The Impact of Localized Energy Resources on Southern California Edison's Transmission and Distribution System

May 2012

Southern California Edison
Distribution Engineering and Advanced Technology

SOUTHERN CALIFORNIA EDISON®
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1.Executive Summary

1.1 Background

During his 2010 gubernatorial campaign, now California Governor Jerry Brown made a promise to create 500,000 jobs in California. This promise included a "Clean Energy Jobs Plan" that called for the installation of 20,000 MW of renewable energy resources by 2020, 12,000 MW of which should be "localized electricity generation" resources, also known as "localized energy resources" ("LER"). The Governor defined LER as "onsite or small energy systems located close to where energy is consumed that can be constructed quickly (without new transmission lines) and typically without any environmental impact."[1] Since his election, the Governor has further explained his goal and has clarified that currently planned and existing resources should count toward the total goal.

This study was undertaken to assess the impacts of increasing penetration of local energy resources into Southern California Edison's ("SCE") distribution system. SCE believes that this knowledge can accomplish two goals. First, this study can help develop possible future implementation of the Governor's goal through educating policymakers on the important implications of LER transmission and distribution impacts. One key aspect of this, of course, is understanding the impacts of this proposal on utility customer rates. Second, the study results will enable SCE to make more informed grid planning decisions on required transmission and distribution upgrades, additional interconnection requirements, and potential smart grid investments.

1.2 Key LER Challenges

SCE's distribution system is designed to safely and reliably deliver power to serve its customers' electrical needs. Generally, the distribution system is designed to send power from the bulk power transmission system directly to the customer through its vast network of distribution lines, equipment, and protective systems. Local renewable generation, in increasing amounts, has begun to change the dynamic behavior of the distribution system by introducing new sources of energy that intermittently change the amount and direction of power flow on the grid. These changes in grid behavior create new challenges for the utility in determining how to plan, design, and operate delivery systems that were not designed for the application of local energy resources. In many ways, the Governor's goal challenges SCE's ability to safely provide reliable and affordable power to our customers.

Some of the major system and operational challenges posed to electric utilities analyzed and discussed in more detail in the report include:

- Grid Stability
- Voltage Regulation and Equipment Loading
- Anti-Islanding
- Protection Coordination
- Available Fault Duty

[1] Jerry Brown campaign literature, http://www.jerrybrown.org/Clean_Energy

In addition to identifying these and other specific operational challenges, this study has translated these findings to potential cost estimates, both on the individual circuit and total system level.

1.3 Study Methodology and Assumptions

This study is comprised of two phases:

1) Feeder Phase – studies of individual feeders were conducted to gain a better understanding of what the impacts of LER will be to the electrical system.
    1. Feeder Modeling - typical urban and rural feeders within SCE's territory were modeled at varying LER penetration assumptions. Specifically, two cases were considered: an "unguided case," where installations were presumed to follow existing interconnection request patterns (with the majority of requests being in suboptimal rural areas that require expensive upgrades), and a "guided case," where installations were modeled in locations that typically have lower total system impacts and costs.
    2. Case Study - case studies were included to illustrate possible system impacts of high concentrations of LER on both a rural substation and an urban circuit. The studies provided review the electric system impacts and provide information on associated mitigation costs.
2) Total System Cost Estimation Phase - Historical system impact studies were used to create a top-down evaluation in calculating system costs of SCE's allocation of the 12,000 MW goal.

Taken together, these two study phases were used to develop a comprehensive assessment of system-wide distribution, interconnection, and transmission costs caused by increasing LER penetration. The assessment also analyzed the reliability impact and cost differences between urban and rural systems. These system impacts are communicated as total potential costs of achieving the LER goals in SCE's service area under both the "guided" and "unguided" scenarios.

While this methodology is a successful way to measure the impact of the Governor's LER goals, it is important to note that not all possible scenarios were considered. For example, the effects of electric vehicle and storage technology penetration were not considered for this study.

1.4 Major Findings

The study focused primarily on added infrastructure cost impacts. Requirements for enhanced operational and control equipment were not considered. Major cost categories considered were transmission upgrades, distribution upgrades, and interconnection requirements. Key findings include the following:

- Locational factors for LER greatly influence the total impact to the distribution and transmission systems.
- Overall costs of LER are significantly higher in rural areas, where the generation is

further from load centers.

- Implementing the Governor's LER goals in SCE's service area may cost up to $4.5 billion in transmission and distribution system upgrades,[2] though with locational restrictions could be as low as $2.1 billion.

While smart grid technologies are expected to mitigate some of the potential impacts of adding LER, the application of these technologies is likely several years away due to the need for standards and technology development and demonstrations.

Thus, strategies to encourage LER to interconnect in preferred locations within the urban network would, when balanced with other procurement factors, likely be of benefit to SCE's customers and to the developers due to the projected cost savings estimated in this study.

1.5 Conclusions and Recommendations

It is clear that LER deployment would benefit from a carefully designed (i.e., "guided") approach to locating installations. These locational costs should thus be considered in utility evaluation of projects; effective changes to the interconnection processes for LER, e.g., Rule 21, or competitive application processes that properly evaluate system impacts could significantly reduce costs and speed up installation. Additionally, any implementation of LER goals should include cost containment provisions to maintain competitiveness.

Future, more detailed studies and models will be required to develop better design and cost estimates for new LER installations. This will require development of advanced modeling techniques and computer applications not currently available. A continuing field program to track impacts of LER as penetration increases is also needed.

[2] This cost does *not* include the cost of the LER systems and their installation

2.SCE's Electrical System

The electrical system at SCE serves nearly 4.8 million customers throughout its 50,000 square mile service territory. The record peak demand recorded in 2007 was just over 23,600 MW. In order to provide reliable service to SCE's customers, the power system is designed to deliver power through its network of transmission, subtransmission, and distribution systems. The transmission system typically consists of high voltage (230kV and 500kV), long lines that are configured in a network system. This network system is designed to allow power to flow in any direction depending on operating conditions. The distribution and subtransmission systems operate at lower voltages (66 – 115kV and 2.4 – 33kV, respectively) and are radial in configuration. Radial systems are designed for one direction power flow from the generator to the customer. Within a radial system, protection, voltage regulation and capacity are monitored and controlled to support the delivery of power from the substation to the load, ensuring stable voltages within utility limits are maintained, and that power is able to be quickly restored in the event of interruption.

SCE's system can be represented by the following diagram:

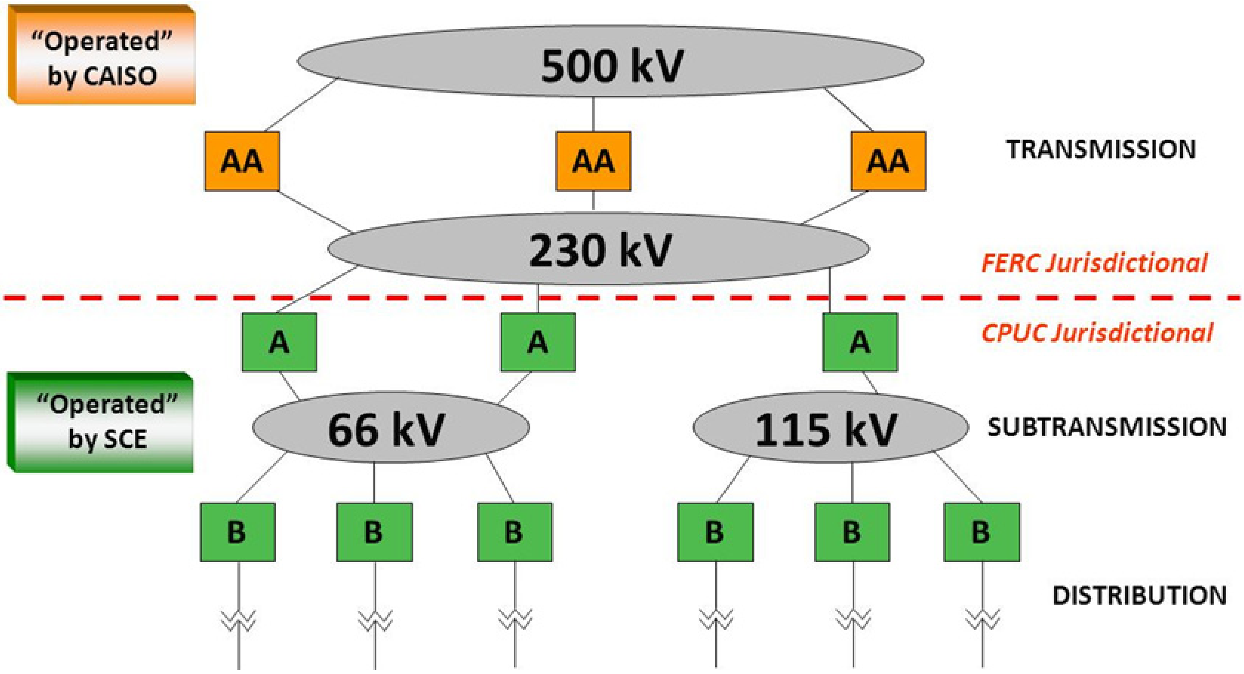


Figure 1: SCE Transmission, Subtransmission, and Distribution System Representation

A typical "peak," or time of highest electricity demand, on a distribution system occurs between the hours of 2-8 p.m., depending on the mixture of load between residential, commercial, and industrial customers. Distribution feeders with a large percentage of commercial and industrial loads tend to peak well before residential loads, typically peaking after 4 p.m. Load profiles on distribution systems are determined by the aggregate load profiles of individual customers. Typical distribution feeder load profiles are depicted on the next page.

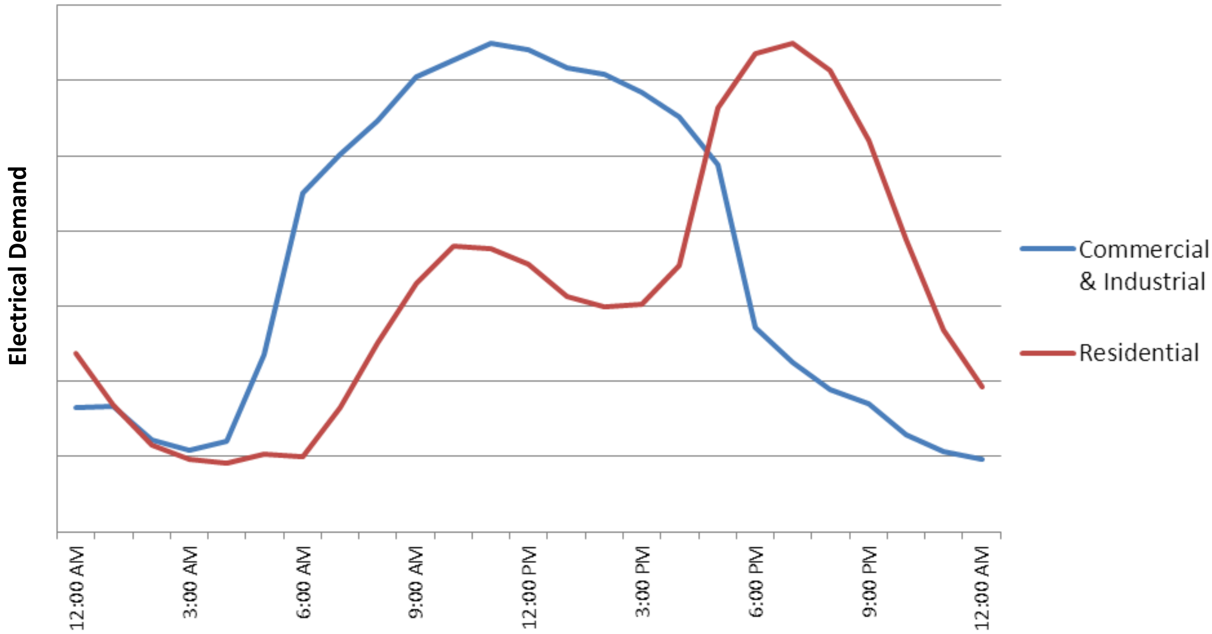


Figure 2: Typical Daily Residential and Commercial Load Profiles

In order to maintain reliable service to customers, distribution systems are designed to serve peak load. When generation sources, such as traditional generators or LER, are present on radial subtransmission and distribution systems, grid operators evaluate these resources by analyzing the historical load profile of the generation and the feeders. This is done by evaluating the historical generation output over a number of years during peak times against the distributed generator capacity to evaluate to what extent the output can be depended upon to provide sufficient power under peak load conditions. If this LER or other generators consistently produces at the correct times, they can be depended on to offset loads. However, generation sources that do not provide stable continuous power during peak periods – such as intermittent renewables like solar and wind – are considered non-dependable generation sources. As such, they often cannot be relied on as true substitutes for subtransmission or distribution system transformers and wires. In the event the LER source output is reduced or not available at any time, the utility system is expected to serve the load without interruption.

The magnitude and time of peak demand also influences the behavior of voltage regulation equipment on the utility system. This equipment, such as capacitors and voltage regulators, is established to maintain feeder voltage within CPUC Rule 2[3] and is tailored to the unique characteristics of the systems they are placed on. Addition or modification of customer load, generation or system configuration may require additional mitigation measures and equipment in order to ensure compliance with CPUC Rule 2 and satisfactory service quality to SCE's customers. Though customers, especially large commercial and industrial entities, are also required to comply with CPUC Rule 2 in order to not adversely

[3] Rule 2 provides an in depth description of service including general service information, phase and voltage specification (single phase, 3-phase, service voltage), motor protection, added facilities and other service options (http://www.sce.com/NR/sc3/tm2/pdf/Rule2.pdf).

impact adjacent customers,[4] the impact of small aggregate LER is often managed by the utility.

SCE's service area covers a diverse geography of urban, suburban, and rural areas. Approximately 75% of SCE's customers reside in urban and suburban communities. However, the remaining 25% of customers served in rural areas, including desert and mountain regions, are spread throughout over 80-85% of SCE's 50,000 square mile service territory.

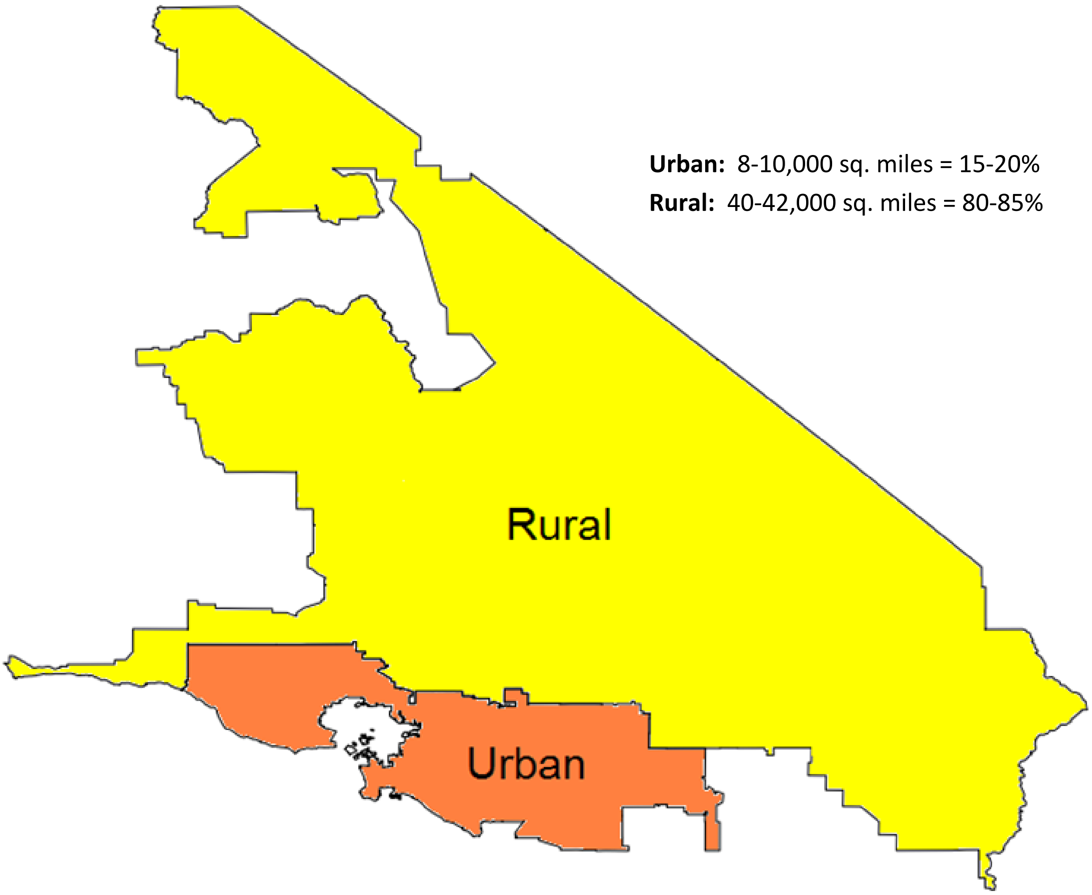


Figure 3: SCE Service Area by Type

System design and characteristics vary significantly between urban and rural feeders. Urban feeders are generally short in length, usually extending between 0.5 and 1.5 miles, and are considered "stiff" systems because of the lower impedance and higher short-circuit duty at the substation. A "stiff" system will typically experience less voltage fluctuations due to variations in load or local generation. Conversely, rural feeders cover much larger areas – often up to 15 or more miles in length. Substations are also generally smaller in rural areas. These longer and lower capacity systems possess higher impedance, or opposition of a line to the passage of electricity from one point to another, than their urban counterparts, and are considered "weaker" for load carrying capability and are more susceptible to voltage fluctuation caused by load variations. These types of systems

[4] Examples of Rule 2 requirements for customers include the starting of large motors, which are restricted to the amount of momentary voltage sag within allowable limits, or the amount of interference from devices such as arc welders and variable speed drives.

typically require additional protective devices to ensure adequate protection against faults is provided throughout the length of the feeder.

Circuits must be configured in different ways in order to reliably serve both rural and urban customer bases. One key difference between urban and rural feeders is the peak load and amount of customers they serve. In high density urban load concentration areas, feeders are shorter in length and built with higher capacity equipment in order to serve many customers in a compact and densely populated area. Feeders in rural areas with both fewer and more spread out customers have to be much longer in length but overall can have lower capacity equipment. Additionally, some feeders must be specially configured in order to ensure reliability and provide adequate flexibility. This allows the utility to minimize the impact to customers during unplanned outages or when maintenance or operations are performed. For example, a typical urban feeder is designed with a minimum of three feeder ties. This enables the ability to switch and isolate faulted areas, and allow for minimum customer interruptions during maintenance activities. Rural feeders contain less flexibility, as there is less infrastructure spread out over larger areas.

As described in detail in Section 2, current distribution systems are designed for radial flow from the transmission system through substations and distribution lines to the end use customer. Large LER and aggregations of smaller LER can result in a reversal of the power flow from the end use customer back to the substation, and in high penetration cases, back toward the transmission system. Although optimal locations of LER can sometimes benefit the distribution system, recent experience has far more often shown LER to pose many challenges to distribution system design and operation.

2.1 Voltage Regulation and Equipment Loading

Typically, LER's initial impacts to the system include voltage regulation and equipment loading concerns. Traditionally, voltage on a feeder is higher at the substation and will steadily decrease as electricity moves further from the substation. This is due to the radial flow from the substation to the end use customer. As LER penetration increases, power flow can reverse and result in a rise in voltage from the substation to the end use customer. While sometimes there is voltage regulation equipment at the substation to modify voltage based on loading, these components begin to reach the limits of their operation ranges with increasing amounts of interconnected LER. Solutions to these voltage issues include installation of additional voltage regulation equipment or modification of the distribution system (e.g., line reconductoring, feeder reconfiguration). However, it should be noted that system modification such as line reconductoring is an expensive option, and reconfiguration of feeders solely for LER may result in reduced system operability (e.g., less ability to quickly restore power after an outage restoration or to switch for planned maintenance).

Similarly, large single or aggregate LER interconnections can result in overloading of existing distribution system components (e.g., overhead / underground lines, switches, feeder breakers, transformer banks). In most cases, facilities can be upgraded (e.g., line reconductoring, transformer replacement / addition). Again however, these are usually expensive forms of mitigation.

2.2 Grid Stability

The stability of the grid is generally defined as the system's ability to withstand sudden disturbances (e.g., line faults) and loss of system components (e.g., loss of generation). Grid integrity must be maintained and system voltage and frequency must be kept within tight tolerances to prevent equipment damage and maintain reliable service to utility customers even under these disturbances.

The current standard for distributed generation or LER, IEEE 1547,[5] and resulting interconnection rules (WDAT, Rule 21[6]) were drafted with the assumption that LER should disconnect from the system for any and all system anomalies (e.g.. voltage fluctuations due to outages, major disturbances on the transmission system). The intent was to maintain a safe working situation for utility workers and simplify operation of the system, specifically around fault location and load restoration, which become more difficult when there are multiple generation sources on the distribution system. This was also based on the assumption of a low penetration of LER such that their impact to grid stability would be negligible.

However, as penetration levels increase across the system, the impact of a sudden loss of all LER can lead to the following:

- Disturbance of system-level generator-to-load balance, resulting in voltage fluctuations and / or additional wear on central station generating units.
- Need for additional spinning reserve, regulating reserve, or new market products to deal with intermittency and the unreliable nature of certain generation technologies (e.g., wind, solar).
- Overload of system components due to the unexpected loss of a large amount of LER (from the system perspective, a loss in LER amounts to an increase in load).
- Unintended operation of protective devices resulting in outages to customers and safety concerns for customers and utility workers.

Additionally, there is no standard in place around how grid interactive inverters should respond to voltage oscillations on the system. In general, the voltage of the transmission and distribution systems is steady, changing only by gradual amounts over long periods of time. However, large fluctuations of load or generation on the system can result in an equal and opposite oscillation of system voltage (as load increases, voltage decreases and vice versa). SCE laboratory testing has shown that some inverters behave such that they may exacerbate these voltage oscillations resulting in increased instability of the system. Even small changes to voltage can damage some customer equipment, and in extreme cases, these oscillations can result in system collapse.

[5] IEEE 1547 is the Institute of Electrical and Electronics Engineers industry standard focused on technical specification and operational requirements for interconnection of Distributed Generation.

[6] SCE's Wholesale Distribution Access Tariff (WDAT) is a Federal Energy Regulatory Commission (FERC) tariff that outlines the interconnection requirements for wholesale interconnections (both load and generation). California Rule 21 is California Public Utilities Commission (CPUC) rule that describes the interconnection, operation and metering requirements for generating facilities connected to SCE's distribution system over which the CPUC has jurisdiction.

2.3 Anti-Islanding

One of the IEEE 1547 requirements is "anti-islanding." Islanding is defined as a condition in which a portion of a distribution system is energized solely by one or more LER while that portion of the distribution system is electrically separated from the rest of the utility system.

LER systems that are certified under the requirements of IEEE 1547 have functionality that is intended to prevent the LER from sustaining an island. This function is intended to ensure the proper operation of distribution circuitry under control of the local utility, system stability (e.g., system voltage within Rule 2 limits) and safety for utility personnel as well as the general public (e.g., prevent energization of a downed conductor, such that feeders can be positively de-energized for emergencies and planned maintenance).

However, the anti-islanding certification is only valid for and tested on a single LER generating unit (e.g., a single inverter). It is currently unclear which penetration scenarios may result in a failure of the anti-islanding function. While the probability of a sustained LER island is very low, there are still concerns that under a high penetration scenario where load and LER are closely matched, the anti-islanding function may fail resulting in above mentioned system and safety concerns.

2.4 Protection Coordination

Protection refers to the installation and coordination of devices designed to detect and isolate faulted sections of the system from the rest of the electrical network. Protection becomes more complex with higher levels of penetration, especially in rural distribution systems where the system is more susceptible to coordination problems and where the system typically lacks substation automation. Devices such as fuses and automatic reclosers are installed to sense and isolate feeders during problems such as car hit poles, fallen conductors, failed equipment and other events that create outages. These devices are coordinated in zones in order to minimize the number of customers affected, requiring devices to work in series with each other. However, as generation output increases on feeders, coordination becomes increasingly difficult, harming the maintenance of adequate protection over the entire feeder length.

Additional protection considerations arise during the switching of feeders during routine maintenance or emergency power restoration activities. Without proper automation within the substation, as normally expected in urban systems, the knowledge of feeder power flow becomes increasingly difficult with higher penetration levels, and the operator has no ability to remotely monitor the load on the utility feeder. Additional automation would be required to allow operators to safely and reliably operate the distribution system to avoid unnecessary operating hazards and outages.

2.5 Available Fault Duty

During electrical short circuits, or faults, the amount of energy delivered at the fault location is referred to as the "available fault duty," or "short circuit duty." The amount of energy delivered is based on the amount of generation present at the time, including contributions from localized generators. Protective devices, such as circuit breakers, are designed to safely interrupt the available fault current in order to properly isolate faults and maintain service. Because localized generation increases the available fault duty expected, there is a potential vulnerability that ratings of circuit breakers may be exceeded. If such areas are identified, there would be a need for significant capital investment to replace with higher rated equipment. As more localized generation is installed, additional costs will be incurred to upgrade infrastructure to ensure devices are properly rated for safe operation.

3.Study Methodology

This study comprises of two main phases, each of which are described in more detail below.

Phase 1 is a development of case studies intended to better understand what impacts LER will have on feeders with varying characteristics. This phase was conducted in two subparts:

a) Typical urban and rural feeders within SCE's territory were modeled, which provided a detailed view of the specific distribution system impacts on these feeders due to varying LER penetration assumptions (methodology detailed in Section 3.1).

b) This case study analyzed two high penetration cases to provide some examples of impacts of high penetration of LER that can reasonably be expected on SCE's system. These cases help to place the model results in a real-world context (methodology detailed in Section 3.2).

Phase 2 provides a top-down approach to estimating likely system-wide impacts and costs of meeting the Governor's LER goals, using recently completed generator system impact studies (methodology detailed in Section 3.3). While Phase 1 of the study helps to provide a robust understanding of the impacts of LER on particular feeders, typically, specific distribution impacts and interconnection facilities – and thus their associated upgrade costs – vary by installation due to differences in distribution feeder design, region topography, substation design and customer density. Because SCE has over 4,500 distribution feeders, and it was not possible to model every one, it was assumed that system impact study averages would serve as an adequate proxy for future installation. Additionally, because feeder models alone do not adequately capture higher-level costs in substations and on the transmission system, a top-down analysis can more accurately view these integrated system effects. System impact studies are detailed assessments of the requirements to connect new generation into SCE's grid, the impact of the added generation, and the associated costs for upgrades. Because these studies cover a broad range of installations throughout SCE's service territory in both rural and urban areas, the average costs for interconnection facilities and system upgrades can be applied to future installations. This review was then used to translate the feeder-specific impacts and costs from the modeling into a comprehensive assessment of system-wide distribution, interconnection, and transmission costs caused by increased LER to the levels of the Governor's goal.

3.1 Feeder Analysis

Phase 1(a) developed load flow models in CYME Cymdist,[7] a widely used software package used for analyzing distribution systems, for the four representative feeders: two urban and two rural. These distribution feeders were selected based on a previously developed algorithm developed by Quanta Technology[8] for use in penetration studies such that each

[7] CYME Cymdist is a distribution system modeling software that SCE utilizes to study the impact of DG interconnections on the SCE distribution system. For more information *see* http://www.cyme.com/software/cymdist/

selected feeder represents typical characteristics of a significant portion of the distribution feeders in SCE's service territory. The algorithm analyzes the characteristics describing a distribution feeder, such as line length and number of customers, then finds a single feeder with characteristics similar to a larger number of feeders. The algorithm was able to find a set of 22 feeders that could be used to reasonably represent characteristics of SCE's entire feeder population. This selection simplifies the analysis by avoiding the need to study each of SCE's 4,500 feeders separately. Below is a brief description of the four representative feeders:

- Aruba 12kV: an urban feeder located in the city of Tustin, Aruba is mainly underground and serves residential and commercial load. There is a large amount of commercial rooftops available in the area that would support 1-2 MW of photovoltaic LER. In addition, there is a high probability of residential rooftop PV in the area.
- Hill 4kV: this is an urban feeder serving residential load in the city of Manhattan Beach. This is a prime location for increasing penetration of LER, given the high concentration of middle to high income residential customers in Manhattan Beach.
- Smoke Tree 12kV: this rural feeder is primarily overhead and serves commercial, industrial, and residential load in the city of Twentynine Palms. The area served by the feeder has high solar insolation and large amounts of open, inexpensive land that is prime for the interconnection of photovoltaic LER.
- Windt 12kV: this feeder is primarily overhead and serves mostly agricultural load in a rural area near the city of Tulare. Similar to the Smoke Tree 12kV feeder, the Windt 12kV feeder serves an area of the SCE service territory with large amounts of open, inexpensive land.

For detailed diagrams on each feeder, see Appendix B

Each of the four feeders selected was modeled under two penetration scenarios: a "guided" and an "unguided" case. The unguided case refers to penetration rates that are reflective of the current pattern of the generation interconnection queue, representing approximately 70% rural and 30% urban interconnection requests. This ratio is based on actual applications filed with SCE for generator interconnection and represents LER penetration based on current incentives and tariffs. Conversely, the guided case is meant to reflect a hypothetical ability for the utility to influence the locations and sizes of generator applications in order to lessen LER impacts to the electricity system. Drawing on the expertise and experience of distribution system operators, this influence would direct LER towards a uniform distribution on urban systems, where the capacity for localized generation tends to be higher. The guided case in this study thus models only 30% of LER installations in rural areas and 70% on urban feeders.[9]

[8] Quanta Technology, 2009, Solar PV Impact Study – SCE Confidential

[9] The "optimal" case for LER penetration may very well be a 100% urban case, as the system impacts and resultant interconnection costs are minimized. However, this study assumes a more reasonable spread of LER throughout the system (70% urban and 30% rural) taking into consideration that customers in rural areas should have the opportunity to interconnect a reasonable amount of generation and that rural interconnections of LER already exist.

In order to determine the capacity of LER that would be installed on a rural or urban feeder under each case, this study made the following assumptions. First, it is assumed that under the Governor's goal, approximately 4,800 MW of LER would be required in SCE's service area.[10] Next, all modeled feeders were considered "blank," or clear of any LER previously installed. This ensures that the cumulative impacts resulting from this analysis are those due to 4,800 MW *total* LER, not incremental to existing resources. Third, this study evenly spreads this quantity of LER across all system feeders – 3,626 urban, 874 rural. This is considered a best-case scenario, as a more uneven distribution, with certain circuits experiencing disproportionately high concentrations of LER, would likely only increase the total costs of the Governor's goal. Some impacts of this concentration of installations are discussed in Phase 1b (see Section 4.2 and 4.3).

In all, penetration assumptions for the unguided and guided cases were as follows:

<u>Unguided</u>

- Urban penetration = (4,800 MW * .3) / 3,626 feeders = 0.40 MW per feeder
- Rural penetration = (4,800 MW * .7) / 874 feeders = 3.84 MW per feeder

<u>Guided</u>

- Urban penetration = (4,800 MW * .7) / 3,626 feeders = 0.93 MW per feeder
- Rural penetration = (4,800 MW * .3) / 874 = 1.65 MW per feeder

Finally, once the four feeders and penetration numbers were determined, a few more assumptions were made in order to further simplify the analysis and ensure reasonable results.

Although SCE strongly endorses a broad definition of LER (as will be further supported in Section 7.3.2), this study modeled all LER as solar photovoltaic ("solar PV"). This trend closely follows the pattern currently seen in LER installations as incentivized by existing programs. Additionally, the generation characteristics of solar PV lead to specific distribution issues that required mitigation, which must be considered in any analysis of increase LER. The size and location of the LER were based on existing land use and areas available to accommodate LER facilities in the unguided and guided scenarios above. In all scenarios the LER was located in a single facility on the distribution feeder.

The final step in this analysis was to estimate the total cost to mitigate modeled feeder impacts under each case. Costs for upgrades were based on unit costs derived from SCE's costs for use in generator interconnection system impact studies. This results in a cost estimation for maintaining reliable and high quality service on each of the four feeders under both the unguided and guided cases. Then these costs were projected over the entire system to create a rough estimate of total system costs. However, as discussed in more detail in Section 6 below, these system costs are primarily used as a bookmark to compare against more realistic total cost estimates derived from the system cost analysis.

[10] This figure was reached by calculating SCE's portion of total California load and multiplying by the total 12,000 MW goal. For the purposes of this study, SCE assumed its portion of the total statewide 12,000 MW goal would be 4,800 MW. This figure was estimated by applying SCE's percentage of total California system load (approximately 40%) to the total 12,000 MW goal. This allocation does not represent SCE's actual or proposed allocation, but is merely used as an assumption for this case study since actual allocation has not yet been determined.

3.2 Distribution Feeder Case Study Analysis

The case studies analyzed in study Phase 1(b) articulate the potential for extreme costs due to the concentration of LER on certain feeders. This grouping of LER can be caused by a number of reasons: an abundance of inexpensive land surrounding a rural feeder, for example, or a concentration of affluent and environmentally-minded residential customers in an urban community. To provide some examples around the impact of high penetration of LER that can reasonably be expected on SCE's system, the analysis of two high penetration case studies were also included. A high penetration rural case and a high penetration urban case were selected to show that clustering of LER at any location (rural or urban) can result in the need for significant system upgrades. The rural area example illustrates a prevailing issue that SCE continues to experience – high penetration of PV interconnections in rural areas where the distribution system is generally weaker. The urban area example illustrates that, although interconnections within system load centers is preferred due to less system impact, there is a point where concentration of LER on an urban circuit or substation may still result in costly system upgrades. The analysis of these high-penetration cases discuss the system impact that resulted and associated costs and can be used as a comparative tool in reaching a total cost estimate of the Governor's LER goals.

3.3 System Impact Study Cost Analysis

Phase 2 of this study was a top-down analysis that identified system-wide average costs for distribution system upgrades as well as interconnection facilities. Transmission costs were treated separately and are discussed in detail in Section 5.

To calculate average system-wide costs for multiple types of installations and locations within SCE's electric system, this study analyzed historical system impact studies of generators requesting interconnection to SCE's distribution system. System impact studies are completed by SCE to determine the impact (and proposed mitigation) of a LER requesting interconnection to the system. To ensure relevant results, 124 system impact studies (i.e., for projects less than 20 MW in size) completed in 2010 and 2011 were analyzed. Thus, this provides a more complete basis for developing total system costs in this study, versus a smaller sample of modeled feeder circuits. For a more detailed overview of these studies, see discussion in Section 6.

Studies were first divided by region, such that rural and urban projects were considered separately. Next, average costs of upgrades per MW were determined. These costs were split into two main categories: 1) distribution system upgrades and 2) interconnection facilities.[11] Using the penetration assumptions developed in the feeder modeling analysis described in Section 3.1, these average costs were scaled up to reach distribution and interconnection system cost estimates for both the guided and unguided cases. These costs were then added to transmission cost estimates developed in Section 5 to reach a total, SCE system cost estimate of the Governor's LER goals.

[11] See SECTION 6.1 for a partial list of specific upgrades that may be included in these estimates

It should be noted that this methodology likely does underestimate actual system impacts, as it is widely acknowledged that higher levels of LER penetration lead to nonlinear increases in integration costs. For example, EPRI conducted a survey of 13 major utilities on the impacts of LER. 85% of the utilities reported experiencing adverse conditions and challenges, such as voltage regulation or protection system problems, on their electric distribution system due to high distributed generation penetration."[12] It is anticipated these impacts will increase the need for upgrades to the distribution system, add additional challenges to utilities for planning and operating distribution systems, and increase the overall costs of LER interconnection.

[12] EPRI, 2010, Circuit Functionality and Requirements for Future Grid Integration of Distributed Renewable Generation, 2010 Technical Report

4. Distribution Feeder Model and Case Study Analysis Results

4.1 Phase 1a - Distribution Feeder Model Results

Each of the four representative feeders was modeled under two penetration assumptions, as laid forth by the guided and unguided cases. The tables below present an overview of the impacts and resulting required upgrades seen on each feeder under each case and are followed by a more detailed discussion of each feeder's impacts. Appendix C provides comprehensive graphs showing the actual results of the analysis throughout a 24-hour period.

Table 1: Guided Case – Summary of Feeder Impacts and Upgrades Required

	Impact	Upgrades Required
Aruba 12kV (Urban #1)	• No observed voltage or overloading issues	• None required
Hill 4kV (Urban #2)	• Unmanageable voltage swing on a 4kV feeder	• Cutover to a 12kV or 16kV feeder required
Smoke Tree 12kV (Rural #1)	• Increased LTC operation due to intermittency	• Additional maintenance cost, possible shorter asset lifespan
Windt 12kV (Rural #2)	• No detectable voltage or overloading issues	• None required

Table 2: Unguided Case: Summary of Feeder Impacts and Upgrades Required

	Impact	Upgrades Required
Aruba 12kV (Urban #1)	• No observed voltage or overloading issues	• None required
Hill 4kV (Urban #2)	• Increase LTC operation due to intermittency	• Additional maintenance cost, possible shorter asset lifespan
Smoke Tree 12kV (Rural #1)	• Overloaded conductor • Customers over Rule 2 voltage limits • Increased LTC operation due to intermittency • System operation becomes more complex due to high penetration of intermittent generation	• Reconductoring required to mitigate conductor overloads • New LTC controller required for bi-directional flow • Additional maintenance cost, possible shorter asset lifespan • Substation automation
Windt 12kV (Rural #2)	• Overloaded conductor • Customers over Rule 2 voltage limits • Increased LTC operation due to intermittency • System operation becomes more complex due to high penetration of intermittent generation	• Reconductoring required to mitigate conductor overloads • Two voltage regulators with bi-directional control for voltage regulation • Increased voltage regulator operation due to PV intermittency

As expected, the rural feeders experienced significant impacts under both cases:

Smoke Tree 12kV (Rural #1):

The 12kV rural feeder is connected to a substation transformer bank with a load tap changer. As a result, the equivalent load and LER from the other two feeders connected to the same substation transformer bank was also modeled. Similar to the 4kV urban case, the introduction of PV-based LER caused the LTC to operate more frequently due to intermittency issues. However, in the unguided case, the mainline had to be reconductored to larger wire from the LER installation to the point where the existing mainline wire was large enough (about 2.5 miles). This was needed to mitigate thermal overload issues and voltage issues. Additionally, the LTC controller in the substation needed to be upgraded to a controller capable of bi-directional flow.

Windt 12kV (Rural #2):

The second 12kV rural feeder did not have any detectable voltage or overloading problems in the guided case, but had significant voltage issues and a small amount of overloading issues in the unguided case. Due to the very long line length of the feeder and the low customer density, a voltage regulator needed to be installed at the substation and midway between the LER and the substation. Additionally, due to the low load density, about 0.5 miles of small conductor needed to be replaced.

The urban feeders, particularly Aruba (12kV), were more able to handle increasing penetrations of LER. However, Hill (4kV) experienced increasing impacts under the higher penetration case.

Hill 4kV (Urban #2):

The 4kV urban feeder was more affected by the LER facility than the 12kV urban feeder. Due to the weaker source and lower noontime demand, the LER facility significantly influenced the voltage on the line. The unguided case, which put a lower amount of generation on the feeder, did impact the feeder by causing the voltage regulator to change taps more often due to intermittent PV generation. For example, LER injecting power on a feeder will raise the voltage at the point of injection which causes the substation voltage regulator to be at a higher voltage buck setting. If the power injection were to disappear due to weather intermittency, the voltage regulator would have to move to a lower buck setting. Depending on the size of the LER, the voltage regulator would have to move more steps to maintain normal line voltage levels. To minimize voltage regulator operations (and maintenance costs in turn), the voltage regulator moves one step at a time after the voltage has been out of range for a certain amount of time (on the order of minutes). At guided LER penetration levels, the voltage regulator would not be able to move fast enough to keep up with weather patterns affecting LER output.

Aruba 12kV (Urban #1):

The 12kV urban feeder was least affected by the installation of a LER facility. Almost all of the feeder's mainline cable was large cable designed to feed a dense urban area. The lowest noontime demand on the feeder was on the order of 2.5 MW and the distance from the LER to the rest of the loads on the feeder was fairly close. As a result, even at high penetration levels no adverse impacts were seen.

We will return to these modeled impacts in Section 6.1 of this study when we discuss costs of upgrades. See Appendix C for detailed impact study results.

4.2 Phase 1b - Case Study: Rural

The first case study examined a small 12kV substation in a rural area of the Antelope Valley near Lancaster, California (see Figure 4 below). The 56.0MVA capacity substation has five feeders serving about 3,500 customers. Electricity demand and feeder loading is predominantly driven by commercial, industrial, and agricultural customers in the area. Given the area and projections of load growth, there are no capital expansion projects to increase capacity at this substation in the 10 year plan.

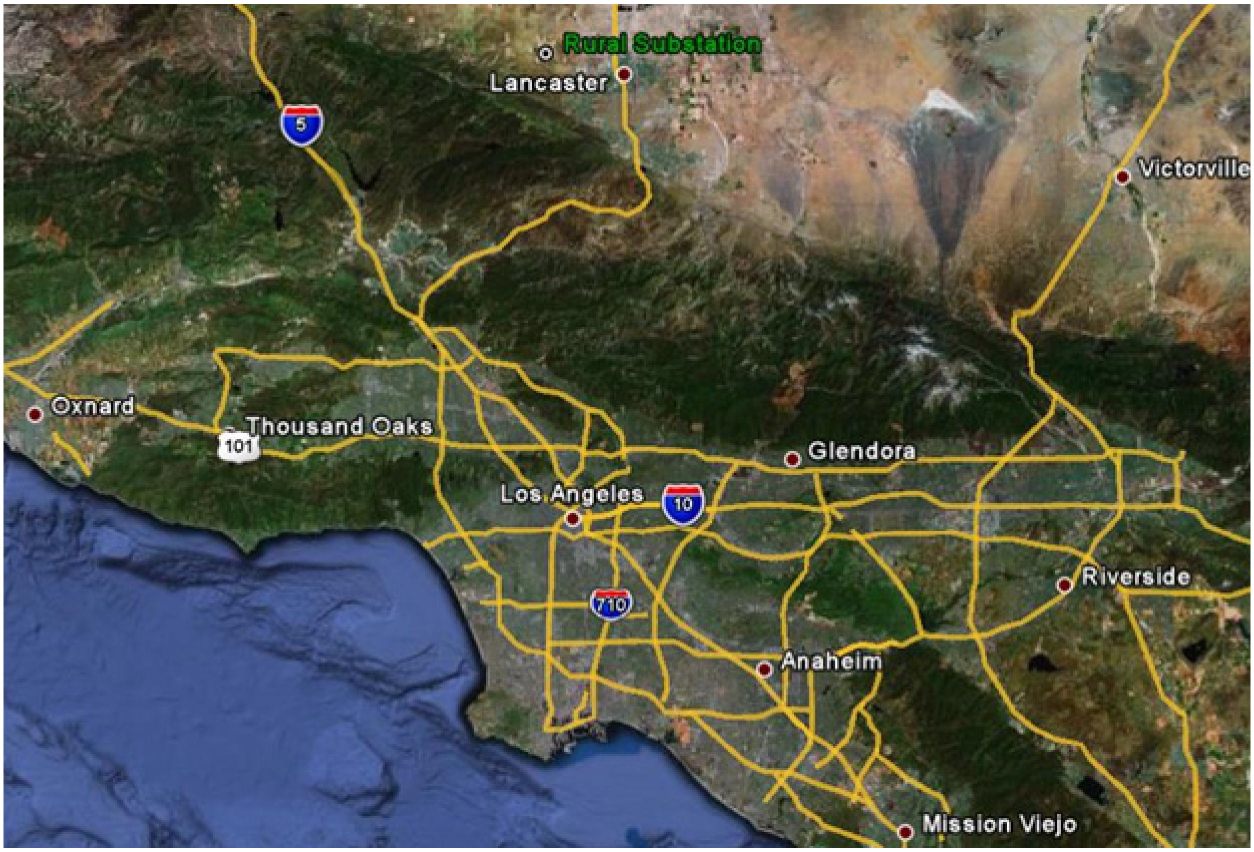


Figure 4: High Penetration Rural Example Location

The high solar irradiance in the Antelope Valley, coupled with cheaper land costs as compared to the urban areas in SCE's service territory, have resulted in 35 separate generator interconnection requests[13] at this rural substation, totaling approximately 102 MW (see Figure 5 on the next page). All of these projects are solar photovoltaic.

[13] These 35 interconnection requests indicate those projects that are currently in the study queue, and are not currently interconnected with the SCE system.

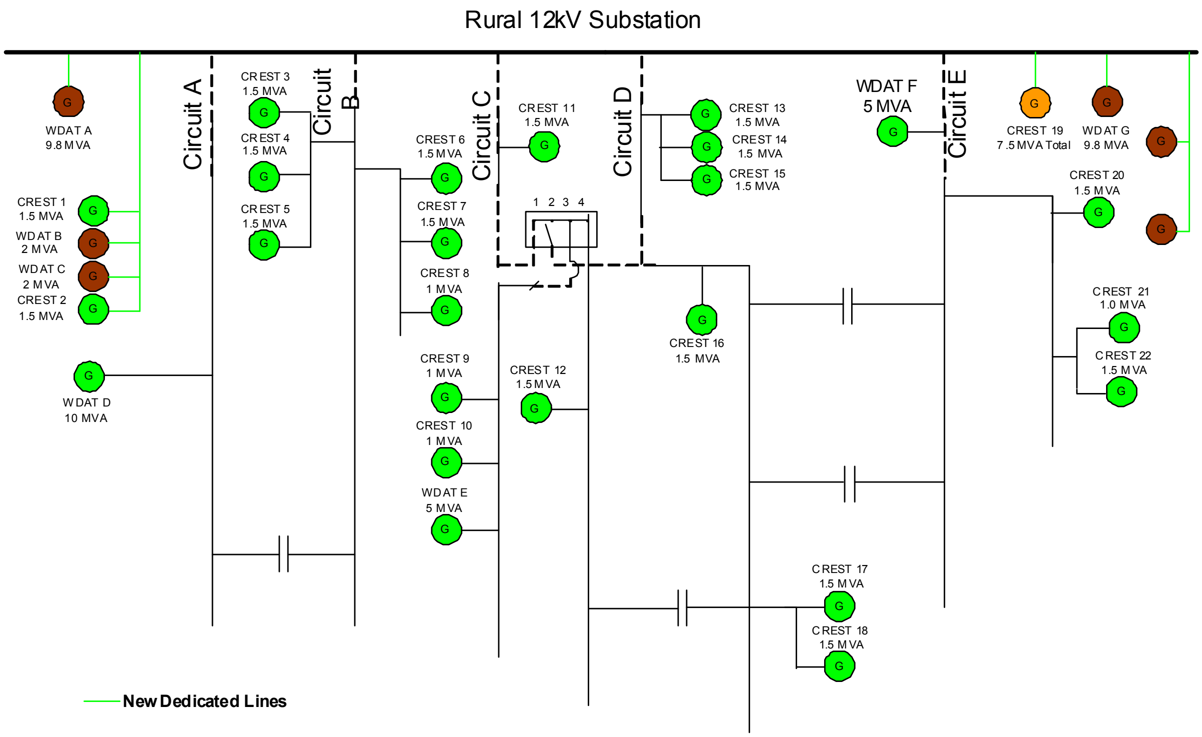


Figure 5: High Penetration Rural Example

Not only have the larger generators and clusters of small projects triggered individual distribution feeder upgrades of over $1.3 million dollars (primarily to reconductor distribution lines to mitigate voltage or overload issues), but taken in aggregate at the substation level, these projects have triggered over $18 million in substation upgrades (to add two 28.0MVA transformer banks and five new 12kV distribution feeders). An additional $9.3 million was identified for interconnection facilities.

Table 3: High Penetration Rural Example Costs

	Generation Amount	Total Cost	Cost ($/MW)
Interconnection Facilities	59.6 MW	$9,300,000	$156,040
Distribution Upgrades		$19,713,000	$330,755

Given the current distribution load fed from this substation, if the 102 MW of queued LER interconnect, the system would experience ~60 MW of power flow back to the subtransmission system during peak times. During off-peak times, this reverse flow could reach close to 90 MW. As penetration levels increase further, upgrades will be triggered at the subtransmission and transmission levels, so that the power can be transmitted over those systems to the urban load centers in SCE's service territory. This would even further increase costs.

Although this is a good example of a high penetration scenario that causes expensive and difficult issues, the substation could in fact support a low level amount of LER. However, the projects would need to be sized for the load served by the substation. For example, in a few cases, smaller (1 – 2 MW) installations were sited close to the substation and did not trigger distribution system upgrades.

4.3 Phase 1b - Case Study: Urban

While it is preferred to interconnect LER in urban load centers in the SCE service territory, there are examples of high penetration urban scenarios that trigger large distribution upgrades. Similar to the rural areas, LER in urban areas should be optimally sized and located such that they serve local load and do not result in power flow back to the subtransmission and transmission systems. Again, this ensures that impacts to the distribution and transmission system are kept to a minimum.

The SCE SPVP program[14] targeted large building rooftops for photovoltaic project interconnections in the 1 – 3 MW range. In many cases, clustering of interconnections resulted due to the dense location of available warehouse rooftops in relatively few locations on the SCE system. While many of the feeders in these areas can indeed handle large amounts of generation (especially compared to similarly-sized rural feeders), increasing penetration levels on a few of the feeders have triggered distribution upgrades.

Similar to Antelope Valley, the Inland Empire experiences high solar irradiance. Coupled with the numerous large rooftops in the area, this resulted in 13.5 MW of requests for PV interconnections to an urban 12kV feeder in San Bernardino.

Figure 6: High Penetration Urban Example: San Bernardino

[14] SCE Solar Photovoltaic Program (SPVP): Program targeted the interconnection of 500 MW of primarily rooftop commercial solar PV on the SCE distribution system

As interconnection requests on the urban 12kV increased, studies indicated that the aggregate generation would result in distribution system voltage outside of Rule 2 requirements as well as feeder penetration levels that exceed SCE standards (10 MW for 12kV feeder). While the first three interconnections did not trigger distribution upgrades, the fourth project on the feeder triggered a $382,000 distribution upgrade to extend a 12kV feeder originating from the same urban substation and transfer two of the projects (totaling 5 MW) to this neighboring feeder. This was necessary in order to mitigate concerns of significant overloading and voltage issues on the original feeder. While this interconnection cost is small as compared to a similar project interconnecting in a rural area, this still adds considerable cost to a small project and illustrates the need for a more even distribution of LER interconnections, even for urban locations.

While this example shows that large amounts of generation can be connected to an urban feeder, there are still many concerns once penetration levels for multiple feeders at a substation increase to these amounts. Similar to the rural example, at periods of light loading, power flow back to the subtransmission and transmission systems may result under these extreme cases. It should be noted that the interconnection requests on the urban 12kV were all located close to the substation, where overloads and voltage impacts are minimized. If these requests were far from the substation, larger distribution upgrade costs would have resulted to address conductor overloads and more severe voltage problems.

5.Transmission System Impacts and Costs

A potentially significant source of LER program costs is transmission upgrades. Even though LER will be installed on the distribution system, as our case studies have shown, increasing penetrations of LER can quickly begin causing substantial subtransmission and transmission upgrades. This section will discuss the types of transmission upgrades experienced and a method for calculating their associated costs. These costs will be included in the total system cost calculations in Section 6.2.

5.1 Differences Between Transmission and Distribution for LER Analysis

Any analysis of LER impacts on transmission needs to begin with a discussion of the important and relevant distinctions between network transmission systems and radial subtransmission and distribution systems.

The transmission system is an integrated network of transmission lines and substations that deliver power to individual radial subtransmission systems. While such radial subtransmission systems are typically designed for one direction power flow from source to load, the transmission system is designed for – and typically exhibits – multiple patterns of power flows depending on operating conditions. The magnitude and direction of these power flows, and the resulting system reliability limits, can be highly influenced by factors including regional power flow schedules, dispatch patterns of generation resources, and relative levels of customer demand in each underbuilt subtransmission system. Because high LER penetration will change dispatch patterns of generation resources, as well as the relative levels of customer demand, the overall impacts of LER on the transmission system cannot be ignored.

One of the most common misperceptions about LER impacts on transmission systems is related to the difference between "net flow" and "network flow impacts." There is a common but misguided belief that if LER connecting to a subtransmission system results in a reduction in load served from that system that there can be no adverse impacts to the transmission system. In reality, reduction of load in a subtransmission system due to LER will always have "network flow impacts" in that there will always be a redistribution of transmission system network flows. In robust transmission areas with available latent transmission capacity and a high degree of operational flexibility, the redistribution of flows can often have no resulting adverse impacts. However, in transmission constrained areas with little or no operational flexibility, the redistribution of transmission flows due to LER can be enough to cause a transmission reliability concern. This potential for adverse impacts is greater with higher LER penetration levels.

Another important distinction between transmission systems and subtransmission systems is the geographic radius of exposure to reliability problems. Reliability problems (e.g., overloads, instability) in a radial subtransmission system can easily impact customers connected to that system. However, the radial nature of the subtransmission system inherently limits the geographic area of customer exposure; any reliability problem in one radial subtransmission system is unlikely to impact customers in another system. In contrast, the transmission system has a much larger geographic reach and simultaneously serves multiple subtransmission systems. Reliability problems on the transmission system could easily impact end-use customers over a wide geographic area. Infamous transmission system disturbances such as those in WSCC in 1996 and the northeast United States and Canada in 2003 illustrate this phenomenon. Failure to consider the LER impacts on the transmission system can have reliability implications even for systems that have no LER penetration.

Furthermore, many of the transmission system reliability issues of concern are nonlinear in nature. In other words, "1 MW" of new LER generation can have far greater than "1 MW" of relative transmission system impact. In a radial distribution line operating at its loading limit, the impact of additional demand is easy to quantify. In such a case, overloads would be MW-for-MW proportional to the additional demand served. In contrast, if a transmission system is operating at a network-defined system limit, the impact of additional demand can be disproportional to the additional demand served. The capability of the existing WECC Path 26 illustrates this phenomenon. Based on the established WECC Path 26 ratings, it takes 1,400 MW of generation tripping to accomplish a 700 MW increase in Path 26 capability. It also takes a combination of 1,400 MW of generation tripping and 500 MW of load shedding to accomplish a 1,000 MW increase in path capability. The impacts of high LER penetration on transmission system limits can be greater than the amount of LER in question.

5.2 Quantifying LER Impacts on Transmission

In order to quantify relative LER impacts on the transmission system, transmission system deliverability study results from the recently published California Independent System Operator (CAISO) Queue Cluster 3 Phase I interconnection studies (QC3 Phase I) were used. These results provide a relative ranking of transmission system impacts and associated transmission system upgrade costs throughout the SCE transmission system. Through a stakeholder review process, the CAISO has determined that these QC3 Phase I results are appropriate for use in developing location-specific transmission "Cost-per-MW" impacts for future generation interconnection cluster studies.[15]

Based on the established CAISO deliverability study methodology, the CAISO 2011 Technical Bulletin pertaining to QC3 and the published QC3 Phase I study results, the relative transmission system deliverability "Cost-per-MW" for various geographic clusters are as follows:

[15] For additional details, see the October 20, 2011 CAISO Technical Bulletin "Generation Interconnection Procedures: Revisions to Cluster 4, Phase 1 Study Methodology" available on the CAISO website (www.caiso.com). Note that this methodology is equally applicable to both transmission and distribution interconnection projects as part of the Cluster 4, Phase 1 study.

Table 4: Transmission System Deliverability "Cost-per-MW"

Transmission Area	Transmission System Deliverability "Cost-per-MW" ($000) Based on QC3 Phase I
Northern Bulk	$742
Control	$4,328
Lugo/Kramer	$1,627
East of Pisgah	$150
Eastern Bulk	$647
LA Basin	$0

It is important to note that the results above are not the result of a bottom-up approach to model a typical transmission feeder or system. Indeed, such bottom-up modeling techniques are meaningless in assessment of the networked transmission system. Instead, the results above reflect CAISO's most recent estimates of upgrade costs to mitigating transmission system congestion, expressed in $/MW and derived from recently published CAISO interconnection studies in rural areas of the SCE transmission system.

The results above clearly show that transmission system impacts of LER will vary significantly depending on areas of LER development and penetration. In predominantly "rural" areas such as the majority of areas outside of the LA Basin, transmission costs associated with LER can be extremely significant.

However, in the predominantly "metro" LA Basin, the transmission cost is negligible. This is consistent with operational knowledge of the SCE transmission system. The transmission system in the LA Basin is characterized by a tightly networked transmission system, with multiple transmission lines in parallel and multiple substations in relatively close geographic and electrical proximity. This transmission system topology is an outcome of historical system needs. The LA Basin was historically designed to accommodate a large portfolio of in-basin generation resources (with multiple possible dispatch patterns) and to serve a large in-basin customer demand (with large variations between maximum and minimum load levels). The LA Basin transmission system therefore needed to be planned with a large degree of operational flexibility to accommodate a wide variety of system conditions in a safe and reliable manner. This operational flexibility is essentially equivalent to "latent transmission capacity" for new generation resources in the LA Basin.

5.3 Unguided and Guided Costs for Transmission Impacts

A survey of active projects in the existing generation interconnection queue was performed to determine the relative distribution of projects in rural transmission areas in an "unguided" case. A selection of 725 active distribution interconnection projects was made, and the transmission area of each project was identified. In this subset of the current queue, approximately 73% of these projects were identified as being interconnected in the predominantly rural areas of Lugo/Kramer, Eastern Bulk, and Northern Bulk. As this percentage is consistent with the overall rural percentage (70%) in the unguided case, this subset of the queue was assumed to be representative of the queue at large and appropriate for use in this study.

The relative distribution of projects in each of these three areas was used to derive the average $/MW transmission cost in the unguided case. See the table below.

Table 5: Relative Weight of Transmission Areas for Rural Projects – Unguided Case (Based on active WDAT and Rule 21 projects)

Transmission Area	Project Count	% Instance	QC3 $000/MW	Unguided Rural $000/ MW
Lugo/Kramer	144	27.1%	$1,627	**$957**
Eastern Bulk	139	26.1%	$647	
Northern Bulk	249	46.8%	$742	
Total	532	100.0%		

In the guided case, it was assumed that there would be fewer rural interconnection projects, and therefore the utility would have greater flexibility to discourage interconnection requests in the most congested transmission area (Lugo/Kramer) and to encourage interconnection requests in the relatively less congested transmission areas of great interest to developers in queue (Eastern Bulk and Northern Bulk). The guided case assumed equal distribution of rural interconnection requests in the Eastern Bulk and Northern Bulk transmission areas for $/MW transmission cost purposes. See the table below.

Table 6: Relative Weight of Transmission Areas for Rural Projects – Guided Case (Assumed)

Transmission Area	% Instance	QC3 $000/MW	Guided Rural $000/MW
Lugo/Kramer	0.0%	$1,627	**$694**
Eastern Bulk	50.0%	$647	
Northern Bulk	50.0%	$742	
Total	100.0%		

6.Overall System Impact Cost Analysis

Per the study methodology laid out in Section 3, this section presents costs of increased LER in two ways: Section 6.1 will present the findings of the Feeder Modeling Analysis (Phase 1a), while Section 6.2 explores the total system costs based on recently completed system impact studies (Phase 2).

6.1 Cost Analysis for Feeder Modeling Analysis (Phase 1a)

For the feeder analysis, costs were identified by developing the scope of the upgrade, and applying SCE's unit cost based data for actual installations for similar distribution upgrades. To determine the cost impact for interconnection facilities, costs were based on historical system studies performed for generators applying to interconnect. Individual cost components are based on the following table:

Table 7: Itemized Cost Components

Interconnection Facilities		
Line extensions	Metering equipment	Switch installations
Protection equipment	Telemetry	

Distribution Impacts		
Voltage regulation equipment	Automation / SCADA addition	Overload mitigation (reconductoring)
Additional switches and feeder ties	Feeder breaker upgrades	Additional protective devices for
Protection upgrades	Additional communication / telecom	New distribution lines or substations

For each of the four circuit models, as described in Section 3.2, distribution impacts were determined for both the guided and unguided cases.

Table 8: Feeder Modeling Estimated Costs

Unguided Case: Feeder Modeling Estimated Costs	**Urban #1 (Aruba 12kV)**	**Urban #2 (Hill 4kV)**	**Rural #1 (Smoke Tree 12kV)**	**Rural #2 (Windt 12kV)**
Penetration (MW)	*0.40*	*0.40*	*3.84*	*3.84*
Distribution System Upgrades ($000)	$53	$53	$1,848	$958
Interconnection Upgrades* ($000)	$75	$75	$345	$345
Total ($000)	**$128**	**$128**	**$2,193**	**$1,302**

**Note: Interconnection costs derived from System Impact Study Average costs for Urban and Rural feeders*

Guided Case: Feeder Modeling Estimated Costs	Urban #1 (Aruba 12kV)	Urban #2 (Hill 4kV)	Rural #1 (Smoke Tree 12kV)	Rural #2 (Windt 12kV)
Penetration (MW)	*0.93*	*0.93*	*1.65*	*1.65*
Distribution System Upgrades ($000)	$106	$250	$0	$0
Interconnection Upgrades* ($000)	$174	$174	$148	$148
Total ($000)	**$280**	**$424**	**$148**	**$148**

**Note: Interconnection costs derived from System Impact Study Average costs for Urban and Rural feeders*

From these eight individual analyses, average cost per MW of installed LER can be derived for comparison purposes.

Table 9: Feeder Modeling Averages (Cost per MW)

Unguided Case: Feeder Modeling Averages ($000/ MW)	Urban #1 (Aruba 12kV)	Urban #2 (Hill 4kV)	Rural #1 (Smoke Tree 12kV)	Rural #2 (Windt 12kV)
Distribution Upgrades	$133	$133	$481	$249
Interconnection Facilities*	$188	$188	$90	$90
Total Cost / MW	**$321**	**$321**	**$570**	**$339**

Guided Cases: Feeder Modeling Averages ($000/ MW)	Urban #1 (Aruba 12kV)	Urban #2 (Hill 4kV)	Rural #1 (Smoke Tree 12kV)	Rural #2 (Windt 12kV)
Distribution Upgrades	$114	$270	$0	$0
Interconnection Facilities*	$188	$188	$90	$90
Total Cost / MW	**$302**	**$457**	**$90**	**$90**

**Note: Interconnection costs derived from System Impact Study Average costs for Urban and Rural feeders*

6.2 Cost Analysis for Total System (Phase 2)

Typically, specific interconnection facilities and associated upgrade costs vary by installation due to differences in distribution feeder design, topography, substation design, and customer density. However, because SCE has over 4,500 distribution feeders, it was assumed that system impact study averages would serve as an adequate proxy for future installation. This assumption is also validated by the comparison between the modeled representative feeder results and the system impact averages that were in relative close proximity to each other in upgrade costs.

Table 10: System Impact Study Averages (Cost per MW)

System Impact Study Averages ($000/MW)	Unguided Case: Urban	Unguided Case: Rural	Guided Case: Urban	Guided Case: Rural
Distribution Upgrades	$25	$210	$25	$210
Transmission Upgrades	$0	$957	$0	$694
Interconnection Facilities	$188	$90	$188	$90
Total Cost / MW	**$212**	**$1,256**	**$212**	**$994**

Significant differences occur between urban and rural areas in all categories between upgrades and interconnection facilities. Interconnection facilities costs are typically found to be lower in rural areas due to the availability of land and the ability to interconnect larger amounts of generation through a single interconnection facility. However, upgrade costs are substantially higher due to the reduced level of infrastructure resulting in less ability to add generation without adding additional equipment or upgrading existing infrastructure. Transmission costs also vary significantly because within SCE's service territory, constrained transmission systems are located in the rural areas due to the existing level of generation already connected. Further reduction in transmission upgrades can be accomplished in some rural areas where less transmission constraints exist.

Differences between urban and rural also become significant when aggregated across the full allocation of 4,800 MW.

Table 11: Total Costs for 4,800 MW LER Addition

Unguided Case: System Wide Estimated Costs	**Urban**	**Rural**
Penetration (MW)	*1,440*	*3,360*
Distribution System Upgrades ($000)	$36,000	$705,000
Transmission Upgrades ($000)	$0	$3,214,000
Interconnection Upgrades ($000)	$270,000	$301,000
Total ($000)	**$306,000**	**$4,220,000**

Guided Case: System Wide Estimated Costs	**Urban**	**Rural**
Penetration (MW)	*3,360*	*1,440*
Distribution System Upgrades ($000)	$83,000	$302,000
Transmission Upgrades ($000)	$0	$1,000,000
Interconnection Upgrades ($000)	$630,000	$129,000
Total ($000)	**$713,000**	**$1,431,000**

Total Unguided Case ($000)	**$4,526,000**
Total Guided Case ($000)	**$2,144,000**

In total, the unguided case represents nearly $4.5 billion in costs to interconnect 4,800 MW of LER. If it was possible to direct generation projects in the urban areas where there is higher capacity, this figure could be reduced to below $2.1 billion. Additional benefits of adding LER in the load centers include the ability to relieve future congestion of the bulk power transmission system and reduce some of the power demand on the distribution system during peak periods.

7.Conclusion and Recommendations

7.1 Summary of Results

The cost of reaching the Governor's goals will be highly dependent on the location of LER development:

- Individual feeder impacts vary greatly between location, size, and other characteristics. For example, comparable penetration levels on the Aruba 12kV urban feeder and the Smoke Tree 12kV rural feeder[16] resulted in vastly different impacts, with the former experiencing no impacts and requiring no upgrades, while the latter saw issues such as overloaded conductors and system operational challenges requiring costly reconductoring, installation of new voltage regulators, and local substation automation.
- Modeled circuits experienced up to a 70% decrease in average cost per MW of installed LER in moving from the unguided to guided case. See Figure 12.

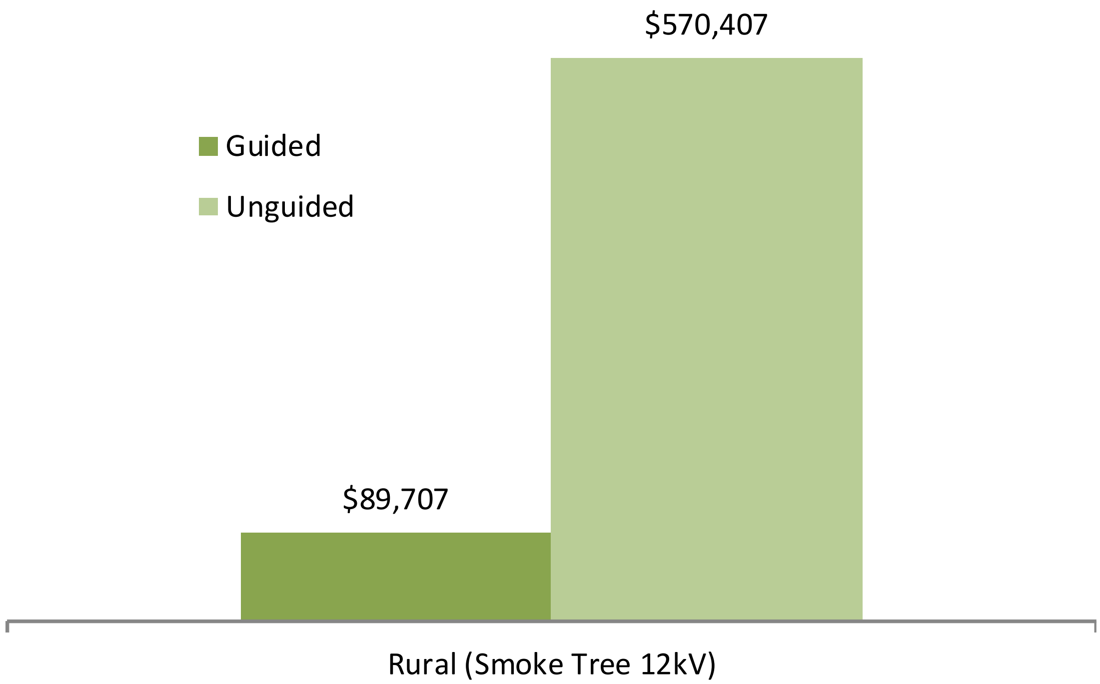


Figure 7: LER Average Distribution and Interconnection Cost / MW (USD)

- Overall costs to connect new LER into the distribution system are highest in rural areas where the generation is further from local loads. However, over 70% of current applications received for new LER are in rural systems. Continuation of this "unguided" scenario would result in overall costs estimated to be approximately $4.5 billion for SCE's estimated share of the 12,000 MW.
- Costs to connect generation were less in local urban load centers where the generation is smaller and more likely to be installed onsite. In the "guided" scenario, where 70% of new LER were located in the urban area, the overall costs of reaching SCE's

[16] This means comparing the Aruba circuit modeling results from the guided case, where higher urban penetration was assumed, to Smoke Tree unguided, or high-rural penetration results.

projected portion of the Governor's goal are estimated to be $2.1 billion. Though this is still a significant investment, it represents a 45% decrease from the "unguided" case. See Figure 13.

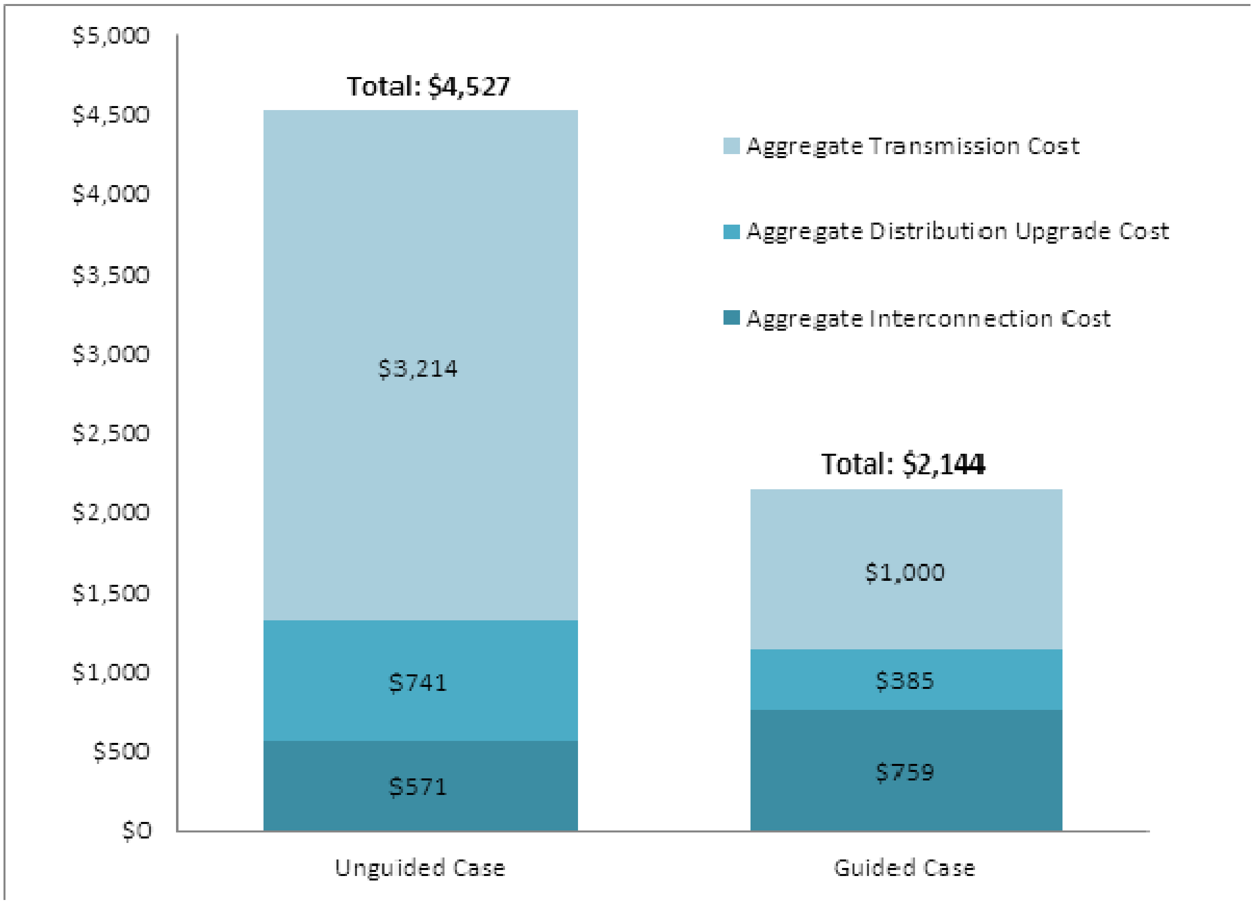


Figure 8: Total SCE System Costs of LER Proposal (Million USD)

– Even greater reduction in costs could possibly be achieved through uniform distribution of LER along the various feeders and substations within SCE's service territory. The case studies included in this study show the high costs of the alternative, or "clustered" installations.

7.2 Conclusions and Recommendations

The key findings of this study point to the extremely high importance of thoughtfully implementing the Governor's goals with locational considerations in mind. Regardless of how carefully the state plans to meet the 12,000 MW goals, high costs will be incurred by electricity customers. However, ensuring that there are appropriate incentives for developers to interconnect in preferred areas will be very important in minimizing these costs as much as possible.

Based on the pattern of current applications submitted, high penetrations of LER in rural areas are anticipated. This report recommends making immediate changes to the interconnection process that will steer new LER projects away from rural areas and encourage future installation in urban load centers. In addition, utilities including SCE currently post pre-application information (e.g., system maps) to encourage use of the current Fast Track and Independent Study Process. More effort should be placed on helping applicants access this information, possibly by developing a user-friendly system to communicate this information. In the end, this study shows that, for new LER, locating in pre-defined "guided" locations can drastically lower costs. This study recommends that any procurement process for the 12,000 MW accurately take into account the significant cost difference between well- and poorly- located projects in order to ensure that true least-cost projects are selected.[17]

Additionally, current efforts to reform Rule 21 distribution interconnection, including the move to adopting a cluster study process from today's current serial study process, will help to ensure upgrade costs are equitably distributed to new applications and help new applicants better assess how to minimize interconnection costs.

Lastly, this study should not be viewed as the most extensive possible costs analysis. More detailed studies will be required to more accurately estimate LER installation costs and create "ideal" location information for project developers. This will require development of advanced models and computer applications not currently available for assessing multiple LER on a feeder. A continuing distribution field monitoring program to track and monitor costs and impacts of LER as penetration increases is also highly recommended. As with all policies, LER development goals should be designed to allow suspension should costs exceed certain thresholds, and policymakers should not rush to reach an arbitrary goal without truly understanding the possible costs.

7.3 Further Study Opportunity: Additional Costs & Possible Mitigation Strategies

This study points to a number of questions that call for additional study. These can be split into two categories: areas of additional costs and possible mitigation strategies.

7.3.1 Additional Costs

Proliferation of localized generation resources will inevitably make the general public more engaged and interested in understanding their sources of electricity. While SCE supports community engagement, it will be important that laypeople understand the very real safety hazards the LER – and their related equipment – can present. Appendix D, for example, gives a brief overview of the dangerous interconnections that SCE has seen installed by contractors for customer-side projects. Especially given the hope that a high percentage of LER will be located in high-populated, load-dense areas, SCE highly recommends that more work is done to develop safe practice standards and understand how to best educate the public on the importance of treating all electrical equipment with the proper caution.

This study assumed, based on existing installation trends, that additional LER would be PV. Clearly, the intermittency of PV systems provides additional challenges to system operability that are not captured by a distribution-only modeling exercise. PV installations need to be monitored more closely by local jurisdictions to adequately protect the public

[17] While not the focus of this study, SCE does recognize that there are many factors that affect the cost of LER installations, including development, land acquisition, and operating costs and believe that grid impacts should be considered on an even playing field with these factors.

from safety and other issues that potentially increase the overall cost and liability to SCE's customers. We recommend that further analysis is conducted around increasing levels of PV penetration before high penetrations of new LER cause safety and reliability concerns on the grid.

7.3.2 Possible Technological Mitigation

One way to reduce the system reliability impacts of LER is to ensure that multiple generation technologies are included in any LER policy. Efficient resources such as fuel cell and combined heat and power facilities can not only help to reduce the intermittency of a LER portfolio as a whole but also are used to help integrate other renewable intermittent resources and increase reliability across the system. Though not undertaken in this study, it is recommended that further analysis is conducted to put numbers to these real and important benefits.

Many discussions of LER focus on the rapid rate of technological change in the electricity sector over the last few decades. SCE strongly believes in the importance of furthering technological development, but cautions against viewing this as a panacea for the very real issues that LER present. For example, smart grid technologies, while expected to have the ability to mitigate some of the integration problems associated with intermittent LER, are not immediately available. SCE is currently assessing resource needs and mitigation measures for "at risk" circuits while performing technology evaluations and real-world pilot projects to prepare for future deployments. Some of these technologies include Distribution and Substation Automation platforms, such as Advanced DMS, GIS and OMS, Distribution Switching Equipment, Advanced Volt/VAR Control devices, Advanced Relays and energy storage. These advanced technologies are planned for deployment in 2012–2020 period, as discussed in SCE's 2011 Smart Grid Deployment Plan.[18] This study recommends continuing important efforts such as these underway at SCE, and suggests that policymakers realistically consider the implementation timeframe for these nascent technologies when developing policy targets and horizons.

Crucial to the development and incorporation of new technologies are uniform standards and practices. For example, SCE's inverter testing laboratory is currently supporting the testing and evaluation of PV inverter systems at the residential and commercial levels. This work has been very useful in determining current inverter performance characteristics and identifying future desirable ones for operation on the grid. In conjunction with this effort, SCE is working closely with standard bodies such as IEEE1547 and Rule 21 groups to

[18] http://docs.cpuc.ca.gov/efile/A/138423.pdf

8.Additional Information and Resources

For more information on SCE's distribution and transmission system, interconnection processes, and commitment to efficient renewables procurement (including Localized Energy Resources), please visit the following pages:

SCE Renewable Energy Overview

http://www.sce.com/PowerandEnvironment/Renewables/default.htm

SCE Interconnection Map (prepared for the Renewable Auction Mechanism)

http://www.sce.com/EnergyProcurement/renewables/renewable-auction-mechanism.htm

SCE Wholesale Distribution Access Tariff Information

http://www.sce.com/AboutSCE/Regulatory/openaccess/default.htm

SCE Transmission Development

http://www.sce.com/PowerandEnvironment/Transmission/default.htm

9. Appendix A: Glossary of Terms

** Starred terms based on IEEE 100 (see: http://www.ieee.org/index.html)*

Available Fault Duty (or **Short Circuit Duty**): The amount of current (usually in thousands of amps) that results when a conductive object (power line) is connected to another conductive object or ground through a low impedance connection.*

Breaker (or **Circuit Breaker**): A device designed to open and close a feeder by nonautomatic means, and to open the circuit automatically on a predetermined overload of current (e.g., fault), without injury to itself when properly applied within its rating.*

Distribution: The part of an electrical system (typically less than 60kV) used for conveying energy to the point of utilization from a source. From the standpoint of a utility system, the area described is between the substation and the customer's entrance equipment.*

Fault: A current that flows from one conductor to ground or to another conductor owing to an abnormal connection (including an arc) between the two.*

Feeder: A conductor or system of conductors operating at primary voltage (4kV, 12kv, 33kV, etc.) through which an electric current is intended to flow. A feeder is usually considered those primary conductors and associated equipment between the substation and the distribution transformers that serve customer load.

Feeder Tie: A point at which two separate feeders meet, usually at a switching device.

IEEE 1547: An Institute of Electrical and Electronics Engineer's (IEEE) standard that provides requirements relevant to the performance, operation, testing, safety considerations and maintenance of distributed generation (DG) interconnected to the distribution system.

Impedance: The resistance to the flow of alternating current in a circuit.*

Interconnection: The physical plant and equipment required to facilitate the transfer of electric energy between two or more entities. It can consist of a substation and an associated transmission line and communications facilities or only a simple electric feeder.*

Intermittency: Erratic output of LER due to fluctuations of its source (e.g., sun, wind). As an example, solar LER output is greatly reduced whenever clouds block the available sunlight.

Inverter: A machine, device or system that changes direct-current power (e.g., from solar panels, batteries) to alternating current power.*

Islanding: A condition in which a portion of the utility system that contains both load and LER remains energized while it is isolated from the remainder of the utility system.*

Load tap changer ("LTC"): A device used to change, raise or lower substation voltage while the transformer is energized and without interrupting the load.*

Localized Energy Resource ("LER"): A facility that is generating electricity for use on-site or exporting to the grid, can be customer or supply-side, up to at least 20 MW in size, interconnects either to the distribution system or to the transmission system in urban load centers that are not generation-constrained, and creates minimal interconnection and T&D modification costs.

Overloading: Loading in excess of normal rating of equipment; operation of equipment in excess of its normal full load rating / ampacity, resulting in possible equipment damage.*

Penetration: A comparison (percentage, typically) of the amount of LER interconnected to the system, feeder, substation, etc. and the peak load of the system, feeder, substation, etc.

Protection: The process of monitoring a system and automatically initiating an action to mitigate faults on the system.*

Reclose: The automatic closing of a circuit-interrupting device following automatic tripping.*

Recloser: A device similar in form and function to a circuit breaker that is installed out on a feeder.

Reconductor: The replacement of overhead or underground wire to a larger size to increase the load capacity of and or improve voltage regulation on a feeder or section of feeder.

Rule 21: A California Public Utilities Commission (CPUC) rule describing the interconnection, operating, and metering requirements for LER to be connected to SCE's Distribution System over which the CPUC has jurisdiction.

Rule 2: A California Public Utilities Commission (CPUC) rule describing utility service requirements. These include available service voltages, system voltage and frequency operation limits, equipment requirements, etc. that the electric utility and customer must follow.

Subtransmission: An interconnected group of electric lines and associated equipment (typically at voltages of 66kV and 115kV for SCE) for the movement or transfer of electric energy between the transmission system and distribution system.

Switching: Operation of the distribution system via switches and circuit breakers to isolate specific sections of the system or to transfer a section from one feeder to another for maintenance, load restoration, or system planning purposes.

System Impact Study: A report outlining the specific impacts of a LER interconnection and provides detail on interconnection requirements, distribution / subtransmission / transmission upgrades and associated costs.

Telemetry: Transmission of measurable quantities (e.g., voltage, current, power) using telecommunication techniques.*

Transmission: An interconnected group of electric lines and associated equipment (typically at voltages of 230kV and greater) for the movement or transfer of electric energy in bulk between points of supply and points for delivery.*

Voltage: The potential difference between any two conductors or between a conductor and ground.*

Voltage Regulation: The degree of control or stability voltage at the load. Voltage regulation is often specified in relation to other parameters, such as input voltage or load variations.*

WDAT (Wholesale Distribution Access Tariff): A Federal Energy Regulatory Commission (FERC) tariff describing the interconnection, operating, and metering requirements for wholesale generating facilities (including LER) that are connected to SCE's Distribution System and deliver capacity and energy to the California ISO Grid.

10.Appendix B: Feeder Diagrams

Below are diagrams of actual feeders used in the study. The single line diagrams show the topology of the four feeders used in the study including the location of the substation source and the location of the LER. Most distribution feeders consist of a mainline or "backbone" that travels from the circuit breaker in the substation to the end of the line. Typical design practice includes several normally open tie switches to other distribution feeders. Most often the mainline of a feeder will follow the major arterial streets in a city. From the mainline, a lateral will tap off to serve a small group of customers such as a small neighborhood or shopping center. In the scenarios below, residential customers receive single phase service and commercial and industrial customers receive three phase service. This information is shown in the four diagrams below; the dashed gray lines show the two phase lines, three phase lines, and three phase commercial / industrial transformers on the feeder. The small grey arrows show where commercial or industrial customers are located. The red, blue, and green colored lines show the single phase laterals to residential customers and the small arrows off the lines show where the individual transformers are located. Each color shows a different phase, A phase is red, B phase is blue, and C phase is green. If the residential transformer is connected line to ground (on Aruba 12kV), the lateral and transformer will be colored red, blue, or green. If the residential transformer is connected phase-phase the line is shown grey, and the transformer is red if the connection is A-B, blue if the connection B-C, or green if the connection is C-A.

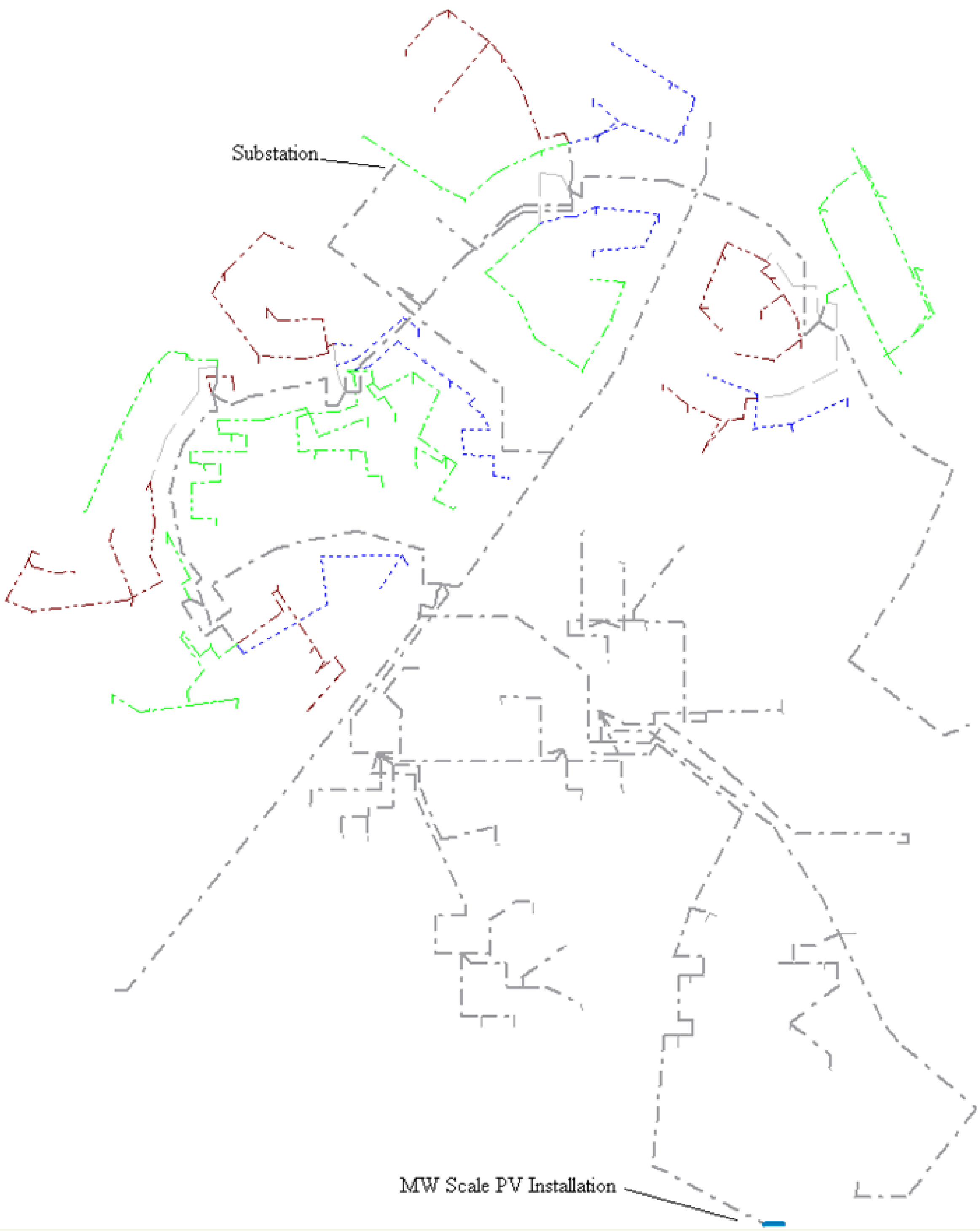


Figure B1: Aruba 12kV Urban Feeder

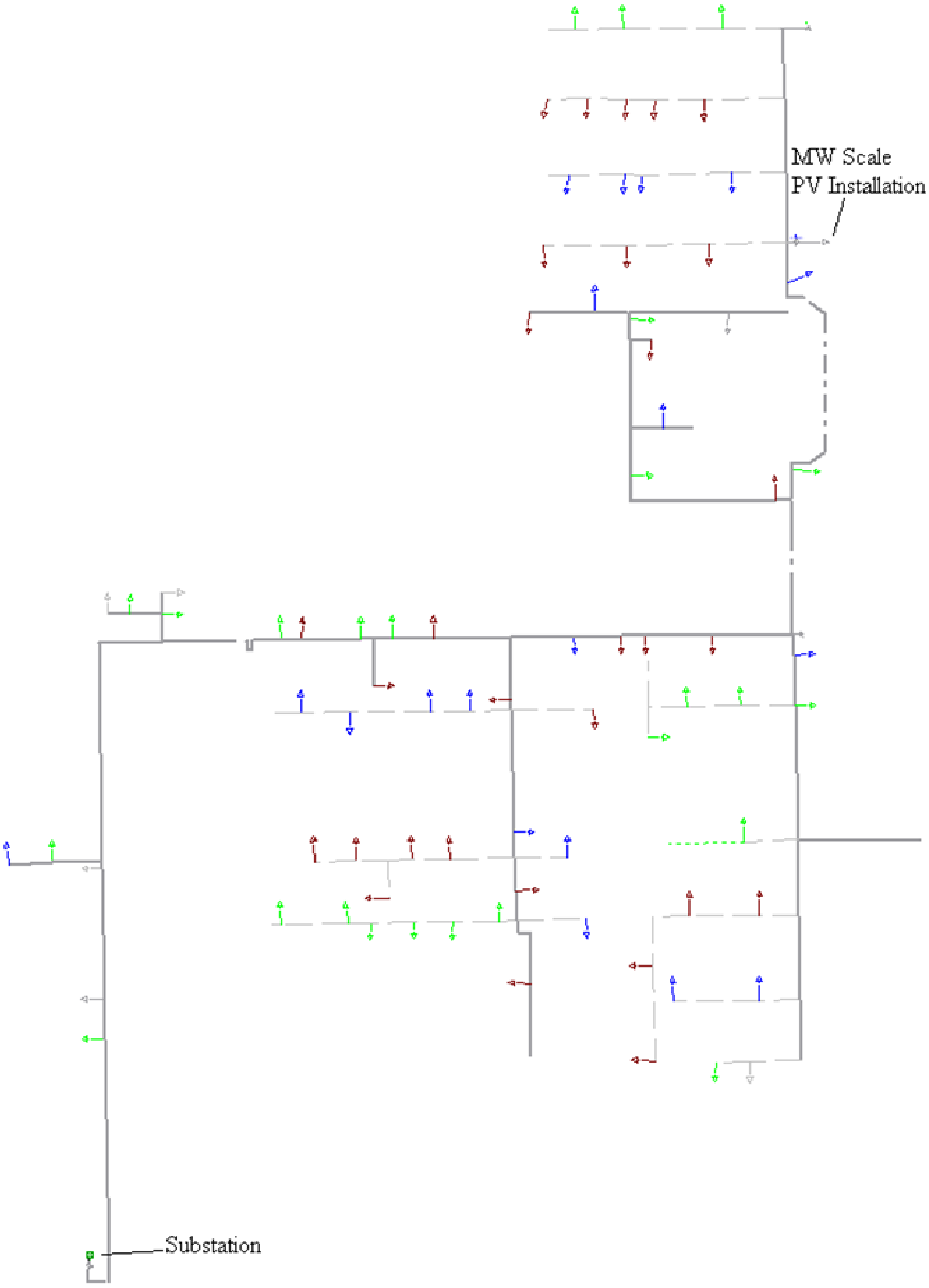


Figure B2: Hill 4kV Urban Feeder

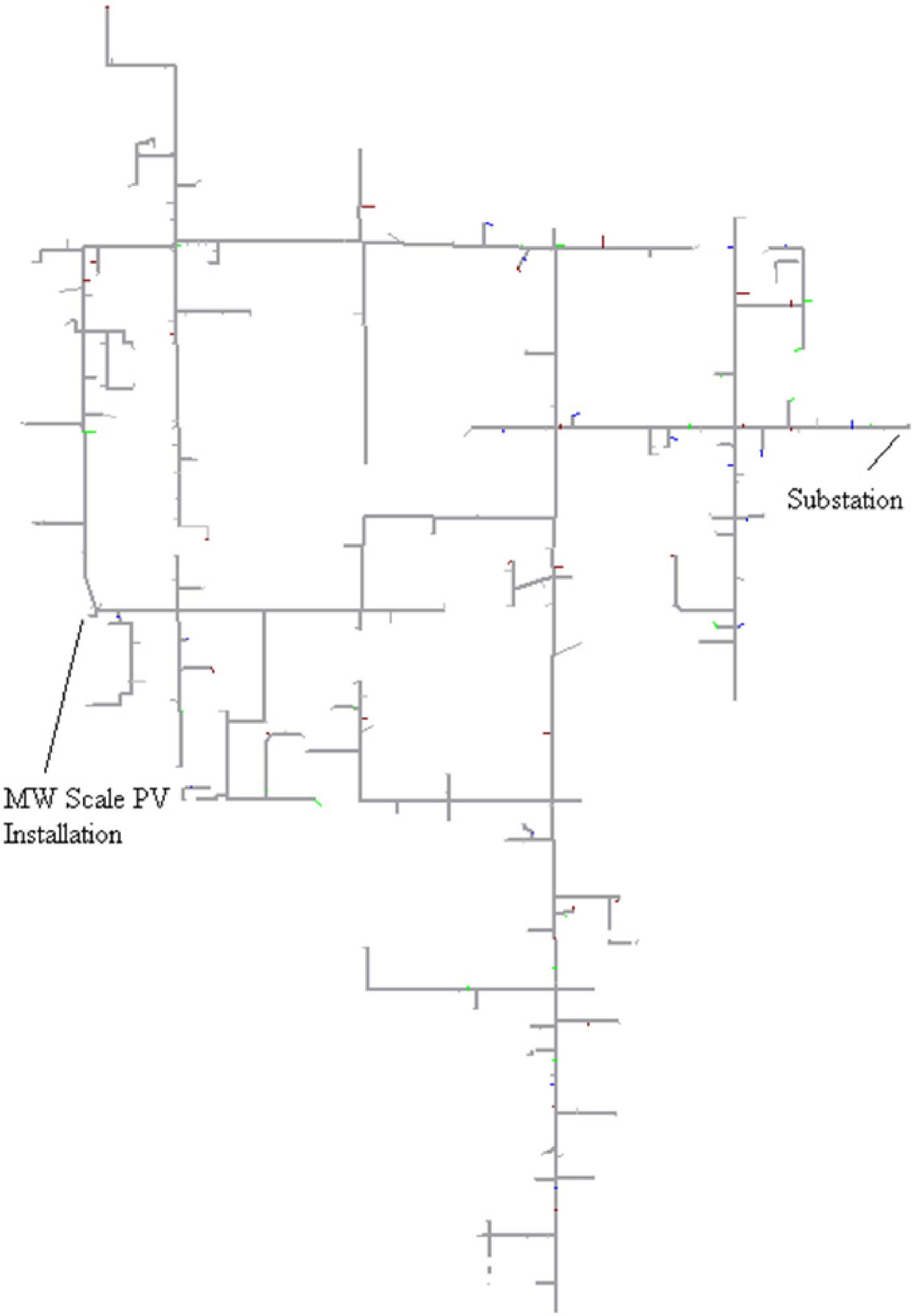


Figure B3: Windt 12kV Rural Feeder

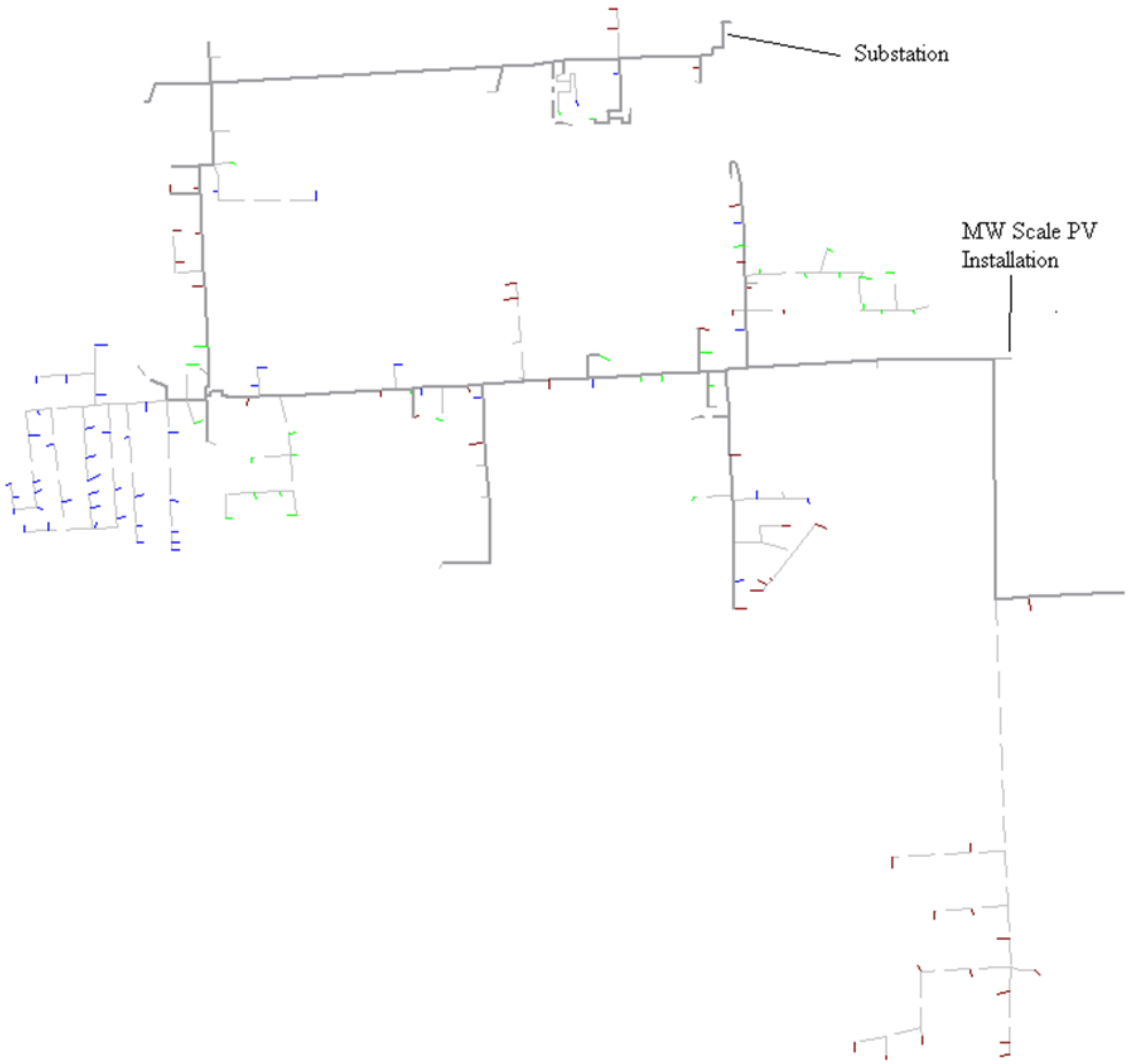


Figure B4: Smoketree 12kV Rural Feeder

Figure B5 below gives a perspective on the sizes of the feeders relative to each other. The rural feeders cover the largest geographic area and the 4kV urban circuit, Hill 4kV, covers the smallest area.

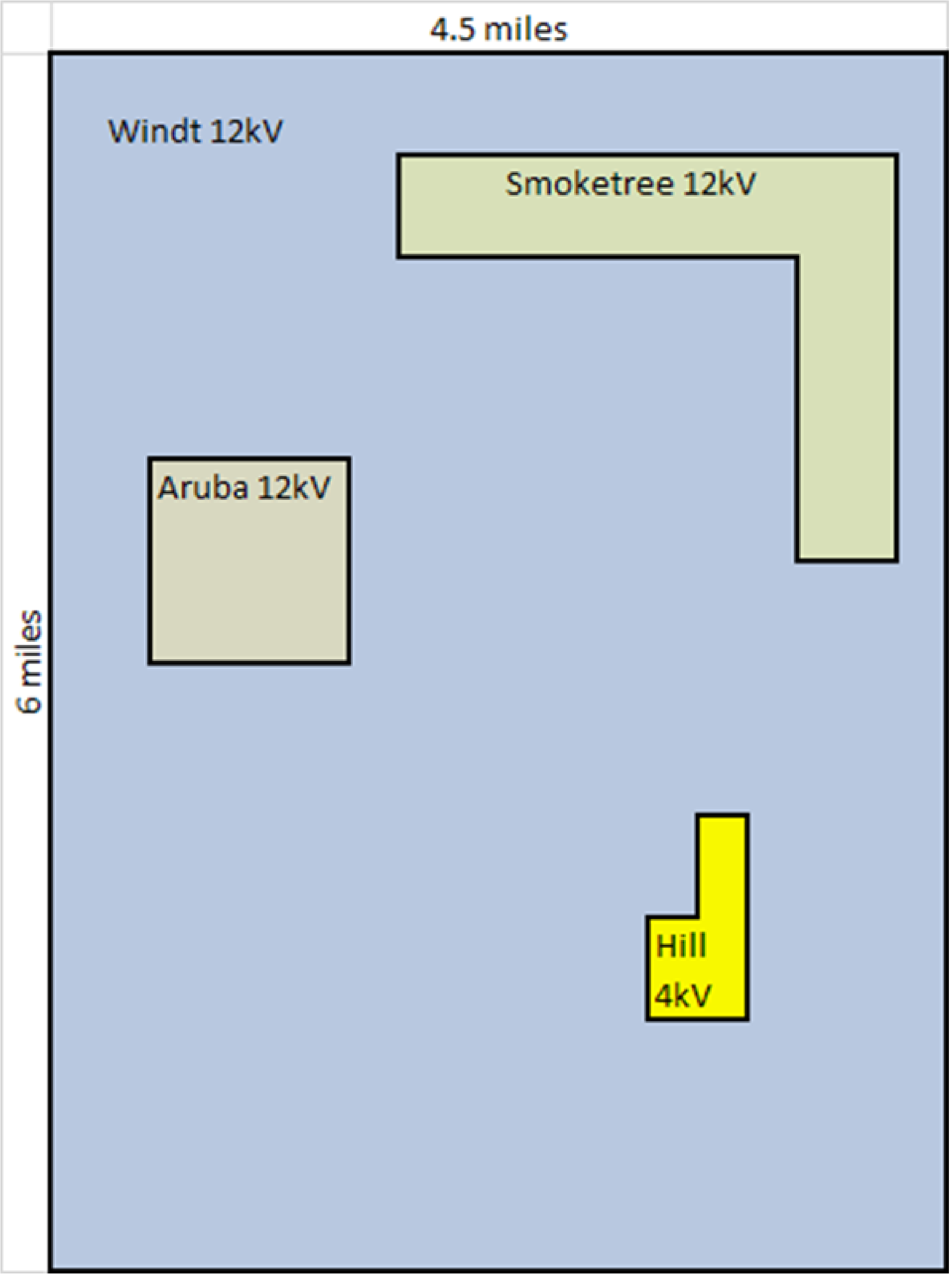


Figure B5: Relative Size of Four Studied Feeders

11.Appendix C: Detailed Feeder Modeling Results

The study results show a 24-hour period showing the hourly impact on real and reactive power flow, voltage regulating equipment, line loading and transformers over or under voltage. The simulation was set up to simulate a severe intermittency event where the PV system output dropped from peak output to 10% output. The 24-hour period that was selected for the study was chosen because it was a day with the lowest mid-day demand with the highest expected PV output. Lastly, it was assumed that the subtransmission system was capable of regulating the 4kV and 12kV bus voltage.

The study shows that 1.5 MW PV generation can be integrated into a typical Urban 12kV feeder with no detectable overloads or voltage issues. Integration of PV systems on the order of hundreds of kW on an Urban 4kV will cause significant voltage regulator operation leading to shorter asset life and higher maintenance cost. It is not recommended to install megawatt-scale PV systems on 4kV feeders. Megawatt-scale PV plants on rural feeders will cause an increase in voltage regulator and load tap changer (LTC) operations leading to a shorter asset life and higher maintenance cost. Past a certain MW size (3.6 MW in this study) the feeder would require cutover to a higher voltage. Additional voltage regulator equipment may also be required depending on feeder topology and LER location. The total cost to cut the system over to 12kV was approximately $250,000, nearly quadrupling the cost of upgrades that would normally be required for a distribution feeder in an urban area.

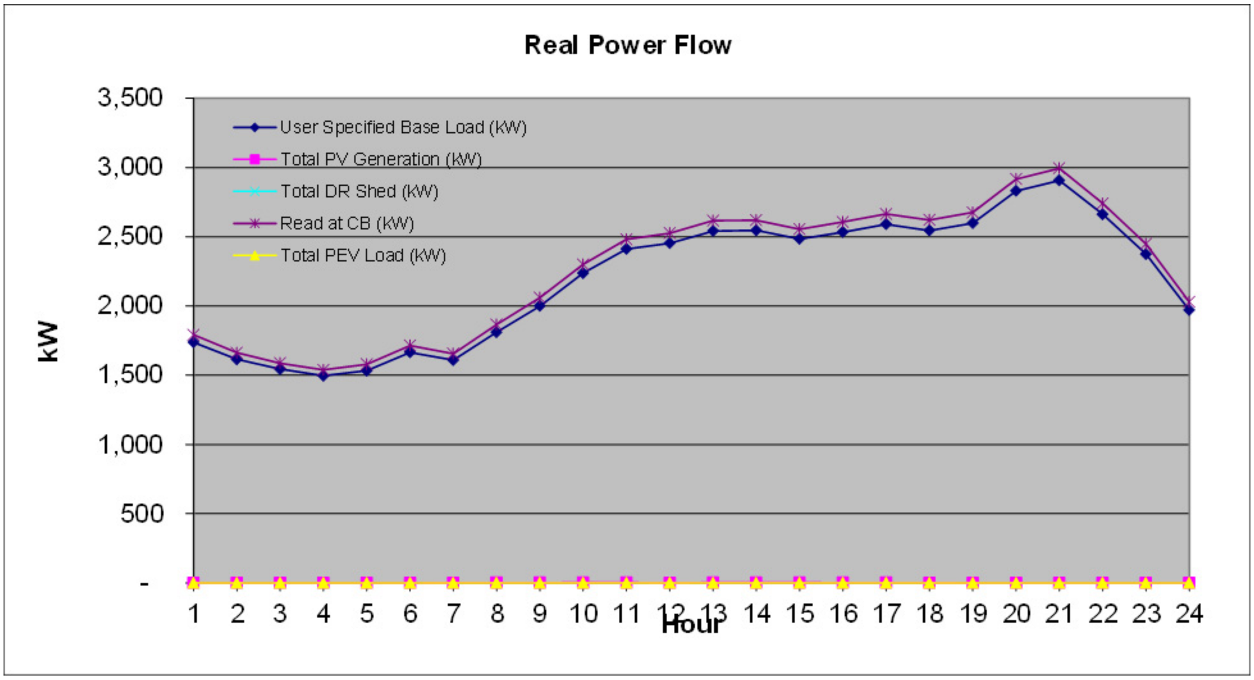


Figure C1: Real Power Flow on Aruba 12kV with no LER

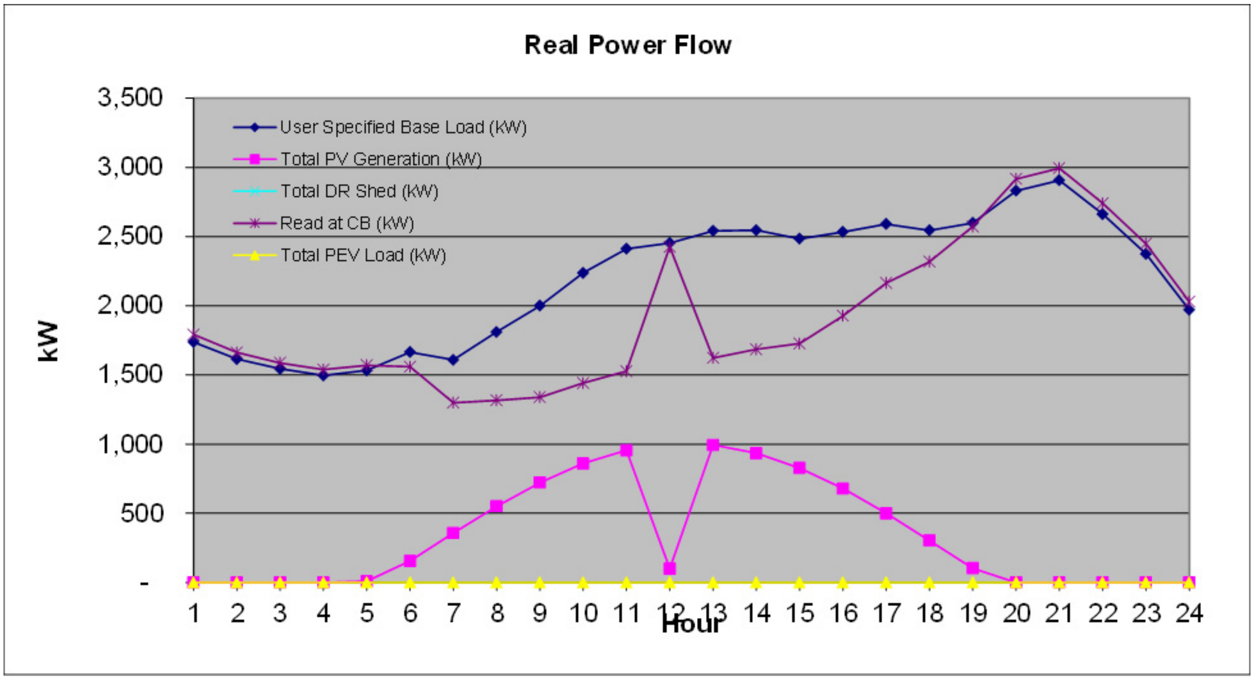


Figure C2: Real Power Flow on Aruba 12kV with Guided LER

11.1 4kV Urban Feeder

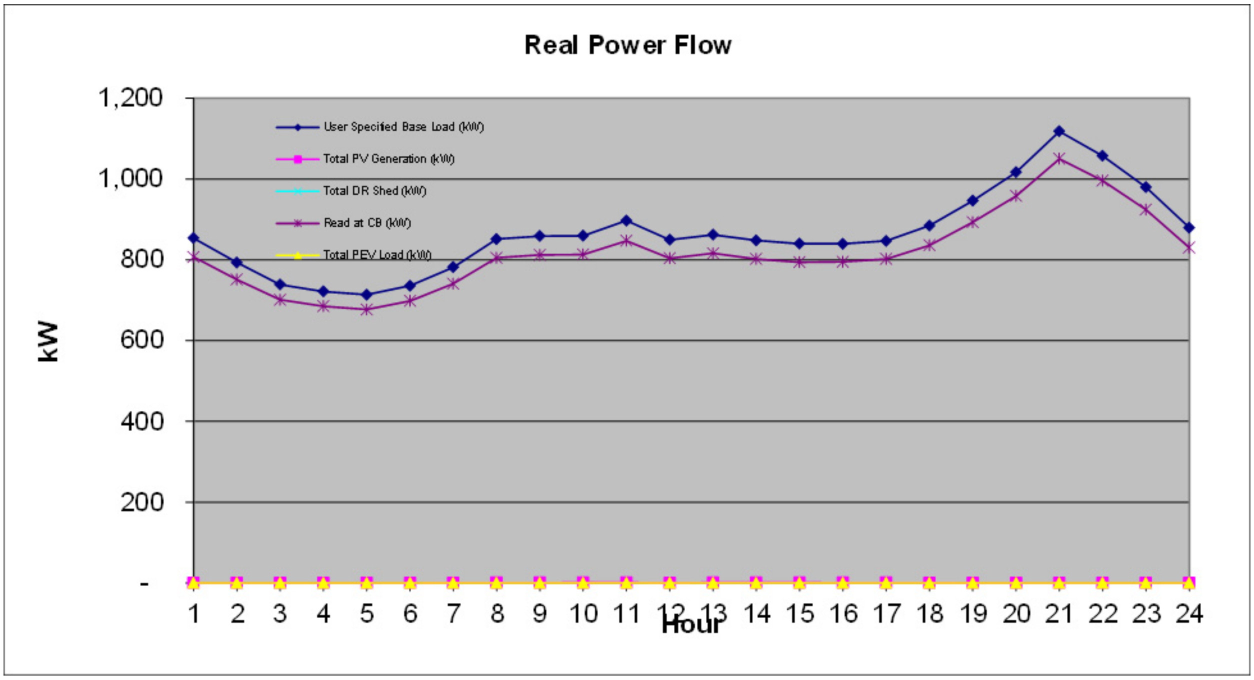


Figure C3: Real Power Flow on Hill 4kV Feeder with no LER

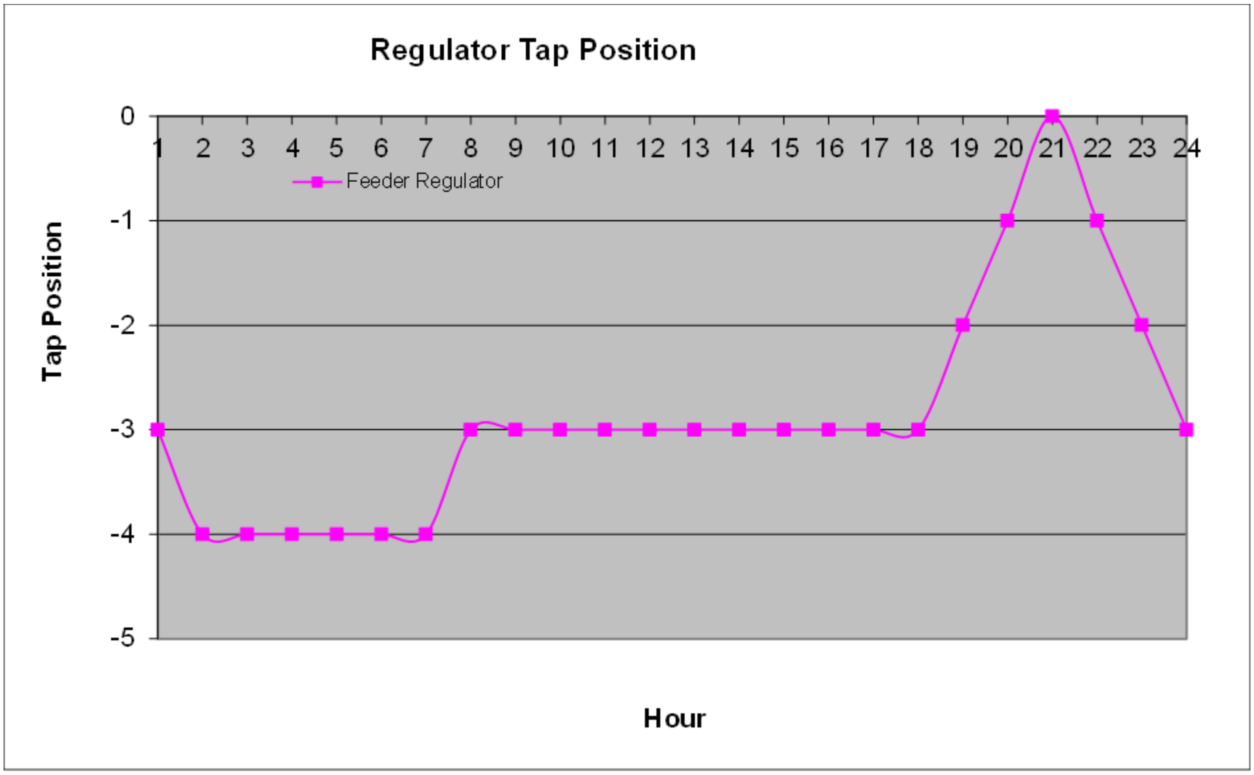


Figure C4: Voltage Regulator Tap Position on Hill 4kV with no LER

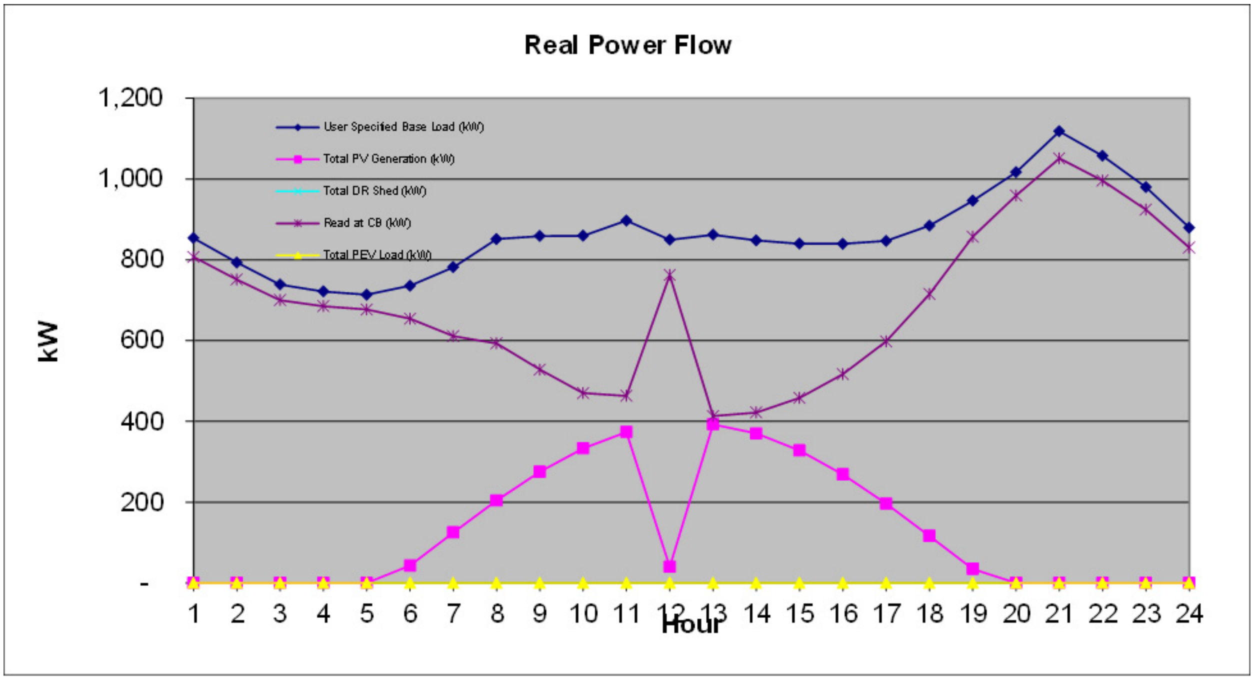


Figure C5: Real Power Flow on Hill 4kV with Unguided LER

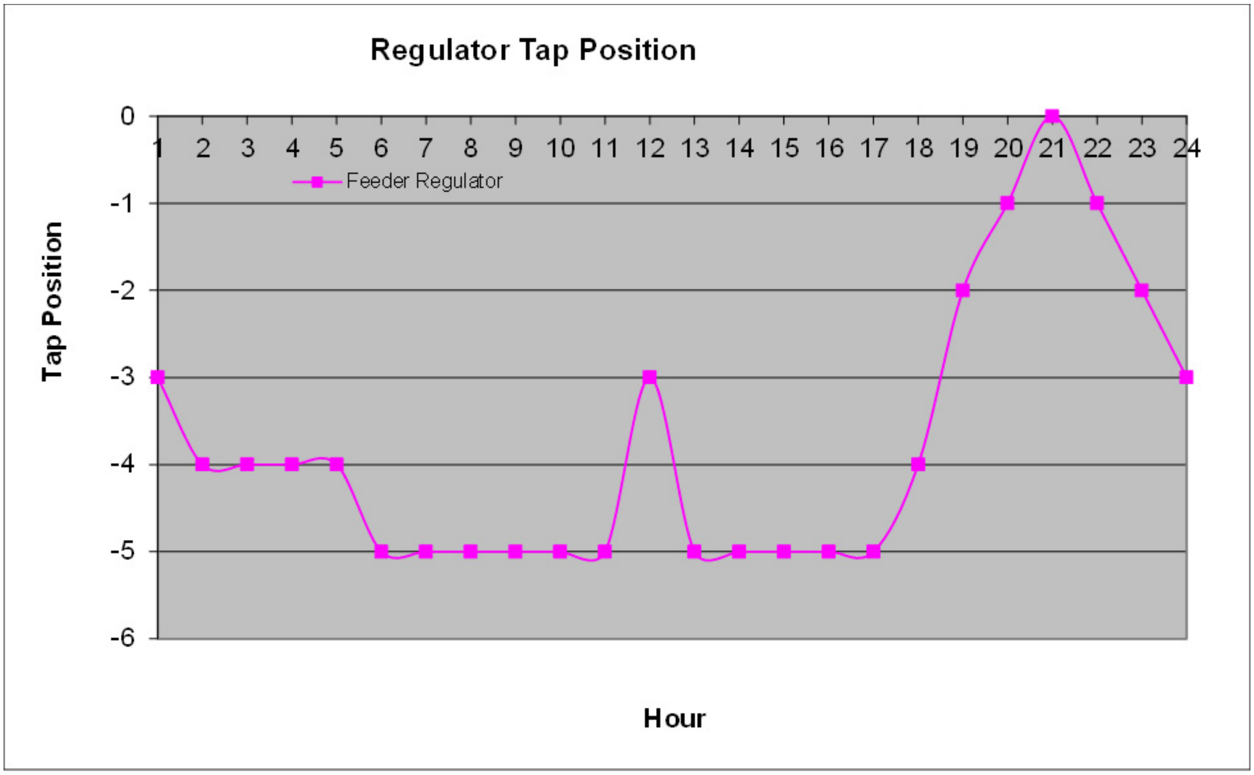


Figure C6: Voltage Regulator Tap Position on Hill 4kV with Unguided LER

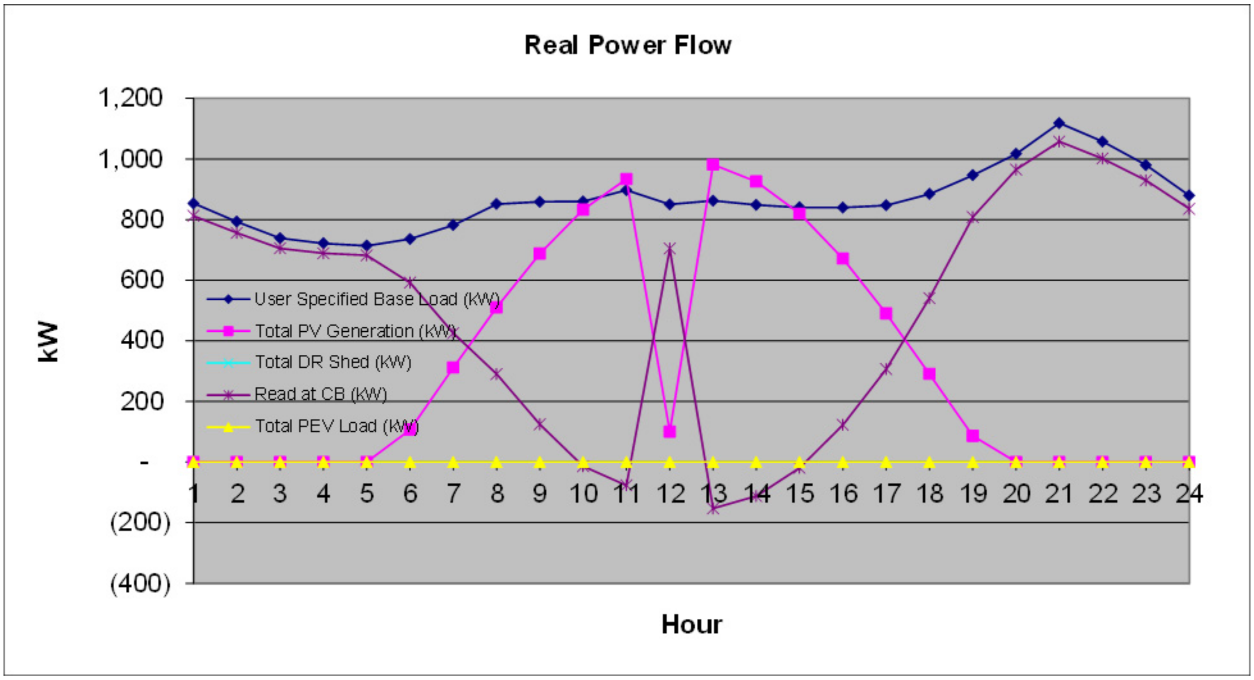


Figure C7: Real Power Flow on Hill 4kV with Guided LER

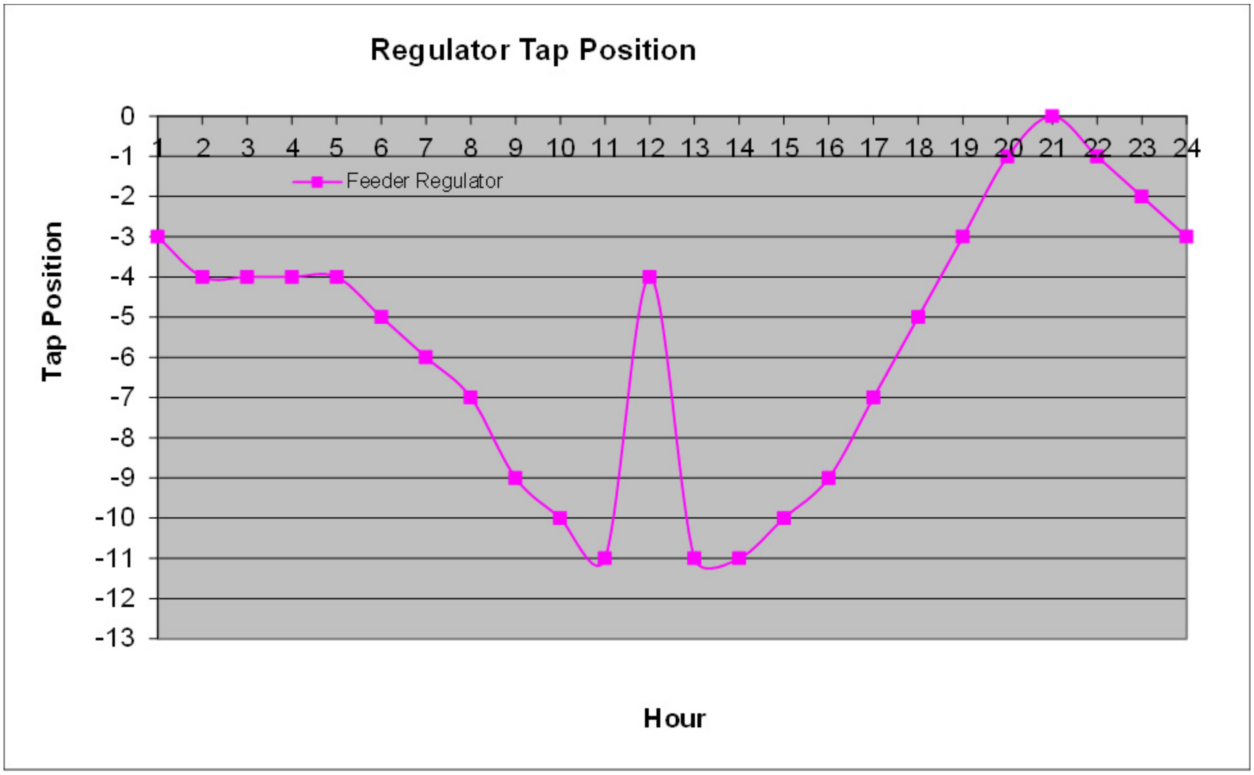


Figure C8: Voltage Regulator Tap Position on Hill 4kV with Guided LER

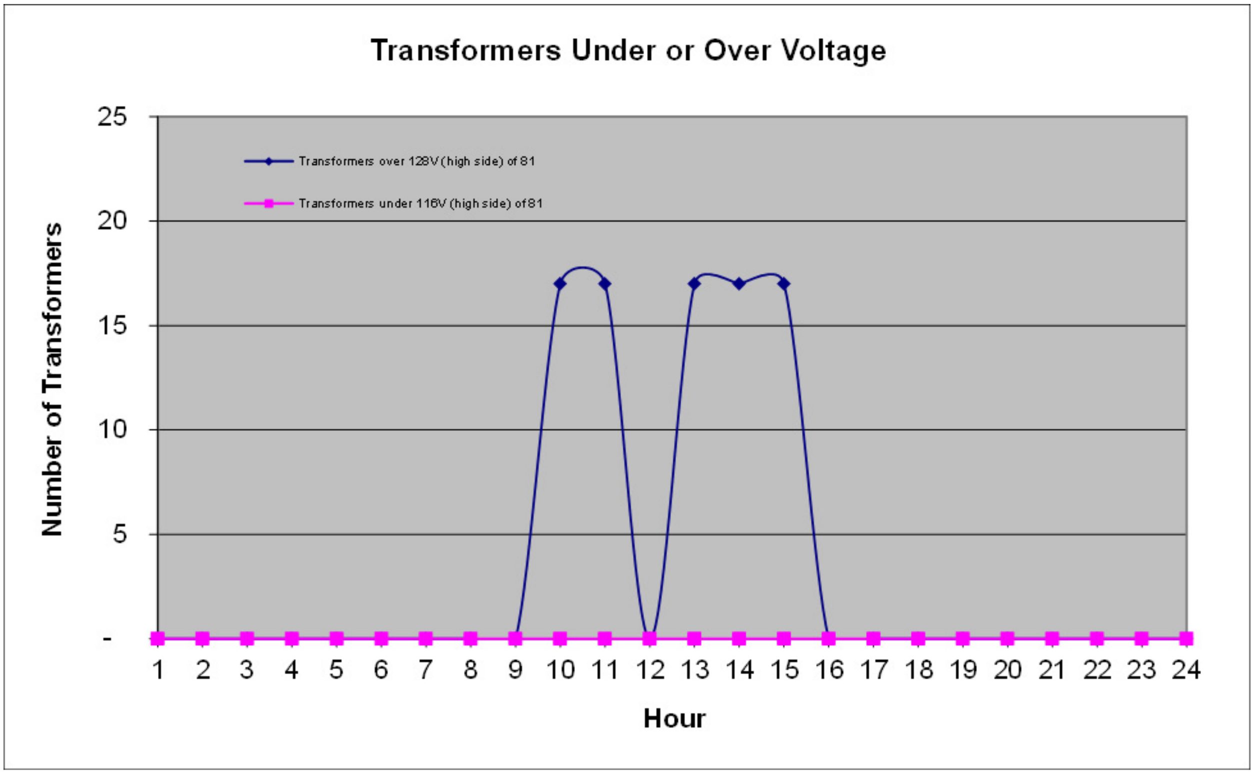


Figure C9: Residential Transformers Overvoltage on Hill 4kV Feeder with Guided LER if the Voltage Regulator Cannot Move as Fast as Weather Patterns

11.2 First 12kV Rural Feeder

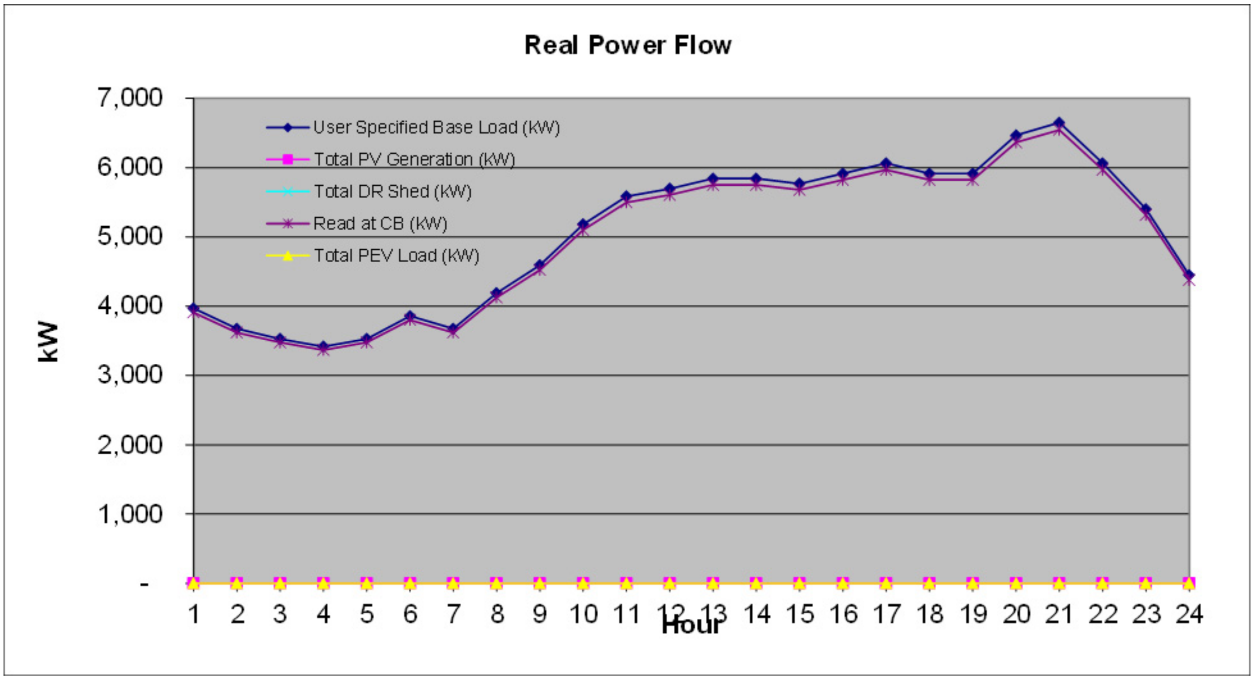


Figure C10: Real Power Flow on the Bank Feeding Smoketree 12kV Feeder with no LER

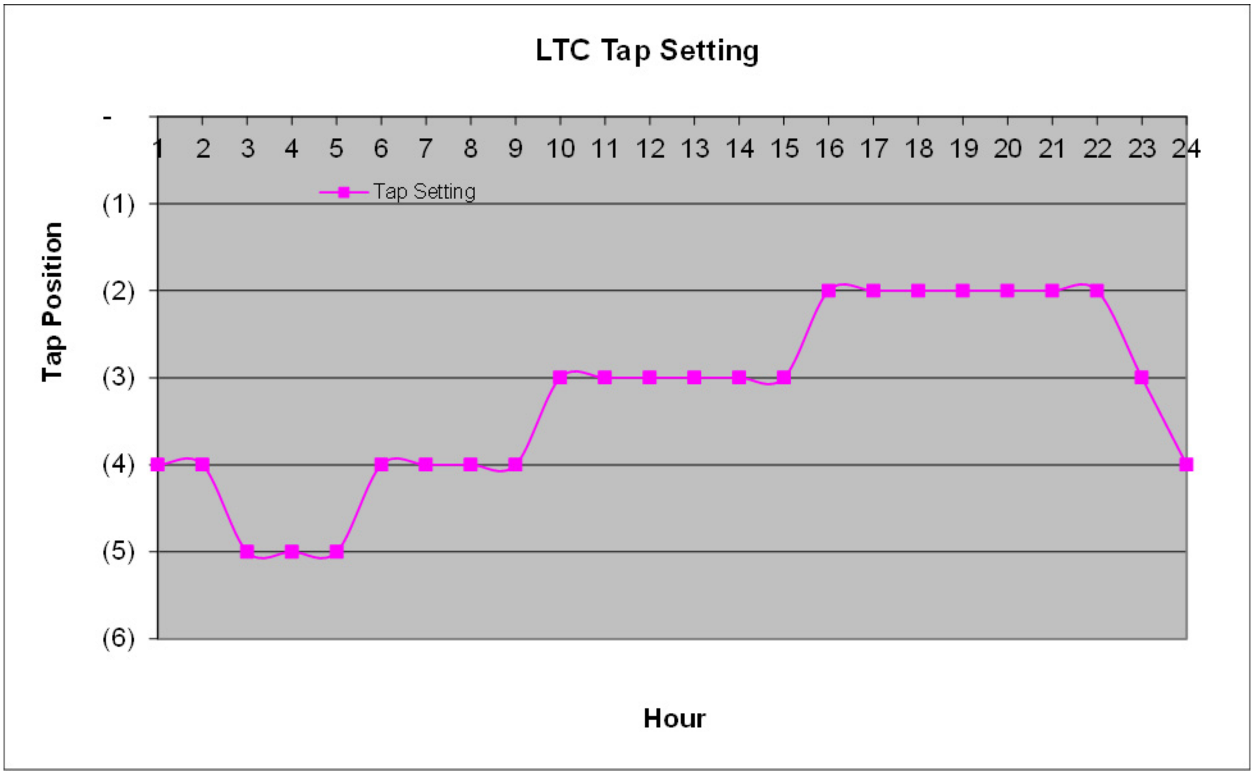


Figure C11: LTC Tap Position on the Bank Feeding Smoketree 12kV Feeder with no LER

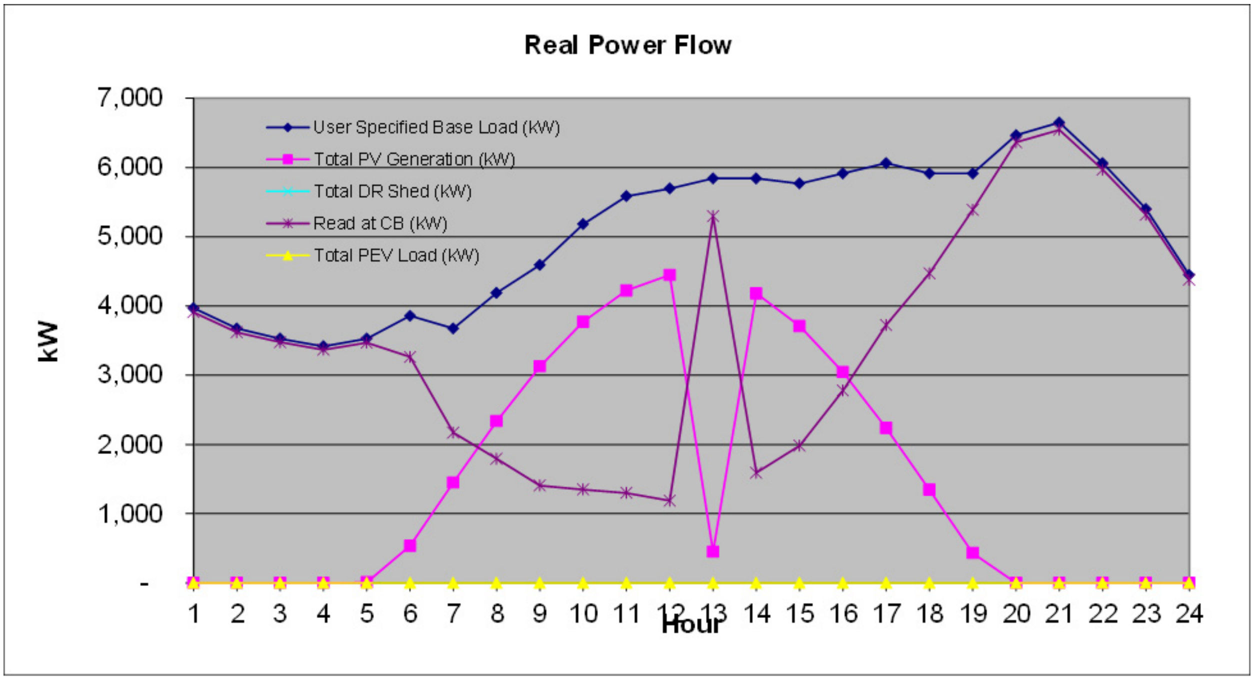


Figure C12: Real Power Flow on the Bank Feeding Smoketree 12kV Feeder with Guided LER

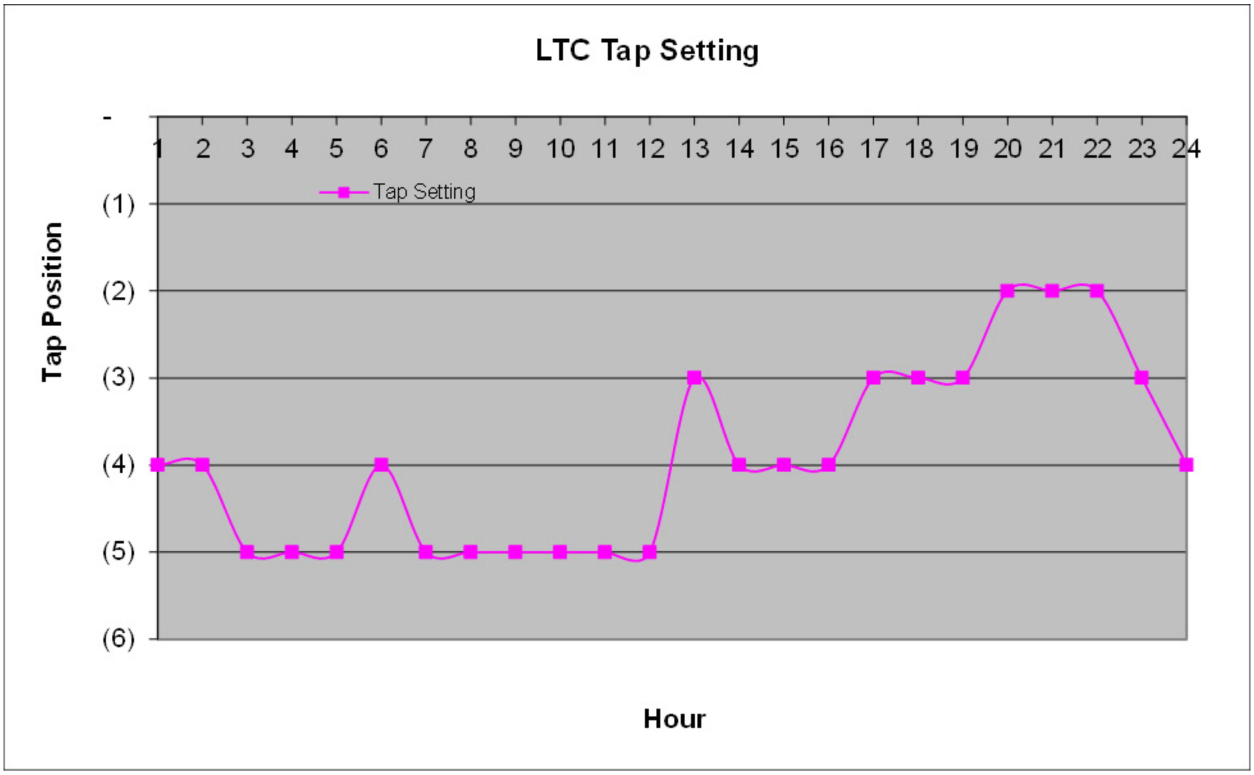


Figure C13: LTC Tap Position on the Bank Feeding Smoketree 12kV Feeder with Guided LER

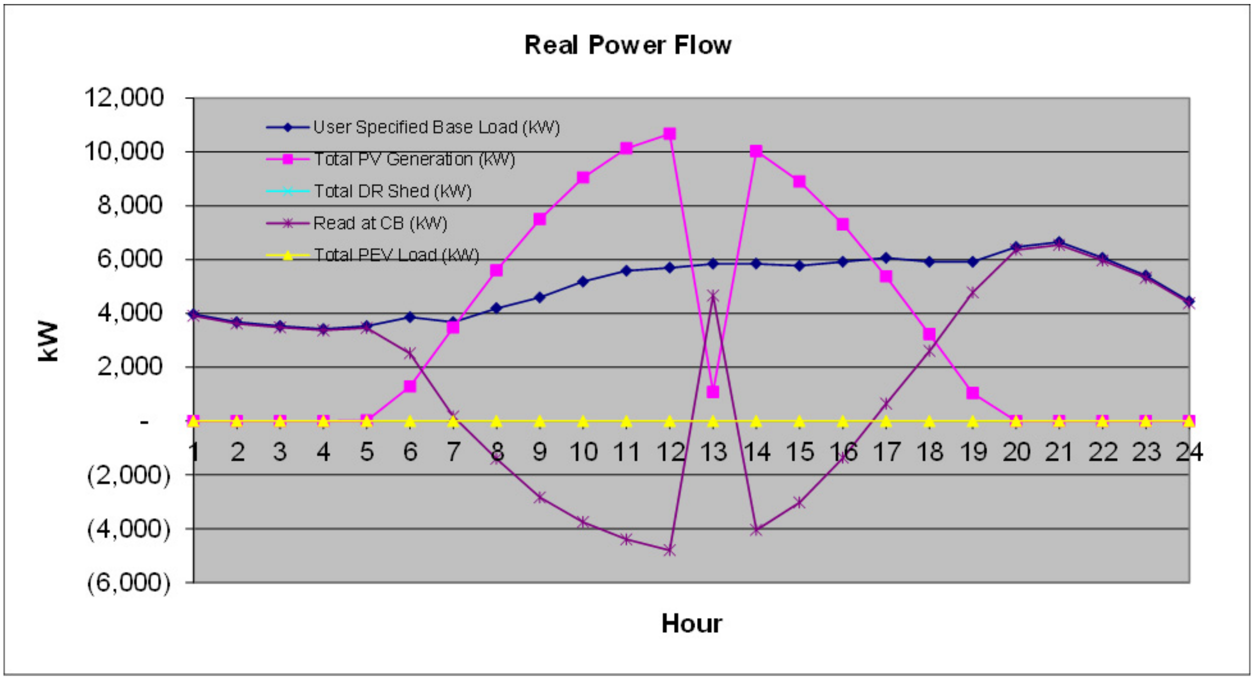


Figure C14: Real Power Flow on the Bank Feeding Smoketree 12kV Feeder with Unguided LER

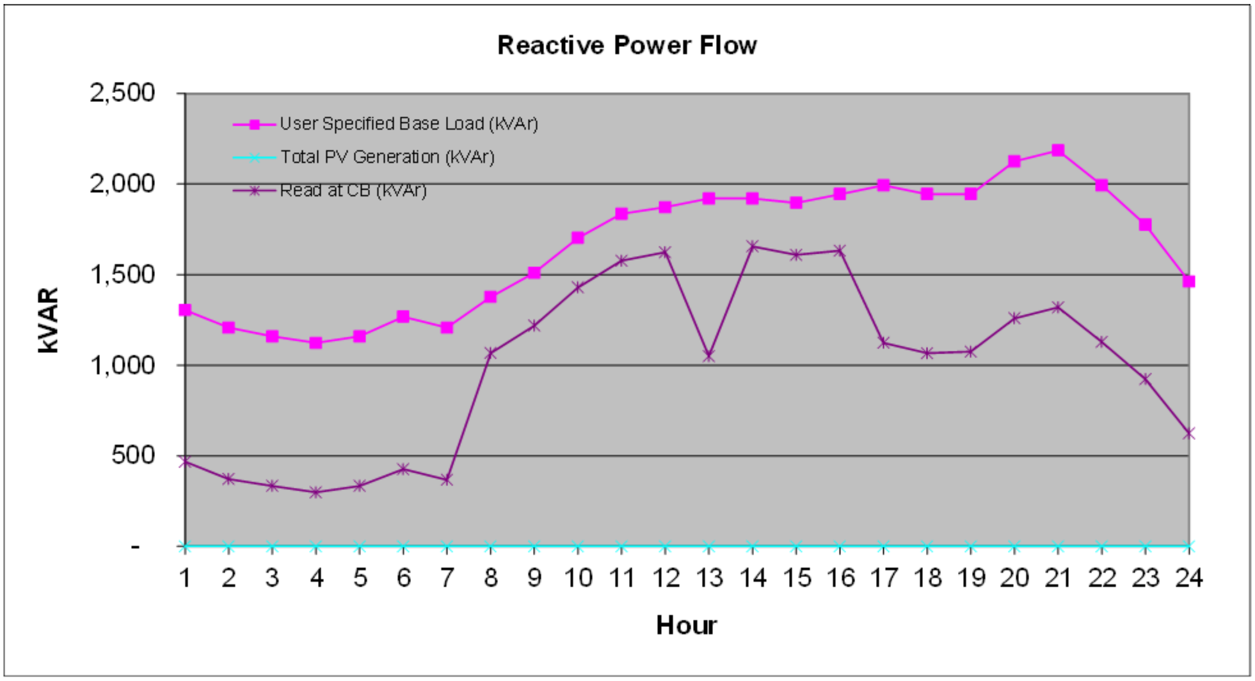


Figure C15: Reactive Power Flow on the Bank Feeding Smoketree 12kV Feeder with Guided LER

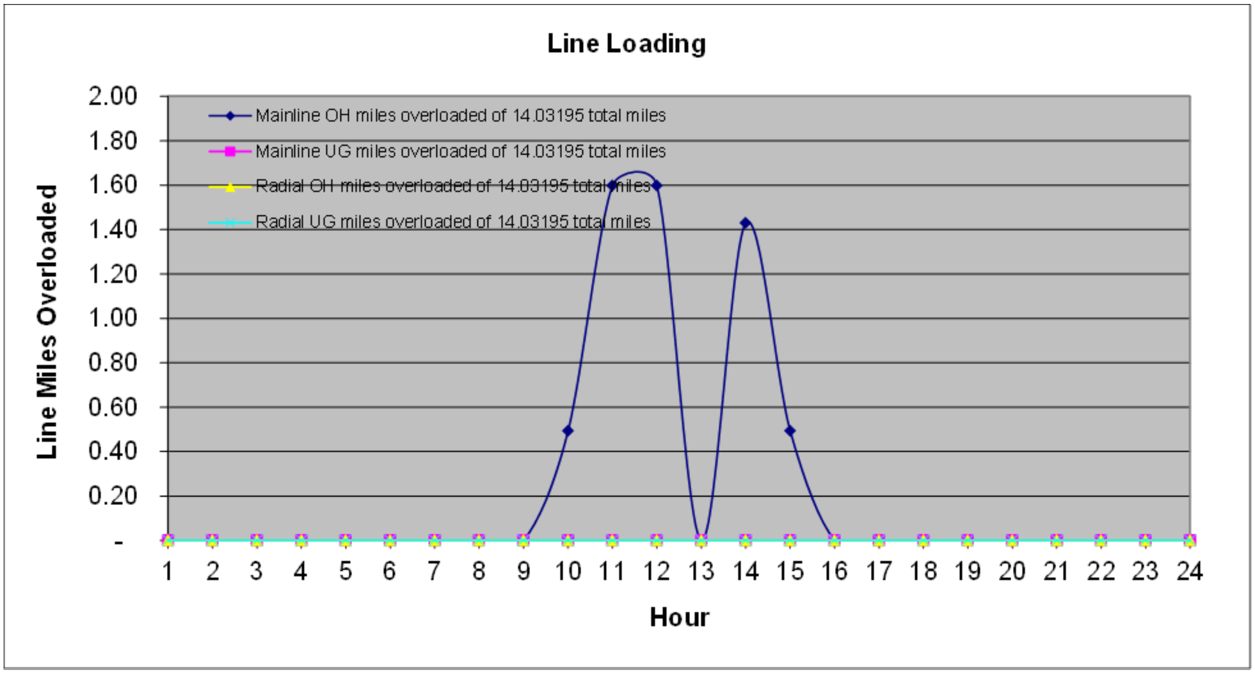


Figure C16: Line Miles Overloaded on the Smoketree 12kV Feeder with Unguided LER

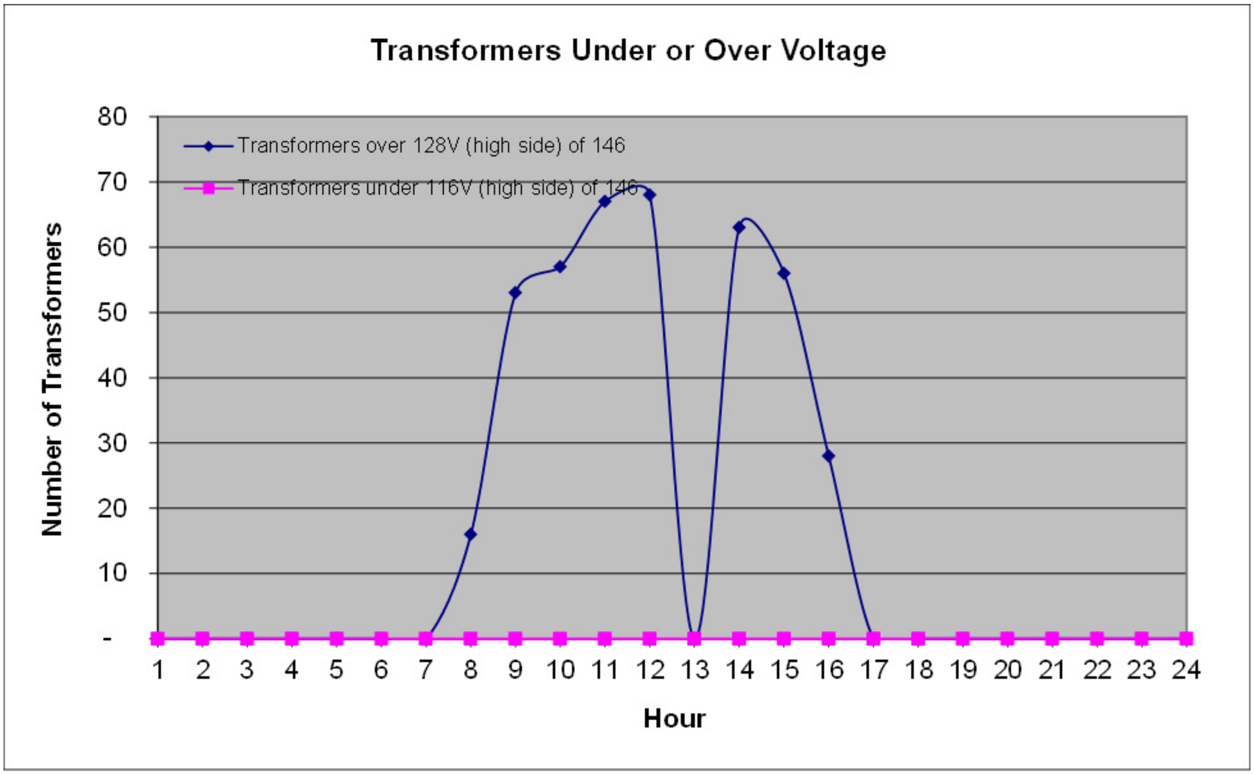


Figure C17: Customers Overvoltage on Smoketree 12kV Feeder with Unguided LER

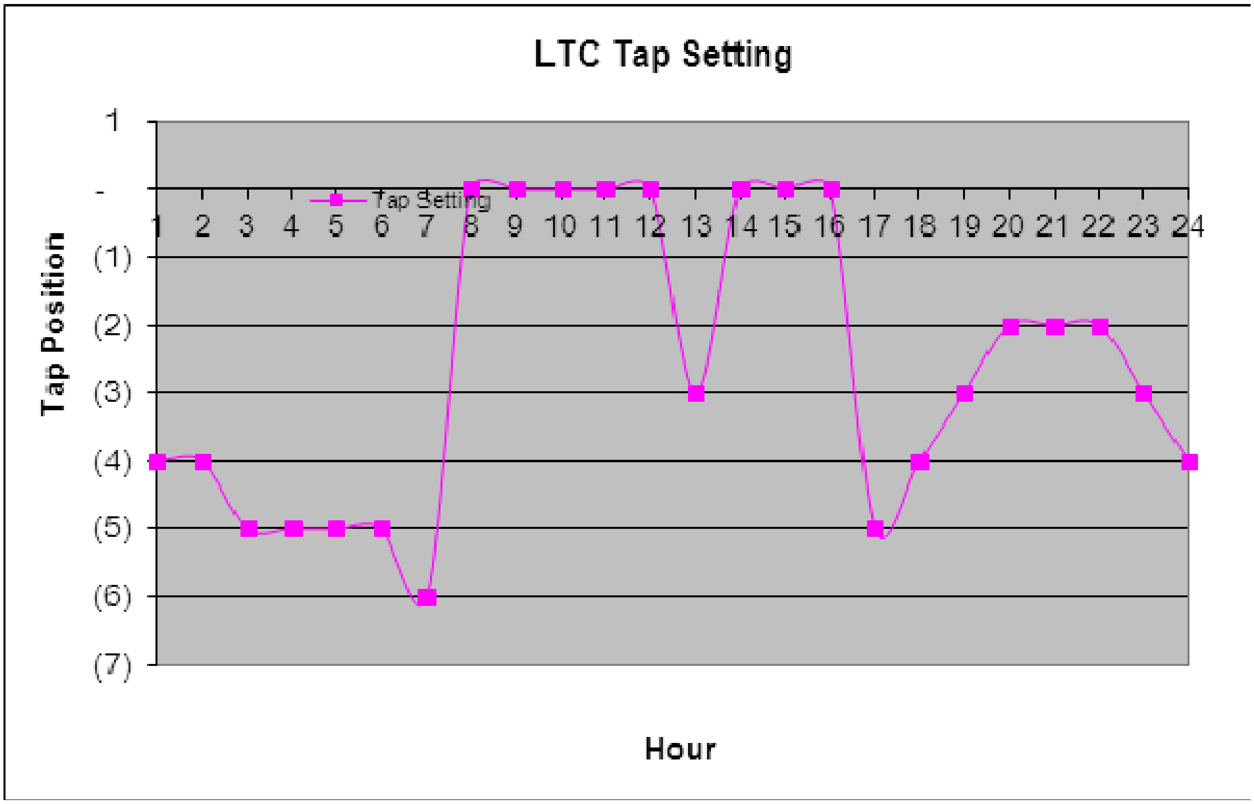


Figure C18: LTC Tap Position on the Bank Feeding Smoketree 12kV Feeder with Unguided LER

10.3 Second 12kV Rural Feeder

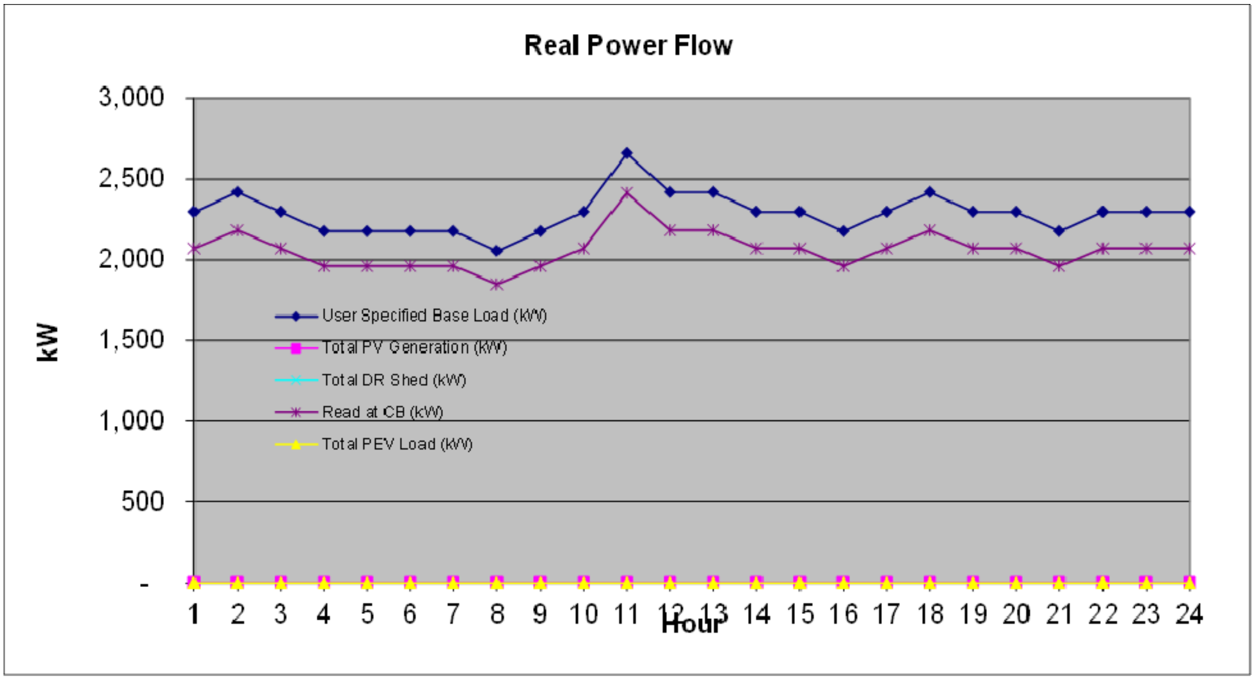


Figure C19: Real Power Flow on the Windt 12kV with no LER

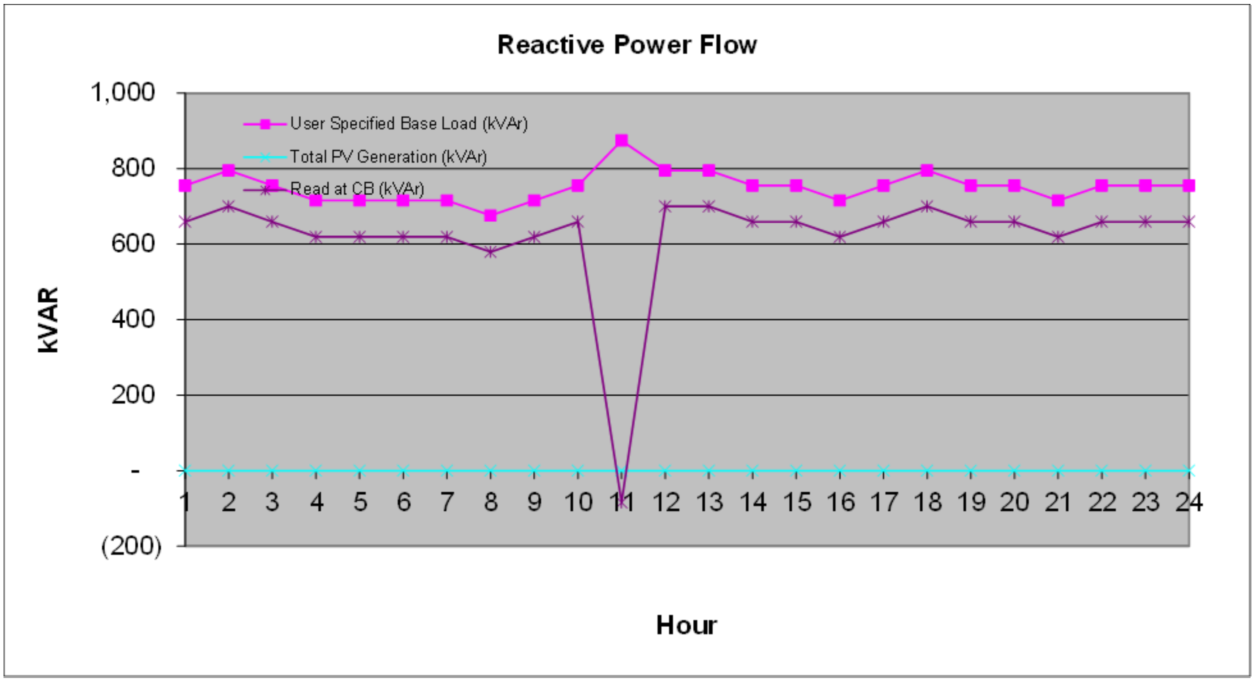


Figure C20: Reactive Power Flow Windt 12kV with no LER

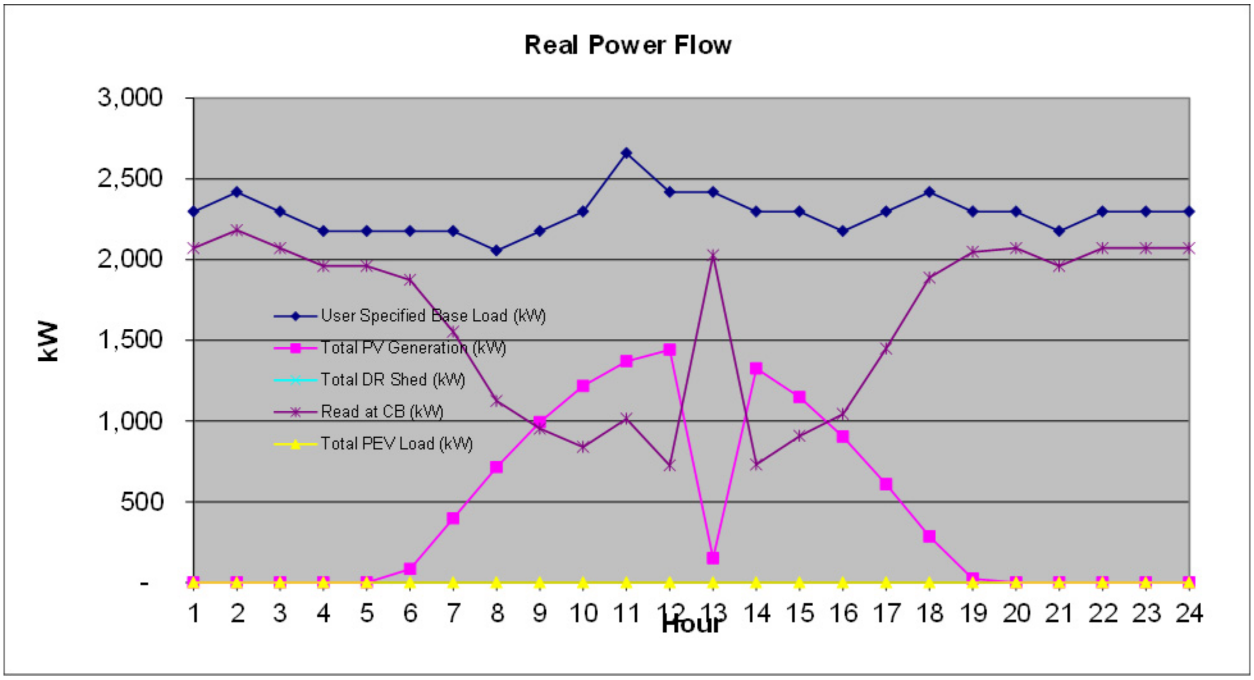


Figure C21: Real Power Flow on Windt 12kV with Guided LER

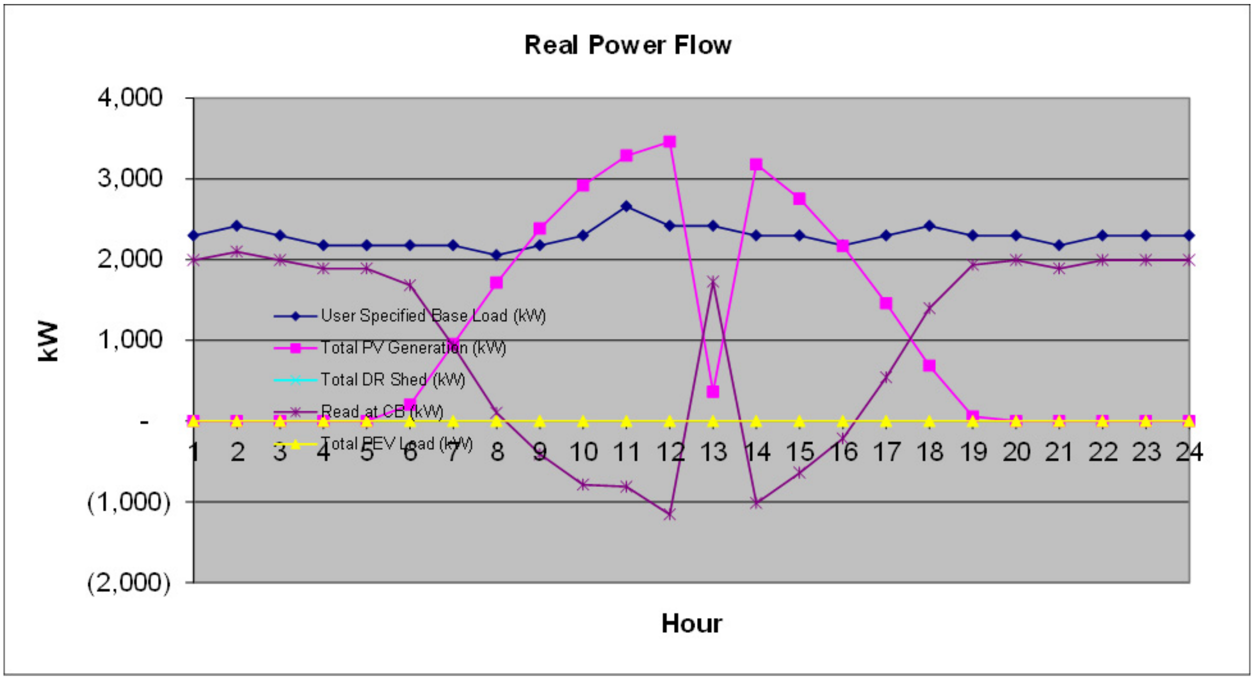


Figure C22: Real Power Flow Windt 12kV with Unguided LER

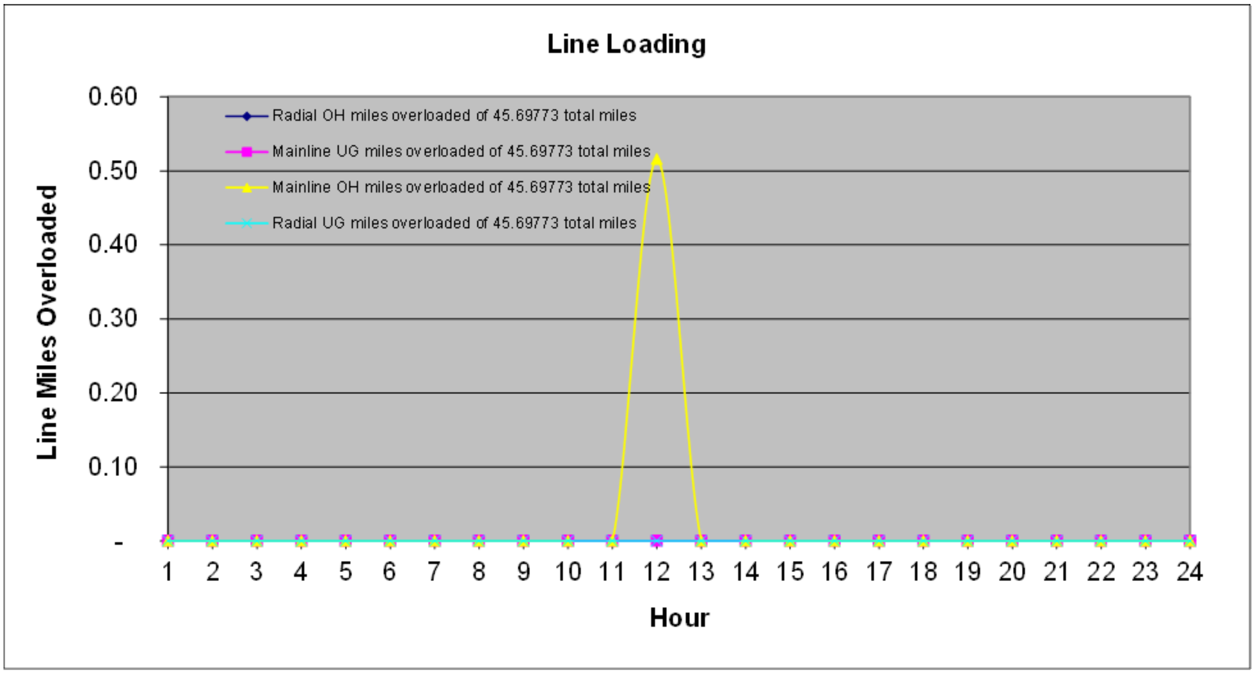


Figure C23: Line Miles Overloaded on Windt 12kV with Unguided LER

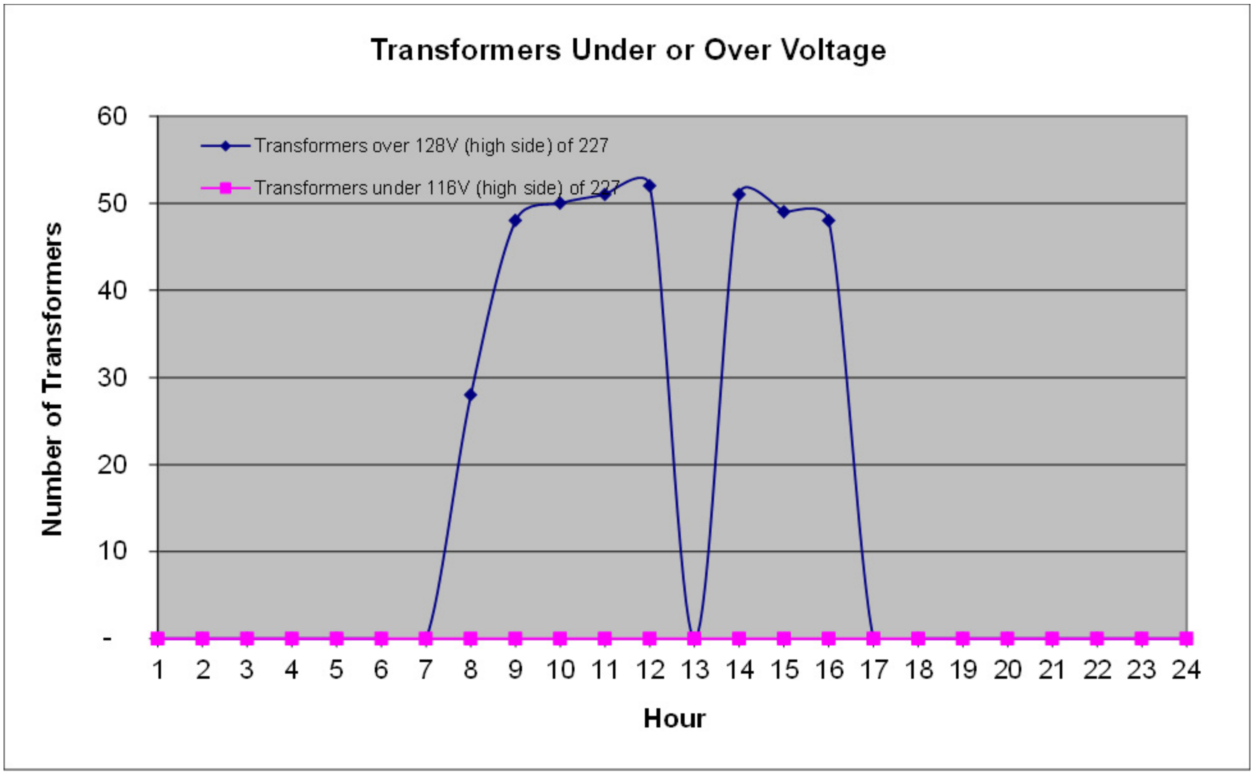


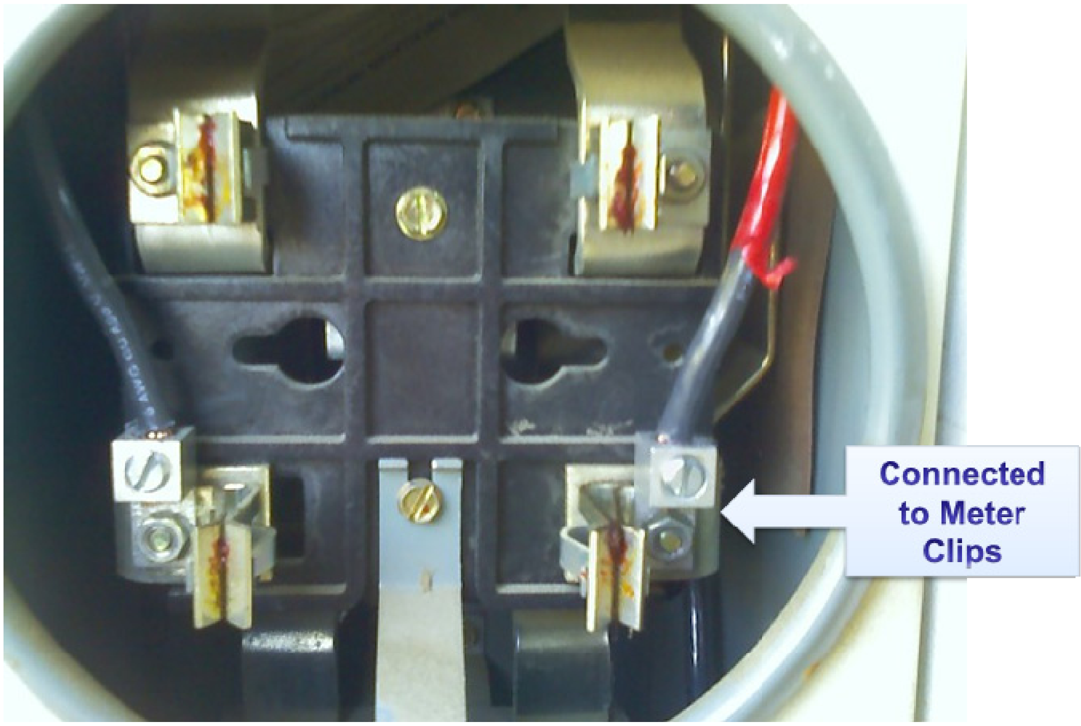
Figure C24: Customers Overvoltage on Windt 12kV with Unguided LER

12. Appendix D: Safety Assessment of Local Net Energy Metering Installations

SCE's process of interconnecting Net Energy Metering (NEM) customers includes a review of diagrams describing the connection points to the utility system and selective spot checks to ensure compliance with SCE's electrical service requirements. These requirements are intended to ensure that services are designed for safe and reliable installations for SCE's customers and utility personnel. While SCE continually attempts to improve processes to accommodate higher volumes of NEM installations, SCE has also worked to educate contractors and municipal jurisdictions over violations of electrical service requirements and potential violations of the National Electric Code. While it is difficult to assign an actual cost to these safety concerns, violations of the aforementioned requirements can result in the following (but not limited to):

- Reduced productivity due to multiple inspections of a single facility.
- Reduced operational flexibility due to improper system design / construction, etc.
- Possible system damage and / or injury of SCE customers or utility personnel due to improper NEM system design / construction, etc.

The following photos represent typical violations within SCE's service territory.



While these findings do not impact the cost to SCE, they do represent potential costs and liabilities to SCE's customers.

13. Appendix E: Potential Opportunities to Mitigate LER Impacts

13.1 Potential Smart Grid Applications

Integration of intermittent distributed generation has been widely viewed as one of the goals of the smart grid. Some smart grid technologies, such as remote control of field devices, are currently deployed. However, more advanced smart grid technologies such as advanced volt / VAR controllers are still in the initial pilot project stages and other technologies, such as distributed energy storage systems, are still several years away. Smart grid technologies are one potential option for integrating distributed intermittent generation. A power grid with high levels of LER penetration will most likely leverage elements from traditional grid and smart grid for safe, reliable, and economic operation.

Another way to mitigate the impacts of LER on the system is to change interconnection standards to allow inverter-based generation to inject or absorb reactive power. Today, interconnection standards in California require inverter-based generation to operate at unity power factor (in other words, only watts can be injected into the system). However, if an inverter-based generator could inject or absorb reactive power, the inverter could be used to regulate the voltage on the distribution feeder. The potential benefit could result in less need for conventional voltage regulating equipment, such as voltage regulators and shunt capacitor banks, capacitor bank switching operations, and tap changer operations, which may result in lower maintenance costs. Several utilities and research entities are running pilot projects of this technology with positive preliminary results.

Energy storage solutions can be used to shift the generation output from a time of low demand to a time of high demand, as a result energy storage can be used to mitigate midday overloads due to PV generation and provide additional feeder demand capacity. For example, the overloads in the study were generally between the hours of 10 a.m. and 3 p.m., and the peak demand typically occurred after 6 p.m. If an energy storage system could be used to store the energy during peak PV generation hours and discharge the energy over peak demand hours, some of the overloads could be mitigated. Currently the high cost of distribution feeder storage is a barrier to adoption of the technology.

13.2 Reliability and Variable Resources

Annually, the utility invests in the capital expansion of their system to ensure adequate capacity and accommodate future growth. A portion of added load may be offset by the installation of LER depending on the amount of LER penetration as well as the dependability of output. Dependability of generation is the degree to which LER output can be relied upon during the time of peak load on the utility's distribution system. Dependable generation refers to the amount of MW output that can reliably be counted towards offsetting the need for additional capacity on the distribution system.

Variability in LER can be represented by examining measured output of PV generation during the time of system peak. Under clear weather conditions, the output of the PV is relatively smooth and influenced by solar intensity. However, cloud cover creates variability in solar intensity as represented by the following figure:

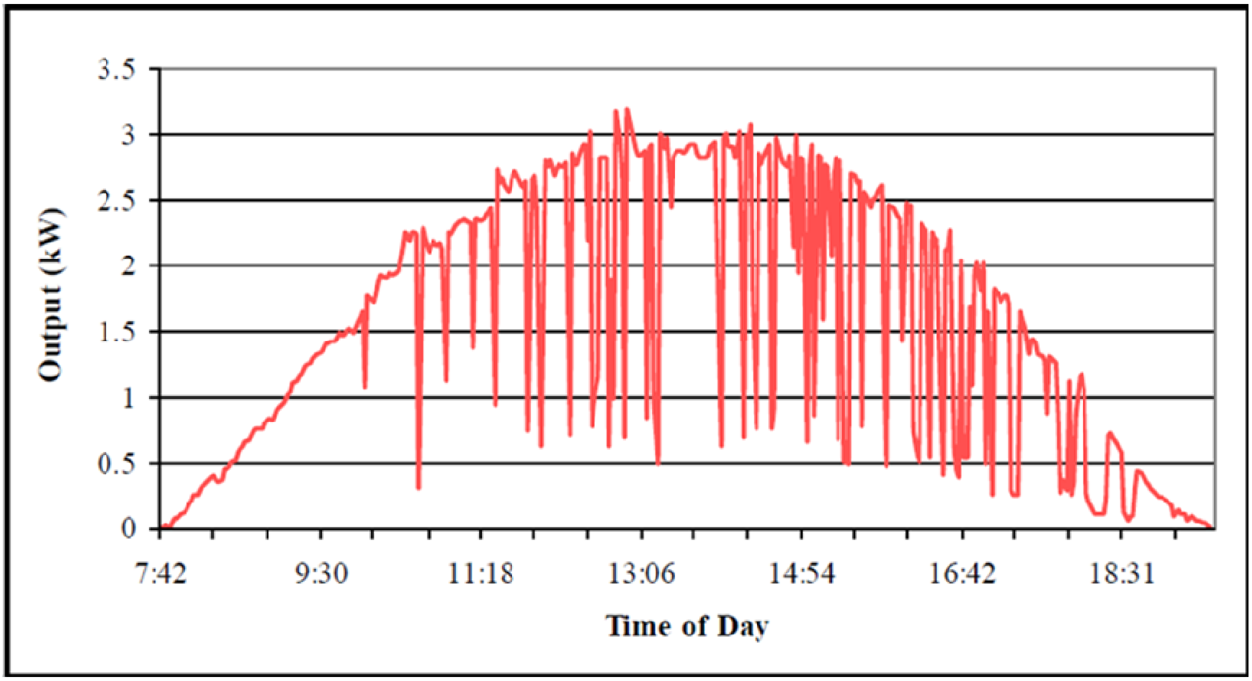


Figure E1: Variable Solar Generation (source: CPUC California Solar Initiative 2009 Impact Evaluation)

The output is measured in kilowatts (kW) and represents the amount of demand that can be offset on the utility system. Variability occurs with variable solar intensity as a result of clouds passing over the solar arrays. Cloud cover is common during peak humid days, conditions that resulted in record peak utility demand days. Dependable generation amounts under this condition can be represented by examining the lower portion of the Figure E2.

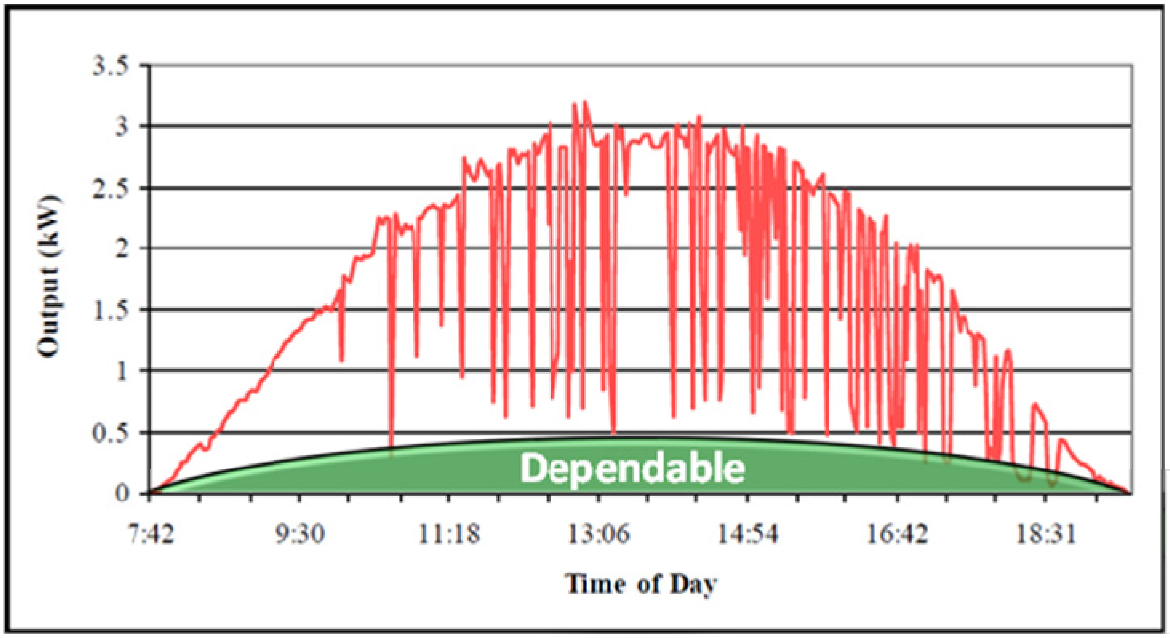


Figure E2: Dependable Solar Generation (source: CPUC California Solar Initiative 2009 Impact Evaluation)

The area in green represents the amount of dependable generation that could potentially be relied upon to offset utility demand, approximately 15% of the PV output.

PV output that could be used to offset utility demand is also influenced by the time of the utility system peak. Utility peaks on the distribution system vary depending on the type of customers being served on a utility feeder. Feeders can be comprised of industrial / commercial and residential customers. Industrial zones typically contain less residential customers while suburban neighborhood distribution systems are dominated by residential load. How the peak output of a PV array compares to the peak demand of each customer type is depicted as follows:

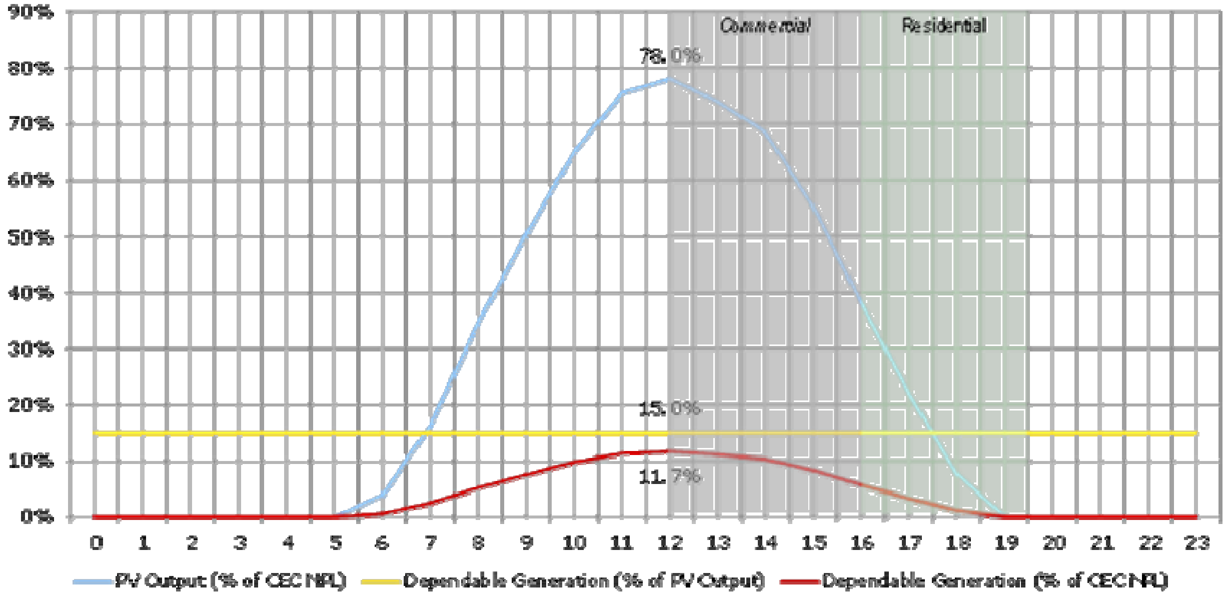


Figure E3: PV Array Peak Output vs. Customer Peak Demand (source: CPUC California Solar Initiative 2009 Impact Evaluation)

Commercial demand typically peaks earlier in the afternoon, while residential peak occurs later towards the evening. The offset of commercial load for the relative PV size ranges from 40 – 78%, while residential PV offsets 0 – 40% of its output.

Maximum output is also limited by the overall efficiency of the inverter. For a typical 4,000 watt inverter (4 kW), a typical maximum output according to this curve would be 3,120 watts. This same inverter would be able to offset between 1,600 – 3,120 watts under clear weather conditions. For residential loads, the same inverter would offset between 0 – 1,600W. Overall, between the efficiency of the inverter and the potential for cloud cover, the amount of dependable inverter generation would range between 0 – 11.7%, or between 0 – 468 watts.

While PV LER does not provide significant benefits to offset customer demand, there is some benefit towards reducing energy consumption, or the amount of energy consumed over time. The challenge presented to the utility is balancing the amount of LER penetration without encountering significant impacts on the distribution system, while maintaining some benefit for energy savings. However, current data suggests little to no benefit towards reducing utility capital investment, expenditures related to load growth expansion, or infrastructure replacement of aging facilities. LER technology outside of PV would be best leveraged for use in offsetting peak demand by providing a less intermittent mix of generation type.

13.3 Other Technologies

Fuel Cells: Fuel cells are another possibility technology for LER. Like PV generation, a fuel cell produces DC power and requires an inverter to convert the power to AC and to interconnect to the distribution system. However, unlike PV generation, fuel cells developed for stationary power applications provide a constant power output. Consequently, fuel cell technology is a good choice for providing power for base load demand. There are several pilot deployments of LER using fuel cells in California, but large scale production is still on the horizon.

Combined Heat and Power (CHP / Co-generation): LER facilities using thermal generation, such as natural gas combined cycle plant, can use the waste heat from the generator for water heating or building heating. Typical CHP applications are found in hospitals, universities and large industrial plants where energy demand is in hundreds of kW to several MW. There is a potential for micro and mini CHP facilities in the kW to hundreds of kW range, but the technology is not widely adopted in California (to the author's knowledge).