	PV Generation Profile (MW)	Annual profile with the rosolution of 10 seconds or better	SCADA data