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ADVANCED CONTROL TECHNOLOGIES FOR DISTRIBUTION GRID VOLTAGE AND STABILITY WITH ELECTRIC VEHICLES AND DISTRIBUTED GENERATION

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PREFACE

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Advanced Control Technologies for Distribution Grid Voltage and Stability with Electric Vehicles and Distributed Generation is the final report for contract number 500-11-018 conducted by Pacific Gas and Electric Company. The information from this project contributes to Energy Research and Development Division's Energy Technology Systems Integration program area.

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ABSTRACT

This project investigated the potential voltage issues that may result as levels of distributed generation increase on typical distribution feeders. The work included literature review, field personnel interviews, and modeling and simulation of representative distribution feeders. The modeling included both steady-state and time-series analysis. Additional simulations of representative secondary systems were also performed.

Results of the distribution feeder simulations indicated that rural type circuits with major generators located toward the end of the feeder have the most voltage issues. Voltage issues appear to be almost independent of distributed generation penetration levels. Equipment such as smart inverters were found to be of some, but limited, value in mitigating the identified voltage issues.

Keywords: distributed generation, Volt/VAR control, smart inverters, distribution modeling, GridLAB-D, CYMDIST

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EXECUTIVE SUMMARY

Introduction

By 2020, California may require an additional 12 gigawatts of distributed generation (DG) from renewable resources such as wind and photovoltaics (PV). This increased amount of DG is expected to create disturbances to the distribution grid unless mitigation measures are implemented. This increased penetration of DG may also test interconnection rules and distribution circuit design standards. Potential impacts include compromised safety systems, voltage quality issues, insufficient and excessive power flows (from renewable generation intermittency), and increased utility equipment operations.

General impacts caused by DG on the electric distribution system can be divided into three general categories: capacity, voltage, and protection. This project focused only on voltage impacts caused by DG, specifically PV systems, since utilities have a standard system voltage range that must be maintained for safe and reliable operation of the distribution system. Also, voltage levels outside the standard operating range are generally the first issues seen as the amount of DG on a circuit increases.

Project Purpose

This project identified and evaluated potential voltage issues as the amount of PV systems increase on a distribution circuit and determined the best method(s) to resolve any voltage issues.

Project Approach

The initial effort of this project was to conduct research to identify what issues utilities face to high penetrations of DG and specifically what distribution system voltage issues have been found. The research involved four activities: reviewing existing research literature, interviewing utility personnel, benchmarking DG and voltage control experiences with other utilities and reviewing existing utility standards as they relate to DG and voltage control on utility systems.

This initial research effort discovered that there was a lack of hard data that could quantify the types and number of voltage issues on the electric distribution system as a result of DG. This may be because DG penetration levels have not increased significantly enough for these issues to manifest themselves. This may also be because the screening process of Rule 21 properly identifies potential voltage issues prior to interconnecting a new DG system, and therefore a number of voltage issues are solved in the engineering phase so that they don't become a problem in the field. Either way, additional hard data must be gathered to quantify the potential impacts of DG.

The second part of this project involved simulating circuit models to further investigate the voltage issues identified. PG&E selected a representative sample of 12 circuits for analysis in this project out of their 3,000 distribution circuits. All circuit data used in this project was "scrubbed" of any potential proprietary and/or private information.

In addition to the traditional steady-state analysis that utilities perform, time-series analyses were performed in this project because it was necessary to demonstrate voltage control issues and how variability of DG impacts voltage performance. Although data for steady-state analysis was readily available, custom computer scripts had to be developed to translate steady-state data into formats suitable for time-series analysis. Two main software packages were used for simulations on this project: CYMDIST® for steady-state analysis (by Eaton's Cooper Power Systems) and GridLAB-D for time-series analysis (by Pacific Northwest National Laboratory).

Project Results

This project helped identify that distribution circuits with long main-line circuits and several stages of voltage regulation have a greater potential for voltage issues caused by DG.

Electric distribution systems generally have some type of voltage control devices that regulate voltage along the distribution system. DG can interact with these voltage control devices causing them to operate improperly or excessively, leading to decreased equipment life.

Designers of distribution systems limit the allowable voltage flicker that customers see. Typically voltage flicker limits are 2.5 percent on the primary voltage system with 5 percent tolerated on industrial and rural circuits. With the addition of DG on an electric distribution system, potential voltage issues may occur when solar irradiation levels abruptly change, such as a cloud passing over the PV panels, or if a large DG system suddenly fails because of interconnecting equipment problems.

The research work identified that voltage issues occur most commonly on the section of the circuit closest to the customers, known as the secondary side of the distribution system. Utilities typically haven't studied the secondary side in great detail because enough design-margin was included to handle typical load variation and power generation was typically not added on the secondary side. However, as more DG is added to a distribution circuit, specifically to the secondary, more detailed analysis is necessary on facilities close to the DG interconnections.

Simulation Results and Conclusions

Impacts from DG Variability. High voltage issues appear to be more dependent upon the type of circuit and the DG's location on the circuit rather than penetration level. However, higher penetration levels do produce higher voltage conditions for the same type of circuit with DG at the same location.

Rural type circuits are more likely to see voltage issues than shorter urban/suburban circuits, although this is not absolute. Since PV developers must locate affordable land to site large systems, which tends to be in remote rural areas, locating a system on a rural circuit toward the end-of-line can be in conflict with developer requirements.

Off-peak and partial-peak loading conditions are the most likely to produce high voltage problems as PV penetration levels increase. However, peak conditions are typically used by distribution planners when designing their systems. As DG penetration levels increase, planning engineers must examine partial-peak conditions to ensure proper operation of the distribution system.

Circuit type, location, and seasonal loading condition are the primary indicators of potential voltage problems while the amount of DG on the circuit appeared to be a somewhat independent variable.

The results of this project show a significant increase in the number of operations for voltage control equipment as a result of increased amounts of PV. Utilities need a more refined analysis to quantify the financial impacts of this added stress to field equipment.

Potential Mitigation Strategies to Resolve Voltage Issues. Three main strategies were investigated to mitigate voltage issues that resulted from various amounts of PV: using smart inverters, using static volt-ampere reactive (VAR) compensators (SVCs), and implementing voltage/VAR optimization control (VVO). VAR is a portion of the total power that is used to regulate the system voltage; the other portion, expressed in watts, is the actual power consumed or used to perform work.

Smart Inverters: Smart inverters can help lower voltage; however, there are limitations to this approach. In several cases, the simulations showed that smart inverters alone cannot overcome all voltage issues and may actually overload the circuit.

Static VAR Compensators: SVCs possibly have a greater ability to reduce high voltage issues compared to smart inverters primarily because they have greater reactive power capacity. As with smart inverters, there is a limit to how much mitigation can be achieved with an SVC and their implementation may also result in overloads on the circuits.

Volt-VAR Optimization: The simulations demonstrated that GridLAB-D's voltage optimization and control model did help lower voltage when PV is connected, but it could not consistently maintain voltage within acceptable limits. Voltage optimization and control models must include more monitoring and status capabilities so that actual interaction between VVO and DG can be better understood and controlled properly.

The interaction between PV and electric vehicle (EV) charging was also examined.

EV Charging: Residential EV charging has little impact when included with PV since the application for EVs in this scenario is typically for commuting. A commuter EV would only be charged during evening hours, therefore the additional load of the EV charger would not help to offset the PV generation, and therefore would not help in reducing potential high voltage problems. Additionally, using EVs as storage devices with PV does not make sense since most EVs would not be present at the residence during peak PV output.

EV charging within a commercial secondary system may demonstrate more benefit because the PV output would coincide with EV charging.

Project Benefits

This research identified that distribution circuits with a long main-line and several stages of voltage regulation will have voltage issues with high levels of DG penetration. These characteristics can be used by utility system planners to pinpoint areas of their systems that

may not be ideal for DG installations. This information can also be used by DG developers to choose the best site for their DG facility and understand any potential interconnection issues.

The research showed that the variability of PV caused an increase in the number of operations for voltage control equipment, identifying the necessity for utilities to consider more frequent equipment replacements in their maintenance budgets as increasing amounts of DG are added to their system.

The voltage mitigation strategies investigated in this project showed limited effect on solving voltage issues; therefore alternative strategies, such as energy storage, must be identified to help with the integrating DG.

The interaction between DG and the utility distribution system is very complex and requires more advanced simulation tools. Using an open-source analysis software tool, such GridLAB-D, provides for continuous, collaborative development and sharing of more advanced models. An open-source analysis approach provides utilities and project developers a platform to leverage each other's analytical work to increase DG penetration.

The scrubbed circuit models and custom scripts created in this project are available through download to the general public through Pacific Northwest National Laboratories' GridLAB-D website at: http://gridlab-d.sourceforge.net/wiki/index.php/PGE_Prototypical_Models.

CHAPTER 1: Introduction

1.1 Problem Statement

This project investigated voltage issues on the electric distribution system as they relate to the integration of distributed generation (DG). The goals of this project were the following:

- Research methods to control voltage regulation to maintain conservation voltage reduction (CVR) limits while coping with ramp rates of photovoltaic (PV) variability.
- Research newer smart grid approaches to Volt/VAR control such as smart PV inverters with reactive power dispatch capability, energy storage, and solid-state dynamic voltage regulators.
- Identify potential tools and methodologies to improve voltage regulation and control under various operating scenarios.
- Demonstrate new simulation tools that can be used in smart grid research.

1.2 Project Objectives

The objectives of this project were to answer the following questions through research and modeling simulation:

- Can system voltage and end-of-line issues be managed through centralized control of distribution line equipment?
- What significant voltage issues are directly related to high penetration levels of PV, or other DG?
- What are the intermittency and variability issues with PV (e.g., cloud cover), and other DG?
- What are the major high/low voltage effects on utility customers caused by DG at higher penetration levels?
- How do high levels of PV and other DG impact system operations?
- What mitigation measures may be necessary to ensure that utility systems will operate safely and reliably for the public, DG owners, and utility workers?

CHAPTER 2:
Research on Field Issues

2.1 Research Approach

The initial effort of this project was to conduct research to better identify what issues utilities face with regard to high penetrations of DG and specifically what distribution system voltage issues have been found. The research involved four activities: review of existing research literature; interviews with utility personnel; benchmarking DG and VVO experiences with other utilities; and review of existing utility standards as they relate to DG and voltage control on utility systems. The following is a summary of the results of these activities:

2.1.1 Review of Research Literature

More than a 100 technical research papers and presentations from various sources were reviewed. Although it is not possible to summarize all of these documents within this report the following key papers do provide insight into what the issues are regarding management of voltage on a distribution system as the result of DG:

- Sandia National Laboratory's report[1] clearly demonstrated the need for time-series analysis to evaluate the impact DG may have on voltage control equipment cycling. The report identified that equipment cycling is an issue on distribution systems with DG. The report indicated that the amount of cycling may be dependent upon seasonal loading conditions.
- Philip Barker's very complete presentation on issues related to DG.[2] Barker is a DG industry expert with significant experience in the engineering and installation of large PV systems. The presentation not only covered voltage issues that he identified from his field experience, but it also covered common protection issues and provided "rules-of-thumb" for screening large DG installations.

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1 Broderick, R.J., J.E. Quiroz, M.J. Reno, A. Ellis, J. Smith, R. Dugan (Sandia National Laboratories). January 2013. *Time Series Power Flow Analysis for Distribution Connected PV Generation.* Sandia National Laboratories. SAND2013-0537. http://energy.sandia.gov/wp/wp-content/gallery/uploads/SAND_Time-Series-Power-Flow-Analysis-for-Distribution-Connected-PV-Generation.pdf.

2 Barker,Philip (Nova Energy Specialists, LLC). February 2012. *Experiences in Integrating PV and Other DG to the Power System*. Presentation at 6th Annual Distribution Wind/Solar Interconnection Workshop. Utility Wind Interest Group. http://www.uwig.org/Golden2012/PVDGIntegration-Barker.pdf.

In addition to Sandia's report, the following key paper provided insight in how potential modeling and simulation techniques could be used for this project:

- Pacific Northwest National Laboratory (PNNL) report[3] that outlined how GridLAB-D was used to evaluate CVR on a collection of representative feeders. The report described how to model voltage-dependent loads with GridLAB-D and stressed the importance of including thermal-cycling models in the analysis.

2.1.2 Interviews with Field Personnel

Interviews were conducted with 18 Pacific Gas and Electric Company (PG&E) internal personnel regarding their experiences with field implementation of DG systems. The interviews involved individuals from the following departments:

- Electric Distribution Generation Engineering
- Electric Distribution Planning
- Engineering and Mapping
- Power Quality Field Investigation
- Electric Distribution System Operations Planning
- Electric Restoration
- Service Planning
- Energy Procurement Ratemaking
- Electric Strategy

The interviewees provided anecdotal evidence of primary system voltage issues. There was a single case of a reverse power flow problem through a line regulator. This problem was solved with modified regulator settings. A line-drop compensator desensitization issue was also identified and this too was solved through an engineered control solution using additional compensating current transformers.

The biggest surprise from the interview process was the lack of hard data on the number and types of DG problems encountered. At the time of the interviews, PG&E had approximately 90,000 DG installations on its system. The Power Quality department tracks all power quality inquiries and had compiled a list of approximately 12 events related to DG. These 12 investigations all related to high voltage problems on the secondary system as the result of PV inverters. For more than 90,000 installations, there were only 12 documented voltage issues.

3 Schneider, K.P., J.C. Fuller, F.K. Tuffner, R. Singh. 2012. *Evaluation of Conversation Voltage Reduction (CVR) on a National Level.* Pacific Northwest National Laboratory. PNNL-19596.

2.1.3 Benchmarking with Other Utilities

Interviews were conducted with one California IOU and three non-California utilities (the other California IOU was not available for interview during this phase of the project). The intention of these interviews was to benchmark what other utilities have experienced with increased penetration of DG and if they have identified any potential issues.

All of the utilities interviewed stated that they were looking to PG&E to see what experience it might have with regard to high levels of DG, since their levels of PV penetration have not reached that of PG&E. Again, no hard data was presented by any of the utilities on how many or what type of problems they are having from increased DG penetration levels.

2.1.4 Review of Industry Standards

The California Public Utility Commission's (CPUC's) Rule 21[4] is a tariff that specifies the interconnection requirements and interconnection process of DG systems. The tariff sets minimum technical standards for interconnection. Rule 21 has been continuously reviewed and adjusted by the CPUC, with input from key stakeholders, to streamline the process of interconnecting DG while still maintaining safety and performance standards.

As was described in the Section 2.1.2, there is no hard data on the number and type of voltage issues that arise as a result of increased PV penetration. This may be because there is both a lack of processes to document DG voltage issues and still limited penetration levels of DG. An additional reason for the current lack of voltage issues found in the field could be the thorough screening procedures defined in Rule 21. Within the Rule 21 screening process new applications for interconnection undergo varying levels of engineering review depending upon a variety of characteristics of the proposed interconnection. The engineering review looks at potential voltage issues that may result from a given interconnection and if it fails initial review a more detailed engineering review is performed. The engineering review process may identify required system upgrades that are needed to maintain voltage levels within acceptable standards and require these be completed prior to the activation of the DG system. It can be said that the current screening process seems to be working and voltage issues are being addressed prior to occurrence in the field.

Some of the engineering screening requirements include:

1. Aggregate generating facility capacity on the line section needs to be less than 15 percent of peak load for all line sections bounded by automatic sectionalizing devices.

4 California Public Utilities Commission. September 20, 2012. *Electric Rule No. 21 - Generating Facility Interconnections*. CPUC Sheet No. 31865-E. http://www.cpuc.ca.gov/PUC/energy/rule21.htm.

2. Aggregate generating facility capacity on the line section needs to less than 100 percent of minimum load for all sections bounded by automatic sectionalizing devices upstream of the generating facility. This can be determined from existing data or power flow model.

It can be seen that it is important to know the coincidental loading and generation output on each line section of a distribution feeder. This requires modeling tools with time-series analysis capabilities.

Rule 21 requires that equipment be "Listed" as defined by the National Electric Code (NEC).[5] The NEC defines "Listed" as "included in a list published by an organization that is acceptable to the authority having jurisdiction [local electric inspector] and concerned with evaluation of products…" In the United States, a typical organization of this type is Underwriters Laboratory (UL). UL has developed several testing standards related to DG including UL 1741,[6] which are used for PV inverter certification. UL 1741 references the Institute of Electrical and Electronic Engineers (IEEE) standard IEEE 1547 – Standard for Interconnecting Distributed Resources with Electric Power Systems.[7] IEEE 1547 has been a major focus in addressing issues related to the interconnection of DG into the utility system.

IEEE 1547 is further broken down into the following sections:

1) IEEE 1547.1- Standard for Conformance Tests Procedures for Equipment Interconnecting Distributed Resources with Electric Power Systems (approved 2005).

2) IEEE 1547.2 - Application Guide for IEEE 1547 Standard for Interconnecting Distributed Resources with Electric Power Systems (published 2008).

3) IEEE 1547.3 - 2007 Guide for Monitoring, Information Exchange, and Control of Distributed Resources Interconnected with Electric Power Systems (published 2007).

4) IEEE 1547.4 - Guide for Design, Operation, and Integration of Distributed Resource Island Systems with Electric Power Systems (published 2011).

5) IEEE P1547.5 - Draft Technical Guidelines for Interconnection of Electric Power Sources Greater than 10MVA to the Power Transmission Grid Withdrawn 12/2011 (not approved).

6) IEEE 1547.65 - Draft Technical Guidelines for Interconnection of Electric Power Source Electric Power Systems Distribution Secondary Networks (published 2011).

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5 Earley, Mark, J.S. Sargent. 2011 edition. *NFPA 70: National Electrical Code Handbook.* National Fire Protection Association. p.30, Article 100, Definitions.

6 Underwriters Laboratories. 2010. *Inverters, Converters, Controllers and Interconnection System Equipment for Use With Distributed Energy Resources*. Underwriters Laboratories. UL 1741.

7 Institute of Electrical and Electronic Engineers. 2003 (R 2008). *Standard for Interconnecting Distributed Resources with Electric Power Systems*. Institute of Electrical and Electronic Engineers. IEEE 1547.

7) IEEE P1547.7 - Draft Guide to Conducting Distribution Impact Studies for Distributed Resource Interconnection (not published).

8) IEEE P1547.8 - Recommended Practice for Establishing Methods and Procedures that Provide Supplemental Support for Implementation Strategies for Expanded Use of IEEE Standard 1547 (not published).

9) IEEE P1547a - Standard for Interconnecting Distributed Resources with Electric Power Systems, Amendment 1 (not approved).

Among the sections listed above, IEEE 1547.1 is the only standard; the rest of the sections are guidelines and recommendations related to DG. For discussion here, IEEE P1547a is of interest as it is an update of IEEE 1547 that is for "establishing updates to voltage regulation, response to area electric power systems abnormal conditions of voltage and frequency…" Under this new amendment, DG could actively participate in voltage regulation by use of reactive power. This project simulated the use of smart inverters to provide reactive power for voltage regulation. Therefore, this standard would have to be finalized and approved before implementation of smart inverter technologies in the field.

2.2 List of Field Issues

Task 2.1 of this project, "Research, Analysis, and Documentation of Distributed Generation Interconnection Issues," required the identification of issues related to feeder voltage regulation and voltage flicker associated with medium and high penetration of DG in California. The deliverable for this subtask was an interim report to the Energy Commission which outlined the key voltage issues that result from the installation of DG. This section summarizes the results of that report.

2.2.1 Overview of Field Issues

General impacts caused by DG on the electric distribution system can be divided into three general categories: Capacity, Voltage, and Protection. This discussion only deals with the second category – Voltage. Voltage issues related to DG can be further divided into three sub - areas: Steady State Voltage, Voltage Control and Flicker.

2.2.2 Steady-State Voltage

The most obvious type of voltage issue is a steady-state high voltage condition because of voltage-rise along a distribution feeder as a result of DG systems. This condition can also be used as an indicator of potential other voltage problems such as flicker. It can also be used to assist in identifying characteristics of distribution feeders that may be prone to voltage issues as the result of DG.

2.2.3 Voltage Control

Electric distribution systems generally have some type of voltage control devices that regulate voltage along the distribution system within American National Standards Institute (ANSI)

standard voltage limits.[8] DG can interact with these voltage control devices causing miss-operation or excessive operation. The voltage control interaction issue can be further broken down into the following subcategories:

2.2.3.1 LTC/Line Regulator/Capacitor Cycling

Most DG has a tendency to vary during a normal daily loading cycle. This variability can cause additional operation, or cycling, of voltage regulating equipment. Specific equipment that may be impacted includes load tap changers (LTC) which are located at the substation, line voltage regulators which can be found at various locations along a distribution feeder, and switch capacitors that provide both voltage support and power factor correction. An increase in operations on these devices can result in shorter life expectancies and more frequent scheduled maintenance requirements.

2.2.3.2 Line Drop Compensators Back-Feed Concerns as a Result of DG

Both LTCs and line voltage regulators use controllers that have a line drop compensator (LDC). This control feature compensates the output voltage set point for varying loading conditions. If DG is located near a voltage regulation device with LDC implemented, the control can be de-sensitized by the current sourced from the DG. This can result in the LDC not properly compensating for the loading conditions and cause low voltage especially during heavy loading conditions.

2.2.3.3 Reverse Power Interactions

LTCs and line voltage regulators are generally designed to operate with power flowing in one direction. With the addition of DG on an electric distribution feeder power flow can be reversed through the regulating equipment. If a couple of voltage regulating devices are operated in series along a feeder, such as having an LTC at the substation and a line regulator farther out on the feeder, and if there is reverse power flow through the one located farthest out on the feeder, the two devices would attempt to regulate voltage on the same section of the feeder. This could result in the controllers fighting each other and voltage on the common regulated section being outside of acceptable voltage levels.

2.2.4 Voltage Flicker

Designers of distribution systems limit the allowable voltage flicker that customers see. Typically, voltage flicker limits are 2.5 percent on the primary voltage system with 5 percent tolerated on industrial and rural circuits. With the addition of DG on an electric distribution system there are two potential causes of flicker: DG variability and a sudden disconnection of a distributed generator for the electric system (loss of plant).

2.2.4.1 DG Variability

The power outputs of PV systems are directly related to the available irradiation from the sun. The solar irradiation level can abruptly change when a cloud passes over an array (cloud

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8 American National Standards Institute, Inc. December 6, 2006. *American National Standard for Electric Power Systems and Equipment - Voltage Ratings (60 Hertz)*. National Electrical Manufacturers Association. ANSI C84.1-2011.

shadow event). This results in a swing in power output of the PV system which can cause voltage swings on the distribution system.

2.2.4.2 Loss of Plant

With a large DG plant located on a feeder there is a potential that this plant could suddenly trip off-line, for example, from misoperation of the interconnection protection equipment. The resulting sudden change in generation can cause voltage flicker on the distribution system.

2.2.5 Secondary Voltage

The research work conducted during the first phase of this project concluded that voltage issues occur most commonly on the secondary of the distribution system. Including the details of secondary system in modeling is not a common practice for distribution system analysis; therefore, detailed data is not readily available. Because of the frequency of voltage issues and its relatively unknown behavior, secondary system issues have been given their own issues category. Both steady-state voltage levels and flicker are voltage issues on the secondary.

2.2.5.1 Secondary Steady-State

Steady-state loading conditions change much more frequently on the secondary compared to the primary because secondary loads, most significantly heating, ventilating, and air conditioning (HVAC) units, behave as binary loading (on or off). Even though they are combined with other secondary loads, the magnitude of these loads will impact neighboring voltage conditions on the system. With the addition of DG, PV specifically, there is an added complexity to the voltage behavior that is dependent upon time-of-day and day-of-the-year conditions. Steady-state conditions on the secondary are also important because almost half of the voltage drop that occurs on the distribution delivery system occurs on the secondary of the system.

2.2.5.2 Secondary Flicker

Flicker on the secondary system can be of two main types. The first type is the cloud shadow event, as was described for the primary system, with the additional problem that the PV arrays do not have as much geographical diversity as is found in a large primary connected array. The second type of flicker is unique to the secondary system. For this type, the inverter's high voltage turn-off setting can be activated when there is a high voltage condition. For example, an inverter turns-on and ramps up to full power. At or near its full power output the voltage has risen enough to exceed the high voltage turn-off set point, so the inverter suddenly turns off causing a voltage flicker to neighboring customers. The process can be repeated until loading or solar irradiation conditions have changed enough to keep voltages within the high voltage turn-off set point limit.

2.3 Distribution Automation Equipment and Commercial Products for Voltage Control

To better facilitate the categorization of different types of technologies available for modern voltage control, the equipment list has been broken down into two general categories: software and hardware.

2.3.1 Commercial Software Products

Appendix A is a list of current commercial software products that provide advanced volt/VAR control.

2.3.2 Equipment for Voltage Control and Regulation

Appendix B is a list of distribution automation hardware equipment that can be used for voltage control and regulation. The list includes the latest technologies that are commercially available.

CHAPTER 3:
Modeling and Simulation Approach

3.1 Selection of Electric Distribution Feeders for Modeling

PG&E has nearly 3,000 medium voltage (primary) feeders on its system. Simulation of every feeder was beyond the scope of this project. By using k-means cluster analysis a representative sample of the 3,000 feeders was selected. This reduced the modeling to a manageable quantity of representative feeders. Clustering is done around key attributes from all of the feeder data. All feeder data used in this project is "scrubbed" of potential proprietary and/or private information.

For this study, most of the primary voltage issues would occur on a feeder with significant voltage drop. Feeders with high voltage drop can be described as "long and skinny" - they have a relatively long mainline length with relatively small conductors (high impedance). On these types of feeders, voltage regulation equipment is often incorporated to compensate for the high voltage drop.

Equipment cycling issues require that either capacitors and/or regulators be included on the feeder model and that, if capacitors are modeled, they need to be switched capacitors. Cluster analysis therefore included the number of regulators and capacitors in the variables to help identify types of feeders with potential equipment cycling issues.

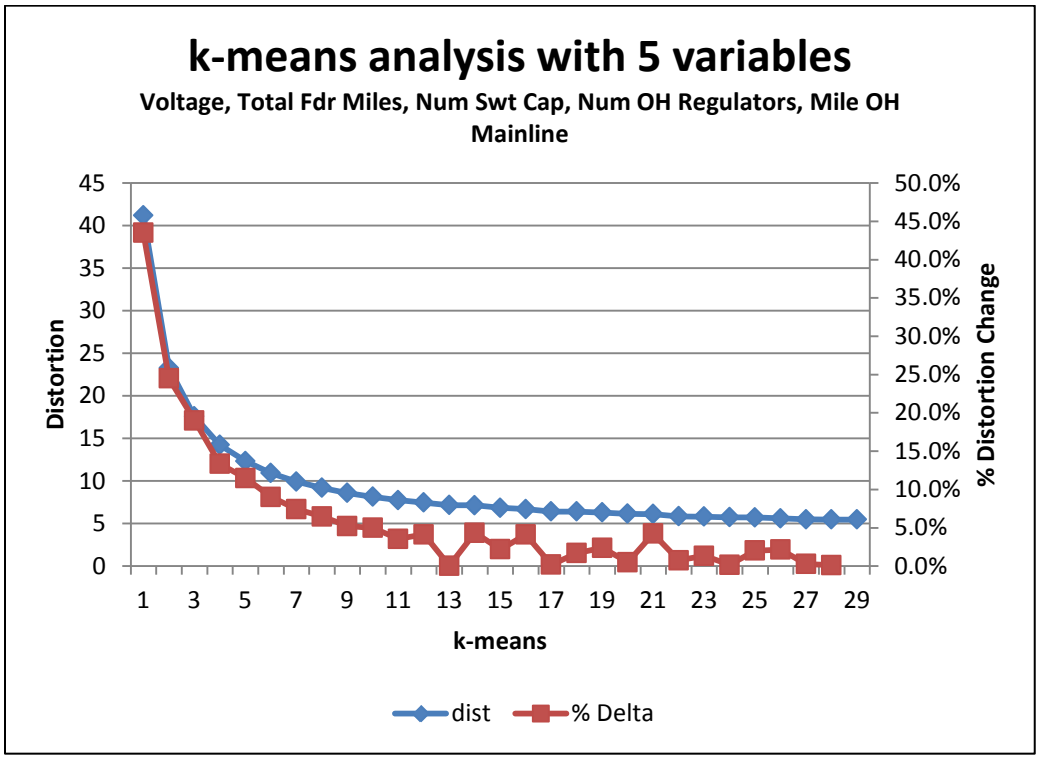
In summary, the following attributes are considered for clustering analysis:

1) Total miles of feeder
2) Miles of overhead feeder mainline
3) Number of regulators
4) Number of switched capacitors
5) Primary voltage

Figure 1 is a graph that shows the average distortion of the k-means analysis as the number of cluster centers is increased. Distortion represents the dissimilarity between a feeder and a cluster's center. A scree point in the graph exists near the 10 cluster center value. Beyond that point there is little improvement in average distortion therefore the 10 cluster centers, or 10 representative circuits, was selected.

Circuits which are located nearest the cluster centers (lowest distortion) were reviewed for their electrical characteristics and available data from the Supervisory Control and Data Acquisition (SCADA) system. If they appeared to be poor candidates for analysis (e.g., no SCADA data), the next nearest feeder to the cluster center was reviewed. The process was repeated until 10 circuits within the 10 clusters were selected.

Figure 1: Distortion and Percent Change in Distortion versus K-means Clusters



Source: Pacific Gas and Electric Company

3.1.1 Supplemental Feeder Selection

Two additional feeders were selected for comparative analysis with the selected cluster feeders. The first was a feeder with existing high penetration levels of distributed PV (greater than 15 percent). The second feeder represented the feeder with the longest circuit length of the 3000 feeders within the PG&E service territory; the analysis on this feeder will provide an extreme outlier of potential voltage issues.

3.1.2 Load Modeling

Traditionally, electric distribution system planning focuses on on-peak and off-peak loading conditions to determine whether voltage limits will be maintained. However, the issues outlined in Section 2.2 of this report may not occur during these periods. For example, PG&E's distribution feeders have a typical daily peak loading condition at approximately 6pm and an off-peak condition occurring during the early morning hours. PV, the DG to be modeled, doesn't operate during these times of the day. PV systems have peak output at noon which is a partial-peak condition with respect to loading.

This is also true from a seasonal perspective. Distribution feeders in California peak during the summer when temperatures are the highest. Off-peak conditions occur during the winter. For a PV plant, maximum plant output occurs during the fall and spring seasons when the temperature is cool (as opposed to the summer) and the sun is high above the horizon (as

opposed to the winter). The feeder loading conditions are also lower at this time, so the potential for voltage issues is greater.

Because of the disparity between system loading and PV output, partial-peak loading conditions were also modeled.

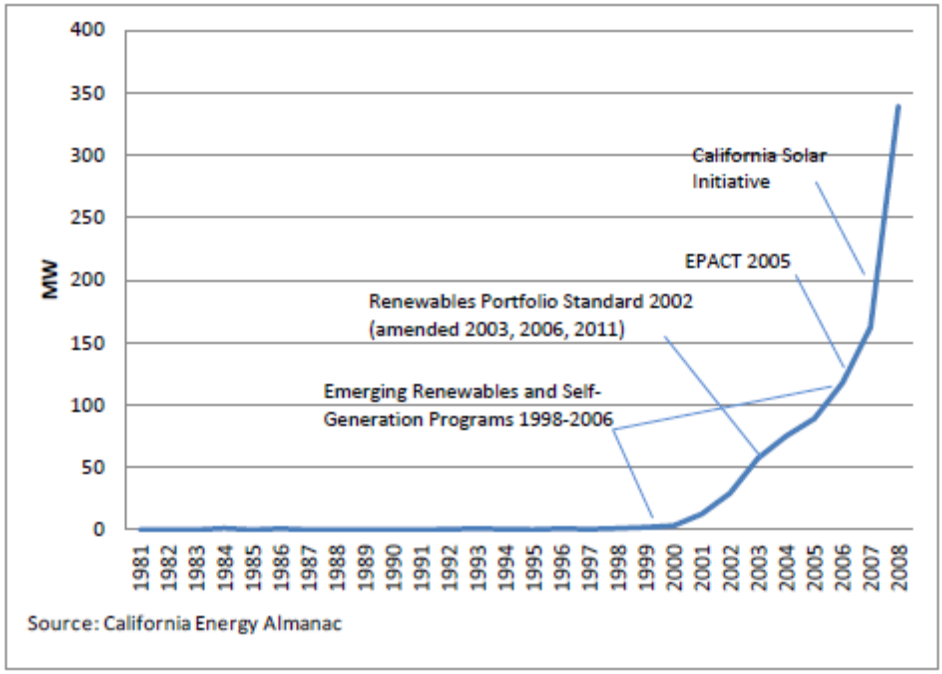
3.2 Distributed Generation Modeling

DG levels in California are driven by regulatory policy. Although a detailed analysis in this area is not part of this project, a simplified overview is necessary to assist in defining the types, sizes, and level of penetration of DG on typical California electric distribution systems.

3.2.1 Penetration Levels

Figure 2 shows the growth of installed solar capacity in California.[9] Correspondingly significant growth in DG follows incentive programs such as the California Solar Initiative (CSI) and the Renewable Portfolio Standard (RPS) as is shown in Figure 2. The types and sizes of systems that meet these programs' requirements are the type of systems that can be expected to cause increases in DG penetration levels in the future.

Figure 2: California's Annual Installed Solar Capacity, 1981-2008



9 Vogt, D. P., S.M. Schexnayder, T.N. Yoder,E.J. Lapsa, A.T. Brewer. 2012. *Assessment of Incentives and Employment Impacts of Solar Industry Deployment*. The Howard H. Baker Jr. Center for Public Policy. http://www.seia.org/sites/default/files/resources/Solar-incentives-and-benefits-_complete-report_May-1-2012.pdf.

Regulatory oversight of DG connected to California utility systems is primarily done by two commissions: the Federal Energy Regulatory Commission (FERC) and the California Public Utilities Commission (CPUC). FERC, in general, addresses connection of large DG systems (greater than 1.5 megawatts [MW]) at wholesale tariff rates. These types of DG are typically connected at transmission or sub-transmission voltage levels (Wholesale Transmission Access Tariff) with the exception of the Wholesale Distribution Access Tariff (WDAT), which is specifically for DG systems connected at distribution voltage levels. WDAT systems are connected directly to the utility system with the required FERC interconnection equipment and no customer load is involved. For transmission connected DG, the California Independent System Operator also has jurisdiction.

CPUC's tariffs cover smaller DG (up to 1.5MW). The primary type of CPUC DG system is net-energy metering (NEM). Standard NEM covers system 10 kilowatts (kW) or smaller while Extended NEM covers systems greater than 10 kW but less than 1MW. DG systems that fall under NEM are connected at the customer's main panel and not directly to the utility. NEM is limited to the following types of DG: PV, wind, biofuel and fuel cells.

There is some overlapping between CPUC and FERC type systems but, in general, for distribution voltage connected systems, large systems are FERC WDAT and small systems are CPUC NEM.

Penetration levels were incrementally increased on each modeled feeder with increments of 15%, 30%, and 50%. The percent penetration level is the ratio of total power output from DG to the feeder's annual peak power. After each increment, the model results were reviewed to determine if the voltage problems identified in Section 2.2 of this report could be found. Also, at each step, the model results were reviewed to determine if there were any normal capacity overloads. If capacity overloads existed this was noted and no further increases in penetration level were analyzed. The reverse situation was also true: if there were no voltage issues found for the critical loading conditions, additional simulations on the less critical conditions were not performed.

3.2.2 Generation Types

PV systems, as opposed to other types of DG, were used in both the single large system and secondary small system scenarios. This allowed evaluation of voltage flicker issues (cloud shadow events) and potential new solutions (smart inverter control) in both scenarios. Large systems followed a typical WDAT system and small systems followed a typical NEM system.

3.3 Steady-State / Time-series Modeling

Steady-state analysis cannot simulate multi-control loop interaction as is needed in issues demonstrating equipment cycling or primary and secondary PV cloud shadow flicker. These types of events can only be simulated using a time-series model, as described in Sandia National Laboratory's report referenced in Section 2.1.1.

It is important to note that the time-series requirement of this effort is not the same as time-series dynamic analysis as found in transmission stability studies. Typical transmission system

dynamic analysis, such as electromagnetic transient (EMTP) or machine response, addresses events that occur in the sub-cycle to 1 minute time range. Time-series events for this project looked at events in the 1 minute to 1 year time range.

Time-series feeder loading data from the PG&E SCADA historian was used for time-series simulations of primary feeders. PV time-series data available from SCADA historian for PG&E owned PV systems was scaled to match penetration modeling requirements.

3.4 Software Used for Modeling

There are two main software packages that were used for simulations on this project: CYMDIST®[10] and GridLAB-D.[11]

3.4.1 CYMDIST

CYMDIST is a product from Cooper Power Systems that is widely used in the electric power industry for electric distribution system analysis. It is part of Cooper Power Systems' CYME software products. CYMDIST is the standard software package that is used by all of California's IOU utilities in their distribution planning. Data is readily available in this format for models of the selected feeders.

3.4.2 GridLAB-D

GridLAB-D is an agent-based simulation environment for use with power systems[12]. Unlike traditional power system analysis software, such as CYME, GridLAB-D models components as individual agents. Thus, it permits the inclusion of multi-loop control mechanisms. Even climate can be considered an agent with Typical Meteorological Year (TMY) type climate files used directly as input to a PV model. Agent based analysis permits the computation of solutions to be divided into smaller parts via multi-threading. This feature can significantly improve software performance.

Because GridLAB-D is open-source, new models and classes can be developed by users. This was explored during the project, however, it was considered beyond the current project's scope.

While GridLAB-D can perform time-series analysis, it has the added feature of varying time-steps. Since each component is an agent, the global clock only looks for change events that drive a state-change in any of the agents. This permits the application of a varying time-scale which gives more detailed information during a transient event and improved efficiency over fixed time-step software.

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10 Cooper Industries, Ltd. 2011. *CYMDIST Basic Analyses Users Guide.*, Version 5.0.4 Cooper Industries, Ltd. http://www.cymetd.com/manuel/dist50/eng/CYME_5-02-Basic_Analyses_User_Guide_EN_V1-2.pdf.

11 Haas, Annie, Frances White. 2012. *GridLAB-D: A Unique Tool to Design the Smart Grid.* Pacific Northwest National Laboratory. PNNL-SA-92325. http://www.gridlabd.org/brochures/20121130_gridlabd_brochure.pdf.

12 Pacific Northwest National Laboratory. GridLAB-D power system simulation tool, 2014 update. http://sourceforge.net/apps/mediawiki/gridlab-d/index.php?title=Main_Page.

3.5 Advanced Technology Modeling

In addition to simulating the issues identified in Section 2.2, this project also simulated potential newer smart grid technologies for use with DG that may solve some of the voltage issues. Specifically, two technologies were addressed: (1) SVC and (2) the use of inverter systems as reactive power sources (smart inverters).

A parallel concern with the high penetrations of DG is high penetrations of electric vehicle (EV) charging systems. The general design philosophy is that DG could be used for EV charging and EV storage could be used to balance DG variability.

Because of the uncertainty of actual penetration levels, modeling of EVs at the primary voltage level is premature and was not considered for this project. However, if problems manifest themselves because of EV charging, this would probably occur closer to the EV devices, namely on the secondary system. To get a better understanding of actual interaction between DG and EVs, modeling of the typical secondary system included analysis with EVs. The EV as a storage device was not addressed in this project.

3.5.1 Static VAR Compensators (SVC)

SVCs have a full rated shunt connected reactive component (an inductor or capacitor) that is switched with a power electronic device. CYMDIST has a SVC model within the software package. According to the user's manual, the SVC model can be operated in either voltage control or fixed shunt. For voltage control, the SVC will attempt to control voltage at a specified node to a reference value by adjusting reactive power. Reference voltage, node specification and device reactive power limits are user inputs. Unfortunately, even after extensive work with Cooper's support group, the project team was unable to get the CYMDIST SVC model to work in voltage control mode as described, therefore only the fixed shunt method was used in simulations.

3.5.2 Smart Inverters

The CPUC is currently reviewing proposed changes to Rule 21 (see Section III and Figure IIIB for reference) based upon an Order Instituting Rulemaking R11-09-011.[13] Work on the technical operating standards is outlined in the assigned CPUC's scoping memo[14] and the CPUC has formed a Smart Grid Inverter Technical Working Group to explore needed inverter functions.

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13 California Public Utilities Commission. September 22, 2011. *Order Instituting Rulemaking on the Commission's Own Motion to improve distribution level interconnection rules and regulations for certain classes of electric generators and electrical storage resources*. R11-09-011. http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M066/K203/66203866.PDF.

14 California Public Utilities Commission. September 26, 2012. *Assigned Commissioner's Amended Scoping Memo and Rule Requesting Comments*. MF1 on R11-09-011. http://www.cpuc.ca.gov/NR/rdonlyres/67A2704B-EF85-43B8-8B40-78C21A273FFC/0/PhaseIII.pdf.

Candidate mandatory autonomous functions for new smart inverters include the following volt/VAR control features:[15]

- Provide volt/VAR control by dynamic reactive power injection through autonomous response to local voltage measurements
- Modify real power output autonomously in response to local voltage variations
- Provide reactive power by fixed power factor

Both CYME and GridLAB-D have the capability to set PV inverter power factor, but neither currently has the capability to model autonomous local control. GridLAB-D can utilize schedules to mimic automatic control; this approach was used in this project.

3.5.4 EVs

GridLAB-D includes an EV model in its residential module (both pure electric and hybrid), thus the combined DG/EV simulations were modeled in GridLAB-D. The GridLAB-D EV model is a deterministic, demand-state profile model[16] and can produce realistic daily load profiles for EV charging based upon typical usage scenarios. This ensured that representative time-series analysis was performed in conjunction with PV systems.

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15 Xanthus Consulting International. June 21, 2013. *Candidate DER Functions*. Presentation at Smart Grid Inverter Technical Group Meeting.

16 Haas, Annie, Frances White. 2012. *GridLAB-D: A Unique Tool to Design the Smart Grid.* Pacific Northwest National Laboratory. PNNL-SA-92325. http://www.gridlabd.org/brochures/20121130_gridlabd_brochure.pdf.

CHAPTER 4:
Simulation Results

4.1 CYMDIST Modeling

The selected feeders described in Section 3.1 are listed in Table 1 and were modeled in CYMDIST. Feeder D0001 was the supplemental feeder with existing high PV penetration and feeder TMP0009 was the outlier with the longest circuit length. The CYMDIST models were available directly from the PG&E distribution database. They were "scrubbed" of all proprietary data before transmitting to the subcontractor.

Table 1: Cluster Analysis Feeders Classified by Rural and Urban/Suburban Categories

							Number of Customers by Type					Number of Cases w/Flicker	
	Feeder Code	**Zone**	**Total Circuit Length (Miles)**	**Number of Voltage Regulators**	**Number of Switch**	**Primary (kilovolts)**	**Residential**	**Commercial**	**Agricultural**	**Industrial**	**Number of Cases w/High Voltage**	**2.5%**	**5%**
1	MC0001	Interior	202.2	6	8	12	1588	158	600	13	19	27	14
2	MC0006	Interior	145.8	5	7	12	1253	158	508	49	2	5	5
3	TMP0009	Interior	533.1	8	17	21	3399	376	369	44	15	27	27
4	HL0004	Interior	331.7	3	4	21	1153	486	159	107	1	7	6
5	OC0001	Coastal	105.9	5	5	12	1727	228	39	28	0	27	27
6	PL0001	Interior	20.11	0	4	12	860	24	18	1	0	7	3
7	MO0001	Interior	50.68	0	5	12	5454	281	12	77	2	3	1
8	AT0001	Interior	35.67	0	4	12	2243	55	8	13	10	6	0
9	AL0001	Interior	76.62	0	5	12	1661	144	5	15	9	11	11
10	BU0001	Coastal	6.87	0	2	4	1133	102	0	12	2	2	1
11	BR0015	Coastal	8.17	0	3	12	7	51	0	42	0	0	0
12	D0001	Interior	17.11	0	6	12	2894	270	0	91	0	1	0
		Rural Feeder				Urban/Suburban Feeder							

Source: Pacific Gas and Electric Company

4.1.1 CYMDIST Modeling Challenges

The CYMDIST software package has many capabilities that make it a useful tool for electric distribution system planning. It is also starting to include features that make it useful for smart grid applications. However, for this project CYMDIST had some limitations that required additional finessing of the models. The following subsections highlight some of the modeling challenges with CYMDIST.

4.1.1.1 PV System Modeling

CYMDIST includes a PV model within its package. This model permits relatively easy addition of PV base generators within a simulation. This model was used for all of the steady-state analysis.

Unfortunately, CYMDIST does not yet have a smart inverter model that permits changes to the output power factor of the inverter. To overcome this difficulty an SVC model was added in parallel to the inverter to act as the reactive source.

4.1.1.2 SVC Modeling

CYMDIST has an SVC model, however getting the SVC to properly regulate terminal voltage in simulations proved to be problematic. Automated voltage regulation with the SVC was not accomplished in this project. The reactive power for the SVC model had to be set manually for each simulation, which required more labor than originally anticipated to complete the SVC simulations.

4.1.2 CYMDIST Simulation Results

4.1.2.1 Steady-State Analysis

The feeder clusters can be divided into two broad types: short feeders that serve mostly urban/suburban areas with commercial and residential customers and long feeders that serve rural areas with a significant number of agricultural customers. Long feeders typically have several stages of voltage regulation and a significant number of switched capacitors. Short feeders typically have no additional voltage regulation equipment but still have a few switch capacitors. Table 1 shows an approximate breakdown of feeder types considered for simulation by rural versus urban/suburban feeder type. The k-means analysis produced feeder centroids which correlate the expected characteristics of total circuit length, number of agricultural customers, and the number of voltage regulators into the two main types of feeders; urban/suburban and rural.

Note that the divide between rural and urban/suburban feeders shown in Table 1 is not absolute. Several of the rural feeders serve a significant number of residential customers. These feeders typically originate in a substation in a suburban area and continue into a rural area outside of the suburban area. These feeders properly belong in a rural classification because locating DG at the end-of-circuit would place them in the rural area and their impact would be mainly on the rural-constructed part of the feeder.

A total of 146 steady-state simulations were run for this project. The third-to-last column of Table 1 shows the number of steady-state simulated cases that resulted in high voltage conditions. More than 60 percent of the cases for the rural circuits have high voltage conditions.

Table 2 shows the number of cases with high voltage conditions by season, penetration level, and DG location. PV penetration level is a percentage of the peak loading condition. In this table, L1 represents PV systems located near the substation, L2 represents PV systems located near the midpoint, and L3 represents PV system located at the end. The table shows that as the DG is moved toward the end of the feeder, there are more voltage problems, as expected. It also shows that the majority of problems occurred under partial-peak conditions, followed by off-peak conditions. Peak loading conditions produced the least amount of problems.

Table 2: Number of High Voltage Cases by Season, PV Penetration Level, and PV Location

126V Max

Season	PV%	L1	L2	L3
Peak	15	0	1	3
	30	0	0	4
	50	0	1	4
Off-Peak	15	0	1	4
	30	0	2	5
	50	2	3	6
Partial-peak	15	1	1	4
	30	1	2	6
	50	1	2	6

Legend:

Number of Cases

0	1	2	3	4	5	6	7	8

Source: Pacific Gas and Electric Company

Table 3 further collects common cases by PV penetration levels (a), PV location (b), and season (c). This table indicates that the high voltage cases are spread almost evenly among levels of penetration. PV penetration level is almost independent of whether a potential voltage issue will arise, and the majority of problem cases occur with penetration levels of 30 percent or less (25%+33.3%=58.3%). The location of PV at the end-of-line (L3) has 70 percent of all high voltage cases and the off-peak and partial-peak seasons have nearly 80 percent of all cases. This is consistent with what is shown in Table 2.

4.1.2.2 Flicker

Primary flicker limits are based upon the accumulated experience of the utility industry and what its customers have deemed tolerable. Within the PG&E service territory, the preferred flicker voltage limit is 2.5% for feeders with residential and commercial customers. On some rural and industrial circuits a limit of 5% can be permitted. The last two columns of Table 1 show the number of cases with high flicker for both 2.5% and 5% limits. For the 2.5% column,

all of the feeders, with one exception (BR00015), have some cases that exceed the flicker limit. It is also important to note that the number of cases with flicker problems is larger than the number of cases with steady-state high voltage. The majority of cases with flicker problems occur on the rural circuits (75% for 2.5% limit and 83% for 5% limit).

Table 3: Summation of High Voltage (HV) Cases by Penetration Level (% PV), Location, and Season

a) PV Penetration Level

% PV	15	30	50	Total
High Voltage Cases	15	20	25	60
% of High Voltage Cases	25.0%	33.3%	41.7%	100.0%

b) PV Location

PV Location	L1	L2	L3	Total
High Voltage Cases	5	13	42	60
% of High Voltage Cases	8.3%	21.7%	70.0%	100.0%

c) Season

Season	Peak	Off-Peak	Partial-Peak	Total
High Voltage Cases	13	23	24	60
% of High Voltage Cases	21.7%	38.3%	40.0%	100.0%

Source: Pacific Gas and Electric Company

Table 4 shows the number of cases that exceed the flicker limit broken down by season, PV penetration level, and location on the feeder. When compared with Table 2 steady-state high voltage cases, the high flicker cases manifest themselves at lower penetration levels, closer to the substation, and across more types of feeders than the steady-state cases. This indicates that the flicker case is potentially a more "severe" test case than the steady-state case. This appears to be true whether the 2.5% or 5% limit is used. The seasonal and location variation for flicker cases match up with those for steady-state high voltage, with off-peak and partial-peak appearing to be the worst conditions. Location at end-of-line can also be identified as the worst case condition.

Table 5 summarizes the 2.5% voltage flicker limit cases by PV penetration levels (a), PV location (b), and season (c). The number of cases spread somewhat evenly among the penetration levels. As was found in the steady-state analysis, but not as dramatically, there were more flicker problems as the location of the PV was moved toward the end. This is also consistent with Table 4. Partial-peak and off-peak problem cases represented over 70 percent of the cases.

4.1.2.3 Smart Inverters

Table 6 shows the steady-analysis for AL0001 feeder both with and without a smart inverter. For these simulations, the smart inverter was set to a -90% power factor (PF) (i.e., absorbing reactive power) to help reduce high voltage conditions. Red text indicates overvoltage conditions and orange-filled text indicates line sections became overloaded in the simulation.

As the table shows, terminal voltage was reduced. However, the reactive power cannot overcome the line section overloads, so voltage control via a smart inverter did not bring terminal voltage to within acceptable limits when an overload condition occurred first.

Table 4: Number of Flicker Cases Greater Than 2.5% and Greater Than 5% by Season, PV Penetration Level, and PV Location

2.5% Max

Season	PV%	L1	L2	L3
Peak	15	3	3	4
	30	3	4	4
	50	3	3	6
Off-Peak	15	3	5	7
	30	3	6	7
	50	4	6	8
Partial-peak	15	3	3	4
	30	3	5	8
	50	3	6	6

5% Max

Season	PV%	L1	L2	L3
Peak	15	2	2	4
	30	3	4	4
	50	3	3	5
Off-Peak	15	2	4	6
	30	2	4	6
	50	4	3	6
Partial-peak	15	2	2	4
	30	2	3	5
	50	2	3	5

Legend:

Number of Cases

0	1	2	3	4	5	6	7	8

Source: Pacific Gas and Electric Company

4.1.2.4 SVCs

Since high voltage is the issue with the addition of large PV, SVCs can be used to absorb reactive power and reduce voltage. Table 7 compares the result of steady-state simulations done without SVCs to those with SVCs added to reduce voltage within acceptable limits (two cases – feeders AT0001 and MC0006). The SVCs absorbing reactive power level was increased in each case until voltage levels were below 126V (on a 120V base). Values with red text indicate overvoltage conditions and orange-filled text indicates that line sections became overloaded in the simulation. In most cases, voltage levels are brought back to acceptable levels. However for the worst-case high voltage conditions, while the addition of the SVC reactive load brought voltage levels back into acceptable conditions, it also resulted in overloaded line sections in the model. The additional reactive power can cause overload problems on the distribution feeders.

Table 5: Summation of 2.5% High Flicker (HF) Cases by Penetration Level (% PV), Location, and Season

a) PV Penetration Level

% PV	15	30	50	Total
High Flicker Cases	35	43	45	123
% of High Flicker Cases	28.5%	35.0%	36.6%	100.0%

b) PV Location

PV Location	L1	L2	L3	Total
High Flicker Cases	28	41	54	123
% of High Flicker Cases	22.8%	33.3%	43.9%	100.0%

c) Season

Season	Peak	Off-Peak	Partial -Peak	Total
High Flicker Cases	33	49	41	123
% of High Flicker Cases	26.8%	39.8%	33.3%	100.0%

Source: Pacific Gas and Electric Company

Table 6: Maximum Voltage from Simulations for Feeder AL0001 Both With and Without Smart Inverter

Feeder AL0001		Base Cases			Smart Inverter (-90% PF)		
Loading (no/PV Max Volt) (no PV Min Volt)	**PV Penetration**	**Maximum Voltage**			**Maximum Voltage**		
		PV Location			**PV Location**		
		L1	**L2**	**L3**	**L1**	**L2**	**L3**
Peak	15			127.06			123.87
126.00	30			135.37			128.95
124.12	50		123.60	144.92			
Off-peak	15			127.07			123.92
126.00	30			135.22			128.72
125.22	50		122.70	144.59			
Partial Peak	15			129.64			126.53
126.00	30			137.66			131.34
125.09	50		124.34	146.98			

Legend:

Overvoltage: XXX

Overloaded Line Section:

Source: Pacific Gas and Electric Company

Table 7: Simulations Results for Cases Without and With SVCs

Feeder AT0001		Base Cases			SVC		
Loading (no/PV Max Volt) (no PV Min Volt)	**PV Penetration**	**Maximum Voltage**			**Maximum Voltage**		
		PV Location			**PV Location**		
		L1	**L2**	**L3**	**L1**	**L2**	**L3**
Peak	15			126.0			
126.0	30		126.0	126.8			126.0
124.1	50	126.0	126.0	128.3			**126.0**
Off-peak	15			126.8			124.6
126.0	30	126.0	126.0	127.9			124.5
125.2	50	126.1	126.0	129.3	124.1	125.3	**123.8**
Partial Peak	15			126.7			124.5
126.0	30		126.0	127.8			124.0
125.1	50	126.0	126.0	129.2			**123.7**

Feeder MC0006		Base Cases			SVC		
Loading (no/PV Max Volt) (no PV Min Volt)	**PV Penetration**	**Maximum Voltage**			**Maximum Voltage**		
		PV Location			**PV Location**		
		L1	**L2**	**L3**	**L1**	**L2**	**L3**
Peak	15						
126.0	30						
115.0	50						
Off-peak	15			126.0			
126.0	30		126.0	127.2			126.0
118.7	50		126.0				**126.0**
Partial Peak	15						
126.0	30						
117.5	50						

Legend:
Overvoltage: XXX
Overloaded Line Section:

Source: Pacific Gas and Electric Company

4.2 GridLAB-D Modeling

4.2.1 Modeling Challenges

GridLAB-D software represented a new set of challenges for modeling and simulation. The existing CYMDIST data could not be directly translated into GridLAB-D. This section discusses the methods and techniques used to get CYMDIST data running in GridLAB-D and the manner in which the complexities of time-series analysis were addressed.

4.2.1.1 Primary System Modeling

All of the primary system GridLAB-D models needed to match the base CYMDIST models. Additional features, such as a VVO controller, could be added after the base GridLAB-D models were validated.

Data Conversion

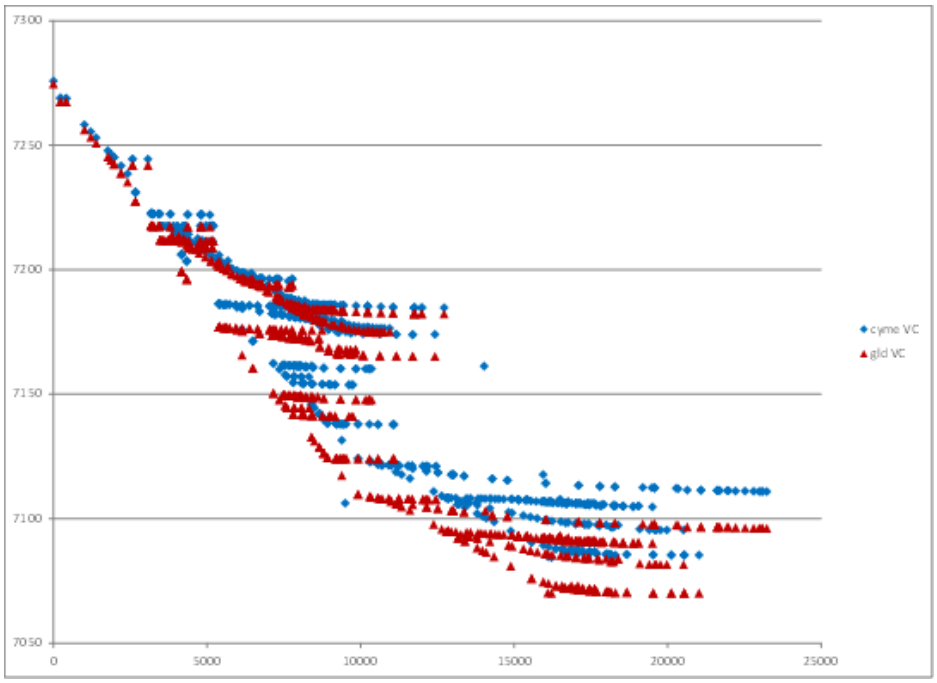
In GridLAB-D, all the distribution network models are considered unbalanced. CYMDIST models used by PG&E are only balanced models with the phasing of single-phase sections and loads not assigned properly for unbalanced analysis. For each feeder considered, an unbalanced CYME study was first created. The load balancing feature in CYMDIST was then used to create an unbalanced self-contained study file in an Extensible Markup Language (XML) format. This feature is an automated process which allocates all single-phase section data, loads, and equipment to an optimum balanced phase connection. Although this is not representative of the actual field conditions, the phase balancing process gives an unbalanced model that is as least as accurate as the original balanced model. The XML file thus created is then processed by Python scripting software that parses the XML files and converts them to a set of generalized linear model (GLM) files that included:

1) Main GLM file: This included network connectivity having nodes, conductors, overhead lines and cables, line spacing, and line configurations.
2) Loads GLM file: This included details of the loads and their daily profiles.
3) Equipment GLM file: This included configurations and listing of capacitors and regulators.
4) PV GLM file: This included transformers (TXs), triplex nodes, meters, inverters, and solar panels.

The converted files were benchmarked to their original CYME models using the power flow function in the CYMDIST software. Figure 3 shows a typical comparison between the CYME analysis and GridLAB-D for the voltage at all of the nodes within the model. The horizontal axis represents distance of the nodes from the source. In all cases, the difference between the two methods was less than one percent.

The data translation required that model connectivity be maintained and after examining the raw CYME data, it was discovered that not all of the feeder sections were properly connected. When these models were used in the CYME software, the CYME software ignored any disconnected sections and had no problem running the analysis. The GridLAB-D software does not have this capability. Therefore, within the translation process, connectivity had to be addressed. Fortunately, Python has several Graph Tree libraries which can directly follow connectivity. These libraries were successfully used during the translation process to ensure connectivity was maintained.

Figure 3: Typical CYME to GridLAB-D



Benchmarking Analysis Showing Node Voltage for Each Analysis in Reference to Distance from Source
Source: Pacific Gas and Electric Company

PV System Modeling

In GridLAB-D, a PV system is modeled as a combination of an inverter and a PV module array connected at secondary voltage. A typical implementation is shown in Figure 4. For a model of PV installation in the primary system, a transformer must be added to the inverter and PV module array. Array modules were assumed to be monocrystal with an efficiency of 20 percent. The inverter and transformer were sized to match the desired output rating of the array.

In GridLAB-D, the PV system output was driven by a climate model. The climate model used a Typical Meteorological Year data file (TMY2). TMY2 files for cities near the feeder model's geographical location were obtained from the National Renewable Energy Laboratory's (NREL's) website.[17] These files showed solar irradiation and temperature variability for the typical geographical location. Using these models permitted the DG to match both daily and seasonally variability. To model voltage flicker from cloud shading events, data from the TMY2 files was imported in a text format to enable modification of the irradiance levels.

17 National Renewable Energy Laboratory. 2012. "National Solar Radiation Data Base." http://rredc.nrel.gov/solar/old_data/nsrdb/.

Load Profile Modeling

A schedule approach was used to vary the load for the time-series analysis. Field data taken from PG&E's SCADA historian was used to determine load shapes for each phase of the unbalanced system. Schedule files were developed to shape peak load to match the feeder's time-variant nature. Figure 5 shows the typical data output from the historian. This data was then normalized to the peak loading to give a time-variant scalar that can be applied to the loads within the model. All loads were scaled proportionally.

Figure 4: PV System and Climate Modeling in GridLAB-D

```
//*********************************************
// Climate
//*********************************************

object climate {
    tmyfile "CA-San_francisco.tmy2";
}
```

```
object transformer {
        name Xfrm_1200166241_C;
        phases CS;
        from N_1200166241;
        to N_1200166241_sec_C;
        configuration Xfrm_config_PV_1200166241;
}
```

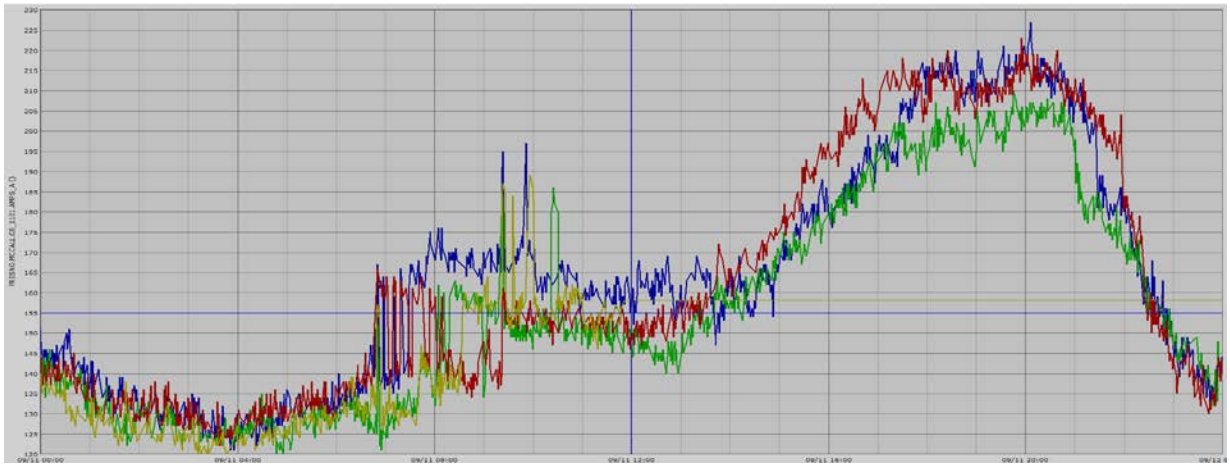
```
object triplex_meter {
        name N_1200166241_sec_C;
        phases CS;
        nominal_voltage 120;
}
```

```
object inverter {
        name inverter_N_1200166241_C;
        parent N_1200166241_sec_C;
        phases CS;
        generator_mode CONSTANT_PF;
        generator_status ONLINE;
        inverter_type PWM;
        power_factor 1.000000;
        rated_power 100000.0;
        inverter_efficiency 0.9;
}
```

```
object solar {
        name solar_N_1200166241_A;
        parent inverter_N_1200166241_A;
        generator_mode SUPPLY_DRIVEN;
        generator_status ONLINE;
        panel_type SINGLE_CRYSTAL_SILICON;
        efficiency 0.2;
        area 200000;
}
```

Source: Pacific Gas and Electric Company

Figure 5: Typical SCADA Historian Feeder Data



Source: Pacific Gas and Electric Company

Capacitor and Regulator Equipment Modeling

GridLAB-D provided both capacitor and regulator models. Their typical implementation is shown in Figure 6. Capacitors were modeled such that they were controlled on or off with voltage control, performed bank operation, and provided a fixed amount of kiloVAR. High voltage and low voltage set points were set as 1.05 and 0.95 per unit of the nominal terminal voltage, respectively.

Modeling of the regulators required introducing an additional node that placed the regulator on the given CYME section in series with an overhead line or underground cable on that section. Regulators were modeled such that they operate on voltage control and perform bank operation. The regulators were assumed to have 16 "raise" or "lower" taps each.

Figure 6: Capacitor and Regulator Models in GridLAB-D

```
object capacitor {
        name N_1200018570_Cap;
        phases ABC;
        pt_phase ABC;
        parent N_1200018570;
        phases_connected ABC;
        control VOLT;
        voltage_set_high 7637.000000;
        voltage_set_low 6910.000000;
        capacitor_A 300000.0;
        capacitor_B 300000.0;
        capacitor_C 300000.0;
        control_level BANK; //INDIVIDUAL;
        time_delay 100.0;
        dwell_time 0.0;
        switchA OPEN;
        switchB OPEN;
        switchC OPEN;
        nominal_voltage 7274.613;
}
```

```
object regulator_configuration {
        name Config_Reg;
        connect_type 1;
        band_center 7274.613;
        band_width 60;
        time_delay 30.0;
        raise_taps 16;
        lower_taps 16;
        current_transducer_ratio 700;
        power_transducer_ratio 20;
        CT_phase A;
        PT_phase A;
        regulation 0.10;
        Control OUTPUT_VOLTAGE;
        control_level BANK; //INDIVIDUAL;
        Type A;
        tap_pos_A 0;
        tap_pos_B 0;
        tap_pos_C 0;
}

object regulator {
        name Reg_78S_254121106;
        phases ABC;
        to N_1200071841;
        from N_1200071841_1;
        configuration Config_Reg;
}
```

Source: Pacific Gas and Electric Company

4.2.1.2 Secondary System Modeling

Unlike primary data, PG&E does not maintain modeling data for its secondary. To develop representative secondary models, an analysis was conducted of actual field equipment maps of the residential areas for the supplementary feeder with existing high PV penetration (D0001).

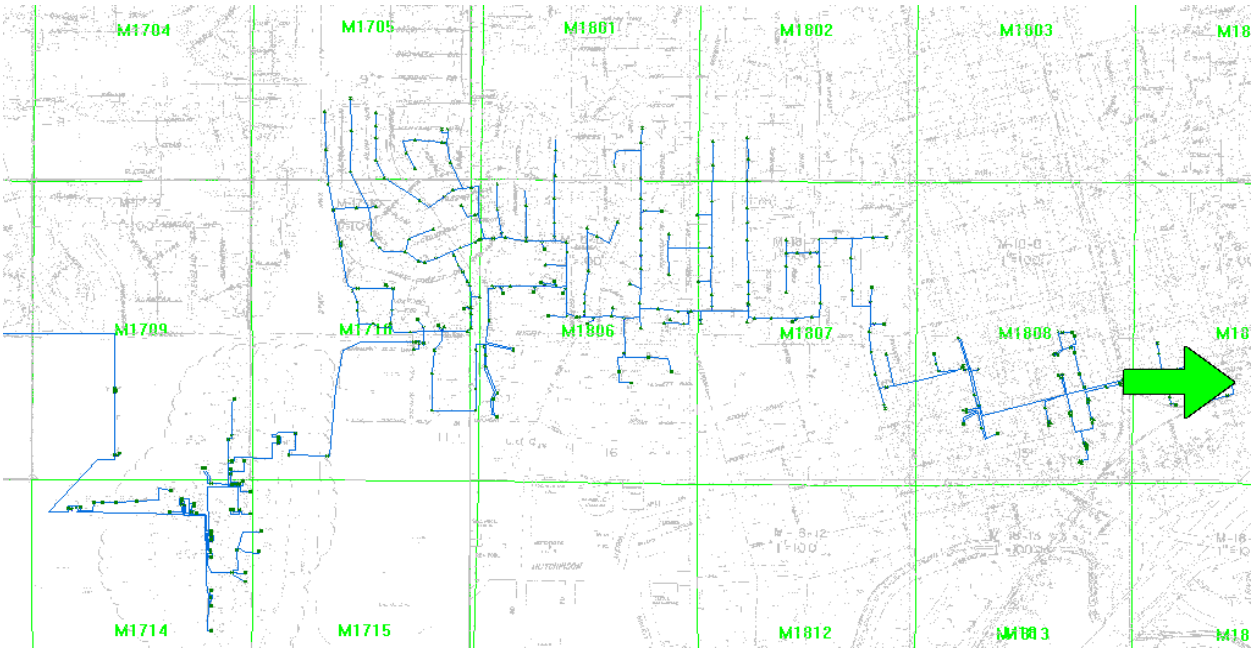
Determination of Typical Secondary System Model

PG&E's existing geographic information system (GIS) system maps were used to identify regions which contained residential subdivisions that have significant amounts of PV systems. Within each map, the average transformer size and number of residential houses per transformer was determined along with a description of the type of neighborhood (age, other non-residential loads). Figure 7 shows a typical primary map for the area used in the analysis with the primary feeder shown in blue and the substation indicated by a green arrow.

Table 8 is a summary of the results of the secondary system sizing analysis. The average transformer size is approximately 100 kVA for a typical residential system. For a transformer of this size, there are typically about 10 residences connected, which is slightly lower than the average number of customers per transformer from the analysis. Based upon this analysis, the secondary representative system was a 100 kVA transformer with 10 customers.

Because voltage drop was the primary issue to be evaluated on the secondary system, two categories of secondary layouts were used. The first layout (shown in Figure 8, left) has the transformer centrally located among a cluster of residences which will result in the lowest average voltage drop on the secondary system. The second layout (shown in Figure 8, right) has the transformer located toward the end of the layout which will have the longest secondary runs and thus the largest voltage drop. Secondary cable lengths were based upon typical lot-line footage for the subdivisions evaluated on the GIS maps. Secondary cable sizes were determined using PG&E's secondary conductor sizing standard.

Figure 7: Typical Primary Map Used for Determining Typical Secondary System



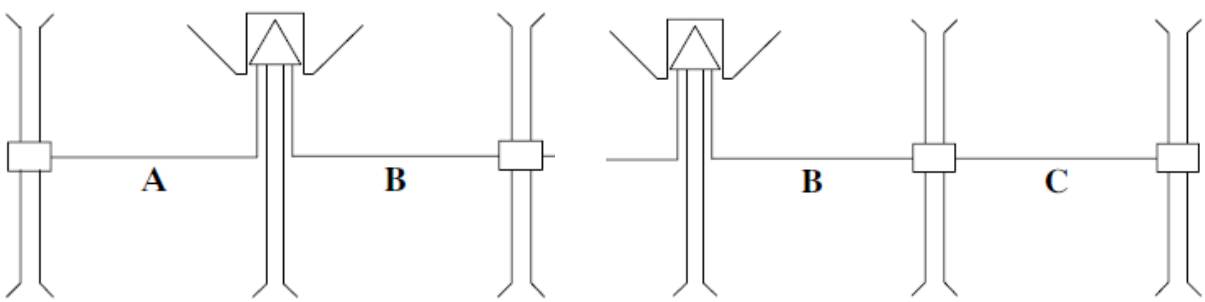
Source: Pacific Gas and Electric Company

Table 8: Results GIS Map Analysis

Geographical regions	Tx kVA (avg)	Num. of houses per tx (avg)	Neighborhood type
Region 1	35.38	9.88	Feeder substation and downtown
Region 2	215.48	11.90	Downtown, older residential areas
Region 3	46.08	7.65	Older residential areas
Region 4	37.60	8.60	Older residential areas, high school
Region 5	92.94	11.57	Newer residential areas, four transformers 150kVA each, shopping mall with several 167kVA transformers and two 750kVA transformers, residential rooftop PV
Region 6	75.07	21.21	Newer residential areas, residential rooftop PV, shopping mall with 225kVA transformer
Region 7	42.29	6.57	Newer residential areas, residential rooftop PV
Region 8	34.50	9.75	Newer residential areas, residential rooftop PV
Region 9	193.75	27.00	residential areas, apartments communities
Region 10	161.14	25.95	residential areas, apartments communities, large parking rooftop PV
Average	**93.42**	**14.01**	

Source: Pacific Gas and Electric Company

Figure 8: Transformer Location for the Two Categories of Secondary Layout



Source: Pacific Gas and Electric Company

Modeling of Residential Dwellings

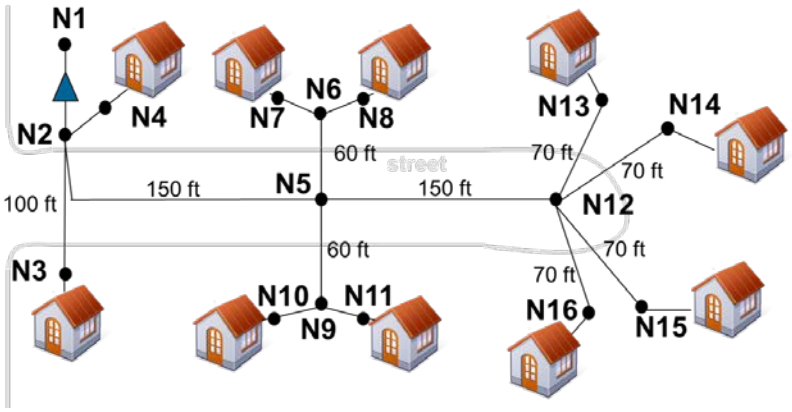
Using the capabilities of GridLAB-D, a detailed model of each residence was developed. The following is a summary of the residential model:

- The average square footage of the residences modeled was 2,000 square feet with a thermal integrity level rating of "good" (the second highest for a modern home).
- Each residence was modeled with an HVAC unit, dishwasher, electric dryer, clothes washer, and refrigerator.
- Plug and lighting load was modeled using a polynomial voltage sensitive model commonly called a ZIP model (ZIP is a reference to the polynomial coefficients: Z is constant impedance, I is constant current, and P is constant power). A seasonal and day-of-the-week load schedule was also applied to this model.

Detail Secondary System Model Development

Figure 9 shows a residential secondary network that was supplied by a transformer between nodes N1 and N2. Node N1 is a terminal node of the distribution primary network while N2 is a triplex node connected from phase A of N1 through the transformer. Triplex cables run from N2 to various houses as shown in the figure.

Figure 9: Representative Residential Distribution Network Secondary

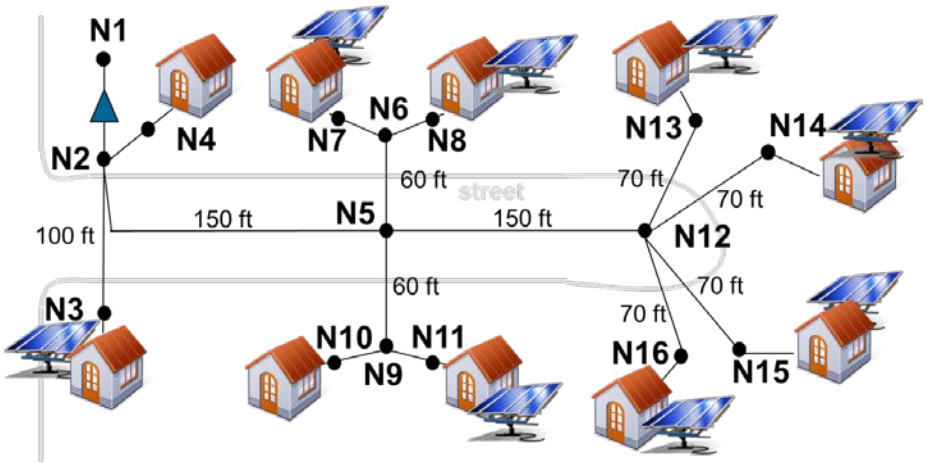


Source: Pacific Gas and Electric Company

The house appliances are modeled using typical daily and seasonal profiles. The same type of appliance in each house uses the same profile except that it is randomly time skewed to model variations between the end-uses of each house.

Figure 10 shows this residential network with distributed PV. An inverter and solar panels are modeled along with the houses and end-use loads within each house. Each solar panel was assumed to have an area of 400 square feet, which represents a 5.5 kW-peak system.

Figure 10: Secondary Network with Distributed PV Generation



Source: Pacific Gas and Electric Company

Three loading levels are considered in the simulations below: on peak loading, partial-peak loading, and off-peak loading. The loading level was simulated by scaling the lighting load profile in each house as well as setting the HVAC set point to higher values. For off-peak cases, the temperature set-point was 70 degrees Fahrenheit.

Time domain simulations are carried out for two consecutive summer weekdays (48 hours).

Climate Modeling

The PV model development followed an approach similar to the primary model. The climate models used in the secondary simulations were similar to those used for the primary analysis. In addition to determining the PV system output, the climate model also determined when the HVAC systems would operate.

Secondary Smart Inverter Modeling

To demonstrate smart inverter capabilities that could control reactive power as well as real power, an inverter power factor schedule was developed that varied the PF of the inverter over a daily time period. The schedules were kept as a separate file so that they could be easily modified.

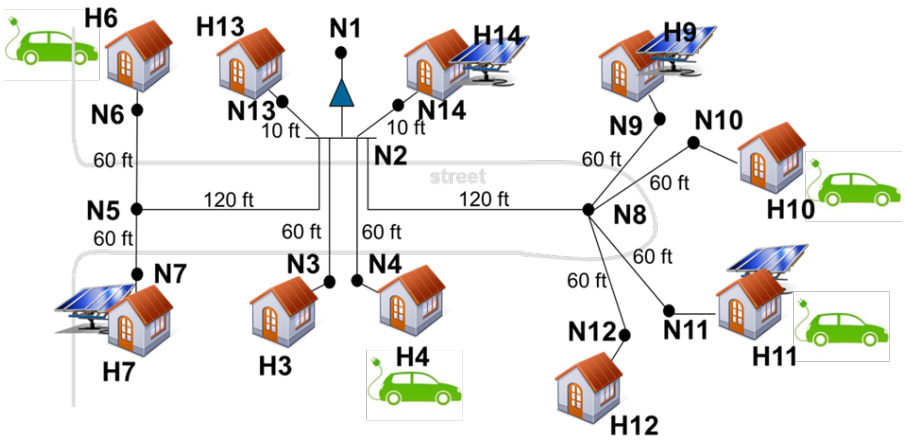
Secondary Flicker Analysis

Flicker due to cloud shadow events for the secondary system was modeled following the same approach that was used with the primary analysis. In addition, voltage flicker caused by inverter shut-off was modeled by adding "overvoltage trip/restart followed by lockout" logic within the section line model that fed the inverter into the secondary model. The inverter model itself could not perform the logic.

EV Charger Modeling

GridLAB-D provided two types of models to model EV: deterministic and stochastic. The deterministic model was used for this analysis. Figure 11 shows the secondary system model used with EV chargers connected to the indicated houses. PV generation was connected to the houses as shown in the figure.

Figure 11: Distribution Secondary with PV and EV



Source: Pacific Gas and Electric Company

To simulate the behavior of the secondary system network in the presence of EV, a daily profile was set randomly for each EV that included time for arrival at work, duration at work, arrival at home, duration at home, etc. as shown in Figure 12. Random variations in the parameter values were introduced for other EV chargers in the network.

4.2.2 Simulation Results

Time-series GridLAB-D simulations were performed using both primary system models and secondary system models. The primary simulations demonstrated equipment cycling issues and cloud-shadow events. Smart inverters and the application of volt/VAR optimization (VVO) were also demonstrated with the primary system model. The secondary simulations demonstrated both steady-state and voltage flicker issues in addition to demonstrating both smart inverter and EV charging technologies. The following sections summarize the result of these simulations

4.2.2.1 Primary System Modeling

GridLAB-D modeling of the primary system examined two issues: equipment cycling and cloud shadow events. Smart inverter and volt/VAR optimization control technologies were also simulated.

Figure 12: Typical Implementation and Parameters for Modeling EV Charger

```
object evcharger_det {
        name ev4;
        parent house_N4;
        charge_rate 4800;
        variation_mean 0;
        variation_std_dev 3600;
        variation_trip_mean 56.25;
        variation_trip_std_dev 6.25;
        mileage_classification 75;
        vehicle_index 2;
        vehicle_location 2;
        arrival_at_work 0730;
        duration_at_work 28800;
        arrival_at_home 1730;
        duration_at_home 57600;
        battery_capacity 25;
        battery_SOC 20;
        battery_size 25;
        maximum_charge_rate 7200;
        mileage_efficiency 3;
        charging_efficiency 0.78;
        groupid house_type_1;
}
```

Source: Pacific Gas and Electric Company

Equipment Cycling Issues

The variable nature of DG can impact the number of operations a voltage regulator or a switched capacitor can experience. A 24-hour, time-series analysis was performed to determine the change in number of operations this equipment could experience under various DG scenarios. Figure 13 shows the typical effect that was observed for most of the scenarios.

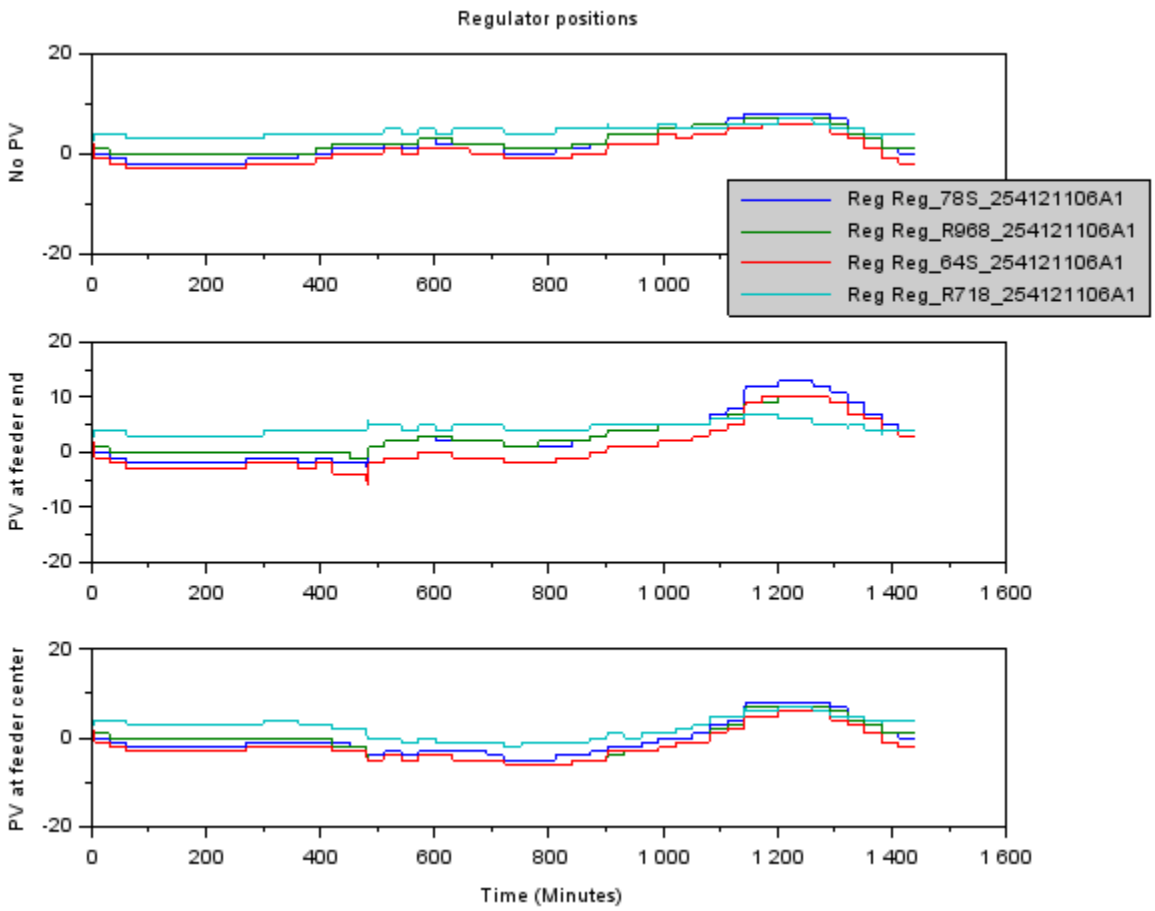
Fixed tilt PV systems have maximum output occurring at noon on a typical day. Feeders on the other hand, especially residential feeders, typically peak during the early evening hours. Voltage regulators typically buck during the light loading period at noon and boost during the peak period of early evening. PV adds to the load reduction during the noon period, but does not help during the peak period, therefore the swing between maximum bucking during noon to maximum boosting during the early evening period is exacerbated by the PV systems. This resulted in an increase in the number of operations of the regulating equipment.

The 24-hour, time-series analysis used TMY climate data to determine PV output. This data includes changes in solar irradiation values caused by typical cloud cover, so the analysis captured potential cycling caused by changes in PV output during the day. It did not include extreme cloud shadow events that could cause rapid change in voltage conditions because the TMY data does not have high enough resolution.

Table 9 shows the change (increase or decrease) in the number of operations per feeder for various loading conditions and various locations of the PV system on the feeder. Feeder TMP0009 was not simulated, as this was an outlier from the 10 cluster feeders by having excessive length and number of stages of regulation. In general, the table shows that the number of operations increased for almost all cases. Voltage regulators showed a greater increase in operations than capacitors, which makes sense as voltage regulators provide more incremental control of voltage than a capacitor. Capacitors that have switched as the result of a high or low voltage condition will remain in their current state (on or off) until their primary

control (either time or temperature) requires a change in state; therefore, they will not switch as often as regulators.

Figure 13: Time-Series Plot of Regulator Tap Position for Partial-Peak Loading Conditions on Feeder MC0006



Top – No PV; Middle – PV at End-of-Line; Bottom – PV at Center of Feeder

Source: Pacific Gas and Electric Company

Table 10 shows a summary of the increase in number of operations from capacitors and regulators. It indicates that the increase in number of operations for capacitors is relatively independent of location of PV on the feeder and loading conditions. The table shows voltage regulators had an increase in operations as the PV location was moved toward the end and that partial-peak and off-peak conditions had a greater increase in operations.

Cloud Shadow Flicker

Using time-series analysis permitted cloud shadow events to be simulated. This was accomplished by changing solar irradiation levels within the climate model. Variations of irradiation were created using a random number generator. Flicker levels were measured at switched shunt capacitor terminals to not only determine flicker magnitude but also to

determine if such variation would cause capacitor controls to switch capacitors on or off. Figure 14 shows the daily voltage for both a clear day and a cloudy day at a capacitor terminal. The result was a 14 percent drop in voltage.

The flicker events that were modeled occurred faster than that required for capacitor or regulator controls to respond by switching in/out or advancing/reducing the tap position.

Table 9: Change in the Number of Operations for Capacitors and Regulators on Study Feeders by PV Location (L2 – center of feeder; L3 – end-of-line) and Loading Condition (peak; partial-peak; off-peak)

Feeder Code	Number of Voltage Regulators	Number of Switch Capacitors	Increase(+)/Decrease(-) in Number of Operations of Equipment											
			Capacitor						Regulator					
			Peak		Partial-Peak		Off-Peak		Peak		Partial-Peak		Off-Peak	
			L2	L3	L2	L3	L2	L3	L2	L3	L2	L3	L2	L3
MC0001	6	8	0	2	-1	5	0	0	0	26	-1	32	0	26
MC0006	5	7	2	0	2	0	1	0	-3	13	19	26	24	28
TMP0009	8	17												
HL0004	3	4	0	0	-1	-1	0	0	0	0	0	0	0	0
OC0001	5	5	0	0	0	0	2	2	38	20	28	18	29	21
PL0001	0	4	0	0	0	0	0	0						
MO0001	0	5	0	0	0	0	0	0						
AT0001	0	4	0	0	0	0	0	0						
AL0001	0	5	0	0	0	0	1	0						
BU0001	0	2	2	2	0	0	0	0						
BR0015	0	3	0	0	2	2	0	0						
D0001	0	6	2	0	2	0	0	0						
Total			6	4	4	6	4	2	35	59	46	76	53	75

Source: Pacific Gas and Electric Company

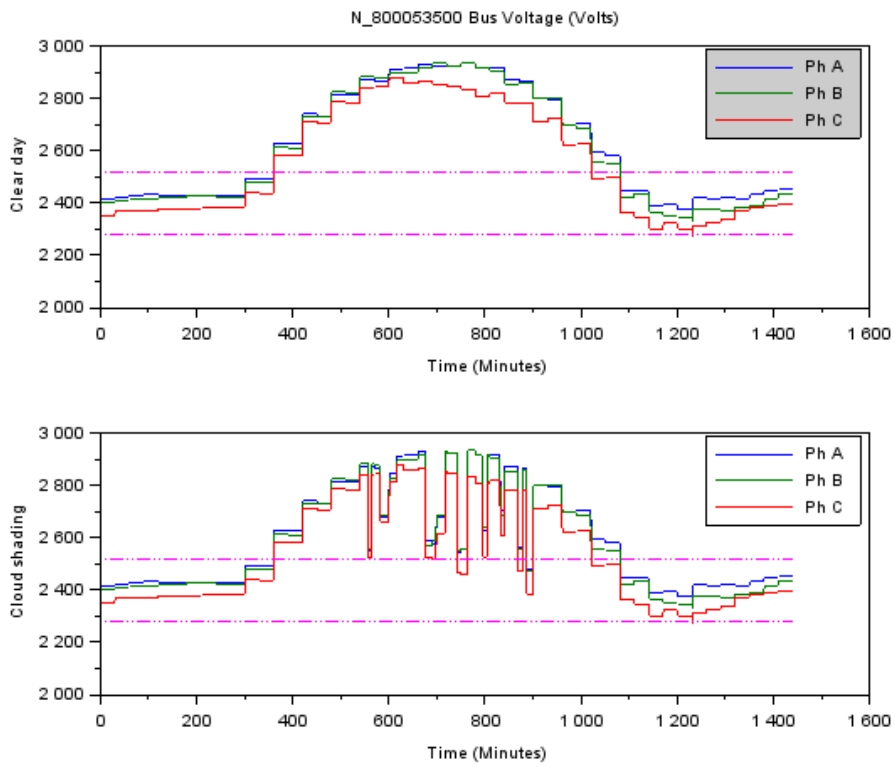
Table 10: Summary of Change in the Number of Operations for Capacitors and Regulators

Increase in Operations			
Capacitor		Regulator	
L2	L3	L2	L3
14	12	134	210

Increase in Operations					
Capacitor			Regulator		
Peak	Partial-Peak	Off-Peak	Peak	Partial-Peak	Off-Peak
10	10	6	94	122	128

Source: Pacific Gas and Electric Company

Figure 14: Voltage Profiles with Capacitors on Local Terminal Voltage Control, Partial-Peak Loading and PV Generation at Feeder End



At Clear Day (top) Versus with Cloud Shading (bottom)

Source: Pacific Gas and Electric Company

Smart Inverters

Figure 15 shows the results of the time series analysis on Feeder AL0001 with a smart inverter controlled to a PF schedule as shown. The proposed schedule reduced voltage during peak PV output conditions, but did not reduce it enough to bring it back to within acceptable voltage limits.

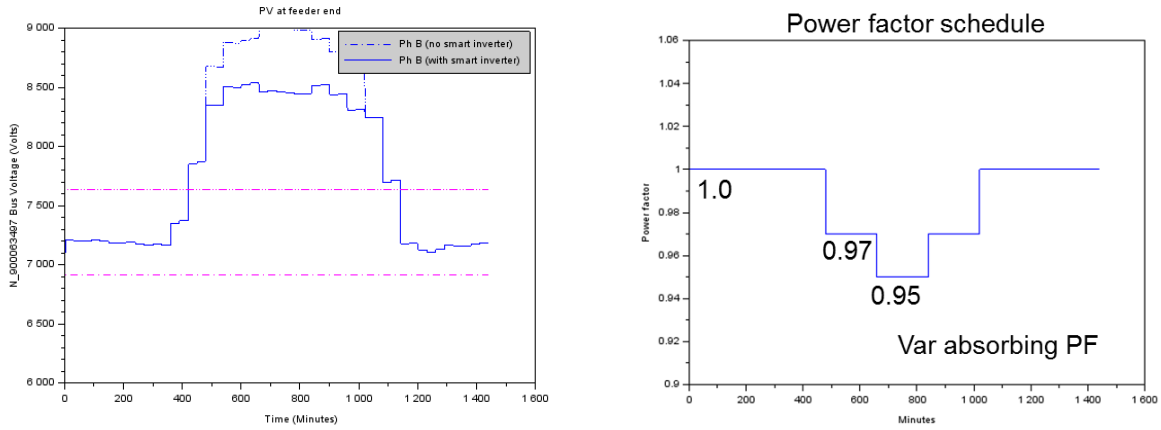
VVO Controller

GridLAB-D has the capability of modeling a VVO controller within the simulation, and although it is not very sophisticated, it provided insight into how a VVO control would behave with DG systems operating. Figure 16 shows the daily voltage profile at a capacitor terminal both with and without VVO operating. The figure shows that voltage is reduced with VVO operating but not within band limits. It also shows that the GridLAB-D VVO control did not maintain voltage during non-PV generating periods.

4.2.2.2 Secondary System Modeling

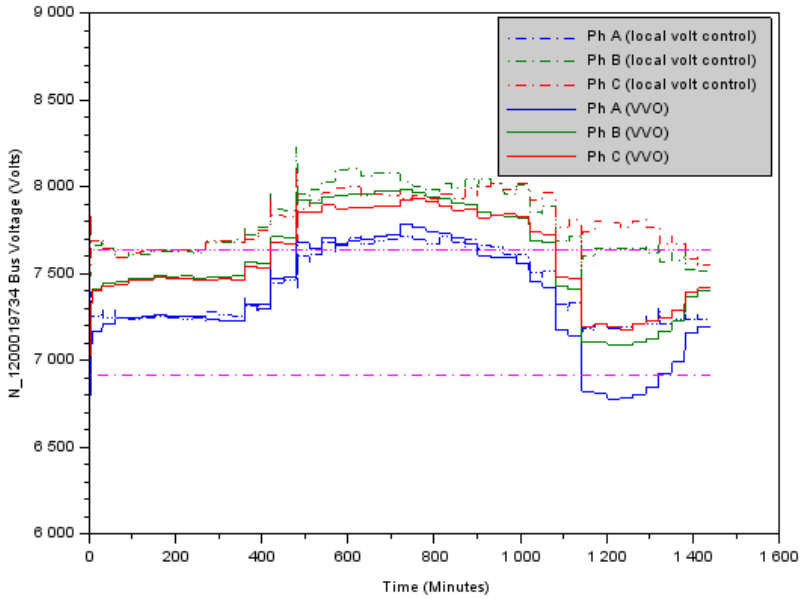
Secondary system modeling included simulations for steady-state conditions and voltage flicker. Simulations were also performed for smart inverters and EV chargers.

Figure 15: Voltage Profile of AT0001 at PV Bus Both With and Without Smart Inverter Power Factor Schedule



Source: Pacific Gas and Electric Company

Figure 16: Voltage Profile at Capacitor Bank with PV With and Without VVO



Source: Pacific Gas and Electric Company

Steady State Conditions

The secondary steady-state simulations were 48-hour, time-series analyses under normal seasonal loading conditions.

(A) Peak Loading

Figure 17 shows the voltage profiles that resulted from time-series simulations for buses N15 and N5 (see Figure 9 for reference to bus locations). Figure 17 (left) shows the voltage plots with and without distributed PV generation. The flicker in the trajectories was caused by the behavior of the end-use appliances in each house, primarily HVAC units. With PV generation, some voltage rise is observed, however it is still within the permissible voltage levels. Figure 17 (right) shows the effect of having larger PV generation equivalent to solar panels having a 600-square foot area at each house. It is observed that larger distributed PV generation resulted in higher voltages when the PVs are peaking (around noon).

Figure 18 shows the inner and outer temperatures of a house at node N15. It is observed that the inner temperature remains in a band around 70 degrees Fahrenheit during the day while the outside temperature has larger excursions. Figure 18 (right) shows the house loading inside the house due to end-use appliances and HVAC units, and the loading measured at the meter. The house load had spikes during the day when the HVAC turns on to maintain the inner temperature within limits, while the net house load measured at the meter became negative during the day when its rooftop PV generation is peaking.

(B) Partial-Peak Loading

A similar exercise was carried out for partial-peak loading. As observed in Figure 19 (left), some voltage rise is observed around noon due to the presence of PV generation, but the voltages were still within the deadband. In Figure 19 (right), the voltage rise exceeded limits when a larger distributed PV system was considered. Overvoltages (above 126 volts) are observed around noon. Also note that the flicker was reduced because of reduced HVAC cycling as compared to that seen in the peak loading case.

(C) Off-Peak Loading

Again, the same exercise was carried out for off-peak loading. Some voltage rise was observed with PV generation as in Figure 20 (left), which got worse when larger distributed PVs were used, as shown in Figure 20 (right). Also note that the flicker was reduced due to reduced HVAC loading as compared to that seen in the peak and partial-peak cases.

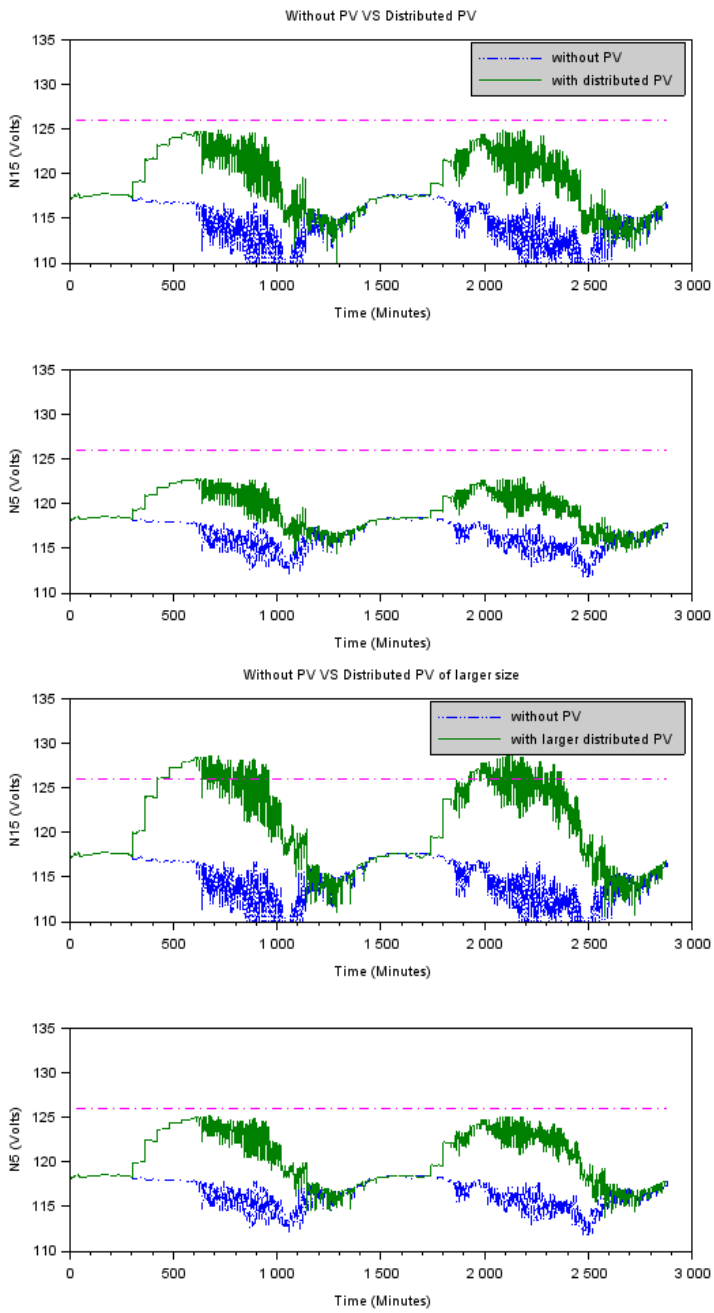
To recap, as observed from the simulations above, the factors contributing to overvoltage issues on a secondary network in the presence of PV include: 1) loading level, 2) PV sizes, and 3) time of the day. As would be expected, off-peak loading, larger PV sizes, and the time of the day when PV units are peaking result in the worst-case overvoltage conditions. Also, residences with PV systems are exporting power during the middle of the day.

Secondary Voltage Flicker

The results of inverter shut-off behavior are shown in Figure 21 for the secondary network shown in Figure 10 for off-peak loading conditions. When PV generation peaked, inverter voltages at nodes N13, N14, N15, and N16 rose above the overvoltage limit of 126 volts. These inverters would trip and restart, and then finally shut down the PV systems. This sudden

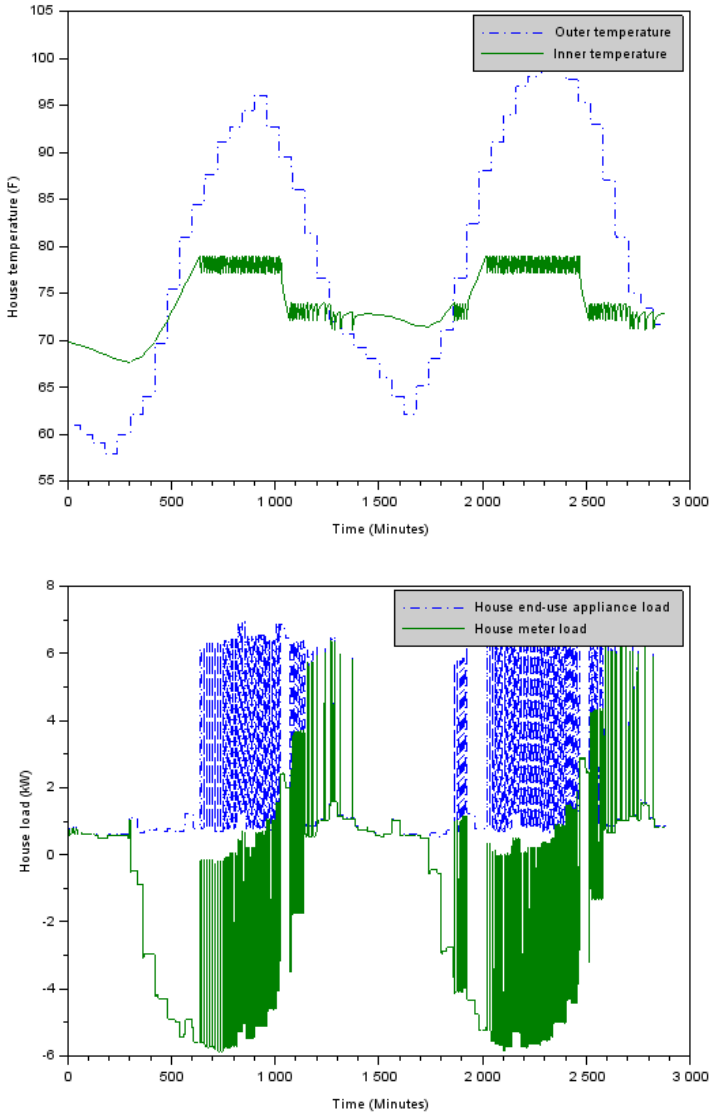
change in voltage caused voltage flicker of about 5 volts at these nodes. The combined flicker does not seem to propagate at the same magnitude to the other nodes within the secondary system as is show in the lower voltage profile in the figure.

Figure 17: (left) Bus Voltages With and Without PV Generation, With Peak Loading; (right) Bus Voltages With and Without Larger PV Generation



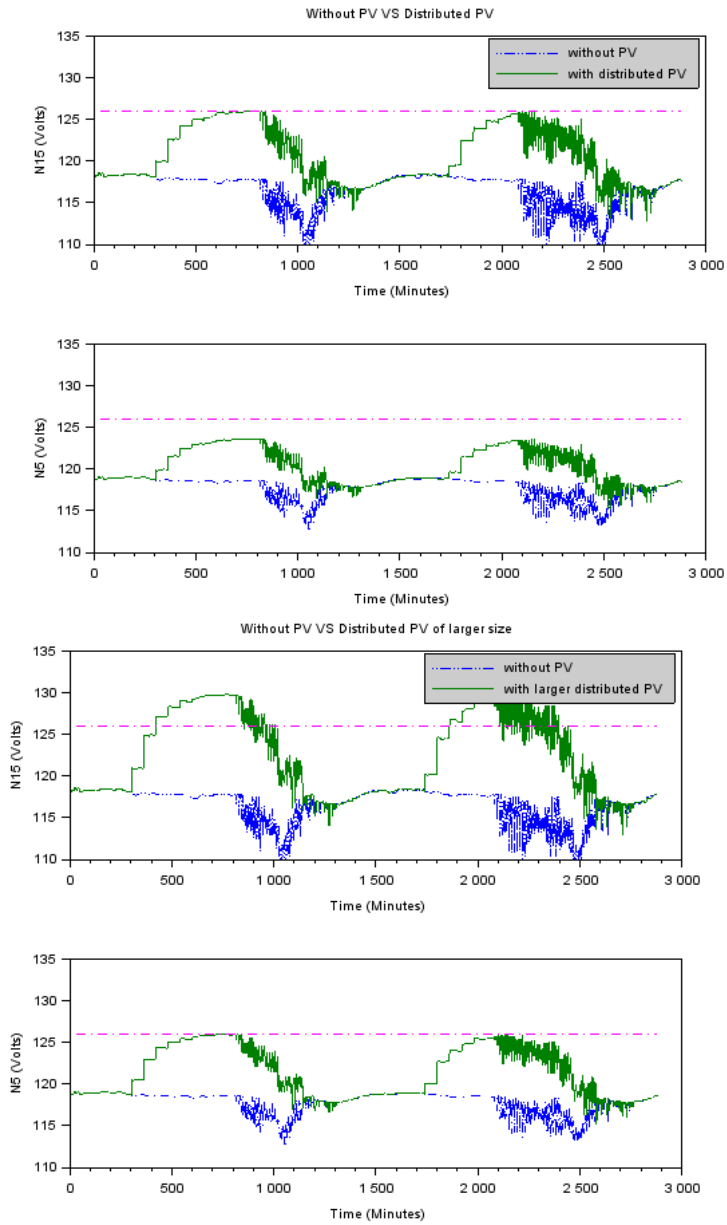
Source: Pacific Gas and Electric Company

Figure 18: (left) House at N15 Temperature; (right) Loading at the House and at the Meter



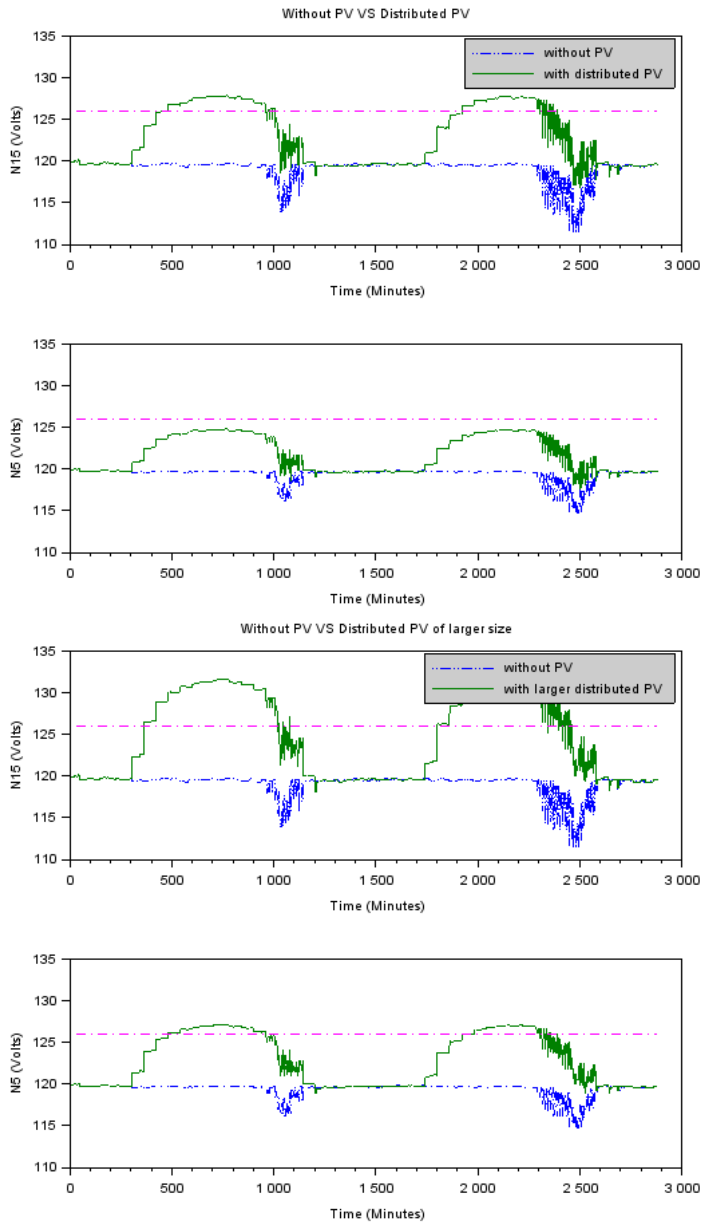
Source: Pacific Gas and Electric Company

Figure 19: (left) Bus Voltages With and Without PV generation, With Partial-Peak Loading; (right) Bus Voltages With and Without Larger PV Generation



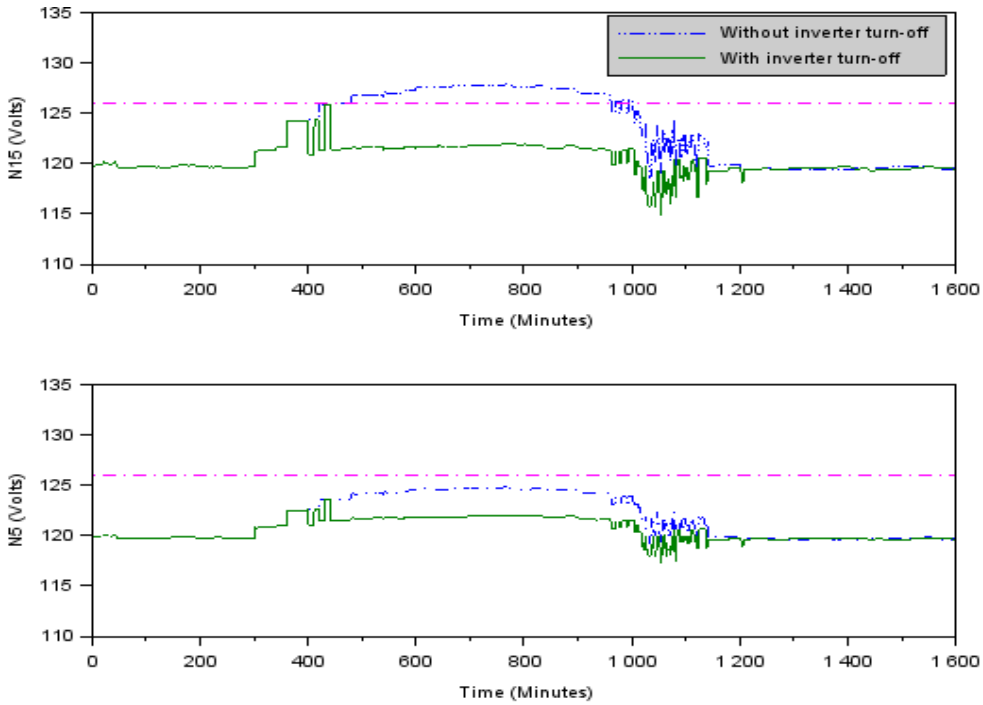
Source: Pacific Gas and Electric Company

Figure 20: (left) Bus Voltages With and Without PV Generation, With Off-Peak loading; (right) Bus Voltages With and Without Larger PV Generation



Source: Pacific Gas and Electric Company

Figure 21: Bus Voltages With and Without Inverter Turn-Off Due to Overvoltages for Off-Peak Loading and Distributed PV



Source: Pacific Gas and Electric Company

A second cause of flicker is associated with cloud shading events. Figure 25 shows voltage profiles at off-peak loading on the secondary system. The top graph is without a cloud shading event with voltage flicker caused by HVAC load cycling. The bottom graph shows the same conditions with increased solar irradiance variation. Flicker was observed in the voltage trajectory at the times of cloud shading in addition to that caused by appliances in the houses.

Smart Inverter Simulation

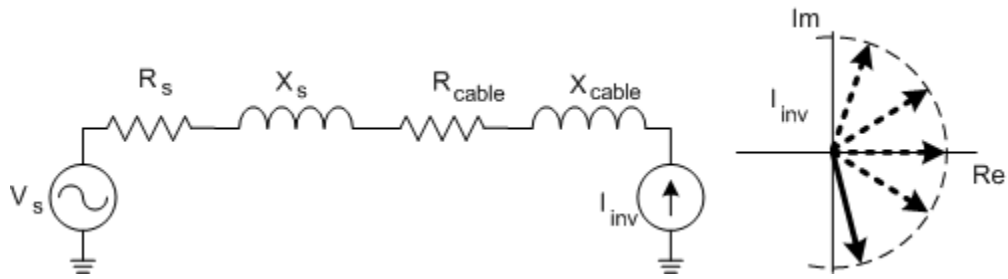
The Figure 26 (left) shows the daily voltage profile with and without smart inverters at selected PV locations. A simple power factor profile was followed as shown in the figure on the right. It is observed that smart inverter behavior helped alleviate voltage rise issues caused by PV generation, but the amount of voltage control is very small and cannot bring the voltage levels at the service entrance to within acceptable levels for the load conditions modeled.

The voltage controllability offered by a smart inverter depends upon the factors such as source impedance and the inverter size. Referring to Figure 10, the source impedance may include the system impedance at the primary node N1, impedance of the service transformer between N1 and N2, and impedance of the secondary network cables that connect the transformer secondary N2 to the inverter.

Consider a simple representative two bus system as shown in Figure 22. The primary node has voltage Vs and it is assumed to be fixed at a nominal value. The secondary node with an

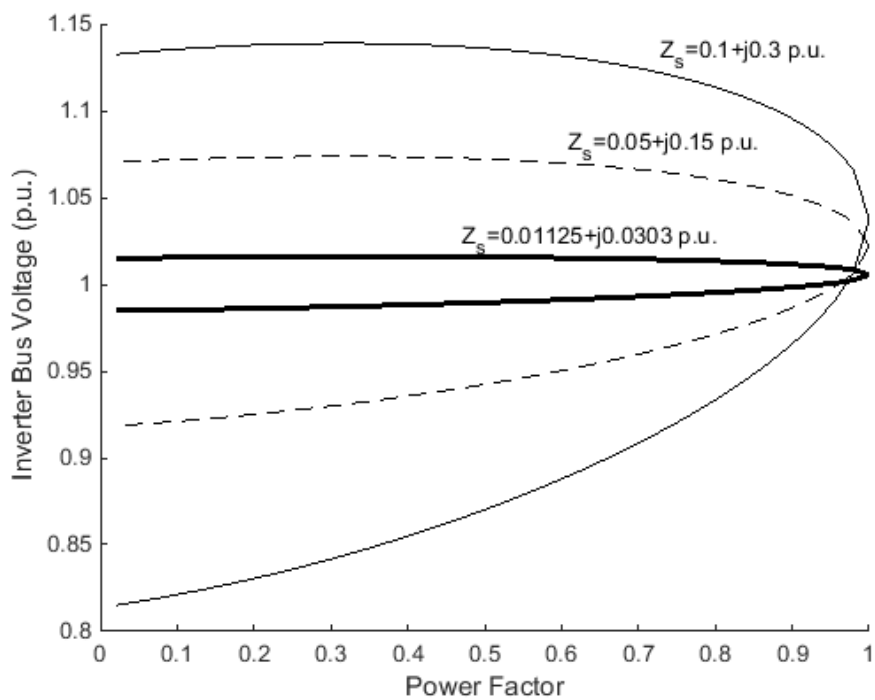
inverter is connected to the primary node through the source and cable impedances. The source impedance includes the transformer impedance and the system impedance. The typical cable and transformer configuration and parameters for distribution secondary are taken from the secondary GridLAB-D model.

Figure 22: Simplified Representation of a Two Bus System with Inverter Current Variation



Using the simplified model above, the inverter bus voltage is plotted against the inverter power factor in Figure 23 with the power factor varied from 90 degrees leading to 90 degrees lagging. The total apparent power at the inverter bus is held constant. The curves are drawn for various values of the source impedance. The thickest curve corresponds to the impedance value used in the GridLAB-D simulation and a cumulative inverter output of all the PV systems of 50kVA (5kVA per system).

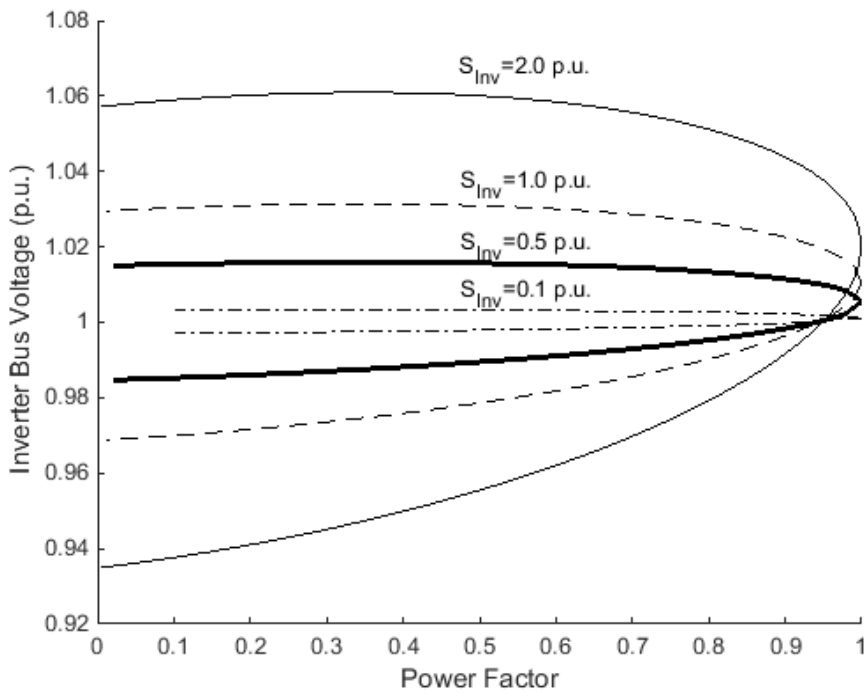
Figure 23: Inverter Bus Voltage verse Inverter Power Factor for Various Source Impedances



For smaller values of the source impedance, the network can be considered "stiff." The variation in the power factor does not influence the inverter bus voltage significantly under the nominal impedance. That is, the smart inverter power factor control would not be effective in lowering the voltage rise produced by the peaking PV. On the other hand, for larger values of the source impedance, the variation in power factor produces greater variation in the bus voltage. Inverter power factor control would be more effective with the higher source impedances.

Figure 24 plots the similar curves, now for the various sizes of the inverter. The larger sized inverter is able to better influence the terminal voltage via power factor control.

Figure 24: Inverter Bus Voltage verses Inverter Power Factor for Various Inverter Apparent Power Levels

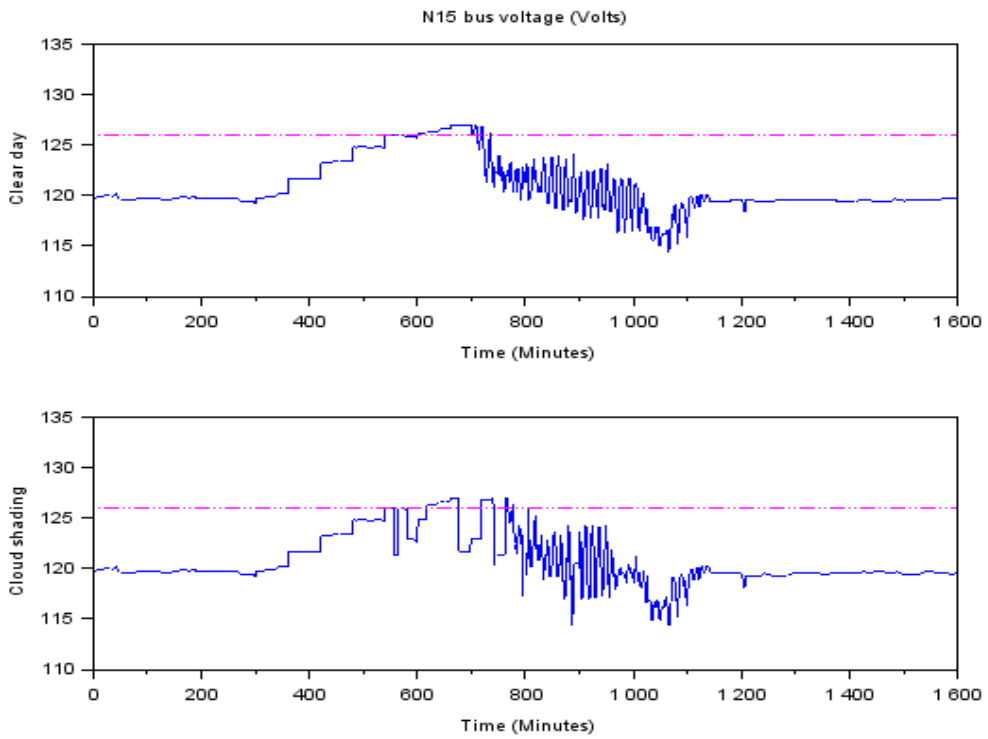


This analysis shows that the amount of voltage control by a smart inverter through reactive power control is limited by the source impedance and the size of the inverter. For the model simulated, which represents a typical secondary system, the source impedance is low enough to limit reactive voltage control to less than 1% over a 0.9 leading/lagging power factor

EV Charger Simulation

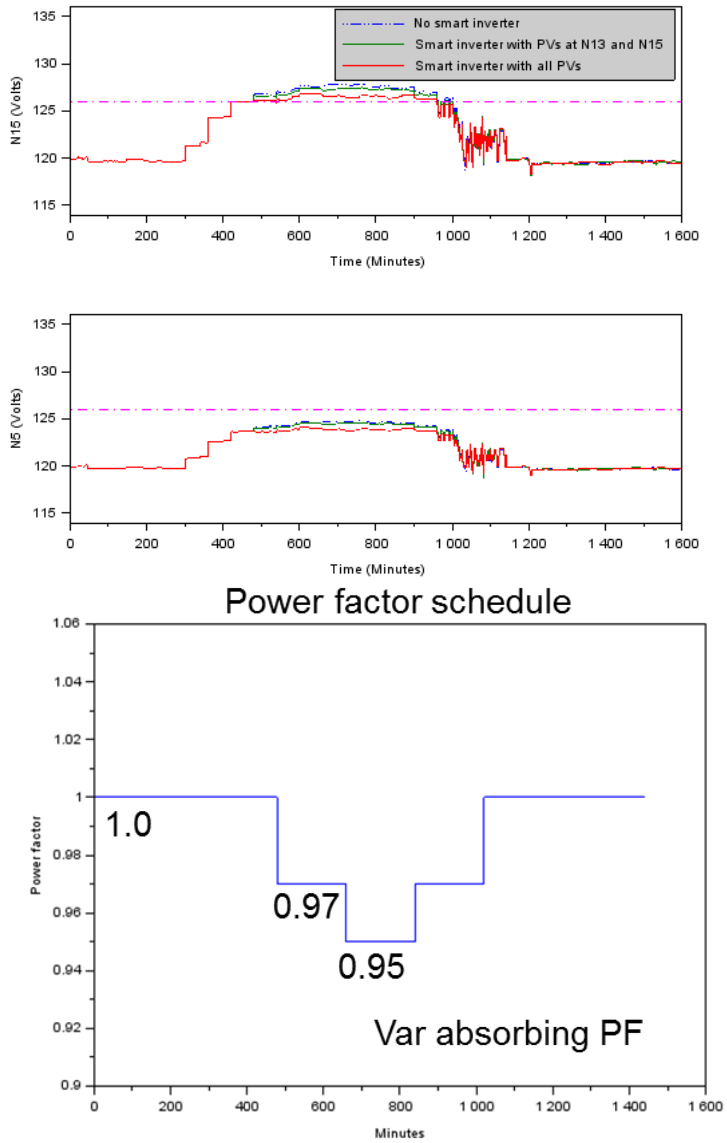
Figure 27 shows a 24-hour, time-series simulation of the network shown in Figure 11. It is observed that the PV peaked around noon with voltage rise resulting at node N11. The effect of EV charging began to show at approximately 6pm, causing voltage drop until the next morning. There is no coincidental interaction between the PV system and the EV charger.

Figure 25: Bus Voltages at Clear Day versus Cloud Shading for Off-Peak Loading and Distributed PV



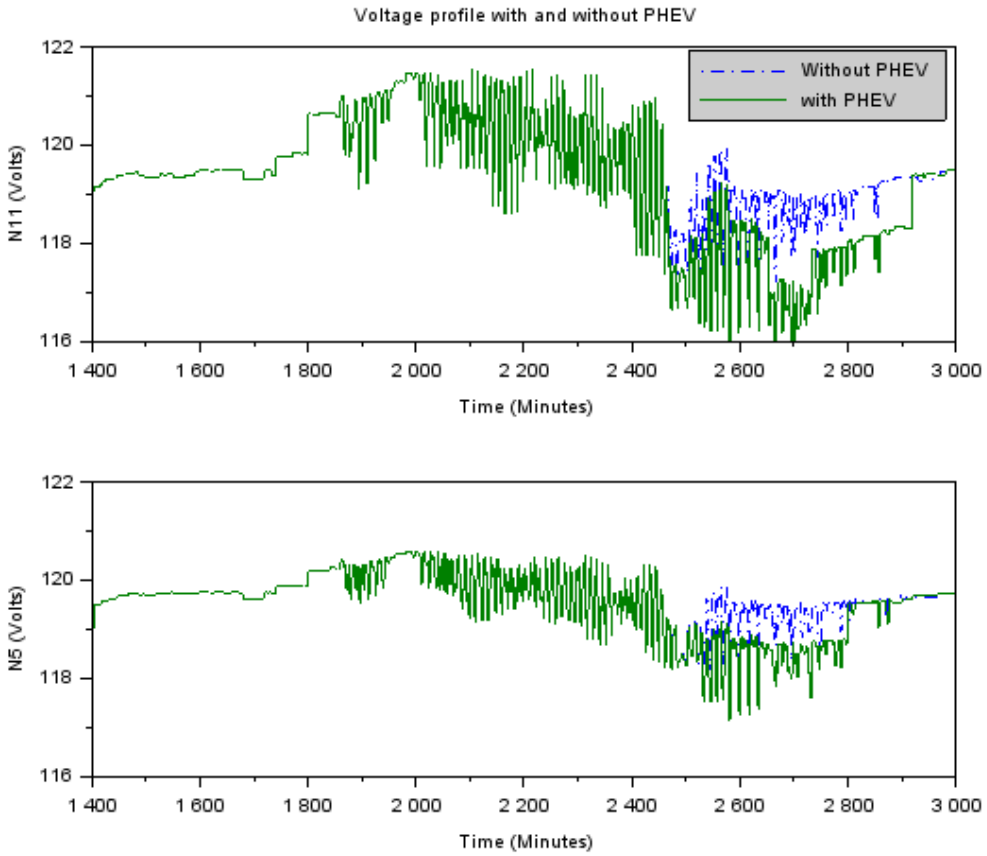
Source: Pacific Gas and Electric Company

Figure 26: (left) Bus Voltages With and Without Smart Inverter, for Off-Peak Loading and Distributed PV; (right) Inverter Power Factor Schedule



Source: Pacific Gas and Electric Company

Figure 27: Bus Voltage Profile With and Without PHEV



Source: Pacific Gas and Electric Company

CHAPTER 5:
Conclusions from Simulation Results

5.1 Impacts from Penetration Levels

Increases in DG penetration levels, specifically PV, on the electric distribution system were examined in this project's analysis. The following conclusions can be drawn regarding the results of this study.

5.1.1 Primary System Penetration Level Issues

High voltage issues appeared to be more dependent upon type of feeder and location on the feeder rather than PV penetration level. However, higher PV penetration levels produced higher voltage conditions for the same type of feeder with DG at the same location.

Rural type feeders were more likely to see voltage issues than shorter urban/suburban feeders, although this is not absolute. Since PV developers need to locate affordable land to site large systems, and this tends to be in remote rural areas, locating a system on a rural feeder toward the end-of-line can be in conflict with developer requirements.

Locating a PV system at the end of a distribution feeder has the highest probability of producing a voltage problem. This is intuitively obvious but has been confirmed by the analysis.

Off-peak and partial-peak loading conditions are the most likely to produce high voltage problems as PV penetration levels increase. Peak conditions are typically used by distribution planners when designing their systems. As PV penetration levels increase, planning engineers will need to examine partial-peak conditions to ensure proper operation of the distribution system.

Loss-of-plant flicker simulations produced the same conclusions as was found in the steady-state analysis, namely that feeder type, location, and seasonal loading condition are the primary indicators of potential problems, while PV penetration level appears to be a somewhat independent variable. Loss-of-plant flicker is a more severe constraint on PV integration than steady-state conditions.

5.1.2 Secondary System Penetration Level Issues

As identified in the research and confirmed in the simulations, voltage issues can manifest themselves on the secondary system. This can occur before any problems are identified on the primary system.

High-voltage conditions occur during peak PV output (noon for fixed-tilt PV systems) and not during peak loading conditions (typically early evening). PV did not improve low voltage conditions during peak loading conditions (6pm) and can cause high voltage issues during the non-peak noon time period. Also, residences with PV can be exporting power during the noon periods.

As with the primary system analysis, secondary system analysis shows that partial-peak seasonal loading conditions have a potential for higher voltage issues than seasonal peak loading conditions. As with primary systems, the analysis confirmed that higher voltage conditions exist toward the end of the secondary system.

5.2 Impacts from DG Variability

The variable nature of DG, specifically PV, was demonstrated using time-series analysis for both primary and secondary systems. The following conclusions can be drawn regarding the results from this analysis:

5.2.1 Primary System Impacts

From the project's research, the variability of DG on the primary system can cause flicker voltage issues. It can also impact the proper operation of voltage control equipment.

5.2.1.1 Cloud Shadow Flicker

The GridLAB-D software successfully modeled cloud shadow events with direct editing of the climate input models, and although the simulation did show that voltage flicker as high as 14 percent resulted from large PV systems, care must be taken in coming to conclusions from this work because much is dependent upon the input data assumptions. The key input that influences cloud shadow flicker is the rate of change of solar irradiance across the complete array. Data on this phenomenon lacks enough detail to produce accurate results. Additional research needs to be performed to generate better cloud shadow input data. Specifically, there is a need to determine the maximum rate of change in power output from PV arrays as a function of array size for a given climate condition.

5.2.1.2 Regulator and Capacitor Operations and Cycling Issues

In general, equipment operations for both capacitors and voltage regulators increased as a result of increased PV penetration levels. Voltage regulators are most likely to be impacted with increased operations. The results of this project showed that an increase in equipment operations is a real issue and that time-series analysis is necessary to evaluate PV's impact on equipment life.

Partial-peak and off-peak loading conditions seemed to cause the greatest increase in operations, however increased operation was seen across all loading conditions. Also, as PV generation moved toward an end-of-line location, there was a greater impact on the increase in equipment operations.

5.2.2 Secondary System Impacts

The variability of PV has the potential to produce voltage issues first on the secondary system. Both diurnal PV generation patterns and cloud shadow events were simulated.

5.2.2.1 Cloud Shadow and Inverter Cycling Flicker

Cloud shadow events were simulated using GridLAB-D and did create voltage flicker in the simulated models. However, the flicker level depends directly on the climate model's solar irradiation levels, which were arbitrarily set in these simulations. Determination of the actual

resulting rate-of-change of voltage and the amount of flicker from cloud shadow events will require accurate solar irradiation data from field installations. Collection and proper application of field solar irradiation data is an area where additional research should be conducted.

Variability of load in combination with cloud shadow events added to the complex behavior of the local voltage variability on the secondary system. Load cycling, such as found with HVAC units, can generate significant voltage flicker by itself, and when combined with PV can cause excessive voltage flicker.

Inverter cycling was successfully reproduced using the GridLAB-D software. The simulation demonstrated that flicker can occur during the start-up process of the inverter during the morning period of a daily load cycle.

5.3 Potential Mitigation Strategies to Offset Impacts

Simulations were run to demonstrate various mitigation strategies that could potentially offset the voltage issues identified in Section 2.2. The results present the following conclusions.

5.3.1 Primary System Mitigation Strategies

Three main strategies were investigated to mitigate voltage issues caused by various levels of PV penetration for the primary voltage simulations; these include smart inverters, SVC, and VVO.

5.3.1.1 Smart Inverters

Smart inverters acting as reactive sources (absorbing reactive power) can help in reducing voltage; however there are limitations to this approach. The simulations showed that smart inverters can only provide reactive power up to their apparent power limits, and this in several cases was not enough to overcome a weak interconnection for the PV system. The addition of reactive power alone cannot overcome all voltage issues and may actually contribute to overload conditions as overall apparent power will increase.

Since voltage issues arise during maximum real power output, the mitigation that can be achieved through reactive power from smart inverters during peak conditions, when it is most needed, is limited.

5.3.1.2 SVC

The application of using an SVC to provide reactive power instead of a smart inverter has the advantage in that the SVC has more reactive power capacity and is not dependent upon the real power rating of the PV inverters. SVCs can, to a certain extent, reduce high voltage issues. However, since they are absorbing reactive power, the apparent power actually increases which can cause overloading. Consequently, as with smart inverters, there is a limit to how much mitigation can be achieved with an SVC, especially with interconnections where the source impedance is high limiting available capacity.

5.3.1.3 VVO

GridLAB-D's existing VVO controller was employed to demonstrate its ability to more precisely maintain voltages within CVR limits. The simulations demonstrated that the current

GridLAB-D VVO model lacks the sophistication that would be found in a production version. It did help lower voltage for simulations with PV, but could not consistently maintain voltage within acceptable limits. VVO control models need to include more monitoring and status capabilities so that actual interaction between VVO and DG can be better understood and controlled properly. A production VVO controller, if implemented in this simulation, should have been able to maintain voltage levels within acceptable limits at all devices and nodes.

5.3.2 Secondary System Mitigation Strategies

The main mitigation strategy that can potentially be applied to a secondary system is smart inverters.

5.3.2.1 Smart Inverters

However, as with the application of smart inverters on the primary system, smart inverters on the secondary system had limited effect on reducing high voltage conditions. In several simulations, the reactive capability of the smart inverter was not able to bring voltages within acceptable limits.

5.3.2.2 EV Chargers

Residential EV charging had little impact on the secondary system when included with PV since the application for EVs in this scenario is typically for commuting. A commuter EV would only be charged during evening hours, therefore the additional load of the EV charger would not help to offset the PV generation and would not help in reducing potential high voltage problems. Additionally, the use of EV as storage devices with PV does not make sense since the EV would not be present at the residence during peak PV output.

GridLAB-D demonstrated its flexibility for modeling complex power devices with its currently available EV model. Further development of the EV model to include vehicle-to-grid (V2G) charging could be possible since the source code is available and the models could be modified.

EV charging within a commercial secondary system may demonstrate more benefit as PV output would coincide with EV charging.

CHAPTER 6: Recommendations

6.1 Areas of Further Research

The following key areas have been identified for further research:

6.1.1 Technology

6.1.1.1 Volt/VAR Controllers

Although this project begins to build a foundation of research concerning VVO and DG integration, its scope does not anticipate all the potential variations of VVO designs. Research needs to continue in the following areas:

1) Continued modeling of the various types of VVO algorithms in terms of how DG interacts with these control systems.

2) Identification and development of communication network technologies to integrate DG with VVO systems. Including the communication system model within GridLAB-D would be a powerful addition.

6.1.1.2 Advanced PV Inverters

Clearly, the direction of research and the industry movement is toward utilizing the reactive capabilities of PV inverters. The California Energy Commission (Energy Commission) is encouraged to continue support of this work by conducting research in the following areas:

1) Develop and demonstrate potential local voltage controls within PV inverters to support system voltage.

2) Continue modeling and simulation work to demonstrate both centralized and local voltage control strategies using inverter reactive capabilities.

3) Develop and demonstrate communications technologies to permit active control by utilities of distributed PV inverters. This should include utilizing the potential monitoring features of inverters.

6.1.1.3 EV Charging Systems

Integration of EV V2G strategies to support VVO needs further research. Specifically, the following areas are recommended for research:

1) Research potential algorithms for integration of VVO control of EV charger systems. This should include simulation and demonstration.

2) Demonstrate reactive support from EV charging technologies.

3) Demonstrate V2G capabilities of EV chargers.

6.1.1.4 Modeling Tools

Although significant research work continues in the development of advanced modeling tools, continued effort in this area needs to be supported. Following an open-source approach is recommended. It ensures thorough review by technology partners and can bring opportunities for co-development across research organizations. This project used GridLAB-D for simulation of voltage issues for these reasons. The following research areas should be pursued:

1) Development of VVO control models to mimic traditional commercial algorithms. Advance VVO control models to include the use of smart inverters and EV charging systems.

2) Development of more robust power flow analysis techniques to expand model sizes and include additional control loops.

3) Development of additional communication system models for use in all smart grid applications.

The scrubbed circuit models and custom scripts created in this project are available through download to the general public through Pacific Northwest National Laboratories' GridLAB-D website at: http://gridlab-d.sourceforge.net/wiki/index.php/PGE_Prototypical_Models.

6.1.2 Data Collection

6.1.2.1 Voltage Complaint Data Related to DG

The Energy Commission can take a leadership role in centralizing the collection of voltage complaint data as it relates to DG. The following potential opportunities should be considered:

1) Development of techniques and processes to better collect voltage complaint data as it relates to DG. This could involve creating a common repository for utilities and other federal and state agencies for the collection of this data. It could also involve working with utilities to expand existing voltage complaint processes.

2) Work with utilities to expand smart metered data collection to include voltage measurement and conduct analysis on this data to correlate DG penetration.

6.1.2.2 Load Modeling Data

Load behavior is dependent upon climate location, day-of-the-year and time-of-day. Load models have been developed for transmission planning but not specifically for distribution system simulations addressing voltage sensitivity. The following research areas are recommended to further improve load models:

1) Conduct research to determine accurate voltage sensitivity of loads using end-use load data and field monitoring verifications. Research should address the time-variant nature of loads.

2) Develop voltage-sensitive load models for use in distribution analysis. These could be simplified versions of transmission models with expanded features for use in advanced analysis software as described in the report section on modeling tools.

6.1.3 Rules/Standards for Interconnection

IEEE 1547a is a milestone in the integration of DG with the electric utility system and has the potential of opening opportunities by extending the benefits of DG. In support of the IEEE 1547a work group effort the following research should be conducted:

1) Develop and simulate centralized control of reactive power from DG systems in support of VVO.
2) Assist IEEE standards work group by supporting technical demonstration of communication and control of DG reactive power by utilities for voltage regulation.

GLOSSARY

Term	Definition
CPUC	California Public Utilities Commission
CSI	California Solar Initiative
DG	Distributed Generation
Energy Commission	California Energy Commission
EV	Electric Vehicle
FERC	Federal Energy Regulatory Commission
Flicker	A rapid change of voltage level
GIS	Geographic Information System
GLM	File extension for simulation used in GridLAB-D software, e.g., "AL0001.GLM" could be the file name of a input file to GridLAB-D
HVAC	Heating, ventilating, and air conditioning
IEEE	Institute of Electrical and Electronic Engineers
K-means Clustering	An algorithm used to group common elements for a given set of variables
kW	Kilowatt
LDC	Load Drop Compensator
Loss of plant	The sudden disconnection of a distributed generator from the electric system
LTC	Load Tap Changer
MW	Megawatt
NEC	National Electric Code
NEM	Net Energy Metering
PG&E	Pacific Gas and Electric Company
PV	Photovoltaic
RPS	Renewable Portfolio Standard
SCADA	System Control and Data Acquisition
Smart Inverter	A current source inverter used in PV installation that has additional "smart" features beyond simple interconnection capabilities
SVC	Static VAR Compensator
TMY	Typical Meteorological Year
UL	Underwriters Laboratory
V2G	Vehicle-to-Grid
VAR	Volt-Amperes Reactive
VVO	Volt/VAR Optimization

WDAT	Wholesale Distribution Access Tariff
ZIP	Polynomial voltage sensitive load model where Z is constant impedance, I is constant current, and P is constant power

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APPENDIX A:
List of Commercial Software Products for Advanced Volt/VAR Control

Number	Vendor Name	Product Name	Description of Product	Type of VVO	Vendor DMS Required?	Is DG Addressed?	Reactive DG Control?
1	Dominion Voltage Inc.	EDGE platform	Platform is three software packages: EDGE Planner is used to integrate AMI data with a circuit planning tool, identifies problems, and recommends which AMI meters to be used for voltage control. EDGE Manager does the actual volt/var control using existing DMS and SCADA systems to control volt/var equipment. EDGE Validator uses the AMI, circuit, and weather data to validate performance of system with software running.	(?) Does not require modeling	No	No	No
2	ABB	Volt-Var Management Software (VVMS)	"Closed-loop voltage and var control". Can operate as stand-alone or can be functionally integrated with SCADA or DMS.	Algorithm (heuristic) based control	No	No	No
3	Cooper	Yukon™ Integrated Volt/Var Controller	Application began as a centralized capacitor bank control first deployed in 2001 for substation and feeder var management. In 2004, functionality was broadened to support substation and feeder voltage management. In 2009 Cooper increased the applications functionality to support Substation LTCs and Voltage Regulators.	Algorithm (heuristic) based control	No (Integrates with most DMS programs)	No	No
4	S and C	IntelliTeam® VV	Software is three application modules: Volt-Var Control, Dynamic Voltage Optimization, and Dynamic Measurement and Verification.	Heuristic based (voltage and vars are decoupled)	No	No	No
5	Telvent/Schneider Electric	Advanced Distribution Management System (ADMS) which has a volt/VAR	Software is an "application" in the DMS software.	Model - based	Requires DMS	Yes	No

Number	Vendor Name	Product Name	Description of Product	Type of VVO	Vendor DMS Required?	Is DG Addressed?	Reactive DG Control?
		function					
6	Ventyx/ABB	VVO for DMS	Uses unbalanced load flow and load allocation applications to obtain network state. All loads are modeled as voltage-dependent.	Model-based	Yes	Say can help with "increased renewable generation"	No
7	Alstrom	e-terradistribution is Alstom's integrated SCADA/DMS system. A Volt/VAR "optimization function" is part of this package.	This feature is provided as a set of "functions" in the DMS software (IVVC). Performs analysis on the "as-operated" system.	Model-based	Requires e-terradistribution integrated SCADA/DMS	Yes	No
8	GE	Integrated Volt-Var Control (IVVC)	Software uses DMS device modeling and connectivity information in its analysis. Can control at either the substation of feeder level.	Model-based	GE DMS system PowerOn™ Fusion Advanced Distribution Management System	No	No
9	DC Systems	RTVVC™ (Real Time Volt/Var Control)	RTVVC software continually calculates the end of line and reduces or increases voltage at the substation in real time, as required. VAR and voltage can be controlled in manual, scheduled, pre-programmed, or automatic modes.	NA	Yes (RTVVC Software)	No	No
10	SEL	VVO and CVR covered under their marketing concept DNA™, not real software package	SEL does not sell a VVO software package but provides hardware that can be integrated into a custom build VVO system	NA	NA	No	No
11	Siemens	Spectrum Power™ Distribution Network Applications (DNA) contains a Volt/VAr control network analysis application	Software provides "recommendations to control" LTC, line regulators and capacitors.	Real-time Modeling	Requires Spectrum Power™ Distribution Network	No	No
12	OSI	OpenAVC™	Software implements voltage and VAR dispatch strategies for transmission, sub-transmission and distribution systems.	Real-time--algorithm	application of Monarch software (Multiplatform Open Network ARCHitecture)	No	No

APPENDIX B:
List of Commercially Available Voltage Control Hardware

Number	Vendor Name	Product Name	Description of Product
1	ABB	PCS100 AVC (Active Voltage Conditioner)	Inverter System based. Available in load capacities of 160kVA - 30MVA. Efficiency: Exceeds 98%. Fast Response to 3-phase sags down to 70%, and single-phase down to 55%. Continuous "Online" Voltage regulation and Load voltage compensation within +/-10% of nominal voltage. Also removes voltage unbalance from the supply. Reduces Maintenance costs.
2	ABB	SVC Light	It generates and absorbs reactive power by electronically processing voltage and current waveforms in a voltage source converter (the grid views it as a synchronous machine without inertia). As a result, capacitor banks and shunt reactors are not needed for SVC Light to generate and absorb reactive power, which enables a compact design and small footprint. The high switching frequency of the IGBTs provides extremely fast control, and is particularly useful in applications such as mitigating the voltage flicker created by electric arc furnaces, voltage balancing, harmonic filtering and grid voltage recovery. – robust voltage support under severe system disturbances where voltage recovery is critical – dynamic voltage balancing when the loads are unsymmetrical and rapidly fluctuating – power oscillation damping capabilities – improved voltage control under contingencies – active filtering of harmonic currents. The SVC Light performance focuses on: – Dynamic Voltage Control in transmission and distribution. – Power Quality Improvement in transmission and distribution. – Simultaneous Control of Active and Reactive Power *
3	ABB	PCS 6000 STATCOM	PCS 6000 are medium frequency converters for STATCOM applications which includes those Characteristics: Connection voltages from 6 kV to 220 kV Nominal power of up to 32 MVA (single module with continuous load) Simple combination of single modules in parallel for larger installations Continually adjustable power factor (capacitive and inductive) Frequency range from 5 Hz to 60 Hz Field proven availability of more than 99.5 % Overall efficiency (including transformers) > 98.0 % Adjustable response time to sudden load changes or load asymmetries < 10 ms Change of the power flow direction typically possible within half a period Minimum maintenance work of one day per year Independent selection of operating modes for P/f, Q/V, variable and / or fixed frequency ratio Complies with all relevant IEC, EN, and railway authority standards Pre-equipped for data transmission via telephone modem or Internet Small footprint thanks to loss-reduced converter design

Number	Vendor Name	Product Name	Description of Product
4	ABB	PCS100 STATCOM	Based around a low voltage converter platform, the PCS100 provides wide bandwidth performance with a flexible and highly reliable modular redundant power electronic configuration, correcting power factor, flicker and other disturbances for renewable generation such as wind, solar and traditional industrial applications. The PCS100 STACOM is available in load capacities of 100kVAr to 10MVAr. Voltage 400-480 AC/3~, ±10%, direct connect or any LV or MV with a standard transformer. Frequency 50 or 60 Hz. Efficiency > 97% at rated power. Overload capability for 480 V modules: 10 min 120 % 30 sec 150% 2 sec 175% 2 sec 200% (75 % preload for 200%) Features : Power factor control Voltage regulation Negative sequence/unbalance compensation of current or voltage Flicker compensation Active resonance damping Multiple system parallel control High and low voltage ride through Modular inverter blocks for simple long term maintenance
7	AC/DC ELECTRONIC SYSTEMS INC.	AC/DC - Static Voltage Regulators	AC/DC - Static Voltage Regulators ; are complete electronic voltage regulators which contain no any moving piece inside. Voltage Correction is realized completely under micro processing control via digital technology in ms. Through (thyristör - IGBT) it responds so fast the loads which require high elevation currents. Static voltage regulators have the ability to open and close each phase independently. - 5000 Volt / Second, - RISC Microprocessor Control, - Excellent Dynamic, Static Regulation, - Large Input Voltage Working Range, 130-270 VAC, - Electronic Protection against overload and short circuit, - 220 VAC / 380 VAC ; ±% 2,5 Regulation.
8	AEG Power Solutions	Thyrobox Voltage Regulator	Thyrobox VR operates as a voltage regulator in distribution networks. Once the power flow reverses, the voltage connected to the secondary network segment is adjusted downwards by up to 8%. Control is continuous and infinitely variable without switching operations. According to power rating, the degree of efficiency is > 99.5%. Thyrobox VR is based on a continuous control system and a state-of-the-art SCR and controller hardware platform. Its installation is super easy, since it is based on standard distribution cabinets. High power factor and 100% fail safe (bypass device in case of short circuits or severe failures).
11	Cooper Power Systems	Single-phase Pad-Mounted Voltage Regulators	Improve the safety, reliability and power quality in existing and new underground distribution systems. The pad-mounted voltage regulator, in conjunction with pad-mounted transformers and switchgear, can be used to create a modular pad-mounted substation. The pad-mounted voltage regulator provides step-type voltage regulation in thirty-two (32) steps of approximately 5/8% each for a maximum of 10% regulation when used singly or in wye-connected banks. The voltage regulator is available in voltage ratings,7620/7200 and 14,400 volt for 60 Hertz systems Current ratings from 50 to 548 amperes are available. Control of the voltage regulator is microprocessor-based, with a digital metering package of Class 1 accuracy. Features include voltage limiting capability, voltage reduction capability, reverse power flow operation, and tap position tracking. One of the advantages is when the regulator needs to be removed, the bypass module option is available to provide hot-stick–operable sectionalizing switches to disconnect the regulator from the system without causing interruption to the downstream load. Contains a CL-7 series Control box that helps in the voltage control (Details are shown in the Catalog provided). The load tap-changer product offering consists of three Quik-Drive Tap-Changers, the most advanced tap changers in the industry. Benefits include: direct motor drive for simplicity and reliability; high-speed tap selection for quicker serviceability; and proven mechanical life (one million operations). Only a single unit is required rather than three individual units. When factoring in cabinet clearance and overall size, the 3-in-1 pad-mounted regulator takes up less than one-third the space.

Number	Vendor Name	Product Name	Description of Product
12	Cooper Power Systems	VR-32 single-phase step voltage regulator	VR-32 are tap-changing autotransformers. Regulate distribution line voltages from 10% raise (boost) to 10% lower (buck) in thirty-two steps of approximately 5/8% each. Voltage ratings are available from 2400 volts (60 kV BIL) to 34,500 volts (200 kV BIL) for 60 Hz and 50 Hz systems. Internal potential winding taps and an external ratio correction transformer are provided on all ratings so that each regulator may be applied to more than one system voltage. The VR-32 includes the CL-7 series control box as well. Internal differential potential transformer for complete reverse power flow with metering. Includes the Quik-Drive Tap-Changers.
15	Eaton	Eaton Power-Sure 700	The Power-Sure 700 combines voltage regulation with a transformer and filter to remove transients and noise. The combined effect is regulating and shielded isolation transformer/system that solves 99 percent of the electrical disturbance problems, including electrical brownouts, sags, surges, transients and other electrical disturbances. The technology is that of tap-changers. Input voltage: +10% to -20% and output voltage of: ±3% typical. Input Frequency: 47-53 Hz for 50 Hz models, 57-73 Hz for 60 Hz models. Efficiency: 97% typical, 95% minimum. Load power factor: 0.6 leading to 0.6 lagging.
17	GE	VR-1 GE Voltage Regulator	Based on actual testing, expected switch contact life is usually a million operations. This means your GE regulator may be in service over 20 years before contact inspection is performed. The GE regulator is a sealed-tank, cover-suspended design that allows the removal of the complete interior from the top for easy maintenance. These regulators have provisions for direct-to-pole, platform, or crossarm mounting. 50 - 833 kVA Voltage From 2500 (for 2500/4330Y Volt Circuits, 60kv-BIL) to 19920 Volts (for 34,500 GrdY / 19920 Circuits, 150kv-BIL). Regulates within +/- 10% of the nominal voltage.
19	Ponovo (China)	STATCOM: also known as: Static Synchronous Compensator (SVG) in China	Accu-Var ASVC consists of circuit-breaker, isolation switch, arrester, reactor/booster, start-up circuit, chain module, control protection system and cooling, etc. auxiliary circuits. The control protection system applies the hierarchical structure, DSP and FPGA to improve the calculation speed and flexibility. Rated frequency: 50Hz, Rated voltage: 3kV/6kV/10kV/20kV/35kV, Rated capacity: ±1~±18Mvar (ASVC-100) ±10~±50Mvar (ASVC-200), Reactive power range: from capacitive reactive power to inductive continual adjustment, Overload ability: 1.15 overload operation time should be no less than 30min, Controller response time: ≤1ms, Output voltage THD before grid: THD<5%, Output current THD: <4%, Unsymmetry of output voltage: <3%, Running efficiency: ≥99%, and Life: 30 years.
20	Rongxin Power Electronic Co., Ltd. (China)	Low Voltage Static Var Generator - STATCOM	Rating range: [04kV-1kV]. SVG components: Transformer, Power unit, Input reactor, control cabinet, full digital control system, and NMI integrative workstation. No need for large volume capacitors or reactors because SVG uses HV IGBT or IGCT with high switching frequency to realize VAR regulation. Advantages over other compensators: --Faster response speed --Stronger voltage flicker restrain capability --Wide operation range --Low harmonic content --Small volume. German made EUPEC top quality IGBT modules. Capacity to bear high currents and voltage spikes. Free Maintenance. Performs great even with high temperatures because of the cooling system design. Compensates load harmonics, load unbalance, reactive power, and stabilizes the grid voltage levels.
21	Rongxin Power Electronic Co., Ltd. (China)	SVG Static Var Generator Electronic--Statcom	Higher rated voltage level: [6kv/10kv/35kv/27.5kv/55kv/110kv]. SAME SPECIFICATIONS AS THE SVG ONE, BUT THIS ONE IS WITH HIGHER VOLTAGE COMPATIBILITY.
24	Siemens	Siemens MJ-4A	It's a 32 bit microprocessor control panel. The MJ-4 is a voltage regulator control panel, which is a series of the digital controls designed to work with regulators and load tap changers. Some of the features of MJ-4 are Voltage Reduction Control, Voltage Limit Control, six Power Flow modes, and Data Logging. One of the good uses and functions of the MJ-4 is that it detects the reverse power flow in the system and adjusts the operating process and selects the corresponding algorithm for the best matching option. Includes convenient communication capabilities such as data port, communication modules, and remote access via laptop computers or SCADA. Modes of operation: Manual Mode, Off mode, Auto-Remote mode (executes its automatic tap control algorithms, unless overridden remotely), and Auto-Local mode (executes normal tap control algorithms).

Number	Vendor Name	Product Name	Description of Product
26	Sprecher automation	SPRECON-E-C-AVR	This is an AVR that controls the Tap Changer of the Transformers. The AVR units have 5 different set point values that can be controlled and selected manually or remotely. One of the added features is the overcurrent blocking and monitoring of both the motor drive and the tap changer. The data is stored on a programmable memory, and therefore, would be safe in case of any voltage failure (No need for any backup power to store the data). The AVR Monitors the tap changer, operating time, tap changer limits, and external limits such as overvoltage, undervoltage and overcurrent limits. It has the feature of accelerating the tap changing operation in case of emergencies. The operation modes are of course "Manual operation" and Automatic Operation" modes. Operating Range: (70 to140)% of voltage measurement. Doable with 50 or 60 Hz system. Communication interfaces are: LAN, RS232, RS422/485 and Fiber optic.
28	Tohokudenkiseizo Ltd. (Japanese)	D-STATCOM (SVC for Distribution)	This SVC is a stable control device for the grid's voltage. It's designed to be used for the distribution power system and networks. It solves the issues with the renewable sources being introduced in the power system, such as solar and wind energies. Its rated voltage is 6600V, Rated frequency 50Hz, Rated Capacity 300kVA, Over load capacity 400kVA , and response time 40ms or less. Benefits of the product: 1) Suppress voltage fluctuation, even sudden changes of PV output and load such as all-electric homes. 2) Suppress system enhancement (such as reinforcement of transmission lines and upgrading of substation). Some of the features for the Voltage analysis tool used are: 1-Generator/Variation load pattern model based on actual measurement. 2-Voltage variation analysis at the time of wind power connection. 3-Estimation of cooperation with SVC introduction effect analysis SVR.