Current Utility Screening Practices, Technical Tools, Impact Studies, and Mitigation Strategies for Interconnecting PV on the Electric Distribution Systems

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ABSTRACT

Interconnection procedures and the various tools and techniques used to evaluate interconnection requests (applications) vary from utility to utility. The photovoltaic (PV) development and installer community clearly benefit when states have standardized procedures for interconnection. Standardized interconnection procedures, permitting procedures, and building guidelines were developed in California before other states began focusing on these topics. These procedures have been put in place to ensure that safety, reliability, and power quality are maintained throughout the grid. It has clearly benefited the PV industry, as can be seen by the gigawatts of distribution-connected PV installations installed in California. However, most PV stakeholders agree that interconnection can be improved by streamlining the entire process from application to interconnection with the utility grid. It is important to note that many of the utilities that have been interviewed have worked diligently over the past few years to improve their study processes thereby reducing the costs and the total time from application to interconnection. This report focuses particularly on the technical models and tools used to evaluate PV system applications. The goal is to identify best practices that might be considered by all utilities that have a large queue of proposed PV installations on their electric distribution systems, as well as those who are positioning themselves for new PV interconnection applications and installations. The summary highlights a number of practices that were deemed useful and best by the authors.

Keywords
Distributed PV
Interconnection
Grid Codes
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Solar

EXECUTIVE SUMMARY

Interconnection procedures and the various tools and techniques used to evaluate interconnection requests (applications) vary from utility to utility. The photovoltaic (PV) development and installer community clearly benefit when states have standardized procedures for interconnection. Standardized interconnection procedures, permitting procedures, and building guidelines were developed in California before other states began focusing on these topics. These procedures have been put in place to ensure that safety, reliability, and power quality are maintained throughout the grid. It has clearly benefited the PV industry, as can be seen by the gigawatts of distribution-connected PV installations installed in California. However, most PV stakeholders agree that interconnection can be improved by streamlining the entire process from application to installation. It is important to note that many of the utilities that have been interviewed have worked diligently over the past few years to improve their study processes thereby reducing the costs and the total time from application through interconnection with the electrical distribution system. This report focuses particularly on the technical models and tools used to evaluate PV system applications. The goal is to identify best practices that might be considered by all utilities that have a large queue of proposed PV installations on their electric distribution systems, as well as those who are positioning themselves for new PV interconnection applications and installations. The summary highlights a number of practices that were deemed useful and best by the authors.

Industry Challenge

Various incentive programs have increased the number of solar PV system interconnection requests to levels never before seen. To ensure ongoing reliable operation of the grid, utilities must evaluate these interconnection requests to ensure proper operation of the grid is maintained. To assist utilities in quickly evaluating these systems, certain "screens" have been developed over the years that help identify when issues may or may not arise. The most common screening method takes into account the ratio of solar PV to peak load (15%), however it does not take into account the locational impact of PV nor the feeder-specific characteristics that can strongly factor in to whether issues may occur. EPRI has shown that a feeder's hosting capacity for accommodating PV is strongly determined by location of PV as well as a specific feeder's characteristics.[1]

[1] Smith, Jeff "Alterative Screening Methods: PV Hosting Capacity in Distribution Systems," DOE/CPUC High Penetration Solar Forum, Feb 13-14, 2013, San Diego, CA. http://calsolarresearch.ca.gov/Funded-Projects/solarforum.html

Project Goal

The objective of this project, entitled *Screening Distribution Feeders: Alternatives to the 15% Rule*, 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.

Benefits

This effort will result in improved methods that will allow utilities to more quickly and accurately perform engineering screens for new interconnection requests of solar PV, thus reducing time and costs associated with interconnection studies.

Approach

This project seeks to provide utilities in California with a useable and accurate way to determine the available capacity for PV generation on existing distribution feeders. The overall project approach will be accomplished via a number of distinct tasks as outlined in Figure 1 and described below:

1. *Document current practices for screening PV interconnections both inside and outside of California.*
2. Determine the range of feeder configurations for California utilities and develop a database of feeder characteristics. Select feeders for modeling and simulation that will be used in developing and validating the proposed screening methodology.
3. Collect high-resolution solar output data for validation of feeder models, definition of scenarios for high-penetration PV output, and verification of screening method with empirical data
4. Complete detailed feeder electrical modeling of selected test group of feeders across California.
5. Simulate a wide range of PV deployment scenarios and penetration levels on each feeder by utilizing EPRI's Distributed PV (DPV) Feeder Analysis Method for determining hosting capacity.
6. Develop practical screening criteria for evaluating new interconnection results.
7. Conduct formal validation process to determine accuracy of screening methodology.

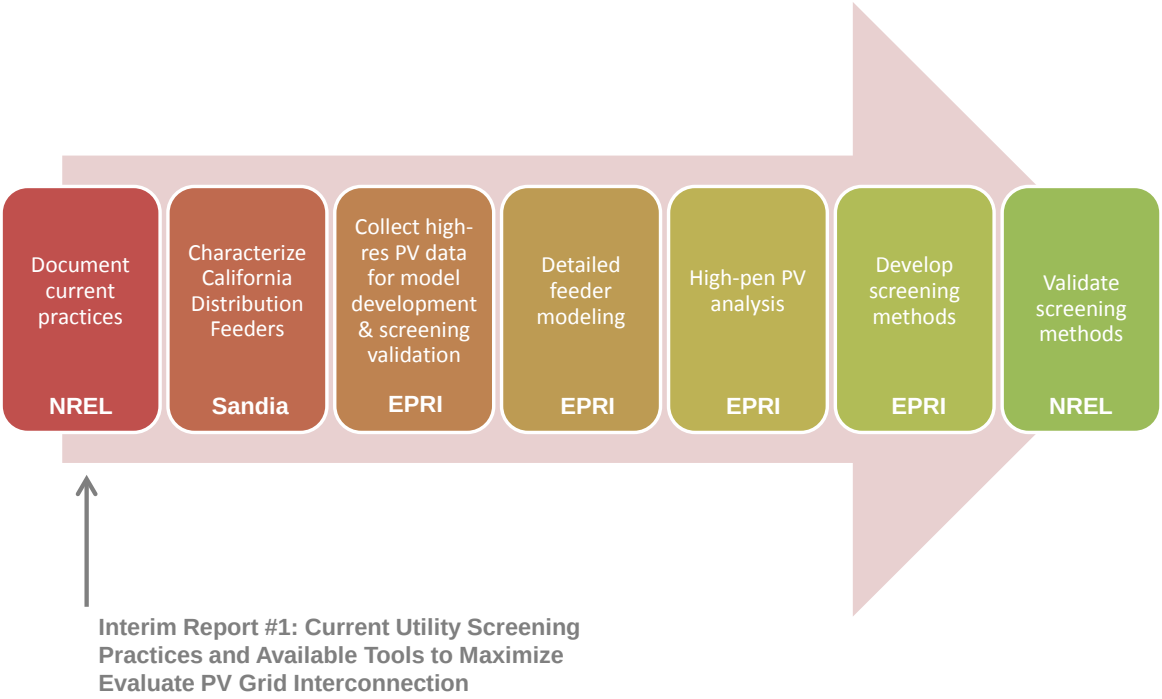

Figure 1: Project Breakdown and Task Leads

The focus of this particular report addresses the first task, which is to document current practices for screening PV interconnections both inside and outside of California.

Project Team

This particular CPUC/CSI project combines the experience of a team of individuals across the industry, including:

- Electric Power Research Institute - Project Lead
- National Renewable Energy Laboratory
- Sandia National Laboratories
- Itron

Utility Partners:

- Southern California Edison (SCE)
- Pacific Gas & Electric (PG&E)
- San Diego Gas & Electric (SDGE)
- Sacramento Municipal Utility District

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1 INTRODUCTION

The purpose of this report is to investigate and document current practices for screening PV interconnection requests among California utilities. The source of the information used in this report is based on interviews with electric utility interconnection experts, as well as published information from utility web sites.

There are a number of federal- and state-level interconnection agreements and procedures pertinent to the connection of any distributed energy resource (DER) to the distribution system. California's Rule 21, California investor owned utility's Wholesale Distribution Access Tariff Generation Interconnection Procedure (WDAT GIP), and the FERC Small Generator Interconnection Procedures (SGIP) are good examples. The project research team has collaborated with our California utility project team participants to detail which interconnection procedures and tools are most commonly used, and are most useful, for evaluating DER interconnection requests.

About the Electric Utilities

Each utility studied in this report has unique characteristics, which include feeder designs, methods of regulating voltage, types of customers served (rural, urban, agricultural, residential, commercial, industrial, and distributed generation), transmission and distribution voltage levels, capacitor use characteristics (VAR support versus voltage support, etc.), protection scheme philosophy, etc. It is important that while all electric utilities strive to serve their customers in a safe, reliable and cost-effective manner, each utility is different and faces unique challenges and thus direct comparisons are often inappropriate. However, there are many characteristics of electric utilities that are very similar in nature, and those similarities are critical in determining best practices.

Ultimately the authors of this report plan to interview and document the procedures for approximately twenty utilities nationwide, while this report focuses on the details within California utilities. All California electric utilities in this study helped develop the Rule 21 interconnection procedures even if they are not under the jurisdiction of the CPUC. Electric utilities outside of California often follow interconnection procedures typically based on the Federal Energy Regulatory Committee (FERC) Small Generator Interconnection Procedures (SGIP). This report will document both the procedures that are followed within each utility for most retail (net energy metering) installations, as well as the modeling platforms, types of studies conducted (when required), and mitigation measures for potential system problems (if required).

2 CASE STUDIES

Each utility that participated in these case studies was asked a series of detailed questions regarding interconnection processes, screens, tools, impact studies and mitigation methods. Some of the utility experts completed many of the questions prior to each interview, and all utilities were included in a conference call. Each utility case study follows a similar format based on the flow of the PV interconnection procedures.

The questionnaire used for the interviews with each utility was identical, and was developed with inputs from the CPUC, Itron, EPRI, IREC, and NREL. While the process and the interconnection application (ICA) statistics for each utility is interesting and important, the primary focus is on the types of impact studies, distribution modeling methodologies, and the mitigation approaches used at each utility, as well as any unique tools or methods that might be highlighted in the report. The information within the report reflects the answers provided by the utilities to the team, and also reflects information contained on utility web pages. The questionnaire is included as Appendix B of this report.

San Diego Gas and Electric (SDG&E)

Overview of the SDG&E interviews and questionnaire: The questionnaire and interview was conducted on December 18, 2012 with members of SDG&E, EPRI and NREL.

Interconnection application process

Types of Interconnection Applications: SDG&E applies one of three different distributed generation (DG) interconnection procedures to evaluate DG interconnections, depending on the type of technology.

i. Net Energy Metering (NEM) - less than 1MW. This has been offered to any customers within the service territory and within the NEM cap. This NEM program allows no standby charges, no departing charges, and no application charges. Approximately 99% of PV interconnection applications (ICA) fall under the NEM umbrella, with less than 1% falling under the new settlement (see next item).
ii. New Settlement – This is a new settlement under Rule 21, and is for interconnection on distribution or state jurisdiction systems. Approximately 18-20 customers are expected in 2013.
iii. Wholesale Distribution Access Tariff (WDAT) small generation interconnection process. These are often, but not always, larger DG systems.

Technical Review Screens

California Rule 21 has specific screens that are followed by SDG&E. For smaller systems, from 1-30kW, a set of simple screens is utilized to evaluate each ICA. For proposed systems between 30kW and 1MW, the screens are more detailed. The Rule 21 settlement illustrates the supplemental screens.

When SDG&E evaluates an ICA using screens, the proposed DG is included with the aggregate (existing) DG on the distribution circuit as well as other proposed projects for the same distribution circuit. Cluster studies are conducted based on the queue of interconnection requests for any particular distribution feeder when SDG&E engineers deem it most efficient. When cluster studies are completed, all PV and other DG are considered in the study.

Tracking ICAs: SDG&E presently has a system in place to communicate with customers and PV developers using an automated email system. Emails are sent to customers and PV developers for specific milestones in the process.

A new ICA Portal has been rolled out by SDG&E, and was developed by the utility. PV and other DG projects can be tracked by customers, and with a username and password a project status can be checked via computer, tablet, or smart phone.

Amount of PV deployed in SDG&E territory: Presently there are approximately 155.5 MW of PV installed in the NEM program. The 2013 expectation is that an additional 37 MW of PV will be installed. There are also approximately 10 MW of PV behind the meter in non-NEM installations. The NEM program is expected to grow until at least 2017 when the federal tax incentives are scheduled to expire.

PV grid hosting capacity limitations: The maximum allowable PV on any distribution feeder varies for SDG&E. The limitations are based on feeder ampacity at the maximum possible level of PV saturation. The rule of thumb within the engineering departments has been a maximum of 10 MW of DG on any feeder. The largest “maximum” limiting factor is the substation breaker rating, followed by the feeder exit rating[2].

The size of the conductor between the substation and the proposed DG is important, but the X/R ratio at the proposed point of interconnection is looked at closely. One of the principal mitigating measures for increasing the amount of PV in a proposed location is to re-conductor the line and improve the X/R ratio. Another key mitigating factor is the presence of load near the proposed DG. As long as sufficient load is near that location, chances of exporting power are minimized and is seen as a positive factor.

If technical screens contained in the initial review process are not passed by an ICA, supplemental screens are applied that focus on voltage, power quality, and reliability. If those supplemental screens cannot be passed, detailed impact studies are the next step.

Technical Concerns: SDG&E engineers have several areas that are of higher concern when evaluating DG ICA. Those areas are listed in Table 2-1. Safety, reliability, voltage control, and the ability to serve load and switch circuits are all primary levels of concern. Many other concerns fall in as secondary, but are certainly considered important when operating the electric system and integrating DG onto the distribution system. It is important to note that the concerns

[2] Feeder exit rating refers to the thermal amperage rating of the conductors that tie the substation distribution feeder breaker to the first device outside the substation, and this is typically the largest rating of a circuit.

differ from utility to utility for many reasons, but the average length and configuration (topology) of the "typical" feeder have a significant impact. In other words, it is much easier to integrate DG on short urban circuits than on longer, rural feeders with fewer Watts per mile.

Table 2-1 List of SDG&E Concerns when evaluating ICAs

Issue	Level
Safety	Primary Concern
Ability to serve load	Primary Concern
Voltage control (and control for CVR)	Primary Concern
Reliability	Primary Concern
Location of proposed DG	Secondary Concern
Capacity of distribution at point of interconnection	Secondary Concern
Distance to substation of proposed DG	Secondary Concern
Is the proposed DG in a transmission-constrained area?	Secondary Concern
What kind of load is near the proposed DG	Secondary Concern
Increased duty on line regulation equipment	Secondary Concern
Protection system coordination	Secondary Concern
Unintentional islanding	Secondary Concern
Reactive power control	Secondary Concern
Variability due to clouds, etc.	Secondary Concern
Balancing resources and demand response	Secondary Concern
Harmonics and power quality	Secondary Concern
Impacts to flexibility for switching and load growth	Secondary Concern

Secondary Network Distribution Systems: SDG&E does not have any secondary network distribution systems in their service territory, and are likely not to have any systems installed in the future. Therefore, the topic is not germane to this case study.

Detailed Impact Studies: Detailed impact studies are rarely needed for those PV systems that come through the NEM process, which is the significant majority of PV system ICAs. Generally, larger systems that come in through the FIT and WDAT process are much more likely to require the detailed impact study process.

SDG&E employs a two-step approach when conducting a detailed impact study. First, a static analysis using *SynerGEE* is employed to look at voltage, protection, etc. The second step is to conduct a quasi-static time-simulation analysis and, if necessary, time-domain (dynamic) analyses. These dynamic analyses are generally conducted by contractors to the utility, and the main focus is on the power quality impacts (e.g. flicker). For PV systems, flicker due to cloud

transients and ramp rates are a concern. Synchronous machines are treated entirely differently as they have a significantly different impact on the distribution system than PV systems.

The following impact study areas are considered for PV systems that require detailed impact study analysis (regardless whether they are NEM, FIT or WDAT):

- Power flow analysis
- Short circuit analysis
- Power quality assessment and analysis
- Quasi-static time series analysis
- Dynamic/transient stability analysis (infrequent)

Rule 21 stipulates that, when supplemental review screens cannot be passed, the detailed impact study process is triggered. The following questions are generally posed when evaluating an ICA:

- Will the proposed DG impact voltage levels significantly?
- Where is the proposed DG system going to tie into the feeder?
- Is the system greater than 1.5 MW? If so, the detailed impact studies will need to be applied.

Methodology for conducting studies: All ICA requests go to the Customer Generation Department first, and that department determines which other organizations within SDG&E need to be involved in each ICA.

There are two groups of engineers at SDG&E that conduct various studies on ICAs. Larger PV systems (as well as other DG) may need to be studied by the transmission planning engineers, using the PSCAD and PSLF modeling platforms. Smaller DG may also be looked at if the proposed DG is in a known constrained area, or if the proposed substation has known issues. In addition, any proposed DG that is 1.5 MW or larger triggers a notification of the Transmission Planning Department. DG system interconnection applications over 20 MW will go directly to the Transmission Planning Department for impact study analysis.

Time and cost constraints for impact studies: California Rule 21 has time guidelines that must be followed for reviewing and studying ICAs. There are occasions when the number of ICAs may have an impact on these timelines, but SDG&E does their best to follow the guidelines. SDG&E employs outside expert consultants for some of their ICA impact study work, which helps meet the time constraints required by Rule 21.

Utility departments impacted by PV Interconnection Applications and installations: Table 2-2 illustrates most of the departments that are involved in the interconnection application and study processes.

Table 2-2 Departments and their roles for interconnection applications

Department	Role of Department
Customer Generation Department (CGD)	The Customer Generation Department handles all ICAs for SDG&E. CGD tracks the ICAs, and works with the other departments to ensure the right people evaluate the appropriate ICA.
Distribution Planning Department (DPD)	The DPD receives copies of all ICAs, and may also contact other departments that need to evaluate a proposed DG. DPD conducts all

	levels of screening (used on most applications) and conducts impact studies when necessary (see discussion above). The DPD also decides the appropriate mitigation measures that may need to be deployed for a proposed DG installation.
Transmission Planning Department (TPD)	The TPD are notified of all PV applications that are over 1.5 MW in size, or are in known constrained areas (see discussion above)
Substation Engineering	Substation Engineering may be involved for larger PV systems (over 1.5 MW) and for any systems that may impact operations or construction at the substation level. This may include any necessary changes to the substation relaying or breakers, the load tap changers (LTCs), etc.
System Protection	System Protection is involved in many ICAs when there are possible impacts to protection coordination. Any changes to reclosing schemes will involve System Protection, and even for fuses that are 150 Amps or larger.
Legal Department	The Legal Department is involved in most ICAs when there are agreements that are signed between utility and customer/developer. There are numerous other reasons why the Legal Department may be involved, and those are based on a case-by-case basis.
Land Use / Environmental	Larger DG ICAs may require that the Land Use / Environmental Department become involved in a project. Any time a line must be upgraded, or equipment may need to be changed out or added, requires land use specialists to be involved.
Metering Department	Any time a meter is changed out for NEM service, or new meters are installed for new PV systems, the Metering Department is involved.
Outside consultants	As discussed above, outside consultants may be used to conduct quasi-static time series analysis and other distribution and transmission studies as needed.

Modeling Platforms and Geographical Information System (GIS): SDG&E uses the ESRI ArcGIS system for mapping all distribution and transmission circuits and equipment. The GIS models are used to extract data into the SynerGEE program for distribution impact studies. Some studies may then move to PSCAD for further analysis, using the SynerGEE circuit models.

The GIS system stores information on all DG and PV systems, and then tracks the type of system and the kW rating of each DG system. All DG systems tracked in the GIS system can be used for extracting into the modeling platforms.

Outputs from distribution modeling studies: While SynerGEE and often PSCAD are used for modeling, there are additional needs in the short circuit analysis area. SDG&E engineering staff would prefer to use a single modeling platform for their modeling studies. Currently a model is extracted from GIS, then evaluated using SynerGEE, and then extracted into PSCAD. If this could be kept within SynerGEE it would eliminate a step in the complex process. SDG&E

engineers expressed a desire for higher fidelity data, with finer resolution, for use in simulation software.

When an ICA fails the impact studies, mitigation measures are required and, consultants often work with SDG&E engineers to work through a series of "what ifs". Voltage control is often the first issue to be analyzed, and the team evaluates various measures to solve the voltage concern. Voltage concerns are typically straight forward to address and resolve, but flicker issues are not as easy. Developers are asked to operate their systems with a power factor of +/- 95% (which may move toward 90% at some point in time). There are a number of possible mitigation measures that may be employed to resolve concerns/problems including line upgrades, line regulator additions/modifications, etc. Curtailment is not an option considered at this time, but may be evaluated in the future.

Mitigation Measures Employed:

- Line size upgrades
- Voltage regulator additions
- Voltage regulator control setting modification
- Bi-directional line regulators (not standard at this time)
- System protection modifications – Both on distribution and transmission are considered. System Protection evaluates all reclosers and fuses 150 Amps and above.
- Advanced inverter technology – This is not common now, but is expected to be more prominent in the future to maintain constant power factor, etc.

Tools: The tools employed by SDG&E are generally what are available in the industry, which include modeling platforms such as SynerGEE, PSCAD, and PSLF. The ESRI ArcGIS system is an important component of the set of tools.

Pacific Gas and Electric (PG&E)

Overview of the PG&E interview and questionnaire: The questionnaire and interview was conducted on January 22, 2013 with members of PG&E, EPRI and NREL.

Interconnection application process

Technical Review Screens: Rule 21 applies to all PV ICAs except for FERC jurisdictional system applications. However, screens are used for all interconnection applications. PG&E offers an option to bypass the fast-track screens and move directly to the detailed study process when it is clearly understood that a detailed study process will be the approach due to size, location, etc.

All DG on a distribution feeder is considered when conducting screens and the 15% penetration screen must consider the total amount of interconnected DG on a feeder. There are generally no bulk or cluster studies considered on the distribution system, as those are used for larger "transmission/bulk power" systems.

Supplemental Screens: Supplemental screens are used in accordance with Rule 21. PG&E works very hard to be transparent in this area and explain to customers and developers exactly how the screens are applied.

Tracking ICAs: PG&E currently tracks ICA requests in their computer system, but it is a manual process without a portal to the outside. They have plans to launch a new system for online applications and tracking and that system will be capable of tracking additional information and statistics.

Technical Screens and Review

PG&E has few limits on DG / PV saturation (grid hosting capacity) other than the circuit ampacity at the substation breaker, which is typically 600 Amps. The technical screen "fast track advisory limits" are 2 MW for 12 kV circuits, and 3 MW for 21 kV circuits. The 2 MW and 3 MW limits are the total DG installed on a circuit. Location of the proposed DG is of great importance, despite these limits. PG&E is developing guidelines that will ultimately be published to help PV developers in siting proposed systems.

When an ICA fails the fast track screening process, the Revised Rule 21[3] has provisions for using supplemental screens to aid in approving more systems without having to go through detailed impact studies. These supplemental screens address issues such as voltage, reliability and power quality.

Technical Concerns: PG&E engineers have several areas that are of concern when evaluating DG ICAs. Those areas are listed in Table 2-3.

Table 2-3 List of PG&E Concerns when evaluating ICAs

Area of Concern	**Level of Concern**
Voltage regulation	Primary Concern
Protection System Coordination	Primary Concern
Unintentional Islanding	Primary Concern
Impact to other customers	Primary Concern
Reverse power flow (exporting systems more closely scrutinized)	Secondary Concern
Flicker	Secondary Concern
Thermal overloads	Secondary Concern
Operational flexibility (operations and engineering)	Secondary Concern
Increased duty on equipment (breakers, fuses, etc.)	Secondary Concern
Inverter trips due to transients	Secondary Concern
Reactive power control (VAR)	Secondary Concern
Variability due to clouds, etc.	Secondary Concern
Network protectors on secondary network distribution systems	Secondary Concern
Temporary overvoltage due to faults	Secondary Concern

[3] http://www.pge.com/tariffs/tm2/pdf/ELEC_RULES_21.pdf

Harmonics (UL certification is checked)	Secondary Concern
Increased capacitor switching	Secondary Concern
Multiple inverter stability	Secondary Concern
Balancing resources and demand response	Secondary Concern

Secondary Network Distribution Systems: PG&E has secondary network distribution systems in several cities in their service territory. PV systems have been installed on their networks, and they have specific rules about interconnection due to the sensitive nature of networks. No PV systems on a network can export power past the utility meter, and generally the systems are designed to ensure that the meter, or point of common coupling, always has a positive load to keep network protectors closed and power flowing (known as minimum import and supervised with relays which trip the PV system off line if power flow drops below a specific level).

PG&E follows the IEEE 1547.6[4] standard for interconnecting DG on secondary networks. This standard was published in 2011 and was developed with many inputs from PG&E engineers. In addition to the minimum import requirement, PG&E also requires that >50% of network protectors are closed that serve the facility hosting the PV system. PG&E has developed custom electronic solutions in order to monitor the position of the network protectors and created a logical circuit in order to ensure PV systems drop offline when the total network protectors serving the location drop to 50% or below.

Detailed Impact Studies: Fast track screens and/or supplemental screens are applied before detailed impact studies are performed. Failed screens will lead to detailed impact studies, yet they may point toward multiple problems that need to be studied and mitigated. The following two study types comprise the bulk of the detailed impact studies:

- Power Flow
- Short Circuit (protection)

Currently quasi-static time series studies are not performed, but are likely to be used in the future. Power quality studies are not part of the impact study analysis, but PG&E verifies that the power electronics are listed to UL1741[5] or other valid certifications to ensure compliant power quality levels. Dynamic/transient stability studies and electromagnetic transient studies are not being used at this time, but may also be coming as the saturation (total amount of DG on a circuit) of DG increases.

While there is no specific methodology used for all PV ICAs, there are “flags” that are raised for certain systems. Large PV systems on smaller primary conductors and at longer distances from the substation are examples of those flags.

PG&E uses internal guidelines and standards for their detailed impact studies. The internal guidelines are drawn from engineering texts as well as work done in Distribution Planning and System Protection departments.

[4] http://grouper.ieee.org/groups/scc21/1547.6/1547.6_index.html
[5] http://ulstandardsinfonet.ul.com/scopes/1741.html

Modeling Platforms employed: The distribution modeling platform used for power flow and short circuit studies is Cymedist. ASPEN is the modeling platform used for transmission level studies at PG&E, which may be used for some larger PV system ICAs. If there is going to be power flow onto the transmission system, then a transmission study will certainly be conducted. PG&E had used a system called CEDSA, but they are moving away from that approach.

Special studies, such as dynamic transient, harmonics, etc., are performed by outside consultants to PG&E.

If the detailed impact studies determine there are mitigating steps that need to be taken, the ICA developer would be responsible to pay for that mitigation.

Time and cost constraints for impact studies: PG&E follows the guidelines in Rule 21 to determine the allowable time and costs for impact studies.

Utility departments impacted by PV Interconnection Applications and installations: Table 2-4 illustrates most of the departments that are involved in the interconnection application and study processes.

Table 2-4 PG&E Departments and their roles for interconnection applications

Department	Role of Department
Distribution Planning Department (DPD)	DPD looks at all ICAs that will interconnect to the distribution system. DPD also does the fast track screening evaluation. The divisional planning engineers handle the PV systems less than 1 MW and the NEM projects, while the central planning engineers handle larger systems or may assist division engineers when there are potential problems or too many applications to process in a timely manner.
System Planning Department (SPD)	SPD is notified when a distribution ICA fails screens and impact studies, or if a system will export power onto the transmission system. SPD engineers also review the much larger, bulk power PV system applications that are outside the distribution systems.
System Protection Department	System Protection engineers also are involved when a distribution level PV ICA fails a detailed impact study or may export to the transmission system. System Protection also works with SPD on larger PV systems that connect to the transmission system.

Modeling Platforms and GIS: PG&E does not have a GIS system currently, but they do use a system called CEDSA that was developed years ago internally to PG&E. The mapping for PG&E is done using a system called DART, which includes utility equipment and DG information, and is geographic in nature. Planning engineers are responsible to add the DG data to the DART system, and that is used for importing into the Cymedist modeling platform. However, the DART system has interesting ways to handle DG systems, and they can be switched ON or OFF within the program. Most engineers switch all DG into the ON position prior to exporting the data to Cymedist and conducting a model run/study.

The DART system captures the DG system size, phase information, manufacturer and type of DG system. There are plans in place to convert the DART system into a GIS system, but details are not available at this time.

Outputs from distribution modeling studies: When detailed impact studies fail, or flags raise potential problems, a solution must be offered to the ICA applicant. Solutions to potential problems may be relatively straight forward and inexpensive, or costly, depending on the necessary mitigation measure. For example, adding a new substation could cost millions of dollars (and years to install) while modifying the system protection scheme may only cost a few thousand dollars and take a few hours. PG&E does not turn down interconnection applications, but offers either approval or a solution that leads to approval. The solutions that lead to approval, whatever the cost, is borne by the ICA applicant if the decision is made to move forward with the project.

Mitigation Measures Employed: The following mitigation schemes are sometimes required to ensure that a PV system stays in compliance with Rule 21 and PG&E requirements:

- Voltage regulation devices – Reset, relocate or replace existing voltage regulation devices or install new devices. Bi-directional controls are sometimes required for reverse power situations.
- Upgraded line sections – this typically includes increasing the size of the conductor, either overhead or underground. This may include the necessary pole and hardware upgrades for overhead, and may include switchgear upgrades for underground systems.
- Protection scheme modifications – There may be times when relays need to be replaced or adjusted, etc. This is most often associated with rotating machine based DG rather than PV systems.
- Direct Transfer Trip (DTT) – This is a method used to help prevent unintentional islanding situations, and requires a communication link. This method is often expensive and PG&E prefers to avoid using DTT.
- Communication and control – There are telemetering requirements for DG systems 1 MW or larger. PG&E SCADA uses fiber if available, or leased lines, or radio (whatever works best)
- Grounding transformers – Sometimes required to prevent transient over voltage (TOV type 1 or 2).
- Advanced inverter technologies
    - Volt/VAR control – For larger PV systems
    - Voltage ride-through – For larger PV systems

Advanced inverter technologies options for constant power factor or scheduled modes of operation are being considered, but are not currently part of the solution set.

Tools: PG&E publishes online maps to help PV developers located the best, and also the least attractive sites to consider for system consideration.

The main tool used by PG&E for the entire process is Rule 21.

Overview of Improvements in ICA: PG&E encourages developers to connect as close to a substation as possible, as line distances exacerbate the problems that may arise with an installation.

Southern California Edison (SCE)

Overview of the Southern California Edison interviews and questionnaire: The questionnaire and interview was conducted on December 18, 2012 with members of SCE, EPRI and NREL. SCE had filled in many of the questions before the call, which assisted in developing greater detail compared to other utilities.

Interconnection application process

The interconnection applications (ICA) are available on the SCE web page[6] and are outlined in the SCE Wholesale Distribution Access Tariff (WDAT) and CPUC Rule 21 areas of the site. The ICAs can be filled out electronically or printed and completed manually. The ICAs can be submitted via email to dedicated inboxes monitored by SCE personnel.

Types of Interconnection Applications: The ICA has different sections for different technologies (inverter-based, synchronous, induction). NEM applications are processed and evaluated differently than non-NEM generation projects. WDAT projects are handled via WDAT-specific processes, and information can be found on the Open Access section of the SCE web page[7]. Rule 21 applications are broken out into four types of application types:

1. NEM Short Form for systems up to 10kW (standard). Note: non-standard would include battery systems, line-side taps, multi-tariff, etc.
2. Large NEM greater than 10kW, non-standard (see note above), and non-exporting.
3. Non- NEM exporting generators
    a. Fast Track Requests
    b. Independent Study Requests
    c. Group Study Requests (Future – Rule 21 phase II)
4. Non-Export

SCE has posted a broad overview of "Open Access information" on their web page[8]. The web page has a comprehensive regulatory information overview of the Net Energy Metering and Rule 21 Tariff, the Public WDAT-Rule 21 Queue, Renewable and Alternative Power documents and forms, as well as many other useful and informative sections.

Online Interconnection Request: The Rule 21 Exporting Generating Facility Interconnection Request[9] is an online document that is in an Adobe PDF format, which can be used for any type of DG technology. The form allows the application to select the study option as "*Fast Track Process*" or the "*Detailed Study Process*". The request may be saved on local or cloud storage devices which is useful for gathering the significant amount of details requested. The request seeks to document important data such as the generator type and size, the proposed location including GPS coordinates, the proposed in-service date, as well as name of the project and the applicant's contact information. The request form also requires the applicant to provide important information on the proposed equipment, which is critical for completing system impact evaluations or studies and to verify that the installed system matches the proposed design.

[6] *http://www.sce.com/AboutSCE/Regulatory/openaccess/default.htm*
[7] *https://www.sce.com/wps/wcm/connect/09007f34-9c05-4ea4-a36d-593d05b12c55/WDATApplicationGIPAPPENDIX1FillableIR.pdf?MOD=AJPERES*
[8] *http://www.sce.com/AboutSCE/Regulatory/openaccess/default.htm*
[9] http://asset.sce.com/Documents/About%20SCE/14-918_Rule21ExportingGeneratingFacilityInterconnectionRequest.pdf

The request form is comprehensive and seeks to gather a significant amount of detail for the utility engineering departments.

Technical Review Screens

SCE uses technical reviews for all ICAs, regardless of size. However, the Rule 21 Exporting Generating Facility Interconnection Request form[10] differentiates between the *Detailed Study Process* and the *Fast Track Process*, which allows for bypassing the fast track screening process for those systems that are larger or more complex, and the developer understands that the detailed study process must be chosen. Proposed PV systems and existing DG systems are considered during the review process.

Supplemental Screens: When an ICA fails the fast track screens, there is an option to go through a second set of screens called *Supplemental Screens* per the Rule 21 Section G[11]. This allows an ICA to be reviewed and may qualify for fast track if those supplemental screens are passed. The WDAT tariff contains language that allows SCE to use the equivalent set of supplemental screens as those in Rule 21.

Tracking ICAs: Currently SCE does not utilize an online tracking program to allow interconnection request customers to access their project status. For WDAT applications, a dedicated project manager is assigned to coordinate each project. A separate department within SCE handles NEM projects, of which there are approximately 700 applications each month.

Technical Review: SCE has specific standards they reference when determining the maximum amount of generation to be connected to a distribution feeder. Circuits rated at 12 kV and 16 kV are allowed to have a maximum of 450 Amps of generation, which is about 10 MW on the 12 kV circuits and 13.5 kV on the 16 kV circuits. SCE also has some 33 kV circuits, which are only limited by the ratings of the conductors, system protective devices, substation capacity, etc. SCE tracks all interconnected generation systems so that this information can be determined when studying a new ICA.

Technical Concerns: SCE engineers have several areas that are of concern when evaluating DG ICAs. Those areas are listed in Table 2-4.

Table 2-5 List of SCE Concerns when evaluating ICAs

Area of Concern	Level of Concern
Voltage regulation (over-voltage)	Primary Concern
Protection system coordination	Primary Concern
Unintentional islanding	Primary Concern
Reverse power flow (especially from distribution to transmission)	Primary Concern
Flicker	Primary Concern
Thermal overloads	Primary Concern

[10] http://asset.sce.com/Documents/About%20SCE/14-918_Rule21ExportingGeneratingFacilityInterconnectionRequest.pdf
[11] see page 89 https://www.sce.com/NR/sc3/tm2/pdf/2780-E.pdf

Operational flexibility (operations and engineering)	Primary Concern
Increased duty on equipment (breakers, fuses, etc.)	Secondary Concern
Inverter trips due to transients	Secondary Concern
Reactive power control (VAR)	Secondary Concern
Variability due to clouds, etc.	Secondary Concern
Protection of network protectors on secondary network distribution systems	Secondary Concern
Temporary overvoltage due to faults	Secondary Concern
Harmonics (THD)	Secondary Concern
Increased capacitor switching	Secondary Concern
Multiple inverter stability	Secondary Concern
Balancing resources and demand response	Secondary Concern

Secondary Network Distribution Systems:

SCE has one secondary network distribution system (network) in their service territory, which is in the Long Beach area. Currently PV and other DG are not considered for interconnection to this network system.

Detailed Impact Studies: When an ICA does not pass the fast track screening process or the supplemental screening process, or the application points toward the Detailed Study Process, SCE engineers conduct the following impact studies[12].

1. Power Flow
2. Short Circuit
3. Power Quality (focus on voltage control issues)
4. Contingency N-1 conditions (this is mainly to check for substation transformer overload conditions. Some applicants may need to be switched to an alternate distribution circuit in the event of system emergencies.)
5. Operational and reconfiguration evaluations
6. Protection evaluations
7. Transmission impact studies

The decision to conduct a detailed impact study sequence is outlined in Rule 21 as well as the WDAT tariffs, and that is followed by SCE. All projects follow the same set of evaluations, which is important due to the complexity of the overall study process.

Methodology for conducting studies: SCE does not have published guidelines or specific engineering texts used when conducting studies, however, their internal practices are based on industry standards for the types of studies (power flow, voltage control, short-circuit duty, etc.)

[12] Impact studies often vary in approach and scope between utilities, and the intent in this report is not to offer significant detail into what is included with each type of study. IEEE 1547.7, to be published in 2013, offers significant detail into what should be included in each study type.

Modeling Platforms employed: The software used for conducting impact studies depends on the voltage class and the type of study. *CYME Cymdist* is employed for many of the distribution level studies (12kV-16kV systems), while *PSLF* is used for 66kV and 115kV systems, as well as 33kV networked systems. *CAPE* is used for conducting duty calculations and other internal programs are used to look at data trending, mapping (GIS), and others. All programs used for these studies and modeling are commercially developed, with no in-house systems developed.

Presently the distribution modeling platforms are deemed adequate for SCE needs, however, as levels of DG saturation increase, additional information or features may be necessary to complete future studies and evaluations. The distribution-modeling platform currently accounts for all DG on each circuit (even though the GIS system doesn't presently track all DG). SCE has created databases that track substations, distribution feeders, etc. The GIS mapping system is also utilized to evaluate adjacent circuit impacts and N-1 impacts.

Time and cost constraints for impact studies: California Rule 21 tariffs and SCE WDAT tariffs have specific timelines for both WDAT and Rule 21 ICAs. Except for Supplemental Review, there are no cost caps on the studies, but there are standard deposit requirements for each study and that is outlined in the tariffs. SCE has seen a high number of ICAs over the past few years, and in some cases, meeting the required timelines has been challenging.

Distribution studies are conducted within SCE, while some transmission level studies may be done by outside consultants when internal resources are not available.

Utility departments impacted by PV Interconnection Applications and installations: Table 2-6 illustrates most of the departments that are involved in the interconnection application and study processes.

Table 2-6 SCE Departments and their roles for interconnection applications

Department	Role of Department
Grid Interconnection & Contract Development	GICD is responsible for non-NEM projects and for meeting with applicants and ensuring all the agreements are executed and that process timelines are met per tariff requirements. GICD issues final approval to interconnect upon approval from Field Engineering
Customer Solar Group (CSG)	CSG handles incoming ICAs for NEM requests and ensures that the ICA is distributed to the appropriate departments. The CSG also tracks the timing of each NEM ICA and notifies the customers and developers when an ICA is received
Customer Solar Group and Local Planning	NEM<10kW interconnection applications
Transmission Planning	Transmission Planning evaluates the effects of generation to the transmission system, determining upgrades, costs, and time to complete the upgrades for the transmission system. Transmission Planning also writes a report to Field Engineering to combine both the Transmission Report and the Field Engineering report into a single document for the PV developer.
Field Engineering (FE)	FE evaluates the effects of generation to the distribution system, determines upgrades, costs, and time to complete the required interconnection facilities and distribution upgrades for the

	distribution system. Upon execution of appropriate ICA, FE corroborates with Planning, Construction and Project Management on the design and construction of the required facilities. Finally, FE is responsible for ensuring that the interconnection meets the SCE requirements and provides technical approval to interconnect.

Modeling Platforms and GIS: SCE currently uses *Smallworld* as their GIS platform. Not all PV systems are currently mapped in the GIS system, while larger systems are mapped. The GIS system is currently being updated and may include all PV and other DG systems in the future. The information tracked in Smallworld is primarily notes, with no specific information tracked other than DG type and size. Future versions of the GIS system will likely utilize a common information model (CIM) for all DG systems interconnected on the SCE electric system.

Outputs from distribution modeling studies: The results from distribution modeling efforts and other impact studies will not result in a rejection of an interconnection request (unless there are errors on a system design, which can be revised). System studies may determine that a proposed generating facility has potentially negative impacts to the distribution system, which will result in required mitigation measures in order to approve interconnection. The result of an impact study is not to dissuade a PV system developer, but rather identify what must be completed, and at what cost, to mitigate any potentially negative impacts to the electric utility system (this includes distribution, substation and transmission systems).

Mitigation Measures Employed: The following list illustrates the most common mitigation measures deployed at SCE. There will likely be future measures deployed as the utility becomes aware of new solutions such as advanced inverter technology.

- Voltage regulation devices
- Line section upgrades
- Protection scheme updates
- Grounding transformers (for TOV mitigation with synchronous generators)
- Volt/VAR – this is beginning to be used for VAR scheduling for larger installations
- Fixed power factor installations
- Communications (telemetry only)
- Ramp rate controls on the generating facility
- Substation capacity upgrades

Tools: SCE has no additional tools outside of what was covered in this brief.

Overview of Improvements in ICA: SCE engineers are always on the watch for improved ways to evaluate the ICA process. Presently maps are published showing preferred PV sites or other DG sites.

Feedback to Customers during pre-application: Customers may elect to pay $300 for a pre-application report that estimates how much generation can be interconnected, distance to nearest feeder, etc., and is based on Rule 21 provisions.

Feeder specific information: In the future, ICA applicants may request that a group of systems be studied as a cluster, but this is not presently a reality. Each system is studied independently as some systems may not move forward. SCE does not have any “closed” distribution circuits that

cannot accept additional DG, however, adding generation to a distribution system that is at or near its capacity will require significant distribution system upgrades.

Sacramento Municipal Utility District (SMUD)

Overview of the SMUD interviews and questionnaire: The questionnaire and interview was conducted on December 19, 2012 with members of SMUD, EPRI and NREL.

Interconnection application process

SMUD is a publicly owned utility that reports to an elected Board of Directors. SMUD was part of the original Rule 21 development and follows the guidelines of the process.

Types of Interconnection Applications: SMUD looks at three types of ICA systems, which include inverter, synchronous machines, and induction machines. All types of DG systems go through the interconnection process, but inverter based systems often receive quick approval.

As is typical in California, there are different contracts and procedures for different programs. There is the Feed-In Tariff (FIT) program, the Net Energy Metering program, and a PPA program for wholesale installations.

Technical Review Screens

Technical screens are applied per Rule 21. If an ICA fails the initial screens, the ICA goes to the supplemental screening process. SMUD uses 100% of minimum daytime load or 30% of the daytime peak load as a penetration parameter, rather than 15% of minimum 24/7 load, for PV system screening. SMUD engineers evaluate all ICAs based on existing DG on each feeder.

Supplemental Screens: SMUD has not officially adopted the new revised Rule 21 (2012), which has modified supplemental screens. Nevertheless, SMUD has regularly employed the concepts in the expanded supplemental review.

Tracking ICAs: SMUD does have an online ICA tracking program, which is commercially available as *PowerClerk*. This allows customers and developers to check their application status in the queue for rebates and timing. There is a tiered rebate program[13], so this queue is very important.

Technical Review: SMUD has more than 135 MW of PV on their distribution systems, and expects about 1-2 MW per month for the foreseeable future. Residential PV systems average about 4 kW today, but that appears to be increasing with leased systems that maximize size and tend to ignore payback.

There is no real PV system limit yet in SMUD territory, as there is always a solution for connecting to the grid, however, they do limit PV deployment at 100% of minimum daytime load for PV systems on a circuit.

PV systems 10 kW and smaller often get a quick approval. These are size limited due to the NEC (limits of main panel, for example). Larger PV systems may need to connect at a higher voltage

[13] A tiered rebate program contains different levels of rebate based upon the position in the queue. This typically results in higher rebates for applications that are accepted early in the process.

level in order to receive quick approval or to pass impact studies. Some slight changes in proposed PV system size early in the process may avoid options like changing out the utility transformer (saving perhaps thousands of dollars).

Technical Concerns: SMUD engineers have several areas that are of concern when evaluating DG ICAs. Those areas are listed in Table 2-6.

Table 2-7 List of SMUD Concerns when evaluating ICAs

Area of Concern	**Level of Concern**
Voltage regulation (over-voltage)	Primary Concern
Protection system coordination	Secondary Concern
Unintentional islanding	Secondary Concern
Reverse power flow (especially from distribution to transmission)	Secondary Concern
Increased duty on equipment (breakers, fuses, etc.)	Secondary Concern
Inverter trips due to transients	Secondary Concern
Temporary overvoltage due to faults	Secondary Concern
Increased capacitor switching	Secondary Concern
Balancing resources and demand response	Secondary Concern

Secondary Network Distribution Systems: SMUD has five secondary network distribution systems in Sacramento. At this time, they do not have PV on their networks and are not expected to have any. If PV was considered, they would likely look to IEEE 1547.6 as the standard.

Detailed Impact Studies: The following impact studies are conducted if a PV application fails the initial screens and fails the supplemental screens;

- Power flow analysis
- Short Circuit analysis
- Power Quality (ensure the PV system will meet IEEE 519[14])

At this time, SMUD does not conduct dynamic/transient stability studies, but is considering this.

Impact studies are conducted for PV ICAs that are over the minimum load or over 30% of peak load. There are not many that fall into this category, and only two or three per year meet that criterion.

SMUD engineers typically look at the short circuit contribution from a proposed DG and then conduct a protection study (short circuit analysis) to see if the utility relaying will be desensitized. PV systems rarely have a protection impact as inverter fault contribution is very low (somewhere around 150% of full load current).

[14] http://ieeexplore.ieee.org/xpl/articleDetails.jsp?reload=true&arnumber=22445

Methodology for conducting studies: Engineers use the California Energy Commission (CEC) guidelines[15] for impact studies.

Modeling Platforms employed: SMUD used SynerGEE for conducting many of their impact studies on the distribution system. ASPEN, a one-line system, is used for some more complicated projects like networked transmission system interconnection. They also use a GIS system by Intergraph called *GTechnology*. This is helpful for determining the location of the proposed PV systems and evaluating potential impact on the feeder.

Time and cost constraints for impact studies: SMUD does not conduct many impact studies, but on average the cost is $10,000 and the studies are almost always for other types of DG (non-PV systems). The average cost for a solar PV study is $1800. NEM customer applications and studies cannot be charged for the costs per CPUC rules.

Utility departments handling impact studies: When a PV ICA comes through the *PowerClerk* system, it goes to Distribution Line Design Department for new construction review, then to System Planning, then to the Metering Department.

Modeling Platforms and GIS: *GTechnology* is used to identify the nearest feeder to the proposed PV system.

All PV systems are tracked and mapped on this GIS system. Size, ownership, load, meter, transformer, location, module type, and date installed are items tracked (but they do not have the inverter information, which is desired by engineering).

SMUD employs a software package called *MiddleLink* that translates the GIS data for use in SynerGEE.

Outputs from distribution modeling studies: If a PV application fails the screens or studies, SMUD engineers often call the customer or the developer to clear up the situation that might be due to a mistake in the ICA. If there is no mistake, and the failure remains, mitigation measures are considered.

Mitigation Measures Employed: The following mitigation measures may be employed at SMUD to correct any situation that may cause problems.

- Voltage Regulation devices – This has typically focused on changing settings rather than installing new devices. However, new device installation is being considered for new systems where it makes sense.
- Upgraded line sections – This may be deployed when there is a thermal limit, but not often for voltage concerns.
- Communication and control – for all systems over 1 MW, telemetry is required.
- Grounding transformers – this is not required for PV, but for rotating machines in some cases.

Advanced inverter technology is being considered for future installations, but none have been deployed at this time.

Tools: SMUD has not developed any specific tools, but rely on those available on the market for evaluating ICAs.

[15] http://www.energy.ca.gov/distgen/interconnection/interconnection.html

Future improvements: SMUD engineers provide preliminary review for large projects before application. This helps steer projects to a suitable location, and engineers typically use the GIS system to assist in these efforts.

3 OVERVIEW OF BEST PRACTICES

The utilities that participated in this first phase of the interconnection process study have illustrated a number of "best practices" based on the opinion and experiences of the authors. As each utility processes interconnection applications differently, and utilizes a myriad of distribution modeling software tools, impact study types and various mitigation strategies when a PV system is identified as creating a problem on a distribution circuit.

There were a number of best practices that were highlighted when working with these four California utilities. In the near future, a revision of this report will highlight another dozen or so utilities around the U.S. and will give the opportunity to identify additional best practices.

Best practices in California for the interconnection of PV systems onto distribution systems include:

- Utilities use a state-wide interconnection procedure (Rule 21 in CA)
- Use of online interconnection applications for PV developers and utility customers.
- Online tracking of PV application for both utility workers and PV stakeholders (e.g. PowerClerk)
- Use industry standard screening processes to identify fast-track PV applications for quick approval
- Use of national standards to ensure power quality and safety (UL1741 and IEEE1547)
- Use of supplemental screens or individual reviews for ICAs that fail fast-track screens but may still qualify for quick approval
- Use "no study solutions" to mitigate potential problems with known approaches that are often low-cost (e.g. changing service transformer or voltage regulator controls)
- Use of GIS systems to track distribution system components for use in modeling efforts.
- Tracking of all DG and PV systems on GIS for fast analysis of new ICAs. This includes timely updates to GIS systems with PV that are attached to the correct area in the distribution system and with significant detail on the size and type of technology.
- Use a standard distribution-modeling platform for evaluating all DG on a circuit. While no single platform currently conducts all types of impact studies, those that can perform several studies are preferred.
- Standard application fees for PV interconnection applications and limited yet reasonable times necessary to perform analysis.

4 CONCLUSIONS

Utilities in states such as California, Arizona, Massachusetts, Hawaii, New Jersey, and Colorado have seen large numbers of interconnection applications in the past five years, which has forced many utilities to adopt an efficient system of screening interconnection applications. Some states have developed their own methods for interconnection, such as the California Rule 21[16]. Many states have yet to adopt a uniform approach for interconnection, while many public utility commissions lack jurisdiction over many of the non-IOU utilities (municipalities, cooperatives, etc.). With each state having different rules, policies, tax incentives and renewable portfolio standards, the landscape for PV developers is complex.

Clearly there are processes that have been developed by many electric utilities to manage the large numbers of interconnection applications. The best interests are served when PV applications can be approved quickly or moved to impact studies quickly, and done so with the safety, reliability and cost-effectiveness of the utility system in mind.

The authors believe that this report, and future updates covering additional utility practices, will be helpful to many utilities in understanding what they might complete to improve their processes, screening procedures, modeling platforms, and mitigation measures for PV integration. Many of the best practices in this report should be considered by electric utilities in the hope of improving their approach to evaluating PV interconnection requests.

[16] http://www.cpuc.ca.gov/PUC/energy/Procurement/LTPP/rule21.htm

A CSI PROJECT TASK 2

Overview: The following areas and questions should be covered with each utility that is being addressed.
Description: Document Current Utility Screening Practices and Available Tools
Deliverable: Report on Current Utility Screening Practices and Available Screening Tools
Purpose of task: The purpose of this task is to investigate and document current practices for screening PV interconnection requests among California utilities and from other sources outside California. Published as well as internal utility screening practices, for both large and small PV systems, will be included.
Background: There are a number of federal- and state-level interconnection agreements and procedures pertinent to the connection of any distributed energy resource (DER) to the distribution system. California's Rule 21 (with revisions), California investor owned utility's WDAT GIP, municipals such as SMUD and City of Palo Alto, and the FERC Small Generator Interconnection Procedures are good examples. The project research team will collaborate with our California utility project participants to detail which interconnection agreement/procedures and tools are most commonly used, and are most useful, for evaluating DER interconnection requests. We will review distribution feeder classification methods currently used in California to identify and map areas capable of hosting DERs, as well as a comparison of how different penetration screens are being applied in CA. Consideration for other locations in U.S. will be given as well, with a matrix to compare CA and other regions regarding screen types and parameters applied. Potentially this effort will identify gaps in existing screening tools that will be addressed during the course of this project.

Task 2.1 – Perform a comprehensive review of current utility screening practices and commonly used tools within California via existing documentation and literature review, telephone interviews, and in-person interviews with appropriate utility personnel. Identify where current screening methods are working well and where improvements are needed in DG screening processes.

Task 2.2 – Perform a review of current utility screening practices used in other states and in Europe. Compare results such as number of connection requested process, average time for processing and levels or specific concerns where additional studies are required. As above, identify where current screening methods outside CA are working well and where improvements are needed in DG screening processes.

B INTERCONNECTION QUESTIONNAIRE

Overview: The following areas and questions should be covered with each utility that is being addressed. Include Task description: Document current utility screening practices and available tools. Deliverable report on current utility screening practices and available screening tools

Interconnection of PV onto the Utility Distribution System

Name of Utility Company:
Person(s) interviewed:
Date:
Is information available and publishable?

Basic Overview

1. Does your utility have a published methodology for your customers or developers to apply for interconnection?
    a. Is your process publicly available?
    b. Do you post your Interconnection Application (ICA) online?
    c. Can applications be electronically submitted?
2. Are there technology distinctions in your ICA? Are there requirements for PV that may be different from other technologies? Is net-metered PV handled differently than non net-metered PV?
3. Do you have demarcation of project size? What are the tiers of interconnection applications: (e.g. >10kW, <100kW, <2MW, etc.?)
4. Does your utility have a different ICA for applicants that will be wholesale installations?
5. Number of ICA
    a. How many PV applications have you received per year over last five years?
    b. How many interconnection (non PV specific) applications per year over last five years?
    c. Transmission vs. distribution?
    d. How many in each size class?
    e. What percentage of ICA is approved in each size class?
    f. Of the approved ICA, what percentage is installed?
6. What is the average size of the PV interconnection application? Is this broken out into classes or groups (e.g. residential average, commercial average, PPA average, etc.)?

Process Questions

7. Are technical review screens utilized for all PV applications, or for certain ranges or types (e.g. net metered, non-export, wholesale)?
    a. At what level (size) of PV project are screens applied?
    b. Do you consider the aggregate amount of PV (existing plus proposed) on the feeder as part of the screen, or do you conduct bulk/cluster evaluations.

8. Are there supplemental screens that are used beyond the initial review screens if an applicant fails one of the initial review screens? If so, are they published?
9. Does your utility use any online tracking software to help customers track their projects through the interconnection review process?
10. How many MW of PV are installed on your distribution system today, and how much is expected over the next year or two? How much on whole system?
11. Are there specific levels of PV (in MW or penetration) that can't be exceeded per circuit and/or per system?
12. Which of the initial technical review screens have pre-identified mitigation measures? If specific fast track screens fail, are there quick methods of mitigating the situation?
13. For PV systems that do not pass any expedited review, are there specific tests that are applied to those applications?

Technical Questions

14. What are your main concerns and secondary concerns when evaluating PV (or any DG)?
    a. Voltage regulation (overvoltage)
    b. Increased duty on line regulation equipment (LTC, line regulators)
    c. Increased capacitor switching
    d. Protection system coordination
    e. Unintentional islanding
    f. Inverter trips due to line transients
    g. Reactive power control (VAR)
    h. Multiple inverter stability
    i. Variability due to clouds, etc.
    j. Balancing resources and demand response
    k. Reverse power flow
    l. Protection of network protectors in secondary networks
    m. Temporary overvoltage due to faults
    n. Harmonics (THD)
    o. Flicker
15. Does your utility have secondary network distribution systems?
16. Do you allow PV on secondary networks? If so, what are your guidelines
17. Do you have standard requirements for PV on networks, such as minimum import and non-export rules?
18. Is there a standard study run for all PV applications? If a PV application must be studied, what types of studies are conducted?
    a. Power Flow
    b. Short Circuit
    c. Power Quality
    d. Quasi-Static
    e. Dynamic/transient Stability
    f. Electromagnetic transient
    g. Others
19. What factors dictate when a study must be performed and what type of study?
20. Are there specific methods to determine what types of impact studies are required?
21. What methodology is employed when conducting these studies?
    a. Do you have published guidelines or engineering texts that are used?

   b. Do you utilize specific software to conduct any of these impact studies?
22. Are there times and/or cost limitations imposed on your utility for these impact studies?
   a. Other resource constraints?
   b. Which department handles these requests?
23. How many employees work on each application?
   a. Which departments cover each ICA?
   b. What are their roles?
24. Do you use outside consultants for any or all types of impact studies? Which types of studies?
25. What computer GIS system do you use?
   a) Does this GIS system tie into your modeling platforms?
   b) Do you map all DG systems on your distribution system?
   c) What information is kept in the GIS database for each DG system?
   d) Do you utilize a common information model (CIM) or EQDB format?
26. What distribution modeling software platforms do you employ?
   a. Are these systems used for evaluating DG?
   b. What limitations do you see with the modeling software as far as evaluating DG?
   c. Does your modeling software account for all existing DG on each feeder?
   d. Do you see any gaps in the information that is collected for PV systems?
   e. Are there "in-house" tools that you have developed in conjunction with your distribution modeling system to help you evaluate PV or DG?
   f. What happens if a PV system fails your tests conducted on your distribution modeling platforms? (does this result in a mitigation measure or a rejection of the request?)
27. What type of mitigation measures do you employ to keep PV "friendly"?
   - Voltage regulation devices (list types employed)
   - Upgraded line sections
   - Modify protection schemes
   - Direct Transfer Trip
   - Communications and control
   - Grounding transformers (TOV mitigation)
   - Advanced inverter technologies
     a. Volt/VAR
     b. Constant PF
     c. Communications
     d. Scheduled modes
28. Do you have any tools that you are developing to make interconnection faster/cheaper/better? Can these tools be shared?
29. Do you have suggestions on methods that might make the process of interconnection easier for both the utility and customer?
30. Are you willing to allow your "best practices" to be shared in a report?
   a. Are you interested in adopting other utility best practices if they are a good fit for your utility?
   b. What areas of ICA are you looking for improvements or "best practices"?
31. Would you be willing to share examples from ICAs that have gone through your process for case study analysis?

C MODELING PLATFORMS, GIS SYSTEMS, AND OTHER USEFUL LINKS

Distribution Modeling Platforms
SynerGEE[17]
CYMDIST[18]
PSLF[19]
Milsoft Windmil[20]
CAPE[21]
PSCAD
OpenDSS
ASPEN

Geographical Information Systems
ESRI ArcGIS[22]
Smallworld[23]
Middlelink[24]
GTechnology[25]

Other links
*Power*Clerk[26]
IEEE 1547[27]
UL1741[28]
IEEE 519[29]

[17] http://www.gl-group.com/en/powergeneration/SynerGEE_Electric.php
[18] http://www.cyme.com/software/cymdist/
[19] http://site.ge-energy.com/prod_serv/products/utility_software/en/ge_pslf/training/index.htm
[20] http://milsoft.com/products/windmil
[21] http://www.electrocon.com/capeintro.html
[22] http://www.esri.com/industries/electric
[23] http://www.mettenmeier.com/mettenmeier/english/smallworld.htm
[24] http://www.sspinnovations.com/blog/2012/09/05/exporting-gis-data-synergee-electric
[25] http://www.intergraph.com/sgi/products/productFamily.aspx?family=9
[26] http://www.cleanpower.com/products/powerclerk/
[27] http://grouper.ieee.org/groups/scc21/
[28] http://ulstandardsinfonet.ul.com/scopes/1741.html
[29] See IEEE transaction http://ieeexplore.ieee.org/stamp/stamp.jsp?tp=&arnumber=44238