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Cooperative Utility PV Field Manual

Volume III

Operations, Maintenance, and Monitoring

Prepared by:

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Volume I: Business Models and Financing Options
Volume II: Planning, Design, Installation/Interconnection, and Commissioning
Volume III: Operations, Maintenance, and Monitoring

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About this Series

Many co-ops are interested in solar PV, but only a few have deployed utility-scale (1 MW or more) systems because of industry gaps in standardized designs; cost-benefit analysis tools; assistance with finance, procurement, and permitting; and training and best practices for operations and maintenance.

NRECA's Cooperative Utility PV Field Manual is a three-volume series designed to support electric cooperatives as they explore and pursue utility-scale, utility-owned solar PV deployments. It is a product of the Solar Utility Network Deployment Acceleration (SUNDA) project, which is a four-year, multi-state 23-MW solar installation research project and a collaboration among U.S. electric cooperatives, the National Rural Utilities Cooperative Finance Corporation (NRUCFC/CFC), Federated Rural Electric Insurance Exchange, PowerSecure Solar, and the National Rural Electric Cooperative Association (NRECA). The SUNDA project is funded in part by the U.S. Department of Energy's SunShot program. Its overarching goal is to address the barriers to utility-scale, utility-owned solar PV systems faced by co-ops. Participating cooperatives include:

Anza Electric Cooperative	Anza, CA
Appalachian Rural Electric Cooperative	New Market, TN
Brunswick Electric Membership Corporation	Shallotte, NC
CoServ Electric	Corinth, TX
Eau Claire Energy Cooperative	Fall Creek, WI
Great River Energy	Maple Grove, MN
Green Power Electric Membership Corporation/Oglethorpe	Tucker, GA
Kansas Electric Power Corporation	Topeka, KS
Middle Tennessee Electric Membership Corporation	Murfreesboro, TN
North Arkansas Electric Cooperative	Salem, AR
Oneida-Madison Electric Cooperative	Bouckville, NY
Owen Electric Cooperative	Owenton, KY
Pedernales Electric Cooperative	Johnson City, TX
Poudre Valley Rural Electric Association	Fort Collins, CO
Sandhills Utility Services	Fort Bragg, NC
Sussex Rural Electric Cooperative	Sussex, NJ
Tri-State G&T Association	Westminster, CO (serving UT, WY, NM, & NE)
Vermont Electric Cooperative	Johnson, VT

The standardized products for evaluation, implementation, and operation of utility-scale solar PV at co-ops are discussed in detail in this Cooperative Utility PV Field Manual:

- Volume I: Business Models and Financing Options
- Volume II: Planning, Design, Installation/Interconnection, and Commissioning
- Volume III: Operations, Maintenance, and Monitoring

This document is the final project release of Volume III.

NOTICE/DISCLAIMER

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Acknowledgments

This is Volume III of the Cooperative Utility PV Field Manual, prepared for the Solar Utility Network Deployment Acceleration (SUNDA) project. It was prepared by the staff of NRECA's Business & Technologies Strategies (BTS) group, with very significant technical support from Jim Dunlop, P.E., and PowerSecure.

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Executive Summary

This manual contains information on the operations and maintenance (O&M) of utility-scale solar photovoltaic (PV) systems and is intended for use by electric utility personnel. It provides recommendations on typical O&M requirements based on best industry practices and applicable standards. Included in this manual are commissioning and system site checklists and tests that can be used during commissioning and during periodic or annual inspections. This volume also includes a sample Operations and Maintenance Annual Report Template.

The responsibility for O&M should be established in the early stages of project planning. There are several options for operating and maintaining a solar PV plant. The best option will depend on ownership structure, the size and location of the system, costs, and the interests of the host utility. O&M activities can be combined and implemented by one party, or any or all maintenance responsibilities can be assigned to service contractors. This manual briefly discusses several options but is intended for use by electric utility personnel.

An important part of ensuring the long-term safe operation of solar PV plants is to execute a thorough commissioning process, followed by regular periodic testing and an effective maintenance program. Commissioning verifies that the installation has been completed satisfactorily and safely according to the plans and applicable codes. Many of these tasks are also conducted routinely over the system lifetime as part of scheduled maintenance.

Most utility-scale PV systems are remotely monitored and controlled. On-site personnel are required only for regularly scheduled preventative and unplanned maintenance. Monitoring systems are used extensively for solar PV plants to verify performance and operational parameters. This information is used to determine the amount of generation and help identify trends or problems that require further investigation or maintenance. Monitoring also alerts operators of faults or other events affecting system safety. The information may also be used to identify and troubleshoot potential problems and take corrective actions.

Maintenance plans should be developed as early in the project planning phase as possible. Maintenance plans are often revised and refined over time, based on plant operating experience and site-specific requirements. Scheduled maintenance includes periodic inspections, testing, cleaning, calibrations, and other recurring requirements to sustain nominal plant operations. Component installation instructions, such as those accompanying listed inverters and PV modules, usually include recommended precautions and maintenance needs to ensure the safest and best performance. It is strongly recommended that ongoing system monitoring and periodic test results be verified with initial baseline data to detect degrading trends or component failures. Information collected in Attachment E: Energy and Capacity Performance Test can be used to compare estimated and/or baseline versus actual production data.

Simple and nonhazardous maintenance, such as cleaning and grounds maintenance, may be performed by individuals unfamiliar with the details of the system. Advanced maintenance, including troubleshooting and component replacement, generally requires an experienced technician familiar with PV systems and the hazards involved. Qualified technicians should have a complete understanding of the system design, functions, and specifications to safely and effectively test, evaluate, and troubleshoot problems with the system.

Maintenance activities for PV systems involve a number of potential hazards to workers, including electrical and fall hazards. PV system safety involves the safety of both workers and the equipment installed. A safe PV system is typically installed according to the Authority Having Jurisdiction (AHJ), which follows applicable codes and standards, such as those of the National Electric Code (NEC), National Fire Protection Association (NFPA), Occupational Safety and Health Administration (OSHA) and Code of Federal Regulations (CFR), Independent Electrical Contractors (IEC), and UL (Underwriters Laboratories). Worker safety includes considerations for a safe work area, safe use of tools and equipment, safe practices for personnel protection, and awareness of safety hazards and how to avoid them.

Routine maintenance requirements for solar PV plants comprise several major categories, including the following:

- Visual inspections
- PV modules and arrays
- Inverter
- Balance of plant
- Grounds maintenance
- Testing, measurements, and calibration
- Test reports/recordkeeping

Troubleshooting progresses from the system to subsystem to component levels, and involves the following:

- Recognizing a problem
- Observing the symptoms
- Diagnosing the cause
- Taking corrective actions

Extensive details for troubleshooting common problems are provided in inverter manufacturer installation instructions and operating manuals.

At some point, a PV power plant will reach the end of its useful life as a generation asset. A decommissioning procedure then is used to safely disconnect and disable the components for disassembly and disposition for salvage.

1 Introduction

This manual contains information on the operations and maintenance (O&M) of utility-scale solar photovoltaic (PV) systems and is intended for use by electric utility personnel. This is Volume III of the Cooperative Utility PV Field Manual prepared for the Solar Utility Network Deployment Acceleration (SUNDA) project, which is being funded by the U.S. Department of Energy (DOE) SunShot program under contract number DE-EE-0006333. Volume I covers business and financing topics; Volume II covers the planning, design, and installation processes for implementing utility-scale, utility-owned PV projects. This manual was prepared by NRECA's Cooperative Research Network (CRN) with technical support from its partners and consultants.

The information presented covers various O&M considerations, including the following:

- System documentation
- Commissioning
- Plant operations
- Plant maintenance
- Maintenance requirements
- Testing
- Decommissioning

1.1 O&M Goals

The ultimate goal of operating and maintaining a PV system is to optimize its economic value by maximizing the energy production while minimizing costs.

A successful O&M program will include both preventative maintenance and the ability to do reactive maintenance. A third maintenance category—condition-based maintenance—is a balance between the other two categories, made possible through detailed system monitoring and performance estimation algorithms.

O&M programs are not "one size fits all." A program for a 500-kW fixed-tilt community solar array located next to a co-op office (where a technician can walk over to check something out) will have different requirements than a multi-megawatt single-axis tracking system located three hours away.

1.2 Responsibilities

The responsibility for O&M should be established in the early stages of project planning. There are several options for operating and maintaining a solar PV plant. The best option will depend on ownership structure, the size and location of the system, costs, and the interests of the host utility.

Under a power purchase agreement (PPA) and third-party ownership, the owner generally would be responsible for all operations, maintenance, and disposition of the system at end of life. However, in some cases, based on the agreement, a utility may assume some operating responsibilities or maintain land or distribution equipment. When utilities, their partners, or their subsidiaries own the system, the utility may elect to operate and maintain the plant itself or assign O&M responsibilities to a qualified service contractor.

O&M activities can be combined and implemented by one party, or specific maintenance responsibilities can be assigned to separate service contractors. A service contractor could be the system installer, system owner, or a specialized firm. In some cases, co-ops with sufficient personnel and equipment resources may want to assume O&M responsibilities themselves. This approach may prove more flexible and the experience gained may be valuable to the utility in future projects. It is common in the industry to establish a separate contract for installation services and an additional contract for O&M services. Depending on the size of the system, a time and materials agreement providing support as needed may be used to maintain and service the plant. At a minimum, it is recommended that for any plant constructed, a qualified electrical contractor perform a thorough annual inspection of the system to ensure safety and reliability, and perform preventative maintenance services that may be required to maintain certain warranties. Solar inverter preventative maintenance requirements found in the manufacturer-provided installation and maintenance manuals are some of the key major components to which attention should be paid when negotiating an O&M contract. Confirmation of the O&M provider's ability to service the solar inverter is another consideration that should be determined.

Careful consideration should be given to drafting an O&M contract so as to balance the performance of the plant and the cost of the contract to ensure it is aligned with the expected levelized cost of electricity. After the project is commissioned, it is normal for an engineering, procurement, and construction (EPC) contractor to guarantee the performance, and the O&M contractor to confirm system availability and performance. A production guarantee generally is requested in conjunction with an O&M contract and based on agreed-to production data used within the agreement. Because the production data typically used in conjunction with a performance agreement are based on historic weather data, a weather-adjusted index can be used as a true-up for site-specific data if the information is available through installation of sensors that track these weather data.

1.3 Applicable Standards

The installation, operations, and maintenance of utility-scale solar PV plants are covered by a number of existing and evolving standards. These standards include both U.S. and international standards and guidelines, including the National Fire Protection Association (NFPA), the International Code Council (ICC), the International Electrotechnical Commission (IEC), the Institute for Electrical and Electronics Engineers (IEEE), the U.S. Occupational Safety and Health Administration (OSHA), and others.

- National Electrical Code (NEC), NFPA 70
- NFPA 70B
- NFPA 70 E / OSHA
- NFPA 1: Fire Code

1.3.1 IEC 62446

This standard defines minimum documentation, commissioning tests, and inspection criteria for grid-connected PV systems. It is intended to verify the safe and proper operation of PV systems, and serve as a guide for designers, installers, and service personnel. Compliance with IEC 62446 provides buyer assurances and correlates with requirements for the verification of safety for all electrical systems. The requirements of IEC 62446 are covered in two parts: (1) system documentation and (2) verification. Additionally, the standard's annex provides sample verification and testing report templates as well as alternative testing methods. Compliance with this standard is highly recommended and provides the best assurances for the owner's investment.

1.3.1.1 System Documentation

IEC 62446 describes the minimum documentation that shall be provided to the customer following installation of a grid-connected PV system. All PV installations should have adequate documentation, providing details of the system design and all components and materials used in their construction. A complete documentation package for PV systems contains essential information for system approvals, installation, and O&M. Documentation requirements and details may vary for different purposes or types of PV systems.

Proper system documentation helps ensure safe and reliable system operations, and generally is required for the following:

- Plan review and permitting process involving local building officials
- Interconnection approval from the local utility
- System installation and maintenance contractors
- System owners and O&M service providers

IEC 62446 requires the system documentation to include basic system information and specifications; contact information for the system designers and installers; detailed wiring diagrams; component manuals and data sheets; structural design information; and procedures for system operations, maintenance, and safety.

Basic system information should include specifications for the rated system size, nominal and maximum operating voltages, and peak power output (kW DC / kVA AC). The manufacturer, model, and quantity of PV modules, inverters, and other major components should also be specified, and any manufacturer instructions or manuals for major components should also be included with the system documentation. The system information should include details for the project location, ownership, and installation and commissioning dates. The names and contact information for companies and individuals responsible for the design, installation, and O&M should also be listed.

Wiring diagrams are needed to inspect and verify designs, and effectively test and troubleshoot system problems. Wiring diagrams should identify the number, type, model, and manufacturer for PV modules, total number of strings per inverter and number of modules in series per string, the number of strings per combiner box, and combiner box ratings. The location, types, and ratings for all conductors, overcurrent protection devices, disconnecting means, connections, terminations, and protective equipment should be identified and properly labeled. Details related to wire management and labeling of all conductors should be identified clearly. All grounding and bonding equipment and surge suppression devices also should be specified clearly on wiring diagrams.

Documentation should include structural drawings that indicate the materials, physical properties, and configuration of the racking systems, foundations, and other equipment, as applicable. Details should be provided on the number, type, and location of PV module clips or attachments, support structures, inverters, raceways, and other equipment. Special considerations and maintenance requirements generally apply to movable sun-tracking mounts, which may need to be fixed or stowed for cleaning or during a high wind event. Special flexible wiring methods are also used for sun-tracking arrays.

O&M information is an essential part of system documentation. This documentation should include procedures for standard operation practices, safety, monitoring, and methods for safe and proper system operation. It should also cover recommended maintenance with associated frequency, as well as anticipated failures and responses to emergency events. Safety considerations and hazard mitigation should be addressed for all O&M tasks. O&M manuals should also include all equipment warranties, warranty terms, and extended warranty options permitted by the manufacturer, if available; service contracts; spare parts agreements (inverters); and describe the terms required for maintenance to ensure

that all warranties are maintained. Any O&M agreement with a third party should consider warranty terms for components, preventative maintenance required by manufacturers, specifics around non-warranty repairs, and details on how non-scheduled maintenance visits are handled for troubleshooting.
Finally, the documentation should contain all commissioning procedures and initial test results for documentation, as well as proper recordkeeping in case of an equipment failure. It should be updated continually by all subsequent maintenance logs, test results, evaluations, and actions taken. This information is critical for maintenance personnel, which may change periodically, and to maintain effective continuity of O&M over the plant lifetime.

1.3.1.2 Verification

IEC 62446 also describes the inspections and testing to be conducted for the initial or periodic verification of system functions and safety. Initial verifications are conducted for new installations or after alterations to existing installations. Periodic verifications are conducted over the system lifetime as part of regularly scheduled maintenance, helping to ensure that the installation remains in a satisfactory condition for use. Initial and periodic verifications should be conducted by qualified persons with knowledge of PV system operations, including system components and functions, test methods, equipment and evaluation techniques, and the ability to identify and mitigate the safety hazards involved.

Verification of a grid-connected PV system should be conducted in accordance with the applicable standards (IEC 60364-6 or NFPA 70B) that provide the requirements for initial and periodic verification of any electrical installation. Additional details on verification tasks are provided throughout this manual.

2 Commissioning

To help ensure the long-term safe operation of solar PV plants, quality installation and service contractors must execute a thorough commissioning process, followed by regular periodic testing and an effective maintenance program. These practices help ensure safety and performance, and provide essential information required to safely and proficiently monitor, troubleshoot, diagnose, and remedy problems with the system.

Commissioning verifies that the installation has been completed satisfactorily and safely according to the plans and applicable codes. Many of these tasks are also conducted routinely over the system lifetime as part of scheduled maintenance. Key steps of a commissioning procedure include the following:

- Completing final installation details
- Completing a checkout and visual inspections for NEC compliance
- Conducting electrical verification tests
- Completing system documentation and labeling requirements
- Conducting user training
- Performing initial start-up and operations
- Verifying actual output and performance compared to estimated

Commissioning is discussed in more detail in Volume II of this manual. Refer to the attachments for forms that should be completed during the commissioning phase. Some of the tests performed during commissioning are repeated during periodic maintenance. These attachments are also available for download at https://www.cooperative.com/programs-services/bts/sunda-solar/Pages/default.aspx, the SUNDA Website.

- Attachment C: PV DC Insulation Test (Fluke 1587 Insulation Multimeter)
- Attachment D: PV String Test (Seaward Solar PV150)
- Attachment E: Energy and Capacity Performance Test

3 Plant Operations

Solar PV plant operations are considerably less intensive than those of traditional power plants and require few if any on-site operations personnel, depending on their size and complexity. Most utility-scale PV systems are remotely monitored and controlled; on-site presence is usually required only for regularly scheduled preventative and unplanned maintenance.

Plant operational considerations include the following categories:

- Monitoring systems
  - Safety
  - Emergencies and response
  - Troubleshooting
  - Remote operations
  - Supervisory control and data acquisition capabilities
  - Site-specific considerations
  - Fleet monitoring

- Assurance and warranties

3.1 Monitoring Systems

Monitoring systems are used extensively for solar PV plants to verify performance and operational parameters. This information is used to determine the amount of generation and help identify trends or problems that require further investigation or maintenance. Monitoring also alerts operators of faults or other events affecting system safety; the information also may be used to identify and troubleshoot potential problems and take corrective actions. Production-based financial incentives and performance-based PPA contracts will require revenue-grade energy metering that meets American National Standards Institute (ANSI) standards for the system output to be verified accurately.

Monitoring involves the continual repeated measurement and recording of system operational parameters. Monitoring systems include various types of instrumentation, data acquisition, recording, communications, and analysis that provide essential information to system operators. Generally, all types of PV systems are monitored to provide information on system status and the amount of energy produced.

3.1.1 Data Acquisition Systems

Most large-scale PV systems include a full data acquisition system (DAS), usually connected to a web-based site for data monitoring and analysis. The DAS typically gathers data from the inverters as well as from one or more weather stations. Communications with the DAS can be via wired or wireless Internet access or via a dedicated radio frequency (RF) or cellular line.

3.1.1.1 Inverter Monitoring

Because they are a central component of the system, all interactive PV inverters internally monitor key operating parameters for their own functions; much of this information is available through inverter displays or remote communications with the inverter.

PV inverters have two levels of monitoring. First, most inverters have a local control panel where a technician can check real-time operating values and adjust some setpoints. The local display typically has little, if any, historical data outside of daily kWh production.

The inverters also record and display numerous error codes and fault conditions associated with problems in both the DC and AC circuits, such as DC ground faults in the array or out-of-range voltages on the array or utility service. The inverters contain a communications port that allows remote access to the full range of real-time and any stored historical data. The data can be set up for access to real-time measurements; however, 1- to 15-minute averages are more common due to the extent of data that may be collected and transmitted.

Interpreting these codes and messages is a fundamental first step for any troubleshooting activities and can help identify specific problems and appropriate courses of action. Extensive details are provided in inverter manufacturer installation instructions and operating manuals.

The SunSpec Alliance ([https://sunspec.org/)](https://sunspec.org/) is promoting an information exchange standard for PV inverters to make data access more uniform.

3.1.1.2 Subarray / Subsystem Monitoring

In addition to providing basic information on the overall AC and DC status of the inverter (AC voltages and current by phase, AC frequency, DC voltage and current, component temperatures), some inverters also provide additional information on individual DC input circuits. This information can allow more granular analysis to troubleshoot system faults and underperformance. Monitoring down to the individual string level can be accomplished via "communicating combiner boxes." The added value from monitoring at this level needs to be carefully balanced against the extra costs of collecting, transmitting, and storing the data.

Systems incorporating distributed three-phase string inverters provide sub-system monitoring but require additional communications links and a central hub to connect to the main DAS.

Systems incorporating trackers might have additional monitoring channels to monitor tracker motors and tilt sensors.

3.1.1.3 Weather Stations

Weather stations are an important component of system monitoring because the real-time weather data can be used to calculate the predicted performance of the system. It can then be compared with the measured performance to determine the overall system health. The uses of this performance ratio (PR) (measured performance divided by predicted performance) is discussed in a later section of this volume.

A weather station typically consists of the following components:

- Global horizontal pyranometer (measures overall sky radiation) – this must be placed in a horizontal position with a full view of the sky and no shading. This is used to compare the actual solar resource at the site to what was calculated using historical data during the design phase. This procedure is important in validating performance guarantees.
- Plane-of-array pyranometer (measures the irradiance on the array surface) – this should be placed at the same tilt and azimuth angle as the array. For trackers, it should be attached to a tracking surface. This is very useful in troubleshooting system performance because any non-unity PR is a sign of a fault somewhere in the system.
- Ambient temperature (dry bulb-type sensor). Again, this is used to verify performance guarantees.
- Cell temperature – Thermistor or thermocouple is attached to the back of a module, preferably away from the edge of an array because the modules in the middle of a structure tend to operate at a higher temperature than those on the edge.
- Anemometer / wind direction. This should be installed at the same approximate height as the

array. The data are used in some of the more advanced calculations for array output.
- Some systems have optional equipment, such as specialized pyranometers for direct and diffuse irradiance, as well as a rainfall gauge (used to evaluate whether soiling might be causing system losses).

A utility-scale PV system should include at least one full weather station, and it is common practice to use two or more stations for redundancy reasons. Large systems typically include multiple weather stations located in different sections of the array.

Note: ISO 9060 specifies three classes of pyranometers:
- **Secondary Standard (highest precision)**
  Most stringent performance compliance; manufacturer directional response and temperature response validation required; for research-grade measurement applications
- **First Class (good precision)**
  For research-grade and routine measurement applications; exceptions: for solar energy test applications, the manufacturer must validate directional response: ISO-9060, pg. 4, 4.3.2
- **Second Class (minimum precision)**
  For routine purpose measurement applications; performance validation not required

The World Meteorological Organization (WMO) has three similar precision classes:
- High Quality
- Good Quality
- Moderate Quality

It is important to note that the pyranometers need to be recalibrated or replaced at periodic intervals (every couple of years) to provide accurate measurements. Cleaning the pyranometers is also an important task, especially in dusty climates.

Reference cells can be a cost-effective replacement for traditional pyranometers, but can underreport irradiance by 5 percent or more, especially at high incidence angles. Also, spectral mismatch between cell types can lead to additional errors.

3.1.1.4 IEC 61724-1:2017 Monitoring Requirements

The new IEC 61724-1:2017 standard for monitoring of solar systems specifies three precision levels. Utility-scale PV systems should be monitored at the highest precision, which includes quantities for the following:
- In-plane irradiance
- Global horizontal irradiance
- Ambient air temperature
- PV module temperature
- Wind speed
- Wind direction
- Tracker tilt angle (if applicable)
- PV array output voltage (DC)
- PV array output current (DC)
- PV array output power (DC)
- Inverter output voltage (AC)
- Inverter output current (AC)

- Inverter output power (AC)
- Inverter output power factor
- System output voltage (AC)
- System output current (AC)
- System output power (AC)
- System power factor

3.1.2 SCADA Remote Monitoring / Control

Larger utility-scale PV systems often include supervisory control and data acquisition (SCADA) capabilities that allow operators to remotely monitor and control inverters and other equipment functions. Most utility-scale PV inverters include built-in SCADA capabilities, but it may take additional effort to integrate them with a utility's existing SCADA network. A separate communications link is also required, which may add expense.

Utility operators are familiar with the emerging standards, protocols, and benefits associated with remote operations and control for their equipment. The same principles apply to solar PV plants. Remote operations use monitoring data to provide information to responsible personnel. These systems can be automated to trigger alarms or other notifications concerning system events, thus minimizing the costs of dedicating full-time personnel to monitor plant operations.

In Europe, all PV plants larger than 0.25 MW are controlled by the host utility. This practice improves safety and reliability, and helps address utility concerns about faults, outages due to frequency or voltage variations, and other solar system events that can adversely affect distribution equipment, power quality, or impacts on consumer-members.

A SCADA system is able to monitor the real-time efficiency of the PV system and continuously compare it with expectations to assess whether the system is operating optimally. This information can be used to establish the general condition of the system and schedule repair or maintenance activities, such as array cleaning. The purpose of any system-monitoring platform is to provide 24/7 site performance monitoring, allowing remote access to manage any site alarms in the event of production interruption or shortfall. Such occurrences could be due to various reasons, including faulty materials, fuses, workmanship issues, animal infestation, water infiltration, and miscellaneous electrical failures such as faults or trips. The selection of a monitoring system, the inverter set points used, and the integration into a SCADA system should be determined in advance of construction to ensure that all interconnection requirements are met during the design phase.

Transmission interconnected projects must typically adhere to a power factor of 0.95 leading at the point of interconnection, with specific requirements for MVARs and harmonics that may be required for interconnection approval.

3.1.3 Production Metering

In addition to monitoring the AC output of the inverter, a typical PV system has one or more production meters at the point of common connection to the utility distribution or transmission system. This is a calibrated, high accuracy, revenue-grade meter. Although this meter can be used to check on the accuracy of the inverter monitoring, the primary purpose is usually revenue calculation or formal performance reporting. Note: This meter may on the grid side of a step-up transformer, so the power and energy calculations may include transformer losses. In addition to total energy produced, a modern production meter can report on voltages, currents, power factors, and frequency at intervals as short as 1/10th of a second, depending on the communications bandwidth available for the meter.

3.1.4 Site-Specific Conditions

The required level of monitoring at a specific site may depend on the system size, location, and configuration. A smaller system may require a simpler monitoring system because there will be fewer parts and array strings to troubleshoot if something goes wrong. In terms of location, a site located closer to a co-op work-yard may require less intensive monitoring than one located far from the location of the maintenance crew. In the second case, a more intensive monitoring, although more expensive than a simpler solution, may allow remote diagnostics of faults, thus allowing more cost-effective dispatch of repair crews.

A system with a few central inverters may benefit from string-level monitoring at combiner boxes, whereas a system with string inverters may provide detailed enough information through the inverter interfaces to provide sufficient information for efficient troubleshooting.

3.1.5 Fleet Monitoring

Many co-ops start with a single system and employ a simplified monitoring package that allows them to provide cost-effective maintenance. However, as additional systems are added, it may be cost-effective to invest in a “fleet monitoring system” that will look at a collection of distributed systems in a single interface. In addition to combined system performance, this type of software can identify performance issues or faults at individual systems and allow the operator to drill down into a particular system before sending out a crew.

These systems are available from companies such as Locus Energy[1] and SolarAnywhere.[2]

3.2 Assurances and Warranties

It is normal for an O&M contractor to provide a warranty guaranteeing the availability of the PV plant. In some cases, when the O&M contractor is also the EPC contractor, it is possible for the warranty to include targets for the PR or energy yield that would be clearly stated within the O&M agreement. The agreed availability limits are often based on the independently verified energy yield report, but provide some leeway.

The O&M contractor may not be able to provide any performance or equipment assurances (these assurances would fall to the installer or manufacturer) but may be responsible for following through on them.

It is important to define the parameters for the operation and maintenance of a PV project during its lifetime. At a minimum, these parameters must cover the maintenance requirements to ensure compliance with the individual component and EPC contract warranties. If an O&M contractor is being employed to undertake these tasks, it is important that the requirements are stated clearly in the contract, along with when and how often the tasks need to be conducted.

Industry standard terms for system warranties include the following:

[1] Available at: https://www.locusenergy.com/solutions/data-acquisition-software/locusnoc%E2%84%A2.
[2] Available at: https://www.solaranywhere.com/products/solaranywhere-fleetview/.

- PV modules: 10 years for workmanship; 90 percent for a 10-year or 80 percent for a 25-year production warranty provided by the manufacturer
- Inverters: 5 years for most utility platforms, with manufacturer extension options to 20 years
- Racking: 10 to 20 years, depending on the manufacturer
- Miscellaneous components: 1 to 5 years
- PV contractor installation and workmanship warranties: Minimum of 2 years, up to 5 years

4 Plant Maintenance

As with any power generation asset, solar PV systems require regular maintenance to help ensure that the equipment remains in a safe and satisfactory operating condition over its lifetime. Maintenance is essential to verify that performance expectations are met and achieve the highest value for system owners and investors. (Refer to Attachment E for a system Energy and Capacity Performance Test procedure.)

PV systems are generally very reliable by their nature and design. Most systems have few if any moving parts; they require no fuel supply other than sunlight to operate; they produce limited noise, waste, or emissions; and they utilize components with long life expectancies. Consequently, maintenance requirements for solar PV systems are quite different and considerably less intensive than those for conventional fossil-fueled generation equipment.

Although they require low maintenance, PV systems, like any other electrical generators, should be routinely monitored, inspected, and tested to help identify and avoid potential problems that affect system function, performance, or safety. Facilitating maintenance should be considered in the planning and design phases of PV projects, such as including provisions for remote monitoring, testing, and isolation points; and providing safe and convenient access to equipment throughout the PV array field.

Scheduled maintenance includes periodic inspections, testing, cleaning, calibrations, and other recurring requirements to sustain nominal plant operations. Component installation instructions, such as those accompanying listed inverters and PV modules, usually include recommended precautions and maintenance needs to ensure the safest and best performance. As with any good maintenance program, it is strongly recommended that these checklists be included as part of your own PV Field Manual and be tracked and kept in a central, easily accessed location. Centralizing the information electronically will provide easy access. It is strongly recommended that ongoing system monitoring and periodic test results be verified with initial baseline data to detect degrading trends or component failures. (Refer to Attachment E for forms that can be used to compare estimated versus actual production data.)

Unscheduled maintenance typically arises due to a fault, failure, or damage to a system component. Anticipating and planning for possible unscheduled maintenance can help avoid excessive downtime and loss of generation revenue. Maintaining spare parts inventories, service contracts, and warranties can help minimize the impacts of unscheduled maintenance. When unexpected problems do occur, a systematic troubleshooting process should be followed to diagnose the symptoms, identify the problem, and take corrective action. (Refer to Attachments A and B for forms you can use annually to identify problems that can lead to future loss of generation revenue.) The site commissioning and annual system site inspection checklists provide ways to identify problems that could lead to future issues.

Reviewing manufacturer manuals will provide component-level troubleshooting steps (e.g., an inverter commissioning checklist).

4.1 Maintenance Safety

Maintenance safety programs for solar PV plants follow guidelines similar to those for installation and construction tasks, and are addressed in the applicable standards. Simple and nonhazardous maintenance, such as cleaning and grounds maintenance, may be performed by individuals unfamiliar with the details of the system. Advanced maintenance, including troubleshooting and component replacement, generally requires an experienced technician familiar with PV systems and the hazards involved. Qualified technicians should have a complete understanding of the system design, functions, and specifications to safely and effectively test, evaluate, and troubleshoot problems with the system.

Maintenance activities for PV systems involve a number of potential hazards to workers, including electrical and fall hazards. PV system safety involves the safety of both workers and the equipment installed. A safe PV system is installed according to the AHJ, following applicable codes and standards such as those of NEC, NFPA, OSHA, IEC, and UL. Worker safety includes considerations for a safe work area, safe use of tools and equipment, safe practices for personnel protection, and awareness of safety hazards and how to avoid them.

Individuals involved in system maintenance activities should have a broad understanding and working knowledge of safety considerations for PV systems, and the ability to do the following:

- Identify the codes and standards that help ensure the safety of workers and electrical installations
- Understand the various safety hazards associated with PV systems and how to avoid them
- Conduct a hazard assessment and safety training
- Utilize the different types of personal protective equipment (PPE) commonly required for installing and maintaining PV systems
- Identify OSHA standards for electrical safety and the use of ladders, stairways, guardrails, fall protection systems, power tools, and others, as applicable (see Section 4.1.1)

4.1.1 OSHA Regulations

OSHA regulations applicable to PV construction and maintenance activities are covered in the following standards:

- Part 1910 – Occupational Safety and Health Standards
- Part 1926 – Safety and Health Regulations for Construction
- Part 1926 (Subpart-K) – Electrical Safety for Construction

These standards address many safety categories, including the following:

- Hazard assessment and training
- PPE
- Employer and employee responsibilities
- Electrical hazards
- Fall hazards
- Stairways and ladders
- Scaffolding
- Power tools
- Materials handling
- Excavations

OSHA-recognized safety training programs are widely available, and periodic training and recertification should be mandatory for any individuals involved with on-site operations or plant maintenance. Workers must also receive additional training on hazards specific to their jobs. The OSHA 10-Hour Construction Industry Training Program is intended to provide entry-level construction workers with a general awareness of how to recognize and prevent hazards on a construction site. The OSHA 30-Hour

Construction Industry Training Program is intended to provide a variety of training to workers having some safety responsibilities.

4.1.1.1 Employer and Employee Responsibilities

The employer is responsible for designating a competent individual to conduct an assessment of the work area, materials, and equipment to identify all safety hazards before the commencement of any work and throughout construction, alterations, or maintenance. The employer is also responsible for training each affected employee on the recognition and avoidance of present and possible safety hazards, and the proper use and care of PPE.

A hazard assessment checklist should be used to document and describe present or anticipated hazards. The co-op should select the appropriate PPE when all engineering controls and work practices cannot eliminate the hazards.

OSHA requires employers to record and report work-related fatalities, injuries, and illnesses. The employer is often required to produce documents related to safety assessments and training after an incident, and can be held legally liable for worker injuries or deaths. Employers with more than 10 employees must keep OSHA injury and illness records unless otherwise exempt. All employers must report to OSHA any workplace incident that results in a fatality or the hospitalization of three or more employees.

4.1.1.2 Equipment and Hazards

PPE includes protective clothing, gloves, footwear, helmets, goggles, hearing protection, respirators, aprons, or other garments designed to protect workers from injury to the body by impacts, electrical hazards, heat and chemicals, and other job-related safety hazards. PPE is the last measure of control when worker exposure to safety hazards cannot be totally eliminated by feasible work practices or engineering controls. The employer is responsible for assessing the workplace hazards, defining PPE requirements, providing PPE, and providing training to employees on its proper use and care. Employees are responsible for using PPE in accordance with training and manufacturer's instructions, inspecting it daily, and maintaining it in a clean and reliable condition.

4.1.1.3 Fall Hazards

Falls are the leading cause of deaths in the construction industry. Most fatalities occur when employees fall from open-sided floors and through floor openings. Because many PV arrays are installed on rooftops or elevated structures, fall protection is a primary concern. Each employee on a walking/working surface with an unprotected side or edge that is 6 feet (1.8 m) or more above a lower level shall be protected from falling by the use of guardrail systems, safety net systems, or personal fall arrest systems (PFAS).

Fall protection options include guardrails, safety nets, and PFAS. The employer shall provide a training program for each employee who might be exposed to fall hazards. The program shall enable each employee to recognize the hazards of falling and train each employee on the information and procedures to be followed to minimize these hazards, including the following:

- The nature of fall hazards in the work area
- The correct procedures for erecting, maintaining, disassembling, and inspecting the fall protection systems to be used
- The use and operation of guardrail systems, PFAS, safety net systems, warning line systems, safety monitoring systems, controlled access zones, and other protection to be used
- The role of each employee in the safety monitoring system when this system is used

- The limitations on the use of mechanical equipment during the performance of roofing work on low-sloped roofs
- The correct procedures for the handling and storage of equipment and materials, and the erection of overhead protection
- The role of employees in fall protection plans
- The applicable standards

When the possibility exists of an employee being exposed to falling objects, the employer shall have each employee wear a hardhat and implement one of the following measures:

- Erect toe boards, screens, or guardrail systems to prevent objects from falling from higher levels
- Erect a canopy structure
- Barricade and prohibit employees from entering areas in which objects could fall

4.1.1.4 Stairways and Ladders

A stairway or ladder is required at points of access to a construction site where there is a break in elevation of 19 inches or more. At least one point of access must be kept clear. Stair rails and handrails must be able to withstand 200 pounds of force applied horizontally to the rail. Stairways with four or more risers, or higher than 30 inches, must be equipped with at least one handrail and a stair rail along each unprotected side or edge. Permanent or temporary stairways used on construction sites must meet the following requirements:

- Stairways must be installed between 30 and 50 degrees.
- Stairways must have uniform riser height and tread depth, with less than 1/4-inch variation.
- Landings must be at least 30 inches deep and 22 inches wide at every 12 feet or less of vertical rise.
- Unprotected sides of landings must have standard 42-inch guardrail systems.
- Platforms must extend at least 20 inches beyond the outward swing of a door.
- Stairways must be free of projections that may cause injuries or snag clothing.

Ladders must be kept in a safe condition and free from slipping hazards. The areas around the top and bottom of a ladder must be kept clear. Rungs, cleats, and steps must be level and uniformly spaced. Rungs must be spaced 10 to 14 inches apart, and side rails 11-1/2 inches apart. Ladders must be used only for their designated purpose. Double-cleated ladders are required for 25 or more employees or two-way traffic. Non-self-supporting ladders must be positioned at an angle at which the horizontal distance from the top support to the foot of the ladder is one-quarter of the working length of the ladder. When using a portable ladder for access to an upper landing surface, the side rails must extend at least 3 feet above the upper landing surface and be adequately secured at the base and top.

General ladder safety practices include the following:

- Never use ladders beyond their maximum rated load capacity or as a scaffold or for any purpose except their intended use.
- Never tie ladders together to make longer sections or use single-rail ladders.
- Always secure ladders and use them on level and stable surfaces to prevent accidental movement.
- Carry tools in pockets or a belt bag, or raise and lower them by a rope or other lifting means.
- Keep areas around the top and bottom of the ladder clear.
- Use only double-insulated or properly grounded electrical tools on a metal ladder.
- Use ladders with nonconductive side rails when exposed to energized electrical equipment.
- Inspect ladders routinely for damage or defects and immediately mark and remove damaged ladders from service.
- Train employees on the proper procedures to minimize ladder hazards.

4.1.1.5 Electrical Hazards

There are four main electrical hazard categories: electrocution or death due to electrical shock, electrical shock, burns, and falls (caused by shock). The severity of an electrical shock depends on the path, amount, and duration of current through the body. Currents above 10 mA can contract muscles; currents above 75 mA can cause a rapid, ineffective heartbeat. Electrical shock-related injuries include burns, which can cause tissue damage or ignite clothing. Arc flash burns are associated with electrical arcs and explosions. Electrical shock can also cause indirect injuries when workers fall from elevated locations. According to OSHA, about five workers are electrocuted every week, causing 12 percent of young worker workplace deaths.

Electrical accidents are usually caused by a combination of three factors: (1) unsafe equipment and/or installation, (2) workplaces made unsafe by the environment, and (3) unsafe work practices. Minimizing electrical hazards involves wearing the appropriate PPE, including Class E electrical hardhat and electrical hazard (EH)-rated footwear. It also involves safe work practices and the safe use of power tools. Whenever possible, work on electrical systems and equipment should be conducted with the equipment in a de-energized state, using lockout and tagout procedures. If working on energized equipment is unavoidable, the appropriate PPE must be used.

4.1.1.6 Lockout/Tagout

Lockout/Tagout (LOTO) are standards and procedures to protect workers from the unexpected energizing and start-up of machinery and equipment or the release of hazardous energy during service and maintenance activities. The OSHA regulations require employers to have practices and procedures in place to shut down equipment, isolate it from its energy sources, and prevent the release of potentially hazardous energy while maintenance and servicing activities are performed.

“Lockout” refers to the placement of a lockout device on an energy-isolating device in accordance with an established procedure, ensuring that the energy-isolating device and the equipment being controlled cannot be operated until the lockout device is removed. “Tagout” refers to the placement of a tagout device on an energy-isolating device in accordance with an established procedure to indicate that the energy-isolating device and the equipment being controlled is being serviced and may not be operated until the tagout device is removed. The employer must provide policies, procedures, documentation, equipment, training, inspection, and maintenance for LOTO programs and equipment to affected employees.

4.1.1.7 Power Tools

Power tools are extremely hazardous when used improperly. Eye protection is usually recommended and required. All hand and power tools and similar equipment, whether furnished by the employer or the employee, shall be maintained in a safe condition and fitted with guards and safety switches.

General safety precautions for the use of power tools include the following:

- Disconnect tools from the power source when not in use, before servicing and cleaning, and when changing accessories.
- Secure work with clamps or a vise, freeing both hands to operate the tool.
- Keep tools sharp and clean.
- Do not wear loose clothing and jewelry that can become caught in moving parts.
- Do not use electric cords to carry, hoist, or lower tools.
- Keep cords and hoses away from heat, oil, and sharp edges.
- Remove damaged tools and tag them: “Do Not Use.”

4.1.1.8 Fire Safety

The employer is also responsible for developing a fire protection program when required and providing access to firefighting equipment at all times without delay. All firefighting equipment shall be conspicuously located and periodically inspected and maintained. Defective equipment shall be replaced immediately.

OSHA requires that employers select and distribute fire extinguishers based on the classes of anticipated workplace fires as well as the size and degree of the hazard that would affect their use. The fire extinguisher classification is a letter classification that designates the class or classes of fire on which an extinguisher will be effective. The letter classifications are defined as follows:

- A Class A fire means a fire involving ordinary combustible materials, such as paper, wood, cloth, and some rubber and plastic materials.
- A Class B fire means a fire involving flammable or combustible liquids, flammable gases, greases and similar materials, and some rubber and plastic materials.
- A Class C fire means a fire involving energized electrical equipment when safety to the employee requires the use of electrically nonconductive extinguishing media. Some fires may involve a combination of these classifications; extinguishers should have ABC ratings.
- A Class D fire means a fire involving combustible metals such as magnesium, titanium, zirconium, sodium, lithium, and potassium. Class D extinguishers do not have multipurpose ratings.

4.1.1.9 First Aid

Provisions shall be made before beginning the project for prompt medical attention in case of serious injury. First aid supplies shall be easily accessible when required. Employers should determine the need for additional first aid kits at larger worksites. In the absence of reasonably accessible emergency facilities, a person certified in first aid by recognized organizations, such as the American Red Cross, shall be available at the worksite to render first aid. Certain OSHA standards for confined spaces and electrical power transmission and distribution also require training in cardiopulmonary resuscitation (CPR).

4.2 Maintenance Plan

A maintenance plan provides the description, procedure, and schedule for all required service over the lifetime of a PV power plant. The plan identifies the tasks and recommended intervals for scheduled maintenance, and helps ensure that essential maintenance is conducted in a timely and cost-effective manner. Maintenance plans should be developed as early in the project planning phase as possible, as maintenance is a key consideration in establishing the financial and contractual responsibilities for the project. Maintenance plans are often revised and refined over time, based on plant operating experience and site-specific requirements. Much of the information required for a maintenance plan is contained in the equipment manufacturer's literature. It is strongly recommended that a maintenance plan be developed from the equipment literature and customized for each project. Consideration should also be given to certain manufacturer requirements and noted in the owner's manual, so that proper preventative maintenance is completed to ensure that warranties are maintained.

Maintenance records are a critical part of system documentation and should indicate the date and description of the service performed, the persons responsible for conducting the service, and the results and any required follow-up actions. The system documentation should include details of the maintenance plan, procedures, and recordkeeping. Recordkeeping is also important for digital files, such as I-V curve traces, photos of damaged equipment, and thermal/infrared photos. All such files should be tagged to a specific location in the system, possibly using geotagging if that function is available in the camera used. If a few dozen infrared photos are taken of combiner boxes during an annual inspection, it will be very difficult to locate the problem again if the files are not properly labeled.

Maintenance is typically divided into two categories—preventative and reactive—with the primary difference being whether the maintenance visit is scheduled or unscheduled. For detailed system monitoring, a third category can be listed: condition-based maintenance. This category covers maintenance/repair issues identified through remote monitoring that may not need immediate attention. These three maintenance categories are discussed in the sections below.

4.3 Preventative (Scheduled) Maintenance

Preventative (scheduled) maintenance for PV systems should be conducted on a regular and routine basis by qualified persons. The maintenance plan should detail the tasks and frequency of the scheduled maintenance required, which should be based on the component manufacturer's instructions, safety considerations, site factors, and costs. Scheduled maintenance requires advance planning and helps to identify and keep problems from occurring that otherwise can lead to safety hazards and non-optimal plant operations.

Regular scheduled maintenance for PV systems typically includes the following:

- Safety compliance
- Module cleaning (if necessary)
- Pyranometer cleaning and weather station maintenance
- Grounds maintenance
- Visual inspections
- Thermal imaging
- Water infiltration
- Animal infestation

- Site erosion
- Corrosion
- Electrical testing
- Monitoring
- Calibrations
- Troubleshooting
- Repairs
- Reporting

(Refer to Attachment B, the PV Site Inspection Checklist, as a good template to modify based on the specific site and/or components used.)

4.4 Reactive (Unscheduled) Maintenance

Reactive (unscheduled) maintenance involves addressing anomalous events that occur over a system's lifetime. The need for unscheduled maintenance may be identified during routine scheduled maintenance, through evaluation of monitoring data, or in response to failures. Some types of unscheduled maintenance may be considered non-critical, such as blown string fuses that do not result in immediate safety hazards or significant loss of performance. However, other types of emergency events, such as faults, physical damage to equipment, or natural disasters, may present serious safety hazards and significant loss of performance, and warrant immediate actions.

Anticipating and planning for potential unscheduled maintenance can help to minimize the associated costs and downtime, and return the plant to nominal operating status in a timely manner. Unscheduled maintenance tasks commonly include the following:

- Component failures
- Emergencies
- Natural disasters
- Breaches in security

The speed of response is an important consideration for unscheduled maintenance. Appropriate response times should be considered with respect to the magnitude and consequences of the failure. For example, a single blown string fuse in a system containing hundreds of strings may not warrant an immediate action due to negative cost/benefit; it may be addressed later during regularly scheduled maintenance.
If plant maintenance is covered under an O&M contract, agreed-upon response times should be stated clearly. Depending on the type of event that occurs, an indicative response time by the contractor performing the service may be within 24 and 48 hours. If the contractor provided a production guarantee under the O&M contract, it is very likely that the contractor will be motivated to respond quickly to ensure that no energy loss penalties will apply. Uptime guarantees can be purchased from most solar inverter manufacturers, although they are not included in a typical O&M contract with the installer. Under an annual servicing contract, a good recommended approach would be to include a specific, agreed-upon number of prepaid remote troubleshooting hours or unscheduled maintenance visits to the site. This approach can help to minimize unnecessary costs for previously unknown issues while putting a cap on various events that may fall outside of traditional annual inspection or maintenance services.

4.4.1 Component Failures

Component failures are a principal cause for unscheduled maintenance. Such failures may be caused by improper application, installation, or maintenance; environmental or physical damage; or design or manufacturing defects integral to the specific component.

Historically, listed PV modules have experienced very low failure rates due to the construction standards and quality controls exercised by most manufacturers. In the past, most failures were related to inverter systems, although this concern has been largely rectified. Modern inverter designs have demonstrated considerably improved reliability and durability, and many manufacturers offer standard 10-year warranties with options for longer service agreements. This development is largely due to the level of remote monitoring, protections, and fault diagnostic capabilities of modern inverters, which allow service personnel to diagnose and correct problems quickly and effectively. Because the life expectancy for inverters is lower than for PV modules, inverter replacements are usually planned at least once over the system's lifetime.

Except for physical damage incurred during installation or service, many types of component failures may be covered under manufacturer or system warranties. The responsible maintenance personnel should be familiar with the warranty provisions and how they are executed. Careful consideration of the construction and O&M contracts should result in clearly stating and defining how manufacturer defects and warranties will be handled.

4.4.2 Workmanship

Quality workmanship is a key factor in minimizing unscheduled maintenance. Additionally, routine maintenance and compliance with commissioning and testing standards can also help reduce unplanned downtime. Generally, the NEC requires that a qualified person must be responsible for the installation of solar PV systems.

The NEC defines a qualified person as an individual who has knowledge, training, and experience with the installation and operation of electrical systems, and an understanding of and ability to identify and mitigate the hazards involved. This requirement suggests that competent electrical workers should be primarily responsible for installing and maintaining PV systems. However, some experienced journeymen may not have much experience with solar PV systems and their intricacies, and so may benefit from supplemental training. On the other hand, although specialty solar installers may have knowledge of and experience with some of the unique aspects of PV systems, they may lack sufficient training on and experience with electrical codes, accepted safety standards, and electrical construction practices.

Common areas of concern due to poor workmanship can include the following:

- Loose conductor connections and terminations resulting from improper torque and installation procedures
- Improper use or installation of listed equipment
- Inadequate labeling of system components and hazards
- Improper ratings or installation of overcurrent devices
- Improper support and attachments for equipment
- Damage to equipment or wiring methods from improper installation

4.4.3 Emergencies and Natural Disasters

Properly designed and installed PV systems should provide many years of reliable service. However, like any other utility infrastructure, PV systems may experience emergency events and natural disasters. Emergencies could also include breaches in plant security. These events can affect the safety and integrity of the plant and warrant an immediate response to mitigate further damage.

Potential emergency events can arise from internal system problems or faults, or damage from breaches to plant security from external sources, such as vehicles, aircraft, animals, or vandalism. Common natural disasters that may affect or damage PV arrays and components include wind storms (hurricanes and tornadoes), hail storms, lightning, floods, and seismic events. Any emergency events or natural disasters can result in electrical shock or fire hazards and further risks to operators and emergency response personnel.

When it is likely that any of these events will occur, certain precautions and design considerations should be instituted to address or mitigate the concerns and should be covered in insurance policies. First responders and firefighters also need to understand how to identify and mitigate the hazards, and safely disable those portions of the system that affect their operations. The electrical and life safety codes contain specific requirements to improve safety for emergency responders. In addition, appropriate emergency access and egress routes to and from the installation should be developed and provided to employees, as well as local authorities and first responders.

Lightning damage is not an uncommon occurrence in large PV arrays. The effects of lightning damage can vary significantly but can be mitigated through the proper installation and maintenance of grounding and bonding equipment, and additional lightning protection systems, as applicable. In the worst cases, lightning can damage PV modules or sensitive inverter circuits and disable entire subarrays or complete systems. Less severe lightning events can result in damage to PV modules, electrical conductors, and monitoring instrumentation, or activate surge suppression and overcurrent protective devices. When a lightning strike occurs, a careful evaluation should be conducted on any affected parts of the system to identify problems and take corrective actions.

4.4.4 Rapid Shutdown

Rapid shutdown is an emergency response provision that permits the isolation and disablement of specific circuits and components of a PV power plant. It is intended as a safety precaution for first responders, firefighters, and operators who may be called to emergencies at the plant and reduces their risk of exposure to energized electrical conductors.

Rapid shutdown, as currently stated in the 2017 NEC Section 690.12, applies only to PV systems on buildings and does not specifically apply to ground-mounted systems that make up most utility-scale PV systems. This section of the code changed rapidly from 2014 to 2017 and is expected to undergo further changes in the 2020 NEC. If a PV system maintained by a co-op is mounted on the roof of a building, it should follow the appropriate code that was in place when the system was installed, including proper labeling.

4.5 Condition-Based Maintenance

Condition-based maintenance (CBM) lies partway between preventive maintenance and reactive maintenance. CBM is based on the premise that maintenance issues can be identified before actual equipment failures. The maintenance operator can then make an economic decision on when to do the maintenance, rather than waiting for a full failure and then dispatching an emergency truck roll.

An example of CBM in a non-solar application is the use of meter-flicker registers to identify potential intermittent distribution line insulator or vegetation management issues before they become serious enough to cause a full fault. With a PV system, one string or inverter may show a slow degradation or intermittent faults. Depending on the seriousness of these problems, a crew could be dispatched immediately, or the situation could wait until a crew is in the area on a different task.

5 Maintenance Requirements

Maintenance requirement for PV plants generally are simple and considerably less intensive and costly than for conventional generators. Routine maintenance requirements for solar PV plants comprise several major categories, including the following:

- Visual inspections
- PV modules and arrays
- Inverter(s)
- Trackers (if used)
- Balance of plant
- Grounds maintenance
- Testing, measurements, and calibration
- Test reports/recordkeeping

(Refer to Attachment B and the Sample O&M Annual Report template for a good reference source regarding what inspections or reports should include.)

5.1 Visual Inspections

Visual inspections for PV systems and components are conducted initially at the time of commissioning, before installing overcurrent devices, closing disconnects, and energizing conductors. The initial inspection verifies that circuits and components have been designed, specified, and installed to the applicable code requirements, and have appropriate listings, ratings, and required labeling. When appropriate, items of concern noted during visual inspections should be photographed and included with the maintenance reports and system documentation.

Periodic visual inspections should be conducted annually over the lifetimes of most PV systems. Component inspections should follow manufacturer's instructions. Periodic inspections should focus on any damage, degradation, or changes in the condition of equipment noted during previous inspections. Certain areas of concern may require more frequent inspection, whereas others may warrant longer inspection intervals, depending on the prevailing site conditions and their effects on specific components.

A sample PV System Site Inspection Checklist is included in Attachment B. This type of report typically would be completed by qualified service personnel and the findings provided to the owner for recording, along with the system documentation for future reference. The Checklist shows the primary components and systems evaluated during an inspection, and the general areas of concern.

(Refer to Attachment B for good examples of the items that should be verified annually.)

5.2 PV Modules and Arrays

PV modules and arrays should be visually inspected for signs of any physical damage or degradation, including bent frames or broken glass. Modules with fractured or damaged laminates eventually will admit moisture and develop high leakage currents and ground faults, and should be removed from the array and replaced. Most PV modules use tempered glass, which shatters into small pieces when stressed or impacted but will generally remain intact within the frame. Physical damage may be obvious in the case of impacts, but fractured glass in a PV module may not be clearly evident from a distance. Modules should also be inspected for excessive soiling and cleaned as required.

Look for delamination, moisture, or corrosion within modules, particularly near cell busbar connections and the edges of laminates. Discoloration inside of module laminates may be an indicator of a failing edge seal or damage to the back of the module laminate. Degradation of solder bonds at internal cell connections can lead to hot spots and ultimately burn through the back of the module, resulting in module failure, reduced system performance, and creation of a fire hazard. Burned busbars, delaminated modules, and damaged wiring systems are likely to show faults during insulation resistance testing.

5.2.1 PV Module Cleaning

Soiling is the accumulation of dust and dirt on a PV array surface that reduces the amount of solar radiation it collects as well as its electrical output. Soiling effects are highly location dependent and can result from bird droppings, nearby industrial emissions or, most commonly, dust and dirt. Arrays installed near dirt roads or in arid, windy areas are more likely to become soiled quickly and require more frequent cleaning to maintain optimal performance. Conversely, in areas with frequent rainfall, the cleaning of arrays may be required minimally, if at all. In severe cases, soiling can reduce output by 5 percent (typically 1–3 percent), and periodic washing should be required. (See Figure 1.)

Different types of soiling affect performance in different ways. An even coating of dust is less critical than large splotches of soiling, such as those caused by bird droppings.

The costs of cleaning arrays must be considered in light of the improvements in performance achieved. One method of evaluating whether soiling is a performance issue is to wash one string or subarray (or the input to one string inverter) while leaving an adjacent section unwashed. Comparing the power/energy output of the cleaned and control sections can help determine whether it is economical to clean the entire array.

Figure 1. Dedicated Solar Panel Cleaning Equipment

Other considerations for array cleaning operations include the following:

- PV modules are always energized when exposed to sunlight; they cannot be turned off. This is a particular concern for the maintenance crews who wash the arrays when they are energized; they should employ certain PPE and other safety equipment and practices.

- PV arrays should be cleaned during low sunlight conditions and the coolest hours of the day to minimize thermal shock to the modules. However, PV modules are designed and tested to endure extreme environmental conditions, including sudden rain showers during the middle of the day.
- Any debris, such as leaves or other dead vegetation that accumulates around or beneath PV arrays and other equipment, should be inspected for and removed. This debris can cause moisture and corrosion problems and present a fire hazard risk.
- Snow removal is usually not required or recommended for PV arrays. Due to the mounting structure tilt angle and operating temperatures of PV modules during the day, snow will either shed naturally from the array or melt. Mounting structures should be designed with the PV modules installed at an appropriate height to account for expected snow accumulations or drifts.
- Because a relatively small amount of shading can reduce their output significantly, any conditions that contribute to increased shading of PV arrays should be evaluated during routine maintenance. Trees and vegetation present ongoing concerns, and may require trimming and maintenance to prevent array shading. Ground-mounted PV arrays may also be susceptible to shading from shrubs or long grass near them. When visual observations cannot determine the extent of shading problems, a solar shading device can be used.

5.3 Inverters

Scheduled maintenance for inverters should be treated as a critical part of any O&M plan. The maintenance requirements of inverters vary with size, type, and manufacturer. Inverter inspections and maintenance should be conducted in accordance with the manufacturer’s listed product instructions and used as the basis for planning maintenance.

Common maintenance tasks include removing any debris or materials restricting air flow and cooling of inverters, and cleaning or replacement of air filters. When applicable, inverter rooms and cabinets should be inspected for any signs of water, insects, or vermin, and proper access and/or egress. Inverters also provide real-time and accumulated data on system operating parameters and performance; these data typically are available on site and through remote access.

Inverter faults can be a common cause of system downtime for PV systems; however, inverter reliability and service have improved dramatically over the past several years. Inverter faults are most commonly attributed to problems with the array or utility connection—e.g., out-of-limit voltages, frequency, ground faults, and so on. The problem most commonly is not with the inverter itself but in the connected DC or AC circuits.

The annual preventative maintenance for an inverter should, at a minimum, include the following:

- Visually inspecting the cabinet, ventilation system, and exposed surfaces
- Inspecting and replacing air filter elements as recommended by the manufacturer
- Checking corrosion on terminals, cables, and enclosures
- Checking and replacing faulty fuses
- Visually inspecting the sub-assemblies, wiring harnesses, contactors, power supplies, and major components
- Checking condition of AC and DC surge suppressors
- Torqueing of terminals and fasteners in power connections only when needed

- Checking operation of all safety devices (e-stops, door switches)
- Recording operating voltages and current readings on display panels
- Recording all inspections when completed
- Performing all other maintenance listed in the inverter installation manual to maintain the warranty
- Informing the manufacturer and client of any deficiencies

Performing all inverter manufacturers' required preventative maintenance activities is strongly recommended in all cases to ensure that inverter warranties are maintained.

5.4 Balance of Plant

5.4.1 Wiring Methods

Special attention should be paid to exposed wiring methods commonly used for inter-module connections within PV array source circuits. Inspect cables and wiring for nicks and abrasions to insulation, proper support, bending radius, and strain relief. Inspect all conduit and raceways for proper support and grounding, especially at couplings, expansion joints, and transitions from above to underground.

5.4.2 Labeling

Inspections shall also verify proper labeling of the system and components, including all required listings and labels for major components, wiring methods, overcurrent devices, disconnecting means, and terminations. IEC 62446 requires suitably affixed and durable signs and labels to be displayed on site, including the following:

- A single-line wiring diagram
- Inverter settings (as applicable)
- Emergency shutdown procedures

A PV system can last for 20 years or more, which means that the labels used at installation will probably fade and need to be replaced several times during the life of the system.

5.4.3 Junction and Combiner Boxes

Inspect all junction boxes and seals for entry of water, dirt, vermin, or insects, and any consequences. Verify that electrical connections are properly torqued, insulated, and labeled. Verify that conductors have proper strain relief and are free from abrasion.

Look especially for discoloration at terminal connections, which may indicate a faulty connection. Imaging of a combiner box under load with a thermal camera can potentially indicate problems with the box itself, or with the strings attached to the box.

5.4.4 Connections and Terminations

Verify the integrity of connections and terminations for PV modules, inverters, disconnecting means, transformers, and other equipment. Recheck terminal torque specifications at all terminations during the first annual service and recheck for subsequent maintenance, as required. Use thermal imaging cameras to detect hot spots and bad connections.

5.4.5 Overcurrent Devices

Inspect all overcurrent devices for proper ratings and specifications, and note any discoloration or corrosion of fuses or fuse holders.

5.4.6 Disconnecting Means

Inspect all disconnecting means and verify proper operation. Verify that disconnect labels are legible and in place, and inspect disconnect enclosures for water, dirt, or insect infestation.

5.4.7 Grounding and Bonding Equipment

Inspect grounding and bonding conductors for continuity breaks, corrosion, and proper connections.

5.4.8 Structural Attachments

Verify the integrity of foundations, connections, equipment grounding, and module attachments.

5.4.9 Racking Systems

For multi-row tracking systems, inspect motors, wiring, bearings, linkages, and wind-dampening systems. For individual-row trackers, inspect the power source (which may include a PV module and battery), wiring, controller, motor, bearings, and linkages. Note that motors, power supplies, and controllers often have a shorter life than the full system, so these will typically have to be replaced at some point. The tracker manufacturer will provide a complete service manual, which must be followed.

5.4.10 Fencing and Security Systems

Inspect fencing for any breaches or damage. Verify proper operation of any passive or active security measures, such as cameras, motion sensors, or alarms.

5.4.11 Safety Equipment

Verify proper operation of all personnel safety and fire protection equipment. Replace fire extinguishers at designated intervals.

5.5 Testing, Measurements, and Calibration

Testing involves initial and periodic measurements conducted during commissioning and again thereafter for regularly scheduled maintenance. System operators and maintenance personnel use both monitoring and testing data to verify system performance expectations, and help identify and troubleshoot potential problems that require further maintenance. Testing may also be used to verify functionality after components are replaced or problems fixed. At least minimum testing, based on a few key categories, should be performed. NEC Article 690 and equipment manufacturer manuals include other requirements for testing that should be considered, such as the following:

- Commissioning test should include insulation resistance, polarity, voltage, and current
- Performance test should include kW Capacity or kWh under certain irradiance conditions
- Annual test should include kW capacity or kWh under certain irradiance conditions

5.5.1 Test Methods and Procedures

Test methods for solar PV plants include tests and equipment used for any electrical systems as well as some special equipment and methods specifically required for PV system testing. Generally, the integrity of any electrical installation can be verified according to industry standards (IEC 60364-6 or NFPA 70B). Additional standards apply to PV systems.

Testing PV systems involves measurements on all DC and AC circuits. Specific tests include the following:

- Continuity and resistance testing verifies the integrity of grounding and bonding systems, conductors, connections, and other terminations.
- Polarity testing verifies the correct polarity for PV DC circuits and proper terminations for DC utilization equipment.
- Voltage and current testing verifies that PV array and system operating parameters are within specifications.
- Performance testing verifies that system power and energy output are consistent with expectations.
- Insulation resistance testing verifies the integrity of wiring and equipment, and is used to detect degradation and faults to wiring insulation.
- Functional tests verify basic system operating functions, safety systems, and disconnecting means.
- Additional optional testing includes thermal imaging and array I-V measurements.

5.5.2 Test Equipment

For periodic testing, handheld test instruments are commonly used, supplemented with real-time data from inverters and monitoring systems, as applicable. System designers and equipment manufacturers sometimes incorporate permanently installed instruments and test points for safe and easy access. Larger systems often incorporate weather stations to monitor solar radiation, temperatures, and other meteorological conditions.

The Fluke 1587 can be used for insulation testing and the Seaward PV150 to test for open-circuit voltage, short-circuit current, and insulation resistance.

Module Temperature and Irradiance Measurements

Representative PV module and equipment operating temperatures can be measured with permanently attached thermocouples or resistance temperature detectors (RTDs) connected to the monitoring system, or by handheld devices. Solar irradiance can be measured with portable sensors or permanently installed pyranometers or reference cells. The data are important in translating array and system output into a standard reference condition for comparison. Horizontal and plane-of-array sensors are used to predict the irradiance required to determine the estimated energy and/or capacity that should be produced. These sensors are used when completing the PV site energy performance and PV site performance capacity tests, as described in Section 2, Commissioning.

Note that the maximum voltage of the system will determine the specific voltage ratings of equipment needed for worker safety. Many utility PV systems are designed for 1,000 VDC operation or higher and require special test equipment rated for these voltages.

The following test equipment can be used:

- Fluke thermal imagers
- Ti125 thermal camera

- Network cable testers
- Electrical installation test instruments per IEC 62446
- Fluke 1587 megger/multimeter
- AC/DC current probes
- Fluke 376 clamp meter
- Seaward Solar PV150 string checker – Solmetric PV1000 I-V Curve Tester
- Torque wrenches
- Various manufacturers' calibrated torque wrenches
- Visible light camera

5.5.3 Testing Safety

It is imperative for those installing, maintaining, and testing PV systems to follow all applicable safety standards and guidelines. Electrical testing on any PV system should be performed by qualified individuals having knowledge of and experience with electrical systems measurements, the test equipment used, the equipment or systems being tested, and an awareness of the hazards involved.

Testing PV systems involves exposure to energized circuits, high voltages, and electrical shock hazards. Higher-voltage installations can also present electrical burn and arc flash hazards. Electrical hazards can be accentuated when compounded by other hazards, such as working at heights and in difficult locations exposed to the elements. It is strongly recommended that a testing procedure be developed to ensure safety, considering the practices listed below.

Mitigating safety hazards for PV plant O&M activities include the following practices:

- Plan and review all maintenance, testing, safety, and emergency procedures in advance.
- Work on electrical equipment and circuits in a de-energized state, using LOTO procedures.
- Wear appropriate PPE, including protective clothing, nonconductive Class E hardhats, EH-rated foot protection, and safety glasses at all times.
- Use electrically insulated hand tools and properly grounded or double-insulated power tools maintained in good condition.
- Use PFAS whenever working at unprotected heights of 6 feet or more.
- Maintain an orderly work site and cautious approach, and always work with a partner.
- Follow manufacturer's instructions for the safe operation of any test instruments.
- Use tools and test instruments only for their intended purpose, and within their established limits and ratings.
- Properly maintain test instruments and recommended calibrations, and carefully inspect test equipment and leads before each use.

Figure 2. Seaward PV150 Tester

Some manufacturers are now offering multi-function test instruments capable of performing all required IEC 62446 testing. These instruments can interface with wireless temperature and irradiance sensors, and store a few hundred data sets for later download to a computer for processing and analyses. (See Figure 2.)

5.5.3.1 Continuity and Polarity Measurements

The polarity of the PV strings must be verified before connecting within the combiner box. After connection, continuity should be verified. A DMV may be used for both of these tests—voltage measurement for polarity and ohms or continuity setting for a continuity check.

5.5.3.2 PV Source Circuit Measurements

PV source circuits, often called strings, are configured with a number of series-connected PV modules to build the DC voltage to a level that will operate within the inverter maximum power point tracking windows under all expected operating conditions. Depending on individual module voltages, source circuits typically may be configured with anywhere between 8 and 22 PV modules in series. Each source circuit is then terminated at an overcurrent device and bus, where it is combined in parallel with a number of other source circuits to form the PV output circuit. (See Figure 3.)

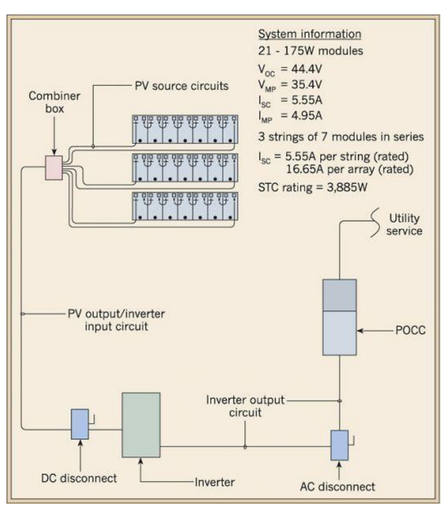


Figure 3. PV Source Circuits, Output Circuits, and Power Source (Source: ECMweb.com)

Listed combiner boxes also incorporate disconnecting means to isolate all of the connected strings. Large utility-scale systems will incorporate a number of source circuit combiner boxes; the PV output circuits ultimately are routed through raceways and other junction boxes, and connected again in parallel at the inverter DC input terminal. Consequently, combiner boxes are often the most convenient point at which to make PV source circuit and output circuit measurements. (See Figure 4.)

Figure 4. Disconnecting Combiner Boxes (Source: SolarBOS.com)

PV source circuit measurements include open-circuit voltage, short-circuit current, and operational tests. PV module response is a function of temperature and irradiance. Please see Volume II for detailed discussions on solar cells and Section 5.5.3.10 (Measurement of Temperature and Irradiance) of this manual for additional information.

5.5.3.3 Open-Circuit Voltage Measurement

These tests are conducted with the source circuit disconnected from inverters and other DC utilization equipment or any other source circuits. Measurements should be compared with expected values. For systems with identical strings, voltages should be within 5 percent for stable irradiance conditions. Reference arrays or translations may be used to normalize results for non-stable temperature or irradiance conditions. Voltages of less than the expected value may indicate one or more modules connected with the wrong polarity, shorted bypass diodes, or faults.

5.5.3.4 PV String Short-Circuit Current Measurement

This testing is conducted with the array disconnected from inverters and other DC utilization equipment, including disconnects and overcurrent devices. Measurements should be compared with expected values. For systems with identical strings, currents should be within 5 percent for stable irradiance conditions.

Reference arrays or translations may be used for non-stable irradiance conditions. A suitable short-circuiting test apparatus shall be used to avoid arcing test leads. Lower-than-expected current measurement may indicate excessive soiling, shading, or module faults.

5.5.3.5 PV String Operational Tests

These tests are performed with the system switched on and in normal operation mode (inverter maximum power point tracking). A suitable clamp-on DC ammeter shall be used and measurements compared with expected values. For systems with identical strings, operating currents should be within 5 percent for stable irradiance conditions. Reference arrays or translations may be used to compare data for non-stable irradiance conditions.

5.5.3.6 Functional Tests

These tests are performed on the following components to ensure correct operation:

- Test switchgear and other control apparatus.
- Test inverters (use manufacturer's procedures).
- Verify inverter automatic shut-down by opening AC disconnect means.
- Verify that inverter resumes normal operation after disconnect means is reclosed (5 minutes).
- Verify the proper operation of disconnecting means and component connection, and disconnection sequences.
- Verify that interactive inverters and AC modules de-energize their output to the utility grid upon loss of grid voltage.
- Verify that interactive inverters automatically reconnect to their output to the grid once the voltage has been restored for at least 5 minutes.
- Verify the proper grid voltage and frequency to operate inverters, including evaluating voltage drop between the inverter AC output and point of connection to the grid.

5.5.3.7 PV Array Insulation Resistance Testing

Insulation testing is used to verify proper installation and integrity, and PV arrays and wiring methods. Insulation resistance testing verifies the integrity of wiring systems and can be used to detect damaged wiring and ground faults in PV system circuits. Insulation resistance testing measures the resistance between ungrounded circuits and ground under the application of high voltage.

Figure 5. Insulation Resistance Tester (Source: Megger.com)

Two methods are defined in the IEC 62446 standard, as follows:

- TEST METHOD 1 – Test between array negative and ground, followed by a test between array positive and ground.
- TEST METHOD 2 – Test between ground and short-circuited array, positive and negative.

Insulation resistance testing measures the resistance from ungrounded circuits to ground and is used to verify and demonstrate the integrity of wiring systems. These tests can be used to identify damage or insulation faults for PV modules and interconnect wiring; locate ground faults; or assess the degradation of array wiring, PV modules, and other system circuits. The insulation tester can be a variable DC power supply or megohmmeter that provides a test voltage of 500 V. (See Figure 5.)

Damage to wiring insulation can be due to improper installation or vermin chewing the wires. Older PV arrays may have significantly higher leakage current than when they were new. Proper insulating gloves and other applicable PPE should be used whenever PV arrays or associated conductive surfaces are touched to protect against electrical shock, especially when ground-fault conditions are indicated.

Insulation resistance for large PV arrays is generally measured at source circuit combiner boxes, where the individual source circuits can be accessed for disconnection and testing. The tests can be conducted dry, or a wetting agent can be sprayed on portions of an array to pinpoint fault locations.

All circuits must be isolated from others for testing; grounding or bonding connections are left connected. Any surge suppression equipment must be removed from the circuits. The positive and negative output leads of the array are connected together and to the positive terminal of the insulation tester. A short-circuiting device is required that is suitable for the source circuit or array maximum current. The negative terminal of the insulation tester is connected to the grounding point for the array or source circuit. A DC test voltage of 500 V then is applied until the capacitive effects subside and readings stabilize. The insulation resistance is measured and recorded in megohms. During the test, it is important to observe and listen to the array for evidence of arcing or flashover. Generally, when a fault exists, resistance measurements will decrease significantly. Tests conducted during system commissioning may be used as a baseline to which later measurements can be compared. See Table 1 for minimum acceptable insulation resistance values.

System Voltage (Voc @ STC × 1.25) VDC	Test Voltage (VDC)	Min. Insulation Resistance (MOhm)
<120	250	0.5
120 – 500	500	1.0
>500	1,000	1.0

Table 1. IEC 62446 – Minimum Acceptable Insulation Resistance Values

Safety precautions should always be followed during insulation resistance testing. Always use insulated rubber gloves with leather protectors when conducting insulation tests. Never connect insulation testers to energized circuits, batteries, or other energy sources. Isolate circuits for testing by opening disconnects and verify that circuits are de-energized by using LOTO procedures before connecting test equipment. The grounded test lead should always be the first to make and last to break any circuit measurement. Never use insulation testers in an explosive environment or around combustible materials. Never use insulation testers on circuits with any electronic equipment, including inverters, charge controllers, instrumentation, or surge suppression equipment, as the application of high-test voltages can damage this equipment. Always ensure that circuits are properly discharged before and after insulation tests, either through the test equipment or externally with a load resistor.

5.5.3.8 Production Measurements

Power and energy measurements for PV plants are essential parameters that establish the value of the system and the revenue produced, and provide a verification of system performance for monitoring and testing purposes. All PV inverters record and provide data on power output and energy production. Additional independent metering is almost always used, especially for larger systems.

Standard utility watt-hour meters are often used to record the energy produced by PV systems over time but can also be used to measure average power over brief intervals. (See Figure 6.) The watt-hour constant (Kh) indicates the watt-hours accumulated per revolution of the meter disk. The smaller the constant, the faster the meter spins for a given amount of power passing through it.

AC power output can be read from inverter displays or by additional power meters, and the array temperatures and solar radiation in the plane of the array can be measured with simple handheld meters without working on energized equipment. AC power verification can be done at any time when the system is operating under steady sunlight conditions, preferably at higher irradiance levels.

Watt-Hour Meters

Traditional watt-hour meters, like those used to meter electricity to a house, use induction principles and a mechanical movement to accumulate and record energy production. Modern electronic watt-hour meters use modern Current Transformers (CTs) and microprocessors with the ability to measure and record many other time-based parameters in addition to energy, including peak power, power factor and reactive power, sags and surges, and other power quality factors.

Watt-hour meters for use at PV inverters frequently include an LCD screen and buttons to allow users to view and analyze the data in many ways.

Figure 6. Watt-Hour Meter

Generally, the maximum AC power output for interactive systems can be related to the rated maximum DC power output rating for the array, adjusted by a number of derating factors. The factors include several types of DC and AC system losses and power conversion efficiencies, which in combination result in AC power output varying between 70 to 85 percent of the PV array DC rating at standard test conditions (STC), depending on temperature.

Estimating the expected AC power output for interactive PV systems begins with getting the DC rating for the PV array and then applying applicable derating factors. The product of the derating factors and DC rating give the estimated system AC power output at a reference solar irradiance and temperature condition. Further translations for temperature and solar radiation provide an estimate for actual operating conditions.

This procedure is valid only for interactive systems with flat-plate crystalline silicon PV arrays (no special bifacial or concentrating modules). The PV array must be oriented in the same direction and unshaded. The inverter must be operating the array at its maximum power point and within prescribed voltage limits. Measurements of solar radiation, temperature, and power output must be done simultaneously for best results, and within ±2 hours of solar noon with incident solar radiation levels 800 W/m^2 or higher, and clear sky conditions.

The expected AC energy production for grid-connected PV systems with no energy storage can be estimated using popular tools such as PVWATTS. PVWATTS first estimates the system AC power output rating at STC based on user-supplied inputs and derating factors. AC power then is estimated on an average hourly basis; energy production is based on the user-selected array tilt, and azimuth angles are selected. PVWATTS then performs an hour-by-hour simulation for a typical year to estimate average power output for each hour and totals the energy production for the entire year. PVWATTS uses an overall DC-to-AC derate factor to determine the rated AC power at STC. Power corrections for PV array operating temperatures are performed for each hour of the year as PVWATTS reads the meteorological data for the location and computes the performance. A power correction of -0.5 percent/°C for crystalline silicon PV modules is used.

The AC energy production (kWh) for grid-connected PV systems is measured over periods of months and years to compare with sizing and long-term performance expectations. Online software tools such as PVWATTS are used to estimate AC energy production based on historical solar radiation and temperature data. Actual solar irradiation (insolation) and array temperatures can be used to more precisely compare with the AC energy produced.

The average daily AC energy production divided by the product of the PV array DC peak power rating at STC and peak sun hours (PSH) is a key indicator of system performance:

AC kWh / (DC kW x PSH) = 0.78 to 0.86 (typical range)

5.5.3.9 I-V Measurements

The current-voltage (I-V) characteristic defines the electrical output of a PV device. It is a graphical representation of all possible current-voltage operating points for a given PV cell, module, or array at a specified level of solar irradiance and cell temperature. Because the product of current and voltage is power, each I-V point also represents a specific power output. The point at which the product of the current and voltage is at maximum is called the maximum power point; it establishes the peak efficiency and output. (See Figure 7.) All utility-interactive inverters incorporate maximum power-tracking functions to operate the array at its maximum power point over all conditions within specified operating voltage ranges.

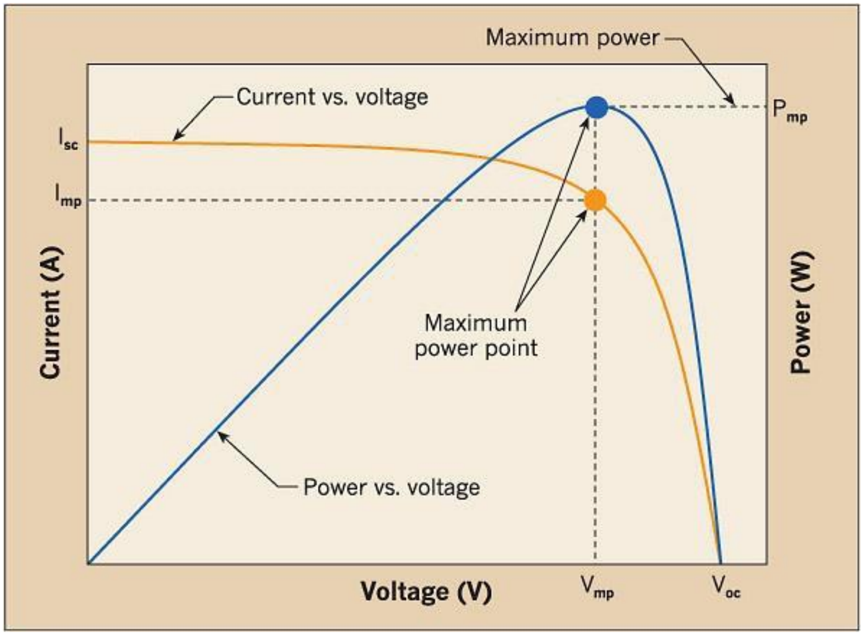


Figure 7. I-V Diagram (Source: ECMweb.com)

Open-circuit voltage (Voc) is the maximum voltage on an I-V curve and is the operating point for a PV device with no connected load. Voc corresponds to an infinite resistance or open-circuit condition and zero current and power output. Open-circuit voltage is independent of cell area, decreases with increasing cell temperature, and is used to determine maximum circuit voltages for PV modules and arrays. For crystalline silicon solar cells, the open-circuit voltage is typically on the order of 0.6 volts at 25°C.

Short-circuit current (Isc) is the maximum current on an I-V curve. Isc corresponds to a zero resistance and short-circuit condition and zero voltage and power output. Short-circuit current is directly proportional to solar irradiance and is used to determine maximum circuit design currents for PV modules and arrays.

The maximum power point (Pmp) of a PV device is the operating point at which the product of current and voltage (power) is at its maximum. *The maximum power voltage (Vmp)* is the corresponding operating voltage at Pmp and is typically 70 to 80 percent of the open-circuit voltage. *The maximum power current (Imp)* is the operating current at Pmp—typically 90 percent of the short-circuit current. The maximum power point is located on the "knee" of the I-V curve and represents the highest efficiency operating point for a PV device under the given conditions of solar irradiance and cell temperature.

Maximum power point tracking (MPPT) refers to the process or electronic equipment used to operate PV devices at their maximum power point under varying conditions; it is integral to interactive inverters and some battery charge controllers to maximize PV array efficiency and energy production.

5.5.3.10 *Measurement of Temperature and Irradiance*

Changes in solar radiation have a direct linear and proportional effect on the current and maximum power output of a PV module or array. Thus, doubling the solar irradiance on the surface of the array doubles the current and maximum power output (assuming constant temperature). Changing irradiance has a smaller effect on voltage, mainly at lower irradiance levels. Because voltage varies little with changing irradiance levels, PV devices are well-suited for battery-charging applications.

PV installers may verify performance of PV systems in the field by measuring the solar irradiance incident on arrays with simple handheld meters and correlating with the actual system power output. For example, if it has been established that the peak output of a PV array is 10 kW under incident radiation levels of 1,000 W/m^2 at normal operating temperatures, then the output of the array should be expected to be around 7 kW if the solar irradiance is 700 W/m,^{2} assuming a constant temperature.

I-V measurements may be used to do the following:

- Determine the true array maximum power point in relation to the operating voltage for inverters, battery systems, and other DC utilization equipment.
- Determine voltage and power degradation rates from baseline measurements and subsequent measurements over time.
- Determine changes in array series and shunt resistance over time.
- Identify array wiring problems or module failures.
- Analyze the effects of shading on electrical output.
- Evaluate losses due to module mismatch and array wiring methods.
- Establish module or array ratings for performance guarantees or warranty purposes.
- Locate open bypass diodes; doing so requires an I-V tracer or DC power supply that reverse biases (applies negative voltage) to the module under test.

I-V curves for PV modules or strings are measured by connecting a variable load to operate the device over its operating range from short-circuit to open-circuit condition. Voltage and current output from the PV device are measured and recorded by a high-speed data acquisition unit at discrete load conditions; the solar irradiance and device temperature are also recorded. The stored data can then be processed and translated to compare the output of various modules or subarrays. A few manufacturers now offer low-cost I-V tracers intended for field technicians and maintenance testing purposes. This equipment typically uses capacitors to load the PV devices and interfaces with a notebook computer for operation, data storage, and processing. (See Figure 8.)

Figure 8. Solmetric PV1000 Tester (Source: Solmetric.com)

5.5.3.11 Thermal Imaging

Electric utility personnel are familiar with the beneficial uses of thermography in their equipment maintenance programs. Thermography can also be a valuable tool for PV power plant maintenance programs and assist in the evaluation of PV arrays, inverters, switchgear, and wiring methods. Thermal imaging can help detect otherwise unnoticed problems early on, which then can be addressed to avoid potentially greater and more costly problems later. Thermography inspections can be conducted initially during commissioning and during periodic maintenance, and can be especially useful in helping to troubleshoot problems suspected within arrays found during a review of monitoring results and string test data. Because thermography uses non-contact means, it is inherently safer to use than other test equipment; measurements and evaluations of the data also can be done quickly for large sections of an array.

Inspections with thermal imaging cameras can detect unusual temperature variations and heating due to faults, poor connections, corrosion, or physical damage. Excessively high temperatures may indicate problems within the modules or array, such as reverse-bias cells, bypass diode failure, solder bond failure, or poor connections. For the best results, PV arrays should be imaged during normal operations at stable irradiance conditions of at least 600 W/m^2, or preferably higher, to ensure that discernable temperature variations can be detected. When accessible, both the front and back sides of PV arrays may be scanned to completely evaluate all of the connections and possible faults. Also, inspection personnel should follow the thermal imaging camera manufacturer’s instructions for the proper use and interpretation of the data.

This testing primarily looks for temperature anomalies within the array and at connections, switchgear, inverters, transformers, and other equipment. Because the average temperature of a PV array will vary quite dramatically over a day due to solar heating, absolute temperatures are less important than the spatial variations from the average. It is at these hot spots where potential problems may exist and warrant further investigations, including visual inspections and insulation resistance and I-V testing. Hot spots due to arcing or corrosion may show visible signs of discoloration. Annotations can be made on a physical layout diagram to identify and record areas of concern detected by the imaging.

PV module temperatures generally should be consistent throughout an individual module during steady irradiance and low wind conditions. However, some variations will occur within properly operating modules, depending on their construction, such as slightly higher temperatures around a junction box and lower temperatures around the edges. Some temperature variations should also be expected for entire arrays as well, due to prevailing wind directions and natural convection.

Bypass diodes typically installed in module junction boxes protect the cell from a reverse-bias condition and potential overheating during partial shading from bird droppings, obstructions, and so on. Under normal conditions, bypass diodes are open and do not conduct current. However, if active, they will dissipate considerable heat, which can be detected with imaging and indicate potential shading concerns.

5.6 Test Reports

Model verification reports are provided in annexes to IEC 62446.

5.7 Grounds Maintenance

Grounds maintenance is a primary and ongoing concern for large PV arrays because they cover such large areas of real estate. Typical grounds maintenance concerns include vegetation control and debris removal, erosion control and drainage, and the management of livestock or wildlife. Any of these factors can contribute to safety hazards or performance loss; the extent to which they apply depends largely on the prevailing site conditions and how the system was designed and installed to minimize grounds maintenance requirements.

Vegetation control is a concern for all PV arrays due to the potential for solar shading, which reduces the output for affected areas of the array. Leaves and other debris can also collect underneath PV arrays and around other electrical equipment, restricting natural ventilation and creating a fire hazard. Where they are enforced, the new fire codes require a non-combustible base beneath ground-mounted PV arrays, such as sand or gravel. However, even with adequate ground covers, weeds likely will surface and must be controlled periodically. Note that the new fire codes also require a minimum 10-foot wide clear access around the perimeter of a ground-mounted PV array for emergency vehicle access. When some type of grass is permitted for use as a ground cover beneath or around the array, the array height and layout should be designed to easily accommodate mowers and other grounds maintenance equipment. In such cases, the costs of a low-maintenance ground cover should be compared with the costs of labor and equipment for ground cover maintenance. Any electrical conductors routed entering the ground should be installed in rigid conduit or otherwise protected from damage due to mowers or weed trimmers. Naturally, vegetation control is a greater concern in wetter climates.

Erosion control and drainage systems are incorporated into the array design but may require periodic maintenance, such as cutting grasses or trimming vegetation used to protect slopes from erosion, clearing drainage canals and culverts, or restoring and shoring up areas washed out during heavy rains. Livestock and wildlife management is a common concern for large ground-mounted PV arrays. Animals can damage PV arrays and wiring systems by rubbing, scratching, or chewing on components or exposed wiring, thus causing safety issues and failures. Barrier fencing will generally protect arrays from most livestock and larger wildlife, and may be electrified as necessary. In populated areas, fencing will usually be required around PV arrays for safety purposes to protect from unauthorized access to the electrical equipment. In very remote areas, fencing may not be required, although the PV arrays and other sensitive components may be installed at sufficient heights to reduce the potential for damage from wildlife. Fencing will not be a deterrent to birds, vermin, burrowing animals, and other wildlife that may nest in and around the arrays or other equipment; these can create erosion problems that ultimately could undermine structural foundations.

6 Troubleshooting

Most PV inverters record and display numerous error codes and fault conditions associated with problems in both the DC and AC circuits, such as DC ground faults in the array or out-of-range voltages on the array or utility service. Interpreting these codes and messages is a fundamental first step for any troubleshooting activities and helps define specific problems and appropriate courses of action. Extensive details for troubleshooting common problems are provided in inverter manufacturer installation instructions and operating manuals.

Troubleshooting progresses from the system to subsystem to component levels, and involves the following:

- Recognizing a problem
- Observing the symptoms
- Diagnosing the cause
- Taking corrective actions

Identification of a problem is a very important first step. For example, if a fuse in a combiner box is found to be open, replacing the fuse will not solve the root cause of the problem. If a circuit breaker is found to be open, however, there is some chance that it was simply turned off during a maintenance visit (for an I-V curve test, for example) and never reset. Looking through performance data to see when the fault first appeared can help resolve these types of questions.

6.1 Performance Ratio

6.1.1 Calculation of Performance Ratio

Performance ratio (PR) is a very useful concept for determining whether a PV system is operating as expected. The PR of a system (or subsystem) is simply the measured output of the system divided by the predicted output of the system. It can be measured either as a ratio of real-time power or a ratio of energy over a specified time. The PR concept can also be applied to the full system or to its subsections.

The predicted output can be calculated using plane-of-array irradiance and cell temperature, either as an instantaneous value or averaged over a full day. If the PR is less than 1.0, it means that some part of the array is not performing adequately.

For example, a PR of 0.75 in a system with four inverters would indicate an inverter failure. A higher but non-unity PR would suggest checking the PR of each inverter/subarray. Once the problem is isolated to a specific inverter, O&M personnel can look at individual source circuits or strings (using multi-meters, I-V curve tracers, or thermal imaging) to determine whether there is a faulty connection, “blown” fuse or circuit breaker, or excessive soiling or shade on part of the array.

If overall system PR matches subsystem PR, the problem is probably soiling or a calibration issue with the pyranometers and/or temperature sensors.

A PR greater than 1.0 is usually an indication of a pyranometer failure. This problem can be alleviated by using redundant weather stations.

6.1.2 Clipping and Curtailment

Most modern PV systems are designed with excess DC capacity, which means there are times during the day when the system output may be limited by the inverter's AC rating. This is a normal function of the system but it must be considered when using daily energy production to calculate PRs. In addition, if a PV system is set to operate at a non-unity power factor, real power may be less than rated power when the system is at or near full inverter rating.

Active curtailment of the system (typically on instructions from the grid operator) will also show up as a non-unity PR. It is important to access this type of information to determine whether a non-unity PR is due to a system problem or normal system operation.

6.2 Ground Faults

A DC ground fault occurs when a positive or negative conductor makes contact with and grounds part of the system—e.g., a grounding conductor, a metal enclosure, the racking system, a PV module frame, and so on. This type of fault can be caused by thermal movement of wires, poor conductor installation (pinched wires, inadequate strain relief), incorrect wiring of modules or combiner boxes, junction boxes filling with water, or improper grounding during installation (grounded DC systems must have only one point of system ground—through the ground fault detection interrupter [GFDI]).

Note that systems installed before 2014 often have only ground-fault-detection and interruption on ungrounded conductors, whereas newer systems detect faults on ungrounded and grounded conductors. Troubleshooting ground faults can be dangerous because of the high voltages involved, so care must be used to employ proper tools and PPE. Multi-meters, insulation resistance testers, and the human eye (version 1.0) are the most common tools used in troubleshooting.

Hard faults (such as an abraded wire rubbing against a junction box) are those easiest to find. Intermittent faults due to wind, heat, or moisture are more difficult to diagnose and may require the use of insulation resistance testing.

6.3 Arc Faults

There are two main types of arc faults:

- Series faults – in which a current-carrying conductor has a high resistance failure across which the current arcs.
- Parallel fault – an inadvertent connection between two current-carrying conductors

Common causes of arc faults include loose wire terminations, inadequate crimps, mismatched male-female quick connectors, or quick connectors not properly plugged together. Arc faults have also been known to occur within PV modules due to cracked cells or faulty soldering during manufacturing.

Although many inverters and combiner boxes now include circuitry to detect an arc fault and then shut down (with a lockout requiring a manual reset), finding arc faults is a difficult process, especially if they are intermittent. The first step toward correcting an arc fault is to look for visual signs of damage—primarily burn marks or melted wires or connectors. If there is no obvious visual damage, the best technique is to divide and conquer—identify the inverter or combiner box in which the fault occurred and then isolate individual circuits to isolate the source of the fault. Thermal imaging may identify "hot spots" not visible by simple visual inspection.

It is important to remember that arc faults occur most often at higher current levels, so it is important to use proper PPE and safety procedures when troubleshooting.

6.4 Grid Interactions

At times, a system fault may occur because of interactions with the electric grid. Inverters on the distribution system are required to follow IEEE 1547, with trips based on specific voltage and frequency conditions. The latest revision of IEEE 1547 requires “ride-through” of certain voltage and frequency excursions. It is important to ensure that the firmware on the inverter has the proper settings, especially after any firmware updates, which may have inadvertently set all values to the manufacturer defaults.

Non-critical voltage excursions on the distribution system may also cause problems because the “trip voltage” is typically measured at the inverter and not the point of connection to the distribution system. An undersized cable between the inverter and distribution grid may operate correctly during normal voltages but could cause erroneous voltage readings when the grid is operating near the edges of the normal voltage window. Voltage excursions caused by interactions with other distributed energy resources or grid voltage adjustment equipment may also cause nuisance trips of an inverter.

PV systems that are connected to the bulk electric system are required to follow NERC PRC-024-2, Generator Frequency and Voltage Protective Relay Settings; these settings are slightly different than the IEEE 1547 requirements. This can be found at:
http://www.nerc.com/pa/Stand/Reliability%20Standards/PRC-024-2.pdf.

7 Decommissioning

At some point, a PV power plant will reach the end of its useful life as a generation asset. The specific point in time may be determined by the lapse of product warranties or level of failure rates, payments on outstanding debt or the return on investment, or simply when maintaining the system in a safe and satisfactory condition is no longer practical or cost-effective. In some cases, the end of life may be predefined as the point at which the PV system output has declined below a certain percentage of the initial performance. A decommissioning procedure then is used to safely disconnect and disable the components for disassembly and disposition for salvage.

Regardless of how the end of life is determined, system owners must make initial decisions about the final disposition of the system and equipment, and how the system will be decommissioned. End-of-life matters typically are the responsibility of the system users/owners, unless specifically covered by a third-party owner or O&M contract. The following questions should be addressed in the initial project development and financial planning phases:

- What is the anticipated project lifetime?
- What is the estimated salvage value of the equipment?
- Who will be responsible for decommissioning and salvage operations?
- What are the decommissioning and salvage costs?
- Will the site be restored or will an upgraded PV plant constructed at the site?

7.1 Factors Affecting Lifetime

Numerous factors can affect the durability and lifetime of PV systems and components, including the quality of the components and materials, workmanship, and maintenance. A site's environmental conditions and extreme weather events also affect durability and lifetime. Generally, as with any type of electrical equipment, higher temperatures and humidity levels accelerate degradation. Properly following manufacturer's installation instructions and recommendations for preventative maintenance can help maximize the life of PV systems and their components.

PV systems installed today are expected to have useful lifetimes of 25 to 30 years. This range is based primarily on the estimated service life of crystalline silicon PV modules, which are the most expensive components in a system and the basis for system lifetime and financial estimates. Generally, most module manufacturers offer warranties of 20 to 25 years to maintain no more than a 20 percent loss of initial rated power output. This range is consistent with measured PV module and system degradation rates of 0.5 to 1 percent per year. Emerging and less-proven thin-film PV module technologies may have shorter life expectancies than traditional crystalline silicon modules and should be considered accordingly in financing schedules. Other components may have a shorter service life and require one or more replacements over the system's lifetime. For example, inverters typically are warrantied for at least 10 years, but many manufacturers offer extended warranties for as long as 20 years. Other equipment, including wiring methods, electrical components, and racking systems, are expected to have a service life at least equal to the PV module lifetimes.

PV Module Reliability

Generally, quality PV module manufacturers not only meet the minimum requirements covered in the product listing/safety standards (UL 1703 or IEC 61730) but also subject samples of their product to additional design qualification testing to help ensure achievement of reliability and warranty periods. Design qualification testing subjects PV modules to accelerated mechanical, electrical, and environmental testing. The applicable standards are IEC 61215 Crystalline Silicon Terrestrial Photovoltaic (PV) Modules – Design Qualification and Type Approval; or IEC 61646 Thin-Film Terrestrial Photovoltaic (PV) Modules – Design Qualification and Type Approval. Modules achieving these certifications are permitted to advertise and label their products accordingly. Although these tests provide only an indication of reliability, many manufacturers now expose new products to other forms of accelerated life and environmental testing to more accurately simulate real application circumstances. However, no abbreviated testing program or certification can absolutely guarantee that a PV module will last for 25+ years under any conditions.

Because PV systems are installed outdoors and in direct sunlight, they suffer the full effects of nature and extreme weather events. Ultimately, most PV modules fail due to a breach of the encapsulation and lamination that provides electrical insulation and protects the solar cells and circuits from moisture. Such breaches can occur naturally over many years or very quickly through physical damage to the module frame or fracture of the glass covering. Delamination allows moisture ingress into the module, leading to corrosion and overheating of cell interconnections. The integrity of module junction boxes, bypass diodes, and external connectors may also be compromised over time, leading to reduced performance and failures. Thermal imaging often is used to inspect for module-level faults.

7.2 Determining Salvage Value

Although there is no simple formula to determine salvage value and costs, knowledge of the contributing factors can be used to make better estimates. Salvage value is primarily established based on the value of recycling metals and other raw materials used in the construction and components. Valuable salvage items include electrical conductors, raceways, switchgear, racking components, PV modules, and inverters. Nearly all PV system components and construction materials are recyclable, and many module manufacturers offer recycling services. Depending on the condition of the materials and their value, salvage value for PV systems can be as high as 10 to 20 percent of the initial equipment costs.

The net salvage value is determined by the difference between salvage value and costs. In most cases, the salvage value and costs will be offsetting and will not be a decisive factor for initial financial planning. When equitable, some salvage contractors may provide their services in exchange for ownership of the salvaged equipment.

Salvage costs include the labor, equipment, and transportation costs required for salvage operations. Although similar tasks used for construction apply to salvage operations in reverse, less skilled workers can be employed for deconstruction. Because the same level of care and planning is not required, labor required for salvage operations should be calculated as a smaller percentage than that required for the initial installation. Demolition and other heavy equipment may be required; the preparation and transportation of equipment to recycling centers is also a factor. Other materials, like concrete rubble or fill, may have no appreciable value unless they can be recycled locally. When no recycle value exists, costs may be associated with the disposal of certain materials in landfills.

Some components may be considered toxic or hazardous waste, and additional salvage costs may apply to them. Example of hazardous wastes may include heavy metals or toxic substances used in the construction of some thin-film PV modules (e.g., cadmium telluride [CdTe]), transformers, or storage batteries, when applicable. Refer to the Material Safety Data Sheets (MSDS) for specific components to determine the hazards and recycling procedures recommended by the manufacturer.

8 Conclusion

Routine maintenance is an ongoing concern for utility-scale PV systems and helps to ensure safe and effective system operations over their lifetimes. In general, due to their simplicity and minimal moving parts, O&M requirements for solar PV power plants are considerably less intensive than for other forms of electricity generation. However, maintenance is still an important factor in maximizing the performance and lifetime of both the plant and its components.

9 References

- Installation standards (NFPA, IEC)
- O&M standards (IEEE, IEC)
- IEC 62446: Grid-Connected Photovoltaic Systems – Minimum Requirements for System Documentation, Commissioning Tests and Inspection. Available at: http://www.iec.ch.
- Product Safety and Reliability Standards (UL 1703, UL 1741, IEC 61215, IEC 62646)
- SolarPro articles – SolarPro is a free industry magazine that often contains technical articles on the latest equipment, design techniques, and O&M requires. Available at: http://solarprofessional.com/.

10 Appendix

- Attachment A: PV Site Commissioning Checklist
- Attachment B: PV System Site Inspection Checklist
- Attachment C: PV DC Insulation Test (Fluke 1587 Insulation Multimeter)
- Attachment D: PV String Test (Seaward Solar PV150)
- Attachment E: Energy and Capacity Performance Test
- Attachment F: Sample Report – Operations and Maintenance Annual Report Template

Attachment A

PV Solar Site Commissioning Checklist

Power Secure
Solar Energy Solutions

Site Name:			
System Designation:		Inverter Type:	
Commissioned Date:		Inverter SN:	

	Safety	Check	Note	Photo
1	AC & DC disconnects are in the open position.			
2	All combiner fuses holders are open.			
3	No voltage is present at either the AC or DC Disconnects.			
4	If disconnects are not in sight during testing use LOTO.			
	Plan Review			
5	Review "As Built" Plan changes.			
6	Equipment locations, model #s and specifications as per Plan.			
7	OCP amperage and voltage as per Plan.			
8	Conduit sizes and materials as per Plan.			
9	Current carrying conductor size and type as per Plan.			
10	Grounding and Bonding Conductor - Size and Type as per Plan.			
11	Equipment and Conduits Grounded or Bonded as per Plan.			
	Inverter Output and AC Disconnects			
12	Net Metered OCP is installed in the correct panel location and is properly labeled.			
13	All Code and PSS required labels are on the AC disconnect cover.			
14	AC disconnect terminations have been torqued and labeled.			
15	The AC disconnect is wired as per Plan.			
16	The AC disconnect is securely attached and neat.			
	Inverter			
17	The Inverter is properly sited and secured with all manufacture's required clearances.			
18	Isolation transformer terminations are as per manufacture's instructions and torqued.			
19	AC & DC terminations are as per manufacture's instructions, torqued and labeled.			
20	Visually inspect the inverter enclosure for signs of damage in shipping or siting and that all doors open freely.			
21	Visually inspect the interior of the inverter and check for loose sub-assemblies and connections.			
22	Inverter ventilation fan moves freely and filters are in-place.			
23	All Code and PSS required labels are on the inverter doors.			
24	Bender RCMS Unit and combiner power supply is properly installed as per PSS's installation instructions.			

	PV Output to Inverter	Check	Note	Photo
25	Junction box terminations are torqued, cables are labeled and properly grounded.			
26	Cables routed through conduit bodies are neat and not damaging Cable insulation.			
27	Expansion joints are installed as per manufacture's instructions and per Plans.			
28	Conduit runs are per Plan, neat, supported properly and the conduit fittings are tight.			
29	The DC disconnect is securely attached and neat.			
30	The DC disconnect is wired as per manufacture's and PSS's instructions.			
31	DC disconnect terminations have been torqued and labeled.			
32	All Code and PSS required labels are on the DC disconnect cover.			
	PV Array			
33	Racking is complete and installed as per the manufacturer's instructions.			
34	The module's nameplate specification are as per the Plans.			
35	Modules are installed and mounted as per the manufacture's instructions.			
36	There are no damaged or misaligned modules in the array.			
37	PV connectors are installed as per the manufacture's instructions and fully engaged.			
38	PV Wiring is properly supported, neat and there are no point where the insulation could become damaged.			
39	Array combiners are terminated as per Plans and are neat.			
40	Combiner terminations have been torqued and labeled.			
41	All Code and PSS required labels are on the combiner cover.			
42	Review the String Open Circuit Voltage and Short Circuit Amperage Test Results.			
43	Review DC Array Megger Test results.			
	Inverter Start-up			
44	Close the inverter AC disconnects and power-up the inverter AC side, record the line voltages.			
45	Turn on the inverter and test all safety interlocks (door switches, Bender, Anti-Islanding, etc).			
46	Close all combiner fuse holders and any manual disconnects			
47	Confirm DC voltage and polarity at the DC disconnect and at the inverter.			
48	Confirm the AC and DC Surge Protection is operational.			
49	Close the inverter DC disconnects and put the inverter on line.			
50	Confirm inverter display voltages and check inverter output.			
51	Complete Performance Testing			

	Monitoring Equipment	Check	Note	Photo
52	Weather Station equipment is installed and wired as per the manufacture's instructions.			
53	Power Monitoring equipment is installed and wired as per the manufacture's instructions.			
54	Monitoiring from the inverter and the Gateway is complete and operational.			
	Inspection Notes			

Readings			
Irradiance - Watt/m2:		Ambient Temp. 0C.:	
Readings from the Inverter Display		Field Measured Readings	
AC Line Voltage		AC Line Voltage	
Phase A to Grd:		Phase A to Grd:	
Phase B to Grd:		Phase B to Grd:	
Phase C to Grd:		Phase C to Grd:	
AC Line Current		AC Line Current	
Phase A:		Phase A:	
Phase B:		Phase B:	
Phase C:		Phase C:	
AC Line KW		AC Line KW	
DC Input Voltage:		DC Input Voltage:	
DC Input Current:		DC Input Current:	
		Control Power:	

Commissioner	

Attachment B

PV Solar Site
Inspection Checklist

Site Name:			
System Designation:		Type of Inspection:	
Inspection Date:		Commissioned Date:	

	Walk the Array - visually checking for the following:	Check	Note	Resolved	Photo
1	Broken, burnt or delaminated modules				
2	Shading or excessive soiling of the modules				
3	Proper grounding of non-current carrying metal parts				
4	PV Source wiring connectors, conductors, conduit and supports				
5	Racking and ballast systems for loose or missing parts				
6	Rodent, bird or insect infestation problems				
7	Roof damage in and around the roof mount array				
8	Erosion in and around the ground mount array				
8	Corrosion or damage to the Combiner Box enclosure				
9	Required NEC Code labeling is installed on the Combiner Box				
10	Corrosion or overheating at Combiner Box terminations				
11	Damage to the Combiner Box conductor insulation				
12	Damage to PV Output conductors, raceways and supports				
13	Proper grounding and weather sealing of PV Output Raceways				
14	Damage to PV Output conductors at accessible locations				
15	Damage to the perimeter fence, gate and cameras				
	Visual inspect the Disconnecting Means for the following:				
16	Corrosion or damage to the enclosure				
16	Corrosion or overheating at the terminations				
17	Signs of damage to the conductor insulation				
18	Signs of corrosion and damage to the enclosure				
19	Required NEC Code labeling is installed on the enclosure				
	Additional Inspections				
20	Perform inverter inspection and complete the checklist				
21	Run String Tests and complete test report				
22	Thermal Scan field terminations and re-torque as needed				
23	Thermal Scan Disconnecting Means and complete report				
24	Megger Test the DC Array and complete the report				
25	Perform any manufacturer warranty required inspections				
26	Confirm monitoring data for accuracy.				
	Reporting				**Check**
28	Inform manufacturers and client of all deficiencies and recommendations.				
29	Provide an inspection report to the client within thirty days of the inspection				

PV Solar Site
Inspection Checklist

1	General site conditions:
2	Array Inspection notes:
3	Thermal Scan notes:
4	Inverter Inspection notes:
5	Megger Test notes:
6	Additional notes:

Solar Tech:	

Attachment C

DC INSULATION TEST

Megger Checks

(Fluke 1587)

Site Name:

Inspection Date: Commissioned Date:

Inverter Designation	Circuit Designation	Test Voltage	Ungrounded to Ground	Grounded to Ground	Ungrounded to Grounded
		1000V	MΩ	MΩ	MΩ

Solar Tech:

Attachment D

COMBINER BOX

PV String Testing

(Seaward Solar PV150)

Site Name:	
Array Designation:	Combiner Box #s:
Inspection Date:	Commissioned Date:

Combiner Box -					
String #	Voltage	Amperage	Irradiance	Cell Temp.	Time
	Voc (VDC)	Isc (ADC)	Irr (W/m2)	Tp (C)	HH:MM:SS
1					
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21					
22					
23					
24					

Attachment E

PV Solar Site

Energy Performance Test

Site Name:			
System Designation:		Type of Inspection:	
Inspection Date:		Commissioned Date:	

Readings between 9:00 and 15:00 Total of Draker 15 Minute Time Weighted Averages)

Module Manufacturer	
Model Number	

Normal Operating Cell Temperature NOCT (800W/m^2 and 45.7°C)

Power Output @ NOCT = (P_{NOTC})		Watts
Power Temp. Coef. = (P_{MPP})		%/°C
Total Number of Modules		Modules

System Peak DC Energy = (E_{MAX})

(E_{MAX}) = (P_{NOTC}) x (# of Mod) x 6 Hrs./1000 = - KWh

System De-rating Factor = (K_S)

Module mismatch	0.97
Inverter efficiency	0.96
Module soiling	1.00
Module nameplate tolerance	0.99
Wiring losses	0.98
Shading	1.00
System availability	1.00
Tacking efficiency	1.00
Age	1.00

(K_S)= the product of all of the above factors = 0.90

Actual Irradiance during the test		Wh/m^2	**> 4.2 KWh/m^2** or 700W/m^2
Actual Module Temperature during the test		°C	

Irradiance Factor = (K_I)

(K_I) = Actual Insolation / 4.8 KWh/m^2 = 0

Module Cell Temperature Facture = (K_T)

(K_T) = 1 + (C_T /100 x (T_C - T_{NOCT})) = 1

Expected System Energy = (E_E)

(E_E) = (E_{MAX}) x (K_I) x (K_T) x (K_S) = - KWh

Actual System Energy Output KWh

Percentage of Expected #DIV/0! **>95% to Pass**

Attachment F

Annual Solar PV Report

2015

Site Name

Address

City, State

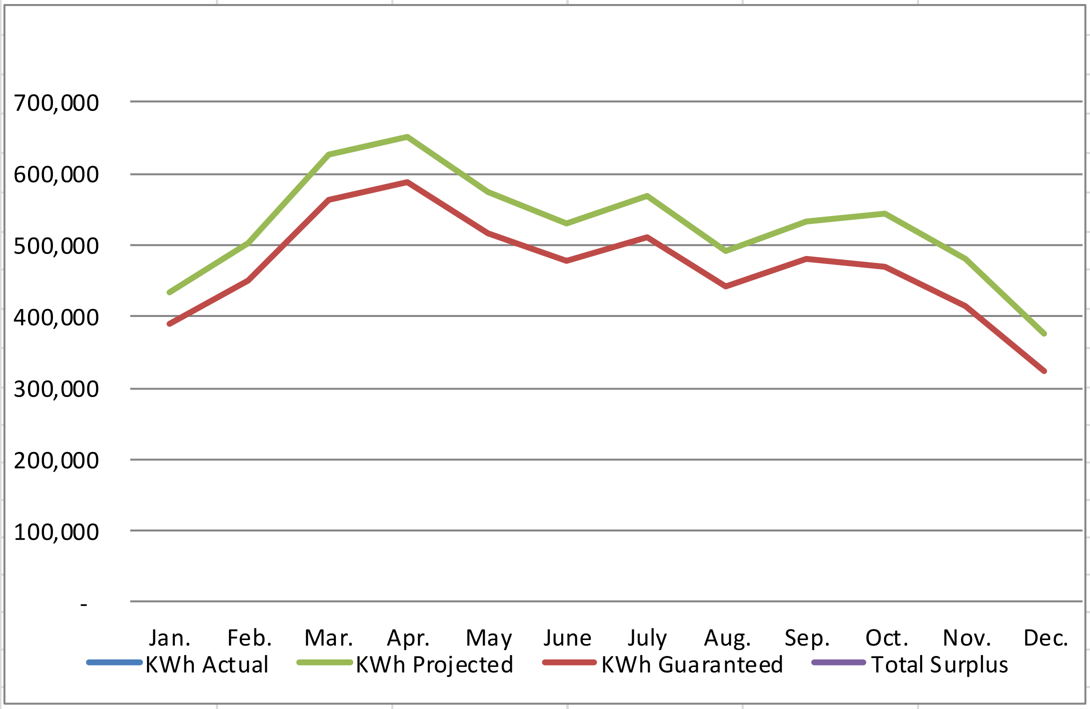
This Report was prepared by Power Secure Solar

Author: System Service Manager

Date

Name, Account Manager

2015 Production



Commissioned: 10/16/2012

Month	Actual	Projected	Guaranteed	Surplus	Total
January	0	433722	390363	0	0
February	0	501740	451582	0	0
March	0	625534	563001	0	0
April	0	652106	586916	0	0
May	0	575023	517539	0	0
June	0	530565	477526	0	0
July	0	567404	510681	0	0
August	0	491200	442095	0	0
September	0	532751	479493	0	0
October	0	544866	468218	0	0
November	0	481020	413353	0	0
December	0	377257	324187	0	0

Actual kWh Production - YTD	-
Projected Annual kWh Production	**6,313,189**
Guaranteed Annual kWh Production	**5,624,954**
Total Generated kWh Surplus	-

Maintenance History

Date	Actions	Resolved

Commissioned: 10/16/2012	Jan.	Feb.	Mar,	Apr.	May	June	July	Aug	Sept	Oct.	Nov.	Dec.	Total			
PVSYST. E-Grid - KWH	430995	498586	621602	648007	571408	527230	563837	488112	529402	544162	480398	376769	6280508	Enter Month E_Grid		
	0.068624	0.079386	0.098973	0.103177	0.090981	0.083947	0.089776	0.077719	0.084293	0.086643	0.07649	0.05999	%			
Projected Production	435901	504261	628678	655383	577912	533232	570255	493668	535428	550356	485866	381058	6352000	Contract	Enter Annual Projected	
2012										550356	485866	381058	1417281			
2013	435901	504261	628678	655383	577912	533232	570255	493668	535428	547604	483437	379153	6344914			
2014	433722	501740	625534	652106	575023	530565	567404	491200	532751	544866	481020	377257	6257000			
													6226000			
Production Guarantee	392325	453851	565830	589866	520139	479925	513248	444317	481902	495338	437295	342964	5717000	0.910	@.5%	Enter Annual Guarantee
2012										495338	437295	342964	1275597			
2013	392325	453851	565830	589866	520139	479925	513248	444317	481902	470571	415430	325816	5653220			
2014	390363	451582	563001	586916	517539	477526	510681	442095	479493	468218	413353	324187	5624954			
2015													0			
2016													0			

Current Year	Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sep.	Oct.	Nov.	Dec.
KWh Actual												
KWh Projected	433722	501740	625534	652106	575023	530565	567404	491200	532751	544866	481020	377257
KWh Guaranteed	390363	451582	563001	586916	517539	477526	510681	442095	479493	468,218	413,353	324,187
KWh Generation Surplus												
Total Surplus	-	-	-	-	-	-	-	-	-	-	-	-

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Anza Electric Cooperative, Inc.
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