# Final Technical Report

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| **Project Title:** | Accelerating Cost-Effective Deployment of Solar Generation on the Distribution Grid |
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## Executive Summary:

The Task 1 objective is to “expedite the PV interconnection process by revising the screening process in California”. The goal of this task is to develop a data-driven, validated approach to determining feeder limits that can simplify interconnection processes and lead to greater PV adoption across the California distribution system. The objective is focused on providing new methods that utilities can use to quickly and accurately determine the capacity of individual distribution feeders to accept new PV projects without risk of grid impacts. **Major accomplishments for Task 1**: The detailed analysis results from the CSI 3 project were used to develop a revised Rule 21 interconnection screening process.

The Task 3 objective is to “determine the technical feasibility of Sunshot high PV deployment scenarios”. The goal of this task is a better basis to estimate the nature of and impact areas associated with high PV deployment. Expanding our understanding of the impacts of high PV deployment on the larger electric distribution system in the U.S. will be crucial to 1) mitigating interconnection costs and 2) focusing time and resources on the interconnection requests with the greatest system impact risk. **Major accomplishments for Task 3:** Demonstrated feeder circuit reduction complexity of greater than 95%, with the reduced model representative of the full model within an error of 0.01%. An advanced simulation tool was developed to quantify system impacts for many PV interconnection scenarios, configurations, and locations and to determine the locational hosting capacity. The locational hosting capacity was determined for 216 feeders using this tool. Published nine conference papers and one journal paper and three SAND reports on the research in this Task for FY13-FY15.

The Task 4 objective is to “develop PV modeling tools and techniques for distribution studies”. The goal of this task is to enhance the accuracy of distribution studies by providing utility planners with appropriate solar data inputs. The end result of this task is a tool that will create high-frequency solar data that is representative of the solar variability in the location specified by the end-user. The tool will be easy to use and will interface with distribution simulation software to simplify distribution studies with accurate solar inputs. Improving the accuracy of distribution studies will allow utilities to better understand the impacts of PV and better identify potential problems on the electric grid. **Major accomplishments for Task 4**: A relationship between high-frequency (30-second) solar variability and low-frequency (1-hour) solar variability was established. Using the high and low-frequency variability relationship, solar variability zones were established using hourly satellite data.

The Task 5 objective is to “engage stakeholders and educate on grid interconnection results and best practices”. The goal of this task is the adoption of new screening processes that are accepted and adopted by utilities within regulatory bounds, policy makers, and the PV industry. Another successful outcome will be industry validation and broad dissemination of guidelines for cost-effective mitigation of high penetration system impacts. This task emphasizes the successfully transferring best analysis practices and techniques to utility engineers performing screening and system impact analysis. **Major accomplishments for Task 5**: The FERC issuance of a revised final ruling of the Small Generator Interconnection Procedures based in part on Sandia white papers and testimony. This was a major accomplishment affecting the interconnection of PV to the grid and leads the way for states to follow the precedent. Technical report on screening provides a full and complete data-driven technical foundation that supports revising the SGIP screens to make them more accurate and effective. Numerous publications and workshops delivered to stakeholders described in task section.

## Contents

## Background for Task 1: Expedite the interconnection screening process in CA

This task describes Sandia's participation funded by DOE as a cost share for the EPRI/CSI project. This is the final year of a two-year research activity that Sandia will conduct in support of the CSI grant project "Screening Distribution Feeders: Alternatives to the 15% Rule", which is led by EPRI. The grant has significant DOE cost-share commitment through Sandia and NREL.

The Renewable Systems Integration (RSI) studies [1-7] identified 15 grid integration issues that needed to be addressed before a high penetration renewable energy future could become a reality. The RSI studies presented a roadmap to address PV integration issues on the distribution system and identified gaps needing further research and development. The published research results from multi-year studies conducted under the DOE High Penetration Solar Deployment projects and the California Public Utilities Commission' California Solar Initiative addresses some, but not all of these gaps [8-13]. Those studies focused on modeling and assessing the impact of high PV penetration scenarios on specific distribution feeders, and do not attempt to develop guidelines that can be applied more generally throughout the U.S.

The existing set of screening criteria is not suitable to efficiently handle the growing number of interconnection requests especially on circuits with high PV deployment. Since most PV systems have a low risk for causing system impacts, the goal for any interconnection screening process is to function as a helpful tool for fast approval of these systems, while continuing to screen out higher risk interconnections that need system impact studies [14-18].

## Project Objectives for Task 1

Two of the largest obstacles to enhancing PV adoption rates are 1) the delays to interconnect while waiting in interconnection study queues and 2) the uncertainty around the timing and costs for system upgrades to interconnect. Both of these obstacles are intensified when more and more high PV penetration interconnection requests unnecessarily fail screening criteria and are dumped into the overloaded study process. To achieve the deployment volumes envisioned by the SunShot Initiative, it is of paramount importance to make the system analysis process more efficient and complete, so that good engineering may be applied to any and all PV projects. Any efforts to improve the screening process must be based on a foundation of in-depth analysis of the impacts, and the thrust of Sandia's proposed work is to expand the analysis foundation. This task focuses on new analysis results, study methods, tools and techniques produced will have a large impact.

This objective is significant because the existing set of screening criteria is not suitable to efficiently handle the growing number of interconnection requests especially on circuits with high PV deployment. The screening process needs to be revised and expedited by utilizing more accurate and sensitive set of screens. The current screening process for interconnections triggers time-consuming and costly studies. The estimated cost for a utility to outsource a typical impact study is $25,000 and the study period is typically 12 to 24 weeks, but can extend for much longer based on the interconnection queue position and the time required to gather necessary data. Since most PV systems have a low risk for causing system impacts, the goal for a new interconnection screening process is to function as a helpful tool for fast approval of these systems, while continuing to screen out higher risk interconnections that need system impact studies.

The project approach is threefold:

(1) Innovative characterization of representative feeders for use in grid impact studies
(2) Feeder analysis with high PV deployment using hosting capacity analysis
(3) Development of new interconnection screens for high penetration PV.

The goal of this task is to develop a screening methodology that efficiently evaluates new interconnection requests while taking into account PV and feeder-specific factors. This method will not only consider peak load levels, but also other critical factors as well including PV location, aggregate PV effects, and most importantly specific feeder characteristics such as voltage class, voltage regulation schemes, and operating criteria. The approach is a data-driven method to determining feeder hosting limits that will simplify interconnection processes and lead to greater PV adoption across the California distribution system.

**Subtasks**

Subtask 1.2: Develop screening methods and design screen criteria that will be applicable to the vast majority of feeder types found throughout California. Establish the technical basis and rational for revising CA RULE 21 (EPRI/CSI Task 6) Development of new interconnection screens that will help integrate large amounts of PV onto distribution systems.

Subtask 1.3: Review the policy impacts of new screening criteria for a balance between accuracy and the time and effort to perform the screen. (EPRI/CSI Task 6)

Subtask 1.4: Perform validation of the new screening criteria on two validation feeders. A full array of possible PV interconnections will be run for each validation distribution feeder with a comparison of the old screening criteria, the newly proposed criteria, and detailed simulation of impacts for each PV scenario. (EPRI/CSI Task 8)
Subtask 1.5: Develop best practices guide for interconnection studies based on analysis of CA and other distribution circuits.

| | Metric Definition | Success Values | Measured Value | Assessment Tool | Goal Met | Data |
|---|---|---|---|---|---|---|
| ***Milestone 1.A*** | A Develop **two alternative** screening criteria/methods to the 15% Rule that will increase the accuracy of the screening process by reducing “false positive results” **by at least 40%** compare to the current 15% screen. A false positive result means the 15% screen incorrectly fails the interconnection request and assigns the interconnection a high risk for causing system impacts. | reduce false positive screening results by **at least 40%** | Two screening methods: Alternative Rule 21 and Short hand equations with thermal limit | Model, simulate and evaluate using QSTS analysis and EPRI DPV | Yes | CSI 3 final report and pages 12-13 of report |
| ***Final Deliverable 1*** | Model, simulate and evaluate **4 or more** representative feeders demonstrating that at least one of the alternative screening criteria/methods will **reduce false positive** screening results by **at least 40%** for interconnection sizes ranging from **0-10 MW.** | | | | | |

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| | This demonstrates a data-driven, validated approach to determining feeder limits more accurately. |
| ***Status Final Deliverable 1*** | Completed. We modeled over 216 feeders including the 22 representative feeders in the CSI 3 project and demonstrated a reduction in the PPI metric of 126% from the PPI for the 15% peak load screen of 364% to the PPI for the SH equations with thermal of 238%. |

| | Metric Definition | Success Values | Measured Value | Assessment Tool | Goal Met | Data |
|---|---|---|---|---|---|---|
| ***Milestone 1.B*** | Demonstrate new screening criteria on **two** validation feeders. The new screening criteria and method should identify **100%** of the interconnection requests that will cause harmful impacts. | New screening criteria and method should identify **100%** of the interconnection requests that will cause harmful impacts for each area of concern: voltage, thermal, etc | Demonstrated new screening criteria on **6** validation feeders. Method identified 100 % of the interconnection requests that will cause harmful impacts. | Model, simulate and evaluate using QSTS analysis and EPRI DPV | Yes | CSI 3 final report |

| | Metric Definition | Success Values | Measured Value | Assessment Tool | Goal Met | Data |
|---|---|---|---|---|---|---|
| ***Milestone 1.C*** | Develop best practices guide for interconnection studies based on analysis of CA and other distribution circuits. | Publish best practices guide for interconnection studies based on analysis of CA and other distribution circuits. | CSI 3 final report providing best practice guidelines for screening interconnection studies using an alternate CA Rule 21 | Document | Yes | CSI 3 final report |

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| ***Final Deliverable 2*** | A data-driven, validated approach to determining feeder limits that can simplify interconnection processes and lead to greater PV adoption across the California distribution system. New methods that utilities can use to quickly and accurately determine the capacity of individual distribution feeders to accept new PV projects without risk of grid impacts. Best practices guide will be made publicly available with accompanying generic data and tools, created specifically for this tasks, via a web download. |

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| ***Status Final Deliverable 2*** | Completed. SAND report of CSI 3 final report available on Sandia Website. Joint CSI 3 reports with EPRI and NREL on CSI website: “Alternatives to the 15% Rule: 1) Final Project Summary, 2) Modeling and Hosting Capacity Analysis of 16 Feeders and 3) Modified Screens and Validation” |

## Project Results and Discussion Task 1

**Overview of Project:**
This task was performed in collaboration with EPRI and NREL. The main outline of the project included: collecting data from PG&E, SCE and SDG&E, clustering feeder characteristic data to attain representative feeders, detailed modeling of 16 representative feeders, analysis of PV impacts to those feeders, refinement of current screening processes, and validation of those suggested refinements. The objective is to develop a screening methodology that efficiently evaluates new interconnection requests while taking into account PV and feeder-specific factors.

The selection of the utility feeders has been based on the results of a comprehensive clustering analysis where each feeder from the three CA investor-owned electric utilities has been characterized and grouped into representative sets. The representative sets are not suggesting all feeders within the set will have a similar response to distributed generation, but the sets allow selection of several feeders that will have considerably different characteristics. These representative feeders from each utility have been placed into two groups. One group of 16 for detailed analysis and another group of 6 for validation.

A detailed feeder model is developed for each of the selected feeders. The models are based on the utility planning model and converted into the OpenDSS distribution software. The OpenDSS distribution software is used so that detailed analysis can be performed similarly across the different utilities even though the original models come from different software platforms.

The analysis of the models is conducted with PV as the distributed energy resource. Rule 21 is inclusive of all distributed generation types, but this project specifically analyzes distributed PV. The hosting capacity analysis determines the amount of PV that can be accommodated on a distribution feeder without impacts exceeding predefined utility guided thresholds. The hosting capacity for each feeder is unique for voltage and protection issues.

The detailed feeder impact analysis performed identifies when potential issues from aggregate distributed generation are not properly identified and also when a feeder is capable of accommodating considerably higher levels of distributed generation.

### Main Project Results for FY13 and FY 14

- Developed statistical clustering method to identify 22 representative feeders out of 8000+ utility feeders from the collaborating utilities PG&E, SCE and SDG&E.
- Obtained feeder information and details from PG&E for 7 representative feeders. And converted PG&E CYME models to OpenDSS models See Figure 1.

- Enhanced the PG&E models and validated to measured data.
- Seven PG&E feeders analyzed using the DPV tool developed by EPRI. The DPV tool determines the hosting capacity, defined as "the amount of PV that can be accommodated without impacting system operation (reliability, power quality, etc.) under existing control and infrastructure configurations for each feeder".

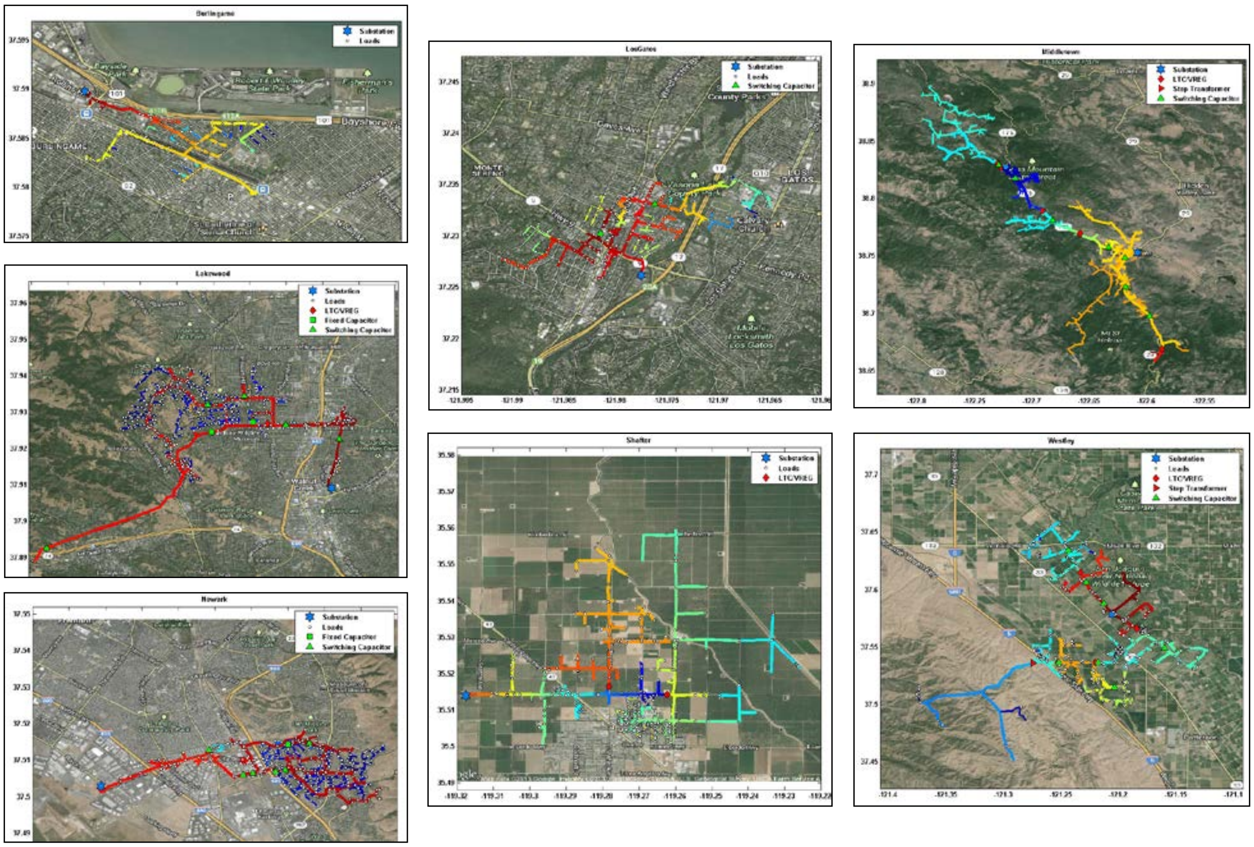


**Figure 1. Seven PG&E Feeders**

## FY15: Development of the Alternative Screening Process

After analyzing the 16 study feeders in the detailed DPV hosting capacity tool, the results were used to develop a modified screening process from the conventional 15% rule and California's Rule 21. The modifications suggested for CA Rule 21 are made based on the technical analysis conducted within this projects detailed PV impact study. The changes suggested are primarily applicable to all forms of generation in the Fast Track Initial Review process. In the Supplemental Review process, some of the recommendations could be ignored when not applicable. The detailed analysis conducted in this project is used to determine the feeder impacts and hosting capacity for issues not specifically identified in Rule 21. The impacts examined can be caused by the aggregate amount of PV on a feeder and are not a function solely of load.

The modified screen includes six short-hand equations to estimate impacts in each of the following areas

1. Primary Node Overvoltage: If voltages might exceed ANSI limits
2. Primary Node Voltage Deviation: If the variable resource could impact sensitive equipment or cause slow variation flicker
3. Voltage Regulation Node Voltage Deviation: If additional tapping might occur
4. Element Fault Current: If protection devices may need to be rated higher due to additional fault current
5. Sympathetic Breaker Tripping: If the breaker might trip on ground current due to a parallel feeder fault
6. Breaker Reduction of Reach: If the breaker may lose visibility to remote feeder faults

The equations for each are shown below. For more details about the variables and notes on specific conditions for each equation, see the Final Report “Alternatives to the 15% Rule”.

SR1

$$VDev = \frac{MaxR}{FeederkVLL^2} \cdot 100$$

$$SR1 = \frac{PrimaryHeadroom}{VDev}$$

SR2

$$VDev = \frac{MaxR}{FeederkVLL^2} \cdot 100$$

$$SR2 = \frac{VoltageDeviationThreshold}{VDev}$$

SR3

$$\mathrm{RthatRegSees} = \mathrm{RtoReg} + \frac{\mathrm{LDC\_Rsetting}}{\mathrm{NCT}} \cdot \mathrm{NPT}$$

$$RegVDev = \frac{RthatRegSees \cdot 1000}{FeederkVLL \cdot NPT \cdot sqrt(3)}$$

$$SR3 = \frac{Bandwidth}{2 \cdot RegVDev}$$

SR4

$$SR4 = PercentIncreaseThreshold \cdot \frac{FeederkVLL^2}{MaxZ} \cdot \frac{2}{FaultIpv}$$

SR5

$$SR5 = SympatheticTrippingThreshold \cdot \frac{FeederkVLL}{1000 \cdot sqrt(3)} \cdot \frac{2}{FaultIpv}$$

SR6

$$SR6 = BreakerSensitivityThreshold \cdot \frac{FeederkVLL^2}{MaxZ} \cdot \frac{2}{FaultIpv}$$

The suggestions to improve the Fast Track Initial Review and Supplemental Review screens in CA Rule 21 are shown in Figure 2. These suggestions target the methods to analyze the impact of aggregate generation and specifically provide "Alternatives to the 15% Rule." The improvements are based on the technical analysis and include:

- Adding screen that addresses if the feeder has line regulators
- Modifying the Initial Review to always address aggregate generation
- Add Supplement Review equations to address the impacts of aggregate generation for issues not dependent solely on load

The modified screens are then applied to the validation feeders to observe and verify the new recommendations. At some point, the aggregate generation on the feeder will cause adverse impact, thus aggregate generation should always be considered during interconnection requests. After determining the approximate hosting capacity with the Supplemental Review equations, the feeders' ability to accommodate PV is shown to be independent of load level and better matches the detailed analysis. Therefore, the modifications to the Initial Review and Supplemental processes can improve screening interconnection requests.

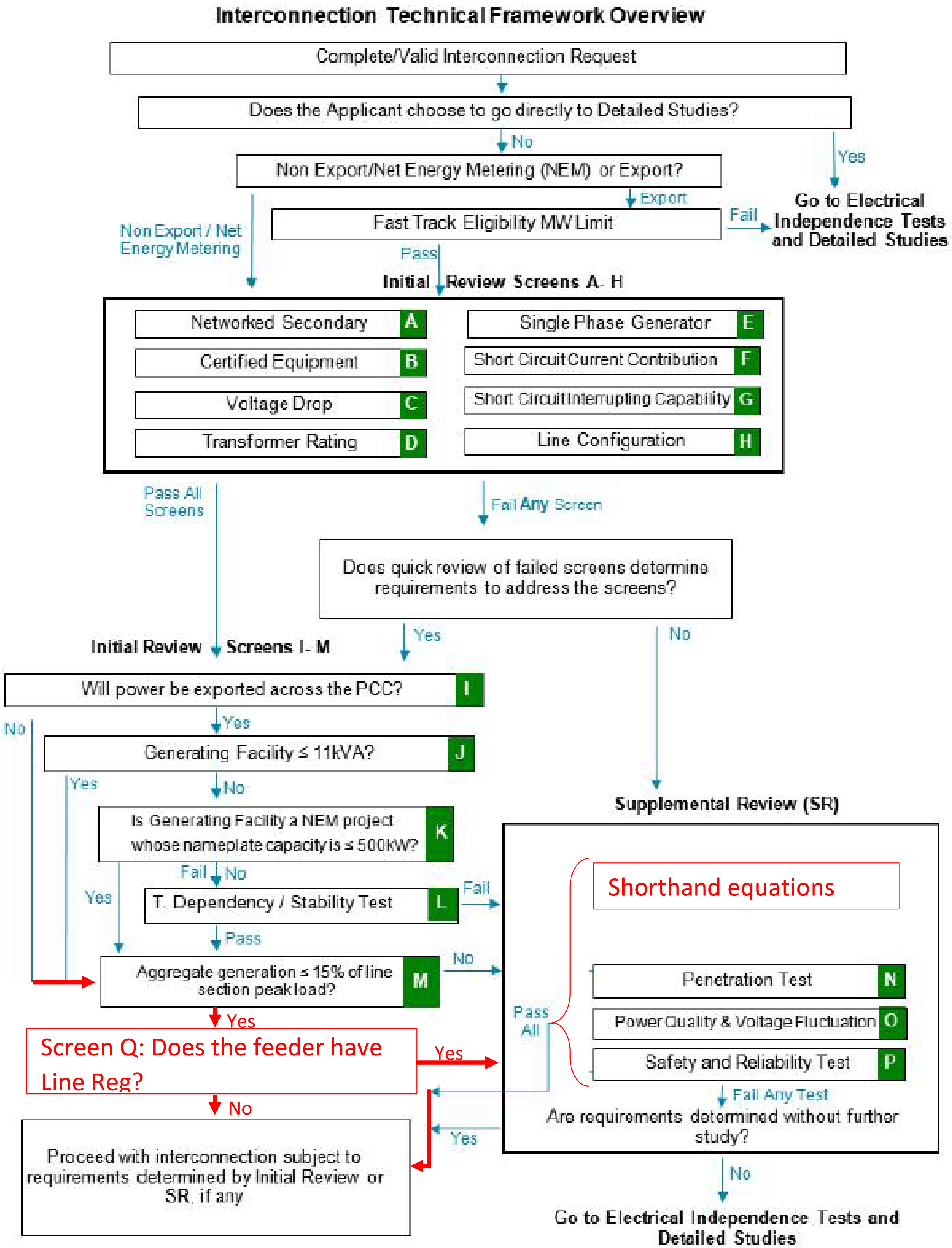



**Figure 2. Suggested Modifications to CA Rule 21**

## FY15: Validation of the Modified Screening Process

Validation of the developed PV screening improvements to Rule 21 included the development of a study control group of feeders that would only be used for validation purposes. Using a control group (referred to as the validation feeders in this study as opposed to the study feeders used to develop the improved screening process) allowed for the investigation of whether the developed PV screening processes could successfully screen PV interconnection on other feeders. The control set included six feeders, two from each utility. These six validation feeders are developed in the same way as the other 16 study feeders and are selected from representative clusters of feeders during the feeder clustering portion of this project. These six feeders represented three medium voltage (MV) classes and included a good mix of general feeder types such as residential and commercial/light industrial dominated feeders.

For each validation feeder, detailed hosting capacity analysis was conducted and six metrics were checked, including primary overvoltage, primary voltage deviation, regulator voltage deviation, element fault current, sympathetic tripping, and reduction of breaker reach. PV deployment was evaluated for residential/commercial PVs. The result of residential/commercial rooftop PVs is based on 100 simulation scenarios, and the customer PV penetration in each scenario increases from 2% to 100% of customers. The supplemental review shorthand equations are used to compute a conservative hosting capacity. These results are then mapped back to the detailed analysis results for comparison.

Figure 3 gives the shorthand hosting capacity for the distributed PV case with PV on residential/commercial rooftops. The asterisk in each bar is the hosting capacity prediction computed using the supplemental review shorthand equations. If the asterisk is not shown on the plot, the shorthand hosting capacity is greater than the range shown in the plot. Except those asterisks in feeders 1231 and 679 exceeding the simulation data limit, all other asterisks in all validation feeders are within green areas or at the transition from green to yellow/red. Thus, it proves that SR shorthand equations can give a good and conservative estimation of PV hosting capacity.

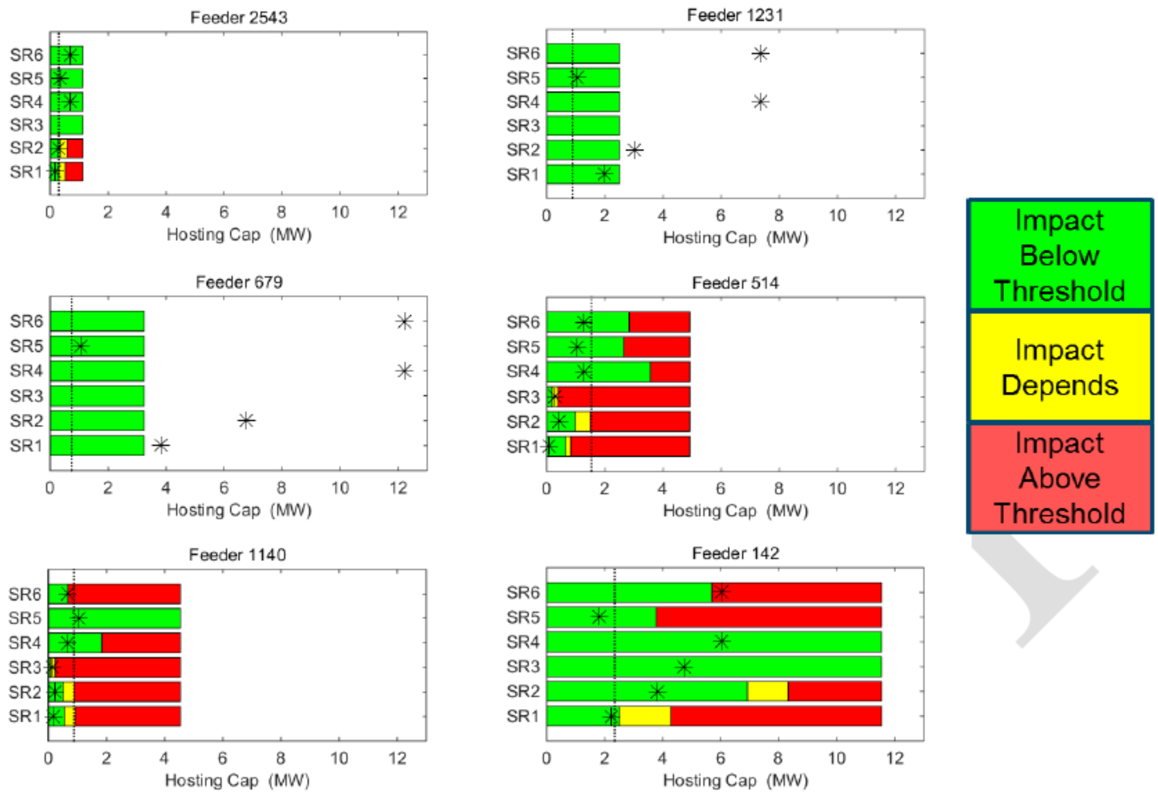



**Figure 3. Residential/Commercial Rooftop PV Hosting Capacity (Dashed lines indicate 15% of breaker peak load)**

## FY15: Evaluation of Screen Accuracy for full set of feeders.

One of the goals of developing new screens is to increase the accuracy of the screening process by reducing “false positive” results from the 15% screen. A false positive result means the 15% screen incorrectly fails the interconnection request and assigns the interconnection a high risk for causing system impacts. The metric we used to evaluate the relative increase the accuracy of the screening process is the potential percent increase or PPI. The PPI is the ratio of potentially allowable interconnections (PAI) to the allowed interconnections (AI). See Figure 4.

Both the AI and PAI are essentially area calculations as shown in Figure 4. The potential percent increase (PPI) in (1) is a ratio of PAI to AI that shows the dramatic number of PV interconnection that could have been allowed by the screen relative to the number that it currently allows.

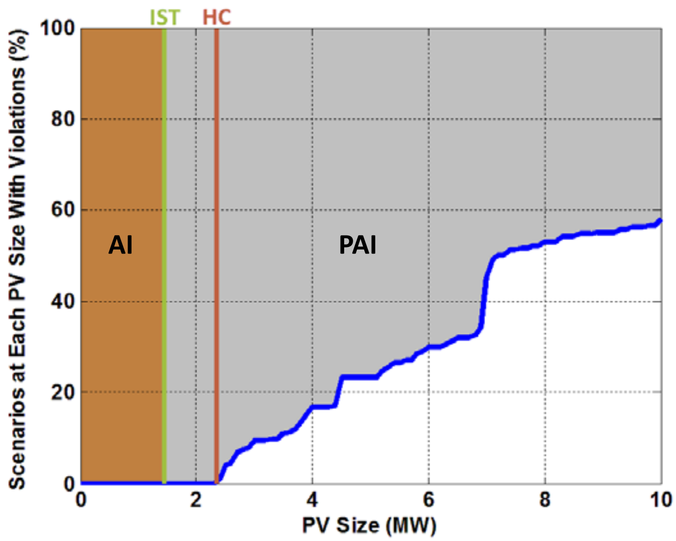


**Figure 4. Example of an interconnection screen threshold (IST) with many potential allowable interconnections (PAI) beyond the allowed interconnections (AI)**

$$PPI = \frac{PAI}{AI} * 100 \qquad \textbf{(1)}$$

We evaluated two screening methods 1) Alternative Rule 21 and 2) Short hand equations with thermal limit. The alternative Rule 21 is discussed above. The other screen is the short-hand equations combined with a thermal limitation. The interconnection thermal limitation is based on the limiting ampacity device or conductor upstream of the interconnection point and the minimum load that occurs during daylight hours.

We evaluated the screens using 216 feeders including the 22 representative feeders in the CSI project. These 216 were analyzed using the locational hosting capacity analysis results discussed later in Task 3. The PPI for the 15% screen and the Alternative Rule 21 and Short hand equations with thermal limit are shown in Figure 5. The short hand equations with thermal limit screen shows a reduction in the PPI metric of 126% from the PPI for the 15% peak load screen of 364% to the PPI for the short hand equations with thermal limit of 238%.

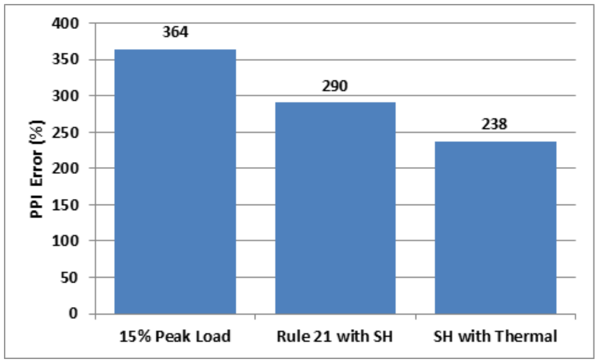



**Figure 5. PPI for three screening methods**

## FY15: Accuracy of Clustering as a Method to Group Distribution Feeders by PV Hosting Capacity

As a result of the CSI work, we were regularly asked how accurate clustering is for grouping distribution feeders by their PV hosting capacity. These questions led to some work building off the results in order to examine the correlation between feeder characteristics and PV hosting capacity. Hosting capacity results for 214 study feeders were used to predict a range of hosting capacities for an addition 7929 feeders using clustering techniques. Several methods were explored to try to improve the accuracy for predicting hosting capacity, including increasing the number of clusters, selecting variables that are highly correlated to hosting capacity for clustering, and weighting highly correlated clustering variables.

The range of hosting capacities for each cluster is shown using boxplots in Figure 6. Boxplots are useful for identifying outliers and for comparing distributions. The blue box is the interquartile range (IQR) and it represents the values between the 75th percentile and the 25th percentile covering the middle 50% of the data. The median for the cluster is shown by the red line and outliers are shown by the red "+" markers. The whiskers extend out to capture all values that are less than third quartile +1.5 IQR and greater than first quartile -1.5 IQR. Any data not included between the whiskers is plotted as an outlier.

The number of study feeders in each cluster is shown in the upper portion of the figure. Clusters with four or more feeders were plotted and analyzed. The minimum number of study feeders per cluster was set at four to ensure sufficient data to define a meaningful range of hosting capacities per cluster. The most populated cluster is cluster 7 with 114 study feeders. It is a 12-13.8 kV cluster with a range of hosting capacities from 0.2 to 4.3 MW excluding outliers. The box height is 1.5 MW which is the range of hosting capacity values for 50% of the study feeders in the cluster. The cluster with the greatest range of hosting capacities is cluster 2 with 37 study feeders. It is a 19.8kV to 34.5kV cluster with a range of hosting capacities from 0.3 to 10.2 MW excluding outliers. The box height is 4.6 MW which is the range of hosting capacity values for 50% of the study feeders in the cluster. The box height represents the central variation in the cluster hosting capacity distribution.

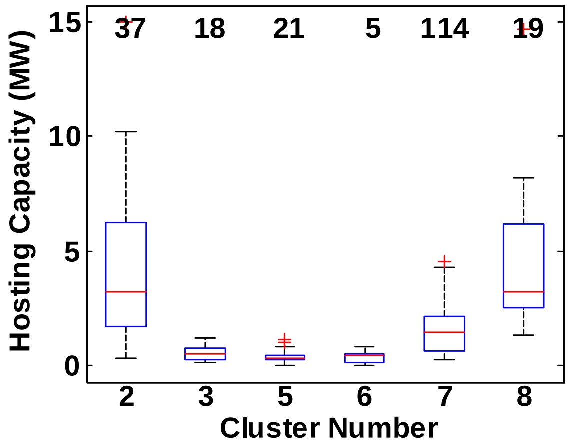



**Figure 6. Boxplot of hosting capacity variation per cluster for 8 cluster solution for 8,143 feeders using 8 cluster variables**

The accuracy of clustering as a method to group distribution feeders into specific ranges of PV hosting capacity is shown to be relatively inaccurate. Clustering is still useful as it provides good separation between clusters in many cases, but it has its limitations. The best clustering solutions for the various methods explored did not predict the hosting capacity accurately and the best solution had an average hosting capacity variation of 76%. Clustering will never perfectly group feeders such that all unique characteristics match with a single PV hosting capacity for the feeder, but it can provide a rough estimate of the hosting capacity for similar types of feeders.

## Significant Accomplishments and Conclusions for Task 1

- Developed statistical clustering method to identify 22 representative feeders out of 8000+ utility feeders from the collaborating utilities PG&E, SCE and SDG&E.
- Suggestions for modifying CA Rule 21 were made based on technical analysis of PV impacts.
- A revised CA Rule 21 interconnection screening process was developed that not only considers peak load levels, but also other critical factors including PV location, aggregate PV effects, and most importantly specific feeder characteristics such as voltage class, voltage regulation schemes, and operating criteria.
- Developed two alternative screens to the 15% Rule that increased the accuracy of the screening process by reducing “false positive results” by at least 70%
- Demonstrated that the new screening criteria identified 100 % of the interconnection requests that will cause harmful impacts. ( 6 validation feeders)

## Inventions, Patents, Publications and Other Results for Task 1

M. J. Reno, and R. J. Broderick, Technical Evaluation of the 15% of Peak Load PV Interconnection Screen, IEEE Photovoltaic Specialists Conference, June 2015.

R. J. Broderick, K. Munoz-Ramos, and M. J. Reno, " Accuracy of Clustering as a Method to Group Distribution Feeders by PV Hosting Capacity", IEEE PES T&D Conference and Exposition, 2016

**Sandia Technical Publications:**

Broderick, Robert J., Joseph R. Williams, and Karina Munoz-Ramos. "Clustering Method and Representative Feeder Selection for the California Solar Initiative." SAND2014-1443

"Alternatives to the 15% Rule," Sandia National Laboratories, SAND, 2015.

**External Technical Reports:**

"Current Utility Screening Practices, Technical Tools, Impact Studies, and Mitigation Strategies for Interconnecting PV on the Electric Distribution Systems," EPRI, Technical Report 3002002562, 2013.

"Clustering Methods and Feeder Selection for PV System Impact Analysis," EPRI, Technical Report 3002002562, 2014.

"Alternatives to the 15% Rule: Final Project Summary," EPRI, Technical Report 3002006594, 2015.

"Alternatives to the 15% Rule: Modeling and Hosting Capacity Analysis of 16 Feeders," EPRI, Technical Report 3002005812, 2015.

"Alternatives to the 15% Rule: Modified Screens and Validation," EPRI, Technical Report 3002005791, 2015.

## Path Forward for Task 1

See overall Path Forward section at end of document.

## Background for Task 3: Technical Feasibility of Sunshot high PV deployment scenarios

Task 3 is to determine by detailed simulation the technical feasibility of achieving high PV deployment on a wide variety of feeders in a cost-effective manner, without compromising safety or reliability. This task covers analysis of a variety of feeder topologies and PV deployment scenarios to develop a more general understanding high penetration PV impacts as a function of feeder characteristics. Sandia will focus on solving modeling challenges with highly distributed PV systems and developing a more general understanding of feeder characteristics that relate to maximum feeder hosting capacity.

Task 3 is significant because the study effort will focus on interconnection issues not covered in detail in previous high PV deployment studies [8-13] These aspects include: (1) developing a more general understanding of feeder characteristics that relate to the feeders locational hosting capacity and focus on analyzing feeder topologies, such as long rural feeders, that are most likely to have impacts, (2) focusing on solving the modeling challenges with highly distributed PV systems in high PV deployment scenarios including the voltage rise issues they may cause on single phase shared distribution secondary and (3) determining low-cost mitigation strategies and solutions for typical impacts.

Task 3 involves developing general guidelines to overcome typical system impacts. Based on the analysis results, Sandia will develop analysis methods to make the impact study process more comprehensive and efficient at identifying potential impacts.

The successful outcome of this project activity will be a better basis to estimate the nature of and impact areas associated with high PV deployment. Expanding our understanding of the impacts of high PV deployment on the larger electric distribution system in the U.S. will be crucial to mitigating interconnection costs and focusing time and resources on the interconnection requests with the greatest system impact risk.

## Project Objectives for Task 3

**Advanced Inverters:**
The main new objective for Smart Inverters is to develop guidelines for effective use of smart inverters given the unique hosting capacity of the California grid. Technical details and requirements of the grid will be considered along with specific functionalities and limits available in modern PV inverters. The research is needed to realize the full value of PV in collaboration with the electric grid.

**Feeder Impact Risk Scoring Technique (FIRST):**
The purpose of this task is to develop by the analysis of detailed simulation a simple methodology for screening new PV installations for risk posed to the distribution network. The methodology will be called the Feeder Impact Risk Scoring Technique, or FIRST for short. This task covers analysis of a variety of feeder topologies and PV deployment scenarios to develop a more general understanding high penetration PV impacts as a function of feeder characteristics. The impacts studied will include voltage, thermal, and protection violations.

Sandia will focus on solving modeling challenges with highly distributed PV systems and developing a more general understanding of feeder characteristics that relate to maximum feeder hosting capacity. To consider any potential feeder configuration and PV deployment requires a large number of scenarios tested on many different feeders. This complicates the analysis to ensure tractability and scalability while still achieving meaningful results.

The approach for Task 2 is to study the following aspects:

(1) Developing a more general understanding of feeder characteristics that relate to locational feeder hosting capacity
(2) Solving the modeling challenges with highly distributed PV systems in high PV deployment scenarios

To accomplish these general goals, a number of feeder models must be studied under various PV placement scenarios. To get a better understanding of how feeder characteristics impact PV locational hosting, the much more tractable analysis of a single three-phase PV plant placed throughout the feeder is made, called a "centralized" PV placement.

**Circuit Reduction:**
Objective of circuit reduction was to develop feeder circuit reduction methods for unbalanced circuits using realistic power system assumptions that allow for faster modeling of distribution feeder in alternative simulation platforms, and for quasi static time series analysis and other advanced studies.

**FY15 Subtasks**

Subtask 3.1: Perform detailed distribution feeder impact analysis with high PV deployments for distribution feeders with a range of feeder topologies and feeder characteristics and simulate Advanced Inverter functionality being proposed under new Rule 21 Advanced inverter task force.
Subtask 3.2: Hosting Capacity Determinations with Smart Inverter Settings: Perform detailed hosting capacity calculations with each smart inverter function.
Subtask 3.3: Develop feeder circuit reduction methods to handle generators with advanced inverter functions and to handle a multiplicity of different load profiles and PV power profiles.
Subtask 3.4: Fully validate FIRST by expanding to a larger set of feeders. Complete the analysis and evaluation of 10 or more feeders with different feeder topologies using FIRST. Protection analysis will be added where data is available.
Subtask 3.5: Develop tool to implement the FIRST method to improve a utilities interconnection screening process.
Subtask 3.6: Develop a method to generate load profiles at high time resolution (1-10second) for QSTS studies using 15 minute load data and load research data from utilities. Investigate the improvements in impact analysis accuracy using high time resolution load profiles rather than smoothed interpolated 15 minute data.

| | Metric Definition | Success Values | Measured Value | Assessment Tool | Goal Met | Data |
|---|---|---|---|---|---|---|
| ***Milestone 3A*** | Grid integration studies for Advanced Inverter functions proposed under new Rule 21 Advanced inverter task force. | Perform detailed distribution feeder impact analysis with high PV deployments for **at least 5** distribution feeders with a range of feeder topologies and feeder characteristics and simulate Advanced Inverter functionality | Completed the analysis and evaluation of **7 feeders**. | Determine the range of advanced inverter functionality and advanced inverter set points. | Yes | See pages 20-32 of report |
| ***Final Deliverable*** | Determine the range of advanced inverter functionality and advanced inverter set points needed to mitigate DG impacts without causing problems for utility distribution operations. This demonstrates the value of advanced inverter functions and promotes their widespread usage to mitigate common grid integration impacts that vary with feeder topologies, feeder characteristics and PV deployment scenarios. | | | | | |
| ***Status of Final Deliverable*** | Several fixed power factor functions (median X/R ratio, weighted DER X/R average, and voltage sensitivity-based), volt/var, and volt/watt advanced inverter functions were simulated on seven feeders with a stochastic hosting capacity analysis in order to demonstrate more than a 50% increase in hosting capacity on average. | | | | | |

| | Metric Definition | Success Values | Measured Value | Assessment Tool | Goal Met | Data |
|---|---|---|---|---|---|---|
| ***Milestone 3B*** | Fully validate FIRST by expanding to a larger set of feeders to determine the likelihood of feeder impact due to high penetration PV for a wider set of feeder types. Quantify the potential improvements in available locational hosting capacity. | Complete the analysis and evaluation **of 10 or more** feeders with different feeder topologies using FIRST. | Completed the analysis and evaluation of **216 feeders.** | Improvement in available locational hosting capacity. | Yes | SAND report and Grid PV toolbox. |
| ***Final Deliverable*** | A tool to implement the FIRST method to improve a utilities interconnection screening process by utilizing feeder classifications to estimate possible impacts of high penetration scenarios. Advanced tool functions, scripts and codes will be made publicly available with simple manual/guide and sample data included via a web download. | | | | | |

| | |
|---|---|
| ***Status of Final Deliverable*** | Completed the analysis and evaluation of **216 feeders** using the feeder impact risk score technique (FIRST). Demonstrated how feeder characteristics relate to maximum feeder hosting capacity. Advanced tool functions, scripts and codes made publicly available as the "GridPV" toolbox on the Sandia Website. |

| | Metric Definition | Success Values | Measured Value | Assessment Tool | Goal Met | Data |
|---|---|---|---|---|---|---|
| ***Milestone 3.C*** | Develop a method to generate load profiles at high time resolution (1-10second) for QSTS studies using 15 minute load data and load research data from utilities | Quantify the improvements in impact analysis accuracy using high time resolution load profiles. Quantify improvements in the two impact areas of voltage regulation and voltage profiles. | High resolution load profiles were found to only improve the accuracy of voltage regulation results by less than 5% | QSTS modeling and studies | Partial | See pages 43-45 of report |

| | |
|---|---|
| ***Final Deliverable*** | A methodology with accompanying tool functions, codes and scripts will be made publicly available with simple manual/guide and sample data included via a web download. |
| ***Status of Final Deliverable*** | Partial complete. Original objective to develop load profiles at high time resolution was found to be unnecessary as linear interpolation of 15 minute load data was found to be very accurate at estimating tap changes on a feeder compared to 1 second load data. The project demonstrated that linear interpolation of low resolution load data has an acceptable accuracy for determining voltage regulator impacts due to load variability. |

## Project Results and Discussion Task 3

### Advanced Inverter Functions

The main goal of this task is to develop guidelines for effective use of smart inverters given the unique hosting capacity of the California grid. Technical details and requirements of the grid are considered along with specific functionalities and limits available in modern PV inverters. The research is needed to realize the full value of PV in collaboration with the electric grid. The project addresses the lack of guidelines for grid support and the lack of available tools to determine effectiveness of inverter advanced functions. The end goal is to be able to recommend settings for the smart inverter functions currently being considered as part of the update to Rule 21 and to provide smart inverter thresholds to enable manufacturers to specify their equipment and suggested defaults.

This task was performed in collaboration with EPRI and NREL. The main outline of the project included: selecting study feeders, a detailed hosting capacity analysis of those feeders, development of advanced inverter functions that range in complexity, and demonstrating the impacts of the advanced inverter functions.

The original selection of the utility feeders was based on the results of a comprehensive clustering analysis where each feeder from the three CA investor-owned electric utilities has been characterized and grouped into representative sets. The representative sets are not suggesting all feeders within the set will have a similar response to distributed generation, but the sets allow selection of several feeders that will have considerably different characteristics. Of the originally selected 22 feeders, 6 were selected for analysis of different advanced inverter functions.

A detailed feeder model was developed for each of the selected feeders. The models are based on the utility planning model and converted into the OpenDSS distribution software. The OpenDSS distribution software was used so that detailed analysis can be performed similarly across the different utilities even though the original models come from different software platforms.

The analysis of the models was conducted with PV as the distributed energy resource. The hosting capacity analysis determines the amount of PV that can be accommodated on a distribution feeder without impacts exceeding predefined utility guided thresholds. The hosting capacity for each feeder is unique for voltage and protection issues. The detailed feeder impact analysis performed identifies when potential issues from aggregate distributed generation are not properly identified and also when a feeder is capable of accommodating considerably higher levels of distributed generation.

<u>Background</u>

Some of our early work showed that advanced inverter functions can be used for removing over-voltage [1-3] and improving hosting capacity [4]. For example, a 12.47kV distribution feeder (peak load of 1.71MVA) with a PV hosting capacity that is limited by voltage constraint violations in Figure 1a. This figure depicts the percentage of buses in the feeder that will allow a particular size PV interconnection before various violations occur. The green region where no buses have violations up to a certain PV size is considered the feeder's hosting capacity (HC). The blue region is where no violations occur based on the locational hosting capacity (LHC). In Figure 1a there is no inverter reactive power control considered.

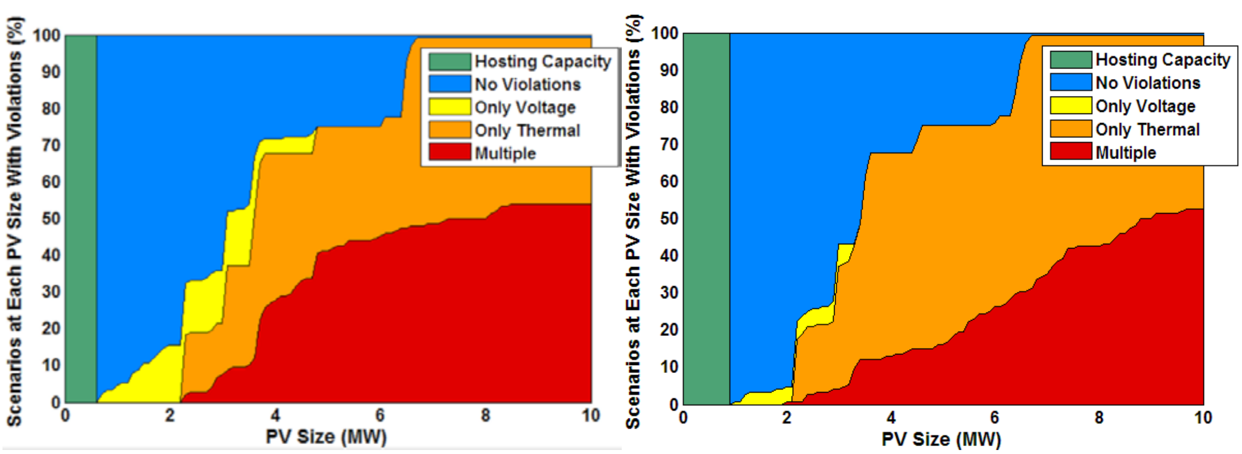



**Figure 7. PV hosting capacity feeder signature for a) base case with no inverter control, and b) volt/var control.**

The simulation is run again with the inverter assumed to have a 20% margin of kVA capacity over the real power output of the PV system and using volt/var control. The results of this case are shown in Figure 1b. Clearly, the voltage regulating control has reduced the yellow voltage violation region. The feeder HC is also increased by 50% from 600kVA to 900kVA, and the LHC is also expanded to more regions on the feeder.

This analysis was run on six different voltage constrained distribution feeders. The results in Table 1 show an average of an 84% increase in hosting capacity with volt/var functionality.

**Table 1. Summary of hosting capacity increase (HCI) due to volt/var control of PV inverters.**

| Feeder # | Voltage (kV) | Peak Load (MVA) | Base HC (kVA) | HCI (kVA) | HCI (%) |
|---|---|---|---|---|---|
| 1 | 12.47 | 1.7 | 600 | 300 | 50 |
| 2 | 12.47 | 7.1 | 500 | 600 | 120 |
| 3 | 12.47 | 6.2 | 1000 | 600 | 60 |
| 4 | 12.47 | 1.17 | 300 | 300 | 100 |
| 5 | 12.47 | 0.93 | 600 | 800 | 133.3 |
| 6 | 12.47 | 3.98 | 1400 | 600 | 42.9 |
| **Avg.** | **12.47** | **3.51** | **733** | **533** | **84.4** |

More details about these results can be seen in [4], but there is obviously some potential advantage to applying advanced inverter controls to PV interconnections.

Study Feeders

As mentioned in the introduction, the 22 feeders from the California clustering analysis were down-selected to 7 feeders for detailed advanced inverter analysis. The study feeders are all from California utilities (PG&E, SDG&E, and SCE) and include a range of topologies and feeder characteristics. The topology of each feeder is shown in Figure 2. The feeders include the variation on voltage classes from 4kV to 21kV, but are mostly in the 12kV class. Two of the feeders include voltage regulators. The study feeders were selected from distribution systems that had previously been analyzed for their PV hosting capacity [5], so a range of hosting capacities was also selected.

| Feeder Name | Peak Load (MW) | Farthest 3-phase Bus (km) | PV Hosting Capacity | Nominal Voltage | Line Regs | Switching Caps |
|---|---|---|---|---|---|---|
| **DC2** | 3.6 | 17.9 | Low | 12 kV | 1 | 1 |
| **DV1** | 3.4 | 11.7 | Moderate | 12 kV | 0 | 1 |
| **QB1** | 2.2 | 2.8 | Low | 4 kV | 0 | 0 |
| **QS1** | 9.2 | 11.9 | Low | 12 kV | 1 | 6 |
| **QN1** | 16.7 | 10.3 | High | 21 kV | 0 | 6 |
| **CG1** | 6.4 | 15.5 | Moderate | 12 kV | 0 | 6 |
| **CS1** | 5.0 | 4.7 | High | 12 kV | 0 | 1 |

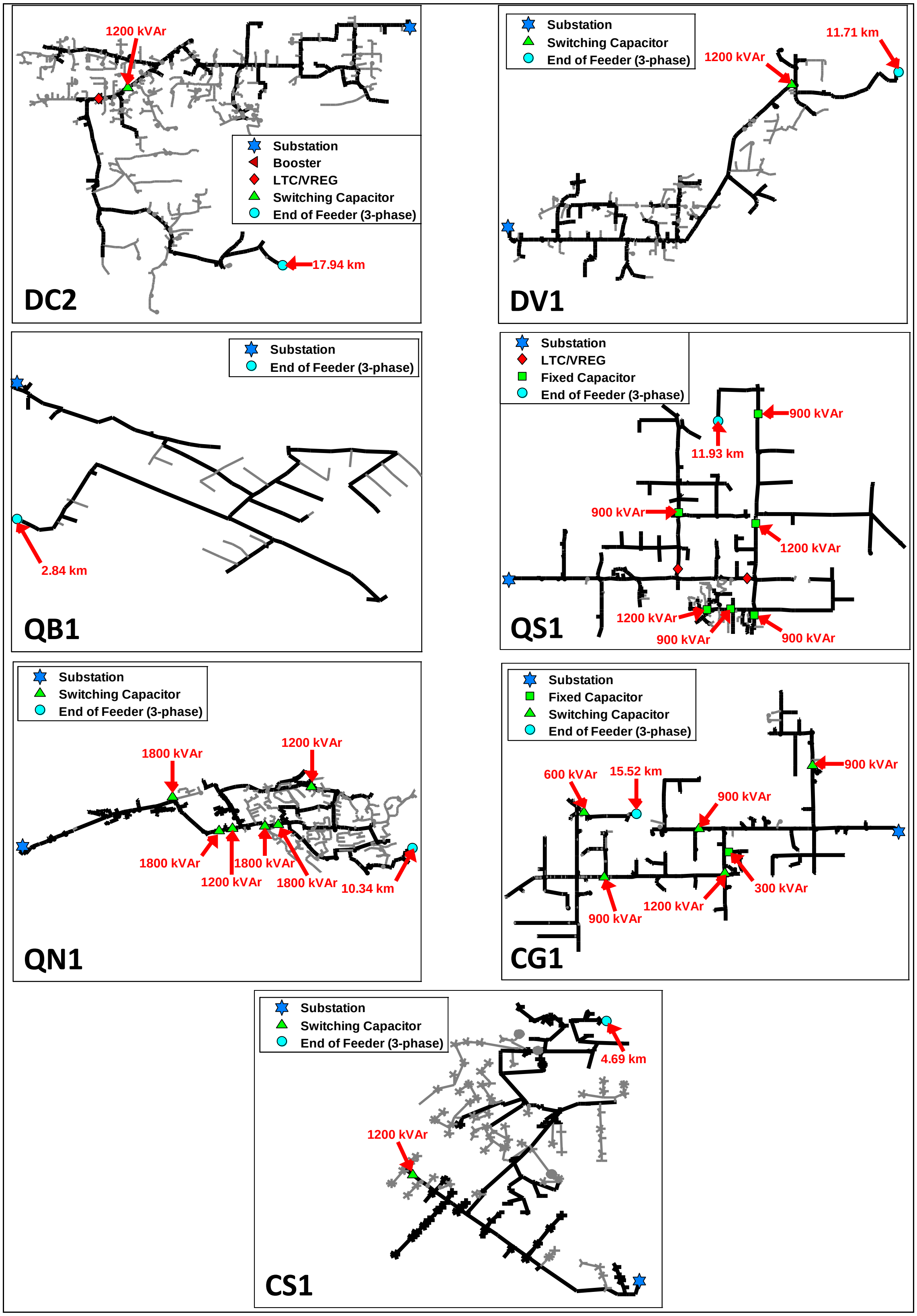



**Figure 8. Topology diagrams for each of the 7 study feeders.**

Rule 21 Advanced Inverter Functions

The California Public Utility Commission (CPUC) is implementing advanced inverters in a phased process. Phase 1 addresses autonomous functionalities, phase 2 addresses communications standards, and phase 3 identifies advanced functionalities, some of which utilize phase 2 communications standards. The phase 1 autonomous functions include the ability to “ride-through” wider ranges of voltage and frequency fluctuations, the capability to actively counteract voltage changes (ramp rate limiting and volt/var control), and the “soft-reconnect” capability to avoid sharp spikes when large numbers of DER systems reconnect to the distribution system, while still safely disconnecting during power outages. In order to improve hosting capacity, our analysis focused on the functions that impact the voltage during normal operations. This includes fixed power factor, volt/var, and volt/watt.

*Fixed Power Factor*

The simplest advanced inverter function is fixed power factor. For a single PV system on a feeder, it is straightforward to calculate the power factor necessary to mitigate any voltage deviation. Using the X/R ratio of the point of common coupling (PCC), the lagging power factor can be directly calculated to absorb enough reactive power to offset any voltage rise from the real power injection. Figure 3 shows an example with a single PV system absorbing reactive power. The equations to derive the power factor are shown below the figure.

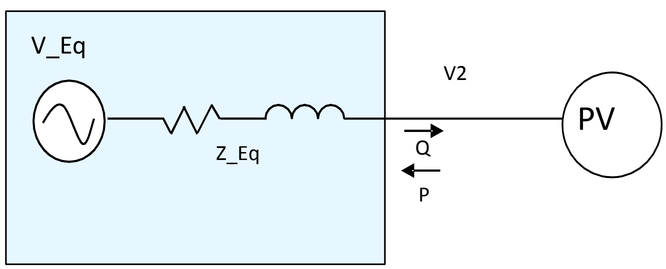



**Figure 9. Example of a single PV system absorbing reactive power.**

$$\Delta V_{pu} \cong \frac{R \times P + X \times Q}{V} = 0$$

$$\frac{P}{Q} = -\frac{X}{R}$$

$$Power\ factor = \frac{\frac{P}{Q}}{\sqrt{\left(\frac{P}{Q}\right)^2 + 1}}$$

Since most PV systems are connected through a step-up interconnection transformer, the percent load loss at full load (%loadloss) and percent reactance (XHL) of the transformer should be included in the calculation. This modifies the equation to:

$$\frac{P}{Q} = -\frac{X}{R} - \left[\left(\frac{\%loadloss}{100}\right) + \frac{X}{R}\left(\frac{XHL}{100}\right)\right]\sqrt{1 + \left(\frac{X}{R}\right)^2})$$

The first thing to notice about these equations is that the power factor to negate voltage rise depends on location. There is not a single power factor setting that will work for every location on the feeder. The most effective solution will involve a site-specific setting based upon PCC X/R ratio.

The second thing to notice is that these calculations work very well for a single inverter, but the situation becomes much more complicated for distributed PV with many systems interconnected around the feeder. It is necessary to develop new methods for determining appropriate settings for multi-inverters power factor control. Three methods are proposed that range in complexity:

**Table 2. Three ways to determine settings for multi-inverter power factor control.**

| Method | Requires Feeder Info | Requires PV Sizes and Locations | Calculation Complexity | Number of Power Factors |
|---|---|---|---|---|
| **Median X/R Ratio of Feeder** | Yes | | Hand | 1 per Feeder |
| **Weighted PCC X/R ratio** | Yes | Yes | Spreadsheet | 1 or 2 per Feeder |
| **Sensitivity-Based Optimization** | Yes | Yes | Optimization | Each PV has unique PF |

*Median X/R ratio along feeder*
This method only requires the short-circuit impedances of the feeder. Independent of the number, size, or locations of PV systems, the value will always be the same. A simple hand calculation is performed to determine the median X/R along the feeder, which is then converted to a single power factor number.

*Weighted DER Point of Interconnect X/R*
This method requires both the feeder information and the locations and sizes of PV currently installed. A spreadsheet calculation can be used to average the X/R ratios of all PV primary buses weighted by the PV size in order to determine the weighted X/R ratio. The power factor is calculated by taking into account the interconnection transformer losses. If the power factor is below 0.9, set it to 0.9. For any PV that by itself at unity power factor causes less than 1% voltage rise at its PCC, set the PV system power factor to unity. This method is effective for a single PV system, but multiple PV systems can result in adverse impacts.

*Sensitivity-based algorithm*
The final method for determining settings for multi-inverter power factor control involves a detailed iterative, load-flow-based optimization calculation. The algorithm is developed and presented in [6]. The optimization uses a linear voltage sensitivity calculation for all buses with PV. The voltage sensitivity matrix SP is used, where $SP_{ij}$ represents the voltage change at bus $i$ for a real power change at bus $j$. The voltage sensitivity matrix SQ has a similar definition for reactive power injections. The sensitivity matrices are filled using iterative load flows adding a PV injection one at a time to each bus $j$ and measuring the increase in voltage at each bus $i$. The objective function of the optimization is to minimize the square of the voltage change at each bus, constrained by the power factor being within [1, ±0.9] for each PV.

$$\Delta V_i = (SP_{i1}P_1 + SQ_{i1}Q_1) + (SP_{i2}P_2 + SQ_{i2}Q_2) + \cdots (SP_{iN}P_N + SQ_{iN}Q_N)$$

Objective: $$min \sum_{i=1}^{N} \Delta V_i^2$$

$$\text{Constraints: } \left|\frac{Q_i}{P_i}\right| \le 0.4843, i = 1 \cdots N \Leftarrow PF_i \in [1, \pm 0.9]$$

*Volt/Var*

The second advanced inverter function studied modifies the reactive power output based on the terminal voltage instead of the magnitude of real power output. The volt/var curve is show in Figure 4. The y-axis (reactive power output) is based on the inverter size. In this case for a 10% over rated inverter, the Qmax and Qmin are 44% of the total kVA rating of the inverter, which equates to a 0.90 power factor under full real power output. This is a fairly conservative volt/var curve with a smooth slope.

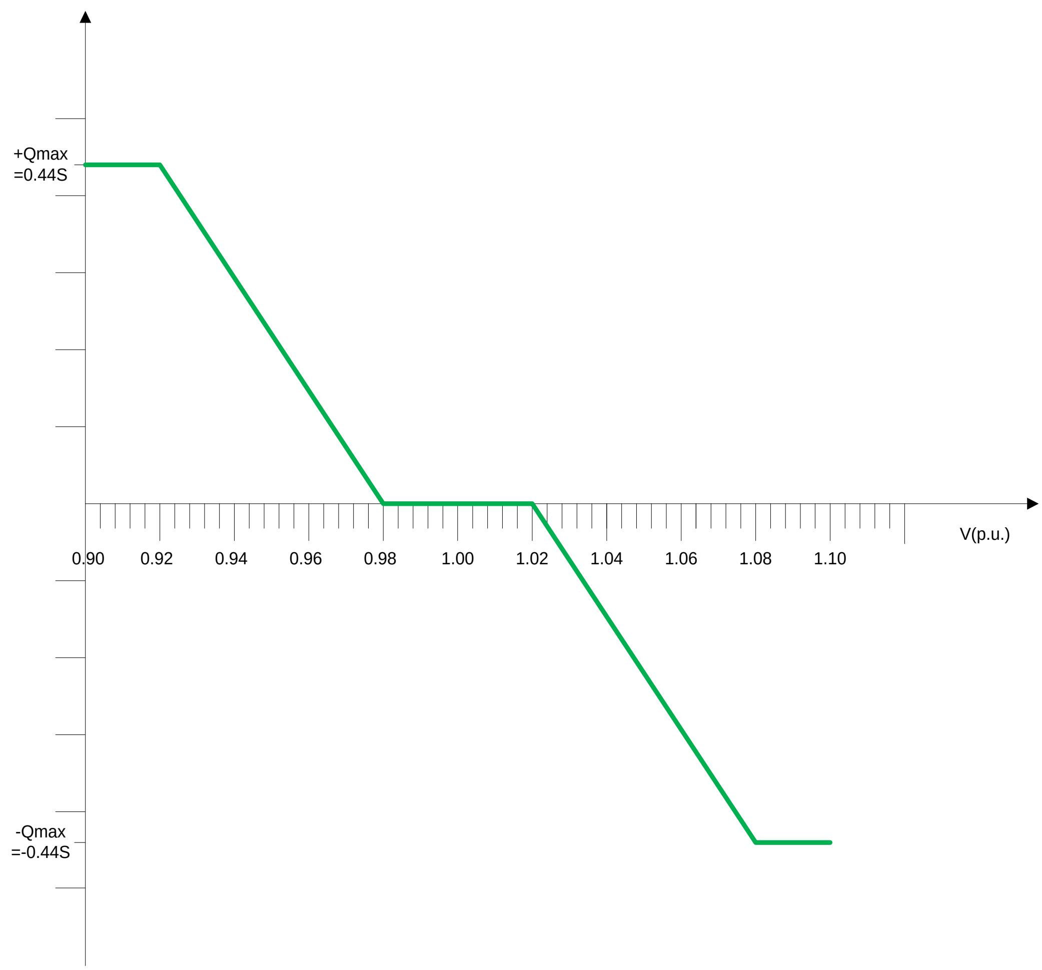



**Figure 10. Volt/var curve for 10% over-rated inverter showing the amount of reactive power output depending on the voltage at the output terminals.**

*Volt/Watt*

An example volt/watt curve is shown in Figure 5. For this analysis, the real power stays at full output until 1.05 pu voltage, and then decreases linearly to zero output at 1.10 pu voltage.

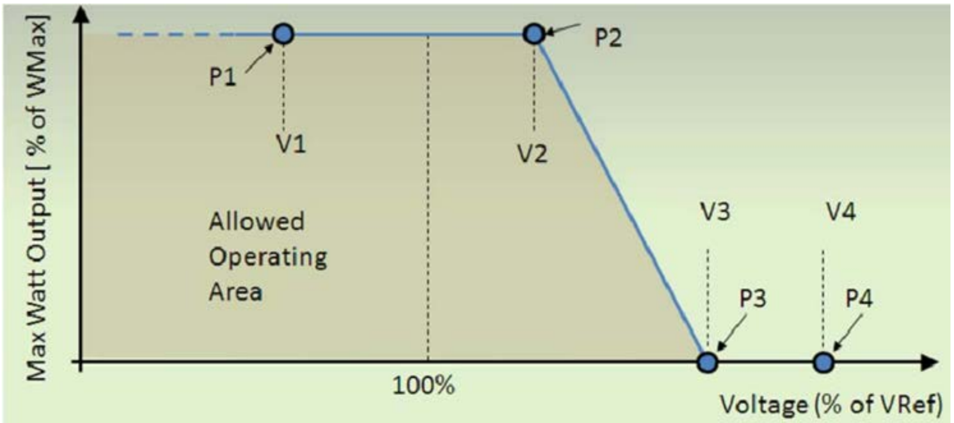



**Figure 11. Volt/Watt curve for the amount of real power output depending on the voltage at the output terminals.**

Analysis

The analysis approach [7] is focused on the feeder hosting capacity for large-scale PV (utility-class). Large-scale PV is based on 500 kW systems interconnecting to the three-phase feeder primary through a step-up transformer. The PV is stochastically deployed and simulated to determine the feeder response. The stochastic nature of the analysis develops thousands of potential distributed PV deployments that capture the unpredictability of 'where' and 'how much' PV will eventually be installed. The hosting capacity is determined when a stochastically created PV deployment causes the feeder-wide response to exceed established thresholds. At this point, the feeder has met the limit for maximum total amount of PV that can be hosted for that particular deployment. However, the analysis is not complete at this point. Since feeder hosting capacity can widely vary based upon the size and location of solar PV, 1000's of different PV deployment scenarios are simulated to determine the range in hosting capacity values that might occur.

Large-Scale PV deployment uses a select number of three-phase primary line locations as probable points of interconnection. At each penetration level, one ungrounded 500 kW PV system is interconnected at a randomly selected location behind a 480 V three-phase step-up transformer. The PV penetration level is increased until 10 MW of PV has been deployed (20 MW for feeders above 15 kV). Each penetration level builds upon the previous penetration level for a given scenario. Figure 6 illustrates the Large-Scale PV deployment.

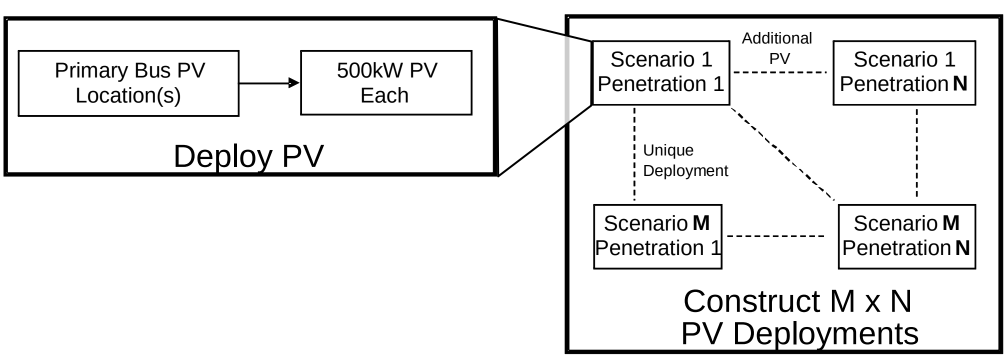



**Figure 12. Large-Scale PV Deployment Routine**

The analysis determined the 'worst case' feeder response that would occur in any condition. The power flow analysis is conducted for the four base load levels:

- Midday maximum – maximum feeder load level derived from 8760 feeder measurement data; 11am-1pm local time considered only
- Midday minimum – minimum feeder load level derived from 8760 feeder measurement data; 11am-1pm local time considered only

The midday maximum and minimum loads determine the most probable bounds for the feeder response during the periods when PV can produce full output.

Table 3 shows a summary of criteria used in the analysis to identify potential issues. The flags in this table were applied for study purposes and are not necessarily planning limits currently applied in the industry. These values were used for the general hosting capacity analysis across all feeders to allow uniform comparisons to be made. For the advanced inverter analysis, the reactive power does not change a PV system's fault current injection or harmonics, so only the voltage analysis is performed.

**Table 3. Monitoring Criteria and Flags for Distribution PV Analysis**

| *Category* | *Criteria* | *Basis* | *Flag* |
|---|---|---|---|
| Voltage | Overvoltage | Feeder voltage | ≥ 1.05 Vpu at primary<br>≥ 1.05 Vpu at secondary |
| | Voltage Deviation | Deviation in voltage from no PV to full PV | ≥ 3% at primary<br>≥ 5% at secondary<br>≥ ½ bandwidth at regulators |
| | Unbalance | Phase voltage deviation from average | ≥ 3% of phase voltage |
| Loading | Thermal | Element loading | ≥ 100% normal rating |
| Protection | Element Fault Current | Deviation in fault current at each sectionalizing device | ≥ 10% increase |
| | Sympathetic Breaker Tripping | Breaker zero sequence current due to an upstream fault | ≥ 150A |
| | Breaker Reduction of Reach | Deviation in breaker fault current for feeder faults | ≥ 10% decrease |
| | Breaker/Fuse Coordination | Fault current increase at fuse relative to change in breaker fault current | ≥ 100A increase |
| | Anti-Islanding | Percent of minimum load | ≥ 50 % |
| Harmonics | Individual Harmonics | Harmonic magnitude | ≥ 3% |
| | THDv | Total harmonic voltage distortion | ≥ 5% |

The analysis examined the voltage impact to the entire modeled feeder. This included all nodes (buses) modeled along primary and secondary lines. Flags for the voltage category were applied separately to primary nodes, secondary nodes, and voltage regulation nodes. The flags were adjusted for nodes with control elements to account for control actions. The modified flag allowed better approximation of the PV penetration when the controls may begin to operate.

Overvoltage issues are a concern for both primary and secondary nodes due to reliability and power quality. Voltage deviation issues were examined for customer power quality, protection of equipment, and to know the potential voltage drop that could occur if PV is suddenly lost on the feeder. Voltage unbalance impacts power quality and equipment health.

The calculation of hosting capacity is best explained via illustration as shown in Figure 7. The figure shows the maximum primary feeder voltage versus total PV penetration. Recall that when applying the hosting capacity method, a wide range of possible PV sizes and locations are simulated. For each simulation, the feeder response was recorded and then post-processed to determine if and when any criteria from Table 3 is violated. When analyzing overvoltage, the absolute highest voltage anywhere on the feeder is determined. Each marker in Figure 7 shows the absolute maximum primary feeder voltage for each unique PV deployment. Once the maximum voltages are determined, the results are then broken down into three regions (A-green, B-yellow, C-red) identified in the figure.

Region A includes PV deployments, regardless of individual PV size or location, that do not cause maximum primary voltages to rise above the ANSI 105% voltage threshold (threshold shown by horizontal red line).

At the start of Region B, the first PV deployment exceeds the voltage threshold. This PV penetration level is termed the **Minimum Hosting Capacity** because the total PV in the deployment is the lowest of those analyzed that cause adverse impact. At the same penetration level there are many PV deployments that do not cause an adverse impact due to more optimal sizes/locations of individual PV systems. Perhaps most of these PV systems are located in areas of the feeder where the voltage is low and there is more headroom, or closer to the substation where the feeder is stronger. As penetration increases further, more and more scenarios begin to cause further impact and eventually result in a violation. It is likely in these PV deployment scenarios that the PV is located further from the substation where the feeder is weak, or near a line regulator or capacitor bank and therefore has less headroom. The rightmost side of Region B defines the **Maximum Hosting Capacity** where all PV deployments, regardless of individual PV sizes or locations, cause primary voltages to exceed the threshold. This is the maximum penetration level that can be accommodated under the given feeder conditions.

Region C identifies PV deployments that exceed the threshold regardless of individual PV sizes or locations. Aggregate PV of this magnitude will be problematic.

Feeder hosting capacity is the range indicated by Region B (yellow). This hosting capacity range depicts more/less optimal PV deployments. The minimum and maximum hosting capacity are metrics for determining the range of aggregate PV that can be accommodated on a feeder. The hosting capacity is similarly calculated for all issues shown in Table 3.

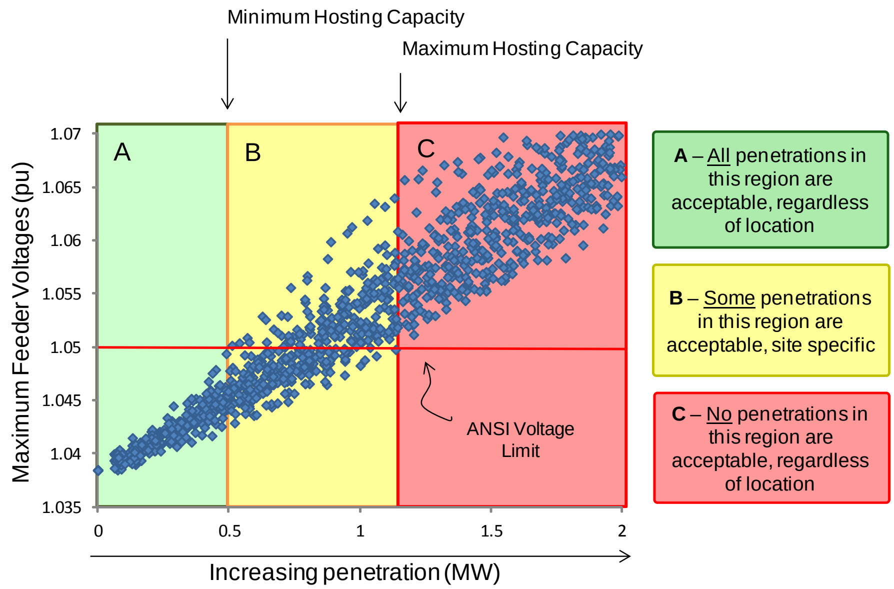



**Figure 13. Example Calculation of Hosting Capacity**

<u>Results</u>
The detailed hosting capacity analysis was performed on each of the seven feeders using each advanced inverter function. For the fixed power factor cases, the median X/R ratio (MR), weighted average (WA), and voltage sensitivity-based methods (VS) methods were used. In addition, the volt/var (VV) and volt/watt (VW) functions were tested. The first row of graphs in Figure 8 shows the hosting capacity of each analysis with the different feeders and advanced inverter functions. The second row of graphs in Figure 8 shows the improvement in hosting capacity from the initial case of unity power factor PV installations. While the advanced inverter functions always improve the hosting capacity due to over-voltage violations, the under-voltage graphs show lower hosting capacity before there is an under-voltage violation. The PV hosting capacity before either an over or under voltage violation occurs is shown in the third column.

In order to simplify the results, the average of the seven feeders was calculated for each hosting capacity improvement, as shown in Figure 9. Because volt/watt is curtailing PV output when there are over-voltages, it has no impact on the under-voltage hosting capacity. Both the median X/R ratio method and the voltage sensitivity-based method increased the over-voltage limited hosting capacity significantly. All fixed power factor methods increased the number of under-voltage issues compared to unity power factor systems, but many of the under-voltage issues existed in the base case without any PV.

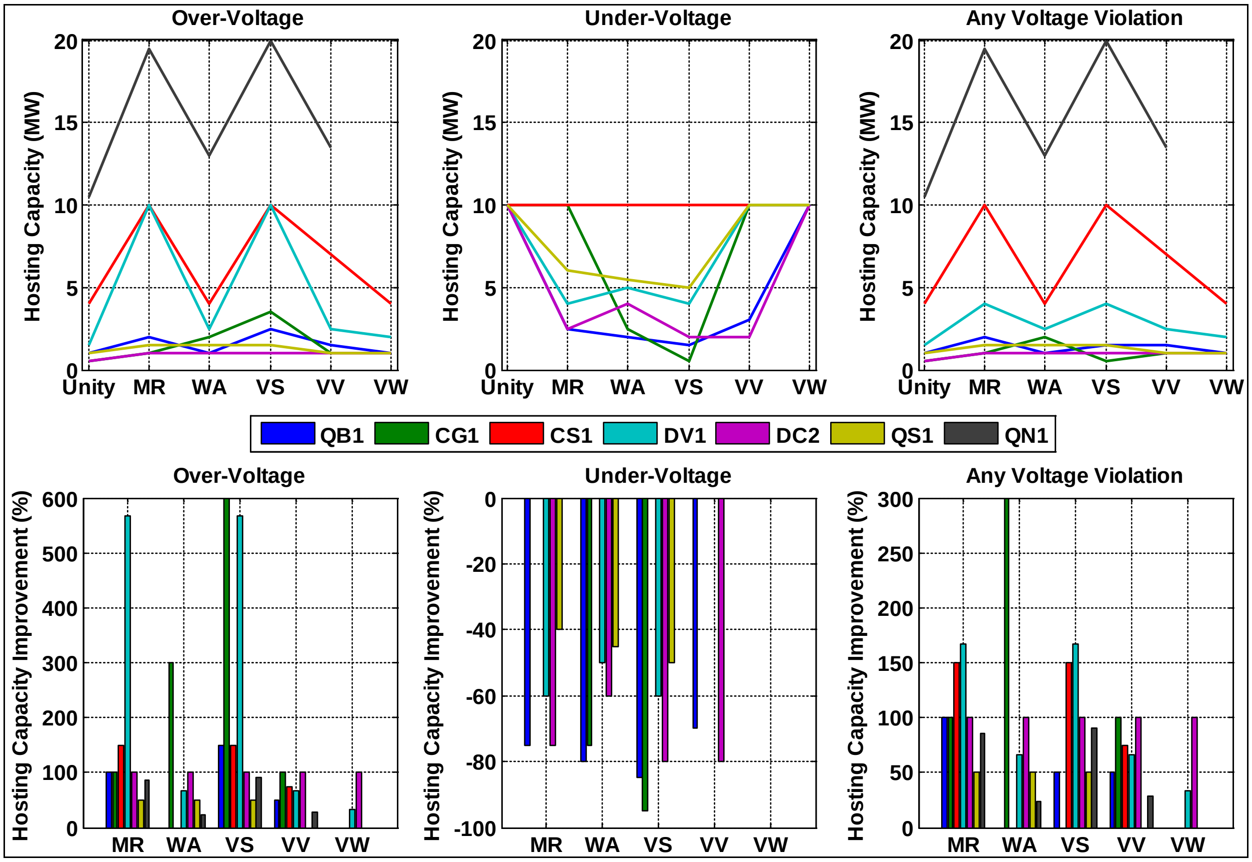



**Figure 14. Hosting capacity and hosting capacity improvement for each feeder using each advanced inverter function.**

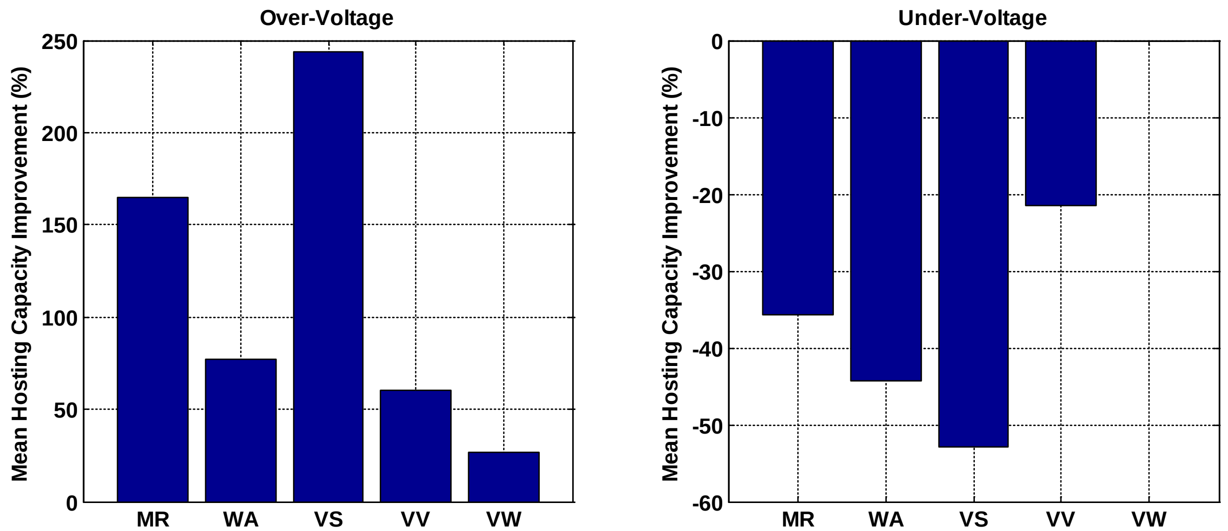



**Figure 15. Hosting capacity improvement averaged for the 7 feeders using each advanced inverter function.**

The results are summarized in Figure 10 for the improvements in hosting capacity before either over or under voltage occurs. There is a surprising conclusion that the simplest fixed power factor method based on the feeder median X/R ratio (MR) performed the best. We expected the voltage sensitivity-based (VS) fixed power factor method to be as close as possible to the optimal solution. While the voltage sensitivity-based method was the best at removing over-voltages, it also increased the under-voltage issues that limited hosting capacity. We expected volt/var (VV) to be more effective, but the initial curve applied was very conservative and not absorbing as much reactive power from the grid as some of the fixed power factor methods. Future work will investigate other volt/var curves. Because the simulated volt/watt curve only curtailed PV output above 1.05, it is not surprising that volt/watt (VW) does not improve hosting capacity significantly.

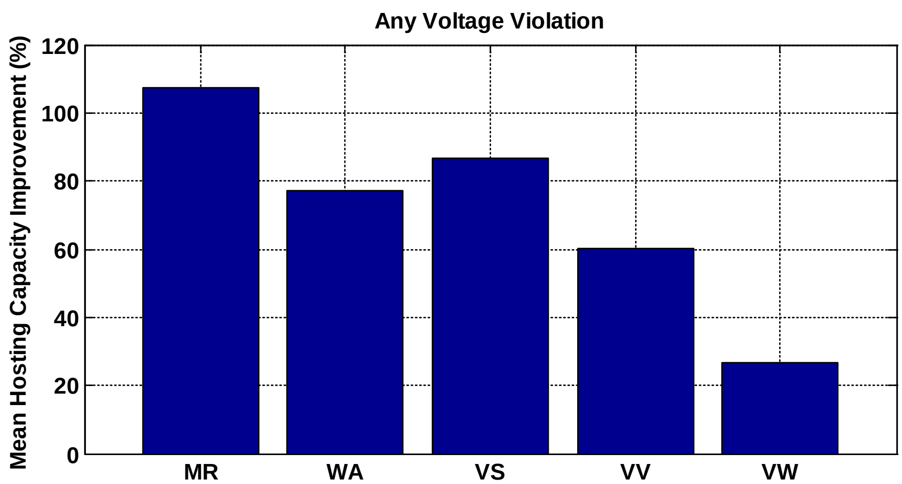



**Figure 16. Average hosting capacity improvement for all feeders limited by over and under voltage.**

Under current projects, there is ongoing and future research to investigate other volt/var and volt/watt curves in order to select the optimal set-points and to recommend appropriate advanced inverter settings. The current work will be used to guide improvements for better curves and settings. In addition, more advanced inverter functions, such as watt-trigged power factor and ramp rate limiting, will be simulated.

## PV Impact Studies:

Perform detailed simulation with advanced tool sets on 216 feeders with differing topologies, voltage control strategies/equipment and thermal limits. Performed simulation studies with high penetration PV on feeders and analyzed: 1) Determined feeder locational hosting capacity and 2) Determined the most likely impacts and 3) Generated a feeder hosting capacity map. See Figure 7 for 128 showing a subset of the 216 feeders analyzed.

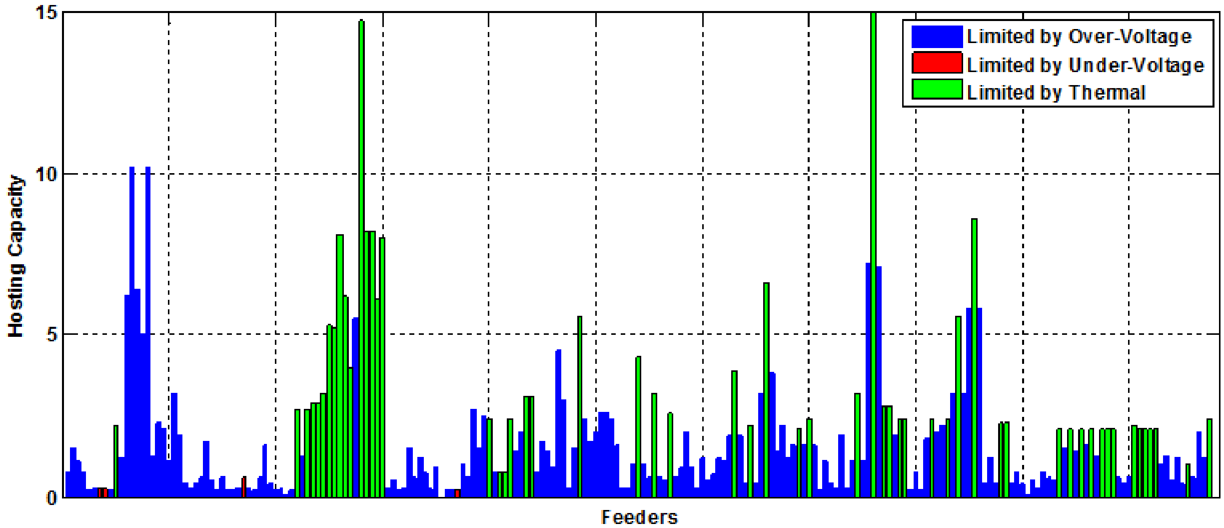
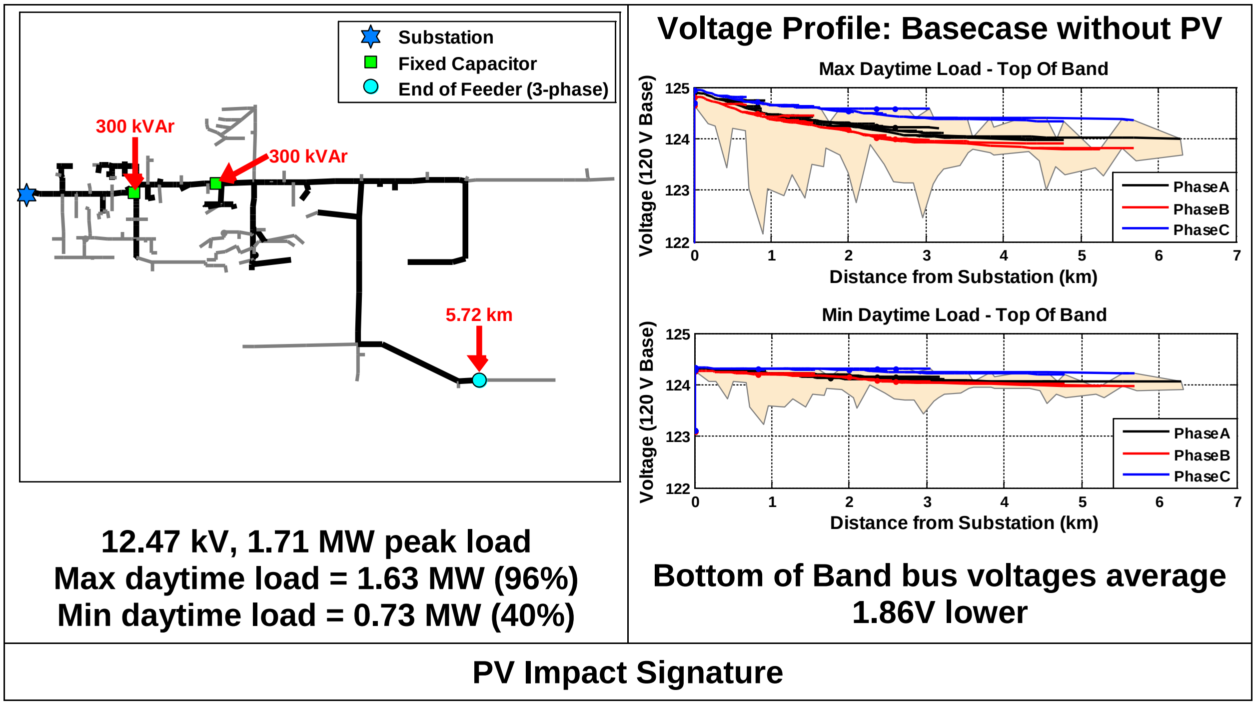



**Figure 17. Hosting Capacity for 216 feeders**

The overall impact of variable-sized PV systems interconnected to the medium-voltage distribution network is demonstrated in a concise, single-page analysis as shown in Figure 8. The efficient representation of a PV's impact on a feeder is an essential outcome of this task's research.



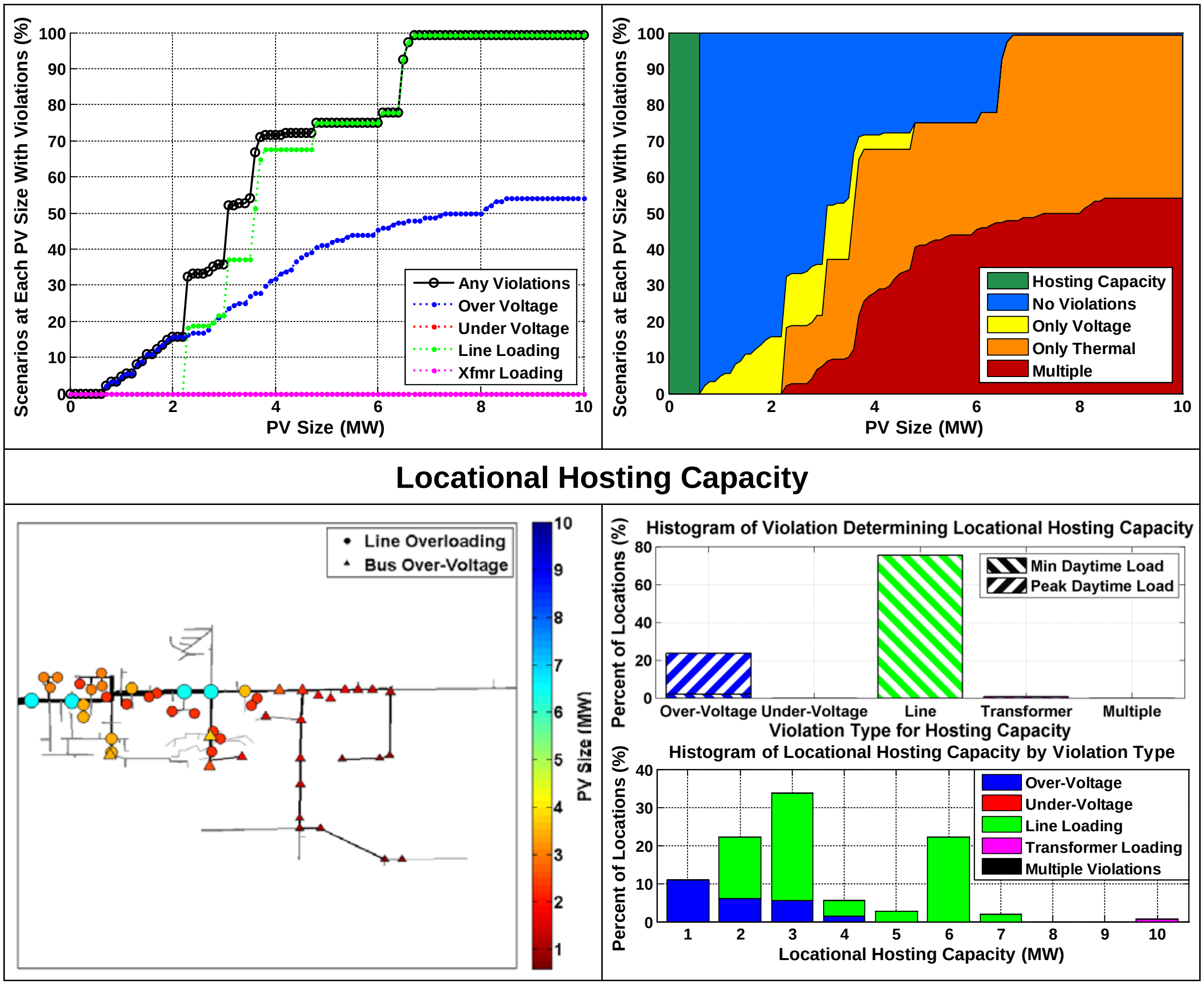



**Figure 18. Consolidated visualization of single three-phase PV placement results.**

**Identification and Generalization of Feeder Violation Regions:**
The colored regions of Figure 9 can be fairly accurately predicted using the following feeder parameters: voltage regulator setting, impedance from PV to regulator, PV size, load downstream of PV, and conductor type. The hosting capacity of the feeder can then be approximated to a good degree of accuracy, as shown in Figure 9. Being able to replicate the complex simulations with simplified calculations in this manner is the key outcome of FIRST.

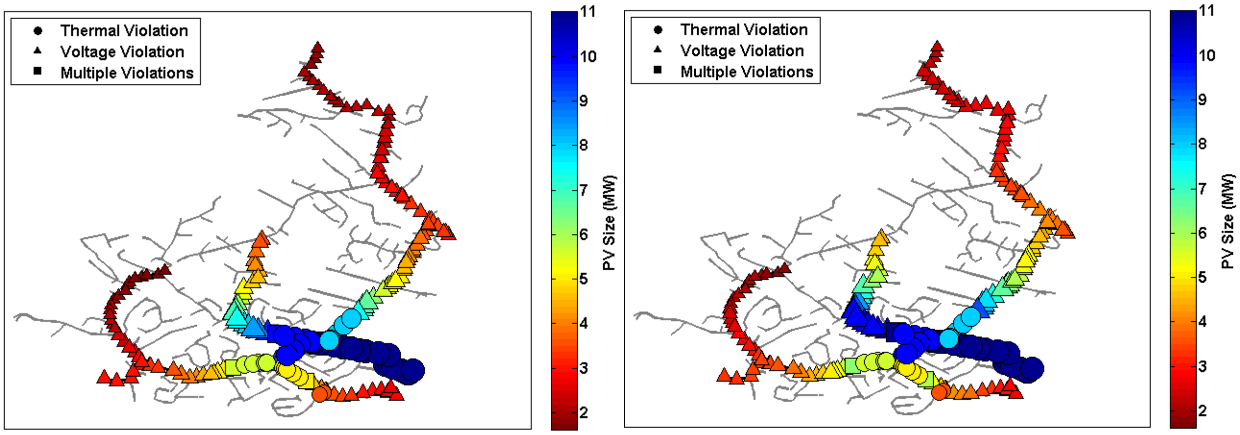



**Figure 19. Locational hosting capacity for 3-phase line sections on Ckt5 using (left) full analysis, and (right) simplified predictive hosting capacity**

## FIRST

As part of the Feeder Impact Risk Score Technique (FIRST) project, a database of distribution system models has been collected from various utilities throughout the United States. In total there are 79 distribution feeders in the database. Each has been converted from the utility software into OpenDSS and setup to run for FIRST. For the majority of feeders, the utility also provided at least a year of substation SCADA measurements for the feeder and the full details about substation impedance, voltage regulator settings, and capacitor switching controls. The load allocation method used for each feeder varies depending on the data provided, such as billing kWh data, metered peak demand, etc. Each feeder also includes an approximate model of the secondary system, often using standard transformer impedances by kVA size and 100 feet of 1/0 triplex cable between the transformer and the customer. Due to the number of feeders, some infrequent features are captured, such as 3-wire feeders without neutral wires and feeders with multiple voltage levels due to step-down transformers. Several surrogate models have been created from the original models by copying and morphing a few settings in the models. All modifications are done in such a way that the systems are still realistic and the gird operations are not impacted.

By the end of the project, the FIRST analysis had been performed on a total of 216 feeders. Compiling the results for a large number of feeders is important in order to capture the range of feeder types, voltages, topologies, and controls. The simulations for each feeder include very detailed results about PV locational hosting capacity and the types of risks and impacts of PV interconnections. The methodology is used to investigate a large number of potential PV scenarios (combinations of PV size and location) in OpenDSS. On average, there are around 40,000 PV scenarios analyzed per feeder. Analyzing such a large number of feeders and interconnections per feeder has resulted in over 3,000 hours of simulation time.

For each PV scenario, a series of simulations is performed to determine if that particular scenario would cause issues on the distribution system. The simulations include a range of load values that occur during daytime hours throughout the year, a range of feeder states as far as regulation equipment taps and switching capacitor states, and simulation of extreme PV output ramps. Steady-state voltage violations are determined using ANSI C84.1, thermal violations are defined by the component's amp rating, and temporary voltage violations are determined using the ITIC (CBEMA) curve.

Using the detailed simulation results, the PV size is increased at locations around the feeder until an issue or violation occurs on the feeder that impacts the power system quality or operation. The maximum amount of PV that can be placed at each location on the feeder is the locational hosting capacity (LHC). The hosting capacity (HC) of the feeder is the largest amount of PV that can be placed anywhere on the feeder, which is equivalent to the lowest LHC of the feeder. Each feeder has a single HC value, so there are 216 total HC values. On the other hand, there are many possible interconnection locations on a feeder, so there is a range of LHC values on each feeder. In the 216 feeders, a total of ~60,000 interconnection locations are studied. A histogram of the HC for the 216 feeders analyzed is shown in Figure 10. The average hosting capacity is 2.05MW, and the median HC is 1.4MW.

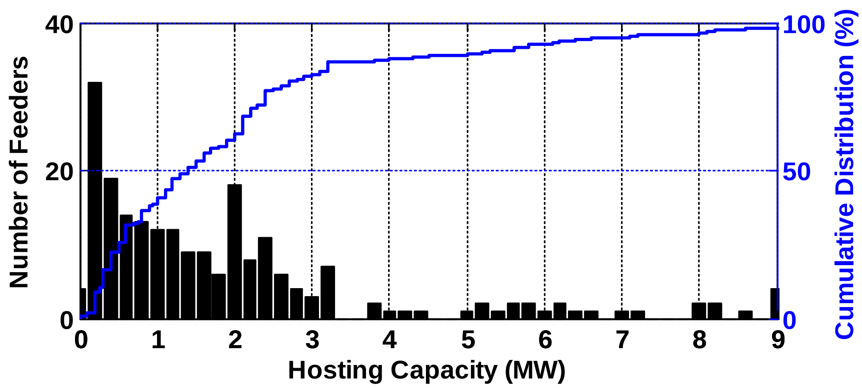



**Figure 20. Pareto plot of hosting capacity for all feeders.**

Since the HC is the minimum LHC on the feeder, the distribution of LHC goes to larger possible PV sizes on the feeder. For example, the HC of the feeder could be the maximum amount of PV that could be placed at the end of the feeder, while the locational hosting capacity of a potential PV interconnection near the substation could be very large without causing issues. Figure 11 show the histogram of LHC for all 60,000 PV interconnection locations on the 216 feeders. The average locational hosting capacity is 5.1MW, and the median LHC is 3.2MW.

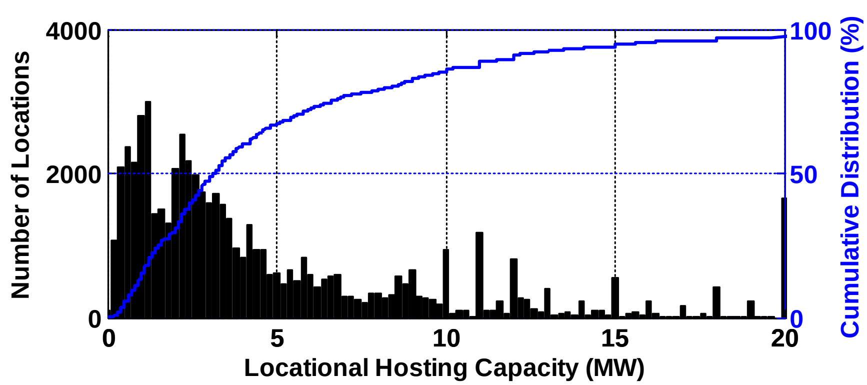



**Figure 21. Pareto plot of locational hosting capacity.**

## Distribution Circuit Reduction

A four step method was developed for simplifying a distribution feeder, typically with hundreds to thousands of line sections and nodes, to a reduced circuit with far fewer line sections and nodes. The reduced circuit is electrically equivalent while reducing the required modeling effort. The steps are as follows:

**Step 1 – Bus Selection:** The user selects any specific buses that should remain in the reduced circuit. The algorithm automatically identifies additional buses of interest such as capacitors, voltage regulators, step transformers between buses of interest, low voltage buses, and junctions required to maintain the topology in the reduced circuit. The end of feeder is also generally a bus of interest, and an algorithm was developed to automatically identify the end of the 3-phase lines to add them to the buses of interest.

**Step 2 – Sequence Component Kron Reduction:** This removes all buses without objects on them or junctions of multiple lines, such as buses that were originally only used for line routing in visualizations and calculating line lengths. The standard Kron reduction method is applied in sequence-components to both the positive and zero sequence Ybus matrices with the line charging capacitance included in the Ybus.

**Step 3 – Sequence Component Norton Equivalent:** This step reduces all loads not on the paths to buses of interest. All loads are condensed to the nearest upstream bus on a path between the substation and a bus of interest. This often moves loads from their interconnection on the end of a triplex line to the medium voltage feeder backbone. Laterals are reduced using a sequence-component Norton equivalent for the lateral that accounts for all line shunt capacitance, transformer magnetizing current, series losses, and unbalanced loads. The positive and zero sequence look-in impedances for $Z_{EQ}$ are found with the open-circuit loads, and the sequence currents are calculated for the head of the lateral shorted to ground.

**Step 4 – Load Bus Reduction:** This novel algorithm performs load bus reduction to recursively move loads to the adjacent buses, hence removing one bus at a time. The formulas apply a ratio of the sequence impedances of the connected lines to move part of the sequence current into the adjacent loads.

The reduction has been implemented in MATLAB using distribution system models from OpenDSS. The MATLAB script retrieves the circuit information from OpenDSS, reduces the circuit, and returns the new circuit to OpenDSS for simplified analysis. An example is shown for the distribution system in Figure 12 where an extremely complex system can be reduced to a simple circuit with only a few parameters that wholly and accurately represents the currents and voltages at all buses of interest in the equivalent circuit.

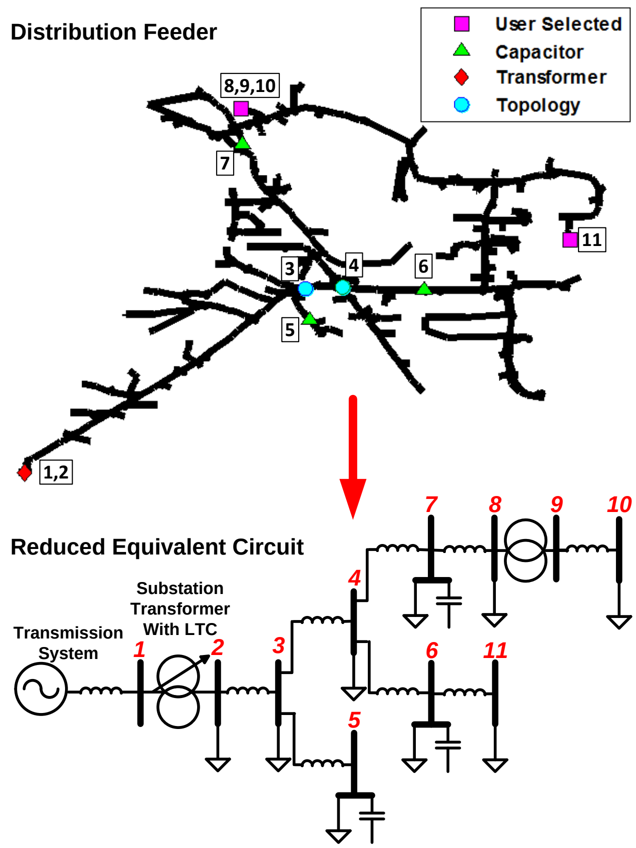



**Figure 22. A full distribution system feeder reduced to a simple equivalent representation**

Figure 13 shows the voltage profile of the full distribution feeder model during the circuit reduction process. These four figures show that during the reduction process, the complexity of the circuit is reduced considerably during each step. However, despite this reduction, the accuracy of the voltage profile at the buses of interest remains unaffected. The reduced circuit also maintains all distances, short circuit currents, and impedances between buses of interest. During the reduction, all other complexity and bus voltages in the original circuit are lost. This is advantageous if the distribution engineer is not interested in the voltage at those thousands of other buses. If the information or characteristics of a bus are desired, it can simply be selected as a bus of interest before reduction.

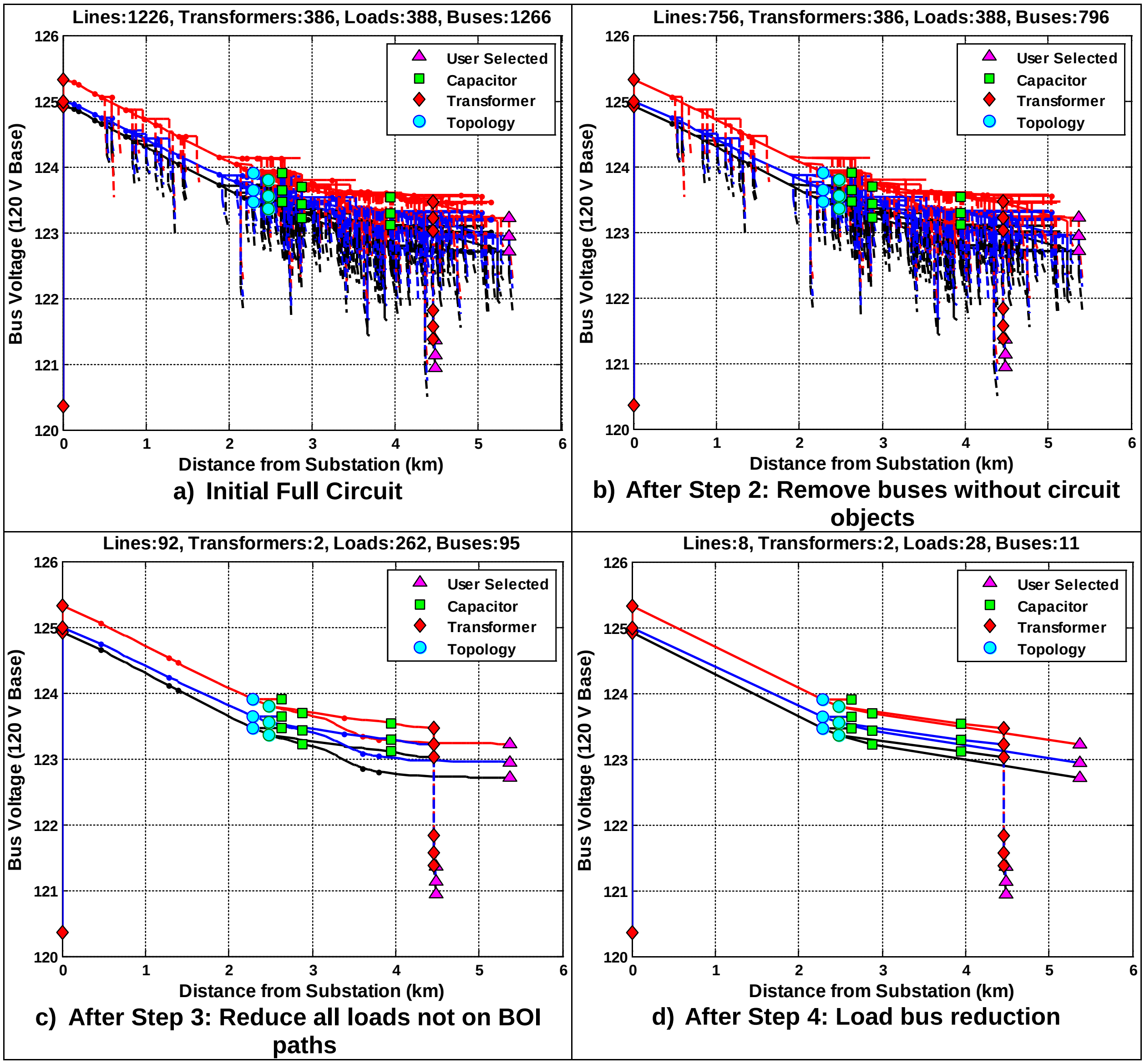



Figure 23. Feeder voltage profile plot a) before circuit reduction, b) after Step 2: removing buses without circuit objects (Kron reduction), c) after Step 3: reduce all loads not on the paths to buses of interest (Norton Equivalent), and d) after Step 4: load bus reduction. Phase voltages A, B, and C are signified with the colors black, red, and blue respectively.

The reduction was validated by simulating the peak-load week for both the full and reduced feeder. The bus voltages at the user-selected buses (bus 10 and bus 11) were monitored and recorded during both runs. The phase-average voltages for each bus during the full and reduced circuit simulations are shown in Figure 14. The resulting error in per-unit voltage can be seen in Figure 15.

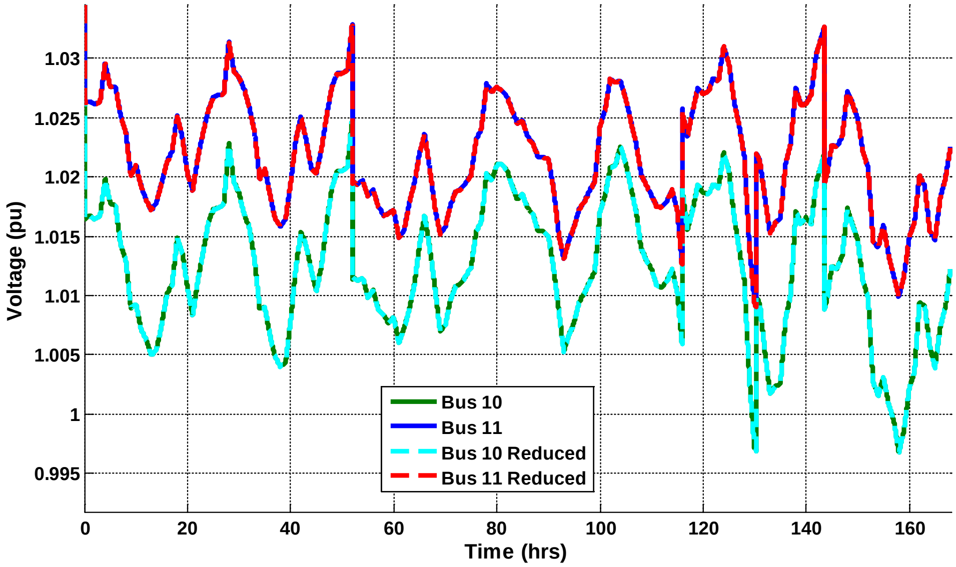



**Figure 24. Average bus voltage during one week time-series simulation**

Figure 15 shows that the error typically only varies by less 3x10$^{-6}$ Vpu. There are two exceptions around hours 130 and 143. These error deviations are a result of the LTC switching. Because the simulations were ran at a 1-minute resolution, the 1 minute difference in switching time between the full and reduced simulations results in a larger error. This error would be reduced for higher simulation resolutions. Note that the error from the circuit reduction is very much on the order of the resolution of the power flow solver, which for this bus is 3.61x10$^{-6}$ Vpu. This difference between the full and reduced circuit can be attributed to some rounding errors.

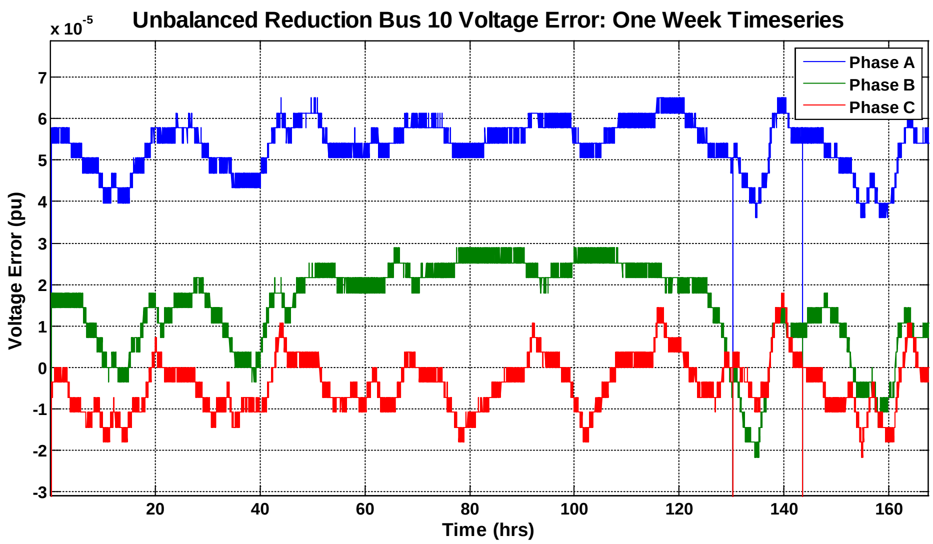



**Figure 25. One week timeseries error of bus 10 per-unit voltage**

The three-phase unbalanced circuit reduction methodology also reduces distributed PV to an equivalent circuit. A total of 7.5 MW of PV was distributed around the center of the feeder, as seen in Figure 16. Buses of interest were selected using the auto-add algorithm for the end of lines and the low/high voltage buses.

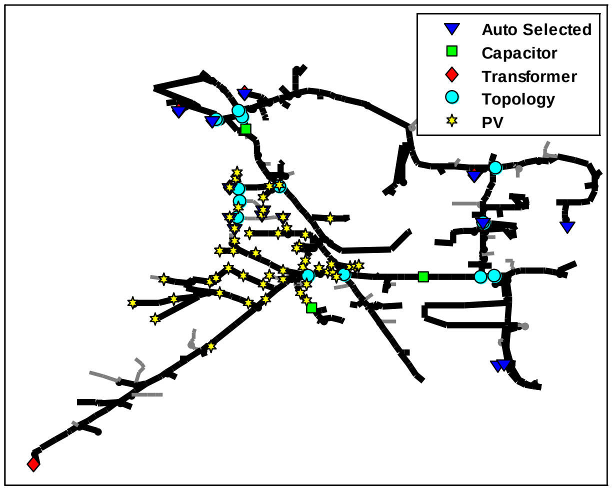



**Figure 26. Circuit plot with PV systems and buses of interest marked**

The feeder voltage profile for the full and reduced circuit is shown in Figure 17. The number of buses has been reduced to 3.4% of the original number, while maintaining the accuracy. The largest voltage error between the full and reduced circuit for any of the buses of interest is 2.1*10-6 pu.

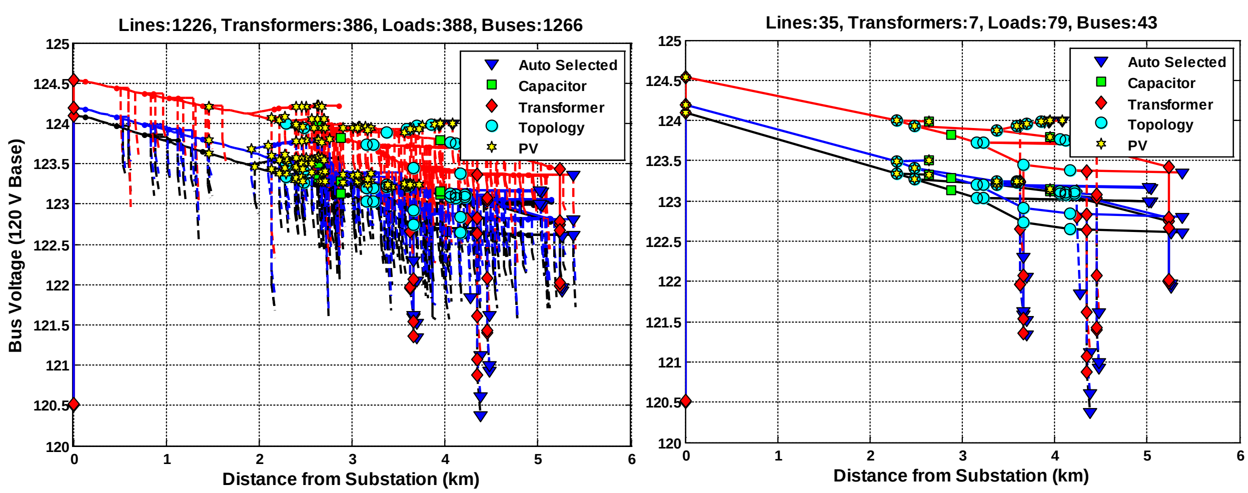



**Figure 27. Feeder voltage profile for the full circuit and the reduced circuit.**

A circuit reduction algorithm was developed to create a simplified equivalent model. The reduction has been applied to unbalanced multi-phase distribution system models, and it has been shown to have high accuracy when validated against the full models. All complexities of realistic distribution systems with load unbalance, mutual line impedances, line charging capacitance, coupling between power lines, voltage regulators, single-phase loads, and transformers with core losses are captured in the algorithm to create the equivalent circuit. The reduction algorithm has been applied to 17 different distribution system models for several different research project applications.

## GridPV

Version 2 for GridPV was developed and put together in final form. New features include:

- A new user manual including 20 new pages of documentation
- 160 revisions to the code
- 24 new plotting features
    - Options for plotting line-to-line and line-to-neutral voltages
    - Color by the direction and magnitude of power flow
    - Plot short-circuit impedance (impedance magnitude, resistance, or reactance)
    - Plot fault current magnitude (single-phase, 3-phase, or line-to-line fault)
    - 6 new options for marker objects in the circuit
    - Color lines by the upstream energy meter
    - Plotting returns the handles to the plotted objects
    - Option for turning on arrow labels
    - Option for changing the distance and volt scale in voltage profile plots
    - Background shade in voltage profile plots
- Updated to use new OpenDSS PVsystem object
- Uses the newest Sandia Wavelet Variability Model (WVM) for PV modeling
- Updated MATLAB help menus for GridPV
- 1 new function

The documentation and toolbox were posted online for public download. The website asks users to input their information (name and affiliation) to understand the most common uses of the toolbox.

## Protection analysis to FIRST

As part of the Feeder Impact Risk Score Technique (FIRST), detailed simulations were included to analyze the impacts of PV on network protection schemes. All protection equipment is modelled with their time-current curves (TCC), including pickup current, time dial settings, and instantaneous trips. With current protection equipment settings, fault analysis is performed to determine the basecase trip times, zones of protection, and coordination. The goal is to determine the maximum PV locational hosting capacity before there is negative impacts to the protection system. The extensive protection simulation studies test all potential fault locations on the feeder and all possible fault types, such as three-phase-to-ground, line-to-line, two-phase-to-ground, and single-line-to-ground.

The protection analysis was run on five PG&E feeders. On these feeders, PV never created an under-reach scenario where any potential fault would not be interrupted by protection devices. Similarly, loss in coordination with the protection zones changing never occurred due to PV. The only protection issues seen were sympathetic tripping and nuisance tripping where very large PV could create enough reverse current to trip a protection device that was not isolating the fault. This can be easily mitigated by changing the TCC curves of the devices or installing directional sensing devices.

An example of the results of the protection analysis is shown in Figure 18 with the locational hosting capacity for buses on feeder QB1. For more details on the protection analysis see “Maximum PV Size Limited by the Impact to Distribution Protection” in the IEEE PVSC

Proceeding 2015, or the SAND report titled “Determining the Impact of Steady-State PV Fault Current Injections on Distribution Protection”.

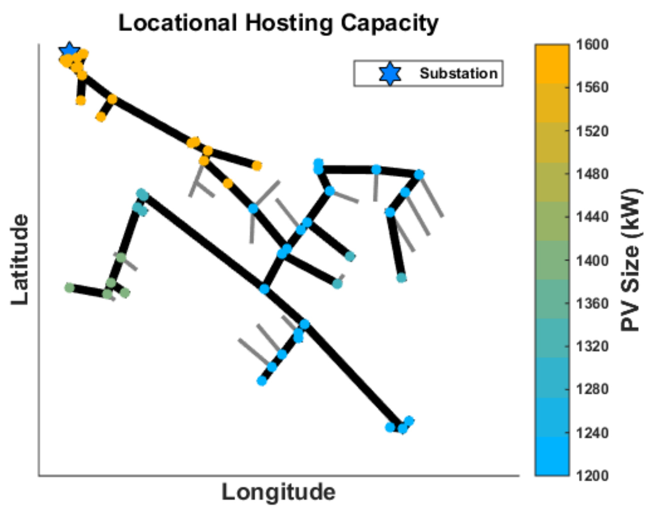



**Figure 28. Maximum PV size that can be interconnected at each location before there are impacts to the distribution system protection.**

## High vs. Low Resolution Load

PV output variability on distribution circuits may lead to excessive voltage swings and increased tap changes on voltage regulation devices. PV variability is often considered a major driver in voltage challenges in the sub-minute time frame, but there has been limited analysis of the impact of load variability for the same resolution.

Most utilities collect load data at intervals of 10-minutes or greater, so it is often not possible to directly compare load variability to 1-minute or 1-second PV variability. Due to load data resolution limitations and the difficulty in estimating feasible load variability, many time-series power flow simulations are performed using linearly interpolated load data.

To test impact to distribution grid simulations of using linear interpolations of time-averaged load data, and to compare to PV variability, one-second load and PV data measured at each of nearly 500 houses in Ota City, Japan was used. Ota City data was used because it was available at high resolution for more than a year.

First, PV and load variability were compared, as seen in Figure 19. Load variability of a single house is high due to household loads that are turned on at the flick of a switch (e.g., a heater). However, when aggregated over many hundreds of houses, load variability is very small. The arrows in Figure 19 show that the smoothing when going from a single house the aggregate of many houses is much larger for load variability than it is for PV variability. This suggests that it will be less important to have high-frequency load data than to have high-frequency PV data.

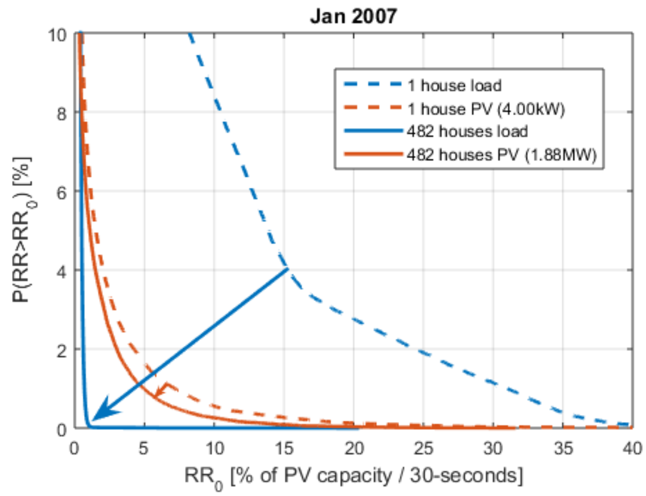



**Figure 29: Ramp rate distributions for load (blue lines) and PV (red lines) for a single house (dashed lines) and the aggregation of 482 houses (solid lines) in Ota City, Japan for January, 2007. Arrows indicate the reduction in variability when aggregating houses.**

To directly test the impact of interpolated load, quasi-static time series simulations using different resolutions of load data were run on a distribution grid setup previously used for PV variability analysis [19]. Simulations were run at one-second resolution for the week containing maximum load, and loads from Ota City were spread evenly across the test feeder. To simulate lower resolutions of load data, the 1-second Ota City load data was averaged and then linearly interpolated, representing the case where a utility SCADA system logs a time-average (e.g., 15-minute or 30-minute) of load. Figure 20 shows the simulation results. The linearly interpolated data leads to modest errors in the number of taps in the sample week: approximately 4% fewer taps for the 15-minute data and approximately 6% fewer taps for the 30-minute data versus the 1-second data. These are much smaller than the 20-70% errors found when using 15-minute averaged PV data on the same test feeder [19], showing that it is more important to have high temporal resolution PV data than load data.

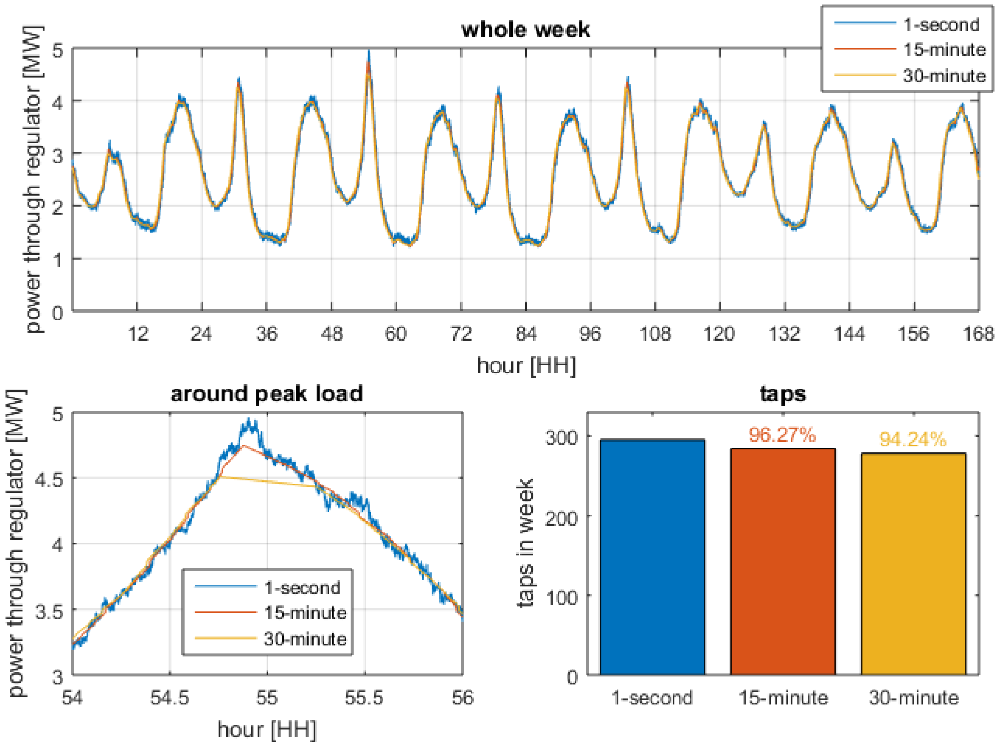



Figure 30: Simulation results when using 1-second, 15-minute, and 30-minute load samples. The percentages in the bottom right plot are the percent of 1-second taps.

## Significant Accomplishments and Conclusions for Task 3

- Demonstrated the appropriate setpoints for advanced inverter functions on 7 feeders and the increased hosting capacity through detailed analysis
- Feeder impact analysis performed on 216 feeders.
- Developed concise visualization of hosting capacity limitations for a single new large PV plant on a feeder.
- Developed a method for distributing multiple PV systems realistically around a feeder.
- Established the basis for testing protection issues arising from large penetration of PV.
- Developed circuit reduction methods for 3-phase unbalanced equivalent reduced models. The methodology works for unbalanced currents, single-phase loads, single-phase lines, shunt capacitance in the lines, and realistic transformer models that include magnetizing losses.
- Demonstrated on 4 different feeder circuits a complexity reduction of at least 95%, with the reduced model representative of the full model within an error of 0.01%. Circuit reduction was validated to be equivalent for time series simulation with time-varying load and variable solar generation. Circuit reduction has been applied to 13 additional feeders to reduce computation times for QSTS and protection analysis.

## Inventions, Patents, Publications and Other Results for Task 3

Published ten conference papers and five SAND reports on the research in this Task for FY13-FY15:

R. J. Broderick, J. E. Quiroz, M. J. Reno, A. Ellis, J. Smith, and R. Dugan, "Time Series Power Flow Analysis for Distribution Connected PV Generation," Sandia National Laboratories SAND2013-0537, 2013.

Reno, Matthew J., et al. "Reduction of distribution feeders for simplified PV impact studies." *Photovoltaic Specialists Conference (PVSC), 2013 IEEE 39th*. IEEE, 2013.

M. J. Reno, R. J. Broderick, and S. Grijalva, "Formulating a Simplified Equivalent Representation of Distribution Circuits for PV Impact Studies," Sandia National Laboratories SAND2013- 2831, 2013.

J. E. Quiroz, M. J. Reno, and R. J. Broderick, "Time Series Simulation of Voltage Regulation Device Control Modes," in IEEE Photovoltaic Specialists Conference, Tampa, FL, 2013.

M. J. Reno, R. J. Broderick, and S. Grijalva, "Smart Inverter Capabilities for Mitigating Over-Voltage on Distribution Systems with High Penetrations of PV," in IEEE Photovoltaic Specialists Conference, Tampa, FL, 2013.

M. J. Reno, K. Coogan, R. J. Broderick, J. Seuss, and S. Grijalva, “Impact of PV Variability and Ramping Events on Distribution Voltage Regulation Equipment,” in IEEE Photovoltaic Specialists Conference, 2014.

K. Coogan, M.J. Reno, S. Grijalva, R. J. Broderick, “Locational dependence of PV hosting capacity correlated with feeder load,” in T&D Conference and Exposition, 2014 IEEE PES, 2014.

M. J. Reno, K. Coogan, S. Grijalva, R. J. Broderick, and J. E. Quiroz, "PV Interconnection Risk Analysis through Distribution System Impact Signatures and Feeder Zones," in IEEE PES General Meeting, National Harbor, MD, 2014.

M.J. Reno, K. Coogan, Grid Integrated Distributed PV (GridPV) Version 2, Albuquerque, NM. SAND 2014-20141.

M. J. Seuss, M. J. Reno, R. J. Broderick, and R. G. Harley, “Evaluation of Reactive Power Control Capabilities of Residential PV in an Unbalanced Distribution Feeder”, 40th IEEE PVSC, Denver, CO, June 2014. SAND2014-4865C

J.E. Quiroz, M. J. Reno, and R. J. Broderick, “PV-Induced Low Voltage and Mitigation Options”, IEEE Photovoltaic Specialists Conference, June 2015.

J. Seuss, M.J. Reno, R.J. Broderick, S. Grijalva, “Improving Distribution Network PV Hosting Capacity via Smart Inverter Reactive Power Support”, Albuquerque, NM and Atlanta, GA, IEEE Power & Energy Society General Meeting, July 2015.

J. Seuss, M. J. Reno, R. J. Broderick, and S. Grijalva, Maximum PV Size Limited by the Impact to Distribution Protection, IEEE Photovoltaic Specialists Conference, June 2015.

J. Seuss, M. J. Reno, M. Lave, R. J. Broderick, and S. Grijalva, "Multi-Objective Advanced Inverter Controls to Dispatch the Real and Reactive Power of Many Distributed PV Systems," Sandia National Laboratories, SAND2015, 2015.

J. Seuss, M. J. Reno, M. Lave, R. J. Broderick, and S. Grijalva, "PV Smart Inverter Functions and Setpoints," Sandia National Laboratories, SAND2015, 2015.

### Path Forward for Task 3

See overall Path Forward section at end of document.

## Background Task 4: Develop PV modeling tools for distribution grid studies

The variable power output of solar photovoltaics (PV) can lead to increased distribution grid operation cost, and so is a concern of distribution grid operators. For example, PV variability may lead to additional voltage regulator tap change operations, necessitating more maintenance and earlier replacement of these mechanical devices. However, high-frequency solar variability (relevant to e.g., voltage regulators which have 30-second to 1-minute time constants) has not been well-characterized.

This three year project had two major outcomes: (a) we quantified and modeled the variability of solar irradiance and solar PV power samples from a variety of locations collected at high-frequency (30-seconds and better) relevant to operation of a distribution grid, and (b) we produced appropriate high-frequency solar inputs for distribution studies by using a combination of 1-hour satellite-derived irradiance and ground-measured high-frequency solar irradiance datasets. This work allows utilities to better understand how PV variability can be different by locations, and to more easily run distribution grid simulations to accurately determine the impact of PV on a distribution grid.

Solar variability at distribution timescales (30-seconds and shorter) has been quantified at a few specific locations previously: (e.g., Woyte, et al. [20], Perez, et al. [21], [Lave, et al. [22], Hinkelman [23]). However, understanding the solar variability at a few select locations may not be helpful to an operator whose distribution grid is not located near one of these known locations. To create more high-frequency data, some studies have taken widely available low-frequency data and downscaled it to represent high-frequency data (e.g., Wegener, et al. [24], Stein, et al. [25], Hummon, et al. [26]). However, it is not clear that these downscaling methods will be accurate for distribution-scale applications as they were either meant for transmission-scale applications and so did not downscale to shorter than 1-minute or have not been validated against measured data.

## Project Objectives for Task 4:

Our approach was different from other works in that we assembled, to our knowledge, the largest library of high-frequency irradiance measurements from different geographic locations (10 locations). Yet, this was still sparse coverage of the United States. To give greater coverage and make our work applicable to more distribution studies, we determined variability zones of like variability (determined from satellite data but validated against measured high-frequency data): high-frequency irradiance measured anywhere in a variability zone is then representative of all locations within that same zone. In this way, at locations across the United States, we are able to produce a representative solar input that does not have any synthetic data, but still accounts for local solar variability.

In this document, we present results from all 3 years, broken down by subtask. Below are some highlights of each subtask.

- **Subtask 4.1: Expand geographic scope of collected high-frequency data.**
    - Collected and analyzed high frequency solar data samples
- **Subtask 4.2: Refine and improve existing methods for scaling the variability observed at a single point of interconnection (POI) using collected data.**
    - Validated the wavelet variability model's ability to model a small PV plant connected to a distribution feeder (500kW).
- **Subtask 4.3: Determine differences in variability statistics geographically, and determine differences in voltage regulator tap changes caused by these differences in solar variability.**
    - Created a solar variability metric to quantify differences in solar variability
    - Computed voltage regulator tap change for different solar samples
    - Showed importance of high-frequency data for accurate grid simulations
- **Subtask 4.4: Develop methods to link high-frequency ramp statistics to low-frequency data with high spatial coverage.**
    - Established a link between low and high frequency solar variability
    - Created solar variability zones of similar high-frequency variability
    - Showed that solar variability zones are correlated with distribution grid impact of solar variability at each location (i.e., tap changes)

FY15 Milestones and Final Deliverable

| | Metric Definition | Success Values | Measured Value | Assessment Tool | Goal Met | Supporting Data |
|---|---|---|---|---|---|---|
| ***Milestone 4.A*** | Variability zone definitions are consistent between high-frequency and low-frequency data. | < 2 point difference in VS_cdf value between pairs of high-frequency data in the same low-frequency variability zone | See page 46 and Figure 32 | variability score from cumulative distribution of ramp rates (VS_cdf) | Yes | See page 46 and Figure 32 |
| ***Milestone 4.B*** | Tool will implement at least six variability regions and variability tool produces accurate and useful data. | Simulated power variability is accurate to within 30 voltage regulator tap changes weekly | See page 48 and Figure 34 | Simulated variability profiles on test feeder | Yes | See page 48 and Figure 34 |
| ***Final Deliverable*** | Successful completion of Milestones 4.1 and 4.2 will result in a validated tool for six variability regions that will easily allow distribution planners to use accurate solar variability inputs in their distribution studies. Improving the accuracy of distribution studies with respect to variability will allow utilities to better understand the impacts of PV and more accurately identify potential problems on the electric grid. Advanced tool functions, codes and scripts will be made publicly available with simple manual/guide and sample data included via a web download. | | | | | |
| ***Status of Final Deliverable*** | Milestones 4.1 and 4.2 are complete. | | | | | |

## Project Results and Discussion Task 4:

***Subtask 4.1: Expand geographic scope of collected high-frequency data.***
We collected a database of high-frequency (time resolution shorter than 30-seconds) global horizontal irradiance (GHI) measurements at 10 different locations in the United States (Figure 21). To our knowledge, this is the largest collection of high-frequency irradiance data collected across different geographic locations. Two Albuquerque locations were collected: “Albuquerque, NM (PSEL)” was collected at Sandia’s Photovoltaic Systems Evaluation Laboratory, while “Albuquerque NM (Mesa)” was collected approximately 10 km southwest at the Mesa Del Sol Facility. These two sites will allow for validation of methods, as similar results should be obtained for each site due to their close proximity.

At two additional locations, (Santa Fe, NM, and Alamosa, CO), high-frequency plane of array (POA) irradiance measurements were collected. POA and GHI measurements cannot be directly compared, but the data collected at Santa Fe and Alamosa was still used to better understand solar variability (e.g., for validating variability scaling).

Our significant efforts to collect high-frequency irradiance data through contacting utility and research partners and through searching for available data on the internet, highlighted the scarcity of such data. While low-frequency (e.g., 1-hour) GHI measurements are relatively common due to their use in PV site prospecting, higher frequency irradiance sampling is much less common.

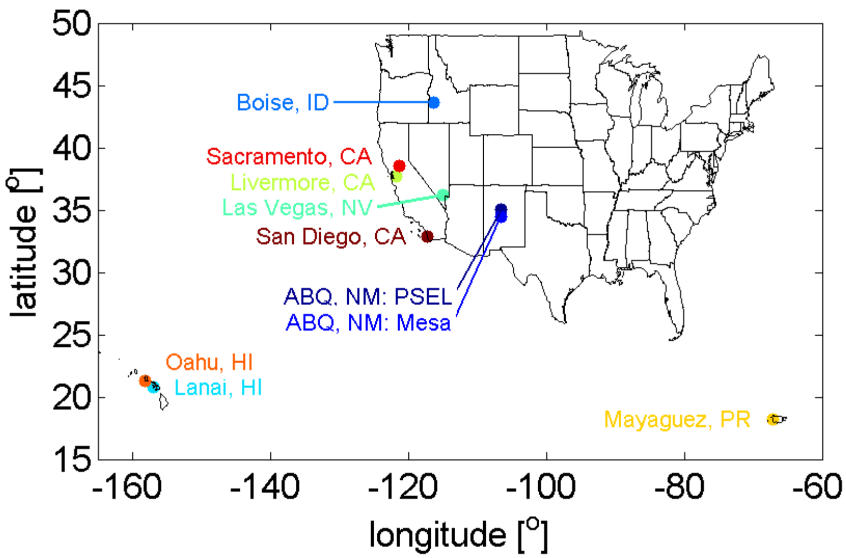



Figure 31: Map of collected high-frequency GHI data.

***Subtask 4.2: Refine and improve existing methods for scaling the variability observed at a single point of interconnection (POI) using collected data.***

To ensure that we could accurately simulate the variability of a small central PV plant that might be connected to a distribution grid, we used measured power output and POA irradiance point sensor measurements from a 500kW PV plant near Santa Fe, NM. The point sensor measurements were smoothed and translated to create a simulated power output that was compared to the measured power output. The Wavelet Variability Model (WVM) [28] was used to estimate the spatial smoothing. The WVM had been validated previously at large central PV plants (>20MW) [28] [29]], and at a large distributed PV plant (2MW) [28], but had not specifically been validated for the case of a single point of interconnection on a distribution feeder representing a small central PV plant.

The results of the comparison of measured variability to simulated variability are shown in Figure 22. In Figure 22, the “no smoothing” case is included in addition to the “WVM” case. The former is the point sensor directly converted to power using the irradiance to power translation, while the latter is first smoothed to represent the average irradiance over the spatial footprint of a 500kW PV plant before being translated to power. Most important in Figure 22 is that the errors in matching the cumulative distribution of measured ramp rates (bottom right plot) are 15 times smaller for the WVM than for the no smoothing case, showing that using the WVM is a significant improvement.

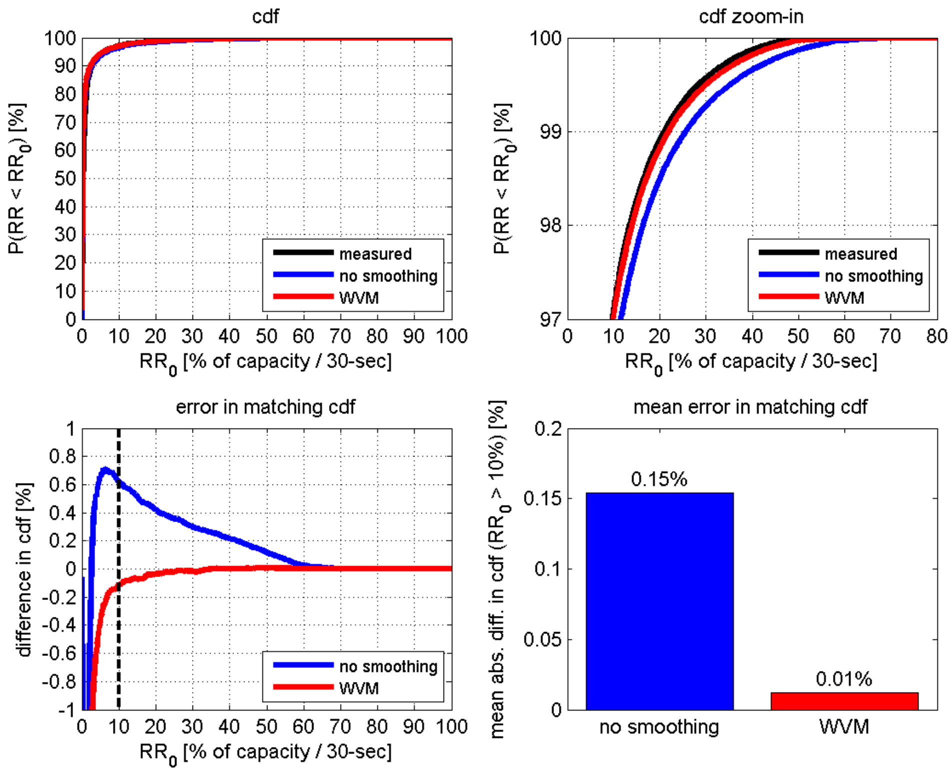



Figure 32: Comparison of measured variability (black lines) to WVM-smoothed variability (blue lines/bar) and unsmoothed point sensor variability. The top plots show the cumulative distribution of ramp rates. The bottom left plot shows the difference in cumulative distributions indicating the errors in each method at matching the measured cumulative distribution. The bottom right plot is the mean absolute error in matching the cumulative distribution, showing the strong improvement of the WVM over the no smoothing case.

***Subtask 4.3: Determine differences in variability statistics geographically, and determine differences in voltage regulator tap changes caused by these differences in solar variability.***

A journal article titled, "Characterizing High-Frequency Solar Variability and its Impact to Distribution Studies" was published on this topic in the journal *Solar Energy.* The high-frequency irradiance database (Figure 21) was used to show the impact of solar variability to distribution grid voltage regulator tap change operations.

For each location, the cumulative distribution of 30-second ramp rates over 1-year were computed, as shown in Figure 23.

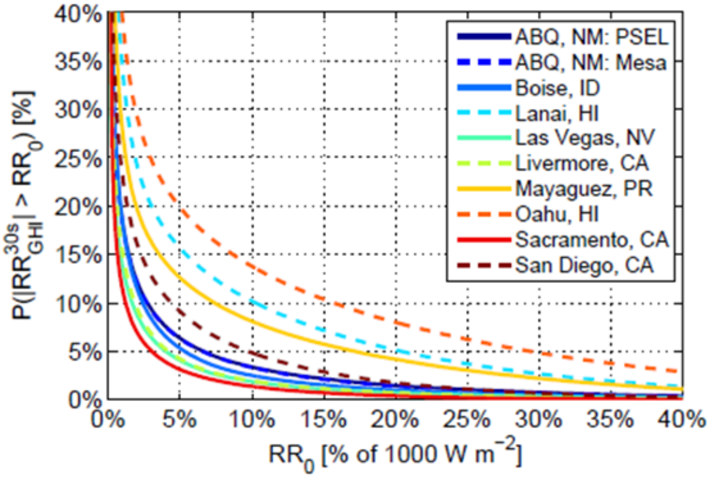



Figure 33: 30-second ramp rate distributions for the various locations.

A variability metric was defined based on the probability of each ramp times its ramp magnitude. The metric is therefore defined by large magnitude ramps which occur frequently; these are the ramps which will have the largest impact on grid operations. We term this metric the variability score from the ramp rate distribution, $VS_{RRdist}$:

$$VS_{RRdist}(\Delta t) = 100 \times max[RR_0 \times P(|RR_{\Delta t}| > RR_0)].$$

The $VS_{RRdist}$ metric was found to be consistent with the widely-used variability index ($VI$) [30], as shown in Figure 24. Even though $VS_{RRdist}$ and $VI$ are consistent, $VS_{RRdist}$ is an improvement over $VI$ due to its simplicity. The $VI$ requires a clear-sky model. While GHI clear-sky models are common and well validated, fixed tilt and single-axis tracking clear-sky models are significantly more complicated and not well validated. Since $VS_{RRdist}$ is computed directly from the ramp rate distribution, it does not require a clear-sky model and so can be just as easily applied to POA, tracking, and power timeseries as it can to GHI timeseries.

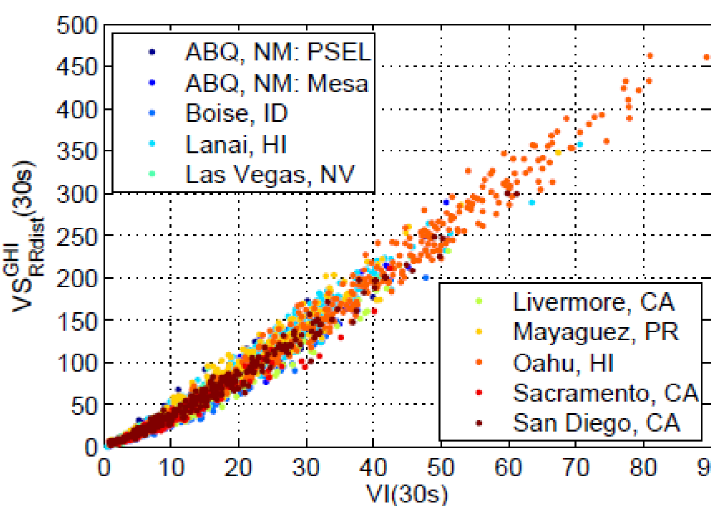



Figure 34: Variability score (y-axis) compared to variability index (x-axis), showing the similarity.

The annual variability score was quantified for each location at timescales of 1s, 10s, 30s, 60s, and 1hr, as seen in Figure 25. At all timescales except 1hr, the ranking of locations from least variable to most variable was consistent: Sacramento and Las Vegas were always the least variable and Oahu, HI was always the most variable.

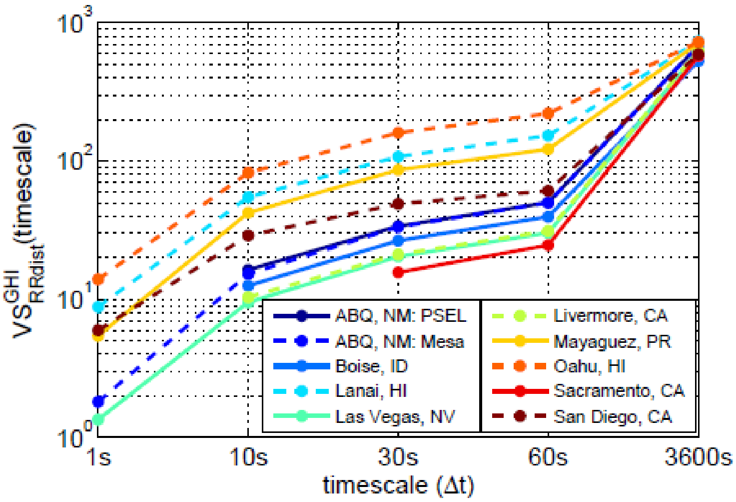



Figure 35: Variability score (y-axis) at each timescale (x-axis) for each location (colors).

To show how irradiance variability (i.e., $VS_{RRdist}$) translates into impacts to distribution feeders, we quantified the number of tap change operations when using PV power output based on a weekly irradiance sample, as shown in Figure 26. Overall, the number of tap change operation were well correlated with the variability score $VS_{RRdist}$. More than a 300% different in the number of tap change operations was seen between the Sacramento and Oahu samples, which had the lowest and highest $VS_{RRdist}$ variability scores. This shows that $VS_{RRdist}$ can be a useful metric for quantifying solar variability.

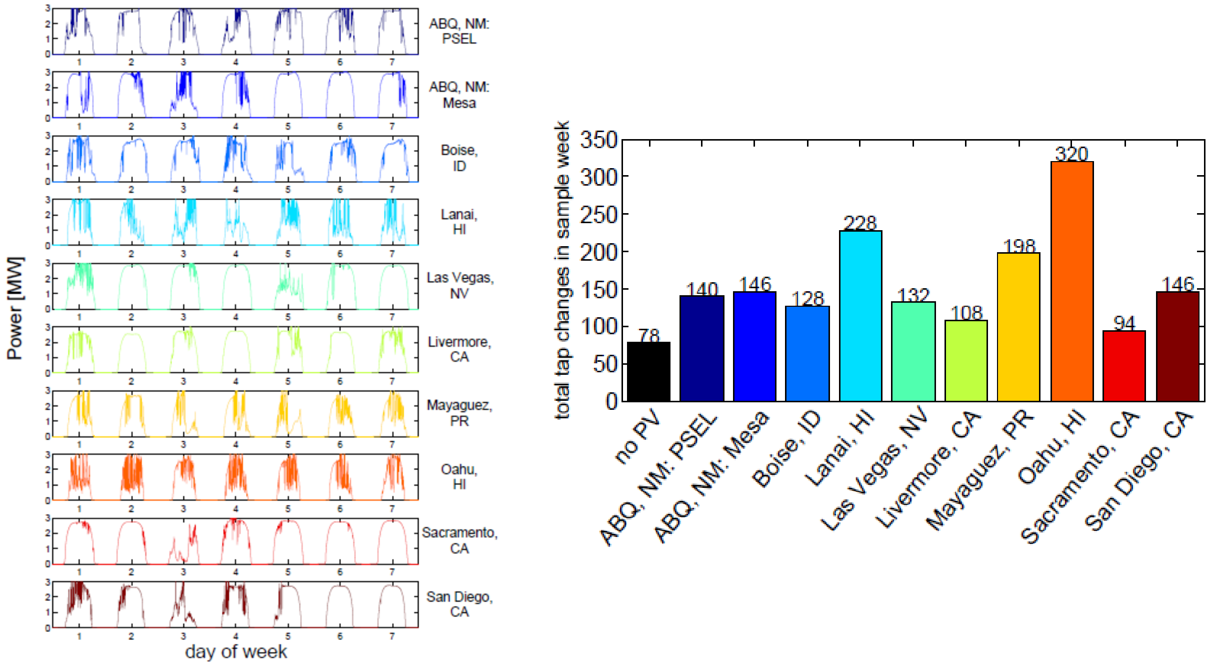



Figure 36: [Left] weekly irradiance samples at each location. [Right] Tap changes in each sample week.

Figure 27 shows the importance of high-frequency solar variability to ensure accurate modeling of distribution grid impacts. Errors when using low-frequency data were always negative; meaning the number of tap changes was always under predicted. Except for the Oahu sample, 1-minute errors were modest (<10%), but errors for 5-minute and 15-minute resolution data were significant, showing the importance of using high-frequency solar variability samples to ensure accurate simulations of the impact of PV on distribution grids.

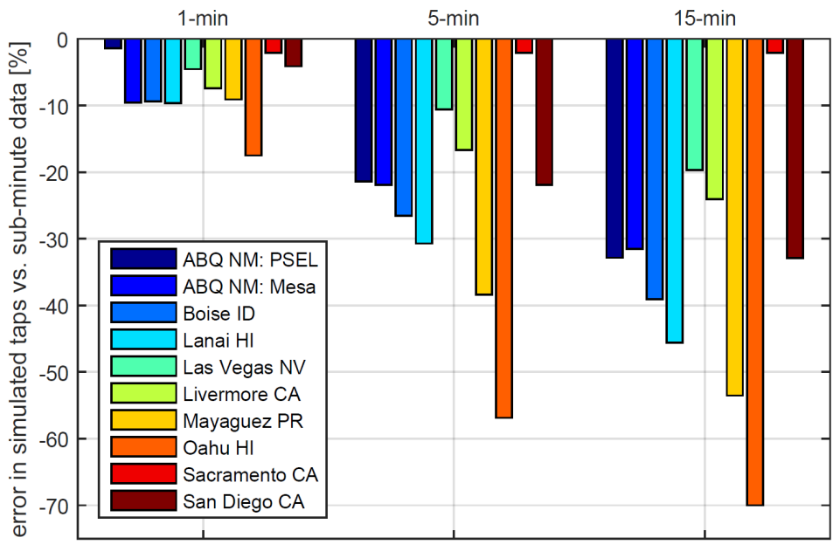



Figure 37: Error (y-axis) when using 1-minute, 5-minute, or 15-minute averaged PV data instead of high-frequency.

***Subtask 4.4: Develop methods to link high-frequency ramp statistics to low-frequency data with high spatial coverage.***

The variability score defined in Subtask 4.3 can be computed for any timescale. Thus, the simplest way to examine 1-hour versus 30-second variability irradiance variability is to compare $VS_{RRdist}^{GHI}(30s)$ to $VS_{RRdist}^{GHI}(1hr)$. Figure 28 shows a scatter plot of the 30-second and 1-hour variability scores as computed from year-long timeseries. While there is positive correlation between these GHI variability scores, the $R^2$ value of 0.491 does not indicate a particularly strong relationship.

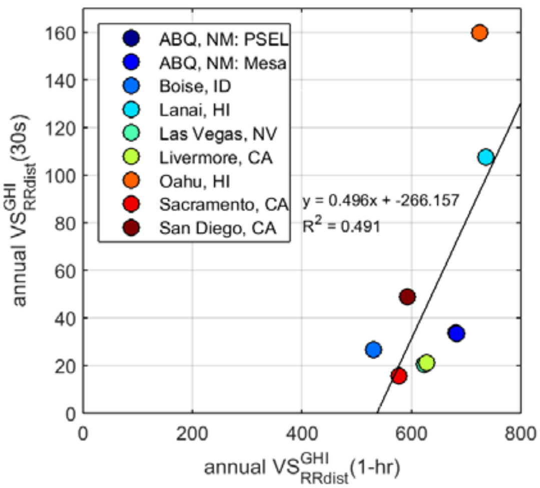



Figure 38: Scatter plot of 30-second versus 1-hour variability score of year-long GHI timeseries. Also included is a best fit line, with equation and R2 value.

At the hourly timescale, variability from the sun's movement through the sky dominates cloud-caused fluctuations. This can be seen in Figure 29, where the hourly variability scores are large even on clear days.

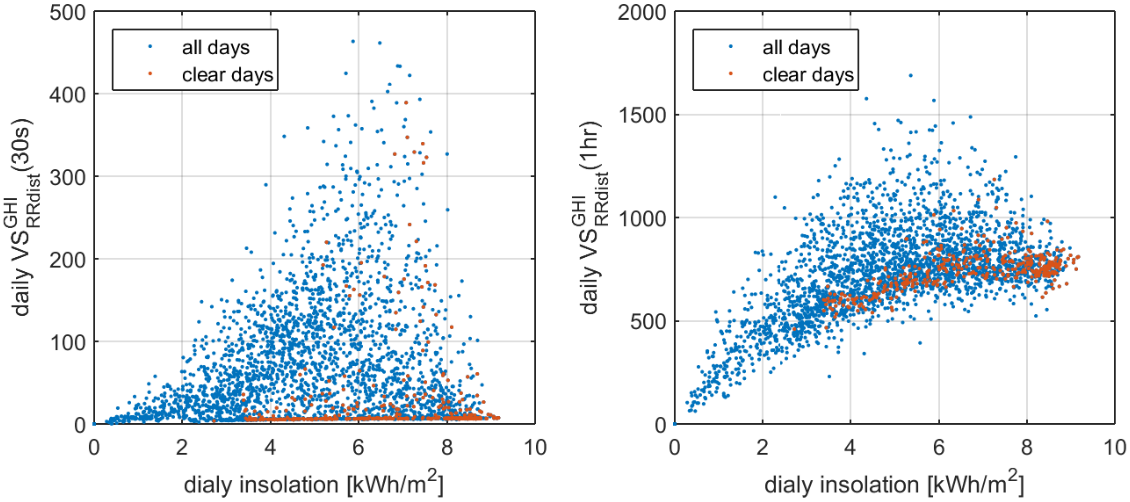



Figure 39: Scatter plots of daily data showing 30-second (left) and 1-hour (right) variability scores as a function of daily insolation. All 9 ground measurements were used to create these plots. Clear days are highlighted in red.

To remove this high variability on clear days, the hourly variability score was instead computed using the clear-sky index (CSI), which accounts for the sun's movement through the sky. Use of the clear sky index removes the dependence on daily insolation and causes the hourly variability score to be close to zero on clear days, as seen in Figure 30.

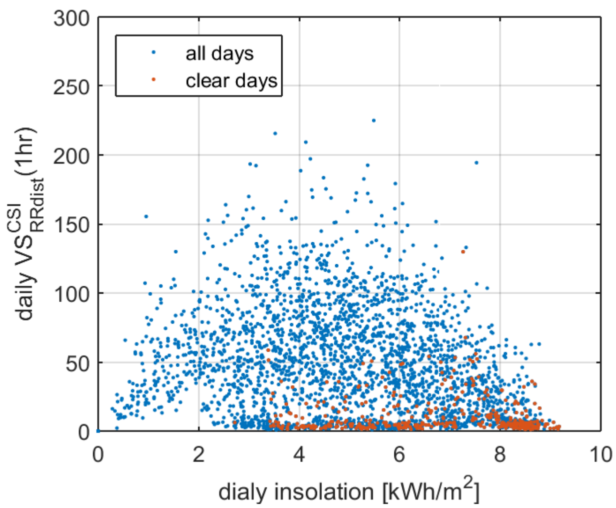



Figure 40: Repeat of the right side of Figure 29, but for the hourly variability score computed from the clear-sky index (CSI).

The improved correlation from using the clear-sky index is seen in Figure 31. We continue to compare hourly variability scores to the 30-second variability score from GHI because this GHI variability score is related to the impact that the solar variability will have on distribution grid operations [31].

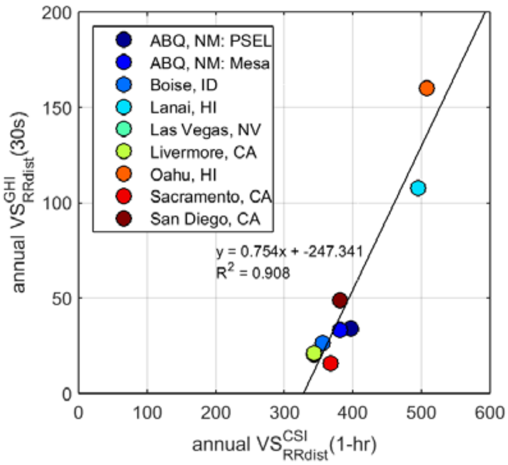



Figure 41: Scatter plot of 30-second variability score computed from a year-long GHI timeseries versus 1-hour variability score of year-long clear-sky index (CSI) timeseries.

When using satellite hourly data (instead of the ground hourly data shown on previous plots), additional modifications to the hourly variability score were found to further enhance the relationship between satellite hourly and ground 30-second variability. Specifically, using the median of all daily variability scores, multiplying the variability score by the median daytime GHI, and spatially smoothing the satellite data were all found to increase the correlation of hourly to 30-second variability scores. The impact of these corrections is shown in Figure 32

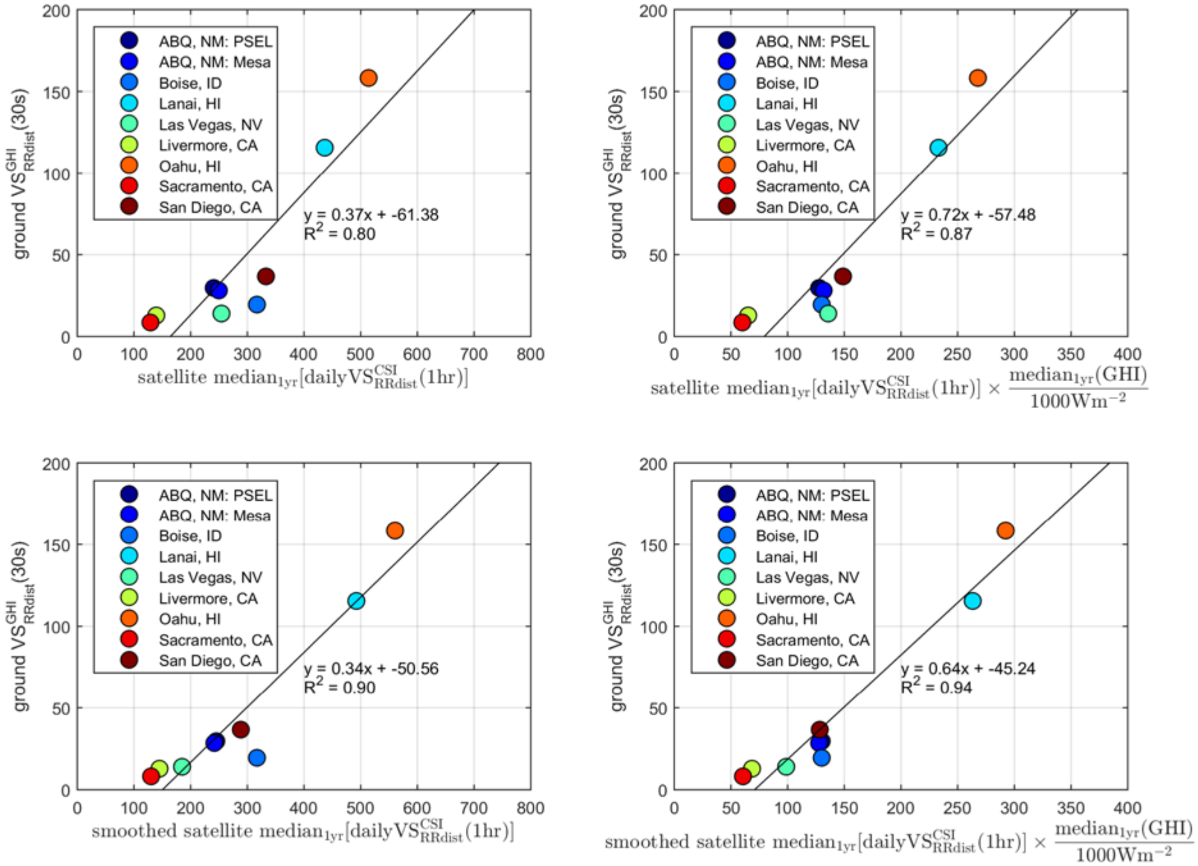



Figure 42: Plots of variability scores derived from hourly satellite data (x-axes) and 30-second ground data (y-axes). The y-axis is the same in all plots. In the top right plot, the x-axis is the median daily 1-hour variability score of the clear-sky index. The top right plot x-axis uses the median GHI, the bottom left plot x-axis uses the smoothed satellite data, and the bottom right x-axis uses both the median GHI and smoothed satellite data.

Solar variability zones were defined based on the smoothed satellite, clear-sky index based variability score with the median GHI correction (i.e., the values shown on the x-axis of the bottom left plot in Figure 32). We chose to define solar variability zones as 50 units of variability score wide, centered on values divisible by 50; variability zones were thus the ranges 25-75, 75-125, 125-175, 175-225, 225-275, 275-332. The last zone (275-332) was extended slightly such that no separate zone was created for the four satellite values between 325 and 332.

Figure 33 shows the solar variability zones. The zone ranging from 25-75 is labeled “very low” solar variability, while the zone ranging from 275-332 is labeled “very high” solar variability. Many parts of California and western Arizona are in the “very low” zone, presumably due to their predominantly sunny locations. However, low solar variability does not necessarily imply high solar resource. The northwest coast, for example, which is infamous for predominantly foggy conditions, is in the “low” solar variability zone. A day which is foggy or cloudy all day has very low variability, just as a clear-day has low variability.

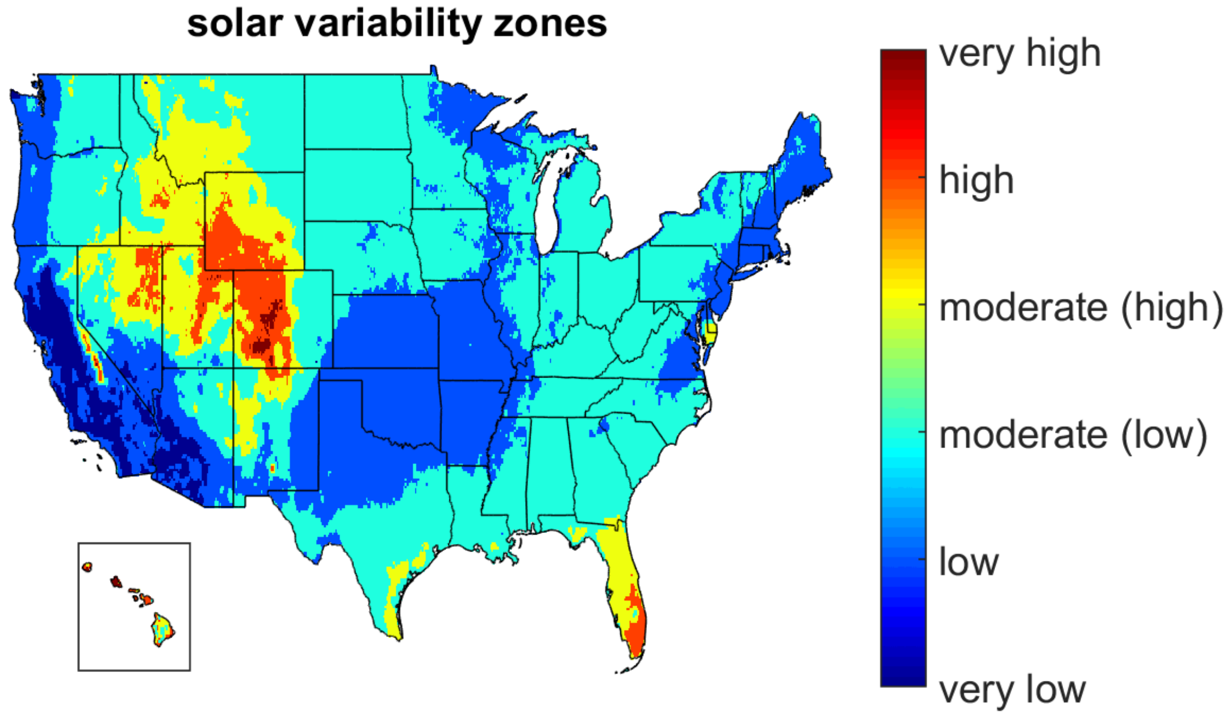



Figure 43: Solar variability zones as determined from satellite data.

A major use of these solar variability zones will be to determine appropriate proxy data for distribution grid integration studies. The concept is that any solar variability sample from the same zone as a location of interest can be used as a proxy. To be useful to grid integration studies, it is important that the suggested proxy variability samples are representative of the impact of PV to distribution grid operations.

To test this, we compare voltage regulator tap change operations. Figure 34 shows the results of quasi-static time series analysis, presented as the average number of tap change operations per week. The x-axis in Figure 34 is the variability zone that each location is classified into based on satellite data. The strong correlation between solar variability zone and number of tap change operations on the sample feeder is evident, with the notable exception of the San Diego sample. Excluding San Diego, pairs of locations in the same zone are at most 10% different in number of tap change operations. The San Diego deviations are thought to be caused by the interplay of load variability with solar variability, as San Diego's solar variability is highest in the summer when the load variability is also high. At other locations, the solar variability is highest in the spring when load variability is lower.

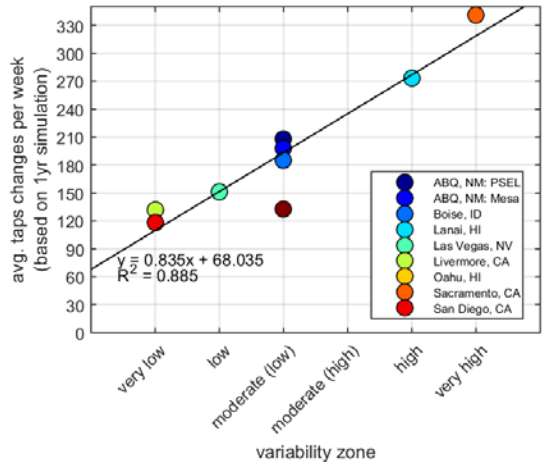



Figure 44: Scatter plot showing the average number of tap changes per week (based on a year simulation) plotted against the solar variability zone.

In summary, the solar variability zones have been shown to be correlated to the impact that solar variability will have on distribution feeder tap change operations. However, tap change operations depend on a variety of factors (including the load profile), and so variability zones alone cannot be used to determine the impact of PV. Instead, variability zones can be used to determine appropriate proxy timeseries for use in quasi static time series analyses which account for the load profile, distribution grid setup, and voltage regulator settings to accurately model the feeder.

## Significant Accomplishments and Conclusions for Task 4

- Collected largest database (to our knowledge) of high-frequency (30-seconds or better) irradiance samples at different geographic locations.
- Developed a metric (variability score) to quantitatively compare solar variability.
- Showed that there can be up to a 300% difference in tap change operations when different solar variability samples are used.
- A relationship between high-frequency (30-second) solar variability and low-frequency (1-hour) solar variability was established.
- Using the high and low-frequency variability relationship, solar variability zones were established using hourly satellite data.

## Inventions, Patents, Publications and Other Results for Task 4

**Peer-Reviewed Journal Publications:**
M. Lave, M. J. Reno, and R. J. Broderick, "Characterizing local high-frequency solar variability and its impact to distribution studies," Solar Energy, vol. 118, pp. 327-337, 2015.

**Honors:** Journal Article – “Characterizing Local High-Frequency Solar Variability and its Impact to Distribution Studies,” selected as “Best Paper 2014-2015” in the “Solar Resource” topic area of the *Solar Energy* journal.

## Path Forward for Task 4

See overall Path Forward section at end of document.

## Background Task 5: Educate and engage stakeholders on grid interconnection results

Sandia provided effective and efficient stakeholder engagement to discuss and disseminate distributed grid integration results and best practices. Sandia pursued this objective in two ways: (1) establish and support stakeholder groups focused on removing key policy obstacles and (2) educate stakeholders through workshops, technical briefs, published papers and best practices guides to convey critical results from our work. The aim was to make available current, reliable information on grid interconnection results and best practices to state regulators in the area of Distributed Grid Integration. We engaged with and reached out to a broad cross-section of stakeholders including utilities, PUCs, FERC, PV industry and universities to proactively guide the advancement of regulatory/policy mechanisms, standards, and best practices.

The adoption of new screening processes and criteria requires building consensus based on sound technical assessments. Industry consensus also guides adoption of better analysis practices, and implementation of cost-effective mitigation measures. There is a clear need to educate key stakeholders about grid integration issues, results and best practices to proactively guide the advancement of regulatory/policy mechanisms, standards, and best practices.

## Project Objectives for Task 5:

The aim is of task 5 is to make available current, reliable information on grid interconnection results and best practices to state regulators in the area of Distributed Grid Integration. We will engage with and reach out to a broad cross-section of stakeholders including utilities, PUCs, FERC, PV industry and universities to proactively guide the advancement of regulatory/policy mechanisms, standards, and best practices.

Subtask 5.1: Establish and lead, in conjunction with NREL, the Interconnection 2.0 Stakeholder Group which will address the regulatory-driven advancements needed for DGI, specifically advanced inverter functionality and evolving screening procedures, and the interface with industry standards that may be lagging state policies. The group will focus on improved screening procedures and develop action plans to address technical and policy issues. Provide technical education to utility commissioners and staff on grid integration issues to inform policy.

Subtask 5.2: Disseminate DGI research and derived best practices at two workshops with key industry and utility stakeholders. Engage and connect with the stakeholders at the workshops and continue the discussion with follow-up calls, webinars and face to face meetings as needed. A multipronged strategy will be employed: 1) Continued technical and regulatory engagement with the California and other state commissions that act as drivers through aggressive state implementation policies and by various other outreach approaches (Sandia Technical Briefs, Webinars, email, etc.) with all of the state commissioners and regulators in US territories, 2) Building a sound foundation for technical interactions with the industry through engineering advancements and modeling, and 3) Collaboration with the Center of Public Utilities which conducts the annual “Commissioners’ Conference for deep dives on current utility issues, and other organization for targeted events/products (i.e. FERC)

Subtask 5.3: Define the technical case for implementing new SGIP screening criteria and disseminate a draft white paper on the technical case in coordination with other stakeholders.

Subtask 5.4: Organize support team to provide technical assistance to U.S. states and U.S. territories located outside of the U.S. mainland.

| | Metric Definition | Success Values | Measured Value | Assessment Tool | Goal Met | Data |
|---|---|---|---|---|---|---|
| ***Milestone 5.A*** | Provide a full and complete data-driven technical foundation that supports revised SGIP screens. | Provide technical foundation for revising at least 2 SGIP screens | Development of screening quality metrics and in depth analysis of 10 potential screens using 216 feeders. | Measured responses from email, Sandia, technical briefs, workshops and events, and technical interfaces with regulatory action, including identification of regulatory consideration of identified technical constraints, approaches, and tools. | Yes | Technical Report |

| | |
|---|---|
| ***Final Deliverable*** | Provide a full and complete data-driven technical foundation that supports revised SGIP screens. Develop new screening procedures and provide technical case and outreach to support implementing new SGIP screens nationwide. New screening procedures and technical case with accompanying tools, scripts, codes and functions will be made publicly available with simple manual/guide and sample data included via a web download. |
| ***Status of Final Deliverable*** | Complete. Technical Report provides a full and complete data-driven technical foundation that supports revising the SGIP screens to make them more accurate and effective. Report describes the two best new screening procedures and makes recommendations for improving the accuracy of the other 8 screens. Technical report will be available on the Sandia Website. |

## Project Results and Discussion Task 5:

### *Engage with stakeholders to discuss and disseminate results of research*

Sandia has continued efforts with the Center for Public Utilities which conducts the annual "Commissioners' Conference for deep dives on current utility issues. Sandia serves on the Advisory Board for the CPU. Sandia hosted members from the Center for Public Utilities (CPU) "Current Issues Conference" in 2014 and 2015. Sandia offered a tour of Sandia Photovoltaic Labs in support of the Issues Conference. We had an excellent response with about 20 commissioners and staff attendees who participated in discussions on Sandia research topics for a full hour and then a tour of the PSEL and DETL. Over half of the attendees were state utility commissioners. The response of the visitors was extremely positive. Sandia has also engaged in direct communications with regulatory staff in two important states as well, California and Hawaii.

In addition to the CPU Commissioners meeting, IEEE PV Specialist Conference papers and the NREL/Sandia webinar described below, Sandia led the effort to put on a PV Systems Symposium in 2014. Sandia/EPRI/NREL Symposium was a major event that was well attended and well received. It was entitled *Accelerating Cost-Effective Deployment of Solar Generation on the Distribution Grid* and occurred in concert with a broad spectrum of industry professional in this area with the 2014 PV Systems Symposium held on May 6 in Santa Clara, California.

The PV Distribution System Modeling Workshop was hosted by Sandia National Laboratories, the Electric Power Research Institute (EPRI), and the National Renewable Energy Laboratory and covered best practices to facilitate integration of PV into the power system. Topics included technical and policy updates for current interconnection and screening practices and technical dive into the use of advanced inverters to mitigate system impacts. Additional topics included Interconnection and Screening Practices, Advanced Inverters: Capabilities and Functionality, Modeling Challenges to Consider for Advanced Inverters and Modeling Software Updates by utility, researchers and industry experts. A California PUC representative spoke on the Interconnection Standards in California Interconnection and Regulatory Approach to a Fast-Changing Grid. Over 130 attendees befitted from the information presented.

### *Establish and lead, in conjunction with NREL, the Interconnection 2.0 Stakeholder Group*

Another significant effort related to establishing an Interconnection Stakeholder Group was in partnership with NREL was the “Mitigation Measures for Distributed PV Interconnection” webinar. Sandia gave a presentation in 2014 on *Analysis of 100 Utility SGIP PV Interconnection Studies.* The conclusions presented included that voltage deviation and protection impact mitigations were overall the most difficult and costly and that Overvoltage impacts were overall the easiest and least expensive to mitigate, with almost half requiring no added cost. This work continues connecting technical interconnect issues to the regulatory policies with which the utility sector operates. SNL works to improve interconnection screens and identify the most efficient mitigation strategies for common impacts. The webinar had 64 attendees.

### *Technical Foundation for Revised Screens*

Large PV installations on the distribution system can have many potential impacts to local customer power quality and reliability, therefore, before PV systems are allowed to interconnect with the grid, they must be studied to analyze and mitigate any impacts. These interconnection policies vary from utility to utility, but many utilities use a standard small generator interconnection procedure (SGIP) process for PV that includes a screen for placing requests on a fast track that do not require more detailed study. One common interconnection screening threshold (IST) fast tracks PV smaller than 15% of peak load.

Previously, very little work has been done to research and perform technical evaluation of the interconnection screening methods. A white paper was written to provide analysis of existing screening methods and to develop a technical case for implementing new SGIP screening criteria. This data-driven technical foundation is based on results from a large number of feeders, and it develops quantitative metrics for calculating the accuracy of the screening methods.

Metrics were developed to not only compare the screen to the feeder's minimum PV hosting capacity, but to also analyze the distribution of the feeder's locational hosting capacity and the number of violations and false-positives that the screen allows. This is an important concept because it analyzes the overall risk by how much of the feeder could handle various sized PV interconnections. There are many locations of a distribution system that can allow significantly more PV than the worst case location (feeder hosting capacity) or what is allowed by the IST.

The first metric investigates how close the IST is relative to the minimum hosting capacity (HC) for each feeder. A screen accuracy ratio (SAR) of the two numbers will be used to determine the closeness of the screen to the first PV size that could potentially cause issues, equation (1).

$$SAR = \frac{HC - IST}{IST} * 100 \qquad (1)$$

This number could be positive or negative, and it is similar to a percent error calculation with respect to the IST for how far it is above or below the HC. Like each of the error metrics defined in this paper, the optimal SAR value is near zero. In the case of SAR, the value is hopefully positive. IST values should be designed to be conservative and smaller than the hosting capacity to ensure that any PV sizes and locations that could potentially cause issues are studied in more detail. For example, in Figure 35 the hosting capacity is 2.3 MW because a PV of that size could be placed anywhere on the feeder without causing issues. In contrast, only 42% of the locations on the feeder could support a 10 MW PV system without violations. In Figure 35a, the SAR is approximately equal to 70%, meaning that the IST could be raised by 70% for this example system. In Figure 35b, the IST is higher than the HC, and SAR≈-40%, meaning that the IST should be lowered by 40%.

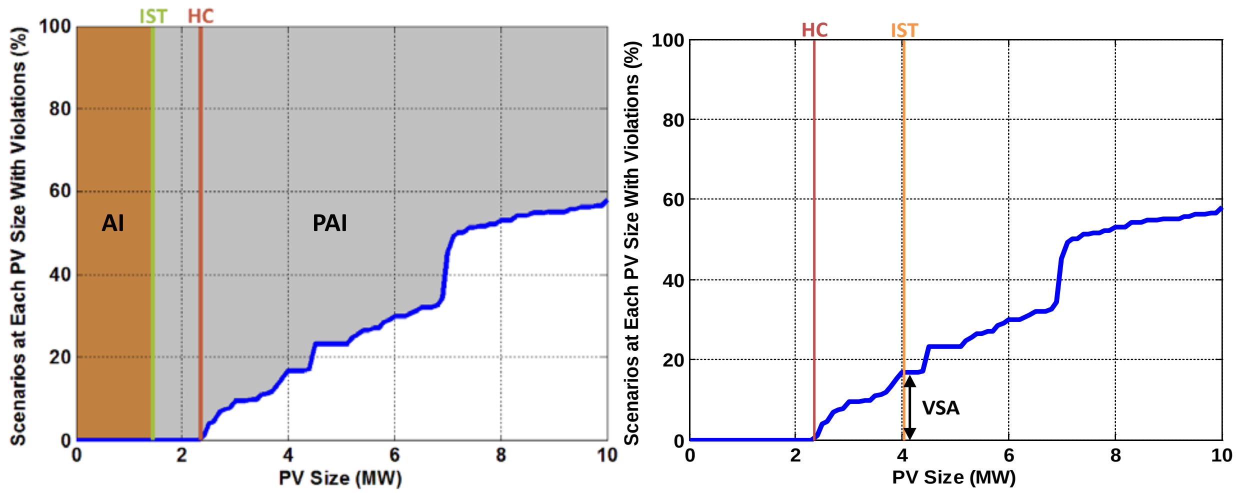



Figure 45. Example of an interconnection screen threshold (IST) with many potential allowable interconnections (PAI) beyond the allowed interconnections (AI), and an IST that passes PV systems that cause violations the screen allowed (VSA).

For the case that SAR is negative, this is caused by the IST being too high. When this occurs, the screening criteria will pass potential PV interconnections that will cause violations on the feeder. This is a serious issue because these PV systems will not be studied in detail, and could have potential impact to the system power quality and reliability. These impacts would normally be analyzed and mitigated during the interconnection process unless the system is fast tracked by the IST. This error metric is simply the number of violations the screen allowed (VSA). For the example in Figure 35 where the IST is higher than the HC, the VSA is approximately 17% and is marked with a black arrow.

While SAR provides information about the interconnection screen's accuracy to the feeder hosting capacity, it does not represent how many potentially allowable interconnections (PAI) should have been passed by the screening method because they would not cause any issues. These false positives in the screening process provide the motivation for more accurate screening methods that detect interconnections without violations beyond the allowed interconnections (AI). A large PAI means that the screen is sending a larger number of interconnection requests to a more detailed study than is necessary, which increases the labor and costs to the utility. In general, the PAI could be decreased by including more locational information into the IST, such as distance to the substation. Both the AI and PAI are essentially areas calculations as shown in Figure 35. The potential percent increase (PPI) in (1) is a ratio of PAI to AI that shows the dramatic number of PV interconnection that could have been allowed by the screen relative to the number that it currently allows.

$$PPI = \frac{PAI}{AI} * 100 \qquad (2)$$

Eleven different screening methods are analyzed. The screens are:

1) FERC fast-track eligibility threshold based on voltage class and if the interconnection is within 2.5 miles on backbone conductor
2) Screen F in Rule 21 that limits the short-circuit current contribution ratio to 0.1
3) 15% of feeder peak load screen
4) Feeder minimum daytime load screen

5) Short-hand equation screen developed in Task 1
6) NREL's proposed screen ("Locational Sensitivity Investigation on PV Hosting Capacity and Fast Track PV Screening" accepted to IEEE T&D 2016)
7) Rule 21 initial screening and supplemental review process
8) Rule 21 process with the load screens applied at a line level at the PCC
9) Modified Rule 21 according to the proposed modifications in Task 1
10) Modified Rule 21 from Task 1 using the line-level load screens
11) Short-hand equations combined with thermal limitations. An interconnection's thermal limitations are calculated by finding the minimum upstream ampacity plus the minimum load that occurs during daylight hours.

As discussed under Task 3, 216 different distribution systems have been analyzed using FIRST in order to determine the locational hosting capacity of approximately 60,000 buses. These results are used in the analysis to compare the accuracy of different screening methods. The results of the 3 error metrics for each of the 11 screens is shown in Figure 36.

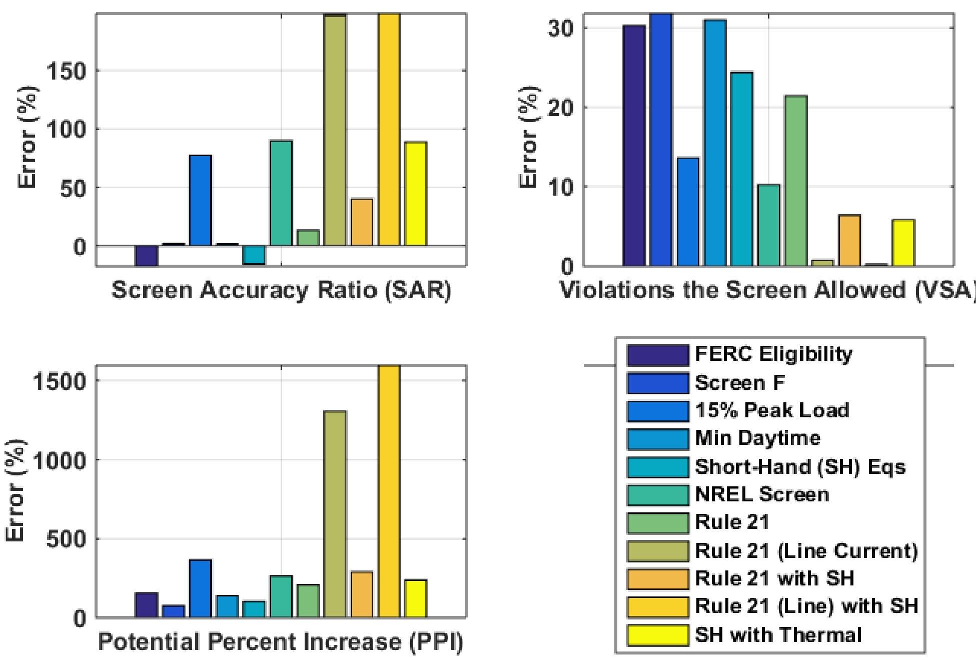


Figure 46. Error for 11 screening methods on 216 distribution systems.

An example of the different screening methods is shown for a 12kV feeder DA1 in Figure 37. The black line represents the locational hosting capacity (LHC) as determined by FIRST.

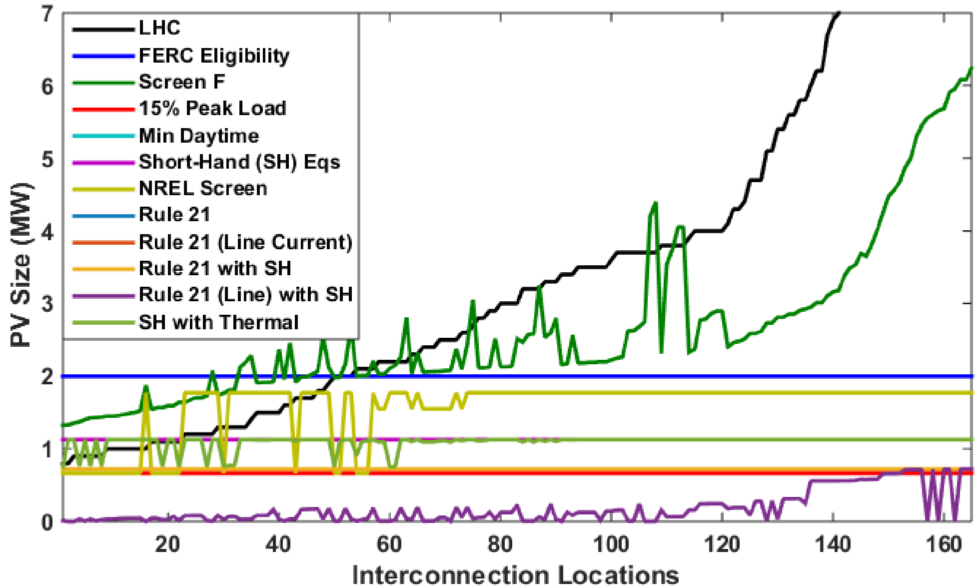



Figure 47. Interconnection screens for feeder DA1 compared to the locational hosting capacity (LHC) at each interconnection location.

Several conclusions can be drawn by looking at Figure 37. FERC eligibility has different thresholds for different voltage classes and if the interconnection is on the backbone. The 600 ampacity rating to be considered as backbone is larger than standard conductor ratings, so that higher threshold does not appear on many feeders. Screen F is based on the short-circuit current, which increases at lower impedances. Screen F best matches the overall shape of the locational hosting capacity, but it also has the largest VSA numbers. For this feeder, the minimum daytime load almost perfectly matches 15% of peak load, so those two lines and the Rule 21 thresholds are at 0.7 MW. The short-hand equations result in a constant number for the feeder of 1.1 MW threshold. When combining the short-hand equations with the thermal loading, some buses result in lower locational hosting capacity. The NREL screen bounces between three conditions of 15%, 35%, and 40% of peak load depending on the distance and impedance. Finally, the Rule 21 conditions with the load screens applied at the line interconnection are at the very bottom.

The accuracy of several screens is clearly dependent on the feeder voltage. For example, looking at the VSA in Figure 38, the FERC eligibility screen drops dramatically at higher voltage levels, meaning that the FERC threshold is too small above 15kV. The NREL screen includes an impedance threshold of 2 ohms. Because the per unit impedance changes at different voltage levels, the threshold is much too high at 4kV with a VSA=55%, and too conservative at the higher voltage levels above 15kV.

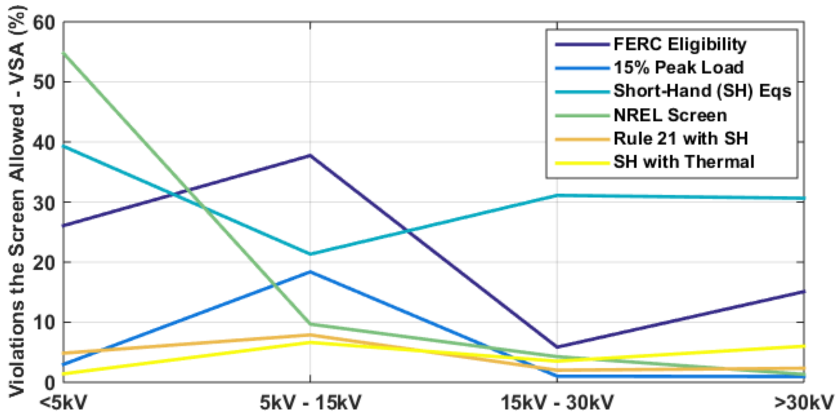



Figure 48. Screening accuracy by feeder voltage level.

The SAR error metric represents the screens ability to predict the feeder's hosting capacity. While this is valuable, it is much more interesting to see the error of the screening process for all potential interconnections in the VSA and PPI. When the load level screens in Rule 21 are applied at a line-level directly at the PCC, they basically never allow PV that will cause problems (VSA~=0), but they are also extremely low thresholds that result in extremely high PPI. For this reason, the line-level screening methods are removed from the rest of the analysis. Utilities regulators are also not likely to allow a screening method that fast-tracks a large percentage of systems that will only cause problems later. With this in mind, only screening methods with a VSA less than 20% are considered. The remaining potential screens are shown in Figure 39.

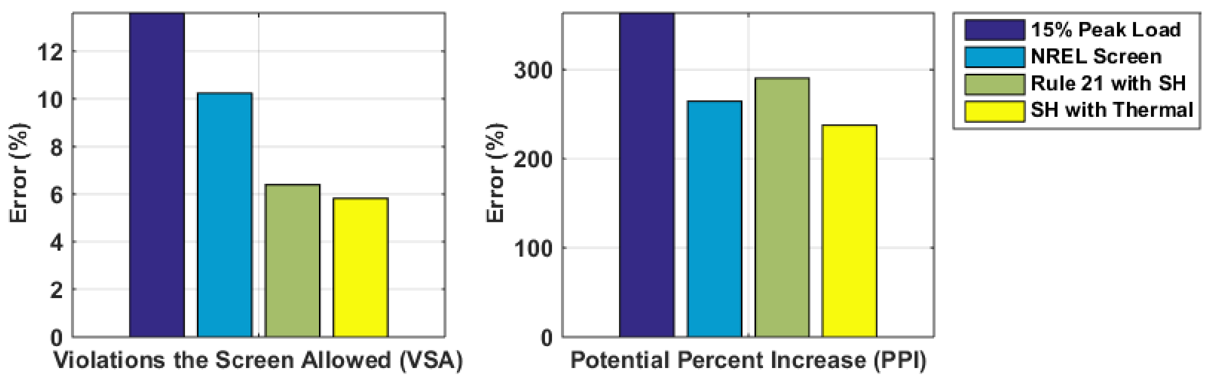



Figure 49. Justification for improved SGIP screening processes and potential improvements over the 15% screening method.

The short-hand equations combined with a thermal screen performs the best, but the NREL screen and the modified Rule 21 proposed in Task 1 also reduce the screening error.

## Significant Accomplishments and Conclusions for Task 5

- Sandia has provided effective and efficient stakeholder engagement to disseminate distributed grid integration results and best practices. We have established and supported stakeholder groups focused on removing key policy obstacles and have educated stakeholders through workshops, technical briefs, published papers and best practices guides to convey critical results from our work. This effort has been targeted to a broad cross-section of stakeholders including utilities, PUCs, FERC, EPRI, PV industry, Commissions, and universities to proactively guide the advancement of regulatory/policy mechanisms, standards, and best practices.

- Early in FY14, FERC issued a final ruling on the much anticipated modification of the FERC SGIP (Small Generator Interconnection Procedures) which governs the interconnection of generators that sell wholesale electricity in interstate commerce. This was a very major accomplishment and it benefits the solar energy sector. This was accomplished through the DOE staff actively teamed up with NREL and SANDIA and engaged with FERC, NRECA, APPA, Edison Electric, SEIA, IREC and others. This was an excellent model which produced results that greatly relaxes and simplifies the process for interconnection. Sandia contributed technical briefs in support of the rule change and provided a white paper entitled *Updating Interconnection Screens for PV System Integration* that was used by SEIA as a basis to petition FERC for the proposed rule change.

- Technical report on screening provides a full and complete data-driven technical foundation that supports revising the SGIP screens to make them more accurate and effective.

## Inventions, Patents, Publications and Other Results for Task 5

See list of inventions, patents, publications and other results listed in each Task above.

## Path Forward Task 5:

See overall Path Forward section at end of document.

## Overall Path Forward:

There are many areas in which we could extend the research created during this three year period. The key research direction in screening is to validate how and why the new screening methods actually reduce the need for expensive impact studies when applied over time to a utilities interconnection screening process. The key research direction in determining the technical feasibility of PV deployment scenarios is to fully characterize the impact of PV at small time scales using time series analysis to fully quantify the impact on voltage regulation equipment. This will require much faster tools to due this time series analysis for the time ranges required by utilities. The key research direction in developing tools to model variability is to gather data at many sites in the US at high resolution so that impact studies can use the correct variability input data. There will be an ongoing need to engage with stakeholders and regulators on the ever evolving technical limits and solutions for integrating high penetrations of PV into the distribution system safety and reliably.

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## Appendix A: Table of Milestones

| | | | | | | |
|---|---|---|---|---|---|---|
| ***Milestone 1.A*** | A Develop **two alternative** screening criteria/methods to the 15% Rule that will increase the accuracy of the screening process by reducing "false positive results" **by at least 40%** compare to the current 15% screen. A false positive result means the 15% screen incorrectly fails the interconnection request and assigns the interconnection a high risk for causing system impacts | reduce false positive screening results by **at least 40%** | Two screening methods: Alternative Rule 21 and Short hand equations with thermal limit | Model, simulate and evaluate using QSTS analysis and EPRI DPV | Yes | CSI 3 final report and pages 12-13 of report |

| | Metric Definition | Success Values | Measured Value | Assessment Tool | Goal Met | Data |
|---|---|---|---|---|---|---|
| ***Milestone 1.B*** | Demonstrate new screening criteria on **two** validation feeders. The new screening criteria and method should identify **100%** of the interconnection requests that will cause harmful impacts. | New screening criteria and method should identify **100%** of the interconnection requests that will cause harmful impacts for each area of concern: voltage, thermal, etc | Demonstrated new screening criteria on **<u>6</u>** validation feeders. Method identified 100 % of the interconnection requests that will cause harmful impacts. | Model, simulate and evaluate using QSTS analysis and EPRI DPV | Yes | CSI 3 final report |

| | Metric Definition | Success Values | Measured Value | Assessment Tool | Goal Met | Data |
|---|---|---|---|---|---|---|
| ***Milestone 1.C*** | Develop best practices guide for interconnection studies based on analysis of CA and other distribution circuits. | Publish best practices guide for interconnection studies based on analysis of CA and other distribution circuits. | CSI 3 final report providing best practice guidelines for screening interconnection studies using an alternate CA Rule 21 | Document | Yes | CSI 3 final report |

| | Metric Definition | Success Values | Measured Value | Assessment Tool | Goal Met | Data |
|---|---|---|---|---|---|---|
| ***Milestone 3A*** | Grid integration studies for Advanced Inverter functions proposed under new Rule 21 Advanced inverter task force. | Perform detailed distribution feeder impact analysis with high PV deployments for **at least 5** distribution feeders with a range of feeder topologies and feeder characteristics and simulate Advanced Inverter functionality | Completed the analysis and evaluation of **7 feeders**. | Determine the range of advanced inverter functionality and advanced inverter set points. | Yes | See pages 20-32 of report |

| | Metric Definition | Success Values | Measured Value | Assessment Tool | Goal Met | Data |
|---|---|---|---|---|---|---|
| ***Milestone 3B*** | Fully validate FIRST by expanding to a larger set of feeders to determine the likelihood of feeder impact due to high penetration PV for a wider set of feeder types. Quantify the potential improvements in available locational hosting capacity. | Complete the analysis and evaluation **of 10 or more** feeders with different feeder topologies using FIRST. | Completed the analysis and evaluation of **216 feeders.** | Improvement in available locational hosting capacity. | Yes | SAND report and Grid PV toolbox. |

| | Metric Definition | Success Values | Measured Value | Assessment Tool | Goal Met | Data |
|---|---|---|---|---|---|---|
| ***Milestone 3.C*** | Develop a method to generate load profiles at high time resolution (1-10second) for QSTS studies using 15 minute load data and load research data from utilities | Quantify the improvements in impact analysis accuracy using high time resolution load profiles. Quantify improvements in the two impact areas of voltage regulation and voltage profiles. | High resolution load profiles were found to only improve the accuracy of voltage regulation results by less than 5% | QSTS modeling and studies | Partial | See pages 31-33 of report |

| | Metric Definition | Success Values | Measured Value | Assessment Tool | Goal Met | Supporting Data |
|---|---|---|---|---|---|---|
| ***Milestone 4.A*** | Variability zone definitions are consistent between high-frequency and low-frequency data. | < 2 point difference in VS_cdf value between pairs of high-frequency data in the same low-frequency variability zone | See page 46 and Figure 32 | variability score from cumulative distribution of ramp rates (VS_cdf) | Yes | See page 46 and Figure 32 |
| ***Milestone 4.B*** | Tool will implement at least six variability regions and variability tool produces accurate and useful data. | Simulated power variability is accurate to within 30 voltage regulator tap changes weekly | See page 48 and Figure 34 | Simulated variability profiles on test feeder | Yes | See page 48 and Figure 34 |

| | Metric Definition | Success Values | Measured Value | Assessment Tool | Goal Met | Data |
|---|---|---|---|---|---|---|
| ***Milestone 5.A*** | Provide a full and complete data-driven technical foundation that supports revised SGIP screens. | Provide technical foundation for revising at least 2 SGIP screens | Development of screening quality metrics and in depth analysis of 10 potential screens using 216 feeders. | Measured responses from email, Sandia, technical briefs, workshops and events, and technical interfaces with regulatory action, including identification of regulatory consideration of identified technical constraints, approaches, and tools. | Yes | Technical Report |