PV System Impact Guide
Foreword

This Photovoltaic (PV) System Impact Guide is part of a series of National Rural Electric Cooperative Association (NRECA) guides including “Cooperative Utility PV Field Manual,” “Project Manager’s PV Quick Start Guide,” and “The Community Solar Playbook.” Both the “Project Manager’s PV Quick Start Guide” and “The Community Solar Playbook” are resources made available to electric cooperatives to aid in the exploration and deployment of utility-owned PV installations. They are part of the Solar Utility Network Deployment Acceleration (SUNDA) project, which is a four-year, multi-state, 23 MW solar installation research project with collaboration from various entities including American electric cooperatives, the National Rural Utilities Cooperative Finance Corporation, Federated Rural Electric Insurance Exchange, PowerSecure Solar, and NRECA.

This guide is designed to equip an electric cooperative member with techniques and a process for evaluating the technical system impacts of interconnecting solar to the electric power system (EPS), from high-level screening techniques to detailed engineering software analysis. Existing NRECA documents and tools that should be considered in technical evaluations are referenced herein. Relevant case studies are included in Appendices A-D to demonstrate actual examples of the application of some of the steps involved in an impact study. In addition, Appendix E includes examples of actual system impact studies completed by Leidos for various co-ops across the nation.
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Introduction

The purpose of this guide is to provide detailed instructions on how to perform PV impact studies for NRECA electric cooperative members. The increasing penetration of DER, including solar PV, on the traditional electric grid has the potential to cause adverse system impacts that may compromise system safety or reliability. Cooperatives must ensure safe and reliable operation of their systems with DER interconnections, which can be achieved by developing and following DER interconnection procedures and standards.

A system impact study identifies the electric system impacts that would result from interconnection and also recommends system upgrades deemed necessary for interconnection of the project. System impact studies can be time consuming. The complexity of the study really depends on the type and size of DER, and on the point of interconnection in the system. For this guide, the focus is on solar PV, and on utility owned solar PV more specifically, with general references to any type of ownership. It is important to note that not all PV interconnections require a detailed impact study. A typical screening process (see Figure 5) can be employed to determine whether a particular interconnection requires a detailed system impact study.

A main focus of the NRECA SUNDA project is to help cooperatives interested in solar PV acquire and operate solar PV and provide tools, standards, and training materials. This assistance helps reduce some of the barriers that make it difficult to get started and reach the finish line: a successfully integrated solar PV site. As mentioned in the foreword, this guide is part of a series of NRECA-published guides related to utility-owned solar PV (shown in Figure 1). Each guide includes fundamental elements to enable electric cooperative stakeholders (including executive management, accounting, and engineering personnel) to interconnect utility-scale PV safely, efficiently, and cost-effectively.

This guide includes the following:

An overview of the typical stages of the PV interconnection process: utility interconnection requirements, application, review, impact study, construction, testing and verification, and permission to operate.
Step-by-step instructions for cooperatives to perform the various engineering analyses typically performed as part of a system impact study

Table templates to store and analyze the study results

References to typical standards and guidelines that govern PV interconnection

Technical case studies illustrating the application of impact study methods for cooperative engineers to follow as needed
The PV Interconnection Process

The utility PV interconnection process consists of a variety of policies and requirements that govern interconnection of PV within a utility’s electric grid. While timelines and specific steps vary from utility to utility, the process, as shown in Figure 2, typically includes stages such as application, review, impact study, construction, testing and verification, and permission to operate. These components are included in a utility interconnection requirements document.

The interconnection process varies based on the PV size; for example, an interconnection of small size, inverter-based, PV less than 300 kW might not require a detailed system impact study. This guide focuses on the utility-owned PV interconnection process. The information provided in this section applies themes and strategies from the NRECA’s reports on the PV interconnection processes.

Figure 2: Lifecycle of DER Interconnection Process

Utility Interconnection Requirements

A utility interconnection requirements document includes the PV interconnection process from application to permission to operate, as well as design, operating, and equipment requirements.

To ensure fair and consistent practices, utility-owned solar generation facilities should meet the same design and equipment requirements as a third-party-owned facility. The requirements should be known up front and used to approve a generation site design concept and the allowable equipment. Requirements are generally inclusive of all of the possible types of customer or utility owned generation that could interconnect, such as rotating or intermittent. The utility interconnection requirements document typically includes considerations and requirements such as:

- Equipment certifications
- Metering
- Communications
- Access and right of way
- Permits and zoning
- Relaying, protection, and disconnects
- Insurance
- Witness testing and commissioning
- Drawings and diagrams of the project design
- Operation of the generation facility
Timelines of inspections and maintenance of the facility
Allowable interconnection voltages
Winding configurations of site transformers
Ramifications of causing adverse or unsafe conditions on the utility system
Allowable criteria on the utility system for voltage, power factor, harmonics, short circuit, islanding, etc

In some cases, utility interconnection requirements include levels of requirements based on the size and type of generation that is interconnecting. There is also an option to have a different document for each class of size.

The NRECA Distributed Generation (DG) Toolkit includes helpful documentation around utility interconnection requirements. It’s available to NRECA cooperative utility members and includes documents and templates to provide guidance on rules, policies, tariffs, contracts, and rates related to DG. The included “Business and Contract Guide for Distributed Generation Interconnection” has a list of certifications and codes that should be included as part of an interconnection requirements document including IEEE 1547, Underwriters Laboratories (UL) 1741, and National Fire Protection Association (NFPA). Applicable industry standards and guidelines are listed at the end of this guide.

**PV Interconnection Process Stages**

**Application**
While the application process is typically more aligned to help outside customers apply for interconnection of solar to the utility system, it’s still an important step to present and can be applicable to utility owned solar generation as the data gathered would be required regardless of ownership. In addition, in some utilities the application process may still be required for utility owned solar to determine queue position for other interconnection requests that might be in process.

The application stage includes a series of suggested steps that prospective PV owners/operators take if they want to operate in parallel with the distribution utility. The application process starts as soon as a potential customer or utility submits an application package and generally requires a fee for non-utility customers. The initial application contains information such as location, technical, and design parameters along with operational and maintenance procedures. In the case of utility-owned projects, depending on the specific rules set by the utility, the formal application process may or may not be required.

The utility approves the application after determining that the application package includes all data required per the set requirements. If the application package is missing any required information, the utility will request the missing information from the customer. Once the application is approved, the accepted application is placed in utility's interconnection inventory, also called the interconnection queue.

A pre-application report (PAR) is included in the amended Small Generator Interconnection Procedures (SGIP)\(^1\) that allows customers to request readily available information, for a fee, on a specific point of

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\(^1\) Federal Energy Regulatory Commission (FERC) generator interconnection procedures
common coupling (PCC) in advance of the official application. SGIP is a Federal Energy Regulatory Commission (FERC document with agreements and procedures for generating facilities less than 20 MW interconnecting to a distribution system. The intent of the PAR is to allow potential applicants to determine which locations on the utility system may most readily accommodate a proposed PV interconnection without the utility having to complete additional studies or analysis.

While there are multiple sources of application materials available in the industry, including SGIP, the NRECA DG toolkit combines and created the following materials to help utilities with the DER application process.

- A PAR template for providing information to a customer requesting information at a specific point of interconnection (POI)
- An application form that must be completed by customers seeking permission to interconnect
- A short form interconnection contract for non-inverter-based DG units of less than 10 kW for installation in a home, residence, business, or farm
- A template interconnection contract for DG units that do not qualify for the short form
- A “10 kW Inverter Process” document, which is a complete set of forms required from an interconnection customer, (from the initial application to the final interconnection agreement) for inverter-based systems of less than 10 kW (e.g., residential solar PV)
- Sample inspection, testing, and commissioning procedures

The application process from NRECA’s “Business and Contract Guide for Distributed Generation Interconnection” document is shown in Figure 3.
Figure 3: Application Process

Review
The review stage generally involves determining scope and nature of the interconnection, reviewing the application package to confirm viability of the documentation, and checking PV equipment certification. The goal of this stage is to determine if a project is eligible for a fact-track interconnection or if it requires a system impact study. The utility determines eligibility of a PV interconnection for a fast-track interconnection process based on the size and type of resource. The amended 2013 SGIP allows DG projects up to 2 MW (or up to 5 MW for inverter-based systems) to qualify for fast-track interconnection,
provided that equipment meets recommended DG interconnection codes and standards. Eligible projects must pass the fast-track screens mentioned below before they are approved for construction. The fast track process from NRECA’s “Business and Contract Guide for Distributed Generation Interconnection” document is shown in Figure 4.

Figure 4: Fast Track Process

If a project fails the fast-track screen where the addition of the DG causes generation on the circuit to exceed 15 percent of the annual peak load, the amended SGIP prescribes a defined supplemental review.
process to determine if a DG interconnection requires a detailed impact study. The supplemental review process is not required if the cooperative is not FERC or state regulated to perform the supplemental review. However, best practice would be to consider it regardless of requirements as long as it fits into existing cooperative policies and procedures.

The supplemental review process includes the following screens.

> Aggregated distributed generation shall not exceed 100 percent of minimum load on line section

> The proposed generation, along with existing generation on the distribution circuit, shall not cause issues with voltage regulation, voltage fluctuations, and harmonic levels
  • This screen can be evaluated using the stiffness factor. Stiffness factor is ratio of the distribution system fault current at the PCC to the aggregate maximum rated output current of the DG system at the selected point of interconnection. This is a measure of the risk of the DG system causing problems with voltage flicker, steady-state voltage regulation or harmonics. Industry preferences suggest a stiffness factor greater than 100 for PV and wind interconnections indicate nearly insignificant problems in regards to voltage flicker, steady-state voltage regulation, or harmonics.

> The proposed generation, along with existing generation on the distribution circuit, shall not cause impacts to safety and reliability
  • The DER interconnection risk to public safety can be evaluated using the guidelines based on the November 2012 Sandia National Lab “Suggested Guidelines for Assessment of DG Unintentional Islanding Risk” report. The risk of islanding (ROI) screening based on the Sandia guidelines is covered in detail in the PV Interconnection Impact Study section of this guide. The DER interconnection that passes ROI screen poses negligible risk of unintentional islanding.

The NRECA TechSurveillance article “DG Interconnections: Rules of Thumb for when System Impact Studies are Required” provides a detailed list of screens cooperatives can use to determine the need for system impact studies, as shown in Figure 5. This combines the technical screens that are included in the sections above for application, fast track, and supplemental processes with some additional components based on Leidos experience and industry best practices. If a project fails any individual screen (meaning a ‘no’ answer to any of the screens listed) then a system impact study is recommended. See the NRECA’s “Business and Contract Guide for Distributed Generation Interconnection” for more information on the DER interconnection review process. Both the above reference documents can be found on the cooperative.com website, in the Distributed Generation Toolkit page.

https://www.cooperative.com/programs-services/bts/Pages/Distributed-Generation-Toolkit.aspx#
System Impact Study

According to the NRECA’s “Business and Contract Guide for Distributed Generation Interconnection,” a system impact study shall be recommended when any of the following are true of the PV project:

1. Is larger than 2 MW but no larger than 20 MW
2. Is not certified
3. Did not pass the fast-track screens
4. Did not pass the supplemental review process if the cooperative offered this and the applicant accepted it

The purpose of a system impact study is to identify and detail the electric system impacts that would result from PV interconnection such as any protective coordination, fault current, thermal, voltage, power quality, or equipment stress concerns. The impact study report includes a detailed description of the reasoning and justification for any system upgrades and associated equipment deemed necessary for interconnection of the project. Cooperatives can reference “IEEE Standard 1547.7 IEEE Guide for
Conducting Distribution Impact Studies for Distributed Resource Interconnection” for guidance on completing any necessary studies.

The complexity of a system impact study depends on the size and type of PV. The costs and timelines involved in performing system impact studies depend on studies required to be performed to assess the overall system impacts. In general, for systems below 2 MW, the impact study involves performing steady-state load flow and short circuit analyses. In some cases where a risk of islanding screening fails, a detailed transient analysis is required. For systems above 2 MW up to 5 MW, additional studies may often be required that include transient analyses such as load rejection overvoltage, ground fault overvoltage, energization/inrush study. Projects above 5 MW require a transmission-level interconnection impact assessment in certain jurisdictions. Figure 6 illustrates study requirements by size of project. Details on how to perform these analyses are shown in the PV Interconnection Impact Study section of this guide.

Figure 6. Study Requirements for System Impact Study

Upon completion of the system impact study, the utility will provide the following to the customer or capture the following for internal documentation of utility owned solar:

1. Notification of whether the proposed system meets the applicable criteria considered in the interconnection process
2. Distribution system impacts
3. A description of where the proposed system is not in compliance with the interconnection requirements
4. Description of any system upgrades and associated equipment deemed necessary for interconnection
5. A good faith, detailed estimate of the total cost of completion of the interconnection of the proposed system including the required upgrades
Construction
Once the interconnection application is approved and after going through the review phase and system impact study phase, if it was required, the utility will build the facility in accordance with the utility-accepted design with in-house resources or through outside contractors. The construction/installation of system modifications and metering requirements will commence. Construction may also include system upgrades required as an outcome of the system impact study or screening process.

Verification and Testing
The verification and testing stage will be carried out by the utility or contracted vendor in accordance with utility-approved test procedure(s), and should include the recommended practices included in IEEE 1547-2018. Depending on the complexity of the project, the utility might want to witness the tests if an outside vendor is performing the testing. If the installation is not utility owned and if the utility opts not to witness the tests, the applicant must send the utility a written notification certifying that the system has been installed and tested in compliance with the approved test procedure(s), the utility-accepted design, and the equipment manufacturer's instructions. Cooperative utilities can review the “Sample PV Testing and Commissioning Checklist” document from the NRECA Toolkit for a detailed checklist and test procedures for a solar PV installation.

Permission to Operate
The facility will enter the permission to operate stage and be allowed to commence parallel operation upon satisfactory completion of the verification and test phase. In addition, the site must have complied with, and must continue to comply with, the contractual and technical requirements set by the utility whether it remains utility owned or is later acquired by an outside party. While this guide focuses on utility-owned solar PV, it is important for the utility to follow the same interconnection requirements as a third-party developer in the event the PV site is later owned by a third-party participant.
PV Interconnection Impact Study

Following a failed PV interconnection screening, a full impact study may be warranted to determine system impacts such as voltage rise, voltage flicker, device coordination, and islanding issues. This section of the guide gives a step-by-step approach to perform a full impact study. A full study includes:

- Data gathering and analysis
- Modeling
- Substation reverse power flow
- Load allocation
- Load flow analysis
- Voltage flicker analysis
- Short circuit and protection analysis
- Effective grounding screening
- Risk of Islanding (ROI) evaluation and transient overvoltage considerations

The steps of an impact study are described in this section with details, examples, and mitigation techniques for when criteria violations are identified. For some analyses, case studies have been prepared and are referenced in the appendices. The analysis presented assumes a working engineering model is available to the cooperative engineer to perform the simulations. A traditional peak planning model can be modified to perform the analysis presented.

Additional transient overvoltage and ROI studies are not included in this guide, as they are special circumstances and have a separate set of parameters and processes. The final step of an impact study will help utilities determine if those special studies should be considered. Should an ROI or transient overvoltage study be required, there are papers available through IEEE with case studies on various DER types. In addition, Leidos and other utility engineering companies perform these studies using transient level software.

Software Considerations

To perform interconnection impact studies, voltage drop hand calculations are not practical given the complexity of load flow with DER installed. Modeling is required to perform the thousands of calculations required for this analysis. There are many dedicated software tools available to assist in the process.

The software or modeling tools selected must have high-level requirements for DER modeling and simulation tasks. The following are a few high-level requirements to be considered.

1. Software shall be capable of performing circuit-level and reverse load flow and short circuit analysis.
2. Software shall be capable of running a reasonable number of variations in system conditions and events in an automated fashion and with reasonable processing time.
3. Models for devices and equipment within the software shall be of appropriate detail for accurate determination of the system response.
4. Ideally, a single software package/model will allow more accurate representation of contingencies. Software such as Milsoft’s Utility Solutions software, WindMi® and LightTable®, DNV Germanischer Lloyd Synergi® Electric software, Cooper Power Systems’ Distribution Network Analysis (CYMDIST), Electrical Distribution Design DEW, and ASPEN Distriview fulfill the above mentioned requirements to perform DER impact studies.

**Data Gathering and Analysis**

Similar to a system planning study, there are quite a few pieces of information required to perform an impact study. Information that is not available is assumed; in general, the fewer the assumptions, the more accurate the analysis. The data gathering initiation begins once an interconnection circuit and PV POI has been determined.

**Load**

1. Collect historic load data, for example from supervisory control and data acquisition (SCADA) (kW, kvar, power factor, amps), for the substation transformer and interconnection feeder to find daytime peak and minimum loading data. If available, collect output or billing data on existing large DER and large customers.
   a. The daytimewindows for PV studies can be from 8:00 a.m. to 6:00 p.m., 10:00 a.m. to 3:00 p.m., or 10:00 a.m. to 4:00 p.m.
   b. At least one year of hourly load data is preferred since it covers seasonal and switching impacts
   c. Load data should be used to filter to an acceptable daytime peak and minimum load condition for the interconnection circuit where the feeder is in normal configuration. Based on the preferred window of solar operation listed above, the lightest feeder load and the peak feeder load in the window should be selected.

2. The peak and minimum load data for adjacent feeders and substation transformer should be determined to be coincident with the selected loads for the feeder in study to accurately study the system in a single load snapshot condition. If coincident data is not available, non-coincident is sufficient but the results may not accurately reflect voltage regulating tap statuses and available load switching capacities.

3. If there are other large DERs on the circuit, calculate peak and minimum gross load by adding the existing DER output to the recorded SCADA data. This calculation negates the impact of the existing DER on the load measured at the feeder and substation level so that total, raw load can be properly allocated in the model(s).

4. If hourly data is not available, use planning level peak load data. Minimum loads can be estimated as a percentage of peak load, and typical percentages are 25 percent, 33 percent, or 40 percent.

**Model**

1. Make a copy of a recent working version of the system engineering analysis model.

2. Confirm the substation and circuit(s) in study and that the model configuration accurately depicts the correct configuration of the circuits in study
3. Review the substation diagram to model the substation source and substation transformer with the proper voltage level

4. Gather substation source impedance and substation transformer impedance along with regulation settings to allow accurate modeling

5. Check existing capacitors and line regulators locations, sizes, and settings

6. Check protection device settings on the interconnection feeder to analyze system coordination

7. Gather the PV site diagram and one line diagram

Modeling
Modeling accuracy is vital to the outcome of the study. Available information and the scenarios to be studied determine what exactly should be modeled. For this guide, the assumption is that a normal system configuration is studied. If contingency scenarios are necessary, where the PV might remain online in off-normal feeder conditions, then the study would be replicated in additional configurations.

1. Model the transmission source with source impedance and nominal voltage, shown in Figure 7

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Figure 7. Example from a CYME Model: High Side Source Details, Substation Transformer with LTC, Distribution Bus
2. Existing substations in the working engineering model will have a source already established. If it's built on the low side bus, it is preferred the source is updated to the high side voltage rating and impedance provided by the cooperative Generation and Transmission (G&T) provider.

3. Model the substation transformer with load-tap changer (LTC) or voltage regulator settings as per the nameplate document. Data required is shown in Figure 7.

4. Adjacent feeders can be modeled as spot loads to reduce model complexity. These contain real and reactive power at the load snapshot of the study.

5. Model the proposed PV site, generation step-up (GSU) transformer, and plant secondary system using data from site plan and one-line documents, shown in Figure 8
   a. Step up transformer modeling will require winding configurations, base kVA, input and output voltage, % impedance, and x/r calculation.
   b. PV inverter modeling will require AC nameplate kW, % power factor (generally assumed as 100%), and fault contribution (generally assumed to be 120% of the continuous current rating of the inverter unless a specification sheets indicates otherwise)

Figure 8. Example from a WindMil® Model: Recloser and Switch, Three Step-down Transformers, and Three Generators (Representing Inverters with PV Modules)
6. If there are existing or already approved other DER (PV, Wind, etc) on the circuits in study, model the sites, if not already modeled; this includes residential rooftop and larger commercial and utility-scale DER projects.

7. Update capacitor and line voltage regulator settings using GIS or other mapping or field data available on status, size, voltage rating, and location.

8. Check and update the mainline conductors and cables in the model between the source and the PV site.

9. Check for uncertainties, for example cable and conductor ratings in the equipment database.

Substation Reverse Power Flow Screening

Energy flowing from the PV towards the substation is in reverse of the traditional power flow from the substation to the load. Significant reverse power flow can cause equipment overload and voltage regulation problems and most wholesale supply contracts prohibit reverse flow into the transmission system. In this evaluation, the PV in study as well as existing or queued-ahead DER resources on all of the circuits tied to the substation in study should be considered.

To calculate if there is potential for reverse power flow through the substation transformer(s) onto the transmission system, two methods can be applied: the annual-hourly approach, and the snapshot of load approach.

Annual-Hourly Approach

1. Estimate hourly output of the PV in study aligned with the month, day, and time of the substation data available. Existing and available, free tools for estimating solar output are available at http://pvwatts.nrel.gov/ and in the PV Cost and Screening tool from NRECA.

2. If there are other large (> 500 kW) DER on the substation circuits, obtain measured outputs from SCADA, e.g., for the same year of the substation transformer loads available. If measured output is not available, estimate hourly output of existing and approved queued-ahead PV using the same NREL tool mentioned in step 1.

3. Build a load duration curve for the substation transformer, considering the impacts of PV in study and existing/approved DER. If the curve goes below the zero line, there could be reverse power flow on the substation transformer due to the proposed interconnection as shown in Figure 9. An example of how to build this curve is shown in Appendix A Case Study 1: Reverse Power.

4. Consideration needs to be given to what happens if the DER system is at full output and the adjacent feeder at the substation is lost. Automated controls may be necessary to prevent reverse flow under these conditions.
Snapshot of Load Approach
1. Total the proposed PV and existing and approved other DER on the substation by nameplate AC value.
2. Identify the daytime minimum load for the substation in study.
3. If the total DER is greater than the minimum load of the substation, there could be potential for reverse power flow through the substation and substation transformers in study.

Note. This method is inherently less accurate as it does not take into account the time at which events take place. The daytime minimum load may be at 9:30am whereas the solar PV may not reach peak output until 11am.

Mitigations
If there is a reverse power flow violation, proper mitigations are required including upgrading substation metering, LTC/voltage regulator controls, and substation protection to include zero sequence overvoltage (3V0) protection. While these mitigations are traditional approaches, some utilities are also considering using energy storage and/or advanced inverter controls to limit reverse power flow impacts and the traditional, costly upgrades. If energy storage is used then consideration needs to be given to whether the storage would be able to accept energy at the times when reverse power flow might occur and the system sized to accept that energy for the expected duration. Advanced inverter controls along with substation monitoring can be used to reduce the output of the PV facility such that reverse power flow would not occur.

Load Allocation
In order to prepare the engineering model for analysis, utility customer loading needs to be estimated for the scenarios being evaluated. Typically, the detailed meter data that aligns with the identified loading scenario is captured by meters at the substation transformer or distribution feeder. This recorded data is
allocated to the customers based on the recorded energy or demand captured by the utility’s customer information system. Load allocation is a routine that can be performed through most industry standard software packages. Some examples are listed at the beginning of this section of the Guide.

The following steps are recommended in performing load allocation specific to a PV impact study analysis.

1. Allocate feeder loads using the calculated gross peak and minimum loads identified in the data analysis step. Unbalanced load allocation is preferred if by-phase load information is available and the updated engineering model is accurate on load phasing.

2. Allocate gross feeder loads with all generation off in the model.

3. If adjacent feeders are modeled as just spot loads, populate the spot loads using the identified historical daytime load coincident with the feeder in study.

4. If data on large customers is available, populate the customer nodes in the model with the recorded load data.

5. Load allocation is done using different methods. Typical methods include “Connected kVA” and “kWH”. If the distribution model has customer kWH or billing information, use this method for better load allocation over “Connected kVA” method. If customer billing data is used, the kwh information from the peak and light load months selected for study should be imported following a standard billing import process established with the engineering load flow model.

6. Check switch capacitor bank statuses based on settings for load allocation. Check using GIS or other maps or field data available.

7. Check power factor of customer loads after load allocation to verify proper load allocation of reactive power amongst the customer nodes. In general, the residential consumer power factor should be in the high 90s. Commercial and industrial customers may vary but will be lower than residential power factor, even as low as the 80s.

Load Flow Analysis
Load flow analysis is a steady-state analysis focused on identifying the thermal and voltage-based limitations of equipment. The primary goal of this evaluation is to check if thermal (capacity) or voltage violations exist in the base system model, prior to interconnecting the PV in study, and then to identify if interconnecting the PV causes criteria violations. The steps include:

1. Perform load flows for four scenarios below in normal system configuration. Load flows should be a standard voltage drop where the proposed PV is either turned on or disconnected in the scenarios. The whole site, including step down transformers, should be disconnected in the “off” state. The analysis is completed using the cooperative preferred engineering analysis software in a working and updated engineering model.
   > Minimum load without proposed PV
   > Minimum load with proposed PV
   > Peak load without proposed PV
   > Peak load with proposed PV

Note: Existing and queued-ahead DER should be online for all four scenarios and considered pre-project.
2. Extract load flow results (kW, kvar, power factor [PF], volts) at the feeder breaker, substation transformer, and POI. A sample template is shown in Table 1.

Table 1. Load Flow Results Template

<table>
<thead>
<tr>
<th>Scenario</th>
<th>DER Project</th>
<th>POI</th>
<th>Study Feeder</th>
<th>Substation Transformer</th>
<th>Minimum Voltage</th>
<th>Maximum Voltage</th>
<th>Maximum Voltage at DER</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>KW</td>
<td>Kvar</td>
<td>PF</td>
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<td>Minimum Load</td>
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<td></td>
<td></td>
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<td>Kvar</td>
<td>PF</td>
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<td></td>
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<td>2</td>
<td>ON</td>
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<tr>
<td>Peak Load</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>KW</td>
<td>Kvar</td>
<td>PF</td>
</tr>
<tr>
<td>3</td>
<td>OFF</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>4</td>
<td>ON</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

3. Extract the by-phase minimum and maximum voltages on the study feeder at the primary voltage level. If voltages are within the planning criteria, there are no voltage violations. Utilities follow American National Standards Institute (ANSI) C84.1 standard for voltage regulation at the customer level, and the allowed primary voltage bandwidth is generally 118 V-126 V, considering a 4 V drop on secondary system.

4. Extract the maximum voltage at the study PV site secondary side to identify if there is unacceptable voltage rise at the project inverters.

5. Find thermal loading (percentage) on primary line sections, including protection devices (fuses, breakers, and reclosers). If loading percentages are within the planning criteria, there are no thermal loading violations. The percentages are calculated in the engineering software during the load flows and can be extracted into Excel.

6. Identify tap changes on substation transformer LTC/voltage regulator and line voltage regulators. Excessive tap changing between PV ON and PV OFF scenarios is a violation. Some utilities consider more than 1 tap movement a violation.

7. Identify if line regulators will experience reverse power flow by reviewing the load flow results at each regulator. If any phase of a three-phase regulator or individual single-phase regulators experiences current flowing towards the utility source, then reverse power flow exists.

Mitigations

The following mitigations are examples to rectify voltage, thermal loading, tap change, and reverse power flow issues.

- Resolve pre-existing imbalance and voltage violations
- Reduced generation
- Generating off unity power factor (consuming vars) (advanced PV inverters can be programmed to do this, however, given the negative impact of lagging power factor, not all utilities permit DER to operate at off-unity power factor.)
Voltage Flicker Analysis

Flicker is a rapid change in voltage that can annoy customers with repetitive light fluctuations and can damage customer equipment. PV is intermittent by nature, which can lead to voltage flicker issues for the area of the electric system where PV is interconnected.

IEEE 1453-2004 replaced the traditional guidance and recommended practices associated with flicker, found in IEEE-519-1992 and IEEE 141-1993. These standards were superseded to allow more in-depth discussion of the issue and to include the definition of a flickermeter. As part of this adoption process, the IEEE standards now reference and adopt the International Electrotechnical Commission 61000-3 series. IEEE 1453-2004 states that for events that occur once per hour or more, the use of a flickermeter and the subsequent short term flicker (Pst) and long term flicker (Plt) terms better characterize the impact than the IEEE 519 and IEEE-141 curves and guidance. It also states that the previous flicker standards mentioned above are still useful for infrequent events (i.e., less frequently than once per hour).

While IEEE 1435 suggests the hourly, flickermeter approach is better suited for PV, much of the industry is still using the conservative approach to capture worst-case conditions. The approach this guide focuses on calculates voltage flicker based on the IEEE 519 (General Electric [GE] flicker curve), which is in line with the concept of conservative planning for worst-case conditions. The method is performed at peak and at minimum load conditions. An example of this analysis is included as Appendix B Case Study 2: Voltage Regulation and Flicker.

1. Perform a load flow with the proposed PV and existing/approved DER ON. Extract the by-phase voltage results on the primary line sections on the interconnection circuit.
2. Lock the voltage regulators, LTCs, and switched capacitors at the step 1 load flow statuses.
3. Reduce the PV on the circuit to no output, or some utilities only reduce to 5 percent, 10 percent or 20 percent (even with cloud cover, ambient light will cause the PV to put out some energy) output to mimic the impact of cloud coverage very rapidly on the output of the solar generation on the interconnection circuit. This includes the proposed PV and the existing other PV on the interconnection circuit. Extract the by-phase voltage results on the primary line sections on the interconnection circuit.
4. Calculate voltage fluctuations between the above two scenarios on each line section of the study feeder by applying the formula in Equation 1 in Microsoft Excel:

\[
1 - \frac{\text{Voltage at DER OFF}}{\text{Voltage at DER ON}}
\]
5. Identify the maximum voltage flicker values for the study feeder at peak and minimum load conditions.
6. Check if the maximum voltage flicker values are above the planning criteria.
   • Some utilities use a typical 2 to 3 percent rule of thumb for PV interconnections.
7. Use the GE flicker curve as the standard.
   • The GE flicker curve shows both a “threshold of visibility” and a “threshold of irritation”. The curve indicates as visible or irritating the expected change in an incandescent bulb lighting as based on percent voltage change (Y axis) and how often the change occurs (X axis) as shown in Figure 10.

![Figure 10. IEEE 519 GE Flicker Curve](image)

**Figure 10. IEEE 519 GE Flicker Curve**

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**Mitigations**

Typical mitigations to rectify voltage flicker issues include,

> Reconductoring
> Generating off unity power factor (consuming vars). This method injects lagging VARs into the utility system, which brings down the voltage slightly at the point of interconnection. When the PV source is lost, as in voltage flicker analysis, the voltage drop isn’t as severe since it has a lower starting point due to VAR injection. The amount of consuming VARs from the PV site is different on a case by case basis, based on size and severity of voltage flicker. In addition, some inverters have the capability to operate at full power output while consuming some level of VARs while
others have to reduce power to achieve the VAR needs. Inverter specifications will have the 
information needed to model it correctly.

> Reduced generation
> Dedicated feeder
> Resolve pre-existing flicker due to single-phase DER
> Static var compensator

**Short Circuit and Protection Analysis**

Short circuit and protection evaluations focus on determining current levels for various types of faults in 
the system. Short circuit analysis is an analysis feature available in the typical distribution engineering 
software packages presented at the beginning of this section. The simulation places a single-phase, two, 
phase, and three-phase fault at each line section or node in the engineering model and calculates the 
fault levels across the system modeled.

PV interconnections can inject fault current into the electric power system, negatively impacting protection 
schemes and exceeding equipment ratings. The main goal of this analysis is to compute the fault levels 
and to check if fault levels are high enough to cause mis-operation of protective devices. An example of 
this analysis is included as **Appendix C Case Study 3: Short Circuit and Protection**.

1. Run short circuit analysis for PV ON and PV OFF scenarios at feeder breaker, substation 
transformer primary, and POI, and extract three-line to ground and line to ground fault current 
values. A sample template is shown in **Table 2**.

<table>
<thead>
<tr>
<th>PV Status</th>
<th>Fault Location</th>
<th>LG (Amps)</th>
<th>LG (MVA)</th>
<th>LLLG (Amps)</th>
<th>LLLG (MVA)</th>
<th>Maximum % Fault Current Contribution</th>
</tr>
</thead>
<tbody>
<tr>
<td>OFF</td>
<td>POI</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>ON</td>
<td>POI</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>OFF</td>
<td>Feeder Breaker</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>ON</td>
<td>Feeder Breaker</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>OFF</td>
<td>Substation Transformer Primary</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>ON</td>
<td>Substation Transformer Primary</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

2. Find the difference in fault current values between the above two scenarios. Some utilities flag 
the violation if the difference in fault values is more than 10 percent. In this case, there is a 
possibility of a protection coordination issue.

3. Check protection coordination issues with the proposed PV online by plotting time current curve 
of all the protection devices between the POI and substation.
4. Check if the fault current values with PV ON scenario violate fault duty on any upstream protection devices. If so, there is a violation and the respective devices need to be upgraded with higher size.

5. Check if the proposed PV fault contribution matches the inverter specification sheets. Industry preference is to assume 120 percent of the continuous current rating for the root mean square (RMS) fault current contribution.

6. Most utilities require a site recloser as a redundant protection for interconnections larger than 500 kW or 1 MW. This would be part of a standard interconnection requirement and would serve to mitigate some of this risk.

Effective Grounding Screening
According to IEEE 1547-2003, the grounding scheme of the interconnection should not cause overvoltages that exceed the rating of the equipment connected to the EPS and should not disrupt the coordination of the ground fault protection on the EPS. This includes solidly grounding the interconnection transformers and evaluating if the EPS is effectively grounded with the PV site online.

1. Evaluate if the site is a solidly grounded interconnection. There are some industry preferences on site transformer windings. See Figure 11.
2. Check if the GSU transformer configuration and PV grounding meet the effective grounding requirements set by the utility. In most cases, effective grounding rules are adopted from industry

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2 Graphic from Nova Energy Specialist, LLC
standards such as IEEE C62.92.1, IEEE Guide for the Application of Neutral Grounding in Electrical Utility Systems.

3. Calculate the ratios mentioned in IEEE C62.92.1 to check if the interconnection is effectively grounded by running short circuit analysis at the POI with PV ON, as shown in Equation 2. Figure 12, which is Table 1 from IEEE C62, presents the results that indicate effective grounding on a distribution system.

![Figure 12. IEEE C62 Characteristics of Distribution System Grounding](image)

<table>
<thead>
<tr>
<th>Grounding classes and means</th>
<th>Ratios of symmetrical component parameters (NOTE 1)</th>
<th>Percent fault current (NOTE 2)</th>
<th>Per unit transient LG voltage (NOTE 3)</th>
<th>Reference</th>
</tr>
</thead>
<tbody>
<tr>
<td>A. Effectively—Note (4)</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>1. Effective</td>
<td>0–3</td>
<td>0–1</td>
<td>&gt;60</td>
<td>≤2</td>
</tr>
<tr>
<td>2. Very effective</td>
<td>0–1</td>
<td>0–0.1</td>
<td>&gt;95</td>
<td>&lt;1.5</td>
</tr>
<tr>
<td>B. Non-effectively</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Inductance</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Low inductance</td>
<td>3–10</td>
<td>0–1</td>
<td>&gt;25</td>
<td>≤2.3</td>
</tr>
<tr>
<td>High inductance</td>
<td>&gt;10</td>
<td>&lt;2</td>
<td>≤25</td>
<td>≤2.73</td>
</tr>
<tr>
<td>Resistance</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Low resistance</td>
<td>0–10</td>
<td>0–2</td>
<td>≤25</td>
<td>≤2.5</td>
</tr>
<tr>
<td>High resistance—Note (8)</td>
<td>&gt;100</td>
<td>≤(-1)</td>
<td>≤1</td>
<td>≤2.73</td>
</tr>
<tr>
<td>Inductance and resistance</td>
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<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Resonant—Note (5)</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Ungrounded capacitance</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Range A—Note (6)</td>
<td>−∞ to −40</td>
<td>−2</td>
<td>≤8</td>
<td>≤3</td>
</tr>
</tbody>
</table>

Equation 2

\[ 0 < \frac{X_o}{X_1} < 3 ; 0 < \frac{R_o}{X_1} < 1 \]

Where \( X_o \) is zero sequence reactance, \( X_1 \) is positive sequence reactance, and \( R_o \) is zero sequence resistance.

4. From the post project fault current calculations from the engineering model used for analysis of the proposed PV site, find post-fault voltages by applying line to ground (LG) fault at the POI. If the line to ground voltages are below 138 percent of pre-fault voltage, then there is no ground fault overvoltage violation. Some utilities use 125 percent criteria.

Mitigations

If the system is not effectively grounded, proper grounding solutions must be considered, such as a grounding transformer or a grounding reactor.
Risk of Islanding Screening
Islanding is the condition in which DER continues to power a location even though electrical grid power is no longer present. Islanding can be dangerous to utility workers, who may not realize that a circuit is still powered, and it may prevent automatic reconnection of devices. Additionally, without strict frequency control, the balance between load and generation in the islanded circuit is going to be violated, leading to abnormal frequencies and voltages. For those reasons, distributed generators must detect islanding and immediately disconnect from the circuit; this is referred to as anti-islanding. An example of this analysis is included as Appendix D Case Study 4: Risk of Islanding Screening.

1. Risk of Islanding (ROI) screening is performed for the potential islands that may be formed at the upstream recloser, feeder, and substation transformer level.
2. ROI screening is typically performed using the guidelines mentioned in the report “Suggested Guidelines for Assessment of DG Unintentional Islanding Risk” by Sandia National Labs.
3. ROI screening is a four-step analysis per the Sandia guidelines, as described below and illustrated in Figure 13.

**Step 1:** “Determine whether the aggregate AC rating of all DG exceeds 2/3 of the minimum feeder loading.” If yes, proceed to Step 2. If no, there is minimal ROI and analysis is complete.

**Step 2:** “Determine whether reactive power from the PV plus reactive power from system load (Q_{PV} + Q_{load}) is within 1 percent of the total aggregate capacitor rating within the island, or alternatively, use real and reactive power flow measurements or simulations at the point at which the island can form to determine whether the feeder power factor is ever higher than 0.99 (lag or lead) at that point for an extended period of time.” If yes to either evaluation, a detailed islanding analysis should be considered. If no, proceed to Step 3.

**Step 3:** “Determine whether the potential island contains both rotating and inverter-based DG, and the sum of the AC ratings of the rotating DG is more than 25 percent of the total AC rating of all DG in the potential island.” If yes, a detailed islanding analysis should be considered. If no, proceed to Step 4.

**Step 4:** “Sort the inverters by manufacturer, sum up the total AC rating of each manufacturer’s product within the potential island, and determine each manufacturer’s percentage of the total DG. If no single manufacturer’s product makes up at least two thirds of the total DG in the potential island, then further study may be prudent. If the situation is such that more than two thirds of the total DG is from a single manufacturer, then the risk of unintentional islanding can be considered negligible.”
Mitigations
If the Sandia Risk of Islanding screen fails, there could be a risk of unintentional islanding due to the proposed PV interconnection and a detailed islanding analysis should be performed. If the detailed study is not feasible, proper islanding mitigations should be considered that include,

1. Direct transfer trip
2. Reclose blocking
3. Power line carrier permissive
4. Redundant protection at the DER site
5. Impedance insertion
6. Phasor-based protection

Applicable Standards and Guidelines
The applicable industry standards to help understand and study PV impacts are identified below. This is a modified list provided in the NRECA’s “Business and Contract Guide for DG Interconnection”.

- IEEE 1547 Standard for Interconnecting Distributed Resources with Electric Power Systems (including use of IEEE 1547.1 testing protocols to establish conformity)
- UL 1741 Inverters, Converters, and Controllers for Use in Independent Power Systems
> NFPA 70 (2002), National Electrical Code
> ANSI C84.1-1995 Electric Power Systems and Equipment – Voltage Ratings (60 Hertz)
> IEEE Standard 100-2000, IEEE Standard Dictionary of Electrical and Electronic Terms
> National Electrical Manufacturers Association (NEMA) MG 1-1998, Motors and Small Resources, Revision 3
> NEMA MG 1-2003 (Rev 2004), Motors and Generators, Revision 1
> Sandia National Lab “Suggested Guidelines for Assessment of DG Unintentional Islanding Risk” report
> IEEE Standard 1453-2015 (Revision of IEEE Std 1453-2011) - IEEE Recommended Practice for the Analysis of Fluctuating Installations on Power Systems
Appendix A

Case Study 1: Reverse Power

Purpose
Reverse power flow screening is typically performed to determine if utility substation equipment requires upgrade. Substation controls, metering, and regulating equipment (such as load-tap changers (LTC) and feeder regulators) may not operate correctly with reverse power. For many utilities, the presence of reverse power flow through the substation transformer is the criteria used to trigger a stability study on upstream sub-transmission or transmission systems.

Analysis Process
There are three possible ways to analyze for reverse power flow into the substation equipment.

Modelling can be used provided the substation, adjacent feeders, and adjacent feeder distributed energy resources (DER) is included in the model. A load flow using the “minimum load with proposed DER” scenario would indicate if substation equipment would see reverse power. Second, a simple calculation can be used to determine if the additional generation at nameplate generation will cause the substation to see reverse power at minimum load. Third, if substation hourly load data is available, the hourly generation can be forecasted and applied to a substation transformer load duration curve.

The first two methods can be considered “worst case” analysis, since nameplate generation may or may not be available when substation minimum load was recorded. Consider solar generation. As shown in the forecasted solar generation curves in Figure A-1, it is unlikely that nameplate generation will be available for a substation minimum load recorded at 8am. For solar based DER, analysis is typically limited to substation loads recorded during “daytime” such as 8am to 6pm, or 10am to 4pm, depending on utility criteria.

Figure A-1. Forecasted Solar Generation Curves

The graphs in Figure A-1 show forecasted hourly generation for two of the units used in this case study, an existing 400 kW unit and the 4,450 kW unit under study. Forecasted generation was obtained using the NREL PVWatts® Calculator available at http://pvwatts.nrel.gov/index.php. The website uses system information such as direct current (DC) system nameplate, site zip code, array tilt and azimuth, and the
DC system to alternating current (AC) system ratio to forecast hourly solar generation based on historical weather information and calculated sun location. The graphs show the peak generation day for both units. The smaller unit never reaches AC nameplate generation due the system tilt, azimuth, and DC to AC ratio. The system under study reaches AC nameplate for four hours on the same day. The system information needed to perform hourly forecasting is typically available on one lines and site plans. If hourly information is available, forecasted generation can be subtracted from substation transformer load to determine if there is likely to be reverse power flow at any hour during the year.

Background
As shown in Table A-1, the study analyzed system impact for the installation of a 4,450 kW solar generation unit to be installed on a feeder with 988 kW of minimum load. The feeder is supplied from a substation transformer with 5,516 kW of minimum load coincident to the feeder load. At this substation, there is 3,666 kW of solar generation approved for interconnection by the utility but not yet installed. The majority of the approved generation is on feeders not involved in the study.

### Table A-1. Recorded Minimum Load and DER Installation Case Study

<table>
<thead>
<tr>
<th></th>
<th>Recorded Daytime Minimum Load (kW)</th>
<th>Approved Solar (kW)</th>
<th>Proposed Solar (kW)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Feeder</td>
<td>988</td>
<td>498</td>
<td>4,450</td>
</tr>
<tr>
<td>Substation Transformer</td>
<td>5,516</td>
<td>3,666</td>
<td>4,450</td>
</tr>
</tbody>
</table>

Results
As shown in Table A-2, load review indicates that the proposed 4,450 kW project will cause reverse power through the substation transformer. According to this analysis, the project will be required to pay for reverse power related substation upgrades. This utility does not require further study for reverse power onto the transmission system, so further study costs are not required. Accurately reflecting approved projects is critical. Projects installed before the daytime minimum load was recorded would be part of the minimum load reading and should be removed from the approved amount in Table A-2. It is important to track the installation date of approved projects. Approved projects that have been cancelled should be removed from the calculation. From this calculation, to avoid costs associated with reverse power, the project size would have to be reduced from 4,450 kW to 1,850 kW.

### Table A-2. Reverse Power Desktop Calculation Case Study

<table>
<thead>
<tr>
<th>Substation Transformer</th>
<th>Load (kW)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Daytime Minimum Load</td>
<td>5,516</td>
</tr>
<tr>
<td>Approved DER Projects</td>
<td>-3,666</td>
</tr>
<tr>
<td>Proposed DER Under Study</td>
<td>-4,450</td>
</tr>
<tr>
<td>Total Forecasted Load</td>
<td>-2,600</td>
</tr>
</tbody>
</table>

---

3 Analysis is typically performed at feeder minimum load. The substation loading used in analysis is the load coincident to the feeder minimum load.
The results are different when performing analysis using a load duration curve based on hourly recorded substation load, and forecasted approved and proposed generation from the PVWatts® or NREL solar output calculator. The graph in Figure A-2 shows the annual hourly substation transformer load (red line), the forecasted substation load after the approved generation is interconnected (purple line), and the forecasted substation load after the proposed project is interconnected (blue line).

Figure A-2. Load Duration Curve Using Hourly Substation Transformer Load and Forecasted Generation to Forecast Reverse Power

As shown by the blue line, the substation is forecasted to go into reverse power for a small portion of the year. The highest forecasted reverse power was 1,266 kW, and reverse power was calculated for seven hours. This utility does not implement reverse power upgrades unless analysis shows over 20 hours of reverse power, so this project did not require reverse power mitigation. To eliminate all hours of forecasted reverse power, the project size would have to be reduced from 4,450 kW to 3,184 kW.

Figure A-3 shows a screenshot of the Microsoft Excel file used to generate the load duration curves. First, one year of hourly recorded substation transformer load in MW is placed in date/time order. If MW data is not available, MW can be calculated from other recorded information. Since the PVWatts® or NREL solar output calculator will be providing one year of forecasted generation for each hour, remove substation recorded load information that is duplicated for the same hour, and note any hours that are missing recorded load. Next, use the PVWatts® or NREL solar output calculator to provide the hourly forecasted solar generation for the previously approved solar sites (if there are any). Match the recorded data to the forecasted generation using the time stamps, and by removing the solar generation hours that were not included in the recorded load data. After lining up the load and generation data based on the date/time stamps, at each hour subtract forecasted generation from the
same hour of recorded substation transformer load. This will generate a year of forecasted substation transformer loads including the impact of approved DG projects. In a similar way, subtract each hour of forecasted proposed DG generation from each hour of the forecasted substation transformer recorded load (in purple) to generate forecasted hourly substation transformer load when all DG is in service (in blue).

In this case, the year of load data provided was from October, 2016 to October, 2017. The approved 2,412 kW project was in service by January, 2017 - the hours shown below. The impact of the 2,412 kW project is included in the substation transformer recorded load in January, and forecasted generation was not included in the calculation after the generation went into service. As part of the analysis, check for in service dates on approved generation and remove forecasted generation from the calculation for time stamps after the generation came on line.

Prior to graphing the information, remove hours that do not represent actual loading including loads recorded during a contingency or outage, loads impacted by field switching, or where repetitive recordings indicate bad data. For solar generation projects, analysis is limited to daytime hours. Daytime hours are decided by individual utility preference, for example 8am - 6pm or 10am – 4pm. Finally, each set of load data should be sorted in descending order to generate the curves in Figure A-2 above.

**Figure A-3. Sorting Data For Graphing Recorded and Forecasted Load Duration Curves**

<table>
<thead>
<tr>
<th>Month</th>
<th>Day</th>
<th>Hour</th>
<th>Substation Transformer Recorded Load (MW)</th>
<th>Approved Project 2,412 kW (MW)</th>
<th>Approved Project 756 kW (MW)</th>
<th>Approved Project 418 kW (MW)</th>
<th>Substation Transformer with Approved DG (MW)</th>
<th>Proposed Project 4,450 kW (MW)</th>
<th>Substation Transformer with All DG (MW)</th>
<th>Hours</th>
<th>Substation Transformer Load (MW)</th>
<th>Substation Transformer with Approved DG</th>
<th>Substation Transformer with All DG</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>1</td>
<td>8</td>
<td>11.902 0.000 0.206 0.136 11.561 1.266 10.295</td>
<td>0.000</td>
<td>0.000</td>
<td>0.000</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>28.089</td>
<td>28.634</td>
<td>28.428</td>
</tr>
<tr>
<td>1</td>
<td>1</td>
<td>9</td>
<td>11.206 0.386 0.254 10.566 2.373 8.193</td>
<td>1.144</td>
<td>28.114</td>
<td>28.057</td>
<td></td>
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</tr>
<tr>
<td>1</td>
<td>1</td>
<td>10</td>
<td>10.539 0.473 0.311 9.755 2.906 6.849</td>
<td>2.763</td>
<td>27.632</td>
<td>27.015</td>
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<tr>
<td>1</td>
<td>1</td>
<td>11</td>
<td>10.217 0.531 0.349 9.337 3.262 6.075</td>
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<td>26.826</td>
<td>26.666</td>
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<tr>
<td>1</td>
<td>1</td>
<td>12</td>
<td>10.662 0.531 0.350 9.782 3.263 6.519</td>
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<td>26.664</td>
<td>26.437</td>
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</tr>
<tr>
<td>1</td>
<td>1</td>
<td>13</td>
<td>11.204 0.430 0.283 10.491 2.645 7.846</td>
<td>5.689</td>
<td>26.643</td>
<td>26.588</td>
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<tr>
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<td>24.790</td>
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<td>1</td>
<td>3</td>
<td>9</td>
<td>17.509 0.145 0.095 17.269 0.891 16.378</td>
<td>18.656</td>
<td>24.357</td>
<td>23.849</td>
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<td></td>
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</tr>
</tbody>
</table>

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Appendix B

Case Study 2: Voltage Regulation and Flicker

Purpose
Utilities are responsible for delivering acceptable voltage levels at the customer’s meter. Although state requirements vary, American National Standards Institute (ANSI) C84.1 requires 126 V to 114 V at the customer meter on a 120 V basis. Typically, analysis is performed on the primary voltage levels of the system using a criteria of 126 V to 118 V. This assumes a peak voltage drop across the distribution transformer and secondary wires. Analysis at secondary voltage levels is occasionally performed on feeders with heavy rooftop photovoltaic (PV) penetration, and to check for overvoltage behind the meter interconnections.

Flicker is a rapid change in voltage that can annoy customers with repetitive light fluctuations and cause equipment misoperation. As shown on the “GE Flicker Curve” in Figure B-1, voltage flicker is measured as a percent change in voltage (Y-axis), and how often change occurs (X-axis). The two curves indicate as visible or irritating the expected change in incandescent bulb lighting. A voltage change of 2.8 percent once per day hour will cause a visible change (pink dot). A 0.7 percent voltage change occurring five times per second might be irritating (teal dot). Flicker is typically caused by changes in generation or load, especially varying generation such as wind and solar.

---

4 Behind the meter projects are where the DER is installed alongside and shares the meter with existing customer load. DER will have significant impact on utility transformer secondary voltage and could cause voltage issues for customer load installed in parallel behind the same utility meter or transformer.
The purpose of a flicker study is to determine where on the flicker curve DER related voltage changes occur before voltage regulating equipment operates one to two minutes later to correct voltage. Voltage regulation is a longer term consideration, the impact of DER on system voltage after voltage regulating equipment have attempted to regulate steady state voltage.

Analysis Process
Often, the first step in analysis is to determine criteria for voltage regulation and flicker. For example, the minimum acceptable primary voltage based on state standards and expected peak load voltage drop on distribution transformers and secondary system. Utilities, while referencing the GE Flicker Curve, also vary on maximum acceptable “one dip per hour” DER caused voltage change. Utilities also vary on which solutions are acceptable and modelled, although all will attempt to resolve the issues as inexpensively as possible. For example, changing regulator settings might be less expensive than resolving pre-existing imbalance, but more costly if the regulator has to be replaced. Given the negative impact of lagging power factor, not all utilities permit DER to operate at off unity power factor.

Voltage flicker is typically more difficult to resolve than steady state load flow voltage regulation issues. A flicker solution can be determined using flicker analysis, and then a load flow can be performed to determine if the same solution resolves voltage regulation issues. In general, modelling is used to find the problem, and try solutions that mitigate or eliminate the problems. Flicker problems are typically worse at peak load, while overvoltage issues are typically worse at light load. Not all utilities perform analysis at all load levels.

For analysis with varying generation such as wind or PV, there appears to be multiple accepted practices using this “on/off” methodology to analyze flicker. Utilities vary on the assumed amount of solar generation reduction, with some dropping from AC solar nameplate to 0 percent and some dropping to 20 percent. The Institute of Electrical and Electronics Engineers (IEEE) 1547.7 mentions that PV generation can vary from 100 percent to 20 percent in less than a minute, before voltage regulating equipment can operate. To evaluate the flicker impact of generation that does not vary, the general practice is to model generation changing from 100 percent to 0 percent as the “on/off” states. The first step involves a load flow with the PV on and voltage regulating devices operating normally. The by-phase voltages calculated at each primary line section in the model are extracted into a spreadsheet. The second step is to lock all voltage regulating devices from the first step analysis and drop all PV on the circuit to 0 percent. The by-phase voltages are extracted once more. In excel, for each primary line section, voltage flicker is calculated for each phase using the following equation:

\[
\text{Equation 1}
\]

\[
1 - \frac{\text{Voltage at DER OFF}}{\text{Voltage at DER ON}}
\]

The maximum voltage flicker calculated for all of the line sections is considered the worst case voltage flicker, this is then compared to the criteria to determine if the voltage flicker is acceptable or not.
Background
As shown in Figure B-2, consider the case of a 1,980 kW solar DER interconnection proposed on a 13.2 kV feeder with 537 kW of pre-existing rooftop generation. The proposed site is five miles from the substation, including 2,200 feet of overhead construction to connect the inverters to the electric power system (EPS). There are six line regulators and eight fixed capacitor banks consisting of 2,300 kvar. The feeder maximum load is 5.25 MW.

Figure B-2. Proposed Case

Results
Load flow analysis was performed at four scenarios noted in Table B-1. The model screen shot shown in Figure B-3 depicts issues on the feeder at peak load with the DER interconnected (Scenario 4).

<table>
<thead>
<tr>
<th>Scenario</th>
<th>1.5 MW PV Status</th>
<th>PCC V</th>
<th>KW</th>
<th>kVAR</th>
<th>P.F.</th>
<th>Feeder 2094 V</th>
<th>KW</th>
<th>kVAR</th>
<th>P.F.</th>
<th>Minimum Voltage</th>
<th>Location</th>
<th>Maximum Voltage</th>
<th>Location</th>
</tr>
</thead>
<tbody>
<tr>
<td>Light Load</td>
<td>OFF 125.3</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>124.2</td>
<td>1546</td>
<td>-1091</td>
<td>-86.1</td>
<td>117.8</td>
<td>128.4</td>
<td>C213569829_1 (Ph A)</td>
<td>C213569829_2 (Ph A)</td>
<td></td>
</tr>
<tr>
<td>2</td>
<td>CN 129.5</td>
<td>-1980</td>
<td>98</td>
<td>99.9</td>
<td>123.4</td>
<td>-117</td>
<td>-953</td>
<td>-12.2</td>
<td>117.5</td>
<td>128.3</td>
<td>C213569829 (Ph A)</td>
<td>C213569829 (Ph A)</td>
<td></td>
</tr>
<tr>
<td>Peak Load</td>
<td>OFF 124.7</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>126.4</td>
<td>5103</td>
<td>643</td>
<td>99.2</td>
<td>112.4</td>
<td>127.1</td>
<td>C3063522 (Ph C)</td>
<td>C3063522 (Ph C)</td>
<td></td>
</tr>
<tr>
<td>3</td>
<td>CN 126.1</td>
<td>-1980</td>
<td>100</td>
<td>99.9</td>
<td>125.7</td>
<td>3100</td>
<td>694</td>
<td>97.6</td>
<td>112.3</td>
<td>127.2</td>
<td>C3063522 (Ph C)</td>
<td>C3063522 (Ph C)</td>
<td></td>
</tr>
</tbody>
</table>

At peak load, the interconnection issues include low voltage down to 112.3 V marked in red, and high voltage marked in pink to 127.2 V. The high voltage area is downstream of the proposed project. The worst flicker was analyzed to be on phase A at 7.6 percent. This exceeds the utility criteria of two percent.
Solution
Modelling was used to determine the impact of proposed solutions. The mitigations applied to interconnect DER successfully without disrupting the system are upgrading the 600 kvar fixed capacitor bank to time control with voltage override to mitigate high voltage issue, reconductoring 1,370 feet of existing primary 3/0 aluminum conductor steel-reinforced (ACSR) conductor to 336 ACSR conductor, installing 2,200 feet of 336 ACSR overhead conductor to the project site, and reducing the project size from 1,980 kW to 1,700 kW. All of these in combination resolved the issues on this particular study.
Appendix C

Case Study 3: Short Circuit and Protection

Purpose
The increased fault current resulting from DER interconnection can negatively impact the electrical power system, impact protective device coordination, and can exceed system withstand or interrupting ratings. Reverse power steady state current can exceed protective device ratings, such as fuse ratings, or exceed protective device pickup current. While thermal ratings are part of load flow analysis, the impact of protection devices overloads are considered as part of the protection analysis. For example, replacing or relocating an overloaded fuse supplying a proposed DER site should be part of determining protection system solutions.

Utilities have various criteria in screening to determine if short circuit and protection analysis is required. Synchronous and induction generator fault contribution can be from four to ten times nameplate, while inverter based fault contribution is limited to 1 to 2 p.u. For this reason, screening criteria levels are often dependent on DER type. Criteria can also be dependent on voltage level, which impacts available short circuit. DER installations that do not require further study at one voltage level will require study at a lower voltage level.

Analysis Process
The utility in this case study does not consider a 10 percent increase in the DER point of common coupling (PCC) fault current to require mitigation provided the system maintains coordination. Further, all projects greater than 1 MW require a utility-owned site recloser. Analysis is performed from the substation breaker out, and does not include such DER related issues as nuisance tripping on parallel feeders. N-1 contingency analysis was not considered. The DER will be tripped offline using the site recloser for any feeder outage or off schedule condition.

To avoid confusion, recorded fault current location should be clearly identified. In this analysis, the point of interconnection (POI) is an existing utility pole while the PCC, where the change of ownership occurs, is expected to be a utility-owned gang operated air break (GOAB) switch on a pole three spans onto the site from the POI pole. In some cases, the PCC can be several thousand feet from the POI, greatly impacting recorded fault current. For projects downstream of utility-owned distribution transformers, the PCC is at secondary voltage while most reporting is done at primary voltage, often referred to as the POI.

Background
Consider the case of a 7 MW solar generation site interconnecting to a 26.4 kV distribution system. There are three protective devices upstream from the project: a 65T fuse, a hydraulic line recloser, and a feeder breaker. The existing protection scheme includes fuse saving, where the recloser will operate before the fuse starts to melt. According to the DER inverter specification sheet, a fault current contribution of 168 percent of continuous current is used.
Table C-1 shows the utility-provided source impedance, and Figure C-1 shows a system screen shot taken from the modelling software.

Table C-1. Substation Source Impedance Protection Case Study

<table>
<thead>
<tr>
<th>Source</th>
<th>Nominal Voltage (kV)</th>
<th>3LG (amps)</th>
<th>1LG (amps)</th>
<th>Positive Sequence (ohms)</th>
<th>Zero Sequence (ohms)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Substation</td>
<td>138</td>
<td>9,347</td>
<td>5,453</td>
<td>1.5015</td>
<td>8.6143</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td>8.3686</td>
<td>25.4113</td>
</tr>
</tbody>
</table>

Note: Impedance data provided by utility.

Figure C-1. 26.4 kV Circuit Layout for Protection Case Study

Results
Existing system reclose times exceed two seconds. IEEE 1547 mandates that all DER disconnect from the system within two seconds when the system source is removed. In this case, reclose times do not need to be extended.
The short circuit analysis was run with the DER on and the DER off. Results for various faults were recorded at the PCC, the substation distribution bus, and substation transformer primary. At the PCC, the installation is expected to increase line to ground fault current increases from 1,441 A to 1,701 A. This utility does not require mitigation for differences in fault current exceeding 10 percent provided the fault current does not exceed system design levels of 8000 A. The short circuit analysis results are shown in Table C-2.

Table C-2. Short Circuit Analysis Results Protection Case Study

<table>
<thead>
<tr>
<th>GEN Status</th>
<th>Fault Location</th>
<th>LG (Amps)</th>
<th>LG (MVA)</th>
<th>LLL (Amps)</th>
<th>LLL (MVA)</th>
<th>Maximum % Fault Current Contribution</th>
</tr>
</thead>
<tbody>
<tr>
<td>OFF</td>
<td>PCC</td>
<td>1,441</td>
<td>66</td>
<td>2,090</td>
<td>96</td>
<td>18.04%</td>
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<tr>
<td>ON</td>
<td>PCC</td>
<td>1,701</td>
<td>78</td>
<td>2,303</td>
<td>105</td>
<td></td>
</tr>
<tr>
<td>OFF</td>
<td>26.4 kV Substation Bus</td>
<td>7,005</td>
<td>320</td>
<td>6,675</td>
<td>305</td>
<td>3.13%</td>
</tr>
<tr>
<td>ON</td>
<td>26.4 kV Substation Bus</td>
<td>7,187</td>
<td>329</td>
<td>6,884</td>
<td>315</td>
<td></td>
</tr>
<tr>
<td>OFF</td>
<td>138 kV Substation Bus</td>
<td>5,467</td>
<td>1,307</td>
<td>9,371</td>
<td>2240</td>
<td>0.54%</td>
</tr>
<tr>
<td>ON</td>
<td>138 kV Substation Bus</td>
<td>5,479</td>
<td>1,310</td>
<td>9,422</td>
<td>2252</td>
<td></td>
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</table>

In the time current curve graph shown in Figure C-2, red depicts the 65T fuse, green the hydraulic line recloser fast and slow curves, teal the feeder breaker ground curve, and purple the feeder recloser phase curve. The pre-project LG and LLL fault current at the PCC are the purple and light blue vertical lines, respectively. The fault current post-installation of the DER are shown as the blue and green vertical lines. The increased fault current from the DER eliminates coordination on the fuse save scheme. Also, the fuse will be overloaded due to reverse power from the DER. The recloser fast trip curve, at four cycles, does not leave room to install the utility-owned site recloser, as required by this utility for sites over 1,000 kW. For mitigation, the fuse will be relocated downstream of the POI and continue to isolate the side tap past the POI. The fuse save scheme will be abandoned. The hydraulic line recloser will be replaced with an electronic recloser and will be slowed to allow the installation of a site recloser.
Figure C-2. Time Current Curves for Protection Case Study
Appendix D

Case Study 4: Risk of Islanding Screening

Purpose
Unintentional islanding poses a danger to utility workers, the general public, and equipment connected to the system. Most utilities perform risk of islanding (ROI) screenings using Sandia Report guidelines. DER that fail risk of islanding screening may require further dynamic study or a mitigation strategy, depending on utility preference. Most utilities require the installation of a mitigation strategy rather than further study.

Any EPS protection device can form an island such as feeder or substation breakers, or the mid-line recloser shown in Figure D-1. If the EPS has automated reclosing, the mid-line recloser may attempt out-of-sync reclosing into the live island, damaging EPS equipment, customer loads, and DER. IEEE 1547 mandates that the DER detect islands and cease to energize the EPS within two seconds of the island formation. EPS supplying DER should delay reclosing at least two seconds to make sure DER are offline before reclosing. Despite the mandate, DER systems may still pose a risk of unintentional islanding past two seconds if system conditions are right, including a generation to load match.

Figure D-1. Example of Unintentional Islanding Downstream of a Mid-line Recloser

Analysis
The Sandia risk of islanding screening uses system conditions to determine if there is a risk of islanding concern, as described below and illustrated in Figure D-2. Sandia screening can be performed via desktop review depending on available information, although modelling may be required to improve accuracy.
Step 1 is to determine if the aggregate DER capacity is less than two thirds of the potential EPS island minimum load. If minimum feeder load is not known, it can be estimated from peak load. IEEE 1547 mentions assuming minimum load is 33 percent of peak load. In the mid-line recloser island shown in Figure D-1, the recloser minimum load could be taken from historical recorded load, estimated based on feeder maps, or would require modelling. If DER capacity is less than two thirds of load, the DER cannot support the load without the EPS, then there is no risk of islanding and no need to evaluate subsequent steps. If Step 1 indicates a concern, then passing any of the criteria in Steps 2, 3, or 4 indicates there is a risk of islanding.

Step 2 checks for a VAR match, typically checking to see if load VARs (typically lagging) equals the capacitor bank nameplate within the potential island. Actual load VARs typically need to be calculated from recorded loads, which include the impact of connected capacitors. Actual load VARs are difficult to calculate when the status of switched capacitor banks are not known. Typically, assumptions have to be made about switched capacitor bank status when estimating load VARs. Modelling makes it easier to determine load VARs. In systems with fixed capacitance, VARs are sometimes leading at minimum load (when there are less load VARs) and lagging at peak load (as load VARs ramp up with load). While this indicates there is a VAR match somewhere between minimum and peak, Step 2 is only valid if there is a VAR match at the same time as Step 1 is met, when DER is more than 67 percent of load. In situations where DER is generating or consuming VARs, DER VARs are included in the VAR match calculation.

Figure D-2. Steps To Perform Sandia Risk of Islanding Screening

START

STEP 1

DG AC Rating > 2/3 Feeder Minimum Load

STEP 2

PV and Load Reactive Power within 1% of Capacitor Rating

YES

STEP 3

Island contains inverters + rotating DG, AND rotating DG > 25% of total DG

NO

STEP 4

Less than 2/3 of total PV by same inverter manufacturer

NO

Screen Passed

YES

Additional Study or Mitigation Recommended

DE-EE-0006333

4/30/18
Background
The purpose of the study was to evaluate the interconnection of a 3,300 kW solar DER onto a 23 kV distribution feeder. The feeder DER included 1,666 kW installed solar generation, 3,639 kW approved solar generation, and 3,300 kW proposed solar generation. The substation transformer supplies only the feeder under study. There are four voltage-controlled capacitor banks on the feeder and no information on capacitor bank status. The interconnecting utility assumes switched capacitors are off at minimum load and on at peak load; also, that islanding evaluation be performed at DER nameplate against a “daytime” minimum load recorded between 8am and 6pm. Feeder load recording was available including amps, MW, and Mvar. Load MW were available on the two existing DER. There are three line reclosers installed between the substation and the DER under study. Recloser recorded load was not available. There are four voltage controlled switched capacitor banks totaling 3,300 kVAR. Modelling was used to estimate load and VARs at recloser locations. The feeder is expected to have reverse load flow based on approved DER interconnection, made worse by the interconnection of the DER under study. This indicates that Step 1 is “Yes”, aggregate DER exceeds 67 percent (two-thirds) of minimum load.

Results
Step 1: Recorded loads include the impact of existing DER and system capacitor banks. Analysis for Step 1 requires existing DER generation be added to recorded load prior to generate “gross” load. In this case, excel was used to add, for each hour, the recorded DER generation in kW onto hourly recorded feeder load to generate a calculated hourly feeder load over a one year period. The feeder minimum load of 4,720 kW was determined from the recorded data, as shown in Table D-1. Modelling was used to determine recloser load data.

<table>
<thead>
<tr>
<th>Potential Island</th>
<th>Minimum Model Load (kW)</th>
<th>DER Nameplate (kW)</th>
<th>Calculated Gross Load (kW)</th>
<th>DER to Gross Load Ratio</th>
<th>Step 1 Screen</th>
</tr>
</thead>
<tbody>
<tr>
<td>Recloser 1</td>
<td>-1,674</td>
<td>3,300</td>
<td>1,626</td>
<td>203%</td>
<td>Y</td>
</tr>
<tr>
<td>Recloser 2</td>
<td>-4,148</td>
<td>4,740</td>
<td>592</td>
<td>801%</td>
<td>Y</td>
</tr>
<tr>
<td>Recloser 3</td>
<td>-3,985</td>
<td>8,605</td>
<td>4,620</td>
<td>186%</td>
<td>Y</td>
</tr>
<tr>
<td>Feeder/Transformer</td>
<td>-3,885</td>
<td>8,605</td>
<td>4,720</td>
<td>182%</td>
<td>Y</td>
</tr>
</tbody>
</table>

Step 2: There were no fixed capacitance on this feeder and the switched capacitors were assumed off at minimum load. As shown in Table D-2 for each potential island, if all the installed capacitors came online the results would be a leading power factor and a system not capable of maintaining an island due to a VAR match.
Table D-2. ROI Screening Step 2

<table>
<thead>
<tr>
<th>Potential Island</th>
<th>Minimum Model Load (kvar)</th>
<th>Connected at Minimum (kvar)</th>
<th>Calculated Gross Load (kvar)</th>
<th>Installed Capacitance (kvar)</th>
<th>Capacitance to Gross Load Ratio</th>
<th>Step 2 Screen</th>
</tr>
</thead>
<tbody>
<tr>
<td>Recloser 1</td>
<td>490</td>
<td>0</td>
<td>490</td>
<td>0</td>
<td>0%</td>
<td>N</td>
</tr>
<tr>
<td>Recloser 2</td>
<td>1,596</td>
<td>0</td>
<td>1,596</td>
<td>3,300</td>
<td>207%</td>
<td>N</td>
</tr>
<tr>
<td>Recloser 3</td>
<td>1,533</td>
<td>0</td>
<td>1,533</td>
<td>3,300</td>
<td>215%</td>
<td>N</td>
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<tr>
<td>Feeder/Transformer</td>
<td>1,510</td>
<td>0</td>
<td>1,510</td>
<td>3,300</td>
<td>219%</td>
<td>N</td>
</tr>
</tbody>
</table>

On this study, the peak load flow model shows that the feeder is lagging with all switched capacitors online. This indicates there may be a point between minimum daytime load and peak daytime load where the installed capacitance is equal to the gross load VARs. If DER is greater than two-thirds of feeder load at that time, the load match and VAR match represent a potential for unintentional islanding. The graph in Figure D-3 shows gross feeder load in kW (using recorded hourly feeder and existing generation data) in blue and the recorded feeder power factor in green. The recorded power factor in the graph is an absolute power factor, as we are concerned with periods of time where power factor is between -99 percent and +99 percent. While capacitor bank statuses are not known, the recorded power factor includes the impact of the capacitors that were switched during normal operation. The purple line at 99 percent power factor represents the minimum absolute power factor required to generate an unintentional island, while the red line indicates the minimum feeder load required to avoid an island. Given a DER of 8,605 kW, the feeder must be loaded to greater than 12,908 kW (8,605/67 percent) in order to have load that is too high to be supported by the DER in an islanding situation. As shown, there are numerous occasions throughout the recorded year where load is low enough to be supported by the DER but where power factor is between -99 percent and +99 percent. Given this analysis, the feeder would be a “Yes” for Step 2.

Figure D-3. Feeder Recorded Results Risk of Islanding Case Study
Step 3: There is no rotating DER on the feeder, so Step 3 is “No”.

Step 4: Table D-3 shows the analysis for Step 4 at the feeder level. As shown, no single DER inverter dominates the system with 67 percent of the connected inverter nameplate. The inverters can potentially use differing control methods to detect an unintentional island, perhaps even cancelling each other out. The inverters will not act together to force a frequency or voltage shift and might allow an unintentional island to continue. This would result in a “Yes” for Step 4.

Table D-3. Inverter Summing by Manufacturer Results Risk of Islanding Case Study

<table>
<thead>
<tr>
<th>Inverter Model 1 (kW)</th>
<th>Inverter Model 2 (kW)</th>
<th>Unknown Model (kW)</th>
<th>Inverter Model 4 (kW)</th>
<th>Inverter Model 5 (kW)</th>
<th>Grand Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>Feeder</td>
<td>1,440</td>
<td>1,700</td>
<td>499</td>
<td>1,666</td>
<td>3,300</td>
</tr>
<tr>
<td>%</td>
<td>17%</td>
<td>20%</td>
<td>6%</td>
<td>19%</td>
<td>38%</td>
</tr>
</tbody>
</table>
Appendix E

Four System Impact Study Examples
Final Report

Interconnecting Customer
2,010 kW PV Interconnection Impact Study

Electric Cooperative

December 13, 2017

leidos
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Interconnecting Customer
2,010 kW PV Interconnection Impact Study
Electric Cooperative

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EXECUTIVE SUMMARY

This report documents the Interconnection Impact Study that was performed for the distributed energy resource interconnection application submitted by Interconnecting Customer for a 2,010 kW photovoltaic (PV) generation facility located at Address.

The study results show the distributed energy resource (DER) system can connect to the Electric Cooperative (Cooperative) Electric Power System (EPS) under normal system configuration based on applicable standards and consideration of the required facility upgrades identified in the study. The following summarizes interconnection impact study results:

- Reverse power flow is not expected through the MC Substation during minimum load condition with the proposed project on line.
- The proposed PV site will not cause voltage flicker issues on the primary Cooperative system.
- The addition of the proposed PV site is not expected to negatively impact the existing primary steady-state system capacity.
- The analysis results show pre-existing low voltage during peak load condition. The issue was mitigated with the proposed project on line.
- The analysis results show that the line regulators will not have excessive tap movements with the proposed project online.
- Fault contribution from the proposed project is minimal and will not interfere with the existing Cooperative protection scheme.
- There is negligible risk of unintentional islanding.
1.1 Introduction

Leidos Engineering, LLC (Leidos) has completed the Interconnection Impact Study for the addition of 2,010 kW of solar photovoltaic (PV) generation system to the Electric Cooperative (Cooperative) 34.5 kV system. The PV generation will be comprised of a 2,010 kW system located at Address. The Interconnecting Customer is Interconnecting Customer.

The connection to the Cooperative is located on the MC Substation, 34.5 kV line. The point of interconnection (POI) to the primary system is near the Cooperative’s TL Substation.

Figure 1-1 shows the location of the proposed PV as modeled in Milsoft’s WindMil engineering analysis software.
The 2,010 kW site is located on MC 34.5 kV line. This report summarizes details of the analysis and findings of the interconnection impact study.

The study included a review of short circuit, voltage, load flow, grounding, and other impacts, and compliance with the following standard.

The 2,010 kW PV interconnection consists of:
A total of 8,406 Canadian Solar CS6U-330M, 330 W PV modules
Sixty-seven SMA Sunny Tripower 30000TL-US inverters, 30 kW at 480 Vac output
A three-phase 2,000 kVA, 34.5 kV delta – 480 V wye grounded, step-down transformer with assumed 5.75% impedance and 5.66 X/R ratio
The three-line provided by the Interconnecting Customer is in Appendix A.

1.2 Software Application Tools
The PV site was studied using Milsoft’s WindMil engineering analysis software. The model was created by Leidos for analysis.

1.3 Analysis Conducted
For the interconnection impact study, the following analyses were conducted:
Reverse power flow implications
A review of thermal overload or voltage limit violations resulting from the PV site interconnection compared to the ratings in the WindMil® model
A review of feeder voltage regulation and capacitor switching requirements and settings
A review of voltage flicker caused by the intermittent output of the PV site
A review of the short circuit calculations, including contribution from the proposed PV site, and the impact on the Cooperative device coordination
A review of the PV site protection specified by the developer and any grounding requirements
A screening to determine the risk of unintentional islanding

1.4 Basic Data and Assumptions
For the interconnection impact study, the following data and assumptions were included:
The Cooperative provided daytime peak and minimum loads for MC Substation.
Assumed unity power factor for the PV output.
Existing 2,010 kW PV site is modeled as a generator in the WindMil model.
Fault current contribution as provided in the three-line by Interconnecting Customer.
Source impedance for the MC Substation at the 34.5 kV bus was provided by the Cooperative.
N-1 contingency analysis was not conducted. The PV site will be tripped offline for outage of the line or for any off-schedule conditions on line.
The proposed inverters are UL 1741 certified.
Line regulator parameters and settings that were provided by the Cooperative are shown below in Table 1-1.

<table>
<thead>
<tr>
<th>Model ID</th>
<th>Phase</th>
<th>Size (A)</th>
</tr>
</thead>
<tbody>
<tr>
<td>LH REG3</td>
<td>ABC</td>
<td>251</td>
</tr>
<tr>
<td>TL REG6</td>
<td>ABC</td>
<td>251</td>
</tr>
</tbody>
</table>

Note: (1) WindMIL model naming convention
2.1 Steady-State Power Flow

The PV site was analyzed in the interconnection impact study only for the normal system configuration, as served from MC Substation. Table 2-1 presents the daytime maximum and minimum loads that were evaluated.

<table>
<thead>
<tr>
<th>Measured Location</th>
<th>Peak Load (MW)</th>
<th>Peak Power Factor</th>
<th>Min Load (MW)</th>
<th>Min Load Power Factor</th>
</tr>
</thead>
<tbody>
<tr>
<td>MC(^1)</td>
<td>13.79</td>
<td>99.8%</td>
<td>4.98</td>
<td>100.0%</td>
</tr>
<tr>
<td>LH</td>
<td>2.64</td>
<td>99.1%</td>
<td>0.45</td>
<td>-90.1%</td>
</tr>
<tr>
<td>TL</td>
<td>6.76</td>
<td>98.8%</td>
<td>2.99</td>
<td>-98.6%</td>
</tr>
<tr>
<td>R</td>
<td>3.96</td>
<td>99.0%</td>
<td>1.34</td>
<td>-98.0%</td>
</tr>
</tbody>
</table>

Note: (1) Load at MC includes the net value with the 2,010 kW PV site online.

The addition of the Interconnecting Customer project will not cause reverse power flow through the MC Substation.

The study evaluated four scenarios for steady-state load flow:

1. Normal configuration at minimum demand without the 2,010 kW interconnection online
2. Normal configuration at minimum demand with the 2,010 kW interconnection online
3. Normal configuration at peak demand without the 2,010 kW interconnection online
4. Normal configuration at peak demand with the 2,010 kW interconnection online

Table 2-2 presents the distribution analysis results of these scenarios for the voltage, kW, kvar, and power factor (PF) at the MC 34.5 kV line, and at the POI, and for the minimum and maximum voltage on 34.5 kV line.

The analysis indicated that the addition of the PV site would not create primary line capacity violations. Existing low voltage issues were identified during minimum load condition on the primary line, and were mitigated by interconnecting the project.
## Table 2-2
Load Flow Analysis Results

<table>
<thead>
<tr>
<th>Scenario</th>
<th>2,010 kW PV Status</th>
<th>POI</th>
<th>MC 34.5 kV line</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>V</td>
<td>kW</td>
<td>kvar</td>
</tr>
<tr>
<td>Light Load</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>1</td>
<td>OFF</td>
<td>123.3</td>
<td>-</td>
</tr>
<tr>
<td>2</td>
<td>ON</td>
<td>123.1</td>
<td>-1,991</td>
</tr>
<tr>
<td>Peak Load</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>3</td>
<td>OFF</td>
<td>122.8</td>
<td>-</td>
</tr>
<tr>
<td>4</td>
<td>ON</td>
<td>122.7</td>
<td>-1,991</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Scenario</th>
<th>2,010 kW PV Status</th>
<th>Minimum Voltage</th>
<th>Maximum Voltage</th>
<th>Max Voltage at Inverters</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>V Location</td>
<td>V Location</td>
<td>V</td>
<td></td>
</tr>
<tr>
<td>Light Load</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>1</td>
<td>OFF</td>
<td>119.8</td>
<td>OH2 (3-Ph)</td>
<td>123.3 OH8 (3-Ph)</td>
</tr>
<tr>
<td>2</td>
<td>ON</td>
<td>120.0</td>
<td>OH2 (3-Ph)</td>
<td>123.0 OH8 (3-Ph)</td>
</tr>
<tr>
<td>Peak Load</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>3</td>
<td>OFF</td>
<td>117.5</td>
<td>OH5 (3-Ph)</td>
<td>122.6 OH8 (3-Ph)</td>
</tr>
<tr>
<td>4</td>
<td>ON</td>
<td>118.0</td>
<td>OH2 (3-Ph)</td>
<td>122.4 OH8 (3-Ph)</td>
</tr>
</tbody>
</table>
The steady-state load flow results show that the line regulators will not have excessive tap movement from the addition of the PV site. This is indicated by tap movement of 1 tap or less in the steady state conditions. Table 2-3 presents the findings.

<table>
<thead>
<tr>
<th>Scenario</th>
<th>REG3 LH</th>
<th>REG6 TL</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>1,1,1</td>
<td>4,4,4</td>
</tr>
<tr>
<td>2</td>
<td>1,1,1</td>
<td>3,3,3</td>
</tr>
<tr>
<td>3</td>
<td>4,4,4</td>
<td>7,7,7</td>
</tr>
<tr>
<td>4</td>
<td>4,4,4</td>
<td>6,6,6</td>
</tr>
</tbody>
</table>

### 2.2 Steady-State Voltage Fluctuations

Leidos evaluated a review of the maximum and minimum voltage fluctuation on the system experienced when the PV output drops off, before voltage is regulated back at the substation. The criteria used in the study limits voltage fluctuations to the maximum permissible voltage fluctuation at the borderline of visibility curve from the IEEE 519 Standard. See Figure 2-1 for the curve, which indicates the borderline of visibility is 2.8% starting at one voltage dip per hour. Cooperative criteria is 2% for voltage flicker using this method.

![IEEE 519 Flicker Curve](image)

**Figure 2-1. IEEE 519 Flicker Curve**
For the analysis, the 2,010 kW site was reduced to no output from full output at the peak and minimum load day conditions. Voltage fluctuations at each line section were calculated, and the maximum results are shown in Table 2-4 for the primary system.

### Table 2-4
Steady State Voltage Fluctuations

<table>
<thead>
<tr>
<th>Allowable</th>
<th>Primary System</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Min Load Flicker (%)</td>
</tr>
<tr>
<td>2%</td>
<td>0.58%</td>
</tr>
</tbody>
</table>

The voltage flicker calculated at the project primary POI during peak load and minimum load conditions are 0.55% and 0.41%, respectively. These results do not violate the Cooperative planning criterion flicker limit of 2%.

### 2.3 Grounding and Protection

According to the IEEE 1547-2003, the grounding scheme of the interconnection should not cause over-voltages that exceed the rating of the equipment connected to the EPS and should not disrupt the coordination of the ground fault protection on the EPS.

The study results indicate the Cooperative system remains effectively grounded with the proposed project interconnected, based on the IEEE Std C62.92.1™-2016 IEEE Guide for the Application of Neutral Grounding in Electrical Utility Systems standard.

Leidos modeled the 2,010 kW PV site with a total fault current contribution of 2,424 amps at 480 V. When translated across transformer to 34.5 kV, the total three-phase fault contribution is 40 amps. Table 2-5 lists the substation source impedance supplied by the Cooperative and entered in the WindMil model.

### Table 2-5
Source Impedance

<table>
<thead>
<tr>
<th>Source</th>
<th>Nominal Voltage (kV)</th>
<th>3LG (amps)</th>
<th>1LG (amps)</th>
<th>Positive Sequence (ohms)</th>
<th>Zero Sequence (ohms)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td>R</td>
<td>X</td>
</tr>
<tr>
<td>MC</td>
<td>34.5</td>
<td>1,345</td>
<td>1,165</td>
<td>5.5590</td>
<td>14.5170</td>
</tr>
</tbody>
</table>

Note: Impedance in ohms on a 100 MVA base calculated in WindMil model from data provided by the Cooperative.
Table 2-6 summarizes the calculated fault current at the POI’s, and the 34.5 kV substation bus with and without the 2,010 kW PV site online.

<table>
<thead>
<tr>
<th>GEN Status</th>
<th>Fault Location</th>
<th>LG (Amps)</th>
<th>LG (MVA)</th>
<th>LLLG (Amps)</th>
<th>LLLG (MVA)</th>
<th>Maximum % Fault Current Contribution</th>
</tr>
</thead>
<tbody>
<tr>
<td>OFF</td>
<td>POI</td>
<td>712</td>
<td>43</td>
<td>822</td>
<td>49</td>
<td>4.08%</td>
</tr>
<tr>
<td>ON</td>
<td>POI</td>
<td>741</td>
<td>44</td>
<td>855</td>
<td>51</td>
<td></td>
</tr>
<tr>
<td>OFF</td>
<td>34.5 kV Bus Substation</td>
<td>1,165</td>
<td>70</td>
<td>1,345</td>
<td>80</td>
<td>2.44%</td>
</tr>
<tr>
<td>ON</td>
<td>34.5 kV Bus Substation</td>
<td>1,194</td>
<td>71</td>
<td>1,378</td>
<td>82</td>
<td></td>
</tr>
</tbody>
</table>

From the WindMil short circuit analysis, fault contribution from the proposed site is minimal, and the existing Cooperative protection scheme is not negatively impacted.

There is no protective device between the substation and the POI. Based on the source impedance provided, the calculated fault current for phase to phase faults at the primary side point of interconnection (POI) for the PV project does allow an acceptable margin between TL001 phase relay and MC phase recloser of more than 12 cycles. For ground faults at the POI, the MC fast ground may operate before the TL001 ground relay lockout as the response time is less than 12 cycles for any available ground fault. Refer to Figure 2-2 for the time current coordination curves.
2.4 Islanding Evaluation

To analyze the risk of islanding, a four-step analysis was conducted based on the November 2012 Sandia “Suggested Guidelines for Assessment of DER Unintentional Islanding Risk” report. The following steps were conducted:

Step 1: “Determine whether the aggregate AC rating of all DER exceeds 2/3 of the minimum feeder loading.” If Yes, proceed to Step 2. If No, there is minimal risk of islanding and analysis is complete.

Step 2: “Determine whether QPV + Qload is within 1% of the total aggregate capacitor rating within the island, or alternatively, use real and reactive power flow measurements or simulations at the point at which the island can form to determine whether the feeder power factor is ever
higher than 0.99 (lag or lead) at that point for an extended period of time.” If Yes to either evaluation, a detailed islanding analysis should be considered. If No, proceed to Step 3.

**Step 3:** “Determine whether the potential island contains both rotating and inverter-based DER, and the sum of the AC ratings of the rotating DER is more than 25% of the total AC rating of all DER in the potential island.” If Yes, a detailed islanding analysis should be considered. If No, proceed to Step 4.

**Step 4:** “Sort the inverters by manufacturer, sum up the total AC rating of each manufacturer’s product within the potential island, and determine each manufacturer’s percentage of the total DER. If no single manufacturer’s product makes up at least 2/3 of the total DER in the potential island, then further study may be prudent. If the situation is such that more than 2/3 of the total DER is from a single manufacturer, then the risk of unintentional islanding can be considered negligible.”

Each step is evaluated for each potential island in Table 2-7 below. Yes (Y) indicates there is a risk, and No (N) indicates negligible risk.

<table>
<thead>
<tr>
<th>Potential Island</th>
<th>Step 1 (Y/N)</th>
<th>Step 2 (Y/N)</th>
<th>Step 3 (Y/N)</th>
<th>Step 4 (Y/N)</th>
</tr>
</thead>
<tbody>
<tr>
<td>MC</td>
<td>N</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
</tbody>
</table>

Notes:
1. Aggregate DER capacity (2.010 MW) is less than 2/3 of the minimum loading (4.986 MW).
2. No need to evaluate this step.
3. No need to evaluate this step.
4. No need to evaluate this step.

The results indicate that the risk of unintentional islanding for the inverters, as served from MC Substation, is negligible, as the aggregate DER on the line does not exceed 2/3 of the daytime minimum load.
The study results show the distributed energy resource (DER) system can connect to the Cooperative Electric Power System (EPS) under normal system configuration based on applicable standards and consideration of the required facility upgrades identified in the study. The following summarizes interconnection impact study results:

- Reverse power flow is not expected through the MC Substation during minimum load condition with the proposed project on line.
- The proposed PV site will not cause voltage flicker issues on the primary Cooperative system.
- The addition of the proposed PV site is not expected to negatively impact the existing primary steady-state system capacity.
- The analysis results show pre-existing low voltage during peak load condition. The issue was mitigated with the proposed project on line.
- The analysis results show that the line regulators will not have excessive tap movements with the proposed project online.
- Fault contribution from the proposed project is minimal and will not interfere with the existing Cooperative protection scheme.
- There is negligible risk of unintentional islanding.
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This report documents the Interconnection Impact Study that was performed for the distributed energy resource interconnection application submitted by the Interconnecting Customer for a 1,200 kW photovoltaic (PV) and 250 kW Battery Energy Storage System (BESS) generation facility located at Address. The project name is Project.

The study results show the distributed energy resource (DER) system can connect to the Electric Cooperative (Cooperative) Electric Power System (EPS) under normal system configuration based on applicable standards and consideration of the required facility upgrades identified in the study. The following summarizes interconnection impact study results:

The inverters do not appear to be UL 1741 “Standard for Inverters, Converters, Controllers and Interconnection System Equipment for Use With Distributed Energy Resources” certified nor IEEE 1547 “Standard for Interconnecting Distributed Resources with Electric Power Systems” certified.

There is a potential for reverse power flow through Circuit 5 during minimum load condition with the project on line. Reverse power flow is not expected through the DC Substation during minimum load condition with the project on line.

The PV site will not cause voltage flicker issues on the primary Cooperative system.

The addition of the PV site is not expected to negatively impact the existing primary steady-state system capacity.

The analysis results show high voltage during peak and minimum load condition at the point of interconnection (POI) and on the primary Cooperative system with the project on line.

The analysis results show high voltage at the project inverters during peak and minimum load conditions.

The analysis results show pre-existing overload on the feeder regulator. The issue was mitigated with the project online.

The analysis results show that the feeder regulator will not have excessive tap movements with the project online.

Fault contribution from the project is not minimal, but is not expected to interfere with the existing Cooperative protection scheme.

The Cooperative primary distribution system is effectively grounded at the PV site POI.

There is a negligible risk of unintentional islanding.

To resolve the issues identified above, the following mitigation solutions are required:

Interconnect Project at -97% (Consuming Vars) power factor. The expectant peak load power factor at the substation bus after applying this mitigation is 92%. A switched capacitor bank shall be installed on the circuit or in the substation to account for power factor impacts.

Due to expected reverse power flow through the Circuit 5 source regulator bank, controls may need to be updated to respond properly with power flow in the reverse direction.
1.1 Introduction

Leidos Engineering, LLC (Leidos) has completed the Interconnection Impact Study for the addition of 1,200 kW of solar photovoltaic (PV) and 250 kW Battery Energy Storage System (BESS) generation system to the Electric Cooperative (Cooperative) 13.2 kV system. The generation system is comprised of a 1,200 kW PV and 250 kW BESS system located at Address. The Interconnecting Customer is Interconnecting Customer and project is named Project.

The connection to the Cooperative is located on the DC Substation, Circuit 5. The point of interconnection (POI) to the primary system is at the end node J-310754 of the Circuit 5, located approximately 9.75 miles from the substation.

Figure 1-1 shows geographic outlines of the interconnection and inverter locations, provided by the Interconnecting Customer.

Figure 1-1. Site Diagram
Figure 1-2 shows the location of the PV as modeled in Eaton’s CYME® software.

Figure 1-2. DC Substation Circuit 5 Overview

The PV site is located on Circuit 5. This report summarizes details of the analysis and findings of the interconnection impact study.
The study included a review of short circuit, voltage, load flow, grounding, and other impacts, and compliance with the following standard.


The PV interconnection consists of:
A total of 4,640 REC REC315PE72, 315 W PV modules
One Bonfiglioli RPS TL-4Q 1200 inverter, 1,200 kW at 360 Vac output
A three-phase 1,500 kVA, 13.2 kV wye grounded – 360 V delta, step-down transformer with 6% impedance and 8 X/R ratio
Battery Energy Storage System, 250 kW, 750 kWh each for Phase I and Phase II

The three-line provided by the Interconnecting Customer is in Appendix A.

1.2 Software Application Tools
The PV site was studied using Eaton’s CYME® software. The model was provided by the Cooperative for analysis.

1.3 Analysis Conducted
For the interconnection impact study, the following analyses were conducted:
Reverse power flow implications
A review of thermal overload or voltage limit violations resulting from the PV site interconnection compared to the ratings in the CYME® model
A review of feeder voltage regulation and capacitor switching requirements and settings
A review of voltage flicker caused by the intermittent output of the PV site
A review of the short circuit calculations, including contribution from the PV site, and the impact on Cooperative device coordination
A review of the PV site protection specified by the developer and any grounding requirements
A screening to determine the risk of unintentional islanding

1.4 Basic Data and Assumptions
For the interconnection impact study, the following data and assumptions were included:
The Cooperative provided daytime peak and minimum loads for Circuit 5 and adjacent circuits.
Assumed unity power factor for the PV output.
PV site is modeled as a generator in the CYME model.
Fault current contribution of 120% of continuous current is assumed based on typical industry standards.

Leidos, Inc.
BESS is ON during peak load condition and OFF during minimum load condition. The BESS is connected on the DC bus of the project. Therefore, the maximum output of the project is limited to the 1,200 kW inverter rating.

Source impedance for the DC Substation at the 67 kV bus was calculated by Leidos. N-1 contingency analysis was not conducted. The PV site will be tripped offline for outage of the line or for any off-schedule conditions on line.
2.1 Steady-State Power Flow

The PV site was analyzed in the interconnection impact study only for the normal system configuration, as served from Circuit 5. Table 2-1 presents the daytime maximum and minimum loads that were evaluated.

<table>
<thead>
<tr>
<th>Measured Location</th>
<th>Peak Load (MW)</th>
<th>Peak Load Power Factor&lt;sup&gt;2&lt;/sup&gt;</th>
<th>Min Load (MW)</th>
<th>Min Load Power Factor&lt;sup&gt;2&lt;/sup&gt;</th>
</tr>
</thead>
<tbody>
<tr>
<td>DC Substation Xfmr&lt;sup&gt;1&lt;/sup&gt;</td>
<td>10.73</td>
<td>95.0%</td>
<td>2.68</td>
<td>95.0%</td>
</tr>
<tr>
<td>Circuit 5</td>
<td>1.25</td>
<td>95.0%</td>
<td>0.31</td>
<td>95.0%</td>
</tr>
</tbody>
</table>

Notes: (1) Load at DC Substation Xfmr includes the net value with the 1,200 kW PV site online.  
(2) Power factor is assumed to be 95.0%.

The addition of the Interconnecting Customer project will not cause reverse power flow through the DC Substation.

The study evaluated four scenarios for steady-state load flow:
2. Normal configuration at minimum demand without the 1,200 kW interconnection online
Normal configuration at minimum demand with the 1,200 kW interconnection online
Normal configuration at peak demand without the 1,200 kW interconnection online
Normal configuration at peak demand with the 1,200 kW interconnection + 250 kW BESS online

Table 2-2 presents the distribution analysis results of these scenarios for the voltage, kW, kvar, and power factor (PF) at the Circuit 5, DC Substation 13.2 kV bus, and at the POI, and for the minimum and maximum voltage on Circuit 5.

Battery energy storage system (BESS) of 250 kW in size is ON during peak load condition and OFF during minimum load condition. The BESS is connected to the DC side of the interconnection. Therefore, generation output for the analysis was limited to AC nameplate of the inverter for Scenario 4.

The analysis indicates that the addition of the PV site should not create primary line capacity violations. The analysis results show high voltage during peak and minimum load condition at the point of interconnection (POI) and on the primary Cooperative system with the project online. The analysis results show high voltage at the project inverter during peak and minimum load conditions. The analysis results show pre-existing overload on the feeder regulator. The issue is mitigated with the project online.
In order to mitigate the high voltage issues, the project shall be interconnected at -97% (Consuming Vars) power factor. The power factor result at the substation bus after applying mitigation was 92%. A switch capacitor bank shall be installed to account for power factor impacts due to absorbing Vars.
## Table 2-2
Load Flow Analysis Results

<table>
<thead>
<tr>
<th>Scenario</th>
<th>1,200 kW PV + 250 kW BESS Status</th>
<th>POI</th>
<th>Circuit 5</th>
<th>DC Substation Bus</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>V kW kvar P.F.</td>
<td>V kW kvar P.F.</td>
<td>V kW kvar P.F.</td>
<td></td>
</tr>
<tr>
<td>Minimum Load</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>1</td>
<td>OFF</td>
<td>125.1 - - -</td>
<td>125.3</td>
<td>311</td>
</tr>
<tr>
<td>2</td>
<td>ON</td>
<td>127.6 -1,194 51 99.9%</td>
<td>125.3</td>
<td>-860</td>
</tr>
<tr>
<td>Peak Load</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>3</td>
<td>OFF</td>
<td>123.7 - - -</td>
<td>125.1</td>
<td>1,245</td>
</tr>
<tr>
<td>4</td>
<td>ON</td>
<td>126.5 -1,194 51 99.9%</td>
<td>125.3</td>
<td>64</td>
</tr>
</tbody>
</table>

Note: (1) 250 kW BESS is ON for peak load condition and OFF for minimum load condition.

<table>
<thead>
<tr>
<th>Scenario</th>
<th>1,200 kW PV + 250 kW BESS Status</th>
<th>Minimum Voltage</th>
<th>Maximum Voltage</th>
<th>Max Voltage at Inverters</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>V Location</td>
<td>V Location</td>
<td>V</td>
<td></td>
</tr>
<tr>
<td>Light Load</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>1</td>
<td>OFF</td>
<td>125.4 PC-66941 (Ph B)</td>
<td>125.4 PC-252243 (Ph C)</td>
<td>0</td>
</tr>
<tr>
<td>2</td>
<td>ON</td>
<td>125.2 PC-66979 (Ph B)</td>
<td>127.7 PC-175783 (Ph A &amp; C)</td>
<td>128.3 (Ph A)</td>
</tr>
<tr>
<td>Peak Load</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>3</td>
<td>OFF</td>
<td>123.3 PC-65630 (Ph A)</td>
<td>125.2 PC-252243 (Ph C)</td>
<td>0</td>
</tr>
<tr>
<td>4</td>
<td>ON</td>
<td>124.1 PC-66615 (Ph A)</td>
<td>126.5 PC-175783 (Ph C)</td>
<td>127.2 (Ph A)</td>
</tr>
</tbody>
</table>
The steady-state load flow results show that the feeder regulator will not have excessive tap movement from the addition of the PV site. This is indicated by tap movement of one tap or less in the steady-state conditions. Table 2-3 presents the findings.

<table>
<thead>
<tr>
<th>Scenario</th>
<th>Circuit 5 Feeder Regulator</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>9,9,9</td>
</tr>
<tr>
<td>2</td>
<td>9,9,9</td>
</tr>
<tr>
<td>3</td>
<td>14,14,14</td>
</tr>
<tr>
<td>4</td>
<td>14,14,14</td>
</tr>
</tbody>
</table>

### 2.2 Steady-State Voltage Fluctuations

Leidos evaluated a review of the maximum and minimum voltage fluctuation on the system experienced when the PV output drops off, before voltage is regulated back at the substation. The criteria used in the study limits voltage fluctuations to the maximum permissible voltage fluctuation at the borderline of visibility curve from the IEEE 519 Standard. See Figure 2-1 for the curve, which indicates the borderline of visibility is 2.8% starting at one voltage dip per hour. Cooperative criteria is 2% for voltage flicker using this method.
For the analysis, the 1,200 kW site was reduced to no output from full output at the peak and minimum load day conditions. The BESS remained online for the peak analysis of voltage flicker when the PV drops to zero output. Voltage fluctuations at each line section were calculated, and the maximum results are shown in Table 2-4 for the primary system.

<table>
<thead>
<tr>
<th>Allowable</th>
<th>Primary System</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
</tr>
<tr>
<td>Min Load Flicker (%)</td>
<td>Max Load Flicker (%)</td>
</tr>
<tr>
<td>2%</td>
<td>1.96%</td>
</tr>
</tbody>
</table>

The voltage flicker calculated at the project primary POI during peak load and minimum load conditions are 1.96% and 1.66%, respectively. These results do not violate the Cooperative planning criterion flicker limit of 2%.

### 2.3 Grounding and Protection

According to the IEEE 1547-2003, the grounding scheme of the interconnection should not cause over-voltages that exceed the rating of the equipment connected to the EPS and should not disrupt the coordination of the ground fault protection on the EPS.

The study results indicate the Cooperative system remains effectively grounded with the project interconnected, based on the IEEE Std C62.92.1™-2016 IEEE Guide for the Application of Neutral Grounding in Electrical Utility Systems standard.

Leidos modeled the 1,200 kW PV site with a total fault current contribution of 2,304 amps at 360 V. When translated across transformer to 13.2 kV, the total three-phase fault contribution is 63 amps. Table 2-5 lists the substation source impedance supplied by the Cooperative and entered in the CYME model.

<table>
<thead>
<tr>
<th>Source</th>
<th>Nominal Voltage (kV)</th>
<th>3LG (amps)</th>
<th>1LG (amps)</th>
<th>Positive Sequence (ohms)</th>
<th>Zero Sequence (ohms)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td>R  X</td>
<td>R  X</td>
</tr>
<tr>
<td>DC</td>
<td>67</td>
<td>3,655</td>
<td>3,751</td>
<td>0.4342 10.5737</td>
<td>0.3924 9.7629</td>
</tr>
</tbody>
</table>
Table 2-6 summarizes the calculated fault current at the POI, the 13.2 kV substation bus and the 67 kV substation bus, with and without the 1,200 kW PV site online.

<table>
<thead>
<tr>
<th>GEN Status</th>
<th>Fault Location</th>
<th>LG (Amps)</th>
<th>LG (MVA)</th>
<th>LLLG (Amps)</th>
<th>LLLG (MVA)</th>
<th>Maximum % Fault Current Contribution</th>
</tr>
</thead>
<tbody>
<tr>
<td>OFF</td>
<td>POI</td>
<td>442</td>
<td>10</td>
<td>878</td>
<td>20</td>
<td>130.09%</td>
</tr>
<tr>
<td>ON</td>
<td>POI</td>
<td>1,017</td>
<td>23</td>
<td>932</td>
<td>21</td>
<td></td>
</tr>
<tr>
<td>OFF</td>
<td>13.2 kV Bus Substation</td>
<td>5,633</td>
<td>129</td>
<td>5,182</td>
<td>118</td>
<td>1.14%</td>
</tr>
<tr>
<td>ON</td>
<td>13.2 kV Bus Substation</td>
<td>5,697</td>
<td>130</td>
<td>5,239</td>
<td>120</td>
<td></td>
</tr>
<tr>
<td>OFF</td>
<td>67 kV Bus Substation</td>
<td>3,751</td>
<td>435</td>
<td>3,655</td>
<td>424</td>
<td>0.30%</td>
</tr>
<tr>
<td>ON</td>
<td>67 kV Bus Substation</td>
<td>3,755</td>
<td>436</td>
<td>3,666</td>
<td>425</td>
<td></td>
</tr>
</tbody>
</table>

From the CYME short circuit analysis, fault contribution from the site is not minimal, but the existing Cooperative protection scheme is not negatively impacted.

There is no protective device between the substation and the POI.

### 2.4 Islanding Evaluation

To analyze the risk of islanding, a four-step analysis was conducted based on the November 2012 Sandia “Suggested Guidelines for Assessment of DER Unintentional Islanding Risk” report. The following steps were conducted:

**Step 1:** “Determine whether the aggregate AC rating of all DER exceeds 2/3 of the minimum feeder loading.” If Yes, proceed to Step 2. If No, there is minimal risk of islanding and analysis is complete.

**Step 2:** “Determine whether QPV + Qload is within 1% of the total aggregate capacitor rating within the island, or alternatively, use real and reactive power flow measurements or simulations at the point at which the island can form to determine whether the feeder power factor is ever higher than 0.99 (lag or lead) at that point for an extended period of time.” If Yes to either evaluation, a detailed islanding analysis should be considered. If No, proceed to Step 3.

**Step 3:** “Determine whether the potential island contains both rotating and inverter-based DER, and the sum of the AC ratings of the rotating DER is more than 25% of the total AC rating of all DER in the potential island.” If Yes, a detailed islanding analysis should be considered. If No, proceed to Step 4.

**Step 4:** “Sort the inverters by manufacturer, sum up the total AC rating of each manufacturer’s product within the potential island, and determine each manufacturer’s percentage of the total DER. If no single manufacturer’s product makes up at least 2/3 of the total DER in the potential island, then further study may be prudent. If the situation is such that more than 2/3 of the total
DER is from a single manufacturer, then the risk of unintentional islanding can be considered negligible.”

Each step is evaluated for each potential island in Table 2-7 below. Yes (Y) indicates there is a risk, and No (N) indicates negligible risk.

<table>
<thead>
<tr>
<th>Potential Island</th>
<th>Step 1 (Y/N)</th>
<th>Step 2 (Y/N)</th>
<th>Step 3 (Y/N)</th>
<th>Step 4 (Y/N)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Circuit 5</td>
<td>Y</td>
<td>N</td>
<td>N</td>
<td>N</td>
</tr>
</tbody>
</table>

Notes:
5. Aggregate DER capacity (1.2 MW) is less than 2/3 of the minimum loading (0.151 MW).
6. No var match as there are no cap banks on Circuit 5.
7. No rotating DG on Circuit 5.
8. More than 2/3 of total DG capacity is from single inverter manufacturer.

The results indicate that the risk of unintentional islanding for the inverters, as served from Circuit 5, is negligible as there is no var match and more than 2/3 of total DG capacity is from single inverter manufacturer.

### 2.5 Sensitivity Study

Additional analysis was conducted by Leidos to determine the interconnection impact if an additional 1,200 kW PV and 250 kW BESS site is interconnected at the same location as the existing, studied site.

For the Sensitivity Study, the following analyses were conducted:

- **Reverse power flow implications**
  - A review of thermal overload or voltage limit violations resulting from the PV sites interconnection compared to the ratings in the CYME® model
  - A review of feeder voltage regulation and capacitor switching requirements and settings
  - A review of voltage flicker caused by the intermittent output of the PV sites
  - A review of the short circuit calculations, including contribution from the PV sites, and the impact on Cooperative device coordination
  - A review of the PV sites protection specified by the developer and any grounding requirements
  - A screening to determine the risk of unintentional islanding
In addition to the existing project size study results, the following criteria violations were identified for doubling the site size:

Increasing the size creates a very close margin of load to generation at the DC Substation. Based on annual load data provided and AC nameplate of 2,400 kW for the project, Leidos identified a scenario where there could be a load measurement of 122 kW at the substation. If reverse power flow is a concern, mitigations including bi-directional metering and zero sequence overvoltage protection at the substation should be considered.

Voltage flicker exceeds 2% on the circuit

High voltage on the circuit and at the POI, and high voltage at the inverters is exacerbated.

The feeder regulator is over capacity with or without the project online.

To resolve the issues identified above, the following mitigation solutions are required:

Interconnect the inverters at -96% (Consuming Vars) power factor. A switched capacitor on the circuit is still recommended due to poor power factor of 85% at the substation with the inverters operating at off unity power factor.

Due to expected reverse power flow through the Circuit 5 source regulator bank, controls may need to be updated to respond properly with power flow in the reverse direction.

Reduce the feeder regulator voltage setting from 126 V to 125 V.

Upgrade the size of the feeder regulator.
SUMMARY AND RECOMMENDATIONS

The study results show the distributed energy resource (DER) system can connect to the Cooperative Electric Power System (EPS) under normal system configuration based on applicable standards and consideration of the required facility upgrades identified in the study. The following summarizes interconnection impact study results:

The inverters do not appear to be UL 1741 “Standard for Inverters, Converters, Controllers and Interconnection System Equipment for Use With Distributed Energy Resources” certified nor IEEE 1547 “Standard for Interconnecting Distributed Resources with Electric Power Systems” certified.

There is a potential for reverse power flow through Circuit 5 during minimum load condition with the project on line. Reverse power flow is not expected through the DC Substation during minimum load condition with the project on line.

The PV site will not cause voltage flicker issues on the primary Cooperative system.

The addition of the PV site is not expected to negatively impact the existing primary steady-state system capacity.

The analysis results show high voltage during peak and minimum load condition at the point of interconnection (POI) and on the primary Cooperative system with the project on line.

The analysis results show high voltage at the project inverters during peak and minimum load conditions.

The analysis results show pre-existing overload on the feeder regulator. The issue was mitigated with the project online.

The analysis results show that the feeder regulator will not have excessive tap movements with the project online.

Fault contribution from the project is not minimal but is not expected to interfere with the existing Cooperative protection scheme.

The Cooperative primary distribution system is effectively grounded at the PV site POI.

There is a negligible risk of unintentional islanding.

To resolve the issues identified above, the following mitigation solutions are required:

3. Interconnect Project at -97% (Consuming Vars) power factor. The expectant peak load power factor at the substation bus after applying this mitigation is 92%. A switched capacitor bank shall be installed on the circuit or in the substation to account for power factor impacts.

Due to expected reverse power flow through the Circuit 5 source regulator bank, controls may need to be updated to respond properly with power flow in the reverse direction.
Report

Interconnecting Customer
2,000 kW PV Interconnection Impact Study

Electric Cooperative

April 10, 2018
Interconnecting Customer
2,000 kW PV Interconnection Impact Study

> Cooperative

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EXECUTIVE SUMMARY

This report documents the Interconnection Impact Study that was performed for the distributed energy resource interconnection application submitted by the Interconnecting Customer for a 2,000 kW photovoltaic (PV) generation facility located at Address. The 2,000 kW PV is in service.

The study results show the distributed energy resource (DER) system can connect to the Electric Cooperative (Cooperative) Electric Power System (EPS) under normal system configuration based on applicable standards and consideration of the required facility upgrades identified in the study. The following summarizes interconnection impact study results:

There is a potential for reverse power flow through Circuit 2421 during minimum load with the project on line. Reverse power flow is not expected through the A Substation Transformer #2 during minimum load condition with the project on line.

The PV site will not cause voltage flicker issues on the Cooperative primary distribution system.

The addition of the PV site is not expected to negatively impact the existing primary steady-state system capacity.

The analysis results show primary system voltages are within acceptable limits.

The analysis results show that the substation transformer load tap changer (LTC) will not have excessive tap movements with the project online.

Fault contribution from the project is minimal, and is not expected to interfere with the existing Cooperative protection scheme.

There are three protective devices, Substation Recloser AUB2421, Recloser RCL.594, and Fuse FUSE.379974, between the substation and the point of interconnection (POI). The loading on the reclosers and fuse does not exceed its current rating with the project online.

The Cooperative primary distribution system is effectively grounded at the PV site POI.

There is a risk of unintentional islanding.

To resolve the issues identified above, the following mitigation solutions are required:

Reclose blocking is recommended to enable Cooperative to block reclosing on electronic devices in the event that the inverters may not detect the island and shut off automatically.
1.1 Introduction

Leidos Engineering, LLC (Leidos) has completed the Interconnection Impact Study for the addition of 2,000 kW of solar PV generation system to the Cooperative 25 kV system. The generation system is comprised of a 2,000 kW PV system located at Address. The Interconnecting Customer is Interconnecting Customer. The 2,000 kW PV is in service.

The connection to Cooperative is located on the A Substation, Circuit 2421. The POI to the primary system is located approximately 3.55 miles from the substation.
Figure 1-1 shows the location of the PV as modeled in Milsoft’s WindMil engineering analysis software.

Figure 1-1. A Substation Circuit 2421 Overview

The PV site is located on Circuit 2421. This report summarizes details of the analysis and findings of the interconnection impact study.

The study included a review of short circuit, voltage, load flow, grounding, and other impacts, and compliance with the following standard.

The PV interconnection consists of:
A total of 8,448 Solarworld, 315 W PV modules
Four Advanced Energy AE 500 NX inverters, 500 kW at 480 Vac output
Two three-phase 1,000 kVA, 25 kV wye grounded – 480 V wye grounded, interconnection transformers with 5.75% impedance and 8 X/R ratio
The single-line provided by the Interconnecting Customer is in Appendix A.

1.2 Software Application Tools
The PV site was studied using Milsoft’s WindMil engineering analysis software. The model was provided by the Cooperative for analysis.

1.3 Analysis Conducted
For the interconnection impact study, the following analyses were conducted:
Reverse power flow implications
A review of thermal overload or voltage limit violations resulting from the PV site interconnection compared to the ratings in the WindMil® model
A review of feeder voltage regulation and capacitor switching requirements and settings
A review of voltage flicker caused by the intermittent output of the PV site
A review of the short circuit calculations, including contribution from the PV site, and the impact on Cooperative device coordination
A review of the PV site protection specified by the developer and any grounding requirements
A screening to determine the risk of unintentional islanding

1.4 Basic Data and Assumptions
For the interconnection impact study, the following data and assumptions were included:
The Cooperative provided daytime peak and minimum loads for Circuit 2421 and the adjacent circuit.
Assumed unity power factor for the PV output.
PV site is modeled as a generator in the WindMil model.
Fault current contribution of 120% of continuous current is assumed based on typical industry standards.
Source impedance for A Substation at the 138 kV bus was provided by the Cooperative.
N-1 contingency analysis was not conducted. The PV site will be tripped offline for outage of the line or for any off-schedule conditions on line.
The inverters are UL 1741 certified.
Recloser parameters and settings that were provided by the Cooperative are shown below in Table 1-1.

### Table 1-1
**Recloser Parameters**

<table>
<thead>
<tr>
<th>Model ID</th>
<th>Phasing</th>
<th>Type</th>
</tr>
</thead>
<tbody>
<tr>
<td>AUB2421</td>
<td>ABC</td>
<td>480-240 VWVE</td>
</tr>
<tr>
<td>RCL.559</td>
<td>ABC</td>
<td>NovaTS 140/70</td>
</tr>
<tr>
<td>RCL.594</td>
<td>ABC</td>
<td>NovaTS 200/100</td>
</tr>
<tr>
<td>RCL.26594</td>
<td>B</td>
<td>Nova-1 140</td>
</tr>
</tbody>
</table>

Note: WindMil model naming convention

Capacitor parameters and settings that were provided by the Cooperative are shown below in Table 1-2.

### Table 1-2
**Capacitor Parameters**

<table>
<thead>
<tr>
<th>Model ID</th>
<th>kvar/Phase</th>
<th>Control</th>
</tr>
</thead>
<tbody>
<tr>
<td>CAP.76611</td>
<td>100</td>
<td>Switched</td>
</tr>
<tr>
<td>CAP.355</td>
<td>200</td>
<td>Switched</td>
</tr>
<tr>
<td>CAP.38209</td>
<td>200</td>
<td>Switched</td>
</tr>
<tr>
<td>CAP.76625</td>
<td>200</td>
<td>Switched</td>
</tr>
</tbody>
</table>

Note: WindMil model naming convention
Section 2
IMPACT STUDY

2.1 Steady-State Power Flow

The PV site was analyzed in the interconnection impact study only for the normal system configuration, as served from Circuit 2421. Table 2-1 presents the daytime maximum and minimum loads that were evaluated.

<table>
<thead>
<tr>
<th>Measured Location</th>
<th>Peak Load (kVA)</th>
<th>Peak Load Power Factor</th>
<th>Min Load (kVA)</th>
<th>Min Load Power Factor</th>
</tr>
</thead>
<tbody>
<tr>
<td>Circuit 2421¹</td>
<td>7,578</td>
<td>100.0%</td>
<td>1,478</td>
<td>99.6%</td>
</tr>
<tr>
<td>Circuit 2422</td>
<td>6,130</td>
<td>95.0%</td>
<td>2,333</td>
<td>95.0%</td>
</tr>
</tbody>
</table>

Notes:
1. Load at Circuit 2421 is the feeder load after the contribution of the 2,000 kW PV site has been removed from the recorded load.
2. Power factor is calculated using the swing bus in WindMil.

The addition of the Interconnecting Customer project will not cause reverse power flow through the A Substation Transformer #2.

The study evaluated four scenarios for steady-state load flow:

4. Normal configuration at minimum demand without the 2,000 kW interconnection online
Normal configuration at minimum demand with the 2,000 kW interconnection online
Normal configuration at peak demand without the 2,000 kW interconnection online
Normal configuration at peak demand with the 2,000 kW interconnection online

Table 2-2 presents the distribution analysis results of these scenarios for the voltage, kW, kvar, and power factor (PF) at Circuit 2421, A Substation 25 kV bus, and at the POI, and for the minimum and maximum voltage on Circuit 2421.

The analysis indicates that the addition of the PV site will not create primary line voltage and capacity violations.
### Table 2-2
Load Flow Analysis Results

<table>
<thead>
<tr>
<th>Scenario</th>
<th>2,000 kW PV</th>
<th>POI</th>
<th>Circuit 2421</th>
<th>A Substation Xfmr 2 Bus</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td></td>
<td>2421</td>
<td>2</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>V</td>
<td>kW</td>
<td>kvar</td>
<td>P.F.</td>
</tr>
<tr>
<td>Minimum Load</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>1</td>
<td>OFF</td>
<td>124.0</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>2</td>
<td>ON</td>
<td>124.6</td>
<td>-1,987</td>
<td>99 99.9%</td>
</tr>
<tr>
<td>Peak Load</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>3</td>
<td>OFF</td>
<td>121.7</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>4</td>
<td>ON</td>
<td>122.5</td>
<td>-1,986</td>
<td>100 99.9%</td>
</tr>
</tbody>
</table>

Note: Switched capacitor banks were modelled as on for peak analysis and off for minimum analysis.

<table>
<thead>
<tr>
<th>Scenario</th>
<th>2,000 kW PV</th>
<th>Minimum Voltage</th>
<th>Maximum Voltage</th>
<th>Max Voltage at Inverters</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>V Location</td>
<td>V Location</td>
<td>V</td>
</tr>
<tr>
<td>Light Load</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>1</td>
<td>OFF</td>
<td>123.6 OH.11316-S25474 (Ph C)</td>
<td>124.3 OH.807957-S3901 (Ph A)</td>
<td>0</td>
</tr>
<tr>
<td>2</td>
<td>ON</td>
<td>124.1 OH.38988-S4310 (Ph C)</td>
<td>124.7 UG.1332531 (Ph A)</td>
<td>125.4 (Ph A)</td>
</tr>
<tr>
<td>Peak Load</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>3</td>
<td>OFF</td>
<td>119.6 UG.152576 (Ph A)</td>
<td>124.3 OH.306007 (Ph B)</td>
<td>0</td>
</tr>
<tr>
<td>4</td>
<td>ON</td>
<td>120.3 UG.152576 (Ph A)</td>
<td>124.7 UG.1332531 (Ph B)</td>
<td>125.3 (Ph B)</td>
</tr>
</tbody>
</table>

Note: Maximum and minimum voltages are based on WindMi calculations along the primary distribution system by-phase.
The steady-state load flow results show that the substation transformer LTC will not have excessive tap movement from the addition of the PV site. This is indicated by tap movement of one tap or less in the steady-state conditions. Table 2-3 presents the findings.

<table>
<thead>
<tr>
<th>Scenario</th>
<th>Transformer #2 LTC Taps</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>-1,-1,-1</td>
</tr>
<tr>
<td>2</td>
<td>-1,-1,-1</td>
</tr>
<tr>
<td>3</td>
<td>0,0,0</td>
</tr>
<tr>
<td>4</td>
<td>0,0,0</td>
</tr>
</tbody>
</table>

### 2.2 Steady-State Voltage Fluctuations

Leidos evaluated a review of the maximum and minimum voltage fluctuation on the system experienced when the PV output drops off, before voltage is regulated back at the substation. The criteria used in the study limits voltage fluctuations to the maximum permissible voltage fluctuation at the borderline of visibility curve from the IEEE 519 Standard. See Figure 2-1 for the curve, which indicates the borderline of visibility is 2.8% starting at one voltage dip per hour. Cooperative criteria is 2% for voltage flicker using this method.

![Figure 2-1. IEEE 519 Flicker Curve](image-url)
For the analysis, the 2,000 kW site was reduced to no output from full output at the peak and minimum load day conditions. Voltage fluctuations at each line section were calculated, and the maximum results are shown in Table 2-4 for the primary system.

### Table 2-4
Steady State Voltage Fluctuations

<table>
<thead>
<tr>
<th>Allowable</th>
<th>Primary System</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Min Load Flicker (%)</td>
</tr>
<tr>
<td>2%</td>
<td>0.56%</td>
</tr>
</tbody>
</table>

The voltage flicker calculated at the project primary POI during peak load and minimum load conditions are 0.54% and 0.70%, respectively. These results do not violate the Cooperative planning criterion flicker limit of 2%.

### 2.3 Grounding and Protection

According to the IEEE 1547-2003, the grounding scheme of the interconnection should not cause over-voltages that exceed the rating of the equipment connected to the EPS and should not disrupt the coordination of the ground fault protection on the EPS.

The study results indicate the Cooperative system remains effectively grounded with the project interconnected, based on the IEEE Std C62.92.1™-2016 IEEE Guide for the Application of Neutral Grounding in Electrical Utility Systems standard.

Leidos modeled the 2,000 kW PV site with a total fault current contribution of 2,887 amps at 480 V. When translated across transformer to 25 kV, the total three-phase fault contribution is 55 amps. Table 2-5 lists the substation source impedance supplied by the Cooperative and entered in the WindMil model.

### Table 2-5
Source Impedance

<table>
<thead>
<tr>
<th>Source</th>
<th>Nominal Voltage (kV)</th>
<th>3LG (amps)</th>
<th>1LG (amps)</th>
<th>Positive Sequence (ohms)</th>
<th>Zero Sequence (ohms)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td>R</td>
<td>X</td>
</tr>
<tr>
<td>A Substation</td>
<td>138</td>
<td>10,018</td>
<td>8,675</td>
<td>2.2850</td>
<td>14.2830</td>
</tr>
</tbody>
</table>
Table 2-6 summarizes the calculated fault current at the POI, the 25 kV substation bus and the 138 kV substation bus, with and without the 2,000 kW PV site online.

<table>
<thead>
<tr>
<th>GEN Status</th>
<th>Fault Location</th>
<th>LG (Amps)</th>
<th>LG (MVA)</th>
<th>LLLG (Amps)</th>
<th>LLLG (MVA)</th>
<th>Maximum % Fault Current Contribution</th>
</tr>
</thead>
<tbody>
<tr>
<td>OFF</td>
<td>POI</td>
<td>1,613</td>
<td>70</td>
<td>2,109</td>
<td>91</td>
<td>3.73%</td>
</tr>
<tr>
<td>ON</td>
<td>POI</td>
<td>1,673</td>
<td>72</td>
<td>2,163</td>
<td>94</td>
<td></td>
</tr>
<tr>
<td>OFF</td>
<td>25 kV Bus Substation</td>
<td>3,390</td>
<td>147</td>
<td>3,275</td>
<td>142</td>
<td>1.62%</td>
</tr>
<tr>
<td>ON</td>
<td>25 kV Bus Substation</td>
<td>3,443</td>
<td>149</td>
<td>3,328</td>
<td>144</td>
<td></td>
</tr>
<tr>
<td>OFF</td>
<td>138 kV Bus Substation</td>
<td>8,675</td>
<td>2,074</td>
<td>10,018</td>
<td>2,394</td>
<td>0.17%</td>
</tr>
<tr>
<td>ON</td>
<td>138 kV Bus Substation</td>
<td>8,690</td>
<td>2,077</td>
<td>9,869</td>
<td>2,359</td>
<td></td>
</tr>
</tbody>
</table>

From the WindMil short circuit analysis, fault contribution from the site is acceptable, and the existing Cooperative protection scheme is not negatively impacted.

There are three protective devices, Recloser AUB2421, Recloser RCL.594, and Fuse FUSE.379974 between the substation and the POI. The loading on the reclosers and fuse does not exceed its current rating with the project online.

### 2.4 Islanding Evaluation

To analyze the risk of islanding, a four-step analysis was conducted based on the November 2012 Sandia “Suggested Guidelines for Assessment of DER Unintentional Islanding Risk” report. The following steps were conducted:

**Step 1:** “Determine whether the aggregate AC rating of all DER exceeds 2/3 of the minimum feeder loading.” If Yes, proceed to Step 2. If No, there is minimal risk of islanding and analysis is complete.

**Step 2:** “Determine whether QPV + Qload is within 1% of the total aggregate capacitor rating within the island, or alternatively, use real and reactive power flow measurements or simulations at the point at which the island can form to determine whether the feeder power factor is ever higher than 0.99 (lag or lead) at that point for an extended period of time.” If Yes to either evaluation, a detailed islanding analysis should be considered. If No, proceed to Step 3.

**Step 3:** “Determine whether the potential island contains both rotating and inverter-based DER, and the sum of the AC ratings of the rotating DER is more than 25% of the total AC rating of all DER in the potential island.” If Yes, a detailed islanding analysis should be considered. If No, proceed to Step 4.

**Step 4:** “Sort the inverters by manufacturer, sum up the total AC rating of each manufacturer’s product within the potential island, and determine each manufacturer’s percentage of the total DER. If no single manufacturer’s product makes up at least 2/3 of the total DER in the potential
island, then further study may be prudent. If the situation is such that more than 2/3 of the total DER is from a single manufacturer, then the risk of unintentional islanding can be considered negligible.”

Each step is evaluated for each potential island in Table 2-7 below. Yes (Y) indicates there is a risk, and No (N) indicates negligible risk.

<table>
<thead>
<tr>
<th>Potential Island</th>
<th>Step 1 (Y/N)</th>
<th>Step 2 (Y/N)</th>
<th>Step 3 (Y/N)</th>
<th>Step 4 (Y/N)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Circuit 2421</td>
<td>Y¹</td>
<td>Y²</td>
<td>N³</td>
<td>N⁴</td>
</tr>
</tbody>
</table>

Notes:
9. Aggregate DER capacity (2 MW) is more than 2/3 of the minimum loading (1.478 MW).
10. QPV+Qload could be within the 1% of the total aggregate capacitor rating throughout the day.
11. No rotating DG on Circuit 2421.
12. More than 2/3 of total DG capacity is from single inverter manufacturer.

The results indicate that the risk of unintentional islanding for the inverters, as served from Circuit 2421, is probable as the aggregate DG on the feeder exceeds 2/3 of the daytime minimum feeder load and QPV+Qload could be within 1% of the total aggregate capacitor rating throughout the day. The criteria suggesting concern with power factor is directly related to inverters using active islanding incorporating positive feedback on frequency.

Therefore, reclose blocking is recommended to enable the Cooperative to block reclosing on electronic devices in the event that the inverters may not detect the island and shut off automatically.
SUMMARY AND RECOMMENDATIONS

The study results show the DER can connect to the Cooperative EPS under normal system configuration based on applicable standards and consideration of the required facility upgrades identified in the study. The following summarizes interconnection impact study results:

There is a potential for reverse power flow through Circuit 2421 during minimum load with the project on line. Reverse power flow is not expected through the A Substation Transformer #2 during minimum load condition with the project on line.

The PV site will not cause voltage flicker issues on the Cooperative primary distribution system.

The addition of the PV site is not expected to negatively impact the existing primary steady-state system capacity.

The analysis results show primary system voltages are within acceptable limits.

The analysis results show that the substation transformer load tap changer (LTC) will not have excessive tap movements with the project online.

Fault contribution from the project is minimal, and is not expected to interfere with the existing Cooperative protection scheme.

There are three protective devices, Substation Recloser AUB2421, Recloser RCL.594, and Fuse FUSE.379974, between the substation and the point of interconnection (POI). The loading on the reclosers and fuse does not exceed its current rating with the project online.

The Cooperative primary distribution system is effectively grounded at the PV site POI.

There is a risk of unintentional islanding.

To resolve the issues identified above, the following mitigation solutions are required:

5. Reclose blocking is recommended to enable the Cooperative to block reclosing on electronic devices in the event that the inverters may not detect the island and shut off automatically.
Final Report

Interconnecting Customer
500 kW PV Interconnection Impact Study

Electric Cooperative

November 13, 2017
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EXECUTIVE SUMMARY

This report documents the Interconnection Impact Study that was performed for the distributed energy resource interconnection application submitted by Interconnecting Customers for a 500 kW photovoltaic (PV) generation facility located in Location.

The study results show the distributed energy resource (DER) system can connect to the Electric Cooperative (Cooperative) Electric Power System (EPS) under normal system configuration based on applicable standards and consideration of the required facility upgrades identified in the study. The following summarizes interconnection impact study results:

- There is a potential for reverse power flow through Circuit L during minimum load condition with the project on line. Reverse power flow is not expected through the PA Substation #2 during minimum load condition with the project on line.
- The PV site will not cause voltage flicker issues on the primary Cooperative distribution system.
- The addition of the PV site is not expected to negatively impact the existing primary steady-state system capacity.
- The analysis results show primary system voltages are within acceptable limits.
- The Cooperative primary distribution system is effectively grounded at the PV site POI.
- Fault contribution from the project is acceptable.
- There is one protective device, Recloser L, between the substation and the point of interconnection (POI). The loading on the recloser does not exceed its current rating with the project online.
- There is a risk of unintentional islanding.

Mitigation Recommendations

Initiate a reclose blocking scheme in Recloser L to prevent it from closing into a potential island and allow time for the PV site to go offline if an extended island does form.
1.1 Introduction

Leidos Engineering, LLC (Leidos) has completed the Interconnection Impact Study for the addition of 500 kW of solar photovoltaic (PV) generation system to the Electric Cooperative (Cooperative) 12.47 kV distribution system. The PV generation will be comprised of a 500 kW system located in Address. The Interconnecting Customers are Interconnecting Customer.

The connection to Cooperative is located on the PA Substation #2, Circuit L. The point of interconnection (POI) to the primary system is near the Cooperative’s Consumer #011041005004, located approximately 2 miles from the substation.

Figure 1-1 shows geographic outlines of the interconnection and inverter locations, provided by the Interconnecting Customers.

Figure 1-2 shows the location of the PV as modeled in Milsoft’s WindMil engineering analysis software.
Figure 1-2. Circuit L Overview

The 500 kW site is located on Circuit L. This report summarizes details of the analysis and findings of the interconnection impact study.

The study included a review of short circuit, voltage, load flow, grounding, and other impacts, and compliance with the following standard.


The 500 kW PV interconnection consists of:

A total of 1,782 Suniva OPT325-72-4-100, 325 W PV modules
Two Advanced Energy AE250TX inverters, 250 kW at 480 Vac output
A three-phase 1,000 kVA, 12.47 kV wye grounded – 480 V wye grounded, step-down transformer with assumed 5.75% impedance and 4.64 X/R ratio
The three-line and site diagrams provided by the Interconnecting Customers are in Appendix A.

1.2 Software Application Tools
The PV site was studied using Milsoft’s WindMil engineering analysis software. The model was provided by the Cooperative for analysis.

1.3 Analysis Conducted
For the interconnection impact study, the following analyses were conducted:
Reverse power flow implications
A review of thermal overload or voltage limit violations resulting from the PV site interconnection compared to the ratings in the WindMil® model
A review of feeder voltage regulation and capacitor switching requirements and settings
A review of voltage flicker caused by the intermittent output of the PV site
A review of the short circuit calculations, including contribution from the PV site, and the impact on the Cooperative device coordination
A review of the PV site protection specified by the developer and any grounding requirements
A screening to determine the risk of unintentional islanding

1.4 Basic Data and Assumptions
For the interconnection impact study, the following data and assumptions were included:
The Cooperative provided daytime peak and minimum loads for Circuit L.
Assumed unity power factor for the PV output.
Existing 500 kW PV site is modeled as a generator in the WindMil model.
Fault current contribution of 120% of continuous current is assumed based on typical industry standards.
Source impedance for the Circuit L at the 12.47 kV bus was provided by the Cooperative.
N-1 contingency analysis was not conducted. The PV site will be tripped offline for outage of the line or for any off-schedule conditions on line.
The inverters are UL 1741 certified.
Recloser parameters and settings that were provided by the Cooperative are shown below in Table 1-1.

Table 1-1
Recloser Parameters

<table>
<thead>
<tr>
<th>Model ID</th>
<th>Amps/Phase</th>
<th>Type</th>
</tr>
</thead>
<tbody>
<tr>
<td>Recloser L$^1$</td>
<td>300</td>
<td>Nova STS 15 F6</td>
</tr>
</tbody>
</table>

Note: (1) WindMil model naming convention

Capacitor parameters and settings that were provided by the Cooperative are shown below in Table 1-2.

Table 1-2
Capacitor Parameters

<table>
<thead>
<tr>
<th>Model ID</th>
<th>kvar/Phase</th>
<th>Control</th>
</tr>
</thead>
<tbody>
<tr>
<td>L300$^1$</td>
<td>100</td>
<td>Fixed ON</td>
</tr>
</tbody>
</table>

Note: (1) WindMil model naming convention
2.1 Steady-State Power Flow

The PV site was analyzed in the interconnection impact study only for the normal system configuration, as served from Circuit L. Table 2-1 presents the daytime maximum and minimum loads that were evaluated.

<table>
<thead>
<tr>
<th>Measured Location</th>
<th>Peak Load (MW)</th>
<th>Peak Power Factor</th>
<th>Min Load (MW)</th>
<th>Min Load Power Factor</th>
</tr>
</thead>
<tbody>
<tr>
<td>Circuit L¹</td>
<td>1.30</td>
<td>97.5%</td>
<td>0.45</td>
<td>97.6%</td>
</tr>
</tbody>
</table>

Note: (1) Load on Circuit L includes the net value with the 500 kW PV site online.

The addition of the Interconnecting Customer project will not cause reverse power flow through the Substation #2.

The study evaluated four scenarios for steady-state load flow:

6. Normal configuration at minimum demand without the 500 kW interconnection online

Normal configuration at minimum demand with the 500 kW interconnection online

Normal configuration at peak demand without the 500 kW interconnection online

Normal configuration at peak demand with the 500 kW interconnection online

Table 2-2 presents the distribution analysis results of these scenarios for the voltage, kW, kvar, and power factor (PF) at the Circuit L, and at the POI, and for the minimum and maximum voltage on Circuit L.

The analysis indicates that the addition of the PV site will not create primary line voltage and capacity violations.
### Table 2-2
Load Flow Analysis Results

<table>
<thead>
<tr>
<th>Scenario</th>
<th>500 kW PV Status</th>
<th>POI</th>
<th>Circuit L</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>V</td>
<td>kW</td>
<td>kvar</td>
</tr>
<tr>
<td>Light Load</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>1</td>
<td>OFF</td>
<td>119.8</td>
<td>-</td>
</tr>
<tr>
<td>2</td>
<td>ON</td>
<td>120.6</td>
<td>-497</td>
</tr>
<tr>
<td>Peak Load</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>3</td>
<td>OFF</td>
<td>119.2</td>
<td>-</td>
</tr>
<tr>
<td>4</td>
<td>ON</td>
<td>120.1</td>
<td>-497</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Scenario</th>
<th>500 kW PV Status</th>
<th>Minimum Voltage</th>
<th>Maximum Voltage</th>
<th>Max Voltage at Inverters</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>V</td>
<td>Location</td>
<td>V</td>
<td>Location</td>
</tr>
<tr>
<td>Light Load</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>1</td>
<td>OFF</td>
<td>119.7</td>
<td>OH3853 (Ph B)</td>
<td>120.0</td>
</tr>
<tr>
<td>2</td>
<td>ON</td>
<td>120.0</td>
<td>OH3853 (Ph B)</td>
<td>120.6</td>
</tr>
<tr>
<td>Peak Load</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>3</td>
<td>OFF</td>
<td>119.2</td>
<td>UG47466 (Ph C)</td>
<td>120.0</td>
</tr>
<tr>
<td>4</td>
<td>ON</td>
<td>119.5</td>
<td>UG1723 (Ph B)</td>
<td>120.1</td>
</tr>
</tbody>
</table>
2.2 Steady-State Voltage Fluctuations

Leidos evaluated a review of the maximum and minimum voltage fluctuation on the system experienced when the PV output drops off, before voltage is regulated back at the substation. The criteria used in the study limits voltage fluctuations to the maximum permissible voltage fluctuation at the borderline of visibility curve from the IEEE 519 Standard. See Figure 2-1 for the curve, which indicates the borderline of visibility is 2.8% starting at one voltage dip per hour. Cooperative criteria is 2% for voltage flicker using this method.

![Figure 2-1. IEEE 519 Flicker Curve](image)

For the analysis, the 500 kW site was reduced to no output from full output at the peak and minimum load day conditions. Voltage fluctuations at each line section were calculated, and the maximum results are shown in Table 2-3 for the primary system.

<table>
<thead>
<tr>
<th>Allowable</th>
<th>Primary System</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Min Load Flicker (%)</td>
<td>Max Load Flicker (%)</td>
</tr>
<tr>
<td>2%</td>
<td>0.73%</td>
<td>0.73%</td>
</tr>
</tbody>
</table>

Leidos, Inc.
The voltage flicker calculated at the project primary POI during peak load and minimum load conditions are 0.73% and 0.73%, respectively. These results do not violate the Cooperative planning criterion flicker limit of 2%.

## 2.3 Grounding and Protection

According to the IEEE 1547-2003, the grounding scheme of the interconnection should not cause over-voltages that exceed the rating of the equipment connected to the EPS and should not disrupt the coordination of the ground fault protection on the EPS.

The study results indicate the Cooperative system is effectively grounded with the project interconnected, based on the IEEE Std C62.92.1™-2016 IEEE Guide for the Application of Neutral Grounding in Electrical Utility Systems standard.

Leidos modeled the 500 kW PV site with a total fault current contribution of 730 amps at 480 V, assuming a fault contribution of 120% of the rated continuous output current. When translated across the distribution transformer to 12.47 kV, the total three-phase fault contribution is 27 amps. Table 2-4 lists the substation source impedance supplied by Cooperative and entered in the WindMil model.

<table>
<thead>
<tr>
<th>Table 2-4</th>
<th>Source Impedance</th>
</tr>
</thead>
<tbody>
<tr>
<td>Source</td>
<td>Nominal Voltage (kV)</td>
</tr>
<tr>
<td>Substation #2 Circuit L</td>
<td>12.47</td>
</tr>
</tbody>
</table>

Note: Impedance in ohms on a 100 MVA base calculated in WindMil model from data provided by the Cooperative.

Table 2-5 summarizes the calculated fault current at the POI’s, and the 12.47 kV substation bus with and without the 500 kW PV site online.

<table>
<thead>
<tr>
<th>Table 2-5</th>
<th>Calculated Fault Current</th>
</tr>
</thead>
<tbody>
<tr>
<td>GEN Status</td>
<td>Fault Location</td>
</tr>
<tr>
<td>OFF</td>
<td>1,280</td>
</tr>
<tr>
<td>ON</td>
<td>1,311</td>
</tr>
<tr>
<td>OFF</td>
<td>2,317</td>
</tr>
<tr>
<td>ON</td>
<td>2,331</td>
</tr>
</tbody>
</table>

From the WindMil short circuit analysis, fault contribution from the site is acceptable, and the existing Cooperative protection scheme is not negatively impacted.

Leidos, Inc.
There is one protective device, Recloser L, between the substation and the POI. The loading on the recloser does not exceed its current rating with the project online. The PV site is fuse protected. Due to fast response curves in Recloser L, a fuse saving scheme is expected for faults at the PV site.

### 2.4 Islanding Evaluation

To analyze the risk of islanding, a four-step analysis was conducted based on the November 2012 Sandia “Suggested Guidelines for Assessment of DER Unintentional Islanding Risk” report. The following steps were conducted:

**Step 1:** “Determine whether the aggregate AC rating of all DER exceeds 2/3 of the minimum feeder loading.” If Yes, proceed to Step 2. If No, there is minimal risk of islanding and analysis is complete.

**Step 2:** “Determine whether QPV + Qload is within 1% of the total aggregate capacitor rating within the island, or alternatively, use real and reactive power flow measurements or simulations at the point at which the island can form to determine whether the feeder power factor is ever higher than 0.99 (lag or lead) at that point for an extended period of time.” If Yes to either evaluation, a detailed islanding analysis should be considered. If No, proceed to Step 3.

**Step 3:** “Determine whether the potential island contains both rotating and inverter-based DER, and the sum of the AC ratings of the rotating DER is more than 25% of the total AC rating of all DER in the potential island.” If Yes, a detailed islanding analysis should be considered. If No, proceed to Step 4.

**Step 4:** “Sort the inverters by manufacturer, sum up the total AC rating of each manufacturer’s product within the potential island, and determine each manufacturer’s percentage of the total DER. If no single manufacturer’s product makes up at least 2/3 of the total DER in the potential island, then further study may be prudent. If the situation is such that more than 2/3 of the total DER is from a single manufacturer, then the risk of unintentional islanding can be considered negligible.”

Each step is evaluated for each potential island in Table 2-6 below. Yes (Y) indicates there is a risk, and No (N) indicates negligible risk.
## Table 2-6
### Risk of Islanding Evaluation

<table>
<thead>
<tr>
<th>Potential Island</th>
<th>Step 1 (Y/N)</th>
<th>Step 2 (Y/N)</th>
<th>Step 3 (Y/N)</th>
<th>Step 4 (Y/N)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Circuit L</td>
<td>Y(^1)</td>
<td>Y(^2)</td>
<td>N(^3)</td>
<td>N(^4)</td>
</tr>
</tbody>
</table>

Notes:

13. Aggregate DER capacity (0.5 MW) is more than 2/3 of the minimum loading (0.45 MW).
14. QPV+Qload could be within the 1% of the total aggregate capacitor rating throughout the day.
15. No rotating DG on Circuit L.
16. More than 2/3 of total DG capacity is from single inverter manufacturer.

The results indicate that the risk of unintentional islanding for the inverters, as served from Circuit L, is probable as the aggregate DG on the feeder exceeds 2/3 of the daytime minimum feeder load and QPV+Qload could be within 1% of the total aggregate capacitor rating throughout the day. The criteria suggesting concern with power factor is directly related to inverters using active islanding incorporating positive feedback on frequency.

Therefore, reclose blocking is required to enable the Cooperative to block reclosing on electronic devices in the event that the inverters may not detect the island and shut off automatically.
SUMMARY AND RECOMMENDATIONS

The study results show the distributed energy resource (DER) system can connect to the Cooperative Electric Power System (EPS) under normal system configuration based on applicable standards and consideration of the required facility upgrades identified in the study. The following summarizes interconnection impact study results:

- There is a potential for reverse power flow through Circuit L during minimum load condition with the project online. Reverse power flow is not expected through the PA Substation #2 during minimum load condition with the project online.
- The PV site will not cause voltage flicker issues on the primary Cooperative distribution system.
- The addition of the PV site is not expected to negatively impact the existing primary steady-state system capacity.
- The analysis results show primary system voltages are within acceptable limits.
- Fault contribution from the project is acceptable.
- The Cooperative primary distribution system is effectively grounded at the PV site POI.
- There is one protective device, Recloser L, between the substation and the point of interconnection (POI). The loading on the recloser does not exceed its current rating with the project online.
- There is a risk of unintentional islanding.

Mitigation Recommendations

Initiate a reclose blocking scheme in Recloser L to prevent it from closing into a potential island and allow time for the PV site to go offline if an extended island does form.